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FOCUS ON DUTCH GAS 2012



EXECUTIVE SUMMARY

The Dutch annual gas production from small fields (non-Groningen) lingers around 30 BCM, while the Dutch reserves and resource base remains large. The volume of recoverable gas in the contingent resources category is estimated at 159 BCM. The current prospect portfolio contains more than 400 BCM of gas (risky), while shale reservoirs may contain many times that volume.

EBN is seeking to maintain a high gas production from small fields. However, if the current trend persists, annual production from small fields will be only 11 BCM in 2030; in other words, 19 BCM lower than the 30 BCM/year envisaged in EBN's 30/30 ambition for 2030. EBN seeks to be both an enabler and a driver in the process of unlocking both contingent and prospective resources. Therefore, EBN recommends maximising the potential of the Dutch subsurface by increasing activities aimed at producing challenging gas reservoirs and stimulating exploration efforts.

Deliquification technology can now successfully resolve gas-well liquid-loading problems. Current gas-well de-watering projects have added 2 BCM to the resource base and, more importantly, have added an average of more than four years to economic field life, thus also extending infrastructure life. EBN estimates that as much as 35 BCM can be gained from the full scale application of deliquification measures.

As a result of technical improvements and fiscal initiatives, the 130 BCM GIIP locked up in 'stranded fields' is looking increasingly attractive. Many of these fields are very small, while most stranded fields are in the tight category. Developing these tight fields by hydraulic fracturing has proved both safe and successful. Shallow gas fields have

also proved to be commercially producible. The full potential of shallow gas fields is estimated at between 18 and 62 BCM recoverable, but de-risking is required to assess the full potential of shallow gas fields.

Exploration in the Netherlands continues to be very successful. However, exploration discoveries in recent years have clearly been smaller than pre-drill estimates. This reflects a combination of overestimating pre-drill mean volumes and underestimating the probability of success; the average exploration success rate has been over 60% for the period 2005 - 2011. The average cost per recoverable m³ of gas found by an exploration well is between €0.02 and €0.06. On average, actual drilling of exploration wells took 17.5% longer than expected.

The Dutch E&P industry remains very profitable, both for investors and the State. The Dutch government is committed to optimising the investment climate for E&P activities. The recently introduced marginal field tax measure is proving very successful, with 13 out of 14 applications awarded. Following this success, EBN and its stakeholders are exploring new ways to further improve the investment climate. EBN expects the level of investment to remain stable at between €1.5 and €2 billion over the next five years.

While offshore operational expenditure has remained relatively constant over the past few years, unit operating costs have risen as a result of the declining production. Unit operating costs can only be effectively reduced if more reserves are found and brought on stream. Drilling for near-field prospective resources could both reduce unit operating cost and extend infrastructure life as many viable prospects are located just outside platform owners'

acreages. Whereas the E&P industry's own energy consumption has risen, CO₂ emissions per m³ of gas produced have remained stable. Moreover, the E&P industry has managed to reduce its CO₂ footprint by using more efficient techniques, resulting in savings of almost 50 petajoules since 2003.

Decommissioning and removal of infrastructure and wells are still in their infancy in the Netherlands. As a result of a lack of experience, operators' cost estimates for decom-

missioning projects vary greatly. Sharing knowledge and collaboration are, therefore, key to minimising these costs and thus freeing up more capital for new investments.

In summary, the Dutch E&P industry remains very healthy and offers many opportunities. These range from maximising recovery from existing fields to exploring for and producing from challenging reservoirs. EBN is committed to enabling operators to seize these opportunities and to increasing the E&P industry's level of activity.

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RESERVES
AND OPPORTUNITIES



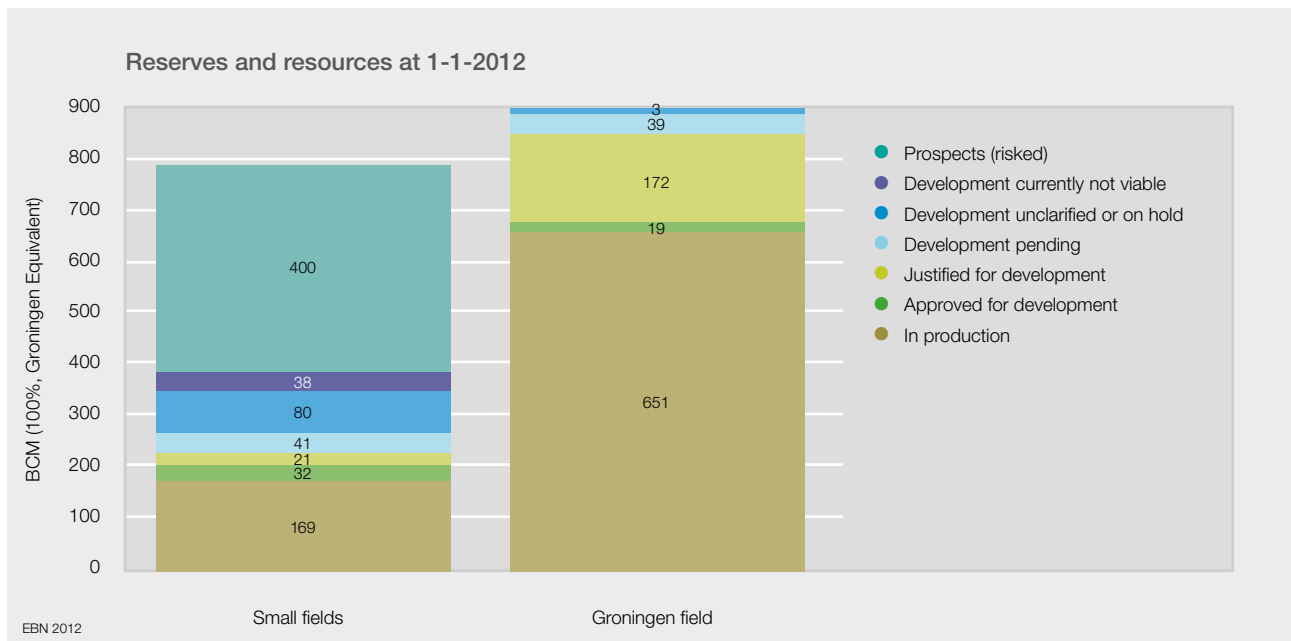
1 RESERVES AND OPPORTUNITIES

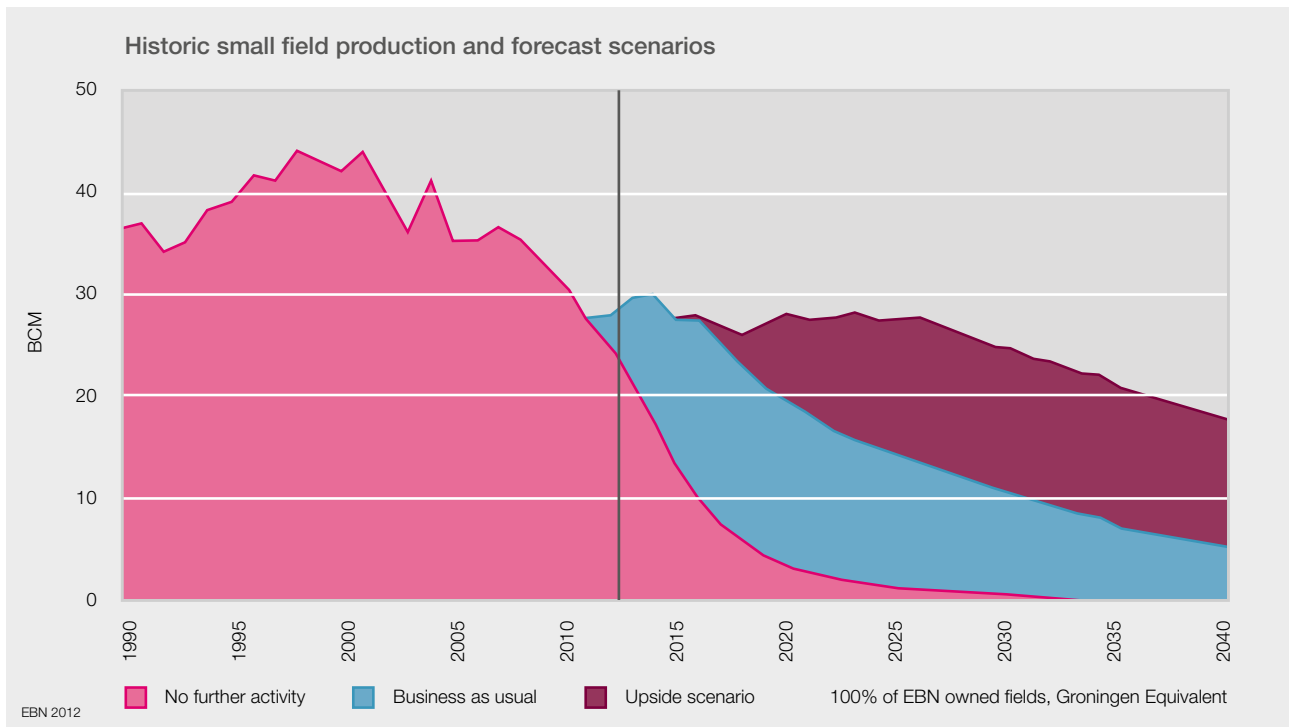
1.1 | Reserves and resources

Total net gas production in 2011 from all fields in which EBN participates was 73.1 BCM, of which 27.6 BCM was produced from small fields (non-Groningen). Although this is less than last year's production, EBN believes that it is feasible to maintain annual production levels at around 30 BCM over the coming years. However, the fact that last year's production came out slightly lower than in previous years highlights the urgent need for EBN and its partners to increase efforts to keep production stable by maturing more reserves and resources and bringing them on stream.

Several positive indicators support EBN's ambition of maintaining continuously high production levels from small fields. The most positive sign is that the reserves and resource base remains very large, even disregarding the

huge Groningen field. Particularly the volume of recoverable gas in the contingent resources category increased significantly in comparison to 2010 and now totals 159 BCM (100%). This is nearly 5.5 times the Dutch annual gas production from all fields combined, excluding Groningen. The contingent resources category includes resources in fields that have been discovered, but not yet developed ('stranded fields'), as well as opportunities within producing fields. There are two reasons for this increase in contingent gas resources. Firstly, EBN and its partners have devoted significant efforts to continuing their analysis of stranded fields in order to reduce uncertainty and investigate concepts for bringing them on stream. Secondly, with more and more fields becoming increasingly mature, Dutch operators are increasing their efforts to maximise recovery from these fields, as reflected by EBN's portfolio of 115 potential infill wells, many of which are expected to be drilled in the next five years.





EBN's prospect portfolio contains over 400 BCM of recoverable gas (risked) from prospects in known and proven plays. Roughly half this volume is uneconomic in the current market conditions. However, if prospective resources from new or underexplored plays, such as gas from challenging reservoirs or plays in the northern Dutch offshore sector, are included, recoverable prospective gas volumes may be much higher than 400 BCM. EBN is consequently actively stimulating exploration for these resources by contributing to research, investing in seismic acquisition and engaging stakeholders.

1.2 | Production forecast

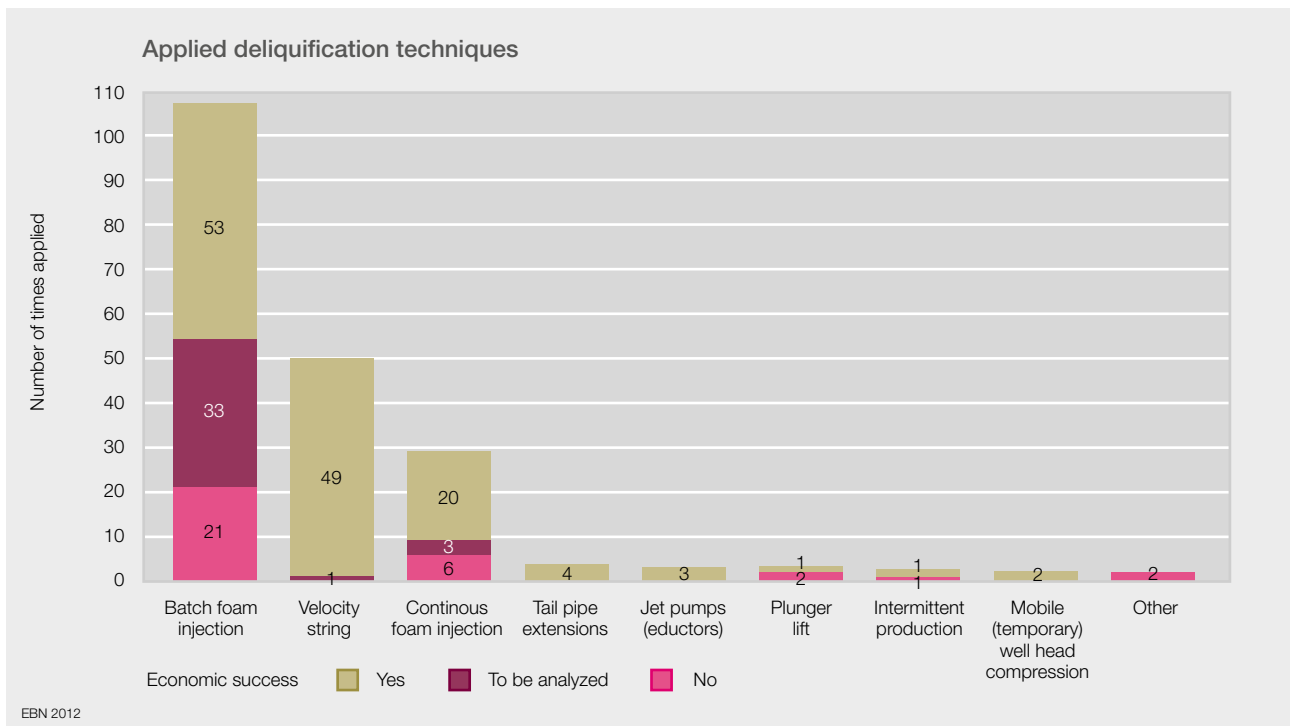
EBN has formulated the ambition to maintain the current level of small field (non-Groningen) gas production at

30 BCM a year until 2030. There are several lines of evidence to support EBN's ambition to maintain this level of production from small fields for the next two decades. It is evident, however, that this will require sustained efforts and investments, which EBN is willing to make.

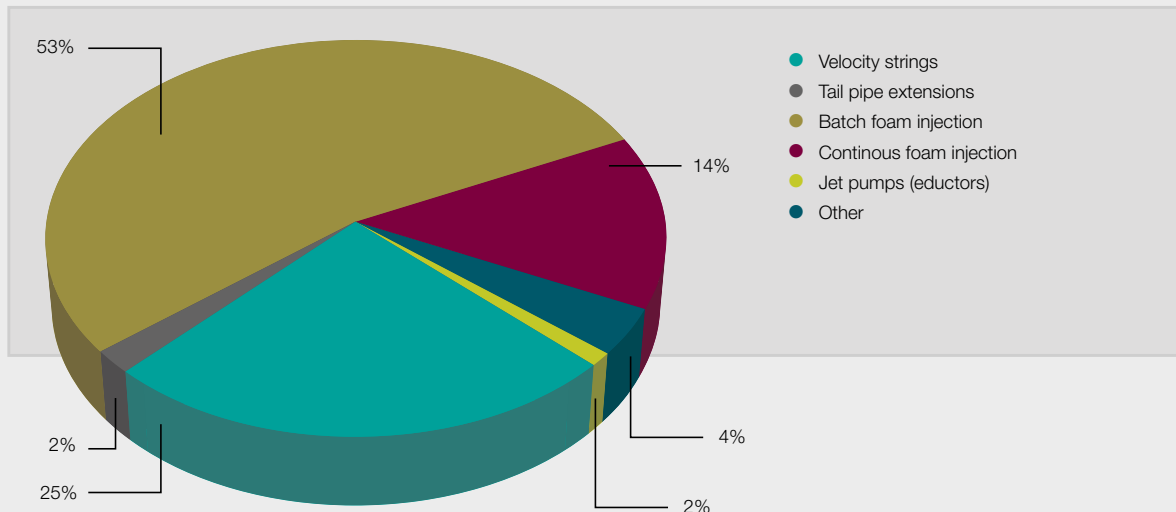
In the pessimistic and highly unrealistic 'no further activity' scenario (NFA), annual production would decline rapidly. This scenario implies production of all the reserves that are currently in the highest category (PRMS category 1). The NFA scenario assumes no further investment in any of the currently producing fields. In this scenario, annual production from small fields by 2015 would be only half the current volume. The rapid decline in the NFA scenario underscores the need for continued investment in projects that either mature reserves or increase the reserves and resource base.

The 'business as usual' scenario assumes a constant investment level, with a gradually decreasing number of exploration wells and a discovery rate in line with the trend over the past decade. Contingent resources in PRMS categories 4, 5 and 6 are risked with a 90, 50 and 10 per cent probability of maturation (POM) respectively. In this scenario, production from small fields can be maintained at a higher level and for a much longer period than in the NFA scenario, but will still result in a 19 BCM/year shortfall relative to EBN's 30 BCM/year ambition for 2030. In the 'business as usual' scenario, 335 BCM more gas could eventually be produced than in the NFA scenario. Of these 335 BCM, approximately 200 BCM would result from successful exploration. This forecast indicates that current investment and exploration levels will probably be insufficient to achieve production of 30 BCM/year in 2030.

The upside scenario forecasts a production profile that can be achieved if the Dutch E&P industry fully maximises the potential of all the opportunities existing in the Dutch subsurface. This is the production profile that EBN is seeking to achieve. In the upside scenario, 310 BCM more gas can be produced than in the 'business as usual' case. It is clear, though, that the investments required to achieve this production level exceed the average investment level of the past few years. The rewards, on the other hand, could be substantial, particularly in challenging reservoirs. Current estimates of recoverable gas in tight Rotliegend sandstones in the southern Dutch offshore are of the order of several dozen BCM (unrisked). However, shale reservoirs could yield substantially larger volumes of technically recoverable resources: estimates for the Posidonia Shale in the Roer Valley Graben alone range from 70 BCM to



Deliquification measures



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over 400 BCM, and this is only one of the shale plays in the Netherlands. If exploration efforts in relatively underexplored plays such as those in the northern Dutch offshore, together with yet unidentified opportunities in existing fields, are included, there is clearly plenty of scope to counter the decline in annual production from small fields. EBN is committed to participating in research, engaging in dialogue and making the investments required to achieve the upside scenario.

1.3 | End of field life

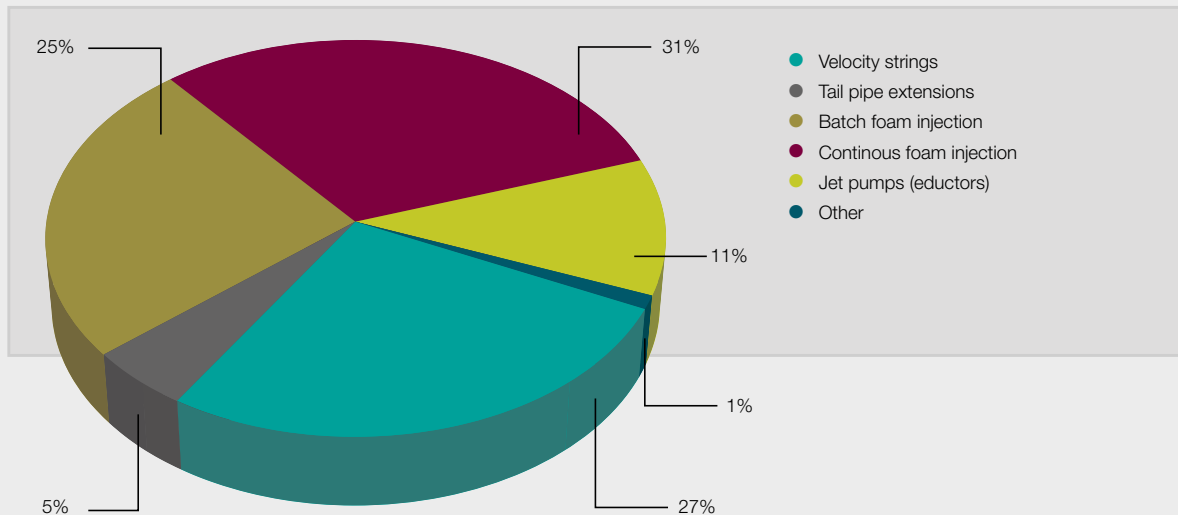
1.3.1 | Overview

Most Dutch gas fields are in the mature or tail-end production phase. Operating and producing these assets presents operational and financial challenges. Lower production rates, combined with ageing infrastructure, not only require effective management of expenditure, but also

implementation of emerging technologies to ensure sustainable gas production in the tail-end production phase of a field. During the past ten years, Dutch operators have implemented various end-of-field-life techniques and these have to date proved very successful. These techniques help to increase recoverable reserves, but are also especially effective in extending the economic life of infrastructure. Approximately 200 wells have now been worked over with end-of-field-life techniques, resulting in a considerable increase in recoverable volumes.

The most commonly applied end-of-field-life techniques are foam injection and velocity strings. These also account for the largest increase in total recoverable volume. Other gas-well deliquification techniques, using jet pumps (eductors), plunger pumps or compressors yield particularly high volume gains per application. Although these deliquification techniques have proven very successful, EBN is actively looking for more cost-effective solutions.

Estimated volume gains from deliquification projects (2 BCM total)



Plunger pumps are a low-cost option and have been used successfully around the world. The first plunger-pump pilot projects in the Netherlands look promising, but efficiency and applicability could be improved. EBN is currently addressing these issues and associated challenges.

1.3.2 | Rewards

According to a recent EBN survey, around 2 BCM of additional gas has been produced to date as a result of end-of-field-life techniques. EBN estimates that this can be increased to about 30-45 BCM of gas under different scenarios. These tail-end production techniques can also increase average field life by more than four years. With the continuing rise in gas prices, these proven production technologies can unlock significant potential for mature assets in the near future. More importantly, however, these tail-end production techniques will also extend the economic life of some of the ageing platforms, thereby postponing decommissioning and leaving a longer

window of opportunity for assets to be developed on or from these platforms.

1.3.3 | Technology

EBN is actively promoting joint industry projects and technical forums to close the information gap in the E&P industry. Last year, EBN and three Dutch operators initiated a 'best practices for gas-well deliquification' project, which is being led by the Netherlands Organisation for Applied Scientific Research (TNO) and focuses on engineering guidelines to solve liquid-loading problems. The project is supported by qualitative and quantitative tools designed to evaluate the effectiveness of these end-of-field-life techniques. The guidelines will establish which deliquification techniques can best be applied in North Sea wells and should help identify end-of-field-life strategies that maximise gas recovery in selected assets.

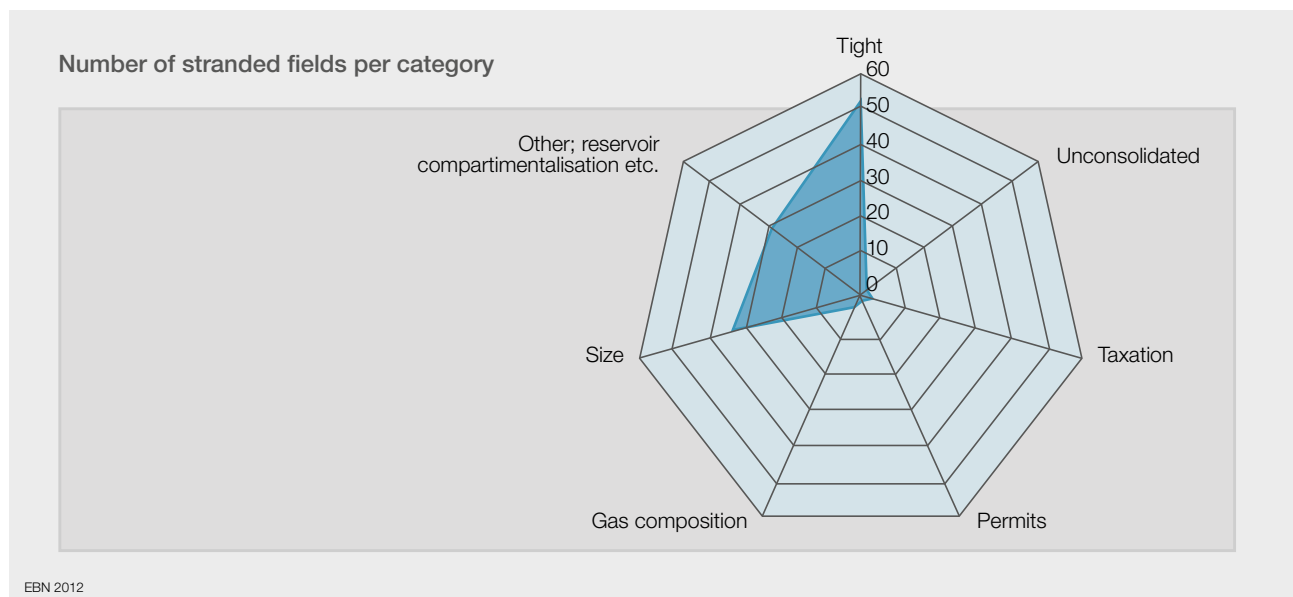
1.4 | Stranded fields

Stranded fields are fields that have been discovered, but, for a variety of reasons, have not yet been developed. These fields are either tight, too small, too remote, unconsolidated or located in sensitive areas, or have a different gas composition or difficult reservoir characteristics. Many fields are stranded because of a combination of two or more of the above reasons. The most common reason preventing successful development is a poor production test in the discovery well. EBN has identified a total of 106 stranded fields; nearly half of these are classified as tight. Total volumes contained in stranded gas fields amount to about 130 BCM (GIIP), and about 60 million m³ (STOIIP) in stranded oil fields.

Various operators are currently addressing the problems in a number of these stranded fields. In addition to an expected lack of productivity, the second most common

reason preventing development of stranded fields is a small size. Many of these fields were not economically viable at the time of discovery, but re-evaluation may show them to be economically viable now or in future. EBN and the *Netherlands Oil and Gas Exploration and Production Association* (NOGEP) have initiated a research programme to determine whether alternative development concepts, such as 'Gas-to-Wire' (on-site power generation from produced gas), may enable economic development. The problems in other, less common categories of stranded fields, such as unconsolidated shallow fields and fields with permitting problems, are also actively being addressed by various operators and EBN.

Some 60% of the stranded fields are located offshore, and 40% onshore. The average size of a stranded gas field is about 1.7 BCM. At 2.2 BCM on average, the offshore stranded gas fields are slightly larger than the onshore fields at 1 BCM. An important factor in developing offshore



stranded fields is that economic viability relies on the presence of existing infrastructure. Since the Dutch offshore is a mature hydrocarbon province, platforms increasingly come up for decommissioning. Timely development of offshore stranded fields is therefore essential.

Analysis shows that the dominant reason preventing development of many of these fields is poor productivity. 'Tight fields' are defined as fields that cannot produce gas in economic quantities without stimulation treatments. Almost half of the stranded gas fields are tight, and these represent a large proportion of the stranded resources; over three quarters (115 BCM) of the 130 BCM GIIP is contained in tight fields. On average, tight fields contain 2.5 BCM GIIP, which is higher than the average GIIP in non-tight stranded gas fields.

EBN has used a Monte Carlo simulation model to make an economic analysis of the stranded gas portfolio. The model assumes a simplified field development plan and associated production profiles. This simulation showed that most stranded gas fields have negative NPV10% values (Net Present Value at 10% discount). These fields are not economically viable even if the lowest acceptable economic hurdle rates are applied. A sensitivity analysis has shown that improving reservoir productivity is the key factor driving project economics. If successful stimulation (hydraulic fracturing) can be achieved for all stranded fields, development of 30 of these fields would be economically viable, thus unlocking 29 BCM of recoverable gas.

Hydraulic fracturing is a technique that improves the flow of gas and/or oil towards production wells in poorly

permeable, tight reservoirs. Since 1950, this technique has been applied commercially all over the world. Recent technological improvements, combined with horizontal wells, have enabled large-scale development of tight reservoirs around the world. Hydraulic fracturing typically improves sustainable flow rates from vertical wells by a factor of three. The sustainable flow rate of a horizontal, multiple-fractured well in the Netherlands is typically some ten times higher than that of a non-fractured vertical well. Occasionally, even greater improvements may be achieved, but these are usually attributable to other factors, such as connecting to zones with a better permeability or a greater reservoir height away from the wellbore, and cannot therefore be attributed to hydraulic fracturing alone.

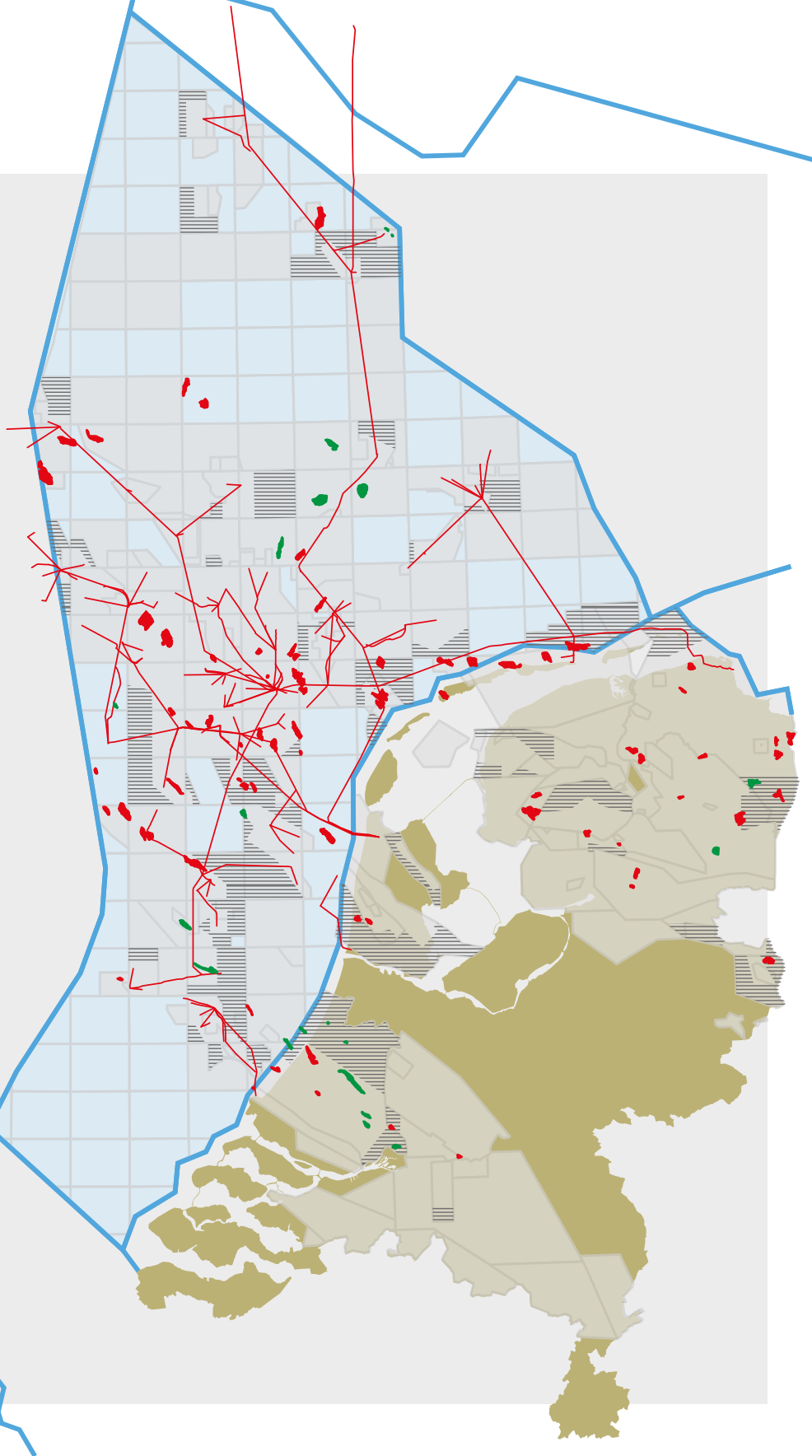
In the Netherlands, over 200 wells have so far been hydraulically fractured in a safe and responsible manner without negative consequences for the population or the environment. Between 2007 and 2011, 22 wells (9 onshore and 13 offshore) were hydraulically fractured. These 22 hydraulic fracturing treatments were necessary to achieve economic production rates in newly discovered and stranded fields, some of which had been discovered back in the 1970s. Since most stranded fields in the Netherlands are tight, hydraulic fracturing is considered the technology of choice for developing these fields.

EBN anticipates that, in the years to come, more stranded fields will be developed using state-of-the-art technology. It is crucial that these enhancement technologies are responsibly deployed in a safe and environmentally sound manner, and in line with the highest operational and technical standards.

Stranded fields

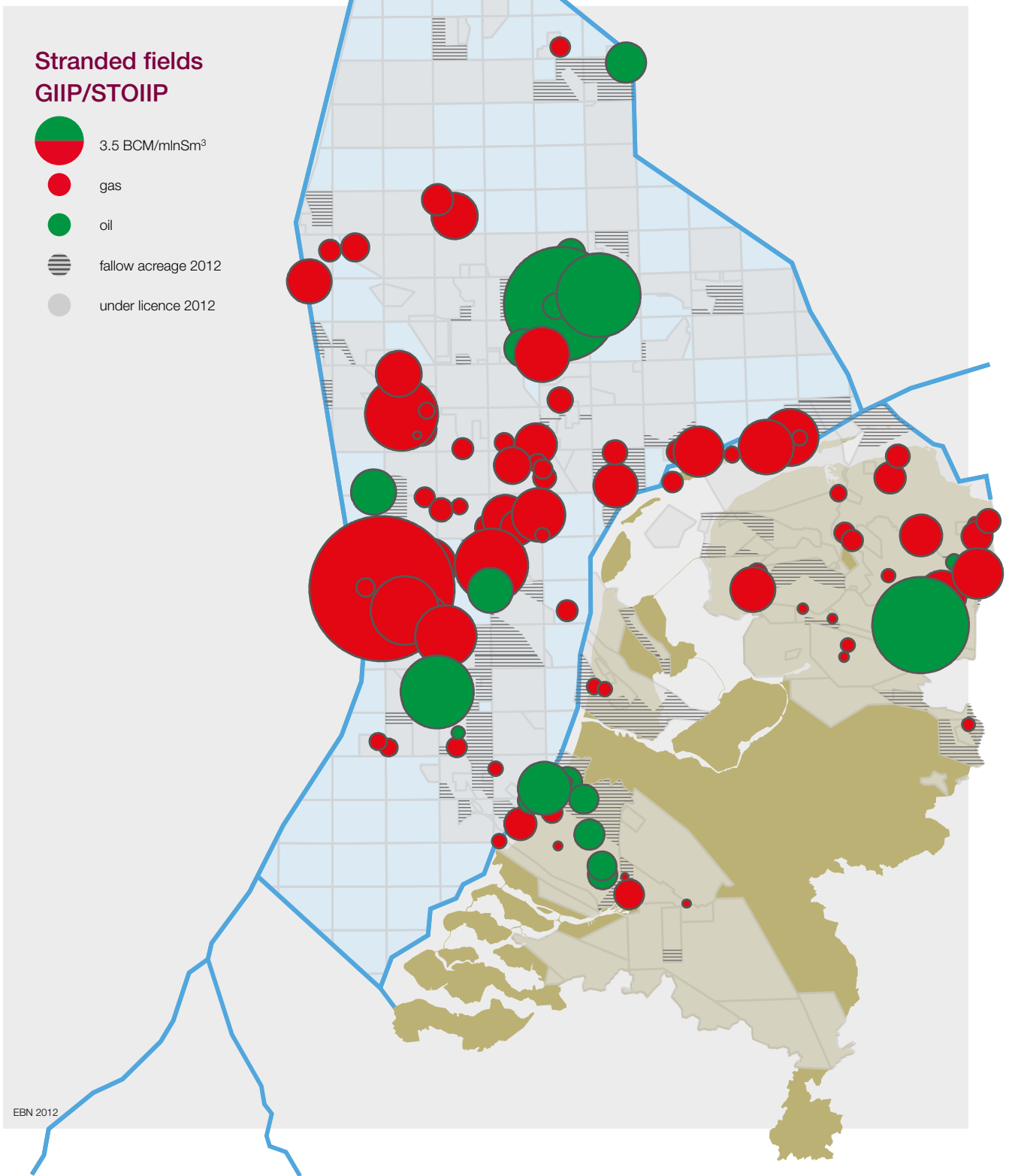
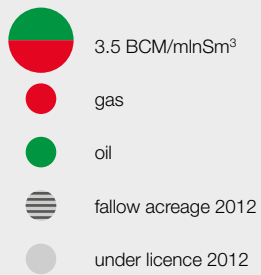
Stranded Fields

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- under licence 2012
- gas pipelines



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Stranded fields GIIP/STOIP



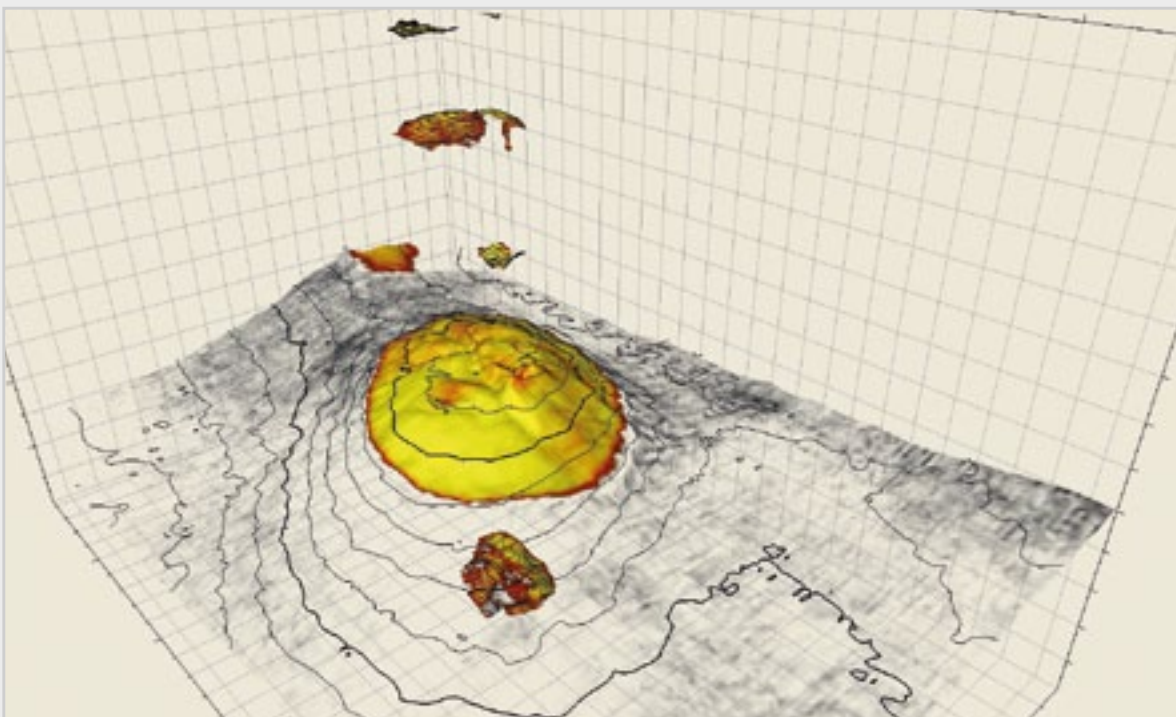
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1.5 | Shallow gas

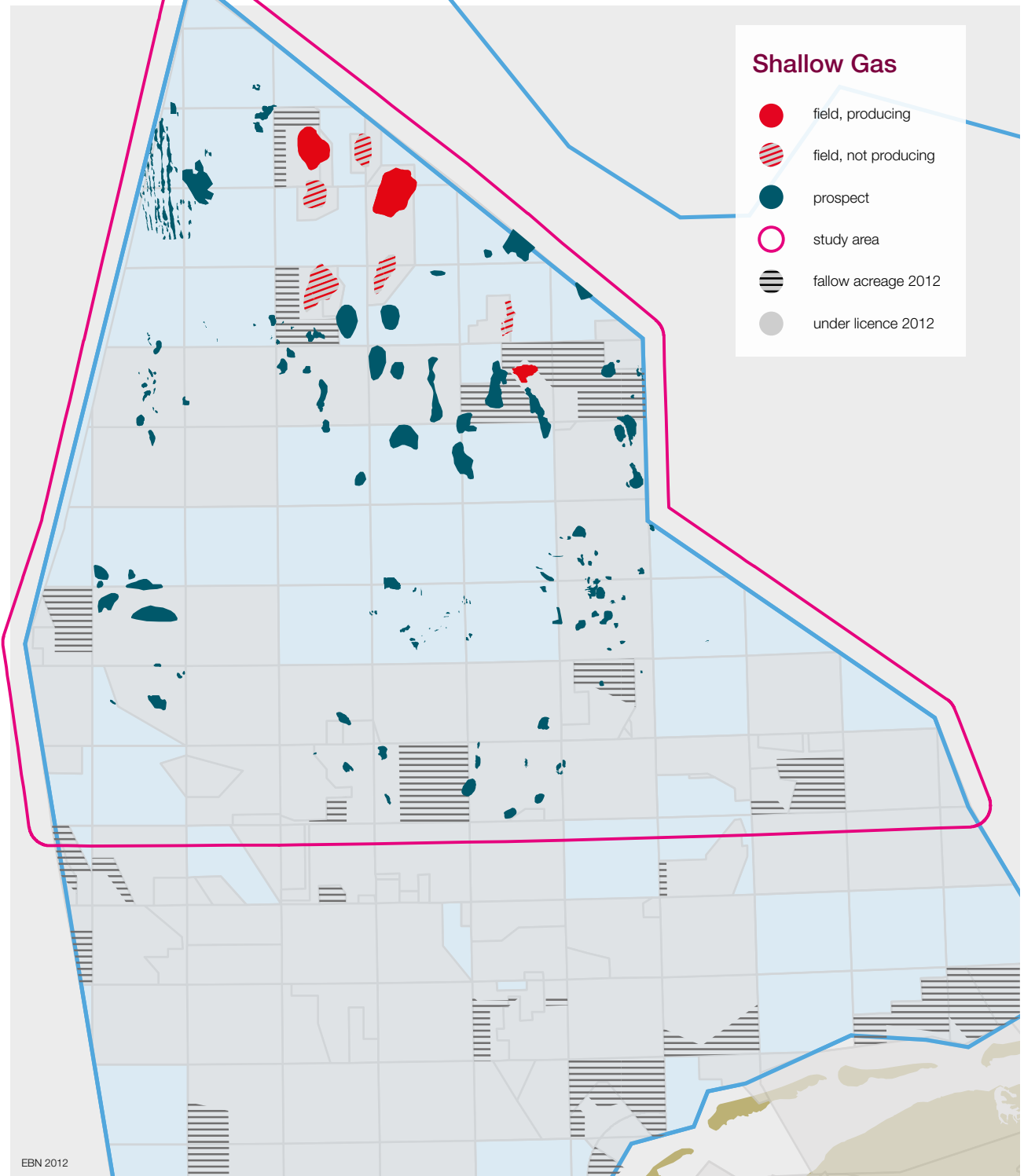
Shallow gas is defined as gas that occurs in relatively shallow reservoirs – typically at depths of less than 1000m – mostly in unconsolidated, low-pressure Tertiary sandstone formations. The presence of shallow gas in the Dutch sector of the North Sea has been known since the early 1970s. Expressions of shallow gas accumulations include gas chimneys and subsurface amplitude anomalies (*bright spots*) that can be easily identified on seismic data. Prospective shallow, gas-bearing sands in the Dutch offshore occur at depths of between 400 and 800m below seabed. These accumulations often consist of multiple, stacked reservoirs above salt domes,

forming salt-induced, low-relief anticlines that trap the gas. After the Dutch shallow gas potential had been the subject of many years of study, the first Dutch offshore shallow gas field (A12-FA) came on stream in 2007.

The second field (F02a-Pliocene), a shallow gas accumulation above the Hanze oil field, started producing in 2009. The third shallow gas field (B13-FA) has been producing since December 2011. Expandable sand screens are part of the well design and have been found to be effective in sand handling. Development plans for five more fields are under consideration and various operators are evaluating additional prospects offshore the Netherlands. Shallow gas is also known to occur onshore in the Netherlands.



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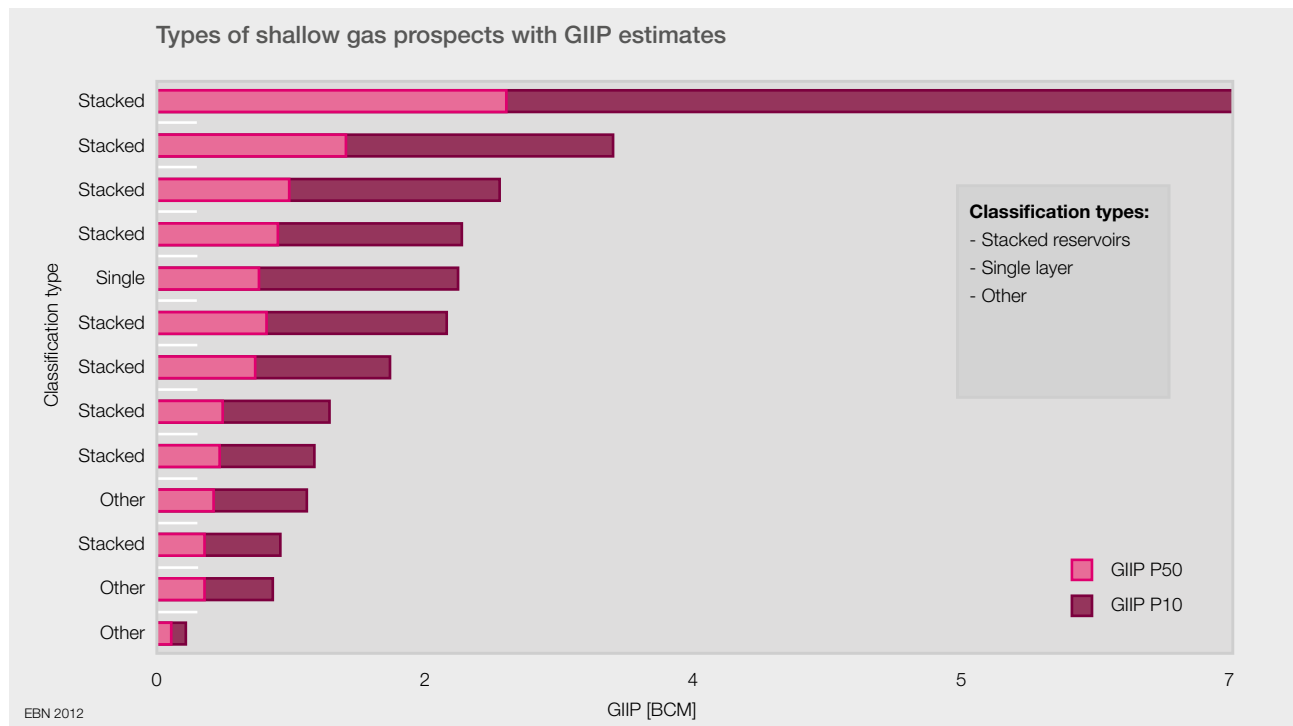
1.5.1 | Exploration window of opportunity

Currently producing fields account for some 8.5 BCM ultimate recovery (UR), with very good production rates per well. The success of these fields has increased the E&P industry's interest in the Dutch shallow play. EBN has currently identified over 150 shallow prospects in the northern offshore area. Around 50 of these, including several in open acreage, are sufficiently promising to warrant further exploration. The areal extents of these prospects range from 0.01 to 40 km². A large (8000 km²) multi-client 3D seismic survey was acquired in the prospective area in 2011. Together with existing data, the shallow gas play area is now largely covered by 3D seismic. The recent advances in shallow gas developments in the northern Dutch offshore and the good seismic coverage currently make exploration for shallow

gas very attractive. This type of play has changed from a drilling hazard and questionable reservoir into a resource with significant potential.

1.5.2 | Shallow gas inventory and potential

EBN is actively investigating the potential of shallow gas in the Dutch North Sea. EBN's first total volume estimates amount to 36-118 BCM GIIP and 18-62 BCM UR. These significant volumes, combined with the success of producing fields, justify a much more detailed analysis. This has been done by means of a shallow gas inventory, starting with the northern Dutch North Sea and based on the evaluation of individual prospects. The inventory includes a classification scheme to enhance the understanding of different types of amplitude anomalies and their potential.



A volumetric assessment is conducted for sufficiently promising prospects. This results in fact sheets that can be used as a starting point for detailed explorations. The fact sheets include maps of each amplitude anomaly, structure, trap type and in place volumes. The southern Dutch North Sea and the onshore Netherlands will subsequently be investigated.

Since well data in or near shallow prospects are scarce, uncertainty ranges can be large. However, certain properties can be extrapolated from known fields with a reasonable degree of confidence. Reservoir properties are also being assessed in a Joint Industry Project. Full de-risking of the prospects will inevitably require exploration wells to be drilled.

Over 50 prospects identified in the northern Dutch offshore are considered to have significant potential on the basis of their structure, depth and size. Some of these prospects have multiple stacked reservoirs and others consist of a single reservoir. A third class of prospects include relatively unknown trap types with very small (<2km²) and very shallow (<250m) amplitude anomalies. At the time of writing, 13 prospects have been analysed in detail, most of them located in the southern E and F blocks. The documented prospects reflect the large uncertainty range in volumes, but show a significant upside, with total GIIP amounting to 9-15 BCM (P50-P10).

1.6 | Exploration performance

How good are the forecasts made by the Dutch E&P operators for the wells they drill? EBN has examined some indicators for all the 66 exploration wells drilled between 2005 and 2011 and in which EBN participated.

The following factors were analysed on the basis of well proposals versus actual results:

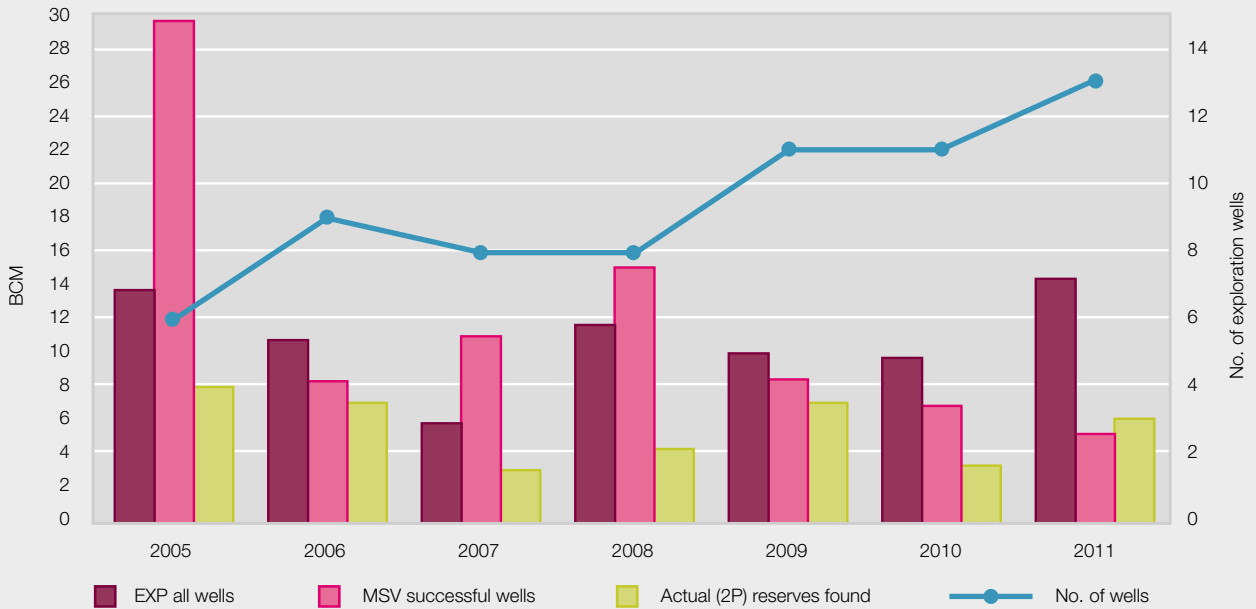
- risking and resources
- top reservoir depth.

1.6.1 | Forecasting risk and resources in exploration

In exploration, Expectation Volumes (EXP) are expressed as Mean Success Volume (MSV; being the mean recoverable volume of gas or oil in the prospect) multiplied by the Probability of Success (POS; being the probability of finding hydrocarbons in the prospect). To put it simply: if five wells are drilled, each with a POS of 20% and with the same MSV, one successful well should find that MSV. This applies over a longer period, i.e. to a larger number of wells. Ideally, the total sum of pre-drill EXPs for all the wells should equal the sum of the resources found by drilling these wells. In other words, successful wells should compensate for dry holes. In addition, a successful well should, on average, find its unrisks MSV (assuming a sufficiently large population). A conversion factor of 1 MMBO = 0.175 BCM of gas is used to allow comparison between oil and gas resources. In reality, this conversion factor obviously depends on the quality of the oil.

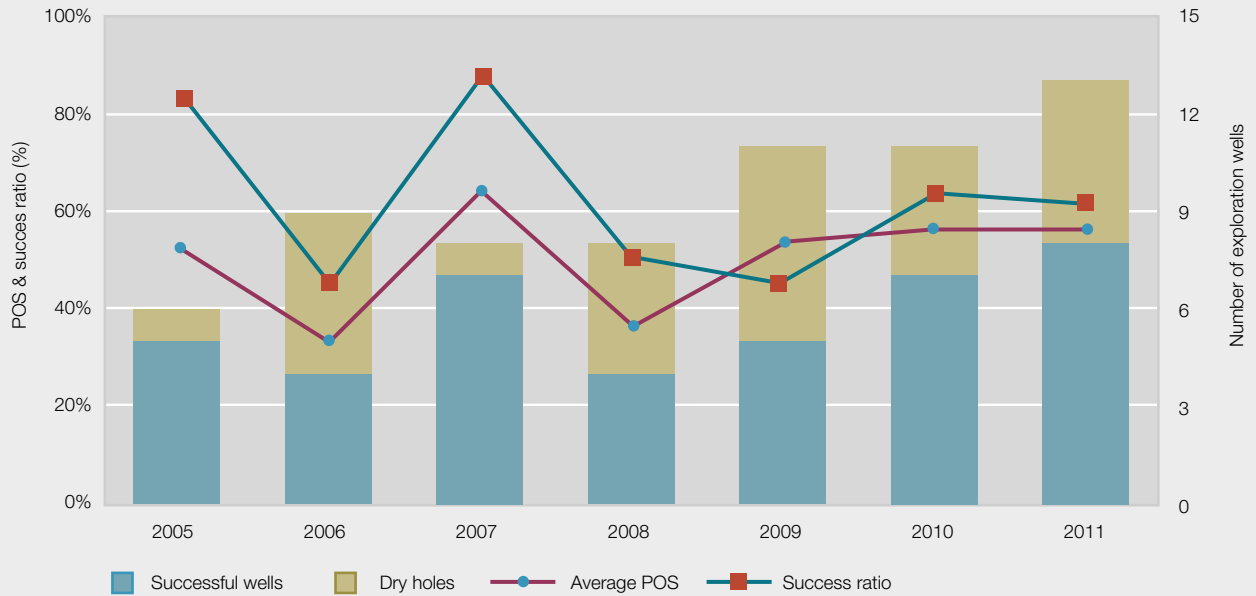
More than 60% of the 66 wells drilled found oil or gas. In the past seven years the EXP for all wells (per year and in total) was never actually found. It was only in 2011, and in the successful wells, that the resources found exceeded the pre-drill MSV. Moreover, only three of all the 66 wells drilled found resources that exceeded pre-drill P10 estimates, whereas 14 found smaller volumes than the pre-drill P90 estimates. It should be noted that the volumes used in this review are the values reported within a year of drilling the well, so the final figures may change. In conclusion: the E&P industry seems to be overestimating prospect volumes.

Exploration wells: total EXP vs. realisation



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Exploration wells: average POS and success ratio



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With respect to prospect risking, however, EBN's analysis points in a different direction. The total POS for all wells could be expected to be close to the multi-year success ratio (i.e. successful wells/total number of wells). The average POS for all wells was found to be 50.7% (48.1% if volume-weighted), whereas the actual success ratio is 60.6%. In other words, estimated risk is much higher (20%; 26% if volume-weighted POS is used) than actual risk.

1.6.2 | Creaming curve

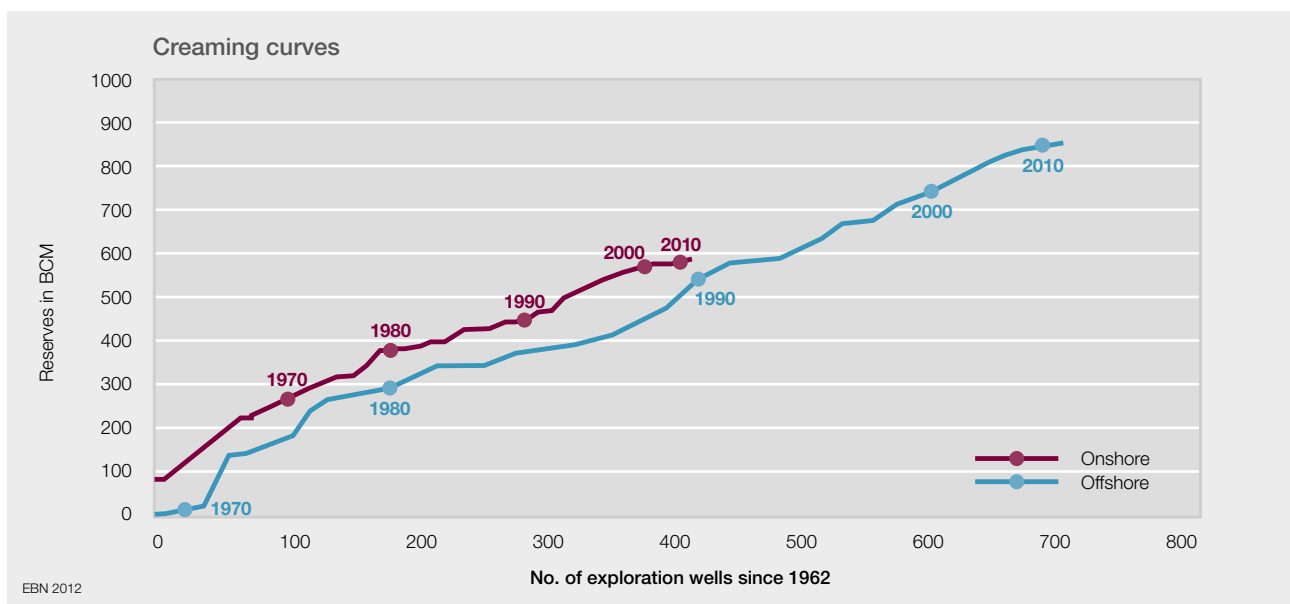
EBN's 2009 *Focus on Dutch gas* report included a creaming curve (total reserves discovered vs. all wells). Since then, some 22 additional exploration wells have been drilled offshore and 12 additional exploration wells onshore, bringing the total number of wells to 693 offshore and 410 onshore. A slight levelling-off in the trend for the offshore is apparent in the most recent years, whereas a noticeable upturn is visible for onshore. Although we have seen a few examples of such levelling-off in the past, the present strong upward trend is certainly evident. Steepening trends can sometimes be correlated with technological

advances, such as the offshore upturn during the late 1980s and early 1990s that resulted from the large number of 3D surveys acquired in that period. Similarly, the fairly steep trend around 2000 shows the impact of pre-stack depth migration (PrSDM) seismic processing.

1.6.3 | Forecasting top reservoir depth

Accurately predicting reservoir depth is very important, especially for smaller prospects. If the reservoir comes in deep to prognosis, this may have an adverse impact on volumes. Obviously, this depends on whether the gas/water contact (GWC) or oil/water contact (OWC) is also deeper or at the predicted level. Likewise, a reservoir depth much shallower than predicted does not necessarily signify larger volumes if the well is successful; juxtaposition factors may, for instance, prevent this.

Of the 66 wells analysed, 22 had a Bunter target, 35 a Rotliegend target, 8 wells had a different objective and one well never encountered the targeted reservoir. A depth error of +/-25m is generally considered good to



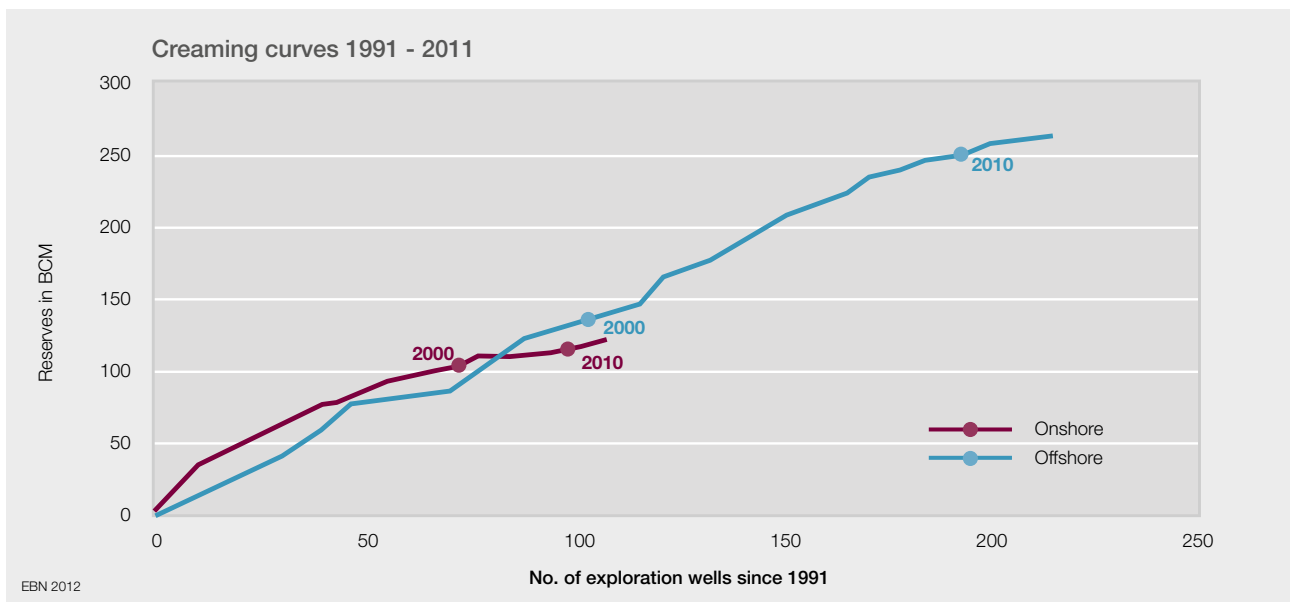
acceptable. This band of +/-25m depends both on the accuracy of the time-depth conversion in the seismic interpretation and on the reservoir. A narrower band can, for example, be expected for a Chalk target than for a Rotliegend reservoir since the Chalk formation occurs at much shallower depths and the top Chalk should therefore be easier to predict.

Of all the wells drilled, 36 (55%) were within the band of +/-25m, while 18 (28%) were in an even in a much narrower band of +/-10m. Of the wells in the band of +/-25m, 19 had a Rotliegend and 12 a Bunter target. Most wells came in deep to prognosis, even though 11 wells (17%) came in shallow. Six Bunter and two Rotliegend wells came in over 25m shallow, with the Bunter wells even coming in more than 50m shallow. Some 45% of the predictions for both the Bunter and Rotliegend reservoirs were out by more than 25m. This is not surprising in the case of the Rotliegend targets, given the uncertainties involved in interpreting top Zechstein salt above Rotliegend targets. In the case of a Bunter target, however, a

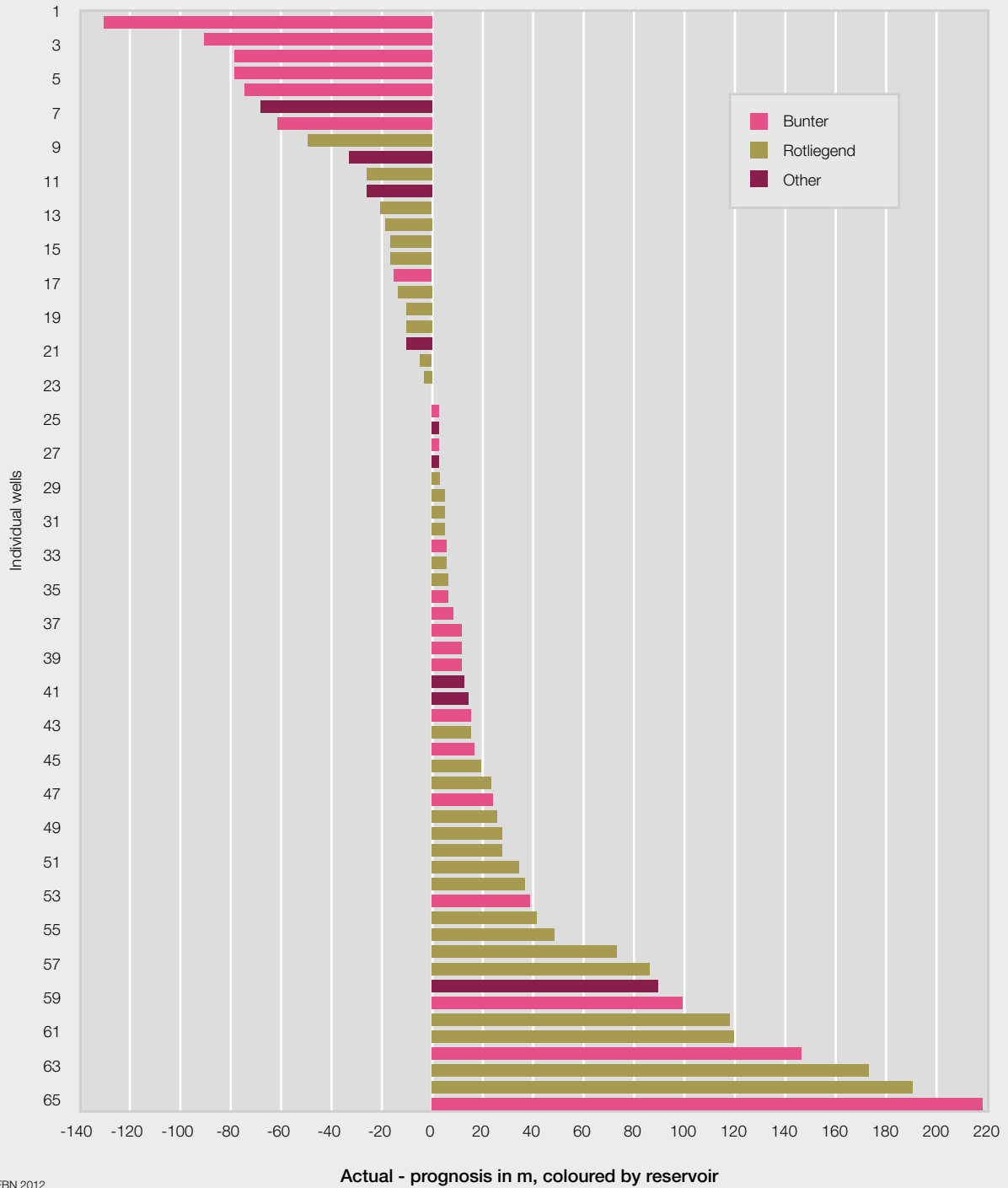
more accurate prediction would be expected.

18 wells came in over +25m deep; of these, 13 had a Rotliegend objective. Four Bunter wells came in over 25m deep. Nine wells came in over 50m deep to prognosis, while seven (11%) came in even more than 100m deep. Of the latter seven, four targeted the Rotliegend group and three the Bunter subgroup.

In conclusion, forecasts of reservoir depths are reasonably accurate, given all the uncertainties involved. Most predictions appear biased to be shallower than the actuals. This may have an impact on the resources found in successful wells. Surprisingly, predicting Bunter depth appears to be harder than previously thought. If a prediction for Bunter depth is out, it is often far out, whereas depth conversion should theoretically be easier for the Bunter reservoir than for the Rotliegend formation. For all wells combined, reservoirs came in a combined 1km deep on a total (forecast) cumulative depth of just over 200km.



Exploration wells: delta reservoir formation depth (actual - prognosis)

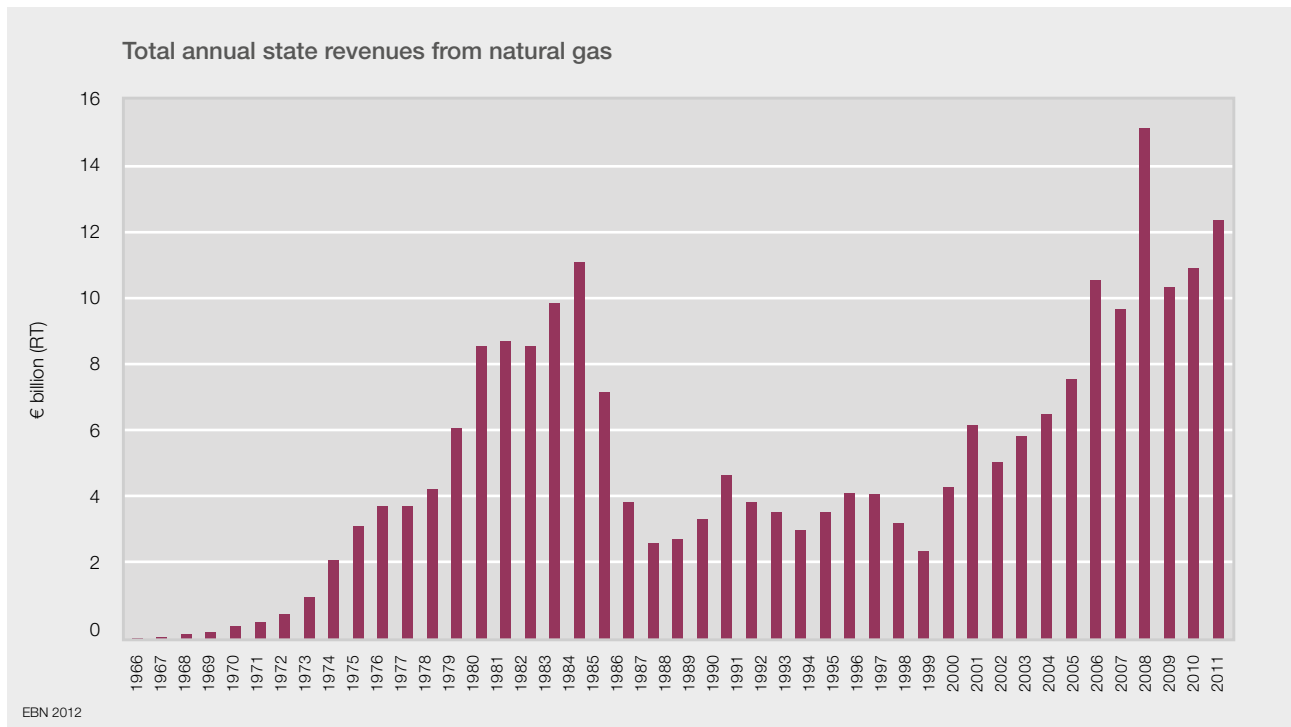


EBN 2012

INVESTMENT CLIMATE
AND ACTIVITY LEVEL

2

2. INVESTMENT CLIMATE AND ACTIVITY LEVEL



2.1 | Natural gas and the Netherlands

The discovery of the huge Groningen natural gas field in 1959 has dramatically changed the way the Netherlands meets its energy needs. Since 1962, practically every Dutch household has been connected to an ever-expanding natural gas grid, and the country has reaped the benefits of natural gas as a clean, valuable and reliable energy source. For decades many industries and people in north-western Europe have benefited from expansive gas exploration and production in the Dutch territory, combined with an elaborate gas infrastructure.

Access to natural gas directly benefits Dutch residents in their everyday lives, and has also made a huge economic contribution to Dutch national wealth. Natural gas revenues now amount to a cumulative nominal total of

over €236 billion, which has been re-invested in Dutch society over the years. The general public is gradually becoming more aware of the contribution of natural gas to the cultural profile of the Netherlands.

2.2 | Regulations, legislation and supervision

The long history of natural gas production in the Netherlands has resulted in a sophisticated regulatory framework, with comprehensive procedures and effective supervision of E&P activities, both onshore and offshore. Given the economic benefits that this energy source has for the Dutch nation, the government has introduced various incentives to make exploitation of smaller subsurface resources attractive to investors. The *kleine velden beleid*

(small fields policy) enables gas-producing companies to sell their gas to GasTerra on reasonable conditions and at market-based prices. The *Regeling investeringsaftrek marginale gasvoorkomens Nederlands continentaal plat* (investment allowance for marginal offshore gas fields) is a tax incentive designed to encourage development of marginal fields. The Fallow Acreage Covenant was agreed between the government and most E&P companies with operations in the Dutch offshore. This covenant is a non-binding agreement that aims to stimulate the exploration for and production of oil and gas reserves in the Dutch part of the continental shelf. It seeks to ensure that if an operator has been insufficiently active for an extended period, a licence holder can voluntarily return licensed acreage to the authority granting the permit (i.e. the Ministry of Economic Affairs, Agriculture and

Innovation). The covenant has been in force since 2011 and has resulted in large acreage positions being declared fallow and, therefore, becoming accessible to E&P investors. If requested by an exploration licence holder, EBN will participate in all the exploration activities covered by a licence, thus reducing the financial impact of a dry well and supporting operators' exploration activities in the Netherlands. In the case of production licences, EBN is the designated partner to participate on behalf of the Dutch State under an agreement with the licence holder(s), unless the State decides otherwise. Given its participation in virtually all licence blocks, EBN is also able to effectively share knowledge of the Dutch subsurface with operators, thus helping operators to explore and produce effectively through cooperation.





2.3 | Engaging stakeholders

The long history of natural gas development in various regions in the Netherlands has resulted in the local population being familiar with the E&P industry and has created an atmosphere of mutual trust and understanding. However, this did not happen automatically, even in the early days. It took time for the benefits, such as direct and indirect employment, to become evident. Over time, these interactions have given the local population a sense of pride and of being involved in natural gas operations.

Successful implementation of large-scale infrastructure projects with local impacts depends very much on how project developers engage stakeholders. Modern stakeholder engagement commences in the early phases of a project and seeks to find solutions that are acceptable to all the stakeholders and take account of their different perspectives, while also harmonising expectations and creating mutual benefits: in other words,

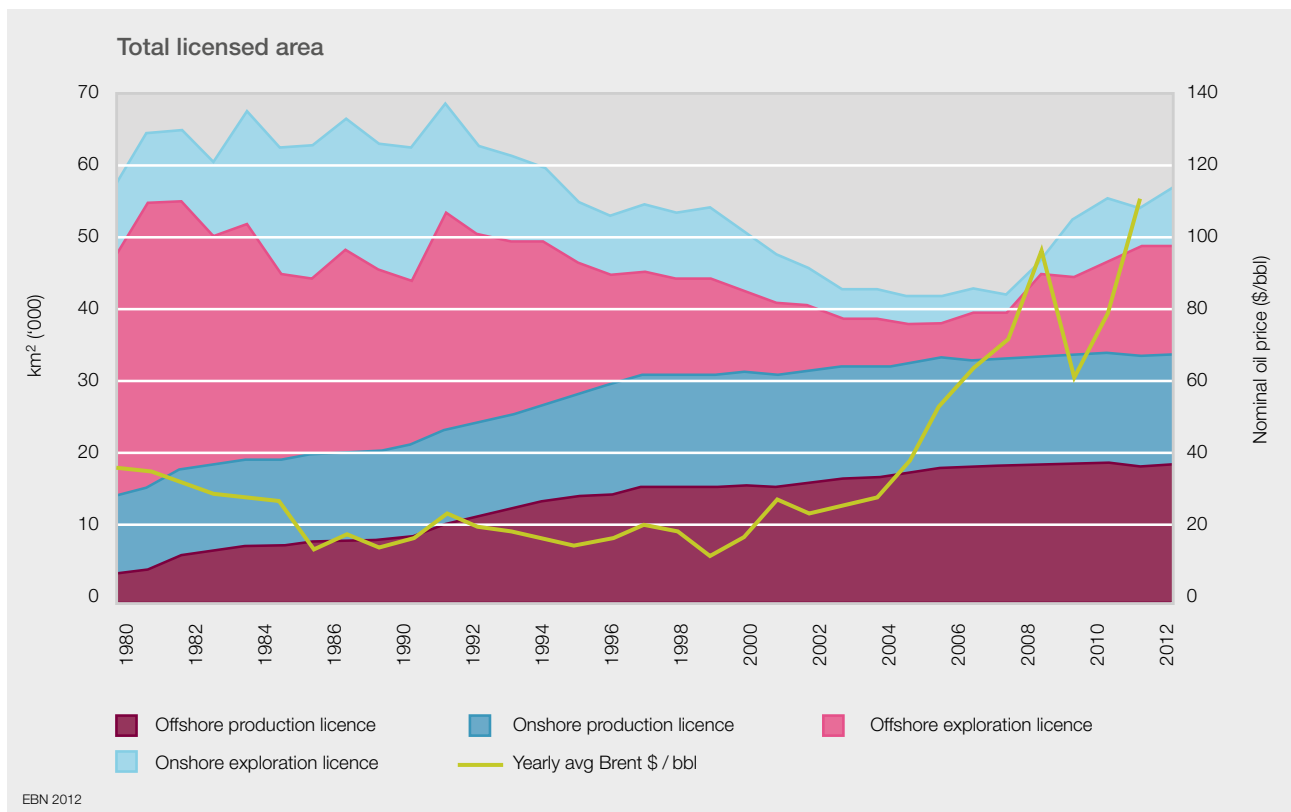
establishing a win-win situation. Transparency, active stakeholder engagement and effective dialogue are important pre-conditions for establishing a relationship of trust. All operators should see embedding their plans in society as an integral part of their project planning. This means integrating facilities both in the physical environment and in the social environment by promoting cooperation and dialogue and identifying interdependencies, as in the early days of natural gas exploration.

EBN is pleased that the E&P industry is becoming increasingly aware of the importance of embedding its activities in society. EBN values transparency and flexibility, both in itself and in the operators. By engaging in communications and dialogue, the natural gas industry will foster trust among the general public and local authorities, and this is crucial for the industry's 'licence to operate' in the Netherlands. EBN's ability to enable and stimulate supports the operators in our common goal of accessing subsurface resources in a safe and socially acceptable manner.

2.4 | Licensing history

The E&P industry has renewed its interest in acquiring more Dutch acreage. The total area covered by exploration licences has increased from a low of 8,100km² in 2005 to a forecast of around 23,000km² in 2012 (including applications to be granted in 2012). This is probably due to two reasons. Firstly, interest in unconventional gas has resulted in several applications for large areas, especially in the southern onshore. Secondly, the large (7,600km²), long-cable, 3D spec seismic survey that Fugro acquired in the offshore D, E and F blocks focuses on an area which has been largely ignored for decades and therefore is highly underexplored. This survey is now nearly complete,

with the last 140km² to be shot in 2012. Initial results are very encouraging. The final product should be ready by late May 2012. Since the start of E&P activities, the total area covered by production licences has gradually increased. This trend is still continuing, and reflects the high success rate of wells drilled in the Netherlands. Although correlation between the total exploration licence area held and the oil price could conceivably be assumed, this is only partly true. No correlation (correlation factor: around -0.3) is evident for the entire period of 1980 to 2011. During the past ten years, however, the correlation has been fairly strong, especially if a two-year lag effect between the area covered by exploration licences and the oil price (correlation factor: 0.86) is assumed.



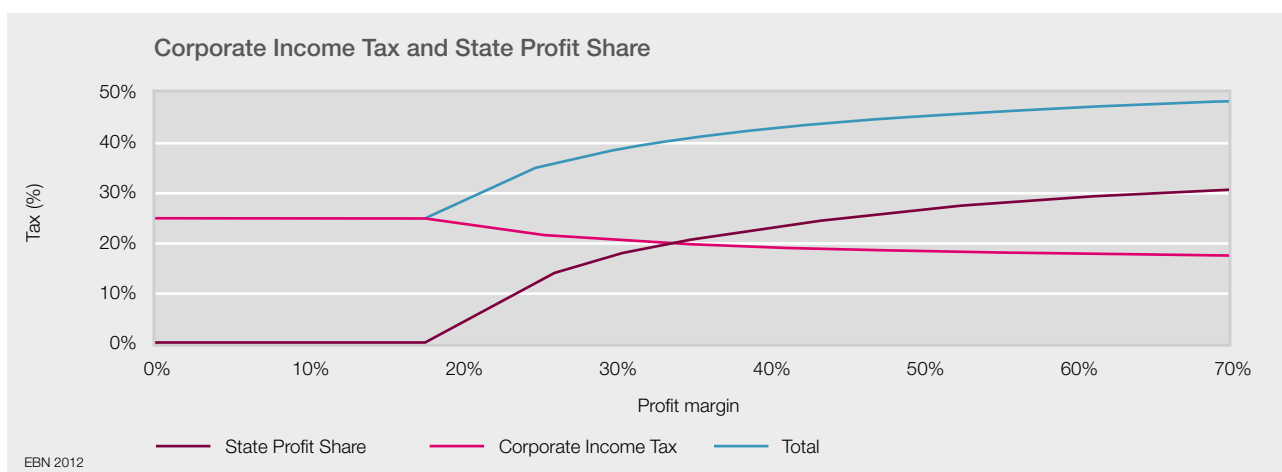
2.5 | Profit and tax

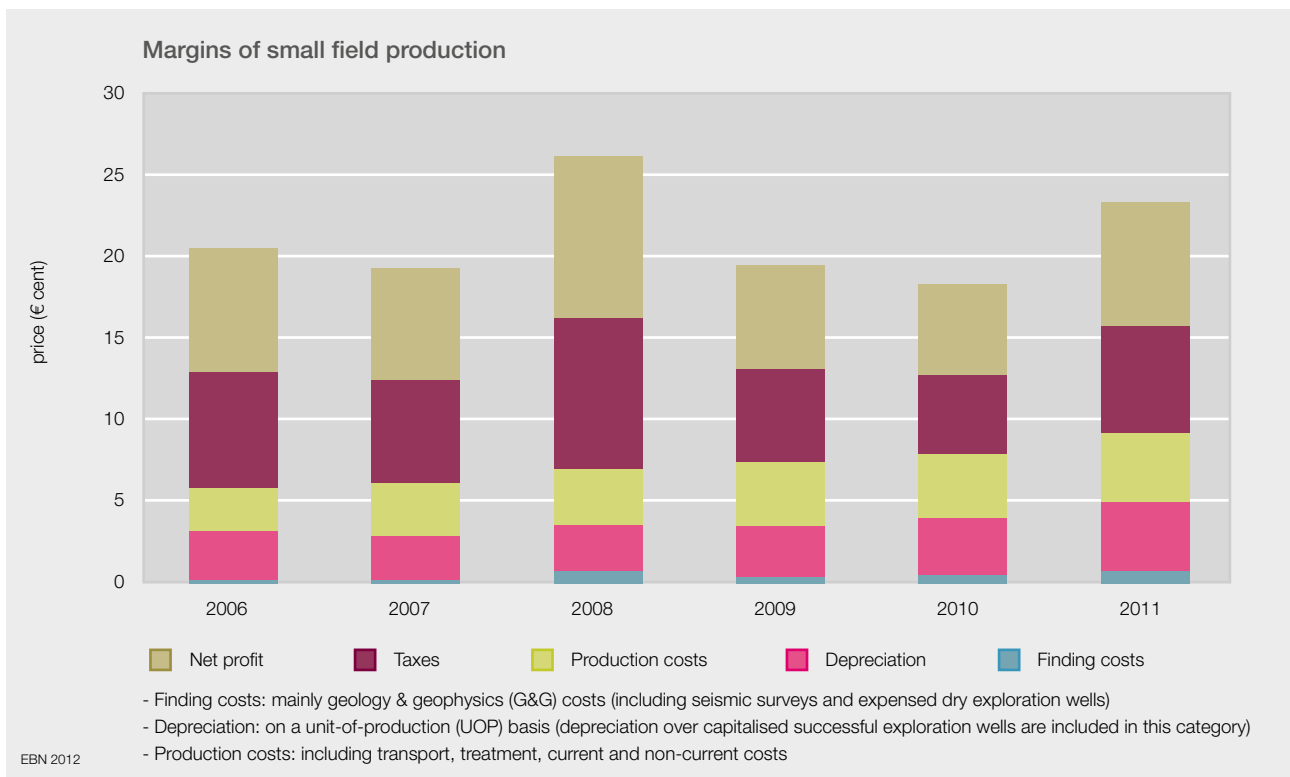
E&P activities in the Netherlands are taxed in accordance with the Mining Act of 1 January 2003. Profits generated by the production and sale of gas are shared between the E&P companies and the State through two payment streams: normal Corporate Income Tax (CIT) and the State Profit Share (SPS). These payments can only be calculated in combination as CIT is deductible from the SPS and vice versa. Although the total effective rate is 50%, the average percentage actually paid is lower because of the 10% cost uplift that can be applied when calculating SPS. Consequently, the higher a company's production costs, the lower the total percentage of payments to the State.

Despite its CIT and SPS obligations, the Dutch E&P industry remains profitable. Although production costs per cubic meter have increased slightly over the years, higher gas prices have helped to maintain satisfactory profit margins. Average revenue per cubic meter is predominantly determined by the price paid by GasTerra since the vast majority of gas produced in the Netherlands is sold

to GasTerra (including production from the Groningen field). This results from GasTerra's public task under the small fields policy laid down in the Gas Act. The operator of a new gas field can always sell its produced gas to GasTerra, and GasTerra is obliged to buy the gas at market-based prices and conditions. However, operators are not obliged to sell to GasTerra. In the past, gas fields were contracted to GasTerra for the life of the field. Recently, however, an opt-in/opt-out clause was added.

Despite the profitability of current production, there is a common understanding among the players in the Dutch E&P industry, including EBN and the Ministry of Economic Affairs, Agriculture and Innovation, that the profitability of future investments is less assured. After more than 30 years of small fields development, the average size of prospects and fields that can still be explored and developed is decreasing. In addition, the available infrastructure is ageing. The government introduced the 'investment allowance for marginal offshore gas fields' in 2010 in order to maintain the momentum for investments, along with the general tax incentives for R&D and innovation.





2.6 | Investment allowance for marginal offshore gas fields

2.6.1 | Effects of the investment allowance for marginal offshore gas fields

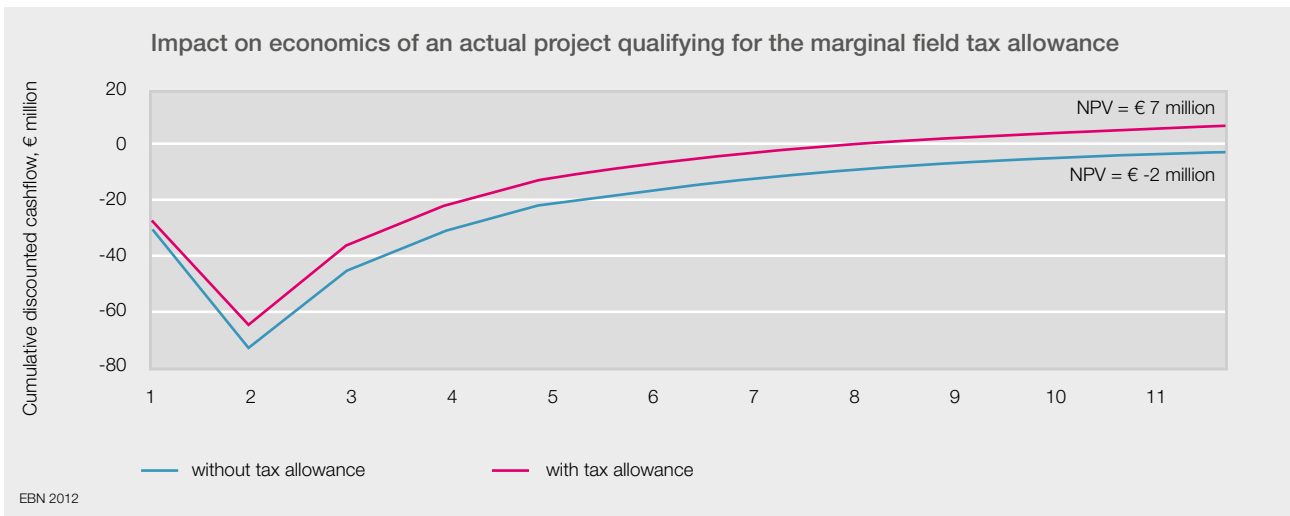
Operators in the offshore Dutch E&P sector planning to explore or develop a prospect/field considered marginal can apply for the investment allowance for marginal offshore gas fields. This tax facility gives licence holders an incentive to drill marginal fields that would otherwise not be drilled. Not only is the average size of fields and prospects decreasing, but so, too, is the Probability of Success (POS) of prospects. One of the objectives of this incentive measure is to encourage operators to drill prospects with a lower POS. Although the success rate is

currently still above 50%, operators will in future need to be willing to invest in lower POS prospects in order to maintain the annual number of exploration wells at a comparable level to the current one. Successful exploration wells are vital if more resources are to be identified.

A field is classified as marginal if it ranks high on the following criteria:

- small (expected) recoverable volume;
- low (expected) well productivity;
- remoteness from the existing platform through which export is planned.

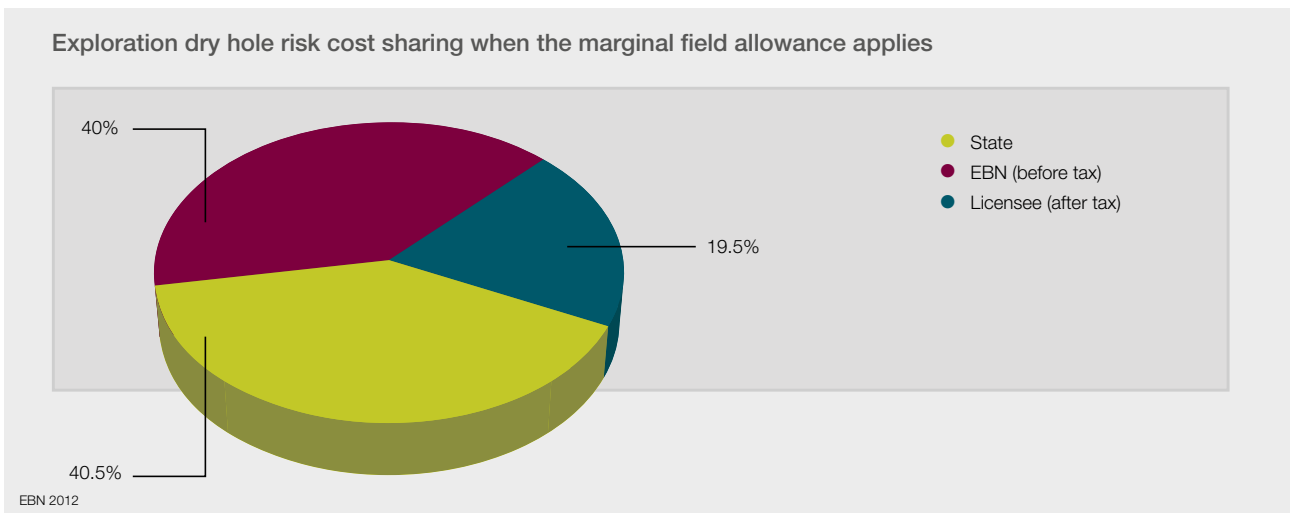
If a field/prospect qualifies as marginal, the operator (and its partners in the licence) can deduct an additional 25%



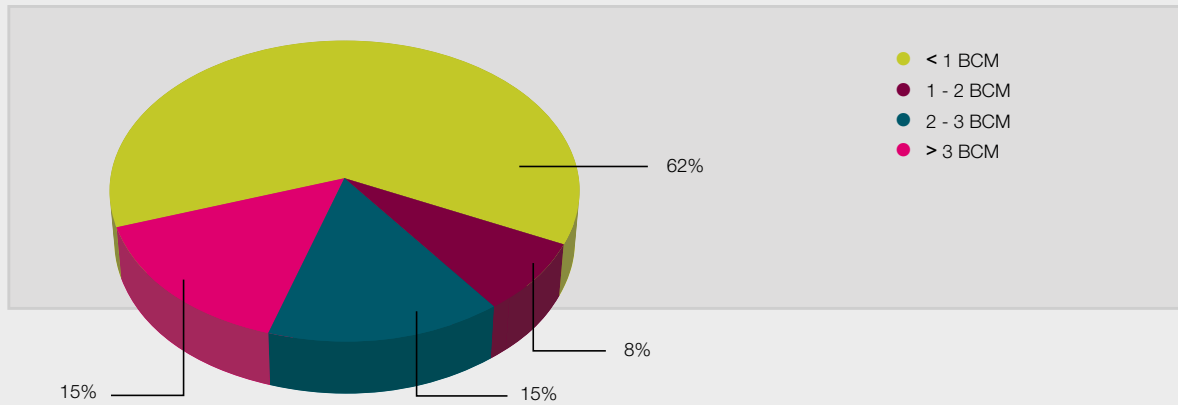
of investments from the financial result calculated for SPS purposes. Consequently, the total SPS + CIT payment is reduced by 12.5% of the capital investment. Since capital expenditure, and hence tax benefits, occur at the start of field development, this results in a direct increase in Net Present Value. EBN's evaluation of a project, for which the operator successfully applied for the allowance, shows an increase in NPV from €2 million negative to €7 million positive. The 25% investment allowance thus improved

the likelihood of the project meeting the operator's investment hurdle rates.

The marginal field tax allowance considerably reduces a licensee's dry-hole risk: after tax, the licensee has only a 32.5% share in the costs of a dry hole. Given EBN's 40% share in the well cost, the licensee therefore only has to bear 19.5% of the total costs of a dry hole.



Sizes of marginal fields (recoverable volumes)



EBN 2012

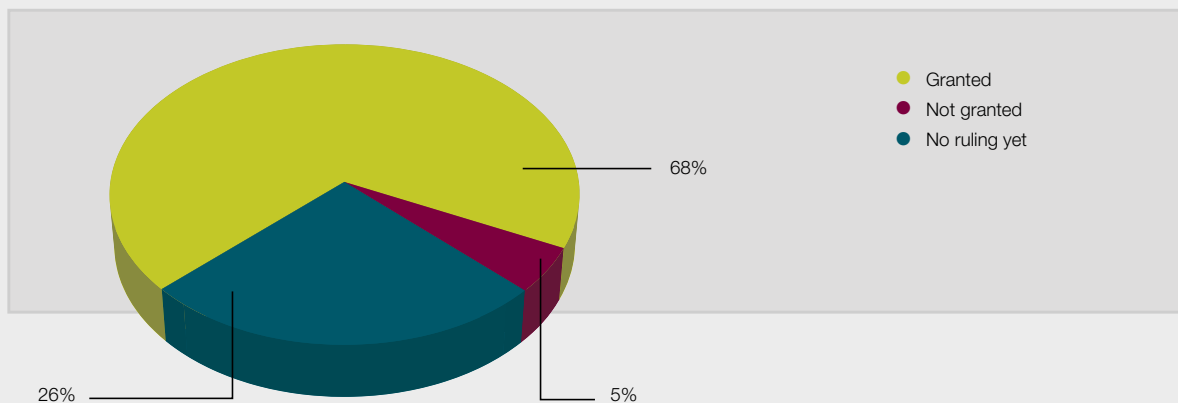
2.6.2 | Applications

The first applications for the investment allowance for marginal offshore gas fields were filed in October 2010. Since then, the total number of projects applied for has risen to 19, by eight different operators. In 13 of the 14 cases the Ministry approved the application and granted the allowance, while decisions on five other applications have not yet been finalised. The (expected) recoverable volume per project in most of the 13 projects for which the

tax allowance has been approved is less than 1 BCM.

These types of field developments are often unlikely to be funded by licence holders unless the government takes a 'backseat' position on its share in the profits. The 13 projects aim to discover and produce a total of 22 BCM (unrisked). Taking into account the Probability of Success, this yields a risked expectation volume of 11 BCM.

Applications for marginal field allowance



EBN 2012

2.7 | Other tax measures and initiatives

The Dutch government is actively pursuing a policy to position the Netherlands as the Northwest European Gas Hub and to promote gas-related investments. The Gas Hub Consultative Platform provides a forum for the Dutch government and the gas industry to align and discuss new initiatives and strategic issues. One of the working groups in this platform is responsible for investigating possible opportunities for improving the E&P investment climate. This working group, involving cooperation between EBN, the industry, TNO (in its role as advisor to the Minister) and the Ministry of Economic Affairs, Agriculture and Innovation, is examining further improvements to the E&P tax system.

Two other specific tax measures introduced by the Dutch government – the Research and Development Allowance (RDA) and the Dutch Innovation Box (DIB) – also provide incentives for future investments. These tax measures, which are intended to encourage research and development, innovation and the use of innovative techniques in general, are particularly attractive for oil and gas companies performing R&D studies and developing and applying innovative techniques in the Netherlands.

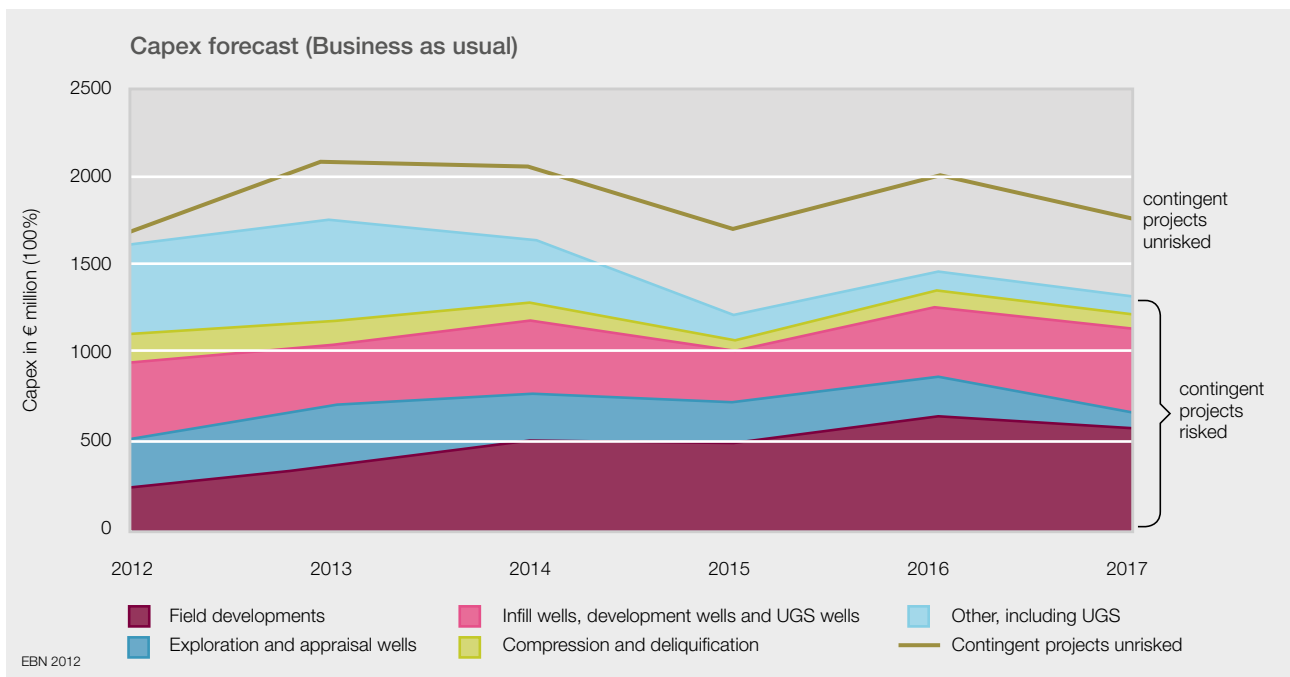
2.7.1 | Research and Development Allowance

The Dutch government has introduced a special tax allowance for research and development. From 2012, 40% of the effective costs and expenses directly attributable to R&D can be deducted from corporate income tax. This applies, for example, to investments in and the costs of operating laboratories, the costs of developing new products and techniques, and technical and feasibility studies. The total budget available in 2012 for this R&D allowance is €250 million, increasing to €500 million in 2014.

Meanwhile, the government is working on a plan to extend this RDA measure to include an additional tax allowance for research and development activities outsourced by private companies to public knowledge institutions. Introduction of what is being referred to as the 'RDA-plus package', which will provide a substantial tax allowance for these activities, is planned for 2013.

2.7.2 | Dutch Innovation Box

Since 2010, the Dutch Innovation Box, which was originally introduced in 2007, has allowed qualifying profits deriving from the application of innovative techniques to be taxed at an effective rate of 5% rather than the usual 25%.



2.8 | Future investments

Looking to 2012 and the five years beyond, EBN expects investment levels in Dutch E&P to remain stable at around €1.5 - €2 billion (real term). The EBN forecast for the next five years foresees investments in some 100 field developments, including hook-ups, and in approximately 260 wells. The actual number of projects will largely be determined by the ability of EBN and its partners to mature the projects in the contingent resources portfolio. The EBN forecast includes 80 exploration wells, 40 of which are expected to result in new field developments.

The forecast is based on EBN's portfolio of currently known, planned projects. It should be noted however, that smaller projects, such as deliquification projects or seismic reprocessing projects, are not usually defined more than three years in advance and so are not known to EBN at this stage. Although the profile presented is generally seen as representing a healthy level of investments, EBN is keen to encourage more exploration drilling, combined with specific investments to unlock gas in challenging reservoirs. A higher level of investment will certainly be required in order to maximise production from small fields in the years to come.

OPERATIONAL
PERFORMANCE AND
FACILITIES

3

3. OPERATIONAL PERFORMANCE AND FACILITIES

3.1 | Exploration: drilling performance

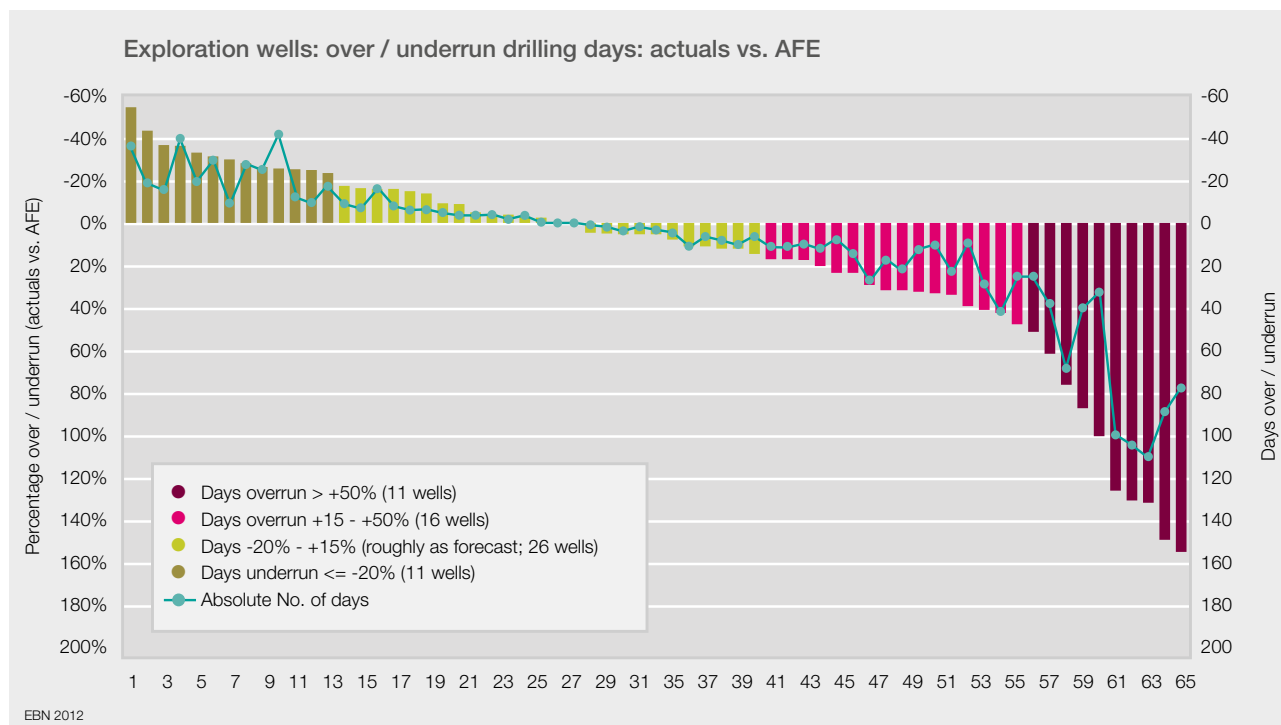
3.1.1 | Rig days for exploration wells

Based on our database of 66 recent wells (see section 1.6), EBN analysed the actual number of rig days (rig on/off location) versus the number of days planned in the *Authorisation for Expenditure* (AFE). This is expressed as a percentage overrun or underrun. It enables direct comparison between deep wells and shallow wells, with the latter typically taking less time to drill. *Waiting on weather* (WOW) time is included.

Wells requiring a sidetrack because of technical problems could be expected to take longer to drill than assumed in the standard 'AFE -20/+15%' bracket. That is not necessarily the case, however. Six of the sidetracked wells

stayed within this band. A total of 13 wells were sidetracked, four of which were sidetracked more than once, while one had a planned sidetrack (which itself had to be sidetracked as well). These were not necessarily strongly deviated wells.

Eight wells took less than 70% of the drilling time planned in the AFE. The number of days planned in the AFE for these wells ranged from 30 to 120. Some wells were tested, while others were not. It seems likely that too many contingencies were included in the well proposals for these wells. In total, 39 wells took longer than planned in the AFE, with 27 of these exceeding the planned drilling time by more than 15%, i.e. falling outside the 'AFE -20/+15%' band.





In conclusion, drilling of most wells took longer than planned. A total of 4,625 rig days were planned (taking into account proper AFEs for tested wells and dry holes) over the seven-year period studied. The total overrun was 813 rig days, or 17.5%, equal to 2.2 years of rig time.

3.1.2 | Exploration - resources: finding cost

A common way of measuring exploration success is the finding cost per m³ of gas. EBN used the AFE budget for this analysis. It is realistic, however, to assume that actual costs may be up to 20% higher (e.g. the 17.5% overrun on AFE rig days). Obviously, there is a strong correlation with rig rates, which themselves correlate strongly with the oil price (lagging the oil price by approximately 1-2 years). The odd year out is 2010, when few resources were added despite a good success ratio. This is also caused by a few expensive exploration wells which were drilled

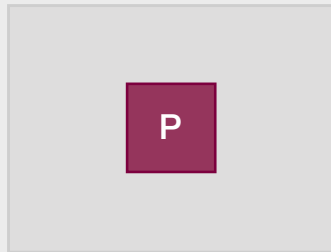
that year. Generally, finding costs can be expected to amount to €0.02 to €0.06 per m³ of gas (taking into account the overrun on AFE rig days). This analysis only took drilling costs into account: seismic, reprocessing, study and other costs were not included.

3.2 | Operational expenditure on facilities

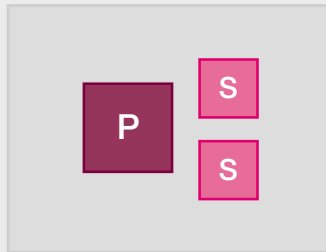
3.2.1 | Historic and current operational expenditure

In the early 1990s, when oil prices were low, EBN initiated the BOON (Benchmarking Opex Offshore Netherlands) exercises to gain insight in the *operational expenditure* (opex) of offshore gas facilities and with a view to assisting operators in reducing their opex. The first BOON exercise was carried out for 1993, while the most recent was for 2010. For the purpose of comparison, platforms

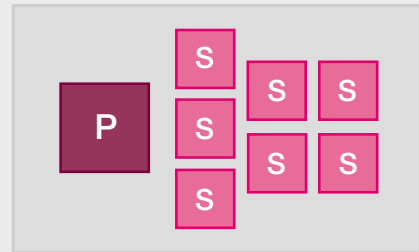
BOON cluster definition



A-cluster, processing platform,
no satellites



B-cluster, processing platform,
1-4 satellites,
normalised to 2 satellites



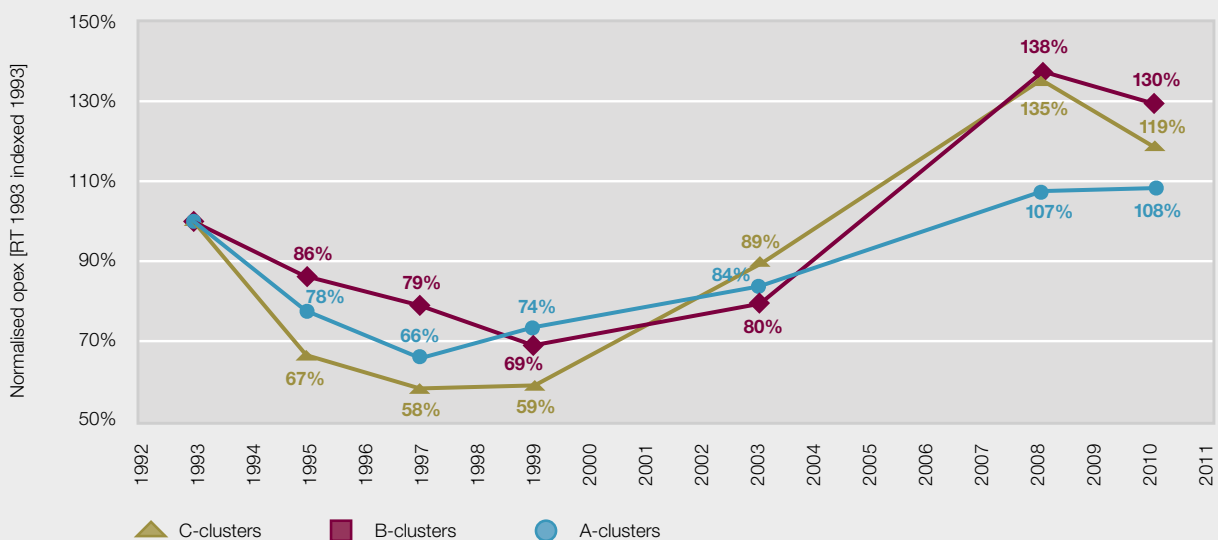
C-cluster, processing platform,
> 4 satellites normalised
to 7 satellites

EBN 2012

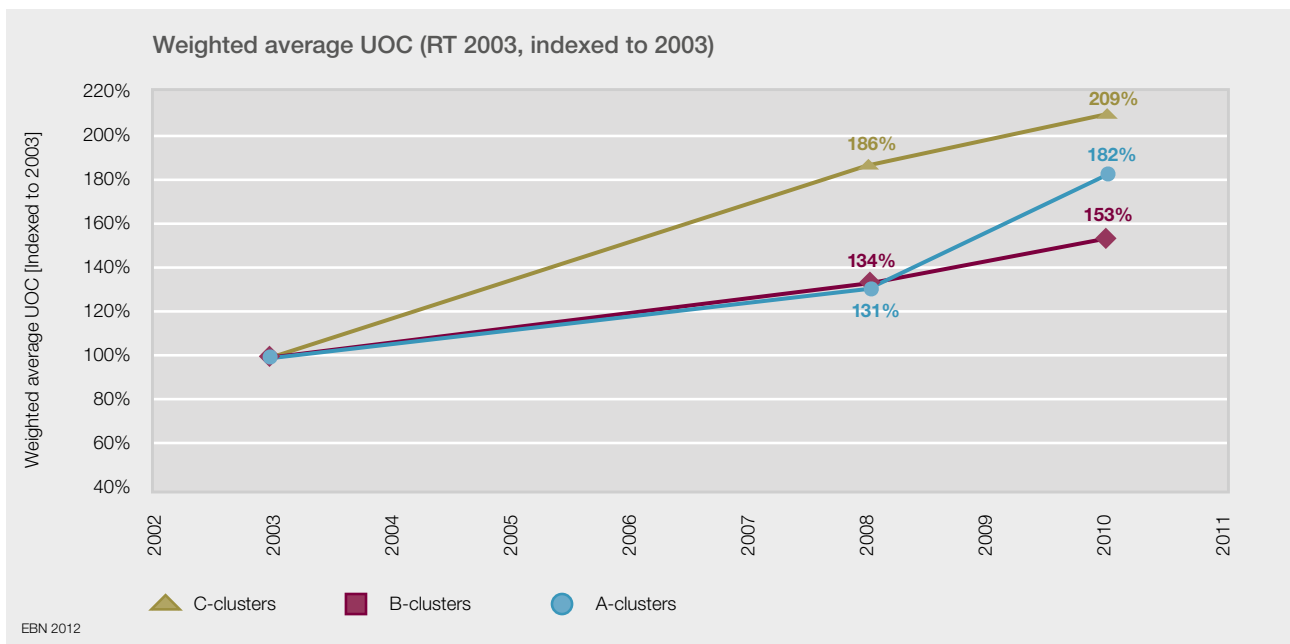
were categorised into A, B and C clusters, depending on the number of satellites attached to a processing hub. The most recent exercise, for 2010, covered 12 A-clusters, 15 B-clusters and 6 C-clusters. Processing and transport payments were not included in the BOON calculations. The two previous exercises, carried out for 2003 and 2008, showed that, even after

adjusting for inflation, the downward trend in opex for Dutch offshore clusters was reversed into an upward trend around 1997-1999. The most recent exercise, for 2010, showed, however, that the trend of rising annual opex per cluster had come to an end. These lower figures were attributable both to market trends and to activities undertaken by operators to reduce opex.

Average annual opex (RT 1993 indexed 1993)



EBN 2012

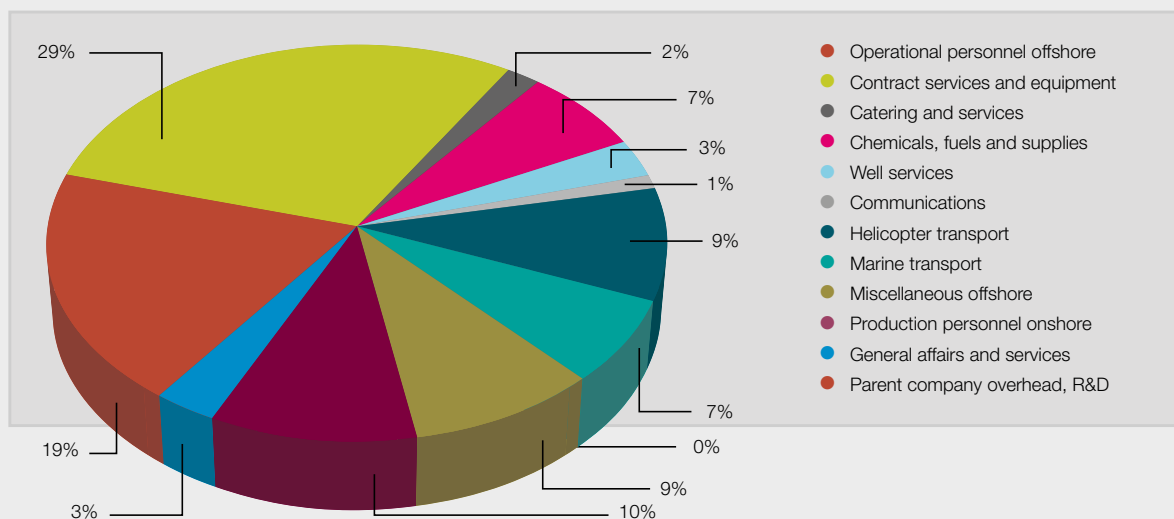


In an environment of declining production and ageing infrastructure, controlling opex is a key factor in extending economic field life. This also holds true for offshore facilities in the Dutch continental shelf. It should be noted that field-life extension will not result in large volumes of extra gas from the fields under consideration as these fields are in their tail-end phase. Reducing opex will, however, extend infrastructure life and so pave the way for developing additional opportunities using that same

infrastructure. Despite lower opex, the Unit Operating Cost (UOC) increased further as a result of declining throughput volumes (from 70 million Nm³ per day in 2008 to 60 million Nm³ per day in 2010).

The effect of the lower throughput volumes is more pronounced than the reduction in operators' opex and so it is very important to keep UOC under control if production is to remain economically viable in future.

Average opex (2010)



EBN 2012

3.2.2 | Opportunities for reducing operational expenditure

In order to identify opportunities for reducing costs it is imperative to understand the relative contribution of each cost element to total opex. Almost 50% of total opex is spent on operational personnel offshore and on contractor services and equipment. Therefore, opex reduction can best be achieved by focusing on these two cost elements. However, these two cost elements show great variation between operators, with some operators spending only 50% of the average opex and others spending as much as 160%. The 'best in class' operators are able to reduce their costs for these cost elements. Other sizeable opex cost elements are helicopter transport (9%) and marine transport (8%).

The relative contributions of the different cost elements vary only slightly between the 2003, 2008 and 2010 BOON exercises, and the division between offshore (78%)

and onshore (22%) has remained stable since 2003.

Cost elements are less easily influenced, e.g. chemicals, fuels & supplies and communications, and these also have less impact on total opex. Initiatives such as pooling services and logistics, offshore demanning and simplifying plants and installations are therefore becoming more important, particularly as platforms are becoming obsolete and, therefore, heavily over-dimensioned for their current purpose. Standardised platform-reduction methods aimed at minimising platform equipment therefore could offer good opportunities to reduce maintenance and personnel costs. The E&P industry is currently actively seeking collaboration in preparing for the tail-end phase of field life.

A good example of opex reduction is the initiative taken by a large Dutch operator to simplify its plants and processes by converting a significant part of its operation from dry-gas transport (requiring gas-dehydration facilities) to

wet-gas transport, thereby removing high-cost equipment from service and preparing these fields for a low-cost tail-end phase. We expect other operators will follow their example and also start downsizing and simplifying their infrastructure.

However, overall activity in these kinds of initiatives is relatively low. In view of the remaining production life and the time and capital involved in maturing these initiatives, there is a real concern that not all operators understand the urgency of the situation. This may be partly due to the way opex is actually distributed among facility users and owners. Traditionally, opex is shared by all the users in a form of unit-of-production (UOP) agreement. Many of the large offshore processing centres are ageing and have

little or no equity production left. Their continuing operation depends largely, therefore, on other gas supply streams. However, opex-sharing provides no incentives to economically optimise hub-facility operations since all opex is reimbursed. As a result, an increasingly smaller throughput is burdened by ever-increasing opex, thus rapidly increasing the *Unit Operating Cost* (UOC) to an extent approaching the economic cut-off value.

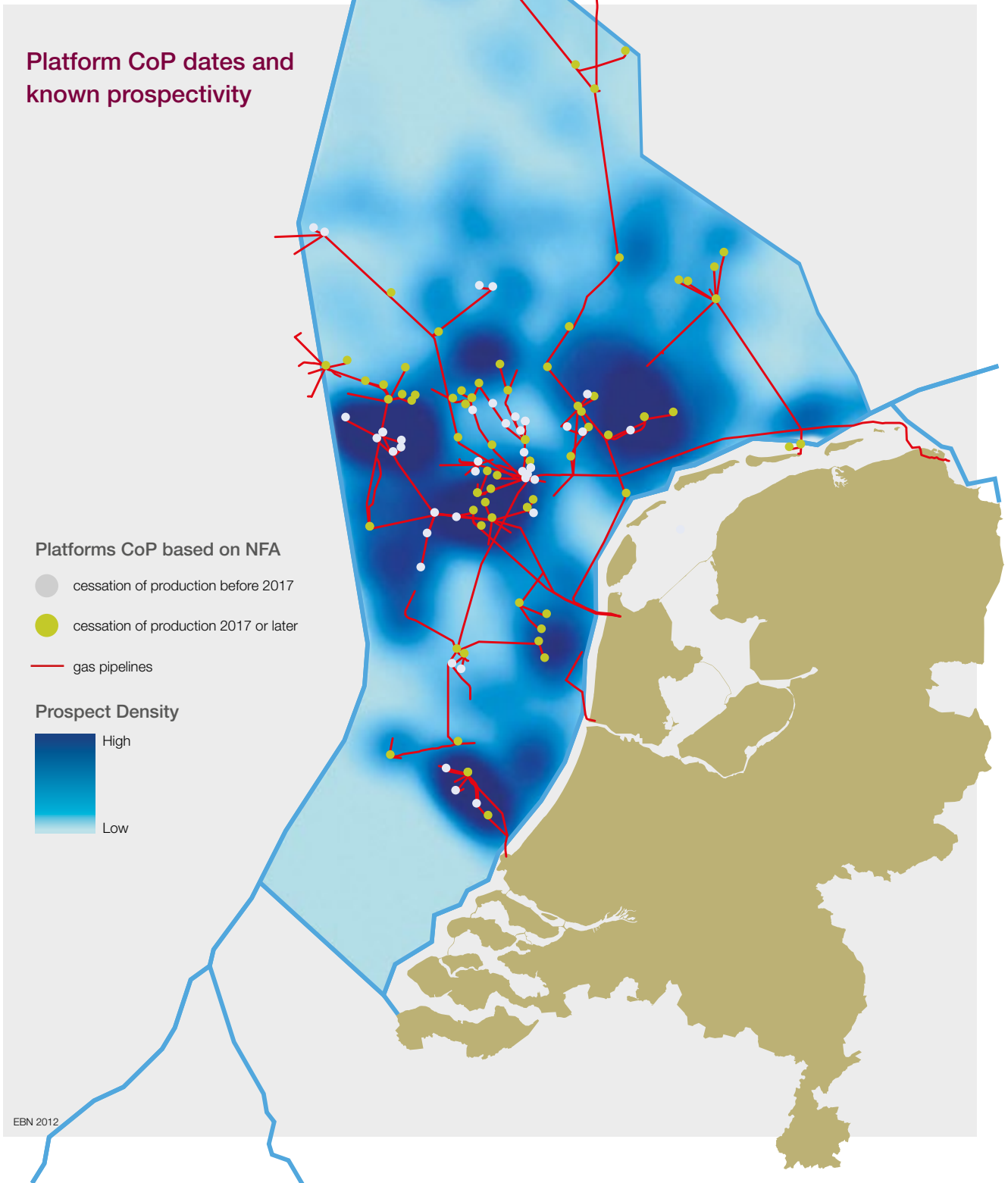
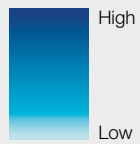
A different way of allocating opex – such as an all-in fee – would act as more of an incentive to operators to optimise their current operations (by, for instance demanning, automating and simplifying activities), thereby increasing reserves and extending facility life for the benefit of users and owners alike.

Platform CoP dates and known prospectivity

Platforms CoP based on NFA

- cessation of production before 2017
- cessation of production 2017 or later
- gas pipelines

Prospect Density



EBN 2012

3.3 | Extending facility life

As EBN's 2011 *Focus on Dutch Gas* explained, finding and developing new gas is more effective than reducing opex when it comes to extending infrastructure life as revenues generated from sales of new gas have a larger impact than opex savings. However, the activities involved in finding new gas carry an inherently larger degree of uncertainty, whereas activities aimed at reducing opex can pay back immediately. Nevertheless, benefits are not easy to achieve, and reducing opex by even a modest percentage often requires a step change in the way business is conducted.

As stated in EBN's 2011 *Focus on Dutch Gas*, around 25% of all platforms could benefit substantially from maturing identified contingent resources. Plenty of infill opportunities and end-of-field-life projects have been identified for many fields. However, the results for most facilities are limited and the contingent resources will not significantly extend the life of the system as a whole. The life of these platforms can only be extended by continued exploration.

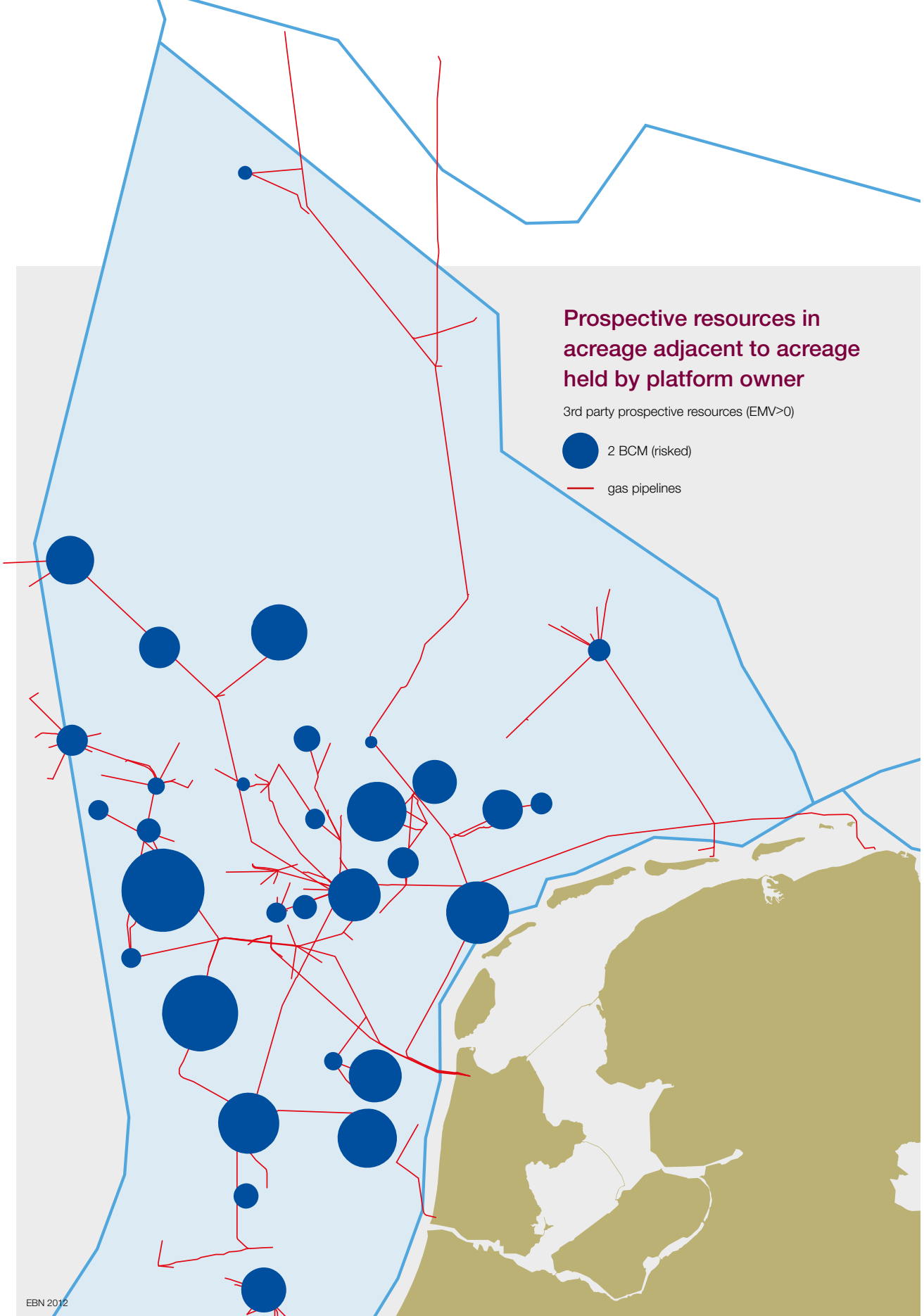
3.3.1 | Opening up new areas for exploration

Analysis shows that around 80% of the economically viable offshore prospects with an *Expected Monetary Value* (EMV) ≥ 0 will lose their primary defined tie-in points within the next ten years. This conclusion is based on the year in which production from a platform will cease, calculated on the basis of current reserves. Taking the

production of all contingent resources in the portfolio into account may postpone *Cessation of Production* (CoP), but 70% losing their tie-in points is still alarming.

In the early phase of E&P activities, exploration eventually resulted in infrastructure. In the current mature phase, the order is reversed: further exploration activities will follow the expansion of infrastructure; in other words, established infrastructure becomes an enabler of exploration. The northern Dutch continental shelf in particular lacks infrastructure and is therefore underexplored, partly because of a lack of proven plays. The low prospect density in this area underscores this statement. Laying a non-dedicated trunk line into that area might act as a catalyst for further development, just like the construction of the NOGAT extension pipeline acted as a catalyst for the development of fields downstream of F03-FB. On the other hand, there may simply not be many prospects in the underexplored region anyhow, and laying a non-dedicated trunk line into that area may not result in significantly more reserves being generated.

More prospects may potentially be found in areas away from existing infrastructure. New exploration efforts, such as Fugro's new, large-scale 3D seismic acquisition survey in the D, E and F blocks investigating underexplored plays and focusing on shallow gas prospectivity, should increase both the number of prospects and the POS of some prospects already identified.



3.3.2 | Third-party prospective resources

Traditionally, operators thoroughly explore their own acreage in order to maximise the value of their licences. The adjacent, non-operated, licence blocks typically receive far less attention. An inventory of prospectivity (listing numbers and volumes of prospects) indicates that many non-operated licence blocks also contain attractive opportunities that may extend platform life.

Of the total prospects portfolio, some 237 offshore prospects, with an associated risked volume of around 110 BCM, should be economically viable under current conditions ($EMV \geq 0$). The licences for around 40% of this prospective volume are held by parties other than the party operating the nearest and most obvious tie-in point for that prospective volume. As 40% of the non-operated prospective resources are contained in only 20% of the prospects; non-operated volumes are mostly in relatively large prospects.

In specific areas it might be rewarding for operators to shift their focus from their own acreages to prospects just outside their own licence blocks. This would benefit both parties: the platform operator can extend the economic life of its platform, while the operator drilling the prospect gets the shortest possible export route. It should be noted, however, that bringing all the economically viable prospective resources on stream requires a joint effort by the holder of the adjacent licence and the operator of the main hub.

3.4 | Environmental performance

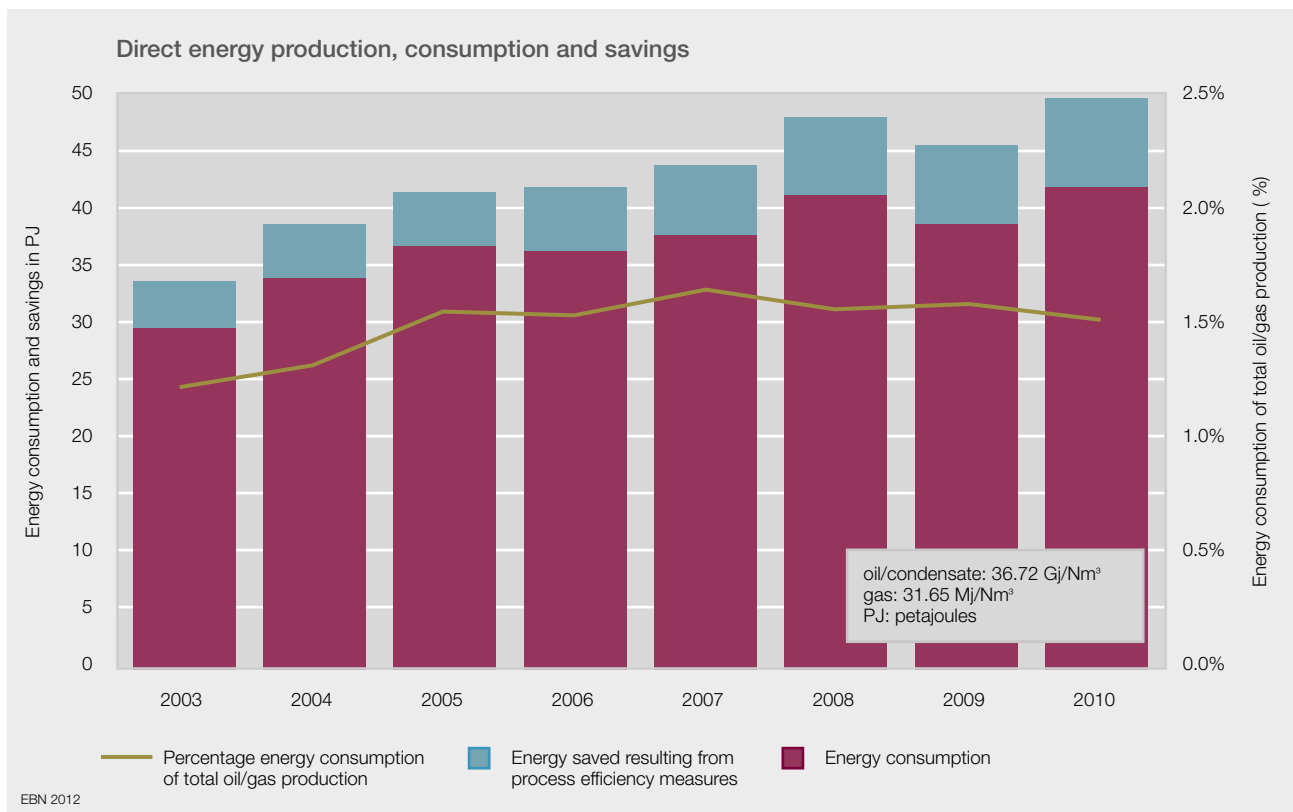
All oil and gas exploration and production activities inevitably have adverse environmental impacts as a result, for instance, of energy consumption and CO₂ and CH₄ emissions. The figures presented in this section cover nearly all onshore and offshore exploration and production activities. These data will also be shown on EBN's website from the second quarter of 2012. The data were extracted from the electronic database into which Dutch operators report production-related data, and converted into graphs. EBN will also add other information to its website, such as background information on the sector's environmental, societal and economic performance, including flared and

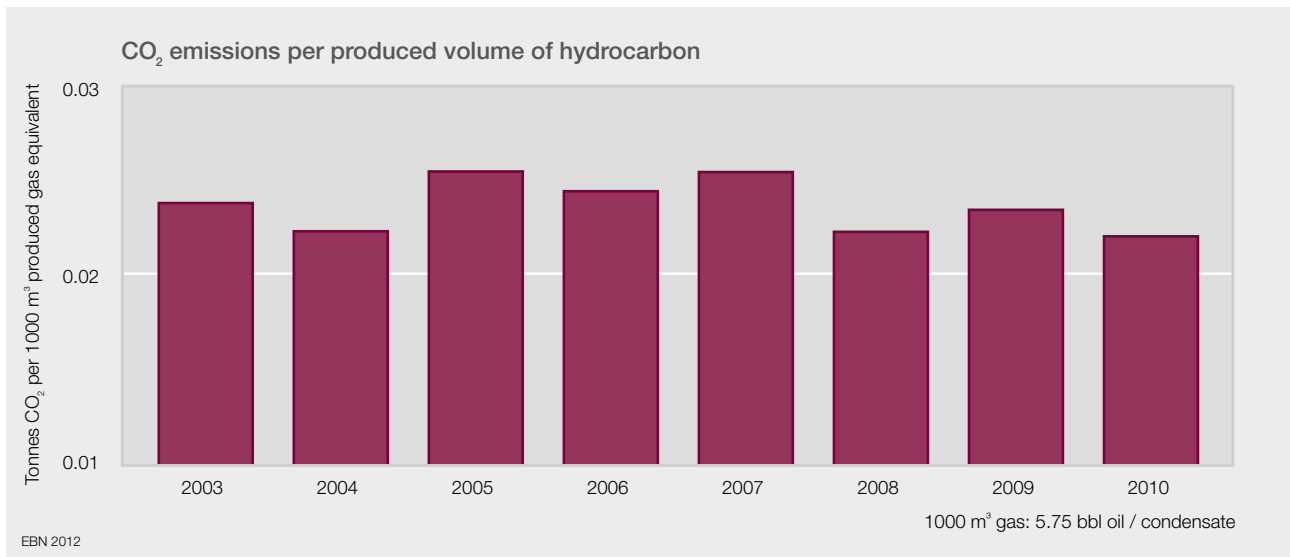
vented hydrocarbons, volumes of condensed formation water and produced water, and numbers of incidents.

EBN initiated reporting on these topics because more transparent communications may encourage operators even more to actively pursue sustainability in their E&P operations and projects. The other reason for publishing these data on EBN's website is to promote societal acceptance of the oil and gas industry in the Netherlands.

3.4.1 | Direct energy consumption (primary energy)

The oil and gas industry used 41.6 PJ of energy in 2010, but produced around 3,000 PJ in gas. The primary energy consumption trend approximately tracks the





gas production trend. Lower reservoir pressures mean more energy is required for gas compression and to bring the gas up to the distributor's specifications. Reservoir depletion directly affects the industry's energy consumption. However, CO₂ emissions per 1,000 m³ of produced gas have not increased in recent years. Compression to counteract depletion accounts for 70% of the E&P industry's total energy consumption, 66% of which derives from gas and 28% from electricity.

3.4.2 | Energy-saving efforts

The Long Term Agreement on Energy Efficiency (LTA-3) formulates specific energy-saving categories for improvements in process efficiency:

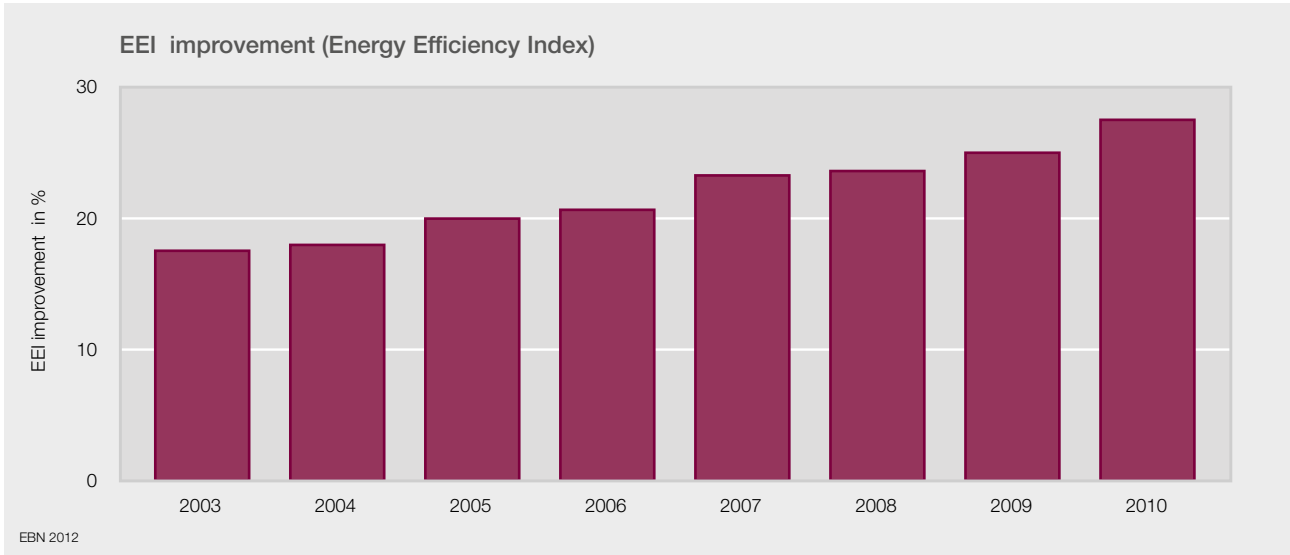
- Improvement attributable to depletion compression/ electrical submersible pumps (ESPs)
- Improvement attributable to process equipment
- Process improvement
- Emission reduction

Maintaining the same level of gas production from the

depleting fields required more depletion-compressor capacity in 2010 than in 2003. The use of more energy-efficient compressors and matching motors contributed most to improving energy efficiency. Whereas the contribution of other energy-saving measures remained almost stable, energy savings resulting from the use of more efficient compressors increased from 982 TJ in 2003 to 3,459 TJ in 2010. As a result, energy savings attributable to depletion compressors increased from 23% in 2003 to 44% of total energy savings in 2010.

3.4.3 | Energy Efficiency Index

The energy efficiency index (EEI) is calculated by dividing the *actual* energy consumption by the *reference* energy consumption. The reference energy consumption is the consumption if no efficiency measures were applied (reference energy consumption = actual consumption + effect of efficiency measures). In the past eight years, energy efficiency has improved from 17.3% to 27.3%. Over 40% of all these savings were achieved through more efficient depletion compressors.



3.5 | Decommissioning

The expected total costs of decommissioning of facilities (including the removal) and the abandonment of wells in the Dutch southern North Sea is currently estimated at approximately €3 billion. Although Dutch tax law allows

operators to expense these costs in the same way as UOP expenditure, actual expenditure has to be funded from the remaining cash flow. The magnitude and timing of these decommissioning costs could leave little scope to fund activities focusing on business growth, and thus lead to a further acceleration of the decline. Therefore, there is



plenty of incentive to reduce, postpone or phase the costs of decommissioning.

Past decommissioning projects have demonstrated that the process is generally poorly understood, with many operators and the service industry being inadequately prepared. This is reflected in, for example, a lack of data and little detailed attention to planning, and results in budget overruns.

Estimates of decommissioning costs are based on removal provisions and the total weight of the platform structures, excluding subsea completions and gravity-based structures (GBSs) from the dataset. Estimates in euro per kg show a wide spread, which indicates that the decommissioning business is still in its infancy. In the near future, considerable expertise and knowledge will be gained in decommissioning and removal projects, and the actual costs incurred will allow more refined estimates to be prepared for subsequent decommissioning activities.

In view of the spread in decommissioning costs between comparable platform structures, but also the high total costs, there should be enough incentive, both for operators and service companies, to develop and optimise efficient decommissioning techniques and approaches through, for instance, combined removal campaigns.

GLOSSARY

AFE

Authorisation For Expenditure

Business as usual

Forecast scenario assuming the E&P industry maintains its current activity level

BCM

Billion Cubic Metres

BOON

Benchmarking Opex Offshore Netherlands

capex

Capital expenditure

CIT

Corporate Income Tax

CO₂

Carbon dioxide (one of the six “greenhouse gases” under the Kyoto protocol)

CoP

Cessation of Production

Decommissioning

Process to decommission facilities from active status including removal

Deliquification

The general term for technologies used to remove water or condensates build-up from producing gas wells

DIB

Dutch Innovation Box: tax measure to promote innovation

E&P

Exploration and Production

EBN

Dutch State owned, non-operating oil and gas exploration and production company

EEl

Energy Efficiency Index: actual energy consumption divided by the reference energy consumption

EMV

Expected Monetary Value

End of field life

Gas or oil field in the final phase of production

ESP

Electrical Submersible Pump

EXP

Expectation volumes for exploration (POS*MSV)

GasTerra

International company trading in natural gas, located in Groningen in the Netherlands

Gas-to-Wire

On-site conversion of produced gas into electricity

GBS

Gravity Based Structure

GIIP

Gas Initially In Place

GWC

Gas/Water Contact

Hydraulic fracturing

Stimulation by injecting heavy liquid under high pressure into a reservoir in order to create fractures, which improve the reservoir’s permeability and thus the flow of gas and/or oil towards production wells

JIP

Joint Industry Project

licence holder

Licensee, holder of a licence for exploration, production or storage activities under the Mining Act

LTA-3

Long-Term Agreement on Energy Efficiency – part of the Sustainability Agreement between the Dutch government and the Confederation of Netherlands Industry and Employers (VNO-NCW)

MMBO

Million Barrels Of Oil

MSV

Mean Success Volume: the predrill estimated mean recoverable volume of gas or oil in the prospect

NFA

‘No Further Activity’ scenario

NOGAT

Northern Offshore Gas Transport pipeline

NOGEPA

Netherlands Oil and Gas
Exploration and Production
Association

NPV10%

Net Present Value at
10% discount

Operator

Party carrying out E&P activities in
a licence on behalf of the partners

Opex

Operational expenditure

OWC

Oil/Water Contact

PJ

Petajoules

POM

Probability of Maturation

POS

Probability Of Success: the
probability of finding hydrocar-
bons in a prospect

PRMS

Petroleum Resources Manage-
ment System: international
classification system describing
the status, the uncertainty and
volumes of oil and gas resources,
SPE 2007

Profit margin

Profit as a percentage of income

PrSDM

Pre-Stack Depth Migration: a
seismic processing method

RDA

Research and Development
Allowance: tax measure to
promote investment in R&D

Reference

Energy Consumption

energy consumption if no energy
saving measures are applied

RT

Real Term

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

Shallow gas

Gas occurring in relatively shallow
reservoirs (< 1000m depth, mostly
unconsolidated)

Sidetrack

A secondary wellbore started
from an original wellbore

SPS

State Profit Share

Stimulation

A treatment performed to restore
or enhance the productivity of
a well. Stimulation treatments fall
into two main groups, hydraulic
fracturing treatments and matrix
treatments.

STOIP

Stock Tank Oil Initially In Place

Stranded fields

Natural gas deposits that are
technically or economically
impractical to develop and
produce at a particular time

Tight gas

Gas in sandstone reservoirs with
insufficient permeability for the
gas to flow naturally in economic
quantities to the well bore

TJ

Terajoule

TNO

Netherlands Organisation for
Applied Scientific Research.

UGS

Underground Gas Storage

UOC

Unit Operating Cost

UOP

Unit Of Production

UR

Ultimate Recovery

Workover

The repair or stimulation of an
existing production well for the
purpose of restoring, prolonging
or enhancing the production of
hydrocarbons.

WOW

Waiting On Weather

ABOUT EBN

Based in Utrecht, EBN B.V. invests in exploration for and production of gas and oil. In the Netherlands EBN does this together with national and international oil and gas companies who, as licence holders, take the lead on these operations. EBN B.V. is itself active in trading gas, condensate and oil and has a 40% interest in the natural gas wholesaling company GasTerra B.V. The profits generated by these activities are paid in full to the Dutch state, our sole shareholder. EBN not only invests but also facilitates and shares knowledge across the sector and advises the Dutch government on the mining climate and on new opportunities for making use of the subsurface. Visit www.ebn.nl for more information.

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