

Focus on Dutch gas **2011**



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Executive summary

A major landmark was reached in 2010: cumulative production of natural gas from fields in which EBN participates passed the 3000 billion cubic metres mark! Meanwhile, the volume of prospective resources remains at around the same level as before. The ambition to maintain annual production at 30 BCM until 2030 is challenging but achievable.

Maturation of the currently identified contingent and prospective resources in the EBN portfolio will enable annual production of around 30 BCM for the next five years. The Dutch E&P industry's level of activity has been stable in recent years, while exploration-related activities are increasing, especially in comparison with the Danish sector of the North Sea and the UK Southern Gas Basin. Mature areas still show significant exploration potential. Renewed exploration efforts have started in underexplored areas, with large-scale seismic studies being a prime example. Encouraging the production of already discovered, but as yet undeveloped fields ("stranded fields") should unlock more significant volumes of gas reserves.

After this five-year period, activities to extend field life, along with exploration and development of challenging reservoirs, will be needed to counter the declining production from identified resources. According to EBN's latest information, the scope for end-of-field-life techniques will add several tens of BCMs to the Dutch reserve base, while the resources contained in challenging reservoirs may add hundreds of BCMs of recoverable gas. These resources could meet Dutch demand for gas for many years to come.

There are various opportunities to add reserves to the system: a number of areas in the tail-end production phase contain significant contingent resources. These areas should be focused on when maturing these contingent resources into reserves through the use of innovative technologies and efficient development strategies. There are also several mature and tail-end areas in which no significant amounts of contingent resources have yet been identified. Renewed exploration of these areas is needed if contingent resources are to be identified.

Availability of infrastructure is essential for production. Significant offshore exploration opportunities exist within 10 km of infrastructure tie-in points, but current production forecasts mean part of this infrastructure may disappear in about five years' time. Joint efforts by all industry partners involved are required to maintain this infrastructure, which will be needed for an efficient and sustainable E&P sector.

The Dutch government is committed to ensuring an attractive mining climate in the Netherlands and has added two additional measures to the successful small fields policy. The first of these is the investment allowance for marginal offshore gas fields, which is expected to result in an additional 20 BCM of reserves. The second incentive involves marking underused acreage as fallow so as to ensure access. Areas currently marked as fallow are estimated to contain some 76 BCM of recoverable gas.

Public acceptance of E&P activities is crucial. It is important for the Dutch E&P industry to work with local communities to minimise the inconvenience caused by E&P activities. In addition, the Dutch government can support the industry by explaining the economic and strategic benefits of domestic gas production to society.

There are clearly some major challenges ahead. At the same time, however, these challenges can be seen as opportunities. Opportunities that contribute to the efficiency and sustainability of the E&P sector and will benefit society as a whole.



1. Resource base



1. Resource base

1.1 2011 reserves and resources

This year, cumulative gas production – since the start of gas production in the Netherlands – from all the fields in which EBN participates reached the landmark of 3000 billion cubic metres (BCM). The cumulative figure is even higher if the fields in licences in which EBN does not participate are included. Last year, production from small fields once again exceeded 30 BCM. Well in line, therefore, with EBN's ambition to maintain production from small fields at more than 30 BCM a year for the next two decades.

Despite the huge volumes of gas already produced; the reserves and resource base remains large, mainly as a result of the huge size of the Groningen gas field. In contrast to the position in last year's Focus report, EBN now has a fully filled portfolio of contingent resources down to SPE's Petroleum Resources Management System (PRMS) category 6, which is a reasonable reflection of the actual state of all the gas discovered in the Netherlands (with EBN participation). This includes discoveries currently considered sub-commercial to develop. It is up to EBN and its industry partners to ensure that these contingent resources are developed and matured into reserves if production of 30 BCM a year from small fields is to be maintained. It should be noted, however, that recovery factors are notoriously difficult to predict for fields in category 6 since, in general, very few data are available. In addition, many of these fields are labelled 'tight' and hence predictions of their ultimate recovery volumes (UR) are by no means certain. This portfolio is under continuous study and will be regularly updated.

Aside from the development of known fields and discoveries, the portfolio of prospects within proven plays still holds an estimated risked volume of well over 400 BCM. Continuous exploration drilling will be needed to ensure these volumes mature into the contingent category and ultimately into reserves.

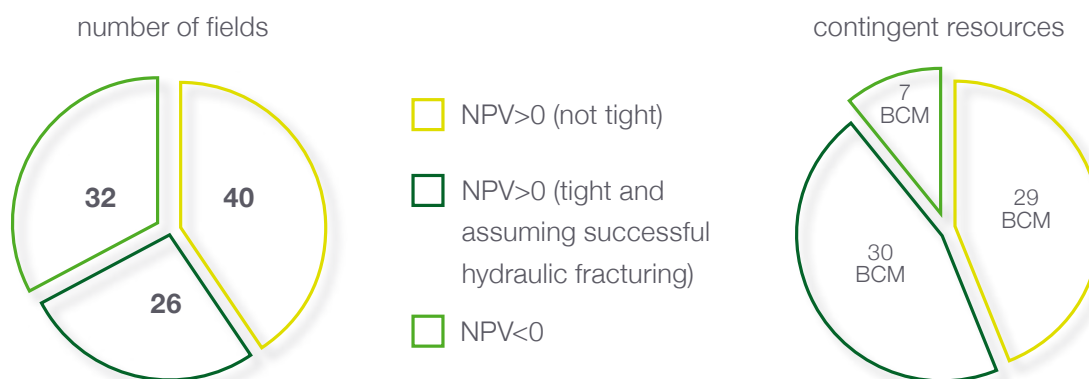
Resource base		Groningen	small fields	total
Reserves and resources (BCM)				
EBN 2011	reserves			
	in production (cat 1)	698	152	850
	approved for development (cat 2)	7	29	36
	justified for development (cat 3)	189	26	215
	contingent resources			
	development pending (cat 4)	35	56	91
	development unclarified/on hold (cat 5)	2	48	50
	development not viable (cat 6)	0	24	24
	unrecoverable (cat 7)			
	prospective resources			
	prospects/leads/plays (cat 8)		>400	>400
	unrecoverable			
100% volumes, Groningen equivalent, categories according to SPE's PRMS 2007				

1.2 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 (characterised by very low flow rates), too small, too remote or located in sensitive areas. EBN has identified a portfolio of 98 stranded fields, both on- and offshore. Of these 98 stranded fields, 34 are classified as tight.

EBN has simulated the development of this portfolio in a field-development simulation program that includes an investment allowance for marginal offshore gas fields, based on remoteness, production rate and gas volume initially in place (see section 2.5.1). The simulation showed that the net present value (NPV) of 40 of the 64 fields that are stranded for reasons other than being tight was higher than 0. Total contingent resources for these fields are estimated at 29 BCM. The benefits of the marginal-fields investment allowance measure are evident: 14 of these 40 fields would not have a positive NPV without the tax benefit for marginal fields.

Stranded fields



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Assuming a standard development scenario, which excludes the option of stimulation (by hydraulically fracturing) of wells located in tight fields, none of the tight stranded fields would achieve a positive commercial screening. Thus, lack of productivity from these fields is a key factor. The average size of a stranded field is small, which is the main reason why a large number of stranded fields have not yet been developed. The average field size of the fields above the NPV > 0 threshold is slightly larger. Fields below that threshold are on average extremely small: 32 fields together contain only 7 BCM. Capital expenditure (capex) control measures, such as reducing drilling costs, together with technological advances and alternative development strategies, could in future unlock more resources in these stranded fields.

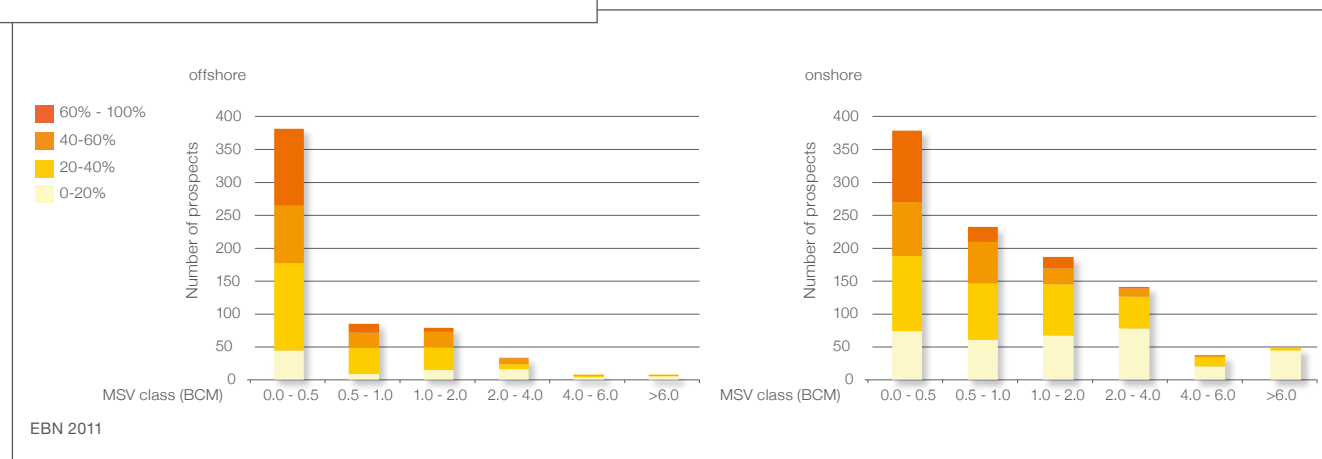
Productivity from tight fields may be enhanced by developing these fields by horizontal wells with stimulation. This may unlock considerable resources from these tight fields. Assuming that hydraulic fracturing these tight reservoirs could increase productivity from 'poor' to 'good', no fewer than 32 of these tight fields would achieve a positive NPV, representing 30 BCM of recoverable gas. The additional costs of hydraulic fracturing were included in the simulation. If overall development costs, including the costs of hydraulic fracturing, could be reduced, even more of these fields could be developed commercially.

1.3 Prospectivity

1.3.1 Prospect portfolio

With nine exploration wells having been drilled in 2010, the portfolio of prospective resources remains very large. Moreover, since more prospects and leads were identified than exploration wells drilled, the prospect portfolio has grown both in terms of the number of prospects and in potential prospective resource volumes. This portfolio only contains prospects within proven plays. If no cut-offs are applied, the portfolio contains over 1400 prospects, with an expectation volume of well over 400 BCM. Expectation is defined as the mean success volume (MSV) multiplied by the probability of success (POS). If we apply cut-off values for MSV and for POS, respecting the difference between offshore and onshore economic conditions, the total risked prospective volume is estimated to be well over 250 BCM.

Prospects in POS-MSV class

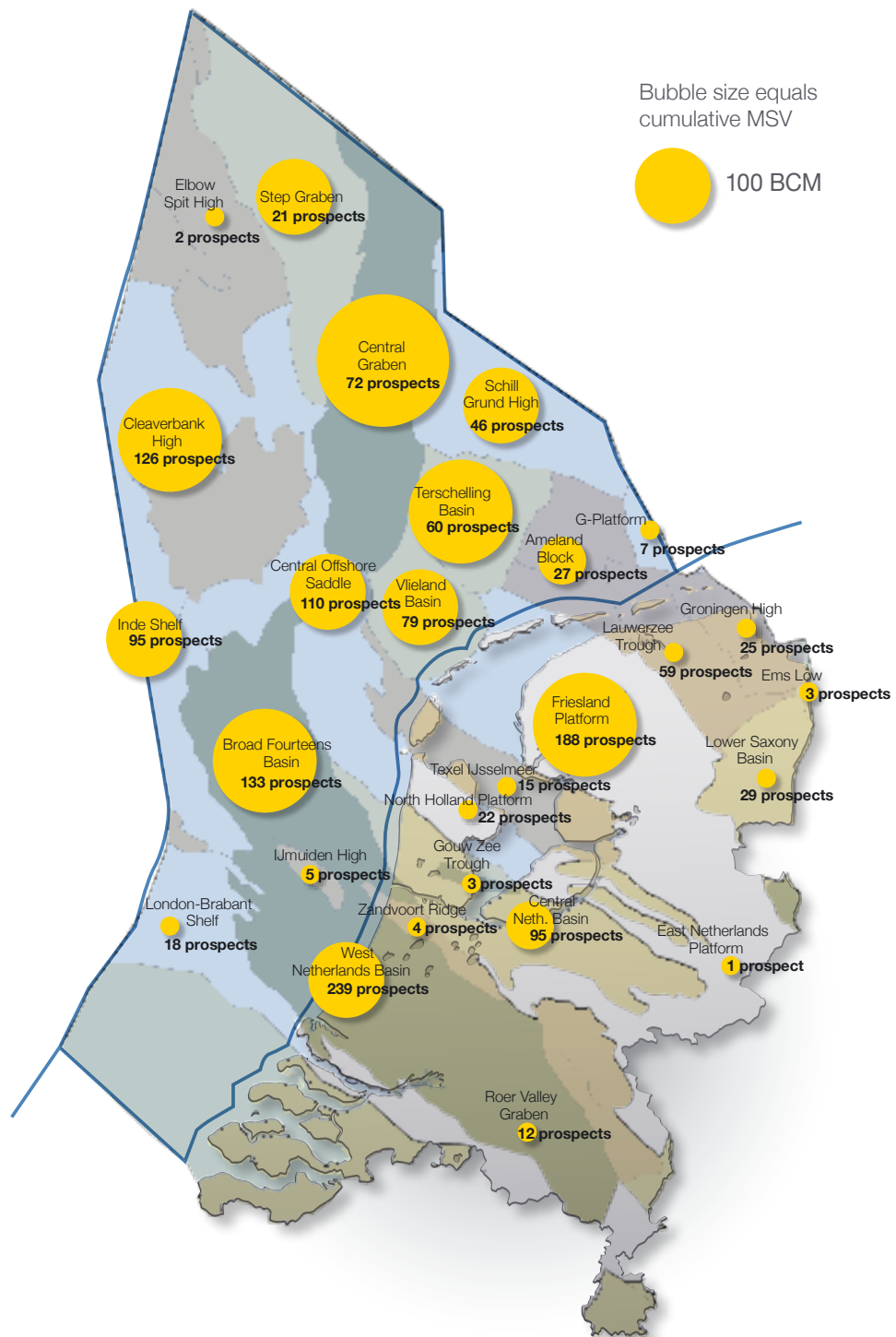


The distribution of offshore prospects in terms of POS and MSV class shows that nearly half of these prospects are in the 0 - 0.5 BCM class, which makes the total risked prospect portfolio very sensitive to the application of cut-off values. Recent and planned offshore exploration drilling efforts, however, frequently show great potential in prospects below 1 BCM MSV, even offshore. Onshore, the percentage of prospects in the lowest volume class is even higher, but the economic conditions for developing fields in this class are much more favourable.

1.3.2 Prospective areas

The geographic spread of this portfolio of over 1400 prospects in proven plays is highly diversified and biased. Many known prospects are located in regions with a long exploration and production history, and in structural elements of which the play mechanisms have been thoroughly studied and well-established (proven plays). Prospectivity in other regions is less well known, simply because these regions, for instance the Elbow Spit High, were under-explored in previous decades. Renewed exploration efforts have started in some of these areas, for instance a large-scale 3D seismic acquisition survey in the D, E and F blocks, and some operators have recently started focusing on the shallow gas prospectivity of the northern Dutch offshore sector. These efforts should increase both the number of prospects and the POS of prospects already identified. Some mature areas, such as the West Netherlands Basin and the Broad Fourteens Basin, apparently still have a huge exploration potential. The proximity to infrastructure in these areas would make even very small prospects commercially viable.

Prospectivity - number of prospects and corresponding cumulative volumes per structural element



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1.4 30/30 ambition and production forecast

In 2009 EBN formulated its ambition to maintain current production levels for the next two decades and to produce some 30 BCM a year from Dutch small gas fields in the year 2030.

This year, we have introduced more realism in forecasting production from contingent resources (categories 4, 5 and 6). The production profile for PRMS reserve category 1 corresponds to the no further activity scenario. In this scenario, production, particularly in offshore fields, will rapidly decrease in the coming decade. To account for the probability that not all the resources in this category will mature, EBN has introduced a 'probability of maturation' (POM) factor to assess production forecasts for resources in various contingent categories. The probability of maturation decreases with subsequent PRMS resource classes: for category 4 POM is 90%, for category 5 it is 50% and for category 6 only 10%. Production forecasts for these categories have been multiplied by the POM factor to obtain a more realistic profile. Category 6 represents resources that cannot be matured commercially in the current economic and technical conditions. Most stranded fields are in this category, including some tight and shallow gas fields. If the Dutch E&P industry manages to mature more resources from categories 5 and 6, significantly higher production of contingent resources can be achieved.

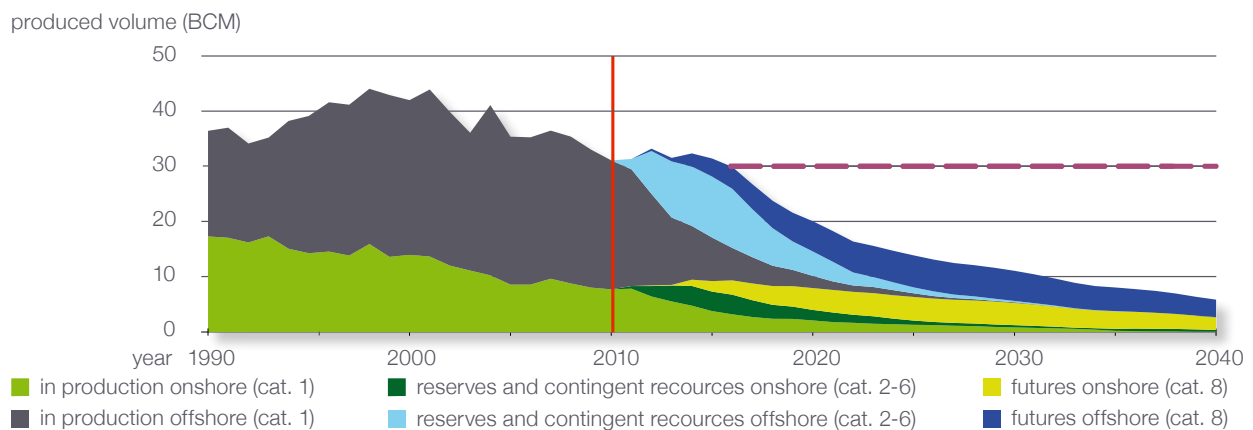
PRMS category 8 is also referred to as futures or prospective resources. The profile for this category has been obtained by combining the risk category 8 resources, based on data from exploration drilling in 2010, with simulated exploration drilling data for the years after 2011. The simulation is based on the current trend, and assumes that 15 exploration wells will be drilled each year, falling to 9 towards 2040, with an initial success ratio of 70%, falling to 40%, which is still a healthy figure for exploration. The average discovery per exploration well starts at 1 BCM and falls to 0.5 BCM. On the basis of these figures, total exploration volumes over the next 30 years will be approximately 240 BCM, which largely corresponds to the total risk volume of the currently known prospect portfolio of proven plays in the Netherlands if using cut-offs respecting the difference between offshore and onshore economic conditions.

The forecast shows that combined production from small fields will fall permanently below 30 BCM/year in 2016 and that the production forecast for 2030 for all reserve categories points to a shortfall of 18 BCM relative to EBN's 30 BCM challenge. EBN believes this shortfall can be filled by adding and maturing more reserves through a combination of four strategies:

- extending production of existing fields, including mapping and drilling un-drained parts of producing fields;
- developing and producing known stranded fields;
- increasing exploration drilling and mapping and working up new prospects in proven plays;
- exploring for natural gas in challenging reservoirs and developing these.

Offshore exploration relies heavily on existing infrastructure to provide evacuation routes. Near-field exploration efforts will ensure that the lifetime of existing hubs can be extended, while stand-alone developments of successfully drilled prospects could open up new opportunities for prospects that are currently too far from a potential tie-in point. A combination of both near-field and far-field exploration is required to produce from new discoveries and maintain the infrastructure.

Historic production and production forecast for small fields



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Natural gas from challenging reservoirs

For many years to come, the world, including the Netherlands, will depend on fossil fuels for energy. Since domestic production is declining and the reserves' replacement ratio is way below 100%, EBN is assessing the potential of resources from challenging reservoirs as future contributions to Dutch natural gas reserves and production. If we resign ourselves to a 'no further activity' scenario, the Netherlands will become a net importer of natural gas, instead of a gas exporting country, within 15 years.

Unconventional gas resources – in other words, natural gas from challenging reservoirs – are best described as gas accumulations that are difficult to find and produce commercially by conventional exploration and production technologies. These resources are typically located in heterogeneous, extremely complex and often poorly understood geologic systems. Furthermore, because of their very low permeability, expensive production-stimulation operations are required to establish reasonably commercial gas flows. Such considerations are responsible for the high development risk factors and unpredictable results that are often associated with unconventional gas exploration and development projects and that inhibit the industry from investing in these resources.

The largest volumes of resources from challenging reservoirs in the Netherlands can be expected in three specific rocks: tight sandstones, shales and coal beds. These three deposits exist in the geologic basins in the subsurface throughout the Netherlands, both on- and offshore. According to EBN's latest insights, all gas resources from challenging reservoirs together may contain producible amounts of natural gas in the order of hundreds of billions of cubic metres. This would meet Dutch gas consumption needs for several decades.

EBN is investigating the nationwide potential of gas resources from challenging reservoirs by conducting in-house research, funding industry research, cooperating in academic research and participating in operations to appraise these resources. Parallel to these technical efforts, we are investigating the possible impact of these resources on the security of supply, on Dutch society and, last but not least, on the environment.

And why gas? It is the greenest of all fossil fuels, the most flexible and the cheapest. For these reasons and because of its abundance, EBN believes that, alongside renewable energy, future demand for gas will remain significant and will contribute to our national budget.



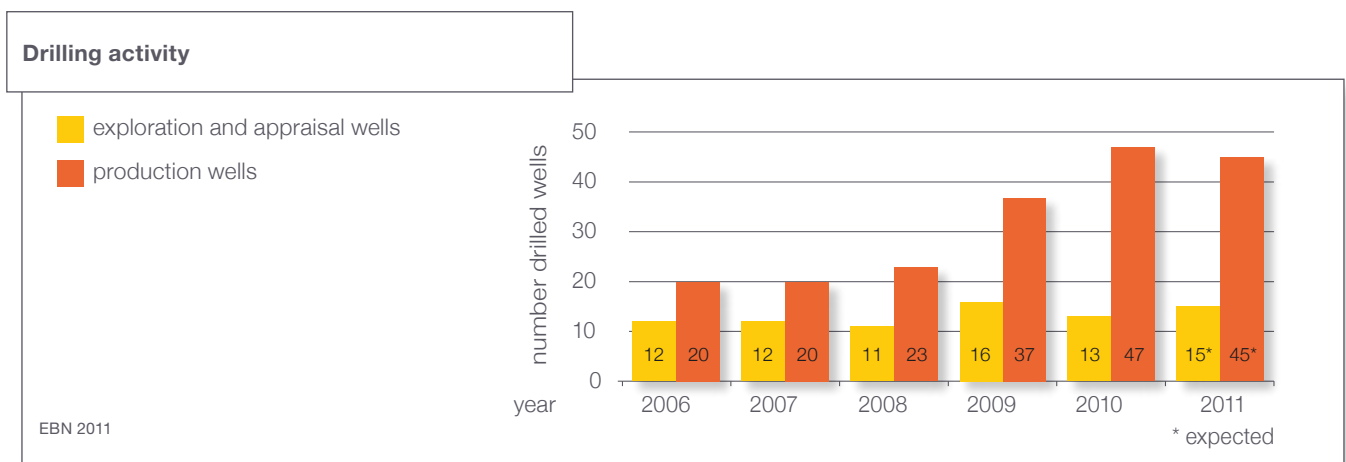


2. Investment level and mining climate

2. Investment level and mining climate

2.1 Drilling

The level of drilling activity in the Dutch E&P industry remains high. A total of 60 wells are expected to be drilled in 2011, which is the same number as in 2010. Even if the Schoonebeek redevelopment wells are disregarded, the number of 39 planned wells, including 15 exploration and appraisal wells, is considerable. This level of activity is expected to continue in the coming years.



A total of 13 exploration and appraisal wells were drilled in 2010. Consisting of nine exploration wells, of which two were onshore. The total new volumes discovered by both exploration and appraisal wells amounted to 7 BCM. Excluding appraisal wells, the success ratio of exploration drilling was 67%, which is exactly the same as in 2009.



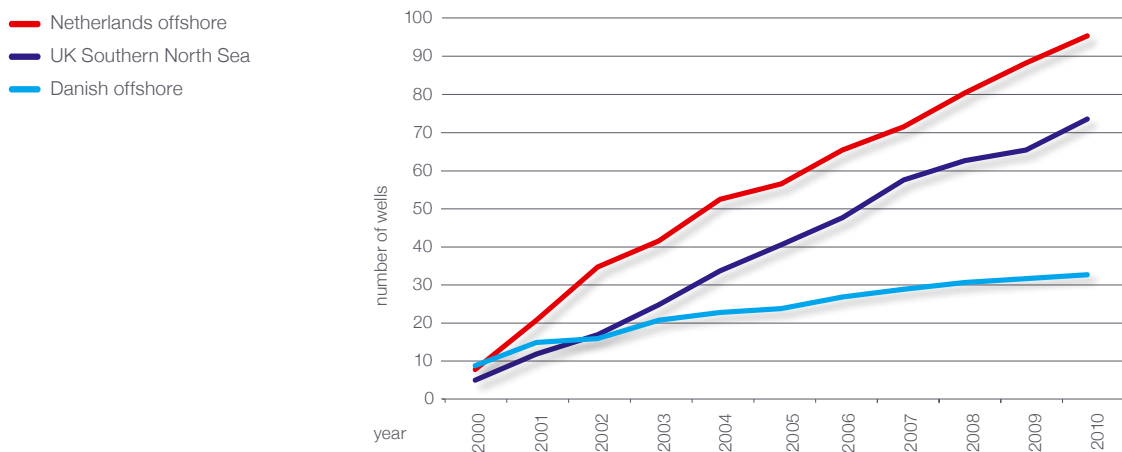
The similarities between 2009 and 2010 go further: the 67% success ratio was once again considerably higher than the average pre-drill POS of 57%, whereas the total discovered volume was lower than the cumulative pre-drill MSV. A similar observation was made for 2009 in last year's Focus report. This implies a consistent tendency to overestimate both the dry-hole risk and the prospects' volumes. There are two reasons behind this: prospect volumes indeed turned out to be lower than assumed, and some of the larger prospects turned out to be dry.

2.2 Exploration efforts

Despite the clear maturity of the Dutch acreage, the remaining exploration potential of the Netherlands is high. This is clearly reflected in a number of key proxies, such as exploration drilling activity and acquisition of new 3D seismic. If these two parameters are compared with neighbouring countries' offshore sectors, with comparable maturity levels, there is still plenty of exploration going on in Dutch onshore and offshore licences.

Since 2000, 94 exploration wells have been drilled in the Netherlands, compared with 72 in the UK Southern Gas Basin, which is also located in the southern North Sea. The cumulative exploration drilling curves for the latter two regions are relatively steady, with a few deviations, and show no signs of flattening off, whereas the opposite clearly applies to the Danish offshore exploration drilling effort. Of the offshore wells drilled in the Netherlands since 2000, 55 have resulted in a discovery, which means an average success ratio of 59% for offshore exploration wells. The total volume of recoverable gas discovered by these wells amounts to well over 100 BCM.

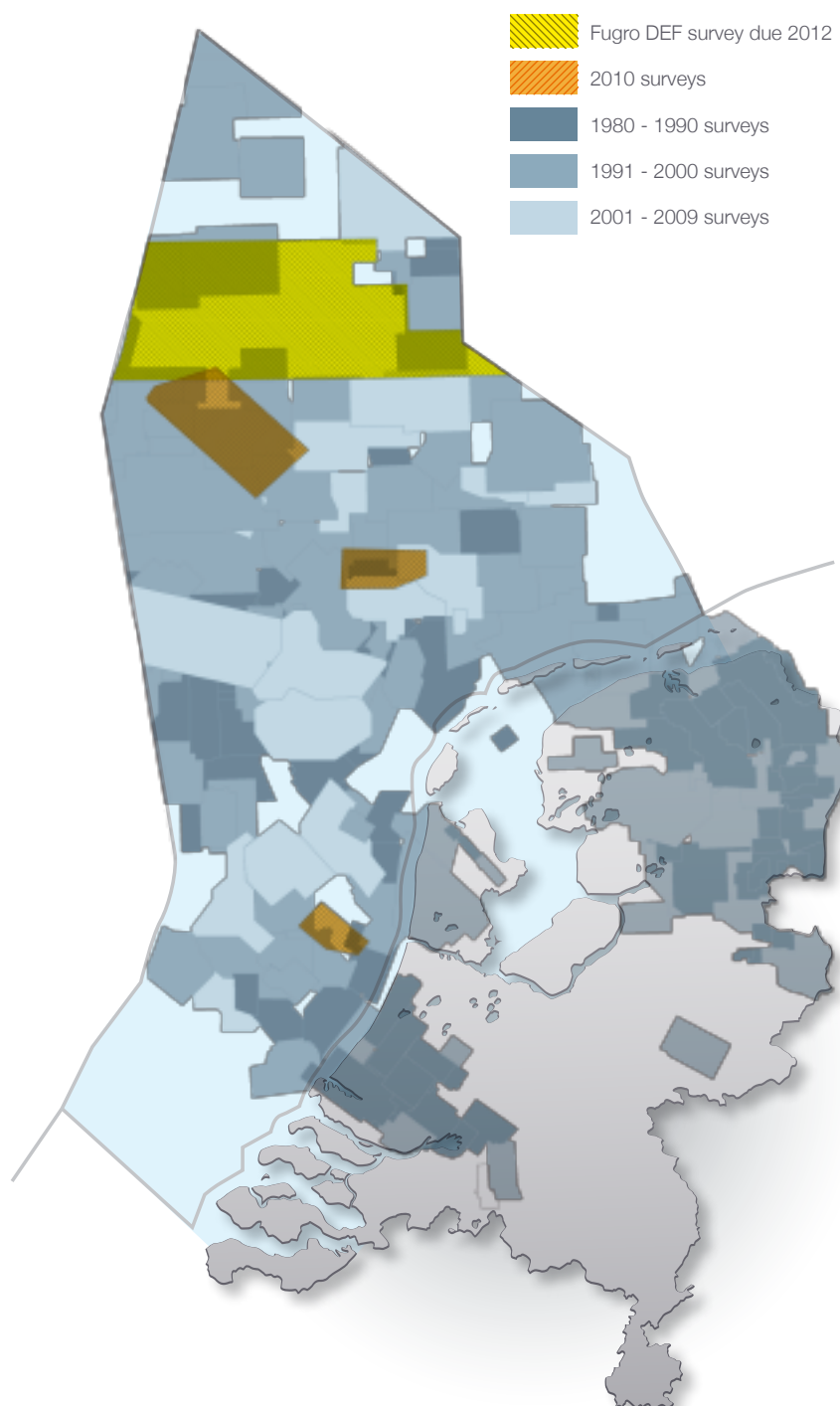
Offshore exploration drilling



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The year 2010 was a remarkable year for offshore seismic 3D acquisition, which reached its highest level since 2000. This is partly attributable to the fact that acquisition of a high quality 3D seismic survey in the D, E and F blocks started in 2010. Not only will this survey cover parts of the Dutch offshore not currently covered by 3D seismic, but total coverage will be more than 6000 km² and it will therefore be the largest 3D seismic survey ever shot in the Netherlands. Only a small part of this survey has been shot to date. The largest contribution to the total area of seismic acquisition in 2010 came from other seismic surveys, shot by various operators.

3D Seismic acquisition

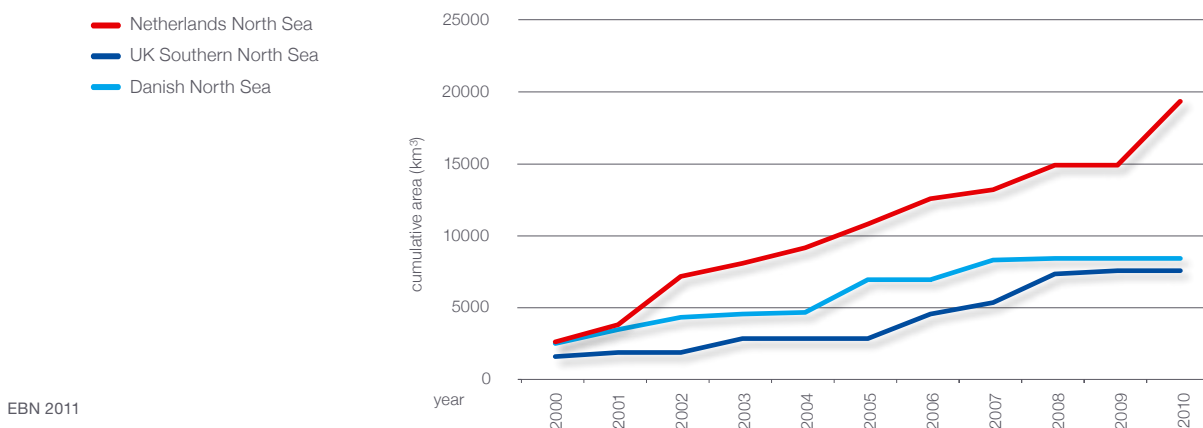


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Last year's Focus reported that current seismic acquisition activity is not as high as in the 1990s. It is, however, considerable compared to neighbouring areas, such as the UK Southern Gas Basin and the Danish North Sea sector. Despite being comparable to the latter two regions both geographically as well as in play size, the Dutch offshore has seen much more 3D seismic acquisition in terms of totally acquired area. Since 2010, nearly 20,000 km² of new, high-quality 3D seismic has been acquired, which is more than twice the area shot in the UK Southern

Gas Basin or the Danish sector of the North Sea. Where possible, 3D seismic has been acquired with long cables, ensuring enhanced imaging. Long-cable 3D acquisition is not always possible, however, because of shallow depths or the presence of offshore infrastructure.

Area of 3D seismic coverage

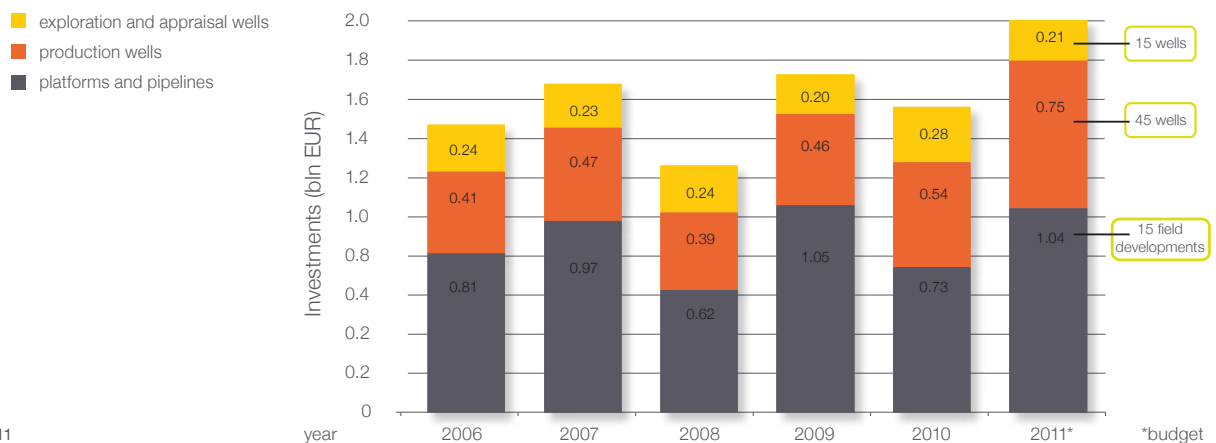


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2.3 Capital expenditure

The high E&P activity level of the past few years is reflected in capital expenditure (capex) figures. Total investments planned for 2011 by the Dutch E&P industry amount to € 2 billion, which is even higher than the actual levels recorded in the preceding years. This amount includes redevelopment of the Schoonebeek oil field, Bergermeer gas storage development, investment in the Norg-Groningen pipeline as part of the Norg gas storage project, drilling of 45 production wells and 15 exploration and appraisal wells, and implementing 15 field-development plans (FDPs). In this year, 10 of these 15 fields are expected to produce their first gas.

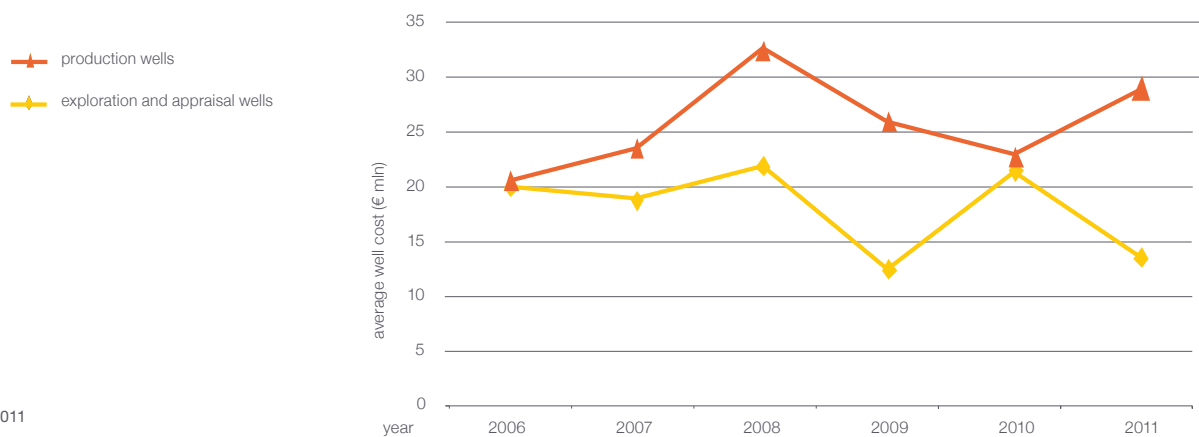
Dutch capital investment



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*budget

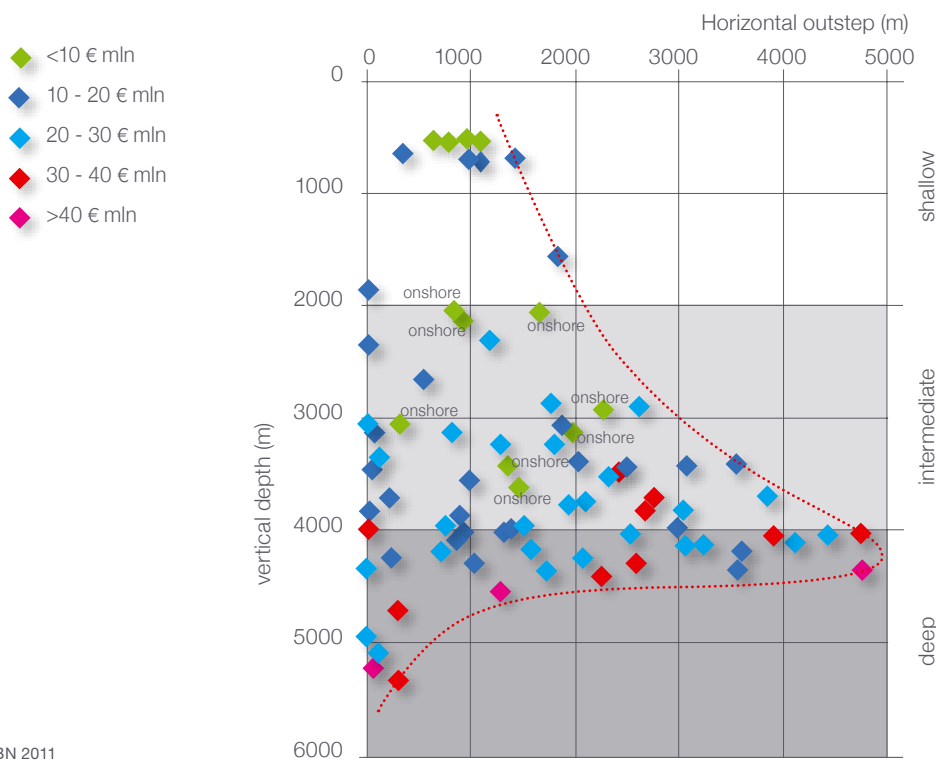
Average well cost



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The average cost of drilling a well has been relatively stable over the past 5 years, both for production and exploration wells. In terms of vertical depth and horizontal offset, wells drilled onshore (all below € 10 million) have a much lower cost level compared to similar wells offshore. The targets of most wells drilled in the past two years were at depths of around 4km, and, at this depth, the outstep is typically not beyond 5km. The most technically challenging wells, i.e. the deeper wells and those with the largest horizontal distance to surface location (outstep), have proven to be the most expensive. However, costs are not only dependent on these two parameters. The costs of offshore wells with similar depths and outsteps can actually vary by tens of millions of euros.

Drilling activity in The Netherlands 2008 - 2010

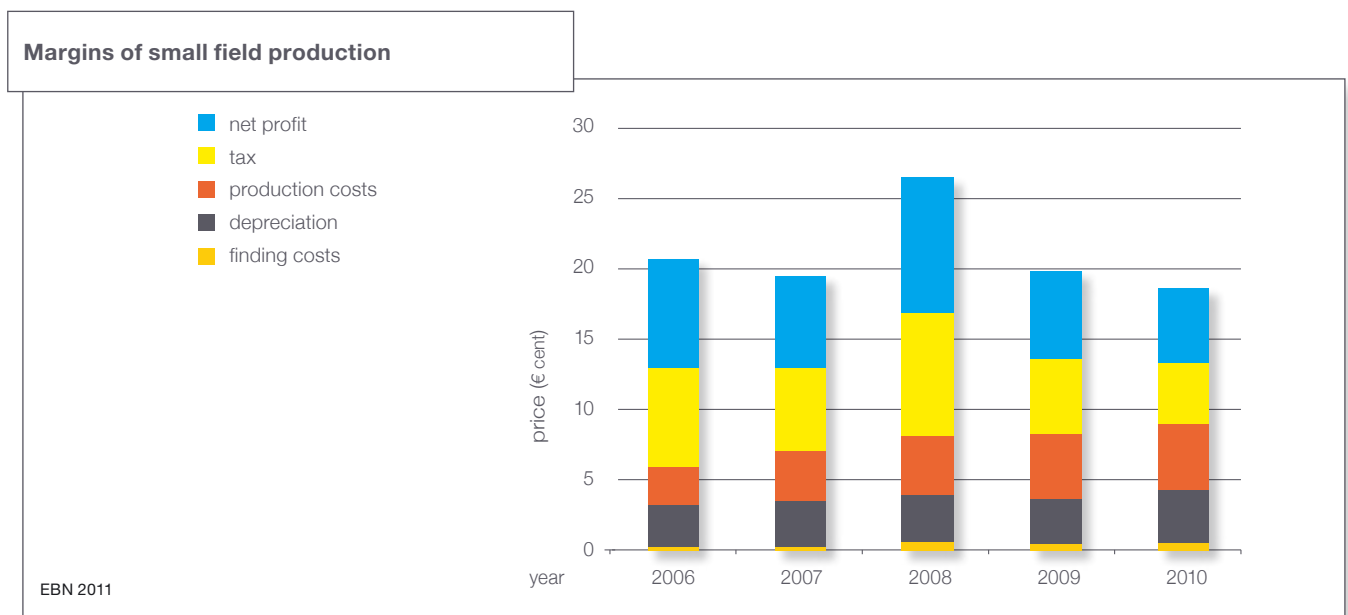


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2.4 Profitability

The profitability of the Dutch E&P industry can be evaluated by analysing the industry's net profits in the past year. Allocation of revenues and expenses to each cubic metre of produced gas shows that profits remain high. Expenses and net profit can be put in perspective of the year's average price for gas from small fields. These expenses comprise:

- finding costs, mainly geology & geophysics (G&G) costs, (including seismic surveys and expensed dry exploration wells);
- depreciation costs, on a unit-of-production (UOP) basis;
- production costs, including transport, treatment, current and non-current costs;
- taxes, mainly corporate income tax (CIT) and state profit share (SPS).



The average price for gas from small fields and thus average revenue per cubic metre vary from year to year, but, with the exception of 2008, the Dutch gas price has generally remained around € 0.20/m³. Production costs per cubic metre of gas, as stated in the above categories, have all increased, partly as a result of production phase and increasing prices in the sector. Consequently, net profit per cubic metre of produced gas has decreased, but was still around 30% in 2010.

The small fields policy of the Netherlands offsets some of the risks inherent to the industry and thus offers gas producers three main benefits:

- steady production close to the maximum capacity of a field;
- offtake and transportation guarantee;
- market-based prices and conditions.

This policy ensures that the Dutch E&P sector remains attractive for major and also smaller players in the industry.

2.5 Regulation and legislation

In order to maintain production from small fields at current levels measures are needed in addition to the small fields policy. The Dutch Government therefore introduced two additional measures in 2010: the investment allowance for marginal offshore gas fields and the fallow acreage covenant.

2.5.1 Investment allowance for marginal offshore gas fields

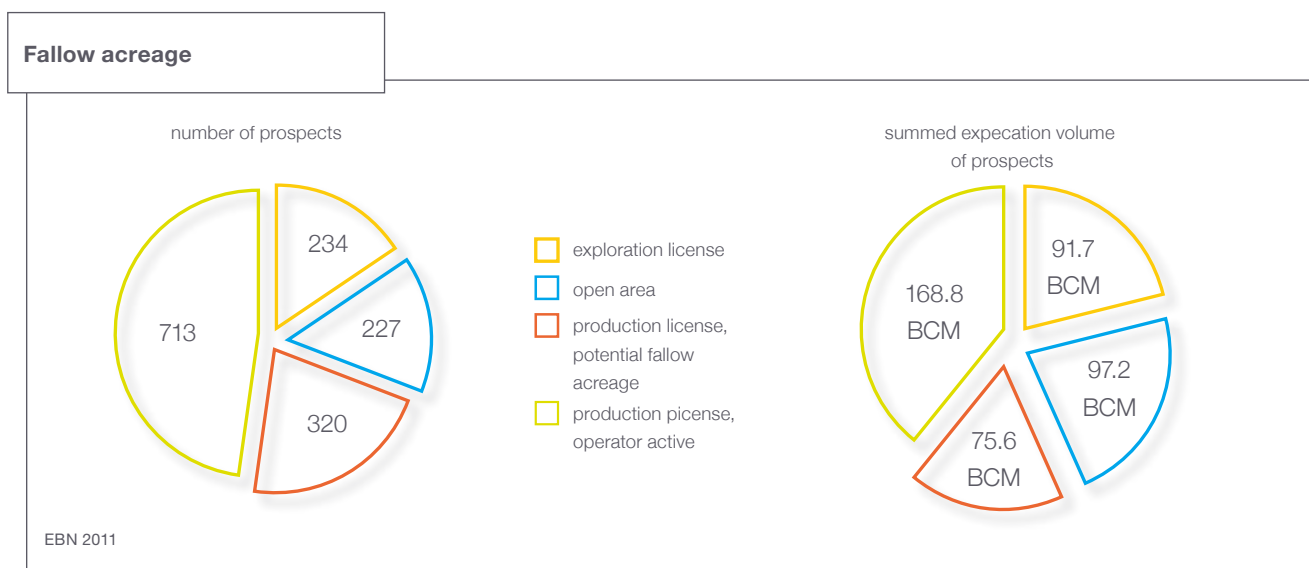
It is crucial for the continuity of the Dutch E&P industry that existing infrastructure is not abandoned prematurely as this would make development of newly discovered marginal fields commercially unattractive. The Dutch government recently introduced a tax measure, as an amendment to the Mining Act, to stimulate exploration for and development of these marginal fields. Under this measure, investments in exploration or production in marginal offshore fields can qualify for a deduction (amounting to 25% of the investment in the year of investment) from the taxable result calculated for state profit share tax purposes. This deduction is in addition to regular depreciation, provided the field ranks high on the following criteria:

- remoteness from the nearest export pipeline;
- low well productivity;
- small volume of Gas Initially In Place (GIIP).

Operators have submitted some nine applications for this tax deduction since the measure came into force in the third quarter of 2010. This shows the success of the measure as it implies that, in the near future, marginal fields will be developed that would probably not otherwise have been developed. The Dutch government expects this tax measure to result in total additional gas production in excess of 20 BCM.

2.5.2 Fallow acreage

The fallow acreage covenant is a non-binding agreement with the majority of E&P companies active in the Dutch offshore sector. It seeks to ensure that acreage can be voluntarily returned to the Ministry of Economic Affairs, Agriculture and Innovation if an operator has been insufficiently active for an extended period. The Minister of Economic Affairs, Agriculture and Innovation already had the power to decrease a licence area in the event of insufficient activity, but this used to be a time-consuming process.



Although the actual sizes and shapes of the acreage that will be declared fallow are still subject to debate, the fallow acreage measure will clearly free up substantial potential for operators who are willing to invest in acreage in which current licensees may not be interested. This process is expected to make more acreage available to other interested E&P companies, thereby promoting exploration and production activity. Currently, 320 prospects on- and offshore may be located in fallow acreage licences, and these are estimated to contain some 76 BCM of recoverable gas (risked). At a gas price of € 0.20 per m³, this portfolio would represent over € 15 billion (real term) in gross revenues. As there have been no exploration efforts in some of these areas for long periods, the number of prospects stated above may be a conservative estimate.

Public acceptance

An important factor in the investment climate for natural gas and oil exploration and production is cooperation with the local communities in which the day-to-day activities are performed. In the Netherlands, public acceptance of any onshore energy-related activity is declining, be it the building of windmills, the building of natural gas storage facilities, the storage of CO₂ in depleted gas fields or the exploration for natural gas from shales.

Local opposition to activity is understandable as the obvious benefits of secure, reliable, cheap and domestically produced energy are often enjoyed at a national level, while the inconvenience is felt only at a local level. Nevertheless, locally initiated protests and legal procedures can often result in costly delays for projects that will benefit society as a whole, and may even push companies and the economic benefits they generate out of the Netherlands altogether.

It is important, therefore, that the E&P industry works with local communities to minimise the inconvenience caused by E&P activities. In addition, the Dutch government can support the industry by explaining the economic and strategic benefits of domestic gas production to society.



3. Infrastructure and opportunities

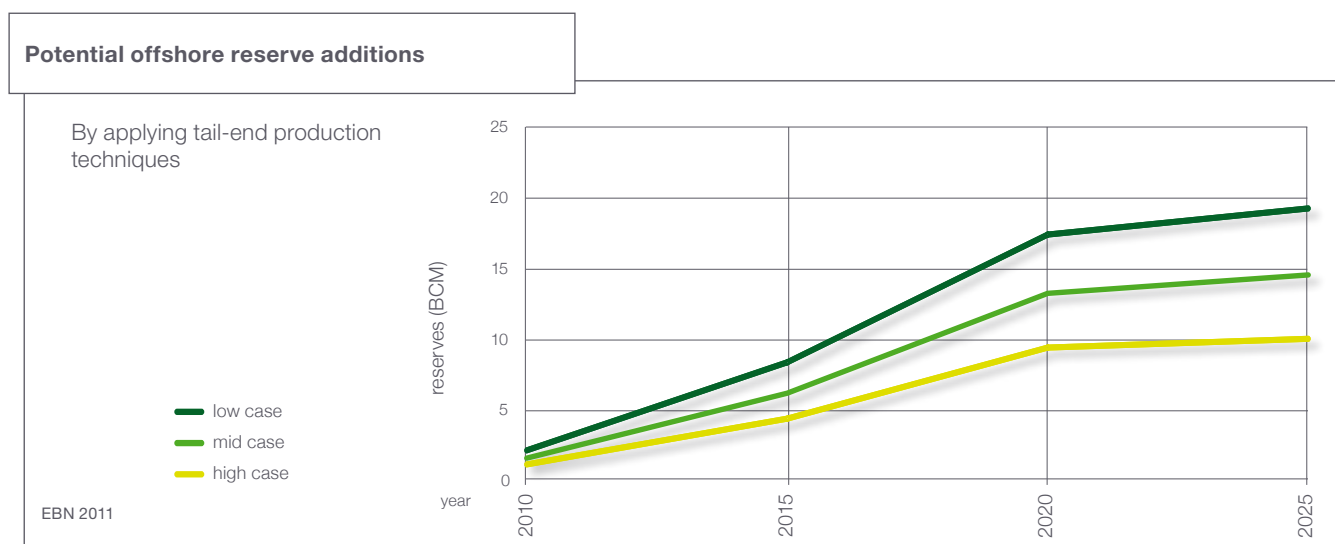


3. Infrastructure and opportunities

3.1 Maintaining the infrastructure

The current resource base is maturing rapidly, while new discoveries and developments are smaller and less numerous. The presence of a fit-for-purpose and cost-effective infrastructure to process and transport produced gas is now more essential than ever if we are to meet society's demand for gas. If more gas is found and developed in the short term, the life of existing infrastructure can be extended, and this will make it possible to produce more gas in the long term. Extending facility life will also allow the industry more time to develop new opportunities, such as new plays or challenging gas resources, and to investigate novel production techniques and gas evacuation solutions. In short, it takes gas to develop more gas.

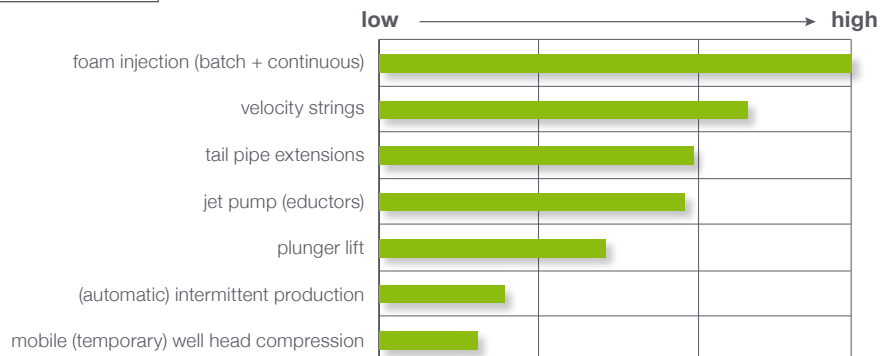
As approximately 75% of all fields are mature or in the tail-end production phase, end-of-field-life technology may offer great opportunities to add gas. Although these techniques have moderate effect on total reserves, they have a pronounced effect on extending platform life, and this will in turn enable reserve additions. Based on currently available technology and current market conditions, applying tail-end production-enhancing techniques may add between 10 and 20 BCM to Dutch offshore reserves, while a total of around 32 BCM may be added to the total Dutch reserve base by also applying these techniques onshore. It may then be possible to increase recovery factors from a general level of around 70-85% to as much as 95% in some cases.



Assuming currently available technology and current market conditions, Dutch operators ranked the scopes of several tail-end production techniques and risked these in terms of operational success, operators' experience and maturation of technology. Dutch operators expect most from velocity strings and foam injection.

Scope

For various offshore tail-end production-enhancing techniques



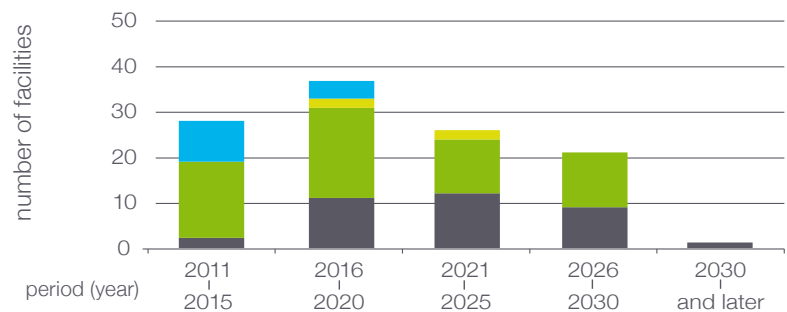
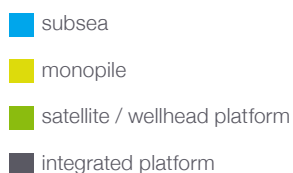
EBN 2011

3.2 Decommissioning and opportunities

A total of € 3 billion has been set aside for decommissioning projects, such as platform and well abandonment in the Dutch southern North Sea, over the coming years. EBN has analysed the estimated end of production dates for the next twenty years, placed into five-year intervals for all trunk line systems.

Facility end of production

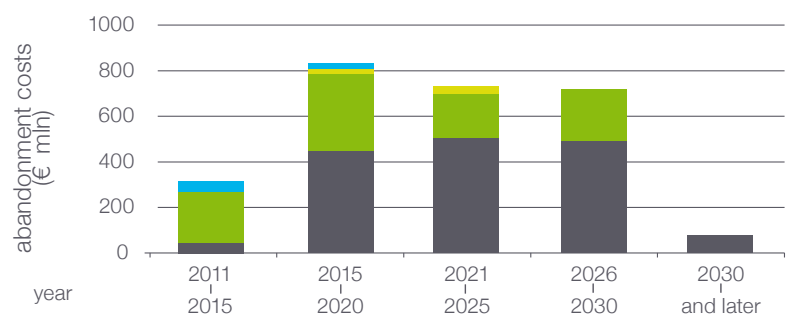
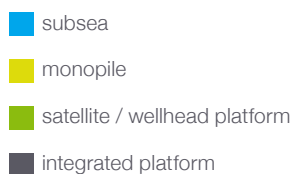
For current reserves and identified contingent resources.



EBN 2011

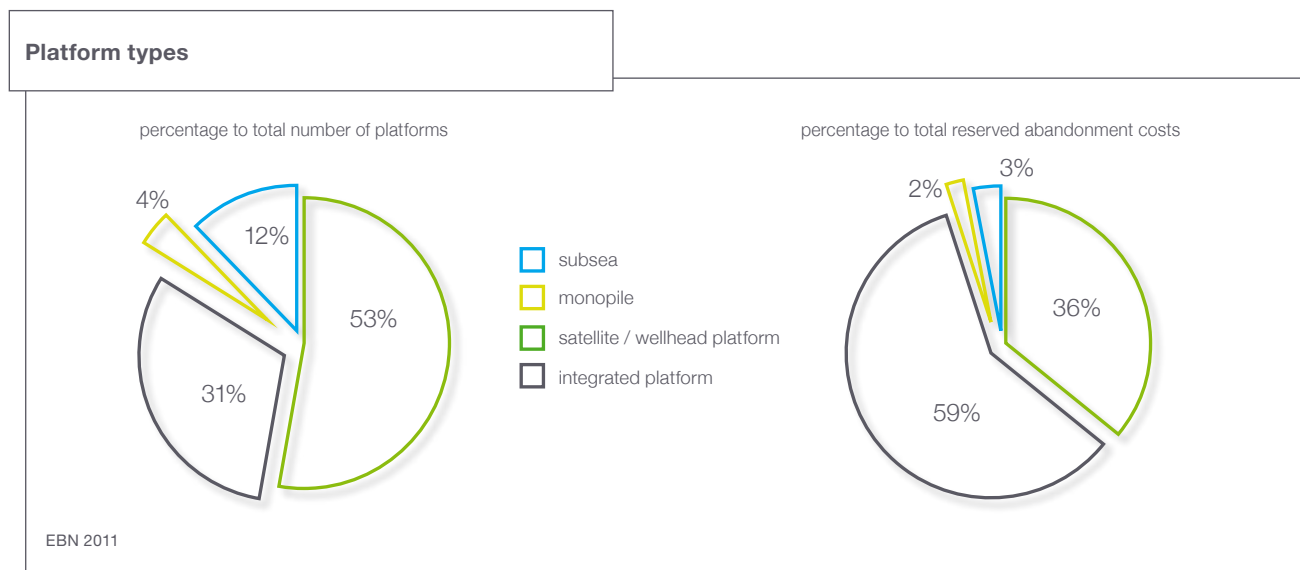
Reserved abandonment costs

Based on current reserves and identified contingent resources.



EBN 2011

The 31% of platforms involving more complex systems account for around 60% of total estimated abandonment costs.



In view of these high costs, there should be enough incentive, both for operators and the service industry, to develop and optimise efficient abandonment techniques and approaches. In the past, many decommissioning projects were inadequately prepared and the abandonment process was generally poorly understood, with inadequate preparation and lack of detailed attention resulting in budget overruns. There is consequently substantial scope for improvement.

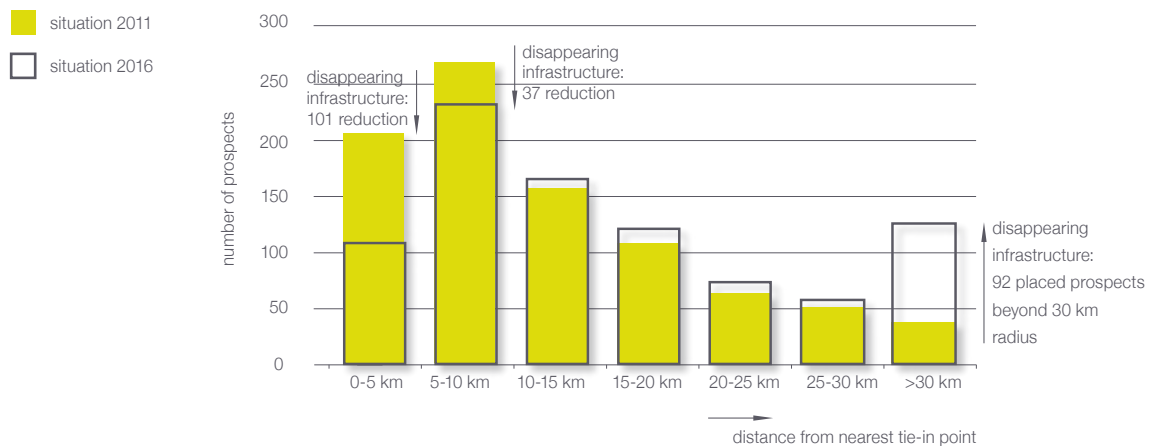
3.3 Exploration opportunities

The existing offshore infrastructure for gas is very closely spaced. Many small offshore prospects with MSV values well below 2 BCM are located very close to existing infrastructure and potential tie-in points. At the time of writing, more than 200 offshore prospects – together representing a total expectation volume of 45 BCM (no cut-off applied) – are located within 5 km of potential tie-in points. With ongoing advances in extended-reach drilling, many of these prospects could be targeted from existing platforms, thus avoiding the cost of a pipeline and a new satellite or subsea wellhead. This makes it possible to target and develop offshore prospects with MSVs as low as 0.5 BCM. The group of offshore prospects located between 5 and 10 km from existing tie-in points is even larger, both in number and in volumes. This group represents more than 80 BCM in expectation volumes. Current economic conditions mean operators could target and commercially develop the latter group of prospects with MSV values as low as 1 BCM. In addition to these small prospects, another 300 offshore prospects exist with MSV values in the range of 1 to 4 BCM.

Currently, the coverage of the offshore gas infrastructure network is probably at its peak, and potential nearby tie-in points for offshore prospects are consequently abundant. However, some of the platforms are approaching the ends of their lives and thus abandonment. Approximately 100 prospects, with a total expectation volume of 15

BCM, are located within 5 km of platforms expected to be abandoned within the next five years. This implies that, for some of these prospects, the end of the window of opportunity is near because the likelihood that prospects can be drilled commercially will decrease rapidly once the nearest tie-in points have gone. A similar but smaller reduction in the number of prospects located between 5 and 10 km from infrastructure is expected between now and 2016, and together these represent around 10 BCM of expectation volumes. And, what is worse, the number of prospects that are more than 30 km removed from existing platforms will almost triple in 2016 in comparison to 2011. This is because some remote systems and platform are expected to be abandoned within the next five years. These numbers imply that near-field exploration opportunities in the Dutch offshore are currently abundant, but that these opportunities will have to be taken up very soon if they are to benefit from the current dense offshore gas infrastructure network. It should be noted that some near-shore prospects may have better tie-in opportunities onshore, which is an option that has not been considered in the present analysis.

Offshore prospects / distance of infrastructure



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3.4 Optimum usage of infrastructure

In addition to efforts to add more gas, cost reduction is also an important factor in extending infrastructure life. As around 50% of the fields are in the tail-end production phase, infrastructure and equipment often have excess capacity at present. Rationalisation and decommissioning excess capacity could therefore reduce costs. Integrating (evacuation) systems could also result in significant cost reductions.

Some of the offshore production areas show a degree of interlinking, with processing platforms in the centre of these complex systems. The inherently high operational expenditure (opex) of these processing platforms is shared by all connected producers. The disadvantage of this cost-sharing is that the ever-increasing operating costs are shared by an ever-decreasing resource base, which makes the system vulnerable in the tail-end phase. Simulating the offshore infrastructure however shows that decoupling the interlinking of the processing systems would only reduce the vulnerability of a few platforms. There is little scope for significant satellite life extension if satellites are decoupled.

Maturing identified contingent resources into reserves will extend the life significantly of more than a dozen platforms. However, in the context of the total number of facilities analysed, the eventual result is limited for most platforms. To date, the contingent resources identified have not been sufficient to have a significant effect on extending the life of the system as a whole. Maturing prospective resources into contingent resources and ultimately into reserves is essential if we are to increase offshore production and meet EBN's 30/30 ambition. Many of the stranded fields are located in areas without infrastructure. As a result, the risks in developing these already high-risk fields are even higher. Opportunities to unlock these volumes may be created by, for example, clustering with other operators or novel evacuation techniques such as offshore 'gas to wire'

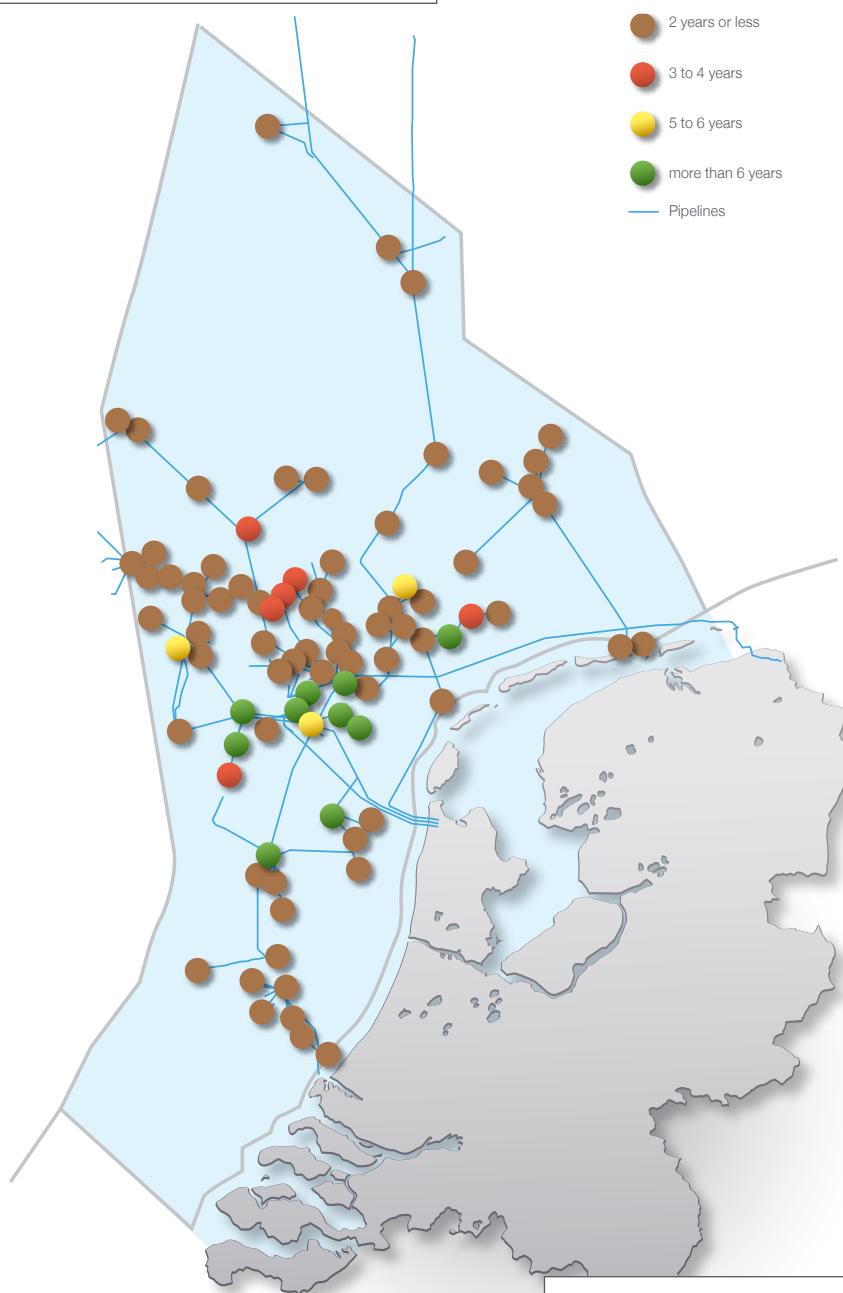
Analysis of areas in which the end of production is looming shows three main opportunities to add reserves to the system, in order of urgency:

Firstly, those areas in the tail-end production phase which have no significant contingent resources identified: here, facility life cannot be extended by more than two years by maturing the identified contingent resources. These areas are the most vulnerable, and adding reserves immediately is essential to maintain this specific infrastructure. Imminent exploration of these areas is needed if contingent resources are to be identified.

Secondly, areas that are also in the tail-end production phase, but do have significant contingent resources identified that may be matured into reserves: here, facility life can be extended significantly. The focus for these areas should be on avoiding wasting these resource opportunities by maturing the identified contingent resources through the use of innovative technologies and efficient development strategies.

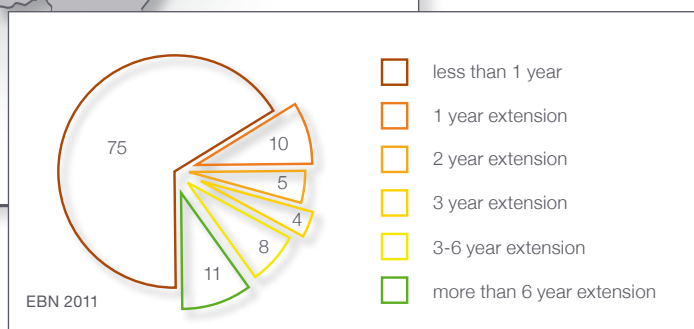
Thirdly, and of less imminent importance than the first two areas, the mature areas with also no significant contingent resources identified. Albeit not in the tail-end phase, the resource maturation process is characterised by long lead times and these mature areas should already be scheduled for reserves additions in the very near future. Renewed exploration of these areas is needed if contingent resources are to be identified.

Facility lifetime extension - effect of adding contingent resources to current reserve

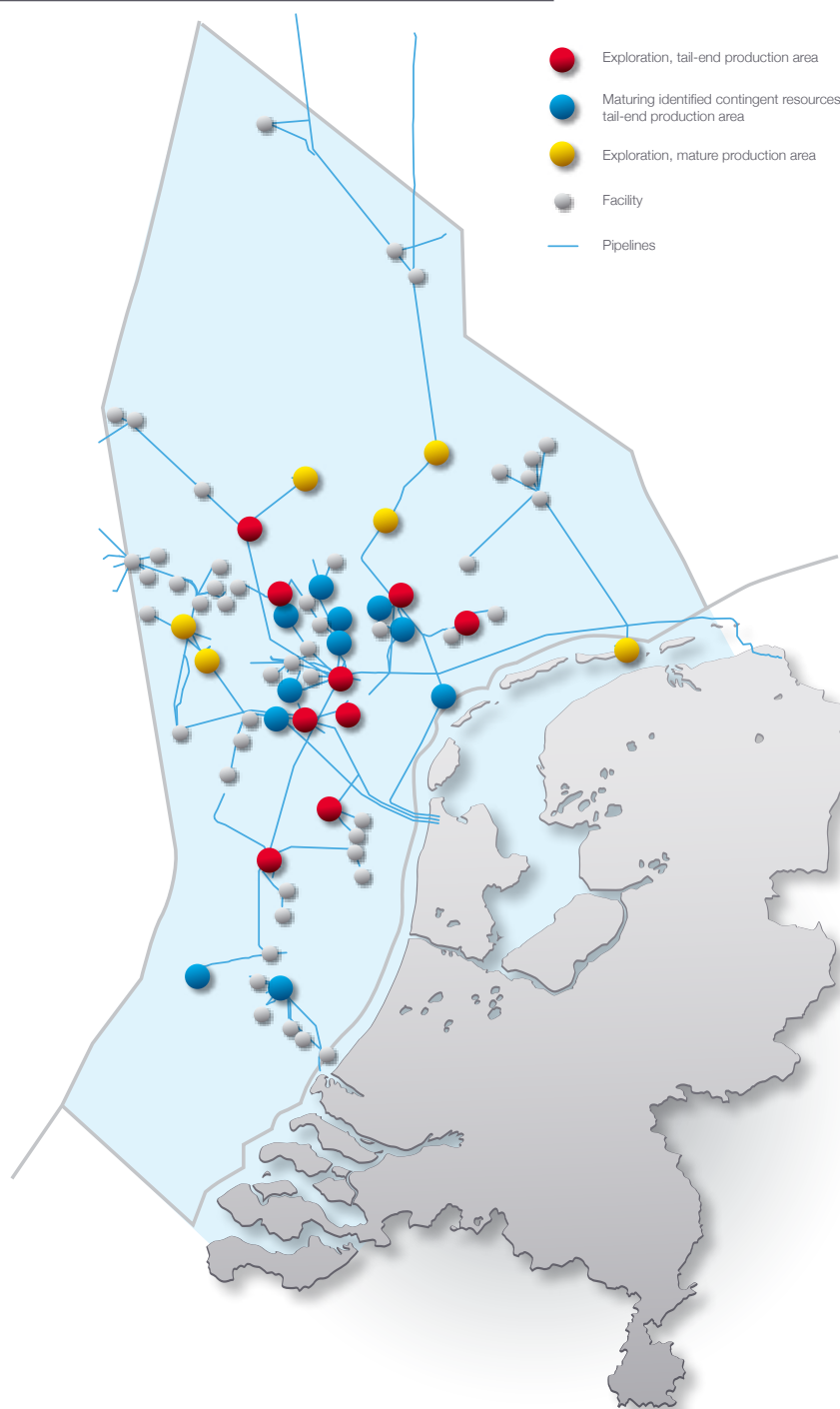


- 2 years or less
- 3 to 4 years
- 5 to 6 years
- more than 6 years
- Pipelines

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Offshore focus areas - for facility lifetime extension, based on production phase and identified contingent resources



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Technology

EBN seeks to promote cooperation between the supply industry, government and academia in order to advance knowledge and technology. The Dutch gas industry has recognised the need to be creative and has already begun devising cost-effective solutions and concepts. Last September, Centrica installed a new Self-Installing Platform fitted with processing and compression equipment. This platform is equipped with suction piles, making it simpler to re-use in new fields. The Self-Installing Platform is a versatile and cost-effective solution for developing small fields. In addition, NAM has developed the SWEEP concept, which involves low-cost daisy chaining of subsea installations and evacuation of the gas via a re-usable Riser Access Tower (which is also equipped with suction-pile technology), adjacent to the production platform.

Maturing resources into reserves in these offshore focus areas is one of the challenges ahead. Creative entrepreneurship and collaboration is required to take on this challenge. Maturation of the currently identified contingent and prospective resources in the EBN portfolio will enable annual production of around 30 BCM for the next five years. After this five-year period, activities to extend field life, along with exploration and development of challenging reservoirs, will be needed to counter the declining production from identified resources.

The Dutch government is committed to ensuring an attractive mining climate in the Netherlands. Public acceptance of E&P activities is crucial and the industry needs work with local communities to minimise the inconvenience caused by E&P activities. While the Dutch government can support the industry by explaining the economic and strategic benefits of domestic gas production to society.

Cumulative production of natural gas from the Netherlands passed the 3000 billion cubic metres mark in 2010. Meanwhile, the volume of prospective resources remains at around the same level as before. There are clearly some major challenges ahead to add more reserves and to maintain production at high levels. At the same time, however, these challenges should also be considered as opportunities. Opportunities that contribute to efficiency and sustainability of the E&P sector and will benefit society as a whole.

About EBN

EBN is active in the exploration for, production of and trading in oil and gas in the Netherlands. Together with other national and international oil and gas companies we invest in exploration and production and in gas-storage facilities in the Netherlands. The initiative for exploration, development and production activities is up to the licence holders. EBN does not aim to be the operator in the joint ventures, but invests, facilitates and shares its knowledge. EBN is also involved in selling Dutch natural gas via its interest in GasTerra. EBN distributes all the profits from these activities to the State, our sole shareholder. EBN also advises the government on the mining climate in the Netherlands and on new applications of the subsurface.

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