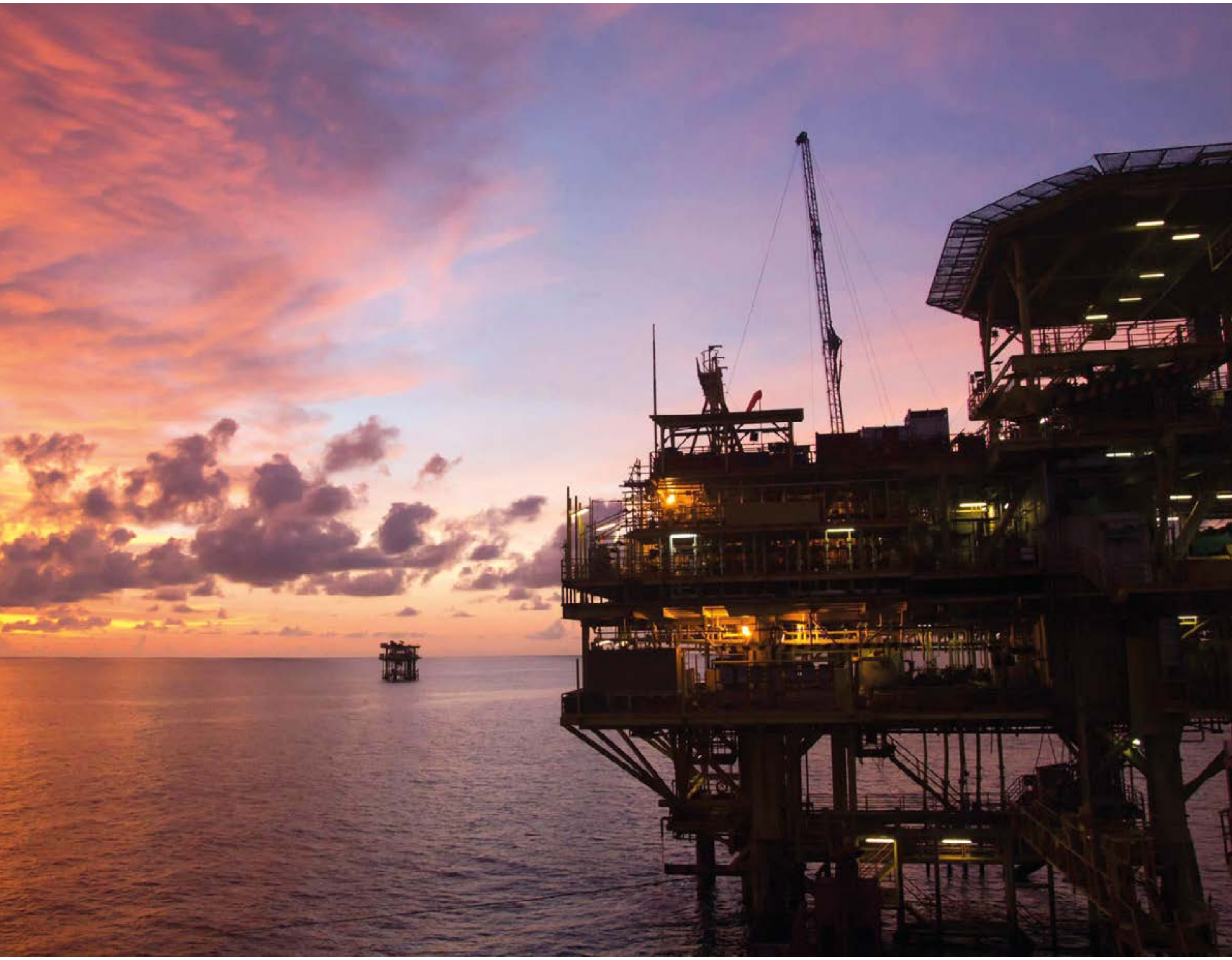
digital energy journal

- Customisable, asset specific AI models
- Integrating operations and engineering data
- Machine learning for your safety systems
- Making software integrations easier

July - August 2021



How to make geothermal businesses work

Finding Petroleum

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Cover photo: TotalEnergies (formerly Total) is developing a satellite imaging methodology to monitor potential methane leaks at offshore facilities. The technology, known as "Glint Mode," is based on observing sunlight reflected by the ocean surface, and interference effects from methane in the air.

Opening

Lone Star – AI and predictive analytics for production assets

Lone Star Analysis of Texas provides software and consulting services which oil and gas companies can customise themselves into asset-specific AI models for their equipment – as an alternative to an outside company doing everything

A common way for oil and gas companies to engage with AI is to work with outside consultancies and software houses, who come in and build AI models for their specific equipment.

Lone Star Analysis of Addison, Texas, has a different customer offering – it provides a foundational AI model on a piece of equipment, such as an electrical submersible pump (ESP), which oil and gas companies can then customise for their specific equipment.

This gives operators the best of all worlds, in that they retain control over the developed AI models, they can develop them to meet their asset, business and operational needs, and can do so much quicker than building a traditional AI model.

Having models already partly built with known physics properties of the asset means that you do not need as much data to train the algorithm as you do in traditional AI engagements. To build an equipment algorithm and to allow the model to learn may take years of data, says Davey Brooks, vice president of automated intelligent analytics solutions with Lone Star.

Also, when companies implement Lone Star analytics models, it is much easier to understand how the AI is working, compared to many 'black box' solutions that don't provide transparency in the computations and results,he says.

"There needs to be auditability of the results, an ability to prove that the results are reasonable and that the predictions make sense, so decision makers are confident that when they apply the results to their business they are going to drive business value."

Lone Star's aim is to develop models and platforms which can be used with a wide range of equipment and customer requirements, as well as a wide range of data qualities and data structures, he says.

Results based

Lone Star builds its business based on customers seeing for themselves that they can achieve good results using the system.

"Our motto is [we help you make] smarter decisions faster," he says.

When organisations take an active role in implementing analytics, it should make it easier to expand their use of analytics

Davey Brooks, vice president of automated intelligent analytics solutions with Lone Star

throughout the company. "You would be much more trusting of someone who works with your company, than just me and my results," he says. "We're a firm believer of the organization taking ownership in that process."

This compares with how many other AI providers promote their technologies, often over-promising what the solutions can deliver, leading to expectations being too high, Mr Brooks says.

As a result of this, many companies have spent more money on AI projects than the results justify, he says.

One reason for results not meeting expectations is a lack of flexibility and extensibility in the solutions they implemented, he says.

ESP analytics

Lone Star's focus is on Electrical Submersible Pumps (ESPs). These sit at the bottom of wells, pumping oil and gas from reservoirs into the well and up to the surface.

ESPs can be much more effective than traditional "sucker rod pumps" (nodding donkeys) at the well head, because they apply their force directly at the reservoir depth.

But ESPs are expensive and difficult to fix if they go wrong. They need to operate in a certain range, including in the mix of oil and gas going through them. If there is too much gas, the motors can spin too fast and burn out.

An analytics system which can give an operator advance warning of an emerging problem, such as having too much gas in the production flow, or a motor being in a critical state, would be extremely useful.

Many analytics companies have tried to develop such a system over the past decade. But oil and gas companies are still trying to make better AI models for ESPs.

Perhaps one of the reasons for the lack of success in the past is the amount of effort and data needed to build AI models for an individual pump, Mr Brooks says.

ESPs are very diverse. “There can be hundreds of different types of ESPs within an organizations’ production operations.”

Also, ESPs can fail in about 60 different ways, and provide a number of data streams from their sensors. There is a lot of work involved building models about how all of those failure modes can be identified from the data.

Lone Star provides a physics-based analytics model of ESPs, which customers have the ability to configure to work with their specific pump.

Customers can add specific information and parameters of the ESP, conditions at the production site, and other variables to tailor the model to the particular production site.

The models are designed to work with the dirty / noisy data, and unstructured data, which ESPs often provide.

It means customers can develop a model for their specific ESP much faster, and with less data, than if they were starting with nothing.

The ESP model has been developed building on customer expertise. “We don’t profess to know everything there is to know about ESPs, we’re not an ESP company. We’ve leveraged the knowledge of [customer] ESP experts and subject matter experts to build this model and identify the value points.”

Other equipment

The same approach can be applied to many other types of assets common in the oil and gas industry.

For example, Lone Star has analytics models for rotary screw compressors, which are typically used in manufacturing operations, to power air-driven tools.

With these compressors, the Lone Star models can be used to determine the best time to put a compressor into ‘idle’ mode or switch it off, taking into consideration the time to start it up again, and the additional wear on the equipment while it is idling.

“You can apply the methodology and model [the method] to virtually any asset. If there’s sensor data available, you can get the data off, and there’s value associated with the asset, you can create a predictive model and prescribe actions” Mr Brooks says.

“You could apply it to anything that spins, creates heat, has liquid flowing through it.”

The analytics capabilities can also be applied to financial and economic problems, but typically not with real-time data.

Combining physics based models

To make it faster to build models for specific equipment, Lone Star combines physics based models, which are based on how we know parameters will relate for reasons of physics, with data based models, which are based purely on patterns seen in the data.

The physics principles “you can’t really argue with. They are principles and calculations which are tried and true,” Mr Brooks says.

With a physics-based model, “you don’t have to train the model to learn things that are already known about the operating properties of the asset.”

Lone Star calls the approach of combining physics-based and data-based models “Evolved AI.”

Mr Brooks believes that oil and gas AI will increasingly be combining physics models with data models in this way.

This is also another way of getting away from the “black box” approach adopted by many providers, where “there seems to be some magic associated with these AI, ML and really complex analytics. The data comes in, goes behind the dark curtain the lights come up and the results are there.”

“You’re unable to audit it, or prove that the results are what you expect.”

“With ‘evolved AI’ because you’re using mathematical and physics equations and principles, we can confidently say “we know this is going to be accurate within some range”.

About Lone Star

Lone Star has over 110 full time personnel. It does not employ traditional data scientists, but employs many mathematicians, physics professionals, and engineers of different disciplines – mechanical, petroleum, systems, electrical.

It also has a roster of around 1400 external subject matter experts. “The problems that we typically are asked to solve are so specific we can’t possibly have all of that knowledge in our organisation and leverage personnel with deep, specific knowledge to help us drive solutions for our cusotmers,” Mr Brooks says.

It claims that its clients get a minimum of 20x return on investment in the solutions, and sometimes as much as 100 x return.

Its analytics models can be run either in the cloud, on the edge or at the wellsite, on local PCs.

“I’m not going to tell you we can solve every problem in the world, but there is a ton of flexibility for us to solve a broad range of business problems within an organisations,” Mr Brooks says.

Challenges integrating operations and engineering data

AVEVA put together a panel of customers to discuss the benefits and challenges of integrating operations data with engineering data, with representatives from Enbridge, General Mills and Nutrien

AVEVA, a UK engineering software company active in the oil and gas sector, put together a panel discussion of customers to discuss benefits and challenges integrating operations data with engineering data. The panel had representatives from Canadian pipeline operator Enbridge, food manufacturer General Mills and Canadian fertiliser company Nutrien.

The panel discussion was held as part of the “AVEVA World Digital” event on June 17.

It follows AVEVA acquiring OSISoft, an operations data company, in August 2020. OSISoft makes the well-known “PI System” data historian, used by many oil and gas companies.

AVEVA is exploring ways it can help customers get value from combining the PI System data with its engineering data. For example, it should be possible to make better plans about maintenance, minimise energy use, and optimise operations. Everybody should have access to the data they need at any time.

Enbridge

“A big focus for [us] is access to data,” said Ray Philipenko, director, Pipeline Control Systems and Leak Detection with Enbridge Pipelines, based in Edmonton, Canada.

“Coming up with a reference architecture in terms of how the data flows is fundamental to the [digital] transformation."

"Getting something in place as quickly as possible is a key enabler to unlocking the value."

Enbridge claims to be "North America's leading energy infrastructure company," operating liquids pipelines and natural gas pipelines, gas utilities and renewable power.

The company has had projects to help people get more insights from data going back as far as 1990, he said. "In our case, the initial architecture was clumsy, it was kind of a brute force method."

"We're completing a reset of our reference architecture which is more optimal and capable of moving a large amount of data with minimum effort."

"You have to remember not to over engineer, that can slow you down. Balancing technical perfection with project execution, speed and agility, that's important. Understand that data perfection cannot happen."

"We've got multiple sites in our industry. Sometimes you have to accept the fact there's items you won't be able to get access to."

A focus of Enbridge is building tools which will enable company staff to do their own data analysis, or maybe build their own tools.

"This concept of self-serve is a big enabler," he said. "There's quite a large category of problems which business stakeholders can solve themselves. You don't want to bottleneck that process."

Enbridge is going through a company wide SCADA replacement program, leading to having standard systems for liquids control through the company. "We'll consolidate four different SCADA systems into one. Maybe we're 20 per cent of the way there. It can't happen fast enough. It's going to help simplify areas for operators."

Enbridge also has a project to try to get more data into its PI historian, "because it is so fundamental to the digital strategy to enable other things," he said.

General Mills

"One of the tools I think has become really valuable [in digital transformation] is what's termed a maturity assessment," said Joe Sanguinetti, technology leader at General Mills, a consumer food manufacturer based in Minnesota.

"How do I put a road map together that looks at where the plant is - as far as their automation journey, where they are at culturally, in terms of accepting technology? Where is the leadership of that plant at?"

"Once you have that, you can map in technologies that are going to transform to drive those business KPIs. That becomes a really valuable tool to explain to the C suite, the people that are going to be making decisions," he said.

Speakers in AVEVA's webinar, "Customer Panel: Connect Your Teams, Accelerate Your Innovation" on Jun 17
Top row: *Rashesh Mody, Senior Vice President of Monitoring and Control Business, AVEVA; Joe Sanguinetti, Technology Leader, General Mills; Stacy Crook, Research Director, Internet of Things, IDC*
Bottom row: *TJ Heidrick, Special Projects Manager, Nutrien; Ray Philipenko, Director of Pipeline Control Systems and Leak Detection, Enbridge*

"Our 42 plants are not all the same, there isn't a 'one size fits all'. [That's why it's a] nice thing [to have] a maturity assessment for each one."

The potential business opportunities vary from plant to plant – in one plant it might be waste reduction, in another it could be improving Overall Equipment Effectiveness (OEE), he said.

"Our biggest [challenge] is, how do we tie all this data together? We use the AVEVA platform, we have a great historian, we have a ton of process data, CMMS [computerised maintenance management systems] we use, we have lots of systems."

"But the data isn't available to people to go and solve problems. How do you put that contextual data together in a way that allows people to go after and get it?"

"The historian allowed people to go back and trend [data], and all that stuff."

As a manufacturer, it would also be useful to have data about the ingredients being used, if there is any change to that.

If you haven't done industry 3.0 [automating processes] it's really hard to do 4.0 [working with sensors and computer controlled equipment].

"If you don't have foundational systems like a MES [manufacturing execution system] some of this stuff becomes very difficult."

Mr Sanguinetti supports the idea of company staff being able to build their own tools. "Our biggest project is trying to come up with a common data model that allows citizen developers to go there and solve problems," he said.

Nutrien

For TJ Heidrick, chemical engineer in the nitrogen and phosphate division at fertiliser company Nutrien, digital transformation is lots of little programs, not a big one.

"The combination of some things which are orchestrated, and some things which are really small, can really add to the overall digital transformation journey," he said.

"There are lots of relevant technologies that can be brought to bear on a whole bunch of different problems. Finding the right use case is really the trick."

"You find other sources of data. You need to get your head around how to make interfacing that stuff easier." For example, Nutrien wants to put enterprise data together with sensor data.

[Normally] "95 per cent of the time is spent trying to dig information up, 5 per cent is spent figuring out what went wrong and what to do about it," he said. "I'd like to see that flip, so the 10 people can spend 95 per cent of their time putting in troubleshooting.

"I see a lot of value in the 'system of systems approach'. If I know someone is looking at rotating equipment, I can bring stuff in from the Manufacturing Execution System (MES), the operator shift system, PI [sensor data]."

"We have the central monitoring centre concept. 10 experts in Colorado in a room connected to everything with a set of tools available to them."

"We can evaluate [if] we have all the data, what data streams do we want, do we have context around the data, how does that help the person sitting in front of the screen."

Digital transformation projects can tend to need to involve many people from the company. "I'll tell you, when I got to the bottom of the list of people I needed to engage for this project, I was astounded," he said.

With digital tools, "it is tough to tell what's working and what's not," he said. "It goes from 'hey I can do stuff on Python' to 'I know your business and what your problems are, I have some things which will help you.'"

With AI and ML, "we're all trying to figure out what to do with it and how it works," he said.

LYTT – processing well fibre acoustic data faster

Fibre optic-enabled software and analytics company LYTT has developed ways to analyse data faster, by extracting only the relevant data as it is recorded, rather than sending all the data for processing

Well acoustic fibre optic technology is a way to identify leaks in a well, and understand production flow, based on the sounds which flowing fluids make.

One drawback with the technology has been the enormous data files involved, up to 1 terabyte an hour for a well, and the data needs to be sent elsewhere for processing.

UK software and analytics company LYTT has developed a way to extract only specific features of interest at the well site, and then using AI pattern recognition in the cloud to discover what is going on.

Technology background

For readers not familiar with the technology, fibre optic cables can be used like microphones, because sound waves will modulate (change) light going down the cable.

This technology has been available since 2009, first used in the field for hydraulic fracture monitoring in Canada and later developed by UK defence contractor QinetiQ in 2012.

If a fibre optic cable is installed on tubing in a hydrocarbon well, it can be used like a string of microphones, creating a recording of audio at any depth of the well. This can be used to detect and understand leaks, among other applications. The technology is known as "distributed acoustic sensing" (DAS).

If this huge volume of data needs to be transferred from the well site to the processing location, however, that means a lot of data communications and a longer lead time.

Another way of reducing data volumes is if you just look at the amplitudes of the waves, not the whole waveform. This will tell you the volume of sounds at different points in the well and at different times. But this method is imperfect as a lot of useful information can be lost.

Comparing recordings

The system developed by LYTT has software which can run in a computer at the well site, extracting useful information instantly to the cloud, where it can then be compared to the acoustic signatures with a database of recordings.

The technology of comparing one acoustic recording with another is similar to the technology in the "Shazam" phone app. It compares the acoustic signal of the song you are listening to, in the phone's microphone, with its database of songs, so it can identify the song.

The LYTT technology does more than compare one acoustic recording with another, however – it has developed physics-based and machine learning-based data analytics techniques that can provide further insights.

There are other examples of AI technologies which compare one signature with another, for example facial recognition apps compare the face in the camera with faces in its database.

The LYTT algorithms can identify from the data whether it is oil, water or gas, or a mixture, because different fluids produce different acoustic signals (make different noises).

You can detect if the fluids are carrying sand, and differentiate between sand being transported into the well and deposited, and sand being carried up the well.

There could be multiple different acoustic signals happening in a well at the same time, as fluids flow through it, and each can be seen in the data.

LYTT developed its library of recordings in the laboratory, recording the noises made as various fluids, solids and mixtures flow through pipes and completion systems, such as oil mixed with sand flowing inside downhole tubing, says Lilia Noble, Product Lead, LYTT.

In laboratory settings, LYTT has set up piping similar to an oil and gas well, including well elements such as perforated casing and open hole gravel packs.

Lilia Noble, Product Lead, LYTT

Using the technology

Two of the real world problems LYTT is focusing on are – understanding well integrity (including identifying and mapping leaks), and understanding production.

For well integrity, the data analysis can answer questions such as where the fluids are flowing into the well, what the fluids are, how the fluids are distributed within the well, and when it started flowing.

There can be leaks in tubing, casing, as well as flow behind casing, and leaks in the overburden above reservoirs. Leaks can also come from poor cement placement, or degradation of cement. There can be leaks in packers and seals, or flow along faults.

Because leaks can be intermittent, it is useful to have constant monitoring.

If you activate any fluid pathways within the duration of survey, you can see if it correlates with any detected events which happened at a specific depth, to understand which elements are causing leaks.

"LYTT helps operators understand the behaviour of their wells," Mrs Noble says.

Flow can be detected behind several layers of casing string, depending on the energy of the sound.

When using the technology for production logging, it is possible to gather analysis which can be used to get a better understanding about how the well could be operated better, such as optimising gas lift, or monitoring ESP operations.

A unique feature of the technology, LYTT says, compared to other companies doing analysis of well fibre acoustic data, is that the data can be analysed in real time – there are no delays while the data is sent to an office to be analysed.

The technology makes a big improvement to usual well analysis methods, because it provides continuous data, rather than just providing a snapshot in time, Mrs Noble says. This is important because many well integrity flow issues are intermittent.

Workflow

For well integrity analysis, the normal workflow companies follow starts with a "pre-job analysis", defining possible leak sources and pathways.

Then they shut in the well, and do a baseline flow logging, looking for the 'background acoustics' or the noises which are always there.

Then they manipulate the pressure in the annulus to see if that will reveal the leaks.

They try to identify if there are any fluids leaking into the annulus which should not be, from looking for responses in the DAS data.

The final step is to analyse recorded data.

North Sea remediation

A LYTT project, published in the media in 2021, brought a 'dead' North Sea oil well back to life after being inactive for 3 years. The well had a leak, which the operator struggled to fix.

The customer's operations team had been trying to find the leak using a multi finger caliper tool, a device for measuring the diameter of the internal wall of casing or tubing.

The process identified a change in wall thickness in a certain area, and a patch was applied in this area, but it failed to address the leak.

Another attempt was made using wireline acoustic sensing, but it also failed.

The well already had a fibre optic cable installed, although it wasn't used for acoustic sensing.

LYTT could analyse the acoustic sensing data, to understand how the fluids were flowing through the well tubing into the annulus.

Then they could isolate the leak points and prevent further pressure build up.

It showed there was evidence of multiple leak points within the wider tubing interval.

With these insights, the company could develop a plan to address the leak points. The company released a technical paper about this work entitled 'Using Distributed Fibre Optic Sensing to Recover Well Integrity and Restore Production'.

P&A in the Americas

LYTT also helped an operator to plug and abandon a well in the Americas.

"LYTT's insights have proved invaluable in supporting our team's work to plug and abandon wells quickly, efficiently, and safely," said Curt Jones, senior drilling engineer with bp, talking about LYTT's work on the project.

"LYTT was able to track flow behind multiple casing strings, precisely identifying the movement of fluids in terms of both time and location."

"Our engineers applied these insights, in conjunction with a highly tailored workflow, to extend the well's first lateral barrier and adjust the position of the planned second barrier."

The company wrote a paper, 'Well Integrity Flow Detection Using Novel Acoustic Pattern Recognition Algorithms', published and presented at the Abu Dhabi International Petroleum Exhibition & Conference (ADIPEC) in 2020, to explain its methodology.

Clair Ridge

LYTT helped bp improve production at its Clair Ridge site by up to 2000 barrels a day with a "tuning" strategy, using real-time well data analysis. Clair Ridge is described as having "challenging reservoir characteristics".

Although the Clair field was discovered in 1977, there was no production at the field until 2005. There were challenges with well integrity, water inflow, and complex fractured subsurface. Clair Ridge entered production in 2018.

The company has demonstrated its work in a paper published and presented at the SPE Annual Technical Conference and Exhibition in October 2020, called 'Production Optimisation Using a 24/7 Distributed Fibre Optic DFO Sensing Based Multiphase Inflow Profiling Capability'.

About LYTT

LYTT was founded by Tommy Langnes and Prad Thiruvenkatanathan. Tommy Langnes worked in well integrity at Shell, bp and NorskHydro for 18 years. Prad Thiruvenkatanathan worked at bp for 6 years as an upstream data scientist.

LYTT is backed by bp's incubator "BP LaunchPad."

Daryn Edgar, CEO of LYTT, is a former VP strategic alliances with SAP and senior sector partner with Athene Capital. She has a background in the oil and gas industry from working with WellPoint Systems and Quorum Business Solutions in Calgary.

LYTT employs a team of data scientists, engineers and oil & gas industry experts.

LYTT says it has customers worldwide, and one of its customers claims it achieved $400m of incremental value in 2019.

Ikon Science's "Curate" cloud service

Subsurface software company Ikon Science has launched a cloud service called Curate, where customers can access cloud versions of its software, and also manage their data and projects

Ikon Science, which describes itself as a "subsurface discovery knowledge management solutions" company, has launched a cloud service called "Curate," where customers can build projects, manage data, and work with cloud based versions of Ikon's software, such as its "RokDoc" rock physics tool.

The idea is that customers can access all kinds of data, including their own data, and publicly available data, in Curate, and then use it in various software packages, including Ikon Science's own, and collaborate with others as they work.

They can also use Curate as a data management system, and access past projects done by people in the company.

Denis Saussus, CEO of Ikon Science, says that Curate is "combining contemporary technology with our 20 years of expertise in geo-prediction, data solutions and subsurface analytics."

"Curate promises to revolutionise how subsurface teams work and collaborate to solve business focussed challenges," he says.

"With Curate, we can embed our tools, packages like RokDoc, and other applications, in a place where the data and the context is readily available," says Nick Huntbatch, product manager – QI (Quantitative Interpretation) Applications with Ikon Science.

By using Curate, customers should be able to reduce the amount of time they need to spend searching for and manipulating information.

They can also reduce the number of decisions made with incomplete information. This often happens when information is not readily available at the time of the decision, he says.

Subsurface work process

The work process with subsurface software – interpretation - could be summarised as taking raw data and making something more useful from it, in pursuit of a goal, he says.

"We can refer to that interpretation of the data as knowledge to some degree, whether it is petrophysical interpretation, rock physics models, perhaps facies cubes from seismic inversion."

When starting a quantitative interpretation project, the first step is often to collate outputs from other workflows, such as fluid properties, core descriptions, petrophysical interpretations, and seismic processing.

"It is outputs of other disciplines, other workflows, aggregated knowledge, basically," he says.

[As an interpreter] "I need to spend a fair bit of time searching that stuff out, making sure I'm using the relevant information and not missing something crucial which will come to haunt me later."

The crucial part which is often missing in geoscience work is having awareness of previous work the company has done on something similar, and the context in which it was done, Mr Huntbatch said.

And often different data files are held in silos, not integrated together. Data can come from corporate subsurface data archives, online public repositories, and personal data.

In one place

With Curate, all the relevant, available data can be accessed from one place.

So you end up with a collaborative workspace, where everybody can look at data, the associated meta data and documents, and put it into projects.

You can see the context around the work. Why it was done, what the parameters were, how applicable it is to the interval you are looking at now.

This should also make it easier to combine output from different disciplines, to ensure the project considers all relevant information.

It also ensures that your work will still be available for people to work with in the future.

How Curate works

Curate can be hosted in the cloud or on premise. It is accessible via a web browser.

When loading in data, you need to ensure that it aligns with certain business rules, like data naming conventions.

You can see data available in the system on a map, with tools to filter it for wells and fields, areas, and show types. You can see third party data, such as block boundaries and accumulation outlines.

You can see the work which has been done on the area you are interested in, such as logs, written reports (documents), and petrophysics studies.

You can create a 'project' on the system, and bring in your colleagues.

You can launch apps, for example open a 'well view app' and use it to view well log data, or study seismic attributes using a seismic viewer.

There are tools to do data analysis, for example study trends in seismic velocity data.

There are tools for modelling, for example adding in the depth of a certain formation using data from another study, or drawing correlations in a number of wells in the study area.

Ikon's own apps are available on the system to visualise the data, including its "RokDoc" for rock physics, geopressure and geomechanics, and its iPoint data management system. There are a number of other cloud based apps for viewing data.

There are workflow apps, which draw data from the system, for example an "amplitude vs offset" app which can investigate how porosity will change the AVO response.

How to make geothermal businesses work

Geothermal businesses do not need high temperatures to be viable, but get easier with higher temperatures, if the well is already drilled, and if you have the right sort of regulatory support, we learned at a Finding Petroleum webinar

Report from Finding Petroleum webinar on May 28, "Geothermal Success"

Geothermal businesses, selling the heat from the earth, can be viable with downhole temperatures of as little as 65 degrees C.

But it is easier to make them viable with higher downhole temperatures, wells which have already been drilled for other purposes, and a regulatory environment which supports risks, provides data, enables construction and more, we learned at a Finding Petroleum webinar on May 28, "Geothermal success".

Kalahari GeoEnergy, based in Zambia, believes it can build a viable business, based on the results of its exploration wells, producing 4.5 MW from 2 production wells, 500m deep.

Rob Westaway, Senior Research Fellow at the University of Glasgow, calculates that hot water produced from the Wytch Farm oil field in Dorset, UK, could provide 90 MW of heat.

Rob Westaway, Senior Research Fellow at the University of Glasgow

But the development would be complicated by restricted planning rules in the region, as a designated Area of Outstanding Natural Beauty, which would probably make it impossible to (for example) send the heat to the nearby town of Bournemouth by pipeline, where it could be used to heat buildings and hot water.

The environmental credentials of geothermal energy are extremely good.

Jon Gluyas, Director of the Durham Energy Institute at Durham University in northeast England, points out that geothermal energy could be developed nearly everywhere on the globe. So it meets the UN Sustainable Development Goal of reducing inequality, as well as being low carbon.

Professor Gluyas has formed the Geothermal Energy Advancement Association, together with Chris Sladen, who has worked for many decades in the petroleum sector.

The Association aims to promote investment and drive awareness in geothermal, across academia and business. It advocates greater support from Governments globally and improved regulations. Ultimately the challenge is create geothermal investments at a similar scale to, say, wind or solar, in a world ultimately using less petroleum.

BP and Chevron are already involved in geothermal, through a stake in Canada geothermal start-up Eavor, announced in Feb 2021. Chevron has also been involved in geothermal in Indonesia for 20 years.

Where?

If you look at a map of the world showing where geothermal energy could be produced, including where heat is close enough to the surface, or where there are aquifers, volcanoes and granites, it includes a large proportion of the earth's surface, Professor Gluyas said.

Most people's idea of geothermal energy is to use it for power generation, Professor Gluyas said. The USA has the most geothermal power generation in the world. The first geothermal power plant in the world was built 100 years ago in Italy, and the next in New Zealand in 1958.

The Philippines was also an early mover. Other leading countries in geothermal power are Indonesia, Mexico, Iceland, Kenya, Japan and Turkey. Altogether 14 GW is generated in 27 countries.

Another application is using the geothermal heat directly. Here, "China and the USA are miles ahead of any other nation," he said. Other countries doing this are Sweden, Turkey, Germany, France, Japan and Iceland.

Iceland covers all its heating and power generation requirements with geothermal energy. There is potential for Iceland to use the energy to make liquid hydrocarbons using captured CO2, to power the transport system.

In the US, there are millions of onshore oil wells which could be candidates for geothermal, including 200,000 wells currently producing hydrocarbons at a rate of less than 1 barrel of oil equivalent per day,

Jon Gluyas, Director of the Durham Energy Institute at Durham University

"These are phenomenal opportunities, and we are only beginning to scratch the surface."

Where in the UK?

Two projects in the UK to use geothermal energy for power (electricity) generation are the United Downs Deep Geothermal Project and the Eden Project, both in Cornwall. "Both should see power generation in the next year or so," Professor Gluyas said. Although we should not forget to use the associated heat directly (such as for buildings).

Professor Gluyas was involved in a geothermal project in the Weardale Granite, in northeast England and in central Newcastle, drilling wells in 2010 and 2011. The granites contain uranium and thorium slowly decaying, which generate heat. The project generates 3.6MW of heat. There are deep saline aquifers in Cheshire, the Midlands and Scotland which could also supply heat he said.

Abandoned coal and metal mines could be suitable for geothermal. There are 23,000 in the UK, all now flooded with water, which ranges in temperature from 10 to 25 degrees C, he said.

North Sea offshore oil and gas fields could be repurposed for geothermal. Some oil fields are already producing 10-20 times as much water as oil by volume, and most of the water is near or even above 100 degrees C.

Power from the water could generate 50 to 60 per cent of the energy needed to run the offshore platforms, he estimates, and could replace energy from burning diesel and gas.

Another business idea is that CO2 storage projects could be turned into geothermal projects, with a technology called "CO2 plume geothermal." Subsurface CO2 absorbs heat from the reservoir, rises to the surface due to its increased buoyancy, and is used to generate power.

One challenge in getting started is that you need to know the permeability of the rock, if the system involves separate injection and production wells. This is not always known, particularly for onshore systems, he said.

Role in global energy

At the moment, the role of geothermal in the global energy system "is about nothing," counting for 1 per cent of global power generation, while gas provides 24 per cent and coal provides 27 per cent, he said.

There are direct connections between geothermal and hydrocarbon, coal and nuclear power, he said. It was the heat in the Earth which enabled coal and hydrocarbons to form. The heat in the earth comes from the decay of uranium and thorium.

For the question of how long geothermal energy can go on for, scientists estimate that 15 per cent of the heat generating capacity of the Earth that is available has been produced over the last 4.5bn years. "We don't need to worry about next week," he said. "It is sustainable as far as any reasonable description of humans as a species go."

The risk of geothermal projects is not the failure of heat in the Earth, but getting the reservoir engineering wrong. "It is possible you can mismanage a system, inject cold water and get cold water back."

"The important point to note is that margins on geothermal are always going to be modest," he said. "There's just not the energy density in a barrel of hot water compared to a barrel of oil."

"Stacking" geothermal

Professor Gluyas envisages a future where heat is used through multiple levels.

If dry-steam is produced at 200 degrees C, and used for power generation, the waste "wet steam" remaining could then be used for food processing, drying timber, "a whole array of industrial applications."

Water at under 100 degrees C can be used for hone heating – this is done on a big scale in Iceland. While lower temperature water can be used for greenhouses and fish farms.

"You stack up your projects and keep taking energy out of the system," he said.

Repurposing UK wells

Rob Westaway, Senior Research Fellow with the University of Glasgow, led research into the potential for repurposing hydrocarbon wells in the UK. The work is funded by the UK's Engineering and Physical Sciences Research Council. Industrial partners are oil services company Schlumberger and oil and gas operator Perenco, operator of Wytch Farm, a strong candidate for geothermal repurposing.

The study found that the "vast majority" of UK onshore wells with potential for geothermal energy are in England.

Dr Westaway's team did a screening survey, to identify the most promising oil and gas wells in the UK for geothermal production.

OGA's well database has 3 categories of well abandonment. Phase 1 means a permanent barrier is placed between the reservoir and the well bore. Phase 2 means zones in the well have been isolated, such as with cement in the well. Phase 3 means the well head, conductor and all surface equipment are removed.

Of these categories, only phase 1 is reversible, meaning the well can be used for geothermal, Dr Westaway said.

This means there are 560 possible onshore wells which could be repurposed as geothermal, of which 293 are currently operating, 83 shut in, 163 in abandonment phase 1, 20 categorised as "plugged". Only 1 of these is outside England.

The key parameters for site screening are the bottom hole temperature, and the formations which a well connects with.

There were 17 wells out of the 560 with an estimated bottom hole temperature above 80 degrees C. They were all in either the East Yorkshire / Lincolnshire basin, or the Wessex basin, which includes Wytch Farm in Dorset.

It is possible to aggregate all the candidate wells in a field, to calculate how much energy each field could 'produce,' if their hot water streams were comingled.

On this basis, Wytch Farm is overwhelmingly the field which could produce the most energy in the UK.

The Wytch farm field is mainly offshore, to the South of Bournemouth, but accessed through onshore wells. The reservoir temperature is 65 degrees C.

The field is in a part of the UK which has the same environmental protections as a national park, as a designated Area of Outstanding Natural Beauty. This means it is unlikely planning permission would be agreed for new infrastructure, such as pipelines to carry heat to nearby large towns to be used for heating.

"If the field was in a less protected area, much more could be done with the heat."

The value of the energy in hot water produced today at Wytch Farm could be equivalent to a third of the total energy produced in the hydrocarbons, if (for example) the water replaced heat from burning the gas in a power station, he calculates.

Still, the value of heat is much less than the value of the hydrocarbons. This means that many technologies which are viable in producing hydrocarbons may be too expensive to use on geothermal wells. And geothermal projects need very careful consideration on costs, otherwise the initial drilling costs will never be recovered.

Ultimately, Dr Westaway calculates that Wytch Farm could generate a thermal power output of 90 MW.

The second most viable fields in the UK for geothermal purposes, Stockbridge and Welton, could yield thermal power outputs of 638 and 251 KW.

Legal complexity

The UK Oil and Gas Authority (OGA) does not have any system in its regulatory framework for hydrocarbon wells being used for geothermal, either alongside hydrocarbons or repurposed for geothermal after hydrocarbons are depleted.

It does not have a simple mechanism for a hydrocarbon operator to pass ownership of the well to a geothermal operator.

"The OGA expects every well to ultimately be decommissioned and expects the owners to commit to doing that. If the liability of decommissioning is transferred to some new operator, there needs to be some framework which ensures they [actually do it]," Dr Westaway said.

Another reason why OGA is reluctant to allow repurposing of wells is concerns raised by environmentalists that conventional hydrocarbon wells might be converted to shale gas wells, and so create a UK shale gas industry by stealth.

The Netherlands has a more favourable regulatory environment for geothermal including a government scheme to provide insurance for drilling risks, he said.

In the Netherlands it is possible to get a license for geothermal drilling in a certain area. In the UK, you would need to take out an exploration license, and then apply for an oil and gas petroleum production license, in order to have exclusive access to an area for geothermal use.

All subsurface data in the Netherlands is publicly available. In the UK the British Geological Survey makes databases for its internal use, but does not provide access to anyone else, he said. If the data was made

Andy Wood, subsurface manager, CeraPhi

available, it would be easier to find targets for geothermal wells.

Professor Gluyas added that the Netherlands has a requirement that oil and gas operators evaluate any failed oil wells for geothermal potential.

CeraPhi Energy – a single well model

CeraPhi Energy of Great Yarmouth, UK, has developed a geothermal technology which requires only one well

CeraPhi Energy of Great Yarmouth, UK, licenses a geothermal well design it has developed which uses a single vertical well. So the water is both injected and produced in the same well (but through different piping inside it). This means there is lower exploration risk.

This system can be retrofitted into an existing oil and gas well, to turn it into a geothermal well, said Andy Wood, subsurface manager, CeraPhi.

The more common geothermal configuration is to have two wells, an injection well and a production well, with water flowing through the reservoir between the two wells, being heated as it does so.

Misconceptions of geothermal

There are many misconceptions of geothermal energy, Mr Wood said.

Many people believe that projects need to be close to volcanoes (as in Iceland). But anywhere in (for example) the UK is capable of having geothermal wells which could create enough heat for district heating (buildings and water), and much of the UK can hold geothermal wells which could be used to generate electricity.

Many people are concerned that the pumping of large volumes of water into the subsurface can cause small earthquakes. This did happen in Basel, Switzerland, in 2006, when an earthquake with a magnitude of 3.4 was triggered by water being injected at high pressure into the ground. But in reality, geothermal projects do not necessarily need hydraulic fracturing, or cooling the subsurface with injection of water, which is what caused the Switzerland earthquake.

There is a perception that the wells need to be very deep, but actually it has worked with wells of "very modest depth," such as with the Zambia example also presented in the webinar (see below).

There is a perception that subsurface uncertainty adds to the risks. But this is only a factor if you go for a two well layout, one well for injection and one for production, and the communication between the wells is not what was expected, due to a failure of reservoir characterisation. The CeraPhi design (described above) avoids this.

There is also a perception that geothermal energy is very expensive.

Mr Wood believes that geothermal energy is already "competitively priced" with today's renewable energy, and the costs will reduce further over time.

The biggest risks are probably in drilling, but the enormous amount of expertise in the oil and gas industry can mitigate this, he said.

It is interesting to consider how much of all energy consumption goes on heating, including heating buildings and domestic water, and heating industrial processes – including drying, cooking, curing, washing, sterilising, distilling, brewing.

In a decarbonised society, it would make far more sense to use heat from the earth for this, rather than generate renewable electricity, he said. And unlike renewables, geothermal energy produces continuously.

The biggest environmental impact of the geothermal project is probably the "well pad," the area of land where you drill, typically 100m x 100m, holding the drilling rig, equipment and vehicles. But after the drilling is done, this can all be replaced by a well head and production system, small enough to conceal within a domestic building.

Oil companies could also plan an oil well which would later be used for geothermal production after depletion of the oil reservoir. Or they could have geothermal energy from the start, producing hot water from a sidetrack well.

Kalahari GeoEnergy – building a business in Zambia.

Kalahari GeoEnergy plans a commercial business in 2022 in Zambia, with 2 production wells 500m deep, expecting to produce 4.5 MW of geothermal energy, following the drilling of 21 experimental wells

Kalahari GeoEnergy plans to have two wells in commercial production in 2022 in Zambia, producing 4.5MW of power in total.

The company was founded by Peter Vivian Neal as an independent sustainable power producer in Zambia. Mr Vivian Neal is a former mining explorer.

The company is currently doing a feasibility study. It has already drilled 21 wells, 6,100m in total (so average 290m each). These are "slim" wells with 3 inch internal diameter.

The best two of these wells are proven to be able to produce hot water with 500 KW of heat. They will be used for a demonstration plant.

In the subsurface, the fluids move upwards from 10km depth through permeable rock, with sedimentary basins forming a caprock above. The wells are drilled through this caprock. There is some additional heat from radioactive granite intrusions. So there may be fluids at above 150 degrees C, at around 1km depth, Mr Vivian Neal said.

The highest temperatures encountered so far are 112 degrees C, at 200m depth.

Mr Vivian Neal believes that 120 degrees may be a good minimum temperature for a commercially viable project.

The demonstration will also show how the heat can be used for growing plants and fish farming.

Some helium is also produced, comprising 2 per cent of produced fluids, coming from deep in the earth's mantle.

Zambia

Today Zambia gets 70 per cent of its primary energy from wood and charcoal, and in chopping down this wood, it has the second highest rate of deforestation in the world (after Brazil), Mr Vivian Neal said. 96 per cent of the rural population has no access to electricity, and about the same number have no sanitation (drinking water /sewage disposal).

There has been some hydrocarbon exploration, but it found that the basins had been too hot, so outside the oil window. There is some interest in solar energy, but no commercially sized storage facilities, or grid management system, Mr Vivian Neal said.

However Zambia has less restrictive regulations than the UK on geothermal projects. It does not have any regulatory restrictions on "independent power producers," you just need to find a creditworthy customer, he said.

"I do think perseverance and enthusiasm are the drivers which will make this work," he said.

Upgraded software in Roxar flowmeter

Emerson Automation is upgraded the embedded software in its Roxar 2600 multiphase flowmeter, to improve resolution and reliability

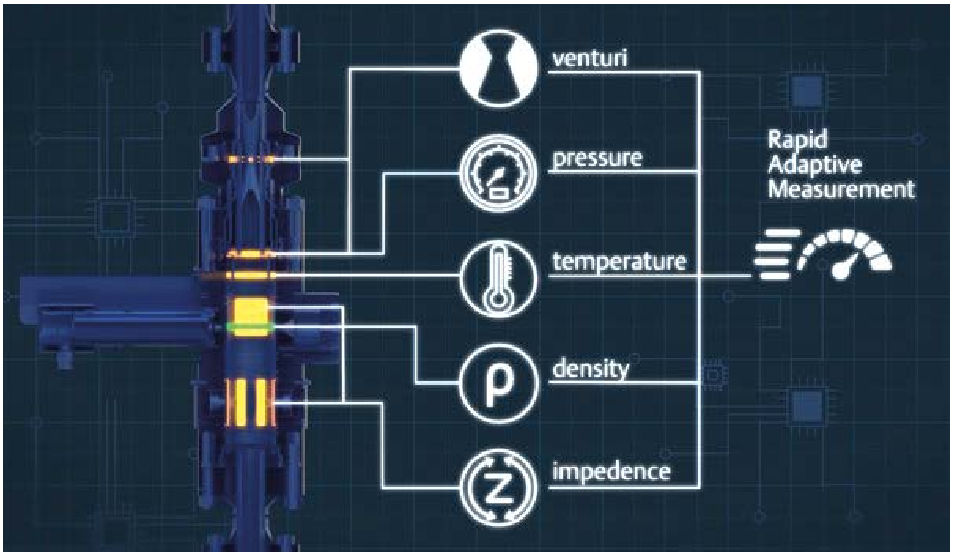
Automation equipment company Emerson has upgraded the embedded software in its Roxar brand 2600 Multiphase Flowmeter, with a system it calls "Roxar Rapid Adaptive Measurement."

It means the flowmeter can handle a much wider range of gas-oil mix, beyond the usual 25 to 85 per cent gas volume fraction range.

The software improvements follow increasingly demanding requirements from customers, says Kelda Dinsdale, Customer Adoption Manager, Emerson Automation Solutions, based in Bergen, Norway.

"Operators are developing more and more complex reservoirs and the demands on instrumentation increase," she says.

One area of improvement is in the reliability of the data, including through a higher resolution sampling of data.



Emerson's flowmeter – measuring pressure, temperature, density and electrical impedance

Kelda Dinsdale, Customer Adoption Manager, Emerson Automation Solutions

"We now perform flow calculations at a speed of 10Hz, meaning no matter how rapidly changing the flow may be, the measurement instrument will capture and reflect this in the data provided," Ms Dinsdale says.

"Since using this software in field, we have measured entire slugs that are under a second from beginning to end. We would not have had the resolution of measurement to capture such events previously."

The software also has more automation, ensuring the optimum meter configuration is in use at any given moment. There are multiple modules software operating in parallel, and arbitrators built into the software to verify and self-select which is the most suitable module at any given moment.

"This ensures no compromises are made on measurement performance, no matter how varied flow conditions may be," she says.

The software is designed for better ease of use. Operators can get best performance without having to develop a lot of expertise or needing to use a lot of time hands on with the meters. "This supports reduction in operating costs and efficient operations," she says.

The flowmeters are generally expected to be used for the lifetime of their well, which can be decades. This means that instrumentation needs to be able to evolve over time.

With this technology, new modules can be added as required and existing modules can be improved without impacting the performance of other modules.

The software has already been installed in a number of locations around the world, including in the North America shale market and a test project in the Middle East, where performance was compared before and after the upgrade.

Validere – gas processing with better data

Gas processing – the purification of natural gas to 'pipeline quality' – can be done more effectively with better use of data – Validere explained how

In gas processing (purifying natural gas from well head quality to pipeline quality), three common business priorities are to make the operation run more efficiently, to minimise and manage air emissions, and to align operations with commercial requirements.

All of these can be done better, with better use of data, explained Ian Burgess, CTO and co-founder of Validere, a company with offices in Houston, Calgary and Toronto, which describes itself as a "data intelligence platform for oil and gas product quality."

He was speaking on a Validere webinar on May 6, "Natural Gas Processing 2.0."

For gas buyers, it is still easier to find the quality and assess the price of a $150 used golf club on eBay, then it is to find the condition of a $1m shipment of crude from an oil company, he said.

This difference could be attributed to two reasons – difficulty of accessing data, and lack of centralisation, he said.

The data about the oil and gas quality is actually harder to generate than data about the used golf clubs, since it comes from scientific equipment, which is often remote and not connected to data storage, he said. And until recently, it was cost prohibitive to beam large amounts of data into cloud servers, so it could only be stored locally.

Ian Burgess, CTO and co-founder of Validere

For centralisation, consider that there has been a centralisation of inventory information for second hand golf clubs (on eBay). There is one place people go to, to buy and sell them, and it can gather together lots of data, so people can find out what they need. This is not true for oil and gas sales, he said.

Re-imagining

What we should be talking about now is "re-imagining the way information flows within your company and across the ecosystem."

A first step to improving data flows is to manage the data much better within the gas processing company. "You need all your inventory information in one database, what you have, where it is, and what is worth," he said.

"You have to make sure that information is true. That is more challenging, because you have the scientific equipment in remote places, a lot of measurements are more technical and there's more things that can go wrong."

Then you need ways to manage the "blending problem" – what to do with data when different production chains are being mingled together.

As Mr Burgess describes it, if you buy a bottle of coke and a bottle of rum in any possible grocery delivery system, you still receive a bottle of coke and a bottle of rum. But in the world of hydrocarbons, what you buy is a blend of products, so it is much harder to know exactly what you are buying.

You need data to be integrated to the level where you can do a systems level analysis, rather than analyse points on the system separately.

An example of systems level analysis is to answer the question "if I only have [resources] to do three things differently this month what should they be," rather than "what are all the things wrong with [one specific] facility."

Once you are able to make priorities and rank them, you have a lot more clarity about what to do. "It allows you to get a lot more done with a lot less effort," he said.

Then you need to actually be able to make the changes. Changing how you manage your supply chains may be very difficult, if it involves say moving 1000 barrels of oil from one place to another. "You can't snap your fingers and do that."

"When you're building in these initiatives, it is not enough to find the right thing to do. you have to find a way to make them easy to do."

Efficient operations

When making operations more efficient, organisations typically do it by taking multiple measurements around the plant, which takes a lot of time.

It also doesn't necessarily help people prioritise what maintenance work to do. You may identify things which are wrong, but not necessarily the most effective 2 or 3 tasks, he said.

Also, if you identify problems, it is useful to be able to distil the possible causes down to one or two, then you can fix it much faster.

If a plant has a new problem, or a new imbalance, it is probably due to one thing which has changed, not multiple things happening at the same time.

"If one thing has 30 per cent odds of breaking, the odds of two things breaking at the same time is 9 per cent. (0.3 x 0.3 = 0.09)."

When plants move from "point analysis" to "systems level analysis", they can usually identify the specific problem faster, he said.

They can also identify the most common causes, and so most likely causes of an unidentified fault. Or you can get a probability weighted list of the most likely causes.

Like a medical doctor, "they start to see these patterns in the data again and again," he said.

If you can get a broader spectrum of information or occurrences, that can make the models more accurate.

"A systems level analysis is good at saying, 'it can't be anything other than this, nothing else can cause an imbalance that looks like this,'" Mr Burgess said.

If you've grown up in an environment where all your data is siloed you're used to living in a world where you have a paucity of data you assume a lot of unknowns," he says.

Emissions / ESG

When it comes to reducing emissions, the 'industry 1.0' approach can be to make spreadsheet forecasts of what gains you think you can make.

Customers set specific targets and plans to reach the targets, but there is not necessarily much auditability.

"The number one mistake that I see being made across the industry on this ESG tracking and reduction is the temptation to build another [data] silo," he says. "This is a black box. We already have accounting, trading, and ops guys all with different data, now we're going to create this other silo called ESG."

Emissions can be measured, and then treated as just another factor to be measured, along with all the other factors. For example, it could be handled similarly to how companies keep track of the sulphur content of oil. "This is just one more thing you have to measure, no different than sulphur content, chlorides."

"I encourage companies to demystify carbon," he said.

The way you "propagate and make decisions on emission information shouldn't be different to any other thing which adds value to the molecule."

"Every time a barrel moves through your supply chain, you have to make sure you're propagating those attributes in your system of record through that supply chain in a way that's accurate and auditable."

You have data of the emissions associated with drilling a well – once the well is drilled, that is a number which does not change.

"These are all properties, not different to sulphur content - you can calculate, you can propagate that number through the supply chain. You don't need to create 16 different systems. Some customers are tracking over 30 ESG attributes".

It is important to get a reliable source of truth, and make it auditable to other people. "This being an emerging field of measurement, I think it is important to understand your uncertainty and what drives your uncertainty," he said. "Measurement infrastructure and methods are evolving."

By demonstrating that a product has a better ESG score, some clients have been able to sell it for a 10 per cent premium, he said.

Commercial understanding

Oil and gas companies need an in-depth understanding of their markets. They often do this based on what has happened in the past, or do it on a reactive basis, changing their assessment when something big changes.

Different groups in the company might use different data sets. "Every time someone has to ask for an e-mail from someone else you're slowing down."

In 'Industry 2.0', we can see companies making more of a "systems level analysis," he said. You can see how fast new conditions arrive, and how fast you can make sense of them.

Data completeness "is generally more important than accuracy," he said.

The more of the 'world' your model covers, the more useful your data analysis can be.

"The biggest mistake we see is when people write off, in the interests of time, anything they don't have perfect information on," he said.

"They end up finding a solution out of a really small [data] set that makes it basically impossible to do something useful.

There are a lot of sub optimal commercial decisions based on inaccurate or incomplete information or trends.

To improve the situation, "speed is really important," he said. You get that speed from systems level information gathering, systems level computation, and completeness of records.

If "version 1.0" of commercial decision making systems is where you can identify things which are wrong, "version 2.0" is picking the top 3 things to focus on."

Kayla Ball, SVP Product, Validere

"The goal is to make the systems level analysis fast enough that you can run it on many different market scenarios," Mr Burgess said.

Many oil and gas companies have long hydrocarbon processing chains, and they may all need to be adjusted if the assessment of the market changes.

A typical "intrabook optimisation" (optimising a company's activities) can include producing wells, midstream facilities where flows are mingled together (including some from other producers), and refinery consumers.

But at the end of the day the math is not really more complicated to optimise that larger book compared to one or two sites, it just takes longer, he said.

The calculations are "not really rocket science. It is about how you reframe the way you ask the questions to your data, once it is all there."

The decisions you make about operations of the plant can be very sensitive to small changes in market spreads (the difference between one option or another). Better data "gives you the ability to analyse those spreads as they come."

A good digital system could help customers identify the most useful elements to target, not just tell them what is wrong.

Altogether, the goal should be to "get to the place where you can start to solve problems faster than they arise, or adapt to new conditions faster then they arise," with a systems level analysis, he said.

With the confidence that your numbers are right, you can make better decisions, taking a profit when it is available, and avoiding a losses, he said.

The Validere platform can show a single source of truth of what is happening now, and work out what the benefit would be of making certain changes, in terms of improved profitability.

You can watch the webinar online here

https://validere.com/webinar-natural-gas-processing-2-0-three-keys/

ML – and being sure our safety systems are working

Safety systems on industrial plant, such as pressure valves or gas detectors, need to be working reliably. The data from maintenance reports can be very hard to analyse. DNV explains how they did it with machine learning

By Andrew Derbyshire, Chris Bell and Gillian Ewan, DNV

Problems with electronic safety systems can be very difficult to resolve, whether it's on a vehicle or equipment in an industrial plant.

A random hardware failure created over time is predictable and quantifiable. But a systemic or human induced issue, normally arising during design or operation, is a challenge to classify or predict and fix.

Such problems are often reported using unstructured or plain text.

For example, when the system sporadically fails, an engineer will come, fix the problem, and write a short note to explain what caused the failure and what work was done to resolve it.

Analysing these notes, when there can be thousands of them, to carry out simple trending and gain valuable insights can be difficult.

The best way to solve the problem may be to devise simpler definitions to search, collate and analyse particular maintenance records.

For electronic safety systems, five years ago, the process industry introduced its own internationally recognised standard for 'functional safety', edition 2 IEC 61511.

This essentially covers the systems designed to automatically prevent dangerous failures or to control them when they occur.

However, it has brought about its own set of challenges, particularly the call for regular mandatory assessments to be performed to monitor the actual behaviour of the safety system.

To ensure operators of offshore installations record and trend data for their assets correctly, a verifier would traditionally carry out a review of random maintenance records for each asset.

While this 'pick and mix' approach may highlight recurring problems on the plant, it will not demonstrate the cause or even that a problem exists at all, due to the way the data is recorded in plain text.

Andrew Derbyshire is Principal Safety Engineer & Technical Manager, DNV and assessor for Shell, ConocoPhillips and Bluewater

Using machine learning

DNV, the independent energy expert and assurance provider, is developing machine learning (ML) algorithms using a variety of data mining techniques to analyse an entire set of maintenance records for a Safety Instrumented System (SIS).

This algorithm can detect data anomalies in the way that maintenance records have been recorded.

This allows for more targeted assessments, providing plant owners with a better understanding of the actual behaviour of the SIS-related devices. It will contribute to a more accurate overview of the integrity of any safety function.

Essentially, once there is a means for the computer to understand large swathes of maintenance reports, it is possible to look at them objectively, and then identify the behaviours which most commonly lead to that issue.

The computer can also identify reports of problems which are worthy of further (human) investigation. This removes the bias of the assessor. It focuses more on records which have anomalies, as opposed to a random sampling method which makes identifying anomalies more difficult.

Fire detector case study

DNV investigated the feasibility of this approach with the inspection dataset of a single fire and gas detector.

This is a common element offshore, which is prone to failure or miscalibration.

A cross-industry process for data mining (CRISP-DM) sprint methodology was used to manage the project, using a combination of natural language processing and ML (linear support vector machine (SVM)) algorithms.

The study aimed to explore the question "can a computer predict the test result by analysing the text?"

The detector had a dataset covering 26 years, containing more than 2,000 records for this single system. 500 were classed either PASS or FAIL. Only 2% of the records reported a failure of the system and 30% of the records had no class assigned.

The analysis was made more complex with many of the records using alternative codes or classes to determine the performance standards of the Safety and Environmentally Critical Elements (SECE), such as "failed", "failing", "failure".

This can make ML predictions based on natural language processing exceptionally difficult. So before running the AI model, this raw text was transformed into a limited feature set. This was the most time-consuming part of the program.

Gillian Ewan, Development and Innovation Manager OPEX, DNV

The open-source Python package scikit-learn (version 0.19.2) was used for the data analysis.

The method, in summary, was to first split the dataset into training (75%) and testing (25%); pre-process the data set; derive numerical features using natural language processing; train a classification model on a training subset to make predictions; predict training subset classes to evaluate model performance; revise feature derivation and model parameters to improve fit (repeat the second step if necessary); predict testing subset classes to evaluate overall model performance; estimate SECE or equipment availability and reliability.

The dataset showed a good accuracy of between 93% to 98% matching PASS records. There were in fact only ten FAIL records in the test dataset and very few in the overall data.

Manual verification

Manual verification of the entire dataset was key in this study to ascertain initial assumptions that the recorded dataset included only a few random errors.

It was the job of an offshore verifier from DNV to review the entire dataset: 2,119 records in all.

The verifier identified 37 of 1,459 records marked as PASS which should have been FAIL, and 3 of 40 records marked FAIL which were really PASS.

This gives a misreporting rate of 2.7%. This rate was initially anticipated to be 5-10%.

The manual verification gave confidence in the predictions based on the unverified dataset. The model was then re-trained using the verified classes.

The algorithm was now able to classify as PASS or FAIL the previously unclassified 30% of records, giving the verifier a much better understanding of the systems performance.

The objective of this work is to focus effort on potential discrepancies in the records. Such records could be screened out by including a simple text-search for PASS or FAIL - prior to the ML model, or if the operator includes more detail in the records themselves.

The approach is currently being refined further before being rolled out across the company's complete verification service.

Using the algorithm

The algorithm automatically highlights areas for investigation in a matter of seconds, reducing the amount of time spent reviewing non-erroneous records.

This increases efficiency and supports prioritisation of budgets based on the findings and recommendations.

Chris Bell, Senior Consultant, DNV

The algorithm also supports automating high-cost, error-prone tasks in which the cumulative effects of inconsistencies and errors in the analysis can adversely impact safety.

This methodology can be easily applied to other systems and assessment criterias, such as IECEx and ATEX, where classifying data into distinct categories for trending and analysis purposes can be useful.

Learnings

The case study has demonstrated that it is essential to do the following.

Store numerical fields in the management system where possible, but as independent fields.

Remove boiler plate text (text which is often reused verbatim) from the management system database.

Have "data gnomes" regularly clean the database; ML can be used to facilitate this.

Train the workforce on data best practice, for instance, what failure codes should be used where and when.

Ensure data is being stored at the correct level. Too many items assessed in one maintenance report is difficult to mine consistently.

Combining the resultant predictions with availability and reliability calculations will help operators trend their asset performance over time, potentially identifying areas for improvement or efficiency gains. This approach can also be used to reconstruct data missing from management systems, as well as to identify potential systemic misreporting issues.

About the authors

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Event driven inspection vs risk based inspection

Inspecting only when data gives us reason to inspect (known as 'event driven inspection') can be more effective than trying to inspect based on knowledge of the risks ('risk based inspection'). IMRANDD explains how it can work

By Christopher Blake, head of new business, IMRANDD

Most operators have turned to a risk-based inspection (RBI) methodology to assess, prioritise and justify their asset integrity decisions.

Risk based inspection is the process of developing a scheme of inspection based on knowledge of the risk of failure.

Good quality RBI enables direct comparison of all equipment via a risk matrix, irrespective of the asset's damage mechanisms. For example, RBIs can be used by asset managers to compare the risk of corrosion on a riser against the risk of a stress fracture on a pressure vessel.

Following an inspection, an asset manager will incorporate observations such as material or equipment condition into the asset's profile.

These observations will change the maintenance recommendations over time.

However, this feedback loop can also sometimes be the undoing of an otherwise sound asset integrity plan.

A weakness of RBI is that conservatism has a habit of creeping into RBI strategies over time through the human bias of inspection.

Engineers lose confidence in the inspection readings and begin to exercise more caution; over the course of a few inspections, the asset's risk profile drifts away from where it should be statistically.

As a result, the profile becomes overly conservative to the point of being toxic, and renders engineers unable to make an accurate assessment based on risk.

Another weakness is that the RBI strategy is primarily based on historic or assumed data, for example, whether an incident has occurred within an organisation or is a common issue within industry.

When much of the decision making is made in isolation of what's happening in the plant's wider operations, valuable real time operational insights such as process data or system changes are not incorporated.

Event driven inspection

Event-driven inspection, in contrast, is based on leading, real-time (or very near to real time) data such as process conditions (for example temperature and pressure) to drive inspection.

Modelling environmental and process data in this way improves accuracy and efficiency of inspection and intervention.

By creating a data model based on the conditions and fluctuations that we know affect degradation rates, and monitoring these conditions accordingly, operators can confidently hone investigative time to those components where conditions have changed.

As an example, under one set of conditions, pressure system "A" will degrade at a certain rate per annum. Event-driven inspection monitors those conditions using environmental and process data and log any instances where the data deviates from the model's 'business as usual' circumstances e.g., an alteration is made to the production fluids within the system.

Because we know this alteration can accelerate corrosion, an event is created that must be reviewed and accounted for.

Event-driven inspection is particularly beneficial for asset managers who have a good handle on degradation mechanics and parameters, and for complex operations where traditional inspection methods can become costly.

If an operator can confidently monitor condition and only command inspections when absolutely necessary, substantial savings can often be made.

However, for older assets, the reality is sometimes a little less black and white.

Being able to handle large volumes of data seamlessly, and sort errors from genuine data variations, is particularly important for creating confidence in event-driven inspection.

While many variations can be legitimately disregarded, such as from human error, poorly calibrated kit or prevailing conditions, a handful will be legitimate indicators of failure.

Operators need to be certain of which data can be excluded, which inconsistencies require further investigation, and where gaps lie.

Real time data

Most operators already collect real-time data on how an asset is operating through sources such as sensors, production and chemical data, but most aren't able to use it in real-time.

But recent advancements in data collection and analysis make this new holy grail of event-driven inspection possible.

Additional real-time data sets captured by different departments can make predictive modelling more targeted, and build up a better, more accurate and holistic view of an asset's condition.

Reviewing data to make event driven inspection

And data no longer needs to be manually curated before an onshore engineer interprets it. Instead, data is being screened, analysed and validated continuously, providing the most timely view of an asset's integrity and substantially reducing the time between decision and implementation.

And new software exists (such as IMRANDD's "AIDA MAX") that can build complex models and analyse data separately, helping to eradicate human bias entirely.

This approach does not require any hardware, just an ability to think differently about the types of data from an asset that could be used to provide insights for the integrity management team.

IMRANDD's offering

IMRANDD's forthcoming solution AIDA MAX will use machine learning to assist the build of its asset degradation models to power event-driven inspection.

It will bring critical, real-time or near real-time insights to complement existing human checks and balances.

Data variations are separated out from the normal ranges to be analysed with more scrutiny and eventually reincluded in models. The software can identify and treat many data variations automatically without an engineer's intervention.

As an example, where the data shows pipe "X" process conditions have changed, the model is then updated with this new information, changing the degradation model that now indicates a likely failure prior to the next planned intervention.

The plan is updated based on this new leading indicator which in turn informs the integrity team to inspect the affected area sooner.

Quality of data integration – and value from software

The value you get from your software investments may come down to how well your various applications integrate together. Chris Lambert from PAYLOAD Technologies shared some advice

Most companies everywhere, including in oil and gas, are increasingly building what might be defined as a "software ecosystem" – a collection of software products which are deployed in a connected software infrastructure, and need some integration between them.

"There are very few software systems in a bubble. Most applications and data services are connected in some way, shape or form, even if they are connected manually," said Chris Lambert, CEO of PAYLOAD Technologies in Calgary.

Chris Lambert, CEO of Payload Technologies

"If you have [all of your software systems] working in isolation your processes will be less effective than in a properly integrated [system]," he said.

"It is not so much about finding the killer app - but finding the killer integration."

He was speaking at the 2021 PIDX Virtual Spring Conference in April 2021.

Mr Lambert has formerly worked in the medical, advertising and financial sectors, as well as oil and gas, with 20 years' experience doing software development and integrations.

"There are a lot of opportunities out there to drive more value from your software systems," he said. "Integrations are a foundation to enable aggregate solutions for the future."

PAYLOAD Technologies, based in Calgary, develops digital solutions for the oil and gas industry, with two main products around digital ticketing and digital manifests. It will shortly launch a product for streamlining the field ticketing process for carriers.

Single vendor vs best of breed

One way to minimise the amount of integration you need to do, is to look for a single vendor which provides all the functions you need but is maybe not the best on the market. "You have one system, one technology stack. You're buying a connected ecosystem of services and skills," he said. But the disadvantage is that a single vendor software implementation can be a massive project, hugely expensive and a lot of work to implement and manoeuvre or update once implemented.

The alternative, which can be called "best of breed," is where you find specialist tools which are best at doing specific tasks, and try to make them all work together.

For example, you find a technology which provides something you need, like field ticketing, and then try to integrate it with your other systems such as invoicing and production accounting.

There are lots of tools out there which integrate with other specialty tools, each focussed on a slice of what you're trying to solve.

Some of these tools are designed to be able to integrate at a deep level with other software tools.

As a customer, when you go for the best of breed approach, you should have more flexibility to change vendors and software products.

In contrast, when you go with a large single vendor solution, it can be harder to change, and harder to change out part of it for a component from another supplier. "The larger the investment you make, the more gravity there is," he said. "This can be a good thing or a bad thing. You have to consider the risks."

The single vendor solution will be typically good on breadth as opposed to depth, and able to solve a wide range of problems.

But best of breed solutions will often get updated faster, because they need to maintain their competitive edge as being the best of breed. They are often less customisable, since they are not designed as "one product fits all," as a single vendor solution would be.

But whichever approach you take, you may find you still need to build integrations with other tools you need to use, he said.

"Integration is an inevitable part of your day as your software ecosystem evolves. You shouldn't look to avoid integration, you should look to embrace it, and look to drive value out of those integrations."

Different integration types

Applications can be integrated at three different levels – in the data they use, as part of a process, and where the apps actually join together.

Integrating at the "data level" means data is extracted out of one application and entered into another.

Integrating at the "process level" means a process involves working on one application then another.

This basically means a process which involves more than one software tool. For example, if you use one software tool to fill in a form and get an output as an electronic file, and another tool to communicate that file, that is a simple process integration, he said.

There are software tools such as Microsoft's Azure Logic Apps, which can build workflows for process level integration, taking the user from one app to the next in the process.

Integrating at the "application level" means "two systems being able to effect each other's state."

Applications commonly integrate using REST Representational state transfer) APIs.

These integration types (data / process / application) are not exclusive – any integration would usually have some connection at the data level, and any automated process integration would have some degree of application integration.

Data integration approaches

One well-known approach to data integration is the "file drop" – when you can export a file in a format like csv from within an application. This is a low cost method to build, but can be complex to work with, because any mismatch, where the receiving application misreads the file, or puts data in the wrong place, needs to be fixed manually, he said.

"These can be good for one-off [jobs] for spreadsheeting, [but] you should probably try to minimise this in your organisation where possible."

A second approach, "data loading," is where you make a script to export data straight from a database. This approach can also be very fragile. "Changes in the data structure will blow it up. You'll spend days trying to investigate what's going on."

A third approach is to use an intermediary data connection system, or "ETL" (extract, transform, load] process, which will manage the work of taking data out, putting it in a suitable format, and loading it into the next system.

If the software tools exchange data via APIs, there are two points of fragility - if the API changes, and if the data structure changes, he said.

An ETL or data connector system can be managed by another company, which offers a service to keep up to date with any changes.

There are sometimes pre-built data connectors available on the market. "A lot of these connectors are pretty good these days, helping you deal with changes as they happen," he said.

Another approach, known as "data virtualisation," is where you can search and retrieve data, which is actually stored in multiple places, but it appears on one search.

You don't need to know how the data is formatted, or where it is physically located, in order to search it. The database itself stays in its original location. By not moving the data (as you would in an ETL process), you reduce the risk of introducing data errors (as data is moved), and you don't try to force a single data model on the data.

Another approach is the 'data lake' approach, taking disparate data sources and "mashing them into a single source of truth."

When we're looking for ways to connect systems together, but ensure that the system is not fragile (so one can keep running even if the other fails), "that comes down to data architectures."

"Your data architect should be looking for ways to isolate the change [of one system being unavailable]. If there is change that impacts the other side you have some way of incrementally mitigating that change."

"You may choose to put in some default data to replace missing data, to stop the system from collapsing."

A further approach is to set up a shared data space, where data is stored and accessed by the various applications, but not controlled by any of the applications. (Mr Lambert likens this to a military 'demilitarized zone').

An example is the service from Snowflake, a cloud based data storage company. It will store your data and make it available to your various applications, he said. You can build "business view layers" which massage the data to how you need to view it.

You can watch Mr Lambert's talk online at
https://register.gotowebinar.com/recording/766560130298445067
Starting at 25.00

"Touchless transactions" in oil and gas

Many consumer businesses have completely automated supplier payments – while oil and gas companies employ many people to process supplier payments manually. Engage's Rob Ratchinsky shared some ideas on how we can improve

There are plenty of examples from the consumer world where payments are made according to a formula or data, automatically, with no manual work involved.

Rob Ratchinsky, CEO of Engage, used the example of digital fitness company Peloton, where the coaches get paid partly on the basis of the number of participants in their online classes. You can imagine this all gets handled automatically. "They don't need to wait 2-3 weeks to get paid," he said.

Rob Ratchinsky, CEO of Engage

In the oil and gas industry, there would be enormous efficiencies if we could do the same thing. "It is amazing that what is happening in the business to consumer community is not coming into our world," he said.

"We have massive amounts of people working on trying to get our data correct."

Engage (www.engagemobilize.com) is in Denver and specialises in financial business automation for the oil and gas industry. Mr Ratchinsky was speaking at the PIDX Virtual Spring Conference in April 2021.

The key to automation is to record the transaction data as close as possible to where and when the service as actually provided, so there is less work needed figuring this out later, or checking someone's claim, he said.

It is important to eliminate as many human touchpoints as possible between client and vendor. With Peloton classes, no human being needs to get involved in the process of taking someone's registration for a class or their payment.

The data also needs to be standardised, so data from various transactions can be aggregated.

Further benefits of such "touchless transactions" are that company management can have much better oversight into business operations, with all data being accurate and up to date, including the balance sheet. And the same goes for vendors, who get the additional benefit of being paid on time.

One obstacle is that the oil and gas industry is wedded to certain document formats, which may be no longer necessary.

"Why does the invoice exist?" he asked. "Try to think about this existentially. [We should] take our current accounting processes, set them aside, and think about the way we are transacting.

B2C transactions do not typically need invoices.

Creating touchless transactions will probably require lots of system integrations, since, unlike Peloton, you are not building completely new software. You might want to integrate with systems used by your buyers, vendors, supply chain management, and accounting department.

"The slowdown to a touchless transaction is your own organisation."

Another factor is environmental issues – as they become more important in the industry, it will become more important to better manage the data which goes together with them, and do it in an automated way.

Better ways of working

A typical procurement workflow in a company, for a task like to construct a well pad, might start with asking a supply chain team to set up a contract, and then someone in the supply chain team has to contact hundreds or thousands of vendors. After the contract is agreed, contact with vendors is made with e-mails and phone calls.

"We have folks show up, do the work, your company man may have gone fishing so they are left chasing signatures. They are trying to get approval at the field to get it back to their office. They have to input the data into multiple systems. Companies are working with 50+ invoicing setups to get paid."

Some operators say that 39 per cent of invoices get disputed before payment, because the data doesn't match the vendors' data, he said.

"As we move to touchless transactions - we want to reduce that to sub 2 per cent."

In a "touchless workflow", as much data as possible would be gathered directly from sensors. "We don't need the human element."

The data about timing, such as how much time was spent drilling, should already be available. "We're all running on the clock," he said.

People and vehicles can be tracked.

When the work is done, the workers submit a 'digital ticket', which can be validated against all the data points, so you can be sure the work was done as the contractor said it was.

For example, if the work is hauling water from a well site, you can compare the data about the water hauled with the sensor data showing how much the water level in the tank changed.

If it was chemical treatment work, you can verify when the workers were on location, and how many gallons they used in the well.

Other examples are services for sand delivery, snow removal, welding, or charges for emissions.

If you are working with outside auditors, you want the audits to take place as close to the well head as possible. "We can blow through the entire accounting process because the approval was already made."

"When you start moving your business into this world of auto validation based on data you're going to see a reduction in cost."

Videos and slides from the PIDX event are online at PIDX Event Recordings - PIDX: The Petroleum Industry Data Exchange

Mr Ratchinksy's talk can be viewed at

https://register.gotowebinar.com/recording/6706621121845524742

From time 5.00

BCG – digital leaders "more profitable"

Boston Consulting Group (BCG) analysis shows that oil and gas companies which are leading in the digital realm are also showing better financial results

Boston Consulting Group "strongly believes [digital] can be one of the levers the oil and gas industry has to embrace, to build a better future for itself," said Pietro Romanin, partner with BCG in Milan, speaking at a webinar organised by Cognite.

Oil and gas companies which BCG considers "digital leaders" have generated much higher shareholder returns, lower break even and higher cash flow, he said.

One problem many companies see is that they cannot get from having a few digital 'use cases' to where they are using digitalisation for their 'end to end' processes. "If you really want to unlock value in upstream you need to bring all these different use cases together in a seamliness environment," he said.

Mr Romanin added that in terms of effort, 20 per cent should go on technology, IT and data itself, 10 per cent on algorithms, and 70 per cent on the business transformation.

It can be good to focus on one good use case as a first step, which is something you might be able to get to scale, "rather than try things here and there".

Eventually you want to "reinvent and optimise the core process end to end."

If people are still working with lots of manual steps, "you are spending money on digital stuff you will probably abandon down the road."

"You have to be obsessed with the 'end user," he said. "Try to understand what is their 'journey ' the worker, maintenance, technical production engineer, logistic engineer does every day, what are his routines."

Anything you build needs a strong IT / data platform behind it, and integrated data, not silos. "We can take the occasion to rethink your underlying systems," he said.

And doing work in small chunks, each delivering value, is important.

"You cannot promise the world is changing 2 years from now. Most people would have lost the appetite after 3 months."

Digital technology needs to be seen as a priority of the company leadership.

It can start as someone's pet project, but "at a certain point you have to pump it up like a balloon that can fly by itself," he says.

And to maintain the leadership support, it is important to have visible and tangible results.

"At a certain point you need to change gear and understand what is driving the value. it is the only way to make change sustainable."

Keep targeted

Many companies are rolling out large data management programs, which are taking a lot of people's energy, when they may better off if the efforts are targeted, he said, with a "more pragmatic use case approach," said Michael Buffet, managing director and partner, Oslo, with Boston Consulting Group.

"You start from friction points, expand, modify the underlying ICT infrastructure, replicate that."

But breadth is also important. To be successful at digital technology, digital should be "embedded at all levels of the organisation, in particular in the businesses where most of the value is created,"

It is also useful for oil and gas companies to work to build a digital ecosystem which incorporates their suppliers, so stretches beyond the company. Often suppliers are not able to invest in this themselves, so operators "have no choice but to drive and fund digital innovation."

If what you develop doesn't go "from end to end", it is better not to start, he said.

"People can be a bit locked into processes. [But] there's a limit to which you can improve a standalone process."

About 40 per cent of BCG's current activities in the oil and gas industry are now about digitalisation, and Mr Buffet has personally been involved in a large number of such projects, he said.

Consulting projects include developing digital strategy road maps for clients, and finding ways to remake their core workflows, so they can take advantage of digital technology.

BCG also has a team of 1000 data scientists and its own digital investment / incubation venture.

Infield and Remote – two new Cognite products

Cognite has developed two new software tools, "Infield", to support oil and gas field workers doing maintenance, and "Remote", to support better remote (office) management of assets

Cognite, a company which describes itself as a "data operations platform", has developed two new software tools. "Cognite Infield", to support field workers doing maintenance, and "Cognite Remote" to allow better use of asset information remotely (from the office).

They build on Cognite's core data platform "Cognite Data Fusion", which companies can use to bring all their live operational data together from multiple sources, and make it available to applications, integrated and contextualised.

The Infield software is designed to support field workers to do maintenance tasks in the most effective way, and ensure they have all the relevant data available to them, said Cathrine Stenstadvold, director of product management, Cognite.

The software can run on phones, tablets and PCs. It is already used by a number of oil and gas companies, she said.

After a worker has been issued with a list of tasks which need to be done, the worker can use the software to re-arrange the order of tasks to something more practical, such as grouping certain tasks together because they are on the same equipment.

Then the software can be used to prepare for the job. It should enable the time needed to be reduced from hours to a few minutes, she said.

The worker can access all the relevant data for the equipment they are maintaining, see what specific tasks are involved, and what tools it needs.

They have access to data such as 3D models, sensor data, equipment data and past work orders. This should be very helpful if they are working on complex equipment, or equipment they are not familiar with.

The underlying Cognite data "engine" can scan paper documents for tag names, so they can be integrated with the digital system, bringing up a scan for the right paper document, if needed.

They can also see information about equipment upstream and downstream a process chain or pipeline from the equipment they are working on.

There is a 'smart' tool for reporting, where you can add photos, data, comments and requests. The text can be entered using 'speech to text' functionality, which makes it easier for someone wearing gloves.

If the worker is investigating a possible problem, or data "anomaly", they can bring up historical data, which may show when a certain change occurred. Then they might be able to see what else was happening at the same time. For example, a problem may have begun immediately after a certain maintenance task was done.

Altogether, it has already been proven to "speed up preventative maintenance between 50 and 80 per cent," she said.

One customer operating an asset in the North Sea found that after using Cognite Infield, he no longer needed paper documents, and sent Cognite a photograph of his office bin to prove it.

"Normally it is filled with P+IDs [piping and instrumentation diagrams] and technical documents and piles of data," she said. "Now it was just Post-it notes and reminders. He sent me the picture to thank me."

Cognite Remote

Another new offering, "Cognite Remote", is for supporting the management of assets remotely (from the office).

It provides engineers with asset structural data, from CAD models or laser scans, combined with operational data, such as from sensors or maintenance reports.

The information for, say, a FPSO would normally be stored in many different computer systems. With Cognite, it is all available on one system, so it is easy to find and use, says Stein Danielsen, Chief solutions officer with Cognite.

This includes data from all the sensors (there can be 100,000 sensors on an FPSO), and documentation.

Cognite connects directly with the data in its source systems, the data is not moved.

The software can extract all the relationships from the data. It can put together 3D models of what the asset looks like, which you can click into to get more information. The equipment has over 30,000 tagged items.

You can break the 3D model into modules, and see what it would look like with different parts removed.

You can do measurements on the 3D model, for example to check how much space is available for moving equipment, or if you have room for a scaffolding.

"I don't need to wonder about what type of lubricant, or what the max torque is, I get all that directly accessible," he said.

You can add a point cloud laser scan, which can be useful if the data about the platform is not completely up to date.

You can add in visual images, which can be useful for example to map or grade corrosion. These can be taken from drones, helmet mounted cameras, CCTV, mobile phones.

The work of building the model starts with 'ingesting' all available data into the Cognite Data Fusion software. This can include data from the engineering / construction stage, such as computer aided design (CAD) models, if they are available.

Compounding small projects

A digital transformation is not a single project, but the compounding of many small projects, said Petter Jacob Jacobsen, Vice President of Business Development - Head of Oil & Gas, Cognite.

"What makes the digital transformation transformative is essentially the aggregate of changing hundreds of workflows, creating hundreds of ML and hybrid physics models, and making hundreds of data driven optimisations to make decisions in real time."

But it can only happen if the cost of making all of those changes is low enough. "If the process of delivering even one of these changes requires almost a [business] program in itself, then the business case will kill any effort to really get to that transformational change," he said.

Cognite's Infield software, for field workers doing maintenance