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Cover image: *The Sleiper platform in Norwegian North Sea. CO2 has been injected since 1996 and now we have an idea about how CO2 moves in the subsurface (See page 16-17). The photo shows Sleipner A accommodation, production and processing offshore platform in the foreground, there is a bridge to Sleiper T carbon dioxide treatment platform behind it. Image credit: Øyvind Hagen. Copyright: Equinor*

Aberdeen OEUK conference – meeting decarbonisation challenges

The OEUK Industry Conference in Aberdeen in May included discussion on meeting the decarbonisation targets, justifying continued exploration, attracting graduates, platform electrification vs CCS, and more

The Offshore Energy UK (formerly Oil and Gas UK) annual industry conference in Aberdeen in May explored meeting the decarbonisation targets, justifying continued exploration, and the UK government's windfall tax.

Also how priorities are changing following the Ukraine war, continued challenges for suppliers getting a fair deal, platform electrification, and developments with carbon capture and storage.

This report covers aspects of the conference with a digital technology aspect to them.

Lord Offord of Garvel, otherwise known as Scottish businessman Malcolm Offord, summarised the decarbonisation challenge, saying that the UK currently gets about 25 per cent of its energy from renewables plus nuclear, the rest from fossil fuels. This will need to switch to 75 per cent from decarbonised fuels by 2050.

Lord Offord of Garvel

"The oil and gas industry is a major part of the fabric of British life. We'll see this [energy transition] as a revolution every bit as big as when the Sea Quest drilling rig hit oil in the North Sea in 1969," he said.

Simon Sjøthun, head of the London office of consultancy Rystad Energy, noted that the Ukraine invasion has changed priorities in what people are asking from the industry.

We have heard many times about the 'energy trilemma' of the three challenges affordability, sustainability and reliability in supply of energy. But the weighting on these is changing. Affordability was the priority in 2014, before the oil price crash; sustainability was the priority in 2018; and now, after the Russian invasion of Ukraine, reliability is the priority. But we still need all three, he said.

Simon Sjøthun, partner, Rystad Energy

Can the industry still attract graduates? Gareth McQueen, FPSO engineering lead with Shell, who received an award for "OEUK Graduate of the Year" in 2018, noted that when he joined the industry in 2015, "it was seen as a prestigious place to be." Since then, "there have been times I felt cautious about telling people what I do."

However, Sarah Cridland, VP commercial and subsea projects UK with Technip noted that the company had received 300 graduate applications this year. Young graduates are interested in working on the challenge of "keeping the lights on," as well as the energy transition, she said.

Decarbonisation targets

A background to much of the discussion was the decarbonisation targets, agreed between UK operators (represented by

Dierdre Michie, CEO, OEUK; Richard Lochhead, Minister with the Scottish Parliament; Linda Cook, CEO, Harbour Energy; Andy Samuel, chief executive, North Sea Transition Authority

Offshore Energies UK), and the government (represented by the North Sea Transition Authority (NSTA). There is a target for reducing operational emissions by 50 per cent by 2030.

Some people say they don't like the targets and the industry should not have committed to them, said Andy Samuel, chief executive of the NSTA. "Well, tough. The two are compatible [production and decarbonisation], please don't put them in opposition."

The UK's Climate Change Committee, a government advisory group, "think the 2030 targets are a bit soft", he added. "They are looking for 68 per cent reduction by 2030, and zero routine flaring by 2030."

To reach the decarbonisation targets "is not a walk in the park," said Deirdre Michie, Chief Executive of OEUK. "What we've set ourselves is not a given. This stuff is different. Technical, commercial and practical issues."

"It was a quid pro quo between industry and government. We're up for working towards it, but we have to be thoughtful about practicality."

"We think carbon neutrality is achievable but only if regulation is right - regulation working with us not against us."

"When we saw the North Sea Transition Deal, I thought the 2030 target was tough," said Arne Gurtner, senior VP UK and Ireland, Equinor. "I still think it is. It needs adding something to the mix, likely to be electrification of one or two clusters."

"There are commercial, technical challenges, and connection challenges. Ordering cable is becoming quite difficult."

Can we justify continued exploration when the pressure to decarbonise is so high? All speakers agreed we should continue, on the basis that even with a decline in demand, UK supply will not meet it, so UK exploration reduces the need to import.

"The decline (in UK supply) is going to keep going," Ms Michie said. "So long as the UK is going to use oil and gas, we should get it locally. This has to be a question for government driving down demand."

Equinor's Mr Gurtner noted that individual fields on the UKCS decline by 15 per cent a year. "So, without exploration we're looking at closing [operations] in 2030. That is something we need to explain in a simpler way."

Arne Gurtner, senior VP UK and Ireland, Equinor

Mr Gurtner was asked whether the company is expecting protests next time it announces a development decision. "That remains to be seen," he replied. But perhaps the way forward is for people in the oil and gas industry to have full belief that their actions are right for social as well as economic reasons.

"When we announce what we are doing with Rosebank we'll do it with our full purpose behind it. Having a belief in what we are putting forward, I think that's important. Not everyone would like it for many reasons."

Windfall tax

A big political issue at the time of the conference was whether the UK government should levy a 'windfall tax' on the oil and gas industry.

"We're being used as a political pawn. It will be a political decision," said Deirdre Michie, Chief Executive, OEUK. "Fixed stability is what we need."

Equinor's Arne Gurtner said it may affect investor appetite. Investors weigh up the risks when valuing a proposal, and if there is additional risk from a "changing fiscal regime", that would mean that more marginal projects can no longer go ahead.

Sarah Cridland, VP commercial and subsea projects UK with Technip said that windfall taxes also make it harder for suppliers. "I'm fighting for resources in the North Sea [internally]. This sort of instability and rumours - the supply chain come through struggling."

Nathalie Thomas, energy correspondent of the Financial Times, moderates a discussion with Sarah Cridland, VP commercial and subsea projects with TechnipFMC

Harbour Energy

On the subject of electrifying offshore platforms, Linda Cook, CEO of Harbour Energy, one of the largest UK operators, thinks that while it may be practical for new developments, "its too early to say if it is viable for existing fields."

"We'll compare potential, costs and benefits with other opportunities," she said.

"I believe CCS has much more potential bang for the buck [compared to electrification]. We can enable large scale and long-term capture. We can repurpose existing infrastructure and create new jobs."

"This is where I believe Harbour and companies like us will make the most significant contribution."

Harbour Energy was founded in 2014 and listed in 2021 in the UK. It has 200,000 bopd UK production, a 25 per cent increase over the past year.

Harbour's project "V Net Zero", in the Humber region, promises to sequester 10m tonnes CO2 a year, a third of the UK's 2030 target. It plans to use a decommissioned pipeline offshore, connecting to industrial emitters onshore.

Harbour Energy is also involved in the Acorn CCS project in North East Scotland, based at the St Fergus gas terminal, repurposing oil and gas infrastructure.

"These projects are very exciting, they enable decades of large-scale emissions reduction," she said. "CCS has the potential to be economically viable and a game changer for the country and our industry."

Andy Samuel, NSTA

Andy Samuel, chief executive of the UK's North Sea Transition Authority (formerly Oil and Gas Authority) noted that the carbon problem with fossil fuels comes from the demand for it, not the supply of it. This should be the response to environmental groups who want the North Sea to shut down.

UK fossil fuel demand is forecast to drop by 40 per cent from 2021 to 2030, as renewable generation increases. But that still means the UK will not be able to supply for its needs without import.

NSTA is continuing its work to encourage higher performance from UK operators. It brings together the leaders of the 22 biggest oil and gas producers every year, to focus on improving the performance of the basin. Each managing director is given a 'personalised pack' of information showing how their company's performance compares to the average, he said.

A current campaign is to get production efficiency back to the 80 per cent level, where it was in 2019 and 2020; it dropped to 73 per cent in 2021 due to the pandemic, and restrictions on maintenance staff being able to get offshore.

Another campaign is to encourage more focus on maintaining older wells. "Some large operators have quite a large well stock not being cherished," he said. "Quite a large number are ready for workovers and intervention."

Many new development projects will go ahead this year. "There's a steady pipeline of projects waiting to be sanctioned," he said.

"We will be robust with licensees sitting on acreage and not progressing it," he said.

"People want us to be robust with others and gentle with them. As regulators we have to be consistent."

The NSTA is talking to investors, oil companies, banks and private equity companies to try to work out what is preventing investment. A key theme is concern about 'fiscal stability' (worrying about a windfall tax) or a lack of confidence in the amount of government support.

There is a vibrant mergers and acquisition market in the UK. "We welcome new players," he says. Although sometimes deals get stuck. "We will launch a consultation [on] how industry wants to solve this."

A common complaint is that the regulatory approval process for new projects is too slow, he said. Although when the reason is looked at closely, "we often find its other parts of the system [holding things up] such as BEIS, National Grid, Ofgem, Crown Estate."

If anyone has specific complaints about a hold-up, "please come forward to my team."

NSTA is encouraging operators to pay their suppliers faster. "70 per cent of invoices are paid in 30 days; some were not, some much more than 60 days. If you're an operator, please do better in that space."

Mr Samuel says he is "really excited" about carbon capture and storage, estimating that the UK has 78 GT of storage potential, a lot of infrastructure, and now signs of an investor appetite. NSTA has been doing a "play fairway analysis", looking at the entire region to work out the most appropriate places for CO2 storage.

NSTA envisages there will be £95bn investment in UK continental shelf oil and gas projects from 2022 to 2030; but also, a little more, £100bn, on wind. It envisages £12bn investment in hydrogen projects and £8bn on CCS.

Supply chain perspective

Ellis Renforth, senior VP upstream with engineering contractor Wood, said that from a supplier's perspective, "this is a tough time to work in oil and gas, no doubt about it."

Ellis Renforth - SVP Upstream - Wood

Environmental groups have propelled the narrative that the oil and gas industry is at the root of the environmental problem. The low point for "popularity" for the industry could be considered the time of the COP event in November 2021.

Although by May 2022, engineering companies like Wood have a backlog of work on new projects, he said.

One way the industry as a whole can reduce costs is by improving their procurement processes – currently suppliers spend a lot of time submitting bids, which does not feel like time well spent.

In one recent case, many suppliers put a lot of effort into submitting multiple bids, and 90 per cent of them were won by a single company. This suggests that winners were chosen on some basis other than the quality of their bid. This is not an example of good collaboration between buyers and suppliers, he said.

To achieve efficiency, "collaboration and trust need to be front and centre," he said.

You can view videos online at
https://vimeo.com/offshoreenergiesuk

You can view presentations online at
https://oeukconference.co.uk/presentations-2/

Carbon ratchets "now routine" in E&P lending contracts

"Margin ratchet" clauses, linking the interest rate on a loan to CO2 emissions and continuous improvement, are becoming "almost routine" on bank financing contracts to independent oil and gas companies, says energy specialist law firm Bracewell

"We're seeing, almost as a routine, margin ratchets being included in bank financing," said Jason Fox, Managing Partner, Bracewell (UK).

A 'margin ratchet' is a technical term for a contractual clause in bank lending, where the price of debt, or the 'margin' the lender makes, depends on the E&P company's carbon performance.

"We see loan agreements that require specific action plans on how the assets will be improved," he said. "It is definitely a feature of most deals now."

These 'margin ratchets' "haven't been around for very long, I saw the first a couple of years ago.

They are contractually binding and usually require independent certification.

It is hard to know what level they are driving behaviour, but "my guess is they would have bitten," he said.

Mr Fox said he is not aware of any disputes which have arisen over whether a company had achieved the emissions that it was claiming.

The difference in interest rates is typically 0.05 per cent to 0.1 per cent, making say 5 to 10 per cent difference in the amount of interest being paid.

Sometimes oil and gas companies themselves encourage these contracts, so they can announce to the market that they have an 'ESG linked loan', which may make it easier to borrow money less expensively from other sources.

Jason Fox, Managing Partner, Bracewell (UK)

The emission metric is often CO_2 emitted per barrel of oil produced, but there can be other metrics, such as for having ethnic minorities on the board of the company, or about using renewable electricity.

There are companies set up to do CO_2 audits. "That is probably a good business - a CO_2 auditor," he said.

Harder to get funding

ESG and climate change are a big 'force of change' in the availability of both debt and equity funding, Mr Fox says. "The 'sting' in the 'ESG force' is biting harder all the time. All of the banks have made commitments to reduce fossil fuel lending."

"Some banks have stepped out entirely of lending in this [oil and gas] arena, some have stepped back from certain markets." For example, some lenders will only fund oil and gas projects in developed economies.

"What I see, when a bank proposes oil and gas lending internally, there's a lot of scrutiny and push back on it. Teams are having to justify, 'why this deal when we're trying to reduce our overall [oil and gas] book.'"

They are looking carefully at the ESG metrics of companies they consider lending to, looking to lend only to companies which are 'best in class,' particularly for CO_2 emissions.

And banks are not funding any projects in Russia. Even if they are not covered by sanctions, the reputational risks are enough to stop lending.

"Banks are more wary of oil than gas. Gas is still seen as the transitional energy in the energy transition," he said.

The debate "got more nuanced" after Russia's invasion of Ukraine, and recognition of the importance of secure energy supply in Europe, he said.

Many banks are still making lending decisions based on an oil price of around $60, although the actual oil price is much higher as of summer 2022.

Some oil and gas companies have been able to lean on their vendors to provide a 'slice' of funding for a company merger, such as between two independent E&P companies. Trading companies are also sometimes taking 'significant' roles'.

A typical set-up is for commercial banks providing 'senior' debt and traders or private funds providing more 'junior' debt, he said.

Banks have got much more wary of oilfield "development financing," which is seen as carrying a greater risk, including to reputation. "For oil and gas companies there may be easier and cheaper ways to acquire reserves than developing new fields," Mr Fox said.

But if no new oilfields are developed, this "feeds into the price increases we're seeing in the market." There is no reduction in demand for hydrocarbons.

"Sometimes you find pools of capital in unexpected places," he said.

As one example, Mr Fox was involved in legal work for development financing for the Shenandoah deepwater oilfield in the Gulf of Mexico, and most of the funding was from Israel, including banks and funds.

"It has been a long time since the winds were behind oil and gas companies, I don't see that changing," he said.

Africa

In Africa, the company is seeing oil majors selling their assets to independent companies – domestic, regional and international. But their buyers have difficulty getting finance for their purchases.

5-10 years ago, "there would have been a range of international lenders happy to fund [African projects]," he said. "That has dramatically reduced."

One source of lending is South African banks and African regional banks, otherwise traders, bond markets, or specialists like Africa Finance Corporation (AFC).

The lack of funding can mean that there are fewer potential buyers for an asset, and perhaps a lower price is paid as a result.

Scope 3 emissions challenges

Counting Scope 3 emissions is a complex challenge. Ian Thomas of Vysus Group explains what is expected, why you should not rely on offsetting or count avoided emissions, and the importance of data credibility

By Ian Thomas, senior principal consultant at global engineering and technical company Vysus Group

"Scope Three" emissions are the emissions associated with the value chain – this includes supply chain provision of goods and services to the disposal of the products a company sells.

In the energy industry such services may include the hire of supply boats, drilling rigs and other equipment. It may include the use of energy products, such as oil and gas.

Less obvious may be the emissions associated with the generation of renewable sources of energy such as biofuels, electricity and hydrogen.

The challenges associated with quantification of Scope Three emissions are considerable.

They start with a requirement to identify those emissions which are considered material to the organisation from a list of 15 categories.

Industry standard methodologies must be used to ensure figures reported are true, verifiable and free of material errors.

From an oil and gas perspective, the 2020 IPIECA guidelines on Scope Three emission reporting focussed on downstream consumption based upon the final product created.

But they left gaps around the upstream supply chain responsibility that is now very much central to the latest GHG Protocol responsibilities for Scope Three.

Measured carefully and reported accurately, Scope Three has the potential to drive innovation sector-wide, improve links and relations with individual groups, and reduce costs through enhanced efficiency.

All of these are fundamental to developing the sustainable future we are striving for.

Scope Three management is an evolving beast.

In the US, the Securities and Exchange Commission (SEC) looks set to bring in a mandate for Scope Three emissions to be disclosed for most companies.

Ian Thomas, senior principal consultant at global engineering and technical company Vysus Group

In the UK, the North Sea Transition Authority, which is overseeing the North Sea Transition Deal, sets out best practice in environmental management within the oil and gas lifecycle.

It does this through a series of stewardship 'expectations' with the latest additions (11 and 12) solely focusing on net zero and the supply chain. These outline the considerations for reducing greenhouse gas emissions on both the physical environment and society.

Expectation 12 references the close collaboration that exists within the energy supply chain, and drawing on this resource to outline transition projects such as CCUS and electrification, amongst others, illustrating further areas for cooperation.

Offsetting

There are signs that offsetting itself has had its day. A major US energy company, NextEra Energy, has coined the phrase 'real zero' – achieving zero climate pollution without the use of offsetting by 2045.

Broadly speaking, the move has been welcomed, albeit with some caveats, and reveals that if accelerating the energy transition is to happen at the pace we need it to, adapting existing processes will be fundamental.

Offsetting can be seen as a method for wealthy countries and companies to greenwash their figures rather than tackle the true global environmental impact of their emissions.

An accounting process for real offsetting, such as permanent CO2 sequestration, remains a work in progress.

Avoided emissions

There has been some use of the term "Scope Four emissions" to pertain to so-called avoided emission. Scope Four is not a recognised term, and it is already being identified as a means of greenwashing.

One example of avoided emissions with which we are all familiar is video conferencing, as this has removed (i.e. avoided) the emissions that would have arisen from attendee transport and using a meeting room with equipment and lighting.

Another example is to use remote inspections of equipment. This can be used to avoid the need to bring in multiple specialists which would result in travel emissions.

Whilst it is legitimate to calculate the emissions avoided by a certain course of action, the fact remains that to do this, Scope One, Two and Three emissions for all options must be assessed.

Credibility of data

It is critical that emissions data is of verifiable quality. Faulty or misleading data, improperly gathered, or secured, can have a significant negative impact on the credibility of reported data or disclosures.

Equally concerning is the scenario where business investment decisions are made on the basis of poor data.

Greenwashing is a term everyone will have come across. An example from 2020 led to the withdrawal of an entire advertising campaign by one multinational oil and gas operator, following complaints to the UK regulator as to the credibility of certain claims in the advertising.

It goes to prove how such messages must always be substantiated by clear evidence and data.

Need for collaboration

Just as we have a shared responsibility to bring down our emissions, we have a shared responsibility to share learning and collaborate together to embed new knowledge and processes into our methods.

As the importance of sustainable reporting and information disclosure continues to expand, there will need to be a closer connection between operators, regulators, investors, joint venture partners and other stakeholders.

Need for specialists

The people responsible for ensuring figures are true, secure and free of material errors should have demonstrable competencies within the industry sector and in the data assurance process.

Organisations that have direct heritage in data verification and assurance, and who have a long history within the oil and gas sector, are more than qualified to understand the challenges and to offer solutions.

Given the acknowledged challenges, it goes without saying that those preparing the figures need to be qualified practitioners and experienced in the industry sector.

That is to say, a specialist in one field such as manufacturing may not be competent to identify emission sources in a completely unrelated industry such as upstream oil and gas or a downstream refinery.

Verifying the vast data streams through an independent and competent third-party adds to the credibility of any statements released to the media or elsewhere, building trust with investors, shareholders and the public.

Also, it reduces the risk of accusations of greenwashing. This is particularly important in a time when there are increasing claims of greenwashing in the media.

Such specialist organisations have 'real world' experience and know how to apply the principles embodied in AA1000 AS or ISAE3000 standards to support operators with net-zero obligations.

Vysus Group became an AccountAbility AA1000AS licensed provider earlier this year, enabling us to offer independent verification of non-financial disclosures and emission statements to our clients within the energy sector.

Combined with our expertise from other technical areas within the industry, we are now in the position where we can cover the full energy value chain, and the various emission levels at specific points.

About Vysus Group

Vysus Group is an engineering and technical consultancy, offering specialist asset performance, risk management and project management expertise across complex industrial assets, energy assets (oil and gas, nuclear, renewables), energy transition projects and rail infrastructure.

For more information about Vysus Group's sustainability commitment campaign, Planit22, visit **https://www.vysusgroup.com/planit22**.

Applying data management skills on low carbon projects

Oil and gas data management skills are very useful on low carbon projects, such as the ability to work out which data types are most important and build governance systems around them. Jess Kozman of Katalyst Data Management explained

The skills of an oil and gas data manager are very useful on low carbon projects, such as for CO_2 sequestration and geothermal, and also for counting emissions.

This includes the ability to work out which data points are most important and building governance systems around them, said Jess Kozman, principal senior consultant with Katalyst Data Management, who is based in Perth, Australia.

He was speaking at the Society of Professional Data Managers (SPDM) Mid Year Conference on June 21-23.

"The core principles we've been using for data governance are going to remain relevant," he said. "We need to pay attention to what subject matter experts are telling us about the 'fit for purpose-ness' of those data types. We need to progress those data governance standards as we work with new kinds of data types."

Connecting data management processes to business value "has always been the issue," he said. "We've got to get better at telling the story about why we should manage data effectively."

The specific data points which are most useful are different for low carbon projects than E&P projects, because the project lifecycles are different. But the same principle applies of looking for the most important data which you want to put governance around, he said,

Low carbon energy projects also have 'stage gates' or milestones in their process where certain data is evaluated to make a business decision. The first task as a data manager is to identify the critical data types being used at these points, he said.

Companies still have a focus on oil and gas exploration. "We need to be open to the idea that exploration data may not be the most critical data," he said.

It is important to think about the aspects and attributes of data, in working out how robust your data governance is.

If we are talking about wells, for CO_2 sequestration or geothermal, there are many data management standards which can be used, such as how to define a unique well, its purpose, its stage in the asset lifecycle.

But a 'well' can look very different for a closed loop geothermal project, compared to a well for oil production. There may not be much appraisal of resources needed, and the well paths can be entirely different. So some of the definitions may need to be changed.

"It leads to questions on how we label data associated with these well bores," he said.

For seismic surveys, the 'navigation' or 'positioning' data is critical in oil exploration, so you know exactly what part of the world the data refers to. This is still important if you are using the data to place wind farms and avoid shallow hazards, he said.

CO_2 sequestration

In Australia, where Mr Kozman works, there are many projects for CO_2 sequestration. The data challenges have much in common with oil exploration, but there are key differences.

Companies are monitoring for ground displacement on CO_2 injection sites. This can be done using SAR (Synthetic Aperture Radar) data, usually taken from an orbiting satellite. This leads to the question of how the data should be stored, and what metadata is needed.

A group within the OSDU open standards organisation are working on a standard format for SAR data, he said.

Within the reservoir, there are models for how CO_2 is being absorbed into the rock, which can take place over tens of thousands of years. This leads to questions about how long the models themselves need to be stored for.

Jess Kozman, principal senior consultant with Katalyst Data Management

"It puts a different perspective on the way we think about things like how we store data, make it accessible, and remain technology agnostic," he said.

The baseline survey is very important for CO_2 sequestration – understanding the situation before CO_2 injection started – because you need to be able to compare this to the situation later. This baseline survey could use the same systems as the oil and gas industry uses, or something finer tuned for the needs of CO_2 sequestration, he said.

Tracking carbon emissions

With tracking carbon emissions, a first challenge is the different units which are used around the world. It is normally emissions per something, but emissions can be measured in pounds or tonnes of CO_2, and the 'something' can be per kilojoule or per megawatt hour.

Data managers are used to this - different parts of the world have always used different units for well depths and sea levels – some feet, some metres.

Regulators may demand emissions data be submitted in custom formats. For example, some regulators require emission data to be sent in spreadsheets, something data managers may look at in horror.

"Excel is not a database, Excel is not a system of record," Mr Kozman said. "There are lots of Excel horror stories. It's a good tool for analysis. But as a robust system - auditable, trail of provenance - there's a lot of problems for that.

I'm concerned that even governance agencies are suggesting that Excel might be a way to track that."

Old data

Many companies have large libraries of old seismic data stored on tape, and think it would be useful to move it to cloud storage, so it can be more easily retrieved, when needed for geothermal or CO2 sequestration projects.

There is a growing appreciation of the value of legacy data in oil and gas companies, he said. People recognise that old data could be useful for finding hydrogen storage sites, geothermal projects or CO2 sequestration.

People often see valuable things in old data, such as a handwritten note in a drill log from 20 years ago, 'I found some inert gas'.

But tape transcription projects can be so big, there is a question of where to start or how the work should be prioritised, he said.

Data managers sometimes think 'first in, first out' – go to the oldest data first. Or maybe they should go do the data which was most important in the discovery of the field – it may have some information about reservoir properties at the beginning of field development.

Data managers can help prioritise, so if there is a limited budget, it can show which data is best to transfer first.

Companies are asking for more granular data about the risk of data loss based on different data types – such as how long seismic tape storage will last for.

Data managers are often asked to give judgement about the risk of losing data in certain 'high risk scenarios'. Pandemics need to be added to this list; we have seen that a pandemic can lead to a number of add-on risks relevant to data management, including people not being able to travel, critical spare parts for networking equipment not being available, and so broken computer networks which cannot be quickly fixed.

Data governance structure

Some companies have developed very "top down" data governance frameworks with many different steps and levels of governance. But many companies would be better served by something more 'digestible', he said.

"Making something fit for purpose involves scaling it back to something people can deploy and are interested in getting involved in."

For data governance, "we generally find that three levels of accountability is about what people can digest."

"We try to bring that to a few key decisions that people in different roles need to make about data governance."

Data privacy

Another consideration is data privacy, particularly when transferring data between different jurisdictions. There may be issues you have not considered.

For example, in Australia, someone's membership of a professional organisation is considered private data. "We raised a hypothetical question, if there's a consultant report [which] indicates the individual is a member of a trade organisation, does that mean they could make a request to have that information purged from a technical data set? It is an open question."

Tagging unstructured documents – and useful search

Tags can be used to describe unstructured documents in many ways, for example their types or scientific disciplines, or the topics they may contain. This can make it much easier for a document search system to retrieve the right document, said Lee Hatfield from Flare Solutions

Just about every company today has large volumes of unstructured documentation in its archives, and finds it hard to get any value from it, said Lee Hatfield, consultant with information management company Flare Solutions. What's more, the documents may be stored in a multitude of places, including archival systems, shared drives or in the cloud.

He was speaking at the Society of Professional Data Managers (SPDM) Mid Year Conference on June 21-23.

Companies want to provide their staff with search tools to help them retrieve documents they need to do their jobs, and as data managers, there are things we can do to help them achieve this.

The most useful step is to add tags to the files, for example stating what the files are (such as a well log), what discipline they relate to, and which well or field they concern.

Before you start tagging files, it is useful to create a taxonomic structure of tag names. This could be asset name, license, business process or document types.

Some tags are geographical, some relate to context, such as topic or discipline.

Many tag terms are hierarchical, such as a well which relates to field which relates to a basin.

Lee Hatfield, consultant with data management company Flare Solutions

The documents themselves will normally refer to something specific, for example an 'end of well report' for drilling a specific well.

The taxonomy can include synonyms, so if someone searches for "reservoir surveillance data" it can look for words with similar meanings, not just those 3 words; and it could understand that a well test report is itself reservoir surveillance data.

"Having the taxonomy really does add value," he said. "When everything is connected in the taxonomy, you can have relationships form that are really powerful."

"When you are building up an index of thousands, perhaps millions, of documents, you learn a lot of lessons. Some tags are relevant to some data types, some are not."

You can select tags to apply to a file by looking at the file's name or the path, or if all files about a certain well are in a certain folder, then by association. The filename extension can also be useful for tagging files, for example if it ends with .las it must be a well log.

When extracting information from the files in order to tag them, you don't necessarily need to scan all the text in the document – maybe you just need to look at the title page and the contents.

Remember that automated tagging systems can make mistakes. For example a sentence "this well was not cored" could mean the file gets mis-tagged as a file of core data.

Using the tagging

Once you have groups of documents tagged, you can do different types of searches.

For example, if you have tagged all the 'end of well' reports for the wells in your field, you can go through them all to extract the total well depths.

If someone asks you for "all the drilling reports" for a certain field, the tagging makes that easy to provide.

The tagging can help you get more insights from documents. For example if you have a well schematic with a date on it, you can use the date referenced to other documents to determine if the diagram was drawn after the well was completed, after it was abandoned, or somewhere in between. This helps you understand how relevant it is.

This tagging work can help make sure you are not holding any documents which should not be stored – in one example, a company found it had an archive of hundreds of CVs, which contain personal data.

You can check you have all the data you should have. For example, if you are responsible for 1000 wells, you can check you have 1000 'end of well' drilling reports.

Implementation

When it comes to implementation, because the volumes of documents are generally so large and require a lot of processor time, you have to start with a "low level pass", to see how far you can get just looking in the metadata – for example to assign tags based on just the file title.

Then you can go to the next level, looking at the basic content of the file. The next level is to look at the whole document.

"The deeper you go, the more value you get," he said. But it means the tagging will take more time. You may prefer to look for quick wins. The effort "has to be appropriate to the value you want to get out of this."

Flare was involved in a data tagging project after a company merger, involving over 300m documents. The entire project took 9months, much of which was spent tagging the documents with automated tools.

Warning about AI

A lot of companies are trying to use AI to tag documents for their search systems, and getting some useful results. "That's good, and pushing the boundaries of what we can do," he said.

"But from a value point of view, I wouldn't understate the power of [just] exposing the right data to the right people at the right time," he said. "If someone can do a search and get results they want and expect, that's a massively powerful tool. Don't underestimate that simple wins!"

Encouraging wider sharing of energy data

Energy companies should be able to see value and pathways to reducing emissions from wider data sharing, said Ed Evans of the Open Data Institute (ODI). But they may need some encouragement

"My premise is that sharing more data is an essential step towards achieving industry and sector goals like reducing carbon emissions and developing offshore renewables," said Ed Evans, data consultant with the ODI, who formerly worked in oil and gas data governance and management.

"Data sharing leads to unforeseen opportunities and innovation."

He was speaking at the Society of Professional Data Managers (SPDM) Mid Year event in June.

'Data sharing' does not necessarily mean providing open access to all of your data, he emphasised. Access to data exists on a spectrum from closed to shared to open.

Highly sensitive commercial or personal data can remain closed whilst other data can be shared within a select group or provided openly.

Some data needs to be anonymised or aggregated before sharing, while retaining its value.

The energy industry already sees benefits from sharing some HSE and logistics data in the UK.

Many businesses are embracing wider data sharing, and are seeing further tangible benefits for their organisations and across their entire sector.

Developing an ecosystem

The ODI looks at ways that organisations can get value from sharing data, under limited conditions, he said.

Not just in a transactional way, but to develop data sharing 'ecosystems' for sustainable benefit.

The ODI was founded in 2012 as a not-for-profit organisation by Sir Tim Berners-Lee, inventor of the world-wide web, and renowned computer scientist Sir Nigel Shadbolt. It supports a vision of a world "where data works for everyone," sharing data in open and trustworthy data ecosystems.

"We see data like infrastructure, like roads, railways, electricity," he said. "The rush to digitalisation shows that we need more data, and more reliable data as a foundation for business."

The oil and gas industry has been successful in setting up data sharing ecosystems, he said. For example, there are many state-run 'National Data Repositories' holding oil and gas data, each exists in a different regulatory regime and with different service and governance models.

Oil and gas people often believe other industry sectors are ahead in working with data. Whilst true in some respects, many other industry sectors put less emphasis on data governance, standards and dedicated data services than oil and gas, he said.

The Open Banking System

There are continuing efforts to set up an open data sharing environment for UK electricity data, modelled on the UK's 'Open Banking Framework'.

The idea is that better data sharing between power suppliers and users would make it easier to make the whole grid balance and encourage innovation, for example in data analytics.

The Open Banking Framework is for sharing sensitive and personal financial data between banks, fintech companies, technical service providers and regulators in the UK.

This is achieved with specific consent from the customer. There are similar initiatives in the European Union (PSD2) and the US (Financial Data Exchange). Banks were not given a choice about whether to participate.

Barriers and benefits

Common barriers to sharing data include a feeling that data is only for the use of the company that collects it, or there is a sense that sharing just helps someone else to recognise its value.

Data managers have been trying to get a message across that data is valuable for many years – but now, ironically, as more data sharing is encouraged, the perception that it is 'valuable' becomes an obstacle, people don't want to share something they think is valuable to them.

There are many recognised benefits to data sharing, from reciprocation, cost savings to supply chain optimisation. It is essential for working together on sector-wide issues.

There can be benefits to organisations from having an outsider looking at the data and coming up with ideas of what to do with it.

"Showing the benefits and the ways that barriers to data sharing have already been overcome is better than simply relying upon legislation for the development of shared data ecosystems," Mr Evans said.

Data governance

If you are going to use someone else's data, you want to be sure it is good quality, so there are data governance challenges with making such a data sharing ecosystem.

"Governance is needed to ensure that trusted data is available in a sustainable way," he said.

It is a challenge to move from looking at data governance internally, to looking at data governance between organisations. Under what kind of organisation does that governance lie?

There may be a need for a state backed regulation. "Regulators can encourage, cajole, pressurise or legislate," he said.

The carbon and energy cost gains from better motors

Vast amounts of energy is wasted in all industries because of motors powered too large for their applications, or not being the most efficient models. Fixing it could offer a quick win for the climate and energy costs

Adrian Guggisberg, president of ABB Motion Services division, says that 45 per cent of all power generation globally goes into running motors, using data from the International Energy Authority. This includes pumps, air con fans, and electric vehicles.

Mr Guggisberg estimates that on average, each motor application could be 22 per cent efficient. This could be achieved from upgrading motors to more efficient models, having a motor which is most power efficient at the load it normally runs at, and using variable speed drives to adjust electricity current.

Putting these numbers together means that it could be possible to reduce worldwide power consumption by 10 per cent, equivalent to a third of all coal power stations.

Variable speed drives can be used to adjust the flow of electrical energy to the motor by adjusting frequency and voltage, thus slowing the motor down. But only 23 per cent of motors in the world are controlled with them.

But if the motor speed cannot be reduced, and its power needs to be constrained, another method needs to be used, such as with a throttling valve downstream of a pump.

From an energy sense that is like driving a car while pressing the accelerator and brake at the same time, he said.

To illustrate with numbers, if the pump is 91 per cent efficient, but the throttling valve reduces flow to 40 per cent, the overall system is 28 per cent efficient.

If a variable speed drive is used to reduce current to the motor, there would be some losses associated with the variable speed drive, but the overall system would now be 82 per cent efficient, rather than 28 per cent.

Adrian Guggisberg, president of ABB Motion Services division

To put these numbers in reverse, for a required output of '100', you would put in 122 with a variable speed drive (100/0.82) and 357 with the throttling valve (100/0.28).

The other issue is that a motor runs most efficiently at about 75 per cent of its maximum load. If the motor is running at slower speeds, the efficiency drops. So, it is best to use a motor sized to run most efficiently at the speed it normally runs at.

Motors last a long time, and most motors in use today were installed in a time where there was less concern about carbon emissions and energy efficiency. They were specified larger than needed, to provide a safety margin.

Business case

The situation is not so simple of course, because there is a lot of cost attached to purchasing variable speed drives and motors, engineering and cost calculations, and installation work. For smaller motors, the savings may not justify the cost.

Industrial customers typically have many motors in their 'fleet', and they will want to prioritise which ones give the biggest returns on an upgrade. They also want to make sure they are not introducing any new risks.

On the other hand, improving motors can offer a relatively easy means for companies to achieve their decarbonisation targets, Mr Guggisberg says.

Many companies are trying to achieve their green targets by purchasing renewable energy. But it is likely that demand for green electricity will greatly exceed supply in a few years, he believes.

Gathering data

The first step to better understanding motors is to gather data. You can install sensors to monitor loads on the motor, fuel consumption, magnetic fields and temperatures.

ABB also offers software tools, under the name ABB Ability™, which can gather and analyse this data providing insights, while service experts can generate recommendations.

Normally, about 3-6 months of data is needed to understand a motor – if it is in a heating or air-cooling system, you would need a year's data to understand the full cycle, Mr Guggisberg says.

Improving motors involves in-depth knowledge, and not all motors are the same. To illustrate the complexity, consider that the biggest failure mechanism on small motors is vibration, and the biggest failure on large motors is the insulation system, he says. "It is all about in-depth knowledge of where you can optimise something."

ABB Motion Services

In May 2022, ABB launched a new digital appraisal service specifically for finding energy saving opportunities in motor driven systems, called "ABB Ability Digital Powertrain Energy Appraisal", harvesting data from 'fleets' of motors and variable speed drives.

Being able to do the data gathering and analysis automatically makes it viable to analyse all motors in a company's fleet continuously or regularly, not just focus on the largest ones intermittently.

Mr Guggisberg gave a case study of a Swedish timber company which used an ABB Ability condition monitoring service to identify the 10 motors with the biggest energy saving potential and prioritised 6 for upgrade.

Another client, SCA Munksund, a Swedish paper mill operator, used the ABB Ability Digital Powertrain solutions to gather and analyse data from its motors.

Some clients use ABB's digital solutions themselves; other clients work with ABB partners, who themselves use the same software. The ABB software can be integrated into other software systems.

ABB Motion Services is offering advisory services to assist with this. While its focus in the past was mainly about reliability, now it has four focus areas – on reliability, digital / innovation, life cycle management, and energy efficiency / circularity, Mr Guggisberg said.

It has four services - recovery services (immediate help after a failure); planned services such as to do motor upgrades and maintenance; modernisation / improvement advice; and data / advisory services. These services can be provided in partnership with other companies.

ABB is investing in ways to make electrical powertrains more efficient. It is developing ways to make motors using materials which are readily available and can be easily recycled, rather than rare earth metal permanent magnets.

Can you develop a solution for IOT + satellite?

Satellite operator Inmarsat has a program to support companies to develop IOT solutions, systems and equipment for onshore oil and gas operators, using its satellite network

Satellite communications have many advantages over cellular and wired communications for communicating IOT data for onshore oil and gas operations, particularly with reliability and ease of deployment.

UK satellite operator Inmarsat is seeking to encourage solution providers, system integrators and equipment manufacturers to develop products which make use of its communications infrastructure.

It has launched the "ELEVATE" development program. By being part of the program, it will be easier for companies to work with Inmarsat's solutions engineering team to develop and test their systems. They can find other companies to collaborate with, to develop and market their products, and promote their products on Inmarsat's online marketplace.

Inmarsat applies the term "IOT" (Internet of Things) for any device which gathers data which can be sent over a communications network, including sensors and cameras, says Nicholas Prevost, industrial IOT innovation advocate with Inmarsat.

Satellite communications can offer higher reliability than cellular, because there is no infrastructure which might be destroyed in fires, earthquakes or floods, apart from the terminals or the sensors themselves.

Oil and gas companies typically use IOT for monitoring, gathering data over a period of time, such as about equipment, to see if any changes have happened.

In the oil and gas sector, many clients use it to monitor artificial lift equipment ('nodding donkeys'). Other clients use it for well head monitoring, communicating data about flow rates and impurities. Another use is for pipeline monitoring systems, including data from flowmeters and pipeline sensors.

Equipment can be controlled remotely via satellite. For example, you might want to switch on a pump when the water level in a dam drops to a certain level, but not necessarily want it to be activated automatically.

Some people have done "full SCADA control" over assets via satellite, Mr Prevost says.

Inmarsat has worked with companies operating drilling rigs in Australia's Northern Territory, where there is no other connectivity available. The communications can be used for safety purposes and for sending operational data – so there is no need for anyone to physically visit the location to download data from an onsite data logger. Physically visiting such a site may involve hundreds of kilometres of driving.

There are also a number of oil and gas clients in Saudi Arabia, UAE, and Brazil.

Inmarsat is launching a new constellation of satellites, known as the "Inmarsat-6" or I-6s, to enter commercial service in 2023. It says these are the world's "largest and most sophisticated commercial communications satellites." These will carry both Ka band and L band communications.

Satellite services

Inmarsat offers several types of satellite services, running over its VSAT / Ka-Band and L-Band satellite constellations. These include GX, the Ka-band high bandwidth network, ELERA L-band and FX, a hybrid service including both GX and ELERA, to cover a wide range of data requirements.

Ka band can carry very high bandwidth, up to gigabit per second speed. This technology is also used for broadcasting satellite TV. But for oil and gas use, it comes with some disadvantages. The equipment is much larger, and may look valuable, making it a target for theft. It takes more power to run, which may make it unsuitable for powering with batteries.

It needs to be pointed more precisely at the satellite, so may need expert technicians, including another call-out if the terminal is ever moved or knocked.

The L band services, now branded "ELERA", carry less bandwidth but do not have these problems. It can carry communications up to megabits per second.

The technology was originally developed for maritime safety communications, and so has extremely high reliability.

Equipment can be moved from one country to another, because the satellite network is global – although they would still need a local connection to a terrestrial system to receive the data.

L band is less affected by weather, such as heavy rain, and the terminals are smaller and do not need so much power.

Nicholas Prevost, industrial IOT innovation advocate with Inmarsat

The terminals are around the size of a laptop, and (unlike a laptop) designed to withstand hostile environmental conditions with a lifespan of 10 years. They don't need to be positioned so precisely at the satellite, and do not need specialist satellite technicians. "You can take a 'BGAN' terminal out of the box, anyone can point it and get connected in minutes," Mr Prevost says.

The terminals can also be managed remotely, including making checks on the terminal status.

The terminals have C1D2 rating to ensure they do not pose any ignition risk.

A specialist terminal "BGAN M2M" is available for machine-to-machine communications for customers sending megabytes per month.

The service is paid for via a monthly plan involving a certain amount of data per month. Pricing plans range from kilobytes per month to gigabytes per month.

Then for communications needs which only require small packets of data, such as in many IOT applications, the "IsatData Pro" or IDP device may be appropriate.

The terminals will have very low power consumption, so more suitable for battery or solar power. Communications are paid for by the kilobyte.

There will be a new terminal coming onto the market shortly called "OGX" which will be more powerful than an IDP, but not as powerful as a BGAN, Mr Prevost says.

How OT security strategies are evolving

Operations technology cybersecurity may be at a similar level of maturity to where IT security was in 2002, says Trustwave's Darren Van Booven. But many companies are starting to think about it much more carefully

The Colonial Pipeline hack in May 2021 was the first time many companies realised how vulnerable operations technology (OT) systems could be to hacking, says Darren Van Booven, Cyber Advisory Practice Lead with cybersecurity consultancy Trustwave and former CISO of the US House of Representatives (2012-2014).

Mr Van Booven has been focussed on the energy sector for the past few years. He has also worked on developing an operations technology (OT) risk strategy for the US Department of Energy.

Cybersecurity in operations technology is at a similar level of maturity to IT security about 20 years ago, when people were only starting to think about it, he says.

In the IT world, the threats are still similar today as they were 20 years ago, but people have much more understanding of how things can be exploited and what the impacts are, and how to stop it.

Trustwave saw a doubling in demand for its operational technology security services since the Colonial Pipeline hack, he says.

Senior managers have been calling for security system audits and assessments, ransomware protection strategies, and detection and response capabilities for advanced threats. They are considering if they can bring in better network segmentation.

"It has raised the potential risk. Senior leadership and boards of directors start to question what they are doing to prevent that kind of thing from happening. It can be a top-down driven initiative."

Organisations are often doing the right things, but there are areas they may need to do them more, he said.

As companies strengthen their IT security systems, they push threat actors to explore other ways of hacking company systems, such as their operations technology.

Engineers and IT people

Most oil and gas companies still keep the management of their operations technology and IT security completely separate, he says.

The people managing control systems typically have engineering backgrounds rather than IT backgrounds, and can be reluctant to see IT based security systems being used, in case they bring in stability risks.

"Your IT security people don't know process control systems. They don't know the mechanics behind the equipment that's being used. [But] often the engineers, running those systems, are not aware of some of the cybersecurity risks," he says.

"I recommend teams that have people from both sides in the same room. [They should] go through training together, so they learn each other's areas a little bit more, what they are concerned about. Having a bunch of people with different views on things can be valuable."

"At the end of the day you have an approach [where] you get people's buy in. If you don't have buy in from all the parties you are working with, it is really hard to make a lot of progress. You can force things on people [but] that's not going to get the same results."

"People don't like change. A lot of people in the OT environment, they have been doing this work for decades. If some cybersecurity people come along and say, 'you've got to do this,' they'll certainly question why."

Building a map

The right approach could be seen as a form of mapmaking, to try to work out where you are, and to see how risks can be reduced, he says.

You don't want any cybersecurity controls themselves leading to more risks or causing problems.

Too often, people just "jump right in with technology tools. Sometimes they don't really know what value they are trying to get from those tools. They don't consider why they are doing it, or if there are other methods they could consider."

Network segmentation

One approach you can take is to actually segment your networks. "If there's an avenue for systems to get to the internet, or systems that are exposed on the internet, that to me is a far greater risk."

Control systems shouldn't be networked to a computer which can access e-mail. "Email is such an important threat vector, it is extremely well used as a way of delivering malware," he says.

"If my [email] machines were compromised somehow, I wouldn't want that spreading into more sensitive networks."

But if you have a really good understanding of your system, how different devices communicate with each other, how your network is structured and segmented, you can be much more confident in the event of an attack, without necessarily needing physical segmentation, he said.

This was lacking in the Colonial Pipeline case. Many systems were shut down just so they could not be hacked – but this meant that the company was no longer able to bill clients.

Scenario planning

Companies can do scenario planning, thinking through what would happen if someone or some malware could get in.

"Its kind of like recovery planning, you start imagining scenarios which would be most likely to occur and how you would respond."

With oil and gas companies, Mr Van Booven has been conducting what he calls 'table top exercises', to think through scenarios which might happen, what the response should be, and whether the company has a response plan in place.

"There's different levels of maturity in all this stuff," he says.

New equipment risks

It is important for companies to consider the risks of new equipment purchases, he says. If you are buying something with a GSM cellular communications chip inside, it might be possible for someone to dial into it remotely and cause problems. Although that risk can be mitigated by changing the password from the initial one.

Newer technology can be much more networked than older equipment, which only had serial connections to connect them to one other device.

Judging the risk

Risk can be thought of as a combination of what you judge to be the likelihood of a certain vulnerability being exploited, bearing in mind the controls you have to prevent it, and the impact if that happens.

Switching off power to an airport would have a high impact, but should have a low likelihood. "To do that I've got to get through a lot of layers of security."

This can be thought of like tumblers in a lock – the key can unlock it if it puts the tumblers in the right order.

One way to assess risk is to look at whether hackers are exploiting the vulnerability elsewhere, or if it is more theoretical. "If it is theoretical the guidance is different, than if things are happening out there," he says.

You can understand risk by understanding that hackers are looking for ways to blackmail people. They aren't necessarily targeting operational technology, "but if they realise they can control the flow of chemicals through a facility, then they think, 'I bet this company will pay a lot of money if I stop it or threaten to stop it.'"

"You're controlling the ability to refine oil or prevent the ability to operate. Attackers are becoming more attuned to that, its effective."

Another way to blackmail companies is to encrypt sensitive data and then threaten to release it.

Training and controls

Training people in general security 'hygiene' is important. But recognise that you will never have all the company staff being security experts. "It is always best effort," he said.

"It is always one person who makes a mistake that can be enough to cause trouble."

You have to make sure your security controls are not impacting the ability for people to do their work. "If you make it harder for them to do their work, they are going to go around you. You defeat the purpose of the changes that you make."

You also need to be open to staff about any controls you are using, such as scanning their e-mails and hard drives to look for hackers, so they know what is going on.

A good approach can be to just work harder to make risks clearer to people, he said. An example of this is the systems which put a banner on external e-mails, "this e-mail does not come from your network so be careful."

"When organisations don't have that, you're making it harder for users to do the right thing," he said.

Using 'edge' computing in gas flow meters

Aramco researchers have developed a wet gas flowmeter with a sophisticated edge computer, with the memory and processing capability to do measurement corrections, equation of state models, diagnostic models and stochastic machine learning models, leading to much more accurate flow measurement

By Saketh Mahalingam, Aberdeen Technology Office, Aramco Overseas, and Gavin Munro, CEO, GM Flow Measurement

Wet gas flow meters measure the flow rate of the gas when some liquid flows with the gas.

These meters often use an intrusive device, such as an orifice plate, a Venturi throat or a V-cone, in the flow. They measure differential pressure across the intrusion and convert this into a gas flow rate.

The gas mass flow rate is calculated using a combination of the Bernoulli equation and conservation of mass equation. It requires the user to enter the correct density of the gas and liquid phase into the calculation.

But since the density values fluctuate over time, the gas flow measurement from the meter may become very inaccurate.

An equation to account of variation of gas density with pressure and temperature is often used. But when small amounts of liquid are entrained in the gas, the basic calculation of the mass flow rate needs to be adjusted to incorporate the density of the mixture of gas and liquid.

A second differential pressure (P3-P2, see Figure 1) is often needed to measure the liquid fraction in the gas.

With time, as a gas well gets depleted and the reservoir pressure decreases, the overall flow rate of gas may decrease considerably.

In addition, the heavier liquid may either drop out of the flow, either in the well bore or in the flow line on surface.

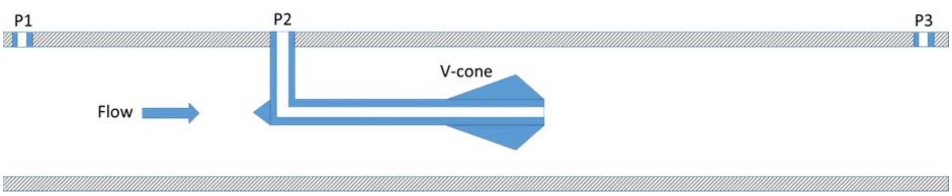
These fluctuations mean that the flow rate, liquid content and the physical properties of the fluids going through the meter change with time.

Consequently, the error in gas flow rate readings may be up to 50 per cent in some cases.

The operating range of a meter is expressed as a ratio of the maximum to minimum gas flow rate it can measure, called the 'turndown ratio'. This is typically about 8:1. But with liquid present in the flow this decreases to about 3:1.

A wet-gas meter, therefore, may be unable to measure the flow from a well within a few years because the wet-gas flow is now outside the measurement range of the meter.

This means that the meter has to be replaced or expensive well testing with a portable test separator have to be carried out.



Aramco Fig. 1 — Internals of V-cone Flow meter

Adjustable cone meter

An improvement on the traditional cone meter is the adjustable cone meter.

A moveable sleeve is placed within the meter and its position is moved using a rack and pinion arrangement.

When the flow rate is high (a – high flow position), the sleeve is downstream of the cone and the meter operates like a normal cone meter.

This means that the differential pressure at the cone (P1 – P2) is sufficiently high and is within the measurable range of the meter.

However, when the flow rate drops below a preset value, the differential pressure (P1 – P2) drops below the measurable range of the meter.

While a conventional cone meter would not be able to measure such flow rates, the adjustable cone meter is able to achieve accurate measurements because the meter detects that the differential pressure is going below the measurable range and automatically moves the sleeve so that it would cover the cone (Figure 2b).

Edge "Flow" Computer

With computing costs coming down, it is possible to do a lot more calculations at the edge.

It means that measurements can be corrected at the source, rather than processing data further downstream.

An edge computer can run equation-of-state (EOS) models. This means that the density of the produced fluids can be computed at the flowing pressure and temperature, based on a composition.

An edge computer can have the memory to run diagnostic models that look at the raw measurements from the meter and compute live uncertainties on the flow rates.

In addition to physics-based deterministic models, stochastic (probability based) machine learning based models may also be implemented.

This offers the possibility of adapting the model as the flow changes with time, and new training data in the form of reference measurements may be periodically available.

Aramco's flowmeter

An adjustable cone meter with these features has been developed and tested by Aramco & GM Flow Measurement.

It is currently awaiting field trial in Saudi Arabia (Fig. 3).

The meter was designed and tested in Scotland and has been demonstrated to have a turndown (max / minimum flow) of 54 in dry gas flow.

Fig 3. Adjustable Cone Wet-Gas Meter

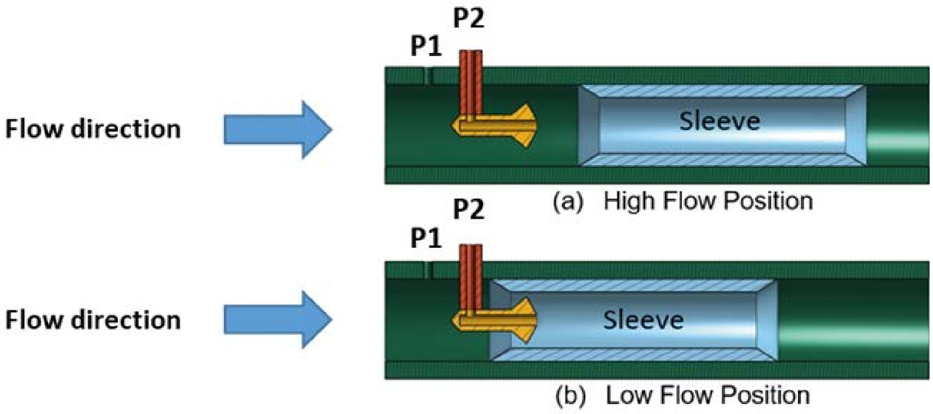


Fig 2. The adjustable cone meter

It is estimated that the meter will have a turndown of up to 20 in wet-gas conditions.

The edge flow computer on this meter is also capable of secure wireless communication to a distance of up to 200m and approved for use in hazardous areas.

This helps avoid laying cables and helps in easier adoption of the technology.

How digital tech can help continuously improve offshore operations

Purchasing and contract management executive Stephane Planeix shares advice on ways to use digital technology to drive continuous improvement in offshore operations, including 'lean', automated data collection, remote monitoring, CMMS and managing supplier performance

By Stephane Planeix, former senior executive in purchasing and contract management with Schlumberger, Seadrill and Det Norske

The performance of a company can be defined as its ability to perform all tasks related to its core activities with a limited percentage of non-performance or waste in its execution.

A four-step strategy such as Plan-Do-Check-Act (PDCA) can include defining corrective actions and redefining corrective actions when necessary, with the full supply chain involved in the process.

An evolution of this is the five step Define-Measure-Analyse-Improve-Control (DMAIC) cycle. This places focus on measurement of performance, and the deployment of automated measurement systems such as edge computing and data analytics.

The "lean" methodology, developed by the Japanese industry in the 1980s, is based on perception of quality. It involves collection of a large amount of reliable measurement data and identifying variations from the expected result. It involves defining what acceptable results are and segregating the various forms of non-conformance. Statistical data analysis is used, defining a cloud of scenarios based on the perception of quality.

In the oil and gas market, you can monitor any offshore plant and measure any deviation in performance, such as variation in quantity and quality, or downtime imposed by conditional maintenance, to obtain an optimized performance.

The methodology can easily identify any defect on sensors, because any out-of-range result received from a sensor would be identified as a defect.

Monitoring equipment

The equipment monitoring process involves statistical analysis of data received from multiple sensors, and identifying all acceptable modes with the manufacturers

An approved procedure with the manufacturer for the periodical check of the measurement tools is always required and must be developed, including any degraded modes to be agreed for each category of equipment.

This includes comparing the sensor reading deviation over time, with what manufacturers say you should expect. More sophisticated analysis may enable you to identify specific emerging operational problems faster.

Monitoring generators

The most important elements of offshore equipment to measure might be the energy consumption from the propulsion and power generations systems and their NOx and Co2 emissions. These may be taxable according to the environmental and climate change regulations in place.

Data from power generators and their electrical distribution systems can give insights into the operating status of equipment on the network.

Equipment manufacturers offer remote equipment management tools, allowing remote management of the performance of generators. Beware that their recommendations may be linked to a technical service offer from the manufacturer. The manufacturer may also control whether the data can be transmitted to an SAP type enterprise resource planning system.

Maintenance software

The use of computerised maintenance management systems (CMMS) such as TM Master, IFS cloud or Maximo has become widespread.

This provides a detailed view of the equipment, its live status and associated operating costs. It makes it possible to estimate maintenance costs and costs related to subcontracting activities.

The management of multiple stocks, minimum quantity stocks, services engineers in house, or contracted resources for multiple sites is possible.

This software does not normally allow simulations of operational costs related to the implementation of various scenarios, which would be needed to determine a means of operational costs reduction.

However, you can estimate costs of different processes by making simulations of the use of the equipment. You can visualize situations which can create a non-optimized operating cost.

For example, when we observe the operation of a set of generators, we will observe peaks in intensity of fuel use linked to electric motor starts.

Once this has been identified, it will be possible to reduce fuel consumption using batteries.

Stephane Planeix, former senior executive in purchasing and contract management with Schlumberger, Seadrill and Det Norske

This reduces the overall operating time of the generators, thus increasing the maintenance intervals of the equipment and reducing operating budgets.

Companies such as Cognite, Shape Digital or Dassault (Simulia 3D) make software which can do this sort of analysis.

Offshore data collection

The collection of data about operations of offshore equipment is subject to the technology used.

The ability to collect data in real time is related to the bandwidth or data quota available with on-board communication systems. It may not be possible to collect real time data. Equipment is not always connected to a cloud-based network.

The data transfer protocols may be subject to user licenses imposed by equipment manufacturers, who may also impose use of proprietary applications.

The deployment of sensors on board may require significant technical modifications to equipment, including wiring them and connecting them to the data transfer networks of the fleet.

Managing suppliers

International offshore service companies can manage tens of thousands of suppliers. This requires managing diverse cultures, practices, and legal obligations.

Buyers must ensure that the subcontractors meet the quality and performance criteria, in accordance with the costs and timeframe defined in the contracts.

This can include security procedures, customer safety rules, environmental rules, including waste management, qualifications of personnel, deployment of IT solutions, inventory management, delivery times, requirements to use specific equipment, requirements to comply with obligations from equipment manufacturers.

A 'smart contract' can establish a framework agreement between two entities, defining the entire scope of activities such as scope of work, costs, quality and obligations of the parties. This can include methods for measuring all these elements (KPIs) and periodic evaluation of performance (milestones).

The contract can include sensor (IOT) data, such as for definition of response times related to condition-based maintenance methods..

Depending on equipment category, the management of offshore and dedicated onshore stocks can be inserted. For example, power generators, mud pumps, mixing equipment and processing activities can be subcontracted and could fall under an all-inclusive service agreement including equipment rental and stocks services.

Improving budgeting analysis

If you need to improve your budgeting or reduce spending, one challenge is the quality of financial data collected.

It can be difficult to link an invoice to a project or to an expense for an equipment when the order reference is non-existent, or the name of the equipment is missing. Purchase requests might be made verbally, rather than through a written purchase order connected to a budget.

It is realistic to say that certain expenses can be randomly allocated, leading to incorrect financial information at the project level or by type of equipment.

The purchase order process ensures that any subsequent invoice is also connected to this budget.

A further problem is if you use ships, which are managed by ship management companies operating global fleets with their own systems. The cost information they provide may be broken down to the needs of the customer, geographical places or to the time schedule for the work, but not to the specific customer project they are working on.

Why exploration skills can be most useful in CO_2 storage

To understand the behaviour of a CO_2 plume in storage, the skills of an exploration geologist may be more relevant than the skills of a reservoir engineer," said Halliburton's Geovani Christopher Kaeng

Geovani Christopher Kaeng, an exploration geologist, basin modeller and petroleum system analyst with Halliburton, says he has had many conversations with people from oil and gas companies looking to move into CO_2 operations over the past few years.

"most of the time" the people he has been talking to have been reservoir engineers and production geologists, as they were given the responsibility of managing CO_2 injection. He was speaking at Finding Petroleum's forum on May 18, CO_2 Storage and Opportunities for Geoscientists.

It may seem to make practical sense for CO_2 injection to be managed by reservoir engineers, if they have the best understanding about depleted reservoirs. But they may not be the people with the best understanding of the most critical issue with CO_2 storage – where the CO_2 is going to go, and if it is going to stay there.

Geovani Christopher Kaeng, an exploration geologist, basin modeller and petroleum system analyst with Halliburton

"I argue it requires exploration geoscience skills to be able to understand the nature of the storage as well as the behaviour of the plume," he said.

The information we now have about the shape of CO_2 storage in Norway's Sleipner field shows that fluid modelling methods used in geoscience exploration would have made a much better prediction of where the CO_2 would go, than the traditional reservoir simulation models which were actually used, he explained. This field started injection in 1996.

Exploration geoscientists may be more willing to consider different options for storage, such as saline aquifers, while reservoir engineers may prefer to start with the reservoirs they know, the depleted hydrocarbon fields. Saline aquifers need to be approached with an 'exploration mindset', because you start with limited to no data . Saline aquifers provide greater capacity than depleted fields and they are arguably safer, he said.

Geoscientists may be more comfortable with working with geological heterogeneity (diversity) and seal assessment than reservoir engineers, he said. "The production teams take the seal for granted. Any fine-grained lithologies are just treated as 'not part of the reservoir.'"

Reservoir engineers express concerns about data scarcity when they talk about building models for CO_2 injection. But exploration geologists are much more comfortable working with data scarcity. "We know how to deal with limited data. We can predict reservoir properties, we can predict seal properties, we have basin modelling methods. We do uncertainty modelling."

So, the management of CO_2 storage should move from a 'production-oriented' mindset to "more of an 'exploration geoscientist-oriented' mindset."

"CO_2 storage injection is more analogous to oil and gas expulsion, migration, and entrapment, than to hydrocarbon production. That's why exploration geologists [need to] get into this area."

Sleipner

CO_2 has been injected into Norway's Sleipner field since 1996, with 3D seismic surveys taking place every few years since then. These data show how the CO_2 plume developed, spreading out in the subsurface until it reached the seal. It makes for an "amazing flow experiment," he said.

Before injection started, the reservoir had been modelled as though it was homogenous. But the seismic data showed layers within the storage site. This is an indication of what could be called 'small scale heterogeneity' — seals actually within the formation that were just 30cm to 1m thick. The geological heterogeneity controls how the CO_2 moves.

A paper published by Equinor and partners, operators of the storage site, showed that the actual CO_2 plume bears very little resemblance to what was expected in the reservoir simulation.

Looking at the development of the CO_2 plume at Sleipner, as it actually happened, there are 3 reservoir sections – a lower section, with vertical stacking, and a strong structure; a middle section, with some lateral movement, first to the north, then back to the middle of the structure, then up and to the south; and an upper section, where the flow is controlled by the seal, so CO_2 can only move sideways.

The variations in the plume shapes have been caused by heterogeneity in the reservoir – the low section is less shaly than the upper section, he said.

A report on saturation analysis from seismic data mentioned that in 2010 most of the CO_2 injected was stored within the intra-formational bodies of the storage

Flow models

Reservoir engineers and exploration geoscientists typically use different methods for working out how fluids flow through the subsurface and building flow models, he said. But Sleipner shows that the exploration geoscientist method is more relevant to how a CO_2 plume develops in a CO_2 storage site.

Reservoir engineers typically model how fluids flow through a reservoir to a well. It is not so important to them which part of the reservoir the hydrocarbons are sourced from.

Exploration geoscientists typically model how hydrocarbons are expelled from their source, migrate through the subsurface and get trapped. Their understanding of the flow is more about understanding flow through narrow capillary spaces in the rock.

CO_2 storage was traditionally simulated using Darcy flow physics, which not only suffers from low resolution and extremely long simulation times, but also fails to model the CO_2 structural trapping after the injection has stopped, making sequestration impossible.

When people drew simplified images of how they thought CO_2 would behave in a storage site, they often drew a simple inverted cone, with CO_2 exiting the well then moving outwards and upwards. As the actual CO_2 plume shape for Sleipner shows us that the movement of CO_2 in the subsurface is controlled by what geoscientists call 'heterogeneity'. Some of the flow was actually horizontal. If we were producing hydrocarbons we might indeed get an inverted cone shape. But CO_2 is injection, not production.

To understand fully how CO_2 would behave in storage, you need a detailed model of the subsurface, with CO_2 flowing into different layers, showing how much each layer stores, and when it leaks into the one above. If the model's scale is reduced, as is often done before running in a reservoir simulator, this detail is lost, Mr Christopher said. You thus lose data about the heights of the various storage spaces, and so cannot calculate the overall capacity of the storage.

Pressure in the subsurface

Another area where the perspective of reservoir engineers and geoscientists may differ is in their understanding of pressure in the subsurface. Reservoir engineers may typically think of the 'reservoir' as a closed system, which will increase in storage pressure after you inject, Mr Christopher said. "We know, as exploration geologists, that pressure always dissipates within the basin and finds balance as quickly as possible."

Liquids and gases move through the subsurface through tiny 'capillary' gaps, not mainly through faults, as some people believe, he said. Whether a gas passes through a capillary depends on the pressure of the gas and the size of the capillary.

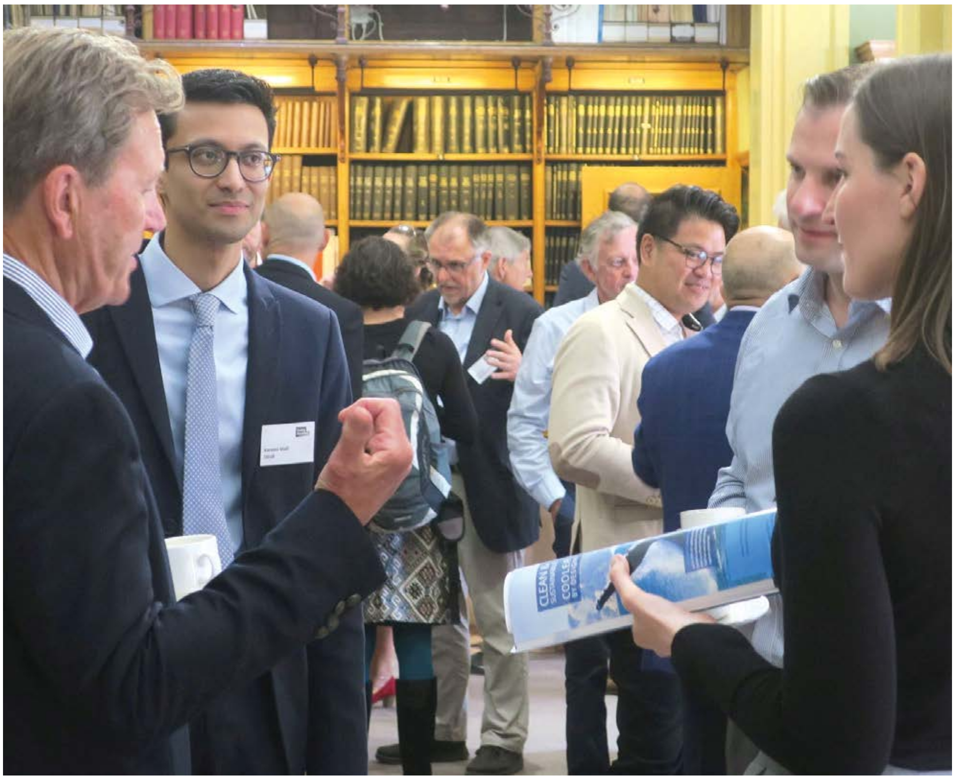
This sounds complicated but looks simple when demonstrated on a YouTube video by Philip Ringrose, Adjunct Professor in CO_2 Storage at the Norwegian University of Science and Technology (NTNU) and Specialist in Geoscience at the Equinor Research Centre in Trondheim, Norway. It is online here https://youtu.be/8-dXwakvmsI

The video shows air being injected under an inverted sieve in a fish tank. Air will be trapped under the sieve, due to capillary trapping. But if the injection rate is increased, the air pressure increases, and eventually the capitally force is overcome by the buoyancy force of the trapped air.

This has long been understood by exploration geologists, who use Young Laplace principles of fluid flow. This models the interaction between fluid buoyancy and capillary pressure. This has been used for decades in exploration, but not yet popular in CO_2 storage.

If you have high velocity, pressurised flow, then it is in the domain of Darcy flow (flow of a fluid through a porous medium), while a relatively slow movement of fluid is in the realm of Young Laplace physics (pressure difference between the inside and the outside of a curved surface). Darcy flow models may be appropriate for CO_2 close to the well bore, but it changes to capillary type migrations just tens of metres away, he said.

Doing a simulation model using Young Laplace physics needs high resolution information, including of the heterogeneity of the subsurface. Equinor did a test to see if it was possible to simulate Sleipner using capillary flow models, which is also called an "Invasion Percolation Model". It found the output was well matched to what happened in reality, as seen in the seismic data, Mr Christopher said.



You can watch Geovani Christopher's talk on video with slides at

https://www.findingpetroleum.com/event/e00f5.aspx

A plan for monitoring CO2 storage integrity

How should companies monitor CO2 storage complexes to ensure CO2 is being stored safely? CCUS consultant Robert Hines shared some advice

The important issues in CO2 storage could be distilled to 3Cs – containment, conformance and confidence, said CCUS consultant Robert Hines, speaking at the Finding Petroleum forum on May 18, "CO2 Storage and Opportunities for Geoscientists".

"Containment" is making sure the sealing mechanisms have got integrity; "conformance" is making sure the CO2 plume is behaving as expected; "confidence" comes from both of these – if someone is paying $50 a tonne to store CO2, having the confidence that is the amount being stored.

The basic elements of a monitoring plan are fairly easy to understand – modelling the storage site, monitoring the plume of CO2 and checking it stays within the storage, looking for routes it could reach the surface, and working out overall risks.

The problems can arise more with effects which cross multiple risks, or which need multiple areas of expertise. For example, a marine biologist could work out the effect of CO2 entering seawater, but is unlikely to know much about seismic "except it upsets dolphins". Similarly exploration geologists are likely not know much about marine biology or ocean chemistry, he said.

Seabed monitoring

There has been some research into methods of seabed monitoring, to see if it is possible to detect bubbles of CO2 coming from the subsurface into the sea, or moving through the sediment on the seabed.

There have been 3 big research programs in the UK so far, which have involved releasing CO2 into and the marine environment and measuring how it affects seawater, using remotely operated vehicles and autonomous underwater vehicles.

All the programmes have released similar amounts of CO2. For example the STEMM-CCS project on the Goldeneye site in the North Sea, where CO2 was injected 3m below the seafloor, with 4.2 tonnes CO2 injected over 37 days.

Over the 3 experiments, the research showed that CO2 bubbles were easy to detect with sonar. Chemical detectors, which aim to detect the CO2 from analysing water samples, did not prove to be so useful. If you can drive a sensor right up to the leak point, it can be detected, but that is not a very practical monitoring method, Mr Hines said.

CO2 dissolves quickly in water, and although this changes the acidity of water, the effects are quickly dissipated in a large volume of water.

In one experiment, with CO2 injected 11m deep into sediment, only 15 per cent of CO2 actually escaped, the rest was trapped by sediment. Although this would probably be different with industrial sized CO2 volumes.

There is a significant question of whether CO2 leaking from deep storage will even be in a gaseous phase, since it is injected in a supercritical state (high pressure) and go through complex phase changes as it bubbles up. When it reaches water, or even saturated sediment, it will quickly dissolve.

There is also a question about how useful shallow monitoring could be, since even if it did detect CO2 leaking, it may be too late to do anything to stop it, because the subsurface seal would already have been long breached.

Seabed monitoring could be useful for detecting any old well bores – there have been concerns that wells drilled in the past, not plugged as well as they should have been, or even forgotten about, could provide a leakage path.

Gases bubbling through old well bores could also be methane from shallow gas reservoirs, he said. Ideally this would be detected in an initial baseline survey, conducted before the CO2 storage begins.

"If you've got old and abandoned infrastructure, you treat that as a known leakage path, you might want to monitor it constantly with a suitable detection system until you've established the confidence that nothing has happened, it is performing as expected," he said.

'Deep' monitoring

It may be more useful to use 'deep' or subsurface monitoring techniques, such as seismic, for CO2 storage. It can be relatively cheap when combined with other activities, with arrays towed from ships. Where there is congestion with other users, such as wind farms, devices can be put on the ocean bottom, which also makes it easier to do repeated surveys. Gravity monitoring may also have a role.

We are looking for signs that the CO2 column and plume is behaving as we expected, he said.

It is important to get a good baseline – a starting idea of how the plume will evolve. If you can demonstrate that the plume is evolving as you expected, that gives you confidence.

Robert Hines, CCUS consultant

If the storage is in an aquifer, another indication that storage is happening as expected is if the CO2 is pushing water into a water production well, designed to release the pressure.

Chemical tracers

There has been some consideration of the use of chemical tracers in CO2 storage – adding a chemical with a unique signature into the CO2 being injected. This would, in theory, make it possible to determine whether any leaking gas comes from this source.

One concern is detectability of the tracer. With such huge amounts of gas involved, to detect any tracer in any leaking gas would require huge amounts of tracers to be added, he said.

A second concern is whether the tracers would be viable over geological scales of storage.

Being sure

Best practice storage monitoring means getting data from multiple sources and putting them together to get a "really good impression," he said.

It's nothing we need to be particularly scared of, there's lots of technically mature options. It is just about joining the dots between them, so we have a solid understanding of our storage."

Knowing if a storage site is leaking or not is quite a simple question; but to know how much is leaking, if it is distributed leaks or a single source, is incredibly difficult to answer. "You need this layered [monitoring] capability," he said.

UK legislation for CO2 monitoring puts the emphasis on the operator to demonstrate best practice. It boils down to, "you tell us what you think good looks like," he said.

The UK requires monitoring for 25 years after injection. "I think that's a fairly arbitrary limit [but can] establish a reasonable confidence and is less onerous than other jurisdictions that require 100 years of monitoring."

Distributed Fibre Optic Sensing for CO2 injection monitoring

Fibre optic cable-based sensing can be used for multiple areas of CO2 storage monitoring, including monitoring CO2 injection into the well, monitoring where the CO2 plume goes, induced seismicity and temperature effects.

Fibre optic cable-based acoustic sensing, technical name 'Distributed Acoustic Sensing' (DAS), can be very useful in CO2 storage. It can be used to better understand the storage site before injection starts, to monitor the injection and check for leaks in the well, to make seismic surveys of the whole storage area and monitor the progress of the CO2 plume deep below the surface, to listen for 'induced seismicity' which could be indicative of movement of CO2 outside the storage area, and to monitor for deformation of the well.

Anna Stork, senior geophysicist with Silixa, a company which provides the technology, explained how it is used, speaking at a Finding Petroleum forum in London in May.

Silixa's DAS instrumentation have and are being used in CCS projects and research in Canada, USA, Iceland, Spain, Norway, Italy, Turkey, Australia, South Korea and Japan, she said. For some projects Silixa provides equipment; for other projects the company also provides data collection and analysis services.

The systems are used at the Otway Project in Australia, a CCS research site. At Otway, Silixa has 40 km of DAS cable installed in 5 different wells, put in place over 2014-2020.

After only 580 tonnes of CO2 had been injected, it was possible to identify the CO2 plume on 2D seismic images, with seismic data captured using the DAS systems.

"We were able to track very quickly, and with great detail, the movement of the CO2," she said.

Anna Stork, senior geophysicist with Silixa

The seismic source, a surface orbital vibrator (SOV), used was the size of a washing machine drum. This is much less disruptive to agriculture than Vibroseis trucks. It can be switched on automatically – something which proved particularly useful when Covid lockdowns made it difficult to travel to the site.

A second case study is the Aquistore Project in Saskatchewan, Canada, a demonstration and technology testing site. It is connected to the Boundary Dam power plant which has carbon capture attached. Most of the CO2 from Boundary Dam is used for EOR projects elsewhere but CO2 has been injected at the Aquistore site since 2015, with over 400,000 tonnes stored so far.

Silixa has recorded repeated seismic surveys since 2013, which provide a baseline pre-injection survey and post-injection surveys, enabling imaging the CO2 plume evolution over time.

As the volume injected increased from 36,000 tonnes to 141,000 tonnes, the plume could be seen growing. If you were able to look at it from above, you would see it grow first towards the North and East, then a bit to the South, she said.

Following these deployments, Silixa has developed a monitoring "solution" specifically for CCS including a range of technologies, called Carina CarbonSecure.

It aims to provide as much processing on site as possible with an "Edge Computing" set-up to reduce the amount of data which needs to be sent off site.

The system can be configured to provide alerts if unusual activity is detected. In this case, a decision can be made to stop injecting.

The technology

DAS technology makes use of the way vibrations and sound waves modulate light going through an optical fibre. The light pulse is produced by an 'interrogator' which also records and processes the returning light from the fibre. The changes in the light are detected by analysing "back scattered light", because some of the light is reflected or 'scattered' back to the starting point of the cable.

The distributed fibre optic sensing family also includes temperature (DTS) and strain (DSS) sensing. The light is modulated by temperature variations and changes as small as 0.01 degrees C can be detected, and strain (stretching of the cable) can be measured at one microstrain (part per million) resolution.

The technology can use the same fibre optic cables which are used for telecommunications. Or it can use a special fibre optic cable designed in a way to increase the amount of backscattering – this means that there is more information coming back to the instrument which can be analysed.

The cables can be tens of kilometres long. The cables are usually about a quarter of an inch thick, and fibres are often encased in a metal tube. The cables do not need any maintenance and are designed to last for decades. In a well, the cable can be clamped to the casing or tubing, or cemented behind the casing.

One cable can contain multiple fibres, and each fibre can be used to measure different parameters (temperature, seismic and strain signals) simultaneously.

Measurements can be made with a resolution of less than 1m along the cable. The measurement is made by taking a moving average of neighbouring points on the fibre.

It is possible to make simultaneous measurements at all points. This way, it is possible to detect changes which only happen at narrow areas of the cable, something which may not be detected if you have a recording system with a limited number of individual receivers.

With the source in one position, it is possible to take seismic 'readings' for each metre of the cable, thus along the full wellbore if it is a borehole deployment. By moving the seismic source to different locations and taking multiple readings, it is possible to make a 3D seismic image. The quality of the signal is monitored throughout a survey.

In acoustic sensing, as used for seismic measurements, the system can record sounds with a dynamic range of 120 dB, at frequencies from millihertz to kHz.

The alternative recording device for seismic in wells is geophones. These are much harder to deploy downhole, being bulkier, and often breaking in harsh environments, Dr Stork said.

Geoscientists needed to define more UK CO2 storage

With the currently licensed UK CO2 storage predicted to provide sufficient capacity until 2030, and new sites needing up to 10 years to characterise and license, geoscientists are needed to work on new storage sites now

The UK government has set a target to store 20-30 million tonnes a year (mtpa) CO2 by 2030. It also has a target to reach 'net zero' by 2050, which would mean 104 mtpa CO2 storage by 2050, according to modelling by the UK's Climate Change Committee, a government advisory group.

So, a significant ramp up over 2030 to 2050. "We were looking ahead at that ramp up rate and saying, what do we need by 2035," said Chris Gent, policy manager at the UK based Carbon Capture and Storage Association, speaking at the Finding Petroleum forum in London on May 18, "CO2 storage - and opportunities for geoscientists."

"We think we need around 50 mt CO2 captured and stored pa [by 2035] to keep on track to net zero."

"Working backwards, we engaged our members in projects and clusters [to discuss] how fast we can go? what does the build out rate look like."

CCSA also looked at what the obstacles might be, such as insufficient financing, storage, or new technology.

The current policy framework and funding is planned around delivering around 22 mtpa storage by 2030, and there isn't yet any framework to go beyond that.

Then there is the question of storage capacity. The current licensed storage capacity can be broken down into the storage it enables per year – showing that new storage capacity will need to be available from 2030, in order to achieve a 2035 target, he said.

Currently the process of obtaining a permit for a new storage site takes potentially up to 10 years, getting from "theoretical to operational," according to studies by the Exploration Task Force, an industry group put together by the UK government.

The process of identifying sites often involves starting with a large number of possibilities, and then whittling the list down, Mr Gent said.

Geoscience

All of this needs plenty of geoscientists to model and help select storage locations, Mr Gent said.

If you have an oil and gas field, you're looking to turn into CO2 storage, there will be a large amount of subsurface data already available. On the other hand, areas of the world which have not been explored for hydrocarbons will not have any data at all to start off with when considering CO2 storage.

Understanding pressure and stress regimes is going to be an important factor of Co2 storage, he said.

Geoscientists might be asked to make a model of all the faults in an area and work out their slip tendency, to try to work out boundaries of how much a reservoir can be pressurised.

Chris Gent, policy manager at the UK based Carbon Capture and Storage Association

There is also work for geoscientists monitoring the storage site after injection has started, to see where the CO2 is going, he said. Repeat seismic surveys will be made "every few years" to understand how the reservoir is evolving.

As the number of stores increases, geoscientists will need to look at the possible pressure interaction between them.

"The more [storage] we bring online the more there's a need for geoscientists," he said.

An example of geoscience project, looking at how stores impact each other on a regional scale, was a study of the "Bunter" formation in the UK North Sea, he said. This contains a target storage site for the Northern Endurance partnership.

The work was to model what injection rate might be feasible over 40 years, storing 600m tonnes in total. It looked at what the pressure and strain impact would be on the overburden, and if that would impact the integrity of the caprock.

CCS and the North Sea Transition Deal

Under the 'North Sea Transition Deal' agreed between UK industry and government, industry will support the deployment of UK CCUS Projects and the transition to low carbon energy by re-purposing relevant assets for CO2 storage, before any decommissioning, explained OEUK's Kareem Shafi

The North Sea Transition Deal is an agreement made between the UK government and the UK's evolving oil and gas industry on the energy transition.

The 'deal' will support CCUS deployment by using existing assets, 'Assets' here includes the reservoir, platforms, pipelines and onshore storage terminals. Operators should also consider whether wells are penetrating saline aquifers which have the potential to store CO2.

The 2020 NSTA Strategy update includes an obligation for operators to consider re-use of assets for CO2 storage, before starting any decommissioning, said Kareem Shafi, business advisor with industry association Offshore Energies UK (OEUK), which represented the sector in the negotiations.

Also in the deal, the UK oil and gas industry agreed to support development of CCS to help industry and society reach net zero emissions.

This could be through developing projects to supply hydrogen fuel, for heating, transportation and industrial use.

The oil and gas industry has agreed to help heavy industry decarbonise, and the main way to do it is with CCS, he said.

In addition to CCS, the deal includes a commitment to decarbonise supply -through using electricity to power offshore platforms and reducing methane from offshore operations. The People & Skills theme in the Deal helps people transfer existing skills to new low carbon energies.

OEUK has established a 'Deal Delivery Group', which oversees the progress made on the commitments of the NSTD. OEUK has also formed a 'CCUS special interest group and CCUS Forum', to identify challenges and develop deliverables such as guidelines to share good industry practice. OEUK has been developing guidelines for its members since 2010 and It will soon be publishing the methane action plan guidelines which will help support the decarbonisation of energy supply and emission reduction.

Kareem Shafi, business advisor with industry association Offshore Energies UK

The UK government targets for carbon capture and storage are to store 20m tonnes CO2 by 2030, increasing it to 50m tonnes by 2035, he said.

Getting better emissions data – PIDX forum

Oil and gas companies can improve their emissions data by using digital technology standards, getting better data from suppliers, and moving from 'proxy' to measured emissions. Report from the June 22 London PIDX forum

For operators to calculate their Scope 3 supplier emissions, they need to get data from suppliers about emissions in creating their product, and they need systems to manage it.

PIDX, an organisation which makes standards for electronic transactions between oil and gas companies and suppliers, decided to get involved in emissions data in 2019. It launched a standard for emissions data exchange between buyers and suppliers, ETDX, in February 2020.

At the moment, much supply chain data is assumption based, said Chris Welsh, chair of the board of PIDX. For example, if a major operator sees that it is responsible for 10 per cent of the total business of an oilfield supplier, it counts its Scope 3 emissions associated with that supplier as being 10 per cent of the total Scope 3 emissions calculated by that supplier.

This is sometimes known as 'top down' reporting. It needs be gradually placed by 'bottom-up reporting', with data being measured and then passed on, he said.

A problem with using such 'top down' estimates and industry averages today is that you may one day discover that the estimates are very different to the actual emissions, he said.

The process of replacing 'top-down reporting' with measured 'bottom up' data will happen gradually, and could be finished around 2030, he said.

The theory is that emissions data can eventually be calculated from 'cradle to factory gate' for any product, and this can be provided to buyers.

If an oil and gas operator wants to know the emissions their submersible pump makes per hour, they can get emission data from their electricity supplier.

PIDX standards are already used for $80bn of transactions between buyers and suppliers, and this data infrastructure can be used for emissions data, he said.

PIDX is looking at which attributes already in the PIDX standard can be extended to include emissions data.

For example, if an oil company is buying drill bits from a manufacturer, who provides the data about emissions per drillbit, this data could be included in the electronic invoice which is already being exchanged using the PIDX infrastructure.

A "proof of concept" project has been done between Schlumberger and ConocoPhillips looking at how emissions data can be handled.

Organisers, chair and keynote speaker of the London PIDX forum at the Geological Society: Mimi Stansbury, OFS Portal; Andrew Mercer, Baringa Partners; Chris Welsh, OFS Portal; Tom Cave, Prospecta

PIDX is keen to see a few oil majors using the standard and sees that as the best way to encourage roll-out through the whole industry. So far BP, Shell, ConocoPhillips, Equinor, Chevron are showing interest, he said.

PIDX does not want to get involved in the emissions calculations, because other standards groups are working on that; it aims to be a mechanism for moving data securely between suppliers and buyers.

Supplier concerns

Mr Welsh emphasised that the discussion so far is about exploring what is possible, not to say it is all yet achievable. Some suppliers have hundreds of thousands of different product lines and are a long way from being able to provide emission data for every product.

So far, suppliers have expressed concerns about any requirement to include emissions data on the invoice, saying, 'we don't want to give the oil company an opportunity not to pay the invoice because emissions data is not there'. Don't give them any excuse not to pay us.'

A better place for emissions data could be the 'field ticket', a document issued after work has been done, or something has been delivered.

Operators typically say they don't mind if it is on the field ticket or the invoice. "We are 'socializing this' with buyers, suppliers and shippers," he said.

Emissions data might one day be included as part of the 'catalogue data' which some suppliers provide to their big buyers, where the prices are agreed as part of an annual contracting process. The emissions data could be provided with the prices.

Some suppliers have expressed concerns that there could be information in their carbon footprint data which would be useful to a competitor – in which case a desire to keep their secrets would probably outweigh the desire to share data with a customer. "That kills the standards," he said.

Open Footprint Forum

Open Footprint Forum is an industry organisation which is developing standard ways to store, manage and share data related to emissions. This is complimentary to the PIDX emissions data exchange project.

To understand the value, consider how it sits in the 'ecosystem' of organisations using emissions data in oil and gas, said Sumouli Bhattacharjee, partner and Digital Advisory Global Lead at Environmental Resources Management (ERM), who is part of the team developing the standard.

This ecosystem includes the operator company, its suppliers, data 'enabler' organisations including solution providers, data service providers, data aggregators and auditors. Then there are the data consumers, which is anyone who might want to use the data – including regulators, government, investors, customers, civil society and media.

Open Footprint's systems can sit between data aggregators and solutions providers. It provides standards for the systems for gathering and storing data, and making it available to solutions providers. Its systems can be used to store raw data, calculated data and metadata.

It provides a "common language" for sharing data, including sharing it with regulators and stakeholders.

Other than Open Footprint, all data platforms are 'more or less' proprietary, there are no common data standards. This "makes it extremely difficult to exchange and share data," he said.

The Open Footprint organisation does not get involved in discussions about how the measurements are actually done – there are other standards organisations addressing this, he said.

Getting past 'proxy'

At the moment, much of the emissions data which companies are reporting is estimated. "There is a term 'proxy emissions', which means estimate of estimates," Mr Bhattacharjee said.

Some companies just estimate proxy data on a basis of their total spend.

"They say, 'based on that [spend], this is my scope 3'. There are auditors who sign it off."

It would be better if more of the data was measured or 'primary' data, and less use was made of proxy data, he said. "If we can get away from that, at least for the more significant [emissions], you can set better targets."

"You should be able to measure the footprint across the supply chain," he said.

Then companies would move from providing 'minimal' to 'reasonable' assurance.

It is unlikely the world will ever move completely to measured data, he said. And not all suppliers have the ability to collect it. But we can move in that direction.

It is also important that people know whether or not data is a proxy, he said.

Supplier emissions data

Supplier emission data is the most diverse, with multiple emission sources from different parts of the supply chain, Mr Bhattacharjee said.

Suppliers vary in their capability to provide emission data, so the data quality and auditability is difficult to manage.

Open Footprint has a workstream to define the data model and schema for Scope 3 emissions. Companies involved include PIDX, Equinor, ERM, Intel, PWC, Shell, Accenture.

It would be very useful to have a mechanism for exchanging data between buyers and suppliers. Buyers could use this information to manage their 'enterprise footprint' and their 'product footprint'.

Open Footprint and PIDX have a collaboration to work together to do this.

An obstacle is that suppliers see that there is a cost to providing all of this data, and it also means sharing data they may not wish to share. "Unless a supplier is secure to do it, they are not going to do it," he said.

Andrew Mercer - improving measurement

"Measurement is the key to closing the gap between company ambition and performance [on emissions]," said Andrew Mercer, associate with consultancy Baringa Partners, and a former director low carbon and sustainability, and director solutions infrastructure, with BP.

Mr Mercer has projects to help investors assess the quality of emissions data from oil and gas companies they are considering investing in. There are projects to help investors determine whether the data shows they are 'Paris aligned' – reducing emissions at a rate which (if every company did the same) would limit temperature rises to 1.5 degrees C.

Mr Mercer has done interesting analysis on the reporting done by different oil and gas companies, and what they include.

Shell shows the largest emissions in its reporting, but this is because it is the only company to include emissions made by its end customers (such as car drivers) as part of its 'value chain'. When all companies count emissions differently, you cannot directly compare emissions numbers between companies.

There is something of a maturity curve in how companies manage their emissions, Mr Mercer said. They might begin by adding together their emissions on different spreadsheets and putting them together, but then move to specialist software or emission 'engines'. Some companies now have software which can do forecasting.

For calculating direct ('Scope 1') emissions in offshore oil and gas, key emissions are usually fuel to power the platform, and flaring and venting.

Mr Mercer has built a model to understand a company's position with its Scope 1 emissions, showing what they currently are, areas where they are greater than they need to be, and so calculating a theoretical minimum.

For example reasons for emissions to be greater than necessary include suboptimal operating conditions, project 'slippage' (such as maintenance delays), or underperformance. This underperformance could be due to issues like well integrity, too many shutdowns, operating pipelines at higher pressure than needed, or doing unnecessary maintenance.

Improving measured data

Too much of the emissions data being circulated at the moment is coming from desktop studies, very few people are doing actual data measurements, said Greg Coleman, CEO of Future Energy Partners, and a former head of HSSE with BP.

In many cases, "right now we have no idea where emissions are coming from," he said.

"Scope 3 is still not very well understood. Every operating company has a different definition of what Scope 3 should be."

Companies with poor data might want to consider that satellite data about emissions is starting to be available, so other people can find out what some of the emissions from their operations are.

In one case, a data company spotted a massive methane leak in Wyoming from satellite data, but no company would claim it, he said. "Eventually [an operator] depressurised a pipeline and it stopped."

Measured data also needs to be integrated with other data to get the most value, he said.

It is not enough to know which valve is leaking, the maintenance department need to be able to prioritise which leak to work on first.

It may be a very large leak which needs immediate attention; it may be a small leak which is 300 miles drive away and is less of a priority, such as if the leak is in Wyoming and the crew are based in Denver, he said.

"Data integration is the big challenge."

"Materials" emissions and data

If individual departments in oil and gas companies want to reduce their emissions, one way they can do that is reduce the emissions associated with the material they purchase, said Tom Cave, sales director with Prospecta Master Data Online, a division of supply chain data quality company Prospecta Software.

This may mean purchasing less. The cleaner the data you have about your department needs and what it currently has in stock, the easier it is to reduce your purchasing, he said.

To put it more succinctly, "clean data is green data."

Having clean data will also help reduce the risk that you constrain purchasing to the point where you are less likely to have an item you need immediately in your inventory, he said.

Having 'clean data' is often about doing regular data maintenance. "The half life of clean data is shorter than people think."

If you have accurate "bills of materials" for each maintenance task - the list of items needed – you can make sure you do not have any spares in your storage which are not associated with any maintenance work.

Other ways to improve emissions are to optimise how you are using energy consuming assets, which, again, might be best achieved by improving your data.

How Schlumberger is driving its emissions

Schlumberger is pursuing a plan to reduce its Scope 1, 2 and 3 emissions, with the toughest categories being the emissions from its customers and its suppliers. Reem Radwan from Schlumberger explained

Oilfield services company Schlumberger has a target of a 30 per cent reduction in scope 1 and 2 emissions by 2025. By 2030, it wants a 50 per cent reduction in scope 1 and 2, and 30 per cent reduction in scope 3. By 2050, it wants ‘net zero’, explained Reem Radwan, sustainability digital enablement program manager with Schlumberger, based in Paris.

She was speaking at the European event of PIDX, an organisation which manages e-commerce and emission standards, particularly between operators and suppliers, held in London on June 22.

As a reminder, “Scope 1” is emissions directly caused by your operations; “Scope 2” is emissions made in providing your purchased energy, such as electricity; “Scope 3” is emissions from other areas of your ‘value chain’ including your suppliers providing of products you buy, and your customers’ use of your products.

Schlumberger calculates its total annual emissions at 54.2 million tonnes a year (mtpa) CO2. Of these, 52.2m are in Scope 3, the vast majority.

“Scope 1 and 2 are relatively easy, as opposed to scope 3,” she said.

Of the 52.2 mtpa of Scope 3 emissions, 38.4m is coming from the use of products (which it calls ‘downstream’) and the remainder, 13.8m, from purchased goods (which it calls ‘upstream’).

Schlumberger’s Scope 3 emissions would also be reported by the customer or supplier company, so the same emission reported twice. This is part of the design of the emissions reporting system.

Downstream emissions

To tackle the emissions from the use of its products, Schlumberger first set internal boundaries around the different emission types, she said. Then it engaged the company subject matter experts (SMEs) to work out how to reduce emissions associated with their products, since they have access to the data, knowledge and documentation for their processes.

Most of the data today is calculated using various reference tables which translate spending into emissions, also taking into consideration how many years a product will be used for. But over time this should be replaced with measured data.

As an example, consider an offshore cement unit which Schlumberger leases to a customer. The emissions the cement unit creates falls under Schlumberger’s Scope 3 emissions. The unit takes in cement and diesel as inputs.

There are reference databases which give data about emissions for power generation and supplied via the grid in different countries.

To work out the emissions you would need to know the ‘uptime’ of the unit, or amount of time it is actually operating. The customer would need to provide this information.

If Schlumberger sells a physical product, it has to count the total emissions in making that product in its own numbers for that year, although the product may last for many years.

The boundaries need thinking through – for example while drilling creates emissions, the use of the drill bit specifically does not.

Upstream emissions

For purchased goods, which it calls ‘upstream’, Schlumberger has 30,000 suppliers. They have a wide range of maturity levels in their ability to provide emissions data.

Its 2021 target was to have 500 suppliers, representing 35 per cent of its 2020 spend, providing emissions data about their products and services.

The 2022 target is to have 1000 suppliers representing over 50 per cent of its 2021 spend providing emissions data.

The ultimate goal is 70 per cent of its spending having “CO2 coverage”, and 50 per cent of its spending routed with “ESG leaders”. This implies that emissions data – both its availability and size of emissions – will be a factor in winning Schlumberger’s business.

And the quality of the emissions data is important. It should relate to the actual emissions made to create that product, not be estimated based on the size of the spend.

“We invited suppliers to a summit to tell them we want to collaborate. The objective was to tell them we were serious about the topic, and show that they need to commit, and [provide] product level emissions eventually,” she said.

The system will be embedded into Schlumberger’s purchasing. “For every supplier we will know their commitment to climate action.”

Technology

Schlumberger develops technology for its customers which can help reduce emissions. For example, if you use a subsea “booster pump”, that can use less energy than gas lift. Schlumberger calculates the emission savings at 62 per cent.

It has a specific service to help customers reduce methane emissions, including planning, measuring and acting, and specific digital tools.

Unfortunately there is no way to account for saving customer emissions on Schlumberger’s emissions balance sheet.

The challenge of reducing emissions can be in opposition to the challenge of increasing business. “The more we sell, the more the emissions,” she said.

The ultimate goal is to reduce emissions and achieve the targets – and on the way, to help people make better decisions. “It is a cultural change.”

Delegates at the PIDX London conference