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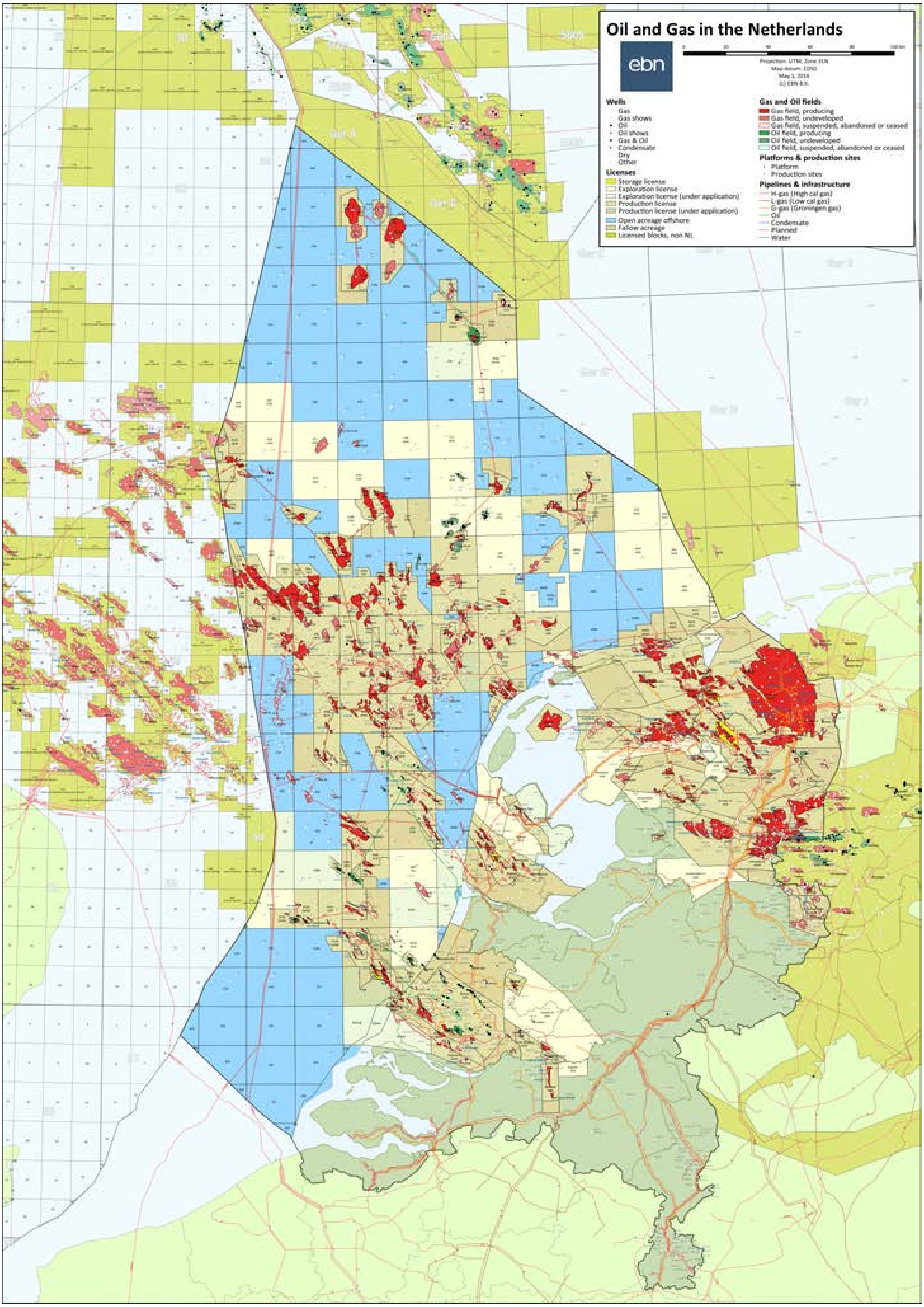
Focus on Dutch Oil & Gas 2016



(data courtesy of CGG)

Contents

Foreword

The future of 'operate' is 'co-operate'

Hope is not a strategy... But without hope, there is no strategy. That was the headline of a column by Nathan Meehan, president of the Society of Petroleum Engineers, in the Journal of Petroleum Technology. I fully subscribe to these words. Hope alone cannot take us into the future, but it can certainly help us face the future with more confidence.

Via this issue of Focus, we wish to inform you about the (recent) developments in our sector. We will, of course, also reflect on the financially difficult times we are going through, in which concepts such as cost saving and efficiency are playing a dominant role. But we also describe the opportunities which, of course, are nevertheless still present. I will return to this point later in this foreword.

I am not offering any new insight when I say that our industry is sailing through a heavy storm. The CAPEX (investments) have been at a low level for some time, and this is having a negative impact on our production. The OPEX (operating expenses) are also under pressure. Where costs can be cut, they will be cut. Every two years, in an effort to identify the key areas for cost savings, EBN carries out a benchmark study of offshore operating costs. Key areas identified in the recent study are the shore-based costs (head office support and overheads, warehousing, etc.), the contract services and equipment costs. Collaboration between operators through sharing knowledge and lessons learnt can also help increase the cost efficiency and safety of decommissioning activities. In this context, cooperation where possible will be a key issue in the coming years. I hope that in this issue of Focus we not only paint a realistic picture of the state of our sector but also express a cautious degree of optimism and hope.

Berend Scheffers, Director Technology EBN

When it comes to decommissioning, we apply the 'repurpose, re-use, recycle' principle. We believe it is important to use our existing infrastructure in a responsible and sustainable manner. I would like to cite two examples of the industry's energetic efforts in this field. The forthcoming decommissioning of three ENGIE gas production platforms in block L10 provides an opportunity to field test whether reusing those platforms will have a positive impact on the environment. The purpose of this pilot project is to develop an innovative alternative to dismantling oil and gas platforms: one that will contribute to restoring and enhancing the precious environment of the North Sea. This initiative has been taken up by ENGIE and EBN. I think this, too, is a successful example of stakeholder engagement, as all the relevant stakeholders have been involved in the project from its outset.

We are currently also involved in a project which is investigating the feasibility of giving old platforms in the North Sea a new, sustainable life. Together with TNO, Siemens and Shell we are looking at the opportunities for linking up the oil and gas industry in the North Sea with offshore wind farms. These are still two separate worlds, but they have much to offer each other. At present we are investigating the opportunities that integration could bring. We are, for example, researching how old platforms and gas fields can be deployed in an innovative way to store energy.

I would also like to dwell for a moment on our changing world and the impact it is having on our business. The Climate Agreement concluded by 196 countries at the Climate Conference COP21 in Paris has undoubtedly changed the energy landscape. For our part, we see the results as a stimulus to boost sustainability. The agreements define our commitment to keep global warming below 1.5°C by 2100 and to reduce net CO_2 emissions to zero in the second half of this century. For us, the fossil fuel industry, this specifically means that we have 35 years to meet these goals, to revise our entire operation and strategies and to come up with innovations that reflect these agreements. This is a huge challenge that is forcing us to change the way we think.

There are still significant gains to be made in the area of sustainability throughout the industry, including in the Netherlands. In 2015 EBN actively pursued the sustainability theme. Together with our partners we will continue to evaluate the opportunities for moving forward. Our wish is to develop clear policy – especially in the area of decommissioning – in consultation with industry, and for this policy to prominently feature the ambition of ensuring sustainability and re-use.

In this issue of Focus on Dutch Oil and Gas we try to show that despite the headwind there are still plenty of opportunities to develop small fields. These opportunities do, however, require (perhaps more than ever) creativity, innovation and entrepreneurship. If we can assure these, the North Sea still offers much development potential. I hope you will enjoy reading this issue.

Executive summary

Focus on Dutch Oil & Gas 2016 provides you with an overview of the current state of affairs and remaining prospectivity of the oil and gas sector in the Netherlands. Finding the opportunities in low price scenarios by knowledge sharing, collaboration and innovation are key items this year. The following are some of the highlights of the respective chapters divided in themes: Exploration, Production, Infrastructure, Decommissioning and Research and Innovation

- The Dutch Continental Shelf still holds a vast potential. The Northern Offshore is the subject of continuous study and up to now structures have been identified containing more than 150 bcm unrisked. To explore these remote areas with limited infrastructure cost efficiency is vital specially in a low price environment. New leads are presented which can be the subject of multi-target exploration campaigns.

- EBN's prospect database contains up to 1300 prospects and leads. Only 25 % of the prospects are actively being studied by operators. Meanwhile the remaining 75% are classified as inactive. A closer look at these prospects reveals that there is still a significant group with a medium-to high POS contained mainly in the Rotliegend and Main Bunter formations. The average prospect size is about 1 bcm. The main risks observed for Rotliegend prospects are seal and reservoir, while charge seems the major risk for Main Bunter prospects.

- With access to most well results EBN is in an excellent position to monitor operator's drilling performance. Closely reviewing 200 recently drilled wells for Reservoir Performance - assessed by comparing pre- and post-drilled UR - only about 30% of the wells reached the mid case UR or better. Assessing the Operational Drilling Performance - by comparing actual with planned drilling time - reveals that about 40% of drilled wells experience more than 125% time overrun. Most of the non-productive-time is the result of drilling events whereby unexpected geology plays a role. EBN has taken the initiative to collate information on these drilling events to compile a database. More information is currently being gathered in collaboration with operators.

- In 2015 gas prices decreased to just below 20 €ct/m3 and have continued to decrease in 2016 to levels below 15 €ct/m3 .As a result of this low price environment and in combination with high operational costs the profitability of the small fields and its related infrastructure come rapidly under pressure.

- In 2015 the total production from smalls fields (excluding UGS) was 22.4 bcm (GE) which corresponds to a decline of about 7% compared to 2014. The reserves totalled 143 bcm GE in 2015 corresponding to annual decline of about 7%. Reserves replacement is key to partly counteract this decline. However, in 2015 the reserves replacement ratio was only 30% compared to an average of 70% in preceding years even with similar levels of investment. Adding reserves has become more capital intensive.

- In order to assess the impact of a changing gas price environment the dynamics of the offshore portfolio were modelled using EBN's simulation tool Infrasim to estimate the Cessation of Production (COP) of platforms and main trunk lines.

- Maturating reserves (i.e., developing the remaining portfolio) is crucial for extending the COP date of some of these platforms and trunk lines. For others, decommissioning seems imminent.

- Although decommissioning will eventually become a reality, if prematurely removed it can lead to a substantial loss of resources (both volumes and infrastructure) and create an undesirable domino effect. About 100 bcm are at risk of being permanently lost in the coming 5 years.

- Offshore OPEX levelled in 2015. The Unit Operating Costs (UOC) also stabilised at about 6.5 €ct/Nm^3 which is still significant given the current gas prices.

- There are plenty of possibilities to optimise these offshore costs and operations as it was manifested in the two-day workshop on low costs development organised by EBN. The synergy with the offshore wind sector was highlighted as well as the importance of knowledge and experience sharing across the industry.

- In an effort to identify the key areas for cost savings, EBN carries out every two years a benchmark study of offshore operating costs. Key areas identified in the recent study are the shore based costs (head offices support and overheard, warehousing, etc.) and the contract services and equipment costs.

- Collaboration between operators by knowledge sharing and taking advantage of the learning curve is also beneficial to increase the cost efficiency and safety of decommissioning activities. An optimisation pilot study initiated by EBN on the collaboration business cases showed that benefiting from the learning curve and increasing the contract size can lead to costs savings of up to 40% when well P&A and decommissioning of installations are done in campaigns.

- Reusing the installations (for the same purpose) has seen only marginal financial benefits. However it has led to a considerable acceleration of field development. Repurposing the installations (e.g. rigs-to-reefs) has also emerged as an important option. Recent pilot studies have shown that platform jackets support the marine ecosystem of rich and biodiverse habitat.

- The actual decommissioning costs of topside and jackets have stayed within a margin of +10% compared to provisions. However, the actual costs of P&A of wells have proven more challenging with margins up to 50% compare to provisions. This is indicative of the underlying uncertainty of P&A of wells: the behaviour of the subsurface and incompleteness or inaccuracy of records and as-built drawings.

- To address this, EBN will be pushing actively to set up a National Decommissioning Platform whereby emphasis will be placed on building an extensive database of the subsurface construction data of the wells and installations.

- Finally, EBN emphasises the relevance of investing in research and innovation, even in low price scenarios, as it is crucial to unlocking the remaining potential of the Dutch subsurface. As such it will continue to invest in JIPs, organising symposia and workshops on relevant topics as a way of generating value and knowledge in partnership.

1

Our challenges

A different attitude towards gas

The onshore activities of the Dutch E & P industry have in recent years increasingly been under pressure. This is due to the seismic events in Groningen resulting from gas production, the accompanying risks to local residents, the spin-off repercussions on other developments (such as in Friesland and in The Green Heart) and also due to the collective resistance to the extraction of shale gas. In addition – this is in general not just pertaining to onshore activities – gas is considered to be a polluting fossil fuel, which is not supportive to its potential role in the energy transition.

The prices for oil and gas have dropped dramatically the last year, the resulting investment level is extremely low and the developments in oil and gas production are drying up fast. In addition, a large number of existing fields are approaching the end of their productive life, which also has its effect on the infrastructure. Yet there are still plenty of opportunities in the Netherlands, both on land and at sea, which – with the aid of new technology – can be developed responsibly and often profitably.

Both the government and the industry recognise the importance of careful interaction with all stakeholders involved. Earlier this year the Minister of Economic Affairs presented his vision on stakeholder management. His view is for all parties to remain in dialogue with each other about their role in energy transition, with faster and better decision-making as a result. All stakeholders will be more closely involved in projects than previously. In all probability, a National Platform for Energy and the Environment will be set up this year, with the aim of improving communication with and between all parties involved in large energy projects.

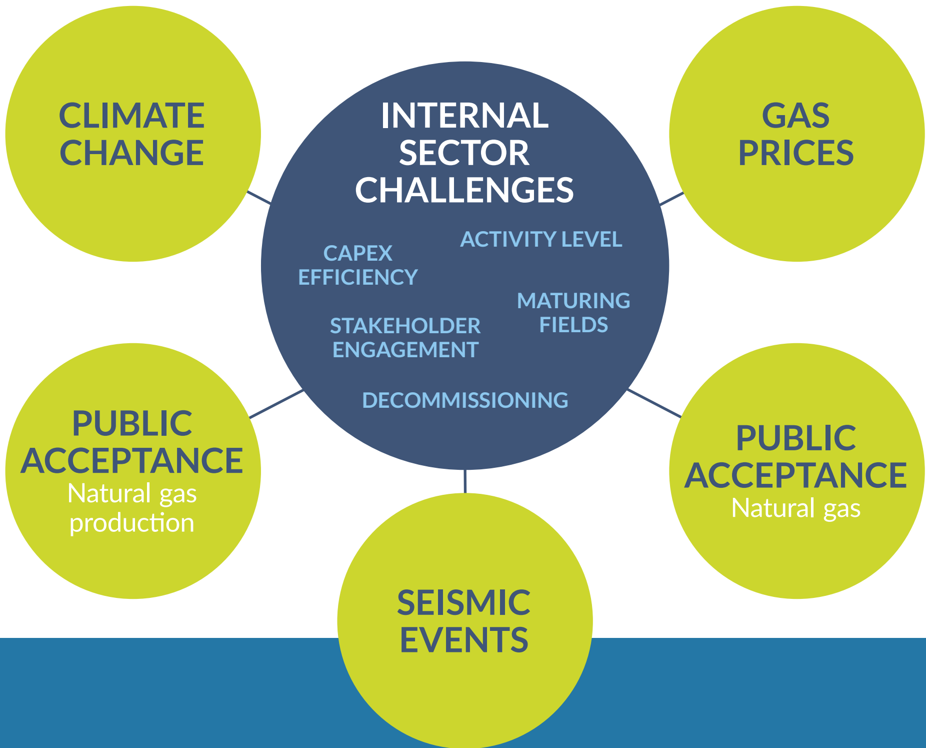
The government is also working on a proposal related to the local benefits and burdens, which is expected to be submitted to parliament in the second half of this year. The E&P sector is developing a ‘stakeholders code of conduct' which pays attention to issues such as communication with all parties involved, the role of E&P stakeholders when planning for projects, and how to handle the possible risks of oil and gas developments. This code will be ready early 2017. EBN also attaches great importance to open and transparent dialogue with all stakeholders and other interested parties and, where possible, will contribute actively together with our partners.

The gas industry works together with the common aim to optimise emission reductions in all energy functionalities and accelerate the transition to a sustainable energy system. Five upstream and midstream companies, of which EBN, do so under the flag of GILDE (an acronym derived from the Dutch phrase meaning ‘Gas In a Long-term Sustainable Energy system’).

GILDE is all about dialogue and outreach. In two years, GILDE has facilitated an outsider's look at the gas industry, leading to a drastic change in attitude towards activities and fuelling our ambitions towards sustainability. GILDE will continue to explore our added value in this respect and will forge new coalitions to achieving these goals.

This encompasses exploring synergies with offshore wind and geothermal energy, carbon capture and storage technology, and green gas production whilst advocating reduction of natural gas use in some markets and increased use in others to contribute directly to mitigate the impact on our environment and planet.

EXTERNAL INFLUENCES



2

Exploration

A mature basin with ample opportunities

Roadmaps form an important part of the long-term strategy of EBN. The topics addressed in this section result from activities carried out under the Exploration Roadmap, which focusses on the identification of new oil and gas occurrences in known plays and under-explored areas. It also looks at cost-effective ways to explore and stimulates the sharing of knowledge and data between operators. Some of the work done by EBN in previous years has led to more exploration activities among operators and it is hoped that this trend will continue, as exploration is essential for replacement of reserves and to assure future supply. Below, the drilling performance of recent years is also reviewed.

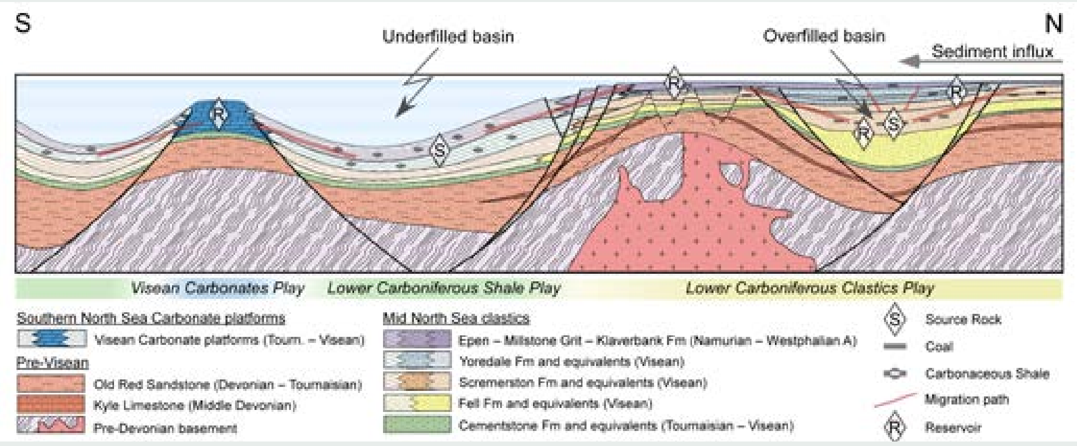
The DEFAB Area

Lower carboniferous clastics play

The Lower Carboniferous clastics play has been proven in the UK Continental Shelf (UKCS), with fields producing from Namurian reservoirs, and the Breagh field development that produces from Visean clastics. From well reviews EBN has concluded that this play is virtually untested in the Dutch Northern Offshore. The Visean and Namurian reservoir rocks are present throughout the DEFAB study area. The sketch illustrates the elements of the Lower Carboniferous play.

Reservoir quality sands become more abundant and thicker from Breagh towards the northeast, and favourable reservoir properties are not limited solely to a zone near the Base Permian Unconformity (BPU).

Elements of the Lower Carboniferous play in the Dutch Northern Offshore



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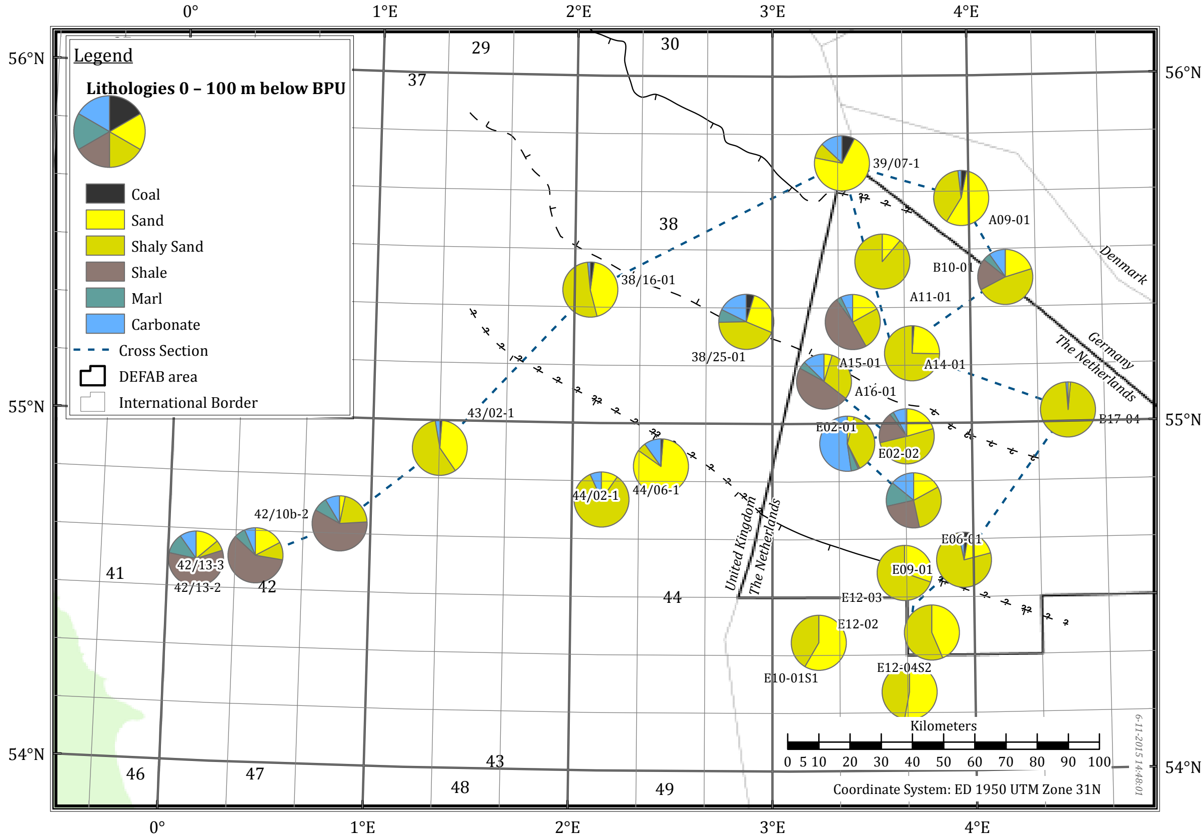
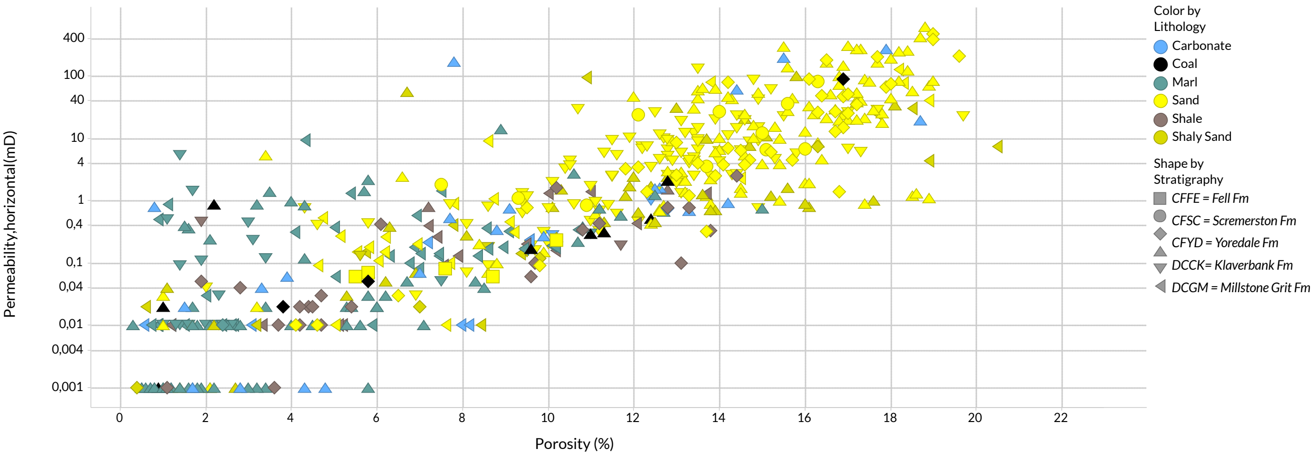
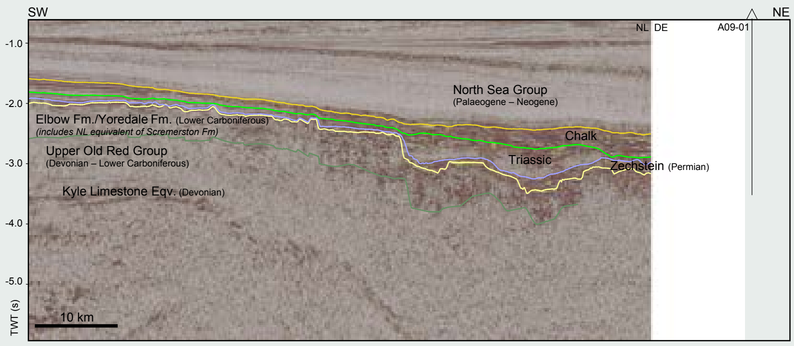


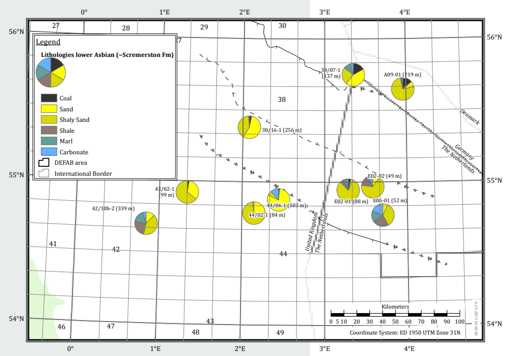
Lithological characteristics of the Lower Carboniferous in the interval 0 – 100 m below the Base Permian Unconformity (BPU).



Porosity and permeability measurements from core plugs for the Lower Carboniferous.
Wells used: 42/13-2, 43/02-01 (UK), A14-01, A16-01, E02-01, E06-01, E12-02, E12-03, E12-04-S2 (NL), B10-01 (DE)

Left: High contrast seismic facies in the Elbow Formation (partial equivalent of the Scremerston formation. The projected position of well A09-01 (30 m coal) is shown. Right: Lithologies in the Lower Asbian (roughly equivalent to the Scremerston Formation))





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The most promising source rocks in the northern part of the DEFAB study area are Lower Carboniferous Scremerston coals. Wells show that coal content increases northwards, with 23 m of coal found in well 39/07-1 and 30 m in well A09-01. In the southern part, charge may occur from Lower Carboniferous basinal shales and laterally from Upper Carboniferous Westphalian coals.

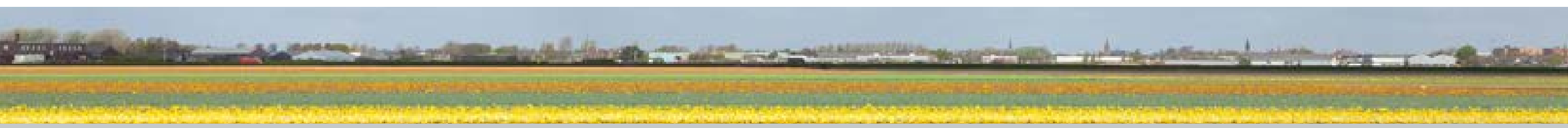
Twenty structures have been identified on the BPU map, with a total P50 GIIP (gas initially in place) of about 75 bcm (unrisked). The presence of intra Lower Carboniferous seals would provide large upside, since many additional structural closures would become prospective. Some of the mapped leads are shown in the section 'Multi-target exploration'.

The triassic main buntsandstein play

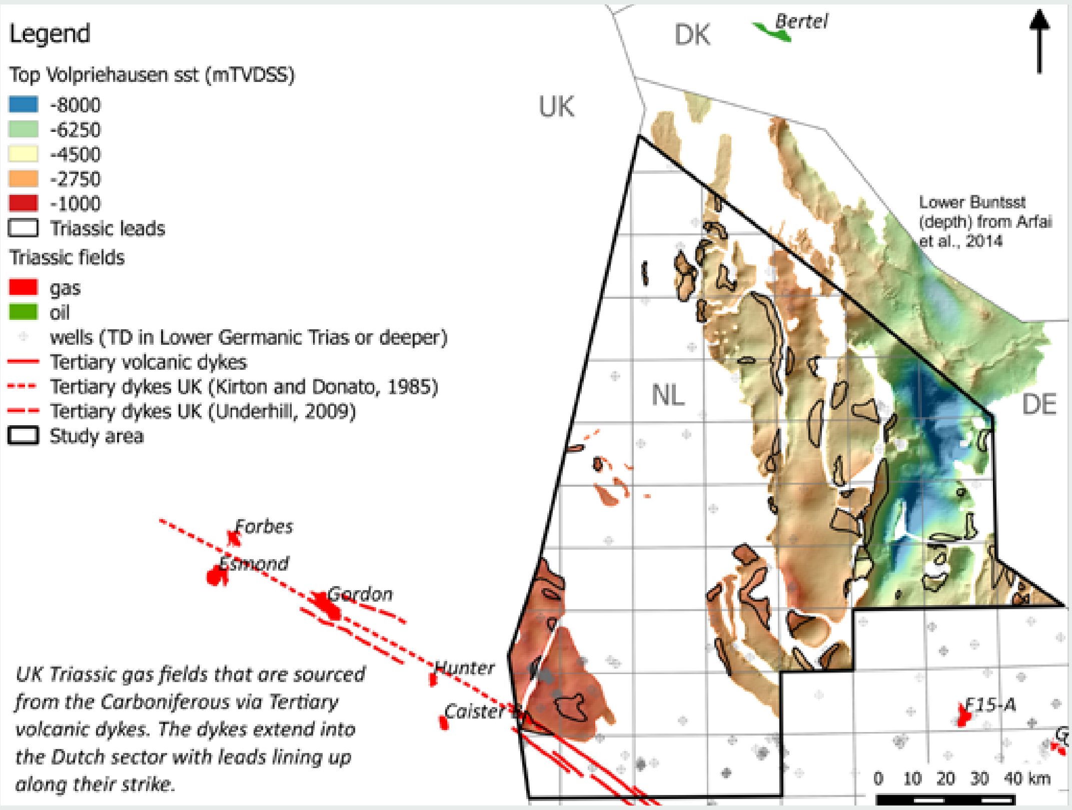
Although the Triassic Main Buntsandstein play is proven in the Netherlands, only 20 wells in the DEFAB area have drilled Triassic. Although none of these proved hydrocarbons, EBN has concluded from well reviews in combination with recent seismic that 11 wells can be classified as invalid tests of the Triassic play.

Three play types have been identified:

1. 'Classic' leads with proven types of trap, source, seal and reservoir.
2. Leads which may have been sourced via Tertiary volcanic dykes, analogous to Triassic gas fields in the UK Southern Gas Basin (e.g. Gordon).
3. Leads with fluvial sands sourced from the north. EBN is currently further investigating the likelihood of such sands by analysing cuttings from key wells in the A blocks.



Top Lower Volpriehausen sandstone depth map with Triassic Leads in the Northern Offshore.



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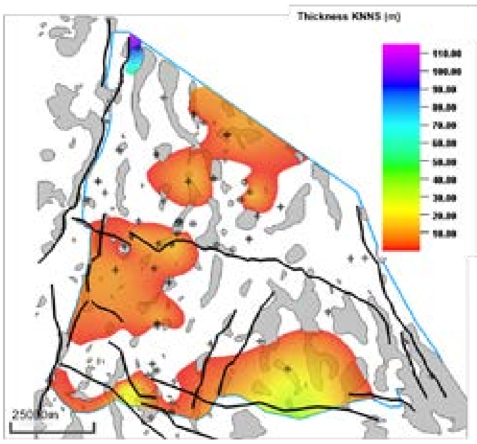
Up to now, 29 structures have been identified, with P50 GIIP ranging from 1–9 bcm, for a total P50 GIIP of 80 bcm unrisked. Some of the identified Triassic leads are shown later, in the section 'Multi-target exploration'. These leads will be evaluated in more detail and the higher-ranking prospects could be part of multi-target exploration wells in combination with prospects at other stratigraphic levels.

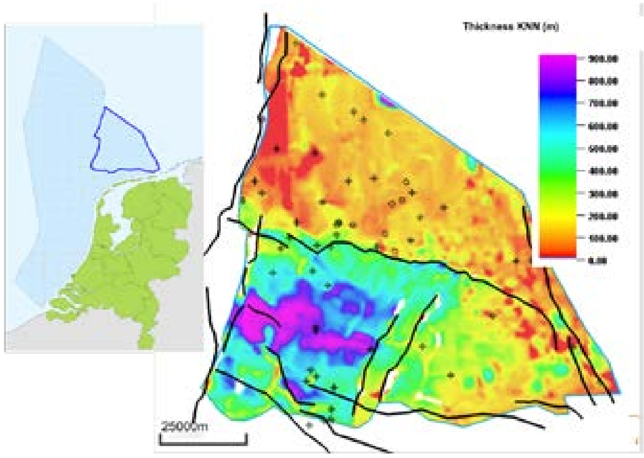
The G and M Blocks

Improving understanding of the distribution of the lower cretaceous sandstones

Close to the eastern boundary fault of the Dutch Central Graben a locally thick 'Vlieland Sandstone' (90m) was drilled by well G07-02. EBN is investigating whether this sand is indeed of Early Cretaceous age and is analysing its relationship with the nearby faults and/or salt activity.



Lower Cretaceous sandstone thickness, based on well data only(*). Grey outlines are salt structures.
(* The thickness is often below seismic resolution).



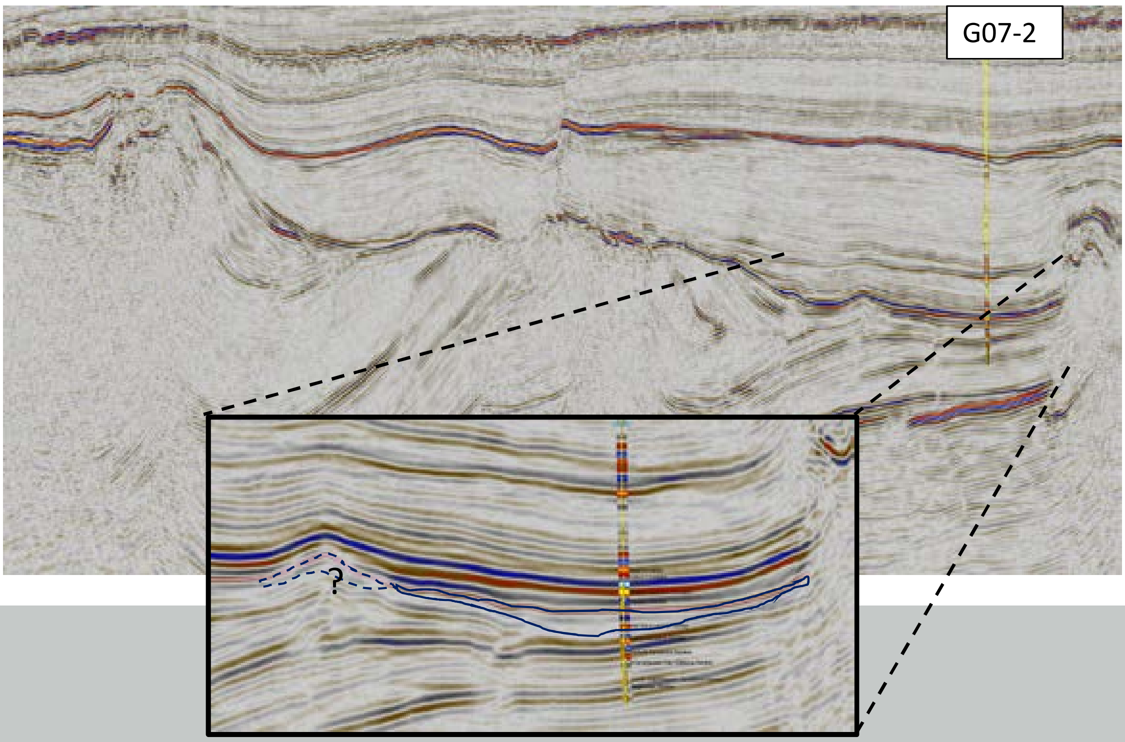
Lower Cretaceous Vlieland subgroup thickness.

It is generally understood that Early Cretaceous sands decrease in thickness and reservoir quality northwards (Jeremiah et al, 2000). If the G07-02 sand is Early Cretaceous in age, it may open up new interest in local Lower Cretaceous sands that are related to local structural highs generating a nearby source of erosional material.

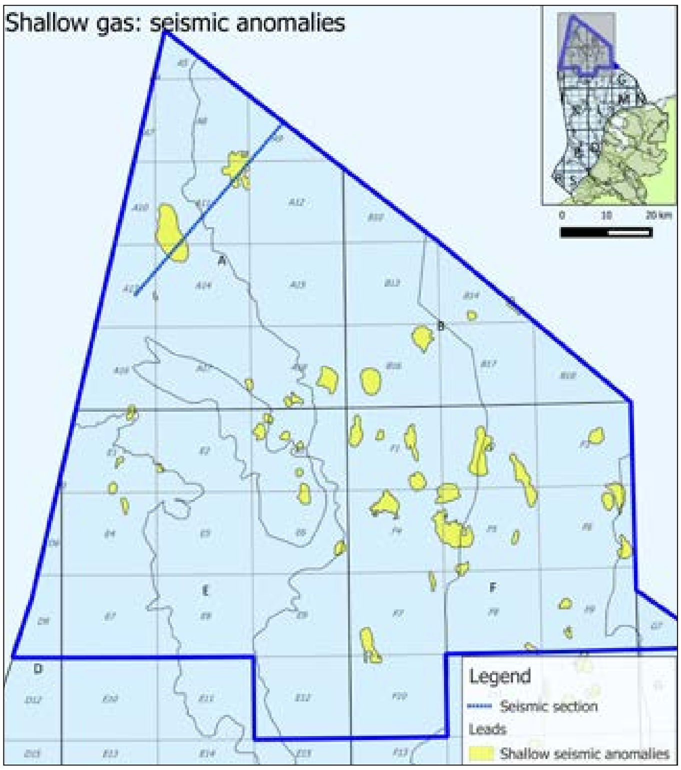
Explore multiple targets

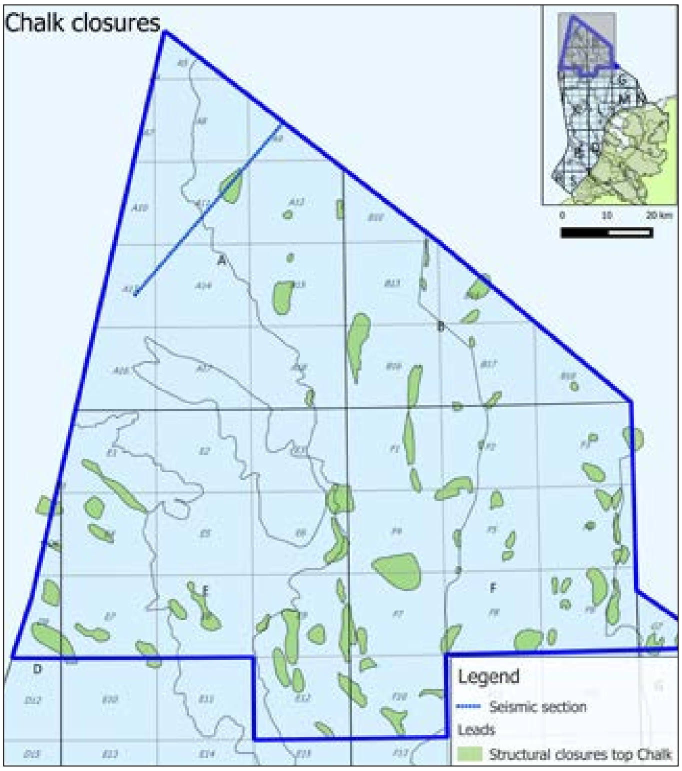
In the current low oil price environment, cost efficiency is required in under-explored areas with limited infrastructure. An effective way of reducing costs while improving the chance of success is to explore multiple targets at different stratigraphic levels, and therefore EBN is evaluating several plays in parallel, de-risking common play elements and identifying leads at multiple levels in the Dutch Northern Offshore.

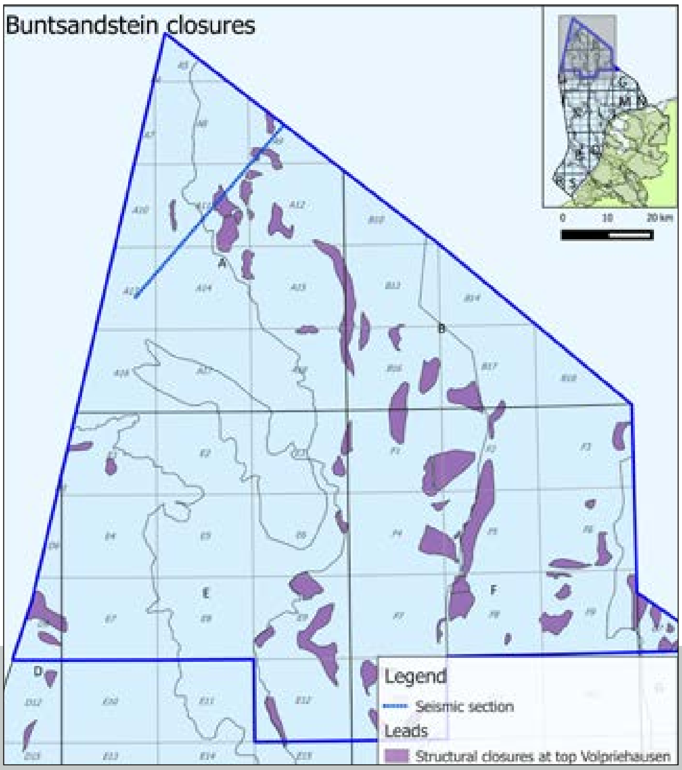
Interpretation of the possible extent of the Vlieland sandstone near G07-02 well G07-02 on the eastern shoulder of the Dutch Central Graben.

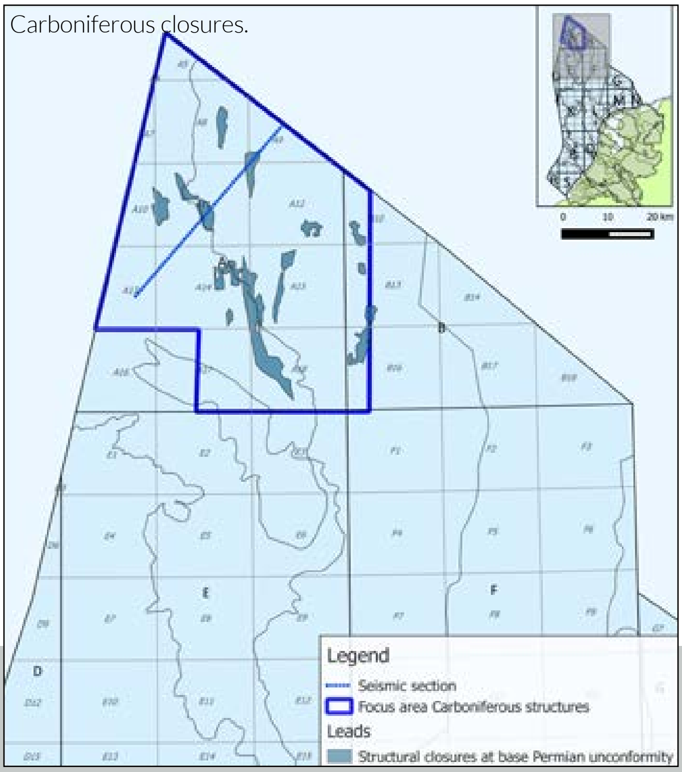


New leads identified by EBN









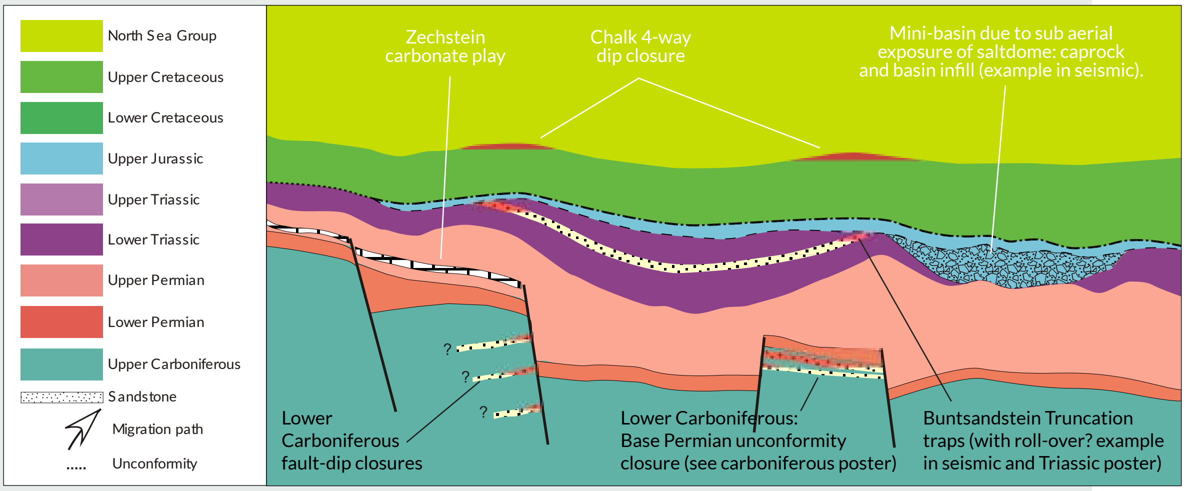
Example: multiple targets in block A11

Potential reservoirs are expected at multiple stratigraphic levels in the A11 block related to a north–south trending graben in this block:

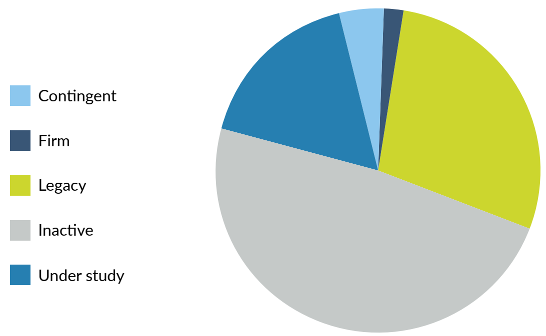
- Ekofisk Chalk is present in low relief anticlines.
- Lower Germanic Triassic strata have been preserved in the north–south trending graben, located in structures which formed on both sides as a result of salt movement. There is potential for northerly sourced Triassic sands;
- A Zechstein salt diapir shows indications of subaerial exposure which may have led to the formation of a caprock reservoir consisting of erosional products, analogous to the G16-A gas field;
- Zechstein carbonate build-ups developed along the margin of the Southern Permian Basin and were preserved in this area;
- Lower Carboniferous clastic reservoirs are expected in this area, and 4-way and fault-dip closures can be identified at BPU level.

Gas charge is expected from mature Lower Carboniferous coals in this area, whereas in the ultimate northern border area early oil charge may have occurred from Upper Jurassic marine clays. EBN will continue to further de-risk the various leads and structures in the area, to work up a viable multi-target opportunity.

Conceptual plays in block A11 (based on seismic section displayed in the Leads maps)



Distribution of summed expectation per prospect status (source EBN)



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Prospect statistics

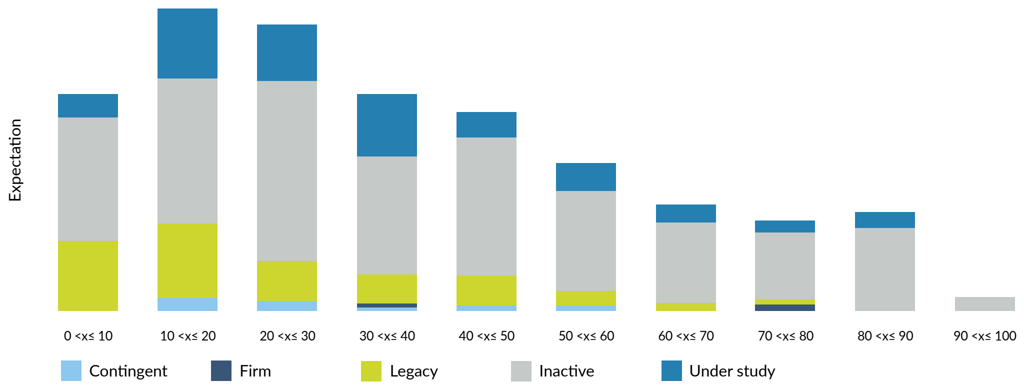
EBN maintains a prospect database containing information on prospects and leads as mapped by all operators, which obviously includes volumes and risks. The database now contains some 1300 prospects/ leads. Analysis of this dataset provides some useful insights.

Active prospects and leads

Of all the prospects and leads in the EBN prospects and leads database, about 25% have an active status, and are further classified as 'firm', 'contingent' or 'under study'. Meanwhile about 75% have an inactive status - meaning they are not being actively looked at ('inactive'), or have a 'legacy' status – meaning the prospects have been interpreted by a previous licence holder or on older seismics.

The histogram of the summed expectation of prospects/leads per (10%) POS (possibility of success) class shows, not surprisingly, that the inactive group contains many prospects with higher risk and lower volume than the 'active' group (contingent + firm + under study). Interestingly, in the 'inactive' category there is also a significant group of prospects with a medium to high POS (50-90%).

Distribution of summed expectation per prospect status and POS class (source EBN)



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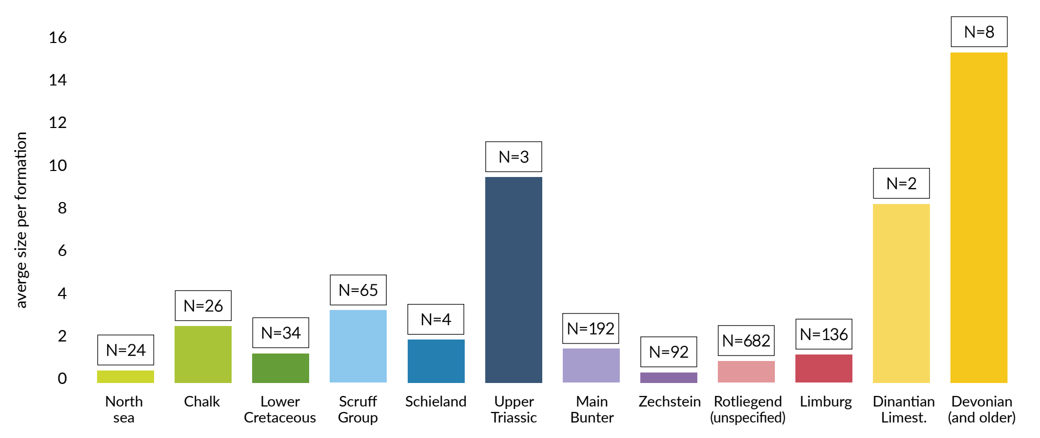
Average prospect size coloured by reservoir (source EBN)



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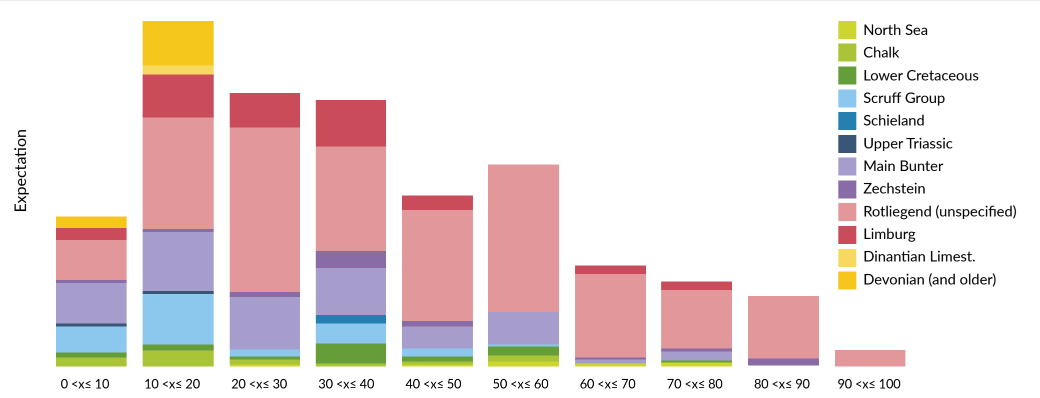
Distribution of volumes per stratigraphic formation

Most prospective volumes remain in the Rotliegend (about 700 bcm GE) and Main Bunter (about 300 bcm GE) . The average prospect size per formation (in bcm GE) is shown together with the number of respective prospects and leads. Although the Rotliegend and Main Bunter host most of the prospective volumes, the average prospect size is much smaller (about 1 bcm GE) than the other formations.

The POS distribution is not evenly spread over the various reservoirs, as can be seen in the graph which displays the distribution of prospective volumes for each POS class and coloured per stratigraphic formation, combining onshore and offshore. Specifically, the Rotliegend prospects and leads dominate the high POS range.

Distribution of summed expectation per POS class per reservoir



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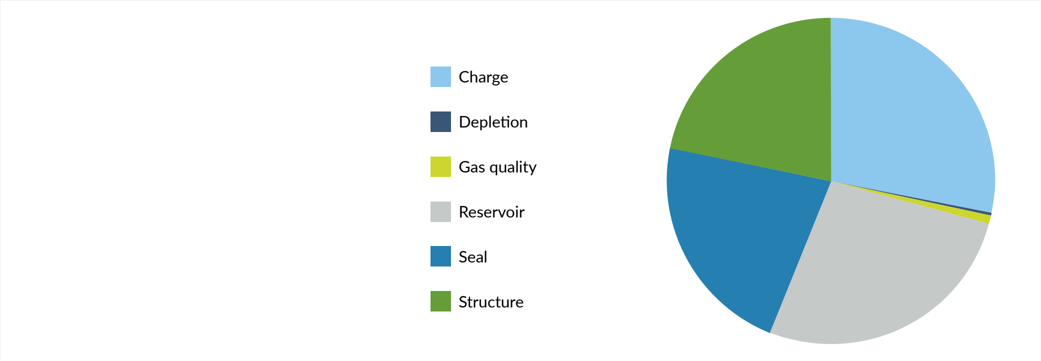
Partition of prospective reserves per main risk (source EBN)



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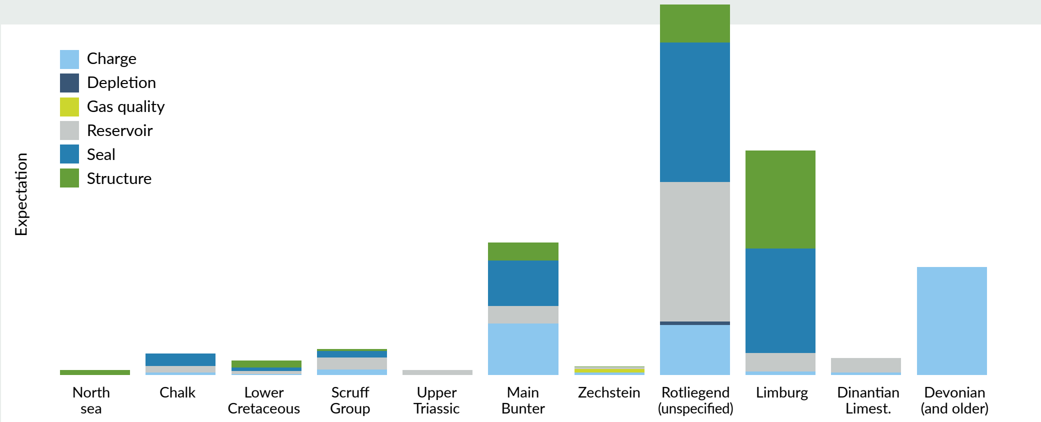
Distribution of risk parameters

If known, the main risk has also been captured in this database. The pie chart shows that the proportion of expectation volumes distributed over risk parameters such as charge, depletion, gas quality, reservoir, seal and structure. These are almost equally distributed between charge, seal, structure and reservoir and show no clear trends.

The next chart displays the main risk for prospects only (i.e. excluding leads). For the Bunter prospects, charge is typically seen as a major risk in 30% of the prospects. For Rotliegend prospects, the main risks for the prospects tend to be seal and reservoir.

EBN will continue to refine and update the prospect database. Further analysis of the prospectivity data will be carried out this year.

Distribution of summed expectation per main risk (source EBN)



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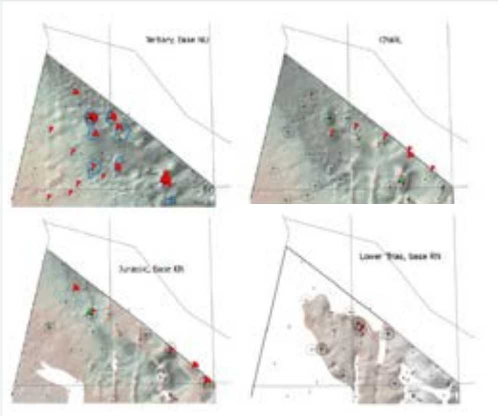
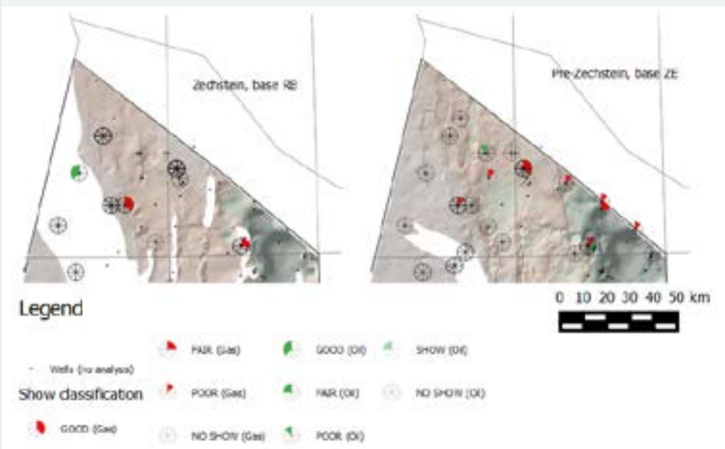
Hydrocarbon shows database

Documenting and visualising HC shows in wells can be a powerful exploration tool, especially in combination with additional productivity indicators such as drill stem tests (DSTs), repeated formation tests (RFTs) and core data (including sidewall data).

EBN has initiated a project aiming at compiling a consistent HC show database. The database focusses on oil and gas readings derived from log data and reports (e.g. mud logs, composite logs). The HC shows are tied to the stratigraphic framework, as defined by TNO. For each stratigraphic interval the 'strongest' gas and oil reading is documented and assigned to one of the following classes: 'no show', 'poor', 'fair' and 'good'. Additionally, several relevant attributes are captured, such as lithology, mud weight, mud type and alkane concentration. Further information on the validity of a HC show is given by DST, RFT and core data, the results of which are listed in separate input formats.

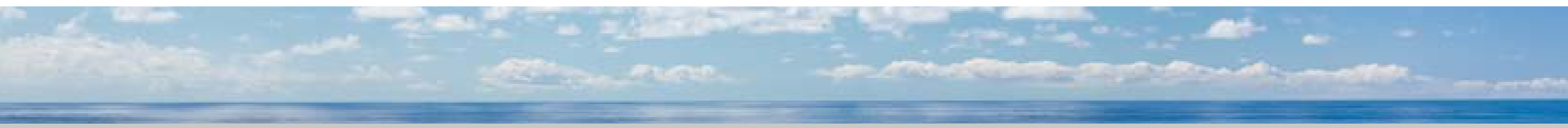


All data entries are coupled to coordinates, depth and stratigraphy. This allows the user to compare the different data types, perform thorough quality checks and investigate the correlation between (un)successful DSTs and HC show classification. Additionally, the segregated data formats can be combined into a single GIS visualisation map to plot e.g. hydrocarbon shows per stratigraphic formation. Currently, about 70 boreholes have been analysed in the Dutch northern offshore. The project aims to gradually expand southwards, which will eventually result in a coverage of all onshore and offshore boreholes. The database is intended to assist in exploration studies and it's expected to be made publicly available.

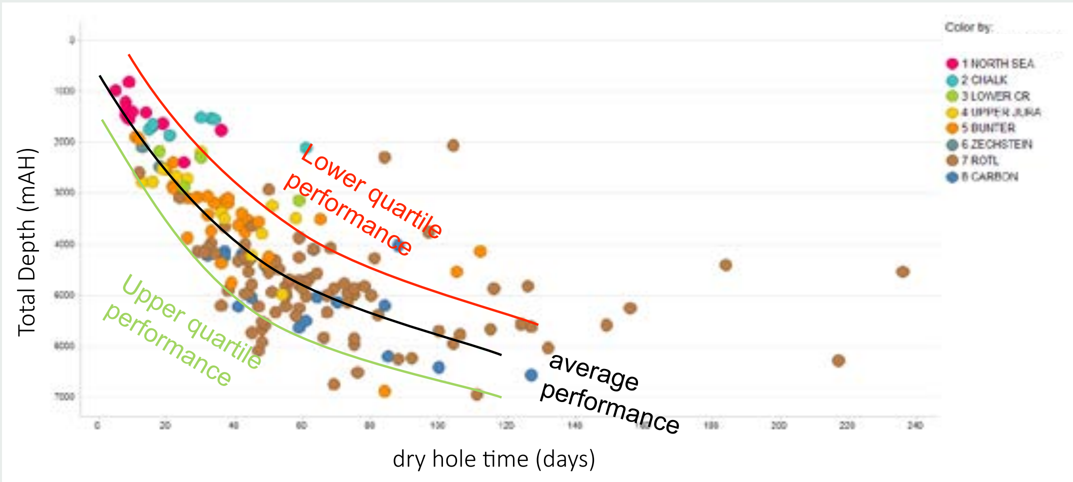


3rd Geophysical symposium

In February 2016 at the third geophysical symposium – ‘Echoes from Seismics’ – organised jointly by EBN and ENGIE, several operators (ENGIE, Hansa, NAM, ONE, Sterling, Total) presented interesting case histories on the results of seismic studies in the North Sea. The topics at this one-day event were wide-ranging, including reprocessing efforts, interpreting results and 4D results. In addition, the results of two types of seismic acquisition new to the Netherlands were shown. They concerned Hansa’s ‘coiled shooting’ acquisition in the G18/H16/M03/N01 blocks, and Sterling’s Broadband acquisition in F17/F18. Both were acquired in 2014 and have shown a significant improvement in data quality. EBN presented the results of the 101 exploration wells drilled in the period 2005–2014, some of which have also been published in the 2012 and 2014 Focus reports. Towards the end of the day, Wintershall presented the results of underwater acoustic measurements carried out to validate TNO’s theoretical models. The day ended with a presentation from Rijkswaterstaat, on policy on underwater acoustic noise and its implementation, with a view to granting exploration permits in the Netherlands and in other countries. About 65 people (including 10 students) attended and the day was very well received. Released presentations have been put on EBN’s website. Topics are being considered for the next symposium, which will be held in 2017.



Estimation of drilling days as function of well depth



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Monitoring drilling performance

With access to most well results, EBN is in an excellent position to monitor operators' drilling performance. Many different parameters have been analysed, to allow benchmarking, e.g. of technologies or plays. The number of drilling days as function of well depth for about 200 recently drilled wells are plotted. The trend lines added show the upper and lower quartiles in terms of drilling performance, thus making it possible to compare a particular well outcome with the entire population. This information also makes it easy to estimate rig times for planned wells.

The life cycle of drilling a well can be reduced to four phases: mob–demob; dry hole time; completion & testing; and suspending or plugging and abandoning. A typical successful Rotliegend well has the following (average) characteristics:

A typical Rotliegend well in NL	• finds hydrocarbons (60% sucess ratio)	
	• has a well TD at 4900 mAH	
	• has an outstep of 2250 m	
	• lasts about 133 days, of which:	17 for mob-demob & prespud
		67 days (dry hole time)
		35 days for completion and testing
		14 days for suspending or P&A

In reality, the average well does not exist as operations have variables with varying weighting factors. To mention a few:

- Well complexity: outstep and maximum inclination
- Different stratigraphic units with accompanying challenges
- Different rigs
- Diverse operators

Two other performance examples are elaborated: 1) Reservoir Performance and 2) Operational Drilling Performance. The results are displayed using traffic light coding, which at a glance shows the outcome of after-action reviews.

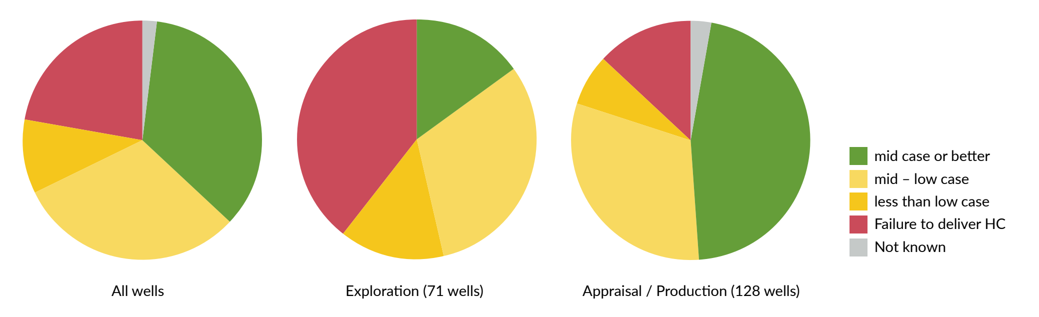
Reservoir performance

Reservoir Performance is a measure to classify outcomes of development wells as well as of exploration wells. The post-drilling Ultimate Recovery (UR) is estimated from logs and/or well tests and the results are compared against the pre-drill parameters as specified in the well proposal. Typically, low case (LC) and high case (HC) are also specified there, in addition to the base case (BC). Further breakdowns can be generated, e.g. per play or per operator. Poor performance might trigger portfolio reviews or lead to a more pro-active Non-Operating Venture (NOV) management from EBN's perspective.

Key facts

- Only 1/3 of drilled wells achieve the mid case or better
- 1/3 of drilled wells lie between the mid and low case
- 1/4 will not deliver any reserves
- There is an overall trend of overestimation of volumes.

Reservoir performance



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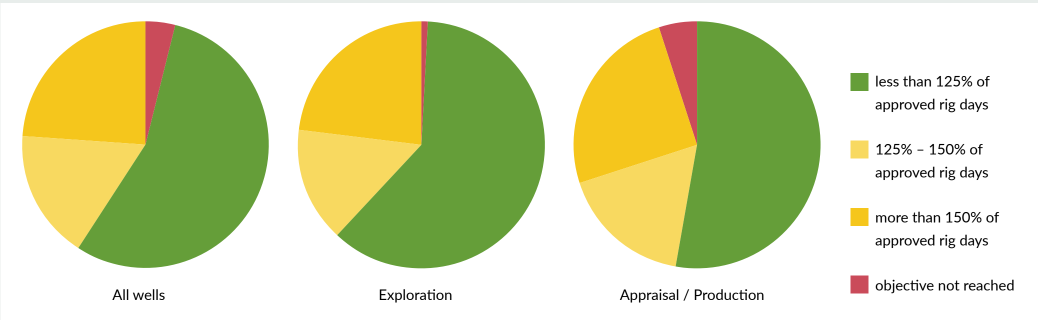
Operational drilling performance

The Operational Drilling Performance is assessed by comparing actual with planned drilling time. If the actual duration is within a certain tolerance (maximum time overrun of 25% compared to prognosis), the well classifies as operationally good (in green). Time overrun from 125%–150% classifies as medium (yellow). Time overrun in excess of 150% classifies as poor (orange). Failing to reach the objective classifies as failure (red). The pie chart (Fig.2) shows the proportion of these categories. Non Productive Time (NPT) is often the result of Geo Drilling Hazards. EBN has taken the initiative to collate information on Geo Drilling Events (see text box).

Key facts

- Main causes observed for deviation from planned day:
  - Geo Drilling Events
  - Equipment failure related
  - Waiting On Weather
- Most wells still show an overoptimistic budgeting

Operational drilling performance



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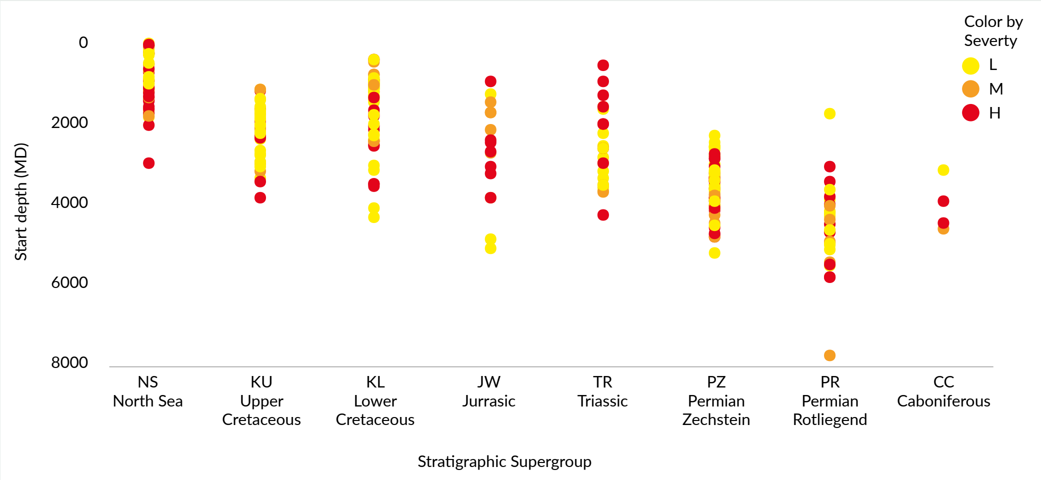
Drilling safer and cheaper wells by sharing information and setting up best practices

Post drilling reviews show that a significant amount of NPT is the result of drilling events in which unexpected geology plays a key role. EBN is developing a tool to help predict these drilling hazards. Access to information on geo drilling events from previous wells allows the risk profile of a planned well to be established. Proper risk profiles help to design wells that are safer and more cost-effective. For this purpose, hundreds of recent wells have been analysed for Geo Drilling Events (GDE). These are events that have often led to NPT and which have their root cause in (unexpected) geological complexities. Typical examples are stuck pipe caused by squeezing formation. Other events, such as a kick (sudden increase in mud returns), are related to overpressures and can lead to a well control event. More information is being gathered in collaboration with the operators.

De-risking future wells

Cross-plotting parameters from the database enables certain trends to be identified. In this example the GDE's are plotted as function of measured depth and stratigraphic supergroup. The colour coding shows the severity of the event: low in yellow, medium in orange, high in red. These types of analysis are based on hard observations in large numbers of wells and enable de-risking of future wells.

Geo Drilling Events per stratigraphic supergroup



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3

Production, reserves and resources

Lower production levels without cost reduction jeopardise the profitability of the small fields

The PRMS classification of reserves and resources

				Resource cat.
Discovered	Commercial	Production		
		Reserves	On production	1
			Approved for development	2
			Justified for development	3
	Sub-commercial	Contingent Resources	Development pending	4
			Development unclarified or on hold	5
			Development not viable	6
		Unrecoverable		
Undiscovered		Prospective Resources	Prospect	8
			Lead	9
			Play	10
		Unrecoverable		

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Both the production and the reserves position of small fields showed a declining trend in previous years even though the reserves replacement ratio was about 70%. Profit margins remained positive. However, after the collapse of the gas price in 2015, the profitability of the small fields rapidly comes under pressure. The following reviews the current production level, the reserves position, the remaining potential, and the impact of a low price scenario.

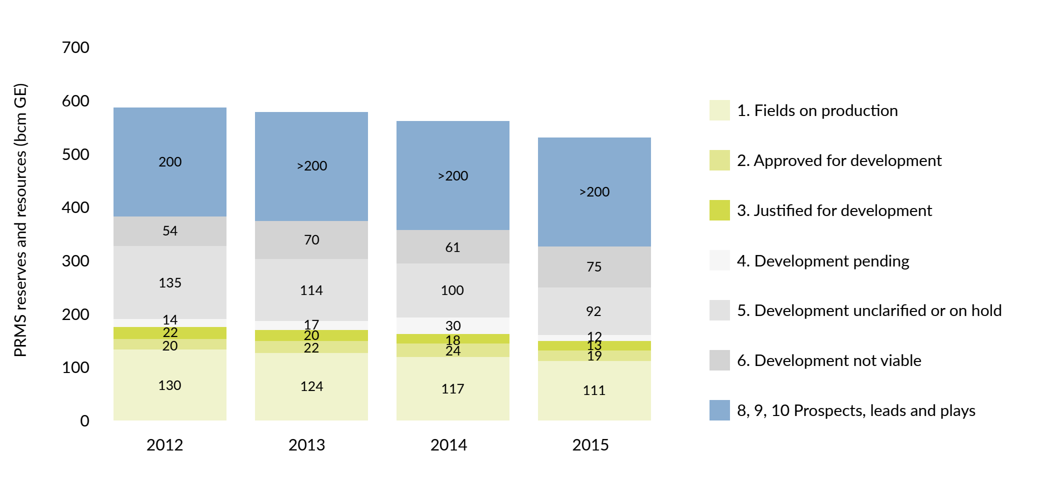
Reserves and resources

Since 2009 EBN has been using the SPE Petroleum Resource Management System (PRMS) for reporting its reserves and resources. Implementation of the PRMS has made monitoring and forecasting of hydrocarbon maturation and resource replacement more transparent, has standardised the reporting of reserves and resources and has made it easier to benchmark the operators' portfolios and performance (SPE 170885, 2014).

In 2015, the total gas production from all fields in which EBN participates was 52.7 bcm GE (Groningen Equivalent), of which 22.4 bcm GE was produced from small fields. The latter are all the existing oil and gas fields except for the Groningen field and the Underground Gas Storages. EBN's participation in the small fields is typically 40%.

The 2015 small field production declined approximately 7% compared to 2014 (22.4 bcm GE) and showed a decline of 5% compared to the average annual production for the preceding 5-year period. By the end of 2015, the small fields' reserves totalled 143 bcm GE, whereas in 2012 these were 172 bcm GE; this corresponds to a decline of about 7% per year.

Remaining reserves and resources from small fields



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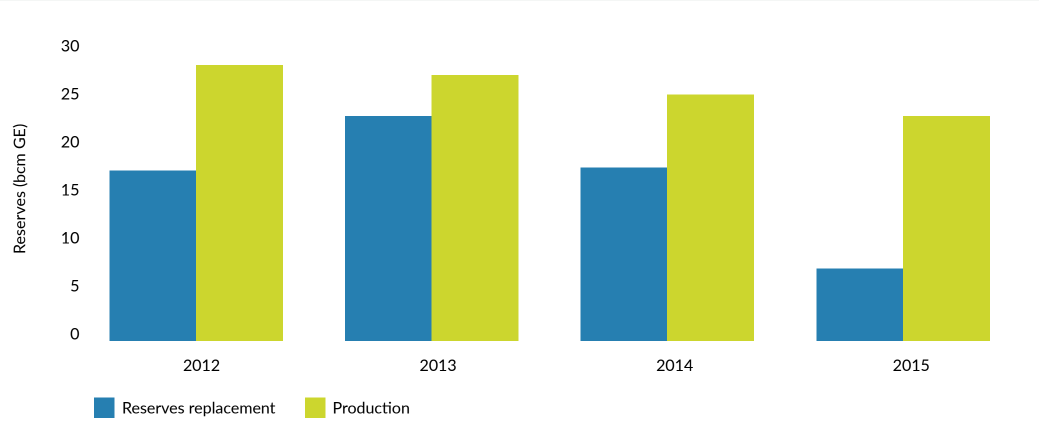
Impact of investment level on production and reserves replacement

The historical development of PRMS volumes shows that the small fields portfolio is in decline. This decline can be attributed mainly to annual production which is only partly compensated by adding reserves. The figure illustrates the annual reserves replacement of the preceding years compared to annual production volumes. In 2015 the replacement ratio was about 30% in contrast with an average of about 70% in the years 2012-2014.

Reserves replacement in preceeding years



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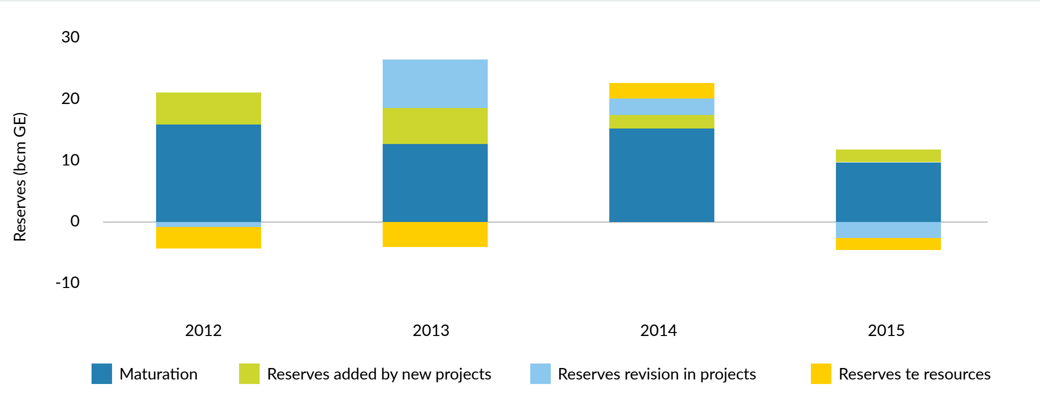
A closer look at the collapse of reserves replacement shows that maturation, i.e. from the contingent and prospective category to the reserves category, and the approval of new projects have been essential factors contributing to reserves replacement. Another factor is the reserves revisions of existing projects which for a mature portfolio are mainly influenced by gas prices, i.e. higher gas prices add reserves by making more volumes economically viable. This was particularly true in 2013 when prices peaked to 25 €ct/Nm^3. Conversely, lower gas prices can lead to a downward revision of project reserves as it was the case in 2015. The last factor is the movement of reserves to the resources category which is typically the result of projects being put on-hold or deemed not economically viable.

As shown, maturation and approval of new projects are essential to maintain the small field's portfolio on an adequate level. This in turn requires an appropriate investment level. When plotted together, we can see the negative correlation to production levels. In contrast, even when investment levels remained rather stable the added reserves still showed a downward trend. This is an indication that reserve replacement has become more capital intensive.

Factors affecting reserves replacement



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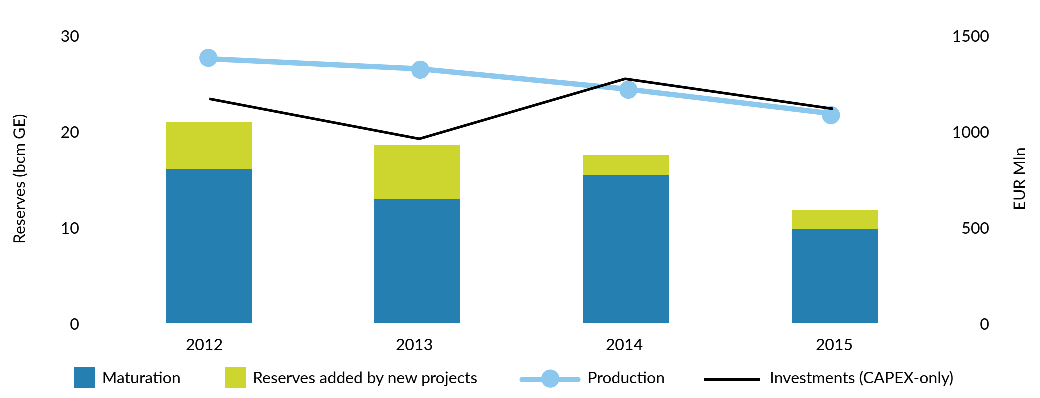
Impact of investment levels on reserves replacement



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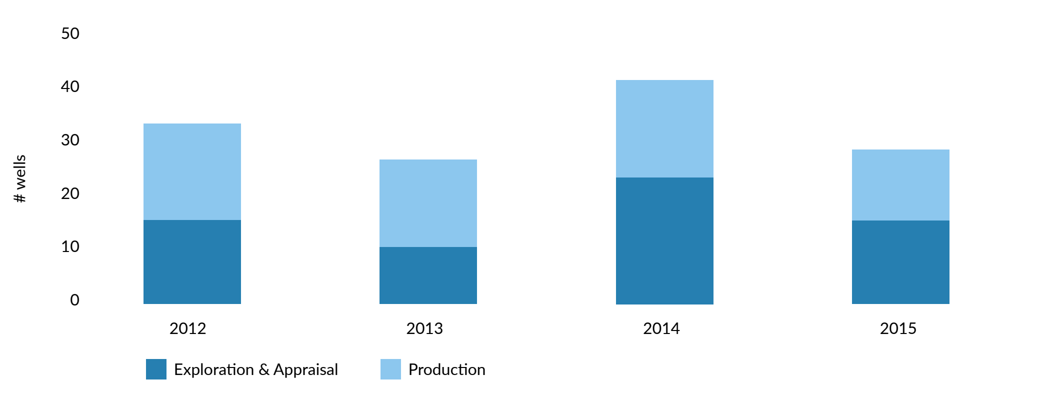
It is shown the newly drilled wells - exploration and appraisal, and production (with EBN participation) in small fields in the period 2011 to 2015. Although the numbers of E&A and production wells vary from year to year, during this period the average well count remained about 30.

As a consequence of the current low price environment, an all-time low investment level and amount of drilled wells is anticipated for 2016.

Exploration & Appraisal and Production wells



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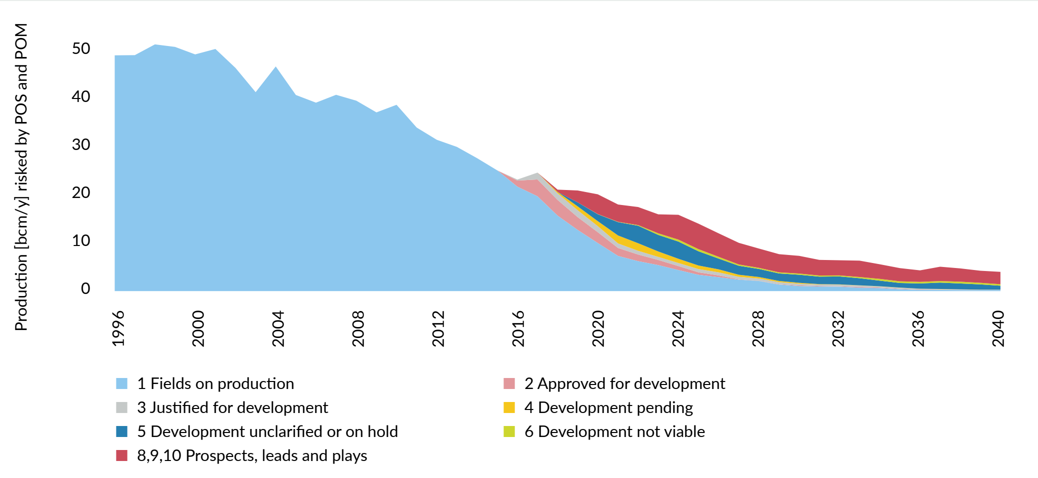
Historical and forecasted production



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Production forecast for the small fields

The remaining reserves and resources potential is still quite significant as illustrated previously. If the currently known portfolio would be developed based on current drilling and development rates and taking into account a gas price of 17.5 €ct/Nm^{3}the annual production level by 2030 could still be about 7 bcm (GE). This production scenario is labelled 'business as usual' (BAU) and is shown in graph.

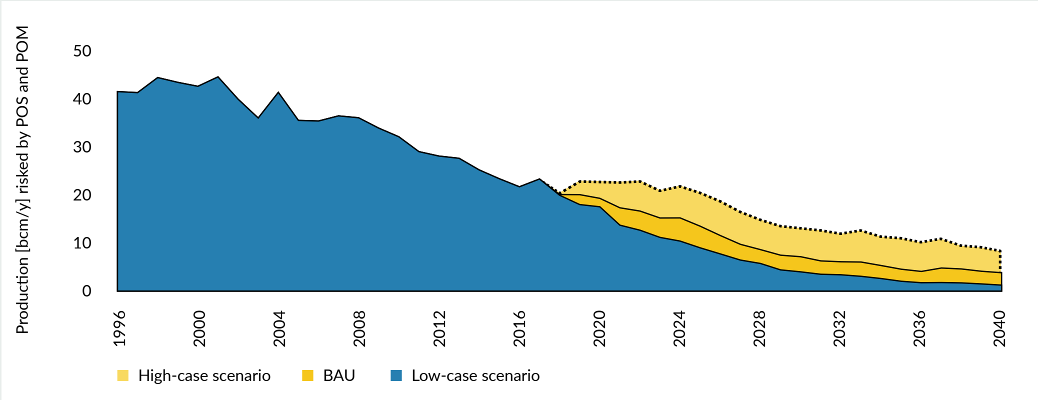
In addition, if all potential contributions from increased exploration activities, tight gas development, maximising recovery from mature fields and infrastructure optimisation would be realised, the annual small-fields gas production could still be about 12.5 bcm (GE) by 2030. EBN has labelled this scenario as 'upside potential' or 'high-case'.

However, the strong impact of the gas price on the BAU scenario becomes clear when considering a gas price of 12 €ct/Nm^3. EBN has labelled this scenario as 'low-case' which would result in a limited annual production of about 4 bcm (GE) by 2030.

Profitability of the small fields

Past revenues, costs and profits associated with exploration and production from small fields are now plotted. In 2015, the realised average gas price level has dropped to just below 20 €ct/Nm^3, in combination with an increase in the cost levels. The cost levels have mainly increased because of accelerated depreciation which is the result of the low price environment. The profitability margins come rapidly under pressure.

The BAU scenario: low- and high-case scenario



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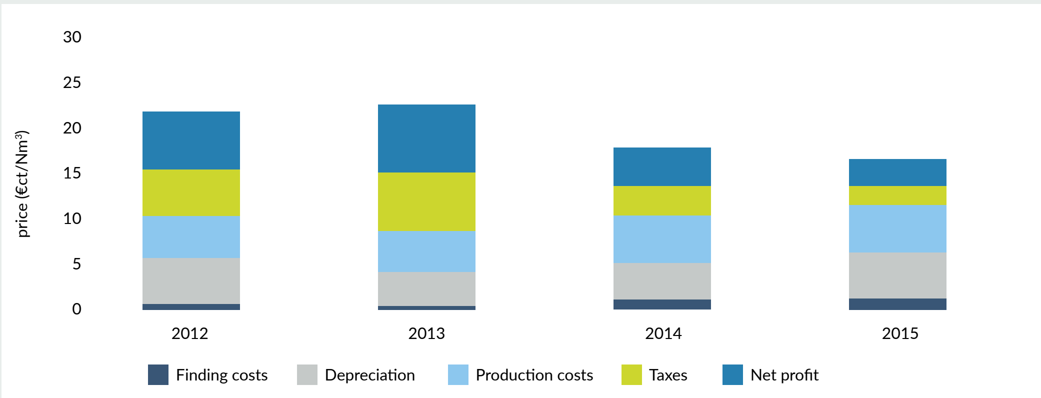
Notes:

- Finding costs: mainly geology and geophysics (G&G) costs (including seismic surveys and dry exploration wells);
- Depreciation: on a unit-of-production (UOP) basis (this category includes depreciation over successful exploration wells that are activated);
- Production costs: including transport, treatment, current and non-current costs;

The estimated gas price for 2016 is dramatically lower and could decrease to an average level below 15 €ct/Nm³. In the next chapter, the impact of the low price environment on the marginal operating profits is analysed, including its potential impact on the infrastructure lifetime and the loss of resources.

Profit margins of small field production



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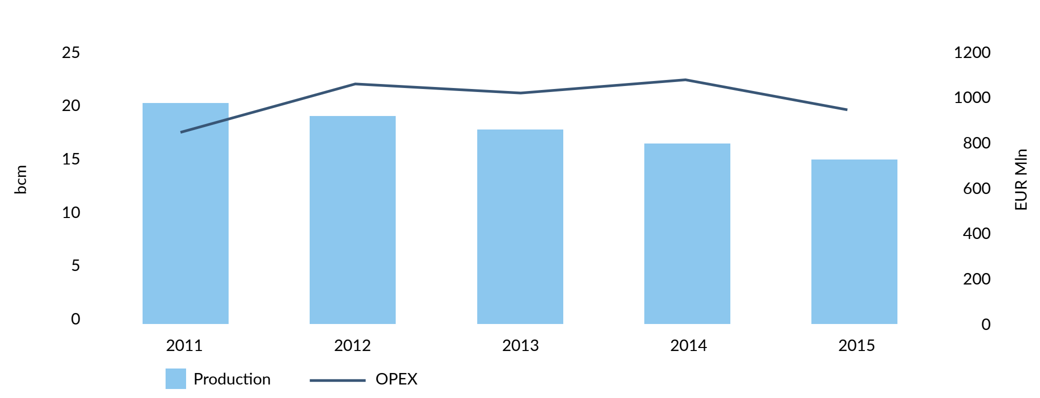
4

4. Infrastructure

Operating in survival-mode

Opex vs production of the offshore gas portfolio



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As of today, only a few platforms have been decommissioned. However, current estimates show that the vast majority of the platforms are at risk in the coming years. Decommissioning will become a reality for a number of these platforms. EBN and partners are working together to ensure that the installations are not prematurely removed and that valuable resources, for both the E&P sector and the Dutch State, are not definitively lost. Lower operational costs are crucial to mitigate such premature removal. In the following, key areas are highlighted for costs savings and an example is showcased of how efficiency in offshore operations can lead to important reduction in operational costs. These and other activities are carried out under the umbrella of EBN's Infrastructure Roadmap.

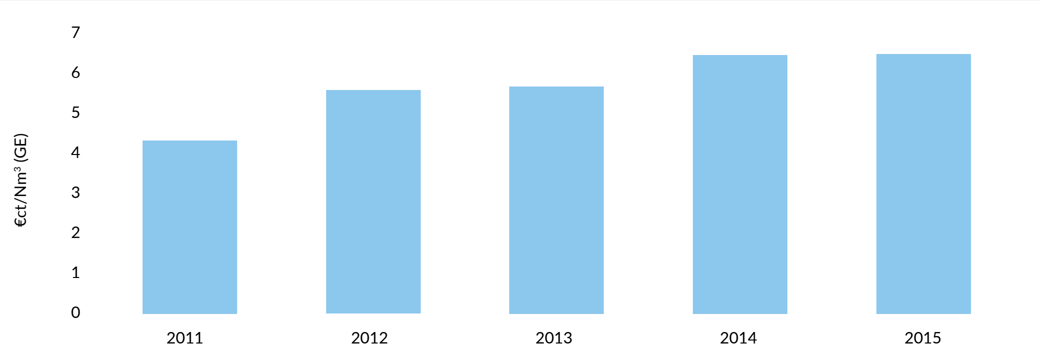
Impact of the low price environment on the marginal profit

The historical trend of marginal profits of offshore production is analysed. This is defined as revenues minus operational costs (OPEX). While the production in the years 2011-2015 showed a steady decline, the opex levels have remained rather stable.

Dividing OPEX by the production results in the Unit Operating Costs (UOC). The UOC of offshore gas showed a steady increase in recent years, but has stabilised in 2015.

Not surprisingly, the gas price is a main driver for the marginal profit as illustrated in graph. The marginal profits are compared for two gas price scenarios:

UOC of offshore gas in the Netherlands



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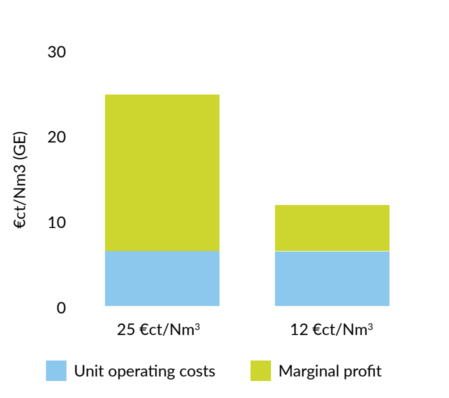
Impact of price level on the marginal profits



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25 €ct/Nm³ (high case and based on prices reached in 2013) and 12 €ct/Nm³ (low case and based on prices early 2016). For this comparison we have applied the actual average UOC in 2015. We observe that the marginal profit drops over 70%, if the gas price declines by some 50%.

The 'Cessation of Production' of offshore infrastructure

As of today, only a few platforms have actually been decommissioned (see Focus on Dutch Oil and Gas report 2015 p39). The economic lifetime of most of the platforms has been successfully extended. EBN's simulation and signalling tool Infrasim was employed to analyse the dynamics of the offshore portfolio. Infrasim incorporates the future production flows through the offshore gas installations and compares the operational costs per platform with the revenues generated. The operational costs per platform per year are built up from tariff expenses, direct opex and 'opex sharing'. The revenues are built up from the value of the gas produced and any tariff income.

In the year in which the operational costs of a platform are higher than the revenues, i.e. cash flow becomes negative, a COP of the platform is assumed. In reality, platforms are not immediately decommissioned once they reach the assumed COP date. However, the COP year is an important indicator for the remaining lifetime of the installations and helps identifying the critical infrastructure. In order to illustrate the dynamics of the offshore infrastructure we have simulated the COP date (year) for the following volume and price scenario's:

Volume scenarios:

- reserves
- reserves + risked contingent
- reserves + risked contingent + risked prospective

It should be noted that the volume scenarios exclude the upside potential as described in chapter 3.

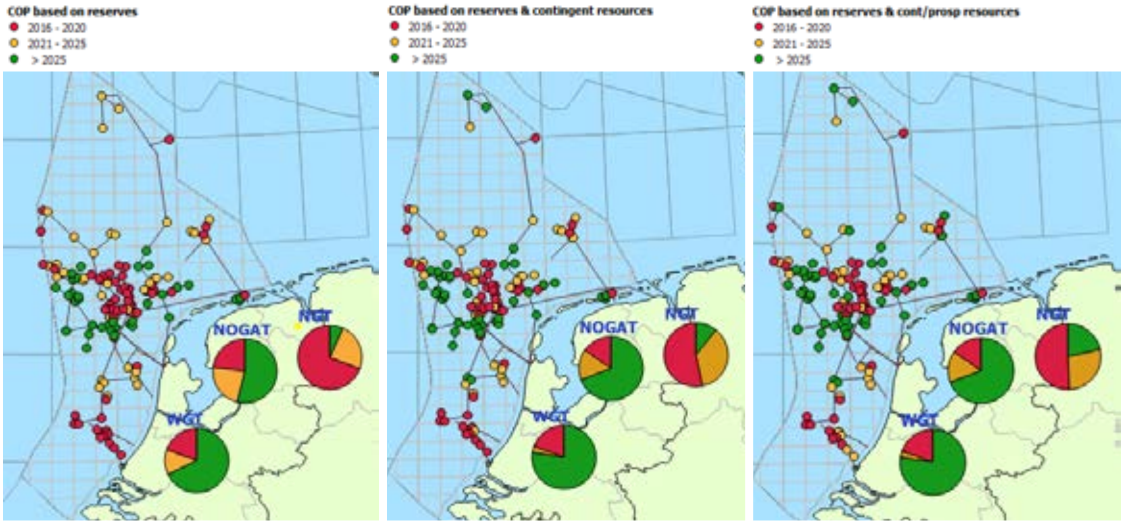
Gas price scenario's:

- 25 €ct/Nm³,
- 17.5 €ct/Nm³
- 12 €ct/Nm³

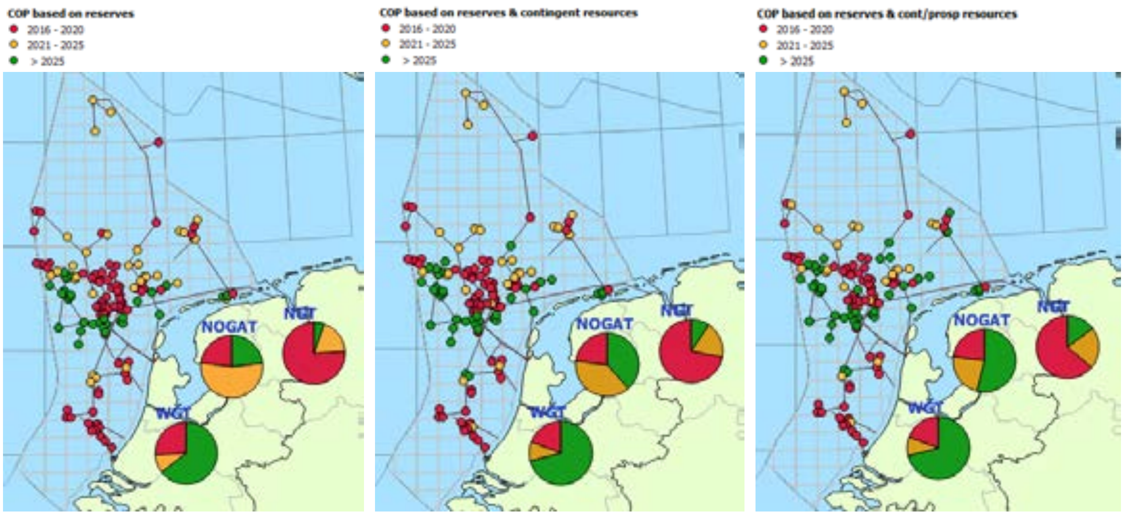
The operational costs, OPEX-sharing and tariffs are based on the 2015 costs levels. For new installations we also have assumed this level of operational costs, opex sharing and tariffs.

A series of maps showing the currently existing offshore platforms and resulting COP's were produced. Potential new platforms, although included in the runs, are not plotted in the pictures. The colour of the bubble indicates the 5-year time period in which the COP of the platform would be reached for the specific scenario. This is also illustrated in pie charts for the three main trunk lines: the NGT, WGT and the NOGAT. Together, these three main trunk lines are connecting 119 (75, 31 and 13 respectively) of the total of 133 offshore gas platforms.

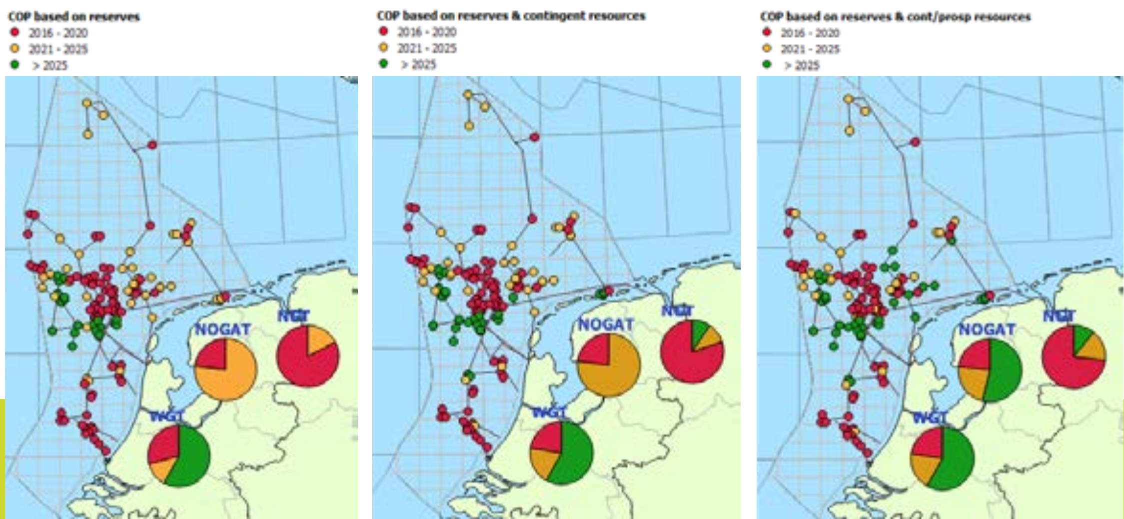
COP of infrastructure assuming a gas price of 25 €ct/Nm³



COP of infrastructure assuming a gas price of 17.5 €ct/Nm³



COP of infrastructure assuming a gas price of 12 €ct/Nm³



Remarkably, the time period in which platforms cease production doesn't change substantially in most scenarios. The NGT is the oldest and largest gathering pipeline system in terms of connected facilities. A large part of the platforms connected to the NGT show a COP already before 2020 for all price scenarios. The largest system in terms of connected reserves is the WGT and this trunk line seems less vulnerable in the near future. The NOGAT seems the most sensitive to price variations and to the impact of the maturation level on the remaining contingent and prospective resources.

As previously described, these COP scenarios have been based on gas prices 25 €ct/Nm^3, 17.5 €ct/Nm^3 and 12 €ct/Nm^3 and current opex levels. The impact of gas price changes and the potential loss and/or gain of reserves are further depicted. It shows that for gas prices lower than 15 €ct/Nm^3 the loss of reserves accelerates creating a 'domino effect'.

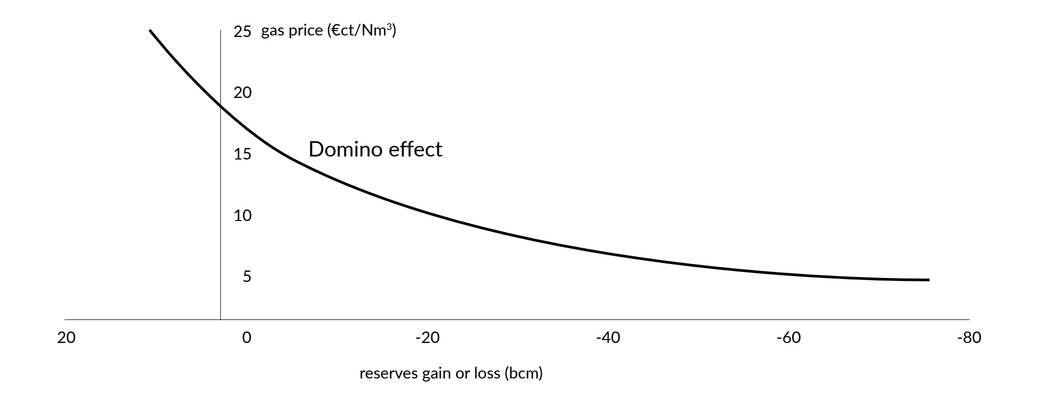
Sensitivity analysis for the offshore infrastructure

The reserves and net profits from all offshore installations depend on more economic parameters than the gas price alone. Factors contributing to the platform performance for a greater or lesser extent, are:

- operational platform expenditures (whether or not shared with client platforms),
- gas processing tariffs and opex to be paid to host platforms, and
- the transport tariffs to be paid for usage of the main trunk lines for evacuating the gas to shore.

The sensitivity of reserves changes to fluctuations (±20%) on these aspects has been analysed using a base gas price of 17.5 €ct/Nm^3.

Impact of gas price on reserves gain/loss



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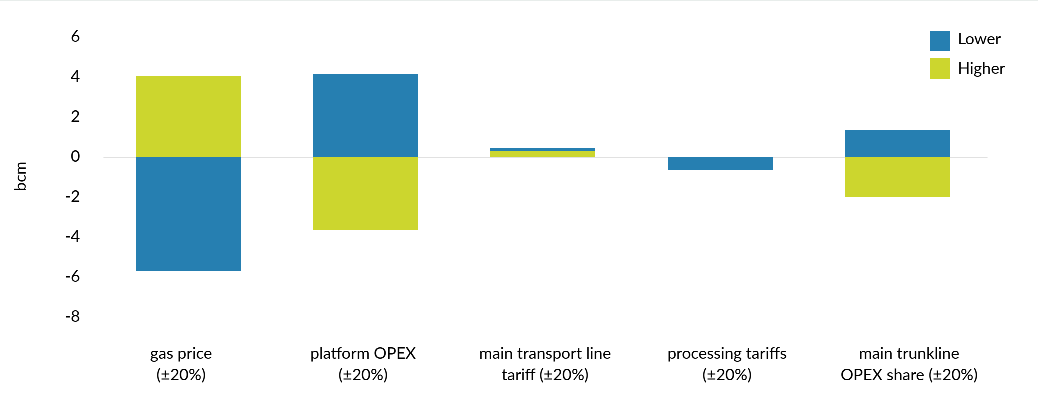
Reserves added or lost



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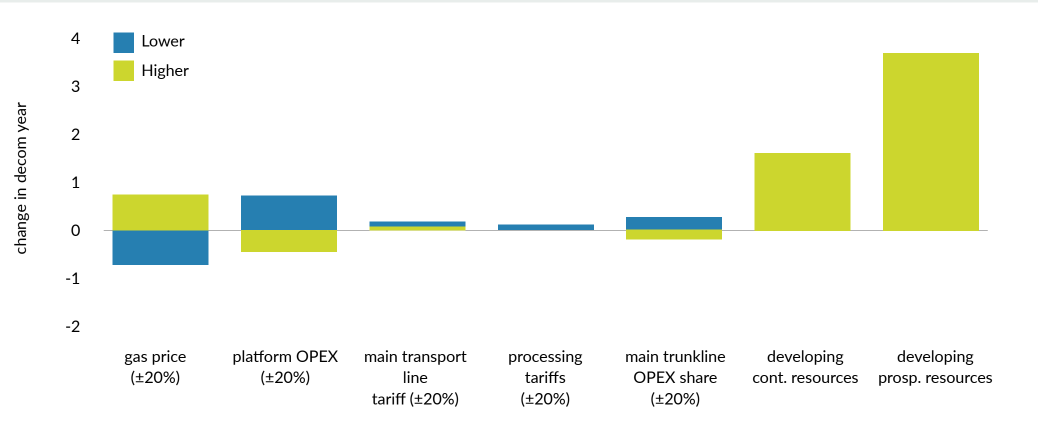
Developing all contingent and prospective resources would add 31 bcm and 42 bcm respectively to the reserves. It shows that relative changes in gas prices have more or less the same (but reverse) impact as the same relative change in the platform opex. A 20% higher gas price has the same effect in terms of reserves as a 20% decline in platform opex. Thus, to counteract any loss of reserves, the platform's opex has to be lowered by about the same order of magnitude as the relative change in gas price.

Relative changes in the gas prices and platform opex have also the same (reverse) effect on the infrastructure life-time. The largest positive impact on the economic lifetime of the assets is the development of resources into reserves. The transport tariffs for evacuating the gas to shore and the processing tariffs to be paid to the service platforms seem to have a minor effect on additional reserves and the average decom year.

Change in average decom year



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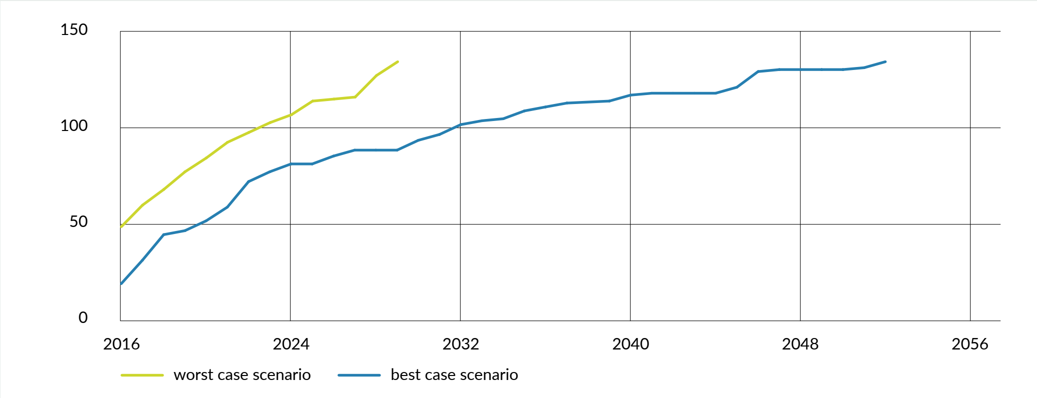
Number of installations that reach COP in upcoming years: best and worst case scenario



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The resources at stake: a best and a worst case scenario

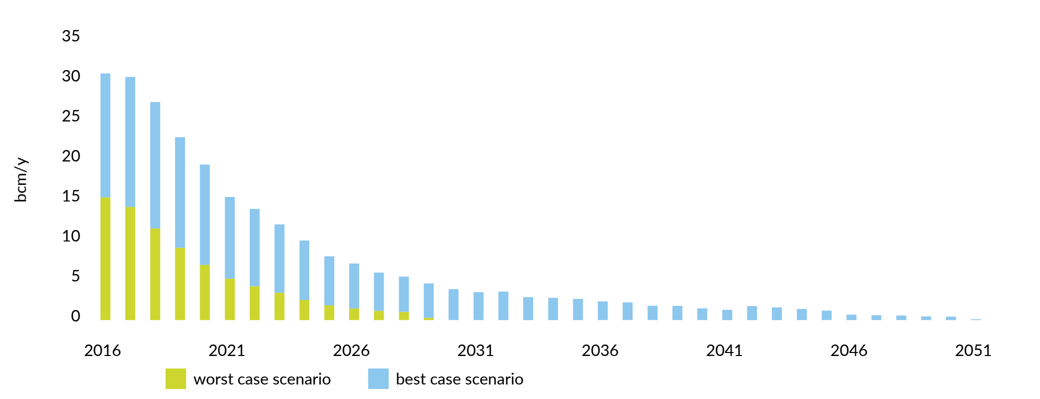
We now illustrate the resources, volumes and installations, that are at risk assuming a best-case and a worst-case scenario.

- The best case scenario is based on gas prices at 25 €ct/Nm^3, the current cost levels, and all resources are maturated (i.e. reserves + risked contingent & prospective)
- The worst-case scenario is based on prolonged low gas prices (at 12 €ct/Nm^3), the current cost levels and reserves-only are developed (maturation has stopped)

In the worst-case scenario, all installations will reach a COP date before 2030. However, in the best-case scenario, it will take 25 more years for the last platform to reach the COP date.

The corresponding production profiles for these scenarios are shown in following graph. The worst case scenario, where no more investments are made to maturate resources, predicts average decline rates of 20% per annum. Compared to the best-case scenario with an average decline rate of 9% per annum.

Production of offshore gas – best and worst case scenario



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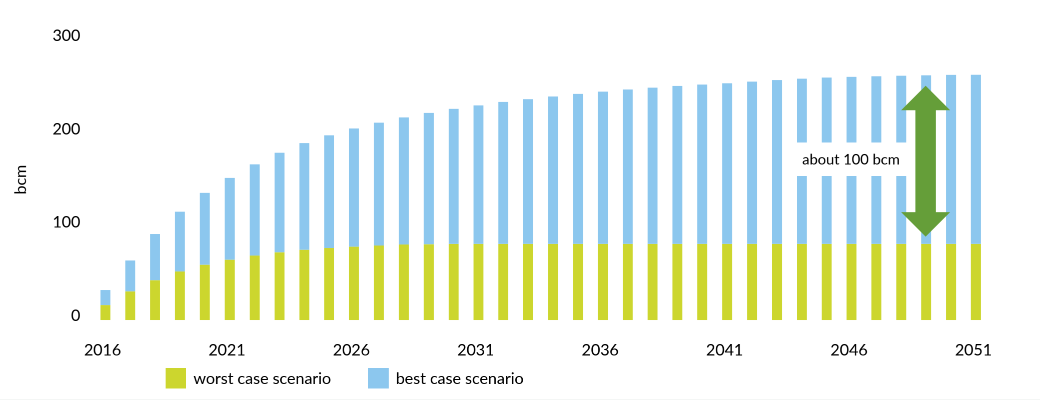
The cumulative volumes show a difference of about 100 bcm between the two scenarios. In other words, these are not only the resources at risk, but also the opportunities to work on.

Benchmarking offshore operating costs

EBN has collaborated with NOGEPA since 1995 to facilitate the offshore operating costs benchmark (BOON) for the gas-producing operators. This benchmark, which is completed every two years, gives the industry an overview of its performance in relation to the operating costs. The pie chart shows the main cost items .

Cumulative production – best and worst case scenario



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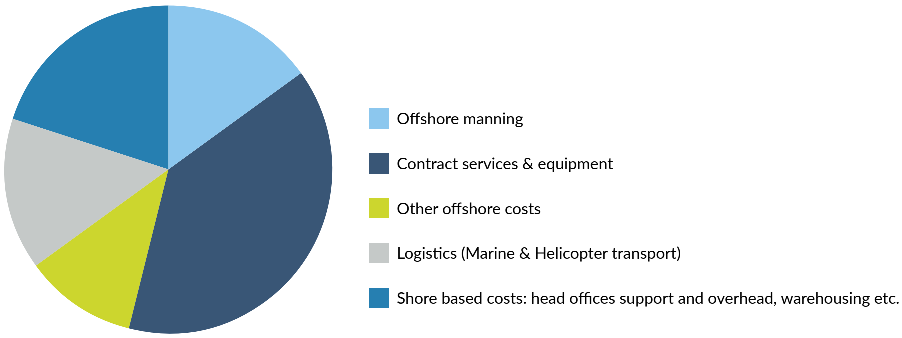
Offshore operating costs distribution of 2014



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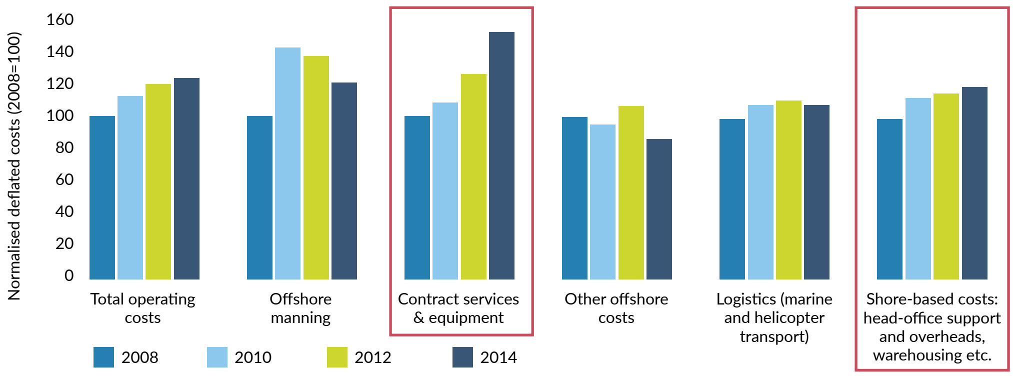
The detailed insights revealed by the benchmark help operators to analyse what action to take to cut operating costs. However, more needs to be done, especially given the upward trend in UOC.

Using the results of the BOON study one can break down the operational costs into various categories. It should be noted that all offshore operating costs have been deflated on the basis of the IHS Upstream Operating Costs Index and the shore-based costs have been deflated on the basis of the Dutch inflation index.

The graph shows that deflated costs have risen consistently for two categories: 'contract services & equipment' and 'shore-based costs'. On some categories, such as offshore manning and logistics, trends suggest that the cost profile will become more stable.

EBN believes that strengthening the contacts with new offshore industries may facilitate optimisation, especially in the category 'contract services & equipment costs'. The offshore wind industry has demonstrated great inventiveness because investments in this industry are only possible at very low operating costs. On the other hand, this new industry can learn from the experiences of the offshore oil and gas industry. EBN has encouraged this by making it possible to exchange knowledge and experiences at the two-day workshop it organised on offshore low cost developments (see text box).

Offshore operating costs: distribution over time



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Previous attempts by the offshore oil and gas industry to optimise logistics, for example in the Southern North Sea pool, have affected the logistics costs, and has resulted in the increased use of walk-to-work vessels rather than helicopters to transport workers (more on this on the 'Kroonborg story'). EBN is of the opinion that sharing best practices would make more improvements like this possible. For the longer term, more detailed insights will be necessary in order to define the areas where improvements could be made. EBN will continue to collaborate closely with the industry to improve this benchmark exercise.

Efficiency in offshore operations reduces opex: the Kroonborg story (courtesy of NAM)

One year ago the award-winning 'Walk to Work' vessel Kroonborg began operations for the unmanned platforms in the southern North Sea. The vessel supports the Nederlandse Aardolie Maatschappij (NAM) and Shell UK in their offshore operations in an efficient, safe and comfortable way. A look back at the first year of working with the Kroonborg follows.

Efficient deployment of personnel

With a length of almost 80 metres, the Kroonborg is not only a workshop and warehouse but also a hotel and a means of transport. It provides accommodation for 60 people, including 40 technicians that can 'walk to work' via a stable gangway connected to an advanced system able to compensate for the motion of waves of up to 3.5 metres high. Before the Kroonborg was brought into service, employees were transported by helicopter daily to work on the platforms, with the result that the average travel time per person per day was about 4 hours. And with adverse weather conditions like fog, high winds or frost, delays were commonplace. In the past year some 12,500 transfers of an employee offshore have been carried out using the Kroonborg. Working with the Kroonborg has thus increased the number of effective worked hours by approximately 30%.

Safe lifting of equipment

The motion-compensated crane on the Kroonborg has proved that equipment can be lifted safely when waves are up to 3 metres high. With its lifting capacity of 5 tonnes and reach of 32 metres, the replacement of wind turbines and solar panels on 6 platforms has been possible, making it unnecessary to use the much more expensive jack-up vessels for these operations. In the past year nearly 1,000 lifting operations were performed safely.

A wide range of operations

Besides standard maintenance work, the Kroonborg is also being used for other operations. For a period of two weeks per year the vessel visits some 10 platforms for highly specialised maintenance, for example of radio equipment and weather stations. And last year, 7 wells were successfully started up by injecting chemicals at high pressure. Using the mobile cold start-up equipment, the Kroonborg can now safely start up a well in a matter of hours, dispensing with the need to rig up a large unit on the platform. The high costs of the latter would make such operations uneconomic in some cases.

Haije Stigter, the "godfather" of Kroonborg

No incidents and few cases of seasickness

The unique design of Kroonborg's thrusters, which compensate for the ship's roll, results in very smooth sailing at sea and means that after their working day the 60 people on board can enjoy relaxing time off, which contributes to working safely at sea. The first year of operation has been incident-free on the Kroonborg itself and the platforms maintained by the vessel. And only one case of seasickness was registered.

More gas produced at reduced opex

Thanks to the effective maintenance that has been possible by deploying the Kroonborg, production from wells has increased and the availability of the installations has been safeguarded and in some cases improved. The deployment of the Kroonborg has led to considerable opex savings, including a reduction in personnel costs of some 40%.

Low-cost development workshop organised by EBN

An increasing number of field developments have become marginal or even sub-economic. Although the operational expenses for existing infrastructure remain relatively stable in absolute terms, because of declining production volumes the operating costs per unit of volume are rising. In addition, the maintenance of existing facilities is often hampered by limited platform accommodation space and / or crane capacity, yet a possible solution, the heave compensation technology developed especially by the offshore wind sector, is still not yet widely used in E&P sector. From its close involvement throughout the industry, EBN is aware of the added value of bringing together the operators and service industry to share knowledge and experience in order to identify opportunities to remedy this situation. To facilitate this, EBN organised a two-day workshop with presentations by operators and service industries, and breakout sessions on various topics intended to encourage innovation. The workshop was attended by a total of 140 people from 10 operators and about 30 companies from the service industry.

5

Decommissioning

Calls for industry-wide cooperation and knowledge sharing

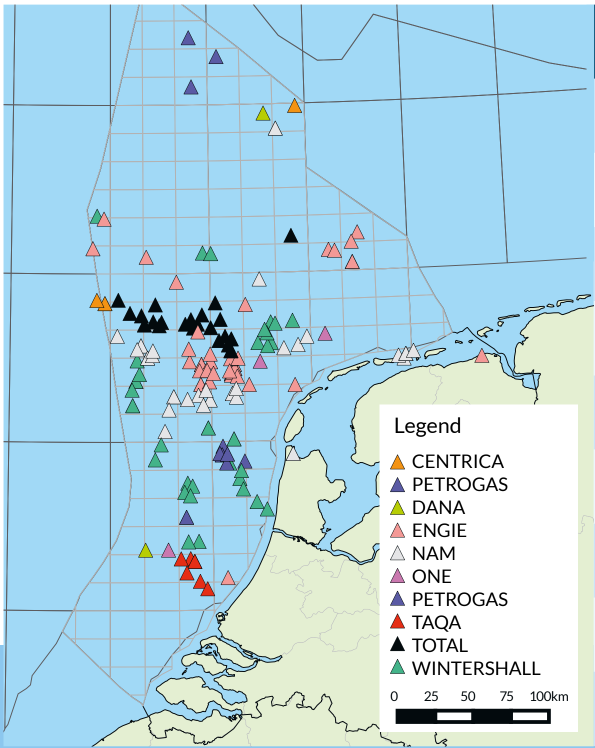
Decommissioning landscape of the Netherlands

For the first E&P drilling activities in the Netherlands we have to go back in time to the early 1940s for land-based operations and the late 1960s for the Dutch Continental Shelf. Since then some 2,400 wells have been drilled onshore and some 1,400 wells offshore (all hydrocarbon-related).

Some 2,000 wells have been permanently abandoned to date, leaving some 1,800 wells more to be permanently abandoned. As most wells were drilled in the 1980s, the average age of the remaining wells is about 30 years which poses a higher uncertainty on the integrity of the wells. EBN is calling for special attention to be paid to the suspended exploration wells which still have to be permanently abandoned.

The regulations for permanent abandonment of wells are laid down in the Mining Regulations; they are prescriptive rather than goal setting and do not cover certain procedures common in today's well abandonment practices, such as casing milling. State Supervision of Mines (SSM) has been closely involved with NOGEPA in developing new guidelines for well abandonment, which are expected to be published shortly. At present, the various North Sea countries still differ in their approaches to permanent well abandonment.

The first offshore platforms in the Dutch sector of the North Sea were installed in 1974 by Placid Oil (now ENGIE) and Pennzoil (now Wintershall) and are still in operation after more than 40 years of service. The present number of platform installations has grown to over 150; 23 platforms have already been decommissioned. The Dutch offshore platform portfolio is held by a total of nine operators but is dominated in numbers by ENGIE, NAM, Total and Wintershall.



Operator	Integrated	Satellites
Centrica	2	1
Dana	2	0
ENGIE	12	24
NAM	12	17
ONE	1	1
Petrogas	5	7
TAQA	2	5
Total	9	20
Wintershall	9	17

The ratified OSPAR Decision 98/3 states that all mining installations are to be removed after service. The Minister of Economic Affairs can impose a deadline on the removal date, but so far has not done so. The interval between cessation of production and actual satellite removal has been four years on average, with a maximum of 12 years.

Drilling of the offshore wells in the southern North Sea was carried out primarily with water-based drilling muds and cuttings were dumped on the seabed. Oil-based drilling fluids were introduced in the 1960s; disposal of contaminated cuttings was phased out, and stopped in 1994. The OSPAR Decision 2000/3 describes the use of Organic-Phase Drilling Fluid (OPF) and disposal of OPF cuttings. Further, OSPAR Recommendation 2006/5 describes a management regime for offshore cuttings piles and OSPAR 2002/8 Guidelines provide options for the management of OPF-contaminated cuttings residue.

In total, over 3,500 km of pipelines have been installed on the Dutch Continental Shelf, some 200 km of which have been decommissioned to date, meaning they have been flushed, cleaned and secured to not pose any danger to other users. Decommissioned pipelines are currently still required to be surveyed annually by the operator, even though the joint venture for the licence has often been disbanded. In the UK, a risk-based approach is being applied to extend the intervals between surveys on the basis of the results of consecutive surveys. At some point a termination of the aftercare liability may be expected.

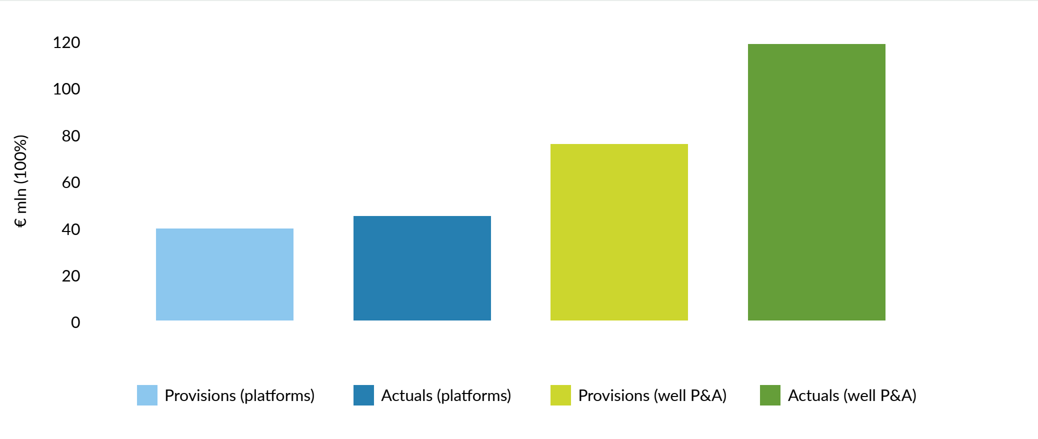
Financial position

The current sum earmarked as a provision for the decommissioning of all Dutch wells and infrastructure is some €7 billion, most (55%) of which is for the offshore sector. Over time the provisional estimates of decommissioning costs have risen steadily (see Focus on Dutch Oil and Gas report 2015). Given the current late-life production phase and low prices this poses a risk, initially for the financial security between co-licensees and ultimately for the Dutch State as well.

Surrounding countries have procedures in place empowering the authorities to guarantee that the decommissioning liabilities can be met. A typical approach is that such security is called on when the expected future revenues equal the estimated decommissioning cost. The Dutch Government is working towards a system for the stricter application of powers to request financial security which are provided by Dutch law.

One of the challenges that EBN envisages is that the provision made for decommissioning of infrastructure may not be sufficient to cover the actual costs. To illustrate this, the actual decommissioning costs for platforms and for wells have been compared with the provisions.

Decommissioning cost: actuals vs provisions (2011-2015)



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In the period between 2011 and 2015 a total of 5 platforms have been decommissioned and 27 offshore wells have been plugged and abandoned (P&A). The graph shows the aggregated provisions and actuals costs for this period.

The provisions made for platform decommissioning agrees relatively well with the actuals and within a relative constant margin of +10%. It seems that decommissioning of topsides and jackets carries less uncertainty, based on limited experience so far.

However, estimation of the actual well P&A costs have proven to be more challenging and can be out with a margin of up to +50%. The variations in actuals vs provisions show no clear trend throughout the years (not shown here). However this may point to an underlying uncertainty with P&A of wells: the behavior of the subsurface and incompleteness or inaccuracy of records and as-built drawings.

EBN acknowledges the complexity of well P&A operations. Therefore EBN will be pushing actively to set up a National Decommissioning Platform where amongst others emphasis will be put on building an extensive database of the subsurface construction data of the wells and infrastructure. It is expected to be complemented with lessons learned and best practices from the operators and service industry across the sector.

Reuse and re-purposing of infrastructure

Historical reuse

In total, 3 processing platforms and 21 satellite platforms on the Dutch continental shelf have been decommissioned to date, the latter after an average service of 15 years. From the satellites removed, a total of 11 topsides (73%) have been reused for other field developments, all within the same affiliates (by Wintershall & ENGIE). The topsides were mostly completely stripped from all processing equipment and only the steel structural was saved, with the result that the financial benefit was relatively small but, more importantly, field development could be accelerated considerably.

The installations were reused solely for the purpose they were originally designed for. So far, installations have not been reused for other purposes.

Future re-purposing: rigs-to-reef pilot, power-to-gas, reuse

The standard practice in the Gulf of Mexico (since 1984 in Louisiana, 1990 in Texas, 1999 in Mississippi) is to donate the steel jackets to the Artificial Reefing Programmes in dedicated deep water locations. Over 450 jackets, amounting to some 10% of the total number of installations, have been reused for artificial reefs in the Gulf of Mexico. Following reefing, the liability for the installation is transferred from the oil company to the authorities. The impact on the marine ecosystem has been very positive. The cost savings are generally equally shared between the industry and the authorities.

Platforms naturally. Focus on new nature (courtesy of George Wurpel, MSG Sustainable Strategies)

Being "less bad" is no good. This slogan from Cradle-to-Cradle design is certainly appropriate for the way we deal with offshore platforms that have reached the end of their economic life. For sure, these structures were never designed for a positive impact on their environment. Nevertheless, in contrast to the often negative public image, the platform jackets support a micro-ecosystem under water. It is the rich and biodiverse habitat that can be found on hard structures and which used to be part of the natural ecosystem of the North Sea.

When it comes to removing these structures, however, the mind-set is on minimizing negative impacts, being "less bad". Rightly so, international legislation prevents dumping and leaving behind harmful substances and materials in the sea. But what about repurposing the structures that might do good? Redesigning old jackets for new nature could be an option for a limited number of the North Sea platforms. Something that might be relevant not only for mature oil and gas assets, but also for future structures in the North Sea.

Together with operators, EBN has theoretically explored this topic for a number of years. Comparison with international rigs-to-reef programs showed that there is potential for similar initiatives in the North Sea. Last year, ENGIE E&P Nederland B.V. took the initiative to test these ideas in practice. ENGIE, EBN and MSG started a project to develop an alternative for the decommissioning of three ENGIE platforms. Together with a team of experts and taking care to involve scientists, green NGO's, governments and fisheries, we are developing a plan for a temporary pilot to transform a mining installation into a structure aimed at nature conservation and restoration. A redesign that will be monitored and allows us to learn by doing. In this way, the pilot could become a stepping stone for a more resilient North Sea as well as a platform for sustainable innovation.

The financial benefits of leaving jackets in place or at a dedicated reefing location are expected to be marginal at best, but the benefits to marine biodiversity are believed to be substantial, as e.g. studied and documented by Joop Coolen from the Wageningen University & Research centre IMARES.

Another re-purposing opportunity identified entails integrating offshore wind parks with the gas infrastructure, thereby allowing any surplus electricity generated to be converted through electrolysis into hydrogen, or alternatively into methane. The hydrogen stream can then be fed into the gas infrastructure or could be temporarily stored in depleted gas reservoirs. Such integration would also enable the offshore installations to be powered by wind energy directly from the wind park or alternatively from shore, which would improve the reliability of the installation as well as reduce the emissions offshore.

RWE has installed a hydrogen generator that feeds into the gas grid at Ibbenbüren (Germany); this had already been tested on a small scale from 2007 to 2012 on Ameland by Eneco, GasTerra and Stedin". The conclusion so far is that the existing natural gas utilities can easily cope with 20% of the volume being taken up by hydrogen. Hydrogen-induced cracking associated with the blending of hydrogen in the existing pipeline systems remains an outstanding issue.

New marginal developments: standardised designs that are reuse- and decommissioning-ready

When developing new fields, especially the more marginal ones, it should be standard practice to reuse existing installations or components such as generator sets, compressors, turbines, pumps, valves and vessels. To encourage this, a reuse website could

Oranje-Nassau Energie's standardised P11-E platform with a reusable modular jacket design.

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be set up, where details are given of equipment that is shortly to be decommissioned and the date when this equipment is expected to become available. This could allow a new market to develop, which would not necessarily be core business for the traditional operating companies.

It can be expected that reuse and decommissioning-readiness will be integrated into the design as a standard practice, also because of the shorter production profiles generally associated with the smaller fields that are still to be developed. A prime example is Oranje-Nassau Energie's standardised P11-E platform with a reusable modular jacket design, which will be installed this year.

Learnings from the UK's joint well P&A campaign

The UK Oil and Gas Authority has initiated a joint operator campaign to plug and abandon 500 wells in the UK southern North Sea. It is claimed that the cost savings will be as high as 40%. For such an approach to be possible in the Dutch part of the North Sea it will be necessary to classify the wells in such a way that similar 'cookie cutter' operations can be clustered, in order to fully benefit from a learning curve. A method for doing so will be developed and agreement will have to be reached on how to share the savings between participating companies. The Dutch E&P sector may be able to learn from the experience of UK counterparts.

EBN's view on decommissioning: collaboration within and across the industry

Clearly, the general view is that collaboration between different operators (but also between operators and supply industry) will be beneficial. This collaboration will be possible by sharing best practices and taking advantage of a learning curve, to increase efficiency by repeating similar operations. Also, offering a larger portfolio to the contracting industry will generally lead to a lower day rate, by providing security for activities.

EBN has initiated an optimisation pilot to study the collaboration business case. Using general assumptions on parameters such as gas price, operating costs and decommissioning costs, it is predicted when installations will cease to be economic. Next, a financial optimisation is used, to select how and when it is best to P&A the wells and decommission the installations – individually, or as part of a campaign. As expected, initial findings indicate that much can be gained by P&A wells and decommissioning installations in campaigns. By increasing the contract size and benefiting from a learning curve, it is expected that savings of up to 40% can be achieved, as has been claimed by other studies (e.g. OGA).

The role of EBN

As part of the strategy review which EBN started early 2016, a high-level strategy has been formulated on reuse and decommissioning. In order to make the value chain more sustainable EBN wishes to make reuse a more common practice throughout the E&P life cycle.

With a general 40% working interest, EBN bears the major burden of the decommissioning cost (ultimately the burden on Dutch tax payers is some 70%). Because of its large portfolio, EBN sees a clear opportunity to fulfil an active facilitating role in a national decommissioning working group and as such participates in the decommissioning working group recently initiated by NOGEPA.

6

Research and innovation

Crucial for unlocking the remaining potential of the small fields

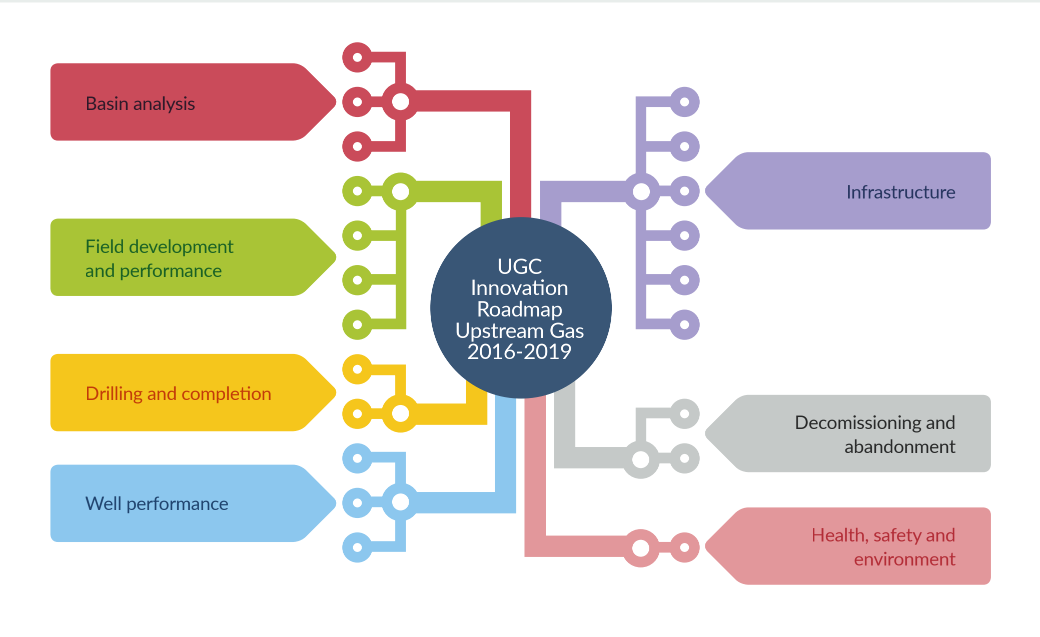
Driving innovation forward has become harder but also more important than ever, given the mounting challenges the E&P sector faces. EBN is convinced that investing in research and innovation is key to unlocking the remaining potential of the Dutch Continental Shelf and therefore participates in Joint Industry Projects (JIPs), organises symposia on relevant topics for the industry. JIPs provide a way of generating knowledge in partnership, to find innovative solutions for discovering and developing more resources, and to collaborate between the various parties involved in the Dutch and international E&P sectors. In the following a brief account is given of various JIPs and initiatives in which EBN participates and that form part of its activities within its Roadmaps Mature Fields, Infrastructure, Tight Gas and Exploration.

New Upstream Gas Consortium roadmap

One of the initiatives in which EBN participates is the TKI Gas – part of the Topsector Energy- which is a strategic R&D programme of the Ministry of Economic Affairs, for investing in technology for upstream gas in order to increase the gas reserves and production levels in the Netherlands. EBN has participated in this programme since its start in 2012. Recently, a new roadmap was prepared for the coming four years, in which seven main themes are central: 1) Basin analysis, 2) Field development and performance, 3) Drilling and completion, 4) Well performance, 5) Infrastructure, 6) Decommissioning, and 7) Health, safety and environment. Several operators active in the Netherlands participate in one or more themes in these programme lines.

EBN also participates in several other initiatives. In the UK, an Exploration Task Force (ETF) has been established to stimulate exploration activities in the

New Upstream Gas Consortium roadmap



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UKCS. The ETF is an initiative of the Oil and Gas Authority in the UK. Within the UK ETF several projects have been defined. EBN participates in the 21CXRM – Regional Petroleum Systems Analysis of the Palaeozoic study, which links up well with the DEFAB project currently being implemented by EBN (see the section on Exploration) – not only in terms of stratigraphy, but also because of the adjacency of the UK and Netherlands blocks.

Salt precipitation

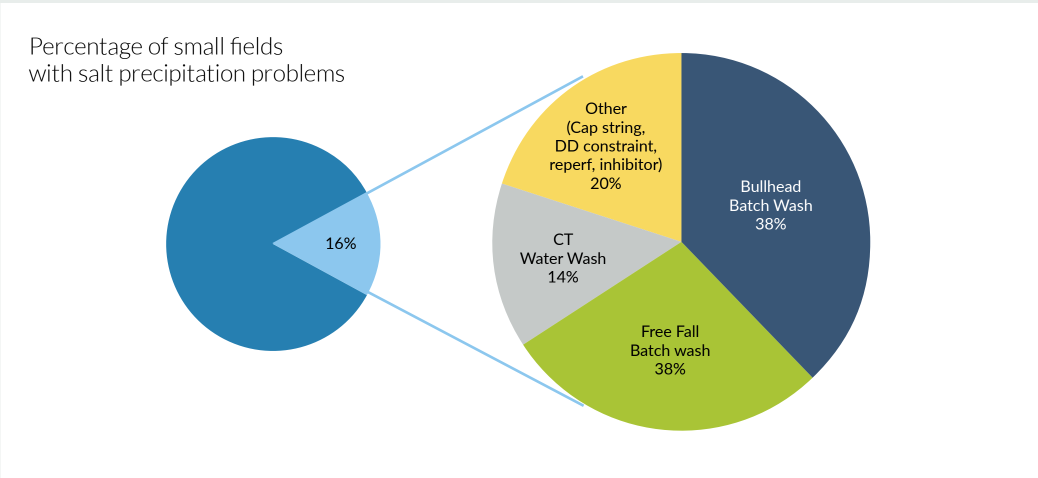
The precipitation of salt in porous reservoir rocks, particularly in mature fields, can impair the productivity and may even culminate in total plugging and ultimately in the abandonment of wells. This behaviour is attributed to halite precipitation in the near wellbore area around the perforated pay zone or within the wellbore, as it is intrinsically linked to pressure drop.

Key facts about salt precipitation and volumes at stake

Since 2010, southern North Sea operators (UK, NL and GER) have shared their experience on halite precipitation in gas wells at the annual salt precipitation forum organised by EBN in which operators and consultants share their experiences in mitigating measures and halite precipitation modelling. Some key facts have been derived.

- Currently about 16% of the Dutch small fields suffer from salt precipitation and this number keeps increasing with time.
- In 71% of these fields the reservoir pressure is below 150 bar at the moment salt mitigation measures are implemented.
- Almost 90% of the Carboniferous and Zechstein fields suffer from salt precipitation when reservoir pressure drops below 150 bar
- Of the remaining fields only about 12% suffer from salt precipitation.
- Reserves maturation resulting from salt mitigation measures is expected to add at least 0.2 bcm/year between 2015 and 2030.
- The expected total gains from implementing salt mitigation measures are some 2% UR (about 8 bcm) of the total small field's gas reserves.

Salt mitigation techniques applied



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Project aims

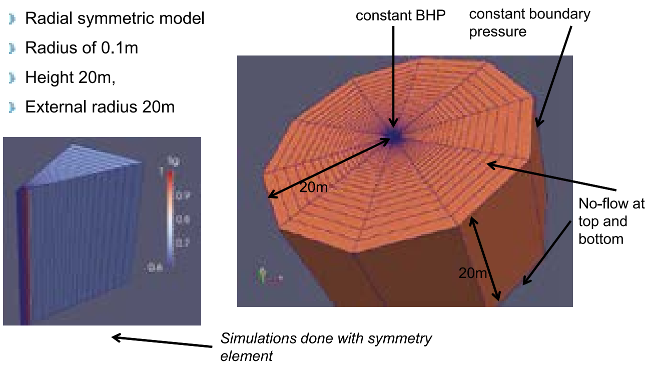
Mitigation in production operations is typically achieved with regular water washes, which dissolve the deposited salt and transport it in the water phase. This is done to restore the original permeability conditions and so restore the production rates. The precipitation itself, as well as the water wash treatments (and associated down time), result in substantial production losses. A method is being sought to predict the amount and location of salt precipitation and the subsequent effect on transport properties, the permeability and capillary pressure. This prediction can be used to model the onset and speed of production decline, as well as optimise mitigation strategies.

The TKI Salt Precipitation project was initiated with the following objectives:

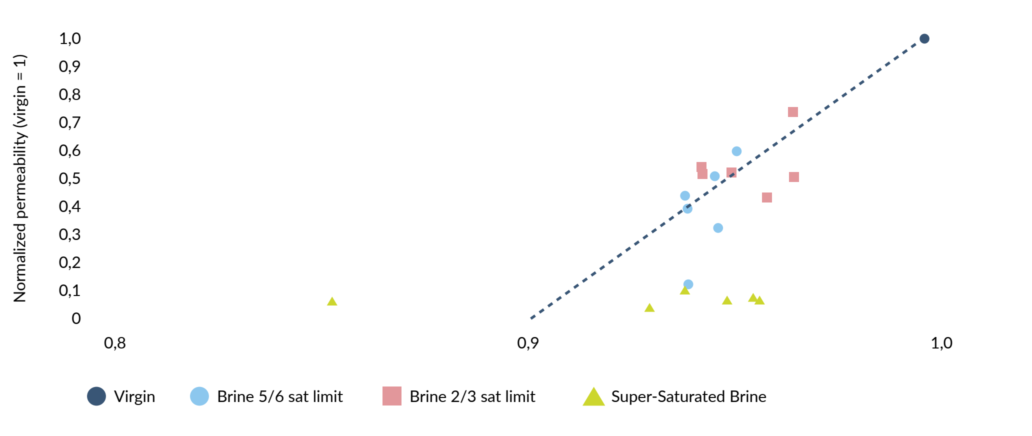
- To model the physical phenomena at the micro pores and understand which parameters determine the salt precipitation. These models will provide input for a larger scale (macro-scale) model describing the near wellbore region. This macro model is to be validated using experimental data.

- To develop a software model that incorporates the relevant physics with which salt precipitation as well as dissolution (during a water wash) can be modelled/predicted in the near wellbore/perforation region as a function of time and location and for use to optimise production strategies. (Since water soaks have a rapid effect/response, the assumption is that the main precipitation is in the near wellbore region and within the first few metres around the wellbore).

Experimental set-up and wellbore model (courtesy of TNO)



Gas permeability reduction (Real Klink)



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- To carry out experiments to study the effects of the salt precipitation on porosity, grain density and permeability to various flow media as input to/verification of the numerical model.

The operators have shared and provided field data to TNO. The partners in this project are Total, Wintershall, ENGIE, ONE and EBN.

Project learnings and deliverables:

- A salt precipitation/dissolution model called SALT-MUX has been developed, based on the DuMuX simulator and was made available in Windows format to the partners, for performing parameter studies and to help predict salt precipitation.
- Experiments have been done on outcrop samples in order to quantify the relevant (input) parameters in the model. Findings show that salt precipitation reduces permeability significantly (see graph).
- A parameter study has been performed to identify the sensitivity of the results to various parameters and to improve understanding of the salt precipitation mechanisms (including salt clogging time and location) in order to help optimise mitigating measures and production.
- A first step has been taken in developing a simplified analytical model (in MATLAB) to evaluate the scope for optimising water washes. This will allow operators in the field to improve production and control and optimise water washes.

Integrated Zechstein study at Durham University

In recent years, the Zechstein carbonate reservoirs in the Southern Permian Basin (SPB) have attracted growing interest. Newly acquired seismic data reveal large carbonate platform build-ups around the Elbow Spit High, with reservoir quality deposits proven by a number of wells in the Dutch and UK sectors. From oil and gas fields with Zechstein carbonate reservoirs it is well known that the quality and the productivity of such reservoirs are notoriously hard to predict. Crucial factors that determine the productivity of a Zechstein carbonate field are facies and diagenesis, but most important is the presence of fractures.

Project learnings and applicability

Along the UK coast south of Newcastle there are a number of world class Zechstein carbonate outcrops where it is possible to better understand the complicated sequences of the deposits along the edges of the highs in the SPB. A number of Zechstein experts have integrated the results of several studies (sequence stratigraphy, Ground Penetrating Radar (GPR) measurements, outcrop fracture analysis, diagenetic processes, comparison of historical production data) on these outcrops and a large number of cores from offset wells. This has made it possible to more confidently predict the reservoir characteristics in different parts of the Zechstein carbonate build-ups. The insights will be used in EBN's evaluation of the prospects with Zechstein carbonate reservoir in the Dutch Northern Offshore. They will also help to improve understanding of the production behaviour of the numerous producing fields in the Netherlands.

System Integration Offshore Energy

Energy is being supplied from the North Sea in various ways. In addition to the energy supplied via the infrastructure of the oil and gas sector, offshore wind has been generated since 2006. Tidal energy has also recently received more attention, especially in the framework of the Energy Agreement.

However, the offshore sector faces several challenges in the short and long term. A big challenge is the target of cutting cost by 40%. Cost reductions are necessary to enable the offshore industry (E&P as well as offshore wind) to sustain economic production while economic market conditions are deteriorating. System integration and innovation can contribute to cost reduction and new opportunities.

To date, no integrated study has been carried out in the Netherlands focussing on the potential advantages of synergies of systems integration in offshore energy generation. This JIP aims at investigating the advantage of the offshore E&P industry collaborating with the offshore wind sector, with the twin aims of reducing costs for maintenance and installation and of making offshore energy generation more sustainable. The project is expected to be completed by late 2016 and the partners are Siemens, Shell and EBN, with TNO as the project developer.

The Upper Jurassic Sandstones project

The Focus project 'Upper Jurassic Sandstones: Detailed sedimentary facies analysis, correlation and stratigraphic architectures of hydrocarbon-bearing shoreface complexes in the Dutch Offshore' was a JIP implemented by TNO. The goal of this project was to investigate the Upper Jurassic and the Lower Cretaceous in the eastern part of the Dutch offshore, in order to provide new insights into the regional and local stratigraphic, depositional and syn-depositional settings. Although this stratigraphic interval contains numerous known reservoirs, key questions remain regarding its depositional environments and the preservation of sandy strata. The project has contributed greatly to the understanding of the Upper Jurassic and Lower Cretaceous in the Dutch offshore by providing a tectono-stratigraphic framework based on modern concepts of sequence stratigraphy and syn-depositional tectonic models.

Jurassic Outcrop in the Boulonnais, France (courtesy of TNO)

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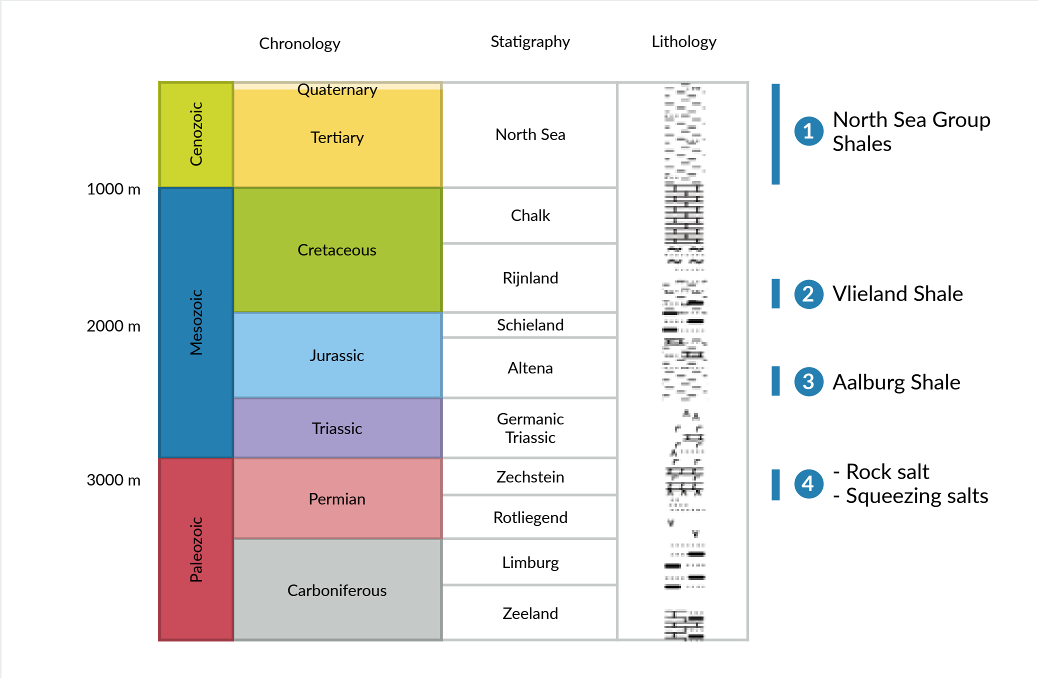
Plugging wells by enhanced formation ductility

The project ‘Plugging wells by enhanced formation ductility’ began in the summer of 2015. The aim of this innovative study is to demonstrate the feasibility of new concepts to accelerate plugging by natural sealing and self-healing materials for well abandonment. The results will be very important for EBN and partners, as EBN stimulates research on cost-efficient and natural ways of reliable well abandonment.

So far, the Dutch subsurface has been geologically screened to ascertain which formations have the potential to naturally self-seal, as shown in the figure. Salt creep has been included in the project’s scope because large Zechstein evaporates are abundantly present in the Dutch subsurface, its basic mechanisms are better understood, the research on it is more advanced and it has been applied more often in the industry (in the Gulf of Mexico). The structural setting of the Zechstein in the Dutch subsurface is that it occurs in thick layers (up to 1000 metres thick), it can form large salt diapirs and salt floaters are also present. Zechstein deposits overlie most of the reservoirs of Rotliegend age. The Zechstein formation consists of various minerals, those most prone to ductile deformation being halite, K-Mg salts and complex salts.

In order to better understand the ductile deformation mechanisms, it is useful to analyse operational field experience: 1) high drilling hazard in the Zechstein overburden drilling; 2) drilling and completion problems arising from squeezing shales; 3) well completion problems caused by obstruction during casing running; 4) casing collapse caused by squeezing salts in production wells. Wells have also been reported to be written off as a result of salt movement. In order to achieve acceptance of these innovative completion techniques, the project has also looked into the Dutch regulations. In Norway and the UK, the NORSOK D-010 standard and

Typical Dutch stratigraphic column with potential self-sealing formations (courtesy of TNO).



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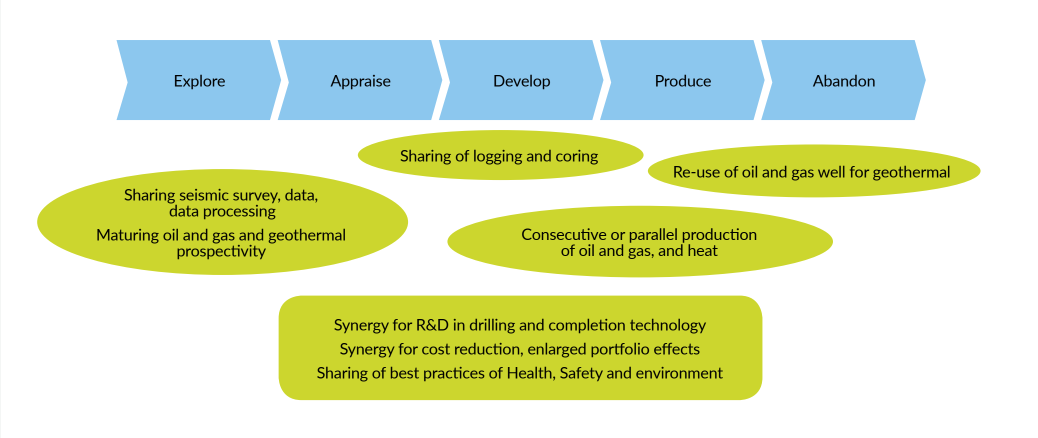
the Oil & Gas guidelines accept shale as an annular barrier (outside the casing) under certain barrier conditions: impermeable, long-term integrity, non-shrinking, ductile, resistance to different chemicals and sufficiently high minimum stress. In practice, this means that the operator needs to prove good shale presence, run ultrasonic and CBL logs and demonstrate that the minimum stress exceeds the maximum reservoir pressure with gas column to barrier. Natural sealing outside the casing has been accepted and applied on the British and Norwegian continental shelf by Statoil, Shell, BP and other operators since 2009. The project participants are Total, NAM (and Shell) and EBN; the project is being implemented by TNO.

Exploring the synergies with Geothermal Energy

Searching for opportunities in low price scenarios sometimes means thinking outside the box. One such opportunity might be to combine upstream oil and gas activities with geothermal activities. The Energy Report (2016) issued by the Ministry of Economic Affairs emphasises an interesting potential of sustainable geothermal energy that can be developed for district heating at lower temperatures (< 100 °C) and also for industrial heating at higher temperatures (100–200°C). Higher-temperature heat would have to come from ultra-deep geothermal projects (depths of 4–8 kilometres) with new plays yet to be developed.

The activities in the subsurface for the exploration of oil and gas and geothermal energy are almost

Synergy possibilities across the life cycle



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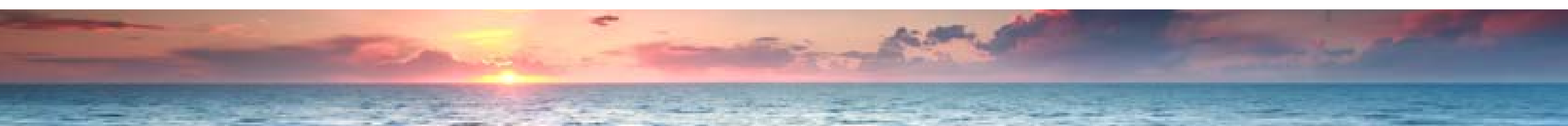
identical. In addition, with its extensive coverage of 2D and 3D seismic and over 3,000 wells for oil and gas development, the Netherlands already has a strong basis of subsurface The following sketch summarises some of the potential synergies across the project life cycle

In recent years EBN has supported a number of synergy activities: co-financing the acquisition of additional well-logging information in the California Geothermal Project. And sponsoring two postdoctoral research projects with the Technical University of Delft about the synergy potential of geothermal energy in stranded oil and gas fields, and with Groningen University about geothermal applications in almost depleted gas fields.

Another more concrete example has been the quick scan executed by EBN and TNO to make a preliminary (rough) assessment of the potential of double plays. A double play is the business case in which the value proposition of oil and gas and geothermal energy reduces the costs by integrating both concepts in one play. Geothermal energy reduces the dry hole risk of oil and gas, because the well is reused for heat and it increases the well's possibility of success. When oil and gas are found instead of heat, the expected revenues from the oil and gas augment the lower revenues of geothermal energy. When this logic was applied to the onshore prospectivity database it was found that under standard conditions and cut-off rates, some 7 bcm might become economic, with an upside potential of up to 25 bcm. Furthermore, it would be possible to develop an additional 100 MW of geothermal energy (see Van Wees et al, 2015) .



Glossary

BAU Business as usual scenario: forecast scenario assuming the E&P industry maintains its current activity level
BCM Billion Cubic Meters
BOON Benchmarking Opex Offshore Netherlands
BPU Base Permian Unconformity
CAPEX Capital expenditure
COP Cessation of production date
DEFAB Exploration study of the D,E.F,A and B blocks
DCS Dutch Continental Shelf
E&P Exploration and Production
GE Groningen Equivalent
GDE Geo Drilling Events
GILDE Acronym derived from the Dutch phrase meaning 'Gas In a Long-term Sustainable Energy system'
GIIP Gas Initially in place
JIP Joint Industry Project
NOGEPA Netherlands Oil and Gas Exploration and Production Association
NOV Non-operating Venture
Operator Party carrying out E&P activities in a licence on behalf of partners
OPEX Operational expenditure
OGA UK's Oil and Gas Authority
POS Probability of Success: the probability of finding hydrocarbons in a prospect
PRMS Petroleum Resources Management System: international classification system describing the status, the uncertainty and volumes of oil and gas resources, SPE 2007 with guidelines updated in 2011
P&A Plugged and Abandoned
Small fields All oil and gas fields except the Groningen field and the Underground Gas Storages
SPE Society of Petroleum Engineers
SSM State Supervision of Mines
Tight gas Gas in reservoirs with insufficient permeability for the gas to flow naturally in economic rates to the well bore
TKI Top consortium for Knowledge and Innovation
TNO Netherlands Organization for Applied Scientific Research
UR Ultimate recovery
UOC Unit Operating Costs
UKCS UK Continental Shelf

About EBN

EBN B.V. is active in exploration, production, storage and trading of natural gas and oil and is the number one partner for oil and gas companies in the Netherlands. Together with national and international oil and gas companies, EBN invests in the exploration for and production of oil and natural gas, as well as gas storage facilities in the Netherlands. The interest in these activities amounts to between 40% to 50%. EBN also advises the Dutch government on the mining climate and on new opportunities for making use of the Dutch subsurface.

National and international oil and gas companies, the licence holders, take the initiative in the area of development, exploration and production of gas and oil. EBN invests, facilitates and shares knowledge. EBN has also interests in offshore gas collection pipelines, onshore underground gas storage and a 40% interest in gas trading company GasTerra B.V. The profits generated by these activities are paid in full to the Dutch State, represented by the Ministry of Economic Affairs, sole shareholder. EBN is head-quartered in Utrecht, the Netherlands.

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