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FOCUS ON DUTCH OIL & GAS 2013

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FOREWORD BY BEREND SCHEFFERS

Director Technology at EBN

In our annual report "Focus on Dutch Oil & Gas", we present a comprehensive overview of the Dutch oil and gas sector, based on our unique knowledge as shareholder in virtually all Dutch onshore and offshore oil and gas fields. The major conclusion of our research is that the Dutch subsurface still offers great opportunities for the exploration and production of oil and gas.

This year's report comes at a critical time. For the first time in many decades, the Dutch gas industry is finding itself at the centre of public attention. In the 1960s, when our unique national gas infrastructure was first rolled out, this new treasure was greeted with enthusiasm throughout society. In more recent times, gas had largely disappeared from the public eye. While the industry went about doing what it does best – producing natural gas in a safe and responsible manner – people simply took for granted that the gas was there, to heat our houses – and support our public finances.

Now gas has again caught the attention of the public, for two reasons. Firstly, the idea has taken hold that the golden age of Dutch gas is coming to an end, as our reserves are thought to be running out. Secondly, environmental issues around gas have come to the forefront in the public debate around shale gas "fracking" and earthquakes.

This presents the Dutch gas sector with a twin challenge. We have to make it clear that gas production is not coming to an end and that as a society we can continue

“It is still rewarding to invest in exploration and production in the Netherlands”

to enjoy the benefits of gas for a long time – if we choose to do so. At the same time, like the oil and gas industry in the rest of the world, we have to prove beyond any possible doubt that gas production can be done in an environmentally safe way.

It is true that for the Netherlands the age of “easy” gas is ending. Production is becoming increasingly challenging. If we follow a business-as-usual scenario, meaning that the industry will gradually reduce the level of investment in exploration and development, the production from small fields in the Netherlands (outside the Groningen field) will decline from 30 BCM (billion cubic metres) per year to 10 BCM in 2030.

Such a decline is by no means inevitable, however. As this report shows, it can still be extremely rewarding to invest in exploration and production in the Netherlands. On the basis of our geological and market knowledge, we have adopted what we believe is an achievable ambition to produce 30 BCM from small fields in 2030.

To realize this ambition does, however, require substantial investments across a range of different activities. We need to explore for new reserves in underexplored areas and increase investment in exploration such as in seismic acquisition. We need to invest in advanced technologies to extend the life of existing fields. And we need to develop “new” types of gas reserves, such as tight gas and shale gas, in challenging reservoirs.

We are convinced that the preconditions for attracting such investments are in place. The Netherlands has the requisite knowledge, infrastructure and spirit of cooperation to make successful oil and gas production activities possible. The Dutch government has worked hard in recent years to create a favourable and stable business climate.

In addition, we believe the Dutch public can be convinced that the preservation of the oil and gas industry is in the public interest, if industry and government show absolute transparency around hydraulic fracturing and other environmental issues. The Dutch government has commissioned a number of independent investigations to find out under which conditions gas from shale reservoirs can be produced safely. The gas industry is fully committed to this process.

It may be worth noting in this context that the technology of hydraulic fracturing is by no means new. Outside of the industry probably few people realize that the technology has been applied in the Netherlands for over fifty years. The first frack in this country was made in 1954! Since then over 200 fractures have been made in conventional plays in the Netherlands. This type of reservoir stimulation has increased our production significantly and it has never caused environmental problems. Shale gas fracking can and must be held to the same standards: it must be safe and it must add value.

With this report we hope to make a contribution to rendering operations in the Dutch gas sector as transparent as possible. Our findings demonstrate the great potential the Netherlands has to maintain its role as an important gas and oil producer. EBN is committed to enabling the industry to realize this potential.

EXECUTIVE SUMMARY

The development of the Dutch reserves and resources base shows mixed signals. The total volume of technically recoverable gas is increasing. An increasingly larger volume, however, is classified as contingent resources, while reserves are decreasing. This signals the need for the Dutch E&P industry to overcome the technical challenges associated with the recovery of these resources, typically in the form of tight gas fields, infill potential and end-of-field-life (EoFL) activities. The prospective resources remain invariably high.

EBN believes that a considerable increase in the level of annual investment is justified. If the Dutch E&P industry continued to develop gas resources along the current trend, gas production from small fields would decrease to only 10 BCM/y in 2030, compared to 30 BCM/y today. In this ‘business as usual’ scenario, the corresponding annual capital investment would drop from around € 1 bln today to virtually zero in 2030. However, based on all the current opportunities identified by EBN and the operators, an increase in the level of investment seems justified. A continuous investment level of € bln 1.4 on an annual basis would minimize production decline and could still warrant 25 BCM/y or more in 2030. Profit margins from small field production are still at an attractive rate of 30% of the revenue, but these can only remain attractive by securing future production.

The past few years have been of great importance for the exploration and production of oil in the Netherlands, with 2 oil fields being redeveloped and 1 new field being taken into production. With several old and new oil discoveries, the northern Dutch offshore is the most promising area. A joint development approach in this area could lead to the production of over 100 MMBO. Considering the size of the remaining oil reserves and resources, it is certainly possible that Dutch annual oil production around 2020 will equal the previous record years of the late 1980’s.

To get the most out of the existing and producing gas fields, 200 wells have already been treated with various end-of-field-life techniques. For some fields the successful application of these techniques has increased the recovery factor by no less than 10%. In many fields, however, increased recovery cannot be achieved by using the existing wells alone, and infill wells should be drilled.

Increased recovery and high gas prices have had a predominantly positive effect on the expected lifetime of the offshore infrastructure. Calculations show that the expected year of cessation of production has been delayed by 3 to 4 years compared to the estimate made in 2009.

At present, an average of 3 exploration wells are drilled from an existing offshore platform every year. Analysis shows there is still great potential in exploration from platforms. With the drilling envelope expanding every decade, by now over 100 prospects and 11 stranded fields are located within the currently known drilling envelope. This makes extended reach drilling an alternative to consider in both the development of stranded fields as well as a continuously attractive option in exploration.

The past 5 years have shown an increase in seismic reprocessing as well as an increase in seismic acquisitions, both of which are clear signs of an ongoing interest in exploration in the Netherlands. Analysis shows that there is a strong correlation between the age of 3D seismic and the success rate of exploration wells. In addition, streamer length and processing type correlate with exploration well success. Acknowledging the fact that seismic activities are usually concentrated around the most prolific areas, the de-risking potential of newly acquired seismic, or at least reprocessed seismic, is unambiguous.

Even in a mature area such as the Netherlands, there is still scope for exploring new plays. EBN has launched two studies. The first one evaluates the play potential of the Dinantian carbonates in the southern offshore and northern onshore. A second study focusses on the far northern offshore (A, B, D, E and F blocks). EBN estimates that more than 100 BCM of gas can be unlocked (unrisked) if a successful play concept can be proven.

Considering a future in which tight gas, and later also potentially shale gas, will take a larger share of the annual gas production, mastering the development of tight gas is paramount. The Dutch E&P sector already has decades of experience with hydraulic fracturing. EBN anticipates that the cost of hydraulic fracturing will go down by continuous innovation and large scale application. On top of the tight development projects already lined up by operators, EBN has calculated that at least 25 BCM could be gained from stranded tight field developments. This number is in turn just a fraction of the gas volume believed to be recoverable from prospects in tight play areas.

The NAM operated gas storage facility near Grijpskerk, which plays a pivotal role in the Dutch domestic gas supply

1

RESOURCES & RESERVES

1 RESOURCES & RESERVES

The Petroleum Resource Management System (PRMS)

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

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1.1 | The Petroleum Resource Management System

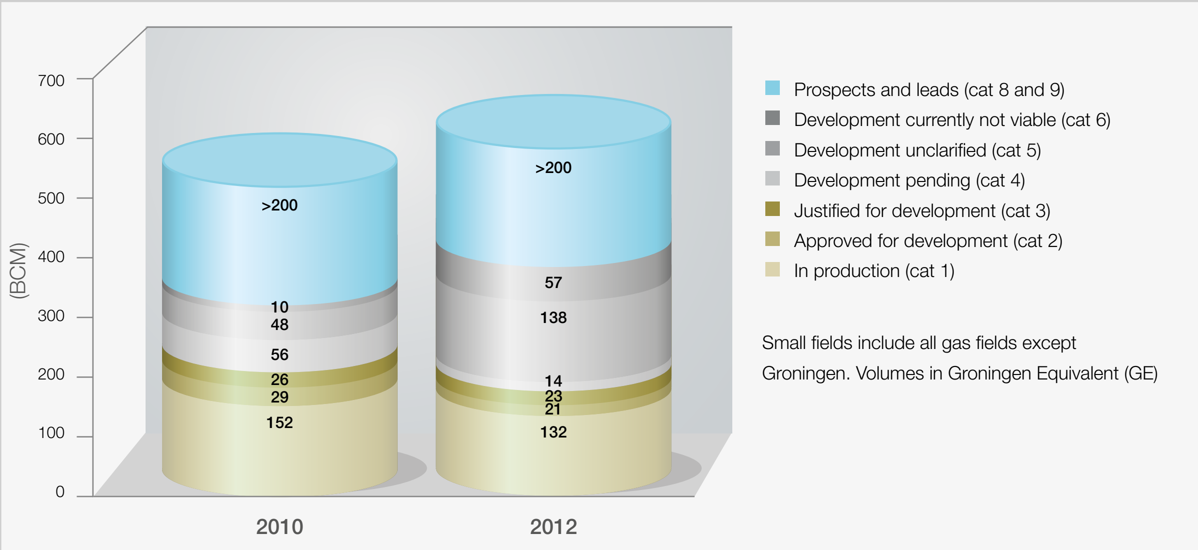
EBN has adopted the Petroleum Resource Management System (PRMS) classification for hydrocarbon reserves and resources. In this report there are frequent references to the different resource categories defined by this system, which distinguishes between reserves, contingent resources and prospective resources. The category depends on the degree of commercial maturity or on the current stage in the hydrocarbon development lifecycle. The PRMS system can be applied to whole fields, prospects or plays as well as individual opportunities within producing fields.

1.2 | Reserves Replacement becomes increasingly challenging

Since 2007, approximately 200 billion cubic meters (BCM) of gas has been produced from small fields in the Netherlands. It is becoming increasingly challenging to replace these produced volumes. The major addition to EBN's reserves and resource database in recent years has been the inclusion of resources not previously identified as recoverable volumes. In addition to this, EBN and its partners are continually looking at potential projects aimed at recovering gas that was previously considered to be uneconomic. Over 60 BCM of gas volumes have been added, and categorized as reserves and resources according to the SPE PRMS since 2007.

The majority of these projects fall into the contingent category. This means that recovering these resources poses substantial technical challenges, but EBN believes many of these projects can be matured into reserves by

Remaining reserves and resources from small gas fields



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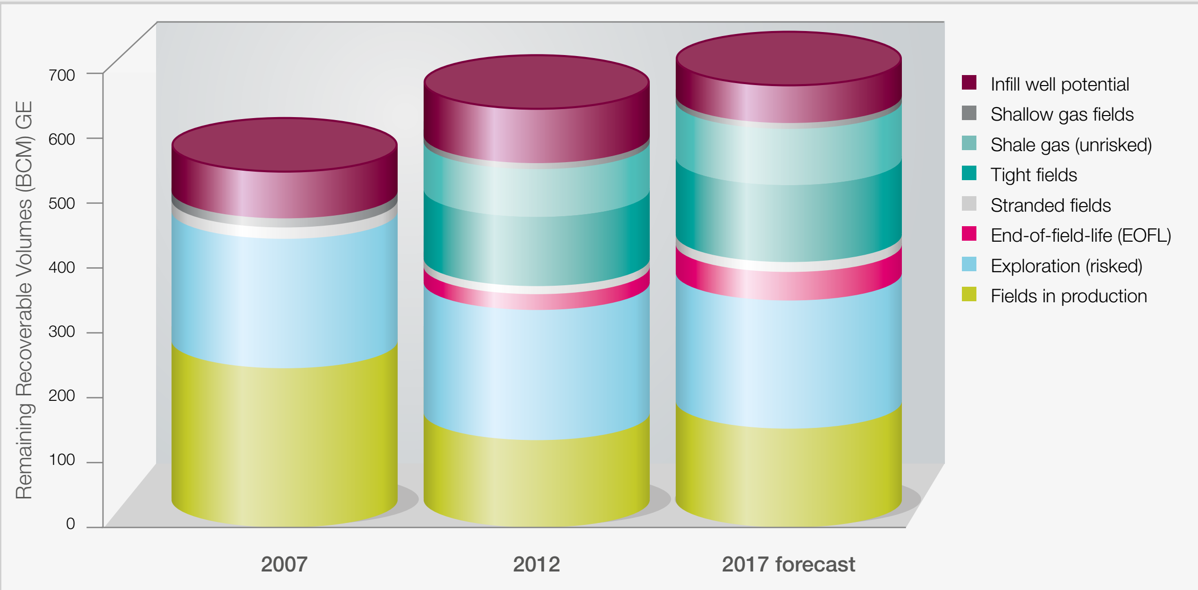
Expected recoverable volumes small gas fields



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applying the latest technology. In addition there is still over 200 BCM of recoverable gas (risked) believed to be contained within known prospects and leads. This number, in turn, is only a fraction of what could be recovered from the shale and the tight gas plays in the Netherlands.

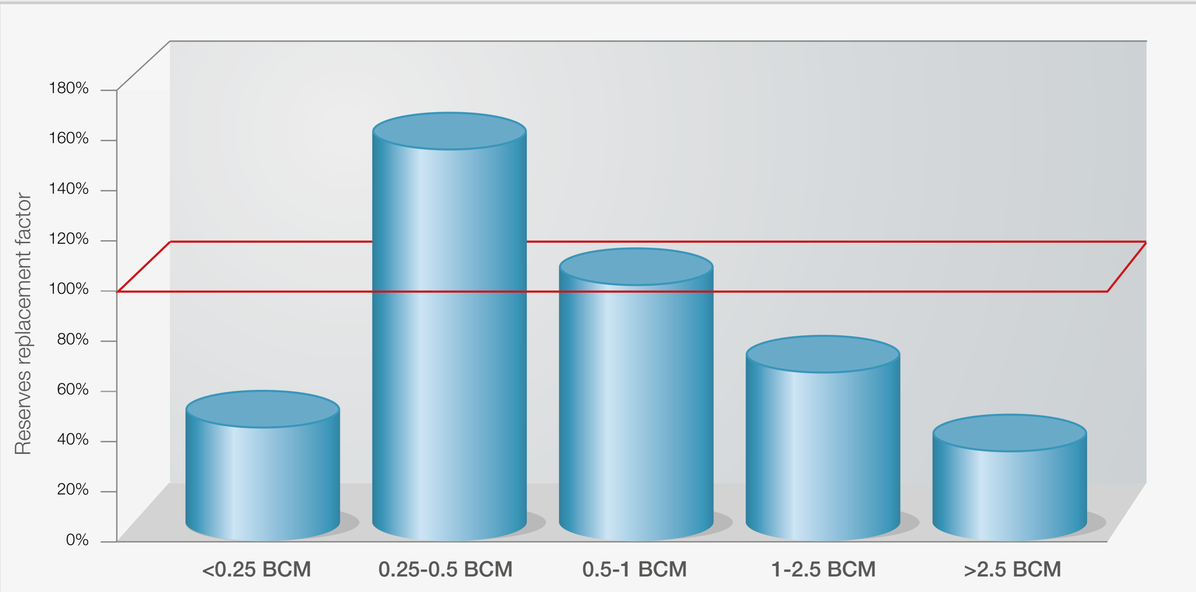
In previous editions of Focus on Dutch Gas, EBN has already highlighted the pivotal role played by offshore infrastructure. Field life extension projects would not just add some 40 BCM directly, but also create additional opportunities by extending the life of existing infrastructure. Drilling for offshore prospects, development of stranded fields and drilling appraisal or infill wells in undrained parts of fields already in production, would all be boosted by the continued existence of this infrastructure.

EBN estimates that the portfolio will continue to grow, based on experience of the historical development in the reserve and resource base over previous years. It is clear that the largest and easiest fields were discovered long ago. The focus must now be directed increasingly toward the more technically and economically challenging gas accumulations, including shale gas, tight gas and shallow gas.

1.3 | Reserve Replacement Ratio for different sized reservoirs

An indicator that is frequently used to assess the performance of oil and gas companies is the reserve replace-

Reserves Replacement per field size



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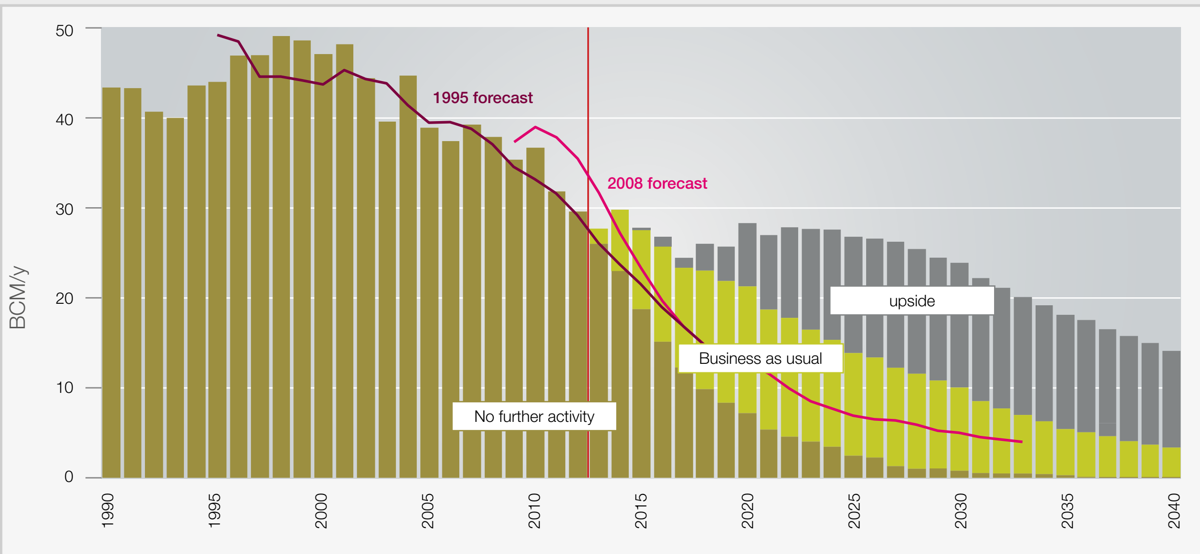
ment ratio. The reserve replacement ratio measures the amount of proven reserves added to a company's reserve base during the year relative to the amount of oil and gas produced. The Dutch gas and oil industry is currently at a stage where maintaining hydrocarbon production levels involves increasing costs, whilst recently discovered fields are smaller than mature fields already in production.

When looking at the gas reserve replacement ratio of EBN's portfolio over the last 5 years, this trend becomes apparent. EBN has managed to replace its reserves from mid-sized fields. For gas fields between 0.2 – 0.5 BCM recoverable, the replacement ratio is higher than 100%. Despite the good performance of these fields, it is not possible to compensate the loss of reserves to production in the larger fields. The reserve replacement ratio for larger fields is well below 100%. The rate at which small fields are being discovered and developed should increase in order to balance the loss of reserves from large fields. EBN believes that development of small and mid-size assets will be one of the keys to prolonging gas production from small fields.

1.4 | Tight gas, shale gas and increased exploration - Key to minimizing production decline

In the 2012 edition of Focus on Dutch Gas, EBN presented three scenarios for the future of natural gas production from small fields. In this edition of Focus on Dutch Oil & Gas, EBN elaborates on the components

Small fields gas production forecast scenarios and historic forecasts



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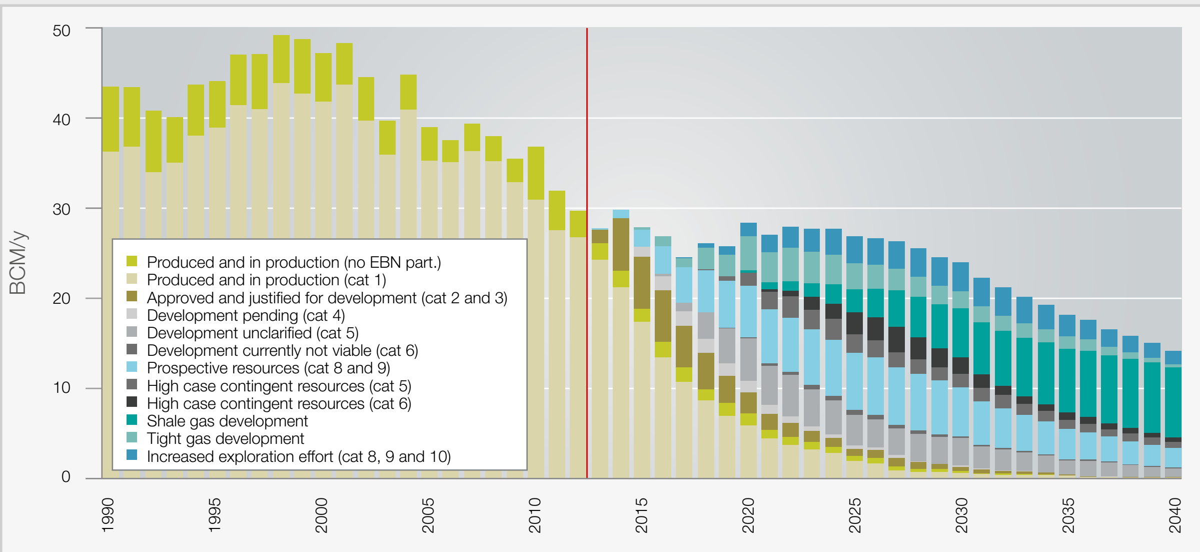
of each scenario. The first scenario is the pessimistic but hypothetical "no further activity" (NFA) forecast. This scenario assumes that producing gas assets are depleted and no new investments are made. Since the investment level in the small fields is still more than € 1 bln per year, it is clear that this scenario is hypothetical and that future small field production will be well above this level.

The "business as usual forecast" (BAU) corresponds with the scenario in which the known resource base is being developed at gradually declining rates and exploration drilling effort is kept at a constant level until the exploration portfolio has been depleted. In other words, the production forecast related to the BAU scenario reflects the future of small field gas production if the current trend in the investment level continues. In this scenario, annual gas production in 2030 from small fields would be close to 10 BCM, which is 20 BCM/y short of EBN's ambition to counter the production decline and maintain a level of production close to 30 BCM/y from now through to 2030. EBN introduced the "upside" forecast scenario as a roadmap for maintaining a higher production level. It is obvious that substantial investments are required in order to achieve this scenario.

Contributions to the "upside" forecast scenario need to come from a variety of sources. First of all, technological advances should make it possible to develop more gas currently booked in the contingent category. This category represents already discovered gas resources, of which the development at this stage is uncertain (cat 5) or uneconomic (cat 6). As stated in the previous chapter, the volume of gas in these categories is very large and

Small fields gas production forecast scenarios breakdown



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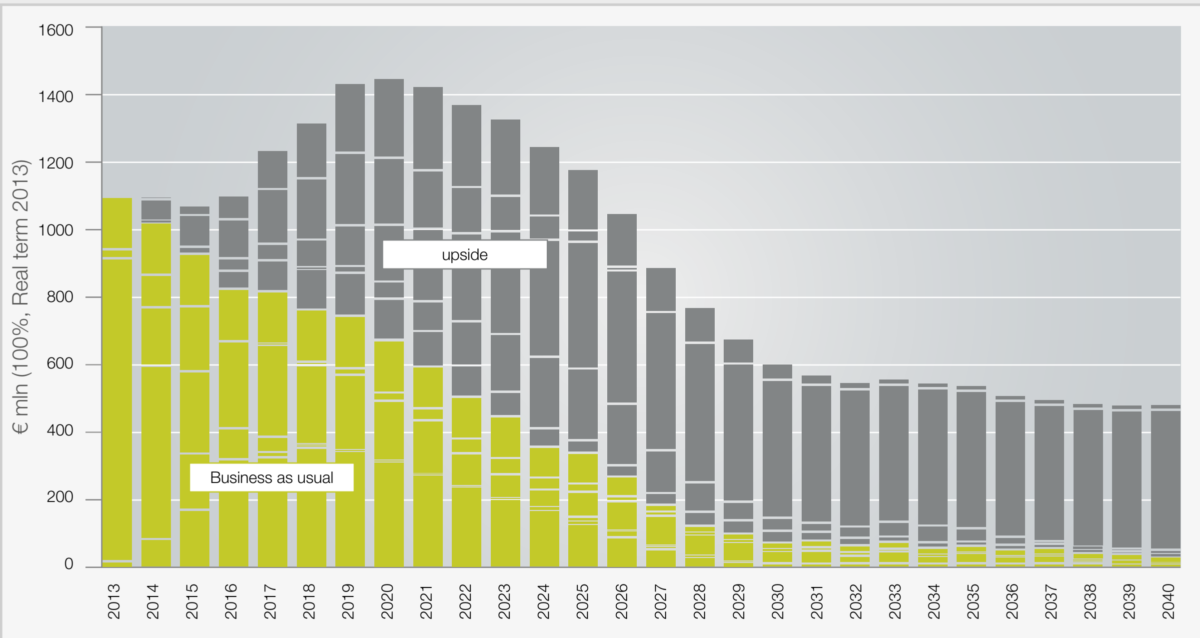
increases every year. Infrastructure lifetime extension and low cost development options, optionally combined with successful exploration campaigns, could lift more of these contingent resources above the economic threshold. In the “business as usual” forecast, EBN risks these resources with 50% and 10% for the resource categories 5 and 6. In the “upside” forecast, this risking factor is limited to 75% and 60%.This difference alone accounts for an increase of 5 BCM/y in production for the year 2030.

The most significant contribution to future annual gas production in the “upside” scenario comes from shale and tight gas. Some sizeable tight gas fields have already been discovered and the development of tight fields has proved possible. For this reason, EBN expects an increasingly larger contribution to annual gas production from tight fields in the near future. If one of the shale plays in the Netherlands proves to be successful, production from shale gas could take off around 2020. An earlier start to production would be preferable if the ambition 30 BCM/y in 2030 is to be met. Regardless of the starting date, an important condition is that exploration and production of natural gas from shale will be performed in a socially and environmentally responsible way.

The final component of the “upside” forecast is additional exploration. With ever-decreasing prospect size, it is evident that an increased level of exploration activity is

Investment outlook in small gas fields



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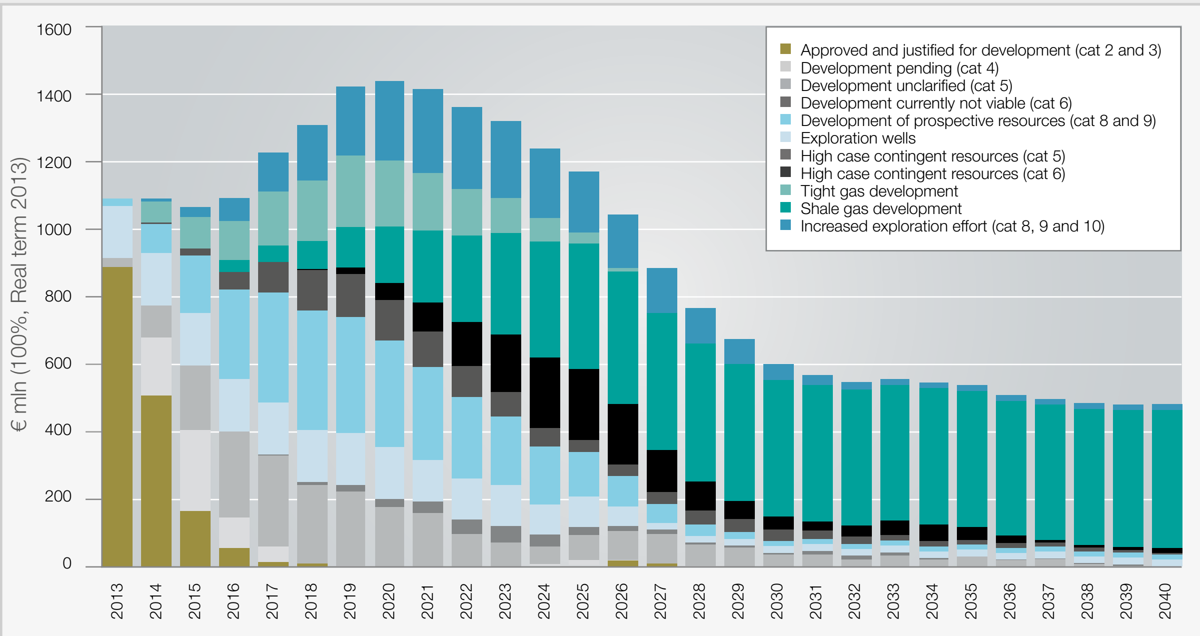
required to match the volumes found by exploration in the past. Analysis by EBN has shown that offshore exploration drilling could eventually come to a halt around 2025. This may happen not because there are no attractive prospects remaining, but because of the limitation posed by the ageing and disappearing infrastructure. Another relevant factor is that the exploration profile (under the pessimistic BAU forecast) is based on currently known prospects. EBN believes that the exploration portfolio can still grow by exploring new plays - such as the Dinantian carbonates - or by extending the boundaries of known plays, such as in the northern Dutch offshore. Higher exploration drilling rates will clearly be required to achieve the "upside" exploration scenario.

1.5 | € 20 bln of investments required to prevent production level decline

Current production levels are already falling behind on forecasts made in the recent past. It is obvious that, since the opportunities are there, the level of activity should increase as soon as possible. The current level of investment in small gas fields, including exploration wells, is around € 1.1 bln on an annual basis (100%, Real Term 2013), excluding investments related to underground gas storage, oil developments and projects that do not mature resources. It goes without saying that the decreasing annual gas production from small fields, as forecast in the "business as usual" scenario, is a result of decreasing

Investment outlook in small gas fields breakdown



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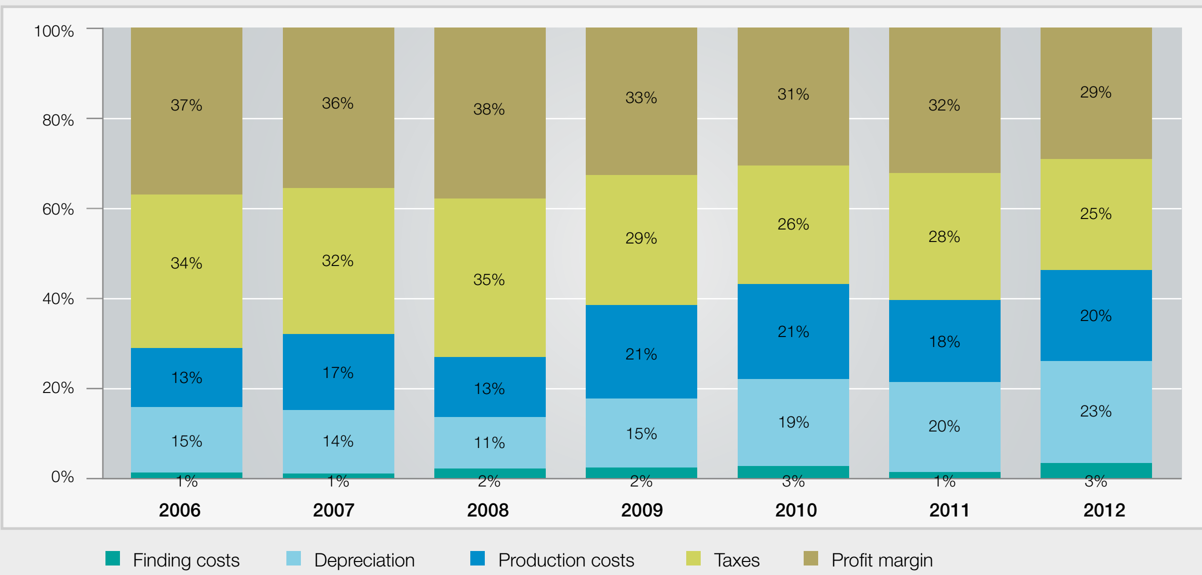
investment levels. The investment level that is required to follow the "business as usual" forecast will decrease to half the current level by 2022, and drop even further to less than € 0.1 bln in 2030.

The annual investment level should increase significantly to above € 1.4 bln in 2020 in order to turn the annual production decline towards the more favorable "upside" scenario. Moreover, these investments should be aimed specifically at the development of tight fields and later also the shale play, combined with an increase in exploration drilling of at least 50%. EBN estimates that the total cumulative investments required to realize the "upside" forecast equals around € 20 bln until 2030, compared to € 10 bln in the "business as usual" scenario. In other words, the level of investment needs to be doubled if the ambition of 30 BCM/y in 2030 is to be met. Although the "upside" production scenario presented in this report is still some 5 BCM/y short of the 30 BCM/y ambition set by EBN for 2030, it should be noted that even higher levels are possible in 2030, particularly from the shale and the tight play. This will only be the case if the level of investment in development of gas from all possible sources increases in the years to come. EBN is committed to making the investments required to fulfill its ambition.

Since EBN acts as non-operator, its strategy is concentrated on enabling and driving the Dutch E&P industry as

Build up of small fields margins (% of revenues)



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

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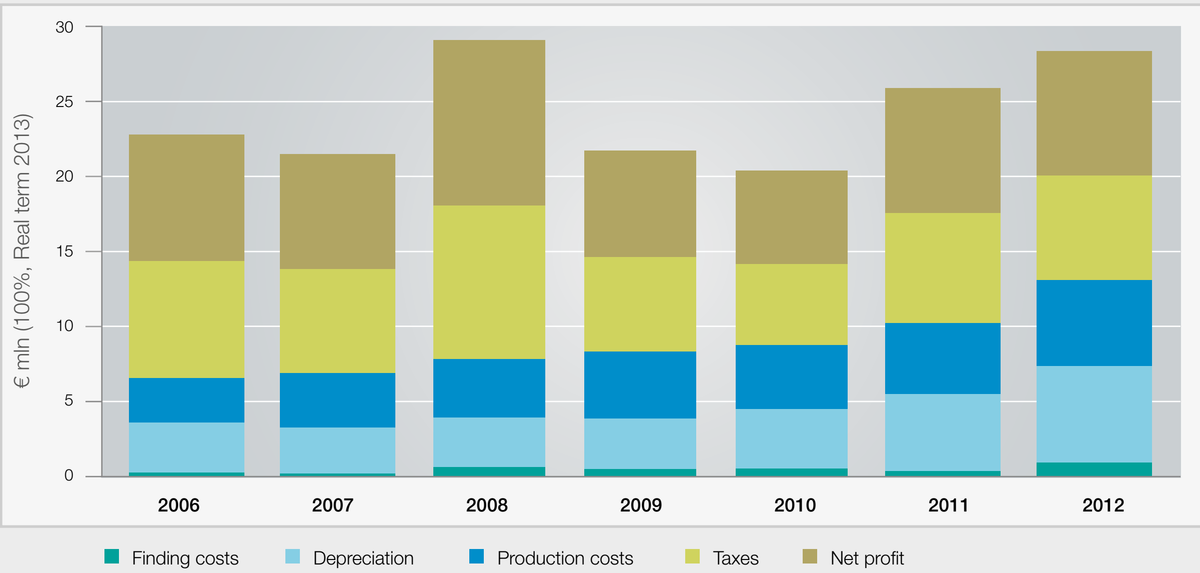
a whole, and operators in the Netherlands in particular, through a tailored approach, to get the most out of the Dutch small gas field reserves and resource base.

1.6 | Profit margins of Dutch small fields are still attractive

One of the ways EBN enables operators to maximize the recovery of gas from the Dutch resource base is its contribution to the improvement of the Dutch E&P investment climate. EBN's efforts have contributed to the fact that profit margins of Dutch small fields are still at an attractive rate of around 30%. Whilst gas production is in decline, small field cost levels have tended to stay at the same level, resulting in an increase in Unit Operating Costs (UOC) and Unit depreciation (from around 30% to around 45%). This increase is compensated by a lower tax burden as a result of marginal field incentives and the opex and capex uplift (decrease from 35% to 25%).

During the period 2006-2012, the gas price showed a continuous average growth rate (CAGR) of 4% per year, but the profit margin hardly grew at all. This gap in growth is mainly the result of an annual average increase of 12% in unit operating costs and depreciation.

Margins of small field production



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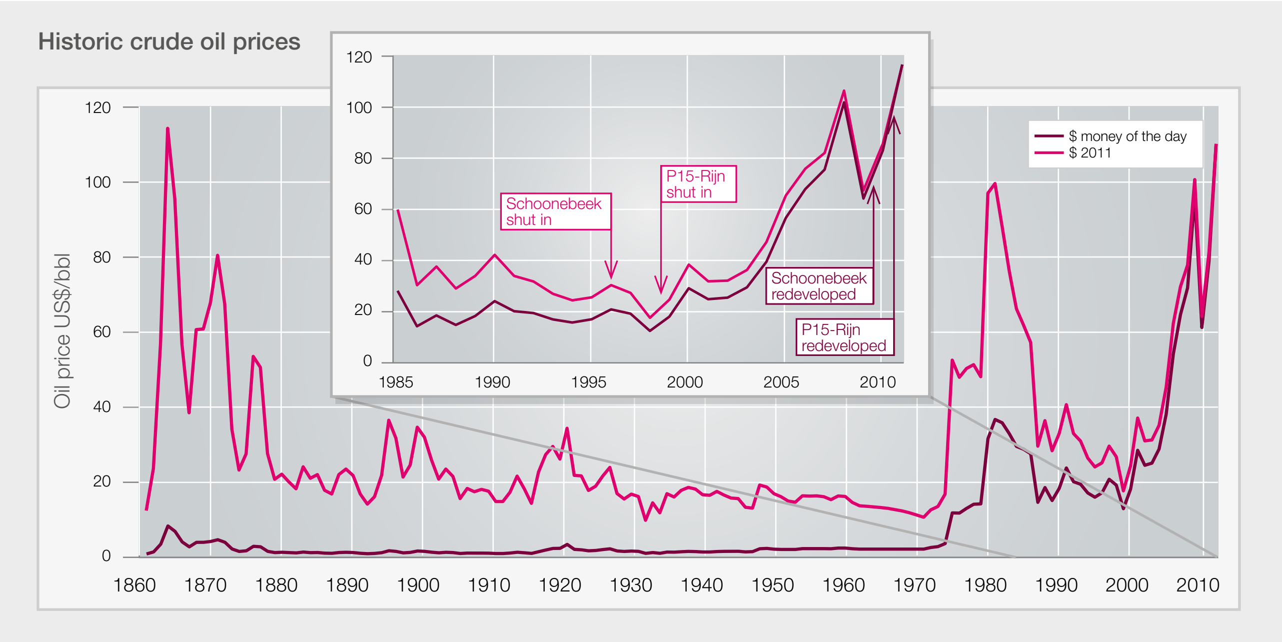
The De Ruyter oil platform, operated by Dana Petroleum, with the Van Ghent well being drilled in the background.

OIL IN THE NETHERLANDS

2

2. OIL IN THE NETHERLANDS



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2.1 | Focus on Dutch Oil

Although the Netherlands is mainly a gas producing country, it also has a long history of exploring for - and indeed, producing - oil. The success of Wintershall's F17-10 Chalk oil well and the subsequent attention it received in the media has provided EBN with a reason this year to put some focus on Dutch oil potential.

2.2 | High oil prices sparked old oil field redevelopments

Recently, two fields have been brought back into production: Schoonebeek and P15-Rijn. The oil price graph shows at least one of the reasons for doing so.

Schoonebeek

The redevelopment of this NAM operated field started in January 2009 and EBN participates in the project. The redevelopment involved the drilling of 73 wells, 25 of which are low-pressure steam injectors with steam generated along with 120-160 MW of electricity by a dedicated cogeneration plant. Approximately 22 km of new pipeline was laid to transport the oil to the BP refinery in Lingen, Germany. Produced water is injected into empty gas fields in the Twente area. Production resumed on 24th January 2012, and in 2012 nearly 290,000 Sm^3 (1.8 MMBO) was produced. The production rate is over 960 Sm^3/d (6040 BOPD end 2012). A higher production rate is expected once steam injection is fully operational. A total production of 16-20 mln Sm^3 (100-120 MMBO) is anticipated over the next 25 years.

P15-Rijn

This field started up in 1985 (when Amoco was the operator) and was closed in 1998, due to high water cut and corrosion problems. By that time it had produced some 4 mln Sm^3 (25 MMBO). By the end of 2010, TAQA had restarted the Rijn oil field. Five producers and five injector wells have been worked over.

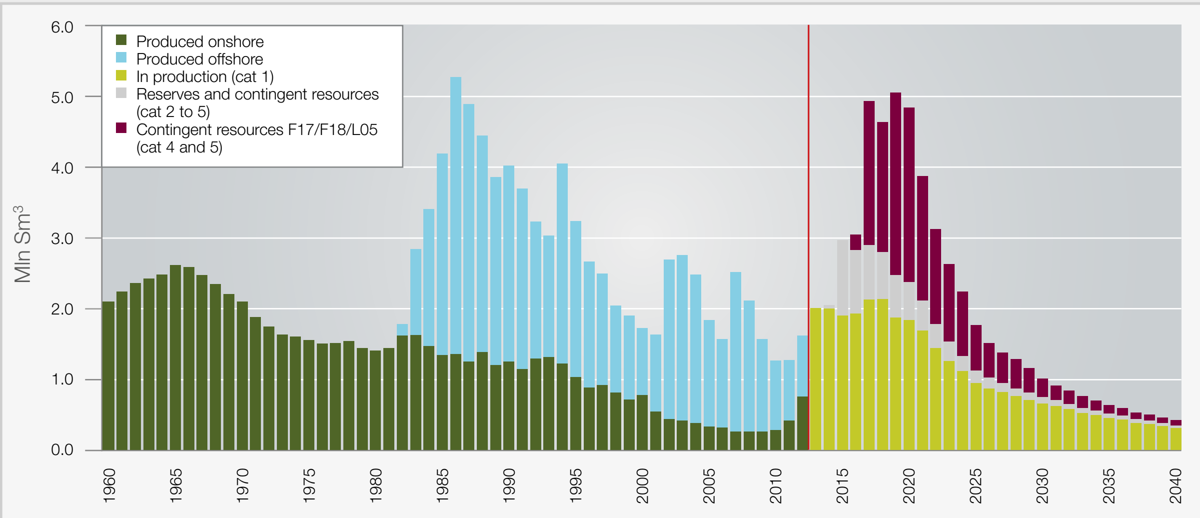
The facilities on P15-C were also upgraded and ESP's were installed in the producing wells. Produced water is re-injected into the reservoir. The field currently produces some 190 Sm^3/d (1200 BOPD) from the Vlieland and Delfland sandstones, down from nearly 445 Sm^3/d (2800 BOPD) in December 2010.

2.3 | Promising oil potential in the northern Dutch offshore

The success of Wintershall's F17-10 Chalk oil well has put the spotlight back onto the larger area around F17, where 4 stranded fields are located: Sterling's F17-Korvet (or F17-FA), F17-Brigantijn (or F17-FB), F18-Fregat (F18-FA) and GDF SUEZ's L05-E. EBN participates in oil in all these licenses.

Two further accumulations have been discovered in F14 and L01b, but these appear to be too small to warrant development. With the exception of F17-10 (Chalk), all other fields have a Jurassic Central Graben reservoir, which has a complex stratigraphy in the Netherlands. Friese Front, Scruff, Lower and Middle Graben sands as

Historic and future oil production



Contingent resources are unrisked.

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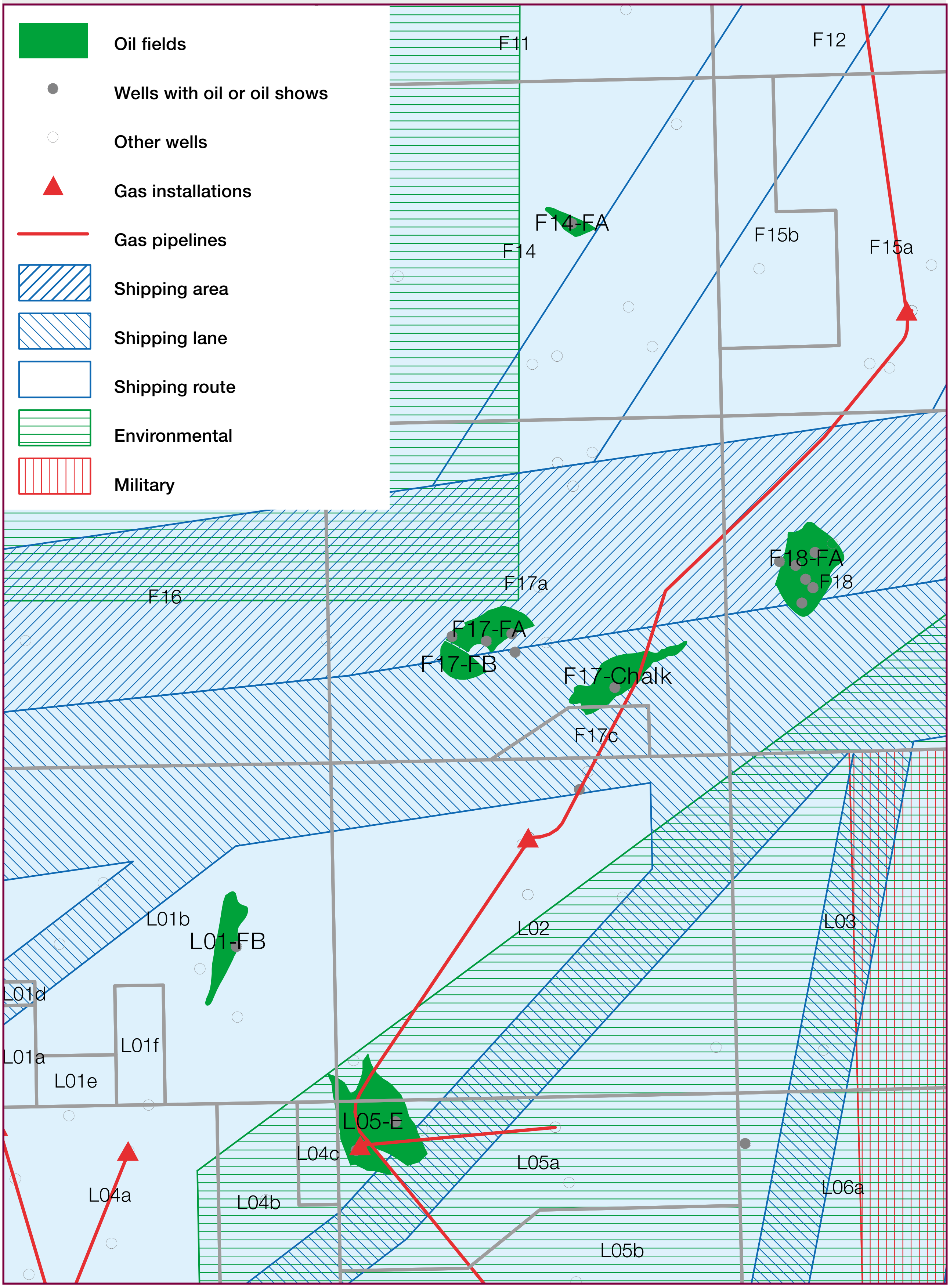
Oil fields and restricted areas F17 region



well as the Schill Grund Member and Puzzle Hole Formation have all been identified in these and surrounding wells.

The F17-10 discovery makes an oil development in this area feasible. The Jurassic fields are severely compartmentalized and development is not straightforward. However, a joint development with the Chalk field makes sense. GDF SUEZ also has plans to develop L05-E. A major challenge is that all F17 and F18 fields are located under a number of shipping lanes and an anchoring area, and are bordered by the Friese Front environmental reserve and a military practice area. Although some shipping lanes will be amended by 1st August 2013, this applies only to those off the West coast. Therefore a platform would have to be located close to L02-FA or outside the shipping lanes entirely.

Because of these constraints all F17 and F18 fields require production and water injection through subsea completions, adding substantially to capital and operating expenditure. Injection and production would require dedicated pipelines with umbilicals. EBN is convinced this is feasible and has carried out a high-level economic analysis to show how much it would benefit stakeholders, including the state.

Several development scenarios are possible. Platform locations may not be important, since most fields would have to be produced with subsea completions anyway. A location close to L02-FA (NAM) or L05-A (GDF SUEZ) would provide the possibility of exporting associated gas through NOGAT. Although the ideas that follow are not necessarily shared by current operators in the area, possible options include:

- a Gravity Based Structure (GBS) near L02-FA with a Tanker Mooring & Loading System (TMLS) located outside the shipping lane.

- a production platform near L02-FA with an export pipeline to K18-Kotter (105 km) or F03-FB (100 km). Export to F03-FB would then require tanker offloading, but would have the benefit of fewer pipeline crossings than when going south.

The other fields in F17 and F18 could be connected by inter-field pipelines with umbilicals (roughly 10-20 km each) for production and water injection, and subsea installations. On L05-E a satellite would be installed, connecting to the production platform or GBS.

EBN estimates that 49 production and injection wells will be necessary, roughly half of the wells will have to be completed subsea. By nature, the Jurassic reservoir needs a lot of wells as a result of limited connectivity and compartmentalization. A forecast has been made which assumes a start-up of the main fields in 2017 and a gradual connection of the other fields through to 2021. Phasing of capital outlay and operating expenditure is based on the phasing of production start, drilling of wells, completion of subseas, platform installation and pipeline laying. Total reserves are estimated to be over 16 mln Sm^3 (100 MMBO).

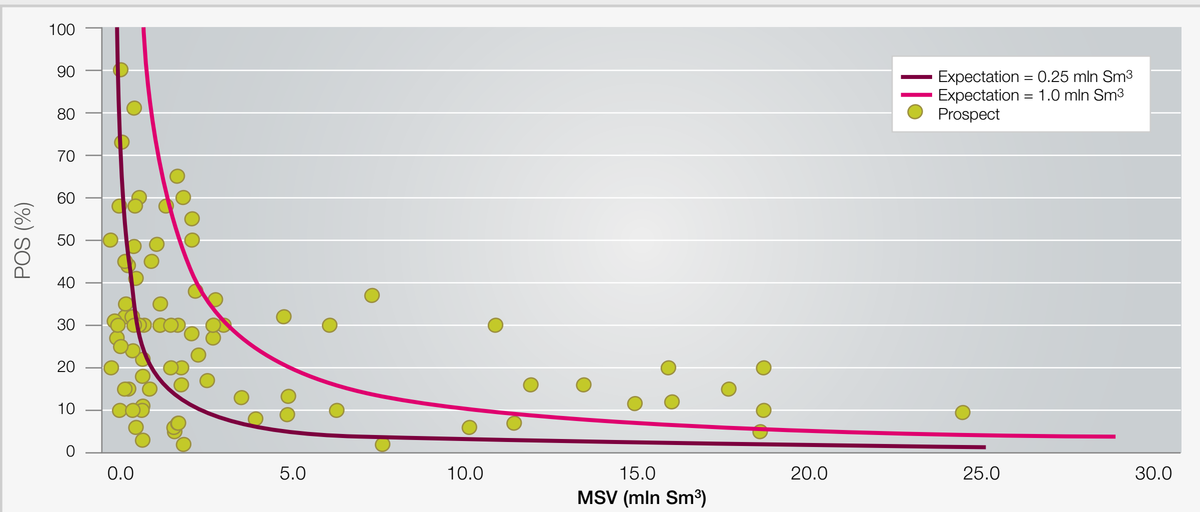
A total investment of roughly € 2.3 bln (all numbers are RT 2013) would be required, estimated with +/-30% accuracy on the individual components. Opex is estimated at 10-50 mln €/year, obviously dependent on the type of development. Total abandonment cost is estimated at roughly € 375 mln. Using a flat oil price scenario at $100/bbl and

2% inflation/year, the total project NPV works out at some € 1.50 bln at a 10% nominal discount/year. This number is after tax and State Profit Share. The impact on the Dutch economy, treasury and oil production resulting from a development in this area would be substantial, with peak production equaling the peak of the 1980's. It should be noted that no risking has been applied to contingent resources. In other words, they will come into production as planned.

2.4 | Remaining oil prospectivity

EBN has a somewhat incomplete database for total prospective oil resources, since EBN does not participate in the first round licences (e.g. F02a oil, F03-FB-oil etc) nor in the older onshore licences. Nevertheless, the EBN prospect database for the offshore contains nearly 90 prospects with some 80 mln Sm^3 (500 MMBO) risked oil resources in place. Average Probability of Success (POS) is 19.8%. The onshore data is very incomplete and is disregarded here. Of the 87 prospects 57 have an Expectation (= POS x Mean Success Volume [MSV]) over 0.25 mln Sm^3 (1.6 MMBO) and 19 of these have an Expectation higher than 1.0 mln Sm^3 (6.3 MMBO). These expectation values may represent potential cut-offs, below which those prospects may not rank economically.

Offshore oil prospects: POS and MSV



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HISTORY OF OIL IN THE NETHERLANDS

In the early 20th century many wells were drilled to assess the potential for coal and salt mining. In 1909 the America-1 well was drilled (this is a township in the De Peel area, not the continent) where oil shows were described in cuttings from a bituminous clay. Most likely the oil originated from the drilling tools. Fifteen years later in 1923 a well was drilled in Corle near Winterswijk, which had clear oil shows in the Zechstein and Carboniferous formations. After attempts to increase inflow, the well had to be abandoned and while pulling the casing some 240 l of oil was recovered. The French geologist Macovei was rumored to have said in 1938 that this was no surprise, “since Winterswijk is on trend with Haarlem, from which city ‘Haarlemmerolie’ (‘Harlem oil’) originates”. Haarlemmerolie is however an 18th-century turpentine-based quack potion.

In 1943, during the German occupation, the Schoonebeek field was discovered by Exploratie Nederland, a subsidiary of BPM - NAM’s predecessor until 1947, when NAM was founded. This field contains initially in-place volumes of 1027 million barrels of viscous, waxy oil in the Cretaceous Bentheim sandstone. It was and still is the largest onshore oil field of Northwestern Europe, partly extending into Germany (operated by Wintershall). It came into production in 1947. Schoonebeek production ceased in 1996, after 40.2 mln m^3 (253 MMBO) had been produced. All installations were removed.

A working rig was included in an exhibition about the Dutch East Indies in 1938, and oil shows were seen in this De Mient-1 well. In 1953 the Rijswijk-1 well (NAM) found oil in commercial quantities. This discovery was quickly followed by several others (e.g. Pijnacker and De Lier). In 1961 the first offshore well in Western Europe was drilled by NAM, using the Triton rig. The Kijkduin-Zee 1 well was P&A’d dry. This was followed in 1962 by the Scheveningen-Zee 1 well (renamed Q13-1) which discovered the Amstel field. Although not tested, oil and gas were recovered from an FMT. The Amstel field is now under development by GDF SUEZ. EBN is participating in this development, and the first oil is expected in 2014. The first ‘official’ offshore discovery of oil was made in 1970 by Tenneco, when F18-1 tested up to 2040 BOPD. Many appraisals over the years by different operators (Tenneco, Agip and NAM) have not yet resulted in a development of the field. In the 1970’s and 1980’s several offshore fields were discovered and came into production. In alphabetical order, they are: K18-Kotter, L16-Logger, P09-Horizon, P15-Rijn, Q1-Helder, - Helm, and -Hoorn. These were followed by F03-FB (1992), F02-Hanze (2002), P10/P11-De Ruyter (2006) and P11-Van Ghent (2012). Of these producing fields, EBN only participates in latter two fields. All the other fields are located in First Round (1968) licences, in which EBN does not participate in oil production by law.

The first regular oil production came from Unocal’s Q01-block (1982), but Pennzoil claimed the ‘very first oil’ in March 1982. This oil was produced into a barge at the K10-B platform from a small pool in the Bunter. After a few months, this production method was discontinued and the pool was closed in.

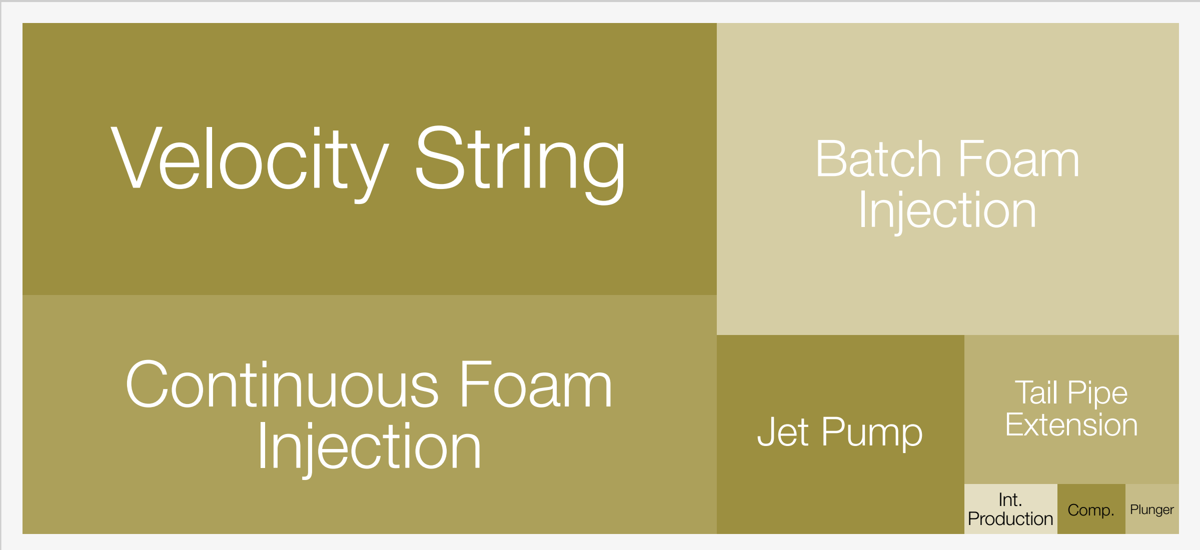
Cleaning out of a well after a successful fracking operation at the Lauwerzijl production location, operated by NAM

3

FIELD LIFE EXTENSION

3. FIELD LIFE EXTENSION

Treemap of applied EOFL techniques | Size: reserves gained, dark: high UPC, light: low UPC



(UPC: Unit Production Cost)

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3.1 | End-of-field-life success - Already 200 wells treated

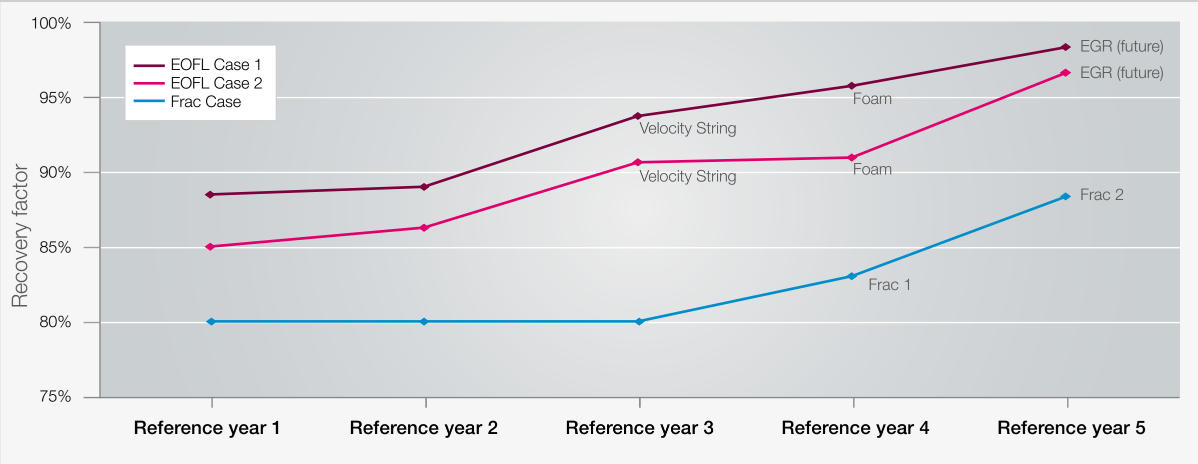
It is obvious that field life extension projects have been very successful in the last 10 years. The implementation of various end-of-field-life techniques has helped to increase recoverable reserves by about 2 BCM of gas. On average, field life has increased by more than 4 years. Over 200 wells have been treated and EBN foresees treatment for another 200 wells in the next 5 years. In the Netherlands, foam and velocity strings are the most commonly applied technologies for gaining additional gas volumes from fields in their tail-end phase. Nevertheless, the application of these technologies must be cost-effective in order to be applied full-scale in the Netherlands.

Costs are the major bottleneck in the application of field life extension projects. EBN is currently appraising the needs of operators and is actively looking for more cost-effective solutions through EOFL technology campaigns and joint industry projects.

3.2 | EOFL and hydraulic fracturing as tools to increase recovery

Apart from the application of EOFL techniques, hydraulic fracturing (fracking) can also be applied to increase the recovery from existing fields, thereby unlocking additional reserves that were not previously assumed to be recover-able. Two EOFL and one fracking example clearly

Increasing recovery factors: 3 successful examples



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demonstrate the increased recovery factors before and after the application of the technology.

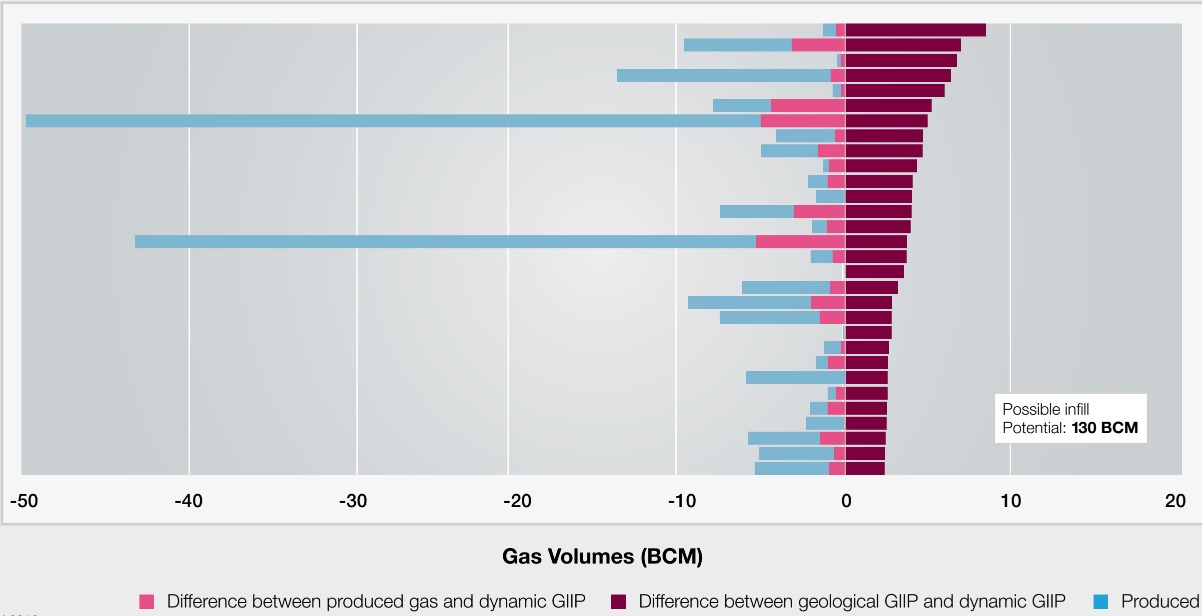
3.3 | Top 30 fields based on infill well potential

Ultimate recovery is a measure in the oil and gas industry that is used to estimate the quantity of oil or gas which is potentially recoverable from an accumulation. It is generally tied to an economic cut-off that operators identify for the production prognosis. Capex, opex, export pressure and productivity are the major parameters that effect ultimate recovery. Ultimate recovery of a field can be increased using several different methods, depending on the individual project and field. Among EBN's portfolio, the top 30 assets that show a mismatch between the dynamic gas in place (GIIP) and the geologically calculated GIIP have been identified. Such a mismatch could occur when the wells in a gas field do not drain the entire reservoir. These gas fields are often the best candidates for additional infill drilling or fraccing.

3.4 | Eductors: scope for offshore compression optimization

Some 38 gas processing platforms are installed on the Dutch continental shelf, of which around 80% have compression facilities. With declining gas throughput, compressors must increasingly be run in 'recycle mode' in order to operate the compressor within its operating envelope. An eductor (jet pump) has been installed or will soon be installed on only 3 platforms (Ameland Westgat 2008, L07-PK 2010 and K9c-A 2014). The eductor utilizes the energy of this recycle stream to further reduce the flowing wellhead pressure. Such a relatively low-cost solution can defer or even replace the need for additional

Infill well potential | Top 30 fields with geological and dynamic GIIP mismatch



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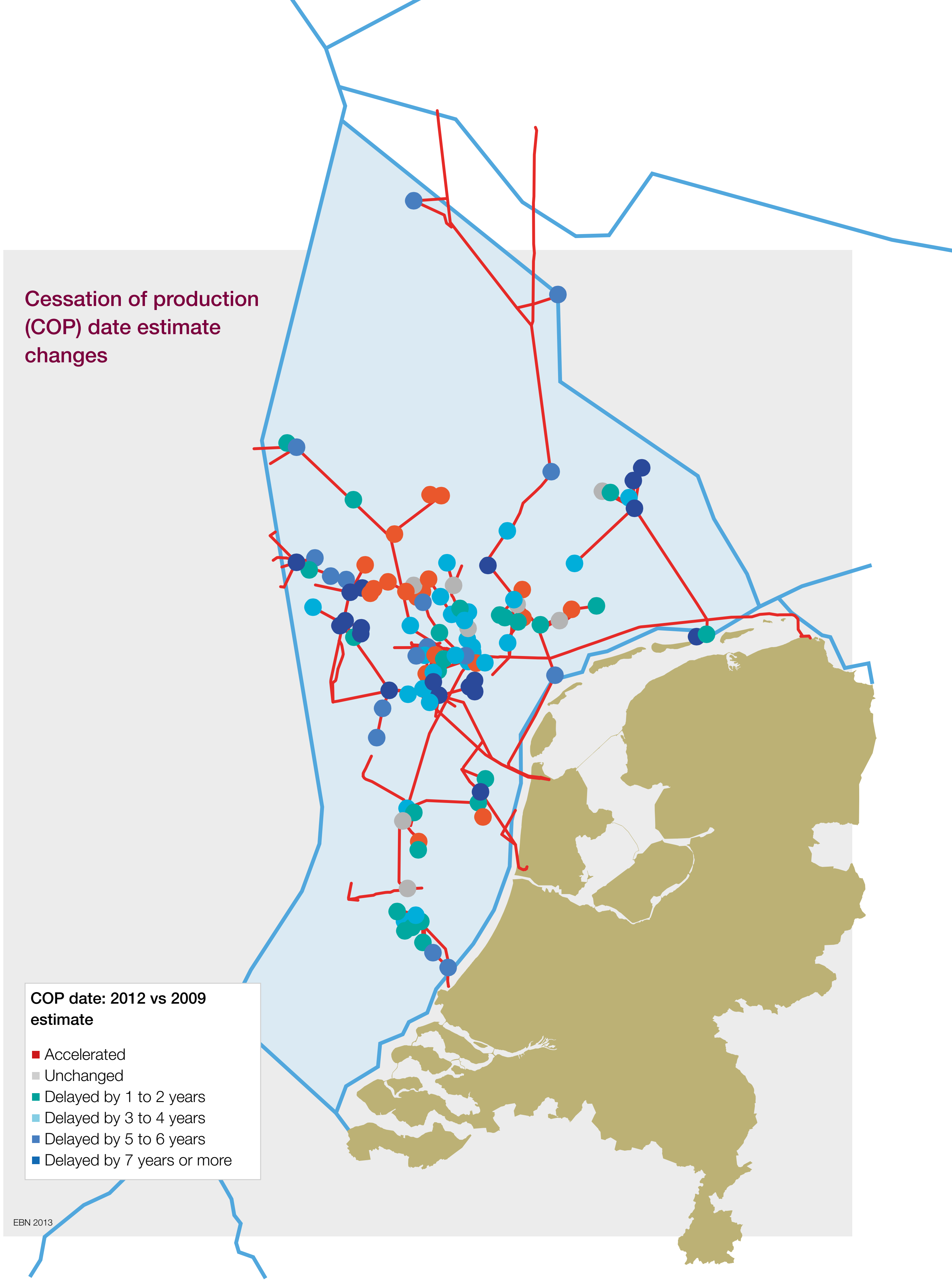
compression or rewheeling, taking advantage of the waste energy of the compressor recycle stream and turning it into additional or accelerated gas production. An eductor that takes advantage of a high pressure well rather than a recycle stream has been installed on 2 other platforms. (L02-FA 2010 and P15-9E2 HP well 2004).

3.5 | Moving towards a longer infrastructure lifetime

The cessation of production (COP) date for various offshore installations has been determined on the basis of production profiles for all individual gas fields, taking into account proven and developed reserves (PRMS cat 1,2 and 3). For the determination of cut-off for technical production profiles, the following rates were consistently applied: 30,000 Nm^3/d for subsea installations/monopods, 60,000 Nm^3/d for satellite platforms and 150,000 Nm^3/d for processing installations. The analysis for 2012, as compared to the analysis carried out for 2009, reveals that the cessation dates are effectively being delayed by an average of 3 to 4 years.

This is mainly the result of an increasing average gas price, which offsets the increasing unit operating cost and declining production from small gas fields offshore. The industry should therefore continue to focus on increasing the throughput of installations. This can be achieved by adding reserves either through drilling prospects and infill


Cessation of production (COP) date estimate changes
COP date: 2012 vs 2009 estimate
Accelerated
Unchanged
Delayed by 1 to 2 years
Delayed by 3 to 4 years
Delayed by 5 to 6 years
Delayed by 7 years or more
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wells, workovers and end-of-field-life projects, while at the same time reducing - or at least controlling - operating expenses.

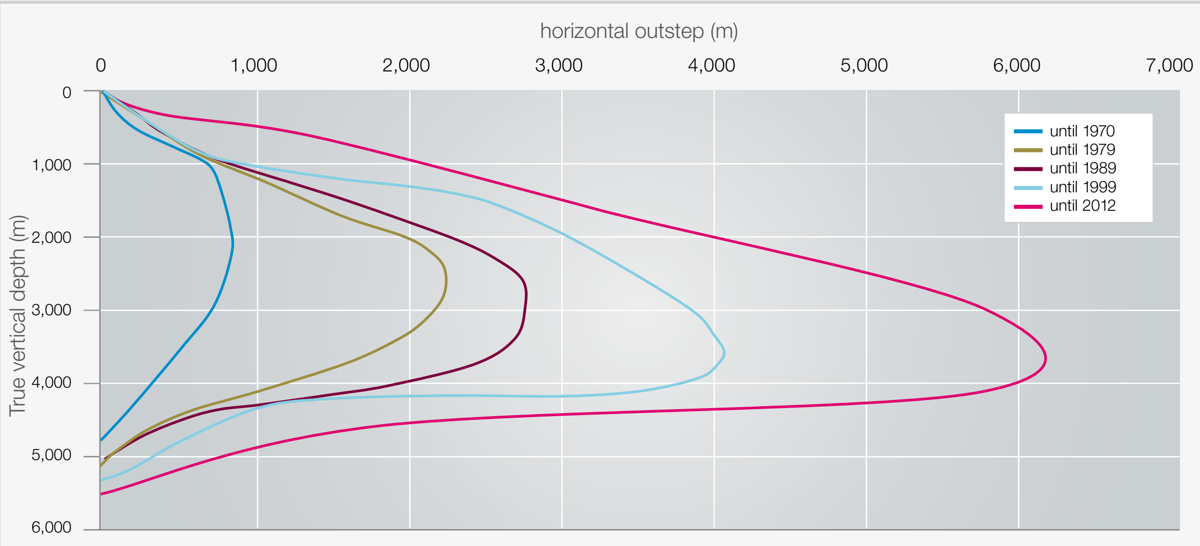
Most of the installations with accelerated cessation dates seem to be clustered in and close to the K- and L-blocks. Several of these fields in the K-block produce from Carboniferous reservoirs, which are generally more heterogeneous and complex than the Rotliegend formations. Of the 20 installations with accelerated cessation dates, most are satellites and 6 of them are production installations. Fortunately, the industry has recognized this and has initiated several projects to preserve the infrastructure and drill additional production or exploration wells.

3.6 | History and future of Extended Reach Drilling (ERD)

Prior to 1970, drilling in the Netherlands was done mainly onshore, and only 52 of the total of 636 wells drilled were drilled offshore. The first offshore exploration well was drilled in 1962, and offshore drilling only picked up in the mid-1970's, starting with the K13 and L10 licenses. Since the early 1980's, the annual number of offshore wells drilled has exceeded the number of onshore wells, except for the recent years in which the Schoonebeek field was redeveloped.

Up to the 1970's, drilling in the Netherlands was mainly vertical with an occasional horizontal outstep up to some 1.5 km. The 'nose plot' clearly shows the onset of

Development of the Dutch drilling envelope



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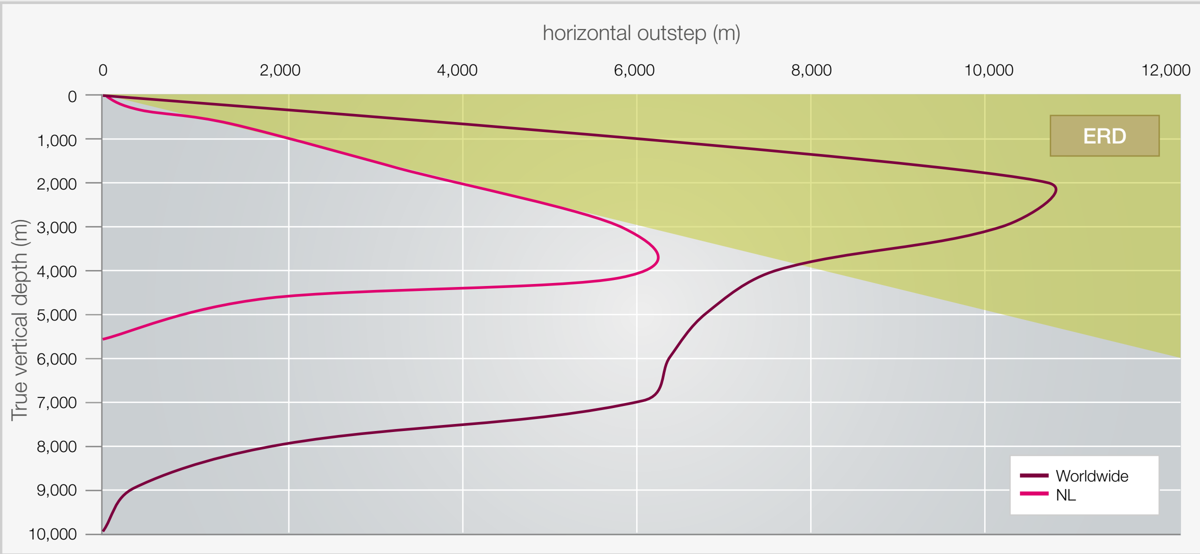
Drilling envelope: worldwide vs the Netherlands



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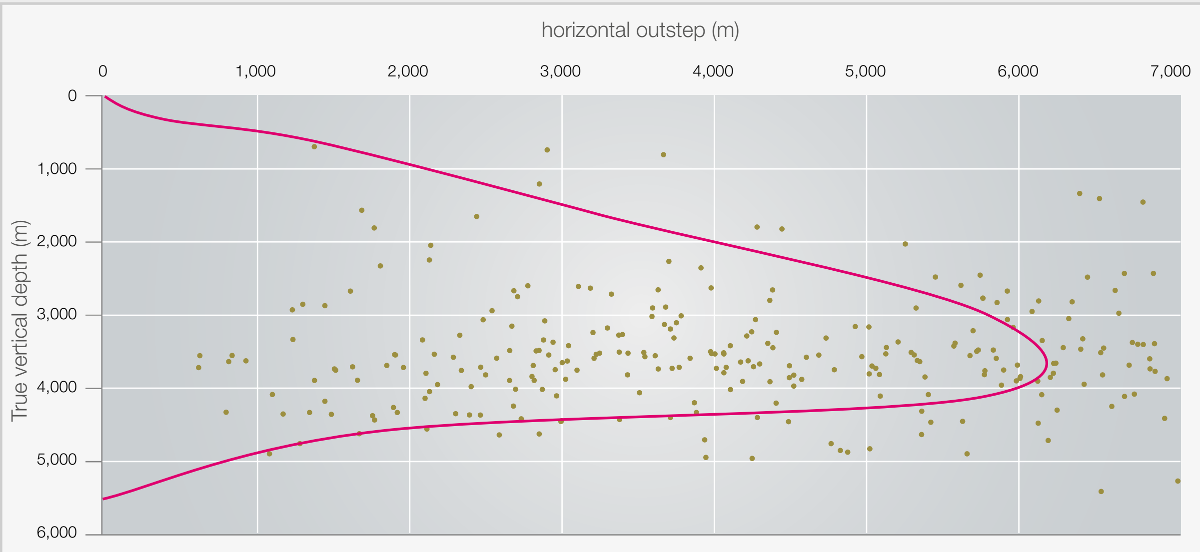
Drilling envelope vs prospects around offshore platforms



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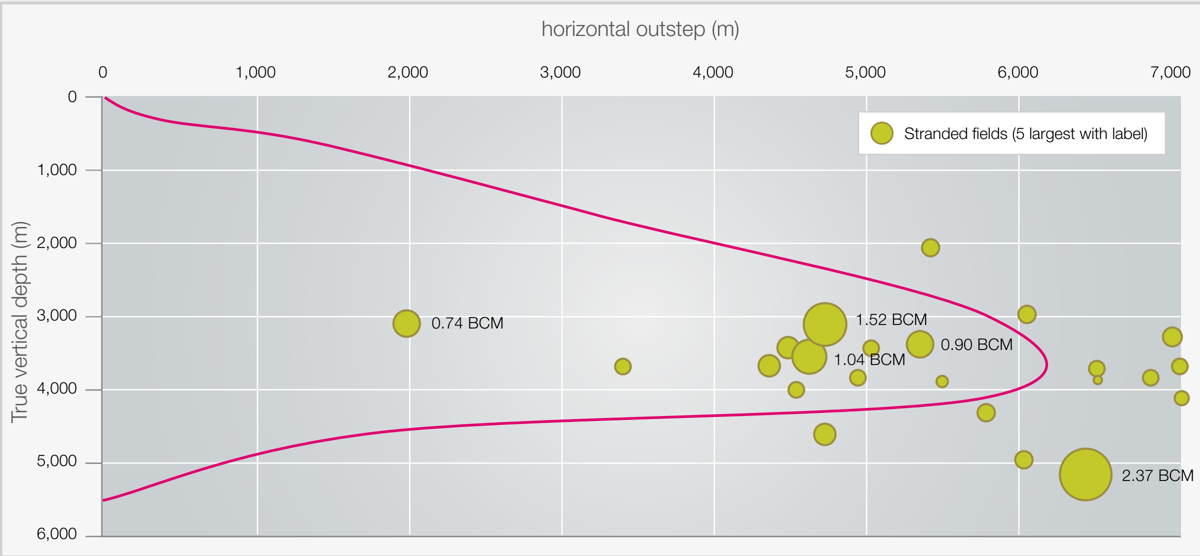
Drilling envelope vs stranded gas fields around offshore platforms



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deviated drilling in the 1970's and an ever-increasing horizontal stepout in each subsequent decade.

Directional drilling has developed through the application of positive displacement motors in combination with a bent sub and steerable drilling motors, allowing directional drilling in sliding mode. Directional control improved with the introduction in the late 1990's of rotary steerable systems, which eliminated the need for drilling in slide mode. This breakthrough has resulted in another 2 km additional extension in the horizontal outstep of the Dutch drilling envelope since the turn of the century.

Wells are often referred to as ERD wells when the ratio of the horizontal outstep and vertical depth is greater than 2. Currently, wells in the Dutch sector are being drilled with a horizontal outstep of 5 to 6 km with a true vertical depth of 3 to 4 km, so according to the common definition the Dutch wells do not actually qualify as ERD wells. The worldwide 'nose plot' shows that true ERD wells are being drilled up to a horizontal outstep of around 10 km and a true vertical depth of around 2 km.

Since 2000, the largest outsteps that have been realized offshore as surface locations are obviously often restricted to already existing wellhead platforms, whereas onshore drilling from a new surface location is financially more attractive than drilling a long reach well.

Of the total prospect inventory, many of the prospects are located in the direct vicinity of existing offshore platforms and well within the established drilling envelope. Over the last 5 years, an average of 3 exploration wells have been drilled from existing platforms per year, and clearly there is still ample scope to continue exploring from offshore platforms. Furthermore, several stranded gas fields fall within the established drilling envelope, some of which have estimated recoverable volumes of well over 1 BCM.

4

EXPLORATION AND CHALLENGING PLAYS

4. EXPLORATION AND CHALLENGING PLAYS

4.1 | The value of seismic acquisition

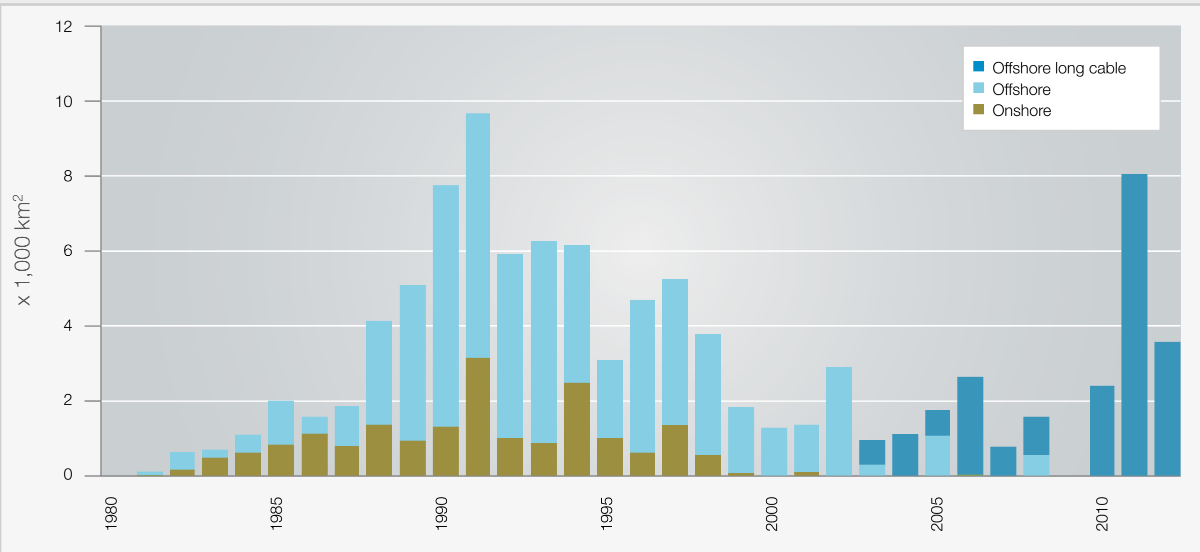
In the 2010 Focus on Dutch Gas report, EBN discussed 3D seismic acquisition in the Netherlands and encouraged the Dutch industry to consider reshooting old surveys through long streamer acquisition. Now, a few years on, there are compelling statistics to underpin the business case for long cable acquisitions (defined as a streamer length of 4500 m or more).

In recent years, a considerable amount of new long cable data has been shot, and long cable acquisition now equals roughly 25% (21,000 km^2) of a total of 82,000 km^2 for all offshore surveys. This includes the large Fugro DEF (2011) and Total 'Pistolet' (2012) surveys.

Analysis of the 55 offshore exploration wells drilled since 2005 reveals a relation between the exploration well success and the age of the 3D seismic on which these wells were planned. Exploration success rates increased from 38% for old 3D surveys to 69% for the most recent 3D acquisitions. In other words, the more recent the seismic, the higher the success rate.

Another way of looking at this data is short streamer vs. long streamer acquisition. Short streamer surveys have an exploration well success rate of 42% (out of 31 wells), and for long streamer surveys this rises to 71% (out of 24 wells). However, it should be noted that new seismic is often acquired in the most prospective areas.

Historic overview of 3D seismic acquisition in the Netherlands



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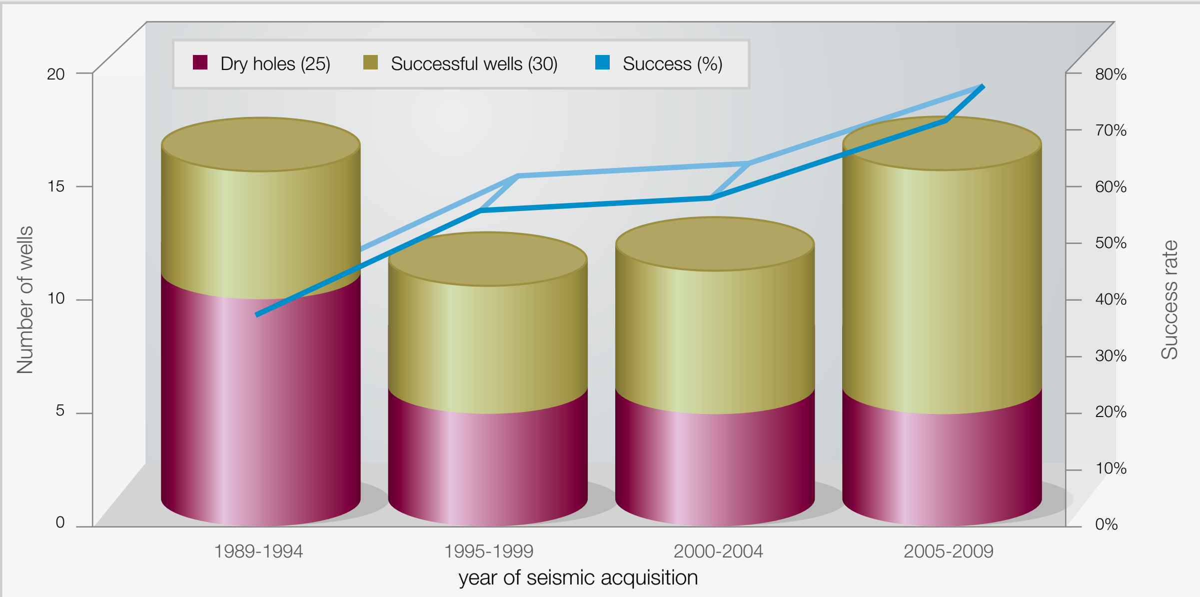
Exploration well success rate by seismic acquisition year



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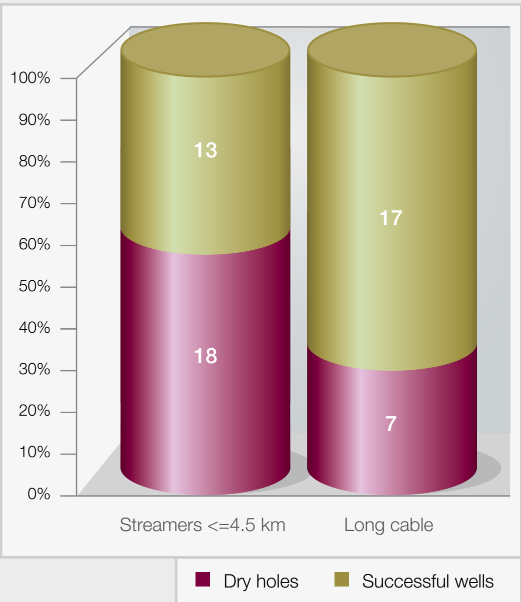
Exploration well success rate by 3D acq. type



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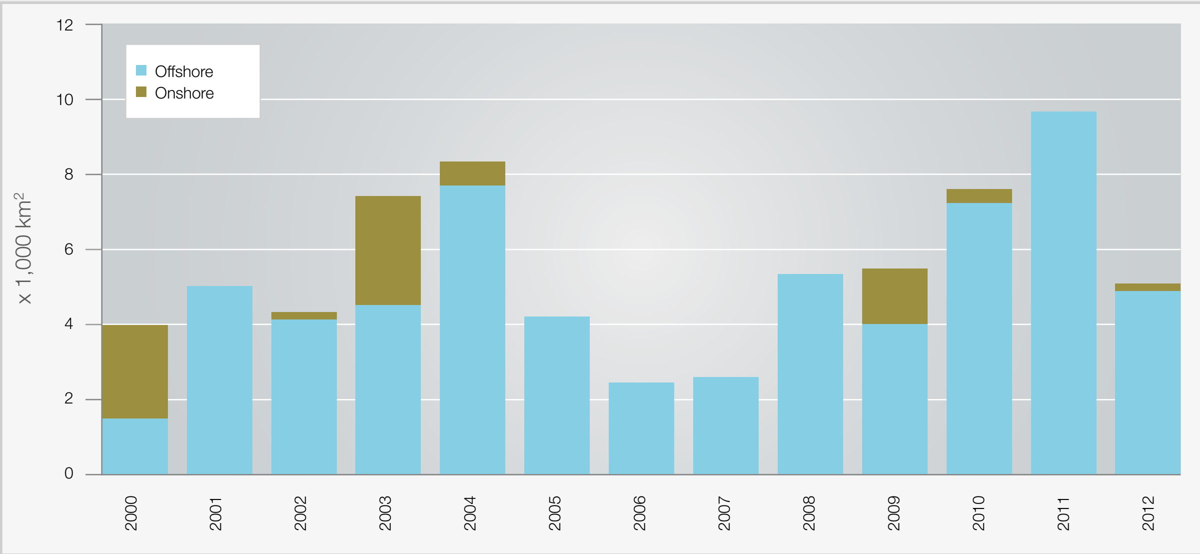
4.2 | The value of seismic reprocessing

EBN's records show that since 1991 at least 67000 km^2 of offshore and 9700 km^2 of onshore 3D data has been reprocessed. Though these numbers are still incomplete, they do give an idea of processing efforts. This compares to nearly 68000 km^2 offshore and over 19000 km^2 of onshore and inshore 3D data acquired since 1980. Prestack Depth Migration (PrSDM) reprocessing is the method of choice, although companies are starting to look at Beam, Wave Equation migration and RTM.

So how does processing affect success rates? For this analysis, all time migrated data, whether prestack or poststack (PrSTM or PoSTM) was lumped together and

3D seismic reprocessing in the Netherlands since 2000



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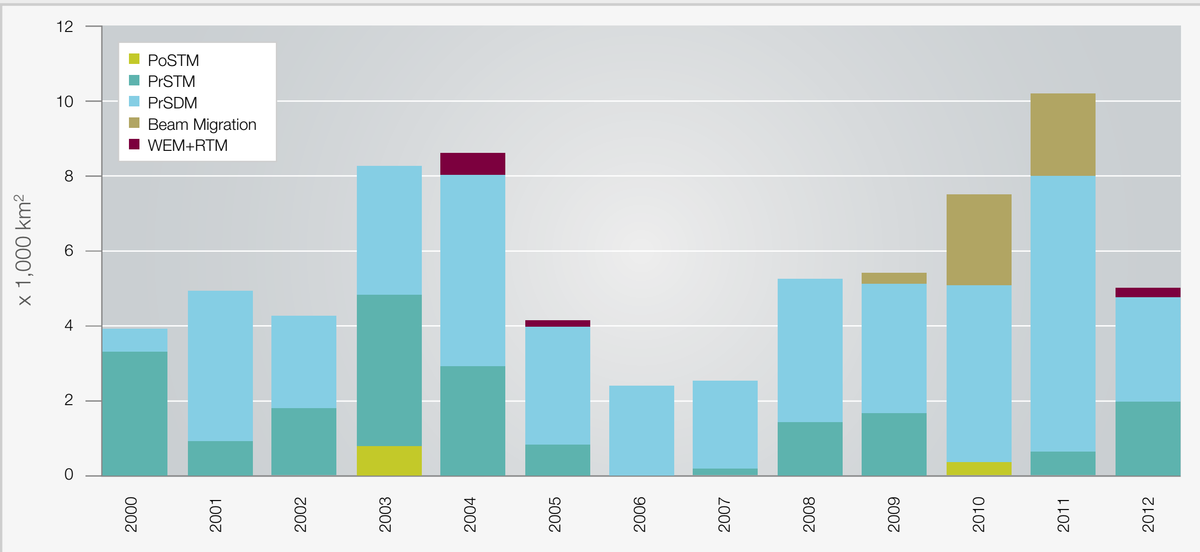
3D reprocessing in the Netherlands by method



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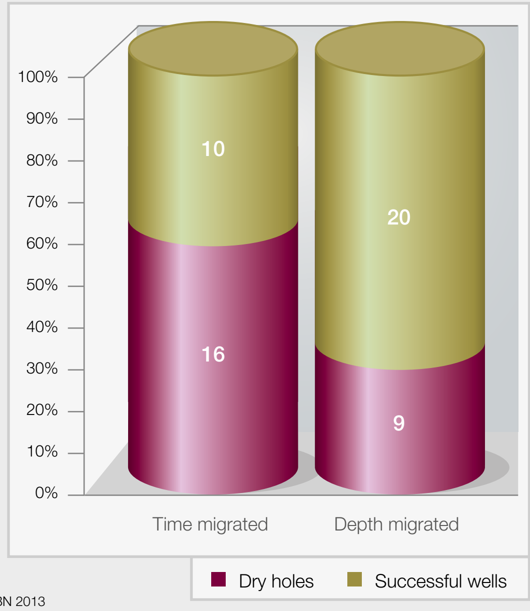
Exploration well success rate by 3D processing type



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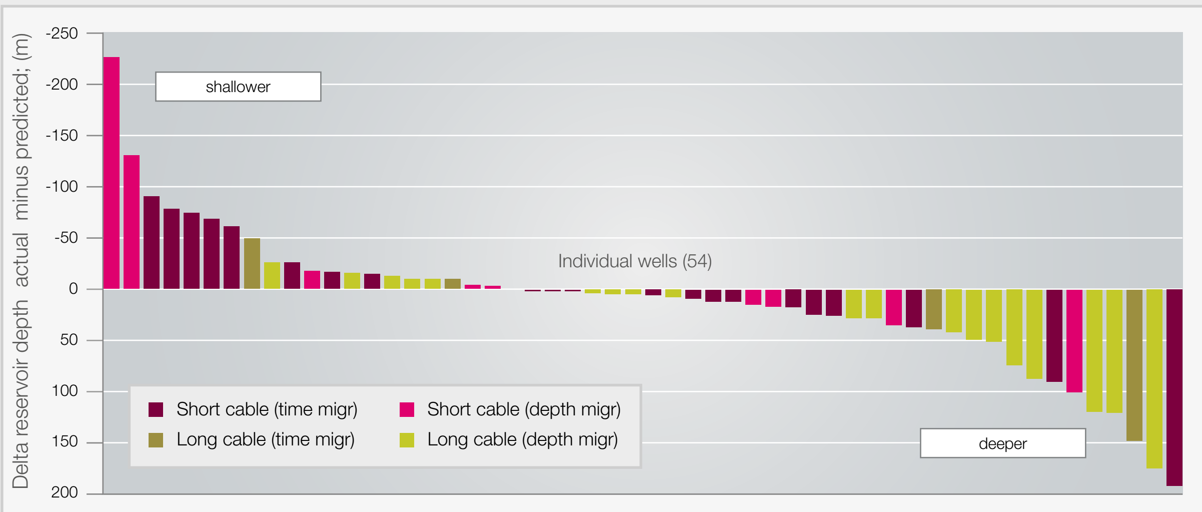
offset against prestack depth migrated data (Kirchhoff, Beam and WEM, etc.). In the long cable surveys, 5 wells were drilled based on time migrated data, 4 of which were dry. 19 wells were planned on long cable data which was prestack depth migrated. Only 3 of these were dry. It should be noted, however, that these 19 wells were mostly drilled in the proliferous K & L area, which is not the case for the 4 dry holes on the time migrated long cable data.

4.3 | Predicting target depth remains difficult

The analysis presented in the previous chapter makes a strong case for long cable acquisition and prestack depth migration, but has the industry become better at depth prediction of the target horizons? It would seem this is not

Delta reservoir depth (actual minus predicted; m) for exploration wells drilled on short or long cable seismic



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the case. In fact, 12 of the 18 wells which came in over 25 m deep to prognosis were drilled on prospects evaluated on long cable seismic. Of the 10 wells which came in deeper than 50 m, 7 were 'long cable wells'. Wells coming in deep does not necessarily imply a failure. Despite the depth difference, 5 of these 10 wells were successful, of which 2 were based on short cable data. An obvious explanation would be that these wells were drilled in very complex areas. This was not the case, however, as the majority were drilled in tectonically relatively quiet areas and/or with little to no diapirism.

It is clear that there is room for improvement in the depth estimates, and that predicted depths should be thoroughly checked. Nevertheless, long cable acquisition and depth processing result in a much better definition of prospects, especially in seismically complex areas like under steep salt diapirs. Target horizons are clearer to interpret and fault definition on long cable seismic is superior. AVO analysis on these data should also give better results, although it is rarely carried out in the Netherlands.

4.4 | New plays in a mature area

Two large exploration studies are executed by EBN: the 'DEFAB' study and the Dinantian carbonates play review.

The DEFAB study is a regional prospectivity screening in the offshore A, B, D, E and F quadrants, started in 2012. In this study, a review of all possible petroleum plays from Chalk to Devonian is combined with the identification of exploration leads. Selected opportunities in currently unlicensed areas will be evaluated in more detail and results will be published in international fora. Preliminary estimates of GIIP contained in this relatively under-explored area are in the order of 100's BCM. Regional mapping of key geological markers is currently ongoing. The recently finished 3D DEF survey is one of the key datasets being used.

The Dinantian carbonate play has hardly been tested in the Netherlands. The data release from two recently drilled wells and the observations from the geothermal well CAL-GT-01, drilled in 2012, created an excellent opportunity to increase the understanding of the reservoir quality in these Lower Carboniferous carbonates. First results have been published already, to be followed by more presentations in international platforms. The review includes prospectivity screening in the Dutch northern onshore and in the Dutch southern offshore. Preliminary estimates of GIIP are in the order of 10's BCM. First results from the Dinantian carbonate review have been published already, and will be followed by more presentations in international conferences. The results are also beneficial to geothermal projects and shale gas exploration.

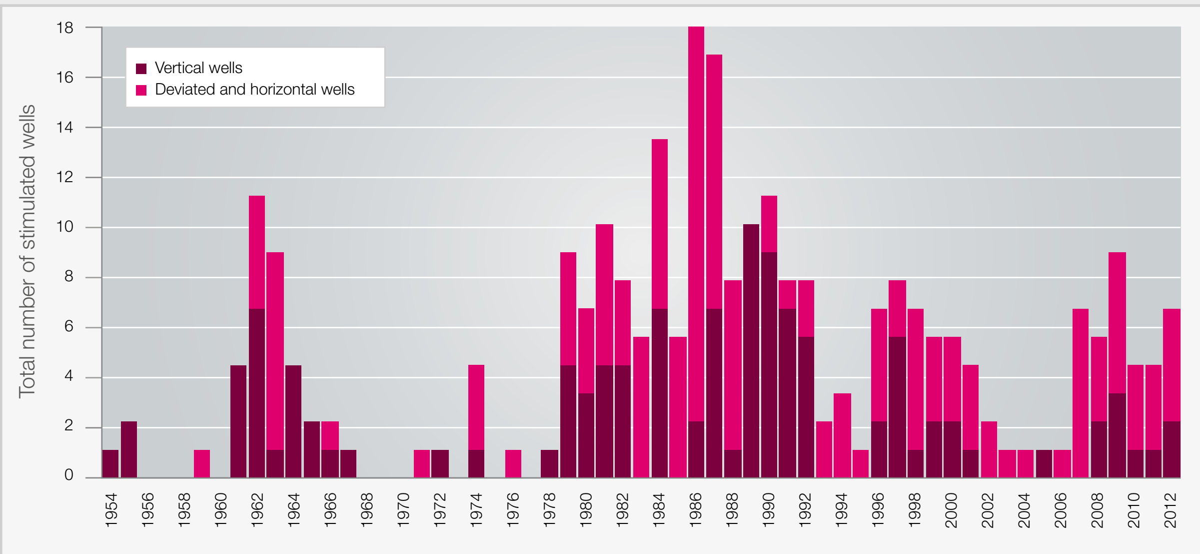
4.5 | Decades of experience in hydraulic fracturing in the Netherlands

Hydraulic fracturing can maximize tight gas reserves and unlock tight gas contingent resources in stranded fields in the Netherlands (portfolio 145 BCM GIIP). Exploration for prospective resources in perceived tight gas areas is uncommon, although the potential may be substantial. Hence hydraulic fracturing has mostly been executed in gas and oil fields that were unexpectedly tight upon discovery. Hydraulic fracturing is a well-established technique. The first well was hydraulically fractured in the

Hugoton gas field in Kansas, USA, in 1947. The technology was quickly adopted in the Netherlands, where the first hydraulic fracture took place in May 1954. Since then, the technique has changed considerably, and the focus has been on hydraulic fracturing of horizontal wells since the early 2000's. This technology enabled the successful development of tight and shale gas /oil in the USA, and increased the appetite for exploration and development of tight and shale gas exploration in the Netherlands. However, it should not be forgotten that hydraulic fracturing could also be applied in conventional reservoirs to accelerate production. Fracture stimulation not only increases the production rate, but can also add reserves that would otherwise have been uneconomical to develop. In the Netherlands, 293 stimulation jobs were performed in 244 wells up to the end of 2012. 223 stimulation jobs were performed in 181 gas wells and 70 stimulation jobs were performed in 63 oil wells. EBN was a partner in 121 jobs in 110 wells out of the total 293 jobs. Of the 244 wells, 202 were stimulated with one or more propped hydraulic fracture(s), 32 were stimulated with acid, and 10 received both acid stimulations and propped hydraulic fractures.

The acid jobs were mostly executed in Zechstein reservoirs, while the propped hydraulic fractures were executed in tighter parts of the Rijnland, Rotliegend and Bunter & Limburg formations. Most of the stimulation jobs were executed in vertical or deviated wells, but in recent years more horizontal wells have been fracked as well.
Since the early eighties, there has been an increase in the number of frac jobs. A decline in the number of fracs is observed in the early 2000's, but since 2007 there has

Total number of stimulated wells since 1954



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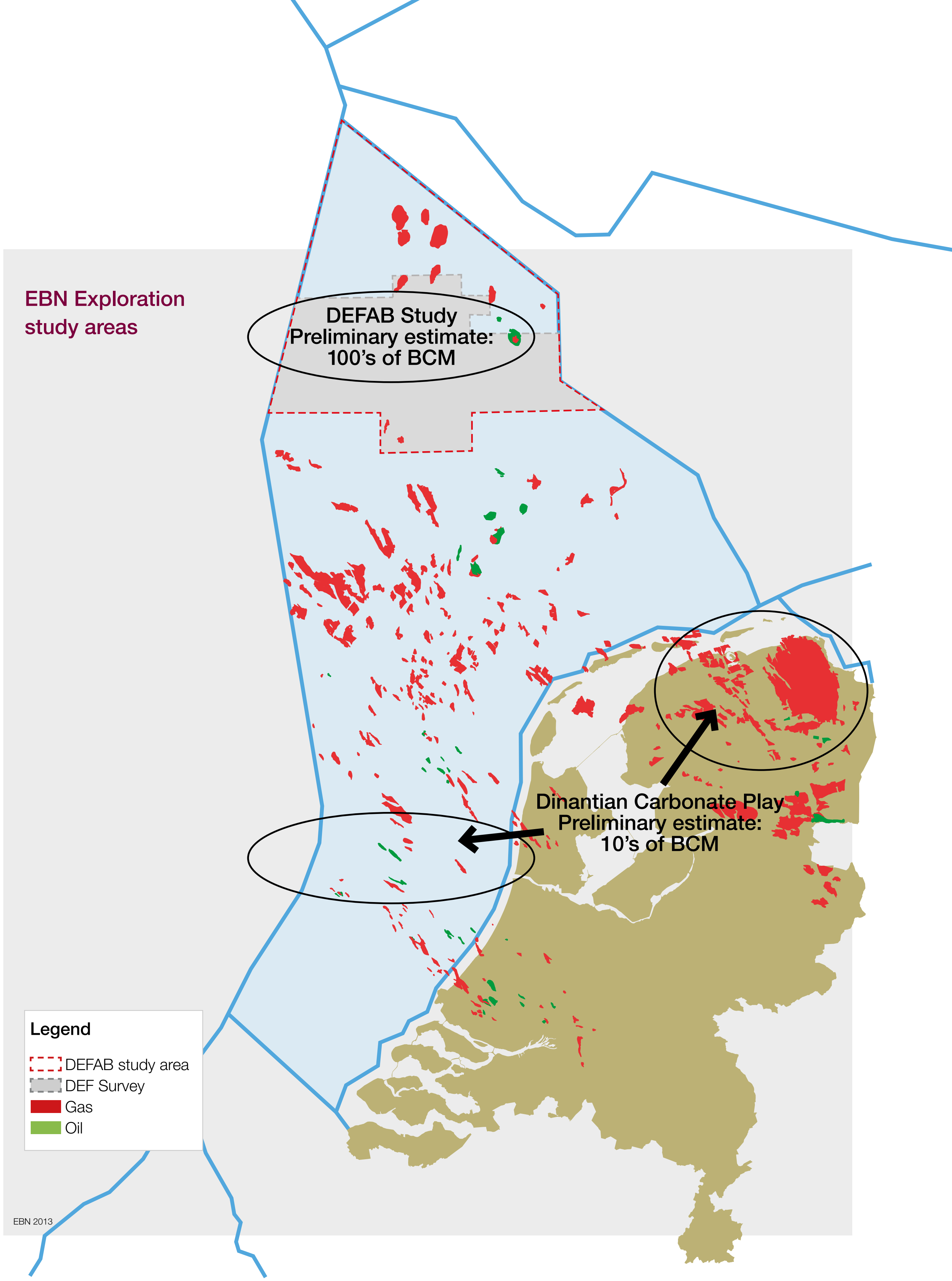
EBN Exploration study areas
DEFAB Study
Preliminary estimate:
100's of BCM
Dinantian Carbonate Play
Preliminary estimate:
10's of BCM
Legend
DEFAB study area
DEF Survey
Gas
Oil
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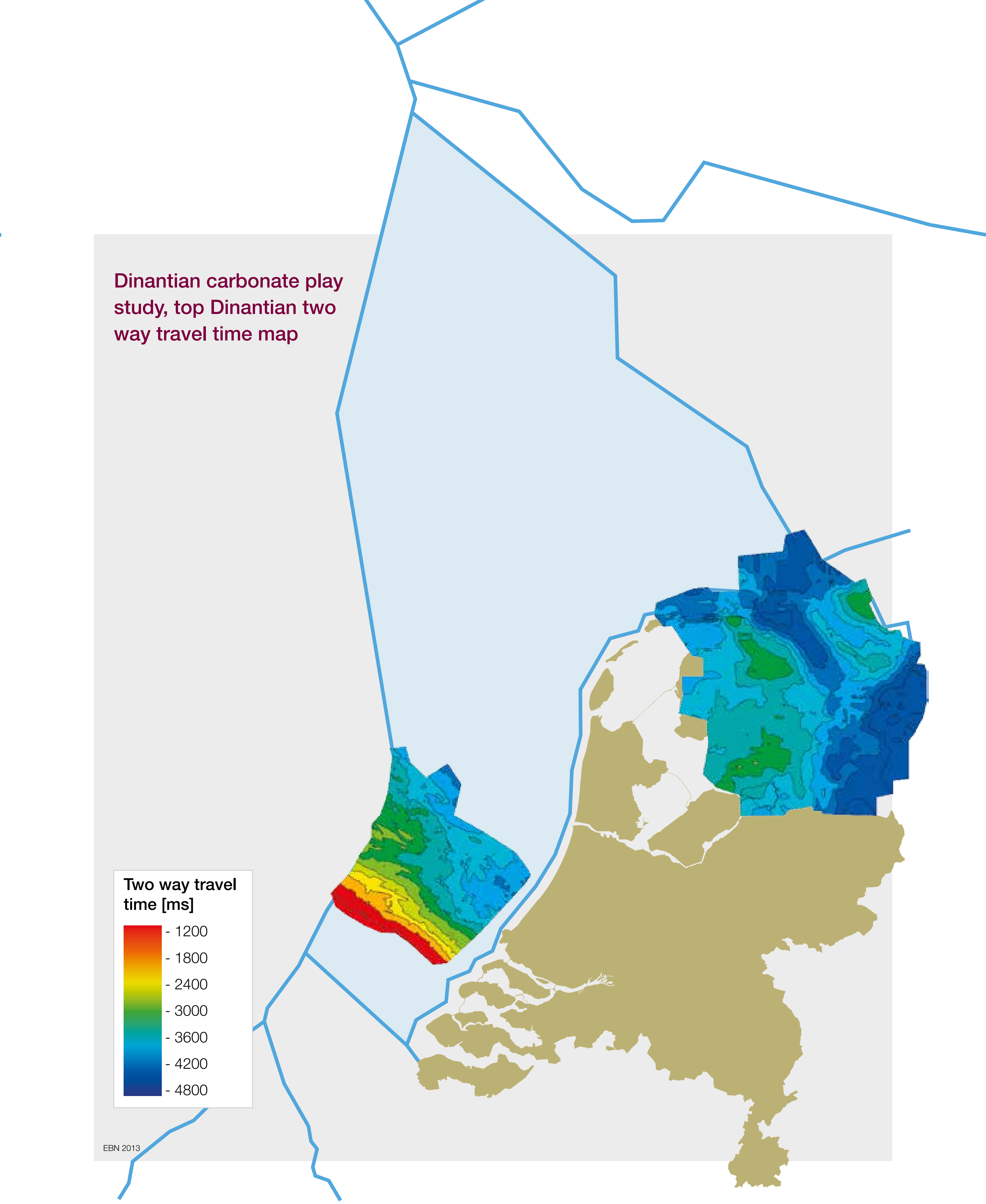
Dinantian carbonate play study, top Dinantian two way travel time map
Two way travel time [ms]
- 1200
- 1800
- 2400
- 3000
- 3600
- 4200
- 4800
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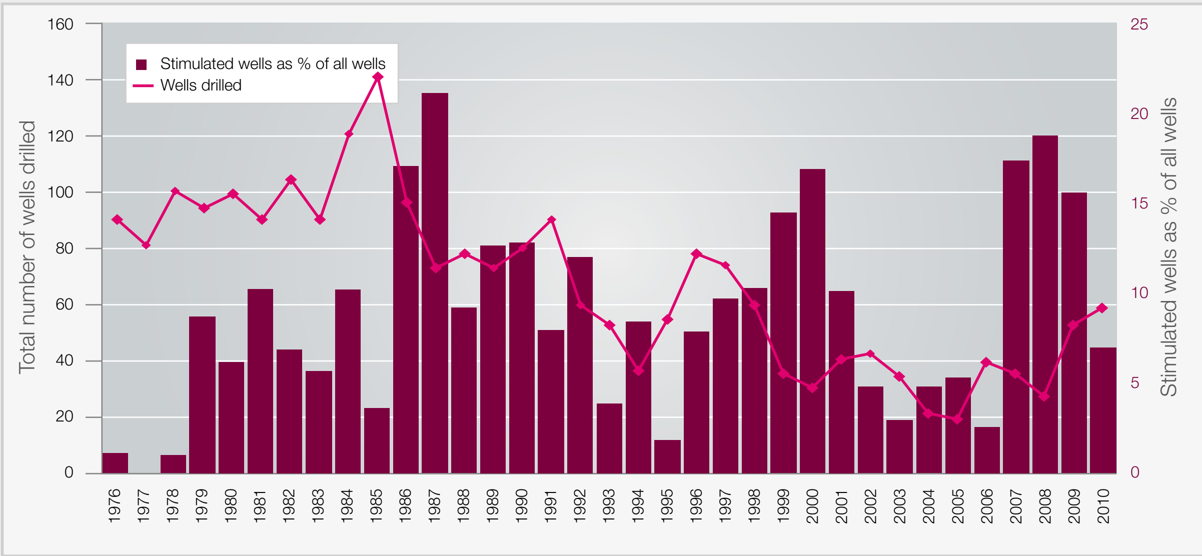
Percentage of wells that are stimulated



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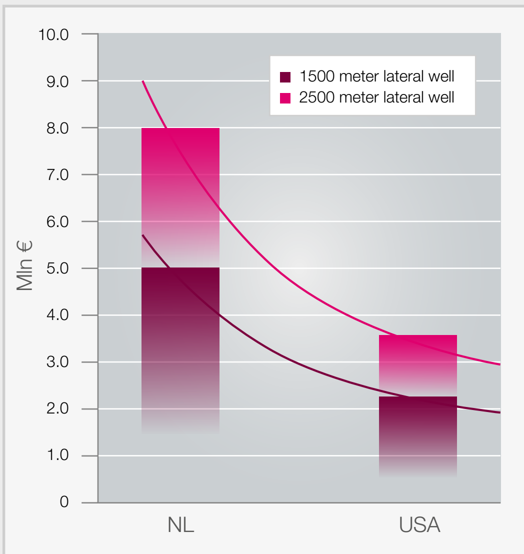
been an increase in stimulated wells. Clearly, hydraulic fracturing is quite common in the Netherlands, although it could be applied on a much larger scale.

4.6 | Costs of hydraulic fracturing likely to decrease

The costs of hydraulic fracturing in Europe are relatively high compared to the costs of hydraulic fracturing in the USA. Although costs might not be the major hurdle to performing more fracs in order to unlock the tight play in the Netherlands, a reduction in cost would facilitate the use of hydraulic fracturing. The shale play development in the USA has caused a significant reduction in cost over the last few years. A large scale application of fracking is

Total fraccing cost estimates for onshore multistage lateral wells



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needed in order to reduce the costs in Europe on the same scale, while continuing innovation is required to strive for greener proppants and fracking fluids

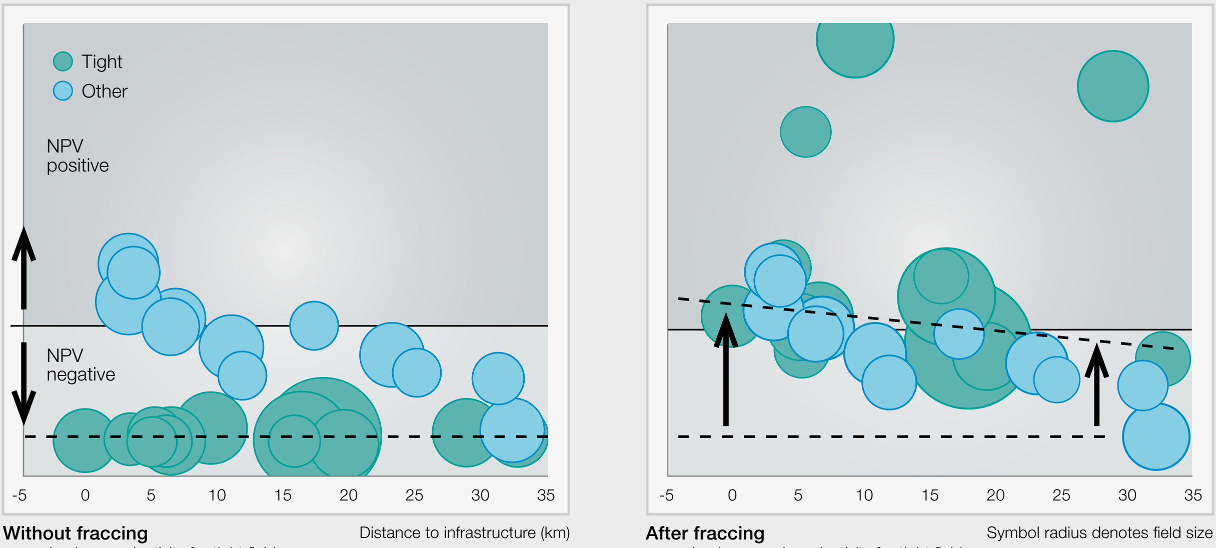
4.7 | Unlocking the tight play

Analysis of the Dutch stranded fields portfolio shows that the dominant obstacle to successful development of these fields is their low reservoir productivity. The EBN definition of a tight field is as follows: a tight field is a field that cannot produce gas in economic rates without stimulation treatments. Not only tight contingent gas resources show potential for development, but the potential in prospects in tight play areas is also substantial. Improvements in technology have created renewed interest in tight gas reservoirs. This has also increased the interest for exploration that targets tight reservoirs.

A Monte Carlo Simulation model has been used for the analysis of volumes in the tight gas portfolio and stranded fields. Gas price, expected hydrocarbon volume, reservoir productivity, development concept, distance to infrastructure and tax regime are all parameters in this simulation.

When applied to the Dutch portfolio of tight stranded fields, the simulation results show that without reservoir stimulation conventional development scenarios are usually uneconomic. These fields are not economically viable even when applying the lowest economic hurdle rates used in the E&P industry.

Economic screening of offshore stranded fields (MSV > 1 BCM)



Without fraccing
assuming low productivity for tight fields

After fraccing
assuming increased productivity for tight fields

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Little information is available about the true productivity of these often older and poorly characterized tight gas fields. Their initial productivity is therefore set at a constant (low) value of 30,000 Nm^3/day. Several case studies have shown that with the reservoir types in question, reservoir stimulation can significantly improve productivity. For this evaluation, it is assumed that productivity can be boosted to 400,000 Nm^3/day. The economic cut-off used is the Value-Investment Ratio (VIR), which is set to a value of 0.2.

Under the current economic conditions, not a single tight stranded field would pass the economic threshold. Re-drilling these fields using multi-frac horizontal wells clearly has an uplifting effect. By applying this technology, an estimated extra 25 BCM of currently stranded gas can be matured. This exercise clearly demonstrates the potential value that fracking technology can provide in developing low productivity assets. EBN actively promotes the use of this enabling technology and, together with various partners, is also involved in scientific research to further improve its effectiveness and minimize its environmental footprint.

A close-up of an inline of the Fugro 'DEF' 3D Survey through the Southern extend of the Central Graben

GLOSSARY

BAU
Business as usual scenario: forecast scenario assuming the E&P industry maintains its current activity level

Bbl
Oil Barrel

BCM
Billion Cubic Meters

BEAM
Beam Migration: a seismic processing method

BOPD
Barrels of oil per day

CAGR
Continuous Average Growth Rate

Capex
Capital expenditure

COP
Cessation of Production

Deliquification
The general term for tech-nologies to remove water or condensates build-up from producing gas wells

E&P
Exploration and Production

EMV
Expected Monetary Value

EOFL
End of Field Life

ERD
Extended Reach Drilling

ESP
Electric Submersible Pump

EXP
Expectation volumes for exploration (POS*MSV)

FMT
Formation Multi Tester

Frac or Fracking
Hydraulic Fracturing

GBS
Gravity Based Structure

GIIP
Gas Initially In Place

GWC
Gas Water Contact

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

Kirchhoff
Kirchhoff Migration: a seismic processing method

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

MMBO
Million Barrels of Oil

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

MW
Mega Watt - unit of power

NFA
'No Further Activity' scenario: forecast scenario assuming no further capital investments

NOGEPA
Netherlands Oil and Gas Exploration and Production Association

Nm^3
Normal cubic meter, measured at 0 °C and 1.01325 bara

NPV
Net Present Value

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

Opex
Operational expenditure

OWC
Oil Water Contact

POS
Probability Of Success: the probability of finding hydrocarbons in a prospect

PRMS
Petroleum Resources Management System: international classification system describing the status, the uncertainty and volumes of oil and gas resources, SPE 2007 with updated application guidelines in 2011

Profit margin
Profit as a percentage of income

PrSDM
Pre-Stack Depth Migration: a seismic processing method

PrSTM
Pre-Stack Time Migration: a seismic processing method

PoSTM
Post-Stack Time Migration: a seismic processing method

Reserve replacement ratio
The amount of proven hydrocarbon reserves added divided by the amount of hydrocarbon produced over a given time period

RT 2013
Real Term 2013, cost expressed in terms of money of 2013

RTM
Reverse Time Migration: a seismic processing method which may improve imaging in areas with steep dips and complex overburden

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 (<1000 m depth, mostly unconsolidated)

Sm^3
Standard cubic meter, measured at 15 °C and 1.01325 bara

Small fields
All gas fields except the Groningen field

SPE
Society of Petroleum Engineers

Stimulation
A treatment performed to restore or enhance the productivity of a well

Stimulation treatments fall into two main groups, hydraulic fracturing and matrix treatments

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

Tight gas
Gas in reservoirs with insufficient permeability for the gas to flow naturally in economic rates to the well bore

TMLS
Tanker Mooring & Loading System

TNO
Netherlands Organisation for Applied Scientific Research

UOC
Unit Operating Costs, opex divided by the amount of hydrocarbon produced over a certain period of time

Velocity string
A small-diameter tubing string run inside the production tubing of a well as a remedial treatment to resolve liquid-loading problems

VIR
Value Investment Ratio

WEM
Wave Equation Migration: a computational intensive seismic processing method which is sometimes used in areas with a very complex overburden

ABOUT EBN

Based in Utrecht, EBN B.V. is active in exploration, production, storage and trading in natural gas and oil and is the number one partner for oil and gas companies in the Netherlands.

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

National and international oil and gas companies, the licence holders, take the initiative in activities in the area of development, exploration and production of gas and oil. EBN invests, facilitates and shares knowledge.

In addition to interests in oil and gas activities, EBN has interests in offshore gas collection pipelines, onshore underground gas storage and a 40% interest in gas trading company GasTerra B.V.

The profits generated by these activities are paid in full to the Dutch State, represented by the Ministry of Economic Affairs, our sole shareholder.

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