Shale Gas Evaluation of the Early Jurassic Posidonia Shale Formation and the Carboniferous Epen Formation in the Netherlands

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ABSTRACT

Since the discovery of the Groningen gas field, the Netherlands has been a large producer and consumer of natural gas. Current forecasts show that production from conventional on- and offshore fields will decline noticeably in the next decades. The Netherlands has the ambition to sustain its prominent role in the northwestern European gas market and will have to be able to meet the future domestic demand. Import of natural gas, either through liquid natural gas import (North Africa, Middle East) or from the East (Nordstream), are therefore evaluated and planned. Following the developments in the United States, the question has arisen if there is shale gas potential in the Netherlands that could add to the domestic gas production. A first evaluation in 2009 confirmed this potential, although the uncertainties are huge. Others have, however, challenged this positive view on the potential resource of the Netherlands. The follow-up work that is presented provides more detailed information based on extensive data evaluations and interpretations of potential shale gas targets in the Netherlands.

The Netherlands has a long and intense exploration history that led to a very high data coverage that is largely in the public domain. A first assessment of possible shale gas reservoirs in the Netherlands was made using this unique data set. The main target formations for shale gas are the Lower Jurassic Posidonia Shale Formation and the Carboniferous (Namurian or
Serpukhovian to Lower Bashkirian) Epen Formation, especially its basal part with high organic content.

The Posidonia Shale Formation is known to be present in the onshore West Netherlands Basin from many well penetrations and its distinct seismic character. Gas logs indicate the presence of gas. Fault-bounded tectonic blocks were identified on three-dimensional seismics with relatively undisturbed deposits. Calculations of gas initially in place were performed for these individual blocks, based on total organic carbon (TOC) and porosity. TOC values were calculated from logs and cross-checked on actual measurements. The deposit is probably brittle (and therefore susceptible for fracturing) throughout most of the area as indicated by log-derived Young’s Moduli. The evaluation showed favorable conditions for shale gas prospects, that is, TOC content of about 6%, porosity of 5–9.5%, and an average thickness of 30 m (98.42 ft). The evaluation of three example fault-bounded blocks indicated total gas volumes of 0.26–0.46 billion cubic meters per square kilometer (STP; 23–42 billion cubic feet of gas per square mile), which merits further investigation into the viability of this gas play. The evaluation of the Carboniferous Epen Formation is more complicated because it is generally deeper. The Geverik Member (~50–70 m (164.04–229.65 ft) thick) is the lowest unit of the formation and is considered a main target for shale gas exploration because of its high organic content (TOC ~7%, Type II). Recent mapping and newly released wells indicate that instead of a uniform basin, the deposition of the formation was controlled by the existing paleogeography that was probably formed by the presence of carbonate platforms. Exploration challenges of the Geverik Member include the scarce data due to limited well penetrations, its present-day depth, and its high maturity (>3.3 % R) for most of the Netherlands, as indicated by modeling and measurements. In conclusion, the presented study provides background information on the geological setting for potential shale gas developments in the Netherlands. The need for such information has become very relevant over the past two years because as of 2010 a total of four exploration licenses have been granted to different companies. This challenges policymakers to take a position on shale gas development in the Netherlands, where public concern has also risen about the environmental impact and safety of shale gas operations.

INTRODUCTION

The Netherlands has developed into one of the major producers of natural gas in northwestern Europe since the discovery of the Groningen gas field more than 50 years ago and heavily depends on gas consumption in its energy supply. With its highly developed gas infrastructure and large domestic market in the heart of the northwestern European gas network, the country plays a prominent role in the northwestern European gas market and has the ambition to sustain this position. However, current forecasts show that domestic production from conventional on- and offshore fields will decline noticeably in the next decades. Possibilities to import natural gas, either through liquid natural gas import (North Africa, Middle East) or through pipeline transport from the east (Nordstream), are therefore evaluated and planned. Following the developments in the United States, the question has arisen if there is also shale gas potential in the Netherlands that could add to domestic gas production.

Several reports have evaluated this potential at a country scale, mostly as part of overall European evaluations. Europe as a whole is prospective for shale gas production because of the combination of its geology, large market, the already widespread pipeline infrastructure, the increasing demand, and the current high dependency on gas imports (Chew, 2010). Despite its favorable conditions, the first shale gas exploration well was drilled not in the Netherlands but in Germany, where Exxon started drilling in the Lower Saxony Basin in 2008. Further initiatives followed thereafter in Europe, as with drilling by Shell in Sweden in November 2009, by various companies in Poland in 2010 and 2011, and by Cuadrilla in the United Kingdom in 2011. At present, nearly all European countries are looking into their shale gas potential. However the increasing interest and attention has also given rise to public concern about the impact and safety of shale gas production leading to drilling moratoria in, among others, France and North Rhine-Westphalia (Germany). The Netherlands is no exception to this trend: public concern about the future activities associated with exploration licenses that were granted in 2009 and 2010 has led to a lot of media attention, town hall meetings, and parliamentary hearings.

A total of four exploration licenses for hydrocarbons have been granted and, given the geological conditions within the areas, are likely associated with the exploration for either shale gas or coalbed methane.
Essential in the debate about the role that nonconventional gas can play in the Dutch energy portfolio are proper estimates of the expected resources in the underground and the uncertainties in these estimates. Pending the results of the exploration wells, which may take five years to enter the public domain under the Dutch regulations, there is a need to evaluate the existing available data to provide these figures to policymakers and other stakeholders. Earlier estimates by Muntendam-Bos et al. (2009), based on regional geology, have been useful to confirm the potential for shale gas production despite its huge uncertainties but were lacking the time-consuming reevaluation and reinterpretation of the vast amount of data that are available for the Dutch subsurface. The high numbers that have been reported by Muntendam-Bos et al. (2009), some in the order of $1.1 \times 10^5$ bcm, represented total volumes in the subsurface without considering local geological surface or technical constraints. The numbers in itself have therefore been challenged by Herber and De Jager (2010), who downgraded the amounts but did not go back to the data for reevaluations.

The follow-up work that is presented here provides more detailed information based on extensive data evaluations and interpretations of potential shale gas targets in the Netherlands. The two major candidates for successful shale gas production in the Netherlands would be the Carboniferous (Namurian or Serpukhovian to Lower Bashkirian) Epen Formation (especially its basal part with high organic content) and the Lower Jurassic Posidonia Shale Formation, both of which are organic-rich black shale deposits. This chapter reports characteristics of these formations that are relevant for the evaluation of their potential for shale gas production. These characteristics are measured or derived from seismic data and interpretation, well data (including logs), and core and cuttings material. Because of a long and intense exploration history, the Netherlands has a very high data coverage that is largely in the public domain, providing a unique data set (Figure 1). For the Posidonia Shale Formation, a first estimation of the gas-in-place is also given for individual fault-bounded blocks to provide some location specific information in addition to the regional or countrywide assessments.

**GENERAL GEOLOGICAL HISTORY**

The geological evolution of the Netherlands resulted in a highly structured and varied subsurface geology, with predominantly siliciclastic sediments overlying the Caledonian basement (De Jager, 2007). This basement of Precambrian to Silurian age is generally deeply buried, moderately deformed, slightly metamorphic, and scarcely known (Geluk et al., 2007). Middle Devonian to Early Carboniferous siliciclastics and carbonates unconformably cover this basement, which is best known from the Anglo-Brabant deformation belt (Geluk et al., 2007). Following the last, Early Devonian, phase of the Caledonian orogeny, a horst-and-graben
topography controlled the deposition, with fluvial deposits residing on the footwall blocks and basinal deposits in the hanging-wall blocks. Horst blocks shielded a large portion of the area from siliciclastic influx coming from the Mid-North Sea High, allowing a widespread carbonate platform to form during the Early Carboniferous in the central and southern Netherlands. The synsedimentary horst-and-graben faults were gradually overstepped and gave way to the regional subsidence of a Silesian coal-bearing molasse basin in the Variscan foreland (Geluk et al., 2007).

The geological record comprising more than 10 km of sediments is, despite several major unconformities, almost continuous from the Late Palaeozoic on (De Jager, 2007). During successive tectonic phases, several preexisting structural elements were reactivated, and new elements appeared (Duin et al., 2006). The various identified regional structural elements are grouped into six tectonically active periods: Late Carboniferous, Permian, Triassic, Late Jurassic, Late Cretaceous, and Cenozoic (Duin et al., 2006). The Mesozoic rifting events accompanied the breakup of Pangea, whereas the later Alpine inversion resulted from the collision of Africa and Europe during the Late Cretaceous and Early Tertiary. During tectonic events in Oligocene times to recent, the Rhine Graben rift system developed (De Jager, 2007).

Duin et al. (2006) demonstrated that many structural elements and fault systems were repeatedly reactivated and that a clear distinction exists between long-lived and short-lived structural elements. The general structural model is, therefore, one of repeated (oblique) reactivation of basement faults, which continue to control the structural grain despite changes in tectonic regime and stress direction (De Jager, 2007). Faulting in the northern Netherlands was heavily influenced by extensive halokinesis of thick Permian Zechstein salt (De Jager, 2007).

In the Netherlands, Early Carboniferous (Tournaisian and Visean) sediments are known from only a few wells, but the existence of Visean carbonate platforms have been confirmed by seismic (Kombrink, 2008). Recent mapping and newly released wells indicate that instead of a uniform basin, the deposition of the formation was controlled by the existing palaeogeography of that geological time frame. This existing topography was probably formed by the presence of the carbonate platforms (Kombrink, 2008). In the southern part of the Dutch onshore and offshore, these sediments consist of black limestones, whereas in the northern offshore, Early Carboniferous rocks are of clastic origin (Duin et al., 2006). Upper Carboniferous deposits (Namurian, Westphalian and Stephanian; Figure 2) are widely distributed in the subsurface of the Netherlands (Van Adrichem Boogaert and Kouwe, 1993–1997). The total thickness and distribution of the Carboniferous strata is not known in detail because of their deep burial. However, in large parts of the Netherlands, the Carboniferous subcrop is well documented, as it is the source rock of many gas fields and a target of gas exploration (Lutgert et al., 2005). The depth to the top of the Carboniferous can be greater than 6000 m, and the Carboniferous deposits locally reach thicknesses of more than 4000 m (TNO-NITG, 2004). The Carboniferous deposits are overlain by Middle and Late Permian sediments of the Upper Rotliegend and Zechstein groups. On structural high elements, such as the Texel-IJsselmeer High, the Carboniferous is unconformably overlain by the Early Cretaceous Rijnland Group or, in the southern parts of the Netherlands, by the Lower Cretaceous Chalk Group. Carboniferous strata are absent in the southernmost part of the onshore, where Devonian strata directly are overlain by the Late Cretaceous Chalk Group. After a period of nondeposition, the sedimentary record continued during the Late Permian without major interruption until the Middle Jurassic. During this period, mainly clastic sediments were deposited. During the Middle Jurassic to Late Jurassic, a major rifting event related to the breakup of Pangea caused extension in east-to-west direction and tilted fault blocks. During this rifting syn-rift, continental sands and shales of the Delfland Subgroup were deposited in subsiding half-grabens. Adjacent highs were subjected to erosion (Den Hartog Jager, 1995). Major faulting ceased at the Early Cretaceous, when the Rijnland Group was deposited regionally in marine to coastal environments onlapping the basin margins. During the Late Cretaceous, the Chalk Group was deposited followed by the onset of an inversion event that caused uplift of the basins and subsidence of the surrounding platforms. This event modified old structures and formed new ones. Uplift and erosion had most effect on the center of the basin. During the Tertiary, the Netherlands onshore experienced relative mild tectonics, and the thick clastic successions of the North Sea Group were deposited. Locally, inversion pulses affected the area until the mid-Tertiary (e.g., the Voorne Trough). In the West Netherlands Basin, the subsidence during the deposition of the Chalk and North Sea groups caused a regional tilt to the south in the basin, and this might have further altered the existing structures (De Jager et al., 1996).

Figure 2. Geological time scale (after Gradstein et al., 2004) and lithostratigraphic column (after Van Adrichem Boogaert and Kouwe, 1993–1997) showing main tectonic deformation phases (after Duin et al., 2006).
EVALUATION OF PROSPECTIVE SHALE DEPOSITS

Criteria for Shale Gas Evaluation

Although the factors that determine successful production of gas from shales vary per basin, there is general consensus about the main criteria that need to be met to make a basin or area prospective. Important factors are thickness, depth, thermal history, TOC content, maturity, geomechanical properties, porosity, and adsorption capacity. Critical values, or the window in which the values should reprise, are given in Table 1. However, it must be emphasized that the values are subject to debate and could vary per basin. They should be used only as guidelines, as one could overlook new plays by imposing these too strictly. For example, biogenic shale gas plays may drop out of the picture, while these can be highly prospective, as shown by the Antrim Shale in the United States.

The Posidonia Shale Formation

Geological Setting

The Posidonia Shale of Toarcian age is a very distinctive interval throughout northwestern Europe, with a present-day distribution from the United Kingdom (Jet Rock Member) to Germany (Posidonienschiefer, or Ölschiefer; Figure 3). Given the uniform character and thickness (mostly around 30–60 m of dark-gray to brownish-black, bituminous, fissile claystones) across these basins, it is commonly suggested that the Posidonia Shale was probably deposited over a large area during a period of high sea level and restricted sea-floor circulation. Its present-day distribution would then reflect erosion on the basin margins and bounding highs (Pletsch et al., 2010). The official Dutch nomenclature (Van Adrichem Boogaert and Kouwe, 1993–1997) describes the formation as being deposited under pelagic deposition under anoxic conditions during a period of high sea level and restricted sea-floor circulation; recent research indicates that this concept should be reconsidered (Trabucho, 2011).

In the Netherlands onshore, the formation is restricted to the centers of rift basins that formed in the Late Jurassic (e.g., West Netherlands Basin and extension into the Roer Valley Graben, the Central Netherlands Basin, and some isolated locations in the Lower Saxony Basin; Figure 3). The common view is also that the sediments deposited outside the basin centers were eroded in parts of the Netherlands because of inversion events (Wong et al., 2007), although this is also debated following observations of syn-sedimentary tectonics in the Early Jurassic.

The Posidonia Shale Formation developed conformably on the nonbituminous claystones of the Lower Jurassic Aalburg Formation, although locally bituminous sections in the Aalburg Formation are known (De Jager et al., 1996). The formation consists of dark-gray to brownish-black bituminous fissile claystones and is a very distinctive interval throughout the Netherlands that can be recognized on wire-line logs by its high gamma ray and resistivity readings (Van Adrichem Boogaert and Kouwe, 1993–1997). Evaluation of the log responses showed that a subdivision can be made into distinct zones within the Posidonia Shale Formation that could be correlated between wells throughout the basin (Figure 4). This indicates that during deposition of the formation, the depositional environment varied, causing variation in log response due to different mineralogy and grain size. Zoning of the Posidonia Shale Formation was also observed in Germany on the basis of geochemical parameters (Frimmel et al., 2004; Schwark and Frimmel, 2004). This can also be seen in the pseudo-van-Krevelen diagram (Figure 5), showing a wide range of kerogen type. The majority of the measurements indicate a typical Type II source rock; the samples indicating a more Type III source rock can result from the variations in depositional environments. Macroscopic and microscopic observations of core samples from the basin confirmed this variability of depositional conditions.

Table 1. Criteria for prospective shale gas reservoirs

<table>
<thead>
<tr>
<th>Property</th>
<th>Limit</th>
<th>Reference</th>
</tr>
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<tbody>
<tr>
<td>Depth</td>
<td>&lt;4 km</td>
<td>(AAPG EMD Annual Report 2010)</td>
</tr>
<tr>
<td>Thickness</td>
<td>&gt;20 m</td>
<td>(AAPG EMD Annual Report 2010)</td>
</tr>
<tr>
<td>TOC-content</td>
<td>&gt;2 weight percentage</td>
<td>(Evans et al. 2003)</td>
</tr>
<tr>
<td>Organic matter</td>
<td>Type II</td>
<td>(Kabula et al. 2003)</td>
</tr>
<tr>
<td>Hydrogen Index</td>
<td>&gt;250 mg/gTOC</td>
<td>(Kabula et al. 2003)</td>
</tr>
<tr>
<td>Maturity</td>
<td>1.4–3.3% Vitrinite reflectance</td>
<td>(Jarvie et al. 2007)</td>
</tr>
</tbody>
</table>
siltstones of the Middle Jurassic Werkendam Formation (Van Adrichem Boogaert and Kouwe 1993–1997; TNO-NITG, 2004), although hiatuses and unconformities were identified at several locations. Onshore the Netherlands, the Posidonia Shale Formation is most widely distributed in the West Netherlands Basin, where it occurs at a depth between 830 and 3055 m (Figure 6). At this location, the Late Jurassic rift and Cretaceous inversion events resulted in the present-day horst-and-graben configuration.

Data
The mining law in the Netherlands imposes that geological data are to be released five years after acquisition. Given the extensive oil and gas exploration history in the country, this resulted in a vast database of public domain data. For the Netherlands on- and offshore, this database contains more than 5000 boreholes, more than 500,000 km of two-dimensional (2-D) seismic lines, more than 70,000 km² of 3-D seismic data sets, and other data. All data for this study were retrieved from this database (http://www.nlog.nl).

A total of 70 wells have penetrated the Posidonia Shale Formation in the onshore West Netherlands Basin, of which 43 were used for this study. Well log coverage varies, for example, because of the age of the well (some were drilled in the 1950s) and included sonic, density, gamma ray, and mud logs. Particular effort has been put into the evaluation of wells...
within areas covered by 3-D seismic. Seismic blocks Uitwijk_L3NAM1988A, Uitwijk_L3NAM1988B, and Waalwijk_L3CLY1992A were selected in the eastern part of the basin for detailed study. Core and cutting measurements, such as porosity and TOC, were taken into account if available. The availability of core material and measurements were limited because the Posidonia Shale Formation usually was not commonly a target for coring in conventional gas wells.

A 3-D basin model of the West Netherlands Basin and the Roer Valley Graben was created by Nelskamp and Verweij (2012). Depth maps were used for all major geological groups from Duin et al. (2006), who based these on wells and 2-D and 3-D seismic data. Additionally, a newly interpreted depth map of the Posidonia Shale Formation (Figure 5) was incorporated in the model. The model has a grid resolution of $143 \times 156$ cells with $1 \times 1$ km per cell. It was calibrated to vitrinite reflectance, present-day temperature, and porosity measurements. Erosion maps were built using structural as well as maturity data. The generation potential of the Posidonia Shale Formation was calculated using the Pepper and Corvi (1995) TII kinetic.

Properties of the Posidonia Shale Formation
Important properties for shale gas of the Posidonia Shale Formation, such as source rock parameter (e.g., kerogen type or TOC), could be derived from the vintage data (Figure 6). Other necessary properties could be calculated on the basis of log data or were taken from the literature. The individual properties are discussed in the following section.

Kerogen Type and TOC Content
In the western part of the West Netherlands Basin, the Posidonia Shale Formation is known to be the most important source rock for oil occurrences (Van Balen et al., 2000; De Jager and Geluk, 2007; Pletsch et al., 2010), and it is suggested that also some associated gas was sourced from the formation. Modeling of the hydrocarbon generation showed that the oil accumulations of the Early Jurassic hydrocarbon system were filled just after the main inversion event. Other results from this study showed that Lower Cretaceous reservoirs of the West Netherlands Basin were filled after the Subhercynian inversion event (Van Balen et al., 2000). Source rock characterization indicates an overall Type II kerogen, with an average TOC content of about 5–7% (can be up to 14%) and average hydrogen index (HI) values of $550 \text{ mg/g TOC}$. HI values can be higher than 1000 mg/g for immature samples. Biomarker analyses indicate marine organic matter (Figure 6; Pletsch et al., 2010). Clearly, these values meet the criteria outlined in Table 1.

TOC measurements on cutting samples of the Posidonia Shale Formation from 11 wells were available, with an average of 5.73% TOC. Additionally, the TOC has been calculated for 10 wells by use of well logs,
Figure 6. Pseudo-van-Krevlen diagram for measurements from the Posidonia Shale Formation onshore (blue) and offshore (red).
using the method of Passey et al. (1990). This calculation resulted in values between 0 and 17.3%. The results for well MRK-01 are shown in Figure 4. The average TOC content over the complete Posidonia Shale Formation in the 10 wells is 5.66%, which is in good agreement with the measurements. A clear correlation can be observed for wells MRK-01 and WED-03 between the density log and the TOC content derived from the deep resistivity and sonic logs (Figure 7), indicating the effect of low-density kerogen on the overall rock density. This correlation could not be confirmed for the other eight wells. The derived log shows the variation in TOC over the Posidonia Shale Formation sequence (Figure 4). This is another indication for changing sedimentary environment during deposition. The highest TOC contents seem to be related to maximum flooding at the base of the formation, gradually decreasing upward.

**Maturity**

Maturity measurements of cutting samples of the Posidonia Shale Formation in the West Netherlands Basin include vitrinite measurements, RockEval $T_{max}$, and biomarker indicators. The reliability of vitrinite reflectance measurements is limited because vitrinite is often difficult to identify in marine Type II sediments. For Type III coals, there is a fair correlation between $R_o$ and $T_{max}$ throughout the sedimentary record (Teichmüller and Durand, 1983) that could be confirmed for Westphalian sediments from the Netherlands. This correlation was used to convert $T_{max}$ values for comparison, even though individual measurements are not fully consistent.

All measurements indicate that, in general, maturity in the West Netherlands Basin decreases from residing in the oil window in the west to immaturity in the east, corresponding to the occurrences of oil fields in the west that are lacking in the east. However, the measurements are performed on samples from wells that were preferably drilled on structural highs, showing lower maturities, as could be expected from surrounding lower areas. As oil occurs also in proximity to wells with immature source rock, main oil generation likely took place in adjacent grabens where the sediments reached the oil window and oil migrated into the structural traps. Two-dimensional and 3-D basin modeling confirmed these observations (van Balen et al., 2000; Nelskamp and Verweij, 2012; Figure 8), although the modeled maturities do not show a very good correlation with the measured values. This difference can be attributed to problems in tying the time-depth-converted seismic data to wells, difficulties measuring vitrinite reflectance in the Posidonia Shale Formation, or the resolution of the model that can obscure the huge depth differences encountered in the area.

Nevertheless, the overall conclusion can be drawn that probably only a small part in the west of the basin reached maturity for gas generation (Figures 8, 9). This indicates that the potential for thermogenic gas generation from the Posidonia Shale Formation and preservation of this gas in the formation is restricted to the deeper, undrilled parts of the basin. Nevertheless, mud logs of the drilled highs indicate that gas is
Figure 8. Vitrinite reflectance calibration quality (a) and maturity map (b) for the Posidonia Shale Formation for the Southern Dutch onshore.

Figure 9. $T_{\text{max}}$ versus HI diagram for Rock-Eval measurements from the Posidonia Shale formation onshore (blue) and offshore (red).
present in the Posidonia Shale Formation even in the immature or oil mature areas.

Gas Content
Mud logs of 26 onshore wells could be retrieved from the database with gas shows at the Posidonia Shale Formation level (Table 2). These gas shows are visible as elevations or peaks in the mud log, and the absolute amount of gas is diverse, ranging from 200 ppm to more than 20,000 ppm for seven cases. Well BRAK-01 is peaking at 175,500 ppm on its mud log for the Posidonia Shale Formation. Several types of maturity measurements have clearly indicated that the formation is immature to early oil mature (Figures 8, 9). For example, several independent maturity measurements of the formation in well OTL-01 confirmed that it resides in the early oil window, while its mud log indicates a gas content of more than 60,000 ppm. Since the kerogen type of the Posidonia Shale Formation is an oil-prone Type II kerogen, only very limited amounts of gas are generated thermogenically at early maturities (Dieckmann et al., 1998). These observations could suggest that the observed gas in the mud logs is of biogenic origin. Direct evidence for biogenic generation cannot be provided in lack of samples. The mud logs show hardly any ethane at the level of the Posidonia Shale Formation, but the fact that it is not present cannot be considered as evidence for biogenic generation. On the other hand, in a large part of the study area, the present-day depth and temperature of the formation is too high for ongoing biogenic gas generation. One assumption could be that the gas is preserved during further burial since generation. A correlation between gas content and burial depth (Figure 10) indicates less gas with increasing burial depth, hinting at further processes that are not yet fully understood.

Because the absolute gas content of the rock cannot be directly derived from the mud log, it is estimated from literature. The total amount of gas in the formation is related to the total porosity. Porosity measurements on the Posidonia Shale Formation could be retrieved for two wells (BRK-01 and LOZ-01). These two measured wells have average porosities of 7.38% (n = 5) and 10.34% (n = 15), respectively, which is more than the required porosity according to the criteria (Table 1). These measurements were performed in the 1950s on plug samples, presumably according to standard procedures for conventional reservoir rocks. Nevertheless, because of a lack of state-of-the-art shale specific porosity measurements, these data were used as calibration data for the porosity map resulting from the 3-D basin model (Figure 11). This map indicates that there is a relation with depth due to compaction of the rock during burial. Given the results, the porosity in the formation is expected to be sufficiently high throughout the basin to meet the criteria outlined in Table 1.

The free gas in the (macro-) pores of the shale will further depend on the water saturation. An average water saturation of 30% was assumed, based on reported averages from the Barnett and Marcellus shales (Bruner and Smosna, 2011).

Estimation of adsorbed gas on the organic matter is very difficult lacking adsorption isotherms of the formation. Ross and Bustin (2009) showed that there is a positive correlation between TOC and the sorption capacity of a shale. It was decided to assume an adsorption capacity based on the isotherm results published by Ross and Bustin (2009). These isotherms were measured at distinctly different conditions (30°C and up to 6.5 MPa) compared to the reservoir conditions of the Posidonia Shale Formation (18–25 MPa, 64–85°C) but are still considered to be representative for shales in lack of basin-specific isotherms. At a TOC value of 5.5%, the Langmuir volumes for shales as measured by Ross and Bustin (2009) vary between 0.4 and 1.6 cc/g. Because these sorption isotherms for methane are stated to be stabilized at the 6.5 MPa (D. J. K. Ross, 2010, personal communication), the amount of adsorbed gas does not increase remarkably at higher pressures (greater depth). However, there is a clear negative effect of temperature on the sorption capacity. The results of Krooss et al. (2002) on coal reveal that correction for temperature is not trivial. For this reason, we propose using a conservative value for the adsorbed gas of 0.4 cc/g rock, or 1 m³ gas/m³ rock at an average shale density of 2.5 g/cm³.

Rock Volume
As a result of the tectonic basin evolution throughout geological history, the deposits of the Posidonia Shale Formation occur within distinct structural blocks that are fault bounded. The orientation of the large-scale fault system in the West Netherlands Basin has a general northwest-to-southeast orientation (Figure 12). Seismic attribute analysis of the Posidonia Shale Formation on the selected 3-D seismic surveys shows that on a local scale, the northwest-to-southeast orientation can be recognized, but a second set of orthogonal faults seem to be present. Interpretation of local faulting on the 3-D seismic shows that major faults occur every 5–10 km, with secondary faults every 1–2 km (Figure 12). The formation shows up as an excellent reflection on seismic, caused by the low acoustic speeds of the bitumen, and can be mapped with great confidence (Figure 13). Within the boundaries of the fault-bounded block, the formation shows a good lateral
continuity and a fairly undisturbed, gentle character. It is assumed that horizontal drilling through the bounding faults can be problematic for technical reasons but also because of the offset of the formation along these faults. Shale gas extraction in the West Netherlands Basin would therefore take place within the boundaries of the fault-bounded blocks, with an areal size in the order of several square kilometers. For this study, three areas in the order of 7–17 square kilometers were selected based on 3-D seismic (Figure 12). The selection of the three areas was, next to the presence of 3-D seismic, based on the proximity of wells with good log coverage and a relatively deep occurrence of the formation.

The thickness of the formation in the West Netherlands Basin ranged from 6 to 62 m but usually around 30–35 m (TNO-NITG, 2004; De Jager and Geluk, 2007). Given the uniform character of the formation (Figure 12) within the tectonic blocks, a constant thickness of 30 m has been chosen for the evaluation of this study. The rock volume of the selected tectonic blocks is taken as the product of the area and the thickness (Table 3).

### Table 2. Wells used in this study with depth of the Posidonia Shale Formation; measured gas peak from logs and measured and calculated maturity.

<table>
<thead>
<tr>
<th>Wells</th>
<th>Depth top (m AH)</th>
<th>Depth bottom (m AH)</th>
<th>Depth top (m TVD)</th>
<th>Depth bottom (m TVD)</th>
<th>Gas peak (ppm)</th>
<th>Tmax (ºC)</th>
<th>%R_o modelled</th>
<th>%R_o measured (from Tmax)</th>
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<td>AND-06</td>
<td>1977</td>
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<td>2021</td>
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<td>BKZ-01</td>
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<td>1883.7</td>
<td>7211</td>
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<td>992</td>
<td>1006</td>
<td>435</td>
<td>0.58</td>
<td>0.805</td>
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<td>BRAK-01</td>
<td>1814</td>
<td>1842</td>
<td>1732</td>
<td>1760</td>
<td>175777</td>
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<tr>
<td>BSKP-01</td>
<td>1408</td>
<td>1439</td>
<td>1405.3</td>
<td>1436.3</td>
<td>3913</td>
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<tr>
<td>GAG-01</td>
<td>2920</td>
<td>2937</td>
<td>2917.5</td>
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<td>0.43</td>
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<td>1940</td>
<td>1989</td>
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<td>1936.9</td>
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<td>0.48 (0.73)</td>
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<td>1400</td>
<td>1422</td>
<td>1399.4</td>
<td>1421.4</td>
<td>430</td>
<td>0.59</td>
<td>0.685</td>
<td>0.61 (0.62)</td>
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<td>HVB-01</td>
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<td>1758</td>
<td>1680.44</td>
<td>1708.44</td>
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<td>0.685</td>
<td>0.61 (0.62)</td>
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<td>IJS-64</td>
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<td>0.755</td>
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<td>2458</td>
<td>2511</td>
<td>421</td>
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<td>0.755</td>
<td>0.966 (0.61)</td>
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<tr>
<td>MKP-01</td>
<td>1148</td>
<td>1177</td>
<td>1142.3</td>
<td>1171.3</td>
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<td>0.685</td>
<td>0.61</td>
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<td>1827</td>
<td>1758.5</td>
<td>1795.5</td>
<td>421</td>
<td>0.685</td>
<td>0.685</td>
<td>0.61</td>
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<tr>
<td>MRK-01</td>
<td>1340</td>
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<td>1291.46</td>
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<td>OTL-01</td>
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<td>1744</td>
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<td>2328.3</td>
<td>2362.3</td>
<td>12517</td>
<td>0.695</td>
<td>0.75</td>
<td>0.63</td>
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<td>RKK-01</td>
<td>2604</td>
<td>2654</td>
<td>2202.57</td>
<td>2252.57</td>
<td>9364</td>
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<tr>
<td>SMG-01</td>
<td>2014</td>
<td>2043</td>
<td>2014</td>
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<td>SPG-01</td>
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<td>1469.5</td>
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<td>VEH-01</td>
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<td>0.97 (0.62)</td>
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<td>VLV3-S5</td>
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<td>1468.93</td>
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<td>0.645</td>
<td>0.43</td>
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<tr>
<td>WAA-01</td>
<td>1622</td>
<td>1650</td>
<td>1621.3</td>
<td>1649.1</td>
<td>430</td>
<td>0.675</td>
<td>0.73</td>
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<tr>
<td>WED-03</td>
<td>2264</td>
<td>2289</td>
<td>2195.64</td>
<td>2220.64</td>
<td>39109</td>
<td>0.815</td>
<td>0.94 (0.59)</td>
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<td>WLK-01</td>
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<td>1099</td>
<td>1008.67</td>
<td>1035.67</td>
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<td>WWK-01</td>
<td>2674</td>
<td>2703</td>
<td>2321.46</td>
<td>2360.46</td>
<td>6522</td>
<td>0.69</td>
<td>0.44</td>
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<td>2435</td>
<td>2475</td>
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<td>2143.69</td>
<td>60251</td>
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<tr>
<td>WWS-01-S1</td>
<td>2586</td>
<td>2615</td>
<td>2254.75</td>
<td>2283.75</td>
<td>0.725</td>
<td>0.52</td>
<td>0.725</td>
<td>0.52</td>
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</tbody>
</table>

Gas-in-place Calculations

Given the range in porosities as described, it was decided to calculate two scenarios, assuming a 5.5% porosity and a 10% porosity. The amount of gas in the pore system was calculated, taking into account a gas saturation of 23% and an expansion factor based on the formation pressure and temperature. These were derived from the basinal hydrostatic pressure gradient.
and the basinal geothermal gradient (31°C/km; TNO-NITG, 2004) by using one depth per block based on well data (Table 3). For the adsorbed gas, a fixed value of 1 m³/m³ of rock was used.

The resulting values (0.26–0.46 bcm/km² and 23–42 bcfg/mi²) are highly uncertain and should be considered only as indicative, pending better estimates after the first results from exploration wells. The values can serve as only a comparison with shale gas fields in the United States. For example gas-in-place values calculated for the Barnett Core area and Tier counties are reported to be around 140–145 bcfg/mi² (Hayden and Pursell, 2005) and for the Marcellus Shale around 30–150 bcfg/mi² (Wrightstone, 2008; Petzet, 2009). Others have estimated lower values for the Marcellus (0.3–2.5 bcfg/mi²; Zielinski and McIver, 1982; Marcellus Shale in New York, 2009). Compared to these U.S. values, the Posidonia Shale Formation

Figure 10. Measured gas content from gas or mud logs versus depth for different wells from the West Netherlands Basin. Red wells could have been buried deeper in the past 500 m (1640.42 ft).
estimates per square kilometer are slightly lower, though some assumptions in this study are conservative. One of the main factors that gives better values for the Barnett Shale compared to the Posidonia Shale Formation is the thickness of the formation (Table 4).

The presence of this amount of gas in the Posidonia Shale Formation needs to be confirmed by exploration wells. Whether this gas can be produced is still unknown and will, next to many other factors, depend on the ability to stimulate the low-permeability rock to be able to extract the gas. Stimulation is usually performed by hydraulic fracturing, which is highly dependent on the geomechanical properties of the rock. For 11 wells in the area, the elastic characteristics (Young’s modulus and Poisson’s ratio) were determined on the basis of logs using the method of Eissa and Kazi (1998) and Castagna et al. (1985). Results of the calculated Young’s modulus show that a rough trend can be observed of increasing values with depth, as one can expect from compaction of the rock (Figure 14). In other words, the rock gets more brittle with depth. Also, the spread in values reflects the variation through the sedimentary section in terms of lithology and mineralogy.

The transition from the ductile to the brittle region can be deduced from Poisson’s ratio (Grieser and Bray, 2007), which is reported to vary from 0.2 to 0.4 (Rider, 1996). Applying the method of Grieser and Bray (2007) with a Poisson’s ratio of 0.2 results in a brittle ductile transition at 1.45 GPa. For the high Poisson’s ratio (0.4), the transition is determined at 6.1 GPa. In the case of an assumed low Poisson’s ratio (0.2), there are no wells with Posidonia Shale Formation that plot in the ductile region. For the assumed high Poisson’s ratio (0.4), part of the Posidonia Shale Formation in two wells is in the ductile region (PKP-01 and OTL-01). The Posidonia Shale Formation of wells MRK-01, RDK-01, BRAK-01, and KWK-01 plot close to the transition, but there is still a gap of 0.6 GPa or more before the ductile regime is met. This means that based on these calculations, it can be expected that almost all the Posidonia Shale Formation in the West Netherlands Basin will act brittle when enough stress is put on the rock body.

The success of hydraulic fracturing will further be highly dependent on the current stress regime, which is compressive in a southwest-to-northeast direction in the West Netherlands Basin (Duin et al., 2006).

The Epen Formation

Geological Setting

Only a limited number of wells have drilled the sediments of the Epen Formation, and only a handful have penetrated the entire sequence. This formation represents most of the Namurian (Serpukhovian to Lower
Bashkirian), locally persisting into the Early Westphalian A (Upper Bashkirian). On the northern flank of the London-Brabant Massif, the base of the formation roughly coincides with the Visean-Namurian boundary.

Based on the information of the wells, the formation is described by Van Adrichem Boogaert and Kouwe (1993–1997) as a succession of dark-gray to black mudstones with a few intercalations of sandstone. Coal seams are absent, but dispersed carbonaceous matter is locally abundant. The interval consists of a number of stacked coarsening-upward sequences, arranged into several large-scale coarsening-upward trends between 50 and 300 m thick. Sandstone sheets are intercalated at the tops of some sequences, especially in the upper part of the formation. Mudstones, some containing marine fossils, dominate the basal and middle parts of each sequence. Locally, a black, bituminous, partially silicified and calcareous shale is found at the base of the formation, which is called the Geverik Member. Its bituminous character suggests that it could be a promising shale gas target. This bituminous shale rests on Dinantian carbonates. In well Geverik-1 (GVK-01), this transition is gradual and apparently conformable, but elsewhere

Figure 12. Left: Time map (in ms) of Posidonia Shale Formation in the selected three-dimensional seismic surveys. The dotted lines indicate the large faults identified from regional mapping, while the solid red lines indicate newly interpreted local faults. Right: Seismic attributes of the Posidonia layer showing limited frequency variations (18–25 Hz) within fault blocks, suggesting uniform bed thickness 1000 m (3280 ft).
this contact can be unconformable. The presence of carbonate rock as a lower boundary could be important for the success of future hydraulic fracturing of the layer, as it provides a natural barrier for fracture propagation out of the formation.

All wells that have penetrated the Epen Formation are located on the margin of the Carboniferous Basin or at elevated structural highs or swells (Figure 15). However, the presence of the formation can be anticipated in large areas, but its properties in these areas are unknown. The depositional setting has been interpreted as cycles of repeated delta progradation into a predominantly lacustrine basin (Van Adrichem Boogaert and Kouwe, 1993–1997). The recent identification of large carbonate platforms on seismics below the Epen Formation (Kombrink et al., 2010) indicates the presence of highs and lows at the time of deposition; these have probably determined the distribution of the Epen Formation and controlled the depositional conditions. The top of the Epen Formation is a diachronous boundary. Depending on the geographic position in the basin, it can vary in age from Namurian B (South-Limburg) to Early Westphalian A (central onshore).

### Table 3. Calculated gas-in-place values for the Posidonia Shale Formation in three selected tectonic blocks onshore the Netherlands.

<table>
<thead>
<tr>
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<th></th>
<th></th>
</tr>
</thead>
<tbody>
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<td>Area I</td>
<td>~3.0 × 7.0</td>
<td>17.3</td>
<td>0.519</td>
<td>2300</td>
<td>81.3</td>
<td>23</td>
<td>195</td>
<td>5.5</td>
<td>4.41</td>
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<tr>
<td>Area II</td>
<td>~ 2.1 × 4.5</td>
<td>8.68</td>
<td>0.260</td>
<td>2455</td>
<td>86</td>
<td>24.5</td>
<td>202</td>
<td>5.5</td>
<td>2.29</td>
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<tr>
<td>Area III</td>
<td>~1.5 × 5.5</td>
<td>7.50</td>
<td>0.225</td>
<td>2485</td>
<td>87</td>
<td>25</td>
<td>205</td>
<td>5.5</td>
<td>2.00</td>
<td>0.27</td>
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</tbody>
</table>
Table 4. Comparison of estimated properties for the Posidonia Shale Formation from this study compared to reported properties for the Barnett Shale (Curtis, 2002).

<table>
<thead>
<tr>
<th>Property</th>
<th>Unit</th>
<th>Barnett (Curtis, 2002)</th>
<th>Posidonia Shale Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth</td>
<td>m</td>
<td>2000–2600</td>
<td>2300–2500</td>
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<tr>
<td>Gross thickness</td>
<td>m</td>
<td>61–91</td>
<td>30</td>
</tr>
<tr>
<td>Net thickness</td>
<td>m</td>
<td>15–61</td>
<td>30</td>
</tr>
<tr>
<td>Bottom-hole T</td>
<td>°C</td>
<td>93</td>
<td>72–85</td>
</tr>
<tr>
<td>TOC</td>
<td>%</td>
<td>4.5</td>
<td>1–15 (5.7)</td>
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<tr>
<td>Vitrinite reflectance</td>
<td>%</td>
<td>1.0–1.3</td>
<td>0.55–1.3</td>
</tr>
<tr>
<td>Total porosity</td>
<td>%</td>
<td>4–5</td>
<td>5–13</td>
</tr>
<tr>
<td>Gas filled porosity</td>
<td>%</td>
<td>2.5</td>
<td>3.9–7.0</td>
</tr>
<tr>
<td>Water filled porosity</td>
<td>%</td>
<td>1.9</td>
<td>1.7–3.0 (assumed)</td>
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<td>Gas-content</td>
<td>m3STP/m3 rock</td>
<td>21–25</td>
<td>8–15 (assumed)</td>
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<tr>
<td>Adsorbed gas</td>
<td>%</td>
<td>20</td>
<td>7–13</td>
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<td>Reservoir Pressure</td>
<td>MPa</td>
<td>20–27</td>
<td>23–26 (assumed)</td>
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<td>GIIP</td>
<td>bcm3STP/km²</td>
<td>0.76–1.53</td>
<td>0.26–0.46</td>
</tr>
</tbody>
</table>

Data
Data of 12 wells that have penetrated the Epen Formation in the Netherlands are in the public domain. The latest well UHM-02 drilled through the entire formation, as shown on a seismic line published by Herber and De Jager (2010). Well logs and measurements on cuttings and cores of the public wells have been evaluated. Mud logs could be retrieved from the database for wells EMO-01, RSB-01, and LTG-01. Seismic interpretations are still to be performed.

Properties of the Epen Formation
Kerogen Type and TOC Content
The type section of the basal part of the formation, the Geverik Member, has been cored completely in well GVK-01 and has been intensely investigated. Additionally, samples have been analyzed from other wells. Geochemical investigations of the Epen Formation, excluding the basal part, showed TOC values up to 5% with a median value of around 1.1%. It must be noted that samples were preferentially taken at intervals with high gamma ray values on the logs, and these may represent the more organic-rich intervals of the sequence. Kerogen typing of these shales is complicated because of its high maturity, but there are strong indications that it is Type II, given the marine character of the deposits as shown by marine fossils (Van Adrichem Boogaert and Kouwe, 1993–1997). This is also in agreement with the marine anoxic depositional environment as described by Pletsch et al. (2010). Some admixture of Type III kerogen is possible (Figure 16). TOC content can be up to 7%, but given its high maturity, it can be anticipated that the original TOC and HI must have been much higher. The role of the Geverik Member as a source rock for oil or gas has not been conclusively confirmed in the Netherlands, although contributions to petroleum occurrences has been suggested and can be presumed (e.g., Van Balen et al., 2000).

Maturity
Given the thickness of the Epen Formation, with a drilled sequence of more than 1700 m in well RSB-01 in the south of the Netherlands, without reaching the base of the formation, and a completely drilled sequence of nearly 1600 m in the center of the Netherlands in well LTG-01, the maturity increases significantly from the top of the formation to its base. For example, the maturity in well RSB-01 increases from about 2% Rₙ at the top of the formation to around 3% Rₙ at the deepest part. In the central part of the Netherlands, there is a steeper maturity trend, as shown by wells NAG-01 and EMO-01 (close to LTG-01 in the center of the Netherlands). In well WSK-01 farther east, the top of the formation has a maturity value of...
around 2% $R_o$ and the basal part 4% or even higher. The Epen Formation in well Geverik-01 in the south-east of the country is not as thickly developed because this well is located on the margin of the basin. The sediments do show a steep maturity trend, increasing from top to base of the formation, from about 2% to 3% $R_o$. The differences in the maturity trend reflect differences in thermal history. There is a general trend of decreasing maturity from east to west, as confirmed by other wells and by basin modeling. This implies that in the southeastern to eastern part of the country, the organic-rich basal part may have too high a maturity for gas preservation, while farther to the west, there may be opportunities for shale gas, though this is high risk because of the high maturity. The upper part of the formation is still within the correct maturity window, although the organic content of the rock may be subcritical.

**Gas Content**

The mud logs from wells RSB-01, EMO-01, and LTG-01 give clear gas kicks at the level of the Westphalian coal seams, indicating the gas preservation potential of the coals at substantial depths (>1700 m). However, gas kicks are also present in the coal-barren upper parts of the Epen Formation in these wells. Even the basal parts of the Epen Formation in the LTG-01 and UHM-02 wells, which are expected to be highly mature, appear to contain some gas though at very low levels. Although these observations do not provide

![Figure 14. Static and Young's modulus results after calculations on selected wells. Separation line between brittle and ductile region is in black, with a Poisson’s ratio of 0.4.](image-url)
The exploration challenges for the organic-rich basal part of the Epen Formation are mainly in localizing those parts of the shale that are within the proper maturity window (i.e. <3.3% R₀) at accessible depths. Possibly, these criteria can be met at less mature local highs, maybe in the western part of the country. The upper parts of the formation are within the proper maturity window, but layers with sufficient organic matter need to be identified.

Apart from the technological challenges, societal issues need to be addressed before shale gas exploitation can take place. Public concern has risen about the environmental impact and safety of shale gas operations, and companies will have to show that they can operate in a responsible and safe way. The need for information on shale gas potential and impact has become very relevant over the past two years since, as of 2010, a total of four exploration licenses have been granted to different companies; this challenges policymakers to take a position on shale gas development in the Netherlands.

**DISCUSSION**

The exploration challenges for the organic-rich basal part of the Epen Formation are mainly in localizing those parts of the shale that are within the proper maturity window (i.e. <3.3% R₀) at accessible depths. Possibly, these criteria can be met at less mature local highs, maybe in the western part of the country. The upper parts of the formation are within the proper maturity window, but layers with sufficient organic matter need to be identified.

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should not be used outside their context. Still, they are valuable for comparison with some producing basins in other parts of the world. Given the data available, it is believed that the evaluations provide sufficient arguments for further investigation and prospecting.

Exploration challenges between the Posidonia Shale Formation and the Epen Formation are different. Whereas the occurrence of the Posidonia Shale Formation is well known and gas has been encountered at shallower depths, as proven by the mud logs, its presence in the deeper parts and its economic producibility should be confirmed. For the Epen Formation, areas with enough net volume of organic-rich rock in the correct maturity window need to be identified.

Future work should focus on the acquisition of more data that are specifically measured for shale gas evaluations. Ideally, these new data would result from new exploration wells and from fresh material in these to other potential plays in Europe, is used for the investigated formations. Many different data types for more than 40 wells have been integrated, including well logs (density, sonic, gamma ray, and resistivity wire-line logs), stratigraphy, geochemical measurements, porosity measurements, temperature and pressure data, and 3-D seismic data, to determine relevant evaluation parameters.

Nevertheless, there are many uncertainties in the critical parameters of the shale gas plays. The uncertainties arise from the quality and quantity of the data because this study relied on data and measurements that were not specifically targeting shale gas when acquired. For example, the geophysical well logs were run for conventional oil and gas operations. This results in, for example, a lower resolution than desired for shale gas evaluations. The calculated gas-in-place values are highly uncertain and even speculative and should not be used outside their context. Still, they are valuable for comparison with some producing basins in other parts of the world. Given the data available, it is believed that the evaluations provide sufficient arguments for further investigation and prospecting.

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Figure 16. Pseudo-van-Krevelen diagram for Rock-Eval measurements from the Geverik Member.
wells, but in the meantime, core material from previous wells is available. New core tests should focus on the determination of geomechanical properties, mineralogy, proper porosity-permeability determinations, adsorption characteristics, and fracture network characterization. Stress determination on a regional geological scale can also be very valuable.

This study has provided background information on the geological setting for potential shale gas developments in the Netherlands. Future exploration and production of shale gas in the Netherlands will depend on the technical ability to produce the gas, if present in sufficient amounts, in a Dutch context. While possible gas-in-place per square kilometer in some defined blocks are in the same order (though lower as some successful plays in the United States), the geological structure is, however, completely different. The basins in the Netherlands are highly faulted, and sediments reside in horst-and-graben structures. Tectonic blocks with relatively undisturbed sediments between their fault boundaries have been identified and range in size between 7.5 and 17.3 km². It is expected that these kinds of blocks could be developed individually, preferably from one location if the economic viability is proven.

CONCLUSION

This study confirmed that the subsurface of the Netherlands contains shale layers that should be investigated further for shale gas, as they could potentially contain a significant amount. Mud logs have provided evidence for the presence of gas in the formations in various wells, indicating the prospectivity of the formations. However, exploration challenges remain that are related mainly to the maturity of the rock (not mature enough in the case of the Posidonia Shale Formation and too mature in the case of the Epen Formation). Possible gas-in-place per square kilometer in some tectonic blocks is lower but in the same order as some successful plays in the United States. The geological structure is, however, completely different from basins in the United States, with the sediments of highly faulted basins residing in horst-and-graben structures. It is expected that tectonic blocks with sizes between 7.5 and 17.3 km² could be developed individually, preferably from one location if the economic viability is proven. In conclusion, this study has provided background information on the geological setting for potential shale gas developments in the Netherlands. The need for such information has become very relevant over the past two years since, as of 2010, a total of four exploration licenses have been granted to different companies. This challenges policymakers to take a position on shale gas development in the Netherlands, where public concern has also risen about the environmental impact and safety of shale gas operations.

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