Potential Environmental Risks from Surface Infrastructure Associated with Shale Gas Extraction by Hydraulic Fracturing

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Sarah Antoinette Clancy

Abstract

The possible development of a shale gas industry within England has raised concerns with regards to the potential impacts of surface infrastructure on the natural environment. The aim of this thesis was to assess and quantify some of these concerns, specifically those related to surface footprint, the potential for spills, and the possible long term implications a shale industry may bring.

The carrying capacity of the licence blocks over the Bowland Shale in northern England has been assessed using a variation on the Buffon's needle approach, with the average carrying capacity for a licence block found to be 26%. The carrying capacity of the land surface, as predicted by this approach, would limit the technically recoverable gas reserves for the Bowland Basin to 2.21 x 10^{11} m^3.

If the average license block was developed to its full potential, a lateral length of 1300 m would be the most probable optimal lateral length required to maximise recoverable gas reserves. This lateral length would generate an average carrying capacity of 12 wells per licence block, generating a technically recoverable gas reserve of 1200 x 10^8 m^3.

Using data from the US and comparator industries within the UK an estimated number of spills both onsite and offsite has been quantified. Based on data from the Texas Railroad Commission, a UK shale industry consisting of well pads with 10 laterals would likely experience a spill for every 16 well pads developed. Using milk tanker data, a well pad of 10 laterals would likely experience a spill for every 19 well pads developed.

From evaluating aerial imaging and performing fieldwork at conventional oil and gas well sites within the UK, surface and subsurface remediation of abandoned well sites was found to be insufficient.

Largely the results from this thesis indicate that the surface impacts of a shale industry are not unique and that existing industries pose similar risks. By assessing comparator industries mitigation strategies have been suggested to manage and mitigate against potential future concerns.

Declaration and copyright

I confirm that no part of the material presented in this thesis has previously been submitted by me or any other person for a degree in this of any university. Where relevant, material from work of others has been acknowledged.

Signed:

Sarah Antoinette Clancy

Date:

5th April, 2019

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Dedication

This thesis is dedicated to Jill Thackray, although no longer with us, I think of her often and remember all she taught me.

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Chapter 1:

Introduction

Potential environmental risks from surface infrastructure associated with shale gas extraction by hydraulic fracturing

1.1 Overview and project rationale

Advances in technological developments, such as horizontal drilling and hydraulic fracturing have enabled enhanced recovery of unconventional gas (Vidic et al., 2013). Within the US these recent developments have led to a rapid growth of shale gas production from negligible levels in 1990, to 475 km^3 in 2017 (Vidic et al., 2013; US EIA, 2018). With the success of shale gas in the US, other more densely populated countries, including several countries in Europe, for example England, have begun exploration for shale gas. With the potential development of a shale gas industry within the UK and the rest of Europe, a number of concerns have arisen with regards to the potential impacts on the natural environment (Cotton et al., 2014). To assess some of the environmental uncertainties associated with shale gas development within Europe, in 2015, the M4ShaleGas consortium (which this PhD project is part of) was established. The key objectives of the consortium was to gain a greater understanding of the potential environmental risks and impacts of shale gas exploration and exploitation, and how best these potential threats could be prevented and mitigated against. The M4ShaleGas consortium consists of 18 research institutions; each researching different potential risk areas associated with shale gas development. Due to a lack of peer-reviewed literature on the potential impacts from surface infrastructure associated with a UK (more specifically England) based shale gas industry, this thesis assesses the following: the potential land disturbance that could be incurred; the likelihood of spills and leaks both onsite and offsite; and the potential legacy and long term impacts from well sites. In addition, the impact of existing surface infrastructure and how the carrying capacity (how much land is available for new developments due the presences of existing infrastructure) and lateral length may limit the amount of technically recoverable gas reserves has been assessed.

1.2 Research review

1.2.1 Land disturbance

Unlike conventional wells (which generate oil and gas from the ground by conventional means and methods), the production of shale gas (an unconventional gas which is obtained from the ground using methods that are considered new and different) requires proportionately more wells to effectively deplete the resource rich shale formation, where only one well is required for conventional gas, often several dozen wells are required for shale gas (Chorn et al., 2014). Thus, landscape disturbance from shale gas developments is inevitable (Drohan et al., 2012). Land disturbance will vary depending on, amongst other considerations, the number of wells per pad (the area required for the borehole, drilling equipment, piping and storage), the well pad size, the well pad density (pads per area), horizontal lateral length, access roads and pipelines, and the specifics of the shale play that is being developed (Baranzelli et al., 2015). In addition, the carrying capacity of the surface, thus how much land is available for new developments due the presences of existing infrastructure limits the number of wells that can be developed. Furthermore, the pattern of land ownership, public engagement and development regulations may cause higher or lower densities of well pads.

1.2.1.1 Well pads

The direct spatial footprint of shale gas developments and thus the disruption at the surface consists of the well pad and the area required for access roads. In part, the number of wells on each pad defines the size of the well pad. In the US, in recent years, the mean and maximum number of wells per site has been increasing, this trend has been attributed to advancements in technology and an understanding that greater consolidation of infrastructure is more efficient and economical (Drohan et al., 2012). In Pennsylvania, Johnson et al. (2010) document a mean of two producing wells per pad, Drohan et al. (2012) reported over 75% of pads to have just one or two wells per pad, whilst Jantz et al. (2014) found a mean of 2.45 wells per pad. When including producing and permitted wells there was a higher mean of 4.67 wells per pad (Jantz et al., 2014). Jantz et al. (2014) focused on the more recently developed Bradford County, Pennsylvania, thereby giving a more recent picture of current development patterns and consolidation of infrastructure. Dale et al. (2013) comments that between 2007 and 2010, well pads had a mean of 3 wells per pad with a range of between 1 and 9 wells, whereas between 2011 and 2012 the mean number of wells per pad had increased to 6, with a range of between 1 and 12 wells. In the UK, Cuadrilla Resource Ltd., herein termed Cuadrilla, who are currently investigating potential shale gas production from the Bowland Shale in Lancashire, have stated that they intend to have 10 wells per pad (Regeneris Consulting, 2011). The UK's Institute of Directors (IoD) suggested two potential production development scenarios, one of which was based on the development of pads with 10 vertical wells and 40 laterals (four laterals per vertical well – Taylor et al., 2013). The US Inner City Fund (2009) summarised planning information requested by the New York Department of Environmental Conservation from three active Marcellus Shale operators and showed that a multi-well pad with 6 to 8 wells would be between 10000 m^2 to 23000 m^2, with a typical site being 19000 m^2. In 2011, Broderick et al. assumed Cuadrilla's well pad developments would consist of 10 wells on a 7000 m^2 well pad (Broderick et al., 2011). Whereas, Taylor et al. (2013) suggest future scenarios with shale gas pads of 20000 m^2. However, Cuadrilla were granted permission to develop surface works at their Preston New Road site in Lancashire of 26500 m^2, of which 16500 m^2 was to be a compacted crushed stone surface from which the drilling, hydraulic fracturing and flow testing activities were to be undertaken (Cuadrilla Bowland Ltd., 2014 –

Figure 1.1). The planning application for Cuadrilla's proposed Roseacre Wood site requested a well pad of 19000 m^2, whilst the total surface area disturbed would extend 65400 m^2 (Cuadrilla Elswick Ltd., 2014 – Figure 1.1). The literature based on the US experience shows that land disturbance from well pads can vary considerably, with the development of new technologies and the need for increased efficiency largely driving these changes. The above literature indicates the potential surface footprint from a shale gas site within the UK and thus the likely area of land that may be disturbed, however these are variable and have not specifically considered factors such the number of wells per site. In addition, there is nothing in the peer-reviewed literature that quantifies where and how many sites could be located over the Bowland Shale and the potential cumulative surface disruption if numerous sites were developed within the UK.

1.2.1.2 Access roads

When considering the surface footprint and land disturbance a potential shale gas industry would create, the area required for access roads also needs to be assessed. However, it is difficult to review the additional footprint required for well site access roads in the US as many researchers have not distinguished between the area required for general infrastructure (e.g. pipelines and storage ponds etc.) and the area specifically required for roads. However, Jantz et al. (2014) made this distinction and found the mean additional area for access roads within Bradford County, Pennsylvania, to be 12000 m^2, with a range of 200 m^2 to 68000 m^2. Jiang et al. (2011) recorded a lower average of 5800 m^2, with a range of 400 m^2 to 11100 m^2 for wells developed in the Marcellus Shale. Access road widths generally range from 6 m to 12 m during the drilling and fracturing phase and from 3 m to 6 m during the production phase (NYS DEC, 2015). Research shows that for every 46 m by 9 m access road, ~400 m^2 is added to the total well site surface acreage (NYS DEC, 2015). Permit applications for Marcellus horizontal wells prior to 2009 recorded road lengths ranging from 40 m to approximately 900 m (NYS DEC, 2015). Within the planning application for the Preston New Road site in Lancashire a 173 m access track was applied for (Cuadrilla Bowland Ltd, 2014). If a shale gas industry was to go ahead in the UK the length and width of the access roads required would vary and would largely depend on where a well site was to be developed. Currently there is nothing written in the peer-reviewed scientific literature estimating the potential surface disruption from access roads associated with a UK based shale gas industry.

1.2.1.3 Setback distances

The physical footprint of the well pads and access roads do not necessarily represent the entire surface area required for shale gas developments as many regulatory bodies have proposed setbacks from the edge of the actual well pad that also need to be considered. Setbacks are defined as the distance that well pads have to be away from existing infrastructure, and although they do not involve the land being physically disturbed, they are enforced to provide additional protection to water resources, personal and public property, and the health and safety of the public (Eshleman and Elmore, 2013). England and several other European countries have no legislative or planning policy requirements on minimum setback distances; they are designated on a site by site basis (Cave, 2015). In the US, restrictions vary from state to state and are often based on local conditions such as population density (Richardson et al., 2013). Of the 20 sites surveyed in Richardson et al. (2013), 65% have building setback restrictions ranging from 30 m to 305 m from the wellbore, with an average of 94 m. Fry (2013) highlights the wide range of setbacks from 26 municipalities, and concludes that the minimum and maximum setback distance from residential properties are 91 m to 457 m. However, 46% of the municipalities studied had a residential setback of 305 m (Fry, 2013). In the State of Illinois all setback distances are taken from the edge of the well pad, with the required distance from any residence, place of worship, school, hospital, licensed nursing home, water well or property line, being 152 m (Illinois Department of Natural Resources, 2014). In addition, well sites have to be: 91 m from a stream, river or lake; 229 m from a nature park; and 457 m from surface water or groundwater intake of public water supply (Illinois Department of Natural Resources, 2014). In Colorado the minimum setback distance from a building, public road, and railway line is 61 m. However, the setback distance required from a high occupancy building (school, hospital) is 305 m (State of Colorado Oil and Gas Commission, 2013; State of Colorado Oil and Gas Commission, unknown). It is not stated if these values are from the borehole or the edge of the well pad. In the State of Maryland the suggested setback distance an occupied building has to be from a borehole is 305 m (Eshleman and Elmore, 2013). There is a lot of literature written about setback distances in the US; however there are no peer-reviewed scientific papers or development scenarios that consider setbacks distances and how they might impact well pad location and spacing, or access to shale gas reserves within the UK.

1.2.1.4 Subsurface footprints

Surface footprint should be considered alongside the subsurface footprint. Geology, planning permits and legal requirements, along with the current onshore drilling technology, limits lateral well extent, and therefore the well pad spacing (NYS DEC, 2015). The 2016 US Energy Information Administration report indicates that since the development of unconventional plays lateral lengths in the US have evolved from typical lengths of 300 m to 3050 m (US EIA, 2016). However, annual rates of increase are slowing, possibly due to limitations imposed by leases, drilling unit sizes and configuration (US EIA, 2016). Generally the longer a single horizontal well, the larger the subsurface area being accessed, providing greater wellbore contact with a larger volume of reservoir rock enabling more gas to be extracted (Fisher et al., 2004).

A lateral length of 2000 m was predicted in Taylor et al. (2013) UK development scenarios and the environmental statement for the Preston New Road site also states that the proposed laterals could extend up to 2000 m (Cuadrilla Bowland Ltd., 2014). The hydraulic fracture plan for the Preston New Road site proposes lateral lengths of 782 m (Cuadrilla Resources, 2018a). However, the first horizontal well drilled at the Preston New Road site in April 2018 reached a depth of 2700 m and ran laterally into the lower Bowland Shale rock for 800 m (Cuadrilla Resources, 2018b). The second horizontal well at the Preston New Road site was completed in July 2018 to a depth of 2100 m and extended laterally through the upper Bowland Shale for some 750 m (Cuadrilla Resources, 2018b).

The Maryland Department of the Environment indicates that spacing multi-well pads in dense clusters located as far apart as is technically feasible makes maximum use of horizontal drilling technology and could minimise the surface footprint (Eshleman and Elmore, 2013). Composite Energy (cited in Broderick et al., 2011) estimates laterals of 1 to 1.5 pads per 1 km^2 should be sufficient in a UK setting. However, even spacing of well pads is often impossible, as it does not account for geology and above ground constraints, such as existing infrastructure (Broderick et al., 2011). There is nothing in the peer-reviewed scientific literature or any of the UK based shale gas industry development scenarios that include the potential variability of lateral length and how this may impact technically recoverable reserves.

1.2.2 Carrying capacity

In sparsely populated countries, such as the US, many shale gas sites have been developed in close proximity to each other on rural and forested land, largely infrastructure free (Drohan et al., 2012). Within densely populated countries such as UK, the carrying capacity of the land (Clancy et al., 2018a) and competition for land with other uses are important factors to consider as they restrict the amount of gas that could be extracted (Baranzelli et al., 2015; Drohan et al., 2012). That is, one needs to study the well pad size and where it, with its corresponding setbacks and subsurface laterals can actually be located within an area heavily populated with existing infrastructure.

There are few studies that assess current and likely future footprints of shale gas sites within Europe (Baranzelli et al., 2015) and the US (Drohan et al., 2012; Racicot et al., 2014; Johnson et al., 2010; Martinez and Preston, 2018) and their impact on the land. However, Racicot et al. (2014) reported on the site location limitations due to surface carrying capacity within the regional county municipalities of Bécancour and Lotbinière, near Quebec. Racicot et al. (2014) considered how many shale gas sites can be located within the area for two scenarios: the first scenario factored in the regulatory setback distance gas wells have to be from certain land cover features and ecological areas; the second scenario included increased setbacks from important environmental and ecological areas (deer parks, maple woodland and wetland). Although gas exploitation was not prohibited in these important ecological areas, societal acceptability of drilling within such ecosystems would be low and the potential environmental impact high (Racicot et al., 2014). The spacing of pads in Racicot et al. (2014) scenario was set to one pad per 2600000 m^3, using these parameters in the areas free of constraints (approximately 54% of the 1400 km^2 study area) the number of well pads that could potentially be located within the area varied from 175 (scenario 1) to 234 (scenario 2). Both scenarios would impact large areas of core forest, with the number of forest patches increasing by 13 - 21% due to fragmentation (Racicot et al., 2014).

Prior to the work carried out in this thesis there were no studies in the peer-reviewed scientific literature that assess the likely limitations due to existing infrastructure for a UK based shale gas industry. However, it has been suggested in a report by UKOOG (2016) that between 7 and 11 production pads would likely be developed within a typical 10 km by 10 km licence block, this is based on the idea that a well pad will have 10 laterals per well pad, draining an area of 6.5 to 10 km^2 but this does not specifically account for existing infrastructure. Thus, there is a lack of understanding as to how many sites could actually be developed within the UK, or more specifically England and the cumulative disruption this may cause to the surface.

1.2.3 Spills and leaks

1.2.3.1 Fluid associated with hydraulic fracturing

The rapid growth in shale gas produced within the US and the potential developments within the UK have raised environmental concerns, such as the impact from spills of fluids associated with the industry (Cotton et al., 2014). The process of hydraulic fracturing involves high-volume fluid injection of fracturing fluid into a shale reservoir at a sufficient rate to raise downhole pressure above the fracture pressure of the formation rock, when the shale is pressurised fissures and interconnected fractures are formed enabling greater flow rates of gas into the well (Gregory et al., 2011; Wilson et al., 2017). Once the hydraulic fracturing processes are performed, the pressure is relieved and the fracturing fluid returns to the surface through the borehole, the returning fluid is termed flowback fluid (Gregory et al., 2011).

Within the US, fracturing fluids (also called fracking fluid) are typically composed of about 90% water, 9% proppant (e.g. sand), and 0.5 – 1% chemical additives (McLaughlin et al., 2016; Vidic et al., 2013). Chemical additives include, gelling agents (to increase viscosity of the fracking fluid), crosslinkers (to maintain fluid viscosity), friction reduces (to reduce interfacial tension between the fluid and borehole), breakers (to reverse crosslinking after fracking has occurred), pH adjusters (increase effectiveness of polymers and crosslinkers), acids (to clean borehole), corrosion inhibitors, scale inhibitors, iron controllers, clay stabilizers and biocides (Ferrer and Thurman, 2015), these are generally delivered to the well site in a concentrated form and stored until they are mixed with the base fluid and proppant and pumped down the production well (USA EPA, 2016). Within the US additives are often stored in multiple, closed containers and moved around the site in specially designed hoses and tubing (USA EPA, 2016).

Flowback fluid is typically highly saline, reaching up to five times the salinity of sea water (Gregory et al., 2011). It can also contain high concentrations of heavy metals, fracking chemicals, naturally occurring radioactive materials and hydrocarbons extracted from the formation (Edminston et al., 2011). Flowback water and produced water have been found to contain high volumes of total dissolved solids, largely comprising of Na and Cl, with elevated concentrations of Ca, Fe, Mg, and Sr (Flynn et al., 2018). Trace elements such as Se, As and Ba have also been found in flowback and produced waters from North America (Flynn et al., 2018). The volume of flowback that returns to the surface is variable, with between 10 – 50% of the fracturing fluid returning to the surface (Akob et al., 2015) during the 'flowback period' (the first two weeks after hydraulically fracturing the rock) (Howarth et al., 2011). During the active gas production stage, aqueous and non-aqueous liquid continue to be produced in considerably lower volumes than the fracking and flowback fluids over the lifeti me of the well (known as produced water - Gregory et al., 2011). Typically within the US, flowback water and produced water flow from the well to onsite tanks or pits through a series of pipes or flowlines before being transported offsite via trucks or pipelines for disposal or reuse (USA EPA, 2016). Therefore, for the development and exploitation of shale gas resources there would be three types of potentially polluting liquids to consider: the fracking/ fluid, the flowback water, and the produced water. In addition, undiluted chemical additives also need to be considered.

In the US it is common for the majority of these potentially hazardous fluids (fracking fluid (also called fracturing fluid), flowback and production waters - Drollette et al., 2015; DiGiulio et al., 2011) to be transported considerable distances by truck on public roads to and from the drilling sites, this can lead to incidents and spillages on the road (Eshleman and Elmore, 2013). In addition to the risks associated with transport, as with other outdoor practises, well pad sites are exposed to extreme weather and environmental conditions (e.g. heavy rainstorms, severe windstorms, floods and freezing conditions) which can also lead to spills and leaks of potentially hazardous fluids on the well site (Eshleman and Elmore, 2013). Even with appropriately designed storage equipment for additives, blended hydraulic fracturing fluids, flowback fluids and produced water, spills could occur.

1.2.3.2 Onsite spills

Within the US a number of studies have considered the risk to the surface and subsurface environment from spills and leaks. Gross et al. (2013) examined the Colorado Oil and Gas Commission's database of incidents and found surface spills were associated with < 0.5% of the active wells. Drollette et al. (2015) found that groundwater near the Marcellus shale gas operations in north eastern Pennsylvania had been contaminated by diesel-range organic compounds via accidental release of fracturing fluid chemicals, derived from the hydraulic fracturing activities at the surface. DiGiulio et al. (2011) found leakages from storage and disposal pits were responsible for the high concentrations of benzene, xylenes, gasoline range organics, diesel range organics and total purgeable hydrocarbons found in shallow ground water around the Pavillion field in Wyoming. The US Environmental Protection Agency assessed data from nine state agencies, nine oil and gas production well operators, nine hydraulic fracturing service companies and determined 457 hydraulic fracturing-related spills occurred between January 2006 and April 2012 (USA EPA, 2015). More recently Patterson et al. (2017) considered spills from unconventional oil and gas wells, in Colorado, New Mexico, North Dakota and Pennsylvania from 2005 to 2014, recording that between 2 – 16% of wells reported a spill each year. Within the UK there have not been any studies published assessing the likelihood of spills occurring on a potential UK shale gas well site.

1.2.3.3 Spills offsite

Much of the US literature focuses on spill and leak incidents onsite, not those occurring offsite. The average multi-stage well in the US requires hundreds to more than a thousand round trips to transport equipment, chemicals, sand and water required for well development and hydraulic fracturing (Adgate et al., 2014; Muehlenbach and Krupnick, 2013). Muehlenbach and Krupnick (2013) found a significant increase in the total number of accidents and accidents involving heavy trucks in counties with a relatively large degree of shale gas development, compared to those counties with less (or no) development: they found one additional well drilled per month raised the frequency of an accident by approximately 2% and increased the risk of a fatality by 0.6%. The Texas Department of Transportation also noted that the influx of traffic from the development of the Permian Basin had generated an increase in the number of road traffic accidents: a 27% increase in roadway fatalities, trucks were involved in 7% of these reported crashes (Texas Department of Transportation, 2013). These studies did not consider the potential for spills and leaks from these offsite incidents. Nor did they compare to other industries, thus it is possible that there is nothing unique in the number of incidents and spills associated with a shale gas industry within the US and that it is comparable to other industries.

With the possibility of a shale gas industry emerging within the UK Goodman et al. (2016) determined the number of truck visits required over the lifetime of a single-well pad with 6 wells was between 4315 and 6590, and from this, the impact upon local air quality, greenhouse gas emissions and noise emissions. However, the number of incidents and spillages were not considered. Lacey and Cole (2003) used information from UK databases on vehicular flow of tankers, accident rate and the probability that an accident would result in a spill; from this they predicted the expected number of spills per year. Their analysis predict the likelihood of a spill which exceeds 150 kg of chemical load spilling on a 2 km section of road is once in 370 years, with a range of 75 to 1800 years. Similarly to onsite there have not been any peer-reviewed studies published that has assessed the likelihood of spills occurring during transportation to and from a UK shale gas well site.

1.2.4 Legacy

Surface disruption related to shale gas development is mainly caused by the construction of well pads, access roads and pipelines (Mitchell and Casman, 2011); however as a temporary industry once the well has reached the end of its life sites should be left in the same state they were found. However, there are a number of concerns that potential newly developed shale gas sites may not be remediated sufficiently and cause long term impacts on the natural environment. Mitchell and Casman (2011) comment that reclamation of the disturbed surface occurs in two stages: (1) shortly after a well begins production the size of the well pad is reduced and impoundments (if present) are removed; (2) once the site is abandoned and permanently taken out of production full reclamation then occurs. Prior to release of the location for other uses, operators are required to test for contamination, clean up if necessary, and restore the location to prior drainage patterns (Robertson and Chilingar, 2017). The main objective of full well site reclamation is to return the disturbed land to its original pre-disturbed condition.

Poorly remediated well sites and access roads may cause long term changes to the natural environment (Mitchell and Casman, 2011). For example, habitat fragmentation and soil erosion can occur; additionally equipment left onsite can also interfere with agricultural land use and threaten wildlife habitats (Mitchell and Casman, 2011). Drohan and Brittingham, (2012) specifically highlight the concerns surrounding soil during and following shale gas development. Drohan and Brittingham, (2012) indicate how the poor management of the soil matrix before and during reclamation of coal-bed surface mining in the US is known to limit reclamation success, indicating similar issues could arise from shale gas activities (Daniels and Zipper, 2010; Zipper et al., 2011). Additionally Jenner and Lamadrid, (2013) highlight that although reforestation of shale gas sites can occur, it can take up to 300 years to restore to a previous or natural state. Improperly closed or abandoned shale gas wells have also been reported to create risks to human health and safety, through potential air pollution, and surface and groundwater contamination (Speight, 2013; Mitchell and Casman, 2011).

Although there are no commercial shale gas wells currently operating within the UK, exploration wells are underway and procedures are in place as to how these and future sites should be remediated. Currently within England and Wales operators are required to present their well site restoration plans as part of the planning application to the Mineral Planning

Authority (DECC, 2013). These plans outline the actions the operators propose to take once operations have reached a conclusion (DECC, 2013). Once a well has been abandoned, the site has to be restored and return to the same or to a better state than prior to operations commencing (DECC, 2013). The Mineral Planning Authority is responsible for ensuring the wells are abandoned and the site is restored in an appropriate time frame (DECC, 2013). In some circumstances it may be appropriate to secure financial guarantees to confirm that appropriate restoration can be achieved should a company cease operating (DECC, 2013).

Third Energy, who are hoping to hydraulically fracture the Kirby Misperton 8 (KM8) well in Kirby Misperton, North Yorkshire (Figure 1.1), have developed a restoration plan for the site once operations have been completed, they indicate it will be a two staged approach: (1) restoration, and (2) aftercare and monitoring (Third Energy, 2017). Their restoration plans start with inspections of the sites surface aggregates prior to removal, if any surface contamination can be identified and if treatment is required this can be carried out either onsite or offsite (Third Energy, 2017). The remaining surface aggregate will be carefully removed for reuse offsite. The impermeable membrane will then be removed and the subsoils exposed and inspected for any localised contamination (Third Energy, 2017). If any is identified the contaminated area will be removed for subsequent offsite treatment and/or disposal at an Environment Agency permitted waste facility (Third Energy, 2017). To confirm no contamination has occurred soil samples will be taken, analysed and compared with soil samples taken prior to construction (Third Energy, 2017). The subsoil will then be deep tine cultivated in strips (Third Energy, 2017). As the topsoil may have degraded whilst being stockpiled onsite, the soils condition will be assessed and treated or if required replaced before being re-laid (Third Energy, 2017). The topsoil will be back-tipped from the stockpile and will be levelled to avoid the formation of depressions which could hold water (Third Energy, 2017). All topsoil areas within the site, including areas not affected by construction will be ploughed and cultivated to ensure that all stones, rubble, vegetation and other extraneous material larger than 75 mm in any direction are removed (Third Energy, 2017). Once the site has been restored to its pre-existing condition, monitoring schemes will be carried out to check air and water quality are the same as pre development levels (Third Energy, 2017). Cuadrilla, who are currently the only company that has hydraulically fractured a horizontal shale gas well in the UK had a similar approach to Third Energy when they restored the Preese Hall well in Lancashire and have stated similar procedures will take place at their other well sites (Preston New Road and Rose Acre – Figure 1.1) (Cuadrilla Elswick Ltd., 2014; Cuadrilla Bowland Ltd., 2014).

Within the US, State agencies typically administer the federal environmental regulations and are tasked with writing and enforcing their own regulations, governing nearly all phases of oil and gas operations (Robertson and Chilingar, 2017). As is possible in England and Wales, most states in the US require operators to post a bond or some form of financial security to ensure compliance, and also to ensure there are funds to properly plug the well once production ceases (Speight, 2013). However, due to the size of the bond it often only covers a small fraction of the site reclamation costs (Mitchell and Casman, 2011) regularly leading to sites being insufficiently remediated (Speight, 2013). Additionally, within the US there are issues with remediation not occurring and remediation occurring but not in an appropriate or sufficient manner. Ho et al. (2016) highlight that due to a lack of monitoring capacity in the US, a well that has been inactive for an extended period of time and is noncompliant with environmental standards may be allowed to remain in temporary abandonment or inactive status so that they can be reactivated when market or technology conditions improve, instead of being permanently plugged and abandoned. Often, however, these wells become abandoned (Ho et al., 2016). For example, in 2014 the Louisiana's Office of Conservation performed an audit of the inactive wells and found that 46.5% of the 11269 wells identified as having future utility had held that status for over 10 years (Ho et al., 2016). Of the 8682 abandoned wells, 22.8% had been in future utility status prior to becoming 'orphaned' (i.e. within Ho et al. (2016) an orphaned well is referring to a well that has no financially accountable owner). It is deemed an orphaned well and either undergoes decommissioning at the expense of the government or becomes abandoned (Ho et al., 2016). A well may become orphaned as it becomes inactive (resulting in an orphaned inactive well) or after it is temporarily abandoned, which results in an orphaned temporarily abandoned well (Ho et al., 2016). Well operators going bankrupt, or simply not found at the time a well requires decommissioning, is a principal reason for wells becoming orphaned (Ho et al., 2016). Orphaned wells are of concern because the remediation process often does not occur, thus wells are not plugged and the well site is not reclaimed as it should be. Orphaned wells are an issue as they are more likely than properly plugged 'abandoned' wells to cause negative environmental risks and human health impacts (Mitchell and Casman, 2011).

Orphaned wells and thus none remediated well sites are also an increasing problem in the Western Canadian provinces, with the potential liability of future wells being even greater. In Alberta, the number of orphaned wells grew from fewer than 100 to 3200 between 2012 and 2017. Dachis et al. (2017) states that of the roughly 450000 wells registered in the province of Alberta, approximately 155000 are no longer producing but are not yet fully remediated. One of the issues is companies are filing bankruptcy to avoid their liabilities thus leaving the well site remediation as a public obligation (Dachis et al., 2017). With a sector wide increase in bankruptcy, Dachis et al. (2017) suggest that the governments in Canada need to reform how they require firms to finance end-of-life well liabilities.

Within the UK, Davies et al. (2014) investigated 2152 UK onshore hydrocarbon wells, of the wells studied they found 33.7% were clearly visible (i.e. the well pad and associated equipment could be seen), 5.5% showed evidence of prior onsite drilling activity without the current presence of drilling production, drilling equipment or a well head, and 65.2% were not visible (Davies et al., 2014). With 5.5% of wells showing evidence of prior onsite drilling activity it is clear that within the UK there are issues with sites being inappropriately remediated.

A further concern related to potential shale gas sites not being appropriately remediated relates to the development of soil compaction. Despite little in the literature on well site remediation causing soil compaction and a subsequent increase in soil strength (which can then lead to lower crop yields) there are a number of studies on the impact of gas, water and oil pipeline installations on soil compaction in many parts of the world (Hamza and Anderson, 2005). Over a 35 year study period Batey (2015) found severe subsurface compaction due to pipeline installation in England and throughout southern and eastern Scotland. In Alberta, Landsburg et al. (1996) also found that pipeline construction caused changes in soil strength on pipeline right of ways. They found the majority of sites showed a decrease in soil strength on the right of way compared to the adjacent controls, though there were some increases. However, they indicated that for the majority of cases most differences, both increases and decreases, had disappeared one year after construction (Landsburg et al., 1996). Within Canada measurements of field-crop yields and soil properties of land traversed by the Sarnia-Montreal oil pipeline constructed between September 1975 and March 1976 indicated that pipeline installation detrimentally affected both crop yields and soil physical and chemical properties (Culley et al., 1981). The impact of soil mixing (top soil mixing with subsoil) and compaction was most dramatic on the right of ways that had medium to fine textured soils (Culley et al., 1981). In some locations crop yields on the right of ways were reduced by 50% for the first two years after installation (Culley et al., 1981). Smaller but significant yield reductions were still apparent four years after installation (Culley et al., 1981). Considerable height differences between midsummer corn and soybean were also apparent (Culley et al., 1981).

Ho et al. (2016) highlights that regulatory, environmentalists, academics and industry have concentrated heavily on the environmental consequences of oil and gas development from active wells rather than on those from inactive wells, or wells that have ceased production. As there are estimated to be over 2.6 million inactive wells in North America, and there is the possibility of large numbers of shale gas wells being developed in parts of the UK, there is a need to ensure wells are correctly remediated so the inactive well sites do not threaten the local ecosystems or cause long term environmental issues (Ho et al., 2016).

1.3 Study area

The lower Carboniferous Hodder Mudstone Formation and the Bowland Shale Formation (informally referred to as the Bowland-Hodder unit) is thought to be the most prospective shale gas play within the UK (Slowakiewicz et al., 2015) and is the main study area within this thesis (Figure 1.1). It is henceforward referred to as the Bowland Shale. The Bowland Shale comprises of Carboniferous organic-rich basinal marine shales which are located across a large section of central Britain (Andrews, 2013 – Figure 1.1). At the time of writing just one well (Preese Hall 1, Lancashire) has been hydraulically fractured within the Bowland Shale, a further two horizontal wells at the Preston New Road site in Lancashire have been drilled, with one of these having undergone hydraulic fracturing (Figure 1.1). Cuadrilla, who drilled these first three wells are planning to drill a further two at the Preston New Road site before the end of 2019. Also within the Bowland Shale the company Third Energy was granted planning permission to hydraulically fracture the Kirby Mispertson 8 (KM8) well located in North Yorkshire, it is thought this well will likely be hydraulically fractured towards the end of 2019 (Figure 1.1).

Despite the recent success of shale gas production in the US, future developments there and throughout the rest of the World remain unclear (Hammond and O'Grady, 2017; McGlade et al., 2012). There are many unanswered questions regarding the amount of gas-in-place and the recoverability of these resources (McGalde et al., 2012). The US has been subject to a number of shale gas resource and technically recoverable reserve estimates; however, these are often ambiguous and highly uncertain (McGalde et al., 2012). There is even greater uncertainty surrounding estimates for countries throughout the rest of the World that have yet to undergo shale gas development, generally once production experience is available, estimates become more reliable and robust (McGlade et al., 2013).

Since the start of exploration for shale gas in the UK there have been various predictions on the amount of shale gas resource and the technically recoverable reserves that are present. However, these are uncertain and difficult to constrain until more wells have been drilled and further analysis and sampling performed. The Department for Business, Energy and Industrial Strategy, BEIS (previously named Department of Energy and Climate Change - DECC) commissioned a British Geological Society report in 2010 which estimated that the Carboniferous upper Bowland Shale, if equivalent to the Barnett Shale of Texas, could potentially yield up to 1.33 x 10^{11} m^3 of shale gas (Andrews, 2013). In 2013, DECC estimated the resource (gas-in-place) for the total area (upper and lower units) of the Bowland Shale, to reflect the range of uncertainty they reported the various estimates in the form of a range, with a low, central and high estimate (Andrews, 2013). They estimated the total gas resource to be 2.33 x 10^{13} m^3 – 3.76 x 10^{13} m^3 – 6.49 x 10^{13} m^3 (Andrews, 2013). Cuadrilla believes there is 5.66 x 10^{12} m^3 of gas trapped in the shale rock within their licence area in the North West of England (Cuadrilla Resource, 2017). IGas announced in 2013, that their licenses over the Bowland Shale have gas-in-place of up to 4.8 x 10^{12} m^3, with a low and central estimate of 4.2 x 10^{11} m^3 and 2.9 x 10^{12} m^3 (IGas, 2013).

Figure 1.1: A map indicating the subsurface extent of the Bowland Shale and the location of the four key wells referred to in this study.

1.4 Research questions, aims and objectives

Given the lack of peer-reviewed literature on the potential impacts of surface infrastructure associated with a shale gas industry for the UK, the overarching aim of this study was to investigate key potential areas of concern and put them into context for a UK based scenario. To address this aim it is useful to answer the following specific research questions:

- Accessible resource estimates within the UK and much of Europe have not considered the carrying capacity of the surface or subsurface footprint and how well site placements are restricted by the current surface environment, e.g. proximity to domestic housing. It will not be possible to drill where these are located without substantial and potentially unacceptable disruption. Chapter 2 aims to determine the likely physical footprint of well pads and their associated setback distances if a shale gas industry were to be developed within the UK. Using these estimates, a better understand of the carrying capacity of the environment and the associated limitations on recoverable resources for the Bowland Basin have been calculated. In addition, to determine if the footprint required for a shale gas industry is unique comparisons have been made to other industries.

- Well pad spacing and optimal lateral length within the UK is key to limiting the surface impact of shale gas developments. Therefore, the aim of Chapter 3 is to determine the probable optimal lateral length for maximising technically recoverable gas reserves for the average licence block located over the Bowland Shale.

- Included in the perceived risk to water is the potential for polluting spills and leaks to contaminate land, surface water and groundwater, which if severe may lead to polluted fluid being exposed to humans and natural ecosystems (Eshleman and Elmore, 2013;

Vengosh et al., 2014). Based on our review there have been no studies published in the peer-reviewed scientific literature addressing the potential for spills and leaks, either onsite (on the well pad) or offsite (during fluid transportation), from possible hydraulic fracturing sites within the UK. Chapter 4 aims to assess the probability of spills occurring both onsite and offsite. In addition, this study aims to assess the volumes spilt and the underlying cause of spills in analogue developments to help generate mitigation strategies for potential future sites in the UK.

- Much of the published research concentrates heavily on the environmental consequences of oil and gas development from active wells rather than on those from inactive wells, or wells that have ceased production. With the possibility of large numbers of shale gas wells being developed in the UK, there is a need to ensure wells are correctly remediated so the inactive well sites do not threaten the local ecosystems or cause long term environmental issues. Thus the aim of Chapter 5 is to assess the level of remediation that is currently occurring on conventional oil and gas well sites and the implications of substandard remediation.

The Conclusion draws together all the analysis from the previous chapters to provide a summary of the key findings, and suggests areas for further work.

Chapter 2:

An assessment of the footprint and carrying capacity of oil and gas well sites: The implication for limiting hydrocarbon reserves[1]

2.1 Introduction

The development of a shale gas industry requires the construction of well pads and associated infrastructure, the development of these sites leads to land disturbance which is a considerable concern raised by the public (Drohan et al., 2012; UKOOG, 2016). The aim of this chapter was to determine the likely surface footprint a potential shale gas industry would generate and its impact on existing infrastructure (e.g. roads, buildings), the carrying capacity of the environment, and how the proportion of technically recoverable gas may be limited. To measure if the impact on the land is unique to the shale industry surface footprints from other industries have been assessed as a comparison. From assessing mitigation methods used in the literature and other comparator industries mitigation strategies to reduce the surface footprint have been developed.

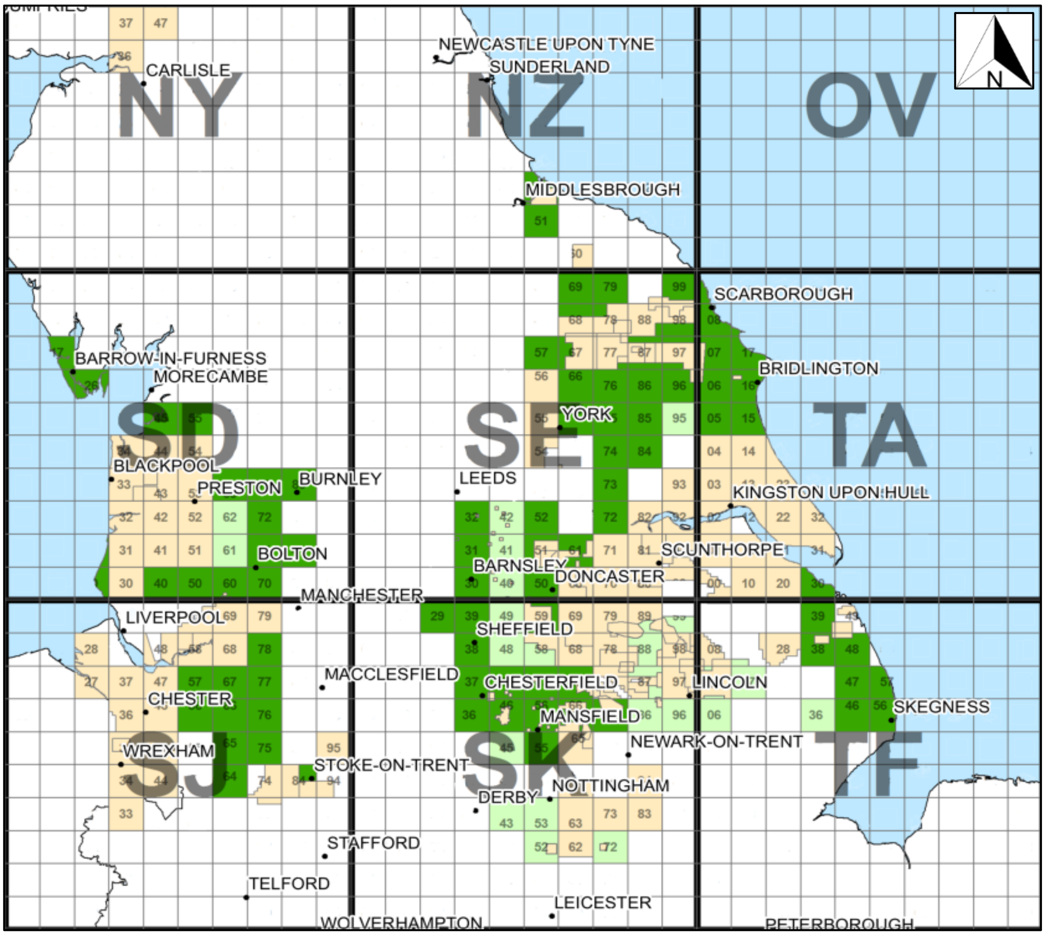
2.2 Approach and methodology

To determine the carrying capacity of the land and the impact this has on restricting recoverable resources over the Bowland Shale, the potential direct and indirect surface and subsurface footprint for a likely shale gas development within the UK have been estimated. Information has been drawn from the US (unconventional wells) and analogues within Europe (conventional wells in the UK, The Netherlands and Poland). At the time of writing, 127 licence blocks over the Bowland Shale are licenced to various operators (Figure 2.1), for this study 20

[1] This chapter is based on a paper that has been published in the journal Science of the Total Environment: Clancy, S. A., Worrall, F., Davies, R. J., Gluyas, J. G., 2018. An assessment of the footprint and carrying capacity of oil and gas well sites: The implications for limiting hydrocarbon reserves. Science of the Total Environment 618: 586-594.

of these blocks have been assessed. Comparisons to other types of currently operating industries such as wastewater treatment works and petrol stations have been undertaken to assess whether the likely footprint from well pads represents an impact unique to shale gas extraction.

Figure 2.1: A section of the north of England showing blocks offered under the 14th Onshore Licensing round (Oil and Gas Authority, 2016b). The cream blocks indicate the 127 currently licensed onshore blocks over the Bowland Shale.



2.2.1 Footprint of conventional onshore hydrocarbon operations within Europe

The onshore conventional well pads of the UK, The Netherlands and Poland were selected for study as the data was comprehensive and publicly accessible. Additionally they represented a range of conventional onshore development styles in countries at varying stages of shale gas exploration. All 2193 wells drilled onshore in the UK were analysed (Oil and Gas Authority, 2016a).

For The Netherlands, 426 of the 4307 onshore wells have been studied (Geological Survey of the Netherlands, 2016). To ensure an unbiased selection, well sites were selected using the stratified random sampling technique; the known wells were considered by their spatial distribution within the 12 Dutch provinces and listed in order of spud date (the date drilling of the well began) before a proportional number from each province with varying spud dates was randomly selected. Of Poland's 8076 onshore wells, 802 were analysed (Polish Geological Survey, 2016). However, due to less readily accessible data in Poland compared to the UK or The Netherlands a different selection process was used; the first 802 onshore wells that were listed on the Polish Geological Survey database being selected.

The direct well site footprint has been defined as the land required for the borehole, drilling and fracturing equipment, storage facilities, and the additional land required for noise and visual barriers such as hedges. For each country, aerial imaging and the Google Earth polygon and ruler tools were used to measure the perimeter and area of each site to obtain the direct footprint. The measurements were then divided by the number of wells per pad to calculate the average area required per well. Where possible additional access road measurements were included (existing roads were not). Access roads were defined as purpose built extensions to existing roads which were solely built to allow for well site access.

The majority of the Google Earth imagery was taken between 2005 and 2015 and of good quality. Where ambiguity in the well site measurements arose (due to issues such as photographic resolution, seasonal cover etc.), they were categorised by reliability. A quality classification system was not used for the access road measurements. In cases where identification was ambiguous measurements were not taken. The well site reliability categories are as follows:

Strong indication: Very clear indication of well site location, no or little ambiguity in defining well site boundaries (Figure 2.2a).

Poor indication: Fairly good indication of well site location. One was relatively confident on defining an accurate perimeter.

Very poor indication: Some indication of a well site being present at some point e.g. (1) well shape patches of field discolouration (Figure 2.2b); (2) a clear patch of woodland or a pond in dense woodland the same shape and size of a well site (Figure 2.2c).

No indication: No well site present or evidence of one having been there.

To ensure a sufficient number of well sites were measured from Poland and The Netherlands the results were bootstrapped. This random sampling technique allowed the confidence in the sample number to be assessed. The bootstrap approach re-samples the current sample and measures how summary statistics vary upon re-sampling as a means of judging the adequacy of the overall sample. By re-sampling 100 measured well sites in groups of 10 the properties of variance have been evaluated and the level of confidence in the sample size determined.

Figure 2.2a: Kirby Misperton 1, 3 and 7 are example of wells with a 'strong indication' of where the well pad boundaries are located (image extracted from Google Earth Pro, 2016). There is little ambiguity as to the boundary location. Site location: latitude 54.2003 and longitude -0.81946.

Figure 2.2b: Castletown 1 well, an example of a well with a 'very poor indication' of where the well pad was once located (image extracted from Google Earth Pro, 2016). The field discoloration clearly indicates where a well site used to be present. Site location: latitude 53.054 and longitude -2.849.

Figure 2.2c: Northwood 1 well, an example of a well with a 'very poor indication' of where a well pad was once located (image extracted from Google Earth Pro, 2016). The pond in the woodland is the same size and shape as a well site indicating where it once was. Site location: latitude 52.974 and longitude -2.235.

Figure 2.2a

Figure 2.2b

Figure 2.2c

2.2.2 Impact of well sites and setbacks on the land in the UK

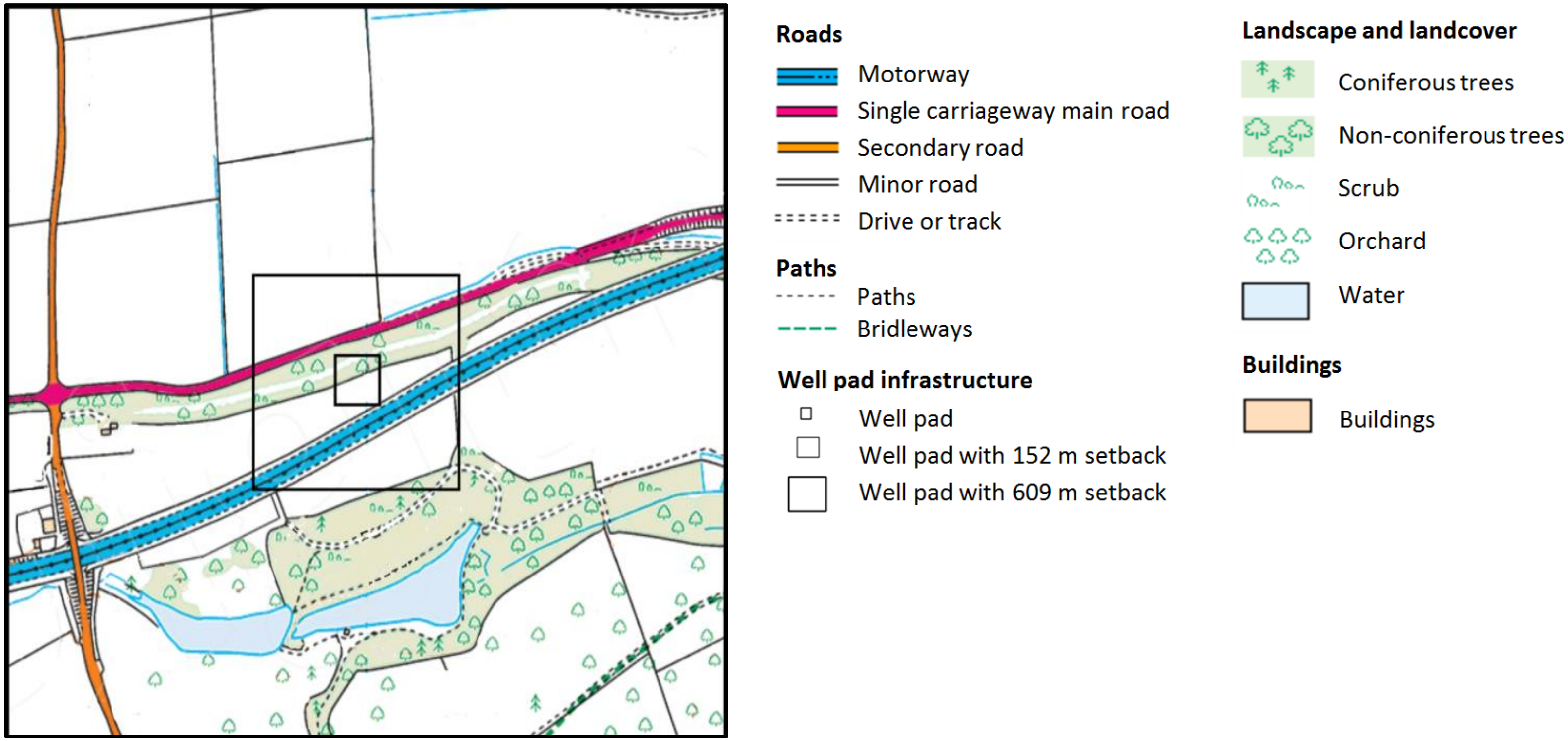
Two of the setback distances suggested for the State of Maryland shale gas developments were used for the purpose of the analysis in this chapter; a 152 m setback from the borehole for private wells, and a 609 m setback from the borehole to upstream public surface water supply intakes and public system wells. These were deemed suitable having been vigorously scrutinized before being recommended for use in the State of Maryland, with the 609 m being an end member, thus the largest setback distance recommended within the report. Whilst nearby states such as Pennsylvania went ahead with the exploration and production of the Marcellus Shale, Maryland had an unofficial moratorium on shale gas development, carefully considering whether exploration could go forward safely (Eshleman and Elmore, 2013). After much assessment of neighbouring states, reviews of current unconventional shale gas development regulations and best management practises, visits to well sites, and an assessment of the available literature, the setback values suggested were determined to be acceptable (Eshleman and Elmore, 2013).

To assess the impact of well pads developed on the UK landscape this study employed a variant of the Buffon's needle approach (Ramaley, 1969). A well pad (as measured above) and its associated setbacks (as taken from State of Maryland developments) were randomly placed into the currently licensed blocks covering the Bowland Shale, then the probability that the direct and indirect footprint enclosed or crossed a feature of interest was calculated (Figure 2.3). This study considered 100 randomly placed well pads based upon the suggested size of the UK industry (Taylor et al., 2013). The license block and the x and y coordinates within that block were randomly generated. The impact on different land types and existing infrastructure were recorded based on their importance as ranked below:

- **Mild (easily movable)**: fields, hedgerows and footpaths.
- **Moderate (movable but with some challenges)**: woodland and tracks.
- **Considerable (movable but extremely challenging)**: roads, railway lines and buildings.
- **Immovable (impossible to move)**: protected ponds, streams and rivers.

To assess if the sample of 100 well sites was an adequate sample size, a bootstrap analysis was performed on the results.

Figure 2.3: An example of a random drop site from the Buffon's needle analysis (map extracted from Digimap, 2016). At this locality, one can see that the well pad with a 609 m setback converges with fields, woodland, footpaths, houses, ponds and several major roads.



2.2.3 Wells per licence block

To determine the carrying capacity of an area for shale gas development the number of well pads and associated setbacks it would be possible to place within a licence block without impacting existing infrastructure or compromising access to the resource was assessed. A licensed block covering the Bowland Shale (Figure 2.1) was selected using the uniform random distribution technique, and then the number of well pads that could be placed into that block with the recommended setbacks was calculated. The recommended setback of 152 m from the borehole determines the indirect surface footprint on the land; it generates a total indirect surface footprint of ~92400 m^2.

The subsurface footprint together with the surface footprint was included in the assessment of carrying capacity. The former was determined by the lateral extent of the horizontal wells: this initial study (expanded in Chapter 3) deemed a 500 m lateral a realistic initial projection for new UK developments, generating a subsurface footprint of 1 km^2. To assess the carrying capacity with respect to the subsurface the number of 1 km^2 sites that could fit into 20 of the 100 km^2 licence blocks without overlap or disruption of surface infrastructure was counted. Of these 20 license blocks, 15 were randomly selected using the uniform random distribution technique, thus the licence blocks were numbered, randomised and then using a random number generator a number (block), was selected and assessed. Whilst five licence blocks were chosen on the basis that they represented end members of the number of sites that could be located within a licence block, these were identified from visually assessing the license blocks with the most and least infrastructure present. To assess if 20 random sites were sufficient to characterise the population a bootstrap analysis was performed on all of the results, resampling in groups of five. From these results a number of shale gas development scenarios were generated based on the physical number of well sites each block can sustain, assuming all 127 currently leased licenced blocks were developed.

2.2.4 Conventional well setbacks

Two of Eshleman and Elmore (2013) recommended setbacks were used in this study. To determine if these were realistic current acceptable setbacks from producing conventional well sites within the UK were measured. Using aerial photographs, the setback distances of 121 producing well sites were measured. Measurements were taken from the borehole to the edge of the nearest building (e.g. house, barn, farm etc.). Where more than one borehole was located on a well site, a central borehole was selected. Where the nearest building was not a house the setback from the borehole to the nearest house was also measured. Setbacks from the nearest train line, pond, flowing water system (e.g. dyke, stream, river, sea) were also measured. If the setback was greater than 650 m from these additional infrastructures it was not considered further.

2.2.5 Footprint of currently operating comparator industries in the UK

To assess whether the footprints from unconventional well sites represent an impact unique to shale gas extraction comparisons to other types of currently operating industries was undertaken. Petrol stations being of roughly a similar size are a good comparison to shale gas well sites, both often located in rural settings and need to manage hazardous chemicals and hydrocarbons. There were 8494 petrol stations in the UK in 2015 (UK Petroleum Industry Association, 2016), 50 were randomly selected and their direct physical footprint measured. This study excludes those attached to supermarkets or with additional shops or carwashes attached. All measurements were subject to a bootstrap analysis in groups of ten to ensure the sample size was sufficient and a fair representation of petrol stations overall.

Wastewater treatment works were also compared to shale gas developments; they too manage hazardous waste and chemicals and are often located in rural settings. Site selection was determined based on data availability from searches carried out online. A search for wastewater treatment works with corresponding Population Equivalent (PE) was completed; the sites recording PE had their physical footprint measured. An assessment of 21 sites with PE varying from 1019 to 1.9 million was performed.

2.3 Results

2.3.1 Footprint of conventional onshore hydrocarbon operations within Europe

2.3.1.1 UK

Well pad size was compared against spud date, well location and the company that drilled the well. Visual inspection of the results showed no variation between the different potential factors, thus these factors did not influence the overall footprint size and so were discarded, focusing instead on the independent well site measurements. The status of the 2193 wells analysed in the UK are given in Table 2.1: 30 were reported as 'void' as their footprints could not be measured; 21 were drilled too recently to appear on the available aerial images; 9 were actually located offshore; 1280 had no surface indication, leaving 883 wells with sufficient indication for a measurement. The average perimeter and area for the 883 wells measured was 422 m and 10800 m^2, with a range of between 21 m and 914 m for the perimeter and 27 m^2 and 35400 m^2 for the area (Table 2.2). The abandoned Poxwell 1 well (Dorset) had the smallest footprint, whilst the producing Welton well pad (Lincolnshire) had the largest: at the time of writing 41 conventional wellbores were located on this site. The average perimeter and area for the 780 wells with a 'strong indication' was 450 m and 11800 m^2 (Table 2.2). The UK averages 20 wells per site, using the average area calculated for all the wells generates an area of 541 m^2/well. The average perimeter and area for the 738 access roads measured was 460 m and 1520 m^2, with an average road length of 230 m. The maximum access road length was 2040 m; however some wells had no additional access road.

2.3.1.2 The Netherlands

Of the 426 wells studied 218 indicated current or past drilling, 179 recorded a 'strong indication' of well site footprint, 9 a 'poor', and 30 a 'very poor' indication of well site footprint (Table 2.1). The average well pad perimeter and area was calculated at 692 m and 44600 m^2. The average well pad perimeter and area for wells with a 'strong indication' was 808 m and 53800 m^2, whereas for 'poor' and 'very poor' they were 173 m and 2220 m^2 and 152 m and 2630 m^2, respectively. Well sites in The Netherlands average 7 wells per site, giving an average of 6370 m^2/well. There were 145 well pads with defined access roads; the average perimeter and area was 620 m and 1950 m^2. The maximum access road length was 1410 m, whilst the average was 310 m.

2.3.1.3 Poland

Well analysis showed, of 802 wells, 160 indicated the location of the well pad footprint. Of these 54 were recorded as showing a 'strong', 25 a 'poor' and 81 a 'very poor' indication of the well site footprint (Table 2.1), the average well pad perimeter and area being 176 m and 2960 m^2. The average area and perimeter for wells with a 'strong indication' of the well site footprint was 194 m and 2940 m^2 (Table 2.2). The average footprint (well pad perimeter and area) with a 'poor indication' was 59 m and 352 m^2, whereas the average with 'very poor indication' was 205 m and 3770 m^2 (Table 2.2), respectively. Poland averages 1.03 wells per site having an average area of 2870 m^2/well. The average access road perimeter and area for the 90 sites measured was 499 m and 1260 m^2. The maximum access road length was 3040 m, whilst the average was 250 m.

Table 2.1: The number of wells analysed for the three countries assessed; the number of wells with some evidence of a well pad footprint; and their relevant classification.

Country	Total number of wells	Total with indication	Strong indication	Poor indication	Very poor indication	No indication	Void
UK	2193	883	780	18	85	1280	30
The Netherlands	426	218	179	9	30	208	0
Poland	802	160	54	25	81	642	0

Table 2.2: Perimeter and area measurements for the all the wells with some evidence of a well pad for the three countries assessed. For easier visualisation well pads with areas >1000 m^2 have been highlighted in bold.

Country	Classification (indication)	Average perimeter (m)	Average area (m^2)	Maximum perimeter (m)	Maximum area (m^2)	Minimum perimeter (m)	Minimum area (m^2)
UK	All wells	422	**10832**	914	**35445**	21	27
The Netherlands	All wells	692	**44591**	**3541**	**682692**	15	14
Poland	All wells	176	**2959**	668	**17692**	9	4
UK	Strong	450	**11814**	914	**35445**	114	1
The Netherlands	Strong	808	**53754**	3541	**682692**	109	219
Poland	Strong	194	**2944**	668	**17692**	16	16
UK	Poor	225	**3351**	361	**7821**	94	540
The Netherlands	Poor	173	**2224**	304	**5073**	53	173
Poland	Poor	59	352	217	**2945**	28	37
UK	Very poor	238	**4022**	591	**21604**	21	**2727**
The Netherlands	Very poor	152	**2633**	517	**16108**	15	14
Poland	Very poor	205	**3768**	506	**13518**	9	4

2.3.2 Impact of well pads and setbacks on the land in the UK

For the UK, the direct footprint would mean a 33% probability of interacting with immovable infrastructure, rising to 73% with a 152 m setback and 91% with a 609 m setback (Table 2.3). The bootstrap analysis on the results from the 100 well sites showed that by a sample size of 80 wells there was no change in the percentage of land impacted, thus the sample size of 100 well sites was appropriate.

Table 2.3: Buffon's needle analysis results showing the impacts on various types of existing infrastructure when 100 well pads and their relevant setbacks are randomly located onto the currently licensed blocks.

Impact from	Mild infrastructure	Moderate infrastructure	Considerable infrastructure	Immoveable infrastructure
well pad (10800 m^2)	93	44	36	33
152 m setback	99	77	74	73
609 m setback	100	98	98	91

2.3.3 Wells per license block

If each well pad had a subsurface footprint of 1 km^2 then one 100 km^2 license block could potentially contain 100 well pads as long as there were no restrictions on the placement of the well pads at the surface. However, due to streams, rivers and manmade infrastructure this will not be possible. Between 5 and 42 well pads were located in the 20 license blocks tested (Figure 2.4) and the average license block could hold 26 well pads. These results highlight that a considerable amount of gas-in-place cannot be extracted due to restrictions from infrastructure (Table 2.4). These results were subject to a bootstrap analysis, showing there was little movement in the average number of wells that could be allocated in each block after 10 blocks indicating the sample size was sufficient.

Using footprint values determined from conventional well sites the likely direct physical footprint from 26 well pads would be 280800 m^2. However, the total indirect surface footprint from the well site increases substantially to 2.4 km^2 when the recommended 152 m setback from the borehole is considered (Table 2.5); this would be 2.4% of the total area of the licensed block. The minimum number of well sites a licence block held was 5, generating a direct surface footprint from the well pad of 54000 m^2 and an indirect surface footprint of 462000 m^2 (Table 2.5). The block that could accommodate 42 well sites would have a direct surface footprint of 453600 m^2, and an indirect surface footprint of 3.88 km^2 (Table 2.5).

Different shale gas development scenarios have been considered based on the physical number of well sites each block can develop, assuming all 127 licenced blocks currently leased are developed. The first scenario considers one well site being developed per block, 127 wells would generate a physical direct footprint of 1.37 km^2 and an indirect surface footprint of 11.7 km^2 (Table 2.5). If 5 were developed in 127 blocks, 635 wells sites would be established generating a direct footprint of 6.86 km^2 and an indirect surface footprint of 58.7 km^2 (Table 2.5). If the average 26 were developed in each block, a total of 3302 well sites would be developed. This scenario of an average of 26 well pads per license block creates a direct footprint of 35.7 km^2 and an indirect surface footprint of 305 km^2 (Table 2.5).

Figure 2.4: A schematic example of how many well pads with the recommended 152 m setback and a 500 m lateral can be located within a currently licensed block (map extracted from Digimap, 2016). In this example 31 well pads could be located within the 100 km² block without impinging on existing infrastructure.

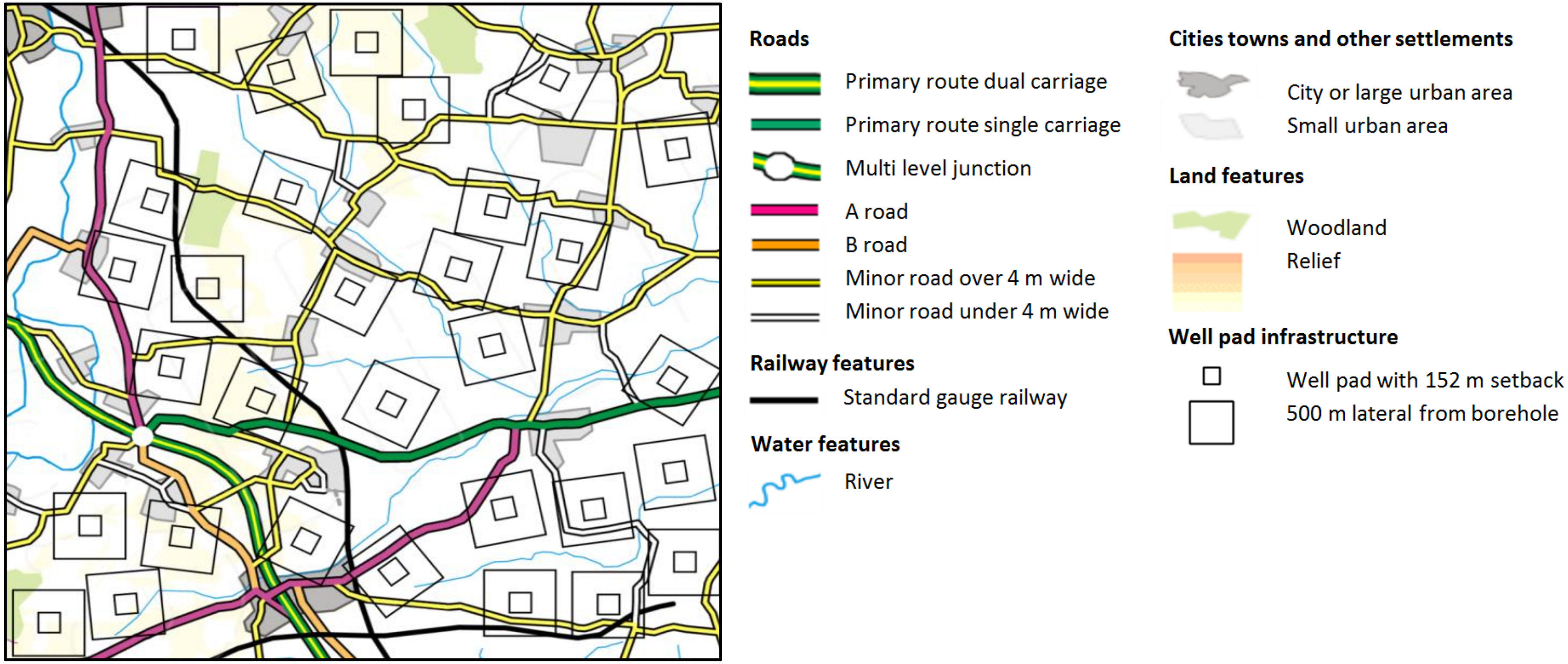


Table 2.4: The potential number of well pads with the recommended 152 m setback and a 500 m lateral that could be located within 20 randomly selected licensed blocks.

Block number	Number of well sites
SD33	18
SD52	5
SE70	34
SE 77	35
SE88	27
SE91	32
SE93	42
SJ33	21
SJ34	13
SJ44	23
SJ79	9
SK63	26
SK68	32
SK77	31
SK79	28
SK83	31
SK84	36
SK97	34
TA20	28
TA3	24

Table 2.5: The approximate direct and indirect surface footprint generated for different well pad development scenarios.

Scenario 1: One block developed			Scenario 2: 127 blocks developed		
Number of wells per block	Well pad area (m^2)	Area for 152 m setback (m^2)	Number of wells per block	Well pad area (m^2)	Area for 152 m setback (m^2)
1	10800	92400	127	1371600	11734800
5	54000	462000	635	6858000	58674000
26	280800	2402400	3302	35661600	305104800
42	453600	3880800	5334	57607200	492861600

2.3.4 Conventional well setbacks

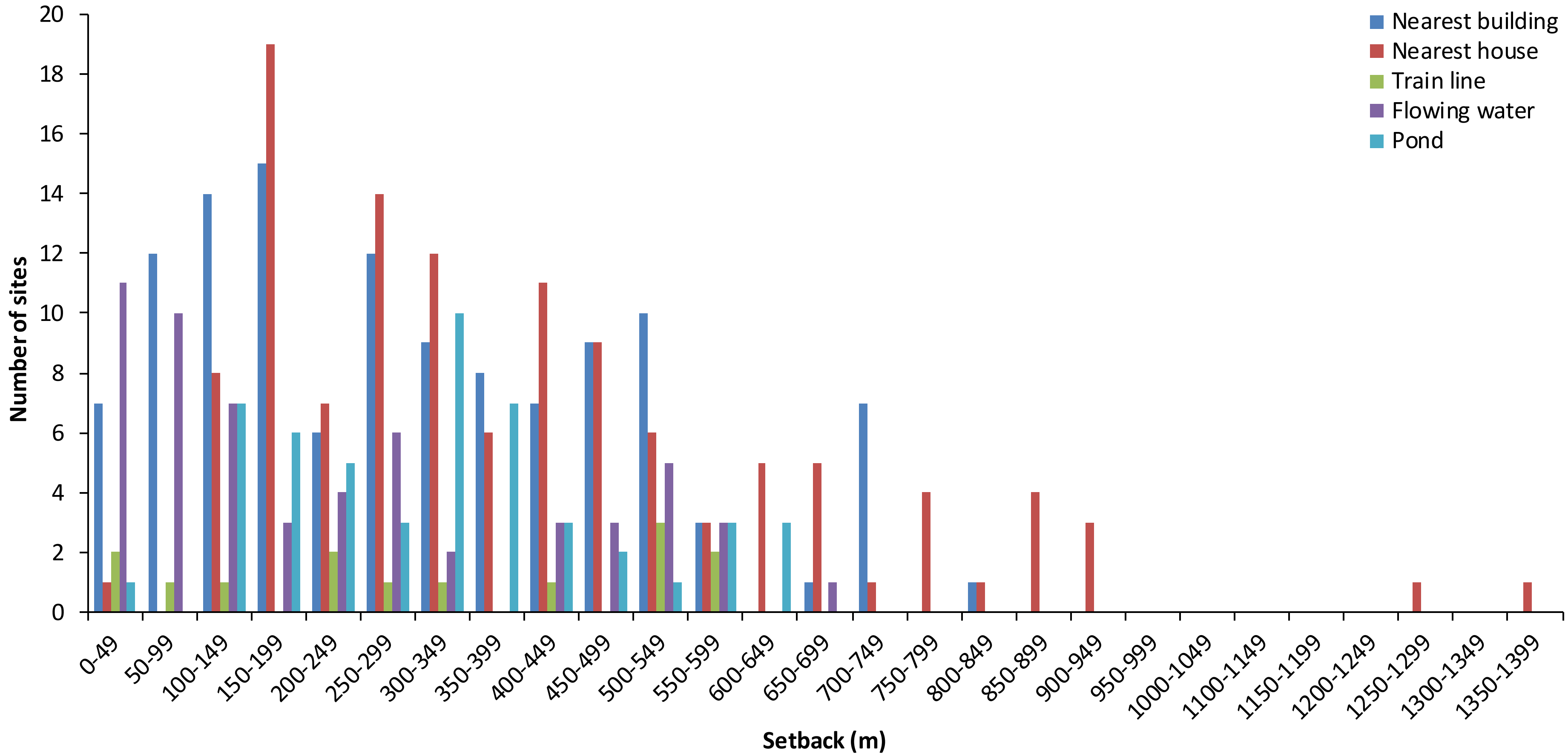
The mean setback for currently producing conventional wells in the UK was 329 m from a building. The minimum setback distance from a building recorded for the Gainsborough 14 well was 21 m. Of the 121 well sites examined, 33 had setbacks from buildings that were below the recommended 152 m set by Eshleman and Elmore (2013) (Figure 2.5). Many of the producing well sites had a number of boreholes on the pad; the above mean values include all 680 wells located on the 121 well sites. If one gives the mean value for just one well per well site, 121 well sites, the mean setback from a building is slightly lower at 303 m.

The mean setback from a house for all the wells was recorded at 447 m; the minimum setback was 46 m recorded for the Gainsborough 29 (A1) well. There were nine well sites with setbacks from houses that were less than the recommended 152 m setback (Figure 2.5). The mean setback from a house when one well per site was considered was 410 m.

There were 14 well sites within 650 m of a train line; four were within the recommended 152 m setback (Figure 2.5). The mean and minimum setback distance from a train line for all wells was 238 m and 38 m. There were 51 well sites within 650 m of a pond; eight were below the recommended 152 m setback (Figure 2.5). The mean and minimum distance from a pond was 371 m and 107 m. The mean distance from flowing water (dyke, stream, river, sea etc.) was 219 m. The minimum distance from a dyke was 26 m. There were

58 well sites within 650 m of flowing water; 28 were below the recommended 152 m setback (Figure 2.5).

Figure 2.5: The distribution of the measured setbacks from the nearest building, house, train line, pond and flowing body of water (e.g. stream, dyke, river, sea) for the 121 sites.



2.3.5 Footprint of currently operating comparator industries in the UK

There were 8494 petrol stations in the UK in 2015 (UK Petroleum Industry Association, 2016). Based upon the random sample the average area was 1360 m^2 with a range of 558 m^2 to 2600 m^2. The petrol station bootstrap analysis results indicate that the sample size was sufficient and that the variance was accounted for. Based on the number of petrol stations recorded in 2015 the total footprint required by petrol stations was calculated at 11.6 km^2. The individual direct surface footprint of a petrol station is considerably less than the direct surface footprint required for a single shale gas well pad.

The 21 measured wastewater treatment works had physical footprints ranging from 2417 m^2 (PE=1718) to 1.48 km^2 (PE=1750000). The Department for Environment, Food and Rural Affairs (DEFRA, 2002), recorded 9000 wastewater treatment works across the UK; if one assumes the range used in this study then the footprint of wastewater treatment works in the UK would be between 54 km^2 and 89 km^2.

2.4 Discussion

The literature states that an average 6 well shale gas pad in the US is approximately 21000 m^2 (US Inner City Fund, 2009), this value is slightly higher than UK estimates of 20000 m^2 for a well pad in the production phase (Taylor et al., 2013). These measurements and projections are higher than the average 10800 m^2 footprint measured for conventional onshore wells in the UK and the average 3000 m^2 site measured in Poland, however they are considerably smaller than The Netherlands average of 44600 m^2. Area per well shows the UK's conventional oil and gas industry to be the most space efficient of the three European countries measured, with an average footprint that is lower than that reported for US shale gas well pads. These differences could be due to a number of factors. Historically, site regulations in the US have been much more relaxed, largely due to differences in land ownership rights. Uniquely, out of the countries considered, in the US private individuals own the majority of the subsurface mineral rights. Many owners are willing to lease acreage for exploration and development as there is considerable financial gain (Jacquet, 2012). Equally, the UK is around seven and a half times (Taylor et al., 2013) and Poland three and a half times (The World Bank, 2016) more densely populated than the US, therefore the US is not under the same space restraints as many European countries. The US shale gas industry has developed substantially in areas such as the Eagle Ford, where population densities might be lower than average and have little existing infrastructure to disturb (Tunstall, 2015).

The UK and The Netherlands are both economically well developed and heavily populated, thus one would expect them to have similar laws and comparable well site sizes; however this appears not to be the case. It appears that each country must have slightly different framework objectives with varying planning laws. In addition, although not supported by the literature, it is possible some of the well site footprint in The Netherlands is inclusive of processing infrastructure, whereas the UK and Poland tend to have separate processing facilities offsite. For example, at the time of writing, Third Energy's four producing gas fields beneath the Vale of Pickering supply the offsite North Yorkshire's Knapton Generating Station. It is apparent when measuring sites in The Netherlands that extra attention has been made to protect surrounding areas against noise and visual pollution; this added mitigation technique also adds acreage to the well site footprint.

Access roads recorded within the US are between 40 m and 914 m long, occupying an additional 12000 m^2 of footprint (NYS DEC, 2015; Jantz et al., 2014). This study found access roads for conventional well pads in the UK averaged 230 m, whilst in Poland they averaged 250 m and in The Netherland's 310 m. As in the UK standard practise in the US involves connecting the well pads to the nearest existing public road, or if granted permission the nearest private road using the shortest possible distance (Racicot et al., 2014). US access roads are longer than in Europe, which is unsurprising given the lower population density of the US.

The British Geological Survey (BGS) in association with the UK Department of Energy and Climate Change (renamed to 'BEIS') estimated the resource (gas-in-place) for the Bowland Shale to be between approximately 2.33 x 10^{13} m^3 to 6.49 x 10^{13} m^3, and projected a central estimate of 3.76 x 10^{13} m^3 (Andrews, 2013). More important is the highly variable technically recoverable reserve, a BGS report for DECC in 2010 estimated shale gas reserves of 1.33 x 10^{11} m^3 in the upper Bowland Shale Basin (Andrews, 2013). The US Energy Information Administration (US EIA) at the Department of Energy estimated the total UK shale gas resource in place at 2.75 x 10^{12} m^3 and assumed a 21% recovery factor, resulting in recoverable reserves of 5.66 x 10^{11} m^3 (The Geological Society, 2012). Cuadrilla estimate at least 5.66 x 10^{12} m^3 shale gas resource is in place in the Bowland Basin and they propose a conservative recovery factor of 15% would yield a reserve of around 1.27 x 10^{12} m^3. However the BGS have since revised these calculations and noted that a recovery factor of 15% would in fact yield a technically recoverable reserve of 8.5 x 10^{11} m^3 (The Geological Society, 2012). The Geological Society (2012) summaries three UK shale reserves estimates as 2.83 x 10^{11} m^3 (England only), 5.66 x 10^{11} m^3 (UK), and 8.5 x 10^{11} m^3 (Bowland Basin only). However, these technically recoverable shale gas reserves estimates have not considered limitations from existing infrastructure and the carrying capacity of the surface.

The premise of this study has been that the recoverable reserve is limited by the carrying capacity of the surface. Taking into consideration Cuadrilla's technically recoverable reserve estimate of 8.5 x 10^{11} m^3, the actual accessibility due to infrastructure constraints and the fact that just 26% is likely to be recovered (with the scenarios outlined in Section 2.2.3) means that approximately 2.21 x 10^{11} m^3 could feasibly be extracted. To produce a more accurate extraction assessment a number of additional considerations need to be included. If setback restrictions were relaxed additional well sites could be located per block: for example, if 42 wells were the average per block, this would mean approximately 42% of the estimated shale gas could be extracted. In this instance, with Cuadrilla's corrected technically recoverable reserve estimate approximately 3.57 x 10^{11} m^3 of gas could be extracted.

Setback restrictions within the US can vary considerably, within this chapter setbacks recommended for the Marcellus Shale gas developments in Maryland was used. To determine if they were realistic the setbacks of the currently producing wells in the UK were measured. The Gainsborough 29 (A1) well has the shortest setback from a house (46 m); since the well was spudded in 1962 a housing estate has developed around the well. The fact that people are buying houses and living in close proximity to these to working wells indicates the public's acceptance of them and their trust that they are not a matter of concern. These setback results show the average is greater than those suggested by Eshleman and Elmore (2013) for developments in Maryland; however there are many cases where the setbacks for conventional wells are smaller than 152 m.

Within the US lateral lengths vary between well pads and locations, however technological advancements have led to a gradual increase in lateral length (US EIA, 2016). Within this study laterals extending 500 m were used for the likely shale gas development scenario. A value of 500 m was assumed a realistic initial lateral length within the UK as at the time no horizontal wells had been drilled. Since this study was completed Cuadrilla has drilled two horizontal wells into the Bowland Shale, one 750 m long and the other 800 m. These lateral lengths achieved by Cuadrilla indicate that the 500 m used in this study is rather conservative; thus, the methodologies used in this study have been developed further in Chapter 3 to account for a wider range of potential lateral lengths.

If one assumes all 127 licenced blocks currently leased were developed with an average of 26 well pads per block, 3302 well pads could be developed. This would generate a direct footprint of 35.7 km^2, and an indirect surface footprint of 305 km^2. The average area of a single petrol station was 1360 m^2, a rough approximation of the total footprint required for the 8494 across the UK was calculated at 11.6 km^2, and for wastewater treatment works the total

UK footprint was between 54 km^2 and 89 km^2. The footprint sizes calculated for these industries indicate that the footprint required for shale gas development is similar in magnitude to the other industry infrastructure. However, in the UK neither petrol stations nor wastewater treatment works have set regulated setback distances when being developed, unlike those that have been considered here for shale gas development. Consequently the potential development of a shale gas industry with associated setback distances creates a far larger footprint than comparator industries without the need for them. To minimise the footprint required for shale gas developments sites should be multi-well and located at an optimal distance from each other. This will reduce the area required per well and ensure optimal use of horizontal drilling technology.

This study has largely focused on the shale gas industry within Europe but the methodologies applied are transferrable across other industries and different disciplines. The Buffon's needle analysis is a useful method to determine the spacing and the likely carrying capacity of future developments such as housing, retail centres and industrial sites (e.g. wastewater treatment works, recycling centres). With global population set to increase, these developments and additional infrastructure is inevitable, highlighting the need for a systematic approach to where these sites can be located with minimum impact. Acknowledging the importance of site location and the need of setbacks in other industries, such as recycling centres, is also of vital importance when developing new sites. In a society that is continuously growing one needs to protect specific infrastructure with appropriate setbacks. However, it should be remembered that the carrying capacity is always going to be defined by public consent; this study has assumed the importance of surface features and infrastructure, e.g. the immovability of rivers. In a different era such assumption of acceptability may be incorrect.

2.5 Conclusion

This study has developed a Buffon's needle analysis approach to understand the carrying capacity from new shale gas related infrastructure and its impact on existing infrastructure and the environment. Using this analysis the potential impact from developing a shale gas industry within the UK has been evaluated. This study found that there is a 33% probability that a shale gas well pad would directly contact immovable infrastructure, increasing to 91% when a setback of 609 m is used. In the UK, the average actual setback from conventional onshore well pads is 329 m for any building or 447 m for a house, but it can be as low as 21 m and 46 m, respectively. The carrying capacity of the surface when a well pad has a setback distance of 152 m and lateral lengths of 500 m is on average 26% but ranges between 5 and 42%. Thus, the likely maximum number of wells and associated setbacks that could be located within a block (typically 10 km by 10 km) would be 26. The carrying capacity of the land surface, as predicted by this approach, would limit the technically recoverable gas reserves for the Bowland Basin from the predicted 8.5×10^{11} m^3 to only 2.21×10^{11} m^3.

Chapter 3:

The optimal lateral length for maximising technically recoverable gas reserves over the Bowland Shale.

3.1 Introduction

As highlighted in Chapter 2, within densely populated countries the carrying capacity of the land and competition for land with other uses are important factors to consider as they restrict the number of well sites that can be developed and the amount of gas that could be extracted (Baranzelli et al., 2015; Clancy et al., 2018a). Based on a review of the literature there have been no peer-reviewed scientific studies that address well pad spacing and optimal lateral length. Therefore, the main aim of this chapter was to build on methodologies developed in Chapter 2 and determine the most probable optimum lateral length that limits disruption on the surface but maximises technically recoverable gas reserves for the region over the Bowland Shale.

3.2 Approach and methodology

The approach of this study was to consider the relationship between estimated recoverable resources with various recovery factors applied and to relate all estimates to lateral length. For the purposes of this study the following are estimated: direct footprint, indirect footprint, subsurface footprint, and technically recoverable gas reserve estimates. Given the range of situations where shale gas is either being exploited or at least considered, and the uncertainty within resource estimates a stochastic approach was taken with ranges for inputs being defined from the literature.

3.2.1 Direct footprint

The direct surface footprint of any given well pad is:

$$S_f = W_a + (L_a L_n) \quad \text{(Equation 3.1)}$$

Where: S_f - Surface footprint (m^2); W_a - Area required for a single-well pad with one well (m^2); L_a - Area required per lateral (m^2); and L_n - Number of laterals.

The area needed for a single-well pad with one well (W_a) and the additional area required for a lateral (L_a) are not often specifically documented in the literature. Instead, as mentioned in Section 1.2.1, the area required for a whole well pad where sites have several wells located on them is recorded. However, the US Inner City Fund suggested a 'rule-of-thumb', based on discussions with operators: assume an initial single-well pad size of 13000 m^2 that increases by approximately 1600 m^2 per well, i.e. according to these guidelines, a 6 well pad would have a footprint of 21000 m^2 (US Inner City Fund, 2009). In the UK, Broderick et al. (2011) suggest Cuadrilla may develop 10 wells on a 7000 m^2 well pad at their sites within the Bowland Basin. Whereas, Taylor et al. (2013) suggest future scenarios where a single 10 well pad would be 20000 m^2. However, Cuadrilla state in their environmental statement (a document necessary for regulatory permissions) for their Preston New Road site in Lancashire that surface works would need a total area of 26500 m^2, of which 16500 m^2 is composed of compacted crushed stone for the surfaced well pad from which the drilling, hydraulic fracturing and flow testing activities will be undertaken (Cuadrilla Bowland Ltd., 2014). Cuadrilla state that the remainder of the 73400 m^2 application site will consist of surface water collection ditches, landscape bunds and fencing and land required for the flow test pipeline and connection (Cuadrilla Bowland Ltd., 2014). When the Preston New Road site was measured from aerial imaging for this study in July 2017 it had an area of 41437 m^2. Cuadrilla's environmental statement for the Roseacre Wood well, Lancashire, requested a total area for the surface works of 65400 m^2, of which 13400 m^2 would be a compacted crushed stone surfaced well pad from which drilling, hydraulic fracturing and flow testing activities would be undertaken from (Cuadrilla Elswick Ltd., 2014). The literature shows the surface footprint required in the US and the predicted and practiced surface footprint for a well pad in the UK differs considerably (Broderick et al., 2011; Taylor et al., 2013). In Chapter 2, a measured surface footprint of conventional wells in the UK was used as an analogue to likely future shale gas site sizes, thus a S_f value of 10800 m^2 was used (Section 2.2.2). In this study an upper and lower estimate for both W_a and L_a has been used to calculate Equation 3.1. The lower bound estimates for W_a and L_a was derived from visual imaging results collected in Chapter 2, although based on data from the conventional oil and gas industry these were used as they represent current accepted practice within the UK (Table 3.1). The visual imaging results for the 780 wells that were determined in Chapter 2 to have a 'good indication' of where the well pad boundaries were located were assessed through a regression analysis, the area of the 780 wells were plotted against the number of wells on each site. The fit of the derived regression equation provides the uncertainty on the estimate of W_a and L_a and these are expressed as the 95% confidence interval on the mean estimate assuming a normal distribution. The upper bound W_a and L_a estimates of 13000 m^2 and 1600 m^2 have been taken from the US experience recorded in the literature (US Inner City Fund, 2009 - Table 3.1).

The L_n per pad has been assumed to be between 6 and 10 wells, with all wells being on a single storey and with one lateral each (Table 3.1). This range was deemed reasonable as these values have been used for predicted potential future UK shale gas development scenarios. The UK's Institute of Directors (IoD) suggested two potential development scenarios; the first of these was based on the development of a well pad with 10 wells where each well is a single lateral (Taylor et al., 2013). Bond et al. (2014) also used 10 wells per pad in their development scenario, whereas Broderick et al. (2011) assesses potential future scenarios where well pads had 6 wells. The above values were inputted into Equation 3.1 and the linear model was run 500 times, the subsurface footprint results were then recorded in a frequency plot.

3.2.2 Subsurface footprint

The subsurface footprint of any well pad can be defined as:

$$S_{sf} = (L_l\, L_w)\ Ln \qquad \text{(Equation 3.2)}$$

Where: S_{sf} – subsurface footprint (m^2); L_l - lateral length (m); L_w - the drainage width accessed by any lateral (m); and L_n - number of lateral wells on the pad. Note that the value of the subsurface footprint is independent of the number of storeys of laterals from the well pad.

To calculate Equation 3.2 the number of laterals (L_n) ranged between 6 to 10 wells per pad, as defined in Section 3.2.1. Bond et al. (2014) used a lateral drainage width (L_w) of 140 m and 200 m for their two development scenarios, whereas UKOOG assumed a drainage width of 300 m (UKOOG, 2016). In this study a L_w range of 100 m to 350 m, with a uniform distribution, was used to calculate Equation 3.2. A low end lateral width of 100 m was used as initial development could potentially see shorter drainage distances than those initially anticipated. An ambitious high end lateral width of 350 m was used as Davies et al., (2012) recorded that the probability of a stimulated hydraulic fracture extending further than >350 m was ~1%.

UKOOG (2016) assumed in their development scenarios that a typical development in the UK would have 10 wells per pad each extending between 1.5 and 2.5 km. A lateral length of 2000 m was predicted in Taylor et al. (2013) development scenarios, this value was also used in the environmental statement for the Preston New Road site (Cuadrilla Bowland Ltd., 2014 – Figure 1.1). However, the hydraulic fracture plan for the Preston New Road site proposes lateral lengths of 782 m (Cuadrilla Resources, 2018a). The first horizontal well drilled at the Preston New Road site in April 2018 reached a depth of 2700 m and ran laterally into the lower Bowland Shale rock for 800 m (Cuadrilla Resources, 2018b). The second horizontal well at the Preston New Road 1 site was completed in July 2018 to a depth of 2100 m, extending laterally through the upper Bowland Shale for some 750 m (Cuadrilla Resources, 2018b). There are a further two wells planned at Preston New Road site which are hoped to extend further. The 2016 US Energy Information Administration report indicates that since the development of unconventional plays, lateral lengths in the US have evolved from typical lengths of 300 m to 3050 m (US EIA, 2016). In addition, although not currently the norm, hydraulically fractured wells have been reported in the media to extend over 4800 m in North Dakota's Bakken play (Kachkova, 2017). To account for early developments that do not achieve initial lateral length targets, and potential future developments which might include technical advancements, a lateral length (L_l) range of 500 to 3500 m, with a uniform distribution, were used in Equation 3.2 to determine the likely subsurface footprint for an average well pad over the Bowland Shale (Table 3.1). The linear model (Equation 3.2) was run 500 times and the subsurface footprint results were recorded in a frequency plot.

3.2.3 Indirect surface footprint

The indirect surface footprint is determined from the required setback distance a borehole has to be away from existing infrastructure. The indirect surface footprint (I_f) is:

$$I_f = (2B)^2 \qquad \text{(Equation 3.3)}$$

Where: I_f = indirect surface footprint (m^2), and B = setback distance (m).

As mentioned in Section 1.2.1.3 within the US the setback distance (B) a well has to be away from existing infrastructure, such as residential property varies from state to state. Within the UK there is not a fixed distance a borehole or a well site has to be away from existing infrastructure; currently the setback distance is determined on a site by site basis during the planning processes. However, from Chapter 2 it is apparent that setback distances between conventional wellbores and the nearest building and house are as low as 21 m and 46 m, respectively. Due to the contentious nature of the potential shale industry within the UK it is unlikely setback distances will be as low as 21 m or 46 m. Therefore, to acknowledge US experience highlighted in Section 1.2.1.3 a setback distance range of between 100 to 600 m with a uniform distribution (Table 3.1) was used within Equation 3.3 to determine the likely indirect surface footprint for an average well pad located over the Bowland Shale. The linear model (Equation 3.3) was run 500 times and the indirect surface footprint results were recorded in a frequency plot.

3.2.4 Carrying capacity

The carrying capacity is as defined in Chapter 2, i.e. the number of well pads that could be located, without overlap or disruption of the surface infrastructure (including all roads, buildings, water ways, ponds and woodland) in a 100 km^2 licence blocks over the Bowland Shale. Expanding on methodologies developed in Chapter 2 the carrying capacity (θ) for well pads with varying inputs was calculated. Initially, the number of well pads with the following variables that could be physically located within 20 licence blocks was assessed: lateral length (L_l) set at 3 levels - 500 m, 750 m and 1250 m; setback distance (B) set at 3 levels – 152 m, 305 m and 457 m. For consistency with Chapter 2 a 500 m lateral was used, the 750 m and 1250 m laterals were also chosen as they represent realistic developments scenarios and are the same as those used in Bond et al's Scottish development scenarios (Bond et al., 2014). These lateral lengths differ from the wider range used in Section 3.2.2, as these carrying capacity assessments are based on the more realistic initial development scenarios rather than the more ambitious future scenarios. Setback distances of 152 m, 305 m and 457 m were chosen as they seemed a reasonable range from US experiences recorded in Section 3.2.3. In a similar manner to Bond et al. (2014) but in contrast to Chapter 2 the 10 well pads were envisaged to physically comprise of five laterals in each direction, all parallel to the axis of minimum horizontal stress. The 20 license blocks used in Chapter 2 have been used again in this study. The number of well pads that could be located in each of the 20 license blocks for each of the combinations of lateral length (L_l) and setback distance (B) were plotted and assessed.

To understand the relationship between carrying capacity and lateral length an analysis of variance (ANOVA) was performed. A two-way ANOVA was performed with the factors lateral length and the number of laterals per well pad, to assess the controls on the carrying capacity in 20 licence blocks. The ANOVA assumes that the distribution of data is normal and that there is homogeneity of variance. The normality of the distribution was tested using the Anderson-Darling test (Anderson and Darling, 1954) and no normalisation or transformation of the data was deemed necessary. The resulting general linear model was run 500 times.

3.2.5 Resource and technically recoverable reserve estimates

Resource estimates should be presented as a probability distribution or to a given level of confidence; often however, single 'point' estimates with undefined levels of confidence are common (McGlade et al., 2012). Chapter 2 proposed that the technically recoverable reserves, determined from the resource estimates, are limited by the recovery factor and the surface carrying capacity, that is:

$$T = \theta\varphi R \qquad \text{(Equation 3.4)}$$

Where: T - technically recoverable reserves per license block (m^3 of gas); θ - surface carry capacity (fraction of the land surface available for future development that is not already taken up by existing infrastructure); φ - recovery factor (fraction of the estimated resource that it would be technically recoverable); and R - estimated resource (gas m^3/m of lateral).

As referenced in Section 2.4, since the discovery and exploration of shale gas in the UK there have been various predictions on the amount of shale gas resource and the technically recoverable reserves that are present. Taylor et al. (2013) estimated that a single 10 well pad of 10 laterals could generate 8.9×10^8 m^3 of gas; this assumed a lateral extent of 2000 m and a recovery factor of 10%. Therefore, Taylor et al. (2013) estimated the gas generated per each individual 2000 m lateral would be 8.9×10^7 m^3. However, when recovery factors are not accounted for the resource per lateral can be calculated as 8.9×10^8 m^3, dividing this by 2000 m gives us the volume of gas resource per metre (R), which is 445000 m^3/m of lateral. Taylor et al. (2013) predictions have been used in this study, however they suggest a single point value rather than a range, for the purpose of this study a range defined by ±50%, thus a range of 222500 and 667500 m^3/m of lateral, has been used with a uniform distribution for the estimated resource (R) values.

To apply to Equation 3.4 the resource estimate (R) range based on Taylor et al. (2013) has been used alongside a range of recovery factors (φ) extracted from the literature. The US experience of shale gas production indicates recovery factors generally ranging from 20 to 30%, with values as low as 15% and as high as 35% in some exceptional cases (US EIA, 2015). Within the UK more conservative estimates have been used, as mentioned above Taylor et al. (2013) used a recovery factor of 10%. To account for the range of recovery factors (φ) recorded in the literature and a shale that may not be as productive as hoped, a range of between 5 and 35%, with a uniform distribution, was applied to R.

The range of resource estimate (R) and recovery factors (φ) mentioned above and the surface carrying capacity (θ) as determined via the ANOVA analysis in Section 3.2.4 were inputted into Equation 3.4 to calculate the technically recoverable reserves for an average license block. The linear model (Equation 3.4) was run 500 times. The linear model results for the predicted technically recoverable reserve estimates (Mm^3) and the carrying capacity against lateral length (m) were plotted in a scatter graph for analysis. Thus, an assessment of the most probable optimal lateral length for an average license block was determined.

Further analysis was then carried on out on the now defined probable optimal lateral length range. An ANOVA analysis using the probable lateral length range (1000 m to 1750 m), and the previously defined resource estimates (R), recovery factors (φ) and the calculated surface carrying capacity (θ) was carried out. The resulting general linear model was run 5000 times, the run value was increased from 500 so the nature of the distribution between the narrower probable lateral range could be analysed in more detail.

Table 3.1: The range of inputs taken from the literature to estimate: direct footprint, indirect footprint, subsurface footprint, and technically recoverable reserve estimates based on the carrying capacity of the licenced blocks. Note values for W_a and L_a are the upper bound values.

Input		Value	Reference
W_a	Area required for a single-well pad with one well (m^2)	13000	US Inner City Fund, 2009.
L_a	Area required per lateral (m^2)	1600	US Inner City Fund, 2009.
L_n	Number of laterals	6 - 10	Broderick et al., 2011; Bond et al., 2014; Taylor et al., 2013.
L_l	Lateral length (m)	500 - 3500	Derived from Cuadrilla Bowland Ltd., 2014; Cuadrilla Resources, 2018a; Cuadrilla Resources, 2018b; US EIA, 2016.
L_w	Lateral width (m)	100 – 350	Bond et al., 2014; Davies et al., 2012.
B	Setback distance (m)	100 - 600	Eshleman and Elmore, 2013, Fry, 2013; Illinois Department of Natural Resources, 2014; State of Colorado Oil and Gas Commission, 2013; State of Colorado Oil and Gas Commission, unknown.
φ	Recovery factor (%)	5 - 35	US EIA, 2015; Taylor et al., 2013.
R	Estimate resource (m^3/m)	445000 (±50%)	Taylor et al., 2013.

3.3 Results

3.3.1 Direct surface footprint

As the number of wells on a well pad increases the surface footprint also increases. Figure 3.1 shows the surface footprint regression analysis based on the 780 UK wells measured. The linear regression equation, Equation 3.5, indicates the average single-well pad has a surface footprint of 6113 m^2 and increases by 328 m^2 for every additional well (Table 3.2).

$$S_f = 327.9\ L_n + 6112.7 \qquad \text{(Equation 3.5)}$$

$$(\pm 28) \qquad (\pm 673)$$

Where: S_f - Surface footprint (m^2), and L_n number of laterals.

Figure 3.2 shows when values from the regression analysis (Equation 3.5) are used in the linear model and the results plotted in a frequency plot the results are positively skewed, with a modal surface footprint range of 5000 – 9999 m^2. Figure 3.3 shows the frequency results based on the surface footprint estimates from US literature are negatively skewed, with a modal surface footprint of 25000 – 29999 m^2.

Figure 3.1: Regression analysis of the direct surface footprints for the 780 UK wells measured that were determined to show a 'good indication' of the well site location.

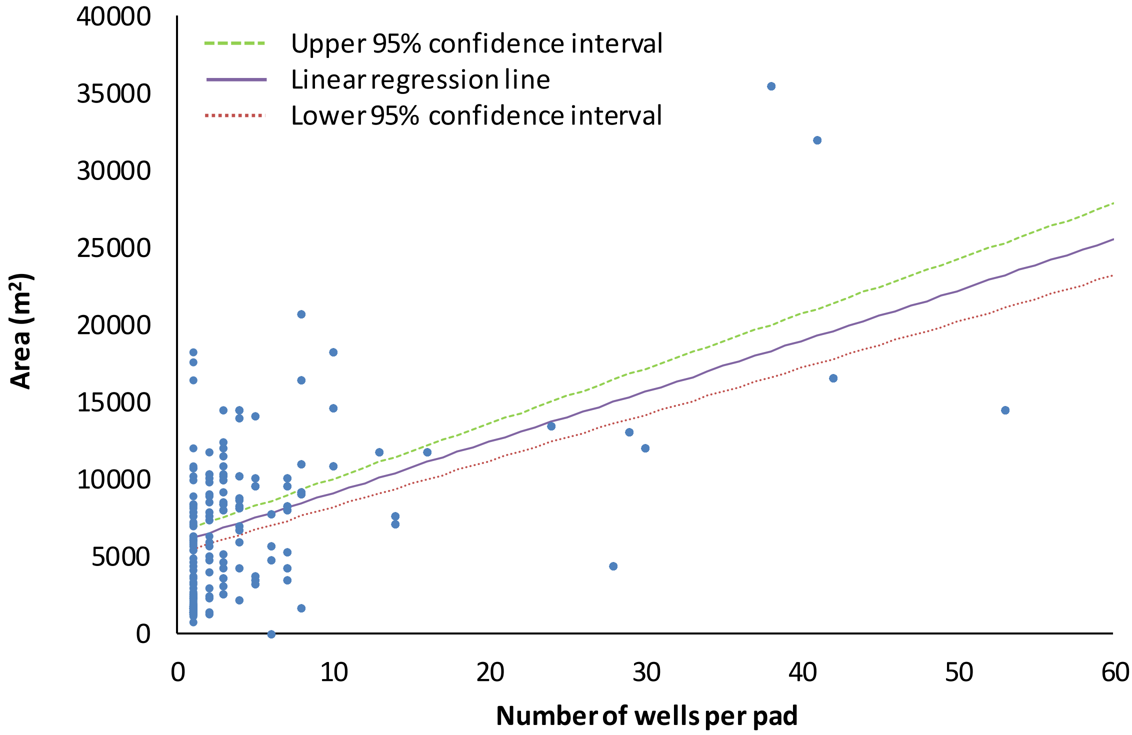


Table 3.2: The calculated lower bound values for W_a and L_a with corresponding confidence intervals.

Input		Value	Reference
W_a	Area required for a single-well pad with one well (m^2)	6113 (±673)	Derived from Chapter 2 results (Clancy et al., 2018a).
L_a	Area required per lateral (m^2)	328 (±28)	Derived from Chapter 2 results (Clancy et al., 2018a).

Figure 3.2: *A frequency plot for the surface footprint results for an average well pad located over the Bowland Shale, using the lower bound well pad and lateral areas generated from Figure 3.1.*

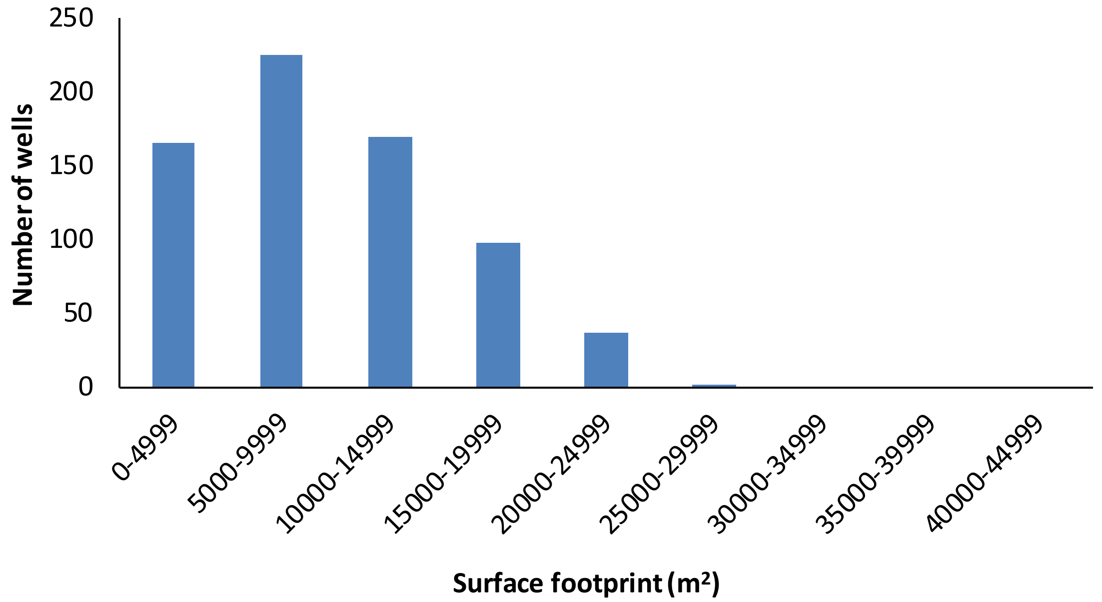
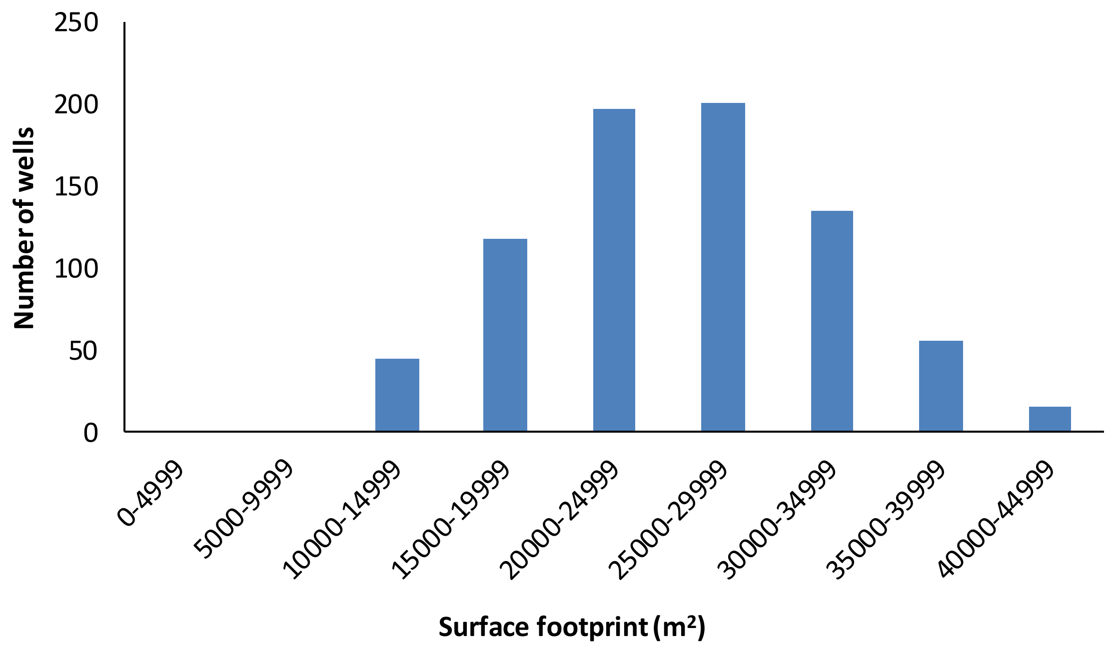


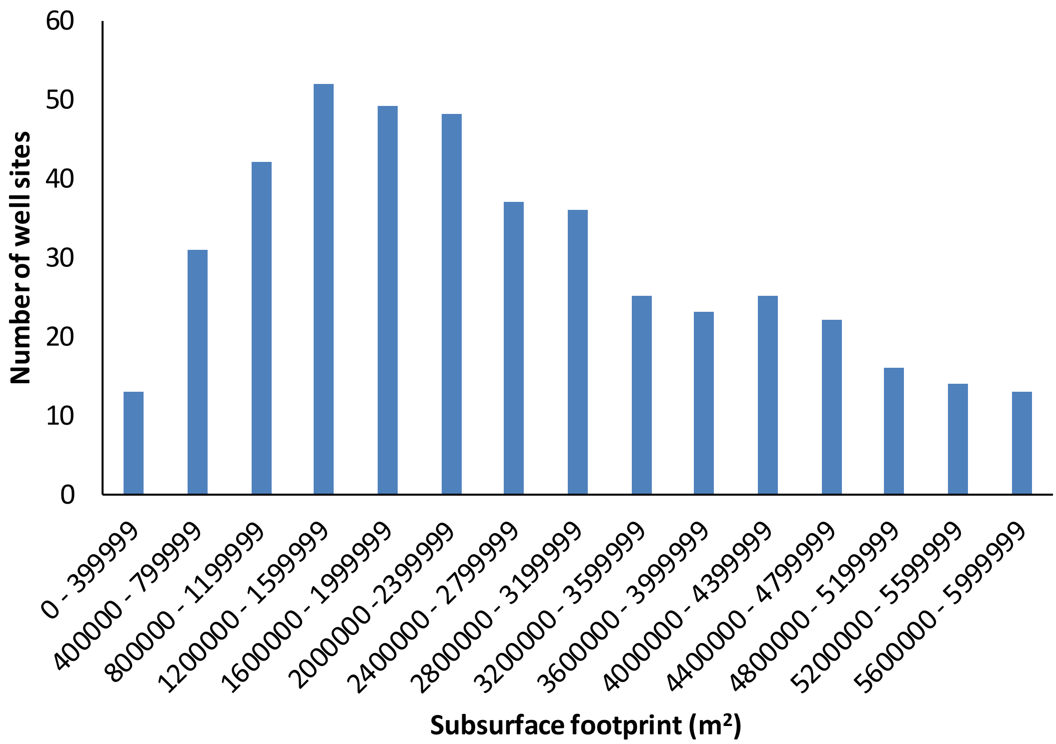
Figure 3.3: *A frequency plot for the surface footprint results for an average well pad located over the Bowland Shale, results generated from the upper bound surface footprint measurements taken from the US Inner City Fund (2009).*



3.3.2 Subsurface footprints

As one expects, as the lateral length and width increases and the number of laterals per well pad increases the subsurface footprint also increases. The subsurface footprint (S_{sf}) results for an average well pad located over the Bowland Shale show a positively skewed distribution (Figure 3.4). The modal subsurface footprint for a well pad ranged was 1200000 to 1599999 m^2.

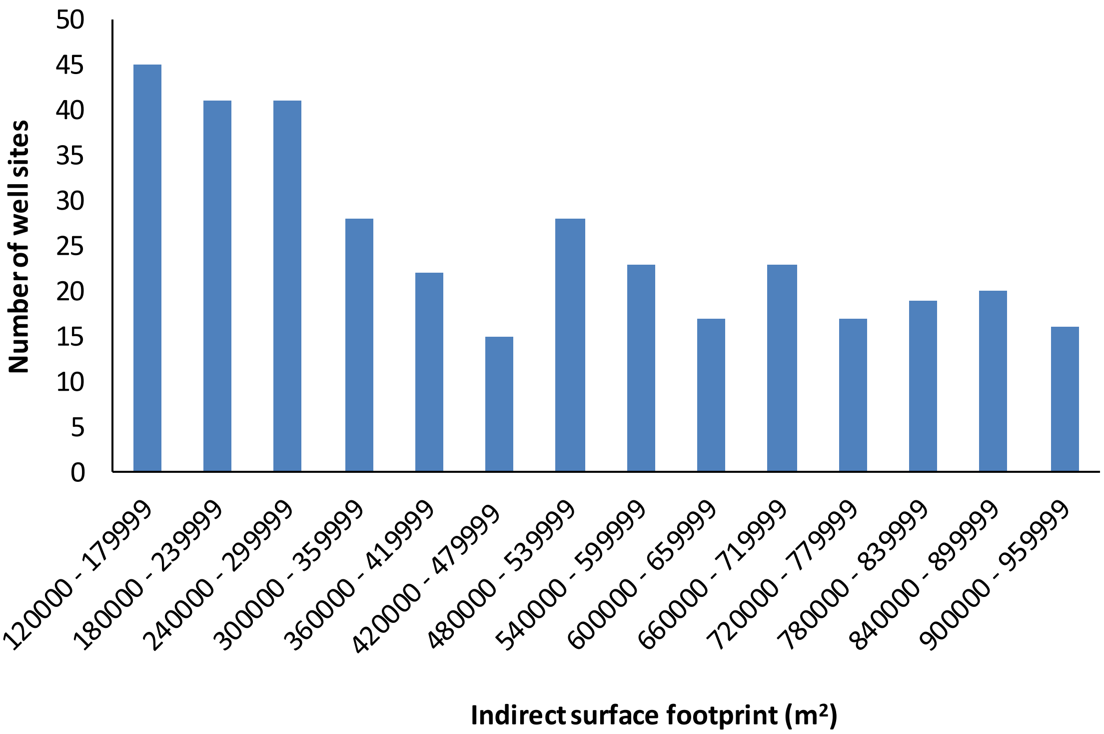
Figure 3.4: A frequency plot for the subsurface footprint results for an average well pad located over the Bowland Shale.



3.3.3 Indirect surface footprint

As the setback distance increases the indirect surface footprint increases. Figure 3.5 shows the distribution results for the indirect surface footprint (I_f) for an average well pad located over the Bowland Shale are positively skewed. Figure 3.5 indicates the modal indirect surface footprint (I_f) range was between 120000 and 179999 m^2.

Figure 3.5: A frequency plot for the indirect surface footprint results for an average well pad located over the Bowland Shale.



3.3.4 Carrying capacity

When the setback distance (B) between existing infrastructure and the borehole is 152 m, the average number of single-well pads with 10 laterals, each 500 m long that could be located within a licence block was 59, whilst the minimum and maximum number of well pads that could be located within a licence block was 20 and 156 well pads respectively (Table 3.3). The average number of single-well pads with 10 laterals each 750 m long that could be located within a licence block was 30, with a minimum and maximum number of well pads that could be located within a licence block being 10 and 74 well pads respectively (Table 3.3). The average number of single-well pads with 10 laterals each 1250 m long that could be located within a licence block was 15, whilst the minimum and maximum number of well pads that could be located within a licence block was 6 and 18 respectively (Table 3.3).

When the setback distance (*B*) was increased to 305 m the average number of single-well pads with 10 laterals, each 500 m in length that could be located within a licence block was 9, with a minimum and maximum of 0 and 32 well pads respectively (Table 3.3). When the lateral length (L_l) is increased to 750 m the average number of well pads that could be located per licence block was 7, with a minimum and maximum of 0 and 25 (Table 3.3). A lateral length of 1250 m reduces the average number of well pads that could be located within a licence block to 5, with a minimum and maximum of 0 and 10 (Table 3.3).

When the setback distance (*B*) was 457 m the average number of single-well pads with 10 laterals, each 500 m or 750 m in length that could be located within a licence block was 1, with a minimum and maximum of 0 and 3 respectively (Table 3.3). A lateral length (L_l) of 1250 m reduces the average number of well pads that could be located within a licence block to 0, with a minimum and maximum of 0 and 3 (Table 3.3). This study indicates that each block is different, and carrying capacity (θ) varies substantially due to limitations from existing surface infrastructure. It is worth noting that if a licence block was extremely populated with infrastructure that regardless of the lateral length and setback distance it may be impossible to locate any well pads within that licence block.

Figure 3.6 shows the linear model results for the carrying capacity of licence blocks where lateral lengths are 500 m, 750 m and 1250 m. Equation 3.6 and Figure 3.6 indicate the linear equation and the r^2 value. The r^2 value was calculated at 0.42, using this results an ANOVA analysis of the carrying capacity results (based on the results recorded earlier in this section for lateral length and setback distances at the three levels) allows the carrying capacity of a random licence block with a range of input variables, as recorded in Table 3.1, to be generated; these values were then used to calculate the amount of gas that could technically be recovered for an average licence block (Section 3.3.5).

$$\theta = -0.0193\ L_l + 36.664 \qquad r^2 = 0.4187 \qquad \text{(Equation 3.6)}$$

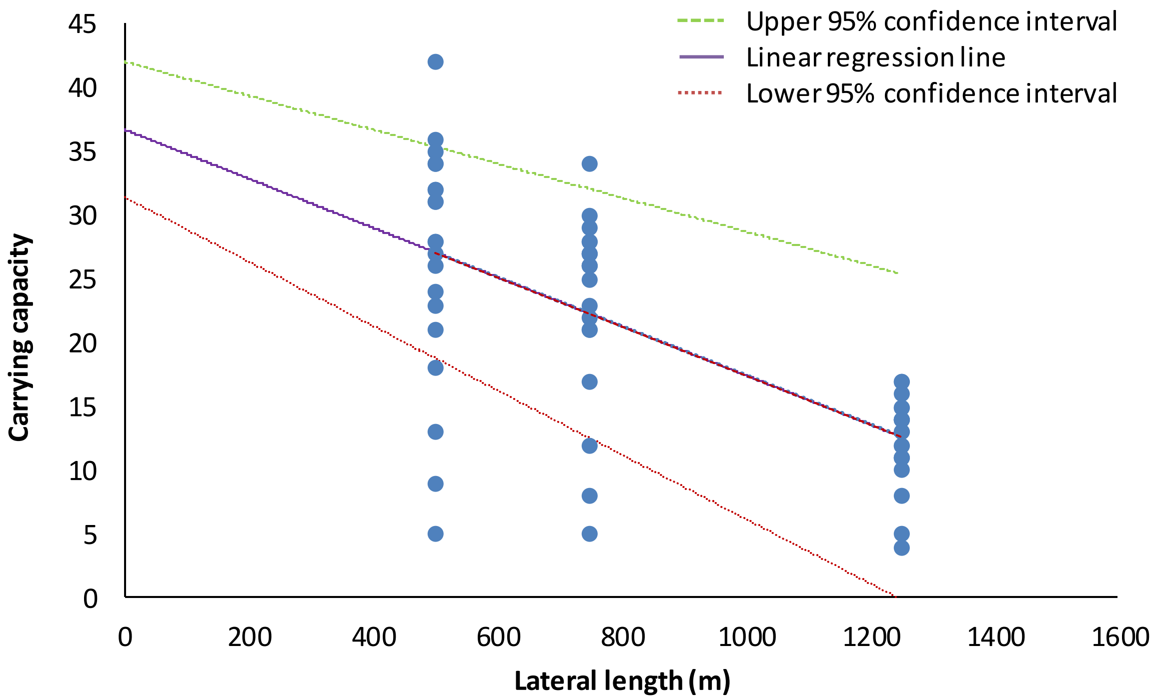
$$(\pm 0.006) \quad (\pm 5.31)$$

Where: θ – carrying capacity, and L_l is lateral length (m).

Table 3.3: The minimum, average and maximum number of well sites with setbacks of 152 m, 305 m and 457 m and lateral of 500 m, 750 m and 1250 m that can be located within a licence block.

Lateral Length (m)	Setback Distance								
	152 m			305 m			457 m		
	Number of well pads per block			Number of well pads per block			Number of well pads per block		
	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum
500	20	59	156	0	9	32	0	1	3
750	10	30	74	0	7	25	0	1	3
1250	6	15	18	0	5	10	0	0	3

Figure 3.6: The linear model results for the carrying capacity of licence blocks where lateral lengths are 500 m, 750 m and 1250 m.



3.3.5 Resource and technically recoverable reserve estimates

From Figure 3.7 it can be observed that as lateral length increases so too does the volume of technically recoverable reserves, in addition as lateral length increases the carrying capacity of a license block decreases. The general linear model predicts at a 95% probability no laterals greater than 1750 m when a whole licence block is developed. The crossover between the two lines of data forms a bivariate distribution and so indicates a sweet spot, thus the optimal conditions that will generate the greatest volume of technically recoverable gas reserve. Based on Figure 3.7 this sweet spot indicates that if the average license block was developed to its full potential using the variables from Table 3.1 and Table 3.2, a lateral length of 1300 m would be the most probable lateral length. Lateral lengths of 1300 m correspond to a probable carrying capacity of 12 wells per licence block, generating a technically recoverable gas reserve of 1200 x 10^8 m^3. To evaluate these results further a surface frequency plot (Figure 3.8) focusing on the sweet spot area (where laterals extend between 1000 m and 1700 m) was generated. Figure 3.8 indicates the most frequent technically recoverable reserve volume for a lateral of 1300 m would be between 200 x 10^8 m^3 and 1250 x 10^8 m^3.

Figure 3.7: A scatter plot for the technically recoverable reserves estimates (Mm^3) and carrying capacity per license block against lateral length (m).

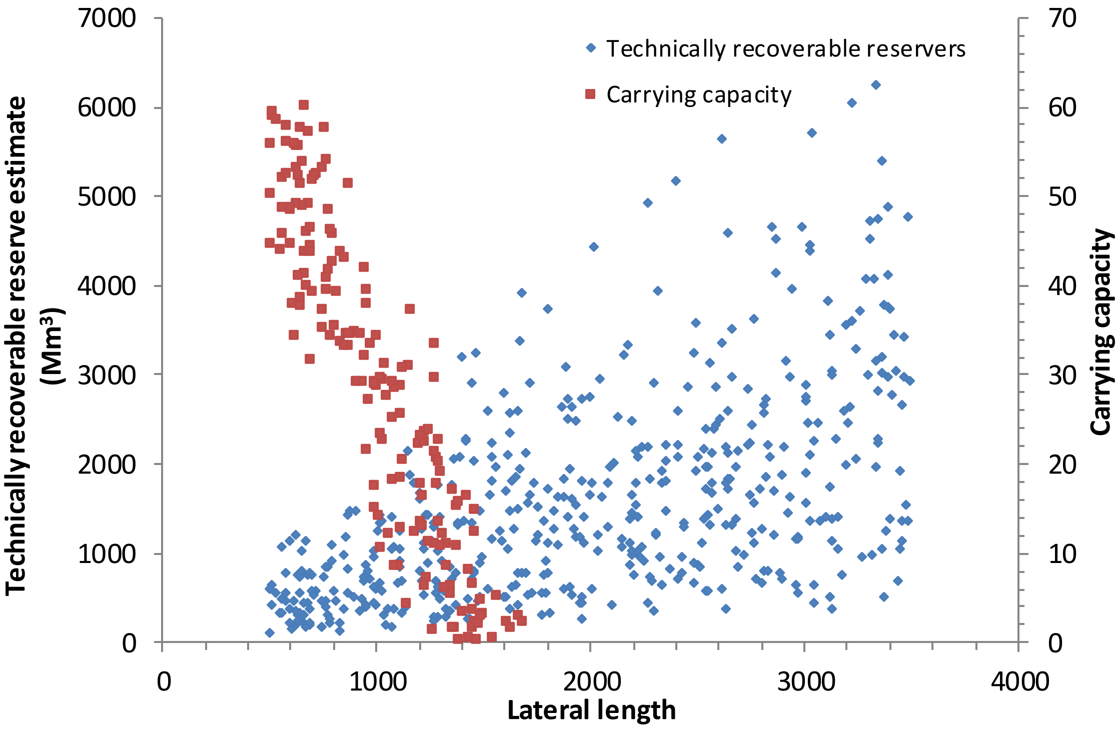
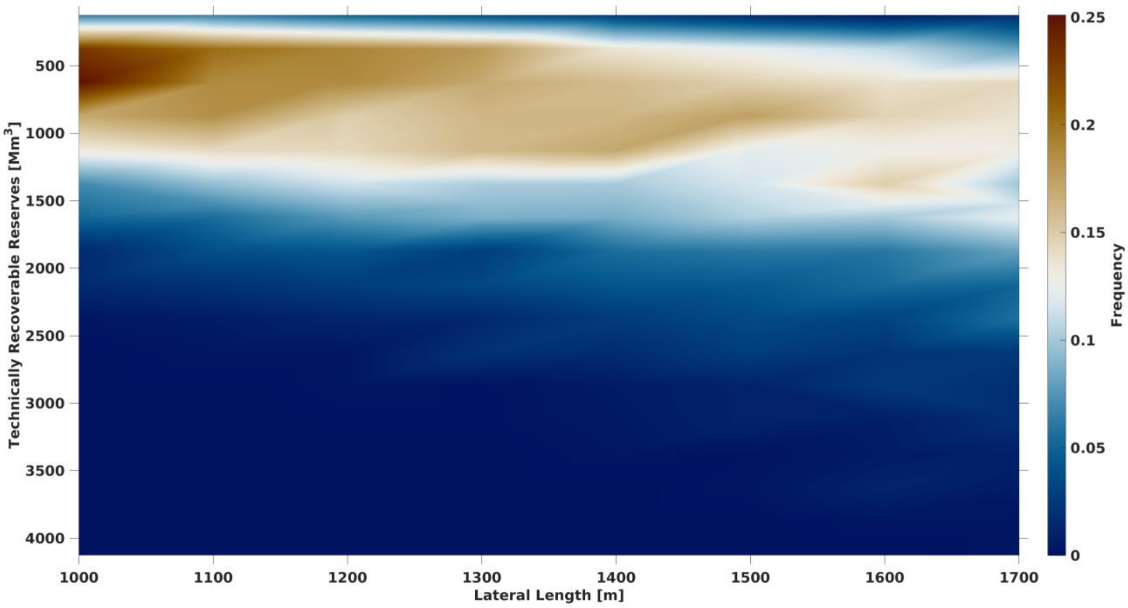


Figure 3.8: A surface graph for the technically recoverable reserves (Mm^3) and frequency against lateral length (m).



3.4 Discussion

As the number of wells on a well pad increases so too does the surface footprint. As the setback distance the borehole has to be away from existing infrastructure increases the indirect surface footprint increases. An increase in setback distances in densely populated licence blocks can potentially considerably reduce the access to resources. In England there are no legislative or national planning policy requirements on minimum setback distances (Cave et al., 2015). Similarly to the UK's policy on wind turbines (Barclay, 2010), the setback limits associated with shale gas sites within England are self-imposed, with the local planning developers and the public largely determining what is considered an acceptable distance. From Chapter 2 it can be seen that a 46 m setback distance between conventional oil and gas wells and houses is accepted, indicating that public opinion surrounding these developments is arguably more relaxed. Thus there is the potential that if a shale gas industry went ahead within England or elsewhere in the UK, and became well established, it may become more accepted and setback distances may decrease.

There is also the potential for setback distances to increase to protect against perceived risks associated with a shale gas industry. Currently there is no set distance a shale gas borehole or associated laterals need to be away from faults; however, an increase in the setback distance a borehole has to be away from faults may be introduced. Recent work by Wilson et al. (2018) suggests to prevent against induced seismicity or shallow groundwater contamination a horizontal respect distance of 895 m should be used between the horizontal boreholes orientated perpendicular to the maximum horizontal stress direction and faults optimally orientated for failure in their regional stress state. If regulations accounted for these recommendations the land available for potential shale gas sites in certain areas could be reduced, thus decreasing the carrying capacity of the land.

As highlighted by Ferguson (2013), subsurface planning is necessary to ensure optimal development of the Earth's crust to support energy security. Yuan et al. (2017) indicates that there is no advantage of drilling a well with longer lateral length with regards to production, thus within relatively low-productivity shale formations, well production shows an almost linear increase as the lateral length increases. However, as lateral length and width increases and the number of laterals per well pad increases the subsurface footprint also increases. This in turn impacts the carrying capacity of a license block, this study highlights that the number of well sites that can be located within a block is largely dependent on the individual licence block. Blocks that include large cities and towns have more existing infrastructure limiting the space available for potential well pads and associated setbacks. This study shows the most probable optimal lateral length for an average licence block located over the Bowland Shale where the setback distance and number of wells per license block vary would be approximately 1300 m, generating a technically recoverable reserves of 1200 x 10^8 m^3 when the whole block is developed. It is worth noting that in reality the placement of well sites is carefully determined and is not only based on the location of existing infrastructure but the underlying geology, specific of the shale play, as well as land ownership and planning laws. In addition, the population of the UK is growing (Office for National Statistics, 2017) and with this new infrastructure such as housing and roads are being built to meet demand; this reduces the carrying capacity of the surface to sustain a large number of shale gas developments. Thus to maximise gas extraction but minimise the impact on the land the wider cumulative development of shale gas sites is particularly important when considering future developments.

This studies results indicate that when a whole licence block is developed the probable lateral length for an average licence block located over the Bowland Shale would be approximately 1300 m, this is not consistent with general practise in the US or Canada. Largely within these sparely populated countries increasing lateral length with optimal fracture distances is the goal. However, there are examples in the literature that suggest longer laterals are not always most efficient and support the conclusion that regions need to be assessed on an individual basis. Yang et al. (2016) conclude that as the horizontal section length increases, the increasing rate of gas produced by the single-well decreases, recommending a horizontal lateral length of 1400 m to 1800 m for the Changning Block in the Sichuan Basin, China. Using economic parameters such as income per unit length and drilling costs Luo et al. (2016) conclude that an optimal horizontal wells length in the Sulige Gasfield in Inner Mongolia is 1200 m, stating that longer wells are not profitable. This is largely due to the fact that the reservoir is made up of very short sand bodies, therefore longer wells will just pass through and out of the reservoir (Luo et al., 2016). This chapter highlights the importance of existing infrastructure and how it may limit shale gas development. It is essential that practises are based on individual license blocks, their level of development and the precise geology at the exploration location.

There is a strong need to update resource estimates in Europe as the geological basis that the current estimates are based on is questionable. The main uncertainties are related to gas saturation and recovery factors. However, if a shale gas industry was developed in England or elsewhere in Europe, naturally over time a better understanding of the reserves, the shale's properties and how to extract the reserves in the most efficient and environmentally responsible way would be developed. In addition, advances in technology, developments in laws and possible changes in public opinion may alter the way a shale gas industry would be developed. During the recent US and Canadian boom in shale gas production considerable technological advances and regulatory frameworks have been developed to make hydraulic fracturing safer and more efficient. One key development seen over the last few decades which current shale gas production relies upon is horizontal drilling, which is continuously evolving to make hydraulic fracturing more efficient and economically viable (Arthur et al., 2010). Another improvement is the transitioning from drilling shale gas wells on single pads, to drilling multiple wells on one pad. This change was driven by economic reasons owing to the large costs associated with demobilising and moving a drill rig from one pad to another, however these changes also had a number of positive environmental impacts including less tanker traffic and pipeline infrastructure (Manda et al., 2014; US EIA, 2012).

Since Manda et al. (2014) companies have made further technological advances and are now building super-pads where wells are stacked in multiple zones (US EIA, 2016), which hold as many as 40 wells. For example, the US Company Pioneer is currently drilling the thick Spraberry/Wolfcamp shale in one of the biggest oil fields in the US, due to the considerable thickness of the shale the company are hoping to drill 30 to 40 horizontal wells from the same well pad through 6 different stratas (Dove, 2013). These giant pads increase efficiency in a number of ways. In places the combined upper and lower Bowland Shale within the Bowland Basin is thought to be over 650 m thick (Fauchille et al., 2017), a fact Taylor et al. (2013) took into consideration when suggesting their development scenarios, one of which includes four levels, where each level has 10 wells. If the UK shale gas industry were developed with a large number of wells being multi storey, for example with each well pad consisting of 40 wells, the cumulative surface footprint to gas extracted would be considerable reduced. It is worth noting that technological advances and development efficiencies can be limited by the company drilling the well, and the investments and technologies available to them.

As there is not a currently operating shale industry within the UK, much of the data used within this study is hypothetical and based on US experience. Therefore, many of the ranges (e.g. reserve estimates) used are large and potentially an under or over estimate of what a likely UK shale industry would actually look like.

3.5 Conclusion

This chapter shows the probable optimal lateral length for an average licence block located over the Bowland Shale when developing the whole block to be 1300 m, generating technically recoverable gas reserves of 1200 x 10^8 m^3. This result highlights that longer laterals are not necessarily the most efficient when developing whole licence blocks, which is not consistent with general practise in the US or Canada. Largely within these sparsely populated countries increasing lateral length with optimal fracture distances is the goal. However, there are examples in the literature that suggest longer laterals are not always most efficient and support the conclusion that regions need to be assessed on an individual basis.

Chapter 4:

The potential for spills and leaks of contaminated liquids from shale gas developments[2]

4.1 Introduction and aims

The risk of spills and leaks of potentially toxic fluids associated with a possible shale gas industry is a great concern for the public (Gross et al., 2013; Patterson et al., 2017). This chapter aims to investigate the likelihood of spills and leaks of fluids required for shale gas production occurring both on a well site and during transportation to and from the well site.

Reports from the Texas Railroad Commission (1999 to 2015) and the Colorado Oil and Gas Commission (2009 to 2015) were used to examine spill rates from oil and gas well pads within these US states. These analogous results have been used to estimate the likelihood of a spill onsite for different UK shale gas development scenarios. Road transport incident data for the UK and the Environment Agency's pollution incident records for England were examined as an analogue for potential offsite spills associated with transport for a developing shale industry. From assessing the different pathways spills and leaks are currently occurring within the existing oil and gas industries and comparator industries, mitigation strategies have been developed.

4.2 Approach and methodology

A leak is a way for fluid to escape a container or fluid-containing system. The word leak usually refers to a gradual loss; while a sudden loss is usually called a spill. For simplicity this study refers to any accidental and undesired escape of fluid as a spill. Additionally the

[2] This chapter is based on a paper that has been published in the journal Science of the Total Environment: Clancy, S. A., Worrall, F., Davies, R. J., Gluyas, J. G., 2018b. The potential for spills and leaks of contaminated liquids from shale gas developments. Science of the Total Environment 626, 1463-1473.

difference between types of fluids spilt (e.g. flowback water, fracking fluid, produced waters) have not been distinguished. The toxicity of the type of fluid spilt and therefore the impact of the spill can vary considerably, for example spilling a highly saline flowback water is very different to spilling produced waters contaminated with BTEX or crude oil. However, this study has focused on the probability of an incident occurring rather than the consequence.

As no shale gas industry currently operates within Europe information has been drawn from both onsite and offsite experiences in the US and analogues from within the UK. Due to differences in the source and occurrence of the spills, this study has analysed onsite and offsite incidents separately. Two US state data sources were considered: the Texas Railroad Commission (Texas RRC – RRC, 2017a) and the Colorado Oil and Gas Commission (COGCC - COGCC, 2017a, b). The recorded spills have been evaluated to assess the type, volume and reasons for the currently occurring spills. From this spill analysis the probability of spills onsite for potential shale gas developments within Europe has been assessed. In England, spills from oil and gas sites are reported to the Environment Agency and recorded in the pollution incident database. This database was analysed to access the number of incidents that have occurred on conventional well pads within England.

Without a fully developed shale gas industry within the UK, potentially toxic fracking fluid, produced water and flowback fluid (as described in Section 1.2.3.1) will be transported to and from the site via tanker trucks. The flowback fluid from Cuadrilla's Preese Hall well was trucked to Davyhume in Manchester (EA, 2011), located over 80 kilometres from the site. Although unconfirmed at present, the Preston New Road fracking site in Lancashire will possibly require produced and flowback fluid to be transported even further, with Knostrop wastewater treatment works located in Leeds being suggested. Within this study the distance the wastewater must travel has not been factored into the calculations and so a confirmed wastewater treatment works and thus distance travelled is not required. However, with an increase in the distance travelled from the Preston New Road site to the selected wastewater treatment works the chance of an incident or spill offsite obviously increases. With a lack of information in Europe and the US for incidents offsite, UK milk and fuel (petrol and diesel) tanker incidents were analysed as an analogue to determine the probability of an incident related to hydraulic fracturing occurring on the road for different shale gas development scenarios. These vehicle types have been identified within the records and considered a good analogue for the transport required within a UK shale gas industry as they often operate on rural roads, carrying liquid that is a pollutant with respect to surface waters. Recorded tanker incidents have been cross-checked with the Environment Agency's pollution incident database for England to determine their environmental impact.

4.2.1 Onsite

4.2.1.1 Texas Railroad Commission (Texas RRC) database

The Texas RRC enforces the delineation and reporting of any spill of 0.8 m^3 or more within the state (RRC, 2017b). The dataset includes surface spills of crude oil, gas well liquid[3], products[4] and combined[5] (RRC, 2017a). This data is publically available and documents the number of spills, volume spilt, spill type, facility type that the loss was from and the cause for all spills from 2009 to 2016. The data indicates the gross loss per spill, the amount of spill recovered and the net loss. The data were evaluated for each year individually and then compiled to assess trends within the whole dataset. The statistical significance of trends was assessed using a t-test and in all cases significance was judged at a probability of not being zero of 95%. The Texas RRC also records the number of wells active per year and the volumes of crude oil produced; from these the percentage of produced crude oil spilt was calculated. From the

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[3] Condensate or other hydrocarbons produced from a gas well.
[4] Derived from petroleum hydrocarbons, for example, crude oil, processed crude petroleum, residue from crude petroleum, fuel oil, natural gas gasoline, gas oil, waste oil, blended gasoline, lubricating oil, blends or mixtures of petroleum, and/or any and all liquid products or by-products derived from crude petroleum oil or gas, whether hereinabove enumerated or not.
[5] Combination of crude, condensate, and/or other produced water.

average number of spills per year and the average number of active wells per year, the average number of spills per well has also been calculated.

4.2.1.2 Colorado Oil and Gas Commission (COGCC) database

The COGCC require operators to fully report: (1) spills of any size that impact or threaten to impact waters of the state (streams, lakes, ponds, drainage ditches), structures, livestock, public byways; (2) spills greater than 0.2 m^3 that released exploration and production (E&P), or produced water outside of the berm or other secondary containment; (3) spill of 0.8 m^3 or more, regardless of whether the spill was contained within the berms or other secondary containments (COGCC, 2015). The COGCC has two spill databases, due to considerable changes in processing and data collection they are not comparable and have been analysed separately and henceforward are referred to as: '1999 – 2015 spill data', and '2014 – 2015 spill data' (COGCC, 2017a; COGCC, 2017b). Both datasets included data for 2016; however, data were only available for the first two quarters of 2016, being incomplete it was not included in this study. The '2014 – 2015 spill dataset' provides the following information on each spill; timing, location, type and volume, facility type (where breach occurred) and the impact on land and surrounding environment. Conversely the '1999 – 2015 spill dataset' is less comprehensive, consisting only of the number of active wells, annual volume of oil and water spilt and produced and percentage of the produced oil and water spilt. From this data the changes and patterns in oil and water spill numbers and volumes over the 17 years recorded have been assessed. Using the number of active wells per year and the '1999 – 2015 spill data' the average number of spills per well has been calculated.

4.2.1.3 Pollution incident database

The Environment Agency records the pollution incidents in England and classifies them according to their impact on population, environment and level of response required (EA, 2017). Each is recorded by date and location and categorised on pollution type and impact. The pollution impact category system is 1 (major) to 4 (no impact). The pollution incident database for England contains 12335 incidents recorded between March 2001 and December 2016 (EA, 2017).

To determine the number and cause of incidents related to well integrity failure within England, Davies et al. (2014) analysed this database. Davies et al. (2014) only reported incidents which could be confirmed as being due to well integrity failure, whereas this study considered all incidents reported, from any well pad. Identification and analysis of the cause of releases in currently operating industries allows for lessons to be learnt and mitigation strategies to be put in place avoiding repeating these incidents.

4.2.1.4 Onsite industrial development scenarios

The UK's Institute of Directors (IoD) have suggested several shale gas development scenarios for the UK, the first is based on the development of a 10 well pad of 10 laterals (one well pad with 10 wells each with one lateral) (Taylor et al., 2013). The second involved the development of a 10 well pad of 40 laterals (one well pad with 10 wells each with four laterals) (Taylor et al., 2013). These two scenarios have been used along with the calculated number of spills per well (based on data from the Texas RRC, the COGCC and the pollution incident database) to determine the likely number of spills occurring on a single site, and how many sites would need to be developed before a spill is likely to be experienced. As it is unlikely only one site would be developed these results highlight the accumulative risk of a number of well sites.

4.2.2 Offsite

4.2.2.1 Milk tankers

Without a shale gas industry currently operating within Europe this study has used an analogue of UK milk tanker journeys to predict the probability of spills during the transportation of fracking fluid, produced water and flowback water to and from the well site. Milk tankers are a good analogue to tankers that may be used within the shale gas industry as they are a similar size and travel along similar road types. Within this study milk tankers are defined as vessels used to transport large quantities of milk (approximately 30 m^3), references to milk floats, vans or lorries are not included. Assuming an average milk tanker size of 30 m^3, some 366667 journeys are required to transport the 11 million m^3 of milk produced by British farmers each year (Taylor et al., 2013). A search of local media reports involving milk tanker incidents in the UK between 1998 and 2016 was carried out. Boolean operators were used to connect and define the relationships between the different search terms. Search terms were built upon a combination of primary, secondary and tertiary search terms. The two Boolean operators used were AND and OR. The primary search term 'milk', was combined with the secondary search term 'tanker', and the tertiary search terms 'accident' OR 'incident' OR 'road' OR 'crashes' OR 'overturned' OR 'spillage'. There was no discrimination on the type of report or article, authorship or publisher used; incidents due to engine fires were not recorded. Only articles written in English were analysed. Reports were screened based on relevance to the UK; incidents and spillages based outside the UK were not considered further. The number reported was recorded, those resulting in a spillage of milk or flammable liquid (e.g. diesel) were logged, as were, if documented, the volumes spilt and cause of incident. Also noted, was if the incident resulted in injuries or fatalities.

Where possible incidents reported in the media were matched to those recorded in the Environment Agency's pollution incident database, and the type and scale of the pollution caused by the spill incidents assessed. As this database only includes incidents from England, only these have been matched.

4.2.2.2 Fuel tankers

The UK road fuel (petrol and diesel) tanker fleet is estimated to be around 1000 to 1500 vehicles, these are estimated to travel some 220000 km each year (Robinson et al., 2014). The size and volume capacity of fuel tankers varies considerably. Commonly large tankers with capacities of between 21 to 44 m^3 are used to transport petrol and diesel to filling stations (Madigan, 2017). Fuel tankers have been studied, as similarly to milk tankers they are a good analogue for the tanker movements that would be associated with a UK shale gas industry. Unlike milk tankers the average number of journeys required each year to transport the nations fuel is undocumented in the literature. Therefore, the number of journeys has been determined from the known volume of motor fuel consumed by the UK, recorded by the Department for Business, Energy and Industrial Strategy (BEIS, 2017) and the UK average tanker size. This estimate was then used to determine the probability of an incident or spill per year.

The Transport Research Laboratory (TRL) compiled data on all tanker accidents by carrying out a search of local BBC news reports involving tanker incidents which occurred in the UK between 2009 and 2014 (Robinson et al., 2014). Their data collection involved searching for all media articles that mentioned ‘tanker’ and ‘accident’ on the BBC news website. These were then assessed on whether a spill occurred; a flammable liquid was spilt; an injury resulted; the incident was caused by a collision or the tanker overturned; and if the tanker overturning led to a spillage (Robinson et al., 2014). This study continued the search for 2015 and 2016 using the same method used by TRL. In a similar manner to milk tankers a broader search was then conducted just for fuel tankers between 2009 to 2016, using the same method and search terms to check for milk tanker accidents, with the addition of ‘milk’ being substituted for 'fuel' OR 'petrol' OR 'diesel'. As with milk tankers, where possible, spill incidents related to fuel tankers were matched to incidents recorded in the Environment Agency's pollution incident database.

4.2.2.3 Offsite industrial development scenarios

The development scenarios proposed by Taylor et al. (2013), along with the annual number of incidents and spills per milk and fuel tanker on the road for 2016 have been used to calculate the potential number of offsite incidents and spills related to a future UK shale gas industry. Data for 2016 was used to generate the following scenarios, as being the most recent it was deemed the most accurate.

Taylor et al. (2013) first scenario based on the development of a single 10 well pad of 10 laterals would potentially produce 0.9 km^3 of gas, requiring 136000 m^3 of water per well. Initially it is likely that the water will be trucked to the site rather than piped, requiring between 2856 and 7890 tankers over a 20 year period (the likely lifetime of a shale gas well - Taylor et al., 2013). If tanker movement was concentrated in the early years of drilling activity, which is most likely, this would average out at 3.9 – 10.8 tanker movements per day over two years, or if spread over 20 years this would decrease to 0.4 – 1.1 per day (Taylor et al., 2013). The second scenario, based on a single 10 well pad of 40 laterals, potentially producing 3.6 km^3 of gas and using 544000 m^3 of water per pad equates to between 11155 and 31288 tanker movements over 20 years, or 1.5 – 4.2 tanker movements per day (Taylor et al., 2013): when averaged out over five years this equals 6.1 - 17.1 tanker movements per day (Taylor et al., 2013). As it is unlikely that just one well pad would be developed the probability of an incident or spill occurring from a number of well pads was estimated.

4.3 Results

The analysis of the results has been split into incidents that occurred onsite and those occurring offsite during transportation.

4.3.1 Onsite

4.3.1.1 Texas Railroad Commission

The number of reported spills between 2009 and 2015 has increased each year with 675 reported in 2009 and 1485 in 2015 (Table 4.1). Over the same period the number of producing wells also increased from 157807 in 2009 to 193807 in 2015. The number of spills per producing well increased at an average rate of 0.0006 spills/yr^2, the t-test showed that the increase in spill rate was significant at 95% probability. Of the 7820 spills recorded during the study period the majority (83%) involved the loss of crude oil (Table 4.1). The most common cause of leakage was due to equipment failure; the second was due to corrosion (rust) of equipment, followed by 'Acts of God' and human error. The most common location for a spill to occur was around the tank battery (the device used to store crude oil which has been generated from a well - 70% of the spills), followed by the flow line (10% of the spills) and pipeline (8% of the spills).

The number of crude oil spills has increased year on year since 2009, with 549 reported in 2009 and 1270 in 2015. The average per year was 924. The number per producing well increased at a rate of 0.0001 spills/yr^2, this was significant at the 95% probability (Table 4.1). The total annual volume of crude oil spilt varied from 6713 m^3 (2009) to 14158 m^3 (2015) (Table 4.1). The average rate of change over this seven-year period was 805 m^3/yr^2, which was statistically significant at 95% probability. Clean-up operations recover some of the lost fluid however much is left unrecovered. Annually between 50 and 76% of the crude oil spilt is recovered, with an annual average of 59% (Table 4.1). The largest spill was recorded in 2010 with 3975 m^3 escaping in one incident; however, 99.7% of this was recovered (Table 4.1). The largest reported net loss of crude oil for a single spill was 1069 m^3 (Table 4.1).

Between 2009 and 2015, 715 producing wells reported gas well liquid spills, with the number decreasing over the time period analysed, this trend was not statistically significant (Table 4.1). The total annual volume of gas well liquid spilt ranged from 489 m^3 in 2015 to 2438 m^3 in 2013 (Table 4.1), the annual average percentage recovered was 30%.

The number of spills involving product (as defined in Section 4.2.1.1) varied year on year, from five in 2015 to 95 in 2013 (Table 4.1). Although there has been an increase in the number of wells and spills per year the trend was not statistically significant. The annual percentage recovery rates show that 65% of the product is recovered after a spill (Table 4.1). The annual average minimum and maximum recovery ranged from 16% in 2012 to 94% in 2010 (Table 4.1).

There has been a statistically significant change over the time period recorded for the loss of combined liquids: in 2009 three cases were recorded, whilst in 2015 154 cases were recorded (Table 4.1). The annual average minimum and maximum recovery ranges from 20% in 2011 to 91% in 2010 (Table 4.1).

Table 4.1: The annual number of active wells, and associated gross loss, fluid recovered, net loss and percentage recovered for crude oil, gas well liquids or associated products. Data recorded by the Texas Railroad Commission (RRC, 2017a; RRC, 2017c).

Year	Number of producing wells	Number of spills	Number of spills by type				Combined				Crude				Gas Well Liquid				Products			
			Combined	Crude	Gas well liquid	Products	Gross loss (m^3)	Recovered (m^3)	Net loss (m^3)	% Recovered	Gross loss (m^3)	Recovered (m^3)	Net loss (m^3)	% Recovered	Gross loss (m^3)	Recovered (m^3)	Net loss (m^3)	% Recovered	Gross loss (m^3)	Recovered (m^3)	Net loss (m^3)	% Recovered
2009	157807	675	3	549	91	32	20	10	10	52	6713	3418	3296	51	1049	384	665	37	1120	920	200	82
2010	158451	796	5	630	123	38	351	320	31	91	12414	9449	2964	76	1522	617	905	41	3074	2878	197	94
2011	161402	869	8	724	101	36	101	20	81	20	9698	4863	4835	50	1158	409	749	35	956	460	496	48
2012	167864	1236	19	1028	128	61	252	170	82	68	12015	6934	5081	58	1883	497	1387	26	6463	1062	5401	16
2013	179797	1354	29	1105	125	95	418	268	151	64	12548	7289	5259	58	2438	581	1857	24	3376	2153	1223	64
2014	190331	1405	122	1160	91	32	2850	1208	1642	42	11099	6118	4981	55	761	143	618	19	2044	1531	513	75
2015	193807	1485	154	1270	56	5	4441	2750	1691	62	14156	8759	5397	62	489	133	356	27	34	26	8	77
Total	1209459	7820	340	6466	715	299	8433	4746	3686		78643	46830	31813		9300	2764	6536		17068	9030	8038	

4.3.1.2 Colorado Oil and Gas Commission

The '1999 - 2015 spill' data does not distinguish between whether it was oil or water spilt, recording a total of 6617 spills, the maximum and minimum numbers of spills per year were 789 in 2014 and 193 in 2002 (Table 4.2). The average was 389. Between 1999 and 2015 there was an increase in the number of active producing wells and the number of spills, at a rate of 0.00017 spills/yr^2, however this increase is not statistically significant at the 95% probability. A total of 0.11 km^3 of oil and 0.88 km^3 of water were produced between 1999 and 2015. Of this, 8670 m^3 of oil and 81200 m^3 of water were spilt, equivalent to 0.008% and 0.009% of the oil and water produced (Table 4.2). For this dataset there is no information on recovery rate or reasons for the spills.

Of the '2009 - 2015 spill data' only years 2014 and 2015 are complete, therefore only those years have been studied. Of the 2893 spills recorded during this period; 563 were oil, 401 condensate, 50 flowback water, 1399 produced water, 78 E&P waste and 129 drilling fluid (Table 4.3). The volume spilt varies considerably; 188 spills were recorded between >0 and <0.2 m^3, 1201 were between >=0.2 m^3 and <0.8 m^3, 1051 were between >=0.8 m^3 and <16 m^3 and 180 were >=16 m^3 (Table 4.3). The average length and width of a spill was 33 m and 10 m respectively, whilst the maximum was 1416 m and 152 m respectively. The average depth to groundwater in the spill locality was 28 m and the average depth the spill impacted was 2.5 m, with a maximum depth impact of 22 m. Just over 73% (2112) of spills had >=0.16 m^3 of fluid leak outside the berm of the well pad, with three sites requiring an emergency pit to be constructed. The average volume of soil that needed to be excavated due to pollution from a spill was 220 m^3, with a maximum of 10780 m^3 being removed from one site. Polluted soil was excavated offsite from 471 sites; 62 sites treated the soil onsite, whilst 74 sites had the soil disposed of by alternative methods. The average volume of groundwater removed was 42 m^3, with 484 m^3 being the maximum quantity removed from one site. At two sites 1 m^3 and 6 m^3

of surface water was removed. Of the spills documented; 1107 impacted soil, 260 groundwater, 16 surface water and 30 dry drainage features.

Of the spills 1946 were termed 'recent', meaning recent or ongoing at the time of discovery, whereas 947 were termed 'historical', having occurred at a time unknown or discovered during activities such as plugging and abandonment or site reclamation. Of the spills 653 were reportedly due to equipment failure, 254 human errors, 186 were historical and 46 were recorded as 'other'. Examples of 'other' include weather, vandalism and external sources of interference such as cattle. In 2014, one instance involved cattle rubbing against the valve handle of the wellhead and partially opening the valve allowing produced water to spill out. In 2015, there was a report of wild horses pushing open a 2.5 cm valve, this was determined by tracks and faeces left in the area. The most common location facility type from which spills originated from was the tank battery, with 36% of spills initiating there, whereas 6% of the spills were associated with pipelines.

Table 4.2: The annual number of active wells, number of spills and volumes of oil and water produced and spilt for Colorado. Data recorded by the Colorado Oil and Gas Commission (COGCC, 2017a).

Year	Number of active wells	Number of spills	Oil spilled (m^3)	Water spilled (m^3)	Oil produced (m^3)	% Produced oil spilled	Water produced (m^3)	% Produced water spilled	Average oil spilled (m^3) per incident	Average water spilled (m^3) per incident	Average oil produced (m^3) per incident	Average water produced (m^3) per incident	% Of active wells that spilled
1999	21745	263	363	6576	3131683	0.01	36590207	0.02	1	25	11908	139126	1.21
2000	22228	254	569	3584	3183339	0.02	40227601	0.01	2	14	12533	158376	1.14
2001	22879	206	308	1682	3208682	0.01	42335137	0.00	1	8	15576	205510	0.90
2002	23711	193	509	9196	3270789	0.02	45013104	0.02	3	48	16947	233229	0.81
2003	25042	213	465	3105	3434841	0.01	48137113	0.01	2	15	16126	225996	0.85
2004	26968	222	637	5898	3588455	0.02	46985899	0.01	3	27	16164	211648	0.82
2005	28952	326	797	3917	3692872	0.02	55177628	0.01	2	12	11328	169257	1.13
2006	31096	336	414	5317	3894915	0.01	63313559	0.01	1	16	11592	188433	1.08
2007	33815	376	648	4308	4163614	0.02	62628307	0.01	2	11	11073	166565	1.11
2008	39944	408	508	11441	4759933	0.01	58431321	0.02	1	28	11667	143214	1.02
2009	37311	368	443	3532	4827681	0.01	57129268	0.01	1	10	13119	155243	0.99
2010	41010	499	521	5349	5243162	0.01	57559586	0.01	1	11	10507	115350	1.22
2011	43354	501	522	5374	6271776	0.01	54762143	0.01	1	11	12519	109306	1.16
2012	46835	407	716	2334	7869668	0.01	52857376	0.00	2	6	19336	129871	0.87
2013	50067	633	627	2281	10397330	0.01	52203721	0.00	1	4	16425	82470	1.26
2014	51737	789	388	2847	15230669	0.00	53356073	0.01	0	4	19304	67625	1.53
2015	53054	623	233	4468	20038113	0.00	52190327	0.01	0	7	32164	83773	1.17
Total	599748	6617	8670	81208	106207523	0.01	878898369	0.01					1.10
Average		389	510	4777	6247501		51699904						
Maximum		789	797	11441	20038113		63313559						
Minimum		193	233	1682	3131683		36590207						

Table 4.3: The type of fluid spilt and volume of fluid spilt for 2014 and 2015 in the State of Colorado. Data from Colorado Oil and Gas Commission (COGCC, 2017b).

Volume spilt (m^3)	Number of oil spills	Number of condensate spills	Number of flowback water spills	Number of produced water spills	Number of E&P waste spills	Number of drilling fluid spills	Total number of spills
0	2083	2125	2801	912	2778	2094	
>0 and <0.2	98	41	0	43	1	5	188
>=0.2 and <0.8	265	259	15	607	24	31	1201
>=0.8 and <15.9	191	90	30	606	46	88	1051
>=15.9	9	11	5	143	7	5	180
unknown	247	367	42	582	37	670	1945
Total number of spills	563	401	50	1399	78	129	

4.3.1.3 Pollution incident database

Based on data provided by DECC, Davies et al. (2014) comments that there were 143 onshore oil and gas wells producing at the start of 2000. Between 2000 and 2013 the Environment Agency recorded nine pollution incidents involving the release of crude oil within 1 km of an oil and gas well. Two of the spills were recorded at the Singleton Oil Field and were caused by borehole cement failure. The other seven were due to leaks from pipework linked to the well (Davies et al., 2014). Between 2000 and 2013 the pollution incident rate was 0.0045 incidents/well/yr.

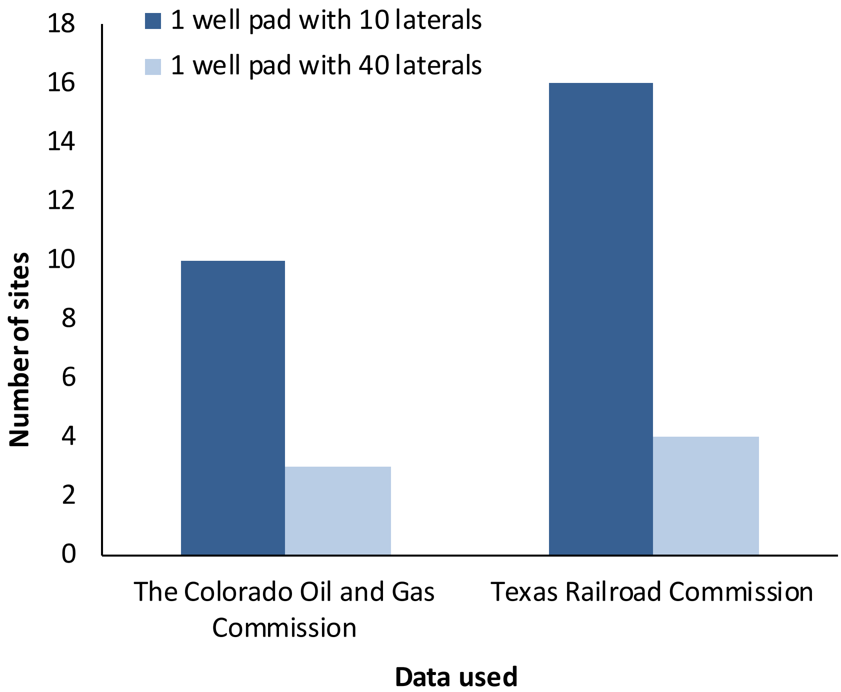
4.3.2 Application

Using data from the Texas RRC and values from the first scenario (based on well pads with 10 wells, each with one lateral) the probability of a spill occurring on a developed site in the UK was calculated at 0.06 spills/well pad; therefore there would likely be a spill onsite for every 16 well pads developed (Figure 4.1). When the COGCC '1999 – 2015 spill data' and values from the first scenario are used the likelihood of a spill is 0.11 spills/well pad; therefore a spill would likely occur for every 10 well pads developed (Figure 4.1).

Using Texas RRC data and values from the second scenario (based on well pads with 10 wells, each with four laterals) the likelihood of a spill onsite was 0.26 spills/well pad; therefore it is likely that a spill would occur for every four well pads developed (Figure 4.1). Using the COGCC '1999 - 2015 spill data' and values from the second scenario the likelihood of a spill is 0.44 spills/single-well pad, therefore there would likely be a spill for every three well pads developed (Figure 4.1).

Using data from the Environment Agency's pollution incident database the results for the first scenario showed that the likelihood of a spill onsite was 0.045 incidents/single-well pad; therefore a spill would likely occur for every 23 well pads developed. Applying these values to the second scenario the likelihood of a spill onsite was 0.18 incidents/well pad; therefore there would likely be a spill for every six well pads developed.

Figure 4.1: The number of sites that need to be developed before a spill is likely to occur onsite based on data from the Texas RRC and COGCC. Scenario 1 (dark blue bars): Single-well pad with 10 wells, each well is a lateral; Scenario 2 (light blue bars): Single-well pad with 10 wells, each well has four laterals.



4.3.3 Offsite

4.3.3.1 Milk tankers

Between 1998 and 2016 122 milk tanker incidents were recorded, 54 of these were reported to have spills associated with them. The last four years studied saw the highest number of annual incidents, between 1998 and 2016 the number of incidents per year increased at a rate of 0.6 incidents/yr^2. The rate of change over this 19 year period was statistically significant at the 95% probability. The greatest number of milk spills recorded in a year was six, in 2016. The number of spills per year has increased at a rate of 0.5 spills/yr^2, this was statistically significant at the 95% probability. Of the spills 89% consisted of milk and 24% flammable liquid, and where mentioned it was always diesel, implying that the accident had been severe enough to rupture a fuel tank. The largest spill involved 20 m^3 of milk escaping from the tanker, however many media reports have not recorded the quantity of milk spilt, nor were the volumes of flammable liquid spilt commented on. Of the incidents assessed 61% were caused by a collision, most commonly milk tankers with cars but also with central reservations, hedges, houses and in one incident a bridge. Tankers rolled over in 43% of the reported cases, often due to a collision but also due to tankers jack knifing or breaking away from the drivers cab and drivers losing control. One of the spills was caused by a faulty valve. Injuries were reported in 58% of incidents, 16% of these resulted in death.

Six milk tanker incidents reported in media reports matched with an incident in the pollution incident database, i.e. 48 milk spills were not found to be recorded in the pollution incident database. Air pollution was recorded in two of the incidences; the impacts of these events were reported as being minor and "significant" (note that the term significant is as used within the database and implies no statistical significance as is the case in the rest of this study). Two incidents were reported as causing land pollution; one was considered as having minor impact and the other "significant". All the incidents were recorded as polluting a water system; two were determined minor and four as "significant". Pollutant type has been determined for each incident, three spills were categorised as oils and fuel, and the other three were recorded as: organic chemicals or product, general biodegradable material and wastes, and specific waste materials, i.e. each of these could be a description of a milk tanker incident.

4.3.3.2 Fuel tankers

From the review of the local BBC media reports between 2009 and 2014, TRL identified 59 incidents involving a variety of vehicles (both rigid and articulated) and loads (foodstuff, chemicals and fuels) (Robinson et al., 2014). Of those recorded 42% were found to be spillage incidents, with 80% of those cases involving flammable liquids (Robinson et al., 2014). A tanker overturned in 37% of the media reported incidents (Robinson et al., 2014). Of these 64% were then reported to have spilled their load. When this study continued the search for 2015 no additional media stories were recorded, however when the media search was conducted using the broader approach, as used for identifying milk tanker incidents, the reported fuel tanker incident numbers for 2015 and 2016 were 14 and 17 respectively. Of these 36% and 53% resulted in a fuel spillage. The largest known spill volume was 8 m^3 in 2016, however this could be far higher as many of the media reports did not record the volume spilt. When assessing the media reports between 2009 and 2016 with the broader search terms 61 incidents were recorded, of these 44% had associated spills. The incident rate increased annually by 1.7 incidents/yr^2, whilst the spill rate increased annually by 0.96 spills/yr^2, these rate increases were statistically significant at the 95% probability. Of the incidents reported 51% involved an injury, whereas 23% were associated with a fatality. All incidents were caused by some sort of collision with 28% of the incidents resulting in the tanker overturning. There were no matches between the fuel tanker incidents recorded in the media and the pollution incident database.

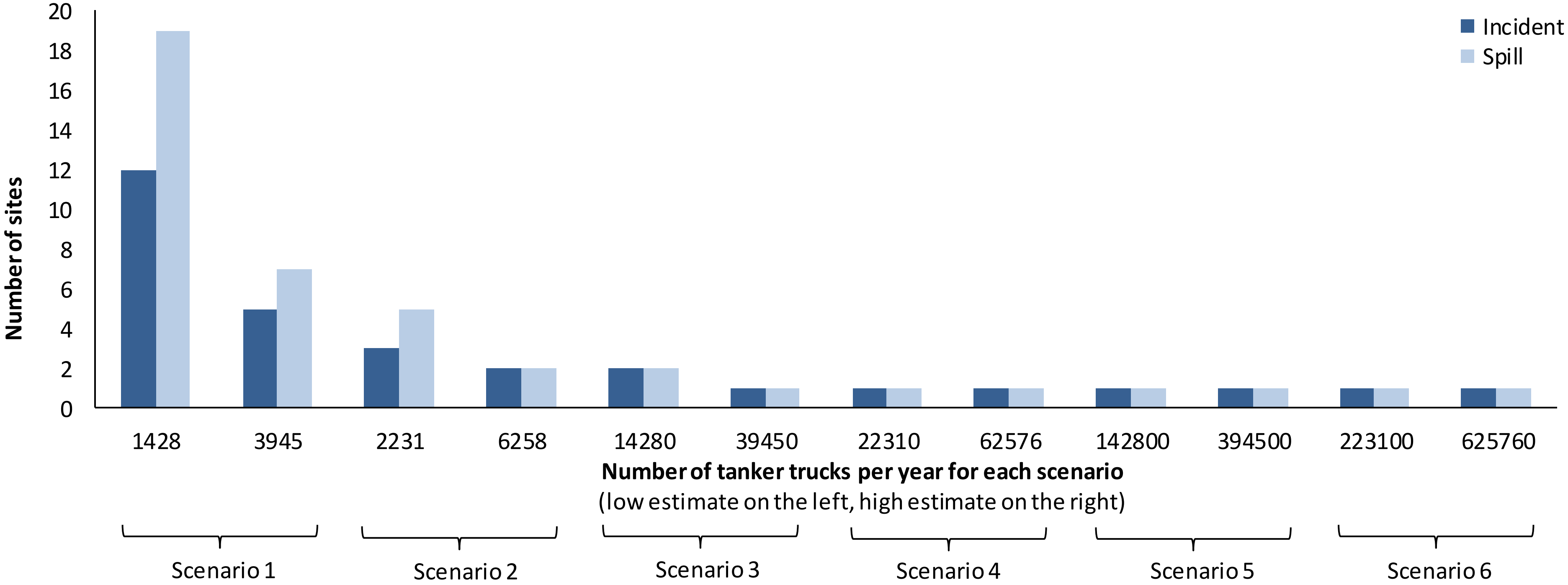
4.3.4 Application

4.3.4.1 Milk tankers

The first scenario results (based on well pads with 10 wells, each with one lateral) with the lower tanker movement estimate (2856 tankers) concentrated over the first two years of drilling resulted in the probable number of incidents and subsequent spills being between 0.043 – 0.118 incidents/year and 0.027 – 0.075 spills/year. When spread over 20 years the probable number of incidents was between 0.004 – 0.012 incidents/year, with the predicted number of spills being between 0.003 – 0.008 spills/year. The accumulative risk of an incident or spill over the lifetime of a well (in this case 20 years as assumed in Taylor et al., 2013) for this scenario was between 0.086 – 0.237 incidents/lifetime of the well pad and 0.055 – 0.151 spills/lifetime of the well pad. Based on the milk tanker data and the lower tanker movement estimate spread over two years, there would likely be one incident on the road for every 12 well pads developed and a spill for every 19 well pads developed (Figure 4.2). This rate is equivalent to one 30 m^3 tanker spilling part of its load out of the 54264 required to transport the 1628000 m^3 of fluid needed for 19 well sites.

The likely annual number of incidents and spills for the second scenario (based on well pads with 10 wells per pad, each with four laterals) if the lower tanker estimate (11155 tankers) movements were concentrated over five years would be between 0.067 - 0.118 incidents/year, and 0.043 – 0.119 spills/year. When tanker movements were spread over 20 years the probability of an incident and spill was between 0.017 – 0.047 incidents/year and 0.011 – 0.03 spills/year. The accumulative risk of an incident or spill over the lifetime of a well for this scenario would be between 0.304 – 0.853 incidents/lifetime of the well pad and 0.183 – 0.512 spills/lifetime of the well pad. Based on the milk tanker data and the lower tanker movement estimate spread over five years, there would likely be an incident on the road for every three well pads developed and a spill for every five well pads developed (Figure 4.2). This rate is equivalent to one tanker out of the 55775 required for five well sites spilling part or its entire load.

Figure 4.2: The number of sites that need to be developed before an incident or spill is likely to occur based on the milk tankers data and minimum and maximum tanker numbers from the IoD report. Scenario 1: Single-well pad with 10 wells with 10 laterals developed over two years; Scenario 2: Single-well pad with 10 wells with 40 laterals developed over five years. Scenario 3: 10 well pads with 10 wells with 10 laterals developed over two years; Scenario 4: 10 well pads with 10 wells with 40 laterals developed over five years. Scenario 5: One hundred well pads with 10 wells with 10 laterals developed over two years; Scenario 6: One hundred well pads with 10 wells with 40 laterals developed over five years.



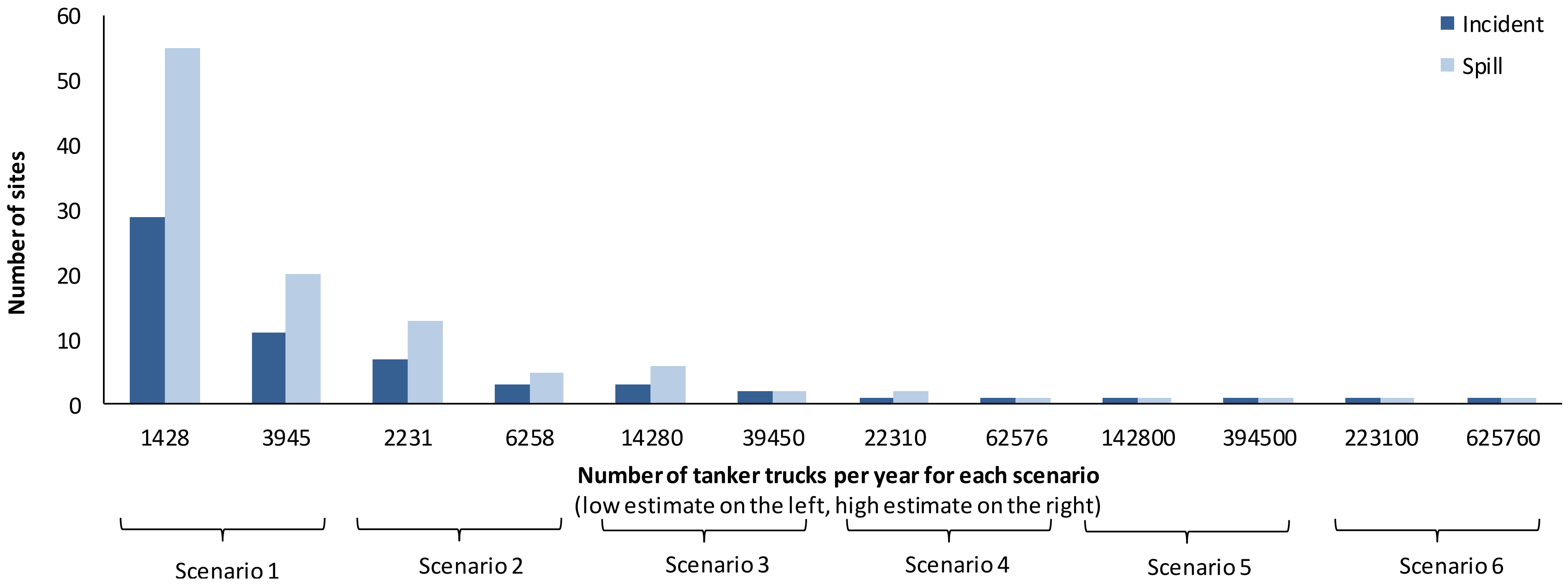
4.3.4.2 Fuel tankers

For 2016 the recorded volume of motor spirit (gasoline/petrol) and Derv (road diesel) used were 11951 KT and 24648 KT (BEIS, 2017): or 15800000 m^3 of gasoline, 29200000 m^3 of diesel and a total of 45000000 m^3 of hydrocarbon road fuels. A large tanker generally used for fuel transportation has a capacity of between 21 and 44 m^3, these values have been averaged for this study. Therefore, with an average fuel tanker capacity of 32.5 m^3, 1384415 fuel tanker journeys would be required annually.

The results for the first scenario (based on a well pad with 10 wells, each with one lateral) with tanker movement concentrated over the first two years of drilling resulted in the probable number of incidents and subsequent spills being between 0.018 – 0.048 incidents/year and 0.009 – 0.026 spills/year. When tanker movement was spread over 20 years the probable annual number of incidents and spills was between 0.002 – 0.005 incidents/year and 0.001 – 0.003 spills/year. The accumulated risk of an incident or spill over the lifetime of a well would be between 0.035 – 0.097 incidents/lifetime of the well pad and 0.019 – 0.051 spills/lifetime of the well pad, therefore there would likely be an incident on the road for every 29 well pads developed and a spill for every 55 well pads developed (Figure 4.3).

The likely annual number of incidents and spills for the second scenario (based on well pads with 10 wells, each with four laterals) if tanker movement was concentrated over five years would be between 0.027 - 0.077 incidents/year and 0.015 – 0.041 spills/year. When tanker movement was spread over 20 years the probability of an incident and spill was between 0.007 – 0.019 incidents/year and 0.004 – 0.010 spills/year. The accumulated risk of an incident or spill over the lifetime of a well for this scenario would be between 0.137 – 0.384 incidents/lifetime of the well pad and 0.073 – 0.203 spills/lifetime of the well pad. Based on the fuel tanker data and the lower tanker movement estimate spread over five years, an incident on the road would likely occur for every seven well pads developed and a spill would likely occur for every 13 well pads developed (Figure 4.3).

Figure 4.3: The number of sites that need to be developed before an incident or spill is likely to occur based on the petrol tankers data and minimum and maximum tanker numbers from the IoD report. Scenario 1: Single-well pad with 10 wells with 10 laterals developed over two years; Scenario 2: Single-well pad with 10 wells with 40 laterals developed over five years. Scenario 3: 10 well pads with 10 wells with 10 laterals developed over two years; Scenario 4: 10 well pads with 10 wells with 40 laterals developed over five years. Scenario 5: One hundred well pads with 10 wells with 10 laterals developed over two years; Scenario 6: One hundred well pads with 10 wells with 40 laterals developed over five years.



4.4 Discussion

It is unrealistic to assume that all the spills within Texas and Colorado were reported, further back in time incidents may have been left unreported due to a lack of regulation, more recently due to lack of regulatory compliance, or may have occurred undetected, therefore there could be bias in the results. Despite the limiting factors mentioned these values allow me to attempt to determine the annual spill rates onsite within these states. The analysis of the Texas RRC dataset from between 2009 and 2015 and the COGCC dataset from 1999 to 2015 highlight that there has been an increase in the annual rate of crude oil spills. The increased spill rate for the Texas RRC was statistically significant at 95% probability. The increase could be due to tighter and stricter enforcement on reporting of spills, or due to companies being more honest and reporting a higher number of spill incidents. Alternatively, it could be due to companies not learning from experience and who are getting worse at managing site equipment (for example there is a mismatch between equipment lifetime and maintenance), leading to an increase in spill rates.

The US EPA (2015) determined 457 hydraulic fracturing-related spills occurred in 11 different states between January 2006 and April 2012, with spills of flowback water being the most common spill type reported. Among the spills for which the cause was reported the most common was human error (33%) and equipment failure (27%) (US EPA, 2015). The most common cause of a spill within both Texas and Colorado in this study was equipment failure, which like the US EPA report indicates the need for improvements in maintenance and equipment checks onsite. Although the Texas RRC results highlight that clean-up operations recover between 5 and 76% of the crude oil spill, prevention is vital, releases into the environment pose a considerable risk to the surrounding ecosystems.

The study by Patterson et al. (2017) showed 50% of the spills were related to storage and moving fluids via flowlines. The US EPA study records the most common source of a spill within the 11 states assessed was from storage units (US EPA, 2015). Within this study the most common location for a spill within both states was from the tank battery (oil storage tanks), with 70% of the spills in Texas being associated with tanker batteries, compared with 8% of spills being associated with pipelines.

Patterson et al. (2017) studied the states of Colorado, New Mexico, North Dakota and Pennsylvania and found the median spill volume ranged from 0.5 m^3 in Pennsylvania to 4.9 m^3 in New Mexico; whilst the largest spills exceeded 100 m^3. Of the 457 hydraulic fracturing-related spills reported by US EPA, 88 were of fracking fluid, with the median spill volume being 3.1 m^3 (US EPA, 2015). In addition there were 225 spills involving flowback and produced water, these had a median spill volume of ~3.4 m^3. Of the 2893 spills recorded in the '2009 - 2015 spill data' from the COGCC records, the majority were of low volumes, between >=0.2 and <0.8 m^3. However, spills often reached considerable sizes (180 reached >=16 m^3) and therefore impacted extensive areas. One reported spill reached a depth of 22 m. In many cases spills have led to large quantities of soil and groundwater being removed. Within the literature there are also reports of spills reaching groundwater, indicating that these incidences are not as rare as one would hope (US EPA, 2015). EPA also reported that 7% of the hydraulic fracturing-related spills in their study reached a surface water body (often streams or creeks); the median volume per spill was ~13 m^3, with volumes per spill ranging from ~0.3 m^3 (5^{th} percentile) to ~170 m^3 (95^{th} percentile) (US EPA, 2015). The results from this chapter show that over 70% of the spills involved leaks outside the berm, with emergency pits often being required to prevent serious pollution incidents. The issue with regard to spills is therefore twofold. It is apparent that spills occur due to equipment failure, also the lack of spill management practise allows for the spill to continue and pollute greater areas. Given so many onsite spills and leaks breach the berms highlights that well pad infrastructure is not fit for purpose and needs to be reassessed, with more appropriate infrastructure put in place. More stringent onsite spill management practises would hopefully prevent spills occurring and causing considerable, avoidable damage.

Manda et al. (2014) found that there were more environmental violations on a multi-well pad than on a single-well pad, however when the number of wells were taken into account, fewer environmental violations per well were observed on a multi-well pad than on a single-well pad. This chapter focused on the likelihood of spills from potential development scenarios where well pads were developed with either 10 wells or 40 wells per pad where each well had equal chance of having an associated spill. Thus, further work could look at the potential number of spills per well pad with different number of wells located on that site.

It is unrealistic to assume that all incidents involving milk and fuel tankers on UK roads were identified from the approach used in this study. Media reports were mainly produced for milk and fuel tanker incidents which were notable for a particular reason. For example: the tanker shed its load during the incident, particularly if large quantities were spilled or the load posed a threat to the public; the accident caused roads to be closed causing severe congestion or delays; the accident had a high severity, including fatalities or injuries. The further back one searches for events the fewer are found, the results from the media articles are likely to be low estimates of the actual number of tanker related incidents in a year. Despite the limiting factors mentioned these values enable us to attempt to determine the likely annual number of tanker incidents and spills. Using the milk tanker results as an analogue and different development scenarios given by the IoD report, the analysis in this study shows that when (2856 – 7890) tanker movements for a single 10 well pad with 10 laterals is concentrated over two years the likely annual number of spills is less than one. However, the production of the low permeability shale formations decreases rapidly over the first few years of drilling; it is thought by up to 85% during the first three years (Vengosh et al., 2014). Therefore shale gas wells are required to be drilled at high rates to overcome the rapid decline in production. If hydraulic fracturing was to go forward in the UK this would potentially mean tens to hundreds of well pads with hundreds to thousands of laterals being drilled over several years. As indicated in Chapter 2 and 3 the number of well sites that could be located within the UK would be limited by the carrying capacity of the surface, of the presence of existing infrastructure, and the setbacks each well requires. Thus, within Chapter 2 the average carrying capacity for a well pad measuring 10800 m^2 (average conventional UK well pad size), with a setback of 152 m and a lateral of 500 m was 26%. Therefore 26 well pads could be located on average per licence block, with a range of between 5 and 42 (Clancy et al, 2018a). The calculations in this study show that the number of spills increases to 2 - 6 when 100 well sites with 10 wells per pad with one lateral each is developed.

The majority of the reported traffic incidents were caused by collisions, most commonly milk tankers with cars. Research suggests that drivers who drive for business purposes are at an above average risk of accident involvement relative to the general driving population (Clarke et al., 2005). Generally heavy goods vehicles such as milk tankers are 7.5 times more likely to present an accident risk to other road user per kilometre (Copsey et al., 2010). Different explanations are put forward in the literature to explain the higher number of accidents involving commercial road transport, it is important to understand these so appropriate mitigation strategies can be developed. Several suggested explanations why heavy goods vehicle drivers are at a higher risk are, they undertake longer journeys, often driving late at night or during the early hours when fatigue and drowsiness is more likely to occur (Copsey et al., 2010; RoSPA, 2001). Truck drivers are often driving under time pressure and are more likely to carry out distracting tasks while driving, such as making phone calls, eating and drinking (Copsey et al., 2010; Broughton et al., 2003). Milk tankers are also required to carry heavy loads down small country tracks which are often unfit for purpose and sometimes made worse by bad weather conditions or heavy traffic. To minimise the likelihood of an incident occurring there are a number of mitigations strategies that could be put in place, these include: regular vehicle inspections and maintenance of vehicles; specialised training and instruction for drivers; selecting appropriate route and planning trips according to weather and road conditions. It is also important for the employer to avoid tight schedules for drivers and to make sure a sufficient number of rest stops are planned.

This study has focused on estimating the number of spills from potential shale gas developments but not the consequences of these spills. The consequence of surface spills associated with hydraulic fracturing is a complex issue and one that is difficult to measure as there have been few incidents documented in the peer-reviewed scientific literature. Papoulias and Velasco (2013) record a leak of fracking chemical into a 2 km stretch of Acorn Fork Creek in Kentucky (US) in May and June 2007. The incident led to the streams pH dropping to 5.6, the conductivity increasing to 35000 µS/cm, aquatic invertebrates and fish dying and those that were not killed being left in distress (Papoulias and Velasco, 2013). Fish examination from the polluted stretch of the river by the US Geological Survey showed that of the 45 fish examined all had severe gill lesions, consistent with exposure to low pH and toxic concentrations of heavy metals (Papoulias and Velasco, 2013). Bamberger and Oswald (2012) documented several experiences farmers have had with regards to shale gas operations leading to environmental impacts. One example involved a release of fracturing fluid due to a worker shutting down a chemical blender during the fracturing process (Bamberger and Oswald, 2012). The fluids released flowed into an adjacent cow pasture which was then reported to have led to the death of 17 cows within one hour (Bamberger and Oswald, 2012). Another reported example was caused by a defective valve on a hydraulic fracturing fluid tank, the fault led to hundreds of litres of hydraulic fracturing fluid leaking onto a goat pasture (Bamberger and Oswald, 2012). The goats exposed to the fluid were later reported to have issues reproducing over the following two years (Bamberger and Oswald, 2012). However, it should be noted that the studies of Papoulias and Velasco (2013) and Bamberger and Oswald (2012) had no control to know what might have happened had no spill occurred, or if another fluid type had been spilt. Furthermore, it should be noted that these examples are not unique to a shale gas industry.

In Europe, hydraulic fracturing is still in the exploratory stage, however, a report in the German Tax De newspaper reported a leak which occurred in 2007 (Kummetz, 2011). The report claimed that a waste water pipe leaked at a tight gas field in Söhlingen, Germany, causing groundwater contamination with benzene and mercury (Kummetz, 2011). Similarly, on the 24th July 2002, 19 m^3 of milk was spilt into a stream flowing into Rudyard Lake near Leek in Staffordshire, this incident correlates with an 'organic chemicals/products' spillage in the pollution incident database. The impact of the incident were classified as follows; air pollution category 2 ("significant"); land pollution category 4 (no impact); water pollution category 3 (minor). A BBC news report commented that 50000 fish were in danger if the milk entered the reservoir after a milk tanker crashed into a bridge (BBC news, 2002).

Given the highlighted risks of spills from shale gas operations, mitigation methods are a necessity. Procedures need to be in place to identify, evaluate and mitigate potential risks associated with the transportation, handling, storage and disposal of hydraulic fracturing related fluids. Patterson et al. (2017) comments that enhanced and standardised regulatory requirements for reporting spills could improve the accuracy and speed of analyses to identify and prevent spill risks and mitigate potential environmental damage. At the time of writing, just two horizontal wells have been drilled at the Preston New Road site under environmental regulations set out by the Environment Agency, with one of these wells having undergone hydraulic fracturing. The current Environment Agency's regulations for the onshore oil and gas sector include: all onsite storage tanks to be bunded; all operators to have a spill management plan which ensure any material spilt onsite will be contained and removed appropriately; and the pipework and the associated storage tanks of the drilling mud systems are inspected daily for leaks and damage (EA, 2016). Since the drilling began at the Preston New Road site in mid-2017 the Environment Agency has reported six permit breaches. The sixth breach was reported in August 2018 and was related waste management on the site (EA, 2018). These breaches indicate that failings do occur, thus as Patterson et al. (2017) states this potential new industry needs to be continuously and sufficiently monitored to minimise the number of breaches and to make sure repeat incidents do not occur. Baseline, site and monitoring after plugging and abandonment are essential. Initial baseline monitoring at the site and in the surrounding area allows for comparisons to be made to the original environment so deviations from the norm can be recognised. Systematic equipment checks and regular site monitoring should allow for any equipment failures to be acknowledged and dealt with rapidly, thus avoiding future spills. Long term monitoring after plugging and abandonment allows for equipment failures to be recognised so any issues that do arise can be dealt with appropriately. It is important that those responsible for the above monitoring are confirmed, and that adequate monetary provision is made prior to drilling, so all concerned are aware of whom is responsible for the long term maintenance of the wells and funds are available. Transparent and consistently measured data sharing allows for insights to be gained into when and where spills are most likely to occur, and the underlying causes. Better understanding of these factors would provide regulatory bodies and industry makers with important information on where to target efforts for locating and preventing future spills (Patterson et al., 2017).

All equipment should be fit for purpose and investment must be made into sourcing the most up to date and appropriate technologies. Well sites and equipment should also be appropriately designed for adverse weather conditions, including severe flooding. On large-scale development projects pipeline construction should be considered instead of trucking the fluid required for hydraulic fracturing, although it is worth noting that pipelines can also leak and spillages are often difficult to identify. Common practise within the UK by water treatment works is site contained drainage, this has been adapted by the Environment Agency, who also indicate best practise on well sites should include sites being lined with an impermeable membrane and any fluid discharged being directed towards carefully located drains and collected in tanks underground. The fluids collected can therefore be appropriately dealt with. This practise should be introduced at all sites within Europe to contain any spills that do occur.

4.5 Conclusion

Results from Colorado and Texas show that spill rate is increasing and within Texas it is statistically significant. Based on data from Texas RRC, a UK shale gas industry consisting of well pads with 10 laterals would likely experience a spill for every 16 well pads developed. When 40 laterals are developed on a single-well pad a spill would likely occur for every four well pads developed. The datasets these values are based upon specify the leading cause of a spill is equipment failure, followed by human error. With 33% of the spills recorded in Colorado being found during site remediation and random site inspections it is important that regular site inspections are performed by an appropriately trained work force and where possible constant onsite monitoring is carried out.

Based on the milk tanker data and tanker movement estimates of 2856 tankers over two years a well pad of 10 laterals would likely experience an incident for every 12 well pads developed and a spill for every 19. So, should a shale gas industry go forward within the UK, or indeed anywhere else in Europe, it is important that appropriate, well managed, mitigation strategies are in place to minimise the risk of spills associated with well pad activities and fluid transportation movements.

Chapter 5:

An assessment of UK conventional oil and gas well sites remediation

5.1 Introduction

With the potential development of a large shale gas industry within UK over the next few decades, there is the possibility that tens, to tens of thousands of new onshore wells could be drilled. Given shale gas development is a temporary activity, with well operational life lasting from a few years up to several decades, there is a growing concern about the legacy of these sites (Ho et al., 2016). In a densely populated country such as the UK, land is precious (Moffat and McNeill, 1994); therefore, it is imperative that the land affected by this new industry is appropriately developed and when no longer required carefully remediated to ensure inactive well sites do not threaten the local ecosystems or cause long term environmental issues. Thus the aim of this study was to assess the level of remediation conventional well sites have received, determine if there are existing remediation issues within the UK, the scale of the problem and the potential long term implications a new industry such as shale gas might bring. From this assessment suitable mitigation strategies required to prevent potential long term impacts were developed.

5.2 Approach and methodology

Since the first gas well was drilled in the UK in 1895 (UKOOG, 2013) there have been over 2000 wells developed, a large number of these are claimed to be fully remediated, thus the wells are plugged and abandoned, and if on land the well-head is cut off below ground level so that agriculture or other practices can resume over the well site. Using aerial imaging, similar to the approach of Davies et al. (2014) and the methodology used in Chapter 2, the activity status of each well, the level of surface disruption well sites were generating (if any), and the level of remediation that abandoned wells had received was analysed. Following this 15 sites were visited to assess if these abandoned and remediated oil and gas well sites showed differences in soil compaction compared to land that had been undisturbed.

5.2.1 Surface disturbance

Using aerial imaging the surface disturbance for the 2193 UK wells drilled between 1895 and 2017 was evaluated. Each well was assessed to determine the level of activity on the site and where not in production the level of remediation using the following criteria; (1) site fully restored, no indication of a well site ever being present (Figure 5.1a); (2) some indication that a well site has been present but the boundaries of the site are not clear (Figure 5.1b); (3) well pad location and the site boundaries clear (Figure 5.1c). The presence of a well head or the hard standing the well site was built upon, and indications of hard standing were also recorded. Where land use had changed, for example, from arable to forested, or forested to arable, or the land was now built on, was also noted. The imagery is acquired at a point in time, thus imagery in some areas dates back to 2005, however most dates from 2015 and 2017. Where imagery was not available for recently drilled sites, these were not included in the study.

Figure 5.1: Examples of the classification system used for the abandoned wells. Figure 5.1a: The Plungar 2 well site, from visual imagery the site looks to be fully remediated with no indication of the presence of a previous well site. Site location: latitude 52.53256 and longitude -0.511232 (image extracted from Google Earth Pro, 2018).

Figure 5.1b: The Castletown 1 well, through grass discoloration the image indicates where the well site was located but the boundaries of the site are not clear. Site location: latitude 53.31486 and longitude -2.505735 (image extracted from Google Earth Pro, 2018).

Figure 5.1c: The Syndale 1 well, the well pad and access roads are clearly visible on this abandoned well site. Site location: latitude 53.403736 and longitude -1.224523 (image extracted from Google Earth Pro, 2018).

Figure 5.1a

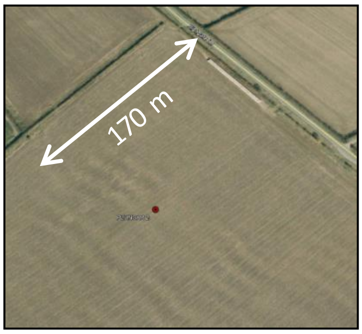
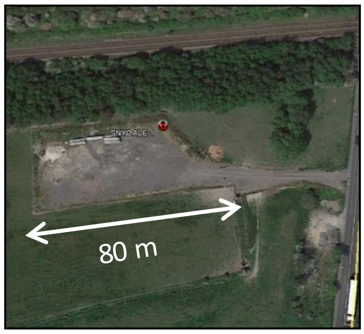


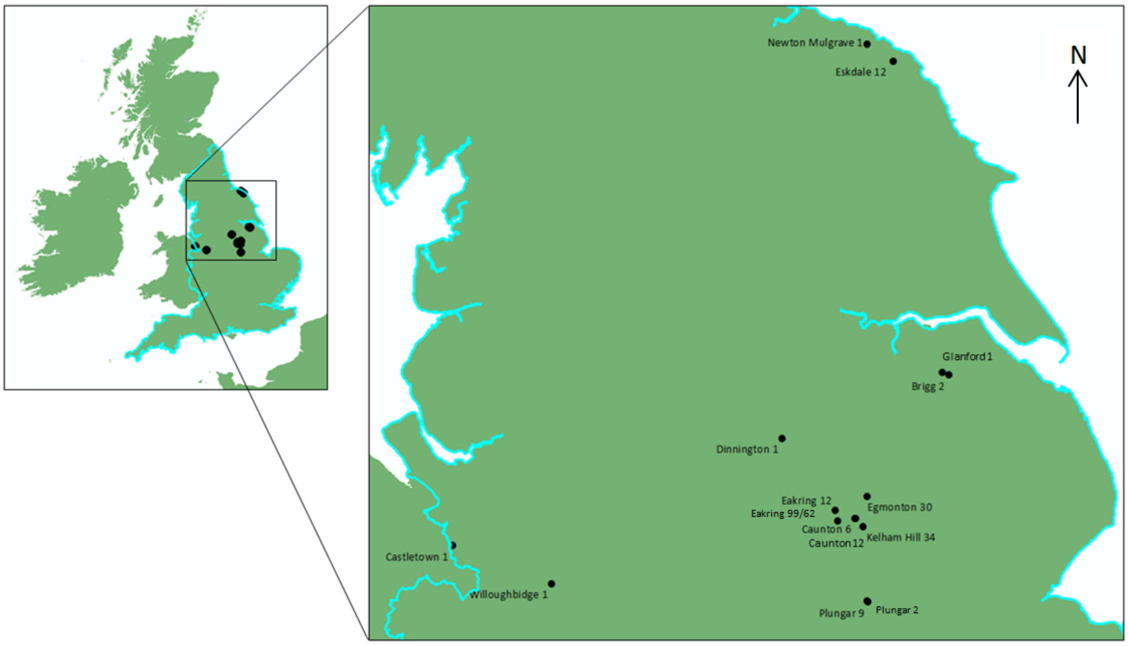
Figure 5.1b

Figure 5.1c



Potential surface legacies from 15 abandoned hydrocarbon well sites were observed in the field. The 15 sites assessed are located within the North West and East of England (Figure 5.2) and were chosen as they represented a variety of different surface expressions from aerial imaging. Thus, five were chosen as there was no evidence that a well pad had been present in that location (Figure 5.1a), whilst ten were selected because there was some indication of where a well pad had once been located (e.g. grass discolouration (Figure 5.1b), clear abrupt changes in vegetation cover). Visual observations were made between the remediated well sites and a nearby control area so comparison between the two locations could be made. If present, evidence of the pre-existing well site (e.g. rubble, well head) was recorded. If available additional information and details on the remediated land from the farmers was recorded (e.g. differences in crop growth, ploughing dynamics and water retention over the remediated site).

Figure 5.2: A map of the 15 abandoned oil and gas well locations assessed for soil compaction.



5.2.2 Soil compaction

The capacity of soil to resist deformation is the soil strength and refers to the amount of energy that is required to break apart aggregates or move implements through the soil (Carter and Gregorich, 2007). The strength of soil results from cohesive forces between soil particles and their frictional resistance to sliding past or over one another (Vanags et al., 2004), this resistance pressure has been described as *cone index* and is expressed in pressure units (Lowery and Morrison, 2002). Soil strength is an important characteristic affecting many aspects of agricultural soils, such as the performance of cultivation tools, traffic ability of farming machinery, root growth and water percolation (Vanags et al., 2004; Batey and McKenzie, 2006). Subsurface compaction and a subsequent increase in soil strength has been reported in the scientific literature to lower crop yield and stunt crop growth for many years after initial compaction (Culley et al., 1981; Batey and McKenzie, 2006).

Hand-operated penetrometers (also called soil compaction testers) are used to measure resistance at near surface depths and for many years have been used to measure soil strength in agricultural and engineering applications (Dunker et al., 1994). The ease with which an object can be pushed or driven into the soil is a measure of the soil penetrability (Dunker et al., 1994). The use of a penetrometer is a relatively fast and non-destructive method of assessing compaction (Dunker et al., 1994). Dunker et al. (1994) concludes that a penetrometer can be an important management tool for the mine operator to assess levels of soil compaction created during soil reclamation and to evaluate the effectiveness and depth of deep tillage operations. Within this study a static cone hand-operated penetrometer was used to assess levels of soil compaction (if present) at 15 abandoned and remediated conventional oil and gas well sites, and associated control sites, located on agricultural land and moorland. As mentioned in Section 5.2.1, these 15 sites were located within the North West and East of England (Figure 5.2) and were chosen as they represented a variety of different surface expressions from aerial imaging. Soil factors influencing penetration resistance are matrix potential (water content), bulk density, soil compressibility, soil strength parameters, soil structure, and soil texture (Dunker et al., 1994). To account for these influencing factors, in addition to taking readings over the abandoned well site area, a control was also measured. Where possible the control was measured in the same field but at some distance from the well pad to maintain surface cover consistency, where this was not possible the control measurements were performed in an adjacent field with similar land use.

The soil compaction measurements were taken using a DICKEY-john soil compaction tester (Figure 5.3). Measurements were taken using the half cone tip (1.3 cm), at 10 pace (approximately 10 m) intervals in the shape of a cross over the well pad location on each site, with the wellbore being located approximately at the centre of the cross. In a similar manner a control site was also measured, thus measurements were taken in the shape of a cross in a location undisturbed by previous exploration activities. The soil compaction tester was pushed into the soil at a constant pressure until the pressure gauge reached 20 atm (the depth of the soil compaction), at this point the penetrometer was removed and the depth the penetrometer reached was recorded. To account for variability in the soil compaction measurements, three measurements were taken at each point and an average penetration depth was calculated. The accuracy of the instrument is limited by the ability of the operator to maintain constant pressure, and the applied force is limited by the strength of the operator (Carter and Gregorich, 2007), in an attempt to maximise consistency and accuracy all the measurements were performed by the same person. In addition, the measurements were collected in spring, when the soils are most likely to be uniformly moist and near field capacity (Dunker et al., 1994).

Figure 5.3: The DICKEY-john soil compaction tester used for this study. Figure 5.3a shows the soil compaction tester in the ground at the Caunton 12 well site. Site location: latitude 53.75722 and longitude -0.54997. Figure 5.3b shows the soil compaction tester pressure gauge.

Figure 5.3a *Figure 5.3b*

Initially the results collected were tested for normality using the Anderson and Darling test (Anderson and Darling, 1952). Following this the arithmetic mean of the compaction measurements for the control were taken and the compaction measurements taken over the remediated well site were then ratioed to that. To determine if the compaction depth measurements taken over the 15 abandoned well sites were statistically significantly different to each other, a one-way analysis of variance (ANOVA) was performed. The design and use of the ANOVA allowed determination of whether the variation in soil compaction depths between the 15 sites assessed was significant at the 95% probability of being different from zero. Given that each site was ratioed to its control, then the test was that the value for each site was different from 1. Therefore, post hoc testing, using the Tukey test, was used to assess differences from one and differences between sites. Values are reported as least square means of the ratioed data.

5.3 Results

5.3.1 Surface disturbance

Of the 2193 wells assessed in this study 1210 (55%) showed no visible signs of the well pad or production facility and so were judged to be fully remediated from the aerial photography, with the land of an additional 65 (3%) individual well sites (with one well per site) having changed use. The main land use change was from arable to housing and industrial estates. From our assessment 682 (31%) wells were located on 79 separate well sites, where one or more wells located on the site were in production: thus these sites clearly had production equipment or nodding donkeys present. There were 133 wells (6%) located on 94 individual well sites which clearly showed the well site boundaries. There were 78 wells (4%) on individual well sites that showed some indication of a well pad but the boundaries were not clearly visible. In addition, there were 25 wells (1%) that were actually located offshore or had no imagining.

Of the 133 wells (located on 94 sites) where the well pad boundary was clear, the hard standing was clearly present for 119 wells (5%), whilst there was some indication of hard standing for 8 wells (0.4%). There was a well head clearly present for 78 wells (3.6%). Of the 78 well sites where the well pad boundaries were ambiguous 17 wells (0.8%) had hard standing present and 5 wells (0.2%) had a clear well head. Thus, as 6% of the wells were deemed insufficiently remediated by the criteria outlined in Section 5.2.1, a field assessment to confirm observations from visual imaging was carried out at 15 sites.

Visible differences observed in the field between the well sites and the controls (e.g. changes in vegetation, presence of rubble, presence of well pad etc.) were noted, in addition several farmers commented on their experience and knowledge of the land. For three of the 15 sites assessed the farmers commented that when ploughing the land over the former well sites they often had issues with rubble and large stones. Our field assessment of these three well sites clearly supported these farmers' statements. These sites had considerable volumes of rubble (e.g. stones and on two well sites pieces of terracotta) located precisely over the previous well pad location but not over the control (Figure 5.4a). A farmer, who owned the field one of these wells was on (Dinnington 1), stated the reason for the large quantity of debris left over the previous well site is due to the company who abandoned the well not remediating the well or the well site. Therefore, the farmer had to remediate the site himself, thus remove the well pad best he could and construct a concrete platform for the well head (Figure 5.4b).

Several farmers mentioned that the remediated well pad areas tended to retain water and become more water logged compared to the rest of the field. Visible observations indicated that for several of the well sites the land where the well pad had once been located was flatter than the rest of the undisturbed field; this could possibly contribute to the water retention mentioned by the farmers.

A lack of crop growth and patchy vegetation over several abandoned well site indicated where the well pad may have been located. However, due to other places within the same field also having patchy vegetation this could not be definitively associated with a previous well site and used as a determining factor of poor remediation. Two sites clearly showed a distinct change in vegetation where the boundary of the abandoned well site was located. The vegetation change from green luscious grass to browner grass/straw and buttercups within Figure 5.4c undoubtedly indicates the location of the previous well site.

Of the 15 sites assessed in the field there were 11 sites that still had the old well site entrance present (e.g. gates) and five sites with access tracks which are still in use today (Figure 5.4d). One farmer mentioned that as a boy he remembers the land around his farm in Eakring being covered in wells; however, he said the tracks are now largely all that remains of the oil and gas industry in the area. The farmer highlighted how many of these tracks are still used and that they are very grateful for them.

Figure 5.4: Figure 5.4a shows the terracotta rubble left on the Plungar 2 well site. Site location: latitude 52.53256 and longitude -0.511232.

Figure 5.4b shows the Dinnington 1 well head. Site location: latitude 53.22283 and longitude -1.151368.

Figure 5.4c shows the distinct change in vegetation over the location of the Eakring 62 and 99 remediated well sites - over the well site there are more yellow butter cups and brown grass/straw. Site location: latitude 53.7341 and longitude -0.59155.

Figure 5.4d is an access track at the Newton Mulgrave 1 well site that has not been remediated. Site location: latitude 54.304250 and longitude -0.482178.

Figure 5.4a

Figure 5.4b

Figure 5.4c

Figure 5.4d

5.3.2 Soil compaction

The compaction depth results were collected and inputted into ArcGIS for visual analysis. From a visual analysis of the results the majority of sites indicated that the land where a well site was once located had a shallower compaction depth in comparison to the control (Figure 5.5a, 5.5b and 5.5c). Thus, for the majority of well sites the soil strength had increased to a shallower depth where the well site was once located in comparison to the undisturbed land. However, two sites had the opposite result, thus soil strength and compaction depth was deeper where the well site had once been located (Figure 5.5d).

To assess the probability distribution of the compaction results an Anderson Darling statistical test was performed, the results indicated the soil compaction results were log normal. Thus, the compaction results are lognormally distributed. The one way ANOVA test results indicate that for certain wells the compaction depths between the abandoned well sites was statistically significant. There were 13 wells that showed a significant difference between the compaction depths at the well sites compared to the control. Of these 13 well sites, 10 recorded the compaction depth where the well pad was once located as shallower than the compaction depth of the control. Whereas three sites showed the opposite, therefore the compaction depth where the well pad was once located was deeper than the location of the control. While two well sites indicated that there was no significant difference between the compaction depth of the abandoned well site or the control area.

Figure 5.5: Shows the soil compaction depth results for four well sites. Figures 5.5a (Plungar 9 – site location: latitude 52.531439 and longitude -0.505068), 5.5b (Dinnington 1 - site location: latitude 53.22283 and longitude -1.151368) and 5.5c (Eakring 12 – site location: latitude 53.91899 and longitude -0.595051) are examples of where the average compaction depth over the previous well pad is shallower than the control location.

Figure 5.5d (Willoughbridge 1 – site location: latitude 52.564665 and longitude -2.221558) is an example of where the compaction depth over the previous well pad is deeper than the control location.

Figure 5.5a

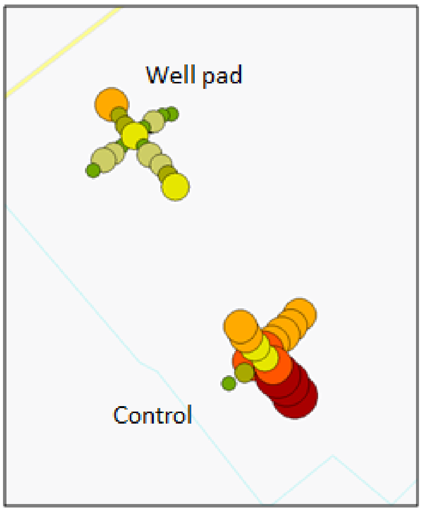


Figure 5.5b

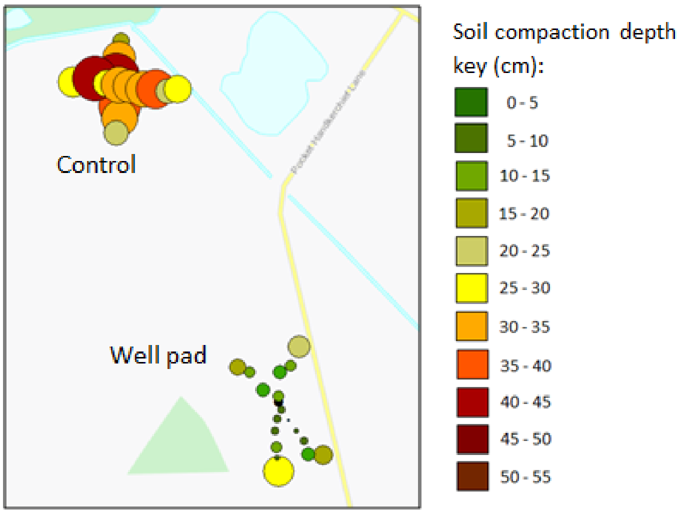


Figure 5.5c

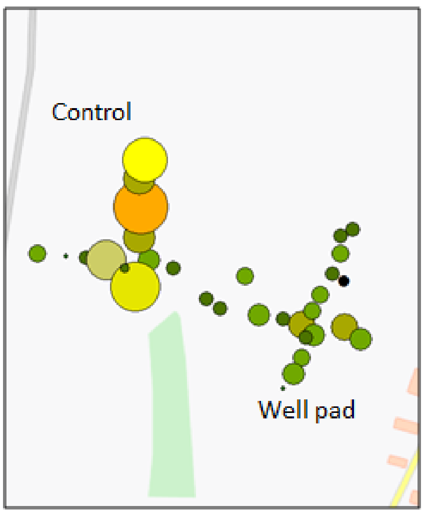


Figure 5.5d

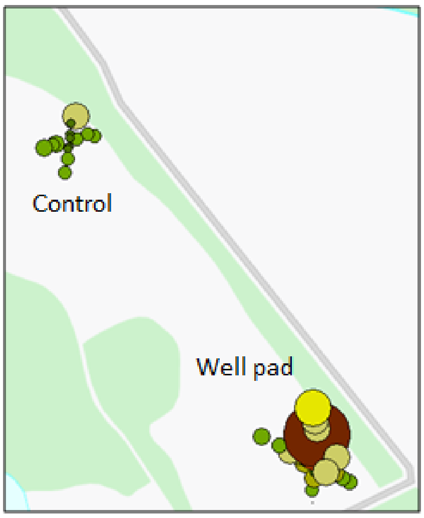


Table 5.1: The Tukey test results for the abandoned well sites.

Well name	Least squares Mean	Standard Error	Upper confidence interval	Lower confidence interval
Brigg 1	-0.015	0.13	1.945	-1.975
Castletown 1	0.004	0.137	1.964	-1.956
Caunton 12	-0.318	0.137	1.642	-2.278
Caunton 6	-0.48	0.161	1.48	-2.44
Dinnington 1	-1.427	0.194	0.533	-3.387
Eakring 12	-0.346	0.134	1.614	-2.306
Eakring 62 and 99	0.083	0.114	2.043	-1.877
Egmanton 30	-0.678	0.146	1.282	-2.638
Eskdale 12	-0.394	0.161	1.566	-2.354
Glanford 1	-0.281	0.13	1.679	-2.241
Kelham Hills 34	-0.52	0.15	1.44	-2.48
Newton Mulgrave 1	1.035	0.146	2.995	-0.925
Plungar 2	0.09	0.124	2.05	-1.87
Plungar 9	-0.6	0.137	1.36	-2.56
Willoughbridge 1	0.233	0.146	2.193	-1.727

5.4 Discussion

Approximately 10% of the wells investigated for surface disturbance across the UK clearly showed or indicated where the well pad was once located, thus indicating there is an issue with regards to old conventional hydrocarbon well sites not being appropriately remediated. As mentioned in Section 5.2.1 it should be noted that visual imagery was taken at a point in time and thus it is possible that due to seasonal variations in land cover there may be bias in well site interpretation. Thus, a well site may look to have been remediated but in reality there is just more vegetation covering the site giving the impression of better remediation. In an attempt to mitigate against this, where possible well site imaging was compared through time. It is also worth noting that due to the majority of the well sites being located within agricultural fields; natural land reclamation by woodland is not seen, therefore enabling a greater understanding of where appropriate remediation has not taken place. Current practise indicates that once a well has been abandoned, the site should be restored and a period of aftercare conducted to ensure the land returns to a state that is the same or better than it was prior to operations commencing (DECC, 2013). Restoration is supposed to involve the removal of all equipment that was not originally at the site and which has been brought in to conduct operations, with the Mineral Planning Authority responsible for ensuring the wells are abandoned and the site is restored (DECC, 2013). However, it would appear these regulations are not currently being adhered to or enforce as there are tens of wells, such as Reepham 1 (drilled in 1998 and operational until 2002), Ebberston Moor 1 (drilled in 2007 and released in 2012) and Lingfield 1 (drilled in 1999 and released in 2004), that have been completed and released within the last 20 years but have not complied to these protocols, thus the well pad is still visible.

In addition to the well pad's hard standing and hard core being left onsite clearly indicating where previous well sites had been located, in some locations visual evidence in the field also indicated previous site locations. For a number of sites, stone and rubble were located over the abandoned well sites, whereas in other locations the abandoned well sites were apparent due to the land being more level than the surrounding undisturbed land. This visual analysis was performed during late spring when crops were established on many of the sites, therefore it is highly probably that additional evidence of prior well pad locations were not observed due to the heavy surface cover. One farmer indicated that we should come back in autumn because at that time of year the crops will have been removed and it is clear exactly where the well pad was once located. These results indicate that although from a distance well sites look to be remediated, on closer inspection many well sites have been insufficiently remediated and farmers have been left to deal with the consequences. With regards to shale gas, Third Energy who are hoping to hydraulically fracture at the KM8 site in North Yorkshire, have stated that all topsoil areas within their well site, including areas not affected by construction will be ploughed and cultivated to ensure that all stones, rubble, vegetation and other extraneous material larger than 75 mm in any direction are removed (Third Energy, 2017). If carried out sufficiently these remediation strategies should reduce the likelihood of farming issues when ploughing remediated site.

In addition to rubble being left onsite three of the farmers mentioned oil and gas pipelines left underground have caused mechanical issues when ploughing. Due to the damage and inconvenience these unused abandoned pipelines have caused several farmers mentioned removing these pipelines themselves. One farmer told me that once he was removing a disused pipeline and as they were pulling it up they noticed that it was leaking oil, unsure of what to do and in order to stem the flow they set fire to the fluid. Presumably this leakage should have been reported to the correct authority and was not, however if the site had been remediated correctly the pipeline should not have been leaking fluids. HSE regulations for decommissioning pipelines indicate that once a pipeline comes to the end of its useful life, it should either be dismantled and removed or left in a safe condition (HSE, 1996). The HSE indicate that purging or cleaning the pipeline of hazardous properties prior to being left in the ground may also need to be carried out (HSE, 1996). The farmers experience indicates that there may have been lapses in protocol and regulations may not have been sufficiently followed. If a shale gas industry were to go ahead within the UK clear rules and stringent law enforcement must be carried out to avoid such situations in the future.

Evidence of soil compaction at the surface was often not present at the abandoned well sites visited; however, the soil compaction tests clearly indicated substandard remediation of the well sites has led to soil compaction in almost two thirds of the sites assessed. This is possibly due to protocols on well site remediation in the past not being as sufficient as they are now, or companies not following regulations as comprehensively as they should. Soil compaction is a concern as it can cause considerable damage to the soil and decrease yield for some time, however, there are practises recorded in the literature that have been suggested to minimise these impacts. Batey (2015) stated that all soil types are susceptible to soil compaction, especially those with poor or impeded drainage (Batey, 2015).

Batey (2015) indicated that heavy or prolonged rain during pipeline installation increases the risk of compaction (Landsburg et al., 1996), thus should be avoided. Consideration of how well site construction during the UK's wetter months could negatively impact soil compaction should be acknowledged and thus factored into mitigation strategies for avoiding long term implications associated with a shale gas industry. Batey (2015) also stated that careful replacement of the topsoil is key to avoiding soil compaction. To avoid soil compaction Third Energy states that on leaving their shale gas site in North Yorkshire the subsoil will be deep tine cultivated in strips (Third Energy, 2017). As the topsoil may have degraded whilst being stockpiled onsite, the soil's condition will be assessed and treated or if required replaced before being re-laid (Third Energy, 2017). The topsoil will be back-tipped from the stockpile and will be levelled to avoid the formation of depressions which could hold water (Third Energy, 2017). Thus the site will be fully restored to its pre-existing condition with no long term impacts.

Hamza and Anderson (2005) state, that where soil compaction exists and causes sufficient issues to warrant measures to reduce the impacts there are several methods to alleviate the problem. As soil compaction mainly decreases soil porosity, increasing soil porosity is a clear way of reducing or eliminating soil compaction (Hamza and Anderson, 2005). Soil compaction can be reversed through appropriate application of some or all of the following techniques: (1) addition of organic matter; (2) controlled traffic; (3) mechanical loosening such as deep ripping; (4) selecting a rotation which includes crops and pasture plants with strong tap roots able to penetrate and break down compacted soils (Hamza and Anderson, 2005). Within this study there were no well site that was so severely impacted by soil compaction that these practises needed to be put into action.

In addition to having lots of debris located over the previous well site, the well head of the Dinnington 1 well (Figure 5.4b) was also present. The owner of the field the well head was located in said the reason for the poor remediation was that he had had to do the remediation himself as the company doing the exploration had gone bankrupt and left everything onsite. Although an insurance policy was thought to be in place, and should have been for such a situation, one was not and the well site was left without any remediation. The farmer informed us that after the company who drilled the well went bankrupt they left everything onsite, including all the drilling equipment, storage containers, and caravans with all the drilling notes and cores etc. As the well was left half explored a couple of years later another company picked up where the previous company had left off. When the second company left the site they removed the drilling equipment from the site, however they did not remediate the well pad itself or the borehole. The farmer who owned the field had to clear up the well pad and build a concrete platform around the wellbore himself. Although it would seem this situation is not a frequent occurrence it would be interesting to extend this study and see how often this has happened in the past. From Oil and Gas Authority database (Oil and Gas Authority, 2018) we can see that this well was spudded in 2002 and released in 2007, highlighting that this is a current problem that exists and one that needs addressing.

Another concern that arose from the fieldwork was the level of remediation suspended wells received. Drilled in 2008 and released in 2015 Dukes Wood 1 in Nottinghamshire was an example of a poorly suspended well. Although Dukes Wood 1 was not one of the 15 sites selected for analysis, it was observed by chance as it was next to one of 15 selected field sites. On approaching the site there was a gate but no fence, thus as a footpath was located nearby anyone could walk freely onto the site. Left on the suspended site was equipment including, a dismantled nodding donkey, a concrete storage pond, oil barrels, electrical equipment and pipelines (Figure 5.6). There was also a strong smell of oil on the well site. The owner of the land the well site was located on highlighted that the well has been left temporary abandoned and the company might come back when the oil price picks up. Although suspending wells has long been an accepted part of the oil and gas industry this site indicates that improvements into the current management of these sites is required.

Figure 5.6: Images of the poorly suspended Dukes Wood 1 well. Site location: latitude 53.74485 and longitude -0.592472.

In Canada, to avoid wells being left when companies go bankrupt Dachis et al. (2017) suggests that the Albertan government reform the province's well liability policies and introduce an upfront bonding requirement. It is suggested this bonding requirement should be less than the full expected liability cost, therefore recognising that society should accept some risk in exchange for greater economic activity. Additionally, Dachis et al. (2017) recommend once a well enters the inactive phase, the province should require companies to hold insurance to cover the cost of cleaning up the well. A strict time limit on inactive wells and an insurance requirement would allow firms to weigh the increased cost of holding unproductive wells against the potential value of returning them to production. Should a shale gas industry be developed in the UK or elsewhere in Europe these suggestions would be highly recommended. In addition, regular inspection of temporarily suspended wells and inspections when a well site has been fully remediated should be considered to avoid the issues seen within the conventional oil and gas industry. Within the UK at this time there is little in the literature as to what the government is planning on doing with regards to bonding requirements or financial guarantees.

This study has highlighted several different issues with regards to poor well site remediation during both abandonment (e.g. Dinnington 1) and suspension (e.g. Dukes Wood 1). However, the scale of the issue across the UK has not been addressed in this study due to a limitation on time. A future study visiting a greater number of abandoned and suspended wells would allow for a better picture of the situation and the degree of the problem. In addition, further field-experiments to evaluate the degree of soil compaction on these remediated sites could also be carried out, these could include: measuring the bulk density, infiltration rate, and hydraulic conductivity. Drohan and Brittingham (2012) indicate that fertility and organic matter percentage assessments could also indicate improper well site reclamation, this could be assessed by testing the soil.

Due to time limitations comparisons between soil compaction depths for other industries with temporary infrastructures and their controls has not be possible. It would have been interesting to investigate if other industries such as old airfields, disused and abandoned factories for example caused alterations in soil compaction depth or if the issue is unique to the oil and gas industry.

Further study on buried pipelines associated with abandoned oil and gas wells would also be interesting as a number of farmers commented that they had pulled up a large number of disused pipelines over the years. It seems for a number of wells the well pad itself was remediated but not all the subsurface infrastructure was removed. With abandoned pipelines leading to a number of environmental issues; over the last decade pipeline corrosion is a problem that has been recognised worldwide, being a major concern for the owners of pipelines, land owners and local governments (Shabangu et al., 2015), it is something that needs to be addressed.

5.5 Conclusion

For the first time this study highlights two main issues the UK experiences with regards to oil and gas well site remediation. Firstly, there are well sites that have not been remediated fully. Thus, approximately 10% of the wells investigated for surface disturbance across the UK clearly showed or indicated where the well pad was once located, e.g. well pads, hard core and well site equipment have been left onsite. Secondly, well sites have been remediated at the surface; however subsurface remediation is potentially not sufficient. Thus, of the 15 sites assessed in the field 13 wells sites showed a significant difference between the compaction depths at the well sites compared to the control, with 10 of these sites leading to soil compaction, thus an increase in soil strength leading to changes in vegetation cover and waterlogging.

As many well sites have not been appropriately remediated it indicates that improvements in the remediation process would be advantageous to limit further long term implications from oil and gas exploration. Consequently, if a shale gas industry was to be developed independent checks and assessments onsite, and regular inspection of completed, abandoned and suspended well sites should be a key requirement for both the current onshore oil and gas industry and any future industry.

Chapter 6:

Conclusions

6.1 Overview of thesis

The aim of this thesis was to assess several public concerns regarding the potential impacts from surface infrastructure associated with the development of a shale gas industry within the UK. This study has determined the carrying capacity of the land over the Bowland Shale and the likely number of well sites that could be situated within the licenced regions for various potential shale gas development scenarios. The limitations from existing infrastructure on the amount of accessible resource have been assessed and the probable optimal lateral length has been determined. The likelihood of a spill both onsite and offsite for two development scenarios has been quantified and mitigation strategies have been suggested to minimise the occurrence and impact of spills if a shale gas industry were to go ahead within the UK. An assessment of conventional oil and gas wells within the UK was performed to determine if well sites have been sufficiently remediated and where improvements maybe necessary.

6.2 Key objectives and findings

6.2.1 An assessment of the footprint and carrying capacity of oil and gas well sites: The implication for limiting hydrocarbon reserves

The UK is a densely populated country; there are considerable limitations as to where well sites can be located due to the presence of existing infrastructure. In the UK, the average setback from a conventional onshore well pad to the nearest building is 329 m, whilst the average setback from a house is 447 m, but can be as low as 21 m and 46 m, respectively. The carrying capacity of the surface for a development scenario where the well pads have setbacks of 152 m and lateral lengths of 500 m averages 26% but ranges between 5 and 42%. Thus, the likely maximum number of wells and associated setbacks that could be located within a typical licence block would be 26. The carrying capacity of the land surface, as predicted by this approach, using resource estimates from The Geological Society (2012) would limit the technically recoverable gas reserves for the Bowland Basin from the predicted 8.5 x 10^{11} m^3 to 2.21 x 10^{11} m^3.

6.2.2 The probable optimal lateral length for maximising technically recoverable gas reserves of shale gas over the Bowland Shale

This study indicates that if the average license block was developed to its full potential, a lateral length of 1300 m would be the most probable optimal lateral length. This lateral length would generate an average carrying capacity of 12 wells per licence block, generating a technically recoverable gas reserve of 1200 x 10^8 m^3. These findings, that longer laterals are not necessarily the most efficient is not consistent with general practise within North America. Within sparsely populated countries such as the US increasing lateral length with optimal fracture distance is the goal. Consequently, should a shale industry go forward within the UK, or anywhere else in Europe, it is important that potential site locations are carefully assessed and the potential for large numbers of well pads being developed are taken into account.

6.2.3 The potential for spills and leaks of contaminated liquids from shale gas developments

Assessments of data from Colorado and Texas show that spill rate is increasing, and within Texas this increase is statistically significant. Based on data from Texas RRC, a UK shale industry consisting of well pads with 10 laterals would likely experience a spill for every 16 well pads developed. When 40 laterals are developed on a single-well pad, a spill would likely occur for every four well pads developed. The datasets these values are based upon specify the leading cause of a spill is equipment failure, followed by human error. With 33% of the spills recorded in Colorado found during site remediation and random site inspections it is important that regular site inspections are performed by an appropriately trained work force and where possible constant onsite monitoring is carried out.

Based on the milk tanker data and tanker movement estimates of 2856 tankers over two years, a well pad of 10 laterals would likely experience an incident for every 12 well pads developed and a spill for every 19 well pads developed. Consequently, it is important that appropriate mitigation strategies are in place to minimise the risk of spills associated with well pad activities and fluid transportation movements if a shale industry were to go forward within the UK, or elsewhere in Europe.

6.2.4 An assessment of UK conventional oil and gas well site remediation

The UK experiences two main issues with regards to oil and gas well site legacy: (1) well sites are not being appropriately remediated, e.g. well pads, hard core and well site equipment have been left onsite; (2) well sites have been remediated at the surface, however, subsurface remediation is not sufficient with soils being left compacted.

With 10% of the wells investigated for surface disturbance across the UK clearly showing or indicating where the well pad was once located, and 10 of the 15 well sites assessed in the field indicating soil compaction, improvements in the remediation process would be advantageous to limit further long term implications from conventional oil and gas exploration. Regular independent checks, assessments onsite, inspection of both completed, abandoned and suspended well sites should be a key requirement for both the current onshore oil and gas industry and any future industry.

6.3 Limitations

Without a currently operating shale gas industry within the UK several assumptions associated with potential developments have had to be made within this study. Within Chapter 2 and 3 setback distances and lateral lengths have been assumed based on predicted UK development scenarios and experiences from the US recorded in the literature. Within Chapter 2 just one potential scenario was developed with setback distances and lateral lengths set at 152 m, 609 m and 500 m, respectively. Although these distances were taken from the literature it is likely that the setback distance of 609 m was rather generous, whilst 500 m lateral was too conservative, with the first two lateral shale gas wells drilled into the Bowland Shale extending 750 m and 800 m. Although setback distances and lateral lengths will vary between sites, a more defined range of actual values used cannot be confirmed until further drilling is carried out. Again within Chapter 3 lateral lengths have been assumed to range between 500 m and 3500 m, whilst lateral widths were assumed to range between 100 m and 350 m. It is difficult to determine how realistic these assumptions are until wells have actually been drilled and the technology available established.

For Chapter 2 and 3 resource and recovery factors have also been extracted from the literature; however, until the Bowland Shale is hydraulically fractured it is very difficult to estimate how accurate these estimates are and how much shale gas resource is actually located within northern England. It will take a number of wells across the region to accurately determine where the sweet spots are located, the recovery factors and the volume of technically recoverable gas reserve that can be extracted. Thus, the resource and recovery factors used in this study may be inaccurate.

Assumptions made in this study may under estimate the actual number of wells developed per well pad. The number of laterals used in the development scenari os in Chapter 2 was four, whilst within Chapter 3 the range used was between 6 and 10. However, as mentioned in Chapter 4 it is possible well pads could have up to 40 wells. Until further testing is performed on the Bowland Shale it is difficult to determi ne how many wells would likely be developed and how many levels these would be on.

The likely number of shale gas developments is also questionable. There is very little in the literature stating the potential number of shale gas sites that may be developed if a shale gas industry were to go forward within the UK. Within Chapter 2, development scenarios where 1 and 16 wells per licence block are developed was assumed, however, the likelihood of all the licence blocks being developed is not realistic. It is more likely that wells will be concentrated in licence blocks where productivity is highest, rather than spread equally across all the leased licence blocks. Until more wells are drilled and the shale is tested the quality and extractability of the gas, and thus the likely number of wells to be developed is unknown. Additionally, only with further development will the known sweet spots for the recoverable gas resource within the Bowland Shale be identified and from this the likely areas that will be highly populated with wells.

The likely onsite and offsite spill scenarios determined within Chapter 5 assumes all spills are the same, thus the type of fluid spilt and the likely size of the spill have not been defined; therefore the impacts of these spills cannot be wholly assessed. Tanker movement values from Taylor et al., (2013) have been used within Chapter 4's development scenarios, however, from assessing the current number of tanker movements experienced at Cuadrilla's Preston New Road site these values are potentially too low and not a true representation of likely numbers. For example, between the January and December of 2017, 5312 tanker trucks were recorded going to and from the Preston New Road site, whereas in Cuadrilla's Environmental Statement just 221 two-way journeys were expected for the entire development of the Preston New Road site (Cuadrilla Bowland Ltd, 2014). As previously mentioned, until an industry is establish it is difficult to determine accurately the likely volume of fracking fluid required, flowback water produced and tankers required to deliver and remove these fluids. Until further developments are carried out it will be difficult to determine the real probability of the impacts of spills.

There were 15 sites sampled within Chapter 6, with over 2193 wells having been drilled within the UK since 1895 this is a rather small sample size, thus the conclusions from this chapter are based on results from just a few sites. Therefore, additional field sites would increase the sample size allowing for a greater understanding of general trends with regards to legacies left by conventional oil and gas well sites. In addition, compaction tests were not carried out at comparator industry sites, thus it is difficult to say if soil compaction is unique to conventional oil and gas as other industries were not measured.

6.4 Implications

The potential development of a shale gas industry within parts of the UK raises a number of concerns. This study focuses on addressing three key areas of concern: surface disruption, the potential for spills and leaks, and the potential long term implications. Largely the results from this study indicate that the surface impacts from a shale gas industry are not unique and that other currently existing industries pose similar risks to that of a shale gas industry. Thus, by assessing comparator industries mitigation strategies have been suggested to manage and mitigate against potential future concerns both onsite and offsite. For example, with regards to spills it is vital that all aspects of risk are considered to minimise the chance of a spill, thus both onsite and offsite equipment needs to be fit for purpose and managed by a well trained work force with regular independent inspections carried out to ensure high equipment standards. The Environment Agency's regulations include: that an impermeable membrane must be installed across all areas of the site, that all onsite storage tanks should be bunded, and that all pipework and storage tanks are inspected daily. This thesis indicates that additional practises could be developed to improve the current Environment Agency's regulations and help prevent future spills, for example we must learn from past experience. Thus, when environmental breaches occur these need to be recorded and the data shared, thus allowing for insights into when and where spills are most likely to occur, and the underlying causes. A better understanding of these factors would provide regulatory bodies and industry makers with important information on where to target efforts for locating and preventing future spills. Consideration for issues that may arise during transportation also needs to be carefully mitigated against as there is little mention of this with regulation, thus truck drivers should have sufficient time to make deliveries, regular breaks and constant updates on road conditions to make transportation of potentially hazardous fluids safe.

Although there are Environment Agency regulations on well pad construction there is currently no clear regulation on where well sites can and cannot be located. The decisions are largely made on an induvial planning application by the local planning offices on what they deem appropriate and publically acceptable. The results from this thesis indicate that the carrying capacity, thus the number of well sites that can be located per licence block is determined by the setback distances applied to the site and lateral lengths. Thus, the number and spacing of potential shale gas well sites within UK licence blocks is poorly defined and could potentially be variable throughout the country.

Once decommissioning of a well occurs the operator must abide to a number of procedures and regulations. This largely involves the wellhead to be removed and the casing cut and sealed below ground level. The site should then be remediated to its pre-industrial use. This is then reviewed by an independent well examiner and the HSE (EA, 2016). It is apparent from the results in this thesis that breaches in regulations are occurring and more is required to enforce a higher standard of site remediation. Further work needs to be completed to assess specifically how and why sites have managed to breach these regulations.

This thesis highlights that when assessing the likely impacts from a potential shale industry one needs to consider the a whole array of possible impacts and the cumulative impacts that may occur if several wells are developed in a number of licence blocks, rather than focusing on the development of a single-well pad.

6.5 Further work

- As mentioned in Section 6.3 many assumptions have been made with regards to setback distances, lateral lengths, lateral widths, resource values and recovery factors. If a shale gas industry is developed within the UK, specifically England, a future study using actual data and methodologies developed in Chapter 2 and 3 could be used to determine optimal well locations.
- In Chapter 4, spills experienced in the US have been used as an analogy for determining likely spill numbers for different development scenarios in the UK. This study focused on the number, location and cause of the spills; however the type of fluid and its toxicity was not assessed. Thus the potential threat of the spill was not fully quantified; therefore future studies on spill rate scenarios could be expanded to include these factors.
- The analysis of likely spill numbers offsite did not include distance travelled, as the distance tankers are required to travel have yet to be confirmed; therefore future studies could include a model that factored in the distance travelled into the chance of a spill.
- Although not an aim of this study, Chapter 5 highlights the potential environmental issue with regards to suspended conventional oil and gas well sites not being left in an appropriate state. A future study assessing the scale of the issue and the impacts these sites have on the environment is required.
- Within Texas soil samples from oil and gas drilling and production operation sites showed evidence of elevated levels of heavy metals (including barium, chromium, lead and zinc), sodium, salinity, pH, and/or petroleum hydrocarbons (Carls et al., 1995). Potential contamination from spills on suspended and remediated well pads could be studied, thus soil samples could be taken, assessed and compared against a control to see if spilt chemicals and/or fluids used within the hydraulic fracturing produces could

be identified and their potential impact on the environment. This would help determine if current spill management practices and remediation practises are being carried out effectively.

- Additional field-experiments to further evaluate the degree of soil compaction on remediated well sites could be carried out, these could include: measuring the bulk density, infiltration rate, and hydraulic conductivity (Zhang et al., 2006). To indicate the degree of damage incurred from improper well site remediation, Drohan and Brittingham (2012) indicate that testing the soils fertility and organic matter percentage could be undertaken.

Appendices

The appendices are provided on CD, and a brief outline is given below:

Appendix 1

Soil compaction data collected for Chapter 5.

Appendix 2

Milk and petrol tanker data collected from online sources for Chapter 4.

Appendices

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