Finding Petroleum

Azinor Catalyst sees opportunities in the North Sea

Kimmeridge Energy's plan for offshore "small pool" development with offshore fraccing

Doing more with offshore magnetics

Using reservoir understanding to make fraccing better

Event Report, Finding & Exploiting new petroleum resources in Europe, Mar 8, 2017, London

Special report

Finding & Exploiting new petroleum resources in Europe

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Report written by Karl Jeffery, editor of Digital Energy Journal
jeffery@d-e-j.com
Tel 44 208 150 5292

Sales manager
Richard McIntyre
rmcintyre@d-e-j.com
Tel 44 208 150 5291

Conference chairman and producer: David Bamford

Layout by Laura Jones, Very Vermilion Ltd

Cover art by Alexandra Mckenzie

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www.d-e-j.com

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39-41 North Road,
London, N7 9DP, UK
www.fuenp.com

Finding & Exploiting new petroleum resources in Europe

Finding Petroleum held a forum on March 8 2017 in London looking at new petroleum resources in Europe, including onshore unconventionals, offshore EM, offshore exploration opportunities, developments at Azinor Petroleum, and Kimmeridge Energy's plan to frac offshore

Finding Petroleum's forum in London on March 8 2017 in London looked at opportunities for finding and exploiting new petroleum resources in Europe.

The event covered why Azinor Catalyst believes there is a good business developing conventional offshore oilfields; Kimmeridge Energy's plan to develop offshore conventional and unconventional oilfields at the same time; how to make onshore fraccing more financially viable; and how offshore towed streamer electromagnetics can help better understand reservoirs.

Some of the videos and presentations from the conference can be downloaded from the event website at http://www.findingpetroleum.com/event/3fbb4.aspx

Note: not all of the speakers were able to agree for their presentations and videos to be posted online. This report only covers talks where the presentations and videos are available online

Geosphere – how to make fraccing more financially viable

Commonly, not all of the stages of a hydraulic fracture in a well contribute to hydrocarbon production. A better understanding of the reservoir might make it possible to plan the frac so more stages are productive, said Tim Harper, a consultant with Geosphere.

As a rule of thumb, it has been said that 25 per cent of the clusters produce 75 per cent of the gas. Additionally, "when you have a group of 5 perforation clusters it has recently been shown that only 1 or 2 produce afterwards," he said.

Tim Harper

Also, it is not commonly recognised that unproductive fractures can lead to a reduced efficiency of the productive fractures – each fracture increases the pressure in the rock around it, which can lead to subsequent fractures being less effective, he said.

It is hard to estimate how much of that wastage could be reduced through better understanding. "But we're not talking about 1 per cent, probably 10, 20 per cent maybe even better," he said. "I'm optimistic that it is tens of percentages."

Companies often try to improve the fracturing by empirically changing the fracture designs – but they might be better off trying to better understand the reservoir, using all of the available information, he said.

"If we can understand the genesis of that stress distribution, if this understanding is based on something we can measure or get a good handle on, now we're beginning to get a bit of a toehold at the top of the cliff," he said. "Even if we only get a statistical distribution of how stress varies we can design the fractures so we are not wasting so much material".

A starting point is to recognise that every fracture is different. We typically imagine that all of the fractures in a well are of perfectly elliptical shape and all the same size – but the reality is very different.

Fractures are different because subsurface rock stress is highly heterogeneous (varied). The stress in the reservoir is different in different places, as a result of the geological history.

Tim Harper has been involved with the subject for a long time – he originally joined BP in 1981 to build its first technical service capability in hydraulic fracturing. His work included making major cost savings which led to being a joint recipient of the most significant award of the Royal Academy of Engineering, the only occasion the medal was awarded for subsurface engineering.

Initial reservoir stress and its influence

Mr Harper talked about an example from an earlier speaker, who had said it took 500 wells in the US Permian Basin before a commercial well was achieved.

But in the UK, where it would not be realistic to drill 500 wells to achieve a first commercial well, another speaker suggested you would need to be able to gather the same amount of information from 12 wells by using more science.

Mr Harper's talk addressed this application of "more science" from the point of view of geomechanics. "We can change a completion but not the reservoir," he said.

As mentioned before, studies of fracturing projects commonly show that many of the stages don't subsequently lead to oil production, and so proppant and fluids have been wasted.

"I draw the conclusion that there is a massive potential for improving hydraulic fracturing if we could find a way to do it," he said.

"Fraccing is basically a geomechanical process, and so geomechanical advances offer the industry a major opportunity."

The role of geomechanics can be illustrated by two simple examples. "If we go directly to geomechanics, move away from the mineralogy [as a proxy for the geomechanics], we can start to see things which make sense in terms of what the production tells us. That, I would suggest, offers hope", he said.

Most of us have a mental picture of a series of hydraulic fractures as identical, with each having a smooth elliptical opening centred about the perforations.

However, the natural variation of stress associated with natural fractures corresponds to a variation of elastic strains within many reservoirs.

Stress state is typically heterogeneous.

When the rock is deformed by hydraulic fracturing, the irregular natural in situ elastic strains combine with the strains induced by hydrofracturing.
This 'strain superposition' results in hydrofractures which vary stage-to-stage, are often asymmetric and typically differ from our concept of a smoothly elliptical opening.

This variability is consistent with a variability of production seen from stage to stage.

The stress increase induced by fracturing

If you consider a horizontal well with 10 fractures along its length, after the fracturing, there is cylindrical zone of high stress in the rock around the wellbore. Each stage increases the stress parallel to the well. This stress increase can be so high as to prevent gas flow in the reservoir matrix in this cylindrical zone.
At the heel of the well, the last frac is only subjected to this cylindrical zone of stress concentration in the direction of the toe. This leaves the last frac free to open towards the heel with-

out being as stressed as the earlier stages nor tightened by any subsequent fracs.

This offers a straightforward geomechanical explanation for the effectiveness of the last (i.e. towards the heel) frac of a group of (closely spaced) fracs, whether as one of multiple stages or one of a cluster, seen in practice.

Relevance of stress

The next question is, how is reservoir stress state influence relevant to exploration and Appraisal in the UK?

Judging by the reservoir descriptions which are carried out during the exploration and even appraisal stages of unconventional reservoirs, many operators appear to believe that the reservoir geomechanics does not have significant impact on the economics and success of E & A programmes, he said. Stress state (and rock mechanical properties) are given very low priority.

It therefore seems appropriate here to explain how various aspects of the stress state within a licence, or group of licences, influence the effectiveness of horizontal wells completed in shales and hence the success of a drilling campaign.

For practical purposes, descriptions of rock stress are often simplified to the magnitudes of the maximum and minimum horizontal stress, their azimuth, the magnitude of the vertical stress and the reservoir pore pressure.

Azimuth and max / min stress

The next question is about the azimuth of the maximum and minimum horizontal stresses.

In choosing the azimuth of a horizontal well, drillers would normally plan to drill the well along the axis of the minimum stress.

"Some people like to drill at 90 degrees to that, but that's much less common," he said. Either way, the azimuth of the minimum or maximum horizontal stress normally determines the selection of well azimuth.

The direction of the minimum and maximum horizontal stresses varies and cannot simply be assumed to be parallel to the regional direction. For example, if you look at a picture of the whole of the UK, most of the maximum horizontal stress directions are approximately North-North-West to South-South-East.

But if you look at a smaller region, for example the East Midlands, they seem to point in many directions. So if you act on the assumption that the maximum horizontal stress azimuths are consistently all the same as the national picture (NNW – SSE) you will probably fall foul of local differences, he said.

Minimum stress / fracture window

The next question is the magnitude of the minimum stress and the fracture window.

For the fracturing itself, vertical fractures usually lead to more production than horizontal ones, probably because the vertical permeability of shale is so low, he said.

Usually the rock needs higher pumping pressure to make horizontal fractures than vertical ones. So you want a treating pressure in the 'window' where you have enough stress to make vertical fractures but not so high that you get horizontal ones.

It is convenient to describe stress magnitude in terms of the gradient with depth. In the UK, this minimum horizontal stress gradient (which must be overcome to create vertical fractures) increases with depth. It is "probably 0.5 to 1 psi per foot, more typically 0.6 to 0.85," he said.

In Well Preese Hall-1, the only shale gas exploration well where fraccing has been carried out to date in the UK, it varies between 0.7 and 0.8 in the reservoir section. This means for a well at 10,000 feet, you'll need a minimum of about 7,500 psi bottom hole pressure.

The vertical stress meanwhile is about 1 psi per foot. If you exceed that, you can get horizontal fractures. So at 10,000 feet that means 10,000 psi.

So there's a window of 2,500 psi per foot where you can expect to create vertical fractures.

If you want to add in a safety factor to avoid horizontal fractures, you might have 1500 psi to play with.

Orientation of the minimum stress

The faulting environment can change, both with depth and laterally. This corresponds to changes in the relative magnitudes of the principal stresses.

If you try to fracture in a thrust fault environment, where the minimum stress is vertical, you will usually get a horizontal fracture, because that is the direction of least stress, and so the easiest fracture to form. As described earlier, horizontal fractures are well known not to be productive.

There are many thrust fault environments in the UK, usually extending only down to a certain depth. "In my opinion they should be no-go regions if you are planning to frac because you are not likely to be successful. Waste of money. That's the simple message," he said.

If you have determined the magnitudes of the stresses, you can make sure you do not get surplus pumping equipment delivered to the well site to achieve a pressure which you will not need.

Induced seismicity

A further factor is induced seismicity (minor earthquakes), definitely something to avoid.

Here, oil companies might learn some lessons from another kind of reservoir engineer, who were involved in building dams for water reservoirs around 45 years ago.

The engineers noted that some of dams created seismicity and others didn't, and tried to work out why.

They found it was helpful to look at the recent geological history and, using available geological information, describe the recent trends of effective stress changes. These trends of stress change can indicate whether a given fault, or fault trend, is becoming increasingly stable and so unlikely to slip again or, to the contrary, becoming less stable.

Faults which are deemed 'critical'(on the point of slip) based a generalised averaged value of reservoir stress (implicitly oversimplifying again by assuming the stress state is homogeneous) may in fact be stable.

For example, the fault may have slipped in the recent geological past and relieved the shear stresses promoting instability. "We can't in practice make sufficient stress determinations around a fault to determine if it is stable or not. But we do [in the UK] have a good geologic database which can allow us to understand the processes that have occurred."

Extrapolating data

A big question is how much you can extrapolate data, using geomechanical data from one well (such as minimum stress magnitude and direction) to help plan a fracture on the next well. You can either assume that the stress state is homogeneous or use the available information to interpret how it may change.

As mentioned earlier, each fracture puts more stress into the rock – and so subsequent nearby fracs will need more pressure to fracture. Something similar happens at the well scale "If you have three wells, and start making another fracture in an adjacent fourth well, don't expect the rock stress to be the same as it was in the virgin state," he said.

Use available data

A representative geomechanical description of an operator's reservoir can be achieved fastest by making the most of all the data normally acquired. It would make sense to spend as much time with the available data, often mainly geoscientific, before drilling, putting it together into a preliminary geomechanical model for the licence, then progressively testing and refining the model as the exploration campaign progresses.

Explorers often have a large geoscientific database. The UK is also well examined geologically, and this can be turned into stress information. "Stress derives from geological history."

Offset well records may be decades old but helpful. In the east Midlands, BP recorded data about all of its fracs going back to 1958. This data can be helpful in working out the minimum stress. You can see if the minimum stress varies or not, and determine the magnitude of the fracture window.

If there has been coal mining in the region and the coal board has done some mechanical testing in the past, that may be available.

Some coal authorities funded hydraulic fracturing stress determinations, and laboratory work, describing rock properties. In some mines, they worked out the optimum stress direction, in order to design the most stable openings, just like horizontal wells.

With coal mine data, unfortunately much of it has been lost, often due to an unhappy atmosphere when pits were being closed, so people may not have been inclined to worry about keeping data.

The point is that whatever data is freely available can be interpreted, before you start drilling, to start building a picture of the geomechanical state of the license.

Azinor Catalyst – opportunities in the North Sea

Azinor Catalyst believes that there are still good exploration opportunities in the North Sea. Managing director Nick Terrell explained why

The commercial exploration success rates for wells for the UK North Sea are "well over 40 per cent now for both 2015 and 2016," said Nick Terrell, managing director of oil and gas operator Azinor Catalyst and the current president of the Petroleum Exploration Society of Great Britain (PESGB).

Exploration success means that companies are "generating material discovered volumes per well."

Exploring in the UK North Sea fits with the current industry trend for companies to move towards areas they think are lower risk in terms of the jurisdiction, and core heartlands and mature basins.

There has been a further 360m barrels discovered during 2016, which is "not to be sniffed at, we're in the 10 countries of the world according to reserve adds," he said.

There has also been a big drop in costs in the UK, although it had become previously an "embarrassingly high cost environment to operate in." Industry association Oil and Gas UK says that drilling costs have dropped 50 per cent, Azinor sees drops of over 60 per cent since the highs of 2013-2014.

There has been strong co-ordination between industry and the regulator to drive cost out.

Today, "you can go to the basin and drill a simple, modest depth well - and look to spend less than $10m easily," he said. "That fundamentally changes the risk appetite for a number of investors."

Also the taxation terms are "globally competitive now, finally". Historically, UK taxation has been very variable. Mr Terrell has a graph showing changes in the tax regime over 10-15 years.

Past tax hikes are slowly being forgotten, because "we clearly now have a fiscal regime in line with the opportunity set. Government and treasury are listening to industry."

Azinor has identified greenfield projects where it can break even at an oil price of less than $40 a barrel. The combination of better reservoir characterisation and low cost drilling "has allowed us to build a high value portfolio where we can move forward."

Geology

In terms of the geology, most of the 40+ billion barrels of UK production over the past has come from big fault blocks, the bulk of which were discovered before the 1990s.

There has been a part played by stratigraphic traps, the Alba Field and fields like Buzzard. And as companies have gone deeper and spent more money, the high pressure, high temperature plays have started to emerge.

However, not all the plays in the Central North Sea are currently considered mature. There are some "outliers in terms of maturity," including the Eocene, lower Cretaceous, Triassic, 'to some extent' upper Jurassic, and recently the Palaeozoic play West of Shetland, where Hurricane Energy has been active over the last year.

Consultancy Richmond Energy Partners has done an analysis of which geology has proved most successful for exploration over the past 8 years, and it shows the "lower Cretaceous has dominated, and more than half of low Cretaceous plays have a stratigraphic element to them."

Also a deeper structural play in the Triassic, which needs larger capex, "seems to be working over the last 8 years".

If you widen the scope to include Norway, there are some clear geological frontrunners – the Eocene, lower Cretaceous and Triassic seem to be working, he said.

Private equity

Private equity companies are playing an increasing role across the whole E+P lifecycle, and are getting involved in the North Sea.
To some extent, they are replacing the lack of corporate and market capital coming into the basin, to fund independent oil companies.

"Private equity companies tend to be more nimble, debt free, and well capitalised," he said. "Also, they often have a strong technology focus."


Nick Terrell

Azinor is backed by Seacrest Capital Group, a Bermuda based private equity fund, with half a billion dollars invested globally, including in other oil and gas companies.

Other private equity backed companies are Hurricane (backed by Kerogen Capital), Carlyle-backed Neptune Oil and Gas, Chrysaor (backed by NGP).

Technology

Azinor is very keen to use 'cutting edge' imaging technology, which can transform the risk profile of investing in stratigraphic traps, he said.

The company has made significant investments in seismic, and now has one of the biggest broadband seismic data sets for the North Sea. "This empowers our teams to use this technology to de-risk the basin's prospectivity," he said.

"We use advanced quantitative exploration techniques, which we feel gives us a real strategic edge."

In the North Sea, "many exploration opportunities have been developed and reviewed many many times. But with new data and seismic technology we are able to move a lot of these old ideas, prospects forward with essentially new eyes."

Azinor is chasing the 'panacea of true reflectivity', getting a detailed view of the subsurface, with better signal to noise and being able to see a wide range of depths.

As an example, Azinor used advanced seismic in its work on the Eocene "Agar" discovery in 2014 in blocks 9/9d and 9/14a, east of Shetland. It was looking for injectites (structures formed by sediment injection).

The seismic shows a string of small reservoirs going downdip from the discovery well, with a combination of deepwater channel sands and injectites. It is a stratigraphic play which is "hugely unexplored".

"Incumbent operators have started to recognise from their reservoir models that injectites play a significant role within their fields in this area," he said.

"If you encounter an Eocene sand, here it's got hydrocarbons in it. I can't find a single well that doesn't. There's a lot of hydrocarbons playing through the system, which will essentially migrate up to the highest sand."

This cannot be seen on older seismic. If you take a 3D seismic line from the early 1990s, "you see some character in there, but it is hard to see anything that looks particularly attractive," he said.

With broadband data acquired in 2013 and processed in 2014, and subsequently re-processed, there is "some character but nothing that screams hydrocarbons at you. Some possible injectites type features."

But if you move to ultra-far stack data, you can get a real "softening" of the image and see the top and bottom of the reservoir. An ultra-far stack anomaly map directly shows the hydrocarbons.

Then if you bring in impedance data, "you can define the hydrocarbons really well. The system can be mapped out in 3D, and you can see the system is very extensive.

"We're talking about 60m+ barrels, just within the Agar area, so it is very commercially attractive," he said. "We're going to put an appraisal well down later this year."

Regional understanding

Another way to improve understanding of a play is to try to put together the regional picture.

Azinor is very interested in a certain lower Cretaceous play, where it has used high fidelity regional data sets to try to build an understanding. This is in a part of the North Sea which is perceived to be mature, although it has never had a 3D survey, he said.

To build a regional understanding, Azinor draws regional isopach maps (with lines connecting points beneath which a particular stratum has the same thickness). These help show how the basins have evolved.

It integrates geological mapping and models with rock physics and seismic models.

The company is planning to drill a well in summer 2017 in this play. It expects drilling to cost around $8m, but the reservoir to have a net present value of a billion dollars. "It is extremely high value if we are successful," he said.

Infrastructure

Mr Terrell was asked by one audience delegate how much a problem getting access to infrastructure (nearby production facilities) is, because this factor stopped many projects going ahead in the past.

"I was involved in a number of projects which suffered extremely badly due to "access to infrastructure" issues, 10 years, 15 years ago," Mr Terrell replied. It has changed in that "We [now] have a regulator that has a handle on the issue and is engaged."

"There's also, a more of a collaborative culture - and there's also a recognition of the infrastructure owners - they really need to push out cessation of production - they can only do it through 3rd party tiebacks," he said.

"So a combination of regulator, operator, just commercial dynamics."

PGS – you can do more with offshore electromagnetics

Companies usually see offshore Towed Streamer electromagnetics as a way to do large regional surveys – but it can also be a way to get detailed characterisation of a reservoir, including understanding hydrocarbon saturation, says Joshua May of PGS

Using offshore Towed Streamer electromagnetics (EM) is usually seen as a way to de-risk large frontier areas, while interpretation with seismic data significantly imporves sub-surface understanding.

But it is becoming possible to do surveys at increasingly high density / resolution, so it is possible to pick out reservoirs and estimate the hydrocarbon saturation level within them, including on reservoirs which have also been discovered, said Joshua May, EM Sales and Marketing Manager of PGS.

Technologies for both "unconstrained inversion" (converting EM field data into resistivity sections and volmes without prior knowledge) and "guided inversion" (converting EM field data into resistivity sections and volumes with the help of seismic horizons) are both improving, he said.

It is possible to use rock physics models and well log data together with the EM to get an even better picture, he said.

As examples, it has been used to understand gas saturation in the Peon reservoir, in the Tampen Spur of the Norwegian Continental Shelf.

In Europe, there has been a big increase in references to offshore electromagnetics in work programs in 2015 in Norway, ranging from a simple feasibility study to a full 3D Controlled Source electromagnetics (CSEM) commitment.

In 2016 the number of references to electromagnetics in APA round work commitments offshore Norway dropped, probably due to the difficult times for the industry, but the number of 3D commitments increased. There are also 3 3D CSEM commitments now in offshore Norway.

CSEM technology may have been a little overpromised 10 years ago, now it is possible to target the specific areas where it can add value through operational assessments and feasibility studies, he said.

Recording system

PGS does a 2D EM survey at the same time as it does a seismic survey, with both streamers towed behind the same vessel, and both data sets being recorded at the same time. Both recordings can be made at the same vessel speed, usually about 4.4 knots.

The electromagnetic source is 800m long and towed 10m below the water surface, suspended below two floats, the positions of which are recorded.

The shot is similar to Vibroseis, cycling through a range of frequencies from 0.1 to 10 Hertz. The source is turned on for 100 seconds, and recording of noise records is made for 20 seconds.

The standard shot spacing is 250m, which gives "exceptionally high sensitivity" for shallow subsurface imaging. The boat moves 250m forward every 120 seconds at 4 knots. So a new shot is started every 120 seconds.

The EM recording system is visually indistinguishable from a seismic recording system – the streamer is 8.7km long, slightly longer than a traditional seismic streamer. It is towed at a depth of 100m below the water surface, or less if the water is shallower. It is typically used in water depths of between 40m and 500m.

The EM streamer has 72 receiver pairs, varying in length between 200 and 1,100 meters, so you have a broad range of offsets and a very dense spacing of receivers.

The vertical resistivity can be recovered at up to 3000m below the mud zone on the seabed, with horizontal resistivity being reliably recovered down to up to 6000 meters below mud.

Joshua May

Only one cable is needed to acquire 3D controlled source electromagnetics, compared to multiple cables usually used for 3D seismic acquisition.

The towed EM streamer doesn't need a special vessel – 2D or 3D seismic survey vessels are fine. The same crew can be used for both surveys. The EM equipment can be sent in a container to wherever it needs to go. Setting it up on a vessel takes about 2 weeks, even if that vessel hasn't been used to acquire Towed Streamer EM in the past.

If the electromagnetic streamer and a seismic streamer are used at the same time, there is usually a 100m offset between the EM source and the seismic streamer, which ensures that any interference between the two is minimized, and prevents physical entanglement.

With a sail line spacing of up to 1.5km, it is possible to acquire a full 3D image of resistivity, including calculating volumes. With a sail line of more than 1.5km, it is considered "two and half dimensions", he said.

The horizontal resistivity gathered with Towed Streamer EM is complemented by the vertical EM picture. The horizontal picture can show large scale resistive trends and the vertical picture can pick out thin resistive layers.

Towed Streamer EM can be much faster than recording with nodes (electronic devices) placed on the seabed, which take time to deploy and retrieve, you can typically acquire 120 line km a day using towed streamer, he said.

The EM data can be quality controlled as it is acquired, something you can't do with node acquisition. "We conduct simple 1D QC inversion on the vessel of every shot we take," he said. "We can monitor the data online as you would with seismic."

The towed streamer technique can also provide slightly higher resolution data than traditional node based techniques (where node spacing is 3km).

Constrained and unconstrained

If you have only electromagnetic data available (no seismic or well log data), then the inversion process is purely data driven; an "unconstrained inversion". Indeed, this is the start point for all inversion work and is a necessary and valuable stage in the process of progressing to seismically guided inversion.

You start off with a homogenous model of the subsurface, it has the same resistivity everywhere of somewhere between 5 and 20 ohm meters (in the Barents Sea for example, this is a realistic background range).

Then you let the inversion run until it converges on the best model.

If you input the initial background resistivity level inaccurately, the inversion would end up converging on the same answer, but would take a few more iterations to get there, Mr May said. This is an artefact of both the inversion code but also the high density of data acquired using Towed Streamer EM.

If you already have an understanding of the background resistivity, for example from well logs, this can reduce the time taken preparing for inversion. For example, some areas of the Barents Sea survey were 200km to the nearest well. In this case, there is a great deal of value in having an order of magnitude higher data density as this provides confidence in the accuracy of the inversion results, even when starting from a homogeneous half space.

If you have seismic horizon data, you can use it to guide the inversion (so it becomes 'seismically guided'. You can do this with 1 horizon or up to 5. If the seismic is used to inform the inversion, you can anticipate a change in resistivity at a specific boundary. "We can use as much or as little information as we like," he said.

In the process, it can be useful to compare the measured EM data with the inversion results. PGS delivers misfit data between the two to enable oil companies to assign a value to the EM data and the impact it should have in the exploration workflow and statistical ranking exercise.

You may decide only to focus on the nearer offsets or only the further offsets from the EM, depending on whether you are imaging a shallow depth or something deep.

Mr May presented an example of using EM together with seismic for finding oil reservoirs which can add to the company's portfolio of reserves.

The example was a structure in the Albatross discovery and Snovhit field of the Barents Sea, where PGS had recorded a 44km long section, 3.5km deep.

With just 3D seismic data, you can see there could be a potential reservoir and make estimates about the volume of it. If you have unconstrained vertical resistivity data, you can see it may be worth more detailed investigation, and have more confidence about the seal and charge. With Towed Streamer EM, you can get a much clearer picture compared to interpreting seismic alone.

Saturation

When combined with seismic, resistivity data can be used to calculate hydrocarbon saturation in a reservoir (the amount of the reservoir which is hydrocarbons), and show how it changes within the reservoir.

This was done on the Peon gas field, where a sequence of 2D lines were acquired in 2010. There is an area of high resistivity which sits within the reservoir outline.

Peon was surveyed simultaneously with a seismic streamer and CSEM, and the seismic data was used to provide porosity. By integrating the seismic with resistivity, together with some rock physics, it as possible to show where the saturation varies between 50 and 90 per cent within the reservoir.

The next stage in integration can involve seismic data being used to guide the electromagnetic inversion, and that being used to calculate reservoir saturation. Using a combination of saturation, porosity, rock physics models and well logs, it is possible to infer the hydrocarbon volume in place index.

Improvements

Mr May was asked what has changed in the past few years – whether the technology has improved or there has been improvements in data density.

"It is a bit of both," he replied. "We acquire data much more effectively and cost efficiently. It leads to a richer data set and both industry and the company has worked out better ways to work with it."

There are improved "inversion codes" coming on the market with calculation methods for how to handle the data. The Scripps Institution of Oceanography (San Diego) has developed a 2D code, available open source, which PGS uses. This enables the amount of inversion to increase from 30-40 line KM sections to over 200km.

PGS is also further developing its own 3D inversion code, using a Gauss-Newton method. "You end up with more accurate models, faster," he said.

So it enables the company and our customers to do more with the vast Towed Streamer EM data sets.

Kimmeridge - unconventionals and conventionals in the same place

Kimmeridge Energy wants to try hydraulic fracturing offshore – but doing it in the same place as it can produce conventionally, in order to cover the risk

Kimmeridge Energy has a business plan to develop hydraulic fracturing offshore – but do it in the same place as it can produce conventionally, in order to cover the risk.

Fraccing has not been done in the UK Continental Shelf in the recent past, but it has been done before. Offshore fraccing in some ways can be easier than onshore fraccing, since you can use seawater rather than water from the mains supply, you can deliver sand in barges rather than dumper trucks, and there are no nearby dwellings.

Mark Enfield, managing director of the geoscience division of EPI, which is working for Kimmeridge Energy, explained how the plan works from a geological point of view. He was joined by Rob Gill, senior advisor at Advisian, part of engineering company Worley Parsons, who explained how the field might be developed.

Dr Enfield was previously managing director of exploration consultancy P.D.F. Ltd, which was acquired by EPI in December 2016.

Exploration strategy

Kimmeridge has acquired acreage which it plans to develop both conventionally and unconventionally. The blocks are blocks 14/30b and 15/26b in the Outer Moray Firth, acquired in the UK's 28th licensing round.

"Kimmeridge's philosophy, borne out of practise, is that the best unconventional fields are in areas where you've produced / developed conventional fields," Dr Enfield said. "And these are the areas of Kimmeridge's experience of unconventionals."

The company also wanted to find discoveries linked with the Kimmeridge Clay source rock (note – both the oil company and the source rock are called Kimmeridge).

Dr Enfield had previously worked in the same area in 1999, undertaking source rock and maturity exploration studies working for an operator called PanCanadian – this work culminated in drilling and discovery of the giant Buzzard oil field.

"It is an area where Kimmeridge Clay is thick - better than 50m. This is a key parameter," he said. The existing discovery wells prove that the source rock works.

There has been extensive maturity modelling done on the Kimmeridge Clay in the area, including looking at discoveries in reservoirs adjacent to, and directly plumbed into the Kimmeridge Clay, Dr Enfield said.

There are two discoveries immediately to the North of the blocks, called Kildare and Finlay, which are drilled but undeveloped fields, discovered by Nexen. The block was relinquished in 2014.

The Tweedsmuir il Field, in the same field, has 71 million barrels of oil equivalent, according to the operator's reports. The reservoir is in the Upper Jurassic.

The Finlay reservoir is deeper, has a thicker sandstone, and a larger volume. There is 78 feet of pay. The well tested 42 API oil at 4250 bopd. The depth is 13700 to 13900 feet.

There is a 3 way structural closure, with sealing faults to the North and West. The volumetric calculation of recoverable resource gives a P90 of 3.9m boe, a P50 of 15.7m boe, a P10 of 40.1m boe and a mean of 19.3m boe.

The Kildare reservoir is shallower, with 16 feet of sandstone pay in a conventional reservoir, but there are lots of thinner sands and heterolithic facies. The depth is 12,000 feet to 12,500.

The discovery well found no oil water contact, and the well tested 2560 bpd.
It has fault sealing to the North, and a structural 3 way closure. The recoverable resources are calculated to have a mean of 4.5m boe, probably too small to be viable on its own.

On Kildare, it looks like there is an upthrown side to the structure, on the other side of a fault, which wasn't tested. So there is a possible "Kildare Field extension field" extending out to the North East.

Also, the seismic data (both seismic attributes and from looking at the geometries) shows that to the west of the reservoir is a region where the attributes and strata geometries are "markedly different".

However the discoveries may look much more interesting when there is also an unconventional story, Dr Enfield said.

There are also thin bed sandstones, within the source rich Kimmeridge Clay, extending beyond the main structure. These 'unconventional' reservoirs could potentially be produced through fraccing at the same time as the conventional reservoirs. There could be in excess of 150m boe STOIIP in the 'unconventional' reservoirs (thin bed sandstones and Kimmeridge Clay), much bigger than in the conventional fields.

As a development plan for the lower reservoir (Finlay), you could start with extended reach drilling into the structural closure, and extend the drilling if it is a larger structure.

For the higher reservoir (Kildare) you can look at drilling into the upthrown fault block to the North East, and going south into the downthrown area which is already proven to have oil.

In the analysis for this current project, Dr Enfield was able to use knowledge gained from previous work his team had done in 1999 in the area. We took this whole area apart and looked at all of the wells and both core and cuttings data. We've got precise basin modelling data so we understand the distribution of maturities, he said.

Note – Dr Enfield's talk included more detailed description of the reservoirs which has not been included in this written report, but you can see a video of the talk and the slides on the Finding Petroleum website.

Development plan

The talk was continued by Rob Gill, senior advisor at Advisian, part of Worley Parsons group, an engineering company, who explained some of the engineering plan.

Advisian's sister company Intecsea, also part of Worley Parsons, has been involved in the design of many offshore facilities, including 4 of the 5 deepwater facilities in Ghana at depths up to 3000m,

Advisian was asked to first put together a plan to commercially develop the Finlay and Kildare fields, in order to provide a revenue stream for the development and to install the infrastructure required for a fraccing test.

The block is 11km north of the Tweedsmuir South field, operated by Talisman, which has a subsea manifold. So a subsea tieback to Tweedmuir South could be the easiest way to achieve this.

Finlay and Kildare could be connected with Tweedsmuir's system either via a subsea manifold, or a normally unmanned wellhead platform.

The choice will depend on the number of slots and the water depth. A subsea manifold is more expensive the more slots it has. A platform is more expensive the greater the water depth. In most scenarios, it works out that an unmanned platform is the best option if there are more than 3 well slots, Mr Gill said.

There would be an 11km pipeline from the new manifold to the Tweedsmuir manifold. The control system for the new manifold could be connected to the control system for the existing Tweedsmuir manifold, which is in turn connected to the Piper platform.

There would be a water injection pipeline, a production pipeline and a controls umbilical running from the existing Tweedsmuir manifold to the new manifold. There could also be a power line if necessary, to connect to subsurface pumping. "There's lots of infrastructure in the North Sea, it's not very difficult to do," he said.

A standard 120m platform

Mr Gill believes that there could be an interesting business opportunity for Worley Parsons developing a standard normally unmanned platform, for water depths of between 80m and 120m, which could be produced by the thousand in a production line type process if subsea fraccing was to be proven, thus reducing costs.

Worley Parsons has already designed 500 normally unmanned platforms, mainly in the Middle East, South East Asia and Australasia, including 50 for Saudi Arabia. They are all designed to be "low cost, low maintenance, 1 visit per year".

Most of these don't have helidecks or accommodation, so they are similar to offshore windfarms.

This could be relevant especially in the Norwegian sector, "where everyone is talking about cheap, low cost development of satellite fields, close to central processing facilities," he said.

The platforms could be used both for producing small reservoirs ('small pools') and for unconventional reservoirs.

There would be a standardised base, and then various modules for the topsides which would be available on option, each designed with a low number of standardised components.

There would perhaps be only 10 different steel profile sizes, "rather than 40 different pipes and thicknesses you see on other platforms."

"Everything is designed in a modular manner. We think these things can be knocked out by our own yard in Stavanger very economically, or at other people's yards."

If there are 2000 horizontal wells drilled in the North Sea, and there are three wells for each drilling template or six wells to an unmanned production platform, and that means 600 drilling templates or 300 unmanned platforms, he said. "The market is absolutely huge."

Offshore fraccing

In water depths of under 120m, it is possible to use a jack up rig, and drill a horizontal well bore for the unconventional well. "I don't think there's' anything out of the ordinary for a conventional development," he said.

A number of 'frac boats' have been built, which can store fraccing fluids and have pumps onboard. Both Halliburton and Schlumberger have them. "There's been plenty of examples where conventional [offshore] wells have been stimulated by fraccing," he said.

The fraccing sand can be delivered by barge. It would probably be easier to deliver large volumes of sand to an offshore fraccing site than an onshore site, where you need hundreds of trucks.

The actual fraccing process, using multiple fracs and drillable plugs, can be done offshore exactly the same as it is done onshore.

Water disposal can be a problem – because it is not possible to predict what impurities will be present in the water, and so what kind of disposal method might be needed. Typically about a quarter of the fraccing water comes back up the well. "It could contain a range of contaminants - gas, H2S, some hydrocarbons," he said.

The water could be run through separation facilities on the drilling rig, then put into a tanker, which would then be sent onshore for clean-up, or perhaps poured into a "friendly disposal well, many of which exist on the North Sea."

Rolling it out

If the trial is successful, the next step would be to industrialise the fraccing process.

Mr Gill envisages a grid formation of multiple horizontal wells drilled from subsea templates, with each well covering a 10,000 feet square block. About 6 wells could connect into a single unmanned platform, and all these platforms would connect to a central processing facility. So a spider web of laterals.

There would probably not be a shortage of oil processing capacity offshore, because there are many platforms in the North Sea which are now operating at 2 to 5 per cent of the capacity they were designed for, including platforms close to Kildare and Finlay. Putting more production through existing platforms "has got to be a good thing," he said.

Some of these underutilised platforms also have drilling facilities in place, which it might be possible to use.

Reducing costs

The cost of drilling a well will have a big impact on the overall viability of the project. Ideally it will be possible to drill a horizontal well offshore for $10m.

One way to reduce costs is to use standardised equipment, such as Worley Parsons proposed unmanned production platform for 80-120m depth (described above).

"We have to get away from the customised engineering and move onto some sort of production line and modular building type philosophy that you see in other industries," he said.

US fraccing uses standardised components. If this is going to work in the UK, "that's the sort of thinking we need to adopt."

It would be likely that an oil and gas company involved in offshore fraccing would do its own drilling, rather than work with drilling contractors. It would probably be drilling continuously. Drilling "will come right to the core of the attention of the operating company," he said.

What did you enjoy most about the event?

> **That a lot of people came and there were discussions all round everywhere.**

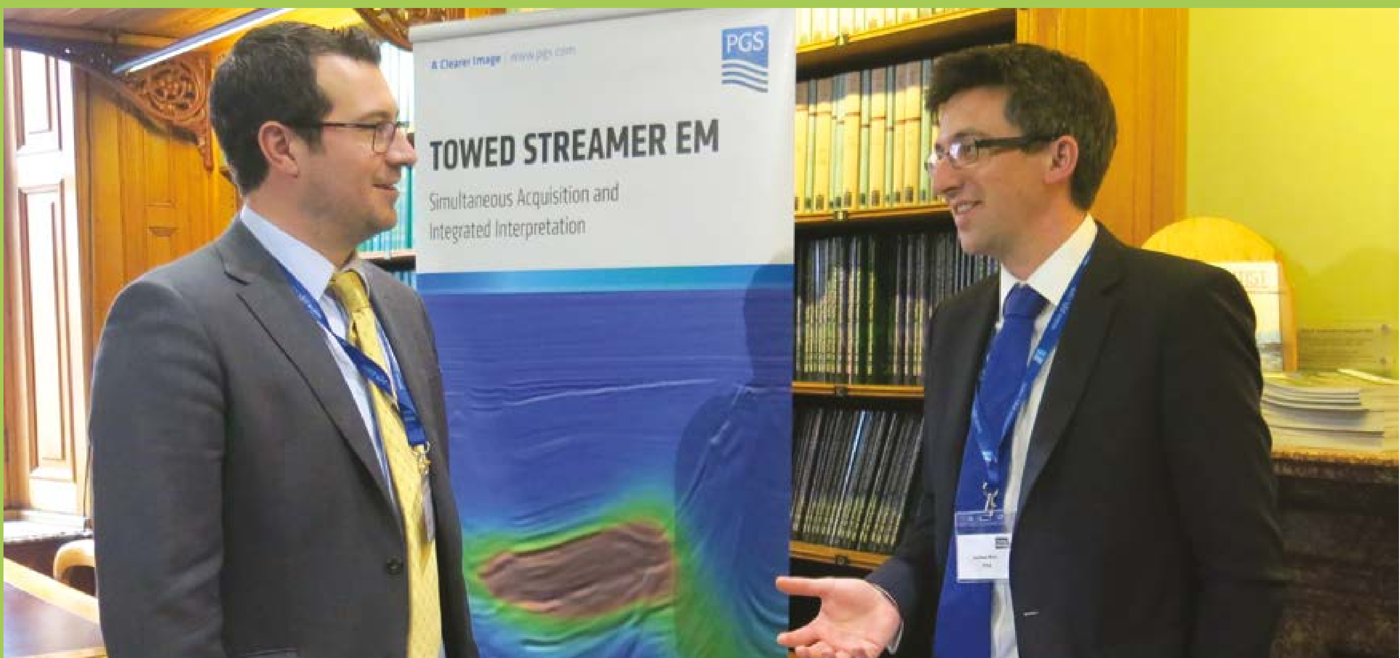
> **The Ian Roche presentation on UK Shale Gas.**
> *Graham Dean (Reach CSG)*

> **Good to see how people think they can make money in the North Sea at these prices. Also enjoyed the Kimmeridge and Aurora presentations although I'm still a bit sceptical about how long (and what prices) it will take for unconventionals to be commercial in the UK.**
> *Roger Doery (Consultant)*

> **The integrated subsurface and commercial perspectives.**
> *Frederic Yeterian (Philax Resources)*

> **Quality of the material presented; learning about shale production potential; networking opportunities in the interval.**
> *(Rego Exploration)*

> **Well balanced - mostly technical with minimal 'advertising'!**
> *Joe M Boztas (Boz Seismic Services)*



Finding & Exploiting new petroleum resources in Europe
The Geological Society, London, March 8 2017 Attendee list

Christian Bukovics, Partner, Adamant Ventures

Rob Gill, Senior Advisor, Advisian

Alexander Estrin, AL Capital Management

Geoffrey Boyd, Field Development Consultant, Antium Frontfield

David Craik, Consultant, Atlaslocal

Ian Roche, Managing Director, Aurora Energy Resources Ltd

Henry Morris, Technical Director, Azinor Catalyst

Nick Terrell, Managing Director, Azinor Catalyst

Joe M Boztas, Director/Interpreter, Boz Seismic Services

Barnaby Roome, senior geologist, BP

Raffaele Bitonte, Exploration - Structural Geologist, Consultant

Roger Doery, Consultant

Micky Allen, Consultant

Stefano Pugliese, Consultant

Robert Ward, Advisor, Decision Frameworks

Stephen Norman, Business Development Manager, DNV GL

David Jackson, Global Manager G&G New Ventures, Dolphin Geophysical Limited

Ahron Peskin, Data Analyst, Drillinginfo

Fernando Botin, Exploration Team Leader, ENI

Dario Del Gaudio, Atlantic Margin Exploration Project Manager, ENI

Boff Anderson, Snr. Land Operations Manager, EPI Group

Avinga Pallangyo, Conference Organiser, Finding Petroleum

Karl Jeffery, Editor, Finding Petroleum

Richard McIntyre, Sales Manager, Finding Petroleum

Richard Walker, Geophysicist & Team Leader

Tim Harper, Founder & Director, Geosphere Ltd

Paul Harris, Director, European B2B Markets, Glacier Media Inc.

Wally Jakubowicz, Managing Director, Hampton Data Services

Norman Hempstead, Director, Hempstead Geophysical Svcs

Naofumi Sakuyama, Chief Geoscientist, Idemitsu

Kevin Phillips, Principal Basin Research Geologist, IHS Markit

William Slade, Ikon Science

Peter Dolan, Chairman, Ikon Science Limited

Martyn Millwood Hargrave, CEO, Ikon Science Ltd

Neil Dyer, Independent

Manouchehr Takin, Independent Consultant

Mike Hibbert, Independent Consultant

Ben Dewhirst, Geologist, Independent Resources PLC

Jonathan Bedford, Director, JXT

Peter Allen, Consultant, Layla Resources

Neville Hall, Director, Llahven Ltd.

Colin Clarke, Geophysicist, Lloyd's Register

Alan Smith, Director, Luchelan Limited

Anne-Mette Cheese, Exploration Geologist, Lukoil

Nina Gray, Managing Director, Major, Lindsey & Africa

David Bamford, Director, New Eyes Exploration Ltd.

Mike King, Oil & Gas Manager, NPA Satellite Mapping

Helen Turnell, Principal Consultant, NR Global Consulting Ltd

Mark Robinson, Managing Director - Geoscientist, Oil and Gas Consultancy

Stephen Birrell, Advisor, Ossian Energy Ltd.

Mark Enfield, Managing Director, P.D.F. Limited (An EPI group company)

Tim Beal, Explorationist, PDF

Robert Parker, Consultant, Parker

Mike Rego, Independent Consultant, PetroMall Ltd

Claudio Paleari, Petrotrace Geoscience

Henry Dodwell, Consultant, PetroVannin

Joshua May, Sales and Marketing Manager, PGS

Craig Jones, Sales Supervisor, PGS

Frederic Yeterian, Director, Philax International (UK) Ltd

Josh King, Analyst, RAB Capital

Graham Dean, Director, Reach Coal Seam Gas Limited

Kes Heffer, Director, Reservoir Dynamics Ltd

Robert Snashall, Consultant, RGSConsult

Alastair Bee, Partner, Richmond Energy Partners

Patrick Taylor, Director, RISC (UK) Limited

Brian Hepp, President, Rocky Mountain Limited

Norrie Stanley, Consultant, RPS Energy

Paul Strachowski, Seismic QC, RPS Energy

David Webber, Seismic Operations Supervisor, Sceptre Oil & Gas

Miles Dyton, Schlumberger

Diz Mackewn, Chief Technology Officer, Seacrest

Alexander Chalke, Business Development Director, Simpson Booth

Glyn Roberts, Director, Spec Partners Ltd.

Vibhusha Raj Sharma, StrategicFit

Brian McBeth, Managing Partner, The Oxford Consultancy Group

Nigel Quinton, Consultant, Tower Resources PLC

Sid Shamnath, Managing Director, Tridevi Capital

Alex Dimitriou, Tridevi Capital

Richard Nolan, CEO, Tridevi Capital

Sarah Al-jasseri, Business Development Manager, Tridevi Capital

Mihiri Jayaweera, Tridevi Capital

John Weston, Tecnical Director, Tridevi Energy & Resources

Steven McTiernan, Director, Tullow Oil PLC

Hugh Ebbutt, Independent, Upstream Adviser

John Wood, Geoscientist, Wood Geoscience Limited

Helen Ricketts, Business Development Manager, Wood Group Kenny

Gabriel Mynheer, Analyst, Wood Mackenzie