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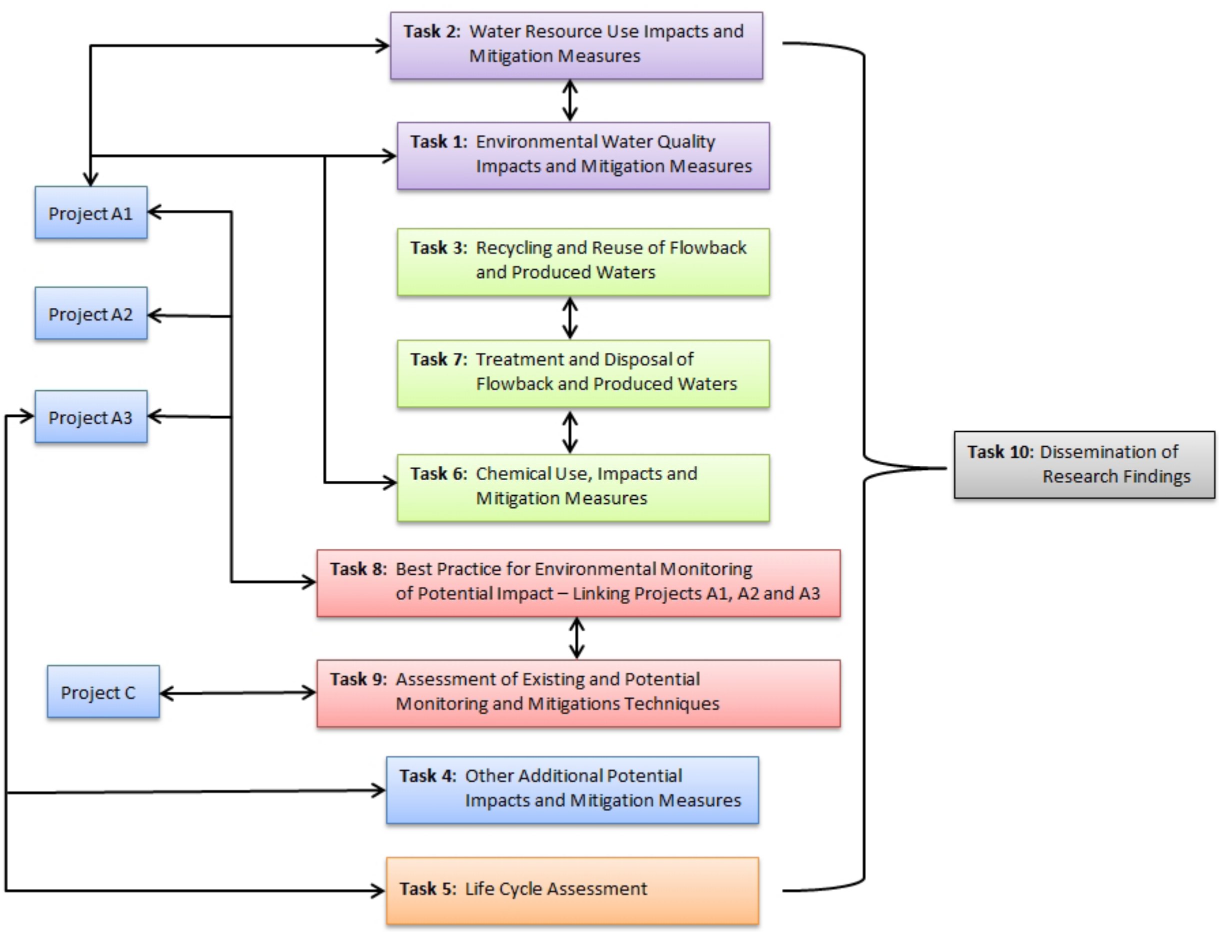
Unconventional Gas Exploration and Extraction (UGEE) Joint Research Programme

Final Report 4: Impacts and Mitigation Measures

Authors: Roger Olsen, Dawn Keating, Carlos Claros, Henning Moe and Lorraine Gaston



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On the 23rd of July 2016, the Department of Communications, Energy and Natural Resources (DCENR) became the DCCAE. Along with a name change, the new Department incorporates functions that were formerly held within the Environment Division of the DECLG. The Department retains responsibility for the Telecommunications, Broadcasting and Energy sectors. It regulates, protects, develops and advises on the Natural Resources of Ireland. Of particular relevance is the role of the Petroleum Affairs Division (PAD) to maximise the benefits to the State from exploration for and production of indigenous oil and gas resources, while ensuring that activities are conducted safely and with due regard to their impact on the environment and other land/sea users. The Geological Survey of Ireland (GSI) is also within DCCAE and provides advice and guidance in all areas of geology including geohazards and groundwater and maintains strong connections to geoscience expertise in Ireland.

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This Research Programme is being administered by the EPA and steered by a committee with representatives from DCCAE (formerly DCENR and the Environment Division of the DECLG), the Commission for Energy Regulation (CER), An Bord Pleanála (ABP), the GSI, NIEA, the Geological Survey of Northern Ireland (GSNI), as well as a Health representative nominated by the Health Service Executive (HSE).

UGEE Joint Research Programme

Environmental Impacts of Unconventional Gas Exploration and Extraction (UGEE)

(2014-W-UGEE-1)

Final Report 4:

Impacts and Mitigation Measures

by

CDM Smith Ireland Ltd

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References to government departments (DCENR and DCELG) throughout the report use the names of these departments prior to July 2016. References to the Department for the Economy (DfE) throughout the report use the name of its predecessor, the Department of Enterprise Trade and Investment (DETI), the department responsible for petroleum licensing in Northern Ireland until May 2016.

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Project B Internal Review Panel[1]

CDM Smith Inc., Independent reviewer (German University), AMEC Foster Wheeler

1 More details available at: http://www.epa.ie/pubs/reports/research/ugeejointresearchprogramme/ugeejrptasksorganisations.html

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Executive Summary

Unconventional gas exploration and extraction (UGEE) involves hydraulic fracturing (fracking) of low-permeability rock to permit the extraction of natural gas on a commercial scale from unconventional sources such as shale gas deposits, coal seams and tight sandstone. The Environmental Protection Agency (EPA), the Department of Communications, Energy and Natural Resources (DCENR) and the Northern Ireland Environment Agency (NIEA) awarded a contract in August 2014 to a consortium, led by CDM Smith Ireland Limited, to carry out a 24-month research programme looking at the potential impacts on the environment and human health of UGEE projects and operations (including construction, operation and aftercare).

The UGEE Joint Research Programme (JRP)[2] is composed of five interlinked projects and involves field studies (baseline monitoring of water and seismicity), as well as an extensive desk-based literature review of UGEE practices and regulations worldwide. The UGEE JRP was designed to produce the scientific basis that will assist regulators – in both Ireland and Northern Ireland – to make an informed decision about whether or not it is environmentally safe to allow fracking. As well as research in Ireland, the UGEE JRP looks at and collates evidence from other countries.

Project B comprises the identification and a detailed examination of the potential impacts on the environment and human health, as well as mitigation measures to counteract these impacts, that are associated with UGEE projects and operations and that have come to the fore worldwide by using published reports and other sources. The assessment takes into account commercially likely scenarios. Where appropriate, findings are accompanied by reference to experiences in other countries. Project B comprised the following tasks.

Task 1. Impacts on Environmental Water Quality and Mitigation Measures. This task examines the potential environmental impacts of UGEE projects and operations on groundwater and surface water bodies, including the potential migration of methane, chemicals and other contaminants, from both surface and subsurface sources. The findings are informed by an objective assessment of the risks and hazards posed by UGEE projects and operations and supported by a literature review and experience from other jurisdictions. Mitigation measures to address water impacts (including, but not limited to, effluent management and treatment and well construction) are critically reviewed and presented. This includes a review of the success of innovative developments within the industry to reduce water impacts.

Task 2.Impacts on water Resource Use and Mitigation Measures. This task comprises an assessment of the direct (e.g. abstraction) and indirect impacts (e.g. drinking water, other receptors) of the use of local water sources for UGEE projects and operations and, specifically, fracking. This includes a review of innovation within the industry to source water from existing industrial processes, such as cooling water, wastewater treatment works effluent and innovation related to water-free fracking.

Task 3. Recycling and Reuse of Flowback and Produced Waters. This task comprises a comprehensive assessment of experience of the level of use of recycled flowback water in UGEE projects and operations and the potential for increasing these levels and of the scope for, and implications of, recycling the flowback water for reuse in further fracturing operations in the case study areas used for Project A1.

2 www.ugeeresearch.ie

Task 4. Other Potential Impacts and Mitigation Measures. This task employs approaches similar to those of Task 1 to examine impacts from UGEE projects and operations in other areas, including, but not limited to, human beings, flora and fauna (including agricultural and domestic animals), air, landscape, material assets and cultural heritage, as well as the interaction between these areas. Mitigation measures to address these potential impacts are presented.

Task 5. Life Cycle Assessment. This task comprises discussion of the cumulative environmental impact of UGEE projects and operations supported by a literature review and experience from other jurisdictions and compared with similar published assessments of other energy sources.

Task 6. Chemical Use, Impacts and Mitigation Measures. This task examines techniques in UGEE projects and operations, including evidence of chemical-free UGEE projects and operations and the purposes of individual additives, to ascertain current and emerging practices in the context of avoidance of the use of additives that have the potential to harm the environment.

Task 7. Treatment and Disposal of Flowback and Produced Waters. This task comprises the identification and assessment of treatment and disposal methods for flowback fluid, identifying specific case studies. Linked to Task 6, it identifies the treatment technologies available to adequately treat typical chemicals used in the process, in combination with likely constituents of produced water. Disposal options linked to the available treatment options are reviewed and assessed.

Task 8. Best Practice for Environmental Monitoring of Potential Impacts – Linking Projects A1, A2 and A3. This task comprises research into identifying best practice for environmental monitoring of potential impacts arising from individual UGEE projects and operations sites (including emissions monitoring, monitoring of the effectiveness of mitigation measures, and of impacts on the receiving environment).

Task 9. Assessment of Existing and Potential Monitoring and Mitigation Techniques. This task comprises the examination of the validity and range of existing and potential monitoring and mitigation techniques, including, but not limited to, geophysical techniques (downhole and surface) for use in monitoring, control, horizon selection and injection management.

These tasks are summarised and the key conclusions and recommendations set out in section 13.

In common with all projects forming part of the UGEE JRP, effective dissemination of the research findings in accordance with the overall dissemination plan of the research programme is an important part of Project B.

1 Introduction

Unconventional gas exploration and extraction (UGEE) involves hydraulic fracturing (fracking) of low-permeability rock to permit the extraction of natural gas on a commercial scale from unconventional sources, such as shale gas deposits, coal seams and tight sandstone. The Environmental Protection Agency (EPA), the Department of Communications, Energy and Natural Resources (DCENR) and the Northern Ireland Environment Agency (NIEA) awarded a contract in August 2014 to a consortium, led by CDM Smith Ireland Limited, to carry out a 24-month research programme looking at the potential impacts on the environment and human health of UGEE projects and operations (including construction, operation and aftercare).

The UGEE Joint Research Programme (JRP)[3] is composed of five interlinked projects and involves field studies (baseline monitoring of water and seismicity), as well as an extensive desk-based literature review of UGEE practices and regulations worldwide. The UGEE JRP was designed to produce the scientific basis that will assist regulators – in both Ireland and Northern Ireland – to make an informed decision about whether or not it is environmentally safe to permit UGEE projects and operations involving fracking. As well as research in Ireland, the UGEE JRP looks at and collates evidence from other countries.

The environmental impacts of UGEE projects and operations to be considered are those arising from UGEE projects and operations in their totality, not just from fracking activities. Furthermore, all stages of UGEE projects and operations must be considered (i.e. including construction, commissioning, operation, decommissioning and aftercare, as well as off-site and other developments).

1.1 Context

In Ireland, Onshore Petroleum Licensing Options were awarded in March 2011, as preliminary authorisations, to three exploration companies seeking to assess the shale gas potential within the Northwest Carboniferous Basin (NCB) and the Clare Basin (CB). In Northern Ireland, one exploration company secured a Petroleum Licence from the Department of Enterprise, Trade and Investment (DETI) to explore the potential for shale gas reserves in County Fermanagh, within the NCB. The specific UGEE exploration areas, based on the licences that were held until recently, are shown in Figure 1.1.

In Ireland, exploration drilling, including drilling that would involve hydraulic fracturing, is not allowed under current licensing options. Nonetheless, two of the three companies have submitted applications for follow-on licences, which would include exploration drilling. The DCENR will not consider these applications further until the findings of this UGEE JRP have been published. In addition, the DCENR will not consider any applications for exploration authorisations in other onshore areas until the UGEE JRP has concluded. In Northern Ireland, the referenced DETI licence was terminated, as the licence conditions (a “drill or drop” work programme requiring specified exploration, including drilling a stratigraphic borehole, in the first 3 years and, before the end of year 3, a commitment to drilling an exploration well within the following 2 years) were not met.

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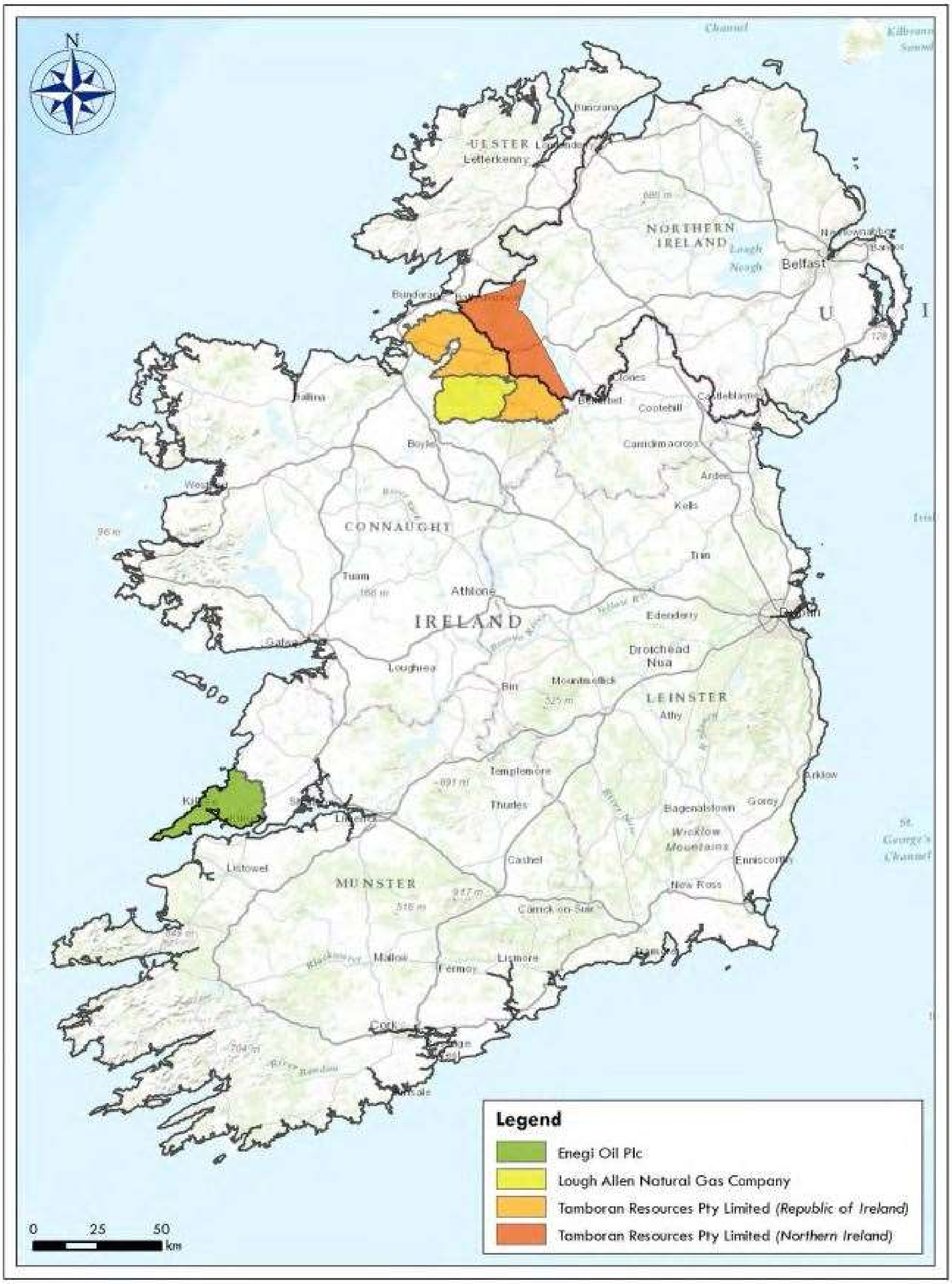

Figure 1.1. Overview of the case study areas of the UGEE JRP.

In May 2012, the EPA released the report *Hydraulic Fracturing or "Fracking": A Short Summary of Current Knowledge and Potential Environmental Impacts* from a preliminary study (Healy, 2012).[4] This short desk study was conducted for the EPA by the University of Aberdeen and provided an introduction to the environmental aspects of UGEE projects and operations, including a review of regulatory approaches used in other countries and areas for further investigation and research.

In brief, some of the key findings of this study were:

- the importance of adequate knowledge of local geology in order to assess potential impacts on groundwater quality and the possibility of induced seismic activity;
- the importance of well integrity for preventing groundwater contamination;
- the uncertainty regarding the "carbon footprint" of shale gas in comparison with conventional natural gas; this is an important issue in relation to climate change;
- baseline studies are needed (of surface water and groundwater and seismic studies) before drilling begins;
- UGEE is a relatively new area of research (i.e. only a limited number of published, peer-reviewed, scientific studies are available in this area).

The information provided by this preliminary research project was used along with other sources, such as European Commission reports,[5] to develop the Terms of Reference for a more comprehensive research programme. Between 11 January and 8 March 2013, the EPA administered a public consultation[6] in relation to the revised terms of reference[7] for this research programme. Submissions[8] were assessed and relevant comments taken into account, when finalising the document.

In order to assist government bodies to make informed decisions about any potential future licensing and management of UGEE projects and operations on the island of Ireland, comprehensive knowledge of the potential impacts of this process on the environment and human health is required. This knowledge will be generated from a number of sources including research in the European Union (EU) and internationally and through this programme of research.

The key questions to be addressed by the UGEE JRP are:

1. Can UGEE projects and operations be carried out in the island of Ireland while also protecting the environment and human health?
2. What is "best environmental practice" in relation to UGEE projects and operations?

The JRP is funded by the EPA, the DCENR and NIEA. It is managed by a steering committee comprising the EPA, the Department of Environment, Community and Local Government (DECLG), DCENR, the Geological Survey of Ireland (GSI), the Commission for Energy Regulation, An Bord Pleanála, the NIEA, the Geological Survey of Northern Ireland (GSNI) and the Health Services Executive.

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4 http://www.epa.ie/pubs/reports/research/sss/epa-strivesmallscalestudyreport.html

5 http://ec.europa.eu/energy/studies/energy_en.htm

6 http://www.epa.ie/researchandeducation/research/researchpillars/water/ugee%20research/2013publicconsultation/

7 http://www.epa.ie/pubs/reports/research/ugeejointresearchprogramme/drafttermsofreferenceforugeeresearchprogramme.html

8 http://erc.epa.ie/public_consultation/

1.1.1 Overview of the UGEE JRP

The main aim of the UGEE JRP is to further the understanding of potential impacts on the environment and human health from UGEE projects and operations. It comprises five separate but interlinked projects as follows:

- Baseline characterisation:
  - Project A1 (Groundwater, Surface Water and Associated Ecosystems);
  - Project A2 (Seismicity);
  - Project A3 (Air Quality).
- Impacts and mitigation measures**:**
  - Project B: UGEE Projects/Operations: Impacts and Mitigation Measures.
- Regulatory framework**:**
  - Project C: Regulatory Framework for Environmental Protection.

1.2 Objectives and Scope of Project B

Project B involves the assessment of the impacts of and mitigation measures for UGEE projects and operations. The objectives of Project B include the following:

- identification and detailed evaluation of the potential impacts on the environment and human health associated with UGEE projects and operations; and
- identification and evaluation of successful mitigation measures for the potential impacts.

The Environmental Impact Assessment (EIA) Directive (EU, 2011) will apply to all UGEE projects and operations in which hydraulic fracturing is proposed. The outputs from Project B will assist regulators who may be required to assess EIAs for UGEE projects in the future to understand the potential impacts that should be considered by the applicants, as well as the information required to effectively evaluate the proposed mitigation measures.

There are nine tasks in Project B (Figure 1.2) that deal with specific elements of the impacts of and mitigation measures for UGEE projects. The tasks include the following, which are described in their respective chapters:

- Chapter 4 Impacts on Environmental Water Quality and Mitigation Measures (Task 1);
- Chapter 5 Impacts on Water Resource Use and Mitigation Measures (Task 2);
- Chapter 6 Recycling and Reuse of Flowback and Produced Waters (Task 3);
- Chapter 7 Other Additional Potential Impacts and Mitigation Measures (Task 4);
- Chapter 8 Life Cycle Assessment (Task 5);
- Chapter 9 Chemical Use, Impacts and Mitigation Measures (Task 6);
- Chapter 10 Treatment and Disposal of Flowback and Produced Waters (Task 7);
- Chapter 11 Best Practice for Environmental Monitoring of Potential Impacts – Linking Projects A1, A2 and A3 (Task 8);
- Chapter 12 Assessment of Existing and Potential Monitoring and Mitigations Techniques (Task 9).

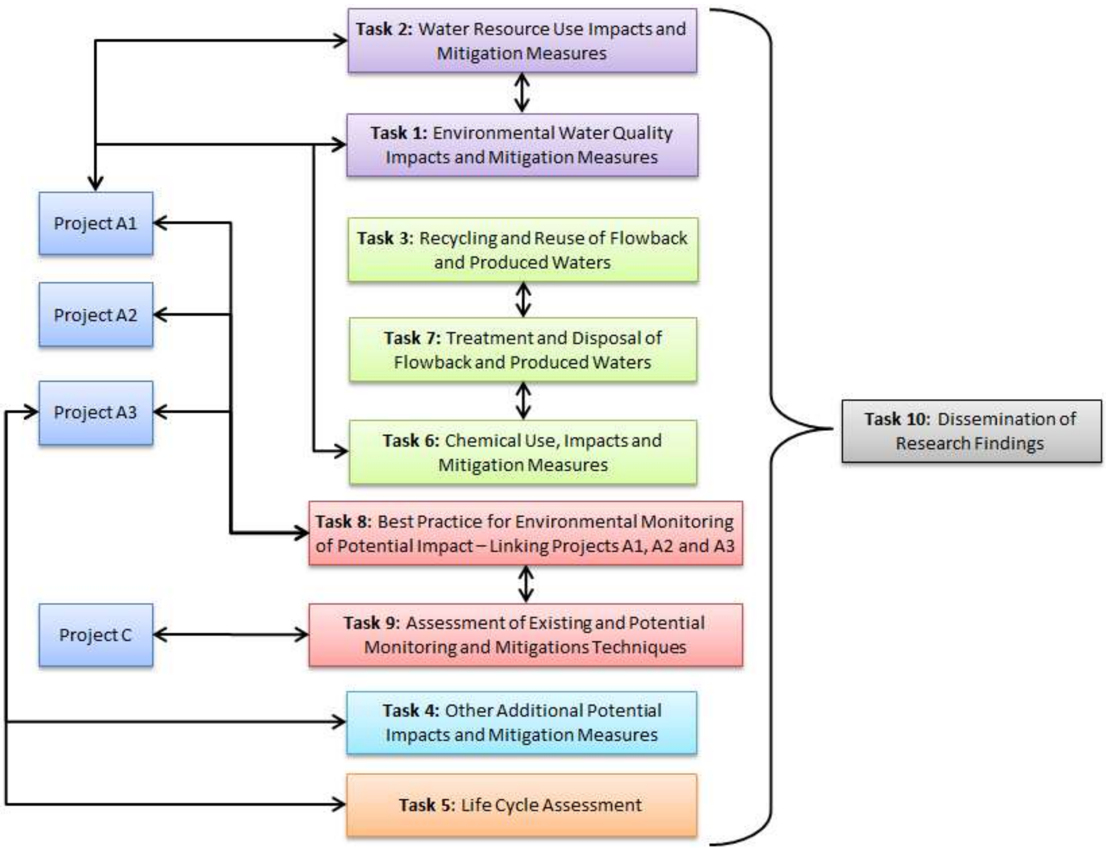


Figure 1.2. Tasks of Project B of the UGEE JRP.

1.3 Methodology

1.3.1 Overall approach

The approach taken to accomplish these objectives included:

- review and evaluation of relevant published reports including impacts, risk mitigation measures and best available techniques;
- review and evaluation of relevant regulatory criteria and requirements particularly associated with required mitigation measures;
- practical experience gained through project work relating to the environmental mitigation of impacts associated with the oil and gas industry;
- during the detailed examinations, the evaluations were focused on the conditions in Ireland, particularly the case study areas identified, and commercially likely scenarios in these areas;
- the overall evaluations of impact will be implemented using the source–pathway–receptor approach, which will result in assessment of risks to potential human and environmental receptors; risks and impacts on natural resources (e.g. water quality, water quantity) will also be evaluated; and
- the evaluations will be closely co-ordinated with other parts of this project, particularly Projects A and C of the UGEE JRP.

The probable commercial scenario approach was used to assess the potential impacts on the environment and human health and the mitigation measures. This approach standardises assumptions made about future UGEE activities, given the uncertainty of whether or not developments will proceed in Ireland and, if so, how they will proceed. The probable commercial scenarios are described in Chapter 2.

1.2.1 Review and evaluation of relevant published reports

There are many published reports and journal articles that relate to the impacts of and mitigation measures for UGEE projects in the USA and the EU. The majority of the published documents utilised were either extensive reviews carried out by experts on behalf of government departments or peer-reviewed articles in scientific journals. The published documents were gathered and their relevance to each of the project tasks was established. Appendix A contains a list of relevant published documents, reviewed as part of Project B, particularly related to establishing the probable commercial scenarios.

In addition, over 100 references to studies and news articles were made during the public consultation process. The references that were identifiable were obtained and assessed to see whether they were peer reviewed or from a relevant source. These documents were then added to the review process. Repeat references were excluded.

During each of the project tasks, further reviews of published literature were utilised in order to carry out the impact assessments and assess mitigation measures. All of the references cited in this report are provided in the reference section.

2 Unconventional Gas Exploration and Extraction Projects and Operations

2.1 Background

This chapter describes the various stages of UGEE projects and operations and explains the terminology used. It also sets out probable commercial scenarios, which describe the likely characteristics of operations in the event that UGEE operations proceed in the study areas. While it is currently very uncertain whether or not UGEE activities are likely to proceed in Ireland at any level, setting out commercial scenarios provides a framework within which potential impacts can be evaluated.

2.2 Introduction to UGEE Operations and Technology

2.2.1 Unconventional gas

Natural gas is a general term for the mixture of methane gas (typically 85% of the total) and other hydrocarbons, such as ethane, propane, butane and pentane, as well as carbon dioxide, and trace amounts of nitrogen, helium and hydrogen sulfide (Atherton *et al.*, 2014). Oil and natural gas resources are commonly divided into two categories: conventional (i.e. formations with high permeability that are relatively inexpensive and easy to develop via traditional extraction methods) and unconventional. The term “unconventional” is used, as these oil and natural gas resources are found in reservoirs with low permeability and, therefore, cannot be extracted using traditional methods. Although the unconventional gas sources may include shale, coal seam and tight sandstone deposits, the focus of this report is on shale deposits because these would be the primary source deposits in the NCB and CB study areas. Therefore in this report, unconventional gas is a broad descriptor used for the term “shale gas” (Council of Canadian Academies, 2014).

Shale is a sedimentary rock composed primarily of silt, clay and organic matter (algae, plant and animal derived) deposited over millions of years in deep water basins (Atherton *et al.*, 2014). Shale gas is generated from organic matter that is fragmented or decomposed at deeper depths under high pressure and temperature (thermogenic gas) or by the anaerobic decomposition of organic matter at more shallow depths (biogenic gas) (Jackson *et al.*, 2013). Shale rock formations have low permeability, making it difficult for fluids such as oil and gas to migrate towards the reservoir surface. The pore size in a shale formation can be up to 1000 times smaller than the pores in a conventional gas reservoir (Council of Canadian Academies, 2014). Therefore, shale gas was not historically considered a resource that could be extracted economically. As a result, unconventional extraction methods such as hydraulic fracturing have been developed to facilitate extraction.

2.2.2 UGEE and hydraulic fracturing

Hydraulic fracturing is designed to open existing natural fractures and create new fractures within a rock formation, typically by pumping large quantities of fluids (water and other components) down a well at high pressure. In doing so, it is intended to generate an interconnected, open network of fractures within the rock formation that stimulates the return flow of gas and/or fluid to the drilled well(s) or “wellbore(s)”, thereby increasing the volumes of oil or gas that can be recovered. Fractures are generally already present in these underground rock formations (similar to hairline cracks observed in concrete pavements). Hydraulic fracturing through the wellbore creates pathways to these existing fractures while also creating additional small-scale, often microscopic, fractures to increase oil and gas recovery (Atherton *et al.*, 2014).

In general terms, UGEE projects follow the phases described below:

- *Pre-development: exploration, well pad identification and initial site access*. This stage includes site identification and selection; site characterisation – establishment of baseline conditions for air, water, land, geology and deep-ground conditions; initial evaluation of potential environmental impacts; initial development of a geological conceptual model and geological risk assessment; exploratory boreholes for evaluation of geology and the reserve; seismic surveys; and securing necessary development and operation permits. Exploratory drilling is performed to identify whether or not gas can be produced profitably. This stage also includes pad construction and site preparation including construction of roads and any water containment structures.
- *Well design and construction, hydraulic fracturing and well completion*. This stage includes pilot well drilling; drilling initial horizontal wells to determine reservoir properties and required well completion techniques; further development of the geological conceptual model following test fractures; wellhead and well design and construction (drilling, casing, cementing, integrity testing); multi-stage hydraulic fracturing (injection of fracture fluid and management of flowback and produced water and emissions); and well completion.
- *Production (gas extraction)*. The production stage involves the commercial production of shale gas. The well pad is expanded and the necessary facilities constructed, including storage tanks, impoundments and secondary containment structures. The necessary equipment, water and chemical additives are transported to the site. Horizontal drilling is followed by hydraulic fracturing and gas production.
- *Project cessation, well closure and decommissioning*. The well is decommissioned once it reaches the end of its producing life. Sections of the well are filled with cement to prevent gas flowing into water-bearing zones or up to the surface. A cap is welded into place and then buried, and work is carried out on site to return it to a satisfactory state.

2.2.3 UGEE processes, construction and drilling activities

2.2.3.1 Road and well pad construction

A well requires a prepared area on the surface, called a pad, that provides a stable base for a drilling rig, retention impoundments, water storage tanks, loading areas for water lorries, associated piping, and pumping and transport lorries. During construction, the well pad covers between 2 and 6 ha (typically), this area being reduced to 1–2 ha during operation. The size depends on the depth of the well and the number of wells to be drilled on the site. After well completion, the pad serves as the location of the wellhead and other equipment. Preparing a pad involves clearing and levelling the ground; there may be screening or a grass bank built around the pad. In addition to the land disturbed in building the well pad, approximately 2–5 ha per pad are disturbed by roads and utilities to service the pad.

2.2.3.2 Drilling

The initial step is the drilling of a vertical borehole to a prescribed depth. Within the two study areas, the likely depth of any vertical well would be between 600 and 1300 m. The wellbore is drilled vertically downwards until a suitable vertical distance above the shale formation is reached, upon which the drill rig operator proceeds with angled or curved drilling up to, and subsequently horizontal drilling in, the shale formation. The determination of the angle(s) of the borehole is determined by the drilling team, based on stratigraphy, geological structure and the operational constraints of the drilling equipment used. It is anticipated that the horizontal length of drilling would be between 1200 m and 1500 m within the study areas. Multiple vertical and horizontal wells accessing different parts of the shale formation may be drilled from a single pad. Horizontal drilling reduces the footprint of these operations by enabling a large underground area of shale to be accessed from a single pad.

2.2.3.3 Casing and perforating

At various stages in the drilling process, drilling would be stopped and steel casing pipe would be installed in the wellbore. Cement would be pumped into the annulus between the borehole wall and the casing materials for sealing and casing installation purposes. After the borehole reaches a depth below the deepest freshwater aquifer, casing and cement would be installed to protect the groundwater from risk of contamination associated with the drilling and production processes. Additional casing (typically three sets) and cementing along the entire wellbore occurs after the well has reached its full vertical depth and horizontal length. This process is intended to prevent leakage of flowback water, produced water and natural gas from the well to the rock layers between the shale formation and the surface, as well as to prevent the escape of natural gas to the surface through the annulus. The production of gas from the formation includes perforating the horizontal well casing with tiny holes using controlled explosive charges. The perforations allow the fracturing fluid to enter the formation and fracture the shale, which in turn is followed by the formation's release of its trapped natural gas.

2.2.3.4 Hydraulic fracturing and completion

Although the horizontal well casing is perforated, little natural gas will flow freely into the well from the shale. Fracture networks must be created in the shale to allow gas to escape from the pores and natural fractures where it is trapped in the rock. This is accomplished by hydraulic fracturing. A water-based fracturing fluid is pumped into a borehole at high pressure. The fluid contains small particles known as proppant (typically 4–10% by volume and typically quartz sand or ceramic beads) and small quantities (typically 0.1–0.5% by volume) of chemical additives such as acids, corrosion and scale inhibitors and gelling agents. Under pressure, the fluid flows through the perforations in the horizontal well casing and creates open fractures in the shale – connecting pores and existing fractures and providing a pathway for natural gas to flow back into the well. The proppant lodges in the fractures and keeps them open. The overall process is shown in Figure 2.1.

Approximately 300 m of horizontal wellbore is hydraulically fractured at a time, so each well must be hydraulically fractured in multiple stages, beginning at the furthest end of the wellbore. Cement plugs isolate each hydraulic fracture stage and must be drilled out to enable the flow of natural gas up the well after all hydraulic fracturing is complete (Clark *et al.*, 2013a). During the hydraulic fracturing, between 5000 and 15,000 m^3 of fracturing fluid is used per well, depending on the characteristics of the shale formation and horizontal length of the wells. The hydraulic fracturing process typically takes 2–10 days per well, depending upon the depth and horizontal length of the wells and the shale formation.

Once the hydraulic fracturing is completed and the pressure is released, fluid (commonly referred to as flowback water) flows back out the top of the well. The flowback fluid that is recovered not only contains the blend of chemicals present in the hydraulic fracturing fluid, but also contains formation water and chemicals naturally present in the shale, including hydrocarbons, salts, minerals and naturally occurring radioactive materials (NORM) that leach into the fluid from the shale or result from mixing of the hydraulic fracturing fluid with water already present in the shale gas formation or "formation water" (typically a brine or salty water) already present in the formation. The flowback water is mainly composed of the hydraulic fracturing fluid with a relatively low salt (or total dissolved solids, TDS) content (i.e. the flowback contains some water from the shale, called formation water, that typically has high concentrations of TDS). The flowback of the hydraulic fracturing fluids occurs over a relatively short period of time, typically over a 2- to 8-week period, with the majority occurring during the first week. Overall only 25–40% of the hydraulic fracturing fluid is returned to the surface. Over this initial flowback period, the salinity (or TDS content) of the water increases owing to the larger quantity of formation water and dissolved minerals. In addition, the volume of water produced from the well decreases to a smaller and constant volume. This high-salinity water with a constant flow rate continues over the production life of the well and is referred to as produced water (or production water). In some literature, the waters that flow from the well are referred to as wastewater (both flowback and produced waters). In this report, we will distinguish between the flowback and produced water because of the differences in their volumes and chemical composition.

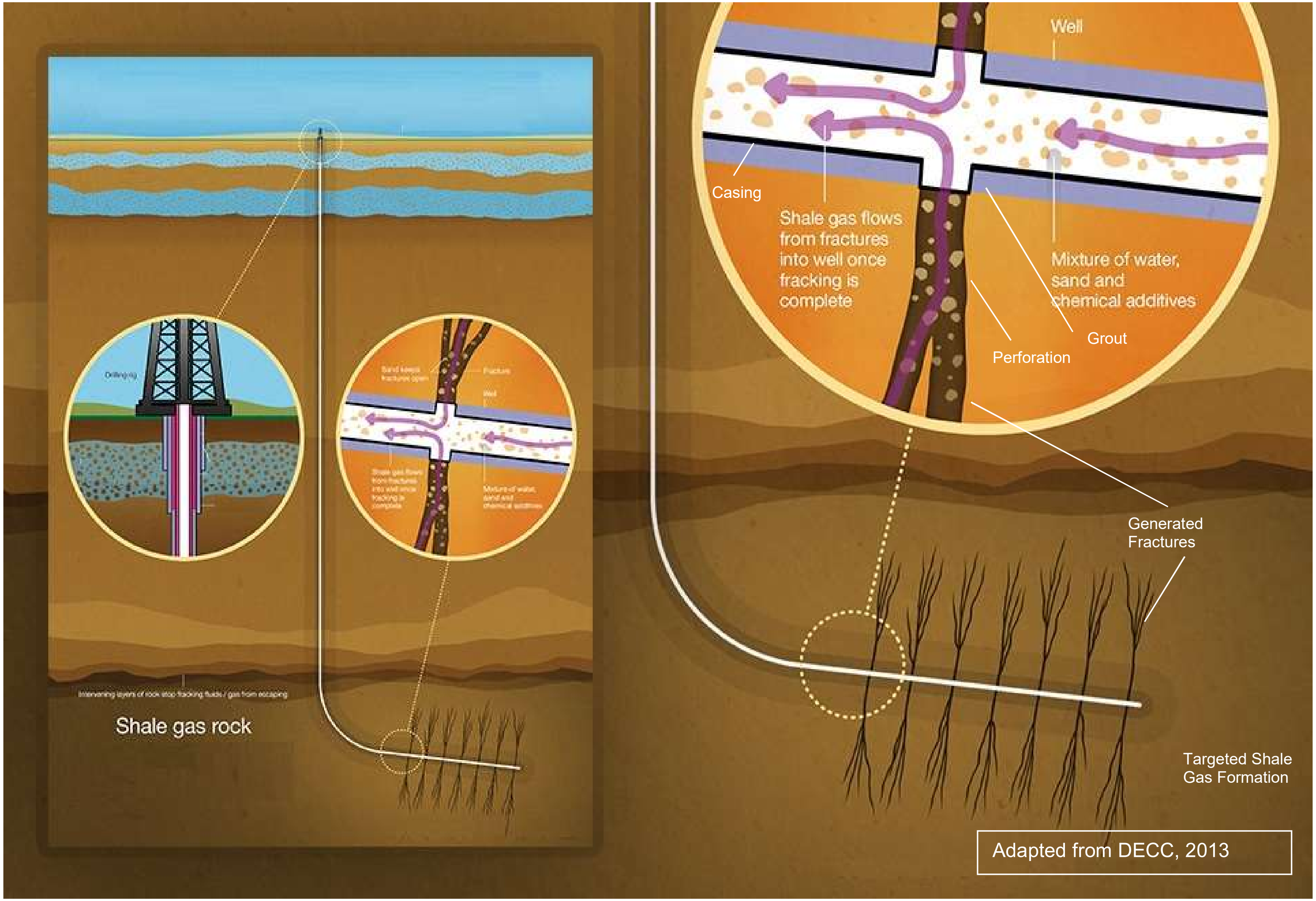


Figure 2.1. UGEE drilling operations.

2.2.3.5 Production, decommissioning and reclamation

During production, gas that is recovered from the well is separated from the produced waters at the wellhead using a gas–water separator and sent to small diameter gathering pipelines connecting to larger pipelines that collect gas from a network of production wells. Because large-scale shale gas production has only been undertaken very recently, the production lifetime of shale gas wells is not fully established. Although there is substantial debate on the issue, it is generally observed that production from shale gas wells declines faster than that from conventional natural gas installations. The estimated lifetime production varies significantly by well. Some wells are expected to produce for up to 40 years without further stimulation, while others may produce economically for only 10 years (EPA, 2015). Tamboran (undated) projected economic gas production in the NCB for over 20 years from wells, but most of the production occurred over an 8- to 10-year period. Most recent studies and evaluations assume an average production lifetime of approximately 10 years (JRC, 2013a; AMEC, 2014; USEPA, 2015a). For the evaluations in this document, the 10-year lifetime has also been used. Once a well no longer produces at an economic rate, the wellhead is removed, the wellbore is filled with cement to prevent leakage of gas into the air, the surface is reclaimed (either to its pre-well state or to another condition agreed upon with the landowner), and the site is returned to the holder of the land's surface rights (Clark *et al.*, 2013). The previously agreed programme of post-closure monitoring is continued.

2.3 Probable Commercial Scenarios

The probable commercial scenario approach was used to assess the impacts on the environment and human health and the mitigation measures. This approach is a way of standardising assumptions made about future UGEE activities, given the uncertainty of whether or not developments will proceed and, if so, how it will develop in Ireland.

Table 2.1 presents the parameters and the values used for the probable commercial scenarios for the CB and the NCB. The parameters and associated values were initially based on the ones used in the European Commission study (AMEC, 2014). A review of the literature (see section 1.1.2), the geology and source formations in the CB and NCB (see section 3) and the physical sizes and characteristics of the actual lease areas in the CB and NCB were used to select appropriate values for the parameters, including parameters such as the typical number of wells, well depth and water consumption in the two study areas. The values selected are typically presented as ranges to provide evaluations under various best-, moderate- and worst-case impact scenarios. For example, section 5 on impacts on water resources evaluates low, moderate and high water demand scenarios. The data sources and assumptions are described in Table 2.1.

Information for the values presented in Table 2.1 were sourced from studies in various countries including:

- Two major North American studies:
  - Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (NYSDEC, 2011);
  - Environmental Impacts of Shale Gas Extraction in Canada (Council of Canadian Academies, 2014).
- A major European Commission report, *Technical Support for Assessing the Need For a Risk Management Framework For Unconventional Gas Extraction* (AMEC, 2014), which utilised information from various European studies including:
  - Support to the Identification of Potential Risks for the Environment and Human Health arising from Hydrocarbons Operations involving Hydraulic Fracturing in Europe (AEA, 2012a);

  - Water Management Associated with Hydraulic Fracturing (API, 2010);
  - Spatially-resolved Assessment of Land and Water Use Scenarios for Shale Gas Development: Poland and Germany (JRC, 2013b).
- In addition, information was obtained from proposed hydraulic fracturing exploration activities in the UK, which is the UGEE activity closest to Ireland:
  - Temporary Shale Gas Exploration, Roseacre Wood, Lancashire, Environmental Statement (Cuadrilla, 2014a).
- Information on greenhouse gas emissions was sourced from the UK Department of Energy & Climate Change (DECC) report, *Potential Greenhouse Gas Emissions Associated with Shale Gas Extraction and Use* (DECC, 2013a).

Given the uncertainty of the development of UGEE activities in Ireland, ranges rather than single values were selected for many of the parameters. The range represents what is considered to be the likely scenario, based on the above-mentioned studies and knowledge of UGEE activities in the EU. On this basis, the range has been named a "typical range" and it does not include extreme values associated with site-specific scenarios in other countries.

Information about the potential depth of wells was provided in *Final Report 1*: *Baseline Characterisation of Groundwater, Surface Water and Aquatic Ecosystems* of the UGEE JRP. The only guideline value concerning depth currently available within legislation for any of the UGEE parameters listed in Table 2.1 is from the UK Infrastructure Act 2015 (Great Britain, 2015), which states that hydraulic fracturing wells must be drilled to a minimum depth of 1000 m.

The project team has also made some assumptions that EU regulations will increase the requirements for the rate of water recycling and that there may be more wells per pad owing to planning restrictions. Chemicals used as part of UGEE projects were not specifically listed as part of the development of probable commercial scenarios; however, the chemicals are discussed in detail in section 9.

Table 2.1. Probable commercial scenarios for UGEE projects in Ireland

	Parameter	Type	Unit	CB	NCB	Guidance values	Description of source of data or assumptions	References
1	Length of horizontal well	Physical	m	1200–1500	1200–1500	–	Typical range	AEA (2012a); AMEC (2014)
2	Depth of vertical well	Physical	m	600–1300	600–1300	> 1000	Report A1-2 Minimum depth proposed by the UK Infrastructure Act (Great Britain, 2015)	Depths in basins – Report A1-2 Guideline value – Infrastructure Act (Great Britain, 2015)
3	Area (overground) covered by well pad during construction	Physical	ha	2–6	2–6	–	Typical range	NYSDEC (2011); JRC (2013b); AMEC (2014); Cuadrilla (2014a); Council of Canadian Academies (2014)
4	Area (overground) covered by well pad during operation	Physical	ha	1–2	1–2	–	Typical range	NYSDEC (2011); JRC (2013b); AMEC (2014); Council of Canadian Academies (2014)
5	Area (overground) covered by roads, corridors, etc.	Physical	ha	2–5	2–5	–	Typical range	Council of Canadian Academies (2014); Cuadrilla (2014a)
6	Area per concession (or lease area)	Physical	km^2	500	470, 750, 1000	–	Licensing areas within NI and ROI	DCENR (2011)
7	No. of well pad sites per concession (or lease area)	Physical	Units	50	60	–	Hypothetical maximum – approximately the number of 1000-m diameter circles per lease area	
8	No. of wellheads per well pad	Physical	Units/well pad	8–16	8–16	–	High range based on industry average assumed	NYSDEC (2011); JRC (2013b); AMEC (2014); Council of Canadian Academies (2014)

	Parameter	Type	Unit	CB	NCB	Guidance values	Description of source of data or assumptions	References
9	Pad density	Physical	Pads/km^2	0.10	0.06, 0.08, 0.12	–	Calculated (lease area/no. wells per lease area)	
10	Days required for vertical drilling	Time	Days/well	15–75	10–75	–	Depends on depth. Existing data from well completion reports suggests 30 days per 1000-m borehole, including geophysical logging and gas pressure monitoring	Well completion reports available in DCENR and DETI files
11	Days for construction (roads and pad)	Time	Days/pad	30–60	30–60	–	Typical range	NYSDEC (2011); Cuadrilla (2014a)
12	Days required for horizontal drilling and site preparation	Time	Days/pad	25–60	25–60	–	Typical range	AMEC (2014); Cuadrilla (2014a)
13	Duration of the drilling stage	Time	Days/pad	35–75	35–75	–	Calculated (total vertical plus horizontal drilling days)	
14	Mud and drill cuttings generated	Waste	m^3 /well pad	1500–2500	1500–2500	–	Typical range	AMEC (2014); Cuadrilla (2014a)
15	Number of fractures per well during lifetime	Physical	Times	1	1	–	Typical commercial scenario	NYSDEC (2011)
16	Required volume of fracture fluid per fracture programme	Resource	m^3	5000–15,000	5000–15,000	–	Reasonable range based on well depths and pressures	JRC (2013b); AMEC (2014)
17	Percentage flowback of fracture fluid per fracture programme	Waste	%	25–40	25–40	–	Typical range	JRC (2013b); AMEC (2014); Cuadrilla (2014a)
18	Percentage flowback recycle rate	Waste	%	40–80	40–80	–	Reasonable range based experience in the EU	JRC (2013b); AMEC (2014); Cuadrilla (2014a)

Parameter		Type	Unit	CB	NCB	Guidance values	Description of source of data or assumptions	References
19	Percentage water content of fracture fluid	Resource	%	90–96	90–96	–	Reasonable range based experience in the EU	API (2010); AMEC (2014); Cuadrilla (2014a)
20	Volume of water (fresh or recycle) per fracture programme	Resource	m^3	4500–14,400	4500–14,400	–	Calculated (based on percentage water content of fracture fluid and volume of fracture fluid)	
21	Proppant content in fracture fluid	Resource	%	4–10	4–10	–	Reasonable range based experience in the EU	API (2010); AMEC (2014); Cuadrilla (2014a)
22	Density of proppant	Resource	t/m^3	2	2	–	Typical commercial scenario	Cuadrilla (2014a)
23	Quantity of proppant in fracture fluid per fracture programme	Resource	t	1200–4000	1200–4000	–	Calculated (based on proppant content and volume of fracture fluid	
24	Percentage fracture fluid – additives	Resource	% of total volume	0.1–0.5	0.1–0.5	–	Reasonable range based experience in the EU	API (2010); AMEC (2014)
25	Volume of additives in fracture fluid per fracture programme	Resource	m^3	15–100	15–100	–	Calculated(based on% facture fluid/additive and required volume of fracture fluid)	
26	Required water storage availability	Resource	m^3	4500–14,400	4500–14,400	–	Calculated (based on percentage fracture fluid/additive and required volume of fracture fluid)	
27	Required proppant storage availability	Resource	t	1200–4000	1200–4000	–	Calculated (based on percentage fracture fluid/additive and required volume of fracture fluid)	

Parameter		Type	Unit	CB	NCB	Guidance values	Description of source of data or assumptions	References
28	Required additive storage availability	Resource	m^3	15–100	15–100	–	Calculated (based on percentage fracture fluid/additive and required volume of fracture fluid)	
29	Storage capacity per truck	Resource	m^3	25	25	–	Typical truck capacity	AEA (2012a); AMEC (2014)
30	No. of truck movements to manage fresh water per fracture programme	Resource	Trucks	180–580	180–580	–	Reasonable range based on capacity of truck and some water source availability on site	
31	No. of trucks for additives	Resource	Trucks	1–5	1–5	–	Calculated (based on volume of additive and truck size)	
32	No. of trucks for proppant	Resource	Trucks	50–160	50–160	–	Calculated [based on quantity of proppant, density of proppant (to get volume) and truck size]	
33	No. of truck movements to manage flowback per fracture programme	Resource	Trucks	80–150	80–150	–	Calculated (based on volume of flowback water and percentage of recycling and truck size – see also section 4.7)	
34	No. of site construction truck movements	Resource	Trucks	45–135	45–135	–		
35	No. of drilling stage truck movements	Resource	Trucks	100–200	100–200	–		
36	Total truck trips per fracture programme	Resource	Trucks	455–1230	455–1230	–	Calculated (totalled truck trips)	

Parameter		Type	Unit	CB	NCB	Guidance values	Description of source of data or assumptions	References
37	Salinity of produced water	Waste	ppm	> 40,000 to > 70,000	> 40,000 to > 70,000	–		Report A1-2
38	Types and levels of contaminants in flowback water	Waste		See list in section 9	See list in section 9	–		
39	Gas production (estimated ultimate recovery, EUR)	Output	Million m^3/well	57–140	57–140	–	Overall productivity or EUR	DECC (2013a)
40	Well lifetime	Time	Years	10	10	–	Average	AEA (2012a); JRC (2013b); AMEC (2014); EPA (2015)
41	Greenhouse gas emission pre-production	Physical	CO_2 eq/well	2600–9400	2600–9400	–	Emissions assuming that the methane released during flowback is 90% captured and flared	DECC (2013a)
42	Life cycle greenhouse gas emissions	Physical	g CO_2 eq/kWh/well	11–28	11–28	–	Emissions assuming that the methane released during flowback is 90% captured and flared	DECC (2013a)

3 Environmental Settings of the Study Areas

3.1 Northwest Carboniferous Basin

3.1.1 Location

The NCB study area is located in the north-west of Ireland. It includes parts of Counties Leitrim, Sligo, Cavan and Roscommon in Ireland, and part of County Fermanagh in Northern Ireland (Figure 3.1). The total area of the NCB study area is 2201 km^2, with 1453 km^2 in Ireland and 748 km^2 in Northern Ireland. The average population density of County Fermanagh is 31 persons/km^2 (Fermanagh District Council, 2011). Fermanagh accounts for 13.2% of land mass of Northern Ireland (NI) and 30% of Fermanagh is covered with lakes and waterways (Fermanagh District Council, 2015). The average population density in the Ireland portion of the NCB study area is approximately 11.8 persons/km^2 (CSO, 2011). The Ireland portion of the NCB accounts for 2.0% of the land mass of Ireland and approximately 4.30% is covered with lakes and waterways. The primary land uses in the NCB study area are sheep and cattle grazing on agricultural pastures (approximately 46%), peat bog (approximately 22%) and coniferous forestry (approximately 7.5%) (EEA, 2006).

3.1.2 Physiography

The physiography (physical geography) of the NCB study area is described by distinct upland and lowland regions in which:

- upland regions are characterised by flat-topped mountains, which are often covered by “blanket peat” and heath; and
- lowland regions are characterised by broad, open valley floors in the east and U-shaped valleys (“glens”) in the west.

The last glacial period marked the landscape with landforms such as U-shaped valleys, corries, drumlins, ribbed moraines and eskers (Thorn, 1985; Coxon and Browne, 1991). Some landforms were carved out by retreating glaciers and ice sheets, while others were formed by the deposition of sediments from glacial meltwaters. The NCB is part of the glacial “drumlin belt”, which extends from Clew Bay in the west of Ireland to Antrim in the north-east (Vernon, 1966; Meehan *et al.*, 2014). The “drumlin belt” comprises thousands of streamlined, oval-shaped hills oriented in a mostly north-west to south-east direction. Individually, they are tens of metres wide and a few hundred metres long. The drumlins are superimposed on larger, curved “‘ribbed moraines” (Dunlop and Clark, 2006; Lemon, 2009; Meehan *et al.,* 2014), which can be upwards of tens of metres high and up to a kilometre wide. The glacially carved U-shaped valleys are visible on the topography map (Figure 3.2).

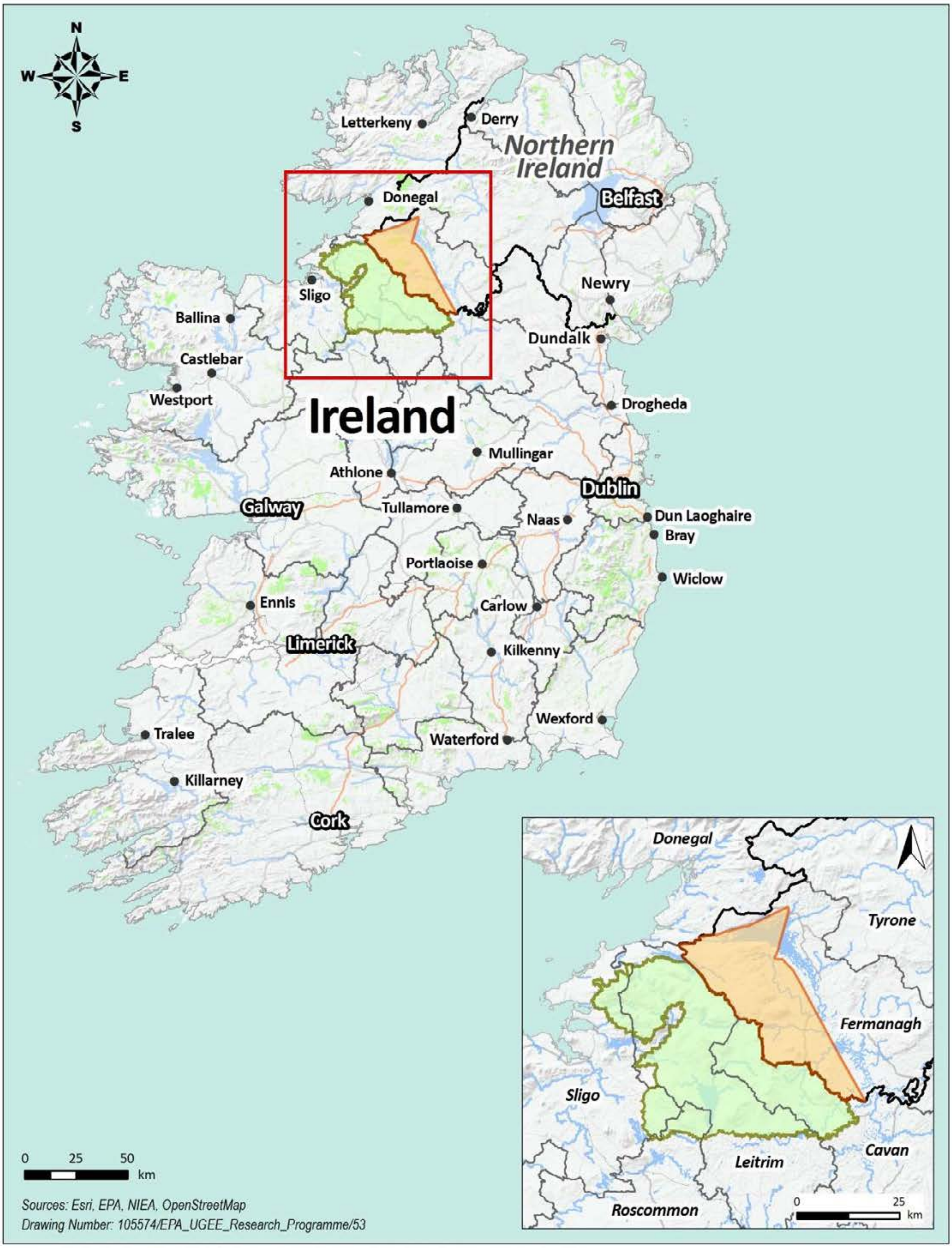


Figure 3.1. NCB – location map.

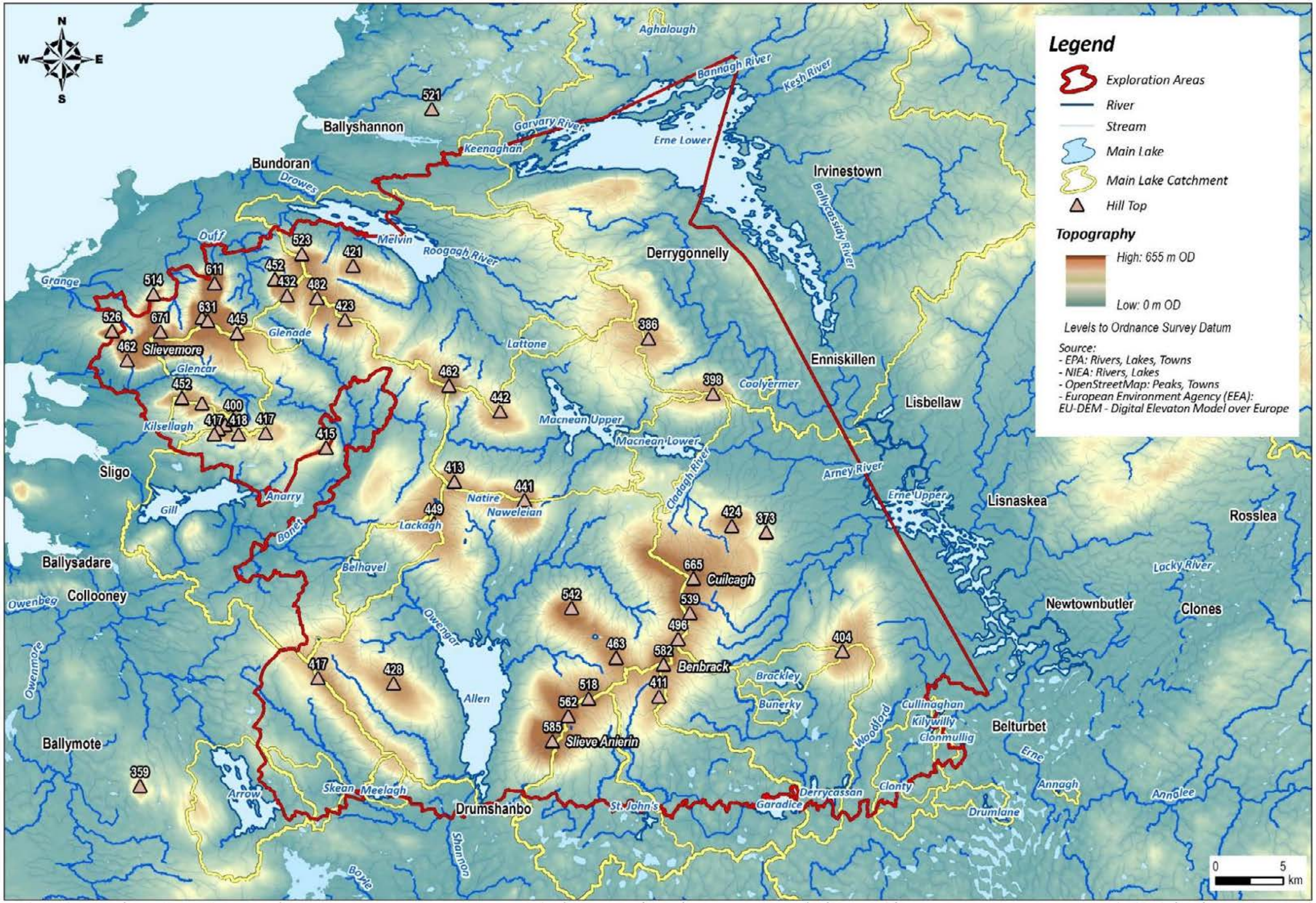


Figure 3.2. NCB – topography map.

3.1.3 Geology

3.1.3.1 Subsoil

The subsoil in the region is primarily peat, and glacial till deposits (“boulder clay”), which comprise the drumlins. Three types of peat are found in the study area: blanket peat, raised bog and fens. The peat has accumulated since the end of the last ice age (approximately 11,700 years ago) and the three types are differentiated by their origins. Blanket peat covers gently undulating upland regions where there is high rainfall and humidity, whereas raised bogs and fens are found mostly in the lowlands. Raised bogs and fens form discreet, dome-shaped masses in or along former lakes or shallow depressions, hollows and river valleys. Fens are associated with limestone areas and thus less acidic conditions relative to raised bogs. Distinct plant communities develop on fens and raised bogs, and it is these communities that differentiate the two type of bogs.

The glacial till is a heterogeneous mix of unconsolidated clay, silt, sand, gravel, pebbles and boulders. This is generally unsorted, unbedded and densely packed. Tills in the area are largely derived from underlying sandstone and shale bedrock (personal communication, GSI, 19 May 2015). Till derived from carbonate (e.g. primarily limestone) formations is the second most common type of till.

3.1.4 Bedrock geology

The bedrock geology of the NCB has been extensively studied by public bodies, such as the GSI and the GSNI, academic research institutions and both oil and gas and mineral exploration companies. A bedrock geological map of the NCB study area is presented in Figure 3.3. The NCB is divided into three main geological “subdivisions”, as follows:

1. Sligo syncline: a regional syncline structure that trends north-east to south-west and is bounded to the west by the shoreline (structure extends offshore) and by the Ox Mountains to the east.
2. Ballymote syncline: a syncline structure that trends north-east to south-west and extends from the Ox Mountains in the west and the Lough Allen Basin in the east.
3. Lough Allen Basin: a regional syncline structure that trends north-east to south-west and extends to Lower Lough Erne in the north, Upper Lough Erne in the east and the Curlew Mountains in the south.

3.1.5 Stratigraphy

The rock layers (strata) and order of layering (stratification) and their relevance in terms of the UGEE JRP are summarised in Figure 3.4. The primary shale formations are the main sources of hydrocarbons, including natural gas. Hydrocarbon exploration has occurred in the Lough Allen Basin in the past and has primarily targeted sandstones in the Tyrone Group, notably;

- Mullaghmore Sandstone Formation;
- Dowra and Drumkeeran Sandstone Members of the Bundoran Shale Formation; and
- “Basal Clastics” (Boyle Sandstone Formation).

The Mullaghmore Sandstone extends across the region, is present in all of the gas exploration wells to date, and is the most extensively tested formation to date. It is up to 200 m thick where it outcrops to the west and north in the NCB, but it thins to the south within the Lough Allen Basin.

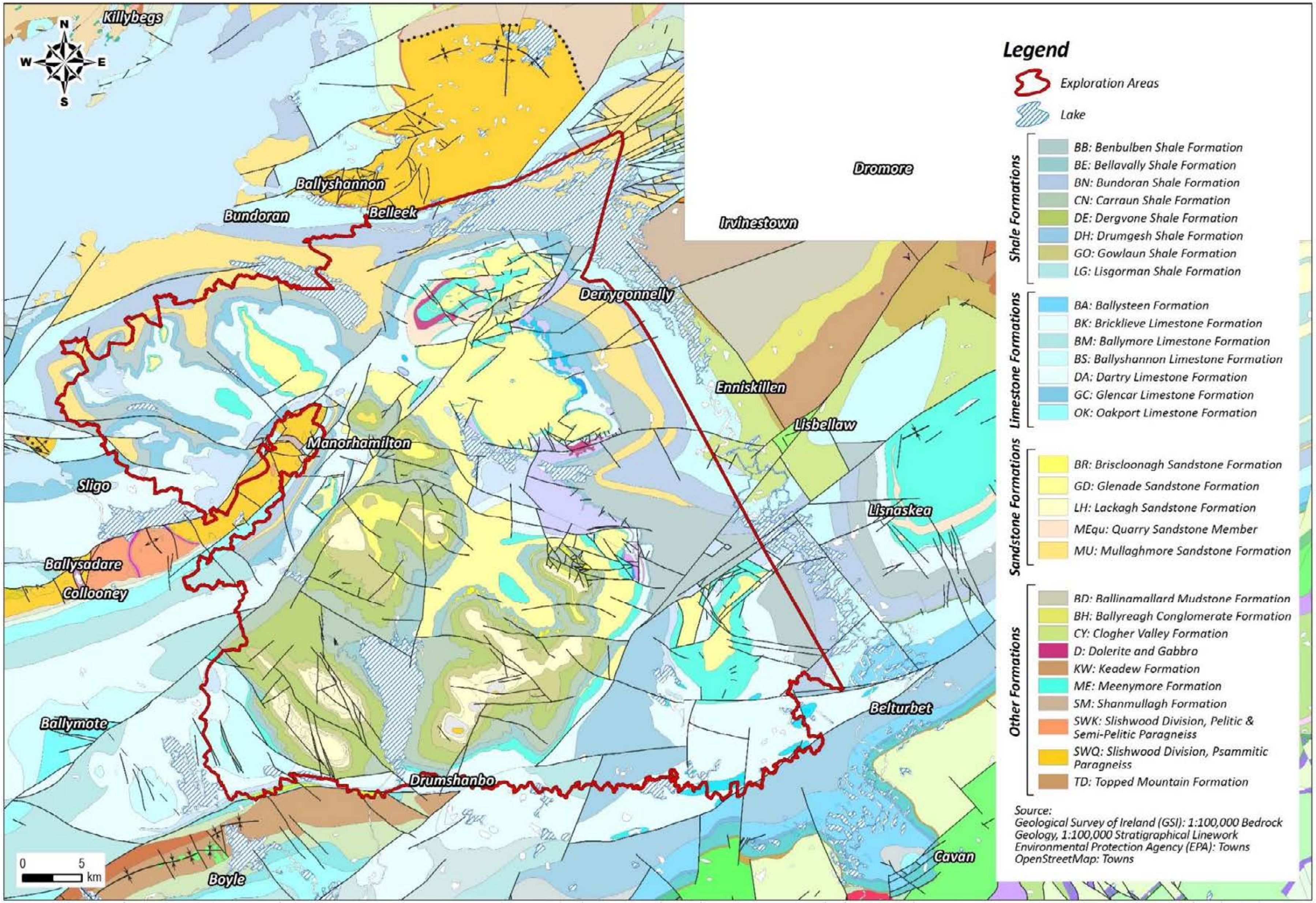


Figure 3.3. NCB – bedrock geology map (adapted from MacDermot *et al.*, 1996, and GSNI, 1997).

The Bundoran Shale Formation is a hydrocarbon source formation in the NCB. The presence of sandstone members within the formation implies that it also serves as a reservoir formation. Technically, it also acts as a cap rock for deeper (older) formations and units with reservoir properties, notably the Basal Clastics. The Bundoran Shale Formation can be found from 490 m to as deep as 1650 m below the ground surface, but the average range is 700 m to 1300 m below the ground surface. The approximately 50-m thick Dowra Sandstone Member of the Bundoran Shale Formation is not known to outcrop and therefore does not appear on existing surface geological maps. However, its presence and extent are inferred from several wells. The Drumkeeran Sandstone Member has been recorded in only one well.

The Benbulben Shale Formation is both a source and a cap rock for deeper shale and gas reservoirs. It is particularly significant because it separates the Bundoran Shale and Mullaghmore Sandstone Formations (i.e. the primary shale gas targets) from the overlying Dartry/Glencar limestone aquifer.

The target formation for UGEE is the Bundoran Shale Formation. Accessing this formation would require wells of depths of 600 m to 1300 m below ground level, depending on location and target depth within the formation (see Table 2.1). The typical horizontal well length range is 1200 m to 1500 m (see Table 2.1; AEA, 2012a; AMEC, 2014).

The geological subdivsions and entire stratigraphic column are illustrated in Figure 3.5, which is a regional scale “reference cross-section” of the whole NCB study area. The section runs from north-west to south-east across the NCB.

3.1.6 Hydrology

The hydrology of the NCB is shaped by its topography, subsoil distribution, underlying geology and climate. The NCB receives significant precipitation, with the annual average (30-year average, 1971–2000) precipitation ranging from 1200 to 2000 mm per year; the higher values in this range are associated with higher elevations (Met Eireann, 2015).

The flat-topped mountains define the boundaries of catchments whose streams and rivers drain west to the coastline or south to the River Shannon. Important lakes, shown in Figure 3.2, include the Upper and Lower Loughs Erne, Upper and Lower Loughs Macnean, Lough Allen and Lough Melvin. Important rivers are the Erne, Arney, Swanlinbar, Woodford, Arigna, Shannon, Owengar, Glencar and Glenade.

The largest catchments are associated with the Lough Erne and Lough Allen drainage systems. These account for approximately 43% and 36% of the total UGEE study area, respectively. The remainder of the catchments (21%) are individually small and drain towards the sea.

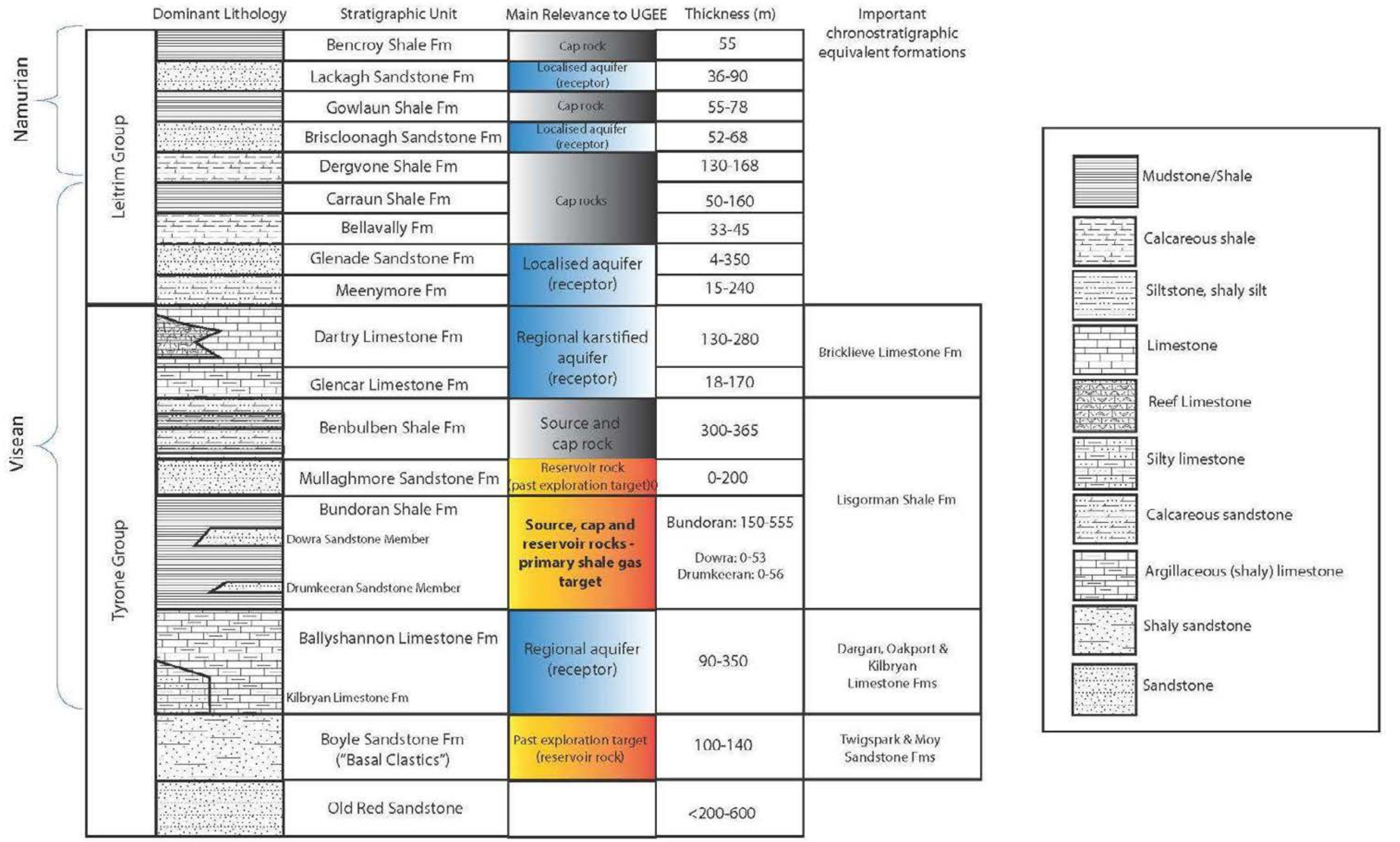


Figure 3.4. Simplified stratigraphy of the NCB.

Fm, Formation.

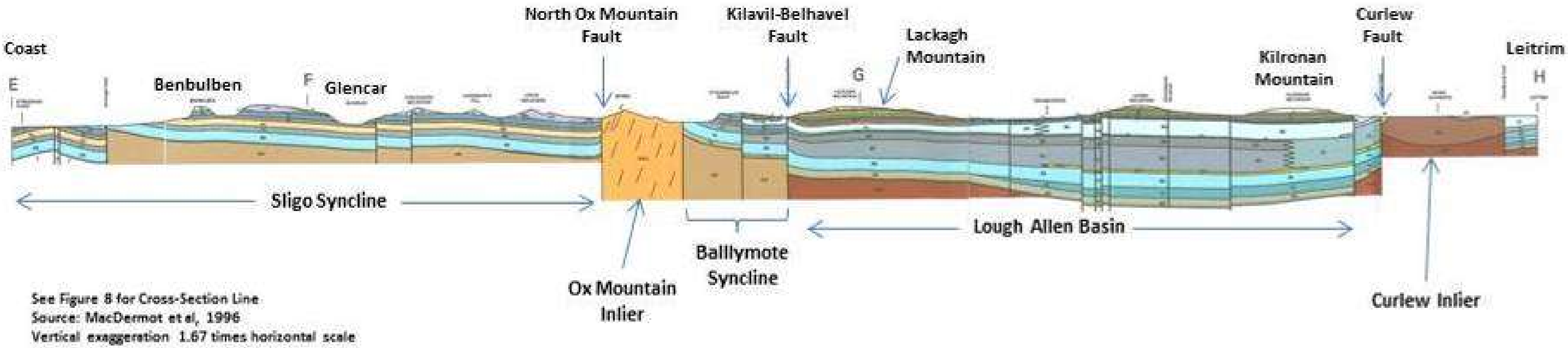


Figure 3.5. Simplified regional cross-section across the NCB (adapted from MacDermott *et al.*, 1996).

The Erne drainage system is hydrologically complex. It is partially sourced from several large karst springs (e.g. Marble Arch, Cascade Springs) at the margins of the Derrygonnelly and Cuilcagh Mountains in County Fermanagh and incorporates several lakes, including Upper and Lower Loughs Macnean. At lower elevations water courses occupy inter-drumlin areas, forming interconnected lakes, bogs and wet meadows (wetlands) where flooding is frequent.

The Lough Allen catchment forms part of the headwaters of the River Shannon system. There are two main sources of water to Lough Allen: (1) direct input from streams that originate on surrounding hilltops; and (2) indirect input from the "Shannon Pot" spring, which is regarded as "the source of the River Shannon". Dams and sluices regulate both the Erne and Lough Allen drainage systems, and both are used for public water supply. The lakes and rivers in the region are important fisheries, supporting several important species of trout, salmon and char.

Runoff from hilltops gives rise to streams that account for the remaining catchments in the study area, including Lough Melvin. In western catchments, streams cut narrow upland valleys (gullies) before entering Lough Gill or flowing to the sea. Waterfalls occur where streams cross harder geological layers (e.g. cherty limestones at Glencar). Harder rock types such as chert can also support the base formation of blanket peat. The limestones are otherwise well drained, and in some places they form patches of limestone pavement.

3.1.7 Water quality

Project A1 of the UGEE JRP includes a detailed characterisation of the groundwater, surface water and associated ecosystems in both study areas and should be referred to for a full description of the aquatic environment and water resources.

Under the Water Framework Directive (WFD) (EC, 2000), a "status" classification has been prepared for each water body (river, transitional, coastal and groundwater), which describes the extent to which "quantitative" and "qualitative" pressures have impacted on the environmental conditions, as obtained from the EPA (2014a) and the NIEA (2014a). In WFD terms, the surface water ecological classification combines three factors: (1) biology; (2) supporting water quality (physicochemical quality); and (3) supporting physical condition (hydrology and morphology). The biological classification system describes the extent to which human activity has altered ecological communities by comparing the condition of aquatic flora and fauna with known, undisturbed or pristine conditions. Figures 3.6 and 3.7 show the surface water bodies and their associated status. Approximately 30% of the river water bodies in the area fail to reach "good" status; failure is on the basis of biological indicators, in particular the quality of macroinvertebrate colonies, as judged from "Q-scores" in Ireland and the "Biological Monitoring Working Party (BMWP) biotic score system in Northern Ireland.

The main cause of the "moderate" and "poor" status of river water bodies in the study area is the composition and abundance of benthic invertebrate fauna. In Ireland, this is mainly attributed to organic (nutrient, e.g. phosphorus) enrichment and oxygen conditions (EPA, 2011a), although there are other pressures that may also contribute, but the specific reasons for the reduced quality of macroinvertebrate colonies in each catchment or water body have not been ascertained and would require further consultation with the EPA and/or NIEA.

All groundwater bodies in the NCB study area are considered to be of good quantitative status, with three groundwater bodies classified as being of poor chemical status: Ballymote, Killarga and Geevagh. In all three cases, the assessment is based on failed phosphorus levels in surface water, whereby the associated karstified limestone aquifers are inferred to contribute greater than 50% of the phosphorus load to the rivers, leading to an exceedance of the river phosphate environmental quality standard.

Transitional waters are surface waters in estuaries that are of a tidal nature, partly saline and also substantially influenced by freshwater outflows. The boundaries of the NCB study area do not extend to the marine environment; however, many of the rivers in the NCB study area flow and discharge into transitional or marine waters further downstream. Of the five transitional water bodies associated with the study area, one is of high status (Drumcliff Estuary), one good (Erne Estuary) and three moderate (Ballysadare Estuary, Drowes Estuary and Duff Estuary).

Although there are no coastal (marine) water bodies within the NCB study area, several streams discharge to coastal waters further downstream. Of those that do, Sligo Bay has been assigned “high” status, but other coastal waters are as yet unassigned by the EPA owing to a lack of monitoring data.

3.1.8 Water-dependent ecosystems

Ecosystems in the two study areas are protected at both the EU and national levels, as follows:

1. EU designated (Natura 2000) sites:
    (a) Special Areas of Conservation (SACs);
    (b) Special Protected Areas (SPAs).
2. National-level designated sites:
    (a) proposed Natural Heritage Areas (pNHAs) and Natural Heritage Areas (NHAs) in Ireland
    (b) Areas of Scientific Interest (ASSIs) in Northern Ireland.

The designated ecological protected areas in the two case study areas are shown and potential impacts discussed in Chapter 7. A Register of Protected Areas for water-dependent habitats and species is maintained by the EPA in Ireland (EPA, 2014b) and by the NIEA in Northern Ireland (NIEA, 2014b) and those that are specifically water-dependent are identified in Figure 3.7 and Figure 3.8.

Further discussion of water quality pressures and classification, water-dependent ecosystems and potential impacts thereon is available in Project A1 of the UGEE JRP.

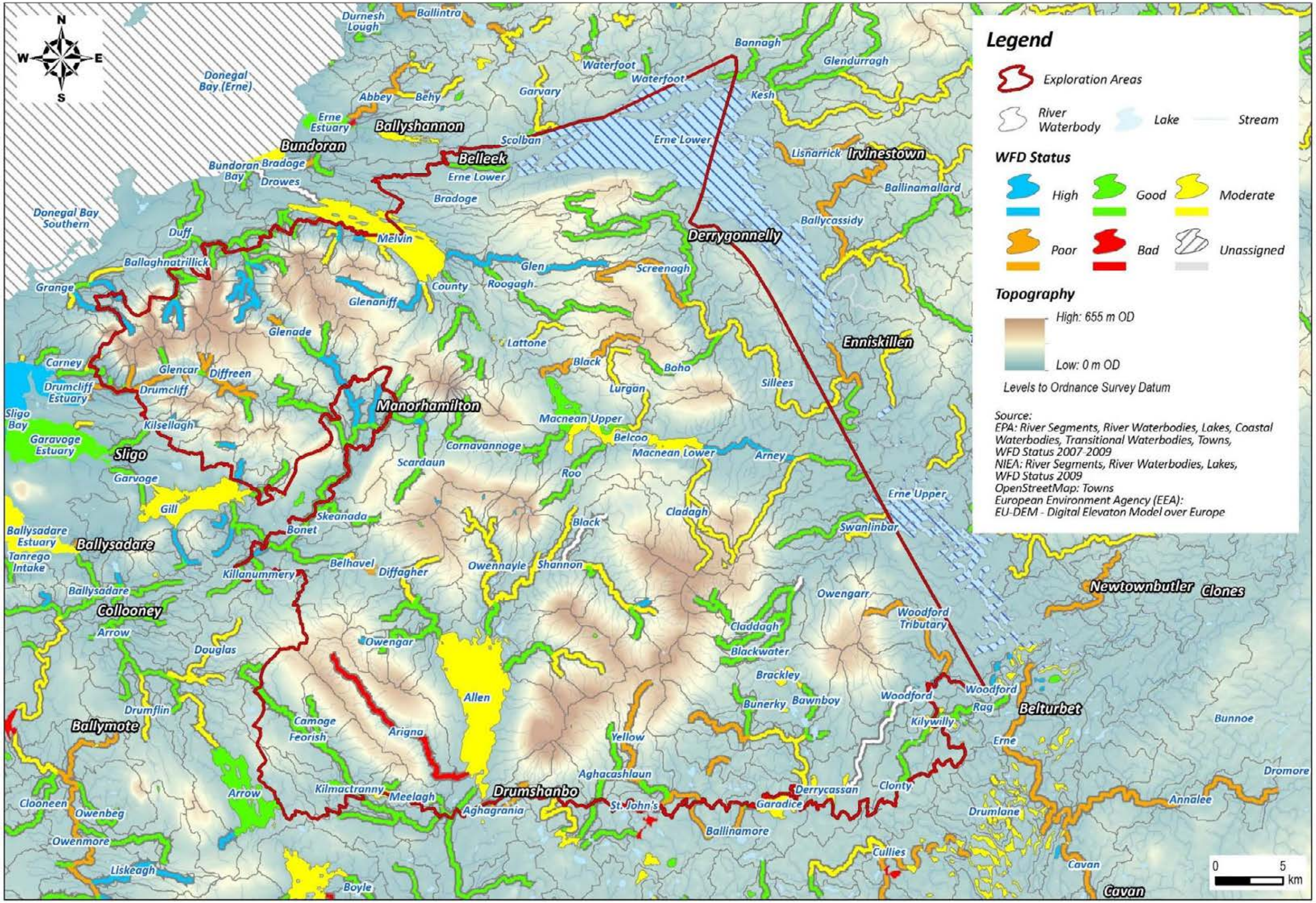


Figure 3.6. NCB – surface water status.

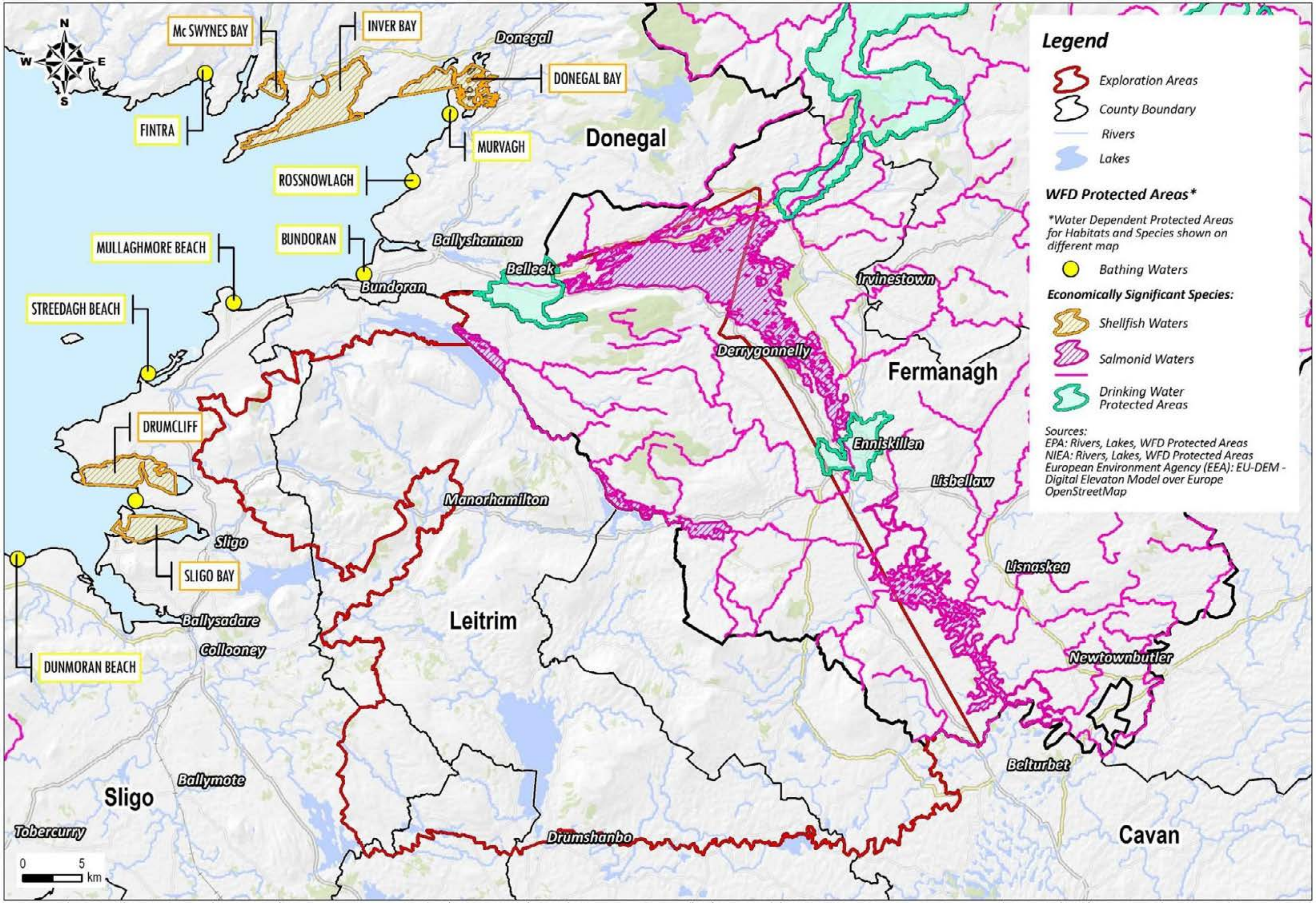


Figure 3.7. NCB – water-dependent protected areas.

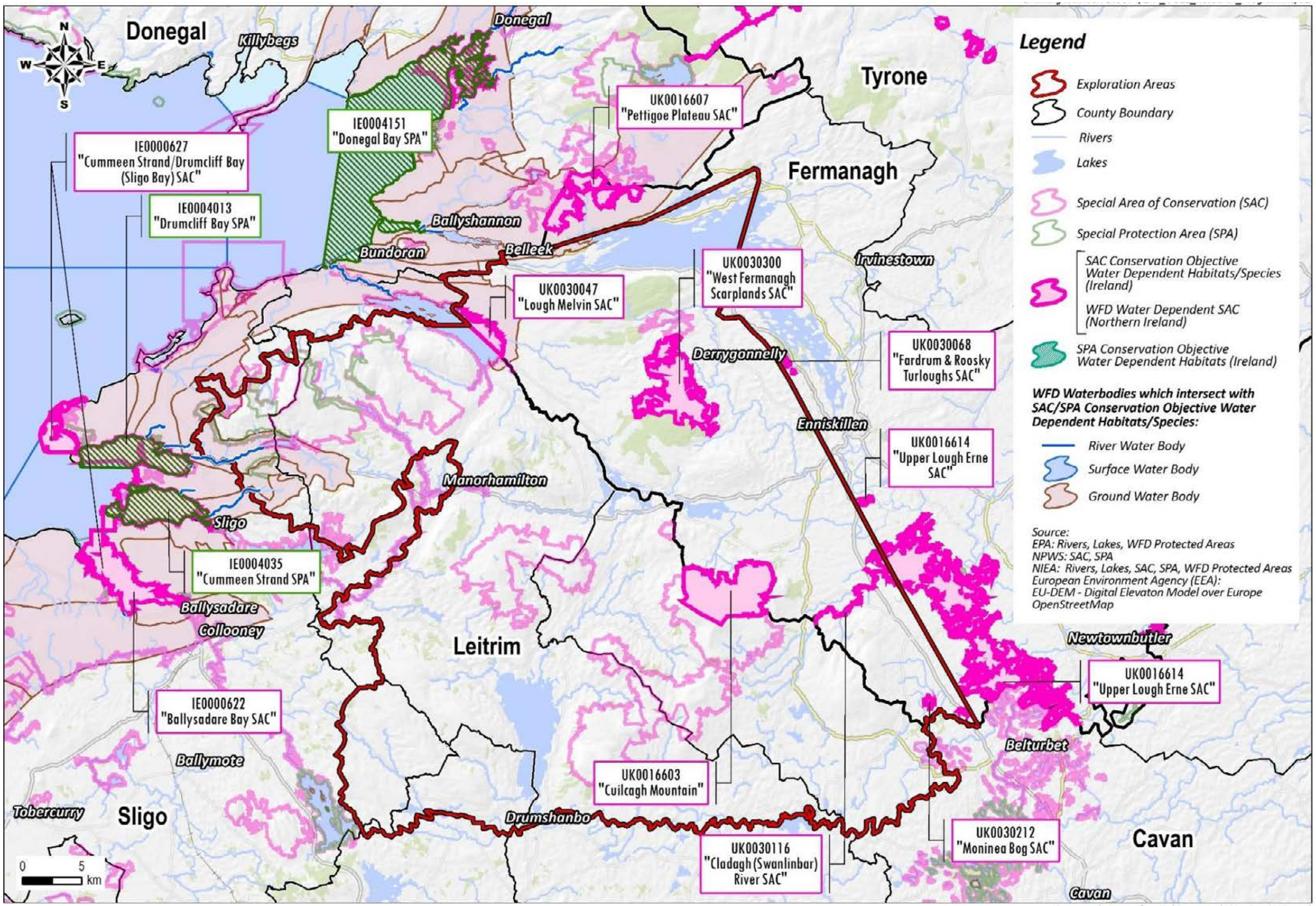


Figure 3.8. NCB – water-dependent protected areas (habitats and species).

3.2 Clare Basin

3.2.1 Location

The CB study area covers 495 km^2 of County Clare, along the Irish west coast (Figure 3.9). The CB study area has a population density of 28.2 persons/km^2 (CSO, 2011) and comprises 0.7% of the total land area of Ireland. Land use in the lowlands consists predominantly of agricultural sheep and cattle grazing (approximately 77%) and peat bog (approximately 6.57%) (EEA, 2006).

3.2.2 Physiography

The CB is a broad upland region with rolling hills that slope gently towards the coastline along the Shannon Estuary and Loop Head Peninsula (Figure 3.10). Maximum elevations in the CB study area are found near Doo Lough (*c*. 150 m above ordnance datum). High rainfall along the west coast has facilitated the formation of extensive blanket peat on both uplands and lowlands. Raised bog can also be found in the lowlands, possibly occupying former (now in-filled) lakes.

3.2.3 Geology

3.2.3.1 Subsoil

Most of the study area is covered by glacial till. The till in the west forms broad sheets several metres thick, while to the east the till forms drumlins. The thickness of till decreases towards the east and there are a number of areas where bedrock is close to or exposed at the surface (outcropping). Alluvial sediments (deposited by water) are found in most stream valleys in the study area. Localised bodies of gravel, which can be more than 10 m thick, occur in the central section of the study area close to Cooraclare and Kilmihil.

3.2.3.2 Bedrock geology

The mapped bedrock geology of the CB study area is shown in Figure 3.11. The CB study area comprises a sedimentary sequence of Namurian age shales, mudstones, siltstones and sandstones resting on older Viséan age limestones (Hodson, 1954; Wignall and Best, 2000). The total sequence of Namurian age rocks is inferred to be 1200 to 1500 m thick near the Shannon Estuary, thinning to the north and south.

Figure 3.9. CB – location map.

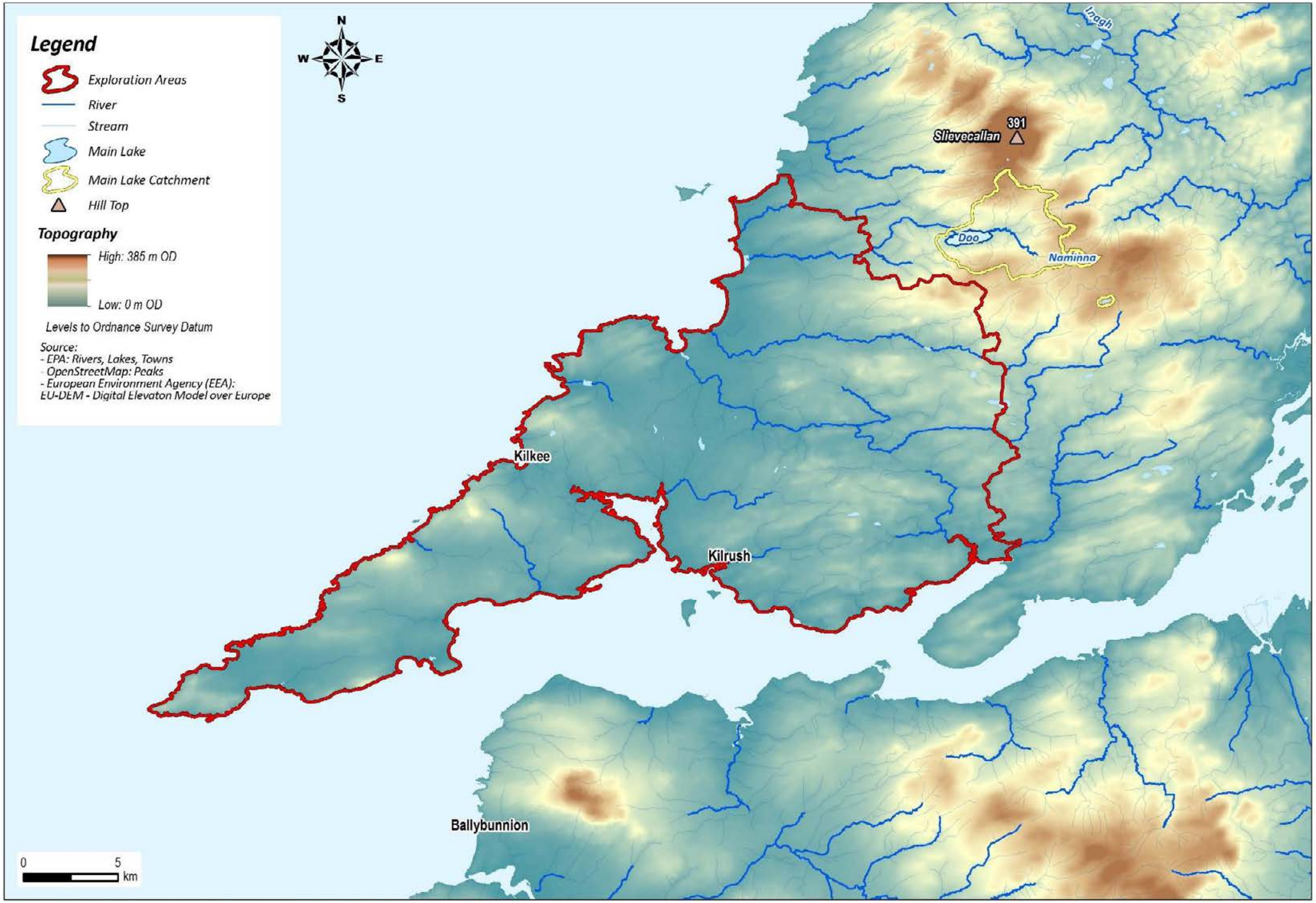


Figure 3.10. CB – topography.

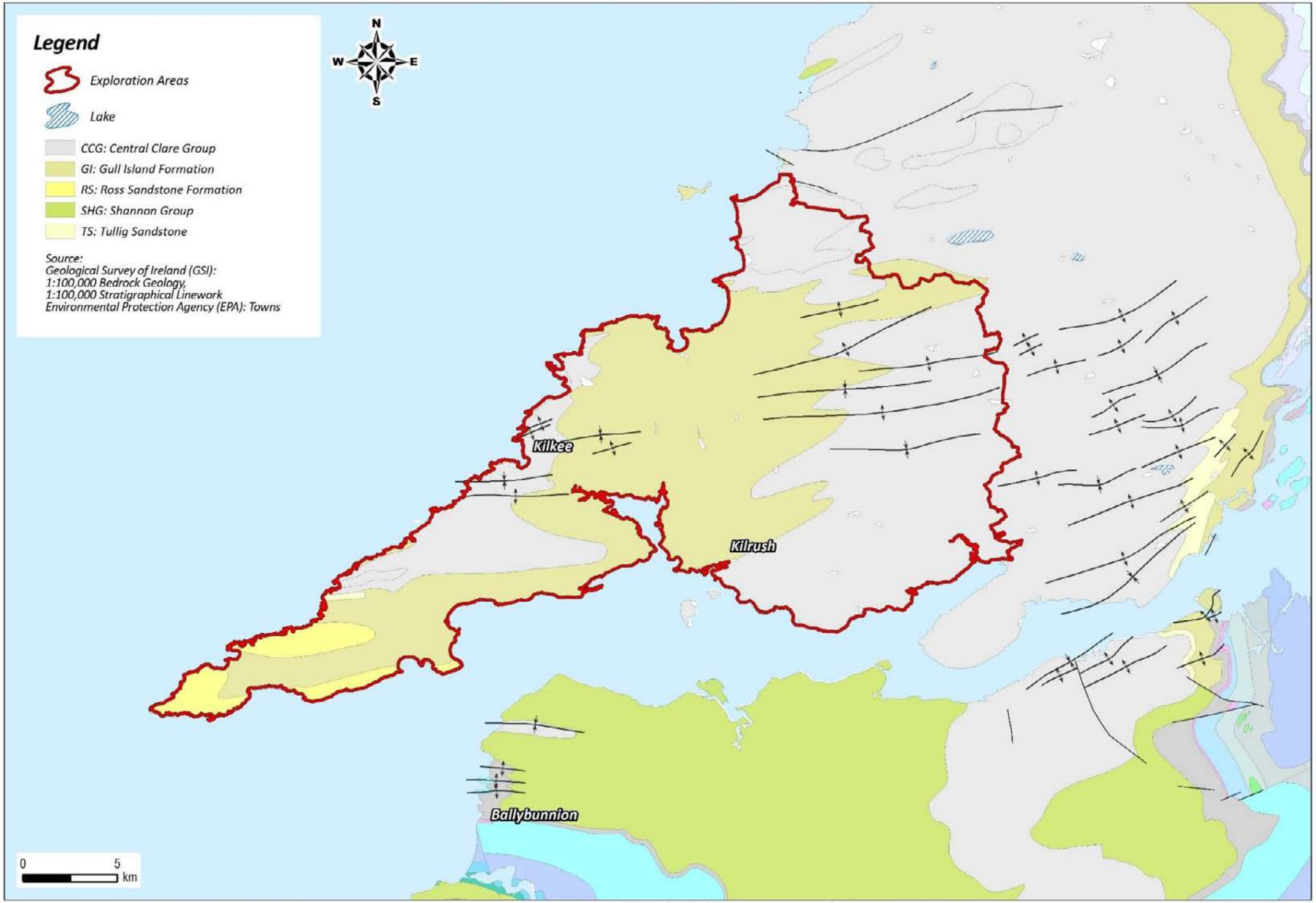


Figure 3.11. CB – bedrock geology.

3.2.4 Stratigraphy

The Namurian age stratigraphic sequence of the CB study, summarised in Figure 3.12, can be broadly divided into two groups (Rider, 1974):

- Shannon Group; and
- Central Clare Group.

The Shannon Group consists of the Clare Shale Formation, the Ross Sandstone Formation and the Gull Island Formation (Rider, 1974). The Central Clare Group consists of five fluvio-deltaic "cyclothems" (Rider, 1974), as described below (Figure 3.12). The target formation for UGEE in the CB is the Clare Shale Formation in the Shannon Group (Figure 3.12). The target vertical well depth is 600–1300 m below ground level, with horizontal well lengths of 1200–1500 m (see Table 2.1; AEA, 2012a; AMEC, 2014). A stratigraphic cross-section of the study area is shown in Figure 3.13 (Sleeman and Pracht, 1999).

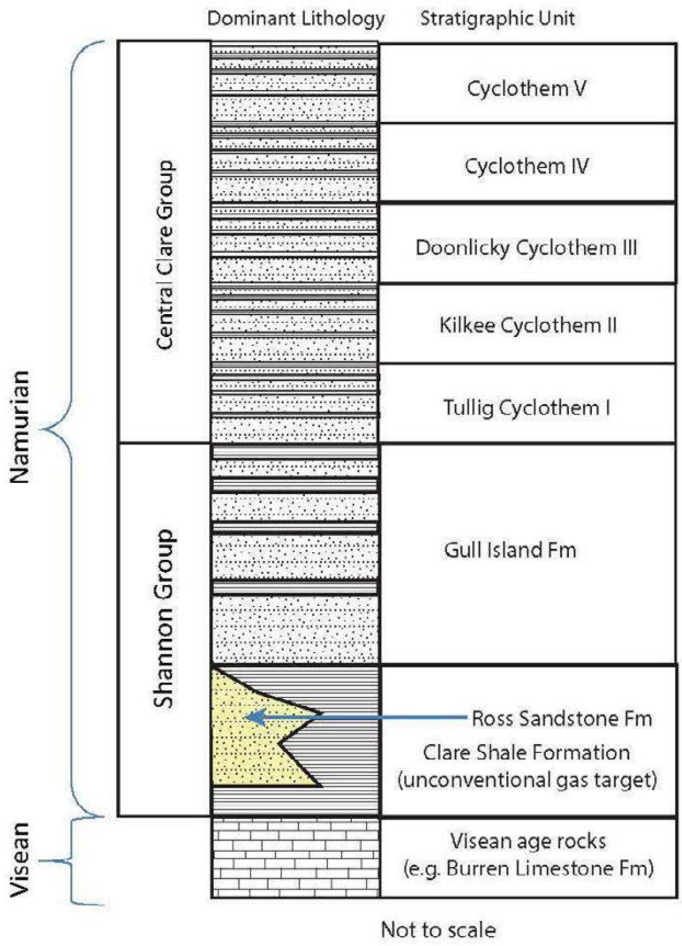


Figure 3.12. Simplified lithological column – CB study area.

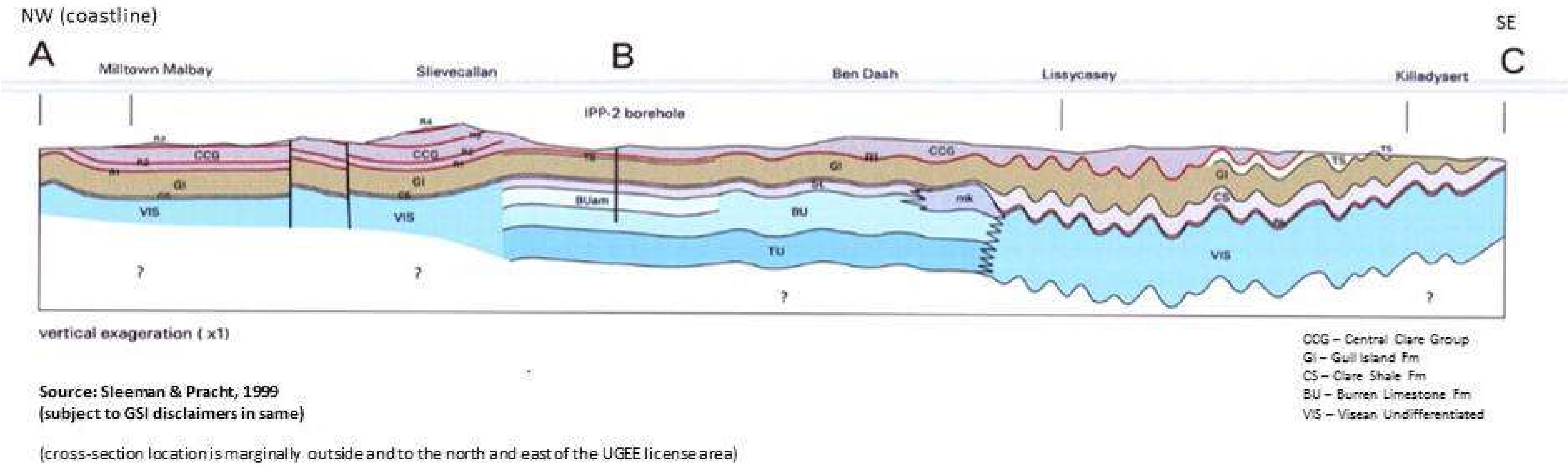


Figure 3.13. Simplified geological cross-section – CB study area. © Geological Society Ireland.

3.2.5 Hydrology

Although several small streams rise from seeps and springs along the margins of bogs on higher ground, there are no major rivers in the CB study area. The streams drain towards the coastline to the west and south. There are several catchments along the coast that are too small to generate any stream flow. Thus, runoff waters flow overland over the cliff landscape along the coastline. There are no medium- or large-sized lakes within the CB study area. The closest sizable lake is Doo Lough to the east, which is part of the Annageragh stream catchment. The annual average precipitation within the study area (30-year average, 1971–2000) ranges from 1200 to 1400 mm per year (Met Eireann, 2015).

3.2.6 Water quality

Project A1 of the UGEE JRP includes a detailed characterisation of the groundwater, surface water and associated ecosystems in the study area and should be referred to for a full description of the aquatic environment and water resources.

Figures 3.14 shows the surface water bodies and their associated status. Approximately 60% of the river water bodies in the area fail to reach “good” status; failure is on the basis of biological indicators, in particular the quality of macroinvertebrate colonies, as judged from “Q-scores” in Ireland and the BMWP biotic score system in Northern Ireland.

Similar to the NCB, the main cause of the “moderate” and “poor” status of river water bodies in the study area is the composition and abundance of benthic invertebrate fauna. In Ireland, this is mainly attributed to organic (nutrient, e.g. phosphorus) enrichment and oxygen conditions (EPA, 2011a), although there are other pressures that may also contribute, but the specific reasons for the reduced quality of macroinvertebrate colonies in each catchment or water body have not been ascertained and would require further consultation with the EPA and/or NIEA.

All groundwater bodies in the CB study area are of good quantitative and chemical status.

Transitional waters are surface waters in estuaries that are of a tidal nature, partly saline and also substantially influenced by freshwater outflows. Of the four transitional water bodies associated with the study area, two are of good status (Clonderalaw Bay and Doonbeg Estuary), one moderate (Lower Shannon Estuary) and one unassigned (Lough Donnell).

Of six coastal water bodies associated with the CB study area, the status of five are unassigned owing to a lack of data. The remaining water body, Mouth of the Shannon, is classified as “high” status.

3.2.7 Water-dependent ecosystems

Ecosystems in the two study areas are protected at both the EU and national levels, as follows:

1. EU designated (Natura 2000) sites:
   (a) Special Areas of Conservation (SACs);
   (b) Special Protected Areas (SPAs).
2. National-level designated sites:
   (a) proposed Natural Heritage Areas (pNHAs) and Natural Heritage Areas (NHAs) in Ireland;
   (b) Areas of Special Scientific Interest (ASSIs) in Northern Ireland.

The designated ecological protected areas in the two case study areas are shown and potential impacts discussed in Chapter 7. A Register of Protected Areas for water-dependent habitats and species is maintained by the EPA in Ireland (EPA, 2014b) and by the NIEA in Northern Ireland (NIEA, 2014b) and those that are specifically water dependent are identified in Figure 3.15 and Figure 3.16.

Further discussion of water quality pressures and classification, water-dependent ecosystems and potential impacts thereon is available in Project A1 of the UGEE JRP.

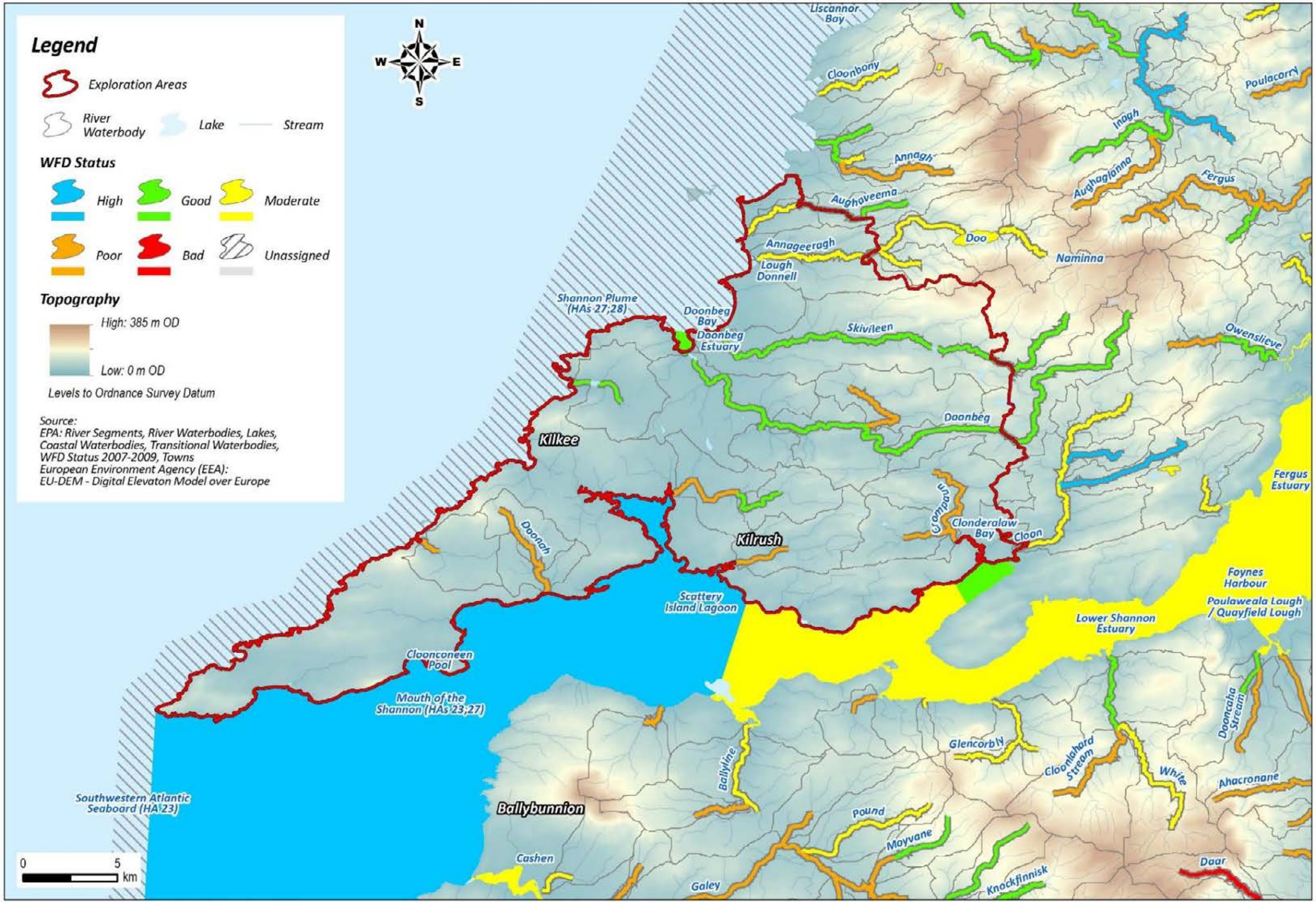


Figure 3.14. CB – surface water status.

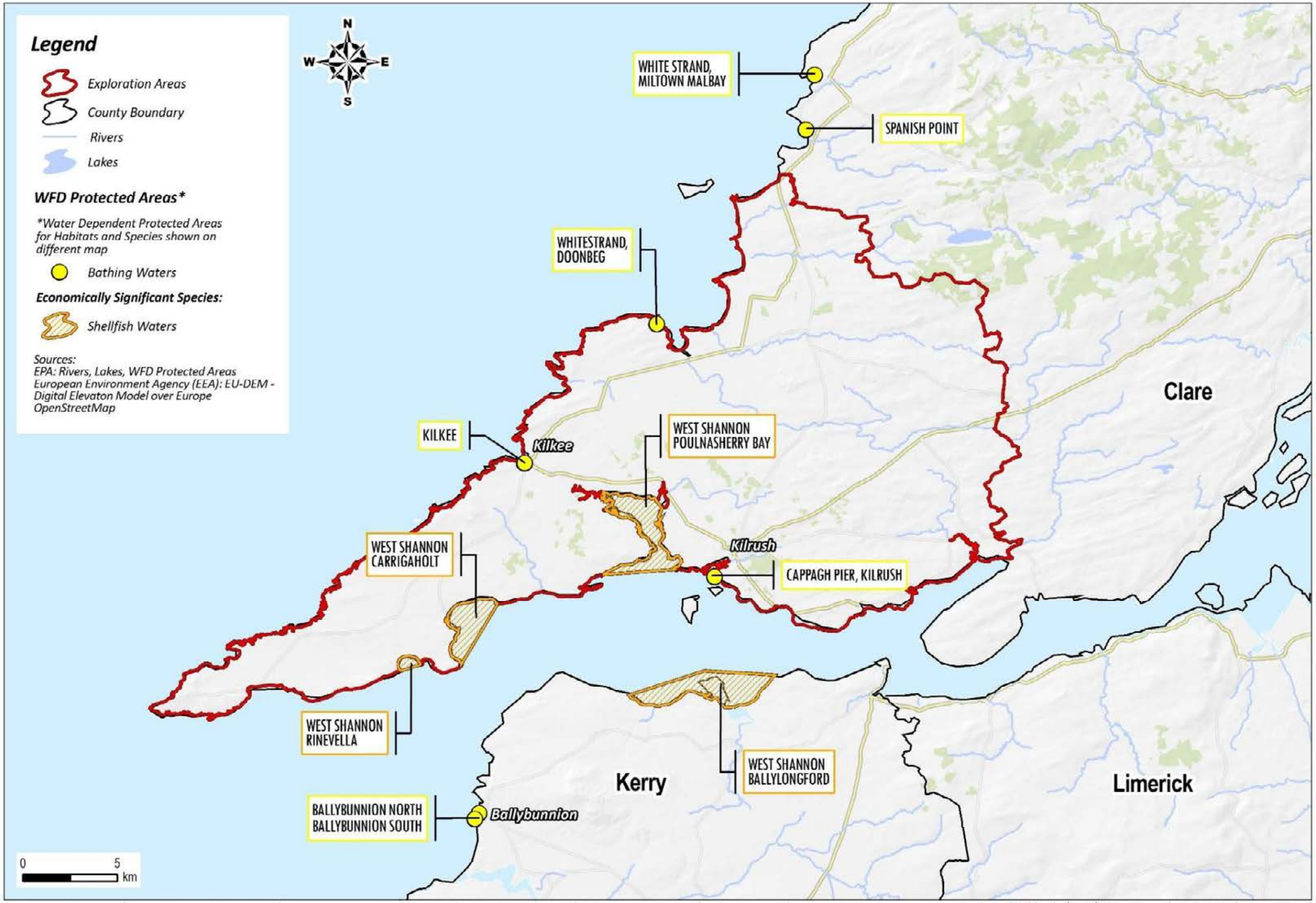


Figure 3.15. CB – water-dependent protected areas.

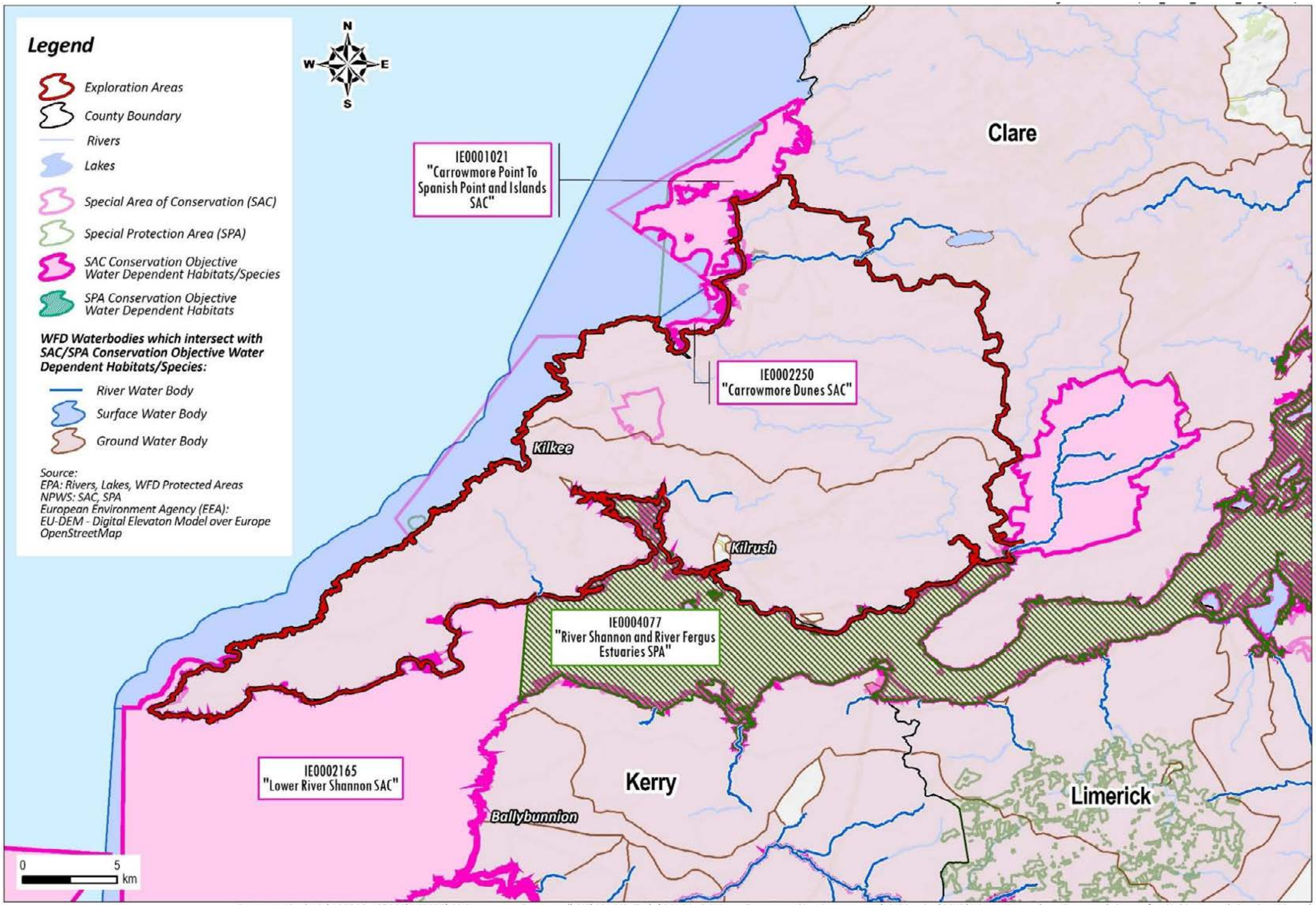


Figure 3.16. CB – water-dependent (habitats and species) protected areas.

4 Impacts on Environmental Water Quality and Mitigation Measures (Task 1)

4.1 Objectives

The overall objective of Task 1 is to evaluate potential impacts (both positive and adverse) on water resources and to identify relevant mitigation measures associated with UGEE development and production. Specifically, Task 1 addresses potential impacts on the quality of water resources in the case study areas, and thus supplements the assessment of Task 2, which addresses the available supply and quantitative aspects of impacts on water resource.

In Task 1, the potential impacts on water quality were evaluated in the context of the following activities:

- storm water runoff and run-on from utility corridors, road and pads;
- surface chemical spills and leaks during transport, storage at well pads, drilling and hydraulic fracturing;
- improper well construction, well completion and operation, including failures during drilling, hydraulic fracturing and production;
- pit, impoundment or tank leaks of on-site stored flowback water, produced water, drilling muds and cuttings; and
- leaks, spills or improper disposal of flowback water, produced water, drilling muds and cuttings during off-site treatment, transport and disposal.

In Europe, shale gas is currently in its exploratory phase. Low numbers of exploratory wells have been drilled, with Spencer *et al*. (2014), reporting that, as at February 2014, approximately 50 wells had been drilled. As a result, this report draws on experience and published information from jurisdictions where UGEE activities are at a more advanced stage, such as the USA.

4.2 Methodology

The assessment methodology followed these basic steps:

- description of specific activities associated with UGEE and their potential impact on water quality (surface and groundwater);
- description of potential impact sources and associated potential contamination (e.g. storm water runoff, additives, drilling muds, flowback water, produced water, etc.) on water resources (i.e. the source element in the source–pathway–receptor model of risk assessment);
- description of potential release scenarios that could have an impact on the quality of water resources (i.e. the pathway element of the source–pathway–receptor model of risk assessment);
- evaluation of the risks of potential impacts for each activity and release scenario, with respect to both potential human and environmental receptors (i.e. the receptor element of the source–pathway–receptor model of risk assessment);
- description of relevant management strategies and mitigation measures to minimise or eliminate risks of potential releases and impact; and
- evaluation of cumulative impacts and associated risks.

4.3 Impacts from Storm Water Runoff

4.3.1 Description of storm water runoff

Water runoff is generated during rainfall events, and the amount of runoff generated is a function of numerous variables that are location specific: rainfall amounts, duration and intensity, evapotranspiration, infiltration capacities of soils, subsoils and bedrock, land slope, land use and presence and density of field drains.

Rainfall runoff from asphalt, gravel and dirt roads, open construction areas and other "made" surfaces is typically referred to as storm water. On made surfaces, the ground surface is compacted, covered or otherwise less pervious, resulting in more runoff that flows with greater intensity than on undisturbed land. Thus, the clearing of vegetation, excavation and compaction of soils associated with new roads, pipeline corridors and well pads will result in an increased potential for storm water generation. The high volumes and intensity of storm water runoff also result in increased erosion, which in turn results in elevated sediment loads and levels of turbidity (suspended solids) from undisturbed land. The storm water runoff from paved areas (e.g. roads) may also have elevated concentrations of organic compounds (e.g. from the asphalt and oil and grease from vehicle leaks) and metals (e.g. lead, cadmium, zinc and copper associated with vehicle traffic generated from mechanical friction of engine systems, brake pad abrasion, tyre wear, vehicle body corrosion, lead tyre weights and leaded fuel; Lancaster and Beutel, 2011).

Storm water runoff and potential concerns are not unique to UGEE operations; however, the quantities of storm water associated with UGEE operations are evaluated in the following paragraphs. For each well pad, the disturbed area is estimated to be 2–6 ha during construction and hydraulic fracturing (see Table 2.1). This is typically excavated open land with subsequent compaction. During production, the disturbed area decreases and is estimated to be 1–2 ha (some covered by impoundments, tanks, wells, etc.). For the roads and other corridors (e.g. for pipelines), the estimated area is 2–5 ha per well pad (see Table 2.1).

The maximum number of well pads per lease area may range from 50 (CB) to 60 (NCB) (see Table 2.1), thus the corresponding areas associated with well pads and roads and corridors in each lease area (three in the NCB and one in the CB) would be:

- per NCB lease area (three in total):
    - pads during construction and hydraulic fracturing: 120–360 ha;
    - pads during production: 60–120 ha;
    - roads and corridors: 120–300 ha;
- total single CB lease area:
    - pads during construction and fracturing: 100–300 ha;
    - pads during production: 50–100 ha;
    - roads and corridors: 100–250 ha.

Chapter 5 discusses low, moderate and high water use (demand) scenarios for the CB and NCB, assuming a 15-year complete build-out of wells and a total production lifetime of 25 years (15-year build-out + 10-year production life per well) in each lease area (see Tables 5.1 and 5.2). Under the various demand scenarios, the number of well pads per lease area ranges from 25–60 for the NCB and from 20–50 for the CB. In addition, a gradual build-out in each lease area is anticipated, with the maximum number of wells and pads completed in years 7–10, resulting in the maximum amount of construction and disturbed pad areas. The maximum number of wells and pads in production will occur during years 12 and 13 given the anticipated 10-year production lifetime for each well, after which wells and pads are closed and reclaimed. Therefore, the values given above for total areas of pads and roads and corridors may be significantly less, depending upon the exact timing of activity and build-out in the lease areas. In addition, there is currently an extensive network of roads and the amount of new construction will depend upon the exact locations of the well pads. The current amount of existing roads was examined for the two case study areas. Given the maximum number of well pads, the potential requirement for new roads was estimated to range from 20–60 km per lease area in the NCB (60–195 ha of new paved road surface), and 10–20 km in the CB (30–65 ha of new surface area). Overall, the amounts of well pads and roads discussed above are conservatively high for the high-demand scenarios and the number of pads is more likely to be between the numbers for the low- and moderate-demand scenarios because of practical spatial constraints in terms of the depth of target gas formations (excluding shallow depths of typically less than 500 m), areas of water bodies, SACs and other environmentally sensitive locations (see section 5.3.1 for more detailed discussion).

Rainfall across the study areas varies significantly, as presented in Appendix B. Based on information sourced from Met Éireann (Met Éireann, 2015; Walsh, 2012), the maximum 30-year monthly average rainfall values are:

- NCB (three lease areas):
  - maximum of 162 mm per month in December;
  - minimum of 81.8 mm per month in June;
- CB (one lease area):
  - maximum of 133 mm per month in October;
  - minimum of 67.9 mm per month in April.

However, there is significant variability in rainfall even within lease areas, as rainfall totals are influenced by topography. Upland regions receive more rainfall than lowland regions (see Appendix B). Rainfall intensities also vary significantly in the two study areas.

Using the maximum areas of well pads and estimated new roads discussed above, the estimated monthly volumes of storm water runoff (assuming a runoff coefficient of 0.6 for bare areas and 0.9 for paved areas) would be:

- per NCB lease area (three in total):
  - pads during construction and fracturing: 60,000–350,000 m^3 per month (1000–5800 m^3 per month per pad);
  - pads during production: 30,000–115,000 m^3 per month (500–1900 m^3 per month per pad);
  - roads: 30,000–85,000 m^3 per month (450–1300 m^3 per month per kilometre);
- total single CB lease area:
  - pads during construction and fracturing: 40,000–240,000 m^3 per month (800–4800 m^3 per month per pad);
  - pads during production: 20,000–80,000 m^3 per month (400–1600 m^3 per month per pad);
  - roads: 12,000–23,000 m^3 per month (400–800 m^3 per month per kilometre).

4.3.2 Description of storm water runoff mitigation and management scenarios

In Ireland and Northern Ireland, regulations and guidance documents are available to manage storm water runoff from roads and facilities. One example of such a document is *The SuDs Manual* (CIRIA,

2015) – from "sustainable drainage systems". It provides guidance for designs and technical details for road drainage, detention basins, runoff calculations, pollution prevention and operations and maintenance. Examples of management of runoff from road and pads would be the use of swales, basins and ponds. The manual also provides references to other guidance documents and regulations, including the following:

- *Code of Practice for Surface Water Management for Development Sites* (BS 8582:2013);
- *Design Manual for Roads and Bridges* (Highways Agency *et al*., 2014).

Operation and maintenance activities for storm water management systems are important in limiting potential impacts and maintaining the effectiveness of the systems. Operations and maintenance activities and detailed protocols are provided in the *The SuDS Manual* and include the following (CIRIA, 2015):

- regular maintenance:
    - inspection;
    - litter and debris removal;
    - grass cutting;
    - weed and invasive plant control;
    - shrub management;
    - aquatic vegetation management;
- occasional maintenance:
    - sediment management;
    - vegetation replacement;
    - vacuum sweeping and brushing;
- remedial maintenance:
    - structure rehabilitation and repair;
    - infiltration surface reconditioning.

In the USA, the major control mechanisms to mitigate potential adverse impacts associated with storm water runoff are provided and documented in a storm water pollution prevention plan (SWPPP). SWPPPs are required for hydraulic fracturing projects and provide the development, implementation and maintenance measures to address the impacts of runoff, including erosion, sedimentation, peak flow volumes and contaminated discharges.

A successful SWPPP employs engineering measures to reduce or prevent erosion and potentially contaminated waters from having an impact on existing surface water bodies and wetlands, as well as maintaining post-development runoff volumes and patterns as close as possible to pre-development conditions. Many potential adverse impacts may be avoided by planning and implementing a development that is specific to the site characteristics. Examples include avoiding steep slopes and maintaining appropriate setback distances to the receptors in question (NYSDEC, 2011). Uncontaminated water (e.g. run-on) should be diverted away from excavated or disturbed areas. Limiting the amount of soil exposed at any one time, stabilising disturbed areas as soon as possible, rapid spill remediation and basic housekeeping practices will minimise the risks of potential impacts. Measures to treat and test storm water and control runoff rates may also be required by regulatory authorities [e.g. New York State (NYSDEC, 2011)]. In addition to the SWPPP, several states in the USA require a specific permit or licence to discharge storm water to existing streams and use of best management practices (BMPs). Requirements include both structural and non-structural BMPs. Structural BMPs include features such as dikes, swales, diversion ditches, drains, traps, silt fences, vegetative buffers, sedimentation ponds, etc. (NYSDEC, 2011). Non-structural BMPs include good housekeeping measures, sheltering activities to minimise exposure to rainfall, preventative maintenance, spill prevention and response protocol, routine inspections and documentation, employee training, etc. (NYSDEC, 2011). Permit conditions require specific monitoring, inspections and record keeping, including visual monitoring, dry weather flow inspections, baseline monitoring and analysis and sample collection and analysis in containment areas before discharges. Most of these requirements are provided in regulations associated with hydraulic fracturing projects (see Project C of the UGEE JRP report for specific case studies).

4.3.3 Evaluation of potential impacts on surface water

Given the potential volumes of runoff estimated in Ireland and Northern Ireland from each pad and road provided in section 4.3.1, the storm water runoff mitigation measures discussed above would significantly limit the potential impacts of storm water during UGEE projects and operations, if implemented and maintained properly. However, even with state-of-the-art storm water controls, there are still risks of impacts as a result of accidental spills, unanticipated events (e.g. rainfall exceeding design capacities), inadequate designs and implementation (see section 4.6.3 for examples concerning impoundments) and lack of proper maintenance. In addition, smaller streams and ecologically sensitive receptors are more vulnerable to storm water runoff. Therefore, there is still a need for appropriate regulations, approvals, oversight and inspections by regulatory bodies.

4.3.4 Evaluation of potential impacts on groundwater

Groundwater is a potential receptor of contaminated storm water, and the risks of impact can be naturally mitigated if well pads and related UGEE activity are directed towards areas of low groundwater vulnerability rather than areas of high or extreme groundwater vulnerability, as mapped by the GSI and the GSNI. The principles of groundwater protection are outlined in guidance from DELG, EPA and GSI (1999) and further described in the EPA guidance document on the prior authorisation of discharges to groundwater (EPA, 2011b).

Groundwater and associated receptors are particularly vulnerable to contamination from surface runoff where such runoff can enter the groundwater environment directly at point recharge locations, such as swallow holes and active dolines in karstified limestone terrains. Karst conduits can transport contaminants over large distances (kilometres) in short periods of time (hours, days) without further attenuation of the contaminants other than dilution and mixing. Therefore, an awareness of pathways and groundwater receptors must be considered in the planning and regulatory context of any future UGEE projects and operations.

4.4 Impacts from Surface Chemical Spills and Leaks

4.4.1 Description of chemicals used during UGEE operations

The additives and chemicals used in UGEE operations include drilling fluids, engine fuels (petrol and diesel), operational fluids (such as lubricants, hydraulic fluids, etc.) and additives used for hydraulic fracturing. The following discussion focuses on additives used during drilling and hydraulic fracturing.

Additives used in hydraulic fracturing are presented in detail in Chapter 9 of this report. As documented in Table 9.1, different types of additives are used for different purposes, and additive types can include, but are not limited to, acids, biocides, breakers, clay stabilisers, corrosion inhibitors, cross-linkers, foamers, defoamers, friction reducers, gellants, pH control, scale control and surfactants. The chemicals that make up the additives include, but are not limited to, petroleum distillates, aromatic hydrocarbons, glycols, ethers, alcohols, aldehydes, amides, amines, acids, salts and esters (see Chapter 9 for further detail). The US Environmental Protection Agency (USEPA, 2015a) noted that the most frequently used chemicals are methanol (72% of disclosures), hydrochloric acid (65%) and hydrotreated light petroleum distillates (65%). Other frequently used chemcials include isopropanol (47%), ethylene glycol (46%), peroxydisulfuric acid diammonium salt (44%), sodium hydroxide (39%) and guar gum (37%).

4.4.2 Quantities of chemicals used for hydraulic fracturing

The quantities of additives expected to be used in hydraulic fracturing under the probable commercial scenarios in Table 2.1 are between 0.1 and 0.5% of the total volume of hydraulic fracturing fluid to be used in each well. This corresponds to approximately 5–75 m^3 by volume per well. As discussed in Chapter 5, low, moderate and high water demand scenarios for the CB and NCB assume a 15-year complete build-out of wells and a total production lifetime of 25 years in each lease area (see Tables 5.1 and 5.2). Under the "high-demand scenario', the maximum number of wells completed (i.e. drilled and hydraulically fractured) would peak in years 7–10 at 100 wells per year as an average in each of the three NCB lease areas and 80 wells per year in the single CB lease area. Under the "low-demand scenario', the maximum number of wells would be 20 per year as an average in each NCB lease area and 16 per year in the CB lease area. These scenarios result in the following range of additive volumes per year in each lease area during the peak operational years (years 7–10):

- NCB lease area: maximum ranges from 500 m^3 (0.1%) to 7500 m^3 (0.5%) (corresponding to 5–75 m^3 per well);
- NCB lease area: minimum ranges from 100 to 1500 m^3;
- CB lease area: maximum ranges from 400 to 6000 m^3; and
- CB lease area: minimum ranges from 80 to 1200m^3.

The USEPA (2015a) recently estimated that the total volume of chemical additives per well ranges from 9.8 to 69 m^3 per well. Assuming a higher additive concentration of 2% by volume, the USEPA (2015a) estimated that the total volume of additives would be 114 m^3 per well. These quantities are within the ranges of values projected for the NCB and CB areas above.

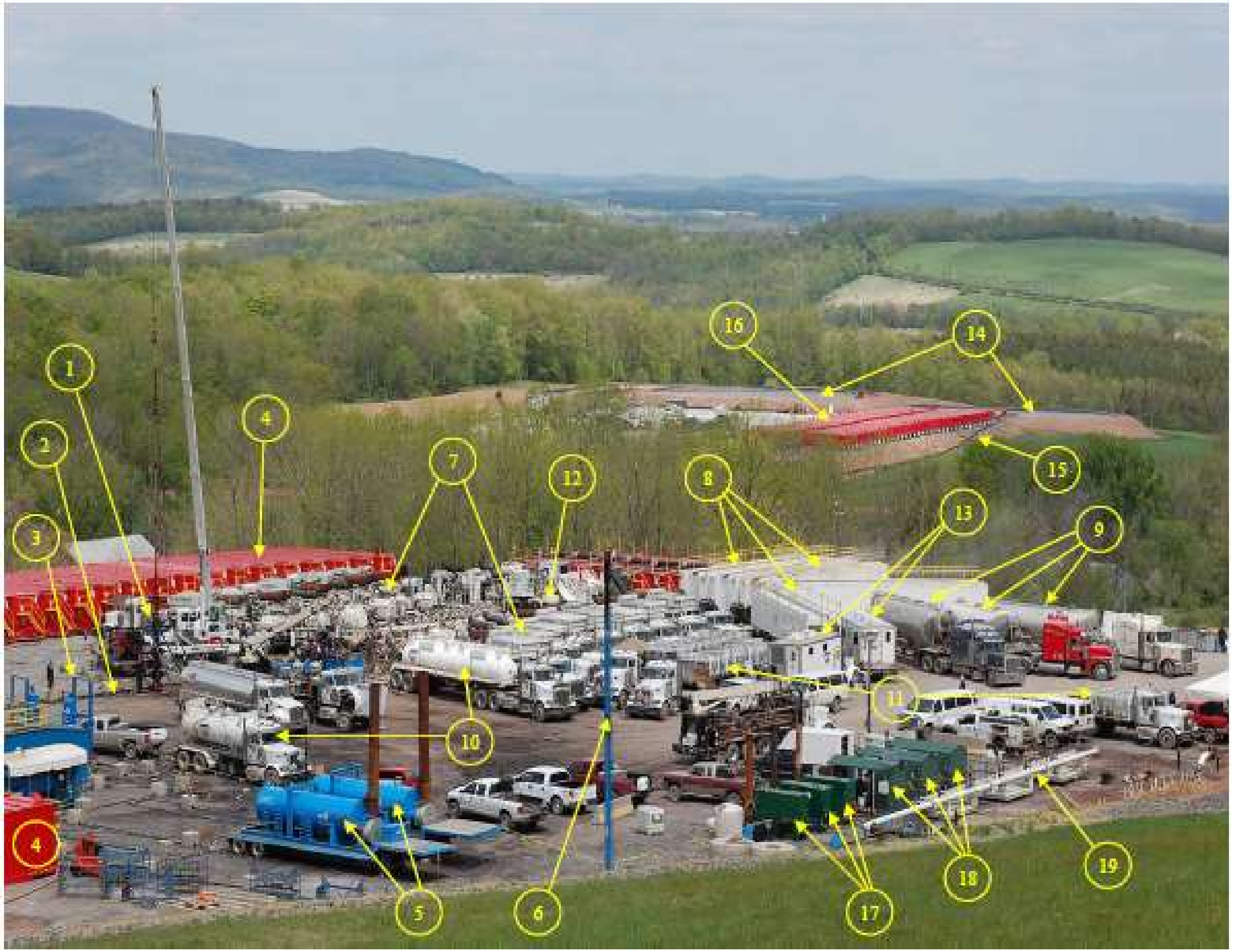
4.4.3 Potential sources of spills: transport and storage of additives and chemicals

The USEPA (2015a) reports that the total volume of additives stored on site, assuming 20–100% more additive volume than needed, is between 8.8 and 25 m^3 per additive (this further assumes three to five additives on site). Additives are typically stored on site on the flatbed lorries or in the vans that delivered them. Additives are usually delivered in 760–1500 L) polyethylene containers, which may be reinforced with metal mesh (USEPA, 2015a); however, in the context of the study area, these details are likely to be determined by suppliers and/or transporters in Ireland and Northern Ireland. Some chemicals would require specialised on-site containers with added spill protection, similar to spill mitigation designs (e.g. bunds) associated with above-ground diesel tanks. For example, acids are typically transported as dangerous substances in specially built tanks or containers that are corrosion protected with chemical-resistant coatings and designs (USEPA, 2015a). Reported transport capacities in the USA range from 11,400 to 19,000 L (USEPA, 2015a). Similar transport capacities (per container) are expected in Ireland and Northern Ireland (HSA, 2012). Note that these volumes are per additive transport container and are much less than the 25 m^3 capacity of water transport lorries.

In addition to the chemical additives, proppant (e.g. quartz sand, see Chapter 9) is also delivered and stored on site. Proppant content usually ranges from 4% to 10% by volume of the fracturing fluids used (see Table 2.1 and Chapter 9). Based on the expected range of water requirements from 5000 to 15,000 m^3 per hydraulic fracturing programme in a single well (see Table 2.1), this corresponds to between 1200 and 4000 t of proppant per well (Table 2.1). The proppant is typically stored on site in 100- to 200-kg capacity tanks or bins (USEPA, 2015a).

The fresh water that is supplied for the hydraulic fracturing can be stored on site in large tanks (e.g. 80,000 L), which are specific to the site and its requirements; however, the trend is to transport fresh water to pads in pipelines from nearby sources on demand rather than constructing expensive storage reservoirs or tanks. However, the potential use of pipelines is site specific, depending upon the quantities of water needed and available resources.

Figure 4.1 shows photographs of a well pad during and after hydraulic fracturing with the associated storage containers, lorries and equipment.



Hydraulic fracturing operation equipment

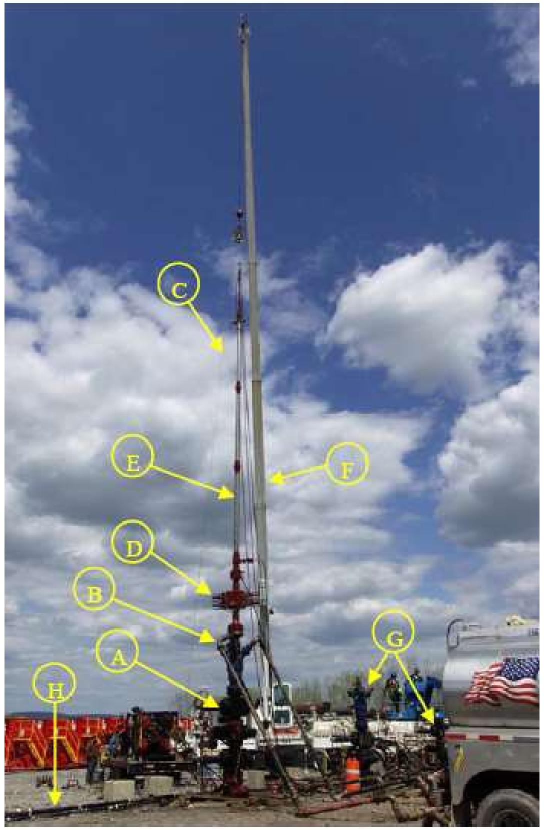
1. Well head and frac tree with "goat head'
2. Flow line (for flowback and testing)
3. Sand separator for flowback
4. Flowback tanks
5. Line heaters
6. Flare stack
7. Pump trucks
8. Sand hogs
9. Sand trucks
10. Acid trucks
11. Frac additive trucks
12. Blender
13. Frac control and monitoring centre
14. Fresh water impoundment
15. Fresh water supply pipeline
16. Extra tanks

Production equipment

17. Line heaters
18. Separator meter skid
19. Production manifold

Figure 4.1. (a) Well pads during hydraulic fracturing.

Fortuna (now Talisman) multiwall pad after hydraulic fracturing of three wells and removal of most hydraulic fracturing equipment. Production equipment for wells is on the right



Wellhead and fracturing equipment
A. Well head and frac tree (valves)
B. Goat head (for frac flow connections)
C. Wireline (used to convey equipment into wellbore)
D. Wireline blowout preventer
E. Wireline lubricator
F. Crane to support wireline equipment
G. Additional wells
H. Flow line (for flowback and testing)

Figure 4.1. (b) Well pads during (right) and after (left) hydraulic fracturing. All images from NYSDEC (2011).

4.4.4 Potential sources of spills: hydraulic fracturing equipment

Besides the storage equipment discussed above (acid transport lorries and containers, additive storage lorries and containers, water and base fluid tanks and proppant storage units), the following equipment is used at each well pad:

- blender;
- hoses and lines (both high- and low-pressure) and suction pumps;
- high-pressure fracturing pumps;
- manifold trailer with hose and pipes; and
- fracturing wellhead and “frac head” (see description below).

The blender is used to mix the additives, proppant and base fluid (typically water, see Chapter 5) as either a batch or a continuous process. The blender consists of suction and metering pumps, a proportioner to measure proppant and a central agitator tank (typically 76,000 L for batch mixing) (USEPA, 2015a). A truck-mounted manifold collects and distributes the fracturing fluid through high-pressure lines to the wellhead. The fracturing process pumps fracturing fluids with proppants down the well, at pressures as high as 70–100 MPa (700–1000 bar or 10,000–15,000 psi, www.marcellus-shale.us), although the latter is case specific according to well depths and design objectives determined from preliminary studies and the results of drilling. A “frac head” is temporarily installed on the wellhead to protect the wellhead and facilitate the injection of the fracturing fluid into the formation under high pressure.

4.4.5 Spills and leaks and associated impacts

The USEPA (2015a) collated and summarised information relating to spills and leakage incidents at UGEE sites in the USA, as recorded in various state databases and service companies’ and operators’ records. Of more than 36,000 reported spills between January 2006 and April 2012:

- 12,000 did not contain sufficient information to evaluate the nature of the spill;
- 24,000 were not related to hydraulic fracturing on or near the well pad;
- 457 occurred on or near the well pad and were associated with hydraulic fracturing activities; and
- of these 457 spills, 151 (33%) were of chemicals, additives or fracturing fluids and 225 (49%) were of flowback or produced waters (spills of flowback and production water are discussed in section 4.6.3);

Of the 151 spills of chemicals, additives or fracturing fluids, the reported causes included:

- 34% caused by equipment failure;
- 25% caused by human error;
- 11% caused by container integrity failure;
- 26% unknown causes; and
- 4% other causes.

Of the 151 spills of chemical, the estimated volumes were recorded for 125:

- the total volume was 697,000 L;
- the volume of spills ranged from 19 to 72,000 L;
- the median spill volume was 1600 L;

- the largest volume of spills was from storage containers (36% or 314,000 L);
- 12% of the volume of spills was from hoses or lines;
- 18% of the volume of spills was from equipment failure;
- 6% of the volume of spills was associated with the well or wellhead; and
- for 28% of the volume of spills, the source was not known.

Of the 151 spills, the affected environmental receptors were reported for 101 as follows:

- 97 of the spills were contained in soils;
- 13 of the spills reached surface water;
- nine of the spills affected both soil and surface water;
- no groundwater impact was reported (but may have occurred and not been identified); and
- spills from storage units were the predominant sources of spills impacting the environment.

For a separate study in Colorado between 2010 and 2013 (USEPA, 2015a), over 60% of the spills associated with hydraulic fracturing activities were associated with equipment failure and between 20% and 25% were associated with human error. These values are similar to those given above.

The USEPA (2015a) also evaluated the rate of surface spills based on four different references:

- 3.3 spills per 100 wells fractured – Marcellus Shale in Pennsylvania (2009–2012, any spill during hydraulic fracturing activities with a reported volume);
- 0.4 spills per 100 wells fractured – Marcellus Shale in Pennsylvania (2008–2013, a volume > 1500 L that reached nearby water bodies);
- 12.2 spills per 100 wells fractured – Marcellus Shale in Pennsylvania (2007 to July 2013, based on violation rates, i.e. an incident reported to the Department of the Environment of a violation of oil and gas regulations); and
- 1.3 spills per 100 wells fractured – State of Colorado (January 2006 to May 2012, specifically related to hydraulic fracturing, spills on or near the well pad).

Overall, the reported "spill rate" is variable, depending upon the reporting protocols and accounting methods and varies between 1.3 and 12.2 spills per 100 wells. Despite the large range of reported spills and associated uncertainties, the fact remains that spills will occur and operators must be prepared with appropriate responses and mitigation measures. Even with laws, regulations and best practices and techniques, spill and leaks happen and, therefore, regulatory oversight and inspections are needed.

4.4.6 Spill and leak prevention, containment and remediation

The factors that influence the risks, prevention and mitigation of spills and leaks include, but are not limited to:

- compliance with governmental laws and regulations (national, local, EU);
- compliance with policies and procedures of the operating companies;
- employee training and experience;
- skill, care and common sense applied by operating companies;
- type, age, condition and maintenance of equipment;

- existence of and compliance with guidance documents and actual implementation of best practice techniques;
- degree of supervision and inspection by regulatory bodies; and
- existence of and compliance with response and emergency plans.

Governmental regulations around the world vary significantly in scope. A review and case histories of relevant regulations in the USA and Europe are provided in the final report of Project C of the UGEE JRP.

Appropriate spill prevention and containment measures are a first line of defence against spills and leaks, and should be implemented through the use of primary, secondary or emergency systems. Primary containment[9] systems are proper, secure storage containers, which were described in section 4.4.3. Secondary containment[10] systems include ditches, liners, berms and bunds, walls and so forth, where the objective is to contain and capture any spilled fluids. These should be constructed during road and pad development, prior to operations, based on a risk assessment of source–pathway–receptors associated with surface spills (including the principles of groundwater vulnerability). Emergency systems are measures and equipment that can be used to respond to unforeseen events, including accidents. Examples would be the availability on site of diggers, oil absorbent pads, booms, neutralising agents and so forth. The availability of a digger would, for example, allow prompt spill containment by soil removal and staging, which are emergency remediation measures. The USEPA (2015a) reports that 50% of emergency responses to spills and leaks involve excavation and disposal of soil. Other remediation actions include the use of vacuum trucks, the application of sorbent materials, neutralising acids and simply flushing with water.

Relevant and comprehensive UGEE-related BMPs proposed by the State of New York, USA (NYSDEC 2011), include:

- identification of a spill response team and employee training on proper spill prevention and responses;
- provision for emergency and response plans;
- inspection and preventative maintenance protocols for tanks and fuelling areas;
- procedures for notifying appropriate authorities in the event of a spill or impoundment failure;
- procedures for immediately stopping the source of the spill and containing the liquid until cleanup is complete;
- ready availability of appropriate spill containment and cleanup materials and equipment including treatment chemicals and absorbents;
- proper disposal of cleanup materials;
- protocols for checking and testing storm water in containment areas prior to discharge;
- conducting tank filling operations under a roof or canopy where possible and preventing rain entering;
- use of drip pans where leaks or spills could occur during tank filling and liquid transfer operations when making and breaking hose connections;

9 Primary containment is the first level of containment of the waters, e.g. tanks.

10 Secondary containment is the level of containment that is external to and separate from primary containment, e.g. a lined bunded area surrounding the tank. Secondary containment safeguards unauthorised releases in the event of spills, leaks or other failure of primary containment.

- use of hoses with check valves to prevent hoses draining after spilling;
- use of spill and overflow protection devices;
- use of diversion dikes, berms, curbing, grading or other equivalent measures to minimise or eliminate runoff and run-on into tank storage and filling areas;
- use of curbing or posts around the fuel and additive tanks to prevent collisions during vehicle ingress and egress;
- availability of manual shutoff valves on transfer hoses and fuelling vehicles;
- inspection and preventative maintenance protocols for tanks, impoundments and liners;
- procedures for immediately repairing tanks, impoundments and liners;
- locating additive containers and transport, mixing and pumping equipment within secondary containments, away from high-traffic areas, as far as is practical from surface waters, not in contact with soil or standing water, and product and hazard labels not exposed to weather;
- inspection and preventative maintenance protocols for containers, pumping systems and piping systems, including staffed monitoring points during additive transfer, mixing and pumping activities;
- a protocol for ensuring that incompatible materials such as acids and bases are not held within the same containment areas;
- maintenance of a running inventory of additive products present and used on site;
- use of drip pads or pans where additives and fracturing fluids are transferred from containers to the blending unit, from the blending unit to the pumping equipment and from the pumping equipment to the well;
- locating tanks within secondary containments, away from high-traffic areas and as far as is practical from surface waters;
- maintenance of a running inventory of flowback water and produced water recovered, present on site and removed from site.

4.4.7 Recommendations

To be able to address prevention, containment and remediation of surface spills and leaks in a comprehensive manner, a complete understanding of planned operations and risks is necessary, on the part of both the operators and the regulators. This includes:

- site layouts;
- details of the chemical composition and volumes of additives and fracturing fluids;
- THE physicochemical properties of chemicals to be used;
- Baseline studies and monitoring of relevant water resources and habitats near individual well pads, at a suitable scale, conducted by suitably qualified specialists in relevant fields;
- sound conceptual models of source–pathway–receptor relationships for operational monitoring purposes; and
- identification and prior agreement on prevention and containment measures.

The planning and prior authorisation phase of UGEE-related activity is, arguably, the most important phase of UGEE development. Whereas implementation of prevention and mitigation measures safeguards against spills and leaks (and, therefore, potential impact), planning establishes rules, expectations and a common understanding.

4.5 Impacts Associated with Well Construction, Completion and Operation

4.5.1 Description of well construction

The primary goals of hydraulic fracturing are to maximise gas production and avoid potential impacts on shallow receptors. This requires that hydraulic fracturing operations are isolated from the shallow environment. While geological structures, hydrogeological characteristics of the intervening bedrock formations and the vertical separation distance between target formations and shallow receptors influence the risks of impact (for more information, see Project A1-2 of the UGEE JRP), proper well construction methods must be employed to accomplish the required isolation. As documented in Project A1 of the UGEE JRP, poorly constructed wells represent potential pathways to the near-surface environment for natural gas constituents, and recent water quality impact studies from the USA and Canada have highlighted poor well construction practices as a likely contributor to the contamination of shallow aquifers. The issue of stray gas emissions is further discussed in section 7.3.3. Some of the associated pathways are summarised in Figure 4.2, and they are represented by voids and cracks in the cement grout that is injected (pumped) into the annular space between borehole walls and steel casing, structural failures and gradual deterioration of the steel casings (e.g. partial collapse, poor welding practice, corrosion, etc.) and incorrect installation materials and procedures. Figure 4.3 shows additional details of typical well construction and potential “flaws” in the cement annulus for gas migration (Vidic *et al.*, 2013).

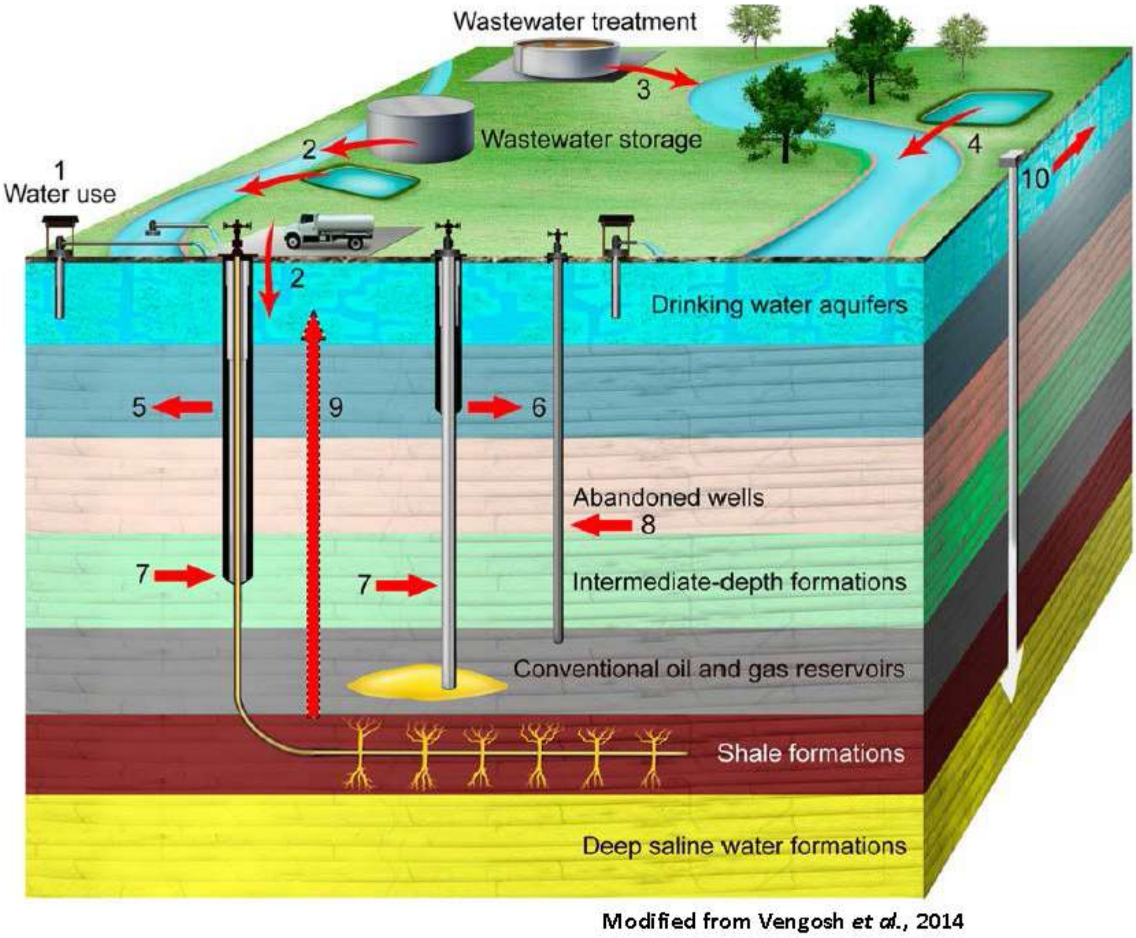
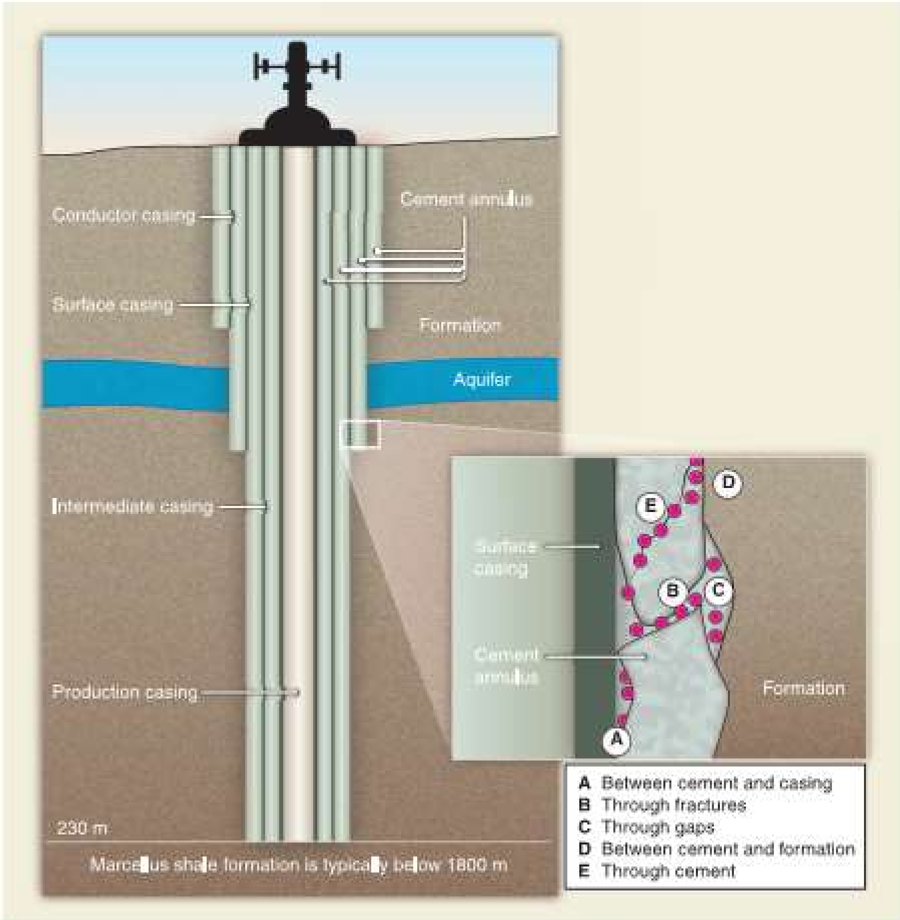


Figure 4.2. Potential mechanisms of impacts on water resources from UGEE operations. Reproduced with permission from the American Chemical Society.

1: Over-abstraction of water from streams, lakes or shallow aquifers – higher risks of impacts during low-flow conditions. 2: Contamination of surface water or groundwater from leaks and spills of waste materials and wastewater storage near drilling. 3: Disposal of inadequately treated wastewater to local streams, lakes or groundwater. 4: Leaks to waterways and/or groundwater from storage ponds. 5: Shallow aquifer contamination by stray gas that originated from the target shale gas formation through a leaking well casing. The stray gas contamination can potentially be followed by salt and chemical contamination from hydraulic fracturing fluids and/or formation waters. 6: Shallow aquifer contamination by stray gas through leaking of previous gas exploration wells (e.g. via casings). 7: Shallow aquifer contamination by stray gas that originated from intermediate geological formations through annulus leaking of previous gas exploration wells (possible in NCB especially). 8: Shallow aquifer contamination through abandoned other wells [via annular spaces (no cases known in the NCB or CB)]. 9: Flow of gas (and saline water, although unlikely) from deep formations to shallow aquifers via natural pathways. 10: Shallow aquifer contamination through leaking of injection wells (potential but unlikely future scenario).



Typical Marcellus well construction. (i) The conductor casing string forms the outermost barrier closest to the surface to keep the upper portion of the well from collapsing and it typically extends less than 12 m (40 ft) from the surface; (ii) the surface casing and the cement sheath surrounding it that extend to a minimum of 15 m below the lowest freshwater zone is the first layer of defense in protecting aquifers; (iii) the annulus between the intermediate casing and the surface casing is filled with cement or a brine solution; and (iv) the production string extends down to the production zone (900 to 2800 m), and cement is also placed in the annulus between the intermediate and production casing. Potential flaws in the cement annulus (Inset, "A" to "E") represent key pathways for gas migration from upper gas-bearing formations or from the target formation.

Figure 4.3. Typical well construction and flaws in cement for gas migration (from Vidic *et al.*, 2013). Reproduced with permission from the American Association for the Advancement of Science.

Given the layered nature of sedimentary basins that host unconventional gas resources, gas production wells are typically completed with multiple sets of casings to accommodate "telescoped drilling" and isolate different formations with depth. The sets of casing provide stability to the drilling operation and borehole, and they also prevent the migration and mixing of fluids between formations. Thus, each set of casing should be properly cement grouted. Each production well at a well pad may be installed differently, according to project objectives, location-specific geology and the driller's judgement during the drilling operation (e.g. isolation of intervals where losses of circulation are encountered).

The USEPA (2015a) report that the majority of hydraulic fracturing wells include at least three sets of casing (see Figure 4.4): “surface casing” (typically extending to the base of water-bearing zones), “intermediate casing” and “production casing” (extending to total depth and along the length of the horizontal section to be fractured).

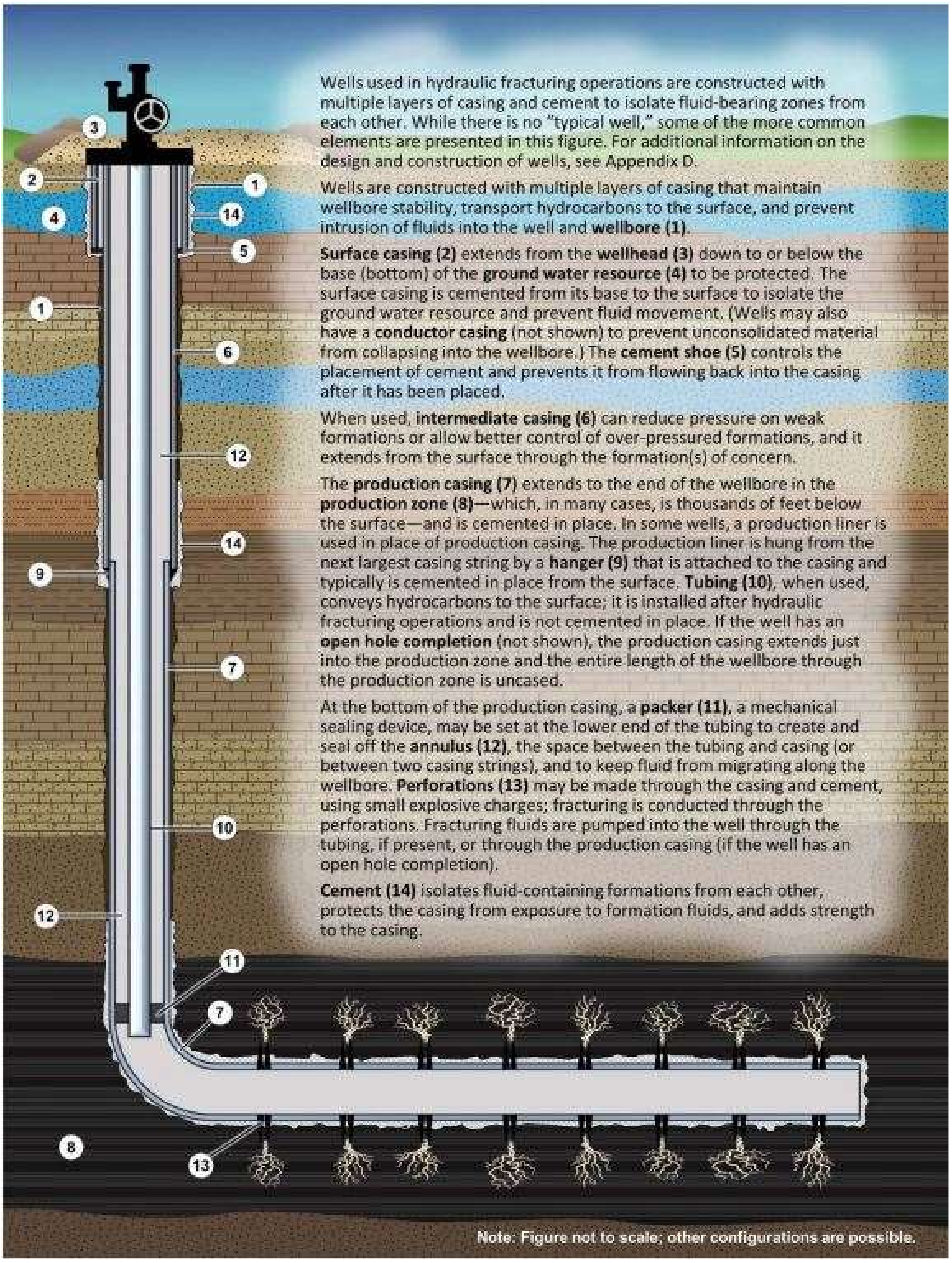


Figure 4.4. Overview of well construction (from USEPA, 2015a).

The cement that is pumped into the annular spaces is usually a neat-cement, which serves to add structural integrity to the well construction and to minimise or eliminate vertical fluid migration from the surface and between formations. The USEPA (2015a) reports that well integrity checks, involving cement bond logging, indicated that 93% of surface casings and 80% of intermediate casings were fully cemented (grouted) in place, but that only 47% of production casings were partially cemented in place. In horizontal boreholes, steel casing extends the full length of the borehole, and it is cemented. Perforations are then completed through the casing and cement in the production zone.

4.5.2 Potential source of contamination

Fluids associated with drilling and hydraulic fracturing operations represent potential sources of contamination to the groundwater environment. Natural gas constituents that are naturally present or are released as a result of hydraulic fracturing operations are also potential sources of contamination if they migrate to the near-surface environment via natural, induced or artificial pathways.

The compositions of drilling fluids are described in Chapter 9. They mostly involve fresh water mixed with mud constituents (bentonite, barite) or synthetic foams or cellulose-based products, which are necessary to stabilise drilling operations and return drill cuttings to the surface. They are typically non-toxic constituents of minimum environmental consequence; however, the formation cuttings in the fluids may contain various constituents, including NORM, requiring proper disposal (see Chapters 9 and 10).

The compositions of additives and chemicals used in the hydraulic fracturing operations are described in Chapter 9, and indicative quantities (by volume) and storage of these fluids were previously described in section 4.4.

The compositions and quantities of flowback and produced waters that arise from the hydraulic fracturing operations and return to the surface under the influence of the high pressures created by the hydraulic fracturing action are described in Chapter 6 and Chapter 10.

4.5.3 Description of potential release scenarios

Potential releases of natural gas constituents from deeper source formations may already occur naturally and/or may be enhanced as a result of future UGEE activities. The extent to which natural gases are presently being released in the NCB and CB, i.e. prior to any future UGEE operations, is examined as part of the subregional baseline monitoring of dissolved methane in groundwater under supplemental Tasks 4 and 6 of Project A1 of the UGEE JRP.

Three types of potential releases of contaminants may result from hydraulic fracturing: (1) chemicals that are injected in the hydraulic fracturing fluids; (2) chemicals and naturally occurring radioactive materials in the formation waters and that dissolve or are otherwise released from the bedrock formations; and (3) natural gas constituents (e.g. methane). These contaminants can migrate and impact shallow receptors (i.e. the environment) in three ways: (1) via natural pathways; (2) via induced pathways; and (3) via artificial pathways. These are described below.

4.5.3.1 Release and migration via natural pathways

Natural pathways would be represented by natural, open fracture networks in the bedrock formations. As described in Report A1-2 of the UGEE JRP, there are indications of and limited evidence for open fractures in deeper formations in both case study areas, raising questions about deeper hydrogeological characteristics and potential hydraulic connections between deeper and shallower formations.

4.5.3.2 Release and migration via induced pathways

Induced pathways are represented by open fractures that result from the hydraulic fracturing action. Potential fluid and gas migration pathways are schematically shown in Figure 4.5. Fracture propagation from hydraulic fracturing would determine the extent to which induced pathways can impact shallow receptors. Such fractures may extend to and create connections with existing natural fractures (e.g. in fault zones) or man-made features, such as the existing gas exploration wells that were drilled and installed in both case study areas in the past. Induced fracturing can thus impart preferential pathways for contaminant migration.

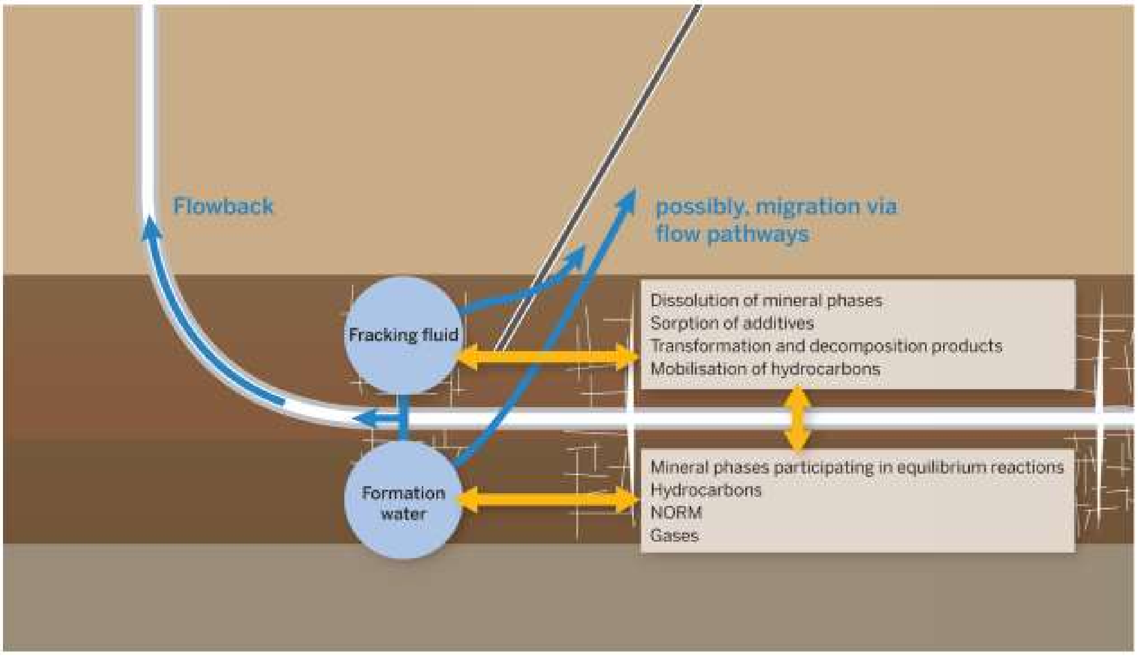


Figure 4.5. Schematic depiction of potential fluid migration pathways (adapted from Meiners *et al*., 2013).

In the NCB, the vertical separation distance between the Bundoran Shale Formation (stated target for UGEE projects) and the Dartry Limestone Formation (primary aquifer) is between 250 and 570 m (for additional information see Report A1-2 of the UGEE JRP). In the CB, vertical separation distances between the Clare Shale Formation (implied target for UGEE projects) and overlying, primarily sandstone, formations are less clear, mainly because the sandstone formations are considerably heterogeneous in three dimensions, and significantly thick shale and mudstone units (e.g. equivalent to the Benbulben Shale Formation in the NCB), which can act as natural protection layers, have not been described.

The concept of vertical separation distance is important in the context of fracture propagation and induced pathways. Reviews of fracturing operations indicate that induced fractures can be expected to extend up to several hundred metres from the horizontally fractured wells, and that fracture propagation lengths may increase with depth of fracturing (Figure 4.6) (Ewen *et al*., 2012). Available data (Davies *et al.,* 2014) indicate that the majority of induced fractures extend less than 100 m from the horizontal wells, and only 1% of induced fractures extend beyond 350 m with a maximum length of 588 m from the horizontal wells. As reported by Kim and Moridis (2015), a study of six hydraulically fractured wells in the Marcellus Shale Formation showed fractures extending between 305 and 579 m above the Marcellus Shale into the overlying Tully Limestone Formation, which was still approximately 1500 m below any aquifers used for water supply purposes (consequently, no impacts were implied). The USEPA (2015a) further reported that 20% of the hydraulically fractured wells in the USA were located in areas where the vertical separation distance between gas “production zones” and shallow aquifers was less than 610 m. An estimated 0.4% of the wells had perforations used for hydraulic fracturing in shallow aquifers.

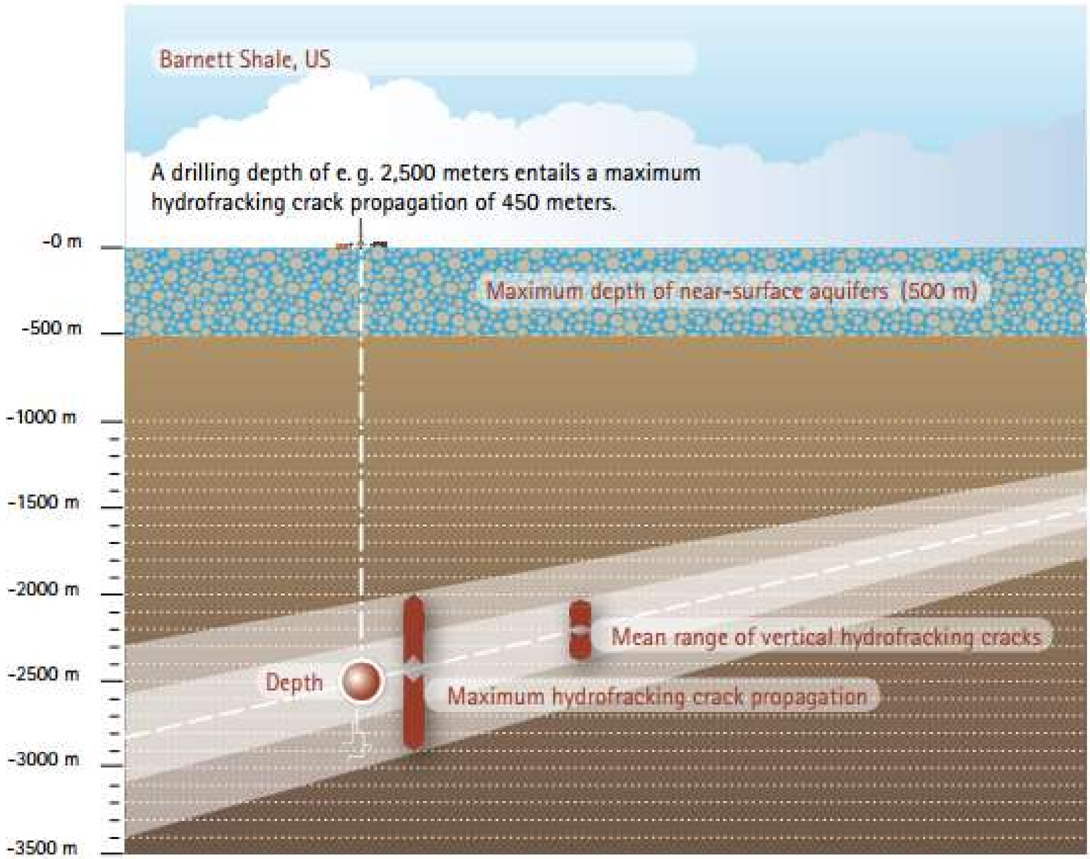


Figure 4.6. Fracture propagation lengths and well depth (from Ewen *et al.*, 2012).

The term "frac hit" is frequently used when hydraulic fractures associated with one well propagate and intersect hydraulic fractures associated with a nearby well. The USEPA (2015a) has recorded numerous incidents of such communication between wells. The key factors controlling the probability of well communication are the distance between and directional of wells, fracture propagation lengths and the geological characteristics of related formations (including the mechanical properties of the bedrock formations at depth). In the reported USA-based incidents, the probability of communication was estimated to be less than 10% in wells more than 1219 m apart, but it was nearly 50% in wells less than 305 m apart (USEPA, 2015a).

The upward vertical migration of fluids from deeper unconventional gas target formations to shallow receptors is less likely than the vertical migration of natural gas constituents (Reagan *et al.*, 2015; USEPA, 2015a). This is because fluids and associated contaminants that are released by hydraulic fracturing have to overcome hydraulic gradients between shallow and deep formations, which requires considerable pressures over extended periods of time. The outward and upward migration of released contaminants is also naturally attenuated by capillary forces and adsorption by clay minerals. Modelling studies suggest that certain conditions of significant vertical hydraulic gradient, permeability, buoyancy and displacement may provide for conditions that will allow for upward flux of fluids, but overall these mechanisms have been found to result in very low flow rates over long distances, in one reported case resulting in simulated travel times of greater than 100,000 years across a 100 m thick layer (Flewelling and Sharma, 2014). Rutqvist *et al.* (2015) noted that deep hydraulic fracturing is not likely to result in a direct flow pathway into shallow aquifers even if the fracturing fluid is injected directly into a fault.

All impact studies must be regarded and reviewed in the contexts of case-specific circumstances (depths, pressures, characteristics and properties). For this reason, future, case-specific risk assessment of any UGEE project in Ireland or Northern Ireland would require prior knowledge of deep hydrogeological conditions, including lithological variations, the presence of open fractures and natural head and pressure gradients across intervening geological formations.

4.5.3.3 Release and migration via artificial pathways

Pathways associated with poor or failed well construction practices are considered artificial. Numerous factors can contribute to the presence of such pathways:

- poor well design;
- poor well construction practice (i.e. means and methods);
- use of inappropriate materials (e.g. steel casing with insufficient collapse pressure);
- poor cementing practice, and/or absence of cement grout;
- microannuli formed from debonding between the cement and steel casing (e.g. as a result of cyclical stresses and potential cracks in cement arising from repetitive pressure surges);
- structural casing failure (e.g. partial collapse, poor welding);
- material degradation with time;
- carelessness or shortcuts taken by the drilling and operation crews; and
- intangibles that can occur on any given construction project (e.g. workers' conflict or late or non-payment of salaries).

As reported by the USEPA (2015a), impact studies show correlations between well age and well integrity, and a common cause of impaired well integrity is corrosion of steel casing in zones that have not been properly cemented. Corrosion is related to material properties and age and also to the hydro-chemical conditions at depth (e.g. salinity and brines, sulfates, sulfide, and carbon dioxide in formation waters).

With regard to impact on shallow groundwater resources, the USEPA (2015a) noted that the risk of impact on shallow groundwater quality was 7 in 1,000,000 wells when the surface casing was set deeper than the "groundwater zone" (i.e. shallow freshwater aquifer), but increased to 6 in 1000 wells when the surface casing was not set sufficiently deep.

The primary risk of impact on groundwater quality is stray gas migration from the gas "production zone" owing to improper, faulty or failing production casing and/or poor or improper cement grouting of casing. A Canadian study (Watson and Bachu, 2009) of stray gas impact reported that 57% of all casing leaks occurred in uncemented zones. Evaluation of wells from 2008 to 2011 (SRSI, 2012) notes that the "violation rate" resulting in "environmental damage" decreased from 53% in 2008 to 21% in 2011. Of the 845 events that were recorded as causing environmental contamination, 10% were associated with casing and cement problems. The remainder of events were related to surface spills and associated remediation. An evaluation of 6061 wells in Pennsylvania noted that between 0.1 and 1% of hydraulic fracturing operations resulted in impact on water resources (USEPA, 2015a).

4.5.4 Recommendations and mitigation measures

There are numerous recommendations and mitigation measures to avoid potential impacts from well construction and integrity issues, and they relate to best techniques and best practice of well drilling and construction as well as environmental monitoring. The list below is not exhaustive but indicative:

- appropriate well designs based on location- and case-specific preliminary studies and assessment of hydrogeological conditions;
- risk analysis of all steps in the drilling and hydraulic fracturing operations;

- specification and use of "correct" materials based on preliminary studies of deeper hydrogeological conditions and well designs;
- baseline monitoring at the local scale of available water resources and potential receptors of contamination, at appropriate times, based on planning and interaction with relevant public regulatory bodies;
- adequate provision for regulatory supervision before, during and following hydraulic fracturing operations;
- adequate provision for operational monitoring of gas constituents and other relevant contaminants before, during and following hydraulic fracturing operations, including stray gas at individual wellheads (also previous gas exploration wells);
- disclosure of chemicals and additives used in the hydraulic fracturing programme at any given wells, which is needed to assess risks of migration and guide monitoring;
- adequate provision of material integrity tests (e.g. mill and test certificates of casing materials);
- adequate provision by operators for proper storage and use of equipment and materials, per manufacturers' and suppliers' specifications;
- integrity testing of materials used, notably steel casing, drilling additives, cement;
- documentation of qualifications of personnel employed for all aspects of work, including prior experience on similar applications;
- running appropriate geophysical logs to characterise each borehole and test adequacy of cementing operations at different stages of drilling and well construction, and prior to any hydraulic fracturing operations;
- preparing, and agreeing on, contingency measures in the event of failed procedures or failed operations (e.g. well decommissioning measures); and
- recording and signing off on activity completed and supervised at any given site, by the operators and those representing regulatory bodies.

Specific recommendations for well construction proposed by the USEPA (2015a) include but are not limited to:

- proper and verified cement seals across all appropriate subsurface zones, including all relevant aquifer and hydrocarbon zones;
- performance logs and tests to verify the quality of cement behind the well casing (e.g. cement bond logs);
- longer cement lengths when casings have lower cement bond indices (API, 2009);
- verified adequate cement bonds over an interval three times the length considered adequate for zone isolation;
- limiting the age of conventional existing wells (not initially constructed for hydraulic fracturing) used for fracturing or older wells used for re-fracturing due to recent technical advances and better subsurface knowledge;
- regular internal mechanical integrity tests (MITs) such as casing inspection logs, caliper logs, annulus pressure monitoring and pressure testing to provide early warnings concerning well integrity and potential problems of fluid leaks;
- setting surface casing deep enough to cover (and be below) all water resource zones and complete to the surface; cement over the complete interval;
- required monitoring and repair of sustained casing vent flow or sustained casing pressure;

- identifying and cementing above the top of the highest gas-containing zone;
- monitoring casing pressures after cementing;
- identifying management options for sustained pressure, including venting, remedial cementing and/or use of kill fluids in the annulus;
- required operational monitoring, including pressure, flow rate, fluid density and additive concentrations using surface equipment and/or downhole sensors;
- external monitoring to collect information on any fracture characteristics and extent during hydraulic fracturing and production (both near and far field) such as tracers, temperature logs, video logs or caliper logs (near field) and microseismic monitoring or tiltmeters (far field);
- setting a minimum distance between the gas-producing formations and shallow receptors of potential contamination, including drinking water resources;
- evaluating communication between wells by monitoring pressure changes at any offset wells, production lost in offset wells and any fluid lost in offset wells;
- constraining the allowable distance between new and existing offset wells, based on analysis and expectations with regard to fracture propagation (e.g. greater than 1200 m depending upon site-specific geology, permeability, etc.);
- limiting hydraulic fracturing in areas of artificial subsurface structures such as mine shafts, solution mining, etc.;
- requiring documentation of designs and as-built well construction details, accompanied by review meetings of suitably qualified specialists on the part of the regulatory bodies and operators;
- recording and submitting all information concerning integrity tests to the regulatory body for review purposes;
- limiting or preventing use of older wells not constructed for hydraulic fracturing purposes;
- providing electronic and systematic information concerning all monitoring data, in the form of both periodic reports and review meetings; and
- conducting verification tests of well integrity (e.g. cement bond logs, acoustic televiewer or video surveys, as appropriate) before and after hydraulic fracturing operations.

4.6 Impoundment and Tank Leaks during Storage and Treatment of Wastes Produced On Site

4.6.1 Summary of on-site produced wastes

The waste materials that are associated with a well pad are derived from drilling operations, hydraulic fracturing operations and gas production (flowback and produced waters), and general site operations.

Drilling operations result in “spent” or unused drilling fluids and formation cuttings. These are described in Chapter 9. Quantities of drilling fluids cannot be predicted for any given site or well with certainty because this depends on drilling progress and the conditions encountered. Nonetheless, for guidance purposes, quantities can range from 0.5 to 0.6 m^3 per metre drilled and total quantities can range from 1500 to 2500 m^3 per well pad, depending upon depth and number of wells (see Table 2.1). Thus, well depths and the number of wells drilled will determine the total quantities of waste produced at a given pad.

Waste materials from hydraulic fracturing operations are mainly flowback and produced waters. The compositions and quantities of these fluids are described in Chapter 6 and Chapter 10. The volume of flowback water depends on the volume of fracturing fluids used during hydraulic fracturing. On the basis of the water use requirement scenarios for the CB and NCB outlined in Chapter 5, and assuming a 15-year complete build-out period for wells in each lease area and a 25-year production life (see Tables 5.1 and 5.2), the total quantities of flowback and produced waters are given in Chapter 10 and, in summary, in the NCB, the following quantities are estimated for each lease area:

- flowback: between 2000 and 3750 m^3 per well:
    - flowback: the peak flowback per lease area is estimated to occur in years 7–10 and range from 40,000 to 375,000 m^3 per year (a moderate value is 141,000 m^3 per year);
- produced water: approximately 1250 m^3 per well per year
    - produced water: the peak amount of produced water is estimated to occur in year 14 and range from 205,000 to 1,025,000 m^3 per year (a moderate value is 444,000 m^3 per year).

4.6.2 Storage and on-site processing and treatment facilities for produced on-site wastes

Drilling muds and fluids are typically stored in mud pits (impoundments) or tanks. The mud pits may or may not be lined, depending on case-specific circumstances and regulatory requirements. Off-site disposal of spent mud and drill cuttings is usually to a regulated facility (e.g. landfills). In rare cases, materials are recycled.

Flowback and produced waters are transported through discharge pipes to storage or treatment units located on site. The fluids may be stored in on-site surface impoundments or storage tanks (see Figure 4.1). The surface impoundments are typically excavated into the ground with surrounding berms or bunds and may or may not be lined, depending upon regulatory requirements and prior authorisations by public regulatory bodies. Surface impoundments may be used for temporary storage before transfer to lorries for off-site disposal or treatment, or may be used as long-term storage for evaporation purposes. Fluids may also be treated on site for reuse, discharge or disposal off site (further detail on treatment options is provided in Chapter 10. Tank storage is typically a closed-loop system from the wellhead to the tanks via pipes. In some cases, pipelines are used to transport flowback and produced waters off site.

4.6.3 Potential release scenarios and impacts

Faulty connections at pipes and leaks or ruptures in lines containing flowback or produced waters can result in surface spills. Failure of storage tanks can also result in surface spills. Flowback and produced waters may overflow surface impoundments as a result of incorrect design or unanticipated weather events. Leakage can also occur from unlined impoundments into the subsurface and groundwater. In some cases, a well blowout can occur, releasing fluids to the environment. However such occurrences are rare owing to the use of blowout preventers at wells. One case was found in which a faulty blowout preventer (rented and not tested) was used during drilling, resulting in a subsequent blowout, fire and one death and two injuries (www.eenews.net/stories/1060007532). Various pathways for spills are shown schematically in Figure 4.2.

As previously discussed, the USEPA (2015a) recently evaluated spills associated with hydraulic fracturing activities. Of the 457 recorded spills related to such activities, 49% (225) were spills of flowback or produced waters, accounting for 84% of the total volume (7.6 million litres). Typically the spills were of small volumes, with 50% of the spills less than approximately 3800 L (1000 US gallons), with few spills exceeding 38,000 L. Overall, 16% of the volume was recovered, 76% was not recovered and 8% was reported as unknown. The sources of the spills include tanks, impoundments, wells and wellheads, hoses and lines, and equipment. Storage containers (both tanks and impoundments) accounted for 58% of the spills. The fewest spills occurred from wells and wellheads, but these spills were larger in volume. The causes of the spills included human error (38%), equipment failures (17%), container integrity failure (13%), and others (including unknown).The majority of the spill volume (74%) was related to a failure in container integrity.

Of the 225 spills of flowback and produced waters, the majority reached environmental receptors: soil (141), surface water (17), groundwater (1), soil and surface water (13) and unknown (30). The total spill volume reaching the environment was 1.6 million litres.

Information concerning hydraulic fracturing-related surface spills in Colorado from July 2010 to July 2011 (Gross *et al.,* 2013, reported by USEPA, 2015a) linked BTEX (benzene, toluene, ethylbenzene, xylenes) in groundwater to 77 spills ("less than 0.5% of nearly 18,000 active wells"). Of the 77 spills, 46 were produced water and oil, 23 were only oil, and eight were only produced water. The average volume of the produced water spills was 1100 L (only five cases had reported volumes). Equipment failure was reported as the most common cause of spills. Of the 77 spills, only 26 had secondary containment.

In Pennsylvania (as reported by USEPA, 2015a), structurally flawed impoundments or inadequate free board in impoundments were the second most frequent type of operational violation (based on 439 cases from 2008 to 2013). Common problems with impoundments in Virginia (also reported by USEPA, 2015a) were slope stability, liner defects, poor construction quality control, lack of compaction testing, incorrect soil types, slope lengths and inadequate erosion control.

In a separate study of Pennsylvania's environmental compliance database associated with UGEE (Brantley *et al.,* 2014), eight spills of flowback and produced waters were reported from May 2009 to April 2013, resulting in spills of 15,000–220,000 L reaching surface waters. The study also indicated that the likelihood of a leak or spill of hydraulic fracturing fluids was low (less than 1%, based on a total of 32 large spills from 4000 wells).

The records itemised above document the fact that spills of flowback and produced water can be expected from UGEE-related activity, and risks of impacts reflect the care and adequacy of operations and case- and site-specific risks. Based on US experience, impacts on water resources are typically directly related to the volume of the spill or leak, and the documented spills of flowback and produced waters are typically small (less than 3800 L).

4.6.4 Potential mitigation measures

Mitigation measures were discussed in section 4.4.6, including the following:

- required secondary containment on all storage tanks;
- required lining of all impoundments and pits;
- required reporting and documentation of all spills and leaks (including volume, composition and remediation);
- routine inspection and documentation of all pipes, hoses, connections, tanks, etc.;
- adequate design and construction regulations for all impoundments (slopes, compaction, liner testing, freeboard, etc.); and
- level alarms for tanks and impoundments.

The State of New York, USA (NYSDEC 2011), has recommended the following additional requirements for flowback waters:

- They should be contained in covered watertight steel tanks or covered watertight tanks constructed of materials approved by the state.
- They should remain on-site no longer than 45 days after completing drilling and hydraulic fracturing.
- At least two vacuum trucks should be on standby at the well pad during flowback operations to contain any spills or unanticipated high volumes.

4.7 Leaks, Spills or Improper Disposal During Off-site Transport, Treatment and Disposal of Produced Wastes

4.7.1 Produced wastes

On-site produced wastes and indicative quantities and compositions were described in section 4.6 and are further described in Chapters 5, 7 and 10.

4.7.2 Off-site facilities

Relevant off-site facilities that can treat, recycle or otherwise dispose of on-site produced wastes are regulated landfills, treatment plants and authorised recycling facilities. Deep well injection of waste fluids is a further option, and is practised in several countries, but it is not considered feasible in Ireland and Northern Ireland without further technical assessment, including hydrogeological characterisation of deeper bedrock formations.

The recycling and reuse of flowback and produced waters is described in Chapter 6. The treatment and disposal of flowback and produced waters is described in Chapter 10. In the USA, selected states have prohibited the disposal and treatment of flowback and produced waters at publicly owned treatment facilities. In addition the USEPA has also proposed regulations prohibiting the disposal and treatment at publicly owned treatment facilities.

The most likely scenarios for management (treatment and disposal) of flowback and produced waters in the two study areas are recycling and reusing and off-site treatment at specialised and/or centralised treatment facilities, typically developed by private companies or the developers.

Drilling muds and fluids are typically disposed of off site in regulated landfills, and the type of disposal site depends upon the composition of the wastes. Article 5.3(a) of Landfill Directive 99/31/EC (EC, 1999a) prohibits the disposal of liquid waste in a landfill site. However, there are various commercial licensed facilities that accept drilling muds and fluids in the liquid state and then treat them before disposal. Solid wastes with elevated levels of NORM typically require disposal at specialised sites that are authorised to accept such wastes.

4.7.3 Transport of wastes to off-site facilities

Flowback and produced waters disposed of and treated off site are typically transported to the facilities in tanker lorries. However, owing to traffic, noise and air emission concerns resulting from heavy traffic, construction and transport via pipelines may be a favoured alternative in certain circumstances.

Regarding lorry traffic, the typical capacity of a lorry, with a gross laden weight of 40 t, used to transport the waters is 24–28 t or m^3 (an average capacity of 25 m^3 was used in the following sections, see Table 2.1). These capacities may be lower in Ireland and Northern Ireland, depending upon the size of the roads. As documented in section 4.6.1, the following quantities of flowback and produced waters are estimated for each lease area in the NCB study area:

- flowback: between 2000 and 3750 m^3 per well:
    - flowback: the peak flowback per lease area is estimated to occur in years 7–10 and range from 40,000 to 375,000 m^3 per year (a moderate value is 141,000 m^3 per year);
- produced water: approximately 1250 m^3 per well per year:
    - produced water: the peak amount of produced water is estimated to occur in year 14 and range from 205,000 to 1,025,000 m^3 per year (a moderate value is 444,000 m^3 per year).

These volumes result in the following number of truck trips:

- flowback: between 80 and 150 trips per well:
  - flowback: the peak flowback per lease area is estimated to occur in years 7–10 and range from 1600 to 15,000 trips per year (a moderate value is 5640 trips per year);
- produced water: approximately 50 trips per well per year:
  - produced water: the peak amount of produced water is estimated to occur in year 14 and range from 8200 to 41,000 trips per year (a moderate value is 17,800 trips per year).

As discussed in Chapter 9, a minimum of one centralised treatment facility per lease area (one in the CB and three in the NCB) is estimated to be required and to be designed, built and operated by the UGEE or private developers. Considering discharge licensing of treated water, and the limited assimilative capacities of the smaller streams that characterise the two study areas, the placement of treatment facilities would need to be carefully planned to minimise the risks of impact on surface waters and associated ecosystems.

In the NCB, probably only a total of two facilities for all three lease areas would be required, depending upon the build-out time in the specific lease areas. The average round lorry trip is estimated to be 25–35 km. The lorries would be transporting wastewaters only one way, resulting in 12–17 km per lorry trip with the potential for spillage of flowback or production fluids. Rounding these values to an average of 15 km results in the following distances travelled by the lorries:

- flowback: between 1200 and 2250 km per well:
  - flowback: the peak flowback per lease area is estimated to occur in years 7–10 and range from 24,000 to 225,000 km per year (a moderate value is 84,600 km per year);
- produced water: approximately 750 km per well per year:
  - produced water: the peak amount of produced water is estimated to occur in year 14 and range from 123,000 to 615,000 km per year (a moderate value is 266,400 km per year).

4.7.4 Description of treated wastes

The treatment of flowback and produced waters is discussed in detail in Chapter 10. The resulting water quality of flowback and produced waters after treatment is dependent on the proposed use and disposal and discharge of the waters. The required quality for reusing or recycling would be very different (less stringent) than the required quality for discharge to surface or groundwater. Mandatory requirements for reuse and discharge to surface waters in the USA, Ireland and Northern Ireland are also discussed in Chapter 10.

Chapter 10 and the USEPA (2015a) identify and evaluate treatment of the following constituents of concern in flowback and produced waters:

- Total suspended solids (TSS): a reduction in TSS is required for both reusing and recycling and discharge to surface water.
- Total dissolved solids (TDS): flowback and produced waters have high levels of TDS (see Chapter 10). Depending upon the intended use or regulated discharge of the treated effluent, advanced treatment methods may be required (see Chapter 10).
- Anions: levels of bromide, chloride and sulfate are typically high in flowback and produced waters. High sulfate levels can create potential problems (e.g. scaling) for reusing and recycling. High levels of bromide can result in the formation of toxic disinfection by-products (e.g. trihalomethanes, THMs) if the water is further treated for drinking water use (see Chapter 10 and USEPA, 2015a).

- Metals and metalloids: depending upon the intended use or regulated discharge, treatment may be required for barium, cadmium, chromium, lead, copper, manganese, nickel, thorium, zinc or boron.
- Radionuclides/NORM: elevated levels of radionuclides (e.g. radium) have been identified in flowback and produced water (see Chapter 10). Elevated levels of radium in sediments have been observed in locations downstream of publicly owned treatment plants treating produced waters from hydraulic fracturing (Warner *et al.,* 2013, also see Chapter 10). Depending upon the intended use of the treated effluent and regulatory requirements, treatment may be required for radionuclides.
- Organics: various levels of organic compounds have been identified in flowback and produced waters (see Chapter 10). Depending upon the intended use and regulatory requirements for the treated effluent, treatment may be required for specific organic compounds.

The various options for treatment of these constituents and the removal efficiencies are discussed in Chapter 10.

4.7.5 Potential release scenarios and potential impacts

Releases of flowback and produced waters or their associated chemical constituents to the environment can occur as a result of:

- spills and leaks during transport (e.g. accidents);
- deliberate illicit disposal during transport;
- leaks from pipelines if transport to treatment facilities is via pipelines;
- insufficient treatment capacity or breakdown of treatment equipment; and
- inadequate treatment with regard to disposal regulations and criteria.

Releases during transport. The USEPA (2015a) reported an estimate of approximately 70 crashes of large lorries per 100 million kilometres travelled to evaluate impact of spills during transport of wastewaters from hydraulic fracturing operations, and further estimated that the probability of a spill release from a crash was 8.1–9.0%. Similar statistics were not found for lorry accidents in Ireland or Northern Ireland. Using the above statistics from the USA and the largest estimated distance of lorry travel per year in the NCB (615,000 km, see section 4.7.3), this equates to a rate of 0.035–0.039 spills per year from lorry accidents involving transport of flowback and produced waters. However, the potential of the spill to have an impact on surface water would even be less than the values above; therefore, overall, the risk of impact from spills of flowback and produced water during transport is considered to be low. This does not preclude the fact that a spill could result in an environmental impact.

Releases during treatment. No specific information is available for spills from treatment facilities used for treatment of flowback and produced waters from hydraulic fracturing facilities. However, the previous sections discuss spills and leaks at or near the pads (“on site”) associated with storage and use of additives and chemicals (sections 4.4.3 and 4.4.5) and storage and treatment of produced wastes (sections 4.6 and 4.6.3). The observations made in these sections are generally applicable to off-site treatment facilities.

Releases of chemical constituents due to inadequate treatment. The potential impacts to the environment (in particular from treated effluents discharged to streams) depend upon the compositions of the incoming wastewaters, the types and effectiveness of the treatment systems and the characteristics of the receiving stream (e.g. potential for dilution). Specific chemical constituents are discussed below:

Bromide and chloride. Inadequate treatment of bromide and chloride can result in elevated concentrations in the receiving water bodies (NYSDEC, 2011). Subsequent treatment of the waters (e.g. chlorination for drinking water) can result in the formation of THMs such as bromoform, dibromochloromethane, etc. (USEPA, 2015a). THMs are highly toxic and regulated in most water bodies and drinking water. Publicly owned treatment facilities are not designed to treat high concentrations of TDS, bromides or chlorides; therefore, as previously discussed, the USEPA has proposed to prohibit treatment of oil and gas wastewaters at such facilities (USEPA, 2015b).

Radionuclides. Inadequate treatment of radionuclides has resulted in elevated concentrations of radionuclides (e.g. radium) in sediments in rivers downstream of treatment facilities (e.g. particularly publicly owned treatment works) accepting wastewater from hydraulic fracturing activities (Warner *et al.,* 2013). The USEPA (2015a) has reviewed information concerning the concentrations of radionuclides in effluent discharges from treatment facilities and found both elevated concentrations and inconclusive information concerning concentrations. The USEPA (2015a) also reported elevated radium concentrations in filter cakes from treatment plants and scales from pipe and tanks used in hydraulic fracturing operations.

Metals. USEPA (2015a) found elevated concentrations of barium and strontium in effluents from treatment facilities receiving wastewaters from hydraulic fracturing operations. They concluded that the elevated concentrations may impact surface waters if not managed properly.

Volatile organic compounds (VOCs). The USEPA (2015a) reported that the concentrations of BTEX in effluents from a centralised treatment facility in Pennsylvania, USA, ranged from about 2 to 46 µg/L. The treatment facility was not specifically designed to treat VOCs (e.g. it had no aeration).

Semi-volatile organic compounds (SVOCs). Some SVOC chemical additives used in fracturing fluids (e.g. 2-butoxyethanol) have been detected in an effluent from a centralised treatment facility in Pennsylvania, USA (USEPA, 2015a). Some polycyclic aromatic hydrocarbons (PAHs) have also been identified in environmental media (USEPA, 2015a).

4.7.6 Potential mitigation measures and recommendations

A full evaluation of the methods and practices being used to manage wastes from hydraulic fracturing operations is limited owing to a lack of and organisation of available data. The following improvements are recommended (some from USEPA, 2015a):

- Updated information on the volumes of hydraulic fracturing wastewaters disposed of in injection wells needs to be reported consistently in all states.
- Updated information on the volumes of hydraulic fracturing wastewaters received and treated at facilities needs to be reported consistently in all states.
- Both influent and effluent chemical compositions from treatment facilities needs to be routinely measured and reported.
- A wider range of chemical compositions need to be measured and reported more frequently.
- Better analytical techniques need to be used for radionuclides.

Potential mitigation measures for spills and leaks have been discussed in previous sections.

4.8 Summary of Potential Impacts on Water Quality and Mitigation Measures

4.8.1 Potential Impacts on Water Quality

Impacts from storm water runoff from road and pads. Storm water runoff from well pads in the NCB and CB may vary from as low as 400 m^3 per month to as high as 5800 m^3 per month, depending upon the time of year (high or low rainfall months) and stage of activity (during construction, fracturing or production). Likewise, the amount of runoff from new roads may vary from 400 m^3 per month per kilometre to as high as 1300 m^3 per month per kilometre. Storm water runoff in not unique to UGEE operations. Given the potential volumes of runoff estimated in Ireland and Northern Ireland from each pad and road, the storm water runoff mitigation measures typically available would significantly limit the potential impacts of storm water during UGEE projects and operations if implemented and maintained properly. However, even with state-of-the-art storm water controls, there are still risks of accidental spills, unanticipated events (e.g. rainfall exceeding design capacities), inadequate design and implementation, and lack of proper maintenance. In addition, smaller streams and ecologically sensitive receptors are more vulnerable to storm water runoff. Therefore there is still a need still for appropriate regulations, approval processes, oversight and inspections by regulatory bodies.

Impacts from surface chemical spills and leaks. The quantity of chemical additives used during hydraulic fracturing varies from 5 to 75 m^3 per well. Overall, the reported “spill rate” of chemical additives is variable, depending upon the reporting protocols and accounting methods and varies between 1.3 and 12.2 spills per 100 wells. The volume of the spills reported ranged from 19 to 72,000 L, with a median volume of 1600 L. Despite the large range of reported spills, volumes and associated uncertainties, the fact remains that spills occur and operators must be prepared with appropriate responses and mitigation measures. Even with laws, regulations and best practices and techniques, spills and leaks happen and, therefore, regulatory oversight and inspections are needed.

Impacts associated with well construction, completion and operation. Fluids associated with drilling and hydraulic fracturing operations represent potential sources of contamination in the groundwater environment. Natural gas constituents that are naturally present or are released as a result of hydraulic fracturing operations are also potential sources of contamination if they migrate to the near-surface environment via natural, induced or artificial pathways.

Induced subsurface pathways result from the fractures associated with the hydraulic fracturing process intended to release gas from the target formation. The length of the induced fractures from the horizontal well may extend to several hundred metres. The vertical separation between the target Bundoran Shale Formation in the NCB and the Dartry Limestone Formation (primary aquifer) varies from 250 to 570 m. Therefore the propagation length of fractures must be monitored and controlled and minimum separation distances between target formations and aquifers specified. In addition, hydraulic fractures associated with one well may propagate and intersect hydraulic fractures associated with a nearby well. Therefore, the distance between hydraulic fracturing operations and wells must be controlled and minimum distances specified.

Given adequate separation distances, the upward vertical migration of fluids from deeper unconventional gas target formations to shallow receptors is less likely than the vertical migration of natural gas constituents. This is because fluids and associated contaminants that are released by hydraulic fracturing have to overcome hydraulic gradients between shallow and deep formations, which requires considerable pressures over extended periods of time. The outward and upward migration of released contaminants is also naturally attenuated by capillary forces and adsorption by clay minerals. Overall, deep hydraulic fracturing is not likely to result in a direct flow pathway into shallow aquifers if adequate separation distances are maintained.

Pathways associated with poor or failed well construction practices are considered artificial. A common cause of impaired well integrity is corrosion of the steel casing in zones that have not been properly cemented. An impact on shallow groundwater resources is also more likely if the surface casing was not set sufficiently deep. Overall the primary risk of an impact on groundwater quality is stray gas migration from the gas production zone due to improper, faulty or failed production casing and/or poor or incorrect cement grouting of the casing. Over one-half of the casing leaks occurred in uncemented zones.

Impacts from impoundment and tanks leaks during storage and treatment of on-site produced wastes. Produced wastes during UGEE operations include drilling fluids/cuttings and flowback and produced waters. Based on studies in the USA, approximately one-half of the recorded spills related to hydraulic fracturing activities were spills of flowback or produced waters. Typical spills are relatively small, with one-half of the spills less than 3800 L and few exceeding 38,000 L. The records document that spills of flowback and produced water can be expected from UGEE-related activity, and the risk of impacts reflects the care and adequacy of operations and case- and site-specific risks. Based on US experience, impacts on water resources are typically directly related to the volume of the spill or leak.

Impacts from spills during off-site transport of produced wastes: releases during transport. The USEPA (2015a) reported an estimate of approximately 70 crashes of large lorries per 100 million kilometres travelled, to evaluate the impact of spills during transport of wastewaters from hydraulic fracturing operations, and further estimated that the probability of a spill from a crash was 8.1–9.0%. Using the above US statistics and the greatest estimated distance travelled by lorry per year in the NCB (384,000 km, see section 4.7.3), this equates to a rate of 0.021–0.024 spills per year from lorry accidents involving transport of flowback and produced waters. However, the potential of the spill impacting surface water would be even less than the values above; therefore, overall the risk of the impact from spills of flowback and produced water during transport is considered to be low. This does not preclude the fact that a spill could result in an environmental impact.

4.8.2 Proposed mitigation measures

Potential mitigations measures associated with each of the above impacts are given in each of the above sections discussing the potential impacts. In addition, Chapter 9 includes detailed lists of existing and potential monitoring and mitigation measures for each phase of UGEE operations. Further discussion of mitigation measures based on case studies can be found in Project C of the UGEE JRP.

5 Impacts on Water Resource Use and Mitigation Measures (Task 2)

5.1 Background

UGEE projects require water for several purposes, including drilling operations, well construction, hydraulic fracturing, sanitation and equipment washing. Concrete plans for and details of future UGEE projects and operations in both Ireland and Northern Ireland are as yet unknown. Accordingly, the actual volumes of water that are needed for operations are uncertain, as they have not been defined. Case-specific circumstances would determine the actual demand for water at any given well pad. For guidance purposes, the range of requirements for water for UGEE projects and operations was researched from published international literature. The following sections are summarised from the quantitative assessment of water resources, which is presented in Appendix B and which was carried out as Task 8 of Project A1 of the UGEE JRP.

5.2 Methodology

The methodology that was followed in the preparation of Report A1-5 has three main components:

1. definition of water requirements for UGEE project and operations, with regard to the "probable commercial scenarios" in Task 2 of Project B;
2. description of available water resources in the two case study areas, based on an analysis of hydrometric data obtained from relevant information sources (see below) and the conceptual hydrogeological models developed in Report A1-2 (EPA, 2015); and
3. comparison of water requirements and available water resources, as a means of identifying potential impact.

The comparison is contextualised with respect to existing legislation and regulations that currently govern the technical assessment of future UGEE-related abstractions, as well as the metrics that are used by regulatory bodies in describing and reporting on the ecological status objectives of the WFD.

5.3 Water Use

The greatest water use at any given well associated with the hydraulic fracturing programme occurs over relatively short periods of time, normally measured in days. In the USA, cited water demands for this purpose are 100–12,000 m^3 per well (Meiners *et al*., 2013), 10,800–35,000 m^3 per well (NYSDEC, 2011) and up to 23,000 m^3 per well (USEPA, 2015a). Vengosh *et al.* (2014) report an average water consumption for a single hydraulic fracturing well in the USA of approximately 15,000–20,000 m^3. In Europe, a review of reported demand found that it generally ranges between approximately 5000 and 15,000 m^3 per well (JRC, 2013; AMEC, 2014), although higher and lower values can apply, depending on case-specific circumstances. The upper end of the quoted range would be the worse-case scenario, but the lower end of quoted ranges is considered to be more likely for the two study areas, as the target shale formations are shallower than in most other countries, with an anticipated range of drilling depths between 700 and 1300 m (for additional information, see Report A1-2 of the UGEE JRP). In addition, it is expected that some of the water would be recycled.

5.3.1 Development of potential water use scenarios

The volumes of water that would be required for the development of UGEE operations at a given site or in a given area depend on:

- the general demand for water (e.g. for sanitation, equipment washing);

- the drilling methods and progress, total drilled vertical depths and lengths of horizontal boreholes, and the degree to which water may be needed for dealing with losses of circulation during drilling;
- the number of well pads in a given area;
- the number of horizontal fracturing wells per well pad;
- details of the hydraulic fracturing programme (e.g. the number of hydraulic fracturing stages (as a function of horizontal length) in each well and the actual volumes used at each stage); and
- the timing and duration of build-out scenarios in UGEE projects and operations.

Other factors that directly influence UGEE-related water usage are the proportions of flowback and production waters that would be generated from the operations and the degree to which these can be treated and recycled, thus reducing the volumes of water that would otherwise be abstracted from local sources and/or “imported or transported” from other available sources.

Estimated water use scenarios are summarised in Table 5.1 and Table 5.2, for the NCB and CB study areas, respectively, based on the “probable commercial scenarios” described in Task 2 in this report, as well as the following inputs and assumptions:

- *Number of well pads*. The number of well pads that can be accommodated and/or developed in a licence area would in reality be determined by constraints placed on the developers. Constraints can be of a regulatory nature (e.g. authorisations) and a practical nature (e.g. landowner agreements, cost of development and operations). The theoretical maximum number of well pads that can be accommodated would be a function of horizontal well lengths and the spatial configuration of the licence area. With regard to horizontal well lengths, there are no specific guidance materials for the two study areas, but, on the basis of published plans in England and the US, lengths of 1500 m can be anticipated. On this basis, an estimated maximum (theoretical) of 180 well pads can be accommodated within the NCB licence area, and 50 well pads can be accommodated in the CB licence area. Accordingly, this maximum theoretical development would represent the “high” water use scenario in Tables 5.1 and 5.2. The actual number of well pads that could be established would be spatially constrained by structural geology as well as restrictions related to UGEE development within the boundaries of SACs, groundwater Source Protection Zones (SPZs) and other environmentally sensitive locations.

Table 5.1. UGEE Water use scenarios for the total licence area – NCB study area

Description	Unit	Low	Moderate	High
Well pads	No.	75	105	180
Wells per pad	No.	8	12	16
Total wells per study area	No.	600	1260	2880
Required volume of water per well/fracture programme	m^3	5000	10,000	15,000
Flowback of fracture fluid per well/fracture programme	%	25	32.5	40
Rate of recycling of flowback water	%	80	40	0

Table 5.2. UGEE Water use scenarios for the total licence area – CB study area

Description	Unit	Low	Moderate	High
Well pads	No.	20	30	50
Wells per pad	No.	8	12	16
Total wells per study area	No.	160	360	800
Required volume of water per well/ fracture programme	m^3	5,000	10,000	15,000
Flowback of fracture fluid per well/fracture programme	%	25	32.5	40
Recycling rate for flowback water	%	80	40	0

Until prospective UGEE plans become known, there is no accurate way to predict or judge precisely what the requirement for water will be in the future. The three scenarios in Table 5.1 and Table 5.2 provide ranges that can guide the assessment of the availability of water resources. However, the "high" scenario is not considered realistic, simply because it includes well pads in locations where UGEE development would not be attempted (e.g. geological constraints, such as shallow depths or absence of relevant formations in a given area). The "moderate" and "low" scenarios would thus be considered to be more realistic, and the actual future scenario might be somewhere in between the two.

- *Number of wells per well pad*. Multiple wells would be expected to be drilled from single well pads. For the three water use scenarios described in the probable commercial scenarios in Chapter 2 of this report, the number of wells drilled per pad is considered to be eight, 12 and 16, respectively.
- *Total wells per UGEE licence area*. As defined in Tables 5.1 and 5.2, total wells per UGEE licence area was calculated by multiplying the number of wells per well pad by the total number of well pads.
- *Required volume of water per hydraulic fracturing event or programme*. The required volume of water for a hydraulic fracturing programme at a single well is guided by published values from UGEE applications in Europe (EPA, 2015), i.e. 5000 m^3 for the low water use scenario, 10,000 m^3 for the moderate water use scenario and 15,000 m^3 for the high water use scenario.
- *Flowback volumes of fracture fluid per fracturing event or programme*. Based on the probable commercial scenarios in Chapter 2, an estimated range of flowback volumes of between 25% and 40% of the water used is considered realistic: 25% for the low water use scenario, 32.5% for the moderate water use scenario and 40% for the high water use scenario.
- *Rate of recycling of flowback water*. Flowback water may be treated and recycled to reduce the water abstracted from local resources. Up to 80% recycling can be accomplished, as described in Task 3 (Chapter 6). In the water use scenarios, 80% is used for the low water use scenario, 40% for the moderate water use scenario and 0% (no recycling) for the high water use scenario. There is an increasing trend worldwide to recycle some proportion of the flowback water, and the degree of recycling is determined by technical considerations (feasibility), cost considerations (the treatability of flowback water vs access to local water sources) and regulatory considerations (e.g. authorisation and ability to discharge wastewater effluents to local water bodies).

There is also a temporal aspect that must be considered, specifically how development proceeds in time, both at an individual well pad and on a cumulative basis across a given licence area. The build-out period of UGEE projects and operations cannot be predicted with any certainty, but for the purposes of this report, it has been assumed that build-out would occur in each lease area over a 15-year period, beginning gradually, peaking in years 7–11, and subsequently declining to year 15. There are three lease areas in the NCB, and it is assumed that development (by different licensees) in each would proceed concurrently. Without knowledge of how UGEE would be planned and developed in the future, this is a “worst-case” or maximum development scenario. The resulting total annualised water usages (m^3 per year) for the build-out period are presented in Table 5.1 and Table 5.2 for the NCB and CB licence areas, respectively. The corresponding estimated annualised maximum water use requirements, expressed in m^3 per day, for years 7–11 of the build-out scenario are summarised in Table 5.3.

Table 5.3. Estimated maximum water use requirements (m^3/day) during the assumed build-out scenarios

Water use	CB	NCB		
		Demand per lease area	No. of lease areas in NCB	Demand for NCB licence area
High	3288	4110	3	12,330
Moderate	858	1,032		3096
Low	149	186		558

5.4 Maximum Daily Water Demand for UGEE Operations

The annualised water use requirements presented above indicate the progression of total and maximum water use requirements for the 15-year build-out scenario. They do not define the maximum daily water demand on any given day, which is defined by the number of hydraulic fracturing stages and the volumes of water needed for each stage. Using the maximum water requirement for a hydraulic fracturing programme at a single well of 15,000 m^3, the water demand for a single well would be determined by how the programme is implemented, specifically how many fracturing stages are undertaken and the duration of the programme.

For a single well, a hydraulic fracturing programme is typically completed within a few (3–10) days (EPA, 2015), but the duration of the programme is subject to case-specific circumstances and objectives. Accordingly, if the programme requires 15,000 m^3 of water over a 3-day implementation period, the maximum daily water demand is 5000 m^3 per day for the single well. If the duration is shorter, or greater volumes of water are required, the daily demand rises. More significantly, if identical programmes are carried out at multiple wells concurrently, the total daily demand becomes significantly greater.

For the peak build-out scenario of the more realistic “moderate” water use scenario presented in section 5.3, there would theoretically be approximately 130 wells drilled and hydraulically fractured per year in the NCB study area. Assuming 3 days per hydraulic fracturing programme, this equates to 390 days of demand at 5000 m^3 per day in the example given above. Such development and demand would have to be supplied from multiple sources. Accordingly, any future proposed UGEE-related abstraction plans would have to be carefully reviewed to define and understand the timeline for total demands, individually and cumulatively, with the involvement of relevant stakeholders and regulatory bodies.

5.5 Sourcing of Water to Meet Demands

It is anticipated that the water required for UGEE projects and operations would be sourced from available water resources within or close to the licence areas in each basin. It is further expected that UGEE developers would try to source water as close as possible to individual wells pads. Precisely how and where the water would be sourced would be determined by practical considerations and cost – specifically the total costs of planning, licensing, constructing and maintaining abstraction points versus the costs of purchase and transport of water from existing water supply schemes in the region.

Given the high rainfall in both case study areas, rainwater harvesting is an option to help reduce demands on water abstraction sources. The use of recycled treated wastewater can also reduce water demands, but the ability to recycle treated wastewater effluent from UGEE operations is influenced by the volumes of the available flowback water and its chemical nature and treatability. Thus, establishing and subsequently monitoring the volumes and quality of flowback and production water become important operational controls (Nicot *et al*., 2014). There is a trend in the industry towards increasing the proportion of recycled flowback and produced water, especially in areas where freshwater resources are limited (Hunter, 2012; Nicot *et al.*, 2014). This is also described in Tasks 3 (Chapter 6) and 7 (Chapter 10) within this report.

Any UGEE-related abstractions would be subject to existing control measures (systems of "prior authorisation") in both Ireland and Northern Ireland. In Northern Ireland, abstractions of all waters are licensed under the Water Abstraction and Impoundment (Licensing) Regulations (Northern Ireland) 2006. In Ireland, abstraction controls are currently defined by: (1) the EIA Directive (85/337/EEC) (EEC, 1985), which is included in statutory instrument (S.I.) No. 93 of 1999 (EC (EIA) (Amendment) Regulations, 1999) and referred to in Part 2 of Schedule 5 of the Planning and Development Regulations, 2001; (2) the Water Supplies Act 1942, as amended by the Planning and Development Act (S.I. No. 30 of 2000); and (3) the Planning and Development Regulations 2001 for groundwater abstraction proposals for water supply to local authorities. Section 4 of the 1964 Sanitary Services Act also provides for water abstraction by a sanitary authority from a reservoir belonging to the Electricity Supply Board.

Specifically which control mechanism would be applied to authorise UGEE-related abstractions would depend on which source of water would be targeted for abstraction development.

Article 11.3(e) (Programme of Measures) of the EU WFD (2000/60/EC) requires a system of "prior authorisation" for water abstractions. It also includes provision for measures to be introduced to mitigate potential impacts of abstraction on water resources. Different water bodies can be impacted in different ways, e.g. by changes in water levels, flow and discharge, quality and/or the status or health of associated aquatic ecosystems. With regard to the latter, the European Court of Justice has ruled that Article 6(3) of the Habitats Directive (EC 92/43/EEC) (EEC, 1992) applies to abstraction projects, whereby an Appropriate Assessment is required where the potential for impact on Natura 2000 sites is identified (EC, 2006). In the Ireland, the need for control measures for groundwater abstractions are specifically addressed by the recently enacted Groundwater Regulations [S.I. No. 9 of 2010].

Within the UGEE licence areas in the NCB, several surface water and groundwater bodies cross the border between Ireland and Northern Ireland. Such water bodies are part of formally designated international river basins under the WFD, e.g. the Northwestern and Neagh-Bann International River Basin Districts. In cross-border river basins, Article 3 (Coordination of administrative arrangements within river basin districts) of the WFD requires Member States to coordinate water resources management. Accordingly, the study and prior authorisation of future abstractions of shared water resources and associated ecosystems in the NCB study area would require co-ordination among the relevant regulatory bodies in Ireland and Northern Ireland.

5.6 Available Water Resources and Potential Impacts of Abstractions

The available water resources of the two study areas are represented by rainwater, lakes and reservoirs, streams and rivers, and groundwater (including springs). The main physiographical, geological and hydrogeological characteristics of the study areas are described in detail in Report A1-2 of the UGEE JRP, and key descriptors are summarised below (with further detail included in Appendix B).

5.6.1 Rainfall/meteorology

The 30-year annual average rainfall distribution for the period 1981–2010 (Met Éireann, 2015) ranges from 800–2400 mm per year across the NCB study area and from 800 to 1400 mm per year across the CB study area. In both instances, the highest rainfall occurs in the winter months in upland areas.

5.6.2 Lakes – NCB study area

There are numerous lakes in the NCB study area, ranging in size from 0.004 km^2 (Lough Nacroagh) to 103.8 km^2 (Lower Lough Erne). The largest lakes are located in lowland, valley settings while smaller lakes tend to be located in uplands. Lakes that are present in valleys occupy inter-drumlin areas that form a complex hydrological system of interconnected lakes, bogs and wet meadows (wetlands) in which flooding occurs frequently.

Lakes are important for recreational uses, including fisheries, and are also sources for public and private water supplies.

Table 5.4 summarises the abstracted lakes within or adjoining the UGEE licence boundaries, indicating lake surface areas, approximate storage volumes, delineated catchment areas, estimated daily mean inflows, abstraction rates, and abstractions as a proportion of estimated daily mean inflows.

Table 5.4. Summary of abstracted lakes in the NCB study area

Name	Lake area	Lake volume[a]	Estimated lake catchment area	Daily mean inflow[b]	Abstraction rate	Abstraction as % of daily mean inflow
	(km^2)	(Km^3)	(km^2)	(m^3/day)	(m^3/day)	(m^3/day)
Aghalough	0.01	0.04	1.4	2805	50	1.8
Anarry Lough	0.11	0.26	0.8	2963	135	4.6
Annagh Lough	0.35	1.20	1.5	2424	1455	60.0
Clonty Lough	0.11	0.12	10.8	23,590	740	3.1
Drumlane Lough	0.64	3.32	8.8	15,545	250	1.6
Lackagh Lough[c]	0.07	0.15	0.6	1262	236	18.7
Lough Arrow	12.47	134.17	50.5	106,938	432	0.4
Lough Erne Lower	103.8	n/a[4]	4106.6	14,299,645[e]	2600[f]	0.0
Lough Erne Upper	32.18	n/a[4]	3296.9	12,427,664[e]	44,000[f]	0.4
Lough Gill	13.81	160.63	375.2	1,439,439	18,902	1.3
Lough Kilsellagh	0.04	0.20	8.7	15,751	4594	29.2
Lough Melvin	22.06	185.69	226.1	705,621	7000	1.0
Lough Nabellbeg	0.01	0.01[d]	0.2	814	83	10.2
Lough Nambrack	0.07	n/a[d]	0.3	656	141	21.5
Lough Naweleian	0.05	0.02	0.5	1138	60	5.3

[a]Estimated from bathymetry data.

[b]Calculated by multiplying catchment areas and estimated specific runoff values.

[c]Flagged as WFD “at-risk” from over abstraction (CDM, 2009).

[d]Bathymetric maps were not obtained but do exist. Upper Lough Erne: mean depth 2.3 m, max. depth 27 m (NIEA, 2015). Lower Lough Erne: mean depth 11.9 m, max. depth 69 m (NIEA, 2009).

[e]From water balance table received from Northern Ireland Water

[f]Maximum licensed. Actual abstractions are less.

The single largest abstraction from lakes is associated with Lough Erne, where the Fermanagh regional water scheme is supplied from two pump stations at Belleek and Killyhevlin. Information obtained from the NIEA indicates that the maximum permissible (i.e. licensed) abstractions from each station are 44,000 m^3 per day and 2600 m^3 per day, respectively, and that, in 2014, the actual abstraction from each station averaged 24,810 m^3 per day and 1640 m^3 per day, respectively (NIEA, 2009). In Ireland, the single largest lake abstraction is from Lough Gill, where approximately 18,900 m^3 per day is abstracted to supply three public water schemes and one private supply. The largest abstraction (8000 m^3 per day) supplies the North Leitrim Regional Supply Scheme.

For the majority of abstracted lakes, water balance and/or design studies were researched with relevant public bodies, but few details have emerged. Bathymetry is known for 33 lakes and all of the major abstracted lakes (Upper and Lower Loughs Erne, Lough Melvin, Lough Gill, Lough Arrow, Upper and Lower Lough Macnean and Lough Allen) are equipped with staff gauges for water level measurements. Loughs Erne and Allen are both regulated water bodies.

5.6.3 Lakes – CB study area

There are no lakes in the UGEE licence area of the CB. However, Doo Lough is located just east of and near the licence area and serves as the main source of public water supply for western County Clare. Water levels in Doo Lough are regulated (impoundment), and the average daily abstraction of approximately 11,500 m^3 per day is below its reported “yield” (i.e. capacity) of approximately 48,400 m^3 per day for its design storage (Bowman *et al.*, 1983).

Two smaller natural lakes, Lough Namina and Lough Acrow, are also located near but outside the UGEE licence area to the east, supplying the Inagh Kilmaly and Lissacasey group water schemes, respectively (for more information, see Report A1-2 of the UGEE JRP).

5.6.4 Lakes – potential impacts from abstraction

Abstraction pressures in lakes manifest as changes in natural and/or or regulated water level cycles and residence times. Abnormally low water levels during periods of high net abstraction represent a particular risk of impact on the shallow littoral zones, which support the main populations of macrophytes and macroinvertebrates (CDM, 2009). Changes from natural conditions, particularly changes in water level regimes, can cause the drying out of biota, increase exposure to wave action, and result in both freezing and changes in light penetration or water temperature. The significance of these effects depends largely on the extent, duration and timing of abstractions, as well as the ability of biota to recover from such changes. Assessing the impacts of abstraction is, accordingly, a complex ecologically based process, requiring the combined inputs of qualified hydrologists and aquatic ecologists on a case-by-case basis.

In the case of severe impacts of abstraction, the volumes abstracted can exceed the ability of a lake’s catchment to restore the water level to typical seasonal high levels, resulting in a longer term decline in lake water levels. Based on the water level records obtained for the NCB study area, such long-term declines are currently not apparent in available datasets.

The reporting of the “ecological status” of lake water bodies for WFD implementation purposes (EPA, 2014a; NIEA, 2014a) does not identify current lake abstractions as a significant environmental pressure. Although several lakes in the NCB are classified as being at “less than good” ecological status, none of them failed classification tests because of abstraction pressures. The majority of “less than good” ecological status cases are based on other factors that relate to biological conditions and water quality, as a result of physical modifications (e.g. dredging) or elevated nutrient (phosphorus) loading.

Volumetrically, future risks of impact from UGEE-related lake abstractions would be considered greater in “small lakes” than in “large lakes’. Further distinction cannot be made or judged without lake-specific knowledge about ecosystems and related environmental sensitivities, as well as water balance studies that define inflows, outflows and throughflows (turnover rates).

The daily maximum water demand of 5000 m^3 per day for a single well represents a negligible volumetric fraction of the storage capacity of large lakes, indicating a negligible risk of impact. However, the scenario of concurrent operations at multiple sites would change the reference point on potential impacts to lakes, and the risks would be greater in small lakes. Accordingly, all future proposed UGEE-related abstractions would have to be carried out individually with the involvement of relevant stakeholders and regulatory bodies, as each lake is different and the risks of impact are case specific.

5.6.5 Streams and rivers – NCB study area

There are 33 active gauging stations in the NCB study area, of which 28 are stream flow recorder sites and five are equipped with staff gauges for water level recording, and from which flow data are estimated using available rating curves. Their locations are shown in Figure 5.1. Using data obtained from the EPA and Office of Public Works in Ireland, and the Rivers Agency in Northern Ireland, the mean and 95th percentile (Q_{95}) flows (i.e. the flow that is exceeded 95% of the time) are summarised in Table 5.5. Flow statistics for ungauged catchments in Ireland were estimated using the EPA's HydroTool. Flow statistics for ungauged catchments in Northern Ireland were estimated by transposing specific runoff estimates from gauging stations in neighbouring catchments that have similar physical characteristics. Flow statistics in ungauged catchments that cover karstified limestones are assigned low confidence, given the dynamic nature and range of flows that characterise such catchments and that cannot be captured with simplified estimation methods.

Table 5.5. Summary of estimated flows in the NCB and CB study areas

Gauged data									
		NCB				CB			
Parameter	Unit	Min.	Max.	Mean	Median	Value	–	–	–
Q_{95} flow	m^3/s	0.06	2.17	0.80	0.34	0.171	–	–	–
Mean flow	m^3/s	0.89	28.56	8.44	4.86	3.039	–	–	–
Specific runoff (Q_{95})	$m^3/s/km^2$	0.0011	0.0066	0.0035	0.0034	0.0016	–	–	–
Specific runoff (mean)	$m^3/s/km^2$	0.0191	0.0777	0.0386	0.0372	0.028	–	–	–
Ungauged data (estimated)									
		NCB				CB			
Paramter	Unit	Min.	Max.	Mean	Median	Min.	Max.	Mean	Median
Q_{95} flow	m^3/s	0.02	1.045	0.2165	0.105	0.011	0.15	0.0548	0.038
Mean flow	m^3/s	0.12	6.634	1.3807	0.54	0.08	1.17	0.4128	0.2805
Specific runoff (Q_{95})	$m^3/s/km^2$	0.0024	0.0063	0.0039	0.0038	0.0007	0.003	0.0019	0.0021
Specific runoff (mean)	$m^3/s/km^2$	0.0165	0.0255	0.0209	0.021	0.0097	0.0222	0.0143	0.0143

Gauged:

NCB: Based on 11 gauging stations with long-term records (period 1946–2015).

CB: Based on Doonbeg gauging station (period 1972–2015).

Ungauged:

NCB: Result from HydroTool in 11 catchments.

CB: Result from HydroTool in 12 catchments.

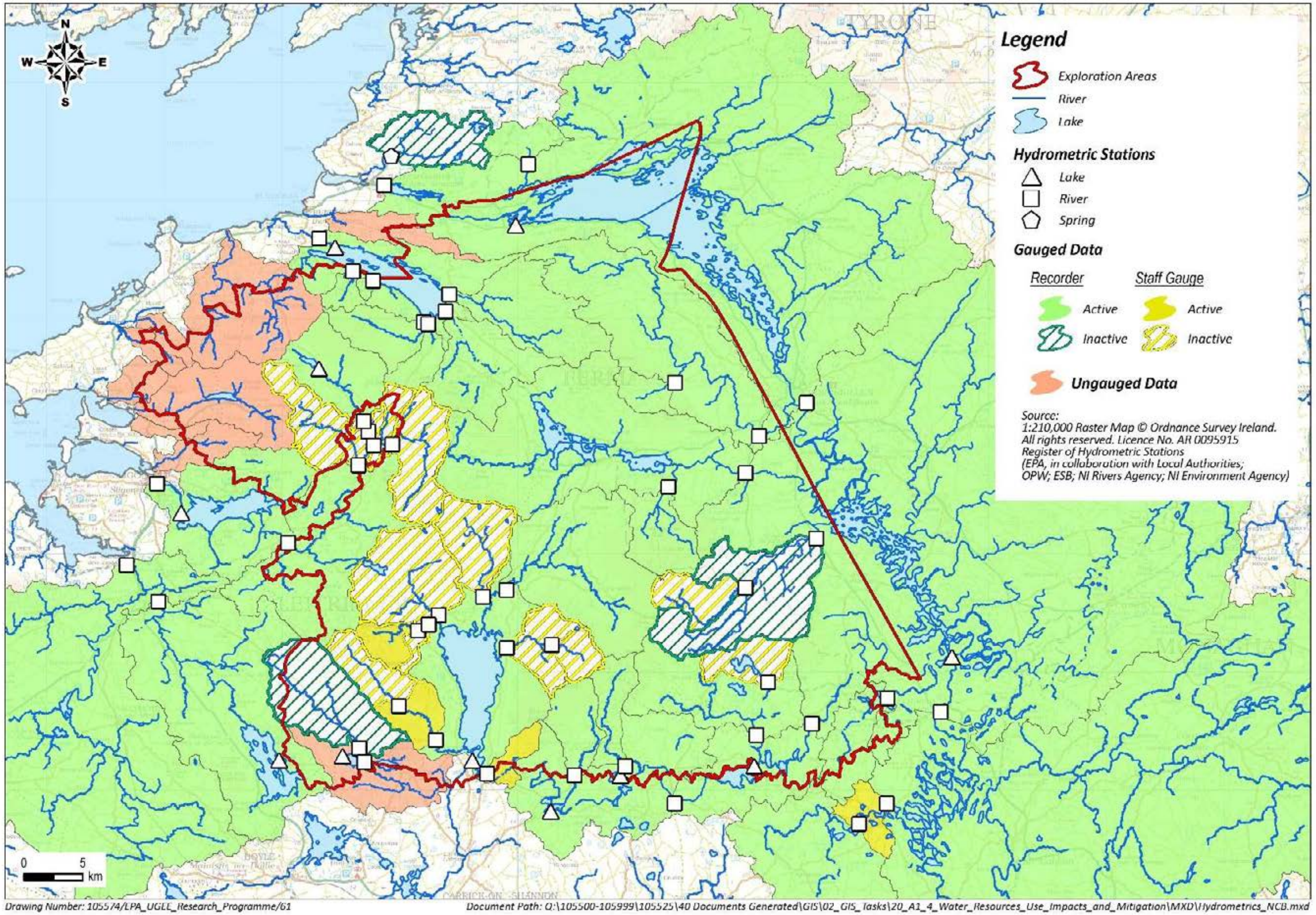


Figure 5.1. Gauging stations in the NCB study area.

Figure 5.2 depicts the hydrograph and flow duration curve for an automatic gauging station at Glenaniff, which measures flow in a dominantly limestone catchment near Lough Melvin. This is a quick-response catchment in which the steeper slope section of the flow duration curve reflects surface runoff and near-surface pathways of water movement, and we infer from the flatter low-flow section of the curve that there wil be groundwater contributions to the measured stream flow. The latter are sustained, but the contributions are volumetrically small (per unit area of discharge to the stream) compared with the shorter duration peak runoff contributions during rainfall events.

The implication is that rainfall runoff coefficients are high and groundwater baseflow contributions are, on the whole, small, even if the latter are important in maintaining baseflow during prolonged dry weather conditions. This characteristic is typical of "poorly productive bedrock" settings, which are present across most of the NCB study area, and are described in Report A1-2 of Project A1 of the UGEE JRP. Other representative gauging stations are presented in Appendix B.

5.6.6 Streams and rivers – CB study area

IN the CB study area, several small streams flow west and south to the sea and the Shannon Estuary from the upland areas in the east. On Loop Head Peninsula, several localised catchments drain directly to the sea over short distances. The single gauging station on the Doonbeg River displays a similar response to Glenaniff, and thus similar conclusions about flow mechanisms apply. Estimated flow statistics for the gauged Doonbeg River and ungauged catchments (using HydroTool) indicate specific runoff values that are of a similar magnitude as that of catchments in the NCB study area. On this basis, the two study areas are broadly considered to be hydrologically similar (i.e. high rainfall, quick hydrological response and low baseflow catchments).

5.6.7 Streams and rivers – potential impacts from abstraction

The quick flashy nature of stream hydrographs, as well as the flat slope of the low-flow sections of available flow duration curves, imply that the majority of streams in the two study areas would be sensitive to stream abstractions. Abstractions reduce stream flows, and impacts are measured by the resulting changes in ecological conditions, including the stream biota, hydromorphology and water quality (CDM, 2008). This is recognised by the methods that are applied by both the EPA and the NIEA in classifying the ecological status of surface waters for WFD reporting purposes. In both Ireland and Northern Ireland, the methods examine and monitor departures from reference conditions with regard to macroinvertebrates, hydromorphology and physicochemical quality:

- Macroinvertebrates are biological indicators that are measured by the number, distribution and quality of colonies. These are judged by "Q-scores" in Ireland and the "BMWP biotic score system" in Northern Ireland.
- Hydromorphological characteristics are described from field observation and survey, notably channel morphology and flow types, channel vegetation, substrate diversity and condition, barriers to flow continuity (e.g. dams), bank structure and stability, bank and bank top vegetation, riparian land cover and floodplain interaction.
- Physicochemical conditions are described by the results of field and laboratory analysis of water samples.

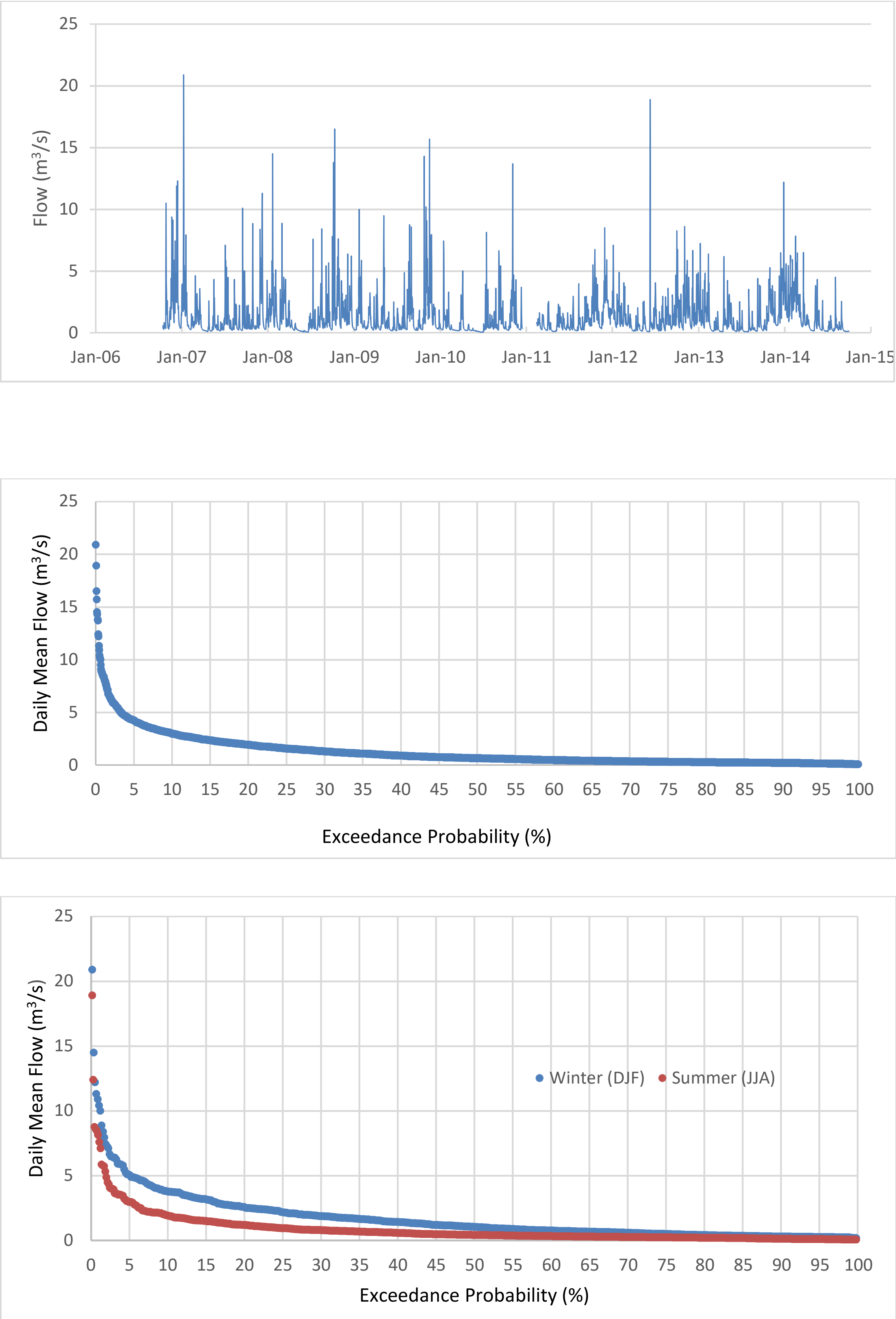


Figure 5.2. Hydrograph and flow duration curves – Glenaniff.

As reported by the EPA (2014) and NIEA (2014a), several streams in both case study areas have been classified as being at “less than good” ecological status in WFD reporting terms, but none failed WFD status objectives on the basis of abstraction pressures alone. The majority of streams that failed to achieve “good ecological status” objectives did so on the basis of biological indicators, in particular the quality of macroinvertebrate colonies that are sensitive to nutrient concentrations. In many cases, the precise cause for the failed status objectives are subject to further study.

Using gauged or estimated flow data and hydrological pressure information (notably abstractions and effluent discharge data from existing licences and knowledge of impoundments), the NIEA also assigns a status to the “hydrological regimes” of rivers and streams in Northern Ireland. The status is reviewed in the context of deviations of water levels or flows that occur from natural reference conditions. For 2014, the “hydrological regimes” of streams within the NCB study area were mostly graded as either “high” or “good’, and streams or sections of streams where hydrological regimes were identified as requiring further study /assessment were flagged in their respective catchment areas.

In the context of abstraction pressures, the Q_{95} flow is often cited as a “critical” baseline characteristic that is used to identify potentially problematic abstractions. In Northern Ireland, the concept of environmental flows for rivers (originally described by Acreman *et al.*, 2006) has been adopted as standards in regulations in Statutory Rule No. 45 of 2015 (DOENI, 2015). In these regulations, permissible abstractions from rivers are judged by river “size’, whereby the relevant metric is a natural mean daily flow that exceeds a flow statistic (e.g. the Q_{95} flow), and river “type” (i.e. its typology), which are also defined in the regulations by combinations of catchment areas, baseflow indices and average annual rainfall over the catchment areas. Specifically, the permissible abstraction is defined as a percentage of the natural daily mean flow that exceeds a specified flow metric for different river types. Accordingly, permissible abstractions can be judged by and take into consideration variable flow conditions (i.e. seasonality) and environmental sensitivity. As such, the environmental flow concept is risk based (i.e. higher risks during low-flow periods). Accordingly, prior authorisations of any future UGEE-related abstractions would have to be reviewed in the context of catchment hydrological conditions, on a case-by-case basis. The review should be based on the principles of environmental flows, i.e. factoring in reference conditions of the water level and flow-dependent ecosystems and habitats.

For the purposes of this report, and as a screening exercise, the daily maximum water demand for a single hydraulic fracturing programme of 5000 m^3 per day (see section 2.2) was compared with the estimated Q_{95} flows in Table 5.5. The demand, alternatively expressed as 0.058 m^3/s, exceeds the minimum estimated Q_{95} flows of 0.02 m^3/s and 0.01 m^3/s for subcatchments in the NCB and CB licence areas, respectively. Accordingly, certain streams would probably not be able support the demand based on the estimated Q_{95}. Spatial representations to illustrate the same point are provided in Figure 5.3 and Figure 5.4 for the two study areas. In both examples, several catchments would not be expected to be able to supply the demand under low-flow conditions, thus indicating a potential risk of impacts on stream biota, and their associated ecosystems, and warranting further detailed study.

Even if the risks of potential impacts from abstractions are reduced during higher flow conditions, and may be temporally adjusted, demands at any given level of abstraction may also be greater than 5000 m^3 per day if several hydraulic fracturing programmes are carried out concurrently; therefore, case-specific risks and capacity would have to be explored in detail as part of a UGEE project’s planning and prior authorisation phase. In reality, it appears unlikely that total water demand for UGEE-related activity can or would be sourced from a single catchment or stream. Few streams in the NCB and no streams in the CB study areas are presently abstracted for public and private water supplies. The single largest suitable abstraction from a stream is 12,000 m^3 per day from the River Shannon, which supplies the South Leitrim Regional Water Supply Scheme (see Table 5.6). The abstraction is outside and downstream of the UGEE licence area in the NCB, but is considered relevant to the study area because Lough Allen, which is within the licence area, is regulated to maintain flow in the River Shannon.

The importance of deriving accurate flow estimates for streams is also illustrated by the example of the abstraction from the North Sligo public water supply in Table 5.6, which is 1850 m^3 per day but distributed over two abstraction points on two separate streams. The distribution of abstraction between the two sources is not known, but, assuming a 50–50 distribution, the abstraction rates exceed the estimated Q_{95} for the respective streams. This simple comparison highlights the fact that the streams may be at risk from overabstraction, notably during low-flow conditions, and further checks on actual flow conditions and related ecology would be recommended. In the case of North Sligo public water supply, abstractions are repositioned downstream to the larger Grange River during low-flow conditions (EPA, 2013).

There are additional abstractions from streams in the NCB study area in which the abstraction point is located immediately downstream of springs. Such abstractions can technically be considered to be groundwater abstractions, but they are located at the headwaters of streams and, as such, reduce flows in streams. Spring discharges support baseflow to streams and related ecosystems further downstream in the same catchments, thus abstractions from headwaters require a larger geographical focus beyond the headwater location.

Although the groundwater flux through bedrock aquifers can be small, especially in poorly productive aquifers, the baseflow components they provide to surface water bodies (e.g. streams) are important for aquatic biota, especially during prolonged dry weather events. Groundwater baseflow to streams may account for 100% of stream flows in such periods (e.g. the summer drought in 2010) but only represent a very small percentage during peak flow conditions (Misstear *et al.*, 2009; O'Brien *et al.*, 2013).

Groundwater availability in the NCB study area is also a function of depth, recharge from rainfall and natural groundwater quality (e.g. whether the formation waters are saline and can be naturally exploited. Certain formations are known to store (and possibly transmit) variably saline formation waters at depth within the central parts of the NCB, which implies that the "resource value" is diminished with depth.

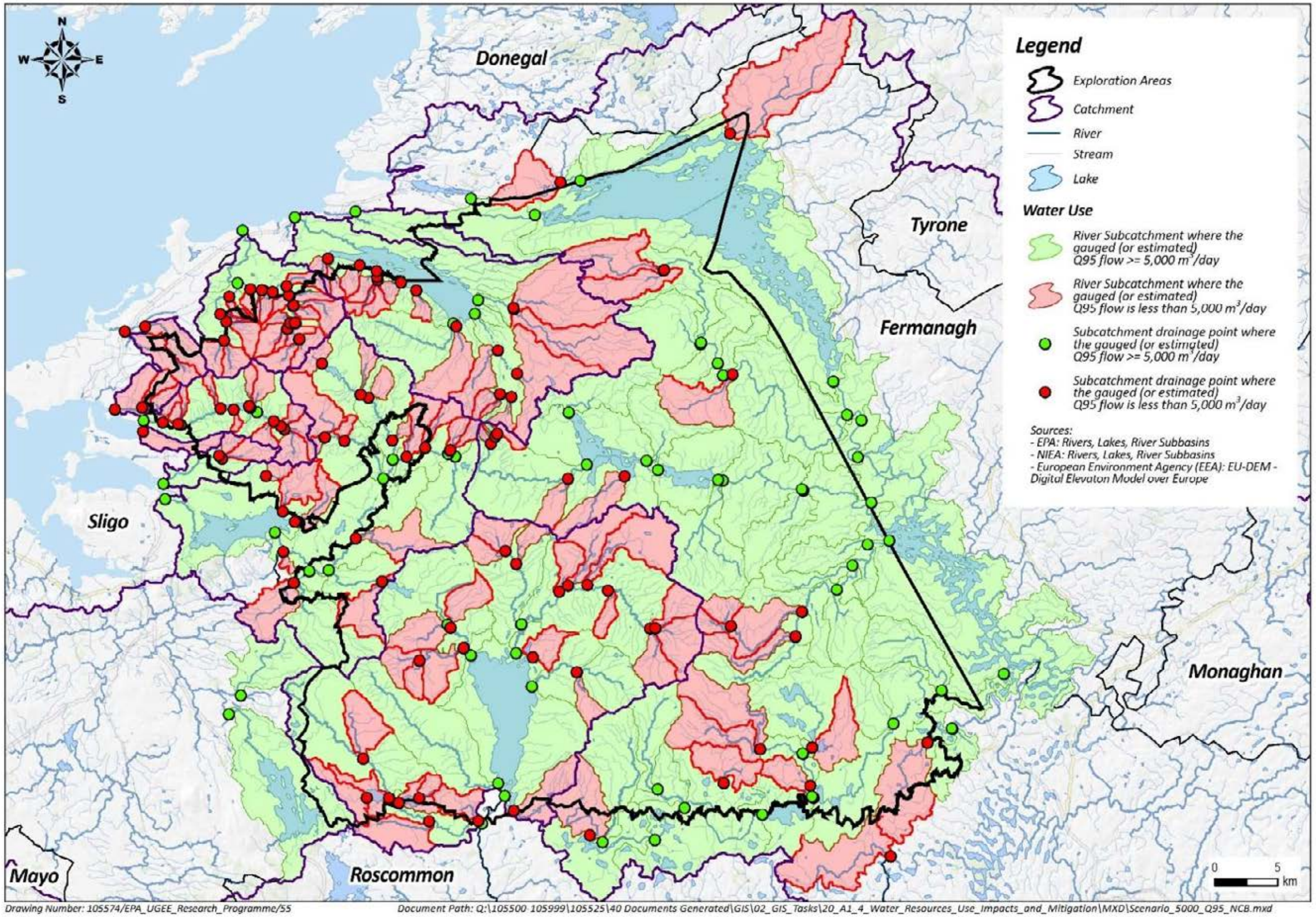


Figure 5.3. Comparison of daily water demand of 5000 m^3 per day and estimated Q$_{95}$ flows – NCB study area.

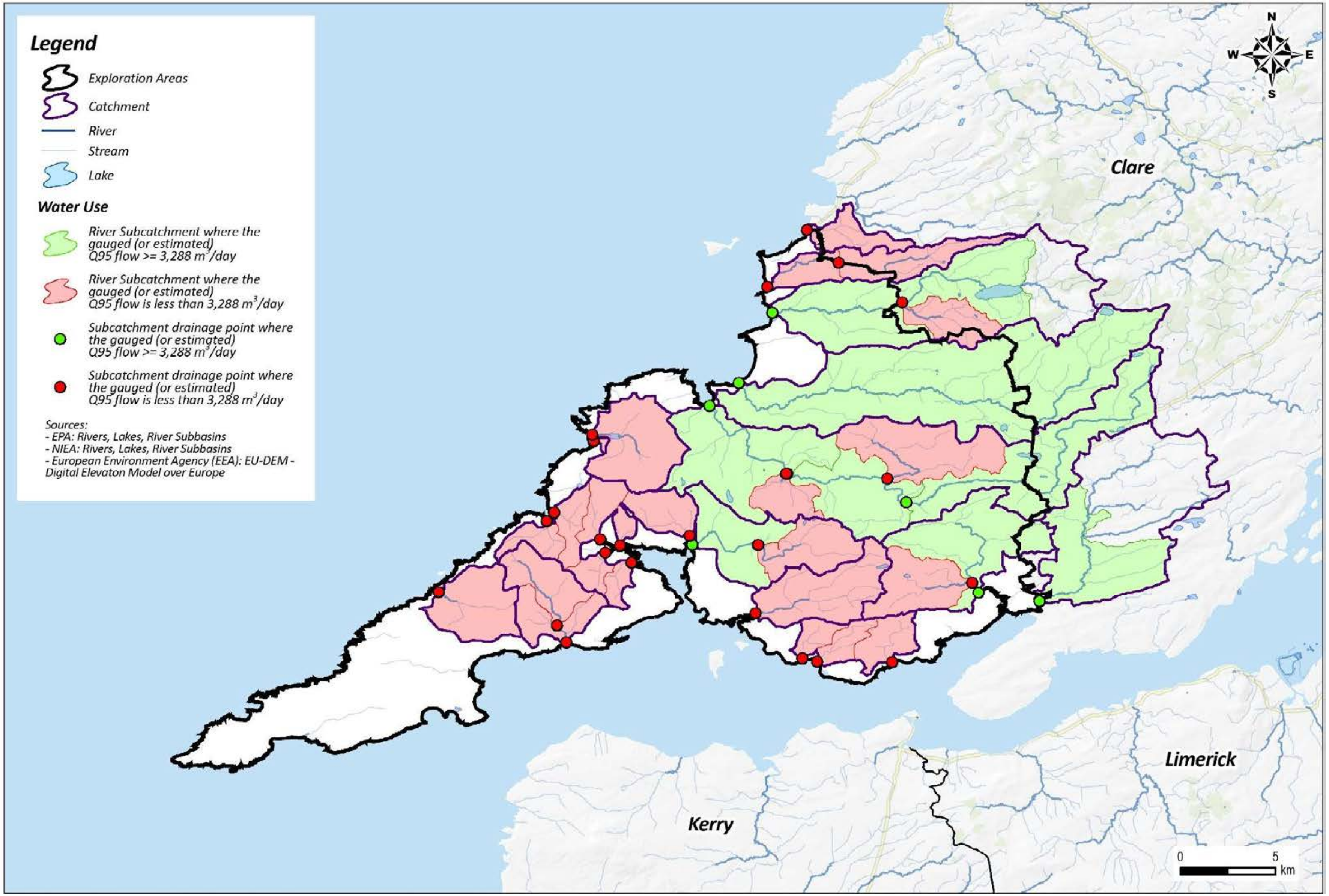


Figure 5.4. Comparison of daily water demand of 5000 m^3 per day and estimated Q_{95} flows – CB study area.

Table 5.6. Abstraction rates

Supply name	Supply type	Stream name	Net abstraction	Q_{95} flow[a]	Mean flow[a]	Abstraction/Q_{95} flow	Abstraction/mean flow
			(m^3/d)	(m^3/day)	(m^3/day)	(%)	(%)
Belturbet public water supply (PWS)	PWS	Erne River	720	135,648	2,467,860	0.5	0.03
Erne & Melvin Enhancement Co.	Private (industry)	Cladagh River	4806 (all returned)	14,274	97,244	31.2	4.6
Errington Trout Farm	Private (industry)	Ballycassidy River	1700	2767	211,838	61.4	0.8
North Sligo PWS	PWS	Gortnaleck Stream	925[b]	785	4811	117.9	19.2
North Sligo PWS	PWS	Lyle River	925[b]	553	3775	167.2	24.5
South Leitrim Regional Water Supply Scheme[c]	PWS	River Shannon	12,000	36,754[d]	278,879[d]	32.6	4.3

[a]Estimated at position of abstraction.

[b]The total abstraction rate for North Sligo PWS from the two rivers (Gortnaleck and Lyle) is approximately 1850 m^3 per day. The abstraction rates from the individual sources were not measured.

[c]Outside the UGEE licence area but connected to Lough Allen, which is in the NCB. Flow estimation based on limited data.

[d]Underestimated values, as estimation does not include all tributaries that are located between the abstraction point and Lough Allen. Thus, percentages are overestimated.

There are hundreds of springs in the NCB study area, of which only a fraction are likely to be represented in available maps. Springs are groundwater discharge points that are used for water supply purposes and that also give rise to stream flow throughout the study area. Accordingly, they play an important role in providing baseflow to surface water bodies and supporting conditions for groundwater-dependent ecosystems. Springs emerge from all bedrock types. They are both stratigraphically and structurally controlled. Despite their hydrogeological and ecological significance, spring discharge records are sparse and represents a significant data gap, particularly where large springs discharge from karstified limestone aquifers. (More information is available in Report A1-2 of the UGEE JRP.)

5.6.8 Groundwater – CB study area

The available groundwater resources in the CB study area are represented by bedrock aquifers, primarily fractured sandstones that are mapped as poorly productive aquifers by the GSI. Although there are no public groundwater supplies within the UGEE licence boundaries, the bedrock aquifers provide water to single homes, farms and commercial facilities (e.g. hotels, water bottling plant). Reports of water strikes to a depth of 600 m in a gas exploration borehole drilled in the 1960s raises questions about the potential presence of a deeper regional groundwater flow component in the study area. (Additional detailed information is available in Report A1-2 of the UGEE JRP.)

Very little is known about deeper hydrogeological conditions in either the NCB and or the CB study areas, and this would have to be addressed as part of future UGEE-related planning and licensing.

5.6.9 Groundwater – assessment of impact potential

The hydrogeological characteristics of the bedrock aquifers in the two case study areas are complex. They are conceptually understood, but there are gaps in the data with regard to quantitative data and information. The complexity and, often, unpredictability of bedrock aquifers implies that well yields and the influences of abstractions cannot be predicted with certainty without detailed study involving field investigations. In the UGEE context, the risks of impacts from groundwater abstractions relate primarily to:

- reduced baseflow to surface water bodies (if groundwater and surface water are hydraulically connected);
- adverse influence on the supporting conditions of nearby groundwater-dependent terrestrial ecosystems; and
- hydraulic interference with existing, neighbouring supply wells (public and private).

As part of the prior authorisation process, both desk study and field surveys would have to be carried out to identify potential features, ecologies and/or populations that might be affected by the proposed abstractions. Following this, the case-specific risks and mitigation measures should be assessed through further study, testing and monitoring.

As documented in Report A1-3 of Project A1 of the UGEE JRP, groundwater is used extensively for both public and private water supply across both study areas. Individual abstraction rates range from less than10 m^3 per day (small group water scheme) to approximately 500 m^3 per day (public scheme). Accordingly, groundwater supplies are volumetrically smaller than abstractions from surface water bodies, but they are no less important for supply purposes.

Overall, existing groundwater abstraction pressures in the two study areas are low. The large number of private wells serving single homes and farms (in the CB study area especially) are of reduced consequence, as the majority of the groundwater that is abstracted for private supply is returned back to the groundwater environment via septic tanks, percolation systems and livestock.

All groundwater bodies in the two study areas are classified as being of “good” or “high” quantitative status with respect to groundwater abstraction pressures (EPA, 2014; NIEA, 2014). Thus, existing abstractions are considered to be sustainable and there are no identified adverse impacts on drinking water sources, surface water bodies or groundwater-dependent terrestrial ecosystems.

Reported yields from pump testing of wells results range from less than 50 to more than 400 m^3 per day. In the context of the UGEE water demand in section 2.2, groundwater is a viable source of water to meet demands, at least in part. The ability to develop a sufficient supply to meet demands locally for hydraulic fracturing programmes would be subject to exploration and testing and might require multiple wells at multiple locations. This would depend on location- and case-specific circumstances of both hydrogeology and actual water demands. The chance of drilling productive wells in bedrock aquifers involves study, skill and a degree of good fortune, and it is not always guaranteed at the first attempt.

5.6.10 Water resource use mitigation measures

There is the opportunity to mitigate against the potential impacts of abstractions by:

- reducing demands on water resources (e.g. by the recycling of flowback waters);
- spreading abstractions among multiple sources;
- directing abstractions towards lower sections of catchments (higher order streams);
- avoiding abstractions from ecologically sensitive catchments and streams; and
- timing operations such that they avoid overlap between maximum demand periods and low-flow conditions.

Carrying out the necessary field studies and monitoring to establish baseline conditions at the appropriate scale for the proposed abstraction should involve the regulatory bodies and relevant specialists in the fields of hydrology, hydrogeology and both terrestrial and freshwater ecology.

5.7 Innovation in Water Supply Sources and Requirements for Hydraulic Fracturing

Research and innovation have developed both alternative water sources and non-water use technologies amid concerns over the large volumes of water used during hydraulic fracturing. Non-potable natural water sources and water alternatives or water-free hydraulic fracturing are discussed below. When sourcing alternative water supplies or deciding on a water alternative, the options need to be evaluated in a holistic manner and the impacts of the full life cycle of the technology considered (NYSDEC, 2011). For example, the use of some alternative water sources may be associated with large carbon footprints, which may outweigh the positive environmental impacts associated with their use (Macy *et al.*, 2014).

5.7.1 Non-potable natural water sources

A number of alternative natural water sources have been explored, notably recycled wastewater treatment plant water, mine effluent, brackish water and water recycled from the fracturing process, which is discussed in Chapter 6. No examples of using existing industrial processes, such as cooling water for hydraulic fracturing, were found in the literature.

When considering these sources, both the availability and suitability of the water resource must be assessed. The alternative water source must be located within a reasonable distance from the well and be of sufficient quantity and quality. Where these conditions are met, the alternative water resource may provide a viable solution to supplement the water needs of the hydraulic fracturing, reducing the pressure on freshwater resources (Mueller, 2013).

5.7.1.1 Recycled wastewater treatment water

Water reuse in the form of treated municipal wastewater effluent can provide a suitable water resource for the hydraulic fracturing process (Mueller, 2013). This is dependent on adequate infrastructure to transport the wastewater to site and the proximity of the water source to the fracturing operation. The town of Edson in Alberta, for example, sells wastewater from its treatment lagoons to Shell Canada and other companies for use in hydraulic fracturing (Moore, 2013). A revenue of CDN $100,000 was expected from the sale of a proposed 50,000 m^3 of wastewater in 2013 (Moore, 2013).

5.7.1.2 Mine effluent

The use of acid or abandoned mine drainage (AMD) as a substitute for fresh water in hydraulic fracturing could benefit the environment by reducing metal loadings and pollutants in catchments and benefit the fracturing operators by reducing fracturing demands on “clean” fresh water (Hunter, 2012). This alternative water source is, however, subject to technical, economic and regulatory issues. Any company considering using AMD for fracturing activities may incur long-term liability because future responsibility is incurred upon moving the AMD, in the USA at least (Conca, 2013). For this reason, drilling companies have been slow to take up this source of water (Conca, 2013). In Pennsylvania, the issue of AMD is so extensive that the state introduced an act, the Environmental Good Samaritan Act, which provides protection from civil liability for projects involving AMD (Conca, 2013).

AMD is used in fracturing operations, though not commonly. Seneca Resources operates a number of gas wells in the Tioga State Forest, Pennsylvania (Phillips, 2013). This company leases the mineral rights from Pennsylvania State and uses AMD to fracture virtually all of its wells in Tioga County. This particular AMD does not have to be treated before it is used in hydraulic fracturing. Furthermore, close proximity of the source of water to the drilling locations mitigates issues associated with transporting the AMD from its point of production to its point of fracturing use (Phillips, 2013).

In the town of Clinton, Pennsylvania, an AMD treatment plant began formal operation in November 2014 with the purpose of rendering AMD fit for use for industrial processes, such as fracturing (Moore, 2014). The company responsible, Winner Water Services (http://www.winnerh2o.com/default.htm) uses “Hydroflex” technology to remove iron and sulfates (Thomas, 2015). The facility has a capacity to treat 375 m^3 of mine water per minute and removes the legal complications for drillers associated with using AMD by ensuring that the water can be used for drilling and stored as “fresh water” without liability (Moore, 2014). Drilling companies, however, have no incentive to buy the reclaimed mine water if municipal sources are closer and more convenient. Treatment plants need to be located in areas with both a legacy of mining and active natural gas drilling for widespread usage to make economic sense (Moore, 2014). Thus, finding suitable locations for the treatment plants is an issue. Winner Water Services currently has two locations from which they source AMD (Thomas, 2015). These are located near fracturing activities, namely near Marcellus Shale activities (Thomas, 2015).

There may be an indirect innovative use for this alternative water source for fracturing. Laboratory data from 2013 suggest that blending flowback water with acid mine drainage causes several ions, sulfate, iron, barium, strontium, and 60–100% of radium (which is a NORM) to precipitate out as newly formed solids composed mostly of strontium barite (Kondash *et al.*, 2013). Thus, blending flowback fluids and acid mine drainage may provide an effective management practice for fracturing wastewater with high NORM concentrations, as well as a beneficial use for acid mine drainage (Kondash *et al.*, 2013).

5.7.1.1 Brackish water

In north-eastern Canada, one producer has tapped into a deep subsurface saline water aquifer for a portion of its supplies for hydraulic fracturing (Kiger, 2014). The classification of brackish groundwater includes a wide range of water quality parameters and only some classes of brackish groundwater falls within the technical specifications needed for the hydraulic fracturing operation (Mueller, 2013). Fracturing may move more towards the use of brackish water to avoid competition with other freshwater users (Nicot and Scanlon, 2012).

5.7.2 Reduced-water and water-free fracturing technologies

Several waterless or reduced-water fracturing technologies have been developed since the 1970s. It is reported that waterless fracturing accounts for only 3% of fracturing activities in the USA and 25% in Canada (Crawford, 2015). A further 20% of Canadian fracturing activities use nitrogen or carbon based foam fracturing (Crawford, 2015). Some of these alternatives are considered "environmentally friendly" as they may reduce the environmental impacts associated with fracturing, particularly on freshwater resources and their dependent ecosystems. Further research into each alternative is, however, required to fully understand their associated potential environmental impacts and/or benefits (NYSDEC, 2011). Each alternative has its own advantages, but there are concerns that there may be issues, possibly greater in magnitude than those associated with water-based hydraulic fracturing fluids. The technologies can be listed and categorised, based on the water alternative that the method employs, as:

- nitrogen (N): nitrogen-based fracturing, nitrogen-energised fracturing and nitrogen-based foam fracturing;
- carbon dioxide (CO_2): carbon dioxide-based fracturing, carbon dioxide-based foam fracturing, carbon dioxide sand fracturing and liquid (supercritical) carbon dioxide fracturing;
- gelled liquefied petroleum gas (LPG) or propane or gelled propane fracturing; and
- air fracturing.

5.7.2.1 Nitrogen-based fracturing

Nitrogen gas can be pumped without surfactants or proppant (sand) (Yost, 2015). Straight nitrogen-based fracturing has been used as an alternative to water-based hydraulic fracturing in shale formations that absorb water and swell, restricting gas flow (Yost, 2015). Liquid nitrogen, a cryogenic fluid, has been used in the laboratory to stimulate fractures by creating a strong thermal gradient, which generates local tensile stress in the rocks surrounding a borehole (Cha *et al.*, 2014).

In nitrogen-energised fracturing, the fracturing fluid is less than 53% volume of nitrogen, with the balance comprising water and additives. This type of fracturing is better suited to deeper formations (up to 2440 m) than pure nitrogen or foam nitrogen fracturing.

Where nitrogen-based foam fracturing is used, compressed nitrogen and surfactants and only 8–25% water are injected under pressure. The "VaproFrac" foam technology, for example, which was developed in the USA by Baker Hughes, is made up of 95% nitrogen and 5% water (Hunter, 2012). This technique has been carried out since the 1970s in Kentucky, USA (Wozniak *et al.*, 2010).

5.7.2.2 Carbon dioxide-based fracturing

Carbon dioxide can be used instead of water. The water that is left behind after conventional water-based hydraulic fracturing can block the path of the natural gas, slowing down production and possibly decreasing the total amount that a well can produce over its lifetime (Bullis, 2013). When carbon dioxide is used instead of water, most of the carbon dioxide comes back out of the well (where it can be captured and used again), allowing natural gas to flow out more freely. Recent research suggests that using carbon dioxide can also result in a better network of fractures, making it easier to extract the shale gas (Ishida *et al.*, 2012). In any shale gas deposit, a large fraction of the natural gas sticks to the shale rather than flowing out. Carbon dioxide has a greater affinity for the shale than does natural gas, so it can be used to displace the shale gas and free it from the rock (Bullis, 2013). If carbon dioxide proves to be an effective fracturing fluid, shale gas formations could become an option for carbon sequestration (Middleton *et al.*, 2015).

There are disadvantages associated with the use of carbon dioxide in fracturing. Relative to a liquid such as water, it is more difficult to compress a gas such as carbon dioxide to the pressures needed for fracturing (Bullis, 2013). The harvested carbon dioxide–natural gas mixture must be separated before the gas can be used, adding costs, and there are issues associated with transporting the gas mixture (local noise, pollution, road damage where transported by trucks) (Bullis, 2013). The use of carbon dioxide can be limited by the availability of carbon dioxide within reasonable trucking, rail, and pipeline distances of well sites. Straight carbon dioxide-based fracturing is used in places such as Wyoming where carbon dioxide pipelines already exist (Bullis, 2013).

Carbon dioxide-based foam fracturing is based on the same premise as nitrogen-based foam fracturing but using compressed carbon dioxide. Carbon dioxide foam fracturing was recently tested on a well site in Ohio by Chesapeake Energy (Yost, 2015).

Carbon dioxide sand fracturing requires sand and carbon dioxide only, i.e. no water. This process has been used successfully on hundreds of wells, mostly in Canada (Yost, 2015). The developer Praxair Inc. further developed this method in a technology called “DryFrac”, which allows liquefied carbon dioxide and sand to be mixed at precise concentrations customised to the shale target formation (Crawford, 2015). DryFrac works well in stimulating low-pressure, low-permeability and strong water-locking or water-sensitive reservoirs (Zhenyun *et al.*, 2014).

Liquid or “supercritical” carbon-dioxide-based fracturing has been used as an alternative to water-based hydraulic fracturing in shale formations that absorb water and swell, restricting gas flow. The gas is pumped without surfactants or proppant (sand) (Yost, 2015). The theoretical potential advantages of liquid carbon dioxide include enhanced fracturing and fracture propagation, reduction of flow-blocking mechanisms, increased desorption of methane adsorbed in organic-rich parts of the shale, and a reduction in or elimination of the deep re-injection of flowback water that has been linked to induced seismicity and other environmental concerns (Middleton *et al.*, 2015). The low density and viscosity of supercritical carbon dioxide in the formation causes low sweep efficiency that manifests as fingering; however, various additives can be incorporated into the fluid to improve the carbon dioxide fracturing effect (Li *et al.*, 2015). This method could lead to substantially increased gas production over time; however, there are high costs involved as well as safety issues associated with handling large volumes of supercritical carbon dioxide (Middleton *et al.*, 2015).

5.7.2.3 Gelled liquefied petroleum gas and propane fracturing

Gelled LPG fracturing is a waterless fracturing fluid that uses LPG (propane and/or butane). The gelled propane turns into a gas and exits the well along with the natural gas or oil stream produced (Soni, 2014). One such technology, “Gasfrac” has reportedly been used 2500 times at 700 wells in Canada and the USA (Kiger, 2014), in areas such as southern Texas and western Canada (Yost, 2015) and in the Utica Shale Formation in Ohio (Hunter, 2012). The gel retains sand better than water and therefore it is possible to get the same production with one-eighth of the liquid and to pump at a slower rate (Kiger, 2014). In addition, the effective fracture length produced by LPG fracturing is greater than that produced by conventional fracturing, increasing productivity (Soni, 2014). Laboratory experiments found that, owing to its lower viscosity, reduced surface tension and lower density, LPG can rapidly and efficiently clean up while reducing the pressure needed to mobilise fracturing fluids (Soni, 2014). A fracturing programme using LPG as an alternative to water was undertaken in Canada’s first commercial unconventional gas field, the McCully field, in 2009, where both sandstone and shale were hydraulically fractured (Leblanc *et al.*, 2011). Both clean-up and initial well performance for these tight sands were significantly enhanced using LPG fracturing rather than water fracturing (Leblanc *et al.*, 2011).

Propane costs more initially, even though it can be resold once recovered. It is also explosive, and it requires special equipment and proper handling to reduce risk (Brino and Nearing, 2011).

5.7.2.4 Air fracturing

The US company Chester Engineers is one of a few companies testing a fracturing method that uses air jets on the drill head, eliminating the need for water. This technology is not widely accepted, and it is unclear whether the performance is adequate to make the wells economical (Hunter, 2012).

5.8 Summary of the Impacts on Water Resources and Recommended Mitigation Measures

The probable commercial scenarios for UGEE development indicate a potentially wide range of water usage during assumed build-out scenarios in future UGEE projects. In the context of the availability of water resources and potential impacts from abstractions, it is the short-term demand for water during individual hydraulic fracturing events that define maximum usage. From the probable commercial scenarios, a total demand of 15,000 m^3 is assigned per well per hydraulic fracturing programme at one well pad. Assuming that the hydraulic fracturing programme is carried out over a 3-day period (conservatively short), the water demand for that programme is 5000 m^3 per day. This figure is provided for guidance purposes only, as actual demands would be case specific, and would have to be declared and identified during future planning and review processes.

More significantly, if identical programmes are carried out at multiple wells concurrently, the total daily demand becomes significantly greater. For the peak build-out scenario defined by the probable commercial scenarios in Project B of the UGEE JRP, there would theoretically be approximately 105 wells for the moderate build-out scenario drilled and hydraulically fractured per year in the NCB study area. Assuming a 3-day duration for each hydraulic fracturing programme, this equates to 315 days of hydraulic fracturing, each requiring 5000 m^3 per day in the example given. Thus, the total demand is driven by how many wells are hydraulically fractured in the same time period, and the potential risk of impact from supply (i.e. abstraction of available water resources) is determined by *how* and *where* the water is sourced.

Such development and demand would have to be supplied from multiple sources. Accordingly, all future proposed UGEE-related abstraction plans would have to be carefully reviewed to understand the timeline of total demands, individually and cumulatively, with the involvement of relevant stakeholders and regulatory bodies.

Available water resources in the two case study areas are represented by rainwater, lakes and reservoirs, streams and rivers, and groundwater in bedrock aquifers. Existing abstraction pressures are currently low. There is capacity to supply the water requirements of potential future UGEE development in both study areas, but this would ultimately be dependent on and influenced by *how* and *where* the development proceeded, both spatially and temporally. Local supply options are considerably wider in the NCB study area than they are in the CB study area. The capacity of any given source would have to be judged by actual total demand, with a clear understanding of timelines of total demands.

The risks of *volumetric impacts* from surface water abstractions (to supply the demand) are lower in large lakes and streams and higher in small lakes and streams. Identifying and documenting volumetric impact is relevant in a regulatory context, but it is *ecological impact* that ultimately determines whether or not an abstraction authorisation should be granted. This is recognised by the methods that are applied by both the EPA and the NIEA in classifying the ecological status of surface water bodies for WFD implementation purposes, and the existing prior authorisation procedures that are in place.

- In lakes, this relates to maintaining water level cycles within natural or regulated ranges in order to avoid adverse impacts on reference conditions in littoral zones.
- In streams, this relates to maintaining "environmental flows', i.e. the critical flow below which stringent flow standards may apply, in order to avoid adverse impacts on the reference conditions required by macroinvertebrates, macrophytes and fish.
- In aquifers, this relates to understanding the hydraulic relationship between groundwater and surface water bodies, with the objective of avoiding impacts on reference conditions in surface water bodies of maintaining the natural supporting conditions of groundwater-dependent terrestrial ecosystems, and of avoiding interference with other groundwater supplies.

With regard to groundwater, the bedrock aquifers in both study areas are viable sources of water to meet demands, at least in part. However, the ability to develop a sufficient supply to meet demands locally for hydraulic fracturing programmes would require prior exploration and testing, and supply would depend on case-specific circumstances of both hydrogeology and actual water demands.

Future UGEE-related abstractions would have to be evaluated at local level (local impact) and catchment level (water body impact). Special attention should be given to the requirements of existing statutory instruments and efforts by the EPA and NIEA to maintain "good quantitative" and "good ecological" status of water bodies. As UGEE activity is rarely confined to single locations, abstractions may have a cumulative impact that would need to be addressed by appropriate monitoring.

For logistical and cost reasons, future UGEE operations would try to obtain water from sources that are easily accessible, i.e. as close to the drill sites as possible. The water needed might be accessed through surface water or groundwater resources, and the water may either be developed by the UGEE companies directly or be purchased from existing supply sources.

Large abstractions in small lakes and streams increases the risk of impacts. Concentrated abstractions in small subcatchments and abstractions in or near ecologically sensitive habitats also increase the potential for impacts. Even short-duration abstractions can cause environmental stresses and impacts, depending on the source, abstraction rate and reference conditions of the source at the time of abstraction. The distinction between "small" and "large" is subjective, and cannot be made without consideration of surface water ecology and following lines of evidence.

In the licensing or prior authorisation of future UGEE-related abstractions, environmental reference conditions would have to be identified on a case-by-case basis, using site- and case-specific inputs (e.g. flow data and ecological datasets) and requiring technical judgement by specialists in related fields. Proper impact assessment can be performed only once the details of proposed future abstractions become known, with scoping and technical review by relevant specialists representing public regulatory bodies in both Ireland and Northern Ireland.

6 Recycling and Reuse of Flowback and Produced Waters (Task 3)

6.1 Background

The recycling and reuse of flowback and produced water is an important development measure to reduce the impact of water requirements for UGEE projects and operations. Water recycling and reuse typically increases as UGEE production expands in the areas, and flowback water becomes available for nearby additional well developments. However, the ability to recycle and reuse flowback waters may be limited by current regulations in Ireland and Northern Ireland (see Project C of the UGEE JRP for additional details).

Operators are likely to support the objective of maximising the reuse of flowback water for subsequent fracturing operations at the same well pad or other well pads to reduce off-site waste disposal cost and associated environmental liability. Reuse consists of either straight dilution of the flowback water with fresh water, or the introduction of treatment prior to reuse of the flowback (NYSCED, 2011). Although straight dilution is attractive, its application may be limited by the chemical composition of the flowback water, requiring the introduction of treatment.

Typically the volume of flowback and production (produced) waters is not sufficient to meet the demand for water for fracturing during the active development of UGEE operations and an external source of water is required (see Chapter 5). When fresh water and flowback or produced waters are used for fracturing, potential incompatibilities between these three streams need to be evaluated. For instance, flowback with high concentrations of barium and strontium is incompatible with fresh water sources with a high sulfate content because it can cause scaling.

Task 3 addresses the current practices and technical aspects of recycling and reusing flowback and produced water. Chapter 10 discusses treatment options for flowback and produced waters that may be necessary for recycling and reusing.

6.2 Approach

The evaluation of the reuse and recycling of flowback and produced waters includes (see also evaluations discussed in Chapter 10):

- review of current examples of recycling and reusing:
    - the water quality and treatment required for reuse;
    - the cost of reuse;
    - the documented quantities of reuse;
- identification of limitations;
- consideration of potential future recycling and reuse estimates and developments; and
- evaluation of potential recycling and reuse in the case study areas.

6.3 Current Examples of Recycling and Reuse

Recycling and reusing of flowback and produced waters is a common and accepted practice in the USA. Jiang *et al.* (2013) reported the typical percentages of water recycled in current UGEE operations in the Marcellus Shale Formation in Pennsylvania, USA. As shown in Figure 6.1, almost all (90–95%) of the flowback water generated during hydraulic fracturing is recycled for blending with fresh water to prepare fracturing fluid. On the other hand, between 55% and 60% of produced water is recycled for the same purpose. A large portion of produced water is disposed of either to deep injection wells (12–33%) or undergoes wastewater treatment (12–30%) for subsequent surface disposal.

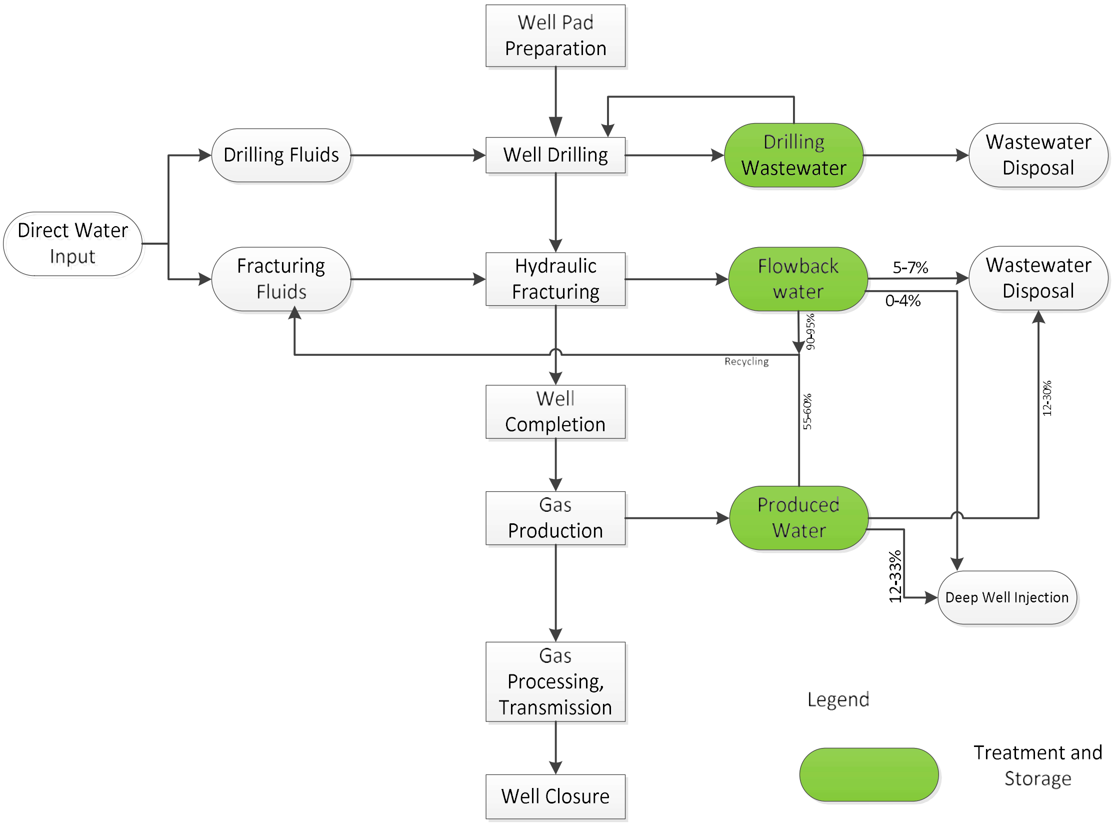


Figure 6.1. Life cycle of shale gas well depicting flowback and produced water recycling and ultimate disposal (adapted from Jiang, *et al.,* 2013).

A more recent report by the USEPA (2015b) states that in the Marcellus Shale Formation in Pennsylvania, USA, between 60% and 90% of the flowback and produced waters are reused. Up to 15% is treated at centralised waste treatment facilities and between 10% and 30% is disposed of in deep injection wells. However, these values vary according to the production basin. For example, in the Barnett Shale Formation in Texas, USA, only approximately 5% of the flowback and produced waters are reused and the rest (95%) is disposed of by deep well injection (USEPA, 2015b).

In the shale gas exploration at the Bowland Shale Formation at Roseacre Wood, Lancashire, UK, Cuadrilla (2014) stated that the flowback generated during the hydraulic fracturing phase would be reused directly in the hydraulic fracturing process. During the initial and extended flow testing phase, the flowback water will be transported off site as a low-level radioactive waste for special treatment (Cuadrilla, 2014a).

In evaluations of water use scenarios for shale gas development in Poland and Germany, an average recycling rate of 35% was assumed for the flowback water (JRC, 2013). A range of 0–70% for their high- and low-impact scenarios was assessed.

Tamboran stated that in the NCB (Tamboran, undated), it proposed to reuse 100% of the recovered water from its proposed UGEE development and production. Currently, there are no UGEE projects known in which 100% of flowback and produced waters have been recycled. Based on a review of available information and basin-specific characteristics, a range of 40–80% recycling was assumed for the two case study areas in Ireland and Northern Ireland (see Chapter 2, Table 2.1, probable commercial scenarios).

6.3.1 *Water quality and treatment required for reuse*

The developing nature of UGEE practices, as well as the commercial sensitivity around proprietary techniques and criteria for water reuse, make it difficult to establish general guidelines for water quality for reuse. The following criteria for water reuse for hydraulic fracturing were found in the literature:

Keister (2010) reported specifications for recycled water, as follows:

- maximum scale formers – 2500 mg/L as calcium carbonate;
- maximum dissolved solids – 50,000 mg/L;
- maximum iron – 3.5 mg/L;
- maximum calcium – 250 mg/L;
- pH range – 6.5–7.5.

The State of New York provided the following list of maximum allowable water quality requirements for fracturing fluids, based on comments from one expert in UGEE (NYSCED, 2011):

- chloride : 3000–90,000 mg/L;
- calcium: 350–1000 mg/L;
- suspended solids: < 50 mg/L;
- entrained oil and soluble organics: < 25 mg/L;
- bacteria: < 100 cells/100 mL;
- barium: low levels.

The water reuse quality criteria described above correspond to the maximum allowable concentrations after treatment and prior to potential additional dilution with fresh water. The reuse criteria used by operators vary based on factors associated with each UGEE development, such as water sourcing and waste disposal costs, shale formation conditions, fracturing techniques used, etc.

Disinfection methods are used to abate certain kinds of bacteria such as sulfate-reducing bacteria (SRBs), which may cause problems in the formation. SRBs produce sulfides, which precipitate metals, ions and scales that can plug the formation. SRBs can also generate hydrogen sulfide, which is highly corrosive and is a health and safety concern.

As an example of a water reuse evaluation from an operator's perspective, Table 6.1 summarises the quality criteria for low-TDS flowback waters and compares this information against a limited set of water reuse criteria for slick water fracturing (low-viscosity fluid with no gels) by one (confidential) operator.

Table 6.1. Feed water quality and reuse targets

Parameter	Units	Fracturing flowback water		Max. water reuse criteria
		Mean	**Max.**	
pH	Standard units	7.2	9	6.5–7.5
Alkalinity	mg/L	920	1500	500
Hardness	mg/L	340	1500	500
Sodium	mg/L	3900	15,000	18,000
Iron	mg/L	42	225	5
Aluminium	mg/L	5	40	4
Sulfate	mg/L	165	1100	400
Chloride	mg/L	6000	25,000	32,000
Silica	mg/L	30	150	10
TDS	mg/L	11,700	35,000	40,000
TSS	mg/L	525	750	50

Source: CDM Smith Webinar (October 2013) – Upstream integrated water management.

As shown in Table 6.1, alkalinity, hardness, iron and TSS exceed the criteria, therefore treatment for removal of these constituents would be required before this flowback water can be adequate for reuse. Other constituents of environmental concern (other pollutants) such as heavy metals, radionuclides and hydrocarbons do not appear to present technical limitations to water reuse for hydraulic fracturing.

In addition to treatment, the blending of flowback water with fresh water helps to achieve the water reuse criteria above, which would make the reuse of flowback water technically feasible.

Ongoing developments in hydraulic fracturing enable the recycling of flowback water with even higher levels of TDS and hardness than reported above. In turn, higher concentrations of other pollutants may be expected in water used in UGEE operations that recycle large volumes of flowback. Although these other pollutants do not limit the performance of hydraulic fracturing, the potential health and safety exposures to workers and potential release to the environment must be considered during permit licensing and planning. For instance, certain heavy metals and radionuclides in the Bowland Shale Formation, UK, flowback and produced waters are present at concentrations above regulatory environmental quality standards (discussed in section 10.3).

6.4 Regulations Applicable to Water Reuse

This section provides relevant excerpts of environmental regulations applicable to reuse and recycle, storage and transfer of flowback and produced water in the Marcellus Shale region (USA), as well as, pertinent regulations in the EU.

6.4.1 Marcellus Shale – Delaware River Basin Commission (DRBC) – Draft Natural Gas Development Regulations, November 8, 2011 (Article 7 of Part III – Basin Regulations)

This draft regulation is still under review by DRBC (2011) and it has yet to be issued as final as of October 2015.

6.4.1.1 Approval for water source

In addition to the use of fresh water from the river basin for hydraulic fracturing (by approval), the commission approved the following water sources:

- treated wastewater or non-contact cooling water;
- mine drainage water; and
- recovered flowback and produced waters.

The recovered flowback and produced waters in the Marcellus Shale Formation can be reused as a water source for fracturing in the following manner:

- If source and receiving projects are located within the same basin and in the same state, flowback water can be reused by complying with standard conditions set forth in the Bulk Water Use and Management Approval (BWA) issued by DRBC to the sending site. In addition, compliance with the Approved List of Water Sources (ALWS) for the receiving site and any other approvals set forth by the host state is required.
- If the source and receiving projects are located within one basin, but in different states, both the source and receiving sites must obtain approval in the context of their BWAs.
- Diversion of flowback and produced waters for treatment, reuse and discharge outside the basin, requires review and approval under the BWA.
- Recovered flowback and produced waters used in natural gas development projects is exempt from water use charges.

The DRBC maintains an ALWS for each natural gas development project that has received one or more BWA.

6.4.1.2 Bulk Water Use and Management Approval

A BWA must be in place before any water source is used for natural gas development activity and before the project commences well pad construction activities or begins operation on a pre-existing natural gas well pad. Requirements include:

- Well stimulation metering and reporting
    - The volume of flowback water and produced water recovered must be metered. Metering must be performed with an automatic continuous metering system or equivalent that measures to within 5% of actual flow.
    - The volume of flowback and produced water recovered on an ongoing basis must be reported quarterly.
- Wastewater metering and reporting
    - Flowback and produced water volumes transferred from each well pad must be recorded along with the transfer destination. This report must be submitted to the DRBC on a quarterly basis.
- Water storage, reuse, treatment and discharge
    - Unless an extension has been authorised, all flowback water recovered from the well must be reused within 90 days of stimulation of the natural gas well at the same site, or transported to a treatment plant or discharge facility or to another well pad site, which has the necessary approval, for reuse.
    - The operator’s programme for storage, reuse and removal of production fluids from the well pad site must be furnished to the DRBC and host state.
    - Flowback and produced waters must be stored in watertight tanks designed and constructed to safely contain the water and meet host state standards.

- o Apart from fresh water, all other sources of water approved for use for hydraulic fracturing can be stored at a centralised wastewater storage facility if approved/permitted by the host state. The facility can supply water for natural gas development projects only after it has been added to the project operator's ALWS.
- o The owner or operator of a facility requires the necessary approval and permits to accept, transfer, treat and discharge domestic and non-domestic wastewater from natural gas development projects.

6.4.2 Regulations in Europe for water reuse

The European Commission (EC) issued recommendations (EC, 2014), dated 22 January 2014, on minimum principles for the exploration and production of hydrocarbons (such as shale gas) using high-volume hydraulic fracturing (2014/70/EU). The recommendations state that the Waste Framework Directive (2008/98/EC) (EC, 2008a) sets out the conditions applicable to the reuse of the fluids that emerge at the surface following high-volume hydraulic fracturing and during production.

Flowback and produced waters may contain radioactive substances and hence are classified as radioactive waste. According to the UK Environment Agency's technical guidance document (2013), an environmental permit is required under schedule 23 of Environmental Permitting Guidance Radioactive Substances Regulation For the Environmental Permitting (England and Wales) Regulations 2010 September 2011 Version 2.0 (EPR 2010) (DEFRA, 2011) for storage and disposal of flowback and produced waters and subsequent disposal. Storage of flowback water in open surface lagoons is not permitted, while on-site storage of flowback fluid shall be no more than 3 months under normal circumstances.

The Ireland and Northern Ireland regulations do not currently have provisions for recycling and reuse of flowback and produced waters from UGEE operations. Recycling and reuse of flowback water would probably be covered under existing regulations relating to the Waste Framework Directive (2008/98/EC) and existing licensing regimes, which are discussed further in Project C of the UGEE JRP (Regulatory Framework for Environmental Protection). The regulatory experience in the USA, particularly in the Marcellus Shale region, may serve as guidelines for regulators in Ireland and Northern Ireland to develop regulations specific to the NCB and CB shale plays.

6.5 Limitations

The recycling of treated flowback over an extended period of time has the potential to accumulate NORM and chemical additives and become an occupational hazard for the treatment facility operators.

Prior to the year 2000, high concentrations of TDS in flowback water was one of the criteria for not recycling, because the TDS could interfere with fracturing chemical additives and/or formation geology. Since then, chemical additives have been designed to enable the use of base fluid with high TDS concentrations, such as flowback and produced waters. Slick fracturing fluid can incorporate pre-treated flowback water as an option for water reuse, whereas cross-linked gel fracturing fluid is not suitable in base fluid with high TDS and boron concentrations. TDS and boron interfere with the properties of cross-linked gels inherent to gel fracturing fluid. Boron is also of concern for reuse and recycling when gel fluid is used because it interferes with the intended delayed activation of cross-linked gels (USEPA, 2015b).

The slick water fracturing method is used to fracture dry natural gas-producing formations, while cross-linked gels are generally used to fracture liquid-rich shales. Cross-linked gel fracturing necessitates less base fluid than slick water fracturing. Aran Energy plc and Evergreen Resources Inc. used gel and sand (Evergreen also used nitrogen) for hydraulic fracturing tests on vertical wells in the NCB (see Report A1-2 of the UGEE JRP). Cuadrilla Resources has conducted exploratory drilling using slick water fracturing in the Bowland Shale Formation, UK. These experiences appear to indicate that either gels or slick water fracturing techniques could be the method of choice for developing the NCB and CB shale natural gas resources.

The USEPA (2015b) summarised the potential problems associated with reusing flowback and produced waters containing excessive amounts of certain constituents, as follows:

- fluid instability (change in fluid properties);
- well plugging (restriction of flow);
- bacterial growth in the well (build-up of bacteria on casing);
- well scaling (accumulation of precipitated solids);
- formation damage (restriction of flow in the reservoir) .

Table 6.2 shows the criteria for water reuse for the fracturing base fluid (water) and the reasons for limiting the concentration. The wide concentration ranges are indicative of the varied water quality requirements among operators driven by different shale geology, formation water, selected fracturing fluid chemistry and operator preferences.

Table 6.2 Reported reuse and recycling criteria

Constituent	Reasons for limiting concentrations	Recommended or observed base fluid target concentrations (mg/L)[a] after blending
TDS	Fluid stability	500–70,000
Chloride	Fluid stability	2000–90,000
Sodium	Fluid stability	2000–5000
Metals		
Iron	Scaling	1–15
Strontium	Scaling	1
Barium	Scaling	2–38
Silica	Scaling	20
Calcium	Scaling	50–4200
Magnesium	Scaling	10–1000
Sulfate	Scaling	124–1000
Potassium	Scaling	100–500
Scale formers[b]	Scaling	2500–2500
Phosphate	Not reported	10
Other		
TSS	Plugging	50–1500
Oil	Fluid stability	5–25
Boron	Fluid stability	0–10
pH (SU)	Fluid stability	6.5–8.1
Bacteria (counts/mL)	Bacterial growth	0–10,000

[a]Unless otherwise noted.

[b]Includes total of barium, calcium, manganese and strontium.

Source: Table D-4 –Technical development document for proposed effluent limitation guidelines and standards for oil and gas extraction (USEPA, 2015b).

6.6 Treatment Costs for Reusing Water

A recent review of the costs of primary treatment for water for reuse and recycling in south-west Texas, USA, was conducted. The primary treatment systems consist of process units for removing oil, suspended solids and iron. The total unit treatment cost ranges from US $0.60 to 1.50 per barrel (€0.11–0.26 per m^3). This cost does not include the cost of storage, conveyance or transport. The lower end of the cost range assumes that oil removal is not included.

6.7 Evaluation of Potential Recycling and Reuse in the Study Areas

Section 10.14 discusses the potential for reusing and recycling of flowback and produced waters for the NCB and CB study areas.

7 Other Additional Potential Impacts and Mitigation Measures (Task 4)

7.1 Background

As required in the Terms of Reference, Project B of the UGEE JRP, Task 4, examines impacts from UGEE projects/operations on other areas not specifically addressed in other sections of this report, such as the evaluations of impacts and mitigation measures on water quality and resources outlined in Tasks 1 and 2.

The newly amended EIA Directive (2014/52/EU) (EU, 2014a) entered into force on 15 May 2014 to simplify the rules for assessing the potential effects of projects on the environment and human health. The new approach pays greater attention to threats and challenges that have emerged since the original rules came into force some 25 years ago, such as climate change. Article 3(1) of the EIA Directive requires that:

> 1. The environmental impact assessment shall identify, describe and assess in an appropriate manner, in the light of each individual case, the direct and indirect significant effects of a project on the following factors:
>
> (a) population and human health;
>
> (b) biodiversity, with particular attention to species and habitats protected under Directive 92/43/EEC and Directive 2009/147/EC;
>
> (c) land, soil, water, air and climate;
>
> (d) material assets, cultural heritage and the landscape;
>
> (e) the interaction between the factors referred to in points (a) to (d).

To support the identification and assessment of significant effects at the project stage, evaluations of the potential environmental impacts due to UGEE projects and operations, and the associated mitigation measures, described in this chapter include the following categories:

- flora, fauna and biodiversity;
- air quality;
- greenhouse gas emissions;
- landscape and visual amenity;
- land take;
- noise;
- archaeology and cultural heritage;
- traffic;
- human beings and community character;
- agricultural and domestic animals; and
- interactions between the foregoing.

A full EIA, with a thorough characterisation of impacts can be carried only out at the project proposal and specification stage when the proposed project details are available.

7.2 Approach

This study inevitably draws on experience from the USA, where UGEE processes have been established for many years, but, where possible, these findings have been set in a European context, and the approach taken is to draw on published information to highlight potential environmental impacts associated with UGEE activities in Ireland and Northern Ireland.

This chapter is not a "life cycle" assessment; further information on life cycle impacts can be found in Chapter 8 (e.g. the specific risks and impacts, resources and energy consumed in order to manufacture chemical additives, sand and other proppants used in fracturing fluids and gravel, stone and other construction materials for well pad construction or to construct and maintain road and pipeline infrastructure).

When considering environmental risks and impacts, it is important to consider the probability and severity of a possible event. King (2012) suggests categorising events according to the significance of their impacts on people and the environment, consistent with more general guidance on environmental risk assessment. Determination of detailed impact probability and severity is not possible until a proposed project is specified; this chapter discusses potential impacts in the following general terms:

- *Imperceptible impact*. An impact capable of being measured but without noticeable consequences, e.g. a planned or unplanned discharge that does not result in exceedances of an environmental quality standard.
- *Minor (or slight) impact*. An impact that causes noticeable changes in the character of the environment without affecting its sensitivities, e.g. a planned or unplanned discharge that could result in exceedances of an environmental quality guideline in the immediate vicinity of the release point, but that would not be expected to have significant environmental or health effects (ecosystem functions are not affected).
- *Moderate impact*. An impact that alters the character of the environment in a manner that is consistent with existing and emerging trends, e.g. a discharge or incident resulting in potential effects on natural ecosystems in the vicinity of the release point or incident; ongoing effects on people in the vicinity of a site due to impacts such as noise, odour or traffic.
- *Significant impact*. An impact that, by its character, magnitude, duration or intensity alters a sensitive aspect of the environment, e.g. an ongoing discharge resulting in persistent exceedances of European environmental quality standards and/or permanent degradation of a protected habitat,
- *Profound impact*. An impact that obliterates sensitive characteristics, e.g. a pollution incident resulting in harm to the health of members of the public over a wide area due to contamination of drinking water supplies or an accident resulting in death or serious injury to workers and/or members of the public.

Where appropriate, potential impacts are discussed under the various stages of UGEE activities as follows:

- *Stage 1 – Well pad identification and initial site access*. This stage includes site identification and selection; site characterisation – establishment of baseline conditions for air, water, land, geology and deep-ground conditions; initial evaluation of potential environmental impacts; initial development of the geological conceptual model and geological risk assessment; exploratory boreholes for evaluation of geology and the reserve; seismic surveys; and securing of necessary development and operation permits. This stage also includes pad construction and site preparation, including construction of roads and any water containment structures.

- *Stage 2 – Well design and construction, hydraulic fracturing and well completion*. This stage includes pilot well drilling; drilling of initial horizontal wells to determine reservoir properties and required well completion techniques; further development of the geological conceptual model following test fractures; wellhead and well design and construction (drilling, casing, cementing, integrity testing); multi-stage hydraulic fracturing (injection of fracture fluid and management of flowback and produced waters and emissions); and well completion.
- *Stage 3 – Production (gas extraction)*. This stage includes development of the field (including further pads, wells, pipelines and additional road infrastructure); management of produced water and emissions; and environmental monitoring and well integrity testing.
- *Stage 4 – Project cessation, well closure and decommissioning*. This stage includes well plugging and testing; site equipment removal; site restoration and reclamation; post-closure environmental monitoring and well integrity testing; and transfer of the wells to a competent authority.

In the assessment of potential environmental and health impacts, it is often necessary to use some judgment because of uncertainty, particularly at this stage, where details of any proposed activities are not as yet known. Information with respect to potential impacts was drawn from reported analyses of hydraulic fracturing activities in the field where such information was available.

7.3 Other Additional Potential Impacts

7.3.1 Flora, fauna and biodiversity

Loss of biodiversity is an enormous challenge in the EU, with around one in four species currently threatened with extinction and 88% of fish stocks overexploited or significantly depleted. The EC has adopted a new strategy to halt the loss of biodiversity and ecosystem services in the EU by 2020 (EC, 2011). UGEE activities can affect the biodiversity of flora and fauna via a number of mechanisms (API, 2009a; Entrekin *et al.,* 2011; NYSDEC, 2015). These include:

- removal of habitat or degradation of habitat (e.g. as a result of excessive water abstraction), or fragmentation (e.g. as a result of fencing, road construction);
- surface runoff;
- introduction of invasive species;[11]
- noise and disturbance; and
- contamination relating to accidental releases/spillages.

Of particular importance is the Natura 2000 network of SPAs and SACs. Natura 2000 is the centrepiece of EU nature and biodiversity policy. It is an EU-wide network of nature protection areas established under the Habitats Directive. The aim of the network is to assure the long-term survival of Europe’s most valuable and threatened species and habitats. It comprises SACs, designated by Member States under the Habitats Directive, and SPAs, designated under the Birds Directive.

Natura 2000 is not a system of strict nature reserves in which all human activities are excluded, but areas where the conservation objectives must be met while taking account of economic, social, cultural, regional and recreational requirements. The establishment of this network of protected areas also fulfils a Community obligation under the UN Convention on Biological Diversity.

11 The term “invasive species’ is not defined in law in Ireland or Northern Ireland. The Convention on Biological Diversity (UN, 1992) defines invasive species as species whose introduction and/or spread outside their natural past or present distribution threatens biological diversity.

A key protection mechanism for Natura 2000 areas is the requirement to consider the possible nature conservation implications of any plan or project on the site network before any decision is made to allow that plan or project to proceed. Not only is every new plan or project captured by this requirement but each plan or project, when being considered for approval at any stage, must take into consideration the possible effects it may have in combination with other plans and projects when going through the process known as Appropriate Assessment. Where there are potential impacts, data and information on the project and on the site and an analysis of potential effects on the site must be obtained and presented in a Natura Impact Statement (NIS). If it can be concluded that there will be no adverse effects on the integrity of a Natura 2000 site, the plan or project can proceed to authorisation, at which point the normal planning or other requirements will apply in reaching a decision to approve or refuse. If adverse effects are likely, or in cases of doubt, the derogation steps will apply, but only in a case in which there are imperative reasons of over-riding public interest (IROPI) requiring a project to proceed, there are no less damaging alternative solutions, and compensatory measures have been identified that can be put in place.

These are prime wildlife conservation areas in the island of Ireland, considered important on a European as well as an Irish level. Conservation management plans are available for many SACs and set out specific management measures for the area. The legal basis on which SACs are selected and designated is the EU Habitats Directive. The directive lists certain habitats and species that must be protected within SACs. Irish habitats include raised bogs, blanket bogs, turloughs, sand dunes, machair (flat sandy plains on the north and west coasts), heaths, lakes, rivers, woodlands, estuaries and sea inlets. The 25 Irish species that must be afforded protection include bats, salmon, otter, freshwater pearl mussel, bottlenose dolphin and Killarney fern.

Favourable conservation status must be maintained for habitats meaning that:

- the natural range and areas covered within that range is stable or increasing;
- the specific structure and functions, which are necessary for long-term maintenance of the habitats, exist and are likely to exist for the foreseeable future;
- THE conservation status of its typical species is favourable.

The island is also required under the terms of the EU Birds Directive to designate SPAs for the protection of endangered species of wild birds, and Ireland’s SPA network encompasses over 570,000 ha of marine and terrestrial habitats. The network covers:

- listed rare and vulnerable species;
- regularly occurring migratory species, such as ducks, geese and waders; and
- wetlands, especially those of international importance, which attract large numbers of migratory birds each year.

Particular attention must be paid to potential impacts on any Natura 2000 areas and the relevant guidance adhered to in the assessment of potential impacts for any potential projects (e.g. the guidance ‘Assessment of plans and projects significantly affecting Natura 2000 sites, Methodological guidance on the provisions of Article 6(3) and (4) of the Habitats Directive 92/43/EEC’, EC, 2002).

Figure 7.2 and Figure 7.1 show the protected areas in the NCB and CB, and these areas are listed in Table 7.2 and Table 7.1. The NCB, in particular, can be seen to have a dense network of protected areas.

Table 7.1. Natura 2000 areas in the NCB

Site code	Site name	County	Country
IE0001403	Arroo Mountain	Leitrim	IE
IE0000623	Ben Bulben, Gleniff and Glenade Complex	Sligo	IE
IE0002032	Boleybrack Mountain	Leitrim	IE
IE0000979	Corratirrim	Cavan	IE
IE0000584	Cuilcagh – Anierin Uplands	Leitrim	IE
IE0001919	Glenade Lough	Leitrim	IE
IE0001673	Lough Arrow	Sligo	IE
IE0001976	Lough Gill	Leitrim	IE
IE0000428	Lough Melvin	Leitrim	IE
IE0000007	Lough Oughter and Associated Loughs	Cavan	IE
UK0030116	Cladagh (Swanlinbar) River	Fermanagh	NI
UK0016603	Cuilcagh Mountain	Fermanagh	NI
UK0030045	Largalinny	Fermanagh	NI
UK0030047	Lough Melvin	Fermanagh	NI
UK0016619	Monawilkin	Fermanagh	NI
UK0030212	Moninea Bog	Fermanagh	NI
UK0016614	Upper Lough Erne	Fermanagh	NI
UK0030300	West Fermanagh Scarplands	Fermanagh	NI

IE, Ireland; NI, Northern Ireland.

Table 7.2. Natura 2000 areas in the CB

Site code	Site name	County	Country
IE0002250	Carrowmore Dunes	Clare	IE
IE0001021	Carrowmore Point to Spanish Point and Islands	Clare	IE
IE0002264	Kilkee Reefs	Clare	IE
IE0002165	Lower River Shannon	Clare	IE
IE0002343	Tullaher Lough And Bog	Clare	IE

IE, Ireland; NI, Northern Ireland.

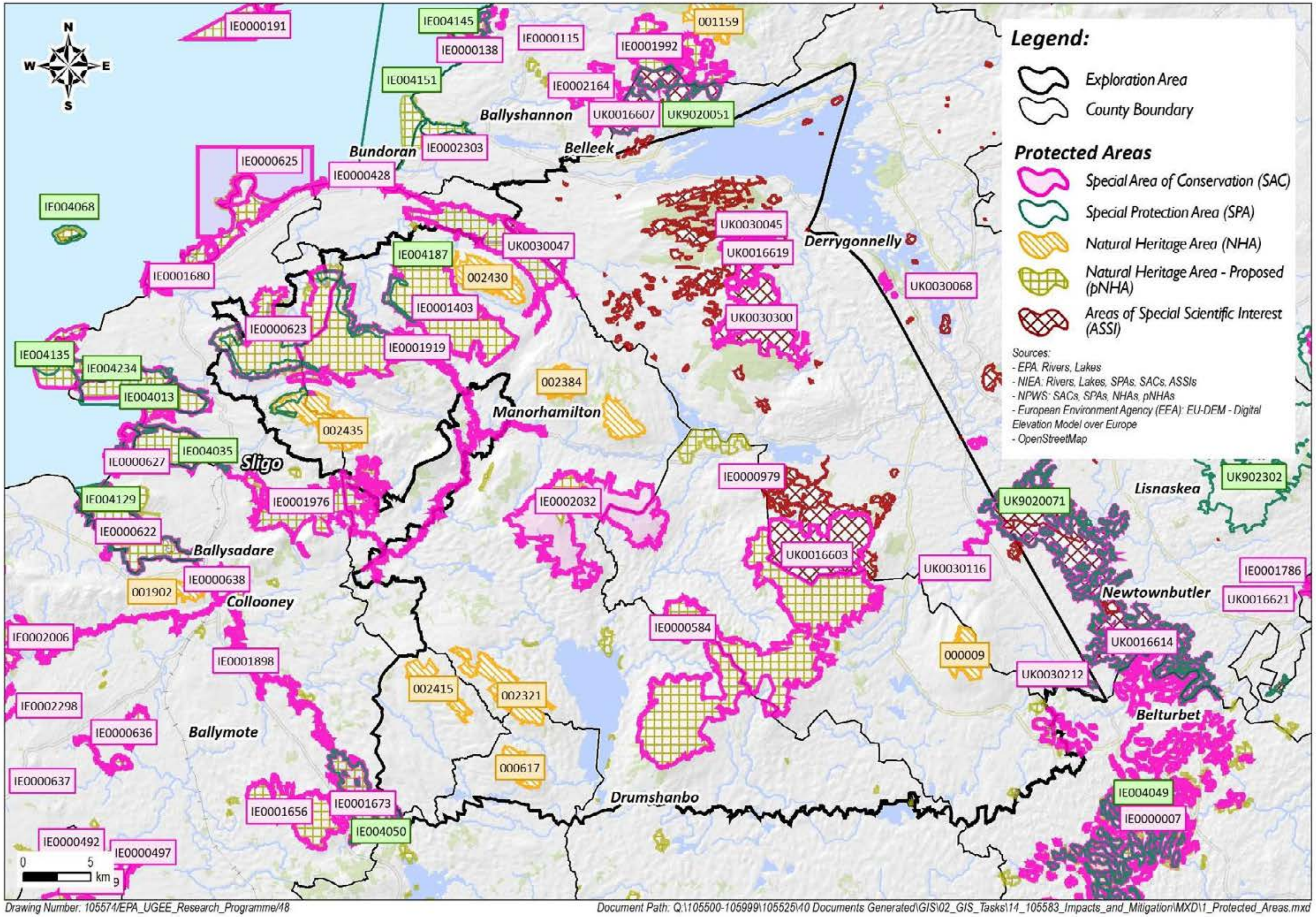


Figure 7.1. Protected areas in the NCB.

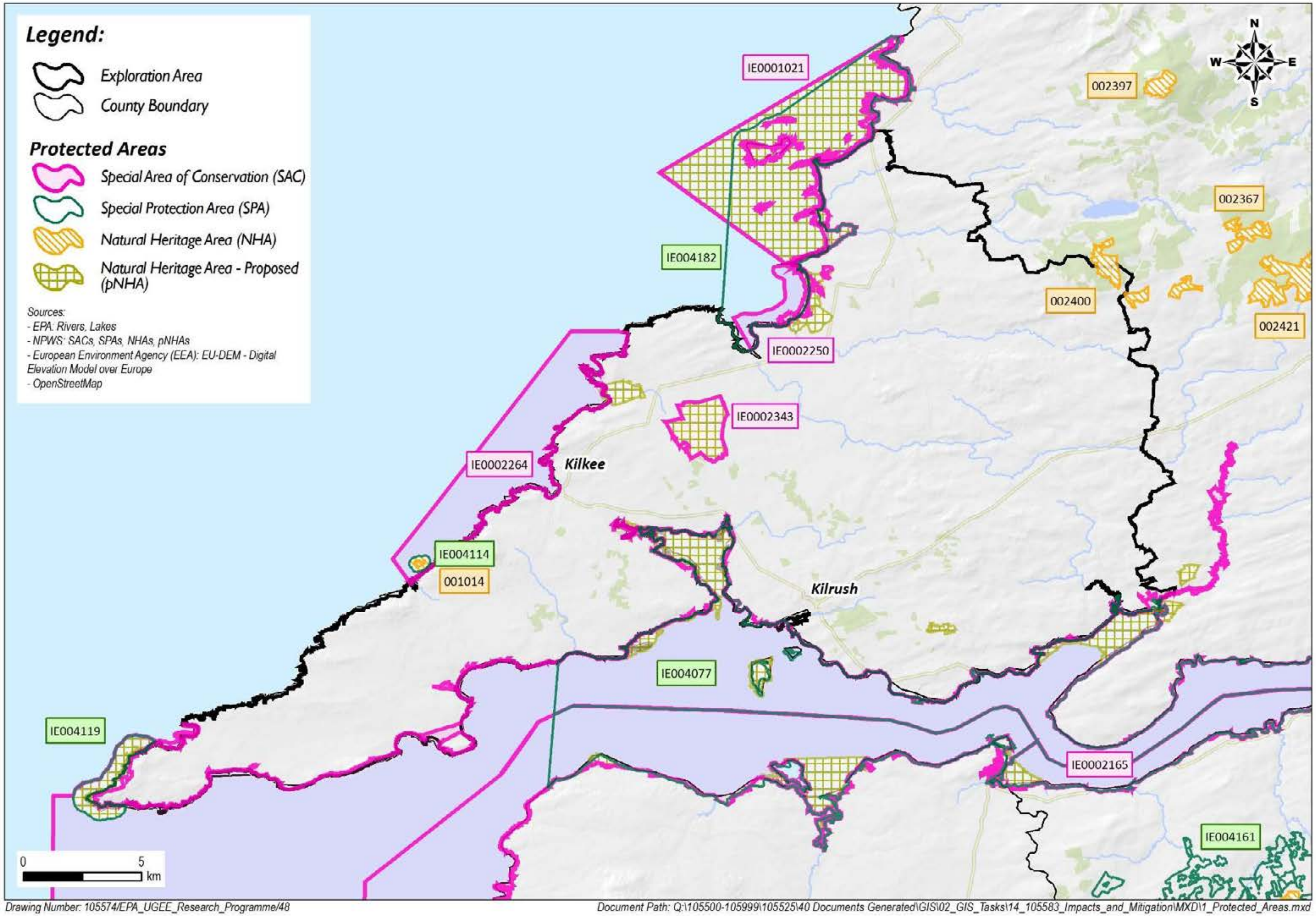


Figure 7.2. Protected areas in the CB.

7.3.1.1 Potential Impacts

Stage 1 – Well pad identification and site preparation

The main impacts at the site preparation stage would be associated with habitat loss or fragmentation, resulting from land take (AEA, 2012a). Full site preparation can result in the degradation or complete removal of a natural habitat by affecting natural water courses, or the splitting up of a habitat as a result of road construction or fencing being erected, or by the construction of the well pad itself.

New, invasive species such as plants, animals or microorganisms may be introduced during the development of the site, affecting both land and water ecosystems, and they may have a potentially negative impact on local flora and fauna (Heatley, 2011, as reported by AEA, 2012a). This is an area of plausible concern, but, as yet, there is no clear evidence base to enable its significance to be assessed.

Site preparation activities can also result in potential impacts with respect to sediment runoff from land clearance into streams and the resultant potential increase in suspended and benthic sediments in surface waters (Entrekin *et al.*, 2011). Nutrients, such as phosphorus, bound to these sediments may also have potentially negative impacts on surface waters by contributing to eutrophication (Entrekin *et al.*, 2011). Entrekin *et al.* (2011) concluded that there were preliminary indications of detectable sedimentation of watercourses due to shale gas development at the landscape scale in the streams they studied in the Fayetteville Shale region in Arkansas. Although Lechtenböhmer *et al.* (2011) found that there were no documented impacts of shale gas extraction on overall biodiversity, they acknowledged that ecological impacts were possible.

Stormwater runoff may result in contaminants such as hydraulic oil, fuel and lubricating fluids entering water bodies, streams and groundwater. Common to industrial activity and construction sites generally, this impact relates to the extent of groundworks and the nature of surface construction (roads, concrete areas, etc.) (API, 2009a, AEA, 2012a). These stormwater impacts can be mitigated through managed drainage and controls on potential groundwater contaminants, as described in Chapter 4.

Well drilling could potentially affect biodiversity through noise, light, vehicle movements and site operations. The treatment and disposal of well drilling fluids also need to be adequately handled to avoid damaging natural habitats. However, these risks are lower than during other stages of shale drilling (AEA, 2012a).

Stage 2 – Well design and construction, hydraulic fracturing and well completion

Gas well drilling could potentially affect local fauna through noise and disturbance caused by the drilling process itself, together with associated vehicle movements and site operations. As set out in the probable commercial scenarios, drilling may take place for up to 75 days per well, with additional time required for fracturing. However, these potential impacts are also associated with other stages of the process, e.g. by land take at the well pad construction stage (NYSDEC, 2015). Consequently, the impacts at this stage are likely to be of minor significance (AEA, 2012a). There is a minor potential for cumulative impacts on biodiversity associated with well drilling at multiple well pad installations (AEA, 2012a).

Adequate handling, treatment and disposal of well drilling fluids is necessary to avoid potentially significant impacts on local flora and fauna (Entrekin *et al.*, 2011).

The potential impacts related to traffic are discussed further in section 7.3.8.

Stage 3 – Well production

Any potential impacts would be strongly location dependent, but there would be potential for disturbance to natural ecosystems during the production phase due to human activity, traffic, land take, habitat degradation and fragmentation, and the introduction of invasive species (NYSDEC, 2015). Potential impacts related to traffic are discussed further in section 7.3.8. Pipelines constructed for use during the production phase would constitute new linear features, which could adversely affect biodiversity, particularly in sensitive ecosystems (AEA, 2012a).

There are also potential impacts related to sediment runoff into streams, reductions in stream flow due to abstraction, and contamination of streams by accidental spills (Entrekin *et al.*, 2011; Michaels *et al.,* 2011). On-site storage and transport of water may potentially affect flora and fauna owing to land take or disturbance and/or by the introduction of non-native invasive species. The magnitude of potential impacts would also be related to the footprint of the development sites, including the effects of access roads and utility services.

Stage 4 – Project cessation, well closure and decommissioning

It may not be possible to return the entire site to its previous state following decommissioning, which could be particularly significant for sites located in sensitive protected areas. Cumulative impacts over a wider area could potentially result in a significant loss or fragmentation of a sensitive natural habitat (NYSDEC 2015)

Summary of general potential impacts

Characterisation of the impacts on ecosystems and wildlife would depend on the location of the well pad and its proximity to protected areas, as well as the sensitivity of the flora and fauna. The impacts on biodiversity associated with individual sites are likely to be limited to the vicinity of the site (Entrekin *et al.*, 2011; Nature Conservancy, 2011). The cumulative effects of the development of multiple sites may be more widespread.

In view of the f limited evidence for the effects of hydraulic fracturing on flora, fauna and biodiversity, their frequency would be considered to be rare. The biodiversity impacts of potential concern (Michaels *et al.,* 2011; AEA, 2012a; NYSDEC, 2015) are associated with cumulative development over a wider area and are judged to be of moderate significance.

It is judged that the consequences for flora, fauna and biodiversity at an individual site in the post-decommissioning phase would be comparable with many other industrial and commercial land uses, and are of no more than minor significance. Over a wider area, this could potentially result in a significant loss of natural habitat.

7.3.1.2 Mitigation measures

The development of an appropriate suite of mitigation measures would be dependent on extensive surveys of local flora and fauna to ensure the development of an appropriate suite of mitigation measures. Measures would also need to be monitored to ensure active management of the mitigation process. Potential mitigation measures include but are not limited to:

- development of and compliance with a suitable Environmental Management Plan;
- management of invasive species in accordance with best practice and the restoration of native vegetation where possible;
- drilling multiple wells on well pads to minimise land take and habitat fragmentation;
- avoiding protected and sensitive areas;

- sensitive design of well pads, including the requirements to fit the available landscape and minimise tree removal and habitat fragmentation;
- maintaining plantings of soft edges around forest clearings by maintaining existing shrub areas, planting shrubs or allowing shrub areas to grow;
- limiting mowing to one cut per year or less after the construction phase of well pads is completed and prohibiting mowing during certain times, such as the nesting season for grassland birds;
- designing lighting to minimise impacts through measures such as the use of low-intensity security lighting, focused task lighting, designing operating lights so that the light levels are as low as safely possible, limiting the height of lighting columns to reduce light spillage, well pad lighting to shine downwards to minimise lighting impacts on sensitive species, and the use of fitted hoods;
- limiting the total area of disturbed ground, number of well pads and, especially, the linear distance of roads, where practicable;
- ensuring that roads, water lines and well pads follow existing road networks and be located as close as possible to existing road networks to minimise disturbance;
- gating single-purpose roads to limit human disturbance;
- reinstating sites following completion as soon as practicable;
- carrying out reinstatement in stages to establish vegetation and habitat incrementally as parts of the site become inactive;
- using native tree, shrub, and grass species that are appropriate to the habitat;
- developing a surface water protection plan, including spill response protocols;
- locating hazardous substances within secondary containment, away from high-traffic areas, as far as is practical from surface waters, not in contact with soil or standing water and with the hazard labels protected from weathering;
- limiting exposed and disturbed ground to prevent erosion and runoff.

Mitigation measures relating to water quality are discussed in Chapter 4.

7.3.2 Air quality

7.3.2.1 Potential impacts

Unconventional natural gas differs from conventional natural gas in three main ways. First, extraction of unconventional natural gas often requires directional or horizontal drilling at much greater depths below the ground surface. Second, well completion (hydraulic fracturing) procedures for unconventional natural gas are much more extensive and expensive those than for conventional wells. Third, production from unconventional natural gas wells typically declines more sharply and the total volume of natural gas recovered per well is less well constrained (based on both economic and practical constraints). Once out of the ground, however, unconventional natural gas is subject to the same fate (i.e. processing, transport, end use) as conventional natural gas, and the atmospheric impacts are indistinguishable between the two forms (Moore*,* 2014).

Air contaminants can adversely affect human health in a multitude of ways. The industrial processes involved in UGEE can result in the emission of air pollutants, which, if present at high enough concentrations, are associated with possible health impacts through direct contact (e.g. to eyes, skin) or through inhalation (e.g. respiratory tract, gastrointestinal tract) (Atherton *et al.*, 2014). Site emissions are likely to include VOCs and methane; in addition, the processes associated with hydraulic fracturing also involve increased traffic and the use of diesel-fuelled machinery, with consequent emissions of unburned hydrocarbons, VOCs, sulfur dioxide (SO_2), particulate matter

(PM), carbon monoxide (CO), and oxides of nitrogen (NO_x). Leaky equipment can also result in fugitive gas emissions, leading to the release of methane and other gases such as VOCs.

Emissions from numerous well developments in a local area or across a wider region could have a potentially significant effect on air quality. For example, the emissions of VOCs and NO_x from wide-scale intensive development of shale gas reservoirs may potentially influence wider ozone (O_3) levels or contribute to elevated ambient pollution levels, which can potentially contribute to adverse effects on respiratory health at sufficiently high concentrations (WHO, 2013).

However, on a site-by-site basis, these emissions are typically intermittent and not unique to shale gas extraction and related activities (Public Health England, 2013). Many pollutants associated with shale gas extraction are also produced in significant quantities from other sources, e.g. primary air pollutants from industry and transport and secondary pollutants from atmospheric processes. Both of these sources or processes contribute to background levels of both primary and secondary pollution, and the background levels of air pollution vary from place to place. In some areas, specific sources, such as traffic, will be dominant, while in other areas, regional, national, or even international sources can be dominant contributors. Without such data it is difficult to undertake a detailed assessment of the impact of emissions on human health (Public Health England, 2013).

UGEE operations and the diesel engines used to support them have the potential to release many hydrocarbons and other contaminants into the air and may result in increases in the occupational and public exposure to these air contaminants of workers in the immediate vicinity and nearby residents, respectively. People may potentially be exposed to higher levels of these contaminants than they would otherwise as they breathe ambient air inside and outside their homes. Some of these contaminants, such as benzene, diesel exhaust and $PM_{2.5}$ (particulate matter less that 2.5 μm diameter) are associated with potentially significant negative health impacts at certain levels (Colorado School of Public Health, 2011). Others can act as irritants of the eyes, skin and respiratory tract or cause neurological effects, if present at high enough concentrations. In addition, hydrocarbons, and nitrogen oxides serve as precursors for the formation of ground-level ozone, which itself is an irritant.

Published evidence from the USA (Groundwater Protection Council, 2009; Colorado School of Public Health, 2011; Walther, 2011; McKenzie *et al.*, 2012; Adgate *et al.,* 2014; Maryland Department of the Environment and Maryland Department of Natural Resources, 2014; Werner *et al.*, 2015) and other countries (Public Health England, 2013) suggests that there is a potentially wide variety of different sources of air pollutants from shale gas extraction and related activities, depending on the process phase. It should be noted that European regulations would result in variations to UGEE processes compared with processes in the USA from where much of the primary data originates. There would, therefore, be reductions or variations in the magnitude of overall emissions associated with particular process stages.

Sources can include:

- direct emissions from conventional diesel engines powering the drilling and tracking operations and compressors used to capture and transport the gas on site; pollutants can include particulate matter , CO, NO_x, including nitrogen dioxide (NO_2);
- emissions from the venting of condensate and oil tanks on site; pollutants can include a range of VOCs;
- emissions from gas capture and flaring; pollutants may include methane, NO_x and other gases associated with the flaring of the gas such as non-methane VOCs, as well as particulate matter ;

- Fugitive EMISSIONS associated with leaks from pumps, flanges, valves, pipe connectors, etc.; pollutants can include methane and VOCs;
- stray gas from wells during production and after well closure (methane emissions following closure are addressed in more detail in section 8.2.2.4); and
- emissions of a number of air pollutants associated with shale gas extraction and related activities can lead to the formation of secondary pollutants such as ozone, which is generated by photochemical reactions involving NO_x and VOCs in the presence of sunlight; emissions from shale gas extraction operations may also lead to the formation of secondary particles.

Several studies are ongoing (NETL, 2013) to attempt to quantify the individual as well as the cumulative impacts; however, studies including Moore *et al.* (2014) and Werner *et al.* (2015) report that a complete inventory and comprehensive classification of emissions during drilling and hydraulic fracturing does not exist.

Stage 1 – Well pad identification and site preparation

A range of pollutants with impacts on the environment and human health have been linked to this stage (DECC, 2014a). Impacts on air quality begin with the use of large diesel-powered equipment during site preparation, including the construction of roads, as well as clearing the well pad (Cabot Oil and Gas Corporation, 2013). Emissions are released from off-road diesel engine use and heavy equipment operation and continue throughout the drilling and hydraulic fracturing phases.

Diesel engine emissions are known to include airborne fine particulate matter (both PM_{10} and $PM_{2.5}$) as well as ozone precursors such as NO_x and non-methane volatile organic compounds (NMVOCs). These pollutants, in sufficient concentrations, can give rise to decreased lung function, asthma and increased respiratory symptoms such as coughing and difficulty breathing (CE Delft, 2009; EEA, 2013; Litovitz *et al.*, 2013).

At the site construction stage, these emissions are not significantly different from those from any other similar construction activity. Attention is normally focused on diesel engine emissions during the drilling and fracturing stages (Howarth *et al.*, 2011) rather than the site preparation phase, and are of less concern during site preparation. (Traffic impacts are discussed in more detail in section 7.3.8.) Similarly, there is a risk of fugitive emissions to air in the event of an equipment fuel or oil spillage, but this risk would be common to any similar activity and controlled by normal procedures for the oil and gas and construction industries. Fugitive dust emissions during construction may potentially cause a nuisance and, as a result, be a source of annoyance for those affected, but impacts are likely to be “negligible”, as long as dust management measures are put in place and roads are paved.

In this context, diesel engine emissions are not expected to pose a significant environmental or health risk, and were assessed as a hazard of minor significance (Lechtenböhmer *et al.*, 2011; AEA, 2012a).

Stage 2 – Well design and construction, hydraulic fracturing and well completion

As the well is drilled, pockets of methane, as well as potentially ethane and propane, can be released. However, little information is available on the frequency and volume of emissions from these releases, which is currently a major uncertainty in emissions inventories (Jiang *et al.*, 2011; Moore *et al.*; 2014; NOAA, 2015).

The main issue of potential concern with regard to emissions to air during well drilling is the risk of emissions of diesel exhaust fumes from well-drilling equipment (Howarth *et al.*, 2011; Lechtenböhmer *et al.,* 2011; DECC, 2014a).

Emissions from diesel-engined plant are well understood, and emissions from plant up to 560 kW are controlled in Europe under Directive 97/68/EC and amendments. In view of this, the emissions from individual installations are judged to be of minor significance. No significant adverse effects on health would be expected to arise from a properly designed and operated individual installation (AEA, 2012a).

In view of the evidence from non-peer reviewed but independent sources of the cumulative effects of emissions to air from US facilities on environmental levels of ozone, the potential significance of these impacts was described as “major” (AEA, 2012a). The atmospheric chemistry in Europe differs from that in continental North America, in that ozone is typically associated with photochemical activity in summer rather than calm winter conditions (Derwent *et al.*, 2003; AEA, 2012a). Nevertheless, should the UGEE industry develop to a similar extent, it is considered, in principle, possible for emissions to have an indirect effect on summer ozone levels in Europe. It is not possible at this stage to quantify the scale of this potential effect on air quality and hence on health (AEA, 2012a), although it should be noted that this potential impact relates to widespread, intensive development on a scale similar to that seen in the USA.

In addition, there is a risk of fugitive emissions to air in the event of an equipment or storage tank fuel or oil spillage; however, this risk would be common to any similar activity. There was no evidence that fuel spillages pose a significant risk to air quality.

The probable commercial scenarios identified that between 1200 and 4000 t of proppant (sand or similar quantities of man-made silica beads) per fracturing programme is likely to be used. On-site handling (by conveyor and blender) of proppant can emit significant quantities of dust. An area of growing concern relates to a particular component of this particulate matter (both PM_{10} and $PM_{2.5}$) on which there is little information, i.e. respirable silica (crystalline silica small enough to enter the gas exchange regions of the lungs) (Chalupka, 2012; Coussens and Martinez, 2013; Esswein *et al.*, 2013; Korfmacher *et al.*, 2013; Witter *et al.*, 2014; Werner *et al.*, 2015). Crystalline silica dust within the respirable size range (< 4 μm) is classified as a carcinogen and a hazardous air pollutant in the USA (Clark *et al.*, 2013) and is covered under occupational exposure limits within Ireland and Northern Ireland. Silica dust generated in the mining and transport of sand to the well site, as well as in the process of moving and mixing sand into the hydraulic fracturing fluid on the well pad, may be inhaled by workers if the correct mitigation measures are not implemented and appropriate personal protective equipment worn. In addition to an increased risk of lung cancer, exposure to crystalline silica can lead to a chronic, inflammatory lung disease called silicosis (Clark *et al.*, 2013; NIOSH, 2014; SIWI, 2014).

The fluid used during hydraulic fracturing can contain hundreds of chemicals, as described in further detail in Chapter 9, including acids, ethylene glycol, and isopropanol (Groundwater Protection Council, 2009; Meiners *et al*., 2013). When a proportion of the fracturing fluid is returned to the surface, it can be stored in tanks, with the associated potential for emission of the fluid components, which can be volatile under atmospheric conditions (Arnaud, 2015; Werner *et al*., 2015).

Following the completion of the drilling and fracturing processes, the well is completed and prepared to produce natural gas. Emissions during the well completion process, particularly during venting and flaring of initial natural gas before the well is connected to a transmission pipeline, can include methane and BTEX (Adgate *et al.*, 2014; USEPA, 2014). These emissions can also contain other non-methane hydrocarbons, along with hydrogen sulfide H_2S, NO_x and, if there is incomplete combustion of natural gas, formaldehyde at concentrations in the air that may have the potential to affect residents living within 800 m of wells (McKenzie *et al.*, 2012).

More recently, reduced emissions completions, or “green completions,” which capture and separate natural gas during well completion and workover (refracturing) activities, have become a key technology to limit the amounts of methane, VOCs and hazardous air pollutants vented during the flowback period (without the disadvantages of flaring). Reduced emissions completions use portable equipment that allows operators to capture natural gas from the flowback water. After the mixture passes through a sand trap, a three-phase separator removes natural gas liquids and water from the gas (Clark *et al.*, 2013). For example, green completions and flaring can reduce methane emissions by as much as 90% (McKay and Stone, 2013) to 95% (DECC, 2014b) versus venting straight into the atmosphere. Green completion technology is expected to develop and become even more effective as the industry develops (DECC, 2014b).

While monitoring of background levels and associated modelling of potential impacts are required for a thorough determination of the potential magnitude of impacts, emissions from individual sites are likely to be of minor significance (AEA, 2012a), but the cumulative impact from multiple sites could potentially be of greater significance. The major contributor to regional air quality issues is likely to be the completion and production stages, and the cumulative impact from the technical hydraulic fracturing stage was judged to be moderate.

Stage 3 – Well production

During production, emission sources can include wellhead compressors or pumps that bring the produced gas up to the surface or up to pipeline pressure (engines are often fired with raw or processed natural gas), well pad equipment bleeding and leaks, flare emissions, maintenance emissions, and compressor station emissions (Litovitz *et al.*, 2013).

During the production phase, other sources of methane and NMVOCs (including BTEX) can include dehydrator regeneration vents,[12] venting from pneumatic pumps and devices that are actuated by natural gas, leaks through faulty casings, incomplete emissions capture, or incomplete burning in flaring systems. Some of these emissions can be continuous or intermittent but would be ongoing during the lifetime of the well, unless direct emissions capture and destruction or recovery are put into place (Moore *et al.*, 2014). Other emissions related to maintenance or production stimulation, for example, would be episodic such as during liquid unloadings and during workovers (Tyner *et al.*, 2014). In addition, oil and gas emissions of ozone precursors have been linked to elevated regional ozone levels (Bar-Ilan *et al.*, 2009; Kemball-Cook *et al.,* 2010; Litovitz *et al.*, 2013). High surface-level ozone concentrations, produced by increased NO_x and abundant VOCs can lead to respiratory symptoms, particularly in children and older adults (WHO, 2003; Ebi and McGregor, 2008).

There is little consensus exists on the magnitude of the impact on air quality due to a number of factors including the variations in composition of the raw gas itself and varying degrees of emission controls and reduction requirements. Published studies report that conclusions vary from significantly detrimental (Gilman *et al.*, 2013; Katzenstein *et al.*, 2003; USEPA, 2015c; Werner *et al.*, 2015) to little or no impact (NUATRC, 2011; Pacsi *et al.*, 2013; USEPA, 2014; Bunch *et al.,* 2014).

In addition, if hydrogen sulfide (H_2S) is present in the extracted gas, emissions as a result of equipment failure or leaks may give rise to odours. Owing to the stringent safety measures and equipment checks, the probability of equipment failure is considered very low. In order for members of the public to experience significant odour impacts, they would need to be very close to the source with the wind to be blowing towards them (Cuadrilla, 2014b).

Stage 4 – Project cessation, well closure and decommissioning

Pipeline-quality natural gas is predominantly methane (McKenzie *et al.*, 2012), therefore, Moore *et al.* (2014) report that few other emissions are reported from the transmission, storage and distribution

12 Glycol dehydrators are the most common equipment for removing water vapour from natural gas.

stage. However, methane emissions from abandoned oil and gas wells appear to be a significant source of methane emissions to the atmosphere (Cherry, 2014; Kang *et al.*, 2014). Due to the lack of detailed information, it is currently not possible to accurately estimate the air quality impacts of this part of the process life cycle (Allen *et al.*, 2013; Kang *et al.*, 2014).

Efforts to improve estimates of methane emissions to the atmosphere from oil and gas production are being driven, in part, by growth in unconventional production. Estimates of methane emissions from activities on producing oil and gas sites are used to develop bottom-up estimates (Howarth *et al.*, 2011; Allen *et al.*, 2013). However, a comparison of bottom-up and top-down estimates indicate that there may be missing sources in bottom-up estimates (Kang *et al.*, 2014).[13]

Much of the information available on the potential for gas leakage is derived primarily from historical studies of conventional wells. While experience in the USA to date indicates that the risks posed by poorly controlled and logged historical wells far outweigh the risks posed by wells designed and constructed to current standards (AEA, 2012a), the industry's experience with the long-term stability of cement shows that gas well cementing does not remain leak-proof indefinitely (Ewen *et al.,* 2012).

In general, where fugitive gas contamination occurs, well integrity problems are most likely associated with casing or cementing issues (Watson and Bachu, 2009; Darrah *et al.*, 2014). Over time the cement (and/or casing) tends to deteriorate, allowing buoyant gas to leak along the annulus between the production casing and the formation or through the wellbore (surface-casing vent flow) (Dusseault *et al.*, 2000; Watson and Bachu, 2009; Ewen *et al.,* 2012) (Figure 7.3). In addition, Mueller and Eid (2006) warn that the pressure testing that occurs soon after cementing the surface casing may cause severe tangential stresses on the cement sheath, contributing to failure, if pressure testing is carried out during the early stages of cement curing.

The source of these leaks is necessarily the original production formation but can be intermediate gas-bearing formation that had not been in production because it was either not known to exist or not of commercial value (Muehlenbachs, 2011).

The proportion of abandoned wells that leak is difficult to estimate (Council of Canadian Academies, 2014). A statistical analysis of a sample of well reports submitted to the Alberta Energy Regulator by the oil and gas industry implies that about 4.5% of Alberta wells show surface-casing vent flows or gas migration (Watson and Bachu, 2009). In a study by Kang *et al.* (2014), 19 abandoned (conventional) wells in Pennsylvania were assessed and the mean methane flow rates measured. The methane flow rates were on average 0.27 kg per day per well compared with a mean methane flow rate at the control locations of 4.5×10^{-6} kg per day location. Three out of the 19 measured wells were high emitters that had methane flow rates that were three orders of magnitude greater than the median flow rate of 1.3×10^{-3} kg per day per well. When scaled up, this equates to 4–7% of the estimated total anthropogenic methane emissions in Pennsylvania. In Quebec, a study found that a large proportion of wells (18 out of the 29 shale gas wells drilled to date) leak, although some leaked at almost imperceptible rates; however, all of these wells were less than 3 years old when tested (BAPE, 2011). These measurements show that methane emissions from abandoned oil and gas wells can be significant (Kang *et al.*, 2014).

Leaking gas from oil and gas wells enters the atmosphere directly, and, in addition, some of the gas may enter shallow aquifers, where traces of sulfurous compounds can render the water non-potable,

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13 A bottom-up approach refers to process-based modelling, which is then used to extrapolate the emissions to larger scales. A top-down approach is based on spatially distributed, temporally continuous observations of concentrations with a series of assumptions used to estimate the natural sinks and distinguish between anthropogenic and natural sources.

or where the methane itself can generate unpleasant effects such as gas locking of household wells, or gas entering household systems and being released when taps are turned on (Dusseault *et al.*, 2000). Abandoned wells have been connected to subsurface methane accumulations that have caused explosions, which is a major concern in urban areas with oil and gas development or natural gas storage reservoirs (Kang *et al.*, 2014). While methane emissions to ambient air pose no major threat to human health (NIOSH, 2000), they may contribute to climate change, as methane's global-warming footprint is 25 times greater than that of carbon dioxide (Dusseault *et al.*, 2000; Ewen *et al.*, 2012).

It is, therefore, important to monitor the integrity of the well's condition after plugging and decommissioning. The long-term management of abandoned gas wells to prevent cross-contamination of waters and soils, along with gas emissions to the atmosphere, is a matter that requires careful attention (Cook *et al.*, 2013). It is a matter of increasing concern in the USA and there is a need to formulate governance and regulation and develop leading industry practice (Cook *et al.*, 2013).

Monitoring protocol should be developed to detect possible well failure post decommissioning. Continuous ground gas monitoring and aquifer sampling could be similar to that carried out before and during fracturing operations. Temporary monitoring equipment could be used, such as that used to monitor emissions from landfill sites, or semi-permanent monitoring stations could be installed. This requires techniques that can reliably distinguish between methane from non-shale operations in the areas of abandoned wells (Royal Society and Royal Academy of Engineering, 2012).

Much less information exists on the non-methane emissions from the other natural gas life cycle stages. Because pipeline-quality natural gas is predominantly methane (McKenzie *et al.*, 2012), Moore *et al.* (2014) report that few other emissions are reported from the transmission, storage and distribution stage.

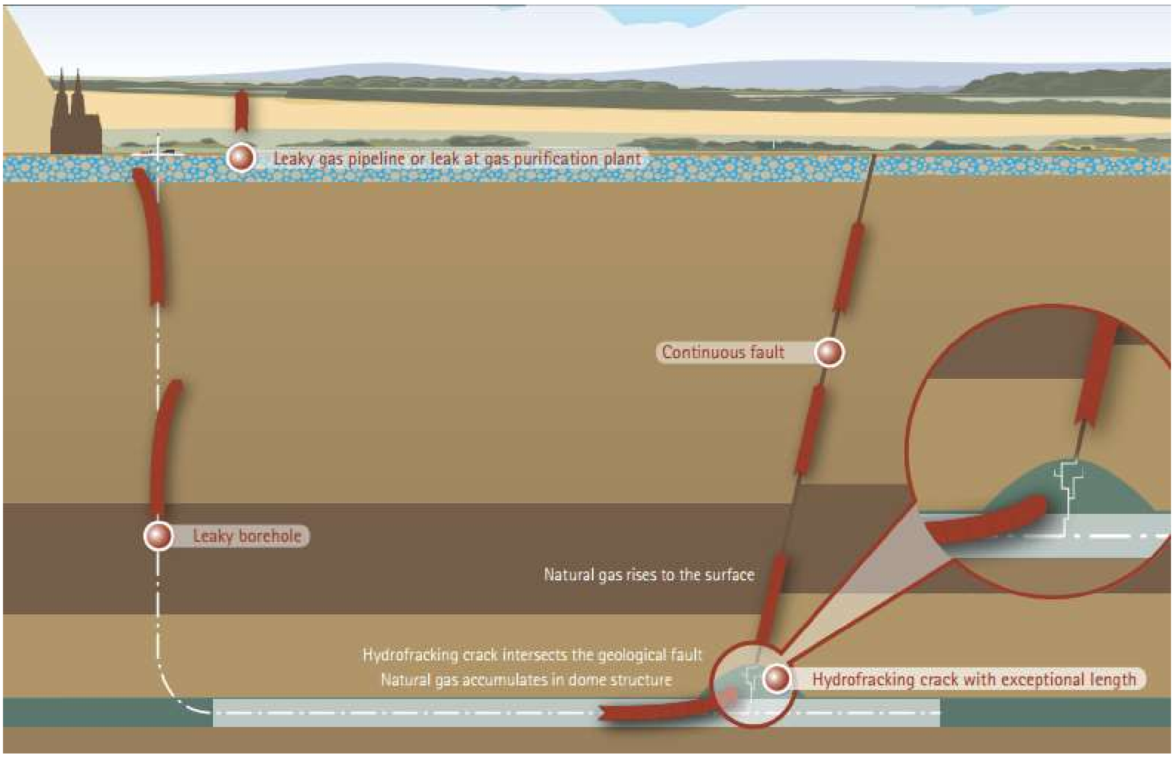

Figure 7.2. Schematic drawing showing the emissions pathway for natural gas (from Ewen *et al.*, 2012).

7.3.2.2 Mitigation measures

This section addresses potential mitigation measures under the following categories:

- work practices to avoid inhalation of respirable particles;
- site management practices to reduce dust and engine emissions; and
- technical mitigation measures to reduce operational and fugitive emissions, including better well closure techniques.

Mitigation measures to reduce the inhalation of respirable particles by workers include (OSHA, 2012):

- short-term work practices:
    - limiting the number of workers, and the time workers must spend in areas where dust and silica levels may be elevated, and considering ways to perform dusty operations remotely to completely remove employees from these areas;
    - modifying processes to reduce dust release, such as limiting the distance sand falls through air to minimise dust;
    - applying water to roads and around the well site to reduce the dust;
- configuration of equipment to reduce emissions:
    - enclosing points where dust is released or installing thick plastic stilling or staging curtains around areas where sand is moved;
    - using enclosed cabs on machinery;
    - using local exhaust ventilation to collect silica-containing dusts and prevent dust escape;
    - installing dust collection systems onto machines or equipment that can release dust;
    - modifying machinery to reduce dust escape; and
- use of respirators.

Measures to mitigate the emission of dust nuisance arising off site during site preparation activities include, where appropriate and practicable:

- wind breaks and barriers;
- frequent cleaning and watering of the construction site and associated access roads;
- control of vehicle access, vehicle speed restrictions;
- covering of piles;
- using gravel at site exit points to remove caked-on dirt from tyres and tracks;
- washing equipment at the end of each work day;
- sweeping hard surface roads to remove any deposited materials;
- restricting unsurfaced roads to essential site traffic only; and
- locating wheel-washing facilities at all exits from the construction site.

Technical operational mitigation measures may include:

- using natural gas-fired or electric grid drilling rig engines, as emissions from natural gas combustion are lower than those from diesel combustion (Hill, 2011);
- using emission controls on lean-burn and rich-burn drilling rig engines (AEA, 2012a);
- using emission control equipment on engines and machinery;
- limiting simultaneous operations associated with pollutant emissions or sequencing of operations on a single well pad to avoid high levels of emissions in one area caused by simultaneous activities;
- limiting flaring of gas;
- reducing NO_x emissions from diesel and dual-fuel engines by de-rating;[14]
- reusing sulfur oxides through the use of low-sulfur fuels;
- using new equipment where appropriate, and servicing equipment regularly;
- locating equipment near to the centre of the well pad where possible to limit concentrations at the boundary; and
- implementing an equipment maintenance and leak detection programme.

7.3.3 Greenhouse gas emissions

7.3.3.1 Potential impacts

Most greenhouse gases (GHGs) have both natural and human sources. According to the Intergovernmental Panel on Climate Change (IPCC), GHG emissions caused by humans disrupt the natural processes occurring in the atmosphere and are extremely likely to be the dominant cause of the observed global warming that has occurred since the mid-20th century. Globally, almost 80% of GHG emissions from human sources come from the burning of fossil fuels and industrial processes. GHGs include carbon dioxide, Methane (CH_4), nitrous oxide (N_2O), ozone, and chlorofluorocarbons (CFCs).

The impact of a particular greenhouse gas on climate depends on the length of time that the gas remains in the atmosphere and each gas's unique ability to absorb energy. These factors determine a gas's global warming potential, compared with an equivalent mass of carbon dioxide (which is defined as having a global warming potential equal to 1) (Cubasch *et al.,* 2013). The Fifth Assessment of the Intergovernmental Panel on Climate Change (IPCC, 2013) estimates that methane has a global warming potential 28−34 times that of carbon dioxide over a 100-year time frame and 84−86 times greater on a 20-year time frame. As the primary chemical constituent of natural gas [70−90% by volume for raw natural gas from the well and > 90% by volume for pipeline-quality natural gas (USEPA, 2013a)], methane can alter global atmospheric chemistry and is the second largest contributor (after carbon dioxide) to the total direct radiative forcing due to long-lived greenhouse gases (O'Hare *et al.*, 2014).

GHG emissions arise from the following aspects of UGEE operations (DECC, 2013a):

- *Vented emissions of methane and carbon dioxide*. Vented emissions are intentional. Many processes associated with shale gas exploration and production can cause gases to be vented, where permitted. Examples include release of gases during flowback, and release for safety reasons and during certain maintenance operations.

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14 De-rating involves restricting the engine operation to lower than normal levels of power production for the given application. Derating reduces cylinder pressures and temperatures, thereby lowering NO_x formation rates.

- *Emissions from combustion of fossil fuels on site*. These emissions come from engines (such as diesel engines used for drilling, truck traffic, hydraulic fracturing and natural gas compression) and from flaring of shale gas. Combustion emissions would be mainly carbon dioxide. However, incomplete combustion could result in other emissions such as methane, VOCs and carbon black, all of which would have global warming and air pollution impacts.
- *Fugitive emissions*. These emissions are unintentional gas leaks and are difficult to quantify and control. There are various potential sources of fugitive emissions, including leaks from valves, wellheads and on-site accidents or accidental releases from the well casing into groundwater.

There are also indirect emissions, which result from processes used in the exploitation of shale gas. These emissions include the emissions from the energy used to treat and transport the water and wastewater, and to manufacture the chemicals and materials of construction. Life cycle emissions of GHGs are addressed in Chapter 9.

It is important to note that there has been little measurement of direct or indirect methane emissions from shale gas exploration and production anywhere in the world (DECC, 2013a). Methane emissions from abandoned wells are discussed in more detail in section 7.3.2.1. In practice, most of the existing studies have drawn upon a narrow set of primary data from shale gas operations in the USA. There is little European evidence, as significant shale gas operations are, with the exception of limited exploration activities, not yet operational in Europe and typical practices are yet to be established (AEA, 2012a). Caution must therefore be used in the extrapolation of impacts, as many circumstances differ including geology and the regulatory framework.

7.3.3.2 Potential mitigation measures for greenhouse gases

Site selection directly impacts the number of rig and equipment mobilisations needed to develop a well pad or area. Related mitigation measures include (NYSDEC, 2015):

- limiting the generation of carbon dioxide by limiting vehicle miles travelled and fuel consumption;
- drilling as many wells as possible on a pad with one rig move;
- spacing of wells for efficient recovery of natural gas;
- hydraulic fracturing of as many wells as possible on a pad with one equipment move; and
- planning for efficient rig and fracturing equipment moves from one pad to another.

Transport related to sourcing of equipment and materials, including waste disposal, was identified as a potential contributor to carbon dioxide emissions and can be mitigated through measures such as:

- sourcing personnel and materials from locations within region to minimise the travelling distance;
- using efficient transport engines.

Well operators can limit GHG emissions during well-drilling operations by effectively designing drilling programmes including measures such as the following:

- extending each lateral wellbore as far as technically and legally possible to reduce the total number of wells required within a spacing unit;
- spacing the lateral wellbores for efficient recovery of natural gas;
- reusing drilling fluids;
- using materials with recycled content (e.g. well casing, drilling fluids);
- using efficient rig engines;

- using efficient air compressor engines for drilling;
- using efficient exterior lighting;
- ensuring that all flow connections are tight and sealed; and
- carrying out leak detection surveys and taking corrective action.

Well completion activities primarily contribute to GHG emissions from the internal combustion engines required for hydraulic fracturing and flaring operations during the flowback period. Examples of measures that could be included in a greenhouse gas emissions impacts mitigation plan include:

- reusing flowback water (if allowed);
- using materials with recycled content (e.g. hydraulic fracturing fluids);
- using efficient hydraulic fracturing pump engines;
- using efficient exterior lighting;
- limiting flaring during the flowback phase by using reduced emissions completion equipment;
- ensuring that all flow connections are tight and sealed; and
- carrying out leak detection surveys and taking corrective action.

Equipment required to process produced natural gas, specifically the glycol dehydrators (i.e. vents and pumps) and pneumatic devices, generate methane emissions during normal production operations. Examples of measures that could be included in a greenhouse gas emissions impacts mitigation plan include:

- replacing glycol dehydrators with desiccant dehydrators;
- replacing gas-assisted glycol pumps with electric pumps;
- optimising glycol circulation and installing flash tank separators in glycol dehydrators;
- using efficient compressor engines;
- using efficient line heaters;
- using efficient glycol dehydrators;
- reusing production flowback and production waters (if allowed);
- ensuring that all flow connections are tight and sealed;
- carrying out leak detection surveys and taking corrective action;
- using efficient exterior lighting; and
- using solar-powered telemetry devices.

The production phase is the greatest contributor of GHGs, and a leak detection and repair programme is a key element of any strategy to mitigate VOC and methane leaks during this phase. A leak detection and repair programme would include the following:

- ongoing site inspection for readily detected leaks by sight and sound;
- inspection for VOC, methane and other gaseous or liquid leaks of all wellhead and production equipment;
- inclusion of all components noted above that are possible sources of leaks in the inspection and repair programme;

- specification of the period within which leaks must be repaired.

Post-closure measures to mitigate against gas leaks include (AMEC, 2014):

- Effective well sealing and closure to avoid leakage due to well integrity problems associated with casing or cementing issues.
- Decommissioning surveys. These surveys could cover a wide range of different parameters such as methane leakage and are important to establish the condition of the site upon decommissioning by the operator.
- Post-closure inspections, long-term monitoring and maintenance. These could help to ensure that any environmental releases are identified in a timely manner and the risks appropriately managed to minimise harm to people or the environment.
- Requirements for retention of ownership and liability for damage, transfer of responsibilities and financial guarantees and contributions from operators to cover the costs of monitoring and remedial action. Given the potential long-term nature of the pollutant release pathways (for example), it is likely to be important to retain appropriate provisions for liability over many years following well closure.

7.3.4 Landscape and visual amenity

7.3.4.1 Potential impacts

Any proposed UGEE developments would have the potential to impact upon both landscape character and visual amenity. Potential impacts include:

- landscape impacts such as:
  - o direct impacts upon specific landscape elements within and adjacent to the site and any associated infrastructure;
  - o effects on the overall pattern of the landscape elements that give rise to the landscape character of the site environs;
  - o impacts upon any visual interests in and around the site and associated infrastructure; and
- visual impacts such as:
  - o direct impacts of the development upon views in the landscape; and
  - o overall impact on visual amenity.

The visual impacts of UGEE activities will vary depending on topographic conditions, vegetation characteristics, time of year, time of day and the distance of one or more well sites from visual resources, visually sensitive areas, viewsheds or other visual receptors. This section addresses impacts and mitigation measures in general in the absence of project-specific data, but a complete landscape and visual assessment would be required at the EIA stage for any proposed development to fully determine potential impacts and specify appropriate mitigation measures. This should include careful reference to the relevant development plans for information on local landscape character, areas of high landscape value, designated scenic routes and particular viewsheds.

Specific landscape and visual elements with particular potential to be adversely impacted are set out within the various development plans. In the CB these include, inter alia:

- designated scenic routes between Loop Head and Kilkee;
- Heritage Landscape Areas along the coast around Loop Head; and

- the landscape character itself (designations include peninsular farmland, flat estuarine farmland and islands, coastal plains and dunes, farmed rolling hills).

In the NCB, these include, inter alia:

- designated Areas of Outstanding Natural Beauty, such as those roughly circumscribed by Kinlough, Lough Melvin, Dowra and Lough Gill, Co. Leitrim;
- listed areas of outstanding views and prospects, such as those in the area circumscribed by Kinlough, Lough Melvin, Dowra and Lough Gill, County Leitrim; west of Blacklion (Gortnahill and Comagee), County Cavan; south of Glangevlin (Altachullion, Dunmakeever, Bellavally Gap), County Cavan) and views in Cuiltygower and Arigna, County Roscommon;
- areas of high visual amenity around Lough Gill, Lough Melvin and Lough Allen, County Leitrim;
- Countryside Policy Areas, such as the shores and islands of Lough Erne, Lough Melvin and Lough Macnean (Upper and Lower) County Fermanagh;
- designated scenic routes, such as Dowra to Glangevlin to Blackrocks Cross, Backlion to Glangevlin, County Cavan; the route along the R280; the elevated scenic route along the third-class road overlooking Lough Allen and Slieve Anierin, County Roscommon; and sections of the R284 and local roads around Geevagh, County Sligo;
- trails such as Dowra to Blacklion (Kingfisher cycle trail), County Cavan, and the Miner's Way Walking Route in County Roscommon; and
- geologically important sites such as Cavan Geopark and designated sites within the park (Lough Macnean, Market House, Blacklion, Whitefathers Cave, Cornagee Scenic Viewpoint, Burren Forest, Moneygashel Ringfort, Garvagh Lough, Shannon Pot, Sean Eamonn Ruairi Trail, Glangevlin, The Courthouse, Dowra, Hawkswood Trail, Swanlinbar, Tullydermot Falls, Altachullion scenic viewpoint, Brackley Lough, Templeport Lake, St Mogue's Island) and the cluster of sites of geological importance in Arigna, County Roscommon, including the Arigna Mining Experience.

Stage 1 – Well pad identification and site preparation

The risk of significant visual impacts during well pad site identification and preparation are considered to be relatively low, given that the visible elements introduced during the well pad construction stage are temporary and common to many other construction projects. The use of heavy plant, stockpiles, fencing, site buildings, etc., could potentially result in negative visual impacts during site preparation, particularly in sensitive areas of high landscape value, or in close proximity to residential areas.

The features introduced as a result of well pad construction, while temporary in nature, may represent a new feature in a particular landscape, and are therefore likely to represent adverse impacts; although the magnitude of the adverse impact would be dependent on project-specific characteristics, it is likely to be at least minor (AEA, 2012a). These features are likely to proceed sequentially as a shale gas play is developed. The sequential development of well pads would reduce the potential for cumulative effects that could result from simultaneous development of a number of pads in a given area, but it would equally tend to make the impacts a longer term feature in the landscape. Cumulative effects are therefore judged to represent at least a minor impact, depending on proposed project characteristics and whether potential developments proceed sequentially or simultaneously.

Stage 2 – Well design and construction, hydraulic fracturing and well completion

New landscape features that would be associated with drilling activities include drill rigs of various heights and dimensions, with heights ranging up to 14 m for “single” rigs and up to 28 m for “double” rigs (see Figure 7.4). Currently, in the USA, the industry also uses triple rigs that can be more than 30 m in height (NYSDEC, 2015).

The equipment typically present on site during the hydraulic fracturing phase includes (NYSDEC, 2015):

- storage tanks that contain the water and additives used for hydraulic fracturing (rectangular red tanks on well site shown in Figure 7.5);
- tanks containing chemicals (blue rectangular);
- compressors (large cylindrical blue equipment and smaller dark green equipment with stacks or vents) used for pumping products through various hoses and pipelines;
- miscellaneous trucks; and
- miscellaneous workers’ vehicles (almost all of the white or silver vehicles shown in Figure 7.5).

Lighting on site may also result in adverse visual intrusion from a distance, as drilling may operate 24 hours a day. The use of large well drilling rigs may also be unsightly during this period, resulting in adverse visual intrusion, especially in or when visible from sensitive high-value agricultural or residential areas. An example drilling rig is shown as the highest vertical feature in Figure 7.4 (AEA, 2012a). Other elements of any potential development that may result in visual intrusion are access roads, pipelines, water impoundment areas, storage vessels and other hydraulic fracturing equipment, vehicles and buildings (NYSDEC, 2015).

Figure 7.3. A drilling rig in a rural setting (from NYSDEC, 2015).

While these impacts would not be permanent, a development would typically represent a new industrial feature in a particular landscape, and the visual impact is, therefore, likely to be of more consequence in developments at more rural locations (Broderick *et al.,* 2011).

In view of the limited duration associated with drilling at individual well pads, the impact associated with a single well pad is likely to be of minor significance (AEA, 2012a). The sequential development of well pads would reduce the potential for cumulative effects that could result from simultaneous development of a number of pads in a given area, but it would equally tend to make the impacts a longer term feature in the landscape. Impacts can be expected to occur at an individual site over a relatively short period, and for multiple well pads over an extended period (AEA, 2012a). The risk of significant effects is considered to be moderate in situations in which multiple pads are developed in a given area.

Figure 7.4. Representative view of active high-volume hydraulic fracturing (from NYSDEC, 2015).

Stage 3 – Well production (gas extraction)

Well head plant and equipment could have a visual impact, particularly in residential areas or areas of high landscape value, but this would be minimal compared with the impacts during the drilling and fracturing stages. Pipelines may have an adverse visual impact, particularly in residential areas or areas of high landscape value, although the magnitude of the impact would be dependent on the characteristics of any proposed project.

Stage 4 – Project cessation, well closure and decommissioning

If well sites are restored to their original state, on-site above-ground structures associated with well production are removed and new landscape features are introduced. The new landscape features would temporarily include bare areas, which would be created by the large-scale earth-moving activity necessary to restore the site to its former condition, and newly placed erosion control materials and vegetation to prevent erosion and facilitate the successful re-establishment of vegetation cover that would, over time, revert to the former vegetation patterns and species (NYSDEC, 2015).

It may not be possible to remove all wellhead equipment from site; however, this is not considered likely to pose a significant impact in view of the small scale of equipment potentially remaining on site. Visual impact is likely to be minor.

7.3.4.2 Potential mitigation measures

Mitigation measures can be described as falling into three main categories, and careful consideration of mitigation measures within each category is required:

- measures, developed through the iterative design process, that have become integrated mainstream components of the project design;
- standard construction practices for avoiding and minimising environmental effects;
- measures designed to address any adverse effects remaining after primary measures and standard construction practices have been incorporated into the scheme.

The main adverse impacts would result from construction of the well pad and well and would typically be of relatively short duration; the ideal strategy for mitigation is avoidance or prevention through site selection and sensitive design.

Other mitigation measures would typically be standard mitigation measures to minimise visual intrusion of a construction site. Measures include, but are not limited to:

- a tabulated list of vegetation that can be retained during construction should be prepared by an appropriate expert;
- screening and/or filtering of views using fencing, walls or soft landscaping;
- relocating or moving facilities or equipment within a site to take advantage of the mitigating effects of topography and/or vegetation;
- camouflaging or disguising using forms, colours, materials and patterns to minimise visual impacts;
- reducing the height of on-site objects to minimise their visibility from surrounding viewsheds;
- reducing the number, areas or density of objects on a site to minimise their visibility from surrounding viewsheds;
- using non-reflective materials to avoid light reflection into surrounding viewsheds;
- designing lighting to minimise impacts through measures such as the use of low-intensity security lighting, focused task lighting, designing operating lights so that the light levels are as low as safely possible, limiting the height of lighting columns to reduce light spillage, well pad lighting shining downwards to minimise lighting impacts on sensitive species, and using fitted hoods;
- siting lighting to minimise off-site light migration, glare, and “sky glow” light pollution.

7.3.5 Material assets and land use

7.3.5.1 Potential impacts

Resources that are valued and that are intrinsic to specific places are called “material assets”. They may be of either human or natural origin and their value may arise for either economic or cultural reasons. Cultural heritage is addressed separately in section 7.3.6.

Material assets can include:

- natural origin:
  - the assimilative capacity of air and water;
  - non-renewable resources (e.g. minerals, soils);
  - renewable resources (hydraulic head, wind exposure);
- human origin:
  - transport infrastructure (such as roads, railways, airports);
  - major utilities (such as water supplies, sewerage, power systems).

Land disturbance and land take may impact negatively on areas of high agricultural, natural, amenity or recreational value. As well as the well pads themselves, the associated infrastructure (access roads and pipelines) also results in additional land take and associated impacts.

Figure 7.6 and Figure 7.7 show the land use in the NCB and CB study areas. The land use mapping shows extensive areas of agricultural and natural land that may be impacted upon by land take associated with pads and associated infrastructure.

The amount of land used for shale gas development is dependent 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 wellbores would have greater associated land requirements owing to the increased amount of equipment necessary to drill the well. More land would also be required to store drill cuttings and flowback water (JRC, 2013). The probable commercial scenarios identify the following:

- 2–6 ha (overground) covered by well pad during construction;
- 1–2 ha (overground) covered by well pad during operation; and
- 2–5 ha (overground) covered by roads, corridors, etc.

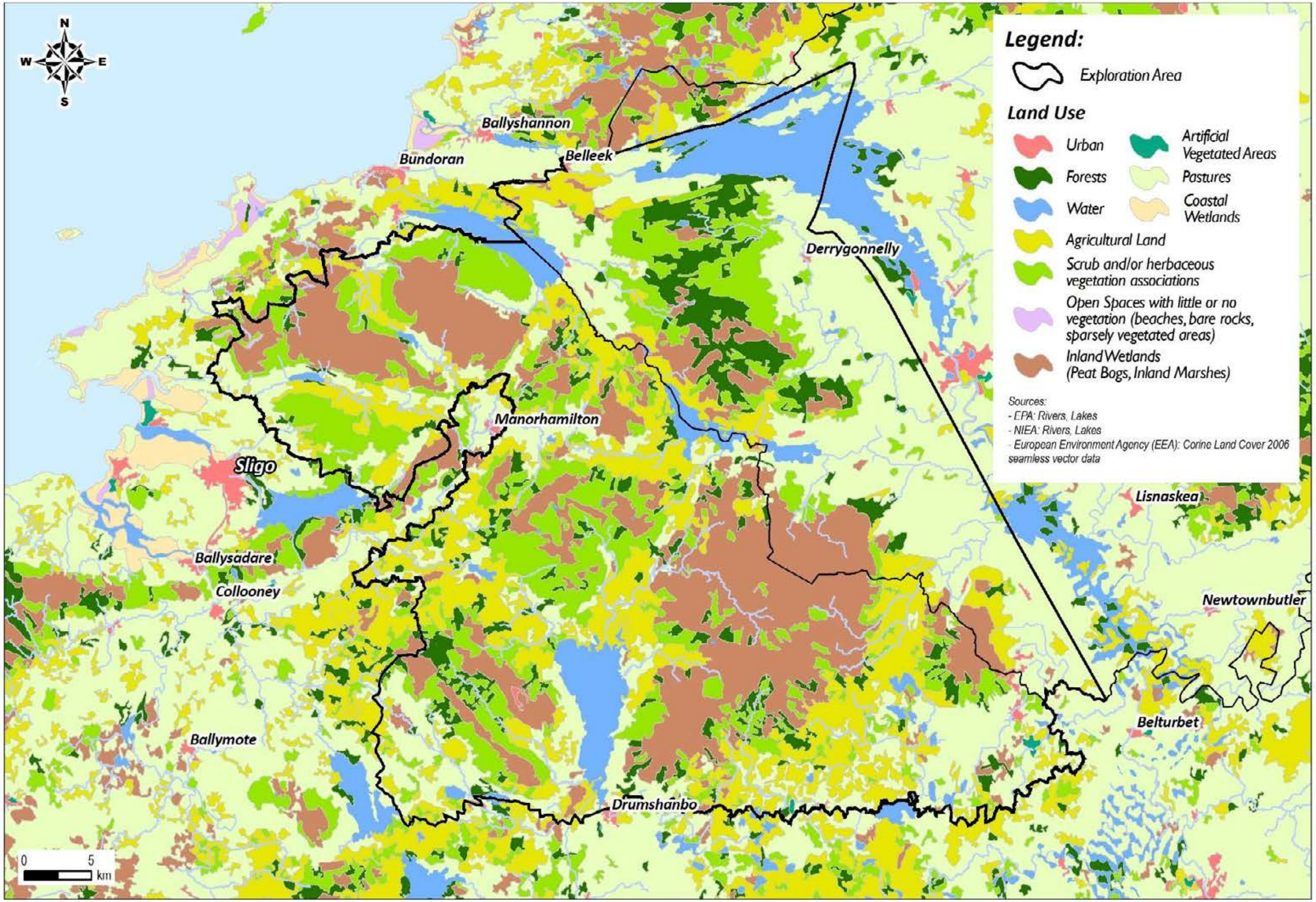

Figure 7.5. Land use in the NCB.

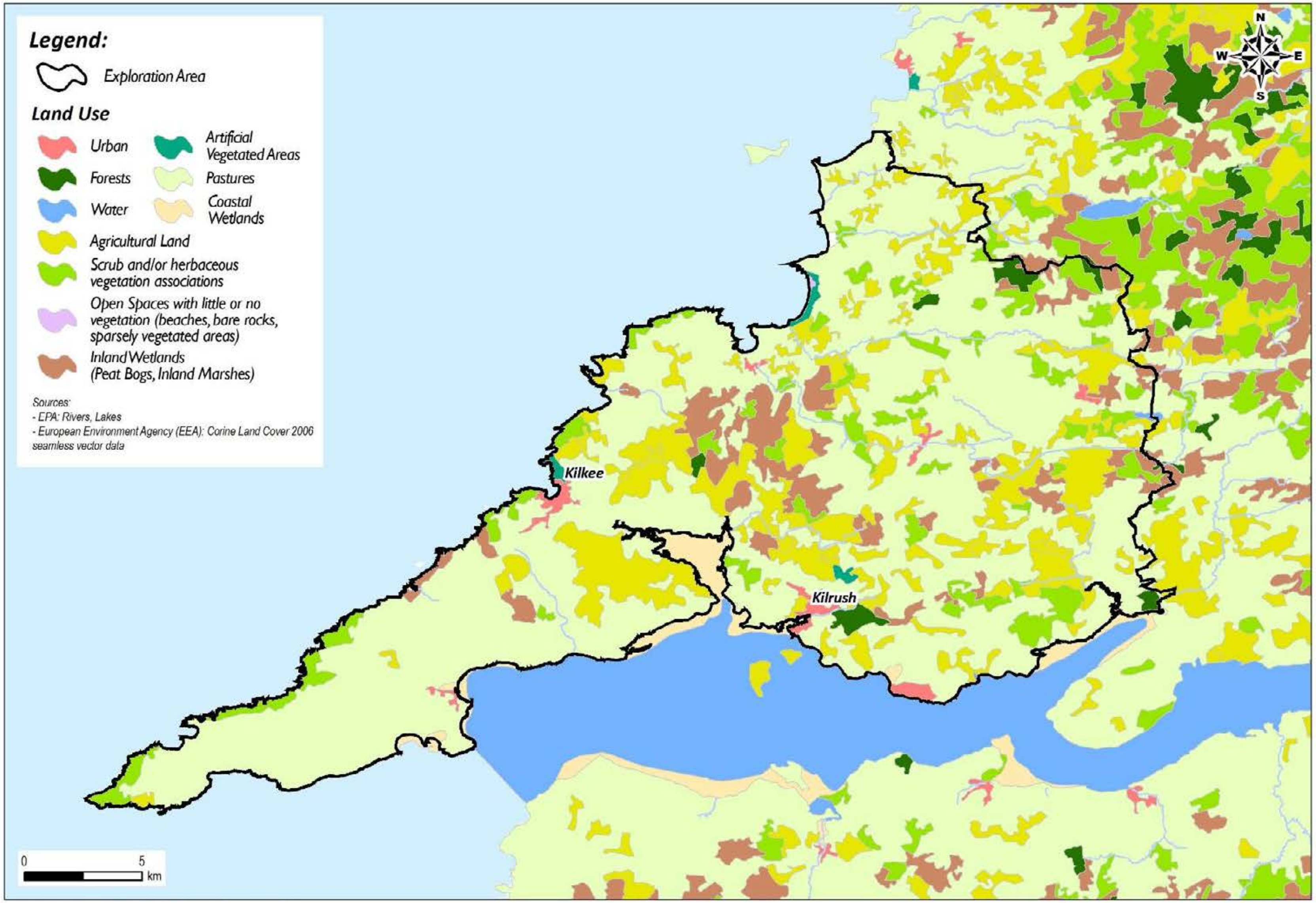

Figure 7.6. Land use in the CB.

Based on the spacing of horizontal wells, there would be a an upper limit of 50 well pads in the CB and 60 well pads in each of the three NCB lease areas, with 8–16 wells per pad. Should UGEE activities be permitted and proceed to development, it is considered unlikely that this upper limit would be reached. The potential phasing of any well pad construction and development is currently unknown.

Depending on site location, UGEE developments also have the potential to negatively impact on recreational and amenity sites, and this should also be taken into account during the site selection phase. Local amenity and recreation sites should be identified and assessed for potential impacts such as direct land take, noise impacts or traffic impacts and avoided where possible.

Potential impacts on agriculture relating to UGEE activities include the temporary reduction in farmable area, the management of excavated soils, stored and replaced on site, and the potential for damage to soils that remain on site, for example through tracking by heavy machinery.

The use of land for gas development could be viewed as incurring an “opportunity cost” owing to its unavailability for other, potentially more beneficial, uses, such as agriculture.

Ground settlement has not, however, been identified as a potential impact relating to UGEE activities in the available literature. DECC (2014c) considers that there is “minimal risk of subsidence resulting from the gas extraction process”. Even with the drilling of hundreds of thousands of wells in the USA, there is currently no documented evidence of subsidence resulting from shale gas extraction (DECC, 2014c,d). While subsidence is associated with mining activities owing to the removal of large amounts of material from the subsurface, UGEE operations remove an extremely small volume of material from the subsurface; therefore, the risk of subsidence can be considered negligible. Subsidence can also happen when sufficiently porous rock is compressed at sufficiently high pressures to begin to collapse the porosity, but the shale in the study areas is a low-porosity rock that is not easily compressed and, therefore, does not present a risk of collapsing and causing subsidence (DECC, 2014d).

Construction of pipelines or access roads may also have the potential for severance[15] issues on agricultural holdings. Issues related to potential contamination of water quality, water resources, air quality or noise are addressed in Chapters 4 and 5, and Sections 7.3.2, and 7.3.7, respectively.

The large number of truck movements associated with UGEE operations may also have the potential to adversely impact the road network through damage to road conditions and pavements, depending on the routes travelled.

It is judged that the residual impacts associated with land take at an individual site in the post-decommissioning phase would be comparable with many other industrial and commercial land uses, and are of no more than minor significance. However, it may not be possible to return the entire site to beneficial use following decommissioning, e.g. due to concerns regarding public safety. Consequently, it may not be possible to fully restore a site, or to return the land to its previous status, resulting in habitat loss (NYSDEC, 2015), which is a long-term impact, as described in previous sections. Over a wider area, this could result in a significant loss of land, and/or fragmentation of land area such as an amenity or recreational facility, valuable farmland, or valuable natural habitat. There is no evidence available to enable the likelihood of permanent effects on land use to be evaluated at this stage, until project-specific details are proposed or specified.

15 Severance refers to separation or partitions between people, between people and places, or between two places.

7.3.5.2 Potential mitigation measures

Mitigation measures relating to land take issues would be dependent on the details of any proposed activities, but may include:

- avoiding potential impacts through site selection or re-routing of pipelines;
- decompaction and deep ripping of disturbed areas prior to topsoil replacement;
- removing construction debris from the site;
- proper disposal of cuttings;
- removing spent drilling muds from sites;
- locating well pads and access roads along field edges and in non-agricultural areas (where practicable);
- removing excess subsoil and rock from the site; and
- strengthening works to roads and bridges.

7.3.6 Archaeological and cultural heritage

7.3.6.1 Potential impacts

Archaeological and cultural assessments deal with elements of the environment that are valued because of their age, history, beauty or tradition. Cultural heritage includes both tangible and intangible aspects. Some may be of national or international importance, whereas others may be of importance on a local or community level. While the characterisation of any impact associated with UGEE activities is highly dependent on the project-level specifics of a proposal, items with the potential to be adverse impacts and that must be considered in an assessment include:

- archaeological remains;
- architectural features;
- landscape and garden design;
- folklore and tradition;
- local battle or ambush sites;
- places of pilgrimage;
- holy or venerated wells;
- sites of local historical or folklore importance;
- established paths and trails;
- language and dialect; or
- settlements and placenames.

Figure 7.8 and Figure 7.9 show the sites requiring protection as listed on:

- the Record of Monuments and Places in Ireland;
- the Register of Historic Monuments in Ireland; and
- the Sites and Monuments Record in Northern Ireland.

Listed sites of archaeological interest are particularly extensive in the NCB. However, it should be noted that these records do not represent an exhaustive list of sites of importance, and other elements of archaeological or cultural heritage may not appear in any official listings or designations but, nonetheless, can be of great importance to the local community. The establishment of a comprehensive list of archaeological and cultural heritage elements is, therefore, an important element of a project-level assessment.

It should also be noted that preserving the context of items of cultural heritage, especially archaeological monuments, can be just as important as preserving the remains themselves.

Land take and site development have the capacity to impact on sites of archaeological or cultural heritage, depending on site location, and these elements should be considered in the site selection. Associated linear development for access roads or pipelines also has the potential to negatively impact sites of cultural heritage or archaeological interest. These activities will require excavation of the topsoil and subsoil, and items of archaeological interest may be encountered that could be lost without specific mitigation measures put in place to prevent that. This potential impact can be mitigated through archaeological surveys, site selection and recording and preserving any items or sites of archaeological interest. Any potential development should also be at a suitable distance from protected sites to ensure no negative impacts. As can be seen in Figure 7.8 and Figure 7.9, detailed survey, assessment and establishment of mitigation measures at a project level would be required, given the numbers and density of sites of importance. In addition, it is important to determine the local significance of items of cultural heritage.

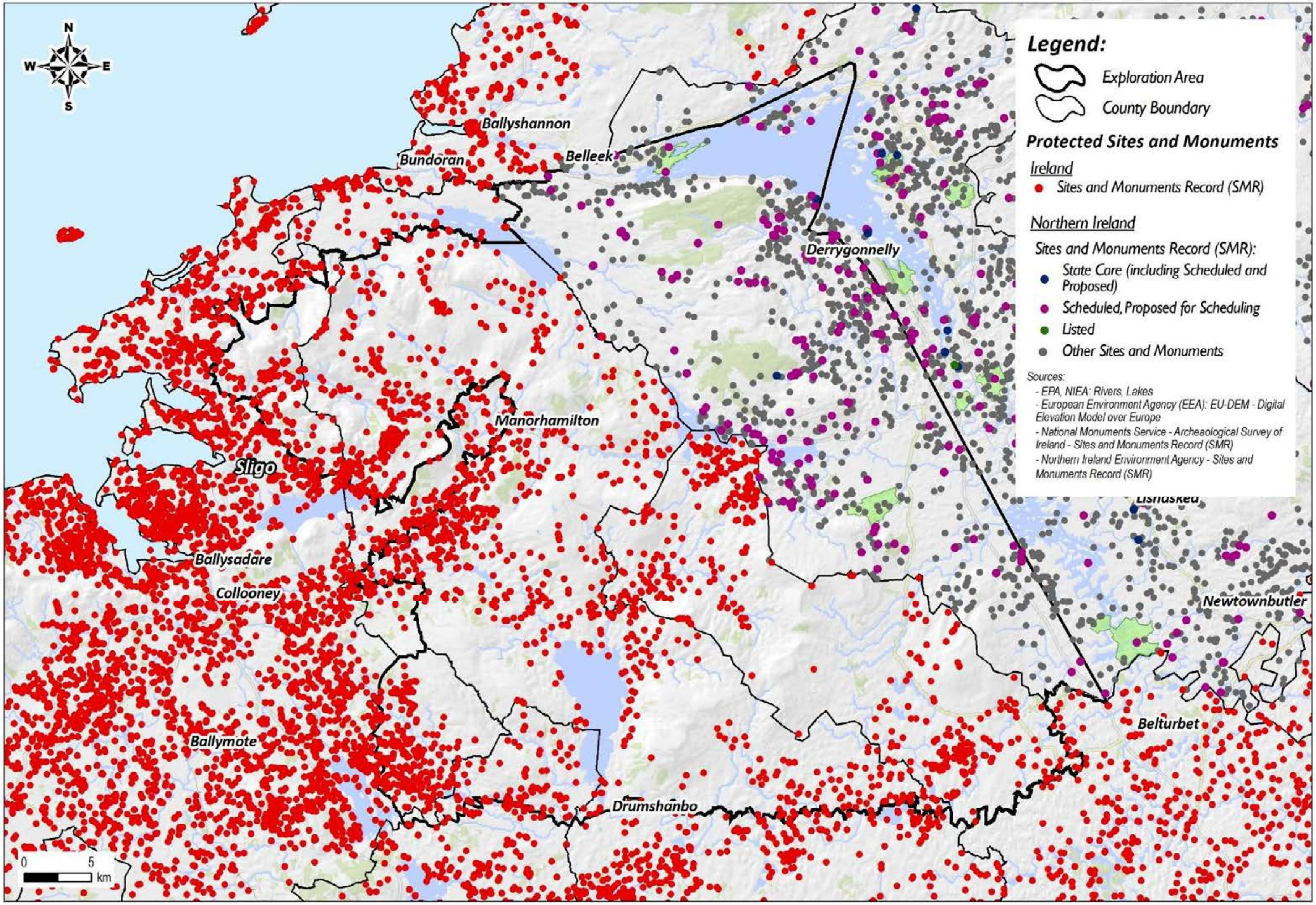

Figure 7.7. Sites of archaeological interest in the NCB.

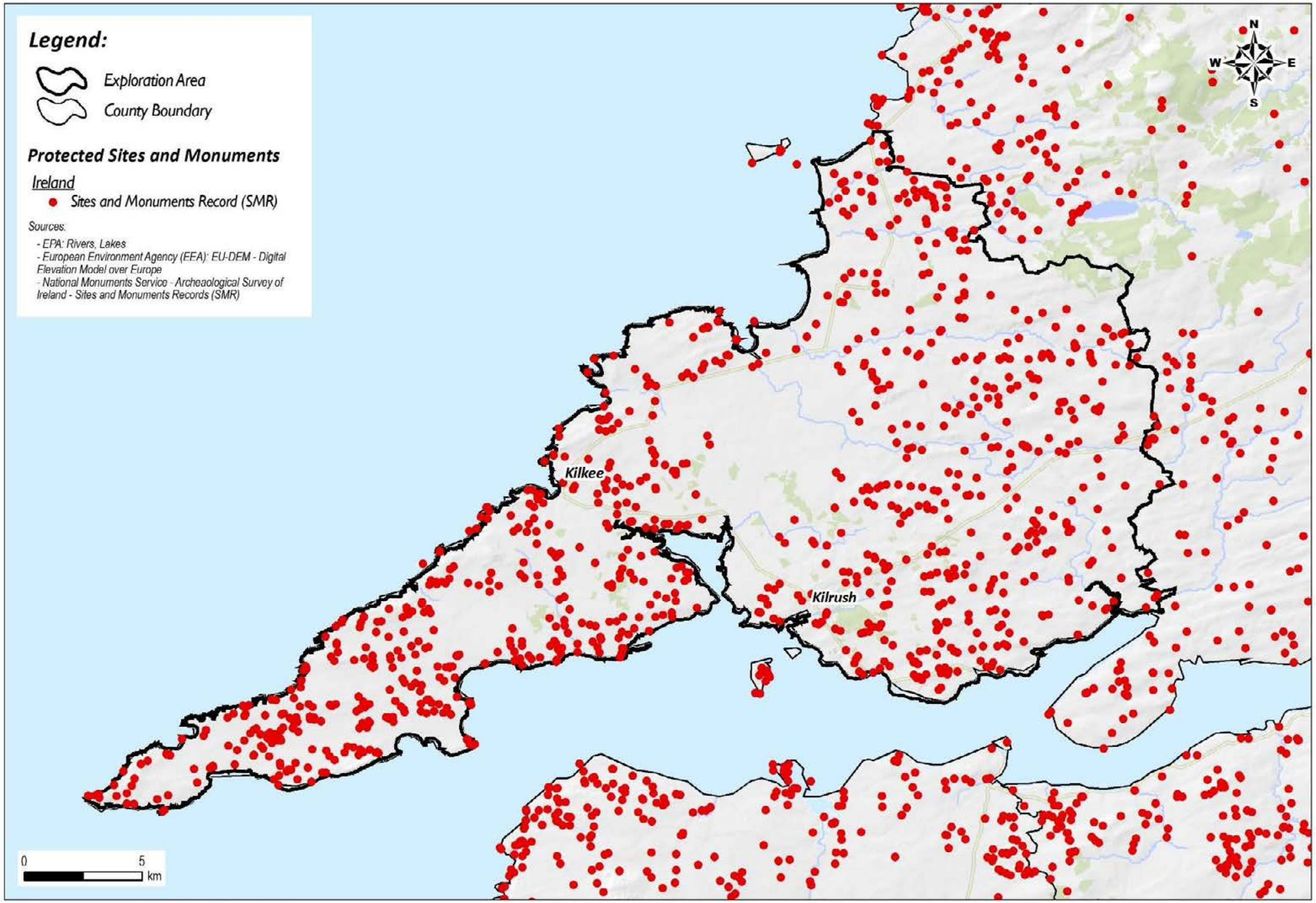

Figure 7.8. Sites of archaeological interest in the CB.

Changes in viewsheds or the character of the surrounding landscape have the potential to negatively impact on cultural heritage features, such as features of archaeological or architectural interest, structures and landmarks.

Should a proposed development result in a relatively large influx of workers in comparison with the local population, this may have an adverse impact on the cultural heritage of a community, such as local traditions.

7.3.6.2 Potential mitigation measures

While the determination of an appropriate suite of mitigation measures would be very dependent on project-specific details and potential impacts, it may include:

- carrying out a thorough programme of liaison with local people to establish locally important cultural heritage that may not be listed in national databases, literature or development plans;
- identifying the full range of sites of archaeological and cultural heritage sites and establishing site boundaries
- establishing appropriate exclusion zones around sites;
- avoiding potential impacts through site selection, or re-routing of pipelines or roads;
- implementing a programme of archaeological works to preserve by record any items of archaeological interest encountered; should the monitoring archaeologist identify any features of interest, a strip, map and record exercise[16] may be appropriate; and
- liaising with the National Monuments Service and complying with any relevant codes of practice.

7.3.7 Noise

7.3.7.1 Potential impacts

Noise has been defined as any sound that has the potential to cause disturbance, discomfort or psychological stress to a subject exposed to it, or any sound that has the potential to cause actual physiological harm to a subject exposed to it or physical damage to any structure exposed to it (EPA, 2006). Potential noise impact is subjective and is dependent on a wide range of factors, such as:

- the sensitivity of any individuals affected;
- the level, time of day and duration of emission;
- the nature of the source;
- the location of noise-sensitive receptors;
- the ambient and background noise level;
- the nature and character of the locality; and
- the presence of special acoustic characteristics such as tones and impulsive elements.

Noise can cause annoyance and disturbance to people at work or during leisure activities. It can also cause sleep disturbance and have a deleterious effect on general physical and mental well-being. People are not equally sensitive to noise, and there is a small but significant minority who are more sensitive than others. Noise can also negatively impact sensitive wildlife.

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16 Strip, map and sample is a method of archaeological excavation used to preserve archaeological remains by record in the face of a development threat. It involves machine stripping of an area, plotting observed features on to a site plan and then partially excavating those features (sampling).

Noise-sensitive receptors within the study areas include any dwelling house, hotel or hostel, health or educational establishment, place of worship or entertainment, or any other facility or area of high amenity that, for its proper enjoyment, requires the absence of noise at nuisance levels (EPA, 2006). Noise-sensitive receptors of all types occur across both study areas.

Stage 1 – Well pad identification and site preparation

Noise from excavation, earth moving, and plant and vehicle transport during site preparation has a potential impact on both residents and local wildlife, particularly in sensitive areas. The site preparation phase would typically last up to 4 weeks (AEA, 2012a) but is not considered to differ greatly in nature from other comparable large-scale construction activities.

The levels of noise are likely to be able to be controlled to avoid risks to health for members of the public (NYSDEC, 2015); however, site operatives and visitors may need additional controls or personal protective equipment to ensure that there are no adverse effects on health due to noise during this stage.

The issues associated with site preparation would be typical of the scale of impacts associated with any comparable construction activity and are, therefore, likely to be of minor significance for an individual development. The separation of well pads identified under the probable commercial scenarios results in over 3 km between multi-well pads, and this separation would result in significant attenuation for receptors potentially affected by multiple developments (AEA, 2012a). Therefore, there is a low risk of additional impacts due to cumulative effects.

Stage 2 – Well design and construction, hydraulic fracturing and well completion

Well drilling and the fracturing process itself are major sources of noise. Other sources include hydraulic fracturing site activities and road traffic (NYSDEC, 2015). As identified in section 2.3, on probable commercial scenarios, drilling is likely to continue for up to 75 days. The primary sources of noise associated with drilling include:

- Drill rigs are typically powered by diesel engines, which generate noise emissions primarily from the air intake, crankcase and exhaust. Noise levels vary depending on the engine speed and load.
- Air compressors are also typically powered by diesel engines and are likely to generate the highest level of noise over the course of drilling operations. Air compressors would be in operation virtually throughout the drilling of a well, but the actual number of operating compressors would vary.
- Tubular preparation and cleaning. This activity includes workers physically hammering the outside of the pipe to displace internal debris. This process, when carried out in the evening, seems to generate the most concern from adjacent landowners, despite the comparatively low level of decibels owing to the nature of the noise.
- The operation of elevators to move drill pipes and casings into and/or out of the wellbore. Elevator operation is not a constant activity and its duration is dependent on the depth of the wellbore. The decibel level is low.
- Drill pipe connections. As the drill bit penetrates the rock, the cuttings must be removed from the wellbore. Cuttings are removed by displacing pressurised air into the wellbore. To connect additional pipe to the drill string, the operator releases the air pressure. It is the release of pressure that creates a higher frequency noise.

As identified in the probable commercial scenarios, vertical drilling is likely to last 10–15 days per well, with the vertical and horizontal drilling process lasting between 35 and 75 days per well.

However, drilling is continuous for 24 hours per day over this time and is likely to be the greatest source of noise pollution (Broderick *et al.*, 2011).

If two wells are drilled simultaneously at a well pad, this could result in a doubling of the source of noise, with a resultant increase in the noise level experienced in the local area by up to 3 dBA. Because of the sensitivity of the human ear to sound, an increase of 3 dBA would be detectable, but it would not be perceived as a doubling of sound level.

Noise from well drilling could potentially affect residential amenity and wildlife, particularly in sensitive areas. Potential impacts on agricultural and domestic animals are further discussed in section 7.3.11.1. The levels of noise expected, when controlled, are not likely to pose risks to health for members of the public (NYSDEC, 2015). Site operatives and visitors may need additional controls to ensure that there are no adverse effects on health due to noise during this stage.

Effective drilling noise abatement controls are well established in the oil and gas industry (NYSDEC, 2015), and it is expected that noise controls would be applied during drilling, reducing the resultant impacts. Consequently, this impact is likely to be of minor significance (AEA, 2012a).

If a number of well pads are developed in a given area close to sensitive residential areas or habitats, the potential for adverse effects would increase, owing to the sustained increase in noise levels for an extended period. While the density of well pads identified in the probable commercial scenarios would allow significant attenuation of cumulative noise impacts, cumulative impacts resulting from drilling would result in a greater impact, which is likely to be of moderate significance (AEA, 2012a).

The most significant source of noise is likely to be the fracturing process itself and relates to the pumping of proppant under high pressure and the associated pumping trucks. For example, night-time sound levels in a quiet rural area may be as low as 30 dBA, while, at a distance of 75 m, the maximum calculated composite noise level for construction equipment is 70 dBA and for horizontal drilling it is 64 dBA. The hydraulic fracturing process, however, can produce noise levels of 90 dBA at that distance (NYSDEC, 2015). This is calculated on the basis that up to 20 diesel pumper trucks are required to operate simultaneously to inject the required volume of water to achieve the necessary pressure. The operation takes place over a period of several days for each well and would be repeated at a site for multiple wells and pads. This noise has the potential to temporarily disrupt and disturb local residents and wildlife, particularly in sensitive areas.

Noise from the well completion process could arise from on-site plant and machinery, but it is likely to be lower than at other stages in the gas extraction process and of limited duration (NYSDEC, 2015).

Noise generation during the flaring process can be minimised using appropriate flare design, and noise from the associated plant and equipment would be expected to have imperceptible effects on public health, provided that established controls used in the oil and gas industry were applied (AEA, 2012a).

Noise from associated pipeline construction could affect residential amenity and wildlife, particularly in sensitive areas.

While various magnitudes of noise impact have been reported in the published literature, e.g. “moderate” to “high” (AEA, 2012a); it should be noted that determination of the magnitude of the impacts in the study areas would be dependent on any proposed project details, such as the location of the sites, numbers of well pads, duration of activities such as drilling, location and types of sensitive receptors, existing noise levels, and the application of appropriate mitigation measures.

Stage 3 – well production (gas extraction)

During production, there is expected to be minimal ongoing noise from wellhead installations (NYSDEC, 2015), although no specific information is available on noise levels (AEA, 2012a). Sources of noise associated with this stage are likely to be gas compressor stations and treatment facilities that may be needed to process the extracted gas (AEA, 2012a). Employee traffic would also generate additional noise. Noise impacts at this stage are expected to be minor.

Stage 4 – Project cessation, well closure and decommissioning

Following project cessation, well closure and decommissioning, there would be no residual noise impacts, except for the occasional traffic arising from monitoring and maintenance.

7.3.7.2 Potential mitigation measures

Noise impacts relating to a potential development would be dependent on site location and the scale of the development. A full characterisation of noise impacts would be required as part of any EIA and would include site surveys and noise modelling, which would in turn determine the most appropriate mitigation measures. Daytime and night-time noise levels should also be specified within any conditions associated with permission for UGEE activities and monitored during works.

Determination of appropriate mitigation measures should follow a three-step process. The first step is the assessment of any existing or planned noise sources and their relative contribution to ambient levels. The next step is the establishment of target noise levels for the particular situation or source to allow estimation of the degree of noise reduction required. Having established the noise reduction required, the next stage is the application of appropriate control measures. The final solution for a noise problem may involve more than one noise control measure (e.g. absorption as well as screening, or isolation as well as damping).

The most effective method is to increase the distance between the source and the receptor; the greater the distance, the lower the noise impact, as topography and vegetation between the pad and receptor can reduce perceived noise levels. UGEE activities are likely to result in between 455 and 1230 truck movements per fracture programme, as described in section 2.3 on probable commercial scenarios. Therefore, where appropriate, access roads should also be located as far as practicable from occupied structures or sensitive receptors. This would serve to protect noise receptors from noise impacts associated with trucking and road construction that could conflict with their use of their property. Traffic noise mitigation measures may include modification of speed limits and restricting or prohibiting truck traffic on certain roads. Restricting truck use on a given roadway would reduce noise levels for nearby receptors, as trucks are louder than cars. However, care should be taken that displacing truck traffic from one roadway to another does not simply shift noise impacts from one area to another. While reducing speeds may reduce noise levels, a reduction of at least 16 km/hour is needed to achieve a noticeable difference in noise level.

Timing also plays a key role in mitigating noise impacts (EPA, 2006). The same noise will be perceived to have a more significant impact at night as opposed to during the day. Scheduling more significant noise-generating operations during daylight hours may make them more tolerable than they would be in the evening hours.

In addition to the use of standard noise mitigation techniques such as process alterations, restriction of hours, modifying site layout and the installation of control equipment (EPA, 2006), site-specific measures that may be drawn on to mitigate the impacts of UGEE activities include (NYSDEC, 2015):

- directing noise-generating equipment away from sensitive receptors;
- installing temporary sound barriers of appropriate heights, based on noise modelling, around the edge of the drilling location, between a noise-generating source and any sensitive surroundings;

- placing tanks, trailers, topsoil stockpiles or sound barriers between the noise sources and receptors;
- using noise-reduction equipment such as mufflers, exhaust manifolds, or other high-grade baffling;
- limiting noisier activities such as cementing operations or drill pipe cleaning (which involves hammering) to certain daytime hours;
- placing air relief lines and installing baffles or mufflers on lines;
- using higher or larger diameter stacks for flare-testing operations;
- placing redundant permanent ignition devices at the terminus of the flow line to minimise noise arising from flare re-ignition;
- liaising with local residents and potential receptors to provide advance notification of the drilling schedules;
- placing conditions on air rotary drilling discharge pipe noise, including:
  - orienting high-pressure discharge pipes away from noise receptors;
  - having the air connection blowdown manifolded into the flow line to provide a larger diameter aperture at the discharge point;
  - shrouding the discharge point by sliding open-ended pieces of larger diameter pipe over them; or
  - re-routing piping so that unusually large compressed air releases (such as connection blowdown on air drilling) would be routed into the larger diameter pit flow line to muffle the noise of any release;
- using rubber hammer covers when clearing drill pipe;
- scheduling drilling operations to avoid simultaneous effects of multiple rigs on the same receptors;
- limiting hydraulic fracturing operations to a single well at a time; and
- using electric pumps.

7.3.8 Traffic

7.3.8.1 Potential impacts

UGEE activities result in increased traffic levels of both light vehicles (employee car trips) and, in particular, the heavy goods vehicles associated with site activities. As identified in the probable commercial scenarios, the likely number of truck movements is between 455 and1230 per well in total, with a breakdown as follows:

- 180–580 truck movements needed to manage transport of fresh water (based on some water being available on site);
- 1–5 truck movements for transport of additives;
- 50–160 truck movements for transport of proppant;
- 80–150 truck movements to manage flowback;
- 45–135 truck movements for site construction; and
- 100–200 truck movements during the drilling stage.

Stage 1 – Well pad identification and site preparation

It is judged that the number of vehicle movements associated with site preparation would be a small proportion of the number of vehicles required to create emissions that would cause significant environmental or health impacts (AEA, 2012a). On this basis, it is likely to represent a minor impact. The potential impacts include an increase in traffic-related air emissions, noise and visual impact, as well as effects on the transport system such as damage to the infrastructure, congestion and effects on road safety during the period of site preparation.

If a number of well pads are simultaneously developed in a given area, the potential for adverse effects would increase, as there would potentially be a sustained increase in the number of goods vehicle movements in the local area. The most sensitive situation is likely to be a route located through a town centre leading to a shale gas development area. A single route could plausibly be needed for the development of a large number of well pads, depending on the scale of development proposed. This could result in a combination of increased numbers of vehicles, or an extension of the period of site development to several years. This is considered likely to present a minor potential impact in view of the longer development period. Any impact is likely to be more severe on unsuitable roads and for longer haulage distances (AEA, 2012a).

Stage 2 – Well design and construction, hydraulic fracturing and well completion

Impacts on local traffic for simultaneous construction of multiple pads in a locality are, clearly, likely to be significant, particularly in a densely populated area. The impacts include air emissions, noise and visual impact, as well as effects on the transport system such as damage to the infrastructure, congestion and effects on road safety during the period of site preparation. If a number of well pads are developed in a given area, the potential for adverse effects would increase, as there would potentially be a sustained increase in numbers of goods vehicle movements in the local area.

Potential impacts associated with truck movements during this stage of UGEE activities include:

- increased traffic on public roadways, which could affect traffic flows and congestion;
- impacts on road safety;
- accelerated degradation of roads, bridges and other infrastructure, which could lead to reduced road quality and increased costs associated with the maintenance of roads not designed to sustain the level of traffic experienced;
- risks of spillages and accidents involving hazardous materials;
- increased traffic-related air emissions with the potential for localised impacts on air quality; and
- potential community severance (a reduction in community interaction as a result of high volumes of traffic), potentially affecting residents. quality of life.

The impacts from traffic associated with an individual site have been estimated to be likely to be “minor” in view of the short duration (AEA, 2015; Cuadrilla, 2014b), although it would potentially be noticeable by local residents. However, according to AEA (2012a), the impact of traffic associated with more widespread development, including the risks posed by traffic accidents, may be of moderate significance. As with other potential impacts, classifying the magnitude of impacts would depend on the details of individual project proposals.

Stage 4 – Project cessation, well closure and decommissioning

While some truck movements are likely to be associated with the process of reinstating original site conditions and appropriate vegetation, this is likely to be minimal and not expected to pose any significant impacts. Following site closure, traffic movements would be limited to those associated with ongoing environmental monitoring and impacts are, therefore, anticipated to be imperceptible.

7.3.8.2 Mitigation measures

Owing to the nature of the analysis possible at this stage and the lack of knowledge on specific routes that would experience increased numbers of truck movements, it is not possible at this time to identify specific operational and safety impacts, nor is it possible to identify operational or safety mitigation strategies for specific locations. However, given the nature of both study areas, it is likely that traffic issues would require careful management, particularly with respect to the increased numbers of truck movements on secondary and local roads. The use of modes of transport such as rail and waterways has the potential to minimise truck movements and traffic impact and should be considered.

A transport and traffic management plan would be required as part of any permit application. The transport plan would include:

- details of materials being carried such as chemical additives, restricted materials, water;
- the number of anticipated truck trips to be generated by the proposed activity and the scheduling of those activities;
- the times of day when it is proposed that trucks will be operating;
- the proposed routes for such truck trips;
- the locations of, and access to and from, appropriate parking and staging areas;
- the ability of the roadways located on such routes to accommodate such truck traffic;
- any proposals to minimise road traffic impacts;
- any local road use agreements;
- reports on the condition of roads and bridges that are expected to be used by trucks directly and indirectly associated with the drilling operation.

Mitigation measures to be considered as part of a traffic management plan, as appropriate, include:

- route selection to maximise efficient driving and public safety;
- road safety assessment and, following agreement, implementation of safety measures such as signage and increasing sight distances;
- avoiding peak traffic hours, school drop-off and pick-up hours in the vicinity of schools and community events and implementing overnight quiet periods;
- upgrades and improvements to roads that would be travelled frequently to transport water to and from many different well sites;
- advance public notice of any necessary detours or road closures;
- adequate off-road parking and delivery areas at the site to avoid lane or road blockage;
- providing frequent passing places (turnouts) on narrow roads;
- limiting truck weight, axle loading and weight; and
- Specifying that the operator would pay for the addition of traffic control devices or trained traffic control agents where required.

7.3.9 Human beings and community character

7.3.9.1 Potential impacts

Potential community impacts related to UGEE activities are likely to depend very much on the level of development. Experiences in Pennsylvania and West Virginia, USA, have shown that intensive and widespread UGEE activities can significantly impact local communities, in both the long and short term (NYSDEC, 2015). However, any development in the study areas is likely to take place on a much smaller scale, with an associated much smaller potential impact on community character and facilities.

How changes within the community would be viewed can be subjective, varies from individual to individual, and is dependent on the scale of the development. Therefore, this section can only highlight potential impacts, as opposed to classifying the scale of the impact or whether it is objectively positive or negative. Community character is also closely linked to cultural heritage, and this is addressed in section 7.3.6.

Potential impacts would also be dependent on the speed at which UGEE activities occur. Slower, more moderate growth of the industry is likely to result in less acute impacts than rapid growth over a shorter time. Potential impacts should also be considered in the context of the policies, plans and objectives specified in the various county development plans and local area plans.

While communities naturally change in response to social, demographic and economic conditions, these are normally gradual and a community has time to adapt and accommodate external pressures. When communities experience abrupt or dramatic changes, they are typically experienced as adverse.

Depending on the scale of any proposed development, the size and structure of local economies could be influenced by development of the UGEE industry. Based on the spacing of horizontal wells, there would be an upper limit of 50 well pads in the CB and 60 well pads in each of the NCB lease areas, with eight to 16 wells per pad. Should UGEE activities be permitted and proceed to development, it is considered unlikely that this upper limit will be reached. The potential phasing of any well pad construction and development is currently unknown. The extent of impacts would be determined by the extent and density of development. Local communities within the study areas that may have been historically stable or declining may experience a degree of growth or temporary increase with transient workers, with an associated increase in the demand on local services. Potential differences in income or lifestyle may further complicate impacts on local communities. New employment sectors, such as suppliers to the UGEE sector, may expand. Employment opportunities may then increase in the communities, with an associated potential increase in local population. New residents would be of working age (employees) or younger (their dependents). In some areas, the housing market may experience an increase in house prices or rents if there is not sufficient supply to meet the increased demand.

There is also the potential for disturbance of local residents, e.g. relating to protest activities.

As discussed previously in this chapter, residents may also experience an increase in traffic on certain roads, increased noise levels and temporary impacts on viewsheds.

7.3.9.2 Mitigation measures

Local and regional planning documents are important in defining and protecting a community's character and are the principal way of managing and guiding positive change and mitigating potential negative impacts within a community.

Care should be taken during site selection to avoid where possible any sites with potential impacts on community amenities such as walking and cycling routes, playing fields and recreational areas.

Additional mitigation measures relating to potential impacts on communities arising from air quality, noise, landscape and traffic impacts are specified in sections 7.3.2, 7.3.7, 7.3.4 and 7.3.8, respectively.

7.3.10 Human health

7.3.10.1 Potential impacts

The following aspects of UGEE development have been considered in terms of any potential human health impacts:

- noise;
- air quality;
- water (surface and groundwater);
- community facilities;
- physical activity and recreational activities; and
- perception effects.

Potential impacts relating to:

- noise are addressed in section 7.3.7;
- air quality are addressed in section 7.3.2;
- water quality are addressed in Chapter 4; and
- community character are addressed in section 7.3.9.

In the event that any potential developments are located adjacent to existing playgrounds or sporting facilities such as pitches, which residents may use for exercise and as part of a healthy lifestyle, there may be a reduction in these activities. An increase in traffic may also deter residents from cycling or walking the roads surrounding the site. Appropriate site location and development, as described in section 7.3.9.2, can be used to mitigate these potential impacts.

Impacts of a development on public health can be related to both the physical emissions of an activity, such as emissions to air or water, but also to the perceptions people have of a development. Risk perception of environmental hazards can cause anxiety, which has a negative impact on public health that is related to how people believe they may be affected by it rather than the likelihood of their exposure to it (Stewart *et al.*, 2010).

A public consultation programme was undertaken by the EPA, NIEA and DCENR on the proposed Terms of Reference for a Programme of Research on Environmental Impacts of Unconventional Gas Exploration and Extraction. Concerns raised during this programme and concerns commonly raised in relation to UGEE activities include:

- emissions to air and airborne contaminants;
- emissions to water and waterborne contaminants;
- exposure to radioactive materials;
- exposure to flammable gases;
- exposure to potentially hazardous materials;
- risks from induced seismicity;
- road safety and traffic concerns; and
- potential impacts on domestic and farm animal health and fish.

To address these concerns, thereby reducing potential health impacts relating to anxiety over impacts, a programme of public engagement, information and consultation should be undertaken involving true two-way communication, as described in section 7.3.10.2. This is further addressed in Project C of the UGEE JRP, under separate cover.

7.3.10.2 Mitigation measures

Good communication and public involvement from an early stage is essential for generating trust. Distrust of authorities is commonly reported in the context of potential environmental impacts of proposed developments (Stewart *et al.*, 2010). Distrust may be an indicator of a lack of common understanding and debates by professionals about whether or not public concerns were justified, or whether or not any hazard actually existed, and the magnitude thereof, can indicate a lack of understanding of the effect of anxiety on public well-being.

Risk communication is not simply a one-way flow from sources of information about the risks posed by environmental hazards to health (scientists, agencies, interest groups, eyewitnesses) through transmitters who amplify the message (media, institutions, interest groups, opinion leaders) to receivers who accept the information (general public, affected people, group members, those exposed), but a two-way exchange, or even dialogue, between all parties (Stewart *et al.*, 2010).

It should be acknowledged that public reactions to risk often have a rationale of their own and that “expert” and “lay” perspectives should inform each other as part of a necessary two-way process (WHO, 2001). This process should include:

- information campaigns;
- adequate and appropriate (two-way) communication activities;
- providing evidence on known risks;
- making sure that information provided is accurate, consistent and provided in clear non-technical language; and
- ongoing programmes to monitor environmental factors that may be perceived to be a health risk.

This is further addressed in Project C of the UGEE JRP, under separate cover.

7.3.11 Agricultural and domestic animals

7.3.11.1 Potential impacts

Potential impacts on agricultural activities and animals relate to the following:

- water depletion;
- water contamination and surface water quality;
- land use;
- degradation of soils;
- public perception; and
- noise.

Issues relating to water quality and water resources and are addressed in Chapters 4 and 5, and air quality in section 7.3.2.

Impacts on land use could potentially occur during the drilling and development phase if there are conflicts with existing or planned agricultural activities. Farmers may be affected by loss of available grazing or crop land, the potential for the introduction of invasive plants that could affect the availability of livestock forage, and possible increases in livestock–vehicle collisions when it is necessary to move livestock across access roads.

Potential impacts to soils during the drilling and development phase would occur as a result of the removal of vegetation, mixing of soil horizons, soil compaction, increased susceptibility of soils to wind and water erosion, contamination of soils with petroleum products, and disturbance of biological soil crusts. Impacts on soils would be proportionate to the amount of disturbance and the mitigation measures in place, but they could potentially reduce agricultural productivity if subsequently returned to agricultural use.

Noise may be considered to be a stressor if it occurs where farm or domestic animals are and if it affects their behaviour and productivity or induces physiological changes, as shown by various studies. Mammals in particular appear to react to noise at sound levels greater than 90 dB and the threshold above which a behavioural response may be expected in animals is 85–90 dB (Manci, 1988).

Scientific sources indicate that noise in farm animal environments is detrimental to animal health. Noise directly affects reproductive physiology or energy consumption (Brouček, 2014). Noise may also have indirect effects on population dynamics through changes in habitat use, courtship and mating, reproduction and parental care (Rabin *et al.*, 2003). Noise, such as the sound of a truck horn, was shown to increase the heart rates of free-ranging cattle, while cattle habituated to the sounds and sights of cars and trucks will readily graze along highways and seldom react (Grandin, 1997). Sheep appear to adapt to increased noise levels, particularly when these are relatively continuous, such as the noise of transport vehicles at around 60–90 dB, although they may show an initial rise in heart rate (Brouček, 2014). However, many studies indicate that sudden, novel sounds seem to affect animal behaviour more than continuous high levels of noise that can be predicted by the animals (Grandin, 1997). General noise at 105 dB, but not at 80 dB, reduced milk yield, rate of milk release and feed intake in dairy cows (Head *et al.,* 1993). Many studies on domestic animals suggest that many species appear to adjust to some forms of sound disturbance.

The hydraulic fracturing process is likely to be the loudest site activity and can produce noise levels of 90 dBA at a distance of 75 m (NYSDEC, 2015); however, noise impacts from this stage, while dependent on the location of the sites, number of well pads, types and numbers of sensitive receptors and the application of appropriate mitigation measures, is still likely to be of "moderate" impact, or "significant" for receptors such as farm environments within 300 m of activities.

Although there are currently few published reports on impacts on farm animals from UGEE activities, Finkel *et al.* (2013) found that "Milk production and milk cows decreased in most counties since 1996, with larger decreases occurring from 2007 through 2011 (when unconventional drilling increased substantially) in five counties with the most wells drilled compared to six adjacent counties with fewer than 100 wells drilled." They caution that this is a descriptive study that has not established causation.

Bamberger and Oswald (2012) presented information based on based on 24 interviews with animal owners in six states and thus provides anecdotal evidence with respect to adverse impacts on farm animals relating primarily to accidents and spillages. The accidental release of fracking fluids into a pasture adjacent to a drilling operation resulted in the death of 17 cows in 2010. Reproductive problems in goats and cows were also reported, following a defective valve resulting in hundreds of barrels of fracturing fluids leaking into a pasture, and the accidental release of drilling chemicals into a pasture following a blowout, respectively.

It is acknowledged that the agri-food sector is currently on a path of sustainable growth, based on emission-efficient food production and high animal welfare, environmental and agronomic standards.

Concerns have been raised that allowing UGEE activities may negatively impact on the perception of the island of Ireland as a green, unpolluted country and, thereby, have a knock-on effect on the agri-food industry, negatively impacting commercial interests both at home and abroad.

7.3.11.2 Mitigation measures

Water quality-related mitigation measures are discussed in Chapter 4.

Mitigation measures relating to the protection of soils are discussed in section 7.3.5.2.

Public perception measures are discussed in section 7.3.10.2.

Noise mitigation measures are discussed in section 7.3.7.2.

Other mitigation measures to minimise the potential impacts on agricultural and domestic animals include:

- sensitive location of well pads and the avoidance of land use conflicts;
- liaison with local farmers to minimise potential impacts on agriculture;
- proper disposal of cuttings;
- prohibition and removal of spent drilling muds from productive agricultural fields;
- locating well pads and access roads along field edges and in non-agricultural areas (where practicable);
- fencing the site when drilling is located in or adjacent to productive pasture areas to prevent access by animals; and
- establishing safeguards to prevent leaks and spillages.

7.3.12 Interaction between impacts

The EIA Directive and its transposing Statutory Instruments requires that an EIA be carried out where a project has the potential to significantly impact the environment. This section considers potential impacts on:

- flora, fauna and biodiversity;
- air quality;
- greenhouse gas emissions;
- landscape and visual amenity;
- noise;
- land take;
- archaeology and cultural heritage;
- traffic;
- human beings and community character;
- agricultural and domestic animals.

In addition, it is required that the detailed inter-relationship between these factors must be taken into account as part of the EIA process. Table 7.3 highlights the areas where there may be potential interactions between impacts. Consideration of these potential interactions is necessary for four main reasons:

1. it is required by legislation;
2. it contributes towards sustainable development;
3. it is good practice; and
4. it aids the decision-making process.

Table 7.4 describes the main mechanisms for interaction between the various impact areas summarised in Table 7.3.

Table 7.3. Matrix of potential environmental interactions

	Flora, fauna and biodiversity	Air quality	Greenhouse gas emissions	Landscape and visual amenity	Material Assets and land use	Archaeology and cultural heritage	Noise	Traffic	Human beings and community Character	Agricultural and domestic animals	Soils and hydrogeology	Water quality
Flora, fauna and biodiversity		◈		◈	◈		◈	◈			◈	◈
Air quality	◈		◈		◈			◈	◈			
Greenhouse gas emissions		◈										
Landscape and visual	◈				◈	◈			◈			
Material assets and land use	◈			◈		◈	◈	◈	◈		◈	◈
Archaeology and cultural heritage					◈				◈			
Noise	◈				◈			◈	◈	◈		
Traffic	◈				◈		◈		◈			
Humans and community character		◈		◈	◈	◈	◈	◈		◈		◈
Agricultural and domestic animals							◈		◈		◈	◈
Soils and hydrogeology	◈				◈					◈		
Water quality	◈				◈				◈	◈		

Table 7.4. Summary of potential interactions

Factor	Interaction with	Interaction
Flora, fauna and biodiversity	Air quality	High levels of NO_x can have a negative effect on vegetation, including leaf damage and reduced growth. It can make vegetation more susceptible to disease and frost damage
	Landscape and visual amenity	Vegetation is an important aspect with respect to providing wildlife habitats and corridors. Removal of or changes to vegetation or planting may impact existing flora and fauna
	Land take	Land take or changes in land usage may impact existing habitats and species, depending on mitigation measures
	Noise	Any increase in noise levels has the potential to impact on noise-sensitive species in the vicinity of the site
	Traffic	Noise or land take related to increased traffic or the construction of access roads may impact upon existing habitats and species, depending on mitigation measures
	Soils and hydrogeology	Any deterioration in soils or changes in hydrogeology may impact upon existing habitats and species
	Water quality	Any deterioration in water quality may impact upon water-dependent species and habitats
Air quality	Greenhouse gases	Ambient air quality and GHG emissions are interdependent
	Material assets and land use	Poor air quality may potentially affect land use such as residential and amenity uses
	Traffic	Ambient air quality may be impacted by increases in traffic
	Humans and community character	Potential deterioration in air quality may impact upon human health, depending on magnitude and mitigation measures
Landscape and visual amenity	Land take	Land take and changes in land use may result in landscape and visual impacts, depending on mitigation measures.
	Archaeology and cultural heritage	Impact on landscape and visual amenity can negatively impact features of archaeological and cultural heritage importance
	Humans and community character	Any proposed UGEE activities have the potential to impact on the landscape and visual resources perceived by humans, depending on mitigation measures
Material assets and land use	Archaeology and cultural heritage	Land take and changes in land use can negatively impact features of archaeological and cultural heritage importance.
	Noise	Noise can adversely impact land use such as residential and amenity uses
	Traffic	Increased levels of traffic, in particular heavy goods vehicles, can negatively impact or degrade road integrity and surfaces
	Humans and community character	Land take and changes in land use may result in impacts on community land use, recreation and amenity, depending on mitigation measures
	Soils and hydrogeology	Any negative impact on the quality and drainage of soils represents a negative impact in terms of natural material assets
	Water quality	Any negative impact on water quality represents a negative impact in terms of natural material assets
Noise	Traffic	Changing traffic patterns or increased traffic may result in noise impacts
	Humans & community character	Noise generated by UGEE activities has the potential to impact on local people, depending on noise levels and mitigation measures

Factor	Interaction with	Interaction
	Agricultural and domestic animals	Noise generated by UGEE activities has the potential to impact on livestock, depending on noise levels and mitigation measures
Traffic	Humans and community character	Changes in traffic patterns or an increase in traffic levels may impact local road users
	Farm and domestic animals	Traffic-related noise generated by UGEE activities has the potential to impact on livestock, depending on noise levels and mitigation measures
Humans and community character	Agricultural and domestic animals	Local animal owners may be impacted, if livestock or domestic animals are impacted by UGEE activities
	Water quality	Human beings have may be impacted in the event that recreational or amenity waters are negatively impacted
Farm and domestic animals	Soils and hydrogeology	Any deterioration in soils and associated grazing, or changes in water resources, have the potential to negatively impact on livestock

8 Life Cycle Assessment (Task 5)

8.1 Background

This chapter addresses Task 5 of Project B, which requires that a comprehensive assessment of the cumulative environmental impact of UGEE projects and operations be conducted, supported by a literature review and experience from other jurisdictions and compared with similar published assessments of other energy sources.

Life cycle assessment (LCA) is a multi-step procedure for measuring the environmental footprint of materials, products and services over their entire lifetime, i.e. from “cradle to grave”. The classic LCA consistent with ISO 14040:2006 consists of four main phases:

1. *Definition of the goal and scope*. In this step, the process to be assessed is defined, a functional basis for comparison is chosen and the required level of detail is defined.
2. *Inventory analysis*. The life cycle inventory is the data collection portion of LCA. It consists of detailed tracking of all the flows in and out of the product system, including raw resources or materials, energy by type, water, and emissions to air, water and land by specific substance. This kind of analysis can be extremely complex and may involve dozens of individual unit processes in a supply chain (e.g. the extraction of raw resources, various primary and secondary production processes, transport, etc.) as well as hundreds of tracked substances.
3. *Impact analysis*. Life cycle impact assessment (LCIA) converts “inventoried” flows into simpler indicators to ensure that any comparison between processes or studies is “apples with apples’. Themes covered in most LCIA studies are the greenhouse effect (or climate change), natural resource depletion, stratospheric ozone depletion, acidification, photochemical ozone creation, eutrophication, human toxicity and aquatic toxicity. These methods aim to simplify the complexity of hundreds of flows into a few environmental areas of interest.
4. *Interpretation*. The results are then reported in the most informative way possible.

The overall goal of an LCA is to compare the full range of environmental impacts in order to improve development and operations, support policy and regulatory needs and provide a basis for decisions. The process is naturally iterative, as the quality and completeness of information and its plausibility is constantly being tested.

Existing LCA information and published assessments focusing on the examination and comparison of LCAs relevant to UGEE processes have been reviewed and are discussed in this chapter.

8.2 Life Cycle Greenhouse Gas Emissions

8.2.1 Background

Human activities result in emissions of four principal GHGs: carbon dioxide, methane, nitrous oxide and the halocarbons (a group of gases containing fluorine, chlorine and bromine). These gases accumulate in the atmosphere, causing concentrations to increase with time (IPCC, 2007). The predominant GHGs related to UGEE activities are carbon dioxide and methane.

It is important to note that there has been limited measurement of direct or indirect methane emissions from shale gas exploration and production anywhere in the world (DECC, 2013a). In practice, most of the existing studies have drawn upon a narrow set of primary data from shale gas operations in the USA. There is little European evidence because significant shale gas operations are, with the exception of limited exploration activities, not yet operational in Europe and typical practices are yet to be established (AEA, 2012a). The current evidence base, therefore, originates mainly from the USA, as shale gas activities elsewhere are mainly at the exploration phase. Caution must therefore be exercised in the extrapolation of impacts, as many circumstances differ, including geology and the regulatory framework.

8.2.2 Emission estimations

8.2.2.1 Stage 1 – Well pad identification and site preparation

GHG emissions associated with site preparation include energy-related emissions from the use of equipment to clear the site (e.g. clearing vegetation) and from the construction of the necessary transport infrastructure (e.g. roads). Emissions associated with changes in land use type (e.g. removal of carbon stocks) are also relevant. Indirect emissions can also be associated with the materials used in the site preparation activities (e.g. embedded emissions in construction products) (AEA, 2012b) and are estimated to be in the order of 158–390 t CO_2 eq per well [17] (Jiang *et al.,* 2011; Santoro *et al.,* 2011; DECC, 2013a). The main uncertainties relate to the representativeness of results from one site to the next. Site-specific characteristics have an important influence on the overall results. There are also certain methodological uncertainties. For example, the emissions associated with vegetation clearance and other land use changes are the subject of debate.

The emissions associated with site preparation are generally small in comparison with other stages in the life cycle. GHG emissions from this stage are dominated by carbon dioxide from energy use, with some small amounts of methane and nitrous oxide emissions also arising from combustion. Land use clearance is also associated with a reduction in carbon sequestration.[18]

The estimates are applicable to the EU, as similar practices will be required for the development of shale gas wells in Europe. However, owing to the generally higher population densities in Europe, it is argued by some that shale gas developments might have a smaller overall land footprint compared with US practices, or with conventional gas developments in Europe, as developers may be under more pressure to reduce the impact of well developments on the landscape, although this would require further analysis (AEA, 2012b).

8.2.2.2 Stage 2 – Well design and construction, hydraulic fracturing and well completion

Emissions arise from the energy used in the drilling of the wells and in the pumping of water and other material during hydraulic fracturing (AEA, 2012b). Energy for the drilling operation (and all ancillary support activities such as well pad lighting and crew housing) is provided by large, diesel-fuelled internal combustion engines. The drilling rig engines are a source of combustion-related pollutants including carbon dioxide. This step of the process is the same for conventional and unconventional gas wells. Horizontal drilling is required for shale gas and may also be used for conventional gas (and oil). Drilling is not a significant source of methane emissions. Appropriate well design and supervision, including choice and depth of casings, seals and monitoring are essential to ensure safety, avoid gas and fluid migration and maintain well integrity during the drilling phase (AEA, 2012b).

Energy for the hydraulic fracturing operation is typically provided by diesel-fuelled internal combustion engines, as for the drilling phase. The drilling phase is likely to last up to 75 days per pad, as identified in section 2.3, Probable commercial scenarios. However, the fracturing phase is generally over a shorter period than that required to drill the wellbore, using flatbed-mounted engines up to 1000 HP capacity. Carbon dioxide emissions during the fracturing phase are primarily a result of fuel combustion. Typically a well pad will include 8–16 wells (as identified in the probable

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17 CO_2 eq (carbon dioxide equivalent) is a measure used to compare the emissions from various GHGs based upon their global warming potential.

18 The removal and storage of carbon from the atmosphere in carbon sinks (such as oceans, forests or soils) through physical or biological processes, such as photosynthesis.

commercial scenarios) and, after completion of the first well, gas is likely to be available at the site and the use of gas engines may be possible if the quality of gas is suitable. Similarly, if a well has to be re-fractured at a later stage, then gas engines could be an alternative to diesel-fuelled engines (AEA, 2012b). Existing estimates of GHG emissions are set out in Table 8.1.

The approach used is applicable to Europe and Ireland, with any adjustment required relating to the depth and lateral length of the wells, which would have an impact on the energy usage.

Table 8.1. Estimates of GHG emissions associated with drilling

Emissions per well (t CO_2 eq)		
Drilling	Pumping	Estimate source
610–1100	230–690	Jiang *et al.* (2011)
1,426		Santoro *et al.* (2011)
771		Stephenson *et al.* (2011)
49–74	295	Broderick *et al.* (2011)[a]
277		NYSDEC (2015)

[a]The estimate of drilling emissions from the Broderick *et al.* (2011) study is significantly lower than other estimates but included only horizontal drilling, as it was focused on additional emissions relating to UGEE processes compared with conventional processes.

UGEE processes involve large quantities of water and sand for the proppant. Transport of the materials will be associated with GHG emissions from vehicle movements, assuming current vehicle technologies, and conventional transport fuels. The fuel consumed in the transport of the water and chemicals, and the associated emissions, is dependent on the quantities of materials that are required and the distances that the materials need to be moved and is, therefore, site specific in nature. Estimates of transport-related GHG emissions are set out in Table 8.2. The difference in estimates appears to be mostly explained by the transport distance assumed and the proportion of water reused.

Owing to the site-specific nature of the characteristics, i.e. the volume of water required, the source of the water and the transport method, care should be taken in extrapolating US and Canadian data to an Irish context.

Table 8.2. Estimates of GHG emissions associated with transport of materials

Emissions per well (t CO_2 eq)	Assumptions	Estimate source
64	Water transported by truck from a local public water system 8–16 km from the site Assume a recycling rate for drilling mud of 85% Uses life cycle emission factor of 0.094 g CO_2 eq/kJ	Jiang *et al.* (2011)
475	Assumes 321 km per truckload for drilling and completion equipment and an average of 201 km for water chemicals and wastes Assumes 280 truckloads for drilling and completion equipment and 1069 truckloads for fresh water, chemicals and wastes. Truckloads are doubled for round trips and 50% load factor assumed Emission factor of 0.455 L/km for diesel trucks Assumes water use of 22,700 m^3 per well for hydraulic fracturing 40% of water brought to well is assumed to be recycled, so water and waste truckloads reduced accordingly	Santoro *et al.* (2011)
224	Analysis based on the assumption of 25,331–37,079 km for a single	Stephenson *et*

Emissions per well (t CO_2 eq)	Assumptions	Estimate source
	well project Assumes 18,160 m^3 of water per well, and that 50% of the water is sent for treatment Water transported by truck with a round trip distance of 241 km by road	*al.* (2011)
38 – 59	Assumes 60-km round trip Assumes 485–750 truck visits per well (of which 90% attributed to fracturing) for water deliveries Assumes a water volume of 9000–29,000 m^3 per well Heavy goods vehicle emission factor of 983 g CO_2/km	Broderick *et al.* (2011)

In addition to the emissions associated with transport, emissions may also be associated with the material used in the hydraulic fracturing process. Energy may be consumed, or process-related GHG emissions released, as part of producing the chemicals used in the hydraulic fracturing and the proppant fluid. In addition, the production of steel and cement used at the site would be associated with emissions of GHGs, having an embedded.[19] carbon dioxide content. The available estimates are set out in Table 8.3. Differences in study methodologies accounts for the significant differences in estimates. The Santoro *et al.* (2011) study includes emissions associated with the material used in the construction of the well pad. These emissions are captured in the Jiang *et al.* (2011) study, as part of the site preparation step. The larger emissions estimate from Santoro *et al.* (2011) for resource use is likely to be compensated a little by the larger emissions estimate from Jiang *et al.* (2011) in the site preparation step. Care should, therefore, be taken in extrapolating to an Irish context.

Table 8.3. Estimates of GHG emissions associated with resource use

Emissions per well drilled (t CO_2 eq)	Assumptions	Estimate Source
100–300	Production of hydraulic fracturing fluid (e.g. chemicals, sand) and drilling mud. Detailed cost estimate	Jiang *et al.* (2011)
1188	Resource consumption: includes steel, cement, chemicals, gravel and asphalt production. These materials are used for upgrading local roads, for the well casing and in the fracturing fluid	Santoro *et al.* (2011)

UGEE processes involve much larger quantities of wastewater than conventional gas extraction. If included within the boundary of the LCA, then further emissions would arise from the treatment of wastewater. Both Jiang *et al.* (2011) and Broderick *et al.* (2011) result in significantly different estimates of emissions (Table 8.4). The Broderick *et al.* (2011) study used an emission factor that was based on the carbon dioxide emissions associated with wastewater treatment in the UK, as reported by the water industry. In the Jiang *et al.* (2011) study, emissions were estimated based on cost data, and the estimated emissions from “support activities for oil and gas”, although a definition of these support activities was not available.

Calculation of GHG emissions associated with wastewater treatment is dependent on the characteristics of the wastewater, the level of reuse and the method of wastewater disposal. Extrapolation to an Irish context would need to reflect current approaches to wastewater treatment.

19 Embedded energy, also known as embodied energy, is defined as the energy that was used in the work of making a product. Embodied energy attempts to measure the total of all the energy necessary for an product’s entire life cycle. This life cycle includes raw material extraction, transport, manufacture, assembly, installation, disassembly, deconstruction and/or decomposition.

Table 8.4. Estimates of GHG emissions associated with wastewater treatment

Emissions per well ($t\ CO_2$ eq)	Assumptions	Estimate source
300	Based on disposal via deep well injection[a] Emissions estimated based on the cost of treatment and emissions associated with "support activities for oil and gas"	Jiang *et al.* (2011)
0.3–9.4	Based on 15–80% recovery of 9000–29,000 m^3 of water Treatment emission factor of 0.406 $t\ CO_2$/mL treated.	Broderick *et al.* (2011)

[a]It should be noted that deep well injection is unlikely to be allowed in the CB and NCB.

Upon completion of hydraulic fracturing, a combination of fracturing fluid and water is returned to the surface (flowback). There is general consensus in the literature that that flowback could cause the highest proportion of emissions from shale gas exploration and extraction (DECC, 2013a). There are, however, few quantifications of these emissions. These quantifications include the studies by Howarth *et al.* (2011) and Jiang *et al.* (2011), which relied on secondary sources and governmental reports (USEPA, 2011a; NYSDEC, 2015) for their estimates of methane emissions (Table 8.5).

From a technical perspective, the results are considered to be applicable to emissions that may arise from UGEE processes in Ireland or the EU. However, actual emissions relating to management of the gases in the flowback are dependent on process management practices, and variations in management practices between the USA and Ireland are likely have an impact on estimates (AEA, 2012b).

Table 8.5. Estimates of GHG emissions associated with flowback

Emissions per well ($t\ CO_2$ eq)	Site	Estimate source
9100	Marcellus	Jiang *et al*. (2011)
102,000	Haynesville	Howarth *et al.* (2011)
5600	Barnett	Howarth *et al.* (2011
3900	Various	USEPA (2011a)
18,000	Haynesville	O’Sullivan and Paltsev (2012)
4100	Barnett	O’Sullivan and Paltsev (2012)
4400	Fayetteville	O’Sullivan and Paltsev (2012)
6100	Marcellus	O’Sullivan and Paltsev (2012)
7300	Woodford	O’Sullivan and Paltsev (2012)

The estimate by Howarth *et al.* (2011), noticeable as being significantly higher than other estimates, has been criticised for a range of reasons including “improper calculation of the average of the individual well flow rates” and an “improper attribution of the (improperly calculated) average flow rates from all the wells as occurring during flow-back operations”, as reported by DECC (2013a). Cathles *et al.* (2012) argue that the assumption by Howarth *et al.* (2011), that the initial production gas flow rate is the same as the gas entrained in the flowback fluid, is incompatible with the basic physics of shale gas production, because the initial production gas flow rate is the highest flow achievable from the wellhead, therefore when the gas is mixed with substantial volumes of flowback fluid, the flow of gas must be lower [this could also apply to the estimate by Jiang *et al.* (2011)]. However, Howarth *et al.* (2012) defended their study and conclusions, and suggested that further work was required.

Recent research based on field measurements of ambient air near natural gas well fields in Colorado and Utah suggest that more than 4% of well production may be leaking into the atmosphere at some production stages of operations (Bradbury *et al.*, 2013). To meet their obligations, operators can control these emissions by using "green completions', equipment that collects and separates the initial flow of water, sand and gas, and separates them so that the gas can be handled (DECC, 2014b). The USEPA analysis assumes that 90% of gas contained within flowback can be recovered (USEPA, 2012).

8.2.2.3 Stage 3 – Well production

After well completion, methane emissions during production and processing can come from compressors, pumps, dehydration equipment, chemical processing and incidental leaks (e.g. from pipe joints), particularly in poorly run, leaky operations. These can be reduced by maintenance of machinery and using vapour recovery units to limit venting from storage tanks.

During production and processing, the most significant GHG emissions are from the compressors, dehydration equipment and some chemical processing (AEA, 2012b). Additional GHG emissions could be fugitive methane in the form of natural gas migration away from a gas well in the event that well integrity has been compromised, especially through failure of the surface casing or the cement used to cap the well.

New York State Department of Environmental Conservation (NYSDEC, 2015) estimates emissions relating to the production phase for the first year and then thereafter, as set out in Table 8.6.

During transport and distribution, methane emissions due to leakage are a significant proportion of the total life cycle emissions. However, once the gas has entered the distribution pipelines, leakage rates, and therefore emissions, are the same whether the gas has been supplied from conventional or shale gas reserves.

Howarth *et al.* (2011) estimate that, for both sources, the fugitive emissions of methane are between 1.4% and 3.6% of the methane produced over the life cycle of a well. However, Stephenson *et al.* (2011) estimate that losses would be lower at 0.066% of gas lost to fugitive emissions (over 1440 km, which was taken as a typical distance for transmission to a power station in the USA). Stephenson *et al.* (2011) also estimate that about 1.4% of gas would be consumed by compressor stations along the pipeline, again assuming a distance of 1440 km.

The figures quoted in Table 8.6 are dependent on production rate and are therefore subject to uncertainly.

Table 8.6. Production phase GHG emission estimates

	Methane (t)	Carbon dioxide (t CO_2 eq)[a]
First full year in which drilling commenced		
Single vertical well	212	5346
Single horizontal well	207	5071
Four-well pad	321	3524
Post first year annual emissions		
Single vertical or horizontal well	221	5591
Four-well pad	512	5608

[a]For the purpose of assessing GHG impacts, each tonne of methane emitted was calculated as equivalent to 25 t of carbon dioxide.

8.2.2.4 Stage 4 – Project cessation, well closure and decommissioning

Decommissioning procedures for gas wells have been motivated mainly by resource conservation and protection and groundwater protection (Kang, 2014). Therefore, the main decommissioning strategy is plugging. While there are regulations for decommissioning procedures and protocols, there is no regulation to address methane emissions from abandoned oil and gas wells and methane emissions from these wells are not included in any emissions inventories (Brandt *et al.,* 2014); the implied assumption in decommissioning regulations is that leakage will not occur. However, it is now recognised that there is potential for gas to escape following well closure due to well failure, leading to environmental risks (AMEC, 2014) as shown in Figure 8.1 and discussed in more detail in section 7.3.2.1. Gas may migrate upwards through a cracked or deformed cement sheath into the atmosphere (Figure 8.2 and Figure 8.3). It is estimated that tens of thousands of inactive oil and gas wells in North America leak gas to the surface (Dusseault *et al*., 2000).

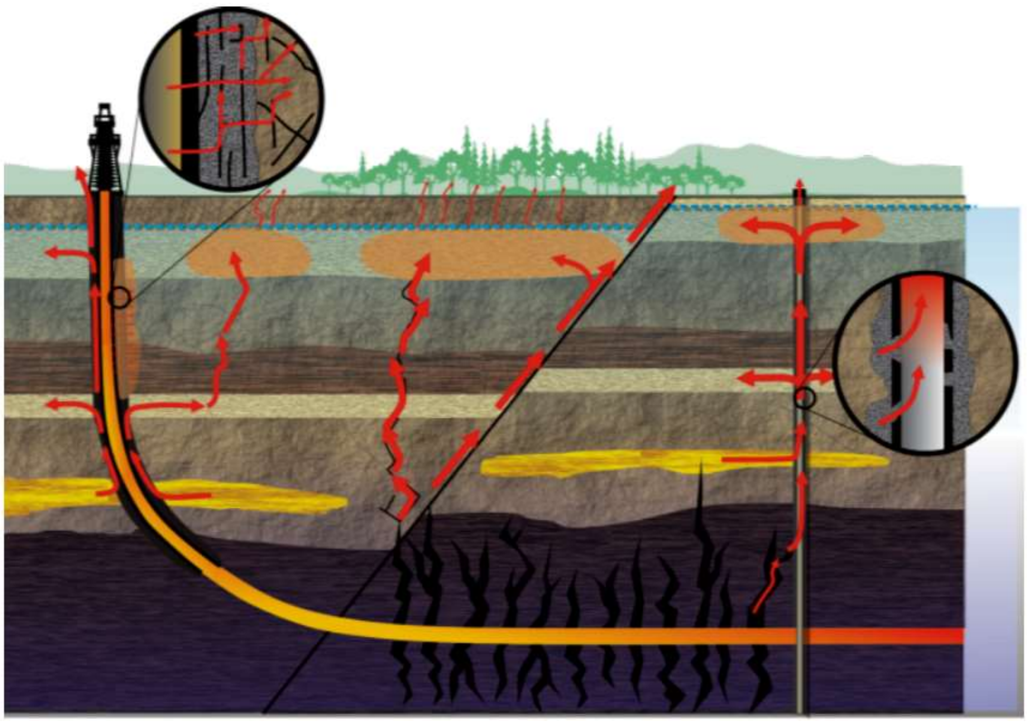

Figure 8.1. Potential impacts of gas migration (courtesy of Cherry, 2014)

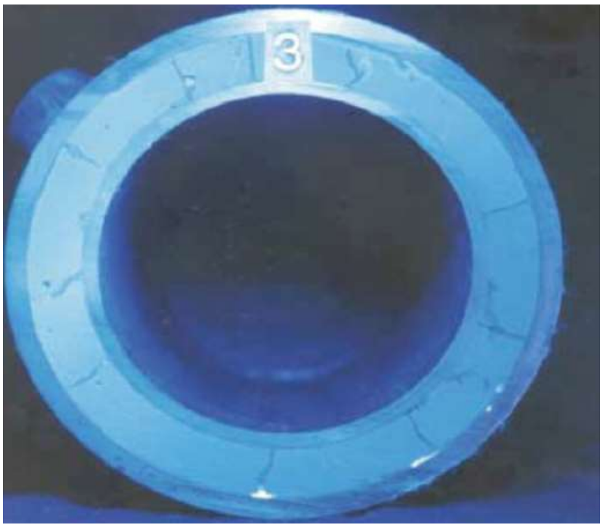

Figure 8.2. Cement sheath failure and resulting cracks (courtesy of Cherry, 2014)

Figure 8.3. Incomplete displacement of drilling mud and resulting cement and drilling fluid channels (courtesy of Cherry, 2014)

Despite a growing awareness of potential fugitive emissions relating to wells following closure, data on emissions are sparse (AEA, 2012b) and the result is a lack of quantification of methane emissions from these wells (Kang, 2014). Problems with cement sheath failure and cement seal deterioration can mean that all wells have the potential to leak gas eventually, although it is not yet clear under what circumstances the leakage may cause substantial harm (Cherry, 2014). A recent study found that methane fluxes from plugged wells were not necessarily lower than methane fluxes at unplugged wells and that methane emissions from abandoned oil and gas wells appears to be a significant source of methane emissions to the atmosphere (Kang, 2014).

8.2.3 Techniques and mitigation measures for reducing greenhouse gas emissions

The greatest contribution to emissions comes from the well completion stage, although estimates of emissions from this stage vary significantly between studies. The second most significant source at this stage is drilling and hydraulic fracturing. The emissions arise from a range of energy-using sources, including powering drilling equipment, transport of water to the site and wastewater away from the site, processes to supply water and treat wastewater, and “embedded carbon” in the proppant and chemicals used in the hydraulic fracturing fluid. Emissions from land clearing, site preparation and construction of the well pad, access roads and well casings, including emissions associated with transport and production of materials, are smaller.

The importance of assumptions about the productivity of the well are shown clearly in the results, as emissions from this pre-production stage are generally independent of lifetime gas production, so their contribution per megajoule of gas declines directly as gas production increases.

Table 8.7 describes techniques and mitigation measures that can be used to minimise the GHG emissions. The effectiveness of these measures in reducing total GHG emissions would, however, be influenced by the relative contribution of that stage to total emissions.

Table 8.7. Techniques and mitigation measures for reducing GHG emissions

Stage	Measure
Site preparation	Drilling as many wells as possible using one rig move
	Optimising the well spacing for efficient recovery of natural gas
	Planning for efficient rig and fracturing equipment moves from one pad to another
	Reducing transport emissions through site selection, where possible
	Ensuring that personnel and equipment can be sourced locally
	Identifying sources or materials locally (including water and sand used in the hydraulic fracturing process)
	Identifying local facilities to recycle and dispose of waste products
	Planning to reduce the number of vehicle journeys
	Using efficient transport engines
Drilling and fracturing	Using gas engines or engines powered from the local electricity grid
	Appropriate well design and supervision, including choice and depth of casings, seals and monitoring are essential to ensure safety, avoid gas and fluid migration and maintain well integrity during the drilling phase
Well completion and flowback	Using green completions
Production	Using vapour recovery units for storage tanks
	Using low-bleed devices to minimise methane emissions from pneumatic devices (liquid level controllers, pressure regulators and valve controllers)
	Enhancing maintenance, cleaning and tuning, repairing or replacing leaking gaskets, tubing fittings and seals to minimise methane emissions from pneumatic devices (liquid level controllers, pressure regulators and valve controllers)
	Establishing an effective leak detection and repair programme
Well plugging and decommissioning	Considering plugging at the planning and development stage
	Bridging, cleaning and perforation of casings to ensure effective seals (particularly across annular spaces and with the geology outside the casing)
	Using multiple plugs where required

8.2.4 European and Irish context

Extrapolation of the foregoing information to the Ireland and Northern Ireland context would be influenced by a range of factors, including the following:

- differing geology;
- build-out periods within the basins, overall timeframe for production and density and numbers of well pads;
- a different processing infrastructure may be required;
- emissions may be influenced by a different regulatory framework; and
- availability of equipment.

In a report for the EC Directorate-General for Climate Action (AEA, 2012b), the potential climate impacts of shale gas production in the EU were assessed. Across a range of scenarios, the emissions from the use of shale gas to produce electricity were estimated to be in the range of 409–

472 g CO_2 eq/kWh of electricity generated. In a similar review of potential GHG emissions for shale gas production in the UK, McKay and Stone (2012) estimated a similar range of 423–535 g CO_2 eq/kWh.

For conventional sources of gas, emissions are dominated by combustion at the electricity generation plant, which typically represents around 90% of the total emissions impact, with the main difference between the shale gas fuel cycle and conventional gas related to the pre-production stage. The overall emissions from unconventional gas were estimated to be of a similar magnitude to those of conventional gas, depending upon the supply source (AEA, 2012b; McKay and Stone, 2013).

Of these pre-combustion stages in the UGEE process, the most significant sources of emissions are well completion and gas treatment, which account for 39% and 27% of pre-combustion emissions, respectively, in the base case assessed in the study. [The base case was developed for the purposes of comparison and based primarily on the characteristics of shale gas exploitation in line with current practice in the USA (AEA, 2012b).]

If flaring of flowback gases or green completion are assumed, however, then the significance of the well completion stage is considerable diminished, accounting for only between 7% and 14% of pre-combustion emissions. Less significant sources are activities associated with well drilling and gas transmission, both of which account for about 10% of emissions in the base case.

For the base case considered for shale gas, the GHG emissions per unit of electricity generated are around 4–8% higher than for electricity generated by conventional pipeline gas from within Europe. If emissions from well completion are mitigated, through flaring, or capture and utilisation, then this difference is reduced (1–5%). This finding is broadly in line with those of other US studies, which found that generation from shale gas had emissions between 2% and 3% higher than those from conventional pipeline gas generation.

DECC (2013a) assessed four well completion scenarios: 100% vented; 90% capture and flare; green completion with 90% methane contained in the flowback captured; and 100% capture. The most extreme of the hypothetical cases (100% vented) resulted in extraction emissions more than double those associated with combustion alone, demonstrating the importance of reduced emissions completions or “green completions”.

The analysis suggests that the emissions from shale gas generation (base case) are 2–10% lower than emissions from electricity generated from conventional pipeline gas located outside Europe (in Russia and Algeria) and 7–10% lower than electricity generated from liquid natural gas (LNG) imported into Europe (AEA, 2012b). However, this conclusion is far from definitive. Under the “worst-case scenario”, in which all flowback gases at well completions are vented, emissions from electricity generated from shale gas would be at a similar level to the upper level of emissions for electricity generated from imported LNG and for that of gas imported from Russia. This suggests that, where emissions from shale gas are uncontrolled, there may be no benefits in terms of GHG emissions from utilising domestic shale gas resources over imports of conventional gas from outside the EU. In fact, for some pipeline sources, emissions from shale gas may exceed emissions from importing conventional gas.

Emissions from shale gas generation are significantly lower (41–49%) than emissions from electricity generated from coal (AEA, 2012b). This is on the basis of methane having a 100-year global warming potential of 25. This finding is consistent with those in most other studies (AEA, 2012b).

8.3 Life Cycle Environmental Impacts

8.3.1 Background

With the exception of a few countries, notably the USA, shale gas exploration and extraction is at a very early stage of development. In the island of Ireland and across Europe, while commercial extraction has typically not yet begun, its potential has stirred controversy over its environmental impacts, its safety and the difficulty of justifying its use to a nation conscious of climate change. There are ongoing debates on whether, and how, shale gas might fit into a world attempting to reduce fossil fuel usage and prevent climate change (Broderick *et al.,* 2011). LCA allows the systematic evaluation of the environmental aspects of a product or service system through all stages of its life cycle.

Limited literature is available on its life cycle impacts owing to the relative immaturity of shale gas fracturing, with most existing information relating to US production. Most available studies (such as Burnham *et al.,* 2011; Howarth *et al.,* 2011; Jiang *et al.,* 2011; Stephenson *et al.,* 2011; Dale *et al.,* 2013; DECC, 2013a) estimate the GHG emissions and related global warming potential of shale gas extraction. Of these studies, only that by the DECC relates to work outside the USA, but it still relies almost entirely on data from the other US-based papers cited above. The first LCA of shale gas used for electricity generation relating to Western Europe appears to be that of Stamford and Azapagic (2014). Outside the USA and the UK, some LCA work has also been conducted for shale gas in China (Chang *et al.,* 2014), again considering GHG emissions – but only for the production stage. Studies considering the life cycle environmental impacts of UGEE processes appear to be largely concerned with global warming potential, with the exception of life cycle water consumption (Clark *et al.,* 2013; Dale *et al.,* 2013) and some qualitative discussion of potential non-global warming potential impacts to air, water and land (Jenner and Lamadrid, 2013).

8.3.2 Life cycle indicators

Stamford and Azapagic (2014) modelled the life cycles of shale gas and other electricity systems and considered a range of indicators to obtain a full picture of the environmental consequences of shale gas, as opposed to previous studies, which considered mainly the global warming potential. A number of cases were assessed and the typical case, “central case”, is discussed below. Shale gas is compared with the following energy sources:

- photovoltaics (solar power);
- offshore wind power;
- nuclear power;
- coal;
- imported LNG; and
- conventional gas.

The energy sources are assessed under the following headings:

- *Abiotic depletion potential – elements (ADP-E)*. This measures the gradual depletion of non-renewable non-organic elements such as metals. ADP-E is determined for extraction of minerals based on the remaining reserves and rate of extraction (BRE, 2005).
- *Abiotic Depletion Potential – Fossil Fuels (ADP-F)*. This measures the gradual depletion of fossil fuels. ADP-F is determined for extraction of fossil fuels based on the remaining reserves and rate of extraction (BRE, 2005).

- *Acidification potential*. The acidification of soils and waters occurs predominantly through the transformation of air pollutants into acids. This leads to a decrease in the pH value of rainwater and fog from 5.6 to 4 and below. Sulfur dioxide and nitrogen oxide and their respective acids (sulfuric acid and nitric acid) produce relevant contributions. This damages ecosystems, forest dieback being the most well-known impact. Acidification potential is a measure of the propensity of a process to result in the contribution of H^+ ions to a medium, causing acidification (McDevitt *et al.*, 2013).
- *Eutrophication potential*. Eutrophication is the enrichment of nutrients in a specific place. Eutrophication can be aquatic or terrestrial. The result in water is accelerated growth of algae, which, in turn, consumes oxygen and prevents sunlight from reaching the lower depths. This leads to a decrease in photosynthesis and reduced oxygen (oxygen depletion) (McDevitt *et al.*, 2013).
- *Freshwater aquatic eco-toxicity potential (FAETP)*. This indicator measures the potential toxic effects of a process on freshwater ecosystems (McDevitt *et al.*, 2013).
- *Human toxicity potential (HTP)*. This indicator measures the potential toxic effects of a process on humans (McDevitt *et al.*, 2013).
- *Marine aquatic eco-toxicity potential (MAETP)*. This indicator measures the potential toxic effects of a process on saltwater ecosystems and species (McDevitt *et al.*, 2013).
- *Ozone layer depletion potential (ODP)*. This indicator measures associated changes in the stratospheric ozone column in a steady state (McDevitt *et al.*, 2013).
- *Photochemical ozone creation potential (POCP)*. This indicator measures the contribution to the formation of photochemical smog (McDevitt *et al.*, 2013).
- *Terrestrial eco-toxicity potential*. This indicator measures the potential toxic effects of a process on terrestrial ecosystems and species.

Abiotic Depletion Potential – Elements

Shale gas was estimated to be comparable to coal power. However, its ADP-E was estimated to be 81% higher than that for North Sea gas and 29 times higher than that for North Sea gas for the worst-case scenario assessed. The last is due to the high volume of drilling fuel assumed per unit of gas extracted in the worst case and particularly due to barite, the main contributor (44%) to this impact.[20] However, this was deemed unlikely, as it is based on a drilling fluid consumption of more than twice the volume estimated by Cuadrilla, as reported in Stamford and Azapagic (2014). The worst case was estimated to be 18% lower than the ADP-E of offshore wind power and 94% lower than that of photovoltaics (PV) because of the use of various metals in their life cycles. Solar PV in particular has a very high ADP-E, primarily due to depletion of silver and tellurium during the manufacture of the metallisation pastes required for silicon cell production (although copper and silver components in capacitors also contribute to this impact).

Abiotic depletion potential – fossil fuels (ADP-F)

The depletion of fossil fuels in the shale gas life cycle was estimated to be comparable to conventional gas and is 43–49% lower than that for coal power. Depletion of shale gas accounts for 88% of this impact, with the remainder comprising gas and diesel usage during its extraction and processing. However, the worst-case scenario was estimated to potentially exceed that of coal. In all cases, solar PV, offshore wind and nuclear power have much lower estimated ADP-F.

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20 Barite is used in drilling muds, and is also used in the manufacture of paints, paper, cloth and rubber and safety materials for blocking X-rays.

Acidification potential

Shale gas was estimated to have a higher AP than conventional gas: about 4.1–7.5 times higher in the central case. In the worst case, the impact could be around four times worse than a typical UK coal power plant. However, in the best case, the AP of shale gas was estimated to be at least 30% lower than that of the conventional gas options and 60% lower than solar PV. Wind power was estimated to be superior in terms of AP in all cases.

More than 80% of this impact is due to the combination of on-site diesel combustion for drilling and other equipment, as well as for raw gas sweetening (removal of hydrogen sulfide). Thus, if on-site equipment is powered from the grid and the extracted gas is low in hydrogen sulfide, as in the best-case scenario, this impact is greatly improved. However, without more information on gas composition, these estimates remain uncertain.

Eutrophication potential

For the central case assessed, electricity from shale gas was estimated to be broadly comparable to conventional gas, lying in between offshore wind and solar PV. About half of the eutrophication impact is caused by diesel combustion in the on-site electric generator used for drilling and other equipment. Therefore, in the best case (with equipment powered by the grid), the impact of shale gas was estimated to be 25% lower than that of North Sea gas. The high impact in the worst case is mainly due to diesel usage for drilling being high relative to the very low gas output of the well. In that case, the EP was estimated to be 38% lower than that of a coal plant. Similar to the AP, the central case assessed was also estimated to be lower than for PV (by 51%) but higher than for wind (57%).

Freshwater aquatic eco-toxicity potential

For the central case assessed, the FAETP of electricity from shale gas is comparable to that of conventional gas. This makes it an order of magnitude better than offshore wind and solar PV and two orders of magnitude better than coal power. Even in the worst case, the FAETP of shale gas is 2.75 times lower than that of coal power.

Human toxicity potential

For the central case, electricity from shale gas was estimated to have an HTP 2.9–4.4 times higher than that of conventional gas; this is related to the disposal of drilling waste to land (however, this would be regulated, and waste properly disposed of, in an Irish context). However, in both the central and best cases, shale gas was calculated to have a low HTP relative to its alternatives, solar and coal power (6 and 10 times higher, respectively).

Marine aquatic eco-toxicity potential

Similar to the other toxicity impacts, landfarming of drilling waste is the main calculated contributor to the MAETP of electricity from shale gas (65% of the total). For this reason, shale gas was estimated to have a MAETP around two to five times higher than that for conventional gas for the central case assessed. However, compared with the other electricity options, both conventional and shale gas were estimated to have low MAETP, with offshore wind and solar PV 1.6–7.8 times worse for the central case and coal 45 times higher.

Ozone layer depletion potential

For the central case assessed, shale gas was estimated to have an ODP directly comparable to conventional gas. Offshore wind, for example, has an estimated ODP around 25 times lower than that of North Sea gas. The main cause of ODP in the shale gas life cycle is leakage of halon during pipeline transport (67% of the total impact in the central case); halons are used as fire retardants and coolants in various processes related to gas pipeline use and maintenance. However, in the worst case assessed, this was also accompanied by very high consumption of diesel in on-site generators relative to gas output. In this case the combined leakage of halons in the diesel and gas transport life cycles resulted in an ODP of about 85 times higher than that of wind power. The potential range of ODP results for shale gas was calculated to overlap with the potential range for solar PV.

Photochemical ozone creation potential

Leakage of VOCs during the removal of hydrogen sulfide (sweetening) is the main potential contributor to POCP (photochemical smog) in the life cycle of shale gas (56% for the central case assessed). The assumption in the central case was that half of the gas requires sweetening and this resulted in an impact of about nine times higher than that of North Sea gas. Therefore, knowledge of the average raw gas composition is essential to quantifying this impact. In the worst case, shale gas may be up to 98 times worse than North Sea gas and 18 times worse than the coal power life cycle. However, in this case the major contributor (70%) is venting of gas during well drilling and completion owing to the worst case assumption that all gas is vented. Therefore, gas venting regulations (such as the requirement for reduced emissions completions) are critical to avoiding such high impacts, and they greatly influence the calculated results. In general terms, shale gas was estimated to have a high POCP, worse than those of solar PV, offshore wind and nuclear power by factors of 3, 26 and 45, respectively ,for the central case assessed. Even in the best case, wind is still preferable by a factor of 3.3.

Terrestrial eco-toxicity potential

The estimated terrestrial eco-toxicity potential of electricity from shale gas for the central case was calculated to be 13–26 times higher than that of conventional gas. This impact is also higher than those of power generated from coal, nuclear, wind or solar PV by between 2 and 4.4 times. However, as is the case for HTP, most of this impact (over 90%) is related to the disposal of drilling waste via landfarming and the subsequent deposition of heavy metals and barium in soil. Therefore, in the best case (in which all drilling waste is landfilled), this impact was calculated to be around one-third lower than that for imported LNG and an order of magnitude lower than that for solar PV, offshore wind and coal. Therefore, this impact is critically dependent on the disposal of drilling wastes and any regulation put in place to monitor the composition of those wastes.

8.4 Summary of Relative Life Cycle Impacts

Based on a literature review of LCA relating to UGEE activities, the key points relating to the relative life cycle impacts of UGEE-generated electricity are:

- The GHG emissions per unit of electricity generated by UGEE are estimated to be around 4–8% higher than those for electricity generated by conventional pipeline gas from within Europe. If emissions from well completion are mitigated, through flaring, or capture and utilisation, then this difference is reduced (1–5%).
- The GHG emissions from shale gas generation (base case) are estimated to be 2–10% lower than emissions from electricity generated from conventional pipeline gas located outside Europe (in Russia and Algeria), and 7–10% lower than electricity generated from LNG imported into Europe.
- Emissions from shale gas generation are estimated to be significantly lower (41–49%) than emissions from electricity generated from coal.
- ADP-E is estimated to be around 50–80% higher than that of conventional gas but 19–244 times lower than for offshore wind or solar PV power.
- Acidification potential is estimated to be 4.1–7.5 times higher than that of conventional gas and similar to or worse than wind or solar PV power.

- Eutrophication potential estimated to be quite comparable to that of LNG, with levels 2.3 times worse than offshore wind, but two and 13 times better than coal and solar PV power, respectively.
- FAETP is estimated to be 60% to 3.8 times worse than that of conventional gas but an order of magnitude better than any of the non-gas technologies.
- HTP is estimated to be 2.9–4.4 times worse than that of conventional gas but an order of magnitude better than solar PV or coal power.
- MAETP is estimated to be two to five times worse than that of conventional gas but comparable to offshore wind and better than solar PV or coal power by 7.8 and 45 times, respectively.
- ODP is estimated to be lower than that of North Sea gas (by 15%) and Qatari LNG (17%), but other technologies are superior in this regard, particularly nuclear power and offshore wind, which have impacts estimated to be two orders of magnitude lower.
- POCP is estimated to be about nine times higher than that of North Sea gas and is also 60% worse than that of coal power (the worst of the other technologies considered).
- Terrestrial eco-toxicity potential is estimated to be 13–26 times worse than that of conventional gas and is also worse than that of any of the other technologies (by a factor of two to four). However, this is only in the case of landfarming of solid waste, which is unlikely to be permitted.

9 Chemical Use, Impacts and Mitigation Measures (Task 6)

9.1 Background

Hydraulic fracturing involves the injection of fluid under pressure to fracture the formation. Hydraulic fracturing fluids often contain chemical additives that are required for different purposes, such as to thicken fluids to increase their viscosity or to reduce the potential for corrosion of pipes and casings. The use of chemicals, particularly additives to hydraulic fracturing solutions, has been a major concern for the public, regulators and the scientific community in recent years. The primary concern has been the use of chemicals that may have potential impacts on human health and/or the environment through the potential contamination of groundwater and the large number of different chemicals used. In addition, much of the public's concern has been over the lack of disclosure of chemicals used in the past and the reluctance of UGEE operators to release what they consider commercially sensitive information concerning their additives.

9.2 Approach

This chapter provides an evaluation of the chemicals used in UGEE projects, including both hydraulic fracturing fluids and drilling fluids. There are many potential pathways that lead to humans and/or the environment being exposed to chemicals, including chemical spills on site or potential underground contamination of groundwater, as shown in Figure 4.2. This chapter specifically deals with the hazards of the chemicals and their potential for causing harm in the event of humans or the environment being exposed to them through groundwater or surface water pathways. The pathways and potential impacts to groundwater and surface water are examined in greater detail in Chapter 4.

First, the various databases (e.g. Colborn *et al.*, 2011; NYSDEC, 2011; United States House of Representatives, 2011; AEA, 2012a; Meiners *et al.*, 2013) of hydraulic fracturing chemicals were reviewed and the most recent study from the USEPA was utilised ,as it is one of the most comprehensive assessments of hydraulic fracturing additives to date. The records of the FracFocus Chemical Disclosure Registry (FracFocus).[21] database were examined by the USEPA, using disclosures with fracture dates between 1 January 2011 and 28 February 2013 (USEPA, 2015d). Similar to Fracfocus, NGSFACTS (ngsfacts.org) is a European voluntary disclosure platform, which currently holds records for a number of wells in Poland.

The hazard classifications of the chemicals were assessed based on existing European legislation. The existing regulatory framework for the management and classification of chemicals is presented, as well as the existing requirements for chemical disclosure. For further analysis of the regulatory framework for UGEE projects, refer to the outputs of Project C of the UGEE JRP, which is designed to assist regulators (in both Ireland and Northern Ireland) in fulfilling their statutory roles.

This chapter also presents the findings of the review of emerging alternatives such as green (or environmentally friendly) and non-toxic chemicals, as well as the viability of chemical-free hydraulic fracturing. This review was based on existing peer-reviewed articles and reports.

21 The Ground Water Protection Council (GWPC) and the Interstate Oil and Gas Compact Commission (IOGCC) in the USA developed FracFocus in response to public interest in the additives within hydraulic fracturing fluids (FracFocus, 2015). It is a public website on which both oil and gas production well operators can voluntarily disclose information about the additives used in hydraulic fracturing fluids at individual wells.

9.3 Hydraulic Fracturing Fluids

9.3.1 Components of hydraulic fracturing fluids

Hydraulic fracturing involves the injection of fluid under pressure to fracture the formation. The resultant fractures need to be held (propped) open by a proppant to allow the gas to flow from the formation rock to the production well. Hydraulic fracturing fluids contain three key elements:

1. Base fluid: proppants and additives are mixed into the base fluid to create fracturing fluid. Water is the predominant component of the base fluid used in hydraulic fracturing for shale gas production (Meiners *et al.,* 2013). In a recent study by the USEPA (2015d), it was found that the median maximum reported concentration of water in hydraulic fracturing fluid was 88% by mass, with a range of 68% to 99% (5th and 95th percentile).
2. Proppants are a material, such as sand, used to help the factures remain open during production. The USEPA (2015d) study found that the median maximum concentration of proppant ingredients in fracturing fluids was 11% by mass, with a range of 2.4% to 24% by mass (5th to 95th percentile). They also found that 10 materials represent over 99% of disclosures on FracFocus: these include quartz, mullite, cristobalite, ferric oxide, alumina aluminium oxide), titanium dioxide, corundum (another aluminium oxide), bauxite and calcined bauxite. Generally, sand is used in shallow fracturing but man-made material is utilised for deeper fracturing, in which additional strength is required to resist overburden pressure.
3. Additives are added to the fracturing fluid to alter the fluid's properties for different purposes. Sometimes an additive is a single chemical and sometimes it's a mixture of chemicals. The chemical additives are discussed in detail in section 9.3.2 and hazards evaluated in section 5.5.

9.3.1.1 Types of hydraulic fracturing fluids

There are three main types of water-based hydraulic fracturing fluids that are currently being used, all of which have different properties and applications. These include:

1. *Water frac or slick water*. The most commonly used fluids in gas wells, this is water containing a friction reducer and possibly a biocide, surfactant, breaker or clay control additive. The fluid has a low viscosity and small-sized proppants are common. The low viscosity results in fractures that are of lesser width and greater in length, which creates better reservoir to borehole connectivity.
2. *Linear fluid*. This is water containing polymers such as guar, hydroxypropyl guar, hydroxyethyl cellulose, carboxymethyl hydroxypropyl guar and carboxymethyl hydroxyethyl cellulose (JRC, 2013a). Other possible additives are buffers, biocides, surfactants, breakers and clay-controlling additives. This fluid has higher viscosity than the slick water and can carry the proppant more effectively.
3. *Cross-linked fluid*. This is water containing any of the polymers used in linear gel and a cross-linker such as borate to provide increased viscosity, which results in better proppant transport and wider fractures.

There are also non-aqueous fracturing fluids that are less commonly used, including fracturing fluids that are oil based, foam based, acid based and gelled LNG (JRC, 2013a). The USEPA study (2015d) found that non-aqueous fluids were reported to be used in 2.2% of the disclosures on FracFocus.

9.3.1.2 Typical composition of hydraulic fracturing fluid

Although fluid composition is evolving, the typical composition of hydraulic fracturing fluid is shown in Figure 9.1, which is taken from the US Department of Energy (2009) report and the volumetric percentages of additives that were used for a hydraulic fracturing operation in a Fayetteville Shale Formation horizontal well. The concentrations of chemicals are generally low but, given the large volumes of fracturing fluid required, the volumes of chemicals can be significant (Public Health England, 2013).

The probable commercial scenarios, presented in Chapter 2 of this report, show that the typical range based on European experience is comparable to the USEPAs findings, as follows:

- water content: 90–96% (API, 2010; AMEC, 2014; Cuadrilla, 2014a);
- proppant content: 4–10% (API, 2010; AMEC, 2014; Cuadrilla, 2014a); and
- chemical additives: 0.1–0.5% (API, 2010; AMEC, 2014).

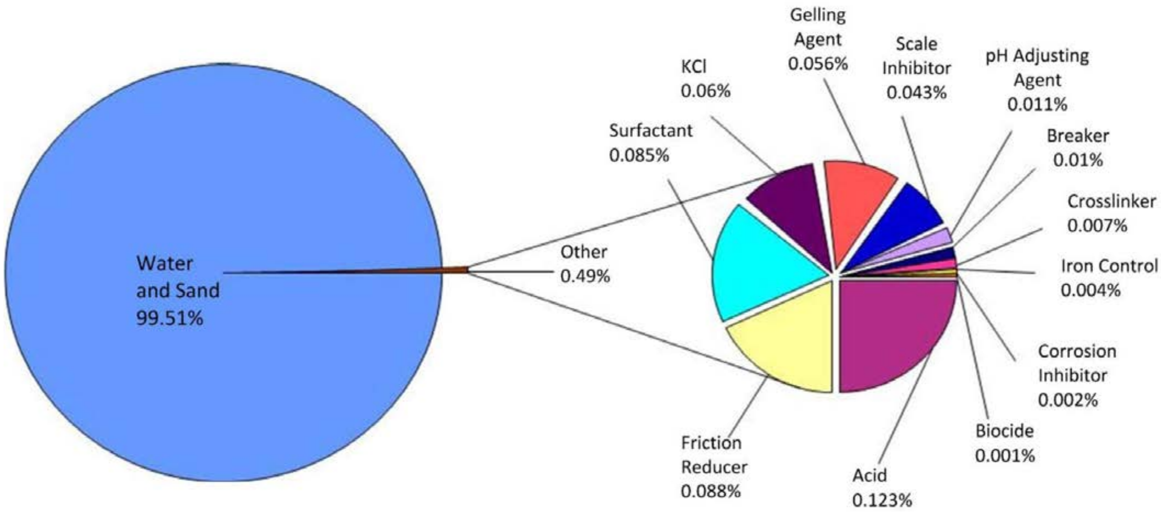

Figure 9.1. Composition of a fracturing fluid (source: US Department of Energy, 2009). KCl, potassium chloride.

However, the actual composition of hydraulic fracturing fluids, and the types and numbers of additives, vary significantly by operation, which is based on site-specific factors such as geological conditions, well design and operator preferences (US Department of Energy, 2009; Meiners *et al*,. 2013). Each UGEE reservoir has unique characteristics that need to be addressed through both fluid design and fracture treatment (JRC, 2013a). Sometimes the additives are determined through modelling to simulate hydraulic fracturing processes or laboratory tests on the rock samples (Meiners *et al.,* 2013). The quantities of additives and proppants are selected based on the prevailing temperatures and pressures (Meiners *et al.,* 2013). In many cases, the specific application of an additive has not been justified with scientifically or technically based arguments, which has led to some public irritation.

9.3.2 Hydraulic fracturing additives

The main purposes of the chemical additives are described by Colborn *et al.* (2011), USEPA (2011b) and Meiners *et al.* (2013) and are discussed below, along with how the additives can be used sequentially:

- *Acids* To achieve greater injection ability or penetration and later to dissolve some minerals or scales and change structural properties of clays to reduce clogging, allowing gas to flow to the surface. May be used as acid pre-treatment to remove remnants of drilling fluids.
- *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. They are added near the end of the fracturing sequence to reduce the viscosity of the fluid and enhance flowback.
- *Clay stabilisers*. To create a fluid barrier to prevent mobilisation of clays, which can plug fractures.
- *Corrosion inhibitors*. To reduce the potential for rusting in pipes and casings. May be used as a pre-treatment.
- *Cross-linkers*. To thicken fluids often with metallic salts in order to increase viscosity and proppant transport. May be added at the same time as the proppant to aid transport.
- *Foamers*. To increase carrying capacity while transporting proppants and decreasing the overall volume of fluid needed.
- *Defoamers*. To reduce foaming after it is no longer needed in order to lower surface tension and allow trapped gas to escape.
- *Friction reducers*. To make water slick and minimise the friction created under high pressure and to increase the rate and efficiency of moving the hydraulic fracturing fluid. Generally used when the hydraulic fracturing pressure is applied to optimise pumping rates.
- *Gellants*. to increase viscosity and suspend sand during proppant transport. May be added at the same time as the proppant to aid 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.

Many of the additives have multiple effects on the fracturing fluid or on the formation, respectively. They may play a role in more than one group. Table 9.1 is from the USEPA's (2015d) review of the FracFocus database and lists the purposes of additives in descending order, by the frequency that they were disclosed as a use in hydraulic fracturing fluids. The additive purpose categories were identified from the FracFocus database and contain many more categories than the main categories described above, e.g. activator is listed but no definition is available. Table 9.1 shows that biocides and breakers or breaker catalysts were the most commonly disclosed chemicals during the 2-year period. The table also shows the number of confidential business information claims per additive purpose. The most significant number of confidential business information ingredient records were associated with corrosion inhibitors and surfactants.

The USEPA (2015d) found that the database contained 692 unique ingredients reported for base fluids, proppants and additives in hydraulic fracturing fluids. The information for all of these chemicals could not be verified (i.e. did not have a valid maximum additive concentration), and a list of 582 additives (including water and quartz) were reported in the USEPA project database for additive ingredients reported in hydraulic fracturing fluids in both oil and gas disclosures (USEPA, 2015d), and they are reproduced in Appendix B. Similar numbers of additives have already been published in the literature by the United States House of Representatives (2011), which reported 750 chemicals, and Colborn *et al.* (2011), who reported 632 chemicals.

From the USEPA's review of the frequency of the reporting of additives, the authors concluded that methanol, hydrochloric acid and hydrotreated light petroleum distillates were consistently used in hydraulic fracturing fluids for gas wells during the assessed period of records (USEPA, 2015d).

However, although the chemicals are only a small percentage of the overall hydraulic fracturing fluid volume, given the large volume of fluid that is injected, the quantities of chemicals on site can be large and there is the risk of spills or leaks on site (Public Health England, 2013; USEPA, 2015b), as fracturing fluids are usually prepared on site by mixing with water (Meiners *et al.*, 2013). For example, the probable commercial scenarios (Chapter 2) show that the typical range based on European experience for water required per fracture per well could range between 5000 and 15,000 m^3 (JRC, 2013b; AMEC, 2014). This would in turn mean that the volume of chemical additives required on site per fracture per well would range from 5 to 75 m^3. The USEPA (2015a) recently estimated that the total volume of chemical additives per well may range from 9.8 to 69 m^3 per well.

Table 9.1. Additive purpose and number of disclosures (source: USEPA, 2015d)

Additive purpose	Number of disclosures	Number of confidential business information ingredient records
Biocides	27,057	3339
Breakers and breaker catalysts	22,283	5325
Friction reducers	18,935	6618
Cross-linkers and related additives	18,353	7137
Gelling agents and gel stabilisers	18,243	7719
Acids	18,138	266
Corrosion inhibitors	17,824	21,519
Surfactants	17,778	21,581
Base fluid	16,112	486
Scale control	15,335	13,090
Iron control agents	13,472	1071
Clay control	11,432	4526
pH control	11,200	245
Non-emulsifiers	10,943	7587
Other/multiples	4207	1406
Solvents	4115	2551
Activators	2652	1031
Inhibitors	1998	1129
Resin curing agents	1473	422
Clean perforations	1373	955
Fluid foaming agents and energisers	1262	147
Stabilisers	917	198
Viscosifiers	900	455
Reducing agent	796	4
Acid inhibitors	786	378
Fluid loss additives	604	139
Oxidiser	513	5
Emulsifiers	510	44
Oxygen scavengers	428	218

Additive purpose	Number of disclosures	Number of confidential business information ingredient records
Antifoaming agents	351	349
Flow enhancers	247	91
Tracers	200	1127
Sulfide scavengers	190	161
Sealers	136	70
Formation breakdown	87	0
Antisludge agents	57	4
Antifreeze	45	0
Flowback control	44	64
Fluid diverters	3	3
Delaying agents	1	0
Proppant resin	1	1

9.4 Drilling Muds (or Fluids)

Drilling muds, or fluids, cool and lubricate the drill bit and string during drilling as well as removing cuttings from the wellbore (IPIECA and IOGP, 2009). Drilling fluids used in unconventional drilling are the same as the ones used in conventional drilling and therefore are discussed only briefly here.

There are two main types of drilling fluid: water-based fluids (WBF) and non-aqueous drilling fluids (NAF). The WBF is normally composed of water or brine with barite and clay and sometimes some chemical additives. There are three categories of NAF based on their aromatic content, as shown in Table 9.2.

Table 9.2. Classification of non-aqueous drilling fluids (source: IPIECA and IOGP, 2009)

Non-aqueous category	Components	Aromatic content
Group I: high aromatic content fluids	Crude oil, diesel oil, and conventional mineral oil	5–35%
Group II: medium aromatic content fluids	Low-toxicity mineral oil	0.5–5%
Group III: low/negligible aromatic content	Ester, LAO, IO, PAO, linear paraffin and highly processed mineral oil	< 0.5% and PAHs lower than 0.001%

IO, internal olefin; LAO, linear alpha olefin; PAO, poly alpha olefin.

In it *UK Onshore Shale Gas Well Guidelines for the Exploration and Appraisal Phase*, UK Onshore Oil and Gas (UKOOG, 2015a) recommends that operators ensure that drilling operations through aquifers are always carried out with water or WBF. This will help to protect the groundwater resource from drilling fluids that would be considered more toxic to human health and the environment. However, a report for the EC on key environmental and health risks (AEA, 2012a) states that, if the risk of impact is low, then low-toxicity NAF may be acceptable (AEA, 2012a).

Typically the vertical well is cased along the potable aquifer[22] section and the horizontal portion may be drilled with a drilling fluid that is either WBF or a low-toxicity mineral oil (group II) or synthetic oil-based fluid (group III) (NYSDEC, 2011). Synthetic oil-based fluids are described as "environmentally friendly" (NYSDEC, 2011) and group I NAF is considered unlikely to be used onshore for UGEE drilling.

Research for the EC (AEA, 2012a) has also recommended that drillers consider their choice of drilling fluids to minimise the hazard posed by drilling wastes (fluids and cuttings) returned to the surface as well as potential impacts to aquifers. Recommendations included the following:

- using WBF or low-toxicity mineral oil fluids rather than diesel-based ones;
- using less hazardous biocides (e.g. isothiazoline, amines);
- using air rotary drilling through surface casing zones to avoid drilling mud contacting potable aquifers and reduce drilling wastes.

The UK Onshore Operators Group (UKOOG, 2015a) further stated that the details of the mud systems (drilling fluid systems) proposed should be disclosed during the planning and permitting stages. This should include disclosure of the chemical additives proposed so that their impact can be risk assessed on a site-specific basis.

9.5 Chemicals Returned in Flowback and Produced Waters

Water produced during this initial period of gas production is termed flowback water because it is mostly composed of the hydraulic fracturing fluid. Water produced after the initial flowback and during the lifetime of gas production is termed produced water or production water. The EC recommendation of 22 January 2014 "on minimum principles for the exploration and production of hydrocarbons (such as shale gas) using high-volume hydraulic fracturing" (EU, 2014b) asked Member States to ensure that:

> (c) the ability to treat fluids that emerge at the surface after high-volume hydraulic fracturing is considered during the selection of the chemical substances to be used.

Section 10.3 provides a detailed analysis of the chemical composition of flowback and produced waters and suitable treatment and disposal methods. In that section, the chemicals that are used in drilling and hydraulic fracturing and that are subsequently returned in flowback or produced waters are discussed. Several studies have indicated that the chemicals used in the drilling and fracturing process are present in the flowback and produced waters (e.g. NYSDEC, 2011; Council of Canadian Academies, 2014; Maguire-Boyle and Barron, 2014; USEPA, 2015b). However, the concentration of chemical additives is lower in flowback and produced waters, as they either remain in the formation and/or become diluted by formation water. Chemical additives diffuse through the pores of the shales and become diluted and some can be adsorbed by organically rich shales (NYSDEC, 2011). Chemicals can also degrade, which would affect their movement in the subsurface, which depends on the chemical properties and the environmental conditions (USEPA, 2015b). The degradation of a chemical can reduce its concentration over time, and the transformation can be through a biotic or abiotic process. In addition, individual chemicals can affect chemicals in a mixture by changing their solubility and biodegradation rates; however, there has been limited research into the fate and transport of chemical mixtures at hydraulic fracturing sites (USEPA, 2015b).

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22 Potable water is water intended for human consumption, and an aquifer is defined as subsurface layer or layers of rock or other geological strata of sufficient porosity and permeability to allow either a significant flow of groundwater or the abstraction of significant quantities of groundwater.

The flow of fracturing fluid into the formation is reversed during flowback and any residual chemicals in the fracturing fluid become diluted by formation water and returned to the surface (NYSDEC, 2011), where it is generally treated and disposed of (refer to Chapter 10 for discussion of treatment and disposal options).

The NYSDEC (2011) highlight the fact that the fracturing fluid additives and their breakdown products are not routinely analysed for in flowback or produced water samples. Maguire-Boyle and Barron (2014) conducted comprehensive analyses of the quality of produced water samples from various US shales where UGEE was under way. Their study is important, as it identifies the likely sources of the chemical constituents. For example, they highlight how the presence of various fatty acid phthalate esters in produced waters from the Barnett and Marcellus shale formations, which were attributed to drilling fluids and/or breaker additives and that dioctadecyl ester of phosphate phosphoric acid ($(C_{18}H_{37}O)_2P(O)_2$) detected in the Marcellus produced water is known as a common lubricant.

9.6 Requirements under Existing Chemicals Legislation

9.6.1 REACH and CLP regulations

Regulation (EC) No. 1907/2006 on the Registration, Evaluation, Authorisation and Restriction of Chemicals, also known as the REACH regulation, would be applicable to UGEE operators with respect to the chemicals that are used in fracturing fluid. The EC recommendation of 22 January 2014 "on minimum principles for the exploration and production of hydrocarbons (such as shale gas) using high-volume hydraulic fracturing" asked for Member States to ensure that:

> (a) manufacturers, importers and downstream users of chemical substances used in hydraulic fracturing refer to "hydraulic fracturing" when complying with their obligations under Regulation (EC) No 1907/2006.

The REACH regulation requires registration of chemical substances manufactured in or placed on the EU market in quantities greater than 1 t per year (by the supplier) and potentially preparation of a chemical safety report (by the supplier and/or potentially the downstream user).

Operators of UGEE projects are likely to be considered as "downstream users" of the chemical substances used in the fracturing fluid, and not the manufacturers/importers, which means that they would not be subject to the main registration obligations. However, when exposure scenarios provided by a supplier during the registration and authorisation process do not cover specific UGEE use, the downstream user is obliged to report and provide relevant information to the European Chemicals Agency (ECHA) and eventually to prepare its own chemical safety report. Each registration dossier[23] is required to include an exposure assessment, which should indicate how impacts on human health and the environment can be avoided (ECHA, 2015).

In the past there has been criticism about the lack of transparency under the REACH regulation with regard to the use of substances used in hydraulic fracturing and under which conditions (Flynn, 2014). Following the EC's Recommendation of 22 January, in March 2015, the ECHA released a notice to the effect that in 2016 companies will be able to report more explicitly to the ECHA the use of substances used during hydraulic fracturing (ECHA, 2015). The ECHA now has a standard label for the use of chemicals in hydraulic fracturing, which is "Hydraulic fracturing for oil and gas exploration and extraction", and a product category, "Oil and gas field fracturing products" (ECHA, 2015).

23 REACH dossier –information submitted to the ECHA for the registration of a substance.

However, this does not provide for disclosure of chemicals used at a particular well. Refer to section 9.6.4 for further information about chemical disclosure.

The operator would have to prepare its own chemical safety report in accordance with Article 37 of the REACH regulation under certain conditions. Alternatively, the operator may ask its supplier to develop an exposure scenario covering its use or find an alternative substance or process.

Of the 582 chemicals listed that the USEPA assessed from the FracFocus database, only 139 are listed in Table 3.1 of Annex VI in the CLP regulation and have hazard classifications associated with them, with the remainder of undetermined hazard classification.[24]

Regulation (EC) No. 1272/2008 on the Classification, Labelling and Packaging of Substances and Mixtures, more commonly known as the CLP regulation, provides the United Nations-harmonised system for classification and labelling of chemicals in Europe. The REACH and CLP regulations are both hazard communication tools; REACH sets out the requirements for safety data sheets, and CLP sets out the rules for labelling and classification of hazards. The CLP codes used for classification are grouped depending on the hazards, as follows:

- H200–H299: physical hazard;
- H300–H399: health hazard; and
- H400–H499: environmental hazard.

Of the 582 chemicals listed that the USEPA assessed from the FracFocus database, only 139 are listed in Table 3.1 of Annex VI in the CLP regulation and have hazard classifications associated with them.

9.6.2 Biocidal Products Regulation

The Biocidal Products Regulation does not impose particular requirements on downstream users, such as UGEE operators. Biocidal products used in UGEE operations would need to comply with the approval and authorisation process set out in the Biocidal Products Regulation.

9.6.3 Water Framework Directive

The WFD (2000/60/EC) states that measures must be put in place to prevent and limit pollution to groundwater. It is important therefore to understand the definition of groundwater and aquifers in the context of the WFD:

- Groundwater is “All water which is below the surface of the ground in the saturation zone (below the water table) and in direct contact with the ground or subsoil”.
- An aquifer is “A subsurface layer or layers of rock or other geological strata of sufficient porosity and permeability to allow either a significant flow of groundwater or the abstraction of significant quantities of groundwater”.

The definition of groundwater has been further clarified in national guidance documents on a Member State basis. In Ireland, groundwater that does not represent a usable groundwater resource for water supply is not considered groundwater (EPA, 2011b). The UK Technical Advisory Group on the Water Framework Directive (UKTAG) has further described how the UK and Ireland have default depth values at which the groundwater ceases to be considered a resource, due to either its value for exploitation or its connection with surface water receptors (UKTAG, 2012). The UKTAG considers groundwater to a depth of 400 m as a resource for WFD purposes, unless specific information

24 The search of the REACH database was carried out on 24 April 2015.

indicates that it should be deeper on a case-by-case basis. The maximum thickness of a groundwater body[25] proposed was 400 m, which was recommended to be revised using local information where available (UKTAG, 2012). This may mean that the "prevent and limit" objective, as described below, may not apply to these deep saline groundwaters in shale formations.

The measures that should be implemented are further described in the Groundwater Daughter Directive (2006/118/EC) (EU, 2006a). This directive describes the "prevent and limit" objective in more detail:

- The "prevent" objective relates to hazardous substances, whereby all necessary and reasonable measures should be taken to avoid the entry of such substances into groundwater and to avoid any significant increase in their concentration in groundwater, even at a local scale.
- The "limit" objective relates to non-hazardous substances, whereby all necessary measures should be taken to limit inputs into groundwater to ensure that such inputs do not cause deterioration in the status of groundwater bodies, or significant and sustained upward trends in groundwater concentrations.

Annex VIII of the WFD lists the main pollutants relevant to the water environment that need to be classified as hazardous and non-hazardous substances. This classification is carried out at a national level: the EPA has completed it for Ireland (EPA, 2010), and the Joint Agencies Groundwater Directive Advisory Group has completed it for the UK including Northern Ireland (JAGDAG, 2014).

Hazardous substances under the WFD are substances or groups of substances that are toxic, persistent and liable to bio-accumulate. Non-hazardous substances are pollutants listed in Annex VIII that are not considered hazardous, as well as any other non-hazardous pollutants not listed that may present a risk of pollution.

For hazardous substances, minimum reporting values (MRVs) are used where there are not yet standards[26] to identify the need for preventative actions (JAGDAG, 2015). An MRV is defined as "the lowest concentration of a substance that can be determined with a known degree of confidence using commonly available laboratory analytical methods, but is not necessarily equivalent to a limit of detection" (EPA, 2011b). As hazardous substances must be prevented from entering groundwater, their use in hydraulic fracturing fluids and drilling muds would be permitted only if there was no risk of entry to groundwater above the MRV. The UK Environment Agency, for example, takes a precautionary approach to groundwater protection and will not authorise the use of substances that are hazardous to groundwater for hydraulic fracturing in UGEE projects.

Entry of non-hazardous substance into groundwater or slight deterioration in groundwater quality is not considered pollution. Pollution will only result where (EPA, 2011b):

- the substance enters groundwater in sufficient quantities to be harmful to human health or to the quality of the aquatic ecosystems or terrestrial ecosystems directly depending on aquatic ecosystems;
- there may be damage to material property; or
- there may be impairment or interference with amenities and other legitimate uses of the environment.

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25 Groundwater bodies are a volume of groundwater defined as a groundwater management unit for the purposes of reporting to the EC under the WFD.

26 Water quality standards such as drinking water quality standards (Directive 98/83/EC) or environmental quality standards (Directive 2008/105/EC).

Non-hazardous substances in hydraulic fracturing fluids and drilling muds can therefore potentially enter into groundwater without causing pollution, but the potential impacts to human health and the environment would need to be assessed on a site-specific basis, considering the sources, pathways and receptors.

9.6.4 Requirements for chemical disclosure

The use of chemicals (particularly additives to the hydraulic fracturing fluids) has been a major concern for the public, regulators and the scientific community. Some of the concern has been because of the reluctance of UGEE operators (and suppliers) to release what they consider confidential business information concerning their additives.

The EC recommendation (EC, 2014) of 22 January 2014 on minimum principles for the exploration and production of hydrocarbons (such as shale gas) using high-volume hydraulic fracturing made specific recommendations with regard to dissemination of information as follows:

> Member States should ensure that: the operator publicly disseminates information on the chemical substances and volumes of water that are intended to be used and are finally used for the high-volume hydraulic fracturing of each well. This information should list the names and Chemical Abstracts Service (CAS) numbers of all substances and include a safety data sheet, if available, and the substance's maximum concentration in the fracturing fluid.

In the last 5 years, there have been major changes in the regulation of the disclosure of chemicals, with many countries now requiring compulsory disclosure of chemicals (Ingelson and Hunter, 2014). This helps UGEE operators to be transparent and may alleviate some public concerns about the impacts on human health and the environment.

What chemical disclosure means in practice differs from country to country and is summarised in Ingelson and Hunter (2014), which is a review of chemical disclosure regulations in the USA, Canada and Australia:

- Some countries require the disclosure of a CAS number whereas others do not.
- UGEE operators may or may not be required to substantiate their claim for confidential business information protection.
- In some states, such as Indiana and Louisiana, disclosure is limited to chemicals that the state defines as hazardous.
- The timing of disclosure differs: some countries require it only after the hydraulic fracturing operations and others before and after.
- In the USA and Canada the disclosed chemicals are stored in a central register (e.g. FracFocus) and in Australia different localised databases are used.

The Council of Australian Government's Standing Council of Energy and Resources has recommended that a balance be sought between the level of public disclosure and the need for confidential business information to encourage innovation and growth in the industry (Ingelson and Hunter, 2014). It is recommended that, where full public disclosure of chemicals is not possible, full disclosure of chemicals to the competent authority on a confidential basis is required in order for risk assessments to be reviewed or carried out (Public Health England, 2013; Ingelson and Hunter, 2014). For example, there were confidential business information claims in approximately 70% of well disclosures on the FracFocus database assessed by the USEPA (2015b), and therefore they had to be excluded from its risk assessment analysis (see also Table 9.1 for number of confidential business information records per additive type). A robust system needs to be in place to facilitate confidential business information claims being disclosed to the competent authorities (Ingelson and Hunter, 2014).

Further considerations include the ability to evaluate legitimate confidential business information claims, in case they are challenged by the public, and whether some information such as the chemical group can be used for the protection of the confidential business information.

9.6.4.1 Current disclosure arrangements in Ireland and Northern Ireland

There are currently no regulations in Ireland or Northern Ireland for the public disclosure of chemicals used in UGEE operations. In their *UK Onshore Gas well guidelines for the Exploration and Appraisal Phase*, UKOOG (2015a) have recommended that the following information is disseminated on a well-by-well basis:

1. any authorisations for fluids and their status as hazardous or non-hazardous substances;
2. safety data sheets;
3. volumes of fracturing fluid, including proppant, base carrier fluid and chemical additives;
4. the name of each additive and its purpose in the fracturing process; and
5. maximum concentrations (in percentages by mass) of each chemical additive.

This is a voluntary method of disclosure. UKOOG has a public disclosure form (Figure 9.2) and the information will be displayed on the UKOOG website. The form states that the CAS number can be left blank if there is confidential business information but there is no guidance on how this is defined or regulated. The UK Environment Agency and the Scottish Environmental Protection Agency,[27] however, have powers to obtain full disclosure of chemicals used in hydraulic fracturing (DECC, 2013b) and therefore it is likely that the EPA and NIEA have similar powers that they can invoke.

27 The Environment Agency requires full public disclosure, whereas the Scottish Environmental Protection Agency requires disclosure to it but not to the public.

UKOOG United Kingdom Onshore Oil and Gas

Shale Gas Well - Hydraulic Fracturing Fluid and Additive Component Transparency Service (HF FACTS)

Well Location		Well Description		Hydraulic Fracturing Fluid Data	
Country		Operator of Well		Water Volume (1) (Cubic Metres)	
Latitude		Name of Well		Max mass % of Total HF Fluid	
Longitude		DECC Well Registration No		Proppant (kilograms)	
Long/Lat projection		HF Completion Date		Max mass % of Total HF Fluid	
County		Well Depth (TVD Meters)		% of Water Volume - recycled/produced water	
Regulator Consents		Avge frac perf depth (TVDm)		% of Water Volume fresh water	
EA EPR Permit No				Max (mass %) Water+Proppant=	
Town & Country Planning consent					
DECC Hydraulic Fracture Programme approval					

HF Fluid Products

Product Trade Names in Fracturing Fluid (if applicable)	Product Purpose in Well	Supplier(s)

HF Fluid Constituents

Chemical Substance in Fracturing Fluid (2)	Chemical Abstract Service Number (CAS Number) (3)	Maximum Chemical substance Mass % in HF Fluid (4)	Comments

Notes:
(1) Water utilized may be any combination of recycled water, produced water or fresh water.
(2) All chemical additive substance data is provided by suppliers and is consistent with Safety Data Sheets.
(3) See www.echa.europa.eu to find ECHA numbers; blank if confidential business information but regulator fully appraised.
(4) Because maximum percentages are shown, total of water, proppant and HF chemical substance components may be greater than 100%.

Figure 9.2. UKOOG Public disclosure of fracture fluid form (source: UKOOG, 2015a)

UKOOG (2015a) also states the water compositional analysis, and any identified contamination issues should be available for disclosure for flowback fluids, but there is no requirement for public disclosure. There is also no requirement for the use of drilling chemicals to be disclosed publicly.

9.7 Potential Hazards of Hydraulic Fracturing Chemicals

9.7.1 Assessment approach

To review the hazards associated with chemicals used in hydraulic fracturing fluids the 582 chemicals assessed by the USEPA (2015a) from FracFocus were reviewed against the CLP and WFD classification systems. A hazard is defined as the potential source of harm or adverse effect on human health and/or the environment. The results of the hazard classification assessments are described below. Note that this assessment does take into account the concentrations of these chemicals in the hydraulic fracturing fluid and that the mere presence of a chemical that falls within a hazard class does not indicate that there will be exposure and harm caused to human health or the environment.

Potential hazard and risks need to be evaluated on a site-specific basis, given the variety of chemicals used in different hydraulic fracturing operations (USEPA, 2015b) and different site-specific exposure pathways, which will identify the chemicals of concern at the local level.

9.7.2 Classification of chemical hazards

The CLP regulation classifies chemicals by their hazard class, whether it is a health or an environmental hazard. The chemicals that were considered to be acutely toxic, to have reproductive toxicity and to be carcinogens were examined. Appendix F lists the 582 chemicals, along with their CLP hazard classifications and frequency of disclosure on the FracFocus database and their maximum concentrations. Physical hazards and hazards to human health, such as eye and skin irritants, are listed in Appendix F but are not discussed further here.

Acute toxicity is defined as having adverse effects occurring following oral or dermal exposure within 24 hours, or an inhalation exposure of 4 hours. The hazard statements for acute toxicity are the following:

- oral: H300, H301, H302;
- dermal: H310, H311, H312;
- inhalation: H330, H331, H332.

Reproductive toxicity is when there is general concern about effects on both fertility and development. H360 and H361 are the hazard statements used.

A carcinogen is a substance or a mixture of substances that induce cancer or increase its incidence. Chemicals that are “known or presumed human carcinogens” (category 1 – H350) or “suspected human carcinogens” (category 2 – H351) are included in the CLP hazard classifications.

Chemicals that are considered hazardous to the aquatic environment are either classified as “aquatic acute” (H400) or “aquatic chronic” (H41 –H413).

9.7.2.1 Results

All the hazard classifications can be found in Appendix F. Note that for the 582 reviewed as part of this assessment, 139 of them had hazard classifications listed in the CLP regulation, therefore the CLP classification for 443 is unknown.

The key findings for human health hazards were that:

- 78 chemicals were classified as acutely toxic by the oral, dermal or inhalation route;
- three chemicals were classified for reproductive toxicity;
- two chemicals were “known or presumed human carcinogens” (category 1 – H350) and 22 chemicals were “suspected human carcinogens” (category 2 – H351).

The key findings for environmental hazards were that:

- 24 chemicals were classified as acutely toxic to aquatic life;
- 27 chemicals were classified as chronically toxic to aquatic life;
- 22 of these chemicals were both acutely and chronically toxic.

9.7.3 Classification under the Water Framework Directive

All the WFD hazardous and non-hazardous classifications can be found in Appendix F. Note that there are some slight differences between the EPA (2010) and the JAGDAG (2014) classifications for the chemicals and both are summarised here, although both are consistent with EU guidelines. In addition, Amec (2015) was commissioned by the Environment Agency to classify (using the JAGDAG methodology) a selection of chemicals commonly used by the oil and gas industry, and these results were incorporated into the assessment. Appendix F lists the 582 chemicals, along with their WFD hazard classifications sorted by frequency of occurrence in the FracFocus database and their maximum concentrations.

EPA hazardous substances classifications had 87 of the 582 chemicals listed (with the remainder unlisted) and the conclusions were as follows:

- 19 chemicals were classified as hazardous in the water environment;

- 21 chemicals were classified as non-hazardous in the water environment; and
- for 47 chemicals, the classification was "undetermined" by the EPA.

JAGDAG hazardous substances classifications had 28 of the 582 chemicals on the list and an additional 26 that were recently classified by the UK Environment Agency (Amec, 2015). In total:

- 14 chemicals were classified as hazardous in the water environment; and
- 40 chemicals were classified as non-hazardous in the water environment.

It should be noted that the review of substances is an ongoing process in the UK and Ireland (through JAGDAG).

9.7.4 Toxicological and physicochemical properties

The USEPA used data on the toxicity, occurrence and physicochemical (mobility, volatility and persistence) properties of chemicals and a ranking system to carry out a high-level national-scale hazard evaluation of the chemicals in the FracFocus database to assess the risk to drinking water supplies (USEPA, 2015b). The USEPA sourced the toxicological information used for human health risk assessments from peer-reviewed sources including the USEPA and the US Agency for Toxic Substances and Disease Registry (ATSDR). Based on available information, they were able to conduct the hazard evaluation on 37 chemicals. They used strict criteria for the selection of chemicals for the hazard assessment, including:

- The chemical had to have a federal chronic oral reference value (RfV),[28] as they have undergone an extensive independent peer review.
- The chemical had available data on frequency of use in hydraulic fracturing fluids.
- The chemical had available information on its physicochemical properties.

The key findings of this assessment were as follows (USEPA, 2015d):

- Propargyl alcohol received the highest hazard score, based on its use in 33% of wells, its likelihood of being transported in water and its low reference dose (RfD)[29] values.
- Methanol, ethylene glycol, 2-butoxyethanol, formic acid, *N*,N-1-dimethylformamide and formaldehyde (used in 73%, 47%, 23%, 11%, 9%, and 7% of wells, respectively) are considered to be highly mobile in water and have low volatility, but have higher RfDs.
- Naphthalene, used in 19% of wells, had a low RfD, but lower transport in water relative to other chemicals.
- Acrylamide was used in only 1% of wells, has a low RfD and is very conducive to transport in water, and thus received a high overall hazard potential score.
- Other chemicals, including benzene and dichloromethane, received lower overall scores because they are used more infrequently (each in less than 0.1% of wells).

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28 Reference values (RfVs): chronic toxicity values for non-cancer oral exposure.

29 Reference dose (RfD): an estimate (with uncertainty) of a daily oral exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime (maximum acceptable oral dose of a toxic substance).

9.7.5 Review of hydraulic fracturing fluids used in Europe

In a German study by Meiners *et al.* (2013), the toxicity of individual fracturing fluids that were used (or proposed for use) in Germany were examined. As fracturing fluids are site specific, the fluids assessed were for illustration purposes only. They determined the hazard potentials of the hydraulic fracturing fluids, based on the individual chemicals, and calculated their individual risk quotients, based on the chemical concentrations and associated assessment values, including the *de minimis* threshold[30] and health-related guidance values for drinking water and predicted no effect concentration[31] for an aquatic organism. They developed a scoring system that showed that when a chemical had a risk quotient[32] of less than 1 no hazard potential was expected, whereas a risk quotient of 1 or more represented a human toxicological or ecotoxicological hazard potential. A high hazard potential was assumed when the risk quotient was greater than 1000.

Table 9.3 shows three of the fracturing fluids examined by Meiners *et al.* (2013) and summarises their findings on the individual fluids' hazard potential. Overall, each of the three fluids was found to have high human toxicological and ecotoxicological hazard potentials. See Table 9.1.

Table 9.3. Fracturing fluids used in Germany and their hazard potential (source: Meiners *et al.*, 2013)

Fluid name and description	Usage	Components	Hazard potential
Söhlingen Z16 (tight gas)	9 fracks in 2008	Water 824 m^3 Proppants 170,100 kg Additives 38,079 kg	High human toxicological and ecotoxicological hazard potential
Damme 3 (shale gas – slick water)	3 fracks in 2008	Water 12,119 m^3 Proppants 588,000 kg Additives 19,873 kg	High human toxicological and ecotoxicological hazard potential
ExxonMobil (slick water)	Planning in 2012	Water 1600 m^3 Proppants unknown Additives 5600 kg	High human toxicological and ecotoxicological hazard potential – based on biocide proposed

Meiners *et al.* (2013) concluded that classification as hazardous to water or using the CLP regulation should act only as guidelines for assessing the hazard potential in terms of protection of human health and the environment, as the Damme 3 fracturing fluid was classified as only "high human toxicological and ecotoxicological hazard potential" on the basis of *de minimis*. Meiners *et al.* (2013) further stated that, in such an instance, a significant volume of water (400,000,000 m^3 or 0.4 km^3) would be required to achieve the appropriate dilution.

ExxonMobil had an improved version of slick water in planning in 2012, in which a number of additives had been replaced with substances less hazardous than Damme 3 (discussed further in section 9.8.1). The hazard that still remained was in relation to the biocide (ethylene glycol bis(hydroxymethyl ether) proposed (Meiners *et al.*, 2013). This biocide is known to decompose into formaldehyde, and therefore the slick water was still classified as having "a high human toxicological and ecotoxicological hazard" (Meiners *et al.,* 2013).

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30 *de minimis* thresholds for assessment of locally confined groundwater pollution have been specified, taking account of the maximum permitted concentrations set in drinking water guidelines and the human toxicologically and ecotoxicologically established effect thresholds (LAWA, 2004; Meiners *et al.,* 2013).

31 The predicted no effect concentration is the maximum concentration of a substance at which no effects on organisms of an aquatic ecosystem are expected.

32 Risk quotient equals the substance concentration in the fluid divided by the assessment value.

Meiners *et al.* (2013) recommended that further information about the hazard potential of the mixture of chemicals is required and that this should be done by carrying out toxicology tests on the complete fluid.

9.8 Alternatives and Emerging Practices for Hydraulic Fracturing Additives

9.8.1 Minimising chemical use and use of non-toxic chemicals and green chemicals

The EC recommendation (EC, 2014) on minimum principles for the exploration and production of hydrocarbons (such as shale gas) using high-volume hydraulic fracturing (2014/70/EU) specified that Member States must ensure that "chemical substances in high-volume hydraulic fracturing is minimised". The EC recommendation also requires that Member States "not use hazardous chemical substances, wherever technically feasible and sound from a human health, environment and climate perspective".

Meiners *et al.* (2013) stated that the company ExxonMobil Production Deutschland GmbH announced that the number of additives used in fracturing fluids could be reduced to fewer than 10 substances and that, in the future, the use of highly toxic substances, carcinogenic, mutagenic and toxic to reproduction substances (CMR) could be discontinued completely. Meiners *et al.* (2013) further concluded that the additives used in the recent past could be improved upon within just a few years.

There have also been some developments in environmentally friendly or green additives in the industry. However, what constitutes environmentally friendly can be largely subjective and depends on the parameters used to judge it, such as physical, chemical and toxicological properties (Nixon *et al.,* 2014). The overall objective of environmentally friendly products is to reduce or eliminate the impact on human health and/or the environment. When developing a hydraulic fracturing fluid, the performance, availability and cost of additives need to be considered as well as its "environmental friendliness" (Nixon *et al.*, 2014).

There appears to be a trend towards less toxic hydraulic fracturing fluids in the industry, but it is difficult to assess because there is limited information available in the public domain because any improvements made to fracturing fluids would be considered sensitive business information. The current developments in the replacement of some toxic chemicals with less toxic alternatives that are available in the literature are presented here:

- Diethanolamine (CAS 111-42-2) has been proposed as a replacement for the more toxic methanol as a solvent (Gordalla *et al.*, 2013).
- Tetramethyl ammonium chloride (CAS 75-57-0) may be replaced by choline chloride (CAS 67-48-1), which has lower human toxicity and ecotoxicity, as a clay stabiliser (Meiners *et al.*, 2013).
- Petroleum distillates (CAS 64742-47-8) may be replaced by butyldiglycol (CAS 112-34-5), as a friction reducer, and is non-toxic under the CLP regulation. It would reduce the factor by which the health related-guidance values would be exceeded (Meiners *et al.,* 2013).

9.8.2 Non-chemical fracturing processes

There are a few examples of fracturing processes that do not use chemicals or certain groups of additives, which are summarised by NYSDEC (2011), the Federal Environment Agency (Meiners *et al.,* 2013) and the EC Joint Research Council (JRC, 2013a), and some examples are as follows:

- LPG, which consists primarily of propane, is known to be a good carrier of proppant. The LPG mixes with the natural gas and it is then recovered almost completely, together with the natural gas released from the rock formation (NYSDEC, 2011; Meiners *et al.,* 2013). Between 2008 and 2012 this method was used about 1000 times in Canada (Meiners *et al.,* 2013).

- One company was investigating the use of ultraviolet (UV) light as a way to inhibit growth of microorganisms, in order to reduce the use of biocides (Meiners *et al.,* 2013). This methodology has not yet been proven to work.
- Another company was working in co-operation with the University of Leoben, Austria, to develop a process that uses no chemicals and relies solely on water, bauxite (a proppant) and corn starch. Its technical feasibility was due to be tested in 2015 (Meiners *et al.,* 2013), but it is understood that the work has been halted.
- Cavitation hydrovibration is a technique developed by the Institute of Technical Mechanics in Dnipropetrovsk, Ukraine, which fractures rock using a high-frequency pulsating flow without the use of chemical additives (JRC, 2013a). The method has been tested and used in the Novojarovskoje sulfur deposit (in the Ukraine) but not for shale gas production, and there is little else known about the status of this system (JRC, 2013a).

These studies concluded that these non-chemical fracturing processes are not mature enough and that much more research will be required before fracturing fluids that do not rely on chemical additives are commercially viable. It should also be noted that eliminating the use of chemicals in hydraulic fracturing fluids does not eliminate the risks of the produced water and its potential pathways.

9.9 Summary of Chemicals Used and Recommended Mitigation Measures

9.9.1 Summary of chemicals used in UGEE activities

Based on the assessment of chemicals used in UGEE activities, the following conclusions can be drawn:

- Full chemical disclosure should be required to be made to the competent authorities, to allow them to complete or review risk assessments in the interests of protecting human health and the environment. However, regulation and guidance would be required for managing a public disclosure process and any commercially confidential information.
- The chemicals used during drilling should be evaluated carefully. Compressed air, water or WBF would be preferred when drilling through potable aquifers. The drilling chemicals used should also be disclosed so that their impact can be risk assessed on a site-specific basis.
- The assessment of the potential hazards of chemicals showed that a significant number are classified as toxic to human health or the environment under the CLP regulation. However, this does not imply that there is a risk to human health or the environment and it is recommended that site-specific risk assessments are carried out for the chemicals proposed for use in hydraulic fracturing that take into account the dilution, fate and pathways to receptors on a case-by-case basis.
- The assessment of the potential hazards of chemicals showed that some chemicals that are classified as hazardous to water under the WFD have been used in hydraulic fracturing operations in the USA. As hazardous substances must be prevented from entering groundwater under the WFD in the EU, their use in hydraulic fracturing fluids and drilling fluids would be permitted only if there was no risk of entry into groundwater above the MRV. The UK Environment Agency, for example, takes a precautionary approach to groundwater protection and will not authorise the use of substances that are hazardous to groundwater to be used for hydraulic fracturing for UGEE projects.
- In the assessment of the potential hazards of chemicals used in hydraulic fracturing it has been determined that there are several gaps in knowledge, including:

- Many of the chemicals listed are currently not registered under the REACH regulation and do not have a CLP or WFD hazardous substance classification associated with them.
- The actual toxicity of many of the chemicals used in hydraulic fracturing fluids is unknown, as there are no RfVs values developed for them.

- Chemicals are also being replaced with less toxic chemicals with the aim of discontinuing the use of highly toxic substances (CMR substances). However, there is little available information on improvements in fracturing fluids in the public domain, as the information would be considered confidential business information.
- The geological setting has to be considered in the assessment of hydraulic fracturing fluid compositions.
- Non-chemical fracturing techniques are available; however, studies indicate that they are not sufficiently mature and that more research will be required before these become available.

9.9.2 Recommended mitigation measures

The impacts and mitigation measures associated with water quality and the potential for chemicals used in UGEE activities to have an impact on water quality are addressed in Chapter 4. These include mitigation measures relating to chemical handling, storage and transport. Issues associated with the regulation of chemicals and their disclosure are dealt with further under Project C of the UGEE JRP.

The following mitigation measures associated specifically with the chemical hazard potential are described here:

- Chemicals should be fully disclosed to competent authorities prior to hydraulic fracturing. This information should include chemical name, CAS number, additive purpose, maximum concentration and safety data sheet information, as a minimum, and should also include the reason for use. This information should be available on a per fracture per well basis. This would allow a site-specific risk assessment of the potential impacts to human health and the environment to be carried out by the developer in consultation with the competent authorities.
- Chemicals ought to be disclosed to the public prior to hydraulic fracturing and made available in a public database. Effective public engagement on UGEE projects may help to address public concerns (TNS BMRB, 2014). It is recommended that confidential business information claims are also substantiated by the operator, to help alleviate public concern.
- Chemicals hazard classifications should be made available, including CLP classifications where available. Chemicals should be defined as hazardous or non-hazardous under the WFD and, if a determination has not yet been made, the chemical should be assessed using the JAGDAG methodology (JAGDAG, 2012). Taking a precautionary approach to the use of chemicals classified as hazardous to groundwater under the WFD, their use in hydraulic fracturing fluids and drilling fluids would be prohibited.
- Chemical toxicological information and exposure scenarios should be available and a site-specific risk assessment of the potential impacts to human health and the environment should be carried out by the developer in consultation with the competent authorities. The potential additive or synergistic effects of chemicals should be considered. The results should be used to inform the additive selection process.
- Developers should be encouraged to minimise the number of chemicals used and the volumes and concentrations required and demonstrate that this has been considered.
- Developers should be required to substitute some chemicals with less toxic ones and demonstrate that this has been considered in their chemical selection process.

- The chemicals used during drilling should be evaluated carefully. Compressed air, water or WBF would be preferred when drilling through potable aquifers.

10 Treatment and Disposal of Flowback and Produced Waters (Task 7)

10.1 Background

Disposal and treatment of flowback and produced water (production water) are a major concern. In the Marcellus Shale Formation, flowback water amounts to between 9% and 35% of the quantity of water used during hydraulic fracturing (NYSDEC, 2011). Sixty per cent of this flowback from the Marcellus Shale occurs in the first 4 days after hydraulic fracturing, while the remaining amount occurs over a 2- to 8-week period (NYSDEC, 2011). The daily quantities of flowback generated for the Marcellus Shale is shown in Figure 10.1 (red line). Also shown in Figure 10.1 is the concentration of TDS, which increases with time and can be as high a 350,000 mg/L in the Marcellus Shale. The Marcellus Shale is of marine origin and, therefore, contains a high concentration of salt. Water produced during this initial period is termed flowback water because it is mostly composed of the injected water and associated chemicals. After this initial period, the flow from the formation decreases substantially and levels off to a rate of a few barrels (0.5 m^3) per day (depending upon the amount of gas being produced). Water produced after the initial flowback and during the gas production phase is termed produced water or production water.

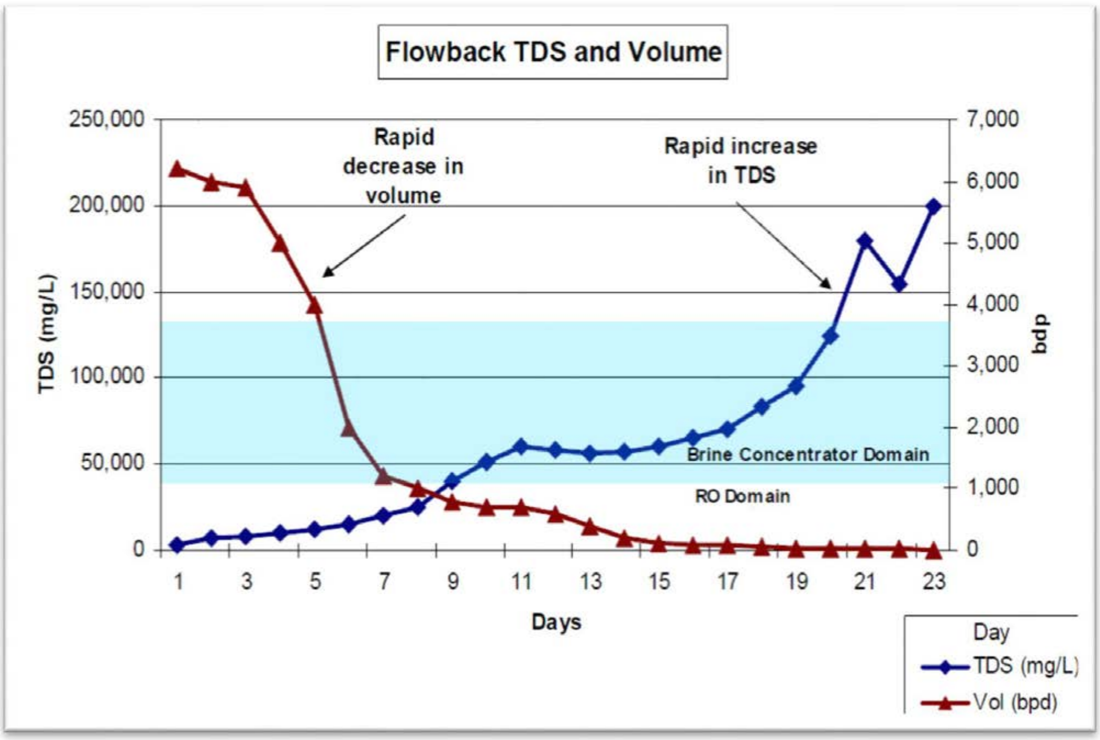

Figure 10.1. Flowback and TDS volume (source: Kimball, 2012).

The quantities and compositions of the flowback and produced waters can vary depending upon the formation waters, the chemical additives used and the time after hydraulic fracturing. In its recent "Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources", the USEPA (2015a) provided the following estimates of the amounts of flowback and produced waters as a percentage of injected fluid in various formations in the USA:

- short duration (0–10 days):
    - Marcellus Shale: 10%;

    - Barnett (Texas): 20%;
    - Haynesville (Texas): 5%;
    - Fayetteville (Arkansas): 10%;
- mid-duration:
    - Marcellus (West Virginia): 8% (30 days);
    - Marcellus Shale: 24% (90 days);
- long duration:
    - Marcellus (West Virginia): 10–30% (up to 115 months)
    - Marcellus Shale: 30% (115 months – statistical curve fit)
    - Barnett (Texas): approximately 100% (72 months)
    - Eagle Ford (Texas); < 20% (lifetime)

The amount of water produced after initial flowback also varies significantly depending upon the formation and time. The USEPA (2015a) estimated that the median amount of water produced over the long term from horizontal shale wells was 3400 L per day (range 0–72,000 L per day). One study of wells in the Marcellus Shale (Hayes, 2009, reported by USEPA, 2015a) resulted in an average of 32,000 L per day after 90 days. Lutz *et al.* (2013, reported by USEPA, 2015a) calculated that wells in the Marcellus Shale produced 4.8 L of water per MMBTU of produced gas.

Based on a review of the available information and formations, the estimated amounts of flowback for the NCB and CB range between 25% and 40% of the amount of injected water (Table 2.1, Probable commercial scenarios).

In the USA, private and commercial treatment facilities, as well as publicly owned treatment works (POTWs), have accepted and treated flowback water. However, recent data have shown that elevated levels of bromide are present in surface water down gradient of discharge points (outfalls) from the treatment facilities treating flowback and produced water (Warner *et al.,* 2013). In addition, elevated levels of radionuclides were found in river bottom sediments near the treatment facilities' outfalls that are attributed to flowback and produced water.

New on-site (at the pads), more advanced facilities are available for treatment of these wastewater streams. This also enables better recycling and reuse for nearby UGEE operations. In addition, in the USA, flowback water is disposed of in deep injection wells.

10.1.1 Fracturing fluid composition

Evergreen Resources Inc. has conducted exploration in the NCB dating back to 2001 and 2002, which consisted of fracturing six wells: three in Ireland and three in Northern Ireland. The fracturing fluid used during exploration was described as a gel, nitrogen and acid frac (see Report A1-2 of the UGEE JRP) and Tamboran's slide presentation, entitled "NW Carboniferous Basin – Natural Gas Project", undated). No flowback quality data were available.

The gel fracturing process typically consists of injection of a polyacrylamide solution as friction reducer followed by the addition of a linear "guar" gel to enable pumping of higher proppant concentrations. Tamboran (undated) stated that, for any full-scale production, only proppant and water would be used for fracturing (i.e. no chemical additives would be used), which is discussed further in Chapter 9.

Cuadrilla's EIA (2014a) described the characteristics of their proposed hydraulic fracturing fluid, which is discussed below:

1. "The hydraulic fracturing fluid will consist of water and proppant (99.95%) and less than 0.05% friction reducer (petroleum distillates) by volume." Typically various chemical additives are used for hydraulic fracturing such as friction reducers, clay stabilisers, gels, corrosion inhibitors and surfactants, which account for 0.5–2% of the fracturing fluid volume. Cuadrilla's plan appears to consist of adding only a small concentration of friction reducer with no other additives. "The description of each major fluid component is provided below:
   (a) Water is the predominant constituent in the fluid. It is intended that the water will be sourced from the mains water supply and by reusing hydraulic fracturing fluid that returns to the surface between hydraulic fracturing stages as a closed loop system. This has the combined benefit of reducing both the consumption of mains water and the quantity of flowback fluid that has to be removed for treatment and disposal off-site.
   (b) Proppant (silica sand) is mixed in with the fracturing fluid at specific stages during the fracturing event to keep the fracture created in the shale open after the hydraulic pressure has been released.
   (c) A friction reducer is added to the water to minimise the pressure losses incurred due to friction between the water and the well casing as the water travels several kilometres from surface through the well to the shale formation. The proposed friction reducer is polyacrylamide which is classified as a non-toxic, non-hazardous pollutant by the Environment Agency of England.
2. There is the potential that the flowback fluid, reused for subsequent hydraulic fracturing, would contain bacteria. To kill this bacteria, UV treatment will be used." However, UV treatment may be ineffective if transmittance is impeded by suspended solids or other components that may cause high turbidity.
3. "As a contingency, dilute hydrochloric acid solution may be used to facilitate the entry of fracturing fluid from openings in the production casing to the body of shale. However, it has not been necessary to use it at other wells drilled in the licence area to date and it is thus included as a contingency."

10.2 Approach

The objectives of Task 7 were to identify and assess the success of treatment and disposal methods for flowback and produced water and provide specific case studies from around the world, with specific reference to European examples. Linking with Task 6 (Chapter 9), Task 7 also identifies the treatment technologies available to adequately treat typical chemicals used in the fracturing process in combination with probable constituents of produced water. Disposal options linked to the available treatment options are also reviewed and assessed.

The currently used treatment and disposal methods for flowback and produced water were evaluated by completing the following assessments:

- composition of flowback and produced water:
- wastewater discharge regulations:
  - surface water discharge;
  - deep well injection (DWI) disposal;
  - POTWs effluent;
- treatment and disposal alternatives:

- municipal or city treatment plants (so-called POTWs in the USA);
- regional or centralised treatment centres:
  - treatment and disposal to surface water (multiple processes);
  - treatment and disposal to DWI ;
- on-site treatment technologies:
  - treatment for recycle and reuse;
  - treatment and disposal to DWI ;
- description of treatment technologies that are components of the treatment schemes above:
  - oil and solids removal;
  - physicochemical treatment;
  - oxidation;
  - membrane technologies;
  - evaporators/crystallisers.

The sections that follow discuss the topics listed above in detail.

10.3 Composition of Flowback and Produced Waters

The quantity and composition of flowback and produced waters depend upon several factors including shale geological characteristics, hydraulic fracturing methodology, formation water quality, and the resource available in the shale formation (i.e. liquid hydrocarbons and/or natural gas).

Water quality data for the NCB study area are limited to sparse measurements of salinity, chlorides and sulfide in water samples collected by drillers. These data are available from Project A of the UGEE JRP (Report A1-2, section 2.7.7,). No water quality data to predict flowback and produced water quality are available for the CB. None of the available data accurately represent the composition of waters in the source zone formations. As a result, only rough estimates of the TDS (> 40,000 to > 70,000 mg/L) were provided in Chapter 2, Table 2.1, Probable commercial scenarios. Olsson *et al.* (2013) found that formation water is the main contributor of high TDS concentrations in flowback and produced waters. Because of the lack of information on specific composition of flowback and produced waters in the NCB and CB, information was collected from a variety of sources including:

- flowback composition:
  - Bowland Shale in the UK (Table 10.1);
  - Marcellus and Barnett Shales in the USA (Table 10.2);
- produced water composition:
  - Marcellus, Eagle Ford and Barnett Shales in the USA (Table 10.3);
- flowback and produced waters (no distinction between the types of waters).

In addition, a very extensive list of chemicals detected in samples of flowback from Marcellus Shale wells is provided in Appendix C-1. Owing to its extensive nature, this information is used along with the Bowland Shale compositional data to compare it with various regulatory standards (Tables 10.5–10.9).

10.3.1 Flowback quality

10.3.1.1 Bowland Shale

The UK Environment Agency (2011) collected flowback water quality data from samples during hydraulic fracturing of an exploratory well advanced in the Bowland Shale Formation by Cuadrilla Resources. Cuadrilla's exploratory activities took place at the Preese Hall site, located in Lancashire in England (Cuadrilla, 2014b). The Environment Agency retained a third-party laboratory to analyse the flowback samples for metals, other non-metal inorganics and radioisotopes. In addition, Cuadrilla has completed an EIA for exploration and production at two new sites (Cuadrilla, 2014a,b).

Owing to its proximity to the NCB, the Preese Hall data are provided and discussed in the following paragraphs. Table 10.1 summarises the flowback water quality for samples collected from 7 April to 17 August 2011. However, this table is not a complete characterisation because it does not show concentrations of important parameters such as boron, calcium, strontium, barium or organic compounds such as PAHs and BTEX.

As shown in Table 10.1, the Preese Hall flowback is characterised by relatively high concentrations of dissolved monovalent ions, namely chloride, sodium and bromide; and moderate to high levels of dissolved magnesium and iron. Heavy metal concentrations are generally low or not detectable, although some zinc and chromium were present, mostly in unfiltered samples. TDS concentrations were calculated from the reported conductivities shown in Table 10.1. The calculated TDS ranged from 85,600 to 113,000 mg/L. One sample had detectable levels of acrylamide, which probably resulted from the polyacrylamide additive used for hydraulic fracturing. No data were reported for oil and TSS concentrations. Although these samples were all termed flowback samples, the elapsed time of sampling and the steep increase in ionic species (e.g. chlorides, magnesium, sodium) from the April samples to the remainder of the samples appear to indicate that the latter samples would be representative of produced water quality.

10.3.1.2 Marcellus and Barnett Shales

Table 10.2 presents a limited set of typical flowback water quality data for US shales obtained from various literature sources. As shown in Table 10.2, the flowback water quality varies over a wide range of concentrations for most constituents. For instance, the Marcellus Shale flowback has very high TDS ,ranging from 17,800 to 201,000 mg/L and relatively low alkalinity. The Barnett Shale flowback has relatively low TDS, with a median of 36,100 mg/L, and higher alkalinity.

Table 10.1. Flowback water quality data: Cuadrilla's exploratory hydraulic fracturing in Bowland Shale Formation, Preese Hall site, Lancashire, UK

Parameters	Sample ID	Sample 1	Sample 2	Sample 3	Sample 4	Sample 5	Sample 6	Sample 7
	Date	7 April 2011	14 April 2011	28 April 2011	18 May 2011	14 June 2011	1 Aug 2011	17 Aug 2011
	Elapsed time (days) No. of samples	0	7	21	41	68	116	132
Conductivity at 25ºC, μS/cm	3	–	–	–	150,614	133,730	176,000	–
pH (SU)	3	–	–	–	6.35	7.06	6.33	–
Acrylamide, μg/L	1	–	–	–	–	–	–	0.05
Lead (filtered), μg/L	7	179	< 20	< 2	< 40	< 40	< 20	< 100
Lead – Pb, μg/L	7	600	< 10	< 10	< 40	44.9	80.5	< 100
Mercury (filtered), μg/L	7	0.01	< 0.01	0.013	< 0.01	< 0.01	< 0.01	< 0.01
Mercury – Hg, μg/L	7	0.024	< 0.01	< 0.01	< 0.01	0.012	0.09	0.038
Cadmium (filtered), μg/L	7	0.674	< 1	1.47	< 2	< 2	< 1	< 5
Cadmium – Cd, μg/L	7	1.29	< 0.5	< 0.5	< 2	< 1	6.02	< 5
Bromide, mg/L	7	–	–	242	854	608	673	1020
Chloride ion, mg/L	7	15,400	34,400	22,200	75,000	64,300	58,000	92,800
Sodium (filtered), mg/L	7	7950	15,100	9330	28,400	200	21,400	33,300
Sodium – Na, mg/L	7	No bottle	15,100	9380	28,400	23,600	21,700	34,800
Potassium (filtered), mg/L	7	23.2	46.4	37.8	82.1	20	64.9	90.7
Potassium – K, mg/L	3	28.8	52.3	40.6	–	–	–	–
Magnesium (filtered), mg/L	3	177	50	397	–	–	–	–
Magnesium – Mg, mg/L	7	No bottle	586	401	1470	1350	1370	2170
Phosphorus – P, mg/L	7	1.28	0.0771	< 0.02	< 0.1	< 0.5	0.532	< 0.2
Chromium (filtered,) μg/L	7	< 3	< 5	0.565	28	< 10	< 5	40
Chromium – Cr, μg/L	7	25	4.03	< 3	20.5	53.9	222	42.9
Zinc – (filtered), μg/L	7	297	< 50	53.6	142	411	107	< 300
Zinc – Zn, μg/L	7	565	51.5	< 30	173	435	382	< 300
Nickel – (filtered), μg/L	7	13.8	< 10	21.5	< 20	< 20	< 50	< 50
Nickel – Ni, μg/L	7	20.3	< 5	< 5	< 20	< 20	< 20	< 50
Silver (filtered), μg/L	7	< 10	< 5	< 10	< 20	< 10	< 1	< 50
Silver, μg/L	5	–	–	< 1	< 20	< 10	< 20	99.4

Parameters	Sample ID	Sample 1	Sample 2	Sample 3	Sample 4	Sample 5	Sample 6	Sample 7
	Date	7 April 2011	14 April 2011	28 April 2011	18 May 2011	14 June 2011	1 Aug 2011	17 Aug 2011
	Elapsed time (days) No. of samples	0	7	21	41	68	116	132
Aluminium (filtered), µg/L	7	< 50	< 100	< 10	< 200	< 200	< 100	< 500
Aluminium – Al, µg/L	7	596	< 50	< 50	< 200	< 100	1590	< 500
Arsenic (filtered), µg/L	7	5.1	< 1	< 1	< 1	< 1	2.3	< 1
Arsenic – As, µg/L	7	6.2	< 1	< 1	1.2	2.6	14.5	< 1
Iron (filtered), µg/L	7	36,600	82,800	35,800	70,700	106,000	74,200	80,200
Iron – Fe, µg/L	7	66,600	80,700	51,800	78,600	112,000	137,000	88,200
Cobalt (filtered), µg/L	7	< 10	< 5	< 10	< 20	13.3	< 1	< 50
Cobalt, µg/L	5	–	–	4.96	< 20	< 50	< 20	< 50
Copper (filtered), µg/L	7	27.5	10	12.4	36	< 20	13.3	< 50
Copper – Cu, µg/L	7	936	8.04	< 5	37.6	34.4	215	< 50
Nitrogen – N, mg/L	7	10.7	52.5	33.4	98.8	77.8	47.9	121
Vanadium (filtered), µg/L	7	< 20	< 10	< 20	< 40	< 20	< 2	< 100
Vanadium – V, µg/L	7	< 4	< 10	< 2	< 40	< 100	< 40	< 100

Source: Environment Agency, 2011.

Table 10.2. Flowback water quality in various US shales

Source	Shale gas information values Platform GFZ[a]	Gas Technology Institute Marcellus[b]	Gas Technology Institute Barnett[c]	University of Pittsburgh and Carnegie Mellon University Marcellus[d]			Field characterisation of flowback waters (approximate concentration ranges)	
Parameters	Mean	Median[e]	Median[e]	Min.	Max.	Average	Min.	Max.
pH (SU)	–	6.6	7.1	5.68	7.11	6.4	–	–
TDS (mg/L)	150,000	67,300	36,100	17,800	201,000	109,400	1000	150,000
TSS (mg/L)	380	99	133	36	1115	576	1000	7000
Hardness (mg/L as $CaCO_3$)	29,000	–	–	–	–	–	–	–
Alkalinity (mg/L as $CaCO_3$)	200	138	610	46	489	268	100	600
Chlorides (mg/L)	76,000	–	–	10,300	116,100	63,200	5000	80,000
Sulfate (mg/L)	7	–	–	0	115	58	10	400
Sodium (mg/L)	33,000	18,000	–	2789	46,260	24,525	4000	40,000
Calcium, total (mg/L)	9800	4950	–	349	17,612	8981	500	12,000
Magnesium, total (mg/L)	–	559	–	–	–	–	50	2000
Strontium, total (mg/L)	2100	–	–	46	2045	1046	50	6000
Barium, total (mg/L)	3300	686	–	70	3000	1535	50	9000
Bromide (mg/L)	1200	–	–	–	–	–	–	–
Iron, total (mg/L)	48	39	–	10	140	75	50	300
Manganese, total (mg/L)	7	559	–	43.1	2600	1322	50	2000
Oil and grease (mg/L)	18	< 5	< 5	–	–	–	–	–
BOD5 (mg/L O_2)	–	2.8	319	–	–	–	–	–
TOC (mg/L)	–	62.8	18.1	–	–	–	–	–
Bicarbonate (mg/L)	–	74.4	–	–	–	–	–	–
Ammonia (mg/L)	–	82.4	–	–	–	–	–	–

[a]Source: http://www.shale-gas-information-platform.org/

[b]Source: Hayes, 2011.

[c]Source: Barbot *et al.*, undated.

[d]Source: Shramko et al., 2009.

[e]Concentrations measured in flowback samples collected at day 5 after hydraulic fracturing.

BOD, biological oxygen demand; TOC, total organic carbon.

10.3.2 Produced water quality

Maguire-Boyle *et al.* (2014) conducted comprehensive water quality analyses of produced water samples from various USA shales in which UGEE is currently under way, shown in Table 10.3. In particular, this reference is important because it provides a complete characterisation of inorganic and organic materials encountered in produced water and identifies the likely sources of these constituents. Grab samples of produced water were collected from fracturing tanks into which the produced water was directly piped. The samples were collected in a single event at three well sites in Marcellus (Pennsylvania), Eagle Ford (Texas) and Barnett (New Mexico) Shale Formations, respectively, with the objective of determining the variability in quality across the different geographic regions.

As shown in Table 10.3, non-purgeable organic carbon (NPOC) is significantly higher than total inorganic carbon (TIC). In practice, NPOC represents total organic carbon (TOC). The ratio of TIC:NPOC was 0.62 for Marcellus and 0.34 for Barnett produced waters. The Barnett sample contained significantly more organic carbon than the other samples and also the percentage of carbon due to organic compounds was higher. The Barnett sample had the highest inorganic content followed by Eagle Ford and then Marcellus, which corresponds with the trend observed in water conductivity. However, the conductivity reported by Maguire-Boyle *et al.* (2014) for the Marcellus Shale is not consistent with the general understanding of Marcellus Shale having the highest salinity in the USA. Thus, either the sample was not representative or the conductivity was reported incorrectly.

The Barnett Shale is known as a "tight" gas reservoir, consisting of relatively impermeable sedimentary rock. In the past, production of natural gas in commercial quantities was impeded by the low permeability of this formation, but hydraulic fracturing has enabled commercial production in this shale play.

The Marcellus and Eagle Ford samples were potassium rich, while the Barnett produced water was lithium rich. Potassium appears to be associated with silicon. Generally, these high concentrations of alkaline metals (sodium, potassium, lithium) are not an issue for the reuse of produced water in subsequent hydraulic fracturing. In contrast, the alkaline earth metals (e.g. calcium, magnesium, barium) are associated with scale formation, in particular when calcium and barium levels are above 20,000 mg/L. In this situation, scale inhibitors must be employed and/or the salt content lowered before the water can be reused downhole.

Table 10.3. Produced water quality in US shales for unconventional production

Source		Marcellus	Eagle Ford	Barnett
pH (SU)		6.85	5.95	7.43
Conductivity (mS/cm)		28.5	31.1	52.8
Total carbon (mg/L)	TC	3808	9286	58,550
Non-purgeable organic carbon (mg/L)	NPOC	2348	6095	43,550
Total inorganic carbon (mg/L)	TIC	1460	3190	15,000
Sodium (mg/L)	Na	523.6	45.9	5548.9
Potassium (mg/L)	K	2605.8	17043.3	4566.5
Lithium (mg/L)	Li	0	1200.6	84,407.4
Rubidium (mg/L)	Rb	47	0	0
Magnesium (mg/L)	Mg	289.7	28.2	5747.2
Calcium (mg/L)	Ca	1387.5	111.2	33,971.8

Source		Marcellus	Eagle Ford	Barnett
Strontium (mg/L)	Sr	92.9	34.5	2461.8
Barium (mg/L)	Ba	0.0	4.7	17.2
Titanium (mg/L)	Ti	0	16.2	15.1
Vanadium (mg/L)	V	4.2	16.2	14.6
Chromium (mg/L)	Cr	11	13.6	11.5
Manganese (mg/L)	Mn	0	11.5	9.4
Iron (mg/L)	Fe	8.4	1246.5	75.7
Nickel (mg/L)	Ni	0	36.5	12
Copper (mg/L)	Cu	2.6	0	0
Zinc (mg/L)	Zn	65.8	0	684.9
Mercury (mg/L)	Hg	14.6	0	0
Boron (mg/L)	B	0	40.2	70.5
Silicon (mg/L)	Si	727.1	4416.6	0
Tin (mg/L)	Sn	206.2	3.1	124.2
Phosphorus (mg/L)	P	0	29.2	1177.1
Arsenic (mg/L)	As	26.1	0	2.1
Antimony (mg/L)	Sb	0.5	2.1	9.9
Bismuth (mg/L)	Bi	36.5	50.1	161.3
Sulfur (mg/L)	S	189	413.9	290.8

Caesium, scandium, yttrium, lanthanum and cadmium probed but not detected.
Source: Maguire-Boyle and Barron, 2014.

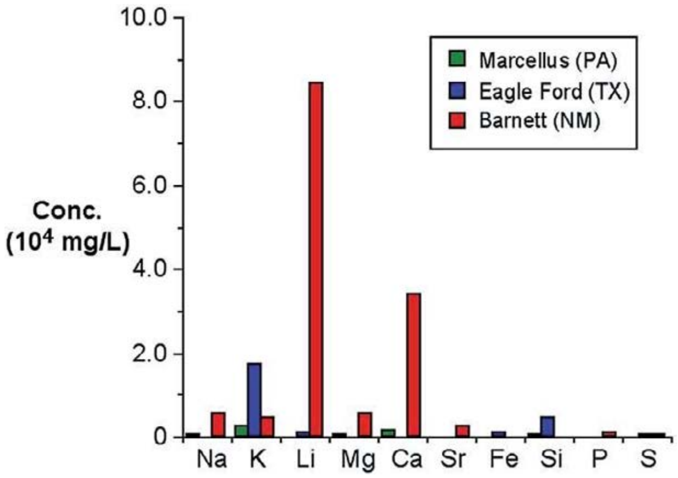

Figure 10.2. The concentration of the 10 most abundant elements found in the produced water samples (source: Maguire-Boyle and Barron, 2014). Reproduced with permission from the Royal Society of Chemistry.

Maguire-Boyle and Barron (2014) conducted gas chromatography/mass spectrometry analysis to determine the organic compound profile of each produced water sample. The results were assessed in a relative manner with no numerical concentrations reported. Figure 10.3 shows the normalised saturate, aromatic, resin and asphaltene (SARA) composition for each of the produced waters. In each case, the major category of organic compounds identified was the saturate group, and relatively smaller fractions under the other three categories.

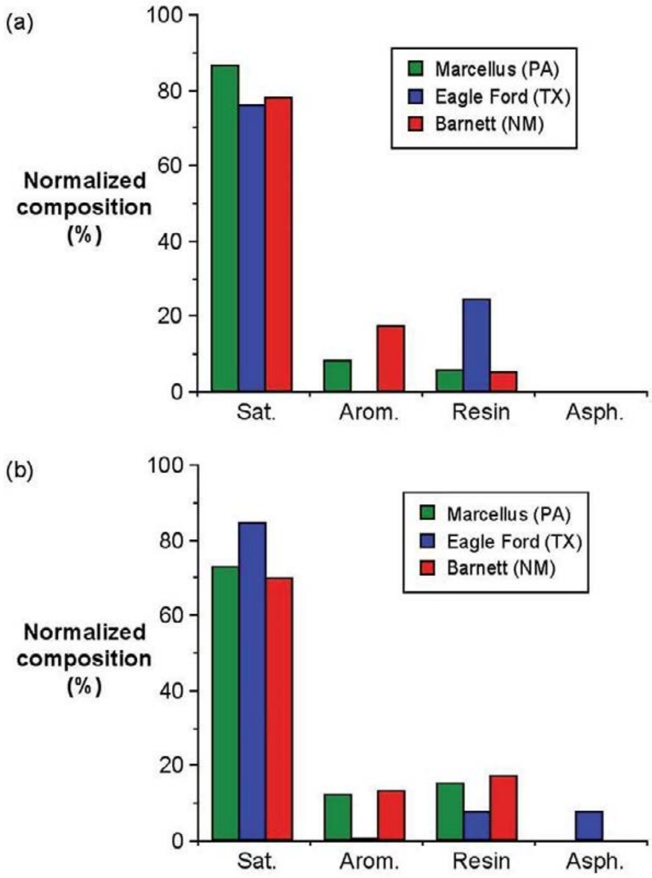

Figure 10.3. The relative saturate, aromatic, resin and asphaltene (SARA) composition for produced water: (a) neutral and (b) acid extraction (source: Maguire-Boyle and Barron, 2014). Reproduced with permission from the Royal Society of Chemistry.

The Marcellus and Barnett produced water samples contained predominantly light C6–C16 hydrocarbons, while the Eagle Ford produced water had the highest concentration in the C17–C30 range. Heterocyclic compounds were identified, with the largest fraction being fatty acids, alcohols, esters, and ethers. Halogen-containing compounds were found in each of the water samples, and although the fluorocarbon compounds identified are used as tracers, the chlorocarbons and organobromides were formed as a consequence of using chlorine-containing oxidants (to remove bacteria from source water).

Substituted compounds such as carboxylic acids and other oxidation products are formed from reactions with humic and fulvic acids in the formation, produced by the biodegradation of dead organic matter. Aromatic compounds are exclusively substituted benzene derivatives, rather than PAHs. The lack of hazardous (carcinogenic) PAHs, and generally low aromatic content, in shale produced water is a positive result, as it reduces the toxicity of the water compared with coalbed methane produced water and offshore produced waters from conventional oil and gas production. The low levels of resins and asphaltenes are also consistent with the “mature” nature of a gas reservoir compared with coal (and to a lesser extent oil) formations, as condensates are virtually devoid of asphaltenes.

The presence of various fatty acid phthalate esters (II) in the Barnett and Marcellus produced waters can be related to their use in drilling fluids and breaker additives, while the dioctadecyl ester of phosphoric acid [$(C_{18}H_{37}O)_2P(O)_2$] found in the Marcellus produced water is a common lubricant. Thus, these chemicals are most likely to be residues from the well drilling and hydraulic fracturing operations, and would be expected to be present in flowback or in the earlier stages of production. The absence of such chemicals in the Eagle Ford sample is due to either the relative age of the well or the use of other chemicals by the driller. The presence of the fluorinated compounds 2,2,3,3,4,4,4-heptafluorobutyl undecylate [2,2,3,3,4,4,4-hepta-fluoro-butanoic acid undecylate ester, $C_3F_7C(O)OC_{11}H_{24}$] in the Marcellus and Eagle Ford samples, *cis*-4-ethyl-5-octyl-2,2-bis(tri-fluoromethyl)-1,3-dioxolane (III) in the Barnett sample, and tri-fluoromethy tetradecylate [trifluoroacetic acid tetradecyl ester, $CF_3C(O)OC_{14}H_{29}$] in the Eagle Ford sample are commonly employed as flow tracers.

At present, owing to the high bacteriological content of natural water (and also produced water upon standing in ponds, which is blended with “fresh” water), chemical treatment is applied before it can be used (reused) for hydraulic fracturing. In many cases, this involves chlorine dioxide or hypochlorite treatments. Such treatments enhance the conversion of naturally occurring hydrocarbons to chlorocarbons and organobromides. Further studies will be required to determine if the reactions are occurring downhole or during the treatment of produced water. In either case, this would suggest that treatment with these chemicals should be limited, as they result in the formation of unwanted non-naturally occurring compounds; treatments involving separation are preferred on the grounds of long-term safety.

Many of the chemicals used in the fracturing process are identified as being present in the produced water; however, they are lower in concentration than those that were naturally present in the connate (formation) waters within the shale. Thus, treatment of produced water and flowback should concentrate on the removal of saturated hydrocarbons rather than the remaining aromatic, resin and asphaltene groups because these are typically encountered at lower, non-toxic concentrations (Maguire-Boyle and Barron, 2014).

The USEPA (2015a) has recently summarised the concentrations of selected organic constituents in produced waters worldwide (Table 10.4).

Table 10.4. Concentrations ranges of several classes of organic chemicals in produced water (conventional wells)

Chemical class	Concentration range (mg/L)
TOC	< 0.1 to > 11,000
Total organic acids	< 0.001 to 10,000
Total saturated hydrocarbons	17–30
Total BTEX	0.068–578
Total steranes/triterpanes	0.140–0.175
Total PAHs	0.040–3
Ketones	1–2
Total phenols	0.400–23

The evaluation of chemistry profiles for inorganic and organic compounds described above is meant to serve the Ireland and Northern Ireland regulatory agencies as an example of studies that would be helpful to conduct for the NCB and CB shale plays to understand the composition of UGEE wastewater and to identify what pollutants are introduced during operations or which ones are naturally occurring and stem from the formation. These studies will help to define the environmental and health risks associated with UGEE and, in particular, to define adequate treatment goals for flowback and produced water.

The composition of the produced water varies by well and formation but consists of both naturally occurring and injected organic chemicals. Additional, more detailed, information concerning the concentrations of specific organic compounds in produced waters is also provided in Appendix C-2 (see section 10.3.3).

10.3.3 Combined flowback and produced water quality

The USEPA (2015a) recently compiled an extensive list of chemical compositional information available from wells in the Bakken, Barnett, Fayetteville and Marcellus Shale Formations (no distinction was made between flowback and produced waters). The information is provided in Appendix C-2 in the following tables:

- Table E-2, General water quality;
- Table E-4, Inorganic constituents;
- Table E-6, Metals and metalloids;
- Table E-8, Radioactive constituents;
- Table E-9, Selected organic parameters;
- Table E-10, Organic constituents.

The data in these tables show the wide variety of chemical compositions depending upon the formation. A summary of major constituents follows:

- *General water quality (Table E-2).* The average TDS values range from 50,550 mg/L (Barnett) to 196,000 mg/L (Bakken). The Marcellus Shale TDS average in Pennsylvania is 106,390 mg/L. The average pH values range from 5.87 (Bakken) to 7.05 (Barnett). The average pH in the Marcellus Shale samples in Pennsylvania is 6.6. Average TOC values range from 9.75 mg/L (Barnett) to 260 mg/L (Marcellus Shale in Pennsylvania).
- *Inorganic constituents (Table E-4).* The average bromide concentrations range from 111 mg/L (Fayetteville) to 589 mg/L (Barnett). The average bromide value in the Marcellus Shale (Pennsylvania) samples is 511 mg/L. Average sulfate concentrations range from 58.9 mg/L (Marcellus Shale, West Virginia and Pennsylvania) to 709 mg/L (Barnett).
- *Metals and metalloids (Table E-6).* The average boron concentrations range from 4.8 mg/L (Fayetteville) to 30.3 mg/L (Barnett). The average boron concentration in the Marcellus Shale samples (West Virginia and Pennsylvania) is 12.2 mg/L. Average iron concentrations range from 7 mg/L (Fayetteville) to 96 mg/L (Bakken). Average barium concentrations range from 3.6 mg/L (Barnett) to 2224 mg/L (Marcellus Shale in Pennsylvania).
- *Radioactive constituents (Table E-8)*. The average total radium concentration in the Marcellus Shale is 7180 pCi/L in produced waters. The average gross alpha is 11,300 pCi/L and the average gross beta is 3.4 pCi/L.
- *Selected organics (Table E-9)*. The average total BTEX range from 2910 mg/L (Marcellus in Pennsylvania) to 1829 mg/L (Barnett).
- *Organic constituents (Table E-10)*. A variety of organic compounds were detected including total phenolic compounds (119.6 µg/L in Barnett), naphthalene (195 µg/L in Marcellus and 238 µg/L in the Barnett) and pyridine (250 µg/L in Marcellus and 413 µg/L in Barnett).

10.3.4 Marcellus Shale flowback quality studies (NYSDEC, 2011).

The Supplemental Generic Environmental Impact Statement report by NYSDEC of July 2011 summarised comprehensive flowback water quality data for the Marcellus Shale (see Appendix C-1). The table in Appendix C-1 was prepared from analytical results of flowback samples provided to NYSDEC by well operators and service companies from operations based in Pennsylvania, USA. Typical classes of parameters encountered in Marcellus flowback samples were:

- dissolved solids (chlorides, sulfates and calcium);
- metals (calcium, magnesium, barium, strontium);
- suspended solids;
- mineral scales (calcium carbonate and barium sulfate);
- friction reducers;
- iron solids(iron oxide and iron sulfide);
- dispersed clay fines, colloids and silts; and
- acid gases (carbon dioxide, hydrogen sulfide).

NYSDEC (2011) also summarised the following conclusions from a more rigorous study conducted by the Marcellus Shale Coalition in 2009:

- Metals and conventional parameters were detected and quantified in many of the samples, consistent with Table 10.5.
- Detectable concentrations of VOCs and SVOCs were present in flowback samples. VOCs detected included BTEX, naphthalene, trimethylbenzene and trichlorobenzene. SVOCs included PAHs, halogenated phenols and cresols.
- Nine organochlorine pesticides and one polychlorinated biphenyl (PCB) were detected that had not been previously identified by the flowback analytical results received from industry. Pesticides and PCBs do not originate within the shale play, and they were probably introduced to the shale or water during drilling or fracturing operations. Whether the pesticides or PCBs were introduced via additives or source water could not be evaluated with the information available.

NYSDEC (2011) observed that the composition of flowback water changes with time over the course of the flowback process, depending on a variety of factors. Limited time-series field data from Marcellus Shale flowback water, including data from the Marcellus Shale Coalition Study Report, indicate that:

- The concentrations of TDS, chloride, and barium increase.
- The levels of radioactivity increase, and sometimes exceed MCLs (maximum contaminant levels, i.e. USEPA drinking water standards.
- Calcium and magnesium hardness increases.
- Iron concentrations increase, unless iron-controlling additives are used.
- Sulfate levels decrease.
- Alkalinity levels decrease, probably because of the use of acid.
- The concentrations of metals increase.

Fracturing fluids pumped into the well, chemical reactions, and mobilisation of materials within the shale may be contributing to the changes seen in hardness, sulfate and metals. The specific changes depend on the shale formation, the fracturing fluids used and the control of fracturing operations.

Because of its extensive characterisation, the information in Appendix C-1 was compared with various regulatory standards in the EU and Ireland.

Table 10.5 compares selected flowback water quality data from Marcellus Shale, USA, and Bowland Shale, UK, with the environmental quality standards (EQS) set out in Annex I of the Priority Substances Directive (2008/105/EC). This comparison shows that flowback concentrations exceed the surface water quality standards in both Ireland and Northern Ireland. However, note that EQSs are not the same as emission limit values; EQSs are threshold concentrations at which no adverse effects are anticipated to occur. They are usually applied at a compliance point that is typically downstream of an actual point source discharge or at the boundary of a facility. Discharge or emission limit values are typically applied at the actual point source (e.g. water discharge or stack emission) and are at higher concentrations than the EQSs. The EQSs serve as a threshold for the potentially most conservative requirements the producers may need to meet.

Table 10.6 compares the discharge limits for municipal sewage treatment plants, as laid out in Ireland's Urban Wastewater Regulation Treatment Directive (91/271/EEC; EEC, 1991) and flowback concentrations for these parameters in Marcellus Shale, USA. The flowback concentrations for these common pollutants are significantly above the discharge limits imposed on municipal treatment plants for surface water discharge, thus flowback would have to be treated to similar limits to be allowed to be discharged to surface water.

10.3.5 Radioactive substances

Radioactive substances encountered in UGEE activities consist of naturally occurring and technologically enhanced radioactive materials. The USEPA and the International Association of Oil and Gas Producers have similar definitions for NORM. In general, NORM is defined as materials that contain radionuclides at concentrations found in nature. These normally exist at trace concentrations in rock formations.

However, NORM is concentrated and enhanced by the oil and gas recovery processes. NORM flows with the oil, gas and water mixture and accumulates inside equipment as scale and/or sludge. This enhanced "NORM" is categorised as TENORM (technologically enhanced naturally occurring radioactive materials), which results from industrial activity increasing the concentrations of radioactive substances in waste residuals (e.g. sludge, drilling mud or pipe scales), or when material is redistributed as a result of human activities or industrial processes.

The USEPA expands the TENORM definition to radioactive substances that are exposed to the environment due to human activities, and it uses the TENORM designation for radioactive substances contained in flowback and produced water as well (USEPA, 2015a). The current EU regulations and guidelines applicable to UGEE do not use the TENORM designation. Therefore, for the purposes of discussing flowback and produced water, and associated residuals from treatment, the term "radioactive substances" or NORM is generally used in this report.

Table 10.7 shows the concentration ranges of radioactive substances present in Marcellus flowback and the USEPA's MCL for these radioactive substances in drinking water. USEPA's MCL has a combined value of 0.18 Bq/L for radium-226 and radium-228.

Table 10.8 shows the list of radioactive substances reported for flowback water and solids samples from the Bowland Shale, as reported by the UK Environment Agency (December 2011). The following radioactive substance had detectable levels in flowback water samples: potassium-40, actinium-228, lead-212, radium-226, lead-214, bismuth-214 and radium-223.

Table 10.9 compares the radioactive substance concentrations in the UK's Bowland Shale flowback water against limits set forth under Schedule 23 of the Environment Permitting Regulation (EPR) (2010). The Environment Agency (2011) reported that radium-226 and radium-228 showed concentrations averaging 29 and 7 Bq/L, respectively. These concentrations exceed the threshold of 1 and 0.1 Bq/L, respectively, set forth by Schedule 23 of the EPR (2010).

Except for radium-226, the other regulated radionuclides noted in Table 10.9 were not reported in the Bowland Shale data shown in Table 10.8 (Environment Agency, 2011).

The analytical methods for radionuclides are based on water matrices with low levels of TDS (< 500 mg/L). The high levels of TDS in flowback and produced waters can result in a significant underestimation of actual concentrations. New methods for the analysis of gross alpha and gross beta particles have been developed by the USEPA to reduce matrix interferences, and other methods are under development for radium analysis (USEPA, 2015a).

Table 10.5. Comparison of flowback water quality and EU environmental quality standards

Parameter	Unit	Median values in Marcellus Shale, US[a]	Minimum, Bowland Shale, UK[b]	Maximum, Bowland Shale, UK[b]	Environmental quality standards (EQS)		
					Annual average (inland surface waters)	Maximum allowable concentration or 95th percentile (inland surface waters)	EQS source/notes
Arsenic	µg/L	0.09	< 1	14.5	Ireland: 25 Northern Ireland: 50	–	Ireland: SI 272/2009 Northern Ireland: SR 2015/45
Benzene	µg/L	479.5	–	–	10	50	Priority Substances (Annex 1, Directive 2008/105/EC)
Bromide	mg/L	607	242	1020	–	–	
Cadmium and its compounds	µg/L	26	< 0.5	6.02	≤ 0.08 (Class 1) 0.08 (Class 2) 0.09 (Class 3) 0.15 (Class 4) 0.25 (Class 5)	≤ 0.45 (Class 1) 0.45 (Class 2) 0.6 (Class 3) 0.9 (Class 4) 1.5 (Class 5)	Priority Substances (Annex 1, Directive 2008/105/EC) – depends on hardness
Chromium (VI), dissolved	µg/L	539	–	–	3.4	–	Ireland: SI 272/2009 Northern Ireland: SR 2015/45
Chromium, dissolved	µg/L	75	0.565	28	–	–	
Cobalt, dissolved	µg/L	489	< 1	13.3	–	–	
Copper	µg/L	24.5	< 5	936	Ireland: 5 or 30 Northern Ireland: 1 bioavailable	–	Ireland: SI 272/2009 – depends on hardness Northern Ireland: SR 2015/45
Cyanide	µg/L	12.5	–	–	Ireland: 10 Northern Ireland: 1	Ireland: – Northern Ireland: 5	Ireland: SI 272/2009 Northern Ireland: SR 2015/46
Fluoride	µg/L	392,000	–	–	Ireland: 500	–	Ireland SI 272/2009
Lead and its compounds	µg/L	35	< 10	600	7.2	NA	Priority Substances (Annex 1, Directive 2008/105/EC)
Mercury and its compounds	µg/L	295	< 0.01	0.09	0.05	0.07	Priority Substances (Annex 1, Directive 2008/105/EC)

Parameter	Unit	Median values in Marcellus Shale, US[a]	Minimum, Bowland Shale, UK[b]	Maximum, Bowland Shale, UK[b]	Environmental quality standards (EQS)		
					Annual average (inland surface waters)	Maximum allowable concentration or 95th percentile (inland surface waters)	EQS source/notes
Naphthalene	µg/L	11.3	–	–	2.4	NA	Priority Substances (Annex 1, Directive 2008/105/EC)
Nickel and its compounds	µg/L	30	< 5	20.3	20	NA	Priority Substances (Annex 1, Directive 2008/105/EC)
Nickel and its compounds (dissolved)	µg/L	71.5	< 10	–	20	NA	Priority Substances (Annex 1, Directive 2008/105/EC)
Potassium, dissolved	mg/L	327	23.2	90.7	–	–	
Sodium, dissolved	mg/L	54800	> 200	33300	–	–	
Tetrachloroethylene	µg/L	5.01	–	–	10	NA	Priority Substances (Annex 1, Directive 2008/105/EC)
Zinc, dissolved	µg/L	70	< 50	< 300	Ireland: 8 or 50 or 100 Northern Ireland: 10.9 bioavailable plus ambient background concentration	–	Ireland: SI 272/2009 – depends on hardness Northern Ireland: SR 2015/45

Sources:

[a]NYSDEC, 2011.

[b]Environment Agency, 2011.

Table 10.6. Comparison of Marcellus flowback quality versus emission limit values for a municipal sewage treatment plant in Ireland

Parameters	Units	Emission limit values (ELVs)[a]	Marcellus Shale flowback, mean concentration
Biochemical oxygen demand (BOD5 at 20°C) without nitrification[a]	mg/L	25 mg/L O_2	200
Chemical oxygen demand (COD)[a]	mg/L	125 mg/L O_2	5645
Total suspended solids[a]	mg/L	35 mg/L	129
Total phosphorus[a,b]	mg/L	2 mg/L (10,000 – 100,000 p.e†.) or 1 mg/L (more than 100,000 p.e.)	1.9
Total nitrogen[1,2]	mg/L	15 mg/L (10,000 – 100,000 p.e.) or 10 mg/L (more than 100,000 p.e.)	58
Coliform	Col/100 mL	—	42

[a]Source: EU Urban Wastewater Regulation Treatment Directive (91/271/EEC).

[b]For discharge to designated nutrient sensitive areas.

p.e., population equivalent.

Table 10.7. Radioactive substances in Marcellus Shale flowback

Parameters	Total no. of samples	NORM concentrations in Marcellus flowback[a]				USEPA MCL for drinking water	
		Min. (pCi/L)	Min. (Bq/L)	Max. (pCi/L)	Max. (Bq/L)	Min.	Min.
Gross alpha	15	22.41	0.83	18,950	701.15	15 (pCi/L)	0.55 Bq/L
Gross beta	15	62	2.29	7445	275.46	4 millirems/year	40 μSv/year
Total alpha radium	6	3.8	0.14	1810	66.97	–	–
Radium-226	3	2.58	0.09	33	1.22	5 (combined for Ra-226 and Ra-228 in pCi/L)	0.18 (combined for Ra-226 and Ra-228 in Bq/L)
Radium-228	3	1.15	0.04	18.41	0.68		

[a]Source: NYSDEC, 2011.

Table 10.8. Indicative list of radioactive substances in Bowland Shale, UK

Sample ref.	Water sample 14/04/11 (Bq/L)	Solids from sample (Bq/kg equivalent)	Water sample 03/05/11 (Bq/L)	Solids from sample (Bq/kg equivalent)	Water sample 23/05/11 (Bq/L)	Solids from sample (Bq/kg equivalent)	Water sample 19/08/11 (Bq/L)	Solids from sample (Bq/kg equivalent)
Analysis date	21/04/11	21/04/11	09/05/11	18/05/11	24/05/11	31/05/11	30/08/11	30/08/11
Potassium-40	< 1.0	< 1.0	3.5 ± 1.1	< 1.0	3.3 ± 1.9	< 1.0	< 3.0	< 1.0
Cobalt-60	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.2	< 0.1
Caesium-137	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.2	< 0.1
Actinium-228	1.7 ± 0.4	< 0.1	2.6 ± 0.5	0.4 ± 0.1	2.9 ± 0.6	1.4 ± 0.3	12 ± 2.5	< 0.2
Thorium-228	< 4.0	< 4.0	< 4.0	< 4.0	< 4.0	< 4.0	< 10	< 2.0
Radium-224	< 4.0	< 4.0	< 4.0	< 4.0	< 4.0	< 4.0	< 4.0	< 1.0
Lead-212	0.4 ± 0.1	< 0.5	0.9 ± 0.1	< 0.5	0.7 ± 0.1	< 0.5	< 0.5	< 0.5
Bismuth-212	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5	< 2.0	< 0.5
Thallium-208	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5
Thorium-234	< 2.0	< 2.0	< 2.0	< 2.0	< 2.0	< 2.0	< 6.0	< 1.0
Radium-226	14 ± 2.1	< 0.2	16 ± 2.1	2.5 ± 0.4	17 ± 2.3	7.2 ± 1.5	90 ± 12	< 1.0
Lead-214	1.4 ± 0.2	< 0.5	6.0 ± 0.7	1.6 ± 0.2	2.3 ± 0.3	2.6 ± 3.3	50 ± 5.6	< 0.5
Bismuth-214	0.9 ± 0.2	< 0.5	5.1 ± 0.6	1.3 ± 0.2	2.1 ± 0.3	2.3 ± 0.3	41 ± 4.6	< 0.5
Uranium-235	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.3	< 0.1
Thorium-227	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5	< 2.0	< 0.5
Radium-223	< 0.5	< 0.5	2.1 ± 0.6	< 0.5	< 0.5	< 0.5	< 2.5	< 0.5
Americium-241	< 0.2	< 0.2	< 0.2	< 0.2	< 0.2	< 0.2	< 0.5	< 0.1

Source: Environment Agency, 2011.

Table 10.9. Comparison of radioactive substances in Bowland Shale, UK, with regulatory limits

Parameters	NORM concentration range in Bowland Shale, UK[a]				Concentration of radionuclides: NORM industrial activities (Schedule 23 of EPR)[b]	
	Water sample (~Bq/L[c])	Water sample average value (Bq/L)	Solids from sample (Bq/kg equivalent)	Solid sample average (Bq/L)	Any other liquid concentration (Bq/L)	Solid or relevant liquid concentration in (Bq/g)
Radium-226	14–90	29	< 0.2–8.7	2.575	1	0.5
Radium-228	–	7	–	–	0.1	1
Lead-210+	–	–	–	–	0.1	5
Polonium-210+	–	–	–	–	0.1	5
Actinium-227	–	–	–	–	0.1	1
Thorium-232	–	–	–	–	10	5
Thorium–232 Sec	–	–	–	–	0.1	0.5

[a]Source: Environment Agency, 2011.

[b]Source: Environmental Permitting Guidance Radioactive Substance Regulation, Department of Energy & Climate Change.

[c]Units are converted from Bq/kg to Bq/L using a specific gravity of water of 1.

10.4 Wastewater Regulations Pertinent to UGEE in Ireland and Other European Countries

UGEE is a developing sector within the oil and gas industry, particularly in the EU. At present, the wastewater regulations for UGEE in the EU are under development. The EC has issued recommendations on UGEE practices that reference existing EU directives on water, solid waste and groundwater. Although the UGEE regulations are more developed in the USA, the regulatory framework is also evolving as a result of ongoing public debate related to the effectiveness of the regulations.

This section provides a review of regulations applicable to the treatment and disposal of flowback and produced waters generated by UGEE in Ireland, as well as providing examples of the regulatory framework in the UK and the USA for comparison.

10.4.1 European Union

The EC issued a recommendation (EC, 2014), dated 22 January 2014, on minimum principles for the exploration and production of hydrocarbons (such as shale gas) using high-volume hydraulic fracturing (2014/70/EU). The recommendations state that both general and environmental EU legislation applies to hydrocarbon exploration and production operations involving high-volume hydraulic fracturing.

The EC recommendations refer to the following directives for regulations on treatment, reuse and/or disposal of flowback and produced waters:

- Mining Waste Directive (2006/21/EC) (EU, 2006b) laying down provisions on mining waste, which regulates the management of surface and underground wastes resulting from the exploration and production of hydrocarbons using high-volume hydraulic fracturing;
- Water Framework Directive (2000/60/EC) establishing the water framework, which requires the operator to obtain authorisation for water abstraction and prohibits the direct discharge of pollutants into groundwater;
- Waste Framework Directive (2008/98/EC) laying down the waste framework, which sets out the conditions applicable to the reuse of the fluids that emerge at the surface following high-volume hydraulic fracturing and during production; and
- Priority Substances Directive (2008/105/EC).

The EC recommendations acknowledge that there is no experience of permitting the production of hydrocarbons using high-volume hydraulic fracturing and limited experience of permitting exploration in the EU, and recommend monitoring the application of this recommendation and EU legislation to identify necessary updates or the development of provisions in view of technical progress.

The EC also recommends that EU Member States:

- ensure that the ability to treat fluids that emerge at the surface after high-volume hydraulic fracturing is considered during the selection of the chemical substances to be used;
- encourage operators to use fracturing techniques that minimise water consumption and waste streams and do not use hazardous chemical substances, wherever technically feasible and sound from human health, environment and climate perspectives;
- require that operators monitor the fluids that emerge at the surface following high-volume hydraulic fracturing – return rate, volumes, characteristics, quantities reused and/or treated – for each well.

In addition, the Groundwater Daughter Directive (2006/118/EC) prohibits the direct discharge of hazardous substances into groundwater and the EC considers that the exception clause under Article 11(3)(j) of the Water Framework Directive (2000/60/EC) does not apply to practices involving hydraulic fracturing (i.e. the exception clause was devised for conventional hydrocarbon operations).

The German Environmental Agency supports DWI and its experts have stated that DWI disposal would not be an issue for deep groundwater that is not suitable for present and future use and is not part of the ecosystem (see Project C of the UGEE JRP). However, Olsson *et al.* (2013) suggests that more investigations are needed on the effects and potential environmental impacts of DWI and environmental resources.

10.4.2 Ireland and Northern Ireland

A full discussion on the regulations that may apply to the treatment and disposal of flowback and produced waters is provided in Project C of the UGEE JRP.

10.5 Wastewater Regulations applicable to UGEE in the USA Marcellus Shale Region

The Marcellus Shale region extends across regions of New York, northern and western Pennsylvania, eastern Ohio, Western Maryland and most of West Virginia. Most of the drilling occurs in Pennsylvania and there is growing interest in West Virginia and New York. The following sections discuss the regulations in place for treatment, reuse and disposal of wastewater. Because Pennsylvania has banned disposal of flowback water in deep injection wells, then flowback disposed of by this route is transported to Ohio for disposal in Class II deep injection wells.

Because fracturing requires large quantities of fresh water, the Delaware and Susquehanna River Basin Commissions play an important role in regulating the use of fresh water and discharges of water into the basin.

A review of current regulations developed by various state environmental agencies, such as Pennsylvania Department of Environment Protection, Ohio Department of Natural Resources (ODNR), Susquehanna River Basin Commission (SRBC), and Delaware River Basin Commission (DRBC), was conducted. These regulations are available on the agencies' websites, links to which are included in the references.

10.5.1 Effluent limitations to surface water

10.5.1.1 Susquehanna River Basin Commission Regulations (SRBC 18 CFR Parts 801, 806, 807 and 808)

- A project approved under approval by rule allows for inter-basin transfer of flowback or production fluid from one well pad drilling site to another site for use in fracturing, provided it is handled, transported and stored in compliance with standards applicable to that jurisdiction and does not require a separate permit.
- A project approved under approval by rule allows diversion of flowback or production fluid to an out-of-basin treatment or disposal facility (authorised under applicable regulation to accept flowback) and does not require a separate permit.
- A post-hydro-fracture report shall be submitted to the SRBC. This report helps the SRBC to track the quantities and sources of fresh water, flowback water or all other water used. This also helps track the destination of wastewater.
- Any flowback or production fluid used in fracturing shall be accounted for separately and should not be included in the daily consumption amount calculated for the project.

- The operator shall certify to the SRBC that all the flowback and production fluids have been reused or treated and disposed of in accordance with the regulation.

10.5.1.2 Delaware River Basin Commission – Draft Natural Gas Development Regulations, 8 November 2011 (Article 7 of Part III – Basin Regulations)

The Delaware River and Bay and tributaries are classified into zones to help maintain the quality of surface water and groundwater. Certain bodies of water in the basin are classified as special protection waters and are subject to more stringent regulations. The treated wastewater discharged from the treatment facility shall comply with the wastewater discharge requirements of the state and demonstrate the following:

- Discharge of treated wastewaters will not contribute to or result in exceedance of the USEPA's primary and secondary drinking water standards (for a list of specific parameters) in the receiving basin waters.
- The TDS concentration shall not exceed 133% of background and in no case exceed 500 mg/L.
- Toxicity in non-tidal basin water must not exceed 0.3 toxic units (acute) except in small sections of mixing areas, as approved by the commission, and 1.0 toxic unit (chronic). The duration of exposure for aquatic organisms shall be 1 hour for acute and 4 days for chronic toxicity.
- Suspended solids :
  - wastewater treatment facilities not to exceed:
    - TSS: 30 mg/L as a 30-day average;
    - TSS: 45 mg/L as a 7-day average;
  - industrial wastewater treatment facilities:
    - up to 100 mg/L as a 30-day average may be permitted.
    - 85% reduction as a 30-day average is achieved.

Additional applicable criteria are provided in Article 7 of Part III – Basins Regulations and sections 3.10 and 4.30 of the Administrative Manual – Part III Water Quality Regulations, 18 CFR (Code of Federal Regulations), Part 410.

10.5.1.3 Pennsylvania Environmental Quality Board (Title 25 code § 95)

Wastewater resulting from the fracturing, production, field exploration, drilling or completion of natural gas wells shall comply with the following:

- The operator shall identify a source reduction strategy that will establish the methods and procedures for recycling and reuse of flowback and produced water. The report shall be updated annually and shall contain the following information:
  - a complete characterisation of the operator's wastewater stream, including chemical analyses, TDS and monthly quantities of flowback and produced water from each well pad;
  - a description and evaluation of reuse and recycling options and the basis for selecting the source reduction method by the operator.
- Discharge of treated wastewater resulting from the natural gas developments operation may be authorised by DEP under the National Pollutant Discharge Elimination System (NPDES) based on the following :
  - Discharges are authorised only from centralised waste treatment (CWT) facilities, as defined in 40 CFR 437.2.

- o Discharge from POTW is not authorised unless the treatment at the CWT meets all requirements and precedes the treatment at the POTW.
- o These standards are based on monthly average and the constituent concentrations in the discharges may not exceed those tabulated in Table 10.10. The discharge complies with 40 CFR 437.45(b).

Table 10.10. Discharge standards

Parameter	Concentration	Units
TDS	500	mg/L
Chlorides	250	mg/L
Barium	10	mg/L
Strontium	10	mg/L

10.5.2 State of New York – Marcellus Shale and other low permeability gas reservoirs

The Department of Environmental Conservation, New York, regulates drilling, operation and plugging of oil and natural gas wells to confirm that the projects comply with statutory mandates in environmental conservation law. Direct discharge of flowback and produced waters into ground- or surface water bodies is prohibited in New York. Flowback and produced waters shall be:

- discharged to treatment facilities (POTWs, privately owned high-volume hydraulic fracturing wastewater treatment facilities);
- recycled; or
- disposed of in permitted wells.

10.5.3 Publicly owned treatment works

Disposal of treated wastewater to surface water from waste treatment facilities is regulated by the corresponding state's environmental agency or the USEPA. Although regulations have been developed for disposal of flowback and produced water to POTWs, a review of existing municipal plants shows that most plants that previously received flowback and produced waters have stopped accepting these wastewaters, as discussed in section 10.7.

In the State of New York, draft regulations for the disposal of flowback and produced waters discuss how the waters could be sent to POTWs for treatment but caution that flowback water contains fracturing chemicals and NORM, which might have impacts on the treatment system, sludge disposal and the receiving streams.

The discharge of treated effluent from facilities to surface waters is regulated by NYSDEC's Pollution Discharge Elimination System. Wastewater discharged from POTWs shall be treated utilising all the treatment processes available and shall not blend any untreated flowback water or other well development water with the treated effluent.

The wastewater facility must evaluate the composition of source wastewater against the capacity of the individual treatment units and the facility as a whole to treat the pollutants in the source wastewater. The evaluation is known as maximum allowable headworks loading analysis (MAH or headworks analysis).

Headwork analysis specific to the parameters expected in the flowback and produced waters, including TDS and NORM, shall be performed and submitted by the permittee to both the NYSDEC (New York) and USEPA Region 2 for review in accordance with Division of Waters Technical and

Operational Guide Series (TOGS) 1.3.8, *New Discharges to Publicly Owned Treatment Works*. The Divisison of Waters and USEPA shall review whether POTWs have evaluated the effects of proposed discharge on the following:

- POTW operation;
- sludge disposal;
- effluent quality;
- POTW health and safety;
- discharge of substances that will be subject to effluent limits; and
- discharge of any bioaccumulation chemicals of concern or persistent toxic substances that may be subject to Pollution Discharge Elimination System effluent limits or other departmental permit requirements.

POTWs accepting flowback shall evaluate appropriate treatment and disposal options for NORM. In addition, POTWs shall limit the concentration of NORM in their influent to prevent its unintentional concentration in the sludge. The proposed influent concentration of radium-226 to the POTW (prior to mixing with POTW influent) shall be limited to 0.55 Bq/L (15 pCi/L) or 25% of 2.22 Bq/L (60 pCi/L), concentration value listed in 6 NYCRR, Part 380, 11.7 (New York Code of Regulations).

As a part of headwork analysis, a list of chemical additives, along with aquatic toxicity data for each chemical, shall be submitted, except if confidentiality is allowed under state law, based on proprietary material. Fracturing additives shall be approved or evaluated in headwork analysis only if the aquatic toxicity data are available.

A high concentration of TDS in flowback water might affect the biological treatment process. The concentration of TDS increases with time and then stabilises over the lifetime of the well. The variation in concentration of TDS over time should be considered while performing the headwork analysis.

10.5.4 Deep well injection disposal

Untreated wastewater is pumped into porous rock formations and the operation is performed under class II disposal wells. Class II disposal wells are used to inject brine and other fluids associated with oil and gas production and hydrocarbon storage. These wells are regulated by the USEPA permitting process.

10.5.4.1 Regulations in the Marcellus Shale Region

In 2012, Pennsylvania had seven injection wells, and no other deep injection wells have been approved in Pennsylvania. Most of the wastewater is transported to Ohio for disposal by DWI.

Disposal of flowback water in injection wells is permanent and the water will be completely lost from the hydrological cycle, which otherwise could have been treated and reused in the fracturing process.

DWI induces seismic activity, which is addressed in Project A1-2 of the UGEE JRP. The City of Youngstown, Ohio (no previous record of earthquakes), experienced over 100 small earthquakes between January 2011 and February 2012. Kim (2013) conducted a study that concluded that earthquake activity appeared to be induced by fluid injection into class II deep injection wells. The level of seismic activity declined following periods when injection volume and pressure were at their lowest.

Following the earthquakes in Youngstown, the ODNR prohibited all drilling in the Precambrian basement rock. New permit requirements were added to class II disposal wells and new rules became effective in October 2012. New rules are implemented on a case-by-case basis. State officials review existing geological data for known faults before approving a class II well. All new class II well permit applicants are required to install a continuous pressure monitoring system and an automatic shut-off system.

10.5.4.2 Ohio Regulations for Disposal in Deep Injection Wells (Underground Injection Control – class II injection wells)

The Oil and Gas Resources Division of ODNR regulates disposal of brine and other waste produced from drilling, stimulation and production of oil and gas. Construction and operation of brine injection wells is regulated by the Underground Injection Control Regulations of the ODNR Division of Oil and Gas Resources (Class II Well Permitting, OAC: 1501:9). To construct, convert to or operate a brine injection well, a permit application is required to be submitted to the division, along with associated fees. The application for permit is evaluated on the basis of an “area of review” surrounding the proposed injection well. The size of the area of review is established by the division, based on the proposed average volume of brine to be injected. Additional tests or evaluations (including geological investigations, seismic activity monitoring plans, radioactive tracer or spinner surveys, etc.) may be required prior to approval of an injection well permit. The permit process includes publication of a legal notice by the applicant, review of any comments and objections filed and subsequent hearings, if necessary. After an application for an injection well permit is approved by the division, the installation of the well is completed in accordance with the construction and initial testing requirements specified in the regulations.

Permitted brine injection wells shall comply with the division’s operating, monitoring and reporting requirements. The owners of injection wells pay ODNR a designated disposal fee per barrel of brine injected. The unit cost of injection (per barrel) is determined, based on the location of production (in reference to oil and gas resources management, the regulatory district in which the well is located) and the number of barrels of substance injected per well in a calendar year. On behalf of the division, the owner is responsible for collecting the levied fee and forwarding it to the division.

10.5.4.3 Delaware River Basin Commission – Draft Natural Gas Development Regulations, 8 November 2011 (Article 7 of Part III – Basin Regulations)

Flowback can be disposed of by underground injection well (underground injection control) within the basin only if the underground injection control facility has the approval of the host state and the USEPA. If the USEPA approves the construction and operation of the facility within the basin, a separate commission review is not required.

10.5.5 Conclusions

The regulatory framework in the Marcellus Shale region, discussed above, shows the complexity and the breadth of regulatory and technical issues pertaining to flowback and produced water management in UGEE activities. The information provided above is intended to help the regulatory agencies in Ireland and Northern Ireland to identify and prioritise the issues that are more prevalent to their region, including public health and safety concerns, protection of the environment, and risks associated with UGEE activities. This will also help with developing local technical guidance in the regulations and defining parameters of performance.

10.6 Treatment Processes for Flowback and Produced Water

Flowback and produced water generated during hydraulic fracturing and subsequent production can be treated for either reuse or disposal. Treatment for reuse consists of removing constituents that may not be compatible with fracturing fluid additives or formation geochemistry. The treatment quality goals for reuse must be agreed upon with the regulators. Treatment for disposal consists of removing or reducing pollutant concentrations to comply with the regulatory limits set forth for surface water disposal and/or DWI. There is a myriad of treatment technologies that can be combined to accomplish either of these objectives.

The treatment technologies used for flowback and produced water treatment are generally grouped under "non-TDS removal" and "TDS removal" categories.

10.6.1 Non-TDS removal technologies

These technologies have as their main goal the removal of non-dissolved constituents such as suspended solids, settleable and filterable solids, oil and grease, bacteria, and certain dissolved ions that can easily form precipitates, such as barium and calcium, that could cause scales on the equipment and interfere with the fracturing chemical additives.

Non-TDS removal technologies are further divided into primary and secondary treatment categories. Primary treatment focuses on the removal of oils and condensates, suspended solids, iron and residual polymeric material, as well as control of bacteria. Primary treatment is typically required for most flowback and produced waters. Primary treatment may include the following technologies:

- oil–water separation [gun barrel tanks, American Petroleum Industry (API) separators];
- chemical oxidation;
- coagulation/flocculation;
- electrocoagulation;
- dissolved air floatation;
- dissolved gas floatation;
- sedimentation (gravity settlers);
- filtration; and
- disinfection (UV, chlorine dioxide, sodium hypochlorite).

Secondary treatment is for selective control of cations and anions for conditioning the water for reuse or DWI disposal. Divalent ions in flowback and produced waters can react with carbonate or sulfate in the formation or in blended water to form scales that can cause equipment and formation plugging, impairing the well's production performance. Furthermore, they may interfere with fracturing chemical additives, in particular for gel fracturing. Similarly, certain cations/anions may react adversely with the DWI formation, forming insoluble scale and impairing the receiving deep formation. Secondary treatment may include the following technologies:

- chemical precipitation (e.g. divalent cations; this does remove some TDS);
- boron removal;
- advanced oxidation/precipitation; and
- radionuclide removal by ion exchange.

10.6.2 TDS removal technologies

These treatment technologies are used to remove dissolved ions and soluble aqueous constituents. Although these technologies are capable of removing contaminants targeted by non-TDS treatment as well, more typically some level of non-TDS treatment precedes TDS removal technologies.

These technologies are considered tertiary treatment, whose objectives are production of clean water (TDS < 500 mg/L) for reuse and/or disposal to surface water.

These technologies produce two streams of effluent: treated water and a concentrated brine. The water stream is very low in salt content and can be returned to the operators for reuse in fracturing. The treated water might contain trace soluble volatile organics or radioactive materials, which may necessitate polishing treatment if the final disposal is to surface water.

The concentrated brine can be either crystallised or disposed of by DWI. If the brine is crystallised, tertiary treatment would be classified as zero liquid discharge, whereby all liquid is recovered for reuse and no liquid effluent leaves the treatment plant.

TDS removal technologies include:

- reverse osmosis (RO) and forward osmosis (FO);
- evaporation/condensation;
- membrane distillation; and
- crystallisation.

10.6.3 Cost comparison and range of applicability

Figure 10.4 shows the range of applicability of non-TDS and TDS removal technologies versus the relative unit cost of treatment. As shown in this figure, TDS removal technologies have a higher unit cost of treatment because they are both more capital intensive and more operation and maintenance intensive.

10.7 On-site Treatment Systems

On-site treatment designed for water reuse reduces the cost of transporting the wastewater to treatment facilities and also reduces the quantity of fresh water used for drilling. However, mobilisation costs and the management and disposal of residuals associated with on-site treatment are potential drawbacks. These systems can be designed to accomplish the degree of treatment required by the operator in order to meet business and regulatory goals.

On-site treatment systems consists of modular equipment that can be deployed and assembled in the field for temporary operation. The modular equipment can be trailer mounted or skid mounted to facilitate transport and assembly. The equipment is typically standard units that are commercially available for either purchase or renting.

Examples of equipment used in on-site treatment systems include the following:

- gun barrel and fracturing tanks;
- oil–water separators;
- lamella clarifiers (inclusive of rapid mix/slow mix chambers);
- dissolved air flotation equipment;
- bag filters, cartridge filters, and/or multimedia filters; and
- evaporators.

Although these pieces of equipment are available off the shelf, the selection of equipment should be based on sound design practices, treatability testing, definition of treatment goals and experience.

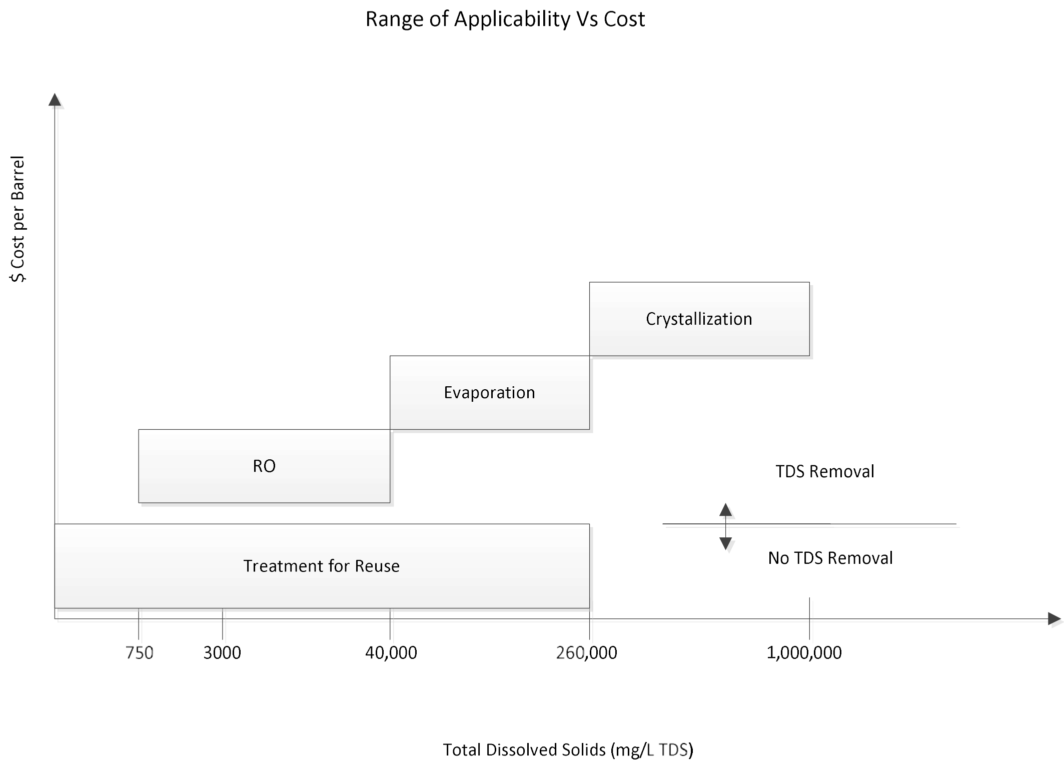

Figure 10.4. Range of applicability versus cost (source: Kimball, 2012).

10.8 Treatment at Publicly Owned Treatment Works

In early 2007, most of the POTWs in the Marcellus Shale Formation in the USA accepted flowback water for treatment. POTWs received flowback at the head of the plant and the high TDS was diluted with the high volume of sewage. Many of the POTWs were designed to treat domestic, commercial and industrial wastewater but were not designed to handle high TDS, chloride, bromide, boron, NORM and other constituents found in flowback and produced waters, which probably led to increased concentrations of TDS and other constituents in the receiving body. Table 10.11 provides a list of POTWs in the Marcellus Shale region that used to accept the flowback and produced water.

Table 10.11 summarises the POTWs that were accepting flowback water and the type of primary treatment conducted in those POTWs. Based on data collected by USEPA in 2014, none of the POTWs listed in the table below are currently accepting flowback and produced water.

The challenges associated with treatment of flowback water in POTWs are:

- most of the POTW treatment systems showed minimal or no removal of TDS, chloride and bromide;
- potential heavy metal (nickel, copper) accumulation in sludge;
- excessive scale formation in pipes and valves could occur due to scale-forming ions present in flowback water;
- sludge from POTWs that accept flowback water might contain elevated concentrations of radioactive materials (radium-226 and -228);
- radiological exposure due to spills and long-term impacts due to disposal of POTW filter cake;
- radium (found in Marcellus Shale flowback) may accumulate in scale and form TENORM;

- toxins inhibiting biological growth in municipal biological treatment systems; and
- discharge of POTW wastewater containing bromide and chloride into receiving streams could affect the operations of downstream drinking water treatment plants by forming carcinogenic by-products following chlorine disinfection (e.g. THMs).

Because of these and other concerns, the USEPA has proposed prohibition of discharges from oil and gas extraction to POTWs (US Federal Register, Vol. 80, No. 66, Tuesday 7 April 2015, 18557–18580). This complete ban on discharges to POTW is consistent with current industrial practices.

Table 10.11. Publicly owned water treatment works

Source no.	Treatment plant	Type	Total capacity (m^3/day)	Brine acceptance volume (m^3/day)	Discharge to	Status	Primary treatment technologies	Pre-treatment	Source	Remarks
1	Clairton Municipal Authority	POTW	22,712	132.5	Peters Creek	Stopped accepting shale gas wastewater from 2011	Screening and grit removal, comminutors aeration basins, clarifiers, activated sludge, aerobic digestion and chlorine disinfection	No	1, 2	Treatment system influent and effluent samples show minimal or no TDS and chloride removal
2	City of McKeesport Municipal Authority	POTW	43,532	386	Monongahela River	Stopped accepting shale gas wastewater from 2011[2]	Screening and grit removal aeration, clarification, activated sludge, aerobic digestion and chlorine disinfection	No	1, 2	Treatment system influent and effluent samples show less than 10% removal of TDS, chloride, sulfate and magnesium
3	Allegheny Valley Joint Sanitary Authority	POTW	20,819	94.6	Allegheny River	Stopped accepting shale gas wastewater from 2008[2]	–	–	1	–
4	Johnstown Redevelopment Authority Dornick Point STP	POTW	45,424	287.6	Conemaugh River	Stopped accepting shale gas wastewater from 2010[2]	Screening, grit removal high-purity oxygen activated sludge aeration with integrated fixed-film activated sludge, final clarification and chlorination	No	1, 2, 3	Higher concentrations of TSS and BOD5 in POTW effluent, including 52 permit limit exceedances, when the POTW was accepting upstream oil and gas extraction wastewater
5	Clearfield Municipal Authority	POTW	17,034	37.8	West Branch Susquehanna River	Stopped accepting shale gas wastewater	–	–	1	–

Source no.	Treatment plant	Type	Total capacity (m^3/day)	Brine acceptance volume (m^3/day)	Discharge to	Status	Primary treatment technologies	Pre-treatment	Source	Remarks
						from 2009[2]				
6	Ridgway Borough	POTW	8327	75.7	Clarion River	Stopped accepting shale gas wastewater from 2011[2]	Screening and grit removal, an equalisation tank, aeration tanks, clarifiers, a chlorination feed system, a chlorine contact tank, aerobic digesters and a belt filter press	–	2	Local limits analysis assumed zero percentage removal of TDS, chloride and sulfate
7	Municipal Authority of Belle Vernon	POTW	1892.7	0.0	Monongahela River	Stopped accepting shale gas wastewater from 2009[2]	–	–	1	O&G waste flow limited to 1% of average daily flow at POTW by DEP order. This facility no longer accepts large volumes of O&G wastewater
8	Brownsville Municipal Authority	POTW	3633	0.0	Dunlap Creek	Stopped accepting shale gas wastewater from 2008[2]	–	–	1	O&G waste flow limited to 1% of average daily flow at POTW by DEP order. This facility no longer accepts large volumes of O&G wastewater
9	Waynesburg Borough	POTW	3028	0.0	South Fork Ten Mile Creek	Stopped accepting shale gas wastewater from 2008[2]	–	–	1	O&G waste flow limited to 1% of average daily flow at POTW by DEP order. This facility no longer accepts large volumes of O&G. High-salinity upstream oil and gas produced water impacted biological growth in trickling filter

Source no.	Treatment plant	Type	Total capacity (m^3/day)	Brine acceptance volume (m^3/day)	Discharge to	Status	Primary treatment technologies	Pre-treatment	Source	Remarks
11	Reynoldsville Boro	POTW	3028	41.6	Sandy Lick Creek	Stopped accepting shale gas wastewater from 2011[2]	–	–	1	Have taken in approx. 52 m^3/day of brine to POTW for a long time
12	Authority of the Borough of Charleroi	POTW	6056	0.0	Monongahela River	Stopped accepting shale gas wastewater from 2008[2]	Screening and grit removal, sedimentation activated sludge and chlorine disinfection	–	2	Treatment system influent and effluent samples show minimal or no TDS removal. The POTW rejects influent O&G wastewater with TDS greater than 30,000 mg/L and/or chloride greater than 15,000 mg/L
13	The Washington–East Washington Joint Authority	POTW	36,983	369	Chartiers Creek	–	–	–	1	O&G waste flow limited to 1% of average daily flow at POTW by DEP order. This facility no longer accepts large volumes of O&G wastewater
14	Franklin Township Sewer Authority/Tri County Wastes (CWT)	POTW receiving indirect discharge from CWT	4731	189	South Fork Ten Mile Creek	Stopped accepting shale gas wastewater from 2011[2]	Aeration, rotating biological contactors, clarification, filtration and chlorination	Yes (filtration, flocculation, and skimming)	1, 2, 3	TDS and chloride concentrations in effluent from the POTW were higher when the POTW was accepting industrial wastewater from the Tri County CWT facility and decreased after it stopped accepting wastewater from this CWT facility

Sources: 1, Veil, 2010; 2, USEPA, 2015b; 3, Skalak et al., 2013.

O&G, oil and gas..

10.9 Centralised Waste Treatment Facilities

In the USA, CWT facilities treat industrial wastewater containing hazardous and non-hazardous substances. The CWT facility discharging to either a POTW or surface water must comply with 40 CFR, Part 437, Centralised Waste Treatment Effluent Limitations and Guidelines, which includes limitations and standards for both direct and indirect discharge. The CWT's treated wastewater may be discharged to one of the following:

- discharge to surface waters;
- discharge to POTWs;
- reuse in fracturing or disposed into class II disposal wells (zero discharge); and
- a combination of the above options.

The USEPA (2015b) reports that 73 CWT facilities (39 facilities are in Pennsylvania) have accepted or plan to accept wastewater from hydraulic fracturing operations, most of these facilities do not accept wastewater from industries other than the oil and gas industry. The treatment capacities of the CWT facilities surveyed by the USEPA range from 330 to 4500 m^3 per day. The majority of the CWTs are located in the area where there are few class II disposal wells. Fifty-eight of these facilities are zero discharge CWT facilities that do not discharge wastewater to surface or POTWs, but typically return it for reuse and recycling.

Table 10.12 below shows a list of CWT plants in the Marcellus Shale region compiled by Veil (2010). This table shows that most of the CWT plants were at “proposed” status in 2010. An updated list of operating CWTs is available in the draft “Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources” (USEPA, 2015a). This updated list is included in Appendix D. With the exception of the Josephine and Franklin facilities, none of those listed in Table 10.11 are included in the USEPA's updated list.

10.9.1 The USA's experience

10.9.1.1 Treatment at existing brine treatment facilities, Pennsylvania

Two commercial wastewater treatment facilities in Josephine in Pennsylvania treat flowback water using chemical precipitation technology. A description of the treatment process at the Josephine facility (which stopped accepting unconventional waste in January 2015) is provided by Veil (2010). The treatment process removes metals but not TDS. The Josephine facility has a capacity of approximately 454 m^3 per day. Flowback and produced waters are transported by lorry to the treatment plant from the well sites. The water passes through screening to remove any coarse particulates or debris. Removal of free oil and heavy settleable solids is accomplished in a settling tank.

The water then flows into an aeration tank, followed by treatment with sodium sulfate and lime. Lime is added to raise pH and sulfates are introduced to precipitate barium, strontium and other divalent metals. Polymers are added to enhance settling. Settled solids from the settling tank are dewatered using a filter press. The treated water is adjusted for pH by adding acid and then discharged into the Blacklick Creek under an existing NPDES permit.

A study conducted by Warner *et al.* (Division of Earth and Ocean Sciences, Duke University) in 2013 showed that discharge of treated wastewater from the Josephine brine treatment facility had a noticeable impact on the water quality of the receiving body. The study focused on the fate of the following constituents: chloride, bromide, sulfate, calcium, sodium, magnesium, barium and strontium. Samples from the plant effluent, surface waters and sediments upstream, and at various distances downstream, of the discharge outfall along Blacklick Creek were collected. Although the treatment reduces the concentration of various elements, the chloride concentrations at 1.7 km downstream of the facility were 2–10 times higher than any recorded chloride concentration in western Pennsylvania streams. The concentrations of bromide in the upstream samples were very low (0.03–0.1 mg/L). Samples analysed at various locations downstream of the discharge point showed a 40-fold increase in bromide concentrations, even at a distance of 1.78 km from the discharge location. High bromide concentrations in river water could have an impact on downstream municipal drinking water treatment due to the formation of trihalomethane compounds during chlorination.

Similarly, the background river sediments in Blacklick Creek directly upstream of the discharge location were low in radium (Ra-226) concentrations (22.2 Bq/kg and 44.4 Bq/kg) and were consistent with the radium activities reported in background soils in western New York. Radium activity immediately adjacent to the facility discharge site was 200 times greater than any background sediment collected either upstream of the facility or from other western Pennsylvania rivers with sediment samples of similar grain size (Ra-226 8732 Bq/kg and Ra-228 2072 Bq/kg).

The use of sodium sulfate (Na_2SO_4) in the treatment facility co-precipitates radium in the barium sulfate precipitate. The accumulation of Ra in the sludge residual generates a waste that is characterised as TENORM, which could pose significant health risks if not properly disposed of.

Although treatment at the Josephine facility potentially reduced radium and barium, there was still discharge of radium and barium into the receiving stream. The study shows that most of radium discharged into streams was absorbed and retained in sediments near the discharge site. Although the radium accumulation appears to be localised near the discharge site, it might pose significant ecological impacts such as bioaccumulation in freshwater fish, invertebrates, molluscs and shells, with reported concentration factors of 100−1000.

Conclusions and recommendations from the study include:

- It concluded that, despite treatment, the quality of the receiving body is still affected by the discharge of the treated effluent.
- It recommended further studies on radium bioaccumulation and other ecological effects at the wastewater discharge site.
- It recommended that advanced treatment technologies be implemented to reduce the concentration of barium and radium.
- It recommended further studies on sludge disposal options and their suitability for disposal in municipal landfills.

According to the USEPA (2015a), the Josephine facility has stopped accepting wastewater from hydraulic fracturing units and plans to install an evaporation system to meet the TDS limit of 500 mg/L.

In general, the incorporation of TDS removal technologies to CWTs such as RO and evaporation/crystallisation can potentially mitigate the effluent quality issues described above. However, the pollutants would be transferred to the residuals of treatment such as the brine or salt cake.

Radium (radionuclides) readily co-precipitates with barium salts, so the precipitation of barium salt would significantly reduce radium concentrations in the water effluent. However, the barium and radium would be transferred to the sludge residual.

Table 10.12. Centralised waste treatment facilities (proposed and active)

Source no.	Treatment plant	Type	Total capacity (m^3/day)	Brine acceptance volume (m^3/day)	Discharge to	Treatment technologies	Source	Remarks
1	Somerset Regional Water Resources	Proposed CWT	1892	1892	North Branch Susquehanna	Metals precipitation, filtration (RO)	1	500 mg/L TDS limitation
2	Keystone Clearwater Solutions LLC	Proposed CWT	1907	1907	Moshannon Creek	Metals precipitation and filtration treatment (nano-filtration and RO)	1	–
3	Dannic Energy Corp.	Proposed CWT	946	946	Hawk Run	Metals precipitation and vacuum evaporator	1	–
4	Keystone Clearwater Solutions LLC	Proposed CWT	1907	1907	West Branch Susquehanna River	Metals precipitation and filtration treatment (nano-filtration and RO)	1	–
5	Dannic Energy Corp.	Proposed CWT	946	946	West Branch Susquehanna River	Metals precipitation and vacuum evaporator	1	–
6	Central PA Wastewater Inc.	Proposed CWT	1514	1514	Unnamed tributary to West Branch Susquehanna River	Metals precipitation is the proposed treatment technology	1	–
7	Construction – Ronco Facility	CWT	1892	1892	Monongahela River	–	1	–
8	Shallenberger Construction	Proposed CWT	3785	3785	Youghiogheny River	–	1	–
9	Tunnelton Liquids	CWT	3785	3785	Conemaugh River	–	1	Acid mine drainage treatment plant + injection well opened in 1998. Initially approved by DEP to receive O&G unconventional wastes. DEP shut down injection well in 2011

Source no.	Treatment plant	Type	Total capacity (m^3/day)	Brine acceptance volume (m^3/day)	Discharge to	Treatment technologies	Source	Remarks
10	Frontier Energy Services	Proposed CWT	3406	3406	Yellow Creek	RO and evaporation	1	–
11	Water Treatment Solutions	Proposed CWT	189	189	Daugherty's Run	Metal precipitation and thermal distillation/crystalliser treatment	1	–
12	Dannic Energy Corp.	Proposed CWT	946	946	Pine Run	Metals precipitation and vacuum evaporator	1	–
13	TerrAqua Resource Management	Proposed CWT	1514	1514	West Branch Susquehanna River	Metals precipitation and thermal distillation	1	–
14	Penn Woods Enterprises, LLC	Proposed CWT	1892	1892	Casselman River		1	–
15	PA Brine Josephine	CWT	454	454	Blacklick Creek	Oil–water separator, aeration, chemical precipitation with sodium sulfate, lime and a polymer, inclined plate clarifier	1	The facility claims to have stopped accepting Marcellus Shale wastewater 30 September 2011.I t treats conventional O&G wastewater. The facility will be upgrading to include evaporative technology that will enable it to achieve monthly average TDS levels of 500 mg/L or less[2]
16	PA Brine Treatment Franklin Facility	CWT	776	545	Allegheny River	Oil Water Separator, Aeration, Chemical Precipitation with Sodium Sulfate, Lime and a Polymer, Inclined plate clarifier	1	Stopped accepting hydraulic fracturing wastewater as of January 2015. The facility will be upgrading to include evaporation technology that will enable it to achieve monthly average TDS levels of 500 mg/L or less

Sources: 1, Veil, 2010; 2, USEPA, 2015a.

O&G, oil and gas..

10.10 Treatment and Disposal to Deep Well Injection

Substantial amounts of flowback water in the USA has been disposed of by DWI. Flowback water can be disposed by this method with minimal treatment. The cost of disposal depends on the distance between producing well and the injection well site. Flowback water from the Marcellus Shale region is transported by truck to Ohio for disposal, and the costs are reported to be USD$2.1–10.5 per barrel (or approximately €0.013–0.073/L) (Keister*,* 2010).

Commercial injection well facilities may impose a surcharge on UGEE producers to dispose of flowback water. Flowback water has lower density than produced water, which is produced over a longer period, and hence requires more power. The injection rate is inversely proportional to the injection pressure owing to technical and permit limitations. Therefore facility operators must inject low-density flowback water at a low flow rate using more power.

Tertiary treatment technologies such as RO and FO will produce a permeate effluent with low TDS (clean water) and a brine stream (reject) with high TDS. The reject can be disposed of in deep injection wells. Similarly, evaporation will produce a brine that can be also sent to DWI.

Hydraulic fracturing has been used for the last 50 years in tight and conventional gas fields in Germany in which one shale gas reservoir was developed. The flowback water of hydraulic fracturing stemming from conventional gas fields is currently treated by removal of solids and oil and grease occurring prior to DWI disposal. This is common practice in conventional oil and gas production in Germany (Olsson *et al.*, 2013). However, the impacts of using DWI disposal as the ultimate fate of UGEE wastewater in Germany are still under review and discussion. The major concerns are the potential for groundwater contamination by toxic or radioactive substances in flowback and produced waters. Olsson *et al.* (2013) suggest that more investigation is needed on the effects and potential environmental impacts of DWI on water and environmental resources. They suggest that disposal of flowback water be supported by detailed monitoring programmes to ensure that substances and volumes injected into the ground can be tracked. They also suggest that evaluation of the capacity of the water-bearing zone and whether or not it can support waste disposal for the entire gas reservoir should be undertaken.

10.11 Disposal of Residuals Containing NORM

The International Association of Oil and Gas Producers developed a guideline document for managing NORM in the oil and gas industry (IOGP, 2008). That document lists various disposal options for NORM including land-based management, salt cavern disposal, landfilling, underground injection and offshore discharge. The document also discusses monitoring, control and decontamination of the equipment. Several disposal methods are discussed in the guidance document including:

- commercial NORM waste facilities to contain NORM waste for long periods with restricted future use after closure;
- burial with unrestricted site use; and
- DWI disposal.

The disposal options for NORM-containing residuals must be carefully examined in relation to their acceptability to the general public, risks, costs and technical feasibility.

10.12 UGEE Water Treatment Practices in Europe

10.12.1 Germany

Most of the hydraulic fracturing experience in Germany to date has been associated with conventional or tight gas fields. The oil and gas exploitations are located in the Lower Saxony region. In 2012, only one well had been advanced in a shale formation by hydraulic fracturing (Olsson *et al.*, 2012).

In Germany, flowback from hydraulic fracturing of conventional gas fields is normally treated by separating coarse particulate by hydrocyclones, followed by solids settling and oil removal using separation tanks and filtration systems. The treated flowback is then disposed of by DWI.

Although treatment technologies such as desalination are capable of achieving treated water suitable for disposal to surface water, the current regulations do not allow it. The reason is that flowback is still not classified as wastewater in Germany, and currently there are no specific environmental legislation and technical standards for flowback management.

Olsson *et al.* (2012) described how one operator conducted a water balance analysis for a lease area of 200 km^2 in the Lower Saxony involving the drilling of 300 wells that would require approximately 3800 hydraulic fracturing stages over a 10-year period. The operator estimated a total water demand amounting to 6.02 million cubic metres of fresh water. Assuming a flowback return of 23% of fracturing fluids, the study estimated that 60% of flowback could be recycled, which would reduce fresh water consumption to 5.19 million cubic metres, while also significantly reducing the wastewater to be treated.

Table 10.13 shows the concentrations of contaminants in samples of flowback collected from exploratory wells in a gas shale formation in Germany.

Table 10.13. Concentrations of parameters in flowback samples from the Damme 3 gas shale formation (Olsson *et al.*, 2012)

Contaminant	Unit	Average concentration	Concentration range (mg/L)
Barium	mg/L	455	180–593
Chloride	mg/L	78,290	40,360–88,440
Sodium	Mg/L	30,582	17,960–36,390
Chromium	mg/L	0.3	0.3
Calcium	mg/L	14,120	6700–16,550
Strontium	mg/L	1455	790–1720
Zinc	mg/L	0.4	0.3–0.5
Sulfate	mg/L	8	4–15
Potassium	mg/L	110	52–157
Lithium	mg/L	5	5–6
Magnesium	mg/L	1799	890–2130
Iron	mg/L	91	23–160
Manganese	mg/L	2.5	–3.7

10.12.2 Poland

Water management strategies have followed a similar pattern to those adopted in the Marcellus Shale region. Owing to unknown characteristics of the formation and limited quantities of produced fluid, hydraulic fracturing during exploration has utilised mainly fresh water. The limited quantity of completed wells has allowed for disposal of flowback fluids in municipal wastewater treatment plants, where fluids were diluted with municipal sewage. In addition, several industrial disposal wells have been used for fluid disposal.

Prior to disposal, pre-treatment was performed with chemical and mechanical treatment systems, including coagulation and settling, to remove suspended solids and reduce the chemical oxygen demand (COD). Soda ash was used for reduce the hardness. Owing to the low concentration of organic compounds in the flowback stream, no initial oxidation step was performed. A heavy metal precipitation step followed suspended solids removal.

Field trials were performed with a mobile coagulation/flocculation/settling system. In addition, mobile evaporators have been tested for TDS removal. While they were successful at removing TDS, it was determined that the evaporators did not produce fluid at an economic rate.

Total disposal capacity via municipal and publicly owned plants and industrial wells was determined to be sufficient for receiving flowback from 10–15 wells concurrently. As a result, preliminary plans were prepared for a large-scale centralised treatment facility, which would gather and treat fluids from wells within a 100-km radius. Owing to pauses in the drilling programmes, these plans were not implemented.

As a result of the lack of regulatory framework, each well required a one-time approval for disposal into the municipal system. Treatment targets were set to protect the biological processes in the wastewater treatment plant from inhibitory effects of the flowback water and to ensure that dissolved solids were diluted to the requirements for wastewater treatment plant effluent. As a result, treatment targets often varied according to the requirements and flow rate of the local plant.

Limited flowback and produced water quality data are available. Table 10.14 illustrates the concentrations of contaminants in flowback water from two wells collected in four ponds at an unspecified time. Produced water data were not obtained. From the available flowback data, there was generally a large variation between wells and between samples from the same pond. Total dissolved solid concentrations varied between 20,000 and 60,000 mg/L. Data on NORM were not obtained. This is of concern for disposal to wastewater treatment plants. As observed in Pennsylvania, municipal treatment plants are often not equipped to treat NORM and probably do not test for these contaminants.

Table 10.14. Flowback water quality from a site in Poland

Contaminant/parameter	Unit	Sewage system limit	Flowback water concentration	Comment
Antimony	mg/L	0.5	< 0.020	
Arsenic	mg/L	0.5	< 0.020	
Ammonium	mg/L	200	10.8–38.6	
Nitrate	mg/L	10	< 4.5	
Nitrogen dioxide	mg/L	--	< 0.3	
Barium	mg/L	5	34.6–128	Imposed limit 2 mg/L
Beryllium	mg/L	1	< 0.005	
Boron	mg/L	10	3.16–11.4	Imposed limit 1 mg/L

Contaminant/parameter	Unit	Sewage system limit	Flowback water concentration	Comment
Chlorine	mg/L	4	0.03–0.24	
Chloride	mg/L	1000	6088–23,598	
Hexavalent chromium	mg/L	0.2	< 0.010	
Chromium	mg/L	1	< 0.002–0.17	
Cyanide	mg/L	0.5	< 0.015	
Tin	mg/L	2	< 0.010	
Zinc	mg/L	5	< 0.025–0.71	
Fluoride	mg/L	20	< 0.5	
Phosphorus	mg/L	--	< 0.2–0.81	
Aluminium	mg/L	--	< 0.1–1.47	
Phenol index	mg/L	15	< 0.002–0.021	
Cadmium	mg/L	0.4	< 0.0025	
Cobalt	mg/L	1	< 0.01	
Silicon dioxide	mg/L		1.79–12.2	
Copper	mg/L	1	< 0.005–0.14	
Molybdenum	mg/L	1	< 0.02–0.04	
Nickel	mg/L	1	< 0.005–0.027	
pH	--	6,5–9,5	7.3–8	
TOC	mg/L	--	16.1–61.8	
Lead	mg/L	1	< 0.005–0.024	
Potassium	mg/L	--	68.4–149	
Conductivity	µS/cm	--	14,400–44,830	
Radon	Bq/L	--	64.9–351	
Thiocyanate	mg/L	30	2.01–3.81	
Mercury	mg/L	0.06	< 0.0005	
Selenium	mg/L	1	< 0.02–0.048	
Sulfate	mg/L	--	< 2.5–19.8	
Sodium	mg/L	--	2172–8914	
Silver	mg/L	0.5	0.019–0.027	
Anionic surfactants	mg/L	15	< 0.8–1.06	
Thallium	mg/L	1	< 0.01–0.11	
Titanium	mg/L	2	< 0.005–0.061	
Uranium	mg/L	--	< 0.008	
Vanadium	mg/L	--	0.013–0.023	
Suspended solids	mg/L	--	29.2–370	
Iron	mg/L	--	< 0.05–132	
Total hardness	mg/L $CaCO_3$	--	3980–9950	

Note: Flowback water concentrations are averaged from two wells flowing into four ponds.

10.12.3 Ukraine

Ukraine has seen limited oil and gas development. Operators have taken different approaches to water management. Regional operators, mostly focused on conventional fields with smaller flowback volumes, have used pond evaporation for water disposal, followed by burying residual solids. Major operators, exploring unconventional fields, have disposed of water in mining and industrial water treatment facilities. The technologies used in these facilities and final disposal locations were not disclosed. Flowback water quality data from a single well are provided in Table 10.15. The four samples were taken from a single impoundment. The operator attributed some of the variation to rainwater dilution.

Table 10.15. Flowback water quality for a single well in Ukraine

Contaminant/parameter	Concentrations of chemicals			
	S1	S2	S3	S4
pH	6.7	7.3	6.6	6.7
Alkalinity, mg/L as CaCO3	7.9	5	4.9	2.1
Hardness, mg/L as CaCO3	109.3	106.9	78	25
Sodium, mg/L	12,779.50	9740	11,000	3700
Calcium, mg/L	1485.20	1292.70	1300	430
Iron, mg/L	1.3	1.1	5.7	0.44
Aluminium, mg/L	0.05	0.05	–	–
Sulfate, mg/L	152	148	160	66
Chloride, mg/L	23,288	18,714	20,000	6900
TDS, mg/L	38,768	30,744	40,800	12,700
TSS, mg/L	1340	1242	190	61

Notes: S1–S4 indicate various samples taken at a single impoundment, filled from one well. The analysis of S1 and S2 was performed by a Ukrainian state-run laboratory and of S3 and S4 by a third-party laboratory.

10.13 Best Management Practices

Table 10.16 summarises current BMPs at various developmental stages of UGEE that are derived from advancements in water and wastewater management practices and regulations from early UGEE developments.

These BMPs support environmentally sound practices. For instance, as discussed earlier, the use of POTWs in the early stages of the Marcellus Shale developments had adverse environmental impacts on surface water. The regulators then prohibited the treatment and disposal of flowback through POTWs, which in turn promoted advances in technologies for reuse and zero discharge facilities, or treatment to discharge utilising evaporation.

Table 10.16. Comparison matrix of environmental challenges and best management practices

Stages	Development phases	Water management – environmental challenges/aspects	Best management practices	Regulatory gateways
1. Well pad identification and initial site access	1.a – Pre-exploration/ permitting and seismic studies	Initial surface water source impacts, erosion and sedimentation	Water law and ownership evaluations	Gross water management plan and water budget submittal
			High-level water availability assessment	EIA studies required up front
	1.b – Exploration/site development and drilling	Source water resource impacts and stress	Development of operational area water management plan	Regulate to achieve no discharge to surface water, ground surface or treatment by POTW
		Impacts on water quality from drilling and completion	Manage flowback and produced waters to limit any spillage or loss to environment	Regulate brackish/wastewater storage and management practices
		Temporary storage and limited infrastructure and service industry	Transport to only to industrial water treatment and disposal facility	
		Limited reuse potential or disposal alternatives due to new field development	Develop initial treatment for reuse options	
		Generation of residuals containing NORM and wastewater	Transport to commercial NORM waste disposal facility	
2. Well design/construction and hydraulic fracturing	2.a – Pre-development pilot phase	Increased demand on water resources and infrastructure challenges	Develop detailed water balance for operations and update water management plan	Require reuse
		Lorries and road impacts	Develop water planning and drill schedule around efficient water use and allocations	Regulate disposal wells and move to no disposal wells in challenging geology
			Initiate development of reuse facilities and centralised disposal facilities	
	2.b – Full development phase	Intensity of demand for water resources	Use of non-public domain water resources	Require reuse
			Reuse requirements/water budgeting tools	Record-keeping requirements for fresh water usage, treated water reuse and wastewater disposal
			Operational and maintenance controls	
			Tools specific to ROI	
3. Production	Operational phase	Produced water storage, collection, treatment, reuse and disposal	100% reuse and 0% liquid discharge	Regulate produced water management and require reuse

Stages	Development phases	Water management – environmental challenges/aspects	Best management practices	Regulatory gateways
			Integrity assessments and maintenance of water infrastructure assets	Develop stringent disposal well guidelines to protect water resources and ensure safe pressures in the formation
4. Project cessation, well closure and decommissioning	Restoration phase	Erosion controls and stormwater management		Require restoration and bond for well sites
		Long-term well integrity		Require well closure records
		Lack of maintenance of old facilities		Require infrastructure, monitoring and maintenance

10.14 Treatment Strategies for UGEE in Ireland and Northern Ireland

The treatment strategies developed in this section are based on available data on flowback quality for the NCB source shale, anticipated hydraulic fracturing techniques, probable commercial scenarios, and the review of background documentation (e.g. IRS, undated). No data on flowback quality were available for the CB.

Centralised treatment and/or on-site treatment systems are technically feasible alternatives for treating flowback and produced waters in shale plays in Ireland and Northern Ireland. However, the extents of the gas shale exploitations seem to favour centralised treatment over on-site treatment systems. According to the commercial scenarios described in section 2.2, the extent of concessions range from 500 to 1000 km^2, which probably represent a distance no greater than 40 km – a relatively short distance for water transport to a centralised location. The centralised facility would receive the water either from receiving water transfer stations or by ground transport (tanker lorries), or both.

If the preference is to use receiving transfer stations, they would be installed at locations near the well pads. The operators would transfer the water from the wells pads to the receiving stations by either pumping or lorries. The receiving transfer stations would consist of unloading pads, receiving above-ground tanks and pump stations, and they would connect to the centralised treatment facility via conveyance piping.

10.14.1 Estimates of flowback and produced water generation

Water demand and wastewater generation projections were developed for a representative lease area in the NCB and CB under three different scenarios ranked as of low, moderate and high water demand. The freshwater demand projections for hydraulic fracturing were discussed in Chapter 5, and the associated assumptions for each scenario are again noted in Table 10.17.

Table 10.17. Description of low-, moderate- and high-demand scenarios per NCB lease area

Description	Unit	Low demand	Moderate demand	High demand
Wells per pad	No.	8	12	16
Required volume of water per fracture programme	m^3	5000	10,000	15,000
Well pads per lease area	No.	25	35	60
Total wells per lease area	No.	200	420	960
Flowback as a percentage of fracture fluid per fracture programme	%	25	32.5	40
Recycling rate for flowback water	%	80	40	0

The high-demand scenario represents a condition in which the producer drills and operates the highest number of wells per lease area, requiring high volumes of water per well installed, and although flowback is returned to the surface, none of it is recycled. On the other hand, the low-demand scenario represents a condition in which the producer drills and operates the lowest number of wells per lease area, requiring low water volumes per well installed, and assumes that 80% of flowback is recycled. Moderate demand corresponds to an intermediate scenario. As previously discussed, the low- to moderate-demand scenarios are the most likely scenarios in the NCB.

These scenarios assume that no produced water is reused or recycled because of its high salinity to assess conservative scenarios from water demand and wastewater management perspectives;

however, in the USA, produced water is reused and recycled with or without treatment (USEPA, 2015b).

Wastewater generation was estimated from the projected total demand for water used in hydraulic fracturing and the following assumptions:

- flowback volume is estimated as a percentage of fresh water injected during fracturing;
- a recycling flowback for reuse as base fluid of up to 80%; and
- produced water is generated at a rate of 1250 m^3 per year per well, which is based on actual data from numerous operating wells (USEPA, 2015b) (note that this value differs from AMEC's value of 4000 m^3 per year per well in Table 2.1 in Chapter 2).

Based on the projections of demand for water and the assumptions above, annual volumes of flowback and produced water were estimated for the lifetime of the lease area for each scenario in Table 10.18. It was assumed that the lifetime of each well is 10 years, so the produced water for a year comes from the wells put into production during the previous 10 years.

To evaluate the size of treatment facilities required, the projections of wastewater generation for the high-demand scenario were reviewed first because it produces the highest wastewater volumes over the lifetime of the lease area operation. The high-demand scenario data tabulated in Table 10.18 were plotted in Figure 10.5. This would be considered the worst-case scenario.

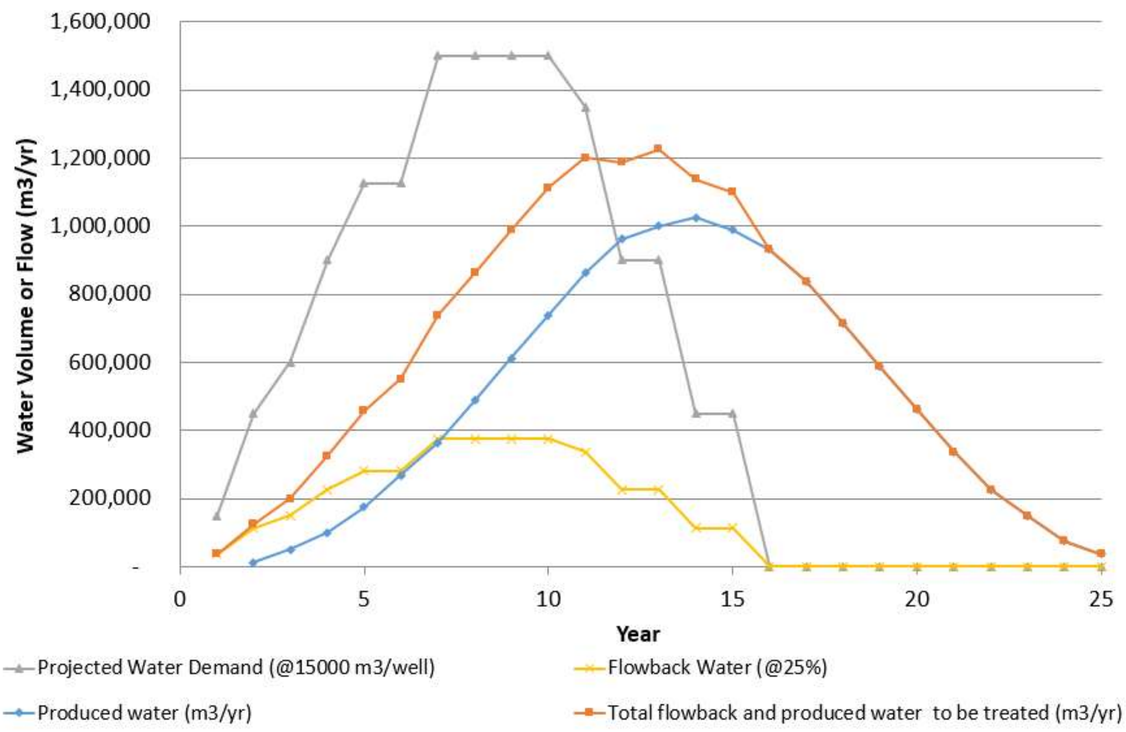

Figure 10.5. Demand for water and production per lease area: NCB high-demand scenario.

As shown in Figure 10.5, for the high-demand scenario, the maximum demand for water occurs from years 7 to 10 at approximately 1.5 million cubic metres annually. In this worst-case scenario, all flowback and produced waters generated need to be treated and disposed of. The total combined flowback and produced water volume gradually increases until it reaches a maximum of approximately 1.2 million cubic metres in years 10–12 at the peak of drilling activity in the lease area.

After year 12, flowback and produced water volumes gradually decline as fewer wells are installed. After year 15, all drilling operations are completed and only produced water is generated.

Table 10.18. Water demand, flowback and produced water volumes per NCB lease area

High-demand scenario							
Year	No. of wells		Annual water flow (m^3/year)		Produced water (m^3/year)	Total freshwater demand (m^3/year)	Total flowback and produced water to be treated (m^3/year)
	Per year	Total	Projected water demand (@15,000 m^3/fracturing programme)	Flowback water (@ 25%)		Projected water demand — recycling of flowback (@ 0%)	Flowback water + produced water – recycled water (m^3/year)
1	10	10	150,000	37,500		150,000	37,500
2	30	40	450,000	112,500	12,500	450,000	125,000
3	40	80	600,000	150,000	50,000	600,000	200,000
4	60	140	900,000	225,000	100,000	900,000	325,000
5	75	215	1,125,000	281,250	175,000	1,125,000	456,250
6	75	290	1,125,000	281,250	268,750	1,125,000	550,000
7	100	390	1,500,000	375,000	362,500	1,500,000	737,500
8	100	490	1,500,000	375,000	487,500	1,500,000	862,500
9	100	590	1,500,000	375,000	612,500	1,500,000	987,500
10	100	690	1,500,000	375,000	737,500	1,500,000	1,112,500
11	90	780	1,350,000	337,500	862,500	1,350,000	1,200,000
12	60	840	900,000	225,000	962,500	900,000	1,187,500
13	60	900	900,000	225,000	1,000,000	900,000	1,225,000
14	30	930	450,000	112,500	1,025,000	450,000	1,137,500
15	30	960	450,000	112,500	987,500	450,000	1,100,000
16	0	960	–	–	931,250	–	931,250
17	0	960	–	–	837,500	–	837,500
18	0	960	–	–	712,500	–	712,500
19	0	960	–	–	587,500	–	587,500
20	0	960	–	–	462,500	–	462,500
21	0	960	–	–	337,500	–	337,500
22	0	960	–	–	225,000	–	225,000
23	0	960	–	–	150,000	–	150,000
24	0	960	–	–	75,000	–	75,000
25	0	960	–	–	37,500	–	37,500
						Median	587,500
						Maximum	1,225,000
						Minimum	37,500

Moderate-demand scenario								
Year	No. of wells		Annual water flow (m^3/year)		Produced water (m^3/year)	Recycled flowback @ 40% (m^3/year)	Wastewater generated to be disposed of (m^3/year) Flowback water + produced water – recycled water	Total wastewater generated (m^3/year)
	Per year	Total	Projected water demand (@ 10,000 m^3/f.p.)	Flowback water (@ 32.5%)				
1	4	10	43,300	14,073		5629	8444	14,073
2	13	23	129,900	42,218	12,500	16,887	37,831	54,718
3	17	40.3	173,200	56,290	28,738	22,516	62,512	85,028
4	26	66.3	259,800	84,435	50,388	33,774	101,049	134,823
5	32	98.8	324,750	105,544	82,863	42,218	146,189	188,406
6	32	131	324,750	105,544	123,456	42,218	186,783	229,000
7	43	175	433,000	140,725	164,050	56,290	248,485	304,775
8	43	218	433,000	140,725	218,175	56,290	302,610	358,900
9	43	261	433,000	140,725	272,300	56,290	356,735	413,025
10	43	304	433,000	140,725	326,425	56,290	410,860	467,150
11	39	343	389,700	126,653	380,550	50,661	456,542	507,203
12	26	369	259,800	84,435	416,763	33,774	467,424	501,198
13	26	395	259,800	84,435	433,000	33,774	483,661	517,435
14	13	408	129,900	42,218	443,825	16,887	469,156	486,043
15	12	420	120,000	39,000	427,588	15,600	450,988	466,588
16	0	420	–	–	401,994	–	401,994	401,994
17	0	420	–	–	361,400	–	361,400	361,400
18	0	420	–	–	307,275	–	307,275	307,275
19	0	420	–	–	253,150	–	253,150	253,150
20	0	420	–	–	199,025	–	199,025	199,025
21	0	420	–	–	144,900	–	144,900	144,900
22	0	420	–	–	96,188	–	96,188	96,188
23	0	420	–	–	63,713	–	63,713	63,713
24	0	420	–	–	31,238	–	31,238	31,238
25	0	420	–	–	15,000	–	15,000	15,000
					Median	16,887	248,485	253,150
					Maximum	56,290	483,661	517,435
					Minimum	–	8,444	14,073

Low-demand scenario							
Year	No. of wells		Annual water flow (m^3/year)		Produced water (m^3/year)	Recycled flowback @ 80% (m^3/year)	Total wastewater generated (m^3/year)
	Per year	Total	Projected water demand (@ 5000 m^3/f.p.)	Flowback water (@ 40%)			Flowback water + produced water – recycled water
1	2	10	10,000	4000		3200	800
2	6	16	30,000	12,000	12,500	9600	14,900
3	8	24	40,000	16,000	20,000	12,800	23,200
4	12	36	60,000	24,000	30,000	19,200	34,800
5	15	51	75,000	30,000	45,000	24,000	51,000
6	15	66	75,000	30,000	63,750	24,000	69,750
7	20	86	100,000	40,000	82,500	32,000	90,500
8	20	106	100,000	40,000	107,500	32,000	115,500
9	20	126	100,000	40,000	132,500	32,000	140,500
10	20	146	100,000	40,000	157,500	32,000	165,500
11	18	164	90,000	36,000	182,500	28,800	189,700
12	12	176	60,000	24,000	192,500	19,200	197,300
13	12	188	60,000	24,000	200,000	19,200	204,800
14	6	194	30,000	12,000	205,000	9,600	207,400
15	6	200	30,000	12,000	197,500	9,600	199,900
16	0	200	–	–	186,250	–	186,250
17	0	200	–	–	167,500	–	167,500
18	0	200	–	–	142,500	–	142,500
19	0	200	–	–	117,500	–	117,500
20	0	200	–	–	92,500	–	92,500
21	0	200	–	–	67,500	–	67,500
22	0	200	–	–	45,000	–	45,000
23	0	200	–	–	30,000	–	30,000
24	0	200	–	–	15,000	–	15,000
25	0	200	–	–	7500	–	7500
						Median	92,500
						Maximum	207,400
						Minimum	800

Table 10.19 summarises the maximum and median annual water demand and combined flowback and produced waters generated for each demand scenario. These annual volumes were averaged.

Table 10.19. Water demand and wastewater generation for a representative lease area in the NCB

Parameter	Units	Low demand	Moderate demand	High demand
Maximum projected water (base fluid) demand	m^3/year	68,000	376,710	1,500,000
Maximum projected water (base fluid) demand	m^3/day	186	1032	4110
Maximum flowback/produced water volume for treatment and disposal	m^3/year	207,400	483,661	1,225,000
	m^3/day	568	1325	3356
	bbl/day	3574	8336	21,112
Median flowback/produced water volume generation	m^3/year	92,500	248,485	587,500
	m^3/day	253	681	1610
	bbl/day	1594	4282	10,125
Year of occurrence of maximum flowback/produced water generation	operating year	11	11	10–12

bbl, barrels.

The high-demand scenario shows a maximum and median total combined flowback and produced water volume averaging 3356 and 1610 m^3 per day (21,100 and 10,125 barrels per day), respectively, as shown in Table 10.19. This daily flow corresponds to large wastewater treatment plant. For instance, in the USA, operating CWT facilities' treatment capacities range from 330 to 4500 m^3 per day (2100 and 29,00 barrels per day).

Because the cumulative increase in wastewater generation is gradual, expandable modular treatment systems are better suited to provide incremental treatment capacity as needed. For the high-demand scenario in one lease area, the recommended initial treatment plant capacity would be the median treatment capacity requirement of 1610 m^3 per day, which coincides with a typical average plant size of 10,000 barrels per day. After year 6, additional capacity would need to be installed to handle the maximum flow of 3356 m^3 per day, occurring in years 10–12. After year 12, there would be excess treatment capacity that could be utilised to accept wastewater from another lease area.

The NCB has three lease areas adjacent to each other within the same region. Assuming concurrent exploitation of two of the three lease areas within the NCB and delaying the exploitation of the third lease area, the high-demand scenario (worst-case) would require two CWT facilities sited in central locations within the NCB and designed to treat wastewater for disposal to surface water. Because there would be excess capacity in the two installed CWTs after year 12, the third lease area would commence operation after year 12.

On the other hand, the CB area would require its own CWT facility, also designed to treat flowback and produced waters for disposal.

Under the moderate-demand scenario, the treatment capacity requirements in the NCB could be satisfied by only one CWT facility designed to provide treatment mainly for disposal, with a smaller fraction for reuse and recycling. If the wastewater is treated to meet stringent surface water standards, the quality would be such that it would all be adequate for reuse. The initial CWT facility capacity would treat the combined wastewater volume generated by concurrent drilling operations in two lease areas amounting to 1388 m^3 per day (694 m^3 per day per lease area × 2). After year 6, the plant would require a treatment capacity of 2836 m^3 per day (1418 × 2). The third lease area would commence operations once the CWT had available capacity or the CWT could be expanded to absorb flows for the third lease area operation.

10.14.2 Treatment for water reuse and recycling

The centralised treatment facilities can be designed to produce a treated water that could be recycled as source water for fracturing fluid preparation. Figure 10.6 shows a generic treatment process to achieve a water quality with the potential for reuse. The treated water would still contain TDS, soluble organics and NORM, but these do not appear to have an adverse effect on slick water or linear gel fracturing fluids, intended for use in the NCB and CB shales.

Depending on the water quality requirements of the UGEE producer, further treatment may be required involving secondary treatment to remove selected divalent cations and anions that interfere with chemical additives and well performance. These issues were described in section 6.5. A potential drawback is the precipitation of barium, which adsorbs NORM and would render the sludge hazardous and radioactive.

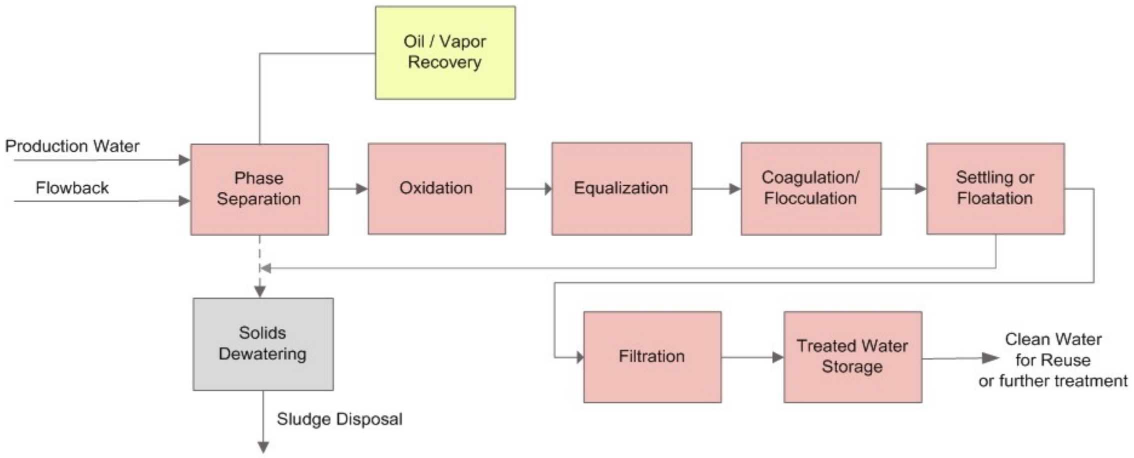

Figure 10.6. Primary treatment of flowback/produced water for reuse.

The first step in the process is to remove any free-phase oil, volatile organic vapours, and/or settleable solids that are present in the raw water. Subsequently, the oxidation process breaks down any residual organics from the fracturing additives and oxidises sulfides and metals before the water is sent to equalisation. The oxidation step has the added benefit of disinfection for bacterial reduction.

As shown in Figure 10.6, the equalised water is then treated by coagulation, flocculation and solids separation processes whereby TSS, emulsified oil and iron are removed. Solids separation can be conducted by either settling or flotation, depending on the characteristics of the flocs formed. Iron can affect slick water fracturing so it is typically a constituent giving rise to concern. Ultimately, the treated water would be blended with fresh water so the chemistry must be carefully examined with the operator to determine whether other constituents must be removed. For instance, if other divalent ions (e.g. barium, calcium) are a concern, subsequent precipitation with sodium sulfate and lime could be added as a downstream treatment.

The final step is filtration that removes any residual TSS that may escape the solids separation step. The treated water is sent to storage. Biocide is added to the treated water to prevent undesirable bacterial growth if the water is reused for fracturing. The pH is adjusted at various points throughout the treatment process.

10.14.3 Treatment for deep well injection

Regulations in Ireland and Northern Ireland prohibit disposal of liquids containing hazardous pollutants into groundwater but do not specifically have provisions for DWI disposal. There are open discussions in the UK and the EU concerning whether DWI would be allowed. DWI does not return flowback water to the same shale formation (low permeability), but it requires the installation of disposal wells in deep water-bearing permeable formations that are not suitable sources of potable water.

If DWI disposal is allowed in the future, the centralised treatment facility could incorporate DWI as an additional means of disposal. Based on experience in the USA, the disposal of flowback and produced waters to DWI requires only pre-treatment consisting of oil and suspended solids removal, as depicted in Figure 10.7. DWI would require purpose-built disposal wells in deep permeable formations.

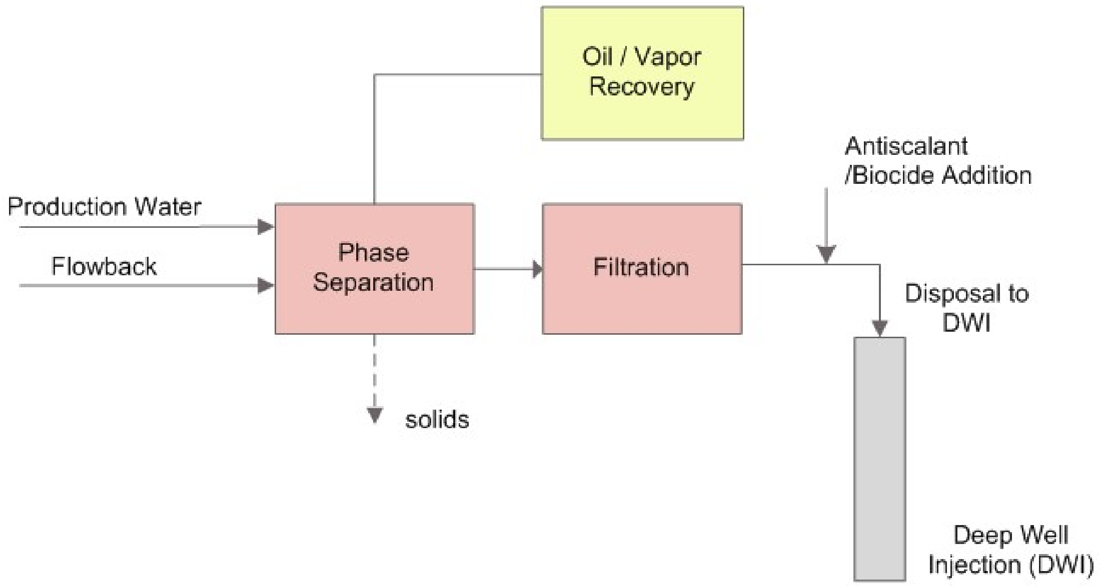

Figure 10.7. Generic treatment process train for DWI disposal.

Figure 10.7 shows a simplified treatment train consisting of phase separation and filtration. The free-phase oil and vapour condensates are recovered for sale as products. The settled solids are withdrawn for disposal. Subsequently, the water is filtered to remove TSS and antiscalant and biocides are added prior to injection into the deep well.

10.14.4 Treatment for surface water disposal

The centralised treatment facilities could also be designed to treat the flowback and produced waters to meet surface water discharge limitations. However, achieving such a level of treatment would be capital intensive, particularly due to the high TDS levels and presence of NORM anticipated in the NCB shale flowback. To accomplish surface discharge goals, the treatment train would consist of primary, secondary and tertiary treatment. Specifically, evaporation and condensation of flowback would be needed to remove TDS. The condensed water is clean water with traces of organic compounds, which might require granular activated carbon adsorption for polishing. The resulting brine from evaporation can be crystallised to salt. The brine and/or salt would contain NORM that would require special disposal.

The anticipated high concentrations of TDS in NCB and CB flowback and produced waters may preclude the use of RO.

The treatment of flowback and produced water in POTWs is not technically feasible because the treatment processes in municipal and publicly owned wastewater treatment plants are not suitable to address priority hazardous substances or chemicals encountered in this water, such as radium, barium and boron, and water high in TDS tends to inhibit the performance of the biological process in the POTW.

10.14.5 Residuals of treatment

The disposal of treatment sludge residuals is regulated under country-specific solid waste regulations. In the USA, although there are extensive federal regulations controlling hazardous waste, the wastes associated with oil and gas activities are currently exempt from federal rules; however, some state regulations may apply under certain circumstances.

For disposal of non-hazardous sludge in a municipal landfill, the waste must pass the paint filter test and toxicity characteristic leaching procedure test. The sludge from physicochemical treatment of flowback and produced water may contain barium and strontium at concentrations that may not pass the toxicity characteristic leaching procedure test. This would require the sludge to be disposed of as hazardous waste, significantly increasing the cost of disposal to landfill.

The residual sludge from treatment would probably contain NORM. The regulations limit the disposal of NORM-containing solid waste in a municipal landfill site. Radioactivity screening is required at all municipal landfill sites and there are established limits. Above the limits, the waste would be classified as low-level radioactive waste and its disposal would be restricted to specially permitted landfill sites.

10.15 Treatment Technologies

The degree of treatment of flowback and produced waters depends on the end use and the applicable regulations in the region. The following sections describe the various treatment technologies available, which are either commercially used or in the preliminary stages of commercial development. Depending on the treatment goals, different combinations of these technologies can be used to treat flowback and produced waters.

10.15.1 Gun barrel tanks

Gun barrel tanks are used for separating free-phase oil (and, to some degree, emulsified oil) from flowback and produced waters recovered from extraction operations. These tanks are designed to provide long retention times that allow coalescence of oil droplets and gravity separation to occur.

The gun barrel tank design consists of an inlet flume at the top and a spreader plate installed at the bottom of the tank. There is an internal gas-separating chamber that extends above the top of the tank where gas is separated and vented. Water with emulsified oil flows down the inlet tube in the middle of the tank to a spreader that is located below the oil–water interface. The oil–water mixture rises to the top of the surrounding layer of water. Passage through the water helps convert the emulsified liquid into distinct oil and water layers. Oil floats to the top and accumulates at the surface. The oil is skimmed off the surface of the gun barrel and the water exits from the bottom either through a water leg or an interface controller and dump valve. The tank is equipped with a vacuum/pressure valve with flame arrester. A gas blanket is maintained above the surface of the liquid in the tank to provide positive pressure and eliminate oxygen. The gun barrel tank can also be designed to remove settleable solids. Typical gun barrel tank sizes are 200, 500 and 1000 barrels (24, 60, 120 m^3, respectively).

10.15.2 American Petroleum Industry separators

In general, flowback or produced water is treated in an oil–water separator as a pre-treatment. An API oil–water separator is used to separate free-phase oil and suspended solids from water. It is a gravity separation device of a design based on Stokes' law. According to the specific gravity difference between oil, water and settleable solids, the solids settle to the bottom, and the oil rises. The floating oil layer is skimmed off the water surface and the settled sludge is removed from the bottom.

For flowback and produced waters, the API separator construction is typically austenitic stainless steel (or higher grade) and/or concrete. Under most operating conditions, the API separator removes both free oil and suspended solids to achieve an effluent concentration of between 50 and 200 mg/L for both parameters. TSS removals in the range of 33–68% have been reported (waterfacts.net). Capital and operational costs for this technology are relatively low. The process removes free oil (> 150-μm particles) and not emulsified oil without using chemicals.

10.15.3 Chemical oxidation

Chemical oxidation is used to oxidise reduced constituents such as sulfides and ferrous iron, and to break down complex organic compounds to simpler biodegradable forms such as acetic acid, formic acid, etc. Some typical chemical oxidants are peroxide and chlorine dioxide, which are discussed below. Selection of the oxidant for a given application depends on factors such as raw water quality, specific contaminants in the water, local power and chemical costs. No waste is generated by oxidation treatment (Guerra *et.al*., 2011)

Maguire-Boyle and Barron (2014) found that oxidative chlorination of flowback water forms chlorocarbons and organobromides, which are environmental pollutants of potential health concern. In addition, the presence of ammonia can form chloramines, which are also potentially toxic and need to be monitored if water is being released to the environment.

10.15.3.1 Chlorine dioxide

Chlorine dioxide is a selective oxidiser that is used to oxidise manganese, iron, phenols, sulfides, cyanides and odour-causing substances (Figure 10.8). It is non-toxic and does not react with NORM and ammonia. It is typically used in the oil industry to mitigate iron sulfide and hydrogen sulfide and to disinfect flowback and produced waters for reuse (Seth *et al.,* 2013).

Figure 10.8. Chlorine dioxide system.

Chlorine dioxide is used as a pre-treatment for stored flowback and produced waters. It breaks down oil emulsions, destroys chemical additives and is used for disinfection. The treated water can be reused in operations such as drilling and hydraulic fracturing (Sabre Companies LLC, 2012).

10.15.3.2 Hydrogen peroxide

Hydrogen peroxide (H_2O_2) is a powerful oxidiser that, through catalysis, forms hydroxyl radicals that promote strong oxidation reactions in the water phase. H_2O_2 is commercially available in various grades, with 30% or 50% (by weight) being the most widely used in wastewater treatment applications. Inhibitors such as phosphate are typically added to prolong the time it can be stored for. Applications of hydrogen peroxide include oxidation of sulfides and toxic and refractory organic compounds. Alkaline peroxidation oxidises formaldehyde. Reactions with hydrogen peroxide alone are slow, therefore a wide variety of chemical catalysts are used.

UV light can also be used as catalyst. A hydrogen peroxide molecule can be directly split into hydroxyl ions by UV light. Compounds effectively treated using UV hydrogen peroxide include benzene, toluene, xylene, trichloroethylene and perchloroethylene. Some compounds that are refractory to treatment include chloroform, acetone, trinitrobenzene and *N*-octane. Hydrogen peroxide can be used to remove priority pollutants, reduce toxicity and/or improve biodegradability. (Eckenfelder, 2000).

10.15.4 Coagulation and flocculation

Coagulation and flocculation treatment of flowback and produced waters is generally used for the removal of heavy metals, emulsified oil and suspended solids. Oxidation typically precedes this process in order to reduce the anti-coagulation and chelating effects of the fracturing additives.

The first step is the coagulation process whereby alkali and coagulant is added to a rapid mix chamber to promote charge destabilisation of colloids and microfloc formation. The coagulants used in UGEE are typically alum or ferric salts. Subsequently, flocculation takes place in a slow-mix tank in which a coagulant aid (based on polymers) facilitates floc agglomeration to form large flocs that can be either floated or settled, depending on their characteristics.

10.15.5 Electrocoagulation

In water treatment, coagulation can be achieved by adding chemicals or by electrical methods. In electrocoagulation, the coagulant is produced in situ by the oxidation of an anode (such as an iron or aluminium sheet) into solution using electricity. The process utilises sacrificial anodes to produce coagulants that are used to remove suspended solids, colloidal particles and dissolved metals from a solution by precipitation. Similar to the chemical precipitation process, electrocoagulation introduces charged ions into the solution. This causes agglomeration of small particles into larger particles. The metallic hydroxide floc (aluminium or iron hydroxide) that is generated in the process attracts ions and other suspended contaminants and aids in their removal (pH adjustment is done to achieve required floc formation). Oxygen and hydrogen are generated at the cathode during electrocoagulation. Suspended particles and agglomerated floc in the solution attach themselves to the gas bubbles and float to the surface. The electrocoagulation process is also used for the de-emulsification of oil from water. Similar to chemical precipitation, no anions are added to the solution in this process.

Electrocoagulation is one of the technologies available for removing suspended solids and metal ions from flowback and produced waters. The process can be used in conjunction with other treatment processes such as softening or RO. As reported in a presentation entitled “Electrocoagulation: An Innovative Approach for Recycling Produced Water and as a Pretreatment to Reverse Osmosis for Emulsified Oils, Heavy Metals and Other Constituents in the Oil and Gas Industry” (Eames, 2013), almost total iron removal of 99.9% and TSS removal of 99.9% from oilfield produced water was achieved using the electrocoagulation process. The effluent from the process was treated using RO. A TDS removal of 95% was noted in the RO effluent.

10.15.6 Gravity settling

Settling or sedimentation utilises the natural process of gravity to separate solids from the liquid. Solid particles, because of their heavier density (compared with water) and net negative buoyant force, settle to the bottom with a terminal velocity that can be estimated using Stokes' law. Gravity settling tanks (typically concrete) can be designed to have vertical or horizontal configurations. Based on the size and specific gravity of the targeted particulates, settling tanks are designed to provide adequate surface area and hydraulic retention time to allow the particles to settle to the bottom of the tank.

For produced waters, a large area is typically required for a settling tank. This treatment process does not remove very small or suspended particles present in the feed water. The operation and maintenance costs of this technology are low and energy consumption is very low.

10.15.7 Dissolved air floatation

Dissolved air flotation (DAF) is used to remove free and dispersed oil and suspended solids (Figure 10.9). In DAF, fine air bubbles are introduced into the liquid at the bottom of a flotation chamber. Flocculated particles, oil droplets and other suspended contaminants attach to the dissolved air bubbles and float to the surface owing to their decreased density. Adequate retention time is provided in the DAF units to allow the buoyant force of the combined air bubble particle units to rise to the surface. Settleable solids collect at the bottom of the DAF chamber as sludge. The sludge is removed using a rake mechanism, while the floating material and foam is skimmed off the top of the chamber. Chemicals including coagulants and flocculants are added upstream as discussed in section 10.15.4 above. DAF is typically used to remove oil particles in the range of 5–100 µm and TSS particles ranging from 5 to 100 µm in size. To remove larger oil particles, upstream gun barrel tanks and/or API separators are typically employed.

The DAF process is energy intensive. To pressurise the system with dissolved gas in the feed stream, energy is needed. Chemicals may be added to enhance the removal of target contaminants. Treatment costs are estimated to be US$0.60 per cubic metre (Çakmakce *et al.,* 2008).

Figure 10.9. Dissolved air flotation.

10.15.8 Dissolved gas floatation

The dissolved gas flotation (DGF) process works based on the same principle as DAF. The method by which bubbles are introduced into the system and retention time vary. A dual-sided impeller in a DGF pump is designed to pull both water and gas. As the impeller draws in the vapour, it is mixed with the liquid being pumped and compressed into micro-fine bubbles. Dissolved gas in the water is maintained under pump discharge back pressure. The mixture of gas and water flows through a globe valve, which introduces a drop in pressure. Owing to the drop in pressure, the entrained and dissolved air is released from the solution. Bubble sizes in the dissolved gas flotation process range from 1 to 100 µm and the backpressure valve on the discharge piping can regulate the bubble size in a DGF pump (Godeaux *et al*., 2007). Energy consumption and operation and maintenance costs are high.

10.15.9 Chemical precipitation

Chemical precipitation is generally used for the removal of divalent metals and certain anions. The process involves separation of either dissolved or suspended solids in solution by formation of a solid precipitate.

Precipitation is enhanced using coagulants or polymers that cause suspended particles and ions in solution to form larger aggregates or floc that can be removed in a settling tank. Chemicals typically used in the precipitation process are lime (calcium oxide), sodium sulfate, sodium carbonate, ferrous sulfate and polymers. The removal of dissolved metals from wastewater can be accomplished by chemical precipitation using lime (which reacts to form calcium carbonate and raises the pH) and ferrous sulfate in the presence of dissolved oxygen to remove barium and strontium. The solubility of the metal compounds is pH dependent so pH adjustment is done at various stages in the process to achieve the removal of target metal ions. After clarification and filtration, the treated water is discharged.

Owing to the high barium and strontium content in the brine discharge from Marcellus Shale and the proposed effluent limits for these constituents in pending Pennsylvania state regulations, the chemical precipitation process alone would be inadequate. As discussed in an article on the science of the Marcellus Shale (Keister, 2010), a modification of the precipitation process is proposed to address this problem. The patented method, the Sequential Precipitation Process, utilises a combination of chemical precipitation and fractional crystallisation treatment processes to reduce barium, strontium, TDS and other constituent concentrations. Barium is first removed in the precipitation process as barium sulfate sludge (some amount of radium is also removed), followed by strontium, calcium, iron, magnesium and manganese in two separate steps using additions of sodium carbonate and sodium hydroxide. Based on treatability tests conducted as part of the study, the barium concentrations measured in treated Marcellus Shale flowback samples were < 0.1 mg/L, compared with concentrations ranging from 69,640 mg/L to 248,428 mg/L in the untreated samples. Similarly, TDS reduction rates ranged from 20% to 40% in untreated flowback water samples containing 69,640 mg/L to 248,428 mg/L TDS. It is proposed that treated flowback wastewater using the Sequential Precipitation Process method be used for recycling or final disposal by evaporation or fractional crystallisation methods.

10.15.10 Filtration

Filtration is used for separating both very fine particles and larger particles, such as sand and scale particles, from the water stream. Filtration is a commonly used technology for treating produced water. Some types of filters commonly used are cartridge filters, bag (or cloth) filters, and media filters. To select the correct size of filter and the appropriate filter medium, the solids concentration and the expected particle size distribution in the feed water stream need to be considered.

10.15.10.1 Bag filters and cloth media filters

A bag filter system has two components – the filter bag that is used to filter the solids from the liquid stream and the filter housing that holds the filter bag. Bag and cloth media filters belong to the category of surface filters and are made from material such as paper, cloth or woven wire. When the volume of solids trapped causes the differential pressure across the filter to exceed a preset limit, the filter system is taken out of service and replaced. TSS removal efficiencies of approximately 95% can be achieved with bag and cloth filters. (M-I SWACO, 2011).

10.15.10.2 Multimedia filtration

Filtration can also be accomplished using different types of media, including sand, gravel and anthracite. The feed water is passed through a vessel packed with the solid media (Figure 10.10). Particles larger in size than the media are captured in the filter as the water flows through. Different layers of filter media of varying size and specific gravity are packed in the filter vessel. When the volume of solids trapped causes the differential pressure across the filter to exceed a pre-set limit, the filter system is taken out of service and backwashed. The waste stream from the backwash cycle is stored and sent for separate treatment. A multimedia filter is typically used to treat feed water containing > 30 mg/L of TSS, with particle sizes ranging from 5 to 100 μm. Pre-treatment is required for waters containing high levels of solids or oil. Up to 70–80% of TSS can be removed using multimedia filters.

Figure 10.10. Multimedia filtration.

10.15.10.3 Walnut shell filters

Walnut shell filters can be used for removal of both TSS and dispersed oil in produced water. The filters are typically used as a tertiary treatment process, following bulk removal of oil and suspended solids in upstream processes. In this type of filter, solids are removed by the capture of particles in the crushed shell medium as the water takes a tortuous path through the filter. Crushed walnut shell medium also provides coalescing sites where oil particles present in the liquid stream can collect. Material captured in the filter medium can be removed during a backwash cycle, allowing the medium to be reused (M-I SWACO, 2011).

These filters are typically designed for an influent concentration of less than 100 mg/L of free oil and suspended solids, with a flux of from 7.0 to 13.5 gallons/minute per square foot (5.7 to 11.0 L/second per m^2) (Catalanotto, 2012). Manufacturers' literature indicates up to 98% removal of free and dispersed hydrocarbons and suspended solids (> 5 μm) in the walnut shell filter treatment system.

10.15.10.4 Ceramic microfiltration

Ceramic membranes are made from oxides, nitrides or carbides of metals such as aluminium, titanium or zirconium. Ceramic membranes are capable of removing particulates (suspended matter), organic matter, oil and grease, and metal oxides. Cartridge filters are used as a pre-treatment for ceramic microfiltration (MF). Similar to other membrane systems, ceramic MF systems also require a break tank for feed water, a feed pump, a rack for membrane modules, a chemical metering system (optional), a tank for filtrate water and a pump and valves for the backwash and cleaning system.

The capital cost of ceramic MF systems will continue to decrease as they become more widely used. Ceramic MF do require backwash, and the backwash waste should be disposed of properly. If the ceramic MF is operated in a cross-flow mode, there will be a residual process stream that requires disposal (Guerra *et al.,* 2011).

10.15.11 Radionuclides treatment and disposal

According to the USEPA, the radioactivity levels in produced waters are generally low, but the volumes are large. According to a study conducted by Almond *et al.* (2014), in terms of energy production, the greatest radioactive footprint is for nuclear power production, followed by coal power production and then shale gas extraction. Radionuclides found in flowback and produced waters can be removed using different treatment technologies, such as RO, coagulation/flocculation/sedimentation, ion exchange, evaporation/crystallisation, etc. However, a percentage of the radium remains in the effluent (Zhang *et al.,* 2014). These treatment processes produce a concentrated waste stream or sludge containing the radionuclides, which may require the treatment residuals to be disposed of in specialised facilities approved to accept NORM wastes. Disposal facilities that can accept this type of waste include select permitted hazardous waste disposal facilities and low-level radioactive waste disposal sites.

Activities such as uranium mining, or sewage sludge treatment, can concentrate or expose NORM in ores, soils, water or other natural materials, forming TENORM. According to the USEPA, the average concentration of radium in sludges associated with oilfield produced water is estimated to be 75 pCi/g. After dewatering, the average concentration of the radium in the solid cake is approximately 120 pCi/g.

Sludges containing elevated TENORM are typically dewatered and held in storage tanks for later disposal. Currently, produced waters are re-injected into deep wells or discharged into non-potable coastal waters (offshore production facilities). According to the USEPA, there are no added radiological risks associated with this disposal method, as long as the radioactive material carried by the produced water is returned in the same or lower concentrations to the formations from which they were derived.

10.15.12 Boron removal

Boron is found in produced waters in some of the USA shales. There are no data on the presence of boron in the NCB and CB. Boron removal is of particular concern, because the presence of boron introduces the threat of prematurely cross-linking the polymer and upsetting the delayed rheology desired in gel formation in the fracturing solutions. Various technologies are available for removing boron from clean water, but these have proved costly and inefficient when used in the oil industry. The current technologies available for removing boron are RO, ion exchange, electrocoagulation and addition of chemicals (Rodarte and Smith, 2014).

To achieve high boron removal in RO, the pH of the feed water must be increased. At neutral pH, RO has poor boron rejection rate and it passes through the membrane in the same way as water. The high initial cost for RO is a limiting factor. In addition, RO cannot be used for feed water containing very high TDS.

Ion exchange uses boron-selective ion exchange resin to remove boron and provides an effluent with a boron concentration of less than 1 mg/L. The influent must be pre-treated to remove suspended solids and large oil particles. The estimated life of the resin is 3–5 years. Removal of the high boron concentrations in Eagle Ford and Bakken Shales requires multiple units in line. The functional group in the resin removes 5 g of boron per litre of resin, and therefore it is best to use a polishing step or a low flow rate before the resin.

Electrocoagulation is a developing technology for the removal of boron. Electrocoagulation destabilises suspended contaminants by contacting the fluid with electric current; efficiency is dependent on current density and pH.

The chemicals used for boron removal are polyvinyl alcohol, lime, magnesium oxide, and magnesium chloride:

- Polyvinyl alcohol (PVOH) is still at the testing stage. Tests were conducted on flowback and produced waters from Eagle Ford Shale and included various grades of PVOH, combinations and doses of flocculants, polyacrylamides, pH adjustments, mixing time adjustments, and changes in the PVOH preparation.
- Lime has proved to be effective in removing boron from wastewater at high temperatures. Lime softening is conducted at 90°C, a parameter that is uncontrolled in the field.
- Magnesium oxide removes boron by electrostatic adsorption. Magnesium oxide is added to water and the pH is elevated to its point of zero charge. Tests conducted have revealed a high chemical consumption and a high cost. The cost of treating flowback and produced waters containing 20 mg/L of boron using magnesium oxide was estimated at US$65 per barrel.
- Magnesium chloride is used as an alternative to magnesium oxide. Research suggests that magnesium chloride has a greater removal efficiency and is not temperature dependent.

10.15.13 Advanced oxidation and precipitation process (AOPP)

The advanced oxidation and precipitation process (AOPP) occurs at a high flow rate and provides removal of bacteria, scale inhibition and the fracturing chemical stability necessary for reuse in hydraulic fracturing.

The AOPP process includes the following:

- ozone : a highly reactive oxidant used to kill bacteria;
- cavitation: generation, subsequent growth and collapse of cavities releasing large amounts of energy, which aids in ozone mass transfer and hydroxyl radical generation; a hydroxyl radical is a highly reactive and non-selective oxidant;
- electro-oxidation: aids in the formation of hydroxyl radicals and aids in the precipitation of scale-forming salts such as calcium carbonate.

A study was conducted by Horn *et al.* (2013) in the Permian Basin in Texas and the Delaware Basin in New Mexico over a period of 15 months. The study was conducted on 177 wells and 21.7 million barrels (3.45 million m^3) of fluid treated, of which 4.5 million barrels (0.7 million m^3) was reused flowback and/or reused fluid. The following results were obtained:

- During the study period (November 2011 to February 2013), the reuse of fluid increased from 0% to 28% and 4 million barrels (0.64 million m^3) of water was reused.
- Analysis of samples taken in Texas (at a time when temperatures are challenging for bacterial treatment in May to July 2012) showed a 99.29% reduction in bacteria with an average of 99.70% reduction in bacteria throughout the whole period.
- Tube blocking tests were conducted to test the ability of AOPP to reduce scaling. The TDS of the tested waters ranged between 1500 mg/L and 180,000 mg/L. The tests show that AOPP equipment was effective in inhibiting scaling.
- Multivalent cations in the flowback and produced waters interfere with friction reducers used in slick water fracturing fluids. Multivalent ions are precipitated as suspended solids that are much

less reactive. A friction loop test conducted at a laboratory in Duncan, Oklahoma, indicated a 27% improvement in friction reduction over a 30-minute period (Horn *et al.*, 2013).

- The FracFocus data (chemical disclosure registry) was analysed and wells that employed the AOPP (February to July 2012) were compared with those that did not. The analysis showed that the wells that did not use AOPP (February to August 2011) used 100% fresh water, and the use of friction reducer by mass was 1.66%. For the wells that did use AOPP equipment, the average composition of fracturing fluid included 16% reused water, and the use of friction reducer during the period was 1.45%. This represents a 12.7% reduction in friction reducer usage.

10.15.14 Membrane technologies

RO is used to treat flowback and produced waters to comply with the regulations. FO is a new membrane technology under development. The driving force for these membrane technologies is pressure gradient. Some of the advantages of using membrane technology to treat flowback and produced waters are less sludge, high-quality permeate, reduced chemical consumption, continuous separation and the possibility of recycling the waste stream. The drawbacks of using membrane technology are membrane fouling, low selectivity or low flux, a short membrane lifetime and limitations in terms of treating feed waters high in TDS.

10.15.14.1Reverse osmosis

RO can be used for on-site treatment in combination with appropriate pre-treatment or it can be employed in CWT facilities for removal of metals and salts (Figure 10.11). RO treatment is effective up to approximately 45,000 mg/L TDS. The process generates concentrated brine, which needs to be properly disposed of. The concentrated brine can either be treated on site or it can be trucked to a CWT facility or DWI.

The disadvantages of RO are: it is energy intensive and the pressure required is operationally impractical for water with chloride levels above 40,000 mg/L.

Figure 10.11. Reverse osmosis system.

A literature review by Horn (2009) shows that an advanced oxidation process (AOP) can be used in combination with RO in a mobile on-site treatment plant. The pilot plant study, conducted in November 2008 for Woodford Shale, Oklahoma, by Newfield Exploration, treated the flowback using AOP/RO processes. 75% of treated flowback water had TDS of less than 500 mg/L and the remaining 25% of concentrated brine could be used in subsequent hydraulic fracturing. The 1% waste stream of the initial bulk volume processed could be disposed of in off-site injection wells (Horn, 2009).

10.15.14.2 Forward osmosis

FO is an engineered osmosis and developing technology. It does not require external pressure to operate. The separation in FO is based on the difference in osmotic pressure across the membranes. The water flows from the low salt concentration to the high salt concentration through a semi-permeable barrier to reach equilibrium. A draw solution (osmotic agent) with a high concentration is used as the driving force to create the osmotic pressure gradient. To achieve the level of treatment required, selection of membranes and of the draw solution is very critical. The draw solution should be easily recoverable and highly soluble in water and impart high osmotic pressure when dissolved in water. FO is less susceptible to membrane fouling than RO. FO can be used either as a standalone system to treat industrial applications or as advanced pre-treatment for RO (Coday *et al.*, 2014).

An FO membrane brine reactor was used in a commercial demonstration to treat flowback water and produced water in the Marcellus Shale and the Permian Basin. The system used in the demonstration was developed by Oasys Water and it employed a patented ammonia/carbon dioxide-based draw solution to treat high-salinity brine steams and oil and gas wastewater. The demonstration system is described in Coday *et al.* (2014). The mobile system consists of pre-treatment, membrane brine reactor and brine-polishing unit. Raw produced water is pre-treated with chemicals to form mineral precipitates and organic flocs. The water is then pumped to a filter press to separate sludge and treated water. Iron and manganese are removed from the pre-treated water using a green sand media filter. Pre-treated produced water is concentrated to between 150,000 mg/L and 250,000 mg/L TDS by the membrane brine reactor. The proprietary draw solution is highly soluble and produces a high osmotic driving force and allows permeation through thin film composite membranes, even when the feed TDS exceeds 200,000 mg/L. Evaporation is used to reconcentrate the draw solution.

The trial run in Marcellus Shale was for a 6-month period and approximately 60,000 gallons (230 m^3) of produced water was treated. The average recovery in the Marcellus Shale region was 64% with an average steady-state water flux of between 2 and 3 L/m^2 per hour.

Approximately 40,000 gallons (150 m^3) of produced water was treated in the Permian Basin with an average feed salinity of 103,000 ± 7000 mg/L, along with high concentrations of boron, TOC and heavy metals. Variations in organic and heavy metal constituents and concentrations were observed in wastewater batches. The TDS of treated water was 737 ± 284 mg/L and that of concentrated brine was 241,000 ± 35,000 mg/L.

The bench-scale and pilot studies showed that FO used low hydraulic pressure, it reduced fouling compared with RO, and there was substantial rejection of known contaminants found in oil and gas waste streams. There is no information on the fouling characteristics of FO in long-term use (> 1 year) in relation to the process efficiency of FO.

10.15.14.3Membrane distillation

Membrane distillation (MD) is a thermally driven process that uses the vapour pressure gradient between the feed solution and the product solution as the driving force. The flux and salt rejection of this process is independent of feed water salinity (Guerra *et al.,* 2011). Water vapour flows across hydrophobic microporous membranes into a condensing fluid from the feed. Feed water has a higher temperature than that on the permeate side. The critical process parameter is the maintenance of the liquid–vapour interface.

The advantage of this process is that it is a thermally driven process, unlike RO, which uses pressure as driving force. MD requires lower operating temperatures. The energy requirement and the cost could increase considerably if the “waste heat source” were not available. Complete rejection (100%) of dissolved solids and salts can be achieved, as non-volatile solutes cannot be transported across the membrane barrier. The main drawback and challenge is the requirement for a waste heat source to drive mass transfer, without which the energy cost would be high.

A joint demonstration project from the US firm GE Power & Water and the German company Memsys saw 200 hours of continuous operation at a Texas-based commercial disposal well. The project reportedly showed that MD combined with vapour compression can handle the high-salinity produced waters associated with UGEE (Waterworld, 2013).

MD is susceptible to pore flooding from fouling, resulting in lack of ion rejection. It is not a proven technology for large-scale installations (Nexus, 2014). Membrane distillation can be used for feed TDS up to 250,000 mg/L and the energy usage is approximately 23–26 kWh/100 gallons (455 L).

10.15.15 Evaporation and crystallisation

Evaporation and crystallisation are liquid–vapour separation processes that are used for treating flowback and produced waters with high levels of TDS. These technologies use heat to distil water and leave either a residual brine or a solid cake containing all of the TDS present in the waste stream.

The process of evaporation can be implemented using natural or mechanical evaporation methods (Figure 10.12). Following evaporation, the concentrated brine can be further treated by crystallisation to produce a salt product.

Mechanical evaporation is an energy- and capital-intensive process, resulting in high capital and operation and maintenance costs. Typical mechanical-type evaporators include vertical tube falling film, horizontal tube spray film and forced circulation. This process is subject to scaling caused by divalent cations such as calcium, barium and strontium, so pre-treatment of flowback prior to mechanical evaporation is recommended.

Natural methods include evaporation ponds, which are limited by the availability of land and cost. In addition, the effectiveness of natural evaporation depends on the brine concentration and the climatic conditions at the treatment site. High rainfall in Ireland and Northern Ireland may preclude this option.

Figure 10.12. Evaporator.

In the USA, mechanical vapour recompression (MVR) evaporation is a technology that has been successfully used in UGEE field applications. MVR uses vapour recompression by a gas compressor as the main driver for water evaporation. The compressed vapour is condensed in the outer tubes of the falling film heat exchanger, where the latent heat is transferred to the brine circulating through the internal tubes.

A technical brief on oil and gas produced water treatment technologies published by the Nexus Group (2014) discusses examples of mechanical evaporation technologies that may be used in treating produced water. The multi-effect distillation process is used to desalinate water with TDS levels of more than 36,000 mg/L. The system consists of a series of evaporators, each operated under a lower pressure than the previous unit. Vapour generated from one unit is used to heat the next while condensing clean water at each stage.

Mechanical evaporation systems also include crystallisers and spray dryers. These devices are used to convert the concentrated brine discharge from RO or evaporation to salt cake, which can be disposed of in a landfill site, thus achieving zero liquid discharge. The crystalliser feed is typically a concentrate stream, which has been reduced in volume by RO or evaporation and has a total solids concentration of 200,000–300,000 mg/L. The energy used for evaporation is approximately 15 kWh/100 gallons (455 L), and for crystallisers it is 40–50 kWh/100 gallons (455 L) (Barbot *et al.,* undated).

10.15.15.1 NOMAD evaporator system

NOMAD is an MVR process developed by Aqua Pure to treat flowback and produced waters. The units are designed to handle the variable nature and composition of the flowback and produced waters. Recovery rates vary between 75% and 95% of the feed volume. The recovered fraction is returned as distilled fresh water, which can then be reused on site or disposed of off site. A standard-sized unit commercially available in the USA is the NOMAD 2000, which is capable of generating 52,458 gallons per day (238.5 m^3 per day) of distilled water.

10.15.15.2 Carrier gas extraction

Carrier gas extraction, developed by Gradiant Corporation, uses a recirculating gas stream that removes water from the brine being treated, leaving the residual brine near the crystallisation point. The water in the gas stream is then condensed by contact cooling with a cold water stream. This process is a mid-temperature and ambient pressure technology for high fresh water recovery from water with high TDS (> 200,000 mg/L) levels.

The system consists of a contacting column that uses a packing medium in which the carrier gas contacts the feed water and the salts crystallise over the packing surface. When the salt load saturates the packing medium, it is removed and replaced, and the removed medium either cleaned or disposed of. The system employs a bubble column exchanger that dehumidifies the carrier gas, which generates purified water. The system includes recirculation fans for the carrier gas and pre-heaters for the influent water, which use effluent from the evaporation column as their heat source.

The pre-treatment system uses soda ash, caustic soda and polymer to facilitate the removal of multivalent ions, and a lamella plate is used for skimming oil. Solids produced from the treatment process have the appearance of fine wet sand and consist mostly of calcium and magnesium salts. About 23 m^3 of sludge is generated when running at the full system rate of 635 m^3/day, and this material is disposed in a landfill site as a non-hazardous waste. One of the unique aspects of the system is that clean brine and 10-lb brine are produced in addition to fresh water (10-lb brine refers to the density of brine when water is saturated with sodium chloride under standard conditions). The 10-lb brine can be used during drilling, as it provides excellent scale inhibition and lubricity and it also has other uses I in oilfield operations. Current cost estimates range from US$2.5 to US$2.75 per barrel ($0.09–0.1/gallon or approximately €0.03/L) of feed water, depending on how the system is sized. This does not include the value that could be obtained from use of the 10-lb brine.

10.16 Treated effluent quality

Table 10.20 summarises the treated flowback and produced quality of selected treatment technologies, or combinations thereof, discussed above.

USEPA (2015a) compiled a summary table of treated water quality for various treatment technologies in a draft report entitled “Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources”. The summary table is included in Appendix E for reference.

Table 10.20. Composition of treated water for various technologies

Name of the plant	Treatment technology	Parameter	Feed water conc.	Treated water conc.	Location	Remarks	Ref.	End use
–	Chemical precipitation	Barium (mg/L)	2300–4300	< 0.1	Pennsylvania State	–	–	–
–		TDS (mg/L)	69,640–248,428	149,057 (max.)				
–	Forward osmosis	TDS (mg/L)	103,000 ± 7000	737 ± 284	Permian Basin	–	1	–
–	Advanced oxidation and precipitation	Bacterial count (MPN/mL)	77,763	237	Permian Basin West Texas	Average result of 38 sample sets	2	Reuse in fracturing
–	Boron removal using polyvinyl alcohol	Boron (mg/L)	58.5	24.7	Eagle Ford	Produced water	4	–
			114	31.8	Eagle Ford	Flowback water		
–	Ion exchange	Boron (mg/L)	–	–	–	–	4	–
–	Purolite		52.5	34.1	Eagle Ford	Produced water	4	–
–	Purolite		102	71.3	Eagle Ford	Flowback water	4	–
–	Amberlite IRA		52.2	9.13	Eagle Ford	Produced water	4	–
–	Amberlite IRA		102	9.41	Eagle Ford	Flowback water	4	–
Josephine Brine Treatment Facility	See section 11.7.1.1	TDS (mg/L)	–	98,899	Marcellus Shale Pennsylvania State	Mean values of effluent 2010 2012 (treated discharge)	3	Discharge to receiving body
		Chloride (mg/L)	–	81,771				
		Bromide (mg/L)	–	643				
		Sulfate (mg/L)	–	1092				
		Calcium (mg/L)	–	12,710				
		Magnesium (mg/L)	–	830				
		Strontium (mg/L)	–	1363				
		Sodium (mg/L)	–	27,670				
		Barium (mg/L)	–	13				
		Radium-226 (pCi/L)	–	4				
		Radium-226 (Bq/L)	–	0.15				
		Radium-228 (pCi/L)	–	2				
		Radium-228(Bq/L)	–	0.09				

References: 1, Coday *et al*., 2014; 2, Horn *et al*., 2013; 3, Warner *et al*., 2013; 4, Rodarte and Smith, 2014.

MPN, most probable number.

11 Best Practice for Environmental Monitoring of Potential Impacts – Linking Projects A1, A2 and A3 (Task 8)

11.1 Introduction

Environmental monitoring is needed before, during and after any UGEE activities (exploration drilling, hydraulic fracturing and potential production) at both subregional and local scales. There are three types of environmental monitoring that relate to the different stages of UGEE activity, as follows:

- baseline monitoring – monitoring conducted prior to any construction or operations, in order to establish pre-existing environmental conditions;
- operational monitoring – monitoring conducted during construction, drilling, hydraulic fracturing and production activities, in order to be able to identify and track changes from the baseline and determine if such changes can be linked to a particular activity;
- post-closure monitoring – monitoring conducted after completion of gas production, well decommissioning and site restoration, to check for potential impact in the longer term and verify that mitigation measures have been effective.

In addition to the temporal aspect of monitoring, consideration of scale is also important. UGEE activity is site specific, thus monitoring at the scale of individual well pads and hydraulic fracturing operations is needed. However, UGEE activity also involves operations at several sites in a given region and therefore also has a larger footprint with the potential for a cumulative impact. Accordingly, monitoring at the subregional scale is also needed.

Subregional baseline monitoring is described in Project A1 of the UGEE JRP for groundwater, surface water and associated ecosystems; in Project A2 of the UGEE JRP for seismicity; and in Project A3 of the UGEE JRP for air quality. The purpose of the current chapter is to co-ordinate the recommended subregional baseline monitoring programmes in Project A with baseline, operational and post-operational monitoring at the local scale in Project B of the UGEE JRP. As such, the following sections outline best practice and the effectiveness of monitoring associated with individual UGEE sites, including the nature and timing of site-specific monitoring in relation to exploration, pilot tests and full-scale UGEE development, as well as operations and post closure.

Additional environmental monitoring not associated with Project A, such as noise, are not addressed in this chapter. Chapter 12 specifically addresses operational monitoring of process streams and waste products.

It is not the intention of this report to be prescriptive in terms of the specifications of monitoring equipment, and the requirements for individual monitor manufacturers, models or measurement principles are not set out.

11.1.1 Baseline monitoring

Baseline monitoring at the local scale is needed prior to UGEE activities at individual sites, and it can be guided by potential sources, pathways and receptors that are defined from site characterisation work, e.g. the development of a conceptual site model (which flags hydrological and hydrogeological linkages) for monitoring of ground- and surface water quality.

While elements of the subregional baseline monitoring are being undertaken by regulatory public bodies, the onus of site-specific baseline characterisation and monitoring is placed on the exploration–production companies at and near proposed exploration and production sites.

Baseline monitoring is carried out to establish pre-existing conditions, against which changes can be identified and tracked, if necessary, and help to determine if such changes can be linked to the UGEE activities. The site-specific baseline monitoring should be proportionate to the scale of operations and inferred environmental risks. The baseline data or information are used to support the site-specific risk assessment, which guides the appropriate environmental mitigation measures.

Monitoring must be guided by characterisation work to ensure that appropriate monitoring sites are located and representative samples from different media can be obtained. Therefore, the first step and early emphasis of UGEE activity is on-site characterisation. The characterisation and subsequent monitoring has to consider the details of the geology of each site and the likely source–pathway–receptor linkages associated with topography, drainage patterns, soils, subsoils, groundwater resources, surface water bodies and associated receptors, as well as ecology, seismicity, air quality, and so on.

11.1.2 Operational monitoring

Operational monitoring is carried out during operations, including mobilisation and set-up, construction, drilling, hydraulic fracturing and production. It involves monitoring of relevant environmental media and pathways, as determined from the initial characterisation work, conceptual site model(s) and representative monitoring programme defined for baseline monitoring purposes.

In addition, operational monitoring would also be conducted on any operational process streams and wastes, which are discussed further in Chapter 12. The list of items to be considered is long and includes, but is not limited to, monitoring of:

- the characteristics and quantity of drilling fluids and drill cuttings (liquids and solids);
- the composition and quantity of hydraulic fracturing fluids;
- the quality and quantity of flowback and produced waters;
- the quality and quantity of the effluent from any treatment processes used on site (e.g. for flowback water);
- the quality and quantity of any sludges or solids from any treatment processes;
- the quality of ambient air at and around the site (including total suspended particles and emissions related to truck traffic);
- the quality of air emissions related to flaring;
- the quality of air emissions at gas transfer and compressor stations;
- the gas content of drilling fluids at the wellhead as they are returned to the surface;
- tank levels and impoundments;
- secondary containment at tanks and leakage collection systems at impoundments;
- surface spills;
- chemical storage areas and secondary containment systems;
- wheel-washing facilities and pipe clearing and cleaning residues and areas;
- surface runoff from roads and well pads;
- noise levels at and around the well sites; and

- ground gas and potential stray gas at the wellhead.

11.1.3 Post-closure monitoring

Post-closure monitoring is carried out after production has ceased, well decommissioning (plugging) is completed, site equipment is removed and site restoration is completed. Post well closure stray gas migration has been identified as a major concern (Cherry, 2014; Vengosh *et al.,* 2014). Therefore, gas emission monitoring at and near the site should be continued for an extended time period after production ceases. In addition, routine monitoring of groundwater, surface water, air quality and seismic activity should also continue at the same monitoring stations used for baseline and operational monitoring purposes. Inspection and maintenance of restoration activities, including revegetation of areas, should also be conducted routinely for an extended period after site closure.

It is proposed that funding for post-closure monitoring is arranged through the provision of a bond by the developer, with a provisional monitoring programme set out for the first 5 years (quarterly at appropriate times of the year in years 1, 3 and 5), to be reviewed at 5-year intervals thereafter, pending review of results and agreement between the regulatory bodies and the developer.

11.1.4 Assessment of cumulative impacts

The assessment of cumulative impacts is an integral part of all stages of the environmental assessment process. Defining cumulative impacts is challenging, but European guidance (EC, 1999b) suggests that indirect impacts, cumulative impacts and impact interactions can all be classed as “cumulative impacts”.

Indirect impacts are those not directly associated with a proposed project, and are also referred to as secondary impacts and may include, for example:

- a proposed development that then attracts ancillary developments in turn; or
- the use of noise barriers as a noise mitigation measure, which then have a negative visual impact.

Impacts that result from incremental changes caused by other past, present or reasonably foreseeable actions in conjunction with the project should be assessed, for example:

- incremental noise from a number of separate proposals that may be slated for simultaneous development;
- the combined effect of individual impacts, e.g. noise, dust and visual, from one development on a particular receptor;
- several developments with insignificant impacts individually but which together have a cumulative effect, e.g. development of a well pad may have an insignificant impact, but when considered with several nearby well pads there could be a significant cumulative impact on the local ecology and landscape.

The cumulative impacts on water resources related to drilling a number of boreholes are discussed in Chapter 5. The issue of impact interactions is addressed in Chapter 7.

11.2 Principles and Approach towards Site-Specific Monitoring

The EC published a recommendation (EC, 2014) on minimum principles for the exploration and production of hydrocarbons (such as shale gas) using high-volume hydraulic fracturing (2014/70/EU). This recommendation included specific recommendations with regard to monitoring, which can be summarised as follows:

- Before hydraulic fracturing starts, the baseline or environmental status of the site and its surrounding surface and underground areas that have the potential to be affected by the activities should be established.
- The operator should regularly monitor both the installation and the surrounding surface and underground areas during exploration and production.
- The baseline monitoring should be used for subsequent monitoring.
- The operator should monitor the impacts of hydraulic fracturing on the integrity of wells and other man-made structures.
- All monitoring results should be reported to the relevant competent authorities.
- A survey should be carried out after each installation's closure to compare the environmental status of the installation site and its surrounding surface and underground area potentially affected by the activities with its status prior to the start of operations, as defined in the baseline study.

UKOOG is the representative body for the UK onshore oil and gas industry, including exploration and production. They have produced *Guidelines for the Establishment of Environmental Baselines for UK Onshore Oil and Gas* (UKOOG, 2015b) which describes how the source–pathway–receptor linkages are central to the assessment and management of site-specific environmental risks (EPA, 2011b; UKOOG, 2015b). The linkages can be assessed qualitatively and quantitatively and as part of the conceptual site model, which would inform the design of an appropriate baseline monitoring programme for the site-specific UGEE activity. The conceptual site model covers:

- specific hazards associated with individual activities (e.g. chemical used, means of storage);
- linkages between relevant features in the source–pathway–receptor model of environmental risk assessment;
- examination and determination of potential consequences of individual site operations; and
- analysis and decisions on appropriate mitigation measures to minimise impacts and their associated consequences.

The principles and approach towards monitoring are thus risk based. Accordingly, operators must consider, implement and demonstrate to the competent authorities that the risks to the environment and human health from UGEE activities are acceptable and/or manageable. UKOOG (2015a) considered that the risk of an incident occurring should be reduced to "as low as reasonably practicable" (or ALARP), which moves away from merely meeting the minimum standards to a continuous striving for improvement. In other words, risk management is objective driven rather than target driven, which is similar to the approach of the EU environmental directives such as the WFD.

Monitoring should consider potential source controls, potentially affected receptors and representative pathways between the two. Monitoring should be used as an early warning system to monitor compliance and trigger action when required and to observe and understand fate and transport processes at and away from potential sources (Ewen *et al.*, 2012; Council of Canadian Academies, 2014). Useful principles of monitoring (Environment Canada, 2011) include:

- a science-based approach that aims to utilise reliable indicators and consistent and standardised methodologies and that results in objective and reliable data;
- an adaptable (flexible) approach to monitoring, so that results and data can be evaluated and monitoring amended if needed or warranted;

- a collaborative approach to prioritise issues during the design of a programme (based on risk); and
- timely and transparent dissemination of information, to be made publicly available.

11.3 Characterisation and Monitoring of Groundwater

11.3.1 Purpose

Baseline monitoring recommendations for groundwater at the subregional scale are described in Report A1-3 of the UGEE JRP based on: (1) review of international best practice (Report A1-1 of the UGEE JRP); and (2) geological characterisation and conceptual hydrogeological models of each study area (Report A1-2 of the UGEE JRP). As highlighted in Report A1-3 of the UGEE JRP, the data and monitoring requirements for subregional baseline monitoring are different from the characterisation and monitoring requirements at the site scale for individual UGEE well pads and hydraulic fracturing operations. The assessment of environmental risks at the site scale requires a more detailed technical approach that examines both surface and subsurface sources of contamination and their potential migration away from a given site. Surface sources of contamination addresses storage, handling, spills, leakages and discharges of chemicals and waste products. Subsurface sources of contamination addresses natural gas constituents, chemicals, formation waters (e.g. high salinity groundwater) and NORM in the groundwater and subsurface environments. Potential migration pathways and fate and transport processes are influenced by soils, subsoils, rock types, hydrogeological conditions and groundwater–surface water interactions at any given site.

11.3.2 Site-specific characterisation of hydrogeological conditions

Site-specific characterisation of potential UGEE sites should follow existing best practice guidelines and be tailored to the hydrological and geological features that are present at, or are associated with, a given site. Whereas the shallow groundwater environment can be examined and characterised by means and methods that are relatively straightforward to implement, deeper groundwater conditions are mostly unexplored in Ireland.

As explained in Report A1-2 of the UGEE JRP, there are indications of formation waters with a range of salinities in deeper formations in the NCB and a potential deep (possibly regional) groundwater flow system in the CB. The available information is indicative and anecdotal rather than quantitative, thus significant investment would be required of the exploration–production companies in the future to ascertain factual information, and each case and site should be characterised on an individual basis.

The characterisation work would involve deep exploration drilling, hydraulic testing and borehole geophysical logging. The specific data derived would include:

- lithological descriptions;
- stratigraphic correlations;
- fracture characterisation, e.g. presence of open fracture networks;
- yields from fracture intervals or zones; and
- water quality.

Exploration boreholes would be converted to monitoring wells, which would be needed in different formations and would be used to obtain water levels for interpretation of flow gradients and potential hydraulic connection across relevant bedrock formations (see Report A1-2 of the UGEE JRP). They would also be used for water quality sampling, and they would serve as sentry or warning wells (Council of Canadian Academies, 2014) for monitoring of potential migration of contaminants from the deeper formations. As such, deep wells would become part of baseline monitoring networks at the local scale (i.e. associated with plans and operations at individual well pads). Deep boreholes in different formations could then serve as sentry (or warning) wells before, during and after hydraulic fracturing operations.

The deep hydrogeological information is needed because of the nature and potential sources of contamination from hydraulic fracturing operations, which in an international context would be relatively shallow in Ireland, as described in Report A1-2 of the UGEE JRP.

An important investigation tool that is considered mandatory for future UGEE-related hydrogeological characterisation is borehole geophysical logging. Geophysical logging tools would include but not be limited to three-arm caliper, natural gamma, spectral gamma (K-U-Th), resistivity (long or short normal, dual focused), spontaneous potential, full-wave sonic, cement bond log, fluid temperature/conductivity, and acoustic/optical televiewer systems.

Each borehole and completed well would also be hydraulically tested to determine how aquifer properties vary with depth. The combination of drilling information, geophysical logging and hydraulic testing provides the data needed to quantify water inflow and water quality and identify groundwater pathways. This in turn informs the decisions to be made about sections of boreholes to leave open or screen for monitoring purposes. Groundwater samples should be representative of the major inflow zones in a given well, as these are the principal pathways and such inflow zones can be identified only from detailed logging and testing. Wells would have to be carefully designed and constructed to prevent cross-flows between formations and potential gas migration to shallow receptors.

The resulting hydrogeological data are used to describe the main hydrogeological factors that determine environmental risk. They include:

- the presence and hydrogeological characteristics of low permeability horizons ("aquitards") at depth, between the unconventional gas target formations and shallow aquifers;
- the presence and nature of (open) fracture networks, including fracturing in formations that separate the unconventional gas target formation from shallow receptors;
- faulting and fault displacements, and the potential for direct juxtaposition of unconventional target formations and shallow aquifers;
- the depth and vertical pervasiveness of geological structures such as faults and fracture (enhanced permeability) zones;
- the structural anisotropy of shale units both in and overlying the unconventional gas target formations;
- the presence, geometry and directionality of cross-cutting geological features such as dykes and dyke swarms;
- the potential roles of shallow groundwater pathways (such as the "transition zone" between subsoil and bedrock; conduits in karstified limestones; subrosive features in salt or anhydrite- and gypsum-bearing strata and subsoils) in delivering groundwater and associated pollutants to streams, lakes and groundwater-dependent terrestrial ecosystems;
- the formation water quality, including NORM, from source zones;
- hydraulic responses and potential connections between different bedrock aquifers (formations).

In layered bedrock formations, such as those of the NCB and CB, vertical hydraulic gradients and vertical migration of groundwater (and contaminants) are primarily controlled by the presence of preferential pathways resulting from fracturing and cross-cutting geological structures.

All aspects of drilling, geophysical logging, installation of monitoring wells, hydraulic testing and groundwater sampling must be carried out by suitably qualified contractors, in line with the best available techniques and best practice that are relevant to Ireland and Northern Ireland. Equally, all work should be supervised and documented by suitably qualified geologists, hydrogeologists and geophysicists, as appropriate to the work being undertaken. This includes representatives of the regulatory bodies.

In addition, source formation water quality would need to be determined as part of these site-specific studies by the developer. This information would be used to assess the risks of impact on groundwater and surface water quality, as well as assessing potential wastewater treatment options.

11.3.3 Baseline monitoring

Details of the recommended baseline monitoring programme for groundwater are provided in Report A1-3 of the UGEE JRP. This includes recommendations for continuous monitoring of field parameters for karst springs and certain stream stations.

Monitoring wells should provide an adequate spatial coverage of the areas that are planned for horizontal hydraulic fracturing operations, and they should also be situated in areas between UGEE sites and important shallow receptors. Groundwater itself is a receptor, being a drinking water supply source or a pathway to rivers or wetlands that receive groundwater baseflow.

Similarly, an adequate vertical coverage of the main formations is needed; the data and associated interpretations serve to document the hydrogeological relationships and potential hydraulic connections between the deep unconventional gas target formations and the shallow receptors, notably those used for water supplies or those that are important groundwater-dependent terrestrial ecosystems. The sampling of such wells also serves to characterise the formation waters at depth in each for the key formations, including the unconventional gas target formations. Best practice for baseline characterisation and monitoring at the site-specific scale requires drilling and testing of deep investigative boreholes (to several hundred metres depth) as well as the installation of dedicated monitoring wells to different depths in the key formations that shape and influence the environmental risks associated with hydraulic fracturing activity. Such wells should be representative of major pathways of potential contaminant migration. This is in itself not an easy objective, and several deep boreholes in a given study area would probably have to be drilled.

Existing public and private drinking water supply wells or springs that may be potential receptors for specific UGEE activities should also be located and monitored. The risk assessment and development of the conceptual site model will inform which drinking water supplies will need to be monitored on a site-specific basis. The monitoring of other receptors such as surface waters and ecosystems are dealt with in the following sections.

The site-specific baseline monitoring (of each well) should be carried out for at least 1 year prior to hydraulic fracturing in order to document existing conditions. The frequency should be based on the risk to groundwater, but quarterly would be recommended as a minimum to provide data for different seasons and groundwater levels, with an understanding of whether the water levels are representative of a typical year. A site-specific baseline groundwater sampling and analysis programme should be developed and submitted with planning documents that must comply with best practice guidance in Ireland and Northern Ireland.

The list of parameters to be considered for analysis of groundwater and surface water are described in Report A1-1 and A1-3 of the UGEE JRP and are reproduced in Table 11.1. In addition, specific chemicals that the operator proposes to use for a given site-specific activity should also be included, where they are known at the baseline stage. Chemicals that are more mobile or are highly toxic can be prioritised.

Table 11.1. Recommendations for parameters to be monitored in groundwater and surface water

Parameter	Groundwater	Surface water	Frequency
Dissolved natural gas components			
Dissolved methane	✓	×	Quarterly
Dissolved carbon dioxide	✓	×	Quarterly
Hydrocarbon gases (C2 to C5)	✓	×	Quarterly
Nutrients and general chemistry			
Ammonia	✓	✓	Quarterly
Ammonium	✓	✓	Quarterly
Nitrite as N	✓	✓	Quarterly
Nitrate as N	✓	✓	Quarterly
Orthophosphate as P	✓	✓	Quarterly
Total phosphorus	✓	✓	Quarterly
TOC	✓	✓	Quarterly
TDS	✓	✓	Quarterly
TSS	×	✓	Quarterly
Major ions			
Alkalinity	✓	✓	Quarterly
Chloride	✓	✓	Quarterly
Fluoride	✓	✓	Quarterly
Sulfate	✓	✓	Quarterly
Sodium	✓	✓	Quarterly
Potassium	✓	✓	Quarterly
Magnesium	✓	✓	Quarterly
Calcium	✓	✓	Quarterly
Iron	✓	✓	Quarterly
Manganese	✓	✓	Quarterly
Boron	✓	✓	Quarterly
Trace elements			
Aluminium	✓	✓	Quarterly
Chromium	✓	✓	Quarterly
Nickel	✓	✓	Quarterly
Copper	✓	✓	Quarterly
Zinc	✓	✓	Quarterly
Arsenic	✓	✓	Quarterly
Cadmium	✓	✓	Quarterly
Antimony	✓	✓	Quarterly
Barium	✓	✓	Quarterly

Parameter	Groundwater	Surface water	Frequency
Lead	✓	✓	Quarterly
Uranium	✓	✓	Quarterly
Mercury	✓	✓	Quarterly
Cobalt	✓	✓	Quarterly
Molybdenum	✓	✓	Quarterly
Strontium	✓	✓	Quarterly
Selenium	✓	✓	Quarterly
Silver	✓	✓	Quarterly
Beryllium	✓	✓	Quarterly
Bromide	✓	✓	Quarterly
Vanadium	✓	✓	Quarterly
Descriptors of carbon sources			
Dissolved organic carbon (DOC)	✓	✓	Quarterly
Dissolved inorganic carbon (DIC)	✓	✓	Quarterly
Trace organic compounds			
PAHs – full suite	✓	✓	Biannually (including low-flow conditions)
VOCs – full suite	✓	✓	Biannually (including low-flow conditions)
Stable isotopes in dissolved methane			
Hydrogen (δD)	✓	×	Quarterly (if methane detected)
Carbon ($\delta^{13}C$)	✓	×	Quarterly (if methane detected)
Oxygen ($\delta^{18}O$)	✓	×	Quarterly (if methane detected)
NORM			
Gross alpha/beta	✓	✓	Quarterly
Ra-226/Ra-228	✓	✓	Quarterly (if a gross alpha/beta threshold exceeded)
Rn-222	✓	✓	Quarterly (if a gross alpha/beta threshold exceeded)

11.3.4 Construction and operational monitoring

Monitoring of groundwater during the construction and operational phase would be carried out to detect any potential impacts on groundwater quality or related receptors due to the UGEE activities. This would require an assessment of the water quality in relation to environmental water quality standards and an evaluation of any changes from the baseline, as well as longer term trends.

The groundwater monitoring during the construction and operational phase should be carried out at appropriate locations, as well as the same locations monitored for baseline characterisation, using consistent sampling techniques and for the same parameters that are relevant to the site-specific application (see section 11.3.3). The timing and frequency of groundwater monitoring would also be informed by the conceptual site model and the activities occurring on site. The frequency would also need to take account of travel times and any seasonal variations in the baseline. In addition, the frequency of sampling may need to be increased during times when the risk of groundwater contamination is higher. The risk to groundwater and its receptors can also help to form an adaptive monitoring approach, whereby not all of the analyses and measurements may be required for each sampling event if the risks are low.

There are three key types of monitoring to be considered during the construction and operation phases, as summarised by the Council of Canadian Academies (2014):

1. *Performance monitoring or defensive monitoring*. This may be required at the wellhead to determine whether or not there is any leakage of gas or fluid from the cement seal. It is also common practice to have groundwater monitoring around each well pad and specific wells around any impoundments used for water management. Wellhead monitoring may not be required if the well integrity can be confirmed by other means (please refer to Chapter 12).
2. *Sentry (or warning) monitoring*. Exploration boreholes could be converted and act as sentry wells to warn of potential contamination from deeper formations. The wells would need to be located so that they represent main pathways, and so that contaminants are detected prior to any impact on sensitive receptors. As there are multiple pathways and receptors, several such wells may be needed.
3. *Receptor monitoring*. This involves direct monitoring of the groundwater receptors, including groundwater resources, surface waters and wetlands. Surface waters and ecological monitoring are discussed in the following sections. In terms of monitoring the groundwater resource, this would involve monitoring the public and private drinking water supply wells or springs that may be potential receptors for specific UGEE activities.

Specifically, what would be required for each well pad would need to be informed by the conceptual site model and the defined risks of impact on receptors.

11.3.5 Post-closure monitoring

Impact studies in the USA have recently flagged stray gas from poorly constructed wells as a likely cause of groundwater contamination of shallow aquifers and related private supply wells, in which the age of wells, their structural integrity and failing and cracked cement grout are all cited as potential causes (as pathways) of stray gas migration from hydraulic fracturing wells (Watson and Bachu, 2009; AEA, 2012b; Ewen *et al.,* 2012; Cherry, 2014; Darrah *et al,* 2014; Vengosh *et al.,* 2014; USEPA, 2015).

Post-closure monitoring of methane gas is, therefore, considered especially important at the wellhead of production wells in the post-closure stage, and dissolved methane gas monitoring in other wells should continue to be compared with baseline conditions.

Owing to the long-term, open-ended nature of the timeframe associated with post-closure monitoring, it may be appropriate for the responsibility for post-closure monitoring of wells to be adopted after a set number of years by the EPA or NIEA, depending on the jurisdiction, with the responsibility for the implementation of any required mitigation measures and associated environmental liability resting with the developer.

Funding for post-closure monitoring is proposed to be arranged through the provision of a bond by the developer, with a provisional monitoring programme set out for the first 5 years (quarterly at appropriate times of the year in years 1, 3 and 5), to be reviewed at 5-year intervals thereafter, pending review of results and agreement between the regulatory bodies and developer.

11.4 Characterisation of Soils and Subsoils

Soils and subsoils are relevant in the context of potential impacts from surface sources of contamination on shallow receptors (groundwater resources, surface waters, ecosystems and water supplies). Soil and subsoil types, permeability and thickness describe groundwater vulnerability (EPA, 2011b) and, as pathways, are important factors to be considered in the UGEE context.

With respect to surface contaminants, UGEE sites and activities that are planned in areas of extreme and high groundwater vulnerability represent, conceptually, a greater risk to groundwater than sites and activities planned in areas of moderate and low groundwater vulnerability. Where subsoils are of low permeability and thick, infiltration capacity is reduced and vulnerability and the risks of impact are transferred to the surface water environment (EPA, 2011b).

Existing vulnerability maps published by the GSI and GSNI provide useful guidance at the subregional scale but do not necessarily reflect vulnerability characteristics at the site-specific scale. For this reason, each site of activity must be investigated and documented with regard to soil and subsoil type, texture, grain size (for permeability determination) and depths. Organic matter content is another variable that should be measured at the site scale, as organic matter is important in determining the attenuation potential of a given contaminant at a given site.

Soil and subsoil sampling is a one-off activity for site characterisation purposes. It is carried out as part of the planning process with descriptions and results provided in the ensuing EIA. Sampling shall follow best available technology and standard methods, e.g. as described by BS ISO 10381 (BSI, 2002) and BS 5930:2015 (BSI, 2015).

11.5 Ground Gas Monitoring

Ground gases (soil gas) can originate from both natural and anthropogenic sources in the subsurface environment. For example, methane can be generated naturally in organic-rich soils and/or rocks such as shales that may be high in TOC, including coal seams. As documented in Report A1-1 of the UGEE JRP, they are also generated by the decomposition of organic material in peat and wetland areas. The presence and migration of ground gas is site specific, as a function of the shallow soil and subsoil geology. Characterising ground gas emissions that may result from UGEE activity is, therefore, also site specific. For this reason, monitoring of ground gas prior to and during UGEE activity is recommended. This may require the installation of appropriately designed standpipes and sampling these regularly or equipping the same with continuous monitoring equipment.

A site-specific baseline ground gas sampling and analysis programme should be developed in line with current best practice guidance for landfills and BS 8576:2013 (BSI, 2013). The site-specific geology and soil pathway considerations developed from conceptual site models should be taken into account.

A long-term methane monitoring programme should be developed to detect possible well failure post decommissioning, which would need to be monitored continuously for ground gas. Refer to section 11.8 for further discussion of stray gas.

11.6 Surface Water and Discharge Monitoring

11.6.1 Purpose

Surface water bodies are important potential receptors for UGEE projects. There are potential sources of pollution from direct discharges of treated wastewaters and indirect discharges from the storage, handling and use of fuels, chemicals and drilling additives.

In addition, surface water bodies represent important potential receptors of potential groundwater pollution from underground sources and stray gas, because groundwater naturally discharges into streams and rivers, reservoirs and lakes, transitional waters and coastal waters. As they discharge, pollutants in groundwater become diluted through mixing with the surface water. Almost all surface water bodies interact with groundwater to some extent. This ranges from 30% to 90% of the annual average stream flow derived from groundwater (Daly and Craig, 2009).

Therefore, it is important to develop a clear conceptual site model to understand the linkages between groundwater and surface water in a hydrogeological setting at a site-specific scale prior to any UGEE projects being undertaken. In addition, surface waters can be at risk from point sources and diffuse pollution from the surrounding land. It is therefore important to know and understand the existing and historic causes of impacts on surface water quality prior to any UGEE activities and include this in the conceptual site model.

Flowback and produced waters may be treated and discharged to surface waters. Some of the chemical constituents associated with flowback and produced waters can potentially partition from the surface water and accumulate in associated sediments. In particular, metals, radionuclides and selected higher molecular weight organic compounds (e.g. SVOCs, if the sediments are high in organic carbon) may become concentrated in sediments, and this could pose a risk of bioaccumulation in the food chain. Therefore, if the operations include discharges of treated wastewaters, then sediment quality should also be examined before, during and after UGEE operations to assess the impact.

The following sections describes the phases of monitoring of surface water for UGEE projects. All sampling of surface waters should be carried out in line with BS ISO 5667–6:2014, Guidance on sampling of rivers and streams.

11.6.2 Baseline monitoring

The key considerations for a baseline surface water monitoring programme are:

- Obtain representative samples from different flow conditions, including low and high flows. This would require baseline monitoring to be carried out over at least a year, with an understanding of whether or not the flow conditions are representative of a typical year. If the baseline year is not considered representative owing to drought or flooding, for example, then the baseline period may need to be extended.
- Samples should be collected both upstream and downstream of the site.
- If there are any existing discharges (such as a spring or seep) in close proximity to the site, it would be beneficial to sample these too, with the aim of characterising the water quality (particularly if there may be similar contaminants of concern associated with UGEE activities).
- If there are no flow-monitoring gauges on the stream or river, the flow should be measured (or estimated) directly at the time of sample collection.

The list of parameters to be considered for analysis are described in Report A1-1 and A1-3 of the UGEE JRP and are reproduced in Table 11.1. The frequency at which parameters should be monitored is not specified and should be determined for each site on the basis of a risk analysis.

Increases in dissolved methane in surface waters is an emerging issue for UGEE projects. The US Geological Survey has carried out tests of a new stream-based methane-monitoring method to identify and quantify groundwater methane discharging into a stream in an area of unconventional gas development. The method (as reported by Heilweil *et al.,* 2015) combines “stream hydrocarbon and noble-gas measurements with mass-balance modelling to estimate thermogenic methane concentrations and fluxes in groundwater discharging to streams”. Described by the authors as the “first watershed-scale method to assess groundwater contamination from shale-gas development”, a review of the method indicates that it would be useful and be valid at the local scale for monitoring of site-specific UGEE activity. If, through the development of the conceptual site model, it is determined that there is potential for methane gas to leak to groundwater that ultimately discharges to surface water, then dissolved methane and its isotopes should also be monitored in surface waters to determine the baseline levels at a site-specific scale (Heilweil *et al.,* 2015). An understanding of gaining and losing stretches of the river would also need to be determined in this instance, possibly by flow measurements and tracer studies (Heilweil *et al.,* 2015).

In addition, specific chemicals that the operator proposes to use or discharge to surface water should also be analysed for, where they are known at the baseline stage. Chemicals that are more mobile or are highly toxic can be prioritised.

11.6.3 Construction and operational monitoring

The purpose of monitoring surface water during the construction and operational phase is to detect any impacts on surface water quality due to the UGEE activities. It can also provide reassurance that any mitigation measures are working appropriately. This would require an assessment of the water quality in relation to background concentrations and environmental water quality standards and an evaluation of any trends.

The surface water monitoring during the construction and operational phase needs to be carried out at the same locations upstream and downstream as during the baseline phase. The same parameters monitored during the baseline phase should also be monitored during the construction and operational phases. The timing and frequency of surface water monitoring will not only be informed by the conceptual site model but also by the activities occurring on site. For example, the frequency of sampling should increase during times when the risk of surface water contamination is higher.

In addition, any discharges such as surface water runoff from the site or treated wastewater would need to be monitored for both quality and flow. Extra sampling locations on the main river may be required upstream and downstream of the actual discharges. The details of discharge monitoring would be specified in some form of discharge licence (e.g. an Integrated Pollution Prevention and Control Licence, Extractive waste, Section 4) that would state the frequencies and permitted discharge standards.

11.6.4 Post-completion monitoring

Surface water sampling for a period of approximately 12 months post completion could be similar to that carried out before and during fracturing operations to confirm that there have been no negative impacts and to determine the success of any mitigation measures and site restoration carried out. Similar to groundwater monitoring, a long-term methane-monitoring programme for surface water that lasts longer than 12 months may also be required to detect possible well failure post decommissioning if the risk to surface water is deemed high.

11.7 Ecosystem Monitoring

11.7.1 Purpose

Characterisation of the impacts on ecosystems and wildlife would depend on the location of the well pad and its proximity to sensitive habitats or species. The impacts on biodiversity associated with individual sites are likely to be limited to the vicinity of the site (Entrekin *et al.,* 2011; Nature Conservancy, 2011). The potential impacts of UGEE activities on flora and fauna are discussed in Chapter 7. The main mechanisms of these potential impacts include (Entrekin *et al.* 2011; NYSDEC, 2015):

- removal of habitat or degradation of habitat (e.g. as a result of excessive water abstraction) or fragmentation (e.g. as a result of fencing, road construction);

- surface runoff;
- introduction of invasive species;
- noise and disturbance;
- contamination relating to surface water discharges or contamination underground that could impact on ecological receptors; and
- contamination relating to accidental releases and spillages.

The development of an appropriate suite of mitigation measures would depend on the baseline ecological environment and the potential impacts at an individual site. Potential mitigation measures are discussed in Chapter 7.

11.7.2 Overarching monitoring requirements

Whether ecological monitoring is required as a mitigation measure would have to be determined on a case-by-case basis by a suitably qualified ecologist during the baseline monitoring phase. It would depend on a number of factors, but the main purpose of ecological monitoring is to examine whether or not there are any changes to habitats or species as a result of UGEE activities or indeed to monitor the effectiveness of mitigation measures that are put in place. Therefore, if it is determined that there is no potential impact at a site from proposed UGEE activities, then no further surveys may be required after the baseline surveys.

Monitoring the environmental supporting conditions of freshwater and wetland habitats may also be required if there is potential for an impact from surface water discharges or underground contamination. This would also be determined during the development of the site conceptual model, namely where the source–pathway–receptor linkages would have to be examined in detail. This monitoring may include surface water quality monitoring downstream of a discharge or testing the water quality of groundwater within designated groundwater-dependent terrestrial ecosystems. In addition, if there is the potential for abstraction of water for water supply to impact upon habitats or species, then flow or level monitoring may be necessary.

If it is determined that there is the potential for adverse impacts as a result of the proposed UGEE activities, then the monitoring plan should be designed in consultation with the National Parks and Wildlife Service in Ireland and the NIEA in Northern Ireland.

Key factors when planning ecological surveys include:

- Most surveys of habitats or species can only be carried out at certain times of the year, depending on the type of flora or fauna. The recommended timings of surveys are detailed in publications such as NRA (2008). If surveys are carried out at the incorrect times, species may be under-recorded or missed. For baseline surveys, it may be necessary to collect data for a year to cover all of the survey seasons.
- Licences may be required to carry out certain types of intrusive ecological surveys.
- The actual survey effort can vary significantly, depending on the habitats or species.
- Surveys need to be carried out by suitably qualified and appropriately experienced ecologists.

The following sections describe the phases of ecological monitoring associated with UGEE projects.

11.7.3 Baseline monitoring

Prior to any drilling, the ecological baseline of the proposed site and its vicinity need to be fully understood. Good practice guidance relating to the collection of baseline data is published by the

Chartered Institute of Ecology and Environmental Management (CIEEM, 2006) for the UK and the (former) National Roads Authority (NRA, 2008) in Ireland.

The zone of influence (NRA, 2008) and the potential ecological receptors within it need to be identified. This would need to be done on a site-specific basis and can be done through desktop studies and walkover surveys, which would help to scope all subsequent surveys and identify whether or not specialist ones are required, such as for terrestrial invertebrates (e.g. marsh snails) or aquatic invertebrates (e.g. freshwater pearl mussel).

The ecological surveys should include designated areas such as SACs and SPAs but also non-designated areas (NRA, 2009). There are many areas outside protected areas that are important for wildlife (NRA, 2009). The NRA (2009) provide guidelines, *Ecological Surveying Techniques for Protected Flora and Fauna during the Planning of National Road Schemes*, on how to assess the value of the ecological resource, based on geographic scales as follows:

- international importance, e.g. SACs and SPAs;
- national importance, e.g. NHAs and ASSIs;
- county importance (or vice-county in the case of plant or insect species), e.g. protected trees or areas of the habitat types listed in Annex I of the Habitats Directive that are not designated;
- local importance (high value), e.g. areas listed in local biodiversity plans or species listed on the Red Lists[33]; and
- local importance (lower value), e.g. sites with small areas of habitat that are of some local importance for wildlife.

The baseline survey should include habitat mapping and evaluation. The boundaries on key vegetation communities and nationally rare species should be shown. Aerial photography can be used to help map habitat boundaries. The baseline maps produced would be utilised for future monitoring (as necessary) to assess change. For habitat monitoring, using transects along set structured walks is often recommended (JNCC, 2004).

11.7.4 Construction and operational monitoring

When it has been determined that ecological monitoring should be undertaken during UGEE projects, it should be undertaken before and during construction, drilling, hydraulic fracturing and production activities. For the monitoring to be effective, there would need to be an understanding and consideration of the biophysical changes that may take place in the habitats or species, as well as in their vulnerability to changes due to environmental stressors (NRA, 2008). Some of these changes may include habitat loss and a decline in species abundance or diversity, and therefore the monitoring should be designed to capture these changes.

Identifying changes can be difficult: in the case of designated protected areas, the Environmental Liability Directive (EC, 2004) defines “environmental damage” as:

> damage to protected species and natural habitats, which is any damage that has significant adverse effects on reaching or maintaining the favourable conservation status of such habitats or species. The significance of such effects is to be assessed with reference to the baseline condition, taking account of the criteria set out in Annex I

whereby

33 Red Lists: all-Ireland lists of rare and threatened species (http://www.npws.ie/publications/red-lists).

Significant adverse changes to the baseline condition should be determined by means of measurable data such as:

- The number of individuals, their density or the area covered,
- The role of the particular individuals or of the damaged area in relation to the species or to the habitat conservation, the rarity of the species or habitat (assessed at local, regional and higher level including at Community level),
- The species' capacity for propagation (according to the dynamics specific to that species or to that population), its viability or the habitat's capacity for natural regeneration (according to the dynamics specific to its characteristic species or to their populations),
- The species' or habitat's capacity, after damage has occurred, to recover within a short time, without any intervention other than increased protection measures, to a condition which leads, solely by virtue of the dynamics of the species or habitat, to a condition deemed equivalent or superior to the baseline condition."

11.7.5 Post-closure monitoring

When it has been determined that ecological monitoring should be undertaken during UGEE projects, it should also be undertaken for at least 12 months following the well closure and decommissioning stage. This would confirm that there have been no negative impacts and would determine the success of any mitigation measures and site restoration carried out. The period of monitoring may need to be extended where vegetation has been replanted or habitat replaced, in order to monitor its establishment and regrowth.

11.8 Air Quality Monitoring

11.8.1 Purpose

In designing air quality-monitoring programmes, the overall monitoring objectives usually determine the target areas for the study, priority pollutants and the number of sites or monitors required, and they include factors such as (WHO, 1999):

- major sources or emissions of pollutants in the area;
- target receptors and environments;
- weather and topography;
- model simulations of dispersion patterns in the area;
- existing air quality information (such as that from screening studies); and
- data on demography, health and land use.

In addition, certain practical considerations also apply to the selection of monitoring sites. They must be accessible for site visits, but have adequate security to minimise the potential for public interference or vandalism. The monitors should be adequately housed to prevent them from being exposed to harsh weather conditions and the elements and be located in areas free from physical obstructions such as nearby vegetation or terrain that could negatively impact measurements. Electricity must also be available for pollutant analysers and the station infrastructure, and the location must facilitate automatic reporting if the station is to automatically transmit monitoring results.

As recommended by Witter *et al.* (2011), monitoring should commence prior to any development activity to establish baseline conditions, and it should continue throughout the entire UGEE process.

Monitoring should be tailored to best characterise air quality and any potential impacts or emissions associated with the activities at that stage.

Monitoring should allow chemical characterisation of emissions including hazardous air pollutants (or "air toxics") during all life cycle stages to understand impacts on air quality and health (Bernstein *et al.,* 2014).

Final Report 3: Baseline Characterisation of Air Quality of the UGEE JRP and Chapter 7 of this report describe in more detail the potential emissions to ambient air that are linked to the UGEE process. Published studies report that impacts on air quality vary from significantly detrimental (Katzenstein *et al.*, 2003; Gilman *et al.*, 2013; USEPA, 2015; Werner *et al.*, 2015) to little or no impact (NUATRC, 2011; Pacsi *et al.*, 2013; Pennsylvania Department of Environmental Protection, 2013; Bunch *et al.*, 2014). Therefore, there is no clear consensus on which compounds should form the critical elements of a monitoring programme or indeed if any should be excluded.

However, while UGEE processes have been linked to a wide range of emissions, the available literature (including Groundwater Protection Council, 2009; Colorado School of Public Health, 2011; Walther, 2011; McKenzie *et al*, 2012; DECC, 2014a; NETL, 2013; Public Health England, 2013; Adgate *et al.* 2014; Maryland Department of the Environment and Maryland Department of Natural Resources, 2014; Moore *et al.*, 2014; Werner *et al.,* 2015), appears to broadly agree on the compounds or families of compounds mostly likely to be emitted during the process, even if estimations of the quantity of emissions can vary and are not yet well quantified (Research Triangle Environmental Health Collaborative, 2013).

Studies of air quality around fracturing wells indicate the presence of chemical contaminants (Wolf Eagle Environmental, 2009; Colborn *et al.*, 2011). Atherton *et al.* (2014) state that, while many contaminants in the air have the potential to cause harm to human health, a number of issues should be noted. First, although the amounts of contaminants in the air may be within safety standards, these standards are often constructed to allow for single-dose exposures of an adult, rather than for chronic, long-term exposure to people who work or live around natural gas installations (Colborn *et al.*, 2014). There may also be subgroups of the population (e.g. children, pregnant women) who have increased susceptibility to environmental toxins by virtue of their physiological and immunological states (Lauver, 2012). In addition, Werner *et al.* (2014) reported that, following a review of available studies, very few, if any, methodologically rigorous studies have examined the potential cause and effect of UGEE activities in the construction of hazard analyses, linked to exposure pathways and the actual health outcomes with respect to air emissions. Overall, adverse health impacts were often attributed to these activities as a principle of precaution. The available evidence, or lack thereof, is not sufficient cause to rule in or out significant or specific, future or cumulative health impacts of UGEE activities.

It is therefore recommended that the precautionary approach must underpin the recommendation of compounds for monitoring; the selection of compounds for supplementary monitoring has been determined based on established links with UGEE activities and potential impacts. Duration of monitoring and the temporal resolution of the data should allow meaningful comparison with the relevant standards and support the estimation of impacts. The following pollutants are addressed in the recommendations contained in this report, based on the compounds and families of compounds agreed to be linked with UGEE activities in the available literature (discussed in more detail in section 4.2), independently of whether or not significant impacts on human health or the environment have been established:

- nitrogen oxides (NO_x) and nitrogen dioxide (NO_2);
- sulfur dioxide (SO_2);

- particulate matter (PM_{10} and $PM_{2.5}$);
- benzene and other NMVOCs;
- benzo[*a*]pyrene and other PAHs;
- radon; and
- methane.

A risk assessment approach has been used in considering the primary air quality pollutants that ought to be addressed by this study (listed above); therefore, those pollutants not regarded as resulting from UGEE activities have not been considered further in this report, including pollutants for which ambient air quality standards have been established in the Directive on Ambient Air Quality and Cleaner Air for Europe (CAFE Directive or Fourth Daughter Directive (EC, 2008b). Furthermore, it should also be borne in mind that, as scientific knowledge and UGEE techniques are currently developing rapidly, any environmental assessment should take account of the latest knowledge available in the science.

11.8.2 Overarching monitoring requirements

In order to ensure that the monitored data are of satisfactory quality, monitoring should be carried out in line with the relevant principles set out in the CAFE Directive. In particular, the monitoring should be carried out in accordance with:

- Annex 1, Data quality objectives; and
- Annex 3, Assessment of ambient air quality and location of sampling points for the measurement of sulfur dioxide, nitrogen dioxide and oxides of nitrogen, particulate matter (PM_{10} and $PM_{2.5}$), lead, benzene and carbon monoxide in ambient air:
    - Part A (General);
    - Part B (Macroscale siting of sampling points);
    - Part C (Microscale siting of sampling points).

Equipment selection should be guided by the requirements for the following:

- meaningful comparison with averaging periods set out in the ambient standards (hourly, daily, etc.);
- meaningful comparison with threshold values in terms of detection limits and accuracy of monitoring equipment (e.g. the limit of detection should be below the relevant standards; and
- meaningful comparison with the existing ambient air monitoring network.

11.8.3 Baseline monitoring

Baseline monitoring should be carried out to establish pre-existing conditions, against which changes can be identified and tracked if necessary, and to help to determine if such changes can be linked to the UGEE activity. This is discussed in detail in *Final Report 3* of the UGEE JRP, but is summarised below.

The purpose of establishing the baseline pollutant concentrations is to:

- measure target pollutant concentrations at a specific location before any UGEE activities occur; supplement or update the understanding of existing pollutant concentrations; or establish the existing local baseline concentrations in areas where measurements are absent because a representative network does not exist or data from an existing national monitoring network is not representative;

- provide baseline information to support environmental assessment of potential impacts;
- provide sufficient background information to support modelling of potential impacts of any proposed UGEE activities;
- allow a distinction to be made between emissions from future UGEE site activities and emissions in the airshed[34] contributed by local and regional sources.

Baseline air monitoring should be carried out for at least 1 year to account for fluctuations due to any seasonal, weekly and daily variations. Table 11.2 summarises the recommendations for supplementary baseline ambient air quality monitoring.

Table 11.2. Recommendations for supplementary baseline ambient air quality monitoring

Pollutant	Monitoring location/locations	Duration of monitoring	Temporal resolution not less than
NO_2	Within the curtilage of the well pad	1 year[b]	Hourly
NO_2	Roadside background[a]	Not less than 1 month	Hourly
NO_x	Within the curtilage of the well pad	1 year[b]	None specified
SO_2	Within the curtilage of the well pad	1 month	Hourly
CO	None specified	None specified	None specified
Ozone	None specified	None specified	None specified
PM_{10}	Within the curtilage of the well pad	1 year[b]	Daily
PM_{10}	Roadside Background	Not less than 1 month	Daily
$PM_{2.5}$	Within the curtilage of the well pad	1 year[b]	Daily
$PM_{2.5}$	Roadside background[a]	Not less than 1 month	Daily
Benzene and NMVOCs	Within the curtilage of the well pad	1 year[b]	Hourly
Benzo[*a*]pyrene	Within the curtilage of the well pad	1 year[b]	None specified
Radon (outdoor)	Within the curtilage of the well pad	1 year[b]	At regular intervals to be defined by monitoring method or equipment
Radon (indoor)	Representative receptors in the vicinity of the proposed development	3 months	NA
Methane	Within the curtilage of the well pad	Not less than 1 month	To be defined by monitoring method or equipment

[a]In Northern Ireland, use may be made of the modelled background concentrations for the purposes of calculating traffic-related impacts.

[b]It is acknowledged that in the case of NO_2, NO_x , PM_{10}, $PM_{2.5}$, benzene and NMVOCs, benzo[*a*]pyrene and radon, the monitored data may indicate that background concentrations are consistent from month to month or that the existing

34 An airshed is a part of the atmosphere that behaves in a coherent way with respect to the dispersion of emissions, or that shares a common flow of air.

network adequately represents ambient concentrations. In this case, it is recommended that the possibility of curtailing the monitoring period be addressed with the relevant agencies, the EPA or the NIEA.

11.8.4 Construction and operational monitoring

In April 2012, the USEPA announced updated air pollution regulations for natural gas facilities including shale gas extraction and related activities. The key tool in these regulations is the use of equipment to control and reduce emissions. The aim is to ensure efficient capture and thereby reduce emissions. In addition to these regulations, a number of US states have started to develop emissions inventories and region-wide monitoring programmes to better quantify the extent and significance of emissions from UGEE, including, for example, in Pennsylvania, monitoring for carbon monoxide, nitrogen oxides, PM_{10}, $PM_{2.5}$, sulfur dioxide and VOCs. Additional reporting is also required for benzene, ethylbenzene, formaldehyde, *N*-hexane, toluene, and 2,2,4-trimethylpentane (Weinhold, 2012). Colorado adopted new air pollution rules for the oil and gas industry in February 2014, which were to be rolled out by 1 May 2016. The rules include a requirement that fugitive leaks be fixed within 5–15 days (compared with 30–60 days in Texas). The rules also specifically address a range of hydrocarbon emissions and include provisions to reduce methane emissions. In New Brunswick, Canada, the Chief Medical Officer recommended that the province establish monitoring networks for ambient air in local areas expected to have shale gas production (Office of the Chief Medical Officer of Health, 2012).

It was recommended that these monitoring networks should be able to detect both local and regional impacts of emissions and provide baseline monitoring, as well as monitoring during the lifetime of the development and post production. Furthermore, the recommendations state that monitoring efforts should be ongoing and not restricted to only “before” and “after” snapshots, because, if impacts do occur, they may not be evenly distributed in time, so relying on a small number of discrete samples could overlook impacts and lead to overconfidence in the quality of the environment.

11.8.4.1 Ambient air quality monitoring (boundary and receptor)

Comprehensive air quality monitoring is required to enable exposure assessment (Public Health England, 2013) and the operational monitoring programme should follow on from the baseline characterisation monitoring in terms of compounds monitored and the temporal resolution of the monitoring, as well as be supplemented by the collection of meteorological information, a comprehensive leak detection programme (including pipes, wells and tanks) and odour monitoring programme for each well pad.

Prior to the licensing of any UGEE activities, a full air quality assessment would be expected to be required to be carried out as part of the EIA process, which would include characterisation of the air quality and pollutant levels during the operational phase. It is, therefore, critical to establish an operational monitoring programme to ensure that the local air quality conforms to the levels predicted.

Monitoring requirements would change over time, requiring different approaches. During drilling and production the following are critical parts of the operational monitoring programme (Environment Agency, 2012):

- fenceline measurement;
- receptor measurement in the wider community;
- methane flux assessment; and
- fugitive releases (leak detection and repair programmes);

It is, therefore, recommended that:

- ambient monitoring be carried out on the downwind boundary of each well pad, as described in Table 11.3, to build on the data collected during the baseline monitoring and to establish impacts on local ambient air quality;
- monitoring of concentrations of NO_2, PM_{10}, and $PM_{2.5}$ at roadside locations be carried out as described in Table 11.4;
- details of site numbers and locations should be determined based on a project-level air quality assessment and EIA, and associated estimates of any significant traffic-related air quality impacts;
- an indoor radon monitoring programme be carried out in a representative selection of local dwellings within the site environs;
- where any potential changes in air quality within communities or sensitive receptors such as schools are predicted in the EIA air quality assessment, air quality monitoring should be carried out at these locations, as set out in Table 11.5, to enable calculation of the magnitude of the impact.

Table 11.3. Recommendations for operational-phase ambient air quality monitoring (site boundary)

Pollutant	Temporal resolution not less than
NO_2	Hourly
NO_x	None specified
SO_2	Hourly
PM_{10}	Daily
$PM_{2.5}$	Daily
Benzene and NMVOCs	Hourly
Benzo[*a*]pyrene	None specified
Radon (outdoor)	At regular intervals to be defined by monitoring method or equipment
Methane	To be defined by monitoring method or equipment

Table 11.4. Recommendations for operational-phase ambient air quality monitoring (roadside[a])

Pollutant	Temporal resolution not less than
NO_2	Hourly
PM_{10}	Daily
$PM_{2.5}$	Daily

[a]Roadside location to be selected based on detailed air quality assessment results.

Table 11.5. Recommendations for operational-phase ambient air quality monitoring (receptor)

Pollutant	Temporal resolution not less than
NO_2	Hourly
NO_x	None specified
SO_2	Hourly
PM_{10}	Daily
$PM_{2.5}$	Daily

Pollutant	Temporal resolution not less than
Benzene and NMVOCs	Hourly
Benzo[*a*]pyrene	None specified
Radon (outdoor)	At regular intervals to be defined by monitoring method or equipment
Methane	To be defined by monitoring method or equipment

11.8.4.2 Methane flux

The use of generic emissions factors to estimate methane emissions from other industries is of questionable value for unconventional gas. As discussed in Chapter 7, there is little agreement regarding fugitive emissions from shale gas extractions. Emission factors derived by the API are widely used to estimate methane emissions in the oil and gas industry. These may not be applicable to the plant and equipment used for UGEE, and they may also reflect outdated practices in the industry (Environment Agency, 2012).

It has been found that conventional oil and gas operator emission estimates in the EU are typically aggregated at the installation level, with no transparency of emissions of methane from specific fugitive or vented sources, or from specific activities on the site.

It is therefore recommended that operators of UGEE facilities carry out surveys to measure ambient methane levels throughout all stages of the UGEE process.

Monitoring methodology may be dependent on the scale of development and build-out schedule. Atmospheric monitoring at all wellheads may be impractically expensive in the event that there are numerous wells. Other options might include arrays of sensors that monitor whole gas fields (at the kilometre scale) to narrow down large leaks to particular areas. In general, it is much easier to detect point sources than large, spatially diffuse sources (ACOLA, 2013).

11.8.4.3 Fugitive emissions (leak detection programme)

The production phase is the greatest contributor of GHGs, and a leak detection and repair programme is a key element of any strategy to mitigate VOC and methane leaks during this phase (as referenced in Task 4, Chapter 7 of this report). A leak detection and repair programme would include the following:

- ongoing site inspection for leaks readily detected by sight and sound;
- inspection for VOCs, methane and other gaseous or liquid leaks of all wellhead and production equipment, surface lines and metering devices at each well and/or well pad, including from the wellhead up to the on-site separator's outlet, within 30 days of a well being placed into production and regularly (e.g. annually) thereafter;
- inclusion of all components noted above that are possible sources of leaks in the inspection and repair programme – these components include but are not limited to line heaters, separators, dehydrators, meters, instruments, pressure relief valves, vents, connectors, flanges, open-ended lines, pumps and valves from and including the wellhead up to the on-site separator's outlet; and
- specification of the period within which leaks must be repaired.

Reference should be made to relevant guidelines and best practice documents such as the USEPA's Natural Gas STAR Program Guidelines and the USEPA's best practice guidelines for leakage detection and repair programmes (USEPA, 2007) to ensure the development and management of an effective leak management programme.

11.8.5 Post-closure monitoring

As discussed in more detail in section 7.3.2.1, methane emissions from abandoned oil and gas wells appear to be a significant source of methane emissions to the atmosphere (Cherry, 2014; Kang *et al.*, 2014), and it is therefore important to monitor the integrity of the well's condition after plugging and decommissioning. The long-term management of abandoned gas wells to protect cross-contamination of waters and soils, along with gas emissions to the atmosphere, is a matter that requires careful attention (ACOLA, 2014). It certainly is a matter of increasing concern in the USA and there is a need to formulate regulation and develop leading industry practice (ACOLA, 2014).

A long-term methane monitoring programme should, therefore, be developed to detect possible well leakage and failure post decommissioning. Temporary monitoring equipment could be used, such as that used to monitor emissions from landfill sites, or semi-permanent monitoring stations could be installed that can continuously measure air emissions including methane. This requires techniques that can reliably distinguish between methane from non-UGEE-related operations and methane from UGEE-related operations in the areas of abandoned wells (Royal Society and Royal Academy of Engineering, 2012).

Owing to the long-term, open-ended nature of the time-frame associated with methane monitoring post closure, it may be appropriate for the responsibility for post-closure monitoring of wells to be adopted after a set number of years by the statutory authorities, with the responsibility for the implementation of any required mitigation measures and associated environmental liability resting with the developer. It is proposed that funding for post-closure monitoring is arranged through the provision of a bond by the developer, with a provisional monitoring programme set out for the first 5 years (quarterly at appropriate times of the year in years 1, 3 and 5), to be reviewed at 5-year intervals thereafter, pending review of results and agreement between the regulatory bodies and the developer.

The statutory authority for air quality monitoring in Ireland is the EPA. In Northern Ireland, the local councils are the statutory authority for air quality issues, unless the activity is listed by the Industrial Emissions Directive (EU, 2010) as one affected by pollution prevention and control. In terms of UGEE, the only such activities are gas flaring over 10 t per day and the refining of oil.

11.9 Seismic monitoring

11.9.1 Purpose

It is relatively well known that anthropogenic activity can result in man-made or "induced" earthquakes. Although such events are generally small compared with natural earthquakes, they are often perceptible at the surface and some have been quite large. Underground mining, deep artificial water reservoirs, oil and gas extraction, geothermal power generation and waste disposal have all resulted in cases of induced seismicity. The general consensus among most authors is that the process of hydraulically fracturing a well, as it is presently implemented for shale gas recovery, does not pose a high risk for inducing either felt, damaging or destructive earthquakes (as discussed in Project A2 of the UGEE JRP in more detail). Experience in the USA, where many thousands of stimulations have been carried out, suggest that the magnitudes of the induced earthquakes in the Barnett and Marcellus Shale regions are typically less than 1 Mw. However, it should be pointed out that most UGEE operation sites lack independent instrumentation for monitoring induced seismicity and that earthquakes with magnitudes of 2.5 Mw or less will fall below the detection thresholds of regional seismic monitoring networks.

There are only three documented examples of earthquakes with magnitudes greater than 2 ML that have be conclusively linked to hydraulic fracturing for shale gas exploration and recovery:

- an earthquake of magnitude 2.3 ML in Blackpool (Preese Hall), UK, in 2011;

- of 86 earthquakes in Garvin County, Oklahoma, in 2011, 16 had a magnitude of greater than 2.0 ML and the largest had a magnitude of 2.9 ML; and
- in a sequence of over 200 earthquakes in Horn River, Canada, also in 2011, 21 had magnitudes of 3 ML or greater and the largest had a magnitude of 3.8 ML.

It is likely that an earthquake of a similar magnitude to the largest that occurred in Horn River would be strongly felt and could even cause some superficial damage. The maximum magnitudes observed in Blackpool and Garvin County would be unlikely to cause any damage.

By contrast, the growing body of evidence of changes in observed seismicity rates and significant earthquakes linked to the long-term disposal of waste water from the hydrocarbon and other industries by injection into deep sedimentary strata suggests that this activity may pose a rather greater seismic risk. However, while DWI is practised in several countries, it is not considered feasible in Ireland and Northern Ireland without further technical assessment, including hydrogeological characterisation of deeper bedrock formations.

Baseline and operational monitoring are therefore an important element of any monitoring regime associated with UGEE activities. A review by the Royal Society and Royal Academy of Engineering (2012) into the risks associated with hydraulic fracturing suggested that monitoring should be carried out before, during and after shale gas operations to inform risk assessments.

11.9.2 Baseline monitoring

Recent experience in UGEE suggests that baseline monitoring should be an essential requirement for any future exploration and extraction, so that background levels of seismicity can be reliably characterised and any unusual seismicity or active faults that could potentially be affected by operations can be identified. In the UK, a series of recommendations made by Green *et al.* (2012) led to a number of non-legislative regulatory measures, requiring operators to review the available information on faults in the area of proposed wells to minimise the risk of activating any fault by fracking, and also to monitor background seismicity before operations commence.

Baseline monitoring is also essential for distinguishing induced earthquakes from natural background earthquake activity, allowing seismicity rates before, during and after operations to be reliably compared and any differences to be identified. Baseline monitoring must be established prior to the commencement of any activity that is known to induce earthquakes.

The duration of the monitoring required before operations start would depend on both:

- the extent of existing monitoring; and
- the rate of natural earthquake activity.

Areas with higher activity rates will require shorter periods of monitoring, whereas in areas where activity rates are low, there may be very few earthquakes in a given period of time, so a longer durations of baseline monitoring is required to reliably determine seismicity rates. This is in keeping with experience in the geothermal industry, where monitoring periods of 6–12 months are common.

The current best estimates of the seismicity rate across the island of Ireland and the surrounding offshore area are low. Scaling these rates to the study areas, suggests that there would be an earthquake with a magnitude of 2 or greater roughly every 60 years in the larger of the two study areas, and even fewer earthquakes in the smaller study area. However, it is important to test the assumption that seismicity rates are uniform across Ireland. Therefore detailed monitoring is recommended in each study area to detect any unusual seismicity that may suggest that seismicity rates are higher in the study areas, or that there is seismicity associated with any specific fault structure. One to two years may be an appropriate monitoring period for this purpose.

Reliable location and measurement of seismicity places additional constraints on the network design, as location and measurement requires monitoring at more stations than detection alone. In addition, location errors depend on the distribution and density of the recording stations. Monitoring network design is discussed in more detail in *Final Report 2: Baseline Characterisation of Seismicity* of the UGEE JRP. The geothermal industry's extensive experience of seismic monitoring may be considered for adoption as "best practice" for UGEE. This would allow many of the methods used for the monitoring of earthquake activity to be readily adopted.

11.9.3 Operational monitoring

The case studies discussed in Project A2 of the UGEE JRP highlight the importance of an appropriate monitoring network for the reliable detection and location of any seismic events, not only before but also during and after any UGEE operations.

It is, therefore, of crucial importance that at least some of the background monitoring stations remain installed throughout all phases of monitoring to ensure continuity and allow relative re-locations of seismicity and analysis of waveform similarity. Reliable and uniform detection of seismic events across a given area of interest requires a uniform distribution of monitoring stations, and Project A2 of the UGEE JRP addresses this in more detail. Noise levels at individual stations also affect detection capability, and these should be low in order to maximise detection potential, and the network must also extend beyond the limits of the area of interest in order to be able to reliably detect earthquakes that occur close to these limits.

Experience of induced seismicity in enhanced geothermal systems has led to a series of measures to address induced seismicity that may be considered as "industry best practice", and, as such, may be considered appropriate for mitigating the risk of induced seismicity in UGEE operations. For example, an operational traffic light system linked to real-time monitoring of seismic activity (e.g. Bommer *et al*., 2006; Majer *et al*., 2012) is an essential mitigation strategy that would also need to accompany any UGEE operations in Ireland. These are essentially control systems for management of induced seismicity that allow for low levels of seismicity but add requirements when seismic events may result in a concern for public health and safety. This would require the definition of acceptable thresholds for the cessation and recommencement of operations and these should be based on levels of ground motion that may represent a hazard or a public nuisance. Existing regulatory guidelines for ground vibrations caused by blasting could also provide a useful framework for this purpose. The direct use of ground motion thresholds rather than derived magnitudes may, in some cases, be preferable, as they allow thresholds to be directly related to these regulatory guidelines.

Table 11.6 sets out the traffic light system currently in operation in the UK, which was developed following the Preese Hall seismic events in 2011. The monitoring system is designed to be extremely cautious (for example, compared with the Swiss traffic light system shown in Table 11.7) and to ensure that operations stop for further investigation if a tremor measuring 0.5 or higher is detected that satisfies the criteria given below. The threshold magnitude of 0.5 was set on the basis of a report by a group of independent experts. This level is well below what could be felt at the surface. For comparison, it is within the range of normal background noise caused by vehicles, trains and farming activities. However, it is above the level expected from normal fracturing operations and so serves as an early warning of the possibility of larger tremors. It should be noted that as more data become available, the DECC and its advisers will keep the effectiveness of these rules, including the trigger level, under review (DECC, 2014c).

The monitoring is required to be carried out by the operator, which is required to submit its results to the DECC promptly and to publish up-to-date information on its website. The DECC says that it will keep these rules, including the trigger level, under review as more data become available. However, any such system requires the definition of acceptable limits for the cessation and recommencement of operations. In addition, an effective monitoring system needs to provide reliable automatic locations and magnitudes in near real-time for very small events in the magnitude range –1 to greater than 1 ML.

Table 11.6. Traffic light monitoring system in place in the UK (as used by DECC)

Traffic light	Measured magnitude on Richter scale	Recommendations
Green	Less than magnitude 0	Injection proceeds as planned
Amber	Magnitude 0–0.5	Injection proceeds with caution, possibly at reduced rates. Monitoring is intensified
Red	Magnitude 0.5 or higher	Injection is suspended immediately

Table 11.7. Seismic response procedure used in Basel, Switzerland[a]

Traffic light	Earthquake activity	Earthquake magnitude on Richter scale	Ground velocity	Action
Green	None felt	< 2.3	< 0.5 mm/s	Regular operation. Continue pumping
Yellow	Some felt	≥ 2.3	≤ 2.0 mm/s	Continue pumping but do not increase flow rate
Orange	Many felt	≤ 2.9	≤ 5.0 mm/s	Maintain wellhead pressure below stimulation pressure
Red	Widely felt	> 2.9	> 5 mm/s	Stop pumping. Bleed off to minimum wellhead pressure

[a]The system is based on three independent parameters: (1) public response; (2) local magnitude (ML); and (3) peak ground velocity.

11.9.4 Post-closure monitoring

In line with recommendations (Royal Society and Royal Academy of Engineering, 2012), seismic monitoring should continue after fracturing. It is proposed that funding for post-closure monitoring is arranged through the provision of a bond by the developer, with a provisional continuous monitoring programme set out for the first 5 years (with reports issued quarterly at appropriate times of the year in years 1, 3 and 5), to be reviewed at 5-year intervals thereafter, pending review of results and agreement between the regulatory bodies and the developer.

12 Assessment of Existing and Potential Monitoring and Mitigation Techniques (Task 9)

12.1 Background

This chapter examines the validity and range of existing and potential monitoring and mitigation techniques including, but not limited to, geophysical techniques (downhole and surface) for use in monitoring, control, horizon selection and injection management. Mitigation measures are those envisaged in order to avoid, reduce and, if possible, remedy significant adverse effects [Article 5.3(b) of the EIA Directive].

This chapter should be read in conjunction with *Final Report 5* (*Regulatory Framework for Environmental Protection*) of the UGEE JRP (Task 4). Project C addresses the regulatory framework covering UGEE operations and reviews the regulatory approach in five case studies. In addition, Task 4 of Project C provides an examination of best practice for UGEE projects and operations through examining regulatory requirements and best practices in relation to aspects such as water resource management, waste management, emissions control, risk quantification and management, avoidance or mitigation of detrimental seismic events, use of chemicals, well construction, well and site remediation, air emissions management and financial provisions. Measures are cross-referenced where relevant. Task 8 (Chapter 11), which links Projects A1, A2 and A3, of this report also describes best practice for environmental monitoring of potential impacts.

Monitoring and mitigation measures are drawn from a literature review of measures and techniques being used or recommended for UGEE operations, particularly those set out in recommendations and best practice guidelines. The validity of each measure or technique is considered for its applicability to the Irish and Northern Irish contexts, and the scale at which the measure applies set out. Although in general not enough information exists to thoroughly evaluate the effectiveness of individual standalone mitigation measures, the role of the measure as part of an effective suite of mitigation measures or monitoring programme is considered.

In many cases, the techniques were compiled from existing rules, regulation and best practice guidance and this chapter does not seek to summarise all of these in detail but rather to address the range of techniques and measures in practice or recommended. These measures and monitoring techniques are not considered to be prescriptive in their scope and specifications, but they represent measures that may be considered in the specification of the operational management plan and environmental management plan. Moreover, mitigation of the environmental impacts from UGEE processes should be based on a comprehensive approach that focuses on five distinct, mutually reinforcing elements (Council of Canadian Academies, 2014):

1. *The technologies to develop and produce shale gas*. Materials, equipment, and products must be adequately designed, installed in compliance with specifications, and reliably maintained.
2. *The management systems to control the risks to the environment and public health*. The comprehensive and rigorous management of materials, equipment, and processes associated with the development and operation of UGEE sites will ensure public safety and reduce environmental risks.
3. *An effective regulatory system*. Rules to govern the development of shale gas must be based on sound science, and governance of shale gas development must be monitored and enforced.
4. *Regional planning*. To protect the environment, drilling and development plans must reflect local and regional environmental conditions, including existing land uses and environmental risks.

Some areas may not be suitable for development, whereas others may require specific management measures.

- *The engagement of local citizens and stakeholders*. Public engagement is necessary not only to inform local residents of development but also to identify what aspects of quality of life and well-being residents value most, in order to develop a process that wins their trust and protects their values.

12.2 Approach

The current and potential monitoring and mitigation measures available to operators were assessed through a desk study of the available literature including:

- best practice guidelines;
- risk review documents; and
- environmental assessment documents.

The regulatory framework with which any proposed UGEE activities must operate is considered in Project C of the UGEE JRP. Project C also summarises the regulatory approaches in five case study areas in Germany, Denmark, the UK, Colorado (USA) and Pennsylvania (USA), and includes a review of existing rules and regulations in these jurisdictions and should be read as complementary information to this section.

Several of the key documents reviewed and the basis for their inclusion are set out below:

- *Technical Support for Assessing the Need for a Risk Management Framework for Unconventional Gas Extraction* (AMEC, 2014). The project was intended to be used by the EC as a “building block” for an impact assessment accompanying a possible proposal for an EU risk management framework for unconventional gas. This work is particularly useful and authoritative because it identified a comprehensive list of measures that might be used to mitigate the risks from UGEE, examined the regulatory framework for UGEE at a European level to determine which measures are definitely required and examined which measures constitute typical practice by industry. The work was undertaken by a group that included experts in European legislation and UGEE. It was subject to extensive review within the EC and also to review by external peer reviewers before publication.
- The UK Task Force on Shale Gas first and second interim reports (Task Force on Shale, 2015a,b) assess potential local environmental and health impacts of a shale gas industry within the UK. They make a series of recommendations based on currently available academic literature, evidence submitted to the Task Force and a consultation process. The reports are considered important in the context of this project because of the focus on potential risks to the UK, and associated evidence-based recommendations. (In the interests of transparency, it should be noted that the Task Force makes it very clear that their work is funded by businesses involved in the shale gas industry, but it commits to impartial assessment.)
- Also important in a European context is the work carried out by Meiners *et al.* (2013) for the Federal Environment Agency (Germany) for the report *Environmental Impacts of Fracking Related to Exploration and Exploitation of Unconventional Natural Gas Deposits – Risk Assessment, Recommendations for Action and Evaluation of Relevant Existing Legal Provisions and Administrative Structures*. The report examines the water-related environmental impacts and the risks for human health and the environment that could potentially arise from hydraulic fracturing (“fracking”) during the exploration and exploitation of unconventional natural gas reservoirs in Germany, and it also covers monitoring and mitigation measures.

- Guidance documents relating to shale gas development and practices for mitigating impacts associated with hydraulic fracturing have been published by both the UKOOG and the API (see references below). The documents identify and describe best practices currently used in the oil and natural gas industry to minimise potential environmental impacts associated with hydraulic fracturing operations, and as such provide a useful suite of monitoring and mitigation measures on which to draw:
  - UKOOG (2015a): *UK Onshore Shale Gas Well Guidelines Exploration and Appraisal Phase,* Issue 3;
  - API (2009a) *Environmental Protection for Onshore Oil and Gas Production Operations and Leases,* API Recommended Practice 51R;
  - API (2010) *Water Management Associated with Hydraulic Fracturing*, API Guidance Document HF2, First edition;
  - API (2009) *Hydraulic Fracturing Operations— Well Construction and Integrity Guidelines*, API Guidance Document HF1, First edition;
  - API (2011) *Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing*, API Guidance Document HF3, First edition.

This study inevitably draws on experience from the USA, where UGEE processes have been ongoing for many years, but, where possible, US findings have been set in a European context, and the approach taken is to draw on published information to highlight potential environmental impacts associated with UGEE activities in Ireland and Northern Ireland. In addition, where available, documents and recommendations specifically related to the European environmental regulatory framework were included.

Monitoring and mitigation measures are divided into the following groupings:

- pre-development: well pad identification and initial site access:
  - well pad location and design;
  - seismic conditions and geology;
- well design and construction, hydraulic fracturing and well completion:
  - well and well pad construction;
  - fracturing/flowback operations;
  - operational management;
- production;
- project cessation, well closure and decommissioning; and
- other measures.

Monitoring and mitigation measures are addressed under each grouping. The aims and overall strategies of each group of measures are discussed and then specific measures typically used or recommended are listed in a table.

This section supplements Task 8 (Chapter 11), which addresses the topic of identifying best practice for environmental monitoring of potential impacts arising from individual UGEE projects/operations sites (including emissions monitoring, monitoring of the effectiveness of mitigation measures, and monitoring of impacts on the receiving environment). However, while this section considers measures targeted at monitoring the operational process with a view to minimising potential environmental impacts, this is not intended to form a complete best practice document. In the event that an operator proceeds to the project stage, then all relevant best practice guidelines should be adhered to.

12.3 Pre-development measures

12.3.1 Well pad location and well design

Table 12.1 addresses mitigation measures relating to the locations of UGEE infrastructure such as well pads, pipelines, access roads, compressor stations and other ancillary facilities. These measures can directly limit the magnitude of environmental effects or remove them entirely by considering location and zoning. Certain ecologically important areas, recreational areas and sources of drinking water may only be fully protected if certain activities are precluded in proximity to the receptors. Similar reasoning can be applied to the protection of archaeological or cultural heritage resources, where the presence of UGEE infrastructure would damage or negatively impact on the archaeological or cultural heritage resource. Minimising conflict with residential and community-based uses is also an important consideration in defining restrictions on location. In addition to designating certain places or features themselves “off limits”, many of these resources also require a minimum setback distance to provide an additional buffer between the development activity and the resource of concern.

Table 12.1. Measures to address risks related to location

Monitoring/mitigation measure	Validity	Range
Location of sites close to existing pipeline infrastructure (AMEC, 2014) or linear infrastructure (such as roads)	Valid potential measure as part of a suite of measures to contribute to the minimisation of potential impacts relating to land take	Project planning at regional level
Compatibility with current and future potential land use (Natura 2000 sites, conservation sites, and sites for human use, industrial use, appropriate zoning, carbon capture and storage, geothermal power generation, water abstraction) (AMEC, 2014) (see also reference measure 1a, Project C)	Valid potential measure as part of a suite of measures to minimise potential impact on nominated land uses or activities. Protection of sites, e.g. Natura 2000, legally required. Measure may be applied through the licensing process	Planning at regional level
Establishment of exclusion areas and setback distances for UGEE activities (see Table 12.2) (AEA, 2012a, Great Britain, 2015)	The establishment of exclusion zones or setback areas, while a common risk minimisation approach, represents a more prescriptive technique than a goal-oriented approach	As part of a national or regional regulatory approach
Requirement that operator prove safe design and operational distances in terms of environmental protection (Precht and Dempster, 2015) e.g. a buffer zone from abandoned wells and other potential pathways for fluid migration (distance specified on risk basis) Minimum vertical distance between fracturing zone depth and water-bearing zone or aquifer to be determined based on risk assessment to be established	Valid approach in which a more goal-oriented, less prescriptive approach is preferred	Project level

Monitoring/mitigation measure	Validity	Range
Additional/higher specification containment for sites near surface water supplies (AMEC, 2014)	Valid measure as part of a suite of measures to minimise potential impact	Planning at well pad level
Optimisation from an environmental perspective, i.e. the number of wells, pad density and pad spacing (Harvard Law School, 2014)	Valid measure as part of a suite of measures to minimise potential impact	Project planning at site level
Consideration of current and future potential land use and targeted risk assessment (Natura 2000 sites, conservation sites, and sites for human use, industrial use, geothermal power generation, water abstraction)	Valid measure as part of a suite of measures to minimise potential impact. Protection of sites e.g. Natura 2000 legally required.	Planning at regional level
Selection of site unlikely to experience seismic events as a result of UGEE activities (Task Force on Shale Gas, 2015b)	Valid measure as part of a suite of measures to minimise potential impact	Project planning level

The specification of horizontal setback distances or buffer zones (such as those specified within the UK Infrastructure Act, Great Britain, 2015) are a key strategy for risk management within many existing regulatory regimes. Setback distances are determined by the regulatory framework, which may include factors such as minimum setback distances from water bodies, zoning requirements, and similar restrictions (AWWA, 2013). However, application of horizontal setback distances without considering a site-specific risk-based approach may not be appropriate where a more goal-oriented approach is preferred, e.g. the Canadian National Energy Board does not make any numerical references to setbacks or minimum distances. The operator proposes appropriate setbacks and demonstrates that the proposed design and operational distances are safe and will protect the environment. Examples of recommended or required setback distances are provided in Table 12.2.

Table 12.2. Examples of exclusions/setback distances required/recommended

Distance		From	To	Location	Source
Feet	Metres				
Freshwater aquifer					
2000	610	Target formation	Deepest freshwater aquifer	Maryland (recommended best practice)	Maryland Department of the Environment and Maryland Department of Natural Resources (2014)
Aquatic and protected habitats					
450	137	Edge of drill pad disturbance	Aquatic habitat (defined as all streams, rivers, seeps, springs, wetlands, lakes, ponds, reservoirs and floodplains)	Maryland (recommended best practice)	Maryland Department of the Environment and Maryland Department of Natural Resources (2014)
300	91	Edge of well site	Perennial stream or from the ordinary high water mark of any river, natural or artificial lake, pond or reservoir	Illinois	Professions, Occupations and Business Operations (225 ILCS 732/) Hydraulic Fracturing Regulatory Act
300	91	Well	Streams, springs, wetlands, and other water bodies	Pennsylvania	West Virginia University College of Law – Centre for Energy and Sustainable
100	30	Centre of well pad	Stream, pond or wetland	West Virginia	

Distance		From	To	Location	Source
Feet	Metres				
300	91	Centre of well pad	Trout stream	West Virginia	Development (2012)
Protected areas					
750	229	Edge of well site	Nature reserve or a site on the Register of Land and Water Reserves	Illinois	Professions, Occupations and Business Operations (225 ILCS 732/) Hydraulic Fracturing Regulatory Act
600	183	Edge of drill pad disturbance	Special conservation areas (e.g. irreplaceable natural areas, wildlands)	Maryland (recommended best practice)	Maryland Department of the Environment and Maryland Department of Natural Resources (2014)
300	91	Edge of drill pad disturbance	All cultural and historical sites, state and federal parks, trails, wildlife management areas, scenic and wild rivers and scenic byways	Maryland (recommended best practice)	
Underground features					
1000	305	Borehole	Mapped limestone outcrops or known caves	Maryland (recommended best practice)	Maryland Department of the Environment and Maryland Department of Natural Resources (2014)
1000	305	Borehole	Mapped underground coal mines	Maryland (recommended best practice)	
1320	402	Any portion of the borehole, including laterals	Historic gas wells	Maryland (recommended best practice)	
Buildings					
1000	305	Compressor stations	Any occupied building	Maryland (recommended best practice)	Maryland Department of the Environment and Maryland Department of Natural Resources (2014)
1,000	305	Borehole	Any occupied building	Maryland (recommended best practice)	
200	61	Well	Any building	Colorado	COGCC (2013)
1000	305	Well	High-occupancy buildings (e.g. schools, nursing facilities, hospitals, correctional facilities)	Colorado	COGCC (2013)
500	152	Edge of well site	Any residence, place of worship, school, hospital or nursing home	Illinois	Professions, Occupations and Business Operations (225 ILCS 732/) Hydraulic Fracturing Regulatory Act
625	191	Centre of well pad	Any occupied dwelling	West Virginia	West Virginia University College of Law – Centre for Energy and Sustainable Development (2012)
150	46	Well	Any structure (unless waiver from structure owner)	Kentucky	
150	46	Well	Any occupied building	Ohio	
Road and rail					

Distance		From	To	Location	Source
Feet	Metres				
50	15	Well	Public road or railway track	Ohio	West Virginia University College of Law – Centre for Energy and Sustainable Development (2012)
200	61	Well	Public road, above ground utility, railroad	Colorado	Oil and Gas Conservation Commission (2013)
Water resources					
1000	305	Edge of drill pad disturbance	Wellhead protection area for public water systems for which a wellhead protection area has not been officially delineated	Maryland (recommended best practice)	Maryland Department of the Environment and Maryland Department of Natural Resources (2014)
1500	457	Well	Surface water or groundwater intake of a public water supply	Illinois	Professions, Occupations and Business Operations (225 ILCS 732/) Hydraulic Fracturing Regulatory Act
1000	305	Centre of well pad	Surface/ground public water supply intake	West Virginia	West Virginia University College of Law – Centre for Energy and Sustainable Development (2012)
1000	305	Well	Water sources used by purveyors	Pennsylvania	
2000	610	Borehole	Private drinking water well	Maryland (recommended best practice)	Maryland Department of the Environment and Maryland Department of Natural Resources (2014)
500	152	Edge of well site	Surface location of any existing water well or developed spring used for human or domestic animal consumption (unless expressly agreed by owner)	Illinois	Professions, Occupations and Business Operations (225 ILCS 732/) Hydraulic Fracturing Regulatory Act
500	152	Well	Water well	Pennsylvania	West Virginia University College of Law – Centre for Energy and Sustainable Development (2012)

12.3.2 Seismic conditions and geology

Investigation of underground conditions ensures that operators have a sound understanding of hydrology, geology and the likelihood and severity of potential seismic activity, against which changes could be monitored on an ongoing basis. The investigations and associated evaluations enable accurate predictions of site-specific benefits enabling accurate predictions of the likely effects and scale of risk to groundwater and to rock formations. A thorough understanding of the geological and hydrogeological environment, together with an appropriate monitoring programme, can minimise environmental risks (AMEC, 2014).

First, small “micro-events” are associated with the formation and propagation of new fractures (fracked tremors). The detection and location of these tiny events is used to map the progress of a hydraulic fracturing operation; they are too small to be felt on the surface (Task Force on Shale Gas, 2015b). Larger seismic events can be induced if fluid is injected into larger, pre-existing fault planes if they are suitably oriented with respect to the natural stress field, through reducing the clamping force across the fault, which may then allow pre-existing natural forces to cause movement (triggered events). Induced seismicity issues are discussed in detail in Project A2 of the UGEE JRP.

The identification and evaluation of potentially active seismic zone and faults minimises the risks of fault movement. Risk assessments would depend on such things as:

- geological knowledge of the source area;
- actual field experience in the area; and
- the depth of fracturing operations (UKOOG, 2015a).

Table 12.3 sets out measures relating to geological, hydrogeological and seismic conditions.

Table 12.3. Measures associated with geology, hydrogeology and seismic conditions

Monitoring/mitigation measure	Validity	Range
Conceptual hydrogeological models should be prepared that support reliable risk analysis for all potential impact pathways. The scope of such conceptual models should be large enough to support assessment of the impacts of exploration and exploitation of unconventional gas both for the specific sites involved and with regard to the large geological systems involved (Meiners *et al.*, 2013)	The cause-and-effect relationships between flow systems are of particular importance with regard to the water-related environmental impacts. To properly assess such water-related risks, and even quantify them, a detailed understanding of the hydrogeological systems is necessary	Regional
For areas in which water-related environmental impacts cannot be ruled out (as shown by risk analysis), numerical groundwater-flow models, with which the pertinent risks can be quantified, should be prepared/refined. As a rule, this will entail preparing a regional-level model that can then serve as a basis for local models within and around the actual gas production area (Meiners *et al.*, 2013)	The cause-and-effect relationships between flow systems are of particular importance with regard to the water-related environmental impacts. To properly assess such water-related risks, and even quantify them, a detailed understanding of the hydrogeological systems is necessary	Regional
Search for and document potential leakage pathways (e.g. other wells, faults, mines) (AMEC, 2014)	Contributes to understanding of the environmental setting and baseline conditions	Regional
Undertake sampling of groundwater (see also measure 3a iii, Project C) Low ambition: sampling of shallow groundwater during wet and dry periods High ambition: borehole to sample deep groundwater and characterise the hydrological series (AMEC, 2014)	Contributes to understanding of the environmental setting and baseline conditions, potential environmental impacts and treatment and recycle of flowback and produced waters	Regional
Establish the presence of methane in groundwater, including drinking water (baseline) (AMEC, 2014) (see also measure 3a xi, Project C)	Contributes to understanding of environmental setting and baseline conditions	Regional
One pilot hole investigation should be drilled for every pad to investigate the geology and determine all strata where liquid or gaseous flow occurs (Maryland Department of the Environment and Maryland Department of Natural Resources, 2014)	To identify geological features, underground voids, gas- or fluid-bearing formations, and the lowest freshwater aquifer in the immediate vicinity of the proposed borehole	Per well pad

Monitoring/mitigation measure	Validity	Range
The area of sampling for baseline characterisation should be based on the anticipated fracture length (propagation distance of the fracture) plus an appropriate safety factor (API, 2009b)	Establishment of study area	Local
Undertake land condition (soil) tests every 5 years outside site boundary (AMEC, 2014)	Ensures lack of contamination of surrounding environment	Local
Develop a geological, hydrogeological and seismic conceptual model, including the following (AMEC, 2014) (see also measures 3a x-a2, 3a x-a7, Project C) Obtain and analyse seismic (earthquake) history Obtain geomechanical information on fractures, stress, rock strength, in situ fluid pressures Undertake surface microseismic survey Develop maps and three-dimensional (3D) models of local geological structure Conduct 3D seismic survey to identify faults and fractures Obtain data on area, thickness, capacity, porosity and permeability of formations	Contributes to understanding of seismic conditions in the region	Regional
The pressure in the well is also a key determinant of induced seismicity and is affected by: The volume of injected fluid. Larger volumes generate higher pressures The volume of flow-back fluid. Larger flow-back volumes reduce the pressure The injection rate. More rapid injection generates higher pressures The flow-back rate. More rapid flow-back reduces the pressure These variables should be monitored in the context of micro-seismic events to allow an evolutionary approach to risk assessment and mitigation (UKOOG, 2015a)	Operational monitoring allows tailoring of control measures. As experience is gained in the area, and where induced seismic events have not occurred, operators may use this as evidence to propose different monitoring and mitigation measures that are sufficient to address the risk (UKOOG, 2015a)	Per drilled hole
Installation of an effective real time seismic monitoring and detection system (Task Force on Shale Gas, 2015a)	Operational monitoring allows tailoring of control measures. As experience is gained in the area and where induced seismic events have not occurred, operators may use this as evidence to propose different monitoring and mitigation measures that are sufficient to address the risk (UKOOG, 2015a)	Project scale
Baseline seismic monitoring should be carried out from the earliest practicable point possible following identification of the site (Green *et al.*, 2012; Task Force on Shale Gas, 2015b) (see also measure N55, Project C)	Contributes to understanding of the setting and baseline conditions and potential impacts	Regional

Monitoring/mitigation measure	Validity	Range
Implement the US Department of Energy Protocol for Addressing Induced Seismicity Associated with Enhanced Geothermal Systems (Majer *et al.,* 2012): Step 1: perform a preliminary screening evaluation Step 2: implement an outreach and communication programme Step 3: review and select criteria for ground vibration and noise Step 4: establish seismic monitoring Step 5: quantify the hazard from natural and induced seismic events Step 6: characterise the risk of induced seismic events Step 7: develop risk-based mitigation plan	Programme for the mitigation of seismic risk	Regional
Operators will need to evaluate the historical and background seismicity and the in situ stress regime, and delineate faults in the area of the proposed well to identify the risk of activating any fault by hydraulic fracturing (DECC, 2015b)	Contributes to understanding of the setting and baseline conditions and potential impacts	Regional
Application of suitable ground motion prediction models to assess the potential impact of any induced earthquakes (Green *et al.*, 2012).	Contributes to understanding of the setting and baseline conditions and potential impacts	Regional
Traffic light monitoring systems will be required to enable operations to mitigate induced seismicity (DECC, 2013c).	Traffic light monitoring systems enable operations to mitigate induced seismicity (DECC, 2013c). It is recommended that the remedial action level for the traffic light system (that is, the “red light”) will be set at magnitude 0.5 (far below a perceptible surface event but greater than the expected level generated by the fracturing of the rock). This will apply to the first set of hydraulic fractures and will be subject to review. This is discussed in more detail in Project A2	System to be put in place by the operator on a project basis
The fracturing plan should also include appropriate plans to monitor seismicity before, during and after the well operations (DECC, 2015b)	Ensure that appropriate controls and measures are put in place	Project basis

12.4 Production

12.4.1 Well and well pad construction

Drilling and completing a UGEE well consists of several sequential activities. They are listed below, and those that have mitigation measures associated with them in the following tables are highlighted in bold. In sequential order, these activities are as follows:

- preparing the site and installing fluid-handling equipment;
- setting up the drilling rig and ancillary equipment and testing all equipment;
- drilling the hole;
- logging the hole (running electrical and other instruments in the well; the objectives are to determine the exact location of the casing, the casing collars and the integrity of the cement (Maryland Department of the Environment and Maryland Department of Natural Resources, 2014));

- running casing (steel pipe);
- cementing the casing;
- logging the casing;
- removing the drilling rig and ancillary equipment;
- perforating the casing;
- hydraulic fracturing or stimulating the well;
- post-hydraulic fracturing monitoring;
- installing surface production equipment;
- putting the well into production;
- monitoring well performance and integrity; and
- reclaiming the parts of the drilling location that are no longer needed and removing equipment no longer used for production.

Operational risk management and mitigation measures reduce the likelihood of well failure resulting in significant underground and surface air and water contamination. Such measures may require changes to operational practices and reduce the likelihood and scale of environmental risks, including unintentional introduction of chemicals underground. These measures focus on structural well design and integrity testing, smaller “pre-injection” tests to empirically observe the effects of rock strata and putting physical distance between well activity and groundwater and local communities. Operators would have their own procedures and systems in place to comply with guidance, best practice, national legislation and licence requirements; Table 12.4 to Table 12.9 set out examples of the potential and recommended mitigation measures available.

Table 12.4. Measures to address well construction and integrity – pre-fracturing

Monitoring/mitigation measure	Validity	Range
Review of the design of the casing, as well as the plan to run and install the casing during well construction (API, 2009b; Drilling and Completions Committee and Enform, 2015)	Design of the steel casing strings is a key part of the well design and a key factor in well success, including ensuring zonal isolation and wellbore integrity	Local/ well pad
Investigation and review of the history of nearby wells for cementing problems encountered, e.g. lost returns, irregular hole erosion, poor hole cleaning, poor cement displacement (API, 2009b)	Placement of the cement completely around the casing and at the proper height above the bottom of the drilled hole is one of the key factors in achieving successful zone isolation and integrity. This is a licence requirement in the UK	Regional
Computer simulation and other planning should be carried out to optimise cement placement procedures (API, 2009b)	Placement of the cement completely around the casing and at the proper height above the bottom of the drilled hole is one of the key factors in achieving successful zone isolation and integrity	Local/ well pad

Table 12.5 Measures to address well construction and integrity – drilling and logging the hole

Monitoring/mitigation measure	Validity	Range
Well completion report to be submitted, including the following measurements (Maryland Department of the Environment and Maryland Department of Natural Resources, 2014): • depth at which any fresh water inflow was encountered • lithology of penetrated strata • total depth of the well • a record of all commercial and non-commercial oil and gas encountered, including depths, tests, and measurements • a record of all salt water inflows Generalised core descriptions, including: • the type and depth of sample • indications of oil, water, or gas • estimates of porosity and permeability • percentage recovery • a copy of all electric, radiation, sonic, caliper, directional and any other type of logs run in the well	Establishes baseline conditions	Per well
Open hole well logging: • Gamma ray – a device that detects naturally occurring gamma radiation (API, 2009b; Maryland Department of the Environment and Maryland Department of Natural Resources, 2014) • Resistivity – measures the electrical resistance between probes on the logging tool in the wellbore. Usually at least three resistivity logs are run, but up to 10 may be run – the difference being the distance between the probes. The radius of investigation is increased with the distance between probes. (API, 2009b; Maryland Department of the Environment and Maryland Department of Natural Resources, 2014) • Density – a device used to measure the bulk density of, and, by inference, the porosity of the formation (API, 2009b; Maryland Department of the Environment and Maryland Department of Natural Resources, 2014) • Caliper – a physical measurement of the diameter of the wellbore. A caliper log run through a wellbore is used to calculate the hole size and volume of the wellbore, and therefore it provides critical data that are used in the design of the cement job (API, 2009b; Maryland Department of the Environment and Maryland Department of Natural Resources, 2014) • Neutron porosity logging (Maryland Department of the Environment and Maryland Department of Natural Resources, 2014)	Enables the locating and evaluating of the hydrocarbon-producing formations. Logging produces valuable information on all formations logged, which is useful in optimising the well design and drilling operation. Logging determines the actual depth and thickness of the subsurface formations in the drilled hole This allows installation of casing strings in exactly the right place to achieve the objectives of the well design and to properly achieve the isolation benefits of the casing and cement	Per drilled hole

Table 12.6. Measures to address well construction and integrity – running the casing

Monitoring/mitigation measure	Validity	Range
Strength testing of the cement after the cement is set and prior to commencing further drilling or completing the operation (API, 2009b; Maryland Department of the Environment and Maryland Department of Natural Resources, 2014)	The cement surrounding the casing shoe should have a compressive strength adequate to withstand the anticipated hydraulic fracturing pressure to ensure well integrity	Per drilled hole
Each casing string, except the conductor casing, should be pressure tested prior to “drill out” (commonly known as a casing pressure test) (API, 2009b)	The test pressure will vary depending on the casing string, depth, and other factors	Per drilled hole
Hydrostatic pressure test of reconditioned casing (Maryland Department of the Environment and Maryland Department of Natural Resources, 2014)	Reconditioned casing may be permanently set in a well only after it has passed a hydrostatic pressure test with an applied pressure at least 1.2 times the maximum internal pressure to which the casing may be subjected, based upon known or anticipated subsurface pressure, or pressure that may be applied during stimulation, whichever is greater, and assuming no external pressure	If reconditioned casing is being used

Table 12.7. Measures to address well construction and integrity – cementing the casing

Monitoring/mitigation measure	Validity	Range
Cementing product and selected cements, additives and mixing fluid should be laboratory tested in advance to ensure that they meet the requirements of the well design (API, 2009b).	Required to ensure the long-term structural integrity of the well	Quantitative tests per materials batch/ well design
Submission of regular (weekly) operations reports to responsible body specialists (e.g. UK Health and Safety Executive) to facilitate the checking of construction against design (DECC, 2014)	Ensures independent checking of construction	Per well/project
Testing of cement slurry design to measure the following parameters, depending on site-specific geological conditions. Parameters may include: • slurry density • thickening time • fluid loss control • free fluid • compressive strength development • fluid compatibility (cement, mix fluid, mud, spacer) • sedimentation control • expansion or shrinkage of set cement • static gel strength development • mechanical properties (Young’s modulus, Poisson’s ratio, etc.) (API, 2009b)	Required to ensure long term structural integrity of well.	Per well pad / slurry mix
Continuous monitoring of slurry rate (API, 2009b)	Indicator of satisfactory placement of slurry	Per well

Table 12.8. Measures to address well construction and integrity – logging the casing

Monitoring/mitigation measure	Validity	Range
Cement integrity (cased-hole) logging (see measure 22b, Project C)	Care should be taken in the interpretation of these test results, as they may not detect all potential casing defects.	Per well
• Gamma ray – a device that detects naturally occurring gamma radiation (API, 2009b)	Measures the presence of cement and the quality of the cement bond or seal between the casing and the formation	
• Collar locator (API, 2009b)	A magnetic device that detects the casing collars to show the location	
• Cement bond log (CBL) (API, 2009b)	An acoustic device that can detect cemented or uncemented casing. Measures the presence of cement and the quality of the cement bond or seal between the casing and the formation	
• Cement bond log (CBL) and variable density log (VDL) (API, 2009b). The CBL is an acoustic device that can detect cemented or uncemented casing. The VDL is a display of the wave train of an acoustic signal (API, 2009b)	The CBL-VDL is the most common type of cement evaluation tool that is used, but other types of cement evaluation tools are available and, depending on the situation, should be considered as a part of a comprehensive cement evaluation programme	
Leakoff test (LOT)/Formation integrity test (FIT) (see measure 22b ii, Project C) This provides a measure of the maximum hole pressure that the formation just under the shoe can withstand (Oil & Gas UK, 2012)	If the test results of the formation pressure integrity test are inadequate, it indicates that remedial measures should be undertaken as appropriate. In particular, in the case of a failure, remedial cementing operations should be undertaken as appropriate. (API, 2009b). This is critical to maintaining well integrity Current understanding is that a correctly conducted integrity test does not reduce the strength of the shale and this is usually the preferred option. (Oil & Gas UK, 2012)	Per well
Pressure testing of production casing should be carried out (commonly known as a casing pressure test) (API, 2009b; Meiners *et al.*, 2013) (see measure 22b iv, Project C)	This test should be conducted at a pressure that will determine if the casing integrity is adequate to meet the well design and construction objectives	Per well

Table 12.9. Measures to address well construction and integrity – perforating the casing

Monitoring/mitigation measure	Validity	Range
Monitoring of location of perforations using a gamma-ray detector run in the hole with the perforating guns. The exact location of the perforating guns with respect to the formations is known by comparison with the gamma-ray response of the open hole log and the CBL (API, 2009b)	A key result of the cased-hole logging programme is to know the exact location of the casing, casing collars, and quality of the cement job relative to each other and relative to the subsurface formation locations. This is important in determining that the well drilling construction is adequate and achieves the desired design objectives. It is also useful information in subsequent checks of well integrity and seals over the productive life of the well	Per well

12.4.2 Fracturing and flowback operations

During the fracturing process itself, pressurised hydraulic fracturing fluid is injected into the well, creating cracks in the geological formation that allow oil or gas to escape through the well to be collected at the surface. In the case of inadequate well construction or operational failure, hydraulic fracturing fluids or substances mobilised from the underground environment can be released to groundwater (via the well casing).

Operational management and monitoring of this process is therefore important to ensure that the fracturing is proceeding as planned and that associated impacts are avoided. Table 12.10 sets out the monitoring and mitigation measures relating to the fracturing and flowback processes.

Table 12.10. Measures relating to fracturing operations

Monitoring/mitigation measure	Validity	Scale
Blowout preventers should be tested at a pressure at least 1.2 times the highest pressure normally experienced during the life of the blowout preventer (Maryland Department of the Environment and Maryland Department of Natural Resources, 2014). A blowout preventer is a mechanical device that can close or seal a wellbore if pressure in the well cannot be contained The blowout preventer must be tested on a weekly basis (Maryland Department of the Environment and Maryland Department of Natural Resources, 2014)	A programme of testing and maintenance is an important part of operational management. Without a correctly functioning blowout preventer, extreme erratic pressures and uncontrolled flow encountered during drilling could cause a blowout – the uncontrolled release of liquid and gas from the well resulting in the ejection of casing, tools and drilling equipment from the well	Per well
Prior to starting hydraulic fracturing, all equipment should be tested to make sure that it is in good operating condition All high-pressure lines leading from the pump trucks to the wellhead should be pressure tested to the maximum treating pressure. Any leaks must be eliminated prior to starting hydraulic fracturing (UKOOG, 2015a)	Testing the equipment before starting fracturing operations minimises the risk of problems during the fracturing process – and the resultant environmental impacts	Per well/well pad
The pressure relief valve should be set so that the pressure exerted on the casing does not exceed the working pressure rating of the casing and the flow line from the relief valve should be secured and diverted to a lined pit or tank (API, 2009b)	Ensures containment of drilling fluids	Per well
Modelling of the fracture	Modelling of the fracture is necessary to help identify when performance deviates from expected	Per well
Continuous monitoring (API, 2009b) of: • slurry rate • proppant concentration • sand or proppant rate	This enables the progression and fracture geometry to be assessed in real time. Unusual or unexpected data could indicate some type of problem. Collected data can also be used to refine computer models to plan future hydraulic fracture treatments	Per well

Monitoring/mitigation measure	Validity	Scale
Pressure monitoring (API, 2009b; UKOOG, 2015a): • continuous monitoring of surface injection pressure at the pump • continuous monitoring of surface injection pressure in the pipe that connects the pump to the wellhead • continuous monitoring of surface injection pressure in the annular space if the annulus between the production casing and the intermediate casing has not been cemented to the surface	Unexpected or unusual pressure behaviour during the hydraulic fracturing process could indicate some type of problem	Per well
Fracture propagation monitoring during fracturing operations (Meiners *et al.*, 2013): • Microseismic surveys • Tiltmeter surveys. A tiltmeter is a device that measures the change in the inclination in the earth's surface (API, 2009b; Maryland Department of the Environment and Maryland Department of Natural Resources, 2014)	Further research is required in the area of fracture propagation with a view to improving modelling and monitoring (Meiners *et al.*, 2013). Current recommended techniques are microseismic and tiltmeter surveys 3D real-time microseismic surveys enable the evaluation of critical hydraulic fracturing parameters such as vertical extent, lateral extent, azimuth, and fracture complexity Operators can use microseismic surveys so that the lateral and vertical extent of fracturing can be maintained within the desired reservoir unit and the results can be used to verify and fine tune computer models used to predict hydraulic fracture performance in an area (API, 2009b)	First well hydraulically fractured on each pad to provide information on the extent, geometry and location of fracturing (Maryland Department of the Environment and Maryland Department of Natural Resources, 2014)
Smaller pre-injection prior to main operations (AMEC, 2014; DECC, 2015b)	Pre-injection will enable the induced seismicity response to be assessed	Per well/local-scale monitoring
Monitoring and control during operations to ensure that hydraulic fractures do not extend beyond the gas-producing formations (AMEC, 2014)	Monitoring and control to ensure that the process does not result in seismic events or damage to buildings/installations	Per well/local-scale monitoring
Microseismicity monitoring and management requirements during operations (Task Force on Shale Gas, 2015b)	Real-time monitoring of microseismicity during all operations allows cessation of fracturing if specified induced seismic activity is detected (using the traffic light system)	Per well/local-scale monitoring

Monitoring/mitigation measure	Validity	Scale
Tagging of sand with tracer to further confirm that the placement of the proppant was as it was intended (API, 2009b)	The radius of investigation of this technique is relatively small, in the order of a metre at best, but it does yield information indicating which perforations accepted proppant, and how the fracture grew immediately outside the perforations Use of this post-hydraulic fracturing monitoring technique is declining with the advent of sophisticated computer modelling techniques	Per well
Maintenance of a temperature log in conjunction with the tracer log. The temperature log measures the variations in temperature throughout the section of interest, which enables the determination of which perforations accepted fracturing fluid, providing insight regarding fracture growth immediately outside the casing (API, 2009b)	Use of this post-hydraulic fracturing monitoring technique is declining with the advent of sophisticated computer modelling techniques	Per well

12.4.3 Operational management of site

When pressure in the well is released, hydraulic fracturing fluid, formation water and natural gas begin to flow back up the well. Flowback involves the return of injected fluid and water produced from the formation to the surface and its subsequent transport for reuse, treatment or disposal, and it continues for several weeks. Flowback is a mixture of fracturing fluids, formation water and potentially reaction products. This combination of fluids, containing hydraulic fracturing chemical additives and naturally occurring substances, must be stored on site – typically in tanks or, in some jurisdictions, pits – before treatment, recycling or disposal. Proper management of flowback fluids is critically important to the protection of the environment, including both surface- and groundwater. To date, no systematic measurements have been carried out for the purpose of identifying transformation and decomposition products in the fluids (Meiners, 2012). Fracturing additives that remain underground may pose a risk for near-surface (exploitable) groundwater, if there is a possibility that they could both migrate into near-surface (exploitable) groundwater, via one or more of the aforementioned impact pathways, and result in a significant deterioration of the groundwater quality. The question of whether or not, and to what extent, substance transport in the direction of exploited groundwater resources occurs thus depends on the relevant, site-specific geological and hydrogeological conditions, as well as on the sorption properties of fracturing additives and the surrounding rock (Meiners, 2012). (Mitigation measures with respect to location and geology, hydrogeology and seismic conditions are set out in Table 12.1 and Table 12.3, respectively.)

In common with the development of any industrial site, good site management practices are important to minimise potential environmental impacts. Table 12.11 sets out monitoring measures relating to the general operational environmental management. Measures relating to post-hydraulic fracturing operations, water management and solid waste management are set out in Table 12.11, Table 12.12 and Table 12.13, respectively. Environmental water quality mitigation measures can be found in Chapter 4 and water resource use mitigation measures can be found in Chapter 5.

Table 12.11. Measures relating to general operational management of site

Monitoring/mitigation measure	Validity	Range
Regular assessment of the physical condition of physical structures such as bunding, impoundments, tanks, drainage arrangements, and maintenance of records of checks and any associated repair or replacement	Site pollution control is a part of the local planning process, and operators should be able to demonstrate best practice in this area, including the prevention of contamination of soils, by the provision of suitably designed impermeable site underlay systems and site drainage arrangements, etc.	Well pad and associated infrastructure
Monitoring/assessment of wheel-washing facilities to ensure proper functioning	Contributes to successful environmental management of site	Well pad and associated infrastructure
Monitoring/assessment of pipe-clearing and -cleaning areas to ensure proper functioning, disposal of solids and testing	Contributes to successful environmental management of site	Well pad and associated infrastructure
Undertake monitoring of the type and volume of chemicals used in all phases of operations, including during fracturing and including record keeping (AMEC, 2014)	Contributes to successful environmental management of site	Well pad

Table 12.12. Measures relating to post-hydraulic fracturing monitoring

Monitoring/mitigation measure	Validity	Range
Mechanical integrity pressure monitoring is used to determine the mechanical integrity of well equipment when the well is producing (API, 2009b)	Monitoring will ensure the integrity of the well and well equipment	Per well
Wellhead seal tests to test the mechanical integrity of the sealing elements (including valve gates and seats) and determine if they are capable of sealing against well pressure (API, 2009b)	If abnormal pressures are noted in an annulus, a re-pressure test of the wellhead seal system can help determine if the source of communication is in the surface in the wellhead system	Per well
When equipment is removed from a well or depressurised for maintenance, a breakdown or visual inspection, including a casing inspection log, should be conducted to document the condition of the equipment after being in service. For example, if tubing is pulled from a well, it can be inspected for corrosion/erosion damage (API, 2009b)	Results will indicate potential issues and the possibility of reusing equipment The steel casing protects the external environment from material inside the wellbore during subsequent drilling operations and, in combination with other steel casing and cement sheaths that are subsequently installed, protects the groundwater with multiple layers of protection for the life of the well	Per well
Regular inspection of casing head equipment (API, 2009b)	Results will indicate any leaks between any of the casing strings	Per well
Regular inspection of annulus pressures (API, 2009b)	Results will indicate any leaks between any of the casing strings	Per well

Environmental water quality mitigation measures can be found in Chapter 4 and water resource use mitigation measures can be found in Chapter 5.

Table 12.13 sets out mitigation measures relating to the management of flowback, produced water and wastewater. Further information on mitigation measures relating to water quality and resource use is available as follows:

- Environmental water quality mitigation measures can be found in Chapter 4.
- Water resource use mitigation measures can be found in Chapter 5.

Table 12.13. Measures relating to flowback, produced water and wastewater

Monitoring/mitigation measure	Validity	Range
Characteristics of flowback have to be individually assessed for each site (Meiners, 2012) Monitoring of flowback, produced waters and any wastewaters related to on-site treatment to establish composition for appropriate treatment or recycling (composition changes over lifetime of well)	The volume and composition of flowback water depends on the properties of the shale, the fracturing design and the type of fracturing fluid used. Produced water will continue to return to the surface over the well's lifetime. These wastewaters typically contain salt, natural organic and inorganic compounds and chemical additives used in fracturing fluid and NORM (Royal Society and Royal Academy of Engineering, 2012). Monitoring is important: • to ensure appropriate handling and treatment • as an indicator that fluid management processes are operating correctly	Well pad
Monitoring of flowback, produced waters and any treated waters for compliance with requirements relating to chosen disposal method	Specific requirements relating to disposal and treatment of wastewaters are addressed in Chapter 10	Well pad.
Visual inspection of primary containment used for fluid storage (AEA, 2012a)	Containment inspection will reduce risk of spills on site.	Well pad
Regular inspection and associated record maintenance of secondary containment around all additive staging areas and fuelling tanks, manned fluid/fuel transfers and visible piping and appropriate use of troughs, drip pads or drip pans (NYSDEC, 2015)	Containment inspection will reduce risk of spills on site	Well pad
Monitoring for and rapid detection of oil spillages (AEA, 2012a)	Rapid detection of spills will contribute to minimising negative environmental impacts	Well pad
Flowback water should be removed from site at regular intervals and within previously agreed time frames or treated	Minimisation of untreated water storage reduces contamination risk	Well pad
Site to be designed to minimise and contain spills (Task Force on Shale Gas, 2015b), e.g. use of impervious site liner under pad (Meiners, 2012; AMEC, 2014) (see measure 33f, Project C)	Required as part of a comprehensive environmental management plan	Well pad
Spill kits to be kept available for use (see measure 33d, Project C)	Required as part of a comprehensive environmental management plan	Well pad
Collection and control of surface runoff (Meiners, 2012)	Required as part of a comprehensive environmental management plan to reduce environmental impacts	Well pad
Secondary containment of all storage tanks (chemicals, fuel, oil, etc.)	Reduces risk of spillage	Well pad

Monitoring/mitigation measure	Validity	Range
Use of tank level alarms (AMEC, 2014) (see measure 33b, Project C)	Indicates when tank levels are too high or too low	Well pad
Use of double-walled closed storage tanks (AMEC, 2014)	Reduces risk of spillage or leakage due to deterioration or damage of tank materials	Well pad
Operator demonstrates availability of appropriate wastewater disposal treatment facilities	Required for appropriate disposal	Well pad
Cuttings and drilling mud, as well as flowback, produced water, residue from treatment of flowback and produced water, and any equipment in which scaling or sludge is likely to occur should be tested for radioactivity and disposed of in accordance with relevant regulations (Maryland Department of the Environment and Maryland Department of Natural Resources, 2014)	Required for appropriate disposal	Well pad

Table 12.14. Measures to manage solid waste

Monitoring/mitigation measure	Validity	Range
Use of best management practice and regulatory frameworks in Europe to manage waste	Legal compliance required	Well pad
Operators should select fluids/mud to minimise the environmental hazard posed by drilling wastes (AEA, 2012a)	Contributes to the reduction of environmental risks	Well pad
Separation of drilling fluids and cuttings to facilitate reuse (AEA, 2012a)	Minimises waste	Well pad
Cuttings and drilling mud also to be tested for contaminants, including sulfates and salinity (Maryland Department of the Environment and Maryland Department of Natural Resources, 2014) and NORM	Required for appropriate disposal	Well pad
Drill cuttings should be tested for compliance with agreed composition specifications according to disposal methods	Required for appropriate disposal	Well pad
Undertake monitoring of drilling mud volumes and treatment (AMEC, 2014)	Contributes to the reduction of environmental risks	Well pad
A waste management plan based on laboratory tests should be put in place (Task Force on Shale Gas, 2015b)	Supports appropriate waste management procedures from the commencement of the project	Well pad/project scale
Authorities to be informed prior to the movement of any waste off site (Task Force on Shale Gas, 2015b).	Supports the oversight of operations by the responsible authorities	Well pad/project scale

12.5 Decommissioning

Decommissioning of the well should be considered at the design stage; UK legislation requires “design for abandonment”, i.e. that the well should be constructed in such a way that it can be safely and satisfactorily decommissioned. Recommended decommissioning and post-closure monitoring and mitigation measures are provided in Table 12.15.

Table 12.15. Post-closure measures

Monitoring/mitigation measure	Validity	Range
Maintain records of well location and depth indefinitely (AMEC, 2014) (see also measure N22, Project C)	Required for future environmental management	Well pad
Follow good practice during construction/deconstruction, including design for well decommissioning (AMEC, 2014)	Required for successful decommissioning	Well pad and associated infrastructure
Operator remains responsible for monitoring, reporting and corrective measures following well closure (or temporary well decommissioning) and prior to transfer of responsibility to competent authority (assume a minimum of 20 years) (AMEC, 2014)	Required for successful decommissioning	Well pad and associated infrastructure
Decommissioning survey: undertake assessment of underground wells and structures (AMEC, 2014) (see also measure 3d ix, Project C)	Required for successful decommissioning	Local area
Decommissioning survey: undertake survey of biodiversity, ecology and invasive species (AMEC, 2014)	Required for successful decommissioning	Local area
Decommissioning survey: undertake sampling of surface water bodies near the pad (AMEC, 2014) (see also measure 13d iii, Project C)	Required for successful decommissioning	Local area
Decommissioning survey: undertake sampling of groundwater near the pad (AMEC, 2014)	Required for successful decommissioning	Local area
Decommissioning survey: obtain data on drinking water abstraction points (wells, boreholes, springs, surface water abstraction points) (AMEC, 2014) (see also measure 13d iv, Project C)	Required for successful decommissioning	Local area
Decommissioning survey: undertake land condition (soil) survey around pad (AMEC, 2014) (see also measure 13d v, Project C)	Required for successful decommissioning	Local area
Decommissioning survey: undertake sampling for methane near the surface in the pad location (AMEC, 2014)	Required for successful decommissioning	Local area
Specific post-closure well inspection, maintenance and monitoring/reporting programme (every 90 days) including: • long-term leak detection • methane monitoring	Required for successful decommissioning in the long term	Well pad and associated infrastructure
Specific post-closure risk assessment, well plugging, inspection and monitoring requirements (e.g. for releases to air, well integrity, periodicity of inspections, wellhead monitoring every 90 days) for a period for be agreed with the relevant regulators (AEA, 2012a; AMEC, 2014) (see also measure N22, Project C)	Required for successful decommissioning	Well pad and associated infrastructure
Transfer ownership and liability to competent authority on surrender of permit to ensure long-term management (AEA, 2012a)	Required for successful decommissioning	Well pad and associated infrastructure

12.6 Other Measures

Other mitigation and monitoring measures are addressed in this document as follows:

- Mitigation measures relating to impacts on water resources are addressed in Chapter 5.
- Mitigation measures relating to potential impacts on surface water are addressed in Chapter 4
- Mitigation and monitoring relating to other additional potential impacts, including flora and fauna, air quality, land take, noise, traffic, human beings and community character, and agriculture and domestic animals, are addressed in Chapter 7.
- Mitigation measures relating to chemical usage are described in Chapter 9.
- Mitigation and monitoring relating to the best practice for environmental monitoring of potential impacts is set out in section 10.1.

In addition, the potential seismic impacts are further discussed in Project A2 and the regulatory framework is discussed in Project C.

13 Summary and Conclusions

13.1 Overview

Project B of the UGEE JPR involved the assessment of the impacts and mitigation measures for UGEE projects and operations: The objectives of Project B included the following:

- identification and detailed evaluation of the potential impacts on human health and the environment associated with UGEE projects and operations; and
- identification and evaluation of successful mitigation measures of the potential impacts.

The nine tasks addressed by the project and this report are:

- Task 1: Impacts on Environmental Water Quality and Mitigation Measures (Chapter 4);
- Task 2: Impacts on Water Resource Use and Mitigation Measures (Chapter 5);
- Task 3: Recycling and Reuse of Flowback and Produced Waters (Chapter 6);
- Task 4: Other Additional Potential Impacts and Mitigation Measures (Chapter 7);
- Task 5: Life Cycle Assessment (Chapter 8);
- Task 6: Chemical Use, Impacts and Mitigation Measures (Chapter 9);
- Task 7: Treatment and Disposal of Flowback and Produced Waters (Chapter 10);
- Task 8: Best Practice for Environmental Monitoring of Potential Impact – Linking Projects A1, A2 and A3 (Chapter 11);
- Task 9: Assessment of Existing and Potential Monitoring and Mitigation Techniques (Chapter 12).

Additional issues were also addressed as they were identified by the project Steering Committee and are incorporated within the body of the report.

13.2 Impacts on Environmental Water Quality and Mitigation Measures (Task 1)

The objective of Task 1 was to evaluate potential impacts (both positive and adverse) on water resources and to identify relevant mitigation measures associated with UGEE development and production. Specifically, Task 1 addressed potential impacts on the quality of water resources in the case study areas, and thus supplemented the assessment of Task 2, which addressed the impacts on available supply and quantitative aspects of water resources.

In Task 1, the potential impacts on water quality were evaluated in the context of the following activities:

- storm water runoff and run-on from utility corridors, road and pads;
- surface chemical spills and leaks during transport, storage at well pads, drilling and hydraulic fracturing;
- incorrect well construction, well completion and operation, including failures during drilling, hydraulic fracturing and production;
- pit, impoundment or tank leaks of on-site stored flowback water, produced water, drilling muds and cuttings; and

- leaks, spills or incorrect disposal of flowback water, produced water, drilling muds and cuttings during off-site treatment, transport and disposal.

The assessment methodology followed these basic steps:

- description of specific activities associated with UGEE and their potential impact on water quality (surface- and groundwater);
- description of potential impact sources and associated potential contamination (e.g. storm water runoff, additives, drilling muds, flowback water, produced water, etc.) on water resources (i.e. the source element in the source–pathway–receptor model of risk assessment);
- description of potential release scenarios that could have an impact on the quality of water resources (i.e. the pathway element of the source–pathway–receptor model of risk assessment);
- evaluation of the risks of potential impacts for each activity and release scenario, with respect to both potential human and potential environmental receptors (i.e. the receptor element of the source–pathway–receptor model of risk assessment);
- description of relevant management strategies and mitigation measures to minimise or eliminate risks of potential releases and their impact; and
- evaluation of cumulative impacts and associated risks.

The general conclusions concerning the impacts and mitigation measures were as follows:

- *Impacts from storm water runoff from road and pads*. Storm water runoff from well pads in the NCB and CB may vary from as low as 400 m^3 per month to as high as 5800 m^3 per month depending upon the time of year (high or low rainfall months) and stage of activity (during construction, fracturing or production). Likewise, the amount of runoff from new roads may vary from 400 m^3 per month per kilometre to as high as 1300 m^3 per month per kilometre. Storm water runoff in not unique to UGEE operations. Given the potential volumes of runoff estimated in Ireland and Northern Ireland from each pad and road, the storm water runoff mitigation measures typically available would significantly limit the potential impacts of storm water during UGEE projects and operations if implemented and maintained properly. However, even with state-of-the-art storm water controls, there are still risks with regard to accidental spills, unanticipated events (e.g. rainfall exceeding design capacities), inadequate designs and implementation and lack of proper maintenance. Therefore, there is still a need for appropriate regulations, approvals, oversight and inspections by regulatory bodies.
- *Impacts from surface chemical spills and leaks*. Despite the large range in the types and volumes of reported spills, and the associated uncertainties, the fact remains that spills will occur and operators must be prepared with appropriate responses and mitigation measures. Even with laws, regulations, approvals and best practices and techniques, spills and leaks will happen and therefore, regulatory oversight and inspections are needed.
- *Impacts associated with well construction, completion and operation*. Fluids associated with drilling and hydraulic fracturing operations represent potential sources of contamination in the groundwater environment. Natural gas constituents that are naturally present or are released as a result of hydraulic fracturing operations are also potential sources of contamination if they migrate to the near-surface environment via natural, induced or artificial pathways. Induced subsurface pathways result from the fractures produced during the hydraulic fracturing process conducted to release gas from the target formation. The propagation length of fractures must be controlled and minimum vertical separation distances between target formations and aquifers specified. In addition, hydraulic fractures associated with one well may propagate and intersect hydraulic fractures associated with a nearby well. Therefore the distance between hydraulic

fracturing operations and wells must be controlled and minimum distances specified. Overall, deep hydraulic fracturing is not likely to result in a direct flow pathway into shallow aquifers if adequate separation distances are maintained. The primary risk of impact on groundwater quality is stray gas migration from the gas production zone due to improper, faulty or failed production casing and/or poor or improper cement grouting of casing.

- *Impacts from impoundment and tanks leaks during storage and treatment of on-site produced wastes*. The records document the fact that spills of flowback and produced waters can be expected from UGEE-related activities and that the risks of impacts would reflect the care and adequacy of operations and case- and site-specific risks.
- *Impacts from spills during off-site transport of produced wastes*. The overall risk of impact from transport-related spills of flowback and produced waters is considered to be low. This does not preclude the fact that a spill could result in an environmental impact.
- The planning and prior authorisation phase of UGEE-related activity is, arguably, the most important phase of UGEE development. Whereas implementation of prevention and mitigation measures safeguards against spills and leaks (and therefore potential impact), planning establishes rules, expectations and common understanding.

13.3 Impacts on Water Resource Use and Mitigation Measures (Task 2)

Task 2 addressed the potential impacts on water resources and associated mitigation measures.

UGEE projects require water for several purposes, including drilling operations, well construction, hydraulic fracturing, sanitation and equipment washing. Concrete plans for or details of any potential future UGEE projects and operations in either Ireland or Northern Ireland are as yet unknown; accordingly, the actual volumes of water that are needed for operations are uncertain. Case-specific circumstances would determine actual water demands at any given well pad. For guidance purposes, ranges of water requirements for UGEE projects and operations were researched from published international literature and applied to the specific characteristics of the study areas (e.g. depth of source formations, spatial distribution of well pads).

To assess the potential impacts on water resources, Task 2:

- defined the potential water requirements for UGEE projects and operations, with regard to the “probable commercial scenarios”, as set out in Chapter 2;
- described the water resources available in the two case study areas, based on analysis of hydrometric data obtained from relevant information sources and the conceptual hydrogeological models developed; and
- compared water requirements and available water resources, as a means of identifying potential impact.

The comparison is contextualised with respect to existing legislation and regulations that currently govern the technical assessment of future UGEE-related abstractions, as well as the metrics that are used by regulatory bodies in describing and reporting on the ecological status objectives of the WFD.

The general conclusions were as follows:

Lakes. Future risks of impact from UGEE-related lake abstractions under the various anticipated water demand scenarios are considered to be small, but this depends on how the water demands develop spatially and temporally. Volumetrically, the risks would be greater in small lakes than in large lakes. Site-specific, case-by-case studies must be conducted to adequately determine potential impacts and mitigation measures. This includes knowledge about ecosystems and related environmental sensitivities, as well as water balance studies that define inflow, outflow and throughflow.

Streams. The quick flashy nature of the streams' hydrographs, as well as the flat slopes of the low-flow section of available flow duration curves, imply that the majority of streams in the two study areas would be sensitive to stream abstractions. Therefore, prior authorisations of any future UGEE-related abstractions should be reviewed in the context of the catchment hydrological conditions on a case-by-case basis. In reality, it appears unlikely that the total water demand for UGEE-related activities can or would be sourced from a single catchment or stream. Abstractions that are concentrated in small areas within the same catchment can give rise to environmental concerns, especially during low-flow conditions.

Groundwater. The hydrogeological characteristics of the bedrock aquifers in the two case study areas are complex. The complexity and, often, the unpredictability of bedrock aquifers implies that well yields and influences of abstractions cannot be predicted with certainty without detailed studies. However, overall, groundwater abstraction pressures in the two study areas are low and in the context of the anticipated UGEE water demand scenarios, groundwater is a viable source of water to meet demands, at least in part. The ability to develop a sufficient supply to meet demands locally for UGEE activities would be subject to exploration and testing and may require multiple wells at multiple locations.

13.4 Recycling and Reuse of Flowback and Produced Waters (Task 3)

Task 3 investigated the current practices and technical aspects of recycling and reuse of flowback and produced waters, as described in Chapter 6:

- examples of current recycling and reuse;
- the regulations applicable to water reuse;
- limitations; and
- the costs of treating water for reuse.

The recycling and reuse of flowback and produced waters is an important development measure to reduce the impact of UGEE projects and operations on water resources. Water recycling and reuse typically increases as UGEE production expands in an area, and flowback and produced waters become available for nearby additional well developments. In particular areas of the USA, up to 90% of the flowback and produced waters are reused for hydraulic fracturing. Technical advances in the properties of hydraulic fracturing fluids have resulted in less stringent requirements for reuse (e.g. waters with a high dissolved solids content can be used). These advances mean that produced waters require less treatment before they can be use as hydraulic fracturing fluids. However, the ability to recycle and reuse flowback or produced waters may be limited by current regulations in Ireland and Northern Ireland (e.g. not all chemical additives would be removed from the flowback water).

13.5 Other Additional Potential Impacts and Mitigation Measures (Task 4)

Task 4 examined the impacts of UGEE projects and operations on other areas not specifically addressed in other sections, such as the evaluation of impacts of and mitigation measures for water quality and resources outlined in Tasks 1 and 2.

The newly amended EIA Directive (2014/52/EU) entered into force on 15 May 2014 and simplifies the rules for assessing the potential effects of projects on the environment. The new approach results in greater attention being given to threats and challenges that have emerged since the original rules came into force some 25 years ago, such as climate change.

To support the identification and assessment of significant effects as part of an EIS, should a potential UGEE project proceed to that stage, the potential environmental impacts, and associated mitigation measures, due to UGEE projects and operations described as part of this task include the following:

- flora, fauna and biodiversity;
- air quality;
- greenhouse gas emissions;
- landscape and visual amenity;
- material assets and land use;
- archaeology and cultural heritage;
- noise;
- traffic;
- human beings and community character;
- agricultural and domestic animals; and
- interactions between the foregoing.

A full EIA, including a comprehensive and detailed assessment of impacts, can be carried out only at the project proposal and specification stage when proposed project details are available. However, many of the potential impacts assessed in Chapter 7 are similar to those managed in other greenfield construction projects, and it is worth noting that, in the majority of cases, there is a large body of knowledge with respect to the successful design and application of these measures. While assessment of potential impacts and associated mitigation measures at this stage is, by necessity, generalised, it is nonetheless estimated that most potential impacts range from imperceptible to moderate, depending on the proximity to receptors and the magnitude of cumulative impacts. One of the main areas assessed as part of Task 4 in which uncertainties are liable to remain relates to the quantification of long-term GHG emissions.

13.6 Life Cycle Assessment (Task 5)

Task 5 evaluated the life cycle environmental assessment of UGEE projects and operations using a literature review and experience from other jurisdictions and compared it with similar published assessments of other energy sources. LCA is a multi-step procedure for measuring the environmental footprint of materials, products and services over their entire lifetime, i.e. from “cradle to grave”.

The overall goal of an LCA is to compare the full range of environmental impacts in order to improve development and operations, support policy and regulatory needs and provide a basis for decision-making. The process is naturally iterative, as the quality and completeness of information and its plausibility is constantly being evaluated and tested.

Published estimations of GHG emissions were reviewed for the activities associated with UGEE projects, such as transport of materials, drilling, flowback and production. There was significant variability in reported estimates, which are sensitive to process management practices and the variations therein. The well completion stage was found to be the most significant source of emissions of the assessed activities, followed by drilling and hydraulic fracturing. Effective implementation of mitigation measures relating to these activities would, therefore, have the most impact on overall levels of emissions. As for conventional sources of gas, emissions are dominated by combustion at the electricity generation plant, which typically represents around 90% of the total emissions impact; therefore, in terms of overall emissions, the implementation of mitigation measures would be limited in reducing overall levels of GHG emissions associated with energy production.

Existing LCA information and published assessments that focus on the examination and comparison of LCA that is relevant to UGEE processes were also reviewed.

The available data comparing UGEE-generated electricity with other methods of electricity generation through the comparison of 10 life cycle indicators were reviewed. The results were highly variable, depending on both the life cycle indicator under consideration and the method of power generation.

UGEE-generated electricity is reported to have a much greater impact than conventional gas on life cycle indicators such as human toxicity potential (2.9–4.4 times worse), marine aquatic eco-toxicity potential (2–5 times worse) and terrestrial eco-toxicity potential (13–26 times worse). However, this reported high impact is associated with the disposal of drilling waste to land (landfarming) in the jurisdictions considered, e.g. disposal of drilling waste to land accounts for 65% of the marine aquatic eco-toxicity potential, but it would not be permitted in Ireland or Northern Ireland.

UGEE-generated electricity was estimated to have a significantly reduced impact on other life cycle indicators, for example:

- The freshwater eco-toxicity potential associated with UGEE was estimated to be an order of magnitude lower than any of the non-gas technologies.
- The eutrophication potential was estimated to be between 2 and 13 times less, emissions were estimated to be significantly lower (41–49%) and the depletion of fossil fuels was estimated to be between 43% and 49% lower than that for coal power.
- The abiotic depletion of elements was estimated to be around 19–244 times lower than that for offshore wind.

13.7 Chemical Use, Impacts and Mitigation Measures (Task 6)

Hydraulic fracturing involves the injection of fluid under pressure to fracture the source formation. Hydraulic fracturing fluids contain chemical additives that are required for different purposes, such as to thicken fluids to increase their viscosity or to reduce the potential for corrosion of pipes and casings. The use of chemicals, particularly additives to hydraulic fracturing solutions, has been a major concern for the public, regulators and the scientific community in recent years. The primary concerns have been the use of chemicals that may have the potential to have an impact on human health and/or the environment through the contamination of groundwater and the large number of different chemicals used. In addition, much of the public concern has been around the lack of disclosure of the chemicals used in the past and the reluctance of UGEE operators to release what they consider to be commercially sensitive information concerning their additives. An evaluation of chemicals used in UGEE projects, including both hydraulic fracturing fluids and drilling fluids, was carried out in Task 6.

There are many potential pathways that lead to humans and/or the environment being exposed to chemicals, including chemical spills on site or potential underground contamination of groundwater. Task 6 specifically deals with the hazards of the chemicals and their potential for causing harm in the event of humans and the environment being exposed to them; the pathways and potential impacts on surface waters and groundwater are examined in greater detail in Chapter 4 (Task 1).

The hazard classifications of the chemicals were assessed, based on existing European legislation. The existing regulatory framework for the management and classification of chemicals is presented, as well as the existing requirements for chemical disclosure. For further analysis on the regulatory framework for UGEE projects, refer to the outputs of Project C of the UGEE JRP, which is designed to assist regulators (in both Ireland and Northern Ireland) in fulfilling their statutory roles.

There are currently no regulations in Ireland or Northern Ireland for the public disclosure of chemicals used in UGEE operations. In their *Well Guidelines for the Exploration and Appraisal Phase*, UKOOG (2015a) have recommended that the following information is disseminated on a well-by-well basis:

- any authorisations for fluids and their status as hazardous or non-hazardous substances;
- information from safety data sheets;
- volumes of fracturing fluid, including proppant, base carrier fluid and chemical additives;
- the name of each additive and its purpose in the fracturing process; and
- maximum concentrations in percentage by mass of each chemical additive.

The UK Environment Agency and the Scottish Environment Protection Agency,[35] however, have powers to obtain full disclosure of the chemicals used in hydraulic fracturing (DECC, 2013b) and therefore it is likely that the EPA and NIEA will have similar powers that they can invoke.

Chapter 9 also presents the findings of the review of emerging alternatives such as green (or environmentally friendly) and non-toxic chemicals, as well as the viability of chemical-free hydraulic fracturing. This review was based on existing peer-reviewed articles and reports. There are a few examples of fracturing processes that do not use chemicals or certain groups of additives; however, studies concluded that these non-chemical fracturing processes are not sufficiently mature and that much more research will be required before fracturing fluids that do not rely on chemical additives are commercially viable. In addition, it should be noted that eliminating the use of chemicals in hydraulic fracturing fluids does not eliminate the risks from the produced water and its potential pathways through the rock formations etc.

13.8 Treatment and Disposal of Flowback and Produced Waters (Task 7)

The disposal and treatment of UGEE flowback and produced waters are major concerns. Task 7 identified and assessed the success of treatment and disposal methods for flowback and produced waters and provided case studies from around the world, with specific reference to European examples. Linking with Task 6 (Chapter 9), Task 7 also identified the treatment technologies available to adequately treat the chemicals typically used in the fracturing process in combination with the compounds likely to be found in produced water. Disposal options linked to the available treatment options were also reviewed and assessed.

The current treatment and disposal methods for flowback and produced waters were evaluated by completing the following assessments:

- composition of flowback and produced waters;

35 The Environment Agency requires full public disclosure, whereas the Scottish Environment Protection Agency requires disclosure to it but not to the public.

- Wastewater Discharge Regulations:
    - surface water discharge;
    - DWI disposal;
    - POTWs effluent;
- treatment and disposal alternatives:
    - municipal or city treatment plants (so-called POTWs in the USA);
    - regional or centralised treatment centres:
        - treatment and disposal to surface water (multiple processes);
        - treatment and disposal to DWI;
    - on-site treatment technologies:
        - treatment for recycling and reuse;
        - treatment and disposal to DWI;
    - description of treatment technologies that are components of the treatment schemes above:
        - oil and solids removal;
        - physicochemical treatment;
        - oxidation;
        - membrane technologies;
        - evaporators/crystallisers.

A review of case studies and operations of POTWs in the USA shows that flowback and produced waters cannot be adequately treated and discharged into streams without impacts on human health and the environment. As a result, several states in the USA have regulations banning the treatment of UGEE flowback and produced waters at municipal treatment plants (the USEPA has also proposed similar regulations). In Ireland and Northern Ireland, DWI would not a be viable disposal option for flowback and produced waters, based on current regulations, the absence of any permitted disposal wells and the need for technical information and evaluation, including evaluation of the hydrogeology of potential deep disposal formations. Overall, there are technologies that can adequately treat flowback and produced waters for reuse as hydraulic fracturing fluids or direct discharge into streams and lakes (i.e. current water quality standards in Ireland and Northern Ireland can be achieved). Based on the probable extent of UGEE development in Ireland and Northern Ireland, and the volumes of flowback and produced waters, the best management option is the use of centralised treatment facilities equipped with proper treatment technologies. One centralised treatment facility would be required in the CB (one lease area) and two to three facilities in the NCB (one per lease area, depending upon the timing of development). On-site treatment of flowback and produced waters at individual well pads using modular units would probably be implemented during initial development in the study areas until adequate volumes of water were produced to maintain centralised treatment facilities.

13.9 Best Practice for Environmental Monitoring of Potential Impact – Linking Projects A1, A2 and A3 (Task 8)

Subregional baseline monitoring is described in Project A1 of the UGEE JPR for groundwater, surface water and associated ecosystems, in Project A2 for seismicity, and in Project A3 for air quality. Task 8 co-ordinated the recommended subregional baseline monitoring programmes in Project A with baseline, operational and post-operational monitoring at the local scale in Project B.

The best practice and effectiveness of monitoring associated with individual UGEE sites are outlined, including the nature and timing of site-specific monitoring in relation to exploration, pilot tests and full-scale UGEE development, as well as operational and post-closure monitoring.

Environmental monitoring is needed before, during and after UGEE activities (exploration drilling, hydraulic fracturing and potential production) at both subregional and local scales. There are three types of environmental monitoring that relate to the different stages of UGEE activity, as follows:

- Baseline monitoring – monitoring conducted, prior to any construction or operations, to establish pre-existing environmental conditions.
- Operational monitoring – monitoring conducted during construction, drilling, hydraulic fracturing and production activities in order to identify and track changes from the baseline and determine whether such changes can be linked to a particular activity.
- Post-closure monitoring – monitoring conducted after completion of gas production, well decommissioning and site restoration to check for potential impact in the longer term and verify that mitigation measures have been effective.

In addition to the temporal aspect of monitoring, consideration of scale is also important. UGEE activity is site specific, thus monitoring at the scale of individual well pads and hydraulic fracturing operations is needed. However, UGEE activity also involves operations at several sites in a given region and therefore also has a larger footprint with the potential for cumulative impact. Accordingly, monitoring at the subregional scale is also needed.

13.10 Assessment of Existing and Potential Monitoring and Mitigation Techniques (Task 9)

Task 9 (Chapter 12) examined the validity and range of existing and potential monitoring and mitigation techniques including, but not limited to, geophysical techniques (downhole and surface) for use in monitoring, control, horizon selection and injection management. This chapter should be read in conjunction with the *Final Report 5* of the UGEE JRP (Task 4). Project C addressed the regulatory framework covering UGEE operations and reviewed the regulatory approach in five case studies.

Monitoring and mitigation measures were compiled from a literature review of measures and techniques being used or recommended for UGEE operations. These measures and monitoring techniques are not considered to be prescriptive in their scope and specifications, but they represent measures that may be considered in the specification of an operational management plan and environmental management plan.

The validity of each measure or technique was considered for its applicability to the contexts in Ireland and Northern Ireland, and the scale at which the measure applies. While in general there is not enough information to thoroughly evaluate the effectiveness of individual standalone mitigation measures, it was found that there is extensive documentation with respect to the management of risks, the effective mitigation of potential impacts and the specification of best practice.

However, in order to effectively and safely manage risks, a comprehensive, multi-pronged approach is necessary involving five distinct, mutually reinforcing elements (Council of Canadian Academies, 2014):

1. Materials, equipment, and products must be adequately designed, installed in compliance with specifications and reliably maintained.

2. Materials, equipment, and processes associated with the development and operation of UGEE sites must be comprehensively and rigorously managed to ensure public safety and reduce environmental risks.
3. An effective regulatory system based on sound science is required and UGEE developments must be strictly approved, monitored and enforced.
4. Drilling and development plans must reflect local and regional environmental conditions, including existing land use and environmental risks. Some areas may not be suitable for development, whereas others may require specific management measures.
5. Public engagement is necessary, not only to inform local residents about developments but also to identify what aspects of quality of life and well-being residents value most, in order to protect what is valued by local communities.

It is proposed that funding for post-closure monitoring is arranged through the provision of a bond by the developer, with a provisional monitoring programme set out for the first 5 years (quarterly at appropriate times of the year in years 1, 3 and 5), to be reviewed at 5-year intervals thereafter, pending review of results and agreement between the regulatory bodies and the developer.

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Abbreviations, symbols and units

µg/L	Micrograms per litre
3D	Three-dimensional
ADP-E	Abiotic depletion potential – elements
ADP-F	Abiotic depletion potential – fossil fuels
ALWS	Approved List of Water Sources
AMD	Abandoned mine drainage
AOPP	Advanced oxidation and precipitation process
API	American Petroleum Industry
ASSI	Area of Scientific Interest
Ba	Barium
bbl	Barrels
BMP	Best management practice
BMWP	Biological Monitoring Working Party
BOD	Biological oxygen demand
Bq/L	Radioactivity per litre
Bq/kg	Radioactivity per kilogram
BTEX	Benzene, toluene, ethylbenzene and xylene
BWA	Bulk Water Use and Management Approval
Ca	Calcium
$CaCO_3$	Calcium carbonate
CAFE	Cleaner Air for Europe (Directive)
CAS	Chemical Abstracts Service
CB	Clare Basin
CBL	Cement bond log
CFR	Code of Federal Regulations
CH_4	Methane
CLP	Classification, labelling and packaging
CMR	Carcinogenic, mutagenic and toxic to reproduction
CO	Carbon monoxide
CO^2	Carbon dioxide
COD	Chemical oxygen demand
CWT	Centralised waste treatment
DAF	Dissolved air flotation
DCENR	Department of Communications, Energy and Natural Resources
DECLG	Department of Environment, Community and Local Government
DEP	Pennsylvania Department of Environment Protection
DETI	Department of Enterprise Trade and Investment
DGF	Dissolved gas flotation
DIC	Dissolved inorganic carbon
DOC	Dissolved organic carbon

DRBC	Delaware River Basin Commission
DWI	Deep well injection
EC	European Commission
ECHA	European Chemicals Agency
EIA	Environmental Impact Assessment
EPA	Environmental Protection Agency
EQS	Environmental quality standards
EU	European Union
EUR	Estimated ultimate recovery
FAETP	Freshwater aquatic eco-toxicity potential
Fe	Iron
FIT	Formation integrity test
FO	Forward osmosis
GHG	Greenhouse gas
GSI	Geological Survey of Ireland
GSNI	Geological Survey of Northern Ireland
ha	Hectare
H_2O_2	Hydrogen peroxide
H_2S	Hydrogen sulfide
HTP	Human toxicity potential
IE	Ireland
IPCC	Intergovernmental Panel on Climate Change
IPPC	Integrated Pollution Prevention and Control
JRP	Joint Research Programme
K	Potassium
kg	Kilogram
km	Kilometre
L	Litre
lb	Pound (weight)
LCA	Life cycle assessment
LCIA	Life cycle impact assessment
Li	Lithium
LNG	Liquid natural gas
LOT	Leakoff test
LPG	Liquefied petroleum gas
m	Metre
m^3	Cubic metre
MAETP	Marine aquatic eco-toxicity potential
MMBTU	Million British thermal units
MCL	Maximum contaminant levels
MCPA	2-methyl-4-chlorophenoxyacetic acid
MD	Membrane distillation
MF	Microfiltration

Mg	Magnesium
mg/L	Milligrams per litre
MIT	Mechanical integrity test
MJ	Megajoules
mL	Millilitre
ML	Local magnitude (commonly referred to as ‘Richter magnitude’)
mm	Millimetre
Mn	Manganese
MPa	Megapascal
MRV	Minimum reporting values
MVR	Mechanical vapour recompression
Mw	Seismic moment magnitude
N	Nitrogen
Na	Sodium
NAF	Non-aqueous drilling fluids
NCB	Northwest Carboniferous Basin
NHA	Natural Heritage Area
NI	Northern Ireland
NIEA	Northern Ireland Environment Agency
NMVOC	Non-methane volatile organic compound
NO_2	Nitrogen dioxide
NO_3	Nitrate
N_2O	Nitrous oxide
NORM	Naturally occurring radioactive materials
NO_x	Oxides of nitrogen
NPDES	National Pollutant Discharge Elimination system
NPOC	Non-purgeable organic carbon
NPWS	National Parks and Wildlife Service
NYSDEC	New York State Department of Environmental Conservation
O_3	Ozone
ODNR	Ohio Department of Natural Resources
ODP	Ozone layer depletion potential
O&G	Oil and gas
PAH	Polycyclic aromatic hydrocarbon
PCB	Polychlorinated biphenyl
pCi/g	Picocuries per gram
pCi/L	Picocuries per litre
PM	Particulate matter
$PM_{2.5}$	Particulate matter less than 2.5 µm diameter
PM_{10}	Particulate matter less than 10 µm diameter
pNHA	Proposed Natural Heritage Sites
POCP	Photochemical ozone creation potential
POTW	Publicly owned treatment works

ppm	Parts per million
psi	Per square inch
PV	Photovoltaic
PVOH	Polyvinyl alcohol
Ra	Radium
REACH	Registration, Evaluation, Authorisation and Restriction of Chemicals (Directive)
RfD	Reference dose
RfV	Reference values
Rkc	Regionally important karstified limestone aquifer
RO	Reverse osmosis
SAC	Special Area of Conservation
SARA	Saturate, aromatic, resin and asphaltene
SO_2	Sulfur dioxide
SPA	Special Protection Area
SPZ	Source Protection Zone
SRBC	Susquehanna River Basin Commission
SVOC	Semi-volatile organic compounds
SWPPP	Storm water pollution prevention plan
t	Tonne
TDS	Total dissolved solids
TENORM	Technologically enhanced, naturally occurring radioactive material
THM	Trihalomethane
TIC	Total inorganic carbon
TOC	Total organic carbon
TSS	Total suspended solids
UGEE	Unconventional gas exploration and exploitation
UK	United Kingdom
UKOOG	United Kingdom Onshore Operators Group
UKTAG	UK Technical Advisory Group
UN	United Nations
USEPA	United States Environmental Protection Agency
UV	Ultraviolet
VDL	Variable density log
VOC	Volatile organic compound
WBF	Water-based fluid
WFD	Water Framework Directive
WHO	World Health Organization