Finding Petroleum

The Super Basins concept

Kimmeridge and ramping up in the Permian

Drilling 48 wells per square mile

What a factory approach offshore would mean

Standardised offshore unmanned platforms

Better ways to finance offshore developments

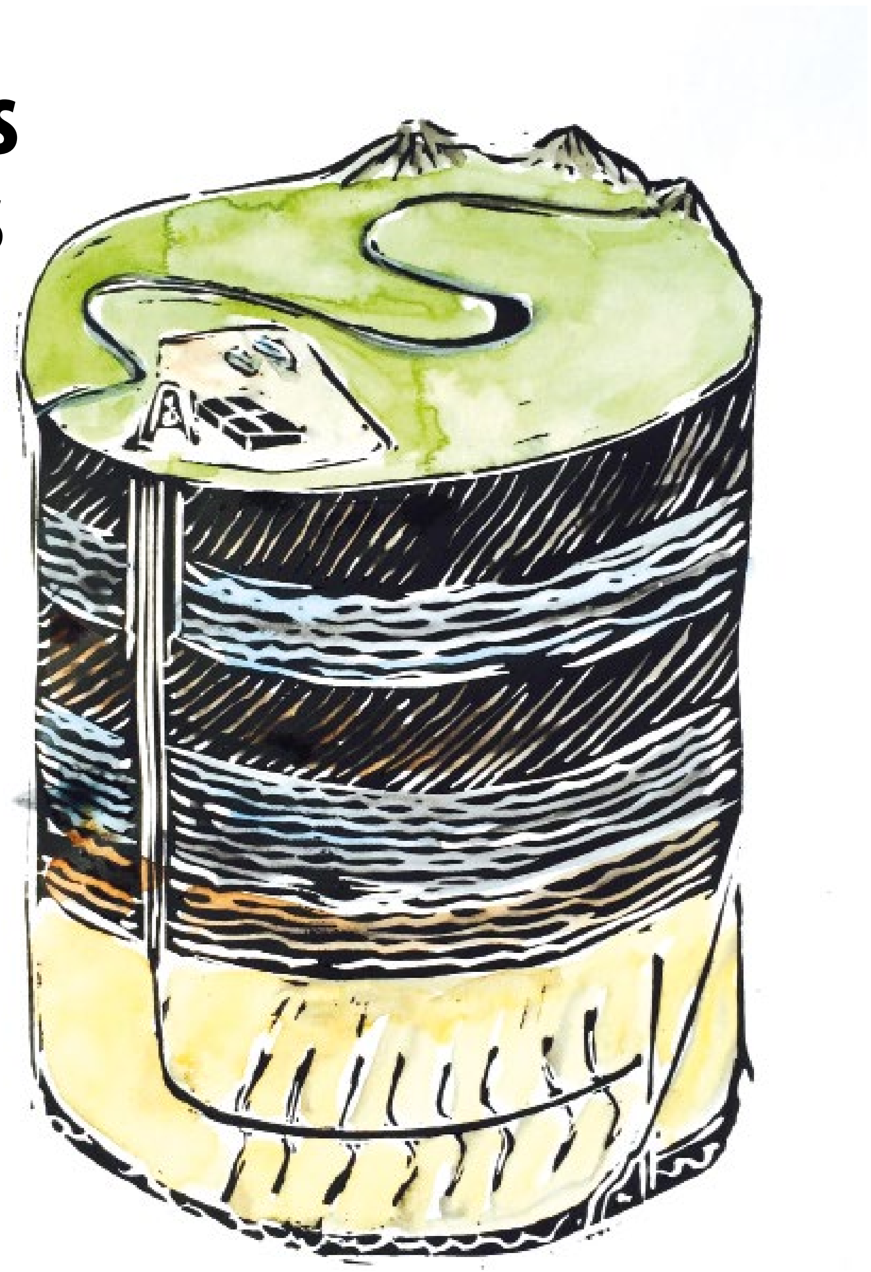
Finding oil in stratigraphic traps

Opportunities in Mature Provinces, London, February 21 2018

Special report

Opportunities in Mature Provinces and Super Basins

February 21 2018,
London



Opportunities in Mature Provinces

Finding Petroleum's "Opportunities in Mature Provinces" forum in London on Feb 21 looked at large low risk onshore opportunities, factory style production in the Permian basin, factory style production in the North Sea, lower cost wellhead platform developments, and using electromagnetics to find new oilfields

Finding Petroleum's forum in London on Feb 21 2018, "Opportunities in Mature Provinces and Super Basins" explored ways that oil and gas companies can find investment opportunities offshore, onshore, in both conventionals and unconventionals.

We explored the 'Super Basins' concept, initially developed by consultancy IHS, which helps answer oil companies' call for low cost, low risk opportunities. Halliburton showed an analysis showing where most of the undiscovered small reservoirs may lie, based on comparing the distribution of discovered reservoirs in both mature and less mature 'Super Basins'.

We heard about Kimmeridge Energy's operations in the US Permian Basin with 'factory-style- drilling, thousands and thousands of wells all exactly the same, with a wells-per-square-mile intensity never seen before, with different wells targeting different reservoirs stacked on top of each other.

Chris Wheaton, investment manager with investment banking firm Stifel, explained how he thinks 'factory-style- drilling could be taken further in the North Sea, with more standardising, better working arrangements with suppliers and better use of data.

Rob Gill of Petromall illustrated how the costs of getting 'small pools' into development could be reduced through low cost, standardised well platform developments, rather than subsea well heads, and how this could be more attractive to investors.

Daniel Baltar, partner in Fox Geo, illustrated how there may be many more reservoirs yet to find in stratigraphic traps, which are hard to de-risk using seismic – but electromagnetic data can play a big part in helping to find them.

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This is a report from the Finding Petroleum conference "Opportunities in Mature Provinces' held in London in February 2018

Event website

http://www.findingpetroleum.com/event/2c77f.aspx

Many of the videos and slides from the event can be downloaded from the event agenda page.

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Super Basins – a different way to see mature fields

The 'Super Basin' concept is a different way to look at mature fields, focussing oil companies on the lowest risk, lowest cost opportunities, which are probably in the largest fields

"Super Basins" is a concept and term developed by oil and gas consultancy IHS, as a way to demonstrate where lower risk oil and gas resources may be available, looking purely onshore and at resources known about today, which can be produced at lower risk and cost. In other words, opportunities which may be viable at today's low oil price.

One purpose for the concept is to help oil and gas companies focus their field development efforts away from expensive offshore frontier locations, where a lot of discoveries were made between 2010 and 2013, but are too expensive to produce at today's oil price.

Owen Sutcliffe, Manager of Exploration Insights at Halliburton, presented his perspective on Super Basins and some of the analysis Halliburton has done to work out where exploration opportunities may lie.

IHS defined two tiers of Super Basin. A "Tier 1" Super Basin is defined as a basin which has produced a minimum of 5bn barrels of oil equivalent in conventional fields, and has have a further 5bn barrels of oil equivalent remaining and proven.

A "Tier 2" Super Basin is defined as the same but with either /or, i.e. either it has produced 5bn barrels of oil equivalent from conventional fields, or it has a further 5bn barrels of oil equivalent remaining and proven.

The Super Basins tend to have two or more source rocks, and multiple stacked plays within them. There are 25 Tier 1 Super Basins and 22 Tier 2 Super Basins in total. The Tier 1 Super Basins are located across North America, Venezuela, North Africa, North West Germany, West Siberia, China and North West Australia. The Super Basins have a great deal of variation and do not have the same exploration potential.


Owen Sutcliffe, Manager of Exploragtion Insights at Halliburton

Halliburton analysed the Super Basins further using its own database of data about petroleum systems around the world, and the Rystad Energy "EQ" database about resources and reserves, to try to work out where the largest opportunities may exist.

Ideal or not?

An interesting question is whether or not the Super Basins are "ideal" petroleum systems.

Halliburton compiled a list of factors which make a basin "ideal", which could be added together to generate a score.

Factors include the thickness and extent of source rocks, how much of the basin is covered by the source rock, and whether the system has thick, high permeability reservoirs with multiple seals.

Other factors are whether there is an 'active charge', putting more oil into the reservoir today. Also whether the charge system is diffuse, spreading oil into a number of different basins. Another factor is if there are many "low strain" traps, which have less propensity to leak.

Some basins had a number of petroleum systems, and they could all be ranked separately.

Observations

A number of interesting general observations can be made from the analysis, Dr Sutcliffe said.

A large variety of geological types can be seen in the list of Super Basins, including rift basins, passive margins, foreland basins, fold and thrust belts. These basins are both clastic and carbonate dominated. There is general observation that foreland basins dominate the portfolios, although passive margins tend to have better petroleum systems. Furthermore, the Tier 1 basins tend to be larger than the Tier 2s. That is probably not a surprise, he said.

The petroleum systems have a wide range of quality, with not all of them "approaching a level of ideality". Many of the 'Super Basins' show "significant departures from ideality," he said.

The most limiting factor on the development of petroleum systems is usually the charge and the source rock system. Second to that, the most limiting factor is the development of the seal and trapping system. There is only one case where the reservoirs are the main limiting factor, which is the Western Siberian basin, he said.

The ability to generate charge is mainly linked to the availability of thick widespread source rocks, indicating a simple, progressive burial, and then the ability to migrate that charge throughout the basin.

The ability to trap charge is affected by the presence of multiple levels of thick effective seals in the basin, and the occurrence of diverse traps in large "low strain" forms.

Another observation is that younger petroleum systems tend to have a better charge within them. These tend to be at their maximum burial depth in the present day, with charge systems which are still active and charging the traps.

For older basins, often around the Palaeozoic, the ability to trap oil becomes a more dominant factor than how good the petroleum system is.

Typically, type 2 Super Basins have more limitation on their ability to trap charge, as well as being smaller, he said.

Halliburton calculated the average reserve thickness for each basin, by dividing the reserves volume with its aerial coverage. It showed that there is a similar thickness for both Tier 1 and Tier 2 basins, but Tier 1 have a larger volume of resources. This could be attributed to the greater area available for the charge, and the greater trapping efficiency of Tier 1s, he said.

Resource heterogeneity

To try to compare the characteristics of the different resources, Halliburton did a study where it normalised the volume of resources in each basin to 1km3.

This made it possible to identify some "End Members", Super Basins which have a certain characteristic more than all of the others.

It found that some basins had a large number of relatively small fields spread throughout the region, others had most of the resource concentrated in a small number of large fields.

Some basins had charge very widespread, in other basins the charge was focussed in a particular area, producing a thicker spread of hydrocarbons.

Two basins with thick hydrocarbon columns are the Rub al Khali and Central Arabia basins with large structural traps draining the adjacent synclines, and multiple stacked pay in reservoirs.

At the other extreme are petroleum systems in the Appalachian and Williston basin, with lots of "fairly small, subtle structures" with hydrocarbon charge distributed widely across the basin.

Exploitation

Perhaps the most useful finding of the study is that you can make an estimate of how much oil remains to be produced in basins from the 'long tail' of smaller fields, because some basins have had more of their 'long tail' produced than others. In other words there are "relatively immature" Super Basins and "more mature" Super Basins.

For example, if you look at the Western Canada sedimentary basin, you see that the large number of smaller fields has been very well developed.

If spacing of fields in Super Basins is normalised and compared to the number of exploration wells, it reveals which basins are less explored, and so should have space for more exploration.

This means you can classify the different Super Basins into their level of exploration maturity. "We've got some surprising results that I don't think we fully expected to see," he said.

"Using this matrix it allows us to have an idea of the trend and trajectories the basins can follow as they transition from a less mature state to a more mature state," he said.

There will be no surprise at the discovery that the Anadarko Basin and US Gulf Coast are "exceptionally well explored".

The analysis also showed that one difference between Tier 1 and Tier 2 basins is that the Tier 2s typically have much less area of ground available for exploration.

By getting data about the known number of fields, and putting it together with the usual probability distribution of fields in Super Basins around the world, you can make an assessment of the likely resource which might still be available.

Kimmeridge - how Permian basin development has evolved

Development in the West Texas Permian basin is arguably going into a third phase of 'factory' type development, with much closer well spacing targeting multiple 'horizons' within the same square mile, said Neil McMahon of Kimmeridge Energy

The Permian Basin of West Texas is arguably now in a very different stage of development to the early days of fracking, with the drilling intensity going to a much higher level, looking more like manufacturing than it did before, said Neil McMahon, managing partner with Kimmeridge Energy.

Geologists often think they are working in an 'old' industry, where everybody knows everything there is to know. But the way companies are working today does not fit with the old knowledge, he said. "The science is embryonic, our understanding of how oil is generated is embryonic, and how oil migrates is embryonic."

"All my training, all my work, from the early 1990s at BP, I've frankly thrown out the window because it is not that relevant any more to modern understanding of petroleum systems, how oil is generated and how oil is migrated," he said.

Understanding petroleum systems is important because the most important factor in governing whether there will be oil in a reservoir is whether the source rocks were in the right temperature 'window' over geological time, so they would turn into gas or oil.

This is a more important factor than the thickness of the reservoirs, he said.

Also, the aerial extent of the source rock is not as important as the aerial extent of the source rock which is in the right window.

Geologists use this understanding to try to define 'hotspots' within the basin, where oil is most likely to be. These are not necessarily the deepest part of the basin.

Understanding West Texas

Texas is a good place to start for an oil company, since over a third of the US onshore oil reserves are there. Texas is not as expensive to operate as Alaska, and not as anti-fracking as California.

And about 40 per cent of the oil in Texas comes from the West Texas Permian basin, he said.

West Texas can be divided into four sub basins, all together making up what is known as the "Permian".

These are the Delaware basin, where "most of the action is happening today". The Central Basin Platform, or CBP, which is the historical centre of West Texas oil industry going back to the 1920s. There is also the Midland Basin and the Eastern Shelf.

All these four still have "significant production per square mile." In some areas, particularly the Central Basin, there has been over a million barrels of conventional production per square mile.

The Permian can be considered a "perfect petroleum system," with an enormous volume of resources and production coming from very few fields, and that was true before unconventionals were developed.

Compare it with Kansas, which has significant oil production, but most of the oil has migrated into Kansas from basins outside. "I would argue that it is not a perfect petroleum system," he said.

History

The first phase of development of the basin, starting in the 1920s, could be called the "main conventional phase." It was initially focussed on the Central Basin Platform, the Delaware basin to the West, Midland basin to the East, and the Eastern Shelf.

This was followed by a period just before 2000, when a lot of vertical fracking started to take place, looking at lower quality reservoirs around the big oil fields.

After 2000, horizontal drilling was first tried through the Bakken and Barnett shales. Companies started targeting reservoirs around or below the main fields, which had a lower porosity and permeability.

Increasing intensity

We are now arguably entering a second phase of unconventional development, focussed on the Delaware Basin, Mr McMahon said. Companies are placing wells much more closely together than they have ever done before.

The Delaware basin currently has 16 per cent of all of the horizontal rigs in the US, and so probably 16 per cent of current drilling activity. "That's going to go up and up," he said.

The best parts of the Delaware basin can work with $30 oil prices, with the most stacked pay and best overall economics.

There was a massive ramp of in activity in 2017, with companies going in full "development" mode, after doing all the de-risking of the reservoirs earlier.

To illustrate the pace of development Kimmeridge has used satellite imagery to compare a picture from January 2007 to January 2018 in the Delaware basin, which shows how many more wells, roads and pipelines there are.

US drilling permits often require companies to drill a new well at least every 120 days or risk losing some of their lease, which also adds to the pressure to keep drilling.

Delaware has multiple different formations, which makes it different to formations such as the Eagleford shale play, which is largely a "one formation unconventional play" and now "getting towards mature mode".

Many parts of the Permian have many levels, described as Wolfcamp A upper and lower, Wolfcamp B upper and lower, Wolfcamp C and D. So if there are multiple wells into each of those, within the same lease block, "
This is what I mean by how exponential the drilling activity is going to take place".

As an example, Energen Resources Corporation is currently targeting many different levels in the "Wolfcamp" reservoirs of the Delaware basin, with laterals all at different levels. The company is planning 16 wells just to go into the "Wolfcamp A" horizon on their lease.

Similarly, Resolute Energy is planning 36 to 48 wells per square mile in its lease in Reeves County, to be drilled over the next 10 years.

"It shows you how the industry is taking these mature old basins and moving them forward," he said.

Tracking source rock

Kimmeridge is making a lot of effort to track which source rock the oil in the reservoirs is coming from, using geochemical methods. "We're coming to the era of the geochemist," he said.

The studies show that about half of the oil is moving moves vertically (upwards) rather than laterally within the reservoirs, coming from older and deeper source rock systems, going through microfractures rather than through faults.

For example, because the Central Basin Platform is sitting on a high, there is very little Permian age strata which has been in the temperature window where it would generate oil, he said. So the oil can only have come from an older source rock.

This is something "the industry hasn't caught up with yet," he said. "It is a different way of thinking about migration to the standard North Sea approach."

Source rock typing is "an absolute must in every basin," he said. "Not many people do it, they say 'it's oil, do we care where it came from'. There's a huge amount of complexity in basic geochemistry."

"We don't fully know how oil forms, we don't fully know the initial migration, and the full extent of vertical vs lateral migration. It's something you'll see develop over the next few years, as majors come into the basins and start putting money behind it."

A similar pattern has been seen in the Anadarko Basin in Oklahoma, where "hundreds and thousands" of wells were drilled, he said. "So pretty much the same rocks and the same targets, but you've got a huge distance between them," he said.

Typically unconventional plays are discovered by independent companies, not majors. But when the majors arrive, "that's when you'll see a lot more science behind it. You have specific intervals that are well understood and mapped out,"

"You're getting these multiple benches as people understand where the data is."

Woodford and Barnett

Building on this geochemical knowledge, there is likely to be a lot more focus on the Woodford and Barnett shales, which sit below the Permian, with the Barnett above the Woodford.

The Woodford shales can be as deep as 16,000 feet, beyond the typical 11,000 feet depth limits of unconventional drilling, so are usually ignored, he said. But in 2016 a company in the Delaware Basin called Jagged Peak drilled a well which started to look at the Woodford.

The well fracking had some problems, with the full lateral not getting fracked. But the fracking that did occur led to "pretty impressive" volumes. It has "given people a lot of focus on Woodford and Barnett."

"If these results keep going I would argue we're going to see a third phase of horizontal drilling in the Permian basin focussing on these older, source rocks around the Woodford and the Barents."

The industry had to drill 700 wells into the Wolfcamp/Bone Springs in the Delaware before it became economic. "So it takes a lot of effort and it take a lot of pain to get there. But once you get there you can get your cost down to $30 barrel for the acreage in the core of the play."

A “factory” approach offshore

If the UK offshore oil and gas industry is going to stay viable, it needs to become more of a factory production line. Chris Wheaton explained what he thinks this means

One of the strategies most likely to lead to commercial success in the North Sea is to take a “factory” approach, thinking like a manufacturer rather than a producer, said Chris Wheaton, investment manager with Stifel, a London investment banking firm.

To see what a ‘factory approach’ looks like, UK oil and gas companies can look across the Atlantic to see how companies are developing unconventional oil and gas resources, as described in the previous talk. They are drilling an enormous number of wells continuously in the same way and continually pushing costs down, he said.

UK North Sea is in competition with US unconventional players, and indeed all other basins globally, in that they are competing for the same pool of investment capital, he said.

The point is that the decline in oil prices has meant action is starting to be made towards a factory approach – and results are becoming apparent, and more profits are being made without any help from the oil price. Yet a lot more progress is possible in this direction, he said.

“To do it, you have to think like a manufacturer, maximise uptime, maximise throughput, get control of operating costs,” he said. “In offshore the large majority your costs are fixed, so by improving uptime your cost per unit improves.”

Taking a manufacturing approach may also mean looking for more effective ways to work with other companies, rather than the traditional adversarial relationship between operators and contractors. For example models where both suppliers and operators share the pain and share the gain. The same can apply to service companies in their relationship to their own suppliers.

Oil companies might do well to think, how would an automobile company or an aerospace manufacturer think about running facilities like this, he said.

The track record

Industry association Oil and Gas UK has calculated that North Sea operating costs

Chris Wheaton, Director, Stifel

doubled from 2007 to 2014. But now costs have been halved in just 3 years. “A fantastic performance,” he said.

In this period that operating costs doubled, there was also a 15-20 per cent reduction in uptime (“production efficiency”), down to about 65 per cent in 2012. “You wouldn’t run a factory at 65 per cent uptime, and you can’t run the North Sea at 60 per cent uptime,” he said. Since then uptime has improved to 73 per cent in 2016, according to OGA figures.

The Oil and Gas Authority has split the causes of production shortfall into four buckets of production facilities, wells, pipelines and shore facilities, and the largest of those is facilities uptime. There is still the potential to improve further across all four areas, he said.

However Statoil’s production uptime in Norway is better – 90 per cent– and that can be taken as a rough figure for the entire Norwegian Continental Shelf, since Statoil operates two thirds of Norwegian production, he said.

The most unreliable platforms are not necessarily the oldest ones, he said. Production efficiency is actually lowest (about 58 per cent) for platforms built 10-15 years ago (2003-2008). Older platforms are showing a higher production efficiency.

Working with data

Data gathering is an important part of the “manufacturing” concept. Over the past few years the cost of gathering data [sensors] and analysing data has fallen dramatically, he said.

“The more data you have the better, given how easy it is to analyse large chunks of data,” he said. “It is much cheaper to look for patterns and opportunities in data than it’s ever been. There’s so much more the industry can do on this.”

“Better data means better safety, better productivity, less unplanned downtime. You can predict when you need to change something and also when you don’t need to change something.

You’ve got better people productivity. You can attack wasted time on wasted tasks, focus expensive people on what really matters.”

There are opportunities for creating digital models of offshore plant, sometimes called “digital twins,” which can be used to test out plant modifications or production optimisation schemes in the virtual world.

“That’s really exciting, it takes an awful lot of effort and risk from offshore and manages it better onshore. The more planning and preparation you can do onshore the better. I think this is a really interesting area for data,” he said.

The industry has found ever more inventive ways of using its ‘data exhaust’, he said. For example oil companies are finally starting to employ data specialists to look through (for example) archived production data, and try to find useful insights from it.

“The more data we’ve got the better it is. I think there’s a big chunk of data completely worthless and some data worth its weight in gold. The rest of the world has got value out of data mining, I can’t imagine the oil industry being any different.”

Remote operations

The future of the oil and gas industry cannot be with more massive conventional projects, with a massive jacket, massive topsides and 200 people working onboard, Mr Wheaton believes.

"Recently I was offshore on a platform with a complement of 190 people. I tore my hair out [asking] why do you still have 190 people on the platform - have you seen the oil price?"

There is an increasing number of oilfields being operated from onshore, for example Statoil's Johan Castberg platform. Statoil is also creating a 'digital twin' for the Johan Sverdrup project so it can be run from onshore if desired.

Statoil says it aims to develop a "remotely operated factory", Mr Wheaton says. "These kinds of opportunities are really about saving people time, maximising people's productivity, focussing on maximising production, maximising cash flow, shareholder value," he said.

Remote or onshore operations can also be used in drilling and optimising production. "This industry has only just started to look at these opportunities," he said.

Fields per operator

It is interesting to look at differences in the number of operators on either side of the North Sea.

Norway has 26 producing license operators on 110 producing fields. If you exclude operators which are just exploring, and take out Statoil, you end up with 13 operators on 53 producing fields, so 1 operator managing about 4 fields, "which sounds kind of where you'd expect."

In the UK there are 29 producing operators in 322 producing fields. That works out at 10-11 fields per operator. "That seems to be a large number," he said.

There is a valid argument that the UK has more smaller fields than Norway, because it started producing 5-10 years earlier, but still it seems a lot of fields which an average operator looks after.

Supplier collaboration

Aker BP presented an interesting case at a capital markets day in January 2018, how the company managed to reduce the costs of a traditional subsea tieback by 30 per cent, through different business models, sharing risk between contractors and license owners in different ways, Mr Wheaton said. This means that contractors have an incentive to look for ways to reduce project costs.

Three years ago, an average upstream project globally was 19 per cent over budget, with 9 months late. This makes a big dent in the value of the project and returns to shareholders. Now, in some companies, the opposite is happening, with projects often coming in early and below budget. "That's how you create a factory style manufacturing process," he said.

Decommissioning

A further issue is decommissioning costs, an increasing issue on the UK North Sea. Half the costs of decommissioning, and much of the risk, are in wells.

Part of taking a "factory" approach to North Sea operations is working out how to squeeze more value out of the assets before they need to be decommissioned, thus pushing the liability out.

Then there is a huge incentive for operators to collaborate together, put equipment into a pool, try to get unit costs down.

There is a big need for more decommissioning data, to help get a better sense of the risks, which is not available from the handful of big projects completed to date. With more data, it might be possible to get better arrangements for decommissioning insurance, and access third party capital.

"That means potentially more sources of capital for the North Sea, more investment, more recovery of hydrocarbons. That's a really good virtual circle to get into."

Standards

"I think there's more to do on standards," he said. "I think you've got to have common data standards, data platforms, to really share information," he said.

The automotive industry had a big push for standardisation in the 1980s, and its practises were then taken up by the chemical industry.

The downstream oil and gas industry has made much more use of standards than the upstream. This work may spread to upstream, now we have many former downstream people managing upstream, such as Shell CEO Ben van Beurden and ExxonMobil CEO Daryl Woods, both former heads of downstream in their companies, he said.

Rob Gill – reducing costs of new offshore developments

One way to reduce the costs of new offshore developments is to use standardised, simplified offshore

Given that much of the UK North Sea infrastructure is currently grossly underutilised and will shortly need to be decommissioned due to lack of hydrocarbon production (not due to aging of the asset), it makes sense to look for low cost ways to get more hydrocarbons through it, said Rob Gill, consultant with Petromall, formerly EAME business development manager with Advisian Worley Parsons.

This can only be done by increasing production from existing wells (e.g. through EOR) or by developing new fields or "small pools" which can be 'tied back' to the existing infrastructure, Mr Gill said. This talk focussed only on small pools.

The UK Oil and Gas Authority has been helpful in identifying 300 small pools in the UK sector of the North Sea which could be developed which haven't been developed yet. These have been analysed in terms of their size and distance from existing infrastructure. They are more likely to make viable development projects if they are larger and closer to infrastructure, and the reverse is also true.

The industry typically considers a 10m barrel "small pool" as too small to bother with, Mr Gill said. So it may be useful to consider that a 10m pool could provide $300m of revenue (at 50% recovery and a $60 oil price). There are very few other industries which would consider $300m too small a sum to bother with, he said.

Subsea vs platform well head

A first consideration is whether the pools are better developed with subsea wells or with platforms. Platforms are typically more expensive to build, but make for much easier well intervention work later (putting tools and equipment into the well to improve production).

A number of designs for platform well heads have been developed which are as simple (in terms of the services they offer) as the subsea equipment, so do not include any compression or processing.

The costs of putting the well head above the water mainly depend on the water depth, and so the amount of steel needed for the legs, whereas the cost of a subsea development is fairly independent of water depth, he said.

Roughly speaking, at 30m water depth, you could build a well head above the water for the same price as one subsea well. But at 90m water depth, one well head above water would cost the same as three subsea well heads – so you would need to have three well heads on the same platform to make it worthwhile.

North Sea platform costs are a little higher due to weather and waves, and based on real calculations a well head platform is typically the same cost as two subsea wells in the Southern North Sea, and the same cost as four subsea wells in the central and Northern North Sea, he said.

A well head platform is "low cost, low risk, completely unmanned, with no accommodation, no processing whatsoever," he said. There is generally no helideck. It can be produced in standardised modules, thus reducing the design and construction cost.

Personnel access is by so called "walk to work" vessels, which have a walkway from a vessel to the platform. The walkway "compensates" for wave movement, i.e. uses sensors and motors to keep the walkway completely still, even though the vessel is moving on the waves.

The "walk to work" system is also the emergency escape route for personnel (so the vessel will be there as long as people are).

Examples of standardised designs

Engineering company Worley Parsons did a lot of work developing standardised platforms in the Gulf of Thailand, working for Unocal (later acquired by Chevron in 2005).

They managed to reduce the typical installation time from 8 days to 2, with a range of different innovations, such as different methods for putting tubulars into the seabed ("swaged piles" rather than "grouted piles" in the jargon.

The platforms could be manufactured quickly to order without any new design work required, put on a barge two at a time, and then offloaded offshore. They also have bolted connections, so that platforms could be moved somewhere else after use.

Worley Parsons decided that a design with 16 slots (for different wells) might be good for a majority of projects, so they made it the standard size. They designed a jacket with a lower weight, and a topsides which are fully automated, with space for booster compression. They managed to reduce the construction costs from $10m to $6m between 1993 and 2003. Worley Parsons has 500 such unmanned platforms currently in service.

On a similar platform in New Zealand, staff will visit every 6 months, and send an automatic pig launcher into the well to do an inspection. A new automated system is being developed to stop slugging.

Another platform standardisation project was recently initiated by Saudi Aramco, under the label "3S", standardisation, simplification and 'simultaneous' operation. The Persian Gulf water depths range from 10m to 50m.

The only variability in the standard structure was in the length of the legs. Saudi Aramco also standardised on just two topside designs, powered or unpowered, and standardised on 10 well slots.

Today, if an engineer in Saudi Aramco wants an oil platform, they should specify whether or not it is powered, the water depth, and the soil conditions for the piling arrangement. No further design needs to be done. If someone just wants 5 well slots, they have to have 10. "While each platform may not be optimised for its location, the entire supply chain is optimised," he said.

If the standardised jackets and topsides can be manufactured separately that also makes the project more efficient, he said.

Companies are also looking for ways to make platforms easier to install, perhaps with the same jack-up rig which was used for drilling, rather than bring in another heavy crane.

Worley Parsons in Coogee, Australia, developed a tripod design, which could be launched directly from a barge, only requiring a 5 tonne crane. Not needing a heavy crane vessel gives operating companies a lot more flexibility.

The platform has been designed in two different sizes, "large" (12-16 well slots) and "smaller" (4-6 slots). The only allowed variability is in the height of the legs in between, which can be altered in increments of 1m.

"It changes the concept of a production yard to a production line," he said.

In the Southern North Sea, there are many unmanned platforms in the Dutch and Danish sectors, many without any helideck, relying on 'walk to work' technology for access from a vessel, as described above.

Unmanned wellhead platforms was a major topic of conversation for the Stavanger ONS conference in Autumn 2016, following a study on the subject done by the Norwegian Petroleum Directorate, and a number of designs proposed as a standardised structure for the deeper water of th North Sea.

Heerema won a contract to install a platform for Statoil in 105m water.

Kvaerner made a contract with Aker Solutions to design "subsea on a stick", a platform in 120m of water. That is about the depth limit for simple platforms, because it is the limit of depth that a jack-up rig can work in, and going deeper requires more expensive equipment.

"All of the larger operators in Norway really have taken this onboard," he said. "Statoil, Conoco Phillips, Ekofisk area, Aker BP, Lundin, They've all been looking at wellhead platforms."

By comparison, one of the first unmanned well head platforms, in the Norwegian sector of the North Sea, had a 2,000 tonne jacket, which was put in place using a 10,000 tonne crane, which was all the company had available.

How many small pools?

Taking these ideas back to the OGA's analysis of small pools in the North Sea, Mr Gill thinks that it could make it viable to produce a field which is just 3 or 4m barrels of oil recoverable using standardised wellhead platforms. In the Northern North Sea, where costs are higher, perhaps 9-10m barrels would be the minimum viable size.

Altogether, 60 per cent of small pools identified by OGA could be targeted, equating to 94 per cent of the oil. "I don't think this is a solution for very small pools, but certainly we could hoover most of them up."

Investability

Another factor is how companies can raise the money from investors for wellhead developments. Currently oil companies are not in strong flavour with investors. This is indicated by oil company shares having a lower average price/earnings ratio than most other large industry sectors, including consumer, financials, healthcare, industrial, IT, materials, telecoms, and utilities, he said.

Earnings are not so high for oil and gas, so the reason for the low P/E ratio must be that investors perceive oil and gas companies to be very high risk.

And typically it is small independent oil companies, rather than majors, which are interested in developing small fields, which are perceived as even higher risk.

The perceived risk is further exacerbated by forthcoming changes to accounting rules which require companies to put assets on lease (such as a FPSO) in their balance sheets, both as assets (equity) and as debt, and consider the lease payments as 'interest'. This worsens their figures for debt/equity ratio and interest coverage (profit before interest and tax divided by interest).

One way companies can make small pool development projects look more attractive to investors, and keep their debts off their own balance sheets, is by setting them up as new companies controlled by the operator, or "special purpose vehicles," Mr Gill suggested.

If the operator only maintain a minority stake in the SPV, then the SPV's debts do not have to be added to the debts of the parent company. However the operator can maintain control over the SPV by having an agreement with all shareholders that the operator has exclusivity over purchase of its oil.

The operator can put the initial cash into the SPV, and then sell equity to other companies, including 'farm-in' operators, private equity and traders. The SPV can also take bank loans.

There could also be an agreement that the first oil revenues would be used to pay suppliers and contractors, before any owners get paid, thus giving suppliers an incentive to help get the project onstream faster, he said.

Is there much more oil in stratigraphic traps?

Most oil fields developed to date are structural traps, easy to identify through seismic. But maybe there are many more oilfields not yet discovered in stratigraphic traps, which cannot be easily de-risked with seismic, but where electromagnetics can play a big part, said Daniel Baltar of Fox Geo

Until now, oil and gas exploration has been extremely focused on structural traps, which are easily identified on seismic data.

However there may be much more oilfields yet to find in stratigraphic traps, where the oil is trapped between different rock layers. These are very hard to de-risk using only seismic, because seismic cannot easily tell if there is a trap and does not provide much information about the fluid content, said Daniel Baltar, partner in Fox Geo and formerly Global Exploration Advisor for EMGS ASA. Hence stratigraphic traps can be in an early stage of creaming because they have been typically regarding as high risk (likely to contain brine) by the industry, hence there is potential for large discoveries even in mature areas.

But this is exactly where electromagnetics can play a part – because brine conducts electricity (is less resistive) and so brine filled sediments show up on an electromagnetic image as low resistivity bodies.

The oil and gas industry's experience with unconventionals illustrates that it is possible to change things, but change typically requires "changing several things at the same time", he said. So if we want to explore high potential stratigraphic plays, we can't expect to succeed by using the same methodologies that have not succeeded in the past.

How CSEM works

Controlled Source Electromagnetic (CSEM) surveys generate an electromagnetic field through the subsurface, and measure what comes back using electromagnetic receivers.

Daniel Baltar, Global Exploration Advisor, Fox Geo Exploration

Most of the material in a sedimentary basin except salt water is highly resistive (not conducting electricity at all). Oil and gas are also resistive.

Hence resistivity can be a great indicator of brine presence or absence, and of the amount of brine not present in the sediment. Hence large and thick hydrocarbon accumulations will show up in the CSEM as high resistivity bodies.

Working with CSEM

Geoscientists have used this CSEM data to evaluate and better understand different drilling options which have already been identified with seismic. In the jargon, they can make a better 'creaming curve', or better order to drill the prospects, with the best looking one first.

An example is on Wisting, a discovery in the Barents Sea in Norwegian waters. The main play is an early Jurassic reservoir in rotated fault blocks. The main risk of the play was a lack of seal.

Before using CSEM, most oil companies had identified the presence of the well-known play, but had deemed it too risky given the high seal risk owing to its shallow burial depth. But with the CSEM, it was possible to see that there were differences in the resistivity in the fault blocks, indicating some them could be hydrocarbon filled, and lowering the seal risk.

Subsequently they the play was drilled and there were 3 oil and gas discoveries in a row, in the right size order, largest to smallest. "That is a very outstanding thing to do, extremely hard to do in reality" he said.

Another example was the Kayak field, a discovery made by the Norwegian oil company Statoil near a dry well in an unproven play with a strong stratigraphic component. It is very likely CSEM has been used in the decision to drill this prospect, it had been discussed by EMGS in publications several times before. Drilled in 2017, it found 40m barrels. Statoil has not yet found the oil water contact so they don't know how large it is, Mr Baltar said.

CSEM data processing is much advanced over the past 15 years, current CSEM inversion is equivalent to seismic full waveform inversion. "You can place things in depth and get an image you can compare to your seismic," he said.

One challenge with EM is explaining to companies that it does not give them a 100 per cent likelihood of success, but when the typical chance of success in exploration wells is as low as 15 per cent, a small de-risking is enormously valuable.

One of the biggest barriers is that most oil and gas companies are not used to integrating CSEM in their decision making, he said.

Mr Baltar started a company called Fox Geo to provide a range of services around using electromagnetics in exploration.

Opportunities in Mature Provinces, February 21 2018, London, Attendees

Hugh Ebbutt, Director, A T Kearney

Christian Bukovics, Partner, Adamant Ventures

Rob Gill, Senior Advisor, Advisian

Julian Moore, Technical Director, APT UK

David Craik, Consultant, Atlaslocal

Paul Mullarkey, Managing Director, Auriga Energy

Christian Richards, Sales Manager, AustinBridgeporth

Steve Callan, Sales / Marketing / Business Development, BGP Marine

Emma Richards, Oil & Gas Analyst, BMI Research

Joe M Boztas, Director/Interpreter, Boz Seismic Services

Robert FE Jones, Director, Caithness Petroleum

Chris Matchette-Downes, MD & Owner, CaribX and MDOIL Limited

James Andrew, Busines Development Mgr EAME, CGG

Andrew Webb, Manager, Petroleum Reservoir and Economics, CGG

Jodie Hunt, Marketing Geologist, CGG

Richard Walker, , Consultant Geophysicist

Peter Farrington, Geophysicist, Consultant Geophysicist

Lisa Randall, Data Analyst, NW Europe, Drillinginfo

Martin Riddle, Technical Manager, Envoi

Richard McIntyre, Sales Manager, Finding Petroleum

Karl Jeffery, Editor, Finding Petroleum

Avinga Pallangyo, Conference Organiser, Finding Petroleum

Daniel Baltar, Global Exploration Advisor, Fox Geo Exploration

Owen Sutcliffe, Head of Stratigraphic Research, Halliburton

Michael Treloar, Geoscientist, Halliburton-Landmark

Norman Hempstead, Director, Hempstead Geophysical Svcs

Jaco Fleumer, Business Development Manager, HSM Offshore B.V.

David Jenkins, Director, Hurricane Energy plc

Alastair Reid, Consultant, IHS

Abbey Hunt, Geoscientist, Impact Oil and Gas

Nick Steel, Consultant, Independent

Neil Simons, Consultant, Independent

Mike Hibbert, Independent consultant

Manouchehr Takin, Independent consultant

Phil Penfold, Partner & Global Director BD, io oil & gas consulting

Naohiro Yoshino, Geoscientist, JAPEX

John Griffith, Upstream Advisor, JJG Consulting International Ltd

Neil McMahon, Director of Research, Kimmeridge Energy

Lauren Mayhew, Geoscientist, Lyme Bay Consulting

David Pilling, Head of Oil & Gas, Nedbank Capital

David Bamford, Director, New Eyes Exploration Ltd

Mike King, Oil & Gas Manager, NPA Satellite Mapping

Abi Mirkhani, COO, OPG Supply

Robert Parker, Consultant, Parker

Yoann Desriac, Perenco

David Sendra, Associate Consultant, Petrophysical Consultant

Frederic Yeterian, Director, Philax International (UK) Ltd

John CLURE, Managing Director, Phoenix Hydrocarbon Resources Ltd

Colin More, , Prospect Geoscience

Richard Herbert, Director, R Herbert Associates

Patrick Taylor, Director, RISC (UK) Limited

David Webber, Seismic Operations Supervisor, Sceptre Oil & Gas

David Jackson, Principal Geologist, Shearwater Geoservices

Laura Lawton, Principal Geoscientist, SLR

David Lawton, Chief Geoscientist, SLR Consulting Ltd

Chris Wheaton, Director, Stifel

Simon Bradbury, Chief Operating Officer, The Steam Oil Production Company Ltd

Deirdre ODonnell, Managing Director, Working Smart

What did you enjoy most about the event?

Diversity of talks & networking.

Presentations very good post coffee.
Deirdre O'Donnell (Working Smart)

New things to learn & networking.
(MDOIL LIMITED)

The first two presentations, plus the range of topics after these.
Hugh Ebbutt (A T Kearney)

Thought provoking presentation by Chris Wheaton on thinking about the oil industry in terms of manufacturing.
Richard Walker (Consultant Geophysicist)

A good mix of topics (with both a technical & commercial spin) around the overall theme of mature provinces and super basins.

Combination of networking and quality of presentations.
Jaco Fleumer (HSM Offshore)