Focus on Dutch Oil and Gas 2015

Contents

Foreword

The reputation of natural gas in the Netherlands, and especially its production, has become increasingly controversial in recent years. There is widespread social concern about various aspects relating to these activities. It is generally recognised, for example, that earthquakes in Groningen are caused by gas production, and there are also concerns about the potential effects of future shale-gas production. Climate change caused by fossil fuels is also a major concern. These issues resulted in the fact that many people in the Netherlands now have a negative view of gas production. As this is the new reality, the E&P industry needs to accept the importance of addressing society's concerns. It is now more important than ever for all parties in the E&P sector to cooperate in minimising the adverse impacts of activities and promoting greater transparency.

Berend Scheffers

In view of the social pressure to reduce production from the Groningen field, every cubic metre of gas that can be produced from small fields is more than welcome, especially as this will reduce the EU's dependence on imported gas. In addition, the objective of the Dutch government's Energy Agreement is for 16% of the country's energy to come from renewable sources by 2023. Even then 84% of our energy needs will have to be met by energy conservation measures or non-renewables. Natural gas is the fossil fuel of choice for minimising emissions of greenhouse gases as it has the lowest CO_2 footprint of all fossil fuels. Demand for Dutch gas is expected to remain considerable also in view of the current economic recovery and the need for security of supply. Dutch small fields are, therefore, becoming increasingly important, given that natural gas production from the Groningen field is being reduced.

We have so far produced over 1500 BCM from small fields in the Netherlands, while approximately 550 BCM is still left in the ground, as indicated in the Dutch reserves and resource base. Profit margins on Dutch gas production are attractive in spite of a drop in oil prices and, to a lesser extent, gas prices, alongside increases in both CAPEX and OPEX. To recover the remaining reserves it is essential that E&P companies remain committed to investing in the Netherlands.

EBN firmly believes that there are still plenty of opportunities for new developments, both onshore and offshore, but especially offshore the window of opportunity is decreasing as the lifespan of critical infrastructure reaches the end of its lifetime. This edition of Focus on Dutch Oil & Gas outlines the remaining opportunities, expectations, the challenges, how we compare with other North Sea countries with respect to investment regimes and exploration successes and by EBN suggested paths for maximizing economic recovery of Dutch oil and gas.

Innovative techniques can create new opportunities for profitably developing fields and extending field life. Minimum-facility platforms, for example, can significantly reduce CAPEX and OPEX, with walk-to-work vessels reducing the number of helicopter trips and so further cutting operating expenditure. E&P companies, service companies and R&D organisations are currently cooperating in several joint industry projects as part of the TKI Upstream Gas programme, which is seeking to identify innovative ways of extending field life. Another issue requiring innovative ideas is platform and well abandonment. The biodiversity under and around our platforms is currently being studied, and 'rigs-to-reefs' solutions may offer potential for better decommissioning.

Exploration and production of gas and oil from Dutch small fields contribute to state profits, security of supply of key energy sources and are therefore of great value for society. A joint commitment to maximize economic recovery safely and responsibly is therefore not only required for the E&P sector itself but also to continue generating contributions to society.

Executive summary

Focus on Dutch Oil & Gas 2015 provides you with the current state and future prospects of the oil and gas industry in the Netherlands. Cooperation, transparency, investment and window of opportunity are key items this year.

As the ageing offshore infrastructure in the mature southern North Sea approaches decommissioning, the window of opportunity for E&P operators in the Netherlands is rapidly closing. The E&P industry must act quickly to develop the remaining gas reserves and mature the gas resources while platforms and pipelines are still operational. Once critical infrastructure has been decommissioned, remaining reserves and resources will be stranded, and these gas volumes will remain stranded unless produced or matured to reserves within the next few years.

Small-fields production and reserves are in decline. Production in 2014 from small fields in which EBN participates was 24.5 BCM. Yet small fields still contain significant reserves (159 BCM) and, with 191 BCM of contingent resources and over 200 BCM of prospective resources, reserves replacement is considerable (70%). Profit margins on gas production remain attractive, although last year's profitability decreased as a result of a combination of lower gas prices and higher OPEX.

The combination of steadily rising production costs and declining production means that Unit Technical Cost (UTC) is increasing. Inevitably this will ultimately result in infrastructure being abandoned. This trend can be slowed down by new reserves maturation, by increasing ultimate recovery and, last but not least, by cutting costs through closer cooperation between operators.

This cooperation and coordination between the different stakeholders is especially critical when infrastructure is near the end of its economic life as decommissioning of key infrastructure will close the window of opportunity for maturing contingent and prospective resources into reserves. There are several ways to address this, with end-of-field life measures such as foam injection, velocity strings, compression and infill drilling commonly being applied to increase the recovery factor in ageing fields and to add BCMs with EOFL measures (an estimated 0.2 to 0.5 BCM per year). A study of the performance of small fields shows there is still scope for increasing the recovery factor. Several joint industry projects are currently executed to innovate and optimise techniques used in end-of-field life production.

Novel designs for satellite platforms can reduce both CAPEX and OPEX and thereby also help to mature resources to reserves. Reduced functionality, such as platforms without helicopter decks or living quarters, reduces CAPEX and so allows development of small and stranded fields that would otherwise be uneconomic. Low-pressure, shallow gas prospects are particularly suited for satellite platforms with reduced functionality. Monotower designs have been shown to be technically feasible, even in water depths of down to 50 m, while initial feasibility studies show that cost savings of up to 50% are achievable on such structures, compared to conventional designs.

Before any E&P activity can begin, Dutch legislation requires operators to obtain a 'licence to operate'. This firstly means meeting all the administrative requirements. It is becoming increasingly important, however, also to obtain a 'social licence to operate', with stakeholder engagement and mitigation of environmental impacts being key in this respect.

Historically, gas developments in the Netherlands have generally been very profitable for investors as well as the State, and they remain attractive even at the current gas prices. Also, the longer-term profitability of Dutch E&P investments looks promising. Although return on capital invested (ROIC) for the Dutch small fields fell from 36% in 2013 to 19% in 2014, globally the decrease of the ROIC of E&P investments has been stronger, as these are more vulnerable to oil price volatility than the Dutch small-fields portfolio.

EBN seeks to maintain gas production from small fields as high as possible. Although annual production is expected to remain above 20 BCM in the coming 5 years, a faster decline is than forecasted to set in. The risked production forecast up to the year 2030 shows that if the known portfolio is developed at the current drilling and development rate ('business as usual' scenario), annual production from small fields will fall to 10 BCM by 2030. The 'upside' scenario also takes into account potential contributions from sources other than known reservoirs and established plays, and from novel technologies. In this scenario, gas production from small fields in 2030 may still be as high as 20 BCM.

The southern North Sea Basin is a mature gas basin that still contains a diverse mix of new plays. Additional exploration targets are likely to result from new studies in the Northern Dutch Offshore, including the shallow gas portfolio. EBN has developed a seismic characterisation system that has identified over 20 amplitude-based leads, with individual in-place volume estimates of up to 2.5 BCM.

The historical exploration success rate of 55% for wells in the Dutch sector is supported by a favourable fiscal regime. The Netherlands continues to offer attractive conditions for E&P investments in terms of available opportunities, returns on investment, favourable commercial conditions and tax regulations. However, the currently low oil prices and, to a lesser extent, gas prices mean that attracting sufficient investments in this mature basin to harvest the sizeable remaining gas resources will present a challenge.

To summarize, now is the time to find and develop the remaining gas reserves and to mature the gas resources before the offshore window of opportunity closes for good.

1 Reserves and Investment opportunities

The Petroleum Resources Management System (PRMS)

				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		

EBN 2015

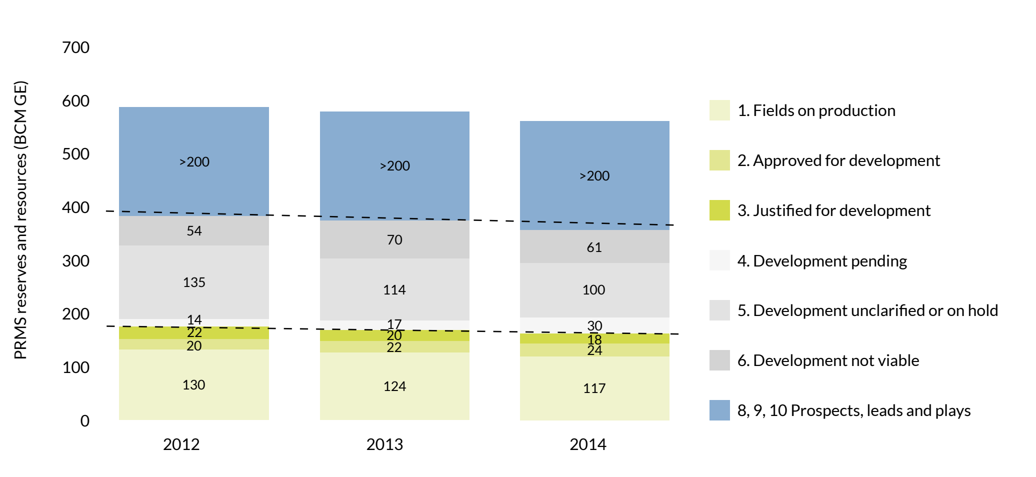
1.1 Reserves and resources – PRMS

EBN adopted the SPE Petroleum Resource Management System (PRMS) in 2009 and has since successfully used it for six years, resulting in consistent and better reporting of reserves and resources. Implementation of the PRMS has made monitoring and forecasting of hydrocarbon maturation and resource replacement much more transparent, as well as standardising the reporting of reserves and resources and making benchmarking the operators' portfolios and performance much easier (SPE 170885, E. Kreft et al., 2014).

Historical development of PRMS volumes shows that the overall small-fields portfolio is in decline. This can be attributed to increased cumulative production, which is only partly compensated for by reserves maturation. Total gas production from all fields in which EBN participates was 66 BCM in 2014, of which 24.5 BCM was produced from small fields (i.e. all fields with the exception of the Groningen field).

Production from small fields declined by 2 BCM over the past year. In the past few years, volumes in the reserves category decreased by about 4% per year, with this decrease being fully attributable to the 'on-production' category 1. Since the reduction in reserves amounts to only one third of the total annual production, ongoing maturation from the contingent-resources category to the reserves category is continuing to prove successful. Alongside maturation from the contingent-resources category, maturation from the prospective-resources category to the contingent-resources category is occurring at approximately the same rate. Ongoing maturation maintains the Dutch gas portfolio at a reasonable level, with the result that the Netherlands remains an attractive area to invest in.

Remaining reserves and resources from small fields



EBN 2015

Small-fields reserves and resources decreased from 234 BCM GE (Groningen Equivalent) in 2007 to 159 BCM GE in 2014.

The reduction in reserves is partly compensated, however, by maturing contingent and prospective resources into category 3 reserves, or by approving new projects (category 2 reserves) and updating the ultimate recovery estimates for existing projects (category 1 reserves). Although the relative importance of these three factors varies from year to year, maturing existing resources into reserves and approval of new projects are currently the most important factors. In 2014, the reserves replacement ratio was some 70%.

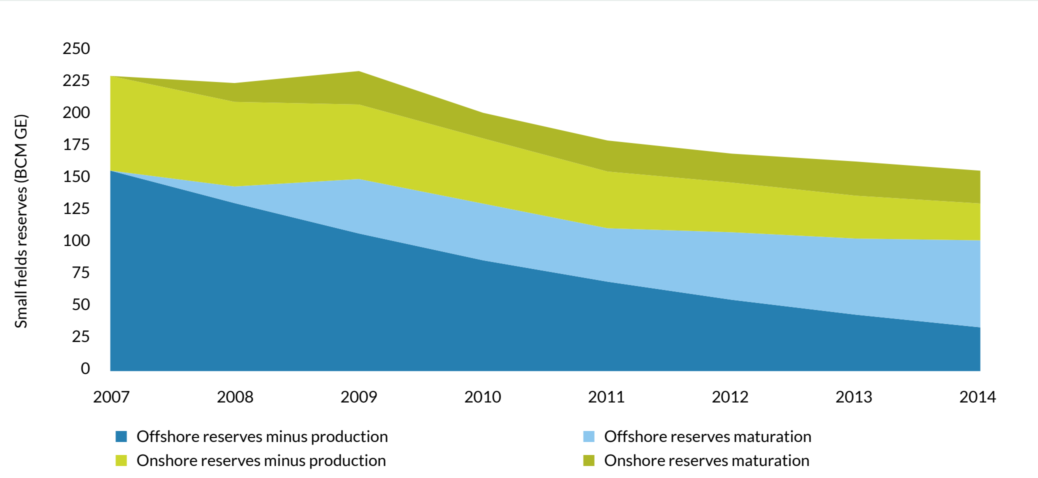
Recent investments resulted in 7 fields (6 gas fields and 1 oil field) coming on stream in 2014. Together with new wells coming on stream in 2014, the 7 new fields contributed 1.2 BCM GE and 2900 BBLS to the 2014 small-fields production of 24.5 BCM GE. Oil production in the Netherlands shows an upward trend.

1.2 Production forecast for small fields

Although many opportunities exist, the Dutch E&P sector has not managed to slow down, let alone halt the decline (currently about 4% a year) in annual production. This is despite the total number of opportunities being higher than ever in terms of the number of prospects, as well as technical projects. The associated volumes of recoverable gas are small, and this implies that the only way to counter the decrease in annual production is by implementing more projects. While many operators in the Netherlands acknowledge this, the current investments level is not sufficient to sustain current annual production levels. EBN firmly believes that the portfolio is sufficiently large and attractive to slow down the rate of decline. However, if the known portfolio is developed at the current drilling and development rate, annual production from small fields will gradually decline to 10 BCM/y (GE) by 2030. In previous editions of Focus on Dutch Oil and Gas, this production trend has been labelled the 'business as usual' (BAU) scenario.

On the other hand, if all potential contributions from sources other than established plays, reservoirs

Small fields maturation



EBN 2015

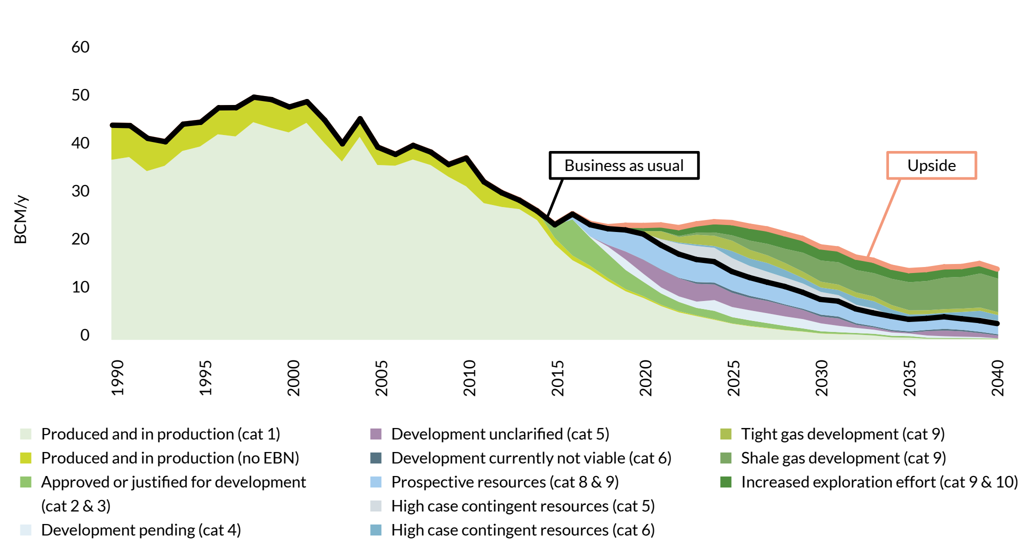
and technologies are taken into account, the annual small-fields gas production could be as high as 20 BCM/y (GE) in 2030. This 'upside' scenario includes maximising the value of the contingent project base, assuming a higher degree of maturation of contingent resources than in the 'business as usual' scenario.

Another significant contribution could come from tight gas fields. The Netherlands has proven gas resources in tight sandstones. Although identification and production of movable gas in tight sandstones presents a challenge, technical advances in hydraulic fracturing and experience gained in previous wells can now begin to unlock the tight gas portfolio.

In contrast to tight gas, the presence of technically producible shale gas in the Netherlands has not yet been proven, thus making it difficult to estimate the potential future contribution of shale gas. While the prospective-resources volumes of shale gas (PMRS categories 9 and 10) are thought to be significant, ongoing public and political controversy about shale gas activities makes potential future production even more uncertain. By the end of 2015, there should be more clarity about whether a first shale-gas exploration well can be drilled. If sufficient shale gas is found in the Netherlands and could be developed in an environmentally responsible and socially acceptable manner, with the support of key stakeholders, shale gas could account for a major share of Dutch natural gas production after 2030. Although ongoing research indicates that Dutch shale gas plays may have good potential, only dedicated exploration wells will conclusively outline the country's shale gas potential.

Last but not least, a key contribution to the 'upside' scenario can be made by simply increasing exploration efforts, i.e. drilling more exploration wells, increasing exploration for new plays and pushing the boundaries of existing plays. EBN strongly supports research into new, ignored, or missed plays, currently focusing on the Northern and North – Eastern Dutch Offshore. As production from these plays could increase annual production from small fields by dozens of BCMs, EBN will continue to encourage its industry partners to pursue these opportunities.

Scenario-based, risked production forecast for small-fields gas production

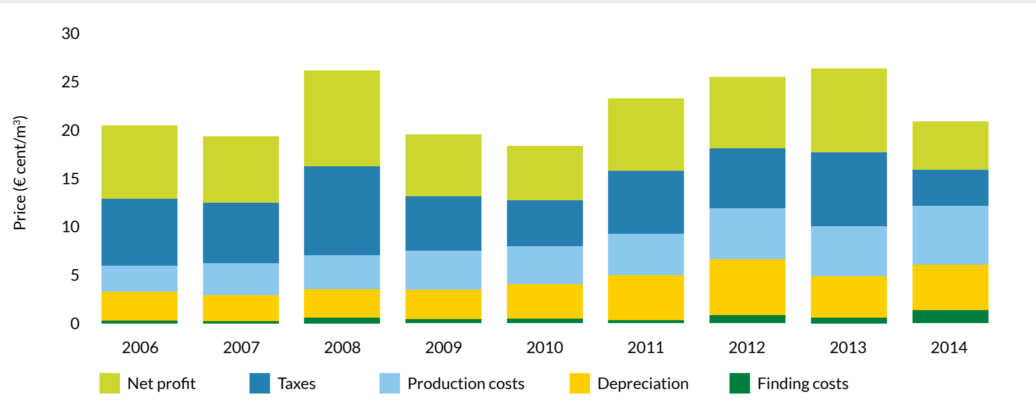


EBN 2015

1.3 Profitability of small-field development in the Netherlands

The profit margins on small-fields production are still attractive. We have estimated past revenues, costs and profits associated with private investments in Dutch small fields. Although production costs and depreciation (a reflection of the CAPEX) have increased over the years, gas prices have always been sufficiently high to generate significant profits, both for industry and society. Despite the recent dramatic fall in global oil prices, market prices for North-West European gas have so far remained reasonably stable. In view of the recently imposed production limits for the Groningen field and the apparent economic recovery, which will increase demand, the outlook for natural gas prices in the Netherlands remains attractive.

Margins of small field production



- Findings costs: mainly geology & geophysics (G&G) costs (including seismic surveys and expensed dry exploration wells);
- Depreciation: on a unit-of-production (UOP) basis (depreciation of successful exploration wells, which are activated, is included in this category);
- Production costs: including transport, treatment, current and non-current costs;
- Taxes: Including Corporate Income Tax (CIT) and State Profit Share (SPS).

EBN 2015

1.4 Return on capital employed, profitability of long-term E&P investments

The 'Margins of small field production' histogram shows the average profitability of the small-fields portfolio in a given year, but the long term capital characteristics of E&P investments also require insight regarding its capital efficiency.

EBN has therefore quantified and visualised an analysis of 'Return on Capital Employed' (ROCE) for our small-fields portfolio of assets over the past decade. The ROCE is a financial ratio that measures a company's profitability and the efficiency with which its capital is employed. The analysis shows that ROCE was very high in the past, but has been declining since 2009.

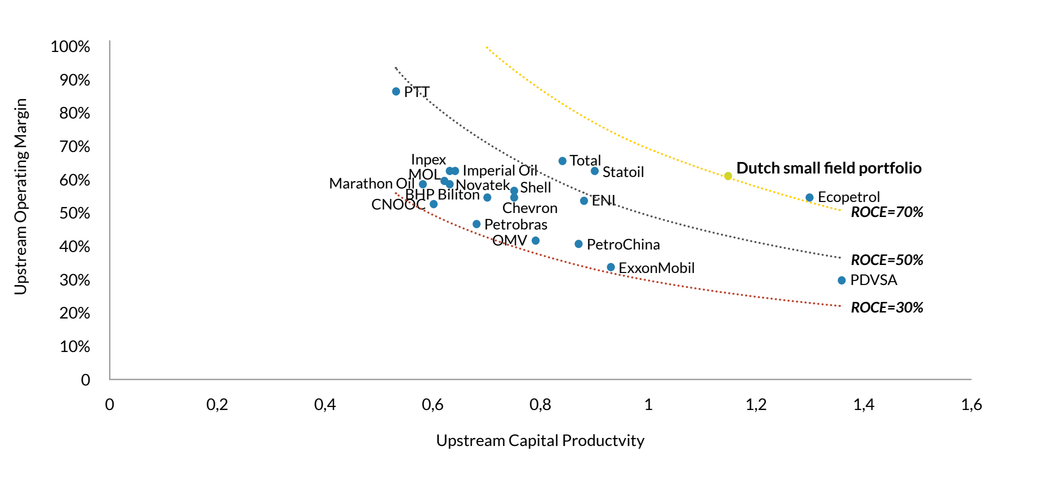
The ROCE is the ratio of EBIT ('Earnings before Interest and Tax') and 'Capital Employed'. EBIT is heavily dependent on the gas price, which is volatile. 'Capital employed' shows a steady increase, reflecting the fact that declining levels of production require an increasing level of investments.

We also considered the Dutch small-fields ROCE in an international perspective. In November 2013, PricewaterhouseCoopers (PwC) published an analysis for 2006-2012: 'Driving value in upstream Oil & Gas, lessons from the energy industry's top performing companies'. We have added the Dutch small-fields portfolio to PwC's graph. PwC presents the ROCE as a combination of the product of operating margin (= EBIT/Revenue) – a measure of cost efficiency – and capital productivity (= Revenue/ Capital employed), a measure of a company's ability to generate turnover from its assets. The Dutch small-fields portfolio has been plotted against PwC's 19 top performers (out of a total set of 74) for these two measures (averaged over the 2006-2012 period). As indicated by the isobars in the graph most of these top performers had ROCEs of between 30% and 50%, whereas the Dutch small-fields portfolio generated 70% over this period. The fact that the Dutch small-fields portfolio ROCE is so high is attributable not so much to the operating margin, but instead to capital productivity. Although we realise that more investments are required over the years to generate production and turnover, the return on capital employed remains very competitive.

Return on Capital employed – Small fields portfolio

EBN 2015

Return on Capital employed for the Dutch small field portfolio compared to top performers in the Global Upstream Oil & Gas sector (2006 – 2012)



EBN 2015

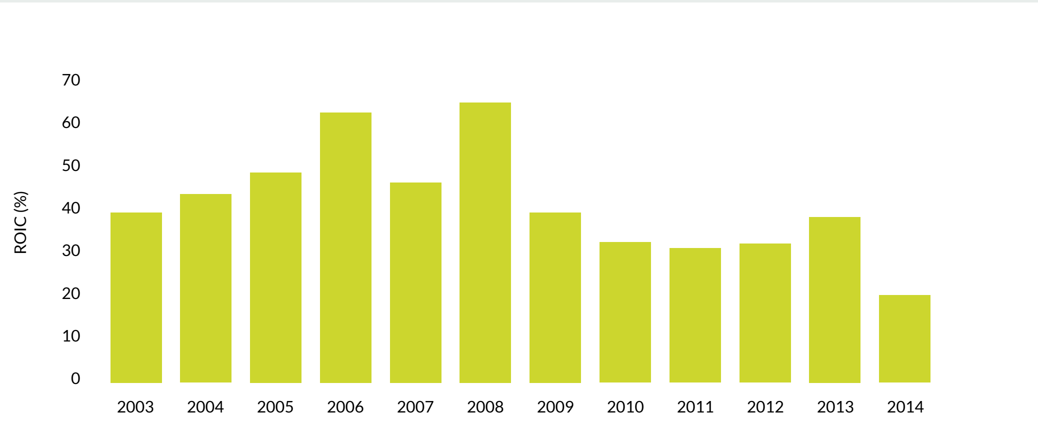
- *ROCE = Upstream Operating Margin * Upstream Capital Productivity*
- *Upstream Operating Margin = EBIT / Revenue*
- *Upstream Capital Productivity = Revenue / Capital employed*

Source: 'Top Performers in the Global Upstream Oil & Gas Sector' (PwC, November 2013, 2006-2012)

In addition to calculating the ROCE, we have also quantified the historical ROIC (Return On Invested Capital), which takes taxes into account.

Our analysis shows that investing in gas development in the Netherlands has on average, been very profitable. The 36% for 2013 in the ROIC graph is far higher than what we believe is representative for investments elsewhere in the world. We have com-

Return On Invested Capital – Small fields in the Netherlands



EBN 2015

pared our annual figures with the ROICs of six major oil and gas companies, whose worldwide activities generated ROICs of 7% to 15% in 2013.

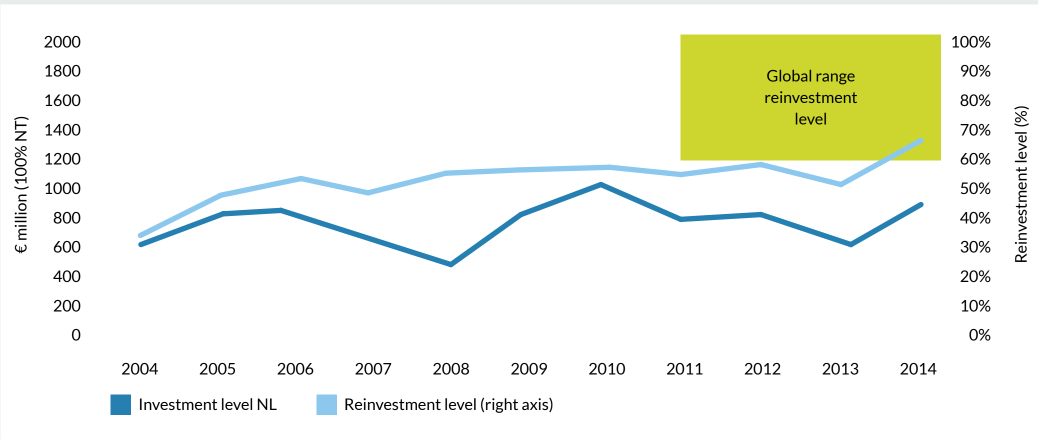
Although the Dutch small-fields ROIC fell to 19% in 2014, it can safely be assumed that the ROICs of global E&P investments also decreased, especially given these ROIC's being more vulnerable to the recent fall in oil prices than the Dutch small-fields portfolio.

1.5 Comparison of reinvestment levels: the Netherlands in global context

EBN also monitors the reinvestment level (RIL), being the ratio between investments and free cash flow. This indicates the extent to which E&P operators reinvest profits generated here into new exploration and field development activities in the Netherlands.

Although we believe there is a considerable portfolio of attractive prospective and contingent resources, this is not always reflected in the RIL for small fields, which in most years is around 30-40%. In 2014, it was around 50%, as a result of higher investments and because of lower gas prices than in previous years. The remaining cash is either invested elsewhere in the world or paid out as dividend to shareholders. It is good to see that investments increased last year, especially since this increase is partly attributable to increased exploration efforts. Although global capital budgets for E&P activities further declined in the past year, we believe that the Dutch basin, especially in comparison with the rest of the world, contains plenty of attractive, relatively low-risk and low-capital opportunities that could suit E&P investors' portfolios well. Notwithstanding the fact that the reinvestment level for the Dutch small fields portfolio has significantly increased in 2014 it still lags the global reinvestment range. We are therefore aiming for further growth of the reinvestment level by encouraging additional investments.

Reinvestment level of Dutch small fields compared to Global range



EBN 2015

1.6 Stable fiscal regime for E&P in the Netherlands

Maintaining a stable and attractive fiscal regime for E&P is a key consideration for the Dutch government. Changes in tax regulations in the past decade have generally been beneficial, both for the sector as well as for society. The most important change was the introduction in 2010 of the 'Marginal Field Tax Allowance' (MFTA). This allowance targets potential investments and developments, including exploration wells, in marginal offshore gas fields that would not otherwise be profitable for investors. Whether applications for the MFTA are granted is determined by three 'technical' parameters: the field's (expected) volume, its distance to existing infrastructure and its (expected) productivity.

Since the MFTA was introduced in 2010, 48 applications for the allowance have been submitted. Of these, 24 were granted, while 5 were rejected and 19 are under consideration.

The marginal field tax allowance especially aims to promote exploration drilling for prospective resources. This means that, when an MFTA application is awarded, an exploration well's dry-hole risk is, to a large extent, carried by the government. We have sought to compare this to the situation in other countries around the North Sea. In the Netherlands, only 32% (net) of the costs of a dry hole are borne by private investors, whereas this would be 45% without the MFTA. The only country where this risk is lower is Norway (because of its high tax rate). Since 2000, companies can request EBN to participate in exploration wells for a stake of 40%, and this has become standard practice. This further reduces private investors' financial risk for a dry well to 19.2%, whereas without the MFTA it would amount to 27%.

Please note that the histogram reflects the situation prior to the recent UK tax changes and excludes participation by EBN.

Comparison dry hole cost sharing between private investors and State

Please note:
Graph shows comparative figures for 2014, prior to the recent UK tax changes.

	The Netherlands	United Kingdom	Germany	Denmark	Norway
State costs	55%	62%	55%	64%	78%
State via marginal field allowance	13%	-	-	-	-
Private investors' costs	32%	38%	45%	36%	22%

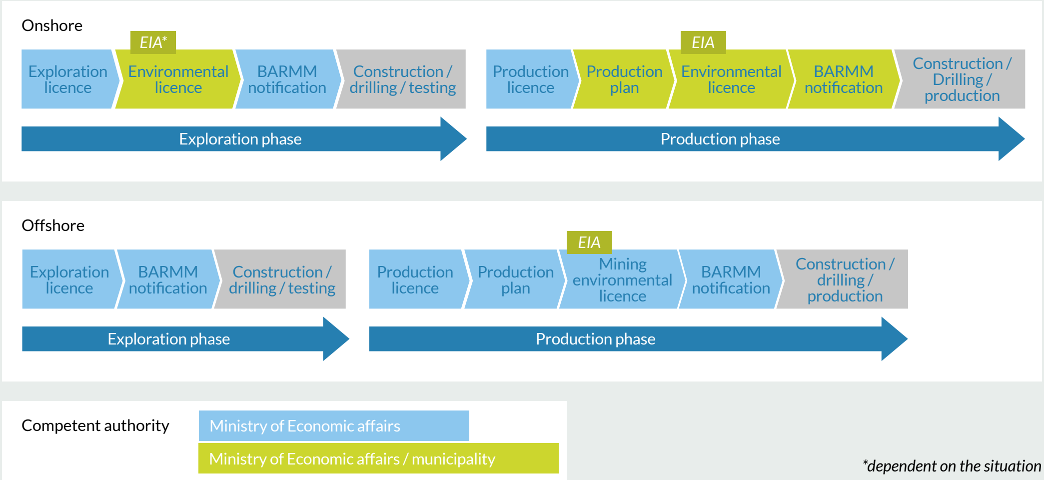
EBN 2015

In addition to the significant exploration opportunities in the Netherlands, combined with the country's healthy historical economic success rate (see chapter 4 of this report), the financial framework for exploration in the Netherlands can also be regarded as very attractive.

Although the E&P investment climate in the Netherlands remains attractive, it is important to continue monitoring how remaining resources can be matured in order to maximise economic recovery, both for the benefit of society and investors. Therefore the government and the E&P sector have started evaluating the existing allowance, as well as considering new stimulation measures.

2 E&P activities, innovations and collaboration

Licence to operate



EBN 2015

Acquiring a 'licence to operate' in the Netherlands is an extensive procedure. Both subsurface and surface-related administrative requirements have to be met. In addition to these administrative requirements, a 'social licence to operate' is becoming increasingly important. Stakeholder engagement and measures to reduce environmental impacts are expected to facilitate such a 'social licence to operate'.

2.1 Dutch Mining Act

The main administrative procedures and regulations governing activities in the deep subsurface of the Netherlands are laid down in the 2003 Dutch Mining Act (MA), Mining Decree and Mining Regulation. The MA also regulates subsurface-related infrastructural works, including platforms, pipelines, terminals and metering. Before any hydrocarbon exploration or production activity in the Netherlands can begin, a licence has to be obtained from the Dutch Ministry of Economic Affairs (the Minister). The application procedures for onshore and offshore exploration and production licences are briefly described below.

Applications for onshore licences have to be submitted to the Minister in duplicate. The Minister will publish the application in the Government Gazette (*Staatscourant*) and the Official Journal of the European Community, and, during a period of thirteen weeks after publication, other natural or legal persons may submit applications for that area. Meanwhile, the Minister obtains geological, financial and technical advice on both the application and the applicant. The Minister shall reach a decision on an application for a licence within six months after its receipt.

The application procedure for an offshore exploration licence is slightly different: first, the draft decision on an application is published. Other natural or legal persons can then submit views on the draft decision. The Minister will then publish the final decision, which can take account of the submitted views.

2.1.1 State participation

By law, the Dutch State participates in the production of hydrocarbons through EBN. Participation by EBN is optional in the case of exploration activities and mandatory in the case of production projects. EBN participates by signing an Agreement of Cooperation (AoC) with the licensee(s) to establish a contractual joint venture, in which EBN holds a standard interest of 40%.

2.2 Environment-related regulations

Regulations on environmental permits, water use, building rights and spatial planning can be found in several documents of Dutch legislation, including the Mining Act, the Act on General Provisions of Environmental Law (*Wabo*), the Flora and Fauna Act, the Spatial Planning Act and the Nature Conservation Act.

2.2.1 Onshore exploration and production

An 'Environmental Licence' (*Omgevingsvergunning*) is required for building an exploration or production site on land. This environmental licence is a 'one-stop shop' covering various aspects, including spatial planning, construction, nature and monuments. However, these various aspects are regulated in separate acts, decrees and regulations, each with their own competent authority (minister, provinces or municipalities).

Exploration - An Environmental Licence is required for non-mining-related activities associated with onshore exploration, such as road and site construction and tree felling. The competent authority is generally the municipality in which the activities are located. An Environmental Licence is not needed for drilling an exploration well unless the operator is intending to erect a permanent facility or is planning an exploration well in a protected area, such as the Natura2000 areas defined by the European Commission. In these cases the Minister is the competent authority for this part of the licence.

The environmental requirements for exploration (both on- and offshore) addressed in the 'Decree on common environmental rules for mining activities' ('BARMM') are not covered by an environmental licence. Operators planning exploration activities have to meet specific environmental requirements laid down in the BARMM Decree and have to announce exploration activities to the Minister four weeks in advance ('BARMM announcement').

Production - After receiving a production licence from the Minister, the operator has to obtain an Environmental Licence to build the necessary production infrastructure and production plant. The Minister is the competent authority for this licence (including any non-mining-related aspects).

2.2.2 Offshore exploration and production

Most legislation on the environment, water use, building rights and spatial planning is not applicable on offshore activities. Operators do not, therefore, have to obtain an Environmental Licence for offshore activities. However, the MA has introduced the 'Environmental Mining Licence' (*Mijnbouwmilieuvergunning*) for offshore production activities. Furthermore, operators planning exploration activities also have to comply with the environmental requirements in the BARMM Decree and announce exploration activities to the Minister four weeks in advance.

2.3 Environmental Impact Assessments

An Environmental Impact Assessment (EIA) is a procedure designed to ensure that proper consideration is given to the environmental implications before any decision is made. Environmental assessments can be undertaken for specific projects, such as platforms or pipelines, or for strategic plans or programmes. The EIA report defines the proposed initiative, describes the current situation (base-line-condition inventory), evaluates the negative and positive impacts of the proposed activities on the environment and compares these with the impacts of possible alternatives in order to identify any environmentally less harmful alternatives. This gives licensees a better understanding of potential environmental impacts early on in the process and enables them, if necessary, to estimate the costs of any mitigation or compensation required. The EIA process also involves a mandatory dialogue with local stakeholders. There are two types of EIA procedures, depending on the type of project:

Mandatory EIA: All projects likely to have significant effects on the environment are subject to an EIA, prior to their approval or authorisation. In the case of oil and gas production, an EIA is generally required for the production of hydrocarbons above certain thresholds and also for the transportation of hydrocarbons above certain thresholds. Notably, an EIA is not mandatory for exploration activities, such as drilling a well.

Discretionary EIA: In the case of certain other projects, national authorities can decide whether an EIA is needed. The categories of projects requiring an EIA in the Netherlands are listed in the Environmental Management Act.

‘Social’ licence to operate, case 1: the Bergermeer gas-storage facility

A depleted gas reservoir in North-Holland near Alkmaar, the Bergermeer field, now has a second life as the biggest open-access, seasonal gas-storage facility in Europe, with a working volume of 46TWh/ 4.1 BCM. To convert this field into a storage facility, the operator TAQA has drilled 14 new wells over a two-year period, and built a compression (6 x 13 KW) and treatment facility on an industrial estate.
The surface facilities are connected to the wells by an 8-km-long pipeline partly laid through rural areas.

An EIA was mandatory for the drilling and the construction of pipelines because some of the drilling locations planned were in a Natura2000 area. Alternatives were compared in the EIA, while the authorities also requested an assessment of alternative treatment and compression locations. Local citizens and the relevant municipality objected to the decision to grant a storage licence, with the subsequent litigation going to the Council of State, the highest administrative-law body in the Netherlands.

Injection/production location during the drilling and construction phase in the Bergermeer (courtesy of TAQA energy B.V.).

To minimise the environmental impact of the pipeline, TAQA agreed to carry out the mitigating measures suggested in the EIA, including:

- Erecting a 10-meter-high noise barrier.
- Using a low-noise drilling rig running on electricity, limiting night-time drilling noise to a maximum of 43 dB at a distance of 300 m.
- Using green lights to illuminating the site at night as these are less disturbing to birds and humans.
- Putting a strict traffic-control plan in place to minimise traffic congestion.
- Maintaining a nesting area of 18.5 hectares adjacent to the drilling site to compensate for the loss of nesting locations for birds.
- Completing the 14 wellheads in cellars below ground level, thus minimising obstruction during the operational phase and ensuring passers-by had a permanently open view of the surrounding landscape across the production location.
- Signing civil-law agreements with the municipalities and the province, in which TAQA promised to operate a transparent procedure for any residents suffering damage as a result of earth tremors or construction work.

These measures all contributed to the success of the project, which was completed on time and within budget. Since 1 April 2015, the Bergermeer gas-storage facility has been playing a crucial role in ensuring security of gas supply and strengthening the Netherlands' position as the major gas hub in North-West Europe.

'Social' licence to operate, case 2: decommissioning of the Berkel-4 production location

From 1983 until September 2013, the Berkel-4 production location near Rotterdam produced oil from the Berkel field in the Rijswijk concession. Over the years, the operator NAM produced 26 million barrels of oil from 22 wells, using characteristic nodding donkey pumping units.

The Mining Act requires mining works to be decommissioned after production ceases. Consequently, the operator is currently in the process of decommissioning the production location under the supervision of the State Supervision of Mines (SodM) and restoring the site to its original condition. The Mining Regulations stipulate that before a well is abandoned, the operator has to plug it downhole at reservoir level and remove the casing to at least three metres below ground level. Once all the wells have been properly plugged, all surface mining installations have to be cleared from the site.

In this case, however, the operator will also remove the tubing to a larger depth, from the top 1400 metres of all 22 wells and place three cement plugs at different depths, thus further reducing the risk of future contamination of the subsurface. Furthermore, the top three metres of soil will be excavated from the entire site and replaced by clean soil, thus further minimising any risk of residual soil contamination.

Before starting to decommission an existing location, operators are required to make a BARMM announcement to the Minister, describing the activities and planning in detail. The contents of the BARMM announcement are disclosed to neighbouring residents, thus allowing them to respond and

Berkel-4 production location (courtesy of NAM B.V.)

provide input. Although not legally required, the operator in this case has used that input to reduce any disturbance to the unavoidable minimum. The following mitigating measures were taken:

- A special transport route was selected to limit traffic and noise, while road transport was also limited to daylight hours so as to reduce noise as much as possible.
- Sound screens were put in place, with drilling slowed down to reduce noise levels even further.
- A dedicated website was built for the operations so as to keep local residents informed about the activities.
- A contact was available on site 24 hours a day to handle any complaints.
- A dedicated team was available to deal with any specific complaints arising. Meetings were held in person with complainants so as to determine the exact problem, while efforts were also made to find immediate solutions, wherever possible. Problems and their suggested solutions were followed up within one week of the meetings.

Decommissioning operations at this location are scheduled to be completed by late 2017. Although the site will have been transformed into a green pasture suitable for agricultural use, the operator will retain ownership of the site so as to enable monitoring of possible future activities. In a country where decommissioning will in the future be more common, this approach is a good example of how to do it safely and in a socially acceptable manner.

2.4 Cooperative authorities

The Dutch continental shelf is increasingly becoming cluttered with a large variety of infrastructural works of many different users. In addition to the E&P industry, the Southern North Sea accommodates an increasing number of wind farms, the shipping and fishing industries, as well as the military. A commonly heard complaint is that the growing number of regulations is hampering E&P development plans. However, some recent projects have proven that the authorities can also be very cooperative.

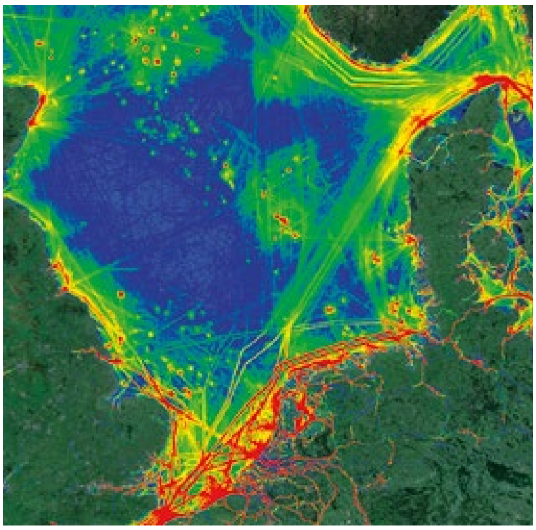
Wintershall's exploration well L06-7 was drilled to the east of the shipping lane within a military exercise area. Development of the High Pressure/High Temperature (HP/HT) gas field L06-B was originally planned by subsea completion of the suspended exploration well as the field is situated underneath both a military practice area and a shipping lane. However, it became clear that a tie-back of the suspended well was not technically feasible. Discussions with the Ministry of Defence were initiated to discuss the possibility of developing the marginal field with a fixed platform and a new production well from within the existing military practice area, to the west of the shipping lane. In view of the marginal economics, it was decided to build a minimum-facilities satellite platform with room for only two wells after approval was obtained of the Ministry of Defence.

Another project demonstrating the willingness of both the Coastguard Service and the International Maritime Organisation (IMO) to cooperate is the development of Wintershall's F17 Chalk oil field, which is situated almost completely underneath a (recently revised) international shipping lane. The development concept has yet to be defined, but will ideally involve the installation of one or more platforms on the crest of the field. The IMO has agreed to a traffic separation scheme to be effective from 1 June 2015 so that fixed surface facilities can be installed.

GDF SUEZ's Q13-Amstel oil field is located only 12 km off the coast of Scheveningen and the Q13-A platform is supplied with 25 kV power through a cable from shore. The power cable passes through an old sewage pipe, which is no longer in use. Allowing this conduit to be used avoided the need for an environmentally sensitive dune crossing; investments and emissions could also be reduced, while the installation's reliability was increased and CO_2 emissions decreased.

In other cases, extensions to limited drilling windows in shipping lanes and military areas were granted when drilling was delayed. The authorities' pragmatic approach avoided additional mobilisation costs for the temporary suspension of wells. Permission was also given to TAQA to drill an exploration well within the Rotterdam harbour approach area in the P18b licence, although, in the event of success, development will have to be subsea.

The Coastguard Service proved to be very helpful in coordinating various activities, especially during recent seismic data acquisition projects, thereby avoiding interruptions and disturbance from other vessels. For example, Hansa's 1100 km2 M03/N01/G18/H16 survey, Sterling's 550 km2 F17/F18 survey and Wintershall's 900 km2 K18b/L16a survey benefitted greatly from the Coastguard Service's cooperation during the acquisition of 3D seismic data; this required efficient manoeuvring of the streamer, which can be up to 6 km long, across busy shipping lanes.



Satellite map of vessel traffic density in the North Sea (http://www.marinetraffic.com/nl/)

2.5 Prospects & stranded-fields inventory

Stranded fields and prospects should be kept on the radar. A great example is the Amstel oil field in the Q13 block which was discovered in 1962, has been stranded for a long period and is now successfully brought to production by GDF SUEZ. The Q13 block changed ownership many times over the years, with the Amstel oil field remaining a stranded field. Development was finally undertaken by GDF SUEZ in 2011. A platform and pipeline were installed in 2013 and first oil was realised in February 2014, with evacuation to the P15-P18 infrastructure. Technical solutions and innovations and suitable infrastructure play an important role in the development of stranded fields and prospects may enable economic development.

Fisher woman looking at Q13-Amstel (courtesy of GDF Suez E&P Nederland B.V.)

In view of future prospect and stranded field development, it is good practice to plan any removals of infrastructure early on and to carefully review adjoining prospects, nearby stranded fields and other upside potential. As EBN participates in almost all exploration and production licences, it is uniquely positioned to provide guidance in these reviews. EBN has developed a simulation tool (InfraSim) to assess the economic life of infrastructure elements, based on input parameters such as production profiles, contingent resources, gas price and operating costs. EBN has also set up a database of prospects and stranded fields, albeit limited to the licences in which it participates or has participated. Another simulation tool (ExploSim) has been developed to allow probabilistic forecasting of 'future volumes', based on input parameters such as development costs, gas price, operating cost and drilling activity.

2.6 Innovation and collaboration

Innovation through industry collaboration between operators and the supply industry will be a key element in controlling operating costs (BOON 2012). In 2015, EBN will carry out its operating cost benchmarking exercise for 2014.

In 2003 Shell-UK and NAM formed the ONEgas business unit to rationalise logistics operations in the Southern North Sea . The two companies have a large Southern North Sea asset portfolio and have identified a cost-saving opportunity: they have since started defining the requirements and specifications for a maintenance vessel. The Kroonborg walk-to-work vessel, operated by Wagenborg Offshore Division, is launched in 2015 and has a 10-year support contract for ONEgas. The impressive Kroonborg vessel is equipped with dynamic positioning, with a motion-compensated Ampelmann walkway and Barge Master crane to facilitate maintenance visits to platforms in the Southern North Sea, and will replace as many as 20 offshore platform cranes.

The 80-meter-long vessel is also equipped with inboard chemical tanks for platform-supply or well-treatment purposes and a large deck space. Its 40-strong maintenance crew will sail between platforms in the Southern North Sea. Being the first vessel powered by GTL (a synthetic diesel fuel manufactured from natural gas), its emissions will be lower than those of traditional ships.

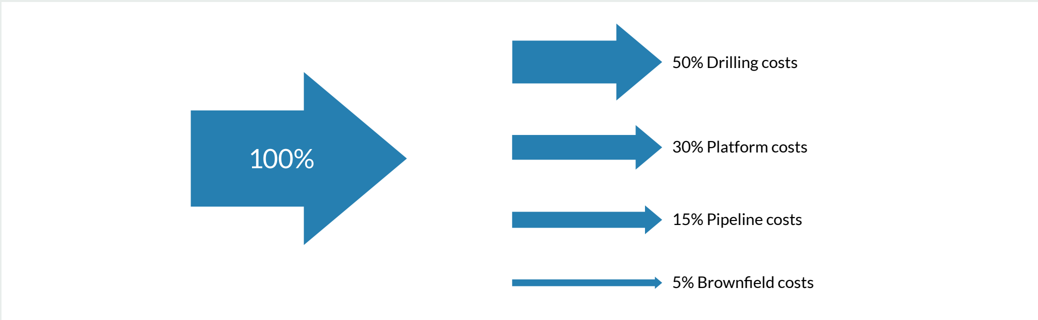
Kroonborg walk-to-work maintenance vessel (courtesy of NAM B.V.)

The E&P industry should also look for synergies with other industries, such as the offshore wind industry. Prompted by the rapid development of wind farms in deeper water, Damen shipyards has developed a maintenance and service vessel to support larger wind farms further from shore. This walk-to-work vessel can also, however, be employed to service the E&P industry's normally unmanned satellite platforms. The dynamically positioned 90-meter-long vessel will be built on speculation and will include a motion-compensated gangway and crane.

In June 2015, EBN will organise a workshop for Dutch E&P operators and offshore suppliers to explore further opportunities for low-cost developments (new platforms). Another important topic during the workshop will be the possibility of reducing operating costs (including maintenance) of existing installations by relocating satellite functionalities such as platform access, cranes and accommodation to support vessels. Other applications of motion-compensated installations that can simplify maintenance operations will also be investigated during a series of interactive sessions.

In addition to platform costs, which account for about 30% of development CAPEX, drilling costs, which account for about 50%, also offer scope for cost reductions.

Subdivision of capital investments



EBN 2015

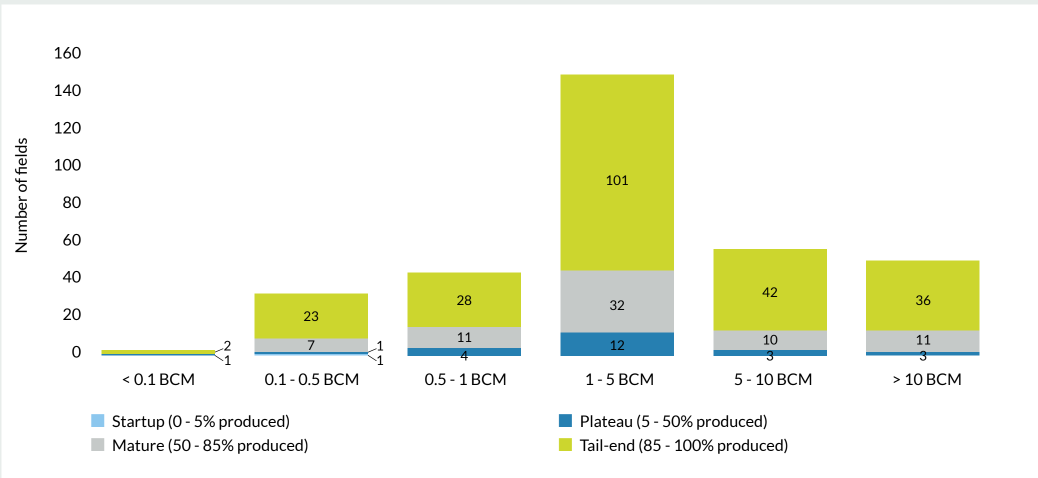
2.7 Mature fields in the Netherlands

Almost 90% of the 282 currently producing gas fields in the Netherlands are either mature, with cumulative gas production (Gp) in the range of 50-85% of expected ultimate recovery (UR), or in the tail-end phase (Gp > 85% UR). Extending the life of these fields will require major efforts and has the full attention of EBN and the operators.

Various enhanced-recovery techniques are being applied to these ageing assets, the most common of which are compression, infill drilling and other end-of-field-life (EOFL) measures to combat liquid loading, such as velocity strings and foam-assisted lift.

Infill drilling is commonly attractive in fields where the static gas initially in place (GIIP) is larger than the observed dynamic GIIP, mostly as a result of

Fields grouped by field size (GIIP) and maturity



EBN 2015

reservoir compartmentalisation. For fields in which this discrepancy exceeds 1 BCM, the sum of these discrepancies for all fields combined exceeds 100 BCM. Reserves maturation resulting from infill drilling in these reservoirs is expected to add some 2 – 5 BCM/year (risked) between 2015 and 2030.

Velocity strings and foam-assisted lift are applied in wells suffering from liquid loading. This occurs in mature gas wells in which the gas-flow rate is insufficient to transport the liquids that enter the wellbore up to the surface. Consequently, liquids will accumulate in the wellbore and can eventually kill the well. Gas-well deliquification is estimated to increase a well's ultimate recovery from roughly 85% to 95% before abandonment. Several gas-well deliquification technologies are available, the most common being the installation of velocity strings and foam-assisted lift.

The velocity-string technique involves installing a small-size tubing to replace the original larger-size tubing, thus reducing the cross-sectional flow area of the tubing which increases the gas-flow velocity. Once the gas-flow velocity exceeds the critical (loading) rate, liquid is transported upwards instead of accumulating in the wellbore. A decrease in diameter also changes the flow rate at which gravity starts to dominate the frictional forces. Consequently, the well can be produced down to a lower gas rate until the critical velocity limit is once again reached, thus resulting in a higher ultimate recovery.

Reserves maturation resulting from EOFL measures is expected to add approximately 0.2 - 0.5 BCM/year between 2015 and 2030.

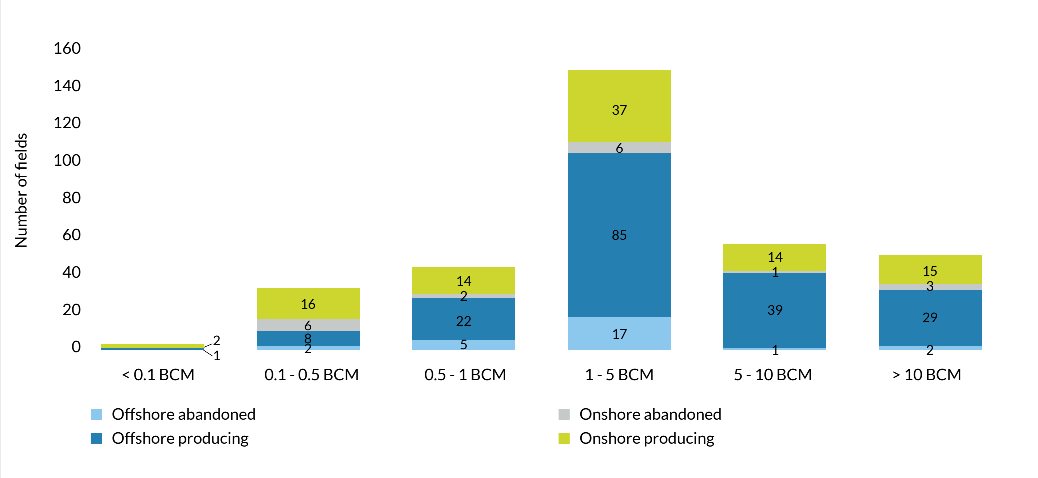
Photo: Velocity string

2.8 Recovery factors

EBN's small-fields portfolio comprises 282 producing fields and 45 abandoned fields. These fields exhibit a wide variety of recovery factors, i.e. the fraction of the gas initially in place that will ultimately be recovered. Both parameters, the gas in place (GIIP) and ultimate recovery (UR), are subject to varying degrees of uncertainty. The uncertainties are typically higher in the early stages of production and progressively reduce in the later stages.

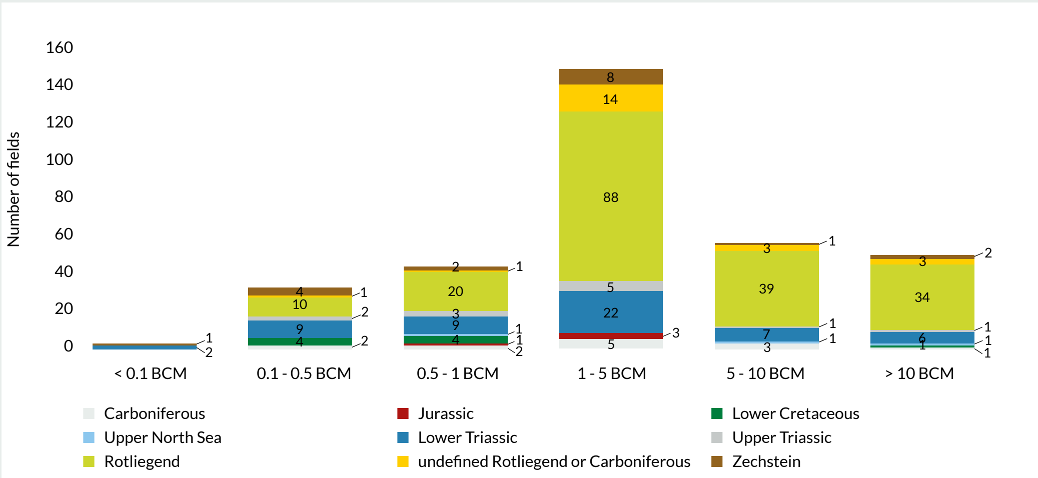
The following presents a statistical summary for producing and abandoned fields in which EBN participates. The fields are grouped into six different categories based to the field size (i.e., GIIP value) and are shown according to their location (onshore/offshore), the producing formations and the field's maturity. It is noted that fields which produce from different formations are treated as one field. These statistics are part of an ongoing study into observed recovery factors and should be considered preliminary. However, with many fields approaching their end of field life, statistics are becoming increasingly representative and reliable.

Fields by field size (GIIP), onshore and offshore distribution



EBN 2015

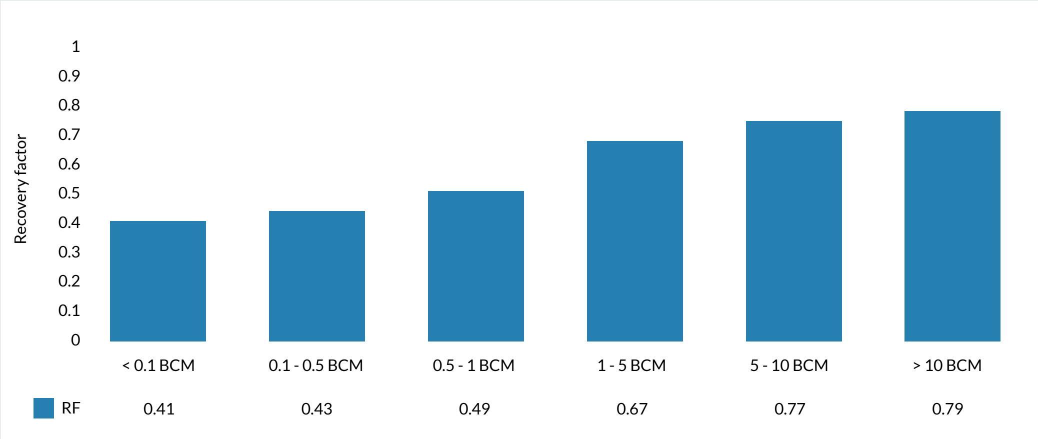
Fields by field size (GIIP) and producing reservoir



EBN 2015

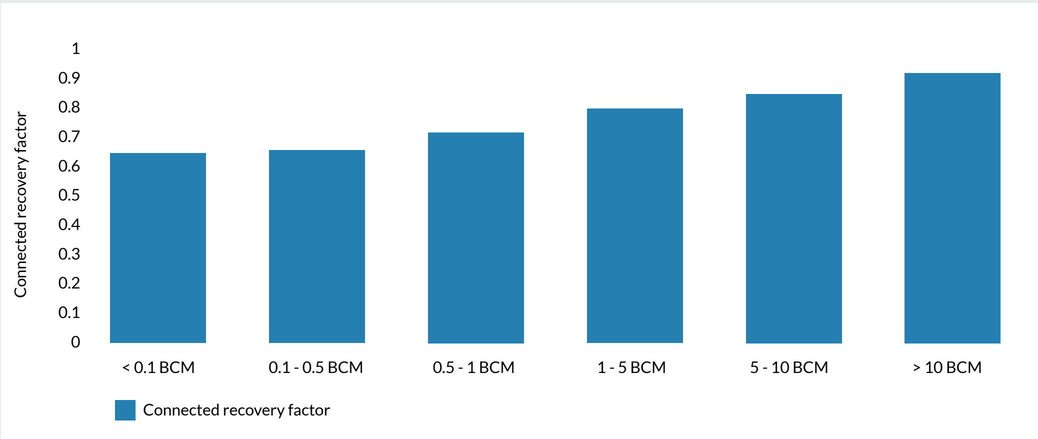
Most of the fields in the portfolio are in the 1 to 5 BCM GIIP category. These fields produce mainly from Permian Rotliegend sandstones and are at the tail-end of production.

Recovery factor for all fields



EBN 2015

Connected recovery factor for all fields



EBN 2015

The following parameters are important for recovery factor (RF) calculations:

- Gas initially in place (GIIP); this refers to the raw gas in place and is obtained from estimates of the gross rock volume, net-to-gross ratio, porosity, gas saturation and the gas expansion factor;
- Connected gas in place (CGIIP); this is also called material-balance GIIP or dynamic GIIP and refers to the portion of the GIIP that is connected to existing wells.
- Ultimate recovery (UR); the estimation of what the field will produce by the predicted end of field life
- Recovery factor (RF); the UR divided by GIIP
- Connected recovery factor (CRF); the UR divided by CGIIP.

In general, the higher the GIIP, the higher the recovery factor. On average, the RF of fields smaller than 1 BCM is 50%, increasing to 80% for fields larger than 10 BCM. If the UR resulting from future projects is included, the recovery factor for all GIIP classes will increase slightly (not shown). However, smaller fields still consistently achieve lower RFs than large fields. The strong correlation between

RF and field size was not previously recognised and is the subject of an ongoing study seeking a better explanation of the observed behaviour.

If the average connected recovery factor (CRF) is plotted, a similar trend is observed. The CRF gives an indication of the technical ability to recover the known volumes. Volumes which cannot be recovered by means of conventional production methods are usually produced after the application of enhanced-recovery techniques, as described above. However, economic feasibility affects the application of these techniques, i.e. the additional recoverable volumes have to be large enough to justify the higher cost. Smaller fields (smaller connected volume) may prove technically more challenging to produce, while the additional recoverable volumes may also not justify the extra investments.

If end-of-field-life techniques are not applied, the observed CRF in fact indicates average conventionally recoverable volumes, which may be the economic limit for smaller fields. This is subject of further study.

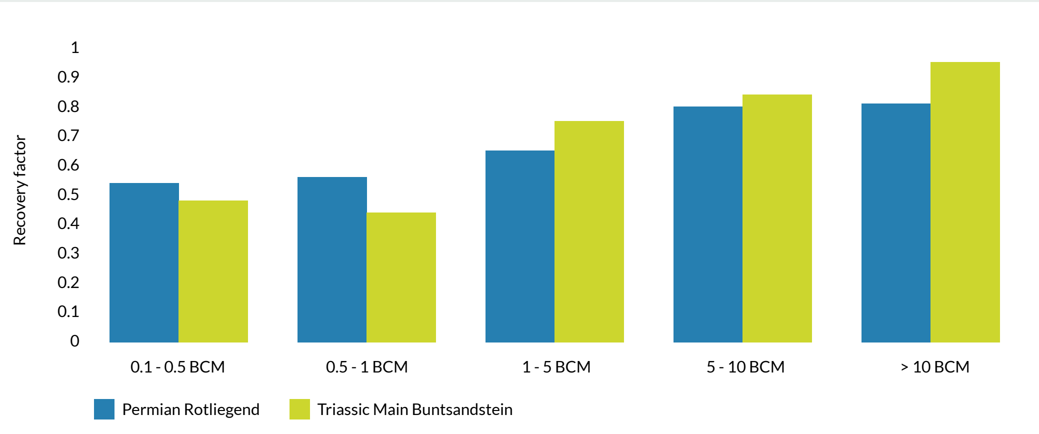
2.8.1 Impact of various parameters on the recovery factor

Producing reservoir - The recovery factor also varies depending on the producing formation. Most of the Dutch fields produce from the Permian Rotliegend (RO) or the Triassic Main Buntsandstein (RB), which are shown here for comparison.

The histogram for these two reservoir units clearly shows that in the case of larger GIIPs, the Bunter fields tend to have a higher recovery factor than comparable Rotliegend fields, whereas the Permian Rotliegend fields show a higher recovery factor for smaller GIIPs. The geological factors behind this phenomenon are currently being studied.

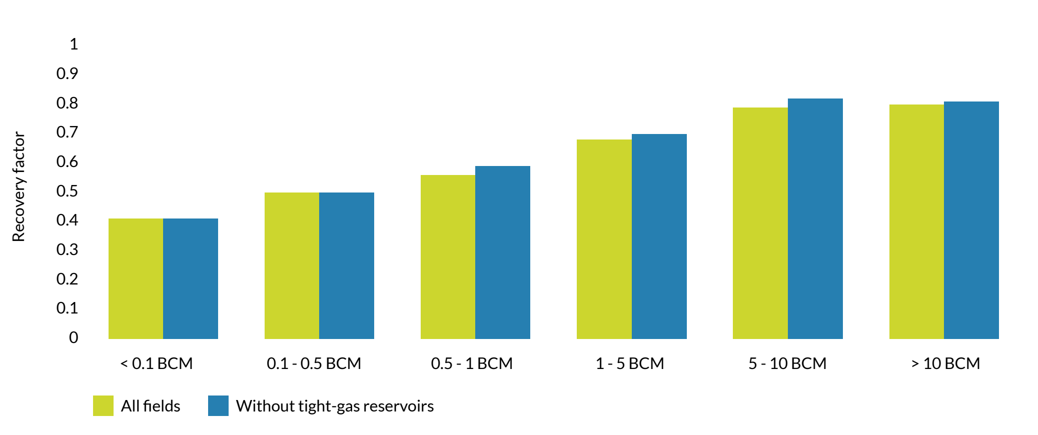
Tight gas reservoirs - Approximately 32 gas fields in the current portfolio are classified as tight because of their low permeabilities and low initial productivities. If the statistics of these tight gas fields are removed from the overall histogram, the overall recovery factor is only slightly higher, thus proving that tight reservoirs can be developed and produced with recovery efficiencies similar to those of non-tight fields.

Average recovery factor of Rotliegend and Triassic reservoirs



EBN 2015

Impact of tight fields on the recovery factor

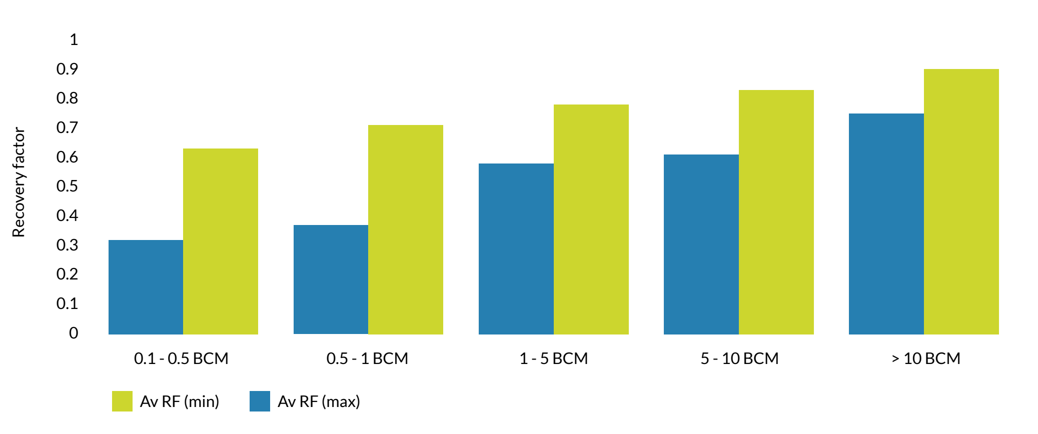


EBN 2015

2.8.2 Operator performance

We have observed that the average recovery factors in the various GIIP categories also vary between operators. We have illustrated this in a histogram showing only those operators with more than three fields per GIIP category. In practice, this means that some operators achieve higher recovery factors than others even though they are producing from fields in the same GIIP category.

Maximum and minimum average RF per GIIP class between the different operators



EBN 2015

2.9 Salt precipitation

Production wells in gas reservoirs occasionally experience a significant and accelerating performance decline as recovery progresses. This is commonly due to salt precipitation from produced water. All formation waters contain at least some dissolved salts. If much formation water is co-produced from a gas reservoir, the dissolved salt may precipitate in the pores of the reservoir rock near the wellbore around the perforated pay zone, particularly in mature fields. This phenomenon is referred to as halite scale. Halite scale will obviously impair well performance as it fills the pores; this prevents flow, and may even culminate in total plugging of the pore throats, thus reducing productivity, and can ultimately even result in abandonment of wells.

In order to mitigate halite scale formation in production wells, fresh-water treatments are performed at regular intervals during production operations. This dissolves the precipitated salt and transports it up to the surface in the produced water. The objective of these interventions is to maintain economic productivity or eventually restore original permeability and so restore production rates. Both the halite scale itself and the water-wash treatments result in substantial production losses.

Predicting the severity and location of salt precipitation and the subsequent effect on permeability, flow behaviour and capillary pressure characteristics remains challenging. A method is therefore being developed to model the onset and speed of production decline, as well as mitigation strategies.

In order to understand, predict and develop techniques to mitigate halite scale, EBN, Total, Wintershall, GDF Suez and ONE have jointly initiated the Salt Precipitation Joint Industry Project (JIP) as part of the Top Consortium for Knowledge and Innovation's (TKI) Upstream Gas line. The objective of this JIP salt precipitation project is to model the physical phenomena that occur at micro-pore scale in order to understand which parameters affect salt precipitation and then scale up the results to wellbore and reservoir scale. The macro model will be validated by field data and can then be used to optimise production strategies. So far, a numerical model has been built, which will soon be calibrated with data from TNO's experiments on outcrop core samples. The operators have provided field data to TNO to complement TNO's experimental work.

British, Dutch and German Southern North Sea operators are currently sharing their experience with halite precipitation in gas wells. EBN is the coordinator of an annual salt precipitation forum during which the participating operators and consultants give presentations about their experience with mitigating measures and halite precipitation modelling.

Test set-up for salt precipitation JIP at TNO Rijswijk

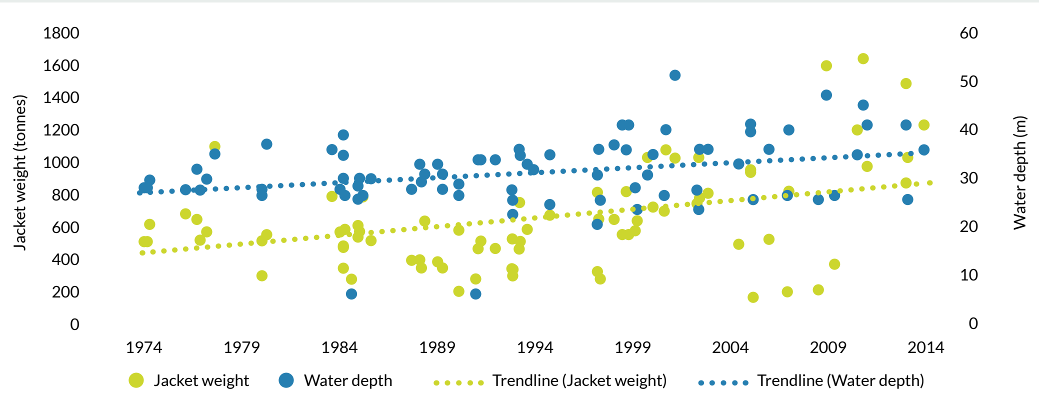
3 Cost-effective development, operations and abandonment

3.1 Cost-effective development, how to reduce CAPEX?

Since the first satellite platform was installed on the Dutch continental shelf in 1974, platform design has evolved from large topsides on a 4- or 6-legged jacket with permanent accommodation quarters, a helideck, local power generation and a crane large enough for offloading supply boats to monopod installations that are normally unmanned. As developments moved into deeper water, heavier jackets were required. Although field sizes gradually decreased, as did the number of well slots, jacket weight gradually increased.

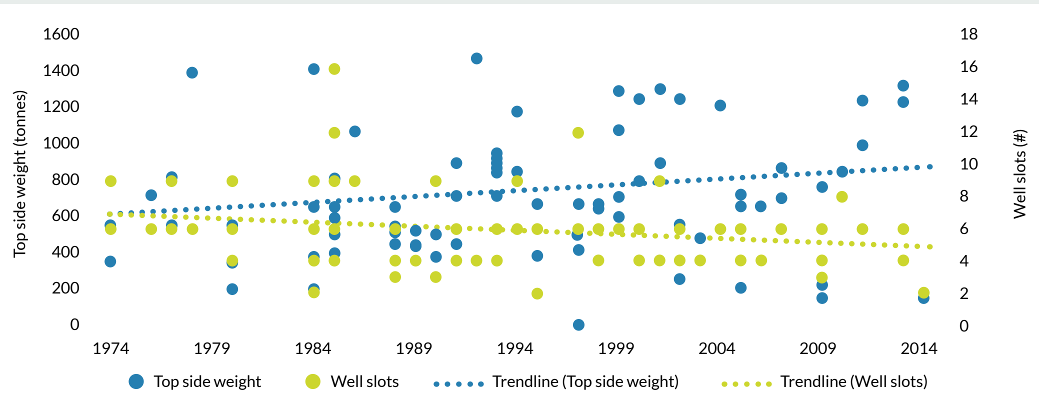
As advances in telecommunications technology made remote control possible, many installations were transformed into normally unmanned installations.

Satellites: Increase of jacket weight & water depth versus time



EBN 2015

Satellites: Top side weight & well slots versus time



EBN 2015

The next-generation satellites could thus be equipped with only temporary living quarters, given that maintenance staff no longer needs to be permanently based on the installations. This reduced functionality is reflected in lower investment costs and has allowed economic development of many small and/or previously stranded fields.

Although the traditional jacket substructure is still common, the first monotower/tripod was installed on the Dutch continental shelf in 1986. In 2005 and 2009, NAM installed 3 monotower satellites equipped with renewable energy systems (wind turbines and solar panels) and without accommodation quarters, crane or a helideck: in other words, marine access only.

In 2014, Wintershall installed the L6-B monotower/tripod which is powered through an umbilical from a host platform. This further reduces topside weight as power generation is no longer needed on the satellite. This minimum-facilities platform has a topside weight of only 170 tonnes and is supported by a tripod substructure with suction piles, which simplifies possible re-use once the reservoir is depleted. The platform was installed as a complete structure, within a record time, in a single-lift operation after the entire 1200 tonne structure had been transported 'in the hooks' of a relative cost effective sheerleg vessel. This platform is a good example of operators and the Dutch supply industry working together to reduce costs through a collaborative process that has resulted in an innovative design and cost-effective installation method. Another example of effective cost reduction is the incorporation of a duplex steel subsea cooling loop so as to reduce CO_2 corrosion at high temperatures. As a result, a lower-cost carbon steel pipeline could be used in combination with the injection of a corrosion inhibitor. The same approach was successfully applied by Wintershall in 2011 in its K18-Golf subsea development.

Minimising on-platform facilities by allowing only marine access, instead of both helicopter and marine access, does not necessarily mean the installation's uptime is reduced. Looking at a well-known oil-patch saying, it could be argued that 'If it ain't there, it won't break and don't need fixing'.

L6-B platform in the hooks (picture courtesy of Wintershall Noordzee B.V./Scaldis)

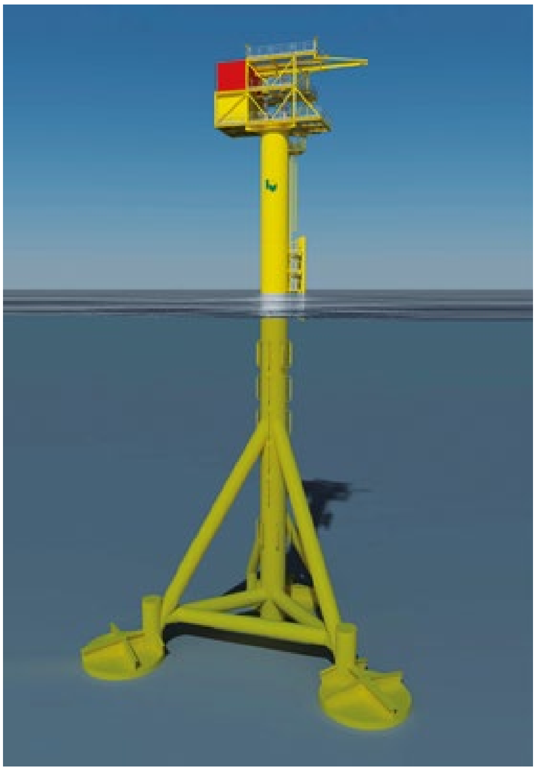
North Sea conditions, with significant wave heights, can seriously hinder platform access by boat. However, the current generation of vessels, equipped with motion-compensated access systems and cranes, allows platform functionality to be reduced further, with only limited loss of uptime. This is especially true for functionality such as large cranes that are used infrequently, but do require auxiliary systems, maintenance and certification.

3.2 Shallow gas – low-cost development

The success of cost-effective minimum-facilities satellite platforms can be of value for the development of shallow gas leads. Shallow gas research focuses on identifying shallow prospects (bright spots) at depths down to some 1000 metres additional to the eight shallow fields.

Many of these prospects have relatively small volumes; economic development consequently is a challenge (section 4.5). Cost-effective, reduced-functionality platform designs such as monotower/tripods are suitable for shallow gas, but present an engineering challenge as this design has only been proven in water depths of less than 40 metres in the Netherlands.

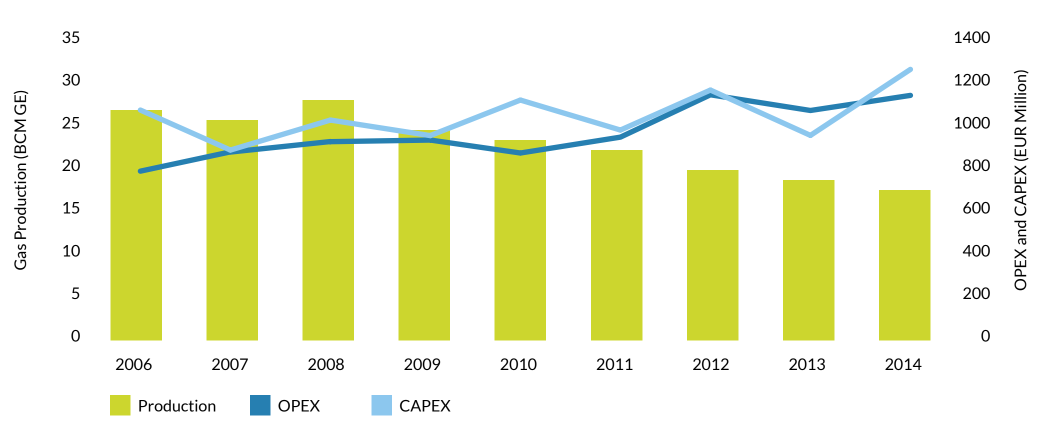
Most Dutch shallow gas fields are located in water depths of down to 50 metres; hence the design should be able to withstand the challenging North Sea conditions. Supported by an experienced engineering company, experts established that a monotower design would be technically feasible for 45-metre water depths, provided the design and manufacturing process also considers fatigue issues caused by the tough North Sea metocean conditions. Initial feasibility studies show that cost savings of up to 50% can be achieved compared to more conventional satellite designs, thus making it possible for more prospects to be developed economically. The fact that gas sales contracts are nowadays all seller-nominated also helps to make developments more economic, while installations can be operated under more constant conditions.



Courtesy of IV

Having explored the opportunities for cost-efficient stand-alone developments, EBN is currently planning to focus on the economics of cluster development of multiple shallow gas leads combined with deeper targets and on more cost-effective exploration of the shallow play by a single drilling campaign covering several prospects rather than by drilling shallow prospects on a stand-alone basis. Shallow gas opportunities are discussed in chapter 4 of this report.

Gas production versus costs offshore small fields in the Netherlands



EBN 2015

3.3 Focussing on OPEX reduction

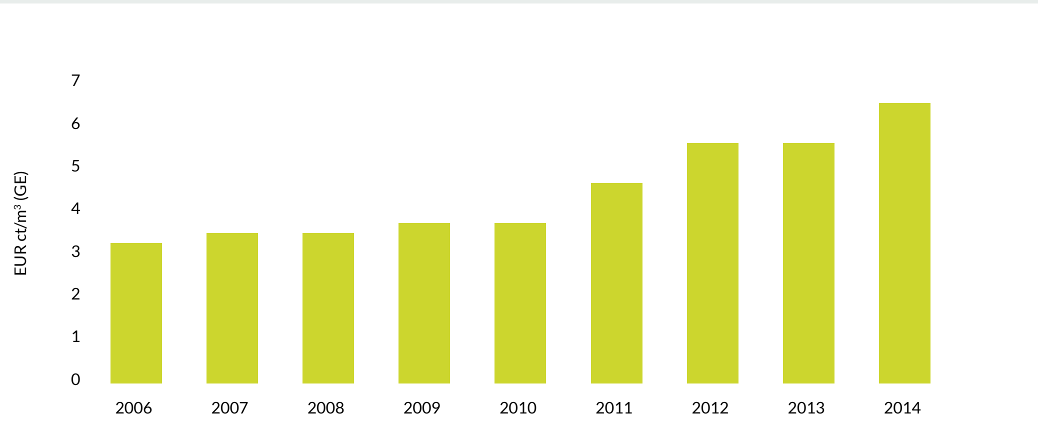
As mentioned in chapter 1, production from small gas fields in the Netherlands is declining steadily.

EBN is aiming to slow down this trend, given the limited window of opportunity that remains as the ageing offshore infrastructure – platforms, pipelines and wells – is rapidly approaching decommissioning. However, production costs are increasing, while the declining production from older gas fields means that there are fewer BCMs to carry these costs.

Moreover, older infrastructure inherently requires more maintenance to continue safe operations.

So far, average OPEX/m^3 is well below the gas sales price, but there are large differences between the various assets. In some assets, OPEX/m^3 is fast approaching or has surpassed the gas sale price. It is therefore imperative to find new ways to slow down this trend.

OPEX per m^3 offshore small fields in the Netherlands



EBN 2015

Next to reducing the OPEX, increasing the production volume is even more important to slow down this trend. Of course, the latter cannot be accomplished easily and will require additional investments. Nevertheless, EBN believes that economically beneficial investments can be increased, resulting in a slowdown of the downward production trend. The stable level of investments confirms the remaining potential of attractive opportunities in the mature Dutch basin.

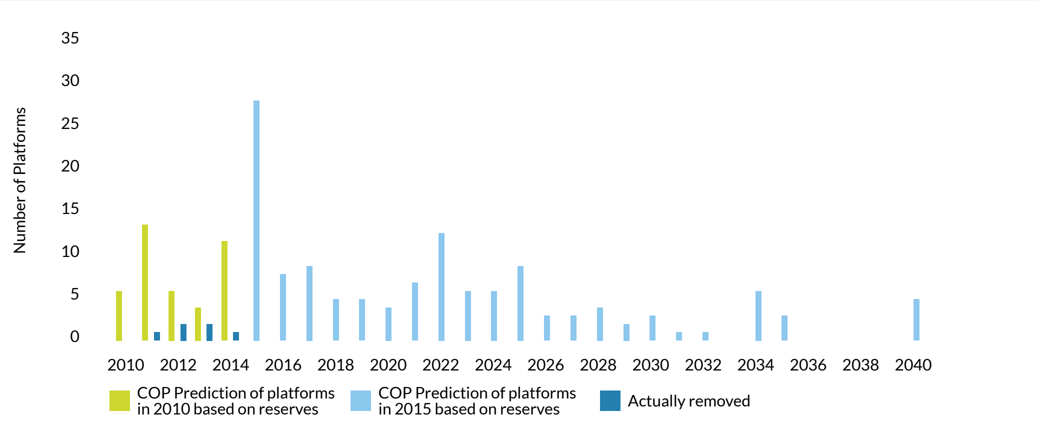
3.4 What is the window of opportunity for offshore infrastructure and what are the resources at risk?

The current resource basis is rapidly maturing, and new discoveries and developments are decreasing in size. Maximising the value of gas resources will be key, while reducing operational and capital expenses will help prolong infrastructure life. It is important to delay decommissioning of infrastructure so as to extend the window of opportunity for (near-field) exploration and make it possible to bring existing and new discoveries on stream by implementing both CAPEX and OPEX reduction. In the past few years, cessation of production (COP) of a number of assets has successfully been deferred.

In 2010, it was estimated, on the basis of reserves, that approximately 40 platforms would be under threat of cessation of production within the next five years. As of today, only a few platforms have actually been decommissioned as maturing contingent volumes and successful new developments have contributed to extending the economic lives of these platforms.

The 2015 estimate of COP based on reserves only shows a significant cessation-of-production peak in the next few years. Many platforms where production was successfully extended will again be at risk in the next few years. With the current gas prices and high operational expenditure, the industry has to face the fact that many platforms will cease production in the near future.

Window of opportunity is extended by maturing resources, but is inevitably closing



EBN 2015

To illustrate the dynamics in the year of the COP, we have estimated the impact of maturing contingent resources and separately the impact of maturing prospective resources regarding the respective infrastructure effected. Obviously maturing of these resource classes will in practice take place in parallel.

Maturing contingent resources will only slightly postpone the moment of cessation of production in the next five years. After 2030, however, this effect on the asset portfolio will become minimal. If contingent resources are matured into producible reserves, the lifespan of 35% of the platforms can be extended up to two years, although extension will be for no longer than one year in the case of the remaining 65%.

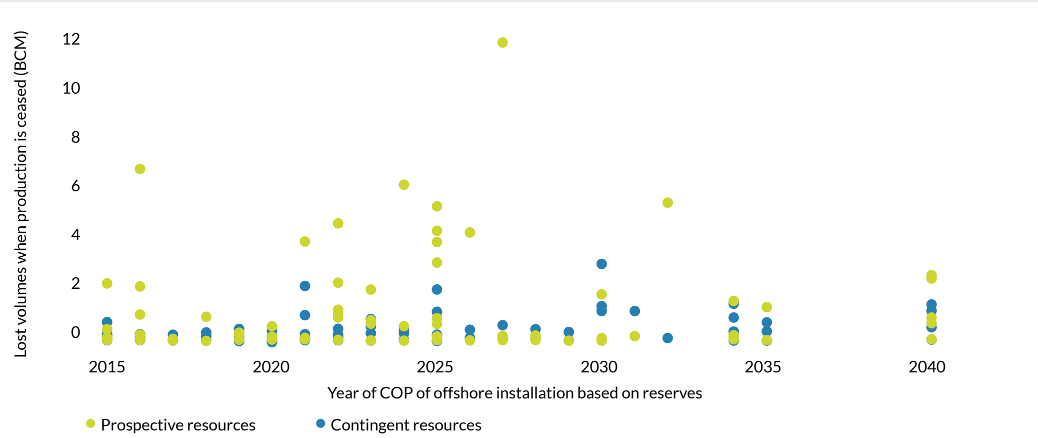
Satellite platforms and subsea installations are the main facilities that will cease production in the near future. Decommissioning can, of course, also be delayed to some extent by maturing prospective resources to a platform's producible reserves.

Although the absolute number of assets affected by an estimated extension platform life is limited, the extra production years and resource volumes are nevertheless substantial. The volumes of contingent and prospective resources have been plotted against the cessation-of-production year for specific platforms. As many platforms that are expected to cease production in the next few years have considerable attached volumes, the contingent and prospective resources urgently need to be developed in time.

3.5 Decommissioning planning and cost, opportunities for collaboration?

As more and more assets are becoming increasingly mature, decommissioning of infrastructure will become more common and will therefore create a new sort of business. Indeed, it is already a 'hot business' for some contractors, and planning of decommissioning should be on the operators' radar.

Resource potential when offshore window of opportunity is extended



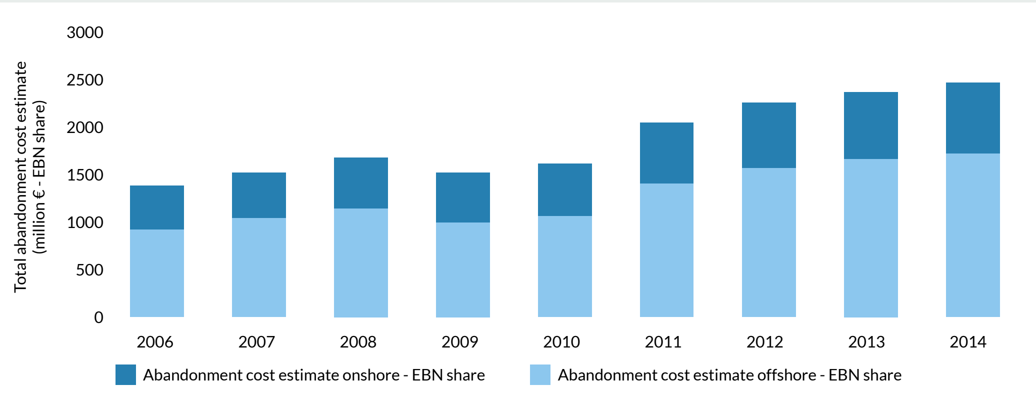
EBN 2015

Removal of platform K10-B (courtesy of Wintershall Noordzee B.V.)

Although decommissioning activities have started in the Dutch North Sea, this is definitively not a mature market and experience currently remains limited. To date, only a few contractors and operators have experience of decommissioning. Wintershall has actively decommissioned a few platforms in the last few years. The K10-B production platform, Q5-A subsea installation and two small satellite platforms Q8-A and Q8-B have been successfully removed from the Dutch sector of the North Sea. Encouraging contractors to plan for flexible facility abandonment within a two-year window could potentially reduce costs for the operator.

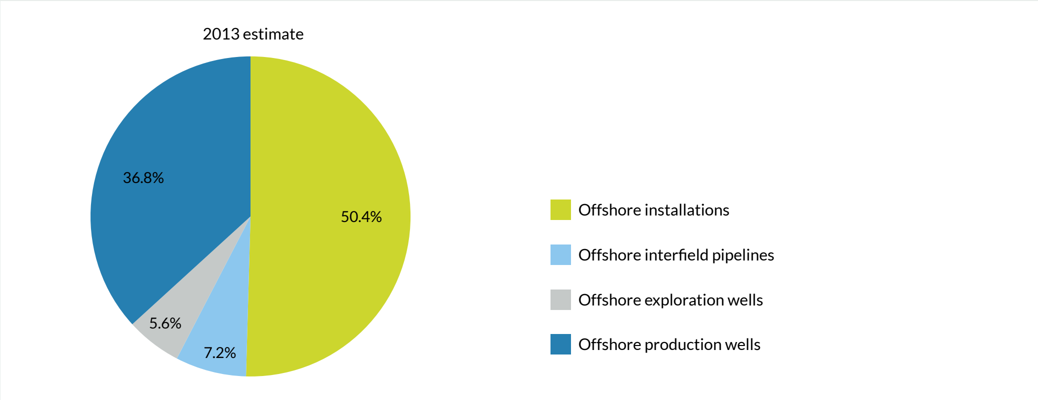
Operators have estimated that total abandonment costs will amount to approximately €4.3 billion. This operator estimate includes plugging and abandoning (P&A) the offshore wells and pipelines, as well as decommissioning the platform structures in which EBN participates in the Dutch Southern North Sea. Abandonment expenditure over the past ten years amounted to only 5% of these total estimated abandonment costs. As for the onshore assets in which EBN participates, operators are expecting to have to allocate approximately €1.9 billion to abandonment. However, these are provisional estimates only and these figures tend to increase each year.

Abandonment cost estimate on- & offshore for existing infrastructure



EBN 2015

Estimated abandonment costs offshore installations



EBN 2015

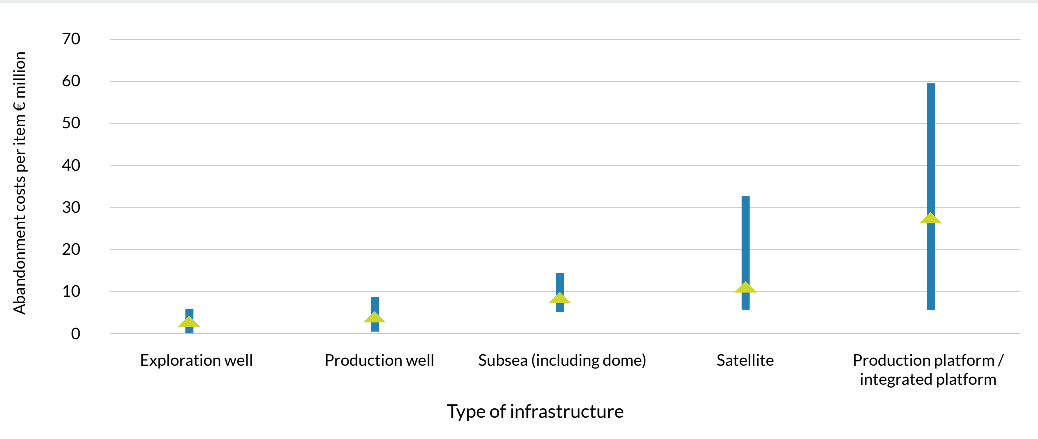
Operator cost estimates per specific abandonment activities also vary greatly, maybe because few assets have so far been completely abandoned, and therefore only limited numbers of reference cases are available.

Abandonment costs per tonne have been plotted for satellite and production platforms. The heavier a platform's topside and jacket, the lower the cost per tonne (€/tonne). Dutch offshore platforms are relatively small, with half of them weighing less than 1500 tonnes and 75% less than 2500 tonnes.

It is very important to start strategic abandonment planning now, especially for those assets that cease production within three to five years. In most cases, lack of accurate data and drawings will complicate the planning of decommissioning projects, especially if a production licence changed ownership during the life of the infrastructure. Corrosion of shut-in platforms may also present a risk.

Well plug and abandonment (P&A) projects are estimated to account for a further 40% of the total abandonment costs. In many cases, well abandon-

Estimated abandonment costs per infrastructure type



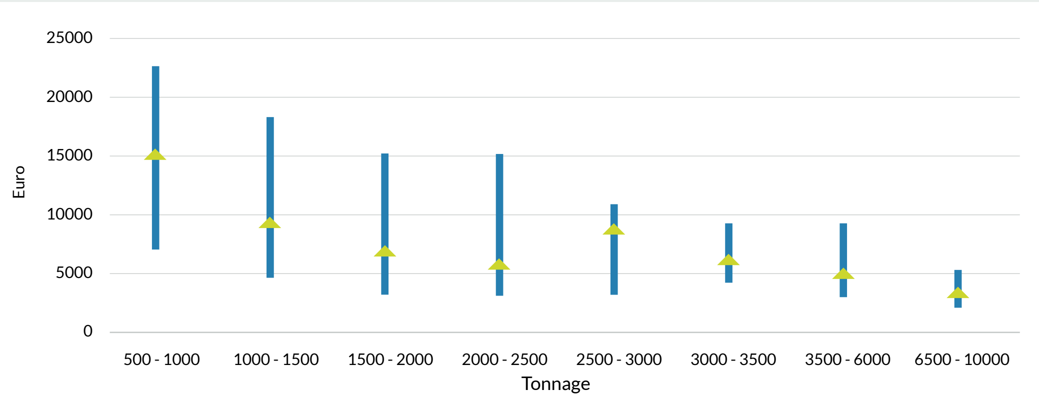
EBN 2015

ment has proved to be more complicated than initially envisaged, either because accurate well data are no longer available or because well integrity and status are poorly understood, but more importantly because 'pressure behind casing' regularly complicates well P&A procedures. The industry has faced cost overruns in the few decommissioning projects that have actually been completed. One could argue if the well P&A has been thoroughly estimated and would not contribute to a bigger portion of the total decommissioning cost estimate.

Cost savings could be achieved in abandonment campaigns if operators collaborate and share their experience during the planning, preparation and definition phases of these campaigns. Preparing the platform for removal and at the same time performing the well P&A may also help to reduce costs. This requires effective planning and communications between an operator's departments. In view of the high costs, however, there should be sufficient incentive for operators and the service industry to seek to develop and optimise efficient abandonment techniques and approaches. EBN is planning to inventorize scenarios for abandonment, like campaigns by, for instance, removing critical parts of comparable platform structures in batch mode.

As platforms have over the years become a haven for marine biodiversity, the impact of removing entire structures to shore should also be investigated. It might be better to leave subsea jackets in place and to remove the topsides only. This may be attractive from a perspective of sustainability and related biodiversity around offshore platforms.

Abandonment costs per tonne for satellites



EBN 2015

4 Exploration: remaining potential of the Dutch continental shelf

4.1 Exploration studies

EBN carries out exploration studies in underexplored areas and on selected subjects to increase the exploration activity level. These exploration projects can be divided into two categories. The first category are projects which are executed at EBN.

EBN teams are currently working on the following in-house studies:

- Prospectivity analysis of the DEFAB area (ongoing)
- Prospectivity analysis of the G&M area (started).

These areas are selected based on their percentages of unlicensed acreage, the presence of underexplored areas or plays and the presence of 'threatened' infrastructure. Other in-house studies have a mixed objective. The recently initiated Chalk Formation evaluation study, for instance, will support asset management in optimizing decisions in both exploration and development.

The second category consists of projects which are executed in Joint industry projects and by MSc students in cooperation with various universities and TNO. This enables EBN to explore a wide range of exploration related subjects and to improve the transition between academia and industry.

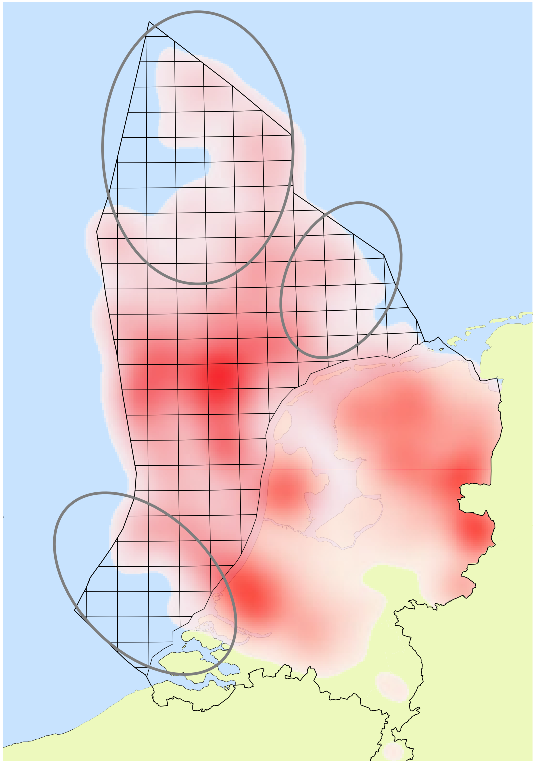
The following external studies were funded by EBN in 2014 and 2015:

Joint industry projects

- New Petroleum systems in Dutch Northern Offshore (2014, 2015 TNO)
- FOCUS on Upper Jurassic Sandstones (2014, 2015 TNO)
- Geochemical composition and origin of natural gas (2015, TNO)
- Integrated pressure information system onshore & offshore (2014, TNO)
- Hydrocarbon potential of the Lias (2015, TNO)
- Integrated multi-client Zechstein study, North Sea (2015-2016, Durham University)

MSc student projects

- Volpriehausen prospectivity review in the northern F blocks;
- Review of the Lower Triassic play in the Roer Valley Graben
- Identifying overlooked exploration opportunities from by-passed pay analyses.
- How do 'salt-induced stress anomalies (SISA)' affect gas production
- Indications for intra-Chalk seals in the F blocks of the Dutch offshore;
- Seismic characterisation of Zechstein carbonates in the Dutch Northern Offshore;
- The shale-oil potential of the Posidonia Formation in the Netherlands;
- Regional context of a potential Dinantian play;
- Special core analysis of the Posidonia shale;
- Seismic (AVO) response of unconsolidated reservoirs as function of gas saturation;
- Stochastic time-depth conversion;
- Gas column cut-off study;
- Salt reconstruction in the Dutch Northern Offshore;
- Review of exploration investment criteria.



Approximate focus areas of exploration studies
Colour indicates exploration density

4.2 Exploration opportunities

A new chance for the Zechstein-2 carbonate play

The Zechstein-2 carbonates form a proven play in the Southern Permian Basin, with oil production in Poland, Germany and onshore the Netherlands. EBN initiated and performed a study in 2014 to investigate the possible presence of Zechstein-2 carbonates along the rim of the Elbow Spit High. Wells and seismic indicate the presence of a non-basinal facies in this area. Seven leads have been identified (Jaarsma et al., 2014) Hydrocarbon charge probably comes from Scremerston coals and/or Zechstein source rocks. To progress this play further EBN is supporting the multi-client integrated Zechstein study in the UK.

The Chalk: a proven, yet underexplored play

Of the 71 wells that drilled through the Chalk Formation in the DEFAB area, 35 did not test a Chalk structure as these targeted deeper objectives. Of the remainder, 17 wells did not test the structure in a crestal location, thus leaving up-dip potential untested; 15 wells were dry wells, most likely as a result of a lack of hydrocarbon charge or a top-seal failure, and four wells were (un)commercial discoveries. In the study area, more than 55 structural Chalk (up-dip) closures remain undrilled, with an estimated STOIIP of 10-300 Million bbls per lead. Less obvious, potential combination stratigraphic/structural Chalk traps, such as the Halfdan and Adda fields in the Danish offshore and the UK Fife field close to the North Sea median line, remain untested in the Netherlands.

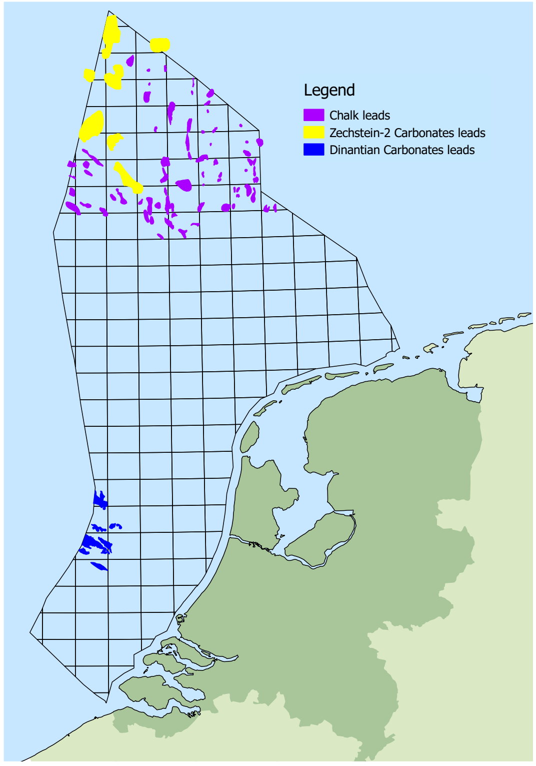
Dinantian carbonates: from tombstone to cave

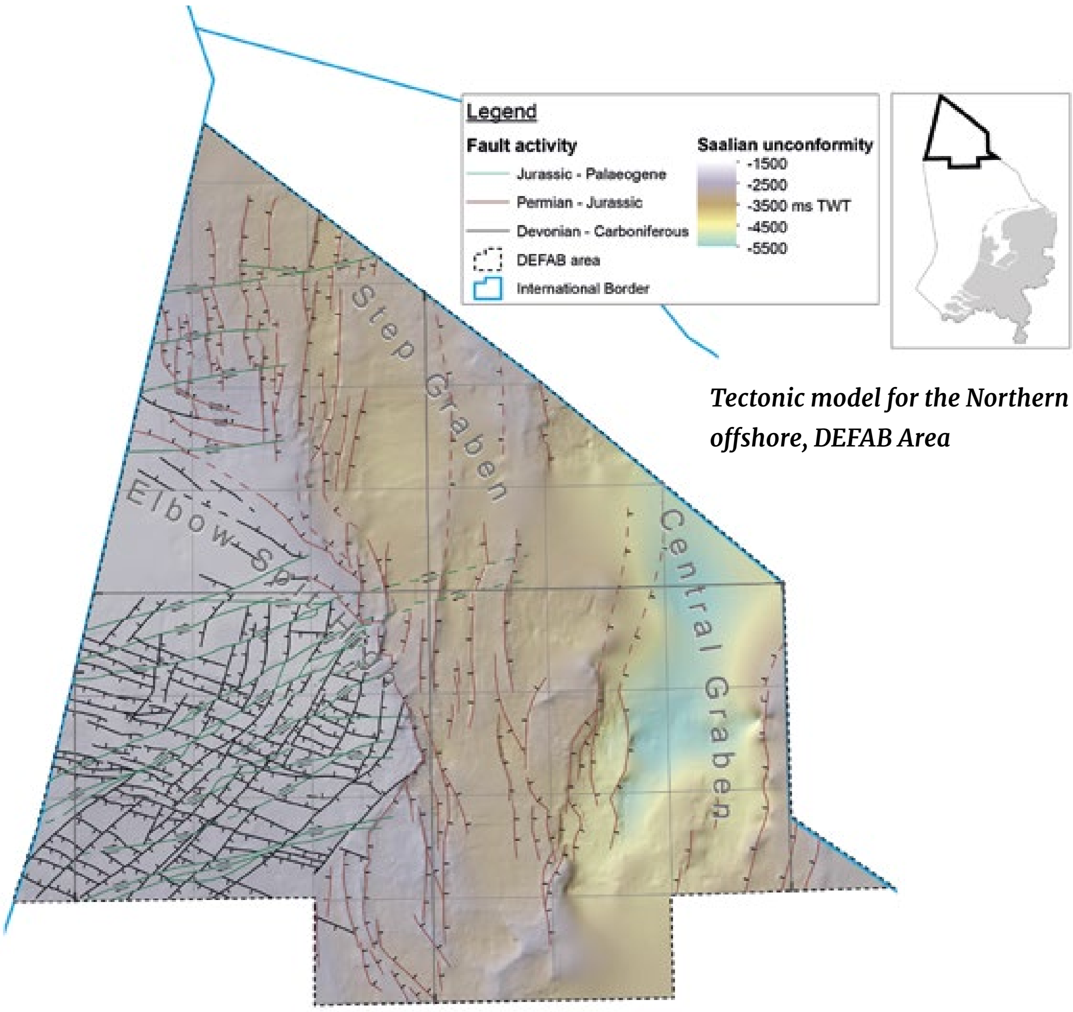
In 2012, the Californië-1 geothermal well near Venlo has shown that extensive karstification in Dinantian limestones is possible, shedding a different light on reservoir quality at this level. A number of leads that straddle the Dutch-UK median line have been identified; these leads are located close to existing infrastructure and may be combined with Namurian secondary targets.

Tectonic model for the Northern Offshore

A tectonic model is being developed for the Northern Offshore as part of the DEFAB study. The tectonic development of the region from the Devonian up to the present was greatly elucidated by the preliminary interpretation of recently acquired high-resolution 3D seismic covering the DEF area.

The results of this review already provide valuable new insights into the presence and distribution of reservoir, source and cap rocks, and into the development of hydrocarbon traps, in particular at Lower Carboniferous and Devonian levels (Ter Borgh et al., EAGE 2015).





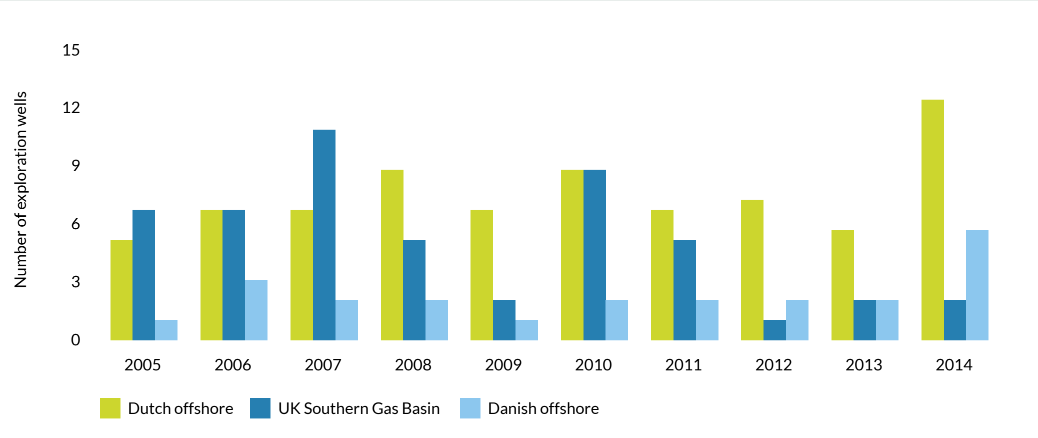
Tectonic model for the Northern offshore, DEFAB Area

4.3 Exploration activity

In 2010, EBN published a comparative analysis of Dutch offshore exploration activities and those in the UK Southern North Sea (SNS) and Denmark. A similar analysis for the 2005-2014 period is presented here. Germany was not included in the study as offshore wells are only sporadically drilled.

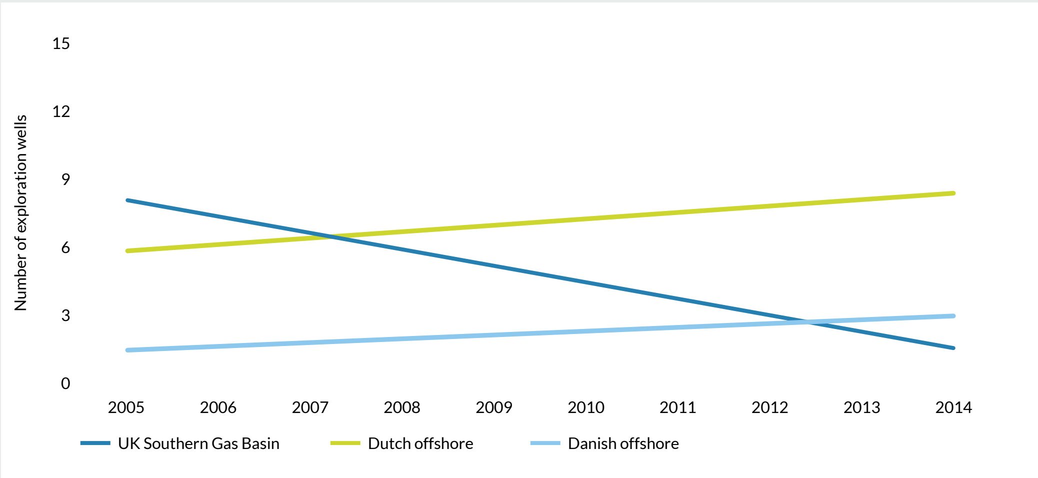
Please note that this comparison includes only exploration wells, appraisal wells were left out. Despite the significant scatter, it is obvious that UK SNS exploration efforts decreased considerably, whereas the number of exploration wells in Denmark and the Netherlands increased.

North Sea area exploration effort



EBN 2015

North Sea area offshore exploration effort



EBN 2015

A probable reason for the observed difference is the UK wells' lack of success: of 48 wells drilled in the UK SNS in this period, only 14 (29%) qualified as 'significant discoveries' (i.e. production tests yielded more than 400,000 m^3/d – DECC definition). Although the Danish and Dutch criteria may be less stringent, 41% of the wells in Denmark were successful (9 out of 22), while 58% of the Dutch offshore exploration wells were successful (41 out of 71) in the 2005-2014 period.

Since a long time EBN advocates a higher level of exploration drilling in view of the disappearing infrastructure. After the infrastructure has gone, much potential value may not be realised as prospects can then no longer be developed economically. It is a positive signal that the 2014 exploration drilling activity can be marked as high as well as it is promising that the forecast for 2015 is of a comparable level. It is however too early to claim a turnaround trend, especially when considering the steep drop in oil price and potential subsequent budget cuts or operations waiting for the rig rate to fall off.

4.4 Forecasting risks and resources in exploration

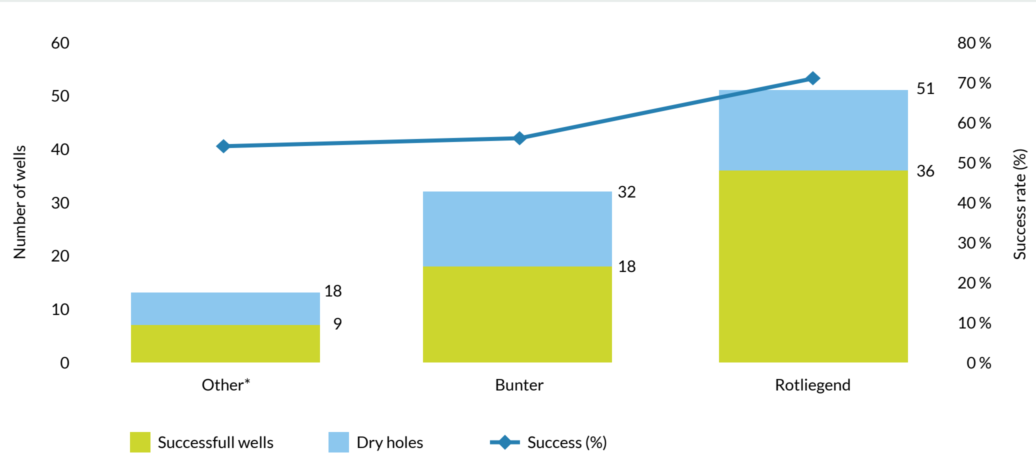
In exploration, Expectation (EXP) is defined as Mean Success Volume (MSV; being the mean recoverable volume of hydrocarbons in the prospect), multiplied by the Probability of Success (POS).

EXP = POS X MSV

To put it simply, if we drill five wells, each with a POS of 20%, and all with the same MSV, we should strike one successful well that finds that MSV. Over a longer period, this should hold true. In an ideal world, the total of the predrill EXP of all drilled prospects should equal the total resources found, i.e. successful wells should compensate for dry holes.

In the following analysis, we have used a conversion factor of 1 MMBO = 0.174 BCM of GE (Groningen equivalent gas quality) for oil resources. In reality, this will obviously depend on the quality of both the oil and the gas. Of the 101 exploration wells (29 onshore and 72 offshore) drilled between 2005 and 2014, 32 were drilled to a primary Bunter target and 51 to a Rotliegend target. The remaining 18 had other primary targets (Chalk, Jurassic, Zechstein or

Success rate exploration wells



EBN 2015

* Other = Carboniferous, Jurassic, Zechstein

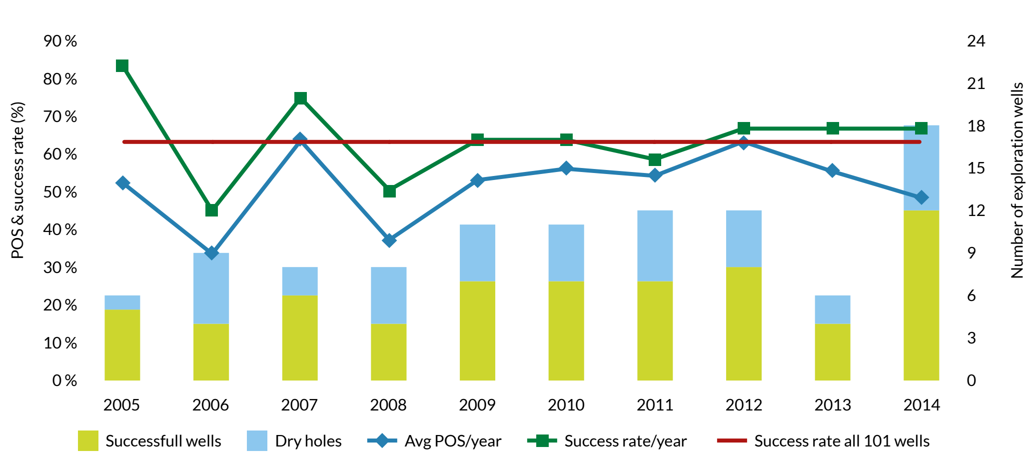
Carboniferous). The success rate per target is shown in the table.

The Rotliegend is the most important and most successful exploration target. This is probably also attributable to the fact that almost 20% of the wells that drilled Rotliegend targets were near-field exploration wells (i.e. drilled from an existing platform).

A review of all 101 exploration wells drilled between 2005-2014 yields a number of interesting conclusions. As an industry we are relatively successful, but we could do better in predicting success. The average POS for all 101 prospects drilled was some 52%, whereas the actual success rate was over 63%. In other words, we underestimated POS by over 11%. This applies to nearly all POS classes. It should be noted, however, that this success rate is a technical success rate (i.e. a puff of gas is sufficient). The commercial success rate of all drilled prospects is still some 55%, assuming some of the more recent discoveries will be developed in the foreseeable future. This 55% compares relatively well with the average POS of 52%, but the latter is always used as the probability of technical success.

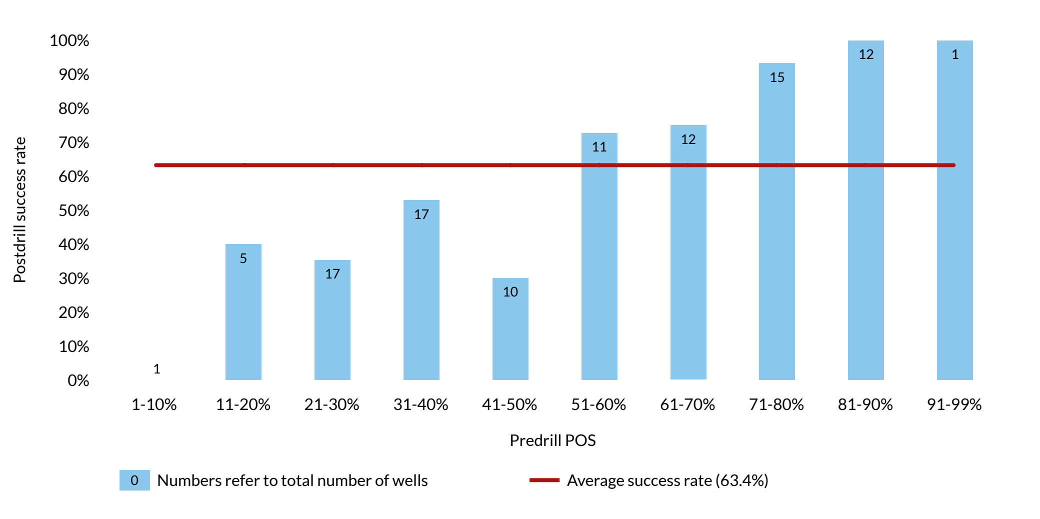
In the graph below the drilled prospects are distributed into POS categories. The success rate for each category (except 41-50%) was approximately 10% higher than predicted. For example, the probability that a prospect with a POS of 60% or more will find hydrocarbons is some 73-95%.

Average POS and success rate



EBN 2015

Postdrill success rate vs predrill POS

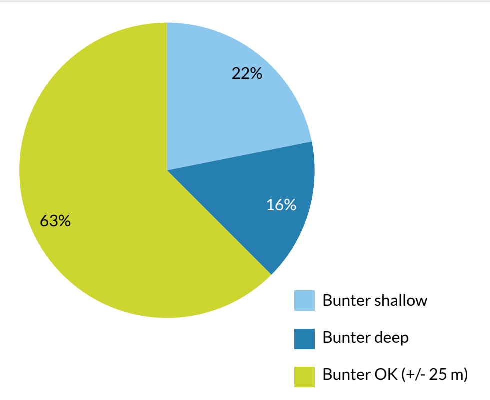


EBN 2015

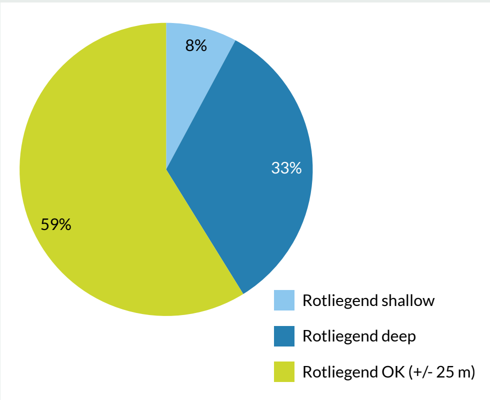
Underestimating the POS will lead to an underestimation of the Expectation volume (EXP = POS X MSV). Given a population of sufficient size (and 101 should qualify), all wells combined (dry and successful) should find the sum of their respective EXPs. Unfortunately, the results are less positive and considerably less is actually found.

As to the possible causes of this discrepancy, errors in depth prediction probably play an important role. Of all wells, some 60% find the reservoir within approximately 25 m of the predrill depth prediction; in other words, 40% do not. This was also pointed out in the Focus 2012 report. For some wells, the errors in depth prediction were even hundreds of metres. A comparison of the results of Bunter wells (32) and Rotliegend wells (51) shows that the depth

Triassic Bunter depth vs depth predictions



Rotliegend depth vs depth predictions



EBN 2015

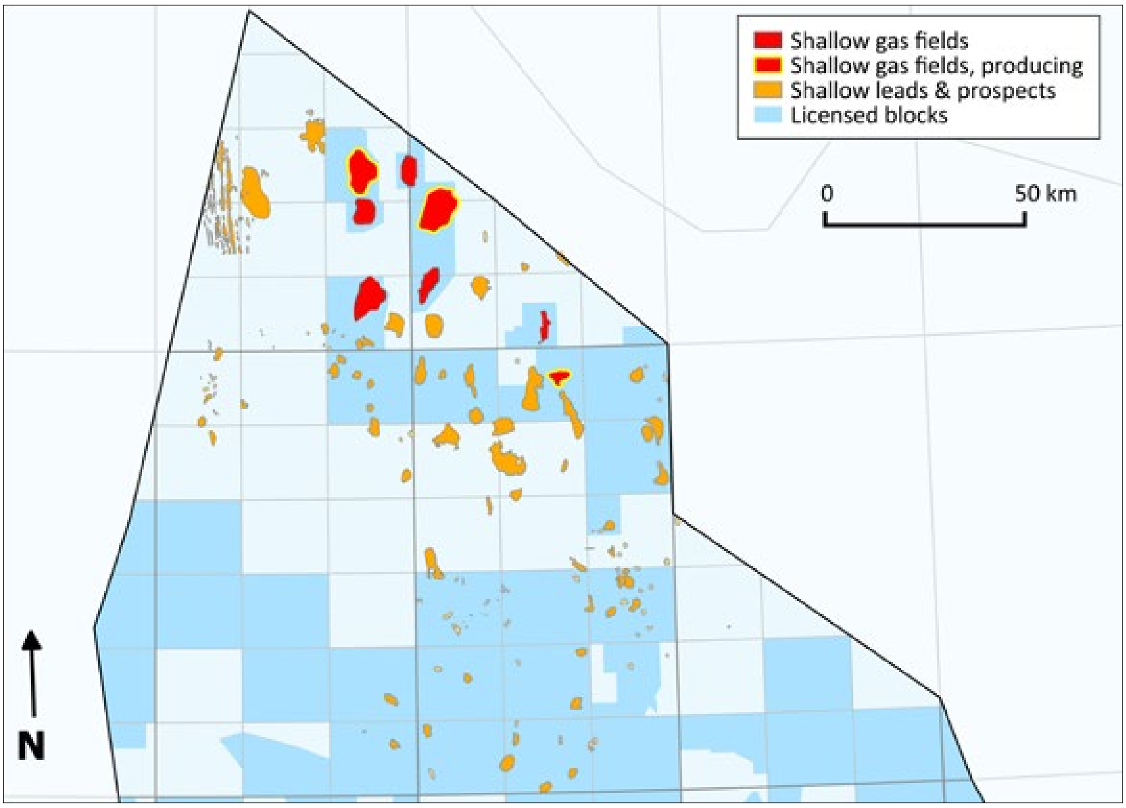
predictions for both are roughly 60% accurate. Surprisingly, seven of the Bunter wells came in shallow (two even by more than 80 m). One third of the Rotliegend wells came in too deep, which is probably due to T/D conversion uncertainties caused by overlying salt diapirs.

Incorrect depth predictions may affect the gas column and hence volumetrics (if the GWC is as expected), as well as fault juxtapositions and possibly reservoir quality.

The success rate for all 101 wells (all targets) was 63%. If the target depth was predicted correctly (i.e. within +/- 25 m), the success rate would increase to 75%. This compares with a relatively poor 48% success rate for the 40 wells outside the +/- 25 m depth-prediction bracket. A correct depth prediction not only results in a higher success rate, but also in the sum of the EXP for all 'correct' prospects being much closer to the actual post-drill volumes found - unfortunately actuals are smaller than hoped for. In conclusion, as an industry we underestimate POS and overestimate MSV.

4.5 Shallow gas opportunities

The Northern Dutch Offshore hosts plenty of amplitude anomalies or bright spots in the Tertiary which can easily be identified on seismic. These anomalies may be related to the presence of hydrocarbons and typically occur above the Mid-Miocene unconformity at depths less than 1000 m. Four-way-dip closures, fault-related structures and stratigraphic traps have



all been observed. The reservoirs are generally thin sandy layers with good porosity and permeability. Stacked, multiple bright spots above salt domes are frequently observed.

While shallow gas was long considered either a drilling hazard or challenging to develop because of the low pressure and unconsolidated nature of the reservoirs, the play has now become a successful part of the Dutch hydrocarbon system. With three producing fields and a fourth field coming on stream in 2016, shallow gas has proven to be a valuable resource. Development of four additional fields is under consideration. Since the first field started producing in 2007, almost 8 BCM has been produced from three fields, mainly by horizontal wells with effective sand control measures such as expandable sand screens or gravel packs.

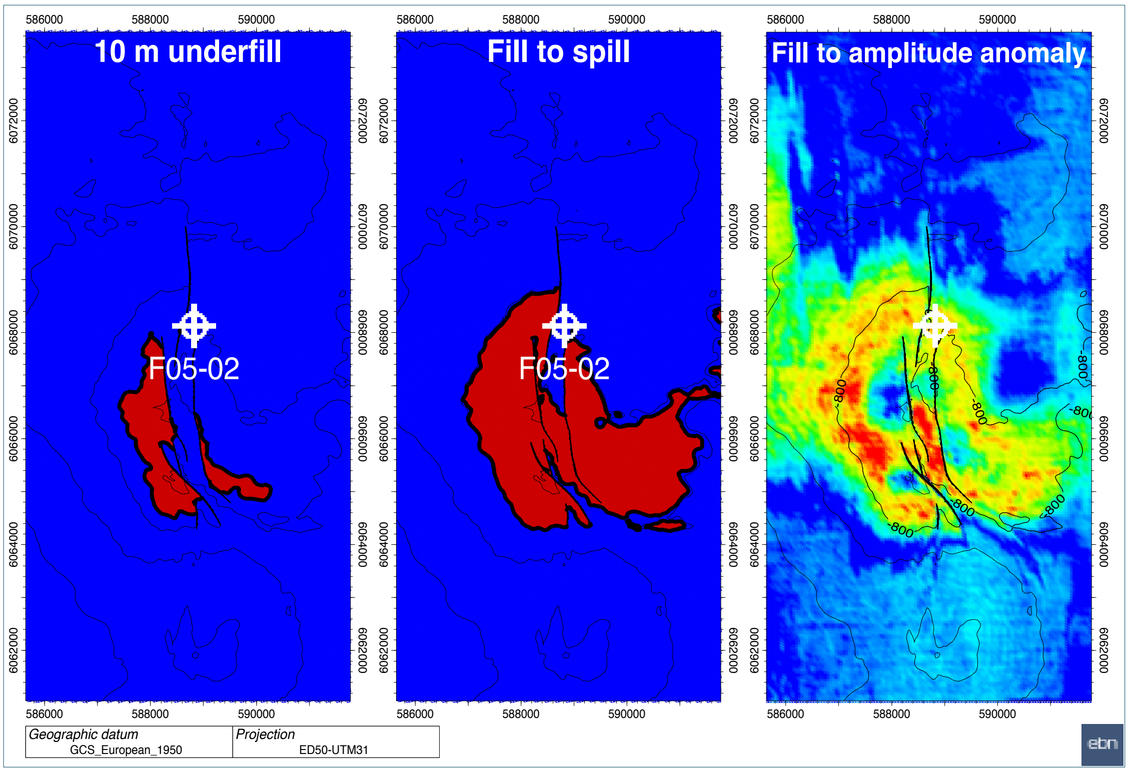
4.5.1 Shallow gas portfolio

The successes of the producing fields and in-place volume estimates are encouraging. The Northern Offshore is now largely covered by 3D seismic, including a multi-client survey shot by Fugro in 2010/2011. Many additional 2D lines are also available. In these seismic data, EBN has identified over 150 bright spots ranging up to 60 km2 in size. Shallow gas is also known to occur onshore, although the focus is currently on the offshore potential.

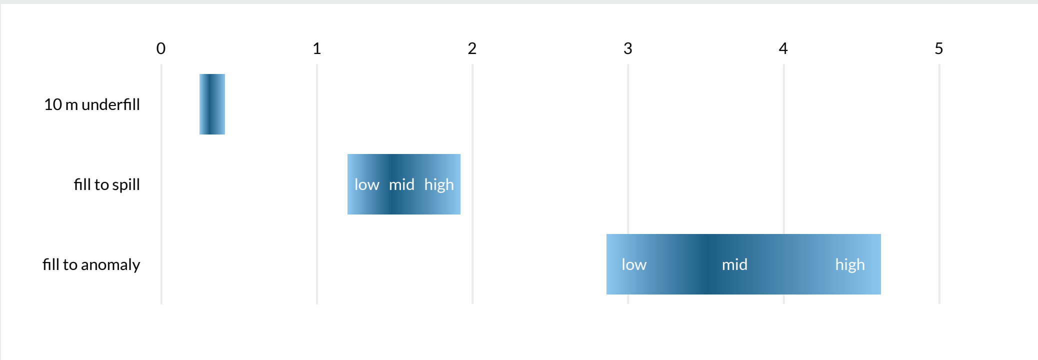
While brightening in shallow reflectors may indicate the presence of gas, it could also be related to uneconomic amounts of hydrocarbons due to the non-linear behaviour of seismic velocity with saturation. Lithological effects could also play a role. Furthermore, not many bright spots have been drilled, and the uncertainty ranges are large.
In order to further assess the potential of the play, EBN has developed a semi-quantitative seismic characterisation system that describes each individual anomaly with respect to size and direct hydrocarbon indicators (DHIs) such as flat spots and velocity pull-down effects. A detailed subsurface analysis, including a volumetric assessment, is done for the highest-ranking leads. This system has identified more than 20 amplitude anomalies as prospective shallow leads, with individual in-place volume estimates of up to 2.5 BCM.

One of the high-ranking amplitude anomalies in open acreage is lead F04/F05-P1, which is now covered by 3D seismic. It shows several reflectors that display both amplitude reversal and brightening in a four-way-dip closure, cut by faults. Even stronger indications for hydrocarbons are the velocity pull-down and amplitude-dimming effects below the bright reflectors. Assuming three gas-bearing reservoirs are present, the estimated GIIP range is 1.2-1.5-1.9 BCM (P90-mean-P10) in a fill-to-spill case. The very flat nature of the trap is represented by the low GIIP range when 10 m underfill to spill point is assumed: this would reduce the GIIP range to 0.2-0.3-0.4 BCM (P90-mean-P10). The figure below shows that the fill-to-spill scenario does not correspond with the outline of the amplitude anomaly. When assuming the full area of the amplitude to be gas-filled, the mean GIIP increases to 3.5 BCM; this however, requires overfill of the mapped four-way dip closure.

The lead was drilled in 1982 by well F05-02 targeting Cretaceous and Triassic levels. Although no specific attention was paid to the Tertiary interval, gas readings of 12% were recorded at the interval corresponding to the deepest two bright levels. With trap and charge evidently present, absence of reser-



F04/F05-P1 GIIP range for different scenarios



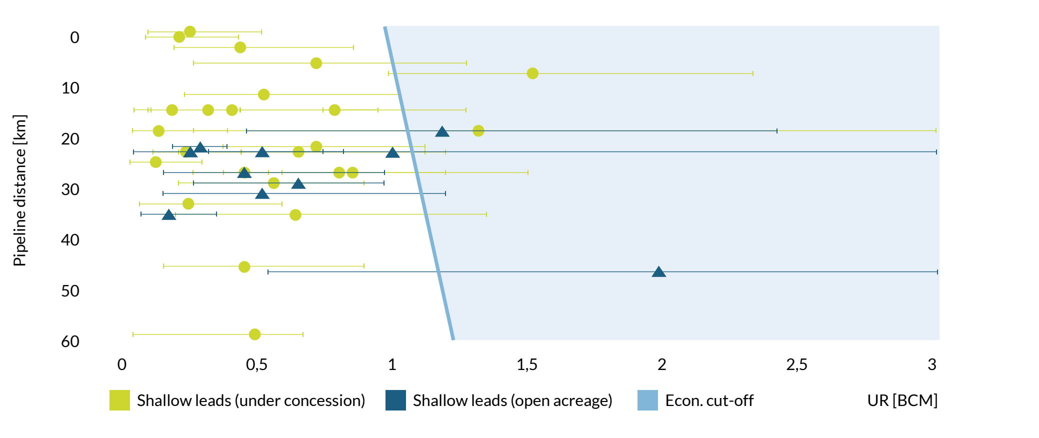
EBN 2015

voir represents the highest risk. Gamma-ray API levels suggest silty sands at best, while no distinct sand-bearing intervals were recognised on the mud logs. However, with a base case GIIP estimate of 1.48 BCM, further exploration of this Tertiary target is justifiable.

4.5.2 Economics of shallow gas leads

The volume ranges of these leads are large because of the uncertainty of gas saturation and other reservoir parameters. Estimated volumes of most of the leads are below 2 BCM GIIP; in many cases, existing infrastructure is also relatively distant. This prompts the question of how these reservoirs can be developed economically. In 2014, EBN studied

Economic screening of shallow gas portiolio



EBN 2015

Pipeline distance to nearest host platform against ultimately recoverable volumes (UR) for all the fields and the highest ranking leads and prospects of the shallow gas portfolio. Volume uncertainties are indicated by error bars. The blue line represents the break-even distance-volume profile, e.g. data points to the right of the line would be economic as stand-alone projects.

the economic potential of the play in a first-order approach. The plot shows the break-even CAPEX curve in relation to pipeline distance and recoverable volumes based on conventional expenditure profiles. The assumption was made that stand-alone development of the leads with satellite platforms connected to the nearest potential host platform would be feasible. The tax incentive applicable to marginal fields in the Netherlands was also taken into account. For a realistic range of pipeline distances in the study area, the break-even volumes range from 1 to 1.2 BCM. The leads that rank highest in the above seismic characterisation system are indicated in the plot; this shows that there are four leads that could be developed economically as stand-alone projects, based on conservative cost estimates. Two of these are situated in open acreage. These promising results justify further study of the development potential of the play.

Obviously, the commerciality of the play will greatly increase if CAPEX and OPEX are reduced. EBN has investigated platform costs as a first step in assessing cost reductions for shallow gas and other marginal developments. Study results show that current costs can be reduced by 50%, as described in section 3.2. On the basis of these results, the economic break-even profile shifts to the left and several additional leads become economic. Additional cost reductions will be investigated in follow-up projects, including a cost-efficient exploration campaign. Economics would clearly also benefit from cluster development of several shallow and other (deeper) accumulations. EBN will therefore conduct a detailed economic analysis for a specific, high-ranking area in the Northern Dutch Offshore in 2015.

EBN is encouraging further exploration of the shallow play in view of the success of three producing shallow fields offshore the Netherlands, the wide availability of 3D seismic data showing numerous additional leads and the economic prospectivity of several of those leads.

Glossary

AOC	Agreement of cooperation
BARMM	Degree on general rules on environment and mining
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
CA	Cooperation agreement
CAPEX	Capital expenditure
CGIIP	Connected gas initially in place
COP	Cessation of production date
CRF	Connected recovery factor
DEFAB	Exploration study of the D,E.F,A and B blocks
DHI	Direct hydrocarbon indicator
EAGE	European Association of Geoscientist & Engineers
EBIT	Earnings before interest and tax
EIA	Environmental impact assessment
E&P	Exploration and Production
EOFL	End of Field Life
EXP	Expectation
GE	Groningen Equivalent
G&G	Geology & Geophysics
GIIP	Gas Initially in place
GTL	Synthetic diesel fuel manufactured from natural gas
HP/HT	High pressure/ high temperature
JIP	Joint Industry Project
MA	Mining Act
MFTA	Marginal Field Tax Allowance
MSV	Mean Success Volume
Operator	Party carrying out E&P activities in a licence on behalf of partners
OPEX	Operational expenditure
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
RF	Recovery factor
RIL	Reinvestment Level
ROCE	Return on capital employed, the profitability of long term E&P investments
ROIC	Return on invested capital
Shale gas	Gas held in tight reservoirs in shales with insufficient permeability for the gas to flow naturally in economic quantities to the well bore
Small fields	All gas fields except the Groningen field
SodM	State supervision of Mines
SPE	Society of Petroleum Engineers
SPS	State Profit Share
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
TWT	Two Way Time
UR	Ultimate recovery
UOP	Unit of production
Velocity string	A small-diameter tubing string run inside the production tubing of a well as a remedial treatment to resolve liquid-loading problems
Wabo	Environmental licensing Bill

About EBN

Based in Utrecht, EBN B.V. is active in exploration, production storage and trading in 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 regime and on new opportunities for making use of the Dutch subsurface.

National and international oil and gas companies, licence holders, take the initiative in the area of development, exploration and production of gas and oil. EBN invests, facilitates and shares knowledge. In addition to interests in oil and gas activities, EBN has 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, our sole shareholder.
Visit www.ebn.nl for more information.

References

- Benchmark Opex Offshore Nederland, BOON-2012. EBN.
- Kreft, E., Godderij, R., Scheffers., B., EBN. SPE-ATCE 2014. SPE 170885, The values added of five years SPE-PRMS.
- Jaarsma, B., Schneider, J., Tolsma, S., Lutgert, J. [2014] A new chance for the Zechstein-2 Carbonate play in the Mid North Sea High area ? EAGE extended abstract, 2014
- PWC, November 2013. Driving value in upstream Oil & Gas, lessons from the energy industry's top performing companies.
- Ter Borgh, M., M., Jaarsma, B., Rosendaal, E. A., [2015]. Go North – a fresh look at the Paleozoic structural framework and hydrocarbon charge in the Dutch northern offshore. EAGE extended abstract 2015.

Acknowledgement

Focus on Dutch Oil and Gas 2015 was made possible by the support of several organisations, including TAQA energy B.V. (photo page 21), Nederlandse Aardolie Maatschappij B.V. (photo page 23 and 26), GDF SUEZ E&P Nederland B.V. (photo page 25), Scaldis (photo page 36), Wintershall Noordzee B.V. (photo page 41), IV (picture page 37) and FUGRO (pictures page 47 and 54). Their input was of great value for realising the report and EBN would like to thank them for their cooperation. The photo at the front page shows sealife on a North Sea rig (Cor Kuyvenhoven).

EBN B.V.
Daalsesingel 1
3511 SV Utrecht

Phone: +31 (0)30 2339001
Mail: ebn.mail@ebn.nl