Engineering in Arctic
Environmental compliance
Geo Estimations for Field Development
Well Engineering
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 its 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 behalf of the Editorial team,

Giedre Malinauskaite

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SPE Norway One Day Seminar
18 April 2018 | Hotel Edvard Grieg | Bergen, Norway

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Changing Industry Context – Challenges and Opportunities within Drilling, Reservoir Management and Production
Dear SPE Members!

I want to use this opportunity to thank you all for your participa-
tion 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 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 media.

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

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News from SPE 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**

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

**October 18-19th:**

SPE Stavanger was present at our own stand at the exhibition. Chairman Vidar Strand participated in a panel debate.

**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.

**November 10th:**

SPE Young Professionals Wine Tasting had 55 social guests.

**November 15th:**

Geothermal Drilling & Energy Production Workshop in cooperation with GGER, Statoil and Husmaan attracted 75 guests.

**October 10th:**

Tore Øian from SPE Stavanger opened the Students’ Bachelor’s & Master’s Day at the University of Stavanger.

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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 GGER Skills and Competency Rune Tvent and Contract Specialist Tore Myldnes 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.

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**The winning team**

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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 Smønnes Tybring-Gjedde from the Ministry of Petroleum and Energy delivered an inspiring talk to our members during the kick-off event on September 6.

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On November 14, three skilled speakers, two professional organisations, one topic - The geological overview of the Barents Sea collected 74 attendees! Erik Henriksen, Nathalia Kuken 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 at-
We have launched a new section website!

It was time for SPE Bergen to renew its 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!

TechNight 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

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 exciting 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.

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.
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

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 operation 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 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 implicitly. Thus is 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 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/fatigue (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 such as ice and snow, cold temperature, polar low, snowdrift, etc. will cause significant challenges if 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 significant deformation. 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 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 failure 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.

- 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 results in micro-scavenging and joint deterioration. Fig. 2 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].

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

Figure 2. Cavitation failure. Source: Corvias

*This article is shortened from the IEEM 2016 conference paper and adapted for The First SPE Norwegian Magazine.
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.

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 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

The First

by I. Thomas, Lloyd’s Register

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

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 a 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 5001 is strongly recommended as the best path forwards; its management system model is based on continual im-
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.

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 chain lengthens. 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 demand owners and operators get value for money from their HSEQ management system.

Lloyd’s Register is a leading, independent provider of asset integrity, compliance and specialist risk consulting services to the energy industry.
The role of Geophysical Uncertainty in Field Development concept selection*  
by S. Romundstad, I. Meisingset, D. Krasova, First Geo; T. Forde, Aker Solutions; and S. Tresselt, IPRES

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.

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Manager Exploration Services, First Geo

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Senior consultant, IPRES

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 options 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 46/5 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 the 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 optimization scenarios are derived, each with an 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 economic value. Based on this, and assuming the best deterministic depth case, measured in terms of field development 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 optimum 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.

Averaged depth map was used to make this map.

The different geophysical maps resulted in different outcomes. In an initial appraisal program, which was proposed by the G&G team for the purpose of reducing the subsurface uncertainties, a series of different development schemes including the economics a computer program (IPRiskField) were used. In this program every parameter is input in a probabilistic manner. Every simulation result consists of 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 that are typical for the North Sea.

The reservoir is a Lower Tertiary basin floor fan, resting 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, but the first three wells found a lower OWC. Examination 4, the discovery well, unexpectedly found oil in the Lower Tertiary. It penetrated 44 ft. of oil in marine fan, fan sand. The OWC is at 5007 ft. It 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 to determine depth conversion down to top reservoir sand. The OWC is at 5007 ft. In determining the best development concept for the Aker Field, seismic processing velocity field is a direct measurement of the average velocity, but it also includes noise.

The formation is classified as soft openoporphyric sandstone. The reservoir section is 50 ft. thick. There are two reservoir sands, with net oil sand at 5007 ft. and net gas sand at 5009 ft. The water is of low salinity and not expected to have a significant effect on the reservoir properties.

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. 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 optimum 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.

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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
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 assumed 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 development 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 under saturated with a low GOR and a slightly viscous oil type (fluid analyses from Exploration_4 well) to be excel lent. 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 to the 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 possibility 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.

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 downs ide of expensive drilling rigs in a demanding market. Separate drilling rigs were accounted for in the scenarios including wellhead platform (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 southeast.

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 field, where uniform water filling 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.

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 for the field size, distance, timing and certainly cost. Cost would both include the investments bringing the fluid to the host and further the cost of processing, consent 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 4. Average well oil, water production profile and water cut
We ended up with three scenarios, ‘Small’, ‘Middle’ and ‘Large’, which were optimized for the reserves before the P90 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 Tota 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 (excluding drilling costs) 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

Economic 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’.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Small development</th>
<th>Middle development</th>
<th>Large development</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAPEX (USD)</td>
<td>1,700</td>
<td>3,700</td>
<td>4,600</td>
</tr>
<tr>
<td>OPEX (USD)</td>
<td>5% CAPEX</td>
<td>5% CAPEX</td>
<td>5% CAPEX</td>
</tr>
</tbody>
</table>

Table 6. CAPEX and OPEX figures for the development scenarios

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, we all have proven is the P90 case, with well Explor.

<table>
<thead>
<tr>
<th>Development Scenarios</th>
<th>NPV (USD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small development</td>
<td>2,588</td>
</tr>
<tr>
<td>Middle development</td>
<td>1,112</td>
</tr>
<tr>
<td>Large development</td>
<td>1,030</td>
</tr>
<tr>
<td>Appraisal simulation (Small vs. Large)</td>
<td>2,975</td>
</tr>
</tbody>
</table>

Table 6. NPV values for the different scenarios (NPVx106)

The optimal decision path is shown in Figure 7. 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 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 sub-surface 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

The authors thank the management of Aker Solutions and IPRES in granting permission to publish this paper. We also thank Rusten Ackora and Arne Borthaug of Aker Solutions for valuable discussions.
Decision models - Geological modelling to guide decisions
by A.-L. Hellman and T. Hultgreen, AGR

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 must 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 temporary P&A 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 geometries 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 of kv/kh in several geological scenarios. This enabled us to be more pragmatic on e.g. how 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 CO2 storage feasibility study in the DG1 phase. Key questions to be addressed were related to the injectivity of CO2, 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...
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 CO2 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 and to not complicate the workflows, modelling techniques and steps. 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.

Our view on trends in geological modelling has regarded 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.

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 summarized 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.

Geo Estimations for Field Development

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

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 equipment downtime.
- No recorded HSE incidents.
- 26 351kg of solids, including fracturing proppants, removed.
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 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 reveal some disadvantages for an operation in general. For drilling activities, the result can typically be thinner hole sizes, reduced kick tolerance, running more casing strings, and 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.

Table 1: Advantages of the RWIS

<table>
<thead>
<tr>
<th>Advantage</th>
<th>RWIS Key Properties</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enables drilling of prolific reservoirs ensuring single relief well contingency</td>
<td>Enables drilling of prolific reservoirs ensuring single relief well contingency</td>
</tr>
<tr>
<td>Increased pump rate and volume required for kill</td>
<td>Increases pump rate and volume required for kill</td>
</tr>
<tr>
<td>Removes kill and choke line bottleneck</td>
<td>Removes kill and choke line bottleneck</td>
</tr>
<tr>
<td>Increases redundancy and flexibility of operations</td>
<td>Increases redundancy and flexibility of operations</td>
</tr>
<tr>
<td>Moves additional pumps and mud storage to remote vessels</td>
<td>Moves additional pumps and mud storage to remote vessels</td>
</tr>
<tr>
<td>No installation of additional pumps and mud storage on relief well rig</td>
<td>No installation of additional pumps and mud storage on relief well rig</td>
</tr>
<tr>
<td>Enables off-bottom kills, faster and reduced spoil volume</td>
<td>Enables off-bottom kills, faster and reduced spoil volume</td>
</tr>
<tr>
<td>Removes the requirement for using mud weights above the fracture gradient</td>
<td>Removes the requirement for using mud weights above the fracture gradient</td>
</tr>
<tr>
<td>It is independent on the relief well rig</td>
<td>It is independent on the relief well rig</td>
</tr>
<tr>
<td>Enables larger and more cost-effective wells</td>
<td>Enables larger and more cost-effective wells</td>
</tr>
<tr>
<td>Saves rig time and cost of casing</td>
<td>Saves rig time and cost of casing</td>
</tr>
<tr>
<td>Increases production rate by larger completions</td>
<td>Increases production rate by larger completions</td>
</tr>
<tr>
<td>Improves safety</td>
<td>Improves safety</td>
</tr>
</tbody>
</table>

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 was during the EU–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, no experience exists on intersecting and co-ordinating a dynamic kill operation in an offshore environment using multiple relief wells.

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

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

Figure 1: RWIS and connections to vessels

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

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 additional flow of kill mud, see example in Figure 1.

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 kill 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) BOP must be disconnected from the wellhead and the RWIS installed on the wellhead via drill pipe or wire-line 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.

The RWIS can be rapidly deployed by air, ground and marine Kirke 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

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 wellbores to reduce the influence of the noise from the tool movement and hence focusing 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 undetected 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 annulus 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 the 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.

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.
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- AVO volumes and Attributes
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- Petrophysical analysis

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- Structural time Maps Preparation
- Preparation of seismic amplitude maps
- Reconstruction of tectonic evaluation
- Sedimentological/Depositional model
- Basin Modelling
- Biostratigraphy

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- 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**
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- Prepare economical analysis
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