European Unconventional Oil and Gas Assessment (EUOGA)

Overview of the current status and development of shale gas and shale oil in Europe

Deliverable T3b
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The status and categorisation given for the situation in Germany reflects the authors judgements based on public documents, especially the report of Schieferöl und Schiefergas in Deutschland (BGR 2016) and personal communication. Germany (Bundesanstalt für Geowissenschaften und Rohstoffe, BGR) is not a member of the EUOGA project consortium.

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Overview of countries invited to participate in EUOGA and their association to the project.
Countries covered in this report

The information in this report has been provided by the European National Geological Surveys or comparable institutions. The text in this report concerning Germany reflects the author’s judgements and is based on public documents, especially the report Schieferöl und Schifergas in Deutschland by Bundesanstalt für Geowissenschaften und Rohstoffe (BGR 2016) and personal communication.

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Abstract

The present status of shale gas and oil development within the European Union member countries including Ukraine and Norway is presented based on a questionnaire sent to all National Geological Surveys (NGS'). The status includes an overview of countries with potential resources, the activity level and the geological surveys have given their analysis on the member state position concerning shale gas and shale oil exploration and hydro fracturing.

A total of 26 countries are covered in this study and 22 out of these countries have a potential shale gas/oil resource within their country. In 15 countries assessments of the shale gas and oil resources have been performed either by the NGS or a third party; however, not all assessments are publicly available.

The level of activities with respect to shale gas and oil exploration in the European countries covered in this report is generally low and 20 countries have no present activities and near future activities are not expected. Out of the remaining 6 countries only 3 countries expects future activities.

The low activity level is related to low political and public support for shale gas and oil exploration and resource development. In Europe shale gas/oil exploration and development is presently only permitted in 7 countries. A low support is in most cases described as concerns related to the use of hydro fracturing and the environmental impact.

The second section of this report provides a summary of the basins that host shale gas and oil, and of the shale oil and gas plays itself with emphasis on exploration and production results and available published assessments.
Executive summary

This report provides an introductory country-per-country overview of the current status and development of shale gas and shale oil in Europe, based on returned questionnaires distributed to the National Geological Surveys (NGS) in June 2015 and updates received in July 2016. The basin-per-basin and play-per-play overview are based on replies in the questionnaires, supplemented with information given in the geological basin reports delivered as part of the EUOGA project in 2016.

Various national assessments of shale gas and shale oil resources for the European countries have been published over the last decade. Differences in methodology, fundamental assumptions, quality and quantity of the underlying geological information of these national assessments, implies that results cannot be directly compared and thus no full overview of the hydrocarbon resource potential from shales in Europe is available. This report focuses on the level of shale hydrocarbon exploration activity, state and nature of previous resource assessments and on the political and public situation related to the exploration and development activities of shale hydrocarbons within the European Union.

The questionnaires were prepared by GEUS and TNO as part of the EUOGA project and sent to all member states NGS’ including Ukraine, Switzerland and Norway. Of the 30 questionnaires distributed to the National Geological Surveys, 25 questionnaires have been completed and returned during the second half of 2015 and in the first half of 2016 (Fig. 1). A summary of the replies is presented in the following sections of this report. The status and categorisation given for the situation in Germany reflects the authors judgements based on public documents, especially the report of (BGR 2016) and personal communication. Germany (BGR) is not a member of EUOGA has not responded to the questionnaire.

Shale gas and Shale oil resources and assessment status

The NGS’ were asked to elaborate whether their respective country had or expected to have a shale gas and shale oil resource. If a resource were known, to what extent had the resource been assessed and by whom.

Four countries replied that they have no hydrocarbon resources in shales onshore or that the shale gas and oil are not considered thermogenic and that a variable biogenic shale play was not present. These countries are Estonia, Finland, Norway and Malta. Consequently no resource assessments had been performed in these countries (Fig.2).

Seven NGS’ responded that their country has a potential shale hydrocarbon resource, but that it has not been assessed. These countries include Austria, Belgium, Czech Republic, France, Ireland, Italy and Portugal. In Austria assessment studies are in progress, but the work is not finalised and the results might not be public.

Four NGS’ responded that their countries have been assessed but without the involvement of the NGS. These countries are Bulgaria, Hungary, Slovenia and Sweden. Assessment studies by the NGS are in progress in Hungary and Spain.

Eleven NGS’ responded that their countries have shale hydrocarbon resources and that it has been assessed with the involvement of the NGS. These countries include Croatia, Denmark, Germany, Latvia, Lithuania, the Netherlands, Poland, Romania, Spain (initiated), Ukraine and the United Kingdom. For some countries the assessments are performed by private companies in specific parts of the country whereas the NGS has assessed other parts, e.g. in Croatia.
Activities related to shale gas and shale oil exploration

The NGS’ were asked to provide a status for the exploration and development of shale hydrocarbon resources together with a description of the political status. Based on the response from 25 countries the question about activity level is summarised as follows (Fig. 3).

In 15 countries there is no activity either because they have no resources, have a possible resource but no permit have been issued for exploration, or that there is a political moratorium or ban on shale gas and oil exploration and/or hydro fracturing.

Countries with no resources are Finland, Norway (possibly offshore resources exist, but are not currently relevant for exploitation) and Malta. In Estonia and Latvia the unconventional hydrocarbon resources are too shallow and immature to be classified as true thermogenic shale hydrocarbons and no viable biogenic play is documented.
Fig. 2. Shale gas and shale oil resources and assessment status, by member state. For country details consult the specific country section.

Countries with a possible shale hydrocarbon resource, but with no present exploration activities occurring are Austria, Belgium, Bulgaria, Croatia, Czech Republic, France, Ireland, Italy, Portugal and Sweden.

Five NGS’ reported that that their countries have low activities. This category cover countries where permits have been issued and/or exploration wells have been drilled in the past, but only very little or no future activities are expected. These countries are Denmark, Germany, the Netherlands, Romania and Slovenia. In Slovenia unconventional hydrocarbon resources are found in sandstone deposits, classified as "tight gas” and this resource is not considered as a shale hydrocarbon resource.

Three NGS’ have reported that their countries have medium level activities and include countries where permits have been granted and wells drilled and where future activities are expected. These countries include Hungary, Lithuania and Spain.
Three NGS’ have reported that their countries have high activity and this category covers countries where permits have been granted and wells drilled and future activities will occur, perhaps even on higher levels than what has been seen until now. These countries include Poland, Ukraine and England in the United Kingdom. For the United Kingdom the “high level activity” does not cover Scotland and Wales, where a moratorium is in place, and North Ireland, where there are no active licenses for unconventional hydrocarbon exploration.

![Map of European Unconventional Oil and Gas Assessment (EUOGA)](image)

Fig. 3. Activities related to shale gas and oil exploration. For country details consult the specific country section.

**Member state position towards shale gas and shale oil exploration**

There is often a close relation between the expected future activity level and the member state position towards shale gas and oil exploration and hydro fracturing within the countries. A low support for shale hydrocarbon exploration are in most cases described as concerns related to the use of hydro fracturing and the environmental impact. The following part of this section summarises the NGS’ analysis on the current status in the member states (Fig. 4).
Exploration for unconventional hydrocarbon resources is permitted in seven countries, implying that the use of hydro fracturing is permitted. These countries are Lithuania, Poland, Romania, Slovenia, Spain, Ukraine and England (United Kingdom except Northern Ireland, Scotland and Wales). In Spain and Romania there is no distinction between conventional and unconventional hydrocarbon resource exploration and legislation in these countries permits hydrocarbon exploration.

Five countries have an unclarified position on shale hydrocarbon exploration activities implying that the political position is divergent towards utilisation of shale gas and oil, or shale gas and oil exploration and development has not yet been an issue. These countries are Belgium, Czech Republic, Hungary and Portugal.

A group of five countries have no support or a moratorium on unconventional hydrocarbon exploration activities and/or hydro fracturing. These countries include Austria, Bulgaria, Denmark, Ireland and the Netherlands.

Five NGS’ reported that hydro fracturing in shale gas and oil deposits is prohibited; these countries are Croatia, Estonia, France, Germany and Italy. And finally, in five countries there are no known onshore shale hydrocarbon resources. Countries included in this category are Finland, Latvia, Malta and Norway. Sweden is included in this category even though there is a minor biogenic gas resource in central Sweden.
Figure 4. The member state position on shale gas and oil exploration and hydrofracturing per July 2016. For country details consult the specific country section.

**Basin and play overview**

This section provides a summary of the basins that host shale gas and oil and of the shale oil and gas plays itself with emphasis on exploration and production results and available published assessments. The lists of basins are not complete as data is progressively being added as they are received from the participating NGS’s. A complete list will be made as part of the assessment task (T7) within the EUOGA project and in dialog with the NGS’s. The basins included here are presented in Figure 5. Some of the basins are grouped into larger basins based on the grouping used in report T4 *Geological resource analysis of shale gas and shale oil in Europe*. This report also presents a geological description of the European basins and shales.

**Norwegian-Danish-South Sweden basin**

The main target for exploration is this basin is the organic rich lower Palaeozoic Alum Shale Formation (M. Cambrian - L. Ordovician). The up to 180 meter thick formation is relative tectonically un-disturbed and has for the Danish territory been assessed by
the United States Geological Survey (USGS) (Gautier et al. 2013). Assuming unrestricted application of best practice current technology, recoverable gas resources of 0 to 130 × 10⁹ Nm³ gas were estimated onshore (mean = 67 × 10⁹ Nm³ gas) and 0 to 228 × 10⁹ Nm³ gas were estimated offshore (mean = 119 × 10⁹ Nm³ gas), i.e. a total estimated mean of 186 × 10⁹ Nm³ gas (Nm³: normal cubic metre, unit used for natural gas at 0°C and 101.325 kPa). The wide range of estimates reflects the sparse data and the geological uncertainty inherent in the still untested play. The first shale gas exploration borehole in Denmark, the Vendsyssel-1 was drilled in northern Jylland in 2015 by the company Total E&P.

A minor resource of biogenic shale gas is present in the Alum Shale in South Central Sweden on the Fennoscandian shield. The expected amount of gas present has not merited it for further analysis within the EUOGA context.

**Baltic basin**

The Baltic basin comprises areas around the Baltic Sea in Denmark, Sweden, Poland, Latvia, Lithuania, but also include the Podlasie–Lublin basin in Poland and Lviv-Volyn basin in Ukraine (Fig. 5). The Lower Paleozoic basin at the western slope of the East European Craton (EEC) has been recognized as one of the most interesting areas for shale gas (and oil) exploration in Europe. The marine-deposited Upper Ordovician and/or Lower Silurian graptolitic shale is here the major potential reservoir formation (Poprawa 2010). Moreover, the Upper Cambrian to Ordovician Alum shale is an additional target locally in the northern part of the Baltic basin (mainly offshore, a small part onshore). Organic matter of the Lower Paleozoic shales is characterized by presence of II type of kerogen (Poprawa 2010).

Unconventional shale oil/gas resource exploration in Latvia has never been carried out. Data that allows for a evaluation of the potential shale oil/gas formations are gained from core description and well logging. Available data can be characterized as sparse, incomplete and contradictory. Four potential shale oil/gas formations are determined in Latvia, but only the Zebrus Formation (Lower Ordovician) correspond to some of the EUOGA screening criteria as the formation lays is deeper than 1.5 km and more than 20 m thick (thickness – gross, m). The formation is, however, immature and no thermogenic resource is expected.

The major shale oil and gas potential in Lithuania is related to the two major complexes of the organic-rich source rocks distributed in Western Lithuania, the Upper Ordovician complex and Lower Silurian complex. The first assessment of unconventional hydrocarbons in Lithuania has been published by Zdanaviciute and Lazauskiene (2009). EIA has assessed the Lithuania shale gas/oil resources in 2011, 2013 and 2015. The Lithuanian Geological Survey prepared from 2011 to 2014 a shale gas report based on actual geological, geophysical and geochemical data. Shale oil and shale gas resources in-place (GIP and OIP) for Late Ordovician – Early Silurian section of 110 m thick. The calculated volumes of generated unconventional hydrocarbons were OIP 3.6 – 18.3 bill. m³ (area: 1134-5691 km²) and GIP 1,03 – 5,13 trill. m³ (area: 1134-5691 km²) (Lazauskiene et al. 2014). Furthermore, have scientists from the Lithuanian Academy of Sciences in 2013-14, evaluated recoverable and in-place shale oil and gas resources for Late Ordovician - Early Silurian section in Šilutė-Tauragė block and western Lithuania (Grigelis ed. 2014)(Fig. 9).

Pilot shale oil/shale gas prospecting projects in western Lithuania started in 2011 and was carried out by 2 oil companies in 2011-2013. During this period 2 new prospecting shale oil/gas wells were drilled through the Lower Silurian and Upper Ordovician strata.
The main target for shale gas and oil in Poland is the Lower Paleozoic Baltic-Podlasie-Lublin basin (Lower Silurian-Upper Ordovician, locally Upper Cambrian) (PGI-NRI, 2012). The main basin has been studied in PGI-NRI (2012) report „Assessment of shale gas and oil resources of the Lower Paleozoic Baltic-Podlasie-Lublin Basin in Poland” and in a number of other published reports (ARI 2009; Wood Mackenzie 2009; EIA 2011, 2013, 2015; Rystad Energy 2010; USGS - Gautier et al. 2012). These reports either utilized actual data from archive wells (PGI-NRI, 2012; USGS - Gautier et al. 2012) or just available publications (ARI 2009; Wood Mackenzie 2009; EIA 2011, 2013, 2015; Rystad Energy 2010). No resource assessment utilizing data from new wells (property of the concession operators - oil & gas companies) has been published yet. New PGI report on the shale gas and oil resources of the Lower Paleozoic Baltic-Podlasie-Lublin basin in Poland, utilizing data from most of these new wells, has been completed by PGI but not approved by Ministry of Environment yet. In case of PGI-NRI (2012) report results laboratory analyses of core samples from 39 archive wells were utilized (mainly values of TOC and thermal maturity - R₀).

As shown in Fig. 10 discrepancies between results obtained from both approaches and particular studies are huge - the range of TRRs is two orders of magnitude. One of the reasons for these discrepancies is the use of different volumetric method and as a result the net thickness and volume of potentially gas (and/or oil) bearing shales were overestimated. Another reason for discrepancies consists in the fact the researchers followed different methodologies and used different assumptions (especially on net thickness of prospective shales).

The moderately complex Lviv-Volyn Basin of western Ukraine is similar to the Lublin Basin in southeast Poland. However, the Silurian black shale belt becomes structurally simpler as it trends towards the southeast across southwestern Ukraine and northern Romania until it reaches the Black Sea. The Silurian is the main petroleum source rock and shale gas exploration targets in the Lviv-Volyn Basin. Compared with Poland, the reservoir characteristics of the Silurian shale in western Ukraine are less certain.

Resource Assessment Risked, technically recoverable resources from Silurian black shale in the Lviv-Volyn Basin is estimated to be 52 Tcf, out of a risked shale gas in-place of 363 Tcf. The play has a moderately high resource concentration of about 113 Bcf/mi², reflecting the significant thickness of the organic-rich shale that is present. Ukraine’s State Commission on Mineral Resources has estimated that the Oleska shale gas license area in the Lviv-Volyn Basin has about 0.8 to 1.5 trillion m³ (28 to 53 Tcf) of shale gas resources. Whether this estimate reflects in-place or recoverable resources was not specified.

In Ukraine Chevron has been in negotiations with the government for a PSA at the Oleska field in western Ukraine. This block is along strike with Poland’s Lublin basin, where Chevron already holds shale licenses. Duration and terms likely would be similar to those granted to Shell for the permit at Yuzivska field in the eastern Dniepr-Donets Basin (assigns oil and gas rights to all strata to a depth of 10 km, including tight and basin-centred gas. The contract allows for 70% investor recovery and a 16.5% government revenue share).

Fore-Sudetic Monocline basin
The Fore-Sudetic Monocline (Lower Carboniferous) has been evaluated by EIA (2013, 2015) reports and its geological-reservoir properties have been studied and reported in a PGI-NRI report on tight gas (Wójcicki et al. 2014) where area prospective for tight and shale gas has been delineated. Only one new well for shale and tight gas
prospecting in Lower Carboniferous has been completed there (San Leon 2012) and only few archive wells explored Lower Carboniferous.

In the Fore-Sudetic Monocline Basin EIA estimated TRRs of 595 Bcm. EIA (2013, 2015). However, the prospective area seems to be overestimated and assumptions on reservoir parameters appeared to be based on a press release/corporate report from just one new well. In 2014 PGI-NRI prepared a report on the tight gas potential in Poland (Wójcicki et al. 2014). In this report the Fore-Sudetic Monocline were included as a basin where unconventional gas occurs. The area where Lower Carboniferous sandstones and shales of sufficient maturity (gas window only) appear was delineated.

Dniepr-Donets basin
The main shale targets in Eastern Europe are marine-deposited black shales within the Carboniferous of the Dniepr-Donets Basin (TRR of 76 Tcf and 1.2 billion barrels, EIA 2013) (Fig. 12). Shale resource assessments are reported to be in progress in Ukraine, but no official assessments have been published yet.

The State Geological and Subsurface Survey of Ukraine (Derzhgeona dra) has announced shale gas resources in the country of total 7 trillion m$^3$ (Tm$^3$) or 247 Tcf. However, the basis for this estimate has not been released and the figure includes some tight gas resources. The newly created Geological Research and Production Center in Poltava plans to coordinate shale gas studies in Ukraine, while monitoring water quality in drilling areas.

On February 23, 2012, the Ukraine government announced a tender for shale exploration and development in the Oleska and Yuzivska blocks of western and eastern Ukraine, respectively. In January 2013, Ukraine awarded the first shale gas PSA, signing with Shell. Shell's 50-year PSA permit at Yuzivska in the eastern Dniepr-Donets Basin assigns oil and gas rights to all strata to a depth of 10 km, including tight and basin-centred gas. The contract allows for 70% investor recovery and a 16.5% government revenue share.

The Dniepr-Donets basin contains a thick sequence of Carboniferous black shale which may be prospective for oil and gas development. Economically important Carboniferous coal deposits and tight sands of the Moscovian overlie these shales, but this coaly sequence does not appear to be a prospective shale target.

The mapped prospective area for the dry shale gas window in southeastern Dniepr-Donets Basin is estimated to be 6,010 mi$^2$. Lower Carboniferous shale (comprising the Rudov Beds and portions of the overlying Upper Visean) has a highly favourable resource concentration of approximately 195 Bcf/mi$^2$. Risked, technically recoverable shale gas resources are estimated to be 59 Tcf, out of a risked shale gas in-place of 235 Tcf. The wet gas prospective area of the Dniepr-Donets Basin extends over about 2,680 mi$^2$. Risked, technically recoverable resources are estimated at 16 Tcf of shale gas and 0.5 billion barrels of condensate from in-place shale gas and shale oil resources of 63 Tcf and 10 billion barrels. The smaller oil window in the northwestern Dniepr-Donets Basin covers a prospective area of about 1,460 mi$^2$. Risked technically recoverable resources are estimated to be about 0.7 billion barrels of shale oil and condensate and 1 Tcf of associated shale gas, out of risked in-place shale oil resources of 13 billion barrels. Ukraine’s State Commission on Mineral Resources has estimated that the Yuzivska shale gas license in the eastern Dniepr-Donets Basin has 2-3 Tm$^3$ (71-107 Tcf) of shale gas and tight gas resources. Whether this estimate reflects in-place or recoverable resources was not specified.
Transylvanian basin

The Transylvanian Basin (Fig. 5) is the most important zone with gas accumulation in Romania. Also, this sedimentary basin is the main gas producer from southeast Europe (Popescu 1995). The gas pools are located in the Middle Miocene–Lower Pliocene (Paraschiv 1979; Popescu 1995). This stratigraphically level is named “Gas-bearing formation” that accumulated only the biogenic methane gases. In the Transylvanian basin the 99% of the gas is methane and it has the biogenic origin, is not reached a thermogenic stage. Until now up to 120 gas fields have been discovered in the Transylvanian basin, 13 of them were discovered before 1950.

Moesian Platform

The northern part of the Moesian Platform is within the Romanian sector while the southern part is within the Bulgarian sector. In the Romanian sector the Moesian Platform covers a surface of more than 43,000 km² and is bordered by the Carpathian Orogeny, Balkan and North Dobrogea orogenic systems. It also covers to the east the continental platform of the Black Sea (Fig. 14).

Moesian Platform is the one of the most important basins for hydrocarbons in Romania. This major sedimentary basin has all geological conditions for hydrocarbons generation, migration and accumulation. As concerning the stage of exploration, many authors considers the Moesian Platform a mature area, but there are still some zones with unsatisfactory petroleum knowledge e.g. Paraschiv (1979), Popescu (1995) and Pene et al. (2006). This sedimentary basin is characterized to the existence of the least three effective petroleum systems, two of them are thermogenic systems represented by the Palaeozoic and the Mesozoic systems and one is biogenic system (Neogene system) (Paraschiv 1979; Pene et al. 2006).

The conventional exploration debuted in the early 1950s. In 1956, the first borehole was drilled which encountered the first hydrocarbon accumulation. Presently, this number of discovery is increased and it is assumed that the number of oil and gas fields is about 145. According to Pene (1996) the initial reserves in 1996 discoveries were $235 \times 10^6$ t and ultimate resources were at least $237 \times 10^6$ t (Popescu 1995). Also, after the same author, the Moesian Platform yields about 40% of the hydrocarbon production of Romania.

Concerning the suitable areas for calculating the shale gas resources of the Silurian deposits in the Moesian Platform, there are 3 system plays in Moesian Platform: Călărași–South Dobrogea Play, Optași–Alexandria Play and Lom-Băilești Play (Fig. 16). Veliciu and Popescu (2012) have estimated the values (Table 3) of the resources for these 3 shale gas plays according to the assessment of methods issued by US Geological Survey (2010).

In the sedimentary successions of the Moesian Platform in Bulgaria, four intervals dominated by organic-rich dark shale have been identified, which would be of interest for shale gas. These are: Silurian – Lower Devonian (?) shales; Lower Carboniferous shales – Trigorska and Konarska Formations; Lower Jurassic shaly sediments – Ozirovo Formation (Bucorovo & Dolnilucovit Mbs); Middle Jurassic shales – Etropole Formation (Stefanets Mb). According to the completed study the shale gas potential of Bulgaria part of the Moesian Platform is moderate to poor. From the estimated 4 targets for shale gas only the Lower Carboniferous shales (in the pointed western zone) and both Jurassic shale intervals may present a moderate interest.

Dinarides-Lemeš basin

Previous studies of the area Lemeš deposits originated from early 1980’s when the Croatian oil company INA conducted studies of the petroleum and potential source
rocks from the area of “Lemeš facies” (Jacob et al. 1983. and unpublished data). On the basis of stratigraphy as well as petrographical and sedimentological features, Lemeš deposits are divided into 9 units that can be mapped over the entire area. The thickness of the Lemeš deposits ranges from 250–450 m. The Lemeš deposits Unit 4 is the most interesting unit with respect to source rock potential and investigations of source potential, organic geochemistry and palynofacies has been carried out by Blažeković Smojić et al. 2009.

Hungarian Paleogene basin
During the Early Oligocene (Early Kiscellian) anoxic black shale, named the Tard Clay, was formed in a thickness of 80-100 m in the southern belt of North Hungary. It is widely believed that the main source rock of the Hungarian Palaeogene Basin is the Tard Clay, with minor source potential locally in the overlying Kiscell Clay formations (Kókai & Pogácsás 1991; Milota et al. 1995). A detailed oil-source rock correlation is missing, therefore the level of certainty of the Tard-Kiscell petroleum system is only hypothetical (Badics and Vető 2012). There are 443 wells with well-top information in the area, of which 85 wells penetrated the Tard Clay (Kőrössy 2004), while the total area is around 7800 km². The main conventional fields are Demjén (70 million barrel oil in-place) and Mezőkeresztes (6.5million barrel oil in-place), both discovered in the 1950s (Fig. 19).

Mura-Zala basin
The most prospective geological area for shale gas and oil in Slovenia is the Mura-Zala Basin situated in the SW part of the Pannonian Basin System. Three prospective areas with oil and gas potentially generating strata are differentiated in the Mura-Zala Basin in Slovenia. Shale oil and gas in Slovenia is only occurring in marls, which are normally classified as unconventional hydrocarbon sources. However, tight oil and gas in sandstones are also treated in this study together with shale oil and gas as they occur together in alternating beds and would be possible to be exploited only with using stimulation techniques to enhance the recovery of hydrocarbons. Both lithology’s have low porosities, marls only about a few %, and sandstones about 10 %. Pre-Tertiary basement rocks were not investigated as source rocks in Slovenia. However, it is not excluded that the basement rocks – especially carbonates – do have some potential for oil and/or gas generation. Clarifying of this question remains for the future exploration.

In western Hungary, the Upper Triassic Kössen Marl has excellent source-rock potential. Fields producing Triassic oils in the Mura-Zala Basin include Bak, Barabásszeg, Nagylengyel, PusztAAPáti, and Szilvágy (Fig. 22). The extent of the Kössen Marl has been investigated in the wells drilled in the Zala Basin and in Transdanubian Range outcrops. There are 534 wells drilled in the area, which have well-top information. 230 wells were drilled into the Triassic, but only 32 wells penetrated the Kössen Marl.

Vienna basin
The main hydrocarbon source rock in the Vienna Basin and Korneuburg Basin (also referred to as the Thaya Basin) is the Mikulov Marl which is present in a strip extending northeast of Vienna to the southeast of the Czech Republic (Fig. 20). It is unknown whether the oil and gas companies operating in Austria have made any assessment of Austrian shale hydrocarbon resources since no public material is available.

Molasse basin
Conventional hydrocarbon exploration has been taking place in the Molasse basin within decades, primarily in Austria and Germany. Over 1200 exploration wells have
been drilled with around 200 conventional oil and gas discoveries. The source rocks in the Molasse basin are the Permo-Carboniferous Weiach-Formation, the Lower Jurassic Posidonia shale, and the Paleogene Fish Shale (BGR, 2016). A thorough shale oil and gas assessments for Germany is published in BGR, 2016. No public assessment for the Austria part of the Molasse basin is available.

**Lombardy basin**
Middle Jurassic dark carbonates and mudstones, Early Jurassic age (Toarcian) black shales and Cretaceous shales and marlstones are potential source rocks in the Lombardy Basin. No published shale gas/oil assessment for the Lombardy basin exists and no exploration for shale oil/gas has been performed.

**Ribolla basin**
The Ribolla basin (Fig. 26) assessment by Bencini et al. (2012) refers to “Fiume Bruna” and “Casoni” exploration licences and all information included in this reported is from this study. A Miocene age organic rich sequence consisting of one laterally continuous 9-11 meter thick seam of coal and black shale, saturated with thermogenic gas, able to produce excellent quality natural gas by desorption after stimulation. It has a permeability of 1-2 mD and responds more like gas shale than a classic high permeability coal. No published shale gas/oil assessment for the Ribolla basin exists and no exploration for shale oil/gas has been performed.

**Emma and Umbria-Marche basin**
Bituminous limestone, evaporitic and black shales of the Upper Triassic and Lower Jurassic (Emma Limestones and limestones inside the Burano formation) are considered the source rocks for many conventional oil reservoirs in the Emma basin. In general, the Umbria-Marche pelagic Mesozoic sequence (Jurassic-Cretaceous) shows a low hydrocarbon potential except for some portion where black shale and rich organic matter levels occur. No published shale gas/oil assessment for the Emma and Umbria-Marche basin exists and no exploration for shale oil/gas has been performed.

**Ragusa basin**
The Ragusa basin lies onshore and offshore in the south-eastern part of Sicily (Fig. 27). The Noto Formation (Rhaetian) is known as the main source rock for the oil fields in this basin (Pieri & Mattavelli 1986; Novelli et al. 1988; Brosse et al. 1988), but only very limited thickness of the shale layers are found. No published shale gas/oil assessment for the Ragusa basin exists and no exploration for shale oil/gas has been performed.

**Caltanissetta basin**
The Tripoli formation of early Messinian (upper Miocene) age is composed of a repetition of sedimentary triplets composed of homogeneous marls, laminated marls (sapropelic) and diatomites. The petroleum potential (oil and combustible gas) for fresh tripolitic rocks is estimated to about 51-88 billion barrels of oil equivalent for a 3,000 km² less tectonically disturbed part of the Caltanissetta basin. No published shale gas/oil assessment for the Caltanissetta basin exists and no exploration for shale oil/gas has been performed.

**Cantabrian Massif**
The Cantabrian Massif comprises materials varying in age from the Precambrian to the Carboniferous. The Cantabrian Massif extends over an approximate surface of 19 000 km². Two hydrocarbon wells were made in the area with an approximate equivalent of 0.1 wells for every 1,000 km². Presence of mine gas has been known since long ago (methane with ethane traces, etc.) in the coal mines especially in the Central
Carboniferous Basin. Also, the presence of mineral oils, distillates and condensates, parafin remains, ozoquerites, etc. is detected in the host rock as well as in the coal beds. All these hydrocarbon displays (solid, liquid and gas) prove that the carboniferous materials constitute a source rock. No published shale gas/oil assessment for the Cantabrian Massif exists and no exploration for shale oil/gas has been performed.

**Basque-Cantabrian basin**

The Basque-Cantabrian Basin is a Mesozoic-Cenozoic basin generated by two stages of subsidence (riifting): Triassic and Lower Cretaceous. The Basque-Cantabrian basin has since the beginning of oil exploration been considered the most interesting area in Spain because of the presence of abundant surface indications such as tar sands in the core of the Zamanzas anticline or asphalts present on the edge of most diapi rs. It occupies an area of approximately 21,000 km² with 202 exploration wells. No published shale gas/oil assessment for the Basque-Cantabrian Basin exists and no exploration for shale oil/gas has been performed.

**Pyrenees basin**

The South-Pyrenean basin is part of the Pyrenean range where Precambrian to Cenozoic materials outcrop. The South-Pyrenean domain encompasses the areas of the eastern, central and west Pyrenees, and has an area of about 20,000 km² in which 63 wells have been drilled. The reservoir consists of two thick calcareous mega-breccias of turbiditic origin forming two separate fields, the Middle and Upper Eocene. The gas source rock may be the dark hemipelagic clays with a low content of organic material, but with a thickness of over 300 m. Production began in 1984 and ended in 1989, when the field became an underground gas storage site. No published shale gas/oil assessment for the Pyrenees basin exists and no exploration for shale oil/gas has been performed.

**Duero basin**

With an approximate total area of 47,500 km², 16 boreholes have been drilled in the Cuenca del Duero-Almazan. No oil system has been found so far. ENDESA currently has drilled deep boreholes for CO₂ storage research in the area of Sahagún. No published shale gas/oil assessment for the Duero Basin exists and no exploration for shale oil/gas has been performed.

**Ebro basin**

The Ebro Basin occupies an area of about 39,700 km² and has a total of 41 drilled boreholes. In the 1980’s Campsa began drilling wells showing the existence of a gas system in Mesozoic formations below the Tertiary series. Studies in the area suggest the existence of Jurassic source rocks, and Jurassic reefs or oolitic bars type reservoirs. The last exploration well drilled in the area in 2010 and has led to the discovery of a new deposit in the area. No published shale gas/oil assessment for the Ebro basin exists and no exploration for shale oil/gas has been performed.

**Iberian chain basin**

It is possible to distinguish six sectors with different characteristics; two of them may have potential shale gas formations, the Cameros-Sierra de la Demanda Structural Unit and the Aragonian Branch. The Iberian Range has an area of about 65,000 km² in which 18 boreholes have been drilled. The explorations have not found effective petroleum systems in the area to date. No published shale gas/oil assessment for the Iberian chain basin exists and no exploration for shale oil/gas has been performed.
Catalonian basin
In the Catalonian Chain area 24 boreholes have been drilled. No proven petroleum systems are known. No published shale gas/oil assessment for the Catalonian basin exists and no exploration for shale oil/gas has been performed.

Guadalquivir basin
Guadalquivir basin covers an area of about 23,000 km², in which 90 wells have been drilled. Exploratory activity is concentrated in two clearly distinct periods. In the period 1945-1969 research period primarily conducted by Adaro, in which wells were drilled to increase the knowledge of the basin but there were no oil discoveries. From 1981-2004 initiated by the Chevron exploration company that interprets the Guadalquivir Basin as a landward continuation of the gas fields discovered in the Gulf of Cadiz. In this period 51 boreholes were drilled. Total production provided by the Guadalquivir fields (biogenic gas with 98% methane) to December 2004 amounted to 1,199,026 MNm³, of which nearly 90% comes from the Campos de Marismas (1,047 MNm³). The interest of this basin for potential shale gas reservoirs focuses on the Palaeozoic substrate. The degree of uncertainty is high, since the Palaeozoic has usually been the level of completion of exploration oil drilling and no petrophysical data are available. Three zones, where the Palaeozoic is covered by Miocene-Quaternary sedimentary series with a variable thickness up to approximately 3,500 m are considered.

Lusitanian basin
Portugal has a potential shale hydrocarbon resource, in particular in the Lower Jurassic of the Lusitanian Basin. The basin has undergone sporadic drilling episodes since 1906. In 1998-2001 four wells were drilled by Mohave Oil & Gas Corp. for conventional resources. In the period 2010-2014 Porto Energy undertook a drilling program where 23 drillings were made as part of an initial exploration of an unconventional gas at the onshore Lusitanian basin. This exploration identified a group of formations with potential for unconventional resources as shale gas and shale oil.

The interest was focused on two organic-rich marls, the Polvoreira Member of the Água de Madeiros Formation and the Vale das Fontes Formation. The 23 boreholes and reports were retained to GALP (Portugal’s oil and Natural Gas Company) and are not available for research for the next 5 years whereup there are relashed.

The main conclusions of these findings are discussed in McWhorter et al. (2014). Porosity (from shallow wells) ranges from 0.2 to 19.8% over a total thickness of up to 400 m (average 200 m). The Lower Jurassic is characterized throughout the basin by a TOC average range of 2.3 to 5.9%, Ro values of 0.5 to 1.8%, and quartz-carbonate content of 63.8 to 83.7%. Organic matter in the Lower Jurassic is dominantly kerogen type II in the prospective middle of the basin, with drilling depths of 1000 to 3500 m, where Tmax mapping also shows the thermal maturity necessary for oil and gas generation (greater than 450 degrees in the prospective areas). Additional information, such as oil and gas shows in old wells throughout the basin, oil seeps at the surface, and live oil in shallow Lias cores verify a viable resource interval. The Lusitanian basin’s Lias were compared in this study to other unconventional resource plays in North America (Eagle Ford, Niobrara, and Utica) as well as other Lias plays in Europe (McWhorter et al. 2014).

Aquitaine basin
The Aquitaine Basin has long exploration history for hydrocarbons and most of the gas resources are found in the southern sub-basins. Among the source rocks deposits are the Sainte-Suzanne shales. The Sainte-Suzanne Marl Formation (Early Cretaceous) is composed of homogenous marine, organic-rich shales with occurrence of bio-clastic
marly limestones. It can reach several hundreds of meters thickness, with a mean TOC at 1-2%. The OM is of type II origin, but the formation has only crossed the oil window in the southern parts of the basin (Serrano et al. 2006). The Sainte-Suzanne marls have been mostly considered as a main cover for petroleum and gas systems and have not been properly studied in an exploration perspective. The regional syntheses of the Aquitaine Basin are based on BRGM (1974) and Serrano et al. (2006).

**South East basin (France)**
The South-East basin is a poly-phased basin, and consequently the South-East Basin is highly complex, with numerous blocks and sub-basins together with thick (up to 11 km) but highly variable sedimentary succession. Because of its complexity the South-East Basin has much less been searched for hydrocarbons. The present day exploration focuses on the Provence, Alès, Causses and Languedoc sub-basins.

In the South-East Basin, several Stephanian and Permian basins are identified along Hercynian structures. Not much public data regarding thickness or TOC content is available from these scattered basins. The Schistes Cartons Formation (Lower Jurassic) deposits are thicker in the Southern part of the South-East Basin (south of Lyon) with thickness up to 500 m.

**Autun basin**
The Autun Basin is a low-elevation topographic depression located in the northern part of the Massif Central. It is a small elliptic basin filled with Carboniferous (Stephanian) to Permian, the so-called Autunian deposits, separated by an unconformity. The Autunian series are more than 1000 m thick. The lacustrine deposits are organic rich, with oil shales and bogheads. The various oil shales intervals were investigated and the potential estimated (Marteau et al. 1982). The petroleum potential ranges from 70 to 100 kg/t and is twice that of the Schistes Cartons. The total reserves estimated (max. 300 m depth) are ± 30 Mt.

**Paris basin**
The main source rocks of the Paris Basin are represented by the Carboniferous to Permian (Stephanian) coal deposits and associated coal bed methane, and the Lower Jurassic marine shales. The Lower Jurassic includes the Promicroceras Shale Formation (Sinemurian), the Amaltheus Shale Formation (Pliensbachian) and the Schistes Carton Formation (Toarcian).

The Late Carboniferous to Permian succession has been poorly studied and is rarely the target of exploration. Therefore, the issues of their extension, thickness, sedimentary filling, internal geometry and structural control still remain open.

The Lower Jurassic shales are black marine shales source rocks (Sinemurian - Pliensbachian) containing type II kerogen. The Promicroceras shale Formation source rocks consist of blue-grey illitic shales with TOC content ranging from 0.2-0.9 wt% (Bessereau & Guillocheau 1994). The Amaltheus Formation shale source rocks comprise grey, silty, and micaceous shales. TOC ranges from 2-4 wt% with a maximum HI value of 130 mg HC/g TOC (Bessereau & Guillocheau 1994).

The Schistes Carton Formation (Lower Jurassic) was deposited during the Toarcian across a large area encompassing several European basins. This is actually the most extended and most organic rich of the Jurassic black shales formations, with an average TOC around 4-5% (Espitalié 1987). It is to some extent comparable to the Bakken shales in the U.S. (Monticone et al. 2012). The OM is a type II kerogen (marine bacterial and algal) with a Hydrogen Index (HI) values ranging from 500 to
750 mg HC/g TOC (Delmas et al. 2002). The oil window of the Schistes Cartons has been traced from the compilation of T max values. The source rock in the Schistes Carton Formation is thought to have maturated in the deepest area, at depths of 2600-2700m, during Maastrichian times and ongoing (Espitalié et al.1987).

**Upper Rhine Graben basin**
The approximatelly 350 km long and 30 – 40 km wide Upper Rhine Graben has a Variscan basement (Late Paleozoic), a Mesozoic cover and a Cenozoic sedimentary fill at the top. The Source rocks are the Lower Jurassic Posidonia Shale and the Oligocene Fish Shale (BGR 2016).

**Northwest European Carboniferous basin**
The Northwest European Carboniferous basin includes the Campine, Mons and Liège basins in Belgium, the Pennine Basin in United Kingdom and Carboniferous shales in the Netherlands and Germany (Fig. 37). In Europe distribution of Carboniferous shales are found in a number of countries. In the Netherlands it is called the Geverik Member of the Epen Formation, this is the time-equivalent of the Upper Bowland Shale Formation in the United Kingdom (Andrews 2013), the Chockier Formation in Belgium (Nyhuis et al. 2014), and the Upper Alum Shale Formation in Germany (Kerschke 2013). In Germany the interval has been drilled for exploration but no production has as of yet occurred (Zijp 2015).

In the Netherlands no oil or gas deposits have been found that can be exclusively linked to the Epen Formation. The Epen Formation is expected to be present in the subsurface of almost all of the Netherlands, but has only been drilled in areas where it is present at a depth of 4-5 km (Zijp & Ter Heege 2014). Of the two licences which were given out in the Netherlands for unconventional resources the northern one (Noordoostpolder) was intended to target the Geverik shale. However, all activity was put on hold in 2010 while the Dutch Government commissioned two studies on the effects and risks of shale gas exploration.

In Belgium research in the Campine region was performed on the hydrocarbon potential of the coal deposits and their capability to produce coal bed methane. The surrounding organic-rich mudstones were largely ignored, but are currently studied in the frame of the increased interest in gas shales (Van de Wijngaerden et al. 2013, 2014, 2015).

The British Geological Survey (BGS) has assessed the shale gas resources of the Carboniferous Bowland–Hodder formation in 2013 (Andrews 2013). The organic content of the Bowland-Hodder shales is typically in the range 1-3%, but can reach 8% (Andrews 2013). Where they have been buried to sufficient depth for the organic material to generate gas, the Bowland-Hodder shales have the potential to form a shale gas resource analogous to the producing shale gas provinces of North America (e.g. Barnett Shale, Marcellus Shale). However, central Britain has experienced a complex tectonic history and the rocks here have been uplifted and partially eroded at least once since Carboniferous times. Large volume of gas has been identified in the shales beneath central Britain, but not enough is yet known to estimate a recovery factor, or to estimate potential reserves (how much gas may be ultimately produced). An estimate was made in the previous DECC-commissioned BGS report (2010) that the Carboniferous Upper Bowland Shale, if equivalent to the Barnett Shale of Texas, could potentially yield up to 4.7 tcf (133 bcm) of shale gas.

**Northwest European Jurassic basin**
The Northwest European Jurassic basin includes the Posidonia Shale Formation in the Netherlands, Germany and France and the Wealden basin in United Kingdom (Fig. 38).
The Posidonia Shale Formation can be classified as a grey to black shale of Early Jurassic (Toarcian age 182-180 Ma). Equivalent formations are deposited throughout Europe, for example the Jet Rock Member in the English Yorkshire Basin.

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. Of the two licences which were given out in the Netherlands for unconventional resources the southern one (Noord-Brabant) was targeted at the Posidonia Shale Formation. However, all activity was put on hold in 2010 while the Dutch Government commissioned two studies on the effects and risks of shale gas exploration.

The Lower Jurassic Posidonia Shale is present in the North German basin, Upper Rhine Graben and a large area in South Germany where the formation partly extends underneath the Molasse basin. The German Posidonia Shale has been described and assessed in BGR (2016).

In the United Kingdom the Weald Basin has a long history of oil and gas exploration; there are 13 producing sites in the basin, some almost 30 years old. The British Geological Survey has studied the Jurassic shales of the Weald Basin (see Andrews 2014). The Jurassic of the Weald Basin contains five organic-rich, marine shales. Where they have been buried to a sufficient depth for the organic material to generate oil, all five prospective shales are considered to have some potential to form a shale oil resource analogous, but on a smaller scale, to the producing shale oil provinces of North America (e.g. Barnett, Woodford and Tuscaloosa). There is unlikely to be any shale gas potential, but there could be shale oil resources in the range of 2.2-8.5 billion barrels of oil (290-1100 million tonnes) in the ground, reflecting uncertainty until further drilling is done.

North German basin
The North German basin is well known for its hydrocarbon resources mainly natural gas. BGR (2016) have identified and assessed several formations with shale gas/oil exploration potential in the North German basin. These are the Kohlenkalk Facies (Lower Carboniferous), the Hangender Alaun Shale (Kulm Facies) (Lower Carboniferous), the Mittelrhät Shale (Upper Triassic), the Posidonia Shale (Lower Jurassic), the Wealden shale (Lower Cretaceous) and the Blättertone (Lower Cretaceous). The shale in the North German basin has been described and assessed in BGR (2016).

Midland Valley Scotland basin
The Midland Valley of Scotland has a long history of oil and gas exploration. The British Geological Survey (BGS) has studied the Carboniferous shales of the Midland Valley of Scotland (See Monaghan 2014)(Fig. 39). The Midland Valley has a complex basin composition with interbedded Carboniferous sedimentary and volcanic rocks forming a succession up to locally over 5,500 m thick. Potentially prospective Carboniferous shales are buried beneath an area from Glasgow to Edinburgh, to the Lothians, Falkirk, Clackmannan and Fife (Monaghan 2014).

As a result of significant burial, uplift and erosion, Carboniferous shales are mature for oil generation at shallow current-day depths over much of the Midland Valley of Scotland study area, and gas-mature shales occur at current-day depths from about 700 m below Ordnance Datum. The current day oil- and gas-mature depths of Midland Valley shales are shallow compared to the UK Bowland-Hodder shales, Jurassic shales of the Weald and many commercial plays in the USA. Locally, maturation is enhanced
by igneous intrusion (Monaghan 2014). Geological and geochemical criteria that are widely used to define a successful shale oil and shale gas play can be met in the Midland Valley of Scotland.

The BGS study offers a range of total in-place oil resource estimates for the Carboniferous shale of the Midland Valley of Scotland of 3.2 - 6.0 - 11.2 billion bbl (421-793-1497 million tonnes) (Table 5). Total in-place gas resource estimates are 49.4 – 80.3 – 134.6 tcf (1.40 – 2.27 – 3.81 tcm). The West Lothian Oil-Shale unit makes the largest contribution to this estimated resource (Monaghan 2014).
Introduction

Various assessments of shale gas and shale oil resources for the European countries have been published over the last decade. The participation of the national geological survey (NGS) in these assessments varies considerably from no participation, to full involvement on all aspects of the assessment (See overview page 6). Furthermore, these assessments differ in methodology, fundamental assumptions, quality and quantity of the underlying geological information, but need to be comparable in order to make a reliable consistent pan-European shale gas and oil resource assessment. The first part of this report provides a country-per-country introductory overview of the current status on development of shale gas and shale oil in Europe. The overview is based on the questionnaires send to the NGS’ in June 2015 and returned to GEUS in the period up to December 15th 2015. The country-per-country overview has been updated with recent information until July 2016. The second half of the report is a Basin-per-basin and play-per-play overview based on basin/geology reports provided by the NGS during 2016 as part of the EUOGA project. In preparation of this report care has been taken to represent the information gathered from the NGS’ as correctly as possible.

The questionnaire distributed to the NGS’ has been completed by 25 European geological surveys or comparable national institutions. The first part of the questionnaire concerned an overview of the present situation and asked two main questions:

- State-of-the-art of shale gas and oil development including political and social status within the country
- Level of knowledge regarding gas and oil resources and performed assessments within each country

The second part concerned availability of information on the shale hydrocarbon formations.

First part of the report is focused on the level of activity, previous assessment and the political and social situation related to exploration and development of shale gas and oil country-per-country. An overview for each country is provided in the following sections and a simplified status for shale gas and oil resource assessment, activities related to shale gas and oil exploration and member states position towards shale gas and oil exploration are given at the end of the each country overviews. The categories used in the status do not entirely cover all situations for the countries, but aims to give a European outline of the situation in July 2016.

The categories used for the executive summary map figures are:

Shale gas and shale oil resource assessment

- No resources
- Potential resource present but it has not been assessed
- Assessed by 3rd party without involvement of NGS
- Assessed by NGS or by 3rd party with involvement of NGS

Activities related to shale gas and shale oil exploration

- Low level of activity: Permits have been issued or exploration wells have been drilled in the past.
- Medium level of activity: Permits have been granted and wells drilled. Future activates are expected.
▪ High level of activity: Permits have been granted and wells drilled. Future activities will occur.
▪ No activities

National position on shale gas and shale oil exploration and hydro fracturing
▪ Exploration and/or hydro fracturing permitted
▪ Unclarified position towards exploration and/or hydro fracturing
▪ No support or moratorium for exploration and/or hydro fracturing
▪ Exploration and/or hydro fracturing is prohibited
▪ No onshore resources

The second part of the report gives an overview of the European geological basins with potential shale gas and oil resources. A description basin-per-basin and play-per-play addressing exploration and production results and published assessments is the prime objective of this section.
Country overviews

Austria

In Austria there is no planned or current activity for shale hydrocarbon exploration and development, but scientific investigations is planned within 2016. The scientific investigations are expected to be finalised in 2017, but at this stage it is unclear when the result from these studies will be released to the public. The Austrian NGS expect that Austria has a potential shale hydrocarbon resource. It is unknown whether the oil and gas companies operating in Austria have made any assessment of Austrian shale hydrocarbon resources themselves since no public material is available.

An amendment from 2012 (BGBl I No 77/2012) to the Austrian Environmental Impact Assessment Act (Umweltverträglichkeitsprüfungsgesetz “UVP-G”), makes it obligatory for hydro fracturing projects to carry out an Environmental Impact Assessment (EIA), this requirement also includes shale hydrocarbon exploration and test drilling.

At present there is no national political support for exploration and development of shale hydrocarbons resources.

Status

- Resource assessment: Potential resource present, but it has not been assessed
- Activities related to exploration: No activities
- Member state position on exploration and/or hydro fracturing: No support

Belgium

Belgium’s interest in unconventional shale gas or shale oil reservoirs is relatively recent and slightly delayed compared to its neighbouring countries. This is partly explained by the lack of conventional hydrocarbon reservoirs, and subsequently much less sufficiently deep exploration cores and geophysical data that are available for resource assessment or research. There have been no explicit exploration efforts for shale gas, but relevant information is available from exploration and research into geothermal reservoirs, studies concerning geological storage of natural gas, and a coalbed methane test project.

Shale gas in Belgium has received public attention for a limited amount of time, mainly for its potential negative environmental effects. Even if these discussions were not scientifically based and highly premature with respect to the currently limited available geological information, several communities issued a ban on drilling and/or hydro fracturing. The topic currently does not receive any particular attention anymore.

A Flemish decree of 8 May 2009 (deep subsurface) states in Art. 26., apart from the moratorium decided by the Flemish government concerning hydraulic fracturing, that exploration and mining Hydrocarbons commissioned by the Flemish region for pure scientific purposes needs direct permits given by the Flemish Government. However, since the Flemish government voted for a moratorium on shale gas exploration and mining it is very unlikely to see them commission studies on shale gas.

Status

- Resource assessment: Potential resource present but it has not been assessed
- Activities related to exploration: No activity
Member state position on exploration and/or hydro fracturing: Prohibited/Unclarified

**Bulgaria**
Potential shale hydrocarbon resources have been identified and assessed in Bulgaria. Results from the assessments are partly public in various media. Bulgaria has a moratorium on shale hydrocarbon exploration since 2012.

*Status*
- Resource assessment: Assessed by 3rd party without involvement of NGS
- Activities related to exploration: No activities
- Member state position on exploration and/or hydro fracturing: Moratorium

**Croatia**
Assessment of shale hydrocarbon resources in Croatia has been performed only for the Dinaric Mountains and thus only partially for the country. The assessment is public available. The north-western Croatia is expected to have been assessed by oil companies, but no data are currently public available. The Croatian Geological Survey have only recently, after the adoption of a new Mining Law in 2014, started to collect data on oil and gas exploration in Croatia, and this data are not yet systematised and evaluated.

The new Mining Law and accompanying regulations does not recognised hydraulic fractoning. The official position of the Republic of Croatia presented to the Commission and the European Parliament is against hydraulic fracturing due to possible significant adverse impact on the nature and environment.

*Status*
- Resource assessment: Assessed by 3rd party without involvement of NGS, one basin assessed by NGS
- Activities related to exploration: No activities
- Member state position on exploration and/or hydro fracturing: Hydro fracturing prohibited

**Czech Republic**
Potential shale hydrocarbon resources are expected to be present in the Czech Republic. Only initial resources evaluation has been performed, but it has not been completed and no assessment is available for the EUOGA study. There is no official moratorium for exploration and/or hydro fracturing activities, but licences for shale hydrocarbon exploration set on hold or have been rejected them.

*Status*
- Resource assessment: Potential resource present but it has not been assessed
- Activities related to exploration: No activities
- Member state position on exploration and/or hydro fracturing: Unclarified

**Denmark**
Shale hydrocarbon resources have been assessed in a joint study by the Geological Survey of Denmark and Greenland (GEUS) and United States Geological Survey (USGS). This assessment is public available.
Shale gas exploration has been ongoing since 2010 and 3 licences has been awarded to different companies. In two licence areas the licence was retoured without any well being drilled. In one licence area one exploration well was drilled in 2015. The well did encounter the expected gas containing shales. According to the operator the well was not tested due to lower than expected gas content and thicknesses of the Lower Palaeozoic formations. In June 2016 this last shale gas exploration licence was returned to the Danish state. The Danish government has since 2012 issued a moratorium for new onshore exploration licences with the goal to exploit for shale resources onshore in Denmark.

**Status**
- Resource assessment: Assessed by NGS or by 3rd party with involvement of NGS
- Activities related to exploration: Low level of activity. Nu future activities are allowed with current legislation in place.
- Member state position on exploration and/or hydro fracturing: Moratorium on onshore exploration licences with the goal to exploit for shale resources onshore in Denmark.

**Estonia**

No thermogenic shale hydrocarbon resources are present in Estonia due to the immature nature of the organic rich shales. Biogenic shale gas might theoretically be present but no indications suggest a viable resource and thus no assessment has been made. In Estonia oil shale is explored and mined. This resource has been assessed. At the moment hydraulic fracturing is banned in Estonia.

**Status**
- Resource assessment: No resources
- Activities related to exploration: No activities
- Member state position on exploration and/or hydro fracturing: No resources

**Finland**

No shale hydrocarbon resources are present onshore Finland due to the geological nature on the country.

**Status**
- Resource assessment: No resources
- Activities related to exploration: No activities
- Member state position on exploration and/or hydro fracturing: No resources

**France**

It is expected that France has potential shale hydrocarbon resources. Since 2011 and by the law No. 2011-835 of July, the 13th, the use of hydro-fracturing methods are prohibited for hydrocarbons exploration and production, and therefore there are no activity in progress or planned for the exploration or production of shale hydrocarbons in France. There is opposition from civil society and politicians against shale hydrocarbon exploration and development, but recently also some questions from the society calling for an independent resource assessment in order to have an objective view of the reality. No assessment has been performed and no publication on the subject is known.
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Status
- Resource assessment: Potential resource present but it has not been assessed
- Activities related to exploration: No activities
- Member state position on exploration and/or hydro fracturing: Hydro fracturing prohibited

Germany
For Germany - not being a member of the EUOGA project consortium - the information given is based on consultation of the NGS.

In Germany there is no production of shale gas and oil, and incipient exploration activities on shale gas and oil have ceased.

With respect to environmental issues of hydraulic stimulation amendments to several federal laws and directives (e.g. Federal Mining act, Federal Water act) have passed the German houses of parliament on 8th July 2016. Several of these amendments have already entered into force. In particular, new regulations in the Federal Water Act prohibit hydraulic stimulation in shale formations and CBM for exploration and exploitation of natural gas and oil. For research purposes on environmental issues of hydraulic stimulation a limited number (max 4) of pilot or demonstration projects are possible provided approval of the federal state governments. In 2021 parliament will re-evaluate the ban, taking into account the results of the demonstration projects. Further regulations among others implement mandatory environmental impact assessments (EIA), restrictions on chemicals used in frac-fluids and ban of fracking in sensitive areas. The amendments of the Federal Water Act in Germany enter into force on 11th February 2017 (For details, see „Gesetz zur Änderung wasser- und naturschutzrechtlicher Vorschriften zur Untersagung und zur Risikominimierung bei den Verfahren der Fracking-Technologie“ in Bundesgesetzblatt Jahrgang 2016 Teil I Nr. 40, ausgegeben zu Bonn am 11. August 2016).

Status
- Resource assessment: Potential resources present and assessed by NGS
- Activities related to exploration: Low activities
- Legal situation- on exploration and/or hydro fracturing/: Hydraulic stimulation in shale formations prohibited; only limited number of pilot projects for environmental research possible; re-evaluation of ban by parliament in 2021

Hungary
The exploration for shale hydrocarbon resources started in Hungary in 2005. Almost 40 wells have been drilled for unconventional hydrocarbons on 10 licensed areas (mining plots) of which 8 wells were tested by fracking and presently one well is producing. The targets were mainly tight gas reservoirs. In some areas the reservoirs built up from marls or intercalated shale/sandstone layers with shale/tight gases.

Oil and gas companies working in Hungary have made assessments of shale gas and oil resources but these are not public. The Geological and Geophysical Institute of Hungary has initiated a work to assess the Hungarian sedimentary basins and the results are not public at present.

As Hungary is dedicated to maximize the exploration and production of unconventional hydrocarbons - while ensuring that the public health, climate and environment are safeguarded, resources are used efficiently, and the public is informed – the Hungarian Government takes into account the Commission Recommendation of 22
January 2014 on minimum principles for the exploration and production of hydrocarbons (such as shale gas) using high-volume hydraulic fracturing (2014/70/EU). The EU questionnaire on this regard was completed by the competent Hungarian authorities and is available at: https://ec.europa.eu/eusurvey/files/6e5f63d7-9191-4ef6-a3d9-06bb5c10700c/.

Hydro fracturing is permitted in Hungary, but the environmental authorities currently do not issue permissions for performing hydraulic fracturing. A new regulation is under preparation.

**Status**
- Resource assessment: Assessed by 3rd party without involvement of NGS
- Activities related to exploration: Medium level activity
- Member state position on exploration and/or hydro fracturing: Unclarified

**Ireland**

It is expected that Ireland has shale hydrocarbon resources, but at present there is no shale gas or unconventional gas exploration operation underway. In 2011 an onshore petroleum licensing round was carried out. Options were offered to three companies. The licensing options awarded were preliminary authorisations and were designed to allow the companies to assess the shale gas potential of the acreage largely based on desktop studies of existing data. Exploration drilling, including drilling that would involve hydraulic fracturing, was not allowed under these Licensing Options. Two of the three companies, which had been granted on-shore licensing options in February 2011, have submitted applications for a follow-on exploration licence.

In response to public concern, a large-scale study into the potential environmental and human health impacts of hydraulic fracturing was commissioned, the 24-month Unconventional Gas Exploration and Extraction (UGEE) Joint Research Programme. Both the Minister and Minister of State have repeatedly stated that no decision will be made on any proposal for the use of hydraulic fracturing in exploration drilling as part of an unconventional gas exploration programme, until there has been time to consider the outcome of the research programme directed at examining the potential environmental and human health impacts of hydraulic fracturing. The project began in August 2014 and is scheduled to be completed in July 2016 and the final report will be made publically available. It is not proposed to consider applications for exploration authorisations in respect of other onshore areas until the 24-month Research Programme has concluded.

**Status**
- Resource assessment: Potential resource present but it has not been assessed
- Activities related to exploration: No activity
- Member state position on exploration and/or hydro fracturing: No support and/or moratorium

**Italy**

In Italy no activity regarding exploration and development of a shale hydrocarbon resource has been made or is planned. Based on the general geological knowledge of Italy it is, however, expected that Italy have potential shale hydrocarbon resources, but no assessment studies have been performed.
According to the national law DECRETO-LEGGE 12 settembre 2014, n. 133 art. 38, in order to prevent groundwater pollution and for a precautionary principle related to the seismic risk, the research and production of shale gas and shale oil are forbidden, with special attention to all the activities that use hydraulic fracturing techniques.

Status
- Resource assessment: Potential resource present but it has not been assessed
- Activities related to exploration: No activities
- Member state position on exploration and/or hydro fracturing: Prohibited

Latvia

No activity regarding exploration and development of shale hydrocarbon resources is ongoing or planned. Based on general petroleum geology studies of the organic rich shale formations, carried out in the 1990-ties by the Geological Survey of Latvia and SINTEF Petroleum Research, Latvia might have a minor shale hydrocarbon resource. The organic rich shale formations are generally at depths between 1500-1700 meters. At present the political and social status on shale hydrocarbon exploration and development are unknown.

Status
- Resource assessment: Assessed by NGS or by 3rd party with involvement of NGS
- Activities related to exploration: No activities
- Member state position on exploration and/or hydro fracturing: No resources

Lithuania

Pilot scale shale hydrocarbon prospecting projects in western Lithuania started in 2011 and were carried out by two oil companies between 2011-2013. Two new prospecting wells were drilled through the Lower Silurian and the Upper Ordovician formations, perforation test and hydraulic fracturing test were made in vertical sections of the conventional oil wells. Lithuanian Geological Survey (LGS) has assessed prospective shale formations and assessed shale oil and gas resources in-place, during the project “Studies of the structure of the shaley Lower Palaeozoic succession in the Lithuania” which was carried out between 2011 and 2014 and the major results were presented in a final project report (Lazauskiene et al. 2014).

“State Commission of the Members of Lithuanian Academy of Sciences for Impact of Shale gas exploration and production on environment and human health” evaluated recoverable and in-place shale oil and gas resources (Grigelis ed. 2014).

No licenses have yet been granted specifically for unconventional hydrocarbons in Lithuania. However, 6 companies hold active licences with the rights for prospecting, exploration and production for both conventional and unconventional hydrocarbons. Strategic EIA has been completed for Šilutė-Tauragė block (comprising one of the most prospective areas regarding unconventional hydrocarbon accumulations) in 2011, the tender conditions are prepared and the block is ready to be offered for the licensing tender.

The government of Lithuania has been actively adapting a more attractive legislation and the recent changes have improved the legal basis for shale oil and gas exploration and production. An active publicity outreach campaign regarding shale gas and oil exploration and production issues, oriented towards media and the general public (especially the local communities) was carried out in 2013-2015.
Implementation of major principles regarding the Recommendation of 22nd January 2014 of the European Commission on the minimum principles for the exploration and production of hydrocarbons using hydro fracturing has been adopted and is ongoing.

**Status**
- Resource assessment: Assessed by NGS or by 3rd party with involvement of NGS
- Activities related to exploration: Medium level of activities
- Member state position on exploration and/or hydro fracturing: Exploration and hydro fracturing permitted

**Malta**
No shale hydrocarbon resources are present onshore Malta due to the geological nature on the country.

**Status**
- Resource assessment: No resources
- Activities related to exploration: No activities
- Member state position on exploration and/or hydro fracturing: No resources

**Netherlands**
In the Netherlands assessments of potential shale hydrocarbon resources have been performed by the national geological survey (TNO). The assessments are public available in various publications. Two exploration licences were granted for unconventional hydrocarbons before 2016 but were not prolonged. All licenses for commercial activities with respect to unconventional hydrocarbons area currently on hold until 2020 following decisions of the ministry.

Shale hydrocarbon exploration has been on hold since 2010 in order to perform research on the effects and risks of shale gas exploitation, and pending new developments regarding a social license to operate. The moratorium status has been extended a number of times, latest by a decision in 10 July 2015, extending the moratorium for 5 years without commercial drilling activities for shale gas.

**Status**
- Resource assessment: Assessed by NGS and by 3rd party with involvement of NGS
- Activities related to exploration: Low level of activity, originally two licences granted and another three requested. Currently all on hold.
- Member state position on exploration and/or hydro fracturing: Moratorium on commercial shale gas activities extended for 5 years without drilling activities.

**Norway**
No shale hydrocarbon resources are present onshore Norway due to the geological nature on the country. The country has previously been assessed by international agenesis that indicated a potential high resource (i.e. EIA 2011). These assessments have been made based on incorrect data.

**Status**
- Resource assessment: No resources
- Activities related to exploration: No activities
- Member state position on exploration and/or hydro fracturing: No resources
Poland
At present there are 31 active concessions granted to 9 Polish and foreign entities that belong to 9 capital groups. As much as 85 shale gas exploration concessions have been relinquished since 2012. By the 30th of June 2016 concession holders (operators of exploration concessions for unconventional and joint unconventional and conventional hydrocarbons) have drilled a total of 67 exploratory wells for unconventional hydrocarbon reservoirs and 5 for conventional reservoirs, including 18 directional/horizontal and 54 vertical wells. Hydraulic fracturing has been performed in 27 vertical and directional/horizontal wells, DFIT (Diagnostic Fracture Injection Test) were performed in 9 vertical wells. According to the Ministry of Environment (the concession authority), test results from a few wells suggested a future production of level of only 10% to 30% of the gas needed to be commercially sustainable.

A new geological and mining law is focusing on exploration and production of hydrocarbons, including unconventional hydrocarbons, and a law on hydrocarbon tax were adopted in July 2014. The government is preparing a special hydrocarbon law that intend to make the concession procedures faster.

Status
- Resource assessment: Assessed by NGS or by 3rd party with involvement of NGS
- Activities related to exploration: High level of activities
- Member state position on exploration and/or hydro fracturing: Exploration and hydro fracturing permitted

Portugal
Portugal has a potential shale hydrocarbon resource, but no assessment have been performed. It should be noted that for the current year no hydrocarbon exploration and/or production activities involving unconventional methods (ex., hydraulic fracturing) are predicted, there should be emphasized that are no companies with concession contracts for the Unconventional Resources in the Lusitanian basin (data from ENMC). ENMC consists in the Portuguese organism that is responsible for the regulation, supervision, control and fiscalisation of the petroleum resources exploration and production activities, assuring the efficient management and the sustainable use of these resources.

In case of such be eventually required by any of the concessionaries, the project will be subject to an Environmental Impact Assessment process, prior to the licensing of the operation, regulated by Decree-Law n.º 151-B/2013, of 31 of October with the amendments made by Decree-Law n.º 47/2014, of 24 March and by Decree-Law n.º 179/2015, of 27 August, and according to the Commission Recommendation. Presently there are 3 concession contracts for conventional resources (Oil and gas) at the Lusitanian Basin, (ENMC data). The concession contracts of "Batalha" and "Pombal" areas were signed, on 2015/09/30, with the company Australis Oil & Gas Portugal. Australis Oil & Gas Ltd. applied for the granting of three concessions through Direct Negotiation.

A working group of state organizations, including LNEG, was established in order to prepare a document on recommended practices to be followed during shale gas exploration/exploitation activities, in accordance with the EUROPEAN COMMISSION RECOMMENDATION of 22.1.2014 on minimum principles for the exploration and
production of unconventional hydrocarbons (such as shale gas) using high volume hydraulic fracturing. In this report the following information’s were reported:

- Total number of boreholes completed and planned projects involving high-volume hydraulic fracturing: None.
- Number of petroleum concessions: 4 onshore concession contracts for petroleum prospecting, exploration, development and production, denominated "Batalha" and "Pombal" (Australis Oil & Gas Portugal) and "Aljezur" and "Tavira" (Portfuel - Petróleos e Gás de Portugal Lda.).
- Baseline study produced under points 6.1 and 6.2 and the monitoring results produced under points 11.1, 11.2 and 11.3(b) to (e): None.

**Status**

- Resource assessment: Potential resource present but it has not been assessed
- Activities related to exploration: No activities
- Member state position on exploration and/or hydro fracturing: Unclarified position

**Romania**

Two licences for shale hydrocarbons exploration in two perimeters – Dobrogea block (Eastern part of the Moesian Platform - 2D and 3D seismic lines recorded) and Barlad block (Scythian Platform – a part of Central European Platform - 2D, 3D seismic lines recorded plus one drilled boreholes) has been granted to an oil company (Chevron company) and another two licence (Prospecting permit in the Eastern part of Moesia – Coltoi eel al, 2016) and NW part of Moldavian Platform) were granted to another oil company (Total France) for research and assessment with the national geological survey (Geological Institute of Romania) as partner.

Presently there are no activities concerning the assessment of the shale hydrocarbon resources. In parallel, in Romania is acting the organisation named Romanian National Committee for the World Energy Council (RNC - WEC). Geological Institute of Romania has no participated in this consortium. This organisation made an inventory concerning the shale gas and the potential of the fuels energy. According to their draft report … “One of the findings is that the assessment of the potential of the country for the discovery of new fossil fuel resources to replace the natural gas reserves, which will soon be depleted, is the necessity and the obligation that the current generation has, at the moment, to provide energy for future generations”... This RNC-WEC created a regional centre for unconventional gases called the European Centre for Excellence in the field of Natural Gas from gas-bearing clays – CENTGAS. In 2014 CENTGAS issued a report named Natural Gas Resources From Unconventional Fields – Potential and Recovery (http://www.cnr-cme.ro/pdf/CENTGAS%20-Summary.pdf).

Hydro fracturing has not been used in Romania, but the authorities are working on improving the legislation concerning exploration and development of unconventional hydrocarbon resources.

**Status**

- Resource assessment: Assessed by NGS or by 3rd party with involvement of NGS
- Activities related to exploration: Medium level of activities
- Member state position on exploration and/or hydro fracturing: Exploration and hydro fracturing permitted
Slovenia

Tight gas and negligible oil amounts occurs in numerous sandy strata at great depth in Slovenia. In that sense no true unconventional shale gas is likely to occur in Slovenia. In the case of exploitation of the tight gas resource it will need to be produced by use of hydro fracturing. Two wells were drilled in 2011 and 5 hydro fracturing have been carried out in depths of more than 3 km. Further exploration and development of the project awaits the final permission from the Ministry of Environment. The delay is partly caused by an expressed negative public opinion towards hydro fracturing in Slovenia. The national geological survey has not been involved in the assessment of the UH resource, but is informed about the assessment.

Shale gas and oil exploration is not banned by law. It is permitted (legal) under regulations of Mining Act and supervision by the Head mining inspector. Mining projects (always reviewed according to the Mining Act) are necessary for all exploration and exploitation activities, and are supervised by the State Public Mining Service (under State Ministry departments responsible for Mining).

Hydro fracturing is not banned, because only low volume hydraulic stimulation was used, and is also planned for the future. For this reason, hydraulic fracturing was mostly not defined in the technical mining projects so far. It is therefore recommended in Slovenia that hydraulic stimulation processes should be defined in the technical mining projects in more detail than previously. Due to very high traditional culture of mining activities in Slovenia there is no fear that such a level of the mining culture would not continue in the future as well.

Status

- Resource assessment: Assessed by 3rd party without involvement of NGS
- Activities related to exploration: Low level activities
- Member state position on exploration and/or hydro fracturing: Permitted

Spain

Shale hydrocarbon exploration is still in the early stages in Spain. In the last few years’ exploration permit applications have increased. At present, 23 exploitation concessions and 55 hydrocarbon exploration permits are active in Spain and about the same number are awaiting approval to initiate their work. At this stage, exploration permits do not have to declare if it is expected to use unconventional techniques in case of future exploitation; this will only be publicly known when the first wells are drilled. Exploration activities are mostly carried out by private companies. Studies and evaluations carried out by private companies in their exploration permits are not available.

Previous exploration activities regarding unconventional resources (at state level), were developed by the Spanish Geological Survey (IGME) during the decade of the 80’s, in order to establish a national inventory of bituminous shales. More recently a study of the potential shale gas resources in Spain has been carried out by the Spanish Geological Survey (IGME), presently being in the first stage of a project that will cover all the country in the coming years. At present, there are two preliminary public reports on shale hydrocarbon resources assessment in Spain (ACIEP 2013; Superior Council of Mining Engineers 2013).

There is a large social opposition towards unconventional hydrocarbon exploration and production, especially against hydraulic fracturing in Spain. Several regional governments have issued laws against hydraulic fracturing in their territories, aiming
to forbid these activities. In some cases, the Constitutional Court has overruled these regional laws because the energy sector is a matter for the National Government only.

National legislation has been modified aiming to get adapted to new technologies regarding exploitation of unconventional hydrocarbons. The new Environmental Evaluation Law implies that any exploration or production project regarding the use of hydro fracturing need to go under Environmental Impact Assessment and the Hydrocarbon Law has been modified with new measures, trying to promote hydrocarbon exploration in the country.

**Status**
- Resource assessment: Partly assessed by NGS or by 3rd party with involvement of NGS
- Activities related to exploration: Medium level of activity
- Member state position on exploration and/or hydro fracturing: Exploration and/or hydro fracturing permitted

**Sweden**
Sweden possibly has a shale hydrocarbon resource, but there are no ongoing or planned activities regarding thermogenic traditional shale hydrocarbons involving hydro fracturing in Sweden. There is although activities related to exploration of shallow biogenic gas in parts of the country. No assessment explicitly on the hydrocarbon resources has been performed by the national geological survey (SGU).

**Status**
- Resource assessment: Assessed by 3rd party without involvement of NGS
- Activities related to exploration: No activities
- Member state position on exploration and/or hydro fracturing: No resources

**Ukraine**
In Ukraine, the geological reserves of shale hydrocarbon resources are explored. Research and exploration are conducted for gas and oil production from shales. Assessments have been performed for several areas in Ukraine, involving both the national geological survey and 3rd parties.

**Status**
- Resource assessment: Assessed by NGS or by 3rd party with involvement of NGS
- Activities related to exploration: High level of activities
- Member state position on exploration and/or hydro fracturing: Exploration and/or hydro fracturing permitted

**United Kingdom**
Moratorium in place in Scotland from January 2015, pending due to assessment of environmental impacts and a moratorium in place in Wales from February 2015. No active licenses in Northern Ireland. Multiple licenses in place in England, limited amount of drilling and/or seismic acquisition presently. Eight wells have been drilled. Tax incentives and simpler planning process implemented by Government. Community benefit fund set up. Up to $750M pledged for exploration.
Detailed regional assessments made for three principal regions/geological units: Mid-Carboniferous Bowland-Hodder unit, northern England; Mid-Carboniferous shales, Midland Valley, Scotland; Jurassic shales, Weald (South-east England). Also, countrywide assessments of shales completed (separate studies for Scotland, Wales, and United Kingdom as a whole) https://www.bgs.ac.uk/shalegas/.

**Status**
- UH resource assessment: Assessed by NGS or by 3rd party with involvement of NGS
- Activities related to exploration: High level of activities in England, no activity in Scotland, Wales and Northern Ireland
- Member state position on exploration and/or hydro fracturing: Exploration and/or hydro fracturing permitted in England. Moratorium place in Wales and Scotland.
Basin and play overview

This section provides a summary of the basins that host shale gas and oil and of the shale oil and gas plays itself with emphasis on exploration and production results and available published assessments. The basins included are presented in Figure 5. This report is not focused on the geological development of the basins; this will be included in report T4 Geological resource analysis of shale gas and shale oil in Europe. Characteristics of the individual shales are presented in the T6 report Overview of shale layers characteristics in Europe relevant for assessment of unconventional resources.

Two major geological periods are dominated by bituminous shale deposits, the carboniferous (359-299 Ma) and the Jurassic (201-145 Ma). Shales deposited in these periods are found in several European basins in particular in Northwest Europe. The Carboniferous and Jurassic shales are therefore grouped and described in two sections named the Northwest European Carboniferous and the Northwest European Jurassic. Some shales as e.g. the Lower Jurassic Posidonia Shale occurs in several basins, and will be referred to in both the period section and in the basin section.
Fig. 5. Overview of the basin areas reported to have a potential shale gas and shale oil resource by the National Geological Surveys. Note that not all basin areas on this map can be assessed due to lack of sufficient information.
Norwegian-Danish-South Sweden basin

The geology of the Norwegian-Danish and South Sweden (Scania) basin (Fig. 6) is very similar with respect to organic rich lower Palaeozoic shales. In Denmark and Sweden Lower Palaeozoic is present onshore in relative tectonically un-disturbed areas whereas in Norway Lower Palaeozoic shales is present locally and in very tectonic disturbed areas. Therefore shales gas and oil in Norway onshore is not relevant despite previous assessment (i.e. EIA 2011, 2013). These assessments were made based on misinterpreted map data.

The unconventional gas resources in the Lower Palaeozoic shale of Denmark were recently assessed by the United States Geological Survey (USGS) (Gautier et al. 2013). Assuming unrestricted application of best practice current technology, recoverable gas resources of 0 to 130 × 10⁹ Nm³ gas were estimated onshore (mean = 67 × 10⁹ Nm³ gas) and 0 to 228 × 10⁹ Nm³ gas were estimated offshore (mean = 119 × 10⁹ Nm³ gas), i.e. a total estimated mean of 186 × 10⁹ Nm³ gas (Nm³: normal cubic metre, unit used for natural gas at 0°C and 101.325 kPa). Nearly all of this potential resource is assumed to be contained in the Cambro-Ordovician Alum Shale. The wide range of estimates reflects the sparse data and the geological uncertainty inherent in the still untested play. The assessment is the result of collaboration between The Geological Survey of Denmark and Greenland (GEUS) and USGS.

The first shale gas exploration borehole in Denmark, the Vendsyssel-1 was drilled in northern Jylland in 2015 by the company Total E&P (Fig. 7). Since 2009, GEUS has conducted a wide range of shale gas evaluation programmes including screening of
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onshore Denmark for potential shale gas units. The evaluation is partly based on extensive shallow coring on Bornholm where the shale is accessible immediately beneath a thin Quaternary cover (Schovsbo et al. 2011). The main target for exploration in Denmark is the Alum Shale Formation, which is up to 180 m thick and unusually rich in organic matter, typically with 5–10% total organic carbon (TOC; Schovsbo et al. 2011). Organic-rich shales also occur in younger Ordovician–Silurian successions. These black shales are thinner and less TOC-rich than the Alum Shale, but may still be interesting for shale gas exploration.

Fig. 7. Map showing simplified distribution of Lower Palaeozoic strata in Denmark and the location of scientific and exploration boreholes used for the geological assessment. The position of the dedicated shale gas exploration wells in Sweden (B2, A3, C4) and in Denmark (Vendsyssel-1) is highlighted. In all boreholes made so far in Denmark and Southernmost Sweden, the Alum Shale is mature to gas rank and positioned beneath a Palaeozoic sequence less than 1 km thick; at these sites the shale did not contain significant amounts of gas. The distribution of Lower Palaeozoic strata is from Nielsen & Schovsbo (2011).

The USGS assessment methodology assumes unrestricted application of best practice current technology, which in the present case is expected to be horizontal drilling with multistage hydro fracturing. In Denmark the Ordovician–Silurian shale overlying the Alum Shale may constitute a rather thick (c. 300 m) additional interval in which other development strategies may be relevant. This inference is based on the Terne-1 borehole where a 250 m thick shale interval with TOC values of 1–3% overlies the Alum Shale. These stratigraphic intervals are the targets for exploration in Poland, Lithuania and other countries in the eastern sector of the basin and may constitute an important additional reservoir in Denmark. In addition, a tight gas play in Upper Silurian or Lower Permian sections may also be present in the subsurface of Denmark and might add to the unconventional resource estimate.

Shale gas exploration in Denmark is in its early stages. This is reflected in the large range of the estimate. It is thus crucial to obtain information from new boreholes, notably from sweet-spot areas, in order to calibrate and constrain the resource estimation model. The impact on the resource estimate from other development strategies or from additional play intervals and plays is not taken into consideration in the gas resource estimate by Gautier et al. (2013). Whether this is relevant awaits the evaluation of the first Danish exploration borehole to be drilled in the Lower Palaeozoic in northern Jylland.
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Exploration undertaken by Shell in South Sweden (Scania) indicates that the Alum Shale Formation, which is located at 700–800 m depth, does not contain gas in economically producible quantities and that gas leakage from the shale has increased the risk for a viable gas play (Pool et al. 2012).

Immature Alum Shale is present in South Central Sweden on the Fennoscandian shield (Fig. 6). The area here was newer deeply buried but experience locally maturation from intrusive Permian-carboniferous. Here biogenic shale gas is present due to local conditions (Erlström 2014; Schultz et al. 2015). The exploration is made by local farmers in the past, but also now by small independent companies. The depths are less than 300 m and no hydraulic fracturing is applied or its extraction. The level of activities and the expected amount of gas present has not merited it for further analysis within the EUOGA context.

**Baltic basin**

The Baltic basin comprises areas around the Baltic Sea in Denmark, Sweden, Poland, Latvia, Lithuania, but also include the Podlasis–Lublin basin in Poland and Lviv-Volyn basin in Ukraine (Fig. 8).

The Lower Paleozoic basin at the western slope of the East European Craton (EEC) has been recognized as one of the most interesting areas for shale gas (and oil) exploration in Europe. The marine-deposited Upper Ordovician and/or Lower Silurian graptolitic shale is here the major potential reservoir formation (Poprawa 2010).
Moreover, the Upper Cambrian to Tremadocian Alum shale is an additional target locally in the northern part of the Baltic basin (mainly offshore, a small part onshore). Organic matter of the Lower Paleozoic shales is characterized by presence of II type of kerogen (Poprawa 2010).

**Latvia**

In both offshore and onshore area of Latvia explorations of hydrocarbon resources go back in history. Deep wells have been drilled also for other purposes, for example – hydrogeological exploration wells, stratigraphic wells for geological mapping etc. However, unconventional shale oil/gas exploration in Latvia has never been carried out. Data that allows determining potential shale oil/gas formations are gained from core description and well logging. Available data can be characterized as sparse, incomplete and contradictory.

There has been no commercial conventional oil discoveries made onshore in Latvia up to present. Exploration was temporarily abandoned in 1971, and renewed exploration programs continued from 1986 however, on a much smaller scale. Prior to the restoration of Latvian’s independence in 1991, all the onshore operations of hydrocarbon exploration were performed by the Ministry of Geology of USSR/Latvian Geological Directorate (later the State Enterprise “Latvijas Ģeoloģija”) (Kanev & Lauritzen 1997). There are no published assessments about shale oil/gas in Latvia and no political/social issues affecting shale oil/gas in Latvia.

Four potential shale oil/gas formations are determined in Latvia, but only the Zebrus Formation (Lower Ordovician) correspond to some of the EUOGA screening criteria as the formation lays is deeper than 1.5 km and more than 20 m thick (thickness – gross, m). The formation is, however, immature and no thermogenic resource is expected.

**Lithuania**

Potential source rocks and hydrocarbon occurrences in the Baltic Basin have been the subject of geological and geochemical research since the early 1990s. The major shale oil and gas potential in Lithuania is related to the two major complexes of the organic-rich source rocks distributed in Western Lithuania, the Upper Ordovician Complex and the Lower Silurian Middle-Upper Llandovery Complex.

*Upper Ordovician Complex of Middle-Late Caradoc-Ashgill (Katian) age* that comprises dark grey and black shales of respectively Mossen Formation (Oandu Regional Stage) and Fjäcka Formation (Vormsi Regional Stage) and are separated by carbonates of 4-16 (~10) m of Rakvere-Nabala Regional Stages. Both Fjäcka and Mossen Formations are generally thin, their total thickness varies in a range from 9 to 20 m. TOC content is mostly in the 0.9 to 10 % range, with occasional higher values of up to 15 %. Oil and gas generation potential has an average of 22 kg HC/trock, rarely reaching 55–70 kg HC/trock. Hydrogen Index reaches up to 521 mg HC/g TOC, Tmax is ca. 424oC. The source rock facies are kerogen type II, reflecting marine conditions.

*Lower Silurian Middle-Upper Llandovery Complex (Aeronian and Telychian Stages; Raikküla-Adavere Regional Stages)*

The unit rests on the tight carbonates of the lowermost Silurian (Lower Llandovery, Rhuddanian Stage) of 2-40 (~ 12 m) of thickness. The shale complex is composed of dark grey and black graptolite shales and dark grey and black clayey marlstones. The Lower Silurian shales overlie thin carbonates of the lowermost Silurian. The depth of the top of the Silurian shales varies from 1170 to 2085 m in the Lithuanian part of the basin, however, only the shales lying below 1500 m were considered further. The
thickness of the shales varies from 15 to 80 m. The organic matter is of ‘oil-producing’ sapropel type II of marine origin and mixed ‘oil-gas producing’ type II/III. The amount of the total organic carbon (TOC) varies from 0.2-3% - 8-11(19%). The most organic rich rocks are recorded within the Middle Llandovery strata and gradually decrease upwards the section. Maturity of the organic matter increases south-westwards from 0.6 to 1.94% Ro. The average content of the organic matter in the Middle Llandovery graptolite shales reaches up to 1.58%.

The first assessment of unconventional hydrocarbons in Lithuania has been published by Zdanavičiute and Lazauskiene (2009). Volume of expelled hydrocarbons in the Early Silurian shales was estimated as high as 13.75 kg, being equivalent to 389 x 105 m³ of methane gas for 150 m thick rock section in the area of 1 km².

EIA (2011) assessed the shale gas potential in the Lithuanian part of Baltic Basin:
- Shale gas in-place resources 17 Tcf (482 bill. m³)
- Technically recoverable shale gas 4 Tcf (113 bill. m³)
- No shale oil potential has been identified.

EIA (2013) re-assessed the shale gas potential in the Lithuanian part of Baltic Basin:
- Shale oil in-place resources 5 bill. Bbl.
- Associated shale gas in-place resource 4 Tcf (113 bill. m³)
- Technically recoverable shale oil 0.3 bill. Bbl.
- Technically recoverable associated shale gas 0 Tcf.

Uncertainties associated with the relative level of geological knowledge and production history of the EIA studies should be taken into account. Presumably, only available publications were sources of knowledge in these studies with no actual comprehensive datasets from laboratory analyses or calibrated well logging data have been utilized. Production history analogues from the US basins were used (EIA 2011, 2013, 2015) in order to assess the recovery factors.

Two comprehensive shale gas reports based on actual geological, geophysical and geochemical data were prepared in Lithuania in years 2013-2014 by Lithuanian Geological Survey and scientists of the Lithuanian Academy of Sciences. Assessment by Lithuanian Geological Survey in 2014 contains information about the structure and composition of the shaley Lower Palaeozoic succession in the Lithuanian part of the Baltic Sedimentary Basin and an assessment of the shale gas and oil potential. The project was carried out in the years 2011-2014 with major results being presented in the final project report 'Studies of the geological structure of the Early Palaeozoic shaly succession' (Lazauskiene et al. 2014).

Analytical studies were performed on ~500 shale samples from archived core from more than 20 boreholes in SW Lithuania. In result of the project, shale oil and shale gas resources in-place for Late Ordovician – Early Silurian section of 110 m thick and the most prospective Late Ordovician – Llandovery section of 30 m thick were assessed.

The probabilistic assessment of the unconventional hydrocarbon generation potential of the Late Ordovician (Katian) to Early Silurian (Llandovery) shales was carried out adopting geological parameters based method using equations of G. E. Claypool (Peters et al. 2006). The extent of the organic matter conversion to petroleum was determined for 3 zones of different maturities assuming that the total amount of generated hydrocarbons would comprise 30% of gaseous and 70% of liquid shale
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hydrocarbons. The extent of the organic matter conversion to petroleum was determined for 3 different areas with different maturities (Fig. 9):

- 1.5–1.0% Ro – area 1134 km²
- 1.5–0.9% Ro – area 2912 km²
- 1.5–0.8% Ro – area 5691 km²

Volumes of generated unconventional hydrocarbons were calculated (see Fig. 9) for:

**Late Ordovician – Early Silurian section 110 m thick:**
- Prognostic resources of shale oil in place 3,6–18,3 bill. m³ (area: 1134-5691 km²)
- Prognostic resources shale gas in place 1,03–5,13 trill. m³ (area: 1134-5691 km²)

**The most prospective Late Ordovician (M.-L. Llandovery) section 30 m thick:**
- Prognostic resources shale oil in place 1,15–5,75 bill. m³ (area: 1134-5691 km²)
- Prognostic resources shale gas in place 0,32–1,61 trill. m³ (area: 1134 -5691 km²)

Recoverable resources have not been assessed specifically due to the low level of the knowledge about the technical recoverability of the resources in place. The assumption for recoverability of 2-11% of the resources in-place has been considered.

In 2013 and 2014, “State Commission of the Members of Lithuanian Academy of Sciences for Impact of Shale gas exploration and production on environment and human health” evaluated recoverable and in-place shale oil and gas resources for Late Ordovician - Early Silurian section in Šilutė-Tauragė block and western Lithuania using the same geological parameters based on method and equations by G. E. Claypool (Peters et al. 2006). The assessment results for Šilutė–Tauragė block (1800 km² area) for 110 m thick Lower Silurian succession were estimated to (Grigelis ed. 2014):
- Shale oil in-place - ~ 6 bill. m³
- Shale gas in-place - ~1,6 trill. m³

A Group of Scientists of Lithuanian Academy of Sciences (Grigelis, ed. 2014) assessed the potential of shale oil/gas resources to:
- Recoverable shale oil resources – 37-1832 mill. m³
- Recoverable shale gas resources – 14-741 bill. m³

EIA (2015) re-assessed the shale gas potential in the Lithuanian part of the Baltic Basin:
- Risked shale oil in-place resources 6 bill. Bbl.
- Risked associated shale gas in-place resources 4 Tcf (113 bill. m³)
- Risked technically recoverable shale oil 0.3 bill. Bbl.
- Risked technically recoverable associated shale gas 0,4 Tcf.
Pilot shale oil/shale gas prospecting projects in western Lithuania started in 2011 and was carried out by 2 oil companies in 2011-2013. During this period 2 new prospecting shale oil/gas wells were drilled through the Lower Silurian and Upper Ordovician strata. Hydraulic fracturing test and perforation test were carried out in 2 conventional vertical oil wells in order to identify shale gas and oil prospective formations. The potential of Silurian and Ordovician shale layers was tested, but not using the high volume hydraulic fracturing method. Shale oil and associated gas were obtained in those 2 wells. Geological and geochemical data were obtained from 5 wells by 3 oil companies in order to evaluate shale oil/gas potential.

Hydrocarbon Licensing Tender that included requirements for exploration of shale oil and (or) gas for Šilutė-Tauragė block has been announced in 2012 and stopped in October 2013 when Chevron Corporation retreated from the Hydrocarbon Licensing Tender. Licensing Tender Conditions included requirements for exploration of shale oil and (or) gas resources in Šilutė-Tauragė block.
Poland

The main target for shale gas and oil in Poland is the Lower Paleozoic Baltic-Podlasie-Lublin basin (Lower Silurian–Upper Ordovician, locally Upper Cambrian). The main basin has been studied in PGI-NRI (2012) report “Assessment of shale gas and oil resources of the Lower Paleozoic Baltic-Podlasie-Lublin Basin in Poland” and in a number of other published reports (ARI 2009; Wood Mackenzie 2009; EIA 2011, 2013, 2015; Rystad Energy 2010; USGS - Gautier et al. 2012). These reports either utilized actual data from archive wells (PGI-NRI, 2012; USGS - Gautier et al. 2012) or just available publications (ARI 2009; Wood Mackenzie 2009; EIA 2011, 2013, 2015; Rystad Energy 2010). No resource assessment utilizing data from new wells (property of the concession operators - oil & gas companies) has been published yet. New PGI report on the shale gas and oil resources of the Lower Paleozoic Baltic-Podlasie-Lublin basin in Poland, utilizing data from most of these new wells, has been completed by PGI but not approved by Ministry of Environment yet. Consequently it was not possible to include the data from new wells in this study and results of PGI-NRI (2012) report have been utilized together with other available publications.

In PGI-NRI (2012) report and other relevant (publicly available) publications there is no comprehensive data on TOC, hydrocarbon filled porosity, clay/silica content within the potentially gas- and oil bearing shale layers. Only general information on the presence of shale layers rich in organics and of sufficient maturity was available for the use in this study (no data from new wells included, only information pertaining to archive wells). Therefore, the uncertainties on the net pay thickness of the relevant shale layers might be quite significant.

Two approaches to resource assessment have been applied in previous studies. ARI (2009), Wood Mackenzie (2009), EIA (2011, 2013, 2015) and Rystad Energy (2010) applied the volumetric method where values of risked Gas in Place/Oil in Place were estimated. These were actually not the total volumes of gas or oil within the shale reservoir but volumes taking into account reservoir parameters like net thickness of shale of certain total organic content, hydrocarbon filled porosity, clay content, etc. Applying gas or oil recovery factors to these volumes and estimation of (hypothetical) technically recoverable resources (TRR) was obtained. The recovery factors in above mentioned studies were assumed as 20-30% in case of shale gas assessment (ARI 2009; Wood Mackenzie 2009; EIA 2011, 2013, 2015; Rystad Energy 2010) and 4-5% in case of shale oil assessment (ARI 2013, 2015). These studies shall take into account the uncertainties associated with the relative level of geological knowledge and production history. However, it seems only available publications and press releases were sources of knowledge in these studies, and no actual comprehensive datasets from laboratory analyses of core samples or calibrated well logging data were utilized. In case of production history analogues from the US basins were utilized (e.g. Marcellus shale - EIA, 2015) in order to assess the recovery factors.

Another approach utilized USGS methodology (Charpentier & Cook 2012) on assessment of (hypothetical) technically recoverable resources. The approach was applied in PGI-NRI (2012) and USGS (Gautier et al. 2012) reports. In short, a range of volumes of Estimated Ultimate Gas Recovery (EUR) was assessed for a directional drilling within the prospective area - Assessment Unit (AU), and then total output range for the prospective area was estimated. Both the PGI-NRI and USGS studies were based on conventional oil and gas logs, laboratory analyses of core samples, and seismic data collected during the 1970-80’s. In case of PGI-NRI (2012) report results laboratory analyses of core samples from 39 archive wells were utilized (mainly values of TOC and thermal maturity - R0).
As shown in Fig. 10 discrepancies between results obtained from both approaches and particular studies are huge - the range of TRRs is two orders of magnitude. In case of studies employing the volumetric method (e.g., EIA 2011, 2013 & 2015 additionally took into consideration the Fore-Sudetic Monocline Basin which however makes only about 15% of the respective value) a larger acreage was adopted than in case of the reports based on USGS methodology (PGI-NRI, 2012 and Gautier et al. 2012), the mean TOC values were overstated and the presence of sufficient overpressure was assumed (Kiersnowski & Dyrka 2013). As a result the net thickness and volume of potentially gas (and/or oil) bearing shales were overestimated. Another reason for discrepancies consists in the fact the researchers followed different methodologies and used different assumptions (especially on net thickness of prospective shales). There is also an important issue on estimating of recovery factor. Sandrea and Sandrea (2014) mentioned the average recovery factor for shale gas plays in the US as of 6-13% which is considerably lower than 20-25% assumed by EIA (2011, 2013, 2015).

There is also a discrepancy between PGI-NRI (2012) report and USGS report (Gautier et al. 2012). They differ in one order of magnitude because in the USGS report a smaller prospective area and EUR were assumed. In terms of estimated TRRs USGS report (Gautier et al. 2012) matches the most pessimistic case of PGI-NRI (2012) report.

**Fig. 10.** Published estimations of (hypothetical) technically recoverable resources of shale gas in Poland versus yearly gas consumption and production (based on Poprawa, 2010 and Kiersnowski and Dyrka, 2013). 1 Bcm = 1 000 000 000 m³.

**Ukraine**

The moderately complex Lviv-Volyn Basin of western Ukraine is similar to the Lublin Basin in southeast Poland. However, the Silurian black shale belt becomes structurally simpler as it trends towards the southeast across southwestern Ukraine and northern Romania until it reaches the Black Sea. Prospective marine black shales of Silurian age
extend continuously within a 50- to 200- km wide Palaeozoic belt, from Poland all the way to the Black Sea. In western Ukraine, Silurian deposits of southeast Poland’s Lublin Basin continue into the adjoining Lviv-Volyn Basin, where 62 conventional oil and gas fields have been developed. Much of the Lviv-Volyn Basin appears to be too deep and faulted for shale development.

However, the Silurian belt becomes wider and structurally simpler as it continues further to the southeast across western Ukraine and northern Romania. After some tectonic disturbance, the Silurian belt re-enters southern Ukraine and eastern Romania in the Scythian Platform before heading out into the Black Sea. It then briefly re-emerges onto land on the Crimean Peninsula near Odessa before continuing offshore. The Lviv-Volyn Basin has good shale gas development potential in Silurian black shales. As the foreland basin to the Carpathian thrust belt, this shale belt dips gently to the southwest and is characterized by mostly simple structure with few faults. Further to the south, the structurally complex Carpathian region also contains multiple rich marine source rocks. These include the 500 m thick Jurassic Kokhanivka Formation with up to 12% TOC, the 200-m thick L. Cretaceous Spas and Shypit formations with 2-7% TOC, and the Oligo-Miocene Lower Menilite Formation with up to 20% TOC. However, the Carpathian region is intensely faulted with complex nappé tectonics and was not assessed.

The Silurian is the main petroleum source rock and shale gas exploration targets in the Lviv-Volyn Basin. Compared with Poland, the reservoir characteristics of the Silurian shale in western Ukraine are less certain. About 400 to 1,000 m of deep-water Silurian shale is present, transitioning eastward into thinner, shallow-water carbonates. The Ludlow member of the Silurian is considered the most prospective interval. The Ludlow ranges from 400 to 600 m thick and occurs at depths of 2 to 3 km in western Ukraine.

Silurian shale TOC may be lower in Ukraine than in Poland, at least based on the single well data point available. Most TOC measurements at a depth range of 1,400 to 1,592 m in this well were less than 1%. However, the original TOC is estimated at 3% prior to thermal alteration. Given the depositional environmental of the Silurian, it is likely that higher TOC exists in places. Thermal maturity mapping, calculated from conodont alternation index, indicates the Silurian is entirely in the dry gas window ($R_o$ of 1.3% to 3.5%). Several (possibly spurious) over-mature values of 5% $R_o$ also were measured. Maturation is believed to have occurred prior to the Mesozoic. As Sachsenhofer and Koltun (2012) noted: “additional investigations are needed to investigate lateral and vertical variations of TOC contents and refine the maturity patterns in Lower Paleozoic rocks”.

The Kovel-1 petroleum well is a key stratigraphic test drilled during the late 1980s in western Volyn, north-western Ukraine. The well is located along the transition between the structurally complex Lublin-Lviv basins on the west and the less deformed Volyn region of the Slope. The Kovel-1 well cored Ordovician at a depth of about 250 m; Silurian apparently had been eroded in this uplifted.

Reservoir Properties (Prospective Area) based on geologic control from regional cross-sections, the total estimated shale gas prospective area in the Lviv-Volyn Basin is estimated to be 11,520 mi$^2$. The target organic-rich portion of the 500 m thick Ludlow Member of the Silurian is estimated to average 300 m thick gross and 3000 m deep within the prospective region, and have 4% porosity. TOC averages a relatively low 2.0% and is in the dry gas window ($R_o$ average 2.5%). The pressure gradient is assumed to be hydrostatic (0.43 psi/ft).
Resource Assessment Risked, technically recoverable resources from Silurian black shale in the Lviv-Volyn Basin is estimated to be 52 Tcf, out of a risked shale gas in-place of 363 Tcf. The play has a moderately high resource concentration of about 113 Bcf/mi², reflecting the significant thickness of the organic-rich shale that is present. Ukraine’s State Commission on Mineral Resources has estimated that the Oleska shale gas license area in the Lviv-Volyn Basin has about 0.8 to 1.5 trillion m³ (28 to 53 Tcf) of shale gas resources. Whether this estimate reflects in-place or recoverable resources was not specified.

In Ukraine Chevron has been in negotiations with the government for a PSA at the Oleska field in western Ukraine. This block is along strike with Poland’s Lublin basin, where Chevron already holds shale licenses. Duration and terms likely would be similar to those granted to Shell for the permit at Yuzivska field in the eastern Dnieper-Donets Basin (assigns oil and gas rights to all strata to a depth of 10 km, including tight and basin-centred gas. The contract allows for 70% investor recovery and a 16.5% government revenue share).

**Fore-Sudetic Monocline basin**

The Fore-Sudetic Monocline (Lower Carboniferous) has been evaluated in EIA (2013, 2015) reports and its geological-reservoir properties have been studied in PGI-NRI report on tight gas (Wójcicki et al. 2014) where area prospective for tight and shale gas has been delineated. Only one new well for shale and tight gas prospecting in Lower Carboniferous has been completed there (San Leon 2012) and a few archive wells explored Lower Carboniferous.

The Lower Carboniferous shales of the Fore-Sudetic Monocline, located within the depth range of 2-5 km, have been analysed. These shales (actually claystones, siltstones and mudstones, accompanied by sandstones, coals and carbonates), associated with the development of depositional facies in the Variscan flysch basin in Visean and Namurian A, are the source rocks in case of Rotliegend conventional and tight gas fields in the Polish Southern Permian basin (Wójcicki et al. 2014; see also Fig. 11). These source rocks contain organic matter mostly of a humic nature gas-prone Type III kerogen of a non- (deep) marine origin and, rarely, mixed Type II/III kerogen (Botor et al. 2013).

The Lower Carboniferous flysch complex in question (Culm) is characterized by a complicated tectonic setting of fold and thrust deformations (Mazur et al. 2003; Wójcicki et al. 2014), which makes it difficult to recognize the regularities governing their natural cracks. It was uplifted in Late Carboniferous to Early Permian, when volcanic activity peaked, then a substantial burial in Mesozoic occurred, and in Late Cretaceous to Paleogene a massive uplift and erosion took place, especially in S and SE part of the area in question (Botor et al. 2013).

The prospective area for shale gas within the Fore-Sudetic Monocline basin has been assumed after PGI report on tight gas potential in Poland (Wójcicki et al. 2014). The delineated area excludes zones where pre-Carboniferous rocks appear below the floor of Rotliegend. Also SE and NE parts of the Fore-Sudetic Monocline where metamorphic rocks (gneisses and phyllites) occur within the shallow Carboniferous basement was excluded (overmature stage - Botor et al. 2013). Last but not the least, the western part of the Fore-Sudetic Monocline where there are no gas fields in Rotliegend or there are fields where nitrogen contribution is far higher than hydrocarbons, correlated with areas of intensive Lower Permian volcanism, was skipped as not prospective (Wójcicki et al. 2014).
The Lower Carboniferous shales of the Fore-Sudetic Monocline might be an equivalent of Lower Carboniferous black shales (Culm) in North German basin (Ladage and Berner 2012), and, to some extent, Lower Carboniferous Bowland shales in northern England (Andrews 2013). However, there is no direct connection between Polish and German plays.

Prospective formations of Lower Carboniferous within the assessment unit 5 occur within gas window (1.1<=Ro<3.5) only. Values of key reservoir parameters of the assessment units 1-4, based on information available in publications, are presented in Table 1.

Thermal maturity of Lower Carboniferous shales in the area of the Fore-Sudetic Monocline increases towards SE, NW and N (Botor et al. 2013), and within the assessment unit 5 is generally within the range of 1.1-3.0 % (wet and dry gas window). In southern and northernmost part of the area of the assessment unit 5 highest maturity values appear, in central part - lowest.

The present depth of the top of Lower Carboniferous within the area in question is 1250-3750 m, increasing towards NNE, and exact thickness of Lower Carboniferous sediments is not known - in one well about 2500 m of sediments were encountered.

Fig. 11. The target basins for shale gas and oil in Poland: (A) the onshore Lower Paleozoic Baltic-Podlasie-Lublin basin (Lower Silurian-Upper Ordovician, locally Upper Cambrian; PGI-NRI, 2012; gas zone 1.1<=Ro<3.5, oil zone 0.6<=Ro<1.1); (B) the Fore-Sudetic Monocline (Lower Carboniferous; Wójcicki et al. 2014; gas zone only).
(Wójcicki et al. 2014). The top of gas window zone appears within depth range of about 1700-3500 m (deepest in north) and thickness of gas window zone is over 1000 m (Wójcicki et al. 2014). Thickness of the Lower Carboniferous shales within the assessment unit 5 is not known in detail (most likely several hundred meters). Average TOC content is in a range of 1 % to 2 % (Botor et al. 2013).

In Siciny 2 well (San Leon, 2012) within depth range of about 2000-3000 m two shale gas intervals (gross thickness 195 and 105 m, respectively) were encountered in Namurian A and one in Visean (gross thickness 130 m) as well as two tight gas intervals within the same complex. Putting all together, the gross thickness of Lower Carboniferous shales in Siciny 2 well is 430 m. These shales are characterised by a wide range of clay content (25 - 66 %), porosity (1.36 - 8.10 %; average 3.7 %) and gas saturation of pore spaces (30-80 %; San Leon, 2012). In Siciny 2 the average TOC of clean Lower Palaeozoic shales is about 1.55 % (range 1,2-3.25 %; San Leon, 2012).

There is no published information regarding the share of shales of TOC>2% in case of Siciny 2 well (or any other well in the area of question) so, as the effective thickness of prospective shales in the Fore-Sudetic Monocline basin the value of net thickness proposed by EIA (2013, 2015) was assumed, i.e. 55 m. However, as an average value of TOC in this play a value halfway between the threshold (2.0 %) and the maximum value (3,25 %), i.e. 2.63 %, seems to be more likely than the value assumed by EIA (2013, 2015), i.e. 3 %.

<table>
<thead>
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<th>Formation/parameter</th>
<th>Lower Carboniferous shale</th>
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<tr>
<td>Average top depth [m]</td>
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<tr>
<td>Average thickness [m]</td>
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</tr>
<tr>
<td>Average TOC [%]</td>
<td>2.63</td>
</tr>
<tr>
<td>Temperature [°C]</td>
<td>85</td>
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</tbody>
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Table 1. Parameters of the prospective Lower Carboniferous shale in the assessment unit 5.

Assuming average porosity and median value of gas saturation obtained in case of Siciny 2 well (San Leon 2012), average gas filled porosity can be estimated as about 2 %. Average value of adsorbed gas content (Langmuir isotherm/sorption capacity) 1.25 m³/t (average of values measured in 15 US shale basins) and average density of shale 2.6 kg/m³ (Andrews 2013) can be ascertained provisionally. According to San Leon press release (San Leon 2012) a slight overpressure was registered in Lower Carboniferous shales in Siciny 2 well.

In case of the Fore-Sudetic Monocline Basin, only EIA (2013, 2015) made a preliminary estimation of (hypothetical) technically recoverable resources, using volumetric method. They estimated TRRs as of 595 Bcm. However, the prospective area seems to be overstated and assumptions on reservoir parameters are likely based on a press release/corporate report from one new well.

In 2014 PGI-NRI elaborated a report on tight gas potential in Poland (Wójcicki et al. 2014) taking into consideration the Fore-Sudetic Monocline as one of basins where
prospects for unconventional gas occur. The area where Lower Carboniferous sandstones and shales of sufficient maturity (gas window only) appear was delineated.

**Dniepr-Donets basin**

The main shale targets in Eastern Europe are marine-deposited black shales within the Carboniferous of the Dniepr-Donets Basin (TRR of 76 Tcf and 1.2 billion barrels, EIA 2013)(Fig. 12). Shale resource assessments are reported to be underway in Ukraine but no official assessments have been published yet. In Ukraine, Shell recently signed a Production Sharing Agreement in the Dniepr-Donets Basin, committing at least $200 million for exploration. This well-defined Late Paleozoic basin in eastern Ukraine and southern Belarus contains prospective organic-rich Carboniferous black shales.

Fig.12. The Dniepr-Donets Shale Basin in Ukraine. The basin includes entire Dniepr-Donets Depression and north-west Donbas Fold Belt. The license area (Yuzivska Field) had been granted to Royal Dutch Shell in 2012.

The State Geological and Subsurface Survey of Ukraine (Derzhgeonadra) has announced shale gas resources in the country of total 7 trillion m$^3$ (Tm$^3$) or 247 Tcf. However, the basis for this estimate has not been released and the figure includes some tight gas resources. The newly created Geological Research and Production Center in Poltava plans to coordinate shale gas studies in Ukraine, while monitoring water quality in drilling areas. Ukraine’s current Production Sharing Agreement (PSA) involves a 5-year exploration period and up to 45 years for development. Tender fees are modest: $60,000 for the tender and $10,000 for the geologic information package.
On February 23, 2012, the Ukraine government announced a tender for shale exploration and development in the Oleska and Yuzivska blocks of western and eastern Ukraine, respectively. In January 2013, Ukraine awarded the first shale gas PSA, signing with Shell at the World Economic Forum in Davos, Switzerland. Shell’s 50-year PSA permit at Yuzivska in the eastern Dniepr-Donets Basin assigns oil and gas rights to all strata to a depth of 10 km, including tight and basin-centred gas. The contract allows for 70% investor recovery and a 16.5% government revenue share.

The Dniepr-Donets Basin (DDB) in eastern Ukraine has at the base a mid-to Late-Devonian failed rift basin on the Eastern European Craton. The basin contains a thick sequence of Carboniferous black shale which may be prospective for oil and gas development. Economically important Carboniferous coal deposits and tight sands of the Moscovian overlie these shales, but this coaly sequence does not appear to be a prospective shale target.

The DDB accounts for most of Ukraine’s onshore petroleum reserves and is comparatively well understood, with several thousand oil and gas wells, some of which reached depths of over 5 km. Carboniferous black shales and coal seams are the main source rocks, while overlying clastic Carboniferous sandstones provide conventional reservoirs within mainly structural traps. To the northwest the DDB continues into the Pripyat Trough of southern Belarus, which appears to be too shallow and low in TOC for shale development. To the southeast the basin continues into the Donbas Folded structure.

Roughly symmetrical, the DDB is about 700 km long, 40 to 70 km wide, and trends northwest-southeast. It comprises a series of half grabens bounded by large-displacement faults (h= 100 m to 2 km). The individual blocks are quite sizeable (50-100 km by 20-40 km), although numerous smaller faults are locally present. The basin contains as much as 15 km of Devonian and younger sedimentary rocks, which includes 1 to 2 km of mostly Devonian (Frasnian) salt deposited under restricted rift conditions. Lower Carboniferous black shale overlies the Devonian salt interval. This black shale and the overlying coal seams sourced most of the conventional oil and gas fields in the basin. The entire Carboniferous section ranges up to 11 km thick in the DDB and is up to 15 km deep near its base along the basin axis. In the northwest portion of the DDB the Carboniferous is continental in origin, but transitions into partly shallow marine depositional cycles, each of which is typically 50 m thick and contains an organic-rich shallow marine shale layer.

Several black shale targets occur within the L. Carboniferous sequence. The Upper Visean Rudov Beds are considered the best quality source rock and shale gas target. These black shales are up to 70 m thick, but more typically 30-40 m, and particularly well developed in the Sribnenska and Zhdanivska depressions where they are quite deep and dry gas prone. The Rudov Beds are rich in siliceous radiolaria, making them potentially brittle, while the lower part of the formation is high in calcite as well as clay. The organic-rich middle section of the Rudov Beds has 3.0% to 10.7% TOC (average 5%), mostly Type III with some Type II kerogen. Additional slightly leaner (TOC of 3.0% to 3.5%) but still quite prospective source rocks occur in the Upper Visean above the Rudov Beds, while the lower Serpukhovian contains black shales with up to 5% TOC.

Thermal maturity of the Rudov Beds and the overlying Upper Visean is mainly in the oil window (Ro 0.8-1.0%) in the central and northwestern DDB, increasing to dry gas maturity (R_o 1.3-3.0%) in the southeast. For example, the Rud-2 petroleum well in the Dniepr-Donets Basin penetrated a nearly 1-km thick Carboniferous Upper Visean shale interval at a depth of 4 to 5 km TOC of up to 4% in this interval is within the oil
thermal maturity window (R_0 0.8-1.0%). The oil window in this basin appears to be normally to under-pressured, while the dry gas window is likely to be over-pressured due to ongoing gas generation, although pressure data control is poor.

The southwest flank of the Dniepr-Donets Basin is characterized by a structurally simple dip slope, where thick of Carboniferous black shale tilts gently to the NNE towards the basin axis. The L. Carboniferous is at ideal depth for shale development (1-5 km) over a broad belt. The northeast flank of the DDB has thinner Carboniferous that is structurally more complex. Lacking a detailed depth map on the Carboniferous, we constrained the depth-prospective area using basement contours and multiple published cross-sections, yielding good control on the prospective area. Note that salt intrusions up to 15 km thick may negatively impact shale potential along various parts of the slope.

Reservoir Properties (Prospective Area) Lower Carboniferous black shales (Rudov Beds, Lower Visean, and Lower Serpukhovian) are prospective within a 10, 150-mi² depth-controlled belt that surrounds the axis of the Dniepr-Donets Basin. These shales are estimated to total about 1 km in thickness but are relatively deep (3-5 km). They largely consist of siliceous or calcareous lithologies rich in radiolarian and thus are expected to be brittle with high porosity (6%). Gas recovery rates also should be favourable (30%) due to the inferred frackability of the shale. TOC appears favorable, averaging about 4.5%. Thermal maturity ranges from oil to dry gas. On the negative side, salt intrusions may sterilize some of the mapped prospective area (10%).

The mapped prospective area for the dry shale gas window in southeastern Dniepr-Donets Basin is estimated at 6,010 mi². Lower Carboniferous shale (comprising the Rudov Beds and portions of the overlying Upper Visean) has a highly favourable resource concentration of approximately 195 Bcf/mi². Risked, technically recoverable shale gas resources are estimated to be 59 Tcf, out of a risked shale gas in-place of 235 Tcf. The wet gas prospective area of the DDB extends over about 2,680 mi². Risked, technically recoverable resources are estimated at 16 Tcf of shale gas and 0.5 billion barrels of condensate from in-place shale gas and shale oil resources of 63 Tcf and 10 billion barrels. The smaller oil window in the northwestern Dniepr-Donets Basin covers a prospective area of about 1,460 mi². Risked technically recoverable resources are estimated to be about 0.7 billion barrels of shale oil and condensate and 1 Tcf of associated shale gas, out of risked in-place shale oil resources of 13 billion barrels.

Ukraine’s State Commission on Mineral Resources has estimated that the Yuzivska shale gas license in the eastern Dniepr-Donets Basin has 2-3 Tm³ (71-107 Tcf) of shale gas and tight gas resources. Whether this estimate reflects in-place or recoverable resources was not specified.

**Transilvanian basin**

The Transylvanian Basin (Fig. 13) is the most important zone with gas accumulation in Romania. Also, this sedimentary basin is the main gas producer from SE Europe (Popescu 1995). The gas pools are located in the Upper Badenian-Lower Pliocene (Paraschiv 1979; Popescu 1995). This stratigraphically level is named “Gas-bearing formation” that accumulated only the biogenic methane gases.
The geological mapping and exploration drilling in the Transylvanian Basin identified a stratigraphic succession reaching 6000 to 8000m concerning the thickness and consisting of an alternation of clays, marls, sandstones, sands and conglomerates. Some of the strata offer favourable hydrocarbon genesis, accumulation and preservation conditions. Other strata, such as the pre-Senonian sedimentary deposits, belonging to the depression basement are of little prospect as they were subject to emergence and erosion for a long period of time and seem to have a very complicated tectonics.

As far as the reservoir rocks are concerned, they are to be found in all the Tertiary formations, from the Eocene to the Pliocene. The micro-conglomerates, sandstones and Eocene limestones should be mentioned as they produced salt water in numerous wells, thus proving their storing and yielding capacity. The Oligocene might be taken into consideration because of the sandstones and sands belonging to the Tic and the Almas Valley beds and because of the arenites sequences in the Salva beds to the east. The Burdigalian and his upper part extend on a great area within the depression and include numerous sand, sandstone and micro-conglomerate horizons or layers. Their storing capacity was checked by production tests (with salt waters) in several wells. The most important reservoir rocks are known in the Upper Miocene, where the Badenian and Sarmatian sandstones and sands show average porosities 20% and permeabilities between 0.1-1000 mD yielding gas on numerous structures. The physical properties of these reservoirs deteriorate with depth owing to the rock compactness. Thus the Badenian sandstones situated at the depth of more than 2800-3000m offer very weak productions (up to 10000 m3/day gas) or do not produce even after special treatments. Also, the frequency, thickness and physical properties
of the Upper Miocene reservoirs decrease from east to west and north-west (Paraschiv 1979). Good reservoirs are also found in the Pliocene but they benefit only locally by protection conditions.

The same pelite rocks represented by clays, marls and limestones mentioned in connection with the protection conditions are considered likely to be hydrocarbon source rocks but not for the accumulated gases from Transylvanian Basin. In the Transylvanian basin the 99% of the gas is methane and it has the biogenic origin, is not reached a themogen stage. Among them, of most interest are the bituminous schists in the Ileanda beds (Oligocene), the radiolarian schist and, generally, all the marly horizons belonging to the Badenian and Sarmatian. Although the respective formations were not the object of any special geochemical studies, the results of the research carried out on some deposits of similar age in the Carpathian Foredeep and the Pannonian Basin justify such statements. The geothermal studies made in 1960-1980 years indicate that the Transylvanian Basin behaves in a unitary way as regards the depth temperatures. The lowest values, 3°/100 m, respectively, are found in the centre of the basin where the new sedimentary deposits reach maximum thicknesses. As the distance from the eastern, northern and southern margins decreases, therefore, as the thickness of the sedimentary deposits decreases and important dislocation lines appear, the value of the geothermal gradients increases, namely from 3°/100 m to 5°/100 m and even more. As compared to the Pannonian Basin, the Transylvanian Basin shows much lower temperature values. The fact might be explained not so much by the upper mantle thickening to 25-30 km, as, especially, by the greater thickness of the Tertiary and Mesozoic deposits. The relatively low geothermal gradient associated with the recent age of the formations of interest is explain, to a certain extent, by the exclusively gaseous nature of the hydrocarbons generated by the Badenian and Sarmatian formations. The productive domes and the adjacent zones are characterized by the presence of waters of CaCl₂, MgCl₂ and NaHCO₃ types, whose mineralization is lower than the one in the Carpathian Foredeep, varying, as a rule, between 30 and 95 g/l. The deep and well protected strata contain chlorocalcic and chloromagnesium waters. As the depth decreases, mixed or only vadose waters appear. Thus, the type and mineralization of the waters indicate the sealing degree of the deposits and, implicitly, the prospects of finding commercial accumulations. The fossil deposit waters contain iodine and bromine which are reevaluated in some watering places.

Hydrocarbon emanations have been known for a long time in the Transylvanian Depression, but the first commercial gas deposit was discovered accidentally only in 1909, by the borehole no.2 Sărmășel. This well started the drilling in November 1908 and in the following year reached a horizon of gas with high pressures, yielding 864000 m³/day of free gas eruption at a depth of 302 m. This important discovery brought about an intensification of the geological research, especially after 1950 years.

Until now in the Transylvanian Depression have been discovered up to 120 gas fields 13 of them were discovered before 1950. The natural gas in these structures is located in the Upper Badenian, Lower Sarmatian (Buglovian), Sarmatian ss. and seldom in the Pliocene deposits, which together, make up "the gas formation" located in the so-called gas-bearing domes. The number and size of the gas-bearing horizons vary from one structure to another according to the thickness of the Upper Miocene sedimentary deposits, to the litho facies and to the geological evolution. Based to these mentioned criteria, the genesis of the structural elements and the post-Pontian denudation played an important part. Taking into account these conditions and criteria, the gas-bearing domes in the Transylvanian Basin could be distributed into five groups:
The central group, consisting of large domes, where the gas formation may reach 3000m in thickness, with very many productive horizons and, generally, protected by Pliocene deposits such as the Delureni, Crăești-Ercea, Bozed, Pâingeni, Dumbrăvioara, Ernei, Tg. Mureș, Acățari, Corunca, Săușa, Suveica, Filitești, Labălăul Mare, Deleni (Saroș), Bazna, Nades, Prod-Soleus structures.

The northern group where the gas formation outcropping was more and more eroded to its total removal in the vicinity of the Someș valley; the number of productive horizons decreases accordingly; this group consists of the Beudiu, Enciu, Strugureni, Puini, Țaga, Buza, Fintinele, Sărmașel, Silivaș, Sinmartin de Cimpie, Uliaș, Sincai, Grebeniș, Zăul de Cimpie, Șaulia, Dobra, Singer, Iclănzel, Vaidei, Luduș.

The western group consisting of the Lechința-Iernut, Bogata, Cucerdea, Cetatea de Băltă, Velț and Tăuni domes, is characterized by the gradual substitution of the psamite complexes, by the pelites and by the reduction up to disappearance of the reservoir horizons towards the Apuseni Mountains.

The southern group represented by the Copșa Mica, Noul Săsesc, Petiș, Bârghiș, Rusi and Ilimbav, where the halokinetic becomes less important towards the South Carpathians so that at one moment there are no diapir anticlines but faulted anticlines (Rusi) or shrinking structures (Ilimbav) as a result, the importance of the accumulations decreases constantly southwards.

The eastern group comprises smaller structures; the tectonic complication of these structures increases reaching the shape of exaggerated and faulted diapirs; the frequency of the unconformities within the gas formations is higher; the protection conditions deteriorate owing to the increasing number of sandstones and the partial invasion of the reservoirs by CO2. The following gas-bearing structures belong to this group: Daia-Telina, Netuș, Retiș, Bârcuț, Bunești-Crit, Beia, Cristur, Eliseni, Chedia, Șoimuș, Sîngeorgiu de Pădure, Gălățeni, Ghinești-Trei Sate, Miercurea Nirajului, Măgherani, Dâmieni, Teleac, Voivodeni, Lunca, Târcești, Bențid, Firtușu, Cușmed, Brădești and Ibănești.

**Moesian Platform**

The northern part of the Moesian Platform is within the Romanian sector while the southern part is within the Bulgarian sector. In the Romanian sector the Moesian Platform covers a surface of more than 43 000 km² and is bordered by the Carpathian Orogeny, Balkan and North Dobrogea orogenic systems. It also covers to the east the continental platform of the Black Sea (Fig. 14).

Concerning the structural setting of Moesian Platform it can say that this is characterised by the specific structural style that comprises a fault network with two dominant trends. After many authors, the most significant ones are the east-west faults; these tectonic accidents are result of regional extension which affected all the strata. Other fault trend, generally perpendicular to the former, includes faults of smaller size and development.

**Romania**

In connection with this tectonic regime who contributed to the appearance of these system faults it is mentioned that in the Moesian Platform (Romanian part) are developed some uplift (Strehaia-Chilia, Craiova-Balș-Optași, Slatina-Corabia and Bordei Verde) and depression zones (Băilești, Roșiori-Alexandria and Urzicieni-
Călărași). These main uplifts and depressions were active until the Early Triassic. Jurassic, Cretaceous and Neogene strata have a monoclinal dip towards the north beneath the Carpathian Foredeep. Middle and Upper Triassic strata have a transitional structure.

![Simplified regional tectonic sketch](image)

Fig. 14. Simplified regional tectonic sketch, showing Moesian platform location (modified after Dabovski & Zagorchev, 2009).

Its crystalline basement (Fig. 15) is divided by the Intra-Moesian Fault (IMF) into two major blocks; East and West Moesia. These two sectors of the platform are unequal in surface area and show differences in the stratigraphy of the sedimentary cover, as well as in their basement structure. The Palaeozoic sediments do not crop out in Moesia and borehole evidence indicates that the heterogeneous basement rocks are overlain by a sedimentary cover including Palaeozoic, Mesozoic and Cenozoic deposits.

Moesian Platform is the one of the most important basins for hydrocarbons in Romania. This major sedimentary basin has all geological conditions for hydrocarbons generation, migration and accumulation. As concerning the stage of exploration, many authors considers the Moesian Platform a mature area, but there are still some zones with unsatisfactory petroleum knowledge e.g. Paraschiv (1979), Popescu (1995) and Pene et al. (2006).

This sedimentary basin is characterized to the existence of the least three effective petroleum systems, two of them are thermogenic systems represented by the Palaeozoic and the Mesozoic systems and one is biogenic system (Neogene system)(Paraschiv 1979; Pene et al. 2006).
The exploration stage debuted in the early 1950s. In 1956, the first borehole was drilled (2 Ciurești borehole) which encountered the first hydrocarbon accumulation in the Sarmatian sandstone (reservoir) from this sedimentary basin. After this reference year have been discovered more than 130 oil and gas fields (Pene 1996). Presently, this number of discovery is increased. It is assumed that the number of oil and gas fields is about 145. According to Pene (1996) the initial reserves in 1996 discoveries were $235 \times 10^6$ t and ultimate resources were at least $237 \times 10^6$ t (Popescu 1995).

Also, after the same author, the Moesian Platform yields about 40% of the hydrocarbon production of Romania.

Taking account of the many papers and reports, the main objectives of the Moesian Platform are refers to the western part of this sedimentary basin concerning the hydrocarbon accumulation, especially to establish the maturity of the source rocks. These researchers had wanted to explain the presence of the oil and gas fields. Thus, in the northwest of the Moesian Platform have been discovered more than 20 oil and gas fields located into Devonian, Permo-Triassic, Middle and Upper Jurassic, Lower and Upper Cretaceous, Sarmatian and Lower Pliocene reservoirs (Paraschiv 1979a,b; Paraschiv 1984; Pătruț et al. 1983; Pene 1996).

The western part of Moesian Platform contains the only hydrocarbon accumulation in Palaeozoic (Devonian) bituminous and fissured dolomites and limestones discovered in Romania. According to Pene (1996), the oil and gas accumulations in Permo-Triassic and Middle Jurassic reservoirs have been discovered only in the northwest of the Moesian Platform. Concluding, in this area, the reservoirs consist of dolomites and limestones in the Devonian, Middle Triassic, Upper Jurassic and Lower Cretaceous and sandstones in the Lower and Upper Triassic, Middle Jurassic, Upper Cretaceous, Sarmatian and Lower Pliocene.
Pene (1996) show that the most important source rocks in western part of the Moesian Platform are Ordovician-Silurian shales, Devonian bituminous limestones and dolomites and Middle Carboniferous, Middle Jurassic and lowermost Sarmatian shales (according to Paraschiv 1979b; Baltes 1983b; Pene 1996). Other source rocks seem to be Oligocene shale deposits located in the north of the area, in the Carpathian Fore Deep (Balteş 1983b; Lafargue et al. 1994; Popescu 1995).

Concerning the geochemical criteria, in the mentioned area has been estimated the hydrocarbon potential using Total Organic Carbon (TOC) analyses and determinations of Organic Matter Type. Based to these analyses, Balteş (1983b) concluded that organic matter contents are relatively reduced (Table 2). The volume of oil generated from a mature source rock is related to the amount, type and maturity of its kerogen.

<table>
<thead>
<tr>
<th>Source interval</th>
<th>Area (km²)</th>
<th>Thickness (m)</th>
<th>Vₘ (10⁶ m³)</th>
<th>Cₒ (%)</th>
<th>Pₒ (%)</th>
<th>Rₒ (%)</th>
<th>Fₒ (%)</th>
<th>Bₒ (%)</th>
<th>Volume of oil generated (10⁶ m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sarmatian</td>
<td>661</td>
<td>25</td>
<td>16525</td>
<td>3.07</td>
<td>35</td>
<td>40</td>
<td>40</td>
<td>1.1</td>
<td>23</td>
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<tr>
<td>Middle Jurassic</td>
<td>778</td>
<td>40</td>
<td>31120</td>
<td>5.31</td>
<td>40</td>
<td>45</td>
<td>45</td>
<td>1.1</td>
<td>130</td>
</tr>
<tr>
<td>Middle Carboniferous</td>
<td>650</td>
<td>40</td>
<td>26000</td>
<td>6.83</td>
<td>32</td>
<td>50</td>
<td>35</td>
<td>1.1</td>
<td>109</td>
</tr>
<tr>
<td>Upper Devonian</td>
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<td>60</td>
<td>161400</td>
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<td>55</td>
<td>50</td>
<td>1.1</td>
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<tr>
<td>Silurian</td>
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<td>60</td>
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<td>50</td>
<td>55</td>
<td>50</td>
<td>1.2</td>
<td>2712</td>
</tr>
<tr>
<td>Generated oil volume</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>4047</td>
</tr>
</tbody>
</table>

* Vₘ is volume of source rock (m³); Cₒ is organic matter content by volume (%); Pₒ is genetic potential (%); Rₒ is transformation ratio (%); Fₒ is fraction of oil in the hydrocarbon yield; Bₒ is volume increase on oil yield. The organic matter content by volume (Cₒ) has been computed using an original volumetric modelling based on a few geochemical analyses.

Table 2. Computation of the generated hydrocarbon volumes of the source rocks from the western part of the Moesian Platform.

Baltes (1983b), basing on the resulted values of H/C and O/C ratios, suggest that the organic matter consists predominantly of type I kerogen for the Ordovician-Silurian shales (see Coltoi et al. 2016). Also, according to the same author, the organic matter from the Upper Devonian bituminous limestones and dolomites consists of mixed kerogen (types I+ II , but predominantly type I). The organic matter content varies vertically and consists of mixed kerogen (sapropelic-humic) in the Middle Carboniferous. In fact, in this stratigraphic age predominantly kerogen is humic type. Based to the same values of ratios index of source rocks belongs to the Middle Jurassic and lowermost Sarmatian, the organic matter seems to consist predominantly of type II kerogen.

Baltes (1983b) and Pene (1996) noticed that the values of alteration index suggest that only Neogene, and in part Jurassic rocks, could have generated liquid hydrocarbons and wet gas. The organic matter in rocks which are older than Jurassic have reached an overmature stage and dry gas has been generated. This idea is sustained and by observations made on the fossil vegetal contents of the cores from Bulbuceni wells. For the source rocks older than Jurassic it can say that the organic matter have reached an over mature stage and dry gas has been generated. By comparing (Lafargue et al. 1994; Pene 1996), the source rocks from Moesian Platform
have similar characteristics to kerogen type II with their stratigraphically equivalent in the Toarcian of the Paris Basin. The most recent public article on Romania's petroleum systems and their remaining potential (Popescu 1995) reports that the Dogger shales yielded 20-30% DOM (dispersed organic matter) and average organic carbon (Corg) content of 0.35%. Popescu (1995) showed that Dogger shales are equivalent to the Eutropole Formation from Bulgaria and are the only source rocks proven to have good hydrocarbon potential. Also, in the western part of the Moesian Platform was estimated the level of thermal maturity which has been calculated from burial histories (Pene 1996). This mentioned author has constructed burial history curves for 175 petroleum exploration wells to establish the maturity.

Another activity to estimate the hydrocarbon potential in the central and northern sector of the Moesian Platform (at contact with Getic Depression) was conducted by the Petrom National Company between years 1998–2004 Thus, the research regarding the carbonate and shale rocks has been performed in order to establish the properties of the source-rock for hydrocarbons. Some differences of the rocks geochemical parameters have been identified. The studied areas are the next: one is perimeter delimited by Bibeşti, Bulbuceni, Malu Mare, Făureşti and Mitrofani locality and the other one is given by Spineni-Optaş, Negreni alignment. These studies showed the differences of organic matter transformation depending on the rock type which preserves the substance.

Research conducted by the Baltes (1983a) suggested that oil reservoirs in Palaeozoic and Triassic rocks originated by lateral migration from younger formations, along the important unconformities. According to Pătruț et al. (1983), from Pene (1996), the oil and gas generation from Middle Jurassic shales started in the Sarmatian at depths between 1900-4500 m in a kitchen beneath the Carpathian ForedEEP, north of the PericarpPathian Fault. At the level of the 1996 year it were calculated the TTI index for the mentioned stratigraphically ages. Also, Corresponding vitrinite reflectance values have been determined. The calculated values (Pene, 1996) have been used to make vitrinite reflectance maps for Upper Devonian, Middle Carboniferous, Middle Jurassic and Sarmatian stratigraphic levels. The same author, in 1996 has tried to estimate the timing of generation. Thus, the timing of generation within the study area as a whole was estimated from its overall thermal and burial history. He concluded that in the southwest part of the western, respectively Girla-Cetate zone, the onset of oil generation for the Silurian shales took place 278 Ma ago. Following the rest of experimental data, Pene (1996) suggest that in the Morunglav area these source rocks began to generate oil 80 Ma ago. The onset of the oil generation from the other analysed source rocks took place during Sarmatian and Pliocene times. Concerning the maturity of Sarmatian age, the source rocks seems that began to generate oil 0.2-0.5 Ma ago and the process of generation continues to the present day (vitrinite reflectance < 1.3%) and these rocks have not passed through the oil generation window.

According to Vinogradov et al. (1999), in their studied sector of Moesian Platform has been accepted the existence of some horizontal migration paths for the hydrocarbon accumulation in the southern proximity of Spineni sector (Oporelu, Negreni, Ciureşti, Ciești, Căldăraru, Barla), in Triassic, Jurassic and Cretaceous formations as well as the existence of some probable vertical migration paths, on faults, up to encountering the PericarpPathian Fault, with the hydrocarbons accommodation in the Tertiary deposits of Getic Depression. Monoclines and faulted anticlines are the main traps. The seals consist of marls, shales and evaporitic rocks.
Concerning the suitable areas for calculating the shale gas resources of the Silurian deposits in the Moesian Platform, there are 3 system plays in Moesian Platform: Călărași–South Dobrogea Play, Optași–Alexandria Play and Lom-Băilești Play (Fig. 16).

The estimate of extended of the Silurian shale gas is:
- Călărași–South Dobrogea Play = about 7000 km²
- Optași–Alexandria–Roșiori Play = about 15000 km²
- Lom–Băilești Play = about 8000 km²

Veliciu and Popescu (2012) have estimated the values (Table 3) of the resources for these 3 shale gas plays according to the assessment of methods issued by US Geological Survey (2010).

Based on formulas used by U.S. Energy Information Administration (World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States – 2011) for volumetric calculation, beside to calculation of GIP, also, the authors calculated the Adsorbed gas in-place following the next formula: GC = (VL * P) / (PL + P) – P is original reservoir pressure.

<table>
<thead>
<tr>
<th>PLAYS</th>
<th>Lom-Băilești</th>
<th>Optași-Alexandria–Roșiori</th>
<th>Călărași - South Dobrogea</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assessment hypothesis</td>
<td>Pessimistic</td>
<td>Mean</td>
<td>Optimistic</td>
</tr>
<tr>
<td>Resources</td>
<td>Original gas in place (Tcf)</td>
<td>29</td>
<td>0.6</td>
</tr>
<tr>
<td></td>
<td>Technically recoverable (Tcf)</td>
<td>0.3</td>
<td>(0.58)</td>
</tr>
</tbody>
</table>

Table 3. Estimation of the shale gas resources in the Moesian Platform for Silurian deposits according to Veliciu & Popescu (2012).
**Bulgaria**

In the sedimentary successions of the Moesian Platform in Bulgaria, four intervals dominated by organic-rich dark shale have been identified, which would be of interest for shale gas. These are:

- **Silurian – Lower Devonian(?) shales**
- **Lower Carboniferous shales – Trigorska and Konarska Formations**
- **Lower Jurassic shaly sediments – Ozirovo Formation (Bucorovo & Dolnilucovit Mbs)**
- **Middle Jurassic shales – Etropole Formation (Stefanets Mb)**

The Middle Triassic dark shales in the Moesian Platform (Mitrovo Formation) have been ignored in this selection, because of lack of appropriate hydrocarbon generative parameters: average TOC - < 0.5%, gross thickness - usually 40-60 m and limited area of extend (Botoucharov & Georgiev 2004; Georgiev et al. 2007).

**Silurian – Lower Devonian(?) shales**

The known extent of this shale unit related with area of 1250 km² in the easternmost uplifted Vetrino block of North Bulgarian arch, bounded by Aksakovo fault to east, by Vetrino fault to west and by Dulovo fault to north (Fig. 17), (Kalinko 1976; Bokov & Tchemberski 1987; Atanasov & Georgiev 1987). These shales are drilled until now by only two boreholes; Vetrino 2 drilled the full section and Mihalitch 2 penetrated only the upper 700 m. Obviously the areal spreading of Silurian shale is expected to be much larger than outlined one, however outside of the marked area the buried depths are greater of 4-5 km. The drilled gross thickness is about 2000 m, but organic-rich thickness averages about 500-550 m. Silurian shales are at buried depths of 1000 to above 3500 m, but the available data are very scant. The TOC is in range of 0.4 - 3.35% (average no more 1.5 -2%), type II-III (mainly gas prone). Porosity is usually less of 3.5 - 4%. Thermal maturity of 1.3 - 2.2% Ro ranges from wet to dry gas.

Very critical for Silurian shale gas potential is the total absence of gas shows during the drilling. The most uplifted part of North Bulgarian arch (Fig. 17), where is situated outlined known and reachable for drilling area is intensively faulted and fragmented in blocks with vertical displacement of up to 2000 m and many inversion and erosion periods took place in the geological history (Atanasov & Georgiev 1987; Kalinko 1976; Bokov & Tchemberski 1987). In the marked area Lower Valanginian–Upper Jurassic carbonates crop out on the earth surface. As well there is a very large stratigraphic gape in the sedimentary succession – the thin Bathonian sediments cover unconformable the Middle Devonian carbonates. That means lack of deposits from about 200 million years geological period. Parts of the absent sediments are eroded, another are not deposited (Atanasov & Georgiev 1987). Up to Late Palaeozoic – Early Mesozoic hiatus the burial depths of Silurian shales were enough for development of hydrocarbon generation in them. However, during the intensive tectonics and erosional processes in Late Palaeozoic–Early Mesozoic time the generated gas (modest in volumes by TOC) had escaped the Silurian shales and they are degasified at present.

**Lower Carboniferous shales – Trigorska and Konarska Formations**

Lower Carboniferous dark to black shale has been drilled by several wells in northern and eastern parts of NE Bulgaria (Fig. 17). Most impressive results have been received from drilled several years ago deep borehole Jernov in central part of North Bulgaria, which penetrated very thick Lower Carboniferous section (> 2400 m). Three intervals in the section are dominated by dark shales with total thickness of about 1100 m. The upper interval, thick about 140 m, related to Konarska Formation (Kulaksazov & Tencho 1973; Tencho 1993); it contains few coal seams (Nikolov et al., 1990). The
middle (850 m) and lower (115 m) shale intervals related respectively to the upper and lower parts of Trigorska Formation (Kulaksazov & Tenchov, 1973; Tenchov, 1993), which thickness is above 2200 m. In generally all these shales are still poor geochemically investigated. The recently accomplished up-to-date and comprehensive study comprises only 70-80 m from shales in Konarska Formation (Nikolov 2014).

The Lower Carboniferous shales extend on area of 12000 km², which comprises two zones separated by Vetrino fault (Fig. 17). The western more elongated and narrow zone covers area of about 4000 km². The Lower Carboniferous thicknesses grow fast towards Danube River to 3000 m and more (Fig. 17). Buried depths to top of Lower Carboniferous range between 2700 and 3400 m. Shale TOC values tend to be good and very good (up to 3-4% and more). Kerogen type is II-III, maturation ranges from immature/early oil to dry gas mature (0.6 – 1.9 % Ro), anthracite inclusions have been observed (Nikolov et al., 1990). There is absorbed gas in the shales with methane content of 3.5-50% (Nikolov 2014). The available geological and especially geochemical data are very scant for estimation of shale gas potential. But there are preconditions it to be moderate to good if the thicknesses are above 400 –500 m. Most critical parameters looks to be the big buried depths and the very old age (320 – 350 My).

The eastern uplifted zone (eastward of Vetrino fault) is two times larger, about 8000 km² in area (Fig. 17). The Lower Carboniferous sequence occurs on shallower depth, between 850 and 3100 m. The total and shale net thicknesses are respectively above of 1000 m and 400 m. The shale organic content has the next parameters: TOC – up to 3 % (average less 2%); kerogen tends to III-th type, maturity is high - up to anthracite level (Todorov 1990; Todorov et al. 1992), as it is for Upper Carboniferous
coals in Dobroudja field (Nikolov 1988). By these characteristics shale gas potential may be estimated to be fair. However, critical for this zone is the absence of gas shows during the drilling, as it is also in Dobroudja coal field. The intensive faulting and fragmentation in blocks with high vertical displacement and many inversions and erosions in the geological history (Atanasov & Georgiev 1987; Kalinko 1976; Bokov & Tchemberski 1987) have caused escaping and vertical migration of the generated gas (modest in volumes by TOC). So the Lower Carboniferous shales in this zone are strongly degasified at present.

Lower – Middle Jurassic shaly sediments
By lithological, log and geochemical features two potentially shale gas intervals have been detected in the Lower-Middle Jurassic sedimentary succession of Moesian platform basin [40]. They respectively related to Bucorovo and Dolnilucovit Members within Ozirovo Formation and to Stefanets Member within Etropole Formation (Sapunov 1983; Sapunov & Tchoumatchenco 1989). Usually their source features improve when the total thickness of Lower-Middle Jurassic sequence is above 350 - 400 m, as much as better (Georgiev & Dabovski 1997). In addition, all oil-gas discoveries in central North Bulgaria (Dolni and Gorni Dubnik, Dolni Lučovit and others) have been chemically linked back to the Etropole and Ozirovo shaly sediments (Georgiev & Ilieva 2007; Georgiev & Dabovski 1997; Georgiev 2000; Georgiev et al. 2001). Areal extension of the thicker Lower-Middle Jurassic sequence has been mapped by a lot of well and seismic data and cover the area of about 10 000 km² (Fig. ?), (Georgiev & Dabovski 1997).

Lower Jurassic shaly sediments – Ozirovo Formation (Bucorovo & Dolnilucovit Members)
The shaly middle part of Ozirovo Fm. comprises Bucorovo member and upper part of the Dolnilucovit member. This shaly unit manifest fair to good hydrocarbon generative features (Georgiev & Ilieva, 2007). The thicknesses vary between 200 and 500 m in the western part of the outlined area, but eastward they reduce to 40-50 m (Fig. 10). Total organic content is usually between 1% and 2%, rarely more. Organic type is I-II and its transformation rate increases southward from peak to late maturity stage (by Ro and Tmax values) together with fast rising of the thicknesses and burial depths from 2600 to 4500 m.

The well Devensi drilled by Direct Petroleum Bulgaria in the southwestern part of outlined area tested good gas-condensate flow from Dolnilucovit member (Trans-Atlantic Petroleum Ltd. 2011; EIA, 2015). Critical for Ozirovo shaly sediments are the thickness, when it is less of 100 m, and not so sufficient organic enriches.

Middle Jurassic shales – Etropole Formation (Stefanets Member)
The organic enriched shales in lower portion of Etropole Fm. represented by Stefanets member are prospective within the outlined 10,000 km² area in central Northern Bulgaria (Fig. ?). Stefanets member contains thick from 250 m to southwest up to 50m to east carbonate-rich (up to 40-50%) black shale that was deposited in a marine environment. Total organic content ranges from 0.7% to 2.95%, kerogen type II predominate (SGRG, 2011; Trans-Atlantic Petroleum Ltd. 2011; EIA 2015; Georgiev & Ilieva 2007; Georgiev & Dabovski 1997; Georgiev et al. 2001). The Stefanets shale generally ranges from 2500 to above 4250 m deep and is overpressured in much of the western zone, with an elevated pressure gradient of 0.78 psi/ft (Trans-Atlantic Petroleum Ltd. 2011; EIA 2015). Thermal maturity falls in the oil window in the north, increasing to wet and dry gas in the south near the Balkan thrust belt (Ro 1.0% to 1.5%). Porosity is assumed to be moderately high (3-4%). Gas recovery rates also could be favourable based on the inferred brittle lithology. Many years ago the located to southwest in the area well Peshtene 5 tasted unstimulated gas-condensate flow
15000 m³/d from conventional carbonate-clastic interval within the Etropole Fm. In 2011 Direct Petroleum Bulgaria drilled near by a new Peshtene 11 exploration well to core and tests the Etropole shale. This well penetrated about 350 m of Etropole shales with numerous gas shows (C1-C3) at depth 3500-3800 m, but was not fracture stimulated as Bulgaria has a ban in place. Critical for Etropole shales are not so sufficient organic enriches and buried depths above 4000 m, because they aggravate technically and costly the exploration.

According to the completed study the shale gas potential of Bulgaria part of the Moesian Platform is moderate to poor. From the estimated 4 targets for shale gas only the Lower Carboniferous shales (in the pointed western zone) and both Jurassic shale intervals may present a moderate interest.

**Dinarides-Lemeš basin**

Previous studies of the area Lemeš deposits originated from early 1980’s when the Croatian oil company INA conducted studies of the petroleum and potential source rocks from the area of “Lemeš facies” (Jacob et al. 1983. and unpublished data). Revival of the investigations originated in early 1990’s with investigations of stratigraphy and sedimentology (unpublished data), and later on investigations of source potential, organic geochemistry and palynofacies (Blažeković Smojić et al. 2009). Location of the Dinarides-Lemeš basin is shown in Figure 18.

![Fig. 18. Location of the Dinarides-Lemeš basin (Red area).](image)

On the basis of stratigraphy as well as petrographical and sedimentological features, Lemeš deposits are divided into 9 units that can be mapped over the entire area. The
thickness of the Lemeš deposits ranges from 250–450 m. The Lemeš deposits Unit 4 is the most interesting unit with respect to source rock potential. Unit 4 beds are characterized by alteration of cherty, silicified, detrital limestone with organic rich laminated limestone and calcareous shale. The laminated limestones and calcareous shales of the Late Jurassic (Kimmeridgian–Tithonian) Lemeš deposits are found to be a very good to excellent, highly oil prone carbonate source rocks. The Unit 4 strata contain abundant organic matter (TOC values 3–9%) that is hydrogen rich (Rock-Eval Hydrogen Index 509–602 mg HC/g TOC; atomic H/C ratios 1.4–1.7). The kerogen is sulfur rich (Type II-S, 9 wt% S) and is composed almost exclusively of fluorescent amorphous organic matter derived mostly from the algal/phytoplankton biomass enriched by bacterial biomass. This high quality petroleum source rock was deposited in a marine environment at low redox potential, characterized by oxygen depleted and euxinic stratified bottom waters, within a relatively shallow intra-platform trough on the Adriatic Carbonate Platform. Summing the interbedded limestones and calcareous shales beds, the Lemeš at the Poštak (Rastičevo) location achieve a thickness of 55–70 m. Of these, 12–20 m contains 2–10% TOC. These organic rich layers vary in thickness but are confirmed to occur within the Late Jurassic syncline covering an area of 42 km².

Hungarian Paleogene basin

The Hungarian Palaeogene Basin is located in the northern part of Hungary, along a SW-NE-striking belt (Fig. 19). A small part of the basin extends over the border into Slovakia.
During the Early Oligocene (Early Kiscellian) anoxic black shale, named the Tard Clay, was formed in a thickness of 80-100 m in the southern belt of North Hungary. It is widely believed that the main source rock of the Hungarian Palaeogene Basin is the Tard Clay, with minor source potential locally in the overlying Kiscell Clay formations (Kókai & Pogácsás 1991; Milota et al. 1995). A detailed oil-source rock correlation is missing, therefore the level of certainty of the Tard-Kiscell petroleum system is only hypothetical (Badics and Vető 2012). There are 443 wells with well-top information in the area, of which 85 wells penetrated the Tard Clay (Kőrössy 2004), while the total area is around 7800 km².

Generation of hydrocarbons probably occurred from Late Miocene to present-day, depending on the amount of tectonically-induced subsidence. Conventional trap formation was related to formation of tilted fault blocks that developed from the Middle Miocene onwards during the several strike-slip movements. Most hydrocarbon generation was late, and post-dated structure development. Conventional exploration started based on surface seeps, resulting in the first discovery at Bükkszék in 1937 (Kőrössy 2004). The main conventional fields are Demjén (70 million barrel oil in-place) and Mezőkeresztes (6.5million barrel oil in-place), both discovered in the 1950s (Fig. 19).

Generated hydrocarbon volume can be evaluated by assuming a mean net (>1%TOC) source rock thickness of 27 m and an oil-mature area of 2600 km², a gas-mature area of 1900 km², 2.21% mean immature TOC and 433 mg HC/g TOC HI, the Tard Clay could have generated up to 18 billion barrel oil and 4 billion barrel oil-equivalent gas in the Palaeogene Basin. If we assume that the accumulations containing 0.12 billion barrel oil-equivalent in-place volumes have been charged from the Tard Clay, the generation/accumulation efficiency would be around 0.5%. Assuming a 60% expulsion ratio, the un expelled petroleum still sitting in the source rock could be up to 7 billion barrel oil-equivalent (Badics & Vető 2012).

The Tard Clay, especially its laminated upper part, could represent the second best potential shale gas/shale oil play in Hungary, due to its organic richness, favourable maturity and large extent. The organic richness is at the lower end of the proven shale gas plays of North America (Jarvie et al. 2007). The depth of the gas-mature section is 3000-4500 m, and 1300-3000 m for the oil-mature section and the total area is extensive, 1900 km² gas-mature and 2600 km² oil mature. Therefore the Tard Clay can represent a potential shale oil/shale gas play. Lower potential fracture barriers exist where the Tard Clay is underlain by Palaeozoic basement or the Buda Marl. In areas where karstified Triassic or Eocene limestones are present, the lower fracture barrier is unlikely. The shale layers of the Kiscell Clay could represent the upper fracture barrier. The high illite content could represent problems for the fracturing (Badics & Vető 2012).

The maturity of the Oligocene source rocks is controlled by their thermal and burial history and the latter is directly connected with the tectonics. The vitrinite reflectance of the studied Oligocene sequences varies between 0.4-1.0% in the near-surface and deep borehole core samples. Much of the Oligocene sequence in the southern part of the basin lies in the oil window. In contrast, kerogens in outcrop and near-surface sediments are immature.
Fig. 20. Tard Clay (Lower Oligocene) source rock properties and Rock-Eval data from Ad-3, Cs-3, Nk-I and V-1 wells in the Palaeogene basin. (a) TOC (wt.% histogram; (b) TOC vs. S2; (c) HI vs. T-max, (Based on IGI’s geochemical software package, p:IGI); (d) Present-day extent and thickness of Tard Clay with most important wells: Ad-3, V-1, Cs-1, Nk-I and fields likely sourced from Tard Clay in italics; (e) Depth to Top Tard Clay; (f) Calculated maturity (shown as vitrinite-reflectance) of Tard Clay (Badics and Vető 2012).

Total organic carbon, extractable organic matter, sulphur content, kerogen type and saturated hydrocarbons have been determined in 25 core samples from an approximately 100 m thick section of the Oligocene Tard Clay, near Budapest. The Tard Clay records a five million yearlong anoxic cycle initiated by isolation of the sea,
development of a positive water balance and resulting density stratification, an a
terminated by there-opening of access to the sea. The lower, non- and moderately
laminated shales record the build-up of anoxia, they contain 0.5-5.0% of organic
carbon and Type III kerogen. The overlying moderately and strongly laminated
sediments containing 1.5-5.0% organic carbon, a predominance of hopanes over the
n-alkanes and Type II kerogen show the imprint of increased planktonic productivity.
The nutrients needed for this high productivity were liberated by alteration processes
of contemporaneous volcanic glass. The upper part of the strongly laminated shales
containing a maximum of 2% organic carbon and Type III kerogen, deposited after
the termination of volcanic ash falls, records a drop of planktonic productivity. At the
top of the Tard Clay the weak lamination and the low content (< 1%) of organic
carbon signifies the end of the bottom water oxygen depletion due to the destruction
of density stratification of the water column (Bruckner-Wein et al. 1990).

**Mura-Zala basin**

The Mura-Zala basin was used to be named the Mura Depression in Slovenia before
2005, and termed the Zala Basin in Hungary (Fig. 21). Due to very successful
geothermal and related cooperation projects within the last 15 years, between
Western Pannonian countries (H-SK-A-SLO-CRO), both depression and basin areas
became to be named the Mura-Zala Basin. It is very typical for this basin that it
consists of SW-NE trending tectonic structures, which can be divided into syn-forms
and anti-forms.

![Fig. 21. Location of the Mura-Zala basin (red area).](image-url)
Slovenia
The most prospective geological area for shale gas and oil in Slovenia is the Mura-Zala Basin situated in the SW part of the Pannonian Basin System. One of the basic studies of this system is a well-known work of Royden and Horváth (1988), which to a high degree influenced later studies in all countries of the Pannonian Basin. One recent overview on the evolution of the Pannonian Basin referring especially to its geothermal resources has been published by Horváth et al. (2015).

Three (3) prospective areas with oil and gas potentially generating strata are differentiated in the Mura-Zala Basin in Slovenia. They are according to their significance:
- Ljutomer sub-Basin and Ormož-Selnica Antiform
- Radgona sub-Basin
- NE slopes of the Murska Sobota Block

The Ljutomer sub-Basin and the Ormož-Selnica Antiform are joined in this study because they were a uniform sedimentary accommodation space during the whole Miocene. Within alternating sands (with time lithified to sandstones, up to 10-40 m thick) and clayey carbonate silts (with time lithified to clayey marls, also up to 10-40 m thick) organic matter was deposited, from organic detritus to peat, which transformed with time to humic/vitrinite particles and sporadic coal measures, the latter especially in the Pontian time, and not over-passing the meta-lignite rank of coalification. In post-Pontian times, during Pliocene, an inversion of the basin occurred between the reverse Ljutomer and Donat Faults. The result of the uplifting was formation of the Ormož-Selnica Antiform. Faults and fissures enabled gases and oil to move upwards from deeper source strata into four main oil and gas-bearing horizons termed as the Petišovci, Lovászi, Ratka, and Paka sandstones, now lying in depths between 1,200 and 1,700 m, and having been exploited most intensively in the 1950s. These “upper” horizons, which are almost entirely depleted, are not the theme of the present study. Theme of the present study is deep Miocene strata in which oil and gas were able to be generated. These strata consist mainly of marls and sandstones.

According to data from the Ljut-1, Pg-5 and Mg-6 wells, oil prone and mature enough (> 0.7 %Ro) strata in the area of the Ljutomer sub-Basin and the Ormož-Selnica Antiform are 0.9–1.2 km thick. They occur in a depth of 2 km and more. Gas prone strata with maturity > 0.9 %Ro occurs from about 2.6 km downwards and are 0.6 – 1.7 km thick. It is estimated that the volume of the potentially oil generating strata (OGS) is 850 km³, and the volume of the potentially gas generating strata is 950 km³.

In the deepest parts of the Ljutomer sub-Basin, Neogene (Miocene and Pliocene) sediments are close to 6 km thick. Gas source sediments are maybe even thicker than 1.7 km, but definite data are lacking because numerous wells did not reach the basement. Gas was more likely to be generated, because kerogen type III with HI <250 mgHC/gTOC highly predominates over the kerogen type II, whereas kerogen type I is not present in the Mura-Zala Basin at all. Kerogen type II is somewhat more outstanding in the Middle and Upper Miocene strata (Sarmatian and Pannonian), attaining up to 420 mgHC/gTOC, but maturity is too low for generation of oil and/or gas, respectively. Another area of both potential oil and/or gas generation is the Radgona sub-Basin. Considering a depth of more than 1.5 km, it embraces a very small volume of potential oil and/or gas generation – less than 18 km³ for oil, and less than 11 km³ for gas.

The third area, in which only oil was maybe generated, is called in this report “the NE slopes of the Murska Sobota Block”. The latter, covered with less than 1.5 km thick
Neogene sediments, is an area of no hydrocarbons generation potential, but hydrocarbons might be generated on the slopes of the mentioned block in sediments deeper than ca. 2.5 – 3 km sediments, which extend and deepen toward NE – to Hungary (to the Zala basin, where also gas might be generated). Organic matter in sediments of the NE slopes of the Murska Sobota Block exhibits lower maturity than in other two areas. It is measured to be lower than 0.7 %Rr, or maybe somewhat higher in the deepest (4 km) sediments, which were penetrated by only one well. In any case, maturity is under 0.9 %Rr, so not reaching the gas window – at least not in Slovenia. Thickness of potentially oil generating strata varies in a range of 0.3–1.7 km. They are developed in an area of 315 km². Volume of the oil generating strata is calculated to be 380 km³.

For the whole Mura-Zala Basin, it is summarized that the volume of oil generating strata (OGS) is about 1,250 km³, and the volume of gas generating strata (GGS) is about 960 km³. Sandstones are considered as tight oil and/or gas potentially generating (and/or bearing) strata, whereas marls are considered as shale oil and/or gas potentially generating strata. Based on previous studies, a 35/65 sandstones to marls ratio (or “tight-to-shale” ratio) is taken into account. Volume of tight OGS is therefore 435 km³, and of shale OGS is 815 km³. Volume of tight GGS is 335 km³, and that of shale GGS is 625 km³.

Total organic carbon (TOC) content does not exceed 2% and this means that source rocks of the Mura-Zala Basin are only “poor” to “fair” source rocks (according to a classification of Schlumberger). An exceptionally high TOC content, 3%, was detected in a marl in only one well in the Radgona sub-Basin.

Shale oil and gas in Slovenia is only occurring in marls, which are normally classified as unconventional hydrocarbon sources. However, tight oil and gas in sandstones are also treated in this study together with shale oil and gas. Namely, they occur together in alternating beds and would be possible to be exploited only with using stimulation techniques to enhance the recovery of hydrocarbons. Both lithology’s have low porosities, marls only about a few %, and sandstones about 10 %. Pre-Tertiary basement rocks were not investigated as source rocks in Slovenia. However, it is not excluded that the basement rocks – especially carbonates – do have some potential for oil and/or gas generation. Clarifying of this question remains for the future exploration.

Hungary

In western Hungary, the Upper Triassic Kössen Marl has excellent source-rock potential. Fields producing Triassic oils in the Mura-Zala Basin include Bak, Barabásszeg, Nagylengyel, Pusztapáti, and Szilvágy (Fig. 22). As a result of extensive successful exploration, the unit has produced substantial oil and gas. Significant traps are associated with basement highs and with structures along strike-slip faults. Reservoirs within nappes of the pre-Tertiary basement constitute important exploration objectives; however, they are pervasively faulted and fractured, and their distribution and structural configurations are not well known. Fields producing Triassic oils in the Zala Basin include Bak, Barabásszeg, Nagylengyel, Pusztapáti, and Szilvágy.
Development of shale gas and shale oil in Europe

Fig. 22. Kössen Marl (Upper Triassic) source rock properties and Rock-Eval data from Rz-1 and Zlt-1 wells. (a) TOC (wt.% histogram; (b) TOC vs. S2; (c) HI vs. T-max, (Based on IGI’s geochemical software package, p:IGI); (d) Thickness and present-day extent with outline of Nagylengyel group of fields in black (based on Dank 1985) and wells with drilled thickness; (e) Depth to Top Kössen Marl; (f) Calculated present-day maturity (expressed as vitrinite-reflectance) of Top Kössen Marl (Badics and Vető 2012).

Unconventional hydrocarbon resource of Kössen Marl – Zala Basin
Upper Triassic Kössen Marl in the basement of the Zala Basin Kertai (1968) first suggested that the organic-rich marls of the Upper Norian-Rhaetian Kössen Marl had sourced the Nagylengyel heavy oil fields in the north of the Zala Basin. Later Koncz
(1990) and then Clayton & Koncz (1994) confirmed the oil-source rock correlation; therefore the Kössen-Cretaceous petroleum system can be considered as known (Badics & Vető 2012). The extent of the Kössen Marl has been investigated in the wells drilled in the Zala Basin and in Transdanubian Range outcrops. There are 534 wells drilled in the area, which have well-top information. 230 wells were drilled into the Triassic, but only 32 wells penetrated the Kössen Marl, as over large areas it had been eroded during Alpine orogenic events in Cretaceous and Palaeogene times (Körössy 1988). The thickness of the formation in the Zala Basin wells ranges between 17 and 575 m, with an average of 200 m, while the total area is around 1500 km² (Badics & Vető 2012). In the outcrops in the Transdanubian Range it varies between 150 m and 50 m and finally thins to 30 m in the north-east (Haas 1993). In the type well, Zalaszentlászló-1 (Zl-1), the thickness is 132 m. The 225 m drilled thickness in the Rezi-1 well (Rz-1) reflects steep dips and is hence not a true orthogonal thickness. The Rezi-1 section displays a gradual but well pronounced upward decrease of carbonate content. The Kössen Marl has been eroded in the north-western part of the basin, where Upper Cretaceous strata directly overlie the eroded top of the thick Norian Main Dolomite. Towards the west and south-west, the formation is buried very deeply, down to 5000-6000 m, under thick Upper Cretaceous and Neogene sediments, so its presence under the western part of the Zala Basin and in Slovenia is likely but unproven. Towards the south it is eroded again along the strike-slip zone of the Balaton line. Beneath the southern part of the Zala Basin, south of the Balaton Line, Triassic strata belong to the South Karavanka Unit, which has a different non-source facies.

The thermal and maturity history and timing of the hydrocarbon generation in the Zala basin has been investigated by PetroMod software (Badics & Vető 2012). A 3D basin model was created using regional depth maps. The observed present-day surface heat-flow and heat-flow evolution during the Neogene (Dövényi & Horváth 1988; Dövényi, 1994) and the average annual temperature (12 °C) were used as thermal boundary conditions. The observed surface heat flow in the Zala Basin is 80-100 mW/m². The 3D model was calibrated to match the measured temperature and vitrinite reflectance data in 25 wells. The amount of eroded section during the Late Cretaceous-Palaeogene uplift event was estimated. The present-day heat-flow could be calibrated very accurately due to the large number of calibration wells. The employed heat-flow history resulted in an uncertainty of the calculated maturity values of (plus-minus) 0.2% Ro. Most of the burial and thermal maturation took place in the Neogene, so the timing uncertainty was small. The deepest part of the Kössen Marl is at 250 C, this being in theory gas generation zone today in the south-western parts of the basin. Under the Nagylengyel field the Kössen Marl is still calculated to be in the oil-generation window, while in the north-east it is immature. The gas-mature area is around 270 km², the oil mature is 450 km² and the immature area is 780 km² (Badics & Vető 2012).

The Kössen Marl in the basin centre was buried into the oil generation zone between 15 and 12 Ma, and into the gas generation zone from 12 Ma onwards in the south-west, based on 3D basin modelling study of the Zala basin. The present-day maturity and maturity history broadly confirm the results of Clayton and Koncz (1994).

Assuming a mean gross formation thickness of 200 m, net source rock (>1% TOC) thickness of 140 m, a mature area of 720 km², 3.86% mean immature TOC and an HI of 516 mg HC/g TOC, the Kössen Marl could have generated up to 24 billion barrel oil and 5 billion barrel oil-equivalent gas in the Zala Basin, using the simple method of Schmoker (1994). The accumulations with proven charge from the Kössen Marl contain 0.35 billion barrel oil-equivalent in-place resources, so the
generation/accumulation efficiency is around 1.2%, a value within the limits set by Magoon and Dow (1994). Assuming a 60% expulsion ratio for the oil, like in the Barnett Shale (Jarvie et al. 2007), the 40% unexpelled petroleum still sitting in the source rock could be up to 9 billion barrel oil-equivalent. Some of that resides in the oil-mature areas as un expelled oil, while in the deeply buried area in the west it is modelled to have been cracked to gas, forming a potential shale gas play (Badics & Vető 2012).

Oil generation and expulsion in the Zala basin began in the Miocene during rapid subsidence and heating (fig. x) caused by lithospheric extension in the Pannonian basin. Geochemical characterization of oils produced from Triassic, Cretaceous, and Miocene reservoirs indicates that at least two, and possibly three, genetically unique oil types are present. One type, produced mainly from Nagylengyel field, is characterized by low pristane/phytane ratio (<1), predominance of the C_{24} tetracyclic terpane in the diterpane fraction, isotopically relative light hydrocarbons, high V and Ni content, and absence of oleanane. In some cases, the oils have CPI values greater than one in the C_{25}-C_{32} n-alkane fraction and relatively low sterane C_{29}aaa 20S/20R ratios, indicating low thermal history for both the source rock and oil. Source rock evaluation indicates that marlstones of the Upper Triassic Kössen Marl adjacent to the oil reservoirs are the probable sources for the oil. These rocks contain the highest amounts of organic carbon of any studied and have hydrocarbon and isotopic compositions similar to the oils. Previous hypothesis that Miocene rocks are the source of these oils are not supported by either correlations of Miocene rocks in the immediate vicinity of the oil accumulations (Clayton & Koncz 1994).

Vienna basin
The main hydrocarbon source rock in the Vienna Basin and Korneuburg Basin (also referred to as the Thaya Basin) is the Mikulov Marl which is present in a strip extending northeast of Vienna to the southeast of the Czech Republic (Fig. 23). The Mikulov Marl Formation reaches a thickness of more than 1000 m (2000 m in the Czech Republic). The largest thicknesses occur through duplications related to external alpidic thrusting within the Alpine-Carpathian foreland.

The Mikulov Marl has a kerogen type II (-III) and TOC’s ranging between 0-10%, but mostly above 2.0%. In addition, it has a wide lateral extent and covers the appropriate maturity range (Ladwein 1988; Ladwein et al. 1991). Lowest reservoir temperature is 70°C. Assuming a geothermal gradient of 2.7° to 2.9° per 100 m, the oil window is at 4000-6000 m depth (Ladwein 1988). At well Zistersdorf (Z-UT 2, Figure 3) a temperature of 230° has been recorded at 8553 m. This implies that the shallower parts of the Mikulov Marl are immature, and the deeper parts are within the oil and thermogenic gas window, and the deepest parts (mainly the eastern extent) are overmature with respect to gas generation (see Ladwein et al. 1991). At a mean depth of 5500 m, maturity is 1.2% Ro. Porosities and permeability are low in case of normal pressure. In case of overpressure, which is common below the Vienna Basin, porosity may reach 8 or 9% (Milan and Sauer, 1996).
**Molasse basin**

The Molasse basin is a foreland basin to the northern Alps and is located in South Germany, but continues to the east into Austria and to the west into Switzerland (Fig. 24). The basin was formed during the Alpine orogeny in Paleogene, and the large amounts of sediments (molasse) from the erosion of the Alps filled up the basin. In Mesozoic time, the area was a shallow sea and the molasse is underlain by 500-1000 m Mesozoic shelf sediments (Bachmann et al. 1987).

The shale oil and gas source rocks are the Permo-Carboniferous Weiach-Formation, the Lower Jurassic Posidonia shale, and the Paleogene Fish Shale (BGR 2016). Besides the presence of the Posidonia shale in the Molasse basin, the Posidonia shale occur north of the Molasse basin, following the southwestern rim of the Bohemian Massif.

Conventional hydrocarbon exploration has been taking place in the Molasse basin within the last decades, primarily in Austria and Germany. Over 1200 exploration wells have been drilled with around 200 conventional oil and gas discoveries.

A thorough shale oil and gas assessments for the German part of the Molasse basin is published in BGR (2016). No public assessment for the Austria part of the Molasse basin is available.
Fig. 24. Distribution of the shales in the German part of the Molasse basin and the northward extension of the Posidonia Shale following the Bohemian massif (red area).

**Lombardy basin**

The depositional history of the Lombardy basin (Fig. 25) began between the middle Permian and the Late Triassic with a continental clastic deposition. A marine transgression, coupled with Middle Triassic syn-sedimentary tectonics, controlled a complex paleogeographic setting: the dominating carbonate platform was complicated by intra-platform basins characterized by repeated episodes of anoxic conditions. The Ladinian rocks consist of carbonate platform deposits and limestones and black shales deposited in the intra-platform troughs (e.g. Besano, Meride, and Perledo-Varenna formations).

The Besano, Meride and Perledo-Varenna formations are the units deposited in the intra-platform anoxic troughs during the Ladinian (Middle Jurassic). These units share common lithological characteristics (Bongiorni 1987; Gaetani et al. 1992; Jadoul & Tintori 2012):

- Dark-grey limestone (mudstone and wackestone) and dolomite (with variable quantity of bitumen) in planar beds; they can either show lamination or no structure at all. This lithofacies make up about 90% of the unit thickness.
- Black fissile marl and shale (oil shale), which may form 10 to 50 cm sets (Besano, Meride p.p., Perledo member).
- Calcarenite and slumped beds.
The thickness of the units ranges from 100 to 400 meters, and the shale lithofacies from 10 to 40 meters (max thicknesses reported for the Meride formation). The units pass laterally and upward to the carbonate platform Esino limestones. Due to the Alpine orogeny these units nowadays appear tilted as a monocline with 30° SW dip under the Po river plain. As a matter of fact it is reported (Bertello et al., 2010) that these units have been found as deep as 4,500 meters (Bongiorni, 1987) in important oil fields in the western part of the Po Plain (Gaggiano, Trecate and Villafortuna). Unfortunately these oil field permits are still active and the well logs are not publicly available, except the Gaggiano 1 well log is published, in a simplified form, by Bongiorni (1987) that mapped also an isochrone and structural map of the top of the Meride formation in the Gaggiano oil field.

Even though it is difficult to map the extension of these units in the subsurface, due to the lack of data and their discontinuous distribution related to paleo-geographic setting, the conventional oil and gas exploration activities carried out from the ’70 have defined a general trend of these units from the outcropping areas (Southern Alps): because of their depth they can be pursued only in the outer sector of the foredeep and in foreland region, whereas along the thrust belt they are generally too deep (> 7,000 m). On the other hand the shallowest depths are registered where the Mesozoic structures are locally inverted by Cenozoic compression (e.g. Gaggiano, Trecate and Villafortuna).

The Late Triassic was characterized by shallow marine carbonate sedimentation, in the shelves, and pelagic limestones and marls deposition in the deeper basins; due to an overall rise of the sea level the troughs became more widespread with thickest and
Development of shale gas and shale oil in Europe

most organic rich rocks (Stefani & Burchell 1990) (e.g. Argilliti di Riva di Solto). This sedimentation was accompanied by a tectonic phase interpreted as the beginning of the rifting that led to the opening of the Ligurian-Piedmont Ocean or as an earlier event.

The outcropping (Iseo Lake area) upper Triassic Argilliti di Riva di Solto are highly overmature $R_o = 4\%$ (Stefani and Burchell, 1990) and are characterized by abundant diasterane content, both marine and continental kerogen types II and III (13-21% amorphous, 34-59% herbaceous, 28-45% woody), and a pristane/phytane ratio near 1 (Stefani and Burchell, 1990, 1993). TOC ranges from 0.5 to 5% with average value of 1.3%, with a sulfur content of 3.1% and HI of 251 mg HC/g rock (Lindquist, 1999). In the public subsurface data the Argilliti di Riva di Solto have been recognized only in two wells (Franciacorta 001 and Gerola 001) at the boundary with the outcropping Southern Alps, at depth of $\approx 3,000$ meters; only schematic distribution of the unit can be proposed after Riva et al. (1986).

Although black shales of Early Jurassic age (Toarcian) are well known in northern Europe (variously called the Posidonien schiefer, Jet Rock Shales and Schistes Cartons in Germany, Britain and France, respectively) their occurrence in the Tethyan domain is less well documented. In the Southern Alps, Toarcian black shales occur in the Lombardy Basin, on the Trento Plateau, in the Belluno Trough and in the Julian Basin (Farrimond et al. 1988). However, their distribution is not continuous across the region; as a matter of fact, Toarcian sequences on part of the Trento Plateau and in some areas of the Lombardy Basin lack black shales (Jenkyns 1988). This unit consists of black shales, dark grey to olive-black shales with carbonate layers, and dark-coloured mudstones or marls, from well to moderately or partly laminated.

The Marne d i Bruntino formation (Cretaceous) consists of thin and medium bedded, black to purple red shales (average thickness 10 meters) and marlstones, locally fissile, following by thick alternations of arenaceous-pelitic and marly calcareous turbidites (average thickness 70 meters), in homogeneous or graded beds, associated with vario coloured shales and black shales. The depositional environment is bathyal, cyclically in anoxic conditions. They are outcropping in the western part of the Southern Alps and drilled in the Po Plain at depth ranging from $\approx 300$ meters (Gerola 001 well) to $\approx 5000$ meters (Malossa field); however they are not continuous and it is not possible to define a well constrained trend of the depth. TOC ranges from 0.03 and 15.5%, with average value of 1.01%; generation potential range from 0.87 to 107.6 mg HC/g rock for samples with at least 1.0% organic carbon (Katz et al., 2000). Kerogen types II and III.

No published shale gas/oil assessment for the Lombardy basin exists and no exploration for shale oil/gas has been performed.

Ribolla basin

The Ribolla basin (Fig. 26) assessment by Bencini et al. (2012) refers to “Fiume Bruna” and “Casoni” exploration licences and all information included in this reported is from this study. A Miocene age organic rich sequence consisting of one laterally continuous 9-11 meter thick seam of coal and black shale, saturated with thermogenic gas, able to produce excellent quality natural gas by desorption after stimulation. It has a permeability of 1-2 mD and responds more like gas shale than a classic high permeability coal.
The TOC value ranges from 1.38 to 56.14%. Average TOC value is approximately 20% and vitrinite reflectance values range from 0.825 to 1.302 %. Gas is interpreted to be producible from both the coal and the organic rich shale that is associated with the coal seam, at an average depth of approximately 1000 m. Additionally, there are indications that the 70 meter thick laminated marl and clay sequence immediately above the main seam may be prospective for shale gas as well (Fig. 27).

Summary of the published results of the assessment from Bencini et al. 2012:
- Single play, coal and gas shale (tens of meters thick)
- Coal and gas shale have similar gas content of 4.7 m³/t (152 scf/ton) at approx. 80 bars.
- Dry organic rock with 1-2 mD permeability and gas saturated.
- Water-based fracking tried. Next step is nitrogen fracking.
- More than 190 km² of potentially productive area an average depth of 1,000 m.
- Estimated 27.4 BCM (968 BCF) of gas in place.
- Estimated 5.7 BCM (203 BCF) of recoverable gas.
- 69% Shale Gas and 31% CBM/CSM.
Emma and Umbria-Marche basin

Bituminous limestone, evaporitic and euxinic black shales of the Upper Triassic and Lower Jurassic (Emma Limestones and euxinic limestones inside the Burano formation) are considered the source rocks for many conventional oil reservoirs in the Emma basin (Adriatic and Apulian area)(Novelli and Demaison 1988; Zappaterra 1994; Bertello et al. 2010)(See Fig. 28 and table 4). Deep wells in the Gargano and Apulian areas show that the present depth of the Upper Triassic black shale is 4,500 to 5,000 meters, but the shales are often thin and irregular in occurrence.

Table 4. Summary of the geochemical parameters estimated for the Late Triassic evaporites and euxinic deposits outcropping in the Apennines range or explored in the Adriatic –Apulia area.
In general, the Umbria-Marche pelagic Mesozoic sequence (Jurassic-Cretaceous) shows a low hydrocarbon potential except for some portion where euxinic black shale and rich organic matter levels occur: Marne del Monte Serrone Formation; Marne a Fucoidi Formation; Livello Bonarelli. These organic enriched formations related to the main Oceanic Anoxic Event (OAE), defined by relatively high total organic carbon (TOC) values and clearly synchronous across Tethys and in global context (Jenkyns 2010; Soua 2014).

**Marne del Monte Serrone Formation**
The lithofacies deposited in the basinal condition on the structural highs are characterized by low TOC % (0.1-0.3). The poorly-oxygenated, black shale and black shale-like sediments originated in the deepest portions of the basin, show higher TOC% (0.5-2.7) (Parisi et al. 1996). The TOC values estimated by Katz et al. (2000) are 0.19–2.34% (mean 0.95%) and the mean value of the Total hydrocarbon generation potentials is 6.19 mg HC/g rock. The organic matter is mostly composed by a mixture of continental organic debris and marine components such as dinoflagellate cysts, foraminifer linings and Tasmanaceae algae (Gugliotti et al. 2012); Katz et al. (2000) classified these sources rock as Type II-III. The thickness of the oxygen-poor deposits is variable and related to the morphology of the basin and the different extension of the stratigraphic succession. In the Umbria-Marche Toarcian outcrops deposits the net thickness of black shale and black shale-like deposits ranges from 1 to 24 meters, with minimum values in the condensed succession (Parisi et al. 1996). Therefore, although this stratigraphic interval displays characteristics typical of potential source rocks, the thickness of the organic-rich interval is much more variable and limited. Not specific information are available for the characteristics of this
formation in the subsurface; basing on the seismic across the anticlines penetrated by the Cornelia 1 and Pesaro Mare wells to the north of Ancona, the depth of the top of the RSN could be evaluated in at least 4,000-5,000 meters for the Northern Adriatic basin.

**Marne a Fucoidi Formation**

The Poggio Guaine section, located between Mount Nerone and Cagli, is considered a reference section for the Aptian-Albian interval. In this section the total thickness of the Marne a Fucoidi Formation is 82.53 m (Coccioni et al. 2012). Basing on field observations of the Marne a Fucoidi Katz et al. (2000) suggest that a typical organic-rich sequence is less than 0.25 m thick, and those organic-rich-organic-poor cycles are 1.5 m thick. The exposed sequence near Gubbio is >50 m thick, implying a net source-rock thickness in excess of 8 m. Arthur and Silva (1982) observed that the highest levels of organic enrichment are largely confined to a 20 m thick, lower to lower-middle Albian interval at Gubbio. Fiet (1998) reported that within the Umbria-Marche Basin, as many as 150 thin black shales may be present in a 42 m gross interval.

**Livello Bonarelli**

The **Livello Bonarelli** represents a regional marker bed located at the top of the Scaglia Bianca Formation, close to the Cenomanian/Turonian boundary. This marker consists of organic-rich sediments related to the well-known Oceanic Anoxic Event 2 (OAE2 – Scoppelliti et al. 2006 and references therein). Unlike the surrounding formations which are rich in foraminifera, strata associated with the Bonarelli Event are rich in radiolaria and fish remains (Jenkyns 2010). Such a shift may indicate an increase in primary productivity. Unweathered samples from the Bonarelli Event analysed by Katz et al. (2000) contained as much 27.5% TOC (mean value 7.71%).

Hydrocarbon generation potentials in excess of 280 mg HC/g rock have been determined for this interval, with a mean generation potential of ≈ 60 mg HC/g rock. When severely weathered, organic carbon contents are less than 0.5% (Katz et al. 2000). Pieri and Mattavelli (1986) described the kerogene type of the Livello Bonarelli as "90% amorphous and marine" and reported an average TOC value of 5.12.

The study carried out by Scoppelliti et al (2006) confirms the high TOC values for the Bonarelli black shale in the Bottaccione section. Although the Cenomanian-Turonian Bonarelli Event displays some of the highest levels of organic enrichment, in the Umbria-Marche domain it obtains thicknesses in outcrop of less than 2 meters at Furlo and Gubbio sections (Passerini et al. 1991). Because of the limited thickness the Livello Bonarelli doesn’t show a relevant interest as potential shale oil source rock. No published shale gas/oil assessment for the Emma and Umbria-Marche basin exists and no exploration for shale oil/gas has been performed.

**Ragusa basin**

The Ragusa basin lies onshore and offshore in the south-eastern part of Sicily (Fig. 29). The Noto Formation (Rhaetian) is known as the main source rock for the oil fields in this basin (Pieri & Mattavelli 1986; Novelli et al. 1988; Brosse et al. 1988). The Noto formation is rather constant in thickness and does not exceed 300 m. Depth of top is 2862 meters and bottom 3076 meters in the Noto2 well (onshore). Very limited thickness of the shale layers are found, for example in the Noto2 well the largest thickness for a single shale layer is of approximately 13 meter at a depth of 3017 meters and the shale layers thickness in this well usually range 1-2 meters. These geometric factors, also found in other wells, limit the economic interest of the Noto Formation as a shale oil resource.
Fig 29. Location of the Ragusa basin (red area).

The Streppenosa Formation is composed of three members (Frixa et al. 2000). The thickness of the Streppenosa Formation as a whole is highly variable, especially in the south-eastern part of the Basin, where it may reach 3000 metres or more. The theoretical highest petroleum potentials are associated with the intercalated black-shales of the Middle Streppenosa Member. The Upper Streppenosa Member has an average TOC of 0.8%. (Pieri & Mattavelli 1986; Brosse et al. 1988). Both members present limited thickness of the shale layers in available well stratigraphy (usually <20 meters), as such the economic interest of the Streppenosa Formation as a shale oil resource is limited.

No published shale gas/oil assessment for the Ragusa basin exists and no exploration for shale oil/gas has been performed.

**Caltanissetta basin**

The Caltanissetta basin was formed by the Maghrebian orogenic front since the beginning of Neogene period (Fig. 30). The deposition of the major part of the early Messinian Tripoli formation took place in near normal marine conditions submitted to cyclically controlled variations of productivity. The Tripoli formation of early Messinian (upper Miocene) age is composed of a repetition of sedimentary triplets composed of homogeneous marls, laminated marls (sapropelic) and diatomites which are usually interpreted as being constrained by the astronomical precession. Polished specimens of tripolitic marls from the Cozzo Disi sulfur mine revealed much interstitial pale
orange-fluorescing organic matter (probable bituminite), sparse vitrinite or inertinite, and much finely disseminated pyrite under UV reflected light (Dyni 1988).

Fig. 30. Location of the Caltanissetta basin (red area).

The Tripoli deposits reach a maximum thickness of 45 m in the centre of the basin. Uplift and emergence of the Messianian rocks with folding and faulting has locally exposed the Tripoli Formation, typically in small synclinal structures, within the basin (Dyni 1988). Much of the Tripoli formation is found in small, commonly faulted, synclinal structures. In parts of the basin, the formation is buried 900 or more meters below the surface. Locally, such as at the Cozzo Disi mine the formation is strongly folded. In other areas, such as at the oil-shale mine near Serradifalco and near Villarosa, the formation is relatively little disturbed (Dyni 1988).

Determinations of the tripolitic rocks are sparse, shale-oil yields estimated from Rock-Eval data range from 8 to 125 l/meter ton with a mean shale-oil estimate of 32.9 l/meter ton (Dyni 1988). The petroleum potential (oil and combustible gas) for fresh tripolitic rocks is estimated to about 51-88 billion barrels of oil equivalent for a 3,000 km$^2$ less tectonically disturbed part of the Caltanissetta basin. Plots of the S2 and S3 data on a Van Krevelen diagram indicate a type I kerogen; Tmax of the kerogen were found to range from 300°C to 400°C (Dyni 1988).

No published shale gas/oil assessment for the Caltanissetta basin exists and no exploration for shale oil/gas has been performed.
Cantabrian Massif

The Cantabrian Massif extends over the NE part of the Iberian Massif and represents the external zone of the Variscan Orogen in the NW of the Iberian Peninsula (Fig. 31). It comprises materials varying in age from the Precambrian to the Carboniferous.

Geologically, a division of the Cantabrian Zone has been established in seven different units that are from west to east: Somiedo, La Sobia-Bodón, Aramo, Central Carboniferous Basin, Mesozoic-Tertiary Cover, Ponga and Picos de Europa Units.

The base rocks are composed by the Lancara Limestones, Oville slates and sandstones and the Barrios quartzites with a Cambrian-Ordovician age. The Silurian is formed by the Formigoso slates and Furada sands. Devonian is represented by the Rafíñes complex, Moniello limestones, Naranco sands, Candás limestones and Candamo limestones. The Carboniferous sequence is constituted by the Griotte and Montaña limestones and the Lema and Sama groups (alternation between marine and continental deposits with coal beds).

The Cantabrian Massif extends over an approximate surface of 19,000 km². Two hydrocarbon wells were made in the area with an approximate equivalent of 0.1 wells for every 1,000 km².

Presence of mine gas has been known since long ago (methane with ethane traces, etc.) in the coal mines especially in the Central Carboniferous Basin. Also, the presence of mineral oils, distillates and condensates, parafin remains, ozokerites, etc. is detected in the host rock as well as in the coal beds. All these hydrocarbon displays (solid, liquid and gas) prove that the carboniferous materials constitute a source rock.

Fig. 31. Location of the Cantabrian Massif (red area).
The first discovered surficial natural gas emanation was the Mecheru de Caldones in 1915, when a prospective coal well reached 563m depth after crossing the Permian cover. Two more emanations in nearby wells appeared in 1920 and 1923. These surficial gas showings boosted a prospection campaign with non-satisfactory results.

The first natural gas drilling in Asturias was the Caldones-1 well in 1967 by CIEPSA in the Gijón Basin. The well reached a depth of 1846 m. The Carboniferous was found at 330m, after crossing the Permo-Liassic cover. Gas presence was detected at various intervals associated to siltstones and clay levels, and rarely to sandstones and carbonates, but were considered non-profitable. Gas was composed of methane in 95.51%, ethane in 2.14% and Nitrogen in 1.89%, with a hydrogen content of 0.46%.

In 1979 the IGME conducted a bituminous shale study of the Quirós, Teverga and San Emiliano Carboniferous Basins (Asturias), within the Spanish Bituminous Shale Exploration Project. The objective of the study was to understand the possibilities of bituminous shales in the Carboniferous basins of Quirós and Teverga, focusing on the productive levels of the Lena and Sama groups, but it was concluded that there was no interest.

In 1992, Hulleras del Norte S.A. (Hunosa) underwrote a protocol with the Spanish subsidiary of the North-American company Union Texas for surveying methane resources in their sites in order to understand the possibilities of exploitation and commercialization. The objective of this evaluation was part of the diversification policy undertaken by the state company. The research campaign focused on the Sama and El Entrego Sinclines associated to the most modern productive mining packages of the Central Carboniferous Basin. The wells drilled were Asturias Central-1 (1575 m) and Modesta-1 (2038 m), which spanned several layers of coal, with contents of 8-10 m³/t y 9-14 m³/t.

Another priority area was the unit from La Justa-Aramil, with a resource estimate of 1,400 Mm³ distributed in different areas (Río Miñera, La Justa, Barros-Tablado y Aramil).

Thermogenic methane (temperature of up to 150°, limit between medium and low volatile bituminous coal) was located in the northern and central part of the Central Carboniferous Basin. Other zones are in the semiantracite-antracite limit (>200°), with less methane accumulation potential. It is estimated that coal layers could accumulate a gas volume between 6 and 15 m³/t. CBM projects in this region focus on four surveys, one located in the Caldones Basin (Gijon), -accomplished by Ciepsa in 1967- and subsequent wells drilled in the middle of Central Carboniferous Basin, in which hydraulic fracturing was used experimentally. Later on, in the vicinity of the Barros well (Langreo), the Asturias CBM-1 survey was carried out, with the aim of assessing petrophysical parameters that affect the gas flow from coal beds.

The considered most favourable zones:

Out-cropping carboniferous basins:
- Sama, El Entrego y Turón Sinclines, in the section comprised between -600 and -2,000 m.
- Riosa-Olloniego Unit, under - 500 m.
- Central Carboniferous Basin, in abandoned mine workings such as Aller (Hunosa).
- Quirós y Teverga Coal Basins.
- Structural traps in carboniferous terranes, i.e. Aller, Pola de Lena and Nalón valley (Repsol, Anschutz).

Coal basins hidden under the Permo-Mesozoic cover with thickness between 400 m-800 m overlying productive coal basins. The most favourable are:
- Permotriassic basin near Gijón, with gas possibilities in the Carboniferous (i.e. Caldones).
- Carboniferous zone underlying the Permo-Mesozoic basin, i.e. La Justa-Aramil unit in the section between Aramil and Lieres (Siero).
- Permian basin of Cabranes-Villaviciosa, overlaying the productive Carboniferous corresponding to the northern extension of the Central Basin. It outcrops in Viñón. The probable extension in the covered Carboniferous is similar to Malón and Siero.
- Allochtonous of the Aramo Unit that thrusts over the Riosa-Olloniego Unit.

**Basque-Cantabrian basin**

The Basque-Cantabrian Basin is a Mesozoic-Cenozoic basin generated by two stages of subsidence (riifting): Triassic and Lower Cretaceous (Fig. 32). It features a Mesozoic-Cenozoic powerful sedimentary record that was folded and faulted during the Alpine Orogeny and represents the western extension of the Pyrenean Range. To the west it is limited by the Cantabrian Massif and to the east by the Palaeozoic Basque Massif. The southern edge borders the Cenozoic Duero and Ebro basins.

![Fig. 32. Location of the Basque-Cantabrian basin (red area).](image)

The Basque-Cantabrian Basin contains in its central part a mid-Triassic to lower Neogene very thick series (several thousand meters) of marine sediments, with Buntsandstein fluvial sediments of clays, sandstones and conglomerates at its base. Subsequent thick layers of evaporitic sediments (gypsum, anhydrite and salt) were deposited, forming the Keuper facies in the basin, which later formed a series of
diapirs. Source rocks appear in the Jurassic and Lower Cretaceous and reservoir rocks are composed of Lower Cretaceous sandstones and Upper Cretaceous limestones when they preserve their original porosity or have been fractured. The Basque-Cantabrian Basin has been considered since the beginning of oil exploration the most interesting area in Spain because of the presence of abundant surface indications such as tar sands in the core of the Zamanzas anticline or asphalts present on the edge of most diapirs, like Maeztu. It occupies an area of approximately 21,000 km² with 202 exploration wells, thus having a ratio of 9 wells per 1,000 km².

Exploration activities have taken place since the 1950s, principally in the Navarro-Cantabrian Trough where boreholes were drilled, particularly in anticlinal structures. The boreholes were Zúñiga-1 (year 1954-1955) and Alda-1 (1956-1959), both on the Gastiain anticline. These wells found gas in the Albo-Cenomanian siliciclastic complex (lateral equivalent of the Valmaseda and Utrillas formations), defining an exploratory objective that remains under investigation (Lower-Upper Cretaceous Hydrocarbon System). Alda-1 was later re-drilled (in the seventies) to reach the Triassic Keuper also finding gas traces in the Jurassic series.

In this early stage of the systematic exploration, several major exploration targets were defined in conventional reservoirs, which have been subsequently explored in the Basque-Cantabrian Basin: Purbeck series, Jurassic carbonates (Lias and Dogger) and Albian-Cenomanian siliciclastic complex.

As the wells (Castillo-1, Castle-2, Zuazo-1 Antezana-1, Vitoria W-1, Vitoria W-2, Castillo-3, Castillo-4, Osma-1, Castillo-5) bored into the later called Valmaseda formation, all of them drained a certain gas volume. In most cases there was no evident trap (anticlines, domes, or stratigraphic traps), nor porous and permeable rocks that could be catalogued at that time as hydrocarbon reservoirs. Although it was known that the Valmaseda formation had a certain content of organic matter, it couldn’t be proved that it was the system source rock.

Wells that investigated the eastwards lateral equivalent of Valmaseda formation found similar responses in siliciclastic Albien-Cenomanian formations.

In the North-Castilian Platform area, Cadialso-1 well (1983-1984) discovered a non-commercial gas accumulation, with spectacular signs of gas in the argillaceous limestones and Dogger marls (source rock). It is really an accumulation of non-conventional hydrocarbons (shale gas type and / or tight gas) in a reservoir with a barely permeable matrix.

In the Navarro-Cantabrian Trough, exploration continued around the Castillo Gas Field, having the Valmaseda formation as the main objective. The Armentia-1 (1997) well was designed to vertically cut the Valmaseda formation with the highest density of natural fractures possible. It was supposed that natural fractures could provide further formation porosity and permeability. Only the upper 447 meters of the Valmaseda formation were drilled, which are predominantly silts and shales (without porous or permeable levels). Still, in a test of long-term production, without any stimulation/fracturing, it supplied more than 0.5 BCF of dry gas, almost pure methane. It is clear that the Valmaseda formation should be treated as an unconventional gas reservoir.

The first oil field found in Spain was the small Castillo Gas Field, discovered in 1960. It produced gas until 1981 that was sold to the local industry of Vitoria. The reservoir consists of Cenomanian-Turonian fractured limestones. The source rock could be the Jurassic marls or the Cretaceous or Cenomanian-Turonian clay formations with high organic content.

The second discovery, the Ayoluengo Field, was made in 1964. It is in a faulted anticline, over a diapiric pad located between the Sedano and Polientes sub-basins.
The reservoir is in the detrital facies of the Purbeck-Weald, consisting of numerous lenticular bodies and highly fractured and faulted sandstones. The cover consists of clays that are intercalated between sand packs. The hydrocarbon source rock has been attributed to a Pliensbachian and Lower Toarcian black marine marl with a high content of organic material. The field began production in 1966 and is still producing oil in small quantities.

The third discovery in the Basque-Cantabrian Basin was made by ENIEPSA in 1980. The Gaviota Field of gas/condensate is located in the Cantabrian Sea about 10 km N of Bermeo. The reservoir consists of a fractured Upper Cretaceous limestone with a complex structure formed during the Late Eocene and Oligocene. Carboniferous coal and clay deposits are probably the source of these hydrocarbons. Production started in 1986 and the field was sold in 1994, having produced a total of 536,000 tons of condensate and 7,286 billion cubic meters of gas. The site and its facilities have been converted to an underground gas storage site.

The fourth discovery was the Albatros, a small field of gas/condensate located NW of the Gaviota field and in a similar position.

**Pyrenees basin**

The Pyrenean range stretches from the Gulf of León in the Mediterranean to the Bay of Biscay in the Atlantic. Structurally it has double verging tectonics. The eastern boundary of the South-Pyrenean slope is the Mediterranean Sea; the western boundary is represented by the structural alignment formed by the Basque-Cantabrian basin. To the south it borders the Rioja-Ebro Basin and at the eastern end with the Catalanian Chain.

The South-Pyrenean Basin is part of the Pyrenean range where Precambrian to Cenozoic materials outcrop. It is a structurally complex area, with a number of south verging sheets from the Alpine orogeny between the axial part of the Pyrenees in the N and the thrust over the Ebro Basin in the S (Fig. 33).

The South-Pyrenean domain encompasses the areas of the eastern, central and west Pyrenees, and has an area of about 20,000 km² in which 63 wells have been drilled (3 wells per 1,000 km²). ENPASA has been the most active company in this area with 24 exploratory wells, followed by ENIEPSA/Hispanoil with twenty surveys between 1978 and 1986 and Campsa and Valdebro with 3 wells each, Campsa in the 80’s and Valdebro in the decade of the 60’s. The maximum number of boreholes drilled per year was in 1964 with 11 wells, 8 of them in the area of the Benabarre structure.

The area was highly explored between 1960 and 1975 without any success; finally in 1975 ENIEPSA discovered the Serrablo gas field in 1978. The reservoir consists of two thick calcareous mega-breccias of turbiditic origin forming two separate fields, the Middle and Upper Eocene. The gas source rock may be the dark hemipelagic clays with a low content of organic material, but with a thickness of over 300 m. Production began in 1984 and ended in 1989, when the field became an underground gas storage site.

Two sites have been discovered, Jaca and Serrablo (1978). The Serrablo-1 discovered the deposit which together with the Jaca has produced a total of 931 Mm³ of gas. The last exploratory wells drilled have been Jaca-18 and Jaca-22 in 2003 by Enagas, for the development of depleted reservoir for the current gas storage site. Despite a gas potential in the Eocene materials, the drilling rate in the area is considered to be low. In 2003 four research permits (Abiego, Peraltillo, Barbastro and Binéfar) were granted to the Petroleum Development Associates Iberica (PDAIs) company. A year later
Cepsa obtained the research permits of Vallfogona East and Vallfogona West that were subsequently resigned.

**Duero basin**

The Duero Basin is located in the northwest quadrant of the Iberian Peninsula (Fig. 34). It has traditionally been considered an intraplate basin with complex evolution which began at the end of the Cretaceous.

The Mesozoic substrate of the basin includes deposits from the Triassic to Upper Cretaceous. It contains an accumulation of Tertiary pre- and syntectonic materials that reach 3,500m although most of the outcrops correspond to Tertiary post-tectonic deposits.

Depending on the tecto-sedimentary features several sectors are distinguished:

- **North sector**: behaving as a foreland basin of the Cantabrian mountain range at least since the Eocene.
- **Eastern sector**: related in the same way with the Alpine evolution of the Iberian Range.
- **Western and South-Western sectors**: characterized by horst and graben tectonics with NE-SW faults and its conjugates, formed mainly during the Paleogene.
- **South sector**: acting as a foreland basin of the Central System during the Oligocene-Miocene.
With an approximate total area of 47,500 km², 16 boreholes have been drilled in the Cuenca del Duero-Almazan (0.36 wells per 1000 km²). Valdebro company was the most active drilling company with five wells drilled in the period between 1955-1961. Phillips explored new areas with 3 wells between 1962 and 1963. Five other wells were drilled by different companies. El Campillo-1 well is the latest drilled by Repsol in 1990. No oil system has been found so far. ENDESA currently has drilled deep boreholes for CO₂ storage research in the area of Sahagún. Deep boreholes are very abundant in the Duero basin. They are particularly concentrated in its eastern part and reflect the existence of an eastern-northern very thick strip that continues in the Almazan Basin and into the Ebro Basin along the corridor of the Bureba.

The Palaeozoic is found at a depth of 799 m. (San Pedro-3) and 2849.5 m. (Villameriel-1). Found lithologies of the Carboniferous are: dolomites at 2517 m. (Alcozar-1), grey sandstone and claystone at 1581 m (The Gredal-1), and slates at 1000 m (Quintana Redonda).

**Ebro basin**

The Tertiary Ebro Basin is, geographically, a triangular depression, framed by the Pyrenees to the north, the Iberian Range to the south and the Costero-Catalonian chain to the east (Fig. 35). At its western end it joins the Duero Basin along the corridor of the Bureba.

The base of the Tertiary is located more than 3,000 meters below sea level in the Pyrenean mountain range and presents a trend of expansive overlap to the south, with
the oldest materials covering the Pyrenees margin and the most modern covering the Iberian margin.

The Ebro Basin occupies an area of about 39,700 km² and has a total of 41 drilled boreholes (1 well per 1,000 km²). The exploration of the area began in 1947 with the Oliana-1 well operated by Ciepsa. The maximum activity occurred in the 1960s, between 1960 and 1964 more than half of the total wells were drilled in this basin by Enpasa, Esso, Valdebro, Erap, Ciepsa and Cepsa companies. Later exploration decreased significantly to one or two wells per year. In the 1980’s Campsa began drilling the Rioja-4 and 5 wells showing the existence of a gas system in Mesozoic formations below powerful Tertiary series. Studies in the area suggest the existence of Jurassic source rocks, and Jurassic reefs or oolitic bars type reservoirs.

The last exploration well drilled in the area has been Viura-1 (2010) by the company Oil & Gas Skills, and has led to the discovery of a new deposit in the area.

Iberian chain basin

The Iberian Chain (or Iberian System) and the Costero-Catalonian Chain are two partially eroded alpine structures located east of the Iberian Peninsula (Fig. 36). Both form two tectonic units of similar age and style. This is a series of mountain ranges of NW-SE (Central Spain) and NE-SW (Cordillera Costero-Catalonian) trends that link in its eastern and southern ends, through El Maestrazgo. Overall, the degree of deformation is moderate, with very little alpine foliation and a very low degree of metamorphism.
The materials forming the Iberian System are mainly Mesozoic and Tertiary, although Palaeozoic base materials integrated in the Alpine foldingoutcrop locally. At the same time there are subsiding depressed areas in which, especially during the Early Cretaceous, thick layers of sediment, such as Cameros and Maestrazgo basins, were accumulated. It is possible to distinguish six sectors with different characteristics; two of them may have potential shale gas formations:

Camos-Sierra de la Demanda Structural Unit
This unit is located on the northern tip of the Iberian Range, and is formed by the mountains of La Demanda, Cameros, Urbión and Cebollera, in which east-west trends predominate. The Sierra de la Demanda is essentially constituted by Paleozoic materials, while the Cameros is constituted by Upper Jurassic and Cretaceous materials.

Aragonian Branch
It is located SE of the Cameros - Demanda structural unit. It consists of the Moncayo, La Virgen, Victor, Algairén and Cucalón Sierras, forming a marked NW-SE direction. The tertiary basin of Calatayud is located within the Aragonian Branch. Paleozoic materials outcrop in the cores of the structures, and Mesozoic materials around them.

The Iberian Range has an area of about 65,000 km² in which 18 boreholes (0.27 wells per 1,000 km²) have been drilled. In 1963 and 1981 up to three surveys per year were drilled, which was the highest drilling rate in this area. Operators who have explored the most in the area have been Amospain, Auxini, Enpasa, Campsa, Shell, INI-Coparex and Tenneco. The explorations have not found effective petroleum...
systems in the area to date. The highest drilling activity occurred during the sixties and seventies, when most of the wells were developed. The latest well drilled in the domain was Cameros-1 (Ciepsa) in 2002.

Catalonian basin

It is a narrow belt of mountains, linked in origin to the Iberian Range, which is divided into three main units: Litoral Chain, Prelitoral Depression and Prelitoral Chain (East to West). The northern part consists mainly of granites and metamorphic rocks of the Palaeozoic, while the southern half consists of predominately Mesozoic outcrops.

Carboniferous outcrops are grouped into two sectors, southern (Priorat and Sierra de Miramar, in Tarragona) and northern (Montnegre, Montseny and around Barcelona).

In the Catalonian Chain area 24 boreholes have been drilled (less than 2 wells per 1,000 km²). The first well was drilled in 1953, La Bisbal-1 by Sepsa. The peak years were 1962 and 1974 with 2 wells in each. Since 1979 a short break in the drilling occurs, until today. No proven petroleum systems are known.

Wells near the Enlace zone are Reus-1, Martorell-1 and San Sadurní-1 that cut across the Mesozoic and Tertiary materials, reaching an indeterminate Palaeozoic in Martorell-1 at 2,247 m. Location of the Catalonian basin is shown in figure 37.
Guadalquivir basin

Guadalquivir Basin is an elongated depression ENE-WSW direction, which is a foreland basin type and is located between the Betic orogeny at the south and the passive Iberian Massif margin at the north (Fig. 38). Its genesis takes place as a result of the deformation of the lithosphere caused during the placement and stacking of External Betic Units.

The sedimentary basin fill is composed by Tortonian and Pleistocene sediments. During the Tortonian, the compressive stresses in the foreland fold belt brought down olistostromes from the South. The northern boundary of the basin is defined by an almost straight lineament separating the Palaeozoic and Mesozoic rocks of the Cenozoic Sierra Morena basement.

The substrate of the Neogene basin is composed of metamorphic or igneous Palaeozoic rocks. In its eastern and western margins the Mesozoic formations emerge, consisting of a basal Triassic in the germanic facies and a Jurassic-Cretaceous carbonate series which progressively appears more complete eastward.

The upper Quaternary-Miocene fill is divided into several units, which form five depositional sequences that prograde from the north, east and south margins towards the centre of the basin and are named by age order: Atlantis, Bética, Andalusia, Marismas and Odiel.

Guadalquivir basin covers an area of about 23,000 km², in which 90 wells have been drilled (almost 3.9 per 1,000 km²).

Fig. 38. Location of the Guadalquivir Basin (red area).
Exploratory activity is concentrated in two clearly distinct periods:

1945-1969 research period primarily conducted by Adaro, in which wells were drilled to increase the knowledge of the basin but there were no oil discoveries.

1981-2004 initiated by the Chevron exploration company that interprets the Guadalquivir Basin as a landward continuation of the gas fields discovered in the Gulf of Cadiz. In this period 51 boreholes were drilled.

The Palancares-1 well drilled by Chevron in 1982, was the first discovery. Other operating companies in addition to Chevron are Repsol, Ciepsa, and, in recent years, Petroleum Oil & Gas which has drilled from 2000 to 2007, the most current surveys in the area.

The success rate, defined as wells put into production, is higher in the case of Chevron, which carries more than 50% of drilled boreholes (80% of its wells find gas, although not all are commercial).

Of the boreholes drilled in the second period 16 were put into production, which provides an overall success rate of more than 30% or 1 in 3 boreholes drilled for commercial discoveries.

Total production provided by the Guadalquivir fields (biogenic gas with 98% methane) to December 2004 amounted to 1,199,026 MNm³, of which nearly 90% comes from the Campos de Marismas (1,047 MNm³).

The interest of this basin for potential shale gas reservoirs focuses on the Palaeozoic substrate. The degree of uncertainty is high, since the Palaeozoic has usually been the level of completion of exploration oil drilling and no petrophysical data are available. Three zones, where the Palaeozoic is covered by Miocene-Quaternary sedimentary series with a variable thickness up to approximately 3500 m are considered.

**Lusitanian basin**

The Lusitanian basin located on and off west-central Portugal, is one of the major sedimentary basins in Portugal and contains formations with potential for conventional and unconventional resources (Fig. 39). It is limited to the east by the Iberian Meseta and extends from south of Lisbon and to northwards to about the city of Porto.

Portugal has a potential shale hydrocarbon resource, in particular in the Lower Jurassic of the Lusitanian Basin. In 2010-2014 a private company (PORTO ENERGY) developed a program to establish the extent of the resource play in the basin, its environment of deposition, its resource play parameters, and "sweet spot" areas to drill in the next phase of its exploration company program (McWhorter et al. 2014).

The basin has undergone sporadic drilling since 1906, in 1998-2001 a four-well campaign by Mohave Oil & Gas Corp for conventional resources. Recently the company Porto Energy (a subsidiary of Mohave Oil & Gas Corp.) drilled 23 wells as part of an initial exploration for unconventional gas in the onshore part of the Lusitanian basin. This exploration identified a group of formations with potential for unconventional resources as shale gas and shale oil. The main potential for unconventional gas and oil was evaluated to be in the Lias (Lower Jurassic) in an Upper Sinemurian/Lower Pliensbachian carbonate section that comprises of alternating, shallow to deep marine argillaceous limestones and marls, as an unconventional resource play (McWhorter et al. 2014). The segments of interest were concentrated in the two organic-rich marls, the Polvoeira Member of the Agua de Madeiros Formation and the Vale das Fontes Formation, separated by a limestone interval of varying thickness. The 23 boreholes...
and reports are retained to GALP (Portugal’s oil and Natural Gas Company) and are locked for research for the next 5 years.

Fig. 39. Location of the Lusitanian Basin (red area).

In this context, 23 shallow wells were drilled (160 m average depth, one well 451 m deep) to collect cuttings and conventional cores in the Lias section over a wide geographic area. The main conclusions are discussed in McWhorter et al. (2014). Porosity (from shallow wells) ranges from 0.2 to 19.8% over a total thickness of up to 400 m (average 200 m). The Lower Jurassic is characterized throughout the basin by a TOC average range of 2.3 to 5.9%, Ro values of 0.5 to 1.8%, and quartz-carbonate content of 63.8 to 83.7%. Organic matter in the Lower Jurassic is dominantly kerogen type II in the prospective middle of the basin, with drilling depths of 1000 to 3500 m, where Tmax mapping also shows the thermal maturity necessary for oil and gas generation (greater than 450 degrees in the prospective areas). Additional information, such as oil and gas shows in old wells throughout the basin, oil seeps at the surface, and live oil in shallow Lias cores verify a viable resource interval. The Lusitanian basin’s Lias were compared in this study to other unconventional resource plays in North America (Eagle Ford, Niobrara, and Utica) as well as other Lias plays in Europe (McWhorter et al. 2014).

**Aquitaine basin**

The Aquitaine Basin is the second most extensive basin in France (66 000 km²) (Fig. 40). For its long and complex evolution, the triangular-shaped Aquitaine Basin can be divided into a northern part which did not undergo much deformation and middle and southern parts which are a complex puzzle of sub-basins under the Cenozoic molassic
cover, with some places that cumulated up to 11 km of deposits. The Aquitaine Basin has long been studied for hydrocarbons, and most of the gas resources come from the southern sub-basins. Among the source rocks deposits are the Sainte Suzanne shales.

The Sainte-Suzanne Marls Formation (Bedoulian – Lower Aptian) is also known as the Deshayesites Marls Formation. It is made of homogenous marine, organic-rich shales with occurrence of bio-clastic marly limestones. It can reach several hundreds of meters thick, with a mean TOC at 1-2%. The OM is of type II origin, but the formation has only crossed the oil window in the southern parts of the basin (Serrano et al. 2006). Actually, the Sainte-Suzanne marls have been mostly considered as a main cover for petroleum and gas systems and were not properly studied in an exploration perspective. The regional synthesis of the Aquitaine Basin is based on BRGM (1974) and Serrano et al. (2006).

**South-East basin (France)**

The South-East Basin is the third most extensive basin in France. It is triangular shaped, with the rhodanian corridor as the main axis, from the Burgundy High and the Bresse Graben (North) to the Provence and Camargue domains (South)(Fig. 41). The South-East basin is a poly-phased basin, and consequently the South-East Basin is highly complex, with numerous blocks and sub-basins together with thick (up to 11 km) but highly variable sedimentary succession. Because of its complexity the South-East Basin has been much less explored for hydrocarbons. The present day exploration is focuses on the Provence, Alès, Causses and Languedoc sub-basins.
The Stephanian stratotype comes from Saint-Etienne city, famous for its coal resources which have been mined for more than 150 years. In the South-East Basin, several Stephanian and Permian sub-basins are identified along Hercynian structures. Not much public data regarding thickness or TOC content is available from these scattered basins. The high subsidence permitted the accumulation of very thick terrestrial series but with frequent lateral changes. Coal seams vary greatly because lenticular shaped, but the organic deposits can represent up to 10% of the Stephanian series in the Blanzy Basin. In the Lons-le-Saunier sub-basin, only known from drilling survey, the coal seams represent only 5% of the 600 m thick Stephanian series. All the Carboniferous sub-basins comprise several coal seams or bituminous shales. Conversely, only some of the Permian sub-basins are organic rich (bog-head and bituminous shales) such as the Blanzy-Creuzot sub-basin and the Causses sub-basin for which no TOC/isopach data is available.

The Schistes Cartons Formation (Toarcian) deposits are thicker in the Southern part of the South-East Basin (south of Lyon), with up to 500 m. In the northern part, the Schistes Cartons Formation is absent (except in Franche-Comté, NE) because of the regional condensed sedimentation around the Lyon High. Conversely, the Schistes Cartons Formation is well developed in the southern part, despite synsedimentary tectonics at some places (Causses sub-basin). Finally, the Subalpine domain recorded a proximal-distal sequence from the south (Nice, Castellane) to the North (Mont Blanc) but with condensed or absence of the Schistes Carton Formation. As a consequence, the South-East Basin lacks precise and dedicated studies for unconventional resources.
The regional syntheses on the South-East Basin, including Bresse, Jura and Causse basin was summarised in the BRGM’s synthesis (Debrand-Passart et al. 1984a, 1984b). More recent works, partly confidential, were dedicated to either Carboniferous/Permian basins (Beccaletto et al. 2015) or Liassic deposits (confidential reports for oil and gas companies).

**Autun basin**

The Autun Basin is a low-elevation topographic depression located in the northern part of the Massif Central (Fig. 42). It is a small elliptic basin of 250 km² (approximately 30 x 12 km) filled with Carboniferous (Stephanian) to Permian deposits, the so-called Autunian deposits, separated by an unconformity. The Autunian series are more than 1000 m thick and comprise the Lower Autunian, including an “autuno-stephanian” interval (the Autunian is not sedimentologically distinct from the Stephanian) and the Upper Autunian. The lacustrine deposits are organic rich, with oil shales and bogheads. The various oil shales intervals were investigated and the potential estimated (Marteau et al. 1982). The petroleum potential ranges from 70 to 100 kg/t and is twice that of the Schistes Cartons. The total reserves estimated (max. 300 m depth) are ± 30 Mt.

![Fig. 42. Location of the Paris and Autun basins (red areas).](image)

**Paris basin**

The Paris Basin has been one of the most studied sedimentary basins worldwide for two centuries (Fig. 42). Most of the published works specifically focused on Mesozoic
and Cenozoic strata and basin evolution (e.g. BRGM 1980; GFEJ 1980; Delmas et al. 2002; Robin et al. 2000; Guillocheau et al. 2000), but seismic and a few well also shown extended and very thick Stephano-Permian basins underneath (Beccaletto et al. 2011, 2015; Gély et al. 2014).

The main source rocks of the Paris Basin are represented by the Carboniferous to Permian Stephanian coal deposits and associated coal bed methane (CBM), and the Lower Jurassic marine shales, including the Promicroceras Shales Formation (Sinemurian), the Amaltheus Shales Formation (Pliensbachian) and the Schistes Carton Formation (Toarcian) which truly is black shale.

The Late Carboniferous to Permian (Stephanian) sub-basins has been poorly studied and are rarely the target of dedicated seismic or drilling surveys by hydrocarbons companies. Therefore, the issues of their extension, thickness, sedimentary filling, internal geometry and structural control still remain open.

The Lower Liassic shales are black marine shales source rocks (Sinemurian - Pliensbachian) containing type II kerogen. The Promicroceras shale Formation (‘Lotharingian’ = Sinemurian) source rocks consist of blue-grey illitic shales with TOC content ranging from 0.2-0.9 wt% (Bessereau & Guillocheau 1994). The Amaltheus Formation (‘Domerian’ = Late Pliensbachian) shale source rocks comprise grey, silty, and micaceous illitic shales. TOC ranges from 2-4 wt% with a maximum HI value of 130 mg HC/g TOC (Bessereau & Guillocheau 1994).

The Schistes Carton Formation (Toarcian), also known as “Lias Marneux” in the South-eastern part of France was deposited during the Toarcian across a large area encompassing several European basins (Fig. 43).

This is actually the most extended and most organic rich of the Jurassic black shales formations, with an average TOC around 4-5% (Espitalié 1987). It is to some extent comparable to the Bakken shales of the U.S. (Monticone et al. 2012). The OM is a type II kerogen (marine bacterial and algal) with a Hydrogen Index (HI) values ranging from 500 to 750 mg HC/g TOC (Delmas et al. 2002). The oil window of the Schistes...
Cartons has been traced from the compilation of T max values. The source rock in the Schistes Carton Formation is thought to have maturated in the deepest area, at depths of 2600-2700m, during Maastrichian times and ongoing (Espitalié et al. 1987).

**Upper Rhine Graben**

The approximately 350 km long and 30 – 40 km wide Upper Rhine Graben has a Variscan basement (Late Paleozoic), a Mesozoic cover and a Cenozoic sedimentary fill at the top (Fig. 44). The Source rocks are the Lower Jurassic Posidonia Shale and the Oligocene Fish Shale. BGR (2016) have assessed the shale gas and oil in Germany per formation. The assessment results are shown in the North German basin section.

![Fig. 44. Location of the Upper Rhine Graben (red area).](image)

**Northwest European Carboniferous**

The Northwest European Carboniferous basin includes the Campine, Mons and Liège basins in Belgium, the Pennine Basin in United Kingdom and Carboniferous shales in the Netherlands and Germany (Fig. 45).

In Europe distribution of Carboniferous shales are found in a number of countries. In the Netherlands it is called the Geverik Member of the Epen formation, this is the time-equivalent of the Upper Bowland Shale Formation in the United Kingdom (Andrews 2013), the Chockier Formation in Belgium (Nyhuis et al. 2014), and the Upper Alum Shale Formation (synonym with Hangender Alaun shale (Kulm Facies)) in
Germany (Kerschke 2013). In Germany the interval has been drilled for exploration but no production has as of yet occurred (Zijp 2015).

![Fig. 45. Location of the Northwest European Carboniferous (red areas) and Lower Jurassic basins (Blue areas).](image)

**The Netherlands**

The Carboniferous Epen Formation is of Namurian age (Serpukhovian to Lower Bashkirian, 326 to 316 Ma.) and has been drilled twelve times in onshore Netherlands. The stratigraphic sequence includes the basal organic-rich Geverik Member, which has been drilled five times (Zijp et al. 2015). Well Geverik-01 is the most prominent source of information. This well has been cored over 1200 m, including the Geverik Member, and used in numerous studies (see Van Bergen et al. 2013 and references therein). Recently, QEM-SCAN analyses have been performed on the Geverik Member showing that most of the samples contain a very high silica content and very low clay content (Zijp et al. 2013). Gerling (1999) and De Jager (1996) suggest that the Geverik Member may have caused hydrocarbon charge, although no oil or gas deposits have been found that can be exclusively linked to the Epen Formation. The Epen Formation is expected to be present in the subsurface of almost all of the Netherlands, but has only been drilled in areas where it is present at a depth of 4-5 km (e.g. wells LTG-01 and UHM-02, Zijp & Ter Heege 2014). Of the two licences which were given out in the Netherlands for unconventional resources the northern one (Noordoostpolder) was intended to target the Geverik shale. However, all activity was put on hold in 2010 while the Dutch Government commissioned two studies on the effects and risks of shale gas exploration.
In the past years a number of studies and assessments on shale gas in the Netherlands have been performed. While most attention is directed at the Jurassic Posidonia Shale Formation, the Epen Formation was also assessed. Muntendam-Bos (2009) did a first estimate based on regional geology, giving numbers in the order of $1.1 \times 10^5$ bcm. These were obtained with large uncertainties and representing total volumes in the subsurface without considering constraints in terms of local geology or technical aspects. These numbers were later challenged by Herber and De Jager (2010) who stated that the volumes must be lower, although they did not do a new assessment. A new assessment was done by Zijp (2012) indicating values of 200-500 bcm of recoverable resources of shale gas for both shale gas formations in the Netherlands. This relates to a GIP of 2571 bcm for the Geverik (Zijp 2014). The 200-500 bcm is currently also the resource amount the Dutch government uses. Follow-up work has been performed by Van Bergen (2013) and Bouw (2012) where Bouw states a gas in place per surface area of 920-1180 m$^3$/m$^2$, or values of 187-238 scf/ton.

**Germany**

In Germany the Lower Carboniferous is present in the North German basin. The source rocks are the Hangender Alaun shale (Kulm Facies) in Westfalen and Southeast Niedersachsen, and Kohlenkalk-Facies in the coast area of the Baltic Sea (BGR 2016).

A Permo-Carboniferous source rocks is located in the Molasse basin in South Germany. The source rock in the Molasse basin is a shale interval in the Upper Carboniferous Weiach Formation (BGR 2016).

**Belgium**

Belgium’s interest in unconventional shale gas or shale oil reservoirs is relatively recent and slightly delayed compared to its neighbouring countries. This is partly explained by the lack of conventional hydrocarbon reservoirs, and subsequently much less sufficiently deep exploration cores and geophysical data that are available for resource assessment or research. There have been no explicit exploration efforts for shale gas, but relevant information is available from exploration and research into geothermal reservoirs, studies concerning geological storage of natural gas, and a coalbed methane test project.

In the past few decades most research in the Campine region was performed on the hydrocarbon potential of the coal deposits and their capability to produce coal bed methane. The surrounding organic-rich mudstones were largely ignored, but are currently studied in the frame of the increased interest in gas shales (Van de Wijngaerden et al. 2013, 2014, 2015). Based on first results, the content of Total Organic Carbon (TOC) and the maturity and S2 values, the Westphalian A and B coalbed roof shales are more interesting than those younger Westphalian units.

**United Kingdom**

The British Geological Survey (BGS) has assessed the shale gas resources of the Carboniferous Bowland–Hodder formation in 2013 (Andrews 2013). Additional information is available at the Oil and Gas Authority (OGA) website. [https://www.ogauthority.co.uk](https://www.ogauthority.co.uk)

The marine shale dominated unit attains a thicknesses of up to 5,000 m (imaged on seismic reflection) in basin depocentres (i.e. the Bowland, Blacon, Gainsborough, Widmerpool, Edale and Cleveland basins), and they contain sufficient organic matter to generate considerable amounts of hydrocarbons. Conventional oil and gas fields around most of these basins attest to their capability to produce hydrocarbons. The organic content of the Bowland-Hodder shales is typically in the range 1-3%, but can reach 8% (Andrews 2013).
The maturity of the Bowland-Hodder shales is a function of burial depth, heat flow and time, but subsequent uplift complicates this analysis. Where they have been buried to sufficient depth for the organic material to generate gas, the Bowland-Hodder shales have the potential to form a shale gas resource analogous to the producing shale gas provinces of North America (e.g. Barnett Shale, Marcellus Shale). Where the shales have been less-deeply buried, there is potential for a shale oil resource (but, as yet, this has not been assessed).

In the BGS study by Andrews (2013), shales are considered mature for gas generation (vitrinite reflectance > 1.1%) at depths greater than c. 2,900 m (where there has been minimal uplift). However, central Britain has experienced a complex tectonic history and the rocks here have been uplifted and partially eroded at least once since Carboniferous times. Because of this, the present-day depth to the top of the gas window is dependent on the amount of uplift, and can occur significantly shallower than 2,900 m (Andrews 2013).

The total volume of potentially productive shale in central Britain was estimated using a 3D geological model generated using seismic mapping, integrated with outcrop and deep borehole information. This volume was truncated upwards at a depth of 1,500 m below land surface (a suggested US upper limit for thermogenic shale gas production) or the depth at which the shale is mature for gas generation (whichever was the shallowest) (Andrews 2013). The volume of potentially productive shale was used as one of the input parameters for a statistical calculation using a Monte Carlo simulation of the in-place gas resource.

For the purposes of resource estimation, the Bowland-Hodder unit is divided into two units:

- The Upper Unit: Organic-rich it is typically up to 150 m thick, and is distributed over a large area. Similar to some of the shale plays in North America.
- The Lower Unit: It is harder to estimate the resource in the lower unit shale because there have been few wells this deep, but it is considerably thicker and likely reaching over 3,000 m in the deepest part of the basins.

This study offers a range of total in-place gas resource estimates for the upper Bowland-Hodder unit shales across central Britain of 164 – 264 – 447 tcf (4.6 – 7.5 – 12.7 tcm) (P90 – P50 – P10)(Table 5). It should be emphasised that these ‘gas-in-place’ figures refer to an estimate for the entire volume of gas contained in the rock formation, not how much can be recovered (Andrews 2013).

There is considerable upside potential in the lower unit, but the resource estimation for this unit has a much higher uncertainty due to the paucity of well data so far and potentially less favourable lithologies. The estimated range of gas in place for this thick unit is 658 – 1065 – 1834 tcf (18.7 – 31.2 – 51.9 tcm)(Table 5). The total range for estimated gas in place is 822 – 1329 – 2281 tcf (23.3 – 37.6 – 64.6 tcm) (P90 – P50 – P10) for the combined upper and lower parts of the Bowland-Hodder unit (Andrews 2013).
Table 5. The gas in place estimates by BGS. Tcf = trillion cubic feet; tcm = trillion cubic metre (Andrews 2013).

<table>
<thead>
<tr>
<th>Bowland-Hodder GIP</th>
<th>Low</th>
<th>Central</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>tcf</td>
<td>tcm</td>
<td>tcf</td>
</tr>
<tr>
<td>Upper Unit</td>
<td>164</td>
<td>4.6</td>
<td>264</td>
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<tr>
<td>Lower Unit</td>
<td>658</td>
<td>18.7</td>
<td>1065</td>
</tr>
<tr>
<td>TOTAL</td>
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</tr>
<tr>
<td></td>
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</tbody>
</table>

This large volume of gas has been identified in the shales beneath central Britain, but not enough is yet known to estimate a recovery factor, or to estimate potential reserves (how much gas may be ultimately produced). An estimate was made in the previous DECC-commissioned BGS report (2010) that the Carboniferous Upper Bowland Shale, if equivalent to the Barnett Shale of Texas, could potentially yield up to 4.7 tcf (133 bcm) of shale gas. In the absence of subsurface volumes of potential gas-bearing shale, this early estimate was based on the relative areal extent of the basins. Now, after detailed subsurface analysis, a “bottom-up” resource assessment of gas in-place has been made, which more accurately reflects the area’s shale gas potential. However, it is still too early to use a more refined methodology, like the USGS’s Technically Recoverable Resource “top-down” estimates which require production data from wells. In time, the drilling and testing of new wells will give an understanding of achievable, sustained production rates. These, combined with other non-geological factors such as gas price, operating costs and the scale of development agreed by the local planning system, will allow estimates of the UK’s shale gas reserves to be made (Andrews 2013).

Northwest European Jurassic

The Northwest European Jurassic basin includes the Posidonia Shale Formation in the Netherlands, Germany and France (in France the formation is called Schistes Carton or Lias Marneux) and the Wealden basin in United Kingdom (Fig. 46).

The Netherlands

The Posidonia Shale Formation can be classified as a grey to black shale of Early Jurassic (Toarcian age 182-180 Ma). Equivalent formations are deposited throughout Europe, for example the Jet Rock Member in the English Yorkshire Basin and the Ölschiefer in Germany. In the Netherlands it can be found at depths ranging from 1800-3800 m depth. The Formation is 30-60 m thick and is identified as a bituminous dark-grey to brown black fissile claystone (Zijp et al. 2013), and has been penetrated by a total of 146 wells of which 75 are onshore.

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 HI values of 550 mg/g TOC. HI values can be higher than 1000 mg/g for immature samples. Biomarker analyses indicate marine organic matter (Pletsch et al. 2010). Several types of maturity measurements have clearly indicated that the formation is immature to early
oil mature. 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 deeper areas.

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. Modelling of the hydrocarbon generation showed that in the Early Jurassic oil system oil accumulations 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).

Fig. 46. Location of the Northwest European Lower Jurassic basins (red areas) and Carboniferous (Grey-green areas). The extent underneath the Molasse basin has been interpolated, marked by question marks.

Of the two licences which were given out in the Netherlands for unconventional resources the southern one (Noord-Brabant) was targeted at the Posidonia Shale Formation. However, all activity was put on hold in 2010 while the Dutch Government commissioned two studies on the effects and risks of shale gas exploration. Commercial activity is currently pending new developments regarding a social license to operate. The Dutch state owned oil and gas company EBN ordered a Notional Field Development Plan in 2011 for the Posidonia Shale Formation which was done by Halliburton, concluding that shale gas can be extracted from this formation.
In the past years a number of studies and assessments have been performed for shale gas in the Netherlands, both for the Carboniferous as for the Jurassic formation. Muntendam-Bos (2009) did a first estimate based on regional geology giving numbers in the order of $1.1 \times 10^5$ bcm. These were obtained with large uncertainties and representing total volumes in the subsurface without considering constraints in terms of local geology or technical aspects. These numbers were later challenged by Herber and De Jager (2010) who stated that the volumes must be lower, although they did not do a new assessment. Zijp (2012) stated values of 200-500 bcm of recoverable resources of shale gas for both Epen and Posidonia Shale Formation in the Netherlands, which relates to a GIP amount of 930 bcm for the Posidonia Shale Formation (Zijp 2014). The 200-500 bcm is currently also the resource amount the Dutch government uses.

Follow-up work has been performed by Van Bergen (2013) and Bouw (2012) which both state gas in place amount per surface area or weight unit. Van Bergen concludes values of 0.26 – 0.46 bcm/km², where Bouw states a gas in place of 676-844 m³/m², or 318-397 scf/ton. Later Zijp (2013) calculated newer values of 0.165 – 0.286 bcm/km².

**Germany**

The Lower Jurassic Posidonia Shale is present in the North German basin, Upper Rhine Graben and a large area in South Germany where the formation partly extends underneath the Molasse basin. The German Posidonia Shale has been described and assessed in BGR (2016). The assessment results are shown in the North German basin section.

**United Kingdom**

The Weald Basin has a long history of oil and gas exploration; there are 13 producing sites in the basin, some almost 30 years old. Hydrocarbons were first produced in the 19th century. The British Geological Survey, commissioned by the Department of Energy and Climate change (DECC) has studied the Jurassic shales of the Weald Basin (see Andrews 2014). The results are based upon 12,200 km detailed seismic mapping and on information from 248 existing oil and gas wells. Additional information is available at the Oil and Gas Authority website. [https://www.ogauthority.co.uk](https://www.ogauthority.co.uk)

The Jurassic of the Weald Basin contains five organic-rich, marine shales: the Lower Jurassic Mid- and Upper Lias, the Oxford Clay, Corallian Clay and Kimmeridge Clay. These have thicknesses of up to 90 m, 67 m, 152 m, 80 m and 550 m respectively (Andrews 2014). Where they have been buried to a sufficient depth for the organic material to generate oil, all five prospective shales are considered to have some potential to form a shale oil resource analogous, but on a smaller scale, to the producing shale oil provinces of North America (e.g. Barnett, Woodford and Tuscaloosa).

The total volume of potentially productive shale in the Weald Basin was estimated using a 3D geological model generated using seismic mapping, integrated with borehole information. This gross volume was then reduced to a net mature organic-rich shale volume using a maximum, pre-uplift burial depth corresponding to a vitrinite reflectance cut-off of 0.6% (modelled at 2,130 m, and 2,440 m)(Andrews 2014). This volume was further truncated upwards at two alternative levels - firstly, at a depth of c. 1,000 m (as proposed by USEIA 2013) and secondly at a depth of c. 1,500 m below land surface (as proposed by Charpentier & Cook 2011 for shale gas) (Andrews 2014). This is a regionally applied cut-off; the depth at which shale oil (or
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shale gas) productivity becomes an issue in terms of pressure and hydrogeology will need to be addressed locally (Andrews 2014).

There is unlikely to be any shale gas potential, but there could be shale oil resources in the range of 2.2-8.5 billion barrels of oil (290-1100 million tonnes) in the ground, reflecting uncertainty until further drilling is done. A reasonable central estimate is 4.4 billion barrels of oil (591 billion tonnes) (Andrews 2014). It should be emphasised that this figure refers to an estimate for the entire volume of oil in the rock, not how much can be recovered. It is still too early to determine how much could technically be extracted at a commercial rate. In time, the drilling and testing of new wells will give an understanding of achievable, sustained production rates (Andrews 2014).

France

The Lower Jurassic (Toarcian age) shale in France is called Schistes Carton or Lias Marneux and is present in the Paris basin and South East basin. More detailed descriptions are found in the Paris basin and South East basin sections.

North German basin

The North German basin is well known for its hydrocarbon resources mainly natural gas. The North German basin is a subbasin to the South Permian basin and includes both North Germany and the northern areas of the Netherlands (Fig. 47).

Fig. 47. Distribution of the bitumeous shales in the North German basin (Based on BGR, 2016).
Gas is produced from the Permian Rotliegend sandstones and one of the world’s largest gas fields lies in Groningen in the Netherlands. Carboniferous (Westphalian) coals are the main gas source rocks in United Kingdom, Netherlands and Germany (Doornenbal & Stevenson 2010).

BGR (2016) have identified and assessed several formations with shale gas/oil exploration potential within the North German basin (Fig. 48). These are:

- Kohlenkalk Facies (Lower Carboniferous)
- Hangender Alaun Shale (Kulm Facies) (Lower Carboniferous)
- Mittelrät Shale (Upper Triassic)
- Posidonia Shale (Lower Jurassic)
- Wealden shale (Lower Cretaceous)
- Blättertone (Lower Cretaceous)

The shale gas and oil assessment by BGR (2016) is calculated per formation and includes the North German basin, the Upper Rhine Graben and the Molasse basin in south Germany (Table 6).
Fig. 48. Distribution of the bituminous shales in the North German basin area. A: All shales. B: Lower Carboniferous Kohlenkalk Facies (Green) and Hangender Alaun Shale (Kulm Facies)(Grey). C: Upper Triassic Mittelrhät Shale. D: Lower Jurassic Posidonia Shale. E: Lower Cretaceous Wealden shale. F: Lower Cretaceous Blättertone. The figure is based on Schieferöl und Schifergas in Deutschland, BGR 2016.
<table>
<thead>
<tr>
<th>Formation</th>
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<th>Oil-In-Place [Mio. t]</th>
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<th>P50</th>
<th>P75</th>
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<td>829</td>
<td>1129</td>
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<tr>
<th>Formation</th>
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<th>Gas-In-Place [Bill. m³]</th>
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<td>8.89</td>
<td>13.85</td>
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Table 6. Statistical core values of the German shale gas and oil estimates by BGR (2016).
Midland Valley Scotland basin

The British Geological Survey, commissioned by the Department of Energy and Climate Change (DECC), has studied the Carboniferous shales of the Midland Valley of Scotland (See Monaghan 2014)(Fig. 49). Additional information is available at the Oil and Gas Authority (OGA) website. https://www.ogauthority.co.uk

The Midland Valley of Scotland has a long history of oil and gas exploration. The West Lothian Oil-Shale Formation was the birthplace of the oil-shale industry in the 1850s with over 100 oil-shale companies active by 1900 in extracting oil by heating the shale in retorts, where it outcrops at the surface (Monaghan 2014).

Underlying the Central Belt of Scotland, from Girvan to Greenock in the west and Dunbar to Stonehaven in the east, is the geological terrane of the Midland Valley of Scotland. It is a fault-bounded, WSW–ENE trending Late Palaeozoic sedimentary basin, bounded by the Caledonide Highland Boundary Fault to the north and the Southern Upland Fault to the south, with an internally complex arrangement of Carboniferous sedimentary basins and Carboniferous volcanic rocks overlying Lower Palaeozoic strata. The interbedded Carboniferous sedimentary and volcanic rocks of the Midland Valley of Scotland form a succession up to locally over 5,500 m thick. Potentially prospective Carboniferous shales are buried beneath an area from Glasgow to Edinburgh, to the Lothians, Falkirk, Clackmannan and Fife (Monaghan 2014).

![Fig. 99. Location of the Midland Valley of Scotland basin (red area).](image)

Four Carboniferous stratigraphic units contain organic-rich; variably mature shale at suitable depths for shale gas and shale oil in basins of the Midland Valley of Scotland:
Historic coal mine workings are present over some of the prospective area and in those areas abandoned deep workings and shafts within the uppermost Limestone Coal Formation are a few tens of metres above prospective shale units within this same formation (Monaghan 2014). Conventional oil and gas fields, discoveries and seeps in the Midland Valley of Scotland attest to source rock maturation. The West Lothian Oil-Shale Formation at outcrop initiated the oil-shale industry in the 1850s, with over 100 oil-shale works having operated in Scotland by the turn of the 20th century.

The BGS study does not consider oil-shale resources, it estimates shale oil and shale gas potential where shale-bearing rocks are more deeply buried and mature for oil and gas generation. Mature organic-rich mudstones are stacked in sandstone/limestone/shale intervals up to 3,000 m thick, with individual shale units varying in thickness from inches to 50 m, the percentage of shale in the succession varies from 0-85%. Organic rich mudstones and oil shales were deposited in ephemeral lakes with anaerobic bottom conditions. The Midland Valley has a complex basin composition with carboniferous aged strata mixed in with volcanic rocks. Syn-depositional volcanism and post-depositional intrusive magmatism increase lithological complexity within the prospective strata. Faulting is observed on numerous orientations and scales, bounding and within the prospective Carboniferous succession (Monaghan 2014).

The total organic carbon content (TOC) of Midland Valley shales is uniformly high (2-6 wt %) throughout the western part of the study area and locally up to 20 wt %. In the east, TOC contents are more variable. A range of kerogen types is indicated with oil-prone Type I and gas-prone Type III being most common, but mixed and Type II kerogen are also present at various levels, consistent with a dominant lacustrine or algal and non-marine source rock with periodic marine influence. Pyrolysis results are scattered, but corrected free hydrocarbon (S1) contents of greater than 100 mg oil/g C suggest that some free oil is present outside the kerogen (Monaghan 2014).

As a result of significant burial, uplift and erosion, Carboniferous shales are mature for oil generation at shallow current-day depths over much of the Midland Valley of Scotland study area, and gas-mature shales occur at current-day depths from about 700 m below Ordnance Datum. The current day oil- and gas-mature depths of Midland Valley shales are shallow compared to the UK Bowland-Hodder shales, Jurassic shales of the Weald and many commercial plays in the USA. Locally, maturation is enhanced by igneous intrusion (Monaghan 2014).

The mineralogical compositions of many of the Midland Valley of Scotland samples are considerably more clay mineral-rich and carbonate-poor than typical USA unconventional gas- and oil-producing shales. The average composition is approximately 59% phyllosilicates/clay minerals, approximately 9% carbonate minerals and approximately 32% QFP (quartz, feldspar and pyrite), though there is a great deal of variability (Monaghan 2014). A resource assessment of ‘hybrid’ plays (low-porosity and low permeability rocks juxtaposed against mature shales) is not within the scope of this report, but could represent an exploration target in the stacked lithology of the Carboniferous, with wells fracturing the brittle layers between the shales. This production method has proven successful in North America (e.g. the...
Bakken oil system). Geological and geochemical criteria that are widely used to define a successful shale oil and shale gas play can be met in the Midland Valley of Scotland. The total volume of potentially productive Carboniferous shale in the Midland Valley of Scotland was estimated using a regional-scale 3D geological model generated using seismic mapping, integrated with borehole, coal mining and outcrop information. This gross volume was then reduced to a net mature organic-rich shale volume using oil and gas maturity-depth maps, percentage shale maps and TOC > 2% maps. This volume was truncated upwards by using a depth cut-off related to a vertical separation from abandoned deep coal mines. The resource estimates presented as headline figures are the best technical case of exploitable oil- and gas in place. A sensitivity test at 305 m depth cut-off was also examined. The volumes of potentially productive shale were used as input parameters for a statistical calculation (using a Monte Carlo simulation) of the in-place oil and gas resource. This study offers a range of total in-place oil resource estimates for the Carboniferous shale of the Midland Valley of Scotland of 3.2 - 6.0 - 11.2 billion bbl (421-793-1497 million tonnes) (Table 7). Total in-place gas resource estimates are 49.4 – 80.3 – 134.6 tcf (1.40 – 2.27 – 3.81 tcm). The West Lothian Oil-Shale unit makes the largest contribution to this estimated resource (Monaghan 2014).

<table>
<thead>
<tr>
<th>Shale Gas</th>
<th>Total gas in-place estimates (tcm)</th>
<th>Total gas in-place estimates (tcf)</th>
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<td>Low (P90)</td>
<td>Central (P50)</td>
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<td>Limestone Coal Formation</td>
<td>0.04</td>
<td>0.09</td>
</tr>
<tr>
<td>Lower Limestone Formation</td>
<td>0.10</td>
<td>0.18</td>
</tr>
<tr>
<td>West Lothian Oil-Shale unit</td>
<td>0.46</td>
<td>0.92</td>
</tr>
<tr>
<td>Gullane unit</td>
<td>0.36</td>
<td>0.91</td>
</tr>
<tr>
<td>Combined</td>
<td>1.40</td>
<td>2.27</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shale Oil</td>
<td>Low (P90)</td>
<td>Central (P50)</td>
</tr>
<tr>
<td>Limestone Coal Formation</td>
<td>42</td>
<td>106</td>
</tr>
<tr>
<td>Lower Limestone Formation</td>
<td>35</td>
<td>78</td>
</tr>
<tr>
<td>West Lothian Oil-Shale unit</td>
<td>192</td>
<td>542</td>
</tr>
<tr>
<td>Gullane unit</td>
<td>13</td>
<td>32</td>
</tr>
<tr>
<td>Combined</td>
<td>421</td>
<td>793</td>
</tr>
</tbody>
</table>

Table 7. Estimates of the total potential in-place shale oil and shale gas resource in the Carboniferous Midland Valley of Scotland study area beneath the mining/depth
cut-off described in section 4.1.1, breakdown by unit. Note that the ‘combined’ resource figures are the result of a separate Monte Carlo simulation; they are not the sum of the four subdivisions. From Monaghan (2014).

It should be emphasised that these ‘oil-in-place’ and ‘gas-in-place’ figures refer to an estimate for the entire volumes of hydrocarbons contained in the rock formations, not how much can be recovered. It is too early to use a more refined methodology, like the USGS’s Technically Recoverable Resource ‘topdown’ estimates, which require production data from wells. In time, the drilling, fracturing and testing of shale wells will demonstrate if commercially viable production rates can be achieved. These, combined with other non-geological factors such as engineering design, operating costs and the scale of development agreed by the local planning system, will allow estimates of the United Kingdom’s producible shale oil and shale gas reserves to be made in the future (Monaghan 2014).
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