Cross Border Exploration between UK and Norway: Comparisons, Contracts and Collaborations

27-28 November 2017

Corporate Supporters

Conference Sponsors

CONTENTS PAGE

Cross Border Exploratiob between UK and Norway: Comparisons, Contracts and Collaborations

27-28 November 2017

Welcome to the Cross Border Exploration between UK & Norway - Comparisons, Contrasts and Collaborations Conference, which has been organised by the Petroleum Group of the Geological Society. Here you will find the programme and the abstracts for all the talks and poster presentations over the three days of the conference. Also, information on the meeting can be found using the Petroleum Group Conference App, downloadable free from all app stores.

The organising committee would like to thank the corporate sponsors BP and Statoil, and conference sponsors Aker BP and PGS for their support of this event. The Petroleum Group and the Geological Society would not be able to continue to organise events of this scale without industry sponsorship.

The objective of the conference is to enhance technical understanding of the status of key plays on each side of the border, to establish points of similarity and difference in both activity and success, and to highlight new opportunities. The conference brings together explorationists from UK, Norway and other European countries to discuss recent discoveries either side of the border, where new plays in one country have yet to be exploited in the other, differences in exploration performance, impact of regulatory and fiscal frameworks, differences in organisation of competences and adoption in technology.

Our thanks go to the Geological Society staff for their help and organisation, particularly Sarah Woodcock for her hard work. We would like to thank all contributors for their abstracts, presentations and posters. Finally, a very big thank you to all conference attendees; we hope that you will find the meeting interesting and enjoyable, with plenty of opportunities to exchange ideas and learn something new.

Convenors:
Gro Haatvedt
Kitty Hall
Ian Wilson

Reference:
Abstracts of 'Cross Border Exploration between UK and Norway: Comparisons, Contracts and Collaborations', *Petroleum Group of the Geological Society, Burlington House,* 27-28 November 2017.

PROGRAMME

CONFERENCE PROGRAMME

Day One	
09.00	**Registration**
09.20	**Welcome**
	Session One: Introduction & Overview
09.30	**Keynote: A regulatory perspective on cross-border exploration and collaboration** **Nick Richardson, *Oil and Gas Authority***
10.00	**Keynote: NPD Overview** **Torgeir Stordal, *Norwegian Petroleum Directorate***
10.30	**Enable globally competitive Exploration in a mature basin** Ole J. Askim, *Aker BP*
10.50	**Does the petroleum geology change across the UK-Norway border?** Dave Quirk, *Manx Geological Survey / University of Manchester*
11.10	**Break** **Session Two: One Basin**
11.40	**Play Based Exploration without borders – a springboard for future material success in the North Sea.** Matthew Allen, *Dana Petroleum*
12.00	**One North Sea fairway analysis; revealing new ideas through data integration at various scales** Paul Roberts, *Statoil*
12.20	**How information from bordering countries will be incorporated to arrive at a new set of publicly available Geological Maps for the UK Continental Shelf** Henk Kombrink, *LR Reservoir Service*
12.40	**The North Sea Toolkit: A comprehensive regional exploration tool** Joya Tetreault, *Exploro AS*
13.00	**Lunch**
	Session Three: Source Rocks
14.00	**Norway – UK Cross Border Petroleum Systems Analysis – The Challenge of Creating a Quality Controlled and Comparable Data Base** Olaf Thießen, *Statoil*
14.20	**One North Sea framework for source rock characterization and prediction** Aart-Jan van Wijngaarden, *Statoil*
14.40	**One North Sea petroleum system gap analysis and a way towards identifying under-explored charge areas** Øyvind Steen, *Statoil*
15.10	**Cross-border paleogeographic perspectives on Lower Jurassic source rocks in the North Sea** Sander Houben, *TNO*
15.20	**Break** **Session Four: Palaeozoic to Permian**
15.50	**Palaeozoic petroleum potential of the five countries area, Southern-Central North Sea, introduction to the PALAEO-FIVE project** Thomas van Hoof, *TNO*
16.10	**Deep frontier plays in post-Variscan intra-platform basins on the East Shetland Platform and southern Norwegian-Danish Basin: a comparative tectono-stratigraphic framework** Stefano Patruno/Verena Lampart, *PGS*

16.30	**Specific Play Knowledge of Zechstein Carbonate Reservoirs Applied across the Northern and Southern Permian Basins** Susie Daniels, *Geospatial Research Ltd*
16.50	**Extending the basal Rotliegend Play across the Germany/Netherlands median line** Simon Lunn, *Hansa Hydrocarbons*
17.10	**Finish**
17.10-19.00	**Wine Reception** **(Sponsored by PGS)**
19:00	**Conference Dinner, The Cavendish Hotel, London** **Speaker - Erling Kvadsheim, *Norwegian Oil and Gas Association***

Day Two

08.30	**Registration**
08.50	**Welcome**
	Session Five: Basin Statistics and Case Studies
09.00	**Keynote: Why explore when already discovered hydrocarbons are well above carbon budgets** **Jarand Rystad, *Rystad Energy***
09.30	**Keynote: A decade of Exploration Performance in the Mature UK and Norwegian North Sea** **Keith Myers, *Westwood Global Energy Group***
10.00	**The Rona Ridge Basement Play : Key learning and implications for future exploration of the UKCS/NCS** Bob Trice, *Hurricane*
10.10	**Langfjellet Discovery: The key to commercialize stranded discoveries** Lena K. Øvrebø, *Aker BP*
10.30	**The Alvheim Area Exploration phase – from gas satellite to oil hub** Hans C. Rønnevik, *Lundin Norway AS*
10.50	**Break** **Session Six: Triassic to Jurassic 1**
11.20	**Identification of cross-border Triassic distributive fluvial systems of the Central North Sea utilising self-organising map predicted facies association distributions** Ewan Gray, *University of Aberdeen*
11.40	**The implications of pore fluid pressure on the reservoir quality of the Skagerrak Formation across the Central North Sea, UK & Norway** Stephan Stricker, *University of Durham*
12.00	**Characterisation and correlation of Triassic Mudstone Members in the Central North Sea: a non-trivial, cross-border challenge** Stuart G. Archer, *Maersk*
12.20	**Heavy Mineral Stratigraphy and Provenance of Triassic Sediments of the UK and Norwegian Central North Sea** Iain Greig, *University of Aberdeen*
12.40	**Lunch**
	Session Seven: Triassic to Jurassic 2
13.50	**Biostratigraphy and Paleo environmental Reconstruction of the Triassic of the Central North Sea** Roger Burgess, *University of Aberdeen*
14.10	**A cross border tectonostratigraphic perspective on the Middle Jurassic to Early Cretaceous rifting in the Southern North Sea** Roel Verreussel, *TNO*

14.30	**Syn-rift exploration challenges in the northern North Sea** Christopher A-L. Jackson, *Imperial College London*
14.50	**Sand-rich, syn-rift, hyperpycnal plays in Norway and the UK** John Cater & John Cummings, *RPS*
15.10	**Break** **Session Eight: Late Jurassic to Tertiary**
15.40	**An holistic approach to exploration of the Upper Jurassic play in the southern Viking Graben** Thomas Harris Uist, *Wintershall Norge AS*
16.00	**Derisking examples and opportunities of the Palaeocene North Sea (UK-Norway) injectites play through reliable pre-stack broadband attributes** Noémie Pernin, *PGS*
16.20	**Chasing the median line Eocene injectite play in the North Sea Viking Graben** Nick Terrell, *Azinor Catayst Limited*
16.40	**Cross-border collaboration on source to sink systems for the Oligocene – Pliocene succession in DK, UK & Norway** Erik S Rasmussen, *Geological Survey of Denmark and Greenland*
17.00	Closing Remarks
	Finish

POSTER PROGRAMME

Correlatability of the Dolomite Stringers in the Haugesund and Farsund Formations of the Norwegian Central Graben: A Case Study in Unconventional Shales using Borehole Image (BHI) Data Meriem Bertouche, *Badley Ashton*
Unconventional wisdom - why shale plays are more conventional than thought Markus Hoppe, *Badley Ashton*
Greater North Sea Basin Area – Exploratory Oil Family Analysis Julian Moore, *Applied Petroleum Technology UK*
Structure and Prospectivity of the Outer Møre Basin with Links to the Faroe-Shetland Basin John Millett, *VBPR*
The search without borders for North Sea basement structures, and their impact on petroleum systems Andy McGrandle, *Big Anomaly*
Glacial effects: A key trigger of the North Sea Petroleum System Ebbe H. Kartz, *Aker BP*

Oral Presentation Abstracts (Presentation order)

Monday 27th November 2017
Session One: Introduction & Overview

KEYNOTE: A Regulatory Perspective on Cross-Border Exploration & Production

Nick Richardson
Oil & Gas Authority

The Oil & Gas Authority was recently established as the UK's regulatory body to maximise the value of recovery of petroleum from the UK continental shelf, with a role to regulate, influence and promote activity across the UK. The OGA, and its predecessor organisations, have worked and continue to work closely with the nations on its borders to facilitate exploration, development, production and transportation activities for the mutual benefit of all parties. The OGA has regular meetings through a number of fora with cross-border regulatory counterparts to discuss subsurface technical issues, drilling and development activity, internal plans, data storage and publication, best practice, and many other issues in order to strengthen cooperation and enhance activity. It is important to understand that cross-border collaboration takes place against a backdrop of differing legal frameworks, tax regimes, regulatory standards, state participation, culture and other factors which can result in imperfect harmonisation of activities and plans. With regard to subsurface understanding, many companies active across the North Sea have taken a borderless approach to their exploration activities, however there are also a number of ongoing initiatives between regulators to align data management activities and subsurface studies with the aim of stimulating exploration across NW Europe.

NOTES:

Enable globally competitive Exploration in a mature basin

Ole J. Askim, Odd Arne Sandstad, Øyvind Kjøsnes, Øivind Runde
Aker BP ASA

The industry is currently renegotiating contracts and tuning the activities – these are the "easy" wins in a downturn. However, deeper changes may be required to create a substantially more competitive offshore E&P industry. The changes that are required demand both a cultural change and a change of mindset of the organizations and the people. We may need to change the business model, remove waste, reduce cost and compress resource progression timeline.

Successful exploration on Norwegian Continental Shelf (NCS) requires utilization of current infrastructure – clustering of discoveries to create new hubs, and investment in data and technology. Furthermore we need to improve the pace we develop resources and how.

High quality data investment in an early phase supports opportunity detection and early maturation of the subsurface, enabling rapid progression of resources by constraining uncertainties.

Continuing to improve drilling performance, provides large opportunity in reducing finding and appraisal cost. Current performance in drilling was not believed possible only a few years ago. From earlier industry average of 84 m/d, we have recorded 285 m/d on the last operated exploration well in 2016. In 2017, we drilled one English mile in 24 hours and expect further improvements to be achieved. Reduced well cost is a key enabler for globally cost competitive exploration and development projects.

Successful exploration does not provide value without being able to lift the discovered resources in globally competitive development projects. A part of this is to make the right discoveries and the right commercial deals (i.e. alignment of ownership) to progress projects. Even so, changes that are more radical may be required to progress our discovered resources below a break-even cost of $35/bbl. New project delivery models and digitalization might be some of these enablers – changing the way we have been working until now.

Exploration activities at Aker BP have progressively changed towards the outlined way of working. One example is in the Vana Sub-basin, which is a prominent core area for Aker BP encompassing of the Alvheim, Bøyla and Volund Fields. The Alvheim Field has a small portion extending into the UK sector, and comprises several hydrocarbon accumulations known as Kameleon, East Kameleon, Boa and Kneler. Aker BP also operates several of the surrounding exploration licenses, representing significant upside potential for existing infrastructure. Small volumes are good tie-in candidates in the area, like the 2017 exploration wells on Hyrokkin and Volund West prospects. The annual APA (Application for Predefined Areas) scheme ensures exploration of mature areas and has been crucial to the activity level on the NCS. The APA process has been important to secure additional production licenses in the Alvheim area with the potential for replacing and growing the resource base for the company.

The reservoir of the Alvheim Field is the upper part of the deep-marine deposited Paleocene Heimdal Formation with a high net-to-gross ratio of more than 85%. The main sediments present in the Rogaland Group are siliciclastic with minor coal, tuff, volcanoclastic, marls and reworked carbonate sediments sourced from the East Shetland Platform. Coarser sediments were reworked and redeposited during three major episodes of sea level fall in this period (Brunstad et al., 2009). The main coarse clastic units of the Rogaland Group are Ty, Heimdal and Hermod formation sandstones interbedded with Lista and Sele shales. All producing fields within Alvheim area are producing from these formations. The formations display high net-to-gross ratios of more than 85%, but compartmentalization is observed. With improved seismic imaging and infill drilling in the Alvheim area, better description of injectites were established and may represent additional potential in the area.

Aligned with Aker BP's exploration strategy, a large PGS Broadband survey was acquired and reprocessed in the Greater Alvheim Area (DN15M01). The work was initiated by the company to get one consistent state-of-the-art dataset that cover the Greater Alvheim Area. With one dataset covering the producing fields and the surrounding prospective areas, it is possible to improve the understanding of the link between seismic character and reservoir properties significantly.

Due to a heterogeneous overburden, the DN15M01 survey was reprocessed using a state-of-the-art pre-stack depth migration (PSDM) processing flow including Full Waveform Inversion (FWI), TTI Velocity Model Building (dual azimuth) and a TTI Q Kirchhoff Migration method. This was done to improve the imaging, and to facilitate consistency in representation of geology over a large area. With high resolution and accurate velocity models, Least Squares Migration (LSM) provides an opportunity to further enhance resolution and compensate for acquisition and propagation effects.

The resulting seismic data now exhibits improved accuracy in calibrating several producing fields and provides more reliability in evaluating surrounding prospects. The data has been mined for opportunities with different approaches to AVO, spectral decomposition, spectral (thin bed) inversion and Bayesian Inversion (among other things). The high-quality seismic data solution becomes more cost effective, robust for imaging and amplitude evaluation when applied regionally. With future discoveries, the likelihood of waiting on seismic work programs is reduced significantly.

Making oil discoveries in a mature basin does not provide high value barrels alone. Piecing together enhanced opportunity detection and front end loaded appraisal, significant reduction in drilling cost and new ways of executing projects that targets waste - provides access to high value barrels even with small discoveries. We are on a path to deliver projects on a compressed timeline and a cost that is globally competitive.

NOTES:

Does the petroleum geology change across the UK-Norway border?

Dave Quirk
Manx Geological Survey / University of Manchester

It is not only language and tax that change across the UK-Norway median line. Historical statistics show there is a large difference in exploration effort, focus and results when wells and discoveries are separated into target plays. The differences include discovery rate (historical chance of success), average discovery size, play richness (mmboe/1000km^2), discovery yield (mmboe/km^2), maturity stage, TD depth and minimum commercial field size. The reasons are partly political but significant differences in geological interpretation are also involved. Even when it comes to stratigraphic nomenclature, there are important distinctions in whether reservoirs, seals and reservoir-seal pairs are grouped together or are separated. And it is worth noting that few of us have worked in integrated UKNOCS teams.

We present key metrics on the spectrum of plays, from Palaeozoic to Cenozoic, which straddle the UK-Norway border and then go on to identify the plays which appear to have significant remaining potential when one side is compared to the other.

NOTES:

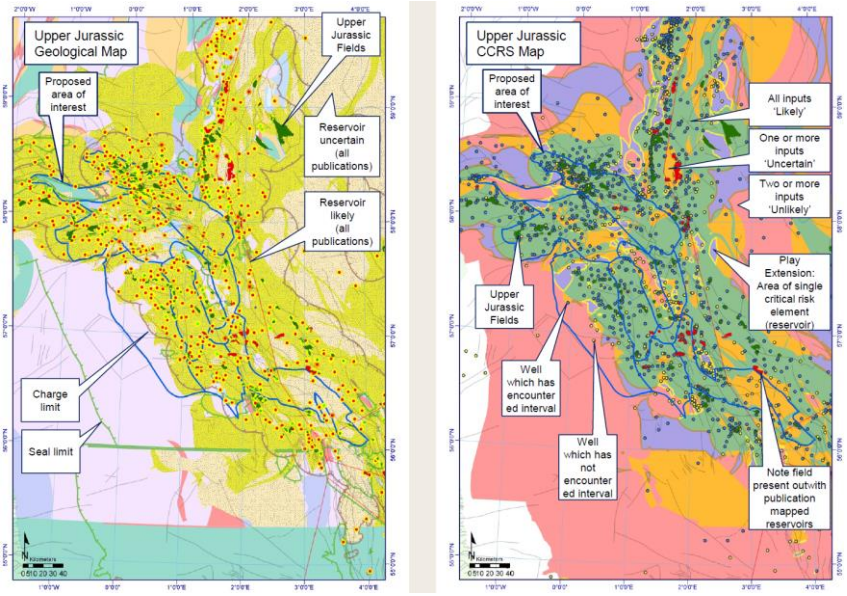
Monday 27th November 2017
Session Two: One Basin

Play Based Exploration without borders – a springboard for future material success in the North Sea

Matthew Allen and Richard Hodgkinson
Dana Petroleum Limited, King's Close, 62, Huntly Street, Aberdeen, AB10 1RS

Play based exploration (PBE) forms a core technical element within the exploration pyramid, a cornerstone of the exploration process within the oil and gas industry. Although many companies have their own methods for play fairway mapping through construction of Common Risk Segment (CRS) and Combined Common Risk Segment (CCRS) maps, the underlying philosophy of incorporating aspects of reservoir, charge and seal is fairly constant. Such PBE methods have been variously described for frontier, underexplored or new basins where data is sparse or not available. However, within the more mature basin context, such as the North Sea, where data is widely available for many thousands of wells, decades of scientific publications exist and is supported by virtually continuous 2D and 3D seismic data such frontier methods are found to be lacking or deemed by some not to be necessary. Essentially, to create CRS and CCRS maps in such an environment, there is a need to reliably assimilate numerous large, diverse and complex datasets for which no reliable method has been presented or published. We present one such approach that has been specifically derived for mature basin working. It is a scalable methodology from which an evaluation of all major plays within the North Sea has been achieved, unbiased, and across-borders. With diligent data management during the assimilation phase, the results are entirely auditable, and reveal hitherto unseen correlations between datasets. This method ultimately yields a robust framework within the GIS environment from which one can assess the remaining exploration potential across the basin. Furthermore, with conditioning and integration of well, field and lead/prospect data, an assessment of the statistics for the basin can be readily defined, ultimately leading to exploration well failure analysis, Chance of Success (COS) and Yet-to-Find (YTF) statements.

This presentation addresses the rationale and methodology employed in the evaluation of the principle plays within the North Sea. Additionally, it is proposed that with the selection and assimilation of regional publication data from a variety of sources, that may include well and field data, in a flexible but consistent and repeatable manner, it can be demonstrated that this method has "evergreen" capability and be used to systematically evaluate opportunities and screen for potential future success.



NOTES:

One North Sea fairway analysis; revealing new ideas through data integration at various scales

Paul Roberts[1], Øyvind Steen[2], Oliver Jordan[1]
[1]*Statoil UK Ltd, London*
[2]*Statoil ASA, Stavanger*

The North Sea has many well-established prolific plays in pre-rift, syn-rift and post-rift successions, predominantly charged from mature Upper Jurassic source rock kitchens. The downward trend of annual discovered resources has cast doubt on the North Sea's exploration future, and yet new appraised discoveries such as Johan Sverdrup have been revealed in recent times. Furthermore, new sub-plays of this petroleum system and new unproven plays with alternative source rocks are still being tested, although often with higher perceived pre-drill subsurface risk (Pg) and/or lower volume potential. Mixed results in the past decade indicate the challenges ahead for the industry in this mature, well-explored basin. However, there is room for new optimism. In what may be termed '4th wave basin exploration', it is likely that new approaches and technologies are probably required to unleash further discoveries, and we believe a One North Sea fairway analysis is a central ingredient to future success.

Our traditional interpretation of fairways is often challenged by the integration of old and new data, patch-work data coverage, cross-border access, and established views of play models. But modern advances of computer power mean that large scale regional evaluations of giant seismic and well datasets are now possible. In order to broaden the opportunities and replenish exploration portfolio, Statoil recently took the initiative to integrate detailed prospect-scale interpretation within a broader 'One North Sea'-scale framework. Efforts have been made to improve access to regional subsurface datasets i.e. to use big data where country borders disappear. Examples of this include: a living horizon-fault framework and data extracted from wells, such as lithofacies, source rock geochemistry, hydrocarbon indicators, temperature, pressure, as well as many more.

The analysis of large datasets allows for the interpretation of One North Sea fairway maps that honor detailed observations made at the prospect scale, and lets interpreters zoom-in and zoom-out to improve their conceptual understanding of hydrocarbon plays. Analogue benchmarking helps the interpreter calibrate the most likely success scenario and visualize the upside. Models of source rock maturity, hydrocarbon expulsion and migration, well shows, gas chimneys, and seismic DHI's are integrated onto regional fairway maps in an effort to follow the hydrocarbons from kitchens to traps. By zooming out, we may see that interpretations made in one part of the basin may reveal opportunities in another. Furthermore, it allows us to compare, and ponder whether the next big opportunity may be on the terrace on the flank of the established basin, or due to fairway plumbing, hydrocarbon focusing and lateral migration, may be many kilometers from the source in what was previously thought to be a migration shadow. New 3D seismic shoots, and reprocessing of seismic data in sweet-spots highlighted by regional work, are key for opening up new sub-plays or unproven plays.

Examples of the Upper Jurassic – Paleocene fairways will be shown to highlight the advantage of a common framework and a zoom-in/zoom-out approach.

NOTES:

How information from bordering countries will be incorporated to arrive at a new set of publicly available Geological Maps for the UK Continental Shelf

Henk Kombrink[1], Moira Belka[1], Claire Imrie[1], David Mudge[2], Steve Spencer[1], Tim Walmsley[1], Joanne Bagguley[3] and Malcolm Gall[3]

[1] *LR Reservoir Services*

[2] *David Mudge Consulting*

[3] *Oil & Gas Authority*

Lloyd's Register (LR) is engaged in a three-year contract with the Oil & Gas Authority to produce a suite of publicly available, regional geological maps for the entire UKCS. The public release is intended to facilitate regional studies, highlight underexplored areas and provide a set of maps and data that enable companies to incorporate the products into their own exploration evaluations. This paper briefly addresses how the maps are being compiled as well as how they will be integrated with information from neighbouring countries in the North Sea to ensure that the maps honour the geology across the median lines.

In the Central North Sea and Moray Firth areas, one of the most important input datasets has been the North Sea Digital Atlas produced by PGS. This dataset consists of a selection of time grids for the main stratigraphic intervals from Miocene to the base Zechstein. In the course of this project these grids are being used as seed interpretations to enable the creation of depth converted surfaces that are tied to hundreds of exploration and appraisal wells. Although the grids were produced using a set of 2D seismic lines, the number of (recent) wells used to guide the depth conversion ensures the grids are being updated to provide an up-to-date interpretation. The extension of these grids into the Norwegian sector ensures that both depth maps and resulting isochores are consistent across the median line.

This project further ensures cross-border correlation of geological units through the use of Ternan Play Fairway mapping studies, the Intellectual Property Rights of which now reside with the OGA. The latest Ternan study (2015) covered both the UKCS and the Norwegian North Sea in an integrated fashion, which ensures that key maps (for example reservoir distribution maps) produced for this project will tie to the Norwegian sector.

The maps that will be produced for the Southern North Sea require integrating the datasets and interpretations with those of the Dutch sector. TNO – *Geological Survey of the Netherlands* – is in the process of updating the depth grids for the main stratigraphic intervals, as well as the distribution maps for the main reservoir units. A collaboration with TNO – *Geological Survey of the Netherlands* – will involve exchange of key grids and interpretations across the UK/Netherlands median line to ensure that the maps resulting from both projects will provide a consistent geological view.

Cross-border collaboration with Ireland, France and the Faroes is also anticipated, again working to produce a set of integrated maps across these additional neighbouring boundaries.

This paper will present an exciting project which, for the first time, ties in the whole of the UKCS with the geology of the neighbouring countries aimed at driving forward exploration activity.

NOTES:

The North Sea Toolkit: A comprehensive regional exploration tool

Joya Tetreault, Alenka Crne, Jan Ove Knudseth, Peder Garten, Roger Flåt, Bjørn Seeland, Laura Marello
Exploro AS, Innherredsveien 7B, N-7014 Trondheim, Norway

The North Sea is a mature hydrocarbon province with still untapped potentials. Geopolitically the North Sea is divided between Norway, the United Kingdom, Denmark, the Netherlands, and Germany. While much of our geological understanding in the North Sea is built upon decades of petroleum research, this knowledge is often based on local studies that are roughly tied together in a regional picture. As new hydrocarbon resources are found in unexpected places, it becomes evident that a regionally-consistent geologic framework is indispensable when exploring the untapped potential of the North Sea. In Norway, Exploro AS is the leader in producing regional-scale, interdisciplinary exploration products, and we have produced comprehensive workstation-ready Toolkits for the Norwegian Continental Shelf. We aim to extend our regional projects across the border from Norway to the UK and promote further exploration.

The Norwegian North Sea Toolkits are designed based on years of experience creating multiclient projects that support the needs of the industry. Our Toolkits have been fundamental to our customers during application rounds, license work and exploration of new areas. These exploration products are created by assembling the enormous amount of publicly available data into a regional database, interpreting the data using multiple geoscience disciplines, and integrating all results into a final comprehensive exploration product. Each Toolkit includes a 3D seismic merge (~60,000 km^2), 2D seismic data, an organized well database (>1100 wells), well-tie wavelets, seismic interpretations, horizon and thickness maps, depositional models, biostratigraphic analyses (>75 wells), petrophysical analyses (> 280 wells), core log analyses, and velocity model. The ideal foundation for seismic interpretation is built into the toolkits: a revised well and seismic database. The 3D merge is a seamless high-quality cube built from time-, phase-, and amplitude matched 3D data. The velocity model is built by integrating well data, 3D and 2D stacked velocities, and regional maps. Biostratigraphic, petrophysical, core log, and well-tie analyses were performed on key wells that assisted the regional seismic and depositional environment interpretations. For the Norwegian sector of the North Sea, we have produced more than 17 horizon maps (from Seabed to Basement) and 10 depositional maps that cover the entire region. The results from the Exploro Toolkits are also included as input for a play-based exploration project that integrates various disciplines into a comprehensive petroleum system model.

However, the Norwegian sector only covers part of the North Sea and a complete understanding of the geological evolution of the northern and central North Sea requires investigation in the UK as well. Thus, Exploro AS has begun the next step: building a UK North Sea Toolkit. The main goal is to bridge the geology across Norway and the UK and to create an integrated and comprehensive tool to explore the North Sea. Like the Norwegian side, all data will be organised in workstation-ready products and interpreted to define the regional seismostratigraphic framework. Our resulting UK North Sea Toolkit, combined with the Norwegian North Sea Toolkits, will provide a complete and integrated knowledge base and a powerful tool for exploration.

NOTES:

Monday 27th November 2017
Session Three: Source Rocks

Norway – UK Cross Border Petroleum Systems Analysis – The Challenge of Creating a Quality Controlled and Comparable Data Base

Olaf Thießen[1], Michael Erdmann[2] & the Norway-UK Regional Exploration and Research & Technology teams
[1]*Statoil ASA, Harstad*
[2]*Statoil ASA, Bergen*

In an ideal geochemical world, the data set under investigation was analysed in the same laboratory, with the same machines and methods and the same technical staff. In reality, the available data is analysed over decades with different analytical systems and in several different laboratories, performing slightly different analytical methods, e.g. using different mass-to-charge ratios (m/z) for biomarker identification and reporting, etc. On the Norwegian Continental Shelf (NCS), however, petroleum system analysts are in a quite comfortable situation as all analytical reporting should be done according to the Norwegian Industry Guide to Organic Geochemical Analyses (NIGOGA; Weiss *et al*., 2000), where the preferred analytical procedures are defined. Quality assurance is also given due to the mandatory reporting of the Norwegian Geochemical Standards, as there is the North Sea Oil Standard 1 (NGS NSO-1, North Sea Block 30/9, Oseberg oil), the Svalbard Rock Sample 1 (NGS SR-1; Middle Triassic Botneheia Formation, Teistberget, Spitsbergen, NO) and the Jet Rock Sample 1 (NGS JR-1, Toarcian Whitby Mudstone Formation, Port Mulgrave, Yorkshire, UK). Moreover, basic geochemical data is released after two years and oil, core and cuttings samples are available at the Norwegian Petroleum Directorate for almost all wellbores being drilled on the NCS. Thus, it is possible for the oil industry or service companies to build up a very detailed high quality data base, even though the companies are not part of the exploration licenses.

For the North Sea cross-border exploration, for example, it is a different picture. Compared to our Statoil Norwegian North Sea data base, the data for the UK side is quite sparse. Moreover, the UK data is often based on governmental and contractor reports, different commercial data bases or just copied from literature. Thus the samples were analysed within many different laboratories and access to physical samples for in-house re-analysis can be challenging. Thus, the interpretations are based on very different data sources and therefore a thorough quality control of the data is necessary.

However, where empirical data is still sparse, for example for PVT data in phase prediction (Fig. 1), modelling approaches are applied. Statoil has developed an in house tool to quickly analyse PVT data sets by using published empirical fluid correlations in order to quickly access if a one or two phase system is present but also to understand the fluid distribution on a regional scale, a method which works best complementary to the interpretation of organic geochemical data.

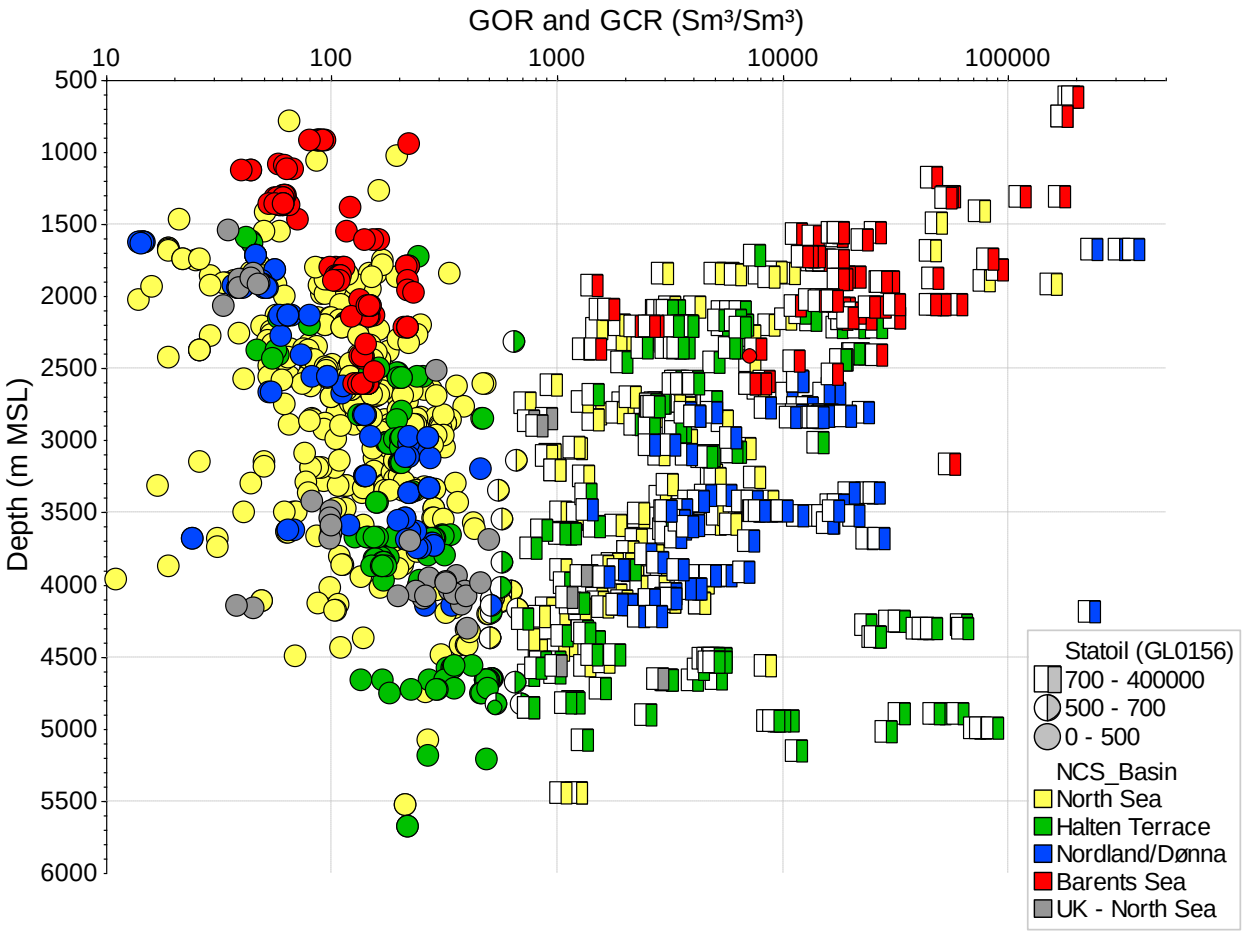


Figure 1: Gas-oil (GOR) and gas-condensate (GCR) ratios from test samples of the Norwegian and UK continental shelf. The empirical data base is used in fluid phase predictions in addition to phase modelling. UK data is quite sparse compared to the Norwegian data set.

Weiss, H.M., Wilhelms, A., Mills, N., Scotchmer, J., Hall, P.B., Lind, K. and Brekke, T. (2000): NIGOGA - The Norwegian Industry Guide to Organic Geochemical Analyses [online]. Edition 4.0 Published by Norsk Hydro, Statoil, Geolab Nor, SINTEF Petroleum Research and the Norwegian Petroleum Directorate. 102 pp [cited *2017-02-26*]. Available from World Wide Web: <http://www.npd.no/engelsk/nigoga/default.htm>.

NOTES:

One North Sea framework for source rock characterization and prediction

Ute Mann[1], Michael Erdmann2, Ulrich W.H. Berner[2], **Aart-Jan van Wijngaarden[2];** *Statoil Exploration Technology - R&T*
[1]Rotvoll Trondheim
[2]Sandsli Bergen, Norway

Statoil utilizes petroleum system analysis (PSA) based workflows to provide the foundation for prospectivity assessment. Given the maturity of exploration in the North Sea, a next "level of detail" is needed to predict the overlooked or underexplored exploration areas based on a PSA perspective.

A model is needed not only for source rock presence, but also for its quality- and thickness variations. In addition, other/additional stratigraphic intervals than the Late Jurassic Kimmeridge Clay Fm. and equivalents might be of relevance in some zoomed-in areas.

For this purpose, an integrated workflow with several methods can be applied and combined to predict and quantify a source rock interval: E.g. information from geophysical well logs projected onto subsurface maps, pre-stack seismic data interpretation, as well as geological forward modelling of source rock deposition. The modelled depositional scenarios can also be further utilized to guide the projection of the well data and geophysical logs, and they can be used to verify the prediction from seismic.

For the modelling of source rock deposition, we are developing an in-house software tool that works on a regional/basin scale. It includes an understanding of the basin evolution in terms of paleo bathymetry as this is important when forward-simulating the process of source rock deposition. The uncertainty in paleo water depths estimates can be easily handled by working with ranges of scenarios.

Input for the expulsion modelling requires the initial or immature TOC and HI values from the source rock. For this we can either use our well-log generated TOC curve and back-calculate to the initial values, or back-calculate from the measured TOC and HI values from well data. But also the source rock depositional model will provide initial TOC and HI values as the source rock is modelled at time of deposition. The modelled initial TOC and HI values can be directly used in the expulsion prediction and/or compared and discussed with the back-calculated values from the other sources.

These workflows and technologies benefit from and contribute to the zoom in / zoom out approach in the regional One North Sea exploration strategy.

NOTES:

One North Sea petroleum system gap analysis and a way towards identifying under-explored charge areas

Suzanne Beglinger[1], **Øyvind Steen**[1], Olaf Thießen[2], Michael Erdmann[3]
[1]*Statoil ASA, Stavanger*
[2]*Statoil ASA, Harstad*
[3]*Statoil ASA, Bergen*

North Sea is a prolific and mature hydrocarbon province and many studies have paid attention to the source rocks, in particular the Upper Jurassic rocks that are by far the most important source for the discovered hydrocarbons. Hydrocarbon expulsion modelling is a useful exercise to learn about the sensitivity of source rock quality and thickness to modelled hydrocarbon volumes. Such models are also used to estimate remaining hydrocarbon potential by comparing it to discovered volumes.

Earlier North Sea studies estimating hydrocarbon system efficiency (volumes discovered/volumes of modelled expulsion) vary widely and can be related to different methods and areas covered. The variation in play types, migration pathways, and exploration history across the North Sea are also influencing these estimates. A better understanding of such factors is important for identifying under-explored areas and steer exploration focus.

A vast amount of 3D seismic is acquired in recent years that can improve source rock models. Constraining modeling inputs from seismic and wells, that are of various age and quality, is however a challenge. For example, stratigraphic correlation across the border need careful attention when data are combined at the super-regional scale.

Statoil is aiming in constructing models of the Upper Jurassic source rocks, expulsion and migration at One North Sea scale. Several in-house petroleum system models are compared, calibrated and integrated with the One North Sea framework. Paleogeographic maps, isopachs, temperatures and framework geometry are essential input to the modelling. Fetch areas and associated migration zones are defined by the detailed framework (e.g. Base Cretaceous Unconformity, Top Balder Fm). Observational data, such as discoveries, hydrocarbon shows, seismic chimneys and DHI's are used to validate the modelled migration fairways.

Final goal of this study is to provide a consistent method for estimating hydrocarbon system efficiency across the North Sea, which in turn forms the basis for identifying under-explored charge areas. Other important aspects include; (1) finer level migration routes and trapping critical for prospect risking, (2) vertical and long-distance migration into shallow strata and through the sea bottom, (3) the contribution from other source rocks, for example deeper strata, which may be significant in platform areas where the Jurassic source rocks are not present or immature. This study also has a longer-term perspective involving research activity. Analysis of well failures due to charge or trap seal and shows studies are also part of this program.

NOTES:

Cross-border paleogeographic perspectives on Lower Jurassic source rocks in the North Sea

Sander Houben[1], Susanne Nelskamp[1], Tanya Goldberg[1], Roel Verreussel[1] and Thijs Boxem[1]
[1]Applied Geosciences Team, Netherlands Organization for Applied Scientific Research (TNO), Princetonlaan 6, 3584CB Utrecht, NL

Knowledge on Early Jurassic deposition in the North Sea area is limited, albeit considered remarkably homogeneous and predominantly fine-grained. In the Early Toarcian, substantial enrichment of organic-matter content occurred, as expressed by the source rocks of the Posidonia Shale Fm. in the Netherlands and Germany. In the UK, depositional patterns are better understood owing to extensive coastal exposures, where facies range from hemipelagic mudstones to marginal marine oolite shoals. In the Norwegian North Sea, the earliest Jurassic Statfjord Group, consisting of paralic sandstones, is overlain by the Dunlin Group, consisting of mudstones from the Amundsen, Burton and Drake Formations and sandstones from the Johansen and Cook Formations. These patterns suggest that there is more variability in depositional facies distribution than often assumed. In addition, Early Jurassic climates were repeatedly perturbed by rapid carbon-cycle anomalies, such as i.e. the Early Toarcian Oceanic Anoxic Event (T-OAE), which is linked to the abovementioned Posidonia Shale. Because most studies focus on short-lived events, the cross-border depositional evolution of the North Sea Basin remains poorly understood.

This contribution, being rooted in several cross-border joint industry projects, aims to overcome this knowledge-gap by providing a stratigraphically sound analysis of the paleoclimatic, -environmental and -geographic evolution of the Early Jurassic in the North Sea Basin. The first phase concerns the construction of an integrated bio- and isotope stratigraphic framework, based on outcrop samples from coastal section in Yorkshire and Dorset (UK). The resulting sample set was subsequently used for an new integrated geochemical (redox and organic geochemistry) and paleo-ecological workflow aimed at deciphering environmental controls on organic carbon-enrichment. The second phase focused on subsurface records from the UK, Netherlands and Norway. Ten cored sections from key intervals throughout the study area were analyzed for the same purposes, while wireline logs from over 120 wells allowed for interpolation of the paleogeographic trends.

The results reveal that climatic changes and hydrological feedbacks were important drivers for organic enrichment. Albeit other phases of anoxia are recorded particularly in the Hettangian and Lowermost Pliensbachian, the T-OAE was clearly the most prominent ‘event’. Even in the expanded and coarse-grained Cook Formation of the northern North Sea, palynological indications for surface-water anoxia are recorded, implying that lateral equivalents with lower sedimentation accumulation rates may be considered as prolific source-rocks. Overall, the results illustrate that the accumulation of organic-rich strata is influenced by an interplay between productivity, anoxia and the rate of dilution by detrital material. These factors appear to have varied in marked response to phases of climatic change.

NOTES:

Monday 27th November 2017
Session Four: Palaeozoic to Permian

Paleozoic petroleum potential of the five countries area, Southern-Central North Sea, introduction to the PALAEO-FIVE project

Thomas van Hoof[1], Alison Monaghan[2], Stavros Arsenikos[2], Roel Verreussel[1] and Renaud Bouroullec[1]
[1]TNO Applied Geosciences, Princetonlaan 6, 3584 CB, Utrecht, The Netherlands
[2] BGS, The Lyell Centre, Research Avenue South, Edinburgh, EH14 4AP,

One result of hydrocarbon exploration in the mature North Sea region moving beyond the classic petroleum systems of the Permian, is a renewed interest in the deeper and older plays of the Paleozoic sequence. Recent attention on the Paleozoic has resulted in two, recently completed, regional exploration studies: the TNO-led "Northern Offshore Project", focusing on the Rotliegendes and Carboniferous of the underexplored northern part of the Dutch offshore; and the BGS-led "21st Century Exploration Roadmap (21CXRM): Paleozoic project", focusing on the Carboniferous and Devonian petroleum systems of the UK Continental Shelf. The "Northern Offshore Project" was a Joint Industry-Dutch Government project executed by TNO that suggests renewed prospectivity for Permian reservoir rocks overlapping with mature Carboniferous source rocks in underexplored areas of the Dutch offshore;. The "21CXRM Palaeozoic Project" was a joint industry–UK Government project that provided evidence of source rock potential within Visean–Namurian sequences mapped within a series of Devono-Carboniferous basins that extend from eastern parts of the UK sector towards the Netherlands, Germany, Denmark and Norwegian sectors of the North Sea.
Key results of both projects highlight the need for further cross-border study into the Paleozoic petroleum potential of the five countries area in the Southern-Central North Sea. Using cross-border datasets with a particular focus on source rocks, several key questions are answered including: what is the extent and maturity of Scremerston-equivalent source rocks in the Dutch subsurface? How can we explain the mismatch between modeled and existing hydrocarbon volumes in the Norwegian sector? What is the potential of oil-prone mudstones within the Scremerston and Yoredale formations? To answer these questions, TNO and BGS are joining effort in the new cross-border PALAEO-FIVE project that focuses on the hydrocarbon potential in the five countries area using a multidisciplinary approach to enhance knowledge for future exploitation.

NOTES:

Deep frontier plays in post-Variscan intra-platform basins on the East Shetland Platform and southern Norwegian-Danish Basin: a comparative tectono-stratigraphic framework

Stefano Patruno, Verena Lampart
PGS

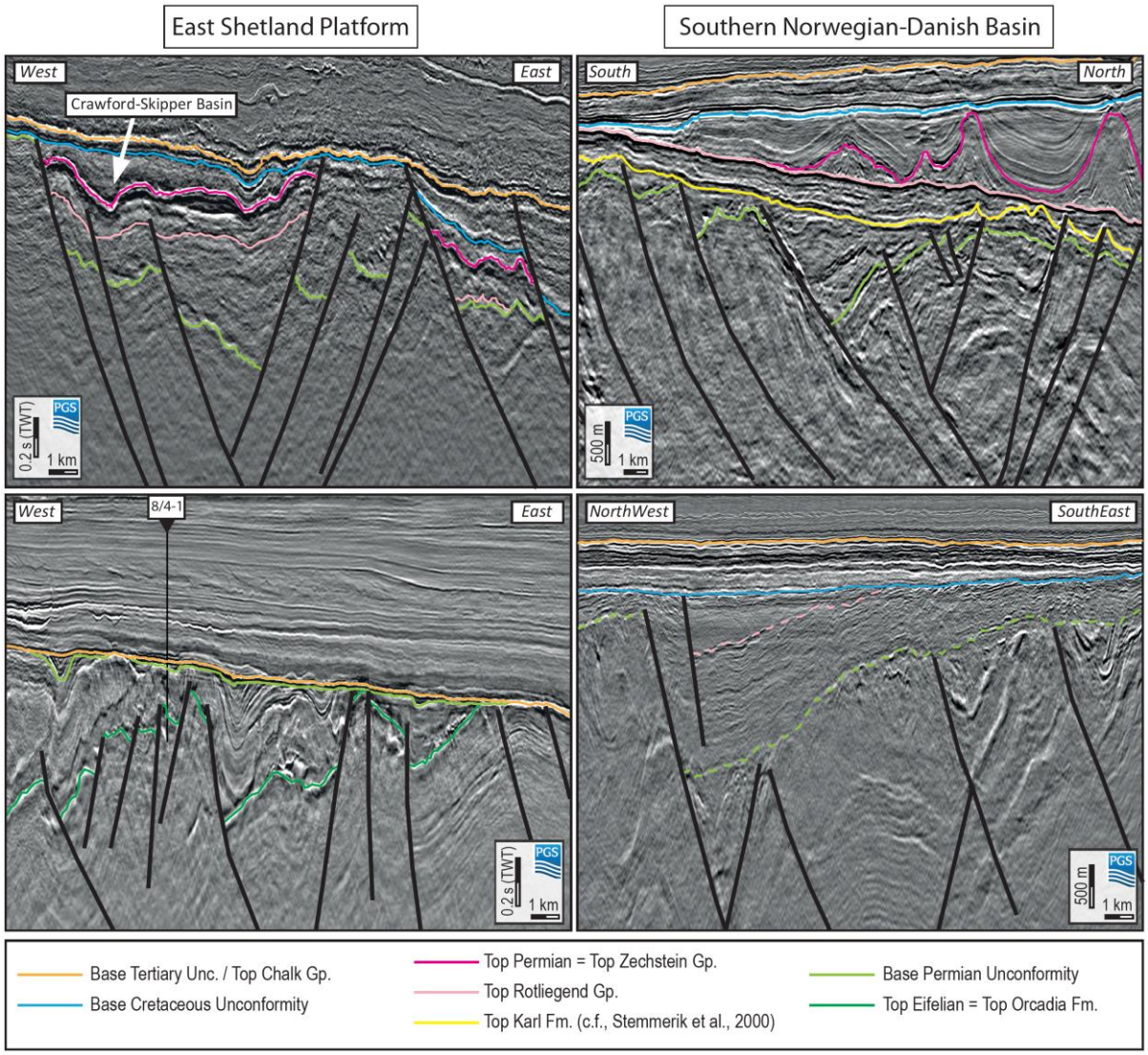
Thick Paleozoic successions are buried under the East Shetland Platform (ESP) and the area between the Ringkøbing-Fyn High and the southern Norwegian-Danish Basin (SNDB). These are large underexplored platform regions flanking the main structural depocentres of the North Sea, situated in the UKCS (ESP) and Norwegian-Danish sectors (SNDB) respectively. Here, seismic interpretation of recent 3D broadband dual-sensor towed streamer seismic data is integrated with well analysis, including 1D basin modelling, in order to better understand the regional tectono-stratigraphic evolution and its influence on the overall hydrocarbon prospectivity. The new broadband seismic enables clearer imaging of deeper and older reflectors, allowing for an improved understanding of the early geological history of the North Sea and on previously overlooked deep platform potential.

The two study areas underwent a largely similar geological evolution, developing deep strutures that are broadly similar to those observable in much part of the platform regions that flank the Central Graben, both to the west (UK Greater Mid North Sea High region) and to the east (from the Norwegian Utsira High to the Danish Ringkøbing-Fyn High). Devono-?Carboniferous strata host numerous extensional and compressional structures, often truncated and unconformably overlain by Permian or younger sediments. Following the Variscan compressional event, both Lower Permian and Triassic syn-depositional half-grabens formed in the ESP and SNDB. Middle Jurassic uplift and erosion followed, particularly at the basinward margins of the two platforms. The present “platform high” structural configuration of the two regions was developed during the Late Jurassic rifting, which focused on the Viking and Central Graben and on their basin-bounding faults.

This history of repeated tectonic inversions created up to four post-Devonian regional unconformities (Base Permian, Base Jurassic, Base Cretaceous and intra-Cretaceous), which merge into fewer, composite erosional surfaces on persistent platform highs, where Tertiary reflectors can be in direct contact with Devonian or older rocks. Elsewhere on the ESP and SNDB, predominantly subsiding Permo-Triassic depocentres contain a more continuous and thicker Paleozoic-Mesozoic succession, largely reflected by negative Bouguer anomalies.

Numerous working reservoir units are present over these frontier areas in the Devonian-Palaeogene interval. In particular, older reservoir units (Devonian and Permo-Triassic) can be characterized by surprisingly good reservoir qualities, as suggested by preliminary rock physics analyses on 11 wells in the ESP, pointing to effective porosity values as high as 22% for upper Devonian rocks. Furthermore, large Paleozoic structural traps have been defined and both stratigraphic and structural traps exist within the intra-platform basins. Structural traps are represented by pre-Triassic fault blocks and anticlines; stratigraphic traps are bounded up-dip by unconformity subcrop geometries or by juxtaposition against the basement.

Hydrocarbon charge to the two platform areas occurs either via lateral migration from the basinal source kitchens (likely up to maximum distances of 30-40 km) or, possibly, via vertical/lateral migration from deeper Devono-Carboniferous source intervals. Seep data and fluid escape features suggest a working 'deep' source in the Greater ESP. Here, the presence of localized Permo-Triassic intra-platform grabens and half-grabens provided sufficient subsidence for the oil-prone middle Devonian unit to eventually enter the oil-maturation window and the dipping geometry of the basins provide easy conduits for upward and outward hydrocarbon migration. Equally, if a Carboniferous or Devonian source rock is present in the SNDB, this is likely to be thermally mature below the untested, likely post-Variscan, intra-platform basins, and the dipping geometry of the basin provides an excellent conduit for hydrocarbons to migrate laterally into potential traps.



Comparison between Paleozoic structures on the East Shetland Platform (left-hand column) and southern Norwegian Danish Basin (right-hand column) (from the following PGS 3D GeoStreamer® surveys: PGS15010ESP, Q16-2013, TEG2013, CGR2015M). In particular the upper two images focus on Rotliegend-age syn-depositional half-grabens whilst the lower two images highlight deeper Devonian age compressional structures, deformed and top-truncated by the Base Permian Unconformity.

NOTES:

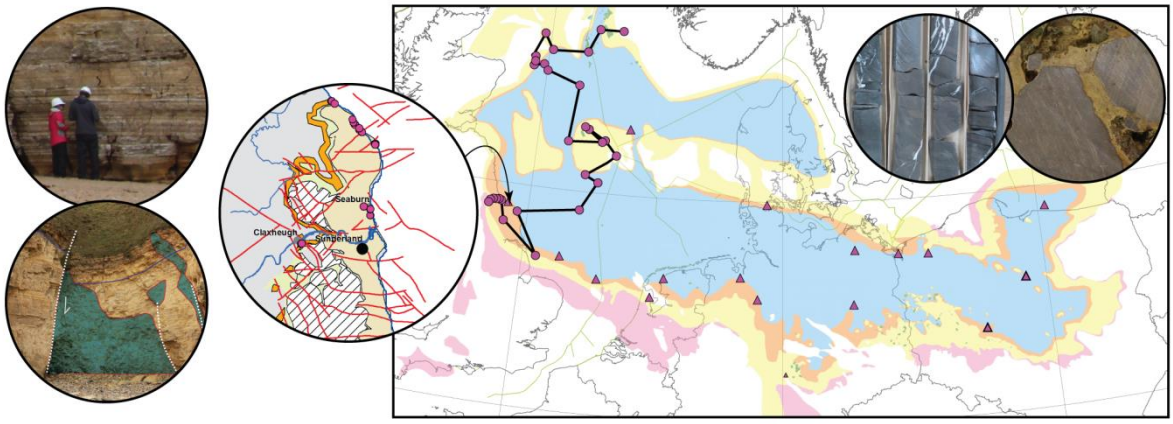
Specific Play Knowledge of Zechstein Carbonate Reservoirs Applied across the Northern and Southern Permian Basins

S.E. Daniels[1], J.L. Long[1], M.J. Mawson[2], M.E. Tucker[2], J.G. Gluyas[2], M.W. Wilkinson[1], R.E. Holdsworth[2], E.A. Vsemirnova[1]
[1]Geospatial Research Ltd, Department of Earth Sciences, Durham University, Durham, DH1 3LE
[2]Department of Earth Sciences, Durham University, Durham, DH1 3LE

Production from Zechstein carbonates in the UK, Norway, Poland and Netherlands is significant today and has been important since UK offshore oil production began in 1975, the Argyll field having been the first offshore UK field on production. These carbonate reservoirs were deposited in the Permian Basin of NW Europe, which is often separated into the Northern and Southern Basins. We completed a multi-disciplinary project on the Zechstein carbonates of NW Europe in 2016. Across the region, an improved understanding of connectivity within the Zechstein carbonates has been achieved through studies of outcrop, core and the subsurface, and a basin-wide literature review.

A stratigraphic correlation across the Northern and Southern Permian Basins (NPB & SPB) has been established, based on published data for the SPB (data from Poland, Germany, Netherlands, UK, and Norway) and core for the NPB.

To understand the internal connectivity of the carbonates at different locations across the basin, each site was located within its sequence stratigraphic and spatial context in the basin, coupled with a broad understanding of its tectonic and burial history. Knowledge of how these factors will impact matrix and fracture permeability has been derived from detailed outcrop and core studies.



Palaeogeographic map for the Z2 (after Slowakiewicz et al., 2015) showing location of field fracture studies in northeast England (inset map), sequence stratigraphic articles reviewed (triangles) and correlation panel (black path). Blue represents basin, orange represents slope, yellow represents platform, pink represents sabkha and salina, white are highs.

The northeast of England hosts world class exposures of Zechstein carbonates, occurring as primary limestones, dolomites and dedolomites, with bedded, replaced and brecciated textures, from lagoonal to lower slope facies. The carbonates have been subjected to fracturing from depositional times onwards, with some locations experiencing faulting and even collapse due to dissolution of underlying evaporites. These well-studied outcrops were used to characterise fracture properties using lidar, photogrammetric and field measurements. The fracture properties are understood within the context of facies, structural and diagenetic history, and, at some locations, evaporite dissolution, to allow prediction of fracture behaviour within reservoirs across the basin. Comparison of the emergent picture from outcrop studies with core has verified that the interpretation is valid in the subsurface.

The final evaluation has been to consider production data from fields located in the UK CNS and Dutch Drenthe Province, in terms of aquifer support, and the vertical and lateral connectivity of the carbonate reservoirs. There were favourable comparisons of the predictions of fracture and matrix permeability with historical field production behaviour (based on facies, faulting, diagenesis and whether evaporite dissolution has occurred).

NOTES:

Extending the basal Rotliegend Play across the Germany/Netherlands median line

Lunn, S.F., Burgess, C.L, Clever, J.E., Corcoran, O.J., Cram, F.M., and Hall, N.T.
Affiliation: Hansa Hydrocarbons Limted

In this paper we shall discuss how the basal Rotliegend play has been extended from Germany across the median line into the Netherlands, including the challenges associated with building a geological model without borders. We will also explore a number of non-technical cross border issues that have impacted on the exploration of this area.

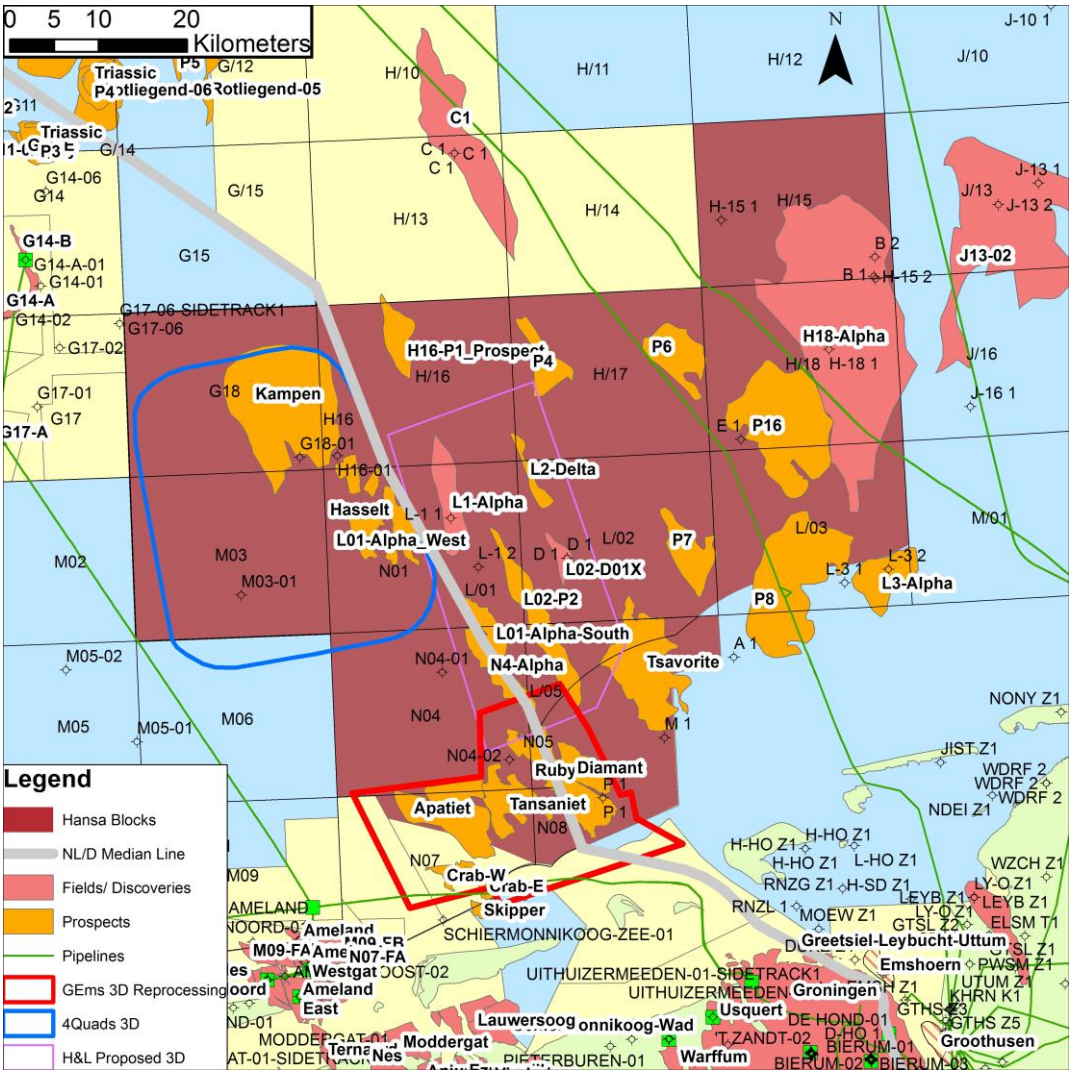


Figure 1. Location Map

Since 2009 Hansa Hydrocarbons Ltd (Hansa) has built a significant acreage position across the Germany Netherlands median line (Figure 1). The portfolio consists of 16 blocks (4489 km^2) acquired through a combination of licence applications and farmins.

The primary objective in this area is the basal Rotliegend sandstone play which is proven in Germany by the offshore discoveries L1-Alpha, L02D-01X and H18-Alpha and the onshore Söhlinghen Field which has been on production since the early 1980s. The play consists of fluvial and aeolian sands deposited on the variable topography of the Base Permian Unconformity. The seal is provided by shales and evaporites of the Lower Silverpit Formation and the source rocks are coals of the Westphalian Coal Measures. The reservoir sands are not deposited uniformly across the area. The gas discovered in the region contains significant quantities of nitrogen with a trend of increasing nitrogen from west to east. In the vicinity of the median line nitrogen has been encountered in the range 17-27%.

In Germany L01-02 well was drilled as an appraisal well to the L1-Alpha Discovery in 2010 and although water bearing it did encounter a well-developed basal Rotliegend reservoir section. The acquisition of modern Vp, Vs and density logs enabled the generation of a good quality synthetic which was key in establishing that the basal Rotliegend sands have lower acoustic impedance than the overlying Permian shales and underlying Carboniferous section and thus can be interpreted directly on seismic data. Simple coloured inversion has proved to be the best approach for enhancing the seismic response of the sand.

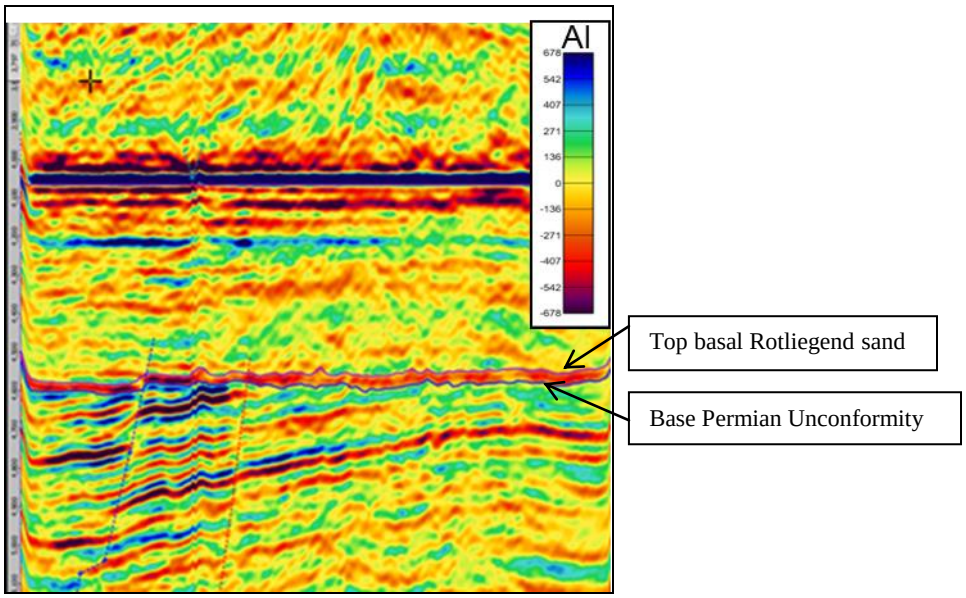


Figure 2. Coloured Inversion example from GEms 3D (flattened on Base Zechstein)

Across the border in the Netherlands four wells (G18-01, H16-01, N04-01 and N04-02) were drilled to test a series of large regional closures. All were drilled on 2D data and encountered thin (<5m) gas bearing basal Rotliegend sandstones. A 3D survey was acquired by Hansa in the 4Quads Licences in 2014 and the existing 3D data in the GEms Licences was reprocessed in 2015. Using inverted 3D seismic volumes we have mapped the variable distribution of the better developed reservoir sands within these closures. Another key element to building a cross border geological model has been a review and resampling of core data from the legacy wells in the Netherlands and Germany. These samples have been analysed for chemostrat, heavy minerals, petrography, palynology and zircon age dating which has provided significant new insights into the basin stratigraphy and enabled us to build a geological model consistent with the seismic observations.

Apart from the technical issues working across international borders can bring with it additional challenges and in this example these have included the following:

1. Significantly different regulations on underwater sound relating to seismic acquisition have meant that cross border surveys are very difficult to execute. To overcome these, the 4Quads 3D survey used a novel shooting technique to maintain fold at the median line.
2. The absence of data release in Germany and restrictive terms on which data can be purchased has made it difficult for our Dutch partners to access key wells and seismic.

Despite the border challenges, in April 2017 Hansa along with partners EBN and Oranje Nassau Energie will spud the N05-01 well in the Netherlands to test a cross border prospect called Ruby (Figure1).

NOTES:

Tuesday 28th November 2017
Session Five: Basin Statistics and Case Studies

KEYNOTE: A decade of Exploration Performance in the Mature UK & Norwegian North Sea

Keith Myers
Westwood Global Energy Group

The exploration performance of the UK and Norway sectors of the North Sea since 2007 have been compared. Given both sides of the median line share similar geology and plays the paper analyses to what extent differences in exploration performance reflect differences in play maturity across the median line. The one off 1.7 billion barrel Johan Sverdrup discovery made in 2010/11 in the Norwegian sector has been excluded from the statistics so that the underlying trends in performance can be examined.

Between 2008 and 2016, 188 wildcat wells were completed in the Norwegian sector compared to 126 in the UK sector. This only partly explains the higher commercial volumes discovered in Norway with 1.8 bnboe compared to 0.9 bnboe in the UK. Exploration efficiency was better in Norway with higher commercial success rates (CSRs) and average discovery sizes contributing to a 40% higher average volume of hydrocarbons discovered per wildcat of 10 mmboe in Norway compared to 7 mmboe in the UK. Surprisingly though, average pre-tax finding costs were still lower in the UK at $5/boe compared to $6.5/boe in Norway, due to substantially higher well costs in Norway. After startlingly poor exploration performance for the UK in 2013/14, success rates in the UK have been on a rising trend and exceeded that of Norway in 2015/16.

In Norway, drilling has been focussed on the Northern North Sea (NNS) sub-basin with 61% of the total Norwegian sector wells finding 77% of the discovered resources. The traditional Lower and Middle Jurassic fault block plays accounted for 70% of discovered volumes in the Norwegian NNS. In the UK, the Central North Sea (CNS) accounted for 77% of wells and 76% of the discovered resources with discoveries spread across Triassic HPHT, Upper Jurassic, Cretaceous and Lower Tertiary plays. In both the UK and Norway, exploration performance in the NNS exceeded that in the CNS where average CSRs declined and finding costs rose to unsustainable levels.

Jurassic plays accounted for most expenditure, especially in Norway where they represented 76% of spend and 82% of discovered volume. In the UK, Jurassic plays accounted for 60% of spend but only 31% of discovered volume. The Middle Jurassic remained the stalwart play in the North Sea during the period, particularly in the NNS, where finding costs were $3.2/boe at a commercial success rate of 57%.

Exploration performance over the last decade has been dragged down by poor performance in one play in particular - the Upper Jurassic. This was the most targeted play in both sectors of the North Sea with 36% of drilling spend, and an overall CSR of 17% and a finding cost of $13.6/boe. Finding costs were highest in the UK CNS and Norwegian NNS at $18.2/boe.

Stimulated by success at Buzzard in 2001 and Johan Sverdrup in 2010/11, the Upper Jurassic has proved a difficult play and the paper looks at the lessons to be learned.

NOTES:

The Rona Ridge Basement Play: Key learning and implications for future exploration of the UKCS/NCS

Bob Trice
Hurricane

To date, naturally fractured crystalline basement reservoirs (basement) on the UKCS and the NCS have been underexplored despite the fact that numerous indications of hydrocarbons have been reported from wells dating back to the 1970s. Over the last twelve years Hurricane Energy have deliberately set out to explore the potential of the Rona Ridge Basement Play, West of Shetland. Data acquired by Hurricane Energy through drilling and drill stem testing of eight wells has provided an insight into the reservoir properties of the Rona Ridge Basement Play. Analysis of these data has allowed for the detection of productive fractures and the characterisation of basement reservoir properties to a sufficient level of understanding that Hurricane Energy is now progressing towards the first UK Basement Field development. The Norwegian Basement Play is also recognised as a potentially material resource with serendipitous oil discoveries but also the 16/1-15 well, drilled in 2011, being the first successful full scale basement test on the NCS. Building on this success the 2016 Rolvsnes Discovery has demonstrated the significant basement potential of the extensive the Haugaland High and thus providing material argument for the materiality of a Norwegian Basement Play

This presentation will summarise the exploration/appraisal approach applied to de-risking the Rona Ridge Play and the reservoir characteristics that typify the Play. This information will be viewed in context to the Basement Play as typified by the NCS with the objective of drawing some preliminary conclusions in optimising future basement play exploration on the UKCS/NCS.

NOTES:

Langfjellet Discovery: The key to commercialize stranded discoveries

Lena K. Øvrebø[1], Evy Glørstad-Clark[1]; Kjell T. Thon[1], Ebbe H. Hartz[1,2], Øyvind Husby[1]
[1] *Aker BP ASA,*
[2] *Centre of Earth Evolution and Dynamics, Oslo, University, Norway*

The area around Frigg Gamma Delta and north of the Frøy Field has several discoveries, but no development solution. The Langfjellet Prospect is a discovery from 2016 together with multiple other discoveries in the Askja Krafla area, witnessing that the region still is prosperous decades after the first well opened the eastern flank of central Viking Graben.

Regionally, the Langfjellet Discovery is located near the boundary between the northward prograding deltaic systems of the upper Brent- and Vestland groups, both containing significant volumes of reservoir-grade sandstones. The depositional setting was a coastal and shallow marine environment that was in continuous transition between dominance by waves, tides, and fluvial processes (Mitchener et al., 1992; Fjellanger et al., 1996; Wei et al., 2016). The stratigraphic scheme of both delta systems represents an overall transgressive development, expressed as a series of regressive pulses (Helland-Hansen et al., 1992; Mitchener et al., 1992; Fjellanger et al., 1996). The sedimentary succession of the cored interval reflects mixed shoreface and near coast sedimentation, possibly within a low-gradient shelf could allow for rapid facies changes. Core, well data and seismic interpretation demonstrating the need for placing the discovery in a regional setting, where a southern sediment source is possible but where also an eastern and possibly a western contribution may be considered.

The Langfjellet wells illustrate a well-developed Mid Jurassic shallow marine reservoir (Hugin Fm), segmented by numerous crosscutting faults. This results in a complex discovery where each well has internally shifting pressures, hydrocarbon type and filling levels, where both contacts and pressure vary between closely spaced wells. Both stratigraphic and minor structural barriers hold up to a few bars fluid pressure, which in turn correspond to tens of meters variation in oil filling. Accordingly, a cross-disciplinary mix of seismic interpretation, sedimentology, structural geology and petrophysics is needed to evaluate both the discovery and the regional setting.

The Langfjellet well was executed with the strategic intent to support an area development solution in cooperation with other operators in the area. Aker BP has a long history in the area, but lacked control. Strategic acquisitions in addition to organic growth improved license position and control as an operator of the area comprising several smaller discoveries. The Langfjellet Discovery represents a typical case for the mature area on the NCS, where most discoveries and prospects do not have stand-alone potential. New business models of cooperation for area solutions need to be found. Going from competition to cooperation!

NOTES:

The Alvheim Area Exploration phase – from gas satellite to oil hub

H. C. Rønnevik and A. K. Jørstad
Lundin Norway AS

Alvheim is a major Lower Tertiary oil field producing from the clustered Kneler, Kameleon, Boa and Snailhead (East Kameleon) discoveries. The Boa discovery straddles the Norway-UK boundary and constitutes a separate cross border production sub-unit. Alvheim is located in the North Sea, west of the Heimdal gas field and production started in June 2008 with the new-built Alvheim FPSO facility. The field is now operated by AkerBP. Lundin has been partner in Alvheim since 2004, when they acquired most of DNO's Norwegian license portfolio. DNO was partner since 2001, buying into the license with an oil strategy of clustering smaller discoveries.

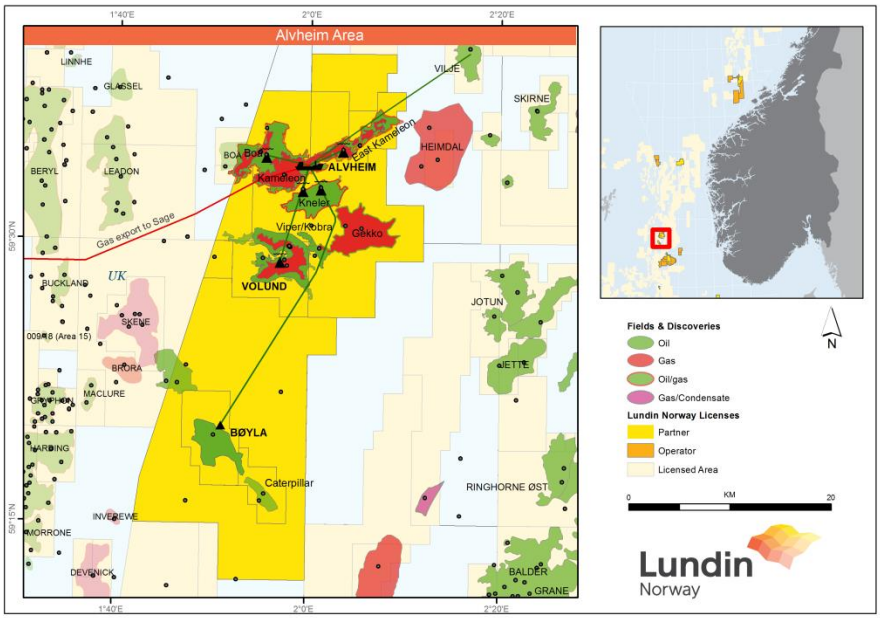


Figure 1 Map of the Alvheim area. Alvheim FPSO is producing oil and gas from Kameleon, East Kameleon, Kneler and Boa. Volund, Viper/Kobra and Bøyla/Caterpillar are sub-sea tie-backs to the Alvheim FPSO.

The main Alvheim licence is PL203 where the first well was drilled in 1998. Well 24/6-2 found gross 52 meter gas and 17 meter oil in Heimdal Mbr sandstone of generally good quality, with locally reduced reservoir properties due to shale sequences. A seismic anomaly was confirmed as hydrocarbon indicator. Located in the vicinity of the Norsk Hydro operated Heimdal gas field, the discovery was early evaluated as a gas satellite development together with the earlier Gekko discovery. The Kameleon structure, tested by well 24/6-2, is a relatively narrow body approximately 20 kilometers long. The neighboring Kneler and Boa structures were untested. Accordingly, the resource estimates in all structures were too uncertain to make a development decision. DNO/Lundin had an oil strategy and supplemented the gas development evaluation with a screening oil study based on an FPSO. Following the transfer of operatorship from Norsk Hydro to Marathon it was agreed to conduct a 4 well exploration drilling campaign in 2003 to decide on development of gas satellites to Heimdal or a clustered oil field solution. Prior to this campaign, the PL 203 licensees acquired the extensions of all structures into neighboring licenses with the exception of the potential extension of the Boa structure into UK.

Despite thorough seismic interpretation and analysis efforts it was not possible, with confidence, to determine fluid contacts and reservoir facies across the Alvheim area. Lundin (then DNO) developed in cooperation with the Norwegian Computing Center (NR) a model with tools for displaying uncertainties and important upside potential seen in the geological and geophysical evaluations. Parametric models for production profiles were also developed. This resulted in a "fast model" that was applied as part of a Monte Carlo model handling all essential elements in the cash flow for various field development concepts. Results from this model demonstrated the value of the appraisal campaign and the value of attacking the largest uncertainty relating to oil development first. The appraisal campaign in 2003 resulted in a 48 meter under-saturated oil column found in the Kneler structure. An oil column of 28 meter below a gas cap was found in Boa. Only a small gas and oil column was found in the Gekko appraisal well. The

Snailhead part of Kameleon was known to offset the main trend and was later proven to have two stacked saturated reservoirs.

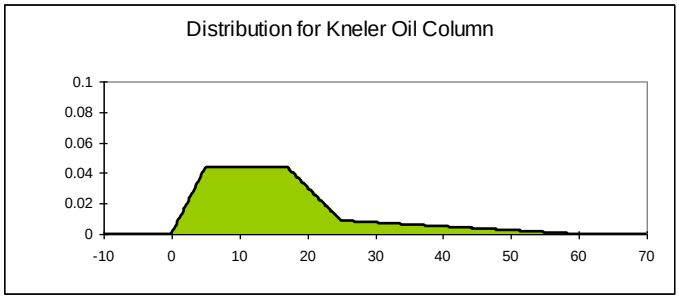


Figure 2 Distribution of oil column in the Kneler structure prior to drilling. Although a less gas prone structure with higher oil column was envisaged from seismic data analysis, much weight was put on the observed oil column of 17 meters in the Kameleon discovery well.

Later exploration and appraisal of the Volund, Kobra and Bøyla discovery has turned the Alvheim oil development from a gas satellite candidate to a successful oil hub close to the Norwegian-UK border.

The Alvheim field development was delayed by one year. However, the development was done in a low cost era and the production started in 2008 in period with high oil price and the field devlopment ended up as very profitable economic venture. The PDO reserves of 134 million bbls oil for the Alvheim Field have increased to close to 300 mill bbls.

The Alvheim Field was found by actions more than predictions under the awareness of the limitation of knowledge at any time. Diversity of details should always be related in a holistic context in addition in to detail individual analysis. Nature given uncertainties should never be influenced too much by human short term smartness on value sharing prior to value creating actions. Open and honest relations are necessary in long-term value creating alignment. The unknown will be in the tacit and cannot be solved by an explicit asset based approach. Humans can be fooled, but not nature. The value of detailed mathematical analysis depends on the quality of the input. The discovery and development of several of the drilled cross border structures have been delayed and/or inefficiently developed due to lack of alignment and seamless cross border data basis. The cross border treaty of 2005 between UK and Norway was developed to compensate for this.

NOTES:

Tuesday 28th November 2017
Session Six: Triassic to Jurassic 1

Identification of cross-border Triassic distributive fluvial systems of the Central North Sea utilising self-organising map predicted facies association distributions

E. Gray[1], A. Hartley[1] and J. Howell[1]
[1]Department of Geology and Petroleum Geology, University of Aberdeen, Aberdeen, UK

Identifying distributive fluvial systems in the Mid-Late Triassic Skagerrak Formation of the Central North Sea relies on the interpretation of subsurface data from both the UK and Norwegian sectors. This study utilises reliably predicted regional facies distributions, and palaeocurrent measurements to identify and quantify the facies proportion distribution of multiple distributive fluvial systems.

The Skagerrak Formation is composed of sandstone and mudstone dominated members, which are thought to represent respective humidity increases and decreases of Scottish Highland and Fennoscandian catchment areas. These changes in humidity are thought to result in the expansion and contraction of distributive fluvial systems, thus explaining the sandstone and mudstone domination of individual members in the Central North Sea. The Skagerrak Formation's sandstone dominated members constitute prolific primary and secondary hydrocarbon reservoirs in the Central North Sea, however their regional correlation and variation is still not fully understood.

This study utilises ten interpreted Triassic cored intervals and their corresponding wireline logs, from UK Quadrants 22, 29 & 30 and Norwegian Quadrant 7, as the basis of learning for self-organising maps. These core learned self-organising maps (SOMs), which are a type of neural network, can be used to predict facies associations from wireline log signature. Each SOM, trained on a single cored well, is used to predict facies associations in the remainder of the cored well's Triassic interval and the Triassic intervals of adjacent un-cored wells.

This prediction of facies associations in >100 UK and Norwegian Central North Sea well's Triassic interval allows a quantitative regional interpretation of the distribution of facies associations and the interpretation of multiple discrete distributive fluvial systems. The facies association proportions within these individual systems quantitatively show relatively more proximal to relatively more distal trends within each, and can be used as a quantitative predictor of facies association proportions.

The identification of cross-border distributive fluvial systems in the Central North Sea subsurface and derivation of facies association proportion trends within these systems can act as a powerful predictive tool in future hydrocarbon exploration in the region as well as defining the dimensions of Triassic fluvial systems in the Central North Sea. It is this ultimate understanding of the distribution of these systems regionally, combined with their internal facies association proportion distributions, which can allow the interpretation of regional and local paleogeographies irrespective of international borders.

NOTES:

The implications of pore fluid pressure on the reservoir quality of the Skagerrak Formation across the Central North Sea, UK & Norway

Stephan Stricker[1], Stuart J. Jones[1] & Neil T. Grant[2]
[1]*Department of Earth Sciences, Durham University, South Road, Durham, DH13LE, UK*
[2]*ConocoPhillips UK Ltd., Rubislaw House, North Anderson Drive, Aberdeen, AB156FZ, UK*

The fluvial sandstones of the Triassic Skagerrak Formation are the host reservoir for a number of high-pressure, high-temperature (HPHT) fields in the Central North Sea, UK and Norway. The reservoir sandstones comprise fine- to medium-grained sub-arkosic to arkosic sandstones that have experienced broadly similar burial and diagenetic histories to their present-day maximum burial depths. Despite similar diagenetic histories, the fluvial reservoirs show major variations in reservoir quality and preserved porosity. Reservoir quality varies from excellent with anomalously high porosities of up to 35% at burial depth of >3500m to non-economic with porosities <10% at burial depth of 4300m. This study has combined detailed petrographic analyses, core analysis and pressure history modelling to assess the impact of differing vertical effective stresses (VES) and high pore fluid pressures (up to 80 MPa) on reservoir quality. It has been recognised that fluvial channel sandstones of the Skagerrak Formation in the UK sector have experienced significantly less mechanical compaction than their equivalents in the Norwegian sector. This difference in mechanical compaction has had a significant impact upon reservoir quality, even though the presence of chlorite grain coatings inhibited macro-quartz cement overgrowths across all Skagerrak Formation reservoirs. The onset of overpressure started once the overlying Chalk seal was buried deeply enough to form a permeability barrier to fluid escape. It is the cumulative effect of varying amounts of overpressure and its effect on the VES history that is key to determining the reservoir quality of these channelized sandstone units across the Central North Sea. The results are consistent with a model where vertical effective stress affects both the compaction state and subsequent quartz cementation of the reservoirs.

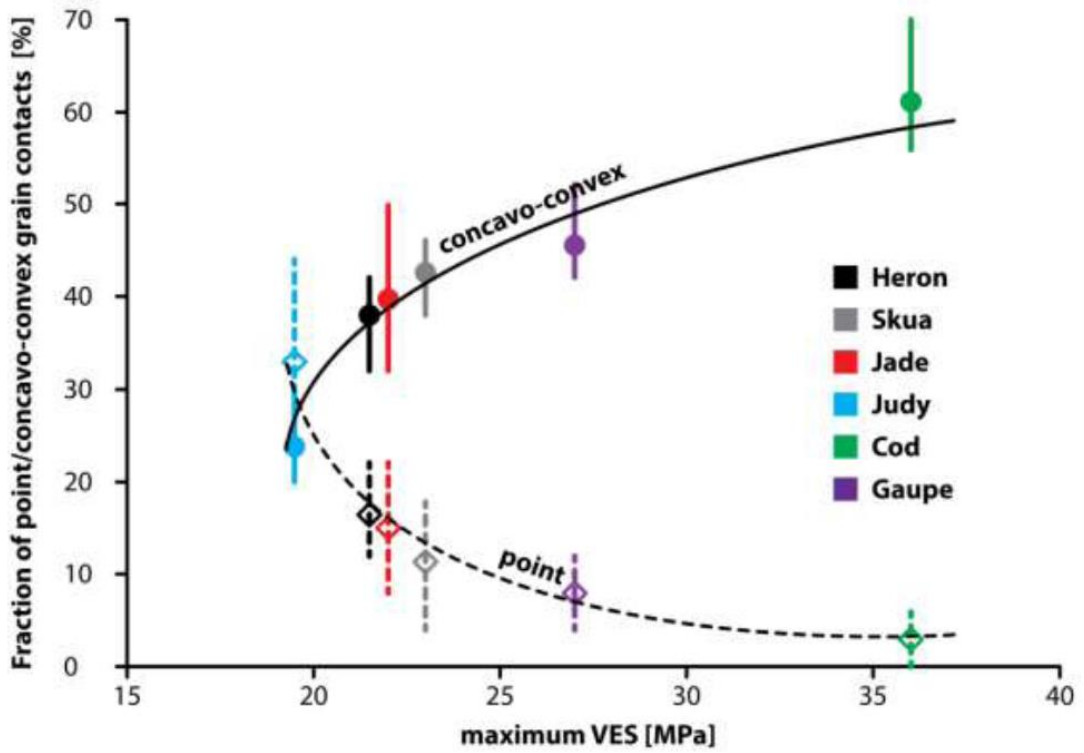


Fig. Fraction of point and concavo-convex grain contacts of Heron, Skua, Jade, Judy, Cod and Gaupe finegrained samples plotted against maximum vertical effective stress (VES) with best-fit trend lines for average fraction point and concavo-convex contacts (Stricker et al., 2016).

NOTES:

Characterisation and correlation of Triassic Mudstone Members in the Central North Sea: a non-trivial, cross-border challenge

Stuart G. Archer[2], Steven D. Andrews[1], Tom Mckie[3], Christabel Osunde[1], Matt Hutchison[1], Anne Wilkins[1], Joanna Jones[1], Bente Sola[2]and Marcus Lang[2]
[1]*Department of Geology and Petroleum Geology, University of Aberdeen, King's College, Aberdeen, AB24 3UE, United Kingdom*
[2]*Maersk Oil, Esplanaden 50, Copenhagen, Denmark*
[3]*Shell UK Ltd, Altens, Aberdeen, Scotland*

The Triassic of the Central North Sea is a continental succession that contains highly prolific hydrocarbon bearing fluvial sandstone reservoirs, partitioned by thick mudstones. UK and Norwegian stratigraphic correlations and comparisons have been problematical for decades, in part due to the fact that the lithostratigraphic nomenclature is vastly different. This study focused on mudstones rather than the sandstones in an attempt to correlate at a regional scale. Within the Skagerrak Formation of the UK sector, the Mudstone Members act as top seals to hydrocarbon accumulations in the Judy, Joanne and Josephine Sandstone Members. The Mudstone Members have been characterised by integrating sedimentological, petrophysical and geophysical data and we investigate their cross-border, semi-regional extent. The mudstone facies recognised in core are indicative of ephemeral lakes where short lived, shallow lacustrine conditions alternated with longer periods of marshy, palustrine conditions favourable for the formation of dolostones. It is suggested that the deposition of the Mudstone Members occurred as a result of the retrogradation of large scale fluvial systems during a change to more arid climatic conditions. Significant diachroneity is associated with these lithological transitions. The reduction in sediment supply during aridification is thought to have caused a change from an overfilled to an underfilled basin which created accommodation for the development of ephemeral lake environments. Core observations have been integrated with wireline log motifs and seismic character to detect lateral facies changes which have important implications for the regional paleogeographies, correlations and for the competency of the Mudstone Members as intraformational top seals. The Jonathan Mudstone Member is interpreted to have a similar origin to the Julius, however the muddy environments lasted for a much longer time; experiencing three separate climate cycles rather than one, and occupying a larger paleogeographic extent. The Jonathan Mudstone Member is thus more correlatable than the Julius (except where eroded by the Mid-Cimmerian unconformity). The interpreted climatic trends recognised within the Skagerrak of the UK are compared to those of adjacent regions to test the importance of climate as an allogenic forcing factor on sedimentation and sequence stratigraphy in this continental succession.

NOTES:

Heavy Mineral Stratigraphy and Provenance of Triassic Sediments of the UK and Norwegian Central North Sea

Iain Greig[1], Adrian Hartley[1], Andrew Morton[2]
[1] *University of Aberdeen, Department of Geology and Petroleum Geology, School of Geosciences, Meston Building, King's College, Aberdeen, AB24 3UE*
[2] *HM Research Associates, St Ishmaels, SA62 3TG*

The Heron Group of the Central North Sea, which is comprised of the Early Triassic aged Smith Bank Formation and Mid-Late Triassic aged Skagerrak Formation, consists of a relatively faunally barren and variably thick, seemingly monotonous sequence of alternating clastic red-bed deposits. Closer inspection reveals a more complex array of fluvial-alluvial sandstones and floodplain-playa-lacustrine mudstones that together represent a long-lived dryland continental succession.

Traditional lithostratigraphic correlation of Triassic packages across the Central North Sea region relies strongly on the fortunate presence of thick intra-formational mudstone units that have allowed an evolving lithostratigraphic framework to be constructed based on alternating sandstone and mudstone dominated members. However, although drilled sandstone or mudstone packages can be attributed to particular members with some confidence in the UK southern Central Graben, correlation and identification becomes difficult where mudstones are poorly preserved, particularly across the northern Central Graben and Norwegian sector where wells have not penetrated multiple recognisable mudstone members. To date, a general absence of published cross border studies, with general bias towards the UK Central Graben, has led to a relatively poor understanding of Skagerrak reservoir / seal distribution and sedimentary sourcing at this wider regional level.

In contrast, heavy mineral analysis is independent of these lithostratigraphic constraints, providing a potential chronostratigraphic and/or provenance specific correlation tool that has allowed individual depositional packages to be characterised, modifying published correlation schemes. With the advancement of heavy mineral techniques since similar Skagerrak studies were published over two decades ago, this study has applied more recent conventional and varietal techniques to both newly drilled areas and historical wells. Future inclusion of geochemical data aims to determine the spatial and temporal variability in provenance, linking these depositional systems to their evolving catchment areas.

The project to date has focussed on UK Quadrants 22 / 29 / 30 and Norwegian Quadrants 2 / 7 / 8 as a core area of interest, establishing a cross-border framework that extends from the West Central Graben across to the Vestland Arch. The encouraging provisional results and future plans for this PhD study are presented.

NOTES:

Tuesday 28th November 2017
Session Six: Triassic to Jurassic 2

Biostratigraphy and Paleo environmental Reconstruction of the Triassic of the Central North Sea

Roger Burgess, David Jolley, and Adrian Hartley
University of Aberdeen

The Skagerrak Formation is a Mid-Late Triassic clastic succession from the Central North Sea comprising alternating fluvial sandstone dominated and playa/lacustrine mudstone dominated members. The Sandstone members form important primary and secondary reservoirs in the Central North Sea whilst the mudstone members can act as potential baffles/seals and lead to the compartmentalisation of these reservoirs. Hydrocarbon extraction has been hampered by a lack of knowledge regarding correlation at a basinal, sub-basinal and field scale and to date the identification; distribution and correlation of the different members is still poorly understood with the added complication of nomenclature changes over the UK/Norwegian border.

Palynology is a powerful tool for well correlation, age assessment and environmental reconstruction and is routinely used within the petroleum industry. However previous palynologcial analysis from Triassic sediments within the Central North Sea have generally yielded poor recovery due to a combination of PDC drilling techniques, oil based muds, poor palynomorph preservation and the heavily oxidised nature of these sediments. By utilising refined palynology processing techniques this study aims to maximise and concentrate palynomorph content from drillcore and well cuttings to construct a robust age model providing the chronostratigraphic framework needed to accurately correlate the different members within the Skagerrak formation as well as allowing for accurate environmental reconstruction.

The focus of this study is on quadrants 22, 29 & 30 from UKCS and Quads 7, 15 and 16 of the Norwegian sector with results providing a better regional understanding of the Skagerrak formation further aiding hydrocarbon exploration and exploitation.

NOTES:

A cross border tectonostratigraphic perspective on the Middle Jurassic to Early Cretaceous rifting in the Southern North Sea

Roel Verreussel[1], Renaud Bouroullec[1] and Sander Houben[1]
[1]Applied Geosciences Team, Netherlands Organization for Applied Scientific Research (TNO), Princetonlaan 6, 3584CB Utrecht, NL

The Middle Jurassic to Lower Cretaceous in the Southern North Sea of the UK, Norway, Denmark, Germany and the Netherlands, accumulated in a failed rift system, dominated by siliciclastic sediments that display complex vertical and lateral facies relationships. This resulted in a prolific hydrocarbon province with numerous remaining challenges for future exploration. Five countries are represented in the relatively small area, with each one having its own stratigraphic schemes, structural and geological models, hampering the recognition of cross-border applicable processes and learnings.

The present contribution describes and compiles new information on the complex basin evolution and concomitant basin-fill of the Central Graben area from Denmark, through Germany to the Netherlands. This study provides a robust tectonostratigraphic framework that bears relevance for deciphering the tectonostratigraphic architecture farther north and west toward the UK and Norwegian sectors.

The Late Jurassic basin evolution is evaluated using chronostratigraphically constrained sedimentary successions deposited in various structural provinces, primarily using palynological and stratigraphic information. An increased temporal resolution was achieved by using quantitative techniques and considering paleoclimatic information. In addition, the palynological assemblages are interpreted in terms of depositional environment and relative sea-level trends. Combined, these interpretations are the building blocks for paleogeographical reconstructions and for determining the step-by-step development in the basin evolution.

Rifting started in the Middle Jurassic, reached a maximum rate during the Oxfordian to Early Volgian and decelerated during the Middle Volgian to Early Cretaceous (Ryazanian). Three major steps in the structural development are recognized, the oldest being the “Graben Axis” phase, where subsidence is related to E-W extension and is limited to the graben axis. At the end of this phase, the tectonic regime changed into NE-SW extension accompanied by the formation and reactivation of NW-SE normal faults. The areas alongside the graben axis became active basins during this time (e.g. the Terschelling Basin area of the Netherlands and the Heno Plateau area in Denmark). The final phase in the Late Jurassic basin evolution is characterized by waning fault activity and shedding of marine sediments onto the adjacent plateaus (e.g., the Outer Rough Basin area of Denmark, Step Graben area in the Netherlands). After the last rifting phase, a large-scale marine transgression blankets the entire Central Graben area.

The results of this study set the stage for a coherent tectonostratigraphic basin evolution model. The concepts of important plays in the area, such as the Scruff Greensand Play (F03-field), the British Fulmar Play (Angus Field) and the Danish/Norwegian Sandnes/Bryne Play (Trym Field) are better understood and consequently their architecture and distribution can be better predicted if these cross-border applicable architectural trends are taken into account.

NOTES:

Syn-rift exploration challenges in the northern North Sea

Christopher A-L. Jackson[1] & Eirik Larsen[2]
[1]*Basins Research Group (BRG), Department of Earth Science and Engineering, Imperial College, LONDON, SW7 2BP, UK*
[2]*Geokonsulentene AS, Vestboehagen 24, 4022 Stavanger, Norway*

From early syn-rift discoveries in Gudrun (1974) and Magnus (1974) to recent discoveries in Astero (2005), Edvard Grieg (2010) and Skarfjell (2012), it is clear that opportunities still exist within the "syn-rift" play after c. 40 years of exploration. However, the syn-rift play remains challenging due to rapid lateral and vertical changes in reservoir type (i.e. shallow- vs. deep-marine) and quality. Furthermore, defining subtle syn-rift traps, be they structural or stratigraphic, may be especially problematic at relatively deep burial depths where seismic imaging is poor and well data are sparse. Better geophysical imaging (e.g. OBS, multi-azimuth, broadband) undoubtedly helps delineate syn-rift reservoirs and traps and emerging technologies such as CSEM may permit direct detection of hydrocarbon fluids. Improvements in geophysical imaging provide only part of the solution to the challenges associated with syn-rift exploration. In this presentation we argue that better application of basic geological knowledge is required to improve our ability to locate and exploit subtle syn-rift reservoirs. Here we review key areas deserving of greater focus when exploring the syn-rift play in the northern North Sea: (i) *sediment source area* - explicit recognition of the role of hinterland composition on reservoir quality is critical for exploration success. The northern North Sea provides examples of syn-rift sediments sourced locally from erosion of intra-basinal highs cored by sedimentary or basement rocks, or sourced more regionally from distant, basement-dominated areas such as the Fennoscandian Shield. Reservoir quality varies according to the sediment source area, and petrographic and provenance data must therefore be integrated when attempting to delineate sediment dispersal pathways and assess syn-rift reservoir quality; (ii) *sediment dispersal, accommodation development and the preservation of reservoir rocks* - the style of syn-rift erosion and sediment dispersal greatly influences reservoir architecture and quality. For example, deep-marine systems supplied by sediments derived from fluvial systems and reworked by waves in a shallow marine environment, may have excellent reservoir quality and continuity. In contrast, fault-scarp degradation complex reservoirs, locally derived locally from denudation of fault block crests, may have complex architectures and highly variable reservoir quality. Careful mapping of palaeotopography and/or bathymetry can therefore strengthen our understanding of reservoir distribution and quality; such careful mapping must be done in the context of a robust structural model that explicitly acknowledges normal fault growth models, and the impact of salt and pre-existing structures on rift development; (iii) *trapping mechanisms* - in addition to the commonly targeted fault block-related traps and stratigraphic pinch-out traps, we assert that extensional fault-related folds, which are ubiquitous in the northern North Sea, may represent prospective hydrocarbon traps. We must understand how and where these structures form, and the range of volumes that may resides in the associated traps; (iv) *source and migration* - the syn-rift play contains examples of self-sourced systems, where reservoirs are encased in mature source rocks, and of reservoirs that have been sourced through longer-distance migration from down-dip hydrocarbon kitchens; (v) *use of analogues* **–** the appropriate use of analogues, drawn from old fields, physical models, outcrop-based studies and modern systems, may help explorationists better understand exploration risk. Legacy data in particular may be a rich source of analogue data and may help us recognise aspects of the syn-rift play that previously were overlooked; and (vi) *novel exploration methods* - the syn-rift exploration workflow may benefit from new approaches to reservoir mapping such as the use of polygonal faults and the use of stratigraphic forward models. In summary, the Upper Jurassic syn-rift succession of the northern North Sea consists predominantly of mudstones. Sandstones are scarce and probably under-represented in the drilled wells. Prospecting for these sands, and the oil within, requires skills that are broadly similar to but subtly different from those we typically use when exploring the mature and well-documented Middle Jurassic "pre-rift" play. We urge explorationists to be creative, use all available data and mine old data for useful information that may have been overlooked. Think visually in space and time, use tailored models and modify them as your understanding and dataset improves. Communicate your ideas and develop them in collaboration with your multi-disciplinary team. Publish and, confidentially permitting, put your work up for public scrutiny.

NOTES:

Sand-rich, syn-rift, hyperpycnal plays in Norway and the UK

John Cater & John Cummings
RPS Ichron

Syn-rift sedimentation along continental margins records a transition from elongate coastal facies belts to fault-segmented mini-basins that form as extension and transtension compartmentalise the margin. Coastal shorelines and tidal flats evolve into fault-bounded marine gulfs, which are prone to rapid accumulation of excellent sandstone reservoirs supplied by hyperpycnal deltaic systems. This presentation shows examples of such systems from the Norwegian Atlantic margin. The main obstacles to drilling prospects of this type on both sides of the border are poor (but improving) seismic resolution and post-depositional structural reorganisation (tilted contacts, meteoric flushing, lack of trap integrity, etc), particularly associated with post-glacial isostatic rebound.

Rifting creates subsiding coastal embayments, which are readily diluted by fluvial flood-water to form brackish-marine gulfs. Low salinity occurs during floods, facilitating sustained hyperpycnal underflows at delta fronts. These transport fluvial suspended load (and potentially bedload) into sand-rich basin-floor fans. Such sustained fluvial-sourced underflows contrast with surge-type 'conventional' gravity flows, which dominate shelf-fed systems.

Hyperpycnal deposits record prolonged, fluctuating gravity-flows containing abundant coaly and woody carbonaceous debris. The deposits are commonly sculpted into metre-scale hummocky bedforms ('HCS') by baroclinic internal waves. Fluvial-sourced underflows tend not to travel as far as 'classical' marine turbidites, due to decreasing density contrast as sediment is deposited. Instead they deposit localised sand-rich basin-floor fans, generally less than 50km from their source. Hyperpycnal deposits tend to lack 'linked' debrites, which are characteristic of 'classical' surge-type gravity-flows triggered by submarine slope failures. However, such failures can occur on unstable delta-front slopes, just as sustained flows can occur within shelf-fed systems (during prolonged retrogressive failure of unconsolidated shelf sands, for example).

Hyperpycnal mini-basin fans differ from 'classical' turbidite fans in shape, size, sediment architecture, reservoir quality and location relative to underlying sand-rich systems. They commonly overlie coastal sand-rich systems, and are usually sealed by transgressive post-rift shales. They may host un-swept 'attic' oil, providing attractive 'late-life' opportunities. Recent successes on the Norwegian side of the border may help to de-risk similar prospects in the UK.

NOTES:

Tuesday 28th November 2017
Session Seven: Late Jurassic to Tertiary

A holistic approach to exploration of the Upper Jurassic play in the southern Viking Graben

Thomas Harris Uist & Marcello Cecchi
Wintershall Norge AS

A long exploration history starting in the 1970's, significant hydrocarbon volumes discovered both early on and recently, large amounts of data: the southern Viking Graben area is an exciting place to explore for hydrocarbons. In order to fully understand the geological history of this area and unlock the remaining hydrocarbon reserves on the terraces of the Viking Graben and southern Utsira High we need to examine every element of the petroleum system within their geodynamic context: individually and integrated together; locally and regionally. An holistic approach. This approach is well known and used amongst explorers, but often sits opposed to the systems and processes oil companies use to run their businesses.

Interpreting well and seismic data from both the UK and norwegian sides of the median line is essential in order to understand the total petroleum system and its individual elements. We present some examples of work using data from both sides of the median line in order to build our geological understanding and guide licence applications and licence work, focussing on the Upper Jurassic syn-rift play.

Tectonics: the main rifting in the southern Viking Graben area occurred from the middle Jurassic (Callovian) to the early Cretaceous (Berriasian), with the timing and style of fault movement affecting the distribution and style of deposition throughout this time interval. The earlier rifting seems to have been spread over a large area, whereas the later rifting appears to be focussed on the graben margins with the asymmetric pattern of the southern Viking Graben developed in the latest Jurassic; coeval with the deposition of the Brae systems. Localised uplift and erosion of fault blocks can be seen in the Ivar Aasen area and in blocks 24 and 25 in the Norwegian sector. Old, large scale, regional tectonics can also be seen to have an imprint on the Jurassic rifting events. Dextral strike-slip lineaments related to the Sorgenfrei-Tornquist zone can be seen to cross-cut the southern Viking Graben area: affecting paleotopography and graben morphologies; influencing pressure barriers; generating fracture networks.

Reservoirs and their depositional systems: the Upper Jurassic sand play is ubiquitous in the southern Viking Graben. The Brae-Miller-Kingfisher-Gudrun systems are sourced from both the Fladen Ground Spur and the Utsira High. The Johan Sverdrup and Brae Volgian systems are both coarse grained fan delta type systems building out into asymmetric grabens from granitic basement highs. The Asha (unitised into Ivar Aasen) Callovian and Johan Sverdrup Volgian systems are both fan delta type depositional systems. Studying the similarities and differences between these systems helps us to understand both the regional patterns and the local variations. Mapping the distribution of Rhaxella sponges helps to understand diagenesis and reservoir performance. A detailed mapping and understanding of the tectonic evolution throughout the syn-rift phases is essential. This regional to local approach has guided licence applications on NOCS leading to the award of PL777 & PL776; guiding the unitisation of the Asha discovery (16/1-16) into the Ivar Aasen field development; and further licence applications.

Hydrocarbon charge and geo-pressures: within the southern Viking Graben the organic rich shales of the Draupne & Heather Fms. provide excellent quality Type II/Type III source rocks which have expelled large quantities of hydrocarbons. Particularly around the Vana & Vilje sub-basins these shales have sourced gas condensate and volatile oil accumulations: East Brae; North Brae; Kingfisher (Intra-Heather); Devenick; Gudrun; 25/7-2. In light of this, old wells drilled on valid structures surrounding the sub-basins and previously described as dry with oil shows are now re-evaluated. Based on petrophysics, cuttings descriptions, detailed geochemistry and modelled charge, these wells are re-interpreted as gas-condensate discoveries.

Access to and integrating data from both sides of the UK-Norway median line is key to understanding the fascinating petroleum geology of the southern Viking Graben area, and to finding more hydrocarbons.

NOTES:

Derisking examples and opportunities of the Palaeocene North Sea (UK-Norway) injectites play through reliable pre-stack broadband attributes

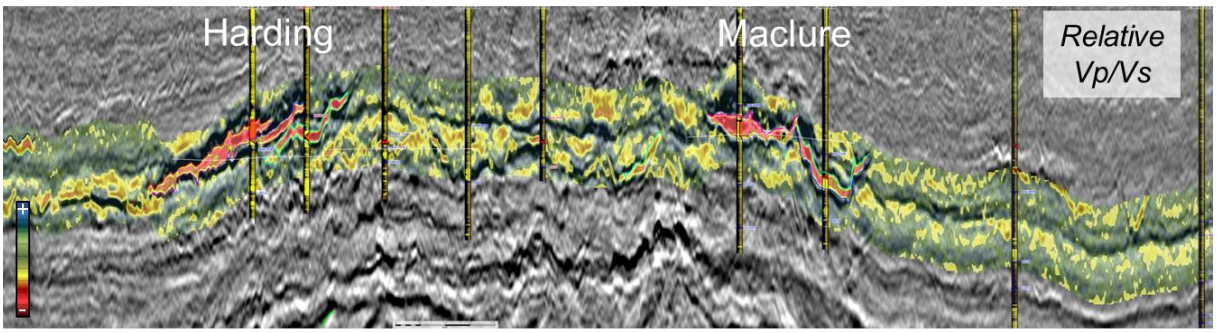
Noémie Pernin, Laurent Feuilleaubois, Mari Schjeldsøe Berg and Cyrille Reiser
PGS

Injected Tertiary sand bodies have been proven to hold significant amounts of hydrocarbons in the North Sea Viking Graben. Geophysical limitations have in the past made injectites difficult to target mainly due to the lack of seismic resolution inducing the presence of high energy side lobes. The mapping and identification of these geological features was very difficult and the estimation of the hydrocarbon presence very challenging. The recent availability of broadband dual-sensor seismic data, in particular, from both sides of the border (Norway and UK) brings clarity to known injectites such as the Volund and Maclure fields and reveals additional hydrocarbon opportunities.

The first well designed to target these features was drilled in the Norwegian sector of the North Sea in 2004. It subsequently led to the discovery of the Volund Field in block 24/9. Well data have been released, made available by the Norwegian Petroleum Directorate and were used in this study for calibration purposes.

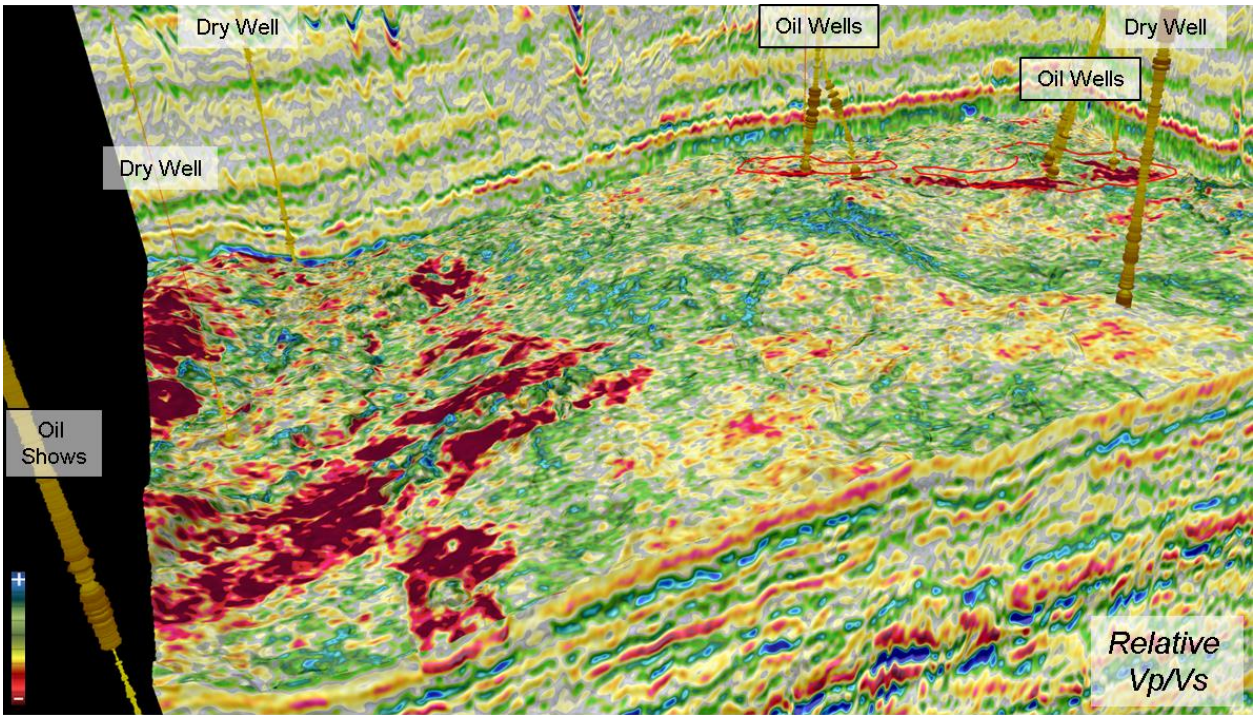
For the wells located further west, data have been gathered by the Oil & Gas UK. The quality and quantity of well information available through the Common Data Access vary from well to well from basic log suites to detailed petrophysical and production results.

Shear, saturation, porosity and CPI logs have been used in the rock physics analysis performed in the Maclure, Gryphon and Harding fields' area in the UK. The fluid effects on the elastic attributes have been modelled at the reservoir level using Gassman fluid substitution. Wells have been tied to the broadband pre-stack seismic elastic attributes (relative acoustic impedance and relative velocity ratio) in order to perform lithological and fluid classifications. A case study over the Maclure Field showed that complex geometries of hydrocarbon-filled injectite reservoirs are well imaged by the dual-sensor pre-stack AVO attributes computed without the use of wells as hard calibration.



Low relative Vp/Vs anomalies (red) highlight two hydrocarbon charged North Sea injectite fields in the UK with very good calibration with gamma-ray and hydrocarbon saturation logs.

Confidence has been gained on the injectite characterization in the UK sector through reliable broadband seismic-driven inversion, rock-physics study and calibration at the wells. This knowledge can be directly applied to near-field exploration just to the east of the Maclure Field where a prospect was identified and de-risked using lithology-fluid prediction suggesting an oil-filled reservoir. In Norway, the rock physics analysis was limited due to the amount of available well data. A pre-stack depth migrated dataset with compensation for amplitude loss and phase distortion has been recently processed in the South Viking Graben. Despite less calibration points, AVO attributes helped to identify leads otherwise missed by several drilling campaigns that targeted deeper reservoirs close to the Bøyla discovery.



Low relative Vp/Vs anomalies (red) match discovery wells and highlight potential opportunities in the Norwegian North Sea.

This work demonstrates the value of using broadband dual-sensor data to provide predictable and reliable pre-stack seismic information and uncover remaining near-field hydrocarbon potential.

NOTES:

Chasing the median line Eocene injectite play in the North Sea Viking Graben

Nick Terrell, Thaddeus Cooper Henry Morris, Michael Lawlor
Azinor Petroleum

Azinor Catalyst participated in the near median line 2014 ‘Agar' discovery through an initial acquisition of 5% interest in the P.1763 Licence. The ‘Agar' discovery well consists of a 30ft oil prone Frigg Sst section comprising an oil-down-to. Over time the company has increased its working interest to 50% and is now preparing to drill an appraisal well to delineate the discovery.

The injectite play has been pursued by companies on both sides of the median line in the area for more than 20 years. Fields such as Harding, Gryphon and Maclure (in the UK) and Volund (in Norway) are testament to the potential of the play and recent discoveries at Corona and Agar illustrate that the play continues to deliver.

With infrastructure options and recently acquired high quality 3D data straddling the median line, this area is ripe for cross border collaboration. Through the careful reprocessing of recently acquired 3D Broadband (Geostreamer) data and the application of advanced quantitative interpretation work flows to these data, the company has been able to effectively delineate the Agar discovery in terms of reservoir and fluids. Imaging of injection dykes and sills has allowed the company to map out the injectite system and develop a set of geological models to explain how these reservoirs have formed on both sides of the median line.

NOTES:

Cross-border collaboration on source to sink systems for the Oligocene – Pliocene succession in DK, UK & Norway

Erik S Rasmussen[1], Tor Eidvin[2], Fridtjof Riis[2], Karen Dybkjær[1], Mette Olivarius[1] & Anders Mathiesen[1]
[1]Geological Survey of Denmark and Greenland (GEUS), Øster Voldgade 10, 1350, Copenhagen K, Denmark
[2]Norwegian Petroleum Directorate (NPD), P. O. Box 600, N-4003 Stavanger, Norway

Over the past 10 years there has been a close collaboration between the Norwegian Petroleum Directorate (NPD) and the Geological Survey of Denmark and Greenland (GEUS) aiming at making a solid stratigraphic framework and to understand the source to sink system for the Oligocene – Pliocene succession in the North Sea and the Norwegian Sea. The studies include micro biostratigraphy, palynology, Sr-isotope stratigraphy, U-Pb geochronology, geochemistry, sedimentology and seismic stratigraphy. Data includes outcrops, well-log data, biostratigraphy, geochemical and seismic data. The main results are a solid and high-resolution stratigraphic framework and a detailed picture of the source to sink system.

In one of our studies, the almost complete, mainly deltaic, upper Paleogene and Neogene succession from Jylland, Denmark, was investigated for $^{87}Sr/^{86}Sr$ ratios in 143 samples from 18 localities. These data together with foraminiferal and pyritized diatoms data were used for correlation to a number of Norwegian wells and boreholes and one well from the British sector of the North Sea (ditch cuttings provided by BGS). The investigation shows that the geological formations in the Danish succession correlate readily with lithological units, in the Norwegian North Sea, the Norwegian Sea shelf and the East Shetland Platform, which have been investigated in the same way. The *Bolboforma* assemblages have their origin in the North Atlantic and the Norwegian Sea and confirm that it was an open strait in the northern North Sea (the only seaway passage into the North Sea Basin) during the Miocene.

Another task of the cooperation, was to establish a clear picture of the source to sink system. The solid biostratigraphic framework forms the basis for a detailed subdivision of the basin fill into depositional sequences. The provenance was investigated by comparing radiometric age dating of the sediments within the sink area to the comprehensive data available from the source area. Detailed sedimentological studies allowed quantification of sediment routing systems and partitioning of clastic sediments around southern Scandinavia. Altogether, this forms the basis for predicting the distribution of reservoir sands and sealing mud in the basin.

Source to sink analyses focus on describing sediment supply pathways from the hinterland to the deep sea. Thus, high-resolution facies architecture and sequence stratigraphy framework have become increasingly important topics for hydrocarbon exploration in sedimentary basins. The well-described Tertiary seismic succession in the Danish North Sea and Norwegian Sea followed by subsequent multidisciplinary analysis can support a detailed description of the source to sink system, and comprises important input for hydrocarbon modelling scenarios. The regional drainage patterns incorporated with analysis results in conceptual drainage models describing the regional-scale drainage evolution including significant shifts between erosional and depositional regimes. Drainage systems with changing drainage directions and varying degree of fluvial connectivity are important for development of well-defined carrier pathways within large-volume and high-quality reservoir systems. By combining the drainage systems with the solid stratigraphic framework and results from the provenance and sedimentological studies, predicted distribution of reservoir sands and sealing muds is used to set up realistic basin modelling to test possible migration scenarios.

NOTES:

Poster Presentation Abstracts

Correlatability of the Dolomite Stringers in the Haugesund and Farsund Formations of the Norwegian Central Graben: A Case Study in Unconventional Shales using Borehole Image (BHI) Data

Meriem Bertouche[1], Nicolas Foote[1] and Lena Øverbø[2]
[1] *Badley Ashton and Associates Ltd*
[2] *Aker BP ASA*

The late Jurassic to early Cretaceous Haugesund and Farsund Formations, which are widespread throughout the Norwegian Central Graben, consist of several hundred metres of grey to black laminated shales with occasional stringers of limestone, dolomite and siltstone. Sandstones are also locally developed, especially in the upper part of the Haugesund Formation. These organic-rich shales were deposited in a low-energy marine environment, with the sandstones likely to be the result of dilute turbidites sourced from the adjacent shelfal areas of the Norwegian, Danish and UK sectors. Together, the Haugesund and Farsund represent two large-scale upward-shallowing regressive cycles that are related to major tectonic episodes of the Jurassic North Sea rifting.

In addition to the very likely presence of conventional (mainly turbiditic) reservoirs within these formations that are yet to be discovered, the recent years' surge in the identification of potential unconventional plays in the North Sea, makes the understanding of the Haugesund/Farsund successions critical. The presence of thin (<1m to a few metres-thick) carbonate and clastic stringers throughout, indicate a complexity and possible cyclicity of deposition of the shales that is yet to be fully understood. Furthermore, the impact that these streaks of coarser/harder material within the otherwise relatively soft mudrocks, is significant on the overall brittleness and rheological profile of the shale successions.

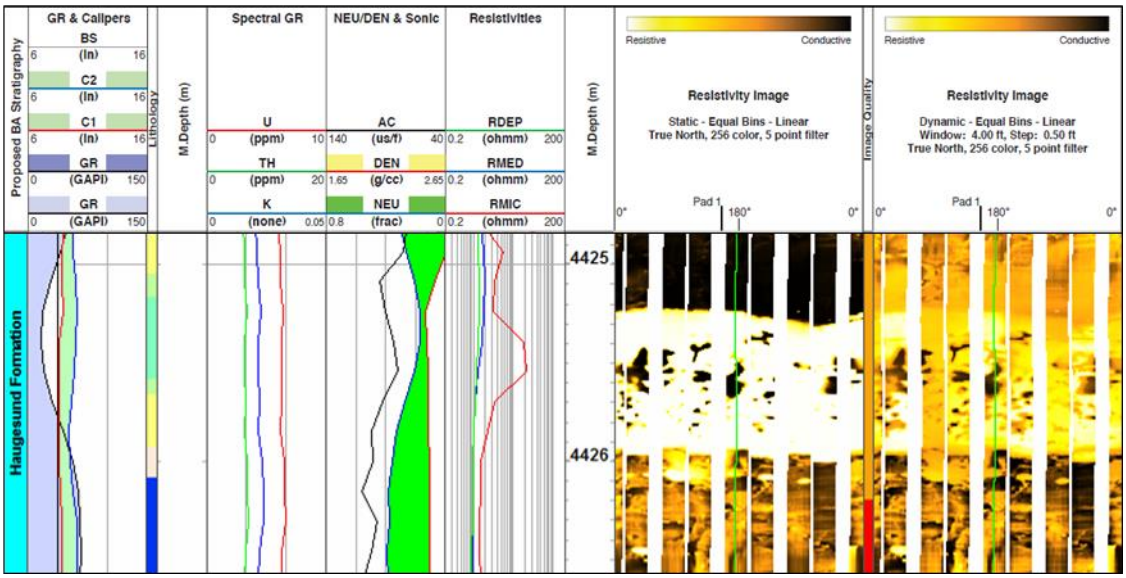
This study focuses on the correlatability of the dolomite stringers observed throughout the Haugesund/Farsund formations in the study area, which is located in the southern corner of the Norwegian sector, about 50km NW of the Danish Sector border and about 50km NE of the UK Sector.

In the study well 2/5-10 and its sidetrack 2/5-10A, located in the Steinbit Terrace, 280m of Haugesund/Farsund has been encountered. Back in 1993, when these exploration wells were drilled, the main targets were deeper Triassic sandstones (and possible Late Jurassic pre-Haugesund Sandstones), hence there is no core available across the Haugesund/Farsund in these penetrations. However, Borehole Image (BHI) data were acquired across the whole upper Jurassic succession, covering the full Haugesund/Farsund interval.

Several intervals of bright image (high resistivity), high densities/low porosities and low GR values have been observed. These are believed to be dolomite-cemented intervals, probably formed during late diagenesis. They seem to occur in both the *in situ* and the deformed muddy units, often at the boundary of lithological or dip trend changes, but their tops and bases are very rarely conformable with the bedding. They commonly contain mottles that are conductive, which could represent remnant non-cemented patches, vugs or possible small-scale fractures. These are typical features that have been observed in various locations within the Jurassic shales of the North Sea, however, it is not clear whether this cementation is distributed 'randomly' and is triggered at specific surfaces where increased compaction and expulsion of cation-rich fluids occurred, or whether it is linked to precursor surfaces/layers where cementation preferentially initiated (*eg.* end tails of turbiditic deposits further up slope). In this study, the comparison of BHI images between two penetrations that are very close-by (a well and its sidetrack with distances of 0m at the top of the Farsund and <150m at the base of the Haugesund) clearly shows that the occurrence of dolomite beds is inconsistent and that these are not readily traceable across very short distances, indicating a more probable patchy distribution, as opposed to a layered (stringer) configuration.

2/5-10

Vertical Scale 1:20



Dolomite-cemented intervals characterised by a bright image (high resistivity), high densities, low porosities and low GR values

Unconventional wisdom - why shale plays are more conventional than thought

Markus Hoppe and Alexander Foote
Badley Ashton and Associates Ltd, Winceby House, Winceby, Horncastle, Lincolnshire LN9 6PB

When it comes to the development of shale reservoirs, Europe appears to be slow, whilst the US are leading the way. Cross-border geoscience cooperation is undoubtedly key to accelerating the learning about the laterally extensive and vastly underexplored unconventional plays in and around the North Sea.

To some extent Europe's sluggish approach to unconventional hydrocarbon production is due to a largely hostile public opinion towards hydraulic fracking, which arguably primarily stems from poor understanding of this decades-old, proven technology that is simply applied to new types of reservoirs. However, the fear of the allegedly unknown is not restricted to the general public. The European oil and gas industry still appears to shy away from making bold advances into this supposedly unpredictable and uncontrollable new territory. There is no question that shale plays are largely uncharted territory, as far as Europe is concerned and they are also undoubtedly technically and scientifically more challenging. But the good news is that following the investment spending spree of the "fat years" of US$100 oil prices, boosting geoscience and engineering, today we are well-equipped to tackle such challenges.

Badley Ashton has worked on offshore Mesozoic to Tertiary shales across several North Sea countries. The experience gained over the years shows that shale plays may be considered unconventional for the time being, but the key to their successful development is and always will be conventional wisdom: solid data acquisition and interpretation.

Just as conventional upstream success has become intimately linked to subsurface knowledge, unconventional reservoir risk is a synonym for lack of information. Efficiency is to have the right information at the right time. Key questions that will always have to be answered before unconventional hydrocarbon can be recovered are kerogen maturity, storage potential and frackability of the reservoir. Geological parameters are required at all stages of decision-making. A wide range of techniques is available and growing, from CT scanning and ad-hoc geochemistry directly on the core, to nano-pore analysis within organic matter, using ion-milled samples under electron microscopic observation (FIB-SEM, *ie*. FIB-FESEM). Pore and core scale integrated sedimentological, diagenetic and structural geological knowledge combined with organic and inorganic geochemistry and rock mechanics will provide all the information needed.

This presentation looks at some of the critical input parameters that must be acquired by geological working methodologies, using example images from North Sea shale plays, such as the Farsund Formation.

Greater North Sea Basin Area – Exploratory Oil Family Analysis

Bastow, M.[1], Cutler, I.[2], Fermor, A.[2], Killops, S.D.[1], **Moore, J.K.S.**[2], Stoddart, D.[3] & Straughan, E.[2]
[1] *Applied Petroleum Technology AS, Oslo, Norway*
[2] *Applied Petroleum Technology UK, Colwyn Bay, UK*
[3] *GeoEight AS, Oslo, Norway*.

To date investigations of oil families in the North Sea region, while insightful, have had limited geographical footprint traditionally restricted to specific areas, not crossing country boundaries and limiting transfer of play knowledge. This has limited the impact of oil family characterisation towards identifying regional fill-spill trends, contributions from different source rocks and ultimately play based exploration methodologies and the principal oil families present in the petroleum system (e.g. Justwan, 2006; Petersen *et al*. 2016). APT is perhaps unique in having access to a large and robust set of geochemical analyses derived from consistent methods spanning the North Sea region. The database selected for this study is comprised of ~687 oils (316 Norway; 371 UK) across the entire North Sea (UKCS and NCS), and a wide range of reservoir ages, pressures, temperature. All the samples have been analysed by GC-MS and for fraction stable carbon isotopes (Figure 1) enabling for the first time the chance define regional oil families. We employ principal component analysis to evaluate the data. We consider what the term oil family means in relation to the principal aspects of a petroleum system (source, maturity, post-expulsion processes etc) and how parameter selection may weigh the derived oil families to these aspects. The aims of the study are two fold: 1) explore the significance and efficiency of different geochemical parameters in establishing robust oil families. 2) interpret the results of PCA analyses in terms of the petroleum system, thereby determining what insights such analyses may bring.

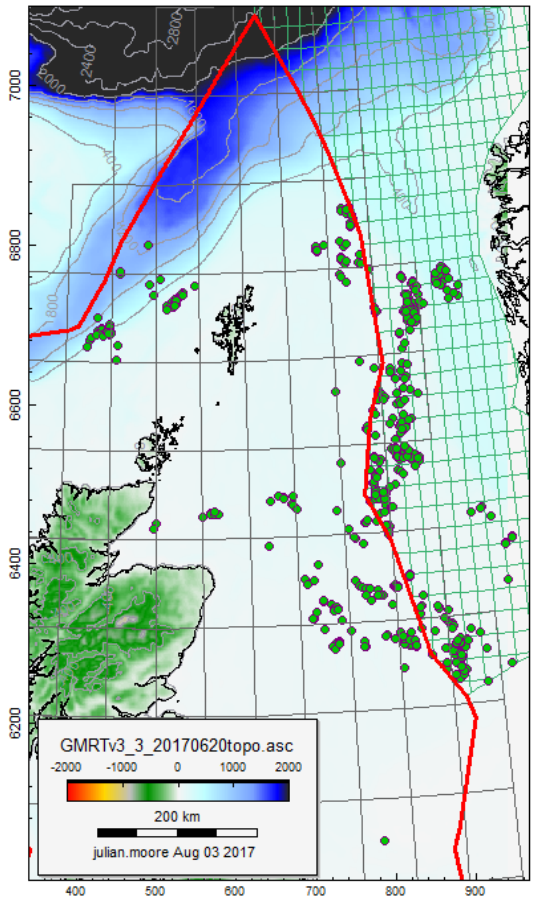


Figure 1. Distribution of the APT Cross Border oils study database

Structure and Prospectivity of the Outer Møre Basin with Links to the Faroe-Shetland Basin

John M. Millett[1,2], Sverre Planke[1,3], Ben M. Manton[1], Mansour M. Abdelmalak[1], Dmitrii Zastrozhnov[1], Dougal A. Jerram[4,3], Jan Inge Faleide[3], Laurent Gernigon[5], Will Bradbury[6], Reidun Myklebust[6], Bent E. Kjølhamar[6], Sindre Jansen[6], Helge Bondesen[6]

[1]*VBPR AS, Oslo Science Park, Norway*
[2]*Department of Geology & Petroleum Geology, University of Aberdeen, UK*
[3]*CEED, University of Oslo, Norway*
[4]*DougalEARTH Ltd., Solihull, UK*
[5]*Geological Survey of Norway (NGU), Trondheim*
[6]*TGS, Lensmannslia 4, 1386 Asker, Norway*

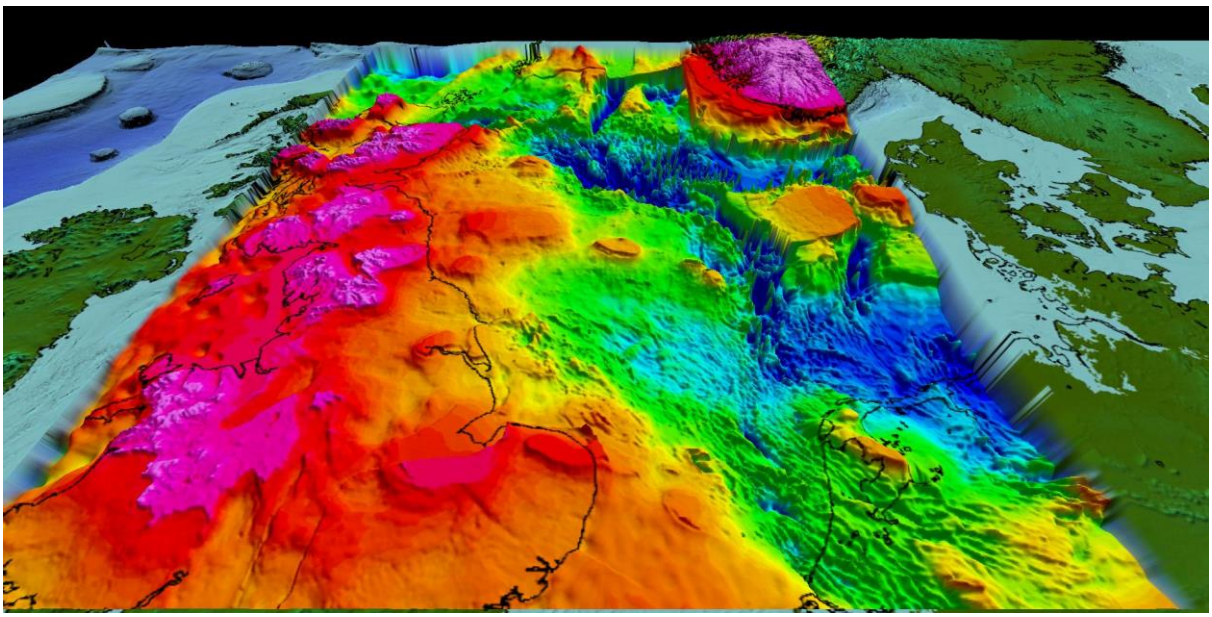
The northeast Atlantic volcanic rifted margin covers a vast offshore area spanning the continental shelves of the UK, Norway and the Faroe Islands, and the conjugate east Greenland margin. Discoveries in the Faroe-Shetland Basin region highlight the diversity of prospectivity along the margin, with discoveries ranging from fractured Lewisian basement to Eocene sandstone reservoirs. The majority of wells, however, have targeted Paleocene reservoirs, with over 20 notable discoveries. To the north, more than 20 exploration wells have been drilled in the mid-Norwegian Vøring Basin, terminating mainly in Upper Cretaceous clastic sequences. One field, the Aasta Hansteen field, will likely come on-line in 2018. Elsewhere, poor reservoir properties have been a major issue. Jurassic sequences have not been proven, but new 3D seismic data on the Vøring Marginal high documents major sub-basalt closures with a pre-Cretaceous potential. Within the volcanic covered region, both pre- and post- basalt drainage systems have also clearly been imaged with implications for the input of reservoir sands into the mud-dominated deep Vøring Basin from the west. The Møre Basin, located in between the Vøring and Faroe-Shetland basins, has been given less exploration focus. Dome structures in the eastern part of the basin are best explored, resulting in the discovery of the Ormen Lange gas field in the late 1990's. A few deep-water exploration wells have been drilled further west, discovering a minor gas field (Tulipan) in the central Møre Basin hosted within lower Paleocene sandstones jacked up by an underlying saucer shaped igneous intrusion. Recently, new and reprocessed seismic data show large-scale structures and gas seepage with a potential for Upper Cretaceous and Paleogene reservoirs. The data furthermore show pipe structures and shallow high-amplitude reflections beneath the interpreted gas hydrate stability zone. Both these features are interpreted as evidence for shallow gas originating from deep-seated reservoirs and source rocks. Further west in the Møre Basin, regional seismic interpretation suggests shallowing of the base Cretaceous unconformity (BCU) and the presence of a marginal plateau with potential Jurassic and/or older sedimentary sequences within the reach of exploration boreholes. Major structural closures and fault blocks are also identified. In conclusion, the regionally extensive outer Møre Basin offers many new exploration opportunities which are currently underexplored, including Jurassic, Cretaceous, Paleogene, and even Neogene plays. Cross-border interpretation and new 3D seismic data in the outer Møre Basin are, therefore, important contributions to improved understanding of the NE Atlantic margin evolution and petroleum potential due to its key position between the Vøring and Faroe-Shetland areas.

The search without borders for North Sea basement structures, and their impact on petroleum systems

R. Milton-Worssell[1], **A. McGrandle[2]**
[1]RMW Oil Advisors Limited
[2]Big Anomaly Ltd

An earlier pilot study published in 2010 showed how potential field data could be used to investigate deeper Palaeozoic basins within the Central North Sea. A follow-up study has been carried out which covers a much larger area including the Inner Moray Firth, Witch Ground Graben, Mid North Sea High, the Central and Southern North Seas and parts of the onshore East Midlands. The study area also extends into parts of the Norwegian and Netherlands (Elbow Spit High) continental shelves and onto the land. This second study was presented at the "Palaeozoic Plays of Northwest Europe, 26-27 May 2016 and is in press in "Palaeozoic Plays Special Publication of the Geological Society". The advantages of this big picture approach with gravity and magnetic data is that it allows a broad regional view which illustrates the continuity of key basement structures across country borders in the North Sea. It also integrates interpretations of modern long-offset seismic datasets with potential field anomalies derived from published grids of gravity and magnetic data to present a regional-scale synthesis of Devonian, Carboniferous and Early Permian basin structures.

The new long offset seismic data, with its deeper penetration, has proved to be of great use in calibrating the modelled basement surface. It reconfirms that Lower Carboniferous basin development was strongly influenced by the disposition of granite-cored Lower Palaeozoic basement blocks of the Farne, Dogger, Devil's Hole Highs, and the Auk-Flora Ridge. Additionally they occur in blocks across the Mid North Sea High linking to the landward occurrences of these granite-cored Lower Palaeozoic basement blocks. The identification of Palaeozoic basins and structures in the North Sea provides a new target for future exploration in the mature North Sea.



Modelled basement surface inset into present day topography and viewed from the south

Glacial effects: A key trigger of the North Sea petroleum systems

Ebbe H. Hartz[1,2], Sergei Medvedev[2], Erik Zakariassen[1], Per Varhaug[1]
[1]*AkerBP ASA,*
[2]*Centre of Earth Evolution and Dynamics, Oslo, University, Norway*

Ice had a major impact on the landscapes, bathymetry and burial in and around the North Sea. Here we argue that it also intensely affected the petroleum systems across the borders and should be considered in petroleum systems evaluations because 1) it represents a huge load driving major pressure excursions and thus fluid movements; 2) by glacial erosion and re-deposition, it tilted traps and shifted migration routes; 3) it led to stress pertubations comparable to plate tectonic stresses and thus challenged seals; 4) it resulted in thermal excursions that sediments probably still are recovering from.

These processes have influenced exploration thinking in recent years. For example sealing and trapping of the Snorre and Visund Fields in the Tampen area (N) (Grollimund and Zoback, 2003). Glacial stresses explained the filling of the Miocene Lille John Field (DK) (Goffey et al., 2016). The Aviat Gas Field (GB) has a reservoir in Pleistocene glacial waste (Rose et al., 2016). Glacially related tilts explain the paleo-oil column in the Troll Field (N) Riis (2017). The filling and spilling of the Sverdrup Field (N) may reflect on glacial processes (Wesenlund, 2016; Hauser et al., 2017).

In this presentation, we explore the effects of glaciations and Late Cenozoic erosion and deposition in general, on the North Sea petroleum system. The study illustrates how the last ice-age may have triggered the life, death and resurrection of giant oil-fields. The analysis is based on tilting studies from the early exploration phase of the 2-3 billion barrel Sverdrup Field, and is then benchmarked against later well data from Sverdrup as well as the Troll Field.

Comparing well-data to models we suggest that tilting the Troll Field back towards its early Neogene position will flatten the paleo-oil-water contact, which today is tilted as much as 70 meters. The Sverdrup field show no evidence of such a tilted Neogene paleo- oil-water contact. In fact the shows below the oil -water contact appear tilted the opposite direction as the Troll field, and not more than what can be dictated by ice-loading alone. The lack of a tilted paleo-oil contact in Sverdrup could suggest that the field only recently has been charged. This suggestion is supported by a tilt-related reorganization of the migration routes into Sverdrup during the Late Cenozoic.

Tilting processes may thus have influenced both giants, but in very different ways. The Troll Field (discovered in 1979) is a quite 'obvious' oil and gas trap, lying on the shoulders of the Viking Graben. Glacial (Late Cenozoic) tilts predominantly spilled oil *out* of this field, which now dominantly is a gas field. In contrast, the Sverdrup Field (first discovered in 2010), lies away from the Viking Graben, in a region that long was considered in the migration shadow. Here it appears that glacial (Late Cenozoic) tilts that helped charge oil *in to* the field.

Collectively we suggest that considering glacial processes may inspire new exploration models, and even discoveries across borders in the North Atlantic realm.

Burlington House
Fire Safety Information

If you hear the Alarm

Alarm Bells are situated throughout the building and will ring continuously for an evacuation. Do not stop to collect your personal belongings.

Leave the building via the nearest and safest exit or the exit that you are advised to by the Fire Marshal on that floor.

Fire Exits from the Geological Society Conference Rooms

Lower Library:
Exit via main reception onto Piccadilly, or via staff entrance onto the courtyard.
Lecture Theatre
Exit at front of theatre (by screen) onto Courtyard or via side door out to Piccadilly entrance or via the doors that link to the Lower Library and to the staff entrance.
Main Piccadilly Entrance
Straight out door and walk around to the Courtyard.

Close the doors when leaving a room. **DO NOT SWITCH OFF THE LIGHTS**.

Assemble in the Courtyard in front of the Royal Academy, outside the Royal Astronomical Society. Event organizers should report as soon as possible to the nearest Fire Marshal on whether all event participants have been safely evacuated.

Please do not re-enter the building except when you are advised that it is safe to do so by the Fire Brigade.

First Aid

All accidents should be reported to Reception and First Aid assistance will be provided if necessary.

Facilities

The ladies toilets are situated in the basement at the bottom of the staircase outside the Lecture Theatre.

The Gents toilets are situated on the ground floor in the corridor leading to the Arthur Holmes Room.

The cloakroom is located along the corridor to the Arthur Holmes Room.

Ground Floor Plan of the Geological Society, Burlington House, Piccadilly