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The First

SPE Norway magazine

To gather members
To share knowledge

In this issue:

The electronic version is available on the page of your section website.

Picture: Bredford Dolphin, source AGR/Dolphin Drilling

Dear "The First" Readers,

Norway has always had excellent engineering expertise despite its small size. In addition to having he world leading technology, the industries have had skills to adjust it to the environmental and economic changes. Transformation and implementing already acquired know-how to new frontiers only reflects the professionalism of the regional engineers. Our Winter issue reflects on many topics actual in our current assignments and the environment around us. We hope you enjoy reading about individual examples of transformation.

On behalf of "The First" editorial team,

Maria Djomina
Editor The First/
Communications Manager, AGR

SPE Oslo
SPE Stavanger
SPE Bergen
SPE Northern Norway
SPE Trondheim

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Editorial content

SPE 2017 President JANEEN JUDAH:

You are at the right time to plan for and begin your career as petroleum engineers

As students, you are at the right time and part of the right organization to plan for and begin your career as petroleum engineers. I am excited to be able to share with you some of my background and history with SPE and how I believe our programs and benefits will serve you in the future.

Like you, I began my SPE tenure as a college student. In fact, next year marks my 40-year anniversary of being an SPE member. I have been involved almost continuously in SPE leadership for those four decades.

I started my SPE leadership journey as secretary of the SPE student chapter at Texas A&M University. After graduating, I moved to Midland, Texas, and volunteered with the local section starting with scholarship committee and then eventually was elected section chairman at age 29. In 1990, I was transferred to Houston and started over on the Gulf Coast Section scholarship committee, moving through several section leadership positions and was eventually section chairman in 2001.

I have served on several local and international committees, and this is my third term on the international board, as regional director, vice president and now president. It has been more than 30 years since a former Gulf Coast Section chair has been SPE President. I learned a lot from local section leadership because it is harder to motivate and lead people when they are doing it for fun rather than when you sign their performance review!

SPE's core mission has always been to provide upstream technical knowledge to members. That won't change, but some of the delivery mechanisms are likely to change, not only for efficiency, but also for generational differences in how members access programs and services. One of the biggest things SPE has done is the OnePetro electronic library, increasing access to SPE members everywhere. I know that the Oslo section has helped the student chapter at the University of Oslo with a subscription to One Petro. That is a tremendous resource, and a great gift that the Oslo professionals gave to the students.

This example of the Oslo professionals helping the students proves that SPE provides invaluable networking. The core reason I believe that people get involved in SPE is **relationships**. SPE allows technical professionals to build their own professional network, and I know it has been very key for me. Meeting other engineers in person is the way to build business connections, and SPE helps make that happen for our members.

SPE provides many benefits to students, similar to what we provide professional members -- technical development and networking. As a student member, you get access to the wealth of knowledge in OnePetro. Students get contact with their sponsoring professional section, through speakers, recruiters, mentoring programs, etc. SPE is still the best way to get started on your professional network and to continue to develop your technical skills.

Digital delivery is not only making things more efficient but also more globally accessible. Your generation thinks and works differently than my generation. Today's students are "digital natives" and expect to have data instantly available. The digital mindset of your generation will drive the Big Data revolution that I've already pre-

dicted, driving change from the bottom up. In the future, more technology will be delivered digitally rather than in person through meetings or programs such as the Distinguished Lecturers. SPE's webinars and interactive video are especially good for remote locations or small sections.

But, of course, we must contend with today and the market downturn. The good news is that we are already seeing the tide turning back – I think we have reached bottom in the downturn. However, I can't predict exactly how fast investment will begin again. As a student, you should not be discouraged about the short-term issues in the industry because it is still a fun industry and hard to beat as an interesting and diverse career opportunity. Petroleum engineering graduates now may have to do more networking and more job hunting this year, but in four to five years this will be a completely different industry. There will be a lot of opportunity because the Big Crew Change has mostly happened.

There are a lot of good data-rich resources on the internet. Two I would recommend are:

1) Shell's scenarios, which show that while renewables will increase, the overall energy demand will roughly double by 2040. Fossil fuels will be essential to light the planet and improve people's lives. Cheap, affordable energy is the most important development when it comes to improving peoples' lives – it enables inexpensive food, clean water, medical care, transportation, education and almost every measure of life improvement.

2) Another reference I recommend is @AlexEpstein's moral case for fossil fuels. Epstein takes a philosopher's view and has ready arguments to refute arguments that fossil fuels should be left in the ground. He's an engaging speaker, and I walk a little taller after hearing him.

As I mentioned in the beginning of this article, you are in college at the right time in our industry's history. Companies will emerge from the downturn ready to hire brilliant, technical engineers such as yourselves. Study hard, but also enjoy your college years. Establish your balance now between work and recreation. I didn't have a lot of fun in college; I regretted that I didn't play more. I worked really hard and graduated in 3½ years at age 21.

I think a terrific way to balance your studies with some fun is to join a Petrobowl team. I am so proud of the team from the University of Stavanger which won the Super-Regional Qualifiers for Petrobowl and advanced to the finals at ATCE alongside the Norwegian University of Science and Technology Chapter.

My most important recommendation to stay on the right track is to preserver and stay tough when times get hard. Most engineers had a rough spot in college, often a tough calculus or physics class, and they toughed it out rather than switching to an easier major. Successful people stick with objectives when times get hard, and that applies to college courses, too. It also applies to life, because sometimes life is hard too.

As SPE's first woman president in many years, I'm often asked how I manage work/life balance. My first reaction is that no one ever asks men about work/life balance! I think it is a coded question for "how do you manage that second job you have when you get home?" So yes, I do all the "wife" chores at my house – I cook, clean (what the 2x/month cleaning lady doesn't do), do laundry, pay bills, even buy most of my husband's clothes for him online.

For me to manage it, I have learned to let go of perfection. Work/life balance gets harder the higher you go, with more demands from people and travel. When you are in management, your team and your boss expect you to be available 24/7. For balance, I try to plan ahead for fun things in my life and then do them. I can do almost anything with enough lead time. I believe you can have it all, just not always at the same time.

The technical career ladder often offers better work/life balance. When you go into management, the demands on your time are more than they are when you are just individual contributor and your staff expects you to be there for them. On the technical ladder, you can go almost as high as the management ladder at the big service and oil companies. That is why I advise young people, especially young women, not to write off being on the technical track because often you have more flexibility and work/life balance.

In Houston, we have a Young Professional named Yoshi Pradhan. She began reading papers in OnePetro when she was still in high school. In college, she joined her student chapter, knowing that she wanted to study petroleum engineering. Now as a professional member, Pradhan is incredibly involved in SPE and was a driving force in creating SPE Cares, the newly established volunteer organization. I would not be surprised if, one day, she becomes SPE president. You can, too, if you stay involved in SPE and focused on your studies.

Janeen Judah is the President of Society of Petroleum Engineers (SPE) 2017. Judah served on the SPE Board of Directors as Vice President of Finance. She has held many SPE leadership positions, including chairing both the Gulf Coast and Permian Basin sections and serving on the Board 2003-2006 as Director for the Gulf Coast North America Region. She was named a Distinguished Member of SPE in 2003 and received the Distinguished Service award in 2010. Judah has served as President of Chevron Environmental Management Company and General Manager of Reservoir and Production Engineering for Chevron Energy Technology Company. Before joining Chevron, she worked for Texaco and ARCO in various upstream petroleum engineering positions, starting in Midland in 1980.

Judah holds BS and MS degrees in petroleum engineering from Texas A&M University, an MBA from The University of Texas of the Permian Basin and a JD from the University of Houston Law Center.

Happy New Year from Regional Director

Dear SPE Friends,

Karl Ludvig Heskestad

SPE Regional Director North Sea
AKER BP
karl.ludvig.heskestad@akerbp.com

I would like to wish all the readers of The First a Happy New Year and I hope you have had a great start to 2017 so far! At the time of writing, the Brent oil price is at 57 USD. A price not seen since July 2015, and is a direct consequence of the news that OPEC and 11 other countries agreed to limit their oil production. As an E&P professional, I try to follow the energy market and my impression is that we will continue to see a volatile market going forward. If you read your monthly edition of the JPT you will find an overview of global oil supply and demand. This overview covers the last four quarters, and you will see that these two fundamentals are now approaching each other. Taking the short-term view, we are still producing more oil and gas than the market demands, but as we approach a supply/demand balance, I think we are in for an even more volatile oil market ahead.

Looking into the future, oil and gas combined with coal expects to provide roughly 80% down from 86% in 2014[1], of the world's total energy supply in 2035. Providing around 60% of the growth in energy[1]. If we combine this with an expected growth in global energy demand, then more talented and creative engineers and scientists are required. This should be a reassurance for both young people who are considering their future career paths and for the well-established professionals who are reconsidering their options due to the current down turn. As oil and gas demand continues to grow so too will the SPE. Today we are around 168 000 members worldwide, where ca 8000 are in the North Sea region. However, the volatility we have seen over the last couple of years has affected membership numbers and as Regional Director for the North Sea region, I expect the coming years to be even more challenging in terms of member retention. The SPE is determined to be there for their members, especially in difficult times. For those who find themselves without employment, the SPE will waive the membership dues for a period of up to two years. I hope this will make it easier for everyone to stay in touch with the industry and his or her network.

The North Sea Region has 12 sections distributed in six countries and the sections are, despite the down turn, keeping up an impressive activity level. I recently had my first call with the Section Chairs and it was very rewarding for us all. By communicating frequently, we will be able to capture and learn lessons from each other's accomplishments share our plans and more importantly, work to address challenges together. The volunteers at the section level are doing so much hard and impressive work and I want to make sure that we continue to build on the local knowledge. This will enable us to learn from each other and continue to grow our sections and SPE even in challenging times. As Regional Director (RD), I am the Sections' voice to the International Board of Directors of the SPE, but I will also try to facilitate communication across the sections. This will further strengthen the good relations that exists among our sections. During my period as RD I will work to identify and allow for synergies between the sections. This could typically be where sections have similar events, with similar topics/themes and would benefit from joining forces.

Many people start the New Year with a New Year resolution. If you are in need of a suggestion for your resolution, I would like to end my message by suggesting one. As readers of The First you are probably aware that the annual SPE Awards nomination is coming up. The deadline for the nomination process is March 15th and I would like to challenge you to nominate one of your peers. There are so many members in our region that would be eligible for such nominations. I hope to receive many nominations by February! Please go to www.spe.org/awards and nominate an SPE friend / colleague today.

[1] BP Energy Outlook 2016

News from SPE Bergen Section

A yearly traditional Lutefisk dinner, organized every November by a SPE Bergen Section, once again has gathered a full house of professionals from Oil & Gas sector. We would like to thank everyone who attended, and our sponsors, for supporting SPE Bergen Section. We look forward welcoming you again next year!

SPE Bergen Section Board

SPE Bergen TechNights

SPE Bergen Section organizes monthly TechNights for members of SPE and other Oil&Gas professionals. TechNights feature both, Distinguished Lecturer presentations, SPE papers and technology presentations.
Do you have a SPE paper you would like to present at one of our TechNights? Has your company developed a ground-breaking technology or maybe performed a project with extraordinary results? SPE Bergen TechNights welcome presentation proposals from across the country.

For more information, contact: Jørn Opsahl opsahl@tomax.no

News from SPE Stavanger

Stavanger Section

SPE Stavanger started 2017 with two distinguished lecturers in January and February respectively, with 50 guests attending each presentation. The meetings are still held at Scandic Stavanger City Hotel, where they serve excellent 3-course dinners following the presentations.

Upcoming events

February 23rd – *YP Social Gathering*
March 2nd – *YP Lecture Series*
March 8th – *SPE Stavanger Meeting*
April 5th – *SPE Stavanger Meeting*
April 20th – *YP Lecture Series*
TBA – *SPE Stavanger Annual BBQ*

News from SPE Northern Norway

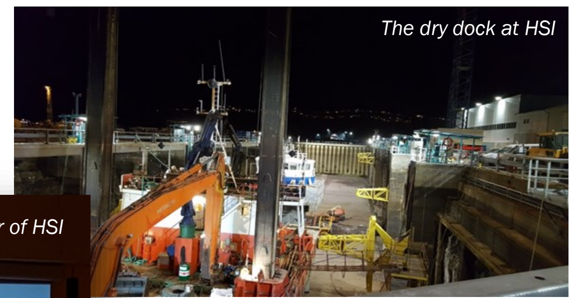
SPE Northern Norway rounded off the year in cooperation with the Norwegian Petroleum Directorate (NPD) 1st December. The head of NPD's Harstad office, Stig-Morten Knutsen, gave the audience an interesting lecture under the title: "The Barents Sea - What to Come and Where to Go: on Continuities and Discontinuities in an Intracratonic Basin in an International Setting". The lecture touched into the blocks next to the Russian border, the famous Loop Hole and also what NPD believes will be the next step in the Barents Sea. 2017 will be an interesting year with a lot of exploration wells taking place.
After the event a delicious Christmas dinner were served at Bark Spiseri & Bar, and the conversation flowed lively around the tables.

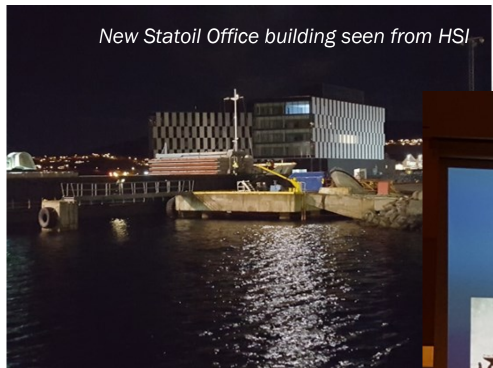

Head of NPD in Harstad, Stig-Morten Knutsen

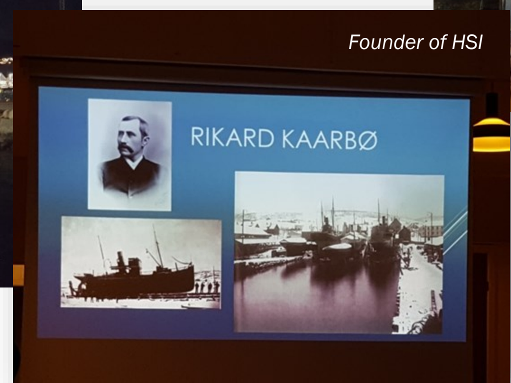

Executed and planned wells in the Barents Sea 2016

Cosy evening together with Harstad Skipsindustri and Hamek

10th November SPE Northern Norway arranged a company visit at one of the oldest companies in Harstad, Harstad Skipsindustri (HSI). Participants of the visit came from oil & gas industry, naval industry, consultant business and also several students from the Arctic University of Norway, UiT.
HSI guided us through the ship history of HSI that formed Harstad to be a city in early 20th century and the founder of HSI, Richard Kaarbø, were also the mayor of Harstad until his death. The presentation took us through the historical steps from the early start of HSI, and also Harstad city, and the company's development from building ships until today's business within naval service. Totally 178 ships, including one of Hurtigruten's ships, has left the shipyard. HAMEK, a subsidiary of HSI, filled in with their working discipline within naval service. They have the 3rd biggest dry dock in Norway, the biggest in Northern Norway, with a length of 145 m. This was ready in 2014, and after 2 years in service the sales are doubled!
HSI have also a big interest in properties around the shipyard, and a part of the presentation gave us an introduction of the plans they are working with and how they will upgrade the area to be a new district of Harstad. Already, the new office building is in place with a magnificent view out Vågsfjorden towards Senja.
After the presentations there were a guided walk around at the shipyard and the dry dock. The participants walked down after the event for a social gathering at one of the restaurants in Harstad.


The dry dock at HSI


New Statoil Office building seen from HSI



Founder of HSI

News from SPE Oslo Section

Christmas Dinner

About 60 members and friends of SPE Oslo met for a traditional Christmas Dinner on December 15 in the beautiful premises of the Continental Hotel in Oslo. Stephen Bull, Senior Vice President for Offshore Wind and CCS at Statoil held a presentation about Statoil's New Energy Solutions focusing on the opportunities in the energy transition.
Statoil is investing in offshore wind in Norway, the UK and Germany with clear ambitions for further growth, including the innovative Hywind floating wind concept. More about the project can be read n the pages of the First (page 44). The company is also a global leader in offshore CO2 storage solutions. It has two CO2 'fossil' re-injected fields. About the new storage fields you can read from the project lead Gassnova (page 46). Both interesting topic and double serving of tasty Pinnekjøtt made the atmosphere very nice as usual.

DL - The Digital Oilfield: Collaborative Working at Global Scale

On November 17, Frans Vandenberggave a talk during a dinner event on the Digital Oilfield: Collaborative Working at Global Scale as part of the SPE Distinguished Lectures Series in Radisson Blu Scandinavia Hotel.
Collaborative working helps companies to operate assets more efficiently and to do so as one team, with the results of higher production; less cost; lower health, safety, and environmental risk exposure; and higher morale.. The presentation highlighted the recent examples where Collaborative Working Environments had been implemented and which value the business had achieved.
If you missed this lecture, we are happy to invite you to the session on Digital Working Environments in our Magazine (page 36).

Lunch and Learn

Resource Classification System and Reserve Reporting, RNB Reporting, and Annual Status Reporting

As a tradition, SPE Oslo friend and sponsor AGR was again a great and warm host for the Lunch lecture. Two technical presentations were delivered: Resource Classification System and Reserve Reporting (SPE) by Mahmood Akbar, AGR and
NPD's Updates on Resource Classification, Revised National Budget (RNB) Reporting, and Annual Status Reporting of the Producing Fields by Jan Bygdevoll, Norwegian Petroleum Directorate (NPD) (full article here). Both presentations got a very good response.
There is no better way to spend your lunch than usefully and tasty!

AWARD!!!

Oslo Section has been selected to receive the 2016 President's Award for Section Excellence

The SPE President 2016 D. Nathan Meehan congratulated SPE Oslo section chairman, Jafar Fathi (Point Resources), on behalf of the Oslo section board in Dubai during the annual ATCE event. The President also mentioned on the stage
The First while giving the prize and told that his grand children will be on the pages of upcoming issue (Autumn 2016).
If you didn't read the September issue yet, please click here.

Congratulation to all SPE Oslo Members!

Student Young Professional Distinguished Lecturer and Quiz Night at Olivia Aker Brygge on 22nd November 2016

About 50 students, young professionals and professionals met for a distinguished lecture jointly organized by the SPE Oslo YP section and the University of Oslo SPE student chapter. The event kicked off with a lecture by *Honore Yenwongfai, currently a PhD student at the University of Oslo. In his presentation "***Unlocking seismic amplitudes for facies prediction using seismic petrophysics – A Goliat case study" Honore presented his current research findings.** In his research Honore integrates a wide range of seismic and well log data to predict lithology and fluids in the subsurface as well as effective porosity and shale volume.
Following the presentation and dinner a quiz event took place with an oil and gas industry theme. The questions covered a wide range from engineering to geosciences and general industry knowledge. The event was a great success and we thank the SPE Board and our sponsors for financial support to make this evening happen.

By Steven Mueller
SPE YP Oslo Chair


presentation


quiz


awards

Renew Your Membership

Society of Petroleum Engineers

Light at the end of the pipeline

by Jon Fredrik Müller, Partner, Rystad Energy

Jon Fredrik Müller
Partner
Rystad Energy

The subsea market has taken hit after hit over the last years with declining revenues and margins. However, at the same time, the industry has adjusted capacity and is now positioned to start taking advantages of increased activity. First on the tendering side, but then on the revenue and margin side as well. In this article we look at the status of the industry and the likely way ahead.

OPEC back in the game

At the end of November 2016, OPEC announced their decision to cut production to a level of 32.5 mmbbl/d. In addition to OPEC, Russia has declared that they are willing to cut 300 kbbl/d and, according to OPEC, other non-OPEC countries will commit to similar cuts as Russia. Since the announcement, the oil price has gained close to 10 USD/bbl and is trading at around 55 USD/bbl at time of writing.

A higher oil price is certainly positive for subsea developments and higher project sanctioning activity. Costs have come down across the entire industry and although several fields are "in the money" at oil prices of 40-50 USD/bbl, these price levels do trigger fewer offshore developments than seen during the 2011-2013 hay days. Looking towards 2020, Rystad Energy sees an increasingly tighter market balance for oil, which implies increasing oil prices. By 2020, Rystad Energy forecasts oil prices to be in the 80-90 USD/bbl range, increasing the need for offshore and subsea developments.

Subsea expenditure – bottoming out in 2017

The bottom of the subsea market is likely still ahead, given the fact that subsea expenditure is relatively late in the cycle. Subsea expenditure (capex and opex) fell from USD 48 billion in 2014 to USD 43 billion in 2015 (Figure 1), a negative growth of 10%. In 2016, the market is forecast to contract by another 16% to USD 36 billion. The market is believed to bottom out next year at USD 31 billion (-14%), before it returns on a growth path from 2018. By 2020, the subsea market is estimated to reach USD 39 billion, and it is forecast to continue to grow into the first half of the 2020's, surpassing the last high from 2014.

The market development is similar when looking at the number of installed subsea Christmas trees. The number of subsea Christmas trees awarded in 2016 will likely come in closer to 1/10 of the ~550 tree awards of 2013. However, installation activities are smoothened out compared to the awards as there are usually several years from award to installation. Rystad Energy follows installation activity field-by-field. Figure 2 shows the number of subsea Christmas trees installed per year since 2010, with forecast towards 2020. In terms of number of installed trees, the bottom is forecast to be 2017 at approximately 160 trees installed globally. However, Rystad Energy believes that the tree awards have hit the bottom this year and that tendering activity will start to pick up next year.

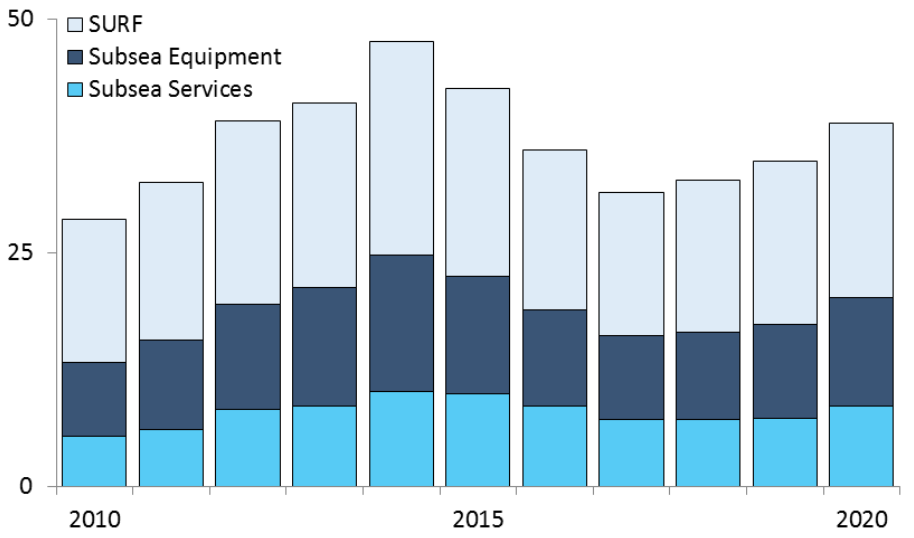


Figure 1. Global subsea expenditure (capex and opex, USD billion) by market segment
Source: Rystad Energy DCube

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About Rystad Energy

Rystad Energy is an independent oil and gas consulting services and business intelligence data firm offering strategy consulting, global databases and research products.

About the author

Jon Fredrik is a Partner in Rystad Energy. His main area of expertise lies in the oil field service segments and particularly within offshore related segments. He holds an M.Sc. in Industrial Economics from NTNU, Norway, with specialization in mechanical engineering and finance, including a graduate exchange program at University of Calgary.

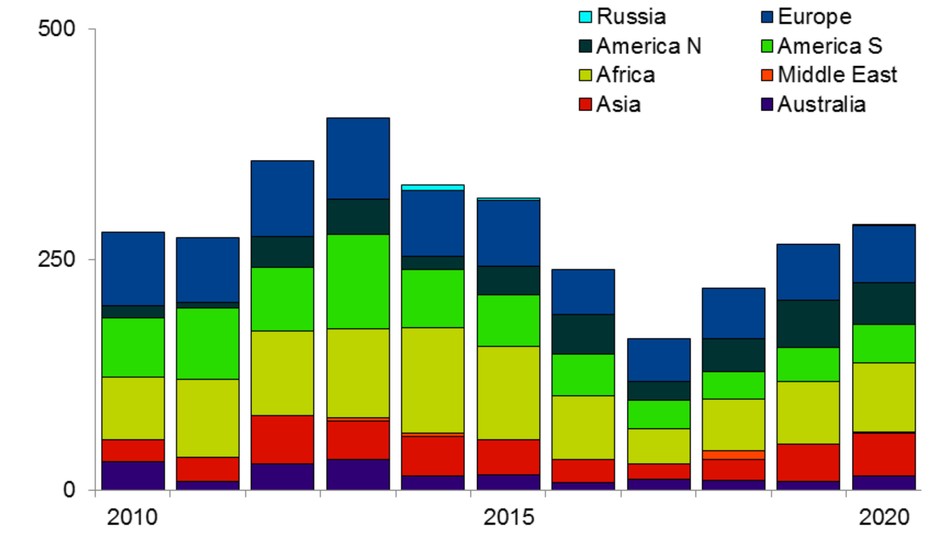


Figure 2. Subsea Christmas Tree Installations (number of trees) by Region
Source: Rystad Energy Oilfield Service Solutions & Analysis

In terms of major subsea markets, it is still the Atlantic basin that will see most of the activity going forward. However, there are also potential deepwater projects in Asia that may drive demand towards the end of the period. Although activity is forecast to improve over the next year, it will likely be into the 2020's before installation activity is back at the high levels witnessed in 2013.

Subsea integration may change field layouts

In terms of subsea structures, the overall market development is quite similar to the subsea Christmas trees. There was a market peak in 2013 and the bottom of this cycle, in terms of installed components, is believed to be in 2017 (Figure 3). However, the different segments fluctuate slightly differently than subsea Christmas trees due to different drivers. For example, protective structures are driven by activity areas/water depths with fisheries, while deepwater developments normally do not include such structures. When it comes to riser bases, you will see much more use in shallow to midwater regions and fewer units in deepwater markets where dynamic loads and riser configurations result in less usage.

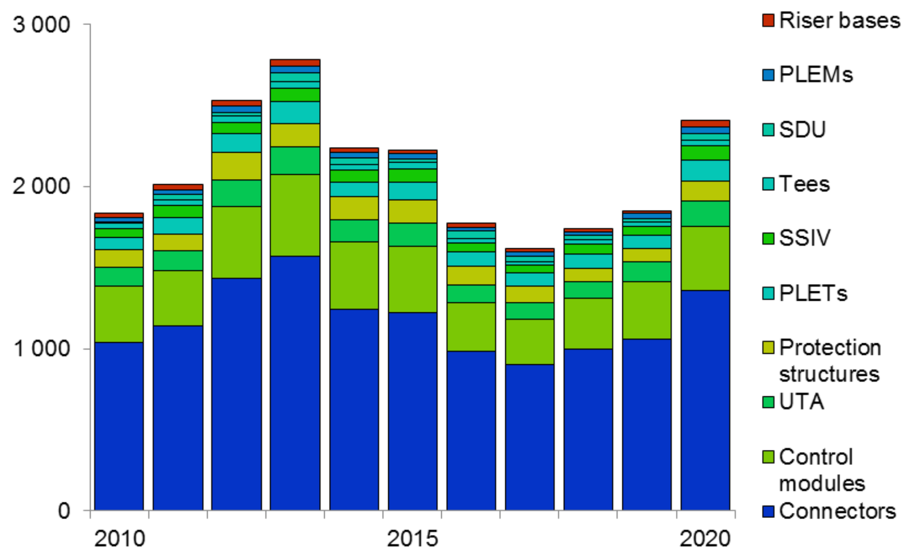


Figure 3. Installation of different subsea structures (number of components)
Source: Rystad Energy Oilfield Service Solutions & Analysis

Figure 3 is based on several years of field–by-field data gathering collected in Rystad Energy. The forecast period is based on communicated plans and subsea developments continuing to utilize similar development solutions that have been seen historically, where plans have not been communicated. It will be interesting to follow the development in subsea infrastructure over the next years to see whether integration in the subsea value chain will result in changes. Mergers like Technip/FMC and Schlumberger/OneSubsea, and different cooperation agreements between actors involved in subsea production systems (SPS) and subsea installation (SURF), might result in improvements of field design and layout. With potential for single contracts covering the total subsea scope, it would be natural to think that one can improve on interfaces and redundancies in system and work processes. Take Pipeline End Terminations (PLET) as an example. The structure is an interface between typical SPS and SURF scope as it functions as a "parking lot" for the end of the pipeline while it awaits final hook-up to the SPS. With a single contractor responsible for both SPS and SURF, it should be possible to plan the installation activities in such a way that you could reduce the need for PLETs. Some may argue that the PLET also performs other functions like capturing horizontal movement in the pipe, but Rystad Energy believe that that could be solved by other measures like laying the pipe in S patterns and/or using flex tails.

Going in to 2017, the subsea industry is in many ways at the bottom. 2017 might be harder still for many companies, however, there should be increased tendering activity as the year progresses, giving more transparency on increased revenues for 2018. The market balance for oil, the likely strengthening of the oil price and a large backlog of discoveries that could be developed should, set the scene for 2018 being the start of the next subsea growth cycle.

Horizon 2020 – EU`s largest research and innovation programme ever

- Open to participation from Norwegian actors on the same terms as actors of any other European nationalities

by Marianne H. Aandahl, Special Adviser, NCP Horizon2020, The Research Council of Norway

Marianne H. Aandahl
Special Adviser,
NCP (national contact point) for the petroleum suppliers and academia towards Horizon 2020

Horizon 2020 is the EU Research and Innovation Program and the largest program of its kind in the world, with a budget of EUR 80 billion for the period 2014–2020. The objective of the program is to boost economic growth and create jobs in Europe. It promises more breakthroughs, discoveries and world-firsts by taking great ideas from the lab to the market. Norway participates as a full member and thus contributes in the program at the same level as other European countries. Until today only about 30 percent of its budget is spent leaving more than half the money available for the best ideas to bring the European countries closer to their targets within a broad range of technological and societal areas. The program addresses academic institutions as well as big and small private enterprises, private and public organizations and communities.

The master idea behind this huge research and innovation program is of course to reach more goals and solve more challenges than any country or institution or enterprise may ever realize by own means and efforts. In addition, the European countries share many of these challenges, and therefore should put efforts together to solve them. An important factor is also that the EU is in need of speeding up its innovation in order to create more jobs and growth in a sustainable way. Horizon 2020 seeks to pave the way to new jobs and businesses through research and high level innovation so that the European countries can stay safe in the global competition for years ahead. There are different ways to participate, but as a general rule you/your company or institution will have to be a partner in a consortium which consists of partners from at least two other countries. This will ensure that the results will have a maximum of common European significance.

The program is divided into three sections of which two are most relevant for private enterprises and companies. These are called:

- **Industrial Leadership** – which comprises Leadership in Enabling and Industrial Technologies (such as ICT, nanotechnology, biotechnology and space technology), risk financing schemes, and innovation schemes for small and medium-sized enterprises (SMEs), and
- **Societal Challenges** – which comprises research and innovation activities to solve seven major societal challenges:

1. Health, Demographic Change and Wellbeing
2. Food Security, Sustainable Agriculture and Forestry, Marine, Maritime and Inland Water Research and the Bioeconomy
3. Secure, Clean and Efficient Energy
4. Smart, Green and Integrated Transport
5. Climate Action, Environment, Resource Efficiency and Raw Materials
6. Europe in a changing world – Inclusive, innovative and reflective societies
7. Secure societies – Protecting freedom and security of Europe and its citizens

The third and last section is called "**Excellent Science"** and is mostly directed towards scientific institutions.

Norway has natural resources that other countries in Europe may envy us, hydropower and oil and gas in abundance. Consequently our industrial base and academic institutions reflect this fortunate position. Since this is not the situation for the average European country, the program does not aim at further develop fossil energy. But that does not mean that the competence, industrial knowhow and advanced knowledge are without relevance for other challenges and needs that are more predominant to our Europeans partners. It seems to be all about seeking new partners, target new markets and give and take from other industrial sectors.

The Research Council of Norway continually seeks up relevant examples of topics with relevance for the subsea and offshore related enterprises, and assists those who are willing to transfer their technology into for example offshore wind, ocean energy, disruptive fishing and harvesting technology, technology for securing national borders at sea and many other areas of societal interests.

Several Horizon 2020 projects with consortia partners from the Norwegian petroleum sector have been awarded funding. Among them are Geowell (geothermal research and innovation) with Icelandic lead, and Miregas (gas detection technology) with Finnish lead.

For more information and possible coaching, please contact National Contact Point, H2020, offshore and maritime technology, Marianne H. Aandahl, The Research Council of Norway mhaa@rcn.no

The First

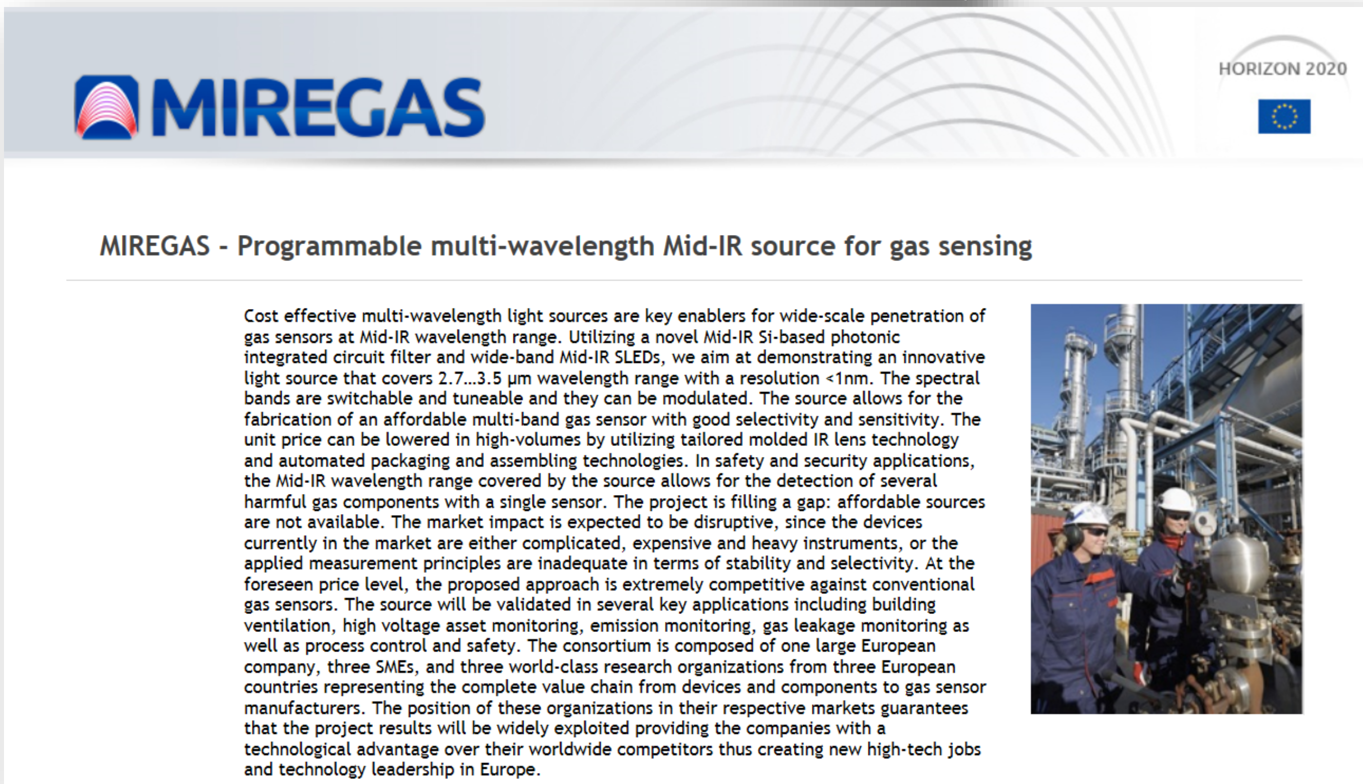
Photo: iStock

GEOWELL – AN EU PROJECT ON GEOTHERMAL WELL TECHNOLOGY

29.09.2015

A consortium consisting of – ISOR, IRIS, GFZ, TNO, BRGM, Statoil, HS Orka and Acquit Business Development, has been awarded a HORIZON 2020 project, which is the EU framework programme for research and innovation.

- Getting awarded this project is a milestone for IRIS Energy, both regarding European funding and being part of such a strong group within geothermal energy research. We hope that this marks the beginning of a significant project portfolio on geothermal energy, says Kristin Flornes.

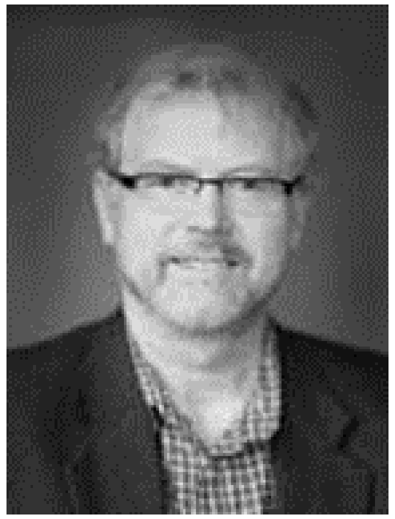


MIREGAS - Programmable multi-wavelength Mid-IR source for gas sensing

Cost effective multi-wavelength light sources are key enablers for wide-scale penetration of gas sensors at Mid-IR wavelength range. Utilizing a novel Mid-IR Si-based photonic integrated circuit filter and wide-band Mid-IR SLEDs, we aim at demonstrating an innovative light source that covers 2.7...3.5 μm wavelength range with a resolution <1nm. The spectral bands are switchable and tuneable and they can be modulated. The source allows for the fabrication of an affordable multi-band gas sensor with good selectivity and sensitivity. The unit price can be lowered in high-volumes by utilizing tailored molded IR lens technology and automated packaging and assembling technologies. In safety and security applications, the Mid-IR wavelength range covered by the source allows for the detection of several harmful gas components with a single sensor. The project is filling a gap: affordable sources are not available. The market impact is expected to be disruptive, since the devices currently in the market are either complicated, expensive and heavy instruments, or the applied measurement principles are inadequate in terms of stability and selectivity. At the foreseen price level, the proposed approach is extremely competitive against conventional gas sensors. The source will be validated in several key applications including building ventilation, high voltage asset monitoring, emission monitoring, gas leakage monitoring as well as process control and safety. The consortium is composed of one large European company, three SMEs, and three world-class research organizations from three European countries representing the complete value chain from devices and components to gas sensor manufacturers. The position of these organizations in their respective markets guarantees that the project results will be widely exploited providing the companies with a technological advantage over their worldwide competitors thus creating new high-tech jobs and technology leadership in Europe.

NPD's Resource Classification System, RNB Reporting, and Annual Status Report for Fields

by Jan Bygdevoll, Senior Reservoir Engineer, NPD



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NPD

Introduction
The Norwegian Petroleum Directorate (NPD) receives various reporting from the operators in order to fulfil various regulatory requirements.

The NPD has its own resource classification system, and this article describes the development of this system. In addition, it provides some highlights regarding the RNB (Revised National Budget) Reporting and Annual Status Report for Fields, which are two of the important reporting requirements. The article is based on a presentation given at a meeting in SPE Oslo in October 2016.

Developments in petroleum resource classification
Resource classification systems for petroleum have developed over a long time. At first, they focused solely on oil and gas reserves, and less on important aspects like maturity and uncertainty.

Some important milestone influencing the development of the NPD system are listed below. (Several organisations has been involved in this kind of work, but only NPD, SPE and UNFC are included.)

- SPE 1988 Definitions of oil and gas reserves
  - Strict definition of reserves
- NPD 1994 Reserves in fields, resources in discoveries and undiscovered resources
- NPD 1997 Fields and discoveries can have resources (reserves) in several resource classes (different projects)
  - First introduction of the term project in resource classification
- NPD 2001 Resource classes and project status categories
  - Based on NPD 1997 with relative minor changes
- UNFC 2004 First framework classification including minerals and fossil fuels
- SPE 2007 Petroleum Resources Management System (PRMS)
  - First use of the term project by SPE
  - Most common system world-wide today
- UNFC 2009 Revised framework classification
  - Also being developed for renewables and CO2 storage
- SPE 2011 Guidelines for application of the Petroleum Resources Management System
  - Definition of term project
- NPD 2016 Harmonize the description with terminology used in UNFC (and SPE PRMS

As we can see from the list, updating of resource classifications is a never-ending story. SPE is planning an update in 2017 and the UNFC may be updated in 2018.

The recent update of the NPD's resource classification system
The NPD's Resource Classification System from 2001 was updated in 2016, but with only minor changes compared to the previous one, as all "boxes" are identical. The changes are mainly language improvements, including new names for some resource classes (boxes). The objective of the update was to harmonize the description with terminology used elsewhere, and clarify the relation to decision milestones used to define project maturation. We attempted, as much as possible, to use the same terminology as in international systems like UNFC and SPE PRMS. The new terminology will be implemented gradually, and will be used when the new resource account is published in February 2017. An overview of the system is shown below.

Definition of a project
A key term in the classification system is 'project'. This term has been used for a long time in resource classification without a proper definition, and was first defined in the SPE PRMS guidelines for 2011. We have used this definition for in this context:

- A project represents the link between the petroleum accumulation and the decision-making process, including budget allocation.
- A project may, for example, constitute the development of a single reservoir or field, or an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership.
- In general, an individual project will represent a specific maturity level at which a decision is made on whether or not to proceed (i.e., spend money), and there should be an associated range of estimated recoverable resources for that project.

Decision milestones in the maturation of a project
There are a number of decision milestones in

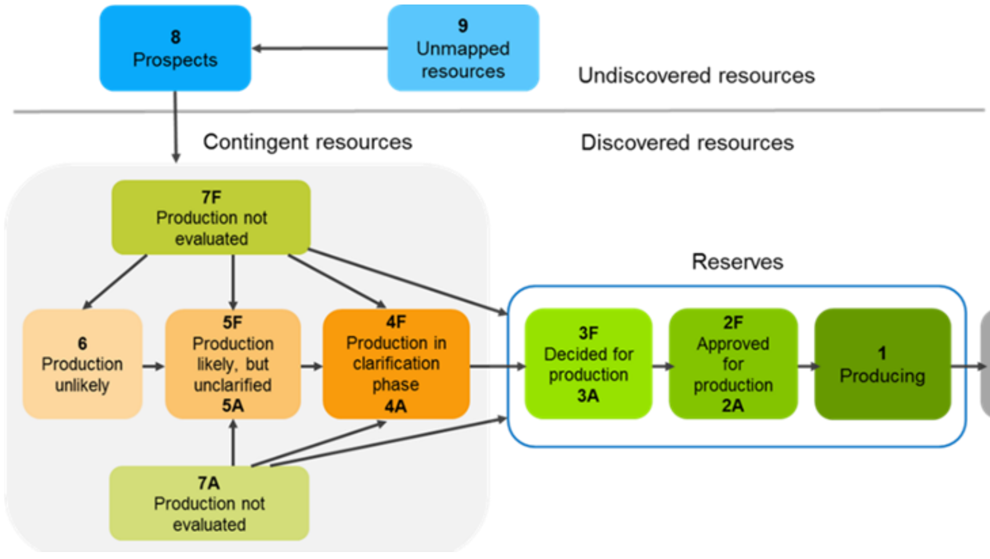

Figure 1. Schematic overview of the NPD 2016 resource classification system

the maturation of a project. These milestones are partly incorporated as terms and conditions in (newer) production licenses on the Norwegian continental shelf, and referred to in the PDO/PIO guidelines.

- Decision to initiate project - BOI: Start of feasibility studies.
- Decision to concretise - BOK: Milestone where the licensees have identified at least one technically and financially feasible concept that provides a basis for commencing studies that lead to concept selection.
- Decision to continue - BOV: Milestone where the licensees have selected a concept and make a decision to continue and initiate further studies that lead to a decision to implement.
- Decision to implement – BOG: Milestone where the licensees make an investment decision which results in the submission of a PDO or PIO.

In the project manuals in companies, these milestones may have different names and abbreviations such as DG1, DG2 etc.

The outcome of all of these milestones could be a decision to take the project to the next phase and continue the work process. However, the decision could also be to shelve or postpone the project, or possibly to re-start the work with a different set of preconditions. In all instances, the classification will reflect relevant project maturation. Figure 2 below shows the connection between project maturation and resource classes, including a short description of the main activity in the phase leading up to the different milestones.

UNFC
UNFC stands for United Nations Framework Classification for Fossil Energy and Mineral Reserves and Resources. It is a universally acceptable and internationally applicable scheme for the classification and reporting of fossil energy and mineral reserves and resources developed by global expert group under the Committee on Sustainable Energy which is the main decision-making intergovernmental body at UNECE responsible for energy issues. And UNCECE is the United Nations Economic Commission for Europe, which is based I Geneva.

UNFC-2009 is a generic principle-based system in which quantities are classified according to the three fundamental criteria of economic and social viability (E), field project status and feasibility (F), and geological knowledge (G), using a numerical and language independent coding scheme. Combinations of these criteria create a uniquely simple and applicable system.

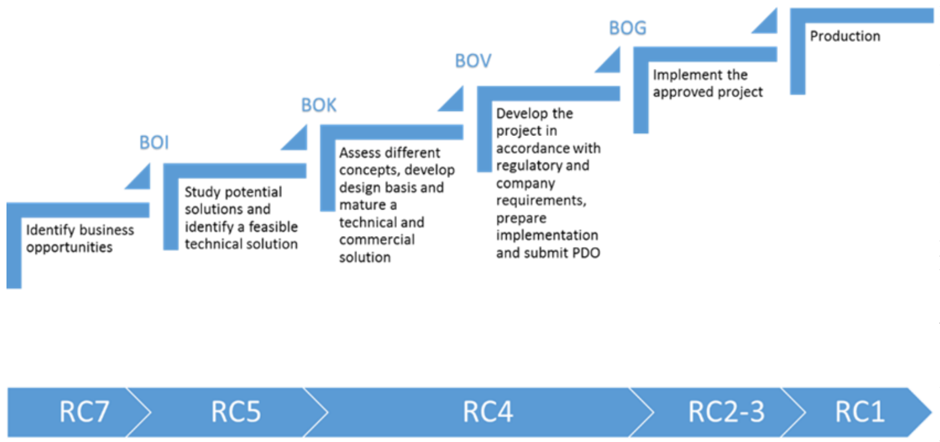

Figure 2. The connection between project maturation and resource classes

The Expert Group that developed the UNFC comprises a broad range of stakeholders worldwide, including both UNECE and non-UNECE member countries, international organizations, industry, the financial community, professional societies and associations, and independent experts.

UNFC has been developed in close cooperation with the Committee for Mineral Reserves International Reporting Standards (CRIRSCO) and the Society of Petroleum Engineers (SPE). UNFC maps directly to the CRIRSCO Template and the SPE-PRMS.

Reporting for the Revised National Budget (RNB)
According to Section 50a of the Petroleum Regulations, operators must submit data for the revised national budget (RNB).

Each autumn, all operating companies submit data and forecasts for their producing fields, discoveries, transportation- and utilization facilities (TUF). The reporting includes corporate financial data, projects, resource volumes and forecasts for production, costs and environmental discharges/emissions.

The reporting to the RNB contributes valuable data for the Government's oil and environmental policy, the fiscal and national budgets. Petroleum activities account for a substantial percentage of Norway's gross domestic product and total export. These forecasts are thus essential tools for the financial governance of Norway, and great emphasis is placed on ensuring that high-quality reporting is provided within the stated deadlines. NPD quality assures reported data, prepares its own estimates based on its own evaluations and assumptions, and prepares overall forecasts. The RNB-data

SPE Norway — Administration

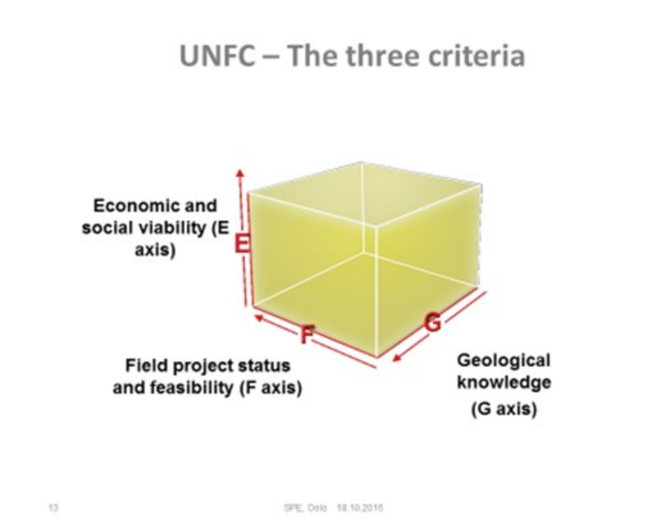

Figure 3. UNFC principles

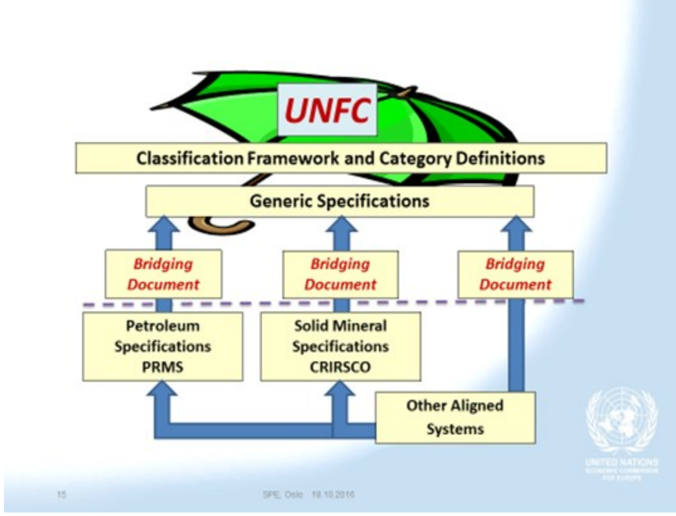

Figure 4, Bridging from aligned systems to UNFC

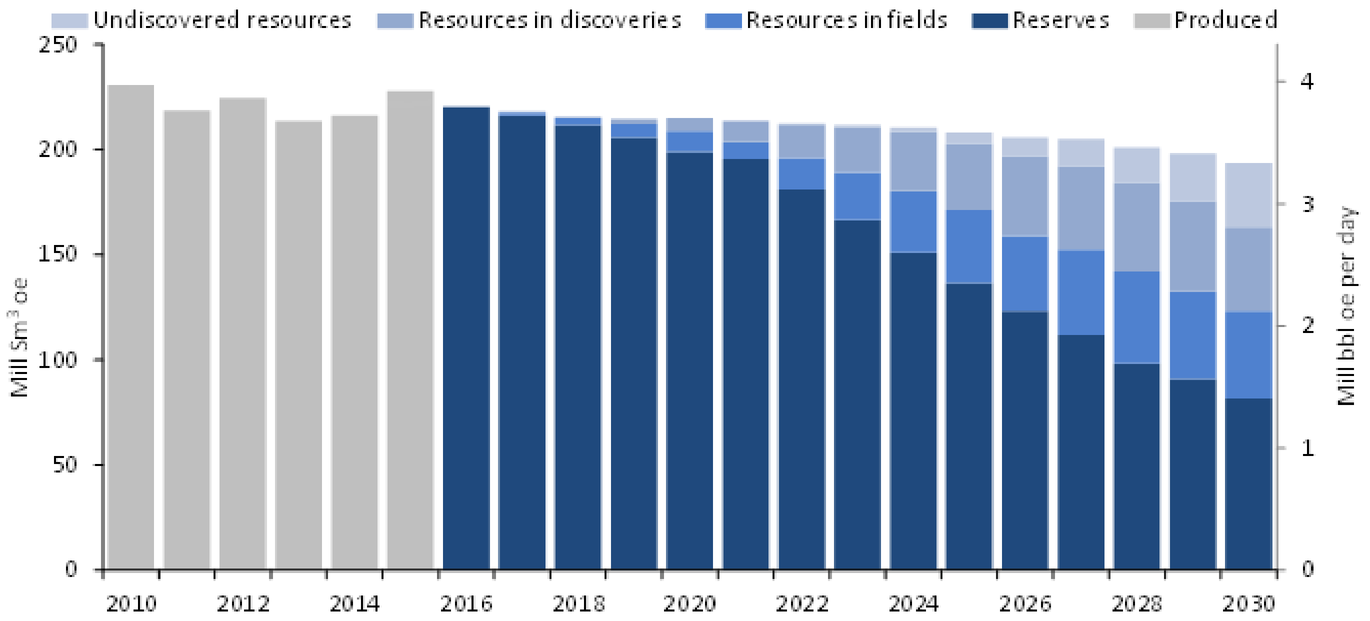

Figure 5 Production forecast (oil equivalents) based on RNB-2016 data from autumn 2015

are also a source for several other analysis and reports, both published and internal.

Annual status report for fields in production

The Annual Status Report (ASR) for fields in production shall be submitted to the NPD by November 1st each year. The information given in the ASR shall conform to, and include necessary explanations regarding prognoses and resource estimates given in the RNB-reporting.

Starting in 2016, the ASR (as the RNB) refers to the standard Joint Operation Agreement (JOA) for Production Licences set by the Ministry of Petroleum and Energy. Also starting with the ASR for 2016, more emphasis is placed on governance, including risk management and time criticality for projects. The ASR forms the basis for the authorities' evaluation of whether a field is being operated in accordance with the preconditions specified in the legal framework. The ASR also form a basis for the application for production permit, including permit relating to flaring and cold venting.

Summary

Resource classification systems develop continuously. The NPD classification system has influenced and been influenced by the development of SPE PRMS. The systems are now reasonable aligned. However, the NPD intends to keep a separate system due to advantages in separating what we call F (first) and A (additional) projects. Changing a system also implies changing in reporting forms and databases that may be complicated.

The operators reporting to the RNB Reporting and Annual Status Report for Fields are important, and provide valuable data for both the NPD and other governmental bodies in managing the petroleum sector. The reporting also comprise parts of the data that are shared with the industry and public trough the NPD Factpages and the site NorwegianPetroleum.

Sounds like oil....?

by Dr. Per Avseth, Adjunct Professor in Petroleum Geophysics, NTNU/ Consulting Geophysicist, G&G Resources

Dr. Per Avseth, Adjunct Professor in Petroleum Geophysics, NTNU/ Consulting Geophysicist, G&G Resources

The million dollar question: One of the most common questions I get as a quantitative seismic interpreter, often from a geologist or an exploration manager, is whether it will be possible to detect oil or not from seismic data in a given area or location. If I know nothing else, my answer is "most likely not". But before I answer, I usually ask some questions back. "What is the age of the reservoir rock?", "How deep is the target buried?", "Has there been any tectonic influence or uplift?", "What is the temperature gradient in the area?", "What is the gravity of the oil?", "What do you know about the cap-rock?", "What is the quality of the seismic data in the area?". If these questions are answered with some degree of certainty, I will normally know quite soon whether there will be any hope of detecting oil from seismic data. How can I tell you? The short answer is "by using the rock physics link between geology and geophysics". The slightly longer answer is elaborated on below (see also Avseth et al., 2005):

It's all about rocks: Before you can say anything about what is inside the pore space of a rock, from seismic signatures, you need to have a very good understanding of the quality of the rock. You need to know your container (Figure 1). Imagine you have a coke bottle of firm glass in your hand and you are located in a dark room. Would you be able to tell whether it is filled with air or coke just by pressing the bottle with your hands? Probably not. What if you had a plastic bottle? Then you would more likely be able to tell the difference. The same concept applies to seismic waves. The propagation velocity of sound waves in rocks is directly linked to the compressibility of the rocks. If the rock is very stiff, it will be very difficult to use the seismic velocity information to discriminate whether the rock is filled with oil or water. However, if the rock is unconsolidated, in fact not a rock at all, but a sediment, then the seismic wave will behave quite differently when the sediment is filled with oil versus with water. The seismic P-wave velocity is normally significantly lower in an oil saturated sand compared to a brine saturated sand with the same porosity and pore stiffness (and even lower if it is filled with gas). So, a good rule of thumb is that if your reservoir is still unconsolidated, you should have a good chance of detecting oil in your reservoir from seismic amplitude data. But in addition, the oil should be relatively light. A heavy, viscous oil will normally have fluid incompressibility that is not very different from that of brine. A light oil (gravity > around 30 API), on the contrary, will be much easier for the P-wave to compress than brine. As rock physicists, we have a very good understanding of the expected fluid sensitivity of a given rock, and we normally use the well-known Gassmann theory to estimate this (Mavko et al., 2009), what we often refer to as "fluid substitution analysis". However, when we use Gassmann, we need to know or assume the amount of pore fluid, that is the rock stiffness. If we have a cemented sandstone, the difference between oil and brine saturated rock will be very small even if the oil is light, and given that there are always some limitations with the seismic data (noise, resolution), it is normally impossible to detect oil in cemented sandstones.

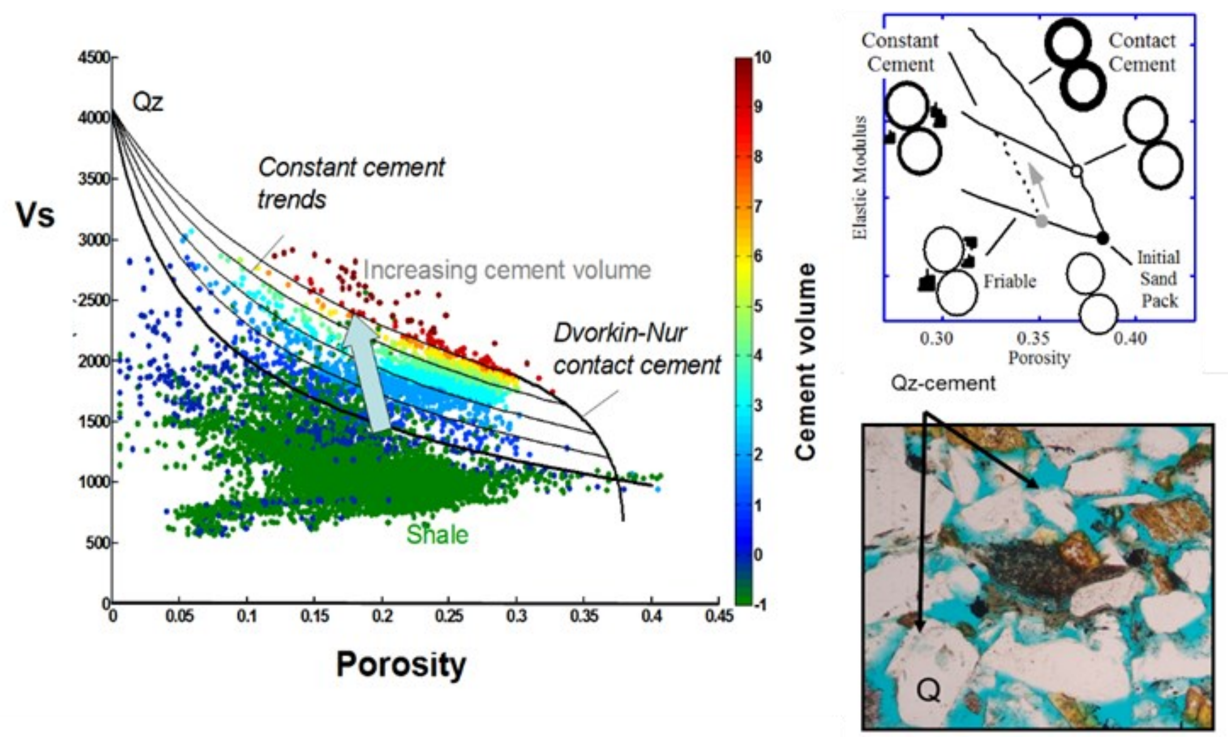

Figure 1. The link between rock texture and elastic moduli (e.g., rock stiffness) is given via rock physics models. Hence, if we know the texture of a sandstone reservoir, we can predict the seismic velocities of this rock. Vice versa, we can predict rock texture from seismic velocities, given that we know the pore fluid. When we want to predict pore fluids from seismic velocities, we need to know the rock texture. Left plot shows well log data from the Alvheim field plotted on top of rock physics models (Shear wave velocity versus porosity). Colour code is estimated quartz cement volume. A thin-section from the same well confirms the presence of cement. The cement stiffen the grain contacts

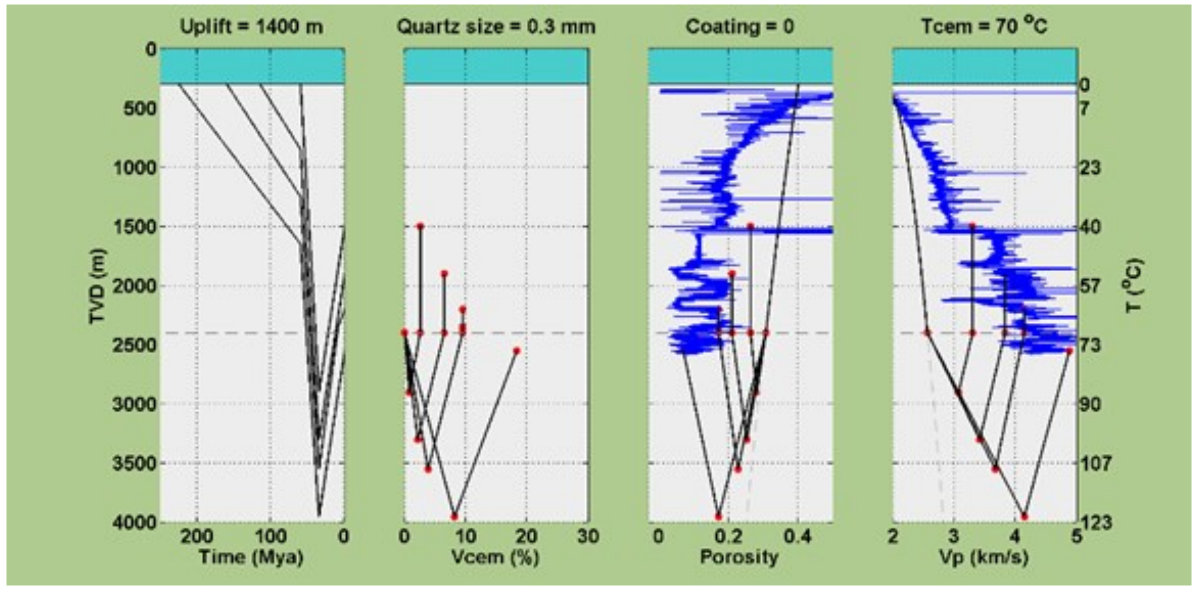

Figure 2. The present day seismic properties will be a function of the burial history of the rock. By linking diagenetic modeling and rock physics modeling, we can predict the seismic velocities of rocks as a function of the geological processes through time. An example from a Barents Sea well, where a significant uplift has occurred, is shown to the right. The reservoir sandstones have been exposed to temperatures high enough to set off chemical compaction and the velocities are increasing drastically as a function of the cement (Avseth and Lehocki, 2016).

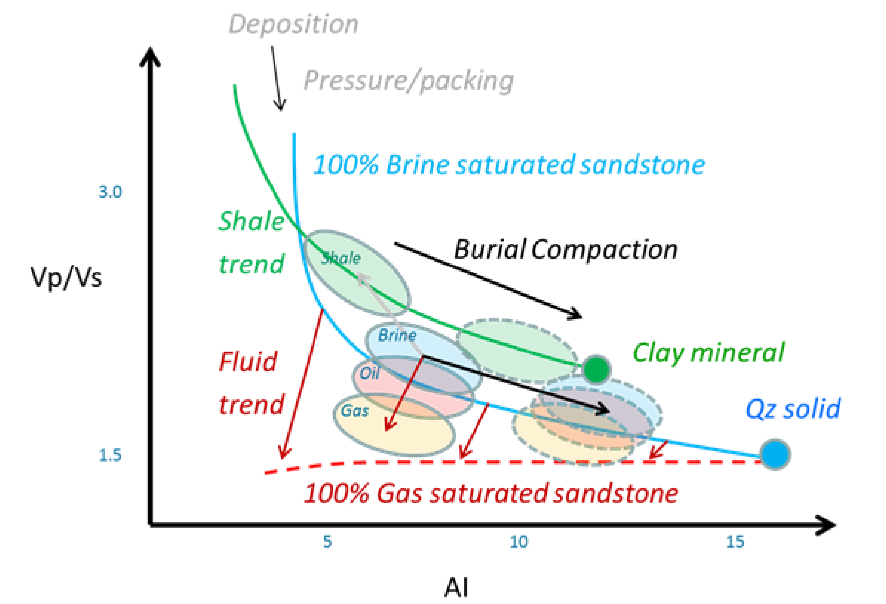

Figure 3. A rock physics template showing expected seismic properties (acoustic impedance versus Vp/Vs) for different lithologies at different burial depths, with different types of pore fluids. There will be overlaps between brine saturated sandstones and oil saturated sandstones, and this overlap increases with increasing burial and rock consolidation. Hence, it will be increasingly difficult to predict hydrocarbons from seismic properties with increasing burial depth. (From Avseth and Veggeland, 2015).

Chemical brothers: So how do we know if the reservoir rock is cemented or not prior to drilling a well through this rock? Well, the geologists usually have a good understanding of the diagenetic processes of a rock. Hence, if we know the age of the rock, and the burial history of this rock, we can actually model and predict the amount of cement. This was done by Walderhaug and others more than 20 years ago at University of Oslo (Walderhaug, 1996). Recently, this knowledge has been incorporated into quantitative interpretation workflows (Dræge et al,, 2014; Avseth and Lehocki, 2016), exactly for the reasons outlined above. By coupling diagenetic models with rock physics models, we can actually predict the rock stiffness for a given rock prior to drilling (Figure 2). Then we can do our Gassmann fluid analysis with much greater precision and certainty. In a way, we can say that the geologic information helps us to constrain our geophysical inversion problem. There are always non-uniqueness and uncertainties in our predictions when we are looking at one or at most two seismic parameters (let's say acoustic impedance and Vp/Vs derived from offset-dependent seismic reflectivities = AVO inversion data) to try to say something about both reservoir quality and pore fluid content (Figure 3). But if we can constrain the reservoir quality from diagenetic models, we can much easier predict the fluid content from these seismic parameters. Also,

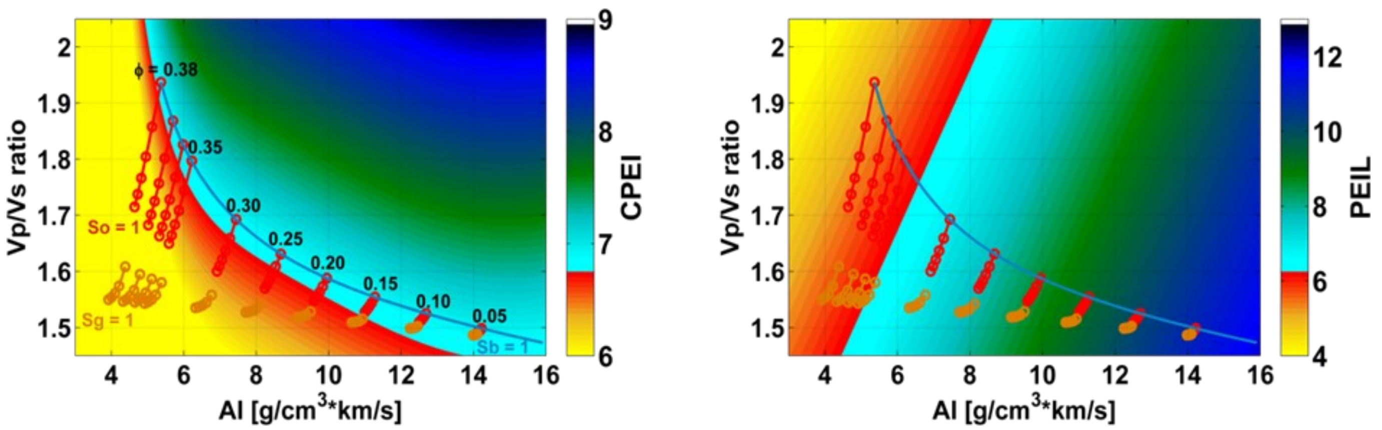

Figure 4. Rock physics attributes defined from rock physics templates. Left: The fluid impedance (also named the "curved pseudo-elastic impedance, CPEI"). Right: The rock impedance (also called the "pseudo-elastic impedance for lithology, PEIL"). The fluid impedance will highlight hydrocarbons, whereas the rock impedance will be independent of fluids, but correlate with rock stiffness.

if we have information about the shear wave velocity (Vs), we have a much greater chance in separating out the effect of fluids from that of lithology or rock stiffness, since the shear waves (as opposed to the pressure or P-waves) are almost insensitive to pore fluids.

All models are wrong, but some are useful: Rock physics templates have been developed as a tool to better discriminate the rock quality effect from the pore fluid effect (Ødegaard and Avseth, 2004), see Figure 3, where the advantage of the shear wave information is included in the Vp/Vs ratio, a parameter that can be estimated from pre-stack seismic amplitudes together with the acoustic impedance. Recently, these templates have been used to constrain some seismic attributes that can be applied to both well log data and seismic inversion data. The fluid impedance (CPEI=curved pseudo elastic impedance) attribute will highlight the fluid effect, but suppress the rock stiffness effect in the data. On the other hand, the rock impedance (PEIL=pseudo elastic impedance for lithology) attribute will highlight variations in rock stiffness and suppress the fluid effect (Avseth and Veggeland, 2015). This is similar to the approach presented by Connolly (1996) and Whitcombe et al. (2001), but we use rock physics models instead of statistical correlations to find the optimal attributes. The attributes are presented in Figure 4, and examples of applications are shown in Figure 5 (well log data) and Figure 6 (seismic AVO inversion data), see also Avseth et al. (2016). By fine-tuning these attributes using well calibrations, we may be able to detect presence of both oil and gas in reservoirs that are even slightly cemented. However, as seen in Figure 4, the fluid sensitivity is drastically reduced with increased burial and associated increased a rock stiffness.

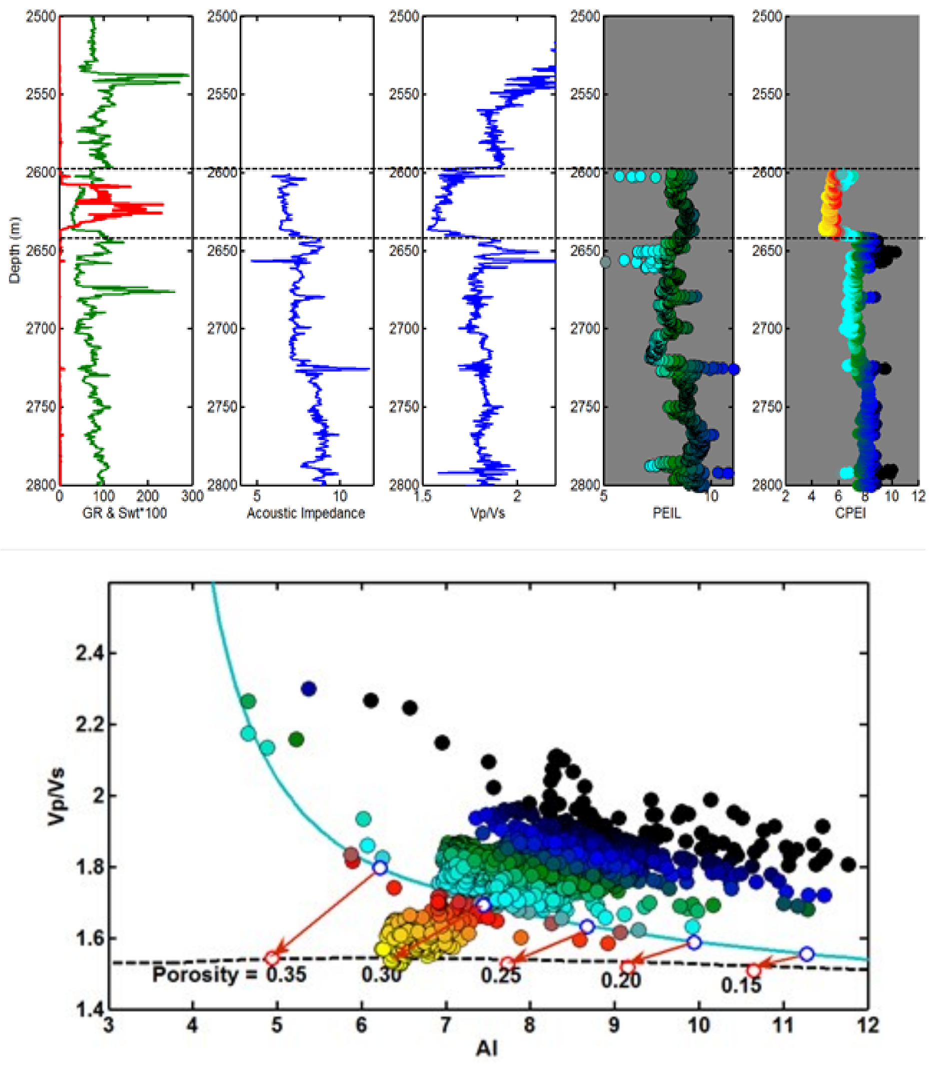

Figure 5. Well log data from a Norwegian Sea well encountering a gas reservoir sandstone. The reservoir zone is easily detected using the fluid impedance (CPEI) rock physics attribute (warm colours in cross plot). Would we have seen this reservoir zone if it was filled with oil instead of gas? With light oil, probably yes, since the reservoir is quite porous and poorly consolidated.

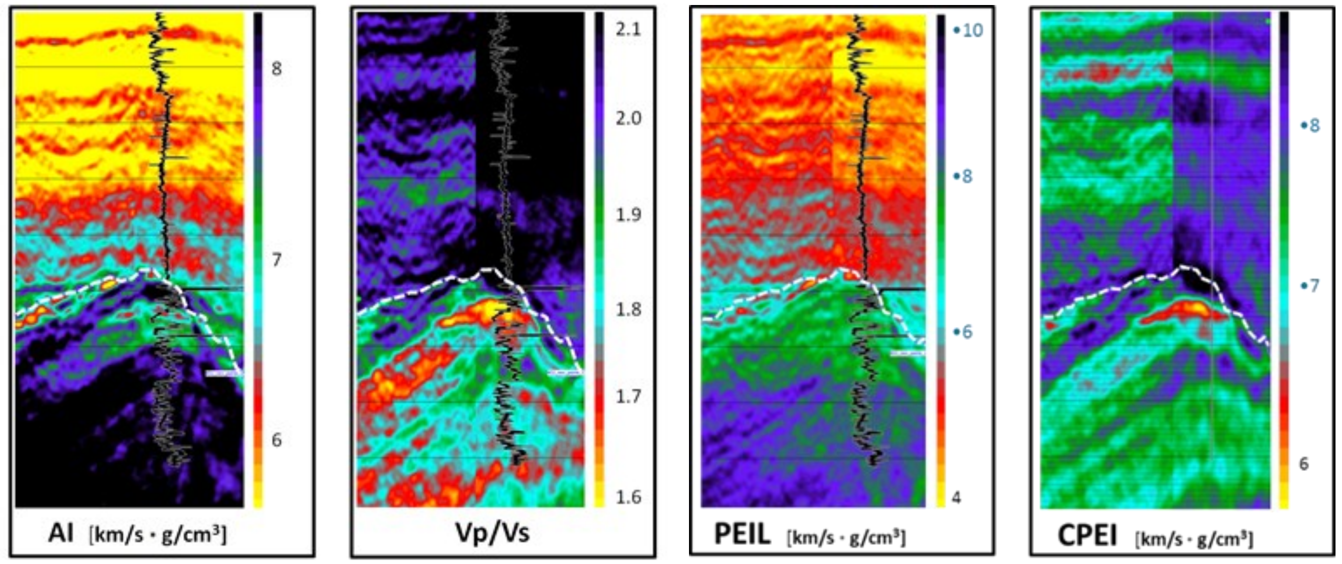

Figure 6. Seismic AVO inversion results (acoustic impedance and Vp/Vs) juxtaposed with rock physics attributes including rock impedance (PEIL) and fluid impedance (CPEI). Note the anomaly in the fluid impedance, corresponding with a gas and condensate discovery in the Norwegian Sea (The Natalia discovery).

The golden zone: It turns out that most oil reservoirs around the world are located around 2-3 km burial depth. This is because the source rocks need to be buried at a certain depth/temperature to become mature and generate oil, the reservoir rocks need to be still quite porous, and the cap-rocks need to be quite dense and impermeable. The combination of these various factors makes it favorable to look for oil in rocks present within this depth range. However, on the Norwegian shelf, the temperature gradients are around 35-40 degrees per km, and quartz cementation tend to start at around 70-80 degrees (Bjørlykke, 2010). Hence, most of our oil reservoirs will be cemented! This is bad news in terms of seismic detectability of oil. What is often seen in seismic is the gas cap on top of oil, and the flat spot between the gas and the oil zone, especially in structural traps where the stratigraphy is oblique. But it is normally very difficult to see the transition from oil to water. However, with improved quality and resolution of seismic data (i.e. broadband data), and improved geological constraints, there is a hope that we should be able to detect presence of oil in cemented reservoirs located at around 2-3 km depth. Also, we see that many reservoirs in the Barents Sea can be oil filled even at much shallower depths due to significant uplift. The Jurassic reservoirs in the Hoop area have been buried at depths of maybe 2.5 km, and are therefore slightly cemented. But because of light oil and good data, geophysicists have been able to detect the presence of oil in these reservoirs. Extra information from CSEM or gravity data have further enabled interpreters to avoid ambiguities between low fizz gas saturation and commercial oil saturation, with great success in the Barents Sea.

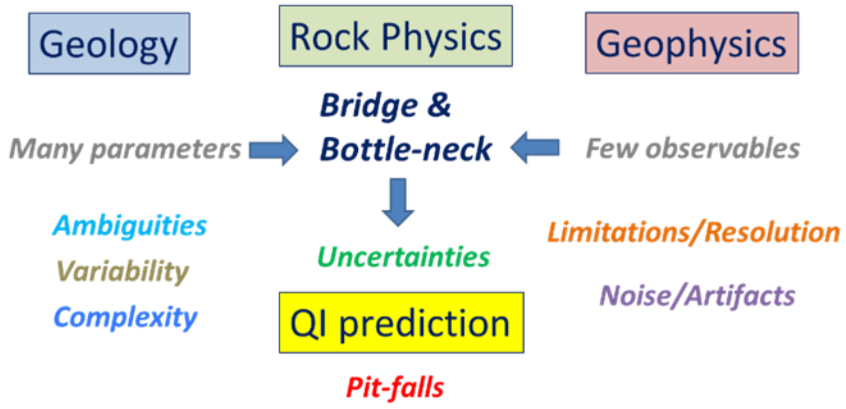

Figure 7. Rock physics is the link between geology and geophysics. It is both a bridge and a bottle-neck during quantitative interpretation, as we often suffer from few geophysical observables, complex geology, model limitations and seismic resolution issues.

Always look on the bright side: We are presently experiencing tough times in our industry, with low oil price and quite a disappointing discovery rate on the Norwegian shelf, as well as in other parts of the world. However, there is currently a shift in focus from conventional interpretation of structural traps to the search for more subtle stratigraphic traps on the Norwegian shelf. The use of broadband data and quantitative seismic interpretation is increasingly important. If we incorporate more geologic knowledge and integrate this with improved geophysical observations, there is a hope that we will be able to detect even more of the hidden oil that is present in relatively stiff sandstones. If we can push our seismic detectability of hydrocarbons only slightly, through improved data and better geologic constraints, we may be able to detect subtle differences between oil and water-filled sandstones tomorrow, that we are not able to detect today. Maybe we can make the dim spots bright up somehow? Promising work has been done (Goloshubin et al., 2014) on attenuation attributes and low-frequency seismic, where pore fluid effects may be manifested even if the amplitudes are dim, but we are still missing a rigorous physical understanding of what is really causing these frequency dependent effects. Moreover, with subtle differences between water-saturated and oil-saturated rocks, we are more prone to suffer from uncertainties and ambiguities (Figure 7). The only certain thing is that there is still plenty of hidden oil left to be discovered (Brown, 2013), and we will be working hard to find more of it from seismic data. Rock physicists and quantitative seismic interpreters will be busy investigating the sound of oil in years to come. So stay tuned for the next chapter in seismic oil exploration!

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His areas of interest include quantitative seismic interpretation and rock physics analysis. Per received his MSc in applied petroleum geosciences from NTNU in 1993, and his PhD in geophysics from Stanford University, California, in 2000. He was the SEG Honorary Lecturer for Europe in 2009.

Per is a co-author of the book Quantitative Seismic Interpretation (Cambridge University Press, 2005).

Back to Basics—the Use of Structural Reliability Analysis in Pipeline Design to Cut Costs in the Maria Development

by Reinert Hansson, Wintershall

Reinert Hansson
Senior Pipeline Engineer
Wintershall

Change of the tides
The oil and gas industry has seen a dramatic reduction in the selling price of its main product, forcing the industry to significantly reduce its cost base. Industry costs rose significantly in previous years, due to several factors including overdesign of facilities. However, cost reduction cannot be allowed to happen nor at the expense of the safety of oil workers nor the environment. In this context, the use of advanced statistics and reliability analyses could offer some solutions, as shown on the Wintershall-operated Maria project.

Reliability Based Design
The oil and gas industry typically requires that the critical components used in facilities have a certain reliability. That means that the probability of failure of the component is below a certain limit in order to ensure safe operation.

The reliability of a structure can be assessed directly by performing a so-called structural reliability analysis (SRA). This involves assessing all the variability and uncertainty governing the loading of a structure and the capacity of the structure to withstand loading. For subsea pipeline design, this includes variability in the environmental conditions, currents and waves, seabed conditions, materials, geometrical properties of the pipe and also uncertainty with respect to correct modelling of a given problem. If the designer can understand and map all this variability and uncertainty, he or she can calculate the probability that a structure will fail. However, in most cases the complexity of the structural reliability analysis method prevents this from being used as a general design tool.

Limit State Design
The majority of subsea pipeline projects globally are designed in accordance with the DNV-OS-F101 design code for Subsea Pipeline Systems. This code instead prescribes a limit state design method. Most engineers will be familiar with limit state methods as they are widely used across the industry. A typical (simplified) formulation will be as follows:

$$\frac{L_{Ch} \times \gamma_L}{R_{Ch} \times \gamma_R} \leq 1$$

On the top of the fraction a characteristic conservative) estimate of the load is multiplied with a given safety factor. On the bottom of the fraction a characteristic (conservative) resistance is multiplied with a given safety factor. The criterion then stipulates that the result of this fraction (typically called the utilisation) shall be below unity. The design code describes how to calculate each of the variables in the formula and thereby removes the majority of the complexity from the design challenge. The beauty of this is that the formula given in the code is calibrated to ensure that the desired reliability of the structure is achieved. Limit state design therefore represents a very efficient although conservative method to ensure the reliability of a system.

Limit state design formulas are typically very general and designed to be applicable for a large variety of cases. In order to ensure that they always offer a conservative result, in most cases they will be very conservative leading to a risk of overdesign. However, the results of limit state design methods are not challenged often enough even when it is clear to engineers that resulting designs are based on very conservative assumptions and the potential cost related to overdesign is significant.

There are many reasons for this. We are a very conservative industry and traditionally not quick to change out methods which are proven to be robust and safe. Moreover, the knowledge among engineers about the background for the formulas used on a daily basis may be lacking, and also not typically described in the design code documents.

Trawl pull-over
The Maria field is served by two subsea templates tied back to three host facilities in the Haltenbanken area of the Norwegian Sea. In an area with some fishing activity, the 100 km of pipelines could come into contact with the heavy equipment the fishermen use to trawl the ocean floor, representing a major risk for any infrastructure on seabed.

In the case of the Maria project an additional challenge is caused by the fact that the pipelines are laid across very uneven seabed created by icebergs which scarred the seafloor at the end of the last ice age. This has created free-spans up to 8m high, leaving up to 60% of the pipeline not in contact with the seabed. Using the standard limit state design method, a design requirement was reached which necessitated that the free-spans under two of Maria's three pipelines were filled. A project of this size requires at least a 3 month campaign with a major rock dumping vessel collecting rock at the shore and shuttling it out to

the Maria field where it would carefully be installed under the lines in order to support them and protect them.

Structural Reliability Analyses
A structural reliability analysis was performed by the project in order to investigate if the high rock volumes needed to fulfill this requirement could be adjusted. First, a sensitivity study was performed to identify the variables which impact the failure probability of the pipe under trawl loading. These included factors such as pipe properties, seabed characteristics, and operating parameters.

The variables which are found to have an impact are included in the reliability analysis as stochastic variables, meaning that their variability is mapped and included in an analysis matrix defining combinations which are analysed in a sophisticated finite element model. A statistical evaluation is performed on the results and finally a Monte Carlo simulation is performed to calculate the failure probability.

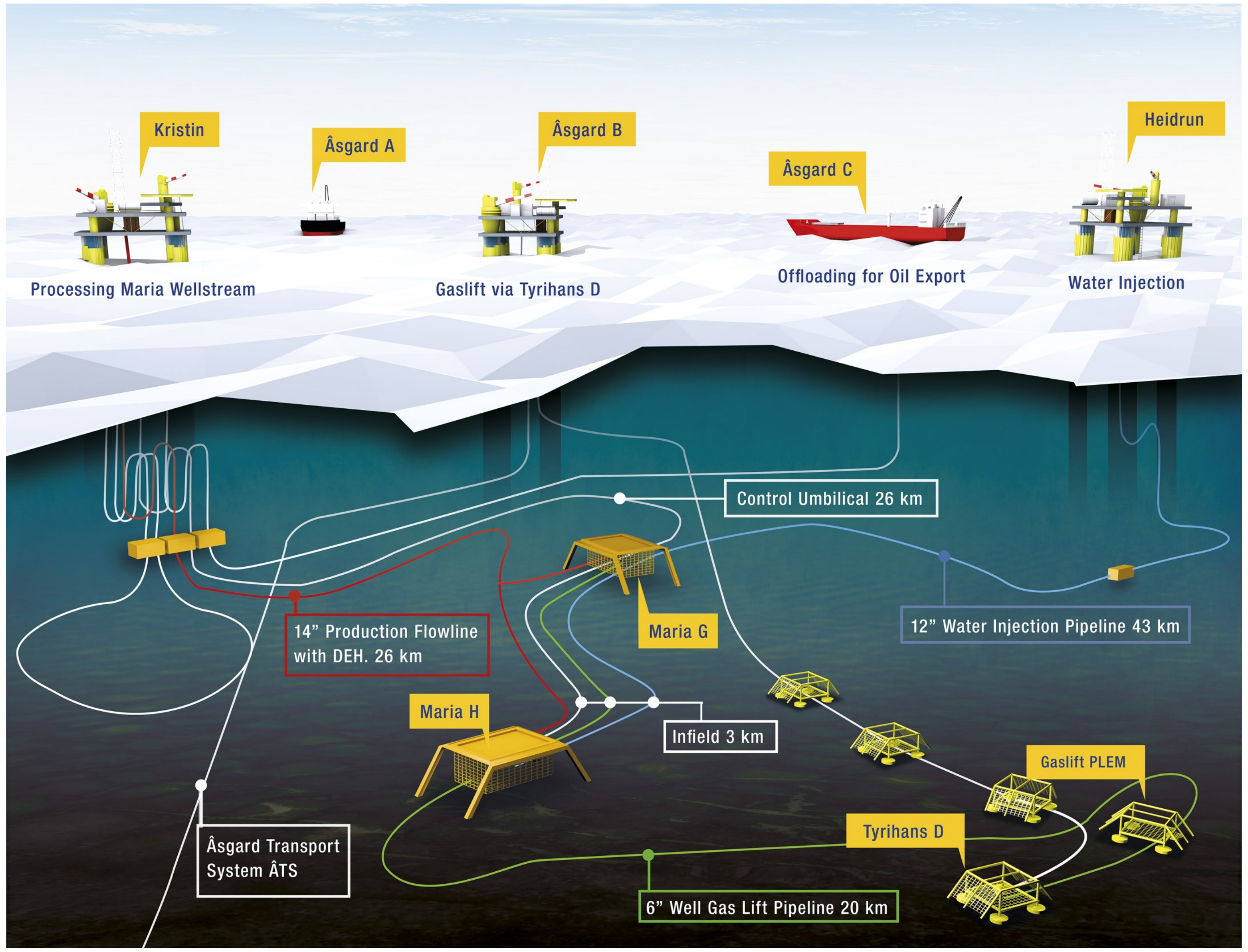
The target maximum probability of failure for a subsea pipeline is typically 1/10,000 years. The SRA showed that the reliability of the Maria pipelines designed according to the standard limit state methods were several orders of magnitude better than the target. Even when all the rock previously included to support the pipelines was removed from the initial design, the reliability was still proven to be 1-2 orders of magnitude better than the target, resulting in considerable cost reductions for the project.

Encouraged by the success on the trawl design similar methods have also been employed in other areas of the pipeline design scope including installation design and design of structural bends, with great success.

The way forward
Pipeline design is by and large performed by use of the limit state design methodology. Considering this age of cost management, I think the use of reliability analyses to support the design and maybe challenge certain critical elements could be interesting to many projects.

This is not something the Maria project has invented. In fact, I hear from many other projects and also other disciplines which are reassessing the "standard ways" of doing things and reliability based methods are being utilised more. This is, of course, related to the recent development of the oil price, leading to a shift from schedule driven projects, where the first oil date has typically been the main priority, to a much higher cost focus, even at the expense of technical complexity related to engineering.

The reliability based methods are attractive because they offer a way to document that project optimization, and sometimes significant cost reductions can be performed without corresponding negative impact on HSE or reliability. Compared to the methods traditionally used, the additional engineering can be significant and in certain cases will involve some additional elements of R&D. However, at least for the Maria project, there has been a very healthy return on invested engineering hours whilst still fulfilling the stringent HSE expectations.



Making sure that the Deepwater Horizon won't happen again

by Vladimir Andreev, Founder, Balanced Solutions

Deepwater Horizon on fire after the explosions

INNOVATION QUOTE

The biggest threat to innovation is internal politics and an organizational culture, which doesn't accept failure and/or doesn't accept ideas from outside, and/or cannot change." Gartner Financial Services Innovation Survey, 2016.

Vladimir Andreev
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Deepwater horizon tragedy

At 9:45 P.M. CDT on 20 April 2010, during the final phases of drilling the exploratory well at Macondo, a geyser of seawater erupted from the marine riser onto the rig, shooting 240 ft (73 m) into the air. This was soon followed by the eruption of a slushy combination of drilling mud, methane gas, and water. The gas component of the slushy material quickly transitioned into a fully gaseous state and then ignited into a series of explosions and then a firestorm. An attempt was made to activate the blowout preventer, but it failed. The final defense to prevent an oil spill, a device known as a blind shear ram, was activated but failed to plug the well.

At the time of the explosion, there were 126 crew on board; seven were employees of BP, 79 of Transocean, there were also employees of various other companies involved in the operation of the rig. Eleven workers were presumed killed in the initial explosion. The rig was evacuated, with injured workers airlifted to medical facilities. Deepwater Horizon sank on 22 April 2010.

The resultant oil spill continued until 15 July when it was closed by a cap. Relief wells were used to permanently seal the well, which was declared "effectively dead" on 19 September 2010.

DNV GL were awarded a contract to undertake the forensic examinations, investigations and tests on the recovered Deepwater Horizon BOP on September 1, 2010. (Ref 1).

What was the cause of the tragedy?

There were numerous factors that had contributed to the tragedy taking place. To name the few extreme press on the drilling team to complete the well as soon as possible, inadequate quality of the cementing, misinterpretation of the readings from the well, etc. However, the main question is why the "last barrier" – Blowout preventer (BOP) had not been able to contain the blowout.

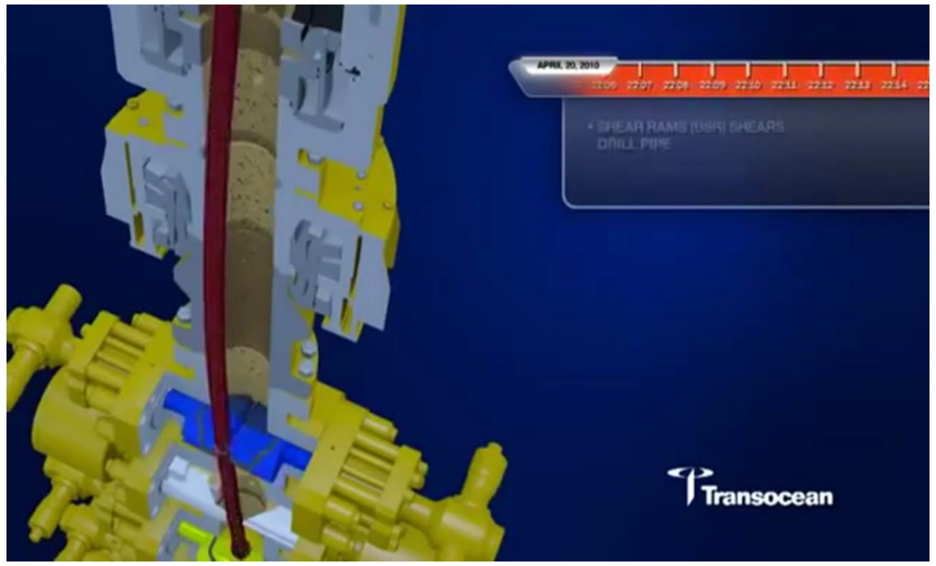
The DNV GL Report (Ref. 1) summarizes its following:

Primary cause of failure:

- The Blind Shear Rams (BSR) failed to fully close and seal the well due to a portion of drill pipe trapped between the blocks.

Contributing causes to the primary cause included:

- The Blind Shear Rams (BSR) were not able to move the entire pipe cross section into the shearing surfaces of the blades.
- Drill pipe in process of shearing was deformed outside the shearing blade surfaces.
- The drill pipe elastically buckled within the wellbore due to forces induced on the drill pipe during loss of well control.



Deepwater Horizon BOP - reconstruction of blowout (courtesy Transocean)

The DNV GL had also provided a set of recommendation for the industry to make sure that the Deepwater Horizon tragedy is not repeated. The recommendations related to the BOPs themselves were:

- Study of Elastic Buckling
- Study of the Shear Blade Surfaces of Shear Rams

Also, the major drilling companies had performed internal evaluations on whether or not their BOPs would be capable of the containing the well in the similar circumstances as were at Macondo well. The findings weren't altogether comforting for the majority of the BOPs:

- The BSRs at some combination of the type of drill pipe and wellbore pressure aren't capable to shear the drill pipe and seal the well.
- The BOP operating procedures don't address any mitigation measures of drill pipe buckling risk and therefore moving the drill pipe from the shearing surfaces of the blades.

Industry response

In the wake of the disaster the industry had mobilized to the bridge the gap where BOPs aren't capable to provide a "last barrier".
The API had developed a revised specification for the BOPs.

Major OEM's (Cameron, GE Hydril, NOV) had been working hard on the improvement of their products. New products have been introduced to dramatically improve shear & seal capabilities.

The efforts have been concentrating to address the following shortcomings of the traditional Shear Rams design:

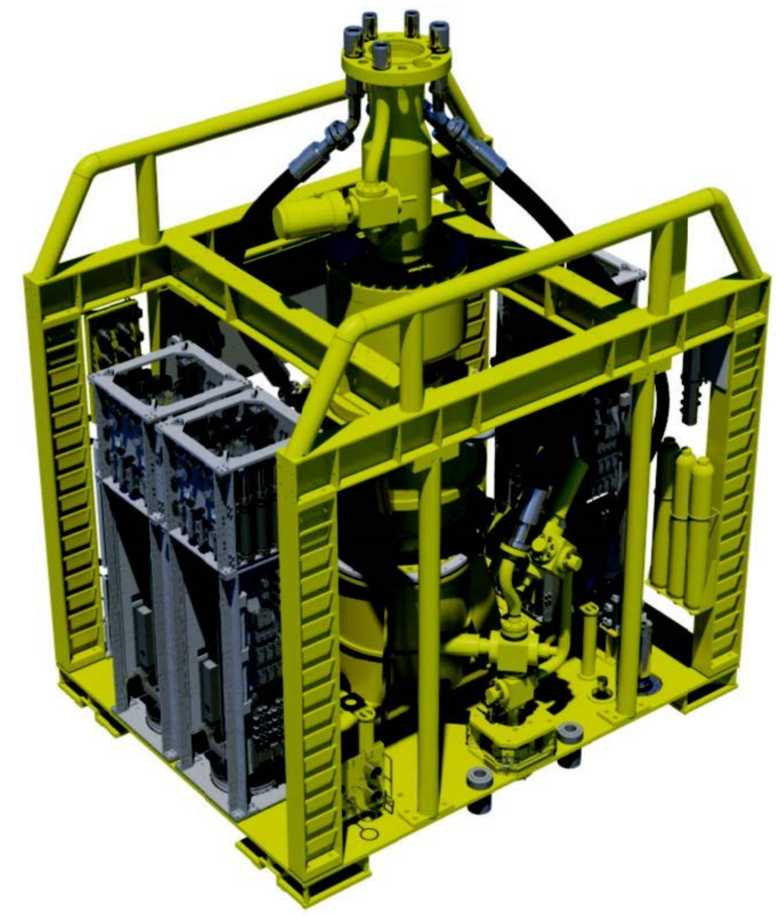
- The Rams are working against wellbore pressure and therefore at high pressure are losing effectiveness.
- The shape of the blades is such that it cannot effectively move buckled pipe into the area where shear blades can effectively cut the pipe.
- There is a limited amount of force can be applied to the cutters.
- Inability of the shear rams to establish a reliable pressure barrier in case of significant flow in the well during blowout.

For the years that have passed since the tragedy number it's been made significant advances in order to address the causes of the Deepwater Horizon BOP failure.

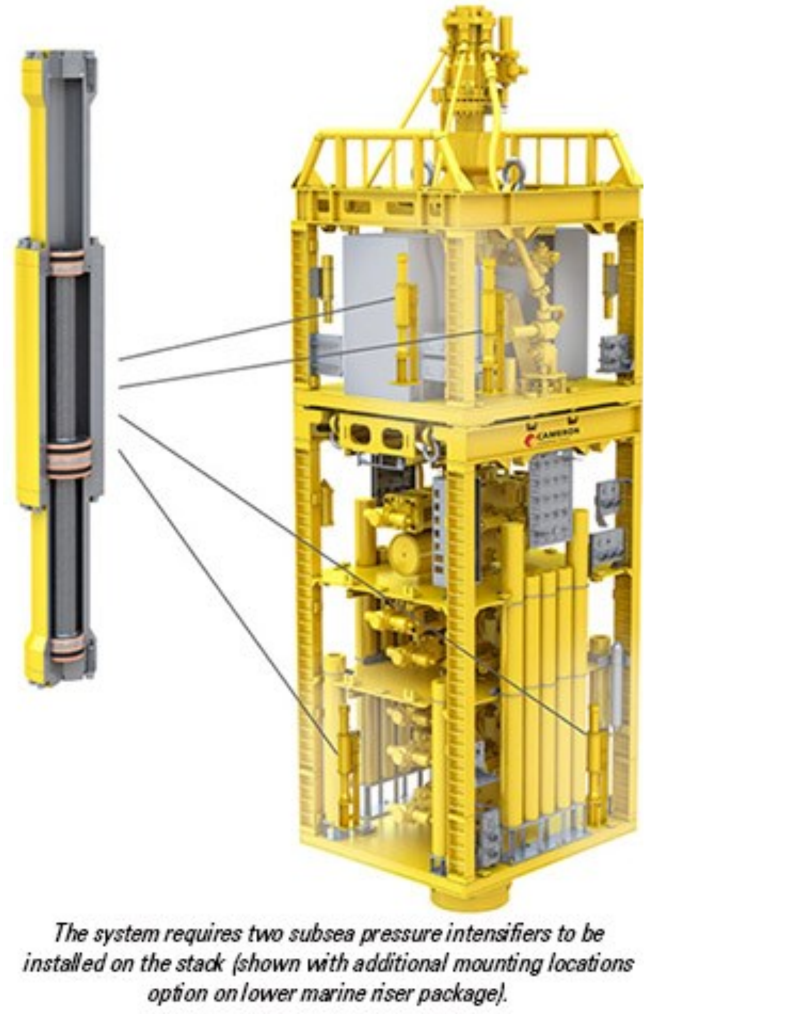
Cameron have improved their BOP controls, by introducing additional control pod in their Mark IV Subsea MUX BOP Control System (Ref. 2) in order to increase availability of BOP controls. In order to address increased shearing capacity, Cameron introduced a Subsea Pressure Intensifier as an option for new builds and retrofit (Ref. 3).

GE Hydril have introduced a wellbore pressure assisted actuation, thus addressing the issue with loss of effectiveness of the shear rams with increased wellbore pressure, in addition GE's BSRs features an automatic pipe centering capability (Ref. 4).

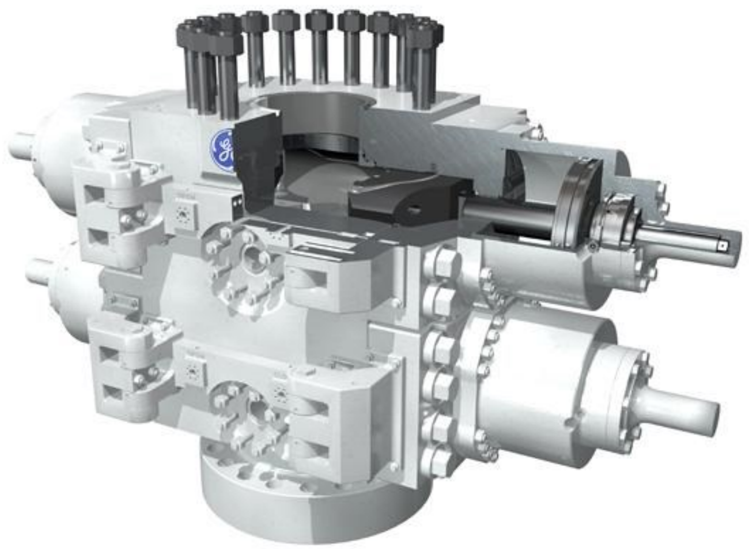
NOV have introduced Low Force Shear Ram with unique profile of the shear blades that in addition to self-centralization capability also provide unmatched shearing capability (Ref. 5). Also NOV have been working on the shearing gate valve concept that also utilizes metal seal.



Mark IV Subsea MUX BOP Control System (courtesy Cameron)



Subsea Pressure Intensifier (courtesy Cameron)



Compact Ram BOP (courtesy GE Hydril)

In addition to major OEM's (Cameron, GE Hydrill and NOV) also smaller manufactures have been developing products that contribute to the industry efforts to BOP shortcomings. One of these manufacturers is Enovate have developed a shear & seal gate valve with bi-directional, metal-to-metal sealing under the trade name En-Tegrity™. The shearing capability of the En-Tegrity BOP is not affected by the increase of wellbore pressure and is capable to reliably seal the well with significant flowrate in the wellbore.

Unfortunately, none of the solutions that are available on the market addressing all of the identified shortcomings of modern BOPs. The solutions do provide an increase in potential shearing capability up to 40-50%, compared to the traditional design. Also, only Enovate and potential future product from NOV solution is capable to seal the flowing well and establish reliable pressure barrier with metal seals.

Therefore, there is still a need for the solution that is capable to address all of the shortcoming and in addition not being limited by the capacity of BOP controls.

The solution

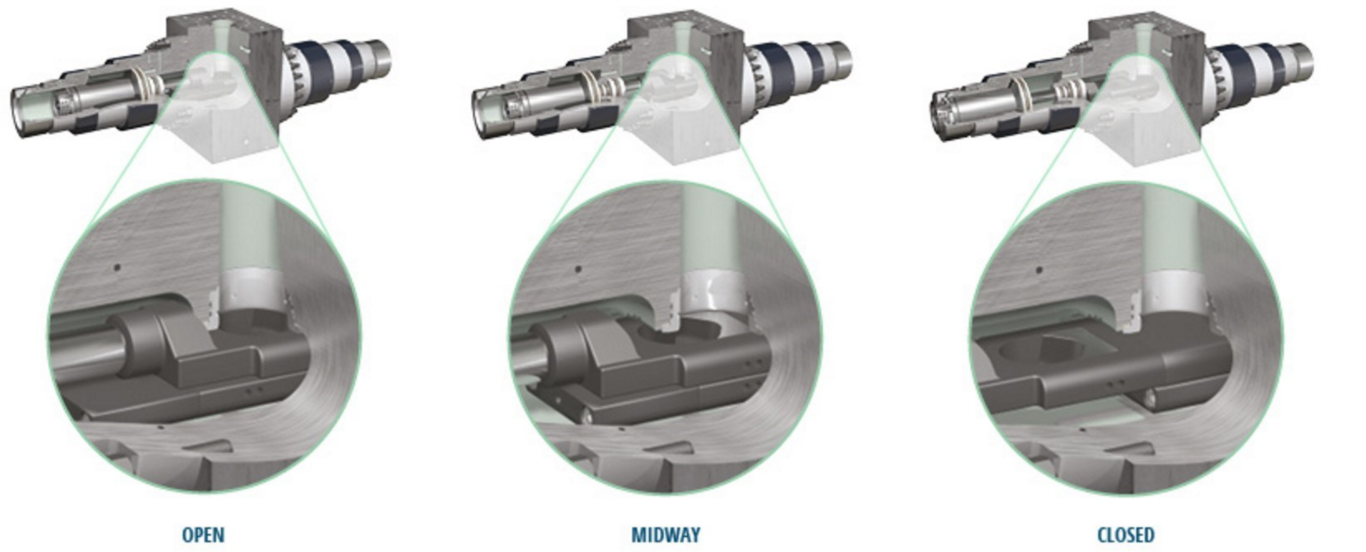
As a response to the challenges associated with the capability of the BOP to actually provide "last barrier", Balanced Solutions have developed a state-of-the-art solution under the name Pressure Balanced Double Acting (PBDA) Shear Gate Valve.

The PBDA Shear Gate Valve featuring following functionality:

- «Gates» with shear blades are simultaneously pushed and pulled by double acting cylinders – pressure compensated against well pressure & double shearing force.
- Pressure isolation provided by metal seals utilizing Double Piston Effect – effective double pressure barrier against hydrocarbons, no temperature degradation of seals.
- Accompanied by the Wellbore Pressure Actuation – Unlimited pressure source with shear pressures up to 1000 bar (15000 psi) or more.

Both PBDA Shear Gate Valve and Wellbore Pressure Actuation are patent pending.

The superior shearing capability of the PBDA Shear Gate Valve means, that it can cut practically anything that is going through the BOP, potentially even tool-joint. While the improved shear rams, when compared to the traditional design have increased capacity by 40-50% the PBDA Shear Gate Valve is capable to exert a shear force up to 200% higher than the traditional shear rams, in case when the wellbore pressure actuation is utilized the exerted shear force will be increased up to



En-Tegrity™ Shear & Seal Valve (courtesy Enovate)

Low Force Shear Ram (courtesy NOV)

About the author

Vladimir Andreev,
Founder, Balanced Solutions.
Over 20 years of Commercial and Technical experience during involvement with Offshore Oil & Gas engineering and offshore construction projects. Has been holding senior technical positions with major offshore drilling and construction companies. During recent years working as independent consultant.
In 2016 has established a Balanced Solutions in order to develop and provide innovative products and services to subsea oil & gas development.

1000% compared to the Deepwater Horizon Shear Rams.

What is also important to note that due to unique double acting hydraulic cylinders the shearing force is not transfer to the PBDA Shear Gate Valve body and therefore with increased pressure in cylinders the loading conditions of the body are unaffected; this feature ensures optimized low-weight design even for high shearing pressures that one would experience in case of Wellbore Pressure Actuation.

Due to the nature of the «Gate Valve Principle» the pressure barrier can be effectively established at any flowrate in the wellbore without risk of compromising the seals. In addition, the PBDA Shear Gate Valve is capable to two self-energizing pressure barriers with metal-to-metal seals.

The pressure-balancing feature of the PBDA Shear Gate Valve eliminates any need for mechanical piston locks thus greatly simplifying its construction and reducing risk of failure.

In comparison with traditional shearing solutions as well as the improvements that are available on the market to date, the Pressure Balanced Double Acting Shear Gate Valve provides a step change in the shearing capabilities. In case of well control accident, especially with flowing blowout the it "pushes" the certainty of cutting the drill string and establishing two reliable pressure barriers between well and the environment to practically 100%.

Balanced Solutions truly believes that the Pressure Balanced Double Acting Shear Gate Valve will make it sure that Deepwater Horizon won't happen again.

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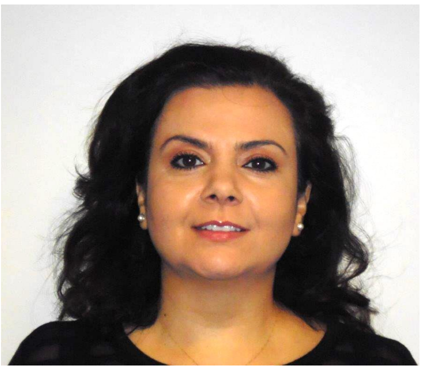
Utilising Spectral Noise Logging and Conventional Production Logging Tools to Assess Reservoir & Completion Performance

by Remke Ellis and Rita-Michel Greiss, TGT Oilfield Services

Remke Ellis
Reservoir Engineer
Domain Champion
TGT Oilfield Services



Rita-Michel Greiss
Business Development Manager
TGT Oilfield Services

Introduction

This article explores challenges many Operators face today – the compliance of reservoir and completion performance to field development plan in order to maximise longevity of optimal production. In this article we examine the importance and added value benefits of acquiring Spectral Noise Logging (SNL) and conventional Production Logging Tool (PLT) data to this effect. We refer to previously published case studies for which spectral noise logging and conventional PLT data allowed oil and gas companies to resolve poor performance issues in both production and injection wells; reviving overall production levels and sustaining field life.

Reservoir and Completion Component Flow

Reservoir flow noise is produced by grain-to-grain, pore throat and fracture vibrations caused by transfer of energy from the flowing fluid to the media. Completion flow noise is typically generated by the vibration (resonation) of the production string (tubing or casing), pipe through-holes (leaks), perforation tunnels, and cement channels. Each source of noise can be distinguished based on acoustic frequency range, amplitude and continuity of the signal with wellbore or reservoir unit limits. Combing SNL and temperature measurements with conventional PLT measurements from flowmeters, heat-exchange sensors etc. allow for differentiating between flow occurring within the borehole or that behind pipe[1]. In the same way assessment of reservoir performance (SNL) and completion performance (PLT) is achieved, all with the same survey run.

High Precision Temperature Logging

Though temperature logging has been extensively used over several decades, the more recent development in simulation methodology and advanced numerical temperature modelling has enabled better interpretation and understanding of fluid flow. The methodology includes thermal model validation and accounting for injection / production history fluid volumes and temperatures. Additionally, the sensitive input parameter, of active unit thickness which previously has been assumed from open-hole logs, is now measured directly with the Spectral Noise Logging tool. This data acquisition now aids in a more robust and representative quantitative determination of fluid flow profile[2].

Spectral Noise Logging

The Spectral Noise Logging tool is specifically designed as a passive acoustic hydrophone, recording sound in the frequency range of 8Hz to 60kHz. The Spectral Noise Logging captures noise associated with liquid or gas movement through a media. This noise is generated from the streamlining (vibration) of the media and from within the fluid itself (if flow is turbulent). The frequency of the noise is inversely proportional to the cross sectional area (aperture) of the flow path. The volume intensity (amplitude) of the noise is dependent on the fluid and medium properties, and proportional to the delta pressure and flowrate.

The SNL tool is used to survey producer and injector wells, under both shut-in and flowing conditions. For shut-in surveys SNL captures noise associated with any cross-flow, crucially fluid cross-flowing behind completion components (tubing and casing). This allows for assessment of completion isolation performance (cement, packers, SSDs, etc) and realisation of inter-layer differential pressure depletion. Under flowing conditions SNL captures noise associated with reservoir flow, enabling assessment of layer performance (e.g. for identifying stimulation candidates) and out of zone contributions (water breakthrough / thief injection).

Injector Wells

The primary objective of injector wells is to ensure that water or gas is effectively placed into the targeted formation layers, to maintain reservoir pressure and mobilise hydrocarbons. Failures in completion component isolation (principally cement sheath or ISO-packers) can result in significant volumes of injected fluid bypassing the target zone. Insufficient layer pressure support and reservoir sweep results, causing reservoir conditions to deviate from field development plan and negative impact on production forecasts and recovery factor. Furthermore, if a polymer or surfactant injection is planned, it is important the calculated volume of chemical reaches the target layer.

In this case conventional PLT could provide quantitative perforation tunnel injection profile (within the wellbore), however what hap-

[1] Arlen Sarsekov, Ahmed Khalifa Al-Neaimi et al ADMA-OPCO, Vasily Skutin, Ruslan Makhiyanov et al TGT Oilfield Services, 2016, Quantitative Evaluation of the Reservoir Flow Profile of Short String Production with High Precision Temperature (HPT) Logging and Spectral Noise Logging (SNL) in the Long String of a Dual Completion Well, SPE-182889-MS

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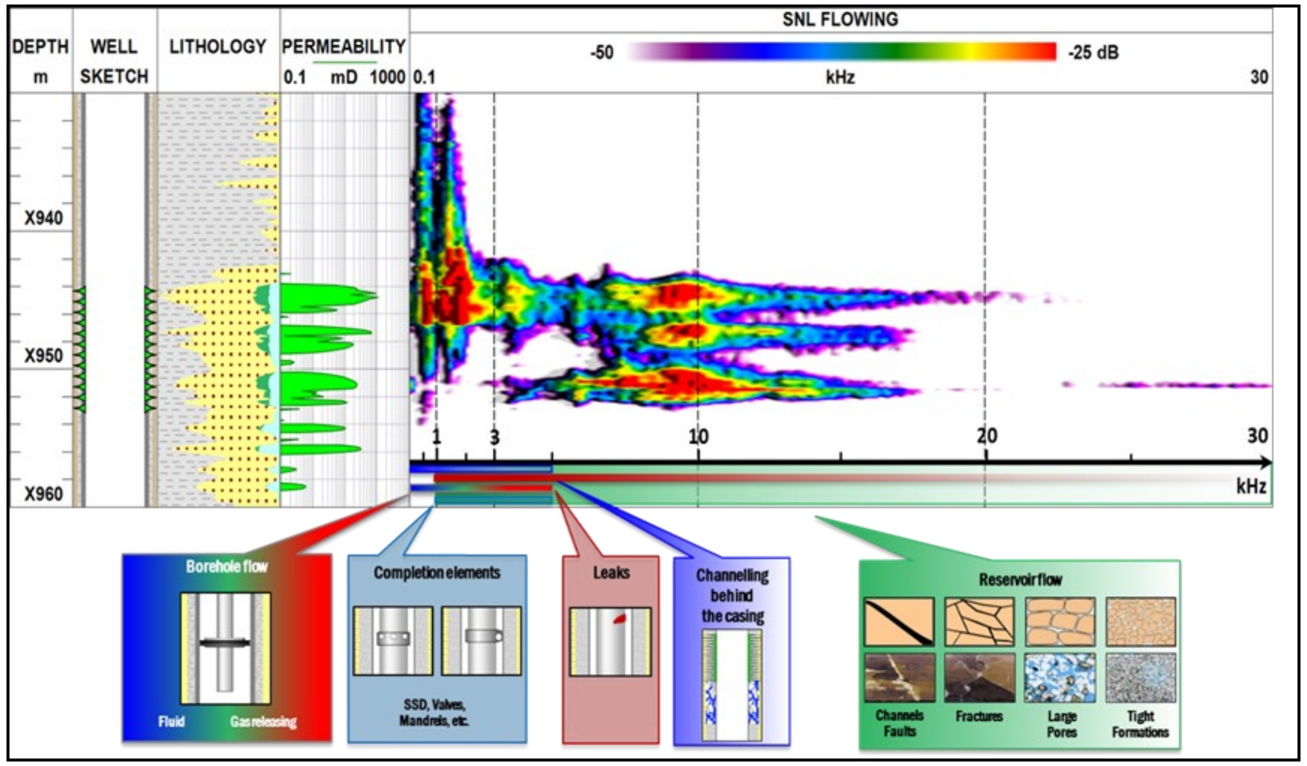

Figure 1. Acoustic Interpretation Fundamentals[3]

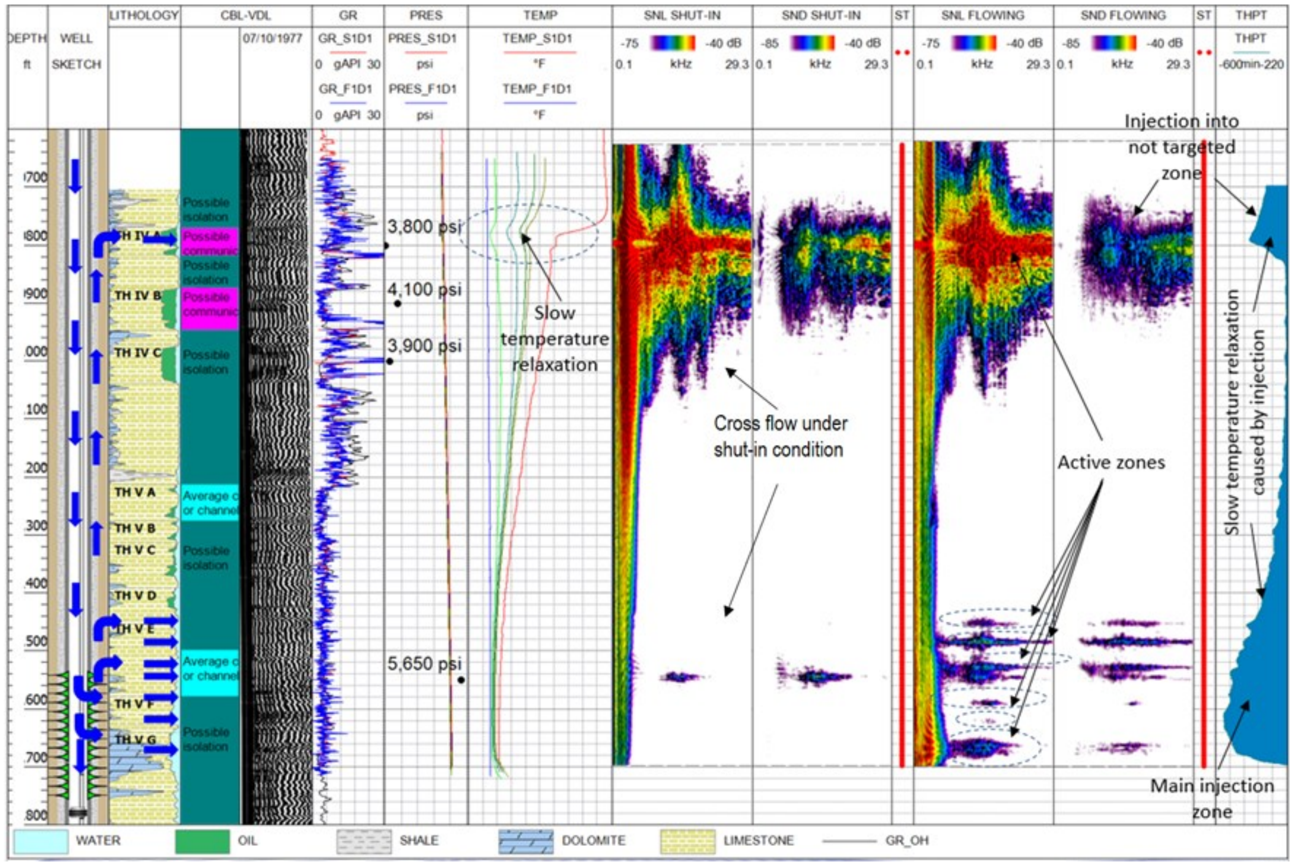

Figure 2. Extensive cement isolation failure resulting in significant volumes of bypassed injection[4]

[3] Arlen Sarsekov, Ahmed Khalifa Al-Neaimi et al ADMA, Raj Tauk, Maxim Volkov et al TGT Oilfield Services, Identification of Thief Zones and Water Allocation In Dual String Water Injectors With Temperature and Spectral Noise Logging, 2016, SPE-183491 MS, paper was presented at the Abu Dhabi International Petroleum Exhibition and Conference

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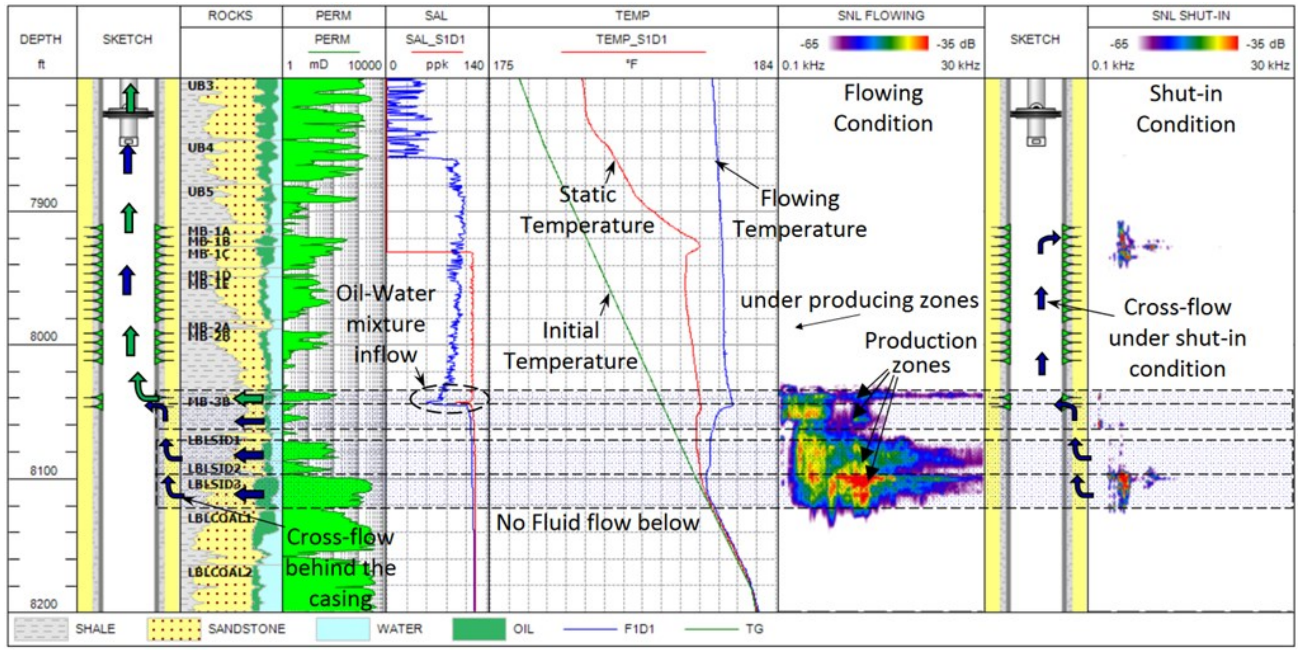

Figure 3. Underlying aquifer contributing water to perforation interval via cement channels[5]

pens after the fluid leaves the perforation tunnels is not realized. Under shut-in conditions SNL identified cross flow occurring behind casing, and under flowing conditions identified behind pipe (reservoir) injection profile. This behind pipe injection profile was then quantified by temperature simulation.

Producer Wells

Optimal production is achieved when reservoir productivity index and completion component (cement sheath, ISO-packer) isolation performance is strong. Under-producing pay zones result in delayed, and often uneven, layer production. Completion component isolation failure allows for out of target interval reservoir and/or aquifer fluid contribution. For smart completions this means a total loss of production / injection control. In this case SNL has identified contribution of layers outwith the perforation interval, and provided evaluation of the pay zone interval performance. Assessing wells with this measurement allows for effective work over planning with respect to water shut-off strategy and reservoir stimulation well candidates.

Conclusion

Assessing reservoir and completion performance is critical for effective reservoir management; sustaining optimal productivity and maximising recovery. Spectral noise logging captures and distinguishes between noise generated from flow occurring within the completion itself (leaking pipes and packers, cement channels, etc.) and flow happening 3 – 5 meters into the formation itself (matrix and fractures).

Spectral Noise Logging For Injectors:

- Locate and constrain limits of injection into layers behind pipe (within and out with perforation interval)
- Detect and differentiate between wellbore and behind casing cross-flows
- Identify leaks occurring across any completion components (tubing, casings, packers, completion jewellery, cement)

Spectral Noise Logging For Producers:

- Locate and constrain limits of producing layers behind pipe (within and out with perforation interval)
- Detect and differentiate between wellbore and behind casing cross-flows
- Identify leaks occurring across any completion components (tubing, casings, packers, completion jewellery, cement)

[5]R. Bhagavatula, M.F. Al-Ajmi, et al Kuwait Oil Company, F.Y. Shnaib, I. Aslanyan, et al, TGT Oilfield Services, An Integrated Downhole Production Logging Suite for Locating Water Sources in Oil Production Wells, 2015, SPE-178112-MS, paper was presented at the SPE Oil and

Continuous solids removal assures continuous production

by Giedre Malinauskaite, FourPhase

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There are a number of aging oil and gas wells in production globally in addition to an increasing number of HPHT wells being drilled and set in production. Both aging wells and HPHT wells have significant challenges related to solids control while at the same time maintaining optimal well flow.

With these challenges present the Oil & Gas Industry must focus on working smarter and more efficiently. There has never been a greater need to apply new technology and implement innovative solutions. It is a fact that solids removal technology plays a major role in materially reducing costs and improving production efficiency in solids producing wells.

Solids removal technology enables Operators to increase the flow rate from producing wells while at the same time staying within the acceptable sand rate (ASR) criteria. This results in improved oil recovery at a lower cost per barrel. Solids removal technology provides a proven solution to maximising profit from each barrel of oil and/or gas. While the oil price is not something Operators can directly affect – increased production rates can compensate for loss of revenue while the oil price stays low. Further, solids removal technology reduces all direct and indirect costs related to reactive sand management:

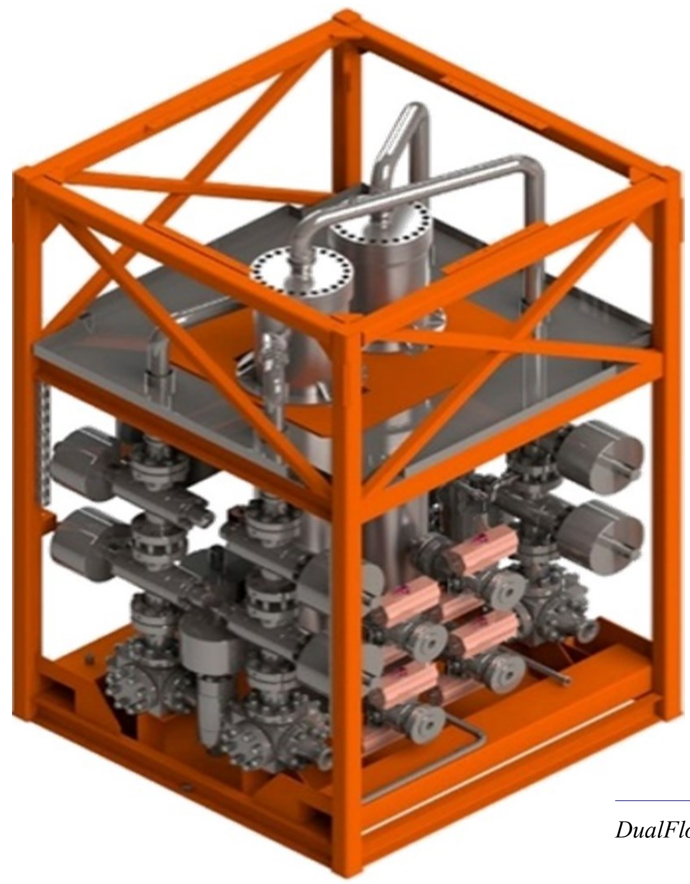
- Well intervention activities such as coiled tubing (CT) and snubbing clean-outs
- Separator cleaning and sand handling
- Heavy lifting
- Erosion of process plant
- POB necessary for doing maintenance on equipment suffering from sand production

Gullfakcs C, Statoil has been among the pioneers in implementing FourPhase's continuous production unit – DualFlow. In the paper presented by Statoil at SPE Sand Management Forum in 2014*, Statoil highlighted the benefits achieved by installing the DualFlow unit for continuous solids removal. According to the presentation, FourPhase's technology resulted in operational benefits (less jetting work, reduced sand problems in process plant, only one rig-up), cost savings (sand handling done offshore by reinjection, less need for CT sand clean out, more time for alternative CT operations) and improved oil recovery (higher flow rates without exceeding ASR, less down time for wells, optimised well performance).

FourPhase has proven to highly reduce and, in some cases, eliminate the need for costly intervention operations. In addition, providing uninterrupted continuous production.

Contact us to learn more about how FourPhase can revolutionize sand management on your installation.

*Optimization of well performance by use of a semi-permanent dynamic desander – SPE SMN European Sand Management Forum 26-27 March 2014



FOUR PHASE

DualFlow – dual non-motorized desander

Bridging the Gap – Coupling Fluid Chemistry with Fluid Dynamics

by Andrea Shmueli, Martin Fossen, Heiner Schümann, SINTEF Petroleum AS

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Martin Fossen
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Introduction

The development of the NCS could not have been possible without the cost savings and design standards provided by the implementation of the multiphase flow technology. As the core of this technology, flow simulators have been extensively used by the industry, to evaluate the feasibility of new development solutions with high credibility. However, the need for reducing investment and operational costs, in line with significantly reduced oil price, increases the demand for more accurate models. Predictability and a proper management of flow assurance problems is a prerequisite for more optimal design margins, gaining both costs, safety and environmental issues.

Flow assurance includes predicting and controlling gas hydrates, waxes, asphaltenes deposition and corrosion and includes the addition of chemicals to the production stream. While used as a remedy, these chemicals together with natural compounds occurring in crude oils (often surface active components) lead to stabilized oil-water dispersions, referred to as emulsions. These emulsions may have to be transported and handled in the processing facilities.

Oil-water dispersions play an important role in the oil and gas production system as they have a direct effect on the pressure drop in the transport lines. Reliable pressure drop predictions will lead to higher energy efficiency and cost reductions, potentially lower investment costs and facilitate the development of longer transport lines and tiebacks.

Water handling costs are high and in 2000 were estimated to be $40 billion/yr on a global scale. A considerable amount of these costs can be ascribed to flow assurance and emulsion treatment. Improved understanding of the formation, stability and rheological properties of emulsions is needed for better subsea processing design (e.g. boosting and separation) and for optimizing separation in the processing facilities. Improving measurement and predication capabilities for multiphase flows with dispersions may lead to huge cost savings during investment and operation.

Transport of produced oil and water

Upon increasing the velocity for a given fluid system the flow will eventually turn from a stratified to a more turbulent regime and ultimately to a dispersed flow where water is broken into droplets and dispersed in the oil or vice versa. In addition, in real production systems, dispersions can already be present in the reservoir or be produced by high shear in pumps and valves. Disregarding the pipe wall material and dimension, the main factors governing pressure drop are the density and viscosity of the fluid, the superficial velocities and which phase being continuous (i.e. oil, water or gas). Depending on these factors, oil-water mixtures can be arranged in different flow configurations (flow patterns) as shown in Figure 1. The left figure (a) shows different flow regimes and types of oil-in-water and water-in-oil dispersions. To the right (b), a typical flow map indicating qualitatively the flow regimes depending on the water cut and the mixture velocity. Such a flow map is very difficult to predict quantitatively and experiments must often be performed on the specific fluid system.

The state of the oil-water mixture can evolve along the transport line. As shown in Figure 2 the flow can develop from being dispersed to stratified (i.e: downstream of a valve or a pump) by separating along the transport line. This development will be highly influenced by the dispersion (droplet-droplet) stability and its rheology. Current models for oil-water flows do neither consider most of the possible oil-water flow patterns, as indicated in Figure 1, nor flow development or artificial mixing. As part of a strategic institute project at SINTEF the uncertainty of not predicting the correct oil-water flow pattern was estimated to be up to 1.7 MW with regard to pumping power. This indicates some of the cost-saving and optimization potential that this research area can contribute with.

The method

Experimental methods for studying dispersions in pipe flow experiments are quite known and tested at SINTEF and other laboratories. However, capturing the evolution of dispersion formation or dissolution during pipe flow would need flow loops in the range of tenths of kilometers. Traditional pipe flow loops are not suitable for studying transients of dispersions, lacking both the distance and (for most loops) the ability of working with real fluids and realistic conditions of pressure and temperature. To solve this challenge, SINTEF is researching on an additional alternative methodology using a wheel shaped flow loop", often referred to as "the wheel" Figure 3.

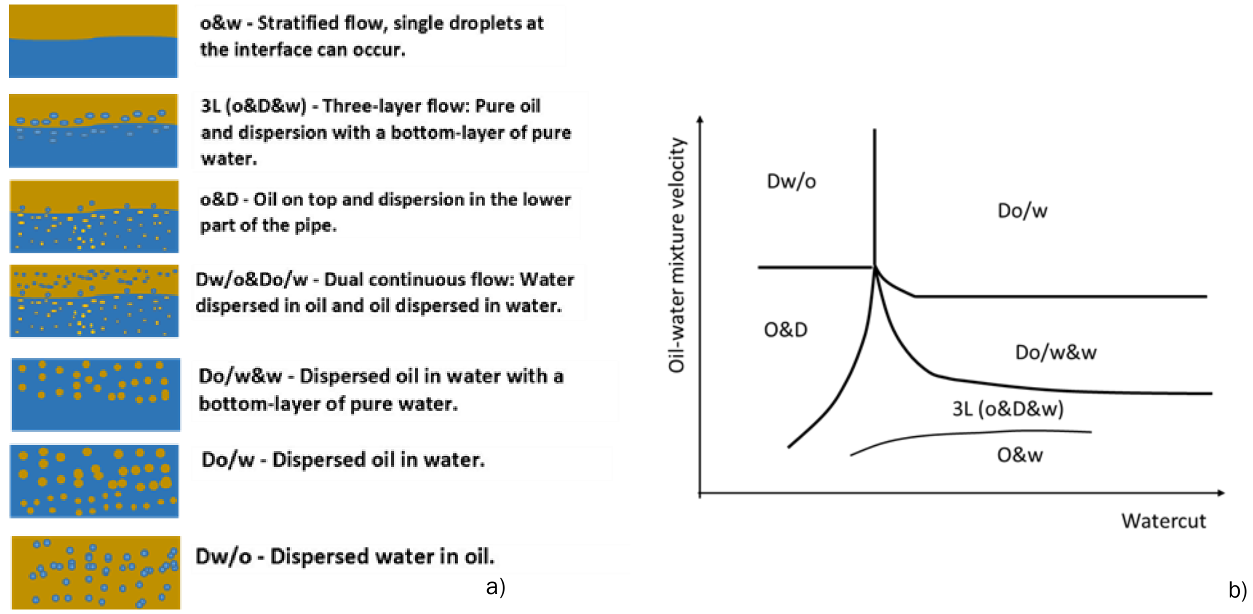

Figure 1. Oil-water flow patterns (a) and flow pattern map (b) in horizontal pipes[1]

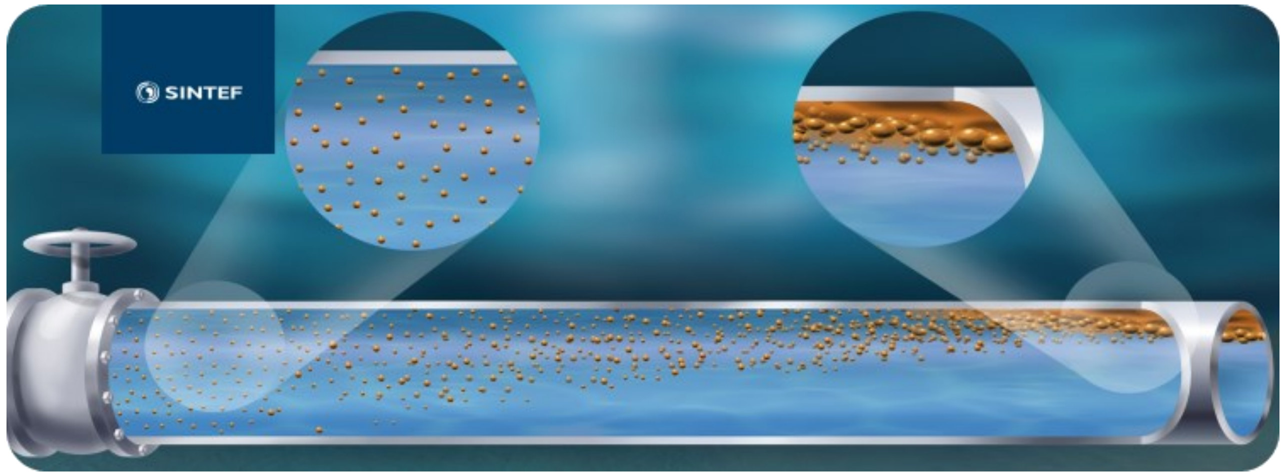

Figure 2. Example of an oil-water development process along the pipeline downstream a choke valve. The length scale for this development can be several kilometres and cannot be predicted by current commercial multiphase flow simulators.

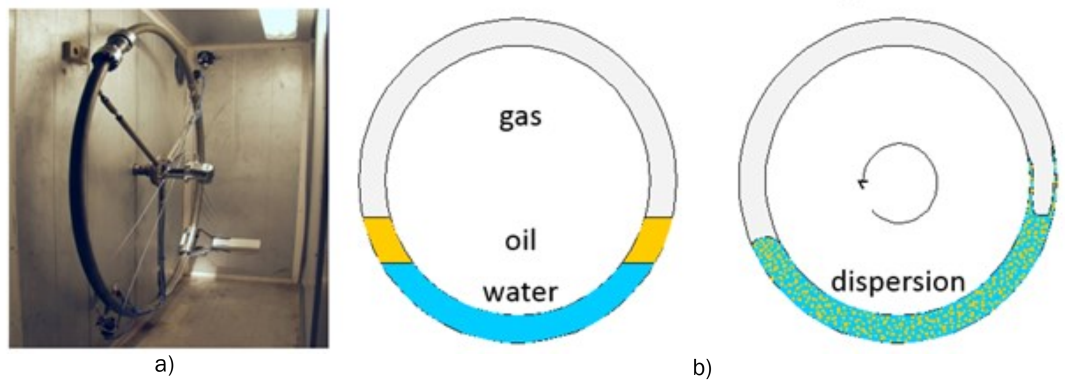

Figure 3. The wheel flow loop at SINTEF has traditionally been used to study formation and flow properties of gas hydrates. Typically, oil companies provide a crude oil of which they want to determine the potential for their system to form gas hydrates that may plug their pipe line. Moreover, the upcoming challenges caused by different production chemicals can evaluated in the wheel in a reliable and low cost way (e.g: LDHI, thermodynamic inhibitors, emulsifiers, etc). (a) The wheel flow loop placed in a climate chamber. (b) Schematic drawing of the wheel filled with a three phase system. Left: At rest and low velocities, the phases are separated. Right: When rotating at sufficiently high velocity, the flow becomes fully dispersed. A liquid tail is drawn up the pipe walls.

[1] Heiner Schümann, Murat Tutkun, Zhilin Yang, Ole Jørgen Nydal, (2016) Experimental study of dispersed oil-water flow in a horizontal pipe with enhanced inlet mixing, Part 1: Flow patterns, phase distributions and pressure gradients, Journal of Petroleum Science and Engineering, Volume 145, Pages 742-752.

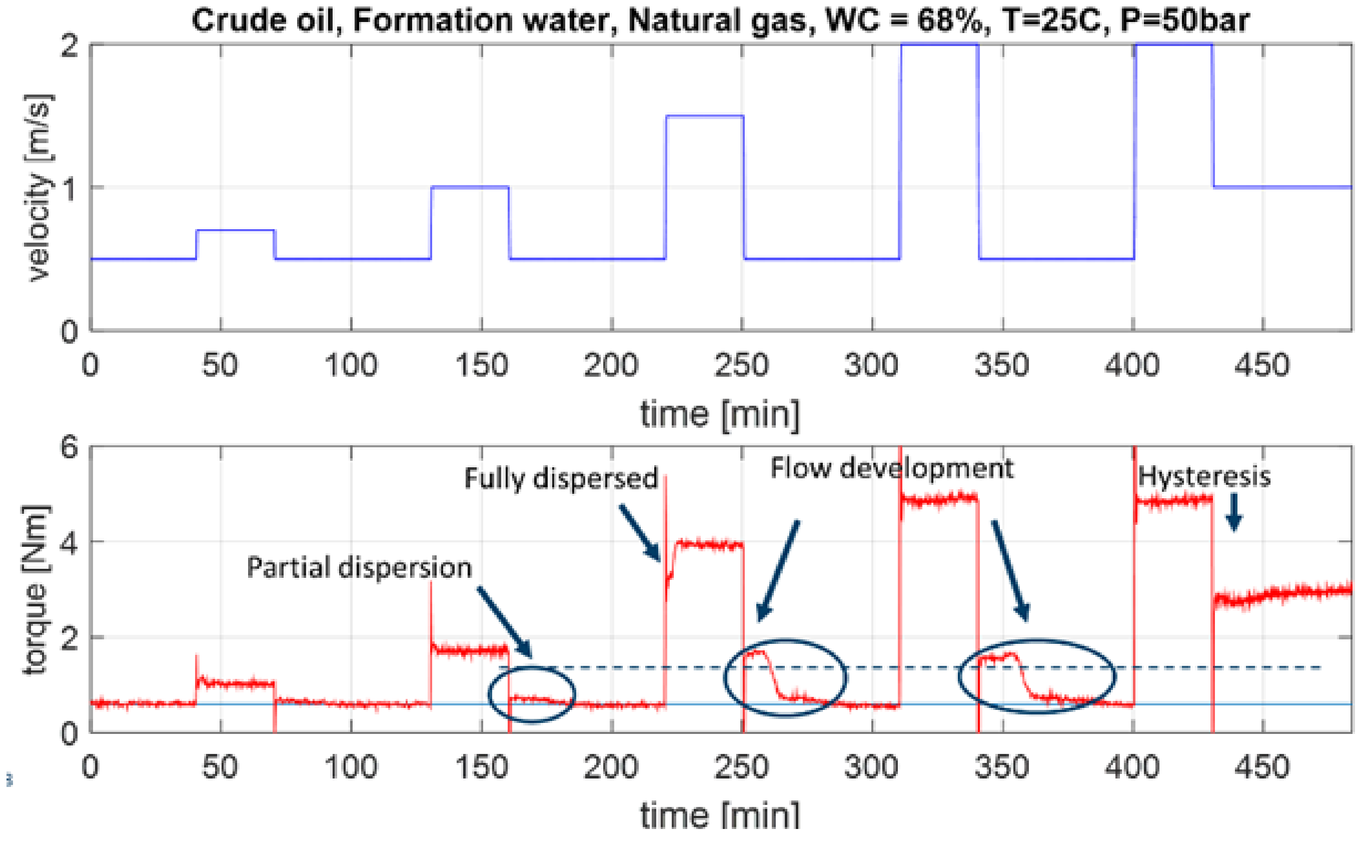

Figure 4. Example of a wheel experiment using a real crude system is shown. A velocity profile with predefined step changes was tested. Long time intervals between velocity changes allowed for flow development. The measured torque profile indicates dispersion formation as well as inflow-separation. When dispersion forms (e.g. after 220 sec), the torque gradually increases until steady state flow conditions are reached. When the mixing velocity is abruptly reduced again, the torque is gradually decreasing (e.g. after 250 sec and 390 sec), which indicates in-flow separation of the phases. The length of the separation time is a measure of dispersion stability under flowing conditions. For some conditions, flow will not separate again and shows a clear hysteresis (e.g. Torque at 450 sec exceeds the torque at 150 sec, even if mixing velocities are identical. At 150 sec phases were initially separated before the velocity was changed, while the flow was initially dispersed at 450 sec).

With the wheel it is possible to study both formation, and stability of dispersions at realistic conditions and in a simple and fast way. Furthermore, the method provides an indication of the viscosity increment when dispersions form. The system is design to run with real fluids at high pressures using hydrocarbon gas phase, brine and production chemicals. When the wheel starts rotating, the phases in the gravity driven flow will start to disperse at sufficiently high velocities. Such behavior can be confirmed with the help of a camera mounted on a window. A torque sensor has proven to be an effective instrument for indirectly measuring the increasing viscosity, sensitive enough to register even small changes in the amount of dispersion. Critical velocities required for dispersion formation can be identified for each fluid system. Testing predefined velocity profiles, a dispersion development timescale can be obtained for different input shear rates (Figure 4). This timescale might give an idea of physical flow development scales along the transport lines. Furthermore, upscaling and transformation to pressure drop in a flow line could be performed, when proper scaling rules are applied.

For oil-water systems modelling and prediction of the occurrence and kinetics of formation and breaking of dispersions is difficult. Nevertheless, it will be of huge value for the industry to be able to accurately predict transients in dispersion flow during production and in separation processes. Ongoing and future activities include finding methods for upscaling of results to be applied to large diameter pipes, characterizing different fluid systems including production chemicals, investigating effects of pressure and temperature, as well as model development considering dispersion stability properties and transient behavior.

The topics discussed in this article are based on ongoing research and development work (at SINTEF). The ideas have been presented in applications for funding to the Petromaks 2 programme by the Research Council of Norway.

Unlocking the value from the 50 years' old Exploration Data

by Håkon Snøtun, Project Leader, AGR Software

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The Unstructured Data Challenge was launched last year with the aim of proving that modern data and information sciences could extract half a century old unstructured data which could be used to create context and clarity by combining it with the structured data.

CDA (Common Data Access), the subsidiary of Oil and Gas UK (established to facilitate the sharing of well and seismic data by the oil and gas industry), launched access to their unstructured data in the summer of 2016. CDA wanted to work with a small number of vendors to see how they could unlock the knowledge in CDA's vast data repositories to help the search for hydrocarbons. AGR Software team welcomed the challenge along with eight other contractors.

As part of the CDA challenge, AGR's Software team were given more than 50 years' worth of data, or as a comparison, 3.5 Terabytes of files, logs and images in a plethora of formats and quality.

AGR carried out the project using its own iQx™ data management software to tackle the CDA data, looking specifically at final well reports, many of which were handwritten with no consistent structure.

AGR Software's main focus has always been to make available data accessible; so the developers started out defining the structured data, finding formation tops and surveys for more than 5,500 wellbores, and parsing wellbore logs to utilise drilling data.

It was found that the data in the Common Data Access was structured in much the same way as on the Norwegian Continental Shelf. Being able to complete the data set for both the British and the Norwegian side is of great importance, since geology is the same despite national borders. Too often we see people use less relevant wells in the same sector rather than the ones across the border because the data is not readily available.

When planning wells, we find that structured and historic data about similar wells is of tremendous benefit in finding trends, making predictions about the area, equipment, time and cost. When anomalies in the data are found, the planning team often spends a lot of time going through verbose final well reports to find if the anomalies arise due to data errors or whether they represent a risk for the project.

Source: AGR

AGR Software developers

That is why we wanted to contextualise the data by presenting the relevant information in the application itself. The team at AGR Software started out looking at the final well reports using OCR to make them machine-readable, then used open-source tools like Lucene to index and make the data searchable. They then began looking for the relevant headers to be able to extract the relevant data such as operational summaries, experiences and risks. Although some of the data was saved as scanned pdf, the team were able to extract value from quite a number of files. When combined with the structured data, it is much easier to understand the context of the data.

CDA did not only want us to create a solution, but gave us an opportunity to define what we wanted to explore, enabling us to think of data in a new way. We were also fortunate enough to present our ideas and findings not only for CDA, but all the other companies that participated in the challenge. This community had approached the challenge in different and interesting ways, which gave CDA great insight not only into the value of their data, but also novel ways to apply this knowledge.

The results of the work underdone and findings were presented during a workshop hosted in Aberdeen in late November. A short summary of all presentations delivered at the workshop held after the Challenge can be read here (http://cdal.com/index.php/2016/12/19/proceedings-now-available-cda-ecim-joint-workshop-on-digital-dividends-from-subsurface-data/).

Making the Digital Oilfield work – Collaborative Work Environments

by Frans Vandenberg, CWE Advisor, Smart Collaboration

SPE Distinguished Lecturer 2016-17 Lecture Season

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Frans Vandenberg
Consultant in the design of Digital Oilfields and Collaborative Work Environments

Do your operations and maintenance teams in the field and the asset teams in the office work together as well as they could to deliver the maximum field performance?

Collaborative Work Environments (CWEs) do precisely this. They help asset staff in field and office to operate more efficiently as one team. This results in higher production, less cost, improved staff efficiency, lower HSE exposure and higher staff morale.

Shell has pursued the Digital Oilfield or Smart Fields for the last fifteen years. This included real time surveillance and optimisation of wells and production as well as introduction of smart wells, time lapse seismic and fibre optics in wells.

Collaborative Work Environments (CWEs) were implemented in most assets. Operational CWEs are now used to manage more than 60% of Shell's production. The CWEs provide high quality video communication and data sharing between the operational teams in the field and the asset teams in the office. Structured processes for surveillance, maintenance and optimisation guide the teams to operate efficiently and manage their field to high performance.

Examples of the business benefits achieved are:

- → Lower production loss, from faster response to events in wells and equipment;
- → Lower maintenance cost, from responding before failure;
- → Higher staff efficiency, from instant decision making instead of waiting for email responses;
- → Lower HSE exposure, from less travelling to field sites.

A structured deployment programme was used, taking assets and projects through a standard design, implementation and embedding approach. The embedding of the new ways of working required a broad focus on the people aspects and change management. Each project included mapping workflows; awareness and training sessions; and establishing coaches and support.

With new technologies, the capabilities are being expanded. Operators with mobile devices in the field have access to real time data, communicate with experts in the CWE, show streaming video and obtain work permits and tasks whilst on site.

Figure 1. Example of Collaborative Environment, with always-on video communication to offshore (Nelson Field, UK)

Figure 2. Large Surveillance room for monitoring of tight gas field, pipeline system and LNG plant

Figure 3. Mobile access to field data, office experts, work permits and work plans

Biography

Frans van den Berg is currently an independent consultant in the design of Digital Oilfields and Collaborative Work Environments.
He has worked 32 years in Shell, lastly in its global Smart Fields or Digital Oilfield program in the technology organisation in the Netherlands. There he led the global implementation of Collaborative Work Environments in Shell.
He has held various positions as a petroleum engineer, head of petrohysics and asset development leader in operational roles and in global technology deployment. He worked ten years in Malaysia and Thailand.
Frans has a PhD and a Master in Physics from Leiden University in the Netherlands. He has been involved in the organisation of the SPE Intelligent Energy and Digital Energy Conferences since 2008.

Increase ROI of your E&P Applications with Software Metering

by Signe Marie Stenseth, VP, Open iT

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Abstract
The documented best way to reduce spending and achieve optimization of your expensive licenses is through software asset management metering tools. These usage metering tools measure how much and how often applications are used and allow managers to quickly and easily analyse true needs, thus helping companies to make intelligent decisions to keep software costs down and prevent them from paying fines for breaching license terms. Some usage metering tools also go further by not only providing historical data but by simulating various types of agreements and scenarios to help managers make more informed decisions.

Business and IT Managers are applying usage data to optimize their resources and save their companies real dollars while creating a competitive edge. Whether you're managing oil and gas applications, usage metering allows you to provide the right software to the right person at the right time thereby optimizing your costs, improving usage efficiencies and increasing your ROI.

With accurate usage data analysis and centralized monitoring, companies can effectively evaluate the utilization of their IT assets, plan their future software purchases while optimizing not just licenses but also their IT budget, and drive business to renewed growth.

1. Introduction
As technology continue to advance, and with technology now becoming the engine of business operations, organizations find it crucial to keep investing in enterprise software in order to survive the competition in the market. Even with the current situation of the global economy signalling a continuation of global downturn, causing firms to scale down on IT spending, studies shows that we will not anticipate any slowdown in the spending levels on enterprise software.

According to Gartner, the enterprise software market will continue to grow by 7.2% in 2017 globally. With this trend, business and IT managers are facing the challenge of increasing the value of their current software investments – especially for technical E&P software applications. There is a need for innovative ways to optimize software assets that will make sure that the business will continue to have the tools and services they need – while ensuring that resources, such as time and money, are used efficiently.

An effective measure to address this challenge is to implement software usage metering solutions. There is a saying that goes "You can't optimize what you can't measure" – while this is highly debatable in other practices such as HR and Management, this saying is particularly accurate, and undoubtedly, the most essential concept for software asset optimization. The first step in software optimization is to collect the usage.

2. The Context
To comprehend the importance of software metering, below is a graph showing a typical scenario that is happening in an organization that is not monitoring their software usage. Below shows actual data from an engineering company showing how much licenses they own for a particular Engineering application, and how much is being utilized over a period of time.

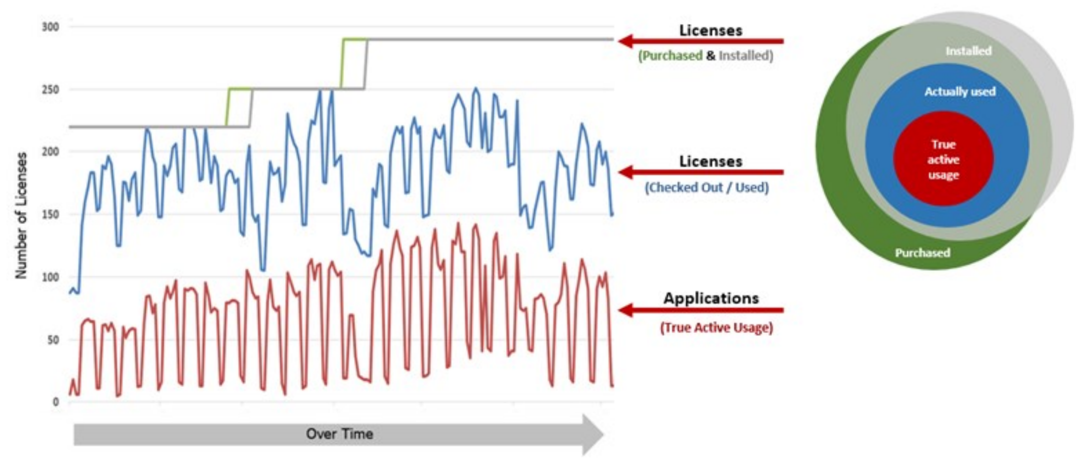


Figure 1. Licenses Owned vs Licenses Checked Out vs True Active Usage

Let's focus first on the green and gray line at the top which represents the purchased and installed licenses. The line shows that the company started with 220 purchased licenses for the application. In the first few months, IT department started receiving phone calls from end users reporting that they were encountering denials when checking out licenses. As a solution, IT purchased additional 30 licenses the following month. However, even with total of 250 licenses, there were still reports of denials from end users. This time, they purchased additional 40 licenses. IT's goal was to prevent the phone from ringing with user complaints and prevent business managers from blaming denials as the cause for the users decrease productivity. The complaints have stopped after purchasing the additional 40 licenses. However, was an informed decision truly made?

Without a software metering tool, the typical response when denials occur is to add more licenses, and numbers are based on assumptions without concrete supporting data. How much licenses do they actually need? How are the end users using the applications? Are the licenses being used efficiently? What is the real story?

These are questions that cannot be answered without a software metering solution in place. The consequences to this is wasted money allocated to purchasing unnecessary additional licenses and a sub-optimal software portfolio. Again, "quantify to justify". The key to software cost optimization is to standardize the justification process for new investments.

3. Software Metering Solutions
Useful information for optimization is derived from various data sources, different metrics, and a thorough analysis of historical usage. Additionally, monitoring usage from the log files and license manager utilities alone can be tedious – taking a lot of time and staff resources, and conclusions based on these tools can be error-prone owing to incorrect assumptions.

Implementing a software usage metering and optimization tool can help achieve large savings within the first six months. Market research supports implementing software usage metering tools and the studies show that these tools have a quick payback period with minimal post-implementation effort. The same study released by Gartner states that "Business leaders can cut software spend by 30% by implementing software optimization practices".

Proactive optimization can also be achieved thru software metering solutions that has the capability to perform automatic license harvesting where it allows companies to track inactive license usage and automatically release back licenses to the server to promote productive use of licenses. A software optimization tool can integrate with business intelligence tools such as Microsoft Excel® and Power BI™, Tableau® and TIBCO Spotfire® and help business leaders to fully understand their application usage in the most simple and interactive way. with a usage interface they already know from before.

Now, let's take a closer look at the steps you can take to improve your software ROI using software metering solutions

Step 1: Capture Usage 360

The first step is to capture all of the usage of your applications - whether it be local, server-based, web-based and applications on Citrix or terminal servers - and consolidate usage data in one central storage. A simple software inventory or discovery tool provides only a baseline of what applications are installed and what users should be using, however, it is essential to capture not only the inventory but also capture how the applications are being used.

An effective tool will be able to provide this, as well as the ability to collect usage regardless of different technical set up. This consolidated data will give you a complete picture of your software portfolio and an accurate understanding of your license position.

Additionally, while some applications are less expensive than others, and thus would seem not as necessary to optimize, it is important to remember that even less expensive software can have a high total cost of ownership. The overall costs should take into account the cost for supporting users, training, backup, and more.

Step 2: Reporting

Software metering solutions will be able to produce comprehensive reports coming from the collected usage data. There are advanced reporting solutions that will enable you to

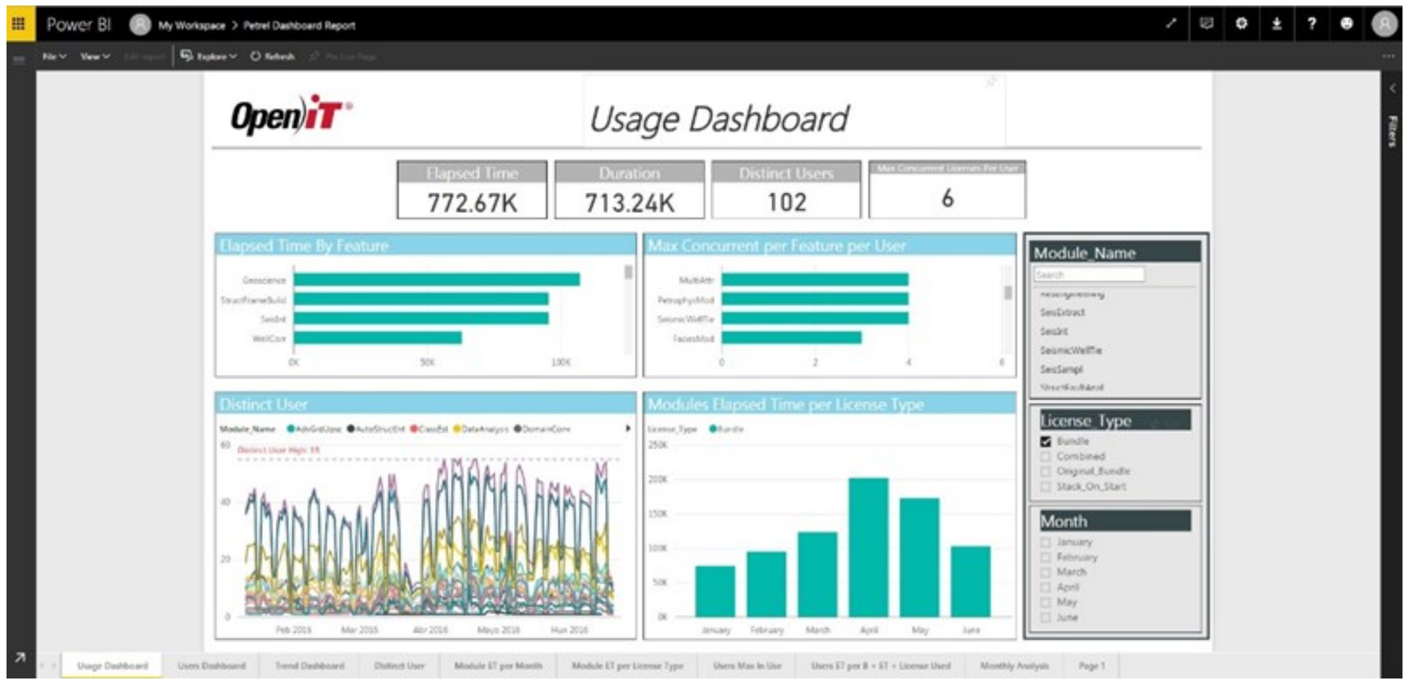
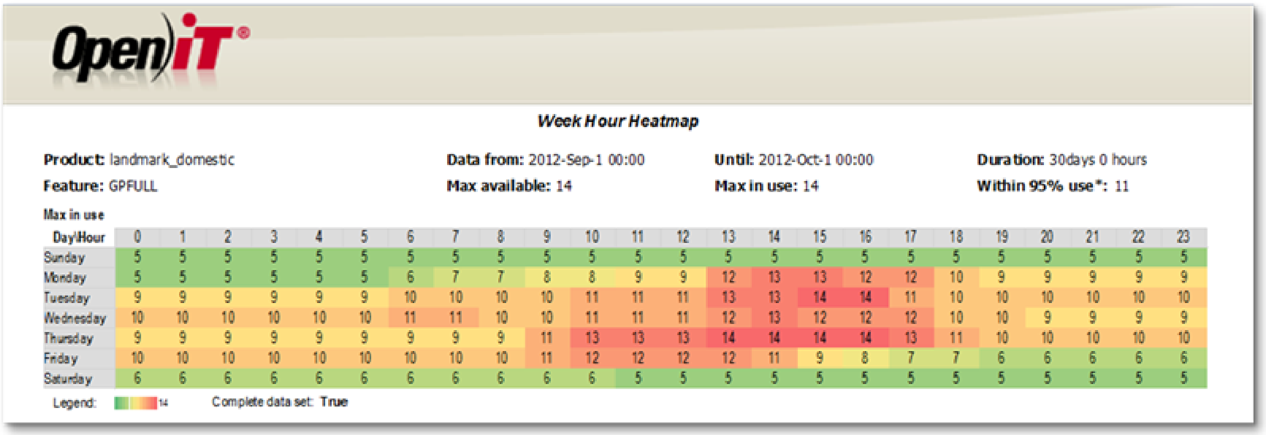


Figure 2. License Utilization Dashboard



Week Hour Heatmap

Product: landmark_domestic | Data from: 2012-Sep-1 00:00 | Until: 2012-Oct-1 00:00 | Duration: 30days 0 hours

Feature: GPFULL | Max available: 14 | Max in use: 14 | Within 95% use*: 11

Max in use

Day\Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Sunday	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Monday	5	5	5	5	5	5	6	7	7	8	8	9	9	12	13	13	12	12	10	9	9	9	9	9
Tuesday	9	9	9	9	9	9	10	10	10	10	11	11	11	13	13	14	14	11	10	10	10	10	10	10
Wednesday	10	10	10	10	10	10	11	11	10	10	11	11	11	12	13	12	12	12	10	10	9	9	9	9
Thursday	9	9	9	9	9	9	9	9	9	11	13	13	13	14	14	14	14	13	11	10	10	10	10	10
Friday	10	10	10	10	10	10	10	10	10	11	12	12	12	12	11	9	8	7	7	6	6	6	6	6
Saturday	6	6	6	6	6	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	5	5	5

Legend: 14 Complete data set: True

Figure 3. License Usage Heatmap. Red areas show maximum use of licenses while green shows time of the day when there are plenty of licenses available

look at the data in all angles and allow you to breakdown the structure in different ways to provide for multiple views. In some software metering tools, these breakdowns are typically limited to snapshots of time buckets, but with a powerful software metering solution, you will also be able to break down the usage by different groupings – which could be the basis for different cost trending. Some examples include cost trending by:

- Business unit or location: IT organizations should be able to communicate how much of the IT budget is dedicated to supporting a particular business unit or a location. IT spending that is dedicated to a particular part of the business, such as business-unit-specific projects or functional should be tracked and represented.
- Application or suite of applications: Understanding overall spending with portfolios of projects is critical for the application planning process.
- User or user-group: helps understand user behaviors within the organization and improve user efficiency.
- Fixed vs. variable costs: allow tracking of those add-on licenses that are leased or which have a pay-per-use agreement with software vendors.
- Vendor: Group applications or products together - to give an overall picture of usage from a vendor.
- Top projects: Organizations must be able to communicate overall project spending and the allocation of money across top projects.

Another advantage of monitoring through software usage metering tools is how it makes understanding your licenses very easy - even without in depth technical knowledge of license administration. It removes the tedious process of manually consolidating usage from different servers and applications – which in turn, lessens the time and resources consumed by IT staff. It is a fast and efficient way to

Feature	Distinct	LAN	WAN
OPENWORKS	1161.00	516.00	435.00
SEIS2D	254.00	65.00	48.00
SEIS3D	620.00	243.00	201.00
STRTWRKS	626.00	80.00	50.00
WLBRPLNR	114.00	32.00	15.00
ZMAPPLUS	329.00	69.00	39.00

Feature	Distinct	LAN	WAN
OPENWORKS	225%	100%	84%
SEIS2D	393%	100%	74%
SEIS3D	255%	100%	83%
STRTWRKS	787%	100%	62%
WLBRPLNR	362%	100%	48%
ZMAPPLUS	476%	100%	57%

Figure 4. License Agreement Simulations

create reports for management to help them make well-informed decisions when it comes to software asset. These reports are typically presented in graphs and tables - in dashboards and in automated reports that are sent directly to managers at regular intervals.

Advanced reporting solutions will also have features such as alerts and notifications when certain events occur – to support a more proactive approach to asset management and removing the need of continuously monitoring.

Step 3: Analysis

Trends reports provide valuable insights for software optimization. Trend reports can be shown by feature, application, location, usercroup etc. It is important that the analysis support the business decision that are on stake. Advanced tool can show you the long term trend, but were you see changes, you can go in a zoom in on specific weeks or days – to look for reasons for sudden change in user behavior or in user needs. Reports showing underutilization of a certain asset – can document ways to cut cost that does not hurt productivity. Below are more examples of areas where you can optimize with insight into usage data:

Improve User Efficiency

Understand the underlying factors behind the usage trends. This is why it is important to look at different metrics when analysing software usage. It is not enough to look at how much license is being checked out, but know how the licenses are being utilized. A software-metering tool can be able to provide usage information down to the user level in order to see user workflow patterns: Are your users using the licenses efficiently? Are they actively using the applications and checking it back into the license pool after doing their task? Or are there users who are unnecessarily hogging the licenses - using more than the needed number of licenses? Analysis the software usage and improving user efficiency is a good starting point for software optimization.

Additionally, software metering is not just about measuring license efficiency but also a tool to improve user productivity. Information from software usage by user or user group levels can give insights into which user groups use tools and where additional training is needed in order to strengthen adoption of a particular tool or a particular functionality within a tool. It is important to find those users that revert back to old tools to get their job done. It is expensive for companies to keep various versions or tools for the same tasks.

Optimizing Named Users License Agreements

To optimize named user license agreements, ideally, only power users should be reserved as named-users. A report that details the usage of users – including the number of days the user accessed the application and how long the user has used the application for a particular period will be very useful for this analysis. It is important to analyse the usage of users from time to time and re-examine if the current named user agreement is optimized. Redeploy assets that you intend to keep but which would benefit another user or user-group more.

Selecting the best application package based on utilization of the package's various components

Software metering can help optimize applications that are sold in packages. Different packages include a set of modules and by tracing the module usage, you will be able to identify which package is needed to cover the usage need while minimizing the cost. As an example, Petrel offers Bundle and Stack-on-Start licenses, using a tool will allow you to look into the modular usage and be able to determine the best type of license that can save on Petrel cost

Optimizing Combination of License Agreements

Some software metering and optimization solutions have advanced capabilities for simulating various license agreements that can help business and IT leaders in deciding which kind of software agreement is best for a given application, whether it is local concurrent, global concurrent, named users, or end-user devices. Typically, the optimal license agreement solution is a mix of global concurrent, local concurrent and named user licenses.

Step 4: Communicate and Optimize

After reports have been reviewed and analyzed, a number of ideas for cost savings and improving user efficiency will emerge. However, prior to making any decisions, it is critical to build common understanding among stakeholders. The findings need to be communicated.

A thorough communication process should be realistic about the differing perceptions among stakeholders. For example, business leaders may think that IT only cares about cutting costs, and not listening to user needs. In a drive to maintain quality, business units can tend to proclaim their right to have certain tools, regardless of the pressure placed on IT budgets. Similarly, IT can be perceived as lacking the agility to respond quickly to changing business needs. In both cases, usage data that is shared in clear and timely report formats allows all players to see where there is waste, bottlenecks and shortages.

Long meetings and decision processes may not be necessary, since the reports already provide clear evidence of the need for action. Understanding each other's perceptions, IT can share in the company's strategic business pressures, while at the same time presenting usage data and how tailored cost savings can be achieved by eliminating clear cases of waste. Shared understanding of the issues among stakeholders is critical in obtaining buy-in for cost-cutting and optimization strategies. Trend and drill-down reports provide a huge advantage for fruitful discussions that are focused on common goals. The risk of battle between business units and IT is eliminated, and working together towards agreed outcome is possible when discussions are centered around the facts.

4. Case Study

A global 500 company was facing a challenge with regards to managing software asset. They started to implement a flexible software management tool with powerful analysis capabilities that would support multiple license managers such as FlexNet and IBM LUM.

The first phase of the tool implementation involved finding actual software usage levels and patterns, by collecting and analysing the license usage data. In this phase, they were already able to gather insights about actual system obsolescence and local application usage.

In the second phase of the project, they added a tool to improve the software license availability. The tool detected licenses that were checked out, but not in active use: the inactive or idle licenses, were release back to the license pool - which resulted in a faster circulation of the available licenses among users. During these two phases of the project, they were able to document a 47% savings of one of their most expensive and critical software.

5. Conclusion

1In order to kick-start the software optimization process, start by harvesting low-hanging fruit: Focus on legacy applications that might have high degree of shelfware and newly adopted software where you need to increase the adoption rate: By looking at trends in usage, you can quickly identify candidates for optimization: Examples include:

- Renew only software that is in active use and adds value to the business
- Based on actual usage profiles, negotiate optimal licensing agreements, sizing and best terms
- Avoid non-compliance
- Reduce uncertainty by forecasting trends in usage
- Eliminate manual reporting internally and for procurement and accounting
- Target user training to improve adoption rate of applications
- Identify power users and product champions, improve support by enabling peer-to-peer user networks
- Document best practices to improve workflow analysis
- Add new technology as budget is freed up – improving usage efficiency and innovation.
- Redeploy assets which benefit another user or user-group more. Redeployment can be automated by setting up specific rules for inactive and active users

Critical to the overall software optimization process is getting IT and business leaders on the same page by creating a deeper and common level of understanding on how key resources are being used. Through this common understanding, you build trust that decision are taken to improve asset and user efficiencies. With this trust between IT and business, you can easier adopt to new changes and stay competitive. This is not a one-time job, but an ongoing process that over time creates an robust, scalable and optimized organization.

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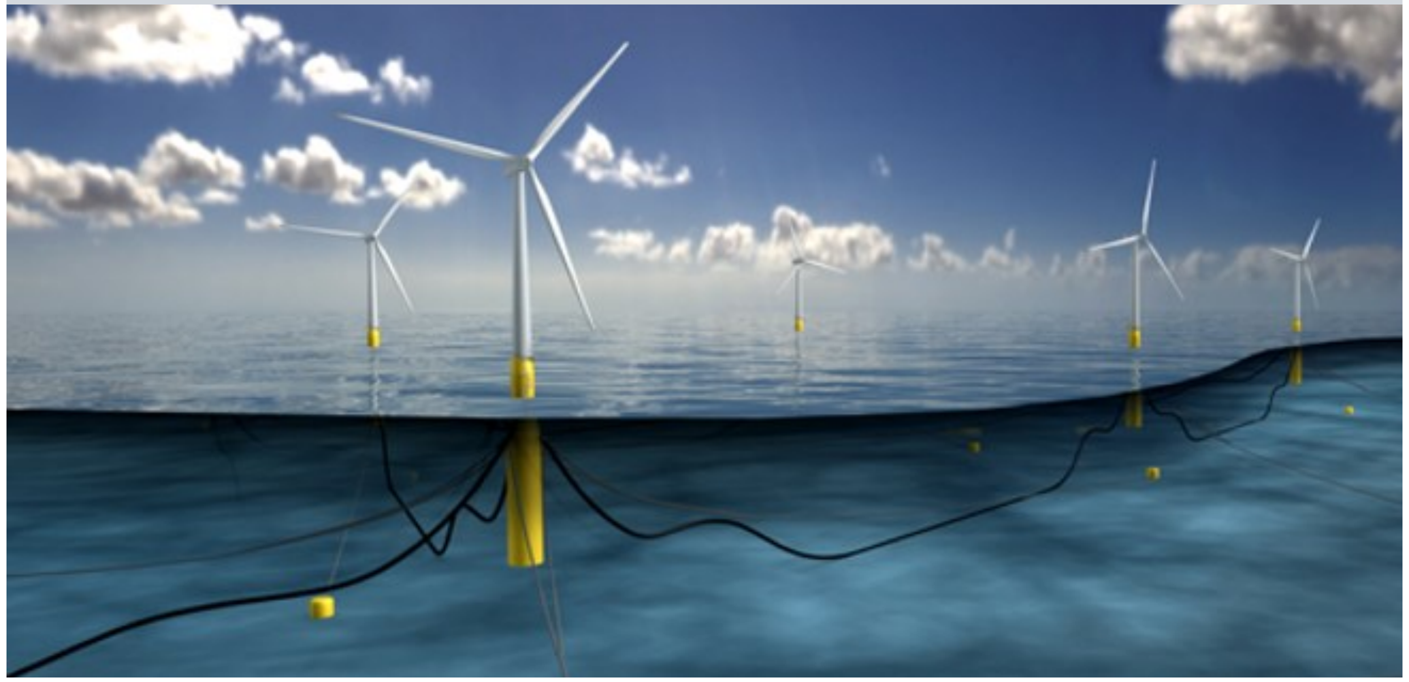

Statoil's Hywind concept – expanding the reach of offshore wind

by Sebastian Bringsværd, Head of Hywind Development, Statoil

By overcoming depth limitations, floating offshore wind greatly expands available areas and markets for the offshore wind sector. In 2017, Statoil is opening the world's first floating offshore wind farm – Hywind Scotland.

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Statoil

Positioning for the next wave in offshore wind

There are several factors that make the floating wind market particularly attractive. While bottom-fixed offshore wind is generally constrained to water depths of ~50 m, floating wind can be installed at water depths from over 50 to 500 meters or more. According to the UN, around 3 billion people live within 100km of the coast. As urbanization grows within developing megacities – offshore wind can provide clean, sustainable power solutions close to demand centers and provide huge opportunities for economic development.

A rising tide lifts all boats

The cost of offshore wind has been declining for some time. Rapid deployment has enabled innovation and enhanced learning, a competitive supply chain and ever larger turbines. Volume matters in this business. Europe now has a total installed capacity of 12,631 MW from 3,589 grid-connected wind turbines in 10 countries, and is providing more than 10 million households with clean energy in Europe every year. On a levelised cost of energy basis (a comparative calculation comparing net unit energy costs) offshore wind is now approaching grid parity in Europe. In effect, this business is rapidly becoming subsidy free and a real alternative to conventional power sources – all without the carbon and the radioactive waste. We expect costs to continue to decline and this development will also contribute to lower costs for floating offshore wind. If we can build a larger pipeline of floating wind projects, we can capture economies of scale, globalise the supply chain and apply innovation and the next stage in the evolution of the offshore wind industry.

The world's most mature floating wind Concept

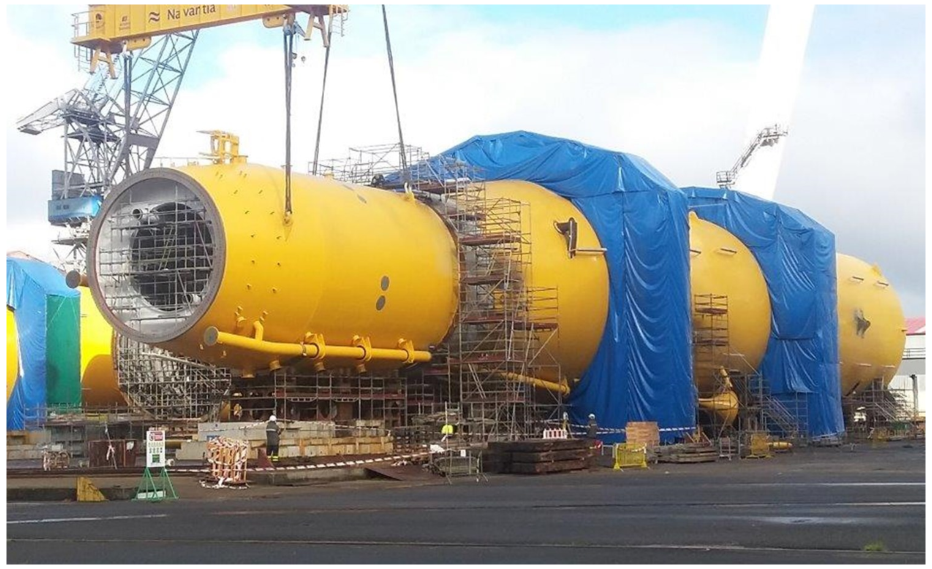
Hywind is Statoil's brand within floating wind and complements our portfolio within traditional, bottom fixed offshore wind. Hywind is the most mature of all floating concepts. Our first pilot, a single 2.3Mw turbine in 95-100 meters water depths off the coast of Norway, has been in operation since 2009 and has experienced hurricane wind speeds and 19 meter wave heights. Our next phase, Hywind Scotland in the Buchan Deep off the coast of Peterhead, Aberdeenshire is a full scale 30Mw windfarm which will power approximately 20,000 households when production starts in late 2017.

Statoil is already a substantial player in the European market for offshore wind, and is now expanding in the growing US market. By demonstrating cost efficient and low risk solutions for future commercial-scale floating wind farms, Hywind Scotland can further

enhance the attractiveness of floating wind to markets like California, Hawaii, France and Japan.

Leveraging our competitive advantages
Through the development of the Hywind concept, Statoil has positioned itself as a leading player within FOW. Hywind is the most mature and derisked of all FOW concepts.

The attractiveness of Hywind is both its simplicity and maturity. Essentially, everything below the water is tested oil and gas technology which you find all over the world – from the spar buoy foundation, to the mooring lines, to the suction anchors. Above the surface, we utilise regular offshore wind turbines and towers. In essence, we are marrying renewables with oil and gas – which puts us in a unique position to accelerate the industrialization of floating wind. There's an 'x-factor' here too, our patented motion control system which ensured stability and higher production. There are several factors that make the FOW market particularly attractive for Statoil. Statoil is already a substantial player in the European market for offshore wind, with assets also in the growing US market. Through the Hywind Scotland pilot farm, Statoil is a leader in technology development and industrialization of floating offshore wind farms. By demonstrating cost efficient and low risk solutions for future commercial-scale floating wind farms, Hywind Scotland can further enhance the attractiveness of FOW.



1st Substructure (HS 3) in full length at Assembly Area

Through continuous simplification of the Hywind concept, the use of standardised industrial components and broadening the supply chain, Statoil aims to significantly reduce costs, accelerate our project pipeline and remain the leading player within floating wind.

More in store — Batwind

The innovation does not stop at floating wind farms. Statoil is developing storage solutions linked to offshore wind (Batwind), with a battery and converter onshore that will become an integrated part of the Hywind concept. The battery storage capacity will hold excess electricity for sale when capacity is free, mitigate intermittency and optimize output through a power management system developed in-house.

This will improve efficiency and lower costs for offshore wind when it comes to exporting power. Linking up batteries with offshore wind highlights how innovation is overcoming traditional obstacles associated with variability in wind power. This lays the ground work for future projects which have the potential to store additional batteries within the structure of the turbines offshore.

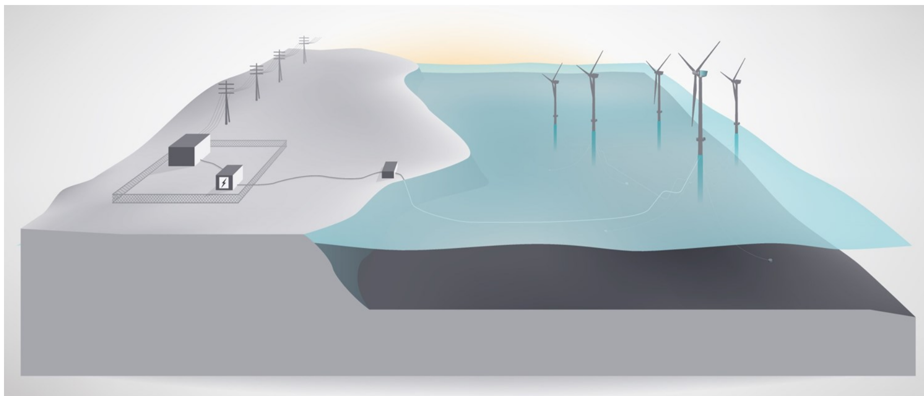
Offering nuanced new energy solutions

Our main aim is to successfully develop full scale commercial parks in countries with a high potential for floating wind, such as Japan, France, US and the UK. Such parks may have a capacity of up to 500 MW or more. However, we also see more nuanced markets developing which will require tailor made engineering to give stakeholders and customers new energy solutions fit for their own purpose:

1) **Big Costal City Markets:** Large cities with congested power supplies and pollution challenges with a desire and means to provide clean power. Examples for this may be New York or Los Angeles with one-off opportunities for developing high-profile utility scale wind farms.
2) **Island States:** Populated islands with deep waters relying on expensive diesel generation with limited potential for onshore renewables. This segment could consist of several one off opportunities for developing wind farms on different locations. Hawaii is the most prominent example where companies have started lease processes for floating wind in deep waters.
3) **Offshore Oil & Gas Installations:** Hywind could be a competitive option to power solutions based on diesel, gas or power from shore, particularly in locations with advantageous regulatory frameworks. Several near term opportunities have been identified in Statoil's own oil and gas portfolio. The market size is small due to the limited size of wind farms needed to serve the power needs (typically 50-100 MW). This may represent an important bridge market and a potential of multiple installations around the world could be targeted.

Our strategic intent – and an invitation for change

Whilst Statoil has developed much if Hywind in-house, we are looking to develop broader partnerships and facilitate new market opportunities across the globe for floating wind. We are open for new partnerships and business models. The Hywind concept is the most mature concept on floating, but we recognise that we will need new sites and areas opened, and for the Hywind concept to succeed the supplier industry needs to go hand in hand with the developers and the technology owners. There is no reason that FW should not follow the path of OW (reaching grid parity this year), or even lower, as FW can be standardised even more than OW. It is just a question of time and the timing is now!



Hywind including Batwind

A new offshore CO_2 storage site in Norway

by Mike Carpenter, Gassnova

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Norway is a leading country for carbon capture and storage (CCS) and the Ministry of Petroleum and Energy has set an ambitious new goal for a further pioneering project to be up and running by 2022.

Two storage sites are already operating off the coast of Norway at the Sleipner and Snøhvit fields, re-injecting 'fossil' CO_2 that comes to the surface mixed with natural gas. Statoil operates these fields in partnership with a number of other oil and gas companies including ExxonMobil (Sleipner) and Total (Snøhvit). The economic incentive for doing so is Norway's offshore CO_2 emissions tax that imposes a penalty of approximately 50 USD per tonne of CO_2 emitted to the atmosphere.

The new Norwegian project is designed to tackle the issue of man-made emissions of greenhouse gases head-on by disposing of CO_2 waste streams generated by industrial sources such as cement manufacturing, ammonia production or the incineration of household waste. In these cases the CO_2 must be separated from a waste gas stream and prevented from entering the atmosphere. The process of separation is often referred to as carbon capture and the new project intends to transport the resulting volumes of CO_2 in a compressed liquid state to offshore injection wells using a combination of ship transport and subsea pipeline from a ship receiving terminal on the west coast. Exactly which industrial sources will eventually be included in the project still remains to be seen.

This technical concept represents the recommendation from a feasibility study that the government commissioned in 2016, and the basis for the conceptual design phase that will begin in 2017. Front End Engineering and Design (FEED) is scheduled to commence in 2018.

The feasibility study was managed by Gassnova, in partnership with a number of companies that expressed an interest in participating in the new CCS project. These companies studied the technical requirements of such a system, how it could be integrated with their existing infrastructure and came up with a +/- 40% cost estimate for the CAPEX and OPEX requirement according to standards laid down by AACE International (Association for the Advancement of Cost Engineering). The following studies were included in the process:

- Capture of CO_2 from cement production by Norcem AS in Brevik;
- Capture of CO_2 from ammonia production by Yara Norge AS in Porsgrunn;
- Capture of CO_2 from household waste incineration by the municipality of Oslo;
- Transport of CO_2 by tanker ship to the west coast by Gassco;
- Storage of CO_2 in offshore geological formations by Statoil ASA.

Gassco is a Norwegian state owned enterprise that operates the natural gas transport network to the rest of Europe and is a sister organization to Gassnova under the jurisdiction of the Ministry of Petroleum and Energy.

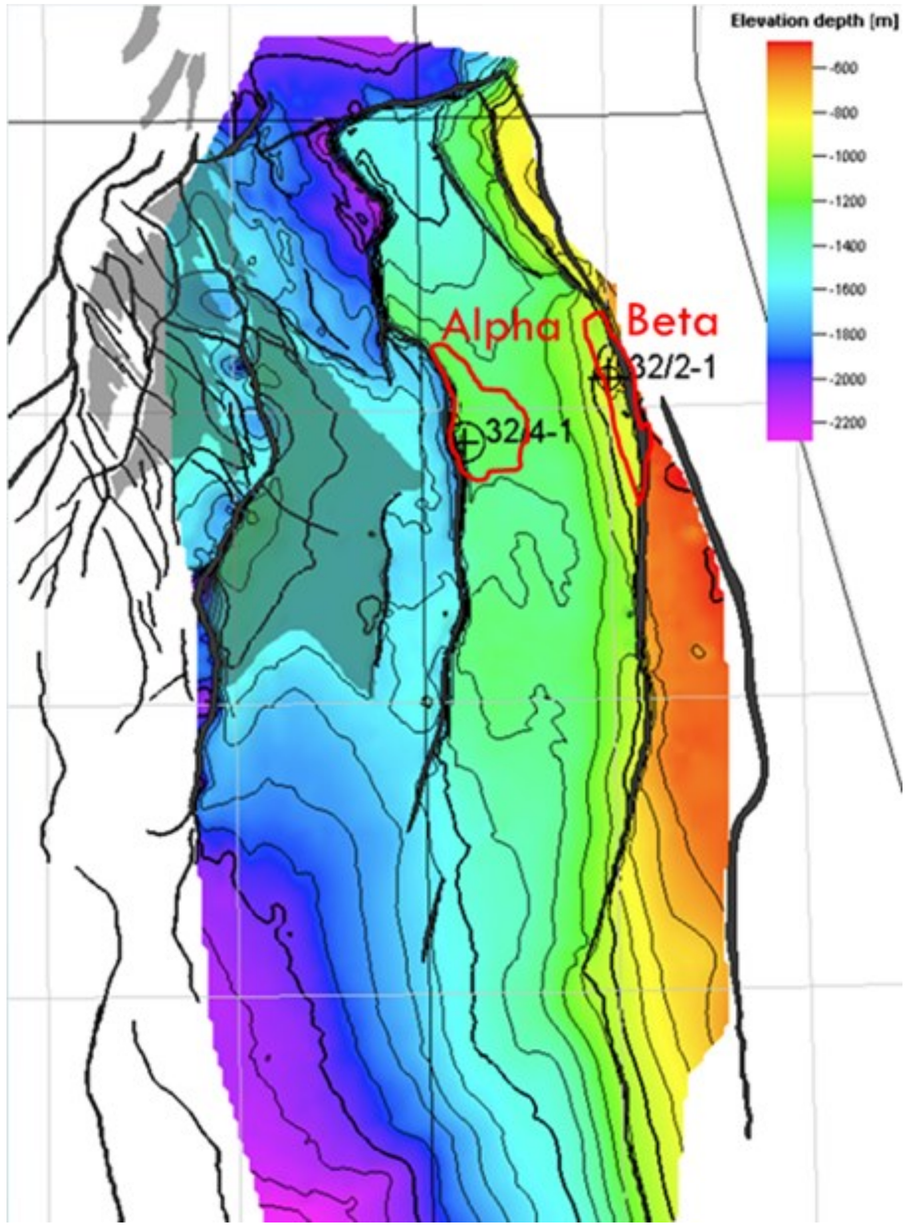
The results of the feasibility study are available online in English from the Gassnova website.

Three potential areas for CO_2 storage were examined on the Norwegian continental shelf and the feasibility study made a clear recommendation to proceed with the area they termed Smeaheia, east of the giant Troll field and sharing similar reservoir properties. A depth map for the top of the Sognefjord Formation reservoir interval is shown below with the shaded outline of the Troll field on the left of the figure.

The Alpha and Beta structural closures are within the Smeaheia area of interest, which represents a rotated fault block within the Viking Graben rift system, in the north-eastern part of the Horda Platform. The rift system was initiated during the Permian period and created a number of half-grabens that contain Triassic and Jurassic sedimentary infill.

The Jurassic sequence of sediments consists of a number of predominantly sandstone units including Sognefjord Formation, Fensfjord Formation, and Krossfjord Formation, interbedded with the locally more silty Heather B and Heather C formations. The Sognefjord Formation varies in depth from approximately 900 – 1300m in the area of interest and is a coastal to shallow marine deposit with porosities up to 30% and Darcy level permeability. Additional storage volumes may also be present in the underlying Fensfjord, Krossfjord and Lunde formations.

The reservoir interval in the area of interest is



The area of interest for geological storage of CO_2, including structural closures Alpha and Beta. The colours represent depth (m) to Top Sognefjord Formation, which is the main reservoir unit. The outline of Troll field is shown on the left and the horizontal distance between the wells in the Alpha and Beta structures is 15 km.

overlain by the Draupne Formation that forms a regional seal consisting of marine, organic rich claystones with its sealing capacity verified at Troll. Porosity ranges from 9% - 18% and vertical permeability is in the order of 6 nano-Darcy. The Lower Cretaceous Cromer Knoll Group and the Nordland Group of sediments form the overburden above Draupne and contain a number of highly effective secondary seals.

The Smeaheia fault block has been the subject of historical oil and gas exploration and enjoys extensive seismic coverage and good well control. No hydrocarbon reserves exist in the area however, as evidenced by the dry exploration wells in the Alpha and Beta structural highs. Despite this lack of hyrdrocarbons, the Smeaheia area is affected by the regional pressure drop caused by reservoir draw-down at Troll and neighboring fields. The Norwegian Petroleum Directorate monitors this pressure effect and anticipates that it is sufficiently large to more than offset any potential pressure increase caused by large scale CO_2 injection.

The conceptual design phase that will begin in 2017 will examine the Alpha and Beta structural traps in more detail and may expand the area of investigation to include other topographic high points in the Sognefjord Formation. This work will be carried out in a manner that is consistent with the new international standard for CO_2 storage sites, ISO 27914, as well as being compliant with Norwegian CCS legislation. This legislation was introduced in 2014 by way of implementing the EU Storage Directive and represents a modified form of Norway's petroleum legislation..

How much CO_2 can be stored in the current area of interest? Almost certainly more than the volumes discussed in the feasibility study, and potentially enough to accept significant volumes from other emission sources in Norway and elsewhere in Europe. The total storage capacity will depend on the number and size of structural traps that can be exploited, the magnitude of regional pressure depletion from hydrocarbon production and the number of injection wells that one is prepared to invest in.

What will the storage site be called? Smeaheia was a working title that was used during the feasibility study and the Norwegian Petroleum Directorate will assign an official field name during 2017. Watch this space.

What happens next? The conceptual design phase is scheduled to begin in 2017 in order to meet the government's ambition of starting CO_2 injection in 2022. The government however has made it clear that it is private industry that will build, own and operate the project – with incentives and investment provided from public funds. That investment will be significant and will require a commitment from the Norwegian parliament before construction can begin. Fortunately, CCS in Norway does attract support from across the political spectrum.

Thank you!

For sponsorship please contact
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