Finding Petroleum

- Advanced gravity survey technology
- Assessing Atomic Dielectric Resonance
- Getting more from mud gas analysis
- Moving subsurface models around using data standards
- Self organising maps on subsurface data

Special report

New Geophysical Approaches

April 30, 2019, London

Event sponsored by:

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Adrok

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What new geophysical methods offer most potential?

Finding Petroleum's April 30th forum in London, "New Geophysical Approaches", explored a range of geophysical and subsurface techniques offering potential to better understand the subsurface, and which methods oil companies and geologists might want to pay most attention to.

We discussed advanced gravity gradiometry measurements, the potential of atomic dielectric resonance (focussed radio waves into the earth), ways to do more with drilling mud gas analysis, how to move subsurface models between software applications using data standards, and machine learning on subsurface data.

One of the most useful technical capabilities in geophysics might just be the ability to integrate multiple data sets, said Dr David Bamford, a former head of geophysics at BP, chairing the event, in his introduction.

David Bamford

To illustrate what is possible by integrating data, Dr Bamford showed a video made by NASA showing earthquakes over the past century on a revolving globe, with the size of a circle being the magnitude of the earthquake. A similar model showed strength and depth of earthquakes, and how they align with plate models. This must have been a very complex data compilation exercise, taking data about earthquakes from the multitude of people recording them around the world over the past century, all in different formats and on different mediums.

The model might be useful in predicting future earthquakes, if you identify that a certain plate boundary has seen no major earthquakes for 50 years, it may be more likely to have an earthquake now.

Similarly, in oil and gas exploration, it is no longer enough just to do a 3D seismic survey of thousands of square kilometres. Getting the understanding we need – such as of petroleum systems – needs more data sources, he said.

This becomes more relevant as we see oil companies of all sizes looking more and more at parts of the world where multiple complex data sets exist, such as onshore US, Middle East, North West Europe and former Soviet Union. The data has a wide range of formats and ages.

We are also seeing companies which operate in mature areas and unconventional areas getting more interest from investors, compared to companies which only explore in frontier areas, he said.

Meanwhile, seismic companies seem to be making plans on the basis that the oil price will soon rise to $100 a barrel, and companies will just start spending as much on seismic technology as they did in the past, with expensive deepwater, frontier, proprietary surveys. "In my own mind, it is not clear where geophysics is going at the moment," he said.

Making better use of gravity and magnetotellurics

Big advances in gravity sensors, magnetotellurics and data methods are providing a much better understanding of the subsurface, better than seismic in some situations, said Mark Davies of Austin Bridgeporth

Big advances in gravity sensors, magnetotellurics (MT) and associated data modelling and processing make it possible to do far more to understand the subsurface, better than seismic in certain situations, said Mark Davies, CEO, Austin Bridgeporth.

An example was presented of oil and gas exploration in the Muskwa-Kechika, a wilderness area in Rocky Mountains of Northern British Columbia, Canada. It is extremely hard to do seismic surveys in the region, with a total elevation variance of 4.5km, and much of the land inaccessible for big equipment.

But it is possible to do gravity surveys by aeroplane, and the data fidelity from gravity surveys has been much improved by new technology, such as the "enhanced full tensor gradiometry" or "eFTG" systems recently made available by Lockheed Martin.

The system includes twice as many accelerometers as the previous iteration of the technology, known just as "FTG", leading to a signal to noise improvement of around 3.6 based on the FTG. This means that one line of eFTG data has the same noise levels as 9 lines of FTG data with the data stacked together.

Mr Davies showed a comparison of the imagery you get from conventional gravity data, FTG and eFTG, with images of the same region of Gabon. Conventional gravity data could not see any salt bodies, FTG can see just large salt bodies, eFTG could see all of them and a defined basin high.

If you are measuring gravity with so much more sensitivity, you also need to make more effort to get rid of "geological noise" - gravity changes caused by other geological features and changes in terrain. Bridgeporth uses hyperspectral imagery and LIDAR tools to help strip this noise out.

Past exploration in Muskwa-Kechika

Mr Davies explained how, in the period 1994 to 2009, Mobil had drilled a dry well in Muskwa-Kechika, and then realised it was because its gravity correction placed the reservoir in the wrong place. It re-drilled 2 years later and hit the reservoir.

In 1994, Mobil had acquired seismic, full tensor gravity gradiometry, magnetic gradiometry, LIDAR (using laser imagery to understand the shape of the terrain), and hyperspectral imagery (analysing the colours in photographs). All the data had been integrated to model a carboniferous reservoir structure at about 4km depth.

It missed the reservoir initially due to an error in the "Bouger correction" – a way of correcting a gravity reading. It adjusts for the terrain, the height it is recorded, and the geology at the surface, as shown in the geological map of the region.

Above the reservoir, there were carbonates shown on the geological map, so the gravity correction would be made based on this. But there were actually clastics beneath the carbonates.

In another part of the survey area, there were clastics on the surface, so the geological map would show clastics, and you would correct for that, but there are actually high density carbonates beneath it, so you end up under correcting.

When the study was done again with greater data fidelity, including FTG gravity data, and a more complicated shallow earth correction based on LIDAR and hyperspectral imaging, the location of the reservoir structure moved to a different location.

You can see that the initial well hit the edge of the reservoir structure and the drillers tried to move towards the reservoir but didn't manage – but when the prospect was re-drilled 2 years later using new data, it hit the structure directly and it was hydrocarbon bearing.

Long wavelength gravity

One criticism of FTG was that it did not measure "long wavelength" gravity information, where there is a big variation in gravity reading, as accurately as a conventional gravity system.
So it was not so effective when recording gravity over a region with big changes in gravity, such as a mountainous region.

But conventional gravity data, because it takes an absolute reading of gravity rather than look for variance in gravity, does not have this problem.

Mark Davies of Austin Bridgeporth

The problem can be fixed using software and algorithms, making it possible to gather both big and small changes in gravity in the same survey system, rather than have to put together data from different systems.

Lockheed Martin has also developed a "Gravity Module Assembly", for directly measuring gravity within the FTG system.

Now, "When we run the depth models, we have the entire gravity data set to work with," he said.

Integrating with magnetotellurics

Oil companies want an independent data set to verify what the gravity is saying, and seismic was tough to gather in the difficult terrain of Muskwa-Kechika. An alternative is magnetotellurics (MT) which measures electrical currents in the subsurface.

There are ultra long wavelength changes in magnetic fields in the earth due to interference from solar radiation, and shorter period changes from lightning storms in tropical regions of the earth, with energy bouncing around the troposphere (up to 6-10km above earth). Different types of rock show up differently in a MT survey.

The MT technology was developed in the Second World War. It was initially very laborious to acquire and interpret data. "You used to spend 3-4 days to acquire one point. You had to get up in the middle of the night, switch over the frequencies that you were measuring, then go back to bed," Mr Davies said.

But between 1980 and 1997, the acquisition technology was made much smaller, so it can be carried to the field by a three man team.

With today's technology, the magnetometer is put in a 6 inch deep trench, 2m in length. There are diodes placed in little holes. It is left for 24 hours. There is no other environmental impact. This means that the technology can be more popular with environmental groups and regulators than seismic surveys. The MT data was used together with gravity data, to build a 3D model of the reservoir, with longwave components from gravity and magnetics to understand the base of the model, and topography, geological maps and hyperspectral data to understand the surface geology.

In the region of the Thunder-Cypress well in Muskwa-Kechika, there was legacy seismic data available, which had been reprocessed a number of times. Some steeply dipping thrust sheets had been imaged.

If you overlay LIDAR data, you can see that some of the thrusts line up perfectly with topographic features. The MT data could additionally help tell you the angle of the thrusts, and show up synclines, anticlines and faults. Some of the results were better than the results from seismic.

Bridgeporth acquired 5 MT lines altogether, 2 of 250km, one 270km, the others "a bit shorter", total 3,500 points. It took less than 3 months to acquire. The costs were around \$6.7m, "a drop in the ocean compared to the seismic that we're currently planning."

Next year, Bridgeporth will take an eFTG survey of the region, add in more MT lines, and then shoot seismic when it is sure of the structures.

Mr Davies was asked if anyone was integrating the various data sets in an integrated way, rather than converting each one separately to depth and then combining them together. "That's the holy grail," he replied. "Many companies say they do it but do they really? Not really," he said.

Assessing ADR

Atomic Dielectric Resonance (ADR) technologies, a form of focussed radio wave, may be able to help understand the subsurface. So far the results look interesting, although some are sceptical. A key point of discussion was around the depth resolution achievable.

Atomic Dielectric Resonance (ADR) technology sends focussed radio waves vertically into the ground, records the reflected response, and analyses the data to try to get an understanding of the subsurface.

The reflections from the subsurface can be recorded and analysed for their energy, frequency and phase.

The technologies have been proven to work over short distances – it was used to test out a folklore story in Scotland about a horse and cart stuck in a concrete railway viaduct from 100 years ago. (Google horse in a viaduct in Scotland" for the story). The technology is also used by Chevron in the US to track subsurface water.

The question is whether they can work over longer distances.

The technology is being developed by Scottish company Adrok (among other companies around the world). Adrok asked Dave Waters, a geologist with UK consultancy Paetoro Consulting UK, to help them assess the results.

Speaking at the Finding Petroleum forum, Dr Waters pointed out that many different variables affect exactly how different radio waves will interact with solids. We think we understand it, when we see how the path of light is blocked and imagine that radio waves would be blocked by the ground in the same way.

But solid material, at an atomic level, contains a lot of space, and the barriers to light we imagine solids might have, are perhaps not as great as we think. We can see that X-rays, which are higher frequency electromagnetic radiation than invisible light, can penetrate the human body. But perhaps also radio waves at much lower frequencies can also penetrate solids. It is a function of the wavelengths of the light and the size of the objects encountered, a bit like how small waves on the sea have little effect on a large cruise liner.

When a radio wave meets a barrier, it can be reflected, transmitted or absorbed, and which of these happens depends on multiple factors related to the electromagnetic energy (wavelength frequency, intensity) and the barrier (chemistry, physical microstructure, thickness). So it may be possible to find wavelengths which are a size which interact with molecules and chemical structures, and pass through it.

Experiments with electromagnetic waves to penetrate the subsurface have been going on for over 100 years, including being used to estimate glaciers in the 1920s. They were used on aircraft and spacecraft in the 1980s and 1990s, with directed radar pulses sent over an area, in a technology called SAR (Synthetic Aperture Radar).

There have been research studies using the technology to study shallow subsurface geology, with some successes in Scotland, the North Sea and Egypt. The same technology was used by a probe on a Mars rover which detected what is believed to be a liquid lake

Dave Waters, geologist with Paetoro Consulting UK

under the South Polar ice cap, looking 1.5km deep. The technology has also been used in medicine, mining, geology, archaeology, geothermal, as well as hydrocarbons.

After LIDAR was invented, using directed lasers to understand the shape of objects, researchers were interested in using directed radio waves in a similar way.

ADR has some similarities with ground penetrating radar (GPR), but GPR uses much shorter wavelengths – typically centimetres, which don't penetrate the ground so easily, so usually used for shallow subsurface. Also GPR is not usually looking at the relative permittivity. ADR is trying to focus intense rays, typically 40cm wide at most.

Developing the technology

Adrok was founded by Colin Stove in 1999, who had been previously working with remote sensing and SAR. He has been doing research on ways to make the radio waves go deeper into the earth, without about 25 patents issued.

The Adrok system uses electromagnetic waves in the 1 to 100mhz band, which is usually used for radio broadcasts. But the waves are specially created to try to give them more power to penetrate the subsurface, using directionality (keeping all the energy focussed in one direction), and coherence (all the source signals have the same wave form, frequency and phase difference).

Adrok has observed that the penetration is greater, the lower the frequency of the radio wave.

Attention is being focussed on the shape of the wave, including combining different frequencies of waves to form directed packets of energy in a fixed pulse and fixed phase relationship.

The wave is multispectral (having a range of different frequencies), in order to capture more response. There are two synchronised waves in phase, which illuminate the subsurface in a narrow converging cone. There is a longer wavelength "carrier" wave which gets more depth, and shorter resonating waves within it – their aim is to enhance as far as possible the vertical resolution.

The surveys are effectively 1D, recording responses at different times, corresponding to different depths.

In a typical survey, 17 different curves will be recorded, 14 looking at various aspects of frequency and reflectivity, and the consistency of these responses, 2 looking at estimating the dielectric constant, and 1 curve looking at the number of harmonics in the frequency response. It is difficult to use just one parameter to identify lithology unambiguously – so Adrok uses curve combinations to help.

The system can be calibrated by shooting it over wells where well logs are available.

Dr Waters anticipates making a kind of 'genome' workflow which can be applied to compare and characterise measurements of calibrating well pairs over a particular interval of subsurface, and then applied to help with predictions elsewhere, where no wells exist.
The tool can be carried in a backpack, so can go anywhere a person can go. The field work is typically done in a few weeks, and processing is more time consuming, taking a few months. But the overall cost is a fraction of seismic, Dr Waters said.

Relative permittivity

One aim from the data analysis is to get insights into the relative permittivity of different layers of the subsurface, and use this to identify the material.

Many rocks have similar values for dielectric constant, typically between 4 and 12. For hydrocarbons it is typically in the range 1-2, and for water it is 80-81. The dielectric constant also varies with temperature, so it could be used to detect steam, useful for geothermal wells. It may be possible to ultimately discern the rock type, porosity and pore fluids in this way.

Relative permittivity is about how polarised a di-electric material becomes when subjected to an electric field. It can be calculated from the recorded ADR data, applying Maxwell's laws.

Case study

Dr Waters was invited to review results of a 2017 test project supported by UK government agency Innovate UK, giving a geologist's perspective, rather than a theoretical physicist's perspective, and exploring the results for objectivity, auditability and repeatability.

From analysing the results, the system proved to work better sometimes than others, he said. It could see some points where there is a big change in the rock, (dielectric contrast) such as bands of carbonate. Seeing hydrocarbons proved a bit harder. Without a big dielectric contrast, "the non-uniqueness of subsurface responses can be an issue."

Similarly it could 'see' where there was a big change in fluid saturation or porosity.

Sometimes there were "blips" which happened to coincide with hydrocarbon bearing reservoirs, but it may be just a coincidence. Where there are near-surface zones of high-water saturation (e.g. deep soils), it can also sometimes affect results, and where possible these are best avoided.

"I'd argue subsurface geology is seen by ADR techniques but not all subsurface geology," he said.

"It readily sees high water content. Purely lithological changes are sometimes discernible. Detecting hydrocarbons in a known reservoir is trickier but also feasible."

It might be most useful in onshore surveys where lithological and structural variations are limited, he said.

The data sets might be appropriate for AI techniques, if they can spot patterns without necessarily understanding what they mean. "This is a young technology – it is under development," he said.

Geoprovider – finding more from mud gas analysis

Data from "mud gas", gas carried to the surface in circulating drilling mud, can provide many insights into the geology. Geoprovider of Stavanger is developing ways to do more with it

Oil companies routinely report data about mud gas – gas which enters a well during drilling and carried to the surface in circulating drilling mud.

But they could perhaps get a lot more insights into the subsurface from this data than they currently do, according to Stavanger / UK company Geoprovider.

Geoprovider has developed a methodology for working with gas data from drilling mud, including quality control of the data, assessing the data, analysing it and finally interpreting it.

Mud gas data is collected for nearly all North Sea wells, said Trym Rognmo, project leader for advanced mud gas and well studies with Geoprovider. The Geoprovider methodology has been tested on data for around 500 wells, mainly in Norway but some in Denmark and UK.

The biggest part of the work can be getting the data in a digital format, assessing and 'conditioning' it, steps which could all be considered part of quality control.

Many wells still only have their logs in paper format, so these have to be digitised. Some mud samples are still physical, with companies sealing a sample of mud and drill cuttings in a can and sending it to a laboratory.

The analysis work starts by looking for signs of a "show" - hydrocarbons in drill cuttings or cores, which must of course be higher readings than the background level. Gas shows are analysed in a graph chromatograph, to find out the presence of different gases such as methane.

Analysis work can involve looking at the gas ratios (the ratio of one gas molecule to another), looking at how strong the various shows are, and indications of where there might be seals in the reservoir, because the gas flows on one side of the seal are different to on the other side.

Trym Rognmo, project leader for advanced mud gas and well studies with Geoprovider

The composition and volume of any gas you find can tell you where the gas has come from - gas which comes with oil is usually much heavier than gas directly from a source rock, he said.

The data can be integrated with other data sets such as seismic or petrophysical parameters when interpreting it.

Quality control

The quality control work involves understanding different factors which might lead to a change in the mud gas reading.

For example if the drilling is overbalanced, with a heavier mud density, less gas will enter the well bore than with normally balanced drilling.

The ability of drilling mud to absorb gas varies with temperature. So if the drilling mud changes in temperature as it flows to the surface, for example for a deep sea well with mud coming from subsurface through cold ocean, that will impact how much gas comes out of the mud.

Another factor is the quality of the systems on the rig used to analyse the mud (chromatographs), and if they were calibrated and used correctly.

Data assessment

One way to assess the quality of well data is to compare the total gas recorded with the gas detector, and the sum of the measurements of individual gases from the gas chromatograph.

The "total gas detector" will record CO2 and other gases which the gas chromatograph won't detect, which you need to correct for, he said.

The data can be considered good quality if the readings are +/- 20 per cent of each other. "A lot of the vintage wells will completely plot outside of this," he said. "The majority of wells we have been working on are from the 70s and 80s."

The poorer quality data can still be used, but with a higher uncertainty assigned to it.

The larger the carbon number of a gas molecule, the higher the critical point of the gas, the temperature at which it will 'degas' from a drilling mud.

One study was made by Weatherford in 2009, injecting gas into drilling mud at the surface, and seeing how much gas came out of the drilling mud as it circulated back to the surface. It found that nearly all the methane injected into the mud was produced. But ethane had about half as much produced as injected, propane about a third, and so on.

The rate of penetration of the drilling can also affect the mud shows. If the rate of penetration is increased, the data for a certain change in depth will be recorded over a shorter time interval, which usually leads to calculations showing an increase in gas concentration for drilling over that interval.

Gas readings are recorded in time, so needs to be projected to convert it to depth, and there can be errors there.

The hole diameter will affect the gas concentration, because the smaller the hole, the less gas can penetrate into it.

A coring task will involve reducing the circulation while the work is done, and so creating less cuttings, also leading to an abrupt change in mud gas concentration. In one example, the gas concentration suddenly changed from 8 per cent to 0.5 when a core was drilled, because the circulation was slowed down and there were no new cuttings.

There was a second core drilled in the same well, with no obvious drop in the gas data – although at this point, the well was drilled into a gas cap, he said. The third core also shows a drop in gas concentration.

Another factor to take into account was the changing practise of recording gases in different years.
In the 1970s, people recorded butane and pentane but not the specific isomers. In the late 70s they started recording pentane (C5) and it wasn't until the mid-90s companies started to split both butane and pentane into isomers.

Isomers are molecules with the same formula but a different structure. For example there are two isomers of butane, they are both C4H10, but one has the carbon atoms in a line, the

other has 3 in a line and the 4th branching off the middle one.

Another factor to consider is the use of oil based muds, which can reduce the interaction between the formations and the well bore, as a kind of blocker. They can also contaminate the gas reading.
Mr Rognmo showed data from a North Sea well using an oil based mud called XP 07. "This mud is a red flag for us, we've often seen this one contaminates mud gas data," he said.

You can spot contamination by looking at the mixture of gases above, in the overburden, which acts as a kind of gas separator. Typically the lightest components will penetrate first (C1), followed by C2, C3 and so on. If you see first methane (C1) and then iC5, that might indicates that something is adding iC5 into the well bore, such as an oil based mud.

There isn't a good way to correct for contaminations other than removing the parameter, but if you are aware of them when you do data anlaysis, you can end up with a better result, he said.

Interpretation

One useful piece of interpretation work is to look for seals. If you see changes in gas signatures from below a certain depth, that indicates a seal, which gas is unable to penetrate through.

You can analyse how the level of gas changes with depth. A big change with depth is an indication of low permeability if the lithology and drilling parameters stays the same.

You can also get a sense of permeability by looking at the ratio of methane to a heavier component. If it is sandstone, which is quite permeable, the ratios between all components will stay the same. But with a tighter formation, the larger molecules can't penetrate as well as before, so the ratios will change, showing an exponential increase between C1 and C2+ . You can get an indication of good permeability, medium, low or tight, in this way.

If the drilling has been done in overbalanced conditions and with oil based mud, it can be quite hard to determine where the gas shows were from looking at gas data. It can be more useful to look for changes in the gas composition, showing you where the seals and impermeable rock is.

Geoprovider did this analysis on a Barents Sea well drilled by Equinor using water based mud in overbalanced conditions. Even though a core was taken in the reservoir, the excellent conditions in the well allowed for the gas-oil contact to easily be identified.
There were increased gas readings in the gas zone, reports of staining on cuttings, and then above it, sands with a different level of hydrocarbons.

The gas "signature", the mix of gases you see, can be different in zones containing oil, gas and inert gas.

The signature will change as oil gets heated and starts to crack (big molecules into smaller ones). It will change when hydrocarbons start migrating, with smallest and lightest molecules leaking off. If a trap is filled with different oils you get a completely new signature.

If there is an interval with no obstacles to flow, all you would expect is the lightest gas components to move towards the top. If there is a break in this pattern, that indicates something is stopping the flow, he said.

Wider analysis

The data can be very useful when multiple wells can be studied at once.

In Quadrant 35 of the North Sea, Geoprovider gathered data from 59 exploration wells, drilled between 1987 and 2017. It is quite a mature area, containing a deep cretaceous basin and a Jurassic play. There have been recent discoveries in the Quadrant, so it is quite "hot" in Norway, Mr Rognmo said.

Geoprovider modified a thickness map of the Jurassic (Millennium Atlas, 2000) play and the study were based on data from the 53 wells which penetrated it.

It presented the wells on a map, with the size of gas shows in the well mapped as bubbles. A bigger bubble represented a bigger show. There was colour coding of pink being wet gas, green being oil, and dark green being residual (heavy) oil, detected from staining on drill cuttings.

Only two wells had strong residual oil shows. They might lie on an oil migration pathway, not in the accumulation themselves, he said.

Another well had clear gas shows in an upper section, but some smaller "blip" gas shows which might easily be missed.

Another project was to plot wells with shows above the Jurassic. They mainly show where the Jurassic is thinnest, as you might expect, but there are some showing where the Jurassic is thick (250 to 500m). These shows also correspond with discoveries made in cretaceous sandstones.

The shows could be an indication of the amount of sealing – a good seal means no hydrocarbons migrates vertically, so there are most likely no shows above the seal.

However another explanation could be that as the Jurassic gets thinner, there is accumulation space to deposit cretaceous sandstones forming a reservoir, so there is more space for the trap.
The Jurassic and Cretaceous were thought to be independent, but perhaps this was not the case.

The data can be used to help improve the "common risk segment maps" which oil companies make, assessing their risks of having source, charge, trap and seal. For example you can say your risks of a seal are 75 per ecnt or 50 per ecnt or 25 per cent. The map can be improved as more data is added.

Moving subsurface models around using data standards

Energistics' RESQML standard makes it much easier to move subsurface models between different software applications. This is particularly useful if the software is cloud hosted, as it increasingly is today. Energistics' Dave Wallis explained further

Energistics' RESQML data standard makes it possible to move data subsurface data and models easily from one software system to another.

Conventionally, you move data between software packages by exporting data from a database in one application, perhaps doing some data configuration, and then importing it into another one. It can be very labour intensive, to the point where the challenges of moving data around prevent people from doing it at all.

Energistics RESQML standard is designed to enable subsurface models to be easily exported from one system and imported into another.

It works with all types of subsurface models and data sets apart from raw subsurface data such as seismic. It includes rock structural data, fluid data, reservoir simulation grids, time lapse data (how the reservoir changes over time). It can handle all the steps from seismic data interpretation to reservoir simulation, and ultimately provide a way for data to be archived.

The data could also be shared between asset teams within one company, and between oil companies. Metadata can be added so you can keep track of the pathways which data has been on before. "If you get a set of data, you want to know who touched it before, whose fingerprints are on it," said David Wallis, senior advisor with Energistics.

If you trust the integrity of the processes the data has been through before it reached you, you can work with the data without wasting time doing more checks on it, he said. Checking data takes a huge amount of people's time, particularly if they have to look at data, and tidying up problems.

The system is completely vendor neutral, for every part of every earth model.

The latest version of RESQML, version 2.0.1, was released in December 2016.

Energistics has 110 members, including E+P companies, oil field service companies, software companies, system integrators, cloud providers, regulatory agencies. It sees itself as a custodian of standards created by the industry, rather than a body which writes standards.

Dave Wallis from Energistics

The three main standards are WITSML, for moving drilling information between and operator and subcontractors; RESQML, for moving earth model data; and PRODML, for moving production data.

In 2016 Energistics created a standard technical architecture for all of them, so oil companies could easily bring together data from production, reservoir and drilling. It also developed the Energistics Transfer Protocol, to move data round quickly. It adapted a protocol developed by NASA for sending data in and out of space.

Amazon and Microsoft have recently joined, because they recognise how the standards can help transfer data into software systems hosted on their cloud, Mr Wallis says.

RESQML demonstration

Energistics conducted a live demonstration of transferring subsurface data via RESQML at the SEG (Society of Exploration Geophysicists) 2018 Annual Meeting in Anaheim, California, in October 2018, at the exhibition stand of the Society of HPC Professionals, basically transferring earth model data across different software applications. The whole demonstration took 45 minutes.

Real data was used, for the Kepler field, jointly operated by Shell and BP, in the Gulf of Mexico. It followed a real geo-modelling workflow.

The process began with a Kepler static model on Emerson software (Roxar RMS), which was updated with static software also owned by Emerson (Paradigm SKUA).

The data was then exported to IFP Beicip OpenFlow to generate additional properties. All of this time, the data was stored on AWS (Amazon) cloud.

Then the data was moved to Schlumberger's Petrel software, using Schlumberger's "DELFI" platform, which runs on Google Cloud.
Then the files were moved back to AWS for mapping new properties to the model on Paradigm's SKUA. Then a simulation was run using the "IMEX" software from Computer Modelling Group, running on AWS. Finally, time-lapse results were viewed on Dynamic Graphics' CoViz4D software on AWS.

At each step, the data in RESQML was read into the application, modifications were made on the model, and the resulting updated model was exported back in RESQML. Metadata was also added at each stage, keeping track of what had been done to the data, who did it, and with which software application.

The data transfer included wells, trajectories, static and dynamic reservoir arrays for one of the reservoirs. The trial was fully pre-prepared and tested, to make sure it would work.

Moving data between applications is necessary because there is no single application which can do everything oil companies need, Mr Wallis said. And the need to move data between software applications looks likely to increase with more "boutique applications" being developed to do specific tasks.

Having the data standard might make it possible to make data models which would otherwise be too time consuming to make, because of the effort exporting and importing data.

There is an interesting project emerging called "Open Subsurface Data Universe" with a number of subsurface data service companies discussing ways to move subsurface data around, he said.

Self organising maps on subsurface data

Self organising maps is a useful machine learning technique to help get a better understanding of subsurface data, by helping you pick out patterns which might identify geological bodies, from spotting patterns in seismic attributes. Tim Gibbons, Managing Director of geoscience sales company Hoolock Consulting, explained

Self organising maps is a technique which can be used to pick out geological bodies on seismic data, on the basis that there are similarities in the seismic attributes (pieces of data derived from seismic data) in different locations of the geobody.

Working this out manually, or with standard computational techniques, is very hard, because there are hundreds of different seismic attributes you can calculate, you don't know which ones are important, and the match is not exact, and some attributes give fairly random data.

The technique uses Principal Component Analysis to determine which attributes are most important (in terms of having the biggest influence on other attributes), and then which areas of the seismic section have a close match of seismic attributes.

You can do this analysis without necessarily understanding what the individual attributes mean, but just on the understanding that there are geological reasons which will cause a change in some of the attributes.

So in this way you reduce a large data problem to a manageable problem, thereby helping you understand subsurface features, providing a better definition of reservoir geometries and improving correlation in difficult strategic environments. It does in no way remove the need for a geoscientist – they are still needed to interpret the results.

A detailed explanation of the Self Organising Map (SOM) technique is beyond the scope of this report (although there are plenty of explanations on the internet). But this is the essence of how it can be used in subsurface exploration, as Tim Gibbons, Managing Director of geoscience sales consulting company Hoolock Consulting, explained.

Mr Gibbons presented a non oil and gas example of where Self Organising Maps is useful – working out which countries are most similar. There are many standard pieces of data available about countries, such as life expectancy and infant mortality. But if you have 30 different data points about 180 countries, it is very difficult to work with. But the SOM technique can crunch the data to show that (for example) Thailand, Ecuador and Mexico are similar in their data.

If you had only two or three variables, you could visualise them in a 2D or 3D graph to see if there is any obvious relationship. But with more variables than that, it gets very difficult to visualise.

The Self Organising Map technique is similar to a technique geologists have been using for years, using log crossplots to determine the lithology at each depth in a well.

Self Organising Maps "works well with the types of data that we've got and the randomness of a lot of that data. It works very well with seismic attributes," he said.

This is a form of machine learning which is called "unsupervised" – it is done with no idea what the answer is, and does not require any person to 'train' the algorithm. It is basically just looking for patterns in the data, and leaving it to an expert to interpret what those patterns might be.

It is possible to bring in other types of subsurface data into the analysis, such as gravity and magnetics. The only criteria that the co-ordinates (x, y, z) uses the same system, so the samples are taken from the same place.

Working with just one attribute can cause problems. For example, a geophysicist might say, because these three points have the same seismic amplitude, they must have the same rock properties.

Mr Gibbons presented an example showing why this is not always true, with a seismic image showing three different wells which had been drilled into a formation with the same amplitude, and one of the three turned out to be dry. It would have been impossible to know that just on the basis of amplitude data. But an analysis of multiple attributes picked out features which were present in the two producing wells but not the third dry one.

As the seismic amplitude is a function of impedance contrast, which is a product of velocity and density, and velocity varies on a lot of different parameters so If 2 parameters change you may end up with the same impedance contrast but you don't necessarily have the same geology, he said.

Over 150 different seismic attributes can be calculated from any seismic volume. 150 is too many to deal with, but they come in families relating to different geological features, for example instantaneous attributes are very good for unconformities and geometric attributes are very good for structural attributes like folds and faults. So you can reduce the number of attributes you want to examine based on what you are looking for.

Tim Gibbons, Managing Director of Hoolock Consulting

In one example from the Norwegian Sea, the SOM picked out 4 distinct layers, which could be highlighted with colours. Another example showed how the analysis could show faults much more clearly.

Mr Gibbons showed a series of examples from an onshore US 3D seismic survey to demonstrate the impact of changing the inputs and parameters

With an analysis based on just the top four attributes, you could just about pick out a channel and faults. With the top seven attributes the channel and faults were clearer. But with 10 attributes, the result was not as good. So too many attributes can be worse than too few.

Another question is how much data to put into an analysis. Mr Gibbons showed results just working with data from just below the channel and just above it, so a lot less data, and it shows a clearer image of the features.

You can choose to only run the process on a certain subset of your data. This is called 'harvesting'.

Mr Gibbons showed an example of a self-organising map which was "harvested" in four different quadrants of the image. The channel only exists in the top left quadrant, and the image harvested on the top left quadrant shows the channel much clearer. The images harvested in the top right, bottom left and bottom right quadrants don't pick out the channel in anywhere near as much detail. One image could not show the channel, just the boundary around it.

Further examples were shown with varying input parameters such as the neural learning rate, initial neighbour distance and number of neurons. However, the impact of changing these was much less than seen in any of the previous examples.

The software system was developed by a specialist geophysical software company.

New Geophysical Approaches, April 30, 2019, London, Attendees

Hugh Ebbutt, Director, A T Kearney

Paul Murphy, Key Account Manager, Oil and Gas Division, Airbus Defence and Space

Peter Browning-Stamp, Geoscientist, Ardent Oil

Jeremy Lynch,Principal Geophysicist, Assala Energy

Bryan Cockrell, Geologist, Assala Energy

Harry Davis, Exploration & Nv Manager, Assala Energy

Christian Richards, Sales Manager, AustinBridgeporth

Phil Jones, Chief Technology Officer, AustinBridgeporth

Simon Berkeley, Director, Berkeley Associates

David Sendra, Associate Consultant, BlackRockQI

Joe M Boztas, Director/Interpreter, Boz Seismic Services

Mark Davies, CEO and Founder, Bridgeporth

Robert FE Jones, Director, Caithness Petroleum

Robert Kennedy, Commercial Director, Caithness Petroleum Limited

Nick Pillar, Manager of Geophysics, Canadian Overseas Petroleum Ltd

John Glass, MD, Cloverfield Consulting Ltd

Diwin Amarasinghe, Geophysical Specialist

Richard Walker, Consultant Geophysicist, Cornhill Economics Ltd

Ian Newth, Director, Count Geophysics

Grahame Grover, Director, Cumbre Consulting

Raffaele Di Cuia, Technical Director, Delta Energy Limited Ltd

Dave Wallis, Senior Advisor, Energistics

Martin Riddle, Technical Manager, Envoi

Karl Jeffery, Editor, Finding Petroleum

Avinga Pallangyo, Events Manager, Finding Petroleum

Trym Rognmo, Project Leader, Geoprovider

Norman Hempstead, Director, Hempstead Geophysical Services

Tim Gibbons, Managing Director, Hoolock Consulting

Mark Robinson, Independent Consultant

Christian Bukovics, Independent Director, JKX Oil&Gas Plc

Tom Meyer, Fellow, Lockheed Martin

Jim Archibald, General Manager, Lockheed Martin

Datta Kulkarni, LTI

Paul Spencer, Senior Production & Seismic Data Manager, Lynx Information Systems Ltd

Mike Larsen, Director, Metastream Ltd

David Bamford, Director, New Eyes Exploration Ltd

Alan Poole, OGA

Abi Mirkhani, COO, OPG Supply

Dave Waters, Director and Geoscience Consultant, Paetoro Consulting UK Ltd

Frederic Yeterian Director Philax, International (UK) Ltd

John Clure, Managing Director, Phoenix Hydrocarbon Resources Ltd

Tim Archer, Managing Director, Reid Geophysics Limited

Martin Smith, Business Development Manager - Operations, RPS Energy

Aaron Lockwood, Software Sales Manager - EAME Shearwater Geoservices

Tom Martin, Director, Shikra Consulting

Tim Browne, Spectrum

Gehrig Schultz, CEO, Surus Geo B. V.

Lisa Warsame, Business development executive - energy, Tessella

What did you enjoy most about the event?

Introduction talk – always good points to think about.

Very interesting presentation and discussion by Adrok - genuinely a new and thought provoking technique. Also an excellent presentation by Hoolock Consulting on the applications of AI.
Richard Walker (Cornhill Economics)

Old and new techniques this time-- just understood about gas shows!

Networking and listening to technical experts.

The Adrok talk.

Meeting new people.

The chance to present is always a privilege.
Dave Waters (Paetoro Consulting for Adrok Ltd)

The talks and the networking.
Trym Rognmo (GeoProvider)

Networking.