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Spatially-resolved Assessment of Land and Water Use Scenarios for Shale Gas Development: Poland and Germany

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EXECUTIVE SUMMARY

Rising energy prices and security of supply concerns have spurred interest in so-called unconventional energy resources. Among these, shale gas has garnered particular attention. This is largely due to techno-economic developments in the United Sates (US), as well as recognized potential for exploitation of shale gas resources in other regions. In the European Union (EU), several Member States are thought to possess notable shale gas resources.

The analysis presented in this report focuses specifically on two issues of potential concern with respect to shale gas development in EU member states using hydraulic fracturing technologies: pressure on freshwater resources, and land use competition. Potential alternative technologies, such as "dry fracking", are not considered, because they are still at the research and development stage.

We reviewed available literature in order to identify important variables that may influence the land and water requirements associated with shale gas development. We further derived a range of representative values spanning worst-, average- and best-case scenarios for each variable. We then coupled specific technology scenarios (incorporating these variables) regarding water and land use requirements for shale gas development from 2013-2028 with spatially-resolved water and land availability/demand modeling tools (i.e. using the European Land Use Modelling Platform (LUMP)). Scenario analyses (intended to represent worst-, average- and best-case assumptions) were subsequently implemented that incorporate a subset of the identified variables for shale gas development in the Lower Paleozoic Baltic-Podlasie-Lublin basin in Poland and for Germany as a whole from 2013-2028.

In addition, we undertook a screening-level risk assessment of potential human and ecosystem health impacts attributable to accidental or operational release of chemicals used in hydraulic fracturing of shale formations, as well as the average gaseous emissions (per active well) associated with shale gas development activities that might be anticipated within a shale play. Finally, we developed a qualitative discussion of

necessary considerations to support future air quality impact assessments for shale gas development activities.

Our analysis suggests that both land consumption and allocation patterns of the well-pads for shale gas development can vary substantially, depending on the assumed technology scenario and context-specific variables. The extent to which shale gas development might actually result in landscape fragmentation and conflicts with other land users will be dependent on the scale of shale gas development, factors such as well pad density and number of wells per pad, existing land-use patterns, and the geological specifics of shale gas deposits. These variables will also be instrumental in determining the number of people living in proximity to shale gas wells, who may potentially be exposed to emissions in the event of operational or accidental release of chemicals associated with shale gas development activities. Under the Average Impact Scenario, the land used for shale gas development could represent a significant percentage of overall land take within the shale play. The land taken up for shale gas extraction as a percentage of the total land converted to industrial purposes within the whole country in the period 2006 - 2028 is 2% in both Poland and Germany. These values range from 2 – 4% for both countries for the low versus high impact scenarios respectively. We also observe that highly complex, multi-use landscapes imply the presence of numerous barriers to drilling activities, which will influence potential development patterns.

The total modeled water use for shale gas development accounted for 0.15% of the total water withdrawals for all sectors in Poland, and 0.10% in Germany for the average impact scenario in 2028. These values range from 0.02% - 1.0% for the low and high impact scenarios for Poland, and 0.01% - 0.7% for Germany.
We also calculated the Water Exploitation Index (WEI) for water withdrawal (WEI_{abs}, the total amount of water withdrawn as a fraction of available surface water) and consumption (WEI_{cns}, the total amount of water consumed as a fraction of available surface water) for each scenario for both countries. The relative changes in both indexes were computed as compared to a baseline scenario (where no shale gas extraction is taken into account). For Poland we calculate increases of WEI_{abs} and WEI_{cns} of 7.8% and 1.2% for the average scenario compared to the baseline (versus 7.4% and 1.2% for the low impact scenario and 8% and 1.5% for the high impact

scenario). The difference in WEI_{cns} between the high and low scenarios as compared to the baseline run is up to 0.4%. For Germany we calculated increases of the WEI_{abs} and WEI_{cns} of 3.1% and 5% for the average scenario compared to the baseline (versus 3.0% and 0.5% for the low impact scenario and 5% and 0.5% for the high impact scenario). Although this is a seemingly small additional amount for the regions considered as a whole, water demand may be significant locally since WEI values vary considerably across the shale play areas. Based on this study, a reasonable conclusion is that implementation of best-practice, water-efficient extraction technologies (for example, optimizing recycling of flowback water), sensitivity to context-specific water availabilities, and attention to both the scale and rate of potential developments may be important. It should also be underscored that direct comparison should not be made between potential water and land use impacts from shale gas development in Poland and Germany on the basis of the current analysis, since the Polish study considers the Lower Paleozoic Baltic-Podlasie-Lublin Basin only, whereas the German study considers shale resources in the whole of Germany.

For Poland the percentage of well pads overlying aquifers in the final year of the simulation modeled ranges from 17 to 29%. Comparable aquifer data was not available for Germany, so the number of well pads falling within areas having an annual water recharge rate of more than 249 mm (representing the three highest classes of recharge areas) was calculated instead. The majority of well pads are located where recharge is greatest since water availability was a major factor taken into account when calculating the suitability maps. This may have important implications for water quality in the event of operational or accidental release of chemicals or flowback water during fracturing operations and subsequent flowback water storage/treatment.

The chemicals potentially emitted via operational or accidental release as a result of shale gas development activities are:

(i) heterogeneous

(ii) characterized by environmental fate pathways that could lead to pollution of water, air and soil

(iii) in many cases highly hydrophobic, with significant potential for bio-concentration and biomagnification in the trophic chain (ultimately affecting human health , e.g. by ingestion)

Moreover, the chemicals potentially used/emitted include substances that are well known for their potential risk for human health. Our screening-level evaluation of ecosystem and human health therefore suggests the need for more comprehensive studies and simulations of context-specific risks. Detailed human and ecological risk assessment is recommended. Since impacts may vary significantly according to spatial and temporal aspects and site-specific contexts, evaluation should be, to the extent possible, site-specific.

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INTRODUCTION

Rising energy prices and security of supply concerns have spurred interest in so-called unconventional energy resources. Among these, shale gas has garnered particular attention, largely due to techno-economic developments in the United States (US) which facilitated rapid growth of the US shale gas sector, as well as recognized potential for exploitation of shale gas resources in other regions (Kavalov and Pelletier 2012; Pearson et al. 2012). Shale gas resources represent a significant share of global natural gas reserves. In the European Union (EU), several Member States are thought to possess notable resources (USDE 2011). Exploratory drilling has been or is being undertaken in a number of countries in the EU-27 to date.

Shale gas is termed an "unconventional" source of natural gas (other unconventional sources include coal bed methane, methyl hydrates and tight sandstones). This is because, due to the low permeability of shale, conventional extraction technologies (i.e. vertical well bores) are insufficient to produce shale gas at commercially viable rates. Instead, alternative technologies must be applied to increase the flow rate of shale gas into well bores. Shale gas is currently exploited by (1) horizontal drilling of shale beds to increase borehole contact with the shale and (2) high-volume hydraulic fracturing (fracking) of the shale surrounding boreholes to enable migration of the gas through the shale. Fracking involves high pressure pumping of fluid through perforations in the well casing in order to produce hydrofractures that propagate through the surrounding shale. Fracking fluid predominately consists of fresh water combined with sand, with a variety of chemical additives including corrosion inhibitors, biocides, thickeners and friction reducers comprising the balance.

Initially, the environmental dimensions of shale gas exploration and exploitation received little attention. With accelerated exploitation of shale gas resources in the US and increased interest in developing resources elsewhere, however, potential environmental concerns have come to the fore. These include: (1) high rates of freshwater use; (2) contamination of freshwater resources by methane, fine particles, chemicals used in fracturing operations, and/or with heavy metals and radioactive elements mobilized by fracturing water; (3) risks associated with wastewater handling, treatment and disposal (4) greenhouse gas emissions, in particular fugitive methane emissions; (5) impacts on local air quality; (6) noise pollution; (7) seismic risks; and (8) potential impacts on biodiversity and nature conservation objectives. As development of shale gas resources requires extensive drilling across large areas, competition for surface area with existing/alternative land uses is also of concern. For a review of the pertinent literature, see Kavalov and Pelletier (2012).

The current analysis focuses primarily on two issues of potential concern with respect to shale gas development in EU Member States: pressure on freshwater resources, and land use competition. Specifically, the key questions motivating our study are:

1.) What are the potential land-use requirements associated with individual shale gas sites, fields, and potential development scenarios? What are the potential land-use conflicts associated with shale gas development in Member States, including competition with alternative land uses (for example, agriculture, industry, and protected areas)?

2.) What are the potential freshwater demands for shale gas extraction in Member States? How do these relate to availability of and demand for freshwater resources at a regional scale? What are the most likely conflicts, and where might they occur?

To answer these questions, we reviewed available literature in order to identify important variables that may influence the land and water requirements associated with shale gas development using hydraulic fracturing technologies. We then derived a range of representative values spanning worst-, average- and best-case scenarios for each variable. On this basis, we coupled specific technology scenarios (incorporating these variables) regarding water and land use requirements for shale gas development from 2013-2028 with spatially-resolved water and land availability/demand modeling tools (i.e. using the European Land Use Modelling Platform (LUMP)). Finally, we implemented scenarios (intended to represent worst-, average- and best-case assumptions) that incorporate a subset of the identified variables for shale gas development in the Lower Paleozoic Baltic-Podlasie-Lublin basin in Poland and for Germany as a whole from 2013-2028. It should be noted that emerging, alternative technologies such as “dry fracking” are not considered in the current analysis, but could potentially be the subject of future, similar analyses.

In addition to this focus on potential land and water use, we also undertook preliminary assessments of potential gaseous emissions to air, or chemical emissions to air, water or soil as a result of shale gas development activities. Here, screening level assessments of the potential harm of the substances based on differing routes of release and pathways were conducted using the multimedia box model USEtox (Rosenbaum et al 2008). Characterization factors were used to calculated mid-point impact potentials. The assessments are intended to provide a general introduction to these issues only, as opposed to comprehensive assessment of possible pollution concerns and attendant impacts on human and/or ecosystem health.

METHODS

2.1 Defining technology scenarios

Although the issue of potential shale gas development in the EU is receiving considerable attention, to date, only a small number of exploratory drilling activities have been undertaken. There is hence little available information at present on which to base EU-specific technology scenarios. Consequently, our approach has been to identify important variables that may influence land and water use requirements for shale gas development. We then derive representative values for each variable spanning worst to best case scenarios. These values are based on literature sources reporting performance parameters for commercial-scale shale gas exploitation in the United States. The US is the only region for which data representing commercial-scale shale gas exploitation is currently available. The purpose of this approach to defining technology variables is to allow for selection of a range of scenarios in order to explore the relevance of water and land use considerations.

Given this reliance on US data, it is important to bear in mind that potential differences between practices/conditions in the United States and the EU may reduce the predictive value of the technology scenarios we employ. For example, differences in road width or size of drilling equipment may result in over- or underestimates of actual land use requirements.

2.1.1 Land requirements

The amount of land use for shale gas development will vary depending on numerous factors. These include well pad density, well pad size, number of wells per pad, and the specifics of the shale play that is exploited. For example, deeper plays that require longer well bores will have larger associated land requirements due to the increased amount of equipment necessary to drill the well. More land will also be required to store drill cuttings and flowback water. We do not further consider possible differences between shale plays. Rather, we focus on defining what might reasonably be anticipated in terms of variation in well-pad size, number of wells per pad, and the well pad density used to exploit the plays.

Land Use for Wells and Supporting Infrastructure

Due to the prevalence of horizontal drilling for shale gas exploitation, wells may be situated in isolation or, more commonly, drilled in clusters on multi-well pads. The latter decreases direct land use requirements, since multi-well pads can be serviced by the same supporting infrastructure. All else being equal, shale play developments featuring multi-well well-pads should be less land demanding than developments featuring single-well well-pads.

For the purpose of the present analysis, estimated land requirements for developing shale gas well-pads are extrapolated from United States Department of the Interior (USDI 2008) scenarios for development of fluid mineral resources. Specifically, land required for horizontal gas well development and associated production facilities and infrastructure are provided by USDI (2008), assuming either one or four wells per pad (Table 1 and Table 3). On this basis, land use requirements for two-, eight- and sixteen- well pads are also estimated (Table 2, Table 4, Table 5). The values derived correspond well with values reported elsewhere in the literature. More recent reports suggest that a much higher number of wells per pad is possible (i.e. 6-20 wells per pad), with an average of 8 wells per pad as the current norm. We hence assume the use of 16-well pads for this variable in our low land-use scenario (Table 5). Similarly, we assume the use of two wells per pad for a high land-use scenario (Table 2), and an eight-well pad for an average case scenario (Table 4).

Table 1: Land Requirements for Shale Gas Wells – 1 Well Per Pad (from USDI 2008)

FACILITIES		Exploratory Well Disturbance (m^2/pad)	Construction Disturbance (m^2/pad)	Operation/ Production Disturbance (m^2/pad)
Well Pad (110 m by 110 m pad during drilling and construction, 61 m by 61 m pad during operation)		12060	12060	3723
Access Roads to Well Sites	Two-track (4.6 m by 0.40 km long)	1821	N/A	N/A
	Graveled (4.6 m by 0.25 km long for construction and operation)	N/A	0	1093
	Bladed (4.6 m by 0.25 km for construction and operation)	N/A	1093	0
Utility Lines[1]	Water lines (4.6 m by 0.80 km)	N/A	3462	0
	Overhead Elec. (3.0 m by 0.25 km)	N/A	728	182
	Underground Elec. (4.6 m by 0.25 km)	N/A	1093	0
Transportation Lines[2]	Intermediate Press. Gas line to and from field compressor (4.6 m by 0.40 km)	N/A	1821	445
	High Press. Gas or Crude Oil Gathering Line (6.1 m by 0.80 km)	N/A	4897	1214
Processing Areas	Tank Battery (one 2023 m^2 tank battery per 16 wells)	N/A	125	125
	Access Roads (7.6 m by 0.08 km)	N/A	607	607
	Field Compressor (2023 m^2 pad per 16 wells)	N/A	125	125
	Sales Compressor (8094 m^2 pad for 128 wells)	N/A	65	65
	Sales Line (6.1 m by 6.4 km per 128 wells)	N/A	303	77
Produced Water Management	Discharge Point	N/A	N/A	N/A
	Storage Impoundment (80937 m^2 each serving 64 wells)	N/A	1255	1255
Total Disturbance per Horizontal Gas Well Pad (m^2)		**13881**	**27923**	**8944**

1. The operation disturbance for utilities assumes all utilities will be completed underground, and the land surface will be reclaimed so that no disturbance should remain except where noted.
2. It is assumed that each gas well will need product pipeline and produced water line from the well. In addition, some wells will need intermediate pipeline run from the field compressor to the sales line.

Table 2: Land Requirements for Shale Gas Wells – 2 Wells per Pad (extrapolated from USDI 2008).

FACILITIES		Exploratory Well Disturbance (m^2/pad)	Construction Disturbance (m^2/pad)	Operation/ Production Disturbance (m^2/pad)
Well Pad (138 m by 131 m pad during drilling and construction, 61 m by 61 m pad during operation)		18078	18078	3723
Access Roads to Well Sites	Two-track (4.6 m by 0.40 km long)	1821	N/A	N/A
	Graveled (4.6 m by 0.25 km long for construction and operation)	N/A	0	1093
	Bladed (4.6 m by 0.25 km for construction and operation)	N/A	1093	0
Utility Lines[1]	Water lines (4.6 m by 0.80 km)	N/A	3462	0
	Overhead Elec. (3.0 m by 0.25 km)	N/A	728	182
	Underground Elec. (4.6 m by 0.25 km)	N/A	1093	0
Transportation Lines[2]	Intermediate Press. Gas line to and from field compressor (4.6 m by 0.40 km)	N/A	1821	445
	High Press. Gas or Crude Oil Gathering Line (6.1 m by 0.80 km)	N/A	4897	1214
Processing Areas	Tank Battery (one 2023 m^2 tank battery per 16 wells)	N/A	250	250
	Access Roads (7.6 m by 0.08 km)	N/A	607	607
	Field Compressor (2023 m^2 pad per 16 wells)	N/A	250	250
	Sales Compressor (8094 m^2 pad for 128 wells)	N/A	130	130
	Sales Line (6.1 m by 6.4 km per 128 wells)	N/A	606	154
Produced Water Management	Discharge Point	N/A	N/A	N/A
	Storage Impoundment (80937 m^2 each serving 64 wells)	N/A	2510	2510
Total Disturbance per Horizontal Gas Well (Total m^2 divided by 2 wells per pad)		**9950**	**5807**	**5279**
Total Disturbance per Horizontal Gas Well Pad (m^2)		**19899**	**35525**	**10558**

1. The operation disturbance for utilities assumes all utilities will be completed underground, and the land surface will be reclaimed so that no disturbance should remain except where noted.
2. It is assumed that each gas well will need product pipeline and produced water line from the well. In addition, some wells will need intermediate pipeline run from the field compressor to the sales line.

Table 3: Land Requirements for Shale Gas Wells– 4 Wells per Pad (from USDI 2008).

FACILITIES		Exploratory Well Disturbance (m^2/pad)	Construction Disturbance (m^2/pad)	Operation/ Production Disturbance (m^2/pad)
Well Pad (165 m by 152 m pad during drilling and construction, 61 m by 61 m pad during operation)		25091	25091	3723
Access Roads to Well Sites	Two-track (4.6 m wide by 0.40 km long)	1821	N/A	N/A
	Graveled (4.6 m by 0.25 km long for construction and operation)	N/A	0	1093
	Bladed (4.6 m by 0.25 km for construction and operation)	N/A	1093	0
Utility Lines[1]	Water lines (4.6 m by 0.80 km)	N/A	3462	0
	Overhead Elec. (3.0 m by 0.25 km)	N/A	728	182
	Underground Elec. (4.6 m by 0.25 km)	N/A	1093	0
Transportation Lines[2]	Intermediate Press. Gas line to and from field compressor (4.6 m by 0.40 km)	N/A	1821	445
	High Press. Gas or Crude Oil Gathering Line (6.1 m by 0.80 km)	N/A	4897	1214
Processing Areas	Tank Battery (one 2023 m^2 tank battery per 16 wells)	N/A	505	505
	Access Roads (7.6 m by 0.08 km)	N/A	607	607
	Field Compressor (2023 m^2 pad per 16 wells)	N/A	505	505
	Sales Compressor (8094 m^2 pad for 128 wells)	N/A	255	255
	Sales Line (6.1 m by 6.4 km per 128 wells)	N/A	1214	308
Produced Water Management	Discharge Point	N/A	N/A	N/A
	Storage Impoundment (80937 m^2 each serving 64 wells)	N/A	5059	5059
Total Disturbance per Horizontal Gas Well (Total m^2 divided by 4 wells per pad)		**6718**	**11614**	**3480**
Total Disturbance per Horizontal Gas Well Pad (m^2)		**26872**	**46456**	**13920**

1. The operation disturbance for utilities assumes all utilities will be completed underground, and the land surface will be reclaimed so that no disturbance should remain except where noted.
2. It is assumed that each well will need product pipeline and produced water line from the well. In addition, some wells will need intermediate pipeline run from the field compressor to the sales line.

Table 4: Land Requirements for Shale Gas Wells– 8 Wells Per Pad (extrapolated from USDI 2008).

FACILITIES		Exploratory Well Disturbance (m²/pad)	Construction Disturbance (m²/pad)	Operation/ Production Disturbance (m²/pad)
Well Pad (assumed to be 50% larger than 4-well pad)		37637	37637	5585
Access Roads to Well Sites (assumed same as for 4 well pad)	Two-track (4.6 m wide by 0.40 km long)	1821	N/A	N/A
	Graveled (4.6 m by 0.25 km long for construction and operation)	N/A	0	1093
	Bladed (4.6 m by 0.25 km for construction and operation)	N/A	1093	0
Utility Lines[1] (assumed same as for 4 well pad)	Water lines (4.6 m by 0.80 km)	N/A	3462	0
	Overhead Elec. (3.0 m by 0.25 km)	N/A	728	182
	Underground Elec. (4.6 m by 0.25 km)	N/A	1093	0
Transportation Lines[2] (assumed same as for 4 well pad)	Intermediate Press. Gas line to and from field compressor (4.6 m by 0.40 km)	N/A	1821	445
	High Press. Gas or Crude Oil Gathering Line (6.1 m by 0.80 km)	N/A	4897	1214
Processing Areas	Tank Battery (one 2023 m² tank battery per 16 wells)	N/A	1010	1010
	Access Roads (7.6 m by 0.08 km)	N/A	607	607
	Field Compressor (2023 m² pad per 16 wells)	N/A	1010	1010
	Sales Compressor (8094 m² pad for 128 wells)	N/A	510	510
	Sales Line (6.1 m by 6.4 km per 128 wells)	N/A	2428	616
Produced Water Management	Discharge Point	N/A	N/A	N/A
	Storage Impoundment (80937 m² each serving 64 wells)	N/A	10117	10117
Total Disturbance per Horizontal Gas Well (Total m² divided by 8 wells per pad)		**4932**	**8302**	**2799**
Total Disturbance per Horizontal Gas Well Pad (m²)		**39458**	**66413**	**22389**

1. The operation disturbance for utilities assumes all utilities will be completed underground, and the land surface will be reclaimed so that no disturbance should remain except where noted.
2. It is assumed that each well will need product pipeline and produced water line from the well. In addition, some wells will need intermediate pipeline run from the field compressor to the sales line.

Table 5: Land Requirements for Shale Gas Wells– 16 Wells Per Pad (extrapolated from USDI 2008).

FACILITIES		Exploratory Well Disturbance (m^2/pad)	Construction Disturbance (m^2/pad)	Operation/ Production Disturbance (m^2/pad)
Well Pad (assumed to be 100% larger than 4-well pad)		50182	50182	7446
Access Roads to Well Sites (assumed same as for 4 well pad)	Two-track (4.6 m wide by 0.40 km long)	1821	N/A	N/A
	Graveled (4.6 m by 0.25 km long for construction and operation)	N/A	0	1093
	Bladed (4.6 m by 0.25 km for construction and operation)	N/A	1093	0
Utility Lines[1] (assumed same as for 4 well pad)	Water lines (4.6 m by 0.80 km)	N/A	3462	0
	Overhead Elec. (3.0 m by 0.25 km)	N/A	728	182
	Underground Elec. (4.6 m by 0.25 km)	N/A	1093	0
Transportation Lines[2] (assumed same as for 4 well pad)	Intermediate Press. Gas line to and from field compressor (4.6 m by 0.40 km)	N/A	1821	445
	High Press. Gas or Crude Oil Gathering Line (6.1 m by 0.80 km)	N/A	4897	1214
Processing Areas	Tank Battery (one 2023 m^2 tank battery per 16 wells)	N/A	2023	2023
	Access Roads (7.6 m by 0.08 km)	N/A	607	607
	Field Compressor (2023 m^2 pad per 16 wells)	N/A	2023	2023
	Sales Compressor (8094 m^2 pad for 128 wells)	N/A	1020	1020
	Sales Line (6.1 m by 6.4 km per 128 wells)	N/A	4856	1232
Produced Water Management	Discharge Point	N/A	N/A	N/A
	Storage Impoundment (80937 m^2 each serving 64 wells)	N/A	20234	20234
Total Disturbance per Horizontal Gas Well (Total m^2 divided by 16 wells per pad)		**3250**	**6208**	**2345**
Total Disturbance per Horizontal Gas Well Pad (m^2)		**52003**	**99322**	**37519**

1. The operation disturbance for utilities assumes all utilities will be completed underground, and the land surface will be reclaimed so that no disturbance should remain except where noted.
2. It is assumed that each gas well will need product pipeline and produced water line from the well. In addition, some wells will need intermediate pipeline run from the field compressor to the sales line.

Well Density

According to this same report (USDI 2008), one square mile (256 hectares) of land surface overlaying a shale play may be exploited with either one four-well pad or four one-well pads. This estimate represents the low-end of the range of reported well densities for shale gas exploitation. Elsewhere, reviews of well density in US shale plays suggest a typical range in spacing of 16-64 hectares (4 – 16 wells per square mile) (Sumi 2008; NYCDEP 2009; SGEIS 2011). In some areas, wells have been drilled at 6-8 hectare spacing (IEA 2009). The number of wells per pad may also be considerably higher. IEA (2009) suggests that as many as 20-40 wells may be drilled from a single surface location, although this is not reflected elsewhere in available literature. We hence adopted a spacing range of 32-1024 hectares for 2-, 8- and 16-well pads (high, average and low impact, respectively) as the basis for our land use scenarios. Table 6 describes a subset of possible scenarios that combine the three variables of number of wells per well-pad, well-pad size at the exploration, construction and operation phases, and well-pad density.

Table 6: Percent land occupation for exploration, construction, and operation/production phases of shale gas wells (including supporting infrastructure).

Land Occupation (%)	Low Land Use/Low Well Density Scenario (16-well pad/1024 ha)	High Land Use/Low Well Density Scenario (Two 2-well pads/256 ha)	Average (8-well pad/320 ha)	Low Land Use/ High Well Density Scenario (16-well pad/256 ha)	High Land Use/High Well Density Scenario (Eight 2-well pads/256 ha)
Exploratory Well	0.51	1.55	1.23	2.03	6.22
Construction Phase	0.96	2.78	2.08	3.88	11.1
Operation/ Production Phase	0.37	0.82	0.70	1.47	3.30

Exploitation Rate

The rate of exploitation of a shale gas play may be described in terms of drilling intensity (i.e. wells drilled per year). The number of wells drilled per year will, in part, depend on target production volumes and anticipated well lifespan. A study of actual production rates in the Barnett Shale found that average well lifespan is 7.5 years (Berman 2009). For the Marcellus shale gas industry, it is estimated that the production rate of a well will decrease by 80 percent in first five years and by 92% by 10 years, falling another 3 percent per year thereafter (NYSDEC 2009). One scenario described by the International Energy Agency (IEA 2009) suggests an optimal exploitation rate of 800 new wells drilled per year based on production profiles in the Barnett Shale. Assuming an average well lifespan of 10 years, the total number of wells would therefore gradually increase from 800 in year 1 of operation to 8000 in year 10 of operation. The number of active wells would be maintained thereafter over time as new wells compensate for retired wells.

The New York City Department of Environmental Protection provides scenarios for the potential rate of exploitation in the city's watershed (NYCDEP 2009). According to these scenarios, annual well completion rates are anticipated to be low initially, averaging 5-20 wells during the exploratory drilling phase. Under favourable economic and regulatory conditions, it is assumed that this could increase to 100-300 wells per year, and potentially peak at 500 wells per year. Potential refracturing of wells is not considered. It is further assumed that 50-100% of land not previously set aside is developable (NYCDEP 2009). The size of the developable area is therefore 500-1000 square miles, or 800-1600 km2. At rates of 100, 300 and 500 new wells drilled per year, this is equivalent to an intensity range of 0.06-0.63 (average 0.25) new wells/km^2/per year for the developable area as a whole.

For Poland, the extent of on-shore gas-saturated shale meeting minimum gas content requirements to merit exploitation has been estimated by the Polish Geological Institute (PGI) as ranging from 12,347 – 33,183 km2 (PGI 2012). Assuming 100% surface availability (i.e. full exploitability) at the aforementioned intensities, this would correspond to 741-20,905 new wells drilled per year. Assuming 50% surface availability, this would correspond to 370-10,453 new wells drilled per year.

However, the possibility of such exploitation rates assumes, among other things, the availability of necessary drilling equipment and personnel. As of 2011, the total European land rig count was 70 rigs compared to 2,084 in the US (Pearson et al. 2012), the majority of which are based on traditional technology. Assuming that all of these rigs are capable of horizontal drilling (according to IEA Golden Rules report (IEA 2012), this may only be true of half of the rigs), an average drilling time of 45 days per well and the availability of all European rigs for drilling in Poland for 340 days per year, the maximum number of wells that could be drilled per year at present is 528. Based on land rigs actually in Poland in 2011 (6) (Pearson et al. 2012), this number drops to 76.

A more realistic basis for modelling potential well developments must therefore take into account current infrastructure limitations, as well as make reasonable assumptions as to rates of infrastructure development. Table 7 describes two example rates of infrastructure development (20 or 40 new rigs constructed or imported by drilling companies per year) and how this impacts on the amount of time that would be required to develop Polish shale gas resources assuming either 50% or 100% of the area identified by PGI (2012) is available. It should be noted that these rates are arbitrary, and are employed for illustrative purpose only. Actual rates will likely be influenced by numerous factors, including economic opportunity.

Table 7: Anticipated total number of pads/wells, along with development time assuming 40 or 20 new rigs per year (NRPY), to fully develop the exploitable area for Polish shale gas in the Lower Paleozoic Baltic-Podlasie-Lublin Basin assuming 100% or 50% surface availability.

	Land Use Scenarios	**Extent of Play (km^2)**	
		12,347	33,183
Total number of well-pads at 100% surface availability, and time to develop entire area assuming 40 or 20 new rigs per year (NRPY)	Low Land Use/Low Well Density Scenario (16-well pad/1024 ha)	1,206/19,296 11 years to develop at 40 NRPY, 15 years to develop at 20 NRPY	3,241/51,848 18 years to develop at 40 NRPY, 26 years at 20 NRPY
	High Land Use/Low Well Density Scenario (Two 2-well pads/256 ha)	9,646/19,292	25,924/51,848
	Average (8-well pad/320 ha)	3,858/30,868 14 years to develop at 40 NRPY, 20 years to develop at 20 NRPY	10,370/82,958 23 years to develop at 40 NRPY, 33 years to develop at 40 NRPY
	Low Land Use/ High Well Density Scenario (16-well pad/256 ha)	4,823/77,169	12,962/207,394
	High Land Use/High Well Density Scenario (Eight 2-well pads/256 ha)	38,584/77,169 22 years to develop at 40 NRPY, 31 years to develop at 20 NRPY	103,697/207,394 37 years to develop at 40 NRPY, 52 years to develop at 20 NPRY
Total number of well-pads at 50% surface availability, and time to develop entire	Low Land Use/Low Well Density Scenario (16-well pad/1024 ha)	603/9,648 8 years to develop at 40 NRPY, 11 years to develop	1,621/25,924 12 years to develop at 40 NRPY, 18 years to develop

area assuming 40 or 20 new rigs per year (NRPY)		at 20 NRPY	at 20 NRPY
	High Land Use/Low Well Density Scenario (Two 2-well pads/256 ha)	4,823/9,646	12,962/25924
	Average (8-well pad/320 ha)	1,929/15,432 10 years to develop at 40 NRPY, 14 years to develop at 20 NRPY	5,185/41,479 16 years to develop at 40 NRPY, 23 years to develop at 20 NRPY
	Low Land Use/ High Well Density Scenario (16-well pad/256 ha)	2,412/38,584	6,481/103,697
	High Land Use/High Well Density Scenario (Eight 2-well pads/256 ha)	19,292/38,584 16 years to develop at 40 NRPY, 22 years to develop at 20 NRPY	51,984/103,697 25 years to develop at 40 NRPY, 37 years to develop at 20 NRPY

According to some estimates (Pearson et al. 2012), the number of wells drilled per year in Europe will increase over time to reach 4200 new wells per year for 2025-2030. According to the IEA Golden Rules projection scenario, the cumulative number of wells drilled in Europe from 2012-2035 is 50,000. Since our analysis extends only to 2028, we hence assume a cumulative total of 29,000 wells will be drilled between 2013 and 2030, and allocate wells to be drilled accordingly over the time interval 2013-2028. If we also assume that 4200 new wells are drilled per year from 2025-2030, this would imply that only 8,000 wells are drilled from 2013-2025. Taking into account potential rates of increase in rig count (i.e. from perhaps 35 rigs capable of horizontal drilling in Europe at present to the roughly 560 rigs necessary to drill 4200 wells per year) that match these projections without too radical an increase in rig count from one year to the next is also necessary. Our assumed rate of well development in the EU-27 between 2013 and 2035 is detailed in Table 8.

On the basis of this pan-European projection for total wells to be developed between 2013 and 2035, it is next necessary to allocation a proportion of the wells to the Member States in which shale gas development may occur over this time interval. Since the current analysis focuses on the Lower Paleozoic Baltic-Podlasie-Lublin Basin in Poland and on Germany as a whole only, we restrict our allocation to these two countries.

Allocating wells between countries could be based on a variety of principles. For example, one might allocate wells in proportion to the % share of total surface area overlaying known shale deposits in Member States relative to the European total. One could equally base the allocation on the ratio of wells drilled to date in Member States, or on Member State forecasts, if available. We elected to base our allocation on the % share of estimated technically recoverable shale gas resources (TRR) in Member States.

The United States Energy Information Administration (USEIA 2011) published a coarse estimate of technically recoverable shale gas resources in 14 regions outside of the US, including Europe. These estimates provide a basis for comparing the % share of estimated recoverable resources between Member States, and allocating projected wells to be developed accordingly. However, more recent and detailed estimates conducted within some Member States are available, and provide sharply conflicting estimates with those of the USEIA report. This is, in part, because the PGI (2012) analysis for Poland (that was used to determine the area to be considered in our model) refers to the Lower Paleozoic Baltic-Podlasie-Lublin Basin only. For example, the USEIA (2011) report indicates that Poland is home to 29.3% of the technically recoverable shale gas in Europe versus 1.3% for Germany. In contrast, the BGR (2012) estimate for TRR for Germany (45 tcf) is substantially higher than the PGI (2012) estimate for the Lower Paleozoic Baltic-Podlasie-Lublin Basin in Poland (19.7 tcf). We allocated shares of total projected wells to be developed using these two latter estimates in relation to the estimate of total TRR for Europe provided by ICF (2013). This resulted in allocating 5.1% of wells projected to be drilled in Europe over the interval considered to Poland (the Lower Paleozoic Baltic-Podlasie-Lublin Basin only) versus 11.6% for Germany.

Clearly, this allocation is not in-line with current levels of shale gas exploration in Poland and Germany and expectations regarding development levels in the short to medium term. However, it may be reasonably reflective given that a limited fraction of Polish territory thought to contain technically recoverable shale gas resources is considered. Indeed, a recent update of the USEIA (2012) report suggests that the most prospective areas for shale gas development in Poland actually lie outside of the Lower Paleozoic Baltic-Podlasie-Lublin Basin – the area considered in the PGI (2012) report that forms the basis for our Poland model. The updated report expands and also further refines the earlier analysis by incorporating variables such as total organic carbon content of shale in the regions evaluated. Based on the resulting estimates, the total share of EU TTR attributable to Poland has actually increased compared to the 2011 report. Alternative allocations, based on consideration of the entire Polish territory should hence be considered a priority focus for future sensitivity analyses and further modeling endeavors. It should also be underscored that direct comparison should not be made between potential water and land use impacts from shale gas development in Poland and Germany on the basis of the current analysis, since the Polish study considers the Lower Paleozoic Baltic-Podlasie-Lublin Basin only, whereas the German study considers shale resources in the whole of Germany.

Table 8. Assumed rate of shale gas wells drilled in the EU-27, Poland (Lower Paleozoic Baltic-Podlasie-Lublin Basin only) and Germany from 2013-2035.

Year	Wells Drilled	Total Wells in EU-27	Wells Drilled in Poland	Wells Drilled in Germany
2013	**10**	**10**	**1**	**1**
2014	**40**	**50**	**2**	**5**
2015	**100**	**150**	**5**	**12**
2016	**200**	**350**	**10**	**23**
2017	**325**	**675**	**16**	**38**
2018	**450**	**1125**	**23**	**52**
2019	**600**	**1725**	**30**	**69**
2020	**775**	**2500**	**39**	**90**
2021	**950**	**3450**	**48**	**110**
2022	**1150**	**4600**	**58**	**133**
2023	**1400**	**6000**	**71**	**162**
2024	**1800**	**7800**	**91**	**208**
2025	**2300**	**10100**	**116**	**266**
2026	**2850**	**12950**	**144**	**330**
2027	**3450**	**16400**	**175**	**399**
2028	**4200**	**20600**	**213**	**486**
2029	4200	24800	213	486
2030	4200	29000	213	486
2031	4200	33200	213	486
2032	4200	37400	213	486
2033	4200	41600	213	486
2034	4200	45800	213	486
2035	4200	50000	213	486

The 2029-2035 numbers provided in Table 8 are solely intended to demonstrate that the total anticipated number of wells drilled by 2035 corresponds to the IEA projection of 50,000 wells by 2035 (this time period is not included in the current analysis, which considers only 2013-2028).

2.1.2 Water consumption

A review of available literature sources indicates considerable variability in reported water requirements for shale gas well development (Sumi 2008; DGIP 2011). Part of this variation can be attributed to differences in wellbore depth, which is a function of depth and thickness of the shale play, as well as substrate permeability. Reported well depths at US shale gas plays suggest a range of 75-3,150 meters. Length of the horizontal bore may similarly vary substantially. For the Marcellus shale, reported well depths varied between 1,500-2,400 meters (Wood et al. 2011). Differences in the depths and dimensions of shale plays within and between regions in Poland will therefore impact on a variety of performance criteria, including water and chemical use, mass of cuttings, duration of drilling, etc.

Based on the wide variation in reported water usage for fracking (Sumi 2008; NYCEP 2009; USEPA 2011; DGIP 2011), we assume use of 3,000 m^3 of freshwater for fracking a single well a single time for our low-impact water use scenario. We further assume use of 15,000 m^3 per frack for our average case scenario, and 45,000 m^3 of water for our high-impact scenario.

Also important to consider is that shale gas wells may be repeatedly fracked to maximize productivity. Each refracking will require similar or slightly greater freshwater and chemical inputs. According to Zoback et al. (2010), shale gas wells are rarely refractured. Berman (2009) claims that wells may be refractured once they are no longer profitable. Following SGEIS (2011), wells will generally be refractured after five years of service, whereas Ineson (2008) (cited in DGIP 2011) claims that wells may be refractured every year. We therefore suggest that scenarios for fracking frequency should also be considered. Our low water use scenario assumes that wells are fracked one time only. Our average case scenario assumes 2 fracks over the wells lifetime, whereas our high impact scenario assumes that the wells are fracked every two years over an anticipated 10 year lifespan (based on reported longevity of shale gas wells in the Barnett Shale (IEA 2009)).

Upon completion of the fracking process, the direction of fluid flow reverses, with some of the injected fluid returning to the surface. This process and the returned water are referred to as "flowback." Estimated flowback rates range from 5-50% of injected freshwater (Sumi 2008; SGEIS 2011; DGIP 2011). Flowback water may also potentially be recycled, hence reducing cumulative freshwater demands for shale gas exploitation. For example one source suggests a recycling rate for flowback water of 70% in Pennsylvania for best-performing companies (Gaudlip and Paugh. 2008). This creates the possibility to consider additional scenarios assuming various flowback and recycling rates.

SUMMARY OF TECHNOLOGY VARIABLES

The specific technology variables employed for the hypothetical low-, average-, and high-impact scenarios that were used evaluate potential water and land use demands for shale gas exploitation in the Lower Paleozoic Baltic-Podlasie-Lublin Basin of Poland and for Germany are listed in Table 9.

Table 9: Specific technology variables employed for the hypothetical worst- and best-case scenarios that were used to test the methodology (note: well pad density was not included, but will be accommodated in future analyses).

Technology Variable	Low-impact Scenario	Average-impact Scenario	High-impact Scenario
Well-pad size (including infrastructure)	Construction – 3.55 ha Operation – 1.06 ha	Construction – 6.24 ha Operation - 2.24 ha	Construction – 9.93 ha Operation – 3.75 ha
Number of wells per pad	2	8	16
Well-pad spacing	Eight 2-well pads/256 ha	8-well pad/320 hectares	16-well pad/1036 ha
Well life-time	10 years	10 years	10 years
Number of times well are fracked	5	2	1
Total lifetime water use per well	225,000 m^3	24,750 (including recycling)	1,950 m^3 (including recycling)
Recycling rate for flowback water	0	35%	70%

2.2 Spatially-resolved land use modelling

2.2.1 Land use scenarios for shale gas development

In order to assess potential impacts on land and water resources associated with shale gas development scenarios for the Lower Paleozoic Baltic-Podlasie-Lublin Basin of Poland and for Germany, a spatially-resolved modelling approach has been developed. The methodology is based on the dynamic interaction between a scenario-driven land-use model and simulation of hypothetical shale gas development scenarios. The assessed scenarios were defined in order to depict hypothetical average and extreme (best-case and worst-case) scenarios for shale gas extraction activities in Poland and Germany, focusing on several key technological parameters. In addition to these scenarios a Baseline Scenario has been implemented. The Baseline Scenario is intended to represent a future land and water demand scenario where no shale gas exploitation activity is undertaken: it can therefore be used for comparative purposes in assessing relative impacts on water and land resources.

All of the developed Scenarios (Baseline, Low Impact, Average Impact and High Impact) assume that current policy provisions are maintained (business-as-usual). These policy provisions have direct spatial implications, thus influencing land use dynamics. As examples; the protection regime enforced in certain areas (e.g. Natura 2000 sites) can prevent the conversion of natural land to artificial surfaces, residential or industrial uses; subsidies targeting areas characterised by specific natural handicaps can prevent land abandonment; and the conversion of agricultural land to other uses (e.g. LFA Supporting Scheme).

Included policies are:

- Natura 2000: Council Directive 92/43/EEC of 21 May 1992 on the conservation of natural habitats and of wild fauna and flora and Directive 2009/147/EC of the European Parliament and of the Council of 30 November 2009 on the conservation of wild birds;

- Nitrate Vulnerable Zones (NVZ): Council Directive of 12 December 1991 concerning the protection of waters against pollution caused by nitrates from agricultural sources (91/676/EEC);
- Erosion sensitive areas: the current GAEC framework (Council Regulation (EC) No. 73/2009, Annex III);
- Less Favoured Areas (LFA): this payment scheme promotes agriculture production in areas with natural handicaps (Articles 18 and 20 of Council Regulation (EC) 1257/1999).

More specifically, NVZ have been taken into consideration by means of mapping riparian areas (Clerici *et al.*, 2011) which are currently designated NVZ. Regarding erosion sensitive areas, two classes have been taken into consideration for this modelling exercise: areas where erosion is between 20 and 50 ton/ha/year, and areas where erosion is >50 ton/ha/year. LFAs are those defined in accordance with Articles 18 ("mountain areas") and 20 ("areas affected by specific handicaps").

Land requirements for shale gas development can vary greatly, depending on the size of well pads, well pad density and number of wells per pad. Land requirements are also different for construction versus operation phases. It is worth noting that the well pad density parameter is to be considered an average density measure: the actual well pad density depends on the specificities of the region where the well pads are located, i.e. the landscape and, as a consequence, the presence of excluded/not-exploitable areas, such as urban settlements or natural protected areas. Therefore, in the well pad allocation procedure, this average density is taken into account by setting the respective minimum distance between well pads (see Table 10). The minimum distance is computed assuming that the allocated well pad is placed in the center of the spacing range and it is strictly respected, whereas the resulting average well pad density may slightly differ (i.e. lower) from the nominal one set in the scenario definition.

Three (high-, average- and low- impact) scenarios are employed in addition to the Baseline scenario, in which well pad size, number of wells per pad and well pads density are varied. Based on the assumptions described in Table 10, Table 11, and Table 12, we are able to calculate anticipated land requirements over time for our hypothetical scenarios.

Table 10: Shale gas land use scenarios assessed

Scenario	Construction land use per well-pad [ha]	Operation land use per well-pad [ha]	Lifespan per well-pad [years]	Minimum distance between well pads [m]
Baseline	-	-	-	-
Low	9.93	3.75	10	3200
Average	6.24	2.24	10	1800
High	3.55	1.06	10	600

Table 11: Land use requirements for shale gas development for the Low, Average and High Impact Scenarios in Poland. The amount of land is reported in [ha]: figures are cumulative and refer to the total amount of land that is required for all the active well pads in the respective year.

Year	Low Scenario		Average Scenario		High Scenario	
	Construction land use	Operation land use	Construction land use	Operation land use	Construction land use	Operation land use
2013	-	-	-	-	-	-
2018	35	14	42	14	113	28
2023	189	76	227	76	606	152
2028	616	246	739	246	1971	493

Table 12: Land use requirements for shale gas development for the Low, Average and High Impact Scenarios in Germany. The amount of land is reported in [ha]: figures are cumulative and refer to the total amount of land that is required for all the active well pads in the respective year.

Year	Low Scenario		Average Scenario		High Scenario	
	Construction land use	Operation land use	Construction land use	Operation land use	Construction land use	Operation land use
2013	-	-	-	-	2	1
2018	81	32	97	32	260	65
2023	433	173	520	173	1386	347
2028	1408	563	1690	563	4507	1127

2.3 Methodological Framework

The developed modelling approach is based on a dynamic allocation of well-pads, starting from 2013 and ending in 2028. This simulation period is able to provide insights as to foreseeable impacts for each scenario to be eventually modelled over the short to medium term only. The exploitation sites are allocated every 5 years, taking into account a yearly rate of development. The frequency of allocation can vary, according to the definition of the scenario(s).

For each allocation year (2013 - 2018 - 2023 - 2028), four main steps are performed:

1. Land use change simulation (Land Use Modelling Platform - LUMP) ;
2. Update of the total Water Exploitation Index (De Roo et al., 2012);
3. Update of the suitability layer;
4. Well-pads allocation.

Each simulation step is performed in a specific language environment (see Figure 1). The input/output interface is then integrated, exchanging data in raster format.

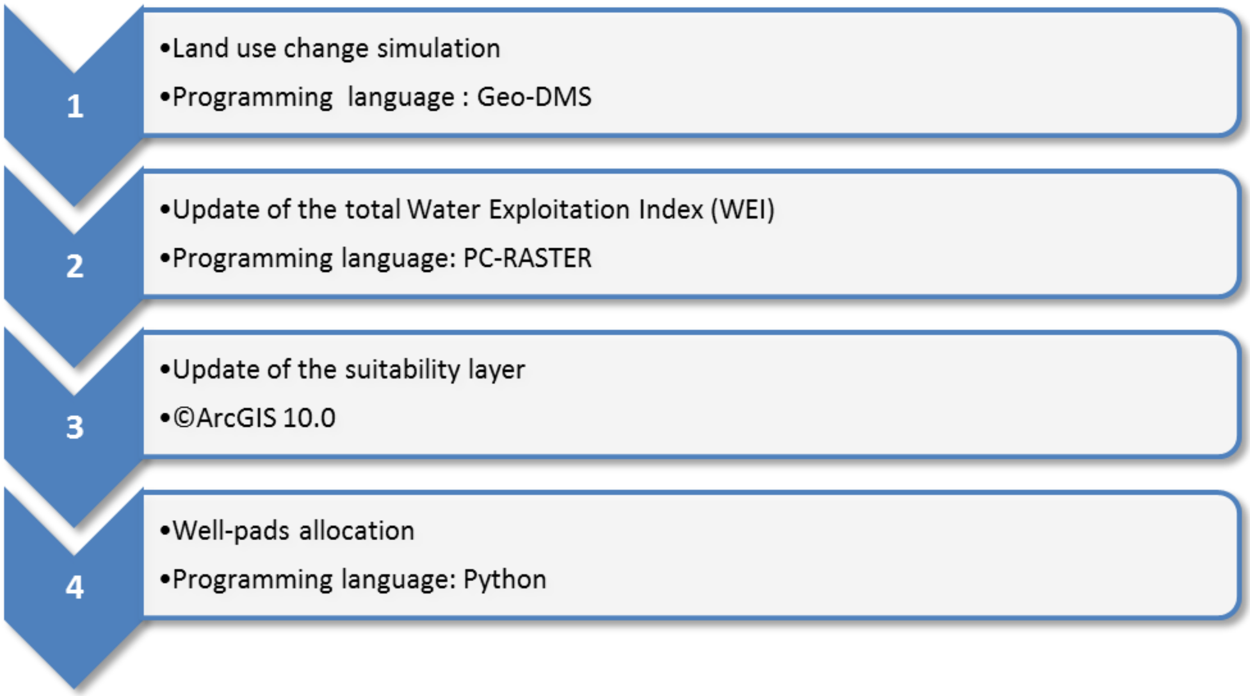

Figure 1: Programming languages used to develop the workflow.

The first step is implemented within the LUMP. Starting from 2006 (base year of the simulation), land use changes are simulated for the entire selected country (Poland or Germany) as a whole. In 2013 the simulation is stopped and the resulting land use map is then used to compute the Water Exploitation Index (WEI) (see Section 2.3), updating the water uses dependent on specific land categories (e.g. *Urban land* for residential uses, *Industrial land* for industrial uses, etc.). In turn, based both on the simulated land use map and the updated WEI, the suitability layer is re-computed. This spatial layer compiles all of the most relevant information indicating the suitability of a certain location to host shale gas extraction activity. Finally, the well-pads are allocated based on the suitability score and a neighbourhood effect: this latter allows for taking into account the location advantage of placing extraction sites in areas where the needed infrastructures have already been developed for the surrounding sites. Once the well-pads have been placed, the updated land use map is then fed back into the LUMP, so as to run the next 5 years of the simulation time period.

In the following section, each of the modelling steps is described in further detail, as summarized in Figure 2.

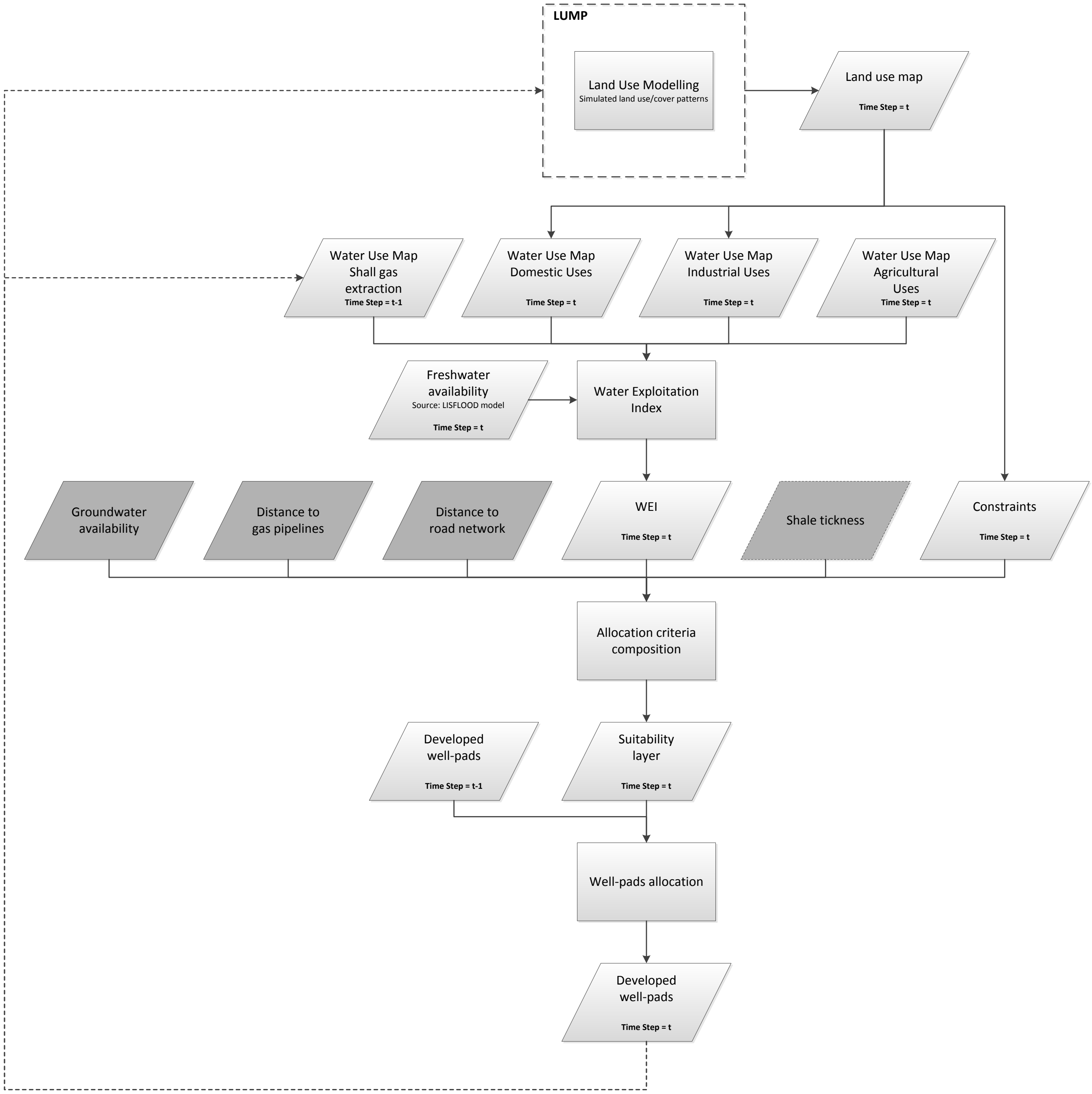

Figure 2: Overall workflow followed for the dynamic allocation of well-pads, for a generic step in time *t*. Feedback mechanisms that directly affect the next time step *t+1* are highlighted by dotted lines. All of the variables are dynamic, with the exception of those represented in solid grey. The *Shale Thickness* layer is dotted, indicating that the respective data is available for Poland, but not for Germany.

1. *The land use allocation*

The land use allocation is performed within the Land Use Modelling Platform (LUMP). A detailed description of the methodology can be found in Lavalle *et al.* (2011a) and Lavalle *et al.* (2011b). In the scope of the present report, only a brief overview will be given.

LUMP integrates diverse and specialized models and data into a coherent workflow. It has a modular structure and is organized in three main components (see Figure 3): the amount of land claimed per land-use type (Land Demand Module), a set of rules to allocate the requested land (Land Allocation Module, EUCS100) and the computation of indicators to facilitate the analysis of results (Indicator Module).

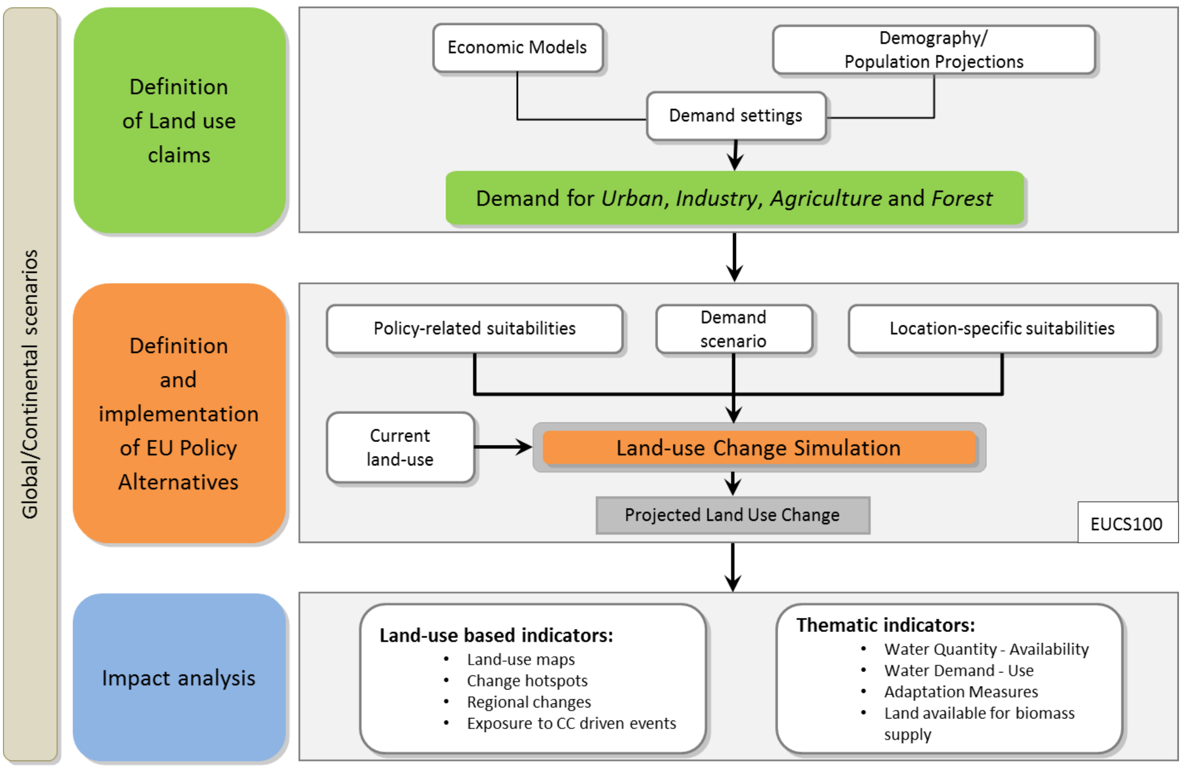

Figure 3: Overall workflow of LUMP highlighting the three main modules of the model (Source: Lavalle *et al.*, 2011b)

At the core of the LUMP is the EUCS100 model operating at 100-meters spatial resolution (Lavalle *et al.*, 2011a). EUCS100 is based on the dynamic simulation of competition between land uses. Its spatial allocation rules build on a set of locally influencing factors which together define the suitability of each land parcel for each land use type.

The current land-use and starting state for the simulation is a refined version of CORINE Land Cover 2006 (CLC_r)[1].

The *Simulated* land use/cover classes are subject to change over the simulation period (in this work from 2006-starting state, to 2028) according to the above workflow, whereas the *Non-simulated* classes are fixed throughout the time span[2]. The legend for the present exercise has been defined as follows (Table 13):

Table 13: *Simulated* and *Non-simulated* land-use/cover classes

Land use classes	
Urban	Simulated
Industrial/Commercial/Services	Simulated
Arable	Simulated
Permanent crops	Simulated
Pastures	Simulated
Forests	Simulated
Semi-natural vegetation	Simulated
Infrastructure	Non simulated
Other nature	Non simulated
Wetlands	Non simulated
Water bodies	Non simulated

Land Demand Module

The Demand Module integrates linkages to exogenous models, in order to provide the amount of land required for each sector driving the simulated land use types.

[1] See Batista e Silva *et al.* (2012) for a detailed description of the CLC_r.

[2] *Arable land* includes cereals, maize and root crops. Additionally, Abandoned agricultural land (*Abandoned arable land*, *Abandoned Permanent crops* and *Abandoned pastures*) is modelled: nevertheless, in the scope of the present case study, it is included in the *Arable* land use class, given the negligible amount of land classified as such.

The land claims in the LUMP are computed at the level of NUTS2 regions[3]. The main inputs are:

1. Common Agricultural Policy Regionalised Impact Modelling System (CAPRI) for agricultural land (Baseline2030 Scenario);
2. Historical trends from Corine Land Cover (CLC) for arable land, permanent crops, pastures and forest;
3. Population projections for urban land (EUROPOP2008 and EUROPOP2010[4]);
4. Economic projections from the LEITAP-IMAGE model for industry/commerce/services.

The supply data of crops from the CAPRI model are used to define the demands for agricultural land (i.e. *Arable land*, *Permanent crops* and *Pastures*) in LUMP. The crop types as detailed in CAPRI are aggregated in accordance with the legend used in EUCS100.

Land claimed for urban areas is given by a measure of residential density, computed using the official population projections from DG ECFIN. A similar approach, but based on the Gross Value Added (GVA), is applied to derive land claims for industrial areas. Forest land claims are extrapolated from historical trends based on CLC data. All of this data is merged within the LUMP configuration to provide input to EUCS100.

Semi-natural vegetation is simulated, although no specific claims are provided for this land use class. Changes to this class are governed primarily by the dynamics of the active classes and possibly by specific policy-driven layers.

Land Allocation Module

The Land Allocation Module is responsible for determining location preferences for the land required per sector, integrating spatially-relevant legislation. Thus, the actual transformation from the current land-use state to a future state is computed considering the most suitable land-use for that specific location at each specific time.

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[3] Nomenclature of Territorial Units for Statistics level 2.

[4] From EUROSTAT/DG ECFIN.

The probability that a specific land use will be allocated to any given cell is defined according to the combination of three main factors:

a) *land-use conversion rules*: they define which land-use transitions are allowed: these may be either natural (natural succession) or anthropogenic. In some cases the conversions may be constrained by succession maps that specify the locations where they are allowed to take place (e.g. Natura2000 sites). All of the possible conversions between the modelled land use classes are taken into account;
b) *bio-physical and geographical properties*: they include accessibility and biophysical properties such as topography, soil characteristics and crop suitability maps (provided by the JRC-IES AGRI4CAST Action, Baruth et al., 2006);
c) *neighbourhood effect*: refers to the attraction and repulsion relationships between land-use types. The neighborhood effect is one of the core components of the allocation module, because the effect of the changing neighborhood is re-calculated at the end of every simulation year, thus changing the location preference for each cell.

The factors contributing to the probability of land-use conversion can be altered (enhanced or reduced) by specific combinations of spatial policies or measures (e.g. subsidies). This alteration is dependent on the type of spatial policy and on the possible overlap of different policies.

2. Assessment of suitability criteria

The allocation of well-pads for the shale gas development scenarios to be modelled is driven by three types of criteria that act as either constraints or favourable location features:

1. *Excluded areas*: the allocation of exploitation sites in these areas is strictly forbidden;
2. *Favourable areas*: allocation preference is given to areas where there are favourable conditions, in terms of resource availability and infrastructure connectivity;
3. *Proximity*: the allocation is more likely to take place as the distance from sensitive areas increases.

A summary of the datasets used is provided in Table 14 and Table 15, for Poland and Germany, respectively. Most of these datasets are Europe-wide and have been used for both countries. The main differences concern groundwater and shale gas resources. In particular, for Germany the layer related to the potential availability of shale gas resources was not available at the time of this report and, therefore, not included. In this regard, it is worth noting that the whole exercise is otherwise consistent between the two countries: they share the same methodology and the vast majority of the data either belongs to the same source or has similar quality. Nevertheless, having more accurate data would have allowed further refining the methodology and analyses.

Excluded areas

Excluded areas refer to any of the following types: urban areas and industrial sites, water bodies, infrastructures, natural protected areas and historical and architectural landmarks. Those areas are accounted for by the actual footprint and a surrounding buffer. The size of the buffer has been decided upon based on the resolution of the modelling system (100m) and available literature. In particular, the setback from populated areas in Germany is 200m (Wozniacki and Bar, 2012). For all the other typologies of areas, in both Germany and Poland, and urban settlements in Poland, the setback is, by default, 100m (although a personal communication from Generalna Dyrekcja Ochrony Środowiska suggests a set-back of only 50 m from places of human habitation in Poland). As a further criterion for exclusion, seismic areas have also been considered, in particular those classified as high to very high seismic risk (see Figure 4 and Figure 5 for Poland and Germany respectively; Figure 72 in Annex II provides a pan-European overview of seismic areas).

Although flood prone areas have not been excluded, they have been taken into account as having a lower suitability for shale gas development. As data source, a Pan-European output of the hydrological model LISFLOOD has been used: the layer shows the maximum flood depth relative to a return period of 100 years, expressed in mm, of flood prone areas.

Table 14: Suitability criteria and respective datasets (Poland).

Criterion	Dataset	Source	Temporal resolution
Urban areas and industrial sites			
Urban and industrial areas	Projected land use map	EUClueScanner	2013 – 2018 – 2023 – 2028
Water bodies			
Water bodies	Catchment Characterisation and Modelling Version 2.1 (CCM2)	JRC	2010
Lakes	EuroRegionalMap Database (ERM 2.0)	EuroGeographics	2007
Water courses	EuroRegionalMap Database (ERM 2.0)	EuroGeographics	2007
Groundwater resources			
Stored groundwater volume	Characterization of groundwater bodies	GŁÓWNY INSPEKTORAT OCHRONY ŚRODOWISKA	2010/2011
Infrastructures			
Road network	EuroRegionalMap Database (ERM 2.0)	EuroGeographics	2007
Railways	EuroRegionalMap Database (ERM 2.0)	EuroGeographics	2007
Road and rail networks and associated areas	Refined Corine Land Cover 2006 v.2	JRC	2006
Port areas	Refined Corine Land Cover 2006 v.2	JRC	2006
Airports	Refined Corine Land Cover 2006 v.2	JRC	2006
Gas pipelines	Gas network	IHS	*Last access to data: March 2013*
Natural protected areas			
National Parks	Parki Narodowe	WMS General Directorate for Environmental Protection	*Last access to data: October 2012*
Reserves	Rezerwaty	WMS General Directorate for Environmental Protection	*Last access to data: October 2012*
Special Areas of Conservation	Specjalne Obszary Ochrony	WMS General Directorate for Environmental Protection	*Last access to data: October 2012*
Special Protection Areas	Obszary Specjalnej Ochrony	WMS General Directorate for Environmental Protection	*Last access to data: October 2012*
Natura2000	Natura2000 Network	European Environment Agency	2010
Nationally Designated Areas	European Common Database on Nationally Designated Areas – Version 9	European Environment Agency	2011
Historical and architectural landmarks			
Historical and architectural	EuroRegionalMap Database	EuroGeographics	2007

landmarks	(ERM 2.0)		
Seismic areas			
Seismic hazard	Seismic Hazard Distribution Map	World Health Organisation	2010

Table 15: Suitability criteria and respective datasets (Germany).

Criterion	Dataset	Source	Temporal resolution
Urban areas and industrial sites			
Urban and industrial areas	Projected land use map	EUClueScanner	2013 – 2018 – 2023 – 2028
Water bodies			
Lakes	EuroRegionalMap Database (ERM 2.0)	EuroGeographics	2007
Water courses	EuroRegionalMap Database (ERM 2.0)	EuroGeographics	2007
Groundwater resources			
Average annual groundwater recharge	Mittlere jährliche Grundwasserneubildung	Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (BMU)	2003
Infrastructures			
Road network	EuroRegionalMap Database (ERM 2.0)	EuroGeographics	2007
Railways	EuroRegionalMap Database (ERM 2.0)	EuroGeographics	2007
Road and rail networks and associated areas	Refined Corine Land Cover 2006 v.2	JRC	2006
Port areas	Refined Corine Land Cover 2006 v.2	JRC	2006
Airports	Refined Corine Land Cover 2006 v.2	JRC	2006
Gas pipelines	Gas network	PLATTS	*Last access to data: April 2013*
Natural protected areas			
Natura2000	Natura2000 Network	European Environment Agency	2010
Nationally Designated Areas	European Common Database on Nationally Designated Areas – Version 9	European Environment Agency	2011
Historical and architectural landmarks			
Historical and architectural landmarks	EuroRegionalMap Database (ERM 2.0)	EuroGeographics	2007
Seismic areas			
Seismic hazard	Karte der Erdbebenzonen in	Helmholtz Centre	2005

	Deutschland	Postdam – GFZ German Research Centre for Geosciences

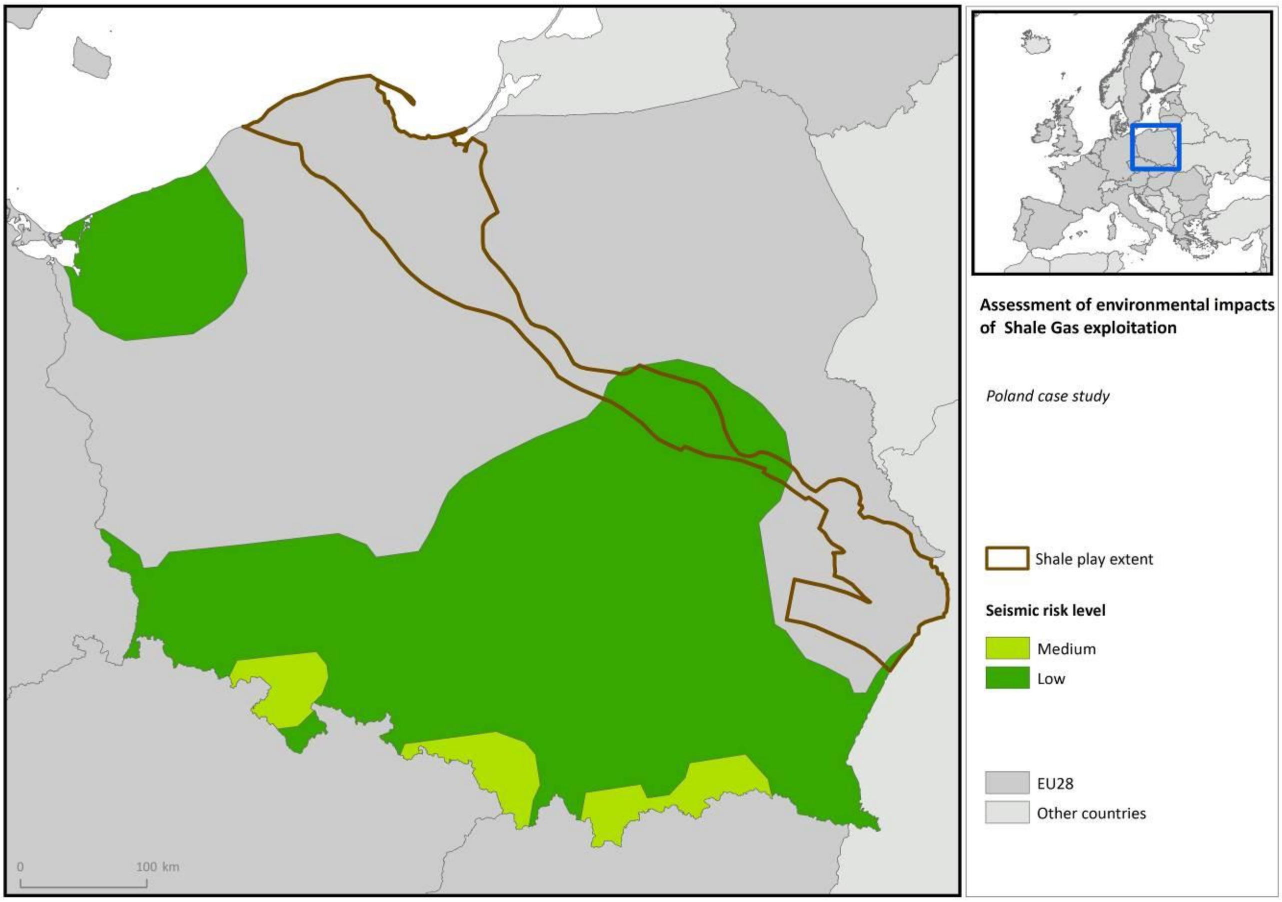

Figure 4 : Seismic risk areas in Poland.

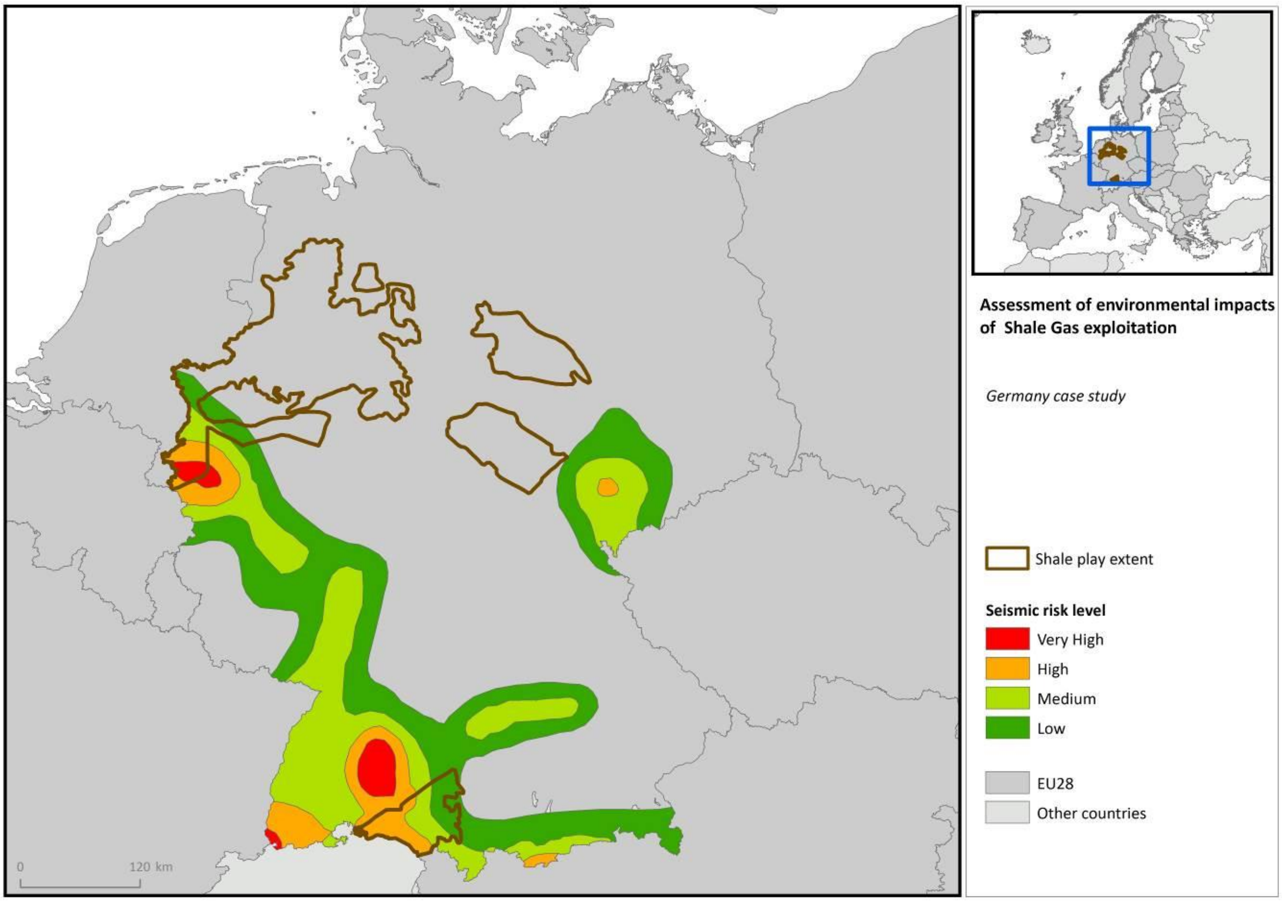

Figure 5 : Seismic risk areas in Germany.

Favourable areas

Favourable areas are identified based on the availability of resources needed for extraction activities (shale gas and water) and by their proximity to existing infrastructures (road network and gas pipelines). In Poland, the thickness of the stratum of shale richest in organic carbon is used as a proxy for the availability of gas in the shale play based on a study by the Polish Geological Institute of the Lower Paleozoic Baltic-Podlasie-Lublin Basin (PGI 2012). In Germany, due to lack of data, only the shale play extent is used in order to drive the allocation of well pads for this variable.

The availability of fresh surface water is measured through the computation of the Water Exploitation Index (WEI) for the shale play region. The WEI is computed per water region, i.e. sub-sets of river catchments[5]. The availability of groundwater resources is based on: in Poland, the stored volume, expressed in [m^3]; in Germany, the average annual groundwater recharge, expressed in [mm/year].

The roads taken into account belong to the first two categories (motorways and primary routes) as per the EuroRegionalMap Database (EuroGeographics, 2007). Proximity to the existing road network is taken into account as the Euclidean distance to the nearest element of the network. The same approach is applied for the existing gas pipelines. The gas distribution networks have been extracted from the best available sources for each of the modelled countries, namely IHS for Poland and PLATTS for Germany. For both countries, two selection criteria have been applied: only the operative lines belonging to the regional/national distribution network have been retained[6]. The resulting selected networks have a similar level of detail and geographic accuracy.

Proximity

Proximity criteria are set in order to take into account the distance from any excluded area. The layer is computed so as to measure the Euclidean distance from the nearest excluded area (pixel level), regardless of the type of area (urban settlement, water body, natural protected area, etc.).

The allocation criteria are combined in a three-step process, so as to compile a unique suitability layer to drive the allocation of new well-pads. In the first step, the excluded areas are removed from the suitable areas. In a second stage, the different thematic layers to be combined are normalised and standardised between 0 and 1. For this purpose a linear function is used: for each layer, the minimum value represented

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[5] For further details, please refer to the chapter dedicated to water use impacts.

[6] In Poland, .a minimum diameter of 16 inch has been considered. In Germany, a minimum diameter of 12 inch has been considered: few segments with smaller diameters have been included only with the purpose to guarantee the connectivity of the selected network. These thresholds have been chosen in order to properly represent each national/regional distribution network, according the specificities of the two different contexts.

corresponds to 0 and the maximum corresponds to 1. An ad hoc approach is applied for the WEI layer: the Water Exploitation Index is linearly transformed so as to give more emphasis to regions whereby the WEI is above the critical threshold identified by the European Commission (2011) (20%). Thus, the same increase in WEI implies a higher growth in the transformed index, if the WEI is above 20%.[7]

Finally, all of the layers are linearly combined in order to produce one unique suitability layer: each of them is weighted in accordance to its relative importance with respect to the others, on a dimensionless scale from 1 to 5. The output is then linearly re-scaled between 0 and 1.

Table 16: Thematic layers composing the overall suitability layer and relative importance weight (Poland).

Layer	Weights
Shale thickness	5
WEI	4
Aquifers	4
Distance to gas pipelines	3
Distance to road network	2
Constraints	1

Table 17: Thematic layers composing the overall suitability layer and relative importance weight (Germany).

Layer	Weights
WEI	5
Aquifers	5
Distance to gas pipelines	4
Distance to road network	3
Seismic areas	2
Constraints	1

[7] For an overview of water stress regions in 2006 and shale gas resources in Europe, see Figure 73 in Annex II.

The weighting systems for Poland and Germany share the same rationale. As highlighted in Table 16 and Table 17, in both sets of weights, shale thickness (when data is available) and water resources are the most influential criteria: this choice is intended to reflect the location criteria that may be most important to shale gas developers. Once the areas potentially richest in resources have been identified, valuable information at a finer geographical scale (local level) is given by the existing road network and the gas pipeline layers: giving preference to land already serviced by necessary infrastructures may play a role in reducing development costs. These two distance layers are only taken into account in the suitability layer used to select new regions and the first extraction locations. The underlying hypothesis is that once the extraction activity has started in a certain region and from a specific (most favourable) location within the region, the following well-pads would take advantage of the already allocated sites and respective infrastructures, without the need to be placed close to existing road networks and gas pipelines. The distance from sensitive areas, such as natural protected areas, urban settlements or medium/low risk seismic areas, is given the lowest weight in both weighting sets. This configuration reflects the lack of relevant legislation forbidding or discouraging the installation of well-pads in the vicinity of such areas.

The availability of freshwater and groundwater resources are assigned the same level of importance: this choice reflects the lack of knowledge about the share of water use from both sources.

Finally, it is worth noting that seismic areas are not included in the weighting scheme for Poland, because of the absence of medium or high level risk areas overlapping with the shale play, as highlighted in Figure 6. On the contrary, in the case of Germany, seismic areas are considered and are assigned a moderate weight.

An example of a suitability layer for Poland is reported in Figure 6; another zoomed area and the related criteria for Germany are reported in Figure 7.

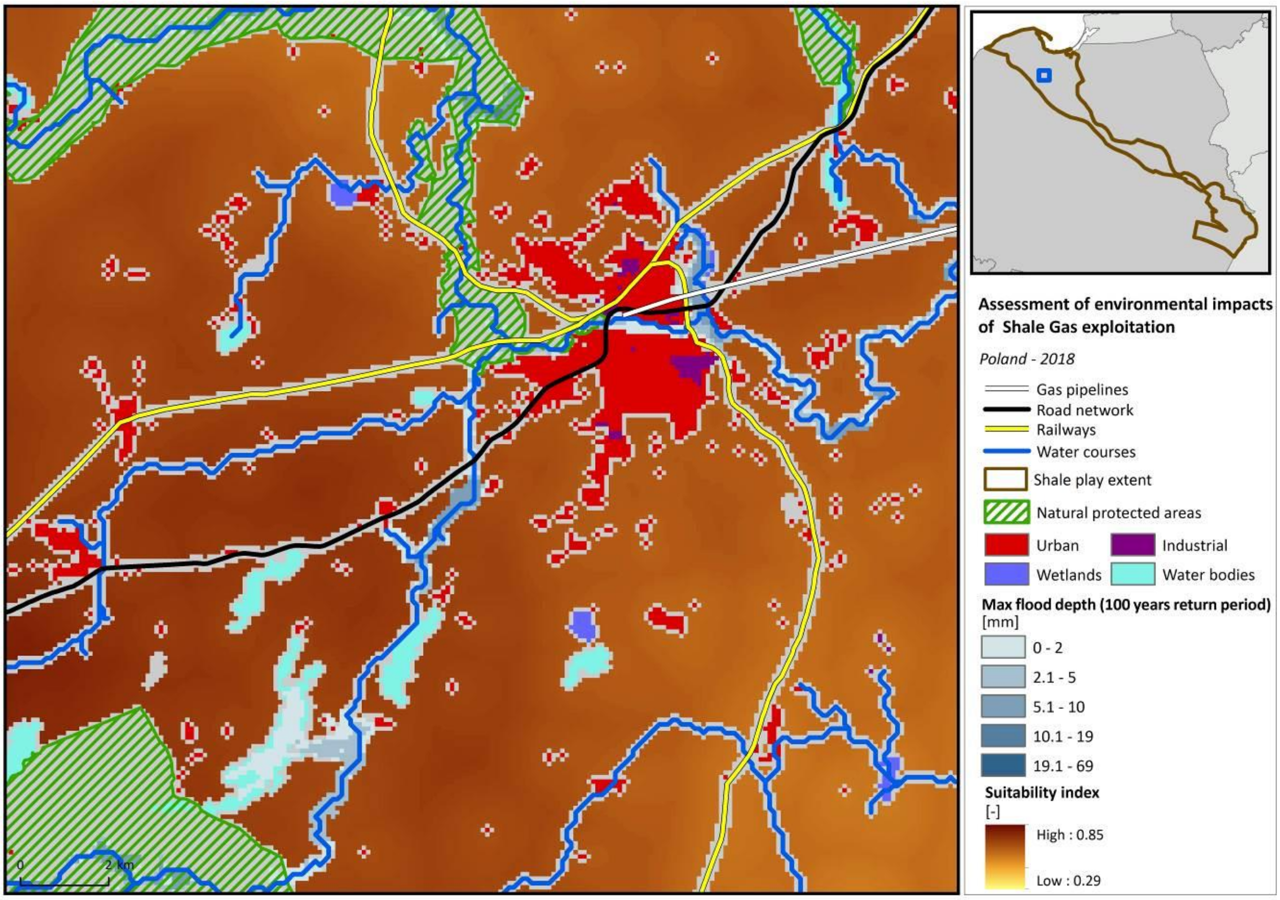

Figure 6: Suitability index used to allocate well pad sites in Poland. The relative exclusion criteria are also highlighted.

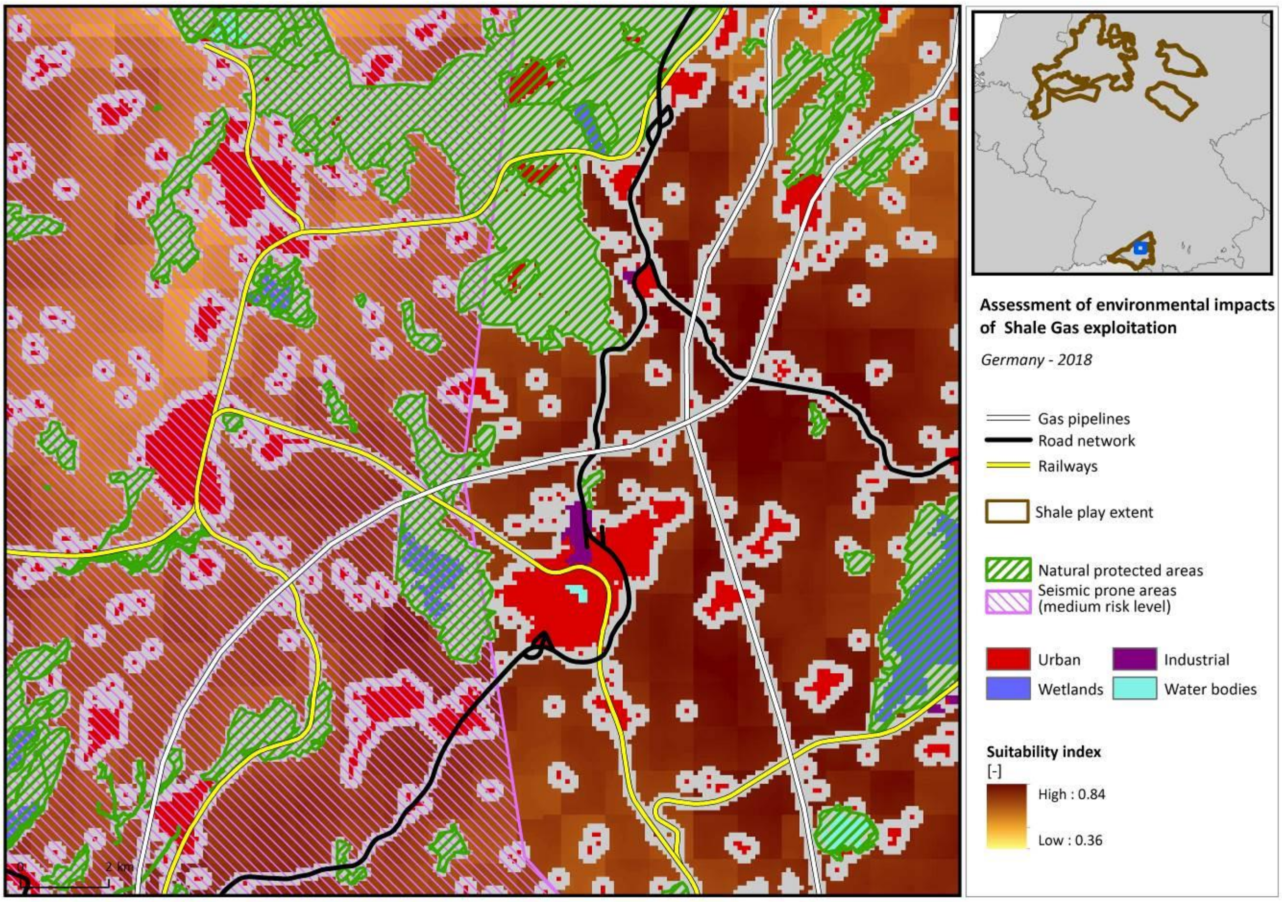

Figure 7 : Suitability index used to allocate well pad sites in Germany. The relative exclusion criteria are also highlighted. Flood prone areas are not shown in the map, because they are not present in the zoomed area.

Concerning natural protected areas, there is no existing national legislation explicitly forbidding drilling activities in such areas. Therefore, a conservative approach has been applied that completely excludes natural protected sites from the land available for drilling activities. In both Poland and Germany, these areas cover a relevant share of the total shale play area. As examples, two zoomed areas are depicted in Figure 8 and Figure 9, whereby the suitability layer is computed within natural protected areas.

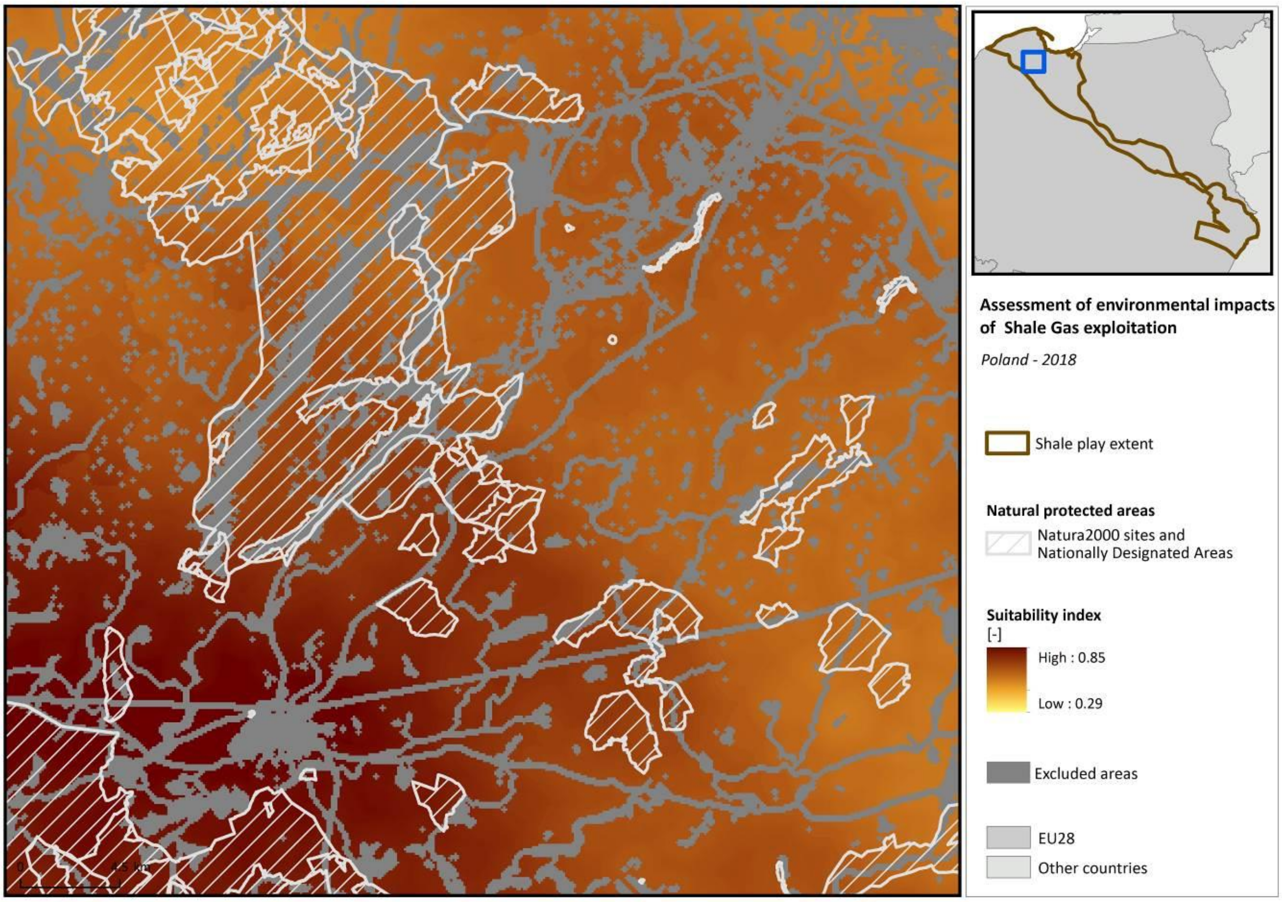

Figure 8: Suitability index computed considering natural protected areas as land available for extraction activities, in Poland. Natural protected areas are depicted in white and exclusion criteria are highlighted in dark grey.

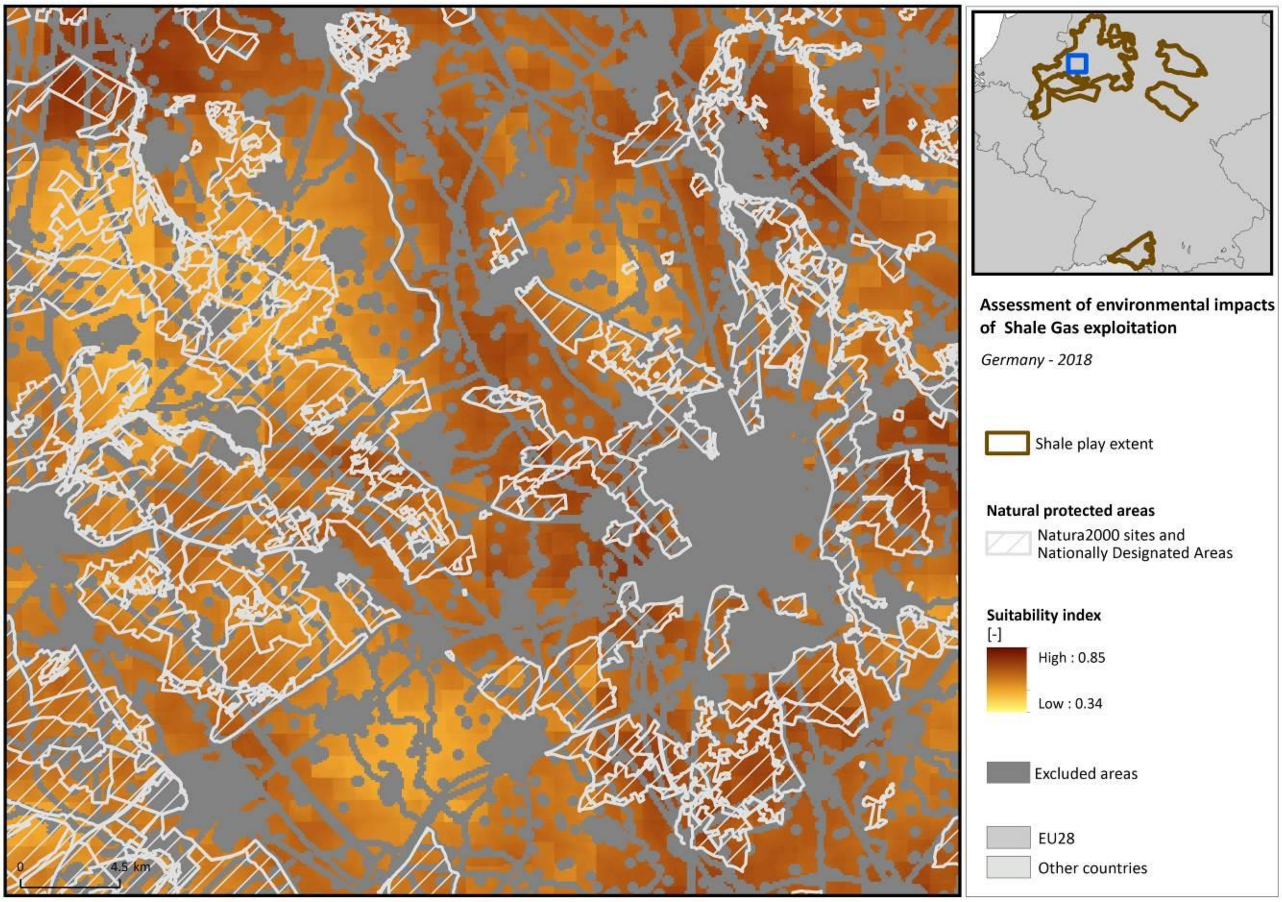

Figure 9: Suitability index computed considering natural protected areas as land available for extraction activities, in Germany. Natural protected areas are depicted in white and exclusion criteria are highlighted in dark grey.

As highlighted in Figures X and X, assuming that no development will occur in natural protected areas, will exclude a large proportion of land highly suitable for drilling activities.

3. *Allocation algorithm*

The allocation of well-pads is implemented in a four-step algorithm:

1. Exclusion of too small regions
2. Location of the well-pad (land for operation)
3. Location of buffer areas (land for construction)
4. Setting the minimum distance between well pads

First, from the suitability layer, all the regions which are too small to host the development foreseen for one well pad (i.e. the overall land needed for both the construction and the operation phases), are excluded.

The second step entails the allocation of the land demanded for the operation of the well-pads. Only adjacent pixels are developed, until the required amount of hectares has been allocated. The land to be developed is selected maximising the allocation function, which takes into account the suitability index and a neighbourhood factor. The latter plays a more influential role in the initial stage of development, i.e. when the number of surrounding developed cells is low.

Third, a construction buffer is allocated around the newly developed well-pads. The cells composing the buffer are selected within the land available for the development. The buffer takes into account the land needed in the construction phase of the well-pads: therefore, it does not change the current use and becomes unavailable to any land use change for the next simulation period (5 years). After 5 years, the construction buffer is removed.

Finally, a minimum distance factor is applied, in order to forbid the development of a new well pad in the vicinity of the already existing exploitation sites, i.e. within a shorter distance than the minimum distance.

2.4 Spatially-resolved water use modelling

2.4.1 Shale gas water withdrawal and consumption scenarios

Three separate water use scenarios were employed for the purpose of developing and applying a methodology for spatially-resolved modeling of water demands for shale gas development in the Lower Paleozoic Baltic-Podlasie-Lublin Basin of Poland and in Germany. These scenarios were compared to a baseline water withdrawal and consumption computation which took into account the evolution of the public, industrial, and agricultural sectors for the period 2006 to 2030, not including potential shale gas extraction activities. The 3 scenarios take into account the additional water withdrawals and consumption related to potential shale gas extraction activities within the shale gas play. Specifically, we assess hypothetical "low", "average" and "high" impact scenarios based on a subset of the variables described in Section 2.1.

The assumptions with respect to water use for each hypothetical scenario are summarised in Table 18. We assumed a range of water use per frack between 3000 m^3 and 45000m^3 for the hypothetical low and high impact scenarios, respectively, and 15000 m^3 for the average impact scenario. In addition, the low impact scenario assumed a single frack during the anticipated 10-year lifetime of the well, the average imact scenario assumed two fracks, and the high impact scenario assumed that each well is fracked 5 times over its lifetime.

Table 18: Shale gas water use scenarios assessed.

Scenario	Fracks per 10 years	Recycling scenario (%)	Water consumption per well per frack (m^3)
BASELINE	-	-	-
LOW	1	70%	3000
AVERAGE	2	35%	15000
HIGH	5	0%	45000

The amount of water used for shale gas extraction, as calculated for each hypothetical scenario, is given in Table 19. We differentiate between water withdrawals and water consumption. Water withdrawal is the total amount of water extracted from any source in the natural environment for the specified purpose. In terms of water required for shale gas extraction this is the total amount of water taken from a water body/resource and destined for use in the shale gas extraction process (the majority of which is used for fracking). Of this total amount of water withdrawn, a portion is 'consumed', that is to say removed from the direct environment through evapotranspiration, conversion into a product or polluted to an extent that it can no longer be used. The remaining water is returned to the environment either directly, or after treatment. In the case of shale gas extraction we interpret the 'consumption' of water as being the amount of water which is "used up" during the fracking process or, more specifically, that which is lost due to leakages, evaporation, or which infiltrates into the ground and can no longer be recovered for re-use. In the case of the low impact scenario we assume that 70% of the flow-back water (which is assumed to be 50% of total injected water) is recovered and recycled, meaning that the balance is assumed to have been 'consumed". In the average scenario we assume that 35% of the flowback water is recycled, and in the high impact scenario we assume that no water is recycled, and therefore 100% of the water withdrawn is consumed. This consumed water includes water that remains underground as well as grey and black water since in both cases the water is lost to the immediate environment (either at unrecoverable depths, or polluted to an extent that it cannot be directly used for other purposes).

Table 19: Withdrawal and consumption of water for shale gas extraction for the low, average and high impact scenarios (in m^3).

DE	Withdrawal			Consumption		
	LOW	AVERAGE	HIGH	LOW	AVERAGE	HIGH
2013	0	0	52065	0	0	52065
2018	50763	325016	1587983	15229	211260	1587983
2023	219975	1715281	10907618	65992	1114933	10907618
2028	658796	5576812	37955385	197639	3624928	37955385
PL	Withdrawal			Consumption		
	LOW	AVERAGE	HIGH	LOW	AVERAGE	HIGH
2013	0	0	0	0	0	0
2018	22201	142142	694485	6660	92392	694485
2023	96203	750158	4770315	28861	487602	4770315
2028	288116	2438952	16599330	86435	1585319	16599330

2.4.2 Competing Water Uses

The impact of the additional water use (i.e. beyond forecasted requirements of other users in the Baseline Scenario) related to shale gas extraction can be quantified by applying our water use module. The module estimates sectorial water withdrawals and consumption for the public, industrial, and agricultural sectors. It computes water withdrawals using the reference year 2006 (for which all necessary data is readily available), and can forecast withdrawals to 2030 using the various data projections. The methodology is based on the disaggregation of water use statistics to the appropriate land use classes using proxy data.

The main statistical data source for Poland was the "Environment 2011" report from the Central Statistical Office of Poland (CSO, 2011), which gives water withdrawals for the public, industrial, and agricultural sectors at regional level (NUTS2). For all sectors, water consumption maps were calculated as a fraction of the withdrawal maps. Figure 10 shows these sectorial maps for the reference year 2006 for Poland. The shale play considered is indicated on all maps in red.

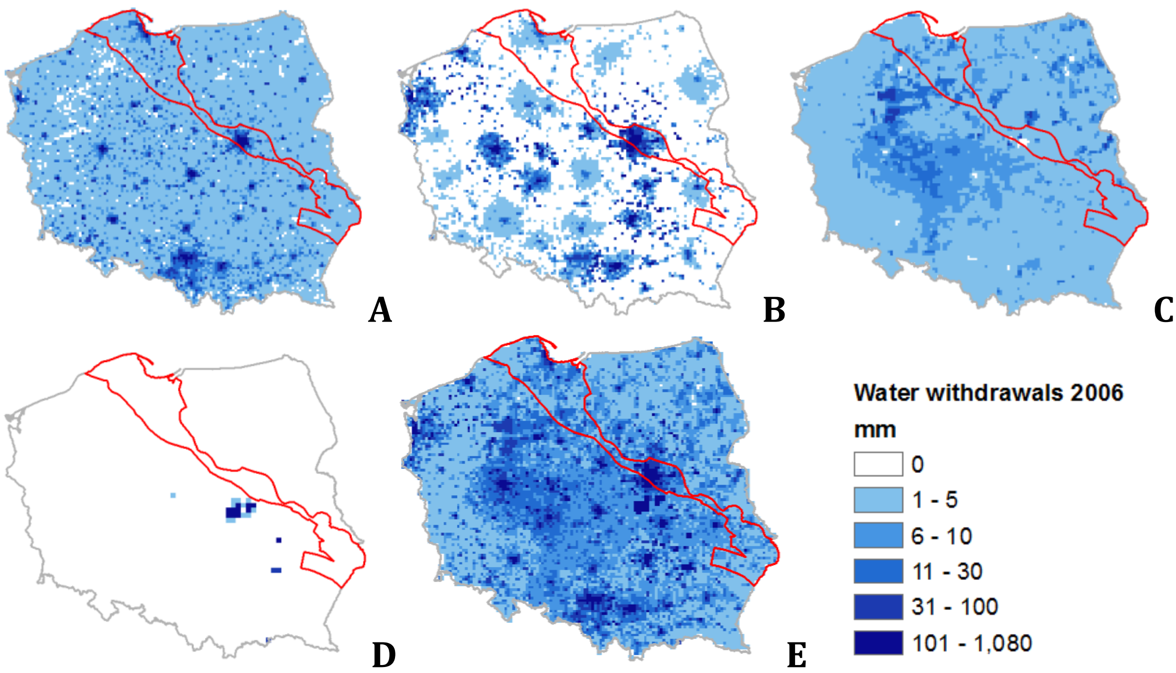

Figure 10: Sectorial water withdrawals for Poland for 2006; A) Public, B) Industry, C) Livestock, D) Irrigation, E) Total withdrawals, shown in mm.

For Germany, our main data source was the German Federal Statistical Office (DESTATIS), which provides sectorial water withdrawal data at NUTS1 resolution (Figure 11).

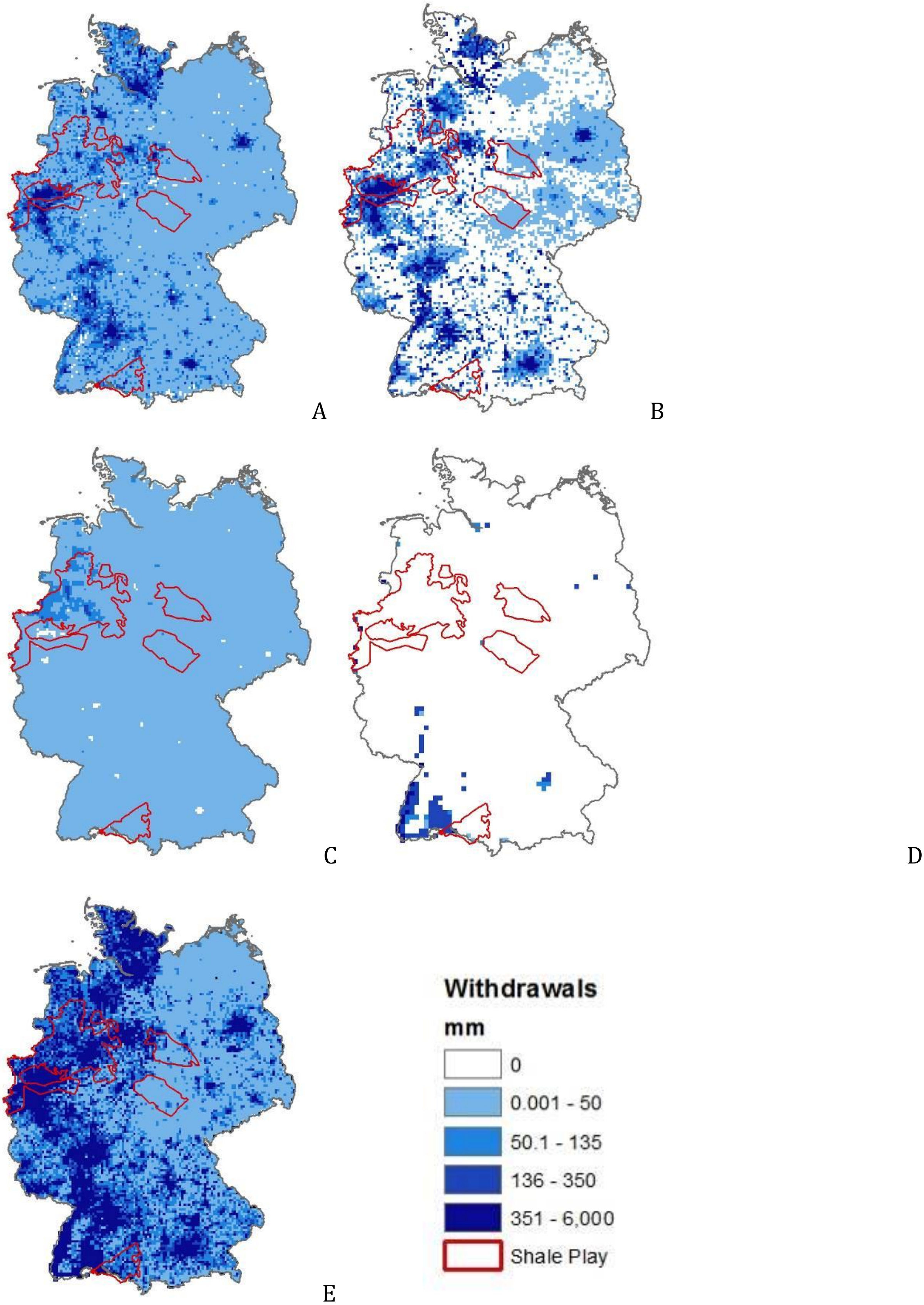

Figure 11: Sectorial water withdrawals for Germany for 2006; A) Public, B) Industry, C) Livestock, D) Irrigation, E) Total withdrawals, shown in mm.

Public water withdrawal

Data used:

- *Water withdrawal:* Public water withdrawal per NUTS2 region (CSO, 2011)
- *Land use:* Corine refined land use/cover map 2006 (De Batista et al., 2012) & projected land use to 2030, modeled using EUClueScanner (Lavalle et al., 2011a)
- *Population:* density maps 2006, 2030 (using EUROSTAT commune population, and forecasted regional population, De Batista et al., in press)
- *Tourism:* Number of nights spent by non-residents (NUTS2, EUROSTAT, ESPON), Number of bedplaces (NUTS3, EUROSTAT, ESPON), Number of nights spent abroad by residents (NUTS0, EUROSTAT), annual tourism growth rate (WTO,2000)

Maps of population and tourism density were created by allocating the relevant numbers of people to the urban and leisure land use classes. The regional statistics on public water withdrawal were then disaggregated to a map of the number of 'users' per pixel. This map was calculated as:

$User\ density = (P - T_o) + 300/160 * (T_i)$

Where P = population density; T_o = the number of nights spent abroad by residents; T_i = number of nights spent by tourists (corrected to NUTS3 level using the number of bedplaces). Tourists were assumed to have higher water withdrawals – we used a ratio of 300/160 (Gössling et al., 2012). To compute water use to 2030 we keep the 2006 water use per user constant, and re-calculate the user density map with the population and tourism growth forecasts.

Industrial water withdrawal

Data used:

- *Water use:* Industrial water use per NUTS2 region (CSO, 2011)
- *Land use:* Corine refined land use/cover map 2006 & projected land use to 2030, modeled using EUClueScanner

- *GVA for industry*: projected values to 2030

The regional statistics on industrial water use were disaggregated directly to the industrial land use within each area. This figure was assumed to include water use for electricity production (cooling water). Land use classes where industrial water use was allocated include Corine classes 121, 123, 124 and 131 (industry and commercial units; port areas; airports; and mineral extraction sites). The forecasted trend in water use was calculated taking into account the relative increase in GVA for industry per year. This was corrected by an "efficiency factor" related to the decreasing historical trend in water usage per unit production:

*Country change factor (%/yr) = Δ GVA for industry (%/yr) – efficiency factor (*1.33 *%/yr)*

Agricultural water withdrawal

Irrigation
Data used:

- *Irrigation requirements: Wriedt et al., 2008*
- *Irrigated area: Global irrigation dataset (Siebert et al., 2005)*
- *Land use:* Corine refined land use/cover map 2006 & projected land use to 2030, modeled using EUClueScanner

Irrigation requirements were estimated based on Wriedt et al. (2008). Monthly averages were derived from this 25-year period, and used for the reference year 2006 and for 2030. The generation of the irrigation map followed a two-step procedure. First, irrigated area was distributed to crop categories at sub-regional level based on statistical information and distribution rules. Next, the regional information was disaggregated to a high resolution dataset based on the crop distribution and a global irrigation dataset (Siebert et al., 2005). Based on crop growth, soil water and the EPIC nutrient model (De Roo, 2012), irrigation water requirements were estimated on a daily basis at a 10 x 10 km grid scale assuming unlimited irrigation. For 2030, the projected land use map computed by EUClueScanner (Lavalle et al., 2011a) was used.

Livestock

Data used:

- *CAPRI regional livestock totals* (CAPRI 2012)
- *Livestock density maps (FAO 2012)*
- *Land use:* Corine refined land use/cover map 2006 & projected land use to 2030, modeled using EUClueScanner

Daily maps of livestock water withdrawals were calculated based on the specific water requirements and spatial distribution of each type of livestock. The livestock water requirement map series is based upon the Food and Agriculture Organization of the United Nations (FAO) livestock density maps (FAO 2012) for 2005 (described in Robinson et al. 2007). Actual livestock figures for 2005 as given by the Complete and Consistent database (Witzke et al. 2011) made available through the Common Agricultural Policy Regionalized Impact Modeling System (CAPRI 2012) are used to refine the livestock density maps. A series of water requirements per livestock type data are taken from the literature in order to compute water requirements per livestock type on a daily basis. No projection of this map has been made as yet, and the 2006 map was kept constant for the calculation of the WEI.

Sectorial water consumption

For each sector we assumed a percentage of the total withdrawals to be fully consumed. Table 20 shows these figures, originating from available literature (*3rd UN World Water Development Report 2009*) and expert opinion. These average values were then used to compute maps of water consumption (by multiplying this sector-specific value with the water withdrawal maps).

Table 20: Actual estimated sectorial consumption of water (% assumed water consumption is the portion of the total abstracted water for each sector that is actually consumed (lost to evaporation, converted into products etc..)).

Water withdrawal sector	Water consumption from literature (%)	Assumed water consumption (%)
Public	10-20	*20.0*
Industry	5-10	*15.0*
Energy	1-2	*2.5*
Irrigation	50-60 (surface); 90 (localised)	*75.0*
Livestock	-	*15.0*

2.4.3 Water exploitation Index

The water exploitation index (WEI) is used as an indicator to assess the relative impact that the various scenarios have on available water resources. The WEI_{abs} was also used as a suitability factor to determine where shale gas extraction should be situated in the next timestep. Where the water exploitation was already high, suitability was decreased, hence discouraging shale gas extraction in that water region.

The index is the ratio of total water withdrawals to the total amount of water available, and can be calculated for both the total amount of water abstracted, and the total amount actually consumed:

$$WEI_{abs} = \textit{total water } \textbf{\textit{abstracted}} \textit{ / total water availability}$$

$$WEI_{cns} = \textit{total water } \textbf{\textit{consumed}} \textit{ / total water availability}$$

We used our water withdrawal and consumption maps in conjunction with the average annual freshwater availability map computed using the LISFLOOD model developed within the European Commission Joint Research Centre Institute for Environment and Sustainability (IES) (De Roo et al. 2012) to compute both indicators.

We computed all water withdrawal and consumption maps and the WEI_{abs} and WEI_{cns} every 5 years, starting from the initial year of possible extraction – 2013. The initial baseline indicators for 2013 serve to help define the optimal location for the first well pads. In the subsequent timesteps, the indicators are re-calculated for each scenario, allowing us to analyse the spatial and temporal effect of the additional water abstractions required for the shale gas extraction on the state of the available water resources.

2.5 Methods for ecological and human health screening risk assessment for chemicals potentially used in hydraulic fracturing of shale formations

Current hydraulic fracturing technologies for shale gas extraction employ a wide variety of chemicals, in combination with water and proppants, to facilitate extraction of gas from host formations. To date, however, most studies of the potential environmental impacts of shale gas development have focused on assessing greenhouse gas emissions associated with shale gas production activities (e.g. Jiang et al 2011, Howarth et al 2011, Weber and Clavin 2012), drinking water quality effects)(Osborne et al. 2011; Gross et al 2013; USEPA 2012), or regional air quality (e.g. McKenzie et al 2012). A recent comprehensive study of surface water exploitation and pollution has been published by Entrekin et al (2011), highlighting that the data required to fully understand potential threats are currently lacking. Other potential impacts related to ecosystem and human health (e.g. ecotoxicity in surface and marine waters as well as in terrestrial ecosystems) are less explored (Rozell and Reaven, 2012). In general, there is a paucity of information and scientific consensus as to the nature and magnitude of environmental and human-health effects due to chemicals potentially released as result of shale gas development activities.

A limited number of studies have reviewed specific toxicological properties of a subset of the chemicals potentially employed in shale gas development. Colborn et al. (2011) analyzed Material Safety Data Sheets (MSDSs) of 353 chemicals used in shale gas operations, identified by CAS number. They concluded that more than 75% of the chemicals considered could affect the skin, eyes, and other sensory organs, and the respiratory and gastrointestinal systems. In addition, approximately 40–50% could affect the brain/nervous system, immune and cardiovascular systems, and the kidneys; 37% could affect the endocrine system; and 25% could cause cancer and mutations. These results indicate that many chemicals potentially used in hydraulic fracturing for shale gas operations may have long-term health effects that are not immediately expressed.

Broderick et al. (2011) undertook a review of the list of fracking chemicals compiled by New York state (2009), cross checking CAS numbers with the following lists on the European Chemical Substances Information System (ESIS)

- toxicity classification: for the purposes of classification and labelling (according to Annex VI of Regulation (EC) No 1272/2008 and the Globally Harmonised System);
- presence on List 1 -4 of priority substances. Since 1994, the European Commission has published four lists of substances requiring immediate attention because of their potential effects on humans or the environment. There are 141 substances on the lists;
- presence on the first list of 33 priority substances established under Annex X of the Water Framework Directive (WFD) 2000/60/EC - now Annex II to the Directive on Priority Substances (Directive 2008/105/EC). Member States must progressively reduce pollution from priority substances;
- presence on the PBT (Persistent, Bioaccumulative and Toxic) list: substances which have been subject to evaluation of their PBT properties under the Interim Strategy for REACH and the ESR

They concluded that 58 of the 260 substances have one or more properties that may give rise to concern, specifically: 15 substances are listed in one of the four priority lists; 6 are present in list 1 (Acrylamide, Benzene, Ethyl Benzene, Isopropylbenzene (cumene), Naphthalene, Tetrasodium Ethylenediaminetetraacetate); one is under investigation as a PBT (Naphthalene bis (1-methylethyl)); 2 are present on the first list of 33 priority substances (Naphthalene and Benzene); 17 are classified as being toxic to aquatic organisms (acute and/or chronic); 38 are classified as being acute toxins (human health); 8 are classified as known carcinogens (Carc. 1A=1, Carc. 1B = 7); 6 are classified as suspected carcinogens (Carc. 2 = 6); 7 are classified as mutagenic (Muta. 1B); and 5 are classified as having reproductive effects (Repr. 1B=2, Repr. 2=3).

On this basis, it appears that several issues will need to be addressed to ensure that shale gas can be produced in a manner that meets environmental and public health protection goals (Howarth and Ingraffea, 2011). Since hydraulic fracturing typically involves the use of large quantities of water and chemicals, associated risks for contamination of ground and surface waters, along with attendant environmental and human health impacts, require careful consideration. In addition, as many of the chemicals used in hydraulic fracturing operations may volatilize in air, potential harm related to human intake via inhalation need also be considered.

Risks for ecosystems and human health (both occupational and for the general population) due to chemicals used in shale gas development should be evaluated in order to characterize:

- Emissions (quantities and ratios of water, proppants, and chemicals; operational/ accidental releases; injected chemicals/formation chemicals)
- Exposure (fate of the chemicals when emitted into air, water and soil; exposure pathways for ecosystems and humans)
- Effects (toxicological endpoint of both the injected and the formation chemicals)

Here, we provide a screening-level risk assessment of potential human and ecosystem health impacts
associated with a subset of the chemicals currently used in hydraulic fracturing of shale gas wells. Specifically, we characterize; the kinds of chemicals used in hydraulic fracturing; potential operational and accidental emission pathways; potential exposure pathways for humans and ecosystems as a result of operational or accidental emissions; and potential human and ecosystem health impacts. Here, we employ the multimedia box model USEtox (Rosenbaum et al 2008). The resulting characterization factors are calculated accounting for potential emissions of fracking chemicals to water, soil and/or air.

2.6 Methods for ecological and human health screening risk assessment for gaseous emissions associated with shale gas development.

The Pennsylvania Department of Environmental Protection (PDEP) collects and compiles data regarding a subset of gaseous emissions from shale gas development activities in Pennsylvania. These data are reported by source category (i.e. Stationary Engines; Heaters/Reboilers; Tanks/Vessels; Dehydrators; Pneumatic pumps;

Venting/Blowdowns; Drill Rigs; Completions/Workovers; and Fugitives) for CO, NOx, PM-10, PM-2.5, SOx, VOC, Benzene. Ethyl Benzene, Formaldehyde, n-Hexane, Toluene, Xylenes and 2,2,4-Trimethyl pentane. The data collected for 2011 are publically available at http://www.dep.state.pa.us/dep/deputate/airwaste/aq/emission/emission_inventory.htm. According to a personal communication from the Environmental Group Manager at PDEP (Michael Rudawski), these data represent activities associated with 3,935 active wells in Pennsylvania in 2011. We re-expressed the data as annual average emissions per active well (
Table 21). In order to evaluate the toxicological profile of these emissions, the data were subsequently assessed using USEtox in order to calculate mid-point human and freshwater ecotoxicity impact potentials. This was done for six of the aforementioned chemicals for which toxicological data were available in the model (Benzene, Ethyl Benzene, Formaldehyde, n-Hexane, Toluene, and Xylenes). Finally, the toxicity potentials were calculated with reference to our technology scenarios by using the LUMP model outputs for population densities to customize the USEtox analysis.

Table 21 Air emissions inventory for shale gas development activities in Pennsylvania in 2011

Source Category	CO	NOx	PM-10	PM-2.5	SOx	VOC	Benzene	Ethyl Benzene	Formaldehyde	n-Hexane	Toluene	Xylenes	2,2,4-Trimethylpentane
Stationary Engines	395.657	685.536	21.762	21.575	1.610	182.310	0.766	0.049	63.219	1.214	0.555	0.219	0.226
Heaters - Reboilers	72.461	81.857	5.408	5.256	0.613	4.621	0.002	0.003	0.068	1.405	0.003	0.005	0.000
Tanks - Vessels	0.023	0.005	0.000	0.000	0.000	78.490	0.097	0.087	0.000	1.705	0.244	0.123	0.118
Dehydrators	17.186	4.048	0.023	0.023	0.001	82.857	2.207	1.018	0.007	1.464	5.482	3.659	0.020
Pneumatic Pumps	0.000	0.000	0.000	0.000	0.000	40.357	0.040	0.003	0.000	1.106	0.051	0.030	0.006
Venting - Blowdowns	0.349	0.559	0.006	0.006	0.004	13.251	0.095	0.092	0.013	1.289	0.127	0.096	0.002
Drill Rigs	468.654	2,119.710	69.021	66.040	20.047	99.598	0.789	0.043	0.428	0.078	0.325	0.210	0.097
Completions - Workovers	787.019	1,312.069	50.319	35.387	8.770	134.043	0.539	0.030	0.136	2.524	0.281	0.155	0.231
Fugitives	0.000	0.007	0.000	0.000	0.000	81.141	0.448	0.045	0.000	2.121	1.519	2.034	0.196
Emission Totals (tonnes)	6,852	16,542	577	505	122	2,820	19.6	5.4	251.3	50.8	33.8	25.7	3.5
Emissions per Active Well (kg)	1,741	4,204	147	128	31	717	5.0	1.4	63.9	12.9	8.6	6.5	0.9

RESULTS AND DISCUSSION

3.1 Land Use for Shale Gas Development Scenarios

Figure 12 and Figure 13 present the landscape as in 2006, the starting year of the simulation in Poland. The Lower Paleozoic formations in the Baltic-Podlasie-Lublin basins delineate the shale play under consideration in this exercise, as defined by PGI (2012). This shale play stretches across Poland from the North coast to the South-East regions, thus covering approximately one tenth of the Polish territory (33,803 km^2).

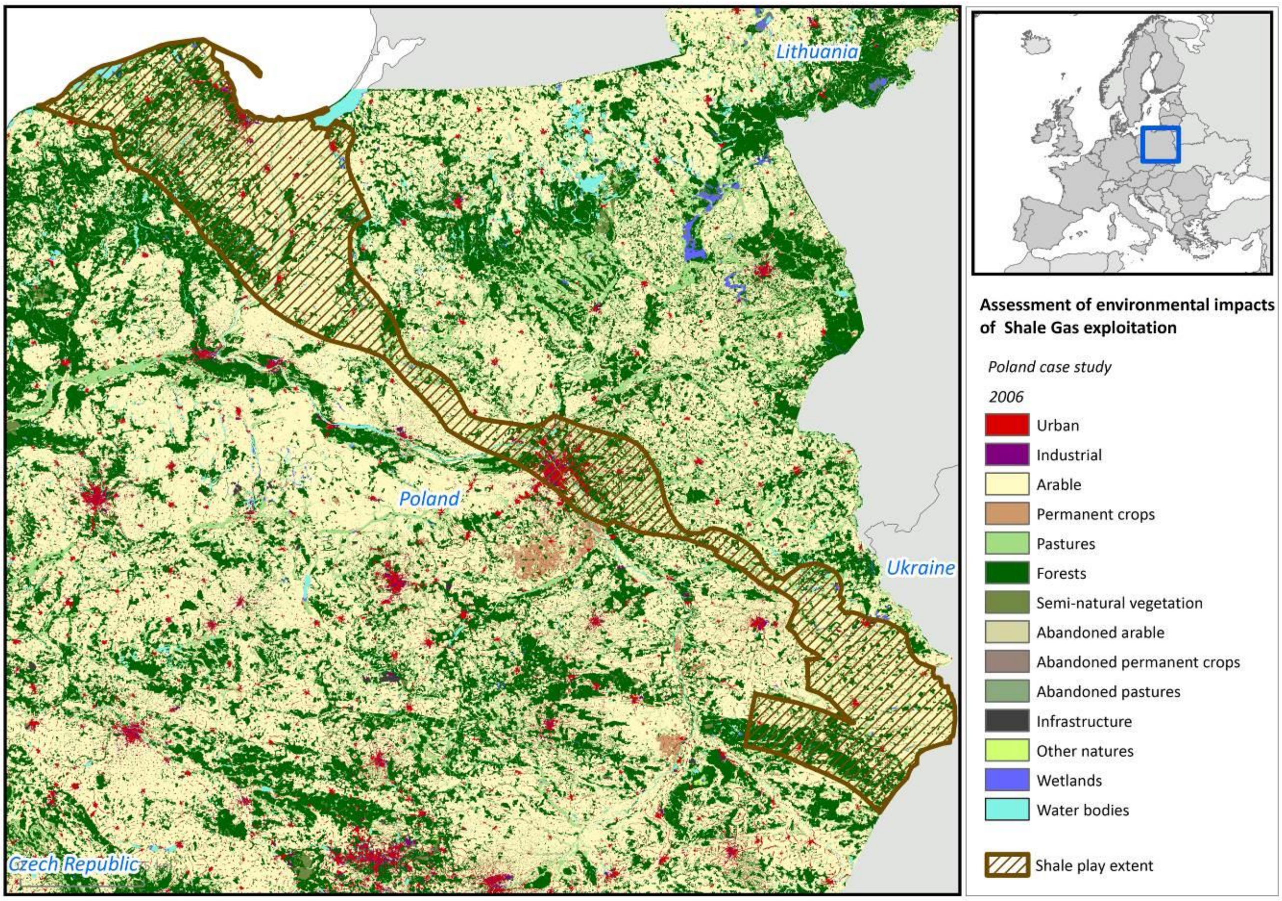

Figure 12: Poland land use map in year 2006, as from the refined version of Corine Land Cover.

As detailed in Table 22, the predominant land uses within the shale play area are *Arable land* and *Forest*, which occupy nearly 56% and more than 27% of the total shale play area, respectively. Other uses, such as *Permanent crops*, are scarcely represented.

The shale play crosses several protected areas under European schemes, namely Natura2000 sites or Nationally Designated Areas. Together these account for approximately 978,824 ha of land (nearly 30% of the shale play). The breakdown according to the type of protection regime counts 173,545 ha mapped as Nationally Designated Areas, 426,357 ha as Natura2000 sites and 378,922 ha preserved under both legislative frameworks.

Although the shale play underlies a predominantly rural landscape, it is worthwhile noting that human presence is significant, not only because of sparse settlements located in the countryside, but also because of historical settlements, such as the capita,l Warsaw, and the city of Gdansk on the coast (Table 22)

Table 22: Land use shares within the shale play in 2006, as per the refined version of Corine Land Cover. The land use classes that were not simulated (fixed during the simulation period) are highlighted in grey.

	2006	
Land use class	**[ha]**	**[%]**
Urban fabric	139,789	4.14
Industry	23,600	0.70
Arable	1,891,504	55.96
Permanent crops	3,936	0.12
Pastures	274,064	8.11
Forests	932,916	27.60
Semi-natural vegetation	17,528	0.52
Infrastructure	11,937	0.35
Other nature	3,453	0.10
Wetlands	15,800	0.47
Water bodies	65,830	1.95
Total shale play area	3,380,357	

In Germany, the shale play boundaries have been defined according to BGR (2012) and comprised 5 zones, as highlighted in Figure 13. The four zones in the north belongs to the Lower Saxony sub-basin: they cover most of the Münster and Detmold regions, touching the Düsseldorf region in the south and the Hannover, Braunschweig, Sachsen-Anhalt and Thüringen regions in the east. The fifth zone included in the analysis covers the Molasse Basin, which is mainly located in the Tübingen region.

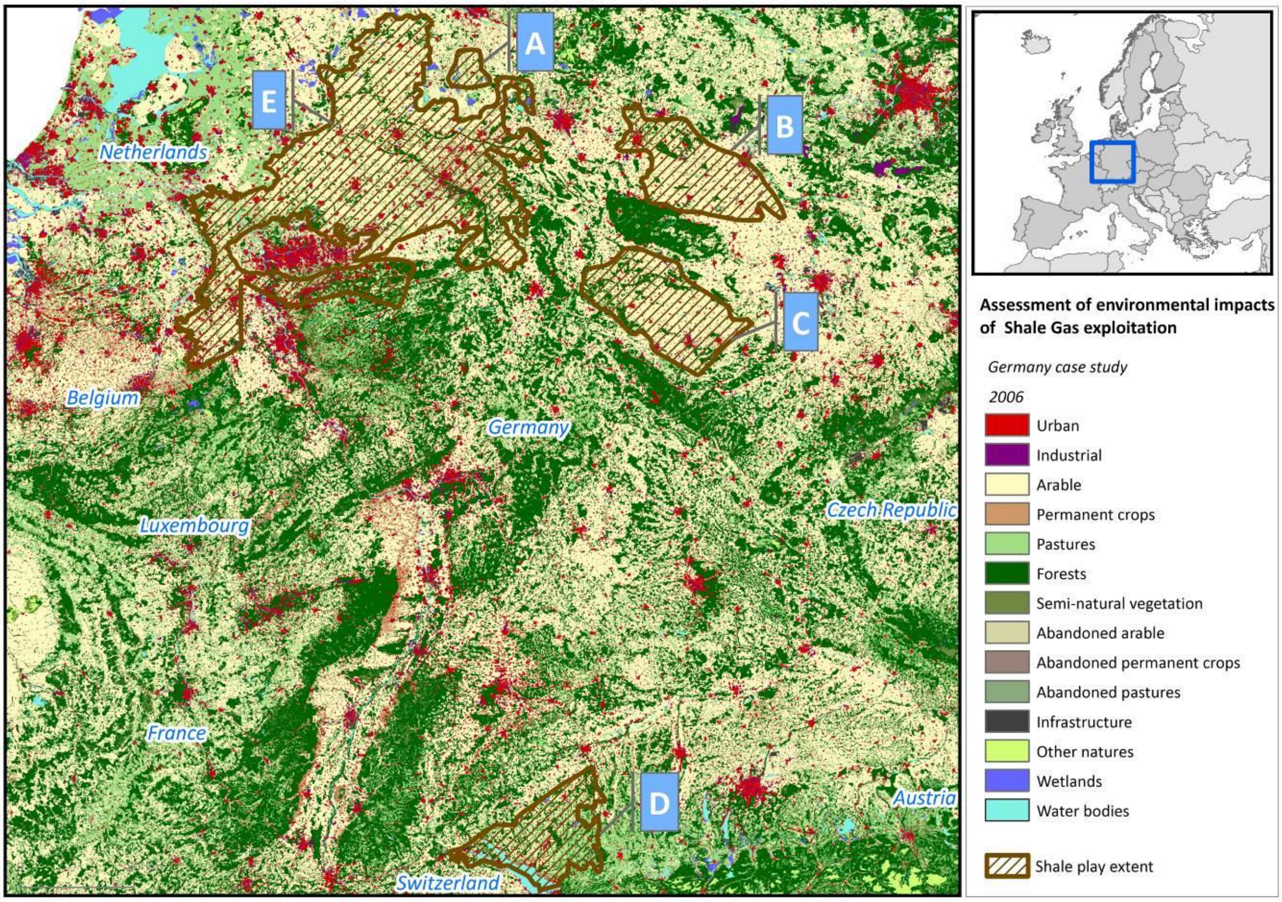

Figure 13: Germany land use map in year 2006, as from the refined version of Corine Land Cover.

An overview of the predominant land uses within the delineated shale play zones are reported in Table 23, expressed in hectares, and in Table 24, expressed in percentages of the respective total shale play zone. According to the refined Corine Land Cover, to which these figures refer, the landscape is predominantly rural, with arable land being the most represented use. On the contrary, the southernmost zone is mostly covered with forest and pastures. All the shale play zones are significantly populated: urban areas cover from 3%, in the smallest zone, to 10% of the respective zone's area.

As in Poland, the shale play in Germany crosses several areas that are protected under European schemes, i.e. Natura2000 sites and Nationally Designated Areas. Together these account for approximately 2,432,535 ha of land (more than 60% of the shale play). Nearly 4% of this land is protected as Natura2000 site, and 46% is designated as Nationally Designated Area. The remaining 11% of natural protected areas is part of both the Natura 2000 network and Nationally Designated Areas database.

Table 23: Land use shares (in ha) within the shale play in 2006, per zone and as per the refined version of Corine Land Cover. The land use classes that were not simulated (fixed during the simulation period) are highlighted in grey.

2006											
Shale play zone	***Urban fabric***	***Industry***	***Arable***	***Permanent crops***	***Pastures***	***Forests***	***Semi-natural vegetation***	**Infrastructure**	**Other nature**	**Wetlands**	**Water bodies**
A	1,859	509	38,021	0	5,867	6,425	164	19	30	2,711	126
B	35,361	8,274	365,613	661	16,098	49,992	712	4,165	42	81	3,025
C	31,477	9,501	376,381	1,730	16,197	99,867	467	2,104	0	104	2,071
D	29,032	3,066	137,732	8,160	96,842	110,023	2,815	1,361	0	5,684	34,088
E	255,979	54,722	1,559,795	102	152,073	443,846	2,056	19,301	2,573	6,578	16,825
Total shale play area							4,022,307				

Table 24: Land use shares (in %) within the shale play in 2006, per zone and as per the refined version of Corine Land Cover. The land use classes that were not simulated (fixed during the simulation period) are highlighted in grey.

2006											
Shale play zone	***Urban fabric***	***Industry***	***Arable***	***Permanent crops***	***Pastures***	***Forests***	***Semi-natural vegetation***	**Infrastructure**	**Other nature**	**Wetlands**	**Water bodies**
A	3.34	0.91	68.22	0.00	10.53	11.53	0.29	0.03	0.05	4.86	0.23
B	7.31	1.71	75.54	0.14	3.33	10.33	0.15	0.86	0.01	0.02	0.62
C	5.83	1.76	69.71	0.32	3.00	18.50	0.09	0.39	0.00	0.02	0.38
D	6.77	0.72	32.12	1.90	22.58	25.66	0.66	0.32	0.00	1.33	7.95
E	10.18	2.18	62.05	0.00	6.05	17.66	0.08	0.77	0.10	0.26	0.67

Land use Scenarios for Poland

Under the High Impact Scenario, the first well pads are allocated in the northern part of the shale play: the development starts in the county of Słupski, in an area characterised by low density population. The development proceeds in Gdanski and Starogardzki: in this latter county, a few well pads are allocated in the vicinity of the small town of Kościerzyna. Towards the end of the simulation, in the year 2028, more than 60 well pads are allocated in Grudziadz county, between 5 and 17 km from Grudziądz, a medium-sized city situated on the Vistula river, in the Kuyavian-Pomeranian Voivodeship.

As in the High Impact Scenario, the development in the Average Impact Scenario kicks off from the northern part of the shale play, in particular from Słupski county. In 2023, the well pads begin to be developed in the county of Starogardzki, within a radius of approximately 10 km from the town of Kościerzyna. After 5 years, a few well pads are allocated in the same county of Starogardzki, 15 km west-southward from the city of Starogard Gdański; the rest of the well pads are placed in Grudziadz county, in the vicinity of Grudziądz.

Under the Low Impact Scenario, the development begins in the northern part of the shale play, between the counties of Słupski and Gdanski. It then spreads further over those same counties and in Grudziadz county.

The absolute land take due to the modelled scenarios for shale gas development was described previously in the section dedicated to Scenarios. The most affected land use classes (i.e. percentage of well pads assumed to be developed in each land use class) for the High, Average and Low Impact Scenarios are detailed in Table 25, Table 26, and

Table 27, respectively, as well as Figure 14, Figure 15 and Figure 16.

Table 25: Percentage of well pads developed in each land use class every 5 years in Poland (High Impact Scenario).

Land use	High Scenario			
	2013 [%]	2018 [%]	2023 [%]	2028 [%]
Arable land	-	67.86	35.77	44.44
Permanent crops	-	0	0	0
Pastures	-	0	0	1.36
Forest	-	32.14	64.23	53.66
Semi-natural vegetation	-	0	0	0.54

Table 26: Percentage of well pads developed in each land use class every 5 years in Poland (Average Impact Scenario).

Land use	Average Scenario			
	2013 [%]	2018 [%]	2023 [%]	2028 [%]
Arable land	-	71.43	40.32	36.41

Permanent crops	-	0	0	0
Pastures	-	0	3.23	1.63
Forest	-	28.57	56.45	61.96
Semi-natural vegetation	-	0	0	0

Table 27: Percentage of well pads developed in each land use class every 5 years in Poland (Low Impact Scenario).

Land use	Low Scenario			
	2013 [%]	2018 [%]	2023 [%]	2028 [%]
Arable land	-	75.00	33.33	48.37
Permanent crops	-	0	0	0
Pastures	-	0	0	2.72
Forest	-	25.00	66.67	48.91
Semi-natural vegetation	-	0	0	0

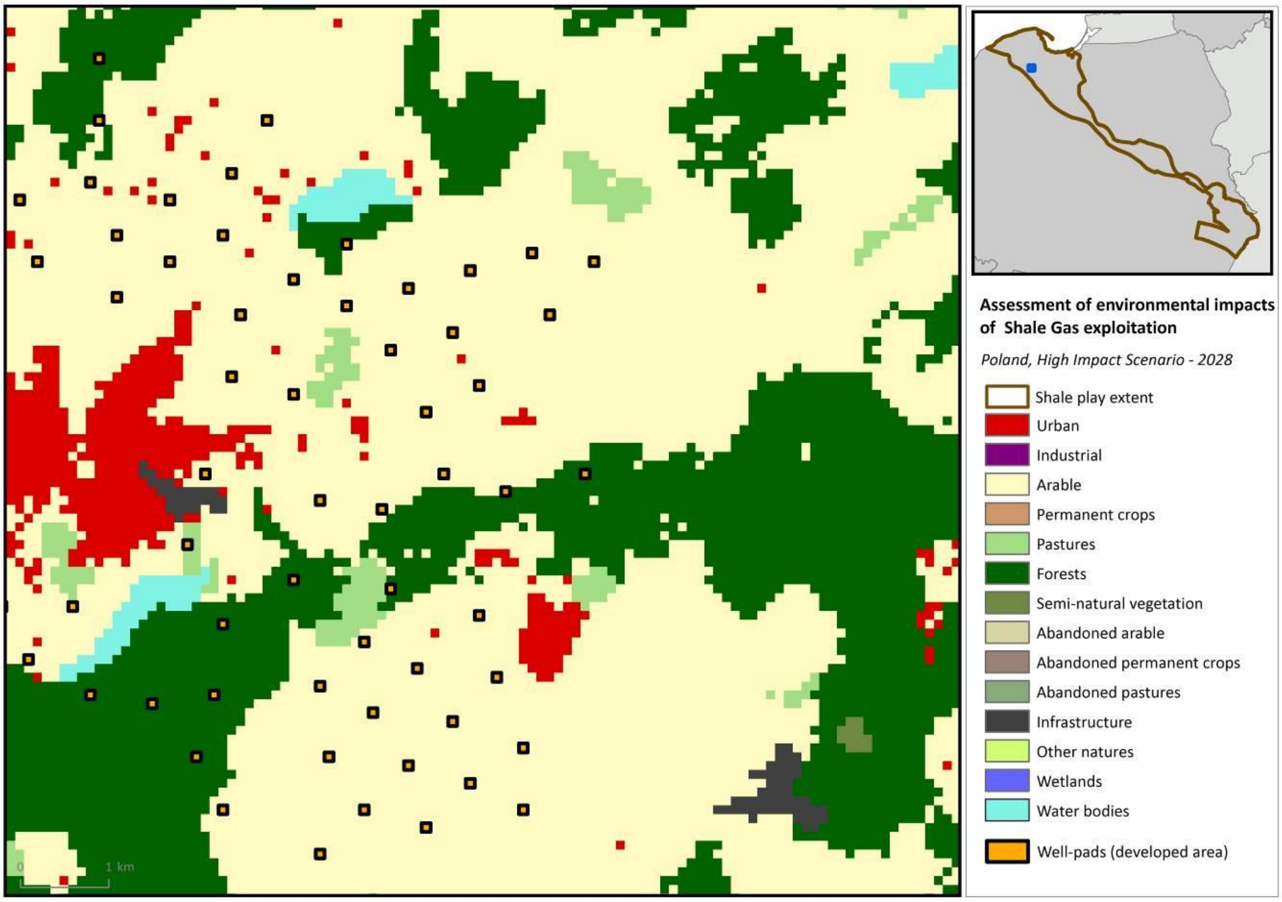

Figure 14: Land use map in Poland under the *High Impact Scenario*, zoomed to the northern region of the shale play.

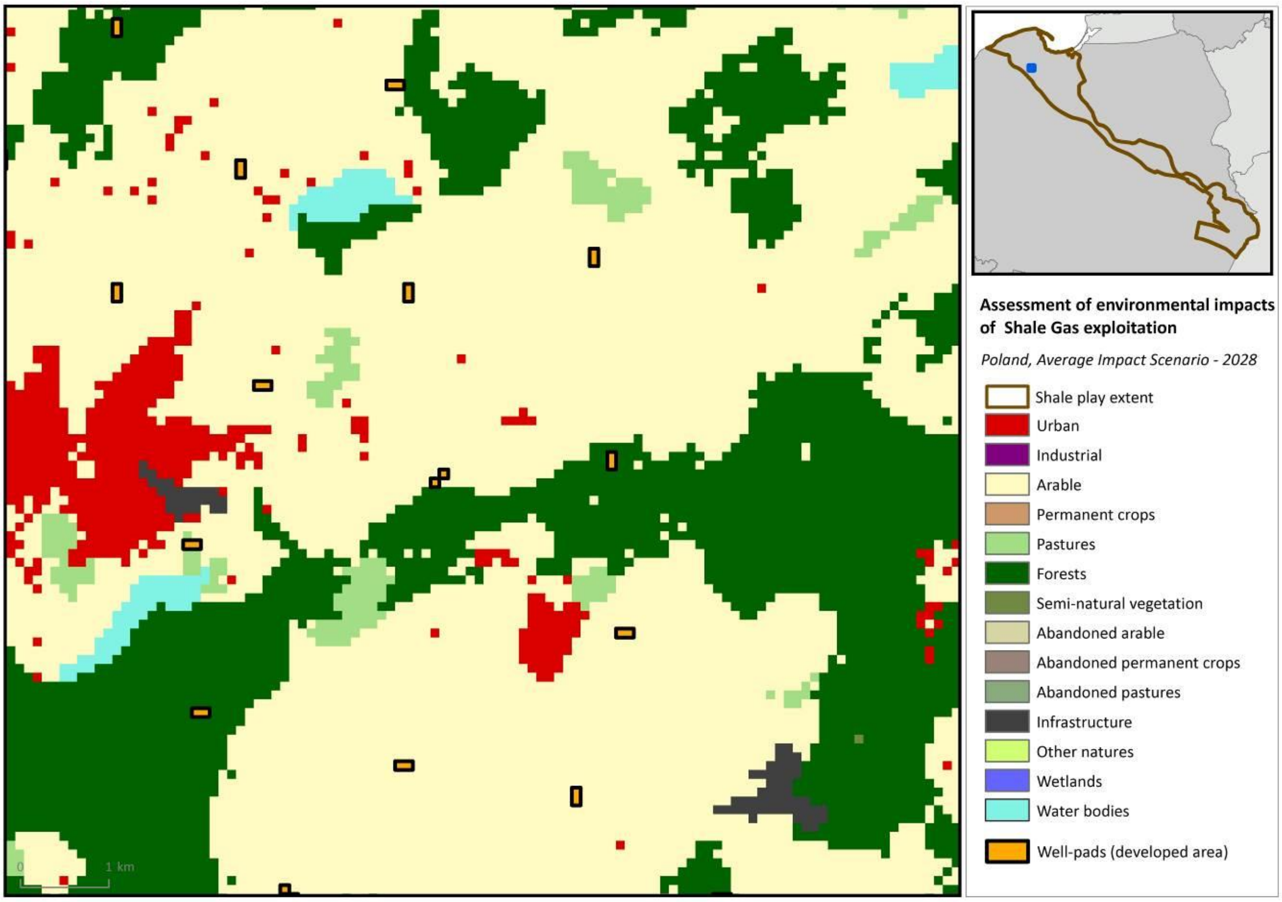

Figure 15: Land use map in Poland under the *Average Impact Scenario*, zoomed to the northern region of the shale play.

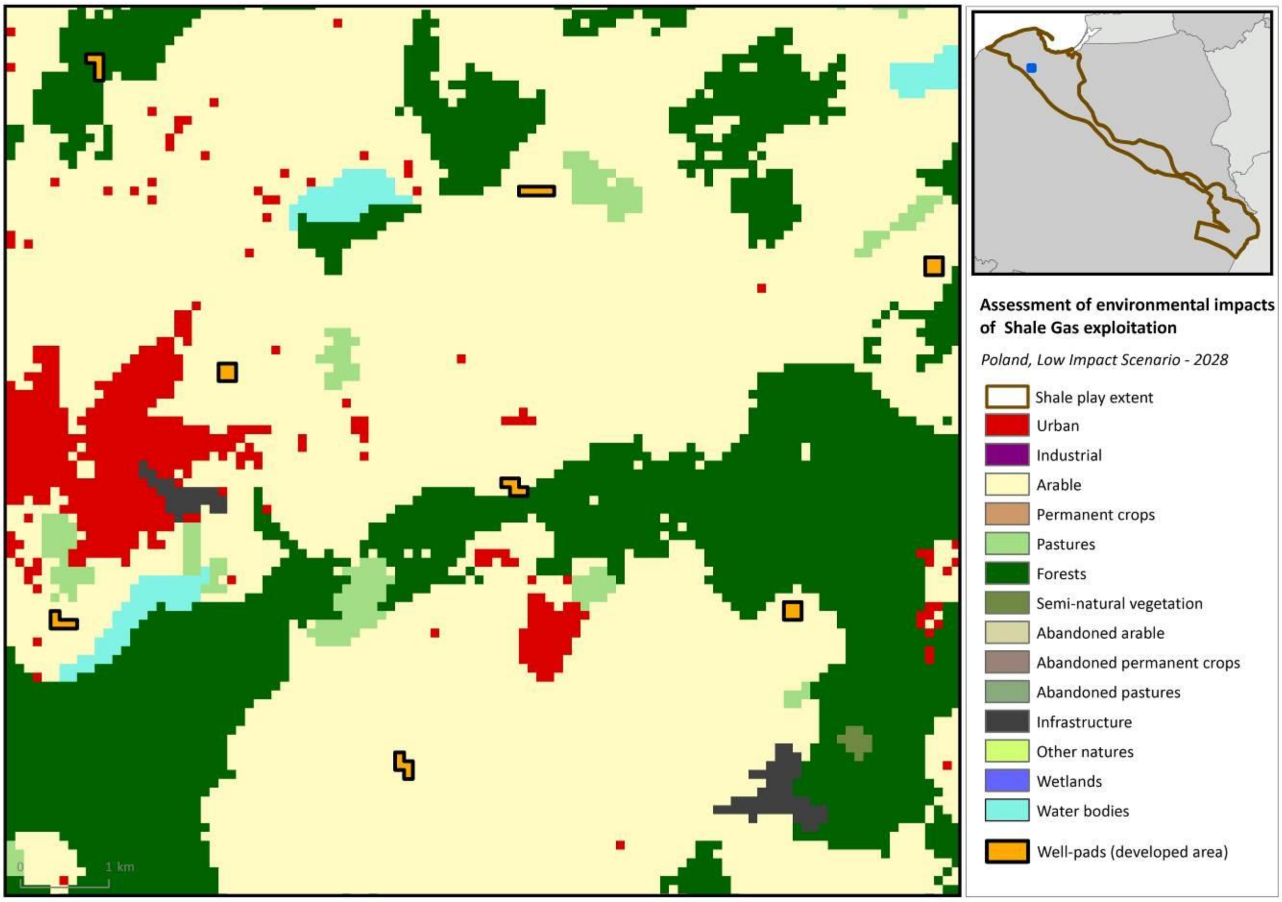

Figure 16: Land use map in Poland under the *Low Impact Scenario*, zoomed to the northern region of the shale play.

Land use Scenarios for Germany

Under the High Impact Scenario, all the well pads are developed in the south part of the shale play, north of the Bodensee. The first well pads are placed south-east of Baden-Württemberg, in the Ravensburg district, south-west from the city of Wangen im Allgäu. The development proceeds in the same district, up to 5 km north and up to 10 km east of Wangen im Allgäu. Well pads are also allocated in two neighbouring districts: in the southern part of Lindau and in Bodenseekreis (south of Tettnang). Between the years 2018 and 2023, some well pads are allocated in the area between the towns of Kißlegg (south of) and Isny im Allgäu (west of). Well pads are also allocated between the cities of Ravensburg and Tettnang, and in the Oberallgäu district, north of Weitnau. The development of well pads affects the northern part of the Ravensburg district, east from the town of Bad Waldsee, as well as the nearby southern part of the Biberach district. In this same region, a few well pads are allocated north-east and north-west of the city of Ochsenhausen. In the last years of the simulation, new well pads are allocated in the aforementioned districts: the development affects mainly Ravensburg district, but the southern region of Biberach and Bodenseekreis are also further developed. New well pads are allocated in the districts of Sigmaringen (south-east, near the town of Bad Saulgau) and Konstanz (south of the town of Stockach and north of Konstanz).

In the first 5 years of development simulated under the Average Impact Scenario, well pads are allocated in the same area as under the High Impact Scenario, between the two district of Ravensburg and Lindau. The development proceeds in the south part of Bodenseekreis and in the whole Ravensburg district, also affecting the south and western parts of the Biberach and Oberallgäu districts, respectively. During the last 5 years of the simulation, a few more well pads are allocated in the southern shale play, in the following districts: Ravensburg, Bodenseekreis and Konstanz. The development also affects the shale play which crosses the north part of the Thüringen region, in particular the following districts: Unstrut-Hainich-Kreis, Kyffhäuserkreis and Wartburgkreis. A few well pads are also allocated in the northernmost shale play, in the Niedersachsen and Nordrhein-Westfalen regions, in particular in the districts of Steinfurt, Emsland, Osnabrück, Landkreis and Nienburg (Weser).

Under the Low Impact Scenario, the well pads allocated until year 2023 follow a development pattern similar to the pattern of the Average Impact Scenario. In the last five years of the simulation, one third of the well pads are then allocated in the middle and northernmost shale plays.

The absolute land take due to the modelled scenarios for shale gas development was described previously in the section dedicated to Scenarios. The most affected land use classes (i.e. percentage of well pads assumed to be developed in each land use class) for the High, Average and Low Impact Scenarios are detailed in Table 28, Table 29 and Table 30, respectively, as well as Figure 17, Figure 18 and Figure 19.

Table 28: Percentage of well pads developed in each land use class every 5 years in Germany (High Impact Scenario).

Land use	High Scenario			
	2013 [%]	2018 [%]	2023 [%]	2028 [%]
Arable land	100	6.15	20.92	31.24
Permanent crops	0	0	4.96	2.72
Pastures	0	69.23	49.65	39.76
Forest	0	20.00	24.47	25.80
Semi-natural vegetation	0	4.62	0	0.47

Table 29: Percentage of well pads developed in each land use class every 5 years in Germany (Average Impact Scenario).

Land use	Average Scenario			
	2013 [%]	2018 [%]	2023 [%]	2028 [%]
Arable land	-	12.50	24.65	39.34
Permanent crops	-	0	5.63	1.18
Pastures	-	65.63	40.14	30.33
Forest	-	21.88	29.58	28.44
Semi-natural vegetation	-	0	0	0.71

Table 30: Percentage of well pads developed in each land use class every 5 years in Germany (Low Impact Scenario).

Land use	Low Scenario			
	2013 [%]	2018 [%]	2023 [%]	2028 [%]
Arable land	-	12.50	25.00	47.88
Permanent crops	-	0	11.43	0.47
Pastures	-	62.50	45.00	79.29
Forest	-	25.00	18.57	77.14
Semi-natural vegetation	-	0	0	0

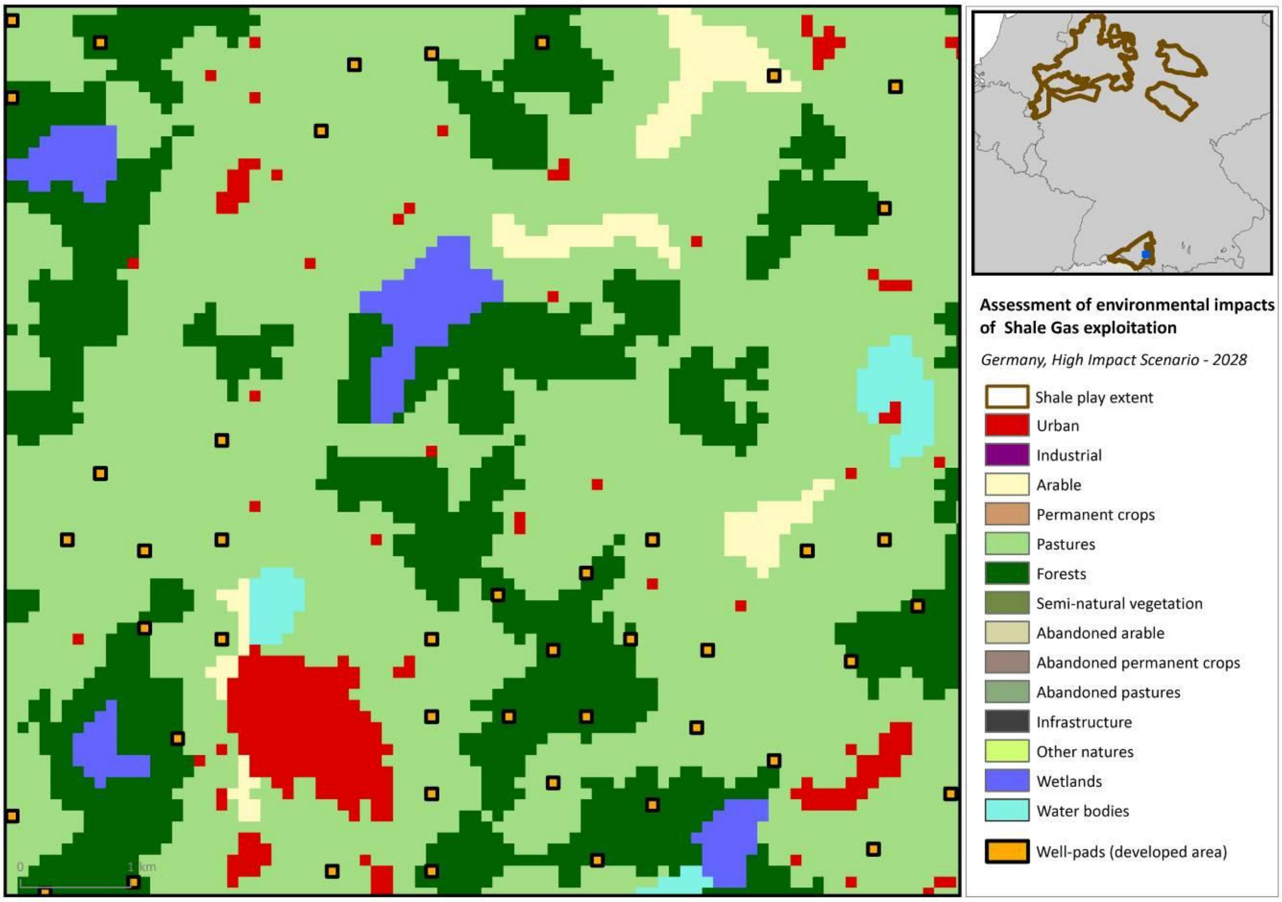

Figure 17: Land use map In Germany under the *High Impact Scenario*, zoomed to the southern region of the shale play.

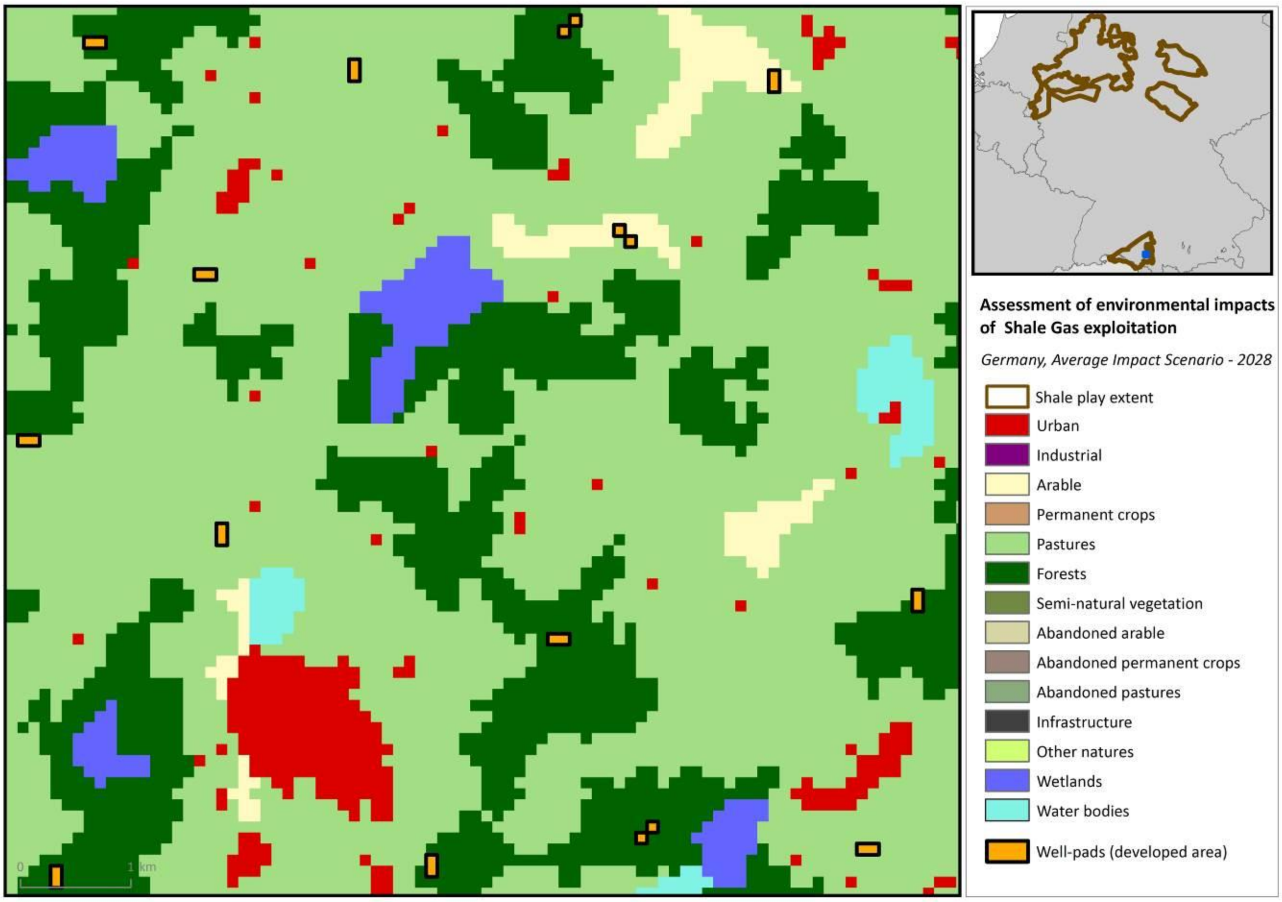

Figure 18: Land use map In Germany under the *Average Impact Scenario*, zoomed to the southern region of the shale play.

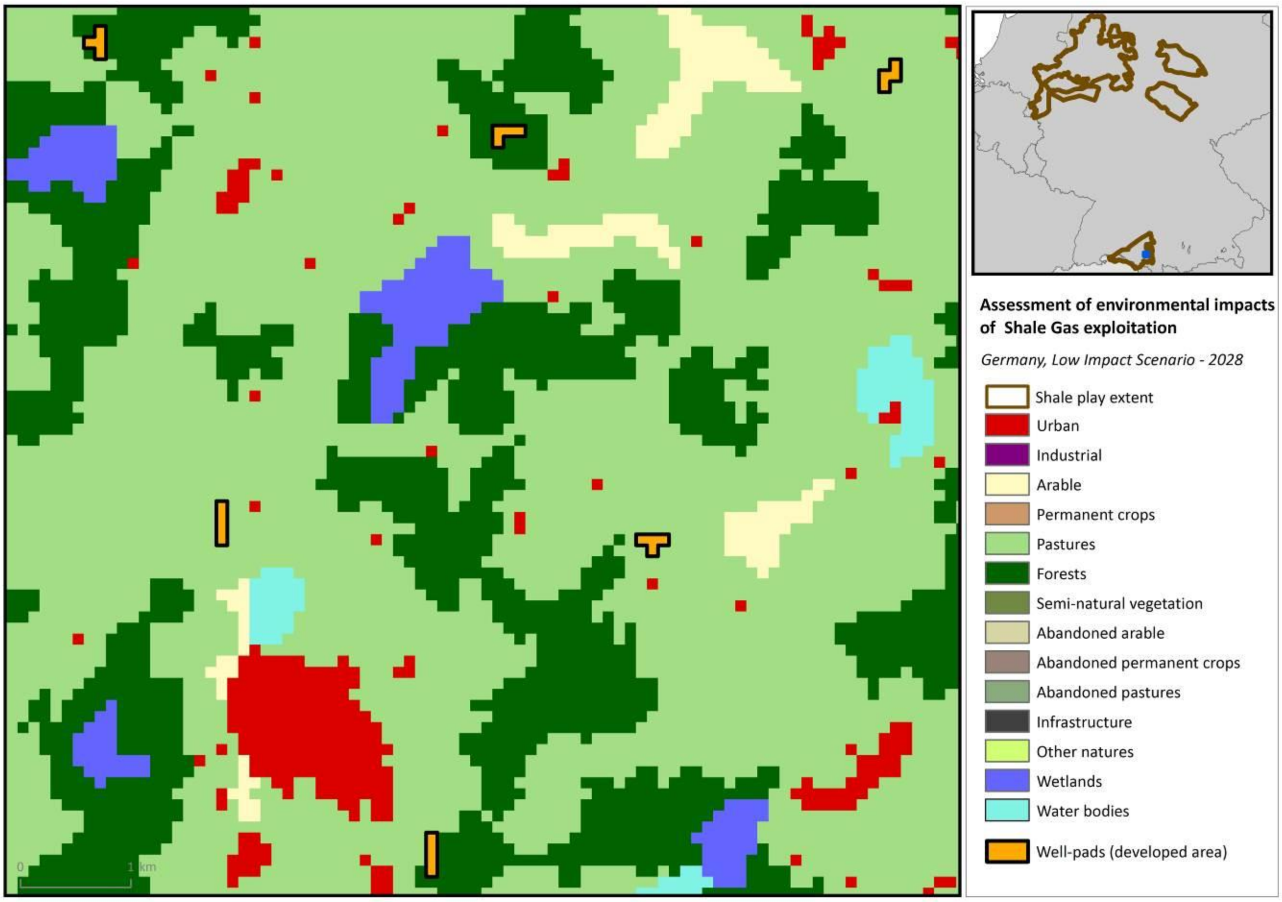

Figure 19: Land use map In Germany under the *Low Impact Scenario*, zoomed to the southern region of the shale play.

Potential impacts associated with human exposure

For each allocation year for all of the simulated Scenarios, the respective population map has been computed, thus allowing for an assessment of the population distribution in the vicinity of the extraction sites. This kind of analysis can provide useful inputs for further assessments, in relation to potential impacts on resident populations potentially exposed to emissions of pollutants (see sections 3.3 and 3.4).

The population density maps are computed by disaggregating population projections (EUROPOP2010) on the simulated land use maps. The applied methodology can be found in Batista et al. (in press). In order to illustrate the different spatial configurations of the extraction sites, as compared to the populated areas, under the three simulated

Scenarios, a zoomed area is shown in Figure 20, Figure 21 and Figure 22 for Poland and Figure 26, Figure 27 and Figure 28 for Germany. The population living within 5 kms of well sites for each year in Poland under the three scenarios is detailed in Figure 23, Figure 24 and Figure 25, and for Germany in Figure 29, Figure 30 and Figure 31.

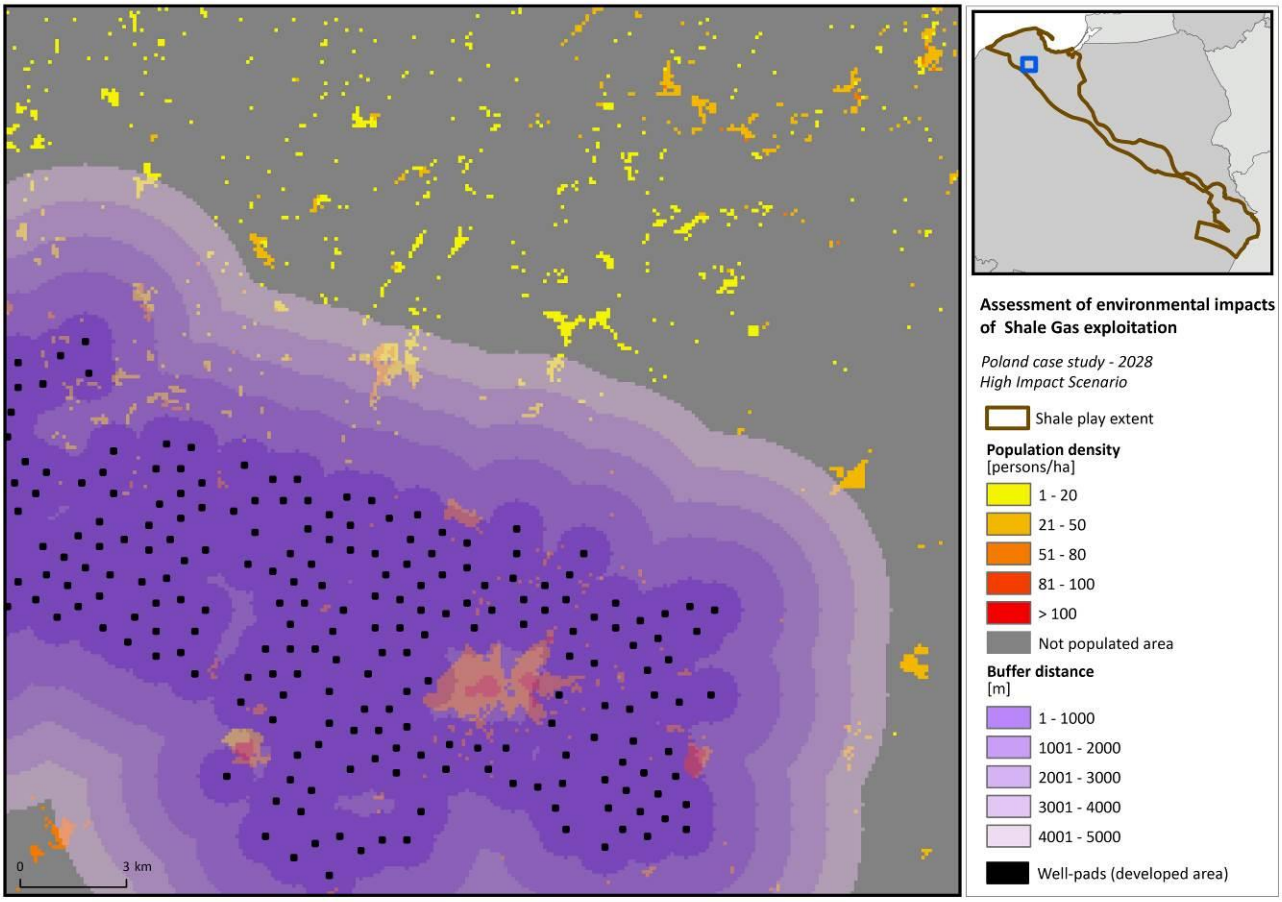

Figure 20: Projected population density map overlain with the allocated well pads and their respective buffer distances, as in year 2028 (High Impact Scenario, Poland).

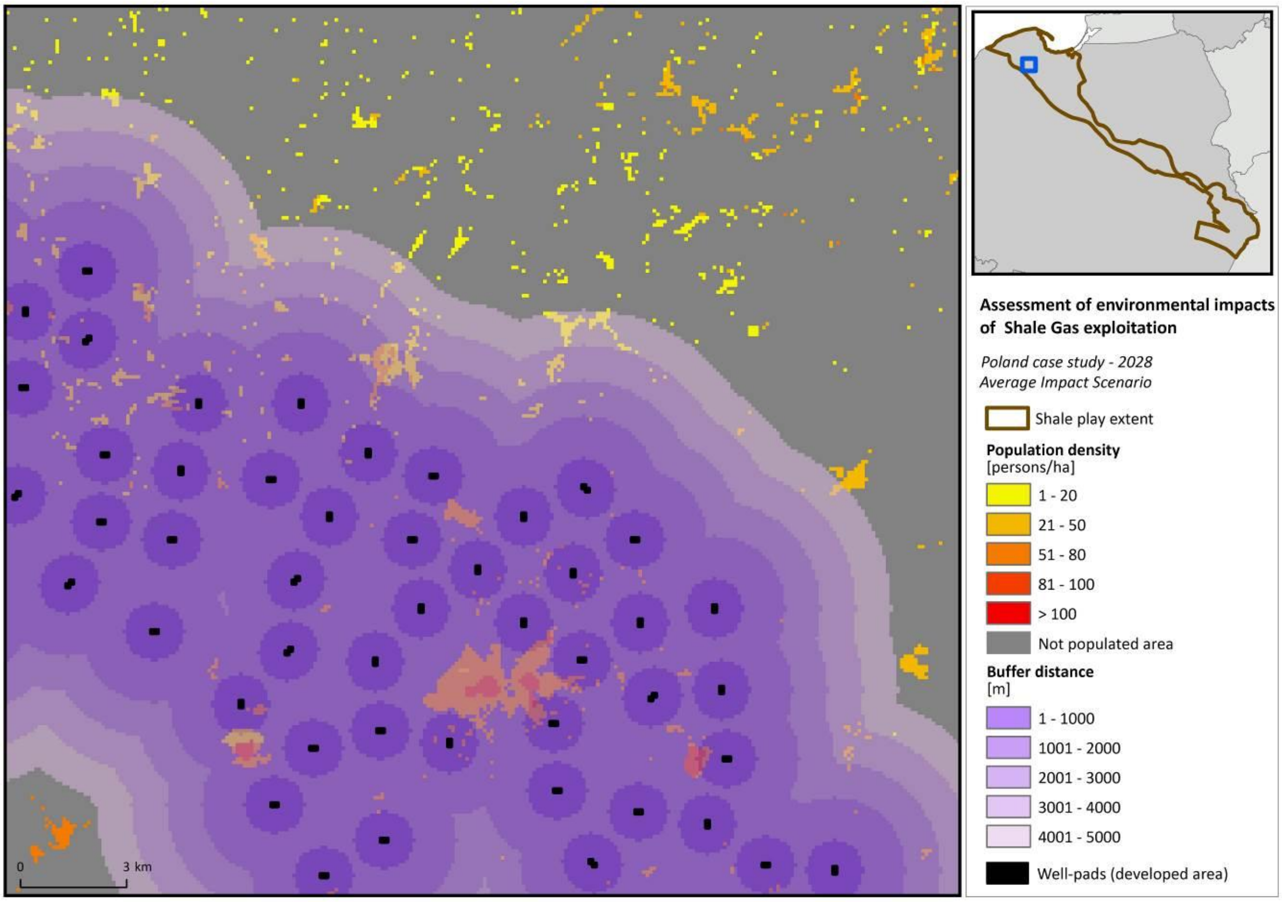

Figure 21: Projected population density map overlain with the allocated well pads and their respective buffer distances, as in year 2028 (Average Impact Scenario, Poland).

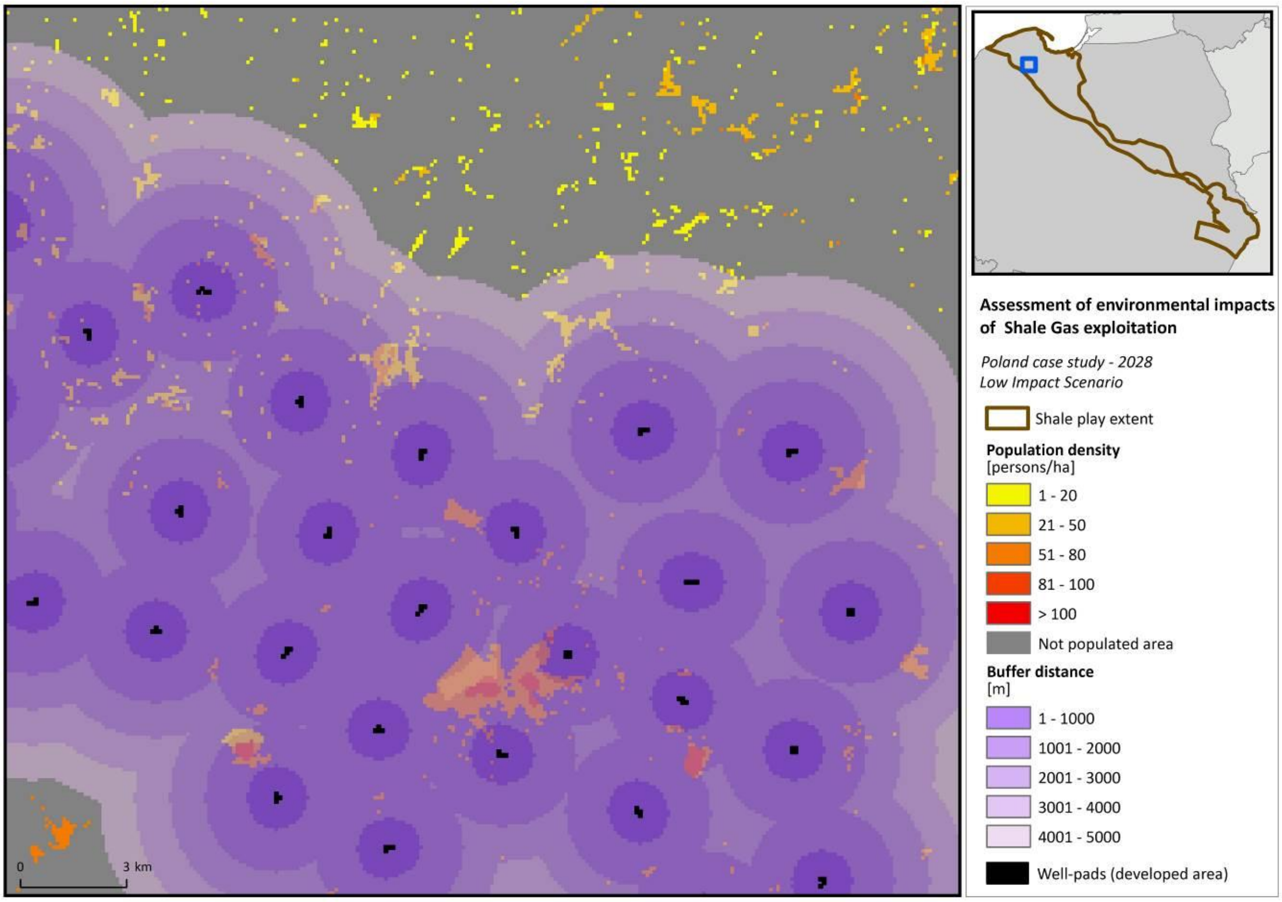

Figure 22: Projected population density map overlain with the allocated well pads and their respective buffer distances, as in year 2028 (Low Impact Scenario, Poland).

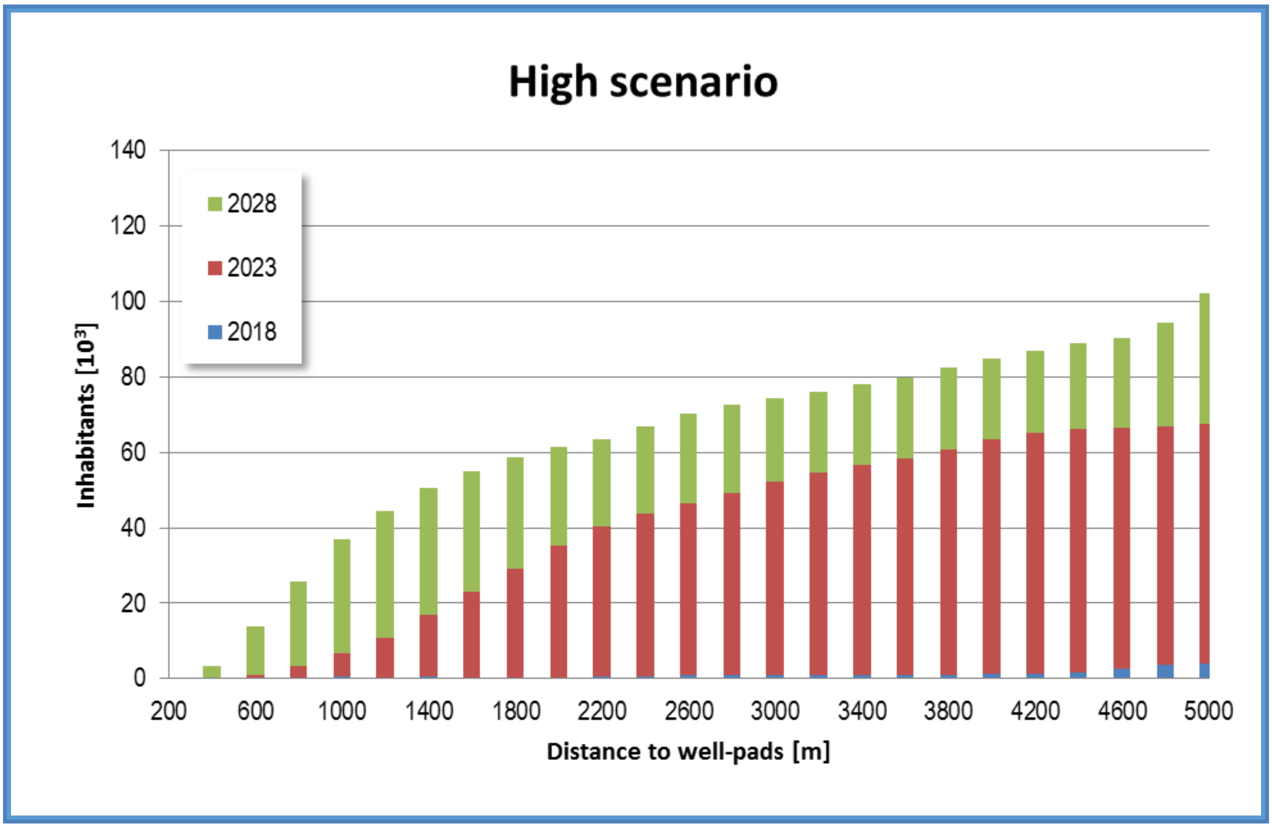

Figure 23: Population living within 5 km from well sites, per allocation year: High Impact Scenario, Poland.

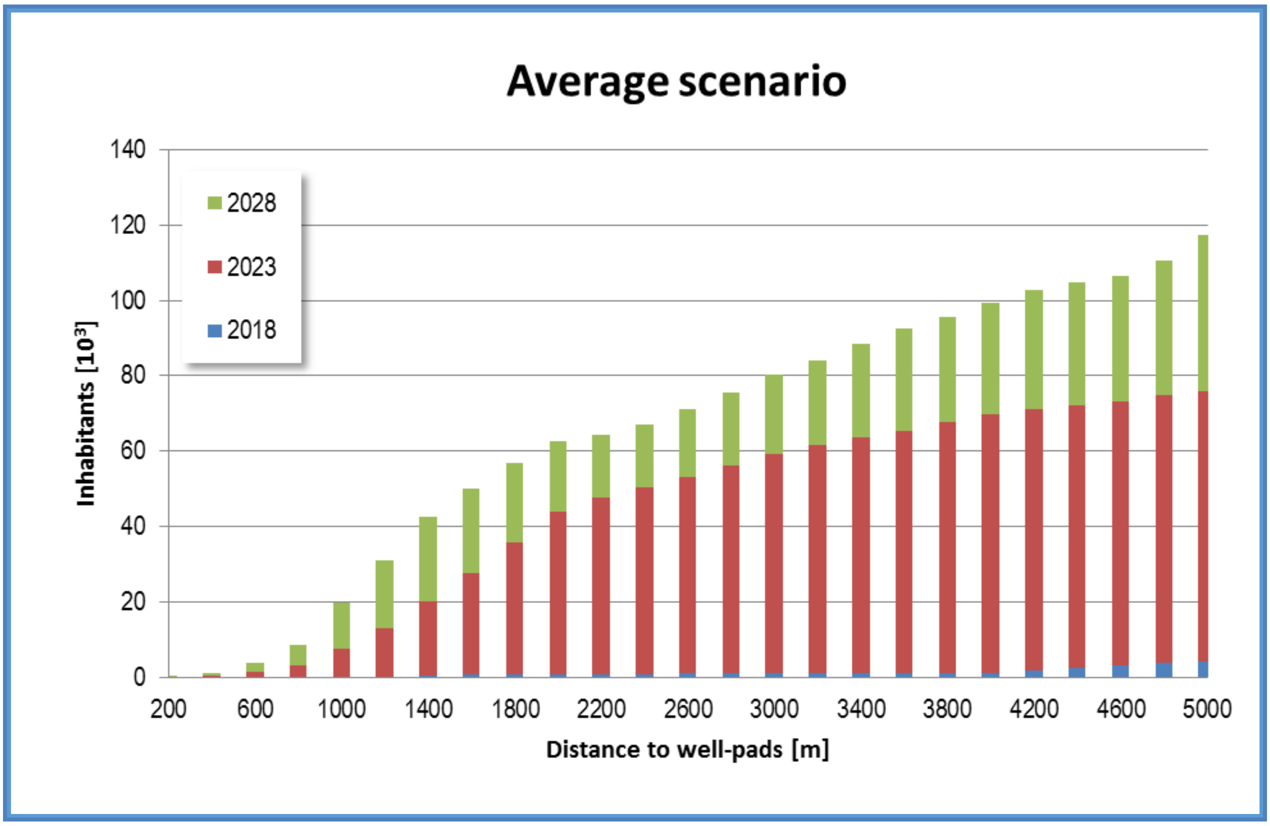

Figure 24: Population living within 5 km from well sites, per allocation year: Average Impact Scenario, Poland.

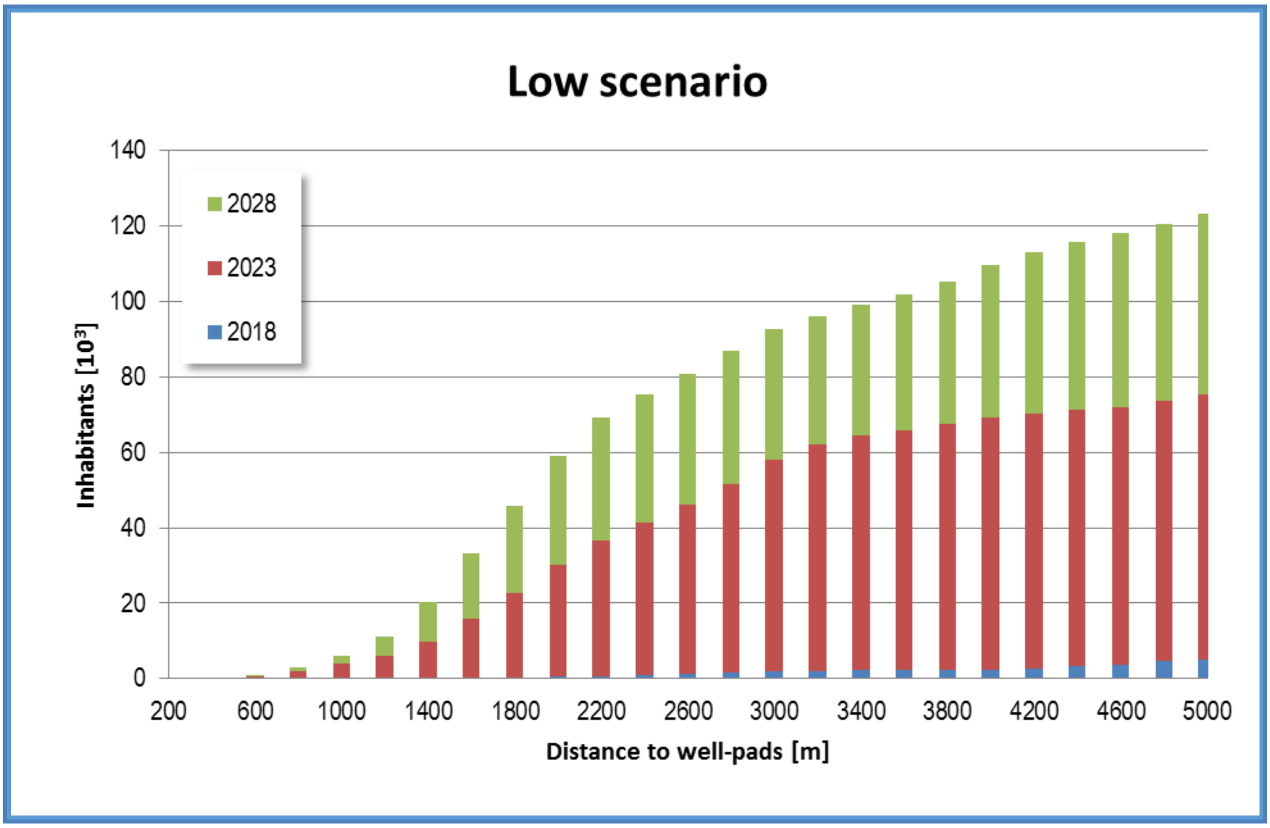

Figure 25: Population living within 5 km from well sites, per allocation year: Low Impact Scenario, Poland.

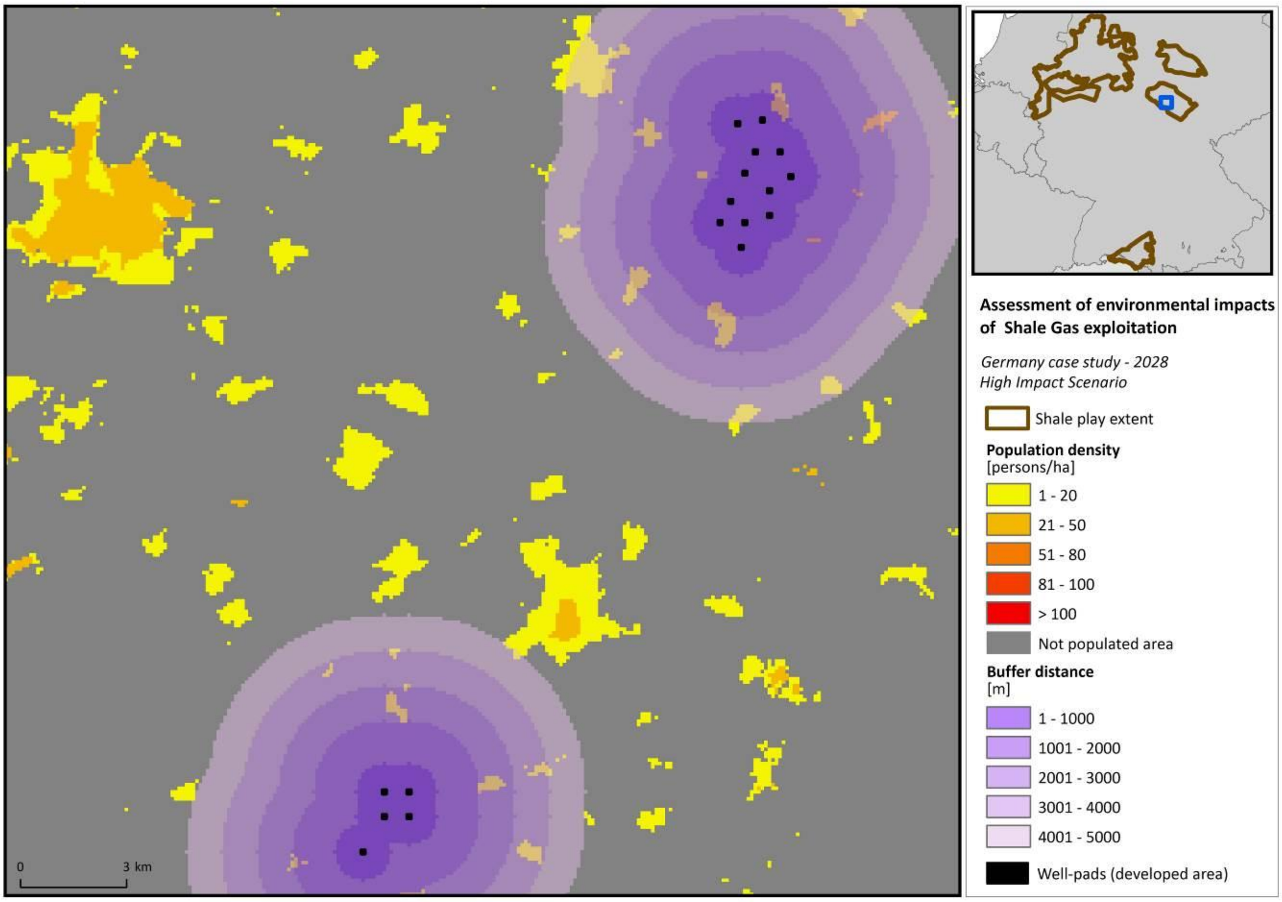

Figure 26: Projected population density map overlain with the allocated well pads and their respective buffer distances, as in year 2028 (High Impact Scenario, Germany).

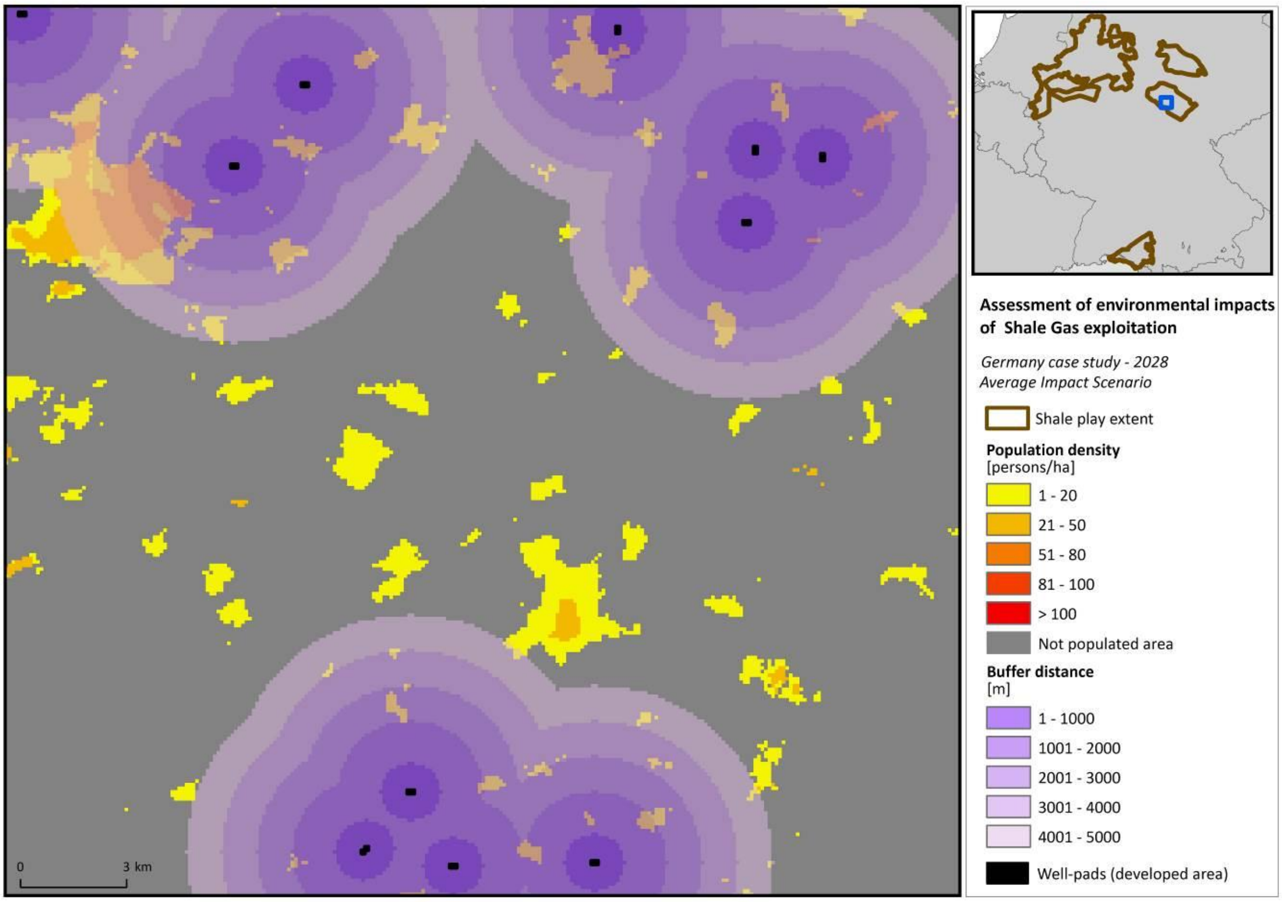

Figure 27: Projected population density map overlain with the allocated well pads and their respective buffer distances, as in year 2028 (Average Impact Scenario, Germany).

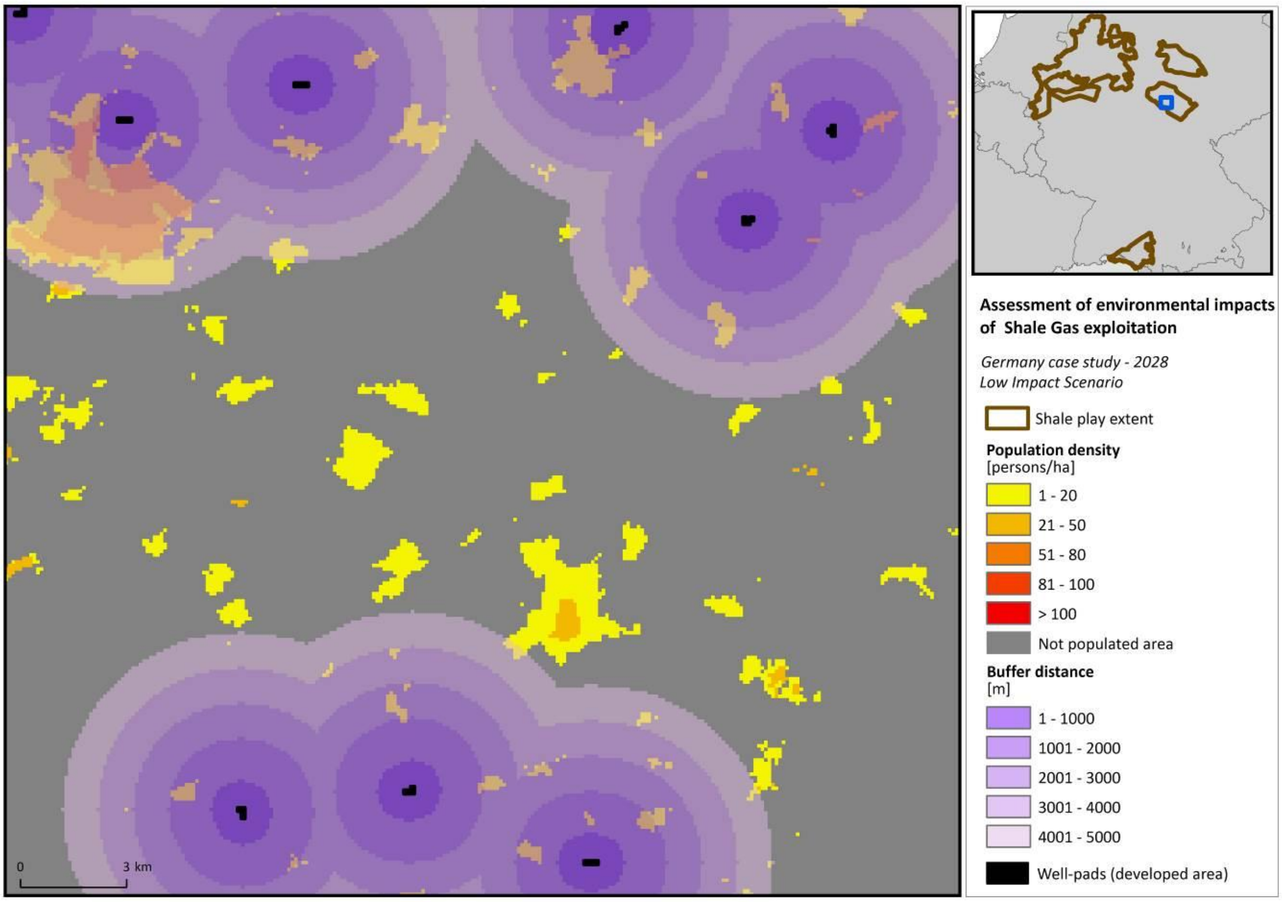

Figure 28: Projected population density map overlain with the allocated well pads and their respective buffer distances, as in year 2028 (Low Impact Scenario, Germany).

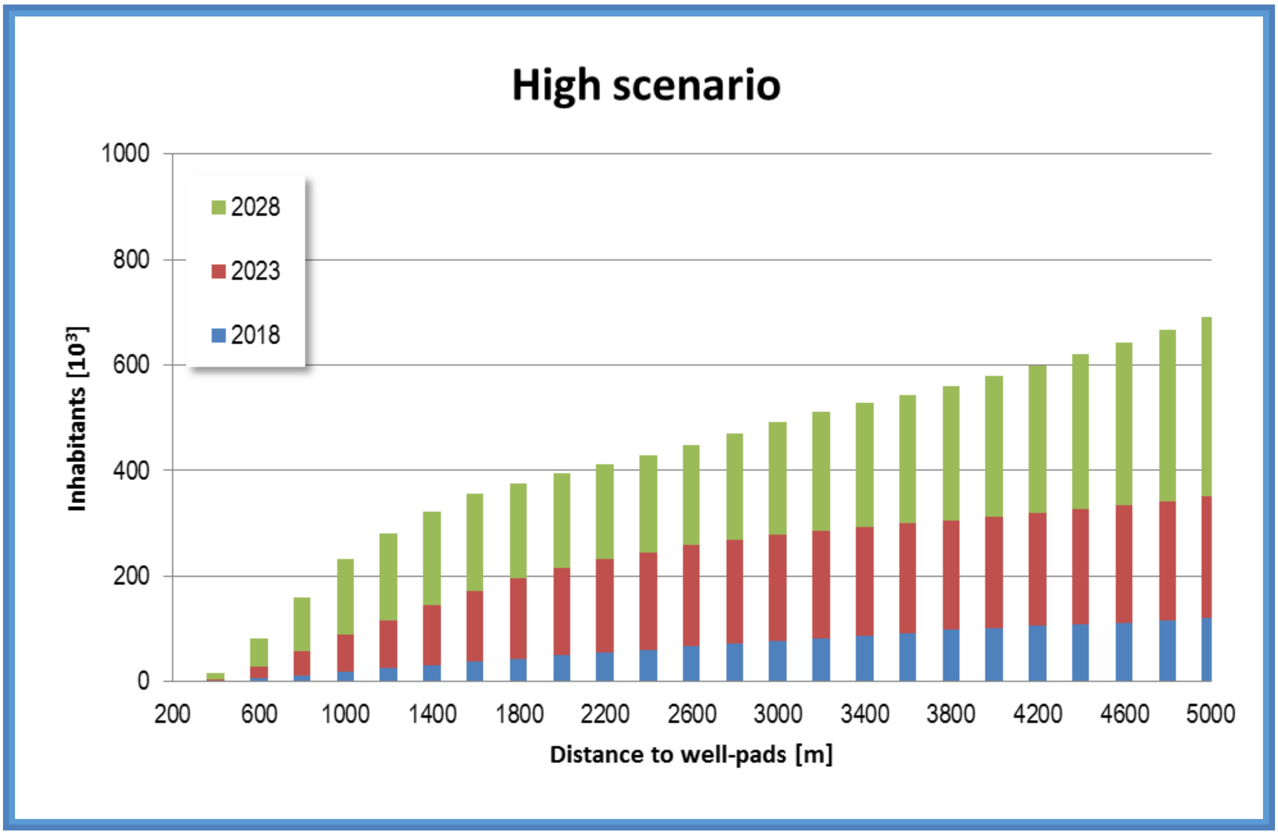

Figure 29: Population living within 5 km from well sites, per allocation year: High Impact Scenario, Germany.

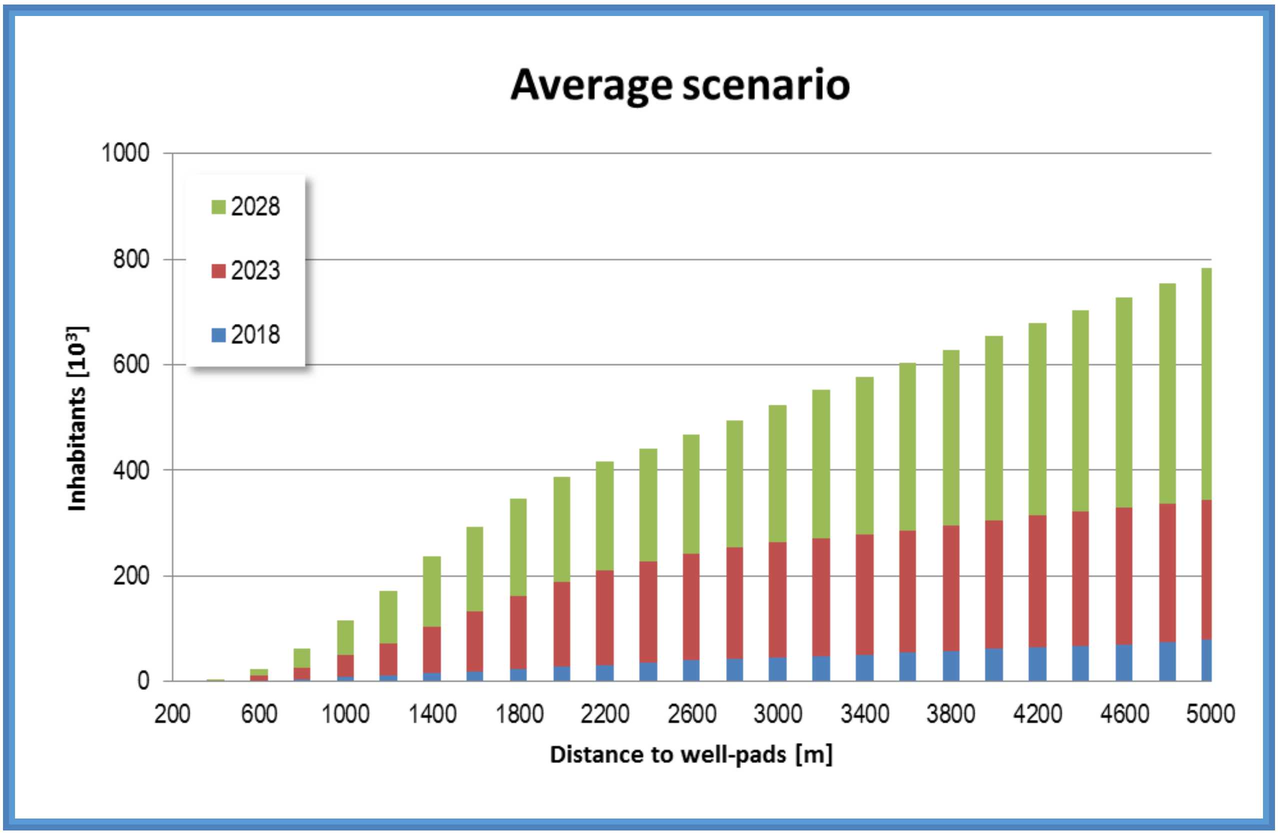

Figure 30: Population living within 5 km from well sites, per allocation year: Average Impact Scenario, Germany.

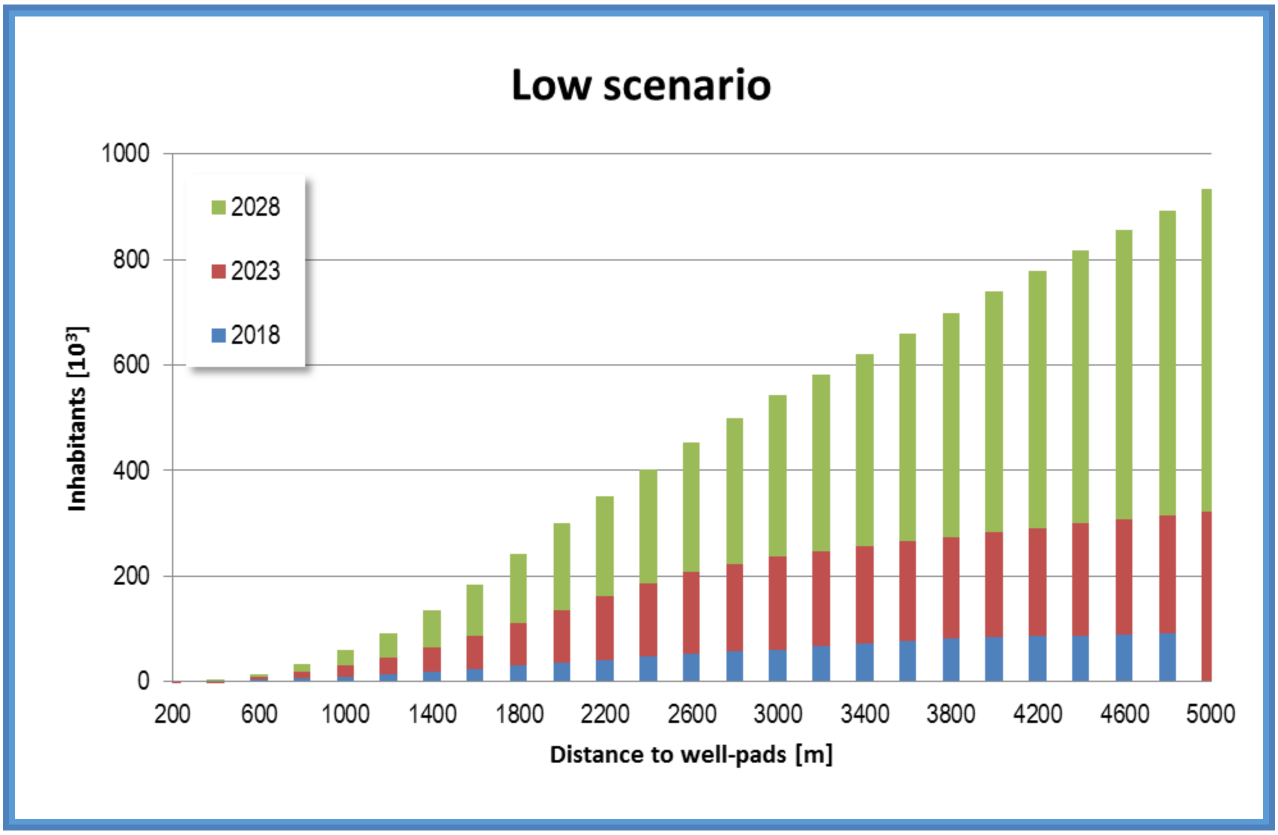

Figure 31: Population living within 5 km from well sites, per allocation year: Low Impact Scenario, Germany.

The differences between Scenarios are highlighted in Figure 32 and Figure 33 as well, for both countries. The High and Low Impact Scenarios are compared to the Average Scenario in terms of number of people living at different distances from the exploitation sites (blue and red line, respectively), in the last allocation year 2028. High and Low Impact Scenarios are also compared directly. Under the High Impact Scenario, more people are living at short distances from the well pads in both Poland and Germany compared to the Low Impact Scenario. Conversely, more people can be found living in the vicinity of the well pads (between 2.2 km and 5 km distance in Poland and between 2.6 km and 5 km in Germany) under the Low Impact Scenario. In general, the differences between Scenarios are more evident in Germany than in Poland. This is mainly due to the different number of exploitation sites that are allocated during the simulation period. It is also worth noting that over longer distances, the Scenarios diverge more sharply in Germany than in Poland where, in fact, the differences remain almost constant. The densely populated landscape and the presence of medium-sized urban settlements throughout the shale play is one of the key factors explaining this difference.

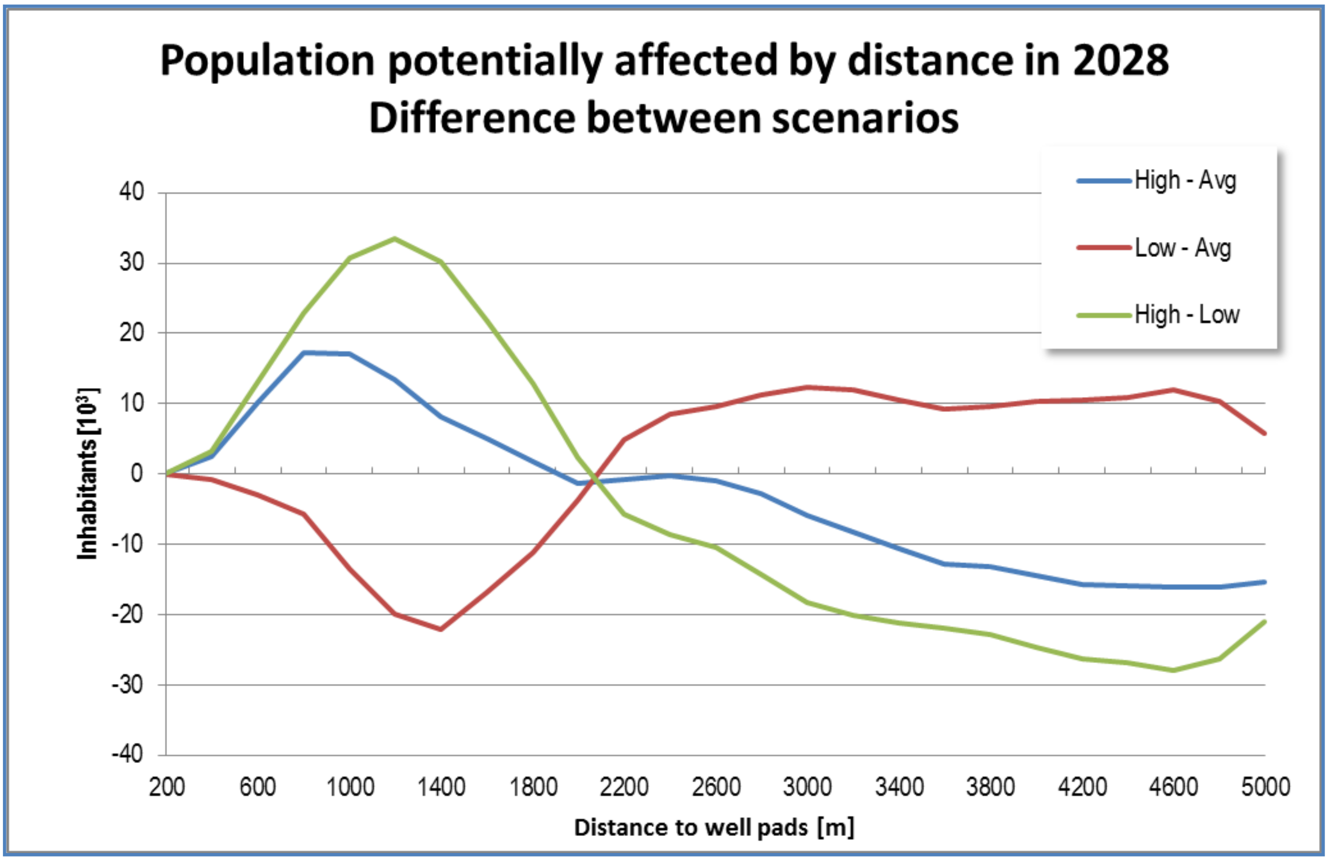

Figure 32: Population potentially affected, reported by distance: difference between Scenarios in year 2028, Poland.

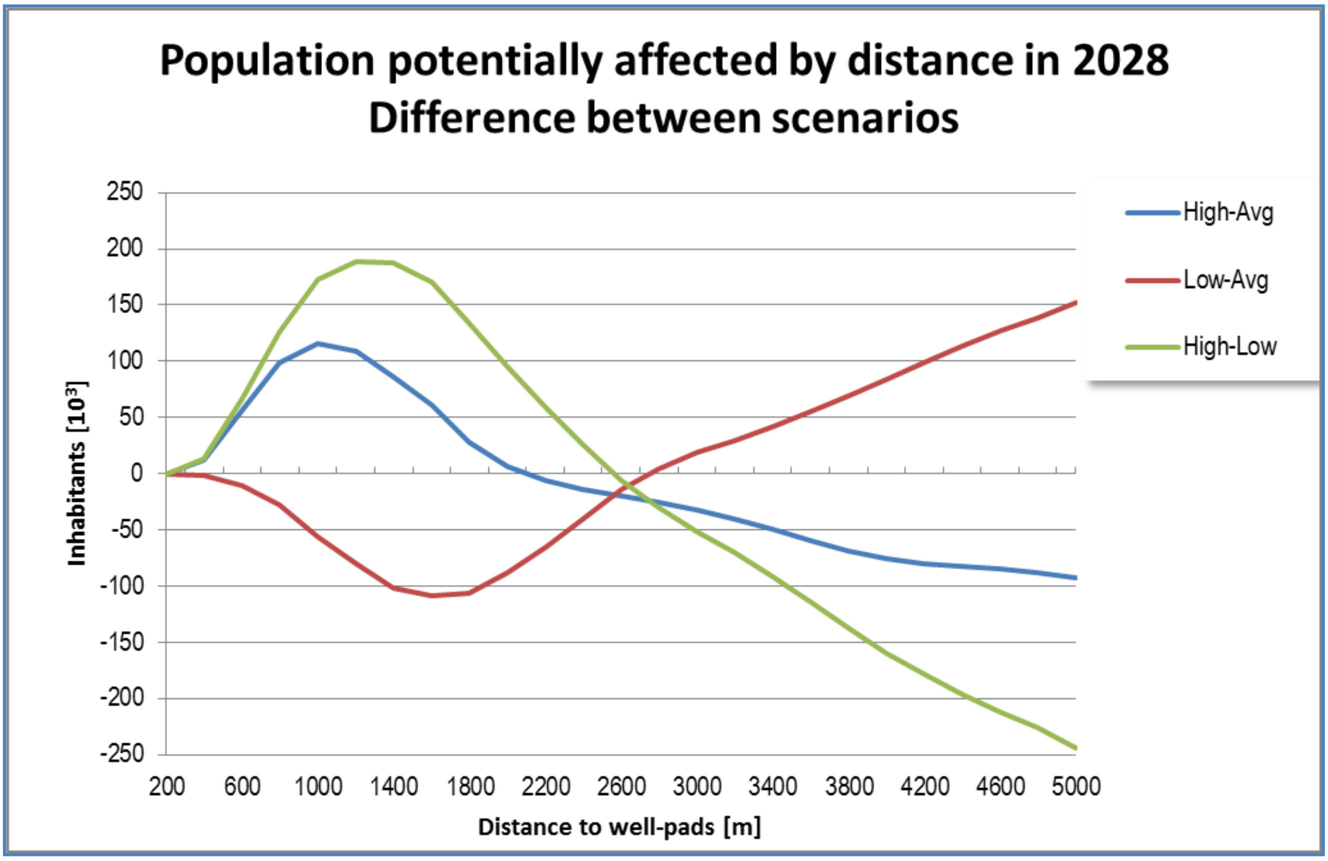

Figure 33: Population potentially affected, reported by distance: difference between Scenarios in year 2028, Germany.

Proximity Indicators

A preliminary analysis has been conducted with the purpose of assessing the potential availability of waste water treatment plants in the vicinity of the exploitation sites. With this aim, the European Pollutant Release and Transfer Register (E-PRTR) has been used. All the waste water treatment plants listed in the database that belong to Poland and Germany have been included in the analysis. This selection of plants does not constitute an exhaustive list of all the plants potentially available to treat waste water originating from shale gas exploitation activity. In fact, it is important to highlight that E-PRTR encompasses only those facilities that fulfill specific criteria related to capacity thresholds, transfers of waste off-site and releases of pollutants specified per media -

air, water and land. This database does not give enough detailed information on the typologies of the recorded facilities.

In order to properly assess the potential capacity of both countries to treat flowback water in waste water treatment facilities, better resolved and complete data would be needed on the characteristics of the plants. Nevertheless we carried out a preliminary assessment on the data available.

Table 31 and

Table 32 **Error! Reference source not found.** present an overview of the potential availability of wastewater treatment plants within 10, 25 and 50 km from the exploitation sites. Similarly**Error! Reference source not found.** Figures 34 and 35 provide a visual representation of the locations of waste water treatment plants in Poland and Germany, respectively, for year 2028 under each Scenario.

Table 31: Proximity of well pads to wastewater treatment plants in Poland, as in year 2028.

Distance [km]	High Scenario Number of well pads [-]	Average Scenario Number of well pads [-]	Low Scenario Number of well pads [-]
10	-	-	-
25	-	-	-
50	-	-	-
Lowest distance [km]			
	81.2	77.2	76.0
Mean lowest distance [km]			
	102.0	99.3	97.4

Table 32: Proximity of well pads to wastewater treatment plants in Germany, as in year 2028.

Distance [km]	High Scenario Number of well pads [-]	Average Scenario Number of well pads [-]	Low Scenario Number of well pads [-]
10	8	14	22
25	24	30	22
50	67	81	89
Lowest distance [km]			
	3.1	3.1	3.0
Mean lowest distance [km]			
	30.0	29.2	27.0

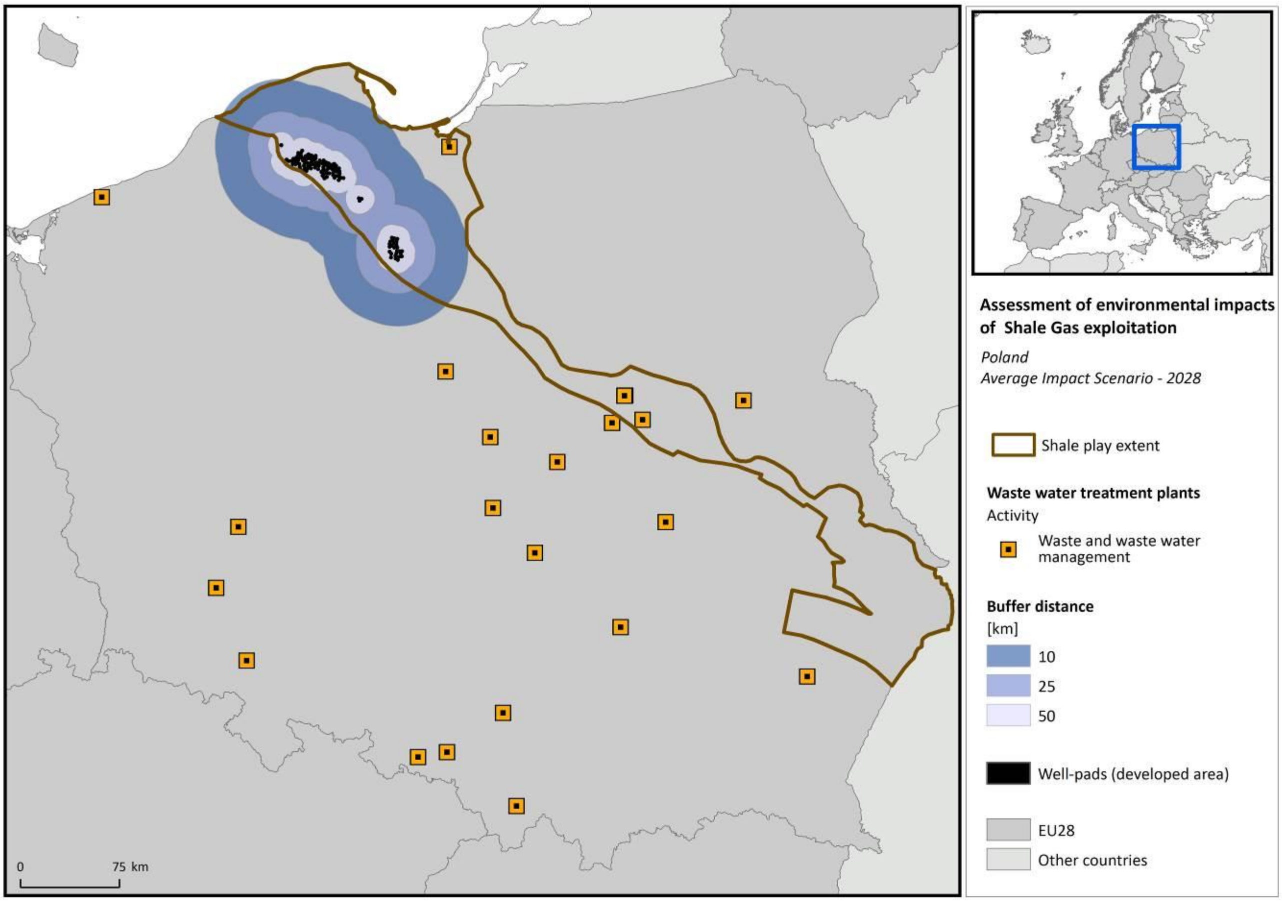

Figure 34: Figure Proximity of exploitation sites to existing waste water treatment plants, as in year 2028 (Average Impact Scenario, Poland)

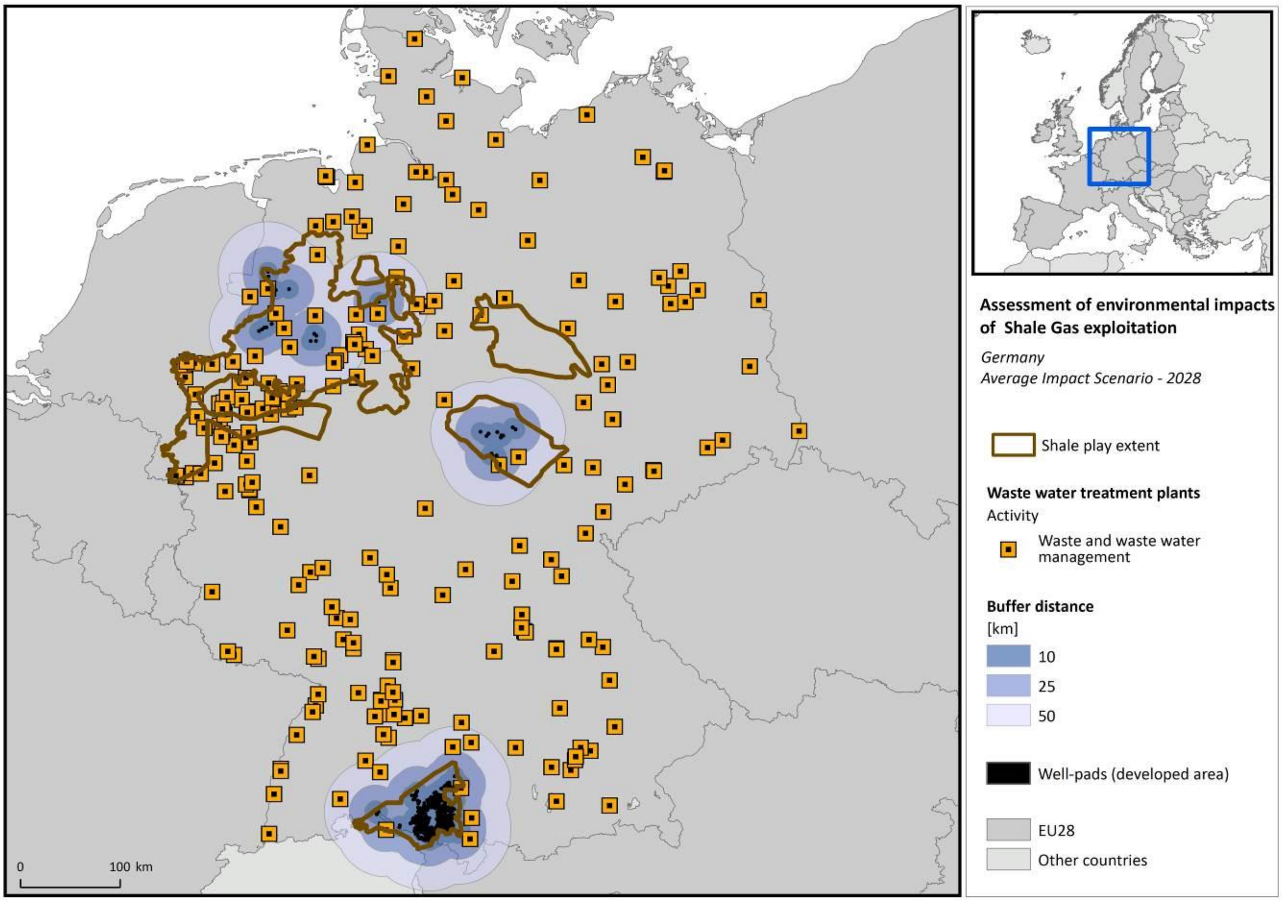

Figure 35: Proximity of exploitation sites to existing waste water treatment plants, as in year 2028 (Average Impact Scenario, Germany).

A useful indicator of potential impacts on sensitive areas is represented in Figures 36-39 for Poland and Figures 40-43 for Germany. A proximity analysis has been carried out in order to highlight the presence of well pads in the proximity of natural protected areas, up to 10km distance. The percentage of developed land for shale gas extraction activities is reported by distance to natural protected areas.

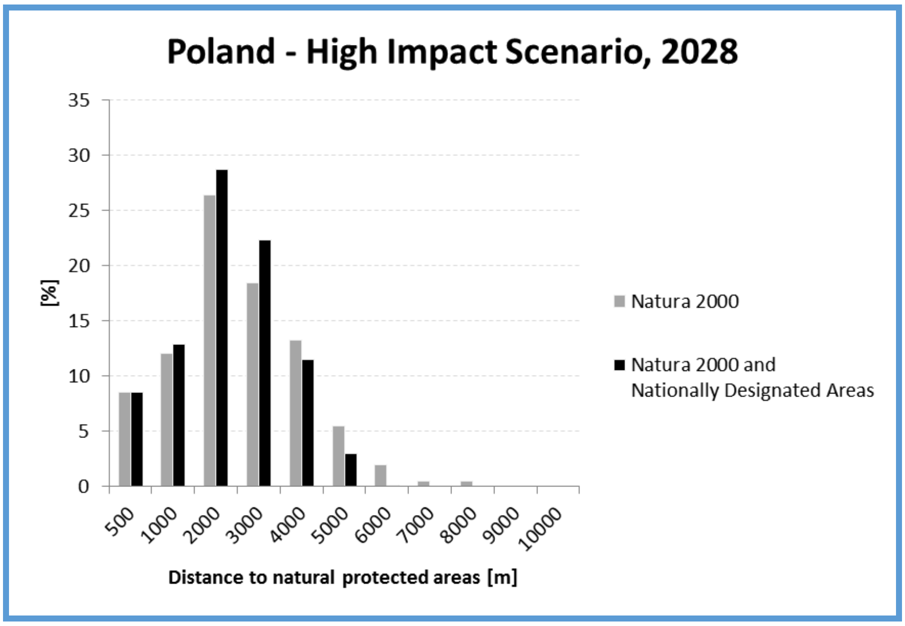

Figure 36: Presence of well pads in the proximity of natural protected areas. The percentage of developed land for shale gas extraction activities is reported by distance to natural protected areas, as in year 2028 under the High Impact Scenario in Poland. The analysis is carried out twice, considering only Natura 2000 sites and Natura 2000 together with Nationally Designated Areas.

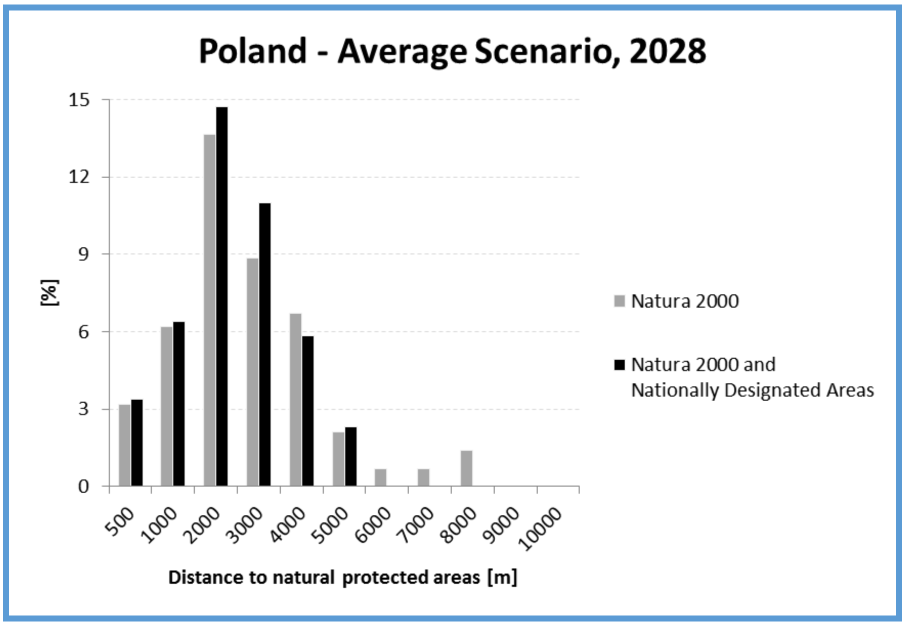

Figure 37: Presence of well pads in the proximity of natural protected areas. The percentage of developed land for shale gas extraction activities is reported by distance to natural protected areas, as in year 2028 under the Average Impact Scenario in Poland. The analysis is carried out twice, considering only Natura 2000 sites and Natura 2000 together with Nationally Designated Areas.

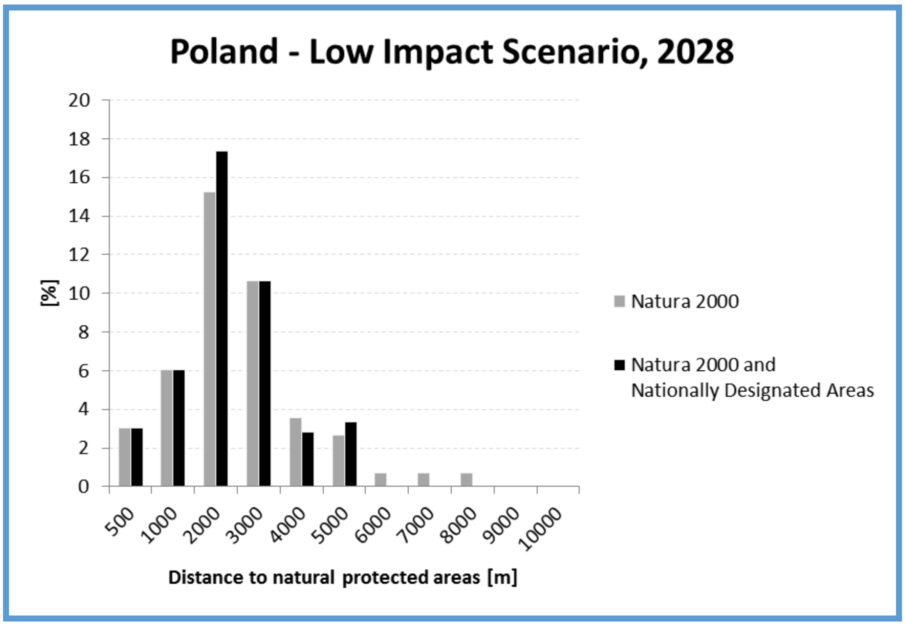

Figure 38: Presence of well pads in the proximity of natural protected areas. The percentage of developed land for shale gas extraction activities is reported by distance to natural protected areas, as in year 2028 under the Low Impact Scenario in Poland. The analysis is carried out twice, considering only Natura 2000 sites and Natura 2000 together with Nationally Designated Areas.

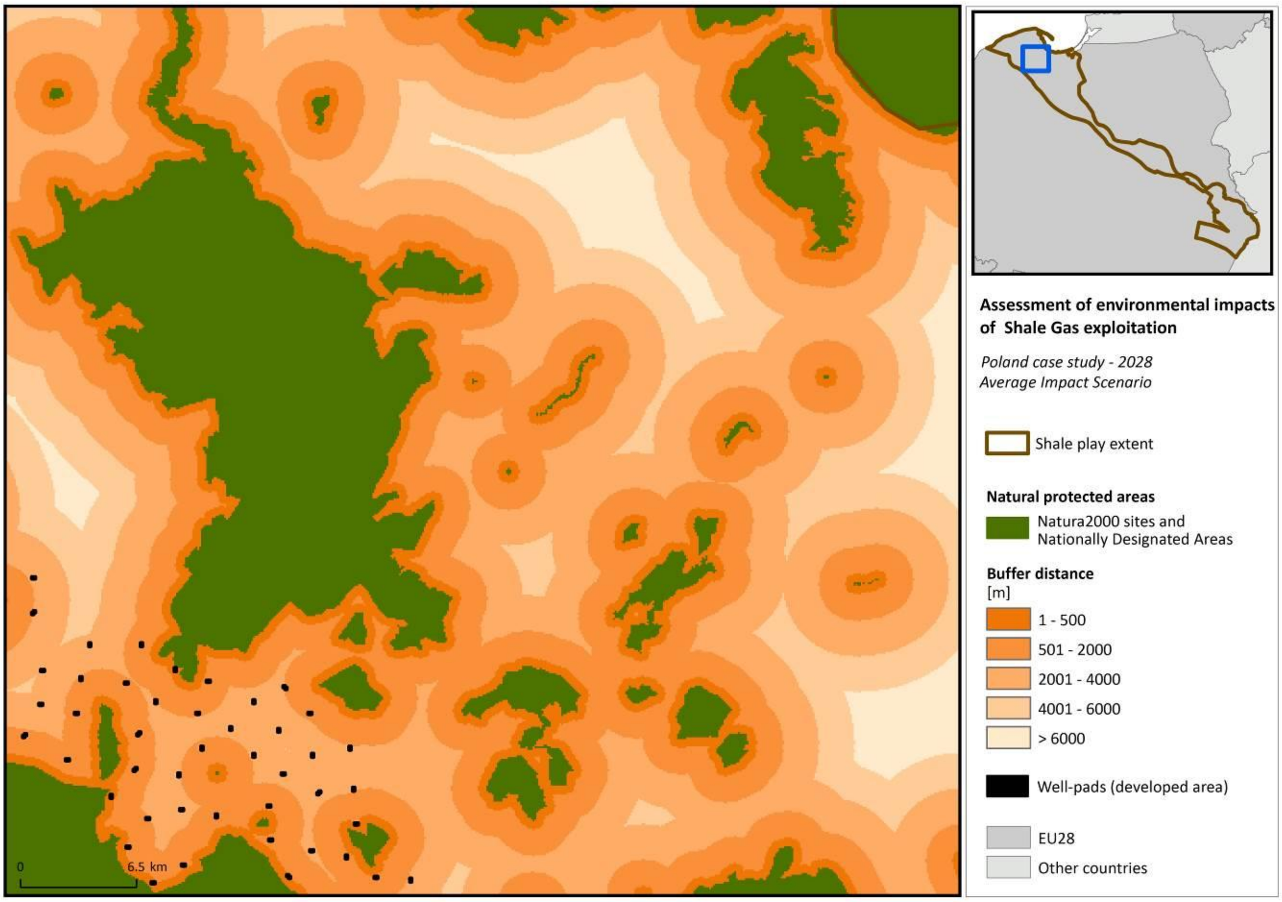

Figure 39: Allocated well pads overlain with natural protected areas tand their respective buffer distances, as in year 2028 (Average Impact Scenario, Poland).

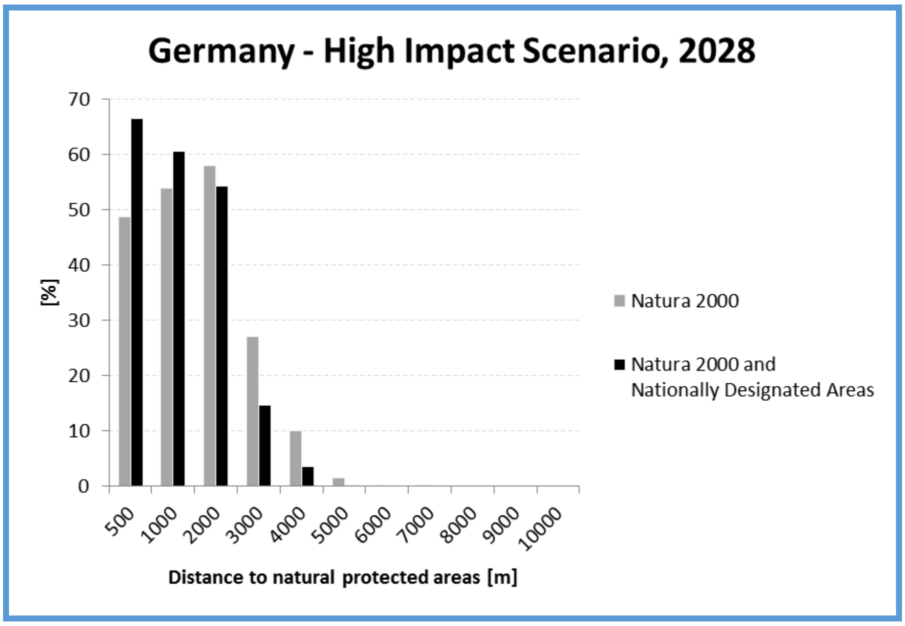

Figure 40: Presence of well pads in the proximity of natural protected areas. The percentage of developed land for shale gas extraction activities is reported by distance to natural protected areas, as in year 2028 under the High Impact Scenario in Germany. The analysis is carried out twice, considering only Natura 2000 sites and Natura 2000 together with Nationally Designated Areas.

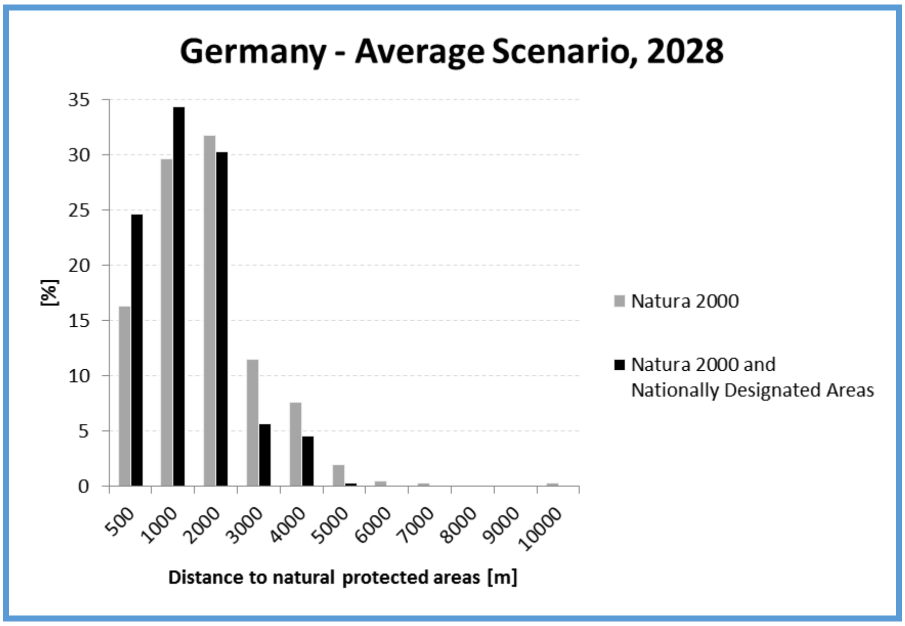

Figure 41: Presence of well pads in the proximity of natural protected areas. The percentage of developed land for shale gas extraction activities is reported by distance to natural protected areas, as in year 2028 under the Average Impact Scenario in Germany. The analysis is carried out twice, considering only Natura 2000 sites and Natura 2000 together with Nationally Designated Areas.

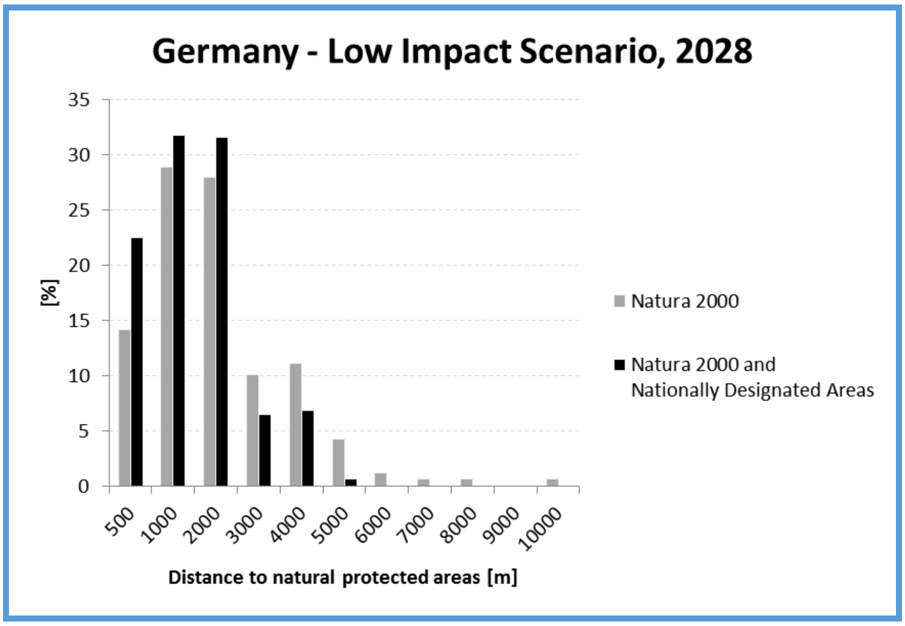

Figure 42: Presence of well pads in the proximity of natural protected areas. The percentage of developed land for shale gas extraction activities is reported by distance to natural protected areas, as in year 2028 under the Low Impact Scenario in Germany. The analysis is carried out twice, considering only Natura 2000 sites and Natura 2000 together with Nationally Designated Areas.

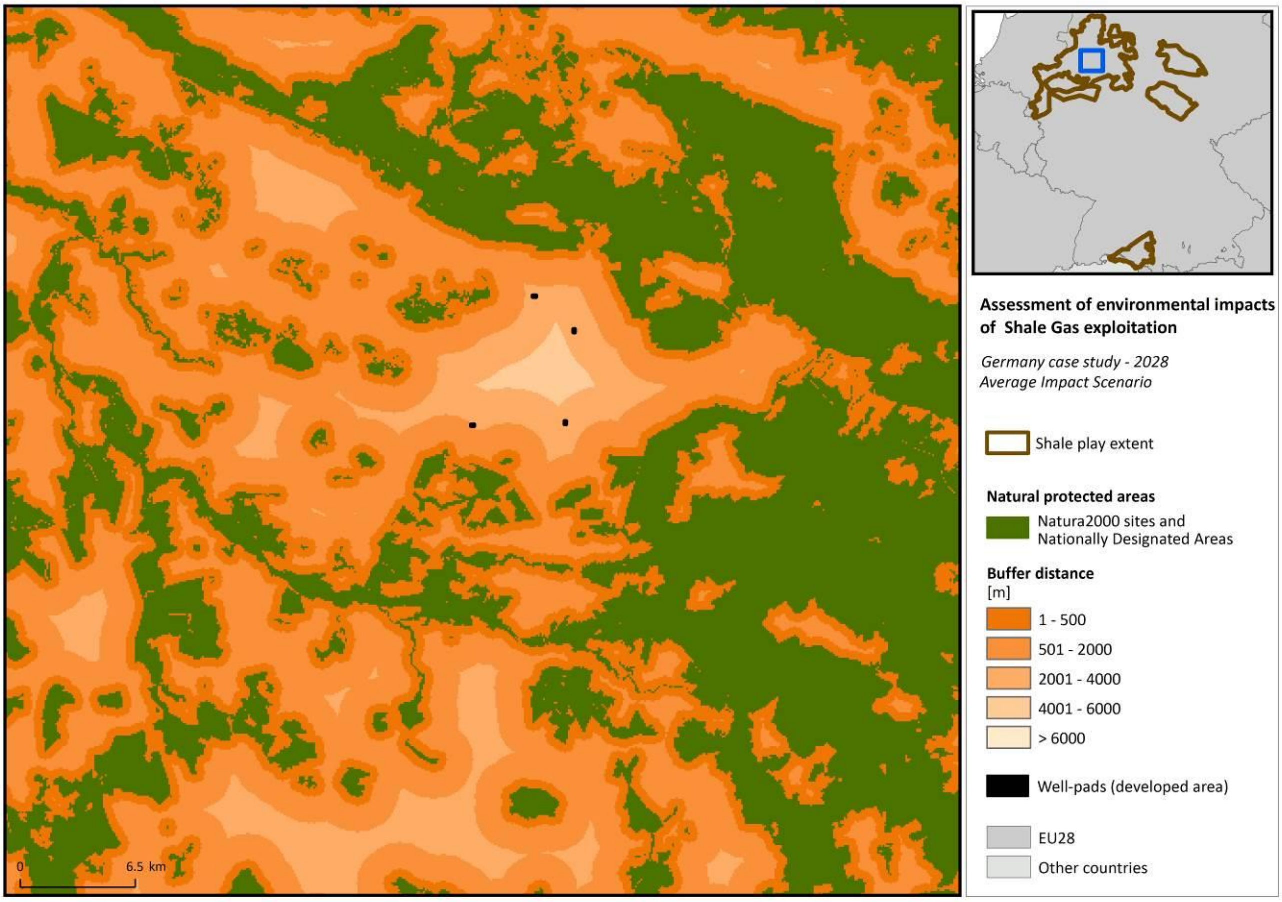

Figure 43: Allocated well pads overlain with natural protected areas tand their respective buffer distances, as in year 2028 (Average Impact Scenario, Germany).

As shown in the figures above, Germany has a greater density and, on average, a more fragmented distribution of natural protected areas. This results in well pads being allocated closer to protected sites than in Poland. The histograms show that, in fact, for both countries the percentage of drilling sites allocated at distances greater than 5 km in Poland and 4 km in Germany, is minimal. This is due to the diffuse presence of natural protected sites.

3.2 Water Use for Shale Gas Development Scenarios

3.2.1 Projected trends in water use in Poland and Germany 2013-2028 (assuming no shale gas developments)

Figure 44 shows the mapped total projected water withdrawals for the modeled years 2013 and 2028 for Poland, not taking into account potential shale gas developments. Particularly high projected withdrawals are seen around the main urban centers. The increases in water withdrawals seen between the two years are mainly due to increasing industrial water withdrawals, the majority of which occur in industrial zones adjacent to the main towns and city centers. Within the shale play, water withdrawals are highest in the towns of Warsaw and Gdansk.

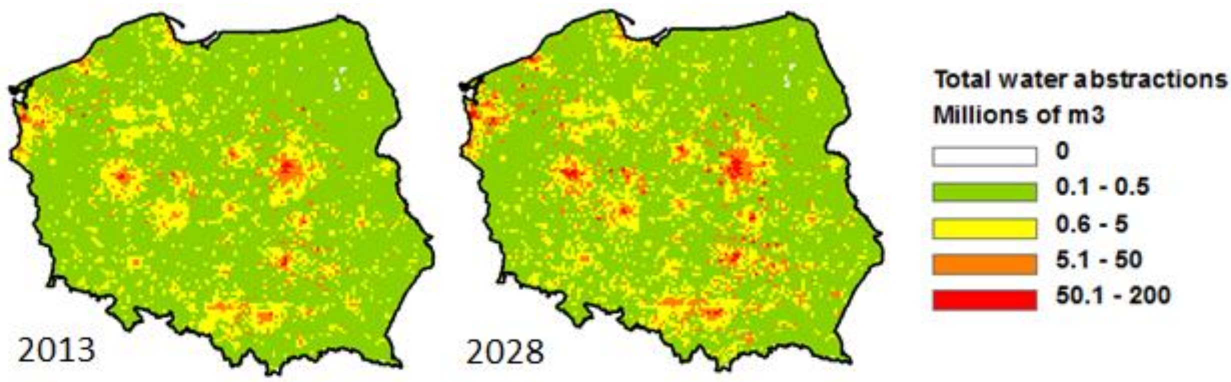

Figure 44: The total amount of water abstracted in Poland by the competing water-using sectors (industry, public, agriculture) for the timesteps 2013 and 2028.

Public water withdrawals for Poland are forecasted to increase by 5% in the period between 2006 and 2030. This is quite moderate compared to the anticipated average European increase of 21%. In contrast, whereas industrial water withdrawals are forecasted to increase to a great extent all over Europe (an average increase of 63% from 2006 to 2030), Poland shows the highest forecasted growth rate (95%) over this same period.

Figure 46 shows the total projected water withdrawals for 2013 and 2028 for Germany. Again, the highest water withdrawals are seen around the urban centers and especially in the industrial zones in eastern Germany.

Public water withdrawals for Germany are forecasted to increase by 4% from 2006 to 2030, again quite low compared to the European average because of moderate population growth trends. Industrial water withdrawals are forecasted to increase by about 55% over the same period in Germany, a figure much closer to the European average.

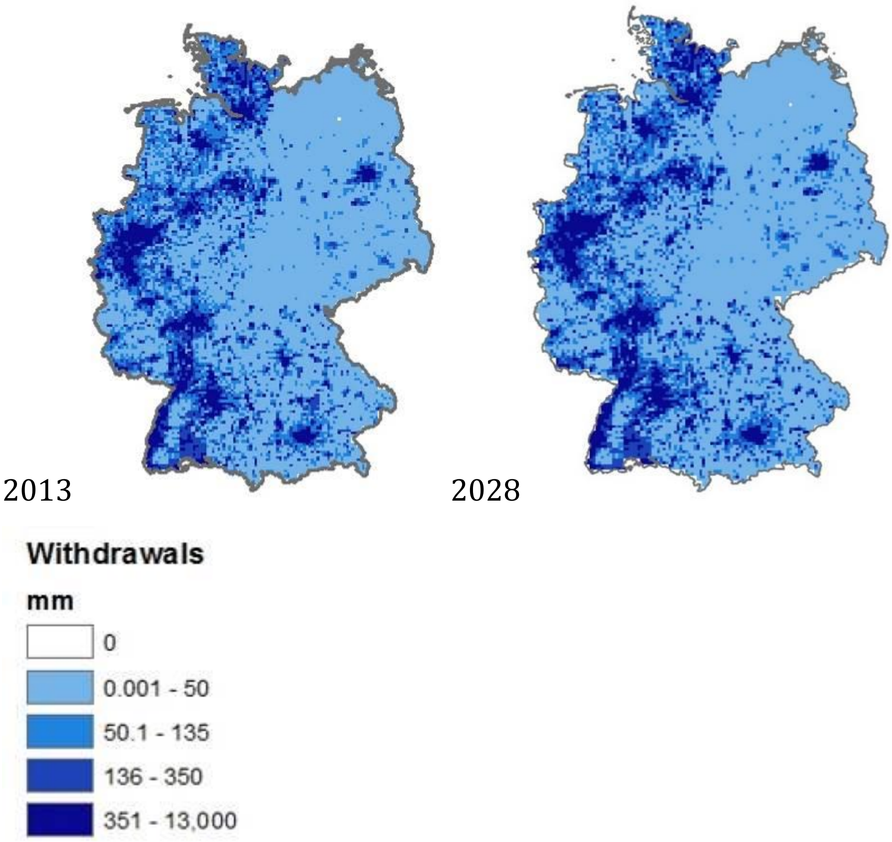

Figure 45: The total amount of water abstracted in Germany by the competing water-using sectors (industry, public, agriculture) for the time steps 2013 and 2028.

In both countries the baseline trends are mostly influenced by the greatly increasing use of water for industrial purposes.

3.2.2 Water use for shale gas extraction as compared to the competing sectors

Table 33 gives the amount of water withdrawn and consumed for shale gas extraction in the hypothetical low, average and high impact scenarios as a percentage of the total withdrawn for all other sectors for the country as a whole.

Table 33: Water use for shale gas extraction as a percentage of the total amount of water used by the competing sectors in Poland and Germany.

PL	Withdrawal			Consumption		
	LOW	AVERAGE	HIGH	LOW	AVERAGE	HIGH
2013	0	0	0	0	0	0
2018	0.0002	0.0012	0.0058	0.0001	0.0008	0.0058
2023	0.0008	0.0063	0.0400	0.0002	0.0041	0.0400
2028	0.0024	0.0204	0.1391	0.0007	0.0133	0.1391

DE	Withdrawal			Consumption		
	LOW	AVERAGE	HIGH	LOW	AVERAGE	HIGH
2013	0	0	0.0002	0	0	0.0002
2018	0.0001	0.0009	0.0045	0.0000	0.0006	0.0045
2023	0.0006	0.0044	0.0283	0.0002	0.0029	0.0283
2028	0.0016	0.0134	0.0909	0.0005	0.0087	0.0909

Table 34 gives the amount of water withdrawn and consumed for shale gas extraction per scenario as a percentage of the total withdrawn for all other sectors *only considering the withdrawals within the shale play areas.*

Table 34: Water use for shale gas extraction as a percentage of the total amount of water used by the competing sectors within the shale play areas of Poland and Germany.

PL	Withdrawal			Consumption		
	LOW	AVERAGE	HIGH	LOW	AVERAGE	HIGH
2013	0	0	0	0	0	0
2018	0.001	0.009	0.045	0.000	0.006	0.045
2023	0.006	0.047	0.299	0.002	0.031	0.299
2028	0.017	0.146	0.996	0.005	0.095	0.996

DE	Withdrawal			Consumption		
	LOW	AVERAGE	HIGH	LOW	AVERAGE	HIGH
2013	0	0	0.001	0	0	0.001
2018	0.001	0.007	0.034	0.000	0.005	0.034
2023	0.004	0.034	0.216	0.001	0.022	0.216
2028	0.012	0.103	0.699	0.004	0.067	0.699

If we consider only the water withdrawals within the shale play area, the share of water use for shale gas extraction accounts for 0.15% of the total water withdrawals for all sectors in Poland, and 0.10% in Germany for the average impact scenario in 2028. These values range from 0.02% - 1.0% for the low and high impact scenarios for Poland, and 0.01% - 0.7% for Germany.

3.2.3 Water Exploitation Index

Both Water Exploitation Indexes (WEI_{cns} and the WEI_{ab}) were calculated for each scenario for both countries. The baseline scenario (where no shale gas extraction is taken into account) is presented showing the absolute values of the indicator, which is expressed as the percentage of the total available water resources for that year which are withdrawn (in the case of the WEI_{abs}), or consumed (in the case of the WEI_{cns}).

In addition, all 3 scenarios are represented to show the differences in the indicator for that scenario as compared to the baseline values. In each case, only the difference between the scenario and the baseline is shown, not the absolute values.

Baseline Scenario

POLAND

Figure 46 and Figure 47 show the WEI_{abs} and WEI_{cns} for the baseline run. The WEI_{abs} ranges from almost 0 in some regions up to a maximum of 87% in 2013, and almost 115% in 2028. The maximum values can be found in the Warsaw watershed, followed by the regions with the highest industrial activity, for instance the zone adjacent to Warsaw in central Poland, and the north-western regions (around Grozow Wielkopolski). Other industrial areas also show values over 20%. Notable for the baseline scenario is that the indicator is quite low within the northern shale play area (around 5.5% for all years), where shale gas extraction activities are modeled to be most concentrated.

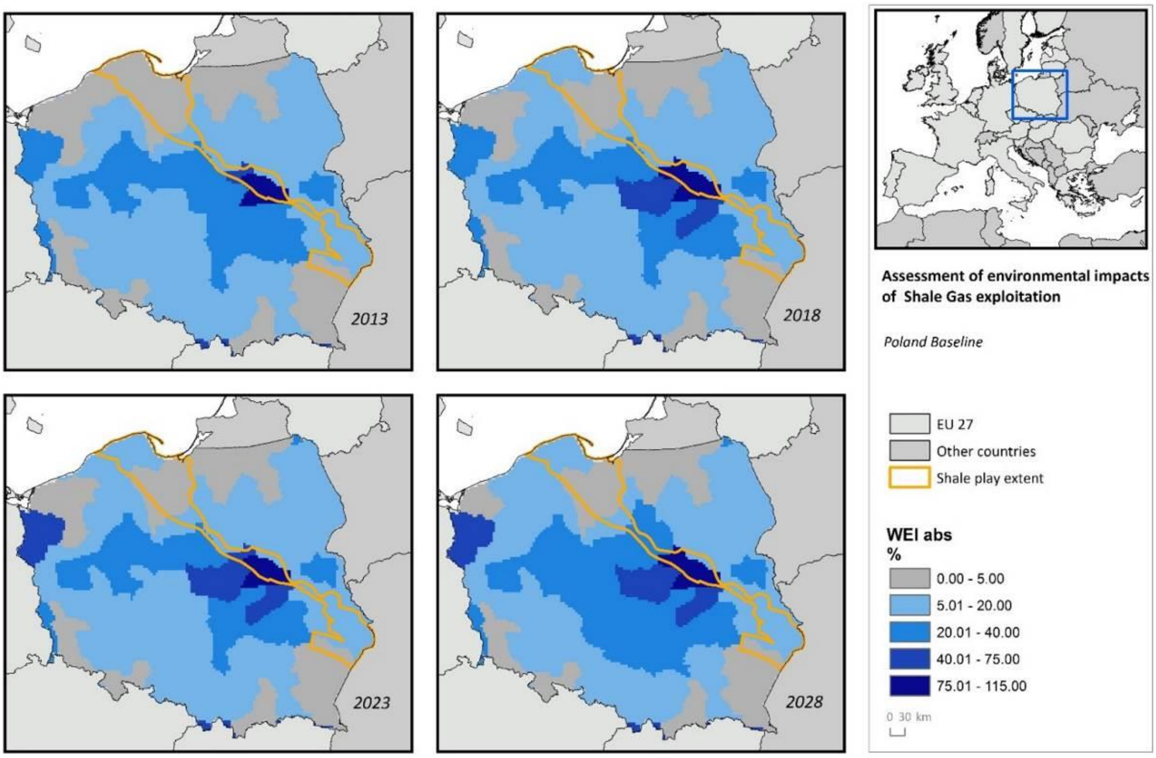

Figure 46: The Water Exploitation Index for abstraction (WEI_{abs}) calculated for the baseline water use, without any additional water use for shale gas extraction.

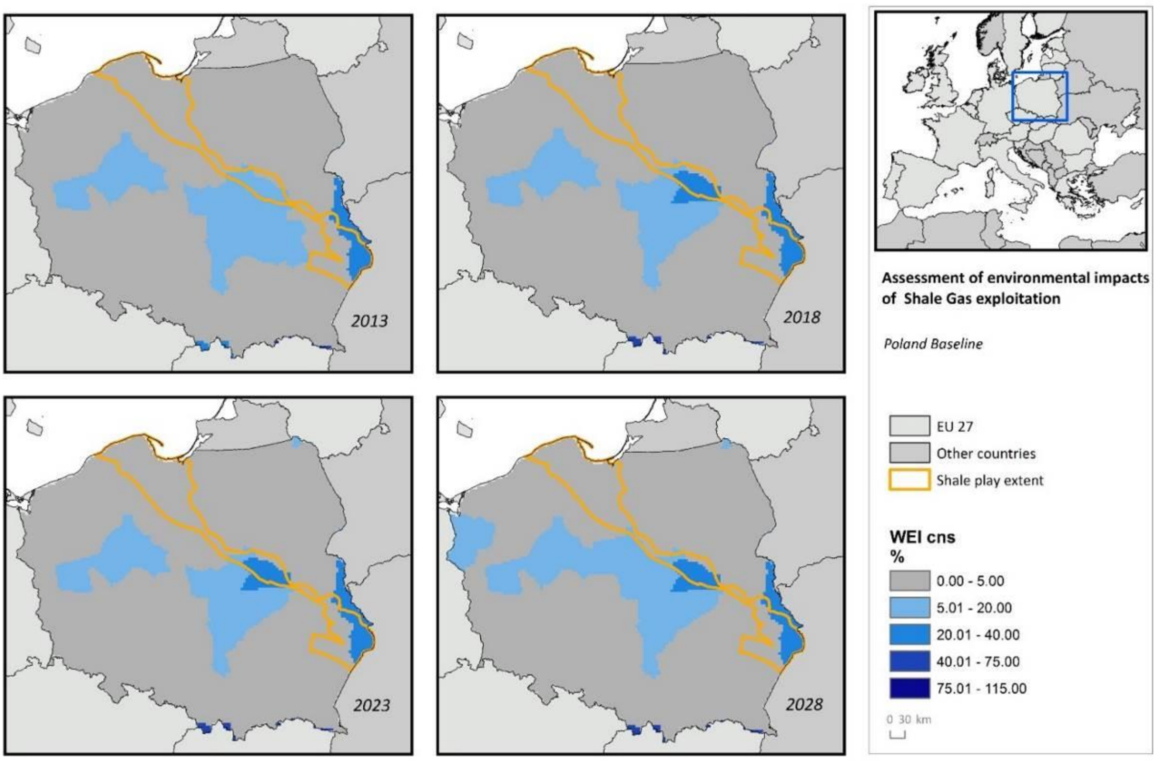

Figure 47: The Water Exploitation Index for consumption (WEI_{cns}) calculated for the baseline water use, without any additional water use for shale gas extraction.

The baseline WEI_{cns} ranges from almost zero to a maximum of 23% for all years in the eastern regions bordering Belarus and Ukraine. The WEI_{cns} slightly increases in the

Warsaw watershed (from 19 in 2013 to 21% in 2028), and in Grozow Wielkopolski (from 4 to 5.5%) and other industrial areas in central Poland. The maps are given in the same scale as the WEI_{abs} for consistency and to allow comparison. Again, the indicator is very low within the areas in which shale gas extraction is modeled to occur.

GERMANY

Figure 48 and Figure 49 show the WEI_{abs} and WEI_{cns} for the baseline run. Again the same scale has been used in order to compare the different scenarios. The WEI_{abs} ranges from almost 1 % in some regions up to a maximum of 160% in 2013, and 180% in 2028. In regions having a Water Exploitation Index of greater than 100%, the amount of water being used is actually more than what is available for use naturally in the catchment. In these cases we assume that a large part of the water used is withdrawn from groundwater resources, or from neigbouring catchments, both of which sources are not taken into account in the index calculation. The maximum values can be found in the western watersheds bordering The Netherlands and Belgium, for all years. All the other watersheds with WEI values over 80% correspond to the most industrialized and populated areas. One exception is Munich, where values are lower than other highly populated areas due to the high water availability for this region.

For the areas where shale gas extraction activities are modeled, the WEI_{abs} values vary. For the central shale plays the WEI_{abs} values are not higher than 7%, while the western shale play shows values around 40%. In the south, where most of the well pads are allocated during the first years, values are round 15%.

Similar results can be found for the WEI_{cns}. The highest values are still in the west of the country (around 95%) followed by the most populated and industrialized areas. Lower values, up to 10%, are found in the majority of the country, also within the extent of the shale plays.

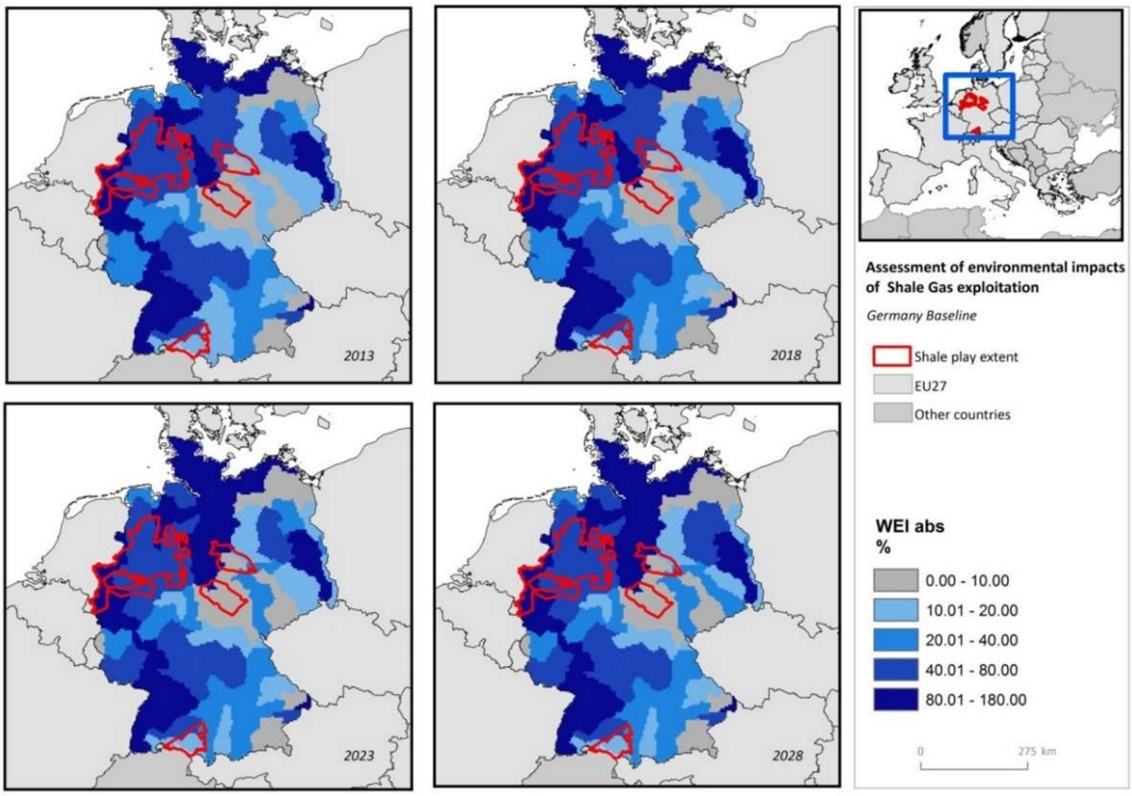

Figure 48: The Water Exploitation Index for abstraction (WEI_{abs}) calculated for the baseline water use, without any additional water use for shale gas extraction.

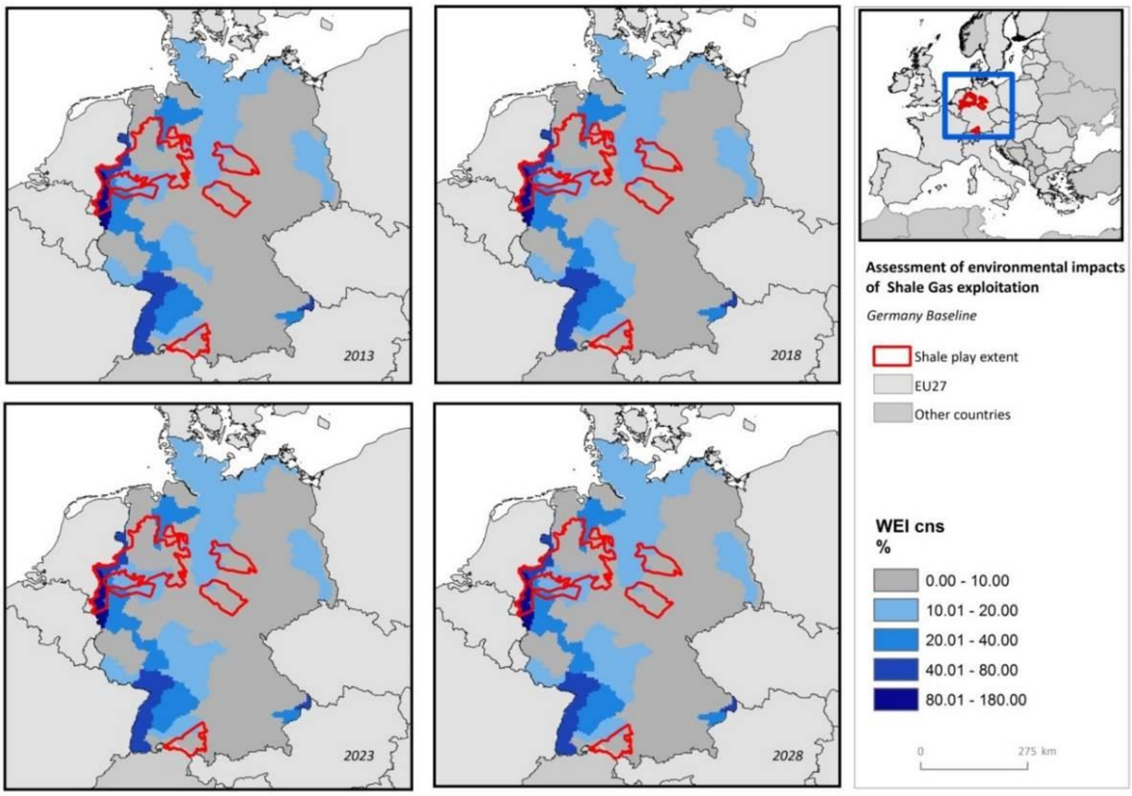

Figure 49: The Water Exploitation Index for consumption (WEI_{cns}) calculated for the baseline water use, without any additional water use for shale gas extraction.

Shale gas water use scenarios

POLAND

Figure 50 and Figure 51 show the WEI_{abs} and WEI_{cns} for the low impact water use scenario, as compared to the baseline. The impact seen within the shale play area is actually very low –there is only a slight increase in both the WEI_{abs} and WEI_{cns} within the northern part of the shale play. The changes seen outside the shale play area can be attributed to the differing land use maps simulated for shale gas extraction scenario as compared to the baseline for each timestep. Depending on where well pads are placed, urban and industrial land may be correspondingly increased or decreased in other regions to compensate and meet the demands which are built into the land use model. This differing land use results in altered water use maps (especially for public and industrial water uses), which in turn directly impact the calculation of the WEI.

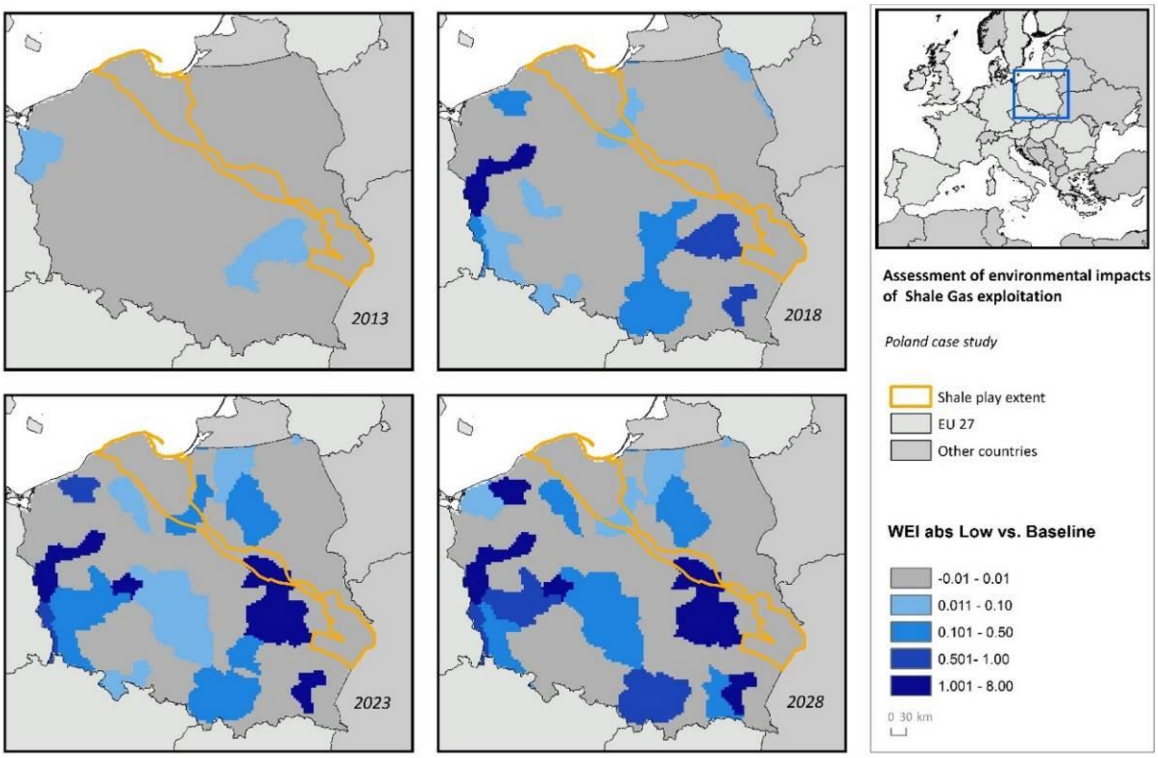

Figure 50: The WEI_{abs} for the hypothetical Low Impact water use scenario.

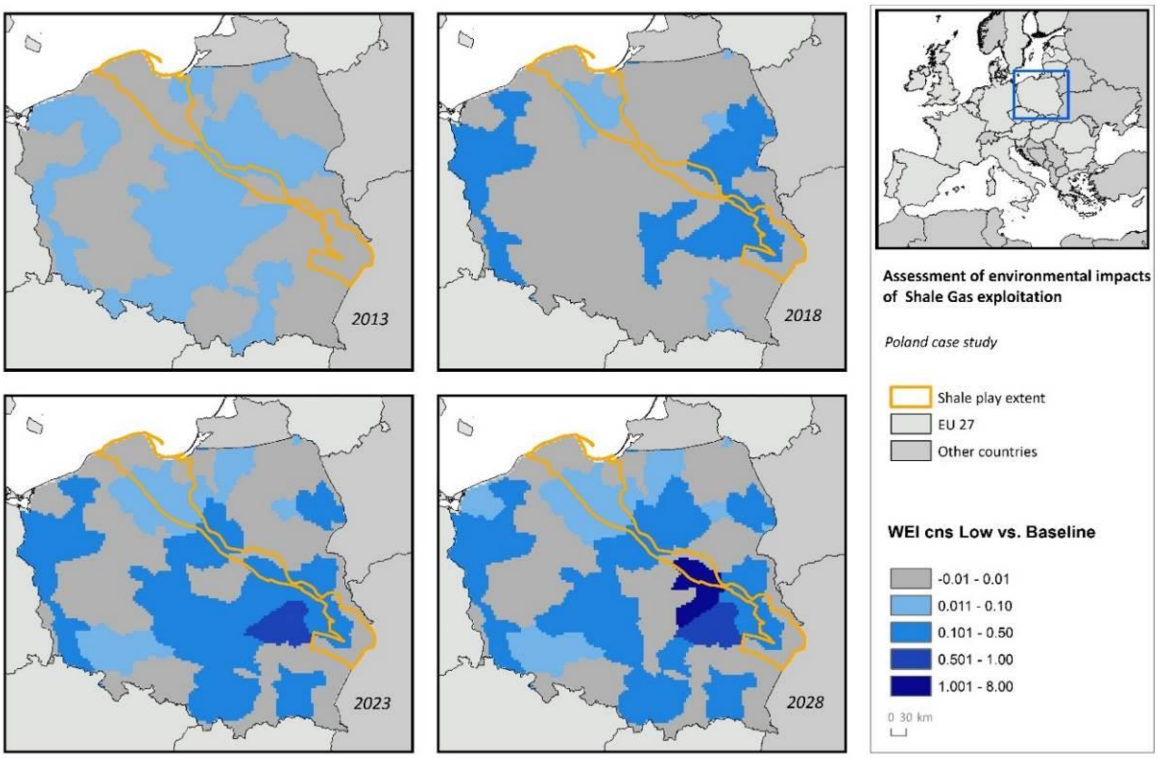

Figure 51: The WEI_{cns} for the hypothetical Low Impact water use scenario.

Figure 54 and Figure 55 show the WEI_{abs} and WEI_{cns} for the average impact water use scenario, as compared to the baseline. The differences with the baseline are more pronounced than for the low impact scenario, and within the shale play there are increases in the WEI_{abs} of up to 7.7% as compared to the baseline.

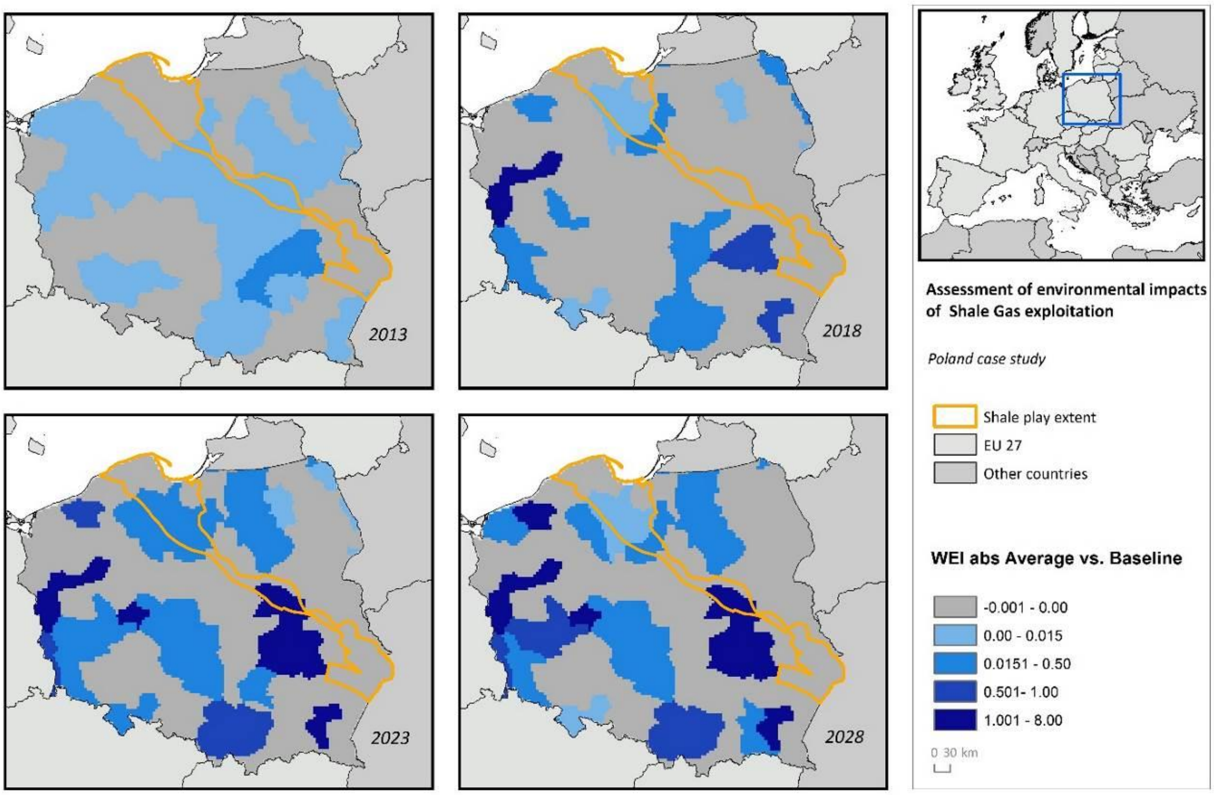

Figure 52: The WEIabs for the hypothetical Average Impact water use scenario.

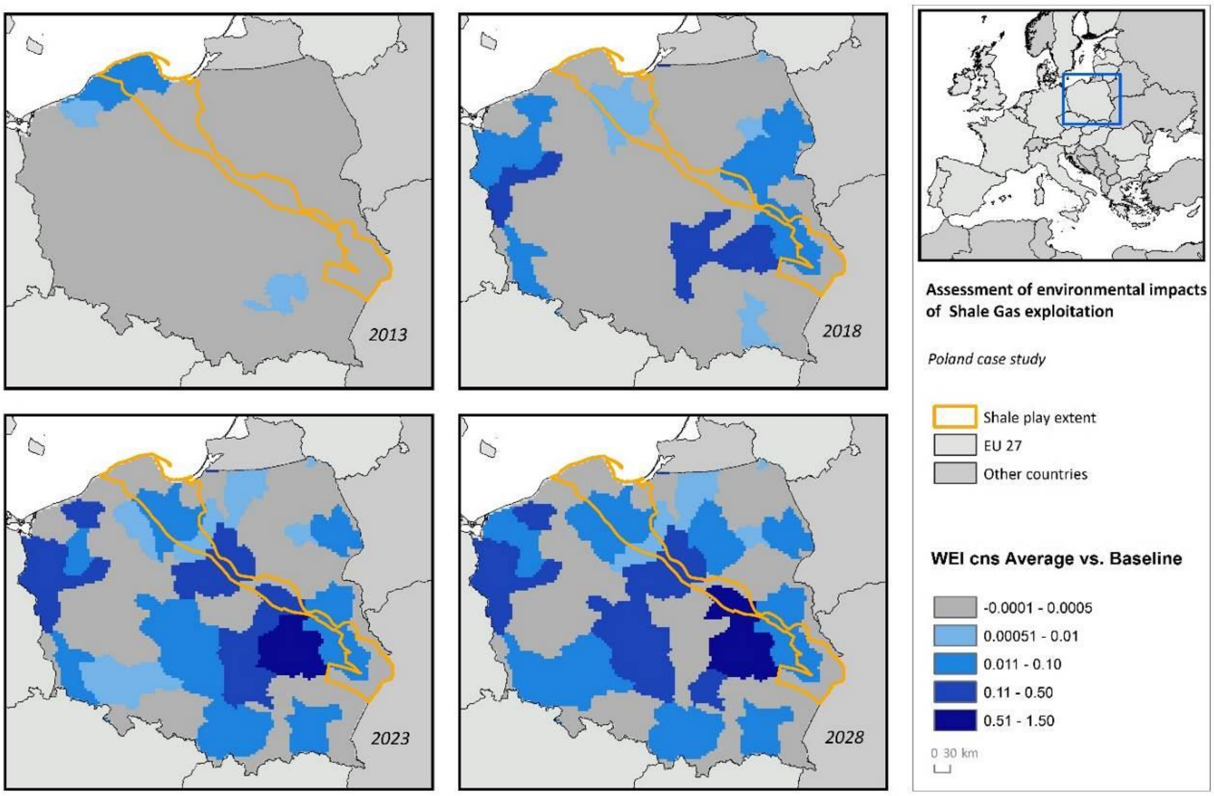

Figure 53: The WEIcns for the hypothetical Average Impact water use scenario.

Figure 54 and Figure 55 show the WEI_{abs} and WEI_{cns} for the high impact water use scenario, as compared to the baseline. Both figures are shown with the same scale for comparability, even though the WEI_{cns} differences are lower (up to 1.5%) than the differences for the WEI_{abs} (up to 8% in a few areas). The impact seen in these maps is greatest within the shale play, where the allocation of extraction sites can be seen to directly (and increasingly over time) impact the WEI, both for abstraction and consumption.

The difference is clearly seen (for both WEI_{cns} and WEI_{abs}) within the northern shale play, where shale gas extraction is concentrated in this simulation. The WEI_{cns} increases up to 0.5% in the catchments where well pads are allocated. In the Warsaw area it increases around 1 %, due to the growth in population and industrial activity over the years.

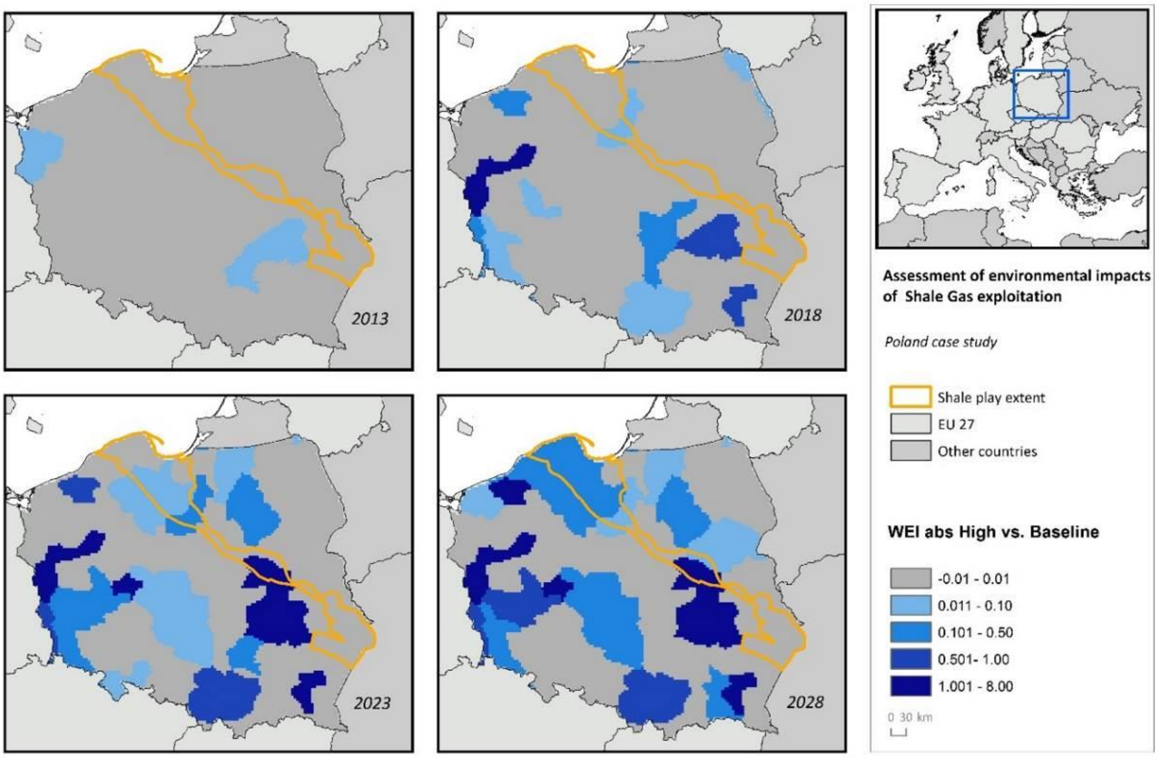

Figure 54: The WEI_{abs} for the hypothetical High Impact water use scenario.

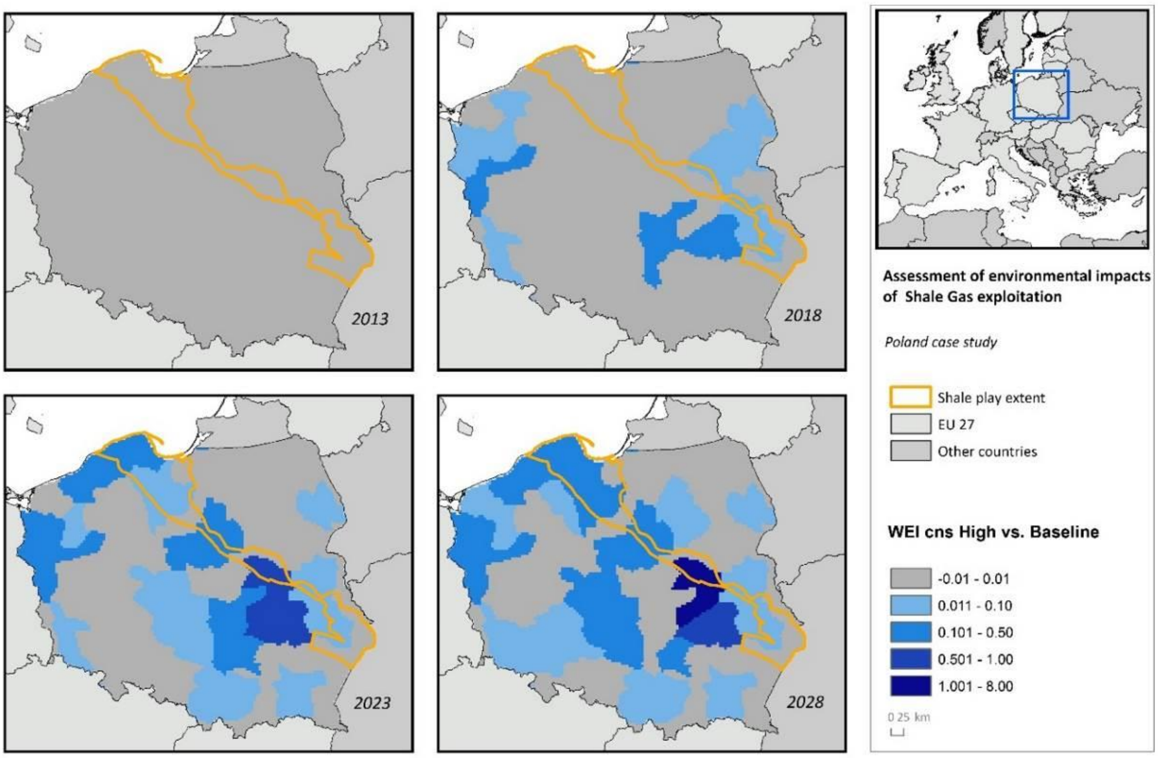

Figure 55: The WEI_{cns} for the hypothetical High Impact water use scenario

Figure 56 shows the difference between the low and high scenarios for the WEI_{cns}. It can be seen that the biggest differences, in 2028 are on the northern area of the shale play extent, where all the well pads are allocated. The difference in this area ranges from 0.3 to 0.4%. These are not large differences, but they may become important at a local scale.

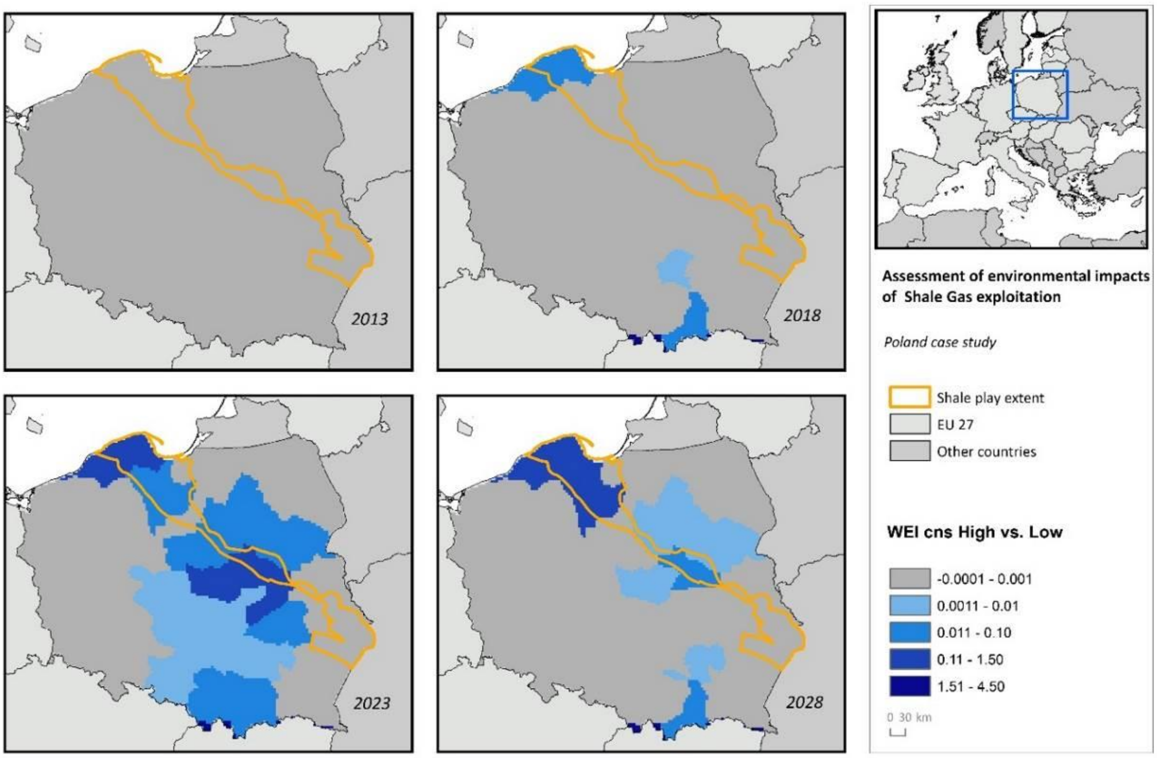

Figure 56: The difference in WEIcns for the hypothetical High as compared to the Low Impact water use scenario

GERMANY

Figure 57 and Figure 58 show the WEI_{abs} and WEI_{cns} for the low impact water use scenario, as compared to the baseline. The maps are in a different scale since the WEI_{cons} is approximately 10 times lower than the WEI_{abs}. The most affected areas are still the highly populated and industrialized ones, but also most of the Bavarian region. Over the years most of these areas have an increasing water exploitation index, both in terms of withdrawals and consumptions. The difference between the baseline and the low scenario for the WEI_{cns} ranges from almost 0 to 0.5%, and for the WEI_{abs} from 0 to up to almost 3%.

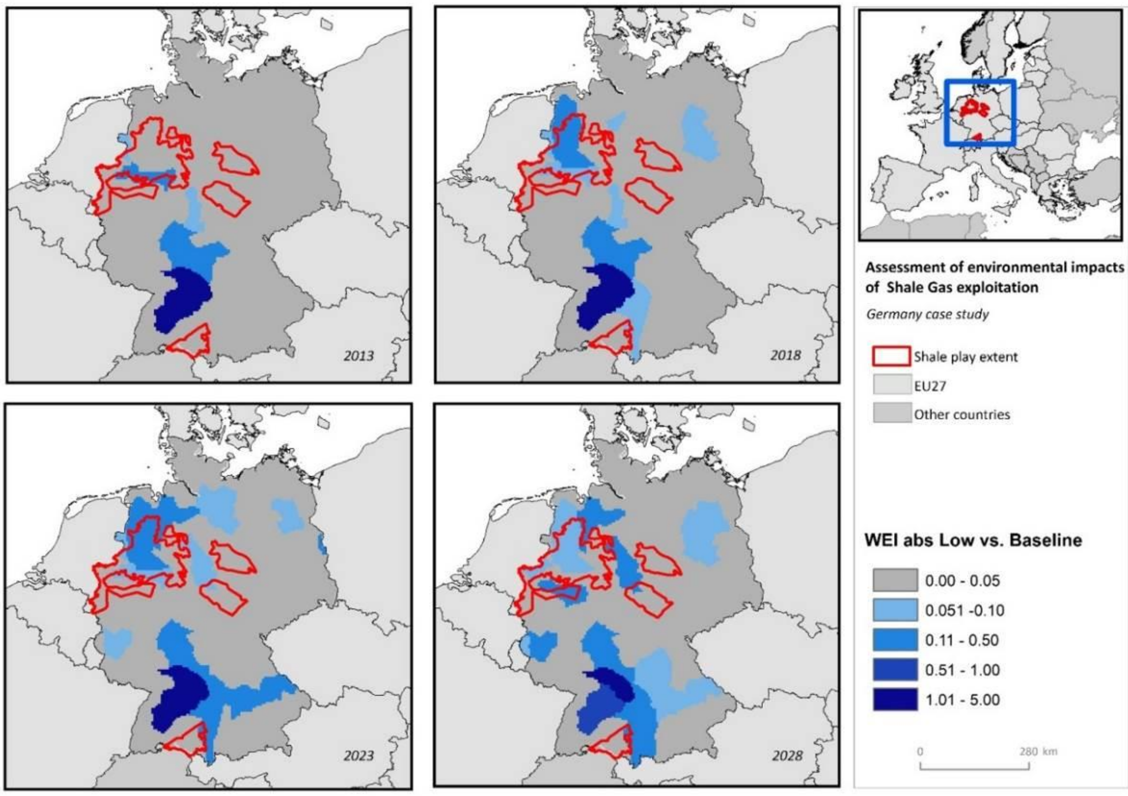

Figure 57: The WEI$_{abs}$ for the hypothetical Low Impact water use scenario.

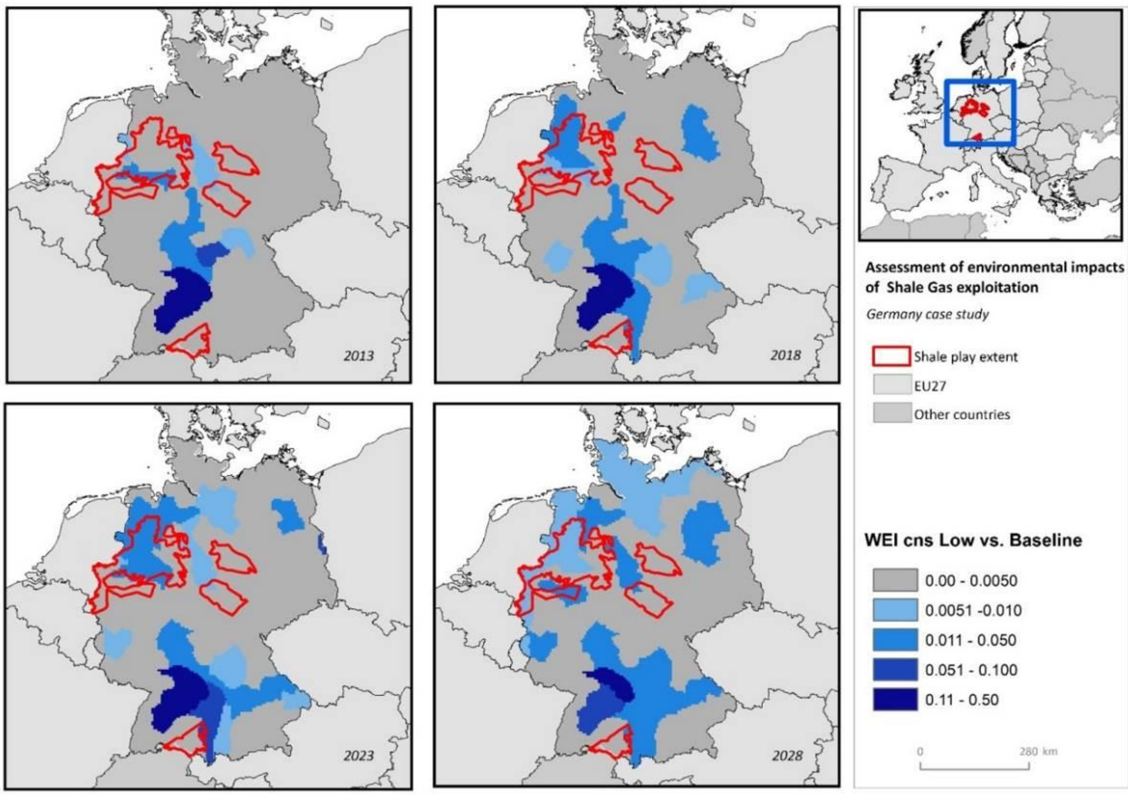

Figure 58: The WEI$_{cns}$ for the hypothetical Low Impact water use scenario.

Figure 59 and Figure 60 show the WEI_{abs} and WEI_{cns} for the average impact scenario. Although the resulting WEI values are similar to those computed in the low impact scenario, the difference in WEI_{abs} as compared to the baseline is greater, now at 3.1%. The impact of additional water use due to shale gas extraction on the WEI_{cns} is seen in the southern shale play in the final year of simulation.

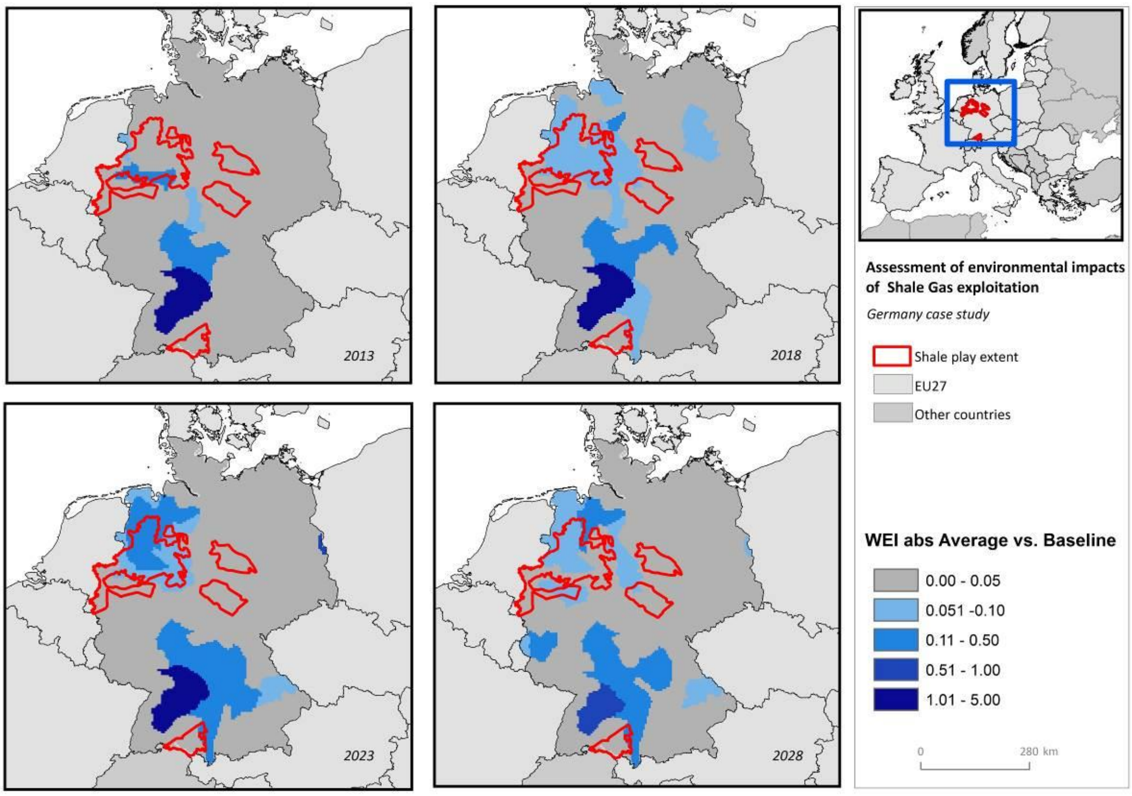

Figure 59: The WEI_{abs} for the hypothetical Average Impact water use scenario.

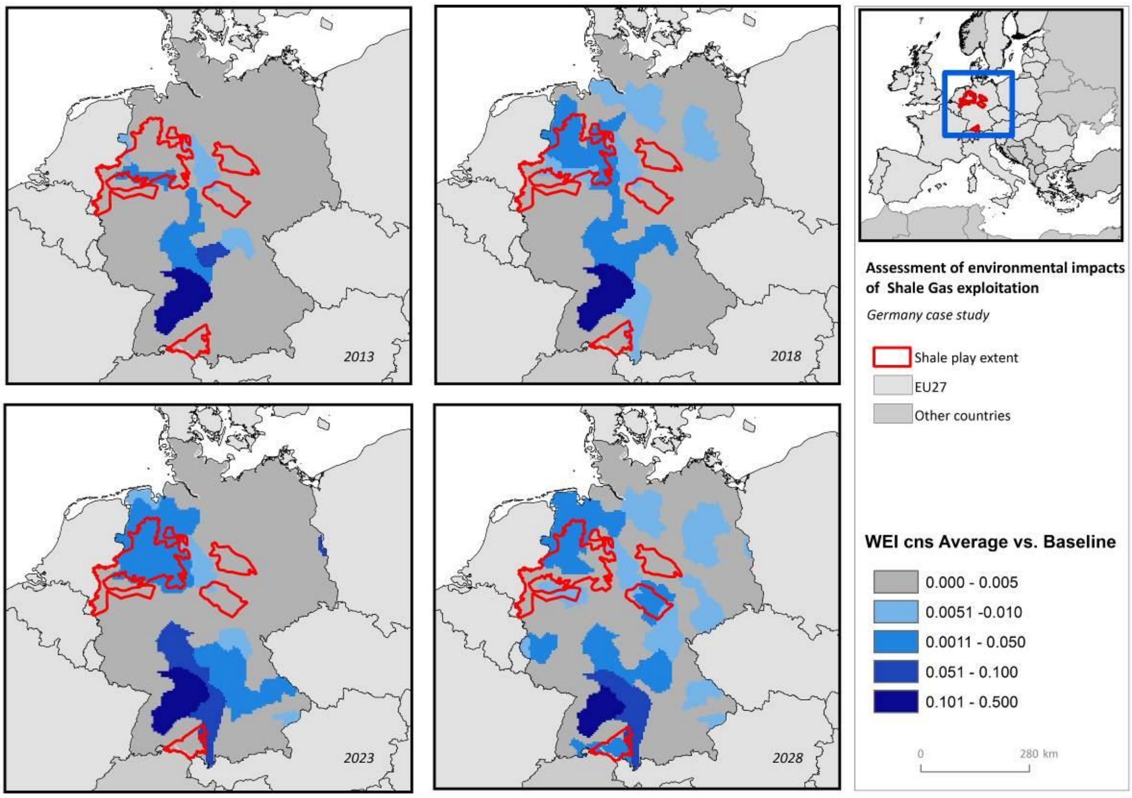

Figure 60: The WEI_{cns} for the hypothetical Average Impact water use scenario.

Figure 61 and Figure 62 show the WEI_{abs} and WEI_{cns} for the high impact water use scenario, as compared to the baseline. The increase of the WEI on the shale plays can be only appreciated for the WEI_{cns} map. Due to the high industrial activity in Germany, the change in WEI_{abs} is greater in the industrial areas than in the shale plays. Only in 2028 can changes in the southern and central shale plays (which are not in industrial zones) owing to the additional water use for shale gas extraction be slightly appreciated. In the southern shale play the differences range from 0% in 2013 to 0.23 % in 2018. In the north-west industrial area where the well pads are allocated the change in the WEI_{abs} ranges from 0.1 to 0.2 %.

The greatest difference between the baseline and the high scenario for the WEI_{cns} is 0.5 %. For both shale plays extents, south and central, the WEI_{cns} ranges from 0 to 0.3 % and 0.054% respectively. For the western shale play the range is lower, from 0.01 % to 0.03%, which could be also affected by the increasing industrial activities.

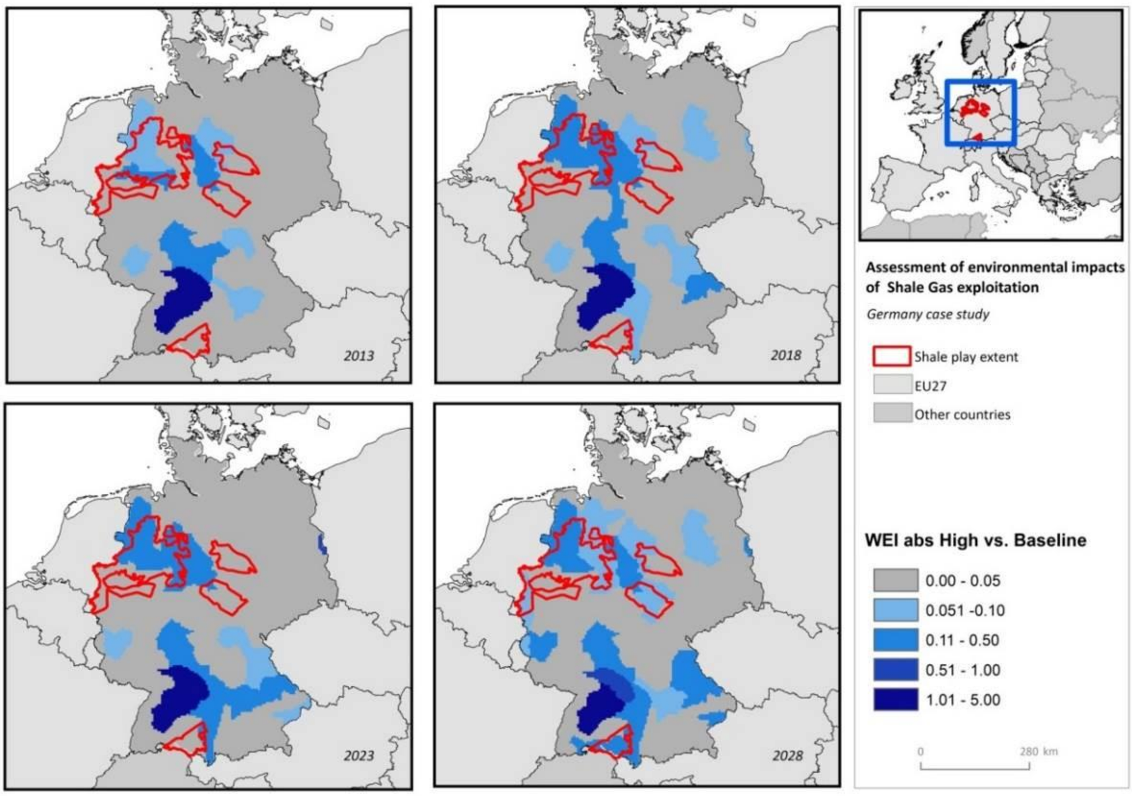

Figure 61: The WEI_{abs} for the hypothetical High Impact water use scenario.

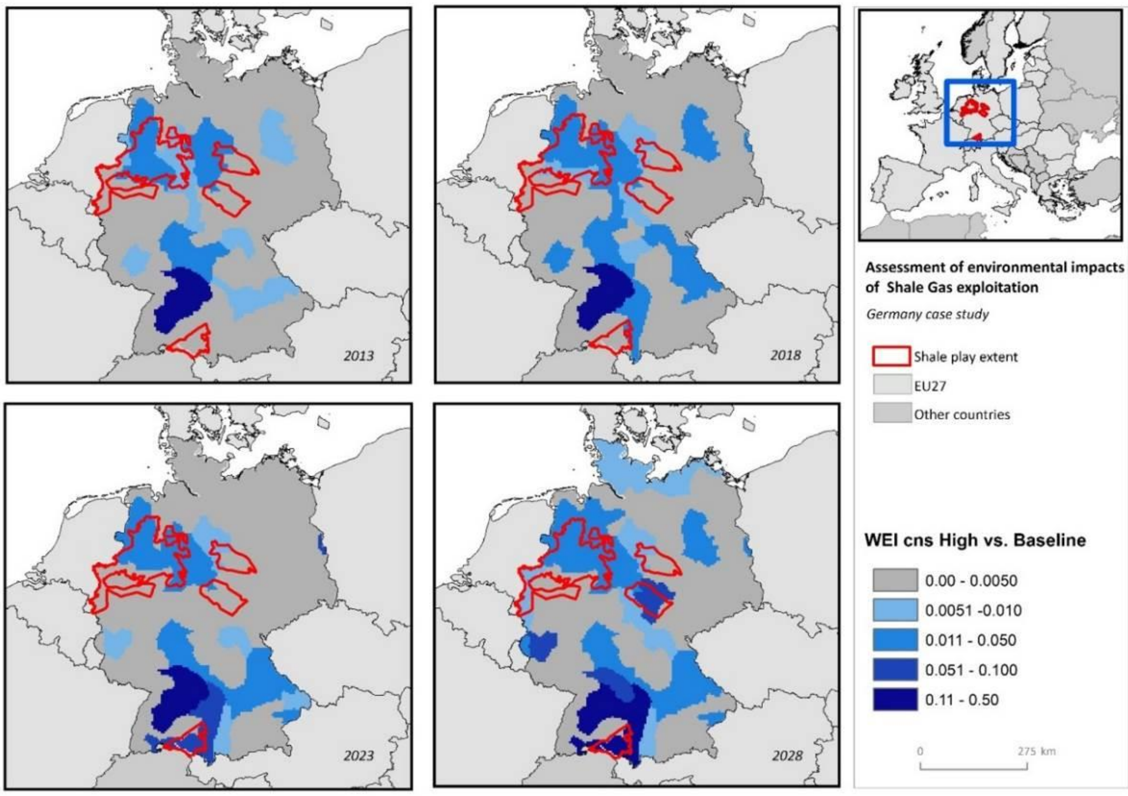

Figure 62: The WEI_{cns} for the hypothetical High Impact water use scenario

Figure 63 shows the difference between the high and the low impact scenarios for the WEI_{abs}.

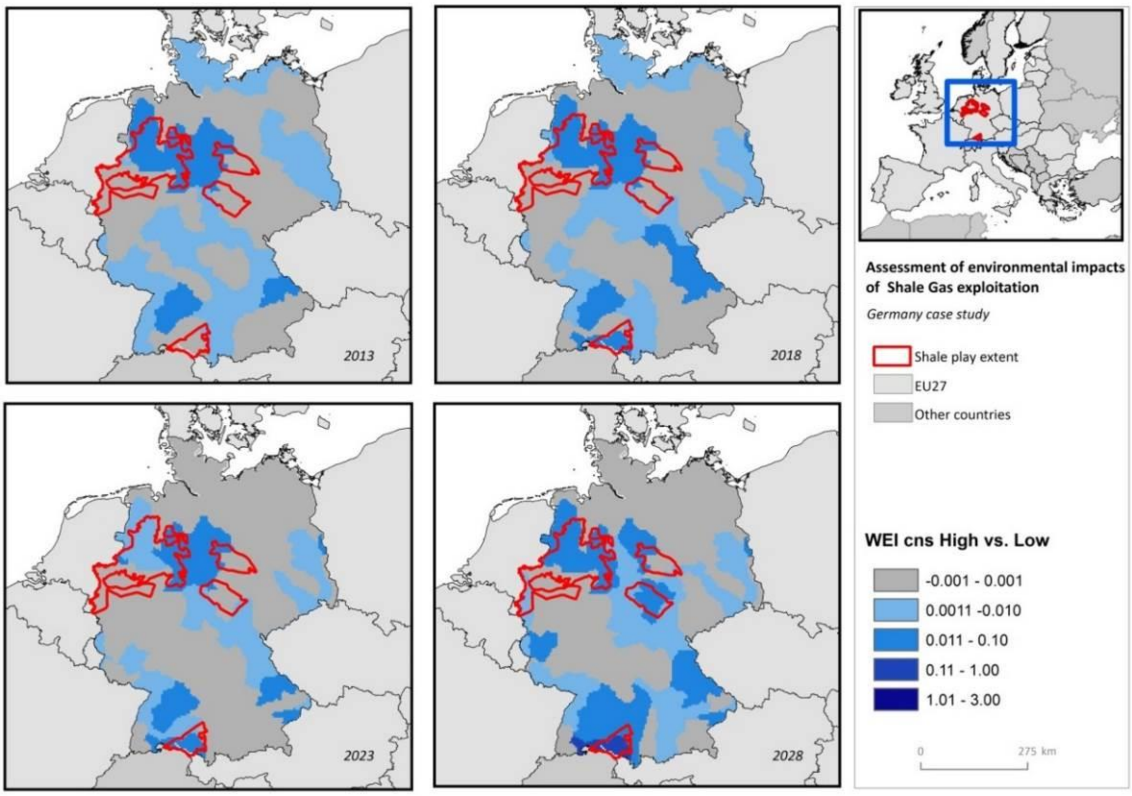

Figure 63: The difference in WEIcns for the hypothetical High as compared to the Low Impact water use scenario

The greatest difference between 2013 and 2028 is in the southern shale play, which is also where most well pads are allocated. This difference ranges from 0 to 0.3%. For the rest of the shale plays the difference is lower, from 0 to 0.05% for the central one and 0.01 to 0.02 % for the north-west shale extent. As in the other maps, a large part of the country does not change over the years, although changes can still be seen in the most populated and industrialized areas, excluding the Bavarian region.

3.2.4 Groundwater Resources

To date, we have focused exclusively on surface water resources; however, a significant amount of water used for fracking could potentially originate from groundwater sources. In this section we look at the placement of modeled shale gas extraction sites as compared to the major groundwater aquifers as mapped for Poland, and the groundwater recharge zones for Germany.

POLAND

The Polish Hydrogeological Survey provides a map of the major groundwater reservoirs (PHS 2012). Our modeled shale gas extraction sites are shown in the northern part of the shale play. Compared to the surrounding areas, there are actually relatively few groundwater reservoirs located within this area. This would not be the case, however, in scenarios where shale gas wells are more widely dispersed across the shale play. Any developments in most of the southern half of the shale play would necessarily coincide with freshwater aquifers.

Table 35 summarises some of the characteristics of the reservoirs. The reservoirs GZWP.82, GZWP.133 and GZWP.162 are those which coincide to some extent with the shale gas extraction sites as modeled in this exercise.

Table 35: Main groundwater reservoirs within the hypothetical modelled shale gas extraction zone.

Aquifer Identification	Surface (km^2)	Estimated Available Water ($1000\ m^2$ / day)	Average Well Depth (m)
GZWP.82	170	25	100
GZWP.133	514	140	10 - 50
GZWP.162	118	29	50
GZWP.11	112	80	50 - 60
GZWP.14	56	25	5
GZWP.153	212	161	5 - 50
GZWP.144	1159	118	5 - 30
GZWP.24	82	30	10 - 50
GZWP.97	80	17	10 - 40
GZWP.98	15	22	5 - 50
GZWP.99	147	294	5 - 10
GZWP.100	1800	110	150
GZWP.163	92	3	5 - 10
GZWP.142	19	23	15

Table 36 gives the number of wellpads that are allocated to regions overlying major aquifers in our scenarios. The percentage of wellpads located above aquifers varies between 17.2% in the low impact scenario to 29.1% in the average impact scenario.

Table 36: Proximity of well pads to known groundwater reservoirs in Poland, as in year 2028.

High Impact Scenario			Average Impact Scenario			Low Impact Scenario		
Total number of well pads	Well pads overlaying with aquifers		Total number of well pads	Well pads overlaying with aquifers		Total number of well pads	Well pads overlaying with aquifers	
[-]	[-]	[%]	[-]	[-]	[%]	[-]	[-]	[%]
246	56	22.8	492	143	29.1	244	42	17.2

GERMANY

We assessed the location of our simulated wellpads in relation to the major recharge zones in Germany. We used the map of groundwater recharge provided by the BGR, as was used in calculating the suitability maps. Table 37 gives the number of wellpads that are allocated to each recharge category for our scenarios. The percentage of wellpads located in the greatest recharge zones (i.e. greater than 249 mm[8]) varies between 56.6% in the low impact scenario to 70.1% in the high impact scenario.

Table 37: Proximity of well pads to known groundwater reservoirs in Germany, as in year 2028.

High Impact Scenario			
Total number of well pads	Groundwater recharge	Well pads overlaying with aquifers	
[-]	[mm/year]	[-]	[%]
1115	≤ 30	0	0
	31 - 103	5	0.4
	104 - 175	48	4.3
	176 - 248	280	25.1

[8] In order to highlight possible impacts on ground water resources, we have defined a minimum threshold value of recharge. This value is based on the original classification used by the BGR, in which we assumed the 3 highest classes (above 249 mm) to represent the most important recharge areas. We consider areas where recharge values are equal or above this threshold, as being important sources of fresh water to be preserved. In addition, placing well pads in these areas would increase the soil sealing and, therefore, could potentially adversely affect the recharge of the aquifers.

This value is slightly higher than the calculated mean recharge for Germany (150-200 mm/yr, as from Döll, P. and Flörke M. 2005. Global-Scale Estimation of Diffuse Groundwater Recharge – Model tuning to local data for semi-arid and arid regions and assessment of climate change impact).

Total number of well pads	Groundwater recharge	Well pads overlaying with aquifers	
	≥ 249	782	70.1
Average Impact Scenario			
Total number of well pads	**Groundwater recharge**	**Well pads overlaying with aquifers**	
[-]	**[mm/year]**	**[-]**	**[%]**
559	≤ 30	0	0
	31 - 103	12	2.1
	104 - 175	47	8.4
	176 - 248	156	27.9
	≥ 249	344	61.5
Low Impact Scenario			
Total number of well pads	**Groundwater recharge**	**Well pads overlaying with aquifers**	
[-]	**[mm/year]**	**[-]**	**[%]**
562	≤ 30	0	0
	31 - 103	19	3.4
	104 - 175	68	12.1
	176 - 248	157	27.9
	≥ 249	318	56.6

In general, the groundwater reservoirs within our study area are quite shallow. In terms of water quality considerations this means two things. First, unrecovered water that has been used for fracking would reside far deeper than the extent of the reservoirs (shale gas reserves are estimated at being at a depth of 1 kilometer or more depending on the location), and may therefore not likely affect the quality of the reservoirs mapped. Second, water that is recovered following use for fracking may be stored either temporarily or for longer time periods on the surface, where risks of accidental spillage may, in fact, jeopardize groundwater aquifers.

Figure 64 shows an excerpt from the International Hydrogeological map for Europe (as compiled by BGR and UNESCO) for Germany and Poland. This map classifies the type of aquifers in terms of main lithology and productivity. The lithology is classified in three classes: porous, fissured and insignificant. Porous aquifers are less sensitive to different pollutants because, while the pollutant is infiltrating the sand grains are able to adsorb some compounds. But karst or fissured aquifers don't have this capacity, and polluted water becomes part of the flow without having been cleaned, such that pollutants can even cause a major dissolution on the aquifer rocks that would allow greater (but polluted) flows through the karst conducts.

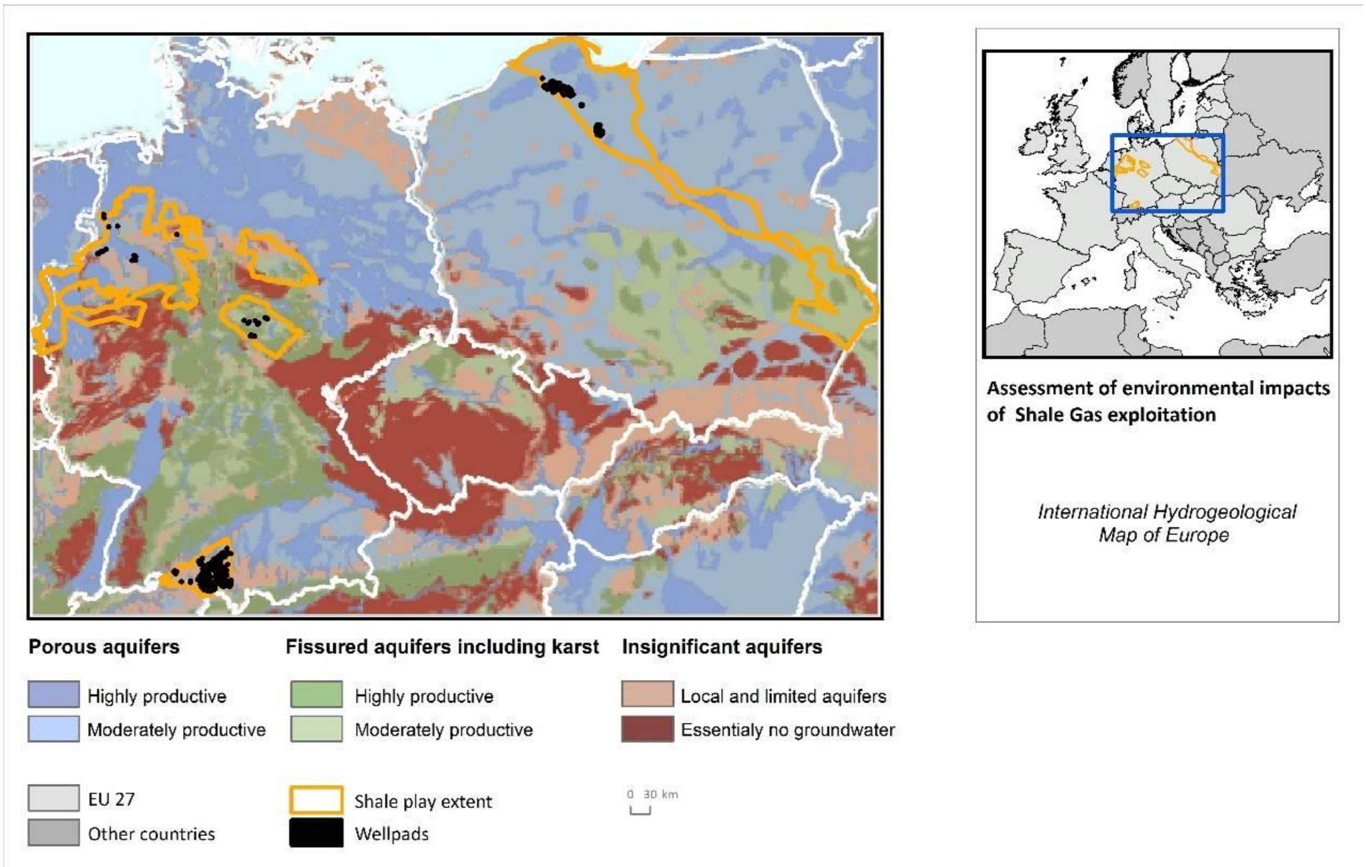

Figure 64: An excerpt of the *International Hydrogeological Map of Europe* for Germany and Poland, showing the location of the shale plays and simulated well pad locations in relation to the productivity and type of aquifers present.

In Poland, well pads are allocated in an area classified as having moderately productive porous aquifers, but close to some highly productive ones. It should be noted that commonly porous aquifers are connected, so if a pollutant is infiltrated through a moderately productive aquifer it could be found, eventually, in a production well situated over a highly productive aquifer.

In Germany, however, the shale plays are situated in geologically different areas. In the northwest shale play well pads are situated in an area classified as highly productive porous aquifer, but in this case, aquifers seem to be isolated, as they are surrounded by insignificant aquifers, which can create what is known as geological traps, in other words impermeable layers between two porous aquifers. In the southern shale play, also local and limited aquifers crossing porous aquifers can be found, so the risk of spreading one pollutant from one aquifer to another is not high.

However, the central shale play extent with allocated well pads is situated on a karst or fissured aquifers area. According to the geological map (from the Federal Institute for Geosciences and Natural Resources, Germany) the area presents calcareous geology (low Quaternary) alternated with sedimentary debris (middle-low Quaternary) and fluvial debris. This geology allows the formation of big caves, which means, water quality in this area is more sensitive than in porous aquifers, and also the underground stability becomes more sensitive to external forces and difficult to study.

3.3 Results for ecological and human health screening risk assessment for chemicals potentially used in hydraulic fracturing of shale formations

Emission characterization

The chemicals potentially used in shale gas development are of different types and employed for various purposes. The following are reported as the main uses of chemicals in shale gas exploitation (Colborn et al 2011):

- Acids: to achieve greater injection ability or penetration and later to dissolve minerals and clays to reduce clogging, allowing gas to flow to the surface.
- Biocides: to prevent bacteria that can produce acids that erode pipes and fittings and break down gellants that ensure that fluid viscosity and proppant transport are maintained.
- Breakers: to allow the breakdown of gellants used to carry the proppant, added near the end of the fracking sequence to enhance flowback.
- Clay stabilizers: to create a fluid barrier to prevent mobilization of clays, which can plug fractures.
- Corrosion inhibitors: to reduce the potential for rusting in pipes and casings.

- Crosslinkers: to thicken fluids often with metallic salts in order to increase viscosity and proppant transport.
- Defoamers; to reduce foaming after it is no longer needed in order to lower surface tension and allow trapped gas to escape.
- Foamers: to increase carrying-capacity while transporting proppants and decreasing the overall volume of fluid needed.
- Friction reducers: to make water slick and minimize the friction created under high pressure and to increase the rate and efficiency of moving the fracking fluid.
- Gellants: to increase viscosity and suspend sand during proppant transport.
- pH control: to maintain the pH at various stages using buffers to ensure maximum effectiveness of various additives.
- Scale control: to prevent build up of mineral scale that can block fluid and gas passage through the pipes.
- Surfactants: to decrease liquid surface tension and improve fluid passage through pipes in either direction.

Quantitative information on the chemicals used and released in shale gas development is generally unavailable. Moreover, the identification of the substances employed is difficult due to mixed reporting of formulations, products or single chemicals. Several lists of chemicals potentially used are available. The two most recent and comprehensive are:

- US House of Representatives (2011), based on survey data, indicating that more than 2500 hydraulic fracturing products were used in the US from 2005 to 2009, containing 750 chemicals and other components;
- USEPA (2012), in which almost 1000 chemicals were listed and identified via CAS number.

This diversity of chemicals reflects the fact that site-specific conditions dictate which combination of chemicals will be used in fracturing, as well as the differing ratios of water, proppant and chemicals employed (literature reports suggest that the proportion of chemicals in water used for hydraulic fracturing ranges from 0.5 up to 2%).

The release of fracking chemicals into the environment may occur under two circumstances: as **operational releases** (due to the specific processes associated with shale gas development) or as **accidental releases** (when there is an unexpected release) (see Table 38 and Figure 65). Moreover, two typologies of chemicals should be considered: the chemicals that are actually injected into the well (**injected chemicals**) and **formation chemicals** that are mobilized from the fractured formation and brought to the surface in flow-back water. Schematically, the key steps in hydraulic fracturing where operational and/or accidental release of chemicals may occur are reported Figure 65.

Table 38: The key steps in hydraulic fracturing where operational and/or accidental release of chemicals may occur

Process Steps	Description of Activity	Potential releases
Chemical mixing	Water is mixed with chemicals and proppant onsite to create the hydraulic fracturing fluid immediately before injection	Accidental release during transport or mixing of the chemicals
Injection	During injections, hydraulic fracturing fluids are pumped into the well at high pressure	Accidental release during injection due to equipment failure, including faulty well casing. Operational release of chemicals into the formation.
Flowback and produced water	The pressure on the hydraulic fracturing fluid is reduced and the flow is reversed. The flowback and produced water contains hydraulic fracturing fluids, native formation water and any substances mobilized by the fracturing fluid from the target formation during the fracturing process. Formation chemicals may include particularly toxic heavy metals (E.g. Hg or Cr), salts, and radionuclides (Kargbo et al. 2010).	Accidental release during flowback due to equipment failure, including faulty well casing.
Flow back water storage	The fluids are separated from gas and stored in either tanks or an open pit	Accidental release during storage options may occur due to spills, leaching, etc. Volatilization from open pit storage may occur.

Wastewater treatment	Flowback and produced water is frequently disposed in deep injection wells but may be trucked, or in same case piped, to a disposal or recycling facility. Once treated, the wastewater may be used reused in subsequent hydraulic fracturing operations or discharged to surface water.	Management of the hydraulic fracturing wastewater varies from site to site. Operational releases to surface water may occur as well as accidental releases before or after waste water treatment.

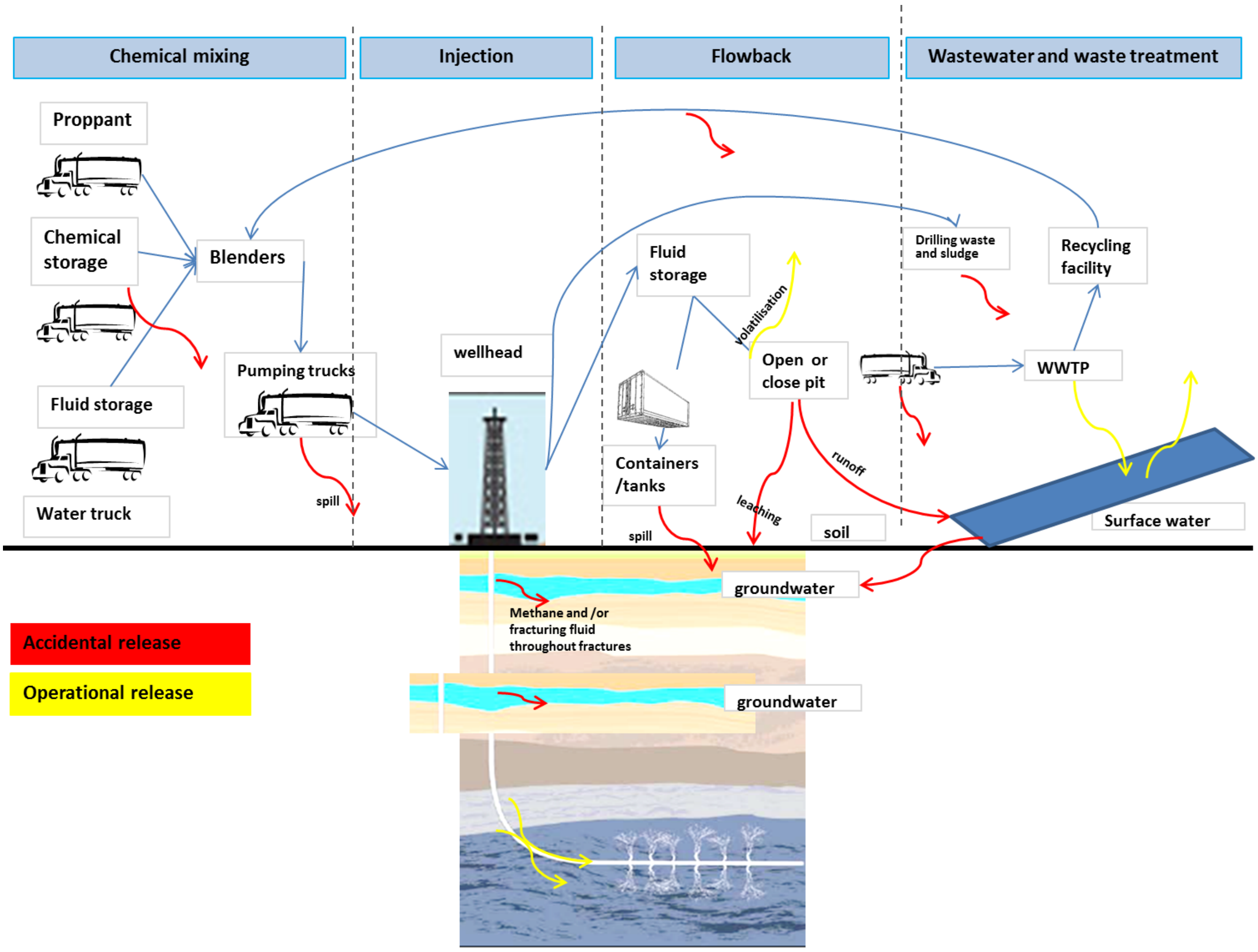

Figure 65: Conceptual diagram of the main steps of shale gas extraction, where operational or accidental releases of chemicals may occur (WWTP- Waste Water Treatment Plant)

According to Rozell and Reaven (2012), there are five major pathways for water contamination: transportation spills, well casing leaks, leaks through fractured rock, drilling site discharge, and wastewater disposal. In this study, the authors also reported probability boxes for each pathway. These accidental/operational releases may also affect air (through volatilization) and soil (if the spill is occurring on soil or if chemicals are returned to the surface in groundwater).

Exposure characterization

The characterization of exposure requires (1) the evaluation of the potential fate of the chemicals when emitted into air, water and soil; and (2) the identification of the exposure pathways which may lead to chemical exposure of ecosystems and humans . This requires consideration of the physico-chemical properties of the chemicals that are used.

Physico-chemical properties and fate of the chemicals

The fate of the chemicals in the environment after either operational or accidental release is driven by their physical chemical properties, such as partitioning properties (Kow- octanol water partitioning ; H – Henry constant; P –Persistence in different media- air, water, soil etc). Data on basic physical chemical properties and toxicological information for the USEPA (2012) list were retrieved via CAS number, where available, using Episuite. The estimation programs interface (EPI) Suite TM is a software developed by the US EPA as a screening level tool. It is intended for use in applications such as screening of chemicals for release potential and to support clustering of chemicals. The domain of application is mainly related to organic chemicals. Inorganic and organic metallic chemicals are generally outside of the scope.

We characterized the physico-chemical properties of the chemicals potentially used in hydraulic fracturing, as reported by the USEPA (2012) in terms of Kow (octanol- water partitioning coefficient) and Kaw (air- water partitioning coefficient). Kow and Kaw are two crucial properties when assessing the environmental fate of chemicals. Kow is an indication of the tendency of a chemical to be soluble in water, and the relative water-organic solubility. The latter predicts the potential of the chemicals for bio-concentration and bio-magnification in the trophic chain. High Kow values are associated with hydrophobicity, and are often found in very persistent, bioaccumulative chemicals. Analogously, Kaw is an indication of the tendency of a chemical to be soluble in water or to volatilize in air. High Kaw values are associated with highly volatile chemicals, whereas low Kaw values with hydrophilic chemicals. If we plot Kow and Kaw, we may define the so called chemical space in which each combination of Kow and Kaw values allows identification of the environmental behavior and fate of chemicals. Figure 66 shows the plot of these chemicals in the chemical space. For 102 of the chemicals reported by USEPA (2012), it was not possible to calculate Kaw with Episuite. The figure below thus reports only the position in the chemical space for 542 chemicals for which data have been calculated with Episuite. The chemicals considered evince considerable heterogeneity in terms of environmental fate. They range from highly volatile to strong lipophilic and hydrophilic chemicals.

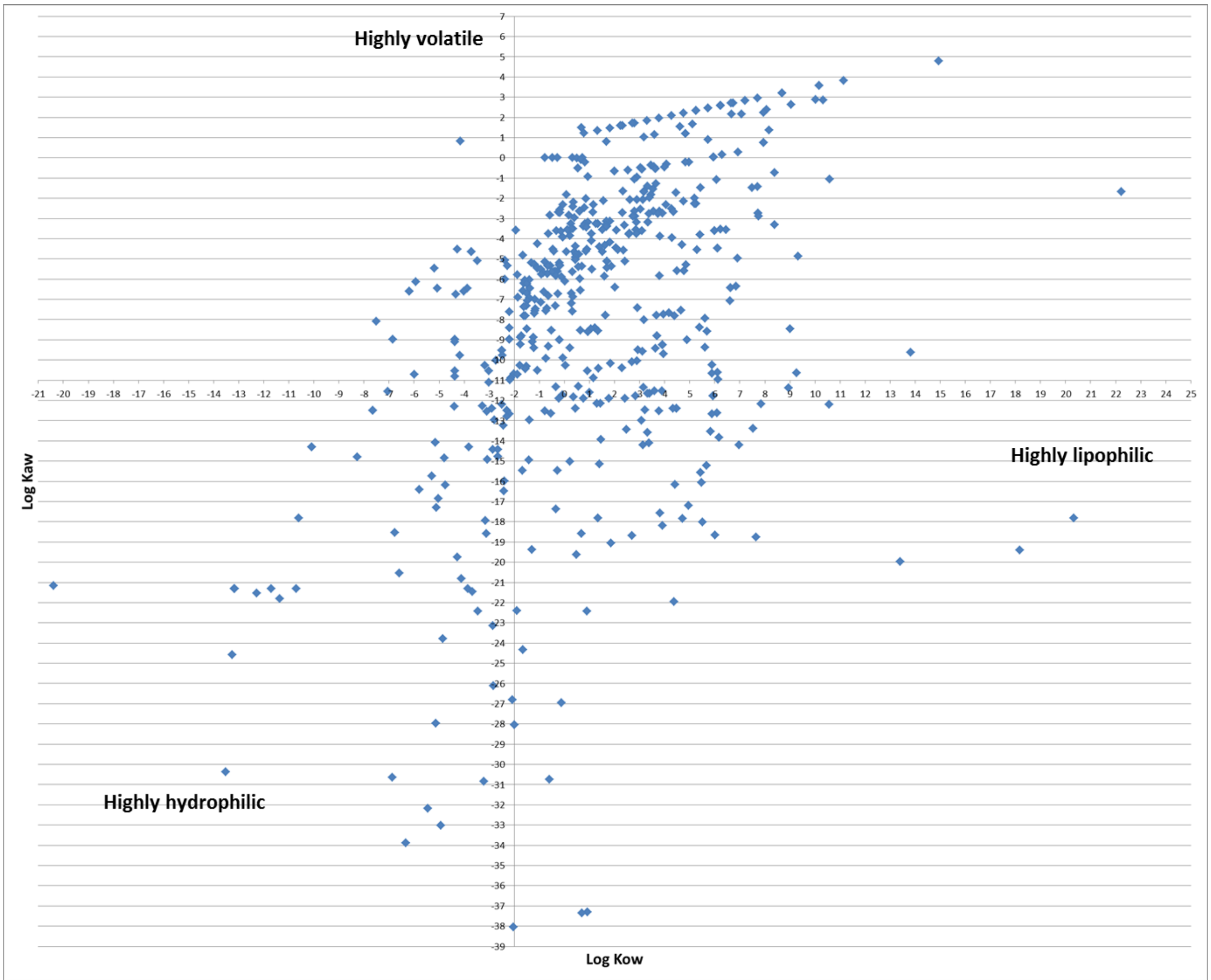

Figure 66: The physical- chemical properties of 542 of the 644 chemicals reported as potentially used in hydraulic fracturing by USEPA (2012).

Most of the chemicals considered are positioned in the right, top quadrant of Figure 66. This is the quadrant in which there are also chemicals with multimedia behavior (namely, for which there is a likelihood that they will be found in air, water and/or soil/biota).

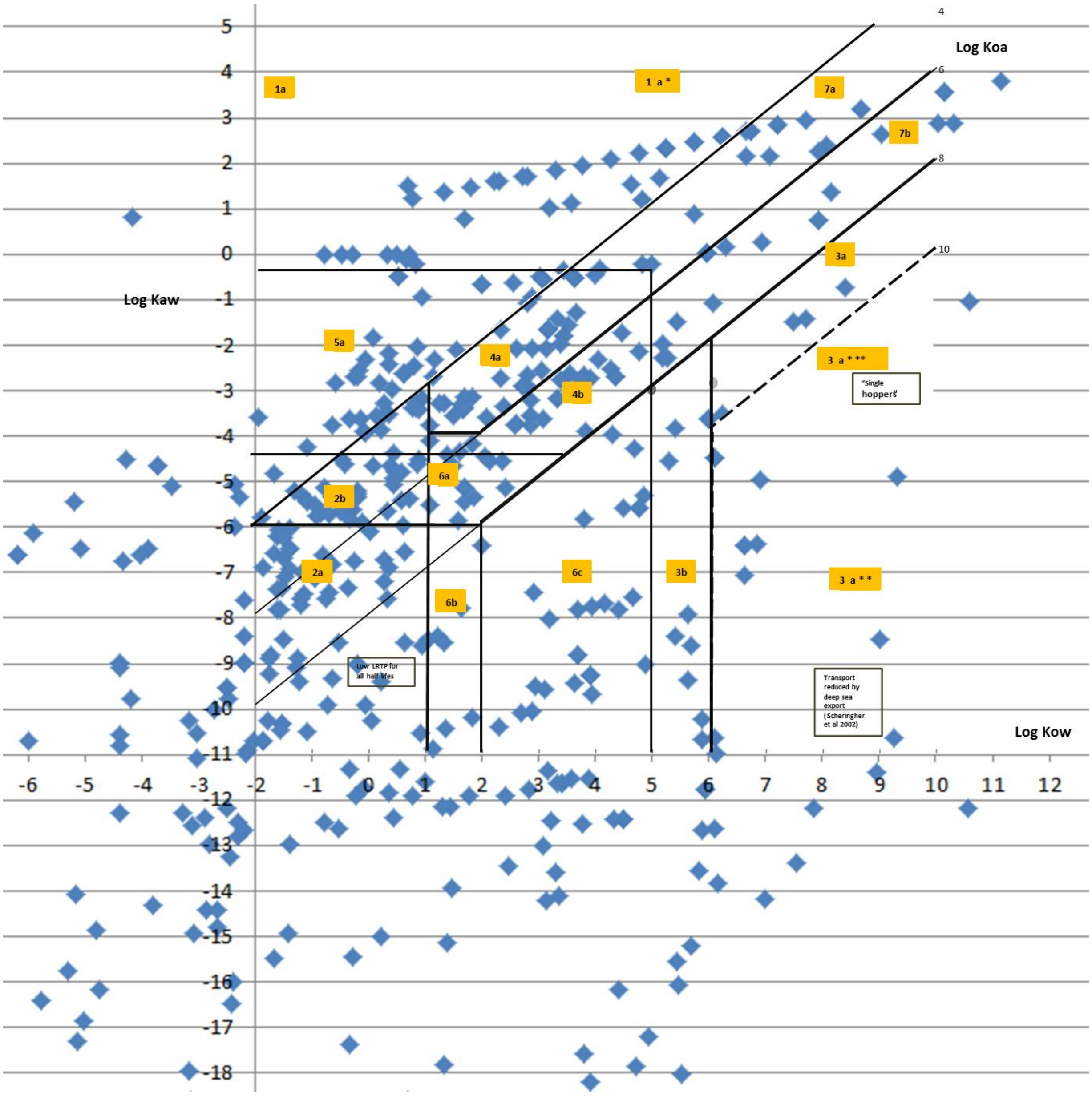

Figure 67: Detail of the upper right quadrant of Figure 66. The legend of the subsections is reported in Table 39

Table 39: Main compartments of environmental fate for the chemicals presenting the combination of Kow, Kaw and Koc as reported in the table. The partitioning and human exposure classes refer to non-dissociating and non-amphiphilic organic chemicals. Sa and Sw refer to source to air and water, respectively (modified from Margni et al 2002)

Subsections	Log Kow	Log Kaw	Log Koa	Main environmental fate compartment	Human Exposure Pathway
1a		> -0.5	<4	air	Inhalation
1a*		>0	<6.5	Air (fliers)	Inhalation
2a	<1	<-6		water	agr.prod. (Sa) or water (Sw)
2b	<1	-4.5>x>-6		water	multipathway
3a	>6		>8	solid	meat+milk (Sa) or fish (Sw)
3a**	>6	<-6		Solid	meat+milk (Sa) or fish (Sw)
3a***			>10	Solid	meat+milk (Sa) or fish (Sw)
3b	5<x<6		>8	solid	agr.prod.(Sa) or multipath. (Sw)
4a	1<x<5	-4.5<x<-0.5	4<x<6	Multimedia	Air/inhalation
4b	1<x<5	-4.5<x<-0.5	6<x<8	Multimedia	multipathway
5a		-4.5<x<-0.5	<4	air-water	Inhalation
6a	1<x<4	-4.5>x>-6	6<x<8	water-solid	multipathway
6b	1<x<2	<-6		water-solid	agr.prod. (Sa) or water (Sw)
6c	2<x<5	<-4.5	>8	water-solid	agr.prod.
7a		>-0.5	4<x<6	air-solid	Inhalation
7b	>5		6<x<8	air-solid	multipathway

Effect characterization

The multimedia box model USEtox (Rosenbaum et al 2008) was used to conduct a screening level assessment of the potential harm of the substances based on different routes of release and pathways. The resulting characterization factors are calculated accounting for a potential emission to water, soil and/or air, and highlight wide variability in terms of potential impacts for ecosystems and human health.

The human exposure model quantifies the increase in amount of a compound transferred into the human population based on the concentration increase in the different media. The exposure pathways are inhalation and ingestion. Human effect factors in USEtox relate the quantity taken in by the population via ingestion and inhalation to the probability of adverse effects (or potential risk) of the chemical in humans. It is based on toxicity data for cancer and non-cancer effects derived from laboratory studies. Under the assumption of a linear dose – response function for each disease endpoint and intake route, the human effect factor is calculated as $0.5/ED_{50}$, where the ED_{50} is the lifetime daily dose resulting in a probability of effect of 0.5.

The characterisation factors for human toxicity (human toxicity potential) are expressed in comparative toxic units (CTUh), providing the estimated increase in morbidity in the total human population per unit mass of a chemical emitted (cases per kilogram)

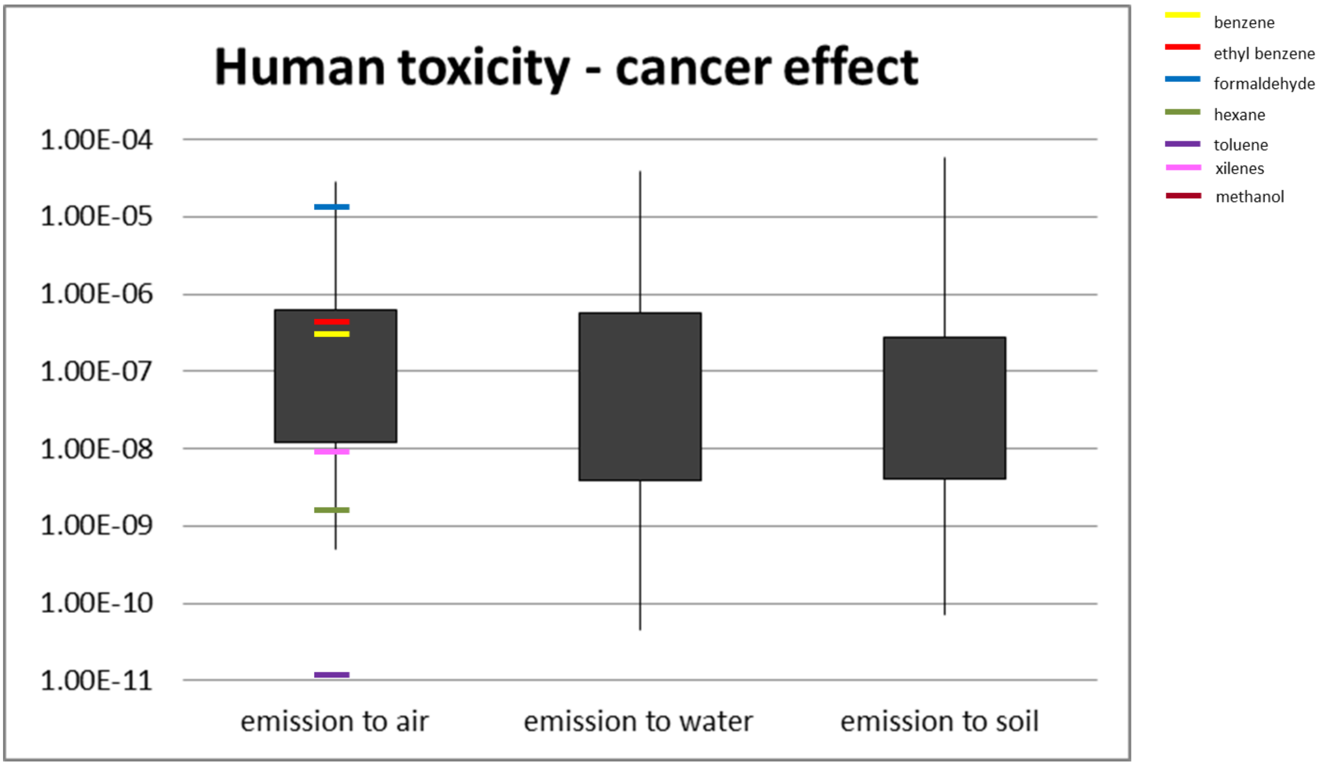

Figure 68: Comparative toxic unit for human toxicity- cancer effects calculated by USEtox for the chemicals reported by USEPA (2012), after an emission to air, water and soil. (5,25,75 and 95th percentiles)

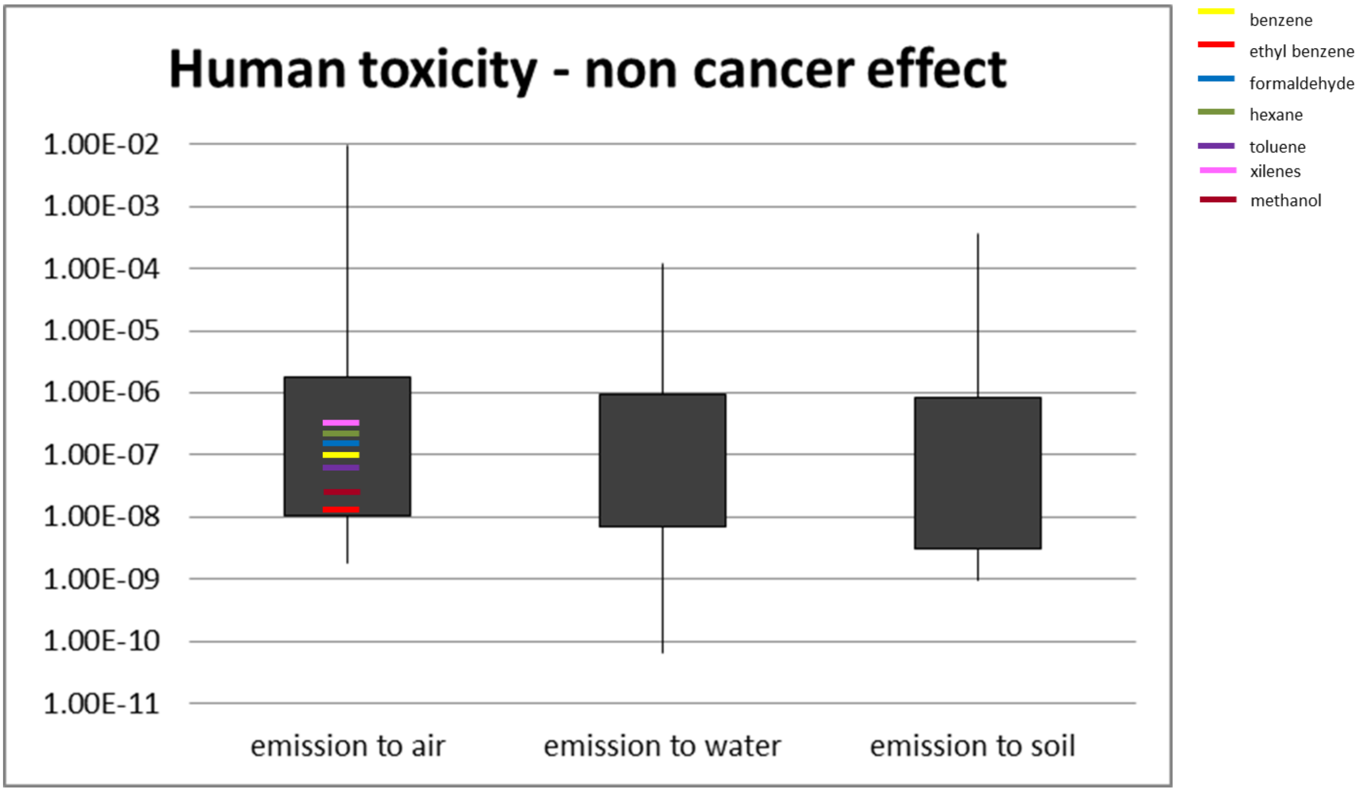

Figure 69: Comparative toxic unit for human toxicity- non cancer effects calculated by USEtox for the chemical reported by USEPA (2012), after an emission to air, water and soil. (5,25,75 and 95th percentiles)

Analyzing Figure 68 and Figure 69 , it is clear that there is considerable variability in the potential toxicological effect of the chemicals that may be used in hydraulic fracturing operations. Irrespective of the route of the emission, the potential toxicological concern related to many chemicals is high.

For aquatic ecotoxicity, the effect factor is calculated using the same linear assumption as for the human effect factor, i.e. linearity in concentration – response, which results in a slope of 0.5/HC50. The HC50, based on species-specific EC50 data, is defined as the hazardous concentration at which 50% of the species are exposed above their EC50. The EC50 is the effective concentration at which 50% of a population displays an effect (e.g. mortality).

The characterisation factor for aquatic ecotoxicity (ecotoxicity potential) is expressed in comparative toxic units (CTUe) and provides an estimate of the potentially affected fraction of species (PAF) integrated over time and volume per unit mass of a chemical emitted (PAF m3day kg^{-1}). Figure 70 reports the results for ecotoxicity. When chemicals are emitted directly to water, there is tremendous variability in potential impacts (i.e. over 12 orders of magnitude).This due to the diverse toxicological properties and potential fates of the chemicals considered. When emitted in water, the chemicals that tend to remain in water imply higher CTUe whereas those that volatilize or are adsorbed by the sediment, resuls in lower CTUe.

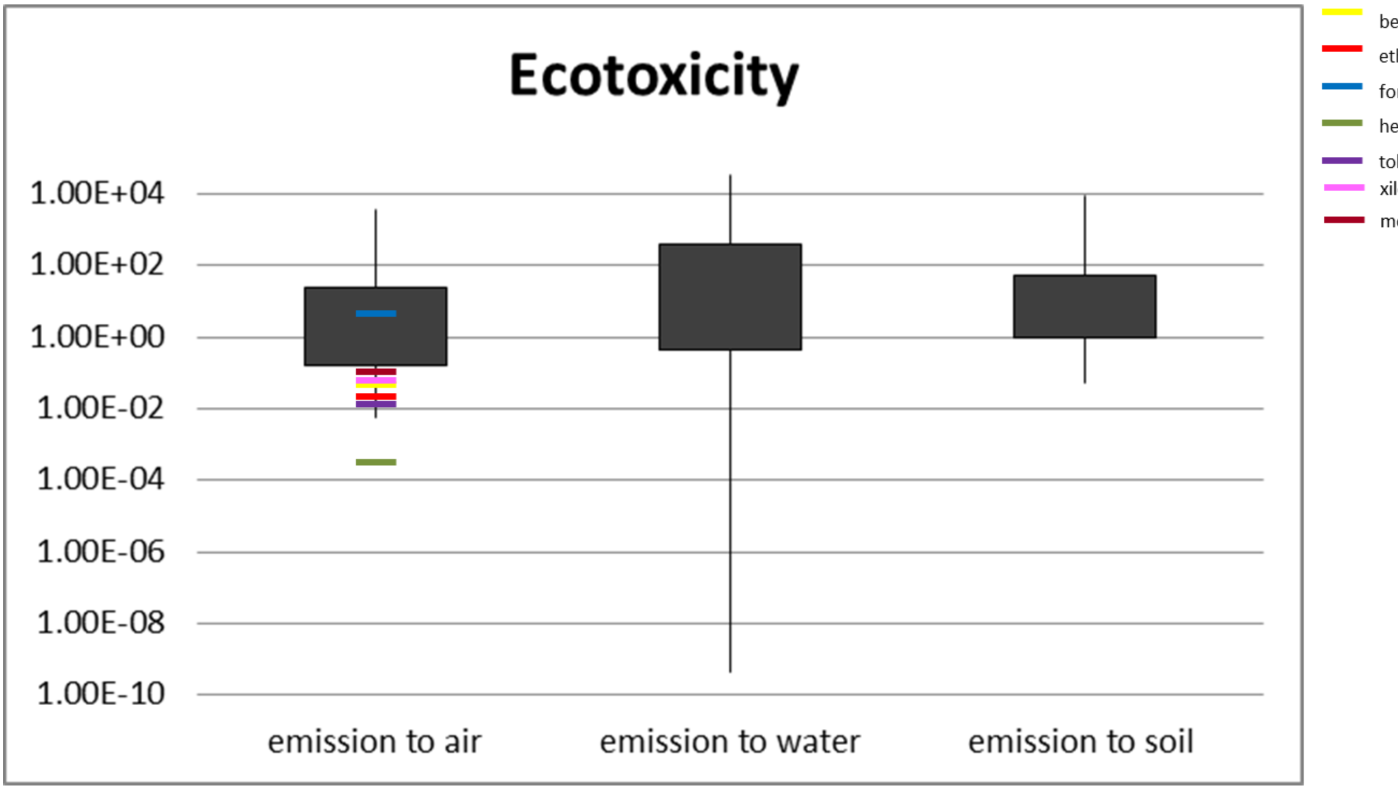

Figure 70: Comparative toxic unit for aquatic ecotoxicity calculated by USEtox for the chemicals reported by USEPA (2012), after an emission to air, water and soil. (5,25,75 and 95th percentiles)

3.4 Results for ecological and human health screening risk assessment for gaseous emissions associated with shale gas development.

The data used in this screening assessment were based on the State of Pennsylvania "Unconventional Natural Gas Emissions Inventory by Source Type." This data refers to emissions of CO, NOx, PM-10, PM-2.5, SOx, VOC, Benzene, Ethyl Benzene, Formaldehyde, n-Hexane, Toluene, Xylenes and 2,2,4-Trimethyl pentane from the following sources only: Stationary Engines; Heaters /Reboilers; Tanks / Vessels; Dehydrators; Pneumatic Pumps; Venting / Blowdowns; Drill Rigs; Completions / Workovers; and Fugitives. The data represent activities for the State of Pennsylvania as a whole in 2011, and refer to 3,935 active, unconventional natural gas wells and supporting infrastructure. We re-expressed the data as average, per-well emissions, meaning that the results are not specific to particular practices but rather to practices when averaged across all represented activities for unconventional natural gas extraction in Pennsylvania.

Customising USEtox with the specific area (183,152 ha) and population (1,687,076 units) in 2028 as modeled for the low impact scenario , we calculated the CTUe and CTUh due to an emission to air as per the emissions per well reported in Table 21 (i.e. average, per well emissions in Pennsylvania in 2011). Three emission scenarios were considered, which provide proxies for proximity of human populations to the emissions source. Emissions to "non-urban air" is a proxy for emissions from a well that is distant from human populations. Emissions to "urban air, close to ground" is a proxy for emissions from a well that is close to human populations. Emissions to "air, unspecified" is a proxy for a situation where proximity of human populations to the emission source is unknown. The results, reported in Figure 71, highlight that, under these different emission scenarios (i.e. emissions to air unspecified, to non-urban air, from high stack, or to urban air at ground level) the highest potential human toxicity impacts occur when human populations are closest to the emissions source in almost all cases (by, at most, one order of magnitude difference). The comparative toxic units multiplied by the emissions span over several orders of magnitude amongst the different chemicals considered.

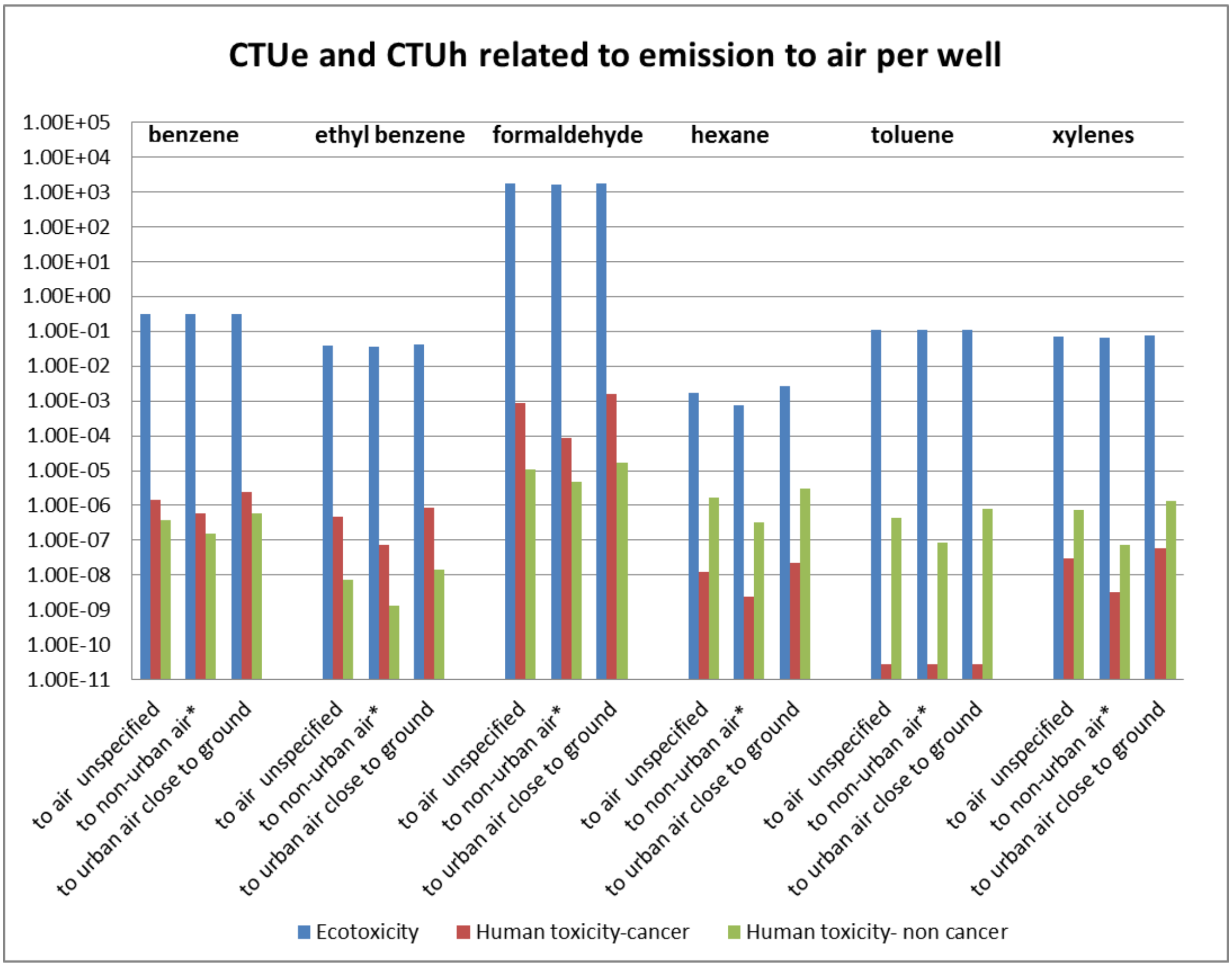

Figure 71: Comparative toxic unit for freshwater ecotoxicity and human toxicity cancer and non cancer due to the emission occurring in each well. *or from high stacks

It is essential to highlight that this analysis is intended for illustrative purposes only. The exercise points towards the kinds and average amounts (per active well) of a subset of emissions that might be reasonably anticipated for shale gas development activities, based on reported data for a single shale gas producing region in the United States, and screening-level toxicity impact potentials. This is not to be considered a comprehensive assessment of potential emissions to air and associated toxicological impacts, but rather a preliminary step only towards describing potential emission sources, levels and effects.

4. QUALITATIVE DISCUSSION OF NECESSARY CONSIDERATIONS FOR AIR QUALITY IMPACT ASSESSMENT

The following discussion is applicable to all unconventional gas development: coal bed, tight sandstone and shale. Potential differences in air quality impacts between development activities for these different categories of unconventional gas relate to the nature of the deposit itself and the techniques that may be applied, for example:

1. Coal bed methane deposits are shallower and require less drilling.
2. The composition of produced gas prior to dehydration will be different and this is a major driver of emission composition and thereby impacts.
3. Gas composition is driven by the basin considered and thus the type of substrate.

The first stage of an air quality impact assessment is determining the amount of pollution emitted from the specified economic activity. Emission inventory calculations often provide the foundational data. Depending upon the ultimate purpose or impact considered, a boundary will set the context, which may be legal or geographic. Other information needs, including existing or supplemental monitoring data, have to be determined on a case-by-case basis. The contribution of the activity considered should also be placed in context with other emissions. Then a specified impact assessment can be performed, examples include: population exposure to toxic air pollutants and prediction of ozone attainment with air quality limit values.

4.1 Estimating air pollutant emissions from unconventional natural gas extraction in Europe

The definition of the emission amounts requires an assessment of the contributing emission sources, more specifically the rate and time duration of emission for a given process for specified pollutants to be considered. Emission inventory databases allow for the derivation of predicted emissions. For actual developments these are formed from calculations that are derived from reported information. For predicted developments scenarios must be developed with key information estimated. For predictive estimation the selection of appropriate surrogate information is essential. The procedure is detailed in Annex I and is outlined below.

4.1.1 Emission inventory procedures for estimating emissions from unconventional natural gas extraction

Emission inventories are the basis of U.S. assessments of pollutant inputs at the national and state level. The U.S. EPA has created an emission inventory specifically designed for estimating nonpoint unconventional oil and gas emissions as a response to underestimation of these sources within the U.S. National Emission Inventory; and also as a systematic consolidation of regionally based initiatives (EPA, 2013). Work performed by the Texas Commission on Environmental Quality (TCEQ), the Western Regional Air Partnership (WRAP) and Central States Air Resources Agencies (CenSARA) provided the foundation for the "U.S. Emission Estimation Tool".

A typical development scenario that outlines potential emissions for the various stages and processes required for the production of unconventional oil and gas resources is shown in Annex I. These upstream operations are within the broader infrastructure of the oil and natural gas supply chain. Emissions from the distribution and supply chain are often not considered with upstream operations.

Wide ranges of potential development scenarios are evident in the U.S. The type of development is set by the geological formation. Other location driven factors also influence the balance of emissions. Important air emission processes are outlined and described in Annex I. Many important emission processes are common. This commonality enables the possibility of comparative emission assessment through the use of emission factors embedded within an emission inventory. Development scenarios may include the influence of emission control as well as other numerous factors that influence emissions; including but no limited to the number of wells to be drilled and the pace of the proposed development.

The U.S. inventory tool provides emission estimates for the nitrogen oxides (NO_x), volatile organic compounds (VOC), particulate matter (PM), carbon monoxide (CO), sulfur dioxide (SO_2), hazardous air pollutants (HAP), hydrogen sulfide (H_2S), methane

(CH_4), and select greenhouse gases (GHG) from upstream oil and gas production activities. The following specific source categories are included in the inventory:

- Artificial Lift Engines
- Wellhead Compressor Engines
- Lateral Compressor Engines
- Drilling Rigs
- Condensate Tanks
- Hydraulic Fracturing Pumps
- Well Completion Venting
- Liquids Unloading
- Associated Gas Venting
- Dehydrators
- Pneumatic Devices
- Heaters
- Crude Oil Tanks
- Produced Water Tanks
- Gas-Actuated Pneumatic Pumps
- Fugitive Emissions
- Mud Degassing
- Hydrocarbon Liquids Loading
- Flaring (when used to control emissions from the unit processes listed above)

These are the most significant categories for which there exists suitable information. Some sources are not included due to limited data availability, including construction equipment, work-over equipment and associated mobile sources. The contributing sources can be broadly characterized as; (i) combustion from engines excluding those from mobile sources (ii) venting or (iii) fugitive. The issue of including or excluding mobile emissions from calculation of development emissions is due to the difficulty of assessing mobile emissions, as there is no set protocol for reporting these emissions.

Emissions from the listed categories are calculated by combining activity inputs, basin factors and emission factors. While consistency of data sources is important the best quality data input is specific to a given geographic basin. The following specific activity parameters are needed to estimate emissions:

- Oil Produced
- Natural Gas Produced
- Condensate Produced
- Casinghead Gas Produced
- Oil Well Counts
- Natural Gas Well Counts
- Oil Well Completions
- Natural Gas Well Completions
- Produced Water at Oil Wells
- Produced Water at Gas Wells
- Spud Counts
- Feet Drilled

With reliable information for the parameters noted above calculations may be performed as a first step for the European situation. There are a number of issues associated with the application of U.S. EPA emission factors. For example, how representative they are for the European situation? Emission factors are applied as set numbers. The use of a distribution function, representing the uncertainty of these emission factors, rather than a fixed number may better reflect reality in the field. The design limitations of emission inventories and in particular the uncertainties of using emission factors are noted in Annex I. A figure and tables showing the relative distribution of emission sources for unconventional gas development in U.S. states are given in Annex 1.

4.2 Air quality concerns related to emissions from unconventional natural gas extraction

With the rapid development of unconventional gas resources air quality concerns have emerged. The U.S. process driven emission estimation tool was developed to assist the large number of states experiencing rapid development. This tool, the culmination of a decade of efforts from a variety of agencies, is however only the first part of more extensive air quality impact assessments.

Emission factor validation is becoming more important given the reliance upon emission inventories as a regulatory management approach. The importance of accurate input data is critical. However even the best emission inventory is a tool and may not reflect actual emissions. Air quality assessment approaches that use air quality monitoring techniques are also necessary. This is important given the range of air quality issues as noted below:

Regulated pollutants

- Ozone, O_3 (VOC + NO_x + sunlight)
- Nitrogen dioxide (NO_2)
- Particulate matter (PM10 ,PM2.5)
- Benzene
- Carbon monoxide (CO)
- Sulphur dioxide (SO2)
- Benzo[a]Pyrene (B[a]P)

Hazardous air pollutants (Air toxics)

- BTEX (benzene, toluene, ethylbenzene and xylene isomers)
- Formaldehyde
- Heavy metals
- Others including certain VOC (e.g.C2-C6 HC), polyaromatic hydrocarbons (PAH) or nitro and oxy-PAH.

Climate forcing pollutants

- CH_4

- CO_2
- Black carbon
- Ozone

Such assessments, while potentially focussed on a selected issue, are important, as emission inventories are likely to be incompatible with reliable exposure estimates derived from air quality measurement campaigns. Regulatory monitoring remains the primary basis of evaluation related to criteria air pollutants. The importance of measurements to better define both the magnitude of emissions is also important for air quality impact assessment work. Health impact assessments may also be performed depending upon predicted ambient concentrations of pollutants with established human health impacts.

4.3 Recommendations for air quality impact assessment for unconventional natural gas extraction

Emission rates from unconventional development remain uncertain, in particular for completion activities and from liquid product handling. A program of work that aims to reduce this uncertainty is essential. By assessing the pollutant fluxes an analysis of the uncertainty of existing bottom up emissions inventory calculations can be performed. Decision-making should rely on the best possible scientific information. It is important to build upon existing knowledge and develop a transparent approach for reducing uncertainty. An approach that uses knowledge already gained from the U.S. combined with European specific supplemental work will provide a cost effective assessment of potential costs and benefits to air quality.

Understanding emission rates from oil and gas sources has a strong connection to on-going international, national and local concerns regarding the environmental impacts of new unconventional developments. The following recommendations are given:

- Perform an evaluation of the recently published EPA national emissions estimation tool developed for the oil and gas sector. Determine the applicability of estimates to emerging developments in the EU.

- Develop scenarios and emission estimates applicable to the European situation that rely upon key input parameters at the gas-basin scale. Consider a program of emission rate validation using field monitoring techniques.

- Perform an evaluation of the current air quality network design to determine the applicability of the established sites for determining air quality impacts.

- Perform pre-exploration and development air quality monitoring for selected areas proposed for exploitation.

- Prepare targeted air quality surveys to assess actual impacts from development activities. Perform pilot projects, by means of remote or screening techniques, to ensure the applicability of proposed monitoring approaches.

- If applicable undertake health impact assessments in populated development areas.

CONCLUSIONS AND LIMITATIONS

Land Use

The modelled high-, average-, and low-impact scenarios vary substantially in terms of both projected land consumption and allocation patterns of the well-pads. The extent to which shale gas development might actually result in landscape fragmentation and conflicts with other land users is hence dependent on the anticipated scale of shale gas development in specific geographical contexts.

The spatial distribution of the exploitation sites is heavily dependent on the density parameter, implemented as a minimum distance between well pads. The effect of this parameter is emphasized by the specificities of the landscape overlaying the shale plays in the two countries considered. Highly complex, multi-use landscapes imply the presence of numerous barriers to drilling activities.

In order to assess overall potential impact in terms of land take (i.e. implying sealing of land which was not already artificial) for shale gas development activities, a comparison can be made with total land take due to industrial activities as a whole within each country. Under the Average Impact Scenario, the land used for shale gas development could represent a significant percentage of overall land take within the shale play. The land taken up for shale gas extraction as a percentage of the total land converted to industrial purposes within the whole country in the period 2006 - 2028 is nearly 2% in both Poland and Germany. These values range from 2 – 4% for the low versus high impact scenarios respectively, in both countries.

The population living in the vicinity and, thus, potentially exposed show a common pattern between Poland and Germany, depending on the distance from the exploitation site: under the High Impact Scenario more people are living at short distances from the well pads than under the Low Impact Scenario. Vice versa, between 2.2 km and 5 km distance in Poland and between 2.6 km and 5 km in Germany, under the Low Impact Scenario more people can be found living in the vicinity of the well pads. Over the longer distances, the Scenarios diverge more sharply in Germany than in Poland where, in fact, the differences keep almost constant. Due to the densely populated landscapes in the two simulated countries, different technological scenarios may lead to very different spatial distributions of the exploitation sites and, as a consequence, different figures of population potentially exposed.

Water Use

The high-, average-, and low-impact scenarios modeled vary greatly in terms of projected water withdrawals and consumption. The modeled water use for shale gas development accounts for up to 1% of total water use for all sectors within the shale plays in Poland, and up to 0.7% in Germany, under the high-impact scenario. For Poland we calculate increases of WEIabs (abstracted water as a fraction of available surface water) and WEIcns (consumed water as a fraction of available surface water) of 7.8% and 1.2% for the average scenario compared to the baseline (versus 7.4% and 1.2% for the low impact scenario and 8% and 1.5% for the high impact scenario). The difference in WEIcns between the high and low scenarios as compared to the baseline run is up to 0.4%. For Germany calculate increases of the WEIabs and WEIcns of 3.1% and 5% for the average scenario compared to the baseline (versus 3.0% and 0.5% for the low impact scenario and 5% and 0.5% for the high impact scenario). Although this is a seemingly small, marginal demand for the regions considered as a whole, we also observed that water demand may be significant locally since WEI values vary considerably across the shale play areas. On this basis, a reasonable conclusion is that implementation of best-practice, water-efficient extraction technologies (for example, optimizing recycling of flowback water), sensitivity to context-specific water availabilities, and attention to both the scale and rate of potential developments may be important.It should be noted that, as with the assumptions made to determine the scenario in terms of land use, the actual situation in terms of water use may be very different in Europe as compared to that in the United States. Indeed, the often-repeated assertion that European shale plays tend to be deeper and more complex suggests that water demands may also be higher.

In calculating the Water Exploitation Index (WEI), we assumed that additional water withdrawals for shale gas extraction would be from fresh surface or near-surface water, and therefore competing directly with other anthropogenic uses. The effect of using deeper groundwater sources, or brackish water should be considered when more data is available, especially since the repercussions on environmental water quality may be significant.

The proximity of modeled well pads to groundwater resources was also assessed for both countries. For Poland, the percentage of well pads overlying aquifers in the final year of simulation ranges from 17 to 29%. For Germany the number of well pads falling within each recharge class was calculated. The majority of well pads are located where recharge is greatest since water availability was a major factor taken into account when calculating the suitability maps. This may have important implications for water quality in the event of operational or accidental release of chemicals or flowback water during fracturing operations and subsequent flowback water storage/treatment.

Ecological and Human Health Risks Associated with Potential Emissions of Fracturing Chemicals

Due to the wide variety of chemicals potentially used for hydraulic fracturing of shale formations, the heterogeneity of their physico-chemical properties, and associated toxicological concerns, a more detailed human and ecological risk assessment is recommended. The screening-level evaluation presented here has highlighted that several chemicals may pose ecosystem and human health risks. Impacts may vary significantly according to spatial and temporal aspects and site-specific contexts, therefore evaluation should be, to the extent possible, site-specific.

It is also important to note that this analysis has focused on injected chemicals only, whereas formation chemicals may also pose environmental and human health concerns. Formation chemicals may include heavy metals, some of which are extremely toxic, as well as salts and radionuclides.

This screening assessment, along with a review of existing studies, supports the following recommendations (most of which are complementary to those provided by Colborn et al. 2011):

- Detailed reporting of chemicals used and quantities employed over time. Specification of the complete formulation of each product, including name, CAS number and amount of every chemical constituent should be required
- Elucidation of the role of REACH Regulation implementation in the systematic accounting of chemicals used in shale gas exploitation and their related physico-chemical and toxicological properties
- Identification of potential mixtures of chemicals that may occur in the event of operational or accidental releases.
- Records keeping for each drilling and fracking operation, listing the total volume of fluid injected, the amount of each product used, the depth at which the products were introduced, and the volume of fluid recovered
- Disclosure of the geology/hydrogeology of the area
- Life cycle assessment of shale gas exploitation, from shale play preparation to play closure and mid-term/long-term impacts.
- The physico-chemical properties and related potential fat of the chemicals that are used suggest the need for systematically accounting for impacts at different scales: local, regional and global
- Climatic characterization of the site (monthly temperature, rain fall, etc) that may influence the fate of the chemicals (e.g. high temperature implying higher volatilization, etc)

Ecological and Human Health Risks Associated with Gaseous Emissions from Shale Gas Development Activities

The chemicals potentially emitted via operational or accidental release as a result of shale gas development activities are:

(i) heterogeneous

(ii) characterized by environmental fate pathways that could lead to pollution of water, air and soil

(iii) in many cases highly hydrophobic, with significant potential for bio-concentration and biomagnification in the trophic chain (ultimately affecting human health , e.g. by ingestion)

Moreover, the subset of chemical emitted in air, derived from data for unconventional gas activities, includes substances that are well known for their potential risk for human health. Our screening-level evaluation of ecosystem and human health risks potentially associated with gaseous emissions from shale gas development activities therefore similarly suggests the need for more comprehensive studies and simulations of context-specific risks

Limitations and Research Needs

It should be noted that our reliance on US data as a basis for defining our technology scenarios may reduce the predictive value of the technology scenarios we employ. Also important to consider is that scale of shale gas development activities will likely increase at an accelerating rate over time as experience is gained and infrastructure developed. In the context of the current analysis the assumed maximum annual rate is only reached in the final year of the interval considered (2013-2028). Further modeling that takes into account a longer time horizon is desirable to assess the extent to which sustained, high levels of development may impact on land and water use considerations.

With respect to modeling land use, an important limitation of this study is the availability of data on the presence of exploitable resources: above all, the study would benefit greatly from the delineation of the most interesting shale gas basins.

Concerning specific policies regulating extraction activities, the best available information has been used: e.g. set-back of at least 50 m (in Poland) (based on a personal communication from the Polish Ministry of Environment, although the minimum considered distance in our models is actually 100 m due to model resolution constraints) and 200 m (in Germany) from places of human habitation, as well as (assumed) disallowance of developments in legally protected natural sites. Nevertheless, it could be envisaged to define *ad hoc* scenarios whereby specific policy configurations are implemented, as defined for the purpose of decision support.

A further important remark should be made regarding the weighting criteria adopted in the definition of the suitability index. The implemented configuration reflects the best information currently available: nevertheless, a sensitivity analysis could be beneficial for validating the weighting criteria. Moreover, the use of data specifically collected for the European context could reinforce the approach.

Another important limitation is the availability of data on water withdrawal and consumption for use in shale gas extraction. As such we have used estimated average values, but this study would benefit greatly from more detailed case-specific data.

Also of note related to the calculation of the Water Exploitation Index is that deeper groundwater sources are not taken into account when calculating the water availability within a region. This means that the absolute WEI values calculated may significantly over-estimate the actual exploitation. For the time being, however, we have insufficient information about the use of groundwater sources in extracting shale gas. This artifact is, however, mitigated by evaluating relative (i.e. both scenarios compared to the baseline, or the high scenario as compared to the low) as opposed to solely absolute impacts specifically relating to the extraction of shale gas.

Considering the outcomes of this study, it would be advisable to focus on a smaller region or case study where there is sufficient data available to minimize the uncertainties of the modeling exercise. This would be especially useful considering that the impacts of shale gas exploitation are likely to be much more significant, and easier to assess on a local scale.

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ANNEX I

1. GENERAL US FRAMEWORK FOR CONSIDERING UNCONVENTIONAL OIL AND GAS DEVELOPMENT AIR QUALITY IMPACTS.

2. RELEVANCE OF THE U.S. AIR QUALITY EXPERIENCE OF SHALE GAS EXPLORATION TO EUROPE.

3. OVERVIEW OF CURRENT STATUS AND CONTEXT OF U.S. AIR QUALITY ASSESSMENTS OF UNCONVENTIONAL GAS DEVELOPMENT.

4. EMISSION ESTIMATION USING INVENTORIES AND ESTIMATION TOOLS INCLUDING A BRIEF SUMMARY OF EMISSION FACTORS AND PROCEDURES USED TO GENERATE EMISSION INVENTORY ESTIMATES.

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1. GENERAL US FRAMEWORK FOR CONSIDERING UNCONVENTIONAL OIL AND GAS DEVELOPMENT AIR QUALITY IMPACTS

In the U.S. there is a complex interwoven set of relationships between the public, regulators and developers with respect to economic developments activities. Oversight of particular oil and gas developments in the US are initially set by land ownership. Development may occur on private, County, State or Federal land. The scale of a potential development may range from a few to many thousands of wells. The situation may be remote or urban. Regardless of land ownership developers must adhere to health and safety requirements and hold the necessary permits and permissions for infrastructure development and equipment operation.

A number of federal laws establish requirements for oil and gas leasing and development on federal lands. The Mining and Minerals Policy Act of 1970 established the policy of encouraging private enterprise while mitigating adverse environmental impacts. The Federal Land Policy and Management Act of 1976 defined the Bureau of Land Management (BLM) as the primary federal agency with responsibilities toward oil and gas development. The BLM within the Department of the Interior, have issued regulations relevant to oil and gas development under the authorities of these laws; portions of these regulations establish requirements related to environmental protection. A new set of regulations from the BLM is due to published in the coming months.

On April 17th 2012, the U.S. EPA issued amendments to air regulations for the oil and gas industry. The Clean Air Act requires EPA to develop new source performance standards (NSPS) for industrial categories that cause, or significantly contribute to, air pollution that may endanger public health or welfare (EPA 2012a). In addition National Emission Standards for Hazardous Air Pollutants (NESHAP) must be reviewed on a regular basis. This mandated New Source Review (NSR) of the oil and gas industry is a legal requirement established in parts C and D of Title I of the Clean Air Act. The purpose of the NSR program is to protect public health and welfare, as well as national parks and wilderness areas. Specifically, its purpose is to ensure that (1) air quality does not worsen where the air is currently unhealthy to breathe, and (2) air quality is not significantly degraded where the air is currently clean. These New Rules and Regulations are set for full implementation in 2015. While previous rules focused on larger point sources the 2012 revision regulates a number of upstream processes not addressed previously, most notably well completions for NSPS and dehydration units for NESHAP.

The new regulations propose inclusion of the following sectors: (a) well completions and re-completions; (b) compressors; (c) pneumatic controllers and (d) storage containers. The rule requires "reduced emissions completions" (REC), also termed green completions, or flaring for most fractured wells. A significance difference for the European perspective is the regulation of benzene in ambient air. Developments with a relatively high non-methane hydrocarbon content have been associated with elevated ambient concentrations of benzene. The 2012 EPA amendments included the first federal air standards for hydraulically fractured natural gas wells. Green completions are now required to reduce emissions from well completion flow-back processes that typically release a high volume of methane, VOC, and air toxics. The VOC emission reductions from wells, combined with reductions from storage tanks and other equipment, are expected to help reduce ground-level ozone in areas where oil and gas production occurs. Improved control technologies are expected to reduce exposures to hazardous air pollutants (HAP) and reduce methane emissions from new and modified wells. The U.S. EPA has projected economic and environmental benefits, including reduced climate change impacts. VOC and HAP reductions are expected to improve outdoor air quality, protect against cancer risk and reduce health effects associated with exposure to ozone (EPA 2012a).

For actions on Federal land the National Environmental policy Act requires an environmental assessment. Unless this initial review produces a finding of no significant impact then an Environmental Impact Assessment (EIS) is undertaken. An EIS will consider the cultural, social, economic and environmental consequences of a number of alternative scenarios. While taking into consideration input from all stakeholders a preferred alternative is selected that defines the characteristics of the given development. An EIS will consider a wide range of environmental factors that while set by location will consider potential regional impacts.

For EIS's related to oil and gas development air quality is at the forefront of decision-making. Potential impacts are based upon the modeled impact of predicted emissions upon air quality. Acceptable air quality is defined by the Clean Air Act's National Ambient Air Quality Standards (NAAQS). The EPA gives oversight of the Clean Air Act. Of particular concern with respect to the oil and gas industry are primary emissions that lead to the production of the criteria pollutants ozone and nitrogen dioxide. Given the secondary nature of these pollutants precursor compounds are considered both in terms of emissions and modeled impacts. Oxides of nitrogen and volatile organic compounds (VOC) have received considerable attention.

Monitoring of air quality to determine compliance with the NAAQS is largely the responsibility of the given State's Department of Environmental Quality (DEQ). If an area is defined as out of compliance then a State implementation Plan (SIP) must be devised that will lead to improved air quality and movement toward compliance. With non-compliance there is a requirement of more stringent permitting together with increased scrutiny upon emission inventory data.

It is also the responsibility of the State DEQ to compile and report a statewide air pollutant emission inventory that is created according to EPA guidelines, to the U.S. EPA. The inventory is set at an annual time scale with reporting requirements for particular set years, namely 2008, 2011 and 2014. This is to ensure consistency between States for the production of national scale air quality assessments. The basic quality is dependent upon data input. This is often dependent upon reporting or retrieval of information from developers and other agencies that hold key input data. At the local State level an "oil and gas commission" is often responsible for the regulation of oil and gas development and production pursuant to the Oil and Gas Act, the Coal and Gas Resource Coordination Act, and the Oil and Gas Conservation Law. At the state level there will also be an inspection programs and the potential for statewide regulation and standards. These agencies will hold information related to well location and status.

Air quality related to oil and gas development is often considered within the overarching framework of NEPA and the Clean Air Act. If applicable, environmental impact statements predict potential impacts as part of the NEPA process. While modeling based upon emissions projections is a requirement for this planning process, air quality monitoring is not. Air national air monitoring site coverage broadly reflects population density and often does not match development activity.

2. RELEVANCE OF THE U.S. AIR QUALITY EXPERIENCE OF SHALE GAS EXPLORATION TO EUROPE

At the end of 2012 the European Commission published three shale gas studies. The first (EU 2012a) report studies the potential risks for the environment and human health arising from hydrocarbons operations involving hydraulic fracturing in Europe. The second (EU 2012b) entitled “Climate Impact of Potential Shale Gas Production in the EU” reported that if impacts are well managed, climate impacts may be less than those resulting from the use of imported gas from outside the EU. The third, EU (2012c) considered the influence of unconventional supplies to global market prices. These studies represent a significant step forward in the development of regulatory policy in relation to shale gas in Europe. However the experience in the U.S. has seen policy catching up with development. European decision makers have an opportunity to develop clear guidelines in advance of the widespread development of shale gas. Of particular relevance is the control of emissions from hydraulic fracturing within the US EPA NSR. Some U.S. States, for example Wyoming, have already instigated similar control measures as a result of the emergence of air quality problems related to unconventional tight sandstone developments. While a variety of regulations related to the management of air quality have seen revisions over recent years in the U.S., most notably the NAAQS for ozone, there has been strong resistance from developers to any additional regulation of unconventional gas development (ARI, 2012).

The EU experience of unconventional gas development is many years behind that in the U.S. Preliminary indications are that extensive shale gas resources are present in Europe. So far only Poland and the UK have performed exploratory shale gas extraction. EU (2012a) note that half of all EU Member States are interested in developing shale gas resources, including Poland, Germany, Netherlands, UK, Spain, Romania, Lithuania and Denmark. However, in response to concerns regarding the risks associated with hydraulic fracturing several European Member States have, or are considering the possibility of restricting the use of hydraulic fracturing. The appropriateness of current legislation and the possibility of specific national requirements for hydraulic fracturing is now under consideration. As such there is a growing need for a clear, predictable and coherent approach to unconventional gas developments (EU, 2012a).

It has already been postulated that information and reporting protocols from regulators in the U.S. could be developed for application in the EU. IPCC Guidelines do not provide emission estimation methodology details or emission factors that are applicable to calculate emissions from sources specific to shale gas exploration and production. It has also been noted that there is a need for specific information to understand potential emission in the European context (EU, 2012b).

The goal of this discussion is to outline the emerging U.S. approach for determining air quality impacts from unconventional shale gas development. This outline is centered upon emission inventory developments while noting recent monitoring based assessments and health impact assessments. With reference to ongoing investigations recommendations are made for applying the U.S. experience to Europe. Thus lessons learned in the U.S. can be applied rather than repeated, in order to provide a bridge for better transatlantic communication on common air quality issues.

3. OVERVIEW OF CURRENT STATUS AND CONTEXT OF U.S. AIR QUALITY ASSESSMENTS OF UNCONVENTIONAL GAS DEVELOPMENT

Oil and natural gas production and processing operations account for nearly 40 percent of all U.S. methane emissions (EPA 2012a). The oil and gas industry is the nation's single largest methane source (EPA 2012a). U.S. natural gas production is increasing while confidence in the accuracy of emission estimates is decreasing due to uncertainties associated with unconventional development of tight sand, shale gas and coal bed methane. Unconventional natural gas production in the U.S. has increased dramatically during the period 2000-2012 (U.S. Energy Information Administration (EIA) 2012). Proponents portray natural gas as a clean-burning, bridge fuel that can reduce greenhouse gas impacts (Cathless 2012). These claims are based upon emission inventory estimates that have come under scrutiny by researchers due to the relatively high levels of uncertainty associated with them (Pétron et al. 2012). Improved accuracy of emission estimates is critical for modeling of impacts. The reporting of greenhouse gases is now a mandatory requirement for the U.S. oil and natural gas sector (EPA 2010).

As conventional gas reserves in the U.S. have declined, unconventional gas production from shale and tight sands gas has increased. The EIA estimates an increase in shale gas production from 5.0 trillion cubic feet per year in 2010 to 13.6 trillion cubic feet per year in 2035. Shale gas production is expected to grow from 23 percent to 49 percent of total U.S. gas production during this period. Tight sands gas production is expected to remain stable at 6.1 trillion cubic feet per year. Over the next 25 years, power generation from natural gas is expected to grow by 25% as coal-fired plants are retired (EIA 2011 and EIA 2012).

The observed increases in unconventional natural gas production are largely due to refinements in hydraulic fracturing and directional drilling technology. Although hydraulic fracturing techniques have been available since the 1950s, it wasn't until the 2000s that the technique was considered economically feasible for large-scale production (EIA 2011). Directional drilling allows the control required to seek out pockets of gas within the geologic formation, particularly useful in tight sand and shale gas fields. This technology allows development of 48 or more wells per drilling pad. Combined, these technological advances have opened up vast natural gas reserves that producers previously considered economically impractical (Wood et al. 2011).

As drilling has encroached on urban areas more attention has been given to the environmental impacts of hydraulic fracturing. Although water quality has received the most attention from government agencies, environmental and industrial groups, interest in the effects of oil and gas development on air quality has recently emerged as a focal issue. Concern has centered upon the impact of exposure to emissions of hazardous air pollutants from drilling, completion and production activities (EPA 2012a; U.S. Department of Energy (DOE) 2011; U.S. Government Accountability Office (GAO) 2012).

A recent Federal review (GAO 2012), considered the environmental and health implications of shale gas and risks associated air quality impacts of emissions from engine exhausts, flaring, venting, storage and faulty equipment. Cumulative impacts upon air quality could not be determined because the extent and severity of risks vary significantly within, and between, developments due to location and process driven factors.

Regardless of regulatory measures, natural gas production is expected to rise. A key argument is that natural gas use allows for continued use of fossil fuels while reducing greenhouse gas emissions and lowering climate impacts from energy production. Based on these assumptions, it has been posited that the unconventional gas reserves will reduce greenhouse gas emissions from fossil fuel usage during the transition towards a low carbon economy (Wood et al. 2011). However, a modeling analysis by Hayhoe et al. (2002) suggests that a coal to gas transition would not significantly mitigate climate-warming effects until up to 80 years out. Wigley (2011) revisited the analysis of Hayhoe et al. (2002) and found that 220-year modeled scenarios of substitution of gas for coal resulted in increased climate warming based upon a 2.5 percent methane leakage rate.

Howarth et al. 2011 reported that methane emissions levels from unconventional shale gas production have an estimated leakage (from drilling through delivery) of 3.6 to 7.9 percent of total production. Although this estimate has been described as “unreasonably large and misleading” (Cathless et al. 2012), it is generally accepted that larger emissions of VOC and methane are associated with unconventional natural gas development (Armendariz, 2009) and that there is a significant level of uncertainty associated with emissions inventories (NARSTO 2005; Miller 2011). Uncertainties are reported as substantial for unconventional natural gas production due to variability of regulatory constraints and changing technology (EPA 2011).

Given the reliance on bottom-up emission inventories for air quality management, regulators, oil and gas developers, and environmental organizations have started to collaborate to improve published emission factors and determine uncertainties. One recent campaign had mixed results indicating that advancing technology has not lowered emissions from compressors used for transmission of natural gas. They also note that protocols used for equipment measurements need improvement (Harrison et al. 2011). Because of the uncertainty associated with bottom-up emission inventories, there is a strong need for expanded refinement of top-down emissions inventory techniques. The North American private/public partnership known as NARSTO was formed in 1995 to consider air quality issues facing North America. NARSTO (2005) highlighted many of the shortcomings and uncertainties present in bottom-up emissions inventories. In order to improve the reliability of emissions estimates, the NARSTO Assessment recommended:

- Expanding the use of a variety of ambient concentration data to cross-check inventory estimates and provide quality-control options;
- Establishing a linkage with “real world” sources, including vehicle fleets, compared with idealized emission conditions;
- Expanding spatial and temporal data for mobile and area sources to improve emission models;
- Providing direct measurements of biogenic and fugitive emissions for incorporation into emission models;
- Providing a basis for determining whether long-term, estimated emission trends are consistent with ambient concentrations.

The increased scrutiny placed upon the oil and gas industry in the past five years has led to the application of a number of distinct but linked research and analysis approaches for understanding and quantifying the impact of oil and gas emissions upon air quality. These can be broadly defined as (i) emission inventory calculation based and (ii) air quality measurement based.

Detailed inventory analysis that started in mid 2000's have led to the production of a national emission inventory and estimation tool for upstream oil and gas operations, set for publication in June 2013. At the present time there are two primary emission inventories that reflect emissions from oil and gas production the National Emission Inventory (NEI) and the Inventory of U.S. Greenhouse Gas (GHG) Emissions and Sinks known as the GHG inventory. Inventory work has highlighted the large uncertainties of emissions from this sector as well as the opportunities for emission reduction. The wide diversity of gas-basin scale operations in the US are associated with a consequent emission profile difference, the significance of which is determined by the processes considered, in particular when combined with control measures. Some states have instigated strong controls while others have not. Clear economic and environmental benefits of improved control at the national scale are shown by the US EPA NSR regulations that are set to dramatically reduce emissions. It has been noted that these regulations, while predicted to be highly effective, could be further strengthened with proven technologies applied to future and existing operations (NRDC, 2012).

At the present time the divergent regulatory approach of State agencies leads to different emission control practices being applied to similar exploration activities. And the level of knowledge of operation also shows diversity based upon the strength of permitting and reporting requirements. Inventory analysis led to the realization that emission factors for certain processes may not be realistic, so efforts have been made to ensure that the best information is applied to derive appropriate emission factors (EPA Natural Gas STAR program). Developers have on a voluntary basis entered into collaborative endeavors with regulators at the Federal and State levels. These collaborations have both informed emission analysis and best practices for emission control.

Given the scale of natural gas operations emission factor assessment is likely to adopt more thorough surveying techniques with direct and indirect measurements, whether direct testing of emission sources or indirect measurement of emission plumes. The latter are now being developed as part of the establishment of the relatively new approach of mobile monitoring.

To address uncertainty related to emission factors the Environmental Defense Fund has formed a partnership between regulators, developers and academics to perform a thorough and transparent assessment of leakage rates. The culmination being an extensive field campaign planned for September 2013. The following sections outline a progressive level of assessment that is aimed at better defining the wide range of air quality impacts. Emission inventory assessments are moving toward a consistent framework for the U.S. as outlined in section 4. While modeling work remains dominant air quality measurement assessments are now recognized as both important validation tools of inventory data and as the approach to define actual impacts upon air quality (Thoma et al. 2012, Pétron et al. 2012). Health impact risk assessments are complicated by numerous factors but nevertheless are essential for understanding chronic and acute impacts of exposure to emissions from oil and gas development (McKenzie et al. 2012).

4. EMISSION ESTIMATION USING INVENTORIES AND ESTIMATION TOOLS INCLUDING A BRIEF SUMMARY OF EMISSION FACTORS AND PROCEDURES USED TO GENERATE EMISSION INVENTORY ESTIMATES.

The scale of estimated loss of natural gas is on an on-going public debate. For 2009 a methane loss rate of 2.4% was estimated for the oil and gas industry (EPA 2011). This amounts to nearly 40% of US methane emissions. Natural gas operations contribute nearly 90% of emissions from the sector. While the EPA has been compiling methane emissions for the US since 1990 the reporting requirements instigated by the Greenhouse Gas Inventory has shown significant uncertainty for estimates of emissions from the oil and gas sector, with a general theme of underestimation (NRDC, 2012). Despite this uncertainty the 2011 Greenhouse Gas Inventory reports a 168 Bcf reduction of methane emissions from a combination of the voluntary Natural Gas STAR program (77 percent), and mandatory regulations (23 percent). These reductions are set within a framework increasing estimates of emissions from the natural gas sector. Since 1990, the EPA has more than doubled its methane emission estimate for natural gas systems from 220 Bcf to 464 Bcf. Emissions from some sources may be much higher than actually reported. Greater understanding of emission sources has led to increases of predicted emissions. In general some emissions were underestimated as sources were not metered or tested accurately to determine realistic emission rates. Small sources that could be that cumulatively large were often not tested or reported. And some emissions were simply not accounted for. Such missing emissions may be due to oversight or the lack of a defined methodology for assessment. This is now the case for emissions from water treatment that is performed off site at facilities that are not defined as large point sources (Field et al., 2012).

4.1. OFFICE OF THE INSPECTOR GENERAL REVIEW

The U.S. Office of the Inspector General (OIG) published the most recent and relevant report for emissions from the oil and gas sector on February 20th 2013 (OIG 2013). The report entitled "EPA Needs to Improve Air Emissions Data for the Oil and Natural Gas Production Sector" highlights the importance of using appropriate information to inform decision-making. OIG (2013) sought to determine if current data was able to properly support regulation development, emission inventory production, enforcement actions, permitting decisions and risk assessments. This is critical due to the reliance of State and Federal agencies upon the use of emission factors for air quality assessments. OIG (2013) highlighted a number of critical information gaps. Most importantly EPA has limited directly measured emissions data for some of the most important production sources, including well completions and evaporative ponds. Furthermore, OIG (2013) noted that EPA does not have a comprehensive strategy for rectifying these data gaps. This is part due to not anticipating the growth of unconventional has development. Limited data can lead to uncertainty related to human health risks and inappropriate design of strategies for addressing pollution issues that require emission control. EPA uses the NEI to assess risks from air toxics. States use the NEI to inform their State Implementation Plans for compliance with NAAQS.

Air emissions data gaps are somewhat hidden by their use to calculate emission factors that are published in their own right in the compendium of Air Emission Factors referred to as AP-42. These are supposed to be representative of the quantity of a pollutant released with an activity associated with its release. Oil and gas emission factors from AP-42 and from the EPA Information Retrieval System (WebFIRE) were reviewed together with production data from the 2008 NEI. OIG (2013) noted that about half of EPA's oil and gas production emission factors are rated below average or unrated as they are based upon insufficient or low quality data. OIG (2013) identified 495 factors, however these related primarily to combustion engine or process heater sources. While emission factors are reported for methane for produced water tanks, well completions and pneumatic devices similar factors are absent for VOC and HAP. However if gas composition is known then calculated emissions of these pollutant classes can be made.

The lack of data for well completion and evaporative ponds for the 2012 NSPS and NESHAP rule development led to the use of GHG inventory data for methane to derive VOC estimates from completions. The lack of emissions data for fugitive emissions from evaporative ponds has led to a lack of regulation for this source. The absence of data for well completions, and other production sources, is due to the lack of suitable methods for direct measurements. Besides technical considerations onsite measurements have numerous difficulties related to access, safety and cost. Direct measurements require a measurement strategy that captures a representative sample for the target process. As such an understanding of the diurnal and longer-term variability of the process is needed. Furthermore some processes, including well completions, may only be practically measured using remote sensing and mobile monitoring techniques. OIG (2013) stated "more research is needed to develop additional methods for several oil and gas production processes". The deficiency of the 2008 NEI for well completions was noted during NSPS and NESHAP rule making. An additional 480,000 tons of VOC emissions were added to the estimated 21,000 tons. The 25 times increase of VOC completion emissions highlights the importance of good input data.

In response to the OIG (2006) reviewed that highlighted deficiencies in the development and management of emission factors, EPA developed an Electronic Reporting Tool (ERT) that acts as a data portal for data submission. This has facilitated the submission of source testing data from State agencies to the EPA. This information is needed for the development and improvement of emission factors. The quality of emission factors is dependent upon the use of realistic data. New data that adds to the data pool is also more likely to reflect current practices. Only since January 2012 have operators been subject to requirements to report source test data directly to EPA, initially through GHG reporting and now also through NSPS and NESHAP regulations.

EPA uses its National Emissions Inventory (NEI) to assess risks, track trends, and analyze envisioned regulatory controls. However, OIG (2013) noted that oil and gas production emissions data in the 2008 NEI are incomplete for a number of air pollutants with many states simply not reporting key data, leading to underestimates of oil and gas emissions. This hinders an accurate assessment of air quality impacts from oil and gas production activities. OIG (2013) recommended that EPA develops and implements a comprehensive strategy for improving air emissions data and emissions factors for the oil and gas production sector to ensure the NEI data for this industry sector are complete. EPA has concurred with this recommendation. The on-going development of a national emission estimation tool for this sector is designed to facilitate the improvement of its emission factors.

The NEI relies upon reporting by the each state of the U.S. The Air Emissions Reporting Requirements (AERR) rule requires that emissions of criteria pollutants and ozone precursors from various source categories be reported to the EPA. Point (large stationary), non-point or area (small stationary) and mobile sources categories are used. Well pad production activities are non point sources and OIG (2013) suspect that these sources are underreported as for the 2008 NEI as only 9 out of 35 states with oil and gas development reported this category. Nevertheless at the national scale non point sources accounted for 98% of all oil and gas VOC emissions for the 2008 NEI. Since the AERR rule does not require reporting of HAP, OIG (2013) also infers under stated HAP emissions for the 2008 NEI. OIG recommends a number of measures to improve the NEI. These include the development of default emission estimates for non-point sources, stricter reporting requirements and improved data collection for small non-point sources. The latter is perhaps the most critical but also the most difficult due to the overwhelming number of sources that are below permitting thresholds and/or are unregulated.

While critical limitations were identified a number of positive steps were recognized. The EPA's voluntary Natural Gas STAR program that partners with oil and gas companies has developed a wide range of best practices that have resulted in an estimated capture of 994 billion cubic feet of methane since the start of the program in 1993. The Greenhouse Gas (GHG) Reporting Rule is now providing data that is improving understanding of the location and magnitude of emissions from the petroleum and natural gas industry. This rule that entered into force in 2009 requires annual reporting of greenhouse gas emissions (EPA, 2010).

The incorporation of emission reporting requirements into NSPS and NESHA rules is improving data quality. EPA is also improving the handling of data within the NEI with an emission inventory system and has also been working toward the development of a national emission estimation tool for upstream emissions from the oil and gas sector.

EPA is conducting field studies to develop new methodologies based on remote techniques to measure fugitive and other emissions from well production activities, including evaporative ponds. Such technique enables offsite data collection. The development of a quantitative methodology suitable for regulatory reporting is critical for subsequent use as pseudo direct measurements, e.g. the instrument manufacturer Picarro already markets a commercial application designed to identify methane leakage in mobile monitoring.

Even if emission factors and calculated emission inventories are known to be of poor quality they are used by many states for permitting and other enforcement decisions. Given that inventory assessment remains the main regulatory tool EPA aim to improve data quality. The use of data that is highly questionable may be the only option as is the case for unconventional completions.

4.2 UNCONVENTIONAL COMPLETIONS

The largest change in methane emission estimates performed by the EPA has been in accounting for wellhead and well pad processing facilities emissions that were substantially underestimated (NRDC, 2012). These sources were not properly defined in studies that built the foundation of estimates. The 2010 Greenhouse Gas Inventory states that "natural gas well venting due to unconventional well completions and work-overs, as well as conventional gas well blow-downs to unload liquids have already been identified as sources for which Natural Gas STAR reported reductions are significantly larger than the estimated inventory emissions." (EPA 2010).

Historically, the US Greenhouse Gas Inventory was based on an emission factor of approximately 3,000 standard cubic feet (3 Mcf) per gas well drilled and completed (EPA 2010). Yet the EPA Natural Gas STAR program partner experience shows three cases where emission factors were thousands of times higher, as indicated by recovery from green completions; (i) 106 wells with 3,300 Mcf of gas recovered per well; (ii) 1,798 wells with 6,300 Mcf of gas recovered per well; (iii) 1,064 wells with 23,000 Mcf of gas recovered per well.

The example of completion emissions shows the importance of the accuracy of information used to derive emission estimations. Can information from one situation be applied to another? A similar process may have widely differing practices in a different location. So the development of an accurate emission factors is a multi-step process that requires the systematic application to particular situations. Revision and updating of emission factors is an iterative and continuous undertaking. This can lead to significant changes from year to year for emission estimations. Even with revisions to the O&G Reporting Rule the EPA continues to report substantial uncertainty in its overall greenhouse gas emission estimates in its ongoing work on the Greenhouse Gas Inventory (EPA 2011). In its 2011 Greenhouse Gas Inventory, the EPA used an average emission factor of 7,700 Mcf per well completions, more than doubling the amount of emissions expected from the increasing number of unconventional well completions (e.g. horizontal and shale gas wells). The US EPA did not include emissions from completions for tight gas wells in the 2011 Greenhouse Gas Inventory, which, as the EPA noted previously in its O&G Reporting Rule Technical Support Document, is a “significant underestimate” of total emissions (EPA, 2012a). This underestimation persists in the inventory for the state of Wyoming, in particular as the emissions are reported as zero by some developers. The EPA also reported zero emissions from well completions in the Northeast region, which is the location of extensive shale gas drilling and well completions in the Marcellus Shale (EPA, 2012a).

Emissions estimates will likely continue to evolve and improve as the EPA obtains improved information including that submitted under its mandatory reporting rule. As with past inventories, it is expected that both emissions factors and their application will continue to be updated. If past trends hold, these factors are likely to be revised upward, as a result of both better understanding of emissions associated with each process and the aggressive pace of drilling and development across the country. However, emissions estimates for individual sources may also be revised downward as the EPA obtains better information about the type and amount of control technology in use. Also the amount of time associated with given processes or activities can also be more accurately defined, for example the amount of time an engine actually operates. Revision of activity factors is part of the refinement and improvement of constructed inventory calculations. While consistency of emission estimation is important therein are two of the fundamental problems of understanding air quality impacts from emerging developments, timescale and reality. The timescale of inventory production may not reflect the pace of development in a given area, the emergence of air quality issues or the diversity of real world operations. An emission inventory is a construct that has value as a predictive tool but may not reflect actual emission and thereby measured air quality impacts. In the past five years the deficiencies of both emission inventories and associated air quality assessments whether through monitoring or modeling approaches has been noted (NARSTO, 2005).

4.3 THE DEVELOPMENT OF COMPREHENSIVE EMISSION INVENTORIES FOR UPSTREAM OIL AND GAS ACTIVITIES

Any emission inventory is a calculated construct that is an accountancy tool designed to be indicative of emissions. Once constructed, they offer the possibility of estimating current (past) and future (present) emissions for the area that they define. And depending upon the level of detail they can show the relative importance of different emission sources for target pollutants. They can also differentiate between different categories so that a given sector can be placed in context with other emission sources within the selected area. Emissions are usually quantified in one of three ways; namely (i) Direct measurement of sources, (ii)

Emission factor estimation, or (iii) Engineering calculations. Direct measurement requires measuring actual emissions in situ. Emission factors relate emission quantity to a given activity or process. Engineering calculation rely upon physical parameters for estimating emission rates. Emission factor estimation is the basis for emission inventory development. Emission factors are typically represents a long-term average for all facilities in a particular source category.

There are a number of fundamental questions that must be considered when developing and using an emission inventory, whether predictive or based upon actual conditions.

- What are the emission sources and how are they being differentiated?

The emission sources must be categorized in a manner that allows for differentiation. This is initially set by size and scale. Sources may be considered as mobile, point or area. Each is characterized in a manner that may broadly define the operation and emissions from the source.

- What is the relevant emission factor and how is the emission factor applied?

Identified emission sources are coupled with a factor that is critically dependent upon input data. For an engine input may be time of operation and loading. Other factors may rely upon flow rates together with additional considerations. The application may not consider a distribution function but more often relies upon a set value. The genesis of the value is critical.

However emission inventories are used by States to define actual emissions through reporting of key input parameters from developers. The accuracy or completeness of this as input data is a major concern. Also the development of an easy to use interface for reporting is critical. It is also clear that some emissions including site visits are not easily documented and as such are outside the scope of reporting requirements. So reporting will be set to enable inclusion of the most important emissions sources whether large or small.

- Is reporting requirement reflective of actual emission sources?

Is the application of information from reporting reflective of in field operations? There are a myriad of issues associated with the potential diversity of development and air pollutant emissions. This is essential as the basis for assessment whether through measurement or modeling.

An example of a state-wide emission inventory specifically designed for unconventional gas development is produced by the State of Wyoming for Sublette County. This county has experienced significant development unconventional tight sandstone development. This inventory has is designed to serve data needs related to attainment of NAAQS for ozone. Table 4.1 shows selected pollutant classes for the 2011 inventory. In addition an inventory is also developed that relates specifically to the months of February and March.

Table 4.1. - Sublette County Wyoming Emission Inventory for 2011

Sources	NO_x (TPY)	VOCs (TPY)	HAPs (TPY)
Stationary Engines	206	64	52
Heaters	735	40	14
Tanks	86	1317	33
Dehydration Units	430	3192	1455

Pneumatics	127	4462	196
Fugitives	0	3375	414
Venting & Blowdown	0	923	54
Drill Rigs	492	43	2
Completions	781	107	9
Truck Loading	0	232	0
Construction Mobile	99	11	1
Total	2955	13767	2230

Abridged from WDEQ (2013)

Table 4.1 shows that the relative importance of combustion and leakage sources between the reported pollutant classes. The following sections outline the broader issues associated with unconventional gas developments and then outline best practice development of an emission estimation tool.

4.3.1 OUTLINE OF A GENERAL SHALE GAS DEVELOPMENT SCENARIO THAT IDENTIFIES IMPORTANT EMISSION SOURCES.

For upstream operations air emissions from any unconventional shale gas development will follow the same basic pathway from inception to operation, namely exploration and production. Identified emissions will have a variety of time periods of operation and magnitudes of pollutant release. Emission rates are reflective of the associated processes that can be broadly characterized as either combustive or fugitive. Combustion emissions are associated with engines and flaring. Fugitive emissions are associated with the production and handling of natural gas at the well-head and through well pad processing and handling equipment.

Exploration becomes important for air quality upon the set-up of infrastructure including well pad preparation. Such activities are related to the operation of heavy equipment that may be considered as mobile sources. The most important exploration emissions are well drilling and completion. Exploration emissions at a given site have a finite operation period, that while dependent upon a number of factors, are usually within the time-frame of weeks to months. Exploration can be separated into:

1. Infrastructure set-up.
2. Well drilling and completion activities.

Production emission encompass all the activities required at the well pad to move natural gas production at the well head to the on site transmission line for natural gas and storage tanks for produced water and condensate. In some developments liquids gathering facilities are established that remove the requirement of well pad tank storage of produced liquids. Upon completion a well is active and is designated as a producing well. Production emissions are long term within the time frame from years to decades. The magnitude of emissions will be dependent upon a number of factors set by production rate, location and management approach. Production can be separated into:

1. On site product handling
2. On site maintenance including work-overs.

Once an unconventional well is in production the supplied gas will become part of the wider oil and natural gas infrastructure. As such downstream operations are analogous to those for conventional production. The only difference is the necessity for hydraulic fracturing and the emissions associated with this process. Consideration of downstream operations may be necessary if an impact assessment of the development is required within a given basin, air-shed or otherwise defined area.

Oil and natural gas systems have an immense scale and diversity of operation. The common principle is movement, handling, processing and transmission products from developers to users. A complete assessment of emissions at the national scale must include producing wells, gathering and processing facilities, storage, transmission and distribution pipelines. There is also a wide range of gas and liquids handling required. The compositional profile of the shale gas is of importance, as transmission pipelines require dry gas with methane content of greater than 95%. This requirement necessitates well pad dehydration that removes water and heavier hydrocarbons. The wetness of a gas is important for product handling and emission estimation.

4.3.1.1 FACTORS INFLUENCING EXPLORATION EMISSIONS

As indicated, there are a number of factors that may influence the magnitude of emissions that are characterized for exploration. Location is the primary consideration that sets the operation of the development.

Location

The location of a specific development is first and foremost tied to infrastructure requirements. And includes following considerations:

- Access to the development site. Are new roads needed? The road network will determine longer term traffic emission related to development management. What level of traffic is anticipated, considering distance from workforce, between development work sites and other necessary infrastructure? Is electrical power available? If certain equipment cannot use electrical power then fuel driven compressor emissions are increased.
- Access to markets. Are there existing transmission pipelines and downstream processing and storage facilities? New infrastructure may be required.

Proximity to existing infrastructure is a driver of potential emissions. A development that is compact and close to existing infrastructure may have lower emissions related to exploration and infrastructure compared to one that is widely dispersed in a remote situation.

Location will also define the geological formation that is exploited. The geologic formation will lead to the following considerations:

- Accessibility of target reservoir formation. Depth is critical for emissions from drilling and this influences time of engine operation and engine loading.
- “Porosity” of target substrate. The intensity of hydraulic fracturing for a particular well will influence a number of emission pathways but initially sets the time of engine operation and engine loading.
- Extent and magnitude of resource. The spatial extent of target substrate and the magnitude of the resource is a critical parameter. The spatial intensity of the extraction will set the emission intensity.

- Gas composition. The proportion of methane, non-methane hydrocarbons, water and other trace components, most notably hydrogen sulfide, are important for consideration of emissions related product handling.
- The rate and balance of production from different wells. The same formation can have different production profiles.

Location also determines the climatic regime and associated weather conditions, which together with the particular orography will affect the level of dispersion and dilution of the emissions. Temperature range influences emissions at both colder and warmer conditions. Developments set in extremely cold environments will have additional emissions from heating of production lines. Temperature can influence equipment operation and associated control mechanisms; hotter environments may experience relatively greater emissions from fugitive emission processes.

While location sets the characteristics of development, air emissions are defined by the actual manner by which the resource is extracted and delivered to production handling equipment.

Operations

The pace of development is the foremost consideration for exploration air emissions. The use of equipment will greatly influence emission rates for drilling and completion activities. Equipment operation will be set within a management regime that is set by the developer. For drilling answers to the following questions are important for defining emissions:

- How long will a drill rig be operating to complete one well bore?
- How many drill rigs will be operating in the given development?
- Will directional drilling be employed?
- What fuel is used for engines?
- What is the emission rating of the drill rig engines?
- What ancillary equipment or infrastructure is required?

While drilling is a short-term activity for a particular well in terms of a development the emission from drilling will be pseudo continuous with minor breaks for movement to a new drilling site. Directional drilling reduces down time for drill rigs but increases the time of emission for drilling processes.

For the use of any equipment there is an inherent assumption that the emission relates to the specified level for the "normal" operation. As such the following are important:

- Are control measures being employed on equipment?
- Is equipment operating "normally" within at a given rating?
- Is operation according to expectation and specifications?
- What is the maintenance and checking protocol?

The factors noted above will also be influenced by the regulation of these operations and in some cases may include external auditing. The quality of equipment will clearly relate to air emissions. Out of tune or overloaded engines are known to emit higher levels of certain pollutants. The calculation of emissions related to drilling operation is related time of operation of specified equipment and is not influenced by the composition of the extracted resource.

Completion activities define unconventional gas exploration, as hydraulic fracturing ("fracking") is required. Fracturing operations require the pumping of a mixture of water, chemicals and a "proppant" (usually sand) into a well at extremely high pressures to fracture rock and enable production of natural gas. Data provided to EPA's Natural Gas STAR Program show that some of the largest air emissions in the natural gas industry occur as fractured well are being prepared for longer term production. During a process termed "flowback," a mixture of fracturing fluids, water, and reservoir gas come to the surface. This mixture includes a high volume of VOC and methane. The EPA reports a typical flowback period of three to 10 days. The management of this process is the centerpiece of the final rule published by the US EPA for air regulations specified for the oil and natural gas industry. As for drilling, equipment operation will be set within a management regime that is set by the developer while conforming to regulations. For completions answers to the following questions are important for defining emissions:

- How long will the hydraulic fracturing operation take?
- How many operations will be performed on a given well before flow back starts?
- How many hydraulic fracturing teams will be operating in the given development?
- What fuel is used for engines?
- What is the emission rating of engines?
- Are control measures being employed on equipment?
- What ancillary equipment or infrastructure is required?
- How is flow back handled?

Emissions related to flow back are the critical consideration. Reduced emission completions are predicted to greatly decrease emissions compared to pit stored with venting to atmosphere. Emissions related to flow back are included within a category known as lost and unaccounted for gas (LUG). Metering of production occurs downstream of both completion and production activities and as such has inherent uncertainty. The considerations above are needed to formulate an estimation approach that starts with the development of an inventory that is capable of estimating emissions.

4.3.1.2 FACTORS INFLUENCING PRODUCTION EMISSIONS

Many of the factors of significance for exploration have similar importance for emissions related to production. Again location is critical. Development layout will influence mobile emissions associated with maintenance activities. The natural gas composition will define the set-up of production equipment and the associated emission rates. The most important emissions are related to the operation of production equipment the important questions are as follows:

- What equipment is needed for on site processing?
- What is the fuel availability, including electricity?
- Is equipment operating "normally" within at a given rating?
- Is operation according to expectation and specifications?
- What is the maintenance and checking protocol?
- Are control measures employed on equipment?

Production and exploration occur in tandem. Constructing an emission inventory that is designed to determine development emissions is a first step toward an air quality impact assessment.

4.4 THE DEVELOPMENT OF A NATIONAL SCALE EMISSION ESTIMATION TOOL FOR UNCONVENTIONAL UPSTREAM NATURAL GAS DEVELOPMENT

The EPA has created an emission inventory specifically designed for estimating nonpoint emissions as a response to underestimation of these sources within the NEI and also as a systematic consolidation of regionally based initiatives (EPA, 2013). Work performed by the Texas Commission on Environmental Quality (TCEQ), the Western Regional Air Partnership (WRAP) and Central States Air Resources Agencies (CenSARA) provided the foundation. CenSARA data was used at the core of the inventory development as these states have a combined 50% share of the national gas production. The estimation tool is critical as it allows for localized emission estimation to the county level. In addition prescribed calculation are used and if better data exists that these may be modified in subsequent versions of the tool that operated in an MS Access. An additional improvement is the use of CenSARA emission factor as surrogates for regions that lack such data so that default factors could be applied to production data to derive emission amounts. The importance of nonpoint upstream activities, broadly classified as processes related to exploration and production, is already established. It is essential accounting of exploration activities include drilling and hydraulic fracturing and production activities include separator, dehydrators, storage tanks and compressor engines is valid for decision-making. To maintain consistency with the NEI a base year of 2011 was selected. The new inventory is coupled with an emissions estimation tool that allows for the manipulation of key input and calculation parameters. This allows for revision and updating to better reflect local conditions. Furthermore given the known differences between different basins the tool enables calculations at the County level within the basin scale. The inventory and tool provides emission estimates for the nitrogen oxides (NOx), volatile organic compounds (VOC), particulate matter (PM), carbon monoxide (CO), sulfur dioxide (SO2), hazardous air pollutants (HAP), hydrogen sulfide (H2S), methane (CH4), and select greenhouse gases (GHG) from upstream oil and gas production activities. The following specific source categories are included in the inventory:

- Artificial Lift Engines
- Wellhead Compressor Engines
- Lateral Compressor Engines
- Drilling Rigs
- Condensate Tanks
- Hydraulic Fracturing Pumps
- Well Completion Venting
- Liquids Unloading
- Associated Gas Venting
- Dehydrators
- Pneumatic Devices
- Heaters
- Crude Oil Tanks
- Produced Water Tanks
- Gas-Actuated Pneumatic Pumps
- Fugitive Emissions
- Mud Degassing
- Hydrocarbon Liquids Loading

- Flaring (when used to control emissions from the unit processes listed above)

These are the most significant categories for which there exists suitable information. Some sources were not included due to limited data availability, including construction equipment, work-over equipment and associated mobile sources. These sources can be broadly characterized as; (i) combustion (ii) venting or (iii) fugitive.

Emissions from the listed categories are calculated by combining activity inputs, basin factors and emission factors. While consistency of data sources is important the best quality data input is specific to a specific basin. The following specific activity parameters are needed to estimate emissions:

- Oil Produced (barrels or BBL)
- Natural Gas Produced (thousand standard cubic feet or MCF)
- Condensate Produced (BBL)
- Casinghead Gas Produced (MCF)
- Oil Well Counts
- Natural Gas Well Counts
- Oil Well Completions
- Natural Gas Well Completions
- Produced Water at Oil Wells (BBL)
- Produced Water at Gas Wells (BBL)
- Spud Counts (Vertical, Horizontal, Directional)
- Feet Drilled (Vertical, Horizontal, Directional)

Obtaining consistent and accurate data is a major consideration, especially considering that for CenSARA states there are over 2 million well level data records. Data processing requires data-base management for the derivation of a number of the parameters noted above, of particular relevance is well designation information as wells may produce condensate (oil) as together with gas. The one input that could not be collected from easily accessible data sources was natural gas composition. This data was collected from a variety of sources to enable calculations for a number of emissions.

Table 4.2 shows statewide oil and gas production for 2011 for selected states. This is the first step toward defining the balance of emission sources.

Table 4.2.- State wide oil and gas production for 2011 for selected state

State	Oil (BBL)	Casinghead Gas (MCF)	Gas Well Gas (MCF)	Condensate (BBL)
Colorado	29,535,047	116,542,644	2,091,278,106	10,497,533
North Dakota	151,156,326	133,023,400	23,636,077	1,275,296
Pennsylvania	2,108,613	10,333,040	1,307,030,772	1,201,918
Texas	454,994,880	1,057,525,915	6,893,217,449	81,507,690
Wyoming	49,985,043	156,430,973	2,218,414,912	11,951,745

Abridged from US EPA 2013

Table 4.2 reveals consideration variation in both absolute and relative amounts of production between these selected states. This highlights the necessity of using appropriate surrogates. For Colorado and Wyoming the ratios of oil to gas well and gas well to condensate production show broad similarity for these neighboring states. While the Rocky Mountain West (Colorado, Utah and Wyoming) is associated with tight sandstones; the rapid developments in North Dakota, Texas, and Pennsylvania are associated with Shale deposits, for example the Bakken Shale, Barnett Shale and Marcellus Shale. The relatively low high ratio of oil to gas production is due to the high level of production of oil in North Dakota from the Bakken Shale, coupled with the extensive flaring of gas due to the lack of transmission infrastructure. The high gas to condensate ratio for Pennsylvania indicates that the gas composition of the Marcellus has relatively low non-methane content.

The next step of calculating emissions for particular source category follows a bottom up approach that begins with developing mass emission rates for each pollutant using an activity surrogate. Surrogate emission rates are selected for the particular process as shown by Table 4.3.

Table 4.3.- Category and Activity Surrogate in the EPA Estimation tool

Category	Activity Basis	Oil	Gas
Artificial Lifts	Oil Well Count	Yes	No
Associated Gas	Casinghead Gas Production	Yes	No
Condensate Tanks	Condensate Production	No	Yes
Crude Oil Tanks	Oil Production	Yes	No
Dehydrators	Gas Production	No	Yes
Drill Rigs	Spud Count	Yes	Yes
Fugitive Leaks	Well Count	Yes	Yes
Gas-Actuated	Pumps Well Count	Yes	Yes
Heaters	Well Count	Yes	Yes
Hydraulic Fracturing Pumps	Horizontal Well Count	Yes	Yes
Lateral/Gathering Compressor Engines	Gas Well	No	Yes
Liquids Unloading	Gas Well Count	No	Yes
Loading	Oil and Condensate Production	Yes	Yes
Mud Degassing	Completion Count	Yes	Yes
Pneumatic Devices	Well Count	Yes	Yes
Produced Water Tanks	Produced Water Production	Yes	Yes
Well Completions	Completion Count	Yes	Yes
Wellhead Compressors	Well Count	No	Yes

Table taken from EPA (2013)

It should be noted that if direct data for specific categories is available then calculations could use actual activity data. Alternatively this data could be used in the scaling processes, for example the time of operation of heaters. Also the time period of the inventory calculation could be adjusted if particular impacts are associated with seasonal conditions. Table 4.4 shows the calculated emissions for the states that were previous highlighted in Table 4.2.

Table 4.4.- State wide oil and gas production for 2011 for selected states

State	NOx (TPY)	VOC (TPY)	CH4 (TPY)	Total HAP (TPY)
Colorado	62,526	177,618	460,949	9,031
North Dakota	13,578	95,642	41,392	2,168
Pennsylvania	104,068	191,893	708,303	8,571
Texas	584,938	1,057,306	1,988,665	35,169
Wyoming	58,434	186,141	462,056	10,622

Abridged from US EPA 2013

While there is some variability related to basin specific influences the state-wide emissions are reflective of activity. The ability of the estimation tool to produce data for county dimensions is of relevance for initial impact assessment of oil and gas emissions upon local and regional air quality. Table 4.5 shows the balance of pollutant emissions from the different source categories identified within Table 4.3 for the US nonpoint oil and gas nonpoint inventory for 2011.

Table 4.5.- Category Emissions for the 2011 nonpoint Oil and Gas inventory

Category	NO_x (TPY)	VOC (TPY)	CH_4 (TPY)	Total HAP (TPY)
Artificial Lifts	122,858	1,602	12,448	1,756
Associated Gas	3	28,922	38.339	49
Condensate Tanks	792	493,177	183,424	4,931
Crude Oil Tanks	173	696,476	95,494	16,959
Dehydrators	88,471	65,303	60,892	46,147
Drill Rigs	51,401	3,118	51	678
Fugitive Leaks		169,783	476,133	1,018
Gas-Actuated		189,247	622,949	1,365
Heaters	136,856	7,527	3,148	3,565
Hydraulic Fracturing Pumps	3,980	251	4	55
Lateral/Gathering Compressor Engines	165,375	5,058	50,756	3,427
Liquids Unloading	137	197,012	1,166,395	618
Loading		9,876	386	125
Mud Degassing		42,253	124,141	80
Pneumatic Devices		1,222,229	4,121,771	8,342
Produced Water Tanks		58,089	176,893	228
Well Completions	295	18,937	45,566	210
Wellhead Compressors	797,108	29,224	297,881	22,950
Total	1,367,451	3,238,085	7,476,670	112,502

Table taken from EPA (2013)

Table 4.5 shows the relative importance of different categories for different pollutant classes. This has implications for air quality monitoring assessments that consider the spatial and temporal impacts of these emissions upon air quality. The distribution of these sources has relevance for assessing the spatial distribution of ozone precursors. While in broad terms emission are associated with development activity Table 4.5 shows that different activities have very different profiles. Wellhead compressors are the dominant NO_x source. Once established, these sources are static and continuous emitters. Pneumatic devices are also ubiquitous at well sites and dominant for methane emissions. Dehydration units are the dominant emission source for HAP.

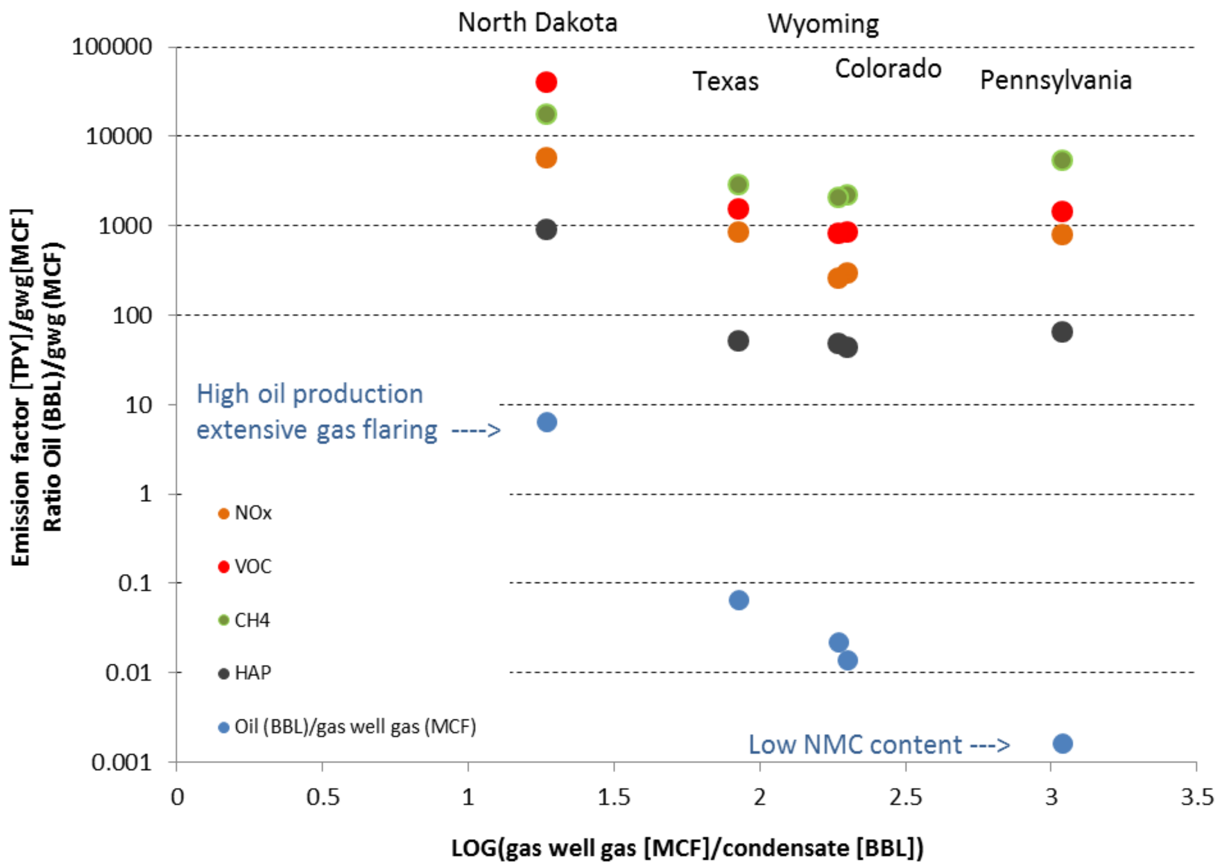

Figure 4.1.- Oil/gas production versus Emission factors

The Figure 4.1 shows the variability of annual emission factors as a function of the annual production of oil, gas well gas and condensate in different states in U.S. The high scattering of these emissions factors, that show a range from 8 to 50 depending on the compound considered, relate to the characteristics of the state considered. The known diversity of emission amounts due to numerous factors; including basin substrate, oil/gas composition and infrastructure, account for these differences. Such uncertainty increases the difficulty associated with the estimation of potential emissions that is based exclusively on production data. These values show that the contributing factors need to be fully considered. Therefore, any review of emissions is the first step of a mitigation approach designed to minimize environmental impacts.

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ANNEX II

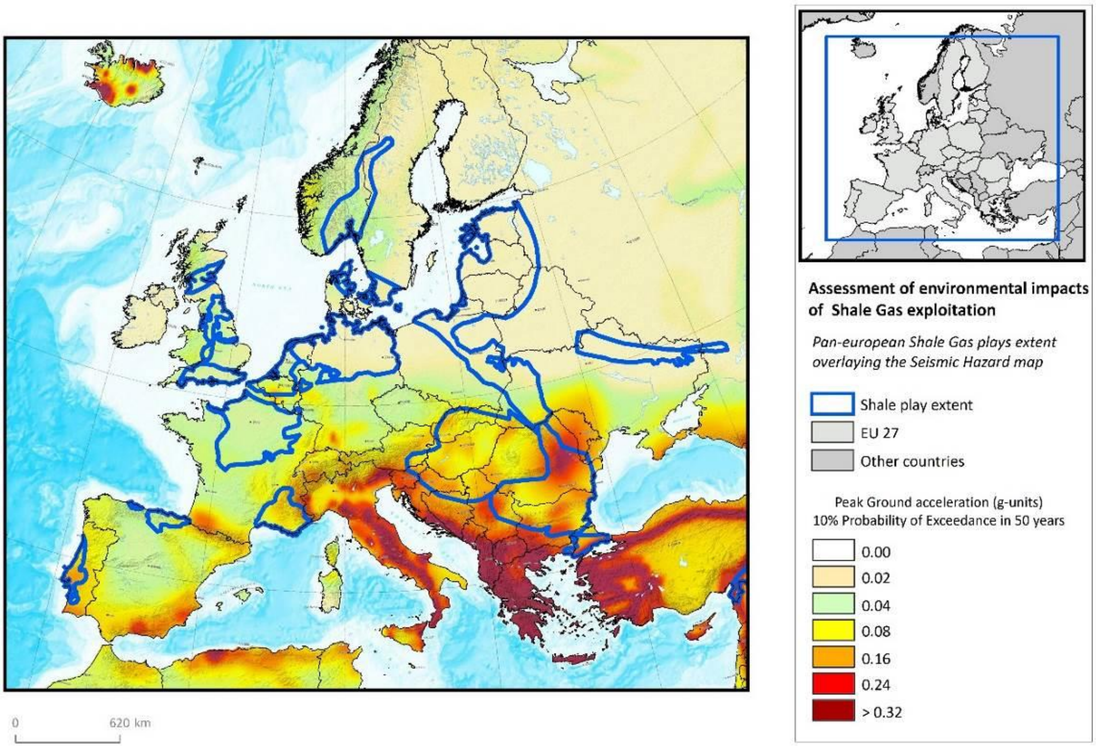

Figure 72: Pan-European map overlaying shale plays extent and seismic hazard.

Data Sources:

- *Shale plays extent*: IEA. 2012. Golden rules for a golden age of gas: World Energy Outlook special report on unconventional gas. International Energy Agency;

- *Seismic hazard*: Solomos, G., Pinto, A., S. Dimova, S. 2008. A Review of the Seismic Hazard Zonation in National Building Codes in the Context of EUROCODE 8. Support to the implementation, harmonization and further development of the Eurocodes. ISSN 1018-5593.

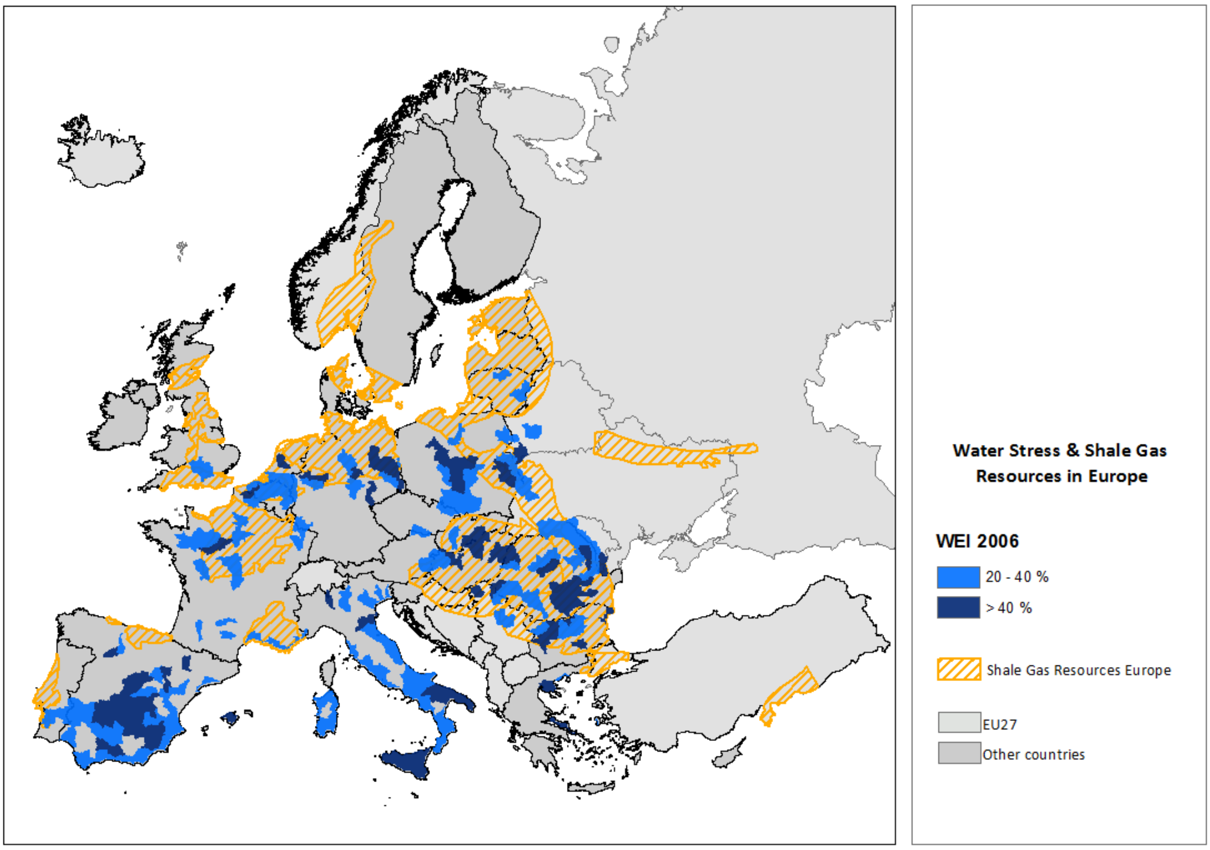

Figure 73: Pan-European map overlaying shale plays extent and water stress regions.

Data Sources:

- *Shale plays extent*: IEA. 2012. Golden rules for a golden age of gas: World Energy Outlook special report on unconventional gas. International Energy Agency;
- *Water Stress*: Water Exploitation Index (WEI) computed using the LISQUAL model, IES, JRC (De Roo, A., Burek, P., Gentile, A., Udlas, A., Bouraoui, F., Aloe, A., Bianchi, A., La Notte, A., Kulk, O., Elorza Tenreiro, J., Vandecasteele, I., Mubareka, S., Baranzelli, C., van der Perk, M., Lavalle, C., Bidoglio, G. 2012. A multi-criteria optimisation of scenarios for the protection of water resources in Europe: Support to the EU Blueprint to Safeguard Europe's Waters. Scientific and Policy Report of the Joint Research Centre, Publications Office of the European Union, Luxembourg. ISBN 978-92-79-27025-3).

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Abstract

Specific technology scenarios regarding water and land use requirements for shale gas development from 2013-2028 were coupled with spatially-resolved water and land availability/demand modeling tools (i.e. using the European Land Use Modelling Platform (LUMP)). Scenario analyses (intended to represent worst-, average- and best-case assumptions) were subsequently implemented that incorporate a subset of the identified variables for shale gas development in the Lower Paleozoic Baltic-Podlasie-Lublin basin in Poland and for Germany as a whole from 2013-2028. We undertook a screening-level risk assessment of potential human and ecosystem health impacts attributable to accidental or operational release of chemicals used in hydraulic fracturing of shale formations, and a qualitative discussion of necessary considerations to support future air quality impact assessments for shale gas development activities.

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