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The First

SPE Norway magazine

To gather members
To share knowledge

Engineering in Arctic
Environmental compliance
Geo Estimations for Field Development
Well Engineering

Art by Ivan Koulakov, Ph.D., Habil., Prof.,Corr. Member of Russian Academy of Sciences. Vice-director IPGG, SB RAS, Head of Seismic Tomography Lab. Original is in Schlumberger office, Moscow.

Inside this issue

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Dear SPE Norway members,

We are facing the end of yet another year and finally, after few years with downturn, the outlook is positive. Stabilized oil price has paved path to optimism and shifted focus from cuts to innovation, digitalization and process efficiency. You will see these topics reflected in this year's last magazine issue.
We are also happy to see the growing activity in local SPE sections that constantly strive to involve Oil&Gas community in knowledge sharing and networking. The sections provide a valuable platform not just for experienced professionals but also for students and young professionals who have just entered the industry. I would like to encourage all of you to be active in supporting your local section by engaging in it's development and actively participating at the events. For those, who are contributing their free time to organize SPE events, your engagement is the best reward.
Finally, I'd like to wish everyone nice holidays. Whether you will spend it offshore with your colleagues or at home with your family – hope you will have time to reflect on everything you have achieved this year and to be proud of yourself!

On behalv of the Editorial tean,
Giedre Malinauskaite

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Editorial content

News from SPE Norway sections 4

Technical Articles

Engineering in Arctic

Degradation mechanisms of Arctic offshore topsides equipment: Risk based inspection perspective. *Y. Z. Ayele, Østfold University College and A. Barabadi, UiT The Arctic University of Norway* 8

Environmental compliance

The environment means business for oil and gas. *I. Thomas, Lloyd's Register* 12

Geo Estimations for Field Development

The role of Geophysical Uncertainty in Field Development concept selection. *S. Romundstad, I. Meisingset, D. Krasova, First Geo; T. Forde, Aker Solutions; and S. Tresselt, IPRES* 16

Decision models - Geological modelling to guide decisions. *A.-L Hellman and T. Hultgreen, AGR* 22

Well Engineering

Separating solids during CT Clean Out & optimizing well production North Sea August - September 2017 Case study. *G. Malinauskaite, FourPhase* 25

Relief Well Injection Spool (RWIS) — Enables single relief well contingency. *M. H. Emilsen, add energy and B. Morry, Trendsetter Engineering* 26

Leak detection - Identification of source of low rate sustained annulus pressure. *M. Volkov and R.-M. Greiss, TGT Oilfield Services* 28

SPE Oslo
SPE Stavanger
SPE Bergen
SPE Northern Norway
SPE Trondheim

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Dear SPE Members!

I want to use this opportunity to thank you all for your participation and engagement with SPE during 2017.
We have had an active year with several events and technical lectures, and I hope many of you have had the opportunity to join any of these sessions to obtain new knowledge, but not a least to also make some new connections.
Though we have gone through a challenging environment in the O&G industry, I think we all can agree there is a growing optimism in the market. No matter what next year will offer, SPE will continue to support its members and sponsors through sharing technology knowledge that eventually can support and grow our businesses. May-be most important, SPE will be here as your arena for networking with other colleagues that may offer you solutions you may need in future, or even offering you new personal development.
Please stay connected through our web site and follow us on the social medias.
A great thanks to all our sponsors, members and board volunteers – wishing you all a Merry Christmas and a Happy Prosperous New Year!

Sincerely,
Vidar Strand
SPE Norway Council/SPE Stavanger Chair
Sr Sales Manager, Baker Hughes, a GE company

News from Stavanger Section

It has been a busy fall season for **SPE Stavanger** with an increasing member count and well attended technical meetings.
We look forward to wrap up 2017 with a fantastic Xmas Party December 1st.

December 1st: Xmas Party

September 13th:
The kickoff presentation about how Spectral Noise may characterize Dynamic Reservoir Conditions by TGT Oilfield Services attracted 50 guests.

October 4th:
Efficient P&A with Formation as Barrier lecture series by Aker BP, ConocoPhillips and Statoil attracted a record high number of 150 guests.

October 10th:
Tore Øian from SPE Stavanger opened the Students' Bachelor's & Master's Day at the University of Stavanger.

October 18-19th:
SPE Stavanger was present at our own stand at the exhibition. Chairman Vidar Strand participated in a panel debate.

November 10th:
SPE Young Professionals Wine Tasting had 55 social guests.

November 15th:
Geothermal Drilling & Energy Production Workshop in cooperation with CGER, Statoil and Huisman attracted 75 guests.

By Tor Jørgen Verås

News from SPE Oslo Section

Company Presentation by ConocoPhillips 28.09.17
Representatives from ConocoPhillips were once again present at UiO for a company presentation. Director of GGRE Skills and Competency Rune Tveit and Certification Specialist Tore Mjølsnes led the presentation and was accompanied by a graduate geologist and geophysicist. It was a very successful afternoon filled with an uplifting presentation, rewarding discussions and plenty of pizza. SPE Oslo Student Chapter really appreciate the consistency of ConocoPhillips annual company presentation and already look forward to next year.

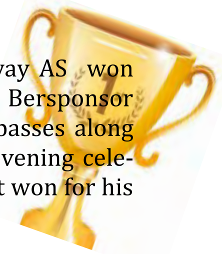
The winning team

Fall Semester Quiz 29.09.17
On Friday 29. of September, the fall semester quiz was organized by the Oslo Student Chapter. The quiz gathered a great number of students, ranging from bachelor to PhD, for a social night of tricky questions and cold beers. Quizmaster Ole Kristian let the teams through rounds like oil&gas industry, general knowledge and music. The winning team, this time consisting of master students, happily received their well-earned movie-tickets as prize.
The next quiz will take place in January/February.

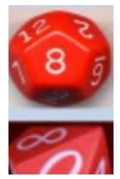
By Ole Kristian B Hansen

25th of January 2018, the SPE Oslo Student Chapter is arranging a "**Meet and Greet**" event at the University of Oslo. The intention is that different companies within the Oil and Gas Industry will participate and represent their companies where the students will have the opportunity to come and ask for information. The main aim of the event is to gather students from the different disciplines so that they can get a perspective on what is like working in the oil and gas industry, further learn about writing their thesis, internships – and graduate programs.

Oslo Kick Off event 06.09.17
State Secretary Ingvil Smines Tybring-Gjedde from the Ministry of Petroleum and Energy delivered an inspiring talk to our members during the kick off event on September 6.



The Man in the Industry 07.09.17
Bernt Rudjord, Senior HSE Advisor, Lundin Norway AS won the SPE Oslo "The Man in Industry" Petro Quiz! Bersponsor Rock Flow Dynamics and 2 free SPE Oslo event passes along with the memorable powerbank! It was a great evening celebrating our dear male colleagues in the industry!nt won for his company tNavigator licence from the event



TechNght 26.09.17
It was the great dinner meeting with guest from Australia, where we learned on the application of Chance of Success (COS) Predictions in exploration from Mr, Balakrishnan Kunjan who has more than 40 years' industry experience from APAC and India.

SPE & EAGE TechNght 14.11.17

On November 14, three skilled speakers, two professional organisations, one topic - **The geological overview of the Barents Sea** collected 74 attendees! Erik Henriksen, Natalia Kukina and Jon Halvard Pedersen made amazing presentations, allowed learning from fundamental knowledge to true science implementation in exploration. The evening was followed by wonderful Spanish tapas dinner providing nice atmosphere for socialization.





TechNght 23.11.17

It was a very nice evening! Mikhail A. Mosesyan, Drilling and Well Manager, LUKOIL Overseas North Shelf AS, Norway delivered the great overview in synergies between NCS Barents - Timan-Pechora - Offshore Caspian in Drilling and Well Construction Industry. The presentation was very well received and caused big interest for discussion later, during the dinner.

Traditional X-mas Dinner Dec 7 2017

We have launched a new section website!

It was time for SPE Bergen to renew it's digital presence and to improve the way we present latest news to our members. Therefore, we have launched a website where we will be posting latest news, event calendar and pictures from our events. Take a look at www.spebergen.no!

News from SPE Bergen Section

SPE Bergen TechNights kick-started in new historical location!

SPE Bergen had first TechNight in the new location – Nøsteboden. Nøsteboden is a historic and unique location in Bergen harbor with authentic interior from the previous century. Our First TechNight there, with presenters from Statoil and Cabot, has gathered a full house – more than 50 participants came to network and see the presentations!


Company presentations with the SPE Student Chapter in Bergen

The goal of the student chapter is to bring the industry and students in the Bergen area closer together. One of the most important and effective ways to achieve this goal is to host company presentations at the universities. We invite all petroleum related companies, big and small, to visit the university to meet with the students and to present current projects, internships or graduate programmes. Students gain valuable insight into the industry and its opportunities while company representatives can communicate directly to potential candidates and the next generation of scientists and engineers.

On the 27th of September we hosted a company presentation with ConocoPhillips Norway at the University of Bergen. This has become an annual tradition where both experienced professionals and recent graduates working in ConocoPhillips present exiting projects and explain opportunities for current students through summer internships and their graduate programme. Food is served after the presentations, and students and company representatives engage in more informal discussions about topics ranging from the application process to the future of the industry. Feedback from students at these events has been very positive, especially as the number of petroleum related company visits to the university has dropped since 2014. It is evident that the presence of potential future employers at the university is a great reassurance for students aiming for a job within the sector.

For several years now, we have also had the pleasure of hosting a company presentation by Lundin Norway during the spring semester. This event has been especially popular within the vibrant geoscience community at the University of Bergen. The student commitment both Lundin Norway and ConocoPhillips have shown through the past three years of low oil prices has solidified their place as popular future employers among the student population in Bergen.

To attract the best students to the petroleum industry, the student chapter in Bergen is working to bridge the gap between them. The recent company presentation with ConocoPhillips is a great example of a way for both students and a company to get to know each other and mutually benefit.

Knut Ringen Viten
Student Chapter Vice President, SPE Bergen.

Company presentation with Lundin Norway, 2017. Foto:

Degradation mechanisms of Arctic offshore topsides equipment: Risk based inspection perspective*

by Y. Z. Ayele, Østfold University College and A. Barabadi, UiT The Arctic University of Norway

Yonas Zewdu Ayele, PhD
Associate Professor, Østfold University College, Norway

Abbas Barabadi, PhD
Associate Professor, UiT The Arctic University of Norway

Introduction

As oil and gas companies in the Arctic attempt to maximize the value of each project and optimize their portfolio of investment opportunities, it has become vital to evaluate the integrity of topsides static mechanical equipment. Effective and regular inspection activity play a crucial role in avoiding business interruption and, reducing the risk of failure. It provides a knowledge about the condition of the topsides static mechanical equipment. In addition, it helps to keep a plant in "as-built" condition and consequently continuing to have its original productive capacity [1]. Increasingly, innovative asset integrity strategies such as risk-based inspection (RBI) methods and tools are being implemented to meet these goals. RBI, in general, is a process that identifies, assesses and maps industrial risks, which aids in the identification of high priority items (i.e., those with high risk) vs. low priority items (i.e., those with low risk). The main aim of RBI tool is to achieve safe operating conditions at minimum inspection cost, and protect human life and the environment from any possible damage during operation.

When we operate in Arctic region, however, it is prudent to accept that operational loads may vary beyond design levels, and that material degradation may be greater than anticipated. Moreover, degradation mechanisms (failure modes) in cold climate are different comparing with 'normal' operating environment. The safety factors used at the design stage may not, therefore, guarantee through-life plant integrity [2]. Hence, probabilistic consideration of the ''peculiar'' mode of failures, due to the Arctic condition, as additional risk, should be carried out to determine the most probable levels of damage, and to check the adequacy of the design loads and resistance values. Further, there are no specific standard/ recommended practices for carrying out RBI analysis for equipment operating in the harsh Arctic conditions. RBI strategies, especially in Arctic region, must take account of the risk of equipment failure due to icing phenomenon and low temperature, in addition to the 'conventional' risk of equipment failure; that is, both the probability of failure and its consequences have to be considered. Using traditional RBI approaches to equipment operating in the harsh Arctic conditions, risk tends only to be considered implicitly. There is thus a real concern that high-risk and low-risk areas may not be clearly identified. This may then mean that low-risk areas are monitored to an excessively high level which leads to needlessly high inspection costs, while high-risk areas may not all be afforded sufficient attention and priority. Without the explicit consideration of risk, it may not therefore be possible to demonstrate that the equipment integrity of the plant has been satisfactorily characterized.

This article discusses the peculiar modes of failure in the Arctic climate and, suggests solutions to fill the gaps that are available in the current RBI practices.

Peculiar modes of failure in the cold Arctic climate

A failure mode is defined as the manner in which a component, subsystem, system, process, etc. could potentially fail to meet the design intent [3]. Examples of potential failure modes include corrosion, embrittlement, torque fatigue, deformation/ buckling (due to compressive overloading), cracking/ fracture (due to static overload, the fracture being either brittle or ductile), failure due to the combined effects of stress and corrosion, failure due to excessive wear, etc.

The peculiar operational conditions of the Arctic, such as ice and snow, cold temperature, polar low, snowdrift, etc. will cause significant challenges if inspection/ maintenance is needed. For instance, many materials experience a shift from ductile to brittle behaviour if the temperature is lowered below a certain point. The temperature at which this shift occurs varies from material to material. It is commonly known as the "ductile-to-brittle-transition" temperature (DBTT), or the "nil-ductility transition" temperature [4]. Further, low temperatures can adversely affect the tensile toughness of many commonly used engineering materials. Tensile toughness is a measure of a material's brittleness or ductility; it is often estimated by calculating the area beneath the stress-strain curve [4]. Ductile materials absorb significant amounts of impact energy before fracturing, resulting in tell-tale deformations. Brittle materials, on the other hand, tend to shatter on impact. Materials with high ductility (i.e. a tendency to deform before fracturing) and high strength have

This article is shortened (from the IEEM 2016 conference paper) and adapted for The First SPE Norway magazine

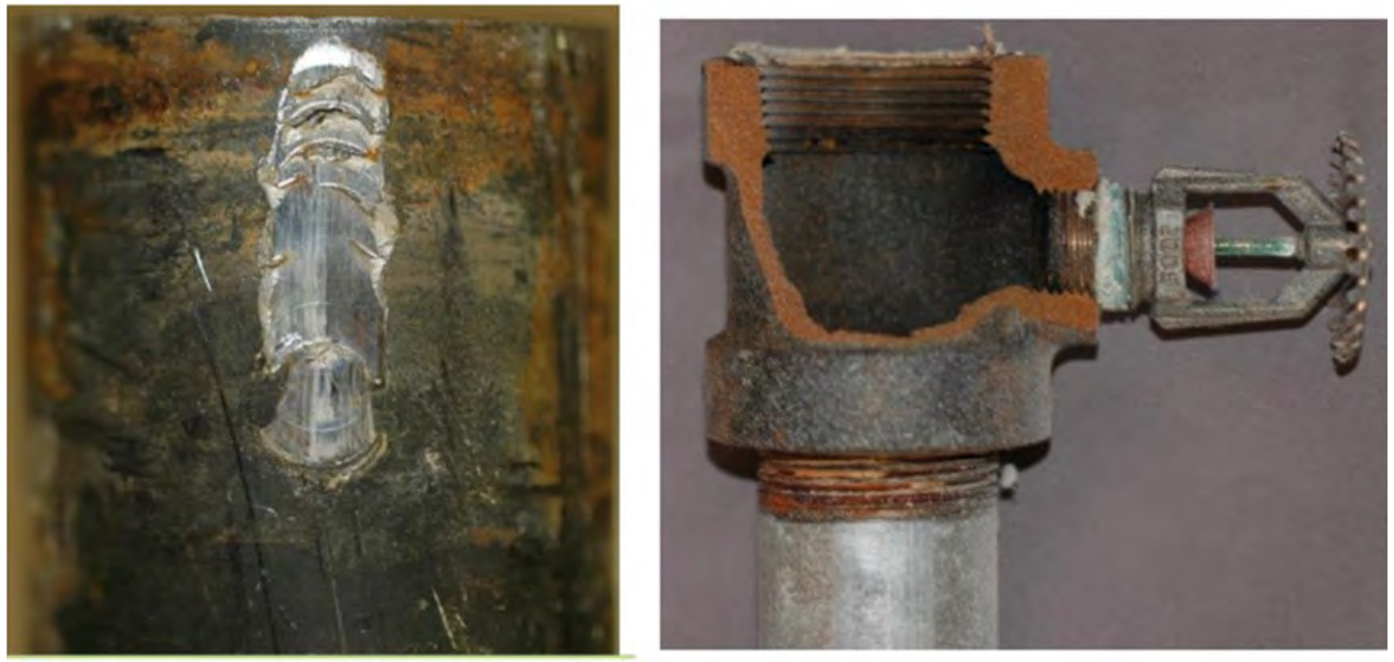


Figure 1. Freeze-up failure. Source: Crane Engineering 2014

good tensile toughness [4]. Depending on the material, tensile toughness can be very sensitive to temperature changes.
The peculiar modes of failure in the cold Arctic climate are (but not limited to):

- ***Freeze failure:*** Freeze failures is a component failure due to volumetric expansion of freezing water (Fig. 1). Freeze failures often yield multiple cracks. Crack initiations generally are critical and need timely detection. Freeze-up failure can induce large-scale deformation. The main factors that affect the crack/fracture of a material in cold climate are:

- *Low temperature.* For instance, steel may behave as a ductile material above, say, 0°C but below that temperature, it becomes brittle. Embrittlement of steel, plastic and composites causing failures at loads that are routinely imposed without damage in warmer climate.
- *Thermal shock.* Occurs when a thermal gradient causes different parts of an object to expand by different amounts.

Figure 2. Cavitation failure. Source: Corvias

- ***Cavitation failure:*** Cavitation is caused by the presence of gas bubbles under high pressure being suddenly subjected to a low pressure. In general, there are two principal types of cavitation: vaporous and gaseous. Vaporous cavitation is an ebullition process, which takes place when the bubble grows explosively in an unrestrained manner as liquid rapidly changes into vapour [5]. On the other hand, gaseous cavitation is a diffusion process, which occurs if the pressure falls below the saturation pressure of the non-condensable gas dissolved in the liquid.

In cold climate, extremely low temperature causes many fluids to congeal, which means that it cannot flow through mechanical systems efficiently. This fluid immobility can starve a pump, which causes potentially harmful vaporous cavitation in the system. Further, cavitation failure also results in high fluid and mechanical friction, as well as lubricant starvation for bearing surfaces. Fig. 2 shows the impact of extremely low temperatures wreak havoc on mechanical systems.

- ***Freeze-thawing failure:*** The other peculiar mode of failure in the cold climate is the freeze-thaw failure. The freeze-thaw conditions cause random cracking, surface scaling and joint deterioration. Fig. 3 illustrates the process of freeze-thawing failure.

- ***Fretting wear failure:*** Cold climates cause failure of lubricant to perform adequately, thereby resulting in increased wear rates. Increased loss of lubricants and coolants can cause fretting wear. In general, fretting is a wear phenomenon that occurs between two contacting surfaces; initially, it is adhesive in nature and vibration or small-amplitude oscillation is an essential causative factor [6].

Rainwater or snow-melt collects in cracks.

When the temperature drops, the water freezes and expands.

The increased in volume of the ice exerts pressure on the cracks, causing them to split further open.

When the temperature goes up, the ice melts and, the water seeps deeper into the cracks.

When the temperature drops, the water freezes again, and the process repeats itself, and so on.

Figure 3. Freeze-thawing failure process

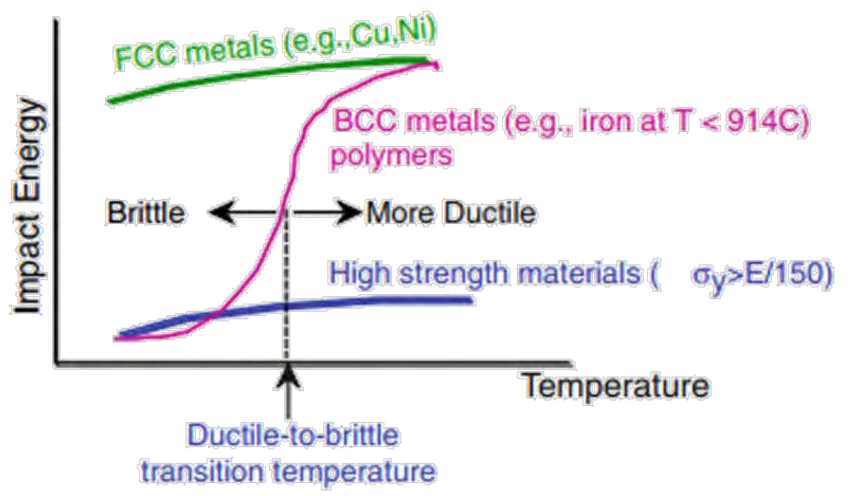


Figure 4. DBTT curve. Source: Callister and Rethwisch [7]

Proposed solutions

- ***Selecting proper alloys:*** The transition temperature of steel is affected by the alloying elements in the steel. For instance, manganese (Mn) and nickel (Ni) reduce the transition temperature. Thus, for low-temperature work, a steel with manganese and nickel alloying elements is preferred. Fig. 4 illustrates the ductile–brittle transition temperature (DBTT) curve for various metals.

- ***Inspect equipment regularly:*** Since Arctic and sub-Arctic, regions possess large variation in temperature during a short period of time; it might be beneficial to consider increasing inspection intervals in these regions. Frequent periodic inspection to look for cracking, nicks, or chipping will help prevent accidents. In addition, increased frequency of monitoring processes such as non-destructive testing (NDT) may also help, if the risk of failure is severe. Moreover, to reduce the fretting failure, using oxidation inhibitors in oil or using oil of lower viscosity, and re-lubricating frequently can be beneficial.

- ***Winterization:*** To reduce the frequency of equipment failure in the cold climate, winterization measure can be implemented. In general, winterization is a process of enclosure of the most susceptible areas (equipment). By implementing winterization measures, materials and equipment shall be adequately protected by the provision of heating or insulation; and consequently, reducing the failure frequency. This can ensure the safe operation of all systems and equipment. It shall also ensure that personal can conduct the required tasks in an ergonomically sound way, with respect to temperatures, wind, visibility and restrictions imposed by personal protective equipment.

- ***Uncertainty reduction:*** To reduce the uncertainty during RBI process, various approaches can be employed. For instance, the probability of failure and the consequence associated with a failure, estimates shall be made by integrating the probability distributions of air temperatures. Moreover, the lowest anticipated service temperature shall be defined. Further, the effects of thermal changes on mechanical/structural behaviour and human capability shall be considered as part of the design and operation of the topsides static mechanical equipment.

Concluding remarks

To date, there are no specific standards and, recommended practices or software tools for carrying out RBI analysis for equipment operating in the harsh Arctic conditions. Moreover, due to lack of experience and data, there are a wide range of sources of uncertainties, such as model, parameter, and incompleteness uncertainty. Hence, it is concluded that for safe Arctic offshore operation, development of RBI procedures that are specifically intended for the analysis of topsides static mechanical equipment installed in Arctic area is vital. That means that revising the current RBI standards, recommended practices and technical documents, by considering the peculiar Arctic operating environments are necessary. Further, understanding the peculiar modes of failure in the cold climate can help to establish risk ranking among individual equipment items in order to optimise inspection efforts and reduce costs. It can also help to extend inspection intervals beyond statutory requirements.

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The environment means business for oil and gas

by I. Thomas, Lloyd's Register

Converging environmental standards are a window of opportunity to be more efficient and productive

Ian Thomas
Principal Consultant,
Lloyd's Register

Environmental standards in the oil and gas industry are ever-changing and often underestimated. Governments in Europe and globally have established best practices to preserve, protect and improve the quality of the environment and ensure the prudent, rational use of resources. These standards apply to exploration and production activities, across asset types (Figure 1). Environmental impacts and compliance issues are wide ranging (Figure 2). Notably, they include reducing, as far as possible, the occurrence of major accidents; protecting the environment and dependent economies against pollution; and establishing suitable response mechanisms in the event of an incident.

Challenges to date

Meeting evolving environmental standards has proved challenging for an industry facing a downturn. Operating in a tough economic climate, where costs must be cut and all eyes are on the balance sheet, hasn't helped. It has been tempting to see the maintenance of certified management systems covering Health, Safety, Environment and Quality (HSEQ) as one overhead too many. The signs are there, as organisations defer transition to the new ISO standards (9001 and 14001) or, worse still, consider dropping certification on the grounds that the costs involved are increasingly difficult to justify. All the while, major environmental incidents continue to appear in the media.

What is required right now is the very opposite stance. A rethink will not just be to the benefit of the environment, but also to efficiency and productivity because standards are converging.

Convergence means new opportunities

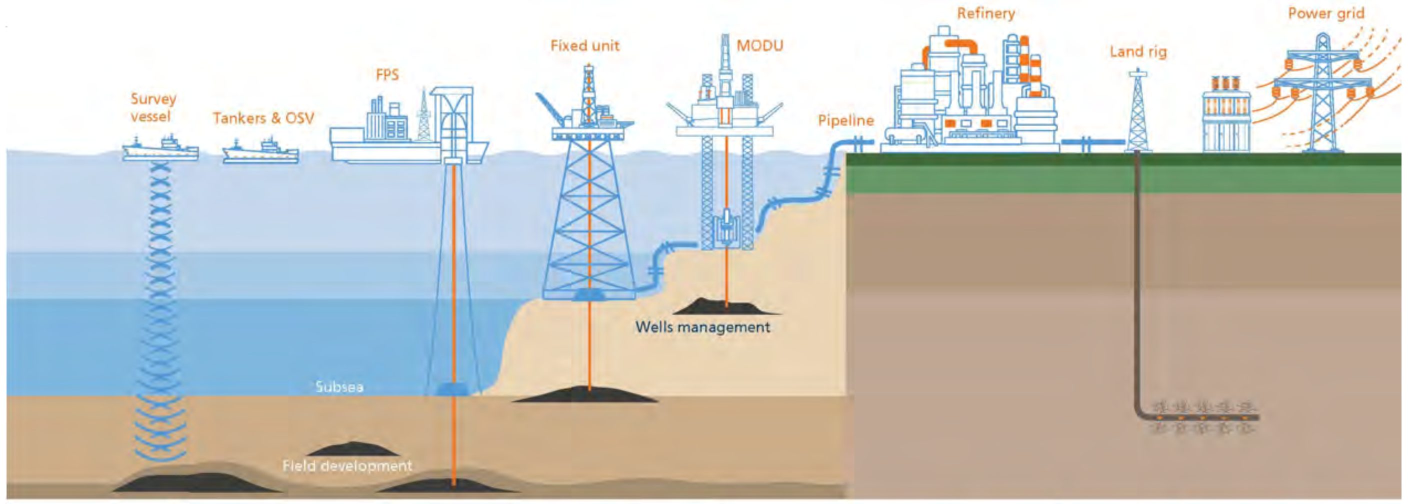
European and UK standards are maturing, taking an enterprise risk management route that can only make them more relevant to the industry. Two events are driving positive changes.

First, the EU Directive (2013/30/EU) on the Safety of Offshore Oil and Gas Operations, and Safety Case Regulations (SCR 2015) in the UK, require a coordinated approach to risk management. This comes in the form of a combined Safety and Environmental Management System (SEMS). In the past, management systems for safety and environment have largely been treated as separate entities. The revised standards promote integration, facilitating compliance and continual improvement. This really is good news for business, however there are nuances that need to be understood. A major accident hazard (MAH), such as a fire or explosion, is a well-established industry term. A major environmental incident (MEI) means an event that has occurred as a result of an MAH. All other incidents, however serious, are classed as pollution incidents, from gas leaks to excursions of oil in water and breaches in atmospheric emissions' permits. Used properly, SEMS should help operators drive down costs and limit liability in all areas mentioned.

Secondly, the requirement for a combined SEMS, which needs to be met by July 2018 for existing production assets, coincides with the timetable to transition from ISO 14001:2004 to ISO 14001:2015 for environmental management and ISO 9001:2008 to ISO 9001:2015 for quality management. ISO model changes mean the suite of standards share a similar structure. With this convergence lies a prime opportunity for the industry to review and align SEMS documentation, taking maximum advantage of common management system elements.

Such a novel approach offers numerous advantages. Integration will minimise compliance work and duplication of activities. It will avoid implementing a piecemeal, often protracted approach to addressing compliance requirements, as is invariably the case when seeking to address 'low hanging fruit'. In addition, there are significant productivity benefits to be realised from a dovetailed approach, covering not just quality and environmental management, but safety management (ISO 45000:2015), asset integrity (ISO 55001:2015) and energy management (ISO 50001:2015). After all, why shouldn't activities for reducing spills, for instance, be linked to maintenance? Why can't energy efficiency regulations be an opportunity to cut costs and improve environmental performance at the same time? Now, they can.

Added value can be achieved by using the common elements of ISO 14001 environmental management and ISO 50001 energy management standards to address other EU Directive compliance requirements for 2018. ISO 50001 is strongly recommended as the best path forwards; its management system model is based on continual im-



	Wells	Subsea	Field	Tankers & OSV	FPS	Fixed Unit	MODU	Refinery	Land Rig	Power Grid	Pipeline
Development	✓	✓	✓							✓	✓
Concept	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
FEED	✓	✓	✓	✓	✓	✓	✓			✓	✓
Sale & Purchase	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Construction		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Commissioning		✓		✓	✓	✓	✓	✓	✓	✓	✓
Operations	✓	✓	✓		✓	✓		✓	✓		✓
Decommissioning	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓

Figure 1. Operational activities, oil and gas exploration and production

	Spills, blow out & leaks	Air emissions	Water use & disposal	Soil & Stability	Noise & Vibration	Processes & Major Accident / Environmental Hazards	Hazardous Substances & Chemicals	Solid wastes	Biodiversity (Flora, Fauna & Ecology)	Physical presence, navigation hazard, aesthetic	Resource use (Community and natural)	Community impacts (Social, economic, heritage, aesthetic, cultural, land use & transportation)
Oil & gas exploration Offshore	✓	✓		✓	✓	✓	✓	✓	✓		✓	✓
Oil & gas production offshore	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓
Oil & gas exploration Onshore	✓	✓	✓	✓	✓	✓	✓	✓				✓
Oil & gas production onshore	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓
Offshore & and onshore renewables (wind, wave, solar)									✓	✓		✓
CHP power generation & transmission	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓
Marine operations	✓	✓	✓			✓	✓	✓	✓			
Mining of natural resources	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Decommissioning	✓	✓	✓	✓		✓	✓	✓	✓	✓		✓

Figure 2. Environmental impacts and compliance issues

provement (like ISO 9001 and 14001), making it simpler and more efficient for organisations to integrate energy management into their overarching quality and environmental management activities. By screening an energy portfolio and thinking strategically, the result can be assets that cost less money to run, daily.

Further value can also be realised by combining the common elements of the asset integrity ISO 55001 framework into a unified approach to HSEQ risk management, assurance and compliance. In addition, applying aligned procedures will help meet OSPAR requirements. OSPAR Recommendation 2012/5 promotes a Risk-based Approach to the Management of Produced Water Discharges from Offshore Installations and is intrinsically linked to ISO 140001 (environmental management).

Business tool, not barrier

The possibilities with the new ISO standard model are vast. A further opportunity is worth highlighting: using ISO 14031 (environmental performance evaluation) to coordinate environmental objectives and targets, deriving the best value possible. Several of our clients have adopted this approach, which allows owners and operators to think more creatively about their environmental risk management responses. Once the objectives and metrics are clear, a range of solutions can simply be brought into play on an ongoing basis, from enhanced procedures, calibration techniques and maintenance regimes to personnel training.

With an integrated approach, an environmental management system becomes a business tool, rather than an operational barrier. It helps manage risk aspects and impacts across an asset's lifecycle, from steady state to life extension and, ultimately, decommissioning.

Looking at the oil and gas landscape and horizon, there are a couple more compelling reasons to adopt an integrated approach.

Environmental expectations are evolving

An important shift is the elevation of environmental risk from the field to board level. New standards put the environment into a company's corporate management policy, lifting it from a paragraph or two to a matter of strategy and leadership. Elsewhere, environmental management requirements will also grow. As expectations of what constitutes an environmental risk becomes clearer to industry, the scope will broaden.

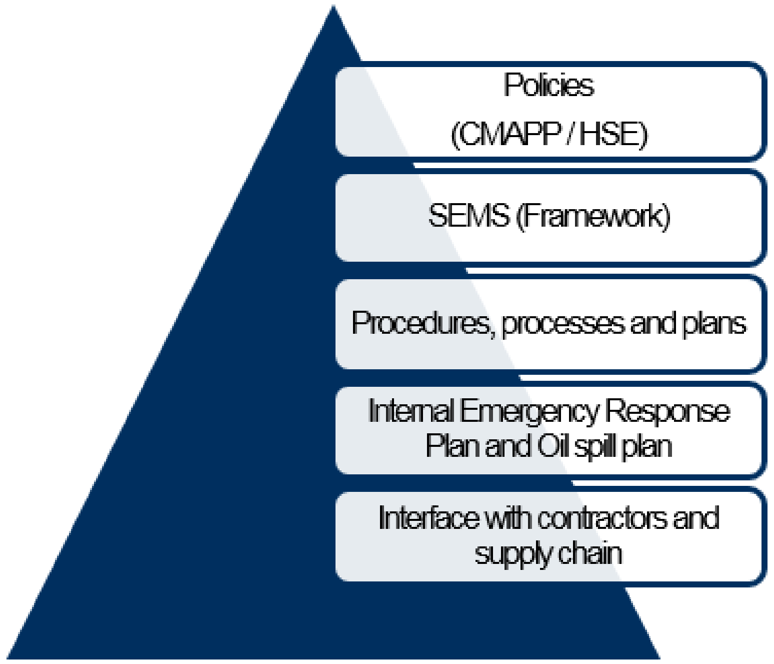


Figure 3. EMS hierarchy

Environmental management systems, like their safety counterparts, have always considered risk.

What has changed with recent revisions to ISO standards is that oil and gas companies now need to understand the context of their operations when managing risk. This is a major development, raising the prominence of some broad themes. These include addressing climate change issues in the context of operations. Regulations are applying increasing pressure to reduce emissions and there are many mechanisms for managing issues associated with climate change and energy management. The repercussions of operating in a challenging marketplace are other key considerations. Low oil prices influence many factors, such as the availability of competent staff in the industry and the right equipment. These can affect the way a company, and a country, is able to manage its environmental impacts. On the UK's horizon, owners and operators must consider another significant factor: Brexit's impact on industry regulations.

Where does a business start? Recent work with an oil and gas exploration and production company operating in the North Sea at multiple fields provides a practical way forward. The company, which places the safety of its people, integrity of its assets and protection of the environment as top priorities, has done an outstanding job of deriving its safety and environmentally critical elements (SECEs) from its different operating scenarios. (SECEs are defined by the EU Offshore Safety Directive and, in the UK, by SCR 2015.) This is the first step, enabling the right integrated procedures to be developed and the appropriate verification scheme implemented. While we are also seeing some good practices elsewhere, to date the opportunities are yet to be grasped more widely.

Supply chains are growing more complex

As the economics for the oil and gas business tighten, supply chains get bigger and more complex. This is true for organisations of all sizes in the marketplace, from the major players to micro operators. Contractor management presents a major, ongoing challenge, as headlines about major incidents highlight. Clearly, more can go wrong as a supply chains lengthen. An operator's expectations must be communicated to, and understood by, every contractor and intermediary it uses, and followed up with the appropriate assurance processes.

The need for robust contractor management is set out in the DECC Guidance and Reporting Requirements in relation to OSPAR Recommendation 2003/5. We know how problematic this is currently; delivering a programme of independent audits, inspections and reviews as a certifying body is a large part of our everyday work. Suitable systems, procedures and interface documentation must be in place to link the systems of operator and contractor. The objective is for the operator's EMS principles, environmental policy and relevant environmental goals, objectives and targets to

environmental goals, objectives and targets to be managed through the contractor's EMS. If both operators and contractors have certification to ISO 14001 (environmental management) and potentially other related ISO standards, the complex is made remarkably straightforward. Environmental advisors can be involved, where required, early on. Expensive errors and costly incidents can be avoided.

Concluding with a short answer

'Do we really need to do this?' is a common industry question to new environmental requirements. The answer is yes for owners and operators looking for help with the bottom line, meeting ever-growing compliance requirements and safeguarding corporate reputation. Converging environmental standards present a unique opportunity to integrate solutions covering numerous operator and supply chain risk management issues. It offers greater value for money and improved performance during exploration and production, throughout asset lifecycles and across the industry's increasingly complex supply chains. And what's more, with the drive to maximise economic recovery, demands for non-financial corporate reporting and revisions to the Insurance Act 2015 to all be considered, who could afford not to have an aligned, integrated management system?

These efficiencies make a difference, especially in a difficult market. Arguments for convergence and streamlining of management system documentation are especially compelling in a time when the industry is looking to achieve cost savings, promote efficiencies and attain benchmark standards for safety and environmental protection. The alternative is to swim against a tide of growing environmental regulations, missing out entirely on the advantages offered by a regulatory trend for closer alignment. Now is the moment to ensure owners and operators get value for money from their HSEQ management system.

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The role of Geophysical Uncertainty in Field Development concept selection*

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We present a great way to improve the net present value of a field development project through cooperation between the subsurface and engineering teams. This study shows how field development concept selection can start at least one phase earlier, in parallel with appraisal drilling, leading up to earlier start of production.

Abstract

The paper presents a parallel, probabilistic approach to field appraisal and development concept selection, rather than the conventional sequential approach. Instead of waiting for appraisal drilling to confirm and finalize the reservoir model, front end concept selection work is started at an earlier stage, based on a model with a high degree of uncertainty. Stochastic depth conversion uncertainty analysis is used to calculate P10 - P50 - P90 structure maps and gross rock volumes, thus quantifying the uncertainty. A series of field development concepts are being estimated to handle the entire uncertainty span. An optimized appraisal drilling program is then proposed, for the purpose of eliminating those uncertainties which would swing the field development concept selection. This combination of geophysical and engineering disciplines leads to a field development scenario with a minimal drilling cost spent on appraisal, and with an assurance that the optimal field development concept has been chosen.

Introduction

A number of cost intensive and technically crucial decisions need to be made in oil and gas field development. A broad range of issues are involved, within geology and geophysics (G&G), reservoir management, drilling/completion technology, production strategy, facilities size/solutions, infrastructure and transportation to the market. Deciding on the right field development option requires an organization that works closely together across the disciplines. Oil and gas companies have come a long way in using modern simulation and modeling tools which are suited for such cooperation.

We have, for the purpose of this study, constructed a synthetic data set, the Aker Field, which is in the early stages of field development planning. The latest exploration well has made a significant oil discovery. The field is located in the Norwegian North Sea. The reservoir is situated relatively shallow, at a depth of about 4675 ft. under 660 ft. of water. Current data indicate that the reservoir has excellent flow properties in clean sands with no indications of complex faults and barriers, but there is still significant uncertainty with regards to top reservoir depth, and as a consequence, the lateral extent of the field. Based on seismic mapping, and reservoir properties from wells in the area, the Aker Field looks very promising, and plans for field appraisal drilling and field development are being made.

The conventional (sequential) approach would be to start with appraisal drilling, confirming the reservoir model of the field, and then hand that model over to engineering as the basis for development concept selection. The alternative, which we are exploring in this paper, is instead to use a parallel, probabilistic approach, where early phase development concept selection is started before appraisal drilling, when the reservoir model still is very uncertain. This is challenging, because people from disciplines who normally do not interact closely have to cooperate, but it can be very rewarding, because the problems are being looked at from additional angles, pulling in expertise that normally is not used at this stage. It is very likely that this approach will lead to improvements in the appraisal program, and in the field development, and thus to significant economic gain.

With the parallel approach it is not necessary to have a final, fixed model of the reservoir, instead it is necessary to understand, and be able to quantify, the most significant G&G and reservoir engineering uncertainties. From this, a small number of reservoir models are made, each with associated probability. For the purpose of this paper we have chosen to concentrate on depth conversion uncertainty, and to construct three reservoir models, at P10, P50 and P90 probability.

Based on these, we have evaluated different appraisal and field development scenarios, and derived an optimized appraisal strategy together with a field development program that includes the entire uncertainty span, reaching the best development solution at the end of the day.

This paper was prepared for presentation at the Offshore Technology Conference held in Houston, Texas, USA, 6–9 May 2013.

Formulation of Problem

1. Evaluate different field development options including the full span of uncertainties
2. Adjust for proposal of an appraisal strategy to reduce the geophysical uncertainties
3. Decide on the best field development scenario in terms of technical robustness and the best economic value.

Methodology

The different geophysical maps resulted in different outcomes. An initial appraisal program was proposed by the G&G team for the purpose of reducing the subsurface uncertainties. In generating the different development schemes including the economics a computer program (IPRiskField) was used. In this program every parameter is input in a probabilistic manner. Every simulation results in a full uncertainty span. Interpretation of these results formed the basis for deciding on a preferred development solution as well as a preferred appraisal program with respect to field development decisions.

Geology & Geophysics

The Aker Field, Figure 1, is a synthetic data set with properties which are typical for the North Sea.

The reservoir is a Lower Tertiary basin floor fan, residing unconformably on Cretaceous limestones. The top and base horizons are well defined from seismic. It is a massive sand body of regional extent, which pinches out towards the west. Excellent aquifer support can be expected. Within the Aker Field there are no continuous shales or faults which could act as barriers during production.

Four exploration wells have been drilled, targeting structures at a deeper level. No oil or gas was found there, and the first three wells were completely dry. Exploration_4, the discovery well, unexpectedly found oil in the Lower Tertiary. It penetrated 44 ft. of oil in massive, clean reservoir sand. The OWC is at 5007 ft. This well controls the northern part of the structure, but the lack of crestal wells in the south and center leaves a significant depth and volume uncertainty. This uncertainty was studied using a self-optimizing depth conversion method which uses seismic processing velocities and well data.

Seismic processing velocities are commonly used for depth conversion down to top reservoir in the North Sea. A seismic processing velocity field is a direct measurement of the average velocity, but it also includes noise.

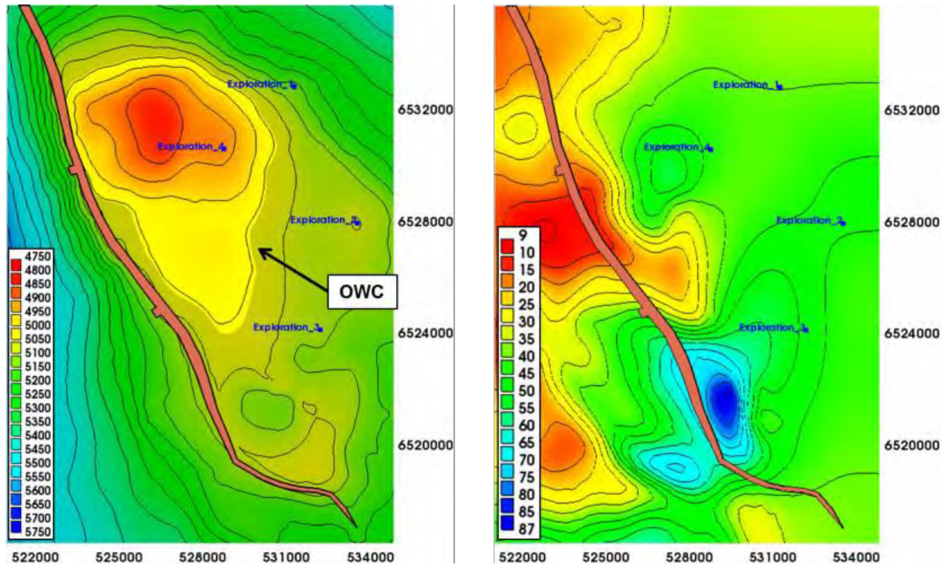

Figure 1. Base Case depth (left) and reservoir isochore (right)

The self-optimizing method searches a large number of noise filter realizations, and finds the best deterministic depth case, measured in terms of depth prediction error in the wells. The method can also be used for stochastic velocity uncertainty modeling. With proper parameter search boundaries, the set of realizations scanned for optima will span the full range of realistic modeling solutions, and it is then possible to calculate meaningful statistical parameters, including standard deviation, mean, minimum and maximum depth maps.

Figure 2 shows standard deviation of depth to top reservoir in the Aker Field. It is zero in the wells, because all realizations have been well tied. The largest uncertainties are located along the fault. This is partly a consequence of soft sediment deformations, and partly an effect of shallow gas, both related to the zone of weakness created by the fault. (A real velocity data set was used to make this map.)

Depth uncertainty is the sum of velocity and seismic interpretation uncertainties. In this study no seismic interpretation uncertainty estimate was available; instead the total depth uncertainty was set to twice the velocity model uncertainty. Based on this, and assuming normal distribution, P10 and P90 depth maps were calculated from the mean depth map, adding / subtracting 2 * standard deviation * 1.28.

The depth conversion Base Case will give the most likely gross rock volumes, and should form the basis for a field development decision. There are two outputs from the optimization routine which can be used as Base Case, either the best deterministic case, which has the smallest depth prediction errors in the wells, or the mean case, which is centered (P50) in terms of velocity uncertainty. In the

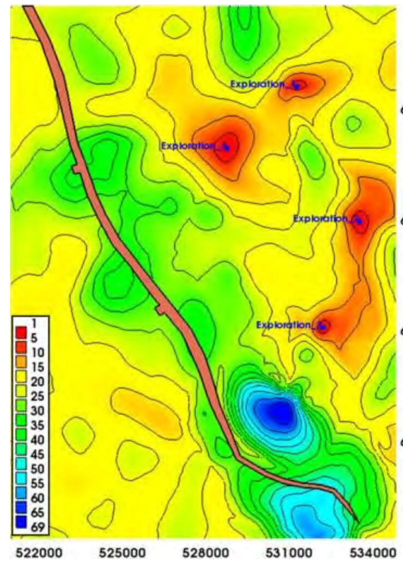

Figure 2. Standard deviation of top reservoir depth

Aker Field, the analyst used the mean. The P90 (Low Case), P50 (Base Case) and P10 (High Case) depth maps from the Aker Field are shown in Figure 3.

The structural uncertainty in the Aker Field is evident from Figure 3. The northern part of the field has a robust closure. The middle and southern parts are flat, and can either be above or below the OWC.

An appraisal program consisting of two wells has been proposed by the G&G team in order to eliminate this uncertainty. Without appraisal, only the northern part of the field, which is above the contact in the Low Case, can be developed.

The first apprisal well, Appraisal_1, is located

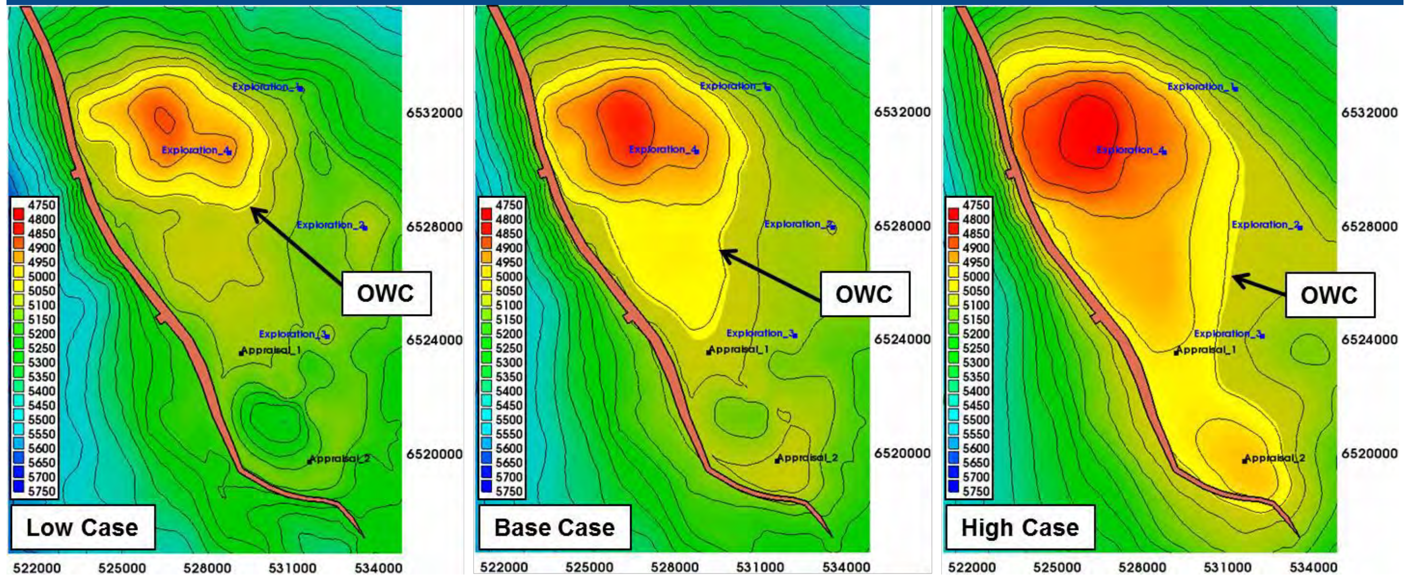

Figure 3. Low (P90), Base (P50) and High (P10) Case depth maps

in the centre of the structure, directly south of the OWC in the Base Case. If this well is successful, it will prove the Base (or High) Case here, and allow the middle of the field to be developed. The second appraisal well, Appraisal_2, is located on the structural crest at the southern end of the field. The purpose of this well is to test the High Case here. If successful, it will allow the southern part of the field to be developed. Seeing a need to confirm the most likely volumes before field development, and believing that the additional high-case potential in the south could wait until later, G&G proposed to drill Appraisal_1 before concept selection, and wait with Appraisal_2 until after start of production.

The geophysical uncertainty estimation method used in this study is a stochastic method which determines uncertainty directly from the data. Together with other objective uncertainty estimation methods, it is well suited for field developent studies, where accurate quantified uncertainties are extremely important as basis for field development decisions.

Reservoir

The Exploration_4 well drilled in 2011 proved oil in Lower Tertiary. Sand of excellent reservoir properties were found. The reservoir is undersaturated with a low GOR and a slightly viscous oil type (fluid analyses from Exploration_4 well). The rock properties are tested (core analyses from Exploration_4 well) to be excellent. The reservoir parameters used in the volume estimate are shown in Table 1.

Even if the reservoir properties from the discovery well showed high quality it is believed to have some variations between the different parts of the field. The field is therefore divided into three parts, North, North-S and South. The permeability and porosity of the sands is believed to stay more or less the same. What could differ are potential shale intrusions toward South, from the North segment into the Middle segment and further down into the South segment. An involvement of some shales in between the sands could easily reduce the recovery factor. Another factor that could easily reduce the recovery here is the fact that both the North-S and the South parts are structurally deeper, opening up the potential for more water encroachment. Based on these thoughts the recovery factors have been adjusted accordingly relative to the expected recovery factors in the North (Low case lowered due to some thinner sands). Despite the relatively small adjustments the well count and the architecture are kept the same. These would all be adjusted as more data becomes available. Estimated recovery factors and wells for the individual parts are shown in Table 2.

Parameter	Units	Mean
Water depth	ft.	660
Reservoir Area	Acre	11400
Top Reservoir Depth	ft.	4675
NTG	Frac.	0,7
Porosity	%	30
HC. Saturation	%	70
Permeability	D.	5
Reservoir Pressure	Psi	2660
Reservoir Temperature	F	176
Saturation Pressure	Psi	1320
Reservoir Oil Viscosity	cP.	2
Reservoir Oil Density	lb./Sft3	50
Oil Formation Volume Factor,Bo	ft3/Sft3	1,13
GOR	Sft3/STB	1590
OWC	ft. TVD MSL	5000

Table 1. Basic reservoir parameters

Parameter	Small development North	North-S	South	Middle development North	North-S	South	Large development North	North-S	South
RF, %	35			40	35		40	35	30
Oil producers	8			12	4		15	9	5
Water injectors	4			6	2		7	5	3

Table 2. Estimated recovery factors and wells (well figures used in estimating CAPEX for the

The tested oil shows somewhat higher viscosity than most oil in the North Sea. A slightly unfavorable mobility ratio would then be expected. The plan is then to increase the number of oil producers and then keep low drawdowns through moderate production rates. Water injection is planned as a recovery mechanism to sustain close to original pressure and stay above saturation pressure. In order to avoid too early water encroachment the planned water injection would have to be under strong surveillance.

Drilling

A decision was made to not predrill any wells for the different scenarios. The reasons are the high risk exposure of drilling development wells without any production history. This was evaluated against the upside potential of earlier production but also the potential downside of expensive drilling rigs in a demanding market. Separate drilling rigs were accounted for in the scenarios including wellhead platforms (one for the small development scenario and one for the large development scenario in the southern part of the field). The wells which are all vertical / deviated will be completed one by one. Average drilling time is estimated to 35 days within the central area and up to 75 days for some of the long reaching wells being drilled southward.

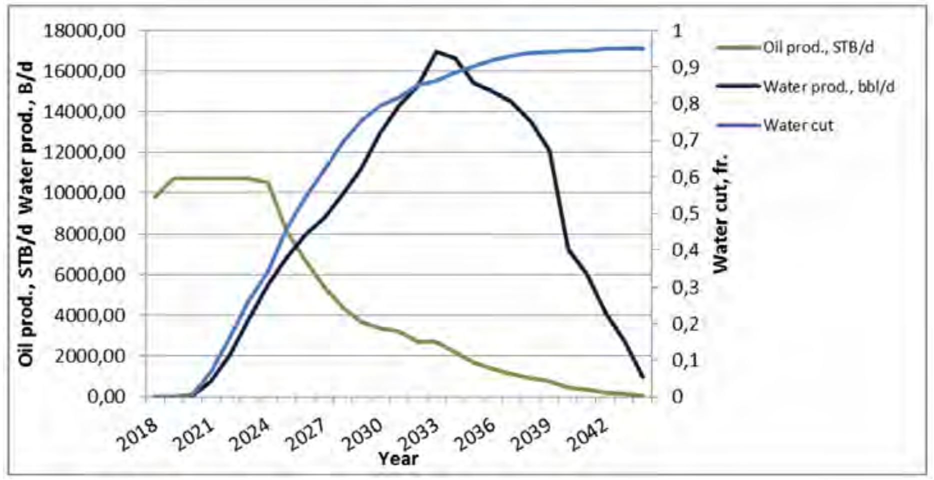

Figure 4. Average well oil, water production profile and water cut

Production

A chosen production scheme from the Aker Field involves the use of vertical/deviated oil producers for reservoir development under water injection.

The best production scenario from current subsurface knowledge of the field involves oil withdrawal with minimum reservoir drawdown. Even with pressure maintenance from both aquifer and water injection some parts of the reservoir will most probably experience some energy loss.

Furthermore, the strategy includes keeping the reservoir above saturation pressure. When the completion waters out owing to either influx and/or water injection, accountable amounts of oil might be left behind the front. In order to reduce this risk a somewhat smaller well spacing combined with moderate withdrawal were decided. Moderate production from this high productivity reservoir with Darcy sand will then demonstrate a long life production profile. However, produced gas which is of a smaller order would be handled and reinjected into a shallower formation. A set of average production profiles (oil, water) is shown in Figure 4.

Devel-opm.	#	Description	Producers	Injectors	Production Capacity (x10³)		
					Oil	Water	Liquid
Large	1	Field senter+ wellhead platform in South	29	15	315	490	570
Large	2	Platform+ subsea tie back in South	29	15	315	490	570
Large	3	Platform (drywells only)	29	15	315	490	570
Middle	1	Platform w/ subsea tie back	16	8	190	270	315
Middle	2	Platform (drywells only)	16	8	190	270	315
Middle	3	Wellhead platform, w/o drilling, tie-back 20-30 km.	16	8	190	270	315
Small	1	Platform w/o drilling	8	4	95	135	160
Small	2	FPSO w/ subsea tie back	8	4	95	135	160
Small	3	Minimum platform w/o drilling tie-back 20-30 km.	8	4	95	135	160

Table 3. Different development scenarios (figures used in estimating CAPEX for the different scenarios)

Key factors	Justifying Comments
Wells Intervention Areal spread Pipeline ditance Production	High number of producers and injectors Possibility for sealing off perfs., reperforate Relatively concentrated area Long flowlines - high natural pressure drop Long production life

Table 4. Key factors – basis for choosing development solutions

Development and Facilities

A large number of different scenarios were considered. Table 3 shows those that remained after initial screening.

Table 4 lists some of the key screening factors. Another factor was the water depth, Figure 5, which is about 660ft in the center of the field, increasing steeply towards the east. We have assumed this to be beyond the capacity of jack-up rigs.

The Aker Field is not located in the vicinity of any hub or large infrastructure, but for the purpose of this study, we have assumed that a "Tora Field" exists about 25 km from Aker Field, that the Tora Field currently is in the maturation stage, and that a PDO (Plan for Development and Operation) submittal is planned in 2015.

The Aker Field has sizeable reserves and could be developed based on either a tie-back solution or a standalone solution. A tie-back solution requires that a host and a transportation system are available. Furthermore, additional main issues to be raised include capacity, fluid quality, flow assurance, physical distance, timing and certainly cost. Cost would both include the investments bringing the fluid to the host and further the cost of processing, operations and possible modifications at the host platform. For a standalone solution there are several options. One category is permanent structures connected to the seafloor and another one is floating devices. A third one might be complete subsea systems directly connected to export pipelines.

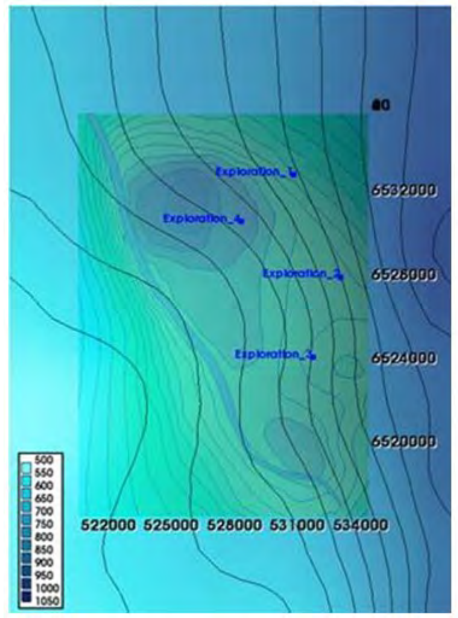

Figure 5. Water depth (ft)

Parameter	Small development	Middle development	Large development
CAPEX OPEX	1,700 5% CAPEX	3,700 5% CAPEX	4,600 5% CAPEX

Table 5. CAPEX and OPEX figures for the development scenarios

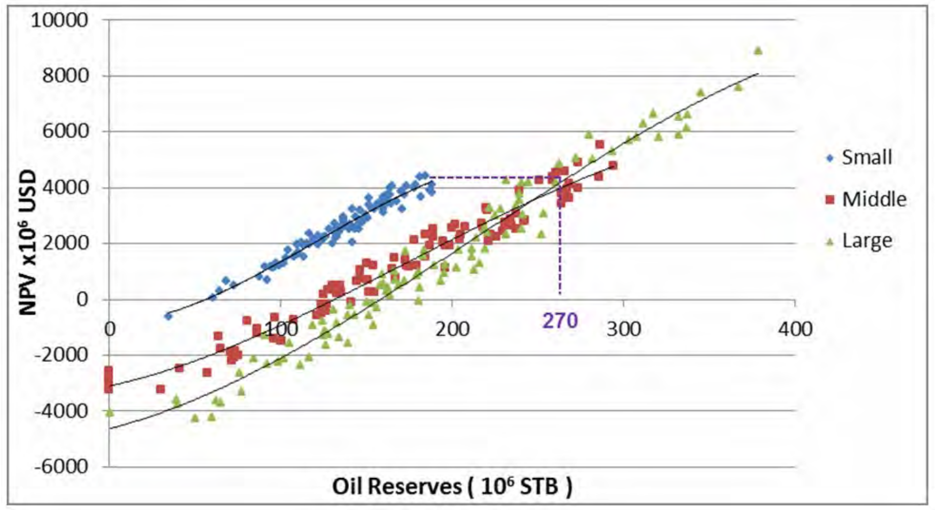

Figure 6. Cross plot of oil reserves vs. NPV, for three different development scenarios

We ended up with three scenarios, 'Small', 'Middle' and 'Large', which were optimized for the reserves in the P90, P50 and P10 reservoir models respectively. 'Small' development is a smaller wellhead platform (15 slots) where the well stream is routed through pipeline with tie-back to the Tora Field. All processing is conducted at the host platform and further export through their pipeline system. 'Middle' development is a 20 slots platform with processing and accommodation capabilities. Here, the well stream goes to an FSU which is a storage unit for further shipment to the market. 'Large' development includes a 30 slot full processing platform. A wellhead platform (10 slots) placed in the south is tied back to the main platform. The total processed well stream then goes from the main platform to the FSU for further shipment and export .

Table 5 shows the CAPEX (excl. drilling cost) and OPEX figures used in the economic analyses. These numbers are input to the program as mode values and include full distribution within the uncertainty span.

An NPV analysis of the three scenarios, Figure 6, shows the 'Small' and 'Large' to be the most favorable.

Discussion of Results

Economics were run probabilistically in order to define the results in evaluating the different development scenarios. The program being used acquires data from different sources and models the various uncertainties. The probabilistic results being calculated gives a good overview of how the different parameters contribute to the overall uncertainty.

The cross plot in Figure 6 shows the reserves vs. NPV for the different development scenarios. The figure shows that the 'Small' development, which reaches a maximum NPV at 200 MM STB of reserves, has a higher NPV than the other scenarios up to 270 MM STB. The investments are relatively small for the 'Small' wellhead platform with minimum topside assumed. Additionally, the oil production is being transported to the host which includes some hook up cost.

The other two development scenarios have to exceed 270 MM STB before they show higher NPV values than the 'Small' development. In this volume range the 'Middle' development has been passed by the 'Large' development. The 'Middle' development is not the best choice in terms of NPV in any volume range. Therefore, only two realistic development scenarios remain, the 'Small' and the 'Large'.

This means, when compared to the P10, P50 and P90 reservoir models, which were derived from depth conversion uncertainty, that the 'Small' development is the best for the P90 and P50 cases, and that the 'Large' development is best for the P10 case, with the dividing line, at 270 MM STB, ca at the midpoint between P50 and P10.

The consequence of this is that it becomes unnecessary to drill Appraisal_1 (Figure 3) before the Aker Field is put on production, because the results of this well will not have any influence on the field development concept selection. Without this well, all we have proven is the P90 case, with well Exploration_4. If Appraisal_1 comes in as prognosed, then we would have proven the P50 case, but we would still go for the 'Small' development. And if Appraisal_1 comes in high, then we would not yet have proven the P10 case, because most of the additional volumes in that case would be in the South part of the field, where the depth uncertainty is larger than elsewhere (Figures 2 and 3). Instead, it becomes necessary to drill Appraisal_2, which is located in the middle of the South part. The purpose of this well is to test the P10 case. If it comes in high, proving the P10 case in that area, then it will prove up sufficient additional volumes to swing the optimal field development from 'Small' to 'Large'. This well must therefore be drilled before concept selection. This is a complete reversal of the appraisal drilling program originally proposed by G&G. They had proposed to drill Appraisal_1 before concept selection and Appraisal_2 after production start.

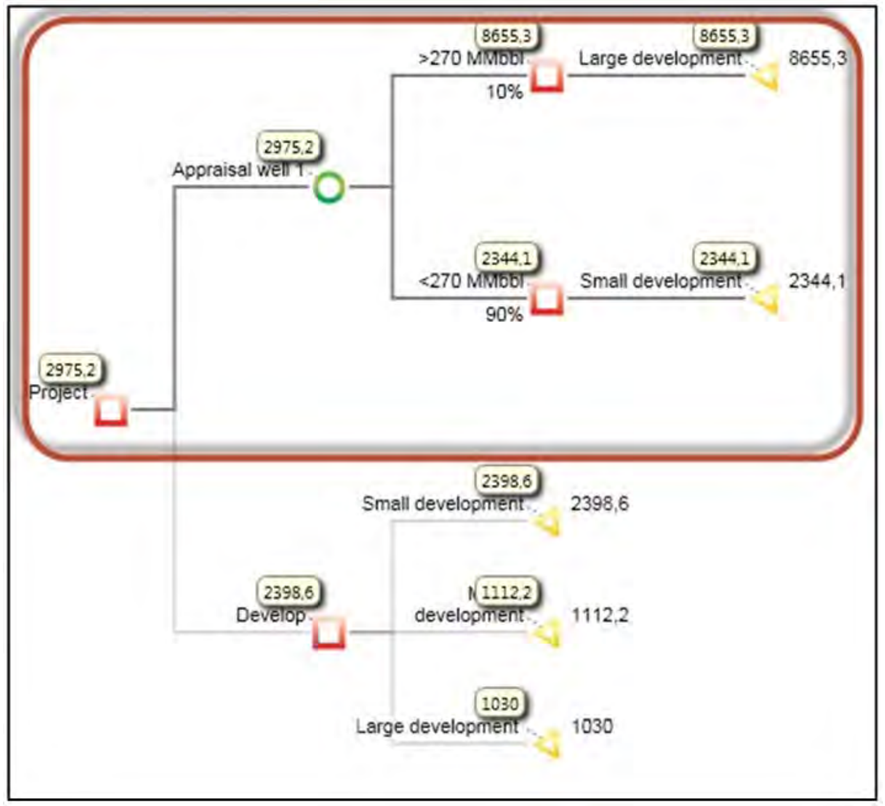

Figure 7: The optimal decision path

Development Scenarios	NPV (10^6 USD)
Small development Middle development Large development	2,398 1,112 1,030
Appraisal simulation (Small vs. Large dev.)	2,975

Table 6: NPV values for the different scenarios (NPVx10^6)

The decision of whether or not to drill Appraisal_2 was based on a risked NPV analysis. The results show that by drilling Appraisal_2 the NPV becomes 2875 MM USD compared to NPV of 2398 MM USD with no appraisal. This is further shown in Table 6. Based on these results the optimal decision path is shown in Figure 7.

Conclusions

On a NPV basis there were eventually two real development options left to compete out of three in total. The small development scenario showed best values up to approximately 270 MM STB in reserves. When the other two development scenarios came to that NPV level there was only the large development that could further improve the value.

Scenario analyses showed that drilling Appraisal_2 well would be beneficial and increase the overall value in choosing the large development option.

By going straight to Appraisal_2 and the chances for larger volumes we 'saved' the work and cost of drilling Appraisal_1. Drilling Appraisal_1 would only prove up volumes which could be handled by the small development scenario. This could also be drilled later directly from the platform to prove the volumes.

This study clearly shows the important role the geophysical uncertainty has in evaluating field development concepts in early stages. Working with the entire uncertainty range could early on rule out some options and easier converge to a certain solution relative to a deterministic approach.

One of the primary reasons for a successful field development study has been to have an innovative formulation of the problem. By this we mean having a manageable number of decision constraints and variables as well as effective workflows being implemented for the problem solution. The workflows would provide frameworks for the solution of the field development problem.

This study has again proved the value of working in integrated teams. By working in parallel and not sequentially as the classical way the team managed to pick up valuable information in an early stage. By having subsurface and facilities (engineering) teams working closely together, data and information exchange in the early phases become a valuable asset.

Having a parallel, probabilistic approach to the project covering the entire span of uncertainties improves the quality of the results and the field development decisions.

Acknowledgments

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Decision models - Geological modelling to guide decisions

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The approach to geological modelling is evolving. The demand from our clients has shifted from holistic full-field models ("resource models") to models where a specific objective is addressed ("decision models"). The latter models focus on the most key factors that have an impact on the decision to be made, and the key factors are determined by a cross disciplinary team.

Decision models are required for all stages in the development chain from appraisal through development to production. They may undertake advanced modelling techniques and workflows, but they most often turn out to be simpler, smaller and more transparent than resource models that are built using standard workflows and acknowledging "all" data available.

When AGR is assigned a modelling study, often as part of a larger study, our team will engage with the client on some key questions before starting: What will the model be used for? Is there a specific decision(s) that the model will guide? What are the key factors, e.g.: What level of resolution is required to make the decision? What is the most important uncertainty for the decision? Which heterogeneities to focus on? How much detail do we need to conclude with confidence? How many scales need to be employed in the model and should it be upscaled? And of course, how does it fit with overall study objectives, schedule and timeline, and what are the deliverables and deadlines.

AGR has a track record of constructing decision models and the following is a brief summary of some recent ones:

Decision in the DG0 phase: AGR was engaged by a Client to guide a "DG0" decision on an oil discovery located in a fairly flat circular structure in a fluvio-deltaic reservoir. A reservoir model was required in order to provide a reliable range of oil volumes and production profiles, and to support further evaluation of development concept including wells, facilities, flow assurance and tie-in possibilities. In the context of the overall study scope and level of decision to be made it was agreed that a coarse reservoir model would be sufficient and that the geological model wouldn't require a high degree of detail. Hence structural, facies and property modelling was set up in an easily repeatable workflow for stochastic uncertainty analysis, see Figure 1. This resulted in a reliable and realistic range of volumes that were key in guiding the access decision.

Decision in the appraisal stage: AGR was engaged by a Client to carry out a reservoir study on a recent discovery. The main objective was to give input to test planning and aid the decision whether or not to perform a production test on the temporarily P&A'd discovery well. A secondary objective was to achieve an outcome space and critical parameters for further development of the discovery.

Excellent reservoir sand was found in distributary channels in a marginal marine setting with tidal influence. One key question to be answered was if and how a possible test could reveal geological information such as geometry and properties of baffles/barriers in the reservoir. The team understood at an early stage that the key factors were reservoir heterogeneities such as thickness, lengths and abundance of shaly layers and that it would be important to run sensitivities on kv/kh in several geological scenarios. This enabled us to be more pragmatic on e.g the fault model and establishing a detailed geological concept for the facies model.

A near wellbore sector model with reduced grid cell size was constructed for the production test simulations. Detailed analysis from MDT pressure build-up gave information about lateral and vertical communication for each of the pressure tests. We plotted the precise depths of the sink probes and the observation probes which enabled linking communication to the geological facies from the core description log and the facies log used in the modelling. Such examples as in Figure 2 gave valuable information for sensitivities of Kv/Kh values per modelled facies in the detailed sector model. It provided a reliable tool to predict the dynamic behaviour of a possible production test and demonstrate to what extent one could expect to see baffles and barriers in the reservoir.

Decision in a CO2 storage feasibility project: AGR was engaged by a Client in a CO_2 storage feasibility study in the DG1 phase. Key questions to be addressed were related to the injectivity of CO_2, plume migration, storage and leaking potential. For the modelling it was agreed that it would be critical to construct a reservoir model that could predict the pressure history and depletion in the area. A regional geological model was constructed to support this, combining data from a nearby detailed full field model with regional surfaces and sparse exploration well data. The main issue in this study was not the whole uncertainty range but the upper margins of pressure

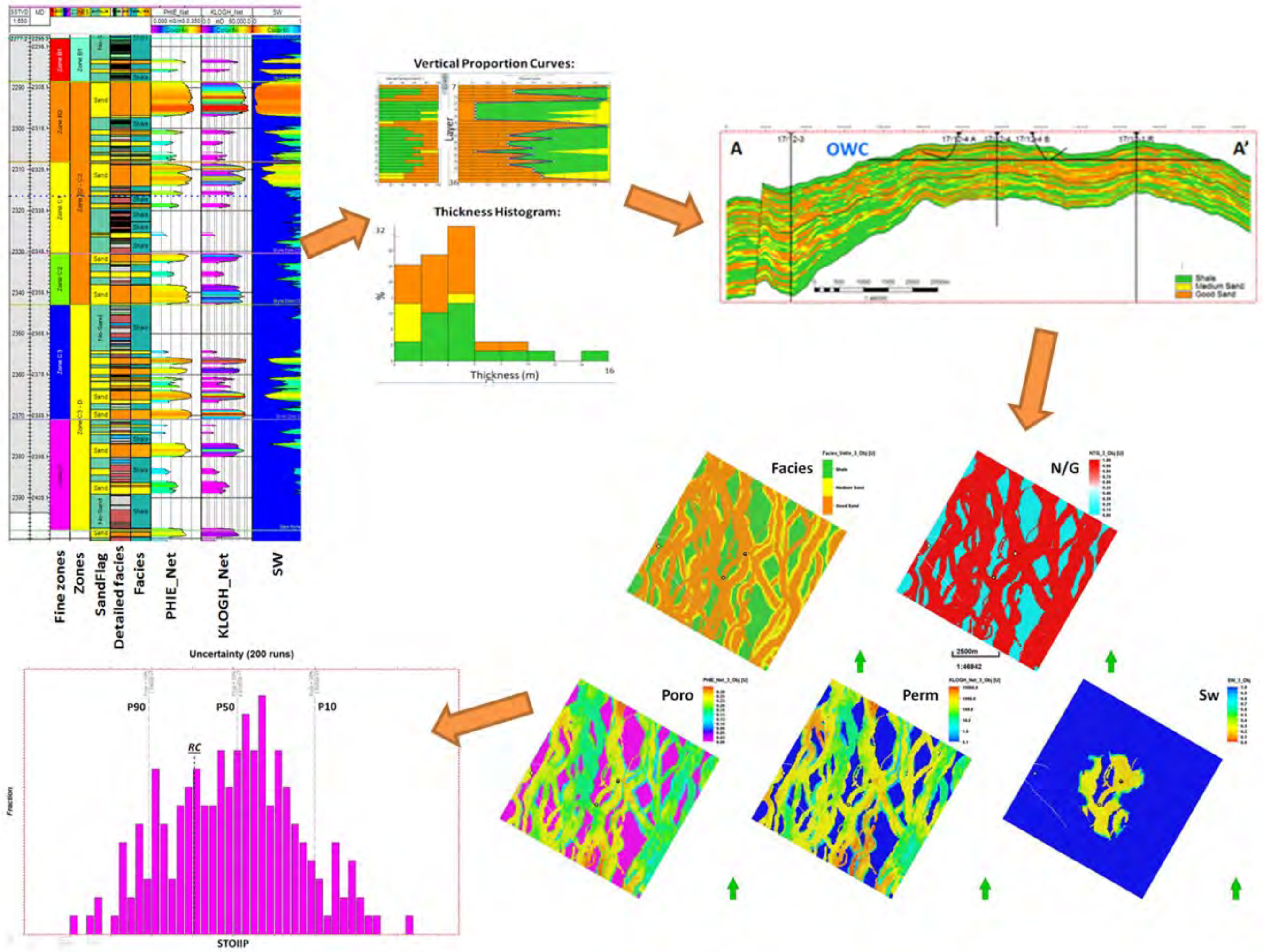


Figure 1. Facies and property modelling; from well logs to model as a basis for static and dynamic uncertainty analysis workflow, assisting a client in a field development study.

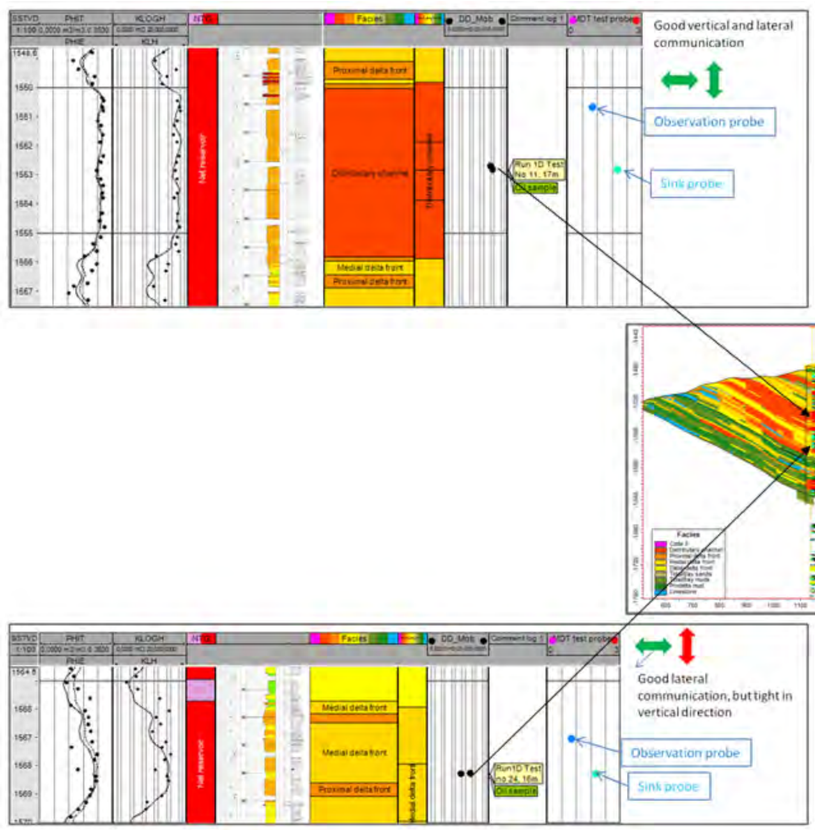


Figure 2. Relating detailed information about vertical and lateral communication from MDT pressure tests to facies. Note the exact depths of the sink/observation probes and the relation to scale in core plugs, core description and facies log used in modelling.

and temperature for an evaluation of the potential and risks. The geological model needed to be coarse. The permeability on a regional scale, together with geometry and communication between layers and fault ramp zones were shown to be key uncertainty factors. The model was used for simulation sensitivities and guided the decision to proceed with the CO_2 project through the DG1 decision gate.

In all of these examples of recent geological modelling projects we have been conscious to focus on the main objective, the key factors, and to not complicate the workflows, modelling techniques and steps. This has also allowed our clients to reproduce the models with tidy workflows. Our workflows were also prepared for uncertainty evaluations, either by stochastic methods or in a scenario-based deterministic approach. And last but not least, the models were suited to answer the most important issues in order to guide the decision to be taken.

Our view on trends in geological modelling

With regards to modelling techniques they have in many ways been similar for decades. Most times we base our models on constructing a grid which is designed to, and constrained by, the flow simulation needs. Quite often we experience that compromises of geological concepts and representing details at small scales have to be done.

These kinds of compromises can be dealt with by applying the well established principles of multi-scale modelling. Further trends go in the direction of grid-independent ways of modelling, surface based or process based, where the geological surfaces and/or processes are "static" and the grid is custom for each simulation purpose.

While these concepts and ideas are exciting and mind-inspiring, the established methodologies should be adequate for most modelling projects as long as we are conscious of the objectives, the key factors and what decision the model is supposed to guide.

We have described how the demand from our clients to some extent has shifted from holistic full-field models to decision models where a specific objective is addressed, what these decision models constitute as well as summarised some examples of recent decision modelling projects that AGR has undertaken. We have stated and argued that for these models we would rather simplify than overcomplicate the modelling techniques and workflows.

Separating solids during CT Clean Out & optimizing well production North Sea August - September 2017 Case study

by G. Malinauskaite, FourPhase

Giedre Malinauskaite
Marketing Manager

Challenge

FourPhase was requested by a well service company to assist in a coiled tubing (CT) well clean out operation which was to be performed offshore for a major North Sea Operator. Initial scope of the operation included solids separation from return flow during CT clean out of three wells. However, during the operation, the scope was expanded to also include post-clean out production test on two of the wells. The aim of the test production was to remove accumulated solids from the wellbore and to identify potential flow rates in correlation with sand lifting rates. This would provide data for optimizing well production and establishing operational boundaries.

Operational considerations:
- High rates of solids were expected from one of the wells scheduled for CT clean out after fracking. High rates of returning proppants could potentially result in high erosion.
- Limited access to empirical data prior to production testing operation.
- Limited knowledge about the solids in wellbore – amount, size/composition of particles and expected solids rates while producing wells.

Solution

FourPhase 5K DualFlow unit was used in a CT operation allowing for safe removal of fracturing proppants and other types of solids. Minimal real estate due to deck load limitations and good separation efficiency were critical, therefore 5K DualFlow (2m X 2m X 3.2m) was mobilized.

Result

DualFlow has showed excellent separation efficiency during CT clean out and flowback operations. The total amount of solids separated during post-fracking clean out and flowback operation from one of the wells was 23 044kg with the separation efficiency of 96,5% during post-fracking clean out and 99,8% during flowback operation. During well CT clean out operations and test-production, the overall combined separation efficiency of the DualFlow unit was never below 98,1%.

Key operational outcomes:
- No recorded HSE incidents.
- No recorded equipment downtime.
- 26 351kg of solids, including fracturing proppants, removed.

Overview of DualFlow on the BOP deck.

Relief Well Injection Spool (RWIS) – Enables single relief well contingency

by M. H. Emilsen, add energy and B. Morry, Trendsetter Engineering

Morten Haug Emilsen
Managing Director,
add energy

Brett Morry
Global Technical Director,
Trendsetter Engineering

In December 2015, a change was implemented in the Activity Regulations relating to drilling and well activities in Norway. Section 86 was updated and now states: "In the event of a well control incident, it shall be possible to regain well control by intervening directly in or on the well or by drilling one (1) relief well. This applies to wells where planning of drilling activities has been decided on after 1 January 2016." This regulatory change emphasizes the importance of having an appropriate and feasible Blowout Contingency Plan in place in the event of a worst-case scenario.

Today, Blowout Contingency Planning is an integral part of the preparations for drilling operations. The primary purpose of a Blowout Contingency Plan is to minimize danger to life and protect the environment and valuable assets by minimizing response times and incorrect actions taken under stress. Questions like: "What if my primary barrier fails during our planned operation?" and "What if all barriers fail resulting in an uncontrolled blowout?" should be answered and mitigating options should be developed well in advance of the spud date.

The increased focus on planning for the worst has affected how wells are designed with the aim of reducing the consequences should a blowout occur. The overall goal with the planning will be to reduce potential errors and ultimately improve the response and limit the consequences should an incident occur.

Unfortunately, planning for the worst case might also unveil some disadvantages for an operation in general. For drilling activities, the result can typically be slimmer hole sizes, reduced kick tolerance, running more casing strings, longer lasting operations and increased overall cost. To reduce the consequences of a hypothetical worst-case scenario, one may in fact end up increasing the probability of an event.

A dynamic kill through a relief well is the safest and most likely successful method to stop a blowout. For many blowouts, it will also be the only alternative to regain control. Typically, relief wells are often referred to as the last line of defense in event of a well control incident. It is therefore vital that the operators address the feasibility of a relief well kill operation in their contingency plans.

For most wells, demonstrating a feasible relief well kill operation should be a manageable task considering the experience gained from several actual kill operations. Relief wells have been drilled regularly since 1933 when the first blowout was killed by directly intersecting the flowing wellbore (Gleason 1934). The dynamic kill method used for most relief wells today makes use of frictional forces caused by the mud pumped into the blowing well to increase the pressure in the wellbore and consequently stop the influx from the reservoir.

Sometimes the pump rate required at the intersection point might exceed the capacity of a single relief well rig. Limitations can be pump rate, pump pressures, pump power or fluid storage capacity. This will trigger options to increase the pumping capacity of the relief well or alternatively require planning for additional relief wells.

The history has shown that single relief well kill operations have had a high rate of success. On the other hand, a kill operation involving two or more relief wells is recognized as a very challenging operation. The only known incident where two relief wells have been used for a dynamic kill operation was during the El□Isba blowout in Syria in 1995. This operation was performed onshore in a controlled environment, something that cannot be compared to an offshore environment. Today,

Table 1: Advantages of the RWIS

- **Enables drilling of prolific reservoirs ensuring single relief well contingency**
  - Increased pump rate and volume required for kill
  - Removes kill- and choke line bottleneck
- **Increases redundancy and flexibility of operations**
  - Moves additional pumps and mud storage to remote vessels
  - No installation of additional pumps and mud storage on relief well rig
  - Enables off-bottom kills, faster and reduced spill volume
  - Removes the requirement for using mud weights above the fracture gradient
  - It is independent on the relief well rig
- **Enables larger and more cost-effective wells**
  - Saves rig time and cost of casing
  - Increases production rate by larger completions
- **Improves safety**
  - Limiting use of vessels in close proximity to the relief well rig
  - No need to challenge pump specifications on relief well rig

add energy

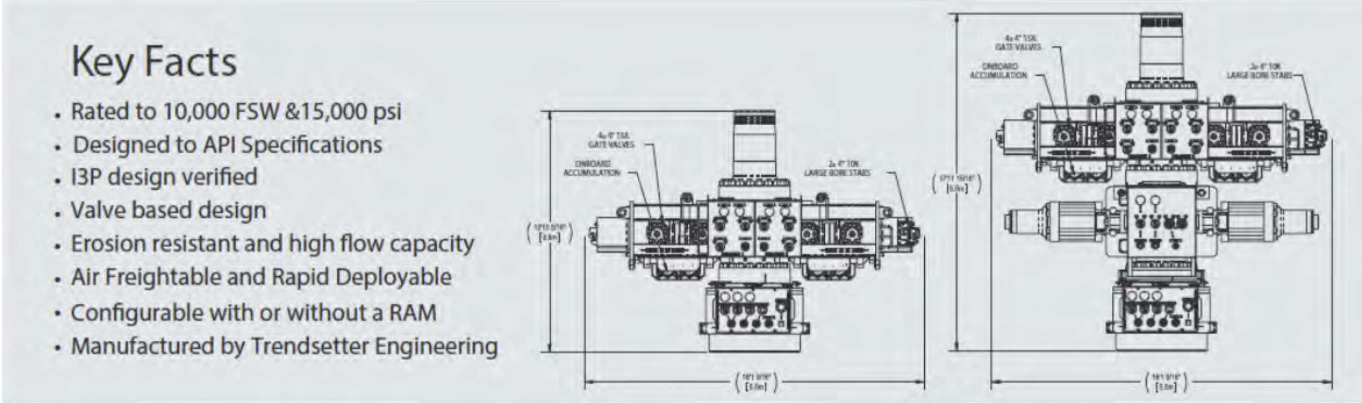


Table 2: RWIS key properties

no experience exists on intersecting and coordinating a dynamic kill operation in an offshore environment using multiple relief wells.

Because of the limited experience and the obvious challenges involved in dual relief well kill operations, many of today's company standards as well as regulating agencies including the Petroleum Safety Authority Norway (PSA) now state that new well designs should have single relief well contingency.

To comply with the new regulations, while at the same time maintaining cost effective and safe well designs and operations, a patented Relief Well Injection Spool (RWIS) has been developed, manufactured, tested and delivered to the subsea oil and gas industry. Kill spools have been used on several onshore blowouts in the past. This field proven application is now ready for subsea use. The patented RWIS is manufactured using field proven conventional components that are utilized daily in deep-water environments.

The RWIS is designed to be installed on a relief well prior to intersecting the blowout well and would be positioned between the wellhead and the blowout preventer (BOP), effectively becoming a subsea injection manifold providing additional inlets for pumping kill mud. Each of these inlets is equipped with dual fail-safe barrier valves to provide the necessary means of pressure containment in the relief well. During the well kill operation, one or more high pressure pumping vessels or drilling rigs (typically the rig drilling the backup relief well) will be connected to the RWIS inlets using high pressure flexible lines to provide the additional flow of kill mud, see example in Figure 1.

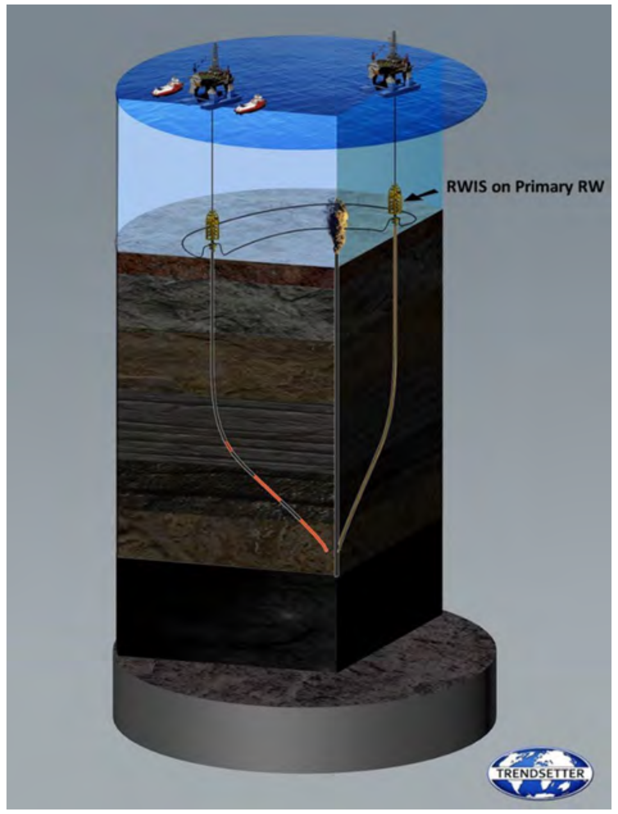


Figure 1: RWIS and connections to vessels

In the event of a blowout, drilling of a relief well will commence immediately as soon as a suitable rig has been identified and mobilized. As part of the preparations for the relief well, the RWIS will be transported to the location. The RWIS can be installed on the wellhead prior to the BOP or alternatively just before making the intersection, and it has the same bore (18 ¾") as the BOP and will not impact ongoing drilling activities.

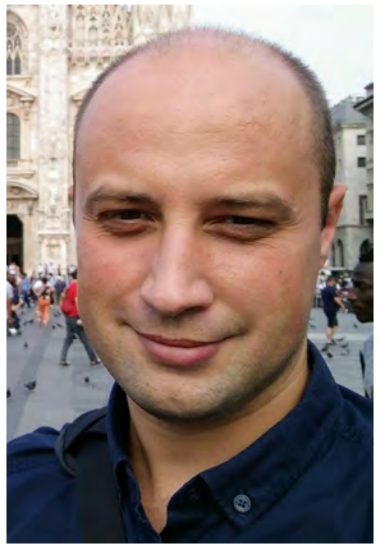
Using downhole ranging techniques, the relief well task force locates the blowing wellbore and directionally steers the bit until it is finally aligned to intersect the blowing well at the planned depth. If the RWIS is not already installed, the relief well BOP must be disconnected from the wellhead and the RWIS installed on the wellhead via drill pipe or wireline rigging arrangements. Subsequently, the BOP is reconnected on top of the RWIS and the lines from the support vessels are attached to the RWIS flowline connectors using an ROV. After assembling the entire dynamic kill pumping system, the relief well can drill the final section and intersect the blowout well. Finally, a high rate dynamic kill is achieved by simultaneously pumping down the kill and choke lines from the relief well rig and from the dedicated support vessels connected to the RWIS.

Figure 2: RWIS ready for mobilization, configured without shear rams

The RWIS can be rapidly deployed by air, ground and marine freight to any region of the world. Because of the projected solution provided to drilling operations, the RWIS has already been contracted for several wells to be drilled in 2017 and 2018.

Leak detection - Identification of source of low rate sustained annulus pressure

by M. Volkov and R.-M. Greiss, TGT Oilfield Services



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Introduction:

This article demonstrates one of the largest challenges many Operators face – low rate leaks in casing annuli. Such leaks show the barrier isolation failure and are critical to fulfill the requirements of regulatory for abandonment or to continue well operation in a healthy manner. With the current development of the logging tools, the source of the sustained annulus pressure can be identified if it builds up more than 1 bar a day. The cases below were published previously by Operators to demonstrate the capabilities of Spectral Noise Logging to investigate the source of low rate build up and leak off.

Spectral Noise Logging for leak source identification:

The passive noise logging is a well-known technique to identify different events downhole. The noise generated by the fluid or gas moving through channels, fractures, pores or wellbore is captured by the sensitive hydrophone. The logging is done via stations while pulling out of the wellbore to reduce the influence of the noise from the tool movement and hence focusing instead on the minor events, such as low rate channeling and contributing reservoir. The captured noise data is then transformed into the spectral panel which describes the frequency and the amplitude of the noise source. The fluid noise spectrum and volume is strongly dependent on the fluid type, pressure, temperature, and flowrate. Although the noise intensity increases linear with increasing flow rate, the noise frequency spectrum depends not on the flow type or velocity but on the type of media or channel through which the fluid moves.

Downhole High Precision Temperature data for tracking the flow:

Leaks in well completion components are conventionally detected by shut-in and bleed-off /leak off temperature logging with subsequent qualitative and quantitative interpretation of temperature logs. The problem in interpreting temperature logs is that they respond to various events and, in many cases, one cannot distinguish if it is vertical flow, lateral flow or some residual effects. In many cases of low rate leaks the behind-casing communications had undetectable differences between shut-in and bleed-off / leak off temperatures, temperature logging was helpless in identifying leak sources, but the temperature gradient change helped to identify the long-term events, such as crossflow or continuous annulus building up / bleed off channeling and pressure source formation.

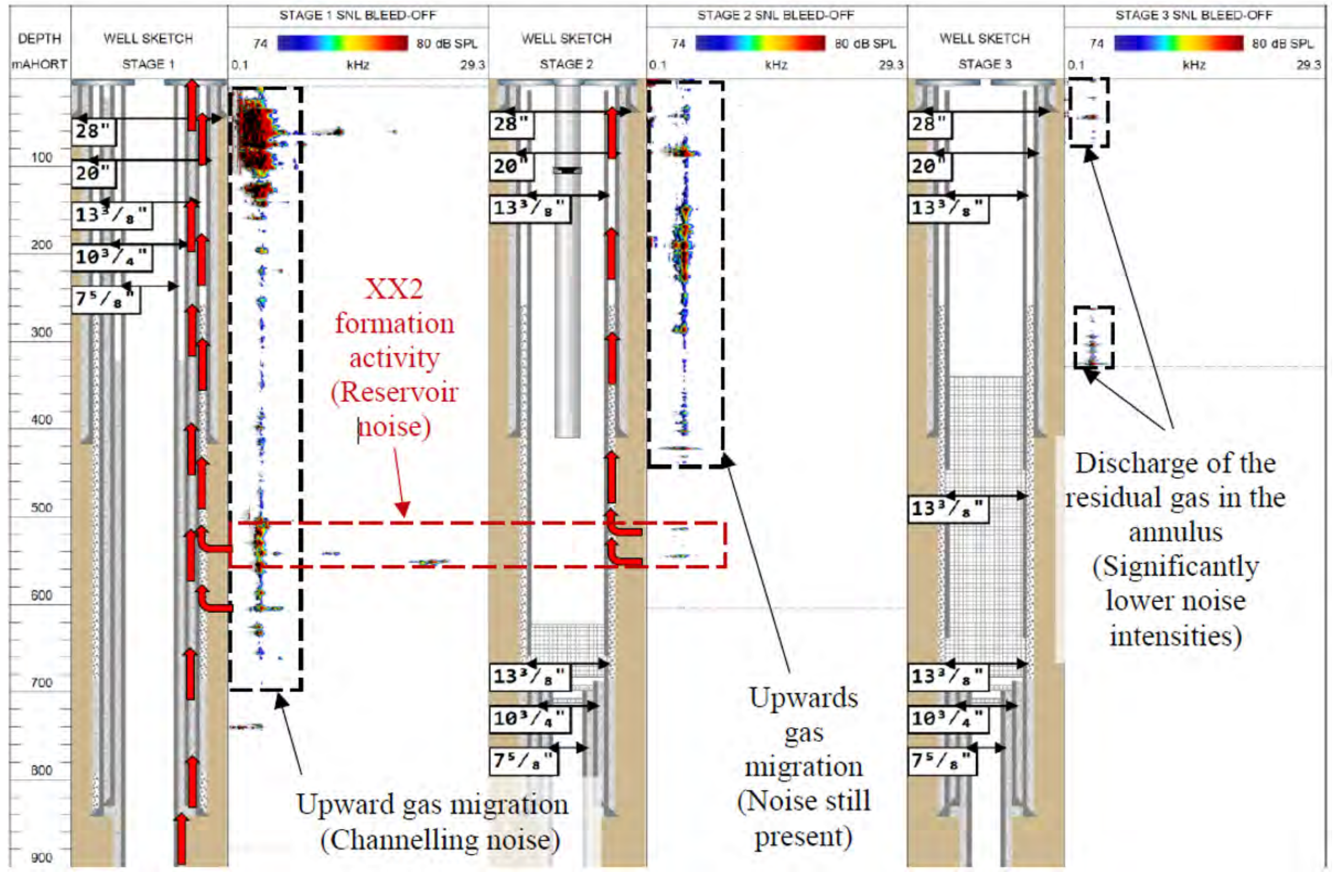
Survey planning:

The minimum criteria for the successful leak detecting and tracking of the path to the leak source are typically 1 bar per day. If the pressure build up is not monitored but there is a continuous leakage of the surface the minimum leak rate is defined as 10 liters per hour. So the well intervention with leak detection is planned if the input parameters exceed the above-mentioned criteria. The logging is started with a shut-in or build up mode. The last one should have close to maximum (flat) sustained annulus. In such logging conditions, the undisturbed baseline temperature and background noise is measured. The next stage is induced leak survey when the differential pressure is applied across the leak zones. The High Precision Temperature and Spectral Noise Logging are acquired and compared to the baseline logs. The difference between the logs is caused by the induced leak, and allows identification of the pressure source and tracks the flow path to the surface.

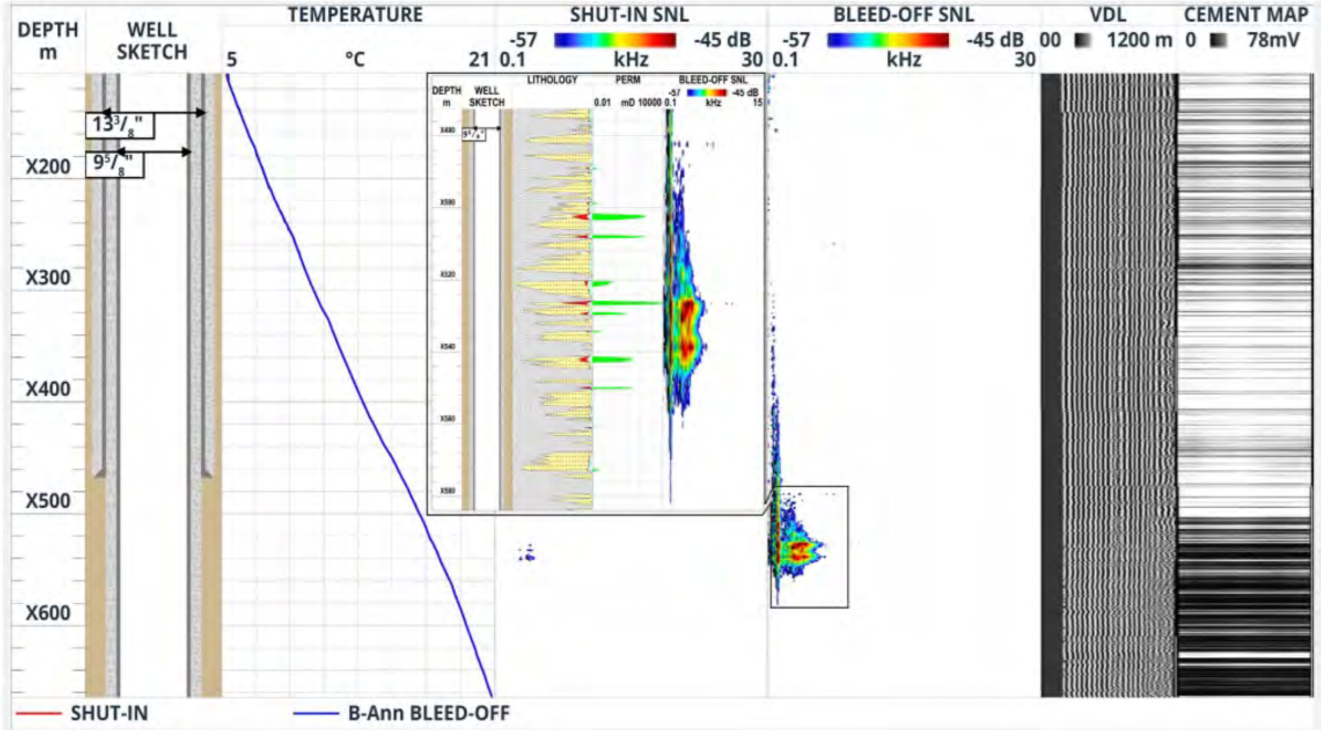
Applications: Spectral noise logging for Pre-& Post Abandonment assessment.

Well #1 was part of an abandonment campaign. The sustained annuli pressure was observed with a rate of 0.1 bar a day in C-annulus and 5 bars a day in B-annulus. The maximum pressure in B-annulus was 35 bars whilst in C-annulus only 3.2 bars. Multiple log and plug/section milling stages were executed in order to abandon the well. Each time, the Spectral Noise Logging and High Precision Temperature logging data analysis aided in determining the plug intervals and verifying the integrity of the plug. After the third stage, the sustained annulus pressure was eliminated in both annuli.

Well #2, a water injector, started experiencing the B-annulus pressure of 5 bars. The build-up rate did not exceed 1 bar a day. A conducted Cement Bond Log survey indicated a good cement bonding below X500 while above the cement was poor quality. A leak detection survey utilizing Spectral Noise Logging and High Precision Temperature analysis was conducted under shut-in and bleed-off survey indicated the activity in the reservoir and channeling up in the good cement bonding area. The frequency noise pattern was in good correlation with saturation and permeability profiles suggesting the gas was produced from these formations.



Well #1 Channelling noise and upward gas migration identified by Spectral Noise Logging and High Precision Temperature logging.



Well #2 Channelling in the good cement bonding area identified by Spectral Noise Logging and High Precision Temperature logging.

The perf and cement squeeze job restored the isolation in the B-annulus and eliminated the sustained annulus pressure.

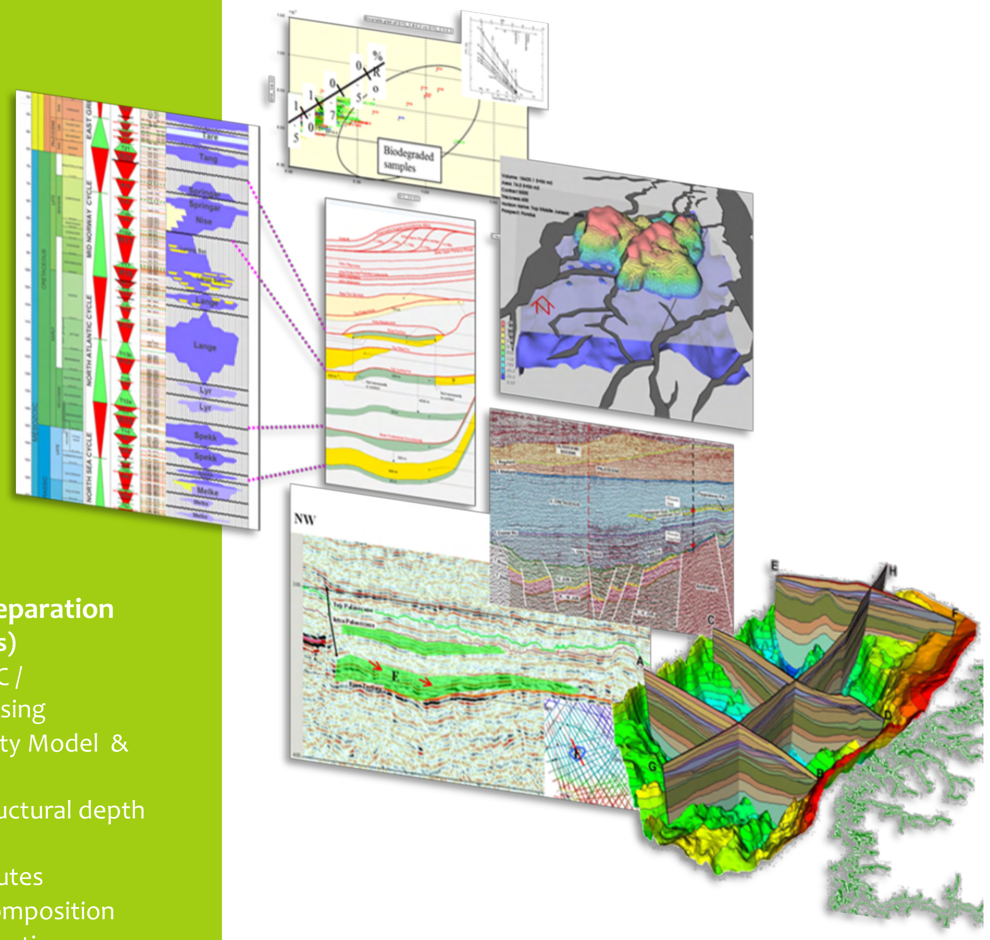
Conclusion

Today with 60$ oil price the oil and gas industry dictate the need for the Operators to reduce costs and operate in an efficient manner during the life of a producing well and abandonment phase. While conventional spinners and production logging temperature can assess first barrier leakages only, the Spectral Noise Logging enables tracking the leaks at very early stages occurring behind multiple barriers with a minor rates enabling intervention and prolonging the well life.

Karenslyst allé 57, Skøyen 0277 Norway

Services

APA Application
License rounds
Prospect Evaluations
Farm-in Estimation



License Application Preparation

Data (Seismic & EM, well logs)

- Survey planning / Data QC / Conditioning /Processing
- Clarification of the Velocity Model & Velocity Model Building
- Depth conversion for structural depth and thickness maps
- AVO volumes and Attributes
- Spectral and Phase Decomposition
- Geological time cubes / sections
- Petrophysical analysis

Geological Interpretation

- Structural Interpretation
- Seismic Facies Analysis
- Structural time Maps Preparation
- Preparation of Seismic amplitude maps
- Reconstruction of tectonic evaluation
- Sedimentological/Depositional model
- Basin Modelling
- Biostratigraphy

Geophysical Interpretation

- Rock Physics Modelling/ Fluid substitution and Synthetic Gathers Modelling
- All types of Inversions (necessary one)
- Seismic Attribute analysis
- Dynamic / AVO Analysis
- Quantitative interpretation

Identification of promising prospects

Field Development concept

- Reservoir Engineering / Prepare production profiles

Administration

- Assessment of geological risks and resource potential
- Prepare Capex and Opex profiles
- Prepare economical analysis
- Application report delivery

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