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Focus on Dutch Oil & Gas 2014

Image - Shell fragment in Posidonia shale.

Focus on Dutch Oil & Gas 2014

Image - Dutch dunes

Foreword

Natural gas production is important to the Dutch economy. Not only because of the state revenues (about EUR 15 billion in 2013), but also because of the employment that the gas industry offers in the Netherlands (16,000 direct and indirect jobs).

The role of the 'small fields' in Dutch gas production will become more important, especially now that production from the Groningen field has been further capped. In 'Focus on Dutch Oil and Gas' we present our annual overview of the state of play of the Dutch small gas and oil fields and of major new developments. The main conclusion this year is that a sharp increase in investment is necessary to maintain production from small fields over the next one-and-a-half decade. In that perspective we have to focus on exploration (fallow acreage, open areas, new plays), continuation of the maximisation of economic recovery, the upside scenario and stakeholder engagement. The opportunities are there, but an increased and cooperative effort is required.

Last year the about 300 small gas fields in which EBN participates produced 26 BCM (billion cubic meters) of natural gas – one-third of total Dutch production (the remaining was production out of the Groningen field and non EBN small fields). Relatively spoken the small fields become more and more important, but we need an extensive exploration, appraisal and production optimisation investment program.

Such investments are urgently required as the long-term production outlook from existing fields continues to level off. Indeed, more needs to be done. This report shows that the growth of production based on the optimisation of existing resources is flattening. To prevent a further decline in production, more investment must be directed at exploring new resources as well as unlocking more challenging resources, such as tight and shale gas plays.

This is not impossible. The good news from this report is that profit margins of small fields production remain attractive. This is partly because gas prices remain robust. Tax incentives for specific marginal developments have also been helpful, although these incentives do need continuous fine-tuning to remain effective.

Although the opportunities are there, the public image of natural gas has worsened considerably in recent years. The industry will have to share its knowledge more extensively with their partners and stakeholders, and enter into the discussion about the benefits and the necessity of gas extraction in the Netherlands. More than ever, it will be necessary to create social support in order to secure the future of the Netherlands as a gas producing country.

This report shows that the Netherlands can remain self-sufficient in gas production for at least a decade and still produce a significant part of its consumption a few decades from now, however, to achieve this goal will be increasingly challenging.

Maximizing economic recovery by means of safe and sustainable domestic production is essential for the Dutch E&P industry as well as the Dutch society, therefore a new commonly shared commitment to small fields exploration and production is necessary.

Berend Scheffers
Director Technology at EBN

Executive summary

This year's Focus on Dutch Oil and Gas reviews the status of the Dutch E&P industry. The Dutch onshore and offshore reserves and resources are still large, but declining. Increased effort and further optimisation are required to minimise the decline in production, in the form of higher investments in exploration and wider applications of new technology. Such optimisation will enable the Netherlands to benefit from the proceeds of Dutch natural gas and oil for many years to come.

Thanks to an increase in activities in recent years, the production decline from the Dutch small fields stabilised at 2.5% over the past two years, while the small-fields reserves base decreased by only 6.3 BCM. Despite these relatively positive signs, the long-term outlook does show a decline in production from 2019 onwards.

The most recent 'business-as-usual' scenario shows a project portfolio that is still substantial enough to maintain a plateau production of 28 BCM for the next five years. However, the decline in production will continue unless investments are made to unlock resources identified by onshore and offshore exploration, but also in more challenging tight and shale plays.

Despite active exploration, the Dutch small-fields onshore and offshore reserves and resources base is declining. The average reserves replacement ratio for on- and offshore fields is well below 100%. Since offshore reserves comprise 63% of the total reserves, maturation of offshore contingent and prospective resources into reserves is required to maintain the offshore fields' sizeable contribution to production and reserves. This requires substantial additional investments in exploration and production activities. EBN will continue to encourage and assist operators to maximise their exploration potential and increase investment levels.

The Dutch E&P sector offers attractive relatively low-capital and low-risk investment opportunities. However, on average only one third of the cash flow generated from E&P activities in the Netherlands is reinvested in new Dutch E&P activities, while the remainder is invested elsewhere in the world or paid out as dividend. The worldwide reinvestment ratio for major E&P operating companies in the past two years was approximately two to three times higher. Consequently, there certainly seems scope for a higher investment level in the Netherlands.

The Netherlands offers a stable and supportive E&P investment climate. In 2010 the Dutch government successfully introduced the 'Marginal Fields Tax Allowance' (MFTA) to improve the attractiveness of investments in developing marginal offshore gas fields. The Wood Review, commissioned by the UK government, describes the Dutch E&P investment climate and stable government regulations as exemplary. However, this does not mean that there is room for complacency.

In the 'business-as-usual' scenario, a further 45 BCM can still be produced from prospective resources in 2050. This estimate is based on currently identified projects and excludes prospects yet to be defined. However, timing is crucial, especially offshore. The risk of offshore infrastructure disappearing in the near future is driving the urgency for exploration. Encouraging timely exploration activities is consequently one of EBN's key missions. Increased throughput of installations and cost-effective tail-end production are becoming progressively important in order to defer abandonment. A side effect of extending production, is the fact that this will also allow deferring the costs of abandonment, currently estimated at around €5 billion.

The Netherlands is a net exporter of natural gas and, based on the current levels of domestic gas consumption, will be able to remain self-sufficient for at least another decade to 2025. If the upside scenario materialises, this might be stretched to 2030. In addition to self-sufficiency, the proceeds from natural gas strongly contribute to Dutch State revenues. Domestic production contributes to a sustainable energy supply because imported gas supplies, such as LNG shipped from Algeria and pipeline gas from Russia, cause considerably higher greenhouse emissions than domestic production.

A total of 85% of the existing gas fields in the Netherlands are producible by conventional technology. Although the remaining Dutch small-fields portfolio is categorised as tight, these fields can also contribute to a sustainable energy supply, particularly if the recovery factor can be increased. A key technology for improving the recovery factor of tight fields is hydraulic stimulation.

This technology has been successfully applied in the Netherlands and elsewhere in the world for over fifty years, with recovery factors increasing every year. EBN anticipates that if multi-stage hydraulic stimulation is systematically applied in the Netherlands on a larger scale, the average recovery factor of tight fields could increase from 47% to 60%. The production success of hydraulic stimulation increases with increasing volumes of pumped liquids and a higher average concentration of pumped proppant. The success rate also increases with the proppant's grain size.

With many gas fields approaching their end of field life, the Netherlands is generally seen as a mature, but attractive gas province. However, some geographical areas or geological plays are still underexplored. EBN is currently focusing on studies aiming at increasing exploration activities and investments by existing operators, and attracting new players.

Contents

Reserves and investment opportunities

1.1 | Reserves and resources reporting – PRMS

The Petroleum Resources Management System (PRMS)

		Production		Resource cat.	Volumes BCM (GE, unrisked)
Discovered	Commercial	Reserves	On production	1	124
Discovered	Commercial	Reserves	Approved for development	2	22
Discovered	Commercial	Reserves	Justified for development	3	20
Discovered	Sub-commercial	Contingent Resources	Development pending	4	17
Discovered	Sub-commercial	Contingent Resources	Development unclarified or on hold	5	114
Discovered	Sub-commercial	Contingent Resources	Development not viable	6	70
Discovered	Sub-commercial	Unrecoverable			
Undiscovered		Prospective Resources	Prospect	8	> 200
Undiscovered		Prospective Resources	Lead	9	
Undiscovered		Prospective Resources	Play	10	
Undiscovered		Unrecoverable			

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N.B.= Cat. 8 and 9 are risked with Probability of Success (POS)

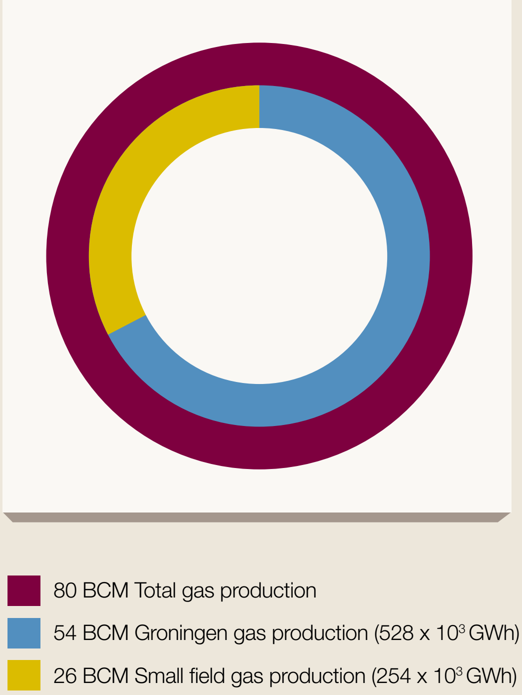
Since 2009, EBN has used the SPE Petroleum Resources Management System (PRMS) for reporting reserves and resources. The PRMS classifies hydrocarbon reserves and resources according to the level of certainty of technically and economically recoverable volumes and their potential to reach commercial status. EBN has a very diverse portfolio of conventional and unconventional assets, currently comprising 870 projects. PRMS makes it possible to track and monitor these assets so as to achieve auditable and consistent reporting standards.

1.2 | General overview of historical production in the Netherlands

The E&P industry has been a major pillar of the Dutch economy for the past 50 years, during which time approximately 3600 billion cubic metres (BCM) of gas have been produced from Dutch fields. The Netherlands is still the largest natural gas producer and exporter in the European Union. The lion's share of this production came from the Groningen field, the ninth largest gas field in the world. In 2013, the Groningen gas field produced approximately 54 BCM.

In order to ensure sustainable production, the Dutch government decided in the early 1970s to introduce the 'small fields policy'. This policy states that small fields are produced in preference to the Groningen field and has been very successful in stimulating exploration for and exploitation of smaller gas fields. Since the policy's introduction in 1974, about 1500 BCM have been discovered in small onshore and offshore gas fields. In 2013, around 26 BCM Groningen Equivalent (GE) of gas were produced from some three hundred small gas fields in which EBN participates.

Gas Production in 2013



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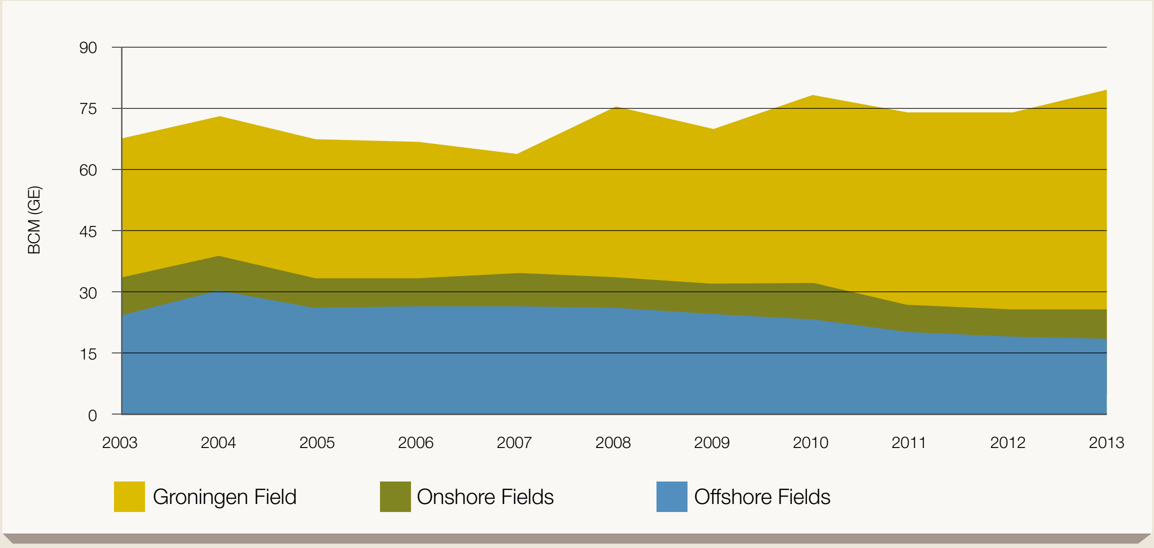
In 2009, EBN formulated its 30/30 ambition for gas production from small fields in an effort to minimise the decline in production from these fields. Thanks to increased activities, this decline, which primarily affects offshore fields, has stabilised at only 2.5% in the past two years.

Applying end of field life (EOFL) techniques, a process known as mature field optimisation, may increase production by several BCMs. EOFL treatments have so far been applied to over 200 wells and EBN expects another 250 wells to be treated in the next five years. 'Foam injection' and 'velocity string' techniques generate the largest increase in production. Although the costs of EOFL techniques are still high, they are expected to fall significantly as these techniques become more widely used. Cooperation between industry partners in, for example, the Top consortium for Knowledge and Innovations (TKI) and Joint Industry (JIP) projects is essential for the further development of EOFL techniques. These techniques, based on innovative ideas that give rise to

2003 - 2013 Dutch gas production, including Groningen



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new technologies, have proven to be highly rewarding, with increases in ultimate recovery of 10% or more being achieved.

1.3 Reserve and resource database

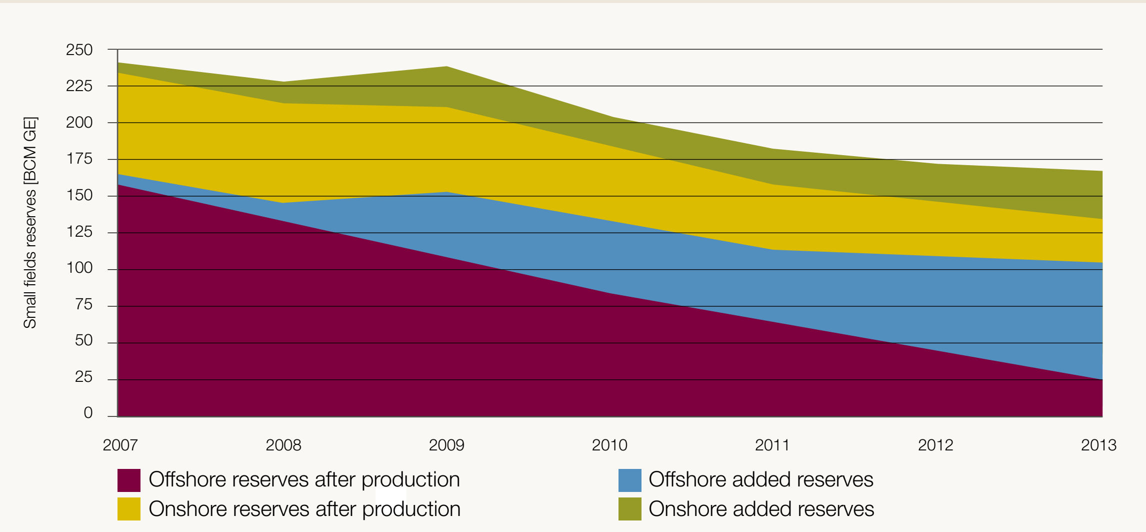
The reserves base of the small fields (i.e. all fields with the exception of Groningen) has decreased from 234 to 166 BCM GE since 31 December 2007 (PRMS categories 1, 2 and 3).

After an initial increase in 2008-2009, followed by a sharp decline between 2009 and 2011, the decrease in reserves has levelled off in recent years. The reductions in offshore and onshore reserves are attributable to production. However, an increase in ultimate recovery has contributed to a slight reduction in decline rate of offshore and onshore reserves. This is the result of a combination of three factors: maturing contingent resources into reserves, definition of new projects with reserves, and updating the ultimate recovery estimates for existing projects. Although the relative importance of these three factors varies from year to year, maturing existing resources and approval of new projects are the most important. Maturation includes the transfer of contingent resources to reserves, re-evaluation of reserve volumes, and re-evaluation and transfer of certain volumes of prospective resources to reserves.

The ratio of offshore reserves to total reserves decreased slightly from 68% to 63% over the six years from 2007 to 2013, while the ratio of offshore production to total production fell from 75% to 71%. Significant maturation of offshore resources into reserves will consequently be required to maintain the offshore fields' share in total production and reserves. This in turn will require considerable investments.

The average maturation into reserves for the 2007-2013 period was 18.6 BCM GE per year, with 13.3 BCM of

Small fields reserves after production and added reserves



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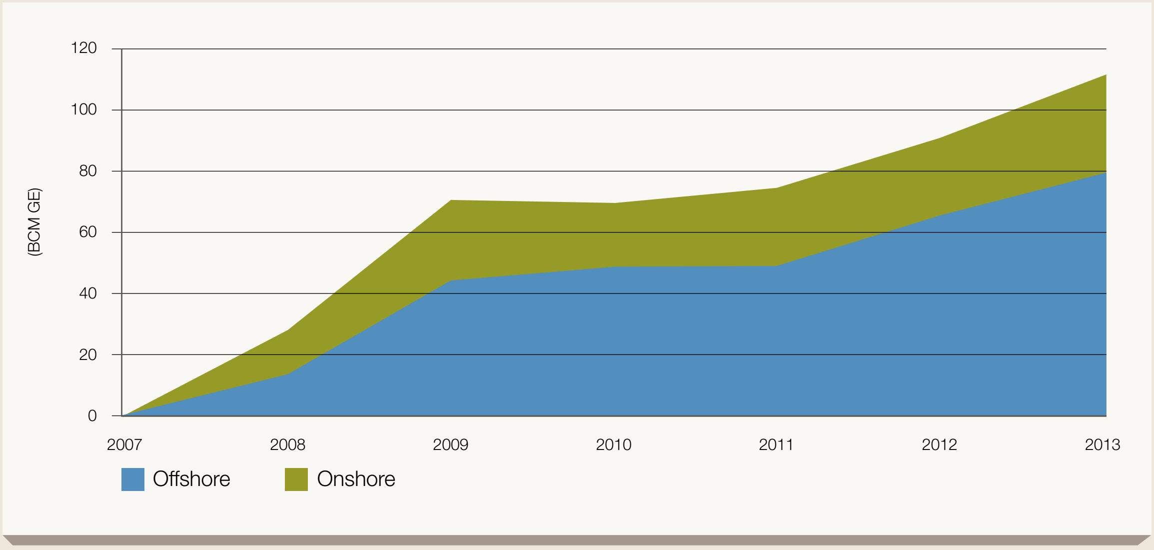
small fields **300** Increased number of activities have stabilized production decline from small fields

Cumulative maturation into reserves for 2007-2013



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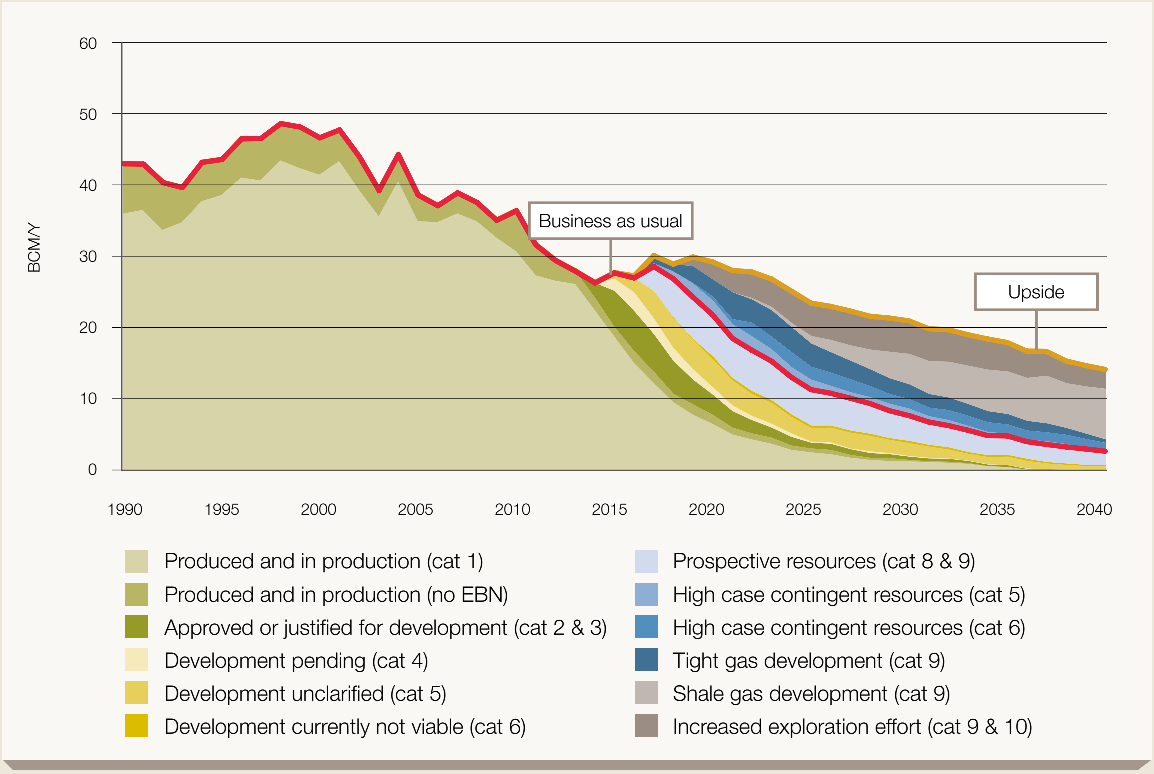
this being contributed by offshore resources. Annual maturation into reserves is still significant: the Dutch E&P industry's continual investments in exploration and development projects have resulted in an average reserves replacement ratio of over 60%. The 2013 reserves replacement ratio was even in excess of 75%. Although the reserves replacement ratio for offshore fields has improved in the past two years, it is still well below 100%.

1.4 | Gas production forecast

Over the past two years, the Dutch E&P sector has seen a small decline (2.5%) in annual gas production from small fields (see section 1.2). Production from the licences in which EBN participates was only 0.4 BCM lower in 2013 than in 2012, while the amount of produced condensate even increased. The small fields reserves base (PRMS categories 1, 2 and 3) fell by only 6.3 BCM. Despite these relatively positive signs, the long-term outlook has changed considerably compared to that published in the 2013 edition of Focus on Dutch Oil and Gas. In the past few years, replenishment of reserves has relied mainly on gas being transferred from the contingent resources categories (PRMS 4, 5 and 6) to the reserves categories (PRMS 1, 2 and 3). Thanks to new technologies and favourable gas prices, Dutch operators have been able to identify increasing opportunities within existing fields and discoveries. Many operators have recently announced plans to start developing long-stranded fields or to push the ultimate recovery of producing

Scenario-based risked production forecast small fields gas production



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fields to even higher levels. There are signs, however, that the underlying growth needed in the contingent resources categories is flattening out, while the numbers of exploration wells and exploration successes in the Dutch E&P sector were both lower in 2013 than required to slow down, let alone halt, the annual decline in production.

Assuming the operators' exploration efforts in recent years to be representative for future exploration activity levels, the annual future gas production in a 'business as usual' (BAU) scenario will fall faster than previously forecast. In previous editions of Focus on Dutch Oil and Gas, EBN assumed that operators holding the most prospective acreages would increase their exploration efforts. If this does not materialise, EBN expects a lower contribution to the forecast from yet to be discovered fields. EBN will therefore continue encouraging operators to aggressively explore their own acreages, while also being committed to encouraging exploration beyond established play boundaries, and promoting a favourable Dutch E&P climate.

The latest BAU forecast represents a scenario in which the project portfolio permits maintaining a plateau production level of 28 BCM for the next five years. After that, the decline will resume, unless investments are made in onshore and offshore exploration to unlock further traditional and also more challenging resources, such as tight gas and shale plays. The 'upside' scenario relies heavily on these latter resources. It is vital to mature these plays if the Netherlands wants to avoid a rapid decline in gas production within the next decade. However, 2013 saw no major breakthroughs in the development of tight gas fields, while political and societal opposition has pushed potential shale gas development even further back in time. EBN nevertheless expects both shale and tight gas to become increasingly important in the coming two decades.

1.5 Benefits of Dutch natural gas

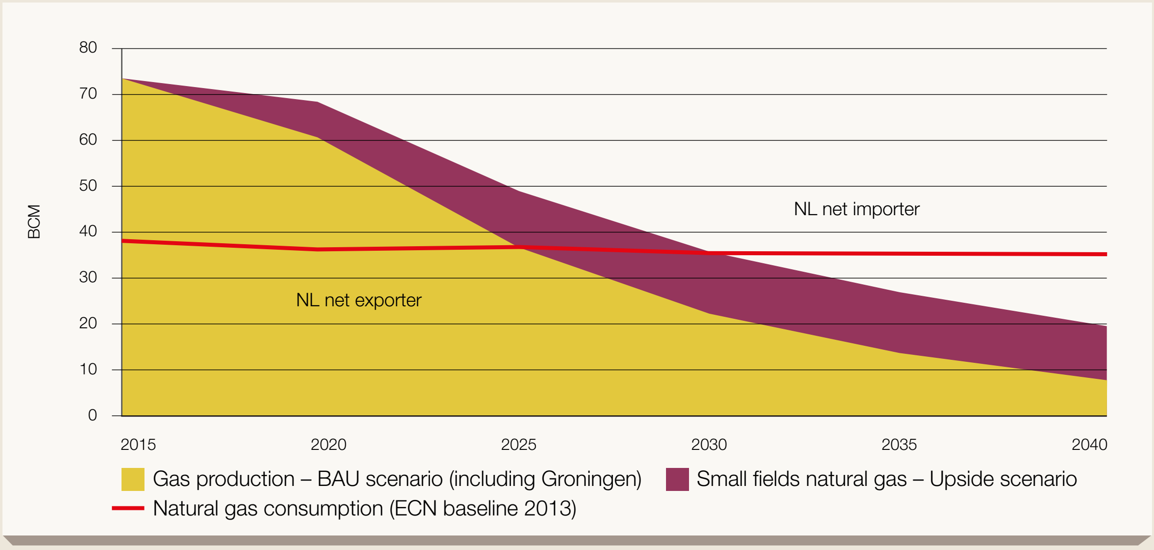
EBN seeks to maximise domestic production of natural gas in a safe and sustainable manner because it contributes to State revenues, employment and energy self-sufficiency, as well as to a sustainable energy supply by minimising greenhouse gas (GHG) emissions.

In discussions about the role of natural gas in the transition towards a more sustainable energy system some parties have claimed that relying on natural gas will frustrate this transition as it is a fossil fuel and thus inherently a cause of GHG emissions. Others claim, however, that natural gas is the ultimate transition, or even destination, fuel as it is the cleanest fossil fuel, with ample global reserves. One argument in favour of natural gas is that it will be needed as a fall-back or base-load energy source because of the intermittent nature of solar and wind energy.

Natural gas is beyond doubt the backbone of the Dutch energy system, and Dutch natural gas seems likely to remain important for the foreseeable future, even if the transition to a fully sustainable energy supply is achievable.

According to the ‘business as usual’ scenario, the Netherlands will be able to remain self-sufficient for at least another decade. In the ‘upside’ scenario, however, we could still produce about half of the country’s

Dutch natural gas consumption and production scenarios



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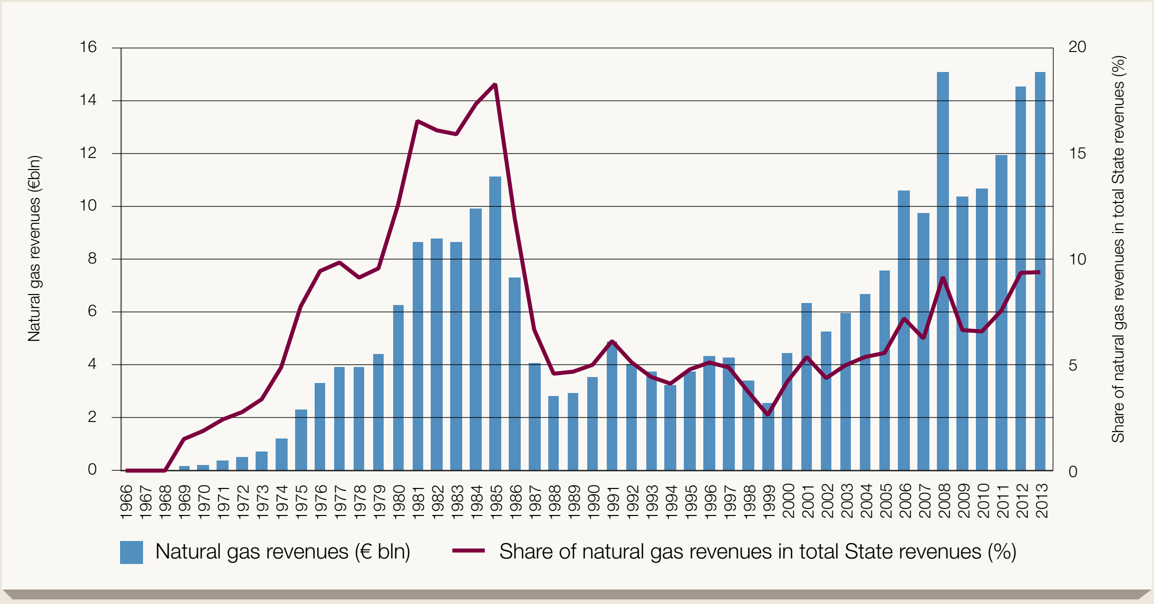
Historical natural gas revenues to Dutch State



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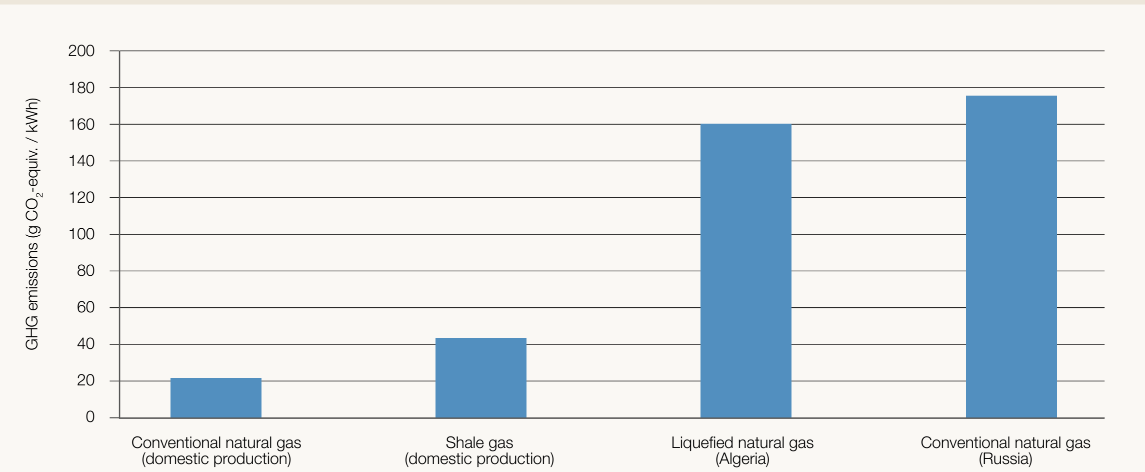
Greenhouse gas footprint: domestic versus imported gas



Comparison of up- and mid-stream greenhouse gas emissions of different natural gas supply sources for consumption in the Netherlands.
(Source: Royal Haskoning DHV, 2013)

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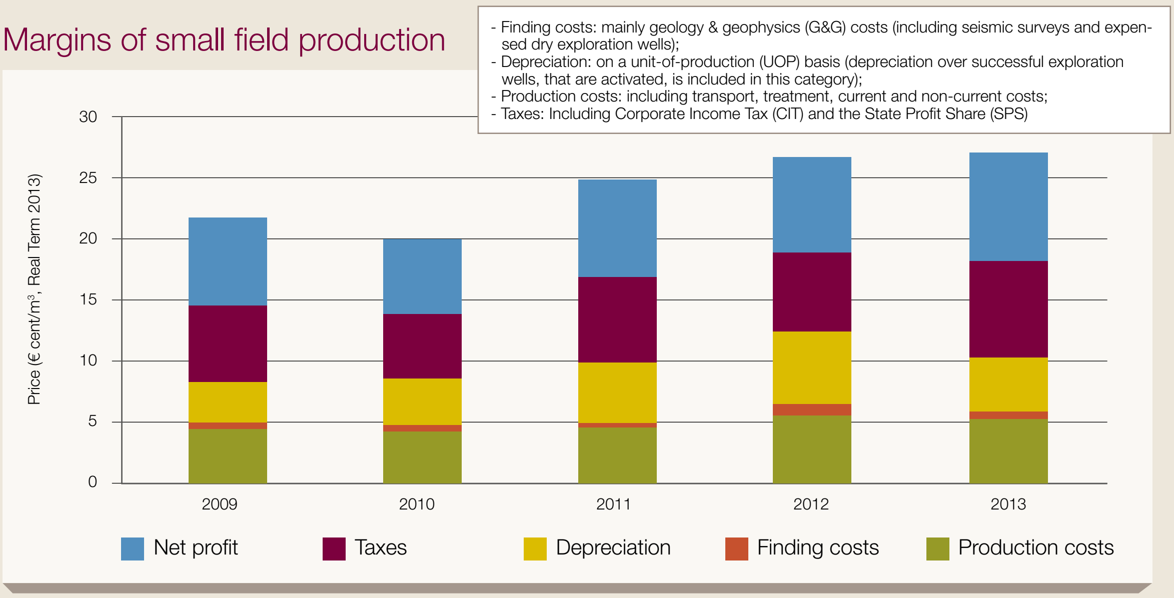
forecast consumption in 2040. Besides self-sufficiency, there are other important reasons for seeking to maximise domestic gas production in a safe and sustainable manner. Revenues from natural gas production are very important to the Dutch State; over the past twenty years, natural gas revenues have on average accounted for 5 to 10% of total State revenues. The gas sector is also important for domestic employment as it is currently directly responsible for some 6,000 highly skilled jobs and indirectly for another 10,000 jobs at supplier and contractor companies.

Another, albeit less well-known aspect is that the GHG footprint of domestic natural gas is considerably smaller than that of imported natural gas.

In 2013, the independent international engineering consultants Royal HaskoningDHV worked with Utrecht University on a life-cycle analysis (LCA) of up- and mid-stream GHG emissions from various energy options. This study compared GHG emissions on a life-cycle basis for various options for supplying natural gas consumed in the Netherlands and also compared these with other energy sources such as coal, nuclear, solar and wind. The study shows that up- and mid-stream GHG emissions from domestic conventional production and domestic production from shale gas amount to 22g CO_2-equiv/ kWh, which is far less than the GHG footprint of imported gas such as Algerian liquefied natural gas (LNG), which is transported by ship, or gas from Russia, which has to travel 6000 kilometres through a pipeline. LNG's larger footprint is due to the fact that the process of production, liquefaction, shipping and regasification is relatively energy-intensive. Import of Russian gas requires compression and inherently leads to small amounts of methane gas leakage as well. As methane gas causes 25 times more global warming than CO_2, imported Russian gas has the highest GHG footprint of the options investigated (177 grams of CO_2-equiv/ kWh). In addition, domestic natural gas is more attractive than imported gas from both a security-of-supply and a balance-of-payments perspective.

Margins of small field production



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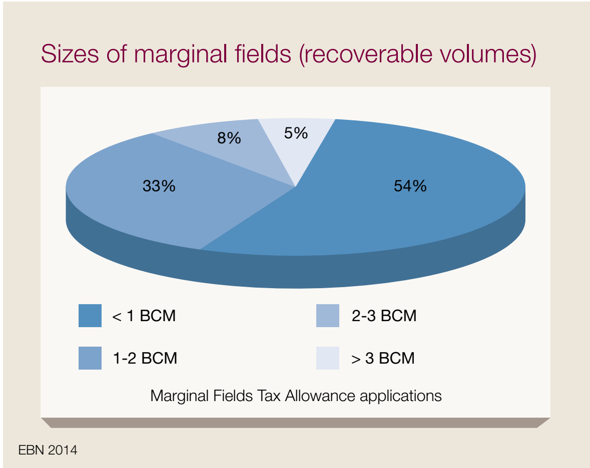
1.6 Profit margins on production from small fields remain attractive

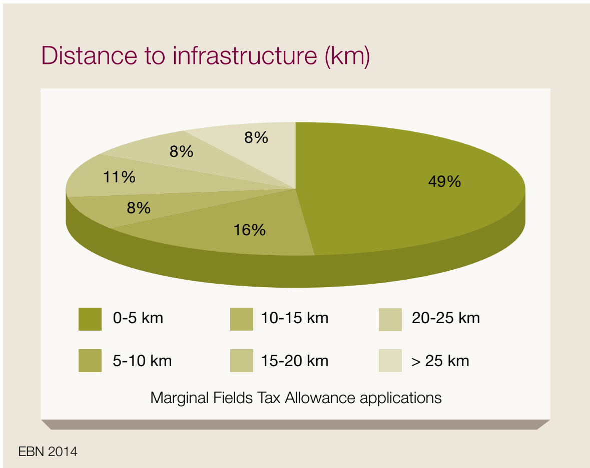
An attractive and stable Dutch E&P investment climate is crucial in order to support investments. As explained earlier, production potential is still significant, and the forecasted long-term demand is also sufficient. A breakdown of the revenues from the production from small fields shows that the actual profit margins on gas production remain attractive. The year 2013 showed a rise in average gas prices for the fourth consecutive year. This resulted in a higher profit margin for the E&P industry ('net profit') and increased tax revenues for the Dutch State ('taxes') per m³.

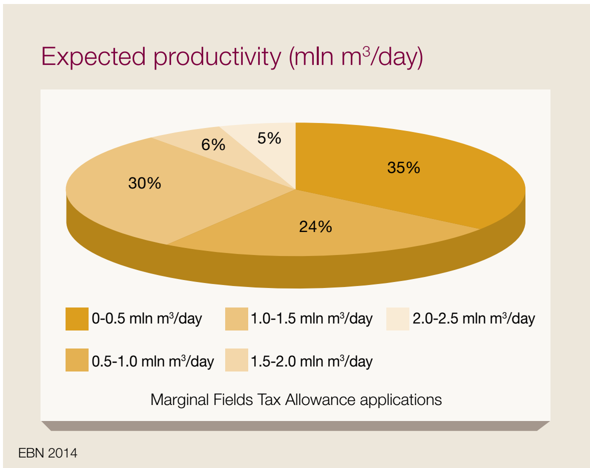
The long term trend of increasing production costs for each m³ of produced gas has not continued in 2013. Constraining production costs is especially important for the continued production of tail-end resources and to extend the lifespan of offshore infrastructure (see section 3.4).

1.7 Marginal fields and prospects incentive

A stable and attractive fiscal climate is necessary to continue and increase exploration and production activity. In 2010 the Dutch Ministry of Economic Affairs introduced a specific investment tax allowance, the 'Marginal Fields Tax Allowance' (MFTA), to make investments in marginal offshore gas fields more attractive. This allowance targets the development of those gas fields and prospects on which returns are expected to be economically marginal as a result of limited volumes, low field productivity, long distances to existing infrastructure or a combination of these aspects. If a field/prospect qualifies as marginal the operator (and its partners in the license) can deduct an additional 25% of the Investments from the financial

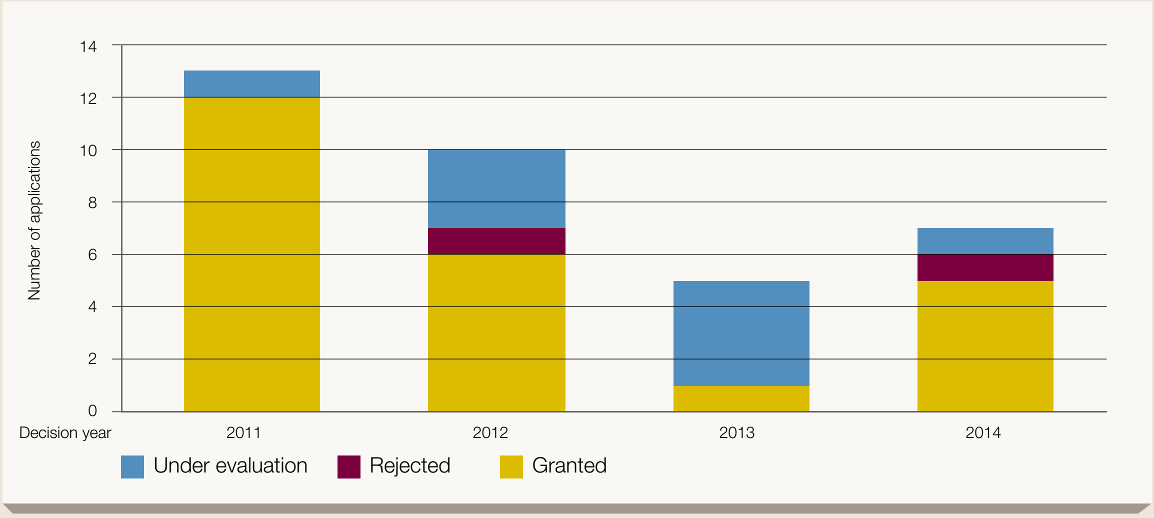






result calculated for SPS purposes (State Profit Share). Since the MFTA's introduction in 2010, 35 applications for the allowance, including some for exploration wells, have been made. Of these, 24 have been granted, and these resulted in 12 field developments being implemented by the end of 2013. Given the total of 23 offshore field developments in the Netherlands between 2010 and 2013, this demonstrates the importance and success of tax incentives for encouraging specific field developments.

Marginal fields tax allowance



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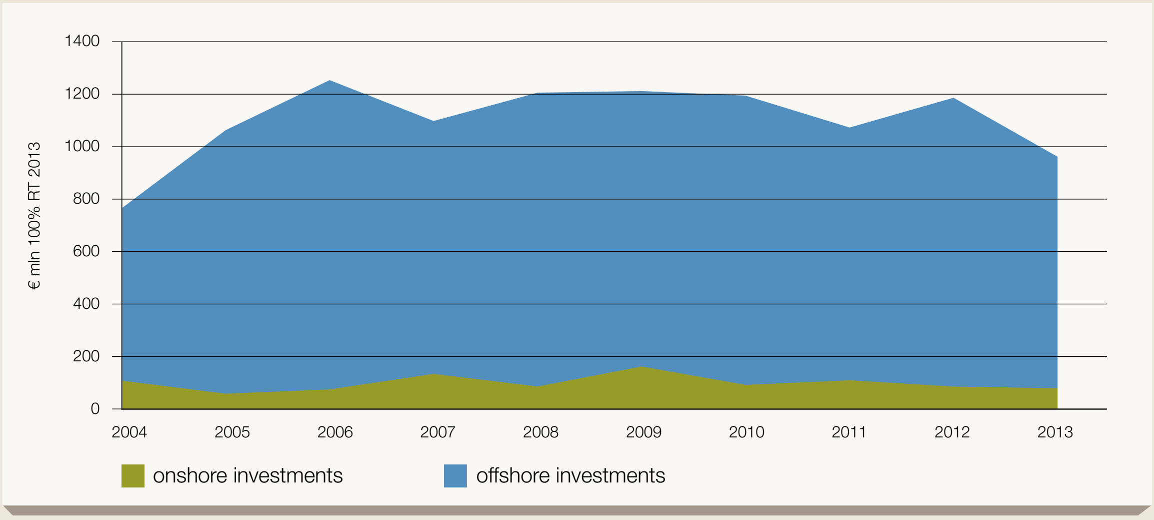
Historical investment level in small gas fields



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EBN will continue to encourage and assist operators to maximize investment level

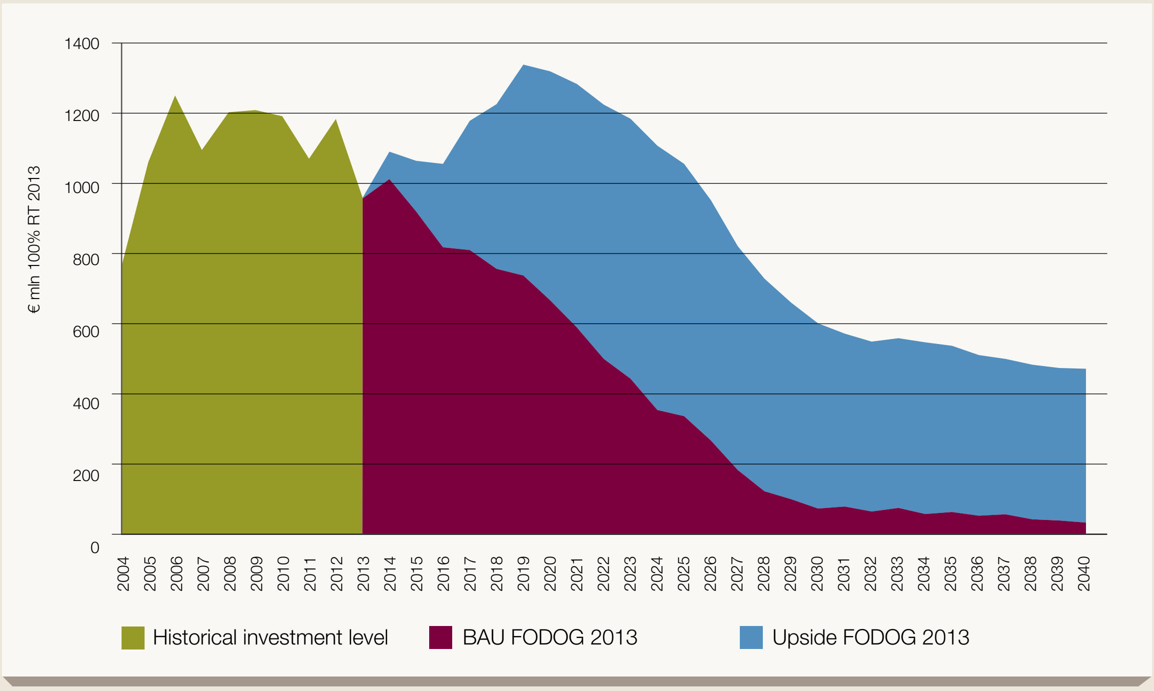
Two MFTA applications have been rejected, while the remainder are still under consideration. More than half the applications relate to small prospects or fields expected to yield less than 1 BCM. Over one third of the applications concern prospects or fields at distances of over 10 km from existing infrastructure, while nearly 60% have low to medium productivity.

1.8 Historical and required investment levels

Although individual operators' investments in the exploration for and production of gas fields vary significantly from year to year, overall investments in small gas fields have remained fairly stable since 2005. Long-term annual investment levels have been around €1.0 to €1.2 billion. In this context, investments include G&G, and exploration costs and capex.

It should be noted that total E&P investment levels in 2013 dropped below €1.0 billion, because some invest-

Investment level scenarios



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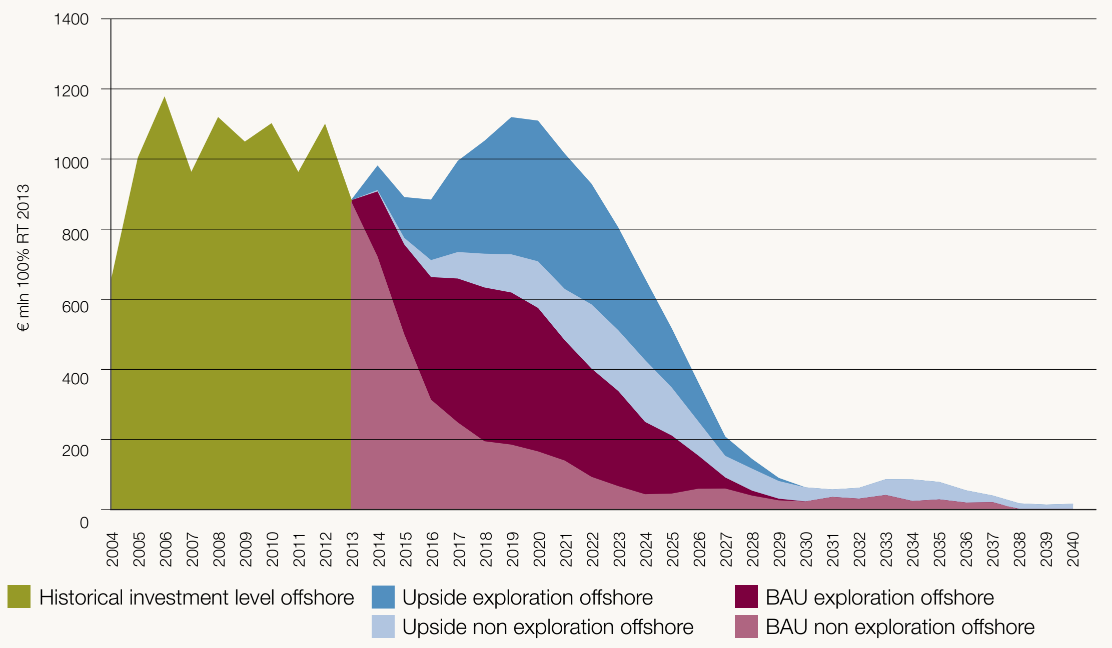
Breakdown offshore investment ambition



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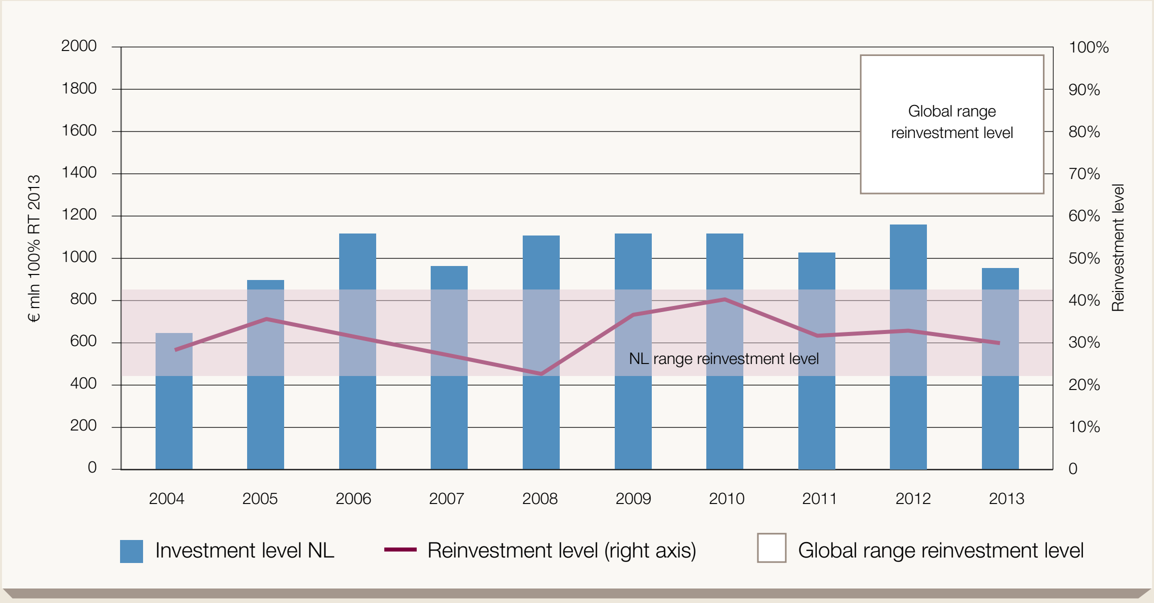
ments were postponed from 2013 to 2014, and also because some investment budgets were transferred from E&P to gas storage projects. However, as the level of investments planned by operators in 2014 looks very promising, the drop in 2013 may prove to be a one-off event. The investment portfolio is dominated by offshore projects.

A limiting factor for offshore investment can be the number of drilling rigs available for the Dutch offshore sector. In order to keep investments at the required level, Dutch operators need to have adequate access to drilling rigs. Failing this, mature well proposals face unnecessary delays which may lead to missed deadlines on well commitments and cause delays down the activity stream. EBN uses its overview of all Dutch E&P activities to monitor drilling schedules and existing drilling opportunities in order to optimise availability and utilisation of available rigs and to ensure that no rig remains idle.

The 2013 edition of 'Focus on Dutch Oil & Gas' presented three scenarios for future production levels and, therefore, investment levels: 'no further activity' (NFA),'-business as usual' (BAU) and the 'upside' scenario, as illustrated in the above diagram. The desired future production levels clearly require a sharp rise in investment over the coming years. Annual investment levels should rise significantly towards the upside scenario, especially if we are seeking to increase exploration activities and subsequently develop tight gas fields and shale plays.

Most of the future investments are required in order to mature offshore resources into reserves. The above diagram shows a breakdown of the offshore investments

Reinvestment level of Dutch small fields compared to Global range



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required, with 'non-exploration' defined as investments required for maturing existing discoveries into reserves on production. Aggressive exploration and appraisal will be needed for maturing prospective resources, including tight gas, into reserves. These investments are labelled as 'exploration' in the diagram on page 17.

EBN is firmly in favour of stimulating offshore exploration in particular because the recent exploration efforts of the industry have caused us to lower the BAU exploration scenario as further stipulated in section 1.4.

A timely focus on investments in offshore exploration is also required because the lifespan of the offshore infrastructure depends on ensuring continued sufficient natural gas production. If key infrastructure is decommissioned, the related exploration potential will also be lost.

In addition to exploration activities in licensed acreages, exploration in open acreages will also be needed to achieve the upside scenario. EBN encourages this by promoting seismic acquisition and sharing data and opportunities identified in in-house studies, as well as by drawing existing and new operators' attention to open acreage.

1.9 Comparison of reinvestment levels: Netherlands versus the rest of the world

In order to assess the current level of E&P investments in the Netherlands, we calculated the percentage of the cash flow from operations that is reinvested in the Dutch E&P sector ('reinvestment level'). Generic assumptions were made for all licence holders in order to estimate operational cash flows. Rather, therefore, than exact figures, the figures presented here are rough estimates of the reinvestment level.

Only a third of the cash flow generated in the Netherlands from Dutch E&P activities is reinvested in new Dutch E&P activities, while the remainder is invested elsewhere in the world or paid out as dividend. The worldwide reinvestment ratio for major E&P operating companies in the past two years was some two to three times higher. The reinvestment level in the Netherlands is consequently lagging seriously behind the global level.

EBN realises that major E&P companies' investments budgets are currently under pressure and that E&P investments are subject to a global ranking process. Investments in high-capital and high-risk projects are coming under particularly close scrutiny by shareholders demanding dividends. On the other hand, this might be an opportunity for a mature basin like the Netherlands offering relatively low capital and low risk projects.

Although EBN's ambition of 30 BCM/year from small gas fields in 2030 and its related investment ambition are challenging, we believe that sufficiently attractive investment opportunities exist and are actively pursuing further improvements in the investment climate. In conclusion: Maximizing economic recovery by means of safe and sustainable domestic gas production, will benefit both the E&P industry and the Dutch society as a whole.

Activities and innovations in the Dutch E&P industry

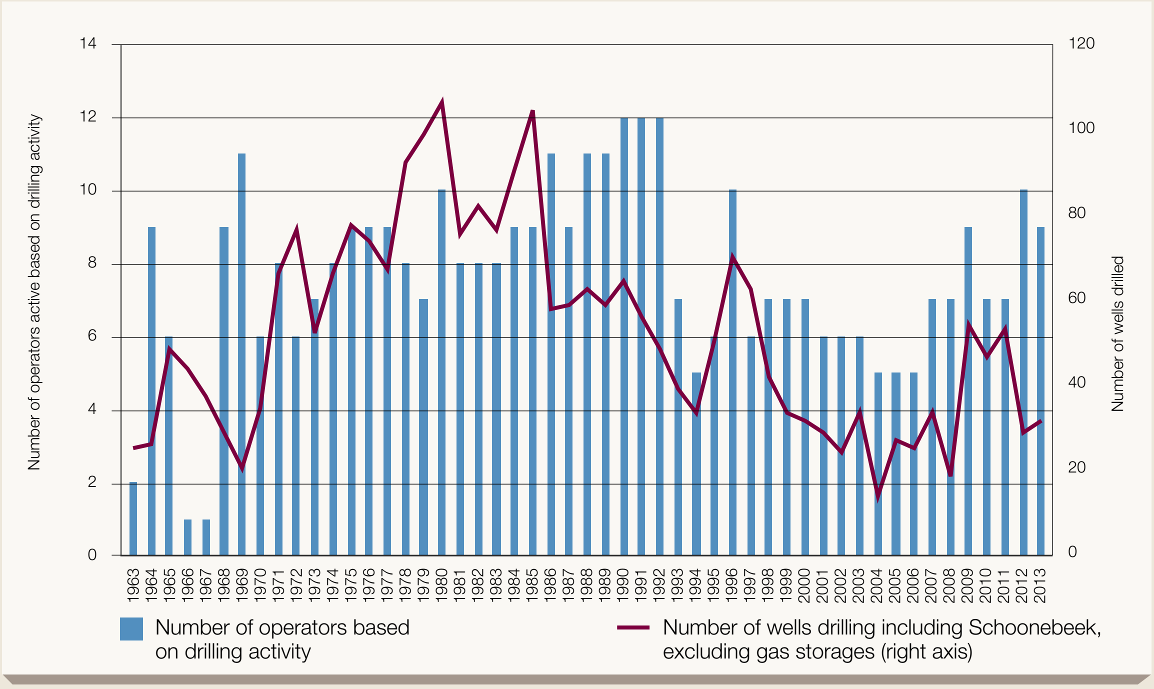
2.1 Increasing drilling activity in the Netherlands

E&P activities in 2014 are expected to be at a higher level than in 2013. EBN classifies oil and gas activities in the Netherlands into six types of projects: field development, wells drilled, enhanced gas recovery, pipelines, storage and abandonment/decommissioning. The number of planned exploration, appraisal and development wells in 2014 is markedly higher than the number of wells drilled in 2013: the total of 36 wells (18 exploration and appraisal wells and 18 production wells) planned for 2014, which is 10 more than in 2013, may herald the start of a much-awaited increase in E&P activity and investments.

2.2 Historical E&P activity levels in the Netherlands

A total of 49 operators have been active in the Netherlands since 1946, when commercial hydrocarbon production in the country started. Between 1937 and 1967, the only operator was NAM (and its predecessor, the Bataafsche Petroleum Maatschappij). In the aftermath of the chaotic exploration situation in 1963, the number and variety of operators increased from 1967 until the early 1990s. This was followed by a significant decrease, which was at least partly due to the low oil prices at the time. Since 2005, however, the number of operators has started increasing again.

Number of operators active in the Netherlands, based on drilling activity



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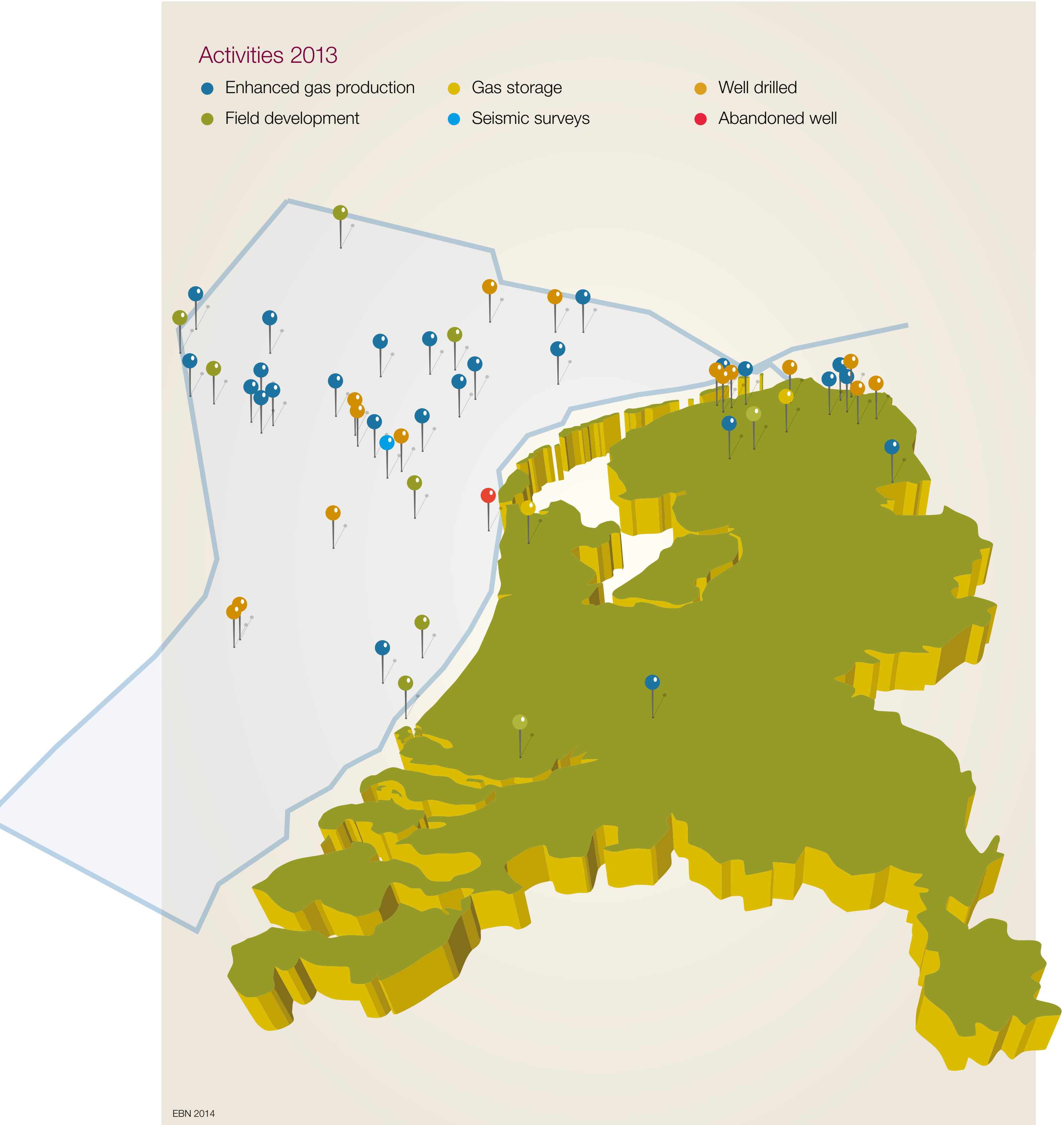

Activities 2013
Enhanced gas production
Gas storage
Well drilled
Field development
Seismic surveys
Abandoned well
EBN 2014

Increase recovery **10%**

Innovative solutions to increase recovery from the small gas fields

Activity: Seismic reprocessing symposium

In February 2014, EBN and GDF SUEZ organised a one-day symposium on ‘Seismic Processing in the Netherlands’, at which ten less well-known geophysical companies presented their seismic processing capabilities to representatives of the Dutch petroleum and geothermal industries. Most of these presentations can be found on our website (www.ebn.nl).

The idea behind this symposium was that numerous 3D surveys have been acquired in the Netherlands to date, while many legacy surveys have now been processed or reprocessed. Most of the reprocessing has been done by three to four large companies, with smaller and relatively unknown companies often being overlooked in the tendering process. By organising this symposium, EBN gave the geophysical contractors a forum to display their capabilities.

Some 70 people from 23 companies active in the Netherlands attended the symposium, with ten geophysical contractors presenting interesting material. The symposium was very well received by contractors and audience alike, and EBN is examining the opportunities for a follow-up in 2014.

2.3 Innovative solutions to increase oil and gas recovery in the Netherlands – TKI innovation projects

In 2012 the Dutch government initiated a policy to encourage innovation, for which nine specific sectors were identified. Dutch academia and industry are seen as having considerable knowledge and experience in these ‘Top Sectors’, which are seen as the most promising targets for successful innovation and international competitiveness. Of particular interest for the oil and gas industry are the ‘energy’ and ‘water’ sectors.

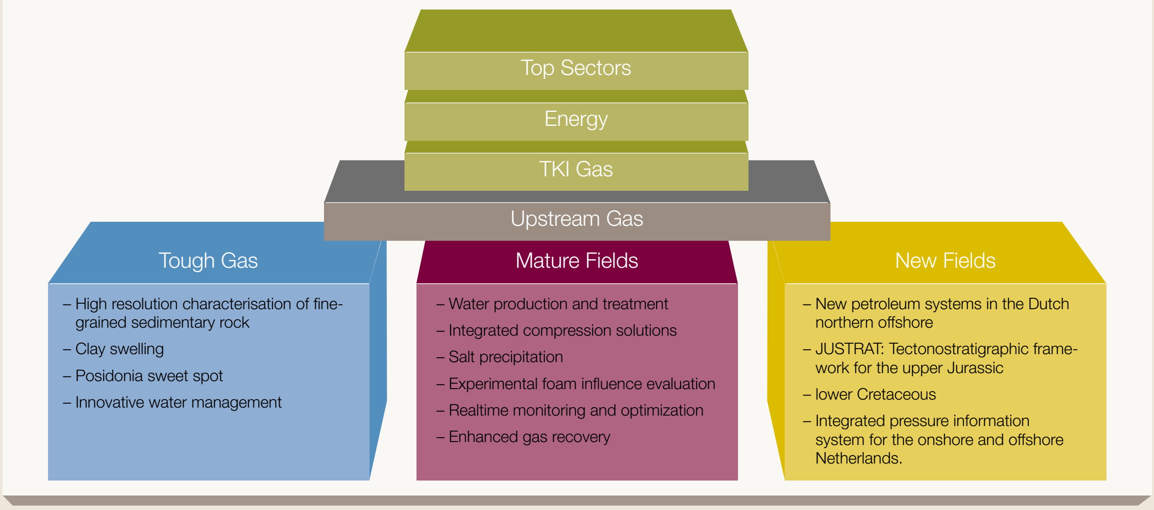
EBN participates in TKI Gas (Top consortium for Knowledge and Innovations), which focuses mainly on upstream gas innovations (www.upstream-gas.nl). The objective of this programme is to develop innovative solutions to help maximise the recovery of gas from the Dutch subsurface, particularly from small fields. The ‘upstream gas’ innovation programme is structured along three lines: Tough Gas, Mature Fields and New Fields.

Several operators active in the Netherlands participate in one or more projects in these programme lines. TNO and the technical universities (Utrecht, Delft and Eindhoven) perform most of the ‘upstream gas’ projects. Several of these projects are described in this year’s edition of Focus on Dutch Oil and Gas.

Tough Gas

Although potentially huge resources of tough gas – such as shale and tight gas – are present in the subsurface of

Upstream gas – innovation projects



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the Netherlands, new technologies are needed to improve the economic viability of such Tough Gas projects.

Mature Fields

In mature fields, the reservoir pressure has decreased to levels where compression is required to produce the gas. Projects in the Mature Fields line focus on technological developments seeking to extend the life of these fields. Relevant research themes fall into the Production & Reservoir Management and the Infrastructure categories.

New Fields

Successful exploration is key to increasing investment levels and production of both gas and oil. Even though the Netherlands is a mature area, new fields are continually being found and developed. And while exploration in a mature province poses special challenges, such as the proximity and multiple use of subsurface resources, it also provides opportunities, given the high-density data and infrastructure cover.

Innovation project: De-risking shale plays and understanding source rock, Posidonia Sweet Spot JIP study

When examining shale reservoirs in outcrop, the first impression may often be that the rocks look very homogeneous and, therefore, that it should be relatively straightforward to predict their reservoir characteristics. This impression is based on the overall fine-grained nature, great lateral continuity and overall constant thickness and dark colour. If, however, we have a closer look, it soon becomes clear that nothing could be further from the truth. Gas and oil shales consist of a complex mixture of clay- and silt-sized particles and have a highly variable organic material content, and it is this organic material that is vital for generating hydrocarbons. In productive shale accumulations elsewhere, this heterogeneity translates into highly variable well productivity.

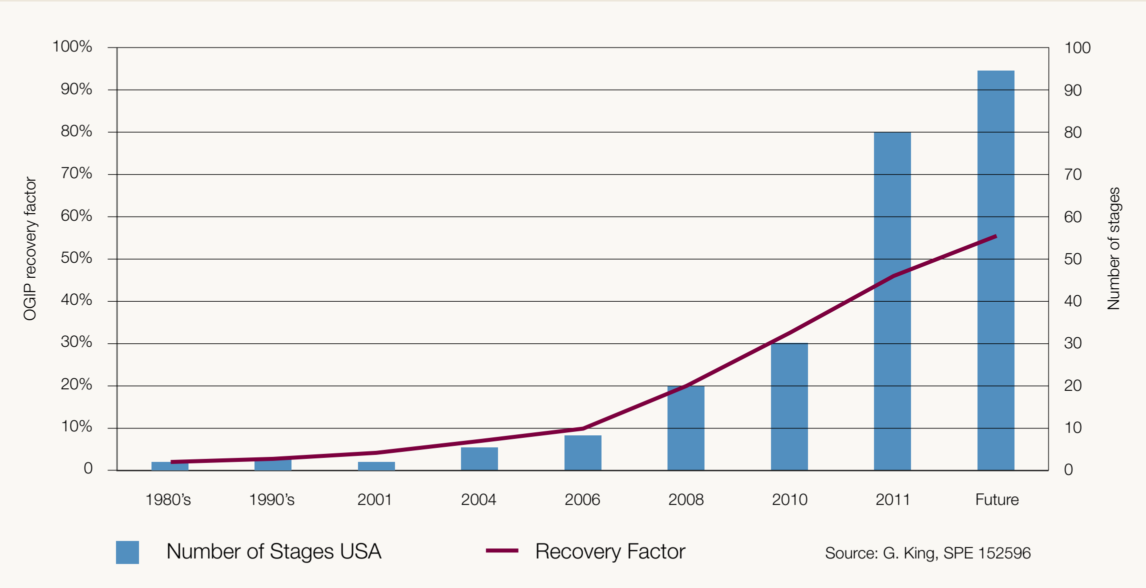
The most important exploration target for shale gas and oil in the Netherlands, the Jurassic Posidonia Formation, lies at a considerable depth. These rocks are known only from borehole measurements and, in the Netherlands, cannot be studied at outcrop. For this reason, EBN is participating in the Posidonia Sweet Spot study, a Joint Industry Project (JIP) aimed at a better understanding of the geological make-up and production characteristics of time-equivalent marine shales exposed along the UK East Coast. Initial results show many similarities with the Dutch subsurface, but have also highlighted many of the small-scale complexities seen in shale provinces around the world. Future results of this work are expected to help us to predict high-productivity intervals more accurately and thus help reduce the development footprint commonly associated with shale developments elsewhere.

2.4 Hydraulic stimulation is key to achieving economic production from poor-quality reservoirs

In the past decade, hydraulic stimulation has become a key technique for achieving economic production from otherwise uneconomic reservoirs. Hydraulic stimulation has been used to enhance hydrocarbon production in the US since the late 1940s, and in the Netherlands since the 1950s. Over the past decade, a combination of horizontal drilling and extended, multi-stage hydraulic stimulation has unlocked the unconventional hydrocarbon potential in the United States. This 'fracking' improves well economics and enables more prolific oil and gas production from zones once considered non-commercial. In the past two decades, gas production from US shale gas reservoirs has risen dramatically from 1% to over 50% of total US gas production and is continuing

Hydraulic Stimulation in the US shale play

Recovery Factor vs. number of stages



Source: G. King, SPE 152596

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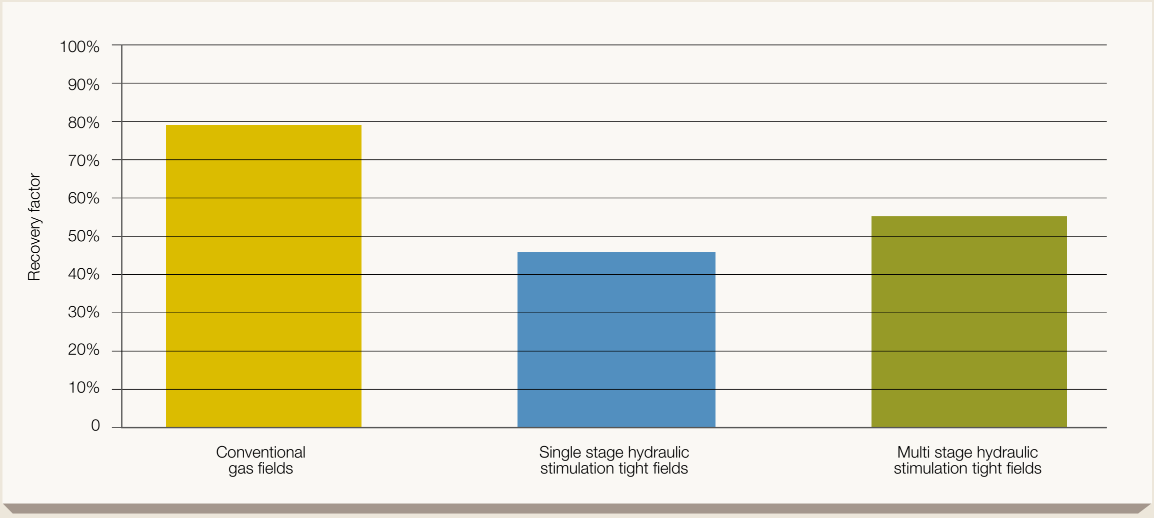
Average recovery factors in conventional fields vs. tight fields in the Netherlands



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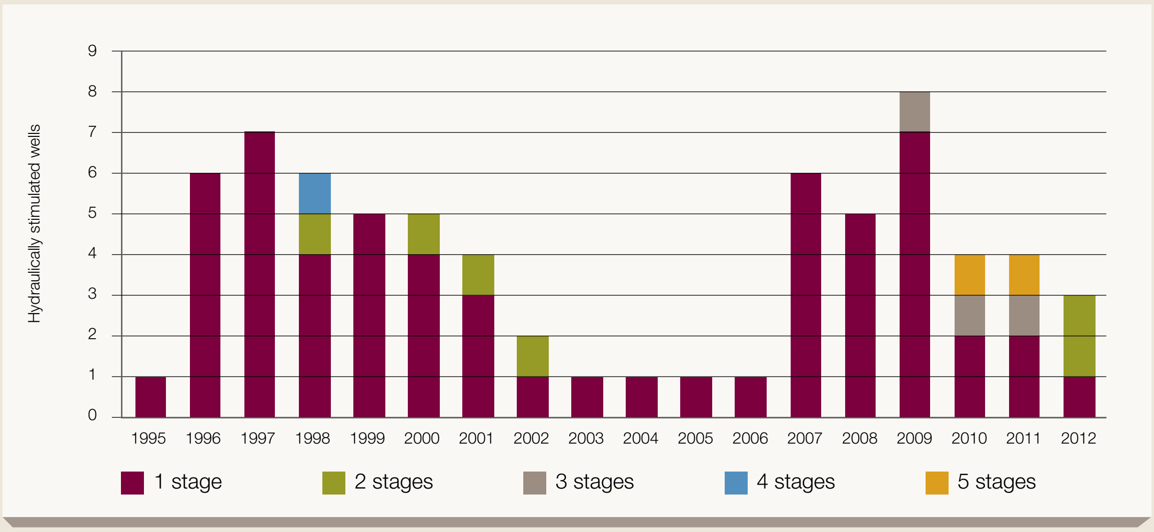
to increase every year. However, it should be noted that the terminologies for shale gas and conventional gas are completely different. The 'recovery factor' in shale gas reservoirs is defined as the fraction of oil/gas recovered from the volume within the anticipated well drainage area, which is largely defined by the well spacing. Conversely, the 'recovery factor' in conventional reservoirs is defined as the fraction of oil/gas recovered from the

Hydraulically stimulated wells with number of stages applied in the Netherlands



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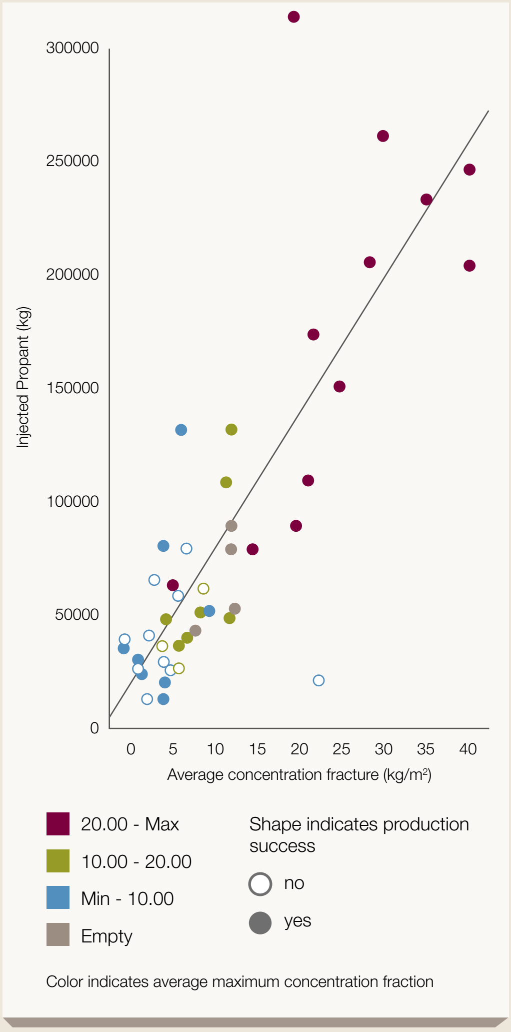
Injected proppant vs. average concentration fracture



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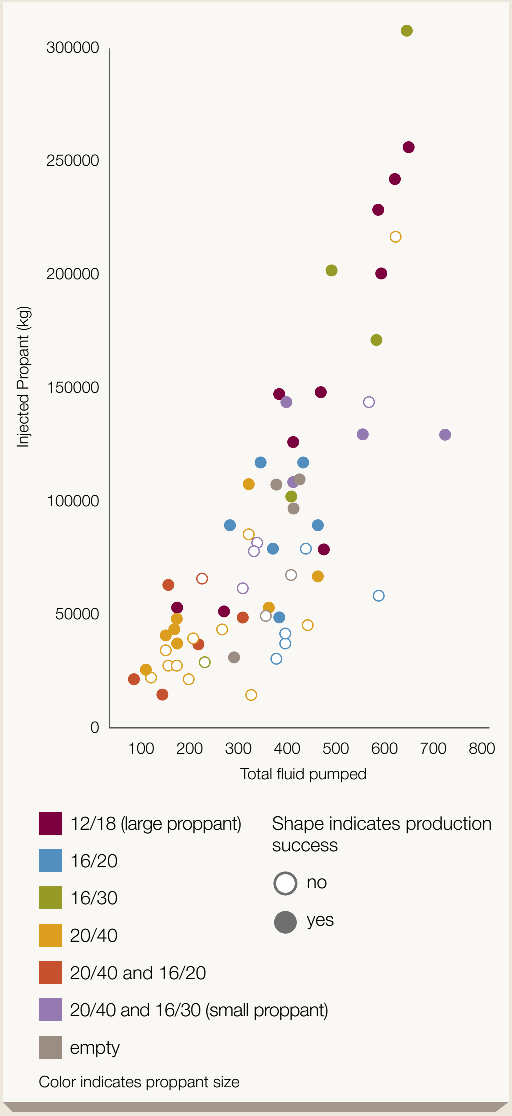
Injected proppant vs. fluid pumped with different proppant sizes



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entire field, and this is not directly related to well spacing. Of the existing gas fields in the Netherlands, 85% are producible by conventional technology. The average recovery factor from these conventional fields is generally around 80% or higher. The remainder of the EBN portfolio is categorised as tight fields, where recovery factors are considerably lower than in conventional fields.

Single-stage hydraulic stimulation (in tight reservoirs) shows an average recovery factor of 47%. In order to increase recovery from these fields, operators have been using multi-stage hydraulic stimulation and horizontal drilling. Although not many multi-stage stimulation operations have been performed in the Netherlands to date, the average recovery factor is 56%. In different upside scenarios, it is possible to reach a 60% recovery factor for these tight fields.

EBN has performed a multivariate statistical analysis on the results of 93 hydraulic stimulation treatments in the 70 wells that were stimulated in the Netherlands between 1995 and 2012. Our analysis took account of the impact of reservoir properties such as formation type and permeability; proppant size and proppant volume pumped; fluid volume; and frac length, height and width. Roughly one in ten wells drilled between 1995 and 2012 was hydraulically stimulated.

EBN collected data for 83 of the 93 hydraulic stimulations. Of these 83 stimulations, 71 were considered a success, meaning that all the proppant was placed as planned and the clean-up of the well was performed without any major operational difficulties. A total of 53 of the stimulations were considered a production success, which is defined as a satisfactory post-frac production rate. A stimulation is considered a production success if the post-frac rate is:

1 | at least twice the pre-frac rate,
2 | comparable to the modelled post-frac rate, or
3 | much better than the rate of an unfracked well in the same field.

Whether the stimulations are also an economic success depends mostly on the duration of the improved well performance.

The likelihood of a hydraulic stimulation treatment being successful increases per frac stage from an average of 55% to over 90% when the pumped proppant volume exceeds 100 tons per frac and/or the average concentration exceeds 10 kg/m^2. The success rate also increases with the grain size of the pumped proppant.

3D seismic coverage of the Netherlands, time slice at 1 second TWT.

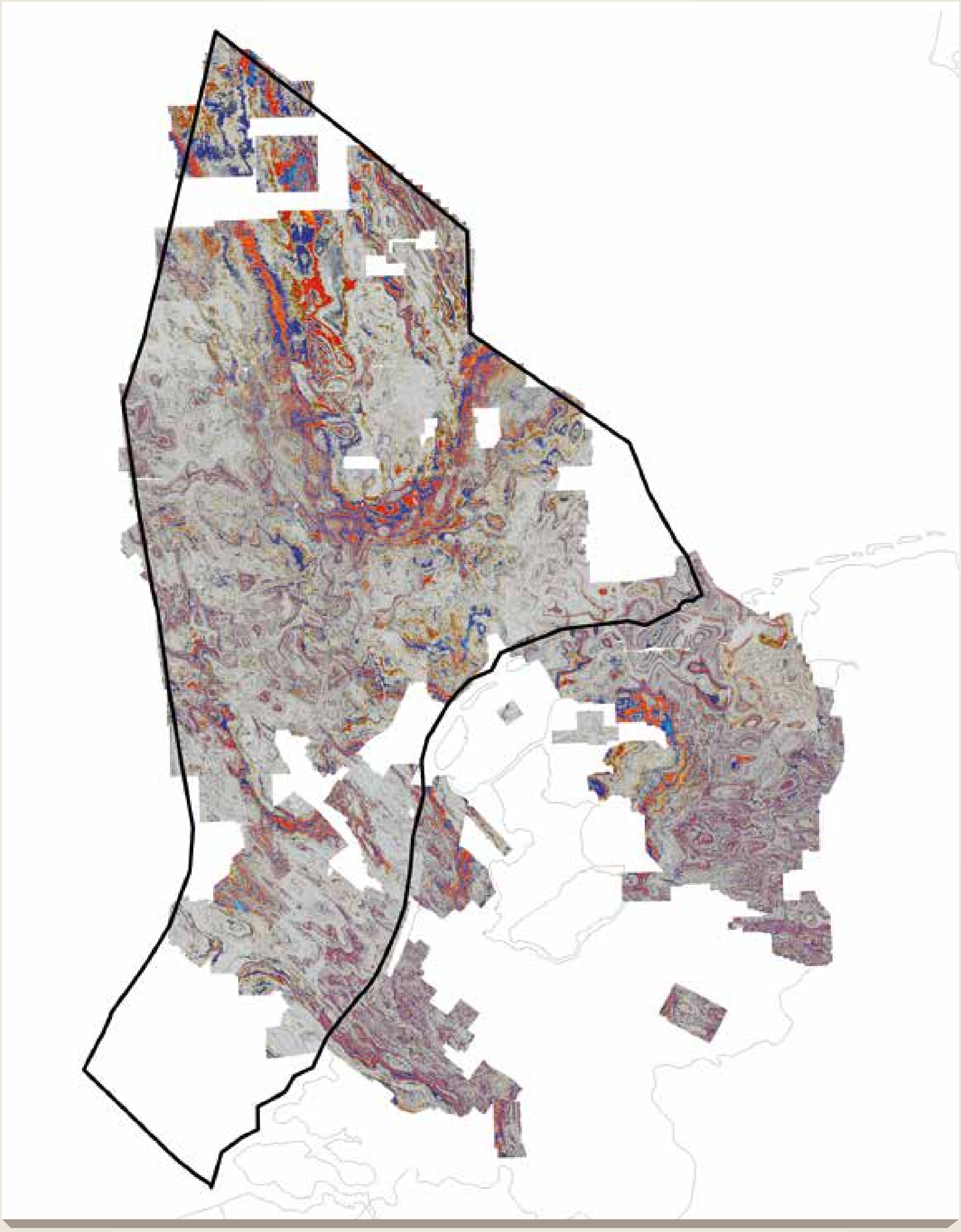

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Image - K5-B Monotower

Developments and innovations of offshore infrastructure

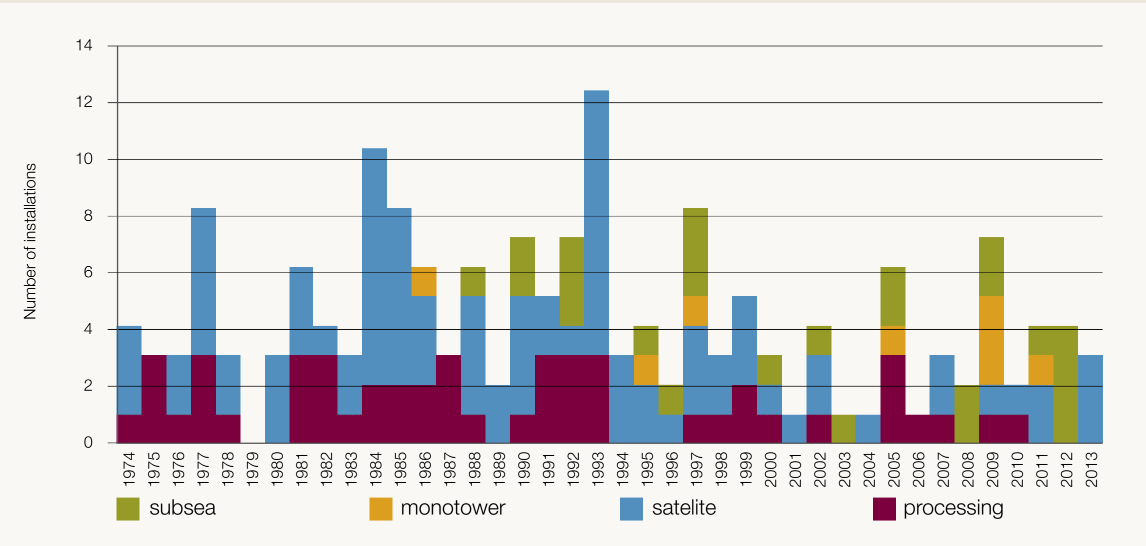
3.1 Offshore infrastructure, a brief history and innovation over time

Exploration drilling on the Dutch continental shelf started in 1962 and picked up later that decade, resulting in the first offshore gas development in license L10/L11a. The first platform on the Dutch continental shelf was part of the Placid (now GDF SUEZ) L10-A central complex, which was built in 1974 and where production commenced in 1975.

In the Dutch offshore, with water depths in the range of 20 to 40 metres, platforms traditionally consist of top-side modules supported by a braced jacket. The first facilities typically consisted of a central processing platform, connected to wellhead platforms (or satellites) and to an accommodation platform. New developments in the vicinity typically used satellite platforms connected via an inter-field pipeline to the central processing (or host) platform.


L10-A central complex (courtesy of GDF SUEZ E&P Nederland B.V.)

Installations installed by year



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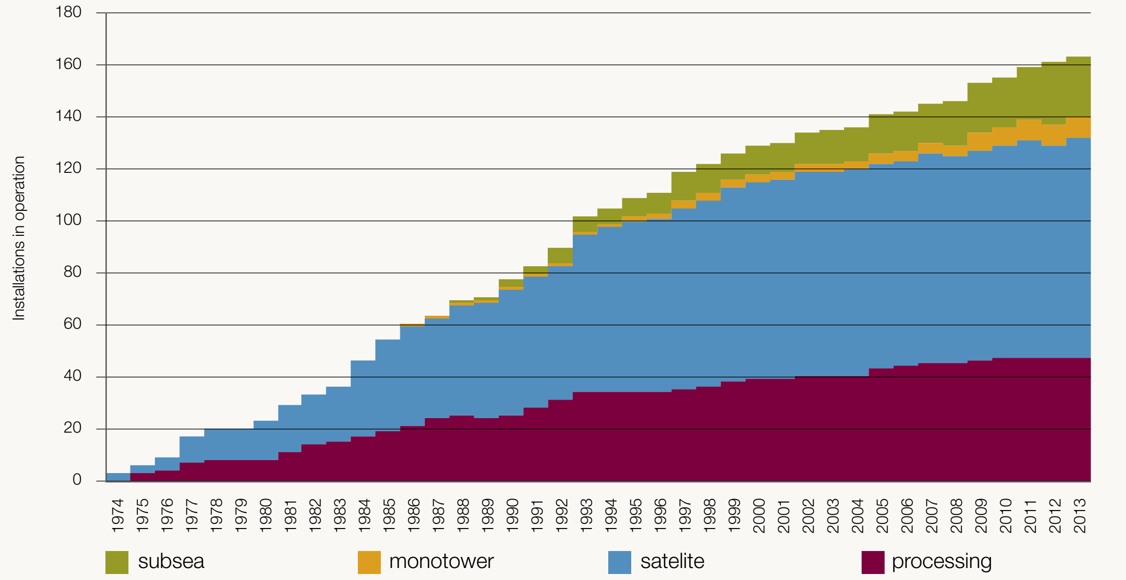
Installations in operation (cumulative)



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Over time, field size decreased and cheaper facility concepts (such as subsea wellheads, tripods and monotowers) had to be designed. Placid was the first party to opt, in 1988, for a facility with subsea wellheads at L10-S1. Subsea wells were tied back to the central host complex by pipelines, similar to traditional satellites. Another lower-cost type of concept, the 'tripod', sometimes referred to as the 'bird box', was first used by Unocal (now Chevron) in 1986 for the Q1-Helder-B oil development and in 1995 also by Elf Petroland (now Total) for the K5-B gas field development. Both platforms have tripod substructures: the platform consists of a tripod below sea level, with a monotower on top.

K5-B monotower with tripod substructure
(courtesy of Total E&P Nederland B.V.)

NAM installed its first (steel) monotower in the K17-FA field in 2005 and placed two more monotowers on L9-FA and L9-FB in 2009. Oranje-Nassau Energie also installed a monotower based on the same design at M7-A in 2009. Whereas satellite platforms used to be equipped with independent power generation by either gas turbines or diesel engines, the K17-FA, L9-FA/FB and M7-A monotowers were equipped with renewable energy systems (windmills and solar panels).

L9- FB-1 monotower (courtesy of NAM B.V.)

In order to reduce operating costs for fields with a declining production, as well as enable the economic development of smaller accumulations, the traditional manning levels of satellite platforms had to be reduced over time. As the continuing innovation in communication technology permits remote operation of satellite platforms, these are now normally unmanned.

3.2 | Innovations in offshore E&P

Suction anchors

Suction anchors were first applied in 1996-1997 by Clyde (now Wintershall) at three satellite platforms in the P2 and P6 blocks. These satellites are now all being re-used for other Wintershall field developments (P2-SE for P6-D in 2000, P2-NE for Q4-B in 2002 and P6-S for Q1-D in 2013). Other applications of suction anchors are at F3-FA installed by Centrica in 2010, at a Riser Access Tower adjacent to NAM's K15-FA platform in 2011, at GDF SUEZ's Q13-A Amstel in 2013 and at Wintershall's L6-B minimum facility monotower/tripod, which is to be installed in 2014.


Q13-A Amstel satellite (courtesy of GDF SUEZ E&P Nederland B.V.) uses suction piles

Eductors

Various operators have recently acquired new seismic data within their mature production licences and are developing smaller accumulations, either with smaller and lower-cost installations or by extended-reach drilling from existing satellites. When high-pressure gas becomes available at existing installations, this energy can be used to enhance the recovery of low-pressure mature fields by applying eductors (i.e. jet pumps; for a detailed

Installations in operation **163**

Exploration efforts must be increased while infrastructure is still in place

description, see the 2013 edition of Focus on Dutch Oil and Gas).

"Walk-to-Work" systems

Satellites were traditionally designed to be self-sufficient and equipped with helicopter decks, cranes and gas or diesel-driven power generation. In 2008, offshore access systems were introduced that, under most conditions, allow marine access to platforms, thus avoiding the need for a helicopter deck and costly helicopter movements. The same technique of compensating vessel motion to provide a stable walkway is also being applied to allow cranes to work off a supply vessel; future installations may, therefore, have smaller or no cranes.

Offshore access system
(courtesy of Ampelmann Operations B.V.)

Innovations: Walk-to-work systems

'Walk-to-work' systems are a relatively new concept and generally consist of a dynamically stabilised access system mounted on a support vessel. The position of the system relative to the platform is maintained by using fast-acting hydraulics to continuously adjust for wave movement, a technology similar to that used in flight simulators. These systems ensure a safe and comfortable transfer of staff from the support vessel to the platform structure, a step change compared with the traditional boat-to-structure transfer methods. The same technology may soon be used for position-compensated cranes and other machinery, thereby increasing the versatility of these vessels and bringing them into direct competition with jack-up systems.

Re-use of platforms

Although re-use of platforms is common in the Gulf of Mexico, re-use within the Dutch E&P sector is typically restricted to the same affiliate. To date 11 satellite platforms (normally only the topsides) have been re-used in new field developments. The main advantage of re-use is not so much saving costs, but rather shortening the lead time needed for constructing new facilities and, therefore, accelerating first production, while at the same time reducing the environmental footprint.

3.3 Tail-end production and optimisation

As the first offshore gas production started some 40 years ago, it is not surprising that many fields have now reached the final phase of production. Because of the maturity of the area, cost-effective tail-end production is becoming increasingly important. In many cases, rapidly declining production revenues no longer cover the costs of operating legacy infrastructure. Drastic steps are, therefore, required, either to reduce operating costs or to add more gas to the system, and preferably the latter.

Innovation project: Emulsion treatment using membranes

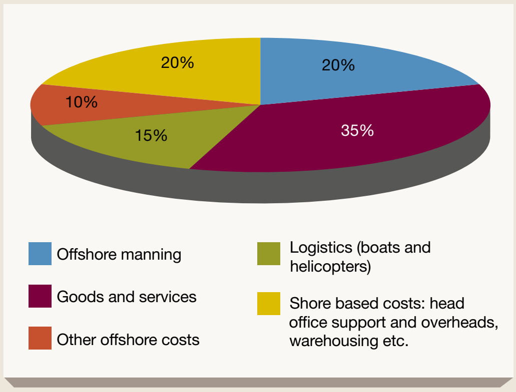
Although membranes have long been in use in industrial applications, offshore operators have been slow to accept them. Membranes have rather a bad reputation; they are seen as being prone to fouling and have a low throughput capacity, while the systems are bulky and heavy, and so not really ideal for offshore applications. Recent developments, however, have changed this reputation. The introduction of membranes based on silicium carbide (SiC) has dramatically reduced fouling problems, while their throughput capacity is also higher. Commercial-sized systems are now being used by at least one major

international operator. Experience so far has confirmed the high expectations. A joint industry effort in the Netherlands is spearheading further development of these systems, under the umbrella of the Dutch government's innovation programme and managed by the Institute of Sustainable Process Technology (ISPT, www.ispt.eu).

3.4 Reduction of operating costs – paradigm shift required

EBN continually strives to minimise production costs by, for example, facilitating the regular benchmark study of offshore operating costs (the 'BOON (Benchmarking Opex Offshore Netherlands) study') in cooperation with NOGEPA (the Netherlands Oil and Gas Exploration and

Operating costs



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Production Association), which is the sector organisation for the Dutch E&P industry. EBN's unique overview of E&P activities in the Dutch offshore enables it to share key insights, benchmarks and best practices with the industry. Constraining operating costs is key to a sustainable E&P industry.

Reducing operating costs in mature areas is a serious challenge. Facilities are often large and underutilised, having been designed for times of plateau production when abundant quantities of gas were going through the systems. Changing long-established operating practices may be only a first step. In addition to transportation costs, financial costs and tariffs, operating costs generally comprise offshore manning, goods and services, logistics, shore-based costs and other miscellaneous offshore costs.

Traditionally, viable operational reliability, or 'up-time', as opposed to operational efficiency, has been key to successful exploitation. However, a paradigm shift is required for a successful tail-end production, where operational efficiency is equally, if not more, important than reliability. Reducing the number of offshore personnel, one of the biggest offshore cost drivers, is an example of such a paradigm shift.

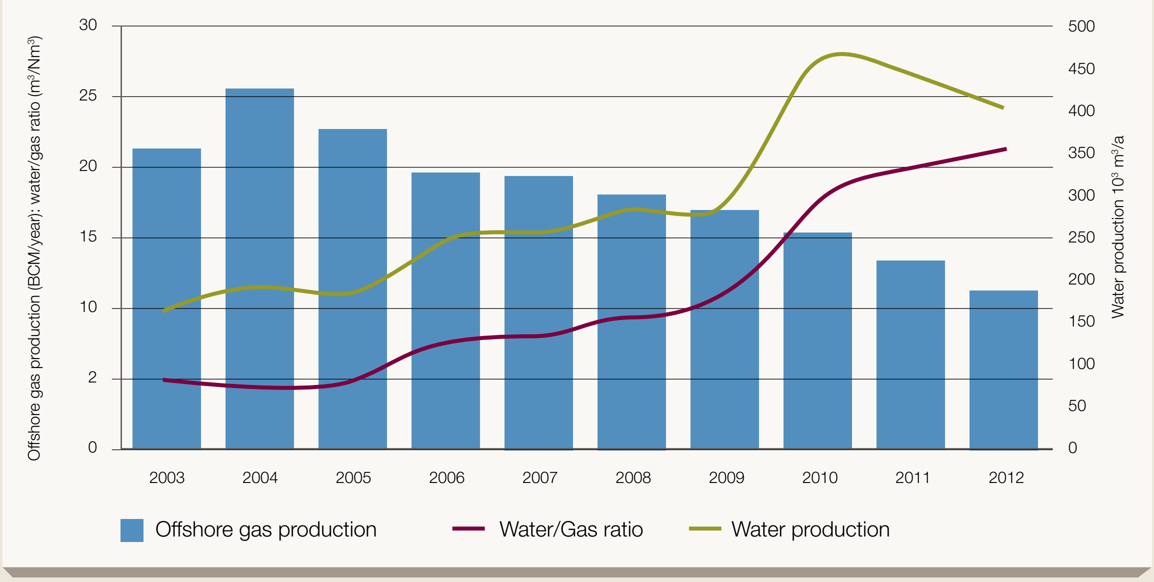
Operational departments are conditioned to believe that manning is the only way to ensure safe and reliable operation of complex facilities. This requires a person either being physically present or at least quickly able to access the platform by helicopter. Removing the helideck, for instance, and switching to 'walk-to-work' systems also removes the need for accommodation and all additional 'knock-on' installations, such as deluge systems and rescue crafts. In combination with decomplexing, a high degree of facility automation will result in substantial savings and thus make it possible to extend the tail-end production phase significantly. This will enable additional reserves to be recovered.

As 'walk-to-work' systems are obviously less versatile than helicopter access as a first-response system, it could be argued that marine access could lead to decreased reliability and, therefore, to production delays. Although only a handful of 'walk-to-work' systems are currently in use, operational data so far do not indicate any significant loss of reliability compared with traditional helicopter access systems.

3.5 Tail-end production challenges: water production

Many mature offshore assets are in the tail-end phase, suffering from declining production and continually increasing volumes of produced water and water-to-gas

Offshore water production



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ratios. It is an ever-increasing challenge to collect and dispose of produced water. Modern production technologies, as well as the need to keep ageing installations in operation, require increasing quantities of production chemicals such as corrosion inhibitors, foaming agents and kinetic hydrate inhibitors. In combination with condensates, these chemicals tend to form emulsions, which are increasingly difficult to handle. The legally permitted water-over-board quality limit of 30 ppm aliphatic hydrocarbons is, in many instances, difficult to achieve. It is often more cost-effective to inject the produced water into dedicated water-disposal or converted production wells.

Traditional produced-water disposal methods have recently been reaching their technological limits, thus requiring the development and maturation of new technologies to handle the more complex mix of chemicals reliably and cost-effectively, while still meeting the continually tightening environmental standards. This is a shared challenge, and something the industry needs to focus on. EBN believes that Dutch industry and R&D institutes, with their uniquely strong position in water management, are excellently positioned to provide innovative solutions and to share their experience and best practices.

Innovation project:
Experimental Foam Evaluation

The reservoir pressure in gas fields decreases over time. Water and condensate can no longer be produced by natural flow. Produced fluids accumulate down hole, which significantly reduces the gas flow or even stops it entirely (liquid loading). This is a serious issue because most gas wells in the Netherlands are at the end of their production life, when liquid loading is a common problem.

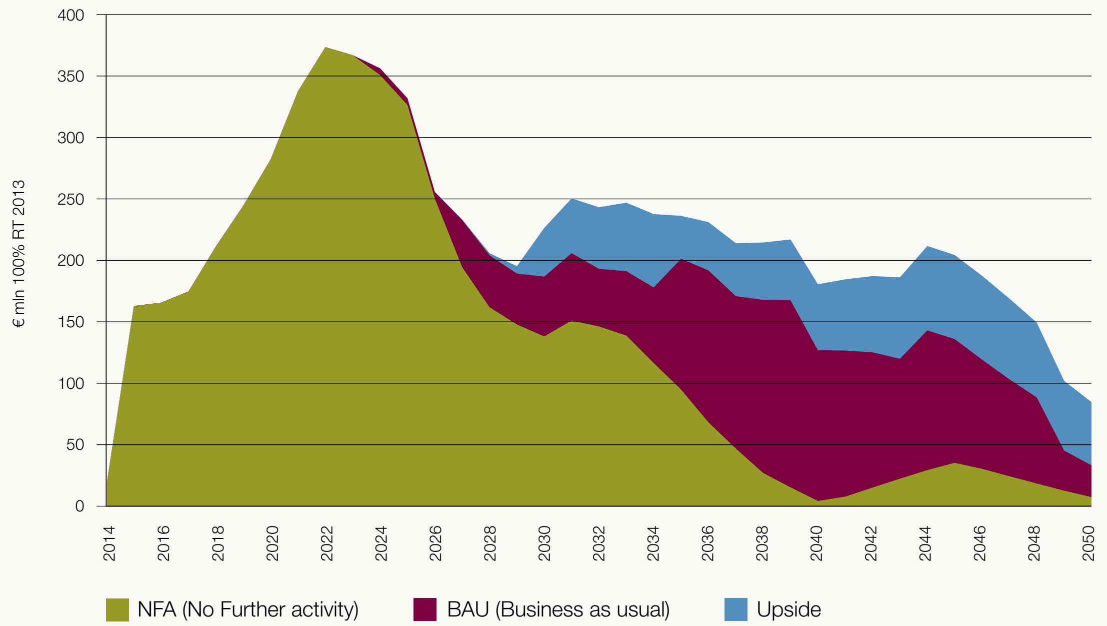
Experimental set-up to prevent liquid loading at TNO (TKI 'experimental foam evaluation' project).

One of the most promising techniques for preventing liquid loading is the use of foamers. Foamers transform liquids into foam, which is much easier to transport to the surface. The practical issues that come with the selection and application of foamers are being addressed in the TKI/JIP 'Experimental Foam Evaluation' project. The partners in this project are NAM, Total, GDF SUEZ, ONE, Taqa and EBN.

3.6 Abandonment expenditure and development over time

Significant abandonment activities will be needed over the coming decades. As very few platforms in the Dutch sector have so far been abandoned, experience in

Estimated abandonment costs for Dutch oil and gas installations



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abandonment operations, and the related cost estimates, is limited. This is illustrated by the fact that the E&P industry's estimates for decommissioning costs until 2050 for currently existing infrastructure increased from approximately €3 billion in 2011 to about €5 billion Real Term in 2013. If account is taken of decommissioning costs related to infrastructure still to be built (in the BAU and Upside investment scenarios), this figure will rise to approximately €8 billion by 2050.

Although the peak of decommissioning is expected to occur in the next decade, it is important to stress that this is a very dynamic picture. Not only are the abandonment costs themselves highly uncertain, but the timing of abandonment is also very uncertain and depends on many factors.

Most of the abandonment activities will be offshore. This means that once major processing hubs are removed, all the nearby exploration prospects and potential development projects, which rely on the availability of these hubs, will automatically become uneconomic. Consequently, the related contingent resources and undeveloped reservoirs will revert to the 'unrecoverable' category. In other words, the longer the lifespan of key offshore infrastructure is extended, the more likely it is that 'BAU' and 'upside' resources can be developed, while these reserves will in turn extend the lifespan of the facilities. EBN is therefore seeking to extend and continue end-of-field-life production and to stimulate exploration activity (see next section) in order to extend and fully use the window of opportunity offered by the existing offshore infrastructure.

Exploration activity

4.1 Measures to increase exploration activity in the Netherlands

Stimulating exploration is one of EBN's key missions. Even though the Netherlands is generally a mature gas province, some basins or geological plays are still under-explored. EBN focuses on these underexplored areas.

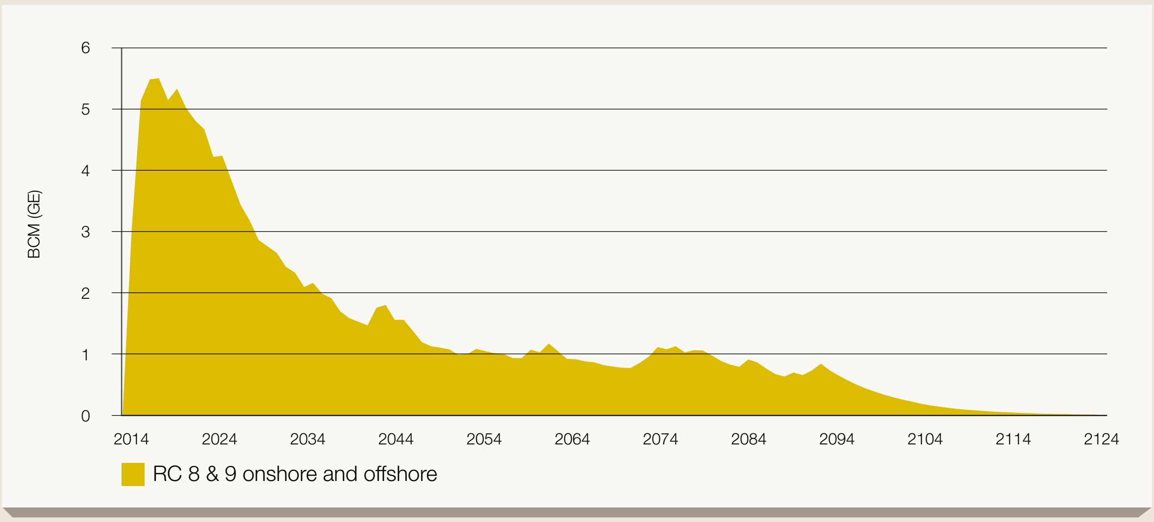
Timing is crucial, especially offshore. The risk of infra-structure disappearing in the near future drives the focus towards exploration. If we continue exploration at the present level, another 45 BCM can still be produced from new exploration finds in 2050. This estimate is based on currently identified prospects and excludes prospects yet to be defined (BAU scenario).

EBN believes it is vital for Dutch society to optimally use the petroleum resources present in the Netherlands. It is therefore essential to ensure that the entire Dutch subsurface is explored while key infrastructure is still operational. Since EBN is a partner in most licences, it has access to numerous technical studies, well results and so on. It is therefore ideally positioned to integrate technical knowledge, to build on it and to make sure everyone can benefit from this integrated knowledge base. The currently ongoing 'DEFAB' (see section 4.3) and Zechstein studies are examples of this. The results of EBN's exploration studies are published at regular conferences and workshops, in scientific publications, on the EBN website and in Focus on Dutch Oil and Gas.

Successful promotion of these exploration studies is expected to result in more exploration activity and investments by current operators and also to attract new players to the Netherlands.

Risked production forecast from future exploration efforts

Based on current prospect database & current exploration rate (BAU)



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Geo – drilling Hazards

Being a partner in most E&P well projects in the Netherlands, EBN has excellent insight into operational drilling performance. Based on internal reviews, it was observed that at least 20% of the wells drilled suffered from serious cost overruns due to unexpected geo-drilling incidents. Geo-drilling incidents are caused by local geological features.

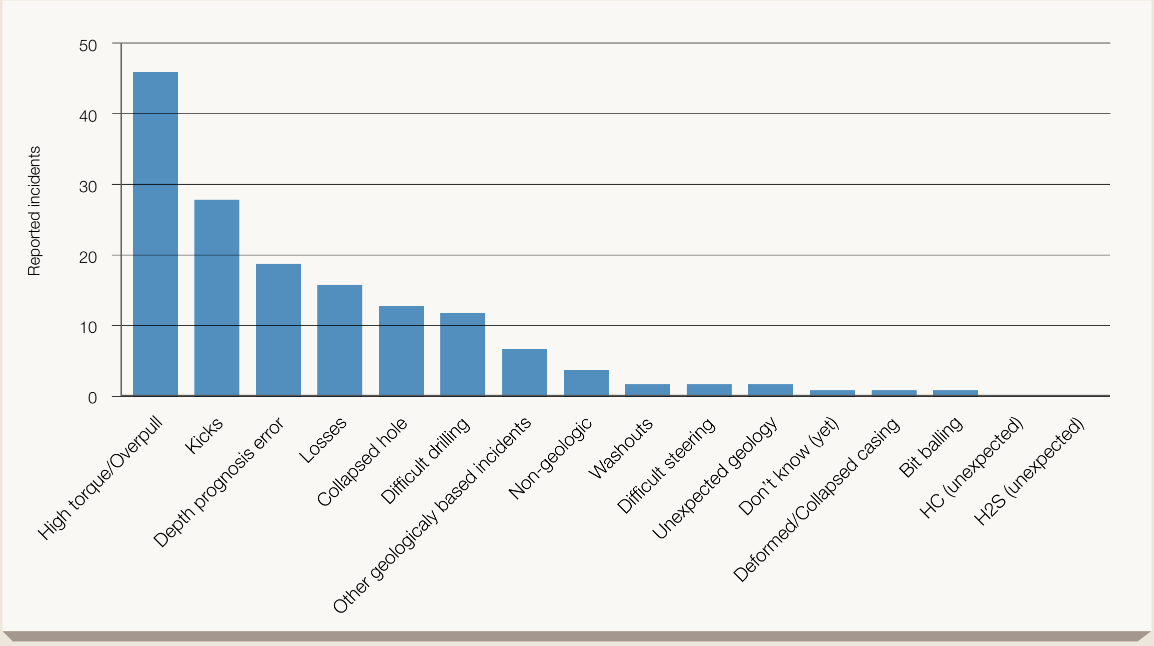
Geo-drilling hazards can cause significant drilling problems, particularly if they are not identified in the well-planning phase. Improved understanding of the local geology is expected to optimise well designs.

This, in turn, will result in fewer unexpected drilling events. Although, obviously, not all geo-hazards can be eliminated, better geological information can be expected, statistically, to improve the well performance of most drilling targets.

Sharing drilling experience across the industry will improve the prediction of geo-drilling hazards. EBN has worked with NOGEPA, TNO and operators to pioneer a method for classifying and sharing observations on geo-drilling hazards (TNO report 2013 R10190). In a pilot study we screened some hundred wells to gather statistics on the frequency of certain drilling incidents. These incidents were subsequently linked to specific geo-drilling hazards.

Applying this approach to more wells may identify regional or other trends and de-risk future wells.

Reported drilling incidents



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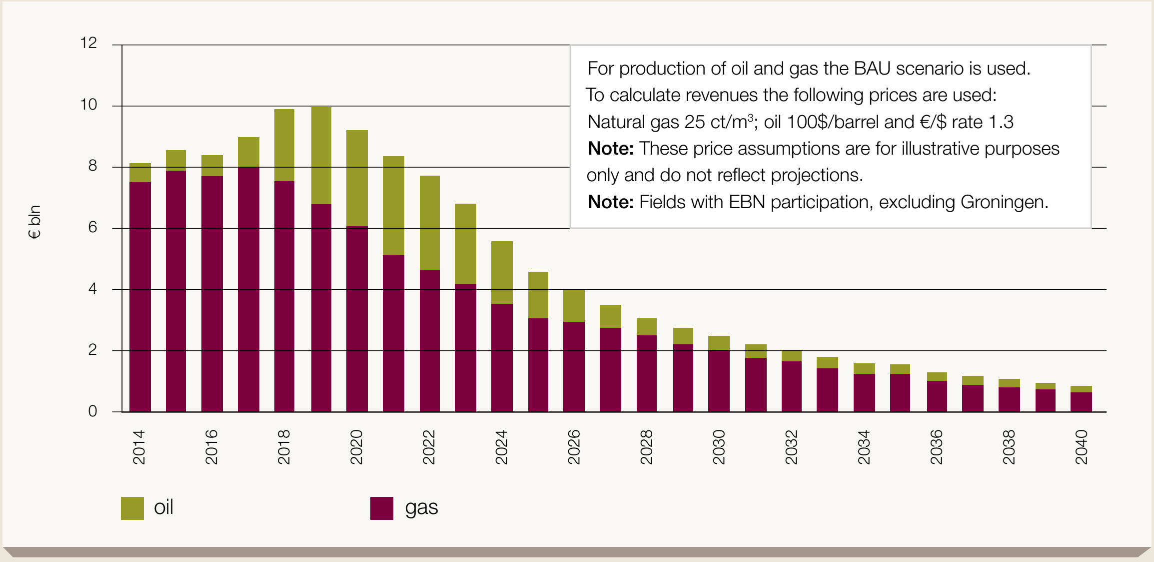
Indication future hydrocarbon revenues NL



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4.2 | Oil activity

Although the Dutch hydrocarbon basins mainly produce gas, significant numbers of oil fields have also been discovered and developed. The ratio of oil revenues to gas revenues is likely to increase in the coming years due to the prognosed increase in oil production and the estimates for oil and gas prices.

High oil prices have recently triggered a revival in oil activity and we are experiencing another peak in drilling activity. Many of the wells in this recent activity peak are attributable to the redevelopment of the Schoonebeek oil field. Offshore oil activity is also increasing, including, for example, the development of the Amstel oil field, oil exploration wells in the DeRuyter and Hanze areas and various oil exploration and appraisal wells in the southern F and northern L areas. Most oil is typically found in Upper Jurassic or Lower Cretaceous sands or Upper Cretaceous chalk, while minor oil is also produced from Triassic and Zechstein sands.

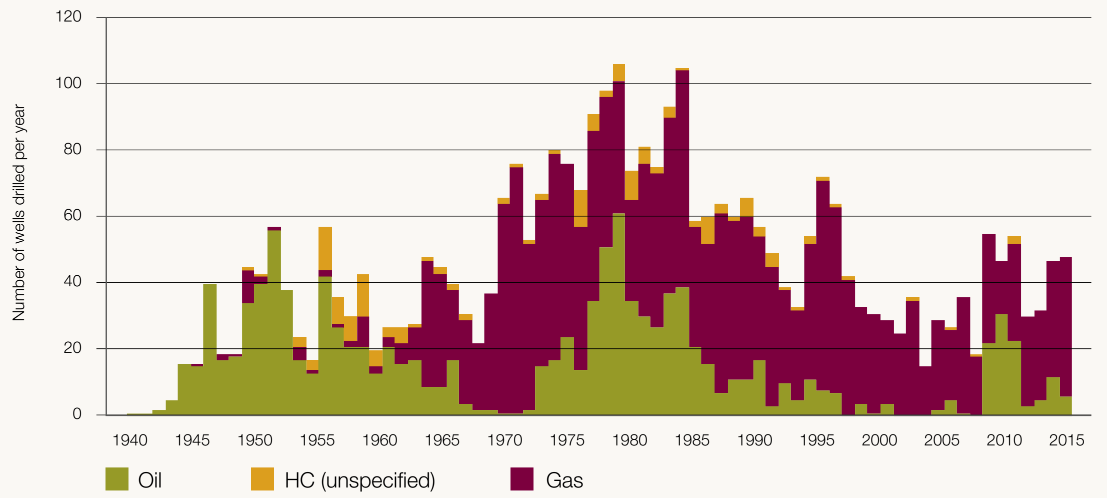
4.3 | Exploration study in the Northern Offshore; D,E,F,A and B blocks

4.3.1 Underexplored Chalk

The first results from EBN's 'DEFAB' study of the D, E, F, A and B blocks in the Northern Offshore indicate the presence of a number of untested Chalk structures, 25 of which are in open acreage. These structures in the A, B and northern E and F blocks are estimated to vary in size from 10 MMbbls to 300 MMbbls oil in place (unrisked).

More than twenty Chalk leads are located close to Posidonia source rocks. Another ten closures are located within 50 km of these Jurassic source rocks. Any potential resources in these structures will depend on effective long-distance oil migration. A map of oil shows versus source rock locations indicates that some oil shows occur at significant distances from the nearest Jurassic source rocks, thus suggesting that long-distance migration is indeed possible. Another explanation for these oil shows is the presence of other oil source rocks (such as

Drilling activity in the Netherlands



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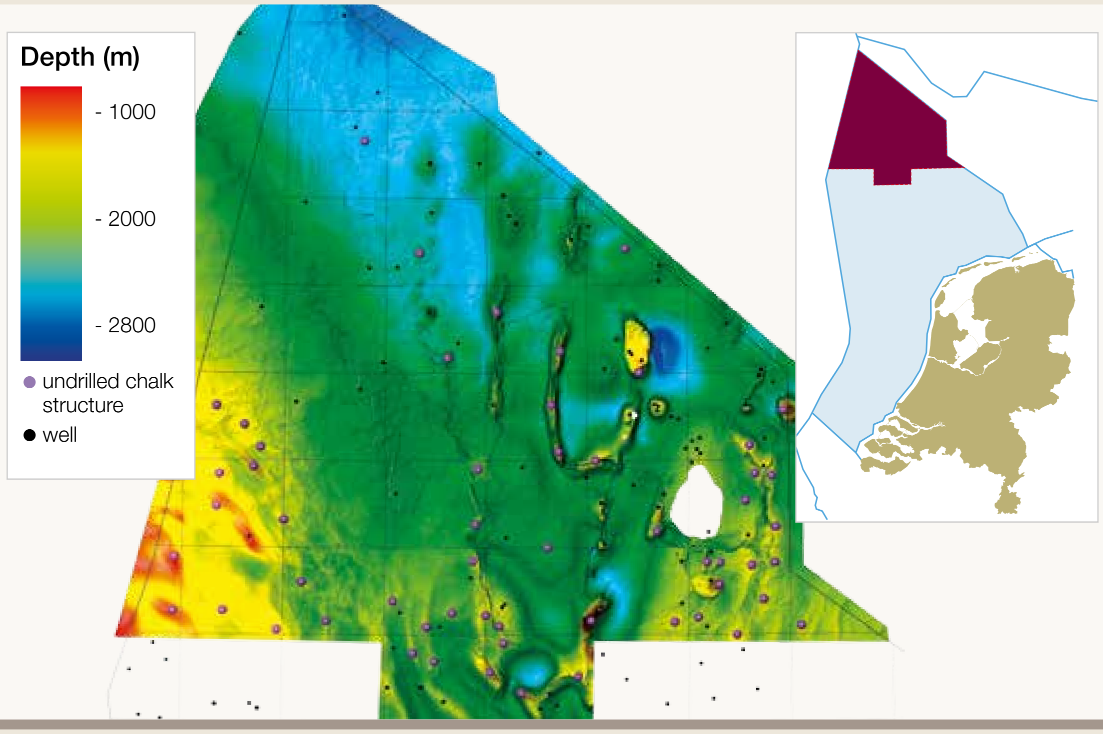
Top Chalk depth map



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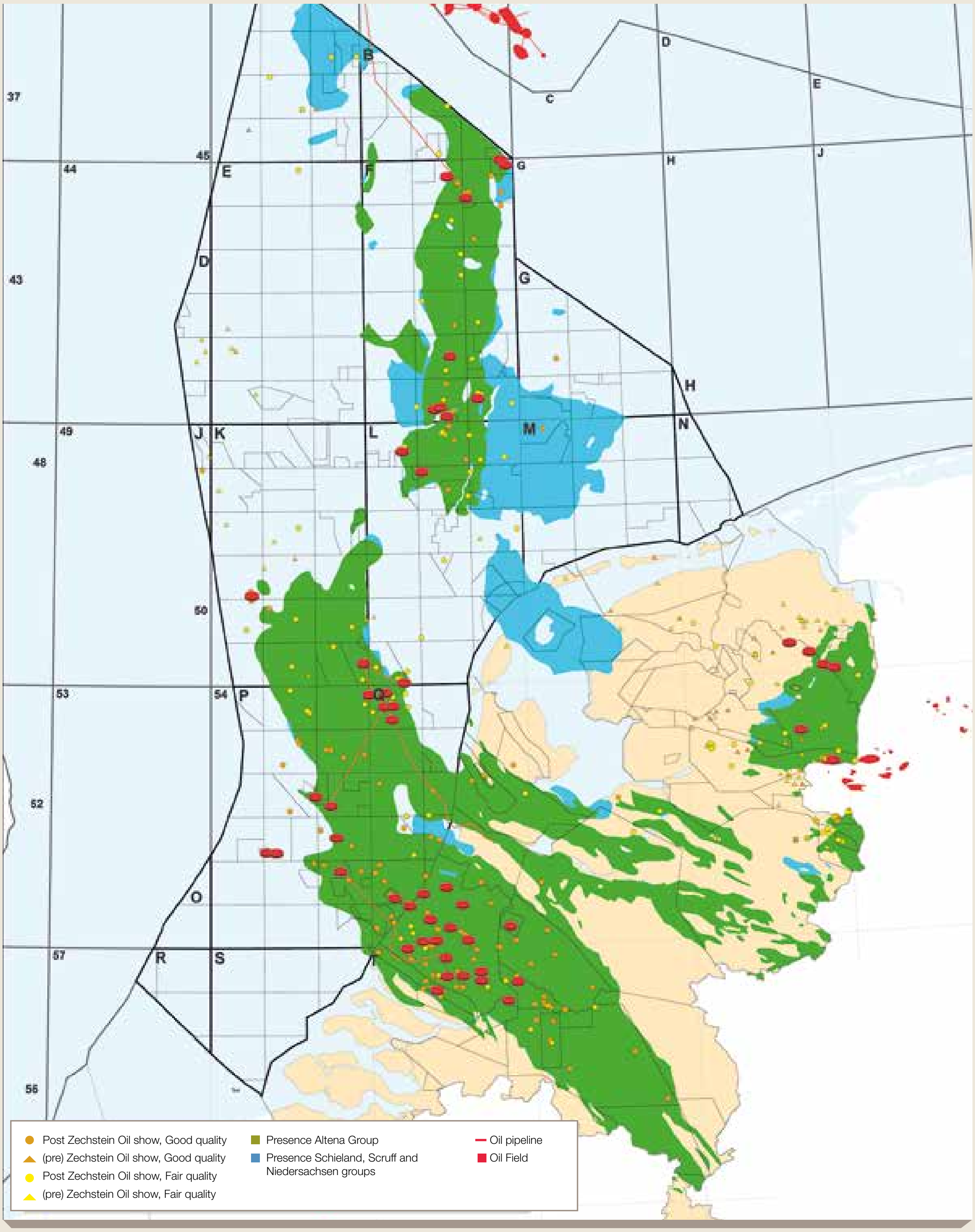
Oil fields and shows in the Netherlands



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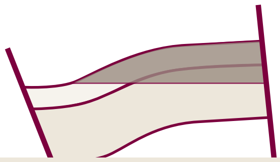
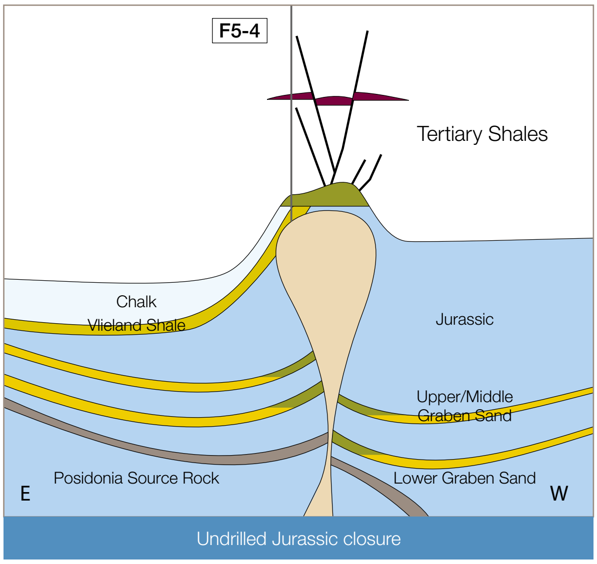


BCM >200

The Netherlands is a mature but still attractive basin for exploration

Zechstein Kupferschiefer shales, Upper Jurassic shales or Carboniferous source rocks). Geochemical fingerprinting of the oil shows may reveal the source rock.



A recent 3D seismic survey helped visualise undrilled Jurassic closures in Blocks F5 and F8. Improved imaging in this recent 3D seismic survey reveals Jurassic oil/gas potential underneath a salt diapir/droplet.

4.3.2 New source rock in the Northern Offshore?

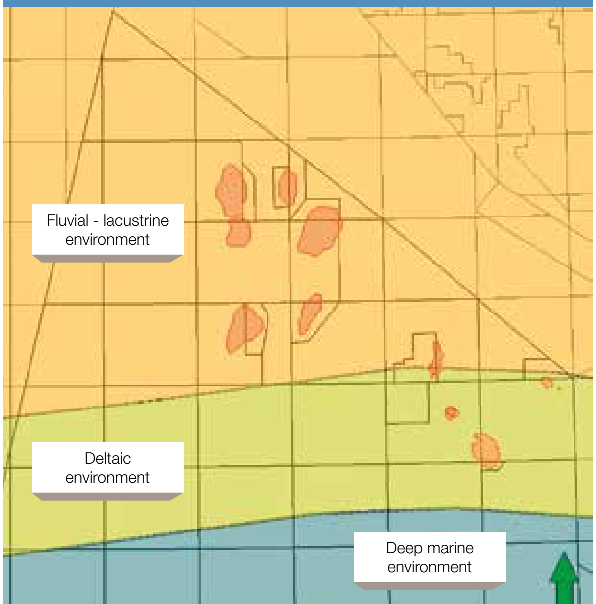
It is widely accepted that most gas in the Dutch offshore sector is sourced from Upper Carboniferous (Westphalian) coals, while the source of most of the oil is the Jurassic Posidonia shale. Towards the north, however, Carboniferous strata are progressively eroded, while Posidonia shales are preserved only in the Dutch Central Graben; in other words, no source rocks are known to exist in part of the Northern Offshore. The presence of shallow Tertiary gas fields in an area without obvious source rocks has always been an enigma. It has been suggested that the origin of the shallow gas may be biogenic rather than thermogenic. Biogenic gas is generated by bacteria feeding on TOC (total organic content) particles in or near the Tertiary reservoir.

Recent publications (Nytoft, EUPP, Kombrink) and recent EBN mapping of the DEFAB area suggest that there may be an active Lower Carboniferous gas source rock present in the A & B blocks. This is in line with earlier indications for this source rock in the PetroPlay study. This possible source rock is known as the Lower Carboniferous Scremerston Formation and has been drilled by various wells in the Dutch, UK, German and Danish sectors. Significant amounts of Lower Carboniferous coal have been found in the northern part of the Dutch sector, where a fluvial/lacustrine depositional environment probably existed in this area in Late Dinantian times. Thick coal layers in UK well 39/07-01 generate an obvious seismic reflector, the continuation of which can be traced into the Dutch A & B blocks.

The overlap of the locations of the shallow gas fields (red outlines) and the distribution of the most deeply buried parts of the gas-prone Scremerston Formation are remarkable.

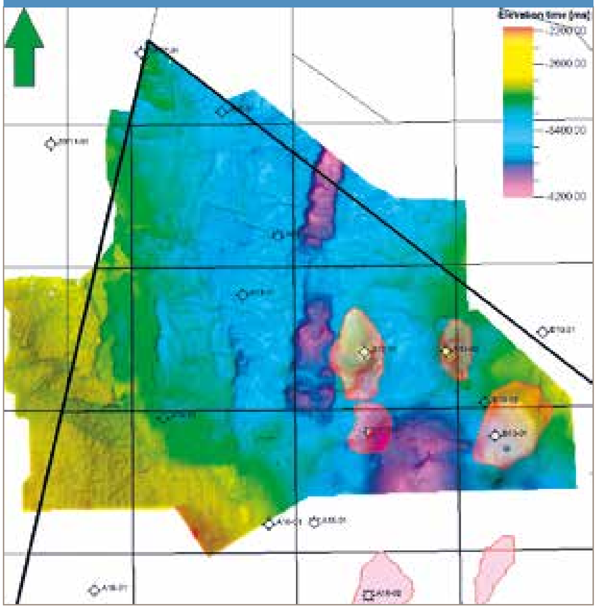
The inferred presence of an active source rock is good news for the Northern Offshore. This area had historically been downgraded because of the perceived absence of

Lower Carboniferous Palaeogeography in the Northern Offshore



After Kombrink 2008

Near top Scremerston Formation TWT
EBN 2013



source rocks. Plays that deserve renewed interest are Jurassic traps sealed by Jurassic or Lower Cretaceous shale or by tight Chalk. Such fields have been found just across the border in the UK (Fife, Fergus and Flora) and Germany (A6-A). Traps in Triassic, Zechstein and local Rotliegend sands and Carboniferous reservoirs also need further study, with particular attention being paid to the sealing units in these areas.

4.3.3 Potential of Zechstein carbonates in the Northern Offshore

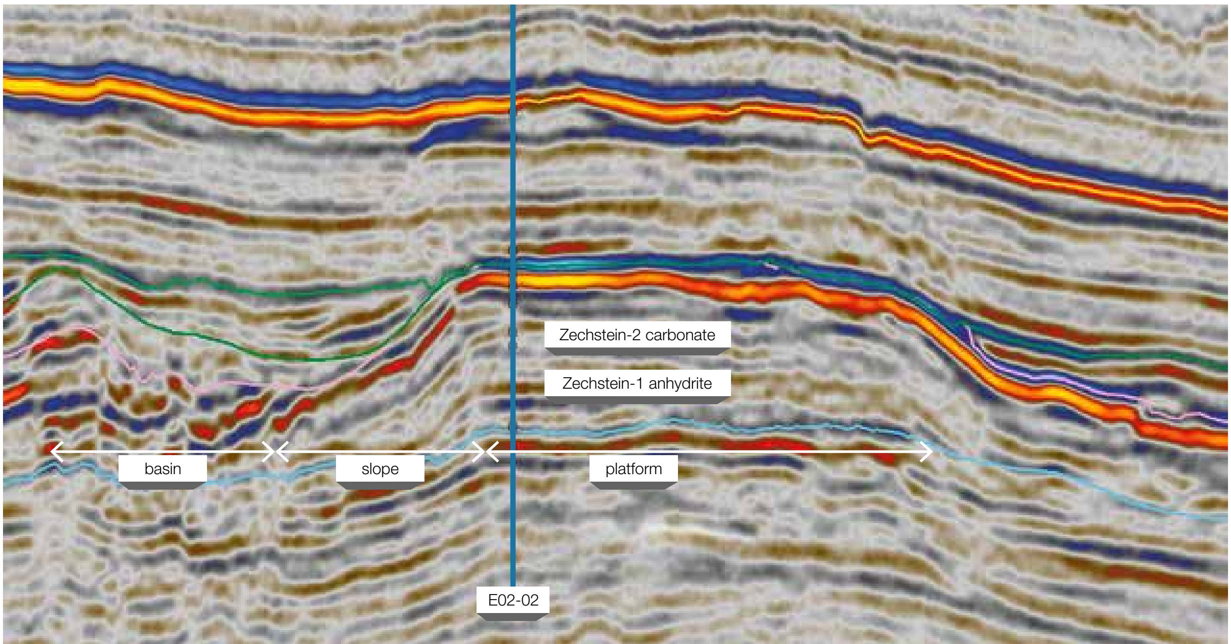
EBN is studying the reservoir potential of the underexplored Zechstein-2 carbonates in the DEFAB area. A regional review of well and seismic data and comparison with producing onshore fields in Poland and the Netherlands indicates potential plays in the DEFAB area, especially around the Elbow Spit High, where conditions were locally favourable for the development of Zechstein carbonate build-ups. Untested structures have been identified, and these could become exploration targets.

East-West seismic cross-section through E02-02. The seismic data show a Zechstein-2 build-up with a transition from platform to basin. Well E02-02, drilled on the flank of the Elbow Spit High, confirmed the presence of Zechstein-2 carbonates developed on top of Zechstein-1 anhydrite (seismic data courtesy of Fugro).

Seismic time slice flattened on base Zechstein horizon. The blue polygon indicates the edge of the Zechstein-2 build-up drilled by well E02-02 (seismic data courtesy of Fugro).

4.4 | Accuracy in prospect risk prediction

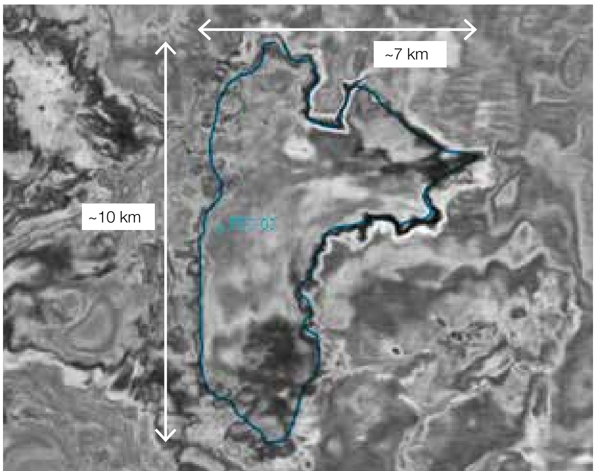
EBN's 2012 edition of Focus on Dutch Oil and Gas analysed the POS (Probability of Success) of finding any hydrocarbons in prospects. We concluded that the POS is usually underestimated: 'the average POS for all wells is 50.7%, whereas the actual success rate is 60.6%'. This analysis was based on 66 exploration wells drilled



East-West cross-section through E02-02. The seismic data shows a Zechstein-2 build-up with the transition from platform to basin. Well E02-02, drilled on the flank of the Elbow Spit High, confirmed the presence of Zechstein-2 carbonates developed on top of Zechstein-1 anhydrite (seismic data courtesy of Fugro).

between 2005 and 2011. Although success does not necessarily result in economic success, it does prove the presence of oil or gas.

The POS is also analysed in this year's edition of Focus on Dutch Oil and Gas, when a total of 86 exploration wells (2005-2013) were investigated. Of these, 56 wells, or 61.6%, were successful (i.e. oil or gas was discovered, albeit not necessarily in commercial quantities), whereas the average POS for all the prospects was 52.5%. Prospects with a higher POS have a higher likelihood of being hydrocarbon-bearing. Although this is a rather obvious outcome, closer examination shows that, for prospects with a POS of less than 30% (which includes the lower POS classes), the average success rate is actually above 31%. The post-drill success rate is higher than the pre-drill estimate for all the POS classes. Strangely enough, the only exception is in the 41-50% POS-bracket, where the success rate is only two out of eight, or 25%. On the other hand, every prospect with a POS of over 60% is almost certain to contain hydrocarbons. In conclusion, the probability of failure is overestimated for virtually all classes of prospects, from rank wildcat to mature near-field prospects.



Seismic time slice flattened on base Zechstein horizon.
The blue polygon indicates the edge of the Zechstein-2 build-up drilled by well E02-02 (seismic data courtesy of Fugro).

Postdrill succes rate vs predrill POS

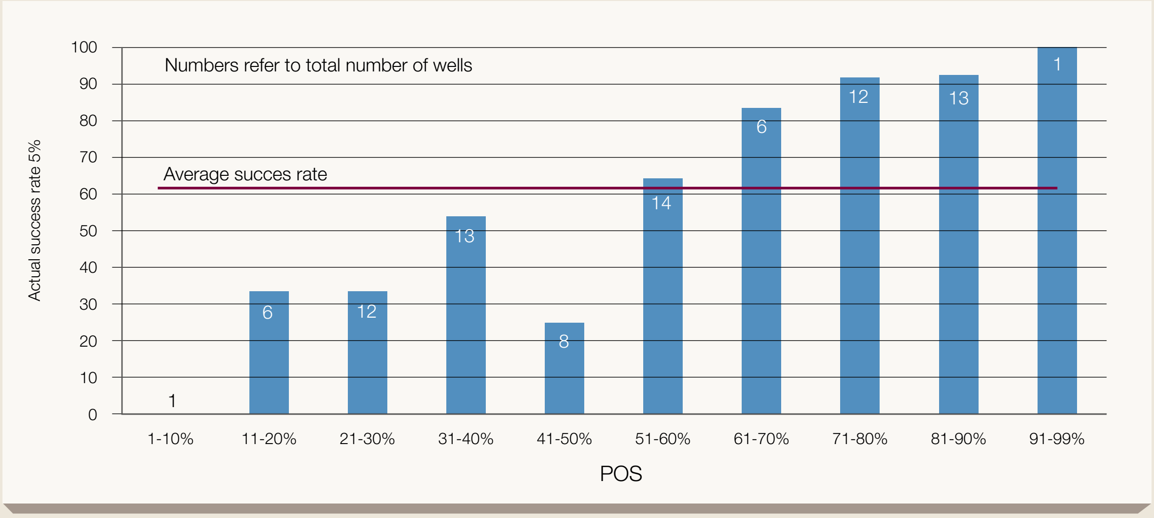


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Image - Offshore acces system

Glossary

BAU	Business as usual scenario: forecast scenario assuming the E&P industry maintains its current activity level
BCM	Billion Cubic Meters
BOON	Benchmarking Opex Offshore Netherlands
Capex	Capital expenditure
CIT	Corporate Income Tax
DEFAB	Exploration study of the D,E.F,A and B blocks
ECN	Energy Research Centre of the Netherlands
E&P	Exploration and Production
EOFL	End of Field Life
Frac	Hydraulic fracturing
GE	Groningen Equivalent
G&G	Geology & Geophysics
GHG	Greenhouse Gas
GIIP	Gas Initially in Place
GWH	Gigawatt Hour
Hydraulic stimulation	Stimulation by injecting liquid under high pressure into a reservoir in order to create fractures, which improve the reservoir's productivity and thus the flow of gas and/or oil towards production wells.
ISPT	Institute of Sustainable Process Technology
JIP	Joint Industry Project
JUSTRAT	Tectonostratigraphic framework for the Upper Jurassic-Lower Cretaceous
LCA	Life Cycle Analysis
LNG	Liquefied Natural Gas
MMbbls	Million Barrels
MFTA	Marginal Fields Tax Allowance
NFA	'No Further Activity' scenario: forecast scenario assuming no further capital investments
NOGEPA	Netherlands Oil and Gas Exploration and Production Association
OGIP	Original gas in place
Operator	Party carrying out E&P activities in a licence on behalf of partners
Opex	Operational expenditure
ppm	parts per million
POS	Probability of Success: the probability of finding hydrocarbons in a prospect
Proppant	A proppant is a solid material, typically treated sand or man-made ceramic materials, mixed with fracturing fluid, designed to keep an induced hydraulic fracture open during or following a hydraulic stimulation treatment.

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
R&D	Research & Development
RIL	Reinvestment Level
RT 2013	Real term 2013, Costs expressed in terms of monetary value in 2013
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
SiC	Silicium Carbide
Small fields	All gas fields except the Groningen field
SPE	Society of Petroleum Engineers
SPS	State Profit Share
Stimulation	A treatment performed to restore or enhance the productivity of a well
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
TOC	Total Organic Content
TWT	Two Way Time
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

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 climate 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

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