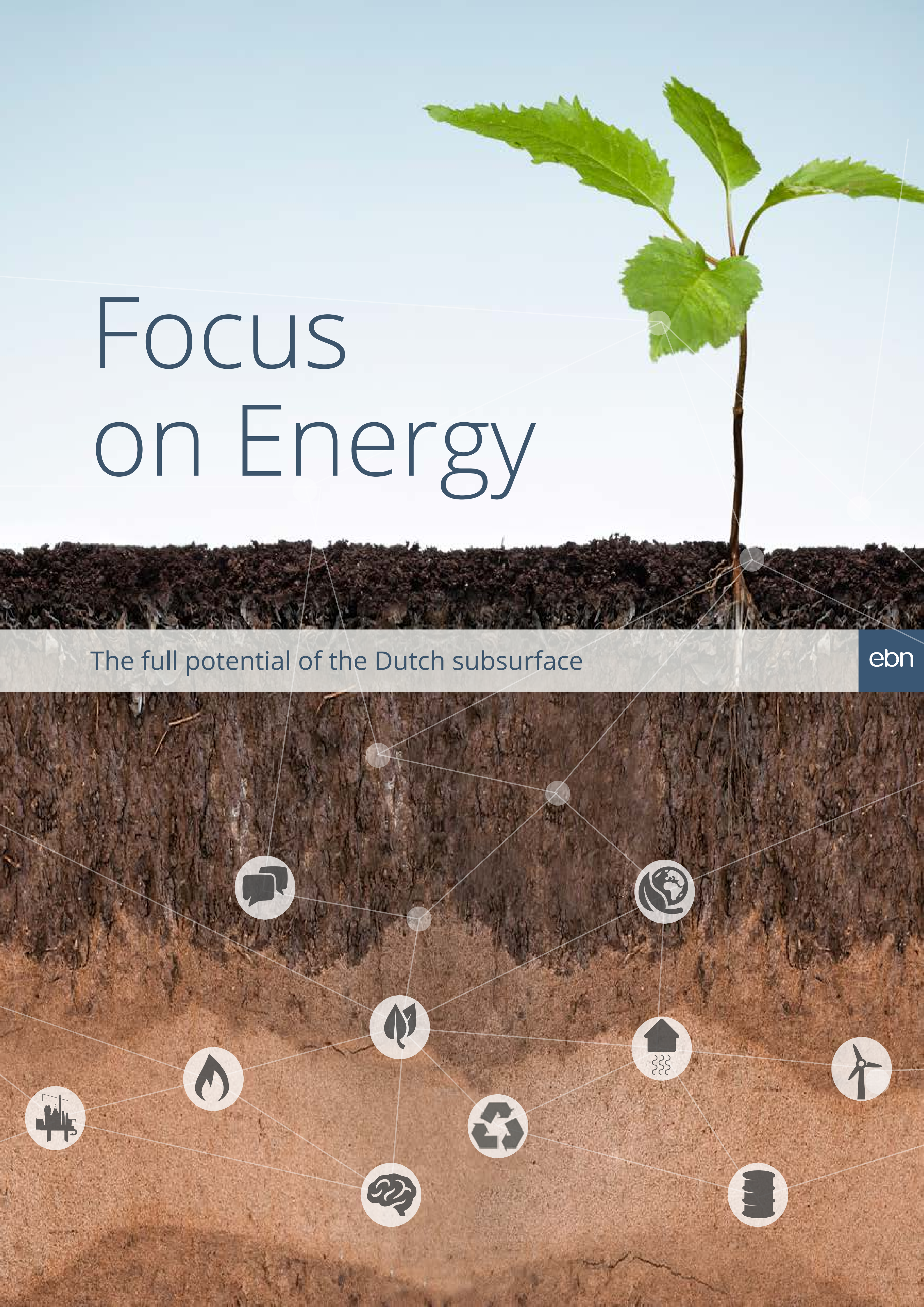
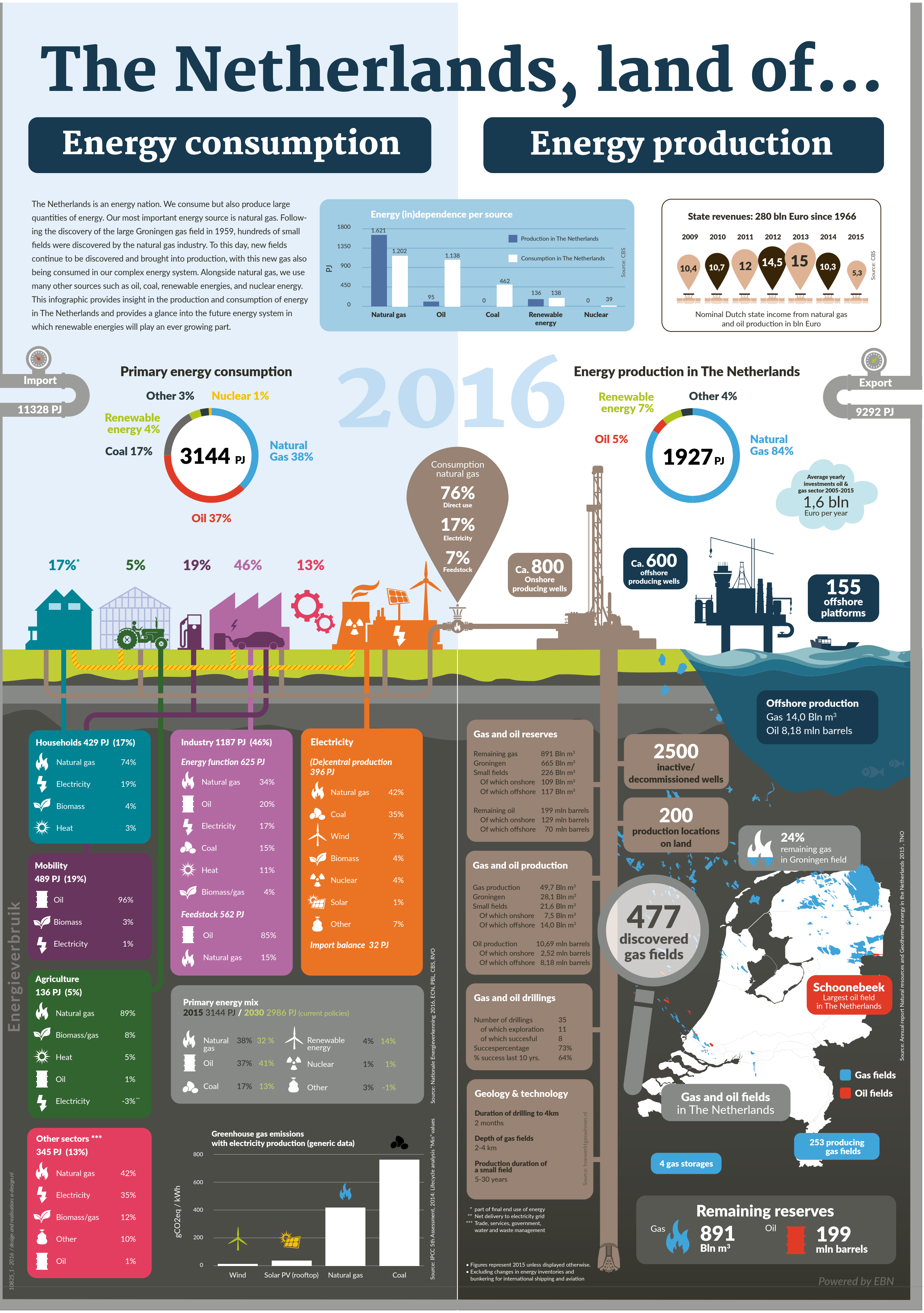
Focus on Energy

The full potential of the Dutch subsurface

ebn





The Netherlands, land of...
Energy consumption
Energy production
The Netherlands is an energy nation. We consume but also produce large quantities of energy. Our most important energy source is natural gas. Following the discovery of the large Groningen gas field in 1959, hundreds of small fields were discovered by the natural gas industry. To this day, new fields continue to be discovered and brought into production, with this new gas also being consumed in our complex energy system. Alongside natural gas, we use many other sources such as oil, coal, renewable energies, and nuclear energy. This infographic provides insight in the production and consumption of energy in The Netherlands and provides a glance into the future energy system in which renewable energies will play an ever growing part.
Energy (in)dependence per source
PJ
1800
1350
900
450
0
1.621
1.202
95
1.138
0
462
136
138
0
39
Production in The Netherlands
Consumption in The Netherlands
Natural gas
Oil
Coal
Renewable energy
Nuclear
Source: CBS
State revenues: 280 bln Euro since 1966
2009 2010 2011 2012 2013 2014 2015
10,4 10,7 12 14,5 15 10,3 5,3
Source: CBS
Nominal Dutch state income from natural gas and oil production in bln Euro
Import
11328 PJ
Primary energy consumption
Other 3%
Nuclear 1%
Renewable energy 4%
Coal 17%
3144 PJ
Natural Gas 38%
Oil 37%
2016
Energy production in The Netherlands
Renewable energy 7%
Other 4%
Oil 5%
1927 PJ
Natural Gas 84%
Export
9292 PJ
Average yearly investments oil & gas sector 2005-2015
1,6 bln
Euro per year
Consumption natural gas
76%
Direct use
17%
Electricity
7%
Feedstock
Ca. 800
Onshore producing wells
Ca. 600
offshore producing wells
155
offshore platforms
17%*
5%
19%
46%
13%
Offshore production
Gas 14,0 Bln m³
Oil 8,18 mln barrels
Households 429 PJ (17%)
Natural gas 74%
Electricity 19%
Biomass 4%
Heat 3%
Mobility
489 PJ (19%)
Oil 96%
Biomass 3%
Electricity 1%
Agriculture
136 PJ (5%)
Natural gas 89%
Biomass/gas 8%
Heat 5%
Oil 1%
Electricity -3%**
Other sectors ***
345 PJ (13%)
Natural gas 42%
Electricity 35%
Biomass/gas 12%
Other 10%
Oil 1%
Energieverbruik
10825_1 - 2016 / design and realisation: a-design.nl
Industry 1187 PJ (46%)
Energy function 625 PJ
Natural gas 34%
Oil 20%
Electricity 17%
Coal 15%
Heat 11%
Biomass/gas 4%
Feedstock 562 PJ
Oil 85%
Natural gas 15%
Electricity
(De)central production 396 PJ
Natural gas 42%
Coal 35%
Wind 7%
Biomass 4%
Nuclear 4%
Solar 1%
Other 7%
Import balance 32 PJ
Primary energy mix
2015 3144 PJ / 2030 2986 PJ (current policies)
Natural gas 38% 32 %
Oil 37% 41%
Coal 17% 13%
Renewable energy 4% 14%
Nuclear 1% 1%
Other 3% -1%
Source: Nationale Energieverkenning 2016, ECN, PBL, CBS, RVO
Greenhouse gas emissions with electricity production (generic data)
gCO2eq / kWh
800
600
400
200
0
Wind
Solar PV (rooftop)
Natural gas
Coal
Source: IPCC 5th Assessment, 2014: Lifecycle analysis "Min" values
Gas and oil reserves
Remaining gas 891 Bln m³
Groningen 665 Bln m³
Small fields 226 Bln m³
Of which onshore 109 Bln m³
Of which offshore 117 Bln m³
Remaining oil 199 mln barrels
Of which onshore 129 mln barrels
Of which offshore 70 mln barrels
Gas and oil production
Gas production 49,7 Bln m³
Groningen 28,1 Bln m³
Small fields 21,6 Bln m³
Of which onshore 7,5 Bln m³
Of which offshore 14,0 Bln m³
Oil production 10,69 mln barrels
Of which onshore 2,52 mln barrels
Of which offshore 8,18 mln barrels
Gas and oil drillings
Number of drillings 35
of which exploration 11
of which succesful 8
Succespercentage 73%
% success last 10 yrs. 64%
Geology & technology
Duration of drilling to 4km
2 months
Depth of gas fields
2-4 km
Production duration of a small field
5-30 years
Source: hoewerktgaswinnen.nl
* part of final end use of energy
** Net delivery to electricity grid
*** Trade, services, government, water and waste management
• Figures represent 2015 unless displayed otherwise.
• Excluding changes in energy inventories and bunkering for international shipping and aviation
2500
inactive/ decommissioned wells
200
production locations on land
24%
remaining gas in Groningen field
477
discovered gas fields
Schoonebeek
Largest oil field in The Netherlands
Gas fields
Oil fields
Gas and oil fields in The Netherlands
253 producing gas fields
4 gas storages
Source: Annual report Natural resources and Geothermal energy in the Netherlands 2015 , TNO
Remaining reserves
Gas 891 Bln m³
Oil 199 mln barrels
Powered by EBN

Contents

Foreword 4
Executive summary 6

1. Energising the transition 8

OUR DUTCH GAS 16

2. Reserves, resources, production & economics 18
- 2.1 Reserves and contingent resources 20
- 2.2 Maturation 20
- 2.3 Stranded fields and prospective resources 21
- 2.4 Industry activity 22
- 2.5 Drilling costs 24
- 2.6 Production 25
- 2.7 Recovery factor 26
- 2.8 Economics 27

3. Exploring for new prospects and play concepts 32
- 3.1 Exploration activity 34
- 3.2 EBN exploration studies 35
  - Ventoux: An Upper Jurassic lead mapped on new seismic data 35
  - Upper Jurassic shallow marine sandstones in the northern offshore 38
  - Triassic reservoir sands in the Dutch northern offshore 38
  - Dinantian carbonates: synergy between hydrocarbon and geothermal projects 40
  - Hydrocarbon shows revisited 42

4. Reservoir stimulation and production optimisation 44
- 4.1 New insights into hydraulic fracturing 46
- 4.2 Gas well deliquification 49

5. Infrastructure in a changing environment 52
- 5.1 Cost reduction initiatives 54
- 5.2 Integrating offshore wind with oil and gas production 54

RETURN TO NATURE 56

6. Decommissioning and re-use of oil and gas infrastructure 58
- 6.1 The decommissioning landscape in the Netherlands 60
- 6.2 Decommissioning: a joint effort 64
- 6.3 Future use of installations: re-using, repurposing and recycling 67
- 6.4 Innovative decommissioning – natural seals 68

NEW ENERGY 72

7. Geo-energy from the Dutch subsurface 74
- 7.1 EBN's involvement in geothermal energy 76
- 7.2 Exploring the potential of ultra-deep geothermal energy 77
- 7.3 Accelerating development of geothermal energy in Brabant 78
- 7.4 Geothermal energy in the 'heat roundabout' 79
- 7.5 Potential synergies between geothermal energy and hydrocarbons 80
- 7.6 Carbon Capture Utilisation and Storage 80

8. Research, development and innovation 85
- 8.1 Joint industry efforts 86
- 8.2 In-house research 88
- 8.3 Student projects 90

Glossary 94
References 95
Acknowledgements 95
About EBN 96
Disclaimer 97

Foreword

The energy transition: From deliberation to deeds

According to the Energy Agenda of the Ministry of Economic Affairs (December 2016), it is “crucial that in the coming years, the remaining, largely marginal, gas reserves on the Dutch part of the continental shelf can still be connected to the infrastructure (platforms and pipelines) present in the North Sea. The stimulation to support the development of small fields will therefore be continued. The reduction of gas production in the North Sea has the inevitable consequence of accelerating the decommissioning, dismantling and removal of the platforms and associated infrastructure. The terrestrial gas-producing locations will also have to be cleared up in the future.”

Two of our strategic pillars connect with this perfectly. In what we call ‘Our Dutch Gas’ we are working on optimising exploration and production of our gas fields, in a sustainable and safe manner. Within the theme ‘Return to Nature’ we are pioneering the effective dismantling and repurposing of abandoned oil and gas platforms.

One challenge arising from the energy transition that touches on another of EBN’s areas of interest is the search for sustainable solutions, for example to meet the demand for both low and high temperature heat. We have therefore added a priority to our strategy: ‘New Energy’. This theme focuses on developing sustainable energy from the subsurface, such as deep and ultra-deep geothermal energy, CCUS and energy storage. We support the Ministry of Economic Affairs in the development of geothermal energy, and together with the Ministry and TNO we explore participation in so-called ‘Green Deals’. Given our knowledge of the subsurface and of investing in subsurface projects, we can be an exceptionally valuable partner in the energy transition.

We believe that it is especially important that the energy transition proceeds smoothly. The run-up phase is over and it is now time for the implementation of the transition and the achievement of tangible results – in other words: there’s an urge to go from deliberation to deeds. The parties that have joined the so-called ‘Transition Coalition’ (of which we are one) are attempting to speed up the energy transition together. The fact that over 60 parties have joined, emphasises the prevailing conviction that we are striving to attain a CO_2-neutral energy system. In order to accomplish this, the subsurface will continue to play an important role in the coming decades. Our focus is therefore no longer so much on oil and gas, but on energy – specifically, energy from the Dutch subsurface, as is reflected by the title of this year’s edition of Focus.

The transition to a sustainable energy mix is a joint effort and we are proud to present interviews with representatives of the Dutch energy world in this publication. Add to these interviews the thorough description of our activities and a glimpse of what the future holds, and we believe that this edition is well worth reading.

We would like to know your ideas about the energy transition and look forward to have a dialogue!

Jan Willem van Hoogstraten,
CEO

Executive summary

The national Energy Agenda foresees gas continuing to play a role in the decades to come. Domestic natural gas is preferable to importing resources, due to its relative low CO_2 emission during production and its important contribution to the Dutch economy. Optimal usage of gas resources ('Our Dutch Gas') is one of the three pillars on which EBN's focus on realising the best value for Dutch geological resources rests. The other two pillars are: taking control of the decommissioning challenge ('Return to Nature'); and optimising geothermal developments ('New Energy').

Our Dutch Gas

- Total reserves from small fields developed with EBN participation declined by 15% in 2016 compared to 2015 due to falling oil and gas (O&G) prices. Reserves accounted for 117 bcm and contingent resources for 181 bcm. The prospective resources included 200 bcm of risked, recoverable volumes from the Rotliegend and 30 – 40 bcm from the Triassic and Carboniferous.
- The maturation figure of 2016 is 9.3 bcm for all small fields, which is comparable to the 2015 figure. Production from small fields was 8% less than in 2015.
- The total invested CAPEX was 50% of that in 2015. Because of the lower costs in the service, supply and construction industries, the potential of the remaining reserves and contingent resources is still high and rewarding. It is expected that investment will recover in the longer run to between some EUR 700 million and EUR 1 billion.
- Due to the low gas price, the net profit margin of small fields has declined sharply, but it is still positive. The unit OPEX has been stable since 2014 at around EUR 0.06/Nm^3. Given the current trends in gas price and expected decreasing production costs per Nm^3, profit margins are likely to recover in 2017.

- EBN sees potential for an upside scenario from enhanced activities such as exploration, tight gas development, increased recovery, infrastructure optimisation and resources that could follow from collaboration within the energy industry. This may add some 150 bcm until 2050.
- Additional exploration opportunities identified by EBN include the Ventoux lead in block F08, which consists of multiple Upper Jurassic targets that can be tested with a single exploration well. Furthermore, recent work shows that the Jurassic Kimmeridgian to Volgian sands from which hydrocarbons are produced in the UK and Germany are also present in the Dutch sector, opening up a potential new play.
- A regional study has found that Triassic Main Buntsandstein reservoir sands do occur north of the main fairway, which shines new light on the Triassic prospectivity in the Dutch northern offshore; 44 untested structures have been identified.
- The Lower Carboniferous Dinantian carbonates have recently become an exploration target for both hydrocarbons and geothermal energy. Evaluation of recent wells and seismic mapping show the potential for fractured and karstified producing reservoirs.
- Tight reservoirs greatly benefit from hydraulic fracturing. Recent modelling shows that the benefits also apply to reservoirs with good permeability, even during advanced stages in their production life. Hydraulic fracturing adds value even when the economic time horizon is short. A portfolio analysis of the hydraulic fractures in the Netherlands reveals that virtually all fracking jobs with pre-fracking production are a technical success and almost always have a positive effect on the NPV.

- Liquid loading is a common challenge for fields in the mature or tail-end production phase. Recent work shows that deliquification methods that use velocity strings and foam have a success rate over 70%, with an NPV of EUR 2 – 20 million per well. These techniques are a very valuable asset and justify the costs of installation.
- The transition to a sustainable energy system is manifested by the current development of wind farms offshore, resulting in an electricity grid to which offshore platforms could be connected. This would eleminate the need for local power generation and subsequently reduce CO_2 emissions and operational costs dramatically, extending the lifetime of the installations.

Return to Nature

- Ultimately, the O&G infrastructure will be decommissioned. Estimated decommissioning costs amount to some EUR 7 billion in total for the Dutch upstream O&G industry. The total infrastructure in line for decommissioning comprises 506 platforms and locations, over 5,500 km of pipelines and about 1400 wells.
- Sustainable dismantling of the infrastructure is key and all the possibilities for future use should be investigated. Naturally, the first choice should be to consider re-using the infrastructure for oil and gas. A second option would be to utilise the infrastructure for alternative purposes, such as power-to-gas, CO_2 storage and compressed air energy storage. Onshore, the re-use of O&G wells for geothermal purposes is being investigated and parts of the pipeline network could be used in the production and transportation of biogas. As a last option, the materials should be optimally recycled.
- It is a shared responsibility of the O&G industry to decommission safely, environmentally responsibly and cost-effectively. Initial priorities in *The Netherlands Masterplan for Decommissioning and Re-use*, as presented in November 2016, are: 1) Establish a National Platform that drives the agenda for decommissioning and re-use, 2) Establish a National Decommissioning Database, 3) Promote effective and efficient regulation, and 4) Share learnings. These priorities have been implemented within a JIP between nine operators and EBN.

New Energy

- With its potential for geothermal energy, Carbon Capture Utilisation and Storage (CCUS) and energy storage, the Dutch subsurface can contribute significantly to a sustainable energy mix. EBN will explore synergies with the development of geothermal energy and will facilitate the development of CCUS.
- Ultra-deep geothermal energy (UDG) could deliver an important contribution to the transition to a sustainable heating system, especially for industrial processes where higher temperatures are necessary. The first step in UDG development will be to explore the Dinantian play in three regions. The ultimate objective is to unlock the UDG potential in the safest, most cost-effective way. EBN anticipates that there will be ample room for synergy between the three sub-plays, resulting in increased quality and reduced costs.
- Because of its expertise in approaching subsurface projects, EBN has worked together with TNO and Geothermie Brabant B.V. on two concepts: integral project development and the introduction and application of the portfolio approach for geothermal projects in Brabant. The combination of both has great benefits for geothermal projects.
- The geothermal and hydrocarbon sectors have joined forces to investigate how synergies might be exploited. EBN is hosting an exploratory roundtable discussion on behalf of DAGO, Stichting Platform Geothermie and KVGN regarding synergies between gas and geothermal energy.

Energising the transition

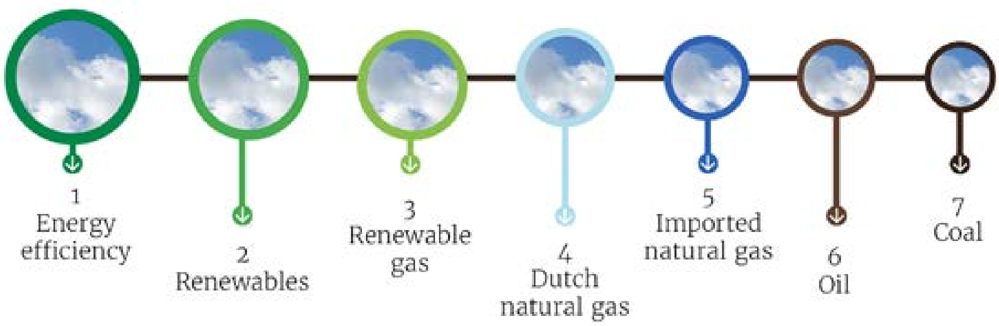
Fossil fuels currently meet 92% of the demand for energy in the Netherlands, revealing the great challenge for the transition to a climate-neutral energy system. Natural gas currently accounts for 38% of the Dutch primary energy mix – a share that has remained fairly constant in recent decades. What particularly defines the versatility of natural gas are its transportability, its capacity to achieve high temperatures when combusted and its chemical structure. On top of this, due to its historical availability, natural gas is the main source of energy for households, industry and agriculture in the Netherlands, and it is used to generate 42% of Dutch electricity. Moreover, it is an important feedstock for several industries. The national Energy Agenda published late 2016 by the Ministry of Economic Affairs foresees gas continuing to play a role in the decades to come.

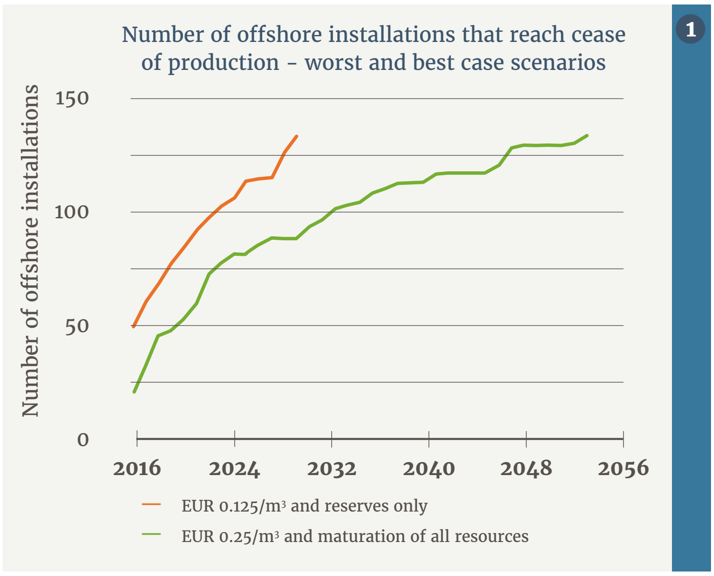
Making the energy system more climate-friendly means meeting the energy demand with the right type of supply. Natural gas occupies the middle rung on the 'the ladder of seven', a system ranking the options for energy supply with respect to CO_2 emissions developped by the national Dutch gas association KVGN. Top priority is 1) energy saving, followed by using 2) renewable sources, 3) green gas, 4) Dutch natural gas, 5) imported natural gas, 6) oil and 7) coal.

Given the importance of natural gas for meeting the demand for energy in the Netherlands, the best way to reduce CO_2 emissions is to use Dutch gas. The Energy Agenda confirms that domestic natural gas is preferable to importing resources, due to the relative low CO_2 emission during production in the Netherlands (see Focus 2014). Furthermore, domestic production contributes significantly to the Dutch economy.

Additionally, the hydrocarbon assets and infrastructure, as well as the knowledge and expertise of the Dutch subsurface resulting from decades of oil and gas (O&G) production, could be used effectively to reduce CO_2 emissions by developing alternatives to natural gas. EBN and other parties in the gas sector have defined a programme in which the strengths of the natural gas value chain are exploited to speed up sustainable projects. For this endeavour to succeed, far-reaching collaboration, innovation and creativity are required. As part of EBN's renewed strategy, EBN will explore synergies with the development of geothermal energy and will facilitate the development of CCUS (Carbon Capture Utilisation and Storage). Other projects are offshore energy integration, renewable gas, LNG in heavy transport and hybrid heat pumps.

Ladder of seven





However, the Dutch gas industry faces many challenges. Earthquakes in Groningen and damage due to gas production from the Groningen field lead to concerns of safety. Concern is also being expressed about small field exploration and production projects. NOGEPA is currently working on a code of conduct to improve stakeholder engagement by operators active in the Netherlands. The current situation regarding financial investments in exploration and production in the Netherlands is rather bleak. In 2015 and 2016 the average gas price fell significantly, causing a drop in investments. Maintaining high investment levels, is important to ensure sufficient resource maturation and reserve replacement and, consequently, to guarantee future production levels. Furthermore, if gas prices remain low, a significant number of platforms and facilities will operate at a loss and will risk being decommissioned at rather short notice. Once the infrastructure has been removed, the associated resources can never be economically developed and could be lost forever, even if gas prices would rise in the future.

> The Dutch gas sector intrinsically bears a responsibility to adapt to New Energy realities. To start a dialogue with stakeholders based on transparency and facts, EBN has developed an energy infographic as shown on the inside front cover. Created from publicly available data from renowned institutes, the graphic accurately depicts the role of energy sources in Dutch end use and the relation to energy production in the Netherlands.

The major impact of trends in gas price and resource maturation on the viability of the offshore infrastructure is illustrated in Figure 1, which was published in Focus 2016. The difference between the worst and best case scenarios is approximately 100 bcm of reserve maturation, which has a significant impact on the COP (cessation of production) dates and remaining asset life. Dismantling the infrastructure too rapidly will limit the options for using O&G infrastructure to support the transition to a sustainable energy system. Furthermore, this could negatively impact the cost effectiveness of decommissioning infrastructure, as dismantling activities will face more time pressure. On the other hand, the low gas price environment has sharpened the focus on reducing unit OPEX levels. In 2016, several operators succeeded in reducing these costs, thereby improving the likelihood of production remaining economically viable in the future. The recent dramatic fall in rig rates, coupled with the introduction of innovative investment solutions, has opened up opportunities for new developments against lower costs. In order to be able to maintain

Our Dutch Gas

Return to Nature

New Energy

EBN creates value and facilitates the transition to a sustainable energy system

Based on the developments in the upstream O&G industry described in this chapter, as well as those in the energy policy arena, EBN has honed its strategy to accommodate the changing context. EBN focuses on creating value from geological resources in a safe, sustainable and economically sound manner. This strategy has three main pillars: optimal usage of Dutch gas resources ('Our Dutch Gas'); taking control of the decommissioning challenge ('Return to Nature'); and strengthening, improving and developing geothermal energy ('New Energy').

adequate production and maturation levels, it is essential that the industry continues to focus on further cost reduction, and on supporting technical and innovative solutions and knowledge sharing.

This edition of Focus elaborates on several developments and activities that facilitate EBN's strategy. In Chapter 2 the reserves and resources are described, as well as current activities and the related economics. The results of exploration studies regarding promising Dutch prospects are illustrated in Chapter 3. Chapter 4 focuses on techniques available to maximise the economic production of oil and gas in mature fields, and the dynamics and potential of the offshore infrastructure are presented in Chapter 5. These first chapters together represent 'Our Dutch Gas'. The objectives and activities of decommissioning and re-use are illustrated in Chapter 6, and represent 'Return to Nature'. Furthermore, 'geo-energy' is represented by Chapter 7: Developments and challenges regarding geo-energy from the Dutch subsurface. Finally, Chapter 8 describes EBN's research, development and innovation activities.

Groningen production

The merits of production from the Groningen field have been overshadowed by induced seismicity, which has had a major impact on the day-to-day lives of many inhabitants of the area. Since 2013, the Dutch government has focused on reducing the yearly production level and has been pursuing safer production methods as well as damage control and compensation.

Over the last few years, production has decreased significantly and fluctuations in production have been removed. EBN developed a variety of activities to contribute to a safer and improved production plan of the Groningen field, in line with its mission and the policy of the Minister of Economic Affairs. Several studies focused at contributing to a better understanding of the processes in the subsurface around the earthquake-prone area. This work complements the investigations carried out by NAM and other parties such as State Supervision of Mines and KNMI. See Chapter 8 for more information on these studies.

The energy supply of the future

Interview with Diederik Samsom, former leader of the Dutch Labour Party (Partij van de Arbeid)

After graduating from Delft University of Technology with a degree in physics, specialising in nuclear physics, Diederik Samsom worked for Greenpeace and was director of the Dutch energy supplier Echte Energie (now Greenchoice). From 2003 to 2016 he was a member of the Dutch House of Representatives; from 2012 to 2016 he was parliamentary leader of the Dutch Labour Party. During his time in the House of Representatives he was very involved in energy issues.

What sparked your interest in the energy sector?

I was 15 years old when the Chernobyl nuclear disaster occurred. In the Netherlands we didn't actually suffer much from this disaster, but the dramatic event was my wake-up call. From that moment on, I knew that everything had to be different – that if we didn't change our energy system, things would go wrong for planet earth. And then when I read Thea Beckman's book *Kinderen van Moeder Aarde* (Children of Mother Earth) I knew for sure that I wanted to work for Greenpeace, to do my bit. In the years that followed, the energy question dogged me.

Together with Jesse Klaver (currently leader of the Green Left party) you submitted a proposal for a climate Act that would help attain a completely sustainable energy mix in the Netherlands by 2050. Is such an energy supply attainable?

I think so – and even before 2050 – but maybe I'm somewhat optimistic. Policymakers usually tend not to want to outline exactly what the energy mix would look like, but now we are able to sketch out clearly what will happen. First, we'll have about 35 gigawatts (GW) from offshore wind. We currently aim for 6 GW offshore wind in the Netherlands. The amount of wind parks should increase to 35 at sea and six to eight on land. Further, I think that solar energy will supply up to 60 GW in 2050. That's bizarrely massive – in total, enough for the entire built-up environment. As well as this we still need to have over 6 GW of energy from geothermal sources to meet the total demand for heat. It's important to develop ultra-deep geothermal energy quickly, particularly for industrial purposes. There would then be a system running on geothermal energy, a fairly stable source, and on sun and wind, both of which are not stable. As a back-up system for the longer-term variations, power-to-gas is needed: about 4 GW. Finally, we need green gas made from biomass: about 25 GW. Green gas is needed not just for energy but also as a new renewable feedstock for the chemical industry.

Our energy supply currently consists of about 75% oil and gas, 17% coal and 3 – 4% renewables. What exactly needs to happen to achieve a sustainable energy mix by 2050?

I think that in 2050, gas will no longer be extracted in the Netherlands. Offshore wind energy and

© Tessa Posthuma de Boer

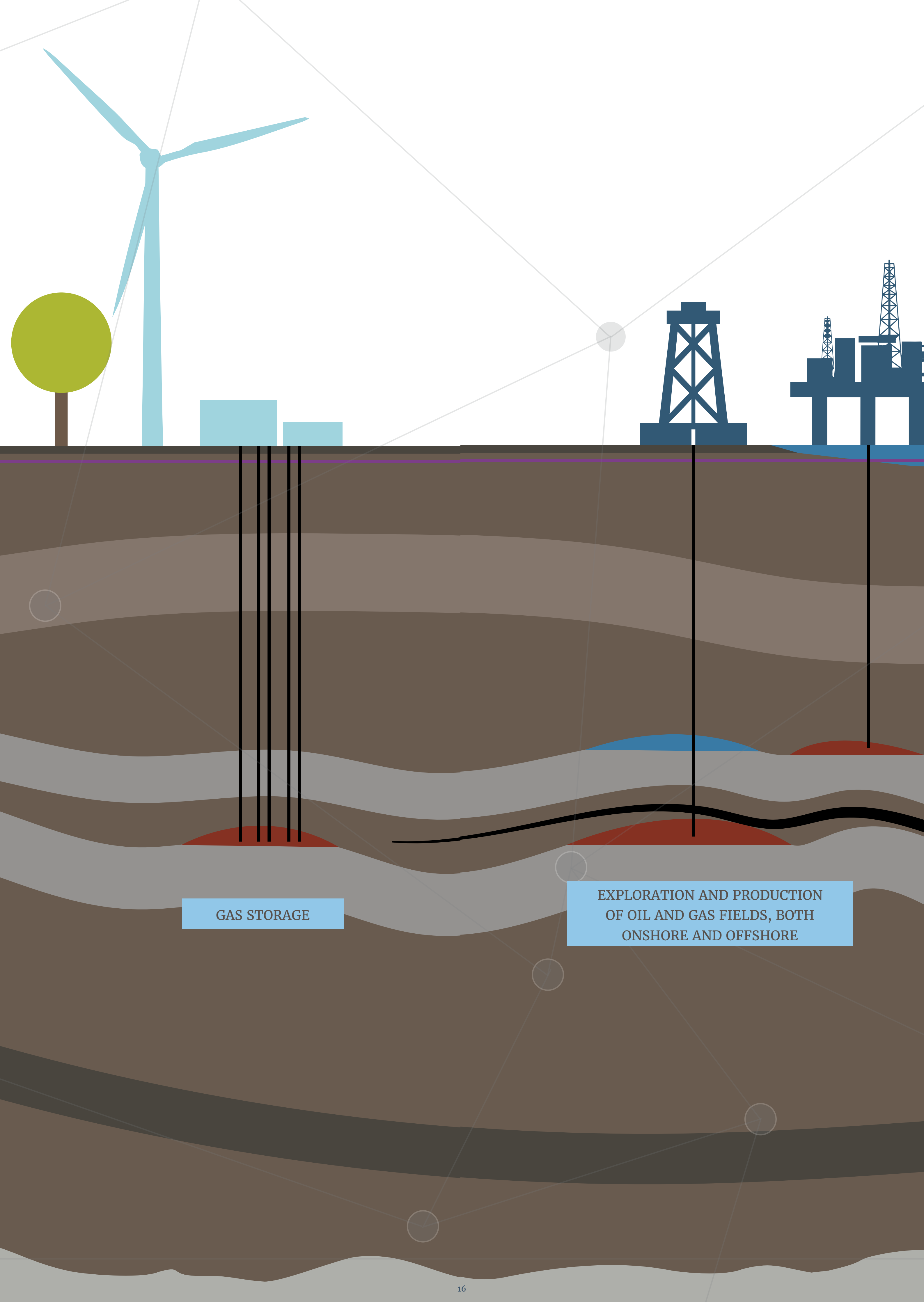
solar energy are relatively simple, because we've already made good progress here. Geothermal energy is a bit more complicated, but the biggest challenge is green gas. Transitioning our entire economy will also be a big job. We need to speed up the current transition. Regarding geothermal energy, we need to ensure that before 2025 it's in the same situation as offshore wind is now: (almost) unsubsidised, with a network that we as a society have paid for. The big challenge is to develop a new model in which production, transport and delivery are linked to each other. Gasunie should transform itself from a gas mover into a heat mover, and EBN from an oil and gas driller to a geothermal driller.

So you see EBN as having a clear role in the transition to a sustainable energy mix?

Yes, I advocated this years ago. I foresee EBN being given the statutory mandate to participate wherever energy is obtained or stored in the subsurface. This should result in EBN participating in at least as many projects as it does now in the oil and gas sector. Of course, wells will have to be drilled for this and, as with all drilling, there are public issues involved. That's exactly why EBN has such a pivotal role to play. EBN can represent the public interest and act like a catalyst by co-investing and contributing knowledge and experience. That's EBN's strength. Geothermal energy will be EBN's new pillar, but EBN should also play a role in gas storage. The gas that's converted with power-to-gas for the energy sector as well as the chemical industry will have to be transported and stored and the gas that's co-produced with geothermal energy will have to be processed. I hope that in the future, storage of CO_2 will not be necessary and that all captured CO_2 can be used. But I think that to drastically reduce CO_2 emissions and achieve negative emissions, storage will be necessary.

What are you yourself going to contribute to this sustainable future?

My wake-up call when I was 15 will always play a role in my life. So I'll also carry on fighting for a sustainable energy supply. In what form I don't know for sure yet, but my ambition is to leave the next generation an earth as beautiful as the one we found.


GAS STORAGE
EXPLORATION AND PRODUCTION OF OIL AND GAS FIELDS, BOTH ONSHORE AND OFFSHORE

Our Dutch Gas

The Netherlands still possesses a considerable potential of oil and gas reserves and resources. Exploration and production in a cost-efficient and safe and sustainable way is continuing to provide the necessary energy from hydrocarbons during the energy transition. Whenever sustainable alternatives are insufficient, Dutch gas will remain the most preferred option. EBN will continue to encourage the oil and gas industry to innovate and develop new knowledge, and to urge its partners to improve sustainability performance.


WWW.AMPELMANN.NL
KROONBORG
DELFZIJL
WAGENBORG

Reserves, resources, production & economics

2

All the on- and offshore fields in the Netherlands except for the giant Groningen field are referred to as "small gas fields". These fields continue to be the core of the Dutch O&G industry. In this chapter, the status of the small fields portfolio is evaluated. Small gas field production has been declining for over a decade. EBN believes that if investment levels pick up again, this decline can be slowed down or even halted. The project portfolio of opportunities identified in or near fields is still rich, as is the potential for exploration in underexplored plays or near the established margins of the known gas plays (Chapter 3).

2.1 Reserves and contingent resources

In 2016, the industry was largely influenced by falling O&G prices. The gas price declined gradually and is now half the price in 2012. The lower gas prices have affected EBN's reserve base. At the end of 2016, the total developed reserves from small fields in which EBN is participating were 117.1 bcm, compared to 143.4 bcm at the end of 2015 (Figure 1). Total gas production from small fields was 20.6 bcm in 2016. In 2016, far fewer projects matured than in the previous year: only five gas fields were brought into production compared to 14 in 2015. A second reason for the reserve decline is that the tailend volumes of some of the mature gas fields were evaluated as sub-economic at current gas prices, and so these volumes were transferred to contingent resources. The contingent resource base increased by 2 bcm to 181 bcm, which still has high potential for recovery. These volumes are either not technically mature yet or are currently not economically attractive.

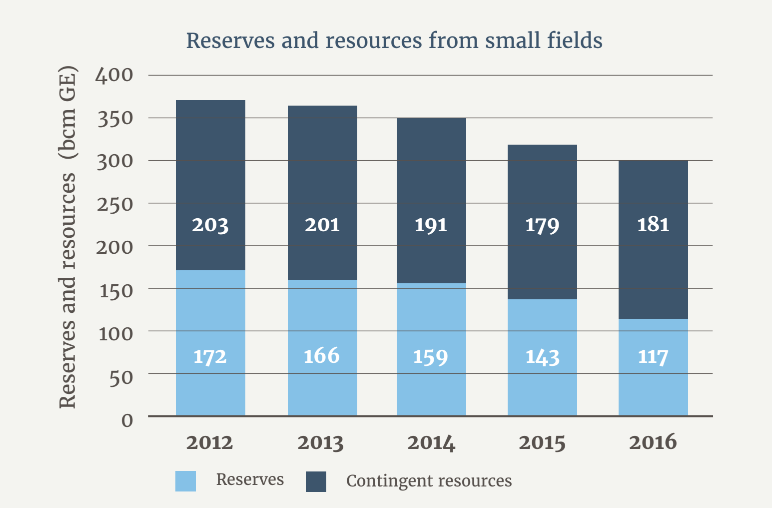
In 2016, the gas price in the Netherlands reached its lowest value since 2010. In this challenging commercial environment, many projects were being delayed. This decrease in price, however, sparked a pressure on costs. Under current conditions, several of the opportunities in the contingent resource portfolio are therefore still as attractive as they were before the downturn in the industry. EBN foresees more gas field developments over the next few years. EBN's focus to stimulate future O&G developments will be on five themes:

1. Sharing knowledge to contribute to reducing CAPEX and OPEX;
2. Reducing the time lag on project start-up;
3. Selecting high-ranking exploration areas;
4. Supporting technological and innovative solutions;
5. Contributing to the energy transition by stimulating synergies within the energy industry.

2.2 Maturation

Maturation is defined as the amount of known resources moving into the reserves category as a result of investments and planned projects. In 2016, the combined volumes of resources matured to

1



reserves plus reserves from new projects was around 13.7 bcm, which is higher than in 2015 and thereby breaks a four-year decline (Figure 2). On the downside, 4.4 bcm moved from reserves to the resource category, mainly as a result of project cancellations or extended delays. This leads to a maturation figure of 9.3 bcm for all small fields in 2016, which is comparable to the 2015 figure.

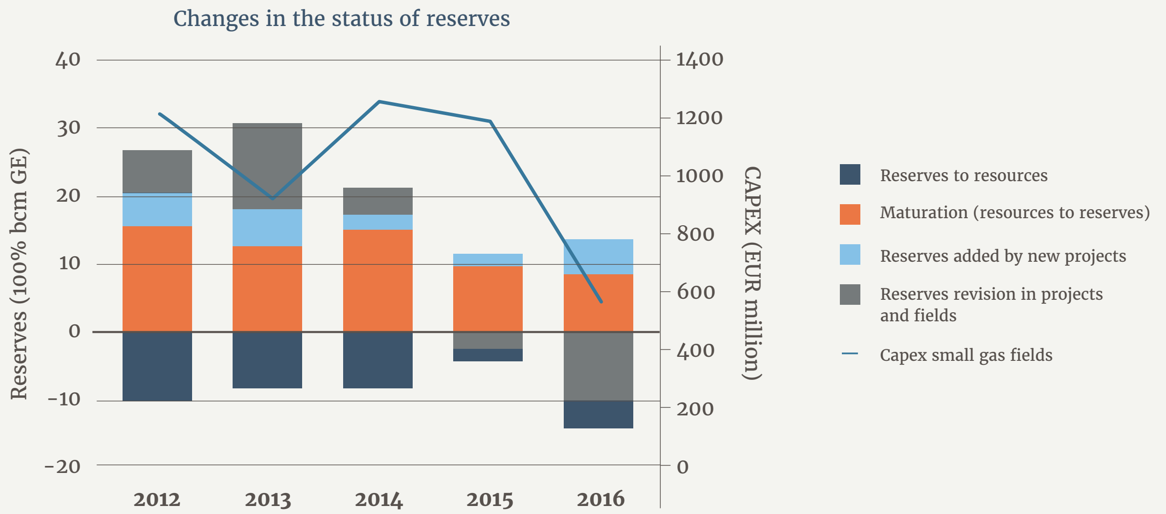
However, there is also a large negative adjustment of the recoverable reserves within producing fields. Due to the volatility of this category and the direct dependence on gas price, EBN does not include these volumes in the maturation numbers, but they do contribute to the adjusted reserve database, as can be seen in Figure 2. In years with good gas prices, less gas was expected to be left in the uneconomic tail-end of the production due to anticipated COP dates further in the future. In 2016 however, the large downward revision of reserves in known fields was seen, primarily because of COP dates moving forward in time. These volumes, combined with the loss of reserves due to cancelled or executed projects, fully offset the amount of gas matured.

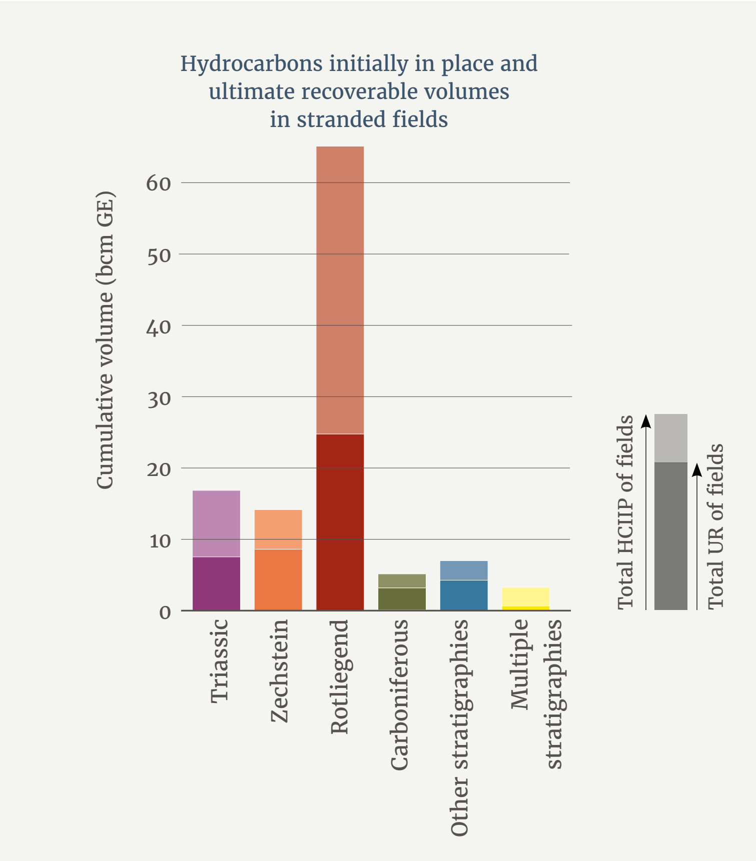
With a total invested CAPEX of slightly less than EUR 600 million in 2016, investment was 50% of that in 2015. Excluding COP date adjustments, it is encouraging that the level of maturation has not dropped in proportion to the decline in CAPEX. This can be interpreted as being a direct result of lower costs in the service, supply and construction industries. Rig rates have also dropped considerably, resulting in significantly decreased costs for drilling wells.

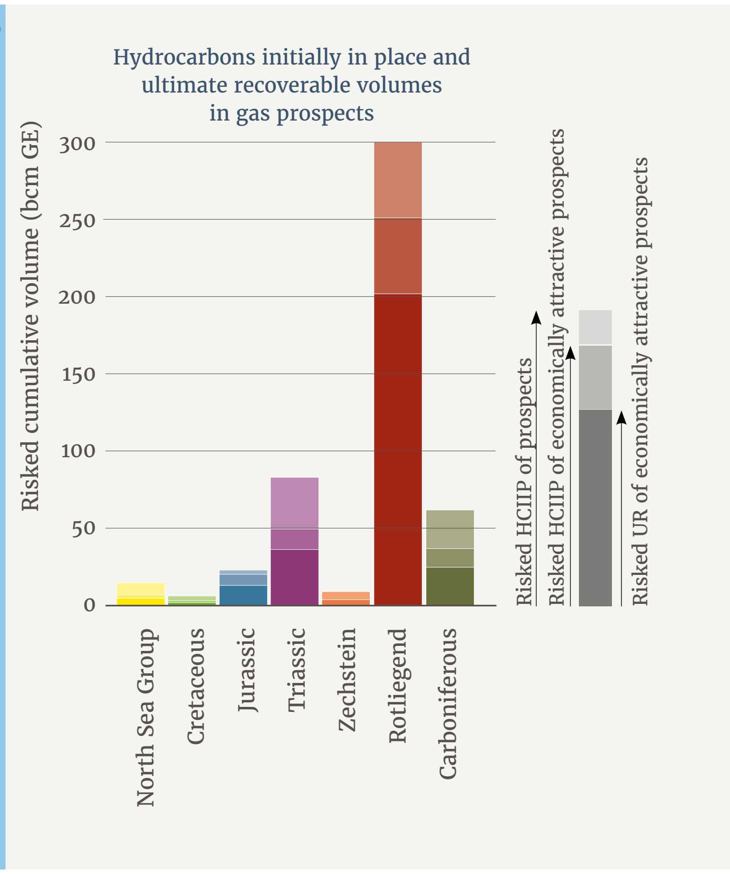
2.3 Stranded fields and prospective resources

Stranded fields are gas discoveries for which no plans for development have been defined yet. Obviously, the designation 'stranded' is not immutable, since options for developing such fields are often being revisited. In the analysis in this chapter, EBN includes all stand-alone proven gas accumulations that do not yet count as reserves. The largest stranded gas resources are in the Rotliegend, the dominant play in the Netherlands. The expected ultimate recovery for these fields is small compared to their in-place volume; poor reservoir quality is one of the main reasons these fields have not yet been developed. Of the more than 65 bcm of gas in place in the Rotliegend stranded fields, currently only 25 bcm is expected to be recoverable (Figure 3). However, there is significant scope for increasing these recoverable volumes by using optimised development concepts for these types of fields, such as horizontal wells and reservoir stimulation technology (Chapter 4).

2







Each year EBN re-evaluates the prospective resources portfolio on the basis of expected future gas prices and cost levels, resulting in a ranking based on likelihood of being economic. Analysis of the prospective portfolio with respect to stratigraphic level clearly shows that the vast majority of the volume is in the Rotliegend play (Figure 4). The full Rotliegend portfolio is expected to contain 300 bcm (risked), of which over 250 bcm is expected to be present in prospects with potential economic viability. In turn, 200 bcm could be recovered from these prospects. The Triassic and Carboniferous plays are expected to yield 30 to 40 bcm of risked recoverable resources, considering only the economically attractive prospects.

These substantial volumes are not reflected in the number of exploration wells drilled in 2016 (section 3.1). There are three reasons for this. Firstly, most of the individual prospects are small and their economic development is attractive only if low-cost development alternatives are used; there is no room for cost overruns or for finding low case volumes. Secondly, onshore operators are facing increasingly complex licensing trajectories, causing them to pursue fewer exploration opportunities, particularly when new drilling locations are required. A final reason is that in these figures, the expected economic lifetime of the vital infrastructure through which the gas is to be evacuated has not yet been taken into account. Sometimes, exploration opportunities are not pursued because of imminent COP dates, yet other operators successfully manage to extend the COP dates of their facilities by unlocking near-field exploration opportunities.

2.4 Industry activity

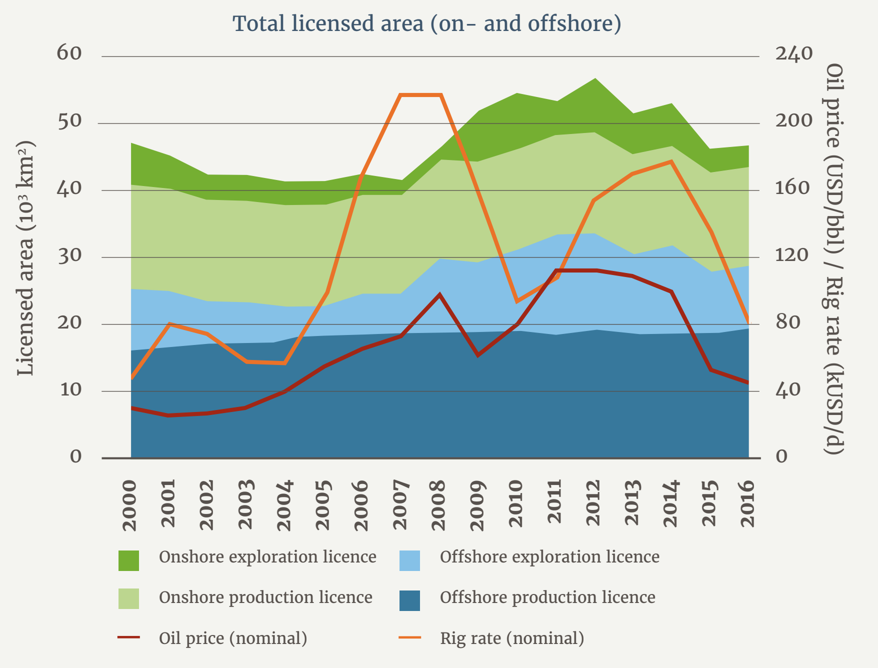
Looking at industry activity since 2000, it is clear that the total area covered by production licences has remained relatively constant (Figure 5). This is to be expected since many of the older licences were granted for 40 years or even indefinitely. Consequently, changes in total area licensed for production are due to additions, rarely to relinquishments. Recently, a duration of 25 years for production licences has become the norm. Figure 5 shows that for exploration licences there is more fluctuation over time.
Statistical analysis reveals there is no significant correlation between the total area of exploration

Rig rates halved since 2014, resulting in 25–30% reduction in well costs per day

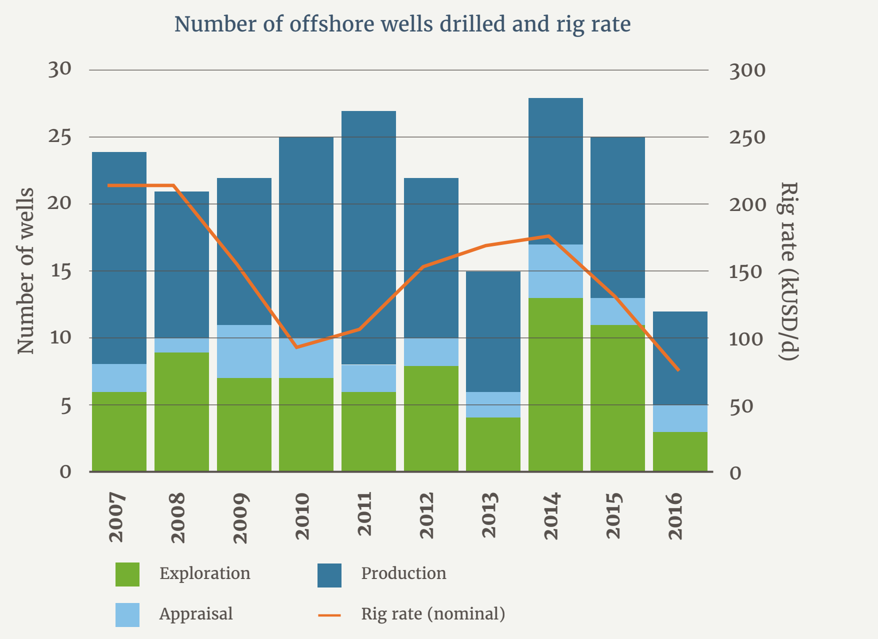
licences and oil price or rig rate for the period 2000 – 2016, even when a delay (rig rate lagging oil price by one, two or three years) is included. Also over a longer period (1980 – 2016) such correlation has not been found. Additionally, there is no clear correlation between the number of exploration wells and rig rate or oil price (Figure 6). Despite the halving of the rig rate since 2014, the decline in drilling effort in the last three years is obvious, reflecting budget cuts by nearly all operators. Also, halving the rig rate does not halve the well expenditures, and personnel costs remain relatively high. Analysis of recent AFEs indicates that halving the rig rates reduces total well cost per day by 25 – 30%.

The tendency to cut down on exploration projects is seen in other Southern North Sea countries as well. As is shown in Figure 7, in Denmark no exploration wells were drilled at all in 2016. In

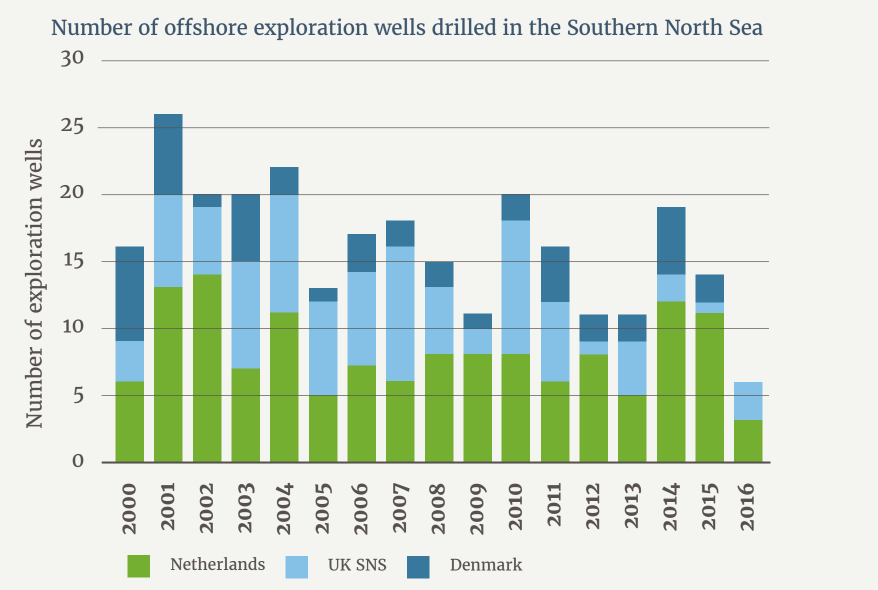
5

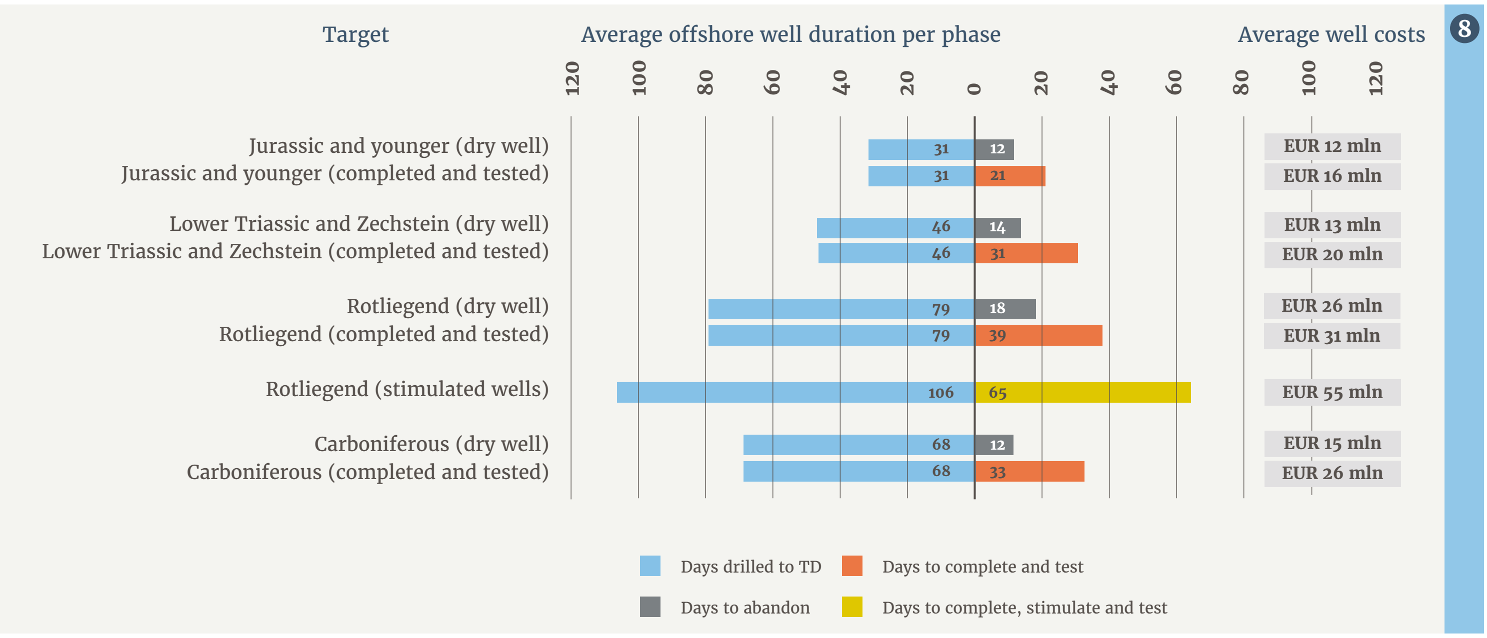


6



7

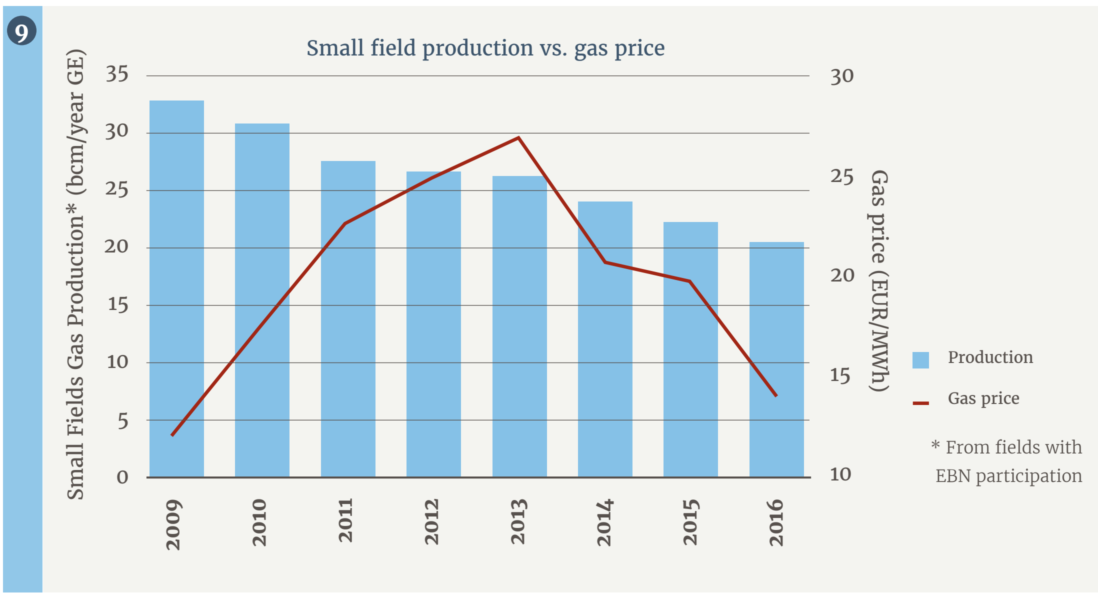


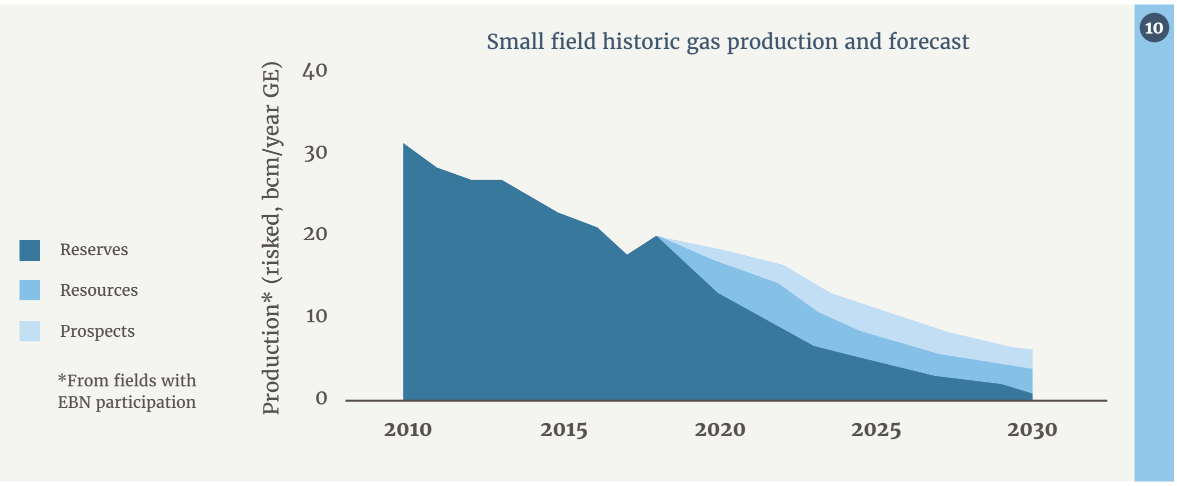


total, 137 exploration wells were drilled in the offshore Netherlands in the period 2000 – 2016, compared to 91 in the UK Southern North Sea and 47 in the Danish offshore. In this period the average amount of exploration wells in the Netherlands was 8.1 wells/year, compared to 5.4 wells/year in the UK and 2.8 wells/year in Denmark. These numbers have dropped considerably for the UK and Denmark when compared to the average of last five years (both 2.2 wells/year), whereas the amount of wells drilled in the Netherlands has remained fairly constant with 7.8 wells/year.

2.5 Drilling costs

Well costs are largely governed by depth, technical complexity and rig rates. Figure 8 shows the average total rig time and total costs for all offshore wells drilled in the last ten years. The data is split by stage. Generally, the deeper the target, the longer each individual stage takes. The figure shows that the post-TD (total depth) time differs significantly. The difference in days between a well that has been plugged and abandoned and a completed well with a Jurassic or younger target is ten days, whereas this difference increases to 20 days for a Rotliegend well. Interestingly, all individual stages for a well with a Carboniferous target are on average shorter than for a Rotliegend well, a result of the fact that many very complex wells drilled in the past had a Rotliegend target. For Rotliegend wells, stimulation activities have been added as an extra stage. A well with an additional fracking job requires 54 more days than an average Rotliegend well that has not been fracked. Half of this extra time is due to complexity related to long horizontal sections in the trajectory. The remaining extra days are needed for a relatively



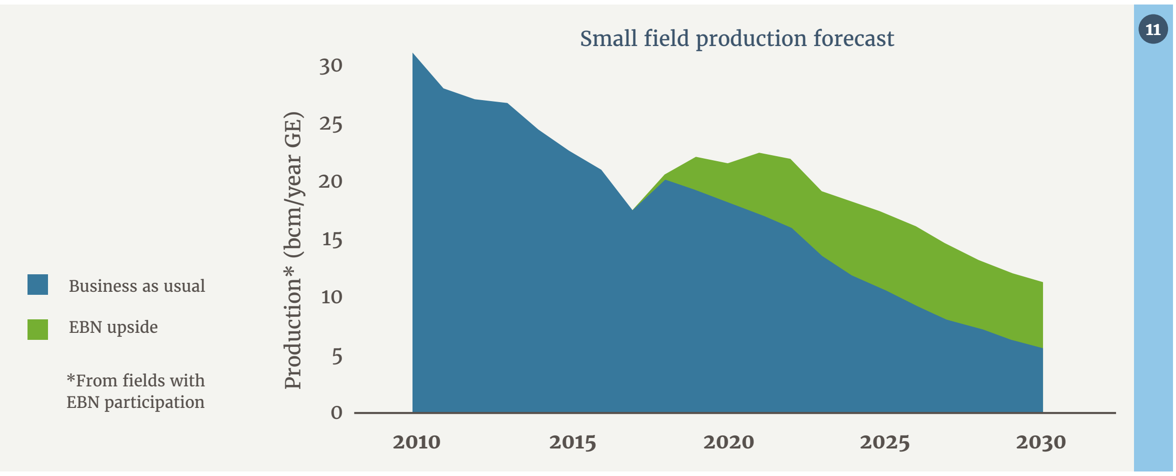


long cleaning up and testing period after the actual fracking job. Both factors also partly account for the increased cost of these wells, as do the costs of the fracking job itself. The resulting extra costs are substantial, yet these are more than compensated for by the incremental flow rates, as is explained in Section 4.2.

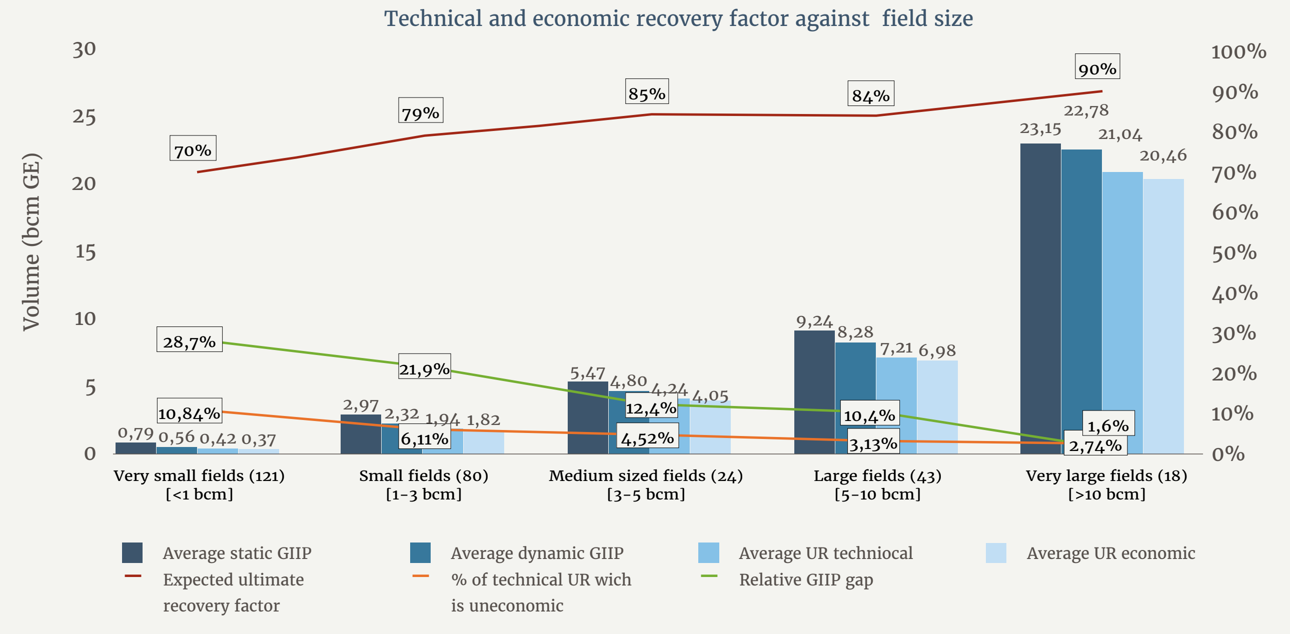
2.6 Production

Figure 9 shows small field gas production vs. gas price between 2009 – 2016. In 2016, gas production from small fields was 20.6 bcm (100%), which is 8% less than in 2015, when 22.4 bcm was produced. In the last eight years, a decline in production of 6 – 11% per year has been observed, with the exception of 2012 and 2013 when the decline was 2 – 3%. In those years, the gas price was historically the highest. It is not unrealistic to expect that the 4 – 6% drop in production will be offset by a favourable trend in gas prices in the future.

EBN aims to stabilise the gas production from small fields at current production level. It is expected that annual production will remain slightly below 20 bcm in coming years. Figure 10 shows historical production and the production forecast based on EBN's reserve and resource database. The volumes shown are regarded as the business-as-usual setting, the most likely scenario if the industry continues to drill and develop its portfolio in the same pace as in previous years. However, EBN sees potential for an upside scenario from enhanced activities such as exploration, increased recovery, tight gas development and infrastructure optimisation as described in Chapters 3 – 5. These volumes are shown in Figure 11. It also includes resources that could follow from collaboration concepts within the energy industry such as gas-to-power, CCUS and geothermal dual-play concepts, although this upside is difficult to quantify. EBN's upside is a growth scenario that is not part of EBN's reserves and resource database. In total, this may add some 150 bcm until 2050. This will enable production to be maintained above 20 bcm/year for the next six to seven years, depending on how fast innovative concepts will be implemented and how quickly the gas price will recover. The (infill) potential of remaining reserves and contingent resources is still high and rewarding. It is vital to continue exploration and drilling activities to maintain the production levels in the small field portfolio.



12

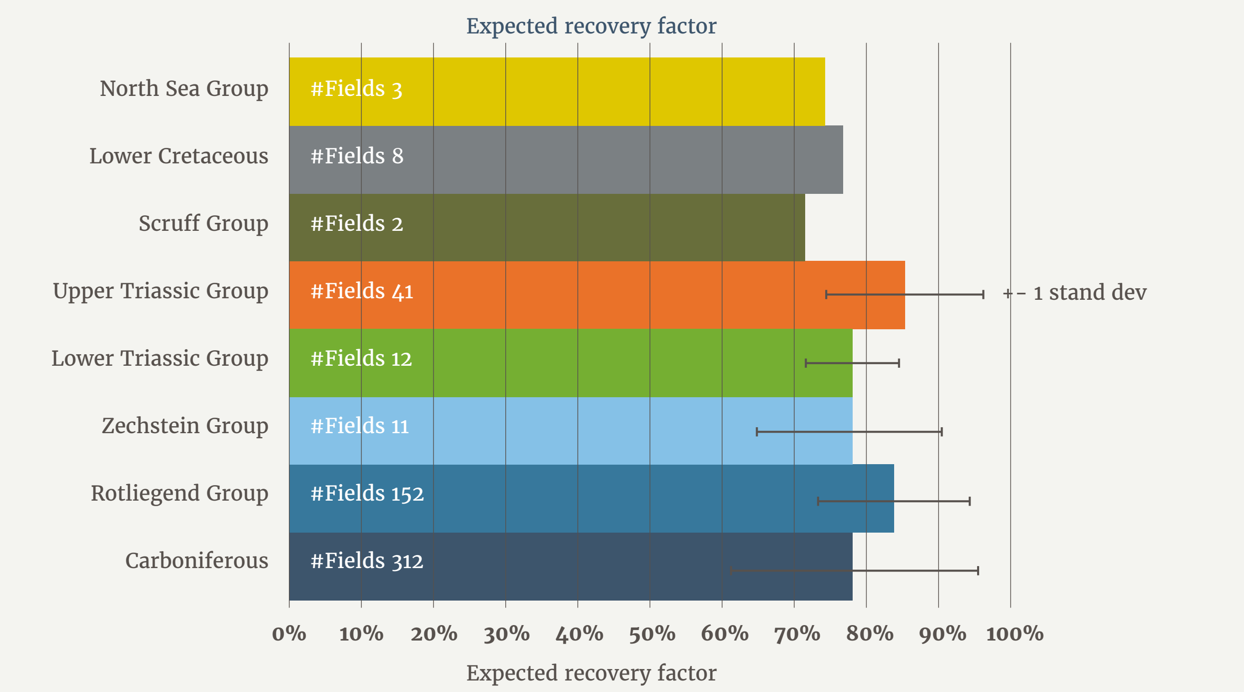


2.7 Recovery factor

The ultimate recovery factor of a field can be analysed by using various factors, one being the impact of field size on production characteristics (Figure 12). The factor refers to the technically recoverable volume from existing wells over the dynamic GIIP (Gas Initially in Place) at the end of the field's life. The assets included in the analysis are the on- and offshore small fields in production in 2016 with EBN as a partner. These assets have been classified into five groups by technically recoverable volume, ranging from very small fields (<1 bcm) up to very large fields (>10 bcm). The GIIP gap shown in the figure is the volume of gas that is not drainable by the current wells but is assumed to be present.

It is important to keep in mind that the distribution of fields is skewed: 20% of the total volume is present in 70% of the smaller fields. In comparison, the fields with a volume larger than 10 bcm represent some 40% of the total portfolio's recoverable volume. A clear relation between field size and performance is

13



Experience and knowledge greatly contribute to maximising field recovery, emphasising the urge for industry cooperation

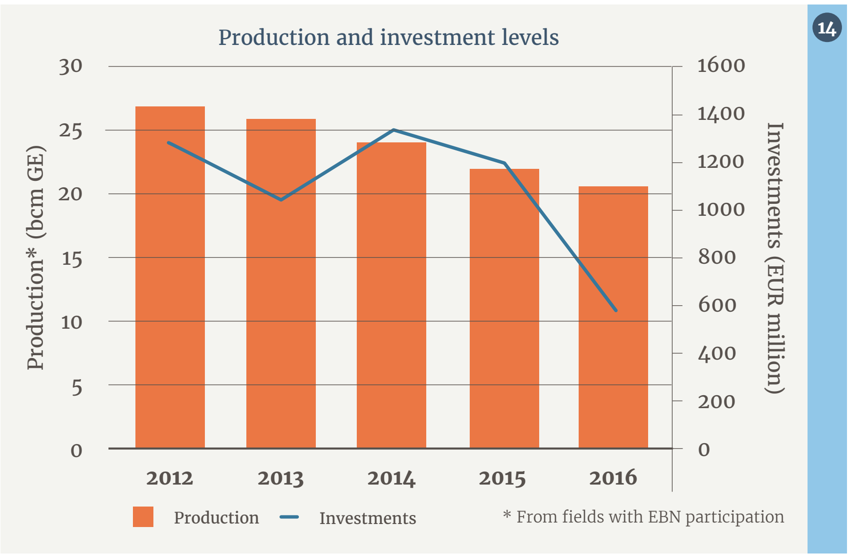
visible: larger fields yield higher recovery factors, show a lower relative GIIP gap and have a smaller segment of technically recoverable volume that is sub-economic. The main reason for this is that larger fields justify higher CAPEX due to larger expected revenues; investments such as higher compressor stages and end of field life (EoFL) measures increase the recovery factor (red line) significantly compared to regular reservoir depletion.

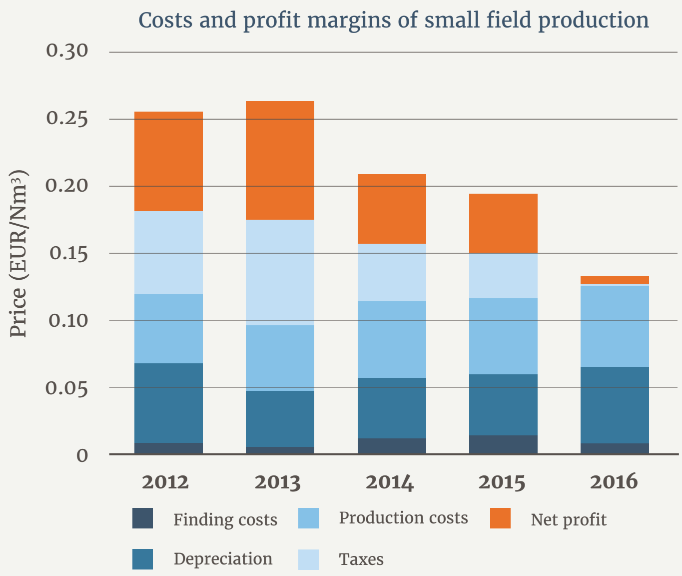
Not only the field size, but also the stratigraphy is key for a field's ultimate recovery factor. In Figure 13 the average ultimate recovery factor per stratigraphic group is depicted, excluding the 19 fields producing from multiple stratigraphies. It shows that the larger the number of fields producing from a certain formation, the higher the recovery factor. This reflects that experience and knowledge greatly contribute to maximising field recovery, emphasising the urge for industry cooperation. For all stratigraphies with more than ten fields, error bars depicting one standard deviation have been included. This reveals that the Carboniferous shows large uncertainty in recovery factor, as is to be expected from this highly heterogeneous stratigraphic interval.

2.8 Economics

Figure 14 shows the investment level in small fields, which has dropped significantly over the last years following the low gas price environment. The low prices have made the industry reluctant to invest in new projects. Since the low point of the gas price in April 2016, actual gas prices have upturned. However, it is not expected that investments will recover to their previous level in 2017, because most O&G projects have long lead times. In the longer run, however, it may be expected that annual investment levels of some EUR 700 million to EUR 1 billion are regained, depending on future gas price developments. A recovery of the investments is crucial to maintain adequate resource maturation and production levels.

Figure 15 shows revenues, costs and profits that are associated with exploration and production from small fields on- and offshore in 2012 – 2016. The net profit margin has declined sharply, but has remained positive. This decline is mainly the result of the low average gas price in 2016, which dropped from just below EUR 0.20/Nm³ in 2015 to just above EUR 0.13/Nm³ in 2016. Furthermore, the figure shows that finding costs, largely based on geology and geophysics costs (e.g. seismic surveys and dry exploration wells), have decreased slightly since 2015. This is mainly due to the reductions in general activities and investment level as described above. Depreciation is shown on a unit-of-production basis, including depreciation over successful exploration wells that have been capitalised in the balance





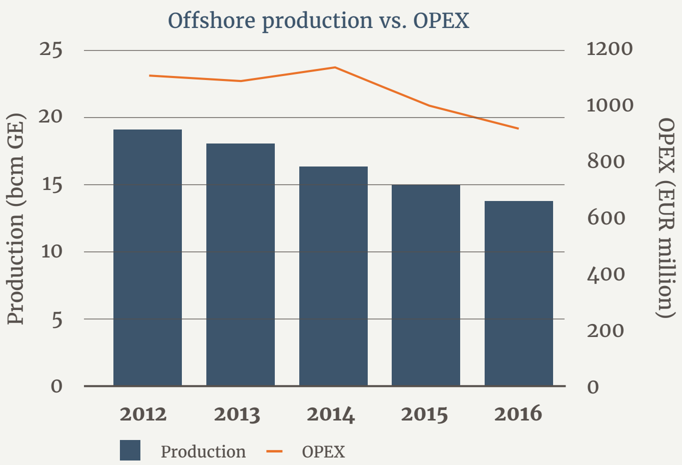
15

Based on current gas price developments and expected decreasing unit OPEX, profit margins are expected to recover in 2017

sheet and excluding any accelerated depreciation. Production costs are the operating costs in the figure. The unit OPEX has stabilised since 2014 at around EUR 0.06/Nm³, which means that in the last few years the industry has been able to lower OPEX to compensate for the decreasing production volumes. OPEX is analysed further below. Based on the current gas price developments and expected decreasing production costs per Nm³, profit margins are expected to recover in 2017.

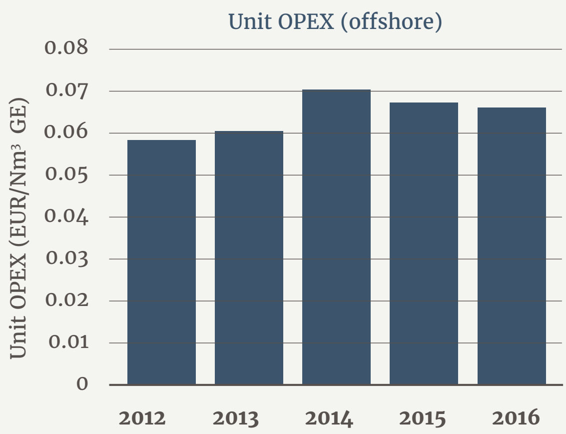
Figure 16 shows the production level versus OPEX for small fields, offshore only. Production from these gas fields is steadily declining, as explained earlier. However, since 2014, offshore OPEX has also been declining and this trend continued in 2015 and 2016. It is attributable not only to the lower production levels, but also to the industry's greater focus on cost-cutting. For 2017, a further reduction of OPEX is expected, in response to a continuing decline in production and more focus on reducing costs.

Driven by a low gas price environment, operators are increasingly focused on reducing OPEX. As a result, the unit OPEX has decreased for offshore gas fields in the last two years (Figure 17). The significant increase in the years before 2014 has clearly been halted, which is a welcome development, as bringing down the unit OPEX is essential for maintaining adequate profit margins and assuring an economically viable future for O&G production activities. Lower OPEX is also likely to extend the window of opportunity that the infrastructure can offer with respect to gas production, the potential for re-using the infrastructure and a cost-effective decommissioning.



16

17



The energy transition in the Netherlands

Interview with Sandor Gaastra, Director-General for Energy, Telecommunications and Competition at the Ministry of Economic Affairs, Agriculture and Innovation

As a representative of the government, what's your take on the energy transition?
We're en route to a CO_2-poor energy supply. The energy transition is a big task that we're tackling by deploying various transition pathways: built-up environment, mobility, industry, and power and light. As you know, we use energy all the time and it's a basic necessity for life. The energy transition doesn't just have a major social and climate objective; it also opens up many economic opportunities. The transitioning efforts of Dutch businesses, for example, are also very marketable – you can already see this happening more and more.

Are we making good progress with the energy transition?
We're still in the beginning stage. The largest part of the work of implementation still lies before us. Just look at the targets in the energy agreement [an agreement for sustainable growth between the Dutch government and over 40 Dutch organisations entered into in 2013]. In 2023, 16% sustainable – so 84% not yet. Each transition pathway will have its own challenges. For example, we need to make seven million homes sustainable. That works out at 250,000 homes a year. It's a huge job that all the parties involved must put their full weight behind. We can succeed only if we have sound and constructive collaboration. It's extraordinary to see that everyone really sees the need for this.

What role do you envisage for the government in this?
I think the government can play an important role in several areas. The Netherlands has committed to the climate agreements made in Paris. The targets formulated there about the warming of the earth are also our targets. The government will have to play an allocative role to stimulate companies and citizens to achieve these targets. I can see the market also obviously having an important role. In terms of innovation, we're very dependent on the propositions the market offers us. The government also has a role here, to regulate everything economically. At the moment, fossil energy is cheaper than sustainable energy, but as a government, we can give sustainable energy the support it needs.

What can natural gas contribute in the energy transition?
The fact is that natural gas is the least polluting of all fossil fuels. In that respect, you could say that by comparison with other fossil fuels we could wait longer with phasing out natural gas. In that respect, the 'ladder of seven' [as described in Chapter 1] is a useful assessment framework. At the same time, it's a given that the natural

gas in the North Sea is finite and that in time it will make up a smaller part of our energy mix. This doesn't alter the fact that in the coming years it is very important that there are gas reserves that we can use. If you decide to stop using Dutch gas, then you have to import gas, which means paying an extra bill for the energy transition. We must ensure that the production of natural gas remains a profitable activity for operators.

How do you feel about the low investment climate in the O&G industry in the Netherlands?

The low investment climate in the upstream O&G industry has our explicit attention. Together with the Minister it must be examined whether measures can be taken for the investment climate. Market uncertainty has, unsurprisingly, made the market more cautious. As the government, we want to bring more certainty back into the market by offering clear time limits to the industry.

What role can EBN play in the energy transition?

In production from the small fields, EBN can ensure that the O&G industry can function optimally. For this, collaboration in all areas is important, as it can limit costs. EBN plays an important role in this. During the energy transition, EBN's role might become broader. EBN has a lot of expertise of the subsurface and this will not be ignored during the energy transition. For the energy transition, we need companies with the right expertise. We'll 'repurpose' some companies. EBN is one such company. EBN could also deploy its expertise in geothermal energy and the underground storage of CO_2. Not only relating to its knowledge of the subsurface but also because EBN is a party that can co-invest.

What's your personal take on the energy transition?

I'm very involved with the energy transition. Our planet's wellbeing is a subject close to my heart. I have two children and I hope that they will also be able to have a pleasant life. I believe that we need to work seriously on the energy transition. It's great that this is a climate issue that can go hand in hand with economic potential. I think that there's a great opportunity for the Netherlands.

Normal fault offsetting the Rotliegend and Zechstein in the Münden Quarry, Germany.

Exploring for new prospects and play concepts

3

EBN's goal is to create value from geological resources in a safe, sustainable and economically responsible way, by exploiting its unique position as participant in almost 200 exploration and production licences and infrastructure, and hence its excellent access to data, knowledge and capital. This chapter deals with the first step in the life cycle of subsurface projects: exploration (Figure 1). EBN stimulates exploration activity in underexplored areas by carrying out and funding studies, and by facilitating the sharing of data and knowledge

In recent years, three regional studies have been carried out: the DEFAB study, the G&M study and a study focusing on the potential of the Dinantian in the P quadrant and adjacent areas (Figure 2). These projects identified significant remaining exploration potential and have facilitated new exploration activity. The DEFAB study in the northern offshore focuses on a wide range of stratigraphic intervals. The results comprise a regional structural framework (Focus 2015), insights into the presence of source rock bearing units and hydrocarbon shows (Focus 2014 and 2016), the distribution of shallow gas opportunities (Focus 2015), and the definition of the potential of Lower Carboniferous clastics (Focus 2016), Zechstein carbonates (Focus 2014), Triassic (this chapter), Jurassic (this chapter), Chalk and the Devonian Kyle limestone. Studies in the G&M area have focused mainly on the Base Cretaceous Unconformity, the Lower Cretaceous (Focus 2016) and the Jurassic. Multiple additional plays have been defined in this area, such as the Upper Cretaceous Chalk sealed by Tertiary shales or intra-Chalk traps and Upper Jurassic sandstones sealed by intra-Jurassic and/or Lower Cretaceous shales. The Dinantian shows potential for fractured and karstified reservoirs in both the Dutch on- and offshore, which are applicable for both hydrocarbon exploration and geothermal energy (this chapter).

3.1 Exploration activity

Exploration wells and licences

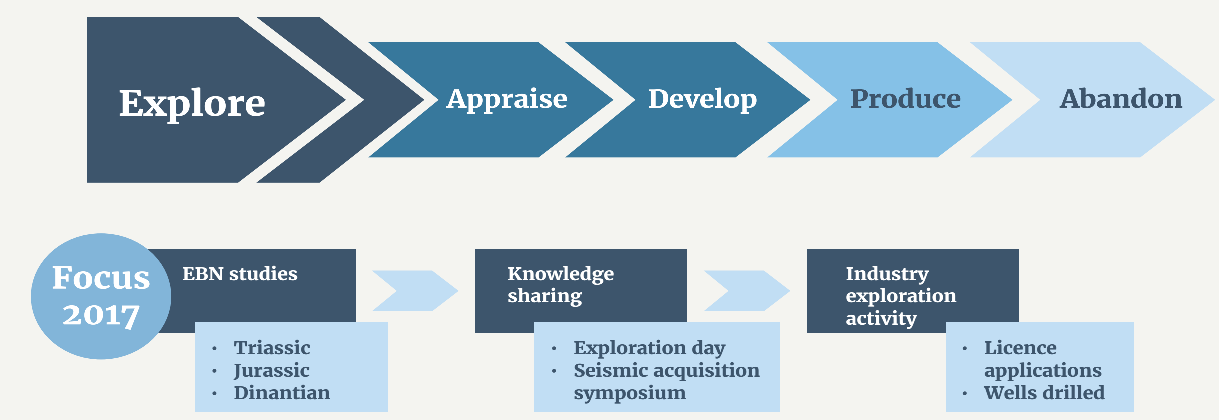
In 2016, six exploration and appraisal wells were drilled with EBN participation, all for near-field exploration in mature areas (Figure 2). In addition, four exploration licences were granted and three new applications were received, most of which are in underexplored offshore areas.

Seismic acquisition

After several decades of 2D seismic reflection data acquisition, the first – experimental – 3D acquisition in the Netherlands took place in 1976. Rapid growth followed in the 1980s, with extensive on-

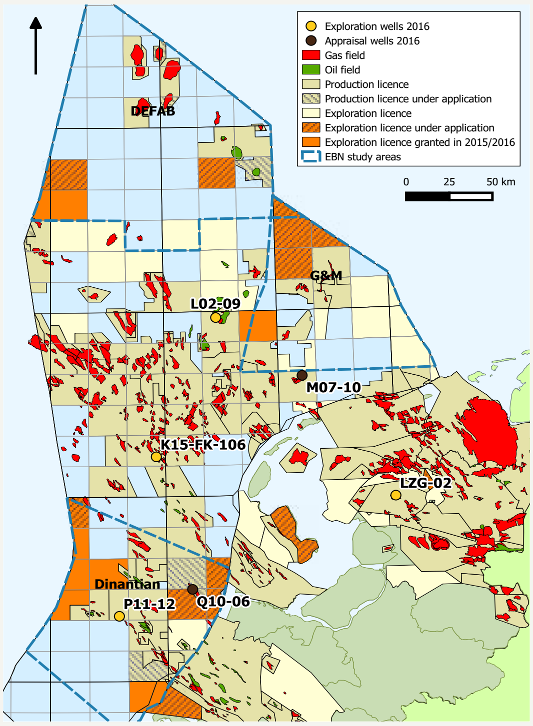
1

Overview of the topics in this chapter



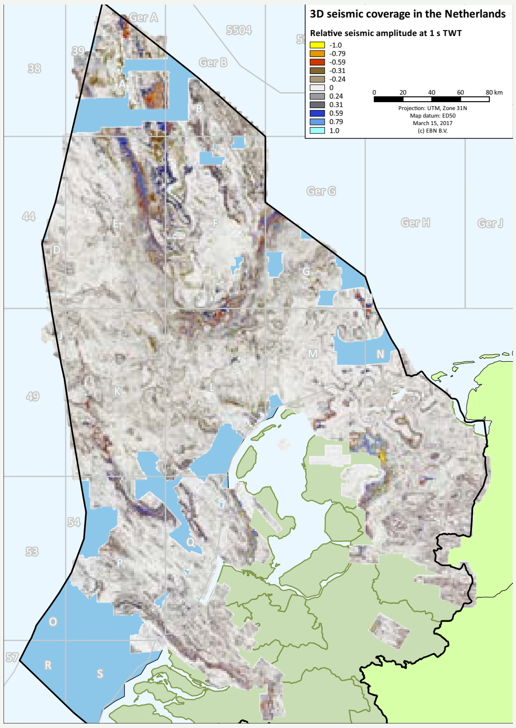
2

EBN exploration studies in underexplored areas and exploration & appraisal wells 2016



3D seismic coverage in the Netherlands - time slice at 1 s TWT

3



and offshore 3D seismic acquisition campaigns. Since then, some 90,000 km² 3D seismic data has been acquired, covering around 37% of the Dutch onshore and 81% of the offshore. The time-slice map displays locations for which 3D seismic data is available today (Figure 3). Figure 4 shows the 3D seismic acquisition activity over the years. The variation in activity is partly explained by the fluctuating oil price and partly by advances in technology and new play concepts. Recently, novel acquisition technologies like 4D data acquisition, broadband seismic or wide-azimuth shooting have been deployed successfully in the Netherlands. No acquisition took place in the last two years, but new 3D seismic acquisition is planned in 2017.

3.2 EBN exploration studies

Ventoux: An Upper Jurassic lead mapped on new seismic data

The Late Jurassic play is well established in the Dutch Central Graben, with 11 O&G fields discovered, including the 125 MMbbl STOIIP & 21 bcm GIIP F03-FB field. Block F08, located in this area, has only recently been covered by 3D seismic data. Using the new data, EBN has evaluated the potential of the Late Jurassic lead Ventoux; a fault-dip closure with the Kimmeridge Clay as top seal.

Ventoux consists of multiple Upper Jurassic targets that can be tested with a single exploration well (Figure 5). Complex faulting structures are observed, soft-linked to deeper extensional faulting. Two targets are the proven Lower and Upper Graben Formation sands. A third target consists of Lower Kimmeridgian sands (Figure 6). This stratigraphic interval has not been tested in the wider area, yet the seismic signature suggests that it is a regressive unit that may well contain sands (Figure 7). Charge is expected from the Lower Jurassic Posidonia Shale Formation, as there have been O&G shows in up-dip well F08-02. Total prospective resources amount to 15-65 MMbbl STOIIP (P90-P10, unrisked) and upside exists in pinch-out and truncation trapping west of the lead. The probability of success ranges from 20 to 35% for the different targets.

Symposium 'Reflections on Seismic Acquisition'

In February 2017, EBN and ENGIE E&P organised the fourth geophysical symposium. The topic this year was seismic acquisition. The purpose was not only to highlight recent advances in acquisition techniques, but also to provide a forum for contractors to present their capabilities to the Dutch O&G and geothermal industries, as well as to highlight issues in acquisition in general.

After a kick-off presentation by EBN on trends in acquisition, the focus in the morning was on offshore acquisition developments, with presentations from PGS, Polarcus, Shearwater and WesternGeco. Whereas in recent years companies have concentrated on more and longer streamers, multi-azimuth surveys and broadband acquisitions, the recent developments are in the area of multiple sources and use of seismic energy generated by sea surface multiples. Despite the bigger processing effort required, the advantage is shorter acquisition time and increased frequency range. Also, new sources have been developed that suppress higher frequencies (> 200 Hz), thereby reducing exposure of marine mammals. This helps limiting the environmental footprint of seismic acquisition.

The afternoon focused on onshore acquisition and started with a presentation on survey design (Cees van der Schans consultancy).

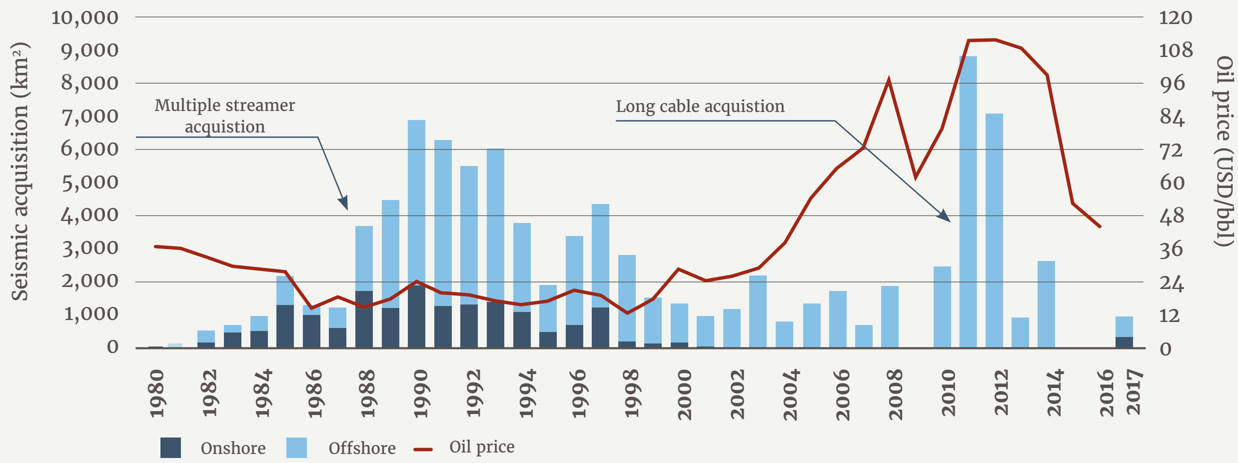
An interesting anecdote was the story of the EAGE annual conference in 1999, where five specialists were asked to design a 3D survey for a specific purpose. The outcome was five different designs, showing the non-unique character of the solution. Uppsala University presented a study on using 4D seismic data to monitor the CO_2 plume development in the CO_2 storage in Ketzin, Germany. The repeatability of the original survey is key to success, but it was also shown that relatively simple acquisition techniques will suffice. This presentation was followed by DMT, which presented on 3D acquisition in the city centre of Munich and the challenges posed by this environment.

Royal HaskoningDHV presented on the permitting procedures for an onshore 3D survey planned in 2017 in the north of the Netherlands. Fourteen permits and exemptions are required from MEA, Rijkswaterstaat, the Water Board, province and municipalities. TNO closed the programme with a presentation on a high-resolution survey for the monitoring of potential CO_2 storage in the P18 licence. They also showed some interesting preliminary results on passive seismic monitoring in the De Peel area.

The day was very well received by the 70 delegates from 28 companies and institutions. Released presentations are available on EBN's website.

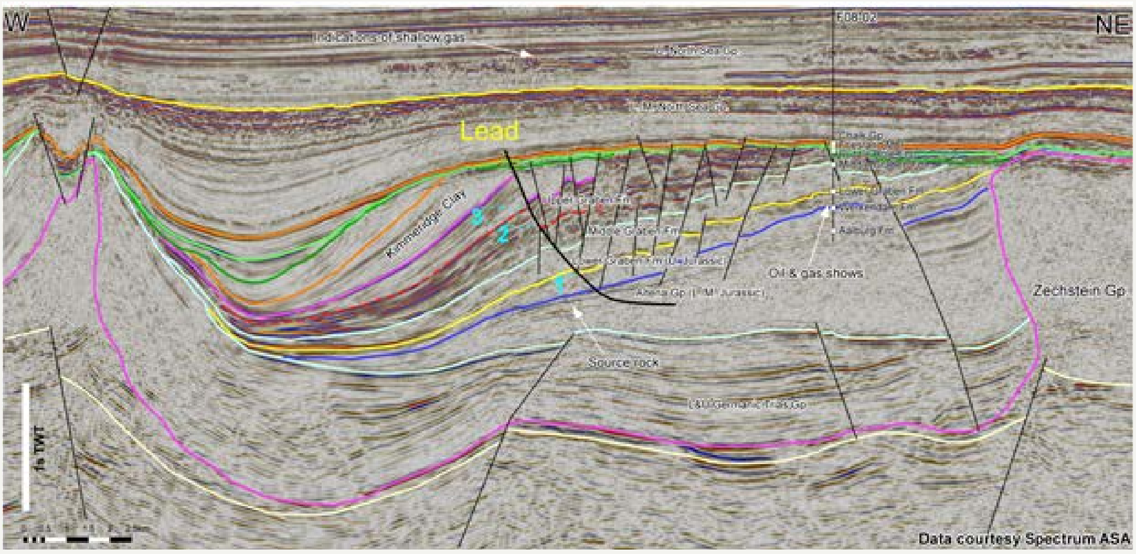
4

3D Seismic acquisition in the Netherlands



5

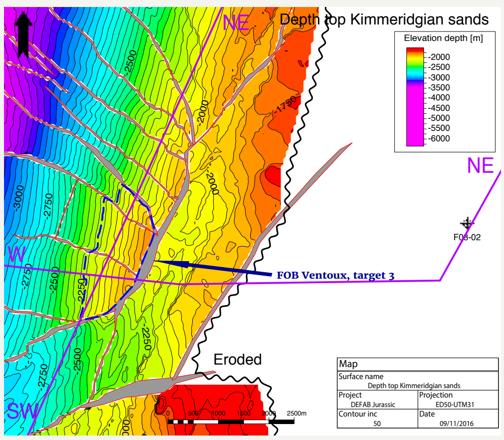
Ventoux lead



Dip line through the Ventoux lead, location shown in Figure 6

6

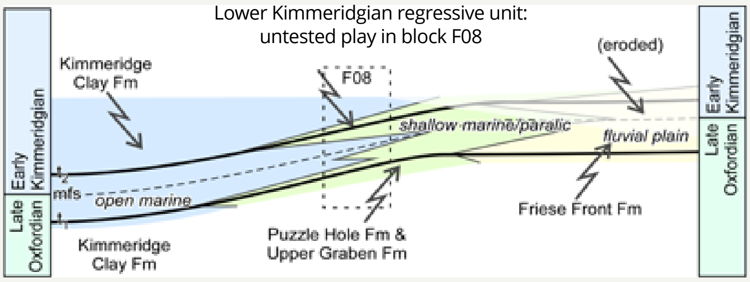
Top structure map of Kimmeridgian sandstones



To further de-risk the lead it is recommended to:

- PSDM reprocess the seismic data to improve the imaging of the complex faulting, increase resolution and to reduce the multiples at the Jurassic–Cretaceous boundary;
- Investigate DHIs and AVO behaviour of the reservoir intervals;
- Further investigate the timing/movement of faulting and fault juxtaposition.

7 Reservoir potential of the Lower Kimmeridgian



Upper Jurassic shallow marine sandstones in the northern offshore

Exploration in the Upper Jurassic in the Dutch Central Graben has focused on look-alikes of F03-FB: a field that produces from Callovian–Oxfordian Lower and Upper Graben Formation sands. In the neighbouring UK (Fife) and German (A6-A) sectors there are fields that produce from younger Jurassic reservoirs: Kimmeridgian to Volgian sands. These sands have also been found in the Danish sector, where they are known as the 'Outer Rough Sands'.

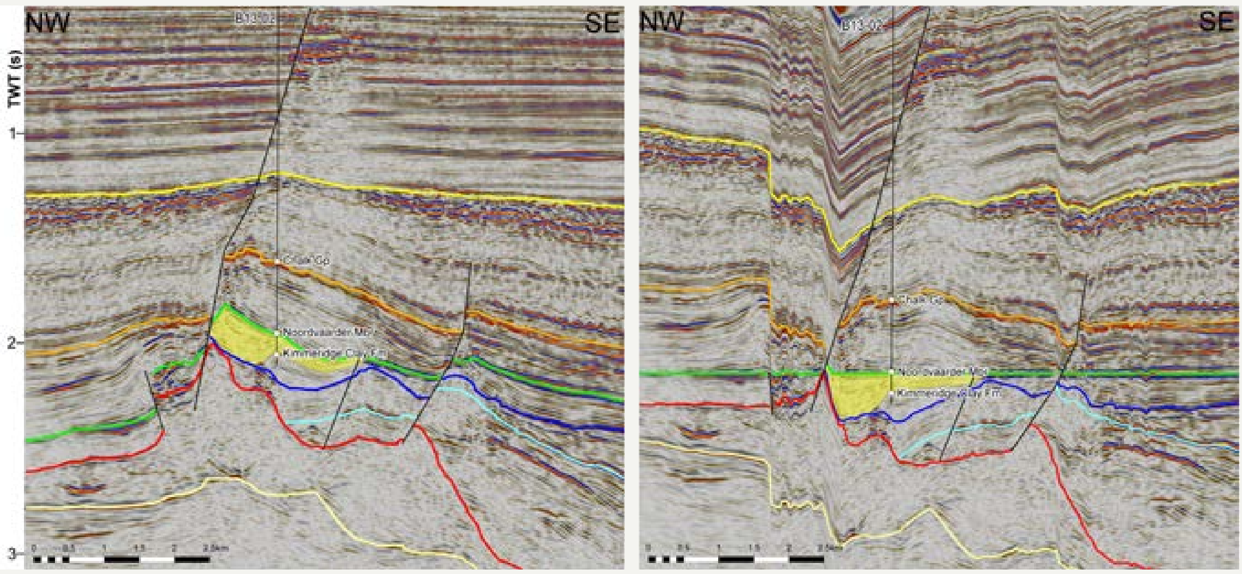
What is not widely known is that similar sands are also present in the Dutch sector and have been drilled in wells B13-02 and B14-02 (Figure 8), where they are part of the Noordvaarder Member. A petrophysical analysis of well B13-02 shows a net sand thickness of 160 m, a net-to-gross ratio of 0.93 and an average porosity of 21%. Core plug measurements confirm the reservoir potential of the interval.

Published regional correlations suggest that these sands may be present in a wider part of the northern Dutch offshore as far east as the B quadrant (Figure 9); more work is recommended to de-risk this new play.

Triassic reservoir sands in the Dutch northern offshore

The Triassic Main Buntsandstein play is well established in the Southern North Sea area. Although the general perception is that the chances of encountering reservoirs decrease northwards, a regional study by EBN shows that reservoir sands do occur north of the main fairway (Figure 10). The lithological character and stratigraphic extent in this area suggest that Lower Triassic fluvial sands with northern provenance may have developed here (Figure 11). In addition, seismic interpretation indicates Early Triassic local depocentre development in the Step Graben area (Figure 12).

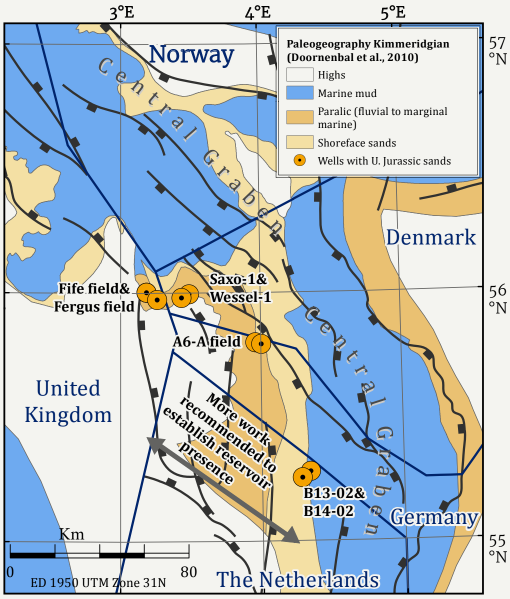
8 Noordvaarder Mb: Shallow marine sandstones



Section flattened at Base Chalk

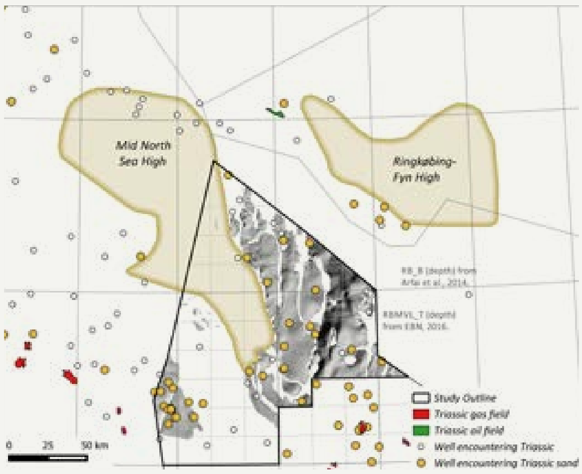
9

Shallow marine Kimmeridgian–Volgian sandstone reservoirs



10

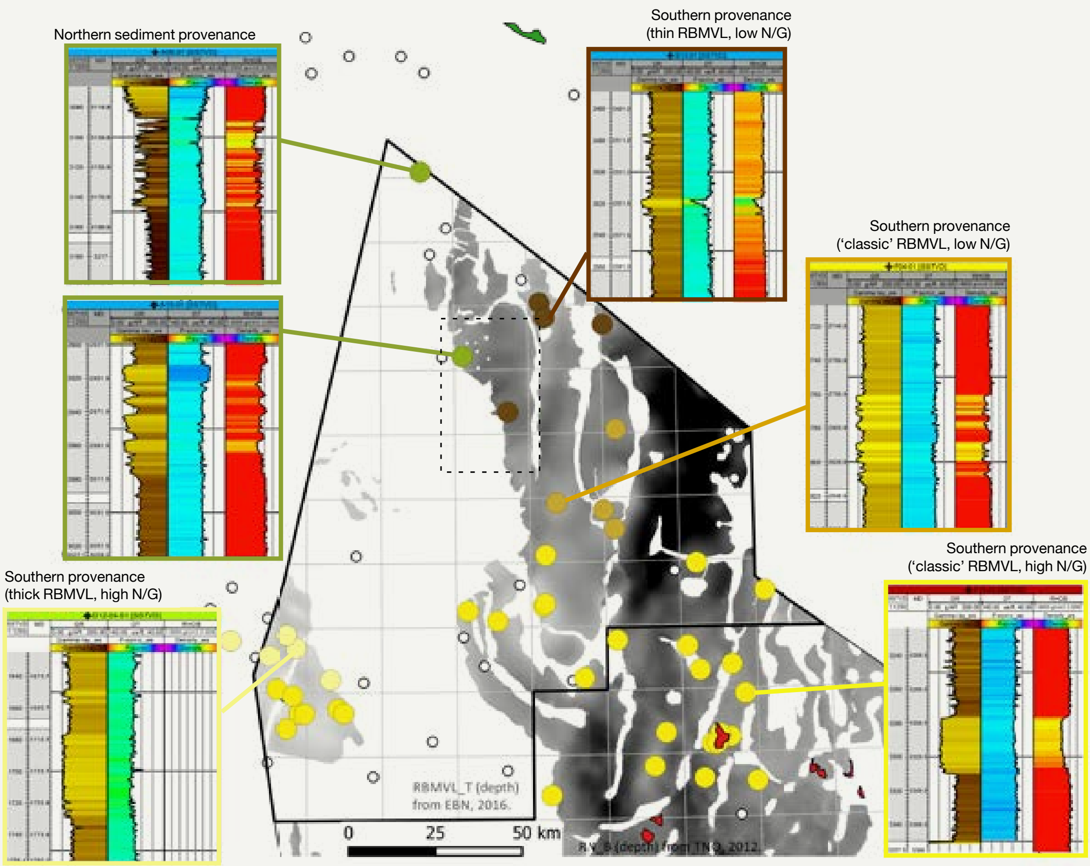
Triassic regional map



Regional map showing all wells that have drilled Triassic strata (white circles) and the wells that have encountered Triassic sands (yellow circles)

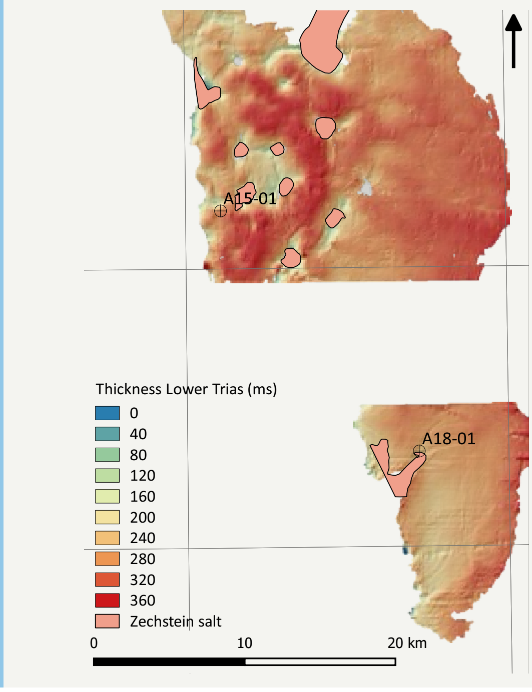
11

Lower Volpriehausen sandstone study area

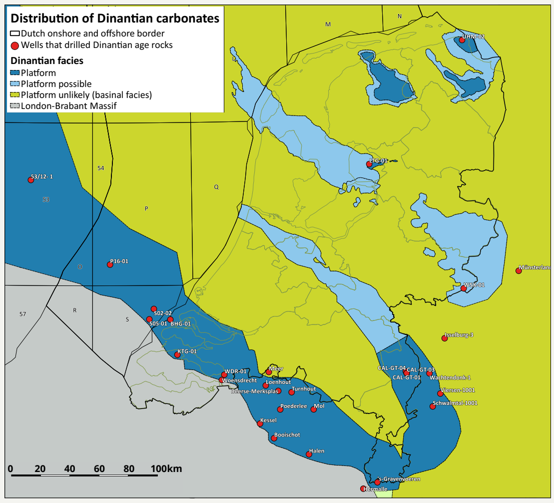


Regional reservoir architecture – typical well-log response for different types of Lower Volpriehausen sandstone (RBMVL). Study area is outlined in solid black, dashed black line indicates the location of the map shown in Figure 12. The grey areas show the distribution of the RBMVL as expressed on seismic.

12 Time isochore map of the Lower Triassic interval (Top Lower Volpriehausen sandstone to Top Zechstein)



13 Distribution map of Dinantian carbonates in the Netherlands



Modified from a TNO report, Boxem et al., 2016

Syn-tectonic strata in local depocentres may have been formed in the northern Dutch offshore due to early halokinesis in the Triassic. These insights shine new light on the Triassic prospectivity in the Dutch northern offshore: 44 untested structures have been identified (EBN, 2016).

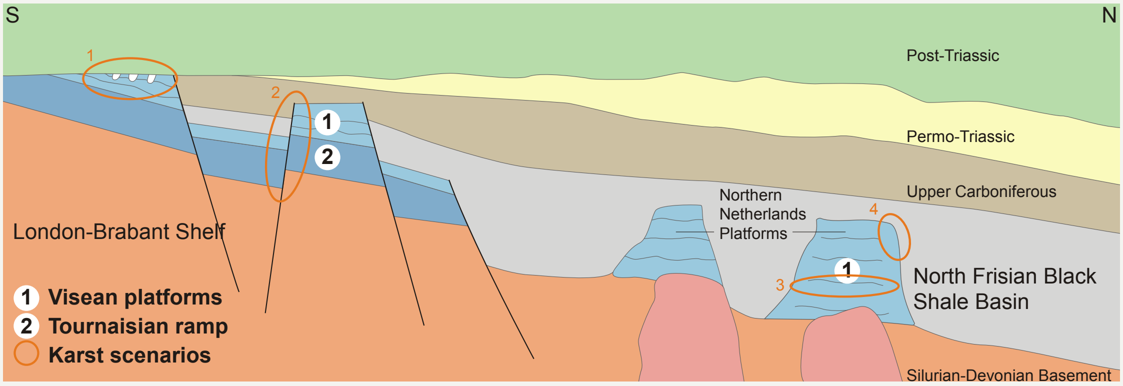
Dinantian carbonates: synergy between hydrocarbon and geothermal projects

The Lower Carboniferous Dinantian carbonates have recently become an exploration target in the Netherlands, for both hydrocarbons and hot water. Evaluation of recent oil, gas and geothermal wells in Belgium and the Netherlands, combined with seismic mapping carried out by TNO and EBN, has resulted in a new distribution map of Dinantian carbonates (Figure 13) and improved understanding of the mechanisms and conditions leading to favourable reservoir quality.

The main reason for the under-exploration of Dinantian carbonates was the misconception that these rocks are always impermeable. However, several wells and seismic data show the potential for a fractured and karstified (producing) reservoir. Gas storage wells in Belgium and recent geothermal wells in that country and the Netherlands have found highly permeable rocks (Figure 14), and therefore opinion about the reservoir potential has changed.

14 Core with karstified Dinantian carbonate rock from Belgian underground gas storage well

Scenarios for karstification and fracturing of Dinantian carbonate reservoir

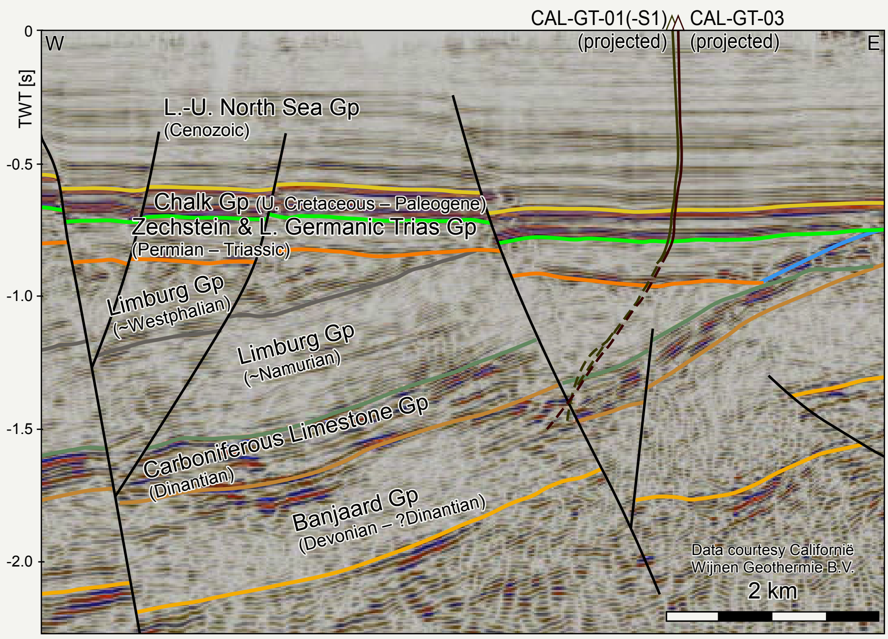


15

Locations with a higher chance of karstification are indicated by orange ellipsoids.

Recent wells have shown that the most promising features for identifying exploration targets are specific depositional and/or structural configurations. The conceptual diagram in Figure 15 shows four different scenarios for karstification and fracturing of a Dinantian carbonate reservoir: 1) Meteoric karstification takes place when the rocks are exposed at surface and fresh water flows through faults and fractures; 2) Hydrothermal karstification takes place when hot fluids flow upwards through deep-seated faults. These fault zones will be fractured too; 3) Intra-platform karstification takes place during low sea level periods that alternate with phases of carbonate development; and 4) Mixed coastal-zone karstification can occur when a carbonate platform is exposed to a mix of fresh and salt water. The edges of the platform will also be more prone to fractures, as a result of instability. The features indicated in Figure 15 can be recognised on seismic data. Figure 16 shows geothermal well CAL-GT-01 that encountered a karstified zone of at least 30 m at the top of the Dinantian section and produced 240 m³/h. The seismics show that the well was drilled close to a fault zone. Evaluation of samples indicates that karstification and dolomitisation were caused by hydrothermal diagenesis (Poty, 2014). Figure 17 shows an example of a Dinantian carbonate platform. Well UHM-02 was drilled in the middle of the platform and encountered a few thin karstified zones. More fractured and karstified, hence more permeable, carbonate rock may be found near the edges of the platform.

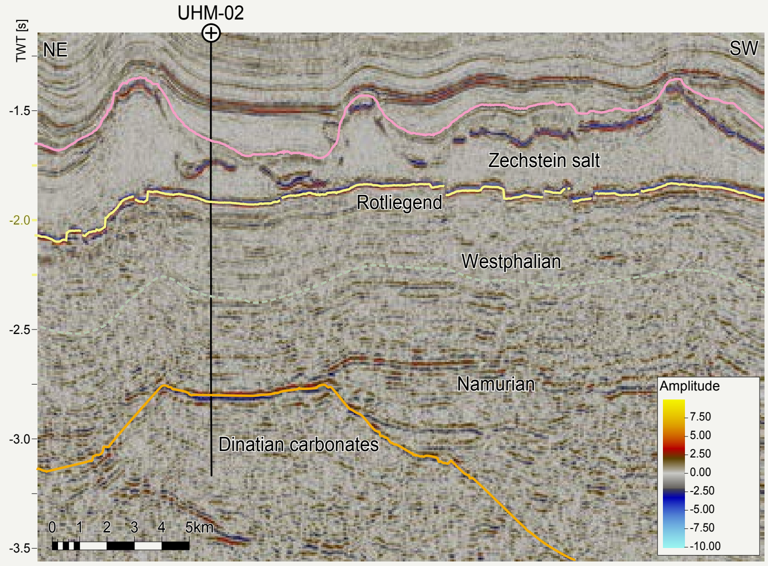
Seismic line through geothermal well CAL-GT-01



16

17

Dinantian carbonate platform visible on seismics (example)



Wells and seismic data show the potential for producing Dinantian carbonate reservoirs.

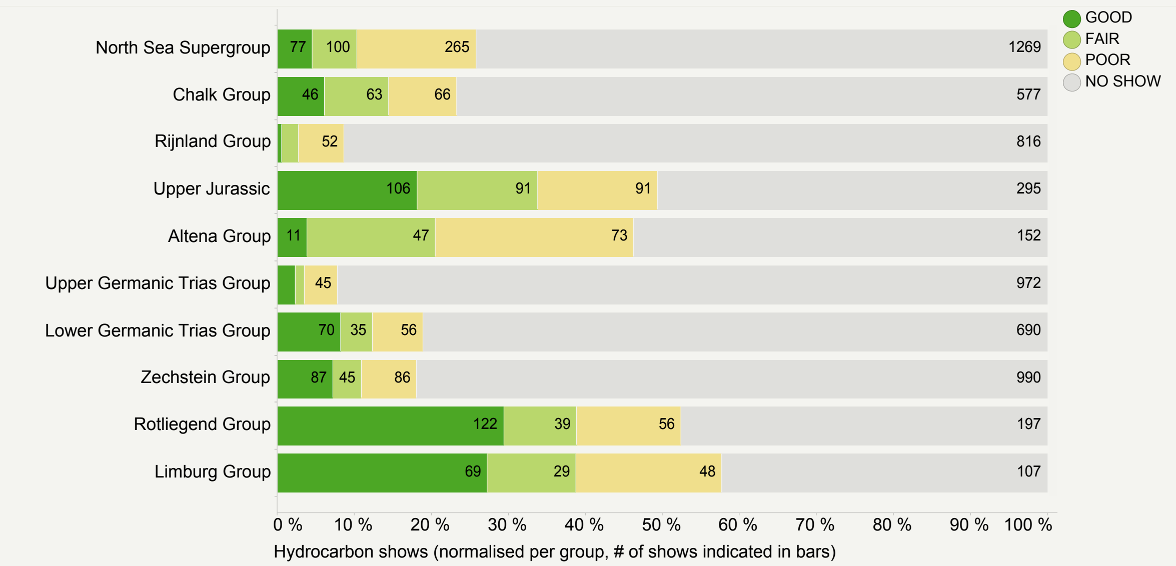
Since exploration for hydrocarbons and geothermal energy require similar type of data and geological knowledge, both will benefit significantly by sharing data and knowledge on the Dinantian strata, and possibly by collaborating on projects. The successful Californië geothermal project in the province of Limburg and the recent award of the Dutch P quadrant hydrocarbon exploration licence show that this play is 'hot' in both industries.

Hydrocarbon shows revisited

Exploration activity requires a good overview of proven occurrences of hydrocarbons. For that purpose, EBN has built a database that contains observations of gas or oil in the subsurface as recorded in wells. Information from mud logs, drill stem tests, repeat formation tests and cores is compiled and described per stratigraphic level (Figure 18). Both the presence and absence of shows are documented and quantified, to enable detailed analyses to be made regarding the prospectivity of an area. This includes analysis of maturity, migration path and the effectiveness of seals. The database can also be used to identify obviously missed pay opportunities. Furthermore, this information can assist in well planning, including for geothermal wells, where a good understanding of the distribution of hydrocarbons is important, even when hydrocarbon saturations are low. Currently, the database covers the entire northern offshore and is being expanded towards the south including onshore.

18

Hydrocarbon shows per stratigraphic group



Dutch Exploration Day

In May 2016, EBN organised the first edition of the Dutch Exploration Day, with the theme 'Sharing Knowledge'. Around 60 representatives from the operators and contractors active in the Dutch O&G industry were welcomed by EBN CEO Jan-Willem van Hoogstraten. The day was of great interest to the industry and was fully booked. After the introduction, EBN's exploration team presented results from their ongoing and completed studies and their plans for upcoming projects. The morning programme ended with a poster session, where knowledge was shared, ideas tested and new contacts made. In the afternoon session, several contractors presented their studies to the industry. The day concluded with a second poster session and drinks.

The day was well received and many delegates expressed the wish for a second edition. It is intended to organise a new edition in the near future, again with the goal to strengthen cooperation within the sector. Presentations and posters are available on the EBN website.

Reservoir stimulation and production optimisation

4

In addition to its efforts to help find new gas resources, EBN aims at maximising recovery from fields already discovered. These include producing fields for which the operators are facing increasing technical and economic challenges. Close to 90% of the fields in which EBN participates are in the mature or tail-end production phase. Recent studies have contributed to optimising the selection of the most valuable end of field life (EoFL) techniques in terms of volume and economics. Moreover, whenever possible, EBN keeps a close eye on the so-called stranded fields, which have not yet been developed, often because of insufficient permeability – a challenge also faced by some prospects. Special attention is given to these tight reservoirs through projects relating to advances in reservoir characterisation and by investigating the potential for stimulation technologies such as hydraulic fracturing.

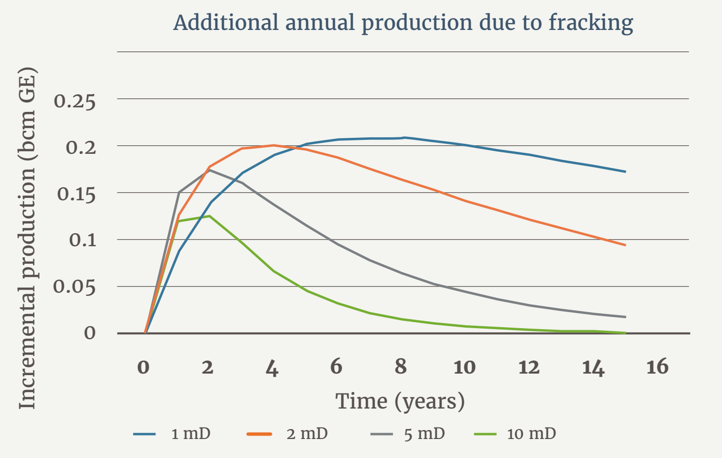
4.1 New insights into hydraulic fracturing

In the gas industry, the application of hydraulic fracturing is a well-known technique to accelerate production and enhance ultimate recovery by increasing the productivity of low permeability reservoirs. What seems less well-known, is the fact that these benefits apply not only to high-pressure virgin reservoirs containing low permeability rocks, but also to reservoirs showing better production characteristics, even during advanced stages in their production life, the so-called brownfields.

In order to assess the benefits resulting from stimulation of brownfields, EBN initiated a study aiming at quantifying the additional production and economic value, evaluating risks, and screening the practical application to the mature gas field portfolio. The project considered the wide range in reservoir characteristics typically observed in the Dutch subsurface. A total of 30 different reservoir configurations has been investigated, each with varying parameters such as thickness, permeability, heterogeneity, GIIP and degree of pressure depletion. It is expected that this study will help to identify gas fields potentially benefiting from and being eligible for hydraulic fracturing.

Figure 1 shows the modelled production increase resulting from hydraulic fracturing for low (1 mD) to higher (10 mD) permeability reservoirs. The extra volume of gas yielded by fracking is biggest for the tightest rocks, but fields with good permeability also profit. Furthermore, the results show that in the case of poor quality reservoirs, the highest incremental production can be expected after approximately five years, whereas for higher permeability reservoirs,

1



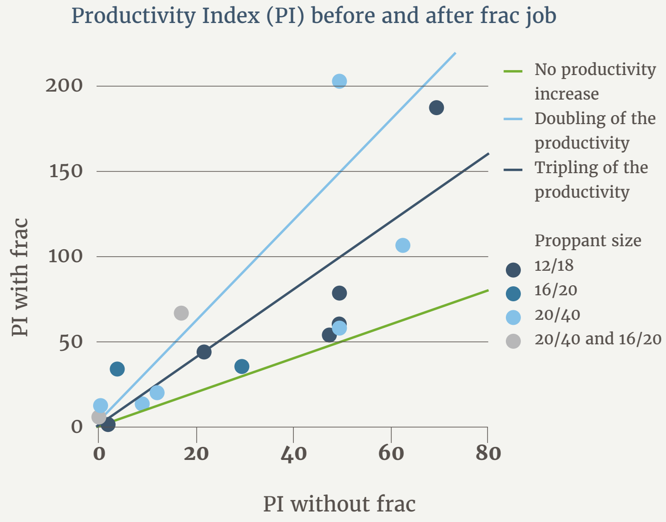
production acceleration occurs within the first few years. This means that hydraulic fracturing does add value and is attractive even when the economic time horizon is short.

Parallel to the work described above, EBN is working on a portfolio analysis of the historical results of hydraulic fractures in the Netherlands, including technical and economic benefits. This involves history matching analytical models with production data, in order to achieve reliable production forecasts required for calculating the economic value of the fracking jobs. The database contains wells with pre-fracking production data and wells that were fracked from the outset. The work is still ongoing, but some preliminary results are given below.

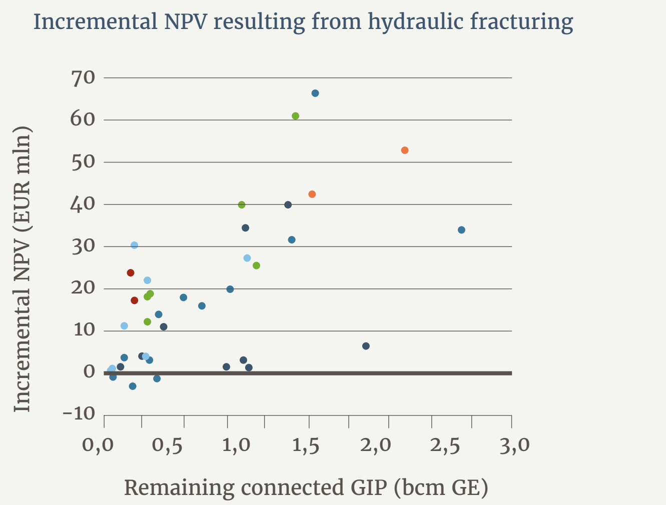
Production benefits from hydraulic fracturing through: 1) accelerating production, 2) reaching a higher total recovery, and 3) connecting extra dynamic volume. The preliminary results of the portfolio analysis reveal that virtually all frack jobs with pre-frac production have led to an increase of productivity index (PI), indicating that practically all jobs are assumed to be a technical success (Figure 2).

Looking at the entire set of fracks that are currently being investigated, including wells that were fracked from the outset, it may be concluded that hydraulic fracturing almost always has a positive effect on the net present value (NPV), independent on the volume of hydrocarbons present in te reservoir (Figure 3a). There seems to be a linear corellation between remaining connected volume and NPV. The negative NPV for three fracturing jobs is due to very low reservoir pressures and remaining reserves at the time of fracking for two projects (Figure 3b) and an extremely small connected volume for another project.

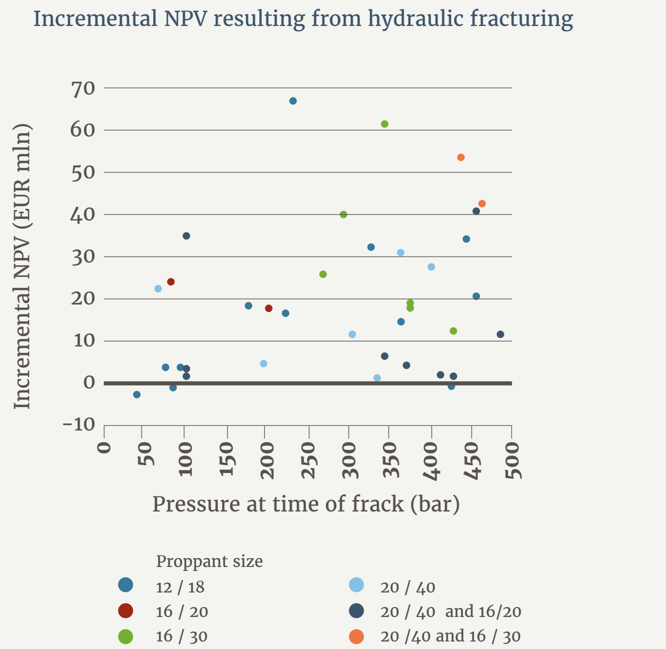
2



3a



3b



Regulation and supervision of hydraulic fracturing

In the last few years, hydraulic fracturing has become a contentious issue, especially in the debate on shale gas. Fracking has been around for many decades. Below a summary of facts related to fracking in the Netherlands is given, largely based on two studies by NOGEPA (NOGEPA Fact Sheet Fracking, NOGEPA 2013) and State Supervision of Mines (Resultaten inventarisatie fracking. De toepassing van fracking, de mogelijke consequenties en de beoordeling daarvan, SodM Feb 2016).

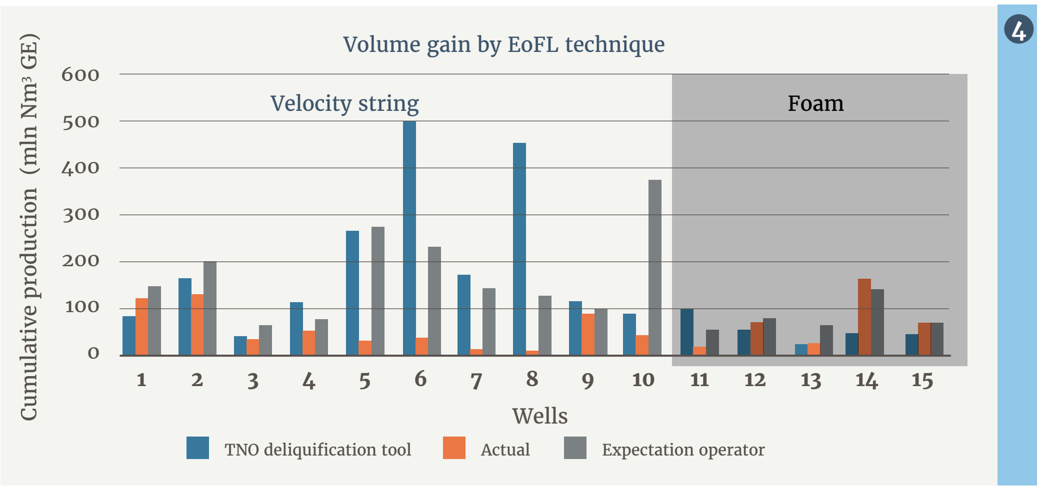
In the Netherlands, fracking fluids are extensively regulated by:
1) The EU, which regulates the use of chemicals through EU 1906/2007 REACH and EU 528/2012 on biocides;
2) The OSPAR convention, which further regulates the use of substances in offshore mining activities;
3) The Dutch Mining Act, the General Mining Industry (Environmental Rules) Decree, the Environmental Management Act and the Health and Safety in the Workplace Act, which regulate, among other things, emissions to the subsurface, surface waters and air, and impose restrictions on sound and light emissions. The regulations are also meant to protect inhabitants and aim to prevent damage due to earth movements.

In February 2016, State Supervision of Mines reported that in total 252 fracks have been executed on- and offshore in the Netherlands, as shown in the table below. The data has been updated with the two offshore wells that since then have been fracked with a single hydraulic fracture.

	Number of fracked wells	Number of fracks
Offshore	157	221
Onshore	97	119
Total	**254**	**340**

State Supervision of Mines investigated the impact of fracking in the Netherlands with respect to people and the environment based on five aspects:
1) Seismic risks due to hydraulic fracturing;
2) Geochemical reactions between injected fluids and the reservoir;
3) Wellbore integrity;
4) Integrity of cap rock and base rock to prevent migration of fluids;
5) Exposure to chemical substances.

Results show that no negative effects for these five aspects have been reported. The following factors are probably contributing to this good safety record:
- Hydraulic fractures are extensively modelled. They are designed not to grow out of the reservoir zone vertically, in order to prevent fluid migration and to avoid larger faults nearby. To further reduce the risk of activating faults leading to tremors, pumped injection volumes are kept to a minimum.
- Wellbores are designed for pressures to which they are exposed during hydraulic fracturing to prevent leakage of fluids. Wellbore pressures are monitored while pumping the hydraulic fracture, to ensure they stay within pressure limits. Multiple layers of steel and cement prevent fluid leakage into potential drinking water sources. A study on water injection wells in the Williston Basin in North Dakota (Michie and Koch, 1991) has shown that when the production casing and surface casing extend below the drinking water source, the risk of leaks is smaller than 0.0007% (seven out of million). Moreover, almost all wells in the Netherlands are designed with more than two casings at drinking water level.

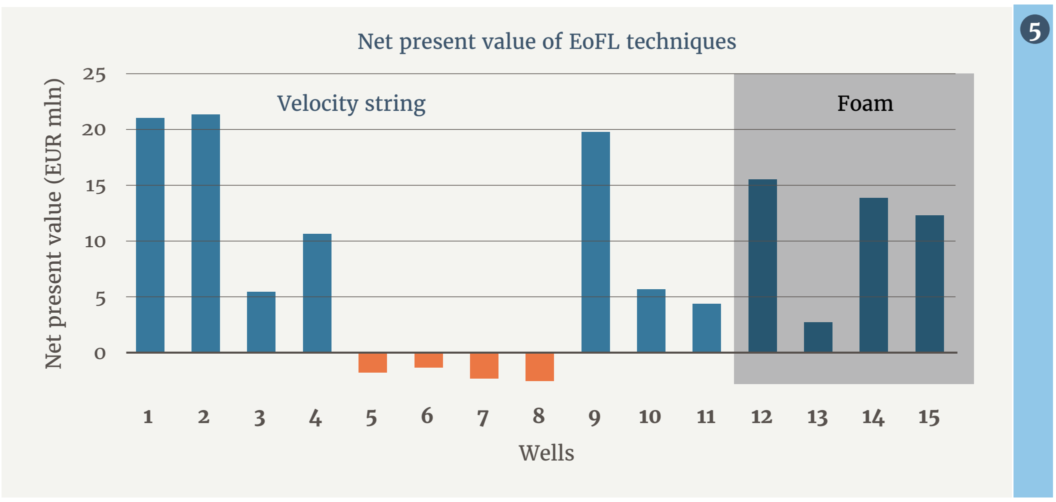


4.2 Gas well deliquification

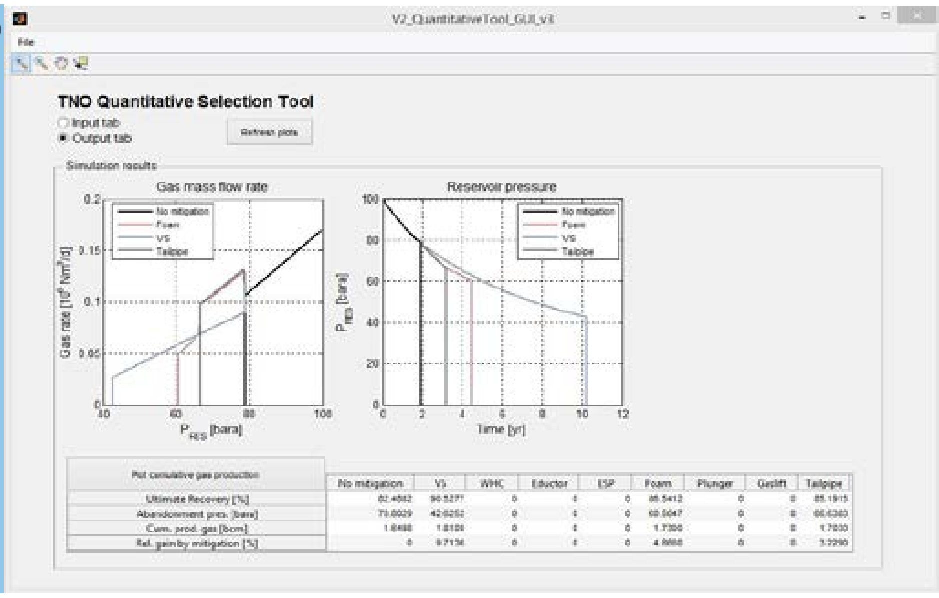
Mature gas wells in which the gas flow rate is insufficient to transport the liquids to the surface suffer from so-called liquid loading. Consequently, liquids will accumulate in the wellbore and can eventually cause the well to stop producing due to the back-pressure that is induced. An EBN inventory shows that liquid loading occurs in approximately 40% of gas wells once the reservoir pressure drops below a critical value of 100 bar. To mitigate liquid loading, gas well deliquification methods can be applied. Several gas well deliquification technologies are available, the most common being the installation of velocity strings and foam-assisted lift. Properly designed gas well deliquification methods are estimated to increase a well's ultimate recovery from roughly 85% to 95%. In addition to liquid loading, mature fields might suffer from salt precipitation. Projects aiming at mitigating salt precipitation were discussed in Focus 2016.

Actual gains from deliquification projects

In 2016, EBN evaluated the five-year historical performance of the EoFL techniques that use velocity strings and foam. The production from a total of 64 liquid-loaded wells was examined, showing that the volume gains using velocity strings or foam injection range widely. About half of the wells produced 10 to 15 million Nm^3 more due to the application of one of the techniques, and some of the remaining wells even produced an extra 100 million Nm^3 or more. This wide range is attributable to well and reservoir conditions. Pressure and inflow characteristics are the important factors affecting ultimate recovery from these techniques. 15 Wells were examined in more detail, particularly in terms of incrementral recovery and economics. First the volumes of the initial project proposal from the operators (i.e. their initial expectation) have been compared with volumes calculated by TNO's deliquification tool (described below). Subsequently actual incremental recovery from the first



6



date of the installation until the end of 2016 has been investigated. The volume gains per EoFL technique for these 15 wells are shown in Figure 4.

The deliquification methods show a high success rate for over 70% of the 15 wells that were analysed, with an NPV between EUR 2 – 20 million per well (Figure 5). The four wells that are already abandoned show a negative NPV, due to operational issues such as poor wellbore conditions and tubing leaks. These EoFL techniques have been demonstrated to be a very valuable asset for mature gas fields. The most important benefits are quantitative and economic and justify the cost of the installation. EoFL methods enable gas wells to remain in production beyond their technical limits, which increases the ultimate recovery.

Joint Industry Projects on gas well deliquification

The various Joint Industry Projects (JIPs) on gas well deliquification in which EBN has participated since 2011 have contributed to the understanding of the impact of reservoir properties on liquid loading in gas wells. The JIPs have resulted in the development of various qualitative and quantitative tools for selecting deliquification techniques and optimising foam. The first project, TNO JIP Deliquification Techniques (2011 – 2012), included a literature study in which US experience was translated to Dutch wells/reservoirs. Also a qualitative tool was developed to select the most suitable deliquification technique for a given well. Finally, a quantitative selection tool was developped that predicts the gains in production and ultimate recovery resulting from the application of a range of methods: velocity string, eductor, wellhead compression, electric submersible pump, foam, gas lift, plunger lift and tailpipe extension (Figure 6).

In the TKI-JIP Foamers for deliquification of gas wells (2012 – 2014), a standard procedure for foam testing was developed, including an improved description of the behaviour of foams under field conditions, resulting in a foam optimisation tool. A more fundamental project, TKI project Unstable flow in liquid loading gas wells (2015 – 2016), was addressing flow behaviour in a well in the unstable liquid loading phase and the influence of reservoir properties on the onset of liquid loading. In the laboratory, most liquid loading experiments are performed at fixed gas and liquid rates (mass flow controlled). In reality, well behaviour is the manifestation of a coupled well–reservoir system in which the reservoir characteristics determine whether the inflow into the well is controlled by pressure or by mass flow. In an innovative experimental setting (Figure 7), the relationship between pressure drop and actual flooding point was tested for reservoir characteristics ranging from tight to prolific. An important conclusion of the study is that stable production (in slugging conditions) is possible below the theoretical flooding point.

Recently the TKI-JIP Foam II project (2016 – 2018) has started. It validates the earlier mentioned foam model with field cases and aims at improving it further. The goal is to select the most suitable foam and operation parameters (such as concentration and volume) for gas well deliquification.

The overall lessons learned from these JIPs are:

- Liquid loading in gas wells can be understood and prognosed;
- The influence of the reservoir properties on the flow behaviour of a well in the unstable liquid loading phase is understood and it has been observed that stable production is possible below the theoretical flooding point;
- The tools developed will help to select the best method to apply to mitigate liquid loading: 1) the selector tool identifies the most suitable deliquification technique; 2) the quantitative selection tool quantifies the gains; and 3) the foam optimisation tool indicates the most suitable foam.

7

Experimental set-up JIP Unstable flow in liquid loading gas wells

The blue 300 litre pressure vessel on the right is connected to the wellbore model on the left.

Symposium ‘Produced water handling’

In 2016, EBN organised a one-day symposium on dealing with production water, attracting delegates from most of the Dutch O&G operators. The themes addressed during the workshop included new water-processing technologies, innovation and sustainability, all contributing to the challenge of handling water that is associated with mature field production. The workshop was organised jointly by EBN, TKI Gas and ISPT and was well received:

“It is very useful and valuable to hear the practical experiences of other operators in this area. Operators have shared a lot of knowledge with each other, and this helps us to identify promising technology and application methods which could be useful for us. By running the workshop the organisers have made it possible for everyone to be aware of the current state of technology.” **Harry Segeren, Wintershall**

“For TNO, a workshop like this is very useful. We now understand better what kind of problems operators are struggling with in this area and this enables us to help them more effectively. The workshop has definitely led to better mutual understanding.” **Maarten Bijl, TNO**


K17-FA-1
K17-FA-1

Infrastructure in a changing environment

5

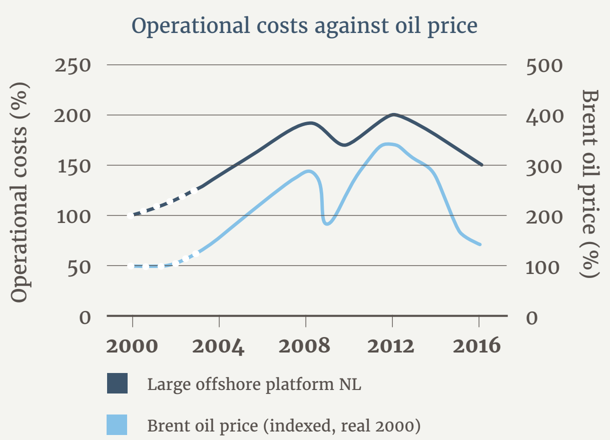
As described in previous chapters, there is a widely felt urgency to lower CO_2 emissions and at the same time reduce the development and operational costs. In the past, reductions in operational costs were often the result of temporary measures – operations were postponed until prices had recovered – but in the current situation this may no longer be the case. The enduring low gas prices and the rapid decrease of the gas reserves are forcing the industry to come up with innovative ideas. EBN embraces these initiatives and actively supports operators and the service industry in the Netherlands in the joint exploration of efficient solutions.**

5.1 Cost reduction initiatives

Figure 1 shows the indexed operational costs of large platforms on the Dutch continental shelf in comparison to the Brent oil price (RT, 2000). Clearly, cost optimisations should be well balanced with QHSE (Quality, Health, Safety and Environment) and production performance. Therefore, the fundamentals of operational and maintenance strategies need to be challenged. EBN is currently investigating a number of new projects, including setting up a benchmark on QHSE and production performance to assist the upstream O&G operations in the coming decades. A recent example of an industry initiative aiming at making operations more environmentally-friendly and cost-effective is NAM's Kroonborg walk-to-work service vessel. Propelled by relatively clean gas-to-liquids fuels, this service vessel is enabling NAM to overhaul its logistical processes, resulting in fewer helicopter flights. The novel vessel design incorporates several new applications to service unmanned platforms throughout the Southern North Sea. The Kroonborg also enables future platforms to be cost-effective, as functional requirements can be reduced when platforms are serviced by the Kroonborg – for example, there is no need for a platform crane. Other operators are currently investigating the feasibility of a similar (shared) walk-to-work service operating vessel.

Another ongoing development led by ONE B.V., with support of several other operators and EBN, is exploring the possible application of Zap-lok in the Netherlands. This novel cost-effective pipe joining method has been applied elsewhere in the world but still needs to be certified for use in the Dutch part of the North Sea.

1

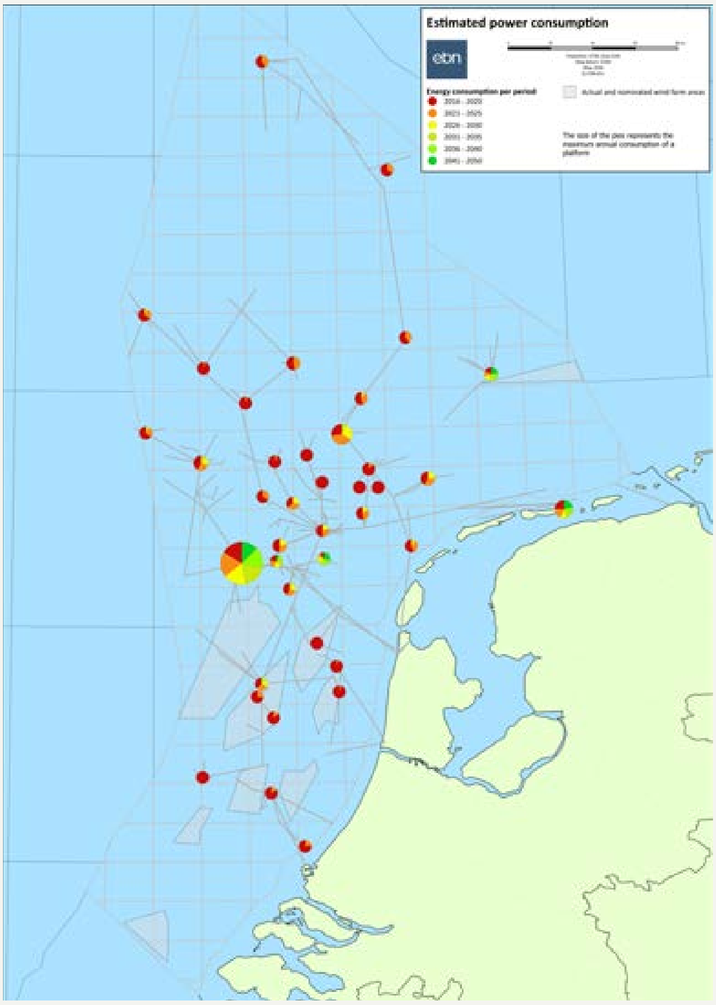


5.2 Integrating offshore wind with oil and gas production

The energy transition is being driven by the urgent need to reduce the CO_2 concentrations in the atmosphere, as noted in Chapter 1. There is a move from the dominant use of fossil fuels to a sustainable energy system driven by wind and solar power. This change is manifested on the Dutch continental shelf by the development of wind farms. Increasing the number of wind farms will in the near future result in the emergence of an electricity grid on the Dutch continental shelf – a development that creates opportunities for connecting offshore platforms to this grid.

To counteract the decline in reservoir pressure during gas production, compression is required. Offshore platforms far from shore generate their own power supply for this process. For economical reasons the design of the power generator on a platform is mainly limited by weight and available space, resulting in relatively inefficient power generation. Offshore wind farms on the Dutch continental shelf provide an

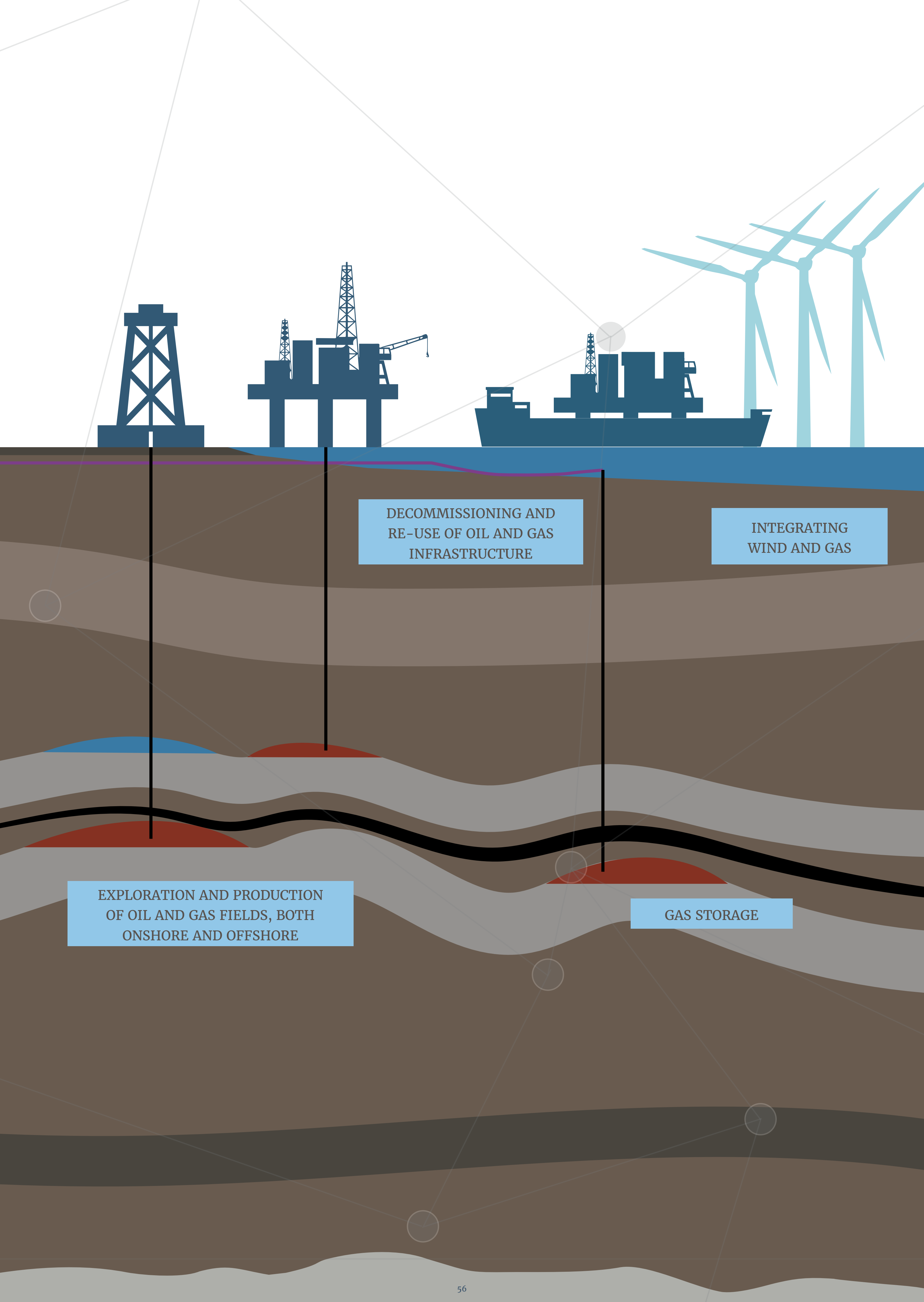
Possible scenario for power consumption of platforms



attractive alternative power supply. Connecting O&G platforms to the wind farms eleminates the need of local power generation on the platforms and subsequently reduces the CO_2 emissions dramatically. The effectiveness of the concept has been demonstrated on the near-shore platform Q13-Amstel, which is connected to onshore power supply.

Figure 2 shows a possible scenario for the energy consumption of O&G platforms over time until 2050. By way of illustration: assuming that 25% of the 40 gas production platforms that consume the most energy during their lifetime could be connected to a wind farm, an average reduction in CO_2 emissions from the offshore production platforms of up to 1 million tons of CO_2 each year could be achieved. The power consumption by the O&G platforms represents in such a scenario a wind farm of 400 MW with a 40% capacity factor.

Connecting O&G platforms to wind farms will not only improve energy efficiency and reduce CO_2 emissions on platforms, but could also benefit wind farms by increasing the number of turbines because of the power consumption increases. The operational costs of O&G installations are also lower, contributing to extending the lifetime of the installations and the production of offshore domestic gas. Apart from the additional state profits and the contribution to lower CO_2 emmissions from Dutch gas compared to imported gas, the strategy would provide more time to explore opportunities for the re-use of installations and reservoirs for innovations such as CO_2 storage, power-to-gas and energy storage.


DECOMMISSIONING AND RE-USE OF OIL AND GAS INFRASTRUCTURE
INTEGRATING WIND AND GAS
EXPLORATION AND PRODUCTION OF OIL AND GAS FIELDS, BOTH ONSHORE AND OFFSHORE
GAS STORAGE

Return to Nature

In the next few decades the upstream oil and gas industry faces a major challenge with regard to the decommissioning and re-use of infrastructure, both onshore and offshore. More and more fields are reaching the end of their economic lifetime, hence, infrastructure needs to be abandoned or re-used. EBN has taken the lead in this decommissioning issue by establishing a National Platform for decommissioning and will continue to strive for safe, sustainable and cost-efficient decommissioning of oil and gas assets.

Decommissioning and re-use of oil and gas infrastructure

6

The production of oil and gas has contributed considerably to the Dutch economy over the past 50 years. The upstream O&G industry in the Netherlands is mature and is facing a future in which hydrocarbon production infrastructure is to be decommissioned. EBN expects that the decommissioning of this infrastructure will take several decades. How long exactly, greatly depends on the number and size of new finds, trends in prices and the transition to renewable sources of energy. It is a shared responsibility of the O&G industry to decommission safely, environmentally responsibly and cost-effectively. At the same time, criteria for re-use and repurposing will be investigated in light of the energy transition. This is a joint effort, involving many stakeholders.

The energy transition towards a CO_2 neutral economy offers both challenges and opportunities for the future use of the infrastructure. In certain areas in the North Sea, O&G activities seem to be competing with new initiatives such as the development of offshore wind farms. Yet, if a well-organised approach is followed, there could be mutual benefits. These lie in the electrification of O&G platforms and the use of the infrastructure for power-to-gas and CO_2 storage. Several research projects are currently investigating how to transform the North Sea into a national 'powerhouse', as described in Section 5.2. Onshore, the re-use of O&G wells for geothermal purposes is being investigated and parts of the pipeline network could be used in the production and transportation of biogas.

6.1 The decommissioning landscape in the Netherlands

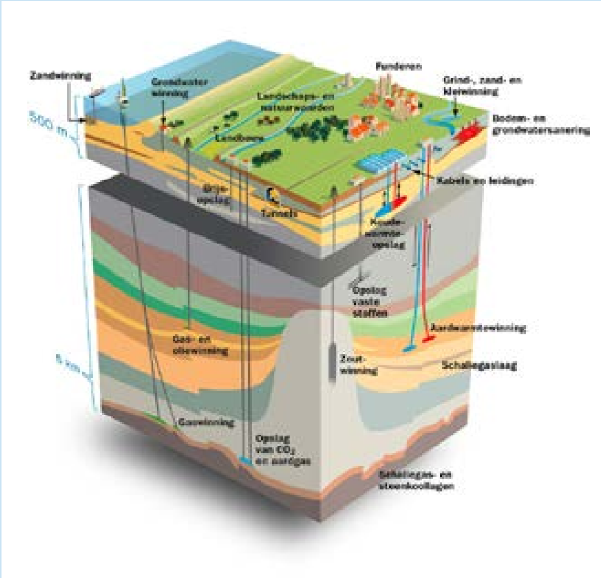
Under the Dutch Mining Act, disused on- and offshore mining installations must be decommissioned and removed. For offshore installations, under the OSPAR Decision 98/3, a derogation for removal may be requested for steel substructures over 10,000 tons, concrete gravity-based installations, concrete floating installations and concrete anchor bases. On the Dutch continental shelf, only four installations consist of a gravity-based substructure. All other installations have a steel jacket substructure.

In addition, disused offshore pipelines are required to be cleaned; they may be securely decommissioned and left in situ, but the Minister of Economic Affairs may also order their removal. Under the most recent North Sea Policy Document (Beleidsnota Noordzee 2016 – 2021), new offshore pipeline permits will include a requirement for the pipeline to be removed when no longer in use, unless it can be demonstrated through a social cost-benefit analysis that in-situ decommissioning is to be preferred. Pipelines onshore often cross private land. Decommissioning of these pipelines and restoration of the pipeline trajectory is typically covered in civil agreements with the landowners. Onshore well and production locations are normally required to be removed, also based on civil agreements with landowners. The Mining Regulations stipulate how wells are required to be securely plugged and decommissioned.

The estimated decommissioning costs amount to some EUR 7 billion in total for the Dutch upstream O&G industry, of which EBN bears approximately 40% directly through its joint ventures. Over 70% of the total bill for decommissioning will be paid by the Dutch State through EBN and reduced national gas income, which makes decommissioning a topic of national interest.

Overview of infrastructure

The total offshore infrastructure in line for decommissioning comprise 156 platforms, over 3,000 km of pipelines and about 700 wells. The total amount of steel associated with these offshore platforms approaches some 400,000 tons (Figure 1a). The platform topside weights range from 150 to 8,000 tons, with over 75% of the topsides weighing less than 2,000 tons (Figure 1b). This means that significant low-weight lifting vessel capacity needs to be available for decommissioning. Onshore,



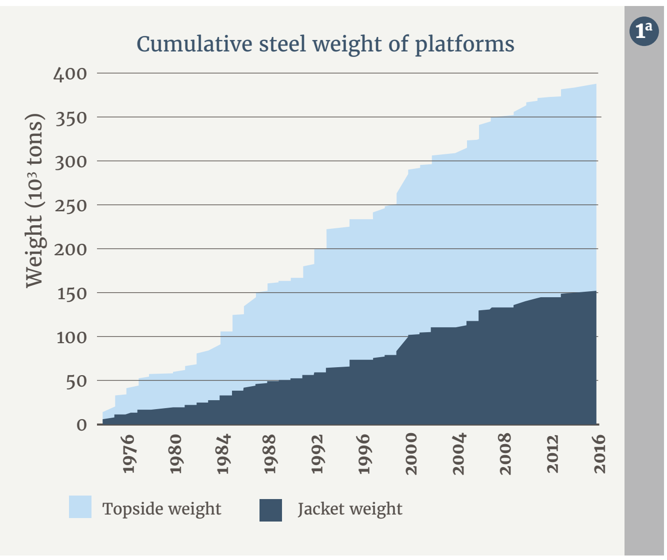
From: Ontwerp Structuurvisie Ondergrond

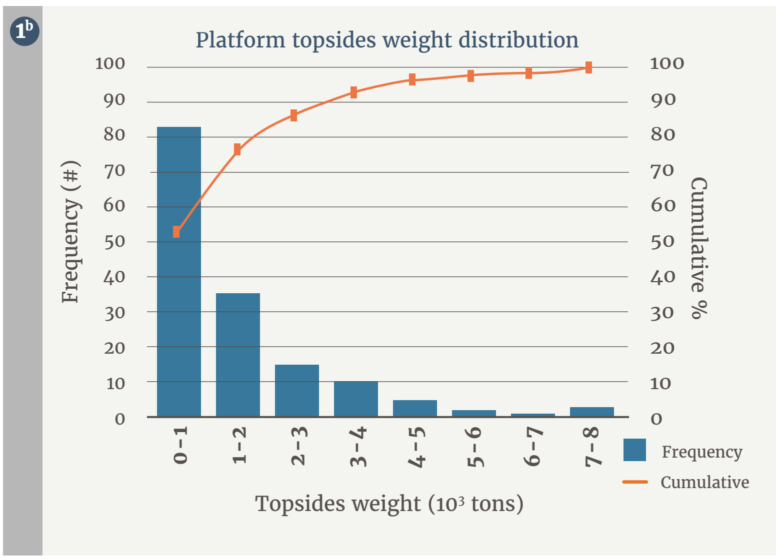
From www.noordzeeloket.nl

Spatial planning and shared use of the subsurface

The Dutch onshore and continental shelf have many different users whose activities interfere with each other. The Ministries of Economic Affairs and of Infrastructure and Environment have therefore drawn up policy documents for the spatial planning and use of the subsurface onshore (Ontwerp Structuurvisie Ondergrond) and a North Sea Policy Document (Beleidsnota Noordzee 2016 – 2021). With the transition to a sustainable energy market, the coordination of offshore O&G activities and the development of new wind farms requires careful attention.

The first wind farm on the Dutch continental shelf had 36 turbines and was installed in 2006, 10 to 18 km from shore, over an area of 27 km² (Egmond aan Zee, 108 MW installed capacity). After the Gemini Windpark set up 85 km off-shore with 150 turbines over an area of 68 km² (600 MW installed capacity) in 2017, the total number of offshore turbines will be 289. The number of wind farms installed on the Dutch continental shelf is likely to increase further over time and will potentially conflict with exploration and production of oil and gas.





the decommissioning entails over 350 locations (varying from processing sites and well sites to scraper stations), over 2,500 km of pipelines (excluding the GTS transmission system) and over 700 wells.

Timing

The actual date of decommissioning depends on many factors, the chief ones being prices and operating costs, but cash flow is also important. Furthermore, the investment level for new O&G projects such as new exploration and infill wells has a large impact on Cessation of Production (COP) dates. Historical performance indicates that on average, the interval between COP and physical removal is four years for the Dutch gas sector (Figure 2). In Focus 2016, COP dates for various gas price scenarios were presented: the results for these, based on reserves and contingent and prospective resources, are shown again in Figure 3.

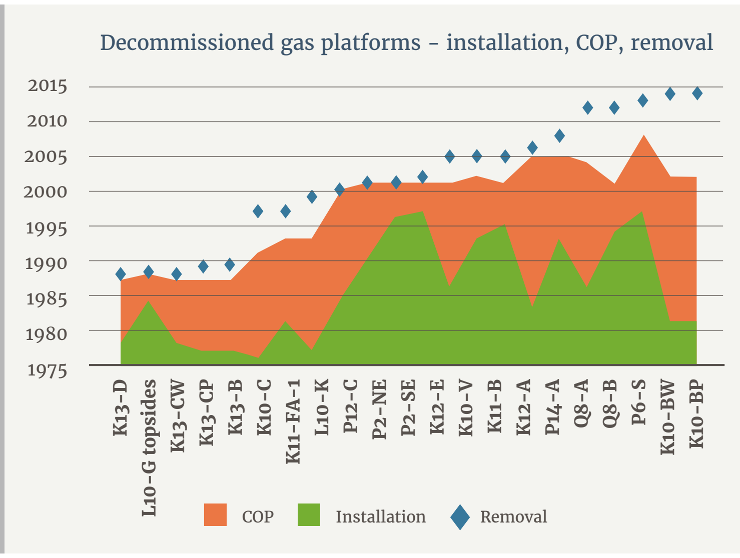
The low gas price has led to a sharp drop in the number of exploration and development activities and has brought several fields to the economic cut-off point. Despite the current low rates for drilling rigs and lifting vessels, there has been only a minor upturn in decommissioning yet, largely because of the cash flow constraints of operators and/or joint venture partners. Stakeholders are currently assessing how best to prepare for decommissioning, in order to benefit from the expected growing demand for decommissioning services.

Actual versus provisions

As presented in Focus 2016, recent decommissioning projects have been realised at higher cost than was provisioned for. The cost of well decommissioning particularly seems to be likely to be underestimated. An updated figure for the period 2011 – 2016 shows that on average, actual expenditure on well decommissioning has exceeded provisions by some 75% (Figure 4).

Each year, EBN receives estimates of decommissioning costs from all its joint venture operators, but the approach and details of these estimates vary greatly between operators. To obtain more realistic cost estimates and actuals, a guideline for using a common breakdown structure would be required, like the one created by Oil & Gas UK. If such data would be incorporated in a decommissioning

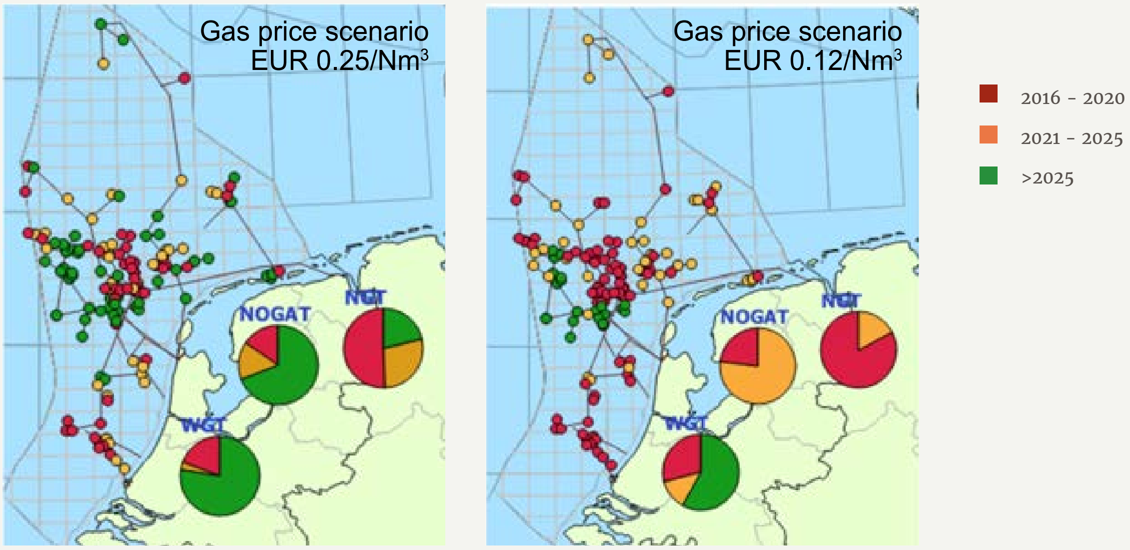
2



It is a shared responsibility of the O&G industry to decommission safely, environmentally responsibly and cost-effectively.

COP of infrastructure, best and worst case scenario

3



COP Based on reserves & cont/prosp resources

COP Based on reserves

From: Focus on Dutch Oil and Gas 2016, EBN

database, benchmarking would be possible allowing for more precise provisions for future projects.

Costs: five-year forecast

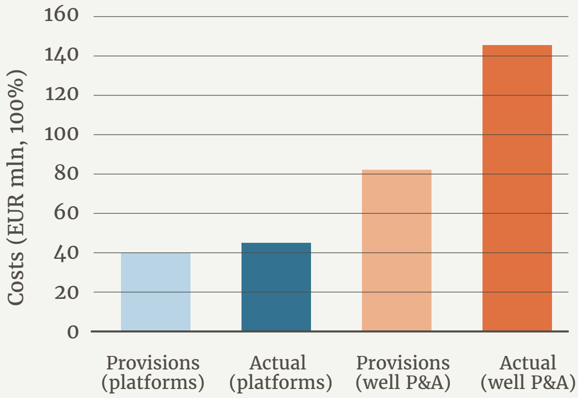
EBN has budgeted for a total of EUR 133 million for decommissioning activities in 2017 in all its joint ventures (100%). In total, 28 wells (nine onshore, 19 offshore) and three platforms and associated pipelines are listed for decommissioning within EBN's joint ventures. For the five-year period beyond 2017, between EUR 0.8 billion and 1 billion is expected to be spent on decommissioning (mainly offshore 100%). According to current estimates, decommissioning is expected to peak between 2023 and 2025 (Figure 5). EBN and operators are currently scrutinising the projected timing of decommissioning under the JIP for decommissioning and re-use in the first half of 2017, as described later in this chapter. In the second half of 2017, an updated and more detailed forecast will be presented.

Decommissioning optimisation in a multi-operator landscape

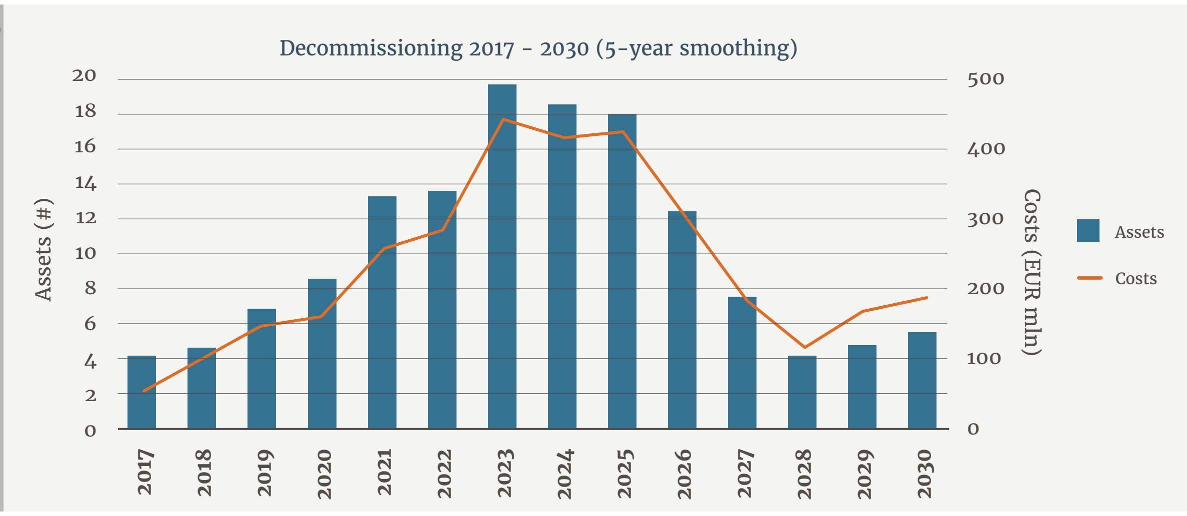
Given the large total scope of the decommissioning work, there is considerable potential to join forces in order to improve the efficiency and consequently optimise costs. EBN has investigated the potential benefits of collaborative decommissioning activities. A network optimisation model including offshore platforms, wells and technical reserves, has been developed to simulate total decommissioning costs under various scenarios and to investigate value optimisation on a portfolio basis, considering gas revenues, OPEX and ABEX (Abandonment Expenditure). The optimisation is based on pre-tax NPV. Two well-known concepts for cost savings have been introduced: 1) learn (apply learnings from previous projects) and 2) economies of scale (large contract volumes). Applying these concepts is a challenge, since the planned decommissioning projects are scattered over 30 years, and spread across ten operators.

Decommisioning costs 2011 - 2016
actual vs provisions

4



5



Multiple scenarios have been run, of which three stand out:

Reference case

No collaboration between operators, stop production of individual installations at zero margin

Operator optimisation

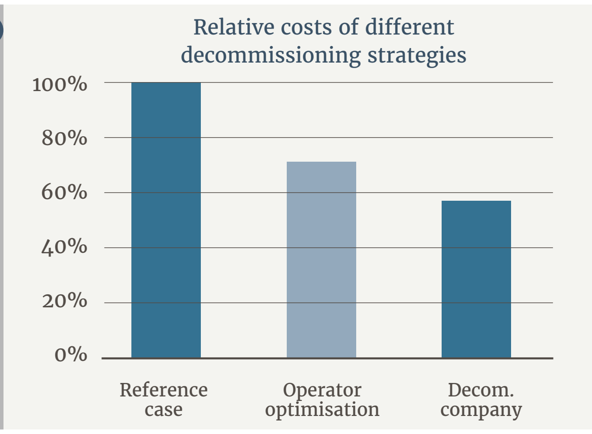
No collaboration between operators, optimise within individual operator portfolios

Decom. company

A separate company to carry out all decommissioning activities

The preliminary results (Figure 6) indicate that optimisation within each operator's portfolio leads to a large cost reduction compared to the reference case, because a few large operators own most of the platforms. The decommissioning company scenario introduces a new type of optimisation strategy, based on creating a constant workload, instead of creating workload peaks, as happening in the other scenarios. This helps in achieving both long-term (> ten years) learning curves, as well as long-term discounts on contract volumes. This scenario leads to an overall cost reduction of 40% compared to the reference case. The findings suggest that orchestrating the decommissioning for the complete offshore of the Netherlands could potentially save hundreds of millions of euros. Therefore a platform that unites all partners should be organised, and industry-wide standards (technical, QHSE, legal) and databases and optimisation models should be developed.

6



6.2 Decommissioning: a joint effort

Given the opportunities and challenges ahead, it is important that the industry partners collaborate closely in decommissioning and re-use, as described in the previous section. In November 2016, *The Netherlands Masterplan for Decommissioning and Re-use* was presented, calling for closer collaboration in various decommissioning and re-use topics. The Masterplan was developed jointly with NOGEPA, IRO and EBN, and contains ten roadmaps (figure 7), each with an agenda of what needs to be done to make decommissioning a success for all. The objective is the safe, environmentally responsible and cost-efficient decommissioning of O&G infrastructure. Four initial priorities have been defined:

- Establish a National Platform that drives the Masterplan forward,
- Establish a National Decommissioning Database to create an integrated view of the work scope and timelines,
- Promote effective and efficient regulation in dialogue with regulators, to improve the clarity, efficiency and effectiveness,
- Establish mechanisms to share learnings, to achieve continuous improvement in cost and performance.

A JIP was launched in March to start executing the priority topics of the Masterplan in the first half of 2017. The project team comprises over 30 persons from nine operators, EBN, and the Boston Consulting Group for providing project support.

In addition to the priority topics, other roadmaps will be launched in 2017. The goals to be achieved by the end of 2017 are:

- Identify opportunities for future joint campaigns,
- Define harmonisation programmes for the most critical and decommissioning operations with the highest value,
- Launch a decommissioning and re-use innovation programme,
- Create a mechanism to incorporate international sources of information and to capture international decommissioning experiences.

National Platform

The priority objective of the JIP is to launch a National Platform that by Q3 2017 should drive the national agenda for decommissioning and re-use of O&G infrastructure. The goal is to serve as the umbrella organisation that proactively coordinates, facilitates and seeks dialogue on this agenda. It is expected that the platform will be established by a group of stakeholders with a key interest in decommissioning and re-use, and that over time it will expand as many more parties join in.

On the short term it is intended to achieve the following:

- Detailed design for the National Platform, including agreement on funding, governance and membership;
- Tools and processes for running the National Platform agreed and finalised;
- Agreements covering legal aspects defined for establishing the National Platform.

National database

Another goal is to centrally capture general parameters of Dutch O&G infrastructure, in order to provide an accurate overview of this infrastructure. This would yield accurate insight into the number of wells and components of infrastructure, estimated and actual costs, as well as various other details of interest to operators, the service industry and other possible stakeholders. The database can help to identify potential opportunities for collaboration between operators and/or the service industry through joint decommissioning campaigns. Another possible application lies in the identification of re-use opportunities for new field developments or repurposing opportunities such as CO_2 storage, power-to-gas, geothermal energy, and synergies with wind farms.

Regulation

The regulatory environment will fundamentally impact the efficiency and effectiveness of the Dutch decommissioning agenda. Regulation ranges from international treaties (e.g. OSPAR) to national legislation (e.g. the Mining Act and ancillary regulations). Most of these regulations were created at the end of the last century and do not always reflect the most recent practical experiences with decommissioning, technical innovation and other insights. As the industry is facing a huge decommissioning challenge over the coming decades, a robust, reliable and unequivocal set of rules is of essence. Therefore, as part of the masterplan, a regulatory joint industry working group (comprised of EBN and operators) has been created, with the goal of enabling the industry to work within a clear and consistent set of regulations, in line with technical best practices and innovations, to support safe, effective and efficient world-class decommissioning and re-use. The approach is to identify topics for improvement, and to prioritise and engage stakeholders and regulators in a structured dialogue. The potential value and viability of the topics will be assessed and for each, the costs and benefits of alternatives will be considered. This analysis, along with stakeholder feedback, will result in a list of priority subjects.

Shared learnings

In the past few years, large international decommissioning projects have been able to secure significant cost savings of up to 40% by efficient transfer of experiences. It is more challenging to achieve such savings in the Netherlands, because large offshore structures with many wells are lacking to continuously improve on the execution of the work scope. Well abandonments have not developed into a core activity and often occur every few years under new management and contractor teams. As a result, abandonment projects go through a new learning curve each time.

The solution for a more efficient way of executing decommissioning projects in the Netherlands lies first and foremost in creating a critical work volume in which the activities can be executed for a long and continuous period by specialised teams. Additionally, a platform is required in which learnings can be shared between peers and the supporting industry to ensure that smart solutions can be repeated and previous mistakes avoided. To accomplish this, a new level of cooperation and mutual trust has to be created between the various stakeholders and within the decommissioning platform. Workshops and conferences will be organised regularly to share experiences and a database will be created in which all relevant learnings are kept for future reference. The shared learnings working group is responsible for developing an environment in which the goals described above can be accomplished efficiently.

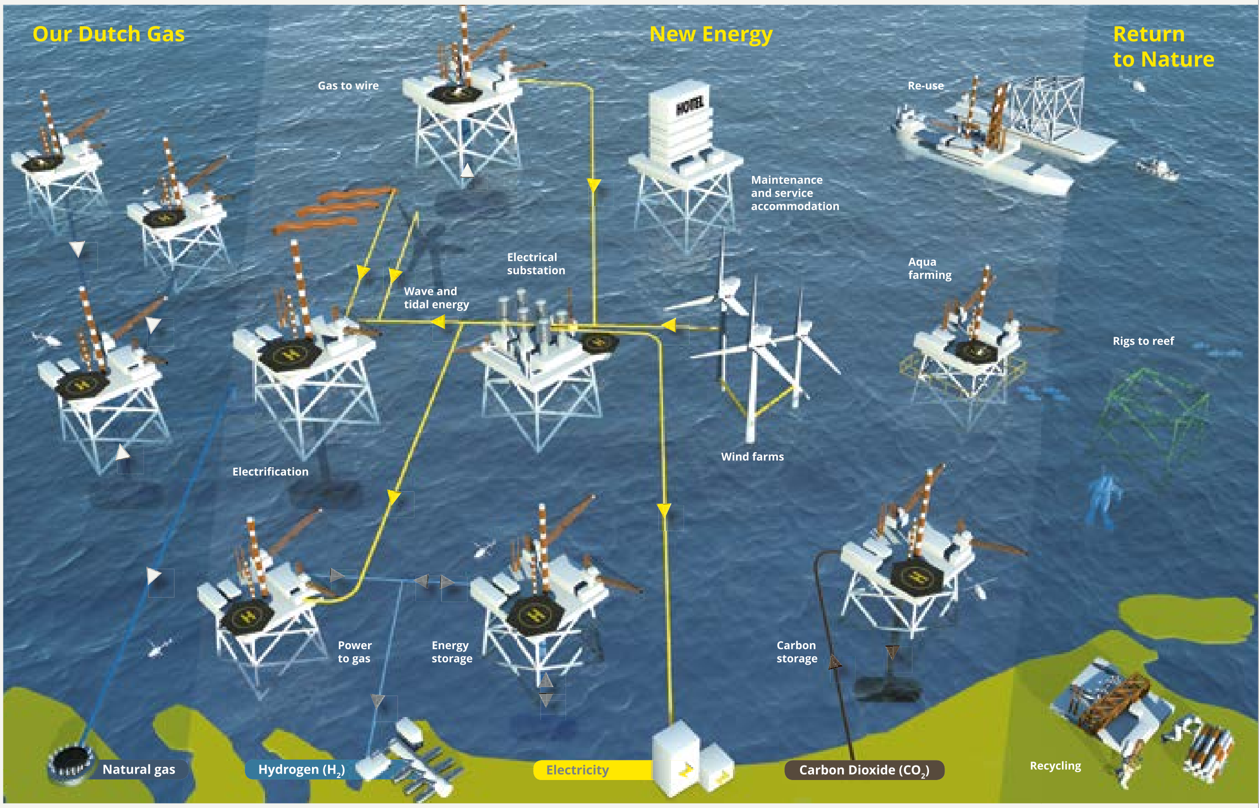
6.3 Future use of installations: re-using, repurposing and recycling

Sustainable dismantling of the infrastructure on the Dutch continental shelf is key and all the possibilities for future use should be investigated (Figure 8). Naturally, the first choice should be to consider re-using the infrastructure for the application it was originally designed for (oil and gas) and this should be taken into account when designing the infrastructure. A second option would be to utilise the infrastructure for alternative purposes, such as power-to-gas, CO_2 storage and CAES. As a last option, the materials should be optimally recycled.

So far, 11 topsides have been re-used for other hydrocarbon field developments (see Focus 2016). An innovative option for re-use is the repurposing of a platform or pipeline. However, without the availability of power, a platform's usefulness is very limited. This could be overcome by electrifying the

Future potential of North Sea platforms

8



International joint efforts

Decommissioning is also a hot topic in other countries, and there have been several large projects that have made significant progress in working in a smarter and more cost-effective way. It is of the utmost importance to stay up to date with new developments abroad and at the same time share Dutch experiences internationally.

The Netherlands Masterplan for Decommissioning and Re-use has not gone unnoticed by neighbouring North Sea countries. Dutch efforts to jointly organise the agenda have been presented in various international conferences, such as Offshore Energy (the NPF Decommissioning Conference in Norway) and Decom Offshore in Aberdeen. The Netherlands is now a front runner in its experience on how decommissioning and re-use could be organised from a national perspective. Denmark, Norway and the UK are following the joint execution of the masterplan with great interest.

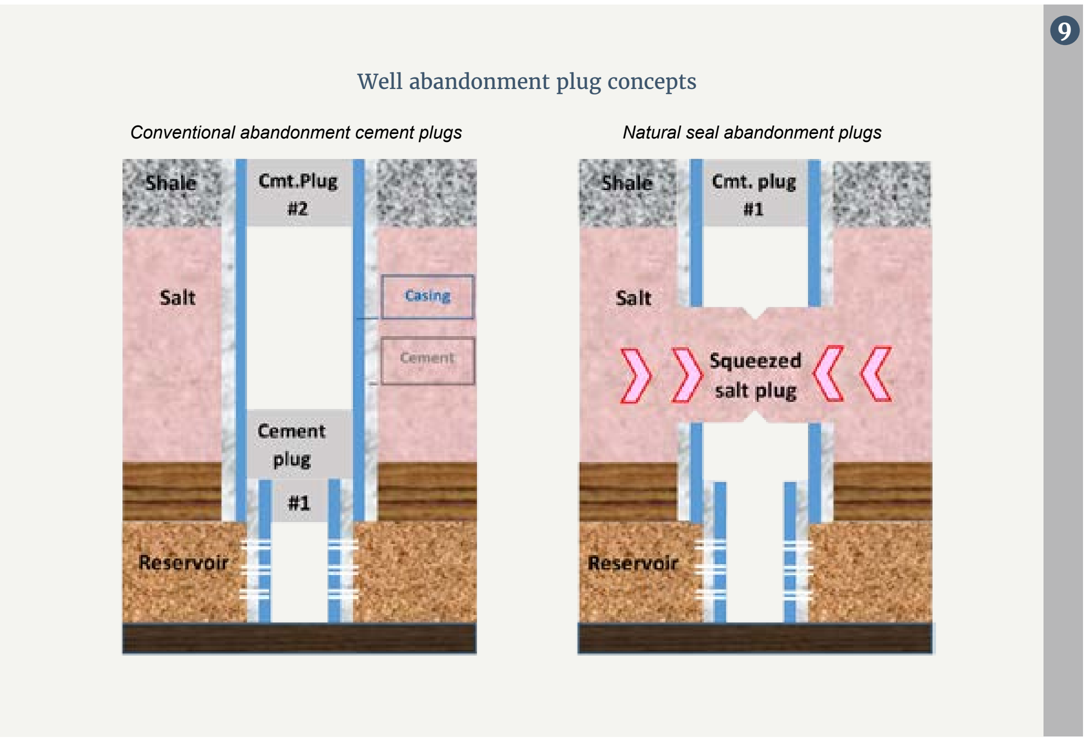
Together with international counterparts such as OGA (UK), NPD (N) and DEA (DK), EBN plans to organise a North Sea Forum on decommissioning and re-use in the second half of 2017. Subjects to be discussed include an international database and collaboration, technology trends and research initiatives, quality and cost-effective harmonisation and repurposing challenges.

platform by wind farms, as energy is available on these platforms even after gas production has ended. Moreover, the power interconnection enables the platform to act as an electrical entry point for electricity generated sustainably on the North Sea. Tidal and wave power generation could more easily be introduced if power hook-ups are available across the North Sea. New industries that consume power, such as power-to-gas, CO_2 storage, CAES and aqua farming, also benefit from a power grid on the Dutch continental shelf. Therefore it is important to investigate ways of prolonging a platform's life by electrification (see also Section 5.2).

Figure 8 illustrates the future possibilities of re-using and repurposing electrified platforms in the North Sea. As the number of activities taking place in this area grows, it is to be expected that new ideas for system-integration and dealing with decommissioned platforms will emerge. The decommissioning project for the Dutch continental shelf has therefore stipulated re-use as one of the important topics to be further investigated.

6.4 Innovative decommissioning – natural seals

Well abandonment entails plugging the wellbore with various pressure and fluid/gas resistant barriers before removing the wellhead and cutting off the well several metres below the surface. To ensure the integrity of the installed barriers, a combination of different blockades or a cement plug that is very long is often used, to prevent flow of hydrocarbons. Alternatively, formations like salt and claystones could potentially be used as natural seals when abandoning wells (Figure 9). These formations have effectively kept hydrocarbons locked up safely inside the earth for millions of years, because these rocks are impermeable. In addition, salt and certain claystone formations are ductile, which means that they are able to flow and to fill voids, such as the uncemented parts of a well. In order to use this possible sealing capacity, not only the outer casing annulus, but also the main bore must be removed, or weakened – for instance, by perforating it to allow the ductile formations to flow in.



To prove the concept and its integrity, field trials are required. In TKI-JIP Downhole field lab – Wellbore sealing by rock salt with TNO and various operators, EBN is actively involved in studying the potential use of these natural seals. The most suitable formations, and techniques to activate, monitor and test the squeezing and sealing effect will be thoroughly investigated before its application can be approved by State Supervision of Mines. This innovative method may lead to more durable and cost-efficient down-hole seals.

Repurposing: rigs-to-reef pilot

Redesigning a limited number of production jackets for 'new nature' is considered a viable option to locally improve the biodiversity in the North Sea. The approach has been shown to be successful in several rigs-to-reef programmes elsewhere in the world. EBN and ENGIE E&P Nederland B.V. together with experts from universities, research institutes, NGOs, governments and fisheries, have developed a feasibility plan for a pilot project consisting of two mining installations that will be re-used as a structure aimed at enriching nature in the L10 blocks. The pilot period of 15 years will yield valuable lessons for future projects. The proposed design will be optimised further and then presented to the government and other stakeholders.


SCALDIS
ALDIS-SMC.COM
MBIZ

Integral agreements are essential

Interview with Floris van Hest, Director of Stichting de Noordzee (the North Sea Foundation)

© Steven Snoep

The North Sea is an important source of energy for the Netherlands, where oil and gas are extracted and the building of various wind farms is proceeding apace. How can we safeguard the North Sea's wildlife?

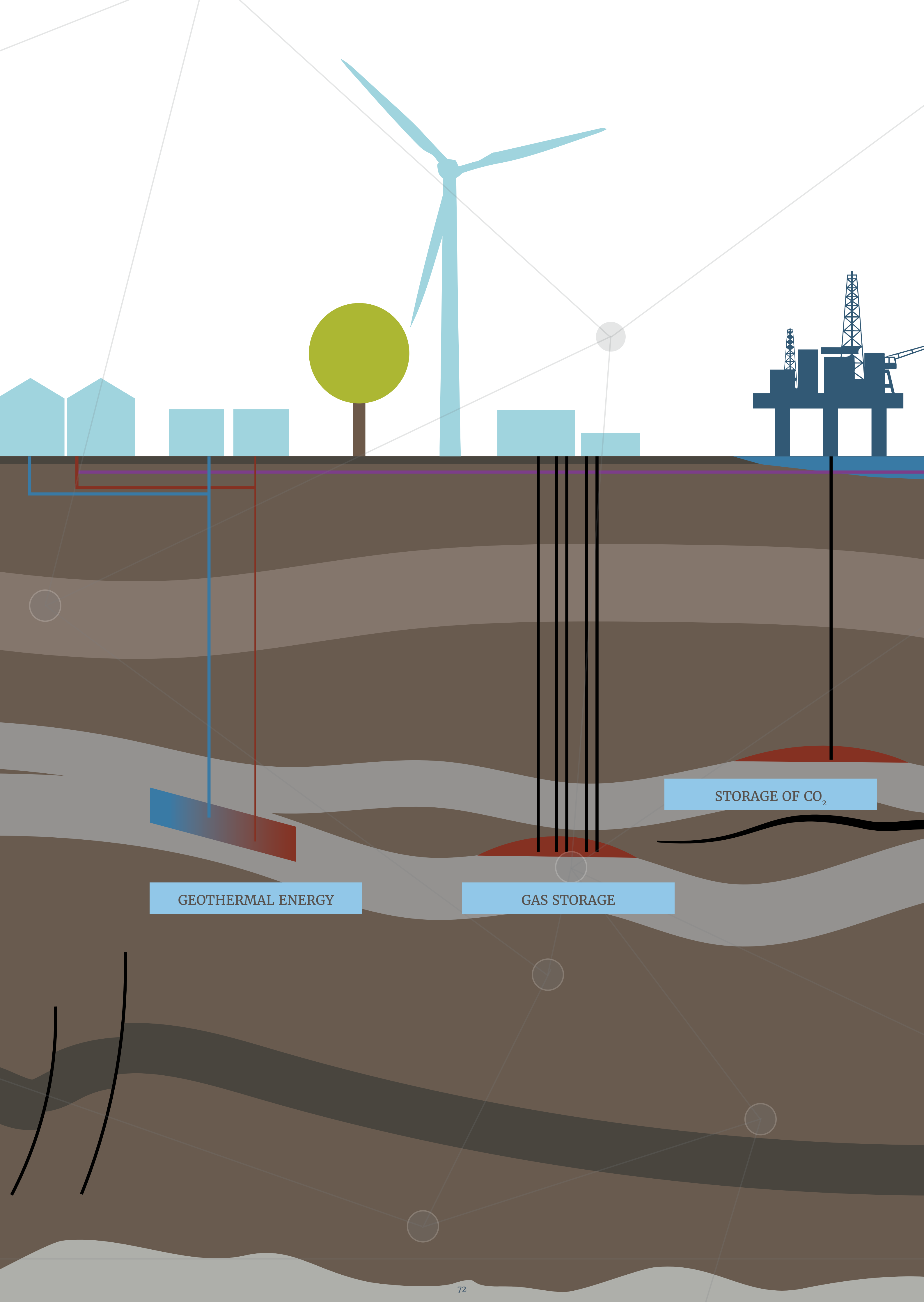
The North Sea could be healthier – that's indisputable. I am referring, for instance, to the oyster reefs that have vanished, several species of large fish, such as rays and sharks that have been diminished, and the plastic and other rubbish floating in the sea. With regard to North Sea energy, we can expect developments in the coming years to carry on accelerating: more wind turbines, but a decrease in the infrastructure for oil and gas production. That's what we're facing. So, within that arena we're trying to minimise the risks and to maximise opportunities from an ecological perspective. That's a big ask, but by adopting an integral approach it should be possible not only to conserve wildlife but also to reinvigorate it. The development of wind energy on the North Sea is an activity that as well as bringing threats also offers opportunities for new life, because wind parks can serve as habitats for many fish and crustacean species. Decisions made in the coming years will determine what the North Sea will be like in the coming years. We see huge opportunities to bring the beautiful North Sea nature in balance with sustainable activities.

Given all the developments in the North Sea, what should be done to achieve the best result?

I think we need to look for integrality. Together, we – all the parties involved and certainly also the government – are looking to see how we can guarantee the long term. It's time to make integral agreements and to implement stable policy that contains all present and future activities as well as nature. This can only be done with parties that commit themselves to the North Sea for the long term and take account of all users and inhabitants, both existing and new.

There are about 155 platforms in the North Sea, most of which will be dismantled or repurposed in the coming years. What's your take on this?

As fields in the North Sea are rapidly nearing their end of life, there is an urgency to consider how to deal with all the infrastructure left redundant. We would like to see ecological considerations being included in discussions on different decommissioning scenarios. We therefore welcome ENGIE and EBN's decision to start a pilot project turning two platform jackets into artificial reefs, as this can provide a factual basis for discussions surrounding the fate of future platforms. As well, I'd like to challenge the parties involved in the decommissioning and repurposing issue to demonstrate – using realistic calculations – whether or not the repurposing of platforms is economically viable. These business cases can change the focus of the current debate from an interesting idea to fact-based decision making. At the moment I miss such an approach. After several years of exploring ideas about repurposing of infrastructure I feel it is time to build solid business cases for repurposing of infrastructure and to make these business cases publicly available.


STORAGE OF CO_2
GEOTHERMAL ENERGY
GAS STORAGE

New Energy

With its potential for geothermal energy, energy storage and Carbon Capture Utilisation and Storage, the Dutch subsurface can contribute significantly to the transition towards a CO_2-neutral energy system. Building on our long history in gas and oil projects and our expertise on the subsurface, EBN is exploring these possibilities and is contributing to a carbon-neutral energy future.

Geothermal drilling MDM GT 06

© Kenneth Stamp on behalf of ECW

Geo-energy from the Dutch subsurface

7

With its potential for geothermal energy, CCUS and energy storage underground, the Dutch subsurface can contribute significantly to the transition towards a sustainable energy mix as described in Chapter 1. EBN can directly help accelerate the development of these activities just as it has done successfully for decades for Dutch oil and gas. It can do so by deploying its broad knowledge and expertise on the subsurface, project development, investments and proactive partnership with operators. EBN is in a position to identify synergies amongst these subsurface activities.

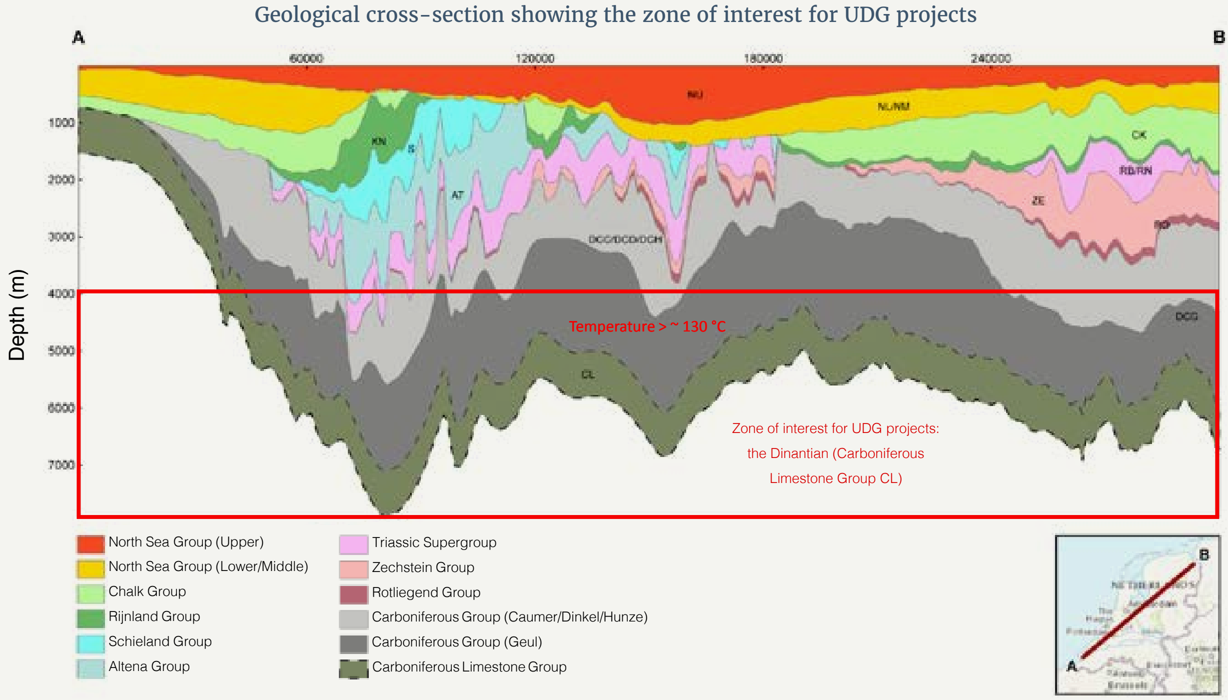
7.1 EBN's involvement in geothermal energy

Based on EBN's expertise on the Dutch subsurface, the Ministry of Economic Affairs requested EBN to explore whether it could contribute to the development of geothermal energy in the Netherlands. This collaboration between the Ministry and EBN has resulted in three areas of investigation:

- Assessing the possible potential of ultra-deep geothermal energy (UDG);
- Accelerating the development of 'regular' geothermal energy in the province of Brabant;
- Developing geothermal energy for the Dutch 'heat roundabout' (a heating scheme for industrial, utility, horticultural and domestic consumers) in general and in the province of South Holland in particular.

The first area of investigation has led to EBN becoming strongly involved in developing the framework how to optimally explore the potential of UDG. The second has resulted in EBN teaming up with the parties of the Green Deal Brabant on behalf of the Ministry to identify ways to accelerate the geothermal projects. For the third area EBN discusses how to optimally develop geothermal energy in combination with heat networks with the relevant parties in South Holland. So far, EBN's role has been to share its expertise on integral subsurface project development, including its portfolio approach. Using the regular business methodology it applies to its O&G activities, EBN induces commercial parties to cooperate in UDG development and to accelerate the

1 Geological cross-section showing the zone of interest for UDG projects



development of regular geothermal projects as safely and cost-effectively as possible. Currently, EBN's role in those emerging activities is being reviewed by the Ministry of Economic Affairs.

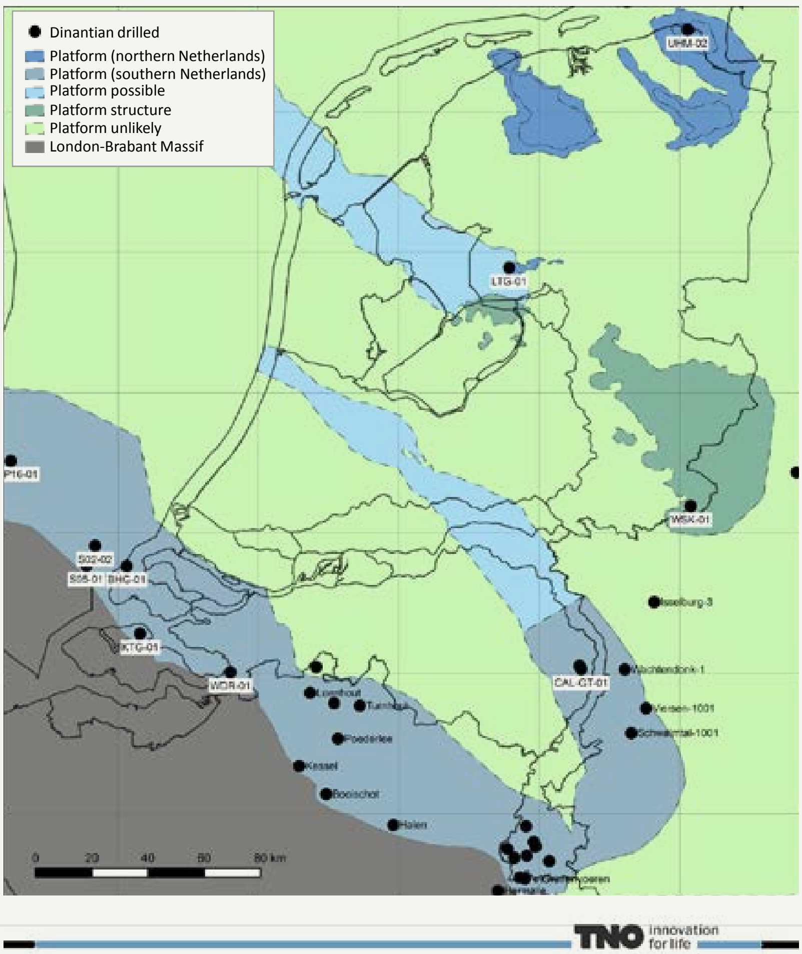
7.2 Exploring the potential of ultra-deep geothermal energy

At the beginning of 2016 the Ministry of Economic Affairs, EBN and TNO embarked on a collaboration to explore the possibilities for the development of UDG in the Netherlands. The goal is to investigate its potential by identifying the best pilot project(s) that can be developed in the near future, preferably before or around 2020. It is anticipated that UDG can potentially deliver an important contribution to the transition to a sustainable heating system, especially to the demand for higher temperature heat for industrial processes, where temperatures over 130 °C are necessary. To reach these temperatures, geothermal reservoirs at depths over 4 km are required in the Netherlands – depths in the Dutch subsurface that very few operators have drilled. Both geologically and technologically, these pilot projects are exploratory and will require innovative methods.

Together with the Ministry and TNO, EBN has organised several workshops and meetings identifying consortia with potential pilot projects that are able to optimally develop these complex projects on this ambitious timeline. Based on the – still limited – amount of subsurface data and knowledge of the Dutch subsurface at large depths, the Dinantian play was identified as the most promising play to exploit (Figure 1). The economic potential of this geothermal play concept depends both on the amount of subsurface heat it could produce and on the demand for heat at the surface, because of the limited distances over which the heat can be transported.

2

The three Dinantian sub-plays



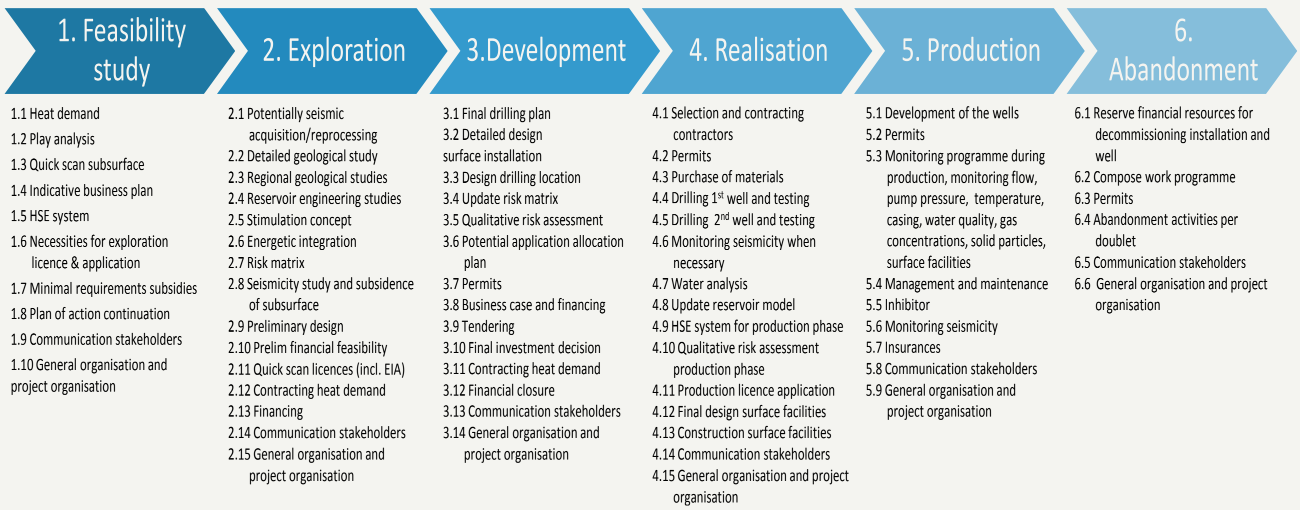
At the moment all parties involved are discussing the possible ways to move forward to cooperate and invest in the development of the pilot project(s) to explore the UDG potential in the Netherlands. A first step would be to further investigate the subsurface of the Dinantian in three regions or sub-plays: Dinantian North ('Friesland'), Middle ('Midden-Nederland') and South ('Rijnmond') (Figure 2). The three regions could best be modelled as joint effort to identify the most suitable projects. EBN anticipates there will be ample room for synergy between the three sub-plays, resulting in increased quality and costs reduction. The ultimate objective is to unlock the UDG potential in the safest, most cost-effective way.

7.3 Accelerating development of geothermal energy in Brabant

On April 14 2016 the Ministry of Economic Affairs, the province of Brabant, several municipalities, Energiefonds Brabant, Hydreco Geomec, several heat users and housing corporations in the province of Brabant signed the Green Deal Brabant. In this Green Deal, the parties have committed to accelerate the development of several geothermal projects in Brabant by reaping the benefits of the economies of scale. The Minister of Economic Affairs subsequently asked EBN to collaborate with Geothermie Brabant B.V. to identify, quantify and qualify such economies of scale, and to capitalise these benefits.

Based on its expertise in approaching subsurface projects from the broader perspective, EBN has worked together with Geothermie Brabant B.V. on the analysis of two concepts: integral geothermal project management and the introduction and application of the portfolio approach for Brabant. Both have great benefits compared to the development of stand-alone geothermal projects. Integral project management involves the contribution of quality and attention in earlier phases of activities in the geothermal life cycle to the predictability, quality and cost efficiency of the later phases, e.g. during production (Figure 3). The lessons learned from one development serve as input for the next and add to optimal project development. Besides collaborating on integral project management, EBN is working together with TNO and Geothermie Brabant B.V. on applying a portfolio approach to the potential

3



geothermal projects in Brabant. Here too, significant benefits have been identified. These include:

- De-risking the geology, especially during the exploration phase of geothermal plays. This could transform negative NPV for stand-alone development into a positive NPV for a portfolio of projects by means of optimal play development;
- Significant cost reduction possibilities because of synergy of repetition and economies of scale (e.g. standardisation, larger-scale procurement and the build-up of expertise and track record);
- Investment benefits (risk sharing and reduction, and cost reduction);
- Continuous improvement on safe and integral project development through learning effects on for example legislation, regulation, QHSE, stakeholder management and cooperating with local civil society;
- A more structural R&D and innovation programme to ensure medium- and longer-term improvements.

Initial results of the analysis are very promising and suggest that for the development of geothermal energy in Brabant, but probably also in the Netherlands in general, it would be beneficial to incorporate both the concept of integral project management and the portfolio approach.

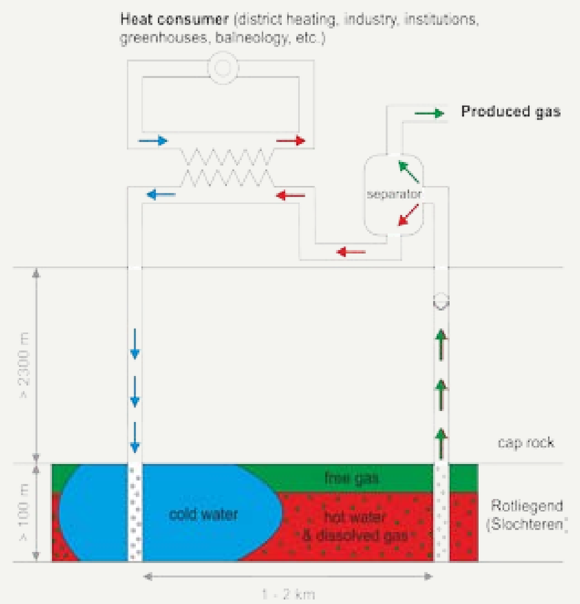
7.4 Geothermal energy in the ‘heat roundabout’

The concept of the ‘heat roundabout’, as mentioned in Section 7.1, encompasses infrastructure to transport heat from various producers (waste heat and geothermal heat) to industrial, utility, horticultural and domestic consumers. Recently, further investigation of the contribution of geothermal energy to this scheme started. Together with parties from the geothermal sector but also Gasunie, the Province of South Holland and other parties, EBN is discussing how – from a business perspective – the transition to a sustainable heat supply can be accelerated. EBN’s contribution includes introducing the concept of integral project management and investigating how the portfolio approach could benefit both the subsurface and surface aspects of development.

Re-use of a gas well for geothermal energy

In addition to its activities in KVGN, EBN also stimulates research projects on the synergy potential between geothermal and oil and gas. One of these studies by University of Groningen focuses on the combined production of heat and gas from ‘watered-out’ gas fields with strong aquifers, as illustrated in the figure. In this concept, a watered-out gas field is (re)used as geothermal aquifer: cold water is injected into one well and gas and hot water are produced from another well. The project will study the feasibility of the concept, focusing on whether there is a synergy benefit in the combined development of the geothermal aquifer and the production of the gas in the field.

Combined production of heat and gas



7.5 Potential synergies between geothermal energy and hydrocarbons

In Focus 2016 EBN addressed the potential for synergies between hydrocarbons and geothermal projects. Both sectors have now joined forces to investigate how those synergies might be exploited: the geothermal sector represented by SPG and DAGO is now working together with the gas sector represented by KVGN, a collaboration between Gasunie, GasTerra, Shell, NOGEPA and EBN. Initiator EBN is hosting an exploratory roundtable discussion on behalf of KVGN called Sustainable heat: synergy between gas and geothermal. Topics will address technical subjects as well as communication, QHSE, legal and operational issues:

- Shared subsurface data, knowledge and expertise, one of the topics mentioned by the Minister of Economic Affairs in his letter to the House of Representatives regarding methods to stimulate sustainable energy production. The O&G industry has vast amounts of seismic and well data, some of which is in the public domain. Recent wells and/or (re)processed seismic data are confidential and as such not yet available to the geothermal sector. The round table will investigate how access to data could be improved.
- Investigating re-use of O&G wells for geothermal projects (text box) and dual-play concepts. The possibilities of combined heat and gas production or de-risking of geothermal projects by oil or gas wells (or vice versa) will be assessed. This also includes surface aspects, such as the heat demand of industry, buildings and the horticulture sector.
- Safe and responsible shared use of the subsurface, including exchange of knowledge on QHSE, but also exploring how the O&G and geothermal communities can deal with common themes such as licensing, seismicity, communication and regulation. Here the successful coexistence with other subsurface activities will also be addressed, including drinking water projects.

7.6 Carbon Capture Utilisation and Storage

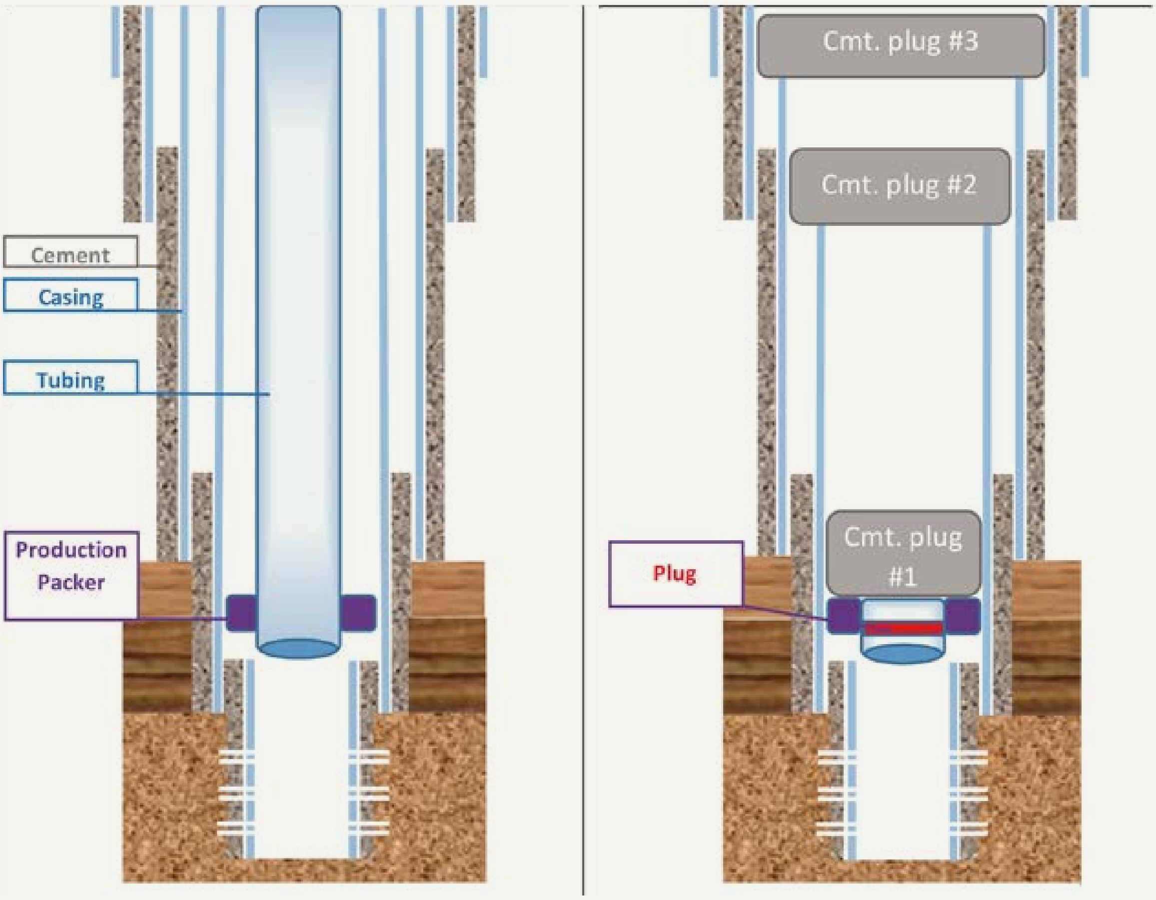
The signing of the Climate Treaty in Paris in 2015 and the goals for a carbon-neutral energy economy by 2050 have enhanced interest in CCUS. The Ministry of Economic Affairs and industry parties have already done much work on how to develop the first pilot projects in the Netherlands. Such projects are complex and involve much preparation. In these trajectories EBN has worked with its partners on the Rotterdam Opslag en Afvang Demonstratieproject (ROAD) that is still under development. Recently, the Ministry of Economic Affairs launched an initiative to develop a roadmap for CCUS in the Netherlands before the end of 2017. It has requested Gasunie and EBN to execute a study that includes an updated inventory of the storage potential in Dutch depleted O&G fields and a number of realistic scenarios for the first phases of offshore storage at a larger scale. Later in 2017, EBN also plans to explore the various options for underground energy storage. Both these studies are examples of EBN’s active contribution to studying and discussing aspects of the energy transition that relate to EBN’s core expertise.

Workshop on shared data, knowledge and expertise

The subsurface is being used for a multitude of reasons: to produce water (including drinking water), oil, gas, minerals (salt), heat and cold (geo-cooling). All these applications require holes to be drilled to depths varying from 50 to 5000 m. Concerns have been raised about whether interference can be prevented when the boreholes are close together and about the drilling fluids that are used. In view of future onshore drilling for both hydrocarbons and geothermal energy, a workshop for the various stakeholders was organised, aiming at exchanging knowledge. When comparing methods of drilling, it appeared that the fundamental differences were small. In particular, the types of fluid used to drill drinking water production wells were identical to those used to drill geothermal and O&G wells in the same geological formations.

Isolation of drinking water layers when drilling wells for other purposes is of prime importance to avoid contamination. This is accomplished by building a so-called bentonite filter cake seal against the freshwater sands during the drilling process to avoid penetration by drilling fluids. Furthermore, a layer of cement between the drilled hole and the protecting steel pipe (casing) is permanently installed as an additional barrier when drilling the deeper formations.

Well design of an O&G well



Gas production well

Abandoned well

The geothermal sector in the Netherlands

Interview with Martin van der Hout (DAGO) and Frank Schoof (SPG)

How is the geothermal sector organised and what is the role of DAGO and SPG?
DAGO is the Dutch Association of Geothermal Operators, which represents the collective interest of geothermal licence owners in the Netherlands. Founded in 2014, its members include 22 companies. It has the same role in geothermal exploration and exploitation as that of NOGEPA in the gas industry. Key activities within DAGO are the development of industrial standards, and the exchange of knowledge and experience. SPG is the Dutch Geothermal Platform (Stichting Platform Geothermie), which was founded in 2002 and has around 85 participants, ranging from provinces to small and medium-sized enterprises and operators. It focuses on the promotion of geothermal energy in the Netherlands. DAGO and SPG work closely together on numerous topics.

What is your view on the current state of the geothermal sector in the Netherlands?
Geothermal energy in the Netherlands started in 2007, when greenhouse entrepreneurs took private initiatives to explore the possibilities of this sustainable form of energy and drilled the first geothermal wells. In 2016, 14 operational doublets (1500 – 3000 m TVD) produced 2.7 PJ of heat for greenhouses, reducing Dutch CO_2 emission by about 160,000 tons. The open and interactive discussions and knowledge-sharing of the DAGO operators are being used to extend geothermal to new operators. After having demonstrated its value to greenhouse horticulture, the geothermal sector is now expanding into more applications, regions and depths. New projects are due to start, including some at depths of 500 – 1500 m. Furthermore, UDG is also being investigated in a joint initiative of the Ministry of Economic Affairs, EBN, and TNO.

What is needed for a further increase in activity level in and use of geothermal energy?
Geothermal energy is one of the main pillars in the recent Energy Agenda, the Dutch government's roadmap for realising a sustainable energy mix in the Netherlands by 2050. To achieve the intended growth, much needs to be done; the main points for attention being lowering the cost price per MWh, sound risk management and reliability. This requires close collaboration between all stakeholders and expertise contributed by the O&G sector.

How can the exploratory round table (Section 7.5) on synergy between oil and gas and geothermal energy assist this?
In the round table we have to work on practical, political and societal issues, with the aim of lowering the cost price while improving risk management and reliability. Practical matters include subsurface

and geological aspects, environmental and best-practice sharing, i.e. for drilling or maintenance. Political and societal topics are QHSE, risk management and public awareness and relations. The energy transition will take many decades, and intensification of geothermal energy demands more key players to actively contribute to a sustainable energy mix. This needs to be done with realistic goal-setting, respecting current and future generations


Left: Martin van der Hout (DAGO) – Right: Frank Schoof (SPG)

What do you think the round table will accomplish?

We believe the round table can contribute to sound structural interaction between gas and geothermal companies on various topics. DAGO has already joined one of the NOGEPA working groups, and this is improving mutual understanding. Existing NOGEPA standards can be used to formulate specific geothermal standards. All participants in the round table should work towards achieving the needed intensification of geothermal energy in NL.

How can EBN and DAGO/SPG cooperate successfully?

EBN is a key player in the Netherlands for data, knowledge and networking on the subsurface and can greatly support further development in cost reduction, effective risk management and reliability. Although geothermal energy differs from oil and gas in several ways, being locally produced and not being a commodity, EBN's project approach, process knowledge and position towards our government, NGOs and gas companies is valuable. EBN already participates in several supervisory groups of the 'Kennisagenda Aardwarmte', a programme to develop geothermal knowledge.

Research, development and innovation

8

EBN is well aware that creating more value from its assets often requires new, innovative ideas. Hence, EBN is participating substantially in research on various topics, covering the full life cycle from exploration to abandonment. A significant part of the research is done collaboratively through JIPs. However, EBN also carries out independent studies, partly in-house and partly outsourced to contractors. In recent years, in-house independent work has included MSc thesis projects and student internships in cooperation with various universities. In this chapter, some of the results of these research projects are highlighted.

8.1 Joint industry efforts

In a rough business climate, joint research ventures in which expertise is shared to optimise exploration and production strategies are critical. The industry is fully aware of this and many JIPs are ongoing. One of these initiatives is the ITF-PETGAS (Petrophysics of Tight Gas Sandstone Reservoirs) project, initiated by the University of Leeds and sponsored by six large operators. Many of the Dutch gas reservoirs are prolific producers, yet some of them exhibit tight reservoir characteristics that prevent economic exploitation. To better understand the geological controls leading to reservoir impairment and also to investigate methods to mitigate the adverse effects on productivity, EBN joined this JIP in 2008. The project is currently in its third phase. A key deliverable of PETGAS is the Atlas of Petrophysical Properties of Tight Gas Sands. It contains detailed descriptions of the characteristics of tight reservoir samples, as well as key controls on these petrophysical properties. This information allows reservoir quality and productivity to be assessed, which is useful for prospect/field evaluation and determining stimulation strategies. The PETGAS data is also very valuable for geothermal, CCUS and underground gas storage projects.

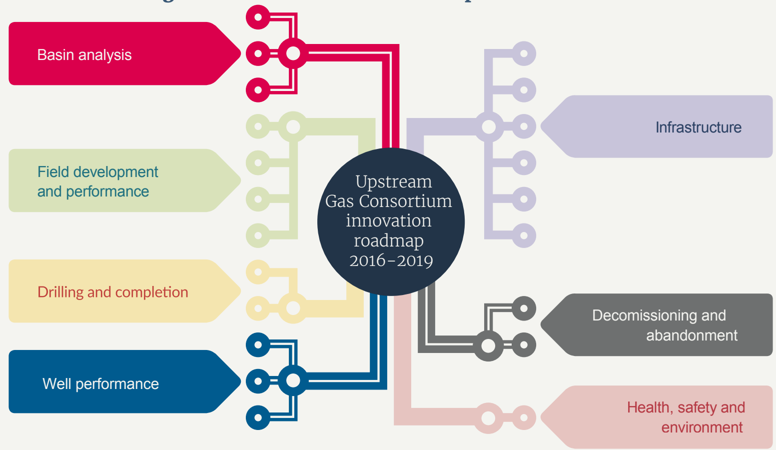
A second JIP initiative is the 21st Century Exploration Roadmap Palaeozoic project initiated by the UK government. In this project, the British Geological Survey worked with the UK Oil and Gas Authority, Oil and Gas UK and a consortium of over 45 companies to evaluate the remaining areas with potential for hydrocarbons on the UK Continental Shelf, including the Mid North Sea High adjacent to the Dutch northern offshore. The multidisciplinary work focused on the Carboniferous and Devonian petroleum systems that are also being explored by EBN. EBN contributed their knowledge to ensure consistency in geological models across the boundary. At the same time, EBN's evaluations in the Dutch sector benefitted from the insights the project yielded.

A third example is the Integrated Zechstein study at Durham University in 2015 – 2016, a JIP conducted together with a number of North Sea operators. This project integrates the results of several studies (such as sequence stratigraphy, Ground Penetrating Radar measurements, outcrop fracture analysis, diagenetic processes and comparison of historical production data) on outcrops of Zechstein carbonates at the coast of northeast England and a large number of cores from North Sea wells. Results help to confidently predict the reservoir characteristics in different parts of the Zechstein carbonate build-ups. The insights will be used in EBN's evaluation of the prospects in the Zechstein carbonate play in the Dutch northern offshore and will help to improve understanding of the production behaviour of numerous producing fields.

TKI Upstream Gas

EBN also participates actively in the Top sector Knowledge Initiative Gas (TKI Gas) – an innovative R&D programme on gas production and usage facilitated by the Ministry of Economic Affairs. In 2015, TNO presented a new programme set-up for Upstream Gas (one of the themes within TKI Gas). It consists of seven programme lines with the following themes: 1) Basin analysis, 2) Field development and performance, 3) Drilling and completion, Programme lines within the TKI Upstream Gas Consortium

1



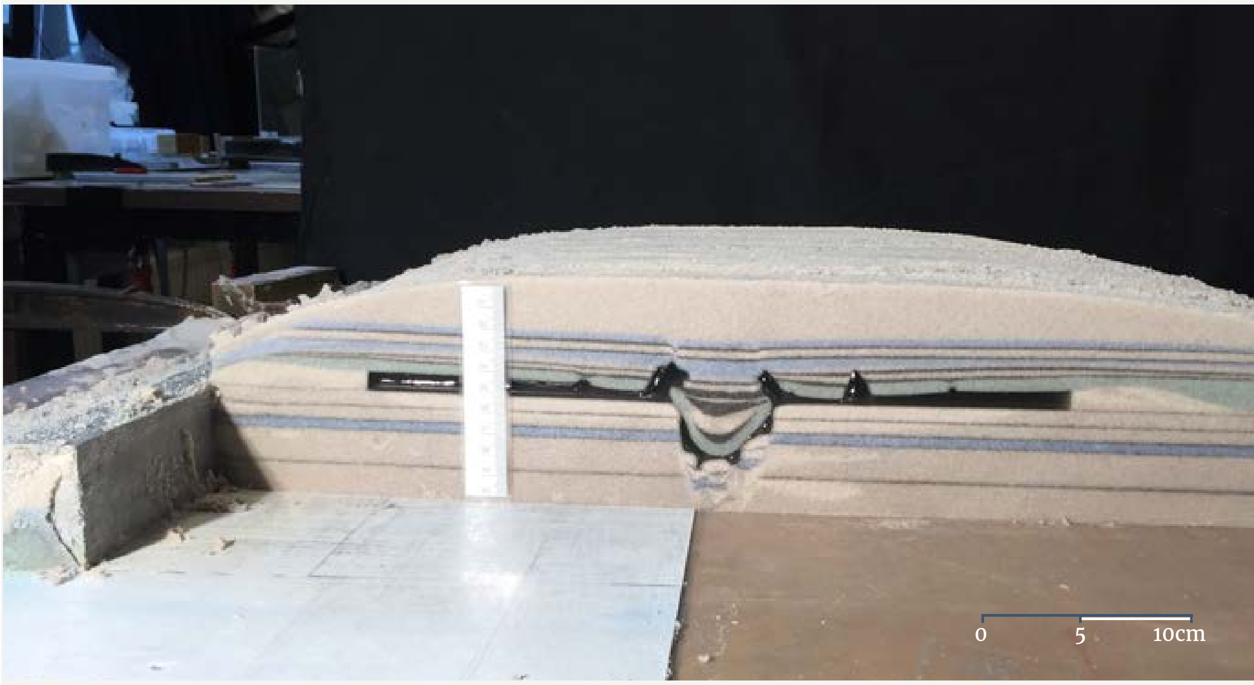
4) Well performance, 5) Infrastructure, 6) Decommissioning and abandonment, and 7) Health, safety and environment. EBN participates in several of the programme lines, as do most operators active in the Netherlands. Collaboration between the parties within these JIPs is important to obtain innovative results. The objectives of TKI Upstream Gas are to increase exploration, production and – ultimately – recovery, while reducing risks and costs. In the latest TKI round, EBN began participating in projects from three programme lines (Figure 1):

- Basin analysis: joint industry research around geology and exploration;
- Well and flowline performance: research on well and flowline design and operating improvements;
- Decommissioning and abandonment: investigating more cost-effective ways to abandon wells and facilities.

Currently, additional projects are being defined for the other project lines.

Sand box model illustrating movement of salt

2



Cross-section of the sand box model after extension, passive diapirism (the salt is represented by black silly putty) and continuing sedimentation during diapirism, followed by strike-slip movement.

Highlighted: STEM project

The STEM project (Salt Tectonics – Early Movement) is an ongoing JIP within the programme line Basin Analysis that is being carried out by TNO in collaboration with two operators, one acquisition contractor and EBN. The project aims at evaluating the impact of early salt movements on Mesozoic petroleum systems in the Dutch offshore by incorporating regional and detailed tectonostratigraphic seismic analysis as well as 2D structural restorations. The project included a one-day salt tectonics course given by TNO, covering: 1) Mechanical behaviour of salt, 2) Passive, active and reactive salt tectonics, 3) Syn-sedimentary effects, and 4) The role of tectonics in basins globally. The day also included a visit to the TecLab of Utrecht University, where the results of a sandbox model were presented (Figure 2). The workshop demonstrated the importance of understanding the timing of salt movement.

Energy Academy Europe

Since 2013, EBN has supported the Energy Academy Europe in its bid to become a key player in accelerating the energy transition in the Netherlands by focusing on education, research and innovation. One of the ongoing projects sponsored by EBN is Energysense, which investigates how energy use, attitudes and innovation in households relate to the energy transition.

In 2017, the Energy Academy Europe will integrate with Energy Delta Institute and Energy Valley to form a single organisation. Energy Delta Institute provides a range of courses for energy sector professionals. Energy Valley focuses on business development in the sustainable energy sector, while the task of Energy Academy Europe is to promote research, education and innovation. At the end of 2016 the three organisations moved into a new building on the University of Groningen campus.

Since 2016, ESTRAC (Energy Systems Transition Centre, part of the Energy Academy Europe) has been the interdisciplinary and open-end innovation centre where energy-related market parties, applied research institutes, universities and other organisations can work together on major energy questions. EBN, together with Gasunie, Gasterra and NAM are among the first Associate Partners of this centre.

8.2 In-house research

In addition to participating in extramural research, EBN conducts in-house research projects to develop practical knowledge for its activities. In cases where the expertise is present within EBN and the data is available, EBN analyses technical topics and shares the results with partners bound by confidentiality agreements where appropriate. Some examples are given below.

Understanding geo drilling hazards

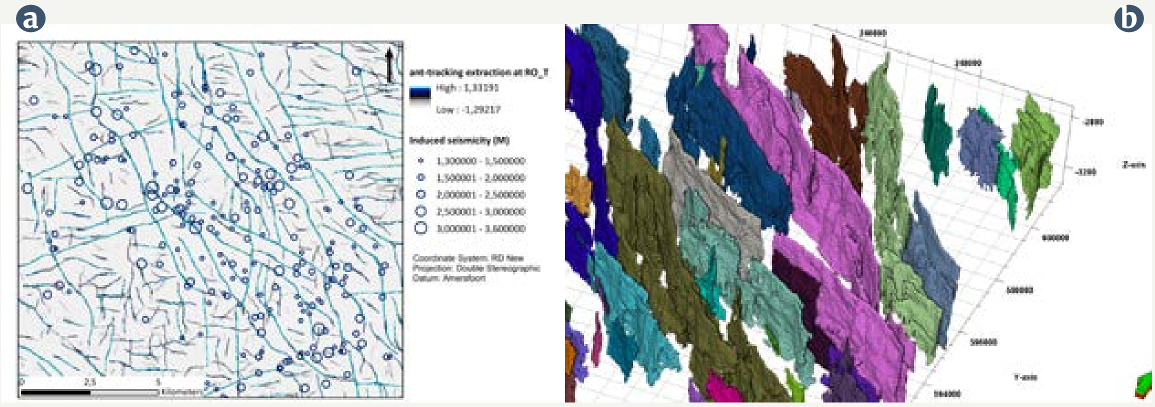
Safety and cost control are critical success factors in the realm of drilling. Actual well costs frequently exceed budget, due to incidents related to geo drilling hazards. A significant part of the non-productive time can be avoided if geo drilling hazards are identified upfront. The risk assessment for a well trajectory is largely based on the experience from offset wells: boreholes in the neighbourhood that have been drilled earlier, or holes drilled through similar geological settings. Easy access to relevant historical drilling data and the records of geo drilling hazards encountered in offset wells is essential for effective de-risking of future drilling programmes. Currently, operators typically have their own databases containing such information. However, these often lack data from competitor wells. Obviously, risk assessment would greatly benefit from access to a complete set of drilling hazard data that makes use of best practices in data. EBN is involved in most of the O&G wells drilled in the Netherlands. Aware of its major vested interest

Faults and fault planes extracted from 3D data

3

a

b



a) Map view of faults identified at top Rotliegend in the Huizinge area. Hypocentres of events recorded from 1991 until recently are plotted as circles with radius proportional to magnitude. b) Detailed northwest—southeast fault planes extracted from 3D seismic data.

in improved drilling performance, EBN has launched a project to capture the geo drilling events that have been observed in wells. This information has been analysed using an advanced event classification scheme and includes reference to the underlying geo drilling hazards. The information has been compiled into a database and made accessible to operators via a web-based interface. In this way, a risk analysis for new wells can be made effectively.

New insights into fracking fluids

As discussed in Section 4.1, hydraulic fracturing is an important technology in O&G production and might also be needed in geothermal projects. EBN research showed that fracking is a valuable method for optimising production, but it should only be used in a safe and responsible way. Although the currently used fracking fluids are REACH-compliant, EBN plans to sponsor a project concerning the potential effects of the fracking fluids on humans and the environment. The project includes investigating the conventional fracking fluids currently used in the Netherlands, and so-called green fracking fluids aiming at identifying what green fracking fluids could possibly contribute to minimising risks. Additionally, EBN is planning to cooperate with a renowned water toxicology institute to investigate the effects of fracking fluids and of fluids produced back during operations in a real-life environment.

EBN studies on seismicity in the Groningen field

EBN has initiated several studies on the induced seismicity in the Groningen field area, complementing research conducted by others. The objective is to gain additional insights that support decisions on production strategy leading to optimising production while minimising seismicity. One study comprises a detailed analysis and refinement of an existing empirical relationship between the cumulative number of seismic events and the gas production in the Groningen field. Results show that a better way to make predictions is to analyse the ratio of the activity rate over the production rate versus the cumulative gas production. The model shows that the ratio of activity rate over production rate increases linearly with volume produced (Hettema et al., 2016). Other projects that started recently focus on the distribution of stress in the Dutch subsurface, on reducing uncertainty in earthquake hypocentre location and on geomechanical behaviour of faults.

In another study, an efficient workflow to improve the definition of natural faults based on 3D seismic data has been developed. The use of seismic attributes can significantly improve fault definition (Figure 3a), while geobodies extracted from these attributes provide detailed fault plane geometries (Figure 3b). Detailed fault mapping contributes to establishing relationships between earthquake hypocentres and faults and to improving understanding of the dynamic behaviour of the field. The extracted fault geobodies are also input for geomechanical modelling of seismogenic behaviour. Improved insights into which faults and fault segments are most susceptible to seismicity could be used to define an optimal production strategy while minimising seismic risk. The findings are currently being used in seismicity studies at EBN, Shell and KNMI. Fault mapping and characterisation is of great importance in subsurface evaluation in general and this workflow is widely applicable not only in O&G developments, but also in geothermal or storage projects.

8.3 Student projects

Since 2010, EBN has offered some 40 students from Vrije Universiteit Amsterdam, Utrecht University and Delft University of Technology the opportunity to carry out research projects in an O&G company setting. The combination of abundant data availability, expertise and the provision of coaching is very attractive for students. The internships and MSc projects typically last 6 – 9 months and offer a mix of research and solving practical problems encountered by EBN. Topics range from exploration analysis, reservoir production behaviour and infrastructure to challenges of the energy transition. The research projects often result in interesting findings that are of value to EBN and the Dutch O&G sector. A list of recent student research projects is given below. Some of these studies can be found on the EBN website and full reports are available upon request. Two recent interns look back on their experience with EBN on the next page. The close collaboration between EBN and Dutch academia goes beyond offering internships. EBN experts are also involved in advising on course subjects and curricula and teach as guest lecturers at universities. This support includes courses on geology, geophysics and petrophysics.

Recent MSc studies

Year	Subject
2009	Shallow Gas in the Dutch part of the Miocene Eridanos Delta.
2010	Onshore Shale Gas Potential of the Lower Jurassic Altena Group in the West Netherlands Basin and Roer Valley Graben
2011	Comparison of the life cycle greenhouse gas emissions of shale gas, conventional fuels and renewable alternatives from a Dutch perspective.
2011	Basin analysis of Tertiary deposits in the Gorredijk concession using 3D seismics and well data
2012	Subsurface sediment remobilization and polygonal faulting in the northern Dutch offshore
2012	Review of Lower Triassic play in the Roer Valley Graben
2013	Dinantian carbonate development and related prospectivity of the onshore Northern Netherlands
2013	Inventory and Analysis of hydraulically fractured wells in the Dutch on- and offshore
2013	Prospectivity analysis of the northern Dutch Central Graben
2014	Fault Mapping and Reconstruction of the Structural History of the Dutch Central Graben
2014	The Role of Reservoir Geology and Reservoir Architecture on Geothermal Doublet Performance
2014	Seismic characterization of the Zechstein carbonates in the Dutch northern offshore
2014	Identifying overlooked exploration opportunities from bypassed pay analysis
2014	The Shale Oil Potential of the Posidonia Formation in the Netherlands
2014	Indications for intra- Chalk seals in the F-blocks of the Dutch offshore by integration of seismic and well data
2014	Volpriehausen Prospectivity Review
2015	Shallow Gas: Rock Physics and AVO: An analysis of the seismic response as a function of gas saturation
2015	An analysis of Depth and gross rock volume uncertainty
2015	Salt Tectonics in the northern Dutch offshore: A study into Zechstein halokinesis in the Dutch Central Graben and Step Graben
2015	Comparative Analysis of Shale Permeability Measurements
2015	Application of a deterministic and stochastic approach on exploration projects in the Dutch Oil and Gas Industry
2015	Production Performance of Radial Jet Drilled Laterals in Tight Gas Reservoirs in the Netherlands: A Simulation Approach and Economic Analysis
2015	A Time to Depth conversion review of the Dutch North Sea area
2015	Geological evolution of the Chalk Group in the northern Dutch North Sea
2015	Towards better understanding of the highly overpressured Lower Triassic Bunter reservoir rocks in the Terschelling Basin
2016	3-D restoration of the Dutch Central Graben: Predicting prospects in the Chalk plays
2016	Inventory of Hydrocarbon Shows in the Dutch Northern offshore
2016	Reservoir compaction in shallow gas reservoirs: The impact of production-induced reservoir compaction on the recovery of gas from shallow reservoirs.
2016	Production Analysis of the fractured Zechstein-2 Carbonate Member in NE Netherlands: A Dual Porosity Model Approach.
2016	Triassic reservoir development in the northern Dutch offshore
2016	Chalk facies and its petrophysical expression from core and wireline data, North Sea Basin, the Netherlands.
2016	Reservoir Properties of Upper Jurassic to Lower Cretaceous Formations in the Northern Dutch Offshore.
2016	Inventory of Hydrocarbon Shows in the Northern Dutch offshore (Phase 2)
2017	Production- and Value Analysis of Hydraulic Fractured Wells in The Netherlands
2017	Analysis of End of Field Life Techniques and predicting Liquid Loading using Artificial Neural Networks
2017	Hydrocarbon Shows database: the power of systematic analysis

Hydrocarbon shows database: The power of systematic analysis

Constantijn Blom, a Master's student in Earth Sciences at Utrecht University, is due to complete a research project at EBN in 2017. During his internship Constantijn analysed and expanded the hydrocarbon shows database described in Section 3.2.

Interview with Constantijn Blom, student

Why did you apply for an internship within EBN?
I had almost completed my Master's thesis at the university and felt that I needed to gain experience working in a professional environment before entering the job market. EBN offers interesting internships, so I applied and, luckily, I was selected.

What was the goal of your internship at EBN?
The goal was to expand and improve the existing hydrocarbon shows database. I mainly focused my work on improving the quality of the data and subsequently analysing the results.

How did you go about improving the database?
There were several tasks that I carried out in order to improve the content and structure. I started by defining a consistent classification scheme for observations from different datatypes: mud logs, well tests and core data. In this way, I was able to combine all the different hydrocarbon show classifiers into a single one, which makes it a lot easier to compare the results from the different data types. After that, I tested and QC-ed the results. I implemented automatic consistency checks, which should prevent mistakes relating to manually entering the data. After that, I continued with a regional analysis of the HC shows data from the Dutch northern offshore. I compared the data with the distribution of hydrocarbon source rocks and checked whether the information from the database correlates with the presence of source rocks in the study area.

Are you satisfied with the work you did?
All my analyses confirmed that the database contains very valuable data. The major strength of this database lies in the fact that it contains quantified and consistent information on hydrocarbon observations from mud logs, well tests and cores. EBN might be able to share the database with its partners and I hope that it will help EBN and partners to make even better decisions in the search for hydrocarbons.

What did you learn from your internship?
I learned that working in a professional environment can be fun. Moreover, I found it highly motivating – a lot more than my university studies. I liked that the work I did was important for others, but that in order to get my work done, I had to rely on others too. This interaction is stimulating. Also, my internship has given me insights into the bigger picture of the Dutch O&G sector.

Would you want to work in the O&G industry?
The work I did here was very interesting, challenging and exciting. Probably more so than in other technical sectors because of the large-scale projects and correspondingly high level of investments. I will definitely try to pursue my career in the O&G sector.

Ellis Bouw is a Petroleum Engineering graduate from Delft University of Technology. She analysed EoFL techniques during her internship at EBN (2016) and researched how to predict liquid loading by using artificial neural networks (ANN). Both studies will give the petroleum industry more insight into how to efficiently produce from mature gas fields (her findings are discussed in Section 4.2).

Analysis of EoFL techniques and predicting liquid loading using artificial neural networks

Interview with Ellis Bouw, graduate

Why did you apply for an internship within EBN?

I wanted to do my internship at EBN because it is very instructive and exciting to apply the knowledge that you acquire during your studies to the industry. Also, EBN is involved in many projects in the Netherlands, enabling you to work with data from various operators, which is unique. This also gave me the opportunity to visit several operators.

What was the main objective of your internship at EBN?

There were two main objectives. Firstly, this study aimed to quantify the potential volume gain of end of field life (EoFL) techniques, particularly velocity strings and foam, as up to now, the availability of data on the potential of EoFL techniques has been limited. Secondly, it is difficult to determine when to implement these techniques, due to the unpredictability of the liquid loading moment. Using big data may allow future instability of production rates to be predicted and may therefore be very useful in foreseeing the liquid loading moment in advance. In my thesis, a first step was taken to use ANN to predict the onset of liquid loading by applying actual field data.

What did you learn from your internship?

I certainly learned a lot. Next to the knowledge I gained about the use of EoFL techniques and ANN, I also gained experience in the petroleum industry. I discovered that the cases I worked on during my time at university differed from reality. In real life, many cases are more complex and sometimes lack data. But the great thing is that you learn to deal with this and that you always find a solution in the end.

Were there any difficulties?

At first, I was drifting a bit, as data from various operators was not easily accessible. However, with the help of EBN staff I managed to get sufficiently reliable information. The research was successful, but it should be noted that it is only a first step in predicting the liquid loading moment.

What does your research mean for EBN?

This research can be valuable for EBN and operators, as the knowledge that was gained by this study gives us more insight into the usefulness of EoFL techniques and provides an opportunity to predict liquid loading at an earlier stage. This can benefit gas production. EBN wants to continue the research and in doing so they will train ANN using more wells. I very much enjoyed this intership and it is great to know that the research will be continued.

What's next?

I have found a job as a field engineer abroad. This was something I wished for. At EBN I experienced the theoretical side and now I am going to explore the practical.

Glossary

ABEX	Abandonment Expenditure
AFE (AFEs)	Authorisation For Expenditure
AVO	Amplitude Versus Offset
BGS	British Geological Survey
CAES	Compressed Air Energy Storage
CAPEX	Capital Expenditure
CCUS	Carbon Capture Utilisation & Storage
COP	Cessation of Production
DAGO	Dutch Association of Geothermal Operators
DEFAB	Study area in the offshore D-E-F-A-B blocks
DHI	Direct Hydrocarbon Indicator
E&P	Exploration and Production
EBN	Energy Beheer Nederland BV
ECN	Energieonderzoek Centrum Nederland
EIA	Environmental Impact Assessment
EoFL	End of Field Life
ESTRAC	Energy Systems Transition Centre
G&M	Study area in the offshore G-M blocks
GE	Groningen Equivalent
GIIP	Gas Initially In Place
GIP	Gas In Place
GTS	Gasunie Transport Services
IRO	Vereniging Industriële Raad voor de Olie en Gas
JIP	Joint Industry Project
KNMI	Koninklijk Nederlands Meteorologisch Instituut
KVGN	Koninklijke Vereniging van Gasfabrikanten in Nederland
MMbbl	One million barrels
ms	Millisecond
MD	Millidarcy
NAM	Nederlandse Aardolie Maatschappij
Nm3	Normal cubic metre
NOGEPA	Nederlandse Olie en Gas Exploratie en Productie Associatie
NPF	Norwegian Petroleum Society
NPV	Net Present Value
O&G	Oil and Gas
ONE BV	Oranje-Naussau Energy BV
OPEX	Operational Expenditures
PETGAS	Petrophysics of Tight Gas Sandstone Reservoirs
PI	Productivity Index
PSDM	PreStack Depth Migration
QHSE	Quality, Health, Safety and Environment
REACH	Registration, Evaluation, Authorisation and Restriction of Chemicals
ROAD	Rotterdam Opslag en Afvang Demonstratieproject
RT	Real Term
Small gas fields	All gas fields except for the Groningen field
SodM	State Supervision of Mines (Staatstoezicht op de Mijnen)
SPG	Stichting Platform Geothermie
STOIIP	Stock-Tank Oil Initially In Place
TD	Total Depth
TKI GAS	Top Sector Knowledge Initiative Gas
TNO	De Nederlandse organisatie voor Toegepast-Natuurwetenschappelijk Onderzoek
TVD	True Vertical Depth
TWT	Two-way Travel Time
UDG	Ultra-Deep Geothermal energy
UR	Ultimate Recovery

References

Boxem, T. et al., 2016.
Ultra-diepe geothermie: Overzicht, inzicht & to-do ondergrond. TNO-report, Utrecht.

EBN, 2016.
Triassic reservoir sands in the Dutch northern offshore – New results from seismic and cutting analyses. PROSPEX, London.

Hettema et al., 2016.
Empirical analysis and prognosis of the induced Seismic activity rate of a depleting gas reservoir in time and space. Abstract [S54B-09], 2016 Fall Meeting AGU, San Francisco.

KVGN, 2016.
Gas op Maat, Nederlandse gassector voor een klimaatneutrale energievoorziening .

Michie and Koch, 1991.
Evaluation of injection-well risk management in the Williston Basin, Journal of Petroleum Technology.

Ministry of Economic Affairs, 2016.
Energy Agenda: Towards a low-carbon energy supply .

Ministry of Infrastructure and the Environment, 2015.
Beleidsnota Noordzee 2016-2021.

Ministry of Infrastructure and the Environment and Ministry of Economic Affairs, 2016.
Ontwerp Structuurvisie Ondergrond .

NOGEPA, 2013.
Fact sheet: fracking nader toegelicht.

Poty, E. 2014.
Report on cuttings from the CAL (California)-GT-01 borehole, University of Liège.

State Supervision of Mines, 2016.
Resultaten inventarisatie fracking. De toepassing van fracking, de mogelijke consequenties en de beoordeling daarvan.

Acknowledgements

We would like to thank the following people and organisations for their contributions to this publication:

- Maarten Bijl, TNO
- Constantijn Blom, student
- Ellis Bouw, graduate
- Sandor Gaastra, Ministry of Economic Affairs
- Hans van Gemert, Ministry of Economic Affairs
- Floris van Hest, North Sea Foundation
- Martin van der Hout, DAGO
- Justine Oomes, Ministry of Economic Affairs
- Tessa Posthuma de Boer, photographer
- Diederik Samsom, former leader of the Dutch Labour Party
- Frank Schoof, SPG
- Harry Segeren, Wintershall
- Steven Snoep, photographer
- Kenneth Stamp, photographer
- KVGN
- Ministry of Economic Affairs
- NAM B.V.
- TNO

About EBN

EBN's strategy focuses on three core areas: Our Dutch Gas, Return to Nature and New Energy.

EBN is active in exploration, production, storage and trading of natural gas and oil from the Dutch subsurface on behalf of the Ministry of Economic Affairs, sole shareholder. EBN invests, facilitates and shares knowledge. The participation in these activities amounts to between 40% and 50%. EBN also has interests in offshore gas collection pipe-lines, onshore underground gas storage and a 40% interest in gas trading company GasTerra B.V.

EBN also advises the Dutch government on the mining climate and on new opportunities for using the Dutch subsurface as a source for energy, such as geothermal energy, and Carbon Capture Utilisation and Storage. By building on our long history in gas and oil projects and our expertise of the subsurface, EBN explores these possibilities contributing to a carbon-neutral energy future. Furthermore EBN has taken the lead in the decommissioning and re-use of ageing oil and gas infrastructure by establishing a National Platform for decommissioning and re-use and will continue to strive for safe, sustainable and cost-efficient decommissioning and re-use of oil and gas assets. EBN is headquartered in Utrecht, the Netherlands.

Visit www.ebn.nl for more information

Editor-in-chief
Mijke van den Boogaard

Editors
Joy Burrough, Unclogged English

Marten ter Borgh, Jouke van Elten, Raymond Godderij, Michiel Harings, Guido Hoetz, Bastiaan Jaarsma, Sander de Jong, Eric Kreft, Ewout Pikaar, Eveline Rosendaal, Barthold Schroot

Board
Marcel Hoenderdos, Jan Willem van Hoogstraten, Berend Scheffers, Thijs Starink, Peter de Vries

Production
Kiki Vergoossen, Maartje Vermeer

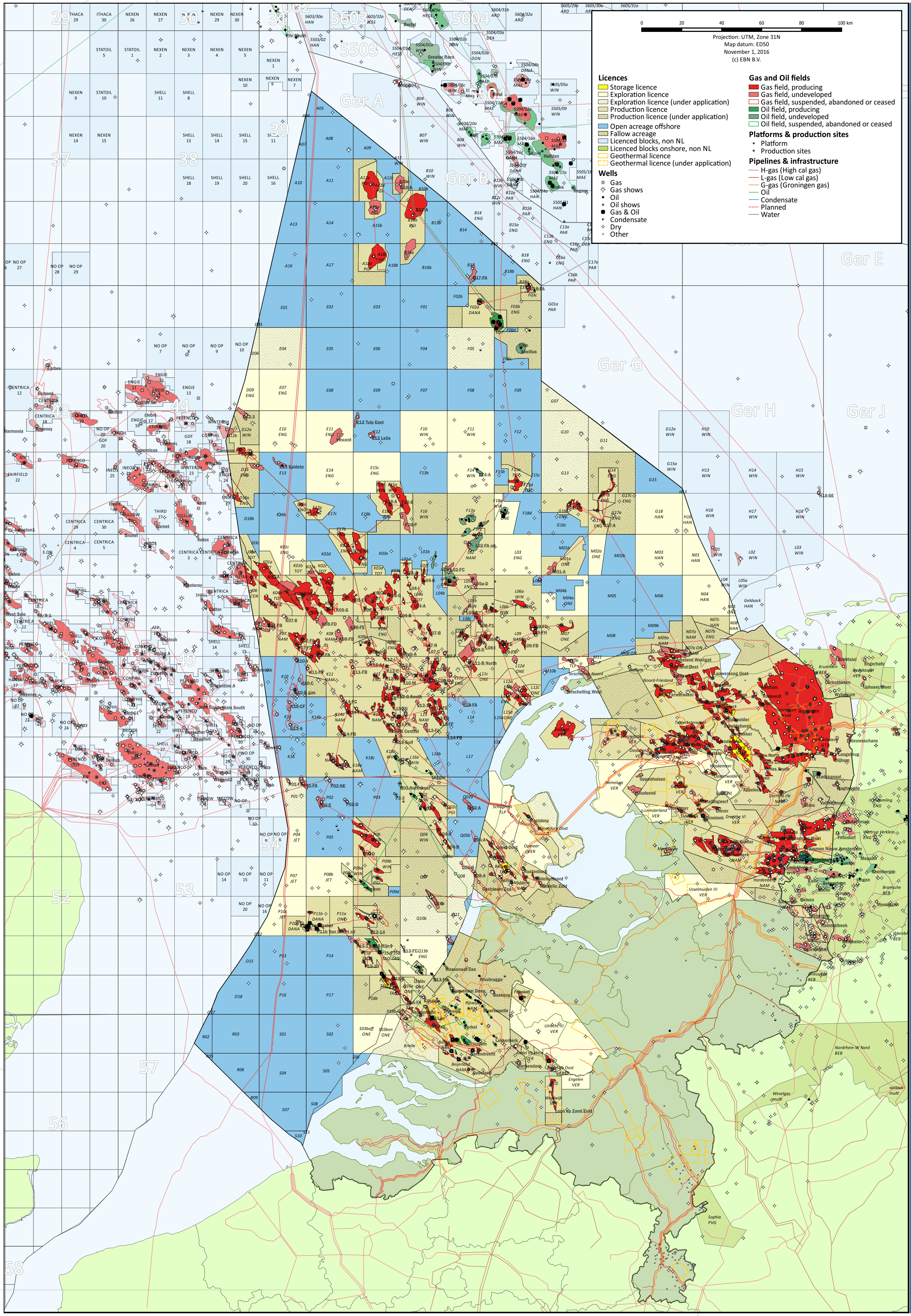
Contributors
Annemiek Asschert, Marten ter Borgh, Bas Borst, Walter Eikelenboom, Jouke van Elten, Ricardo Gijbels, Raymond Godderij, Michiel Harings, Nora Heijnen, Marcel Hoenderdos, Guido Hoetz, Thijs Huijskes, Bastiaan Jaarsma, Sander de Jong, Marloes Jongerius, Marloes Kortekaas, Henk Koster, Eric Kreft, Corne van Langen, Tom Leeftink, Jan Lutgert, Erwin Niessen, Ewout Pikaar, Berend Scheffers, Barthold Schroot, Ruud Schulte, Pieter Slabbekoorn, Renee Stoeller, Maartje Vermeer, Roderick Verstegen, Annelieke Vis, Peter de Vries, Jan Westerweel, Jelle Wielenga, Ferhat Yavuz

Design
Sabel Communicatie

Photography
Tessa Posthuma de Boer, Steven Snoep, Kenneth Stamp

Disclaimer

The information and conclusions contained in this report represent the collective view of EBN, not that of any individual. Any information and conclusion provided in this document are for reference purposes only; they are not intended nor should be used as a substitute for professional advice or judgement in any given circumstance. EBN does not guarantee the adequacy, accuracy, timeliness or completeness of the reports content. EBN therefore disclaims any and all warranties and representations concerning said content, expressed or implied, including warranties of fitness for a particular purpose or use.


0 20 40 60 80 100 km
Projection: UTM, Zone 31N
Map datum: ED50
November 1, 2016
(c) EBN B.V.
Licences
Storage licence
Exploration licence
Exploration licence (under application)
Production licence
Production licence (under application)
Open acreage offshore
Fallow acreage
Licenced blocks, non NL
Licenced blocks onshore, non NL
Geothermal licence
Geothermal licence (under application)
Wells
Gas
Gas shows
Oil
Oil shows
Gas & Oil
Condensate
Dry
Other
Gas and Oil fields
Gas field, producing
Gas field, undeveloped
Gas field, suspended, abandoned or ceased
Oil field, producing
Oil field, undeveloped
Oil field, suspended, abandoned or ceased
Platforms & production sites
Platform
Production sites
Pipelines & infrastructure
H-gas (High cal gas)
L-gas (Low cal gas)
G-gas (Groningen gas)
Oil
Condensate
Planned
Water

EBN. B.V.
Daalsesingel 1
3511 SV Utrecht

Phone: +31 (0)30 2339000
Mail: ebn.mail@ebn.nl

© 2017 EBN Any part of this publication may be copied, reproduced or distributed without the permission of EBN, provided that the materials are not copied, reproduced or distributed for commercial gain and provided that EBN is credited as the source on all copies, reproductions and distributions of the material.