REGIONAL FOCUS:
THE NETHERLANDS

The Netherlands has been an active region for hydrocarbons exploration since the early Sixties. The country has 212 producing fields, dominated by gas exploration, but many of them are considered to be late in life and close to decommissioning. This month we focus on how geoscientists are continuing to demonstrate the great potential of the Dutch oil and gas sector and how mature fields can be reinviogorated to produce the gas that the country desperately needs.

Hanze platform still going strong

It has been 17 years since production started on the F2a-Hanze platform. Dana is operator of the field which is producing light oil from naturally fractured chalks of Danian and Maastrichtian age. Typical chalk porosities of 20-38% are seen, and typical matrix permeability is around 5mD.

The field has been developed with four horizontal/high angle production wells. Pressure support is provided through down dip water injection which complements an active aquifer. The chalk reservoir has proved to be a prolific producer and field production has been characterized by a long plateau production period, followed by a gradual increase in water cut. Ultimate recovery is expected to significantly exceed FDP with a recovery factor >50%. Not only is the reserves increase owing to the performance of the chalk reservoir, but it has also been due to diligent reservoir management over the life of the field.

The field was developed using long, horizontal production wells. High field production rates were sustained through cycles of acidization. These were used to enhance production, both following drilling of the wells, as well as after prolonged production periods, when the wells would show a natural productivity decline. After acidization, the wells exhibited very large increases in production. Further, the production wells were retrofitted with Electrical Submersible Pumps which allowed much higher drawdowns to be realized than the previous gas lifted wells could achieve. This higher drawdown allowed more oil to be produced from the relatively tight chalk matrix.

The platform is now approaching its original design life of 20 years. In 2017, Dana embarked on a lifetime extension project to recertify the installation and ensure that the platform can operate safely for another 20 years. The plan involves careful, continuous investigation of structural integrity of the facility, along with a phased maintenance programme, designed to anticipate upcoming expenditure to aid planning. Finally, near-field exploration opportunities are being considered to provide potential additional production to extend the life of the platform even further.

Shallow gas traps in the Cenozoic Southern North Sea delta, offshore Netherlands

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Introduction

In the Southern North Sea, shallow gas is defined as gas that resides in shallow marine to continental (deltaic) deposits of the Plio-Pleistocene Southern North Sea (SNS) shelf-edge delta. It is either structurally trapped in anticlines above salt domes, associated with lateral fault seals, or occurs in stratigraphic or depositional traps. Traditionally, shallow gas occurrences were regarded as hazardous or non-economic because of low gas saturations ('fizz gas'). Even though the production of shallow gas still is a challenge, to date, four gas fields are producing (Van den Boogaard and Hoetz., this volume).

Kuhlmann et al. (2006) and Kuhlman and Wong (2008), were the first to link to the occurrence of potential gas (or rather acoustic anomalies in seismic data) to specific delta sub environments and stratigraphic intervals. They related variations in sediment properties to changing climate conditions under the inception of Late Cenozoic northern hemisphere glaciations. Their study was instrumental in illustrating and promoting an improved understanding of external controls on shelf delta deposition to the benefit of exploration and production of shallow gas.

This paper focuses on the depositional setting of the bright spots and trap styles within the SNS delta and is based on a multi-disciplinary study that involved 1) paleoenvironmental- and paleoclimatological reconstructions, 2) seismic interpretation to reconstruct the internally complex delta body, and 3) estimation of temporal and lateral variability in reservoir and seal properties (Ten Veen et al., 2013). The results include a first classification of the shallow gas accumulations in terms of trapping style and sealing capacity. The physical and dimensional properties of the bright spots, i.e. the volumes and saturations of the associated shallow gas, are dealt with in the accompanying paper by Van den Boogaard and Hoetz (this volume) that also assesses the economics of shallow gas prospects.

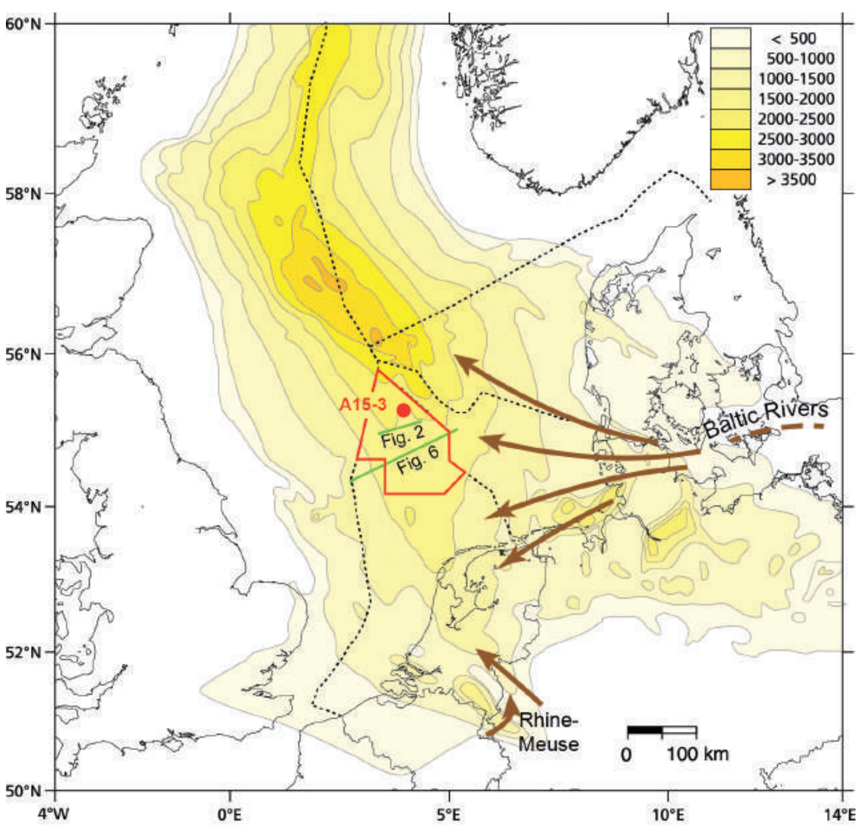

Figure 1 Map showing study area within the Southern North Sea (SNS) Basin with thickness (metres) of Cenozoic sediments (excluding Danian); after Ziegler (1990) and Huuse (2002), modified from Wong et al. (2007). Arrows show course of the main river systems that fed the SNS Basin.

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Geological setting of the SNS delta

The main structural element in the Southern North Sea is the Central Graben, a NNE-SSW Mesozoic structural element along which an intercratonic sag basin (referred to as the Central Trough) developed in the Cenozoic (Huuse and Clausen, 2001; Figure 1). This represents the area of greatest accommodation during the deposition of the Late Cenozoic Southern North Sea shelf delta in the study area (Ziegler, 1990). Rapid subsidence in the centre of the basin and uplift at margins are attributed to intraplate stresses (Overeem et al., 2001). Halokinesis of the Permian Zechstein salt layer occurred during both the Mesozoic and Cenozoic (Remmelts, 1996; Ten Veen et al., 2012) and continued until the Quaternary and attributed to many of the salt structures in the Southern North Sea.

In the Early Miocene the Southern North Sea Basin covered most of present-day Denmark, northern Poland, Germany and the Netherlands (Møller et al., 2009). During the Cenozoic period, the North Sea Basin became bordered by the structural highs of Fennoscandia to the north east, by Western and Central Europe in the south and the British Isles in the west (Wong et al., 2007). From the Late Cenozoic period onwards the Baltic River system (Bijlsma et al., 1981), drained an area of ~1 x 10^6 km^2 of Fennoscandia and northern Europe (Figure 1) and fed a giant delta system in the Southern North Sea Basin, which is comparable in size to the modern Amazon delta. The entire fluvio-deltaic system is referred to as the Eridanos delta (Overeem et al., 2001) or the Southern North Sea delta (SNS). In the Dutch northern offshore, it is mainly the shelf-edge delta that is preserved. It is characterized in seismic data (Figure 1) by progradational sigmoidal and oblique shelf-prism clinoforms that downlap on to the Mid-Miocene Unconformity (MMU). Late Miocene to Pleistocene progradation of SNS delta sediments was roughly from east to west and more proximal deposits have been encountered in the subsurface of the German offshore (e.g. Thöle et al., 2014). This progradation is also reflected by overall upward coarsening, westward fining of the sediments (Schroot et al., 2005) and increased upward occurrence of near-shore biota (Donders et al., 2018). These trends are associated with glacioeustatic sea-level lowering by 100-150 m (cf. Miller et al., 2005) and a general climatic cooling from subtropical to icehouse conditions (Anell et al., 2012). In the adjacent East Anglia basin, the presence of NE- and SE prograding seismic reflectors in Early Pleistocene deposits suggest that there was riverine input by UK sources into the basin as well (Cameron et al., 1987). The SNS delta is terminated by a fluvial topset of Early-Middle Cromerian age to which the southerly Rhine, Meuse and Schelde river systems contributed sediment as well (e.g. Westerhoff, 2009). The SNS delta system is truncated by the Late Pleistocene glaciogenic unconformity which over a large area is marked by the Elsterian Glacial valleys and overlain by Holocene deposits.

Data and results

Seismostratigraphy

For the Plio-Pleistocene interval of the offshore A15 block, 13 key seismostratigraphic horizons and units were initially identified by Kuhlmann and Wong (2008; Figure 2) which were correlated to bio- and magnetostratigraphic levels and log patterns as defined by Kuhlmann et al (2006). All interpreted horizons delineate the top surfaces of distinct clinoform sets and demarcate significant breaks in deposition. The MMU forms the base of the studied sequence. The A15 seismic survey (Z3WI-N2000A) has been used as a reference for the seismic interpretation of the entire study area (Figure 1) and was performed on publicly available 2D and 3D seismic surveys (Ten Veen et al., 2013). Well data and stratigraphic markers were converted to the time domain using a seismic-to-well tie, sonic- and check-shot data enabling the tracing of the seismostratigraphic units beyond the well-studied AB blocks.

Next to horizon interpretation, a seismic geomorphological analysis was performed on 3D seismic data. This resulted in the recognition of elongated contourite bodies, (incised) channels, pockmarks and other features that are of relevance for understanding the controls on delta evolution.

For all key seismic surfaces, the distribution of delta elements, such as topset-, foreset- and toeset-to-prodelta, has been determined, resulting in zonal maps indicating the distribution of these delta elements (Figure 3). Determination of delta element type was based on 1) the geometry of the surface, 2) palynological properties, 3) seismic attribute analysis to recognize paly-nological features (e.g. Stuart and Huuse, 2012), and 4) the relation with internal geometry of the zone beneath and above (downlap, toplap, etc.). Since the clinoforms represent shelf-prism clinoforms, the topset,

Interglacials	Glacials
• Relatively warm climate and relatively high sea surface temperatures • High freshwater input at the base of the interglacials • Relatively open marine conditions • Relatively coarse grainsize (moderate to good reservoir properties) • Relatively high sea level • Relatively high TOC content (possible source for biogenic gas) • Agradational-to-progradational clinoforms	• Relatively cold climate and relatively low sea surface temperatures • Almost no freshwater input • Relatively restricted marine conditions (water stratification) • Very fine grain sizes (excellent seal properties) • Relatively low sea levels • Relatively low TOC content • During seal-level fall: Strongly progradational and lowering clinoforms (forced regressive wedges) • During low stand: predominantly clay deposition (condensed section) • Ice berg scouring in shallow shelf areas • Fluvial incision in exposed areas

Table 1 Listing of interglacial vs. glacial conditions and associated reservoir and seal characteristics.

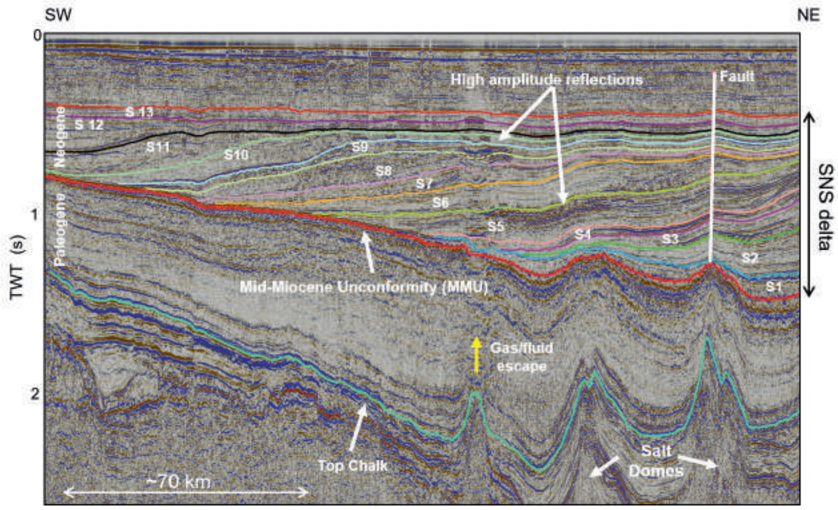

Figure 2 W-NE seismic cross-section (see Figure 1 for locality) showing the westward prograding Southern North Sea delta of Plio-Pleistocene age. Seismostratigraphic units according to Kuhlmann et al. (2006).

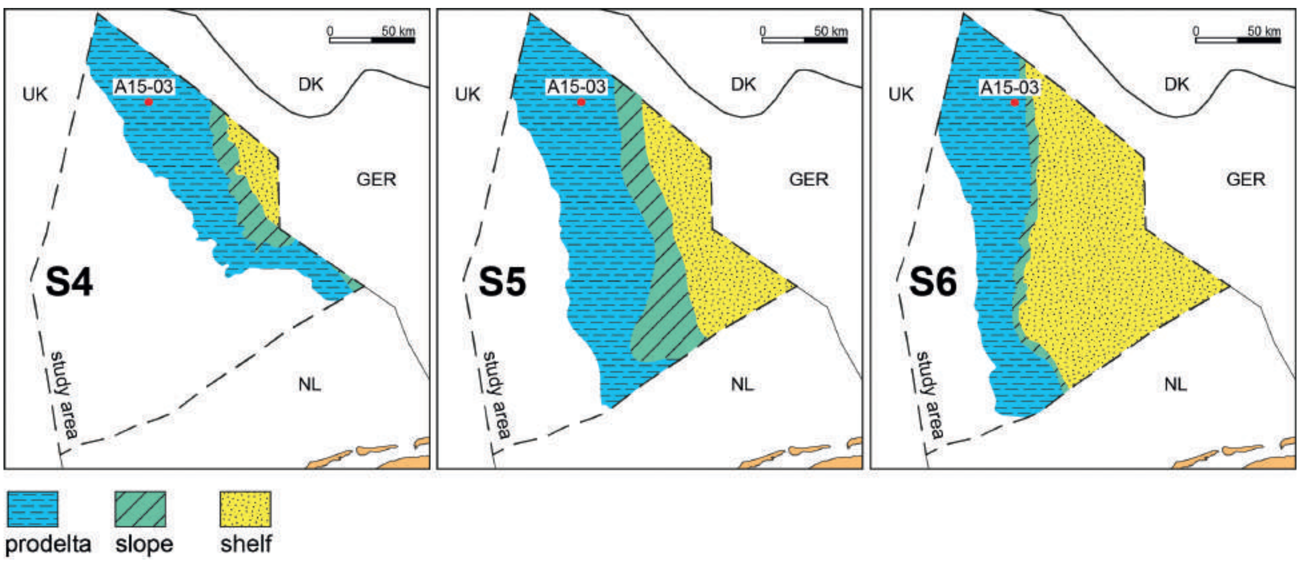

Figure 3 Regional distribution of shelf-prism clinoform elements through time, with shelf (yellow), slope (green) and basin floor (blue) for units S4-S6 showing the regional distribution of delta elements (delta evolution) through time.

foreset and bottomset represent the shelf, the slope and basin floor (pro delta), respectively (Harding, 2015). The rollover point between the topset and foreset defines the shelf break. Smaller-scale clinoforms, i.e. delta-scale clinoforms associated with individual prograding delta lobes, also exist and are sometimes superposed on the shelf clinoforms (Harding, 2015) and are not further considered here. Several zones only consist of one delta element, such as the S1 unit (basin floor facies) and the S12 and S13 units, which consist entirely of delta topset facies.

Paleoenvironmental and paleoclimatological reconstruction

An excellent chronostratigraphic framework available for the SNS succession enables the underlining of the strong coupling of sediment deposition and climate. The A15-3 key well (Figure 1) provides geomagnetic polarity data which enables the precise coupling to global standards (i.e. benthic ocean d^{18}O) by several well calibrated biostratigraphic events and local d^{18}O data (Donders et al., 2018). Based on palynological analysis, Kuhlman et al. (2006) demonstrated the long-term cooling trend from the MMU to the top of the SNS succession.

Quantitative palynological data (pollen) were used to calculate the ratio between tree pollen and herb pollen (the AP/NAP ratio), which positively correlates with temperature. A decrease in the SSTdino ratio, i.e., the ratio between 'warm preference' and 'cool preference' dinoflagellate cysts, is indicative of cooling trends in the marine environment (Figure 4). This trend is punctuated by a couple of distinct higher-frequency cold and warm peaks, interpreted as glacial-interglacial couplets controlled by 41,000-year obliquity cycles. Palynological analysis also measured the sporomorph to dinocyst ratio (SD ratio), which shows the relative contribution of terrestrial vs. marine organic matter input and is a measure for proximity to the coast. A more extensive overview of the palynological and organic geochemical proxies is given by Donders et al. (2018).

In the lower part (S1-S4), the SNS succession contains open marine dinoflagellate cyst and benthic foraminifera assemblages. These correlate roughly with the toe sets of the delta. The middle part (units S5-S7) represents deposition during an alternation of glacial- and interglacial periods. These contrasting climate conditions control the sediment supply both in quantity and type. During the glacial periods the basin was starved and the limited terrestrial supply resulted in a condensed shale layer (Kuhlmann et al., 2004). During the interglacial periods there was a higher sediment influx and sand was deposited that was prone to being captured by contourite currents and accumulated in sandy contourites. Also, the source region of the delta varied in relation to climate change in the Late Cenozoic period. Cold periods coincided with Archean provenance from the Scandinavian shield with a high percentage of illite and chlorite owing to physical weathering of metamorphic rocks by glaciers (Kuhlmann et al., 2004). During the warmer climate conditions, coarser sediment was delivered to the basin by the Baltic river system. These grainsize variations are clearly expressed in both the measured silt fraction and the Gamma-Ray log. The climatically controlled clayey intervals deposited during cold conditions occur basin-wide and act as regional seals. Thus, surprisingly, the warmest intervals or interglacials are coupled to the most coarse-grained sediments, and the coldest intervals or glacials are linked to the most fine-grained sediments.

Geochemical analysis indicated that high TOC content occurs in the silts (low gamma ray), coupled to high SST ratio (based on dinoflagellate cysts), and relatively warm climate (increased forest cover based on high AP/NAP) (Donders et al., 2018). From S5 upward the SNS succession changes via transitional assemblages to restricted marine (S7-S10), with high-dominance and low-diversity dinoflagellate cyst assemblages.

The youngest depositional interval (S8-S13) was deposited in a shallow sea under arctic conditions with sea ice cover. Glacial plow marks are a frequent sight. Some of the units represent warmer periods with an open vegetation and more open marine conditions.

Bright spot mapping

Bright events can be caused by many geological and physical phenomena that cause a local and anomalous impedance contrast that differ from its surrounding. This study only focused on bright spots as DHI's for gas-filled sand layers that appear as low impedance layers with anomalously high amplitude (Figure 5). If the gas-bearing layer is thick enough, the gas-water contact might be identifiable as a flat spot (Figure 5C). It should be noted that the high amplitude, considering the absence of pre-stack amplitude information, is not indicative for gas saturation as even low saturations will produce high amplitude effects detected in post-stack data (Van den Boogaard and Hoetz, this issue).

The bright spots were mapped using an auto-tracker on all available 2D and 3D seismic data. This resulted in stacked bright spots being mapped separately. If bright spots are stacked it is common that the shallowest bright spot reflects most of the seismic energy back to the surface. Because of this transmission effect, the events below have very low amplitudes (Figure 5). Consequently, bright spots below other bright spots sometimes do not meet the criteria for being an anomalously high amplitude event. However, in most cases bright spots become larger with depth (halo-shaped) and can therefore be partially mapped and extrapolated over the transmission domain. Additionally, the gas-filled sand exhibits a pull-down effect which increases with the number of stacked reservoirs (Figure 5A). Next to stacked bright spots, single elongated, bright spots occur that are associated with sandy contourites (Figure 5D) and bright spots that are aligned with the dipping clinoform foresets (Figure 5B); both types represent stratigraphic traps. Some bright spots types are associated with faults and if reservoirs thicknesses are above tuning thickness, gas-water contacts may be visible as flat spots (Figure 5C).

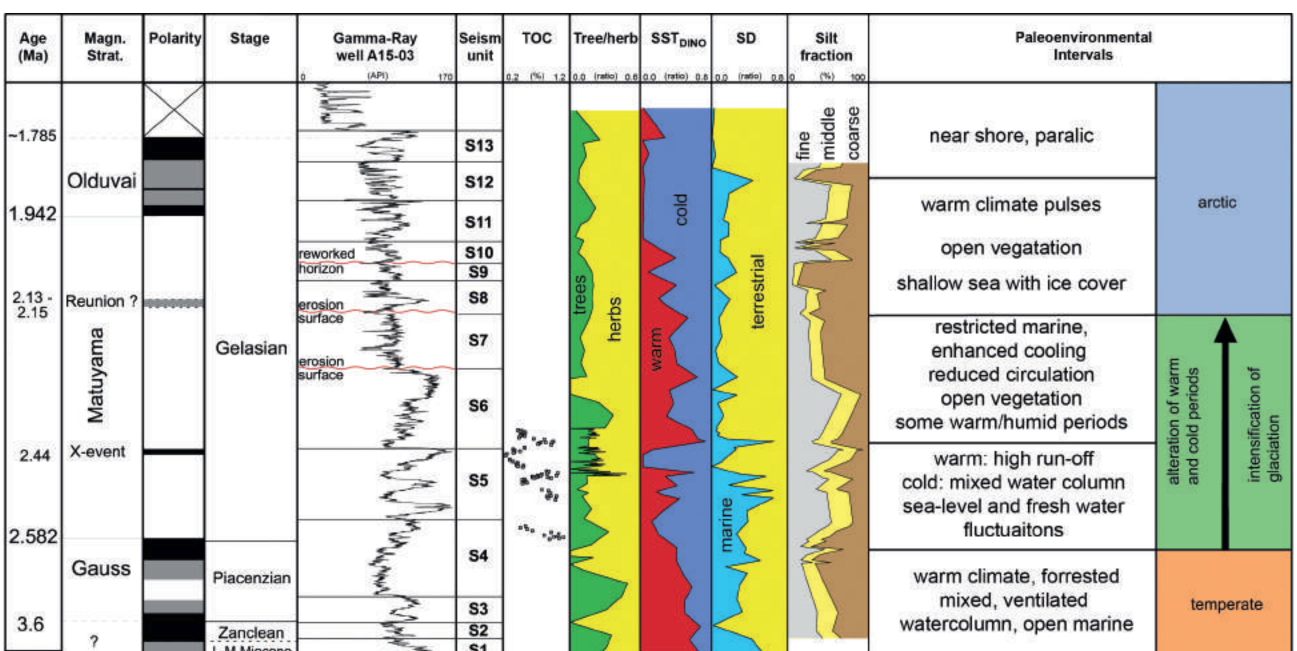

Figure 4 Correlation and interpretation of chronostratigraphy, Gamma-Ray log, seismic units, geochemical and palynological proxies, grain size. Data from Kuhlmann et al. (2006), Kuhlmann and Wong (2008), Donders et al. (2018) and Ten Veen et al. (2013).

Depositional model — synthesis

The presented results enable to draw several important conclusions regarding the coupling between palaeoclimate, paleo sea level, the arrangement of sediment bodies, their morphological expression, rock properties and the occurrence of bright spots. These conclusions enable the delineation of clear characteristics for reservoirs and seals deposited under interglacial (S1-S4), transitional (S5-S7) and full glacial conditions (s8-S13) as presented in Figure 6. Sea level is strongly controlled by paleoclimate and is in line with the expected trend associated with ice sheet build up: high sea levels during the interglacials, low sea levels during the full glacial and highly variable levels during the glacial-interglacial transition. The long-term sea-level trend shows shallowing from the MMU upward and is explained by the progressive infill of accommodation space through the advancing delta.

Distribution of bright spots

Within the study area, bright spots are not present in the units S1-S3 but only in overlying units up until depths of ~450 m below the seafloor. Bright spots occur in delta topset, foreset and prodelta environments throughout all stratigraphic units. Large foreset-type bright spots occur in the S5 foreset delta element in the north-eastern sector of the Dutch Central Graben and are also associated with faults and salt structures delineating the Dutch Central Graben. This suggests that the structural setting may have had a large control on the formation of shallow gas trapping. In the stratigraphically higher units, i.e. S7-S10 and S13-S14, bright spots only occur in topset beds (Figure 7), indicating that the other delta elements are outside the study area, i.e. farther west. Units S11 and S12 have bright spots in all three delta elements.

Elongated bright spots (Figure 7) occur throughout the area in unit S5, S6, S11 and S12, and are related to bright spots in sand contourite fields. Stuart and Huuse (2012) made paleographic reconstructions of the epicontinental North Sea Basin and hypothesised that tidally generated contour currents formed sandy contourites. This suggests open marine conditions prevailed. Sequences S5 and S6 were deposited in a time of alternating glacial and interglacial periods. These contrasting climate conditions control the sediment supply both in quantity and type. During the glacial periods the basin was starved and the limited terrestrial supply resulted in a condensed shale layer (Kuhlmann et al., 2004). During the interglacial periods there was a higher sediment

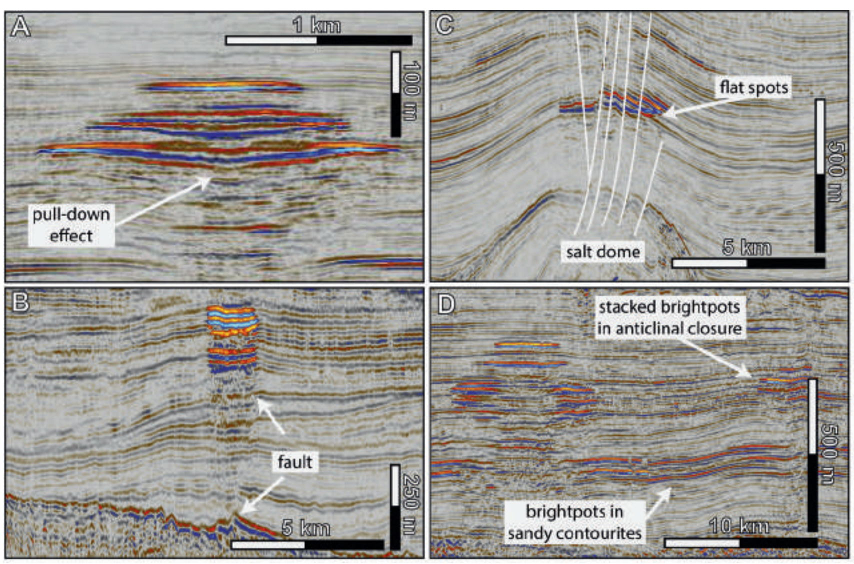

Figure 5 Seismic examples of the various types of identified bright spots . A) Stacked bright spots with 'pull-down' effect indicative of multi-layer gas fields. B) Small-stacked bright spots in clinoform foresets associated with fault zone. C) Bright spots in anticlinal closure with lateral fault seal with GWC visible as flat spot. D) Stacked bright spots in anticlinal (4WD) and bright spots in sandy contourites. Note the presence of amplitudes attenuation below the stacked bright spots owing to the transmission effect. All data was converted to and represented as zero-phase negative polarity, i.e. with bright spots in gas sands kicks represented as peaks (red).

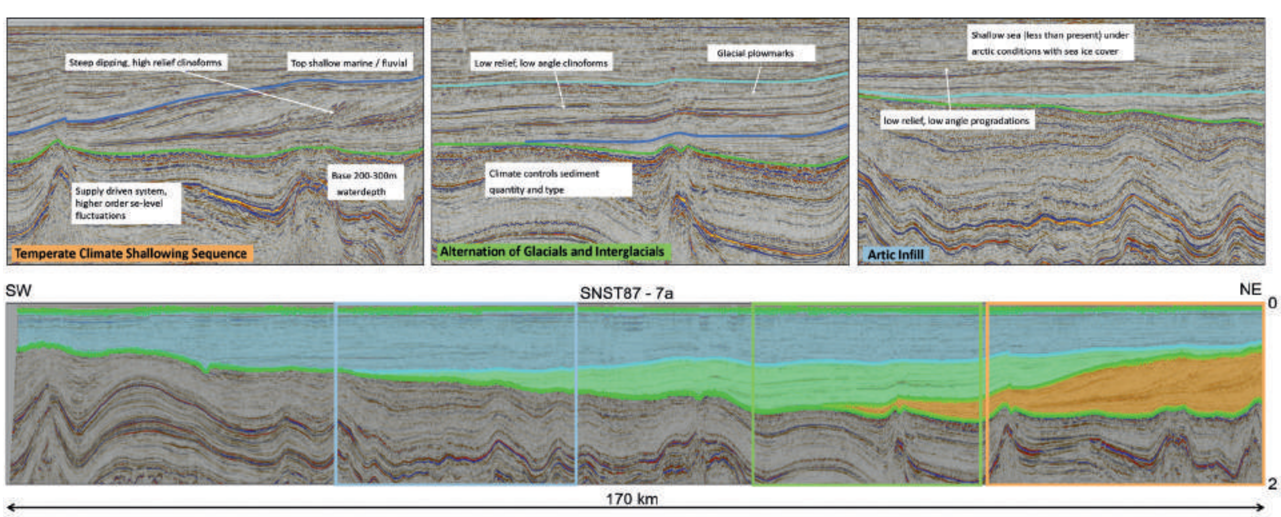

Figure 6 Three depositional megasequences corresponding to specific paleoenvironmental conditions. Colours of the intervals correspond to those in Figure 4.

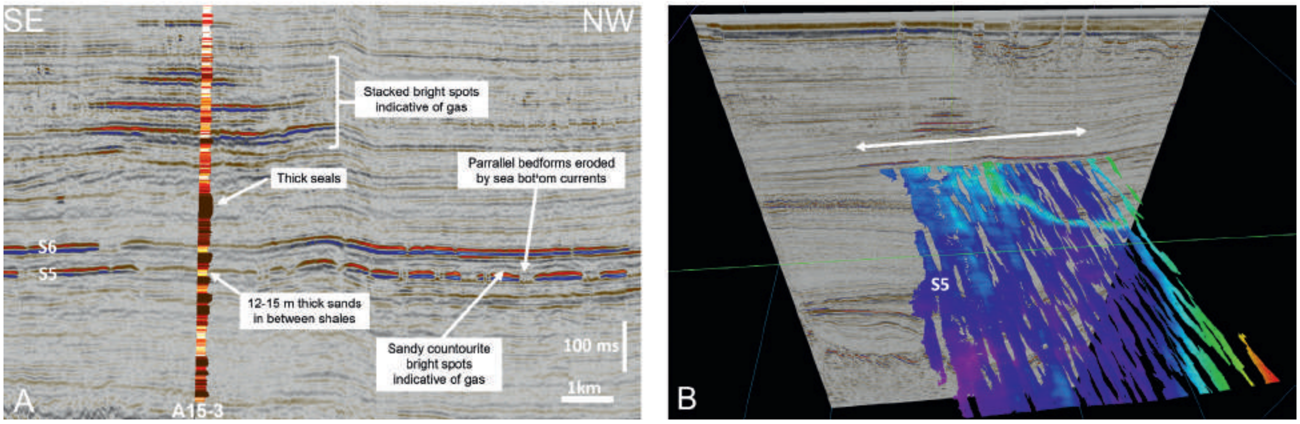

Figure 7 A) Sandy contourite type bright spots in S5 and S6. B) Auto-tracked high amplitude reflections associated with sandy contourites of S5.

influx and sands were deposited that were prone to being captured by contourite currents and which accumulated in sandwaves. Considering that sufficient sea-bottom current activity requires open marine conditions, the presence of contourites in units S11 and S12 indicate a short-lived revival of open marine conditions during the arctic period. This is corroborated by the lower SD ratio in this interval that indicates higher marine influence, which was possibly invoked by a temporal change in oceanic circulation causing melting of the existing sea ice cap.

The spatial distribution of stacked bright spots is closely related to salt domes and ridges forming the structural control on anticlinal closures. Many of the stacked bright spots are not only salt-related, but also fault-related since the salt structures incite fault systems in the overburden as well (e.g. Figure 5C).

Conclusions

The depositional model presented for the SNS delta is important for understanding the trapping of shallow gas within the SNS delta and is made explicit through a series of palynological proxies. The delta sediments were laid down at the time the first ice caps appeared on the Scandinavian shield. This so-called onset of northern Hemisphere glaciations resulted in a series of glacial-interglacial cycles that had a profound impact on the SNS delta behaviour and on the resulting basin-fill. The relevance of the climatic cycles is the fact that they occur basin-wide and control the deposition of clay/silt couplets with good sealing capacity (clays) and reservoir bodies with enhanced TOC.

Consequently, the shallow gas occurrences in the northern Dutch offshore are constrained to specific stratigraphic intervals with recurring combinations of physical properties. The physical properties of reservoirs and seals are determined to a high degree by paleoenvironmental parameters such as climate, productivity and sea level.

Acknowledgments

The workflow and some of the results presented here were developed for the Joint industry Project ‘Shallow Gas’ (TNO, 2013) which was sponsored by Dana Petroleum Netherlands B.V., Total E&P Nederland B.V., Oranje Nassau Energie B.V., Petrogas/Chevron Exploration and Production Netherlands B.V., Energie Beheer Nederland. We would like to thank the sponsors of the project for sharing their insights.

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Oil Fields in the Dutch Offshore: from 2D to depletion

Bert Manders, CGG

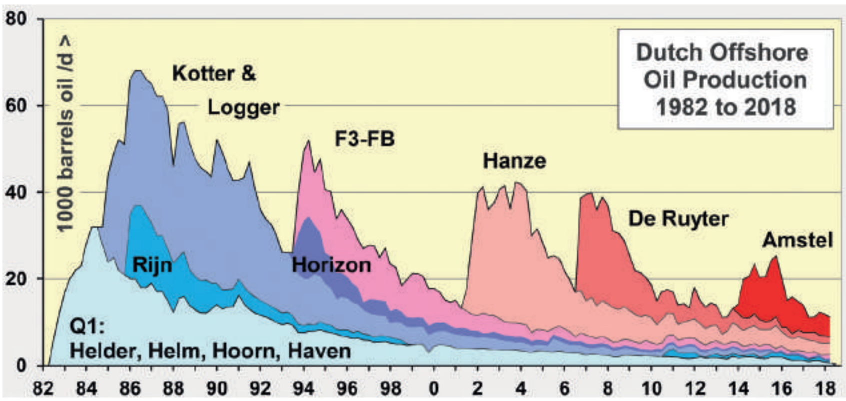


Figure 1 Dutch offshore oil production from 1982 to 2018.

Gas dominates the Dutch Offshore, but about 10% of the extracted hydrocarbons consists of oil. The E&P history of the 12 developed oil fields is reviewed below.

Exploration started in the 1970s with 2D seismic surveys. Most of the oil finds date back to the early 1980s and were located in the southern sector. Early exceptions are Amstel in 1962 (based on gravity surveys) and F3-FB in 1974, while Hanze and De Ruyter of 1996 were relatively late. Rembrandt in 2012 was the last oil discovery.

A cumulative 250,000 km of 2D seismic had been shot in the late 1970s. This corresponds to an average line-spacing of 250 m, which was dense enough to delineate most oil prospects. After 2D activity peaked in 1985, 3D seismic acquisition took over in the 1990s. Although Hanze and Rembrandt are the only discoveries made with 3D, all oil-producing fields received 3D surveys later, mainly to improve the reservoir image and optimize in-fill drilling.

Reservoirs occur at depths of between 1500 m (fields in block Q1) and 2500 m for F3-FB. This is much shallower than the 3000m for the standard Rotliegend gas reservoirs. Early Cretaceous sandstones are the common oil reservoirs, while De Ruyter and F3-FB are in Triassic and Jurassic sandstones. Hanze has Upper Cretaceous Chalk and, thanks to good permeabilities, the field is remarkably efficient. The fractured carbonates produced 60 million barrels (Mbo), almost double the predictions. The worst recovery is in the poorly permeable Lower Cretaceous sandstones of the Horizon field, which delivered less than 10% of the in-place oil.

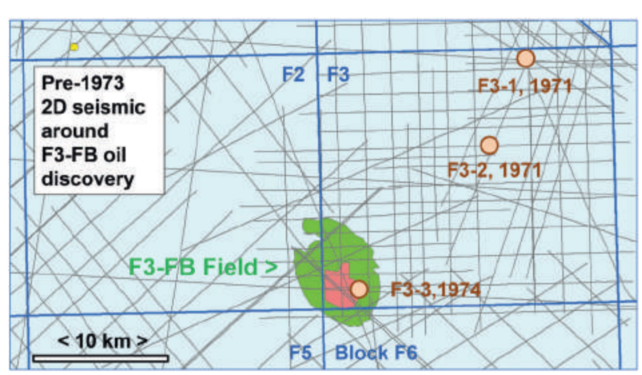
Development of the oil fields was remarkably fast. The usual time between discovery and first oil was only five years. Exceptions are again Amstel and F3-FB, which took 50 and 20 years to come on stream. The very first oil delivery came from the Helder field in the Q1-block in 1982. Already in 1986 the combined output peaked at 75,000 barrels of oil/day (bopd), reducing in a typical saw tooth pattern to 10,000 bopd in 2018 (see Figure 1). A total of 400 Mbo was produced up to 2018.

Operators changed hats often and none of the assets is with the original developer. Early birds were Union, Amoco and Conoco. F3-FB was connected by NAM, which sold it to GDF later. Petro-Canada started Hanze and De Ruyter before Dana took over. Other long gone names include Chevron, BP, Veba and Clyde. Even the latest field Amstel switched ownership from Engie to Neptune already. Operators with currently active oil fields are Petrogas, Taqa, Neptune and Dana.

Depletion and decommissioning are the final inevitable steps in the E&P cycle. Few new production wells were drilled in the older fields during the last decade, although Taqa recovered 10% extra oil so far by refurbishing Rijn. Reducing operational costs (Opex) is the main challenge for the depleting tail-end fields. Opex is spent on work-overs, injecting water and processing vast volumes of oily formation waters. For instance, Kotter and Logger treated 12,000 barrels of liquids a day to recover 500 bopd. These two fields together with Helm, Hoorn and Haven of Petrogas were closed in the last few years. Three platforms are producing less than 1000 bopd and may shut down in the short term, especially at the current oil price.

The marginal L5a-E (Neptune) and Horizon-West (Petrogas) are unlikely to be developed, while Wintershall continues to delay the final investment decision for Rembrandt.

The final step for the five companies responsible for oil platforms will be plugging about 100 producers and injectors and removing the 12 facilities.



Seismic discrimination of an overlooked basal Rotliegend reservoir opens a new play in the Dutch offshore

C.L. Burgess[1]*, J.E. Clever[1], O.J. Corcoran[1], F.M. Cram[1], N.T. Hall[1] and S.F. Lunn[1]

Introduction

The Ruby discovery in the summer of 2017 has been cited as the largest gas discovery in the Netherlands offshore for the last 25 years (Het Financieele Dagblad, 2017), opening a new Dutch play with more than 1 tcf of low risk prospectivity. The Ruby discovery has since been upgraded to a field and renamed N05-A.

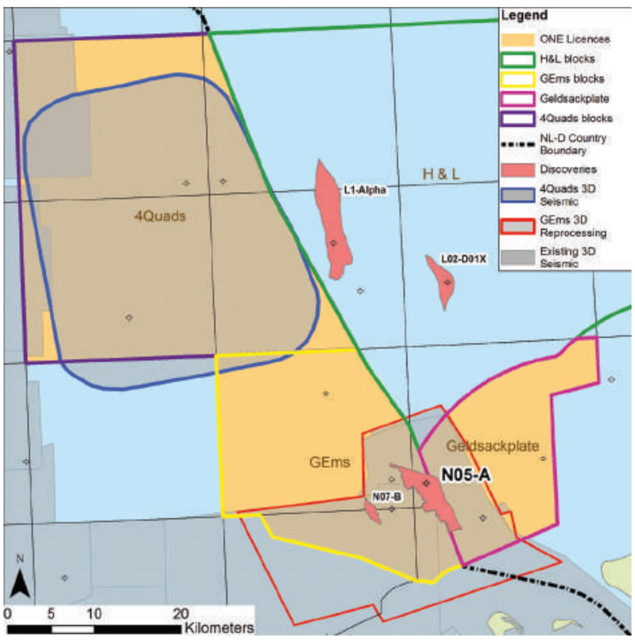


Figure 1 ONE's acreage in the Netherlands and Germany. The N05-A field, formerly Ruby, discovery in 2017 is shown in the GEms acreage. The various licences, GEms, 4Quads, Geldsackplate and H&L make up the collectively named Geldsack.

The play comprises the basal Rotliegend sandstone reservoir — fluvial, alluvial and aeolian sands deposited on the variable topography of the Base Permian Unconformity. The seal is provided by intra-formational shales and evaporites of the Lower Silverpit Formation and the source rocks are coals of the Westphalian Coal Measures.

Ruby was a seismically driven prospect. Historical wells targeting the Rotliegend in this area were sited on structural highs that mostly proved to have poor reservoir development. Significantly, these were all drilled on 2D seismic data. The key advance made in the exploration workflow in recent years was to use geological knowledge and 3D seismic data to delineate reservoir fairways within the play. In particular, key learnings from well and seismic data on the German side of the median line were used to map the basal Rotliegend sand directly on 3D seismic data in the Netherlands and thereby challenge the established industry perception that this area of the Dutch offshore was shale prone.

This paper describes the work undertaken over the last ten years by Hansa Hydrocarbons Ltd. (Hansa), and subsequently its partner Oranje-Nassau Energie B.V. (ONE), which led to the drilling of the commercial discovery in 2017. After the acquisition of Hansa by Discover Exploration in early 2018, ONE took over

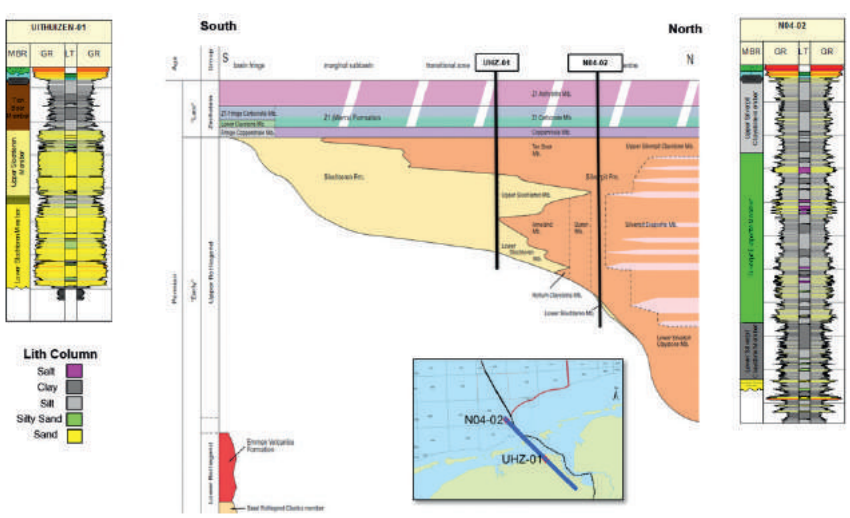


Figure 2 Upper Rotliegend stratigraphy architecture. The previously published stratigraphic model indicates that Hansa's acreage (now ONE's) in the Dutch sector is shale prone (after Van Adrichem Boogaert and Kouwe, 1993-1997).

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operatorship of the three Dutch and German licences (GEms, Geldsackplate, 4Quads). Discover remains a partner in all three of these licences and the adjacent H&L licence in Germany. EBN is also a partner on the Dutch licences (GEms and 4Quads).

Exploration history

Figure 1 shows ONE's Dutch and German licences, collectively called the Geldsack, named after a sand bar in the Ems estuary. This area is relatively underexplored with sporadic exploration activity on both sides of the median line since the 1960s. A number of discoveries in the German area (L1-1 (1975), L2-D1x (1965) and H18-1 (1982)) and several water-bearing wells (P1A, M1 and A1) proved a thick (11-44 m net) basal sandstone sequence with excellent reservoir quality. In the Netherlands, a number of wells (G18-01, H16-01, M03-01, N04-01 and N04-02) were drilled to test a series of structural highs. These five wells encountered thin (1-5 m) gas-bearing basal Rotliegend sandstones (Figure 2). Consequently reservoir development was seen as the key risk in the Dutch area. As a result of the additional risks of seal integrity and nitrogen content, exploration ceased and the area remained overlooked. At this point in time, no well had been drilled on 3D seismic data to test this play.

Figure 1 shows the current distribution of the 3D seismic datasets. In 2014, Hansa acquired 1000 km^2 of 3D seismic data, the '4Quads' survey, filling a large gap in 3D coverage with the Rotliegend basal sand target in mind. Generally, 2D seismic coverage in the Netherlands is dense but comprises a variety of vintages and quality is generally poor sub-salt. In Germany there is virtually no 3D seismic coverage in the southern German North Sea, but the 2D seismic data quality is better.

Sonic and density logs from the German wells show that the basal Rotliegend sand has a lower relative acoustic impedance (AI) than the overlying Rotliegend shales and the underlying sub-cropping Carboniferous. This sand signature can be seen on the vintage 2D seismic data. Despite the well-to-seismic correlations, there was still scepticism that a sub-salt, approximately 25 m sand, could be discriminated on the vintage 2D seismic data.

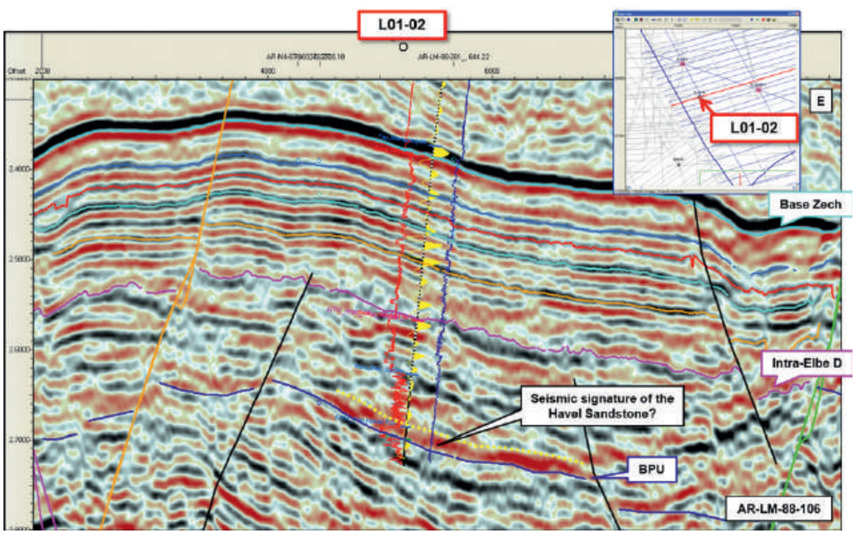

Figure 3 L1-2 well drilled in Germany shows the sands corresponding to a low acoustic impedance unit, the mapped negative (red) interval on the coloured inversion (after Corcoran and Lunn, 2014).

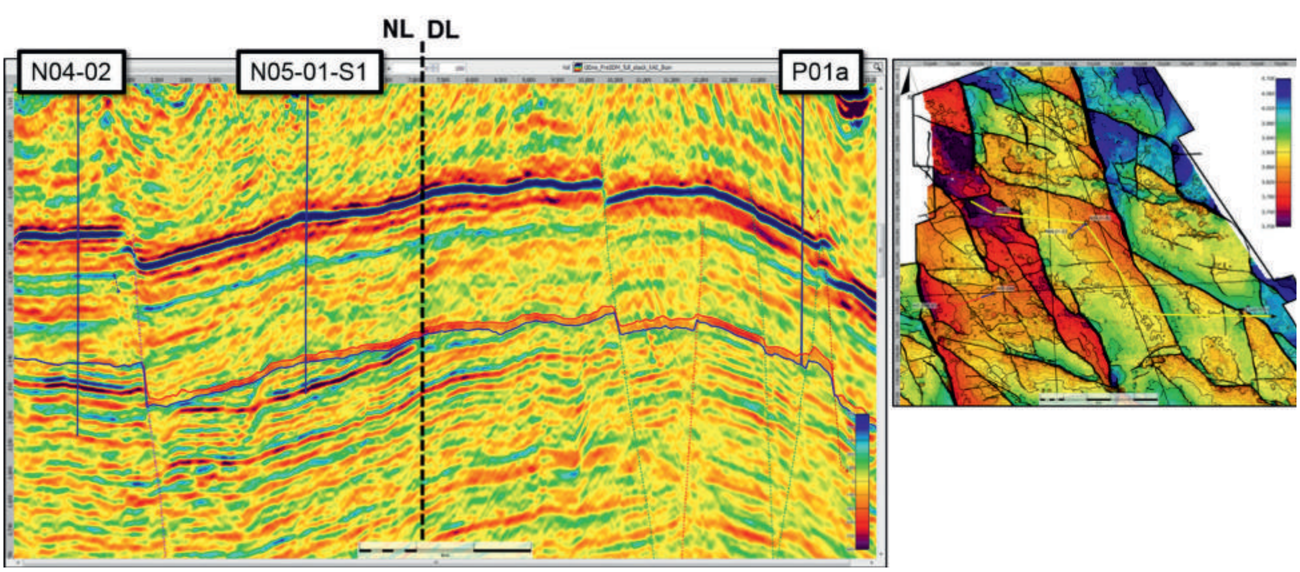

Figure 4 The basal Rotliegend sand can be mapped from Germany into the Netherlands where the reservoir is proven. No low acoustic impedance body is mapped at N04-02 where only thin basal Rotliegend Sandstones were encountered. Inset map is top reservoir depth.

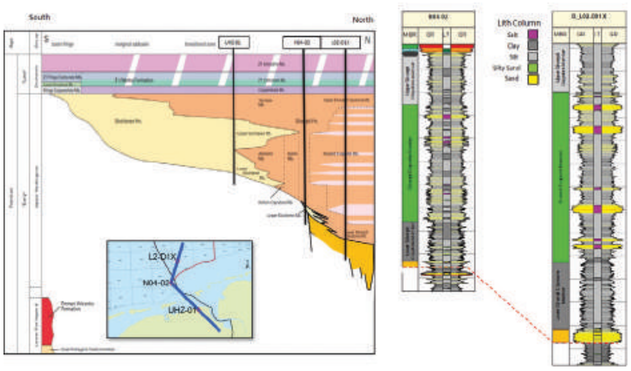

Figure 5 Upper Rotliegend stratigraphy architecture adapted to reflect the new geological model (after Van Adrichem Boogaert, and Kouwe, 1993-1997 and Schröder et al., 1995).

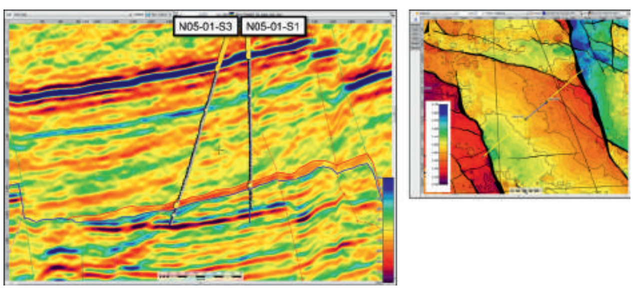

Figure 6 Line through N05-01-S1 and S3 on the coloured inversion volume. Both wells display gamma ray curves. Inset map is top reservoir depth surface.

Play enabler: seismic discrimination of the basal Rotliegend sand

Hansa entered into the German offshore in 2009 when it farmed into the 'H&L' blocks. In 2010, Hansa participated in the drilling of well L1-2, an appraisal well to the L01-Alpha basal Rotliegend discovery. The well was water-bearing, but did encounter an excellent quality, 28 m net basal Rotliegend reservoir section. The acquisition of modern Vp, Vs, density and VSP enabled the generation of a good-quality synthetic and seismic tie to be established.

L1-2 confirmed the low AI basal Rotliegend sand signature as seen in the vintage wells. Furthermore, it demonstrated that the top and base of the reservoir package corresponded to a peak-trough pair on seismic data that could be interpreted from line to line. Simple coloured inversion proved to be the most effective approach for enhancing the seismic response of the sand (Figure 3).

Direct mapping of the low AI unit enabled the basal Rotliegend reservoir fairway to be extended from Germany across the median line into open acreage in the Netherlands which historically was seen as non-prospective (Figure 4). Having gained confidence in reservoir presence, Hansa applied for the open acreage on both sides of the median line.

In conjunction with the regional seismic mapping, a multi-disciplinary approach was taken to try to correlate the basal Rotliegend across the whole Geldsack area, integrating chemostratigraphy, petrography, provenance studies and biostratigraphy to further develop the geological model and mature the play.

Fortuitously, the play extension from Germany to the Netherlands continued into areas covered by 3D seismic data, allowing the prospectivity to be matured quickly, resulting in a number of prospects and leads being identified. Despite numerous cross-border challenges, the Ruby prospect was seen as the best play-opening well and was worked up to drill-ready status.

Ruby gas discovery (N05-01) and the confirmation of a new Dutch play

With reservoir presence largely derisked, seal integrity was now the critical risk. Undaunted by this, in 2016, ONE farmed into part of the Geldsack acreage. In May 2017 the partnership drilled well N05-01, which encountered 28 m of high permeability gas-bearing sand. The pre-drill thickness prediction from the seismic data was 29 m. A core was taken over the whole reservoir interval and a DST was run, which flowed at 53 mmscf/d constrained by surface facilities. After the discovery, a geological side-track was drilled. Both wells targeted the low AI unit seen on the coloured inversion (Figure 6), proving the seismic signature of the basal Rotliegend sand.

Forward work

ONE and its partners are now embarking on an extensive work programme for the area:

- A drilling campaign across the whole of the Dutch and German Geldsack acreage.
- A large 3D seismic reprocessing project.
- 2D seismic reprocessing.
- A new 3D seismic survey acquisition.

Conclusions

Seismic discrimination of the Rotliegend basal sand through routine geophysical techniques has allowed the challenge of the established industry perception. An area thought to be barren of sand actually has a significant sand development. The Ruby discovery well, N05-01, is the culmination of a decade of work on the basal Rotliegend play in Germany and the Netherlands and has proven to be a significant discovery, opening up a new play with more than 1 tcf of low risk prospectivity.

Acknowledgements

The author would like to thank Hansa Hydrocarbons for the opportunity to work on the play, and to ONE for retaining the team to continue to work the area. ONE would like to thank their partners, Discover Exploration and EBN, for their continuing support and contributions to the work on the Geldsack play.

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An integrated field-wide isolation strategy as a key enabler of high-quality, durable and cost-effective abandonments (case history of Roswinkel field abandonment, onshore NL)

Malte Schluter[1]* and Dimas Kodri[1]

Introduction

'Decommissioning is part of the normal life cycle of every oil and gas structure and must be done safely and responsibly when a facility reaches the end of its life' (Shell Sustainability Report, 2016).

A critical part of a successful decommissioning and restoration (D&R) project is the plug and abandonment (P&A) of the existing wells. An appropriate subsurface P&A ensures that any kind of fluid, including unproduced hydrocarbons, is kept safely underground. This could be especially challenging for mature assets with old wells which may have developed integrity issues that need to be remediated.

Projects such as the D&R of a field with several production locations and multiple associated wells, are best done in a campaign mode so that the project can benefit from the synergy of various disciplines, assets or even between operators. In 2016, the Nederlandse Aardolie Maatschappij (NAM) started the journey of abandonment campaigns by identifying and maturing the opportunity to plug and abandon a Triassic sandstone gas field in the eastern part of the Netherlands, Roswinkel (Figure 1). A dedicated Roswinkel abandonment team was put in place consisting of various disciplines, e.g. reservoir engineering, production geology, petrophysics, geophysics, production technology, well engineering, completion engineering and specialists on an as needed basis, e.g. geomechanics, geochemistry or structural geology.

Roswinkel field

The Roswinkel field is located in the eastern part of the Netherlands and can be geologically described as an ENE/WSW trending anticlinal structure. The Triassic sediments are subdivided into a clastic Lower Germanic Trias Group (RN) and an evaporitic Upper Germanic Trias Group (RB). The deposits of the RN mainly comprising the sandstone reservoir and can be further subdivided into three producing formations: Volpriehausen, Detfurth and Basal Solling Sandstone. The source rock for the gas is Upper Carboniferous. The thick RB formations of the Solling Claystone and the evaporitic Röt salt directly overlying the Lower Triassic reservoir units are creating the top seal, while a four-dip closure structure is providing the lateral seal (Figure 2).

The Roswinkel field was discovered in 1976 and production started in 1980 from seven out of the nine wells that were drilled. The field eventually ceased production in 2004 after a cumulative production of 17.1 BCM (recovery factor of around 82%). From the pressure data at end of production, it was apparent that the Volpriehausen sandstone is at a high pressure (~300 Bar) compared to the Detfurth and the Basal Solling sandstone (60-100 Bar). It was not possible to assess whether the Detfurth and Basal Solling are at different pressure regimes as they have never been produced separately and there was also no separate pressure point aside from the initial RFTs. However, there is a clear indication of aquifer support from the pressure recovery observed in both the

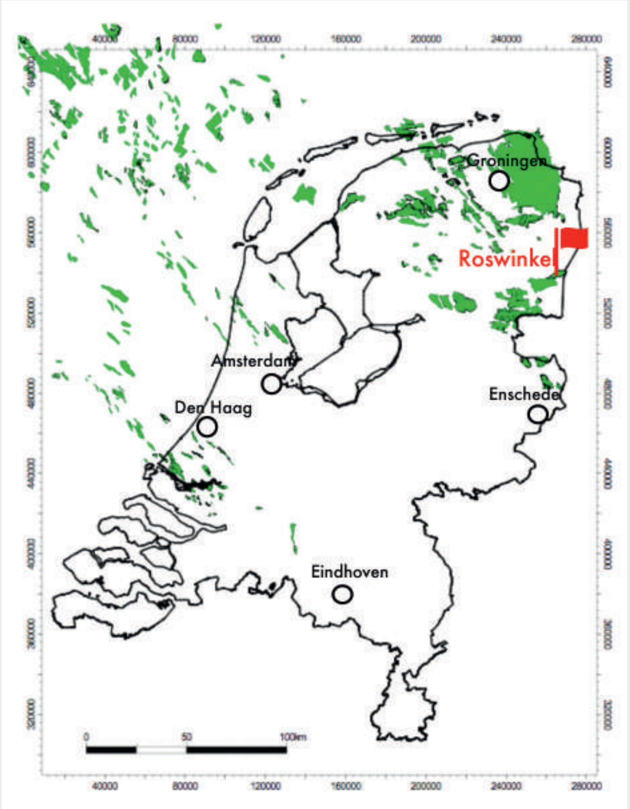

Figure 1 Geographical location of the Roswinkel field.

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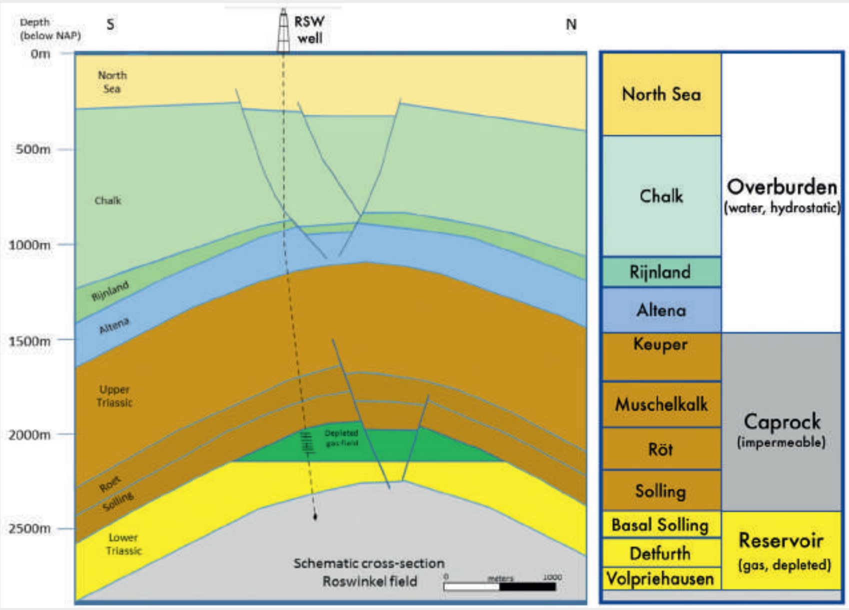

Figure 2 Schematic cross-section of the Roswinkel field, incl. overburden. The stratigraphic chart defines further which formations can be generally grouped into reservoir, caprock and overburden with associated fluid fill and evaluated pressure regime, respectively.

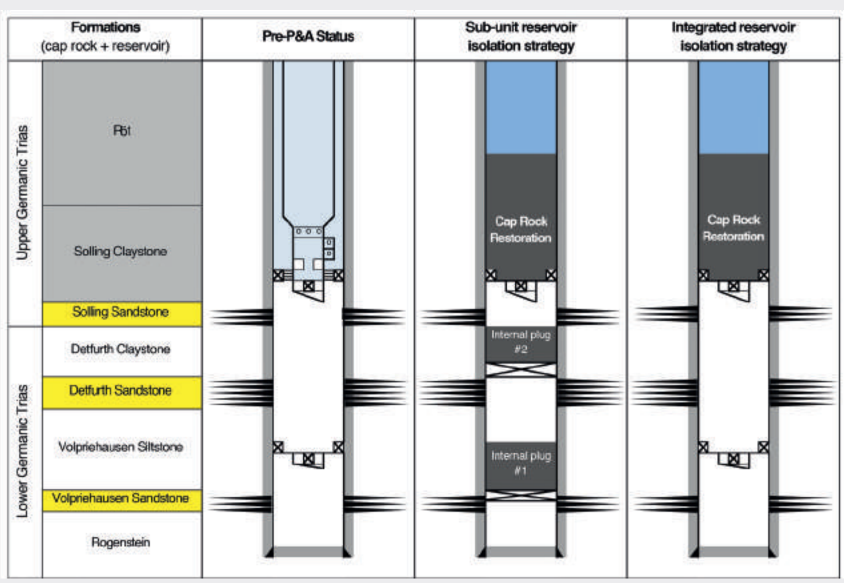

Figure 3 Schematic well status diagram with respect to reservoir units and stepwise improvement of zonal isolation at Roswinkel.

Volpriehausen and Detfurth-Solling sandstone, which is expected to bring the reservoir closer to initial pressure in the future.

Isolation strategy

General

The easiest method to identify a suitable caprock for a reservoir is to use the directly overlying seal, as this is proven by nature to keep fluids in the ground on a geological timescale. However, the subsurface team needs to evaluate the overburden data in more detail to identify formations with similar sealing potential as the directly overlying seal might not be available for restoration, for example owing to mechanical issues in the wellbore. The integrated view of the various disciplines within the team should at least cover field scale, or even, region or basin scale to identify the main risks to loss of containment over large lateral and temporal range. The benefit of understanding the subsurface system and interaction of the various formations is to provide a durable zonal isolation strategy which is based on the natural, geological processes and is supported by latest industry standards, i.e. NOGEPA45. The integrated understanding of the subsurface with respect to the pressure regime, lithology, fluid types, the identification of potential flow-zones with their natural seals associated, and the interaction of all those elements, is therefore crucial. The focus should be on front-end loading of available data from all disciplines involved, followed by sharing and alignment in a joint team discussion. Experience shows that it is beneficial to create this common understanding in a single event, such as a multi-disciplinary workshop with a facilitator setting up the objective, preparing the meeting and summarizing the outcome with tangible action points. The key outcome is a risk-based field wide isolation strategy which needs to be geologically consistent across the field, but also in line with regulations at an individual well level.

Initial

For Roswinkel, the team started the design work with the focus on avoiding any unintended flow, including sub-reservoir to sub-reservoir flow. After every discipline gave their individual input, the recommendation was to put an isolation plug between all reservoir units, i.e. to isolate the Volpriehausen, Detfurth and Basal Solling sandstone in addition to the isolation plug above Volpriehausen (Figure 3). The intra-reservoir isolation plug was deemed to be required as the pressure differential is at the current stage high and a concern existed that fluid movement between Volpriehausen to Detfurth/Basal Solling might have negative consequences. This isolation strategy was then transferred from the subsurface team to the well engineering team and translated into technical solutions at individual well level. During further maturation of the project, it became obvious that the initial strategy would be challenging during execution leading to low probability of success and increased cost, eventually.

Finally, the Roswinkel project team went back to the drawing board to further understand the residual risk of accepting cross-flow between the individual reservoir flow units, once realizing that the technical solution of the initial three-plug reservoir isolation strategy is very challenging. Part of this re-assessment was a fit-for-purpose, dynamic reservoir model to assess the pressure behaviour and risk of cross flow. From the model, two important conclusions were established:

1. The pressure of the Detfurth-Basal Solling is on an increasing trend, likely to be owing to aquifer support, which means the pressure difference with Volpriehausen will decrease with time,
2. Any crossflow from Volpriehausen could be accommodated by the Detfurth-Basal Solling owing to the reservoir size itself where Detfurth-Basal Solling is approximately three times bigger.

The model outcome was supported by a pressure point taken prior to the execution in one of the Roswinkel wells to validate the conclusions of the modelling work.

The dynamic model therefore reaffirmed that the entire sub-reservoir of Lower Germanic Trias of the Roswinkel field is in hydraulic connection at a geological timescale. This is supported by the information that all reservoir flow units share same initial gas-water contact, i.e. can be treated as one hydraulic unit during further evaluation of field-wide isolation strategy.

At this stage it was critical to reflect and align the common understanding of the field data and implications at well level within the full Roswinkel abandonment team. This was achieved by combining all data and all involved disciplines in a single session. The available subsurface data, e.g. lithology, gamma-ray, density, caliper and all well engineering data such as well status diagram, casing size, shoe depth and cement bond logs (top of cement evaluation included) was displayed side by side, discussed with all team members and risk evaluated with respect to the best position of the plug setting depth (Figure 4). Plotting the plug depth with respect to expected pore pressure and associated fracture pressure is very valuable for the risk assessment and to find a common understanding on the shallowest recommended plug depth. This was accompanied by a check of the structural geology to identify formations which need to be of sufficient thickness and consistently present across the whole field without any large fault offset to ensure seal integrity. Based on the understanding of the long-term dynamic reservoir behaviour, the decision was taken during the integrated isolation strategy session that a single plug isolation is adequate. It was recommended to set the plug across the natural, regionally available seal of Upper Germanic Trias evaporitic sediments, e.g. Röt Main Evaporite (mainly salt). The detailed design work on the technical solution of the individual wells resulted

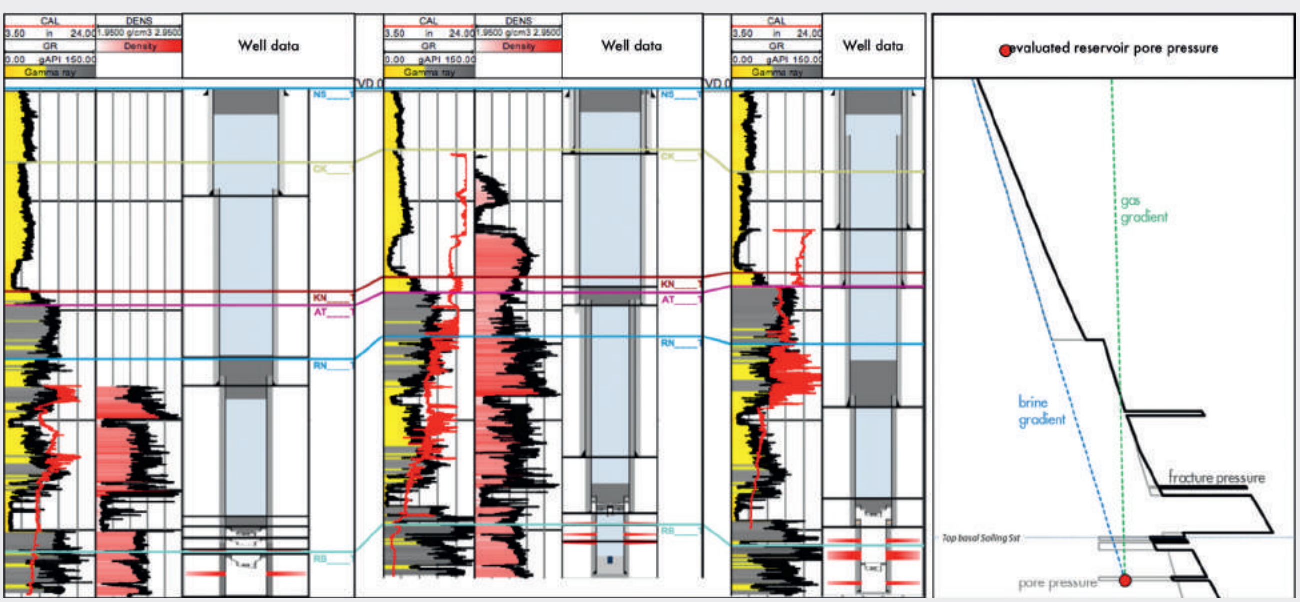

Figure 4 Integrated data visualization on geological, petrophysical, well engineering and geomechanical data. Only three wells are shown as examples. During the Isolation strategy session all wells are plotted and discussed. Note that the mechanical well data is reflecting the final isolation status, including cement plugs across the full wellbore diameter. The focus of this article is on the reservoir isolation.

in a simpler and more robust approach with a higher technical probability of success, based on the updated final field-wide isolation strategy (Figure 3).

The updated strategy was discussed and accepted by the regulator prior to the start of the abandonment campaign, which was executed safely and successfully in 2017, on time and at competitive cost. The lessons learnt from this project are applicable for any scale of abandonment. It is for now considered as best practice standard for continuing and future abandonment campaigns by the NAM.

Conclusion

Profound subsurface understanding and integration of various disciplines is a key enabler to identify a fit for purpose field-wide isolation strategy. The initial focus should be to minimize the risk of harm to people and the environment owing to loss of containment or even induced seismicity, while considering the geological context and future subsurface activities, such as further exploration or geothermal development. In particular, the ALARP approach on the individual well solutions should be integrated in the standard workflow of future abandonments. The multi-disciplinary integration needs to happen in line with government requirements (law), the latest industry standards (NOGEPA 45) and if applicable with other operators of the same basin (Nexstep). The case study of Roswinkel showed that the initial plan using a more traditional approach of separating individual flow units (i.e. defined by different pressure during production time) of the sandstone reservoir, resulted in a technically challenging solution with low probability of success. The integrated reassessment of the approach by the multi-disciplinary team resulted in a solution which was considered fit for purpose and as-low-as-reasonably-practicable (ALARP). The new strategy has proven to be the key enabler for safe, in-time and at competitive cost abandonment for the Roswinkel field.

The end of the Roswinkel field P&A is just the start for future P&A campaigns in NAM. More than 770 wells currently in use onshore Netherlands (Nexstep, 2018) will need to be plugged and abandoned in a safe, durable and efficient manner and it will be therefore crucial to replicate and apply the onshore learnings to the offshore realm, eventually.

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Geophysics in the driving seat of multi-disciplinary integration

Eva-Maria Rumpfhuber[1]*, René Frijhoff[2] and Clemens Visser[2]

Introduction

One of the key challenges for oil and gas companies holding a mature development portfolio is to maximize the value of their assets. The goal is to look for ways to increase the ultimate recovery of (poorly drained) producing fields, and for undrilled near-field opportunities. The first category is worked by drilling of additional drainage points or the execution of a well, reservoir and facility management (WRFM) programme. The second category typically consists of geologically complex structures with limited associated gas initially in-place (GIIP) volumes, which reduces the economic feasibility of such projects. Both categories can benefit from a thorough revision and update of the reservoir models, thereby incorporating all information from well, production and seismic data acquired over the lifetime of the fields.

Such an integrated reservoir model update usually takes place while production is continuing, and therefore the associated time and cost are often heavily scrutinized. It is essential to ensure that the ever more detailed knowledge on a field is honoured by taking a truly multi-disciplinary approach. This effectively enables integration and allows the reservoir model updates to be done faster, cheaper and better.

The technical disciplines involved in a reservoir model update are production geology, petrophysics, reservoir engineering and geophysics. The first three disciplines spend a majority of their time analysing data and information from existing wells in a field and/or within a particular reservoir. Geophysicists, in contrast, spend the majority of their time with seismic data.

The challenge for geophysicists is that seismic data measures impedance contrasts (velocity times density), and therefore statements about the reservoir properties net-to-gross (NtG), porosity (Por), and saturation (Sat) can only be made indirectly. Yet seismic data, if understood within the geological framework, can help to unravel lateral variations of reservoir properties away from existing well locations. Therefore, it can address the critical question about whether the existing wells provide a representative sample of the hydrocarbon accumulation. This is crucial for uncertainty range estimation, more specifically for defining a robust low case, i.e. to reduce the risk of pursuing an uneconomic project.

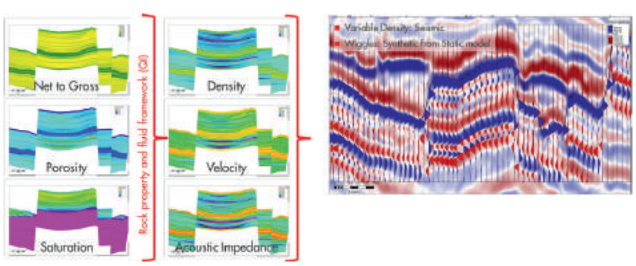

Figure 1 Concept of Check the Loop as a two-stage forward modelling workflow: 1) Convert a reservoir model with net-to-gross, porosity and saturation properties into a velocity and density model. QC at well locations by comparing with wireline velocity and density logs. 2) Convert the velocity and density model into synthetic seismic data and qualitatively assess against measured seismic data.

To fully exploit seismic data, the NAM reservoir modelling community has employed the simple and fast workflow called 'Check the Loop' (ChTL) on a number of projects. 'Check the Loop' is a long-standing seismic forward modelling workflow within Shell, as opposed to 'Close the Loop', which involves seismic inversion and hence takes more time and effort. The ChTL workflow is a two-step process where by the reservoir model (NtG, Por, Sat) is first converted into acoustic/elastic properties (velocity and density) and then turned into synthetic seismic data (Figure 1). The resulting synthetic seismograms can subsequently be qualitatively assessed against the actual seismic data.

The workflow requires integration of all data (seismic, wells, and reservoir model), which reinforces a multi-disciplinary discussion and enables a feedback loop between the reservoir modeller and the geophysicist. Once set up, any model update can be calculated within minutes and therefore any question from the reservoir modeller can be addressed with fast turnaround.

The case studies below show some of the examples where geophysics was closely interlinked in reservoir modelling via the Check the Loop workflow, and as a result the true multi-disciplinary integration had a significant business impact. The questions that can be addressed with this workflow are wide-ranging, from checking updated petrophysical analyses (case study 1) and selecting representative wells for modelling (case study 2), to a comparison between a static and an upscaled dynamic model (case study 3).

Case study 1: Testing petrophysical updates with seismic data (offshore UK)

Rebuilding of an existing reservoir model triggered this check the loop analysis, while static modelling and a petrophysical re-evaluation of the log data was continuing. The petrophysical analysis tested various ways of evaluating net-to-gross ratio for the prospect, which is an important aspect of estimating uncertainties. The forward modelling of the original static model from 2016 shows a good fit (Figure 2) between sonic and density logs (red) and its predictions (blue). In 2017 an alternative reservoir model was tested with a significantly lower NtG and

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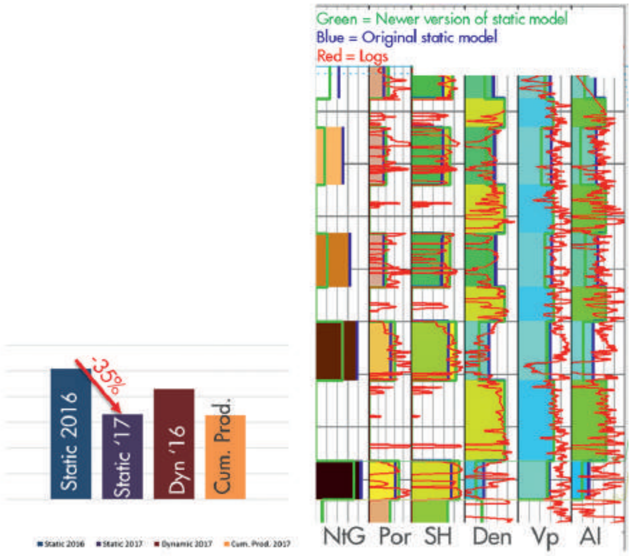

Figure 2 Left: GIIP estimates derived from static models in 2016 and 2017, and a dynamic model from 2017, compared to cumulative production at the end of 2017. Right: Well panel with logs in red indicating net-to-gross (NtG), porosity (Por), hydrocarbon saturation (SH), density (Den), velocity from sonic (Vp), and acoustic impedance (AI). Original 2016 model results in blue and updated 2017 model in green.

associated lower GIIP (green). While the NtG input was deemed plausible in a range of possible input parameters, this alternative reservoir model was disregarded because a similar good match compared with the 2016 model could not be achieved, and given an unrealistic delta between GIIP and the cumulative production of the field. Therefore, the integrated discussion and feedback loop between geology, petrophysics, reservoir engineering and geophysics was central to building a robust static reservoir model, which is also consistent with both seismic and production data. While it is crucial to have a robust uncertainty range for any development project, a low case that is too conservative can unnecessarily put a project into economic jeopardy.

Case study 2: Selection of representative wells of an existing field (offshore Netherlands)

Revision of a static reservoir model for a project offshore Netherlands triggered an integrated discussion on how representative the wells are for the closure they are drilled in. Two wells have been drilled into the main fault block, with significantly varying NtG values. The first well has a NtG of 72%, which is consistent with neighbouring closures. The second well at a distance of ~1.5 km has a NtG of 54%. The low NtG values from the second well, which had not previously been included in the reservoir model, would have resulted in a GIIP decrease of 25% for the overall structure. However, some doubt was raised about the quality of the wireline results, as logging was performed through casing with only a limited set of logs.

These questions prompted a 'Check the Loop' analysis, comparing synthetic seismic of the static model honouring the well 2 log data with actual field seismic. The analysis showed that the low NtG values for well 2, in combination with anomalously high values for porosity, not only resulted in significant lateral changes from well 1 to well 2, but also in significant vertical contrasts in acoustic impedance. Thus, the simulated seismic data from ChTL showed strong, bright amplitudes, while the actual seismic data shows a dim response at the same location. After a discussion with all technical disciplines involved, it was decided to exclude the second well from the reservoir model based on the data quality concerns mentioned above. Excluding this well in the model led to a more robust estimation of GIIP, and a better match of actual and synthetic seismic data. The turnaround for this integrated analysis was only three days.

Case study 3: Indications for rising contacts (onshore Netherlands)

A static and dynamic model update was carried out for a sizable gas field onshore Netherlands. After producing this field for many years, while acquiring a rich dataset on production behaviour (downhole and surface pressure, pulsed neutron logging, gravity), there were still areas in the field where no satisfactory history match could be achieved for all matching parameters together.

One element rebuilding the static model included seismic inversion for porosity. The resulting porosity cube was used to steer the porosity distribution away from areas with good well control, thereby avoiding a potential bias because wells are preferentially targeting better reservoir. A Check the Loop study was carried out to make sure that the synthetic seismic data of the updated model showed a satisfactory match with measured seismic data. This was the case for a larger part of the field, but some areas still showed discrepancies.

Seismic data was acquired at a stage in the lifetime of the field when significant depletion had already taken place. A 4D seismic feasibility study, which tests the changing seismic signature owing to production of a field over time, showed that no 4D seismic signal would be expected over most of the field. However, if depletion would have resulted in a rising contact, as seen in only some wells, this may have sufficiently changed the seismic response to affect the property modelling. As a result, a second Check the Loop iteration was carried out to test this, now based on the upscaled dynamic model with pressure and saturation properties representative for the point in time at which seismic data was acquired. The difference with the results of the first iteration, i.e. with initial reservoir conditions, is subtle but real for selected areas (Figure 4). It was thus concluded that the Check the Loop process can be used to better understand certain aspects of dynamic reservoir behaviour. This in turn may lead to an improved history match.

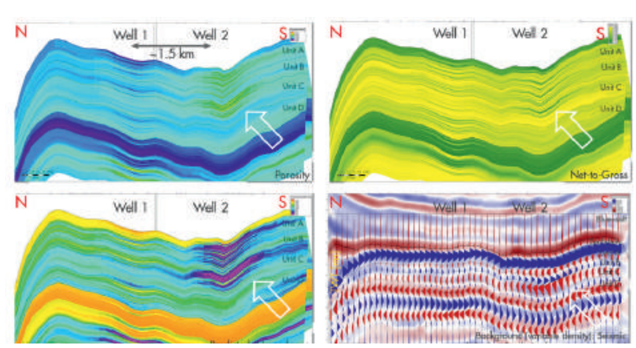

Figure 3 Cross-section from the static reservoir model from well 1 to well 2 displaying porosity (top left) and net to gross ratio (top right). The predicted acoustic impedance from the reservoir model (bottom left) and synthetic seismic data (bottom right) show the strong lateral changes porosity and NtG ratio, which are inconsistent with the actual seismic data (backdrop).

Summary

When it comes to discussions on reservoir property modelling, it may not be a common practice to include the geophysicists, given that they are working with seismic data, which does not measure reservoir properties directly. However, the simple 'Check the Loop' modelling workflow shows that this can be a missed opportunity. The workflow is simple, fast and serves to relate the amplitude response of the seismic data to the reservoir model and its properties. It is applicable to both clastic and carbonate environments, is available in a variety of software tools, and has much untapped potential for implementation. This presents an opportunity for geophysicists to be closely involved in the reservoir modelling process, and the case studies above provide only a few representative examples. However, first and foremost, the workflow provides a platform where different disciplines are encouraged to quality check their respective inputs and work towards a fully integrated reservoir modelling product. All models are wrong, but fully integrated models are useful.

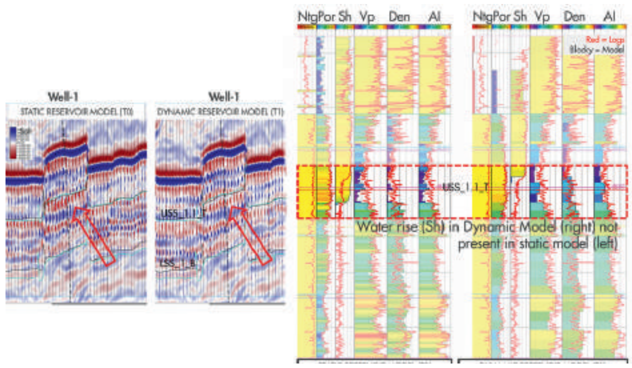

Figure 4 Subtle differences in synthetic seismic data based on initial (T0, left-hand seismic section) and on depleted reservoir conditions (T1) (right-hand section) reveal a rising contact owing to production of hydrocarbons. The same effect is shown in the log panels to the right.

Acknowledgments

We would like to acknowledge the NAM asset teams for their contributions to this article. We would also like to thank ExxonMobil for permission to publish this paper.

Prospectivity analysis of shallow gas in the Netherlands

M. van den Boogaard[1*] and G. Hoetz[1]

Introduction

Cenozoic sediments in the Dutch North Sea host abundant seismic amplitude anomalies, or *bright spots*, of which several are proven to be related to hydrocarbons. The Netherlands was the first country in the North Sea region in which these accumulations have been developed. Currently, four Dutch shallow gas fields are successfully producing, and additional fields are planned to come on stream in the coming years. The success of the producing fields has raised industry interest. The play has proven to be a valuable resource and with several tens of undrilled shallow leads, largely covered by 3D seismic data. It is worth further evaluating the development potential of the play.

The occurrence of bright spots in the northern Dutch offshore at depths up to 1000 m was already known from seismic data in the early Seventies. Subsequently, in the Eighties and Nineties the presence of producible gas was proven in several accumulations by wells. This resulted in the discovery of eight gas fields in Cenozoic clastics. However, owing to expected early water breakthrough relating to the geometry and sand production as a result of the unconsolidated nature of the structures, the play remained undeveloped. After years of studying the area by several operators, the first shallow field in the Netherlands was developed by Chevron – now Petrogas – in 2007. This field (A12-FA) ranked at the time among the best producing gas fields in the country with production rates of some 3 million Nm^3/day via six producers. Nowadays, three more fields are producing (Figure 1): F02-Pliocene operated by Dana Petroleum (2009), and B13-FA (2011) and A18-FA (2015) both operated by Petrogas. The producing fields do not show significant sand or water production.

Features such as conformity to structure, flat spots, velocity push-down effects, attenuation, gas chimneys and pockmarks at the seabed (Schroot et al., 2005) emphasize the potential for the presence of gas in the shallow play. First-order estimates pointed out significant potential for shallow gas in the Netherlands in terms of volumes (Muntendam-Bos et al., 2009). Because of these encouraging results, a further play analysis was carried out. The focus area is the northern Dutch offshore, where most of the bright spots are located.

For developing shallow gas accumulations the following success factors appear key: size of the accumulation in combinations with distance to existing infrastructure, reservoir quality and gas

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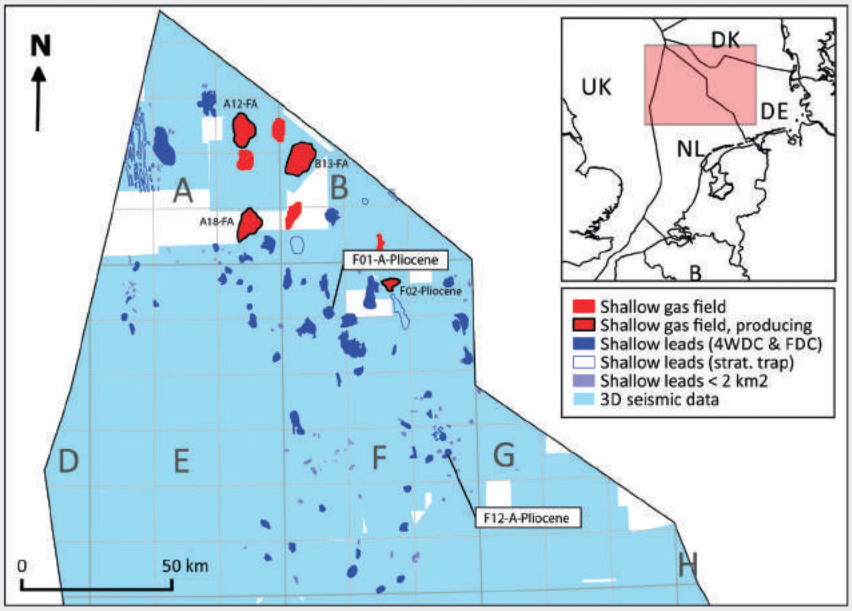

Figure 1 Study area showing the eight shallow fields (red), of which four are currently producing (black outline), and the identified shallow leads. Case study 1 (F01-A-Pliocene) and case study 2 (F12-A-Pliocene) are also indicated. The 3D seismic data coverage in the area is shown in blue.

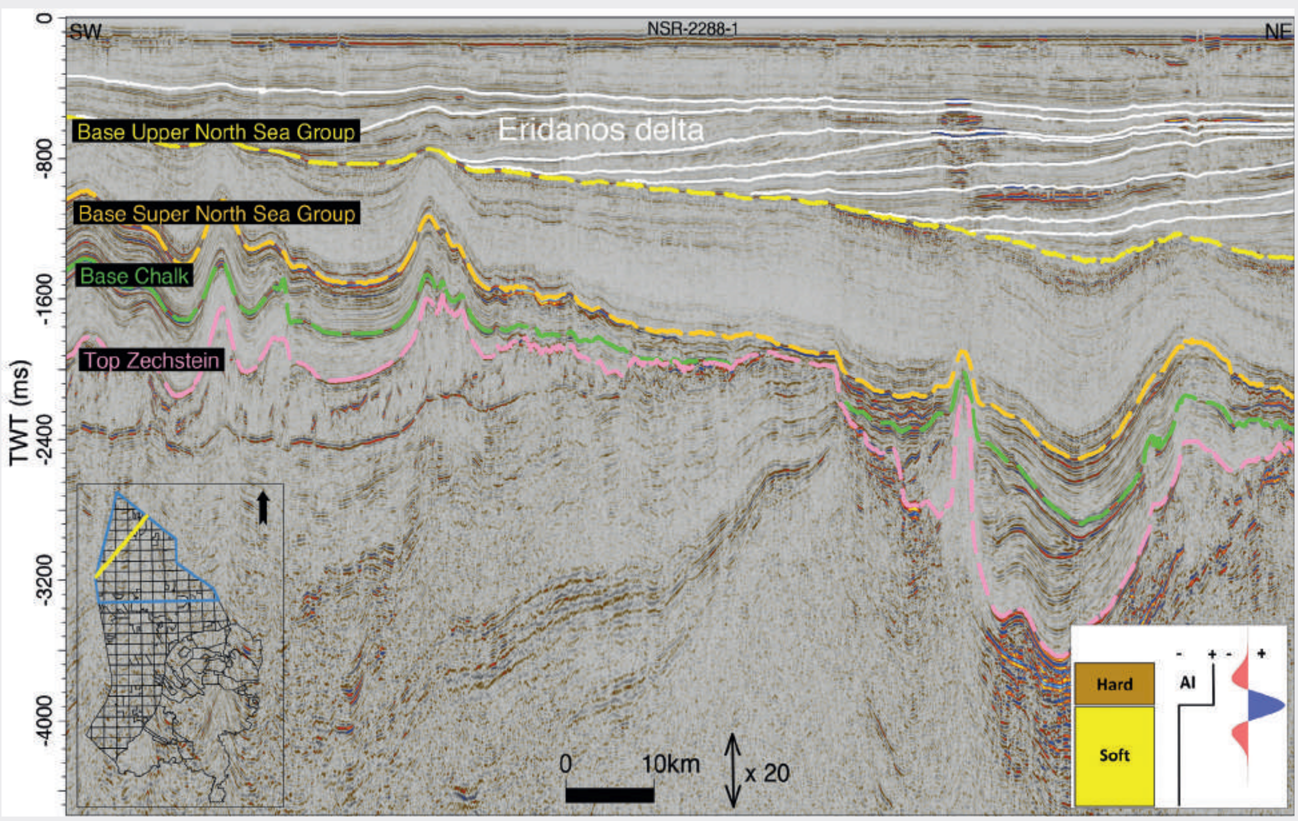

Figure 2 Seismic section through the study area showing the Cenozoic foresets of the Eridanos delta system in white.

saturation. This paper focuses on the latter and presents an inventory of the occurrence of shallow amplitude anomalies based on seismic reflection data. To help select attractive leads, a seismic characterization system was developed in which more than 150 bright spots are ranked. One of the critical factors is the presence of mobile gas and estimating gas saturation prior to drilling. This remains because the seismic attributes included in the ranking system do not distinguish between high and low saturation or even lithological effects. Nevertheless, the system is a valuable tool for selecting those amplitude anomalies that have the highest potential for development and for justifying further assessment, including volumetrics. This paper includes two case studies of high ranking leads.

Geological setting

The study area includes the A-H quadrants in the northern offshore of the Netherlands (Figure 1). Most of the shallow anomalies in the area occur above the Mid-Miocene Unconformity, in formations that are deposited in a late Cenozoic fluvio-deltaic system (Figure 2), generally referred to as the Eridanos Delta (Overeem et al., 2001). The sediments were transported from the uplifted Fenno-Scandian shield in the north east, while later the source area shifted southwards. The delta system covers a large part of the current Southern North Sea and comprises an alternation of shales and clean-to-shaley sands (Rasmussen et al., 2008). The sandy layers form the reservoirs, sealed by shales of various thicknesses. Those shales are believed to have a maximum sealing capacity after which breaching takes place (Verweij et al., 2014), often resulting in a stacked reservoir-seal alternation.

The origin of the gas is debatable. While often it is believed that the gas is biogenic, based on the gas composition which is > 99% methane in most wells (Verweij et al., 2018). There are also indications that the gas has a (partly) thermogenic origin, such as the presence of gas chimneys below the amplitude anomalies and the gas isotopes in some of the wells (Schroot et al. 2005). Often the amplitude anomalies occur above deeper salt domes and many of the bright spots are four-way dip closures, sometimes associated with faults. Amplitude anomalies relating to stratigraphic traps are also observed (Figure 1). However, the current Dutch shallow gas discoveries are all dip-closures and so far no stratigraphic traps are proven gas fields in the area.

Shallow gas portfolio

Shallow gas developments

Four shallow gas fields are currently producing in the northern Dutch offshore: A12-FA, B13-FA, A18-FA (the A & B fields) and F02-Pliocene (Figure 1). Additionally, development of three more fields is under consideration. The field in the F quadrant is a combined development with a Cretaceous oil reservoir, producing gas from one shallow sand at a depth of 700 m. The reservoir is a four-way-dip closure crosscut by a fault. The fields in the A and B quadrants all produce from several stacked reservoirs with depths of 300-700 m. The sediments are deposited in the Pliocene and Pleistocene (2.2-1.4 Ma). Analysis and development of the A & B fields is based on 2D seismic lines, since this area was not covered by 3D data until recently. The fields are low relief dip closures and the number of producing intervals per field range from one to four with scope for additional infill reservoir sands (Figure 3). Gas saturation is typically reasonable to good. Porosity and permeability are good to excellent. Expected ultimate recovery factors are 50-70%.

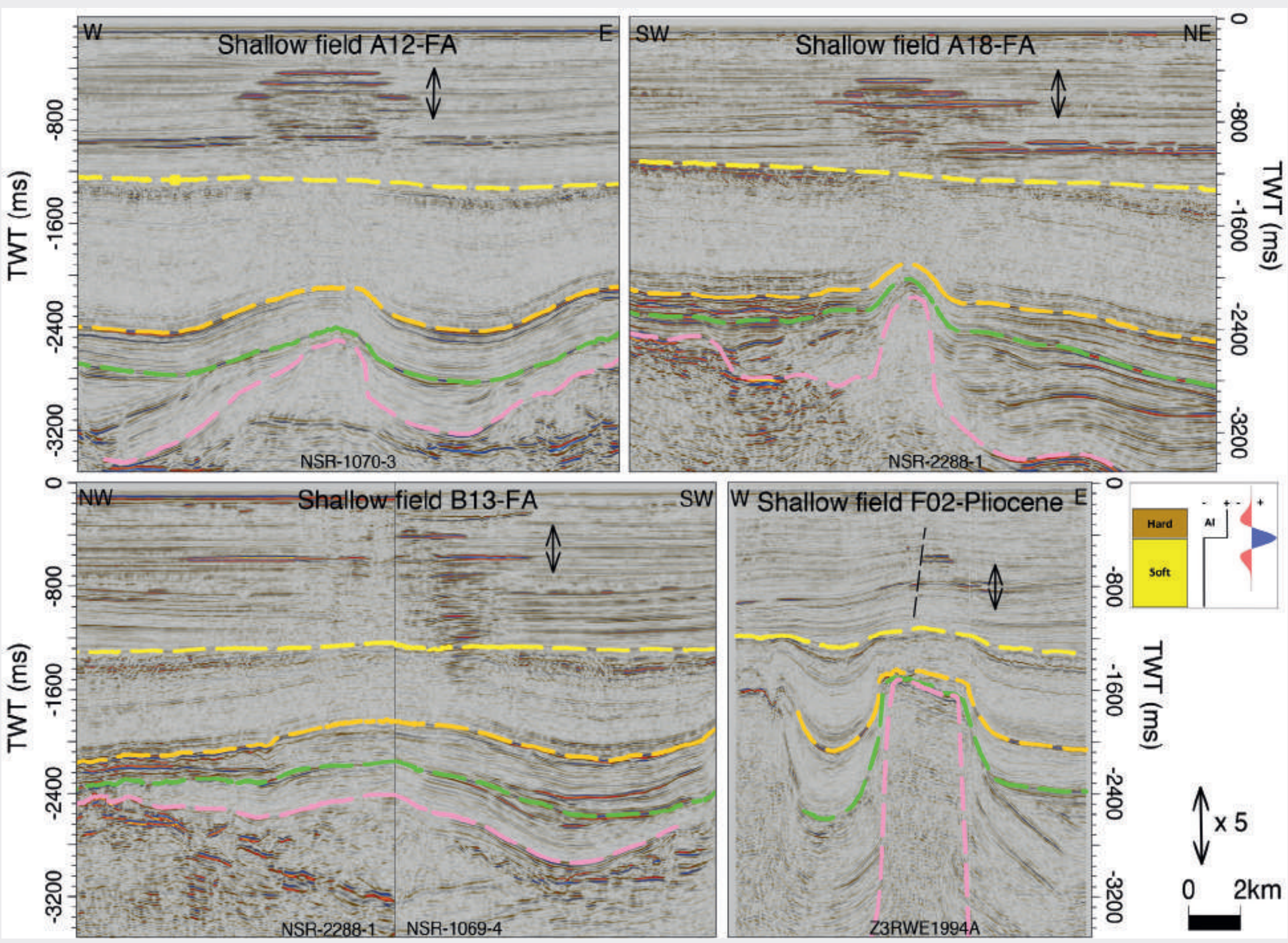

Figure 3 Seismic lines through four producing shallow gas fields in the Netherlands (location indicated on Figure 1). The arrows indicate the producing reservoirs. The Base Upper North Sea Group (yellow), Base North Sea Group (orange), Base Chalk (green) and Top Zechstein (pink) are indicated.

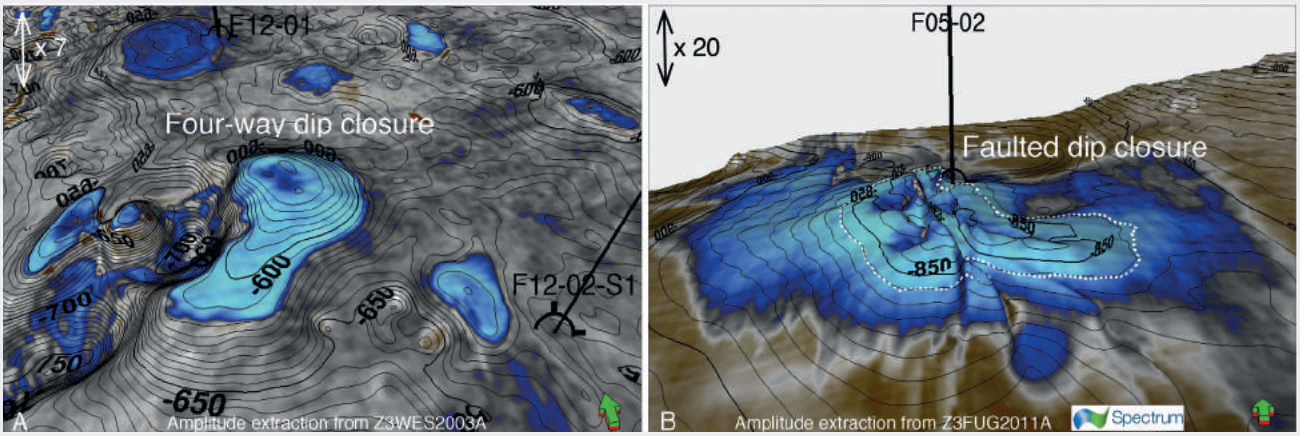

Figure 4 A) Amplitude extraction plotted on the top reservoir map (TWT) of a four-way dip closure bright spot (area 5 km²). B) Amplitude extraction plotted on the top reservoir map (TWT) of a faulted dip closure bright spot (area 40 km²). The white stippled line indicates the brightest part of the anomaly that is conforming to structure.

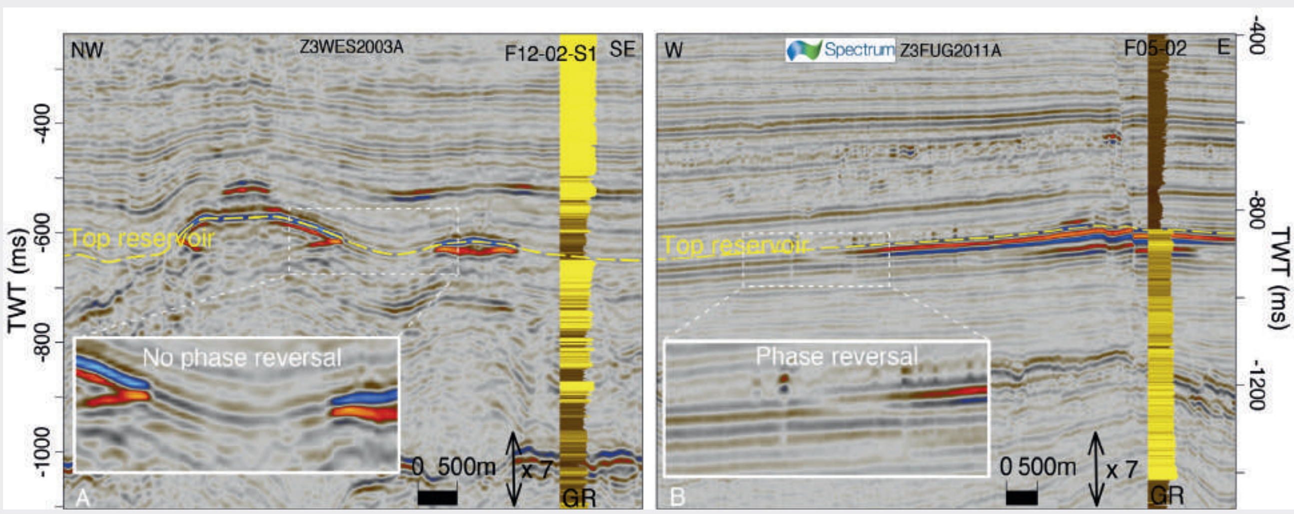

Figure 5 A) Soft event (blue loop) at the top reservoir reflector (indicated by the yellow, dotted line) showing a strong decrease in acoustic impedance at the lead F12-A-Pliocene. B) The top reservoir reflector (indicated by the yellow, dotted line) showing a strong decrease in acoustic impedance resulting in a phase reversal at the gas lead in quadrants F04-F05.

Sand thickness (net) is in the order of a couple of metres, varying per reservoir, and net-to-gross ratio ranges 60 to 100%. Despite the modest reservoir pressures (~50-60 bar) as a result of the shallow depth, initial production rates are in the range of 2-3.5 million Nm³/d.

Water depths in the area are 30-50 m. Whereas the F02-Pliocene gas is treated on the F02 production platform and partly used as fuel for the Chalk oil production, the A & B fields all connect to the A12 central processing platform. The unmanned A18 and B13 satellite platforms do not contain any significant processing or compression facilities. Based on production experience, the operator has simplified the satellite design to a minimum over time, thereby enabling the commercial future production of additional, smaller gas fields in the area. The production wells contain horizontal sections in the reservoir of up to 600 m length. Sand handling is a crucial part of the well design, because of the unconsolidated nature of the reservoir sands. This comprises expandable sand screens (Campbell et al., 2014) in most of the wells. These sand screens have proven to be highly successful. Furthermore, most wells have no or very limited water production and the few wells that do produce water not before 65% of the gas in place has been produced.

More shallow gas opportunities

The success of the producing shallow fields encourages further exploration of the Cenozoic play in the Southern North Sea. Moreover, the availability of 3D seismic data (Figure 1), a tax incentive for developing marginal fields and a guaranteed offtake contribute to the attractiveness of the play. A lead inventory in the study area resulted in more than 50 bright spots mapped from 2D and 3D seismic data. This inventory excludes anomalies shallower than 250 ms TWT (~250 m) and a lateral area smaller than 2 km², since those are likely to be sub-economic.

The bright spots show significant variation in geometry including area, depth, vertical relief and number of stacked amplitude anomalies, all relating to the potential of the lead. Also the trapping mechanism plays an important role in the ranking of the leads; four-way dip closures and faulted dip closures (Figure 4) are considered to have highest potential for development, because of their analogy to the currently producing reservoirs. Closures that show (crestal) faults do have a slightly higher risk of low saturations.

The geometric characteristics relating to the size of the potential accumulation described above are used for a first-order ranking of the bright spot structures. This results in 52 leads with a four-way-dip or faulted dip closure, of which 13 are larger than 10 km^2. For some high-ranking leads, a detailed subsurface analysis was conducted including a volumetric assessment. Because shallow gas was long considered a drilling hazard, only few of the bright spots have been penetrated by wells, which typically went for deeper targets. Hence, well data from offset wells (i.e. nearby wells that did not penetrate bright spots) are used to constrain reservoir properties.

Gas saturation is one of the key subsurface uncertainties in the volumetric assessment, because of the non-linear relation between seismic amplitude and saturation. In total, 16 of the 52 leads with a four-way-dip or faulted dip closure have been drilled. All but one of the 14 public wells report gas shows at the depth of brightening, strongly indicating that there is gas in the system. However, detailed log and hydrocarbon data is most often absent since these wells generally had deeper primary objectives. Results of the continuing work on volumetrics for each of the high-ranking leads look promising, especially when considering the relatively cost-efficient development options for these shallow reservoirs.

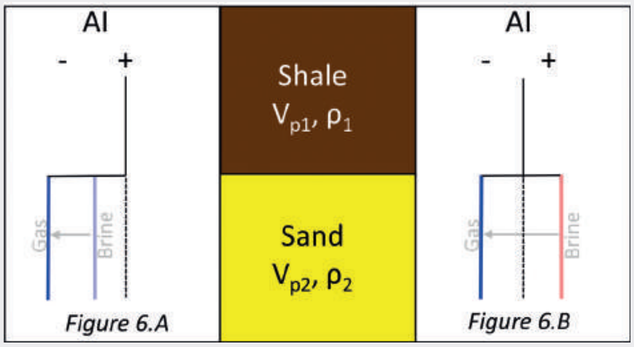

Figure 6 Schematic explanation of Figure 5A and B showing a case in which substituting brine with gas in the reservoir sand results in an amplitude decrease only (left) and a case in which this results in a phase reversal (right).

Seismic lead characterization

In order to further evaluate the development potential of the shallow leads, the seismic character of the individual amplitude anomalies was assessed on migrated stacks. The following features, which can be regarded as Direct Hydrocarbon Indicators (DHIs), have been evaluated: 1) (relative) amplitude, 2) flat spots, 3) velocity push-down, 4) attenuation, and 5) gas chimneys. Based on the geometrical parameters relating to the size of the accumulation as described above and on the DHIs relating to the presence of gas, each bright spot is ranked semi-quantitatively.

Amplitude

Rock physics modelling shows that substituting brine with gas leads to a strong decrease in the P-wave velocity, which can result in a significant increase in acoustic impedance contrast at the shale-sand boundary. This effect is observed by a soft event at the top of the gas reservoir (Figure 5A). Depending on the sediment characteristics, a phase reversal at the top sand reflector might occur at the boundary of the bright spot (Figure 5B) as is schematically indicated in Figure 6. The sand layers can be relatively thin (metre-scale), which is significantly affecting the seismic signature of the top reservoir due to tuning effects. Often it is not possible to define a separate top and bottom reservoir reflector.

Note that amplitude anomalies might also be the result of lithological effects, such as locally increased porosity. Although, strictly, a lithological effect cannot be excluded without an exploration well, the conformity to structure of most of the amplitude anomalies as well as the presence of other DHIs helps to reduce the risk of a lithology effect causing the brightening rather than the presence of gas.

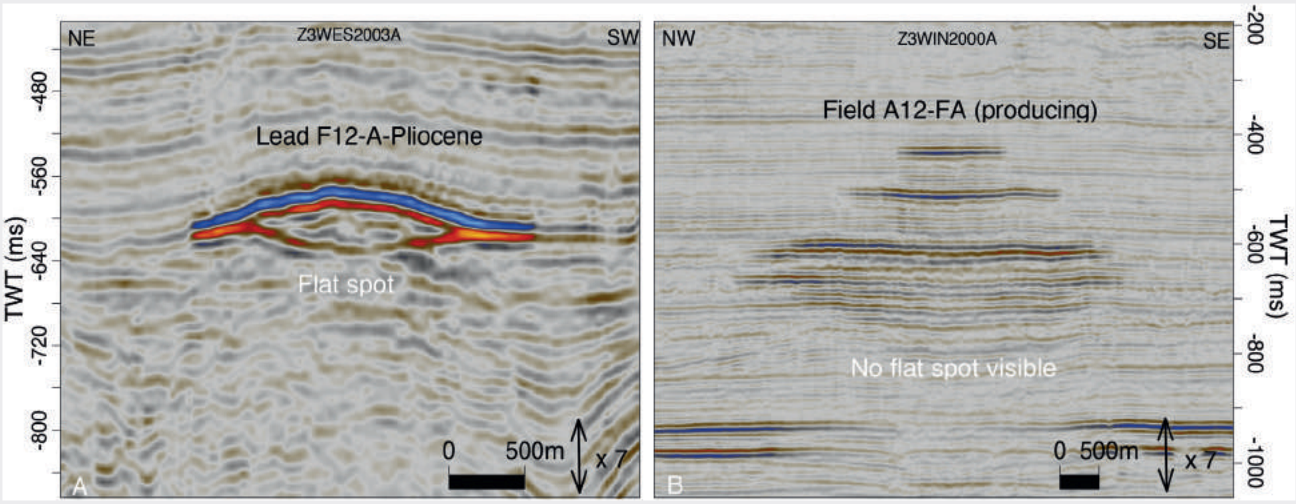

Figure 7 A) Amplitude anomaly F12-A-Pliocene with a clear flat spot, indicative of a GWC. B) No flat spots are visible in producing field A12-FA.

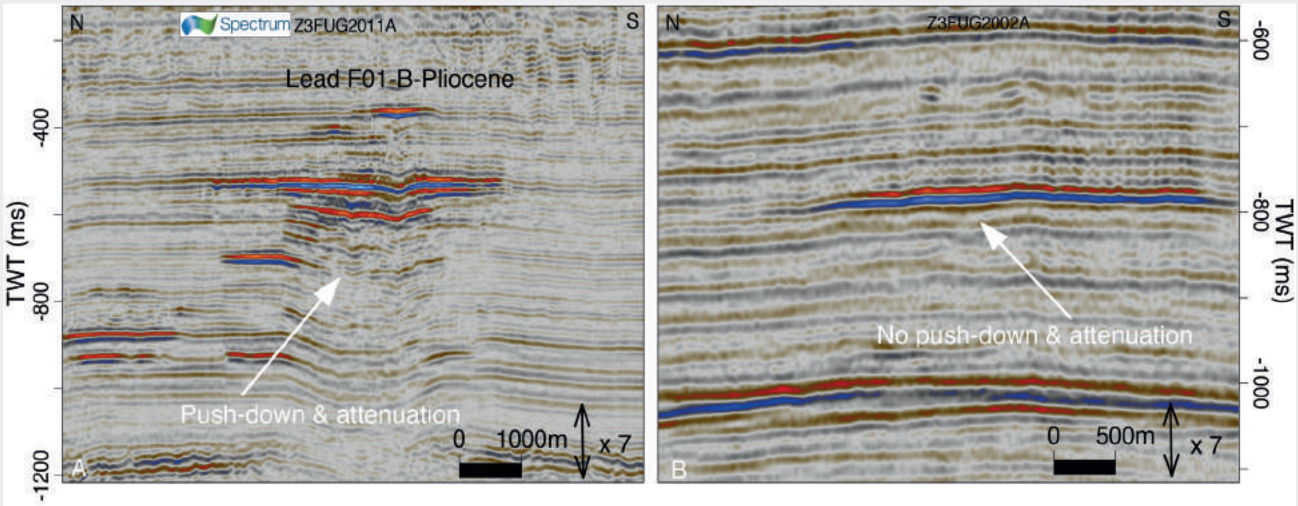

Figure 8 A) Amplitude anomaly in quadrant F01 with a push-down effect, increasing with depth. Also attenuation of the seismic signal is observed. B) Amplitude anomaly in quadrant B14 that does not show a push-down effect nor attenuation.

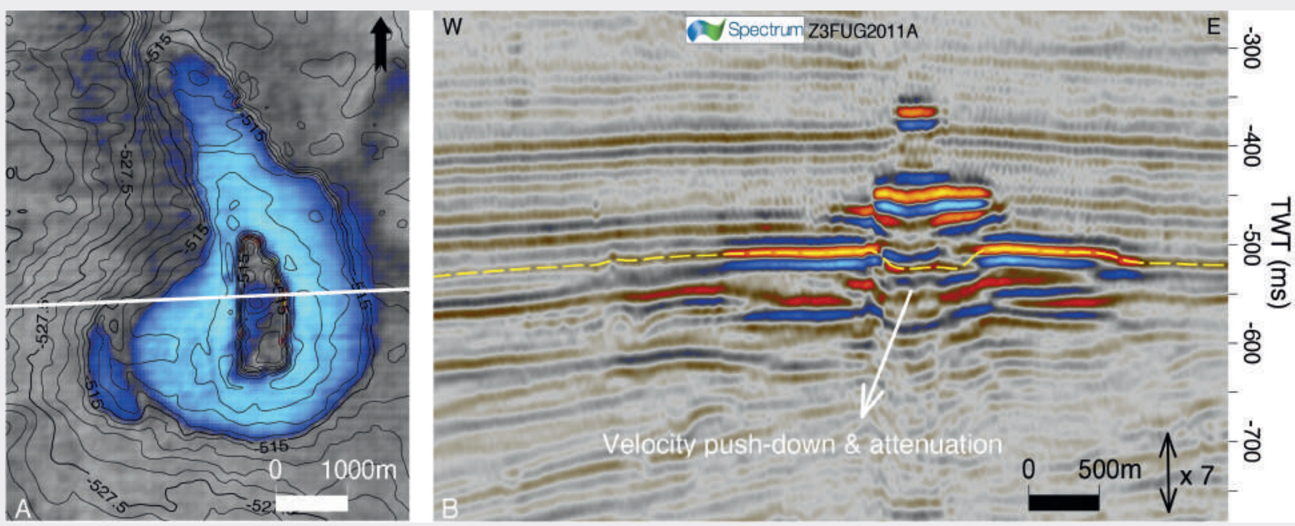

Figure 9 The combination of velocity push-down and attenuation gives rise to the doughnut effect: an artefact that is fairly typical for stacked shallow gas occurrences in the Netherlands.

Flat spots

Since seismic amplitudes are not sensitive to variations in saturation above a low threshold saturation value, additional seismic signatures that relate to the presence of gas are analysed. A flat spot can often be observed on seismic data (Figure 7A) and indicates the presence of a gas-water contact (GWC). However, the absence of a flat spot does not necessarily direct to the absence of gas, as is illustrated by Figure 7B, showing one of the producing fields with high gas saturation, but no visible flat spots.

Velocity push-down

The decrease in seismic velocity when substituting brine with gas causes delayed arrival times of the seismic wave at the receiver, resulting in an apparent push-down effect below the gas zone on the seismic events depicted in time. This effect can be observed on the top reservoir reflectors owing to gas in the system above (Figure 8A) or on the flat spots (Figure 11C). In case of stacked reservoirs it is common that the push-down effect increases with depth. The apparent push-down can have significant impact on the lead analysis, especially regarding the gross rock volume, since it masks the real structure of the bright spot. Modelling shows that the amount of push-down is hardly related to saturation, but reflects the total gas column height. Hence it is difficult to draw conclusions on gas saturation once a push-down has been observed. However, the absence of a velocity push-down below an amplitude anomaly suggests that it is unlikely that the structure is substantially gas-filled (Figure 8B).

Attenuation and gas chimneys

Whenever gas is present in a reservoir, it is likely that the seismic signal underneath the reservoir is masked owing to the absorption of the seismic energy. This attenuation effect underneath a bright spot is a strong hydrocarbon indicator (Figure 8A). On the contrary, when no attenuation is observed, the likelihood for substantial amounts of gas is low. Figure 8.B shows an example of a low ranking bright spot, based on the absence of a push-down effect and attenuation, in addition to its relatively small size. Note that using the attenuation ranking criterion assumes that no special noise suppression techniques or Q compensation filters have been used to hide attenuated zones.

Structural definition

The presence of shallow gas above any target zone causes specific challenges in mapping the structure and hence in assessing the trap size. The velocity push-down effect is reflected in the structure and creates a doughnut-like closure (Figure 9). The central part is severely depressed and the amplitude brightening effect is absent in the core area owing to the attenuation described above. In particular, the topographic distortion at top reservoir should be corrected as it strongly impacts the gross rock volume of the structure. Without correction, the prospect volumetrics will be severely underestimated. Correction can be achieved with careful time-depth conversion.

Portfolio ranking

The work described in this paper indicates that observations of amplitude conformity to structure, flat spots, velocity push-down, attenuation and gas chimneys all contribute to the likelihood of a gas occurrence, although saturation remains uncertain. In total, 26 of the 52 selected four-way dip and faulted dip closure bright spots show a push-down effect, of which 22 leads are also affected by attenuation. For six leads a flat spot can be observed. These DHIs are used for a semi-quantitative ranking of the lead portfolio, together with the geometrical characteristics defining the size of the potential accumulation as discussed earlier. Based on this approach, a number of high potential leads have been selected for further study.

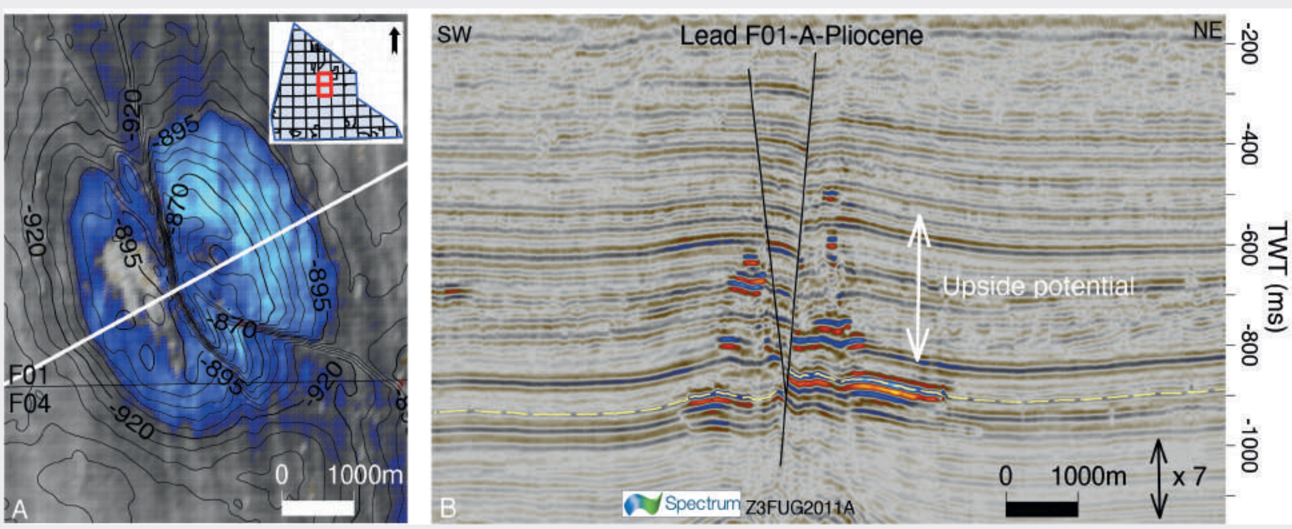

Figure 10 Figure A) Time map of the main reservoir of lead F01-A-Pliocene showing amplitudes. B) Seismic line through this faulted dip closure (location shown on Figure 10A). The top of the main reservoir is indicated by the yellow dotted line.

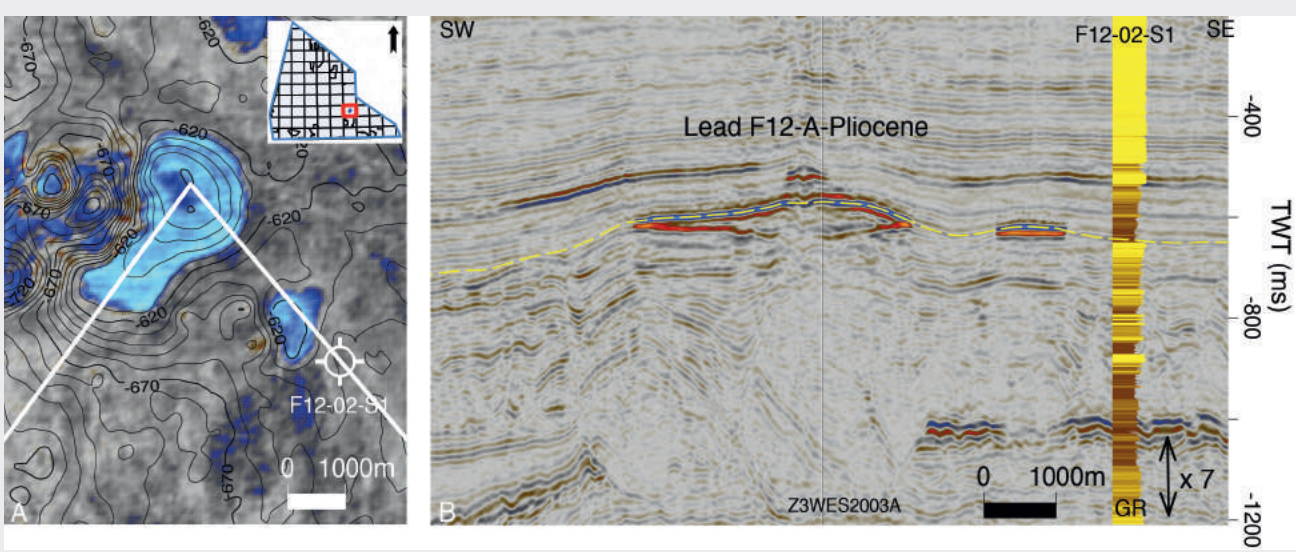

Figure 11 A) Time map of the main reservoir of lead F12-A-Pliocene showing amplitudes. B) Seismic line through this four-way dip closure (location shown on Figure 11A). The top of the main reservoir is indicated by the yellow dotted line.

Case study 1: F01-A-Pliocene

Lead F01-A-Pliocene is a four-way-dip closure with crestal faulting (Figure 10) covered by a high-quality 3D seismic survey (2012). The amplitude anomaly has not been drilled yet. Several stacked bright spots are observed, of which one single sand is considered the main reservoir. The structural spill point fits the outline of the lead. Velocity push-down, attenuation and a gas chimney can be observed. The reservoir parameters are poorly constrained as no proximate wells are available for control. With N/G, porosity and saturation ranges are similar to those in the producing shallow fields, GIIP has been estimated by means of Monte Carlo simulation. With these assumptions, results show a volumetric range from 0.8 to 3 bcm (P10-P90 GIIP) and a P50 volume of 1.5 bcm. These numbers do not include the upside potential of the other sands of the stacked amplitude anomalies. Regarding the presence of several other bright spots in the area (Figure 1) and the potential for deeper exploration, this lead is worth further exploration.

Case study 2: F12-A-Pliocene

F12-A-Pliocene is another high-ranking lead (Figure 11). This structure is a four-way dip closure with a sand thickness of ~50 m and a net-to-gross ratio of around 0.85, based on several offset-wells. The porosity is expected to be more than 25% and gas saturation around 60%. The lead is covered by 3D seismic data and the outline of the amplitude anomaly conforms very well to structure (Figure 11A). A flat spot, a push-down effect and attenuation can be observed below the top sand reflector (Figure 11B). When including uncertainty ranges on the reservoir parameters using Monte Carlo simulation, the static GIIP is 0.8 bcm (P50), with P10 and P90 volumes ranging 0.5 to 1.1 bcm. Considering the presence of several other shallow leads in close proximity (Figure 1) and the opportunity to explore for deeper targets, this lead ranks high for further, detailed analysis.

Conclusions

Since the first Cenozoic gas field in the North Sea area was developed in 2007, the shallow play has proven to be successful, with nowadays four producing fields offshore the Netherlands. These fields typically comprise a stacked set of bright amplitudes that conform to structure and mainly produce from horizontal wells with sands screens or gravel packs to prevent sand production. Reservoir sands generally show good porosity and permeability and are sealed by intercalated shales. As discussed in this paper, the northern Dutch offshore hosts ample additional bright spots that are likely to be associated with producible gas. Most of these amplitude anomalies are four-way dip or faulted dip closures with varying size, vertical relief, depth and number of stacked reservoirs. These geometrical parameters relate to the size of the potential accumulation and help with ranking the individual leads. However, substituting brine with minor, non-producible amounts of gas already results in a strong brightening effect of the top reservoir reflector. Therefore, the gas saturation of these leads remains uncertain. In order to better understand the potential, a semi-quantitative analysis based on the seismic characteristics of the leads has been used for further ranking of the bright spots. The presence of DHIs, including amplitude, flat spots, velocity push-down, attenuation and gas chimneys, has been included in the ranking analysis, resulting in several amplitude anomalies that justify further exploration. Gas saturation remains a risk though, since the presence of a flat spot and velocity push-down do not directly relate to saturation, but to geometrical factors and gas column respectively. Further analysis of the shallow gas leads is possible by deploying advanced technologies, such as inversion of pre-stack data or integration with gravimetry or CSEM data. However, the ultimate derisking of the leads demands an exploration well. Several shallow leads in the area justify an exploration campaign, especially when considering the additional potential of deeper targets nearby.

Acknowledgements

We would like to thank our partners TNO, Petrogas, Dana, ONE, Total and Wintershall for helping us to understand the shallow gas prospectivity of the northern Dutch offshore.

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Exploration in the Netherlands: a sense of urgency

Eric van Ewijk[1*]

Introduction

The Southern North Sea is generally considered to be a mature basin for the exploration and production of hydrocarbon resources even though incremental reserves additions have yet to plateau in the Dutch SNS (Figure 1). Incremental reserves additions have indeed been modest in recent years, supporting the view that traditional hydrocarbon plays located in the Dutch SNS are almost fully creamed off, using prevailing economic screening criteria. In addition, the Dutch SNS has experienced the same reduction of drilling activity that has occurred throughout the industry globally in recent years (Figure 2) exacerbating the recent reduction in reserves additions.

Although it is estimated that many exploration opportunities still remain in the Dutch SNS (Figure 3)[1], the E&P industry is clearly confronted with a number of challenges to successfully identify, mature and screen remaining opportunities against internal investment criteria. These challenges are undoubtedly varied but likely comprise a mix of technical, commercial and strategic considerations.

Northwest Europe, including the Netherlands, has stated ambitions to transition to sustainable energy sources. In reality, the energy transition is likely to span several decades and will be costly. Consequently, natural gas is predicted to remain an important contributor to the Dutch energy supply mix during the energy transition. However, the majority of currently producing gas fields in the Dutch SNS are in decline and many are nearing their economic end-of-field life (EOFL) for low gas price scenarios. This situation has resulted in the timing of decommissioning of infrastructure being brought into focus, with decommissioning plans now being matured and readied for execution. Economic production is generally reliant on existing infrastructure for evacuation. The timing of infrastructure decommissioning thus impacts the economic attractiveness of many remaining exploration prospects and the economic viability of new discoveries. In addition, many identified exploration opportunities have economically marginal Mean Success Volume (MSV) and/or are assessed with a low Probability of Success (PoS), both technically and economically. Opportunities with these characteristics are economically and strategically unattractive for investment. In addition, the planning and execution of exploration activity is being made more challenging by the gradual reduction of space available offshore owing to the emplacement of windfarms and increasingly restrictive environmental constraints. The increasing activity along shipping lanes and fisheries also makes the deployment of modern acquisition systems increasingly difficult and costly.

Unsurprisingly, analysis indicates that from a Dutch state perspective, gas sourced from domestic production is the more economically attractive option, with additional

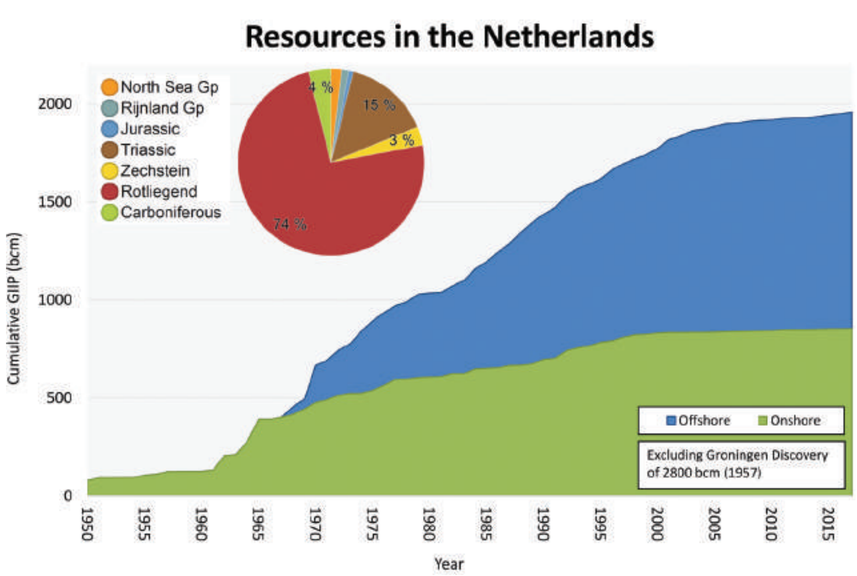

Figure 1 Historical Dutch Gas Resources Onshore and Offshore and % GIIP per Stratigraphic Unit.

[1] The cumulative resources (category 8 and 9) are the simulated expectation volumes calculated from all prospects and leads in the EBN database with ExploSim (with a gas price of 21.5 ct and 40% marginal field measure). The cumulative resources including category 10-11 represents the upside and is calculated as the cumulative resources of category 8 and 9 multiplied by an estimated scaling factor of 1.5.

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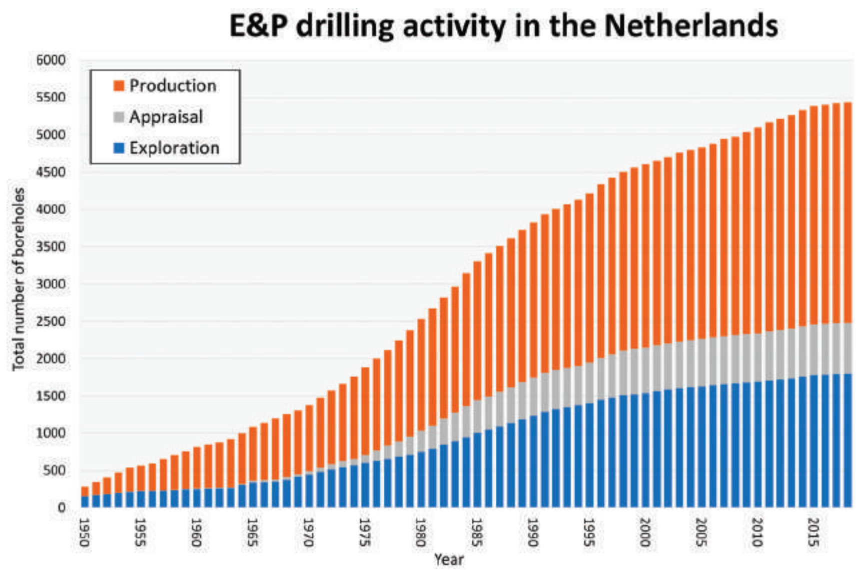

Figure 2 Cumulative drilling activity in the Netherlands.

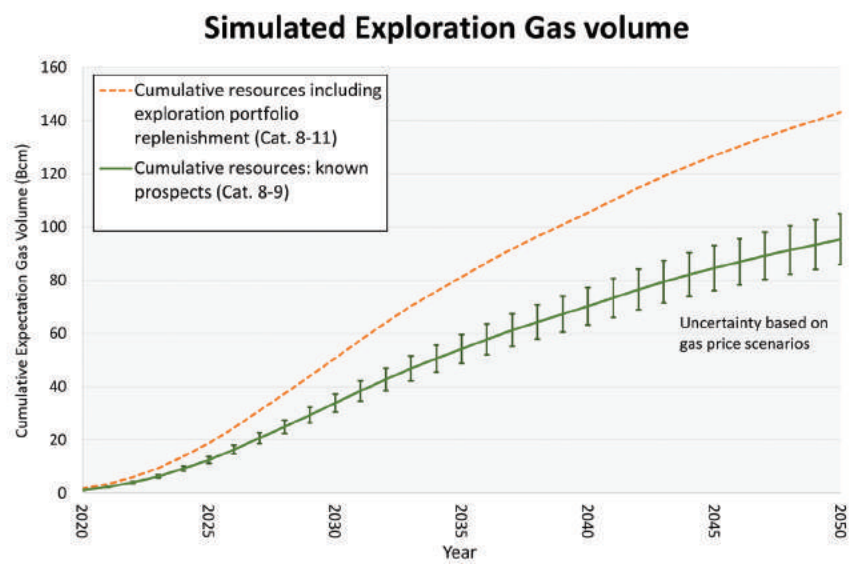

Figure 3 Gas Volumes derived from an exploration simulation exercise using all NL prospects and leads known to EBN.

intangible benefits gained when geopolitical factors are taken into consideration. Studies also indicate that Dutch gas has a lower environmental footprint compared to imported gas, including greenhouse gases.

It is highly beneficial for the Dutch state to ensure that undeveloped gas resources remaining in the Dutch SNS are exploited to support the energy transition, both economically and environmentally.

In summary, it is 'now or never' for the E&P industry to boost the Dutch SNS gas reserves creaming curve by actively exploring for remaining economically attractive 'yet to find' gas. Exploration and development need to be undertaken prior to decommissioning of critical infrastructure and before the currently open window for economic exploitation of these resources closes for good. To make this a reality, what are the realistic options available to the industry to overcome the technical, economic and strategic challenges that currently restrain investment in both the mature plays and those less-mature plays that remain relatively underexplored in the offshore Dutch SNS? This paper suggests some ideas on what might be done and encourages operators to be proactive.

The Netherlands gas balance

Why the urgency for offshore exploration now? Analysis indicates that the balance between produced gas and consumed gas plus contractual export obligations in the Netherlands is negative (Figure 4). The shortfall between demand and the supply of natural gas of approximately 20 bcm is predicted to continue into the foreseeable future requiring a need for substantial gas imports to meet projected domestic demand. The shortfall is owing, in part, to the decision by the Dutch government to progressively reduce production from the Groningen field to zero production in 2030. This decision has been made to reduce and finally eliminate gas production related earthquake activity in the Groningen field area. In addition, a decision has also been taken not to award any new exploration licences onshore the Netherlands. Another factor adding to the shortfall is the late-life production status of many producing fields. Paradoxically, the Netherlands will require substantial volumes of natural gas to help meet societal energy demand during the transition to zero carbon-based and sustainable energy sources in the decades ahead.

One option to change this challenging outlook and help to balance Dutch energy demand is to find innovative ways, both

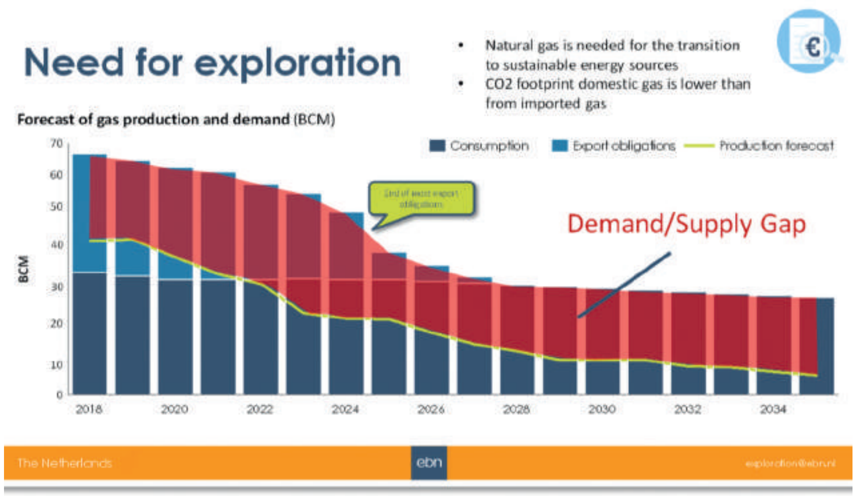

Figure 4 Projected gas supply/demand until 2035.

technical and commercial, to reinvigorate the exploration for gas resources in the Netherlands offshore. Given the already prevailing negative gas balance, it would be desirable to start this process sooner rather than later.

Decommissioning and restrictions in the North Sea

Many producing gas fields in the Dutch SNS are in late-life production decline which is bringing many closer to their economic EOFL when screened at low gas price scenarios. The key to optimising EOFL is a good understanding of the factors that impact profitability, and where these factors are headed for the short-, mid- and long-term. The three **main** factors are production volumes, cost and price.

EBN has investigated the prospectivity of the Dutch offshore and combined that information with the current estimated year of Cessation of Production (COP) of the existing platforms. This analysis is presented in Figure 5. The determination of the year of COP for a platform is based on gas price, production and operating cost (OPEX). The year where the OPEX from a platform is higher than the revenues from the sales of the gas produced at the platform is determined as year of COP. A conservative gas price of 20 EUR ct/m3 has been used and combined the individual COPs into three periods as indicated in the legend of Figure 5: years 2018-2025, 2025-2035, 2035-2055.

A current prospectivity snapshot of the Dutch offshore has been generated by EBN by contouring the cumulative volume of SPE resource categories 6-9 to generate an undiscovered resource density map. EBN can share this analysis, the underlying data and information with all our operators when the data covers open acreage. For areas under licence, the results can be shared with the relevant operators and to discuss possible courses of action.

Several platforms and pipelines are already being decommissioned with others considered for CO_2 storage. Alternative options for platform and pipeline infrastructure include reuse either for E&P activities, possible synergies with sustainable energy options or decommissioning. In the absence of infrastructure, the economic hurdle faced before exploration opportunities are drilled will be higher and any newly discovered gas will require evacuation via longer pipeline routes to remaining infrastructure, which is expensive and might prevent economic development. Using EBN data on reserves, resources and decommissioning projects, the effect on potential natural gas volumes has been calculated. Figure 6 shows the projected volumes as a function of increasing distance to existing infrastructure.

In 2018, prospects with a total volume close to 20 bcm are located less than 3 km from existing platforms. This volume increases to 65 bcm for a distance of more than 10 km from production facilities. In 2028, the total volume less than 3 km from platforms is projected to decrease to 11 bcm. The total volume of natural gas at a distance of more than 10 km from existing infrastructure in 2028 has increased to more than 115 bcm. As this volume is associated with a large number of volumetrically small opportunities, we expect that much of the 115 bcm will not be economic to develop if the distance of the prospect to a platform is more than 10 km. With time, the number and areal distribution

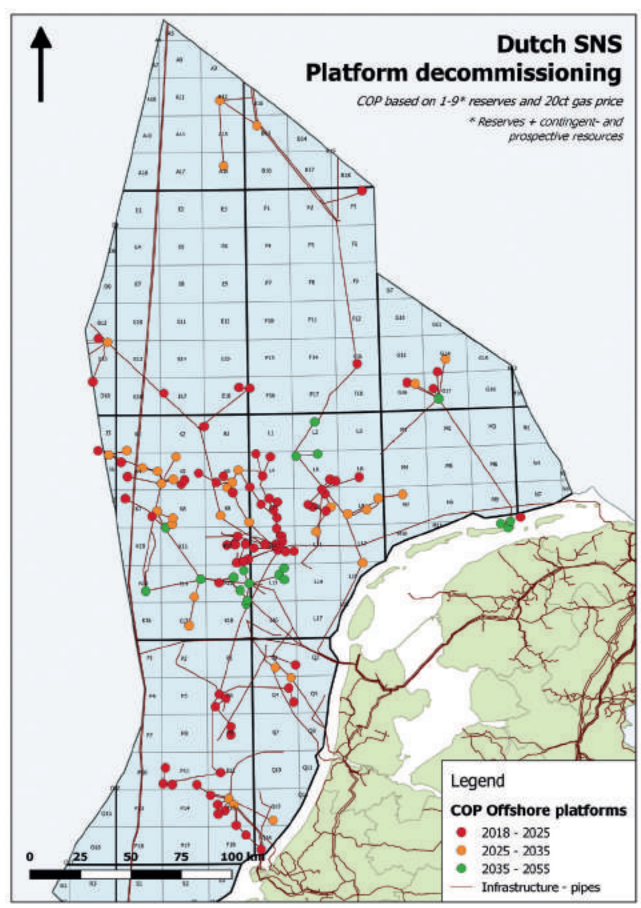

Figure 5 Cessation of Production (COP) timing.

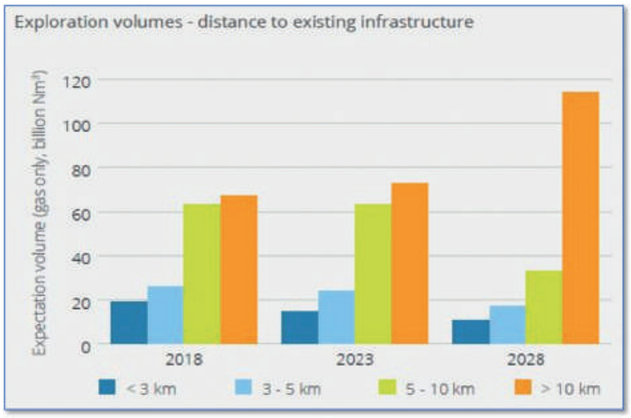

Figure 6 Exploration volumes as function of distance to infrastructure.

of decommissioned platforms will increase, which in turn, will negatively impact the economic attractiveness of those remaining exploration prospects located in proximity to the decommissioned infrastructure. This could mean that significant volumes may be left in the ground undiscovered and undeveloped, and the time window available to explore and develop remaining exploration resources is closing rapidly.

Wind parks, existing and planned, are also increasingly impacting options for exploration activity offshore. Figure 7 indicates the areas (in green) which are designated for future wind parks. Existing wind parks prevent deployment of towed-streamers and may require any future exploration and development wells to be deviated to target any identified opportunities underlying the wind-parks, increasing drilling costs and drilling risks. In addition, the optimal placement of platforms may also be impacted by the presence of wind farms, existing and planned. The E&P industry is encouraged to undertake due diligence and take a 'final look' to investigate and confirm that no prospectivity remains in areas where wind parks are planned.

Dutch gas: environment and economics

Why the need for domestic production of natural gas? As indicated above, the Netherlands has a shortfall in supply/demand which, if addressed with imported gas, will be both costly to the Dutch State and more environmentally damaging. To help minimize the need for imported gas the Netherlands could intensify the search for remaining domestic resources, the intention being to reduce its reliance on imported gas.

Gas can be imported as liquified natural gas (LNG) by boat or through pipelines from other exporting countries. Studies (NRC, 29 November, 2017), later verified by independent investigations (NRC check, 1 December, 2017), indicate that the CO_2 footprint of LNG is 10% higher than from domestic production. The CO_2 footprint from pipeline gas imports is substantially higher with a footprint of 30% above domestic production. These higher percentages are owing to the required transport to bring natural gas to the Netherlands and account for some associated methane (a significant greenhouse gas) leakage. The Netherlands has, like many other countries, established targets to reduce the emission of greenhouse gasses. Hence, minimizing the need for natural gas transportation will aid in achieving a reduction in CO_2 emissions and associated methane leakage.

From a Dutch State perspective, the economics of domestic gas is also preferred compared to imported gas. Imported gas requires state payments to supplier countries with the revenue supplied by Dutch society. In comparison, domestic production generates significantly more economic activity within the Netherlands, resulting in income for Dutch citizens and revenues for the Dutch state.

A final consideration are the geopolitical factors and risks associated with imported gas. Some third-party gas may be sourced from or transported through regions with politically less stable or hostile regimes. Reliance on imported gas will impact security of supply, increasing the risk of abrupt and unscheduled future supply shortfalls to the Netherlands.

In summary, for both economic and environmental reasons, the production of domestic gas is a preferred option compared to imported gas. The continued successful exploration for gas resources in the Dutch SNS is therefore a prerequisite to maintaining domestic production and mitigating geopolitical risks associated with imported gas.

3D data availability and quality

The basis for almost all play-based exploration work and subsequent prospect maturation relies heavily on 2D and 3D seismic data. This data should be of sufficient quality at target play levels to robustly identify the required play elements together with their associated uncertainties. However, much of the existing 3D data covering the Dutch SNS (Figure 8) dates back to the 1980s and 1990s. Although largely adequate for the maturation of

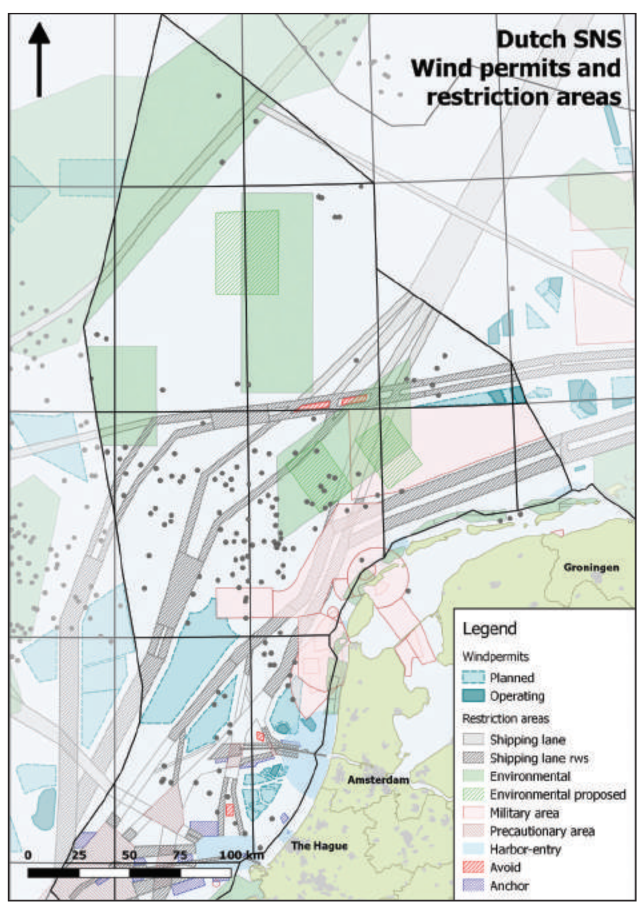

Figure 7 Future and existing restrictions to exploration activity in Dutch SNS.

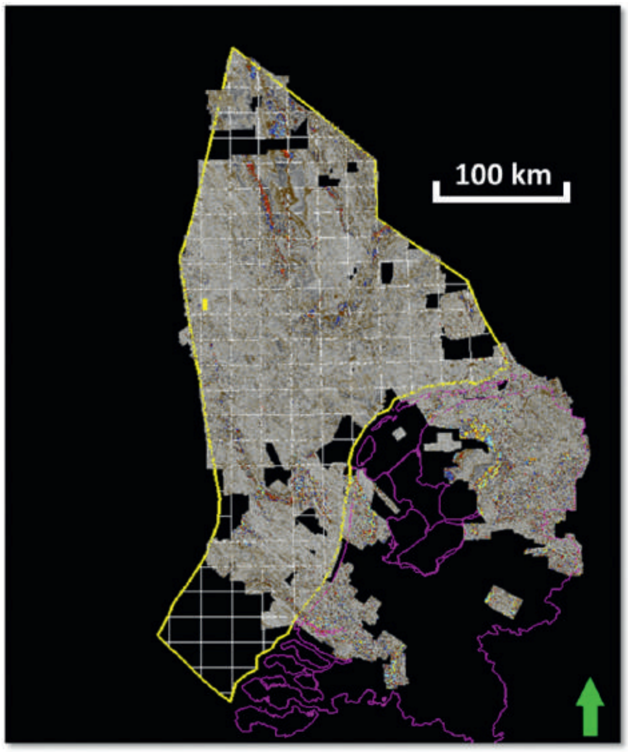

Figure 8 Time-slice illustrating extent of 3D seismic coverage across the Netherlands.

prospectivity associated with main plays present in many areas, the data acquisition parameters and associated processing workflows are not optimal for imaging opportunities located below complex overburden geology and within the Carboniferous. This has inevitably resulted in many opportunities either being poorly defined structurally or completely missed.

The majority of existing 3D data offshore the Netherlands has typically been acquired with a narrow azimuth range, conventional source and cable (non-broadband), limited maximum offsets and low fold. Although the use of modern processing tools can still be applied to this data with some success, the acquisition parameters preclude the optimum application of many modern processing algorithms and workflows which provide incremental improvements in signal processing, imaging and signal penetration. As a result of poor bandwidth, under-illumination and offset limitations, a number of areas at important play levels located in the Dutch SNS suffer from inadequate seismic data quality to allow effective identification and maturation of exploration opportunities that may be present. By implication, areas exist in the Dutch SNS with unidentified potential or poorly constrained leads located within established play fairways in proximity to presently available infrastructure. If these opportunities could be imaged more robustly, identified and assessed more reliably, a number of attractive exploration opportunities would likely arise.

Despite the limitations imposed by the acquisition parameters of vintage 3D data, there are still benefits in reprocessing the data in areas were the available data quality has reached the current limit of usefulness. Given the appropriate business case, if reprocessing has not been undertaken in the past five years, the application of a modern processing suite, including bandwidth enhancement, should be considered.

Alternatively, if reprocessing of existing 3D data is not likely to provide the required seismic data imaging uplift, it is proposed that these areas will benefit from the reshoot of 3D seismic data using modern acquisition parameters and technology. A 3D reshoot survey should be carefully designed and planned to ensure the required sub-surface illumination, sampling and ideally use both broadband source and receiver acquisition technology together with sufficiently long-offsets. Geophysical service providers have indicated that deployment of broadband systems in areas with water depths of 30 m or deeper is desirable. The 30 m water depth constraint permits a significant area in the Dutch SNS, which includes existing fields and infrastructure, to be targeted by broadband acquisition and processing (red contours on Figure 9). Broadband acquisition combined with the latest processing algorithms and workflows including deblending, deghosting, demultiple, denoise, FWI and RTM/LSM PSDM, will provide improved 3D seismic data. This allows for the identification of new opportunities, improved well placement (reducing drilling risk), improved PoS polarization of existing leads and prospects and improved inversion data. Furthermore it enables the interpretation of critical play elements deeper in the stratigraphy than has been achieved to date e.g. within the Carboniferous. Accepting some technical compromise (streamers run shallower) and in the absence of seabed obstacles, broadband acquisition could be deployed in water depths of 25 m or deeper (Figure 9). This relaxed water-depth constraint makes it possible to acquire broadband 3D seismic data across the majority of the Dutch SNS heartland area for gas production and where infrastructure is available.

A final sprint with our operators

The time available to economically explore for and develop remaining gas opportunities in the Dutch SNS is running out. The

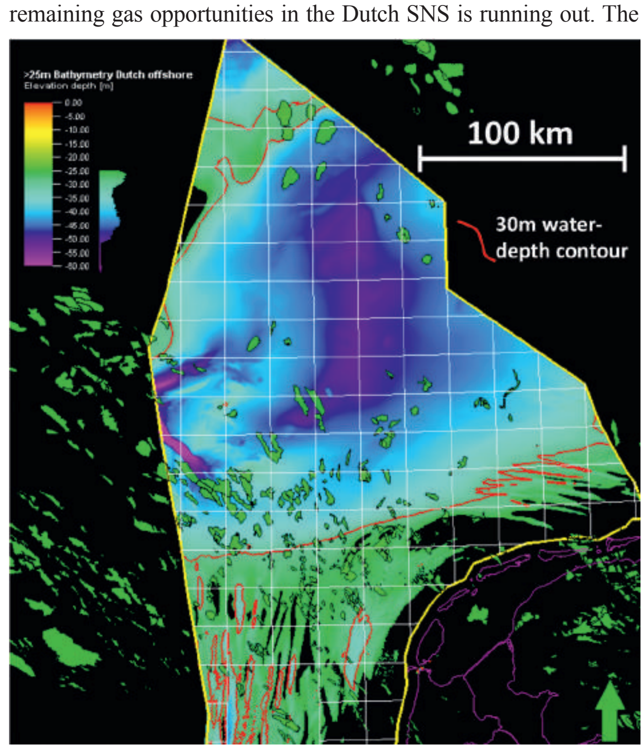

Figure 9 Water depth >25m offshore the Netherlands. 30-m water depth contour indicated in RED.

Dutch state will need access to gas supply to support the energy transition for the foreseeable future. Domestic gas supply is the preferred option for economic, environmental and geopolitical reasons. EBN therefore encourages all operators to review their exploration portfolios with a sense of urgency and to assess the need for either 3D reprocessing using existing data or a 3D survey reshoot using the latest broadband acquisition and processing technology. EBN is both willing and able to support operators that present a viable business case for investment in 3D reprocessing and/or 3D acquisition within their licence.

Acknowledgements

The contributions from the EBN exploration team were invaluable in writing this article. I would like to thank Annemiek Asschert, Kees van Ojik, Marcel Hoenderdos, Guido Hoetz, Linda Janssen, Sabine Korevaar and Martin Ecclestone for reviewing and their suggestions. I would also like to thank EBN for permission to publish this article.

Maastrichtian chalk reservoir quality in the Rembrandt and Vermeer oilfields, Dutch offshore block F17

Henk van Lochem[1]* and Marc Beller[2]

Introduction

In 2012 Wintershall Noordzee BV, as operator of Joint Venture Group F17a Deep (Netherlands offshore) (Figure 1), discovered oil in the Upper Cretaceous Chalk interval with well F17-10. This discovery was later renamed the Rembrandt Field and was subsequently appraised in 2014 by vertical well F17-11 and horizontal well F17-13x. In the same year, well F17-12 discovered oil in a separate Chalk structure, now known as the Vermeer Field.

Extensive core material is available for wells F17-11 and F17-12, covering most of the Maastrichtian chalk reservoir. A sedimentological evaluation of these cores was performed including macroscopic and microscopic descriptions. For the microscopic evaluation both thin sections and SEM/BSEM images were used, which was supplemented by XRD analyses. For the petrophysical characterization of the reservoir, porosity and permeability measurements are available, as well as pore-throat size distributions from MICP (Mercury Injection Capillary Pressure).

A rapid decrease of porosity within the 40-50 m thick Maastrichtian reservoir from around 37% at the top of the reservoir to 22% at the base of Chalk can be observed. The causes of this decrease have been investigated and based on the results a predictive model was made, which was used to guide the porosity modeling in the static reservoir model.

Stratigraphy and Inversion

Block F17 is located at the southern end of the Dutch Central Graben, centrally on the inversion axis of the basin. During the Late Cretaceous to Paleogene period the basin was inverted. It was uplifted and eroded to such an extent that on the axis of the basin the Cretaceous and Upper Jurassic sediments have largely been eroded (De Jager, 2003). On the axis of the Dutch Central Graben the Chalk Group is generally very thin (less than 100 m) or in some areas absent (Duin et al., 2006). Biostratigraphic analysis shows that this thin Chalk interval is the upper part of the Ommelanden Formation, Maastrichtian in age. Below the Maastrichtian Chalk, a Middle Campanian conglomeratic and siliciclastic-rich interval is found locally. Below the Maastrichtian Chalk, or below the Middle Campanian interval, if present, a significant unconformity is observed. Below this unconformity rocks of Early Cretaceous (Barremian) to Cenomanian age have been found in the Rembrandt and Vermeer wells.

Based on the integration of the well data with detailed 3D seismic interpretation it can be determined that the main inversion event in the southern Dutch Central Graben is the Sub-Hercynian Phase (Van Lochem, 2018). After this event, an island was formed in the Chalk sea during the Campanian and Maastrichtian. Around this island, erosion products can be found in the Chalk intervals. These sediments are time and facies comparable to the Vaals Fm. in the south of the Netherlands. Maastrichtian sediments are seen to onlap on to the island, decreasing it in size and influence as a sediment source. During the Danian period, no deposition took place on the inverted Dutch Central Graben and a marine hardground is found at the top of the Maastrichtian Chalk. The inversion and chalk sedimentation stopped during the Paleocene period when deep marine claystones where deposited in this part of the North Sea Basin.

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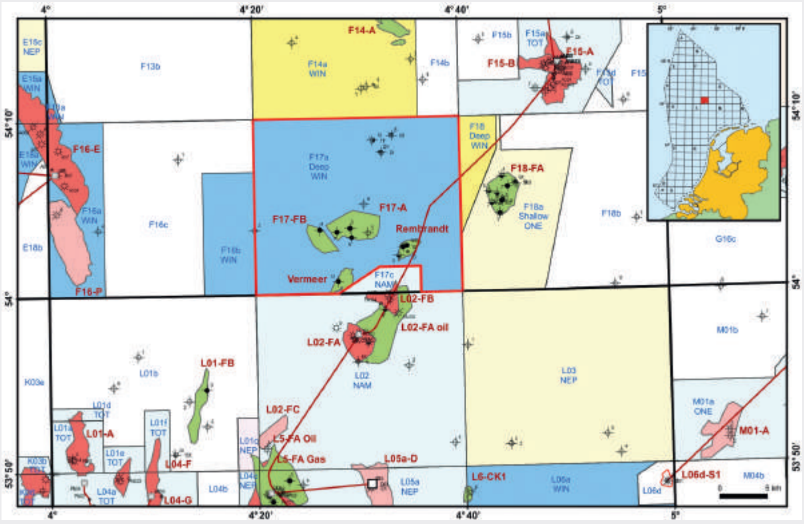

Figure 1 Location of Dutch Offshore block F17a and the Rembrandt and Vermeer Fields.

Maastrichtian Chalk sedimentology

Both well F17-11 (Rembrandt Field) and well F17-12 (Vermeer Field) have been extensively cored and show in general the same phenomena in the Maastrichtian Chalk. In this paper, well F17-11 is taken as an example and discussed in more detail (Figure 2).

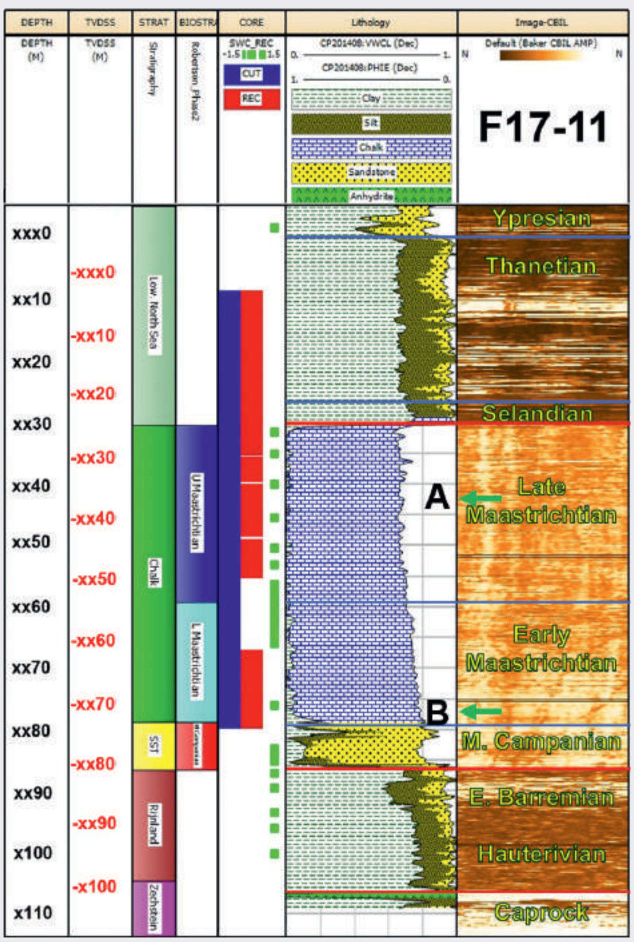

Figure 2 Interpreted well results F17-11. Tracks (from left to right): Depth MD (m), Depth TVDss (m), Lithostratigraphy, Biostratigraphy, Cores, Lithology and Image Log with Biostratigraphical ages. Depths are deliberately masked for confidentiality purposes. Location of samples Figure 3 marked by arrows A and B.

One of the objectives of this well was to fully core the Chalk reservoir interval, including part of the Paleocene overburden (Landen Fm.). This resulted in a 71-m cored section, although there was a 13-m lost section in the middle of the Chalk interval. A surprise in this well was the presence of an 8-m conglomerate and sandstone interval at the base of the Chalk, dated mid-Campanian. The total reservoir interval is 56 m, overlying an interval of 19 m of Early Cretaceous Vlieland Claystone Fm., which rests on Zechstein caprock.

The log evaluation, calibrated by core porosity/permeability measurements every 25-100 cm showed the porosity of the Maastrichtian Chalk to decrease from 37% at the top of the formation to 22% at the base. The question was raised: was this rapid porosity change was caused by primary sedimentological differences or by diagenesis or by compaction? To investigate this a detailed sedimentological evaluation was initiated. Thin sections have been prepared of the trim-ends of core plugs with a circa 2-m interval. SEM and BSEM images of these plugs have also been made. On the thin sections, point counting has been performed to quantify the main rock forming elements.

A distinct difference can be seen between top and base of the formation (Figure 3). The top is what can be called a 'clean' chalk. It is classified as a wackestone and consists mainly of a chalk mudstone matrix of typical coccolith platelets with a large amount of microporosity between them. Floating in this mud matrix are common skeletal grains of calcispheres, benthonic foraminifera, fragments of Inoceramus bivalves and other skeletal debris. Authigenic minerals are present in the form of micrite and microsparitic calcite. Dolomite, pyrite and diagenetic glauconite minerals have rarely been observed. Rare and isolated macropores consist of calcisphere, benthonic foraminifer and bryozoan intraskeletal pores. The XRD analysis typically shows 97% of carbonate and 3% of other material, mainly quartz, to be present.

From the sedimentary and diagenetic point of view the basal interval is rather similar compared to top of the formation. However, the most notable difference is the higher content of siliciclastic material and to a lesser degree an increased amount of skeletal grains. The siliciclastic grains consist of very

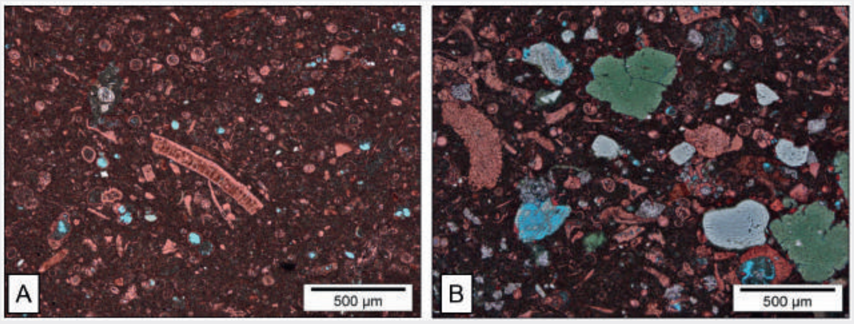

Figure 3 Well F17-11: Thin sections of Upper Maastrichtian clean chalk (A, MD depth xx42.6 m), Lower Maastrichtian sandy chalk (B, MD depth xx77.6 m). Depths are deliberately masked for confidentiality purposes, but compare to Figure 2. Note that the chalk mud matrix is dark in these thin sections; the around 45% microporosity in the chalk mud is not resolved in the thin section.

fine- fine-to-medium sand graded detrital quartz and glauconite/green clay grains. Grains are either dispersed through the matrix or concentrated within burrows, along coarser material laminae or as component of foraminifera agglutinated tests. No differences were seen in the thin sections and (B)SEM images that pointed to increased diagenesis in the lower section, nor did the (B) SEM images and MICP pore-throat data indicate a significantly increased compaction.

The point count results (Figure 4) of the thin sections show an inverse relation between the amount of grains in the Chalk and the porosity. However, the porosity increases if the amount of mud matrix is increasing. It should be noted that the thin sections cannot resolve the microporosity present between the micron-scale coccolith platelets, which is thus included in the count for the mud matrix.

These correlations can be explained by the fact that the presence of skeletal and siliciclastic grains diminishes the space available for the microporous mud matrix. The grains themselves do not contribute at all to the porosity, so exchanging mud by grains results in a direct loss in porosity. Extrapolation of the trendline suggests that in this area and depth, the Chalk could have a maximum porosity of 45% if no grains were present. The same inverse relationship between the presence of larger grains to porosity has also been described in the Ekofisk Formation of the Tyra Field (Danish North Sea) by Røgen et al. (2001).

Reservoir porosity model and conclusion

Based on the observations in the thin sections, it is clear that the main cause of the decrease of porosity with depth is the admixture of grains in the chalk matrix, not diagenesis nor compaction. When plotting calibrated porosity logs versus depth and facies over the Maastrichtian Chalk interval, this insight from thin section observation is nicely captured by simple equations to predict porosity with depth laterally over the entire field area (Figure 5). For the main Rembrandt and Vermeer wells and selected nearby off-structure wells, the porosity relation can be described by two functions. First a compaction trend, which describes the decrease of porosity with depth of a comparable stratigraphic position, e.g. the top of the Chalk interval. This trend only has a minor impact, around 1.6 p.u. per 100m. The second trend describes the decrease of porosity down section of the well- this is the lithology trend- caused by the admixture of grains in the chalk mud. In the F17-11 well this is around 25 p.u. per 100 m. The impact of this last trend seems to be diminishing in the deeper wells. This effect has also been captured in the set of equations. Using the Top Maastrichtian depth map and the obtained equations, a predictive 3D porosity model has been generated for the Rembrandt and Vermeer area.

It is widely recognized that porosity and seismic acoustic impedance are highly correlated in carbonate fields and more particularly in Chalk fields (Herbert et al., 2013). Therefore, porosity from seismic elastic inversion is often considered as trend information during porosity geomodeling and this approach was indeed applied to an early iteration of our static porosity model. However, fluid saturations also have an influence on seismic impedances, although smaller and less correlated than porosity. Neglecting the fluid effect would introduce a small bias into porosity prediction using seismic porosity. A usual workaround would be to introduce facies and/or fluid geobodies in the static model to separate various areas of the model and to treat porosity modelling and relation to seismic acoustic impedance differently according to these areas. In our

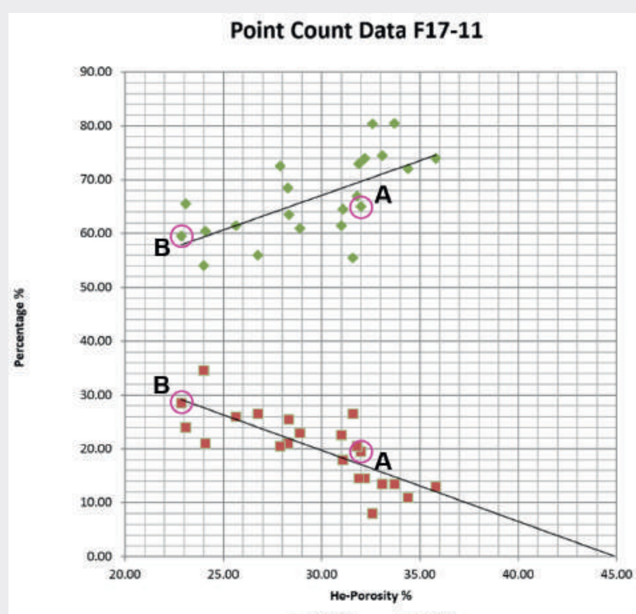

Figure 4 Point Count Results of F17-11 thin sections. Chalk porosity increases with increasing amount of matrix (Note: the mud matrix also contains the microporosity) and decreasing amount of grains (skeletal and siliciclastic grains). Samples Figure 3 marked by circles A and B.

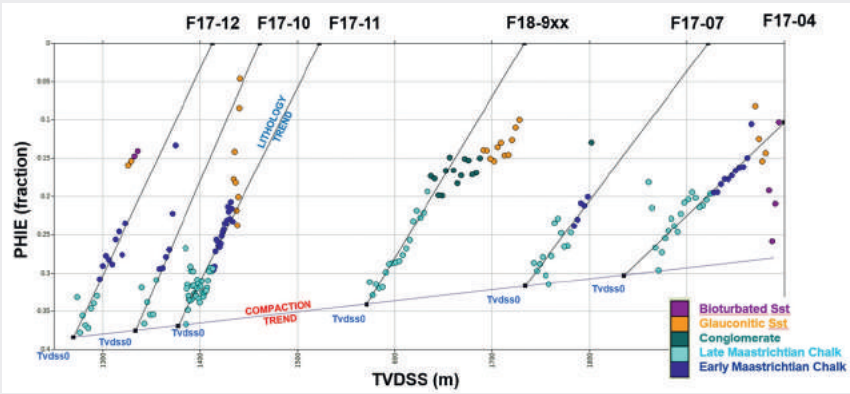

Figure 5 Relationships between porosity and depth for Maastrichtian Chalk in the Rembrandt and Vermeer Fields area. Two trends can be captured by equations: a compaction trend and a lithology trend.

case, considering the thin Chalk interval over Rembrandt and Vermeer fields in relation to seismic resolution, as well as the complex fluid saturation heights function, we believe that this workaround would introduce more uncertainties than benefits. The equation-based predictive model from Figure 5 has the advantage not to be affected by fluid effect, and to capture in a simple way, our understanding of the lithology and depth-based porosity variation in these Chalk fields. In this instance, it was decided for our latest iteration of the static porosity model not to include porosity from inverted seismic acoustic impedance. Instead, the predictive model was used as a 3D porosity trend co-kriged with the well porosity data, under the assumption that the reservoir quality does not largely vary laterally.

Acknowledgements

The authors greatly acknowledge the F17a Deep Area partners EBN, Neptune, Rosewood, and TAQA for permission to publish this paper. The support of Wintershall Noordzee BV and its shareholders is acknowledged, as well as colleagues and contractors that contributed to the underlying work.

This article is the extended abstract (Van Lochem and Beller, 2018) of an oral presentation at the 80th EAGE conference in Copenhagen, with minor modifications.

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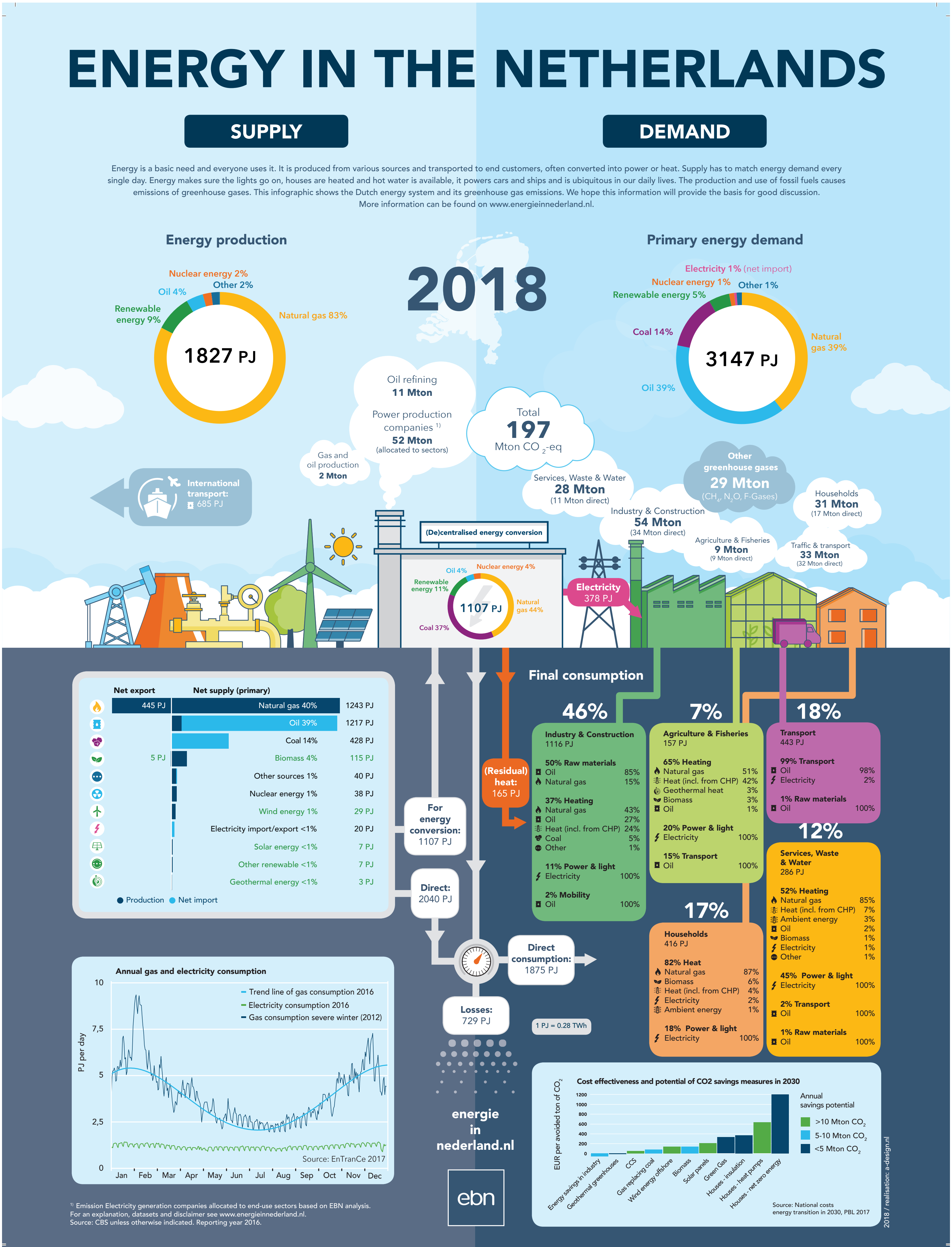
ENERGY IN THE NETHERLANDS
SUPPLY
DEMAND
Energy is a basic need and everyone uses it. It is produced from various sources and transported to end customers, often converted into power or heat. Supply has to match energy demand every single day. Energy makes sure the lights go on, houses are heated and hot water is available, it powers cars and ships and is ubiquitous in our daily lives. The production and use of fossil fuels causes emissions of greenhouse gases. This infographic shows the Dutch energy system and its greenhouse gas emissions. We hope this information will provide the basis for good discussion.
More information can be found on www.energieinnederland.nl.
Energy production
Nuclear energy 2%
Other 2%
Oil 4%
Renewable energy 9%
Natural gas 83%
1827 PJ
2018
Primary energy demand
Electricity 1% (net import)
Nuclear energy 1%
Other 1%
Renewable energy 5%
Coal 14%
Natural gas 39%
Oil 39%
3147 PJ
Oil refining
11 Mton
Power production companies [1]
52 Mton
(allocated to sectors)
Total
197
Mton CO_2-eq
Gas and oil production
2 Mton
International transport:
685 PJ
Services, Waste & Water
28 Mton
(11 Mton direct)
Other greenhouse gases
29 Mton
(CH_4, N_2O, F-Gases)
Households
31 Mton
(17 Mton direct)
Industry & Construction
54 Mton
(34 Mton direct)
Agriculture & Fisheries
9 Mton
(9 Mton direct)
Traffic & transport
33 Mton
(32 Mton direct)
(De)centralised energy conversion
Oil 4%
Nuclear energy 4%
Renewable energy 11%
1107 PJ
Natural gas 44%
Coal 37%
Electricity
378 PJ
Net export
Net supply (primary)
445 PJ
Natural gas 40%
1243 PJ
Oil 39%
1217 PJ
Coal 14%
428 PJ
5 PJ
Biomass 4%
115 PJ
Other sources 1%
40 PJ
Nuclear energy 1%
38 PJ
Wind energy 1%
29 PJ
Electricity import/export <1%
20 PJ
Solar energy <1%
7 PJ
Other renewable <1%
7 PJ
Geothermal energy <1%
3 PJ
Production
Net import
For energy conversion:
1107 PJ
Direct:
2040 PJ
(Residual) heat:
165 PJ
Final consumption
46%
Industry & Construction
1116 PJ
50% Raw materials
Oil 85%
Natural gas 15%
37% Heating
Natural gas 43%
Oil 27%
Heat (incl. from CHP) 24%
Coal 5%
Other 1%
11% Power & light
Electricity 100%
2% Mobility
Oil 100%
7%
Agriculture & Fisheries
157 PJ
65% Heating
Natural gas 51%
Heat (incl. from CHP) 42%
Geothermal heat 3%
Biomass 3%
Oil 1%
20% Power & light
Electricity 100%
15% Transport
Oil 100%
18%
Transport
443 PJ
99% Transport
Oil 98%
Electricity 2%
1% Raw materials
Oil 100%
12%
Services, Waste & Water
286 PJ
52% Heating
Natural gas 85%
Heat (incl. from CHP) 7%
Ambient energy 3%
Oil 2%
Biomass 1%
Electricity 1%
Other 1%
45% Power & light
Electricity 100%
2% Transport
Oil 100%
1% Raw materials
Oil 100%
17%
Households
416 PJ
82% Heat
Natural gas 87%
Biomass 6%
Heat (incl. from CHP) 4%
Electricity 2%
Ambient energy 1%
18% Power & light
Electricity 100%
Direct consumption:
1875 PJ
Losses:
729 PJ
1 PJ = 0.28 TWh
Annual gas and electricity consumption
Trend line of gas consumption 2016
Electricity consumption 2016
Gas consumption severe winter (2012)
PJ per day
10
7,5
5
2,5
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Source: EnTranCe 2017
energie in nederland.nl
ebn
Cost effectiveness and potential of CO2 savings measures in 2030
EUR per avoided ton of CO_2
1200
1000
800
600
400
200
0
Energy savings in industry
Geothermal greenhouses
CCS
Gas replacing coal
Wind energy offshore
Biomass
Solar panels
Green Gas
Houses - insulation
Houses - heat pumps
Houses - net zero energy
Annual savings potential
>10 Mton CO_2
5-10 Mton CO_2
<5 Mton CO_2
Source: National costs energy transition in 2030, PBL 2017
[1] Emission Electricity generation companies allocated to end-use sectors based on EBN analysis.
For an explanation, datasets and disclaimer see www.energieinnederland.nl.
Source: CBS unless otherwise indicated. Reporting year 2016.
2018 / realisation: a-design.nl