ECONOMIC APPRAISAL OF UNDEVELOPED UNCONVENTIONAL GAS;

THE BOWLAND UNITED KINGDOM CASE

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Impact Statement

This study provides insight for academic and non-academic audiences.

In academia, this study contributes by developing novel approaches in undeveloped shale gas resource appraisal; production, costs and economic assessment under carbon constrain. The results could also provide input into whole system energy models as well as macroeconomic input output models. A peer reviewed paper has been published focusing on the production estimation aspect while several others are being finalized. In addition, the research has been presented at conferences as detailed in the publication section.

In terms of non-academic relevance, the models and output provide policymakers in the UK and other relevant regions with a novel approach guiding understanding and insight into energy resource options and energy security assessment. Furthermore, a realistic macroeconomic modelling relating to job creation and value chain impact could be developed based on the appropriate cost and production estimation.

Finally, the research output, developed and applied research framework contributes to the existing knowledge by improving investors with improved appraisal techniques for below ground, oil impact, costs, and carbon constraint uncertainty. The innovative methods could impact effective energy policies founded on a deeper understanding of relevant parameters including the ongoing energy transition towards low carbon and renewable energy technologies as well as climate-effective investment decision making.

ABSTRACT

The estimation of production potential provides the foundation for commercial viability appraisal of natural resources. Due to uncertainty around production assessment approaches in the unconventional petroleum production field, an appropriate production estimation methodology which addresses the requisite uncertainty at the planning stage is required to guide energy policy and planning. This study proposes applying the numerical unconventional production estimation method which relies on geological parameters, (pressure, porosity, permeability, compressibility, viscosity and the formation volume factor) as well as the rock extractive index (a measure of technical efficiency) and develops a model that estimates the appropriate values for four of the parameters required based on a depth correlation matrix while a stochastic process guides the other parameters based on known data range. The developed model is integrated with a numerical model to estimate gas production potential and developed framework is eventually applied to undeveloped shale gas wells located in the Bowland shale, central Britain. The results account for below ground uncertainty and heterogeneity of wells. A sensitivity analysis is applied to consider the relative impacts of individual parameters on production potential. The estimated daily initial gas production rate ranges from 15,000scf to 319,000scf while estimated recovery over 12 years is approximately 1.1bscf in the reference case for wells examined.

In relation to cost, A cost analysis is executed, which guides the identification of cost parameters. This study identifies key cost parameters and then develop a non-static model by examining the trends over the years as well as proposes a work break down cost estimation equation. In addition, a methodology in estimating the costs of developing unconventional gas resources based on the production technique is proposed. In addition, the sources of uncertainty in shale gas development cost estimation are examined and identified. It is found that there is an insignificant correlation of cost parameters with oil prices suggest that additional factors need to be analysed. These empirical model and results suggest that the market oil price impact on shale gas production cost although important but restrained by other factors which may include financial revenue hedging programs aimed at securing higher revenues or endogenous efficiency gains which direct production strategy in low oil prices situations. The results from the learning curve and innovation study shows that drilling technology has driven cost reduction and increased lateral lengths while the hydraulic fracturing technology has relied on more material use volumes. The additional demand in stimulation sand and other production materials as well as their disposal can lead to exogenous cost implications. Other expected exogenous cost implications are environmental, regulation and fiscal regimes which can aid or deter technology adoption in different regions.

The overarching economic appraisal methodology is based on integration of the depth dependent correlation matrix, bottom up cost estimation and the undeveloped unconventional gas development decision models. Additionally, other input and output parameter scenarios are modelled as well as the impact of carbon emission regulation and mitigation.

Publications based on this Thesis

Peer-Reviewed Journal Publications

Nwaobi, U & Anandarajah, G (2018). Parameter Determination for a Numerical Approach to Undeveloped Shale Gas Production Estimation: The UK Shale Region Application. Journal of Natural Gas Science and Engineering 58 (80-91)

Conference Papers

Nwaobi, U & Anandarajah, G (2015). A Methodological Framework for the Estimation of Unconventional Gas Development Costs: Accounting for the of Oil Price Uncertainty. 38th International Association of Energy Economists (IAEE) International Conference. Antalya. Turkey

Nwaobi, U & Anandarajah, G (2015). Production Estimates of Undeveloped Gas Wells: The Bowland Shale Region. 38th International Association of Energy Economists (IAEE) International Conference. Antalya. Turkey

Nwaobi, U & Anandarajah, G (2016). Economic Appraisal of Unconventional Gas Development in the UK. Shale World UK 2016

Nwaobi, U & Anandarajah, G (2016). Production Estimation of Undeveloped Unconventional Gas Development: The Case of Wells in the Bowland Shale Regions. 39th International Association of Energy Economists (IAEE) International Conference. Bergen. Norway

Working Papers

Nwaobi, U, Anandarajah, G & Agnolucci, P. The Economic Appraisal of Shale Gas Wells in the Bowland Shale Play England

Nwaobi, U, Anandarajah, G & Agnolucci, P. The Impact of Oil Price Uncertainty of Shale Gas Development Cost Factors.

DEDICATION

Okoise Daniel & Caroline Nwaobi and Austin Obozuwa

Anthony & Comfort Nwaobi

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Conversion Table

Parameters	Multiply by
Ibs to KG	0.4536
USD to GBP (£)	1.4
Boe to BTU	5.8
MCF to Therm	10.37
ft^2 to BTU	1000
M^3 to BTU	35,375
Therm to BTU	100,000
BOE to SCF	5,800

LIST OF ABBREVIATIONS

ANOVA	Analysis of Variance
BEIS	Department for Business, Energy and Industrial Strategy
Bcf	Billion Cubic Feet
BGS	British Geological Service
BoE	Barrel of Oil Equivalent
CEA	Council of Economic Advisers
CCS	Carbon Capture and Storage
COV	Covariance
CPF	Carbon Price Floor
DECC	Department of Energy and Climate Change
DCA	Decline Curve Analysis
DCF	Discounted Cashflow Analysis
DDCM	Depth Dependent Correlation Matrix
DUKES	Digest of UK Energy Statistics
EUR	Estimated Ultimate Recovery
EU	European Union
Ft	Feet (Length)
FIFA	Fédération Internationale de Football Association
GBP	Great British Pound
GVA	Gross Value Added
HoL	House of Lords
HRD	Horizontal Rig Demand
HFS	Hydraulic Fracturing Sand
HFSD	Hydraulic Fracturing Sand Demand
HMRC	Her Majesty's Revenue and Customs
IFO	Independent Fiscal Office
IGU	International Gas Union
IPCC	Intergovernmental Panel on Climate Change
IP	Initial Production
LNG	Liquified Natural Gas
LBS	Pounds (Weight)
LBD	Learning by Doing
LGM	Logistic Growth Model
MMSCF	Million Standard Cubic Feet
NAO	National Audit Office
NPV	Net Present Value
NRC	National Research Centre
PLE	Power Loss Equation
RFCT	Ring Fence Corporate Tax
R&D	Research and Development
SCF	Standard Cubic Feet
SEPDM	Stretched Exponential Production Decline Method
SD	Steel Demand
TCF	Trillion Cubic Feet
UK	United Kingdom
UKCS	United Kingdom Continental Shelf

US United States of America
USHIDM Undeveloped Shale Gas Investment Decision Model
USEPA United States Environmental Protection Agency
USEIA United States Energy Information Agency
VRD Vertical Rig Demand
WACC Weighted Average Cost of Capital
WEC World Energy Council

1 Introduction

1.1 Background and Context of Study

Energy system sustainability relies on three dimensions: energy security, energy equity, and environmental sustainability of energy systems (WEC, 2019). HoL (2014) notes that the UK energy market experienced energy production decline, shifts experienced in the energy demand and supply mix, and climate impact obligations.

Energy security has been a policy concern with studies revealing UK oil and gas production peaking between 1999 and 2000; thus, the UK Continental Shelf's production has declined (Nakhle, 2007; Helm, 2005, Taylor and Lewis, 2013). In 2013, aggregate primary fuel consumption was not met by indigenous production, which continues the trend observed in 2004 when the UK became a net importer of fuel (DUKES, 2014; Bradshaw and Solman, 2020). DUKES (2014) reveals that in 2013, UK energy production declined by 6.3% due to reduced coal and gas output. A shift away from the two primary electricity generation sources occurred in 2013, with reported drops of 8.7% and 4.5% in coal and gas, respectively (DUKES, 2014). The reduction in electricity generated using coal is attributed to closure and retrofitting of plants to use biomass as fuel. Electricity generation from gas was 50% down than 2010 levels, attributed to high prices due to sourcing constraints. However, the 4.5% drop in demand for electricity generation from gas is offset by a 1% total demand drop due to an increase in demand from industrial and alternate uses, including heating (DUKES,2014).

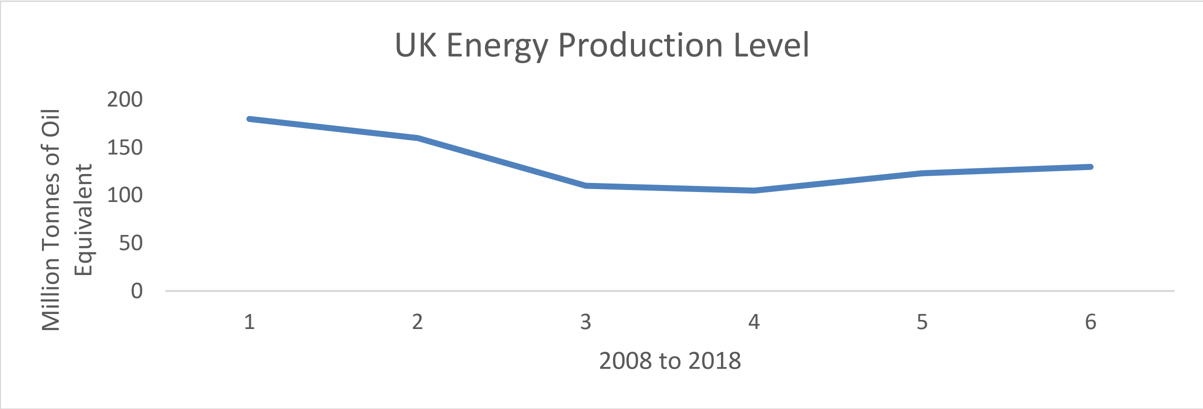

Figure 1 United Kingdom Energy Production Trend (Source: DUKES 2019)

Figure 1 above highlights the 10-year (2008 to 2018) energy (oil and gas) production trend. Bradshaw (2020) notes that UK natural gas production peaked in 2000, and by 2004 the nation became a net importer of natural gas, leading to a continuously growing import dependence. In 2018, natural gas remained the primary fossil fuel in the UK energy mix but now accounts for 79.4%, a record low, and with gas production falling by 3.3% year on year, net imports were up 11%, LNG imports from Asia and US increased by 6.4% while pipeline import fell by 1% majorly due to a 5.1% fall in Norway piped gas imports (BEIS, 2019). The UK's 2019 statutory security of supply report uses the European Union (EU) N-1 calculation for gas security assessment. The N-1 calculation estimates whether peak demand could still be met if the single largest piece of infrastructure fails (BEIS, 2019). The N-1 approach focuses on infrastructure but not gas purchase or supplier availability. Bradshaw and Solman (2019) consider the N-1 approach a single indicator analysis that offers simplicity at the expense of accuracy and offers a false sense of security while proposing an alternative dashboard approach.

Sustainability is also an energy security factor. The Climate Change Act 2008 and Energy Act 2013 addresses the environmental policy constraints on energy use and supply. The environmental policies include the UK government's commitment to long-term carbon reduction emission targets for 2050 and 2020, respectively, a legislative commitment on the UK government to five-yearly carbon budgets. McGlade et al., (2018) notes that the UK's climate targets are ambitious and require a deep decarbonisation of its energy system with the role of natural gas during both the transition towards a future low carbon energy system and when achieved is a significant policy concern. The 2018 study concludes that if coal-fired power generation is removed in the energy generation system and carbon capture and storage deployment is delayed, then a second dash for gas may provide short term gains in carbon emissions, an approach considered not to be the least cost-effective. Asides electricity generation, which is 40% gas-dependent (since 2015 due to the decline of coal power generation), domestic consumption and heating are other demand factors with potential consumption in transportation and hydrogen production technology as a feedstock.

1.2 Unconventional/Shale Gas Development Technology

Clark (2011) also notes that an increase in energy demand, declining production from conventional reservoirs, and increased growth of oil and gas production from Shale reservoirs due to technological improvements have led to an increased development rate in the resource over the past decade. In 2018, the production of natural gas in the US was about 30.6 trillion cubic feet (Tcf) while demand was 30 trillion cubic feet, a production peak was achieved. The US Energy Information identifies that most of the production increase after 2005 is due to horizontal drilling and hydraulic fracturing technology. Shale gas production in the United States (US) boosted domestic gas production previously on a decline due to innovations in drilling techniques (Wang and Krupnick, 2013; Guarnone et al., 2012; Baihly et al., 2010; Pearson et al., 2012).

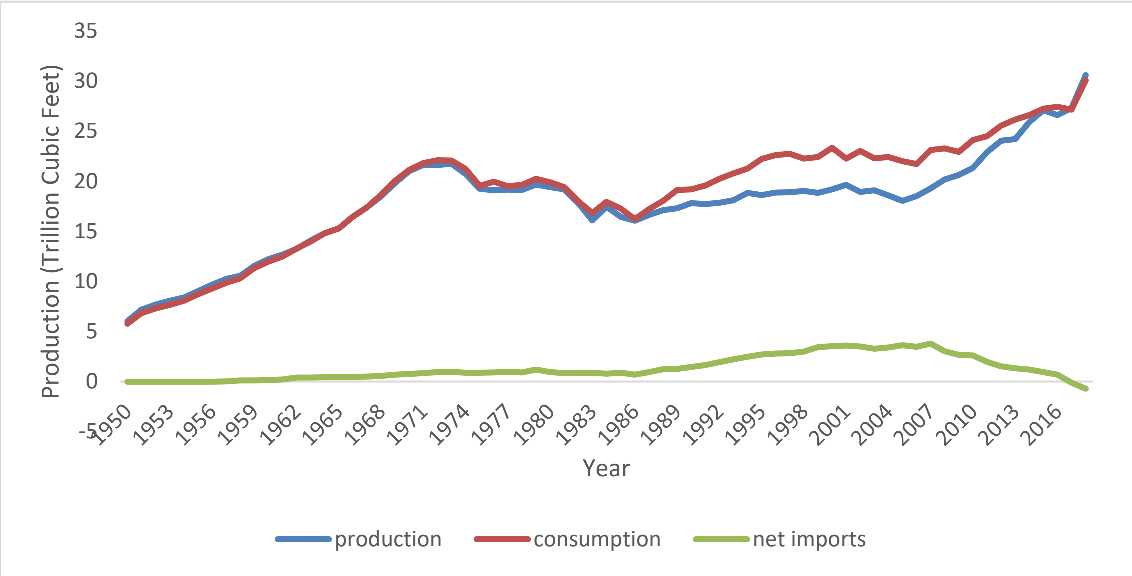

Figure 2 Natural Gas Production, Consumption and Import Trend (Source: USEIA)

Tight gas, coal bed methane and shale gas are unconventional gas resources; the term unconventional refers to the characteristics (typically low permeability) of the source rock and not the composition of the gas (AEA, 2012). See also figure 3.

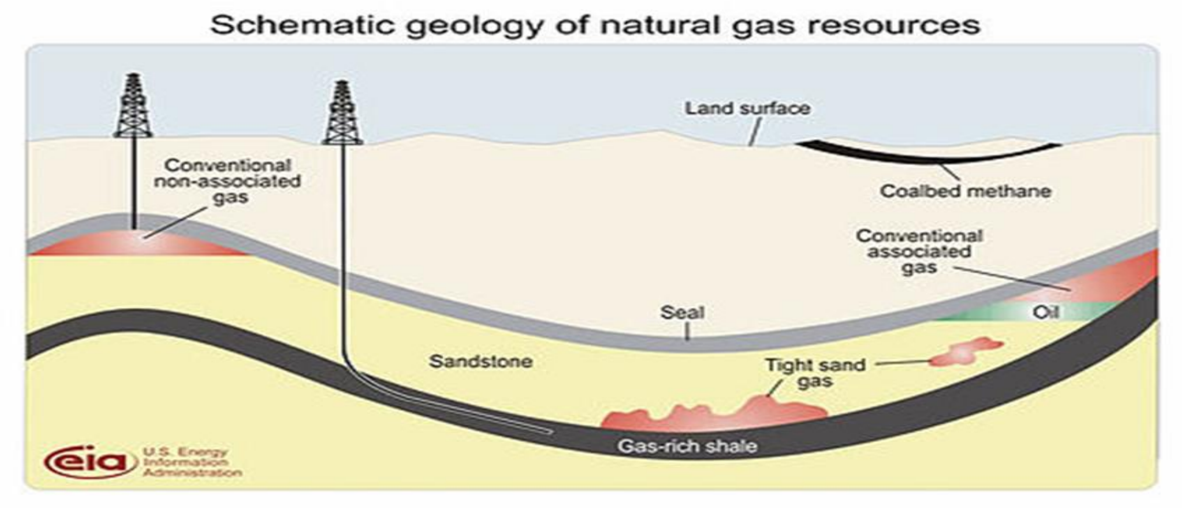

Figure 3 Geology of natural gas resources (Source: USEIA)

The hydraulic fracturing technology application in the United States began with two wells in Oklahoma and Texas around 1949 (Chivers,2013; Rogers, 2011; Zuckerman, 2013). Oil and gas production from shale deposits have grown in the US and Canada over the last decade due partly to directional drilling and hydraulic fracturing technique which requires the injection of pressurized liquid, sand and chemicals into deep shale formations to fracture the rock and aid oil and gas flow (Bradshaw et al., 2018); the difference between unconventional and conventional oil and gas production. Speight (2013) studies the production process for shale gas, which begins with site clearing, exploration, development via vertical and horizontal drilling, hydraulic fracturing, operations, and well abandonment.

Mani and Dayal (2017) notes that shale gas exploration and exploitation are a multiphase process that begins with a shallow seismic survey to provide additional extent and thickness knowledge of the shale formations. The geophysical tool applied for exploring mineral and hydrocarbon located in the subsurface structure is shallow seismology, which uses seismological principles to understand the earth's significant structures by generating either explosive or vibrating seismic waves in the subsurface (Speight, 2013). The waves are mostly refracted or reflected, which are propagated to provide core thickness, mantle, and crust information, with the latter being more useful in the hydrocarbon industry.

The next development phase consists of drilling and hydraulic fracturing/completion. The cementing of pipes and strong lining is essential to avoid rock contamination along the wellbore with high-pressure lining work required for both the vertical and horizontal well. The drilling operation commences with a vertical drilling up until the shale formation is reached. Drilling fluids are applied for the lubrication of drilling assembly and helps to remove formation cuttings. The drilling fluids usually compose of water, bentonite clay, and additives for the fluid's viscosity but vary subject to geological formations. Soeder and Borglum (2019) notes that the combination of advanced directional drilling technology and a 50-year-old reservoir stimulation technique known as hydraulic fracturing applied to develop shale oil and gas by Mitchell energy; who recognized that the horizontal wells (laterals) would contact a much greater volume of the formation compared to vertical wells. Hydraulic fracturing is the next phase in the resource exploitation. There important considerations before hydraulic fracturing begins, such as the amount of water required and proponents for the operation, the fracturing fluid chemical mixture, volume in the subsurface, the pressure of the fluids to be injected, and the volume of area to be hydraulic fractured. During the hydraulic fracturing process, fracking fluid is passed through the core vertical well and then the horizontal well(s) in high pressure. The fluid with elevated pressure opens laminar fractures in the exploited shale via perforations, which increases the volume of the formation but will induce seismicity, albeit at a low level (Mani and Dayal, 2017). The chemicals/fracking fluid composition ratio is 98.5% water, 1% sand, and about 0.05-0.5% chemical additives. The polyacrylamide combined with biocides, surfactants, and scale inhibitors chemicals act as friction reducers while biocides prevent blocking of the "downhole" and fissures by organisms, and sand is kept in fluid suspension by surfactants. Other possible chemicals applied are benzene, chromium, and other compounds (Chivers 2013). The production of oil, gas, or both alongside other waste products commences once wells are connected to processing facilities. Once production becomes unsustainable, a shale gas well is abandoned, facilities are dismantled, and the land returns to its natural state (Speight, 2013).

1.3 Governance

The production and development of natural resources require governance to ensure standards, sustainable practices, and the protection of the environment, ecosystem, and human wellbeing. As with every natural resource development, shale gas production and development also require regulation to protect the ecosystem. Complex sustainability criteria characterize natural gas production via hydraulic fracturing and horizontal drilling from shale rock reservoirs due to debatable environmental benefits and cost implications (Engelder et al., 2014; Howarth et al., 2011; Jackson et al., 2013). Wang et al., 2014, notes that although shale gas exploitation can provide a specific brief and localized economic benefits for resource-endowed nations, the US experience reveals that these gains might also be associated with a range of environmental, social, and community-related problems. The major environmental concerns relating to unconventional gas development include groundwater (aquifer) contamination, waste disposal, as well as use, air quality, social impacts, and land (Rahm and Riha, 2011). Prpich et al. (2016) argues that the most studied shale gas development risks are related to water, air, land, and social impacts. The case for regulation in shale gas development is further highlighted due to its associated environmental, health, social impact, and other concerns.

1.3.1 Exploration and Acquisition

Additionally, test wells are drilled to acquire core samples. The core samples are used to determine the geological characteristics of the prospective well. Also, at this stage of development, preliminary assessment of possible supply routes and stakeholders are evaluated. The environmental risk associated with this process is mainly emissions from equipment and drill rigs and water consumed for drilling the test wells.

1.3.2 Site Clearing

The site clearing process, which involves access road development, construction, and earthworks (cut, fill, and moving), results in loss of vegetation (deforestation), animal and human habitat, and changes to the ecosystem. During this development stage, there is also increased vehicle movement as trucks involved in clearing and settings up the well site make several trips to get the site ready for drilling operations.

1.3.3 Drilling

The much higher drilling intensity in unconventional gas development relative to conventional gas is a common feature that contributes to the operation's externalities, resulting in the impression of more significant risks related to spills and solid waste management (Rahm et al. 2015; Cronshaw and Grafton, 2016).

1.3.4 Completions

The hydraulic fracturing process during the well completion stage involves pressure flushing one to five million gallons or more of "frac fluid"- a mixture of water, proppants (commonly sands), friction reducers, and other chemicals into the well (Willits et al., 2016; Theodori et al., 2014). About 10 to 40% of fluids used in fracturing return to the well surface during the first few weeks; this phase is known as the flowback period (Savacool, 2014). An earlier study by Engelder et al. (2014) argued that the flowback water volume was 40 to 80% of the injected volume but also noted that the quantity and quality would vary over time.

1.3.5 Production and Operations

During the gas production stage, additional water referred to as "production water," which naturally occurs in the reservoir, is brought to the well surface throughout production life (Theodori et. el, 2014). Additionally, there are air emissions from trucks, equipment, vents, and methane leakages.

1.4 Environmental Footprints of Shale Gas Development

Shale gas development might lead to environmental degradation relating to water, air, and the release of radionuclides, public health decline due to climate change, and the displacement of cleaner forms of energy supply (Savacool, 2014). However, Burham et al. (2012) note that combusting natural gas from shale formations to produce electricity produces half as much Carbon dioxide (CO_2) as burning coal or oil with the added advantage of lower emissions sulfur oxides, nitrogen oxides, and mercury. This subsection reviews the significant environmental impacts on water, air, land, and social wellbeing.

1.4.1 Water

Evidence from the United States indicates that the externality associated with unconventional gas, which gets the most attention, is water pollution (Cronshaw and Grafton, 2016). Kreuter et al., (2016) categorizes the water-related issues associated with unconventional gas development into three; water requirements for extraction and processing, potential water contamination, and wastewater disposal. The stimulation of the reservoir during hydraulic fracturing applies about 10-20Million litres of water per well (Stevens et al., 2013), Nicot and Scalon, 2012 estimate 10-30 Million liters per well requirement. However, the water demand varies by site and location, although, as established in earlier chapters, water, and proppant use per well has increased over time. Consequently, the increased demand for water for the stimulation process can lead to water supplies (Cronshaw and Gradfton, 2016). The water requirement intensity of the development process makes it difficult to operate or produce in water-deprived/stressed environment.

The risk to water systems by developing shale gas resources is mainly related to concerns of local water depletion, threats to water quality, and the issues surrounding the safe disposal of wastewater from fracturing operations (Rabe and Borick, 2011). The contamination of groundwater and surface water in the shale gas extraction process is caused by operations procedure failure or inappropriate disposal of wastewater (Guo et al., 2017).

1.4.1.1 Water Quality Risk

Oil and gas production also produce large quantities of water and oil, gas, or oil and gas known as produced water (Reclamation U.D, 2011). The produced water from hydrocarbon wells includes flowback water, formation brine, water condensing from the gas phase, and other mixtures (Orem et al., 2014). The risks to water quality from hydraulic fracturing are via these constituents released on the surface or migration of products from the flowback and production in subsurface aquifers (Graham et al., 2013). The flowback water comprises 40% to 80% of injected fluids, which return to the production area’s surface. The composition of flowback water is dictated by geology. It thus varies by location but mainly comprises of inorganic chemicals (inorganic anions, cations, metals, radioactive materials), organic chemicals (solvents, biocides, hydrocarbons), and unidentified materials measured as total organic carbon (Prpich et al., 2016; USEPA, 2015). Vengosh et al. (2017) analysis flowback and production water volume reveals a much more considerable environmental risk associated with the inorganic contaminants with concentration levels positively correlated with the formation of water's salinity.

Vengosh et al. (2014) note that public concern has been raised about the possibility of hydraulic fracturing to adulterate shallow groundwater and surface water supplies. Zirogiannis et al. (2016) regard water pollution by methane to be the most widely reported caused by well leaks due to compromised or inadequate casing and cement sheaths and inappropriately abandoned wells that have not been effectively plugged. Mehany and Guggemos (2015) and Loomis and Haefele (2015) attribute water pollution to flowback storage pits leakages, faulty well cement operations, and the possible connection of deep fractures with surface water bodies and spills during transportation. The possibility of groundwater contamination is further exuberated due to the proximity of formations to aquifers, the presence of pre-existing faults connected to surface or groundwater in the production area. In contrast, the surface level characteristics determine the impact of leakages (Veiguela et al., 2016).

According to Jackson et al., 2016, theoretically but unlikely, hydraulic fracturing could open emerging fractures located thousands of meters underground, linking shallow drinking water aquifers to deeper layers and providing a channel for fracking chemicals and formation brine to move upwards (Jackson et al., 2016). Most likely, man-made fractures will connect to a natural fault, an abandoned well, or some other underground pathway, allowing fluids to migrate upwards (Myers, 2012). Besides, Jackson et al., 2013, suggests that the distance to a shale gas well determines the methane concentration risk of drinking water sources. Castro-Alvarez (2018) also considers faulty well construction as the most likely cause of aquifer contamination. Howarth et al., (2011) and Osborn et al., (2011) test ground and well water for methane with results suggesting methane migration from proximate hydraulic fractured wells.

Veiguela et al. (2016) argue that documented evidence suggests that defective casing and cementing of wells and leakage from the surface are the major causes of water contamination but are activities associated with both conventional and unconventional gas development and not the hydraulic fracturing procedure.

Water quality factors are essential in the disposal of wastewater from hydraulic fracturing (US EPA, 2012).

1.4.1.2 Wastewater Disposal Risk

The management of wastewaters from unconventional gas extraction is a significant issue in avoiding environmental damage from the oil and gas production process (Vidic et al., 2013; Jackson et al., 2016). A significant disposal problem for environmental regulators and developing companies by unconventional gas production is the produced water due to the large volumes and variable quality (Orem et al., 2014). Harkness et al., (2015) argues that the disposal and management of oil and gas wastewater is an engineering challenge because of the high level of salinity, anthropogenic, naturally occurring organic compounds, heavy metals, and naturally occurring radioactive materials which all pose an environmental and human health risk when released into the environment. Wastewater from the unconventional gas development and production process is known to have high salinity and contain mixtures of chemical and toxic radioactive materials originating from the shale formation and production activities (Barbot et al., 2013; Gregory et al., 2011). Vengosh et al. (2013) concludes that water quality management and wastewater disposal are unquestioned impacts of shale gas exploration and production. The potential pathways for wastewater from disposal facilities to contaminate water bodies are either directly, accidental release from tanker trucks, leakages from onsite storage ponds or tanks, wastewater migration through subsurface aquifers at the injection depth or failed casing and runoff of spills into rainwater and melting snow (Orem et al., 2017). The disposal and management of flowback and produced waters must follow methods approved by state and local regulators (Theodori et al., 2014). However, the United States Environmental Protection Agency (USEPA) regards waste from oil, gas-related exploration and production activities as special wastes which exempts them from federal hazardous waste regulation under subtitle C of the resource conservation and recovery act (Jackson et al., 2016).

In the United States, wastewater from hydraulic fracturing is either disposed of by injection into the underground, sent to municipal or publicly owned water-treatment facilities, and most undesirably sprayed unto roads and lands. There has been progress relating to wastewater recycling techniques and the reduction of waste volume. However, disposal is still required mainly by underground injection due to their unsuitability for standard wastewater treatment facilities in unconventional gas development (Engle et al., 2014).

Orem et al. (2017) examine the organic composition and toxicology of water and sediments in a stream adjacent to an underground injection disposal facility that handles hydraulic fracturing wastewater. Results indicate that wastewater enters the stream that other process derived substances are also present. Osborn et al. (2011) provide evidence of 17 times higher methane, ethane, and methane isotopic signatures pollution in the water supply to homes within 1km proximity to shale gas wells. Analysis by Vengosh et al. (2013) provides evidence from western Pennsylvania in the United States that disposal of wastewaters high in saline content to waterways and brine treatment facilities results in higher salinity and radioactivity river residues and downstream water. Drollette et al. (2015) detect gasoline or diesel related compounds in 32% of drinking water samples taken at hydraulic fracturing sites reported spills. However, Engelder et al. (2014) argue that contrary to suggestions that the hydraulic fracturing process could accelerate brine escape and lead to a higher possibility of near-surface water pollution, on the contrary, the process could reduce the risk. The research concludes that the significant environmental leakage of brine hypothesis by shale gas fails on quantitative grounds.

Overall, evidence from the United States relating to wastewater contamination presented by different authors on different plays, geological locations, and conducted based on different assumptions yield varying results. The various wastewater contamination pathways are also due to inappropriate engineering, disposal procedures, and site spillage, which could be addressed by regulation. Nevertheless, as stated above, in the United States, oil and gas operations are exempted from hazardous waste regulation, which could deter shale gas developers from managing wastewater better. Schon, (2011), Osborn et al. (2011), Wang (2010), Rozell and Reaven (2012), and Rahm et al. (2013) note that the absence of acceptable practices in shale gas development can pollute the marine environment.

1.4.2 Air

The replacement of coal by gas in the power generation system offers environmental benefits due to reduced conventional pollution and lowered greenhouse gas emissions (Cronshaw and Garfton, 2016). The United States is detailed to have reduced its greenhouse gas emissions by 5% from 2010 to 2012 mainly due to the change in power generation options from coal or oil combustion to gas produced mainly via hydraulic fracturing; correlated to a corresponding 9% reduction in CO_2 emission from power generation (US EPA, 2016). US EPA (2016) states that electricity production generates approximately about 30% of total greenhouse gas emissions in the United States while electricity generation through natural gas produces 50% less greenhouse gas than generation via coal on a plant level analysis. However, an average of 4% of gas comprising mainly methane produced via hydraulic fracturing gas is lost to the atmosphere (Tollefson, 2012). De Silva et al. (2016) argues that methane losses are dependent on local conditions such as reservoir depth, permeability, and wellbore integrity and concludes that unconventional gas development displays a similar greenhouse gas footprint as coal due to the associated emissions from its upstream activities.

Methane is considered the most prevalent greenhouse gas; it is more efficient in trapping radiation than CO_2, but methane's life-cycle in the atmosphere is shorter than that of carbon dioxide (Meng, 2017). The Intergovernmental Panel on Climate Change (IPCC) reports (1996 and 2006) agree that natural gas emits half less than coal inefficient power plants. Stocker et al. (2013) show that the Intergovernmental Panel on Climate Change (IPCC) considers methane a much more potent greenhouse gas with a greenhouse gas potential of 86 over 20 years lifetime and 34 over 100 years while carbon dioxide's greenhouse potential is 1. The global warming potential (GWP) for methane is 72-fold more than carbon dioxides when considered over a 20-year time frame, 33-fold moreover 100 years (EPA, 2010) while Moore et al. (2004) stipulates a 28-34-fold range. Nevertheless, Shindell et al. (2009) argue that considering the direct and indirect impact of radioactive responses on the GWP of methane is 79 and 105 over a 20-year time frame.

Empirical evidence from the United States suggests that natural gas and petroleum organizations are the most massive methane emissions (Meng, 2017). Wang et al. (2014) observe that different studies have resulted in complex and conflicting conclusions on the possibility of the greenhouse gas footprint from shale gas development to ease climate change compared to coal and oil due to differences in estimating the total cycle methane emissions from shale gas. The different studies can be categorized into firstly; the theory that shale gas is better than coal and oil for climate change. Jiang et al. (2011) compared emissions associated with a natural gas combined cycle power plant at 50% efficiency powered by shale gas produced from the Marcellus region to emissions from pulverized coal power plants at 39% efficiency resulting in lower emissions by the natural gas-powered plant. Stephenson et al.,

(2011) compares the carbon footprint of conventional gas to shale gas estimating that the well to wire emission intensity by shale gas wells are about 1.8% to 2.4% higher than conventional due mainly to methane releases during well completions with extreme assumptions resulting in 15% higher shale gas emissions. The study also funds that emissions resulting from shale gas electricity are less than from coal-generated electric power. However, Burnham et al. (2011)'s studies the knowledge base of methane emissions from shale gas, conventional gas, coal, and petroleum to estimate greenhouse gas emissions as well as understand the uncertainty involved with determining the life-cycle greenhouse gas impacts. The study concludes that life cycle emission from shale gas is 6% lower than conventional gas, 23% lower than gasoline, and 33% lower than coal. The study further notes that there is a statistical uncertainty whether shale gas emissions are indeed lower than that from conventional due to overlap on the range of values applied for the gas production systems but demonstrates that electricity generated from natural gas has significant life-cycle greenhouse gas benefits over coal power plants.

Alternatively, other studies propose that shale gas might have a worse impact than coal on the climate. The emissions associated with flow back fluids and drilling out of wells during the completion of shale gas leads to a larger greenhouse gas footprint than conventional gas, oil or coal (Howarth et al., 2011b). Combusted natural gas is considered to have half the CO_2 emissions of coal upon combustion (Zirogiannis et al., 2016). Howarth et al., (2011b) argues that over the 20-year time horizon, shale gas's greenhouse gas footprint is 22-43% more than conventional gas, at least 20% more or twice that of coal-based on the quantity of energy available during combustion and in the case of oil at least 50% higher and maybe 2.5 times more. In the 100-year timeframe scenario, shale gas's greenhouse gas footprint is considered to be 14%-19% more than conventional gas, 18% lower than deep mined coal, but 15% more for surface-mined coal and like or 35% more than emissions from oil production.

Furthermore, Wigley (2011) concludes that a 50% reduction in coal use with an equivalent increase in natural gas use over 40years could result in a slight 0.1c increase worldwide temperatures.

Additionally, the study appraises the impact of fugitive emissions using a 0 to 10 % leakage range and found that above 2% leakage during natural gas production results in a more harmful climate impact than coal. Another debate relates to the leakage rate in shale gas development, with most studies referenced in Wigley (2011) estimating above 2% leakage rate and Hashem (2016) proposing an average of 4% produced gas lost the atmosphere without the consideration of additional pipeline and distribution losses. Furthermore, Hultman et al. (2011) conclude that shale gas emissions are 11% worse than conventional gas but better than coal. However, the study assumes that shale gas operations and technology improve by learning from past failures.

Overall, the net impact of greenhouse gas emissions from shale gas development focuses on levels of both emissions associated with electricity production and methane leakages (Alvarez et al., 2012). Nevertheless, the literature review above displays high uncertainty and disparity in the appropriate greenhouse gas associated with shale gas in electricity generation, impacted by the efficiency of the appraised power plants, the global warming potential parameter applied, and the appropriate time frame; 20 years or 100 years. Concerning methane leaks, there is also additional ambiguity with the percentage lost during production and distribution. The uncertainties in both the associated greenhouse gas emissions and methane leakages require additional studies to reduce uncertainty, guide policy development and inform proposed legislation and appropriate regulation. Newell and Raimi (2014) conclude that in the event natural gas continues to displace coal and petroleum rather than nuclear, hydro, and renewables in the energy supply mix, there will be a positive climate change impact. Also, natural gas has a role to positive play in the residential/commercial sectors aside electricity generation by providing an alternative to gasoline in personal transportation and other applications. However, evidence suggests that shale gas has only resulted in an insignificant global greenhouse gas emissions reduction and thus not enough to alter overall greenhouse gas concentrations (Newell and Raimi, 2014).

Asides methane emissions, non-methane air quality impacts of natural gas production include the emissions of other hazardous air pollutants benzene; toluene; ethylbenzene and xylenes popularly referred to as BTEX as well as non-methane volatile organic compounds (NMVOCs) and Nitrogen Oxides (C.W., et al., 2014). Consequently, the appropriate appraisal of shale gas development's air emission sustainability should incorporate both methane and non-methane related emissions in the life cycle. Nevertheless, then again, methane leaks are still the principal emissions associated with shale gas development. Nonetheless, Brandt et al., (2014) debatably argues that 20 years of natural gas systems located in North America found that the level of leakages are more than expected while US EPA (2014) suggests regulation and management best practices aimed at technologies that provide the opportunity to reduce emissions and efficiently detect leakages for repair effectively can considerably increase the air emissions sustainability conditions of shale gas development.

1.4.3 Land

Brittingham et al. (2014) show that land is required for well pad construction, roads, and pipelines by both conventional and unconventional oil and gas systems, which fragmentation of animal habitats. Thus, the requirement for land for unconventional oil and gas development is considered a significant environmental impact (Castro-Alvarez et al., 2018). Meng (2014 and 2015) suggests that shale gas development changes the anthroposphere by removing initial land cover types and well pads and transportation networks. Sites designated for hydraulic fracturing also often intrude into forested and agricultural land and grassland, leading to loss of habitat for animals and plants and climate change impacts due to land-use changes (Meng, 2017). Adams (2011) experienced 56% mortality after two years of exposure to experimental hydraulic fluid spillage simulation. Loomis and Haefele (2017) note that wildlife impacts go beyond actual disturbance and include loss of habitat due to the animals avoiding human activity and noise from shale gas development operations.

Additionally, seismic events are associated with shale gas development during the exploration stage, which may require seismic exploration while searching for drilling prospects (Centner, 2016). Increased seismicity and earthquakes can be associated with hydrofracking and shale gas production, but these are regarded on the annoyance scale rather than destructive catastrophic earthquakes (sovacool, 2014). Leith (2012) and NPR (2012) highlight that wastewater injection into the subsurface during shale gas development can also cause earthquakes. Consequently, NRC (2013) argues that the primary earthquake risk from shale oil and gas production is the high-volume disposal of produced waters into the deep subsurface by injection wells. Furthermore, injection or extraction of fluids at considerable depths is known to alter stresses and thus introduce strain on the earth's crust, which can induce earthquakes (Wang et al., 2014). Wang et al. (2014) note that depths within a few kilometres in the earth's crust are associated with overall stress, which puts faults close to failure. Balcerak (2012) correlates the seismic activities during shale gas development to pore fluid change, subsurface stress around ground faults. Fluid injection during the development stage could also lead to stress condition changes around faults that may trigger an earthquake promoted by a slip on the associated fault (Council of Canadian Academies, 2014). Hydraulic fracturing, wastewater disposal, and other processes such as CO_2 sequestration reactivate faults by increasing pore pressure and reducing the significant stress within a fault zone (NRC, 2013 and Davies et al., 2013).

Additionally, a fault zone can also be intersected directly by injecting fracturing fluids or wastewater underground or by transmitting a pulse in fluid pressure that reduces the significant stress on a fault line (Kratz et al., 2012). According to Baisch and Harjes (2003), the significant stress is relieved by fluid injection forced into faults and fractures. Kargbo et al. (2010), Das and Zoback (2011), and Pearson (1981) suggests that earthquakes could be caused by the drilling technique used in shale gas development. Seismic tremors and minor earthquakes due to shale gas fracking in England led to significant public concern over the energy extraction technology applied to exploratory drilling (Hammond and O'Grady, 2017). Ellsworth et al. (2012) documents a sevenfold increase in seismic activity in the central US from 2008 to 2011, partly due to an increase in gas production by the hydraulic fracturing process. The activities that cause earthquakes during shale gas development are drilling, disposal of large volumes of fluid into the reservoir, and the injection of wastewater into the subsurface (Kargbo et al., 2010; Zoback et al., 2010; Pearson, 1981 and NPR, 2012). Although the seismic impact of shale gas development processes and stages are difficult to quantify because the probability and consequences vary a lot as well as due to the lack of sufficient data (Mehany and Guggemos, 2015); Keranen et al., (2013) conclude that the least common but most impactful seismic event associated with unconventional gas production is caused by wastewater injection into the underground.

The seismic and land use risk to the land from shale gas development highlighted the need to be addressed to ensure the resource's sustainable development. The seismic risk mitigation should address the associated potential loss of life and property from earthquake occurrence. The anticipated and more certain land-use changes and impact on humans and wildlife should also be of concern to all stakeholders. Regulation and good practices-based ethics can, however, mitigate these risks.

1.4.4 Social and Health Impacts

Wang et al. (2014) recognize that shale gas extraction's public health impact was earlier not being considered. Additionally, increased shale gas development has been associated with increased localized occupational safety risks relating to a considerable increase in traffic accidents involving heavy-duty trucks (Zirogiannis et al., 2016, and Muehlenbachs and Krupnicks, 2013). Also, the extraction of gas via hydraulic fracturing in suburban and urban areas in the United States (Pennsylvania, Ohio, Texas, and Colorado) has resulted in opposition partly due to potential negative impacts on property values (Loomis and Haefele, 2017). However, providing housing for the shale gas industry workforce results in increased demand, which may drive housing values up with empirical evidence in North Dakota and Texas (Platt, 2013 and Lopez, 2012).

The rise in property values are encouraging for the realtor sector but undesirable for a renting population. Sun and Wang (2015) also identify the noise and visual/aesthetic impact during the early stages of development and an increase in transportation and delivery truck journeys. A review by Retzer et al. (2013) finds that accidents are six-folds more dominant in the oil and gas industry compared to other sectors.

The pathways for human exposure to chemicals used in shale gas development include drinking water contamination, skin contact, soil and food, and the atmosphere (Earthworks, 2015). According to Colborn et al. (2013), about 632 chemicals are applied to shale gas operations; 75% of 353 these chemicals harm different organs in the human body: the harmful chemicals. Furthermore, more than 50% of these harmful chemicals affect the brain and nervous system, with 40%, 37%, 40%, 46% being injurious to the immune system, endocrine system, kidney, and cardiovascular system and blood, respectively. About 25% of these harmful chemicals are considered carcinogens with others identified as being harmful to body weight, teeth, and bone and the possibility of death. Mckenzie et al. (2014) conclude that proximity to producing shale gas wells is associated with congenital defects in rural Colorado between 1996 and 2009; however, the alleged effects' pathway is unclear.

Sovacool (2014) states analysts argue that collectively the negative impacts from shale gas development are on the air, water, and higher radioactivity with severe health risks for workers in the industry and residents close to shale gas well sites. However, the nature of the damage and risk level is mostly dependent on the composition of the fluids applied. Jackson et al. (2016) recommends the need for short- and long-term studies of the potential effects of shale gas extraction on human health.

1.5 The Current Condition of UK Shale Gas

Unconventional gas resources were accidentally discovered in the United Kingdom (UK) about 139 years ago (Selley, 2011). Selley (1987, 1992, and 2005) focused on evaluating the United Kingdom's (UK) shale gas resources; nevertheless, results did not initiate unconventional gas exploration, which could have been due to its cost-effectiveness in comparison with the UK continental shelf (UKCS).

The interest in developing the United Kingdom's Shale gas resources is based on the US experience. As such, a 2010 department of energy and climate change (DECC) study is based on analogues due to lack of exploration activity estimated reserves of 30bcf for the Jurassic shale play, 2,100 bcf for the carboniferous play and 300 bcf for the Cambria shale gas play (DECC, 2011). However, using a resource assessment methodology estimates the technically recoverable shale gas resource for the UK as 26 tcf not considering the Cambria shale gas play due to lack of applicable data (US EIA, 2013). Recent studies by DECC use a 3D geological model as an input parameter in a Monte Carlo simulation to predict the in-place gas resources of the Bowland, Weald basin, and Scotland (Andrews, 2013; Andrews, 2014 and BGS, 2014).

The estimate given by the USEIA is technically recoverable gas in place, which is achieved via a bottom-up methodology, while DECC's approach is based on predicting gas in-place volumes. However, applying a 10% recoverable factor to DECC's results in a technically recoverable gas resource estimate of 132.9tcf (mid-case) for the

Bowland shale play, while the USEIA estimated 26tcf for the entire UK shale play. The limiting factors to recoverable resources are the reserve size, technology, and economics of unconventional gas development (Taylor and Lewis, 2013). The economics of unconventional gas comprises its production potential, capital costs, operating cost, and regulatory and fiscal regime.

Bradshaw and Solman (2020) further highlights the timeline and current state of the UK shale industry. The study notes that since 2008 interest in onshore petroleum exploration and development licenses increased during the licensing rounds with the 13th round in 2008 seeing the initial interest in the Bowland-Hodder shale play with 93 licenses issued with a further 93 licenses issued in the 2015 14th round. In 2011, a 2.3 magnitude on the Richter scale seismic event occurred while a well was being hydraulically fractured by Cuadrilla (a UK shale oil and gas firm). This incident resulted in a drilling moratorium up until 2012. Consequently, a seismic monitoring traffic light system that requires halting hydraulic fracturing once seismic events above 0.5 magnitude on the Richter scale occur during operation. In 2019, a site at Preston New Road owned by the same firm drilled two wells vertically and horizontally, hydraulic fractured, and a flow test. However, a 2.9 magnitude tremor occurred and resulted in a second moratorium placement on high volume hydraulic fracturing grounded on the perceived lack of capacity by shale gas development operators to predict seismic event magnitude before or during fluid injection (BEIS et al., 2020). Bradshaw and Solman (2020) note that the 2019 seismic magnitude in the UK is below the acceptable range in North America: 2 - 4.5 and below the Cuadrilla's upper limit submitted to the UK Environmental Agency (UKOOG, 2020; Cuadrilla, 2020).

The National Audit Office in a 2019 report notes that the UK shale industry is a long way behind the UK government's original progress timescale, which had as 2016 estimated that 5-20 wells will be hydraulic fractured by mid-2020; only three have been fractured. In addition to the seismic activities encountered in the UK, the earlier identified social and environmental concerns in the United States experienced has led to resistance by both community bodies and environmental organizations. The most recent public attitude survey reveals opposition to shale gas development has increased from 21% to 40% between 2013 and 2019 based on concerns around the risks to the environment, public health, seismicity induced by fracking, and perceived inadequate environmental regulation (National Audit Office, 2019).

The social and environmental issues related the shale gas development in the UK is fundamental. However, the initial consideration for policymakers and investors is the economic and commercial viability of developing the resources while also assessing the comprehensive social and environmental risks. The economic and commercial appraisal based on appropriate shale gas production and comprehensive cost estimation (development and fiscal cost) is a prerequisite to social and environmental evaluation.

1.6 Research Questions, Aims, and Objectives

The overarching aim of this study is to investigate, analyse, and model the parameters that impact production and cost drivers attributable to unconventional gas development. These parameters are then applied to analyse and estimate the production and costs of undeveloped unconventional gas in the United Kingdom.

The economic recovery and production of gas from undeveloped unconventional sources are subject to production, cost, and regulatory drivers.

The following specific research questions are addressed:

1) What is the appropriate production forecast approach for undeveloped unconventional gas wells?

The appropriate model would address the following objectives:

a. The impact geological reservoir parameters, gas properties, and production efficiency have on initial gas flow and estimated ultimate recovery.

b. Estimation methodology on the initial flow rates and estimated recoveries.

c. Characterization of uncertainty in reservoir conditions.

d. Probable production scenarios be modelling to emulate eventual well production in the UK.

2) How is the cost of developing unconventional gas sources estimated?

Output would provide policymakers and stakeholders with the following:

a. The cost drivers of unconventional gas development.

b. The impact of oil price uncertainty on unconventional gas cost parameters and the short, medium, and long-term development outlook.

c. The learning curve that impacts the cost of developing shale gas in the United Kingdom.

d. What influence different regulatory regimes have on unconventional gas development costs.

The results from these enquiries will guide quantitative deliberation on the commercial viability of unconventional gas under below ground, oil price, and regulatory and social licence uncertainty. Figure 4 below, is the overarching research workflow.

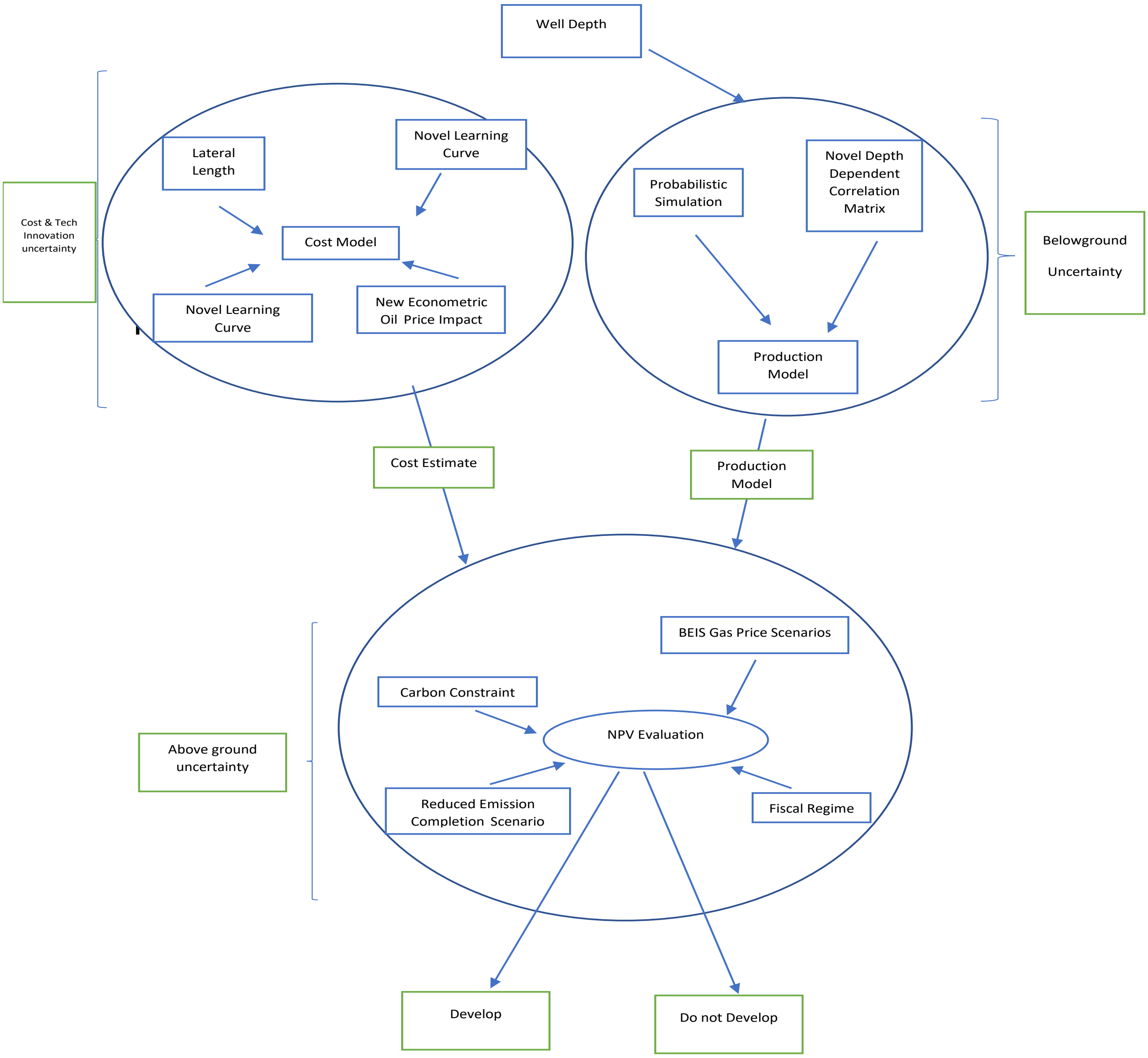

Figure 4 Research Workflow (Step 1 to 13)

1.7 Overview

The rest of this thesis is structured as follows. Chapter 2 begins by providing a detailed review of production estimation methodologies in shale gas development, explaining many of the terms and definitions frequently used in this field. Chapter 3 aims to address the uncertainties identified in chapter 2 by developing a parameter estimation model, which is further applied to the Bowland Shale region in the United Kingdom. The examination of the cost development is separated into two chapters, with Chapter 4 developing a bottom-up cost estimation model and addressing the impact of oil and gas prices on the price of inputs. In contrast, chapter 5 investigates the impact of innovation and the learning curve theory on shale gas input development cost.

Chapter 6 draws the above work together, stipulates the scenarios, and overarching economic modelling approach while chapter 7 reviews and discusses the results. Finally, Chapter 8 correlates results to research questions, states the study's limitations, concludes, and proposes further research areas.

2 Production Estimation

2.1 Introduction

Unconventional gas development has been stalled due to various issues, especially the accurate estimation of future production and, more recently, the impact of climate change mitigation policies. McGlade *et al*., 2012 notes that uncertainty in recoverable resource size impacts unconventional gas development potential. This chapter examines the different approaches and theories that guide production estimation for unconventional gas production. Additionally, the chapter summarizes, reviews approaches, and uses methods to estimate and analyse unconventional recoverable resources.

2.1.1 Macroeconomic Impact

The most common economic assessment method justifying the development and influencing policy towards unconventional petroleum development estimates potential employment and tax revenues as economic benefits; hence this approach is reviewed first. However, this approach is not entirely specific to unconventional resource development evaluation; Black and Veacth (2004) apply it to the renewable energy industry. Lee and Taylor (2004) also apply a similar approach in assessing the impact of the 2002 FIFA World Cup, a sports event. Breitschpf *et al*. (2011) review similar employment assessment methods applied in evaluating renewable energy deployment and classifies approaches into the gross employment studies and net employment studies. However, net-based approaches explore both the negative and positive impacts on employment and impacts on all sectors of the economy while gross studies reveal the employment gains in the industry, ignoring crowding-out effects.

2.1.1.1 Jobs Creation and Gross Value Added by Unconventional Gas Development:

A 2011 study by Regeneris, a consultancy on the economic impact of shale gas development in Lancashire (a prospective UK shale gas site), applied the gross value added (GVA) approach, primarily forecasting its impact employment. Subsequently, Taylor and Lewis (2013) identify the environmental benefits and models of shale gas development's economic impacts. The studies are similar in methodology, applying an analogue of expenses to job creation ratio in the UKCS.

A similar GVA approach has been applied to shale gas plays in the US, Considine et *al*., 2010 and 2009 focuses on the economic impact of the Marcellus Shale play which also reports in GVA terms, Thomas et al., (2012) and Deck, (2008) apply similar approaches to the Ohio and Fayetteville shale prospects, Timilsina et al., (2005) and Honarvar et al., (2011) apply similar methods in appraising Canadian oil sands development. In addition to similarity in modelling approaches, these studies are also conducted in conjunction with industry stakeholders and, therefore, not considered independent. Kinnaman (2011) reviews studies relating to the economic impact of unconventional gas production in the United States and concludes reports affiliated with the natural gas industry apply the “gross” employment, tax gains approach in economic impact assessment perhaps to facilitate favourable public policy.

Considine et al., 2009, and 2010 reveals gross creation of 48,000 jobs by 2009;100,000 jobs by 2010; 160,000 by 2015 and 174,000 jobs by 2020 and associated tax revenue. However, data from the independent fiscal office (IFO) reveals average job gains of 10,700 from 2003-2013 and projects 64,000 from 2013 to 2019 for the entire state economy (IFO, 2013). Considine et al., 2009, and 2010 apply the IMPLAN model, which states gross job gains ignoring a possible crowding-out effect. Also, economic assessment of unconventional gas development applying typical input-output models have been characterized by debatable assumptions. A review of Table 2-1 illustrates the incorporated assumptions in previous studies.

Kinnaman (2011) suggests that input-output models relating to shale gas's economic impact are overstated due to counterclaims on job creation by related industries. Besides, estimating jobs created appeals to elected officials with an affinity for short term job reports than long term benefits. Hahn (2011) acknowledges that most economists and long-term oriented politicians are interested in the overall benefits of extracting gas against the cost. A review of the methodology applied in table 1 by previous studies reveal more focus on jobs benefit while little or no attention is given to the associated cost or the economic value of the produced gas. Besides, the focus on job creation does not present a net scenario being that proposed jobs could indeed be displaced from other industries.

Table 1 A Comparison of Previous Study Results, Assumptions & Disregarded Economic Impacts

Literature	**Estimated jobs created/Region**	**Production estimate assumptions**	**Economic assumptions**	**Ignored effects**
Considine et al. 2009	48,000 jobs/Pennsylvania	unspecified drilling activity to production/drilling ratio	Lease and royalty payments to private households are spent on goods and services produced in Pennsylvania the same year payments are received.	A gross outlook, Dutch disease, and overestimation of benefits confirmed by economic data and ignores natural capital depletion.
Considine et al. 2010	88,588 jobs/Pennsylvania			
Regeneris 2010	250 FTE jobs per well test/ Lancashire (UK)	Not considered	Multiplier of £1 to £1.70 for the UK and 5% flow for Lancashire. A savings ratio of 5% for induced effects.	1995 multiplier applied ignores economic indices, ignores

			Associated spillover effects are assumed	crowding out and natural capital depletion.
Taylor and Lewis, 2013	*10 well pad of 10 laterals yields 406 jobs/UK *10 well pad of 40 laterals yields 1,104 jobs/UK	*10% recovery rate,30.9tcf resource in place, an initial production rate of 2.6MCF 20years production timeframe, hyperbolic decline factor of 0.8436 minimized by unspecified reservoir fluctuation technique.	£6million Drilling cost, facility cost of $15million, and abandonment cost of £10million for a ten well pad of 10 laterals. For a ten well pad of 40 laterals, a cost of £30 million and abandonment cost of £40 million. £0.5 million Variable operational expenses are per bcf and fixed operating expenses of 2.5% of cumulative capital expenditure per	The study applied the US job creation multiplier. A gross approach that ignores crowding out, options, and natural capital depletion.

			year. £1 million expenses in the industry leads to 20 jobs	
Williams and Summerton, 2013	*400,000-600,000/EU	scenarios: no shale, some shale, and shale boom with recovery rates of 0%, 15% and 20% of risked reserves	Household and industry gas and electricity demand are the same; exchange rates are fixed, investment funds readily available. No crowding out Development financed by multinationals.	A gross approach was presented as a net benefit ignoring Dutch disease, rebound effects, investment options, and natural capital depletion.

Based on these reports amongst other geological reports, Her Majesty's Revenue and Customs (HMRC), the British revenue agency proposed a "pad allowance," which would effectively reduce the tax rate for unconventional development from 62% to 30% (HM Treasury, 2013). The economic analysis applied to this policy proposal can be considered incomplete or overstated; the policy measures being considered for the UK shale gas industry might be misguided. Kinnaman (2011) concludes that overstating economic impacts to persuade government officials could cause other disruptions in the economy if private investment decisions are based on poorly estimated impacts. Weber (2012) notes that in the present economic and political situation characterized by unemployment and large public sector deficits makes this approach appealing to political leaders. The study compares ex-post data to ex-ante projections of jobs created by developing the Fayetteville and Marcellus shale gas formations and concludes the input-output approach overestimated the number of jobs created. HoL (2014), a report by the House of Lords economic select committee, notes that Taylor and Lewis's (2013) assumptions rely heavily on US-focused research, which is untested in the UK. This implies that the UK and US job markets are analogues. HoL (2014) concludes that unconventional gas development's economic benefits cannot be quantified without estimating the economic estimated ultimate recovery (EUR) of the gas.

2.1.2 Production Forecast Methodology Applied in Economic Appraisal:

Timisilna et al., 2005 applied multipliers to forecast production of shale sands while Taylor and Lewis (2013) assumes a 10% recovery rate, an initial production, and a hyperbolic decline factor of 0.8436. Considine (2010) applies an unspecified drilling activity to production/output ratio in estimating production, which yields a rate of 170 mmscf/day for 2009, 550 mmscf/day for 2010, 1800 mmscf/day for 2015 and 4,000 mmscf/day by 2020. However, the US energy information agency (USEIA, 2013) shale production data for the Marcellus shale play reveals an average gas production of 178 mmscf/day in 2009 and 1,000 mmscf/day in 2010. Although Considine *et al*. 's (2009) forecast is in proximity to production data, the 2010 forecast is 50% lower than production data. Regeneris (2012) does not consider forecasting gas production in its economic impact assessment. The production estimates applied in the macroeconomic impact studies applied to shale oil and gas rely on recovery potential, drilling activity output, and analogy-based assumptions. Empirical evidence suggests that this approach does not provide proper and specific production perception but relies on micro parameter assumptions.

2.2 Unconventional Well Production Forecast and Analysis

The most obvious benefit and aim of unconventional gas development is the gas produced. Well evaluation and decline characteristics are fundamental to decision making in the petroleum industry; Statton (2012) states that estimating economic hydrocarbon reserves is of utmost importance to engineers, investors, and policymakers/governments. Nonetheless, the recoverable reserve uncertainty creates a challenge for both policymakers and investors appraising the economic viability of shale gas plays. Baihly et al. (2010) state that the most heavily contested point amongst petroleum industry experts is the estimated ultimate recovery (EUR). The EUR of a region, field, play, or well is considered the total amount of gas or oil recoverable over time-based on current applicable technology. Production analysis methods aim to forecast hydrocarbon recovery potential and eventually, the EUR over time. Kaiser (2012) considers EURs and initial production data as the major parameters that contribute to defining an unconventional play's commercial viability.

Nonetheless, studies and methodology analysing and forecasting production from unconventional wells are evolving along with production technology. Forecasting production in the unconventional gas industry can be based on initial production rates (IPs) and applying decline trends analogues from a basin to another basin with less production history (Baihly *et al.,*2010). The study focuses on empirical/decline curve methods, type curves, and analytical/numerical simulation approaches, both scientific and applied.

2.2.1 Empirical Methods (Decline Curve Analysis)

The initial decline curve analysis (DCA) method plots the percentage decrease from initial production rate versus time (Clark, 2011). Arps's 1944 study identified three types of production rate decline during boundary dominated flow; exponential, hyperbolic, and harmonic based on the value of "*b*"; the decline parameter (Kanfar, 2013). Table 2 below reveals the different characteristics associated with the three scenarios.

Table 2 Arps Decline Scenarios

Exponential	Hyperbolic	Harmonic
(b=0)	(0<b<1)	(b=1)

Nevertheless, Lee and Sidle (2010) note that unconventional gas wells have been observed with "*b*" values greater than one, which yields an infinite reserve estimate applying Arps decline methodology. Fetkovich (1999), Lee & Sidle (2010), Clarkson et al., (2012), Statton (2013) and lee and Sidle (2010) all suggest that in order to use Arps equation without ignoring the physics of fluid flow, the reservoir must have a constant bottom hole pressure, be in boundary dominated flow, and have an unchanged drainage area and a constant skin factor. However, unconventional wells violate most of these assumptions, especially the flow regime and unchanged drainage area, but applying Arps equation with b value above 1 in unconventional wells results in indefinite production rates for a finite resource and reservoir overestimation (Clark, 2011). Lee and Sidle (2010) consider reserves derived with *b* values greater than 1 with Arps equation to be physically unreasonable. Although Arps equation proposed for unconventional gas reservoir analysis has a constraint factor (D_{min}), the model, when compared to other empirical models seems optimistic in terms of production forecasts—as such, using Arp's hyperbolic equation in unconventional wells to forecast reserves and production could result in reserve overestimation. Several studies have concentrated on overcoming the issues associated with applying Arps equation in unconventional well production forecasts. Reviewed below are the Stretched Exponential Production Decline Method, Power Law Equation, and Logistic Growth Method.

2.2.1.1 Stretched Exponential Production Decline Method (SEPDM)

The stretched exponential function was introduced in 1854 to describe the capacitors' discharge (Statton, 2012). Many processes have been associated with stretched exponential characteristics in physics; however, Valko and Lee (2010) apply the theory to unconventional gas reservoirs for the first time. The stretched exponential decline method suggests the decline feature of unconventional gas reservoirs is exponential and not hyperbolic.

The physical justification of the SEPDM is based on discharge/production caused by a fixed backpressure resulting in an exponential decline of flow rate over time. Also, the SEPDM eliminates the need to assume a D_{min} in the Arp model, while possessing two-parameter functions that follow the fat tail distribution. Statton (2012) applies the SEPDM to 857 wells concluding the model has the theoretical ability to handle a transition from boundary dominated flow to linear than Arps and gives a conservative forecast when only linear flow data is available. Valko and Lee (2010) note that SEPDM has a better mathematical property than the Arps equation, which gives the SEPDM an advantage. Although the SEPDM has primarily been applied in a cluster of wells by Statton (2012), Valko and Lee (2010) note concerns remain regarding its applicability to individual well analysis. The SEPDM comprises the following parameters; *n* represents an exponential parameter (dimensionless); is the initial gas flow rate (Msc/Month), and *t* is the production time parameter*; Ʈ* is the characteristic time parameter for the SEPDM while *q* is the well flow rate. Equation 1 is the rate expressed as a function of time, while Equation 2 relates to the estimated ultimate recovery in terms of the SEPDM parameters.

$$q = q0 \; exp\left(-\left(\frac{t}{Ʈ}\right)n\right) \qquad \textbf{Equation 1}$$

$$EUR = \frac{q0Ʈ}{n}\Gamma\left(\frac{1}{n}\right) \qquad \textbf{Equation 2}$$

The SEPDM has definite advantages over Arps' decline curves for unconventional gas applications based on perceived good mathematical properties (Valko and Lee, 2010). Statton's 2012 study notes that SEPD models provide a more conservative forecast compared to the Arps model. The SEPDM is considered an empirical model with multiple references in physics' literature, providing evidence of the stretched exponential function's ability to model decays in randomly disordered and chaotic systems.

2.2.1.2 Power Law Equation (PLE):

Johnson and Bollens (1927) introduced extrapolation of well decline curves using a loss ratio approach while Ill et al. (2008) applies the concept to unconventional gas reservoirs. A hyperbolic rate decline relationship (equation 3) interacts with the power-law ratio model presented in equation 4 below.

$$\boldsymbol{q = q_i \left(\frac{1}{((1+bD_i t)^{\frac{1}{b}}}\right)}$$ **Equation 3**

$$\boldsymbol{q = \hat{q}_i \, exp(-D_\infty t - \widehat{D_I} t^n)}$$ **Equation 4**

Where q (t) is the production rate, q1 is the rate intercept, D1 represents decline constant after a time unit, D^{θ} is the decline constant at infinite time, and n is the time exponent.

The power loss equation models the loss-ratio uniquely by assuming that the loss-ratio follows a power-law function early and later becomes constant (Kanfar, 2013). Ilk *et al*. 2008 conclude the power-law loss ratio is more flexible as it can be applied to transient, transition, and boundary-dominated flow data and using the decline constant at "infinite time" yields an exponential decay at substantial times, unlike the Arps exponential decline where the decay is constant. Clark (2011) states that the power-law model has several distinct advantages over the Arps exponential model in that a single continuous function is used in forecasting production; however, concern exists regarding an appropriate value for D_∞ the final decline rate and it is arbitrary. Also, Kanfar (2013) states that the PLE is the only method that models both transient and boundary dominated flow. Weijemars (2013) suggests applying a Levenberg-Marquardt minimization technique to account for fluctuation level in the production rate by minimizing the squared difference between the measured and calculated rates resulting in equation 5 a simple exponential decline.

$$\boldsymbol{q\ (t)\ = q_i exp(-D^{\theta} t)\ + q_i f_n (0.5 - r)}$$ **Equation 5**

Where q (t) is the production rate, q_i *is the initial production,* D^{θ} *is the decline factor, and* f_n *is the scatter level that varies between 0 and 1 and r, which also varies within the same range.*

Besides, the power-law model's practical application is not as simple as an empirical fit with an Arps equation. Furthermore, the four unknown parameters result in an equivalent degree of freedom in non-unique solutions. Clark (2011) suggests the method requires more detail and its applicability to extensive scale field appraisal, which could rather be quickly performed using the Arps equation. The power-law equation differs from the SEPDM by considering the long-term behaviour resulting in the *D*- constant inclusion.

2.2.1.3 Logistic Growth Method (LGM):

Clark (2011) proposes applying the LGM model for analysing and estimating production from unconventional gas reservoirs, although the LGM approach was developed initially for population growth. The LGM is based on the concept that growth is possible only to a specific size (Kanfar, 2013). The maximum growth size is referred to as the carrying capacity; a multiplicative factor applied to an exponential growth equation. Equations 6 and 7 define the production rate and cumulative forms of the LGM approach.

$$\boldsymbol{q}\ (\boldsymbol{t}) = \frac{\boldsymbol{dQ}}{\boldsymbol{dt}} = \frac{\boldsymbol{Knbt^{n-1}}}{(\boldsymbol{a}+\boldsymbol{t^{n}})^{2}} \quad \textbf{Equation 6}$$

$$\boldsymbol{Q}\ (\boldsymbol{t})\ = \boldsymbol{Ktn}/\boldsymbol{a} + \boldsymbol{tn} \quad \textbf{Equation 7}$$

Q represents the cumulative production, while *q* is the production rate. The carrying capacity *k* is the total amount of oil and gas that can be recovered from the well from primary depletion not taking into account economic or time-related cut-offs while the "*a*" constant is the time to the power n at which half of the oil or gas has been produced and *n* the hyperbolic decline exponent (Clark, 2011). Besides comparing LGM to the Arps model, Clark's 2011 study considers the Arps model more optimistic in reserve forecasting, while Kanfar (2013) concludes that the LGM is the easiest method to apply. However, the LGM approach assumes hyperbolic decline characteristics and requires estimating at least two parameters or three parameters at most depending on the availability of well information. The carrying capacity "K," which represents the total amount of oil and gas that can be recovered from the LGM well, introduces uncertainties based on parameters. These uncertainties are due to unconsidered carbon contents in shale formations: free gas and absorbed gas. Besides, the volume of absorbed gas in unconventional gas wells is difficult to estimate and the recovery factor.

2.2.2 Type Curve

Type curve application in unconventional gas production analysis requires fitting historical production data with dimensionless solutions to flow equations corresponding to different well/fracture geometries, reservoir type, and boundary conditions. (Clarkson, 2013). The results from type curve analysis are used for forecasting production and characterizing the reservoir (Nobahkt *et al*., 2013). The type curve methodology has been applied to both production forecast and reservoir characterization for over 70years (Ill *et al.,* 2007). Fetkovich (1980) created the type curve methodology by combining Arps' empirical decline curves for boundary dominated flow and analytical solutions for constant flowing pressure radial flow for liquids (Clarkson, 2013). This study reviews the following type curve approaches; Fetkovich's 1980 and 1987 studies, Blasingame type curves, and recent type curve applications.

2.2.2.1 Fetkovich

The first generation of type curves combined analytical solutions for constant flowing pressure radial flow of liquids with Arps' empirical decline curve for boundary dominated flow. Fetkovich type curves are considered valid with wells producing at constant bottom hole pressure (Fetkivich, 1980; Ill et al., 2007).

The production analysis approach incorporates the ability to generate estimates of reservoir characteristics like pressure transient analysis, an alternative method (Ill et al., 2007). Fetkovich's 1971 and 1980 studies combine transient rate and pseudo-steady state decline curves, which yielded a single-phase flow based on darcy law and material balance. The rate relationship applied in this method combines the early stage, transient time, and pseudo-steady-state solutions (Agrawal et al., 1999).

The Fetkovich type curve method is regarded as a forecasting technique achieved by historically matching rate-time data with an appropriate type curve. Fetkovich (1980) focuses on analyzing oil-producing wells while the 1987 study (Fetkovich, 1987) applies the methodology to a gas well. The 1987 study infers that reserve estimation and production forecasts in low permeable gas reservoirs could be developed more accurately, applying the rate–time data than pressure, gas compressibility, and cumulative production relationship method. Nevertheless, this approach assumes a constant bottom –hole pressure, which has limitations in practice (Ill et al., 2007).

2.2.2.2 Blasingame

Blasingame and Palacio (1993) present an alternative method for production data analysis of single flow in either gas or oil wells by relating Fetkovich type curve methodology with rigorous liquid and semi-rigorous gas stems. This method's utilization enables the consideration of continuous changes in rate and pressure history (Ill et al., 2007). Additionally, the method is noted as useful in gas in place estimation and reservoir permeability and skin.

The Blasingame type curve development applies a plot of the *(q/Δp)* function's logarithm against the logarithm of appropriate material balance time function (Ilk et al., 2007). However, the developed analytical solution exhibits the harmonic form *(b=1)* for both the variable and constant pressure scenarios as such a material balance pseudotime must be applied in calculating the dimensionless variables (Clarkson, 2013). The dimensionless rate and dimensionless decline time are thus defined by the equations below.

$$\boldsymbol{q_{Dd} = q_D b_{Dpss}}$$ **Equation 8**

$$\boldsymbol{t_{Dd} = \left(\frac{2\pi}{b_{Dpss}}\right) t_{DA}}$$ **Equation 9**

Where b_{Dpss} is a pseudo steady state parameter derived by Pratikno et al., 2003; q_{Dd} is the dimensionless decline rate; q_D is the dimensionless rate; t_{Dd} is the dimensionless decline rate while t_{DA} is the dimensionless time based on drainage area. Dimensionless parameter status is achieved by multiplying a group of constants with opposite dimensions.

2.2.2.3 Recent Type Curve Studies & Modification

Bello's 2009 extends El-Banbi's (1998) approach by applying a transient linear flow regime on a linear dual-porosity hydraulic fractured shale gas reservoir. The study identifies five regimes and developed an equation for four regimes. Moreover, the study also incorporates convergence skin into the linear model to account for its horizontal wellbore presence. The type curves developed by Bello (2009) use the constant-rate solution, and thus unit slope of *b=1* during boundary dominated flow applying dimensionless variables for the type curve, specifically in gas reservoirs (Clarkson 2013).

Nobakht (2014) proposes a new method based on the opinion that most existing formulation for linear flow analysis results in production overestimation. The method analyses production data under constant flowing pressure, production rate, and variable flowing pressure and production rate accounting for both desorption and gas slippage. Additionally, the impacts of completion heterogeneity are incorporated by extending a previous study by Nobakht et al., 2010 while a new set of dimensionless type curves are developed for a standard conceptual model for a multi-fractured horizontal well. The study reveals the impact of completions heterogeneity on long term forecasts.

2.2.3 Analytical/Numerical Models

Analytical production analysis methods are also referred to as rate-transient methods based on a similar theory to pressure-transient analysis with a foundation related to the physics of fluid storage and flow (Clarkson, 2013). Pressure–transient methods differ from rate-transient analysis based on pressure and fluid flow changes over time, while rate transient refers to production data (Jafarli, 2013). Transient well analysis in unconventional gas production appraisal includes both traditional pressure and production evaluations (Vera and Ehlig-Economides, 2014). Analytical methods apply logically derived mathematical equations (Lee et. al., 2003). Clarkson (2013) states that analytical models are related to simple reservoir characteristics and boundary conditions, while simulation models apply more complex mathematical models derived from numerical methods. However, Wang (2013) advises that non-linear flow mechanisms should not be disregarded in flow calculations due to the extremely low permeability of unconventional reservoirs. The study proposes the inclusion of reservoir completions in modelling production applying a horizontal well and a numerical model which illustrates the gas flow in unconventional gas reservoirs analysing flow mechanisms considering non-linear flow mechanisms

2.2.3.1 Rock Extractive Index (REI)

Patzek et al developed the REI method., (2013) based on the physics of fluid flow mechanism in horizontal wells. The study extends a mathematical model to incorporate more realistic phase behaviour applying a universal scaling function and two adjustable parameters for each well: the interface time between hydro fractures and the mass of gas in place that can ultimately be removed (Felgueroso and Juanes, 2013). The method's hypothesis suggests transient gas flow lasts for 3months, after which gas flows into the fracture planes as if coming from a semi-infinite region. The study purports that gas production in unconventional gas reservoirs occurs in three phases determined by gas pressure diffusion. The initial high gas pressure stage creates a gas production rate proportional to the inverse of production time's square root. At a latter production stage known as the interference time, pressure drops and causes gas production rate to reduce relative to the square root of time behaviour (Patzek et al., 2013). Eventually, an exponential decay occurs with production proportional to ideal gas in place. The study establishes a pressure-dependent coefficient describing gas pressure diffusion called "hydraulic diffusivity of gas." Gulen et al. (2013) note that Patzek et al.'s 2013 study demonstrates that gas flow is transient and rectilinear for several years in both vertical and horizontal wells, which results in the flow equation represented in equation 10 below.

$$\boldsymbol{q} = \frac{\mathbf{2}}{\sqrt{\boldsymbol{\pi}\left(\sqrt{\boldsymbol{K}}\emptyset\frac{\boldsymbol{c}}{\boldsymbol{\mu}}\right)}}\ \frac{\boldsymbol{Af}}{\boldsymbol{Bg}}\left(\frac{\boldsymbol{\Delta p}}{\sqrt{\boldsymbol{t}}}\right) \quad \textbf{Equation 10}$$

where q is flowrate, K is rock permeability, is rock porosity, c is isothermal compressibility, is natural gas viscosity, A_f *is the area of rock exposed by the hydrofracture (Rock Exposure Index),* B_g *is formation volume factor, p is gas pressure and is the pressure between the reservoir and fracture pressure while t is time.*

Besides, Gulen et al., 2014 comments that Medlock (2012), an independent econometric analysis applying panel data from more than 16,000 wells, gives empirical supports to the Rock Extractive Index approach.

2.3 Discussion

The literature reviewed shows that researchers apply different methods in production analysis and forecast aimed at estimating ultimate recovery; the EUR. Production estimation methods applied to unconventional gas production are either decline curves, type curves, or analytical models.

The SEPDM, LGM, and PLE methods seek to amend some limitations of the Arps decline approach, an empirical method. Alternatively, the SEPDM assumes unconventional well decline in a randomly disordered and chaotic system while the PLE assumes a decline governed by a power-law equation. The LGM is based on the carrying capacity *K,* a parameter dependent on the EUR. However, determining the EUR requires knowledge of the field's recovery factor. Recovery factors of unconventional gas wells have been known to vary. Lee et al., 2011 and Clark (2011) note that the recovery rates of unconventional gas wells are uncertain. As such, the LGM approach is exposed to recovery rate overestimation or underestimation, which impacts the EUR and the carrying capacity *k*. Applying the LGM requires unbiased knowledge of the well recovery rate. Overall, the limitation associated with empirical models is the need to assume a decline trend hyperbolic or exponential and a law guiding the well decay trend. Besides, empirical models avoid accounting for reservoir properties or changes in either reservoir conditions or produced fluids.

Type curves, as the name suggests, are modelled based on reservoir type assumptions. Bello (2009) notes that type curves are mostly based on radial reservoir models with dual porosity. Furthermore, dual-porosity models could be pseudo steady-state or transient state types. Additionally, variations in inner boundary conditions could also be constant pressure and rate, with or without skin and wellbore storage, while outer boundary conditions may well be infinite, semi-infinite, or closed reservoir models. Moreover, recently developed type curves have analysed and incorporated various effects and conditions that impact productivity, previously ignored by empirical and earlier type curve approaches. However, the challenge for non-technical analysts and policymakers evaluating the production for unconventional reservoirs applying type curves is what reservoir type and condition should be applied.

The analytical model developed by Patzek et al. (2013) is based on linear and Darcy gas flow, relying on a simple gas production model related to the physics and geometry of unconventional gas extraction process. The technical but straightforward validation of the analytical model incorporating reservoir conditions makes for easy application by non-technical policymakers and appraisers. Browning et al. (2014) contends that the approach is an integrated bottom-up, multidisciplinary study by geologists, engineers, and economists. The approach could also be used to account for changes in pressure and reservoir conditions. Besides, unlike the LGM, the need to determine a carrying factor dependent on EUR is eliminated. The analytical model can also be considered as a hybrid of an empirical model and type curves. The empirical model characteristic is exhibited by its late time exponential decline, while its type curve similarity is based on gas Darcy law and linear flow basis. However, this approach's validity is questionable if an unconventional reservoir does not demonstrate the empirical conditions (exponential decline) or single-phase Darcy flow.

Overall, this study does not seek to identify a superior approach to unconventional gas production analysis and estimation that works best in all contexts but identifies strengths, fundamentals, and trade-offs. The best response to model selection and review pertaining to unconventional gas production is to figure out which model is most relevant in a scenario. Consequently, model evaluation and application could be based on their applicability to undeveloped unconventional gas fields, the ability to account for uncertainty, and well consideration for reservoir heterogeneity (see table 3 below).

Table 3 Selected Reviewed Studies Applying Production Analysis and Forecast Methodologies

Study	Analysis/ Forecast Method	Parameters Applied	Uncertainty Analysis	Play Type
Kaiser (2012)	Type curves	Initial production distribution and EUR	Gas prices, Expenses and Tax regimes	Developed
Gulen et al. (2013)	Analytic model	Reservoir, gas and source rock properties	Sensitivity to gas prices, cost, fiscal regime & probabilistic rate of returns	Developed
Taylor & Lewis (2013)	Decline curve	Hyperbolic & decline factor	Scenarios (low, central and high)	Undeveloped prospect

Gray.et al (2007)	Type curves	EUR/Well, Historical data	EUR, Costs, and Initial Production	Developed
Valko & Lee (2010)	Decline curve	Exponent & time parameter	Probability distribution	Developed
Weijemers (2013)	Decline curve	Average EUR/Well initial production rates	Well productivity ranges, P (10-50-90)	Undeveloped prospect
Kewen & Horne (2003)	Decline curve	Oil recovery, capillary and gravity constant	Not considered	Developed
Agrawal et al. (1999)	Combined type and decline curves	Gas & reservoir properties, performance data	Not considered	Developed
Nobakht (2014), Nobakht & Clarkson (2010)	Type curves	Reservoir & gas properties, hyperbolic decline function	b value sensitivity	Developed

Wang (2014)	Analytical model	Reservoir & gas properties, production rate	Sensitivity study on various analyzed effects	Developed
Bello (2009)	Type curves	Reservoir property & dimensions, gas properties	Not considered	Developed and synthetic prospect
Kovacs-Williams & Clarkson (2011)	Type curve	Reservoir property & dimensions, gas properties	P (10-50-90) on fracture half lengths and gas grid prices into a probability distribution	Undeveloped prospect

2.3.1 Application to Undeveloped Unconventional Gas

Applying decline and type curves in the appraisal of undeveloped wells, fields, or play requires fitting historical production data sourced from extrapolating analogous developed producing regions. Weijeimars (2013) makes a first attempt to evaluate the economics of undeveloped European shale plays (Poland, Austria, Germany, Sweden, and Turkey) applying a type curve analysis assuming an exponential decline function and applying an estimated ultimate recovery/well from Kuhn and Umbach's 2011 study based on various reports and anonymous analysis. Taylor's and Lewis's (2013) report focusing on the United Kingdom's unconventional gas production potential assumes an average EUR/well based on data from developed US shale plays and an initial production rate. The validity of results based on average EUR/well is highly unlikely. Mc Glade et al. (2013) notes that extrapolation of production experience is appropriate for developing regions where production is relatively advanced, while a bottom-up analysis of geological parameters seems acceptable for undeveloped regions.

The rate transient analysis-based model developed by Patzek et al., (2013) relies on the physics of drained fractured, low permeability shale driven by geological characteristics. Applying rate transient analysis in undeveloped shale plays requires estimating some or all the required geological and reservoir parameters due to limited data availability. However, the estimation process introduces uncertainties in parameter values and the need to account for these in modelling approaches.

2.3.2 Accounting for Uncertainty

Petroleum reservoirs are complex heterogeneous geological systems, thus characterizing the reservoir is difficult due to uncertainty and nonlinearity in reservoir parameters. Gulen et. al. (2013) conducts a sensitivity analysis on the impact of gas price, capital expenditure, taxes, discount, and inflation rate on the Barnet shale play's commercial viability. Weijermars (2013) applies a Monte Carlo simulation to calculate the commercial viability's sensitivity about well productivity. As revealed in Table 2, most studies do not directly consider the reservoir conditions (below ground risk). Most of the economic assessment focuses on above-ground risks, gas prices, fiscal regimes, and costs, mostly due to the appraiser and researcher's expertise. Although above-ground risks are essential, a comprehensive analysis should also incorporate below-ground risks; both (below and above ground) risk categories are essential. The geology and reservoir characteristics are the primary source of uncertainty in unconventional gas reservoirs, which impact production. Many authors (Cheadle *et al.,* (2012); Nakayama (2000); Sermiento and Steingrimsson (2008); Kumar and Varghese (2005); Tavakoli and Reynolds (2009)) propose probabilistic Monte Carlo simulation to address uncertainties in reservoir properties. Andrews (2013 & 2014); BGS (2014) apply stochastic approaches to resource estimates in the United Kingdom. The option of using a decline curve requires applying decline trends analogues from one basin to another and assumes either an exponential or hyperbolic decline. Wejeimars (2013) applies a decline curve analysis assuming an exponential decline function, while Taylor and Lewis (2013) applies a hyperbolic curve with a decline factor of 0.8436. Although Wiiliam-Kovacs and Clarkson (2011) apply a stochastic method in prospect screening using a modified Wattenbarger procedure, uncertainty remains regarding analogue production data selection and fracture properties.

Clarkson et al. (2013) notes that the primary advantage possessed by analytical methods over decline curves is producing a distribution of forecast based on uncertainties of fundamental reservoir properties. Applying an analytical solution that honours the physics of gas flow avoids the debate surrounding hyperbolic or exponential decline and decline factors; Anderson et al., (2012) offers case studies with a rate transient analysis. Felgueroso and Juanes (2013) confirm Patek et al. 's (2013) contribution in reducing uncertainty and unravelling the physics of gas recovery from shale rocks. Furthermore, about recoverable resources, parameter correlations exist between the reservoir properties; perhaps parameter relationships could be established based on data availability. Clarkson et al. (2012) provide common data and analytical sources for key unconventional gas reservoir, fluid, and rock properties.

2.3.3 Accounting for Reservoir Heterogeneity

Unique reservoir properties, along with completion and stimulation style, profoundly impact the type and sequence of flow regimes and, thus, methods used in the analysis (Clarkson, 2013). McGlade et al. (2013) conclude that historical production data reveals empirical evidence that shale productivity varies between shale gas plays. The US Energy Information Administration (USEIA) in a 2013 report notes that shale formations in the US have displayed heterogeneous geophysical characteristics with variance occurring within 1,000 feet or less. Cipolla and Ganguly (2012) attribute the heterogeneity to source rock diversity. Kaiser (2012) suggests the EUR estimation is determined by petrophysical factors and the success of the fractured network in shale gas wells. Gulen et al., (2013) supports the heterogeneous hypothesis by proposing economic evaluation of shale gas basin applying individual well production and economics to the Barnet shale play while Gulen et al., (2014) applies a similar approach to the Fayetteville play. Although Nobahkt (2014) considers completion heterogeneity, reviewed decline, and type curves do not consider reservoir geophysical diversity. Weijermars (2013) applies the decline curve method to entire basins located in different countries, a debatable approach.

2.4 Conclusion

This chapter reviews and summarizes the basis and identifies the limitations of models applied in unconventional gas production analysis and estimation. The methodology applied depends on the researcher's aim, objectives, and data access to applicable parameters. Overall, the methodologies and approaches applied in analysing, as well as forecasting production from unconventional gas wells, are evolving. Most economists interested in the analyses and forecast of production from unconventional gas wells need a basic understanding of the theories guiding various models.

This study probes the impact and applicability of various assumptions guiding the reviewed production analysis and estimation models. Consequently, I conclude that production analysis and estimation of undeveloped unconventional gas reservoirs based on type curves and numerical models present flaws that make them impractical for economic analysis of undeveloped unconventional wells. The impracticality results from the absence of production and drilling data, which could be used to develop decline and type curves usually based on initial production rates. The option of applying analytical methods also presents challenges in terms of data availability. Analytical methods are dependent on rock and reservoir parameters. However, source rock geological parameters are often not publicly available; under United Kingdom onshore license terms, well data available to regulators are confidential for four to five years (Andrews, 2013).

Although much research currently focuses on unconventional gas production analysis and forecast, gaps remain in undeveloped shale play recoverable reserve forecast. As a result, most regions contemplating developing unconventional gas resources do not apply appropriate recoverable reserve methods. This further affects the ability to justify the investment, energy security contributions, and design of robust regulatory regimes to support unconventional gas development if sustainable. Recoverable resource forecasts impact both the economics and sustainability criteria of unconventional gas plays, which could be aided by applying an appropriate production estimation method.

Finally, accounting for uncertainty in belowground parameters has been less analysed with more focus on above-ground risks. The need exists to extend current forecast methods to account for reservoir risks due to reservoir heterogeneity. Also, the extended method could be applied to undeveloped shale gas plays where uncertainty surrounding reservoir data and rock properties are more pronounced. Analytical method application to undeveloped shale plays could be enhanced by introducing stochastic and correlation analysis. Clarkson (2013) proposes a production forecast leading to reserve booking should be modelled applying an analytical method. Although analytical models seem better positioned to be further developed for appraising undeveloped shale plays due to the method's ability to avoid extrapolation, significant research must be conducted to address the identified limitations and ensure sustainable unconventional gas development if commercially viable.

3 Production Estimation in Undeveloped Unconventional Gas Plays

3.1 Introduction

This section has three key objectives. Initially, a review of the parameters applied in the numerical REI model. Secondly, to develop a correlation methodology based on reservoir depth, which estimates REI model parameters. Lastly, to apply the developed correlation matrix with the existing numerical model in estimating initial production and the EUR in an undeveloped unconventional gas potential play.

The study commences with a literature survey on every parameter applied. Applied unconventional reservoir well parameter boundaries are studied via a literature survey. The definition of each parameter and its relationship with other applicable parameters is studied, the established parameter ranges act as a guide in estimation and model validation. This relationship development commences from the reservoir depth hence its termed "depth-dependent correlation matrix" DDCM.

The developed DDCM is integrated with the numerical model and applied to the Bowland Shale located in the North of England, an undeveloped unconventional shale potential play. However, due to data unavailability relating to two parameters (permeability and porosity) and as such uncertainty, the resultant low, mid and high parameter dataset provided by Smith et al., 2010 and Andrew, 2013 are used in establishing scenarios applied in modelling production estimates thereby leading to low, central, and high production estimates.

The results reveal initial production and EUR estimates and sensitivity of results to changes and uncertainty in model input parameters. Additionally, a fourth scenario is generated by applying a Monte Carlo simulation to assess possible permeability and porosity values. This process results in probabilistic results combined with results from the deterministic DDCM, hence a hybrid approach. This chapter is divided into three sections: Section 3.2 describes the prospective UK shale play while 3.3 develops the depth-dependent correlation matrix, and 3.4 reviews the proposed production estimation model, 3.5 reveals the results from the parameter estimation while 3.6 reveals that from the production estimation modelling. Section 3.7 conducts uncertainty analysis while 3.8 and 3.9 discuss and conclude the section based on the results.

3.2 UK Bowland Shale Region

The Carboniferous Bowland shale formation in central Britain is a proven source rock mature for gas production (Smith et al. 2010, DECC 2011). Smith et al., 2010 state that the Bowland Shale formation is the most prospective shale gas play on a regional level. The Bowland shale gas is bounded by complete erosion of the potentially prospective shales over highs to the south, uplift in several areas where the prospective units are at outcrop, and by some facies change in the north and north-east to contemporary deltaic deposits (Andrew, 2013). The Shale formation comprises mudstone and turbidite lithofacies reflecting a pronounced sea-level controlled cyclicity (Gross et al., 2015). Consequently, these previous Bowland UK shale studies provide a foundation for this research due to data availability and significance.

Andrew (2013) applies a 3D geological model as an input parameter in a Monte Carlo simulation to predict the preliminary gas in place by dividing the play into two units an upper and lower unit, with the upper Bowland-Hodder unit estimated to have with a gas in place range of 164-264-447 tcf while the lower unit is estimated to possess a gas in place range of 658-1065-1834tcf. McGlade (2012) notes that the gas in place is the largest resource potential figure; however, the figure conveys incomplete information needed for estimating recoverable resources. The estimated ultimate recovery (EUR) of a region, field, play, or well is considered the total amount of gas or oil recoverable over time while the technically recoverable reserves refer to recovery ability based on the existing applied technology. Although previous studies have defined the gas in place in the Bowland shale play, the estimated ultimate recovery has not been appraised, and thus the commercial viability, energy security implications and commercial viability of developing the play remains uncertain.

3.3 Depth Dependent Correlation Matrix Methodology

An analytical model that accounts for heterogeneity and below ground uncertainty is proposed. However, due to reservoir data unavailability, the analytical model in its present form cannot be applied as such a parameter correlation model is proposed to estimate reservoir parameters. This section reveals the proposed approach based on an existing analytical model, identifies the applicable ranges for parameters via literature review and develops a parameter correlation matrix based on the reservoir's depth. The methodology is based primarily on a developed Depth Dependent Correlation Matrix (DDCM) as well as an existing well production estimation model. The DDCM estimates the unavailable input parameters applied to the production estimation Model. The integration of the models yields the production estimate for an undeveloped unconventional gas well.

3.3.1 Depth Dependent Correlation Matrix (DDCM)

The depth-dependent correlation matrix methodology is developed by reviewing rock property data and studying shale gas rock characterization. This is achieved by studying possible relevant parameters and developing the model based on depth correlations and standard reservoir equations assuming ideal gas to estimate unknown parameters. Figure 3 shows the derivation process as well as correlations which drive the developed depth-dependent correlation matrix. The matrix aims to estimate pressure, compressibility, formation volume factor, and viscosity. The data presented in table 4 below reveals the reservoir depths applied to the DDCM process. The Depth Dependent Correlation Matrix process flow highlighted above commences with the reservoir depth, which has a relationship with pressure and temperature via gradients. The well pressure is an applied parameter to the numerical model and contributes to yielding other direct parameters; compressibility and formation volume factor, which similarly depend on the estimated temperature. Asides the input of estimated temperature on formation volume factor, temperature also supports viscosity valuation, a required numerical model input parameter.

Table 4 Well Depth Data (Source: Andrew, 2013; Smith et al., 2010)

Well Name	Depth (ft^2)
Blacon East	7431.80
Bosley	6568.00
Grove Well	7564.60

Heywood Well	5260.00
Long Eaton	5901.00
Roddlesworth	4226.00
Swinden	2038.00
Wessesnden	3505.00

The wells and data above are based on wells analysed in the referenced studies based on 109 core samples within the Carboniferous Pennine Basin of central Britain and analysed using the British Geological Services' Rock-Eval machine. These are the only shale-related analysed core samples available to the study.

3.4 Unconventional well production model

The rock extractive index, a pressure transient analytic method, is based on equation 11.

$$\boldsymbol{q} = \frac{\frac{2}{\sqrt{\pi\left(\sqrt{K}\emptyset\frac{c}{\mu}\right)}}Af}{Bg}\left(\frac{\Delta p}{\sqrt{t}}\right) \quad \textbf{Equation 11}$$

Where *q* represents flowrate, *K* rock permeability, is rock porosity, *c* is compressibility, is natural gas viscosity, *Af* is an area of rock exposed by the hydraulic fracture (Rock Exposure Index), *Bg* is formation volume factor, *p* is gas pressure and is pressure between reservoir and fracture pressure (assumed as 500psi) while t is time in months.

3.4.1 Reservoir Parameter boundaries for unconventional gas wells

The properties of reservoirs fluids are extensively studied over 18months to compute natural gas characteristics and thus its production potential based on available data. This results in identifying relevant parameters via a review of about 80 literature material based on over 30 years of study with a focus on the underlying principles, which include the Sutton's correlation factor based on 264 different gas samples, z-factor relies on 1,500 data points. Also, the characteristic data range for each parameter is revealed; gas wells both conventional and unconventional possess a characteristic range of value for permeability, porosity, isothermal compressibility, viscosity, formation volume factor and pressure based on other factors. Consequently, individual literature and empirical study on each parameter are conducted over months, depending on data from thousands of producing gas wells and profiles. The literature review on reported values for each parameter results are in Table 5. Specific parameter distributions data is unavailable in undeveloped unconventional wells. Hence, the reservoir parameter boundaries are necessary to establish the appropriate model framework and provide validation based on empirical evidence. Kaiser (2012) notes that parameter distribution is less important than including all relevant variables within their expected ranges while developing a modelling framework.

Table 5 Parameter boundaries

Parameter	Symbol	Minimum Value	Maximum Value	Units	Source
Rock Permeability	K	1.00E-6	1.00E-1	mD	Cipolla et al.,2010; Wang et al.,2013
Rock Porosity	Θ	0.5	9	%	Cipolla et al.,2010; Wang et al.,2013; Lee et al., 2011
Compressibility	C	0.0001015	0.201	Psi^{-1}	Fateke, 2008; Bingxiang et al. 2013; Wang et al. 2013
Gas Viscosity	µ	0.301	0.0101	Cp	Sepehrnoor et al.,2013; Bingxiang et al.,2013; Cander, 2012
Formation Volume Factor	B_g	0.01	0.003	Rcf/scf	McCain W.D, 1990; Bingxiang et al.,2013
Pressure	P	300	4000	Psi	Curtis, 2002; USEIA, 2013; Cipolla and Ganguly, 2012

*Central values are averages.

3.4.1.1 Pressure

The hydrostatic pressure is assumed based on USEIA (2013), and Andrew (2013); the depth-dependent correlation matrix commences applying hydrostatic pressure gradient equation 12 below to estimate the reservoir pressure.

P= 0.433$psi*$Reservoir Depth per $Foot$……………Equation 12

Reservoir temperature is also derived using depth versus temperature gradient equation 13 below.

$$\mathbf{1.25}\boldsymbol{F} = \mathbf{100}\ \boldsymbol{feet\ depth} \quad \textbf{Equation 13}$$

3.4.1.2 Viscosity

The resultant temperature *(T)* is applied to the Sutherland. Equation 14 below has been used to estimate viscosity

$$\mu = \mu\boldsymbol{o} * (\boldsymbol{a}/\boldsymbol{b}) * (\boldsymbol{T}/\boldsymbol{To})^{(3/2)} \quad \textbf{Equation 14}$$

Where

μ=Viscosity in centipoise at input temperature

μ_o=Reference viscosity in centipoise at reference temperature

T= Input Temperature

T_o= Reference Temperature

$$\boldsymbol{a} = \mathbf{0.555}\boldsymbol{To} + \boldsymbol{C} \quad \textbf{Equation 15}$$

$$\boldsymbol{b} = \mathbf{0.555}\boldsymbol{T} + \boldsymbol{C} \quad \textbf{Equation 16}$$

C = Sutherland’s Constant

Natural Gas specific gravity of 0.75 is assumed (Lide, 2005; Durst, 2008; Crane, 1988; CRC, 1984)

3.4.1.3 Compressibility

Compressibility (C) = 1/P (assuming an ideal gas property). Pressure (P) from equation 12 above

3.4.1.4 Formation Volume Factor

The formation volume factor is estimated below

$$\boldsymbol{Bg = 0.02829\left(\frac{Z(T)}{P}\right)} \quad \text{Equation 17}$$

Bg= Formation Volume Factor

Z =Compressibility factor (assumed as 0.8). T & P are based on equations 12 and 13 above.

(Dake, 1998; USEIA, 2013)

Parameter ranges for porosity and Permeability; High, Mid and Low values are applied alongside the other DDCM derived parameters into the numerical model to generate corresponding production scenarios.

3.4.2 Hybrid Approach

The hybrid approach is necessitated to address the high uncertainty introduced into the production estimation by the absence of porosity and permeability values in an undeveloped shale gas. This lack of empirical evidence also impacts the first step and requirement to propose a distribution characteristic. Consequently, the uniform and familiar distribution outlines are applied in this approach; the characteristic high and low values are thus interpreted as either the maximum or minimum values. A risk analysis using a Monte Carlo simulation is applied to randomly estimate the value of porosity and permeability for both the lognormal and uniform distributions using the @Risk software by Palisade. The random sampling and selection process require many iterations; 5×10^3 over 100 times is applied. The results yield the most probable values for these parameters under these distributions.

3.4.3 Lateral Length Evolution

The REI, which represents the area of the rock exposed by the hydraulic fracturing, is considered to relate to the hydraulic fracturing efficiency. The REI value is assumed as 1% of the lateral length. However, lateral has progressed from an average value of $3500ft^2$ to $7500ft^2$ between 2013 and 2016(USEIA, 2016). The impact of lateral length progression over time in shale gas well production profile is also analysed.

3.5 Results

3.5.1 Parameter Determination

The result presented in Table 3 from the DDCM represents the estimated input parameter values for the Blacon East well. Furthermore, Table 3 develops production scenarios applied to the numerical model based on parameter boundaries in rock permeability and porosity data from Bowland shale prospect[1]. The validation of the resulting parameter values is based on reference to established ranges from literature founded on over 20years of shale gas well study, as presented in table 5. Furthermore, in terms of the DDCM's validation, the results in table 6 below reveal a pressure estimate of 3218psi; Viscosity, 0.0126cp; Formation Volume Factor, 0.001

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[1] Smith et al., 2010 provides porosity and permeability data range for the Bowland Shale Play

Rcf/Scf, and compressibility. These results are all within the established range for these parameters in table 5 above, based on empirical shale gas study results. The parameter ranges are characteristic to shale gas wells; all determined values from the DDCM are thus in conformity.

Table 6 Results from the Depth Driven Correlation Matrix (DDCM) for Blacon East Well

Parameter	**Value**	**Unit**
Pressure	3218	psi
Viscosity	0.0126	cp
Formation Volume Factor	0.001	Rcf/scf
Compressibility	0.0003	Psi^{-1}

Table 7 Permeability and Porosity Values Applied in Scenarios

Parameter	Low Case Value	Mid Case Value	High Case Value	Unit
Permeability	0.00000443	0.00355	0.0071	mD
Porosity	3	6.5	10	%

3.6 Production Estimation

The production estimates are for over twelve years with below ground parameter uncertainty establishing production scenarios. The three profiles per well highlighted by our results are low, median, and high production case scenarios. A review of the production profiles indicates that, on average, 50% of production is achieved within the first six years while production peaks in the second or third production months. An appraisal of Figures 5-9 shows that the Blacon east, Bosley, Long Eaton and Heywood wells have high possibility to produce relatively higher volumes of gas amongst the wells analysed; the three wells provide 80% of estimated recoverable reserve (Figure 10). The average daily production of the six wells in the Bowland shale study area is 147,718.64 scf based on the reference scenario, while the average natural gas wells in the US in 2016 produced 132,000 scf per day.

DECC, 2016 notes that UK homes' median annual gas demand in 2013 was 12,400kwh: equivalent to 393 scf. The result suggests that the wells could supply daily the annual gas demand of about 3,000 UK homes based on initial production rates. Additionally, over the estimated production period (Figure 9), the eight wells are estimated to produce about 1.1bcf of gas which can meet the annual gas demand of about 2.8 Million UK homes based on 2013 demand data (DECC, 2015) and the central case production scenarios over twelve years.

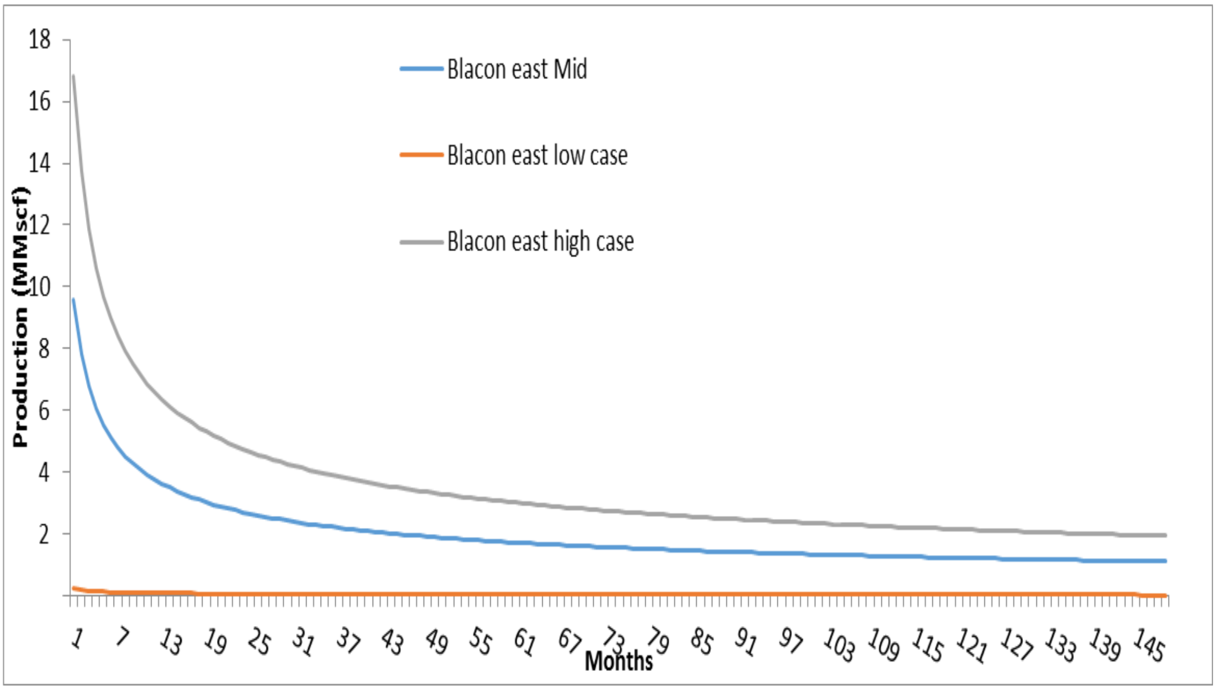


Figure 5 Blacon East Well Production Estimate Profiles

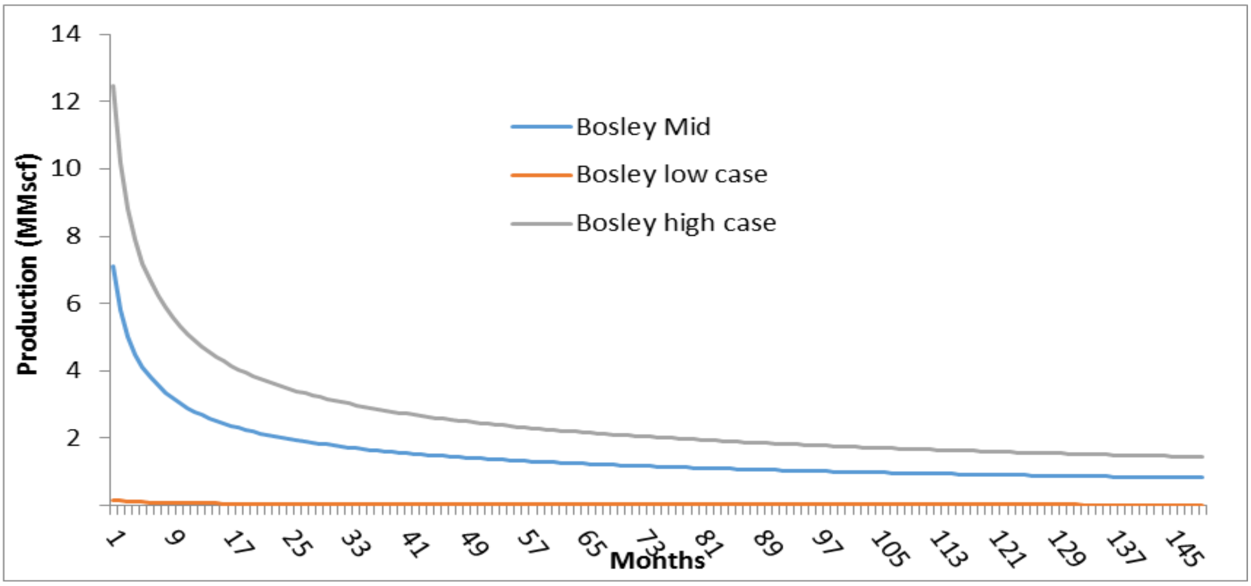


Figure 6 Bosley Well Production Estimate Profiles

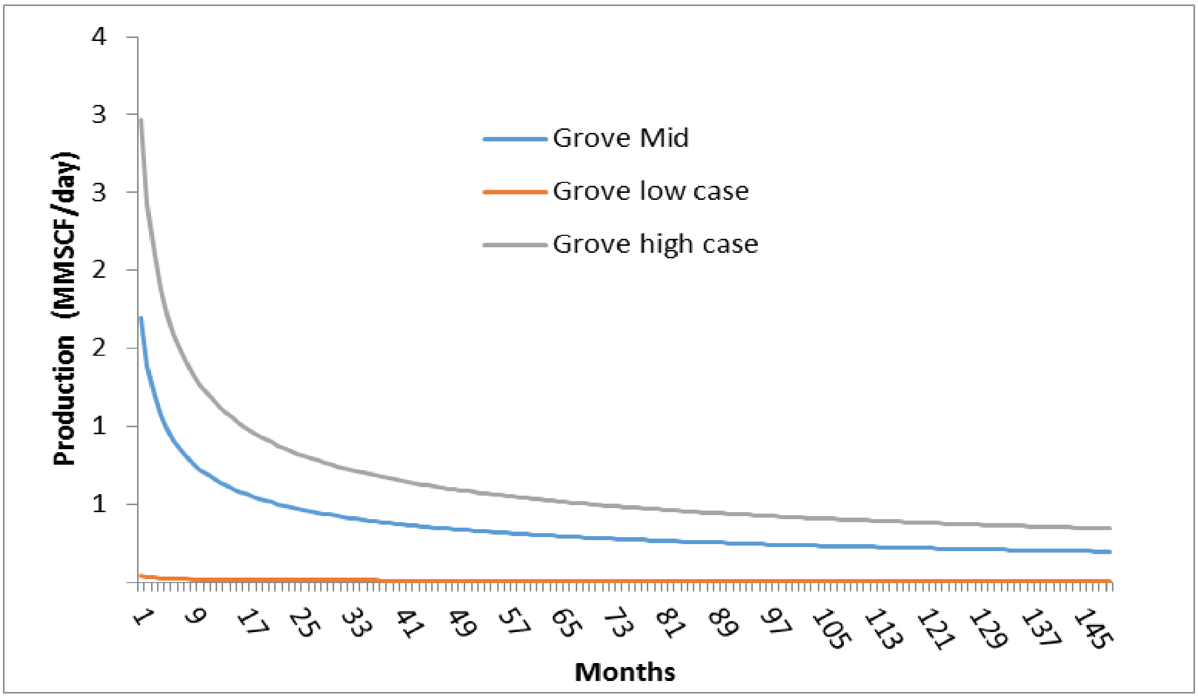


Figure 7 Grove Well Production Estimate Profile

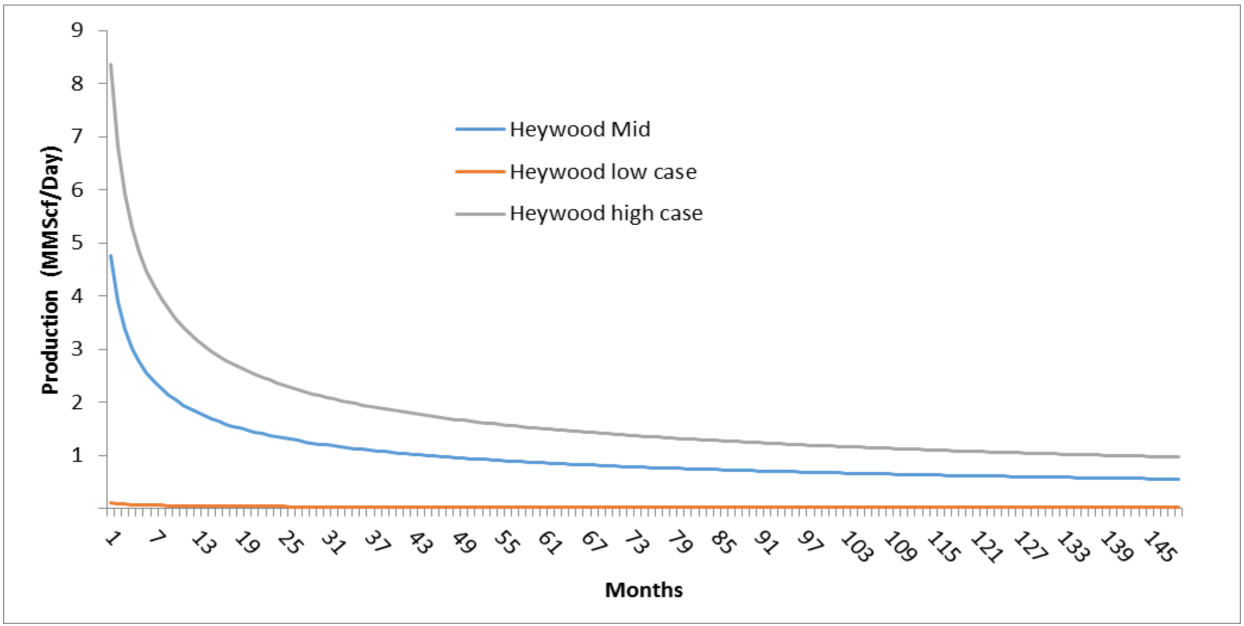


Figure 8 Heywood Well Production Profile

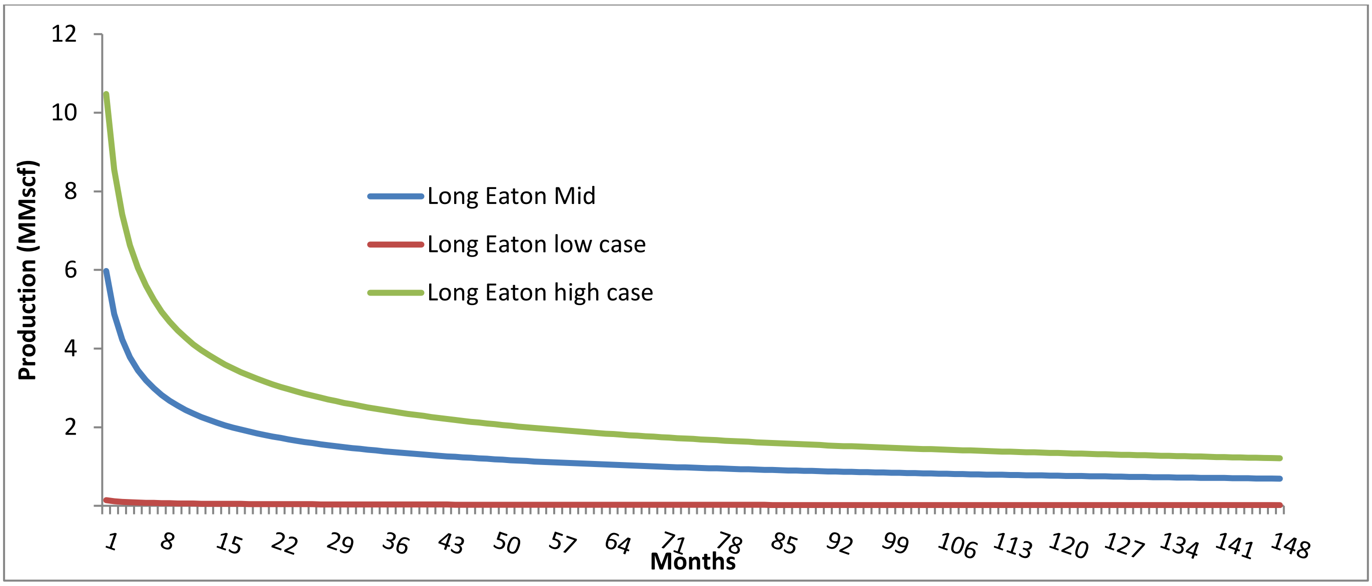


Figure 9 Long Eaton Production Profile

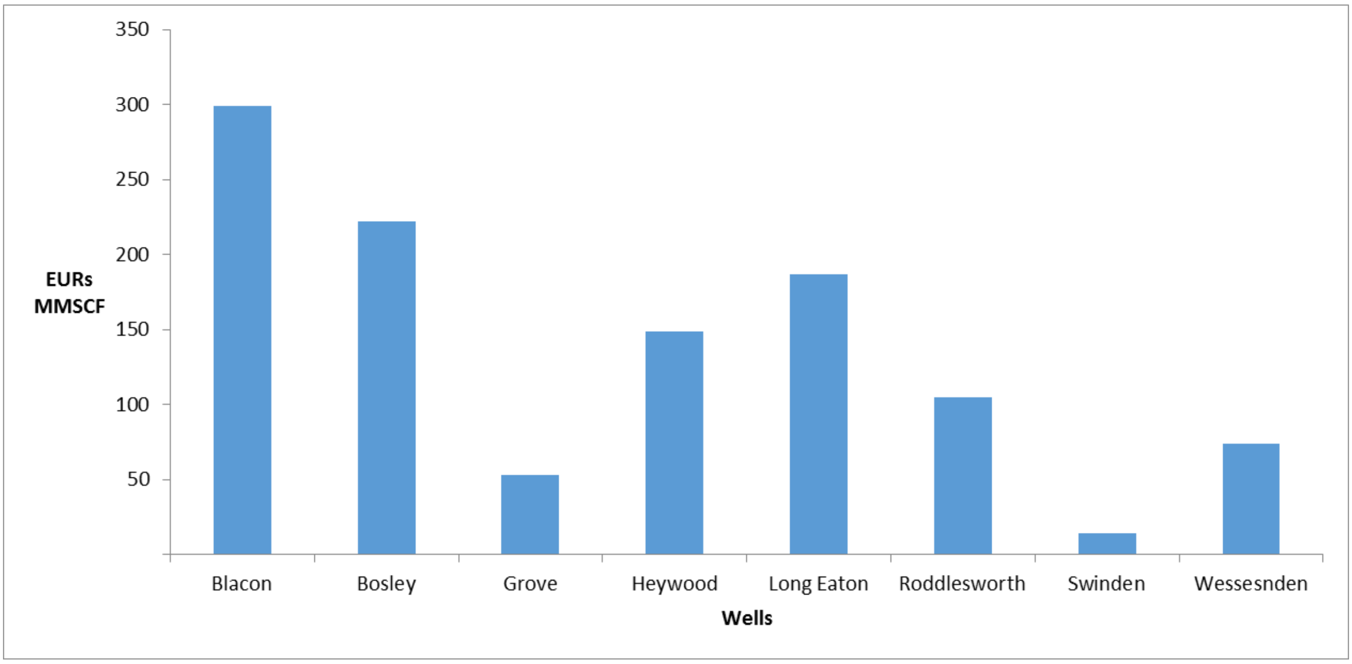


Figure 10 Estimated Ultimate Recovery over 13 years based on the reference case.

3.7 Uncertainty Analysis

3.7.1 Parameter Sensitivity

The sensitivity of production estimates to uncertainties in below-ground/reservoir parameters in terms of production rate was methodically examined. The results in Figure 11 reveals the sensitivity of production rate to estimated input parameters are analysed by varying inputs by + and – 10% while keeping other parameters unchanged. A 10% decrease in input values for permeability, porosity, and compressibility triggers a 20% decrease in estimated recovery, while a 10% reduction in the viscosity value increases gas recovery by 20%: an inverse relationship. In the rock extractive index, a 10% increase in input value results in a 40% estimated gas recovery growth; however, for the formation volume factor, a 40% production decrease yields a 10% value increase.

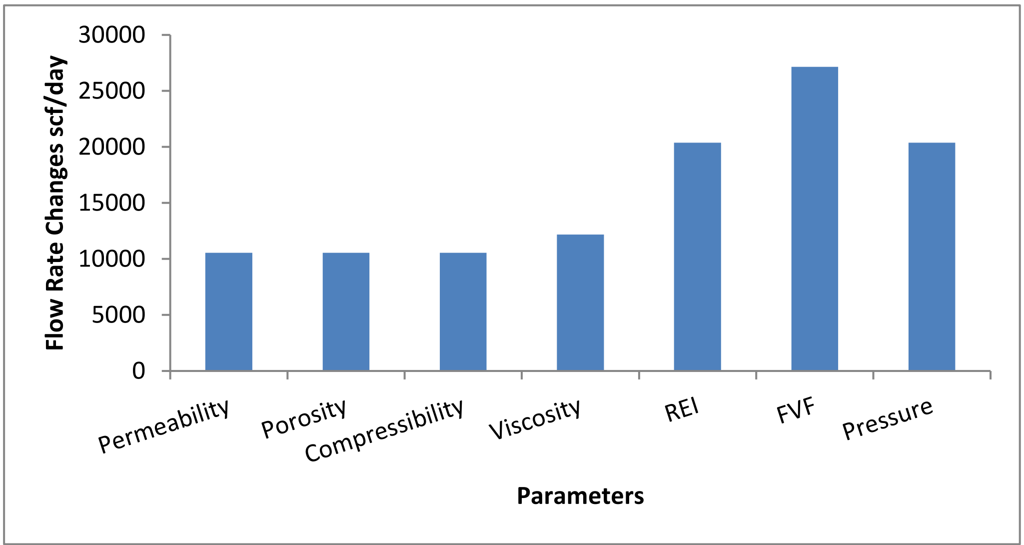


Figure 11 Relative impact of varying parameters (+/-50%) on initial production

Finally, for gas pressure, a 10% input value increment leads to a 40% increase in estimated production. The results suggest the formation volume factor has the most impact on production estimates, the rock exposure that accounts for the hydraulic fracture process's efficiency and technology, then pressure and viscosity while permeability, porosity, and compressibility have the least and similar impacts. Permeability and porosity applied as scenarios due to data unavailability and based on data range in this study have the least impact on recoverable reserve estimation.

The rock exposure identified above is the technology's efficiency, influenced by reducing the lateral length from an average of 7400ft^3 in year 2016 to 3500ft^3 for 2013. This shows a reduction in average initial daily production across the eight wells to 73,000scf from 147,150 scf. Consequently, the EURs over twelve years also reduce from 1.1bcf to 549 mmscf. The specific impact on the Blacon east well production profile is revealed in Figure 11, where initial monthly production reduces from 9mmscf to about 4.5 mmscf. The EUR of the Blacon East well consequently also reduces from 299mmscf to 141mmscf over the analysed timeframe.

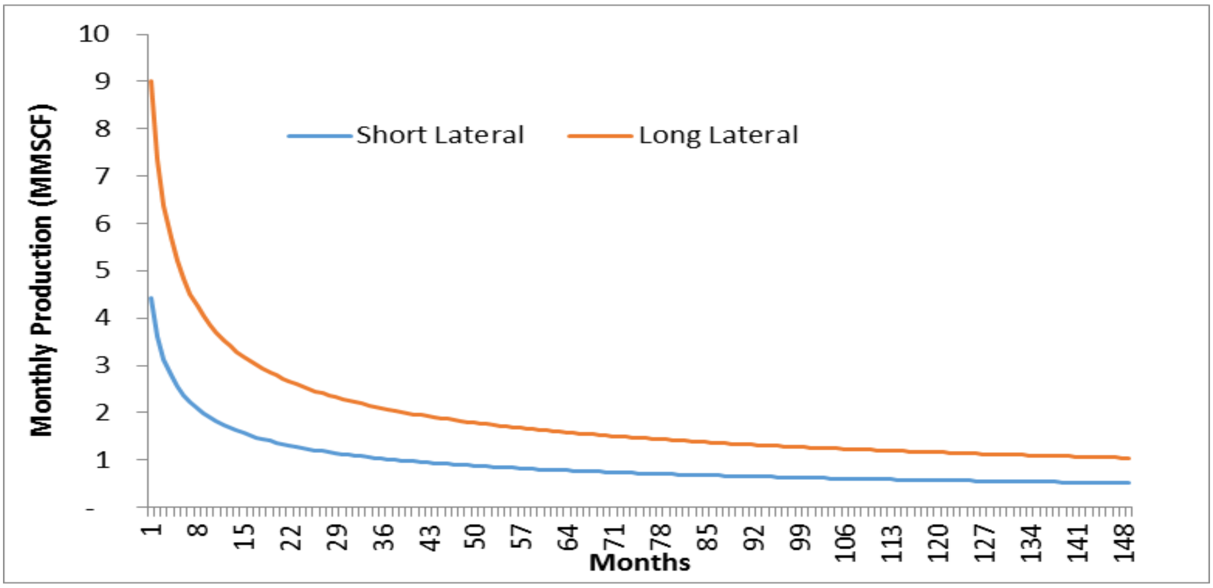


Figure 12 Production Profile of the Blacon East Well with Varying Lateral Lengths

3.7.2 Monte Carlo Simulations

The results of the Monte Carlo simulations, which iterate parameters 5 x 10^3 times over 100 simulations for both normal and uniform distributions concerning permeability and porosity for all wells included in the analysis. The uniform and normal distributions are considered as the current data do not reveal distribution characteristic in the Bowland shale. The uniform distribution scenario assumes that all values within the characteristic ranges for permeability and porosity are assigned an equal possibility of occurrence. Additionally, the normal distribution assumes that about 70% of observations fall within the mean.

Figures 13 and 14 reveal the most probable permeability and porosity values based on a normal data distribution in the Blacon East Well. The established boundaries for permeability in the Bowland shale by Smith et al. (2010) guides the minimum, and maximum values applied in the simulation. The simulation's mode and mean for permeability are 3.0038 x 10^{-3} and 3.0 x 10^{-3}, while the corresponding results for porosity are 6.5917 and 6.5669. A similar simulation is executed for the other seven wells in our analysis with the resultant mode values applied in generating production profiles.

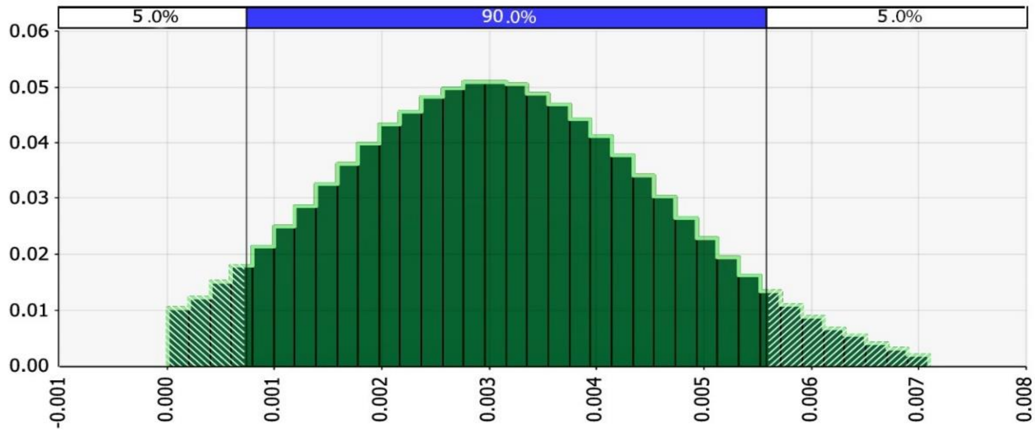


Figure 13 Permeability Summary Trend and Relative Frequency Graphs under Normal Distribution

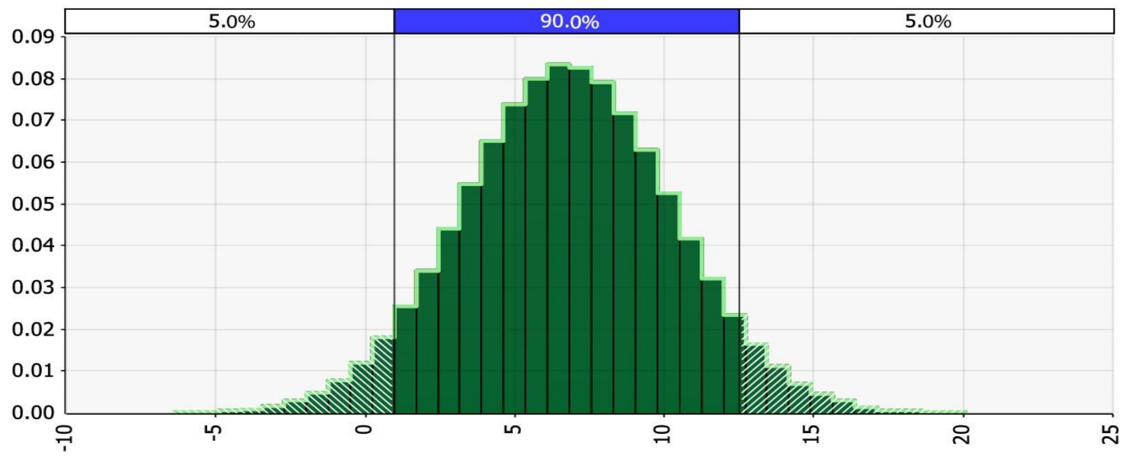


Figure 14 Porosity Summary Trend and Relative Frequency Graphs under Normal Distribution

The results from the uniform distribution simulations for the Blacon East well are revealed in Figures 15 and Figure 16. The mean values for permeability and porosity are 3.0 x 10^{-3} and 6.75, respectively. These resultant parameter values from the simulations are then applied along with the deterministic results from the DDCM into the numerical model yielding the hybrid scenario. The term hybrid is based on the combination of a deterministic and probabilistic parameter estimation model.

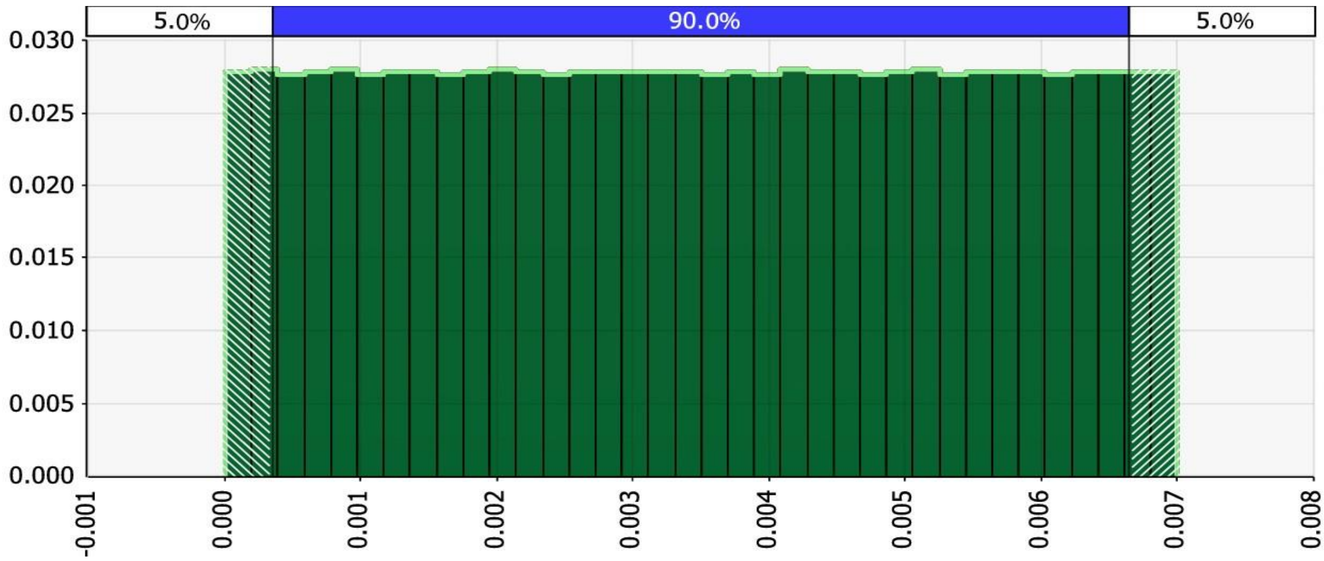


Figure 15 Permeability Summary Trend and Relative Frequency Graphs under Uniform Distribution

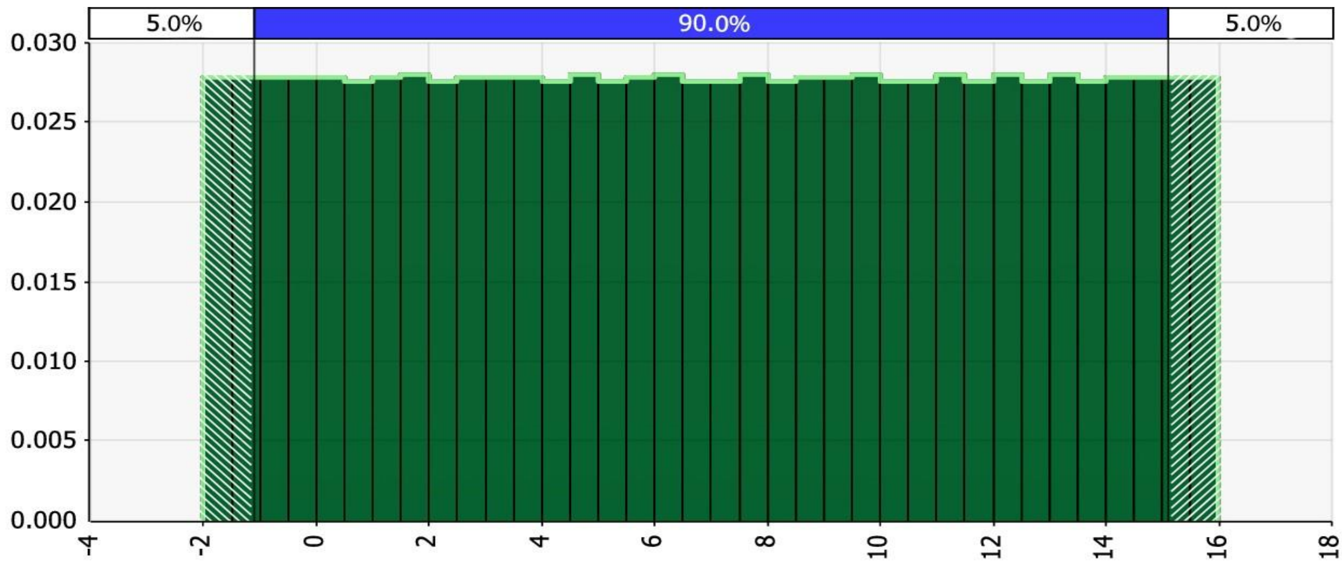


Figure 16 Porosity Summary Trend and Relative Frequency Graphs under Uniform Distribution

3.8 Discussion

The economic appraisal of shale gas reservoirs commences with estimating the technically recoverable volume of the gas resource. The technical efficiency of the drilling and hydraulic fracturing technology is a prerequisite to achieving commercial efficiency. Production estimates contribute 67% of uncertainty in the economic appraisal of typical shale gas wells (Haskett and Brown, 2010). Weijeimars (2013), which studies the economic appraisal of shale gas plays in continental Europe, notes that significant uncertainty resides in the production estimates based on average EUR/well assumptions on each play. Our approach, which incorporates the DDCM enables estimating production estimates without reference to assume averaged estimated recovery or adopted well production values. This study proposes a correlation theory that estimates parameters that impact production in shale gas wells.

The results are generated from a derived correlation model applied to an empirically supported numerical methodology. The technique eliminates the need to apply extrapolated or analogue EURs in production estimation, reduces the production assessment risk while addressing the uncertainty in geological and reservoir parameters.

The resultant production profiles Figure 5-9 are based on scenarios and thus, boundary parameter values from the novel correlation matrix guided by a review of current literature that provides empirical boundary values and model validation. Although the literature provides guidance, the input does not rely on US experience but on a universal scaling function and physical characteristics to identify a well as unconventional (porosity and permeability).

The deterministic approach presents three scenarios, while the hybrid (Both Probabilistic and deterministic) provides an alternative production prospect. Sensitivity analysis is essential in shale gas production modelling due to the uncertainty associated with parameters (Zou et al., 2016). The conducted sensitivity analysis establishes the impact of the input parameters on production rate and ultimate recovery. Additionally, the uncertainty degree associated with individual production drivers is ascertained. For investors and policymakers, the central and probabilistic driven scenarios provide close production estimates while the low production case yields high uncertainty. However, the low production case possibility is due to low rock porosity and permeability values for the same well; there is no empirical evidence to guide this scenario's probability.

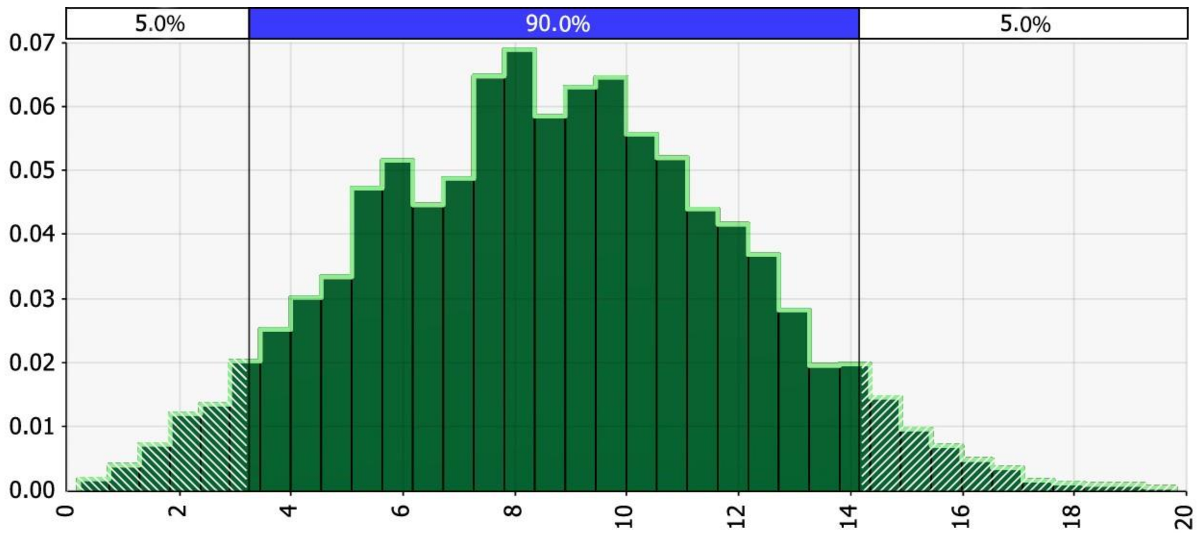


Figure 17 Initial Monthly Production Probability under Normal Distribution Condition for Porosity and Permeability in the Blacon East Well

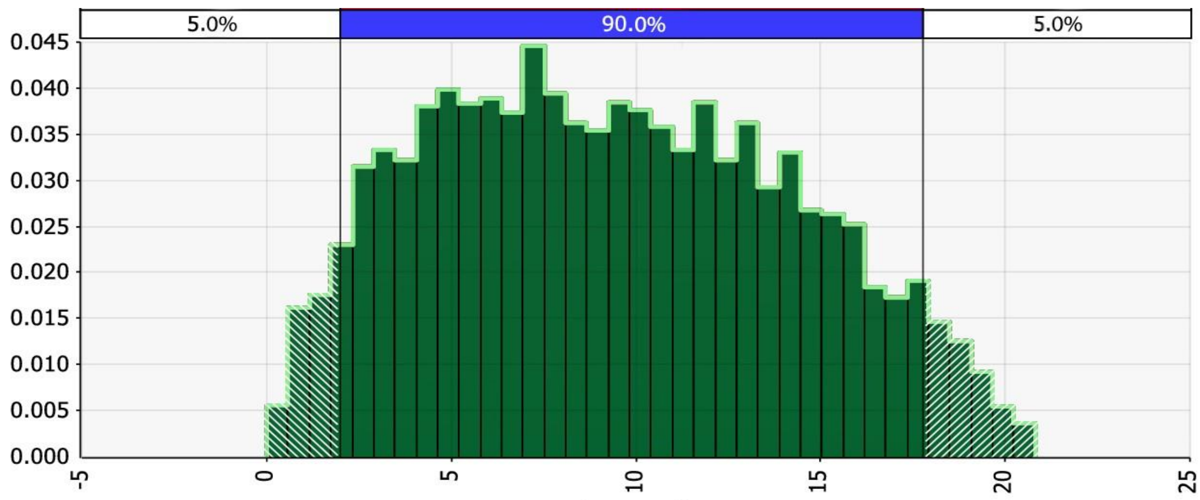


Figure 18 Initial Monthly Production Probability under Uniform Distribution Condition for Porosity and Permeability in the Blacon East Well

A likely shortcoming of the developed modelling approach includes the wide range between the resultant production rates in different scenarios for each well. Consequently, ambiguity in our production appraisal remained primarily due to unavailable porosity and permeability data. However, these are addressed by the probable parameter values results from the Monte Carlo simulation in the hybrid case. The resultant production probability profile for the normal and uniform distribution the most probable monthly production rate of about 9mmscf (normal distribution) and 8.6mmscf (uniform distribution). The uniform parameter derived production profile has an initial monthly production range of 6mmscf to 11mmscf while that of the normal distribution scenario is between 6.4mmscf to 10mmscf.

Additionally, the number of fracture stages and completion strategy gains are not directly considered. Nevertheless, these gains and characteristics all aim to increase the area of the fracture. In our model, the area of fracture (REI) is conservatively assumed as 1% of a 7400ft^2 lateral length; Zou et al. (2016) applies a minimum value of 6903m^2 equivalent to about 74,303ft^2. Further research and clarification are needed to reduce uncertainty in the well specific rock exposure index parameter. However, our analysis of this parameter involved reducing the lateral length by 3,900, which results in a 50% reduction in the initial production rate.

Overall, the modelling framework developed and applied in this study addresses and facilitates production estimation in undeveloped shale gas wells applying the numerical theory. Although the developed and applied method relies upon a lot of specific well data, it provides a more detailed overview of production estimates by accounting for diverse well characteristics. The wells analysed' unique property is further revealed by the initial production rates and estimated recovery, with results yielding diverse input parameters, rates, and recovery.

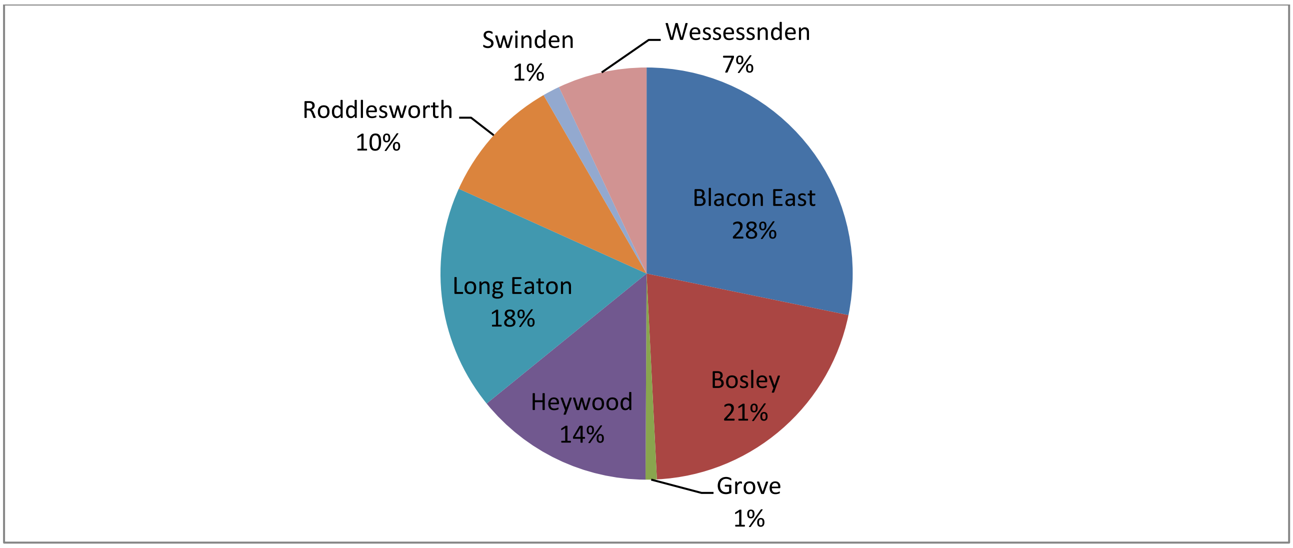


Figure 19 Percentage Contribution to Total EUR Exhibited by wells

The results are thus consistent with the positions of McGlade et al. (201), and USEIA (2013) both note that empirical evidence suggests the heterogeneous nature of unconventional gas plays within plays. Cipolla and Ganguly (2012) attribute the heterogeneity to source rock diversity. Most importantly, the developed and applied method is based on a per well basis; Gulen et al. (2013) propose an economic evaluation of unconventional gas basins should apply individual well production in economic appraisal. The established method provides a conceptual method to appraise production from undeveloped shale gas wells while recognizing the heterogeneity, below ground uncertainty, and identifies probable high production wells (Sweet Spots) within a prospective play.

3.9 Conclusion

This study applies the numerical theory in shale gas production modelling; scenarios based on possible ranges and their median value, which can be equated to P10, P50, P90 used in conventional gas production economic appraisal are developed based on the input parameter value. A further probabilistic scenario is generated with the Monte Carlo simulation. The data range from porosity and permeability, in addition to results from the input parameter estimation, are integrated into the numerical model to reveal production profiles in the Bowland Shale in Britain based on scenarios. This method provides an alternative to the current empirical and type curve practice, which rely on average EURs and initial production data from analogous shale wells/play for undeveloped shale well production estimation.

The Bowland shale case study shows that the eight wells developed and modelled can conservatively produce an average of 147,00scf natural gas daily while the EUR over 12 years is estimated as 1.1bcf of natural gas. Sensitivity analysis shows that the production is highly sensitive to these parameters (Rock Exposure based on technology efficiency, Reservoir Pressure, and the formation volume factor). Moreover, based on the 50% increase in possible production within three years (2013 -2016), delay in well development has indeed enhanced the commercial viability of future potential wells subject to other considerations; costs, risks, and sustainability criteria.

The study infers that an economic model supported by an appropriate production estimation model will provide proper guidance to policymakers and investors. The estimation of gas production from the modeling approach developed in this study and applied to the Bowland shale play can be integrated into an economic model to provide policy guidance. However, further quantitative studies on the source rock's porosity and permeability properties will reduce uncertainty in the production estimates. Exploratory drilling will provide the rock samples and thus precise porosity and permeability data. Finally, the uncertainty concerning cyclical gas prices, regulation, cost of development, and relevant energy policy concerning undeveloped shale gas plays need to be appraised to ascertain their impact on field development planning commercial viability.

4 Unconventional Gas Development Cost

4.1 Introduction

This chapter aims to propose a methodology in estimating the costs of developing unconventional gas resources based on the production technique. Besides, this section also examines and identifies the sources of uncertainty in shale gas development cost estimation. A further aim is to identify key cost parameters and then develop a non-static model by examining the trends. This study proposes a work break down cost estimation equation. A cost analysis is executed, which guides the identification of cost parameters. Consequently, time-series data for identified parameters are obtained from Baker Hughes Drilling Activity Reports, Energy Information Agency (EIA), the US Bureau of Labour Statistics, and Bureau of Economic Analysis. Finally, the impact of macroeconomic changes, specifically, the changes in oil prices on all parameters, is appraised.

Following this introduction, section 4.2 defines cost as well as reviews cost estimation methodologies. Section 4.3 reviews the cost structure of developing shale gas resources by conducting a cost analysis and reveals disaggregated cost components/parameters. Section 4.4 proposes a cost estimation equation based on workflow, while section 4.5 analysis the trends of cost parameters in relation to oil prices, which provides empirical evidence for econometric analysis. Section 4.6 develops an econometric oil price impact uncertainty model, as section 4.7 discusses the results. The chapter is concluded in Section 4.8.

4.2 Cost Definition

The costs of developing petroleum resources are critical factors to secure affordable energy provision (Aguilera, 2013). The delivery process of energy from petroleum resources can be divided into upstream, midstream, and downstream. The upstream process involves the production activities towards the extraction of the resource from a reservoir. Previously, the cost of developing petroleum resources (Oil and Gas) focused on drilling. Toews and Naumov (2015) propose that drilling represents the principal activity in the upstream sector. However, petroleum resources are located either onshore or offshore, and the production technology applied in resource extraction thus differs. The technology applied in the development of specific onshore resources requires vertical and horizontal drilling and hydraulic fracturing to access the petroleum resources buried under and within layers of rock, referred to as unconventional petroleum production based on the technological difference. Kaiser and Yu (2015) note the unique characteristics of unconventional reservoirs that require substantial technical and capital resources to evaluate and establish commercial viability.

British Petroleum BP, (2015) "a new economics of oil" recognizes the different nature of unconventional gas production, a homogenous, repetitive, industrial development while conventional production is like a one-off large-scale project. Conventional petroleum sources are currently located both onshore and offshore drilled both horizontally and vertically but are not hydraulically fractured to recover hydrocarbon, thus not requiring the additional technology and requisite capital.

Ikonnikova and Gulen (2015) state that unconventional gas development's commercial viability depends mainly on resource availability, productivity, extraction costs, and wellhead commodity prices. Nevertheless, the cost structure of developing unconventional resources remains uncertain and less studied in comparison to conventional resources.

The chapter aims to establish a generalized framework for estimating the cost of developing unconventional petroleum resources. The generalized framework is established by identifying and analysing the cost components of different development stages. Additionally, the study applies a bottom-up assessment as well as a parametric estimation method. The parametric estimation's essence is to account for uncertainties and ensure the developed method is dynamic. The study makes the first attempt to incorporate the impact of petroleum price uncertainty into the cost estimation of unconventional petroleum resources.

4.3 Cost Structure of Developing Unconventional Gas

Kaiser (2006) defines the petroleum production costs as expenses incurred while producing, treating, and bring products to the market. This study considers the production costs as upstream expenses/costs. Aguilera (2014) notes that upstream costs typically comprise of capital, operating costs, and return on capital costs while excluding taxation and royalties due to geographical differences. Consequently, this study primarily considers the capital costs of producing unconventional petroleum resources. Moreover, external costs associated with the resources' development process's sustainability criteria are not appraised as a cost; the expectation is that the fiscal regime and environmental policies would account for this.

The estimation of project costs can be either via expert judgment, analogous, parametric, three-point, and bottom-up estimation or a combination. Expert judgment cost estimation applies knowledge gained from past developments; analogous estimates relate metric from a previous project while point estimates determine activity costs based on ranges. The parametric estimation approach applies developed statistical relationships between historical data and other variables to examine expenses while estimating work activities is termed bottom-up estimation.

In the economic assessment of the Barnet shale play, Gulen et al. (2013) assume development capital cost range from US$1 to US$4 Million, a cost estimation point estimate approach. Kaiser's 2012 economic analysis of the Hayneville shale play also applies a point estimate based on company statements; assumes capital expenses with a lower boundary of US$5million based on learning curve considerations and an upper limit of US$15million which factors in completion, high rig demand, development risk and tie in costs. About the application of analogous approaches, Weijemars (2013) applies typical US cost estimates to the economic appraisal of shale gas plays in continental Europe. Anandarajah and Nwaobi (2016) note that petroleum reservoirs are complex heterogeneous geological systems; the drawback associated with applying cost analogues and point estimates is that both methods ignore the geological, heterogeneous nature of unconventional gas wells which can lead to cost underestimation or overestimation. Medlock (2012) considers shale play's geological characteristics by applying a geological econometric model based on US shale plays to other world regions, a hybrid econometric and analogous approach. However, unconventional reservoirs are known to vary in geological parameters within plays. The US Energy Information Administration (USEIA) in a 2013 report notes that shale formations in the US have displayed heterogeneous geophysical characteristics with variance occurring within 1,000 feet or less within a play as such cost estimation based on play characteristics is less detailed.

Aside from the cost input needed for the economic appraisal of unconventional gas, expenses have been applied to the development's economic impact assessment. A 2011 study by Regeneris, a consultancy on the economic impact of shale gas exploration and production in Lancashire (a UK shale gas site), applied a gross value added (GVA) approach principally forecasting the employment impact on the economy. Subsequently, the Institute of Directors (IoD) report "Getting Shale gas working" also models the economic impacts associated with shale gas development. Both reports apply an analogue of expenses to job creation ratio in the UKCS and the United States. A similar approach has been applied to shale gas plays in the US (Considine et al., 2010 and 2009) on the Marcellus Shale play's economic impact, which also reports in GVA terms. The application of cost estimates as inputs in macroeconomic models also necessitates proper cost analysis and appraisal.

Consequently, I hypothesize that the detailed cost estimation of unconventional resources should be on a per well basis while applying a bottom-up work breakdown approach based on cost trends of parameters identified by disaggregated cost analysis. Aguilera (2014) reviews the cost of developing global conventional and unconventional resources; the study maintains that most cost estimates are static, although expenses change over time to a considerable degree. This implies that cost estimates should recognize changes to parameters over time.

4.3.1 Cost Analysis

The cost analysis provides a background for the cost structure of unconventional gas production. A cost analysis is implemented on the different stages of unconventional gas development, drilling, and completion. The objective of the analysis is to identify the cost drivers of unconventional gas resource development.

The analysis of unconventional development cost is conducted with disaggregated data from Kaiser and Yu (2015); comprehensive cost analysis (both drilling and completion) suggests that significant well development costs are; 30 % sand and stimulation based, 13 % drilling and 10% casing (Figure 19).

The result of a decomposed cost analysis focusing on drilling operations in figure 20, further reveals that the costs of casings and drilling rigs represent the major cost parameters. A further similar analysis on completion activity shows the principal cost associated with sand and stimulation (Hydraulic Fracturing Process) in figure 21. These results are consistent with that of a recent study by the US Energy Information Administration (USEEIA, 2016) focusing on the trends in US oil and natural gas upstream costs focusing on four unconventional resource plays identifies five primary cost driver categories; rigs and drilling fluids, casing and cement, Frac pumps and equipment, proppant, completion fluids, and flowback.

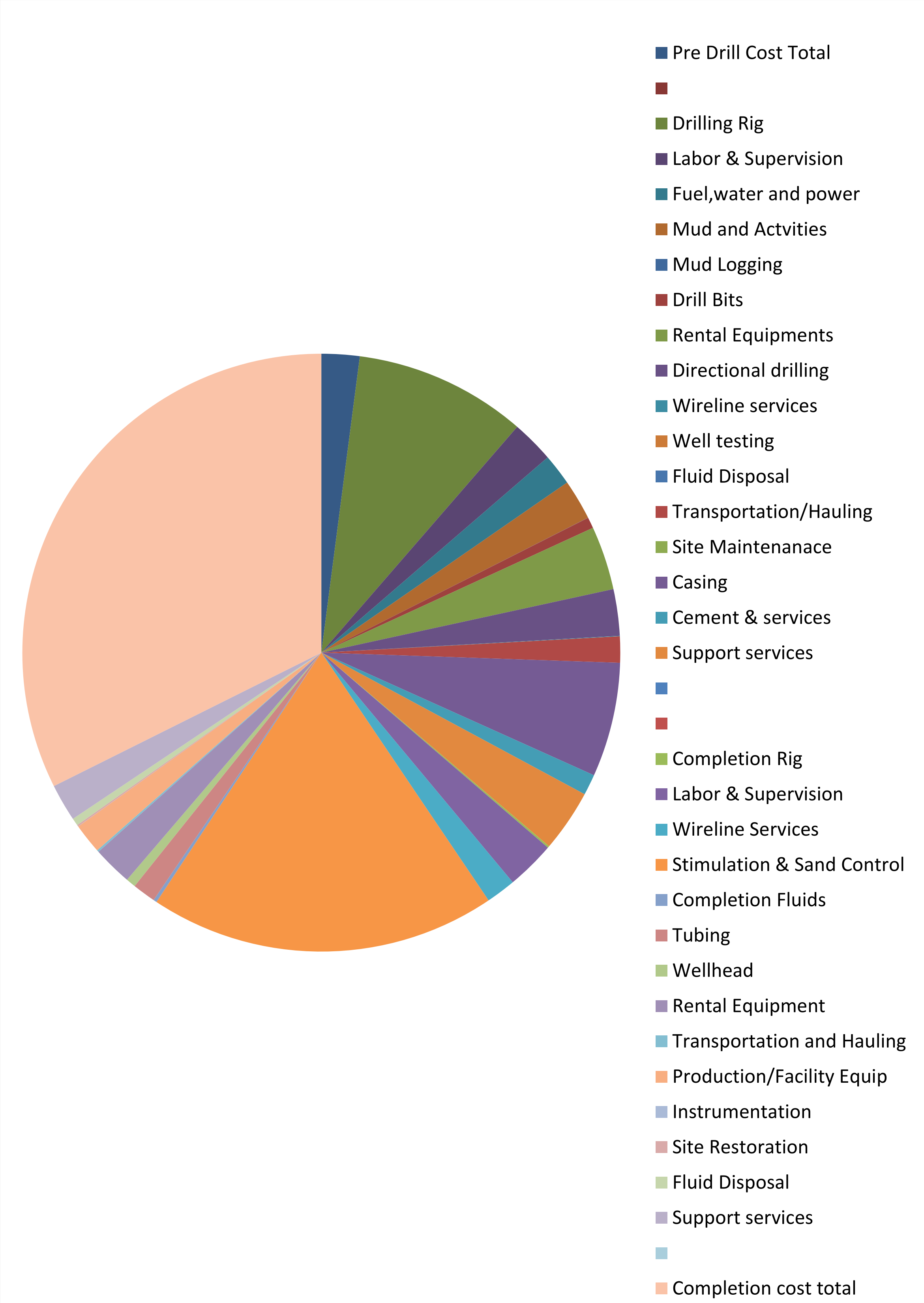


Figure 20 Broad Cost Analysis (Data Source: Kaiser and Yu; 2015)

Aguilera (2014) identifies that oil and gas costs can be affected by geological conditions, depth of accumulations, regulatory environments, and project duration. The analysis represented in Figures 22 & 23 shows the cost component but does not incorporate the following factors that impact development costs; rig specification, reservoir porosity/permeability, and speed. Besides, reservoir depth and heterogeneity of unconventional gas reservoirs need to be considered. The USEIA 2016 study states that changes in development cost can also be attributed to changes in reasonably and completion design leading to variations in primary cost drivers and considers the cost of drilling unconventional wells correlated with formation depth while completion depends linearly on the amount of water and proppant used (Sand and stimulation costs).

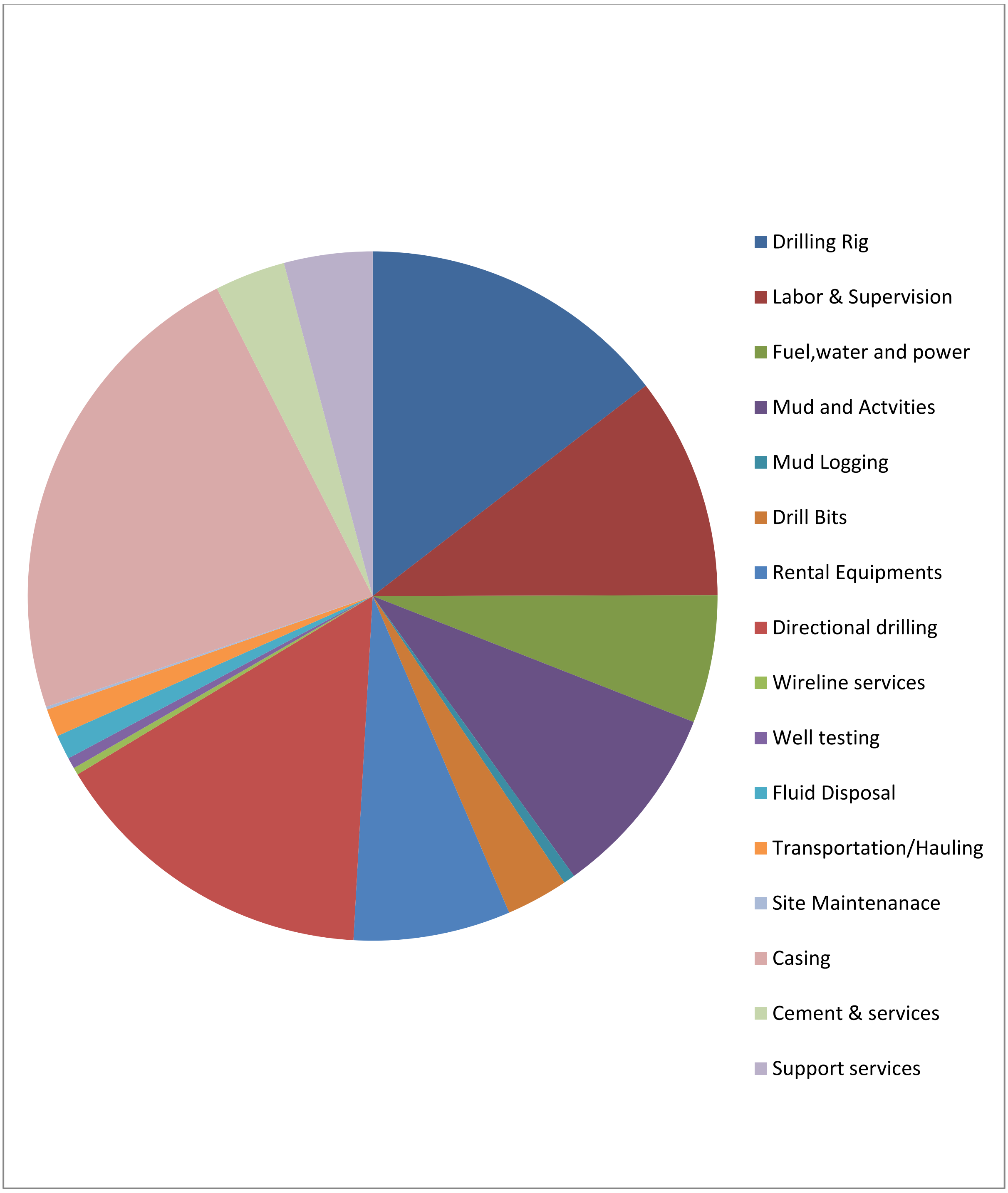


Figure 21 Drilling Cost Components (Data Source: Kaiser and Yu; 2015)

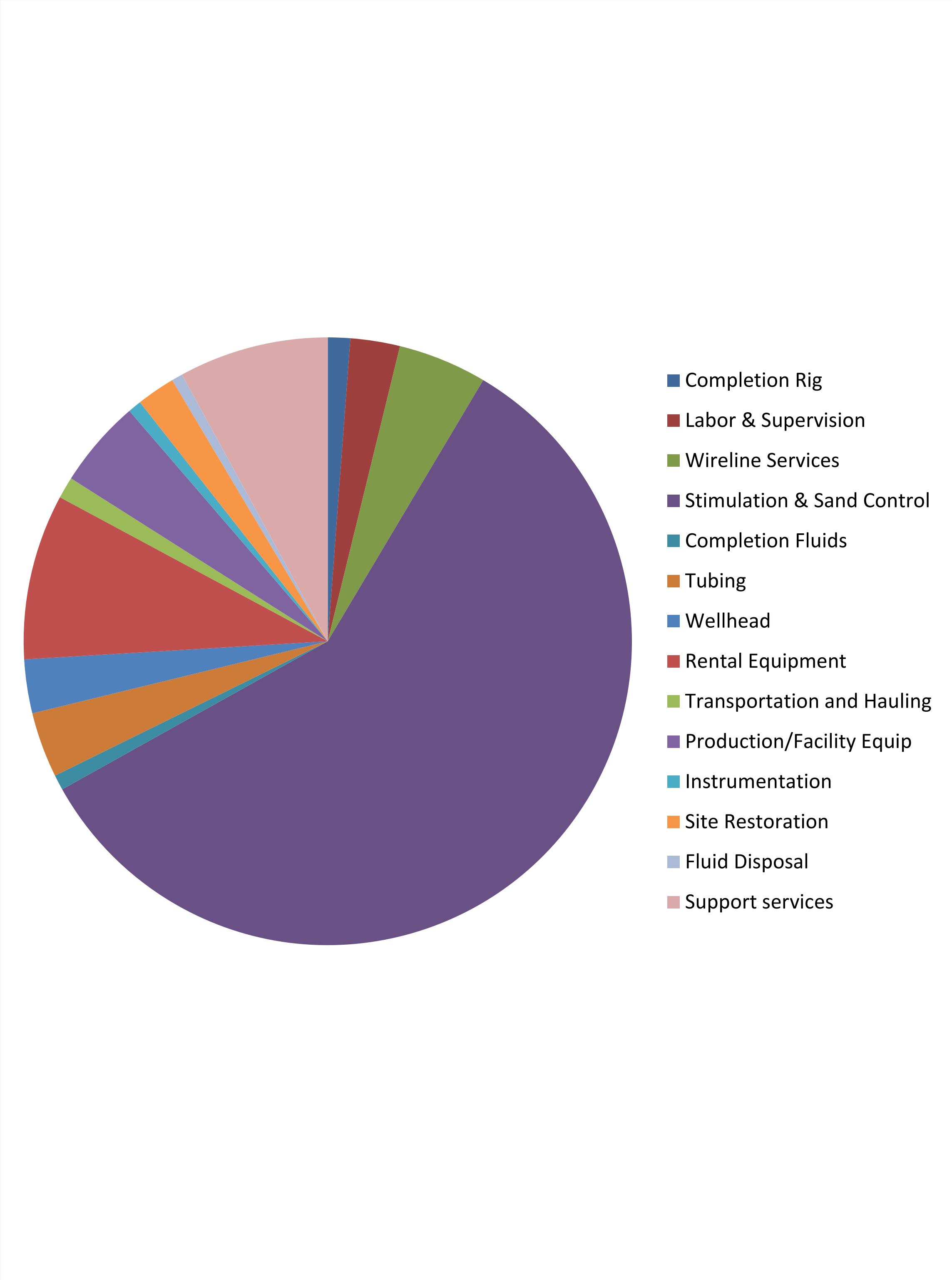


Figure 22 Completion Cost Components adapted from Kaiser and Yu (2015)

4.4 Work Breakdown Cost Estimation

Consequently, in estimating unconventional gas production cost, this study theorizes a bottom-up approach based on work breakdown and activity cycles. Equation 18 focuses on the cost of drilling while equation 20 estimates the cost of completion. Additionally, a material cost equation is introduced to account for water and other materials. Equation 19 addresses the drilling rate via the rate of penetration (ROP); the ROP addresses the type of rig applied and geological conditions of the reservoir. Furthermore, the rig rate accounts for rig specification, which differs based on type and demand for rig activity.

$$\boldsymbol{Drilling\ Cost} = \left(\boldsymbol{VRMC} + \boldsymbol{VDB} + \left(\left(\frac{\boldsymbol{D}}{\boldsymbol{VROP}}\right) * \boldsymbol{VRDR}\right)\right) + (\boldsymbol{HRMC} + \boldsymbol{HDB}\left(\left(\frac{\boldsymbol{L}}{\boldsymbol{HROP}}\right) * \boldsymbol{HRDR}\right))$$ **Equation 18**

Where

VRMC =Vertical Rig Mobilization Cost

VDB= Vertical Drilling Bit

D= Vertical Well Depth

VROP=Vertical Rate of Penetration

VRDR= Vertical Rig Day Rate

HRMC= Horizontal Rig Mobilization Cost

HDB= Horizontal Drilling Bit

L=Length

HROP=Horizontal Rate of Penetration

HRDR=Horizontal Rig Day Rate

$$Casing = CCF * Length$$ **Equation 19**

Where CCF= Casing Cost per Feet

$$\mathrm{Completions} = \mathrm{WHC} + ((\mathrm{SVD}) * \mathrm{SCD}) * \mathrm{D}) + \mathrm{Eq} + \mathrm{Tb} + \mathrm{Cf} + \mathrm{Fd} + \mathrm{Pe}$$ **Equation 20**

Where

WHC= Well Head Cost
SVD= Sand Volume per Depth
SCD= Sand Cost per Depth
D=Depth
Eq= Equipment
Tb=Tubing
Cf= Completion Fluid
Fd= Fluid Disposal
Pe=Production Equipment

Kaiser (2007) identifies the formation geology as an essential factor along with the well characteristics such as drilling bit type. The developed drilling and completion cost functions in equations 18 & 20 address the essential cost components and parameters that affect the cost of developing unconventional gas wells, providing a bottom-up cost estimation approach. The total well construction cost appears to be positively related with measured depths while drilling cost is associated with vertical and measured depth; similarly, completion costs correlate with horizontal displacement (Kaiser and Yu, 2015).

The expense breakdown, as well as the cost estimation functions, reveals critical production inputs. Asides the endogenous well characteristics, other factors affect the costs of developing oil and gas wells. The difference between natural gas production from conventional and unconventional sources is the use of horizontal drilling and hydraulically fracturing of the source rock.

4.5 Trends of Unconventional Gas Development Cost parameters about oil prices

Asides the impacts of technological and geological parameters, commodity prices are acknowledged to influence demand for drilling rigs (Kaiser and Yu, 2015). Besides, Ikonnikova and Gulen (2015) relates the fall in oil prices to the decline in the number of active rigs between October 2014 and June 2015. Furthermore, Toews and Naumov's 2015 study considers the relationship between oil prices and costs in the oil industry, excluding onshore drilling in the United States, which is primarily composed of unconventional oil and gas developments. The study focuses on drilling activity and concludes that after a 10% oil shock, it increases permanently by approximately 3%. The parameters impacting the development of unconventional and conventional resources vary. The variation is mostly based on the technology applied in production; unconventional wells require a horizontal sidetrack and vertical drilling and hydraulic fracturing to be economically viable.

Furthermore, Mc Glade (2013) regards the close correlation of production costs and the price of oil as the most significant uncertainty in estimating future production costs.

As a result, this study suggests that in the estimation of unconventional gas production cost, consideration should exist for the uncertainty introduced by oil prices on the costs and demand for components deployed in unconventional gas development. This study investigates the impact of oil price fluctuation on unconventional gas development cost drivers relying on over 10,673 data points and trends until December 2016.

4.5.1 Drilling Activity Data

As drilling rigs differ in size and specification, this study basis its drilling cost analysis on-demand for onshore drilling rigs used in shale gas development in the United States. The drilling cost analysis in figure 22 above reveals that development costs are more in both the drilling and completion phases of unconventional gas development. Additionally, day rate time trend data for different rigs are not available. However, as shale gas development applies both vertical and horizontal rigs, demand is expected to vary for each rig specification over time. Baker Hughes's drilling activity report provides rig count based on the trajectory (Horizontal and Vertical); applied to this study is a demand trend for both specifications over 300 months and relies on 2730 data collected.

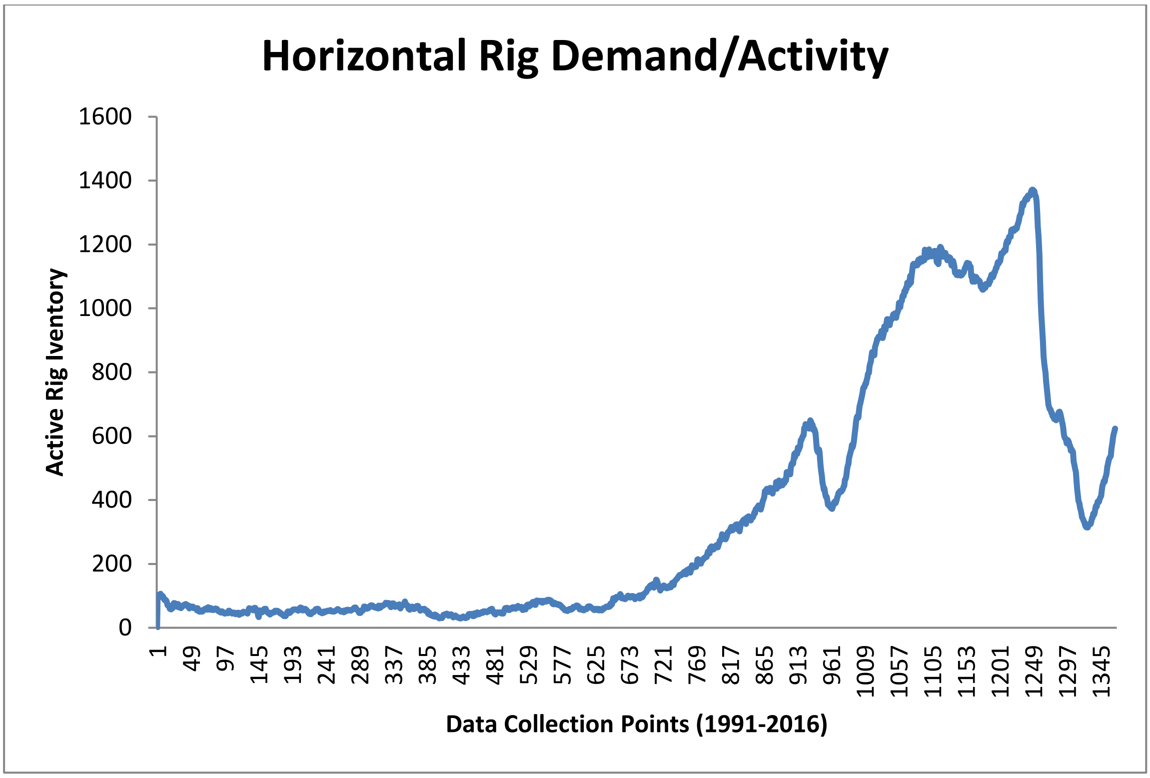


Figure 23 US Horizontal Rig Activity 1991- 2016 (Source: Baker Hughes)

4.5.1.1 Horizontal Rig

Horizontal drilling differentiates shale gas resource development from conventional resources; it is applied to drill horizontal wells that access the shale formation via laterals. The 1365 data points above are recorded over 25 years, thereby yielding time series data revealed in figure 22. The lowest recorded number of horizontal rigs in activity over the 25 years is 29, logged on the 9th of November 1998. The maximum horizontal rig demand of 1372 was noted is on the 21st of November 2014, while the most frequent demand index over the period in review is 59 rigs.

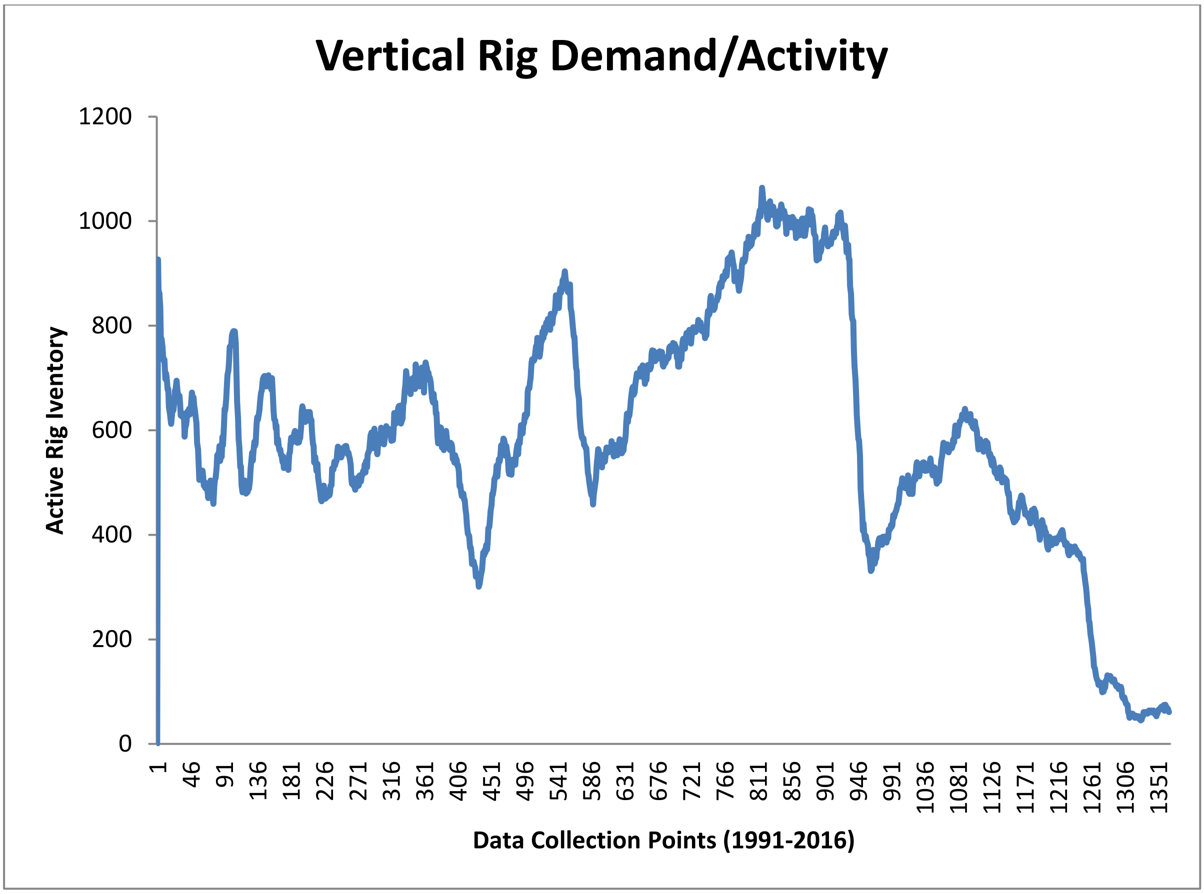


Figure 24 US Vertical Rig Activity 1991- 2016 (Source: Baker Hughes)

4.5.1.2 Vertical Rig

Vertical rig application is common to both conventional and unconventional hydrocarbon development. The 25-year vertical rig demand time trend in figure 24 above is based on 1365 data points. The most frequent demand indicator is 570, while the least and highest demand is 45 and 1064. The maximum rig demand occurred on the 18th of August 2006 while the lowest demand occurred ten years after; the 3rd of June 2016 (during an oil price decline period).

4.5.2 Steel Demand

In the oil industries, steel is used as input for equipment; rigs, casing, and pipes are the major components made from steel used in shale gas development. The US Bureau of economic analysis data provides monthly data from 1980 to 2016 based producers price index is applied for this study, relying on 432 data points.

4.5.3 Stimulation Sand

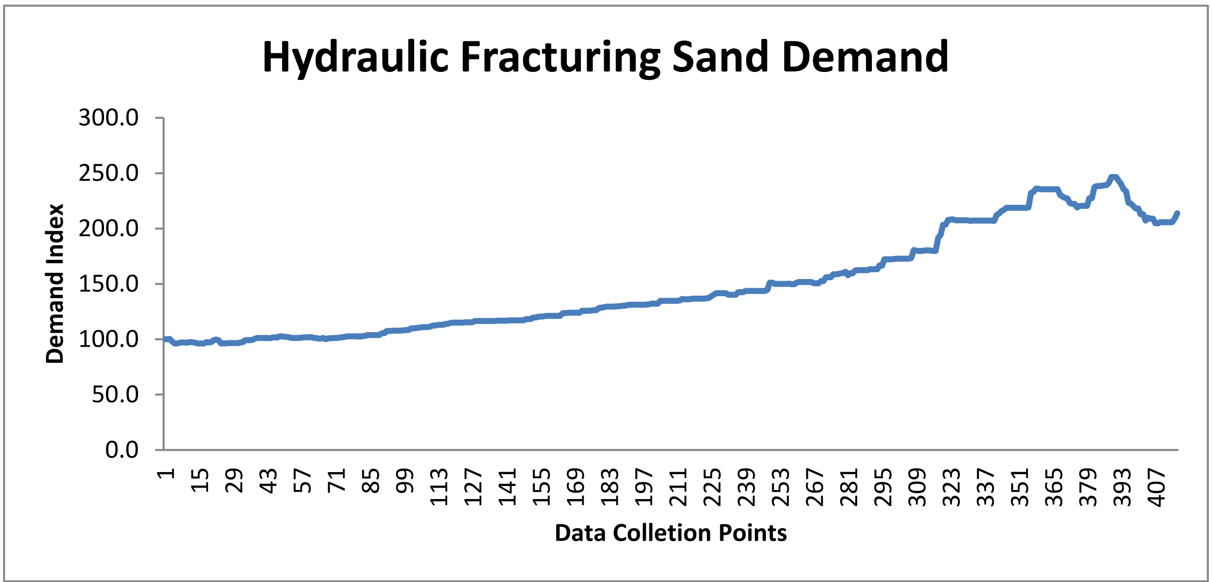


Figure 25 Hydraulic Sand Demand Index 1982-2016 (Source: US Bureau of Labour Statistics)

Figure 24 above represents the demand index for sand applied during hydraulic fracturing operations. The index used commenced at 100 in June 1982 and ended at 209.2 in December 2016. Altogether there are 415 data points; the lowest index occurred between 1982/1983 while the highest was 246.5 in 2014.

The time trends: stimulation sand demand, steel index, horizontal and vertical rig activity vary widely. The variation is a source of uncertainty in planning the development of shale gas resources.

4.5.4 Oil Prices

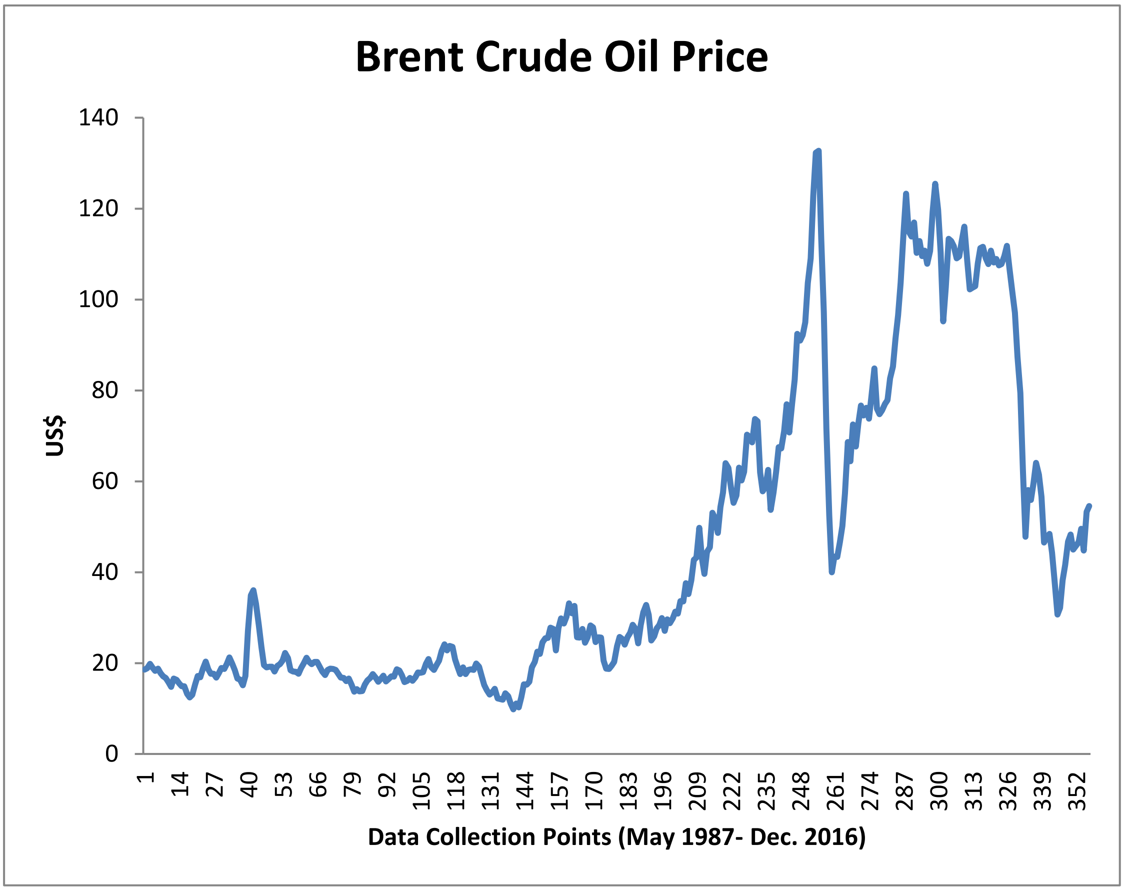


Figure 26 Brent Crude Oil Price (May 1987 to Dec. 2016) Data Source: USEIA

The main benefit of developing hydrocarbon resources is either oil or gas. As such, investors and policymakers interested in the cost will also be keen on these commodities' market price. The price of gas is indexed against oil price; for this part of the study, Brent Crude Oil Price (BCOP) is used from the US Energy Information Authority (USEIA) daily report. The highest 18-year price for BCOP is

US$132.72/Barrel in July 2008 and the lowest US$9.82/Barrel, which occurred in December 1998. A range of US$122.9/Barrel indicates a large uncertainty scale. Furthermore, the impact of oil price uncertainty on shale gas development cost is unknown.

4.6 An econometric analysis of the impact of oil price uncertainty on shale gas cost parameters

In relating the impact of oil price uncertainty on unconventional cost parameters, we have identified the parameters above. This study proposes a correlational scientific study aimed at the natural relationship between oil prices and the identified parameters overtime via statistical modelling and analysis. Data from the steel demand index, Hydraulic Fracturing Sand demand index (Frac), Rig count, and Brent oil price are standardized. In this case, standardization involves creating quarterly averages of time series data from Q1, 1991 to Q4, 2016. This results in 104 data points for every variable. The statistical package applied for data mining, and statistical analysis in this research is SPSS version 22.

4.6.1 Correlation

The data analysis is founded on studying the relationship between oil prices and identified cost parameters of shale gas development; Steel, Hydraulic Sands, and Onshore Rig Activity (Vertical & Horizontal). In this case, Brent crude oil price (BCOP) is regarded as the independent variable while the other parameters are dependent. There are two types of correlation: bivariate and partial. A bivariate correlation aims to expose the relationship between two variables, while partial correlation analysis targets the connection between two variables while regulating other variables' effect.

The study aims to reveal the relationship or interaction between oil prices and individual cost parameters in shale gas development. Consequently, the bivariate correlation is applied, Pearson's product-moment correlation coefficient and Spearman's rho. Pearson correlation coefficient is elaborated in equation 21.

$$\boldsymbol{r} = (\boldsymbol{COV}_{xy})/\boldsymbol{s}_x\boldsymbol{s}_y \qquad \textbf{Equation 21}$$

Where COV is the Covariance

$$COV = \sum(x_i - \bar{x})(y_i - \bar{y})$$

x & y = variables

$\bar{x}$ & $\bar{y}$ = averages

$s_x s_y$ = Standard deviation

Table 8 Descriptive Statistics on Corrected Data

	N	Range	Minimum	Maximum	Mean
	Statistic	Statistic	Statistic	Statistic	Statistic
Horizontal Rigs	104	1327.54	31.69	1359.23	358.20
Vertical Rigs	104	973	50.54	1023.53	595.49
Brent Crude Oil Price	104	109.99	11.21	121.20	48.30
Steel Demand	104	179.33	107.83	287.16	163.58
Frac.	104	174.97	71.53	246.50	155.91

	Std. Deviation	Variance	Skewness		Kurtosis	
	Statistic	Statistic	Statistic	Std. Error	Statistic	Std. Error
Horizontal Rigs	407.38	165955.09	1.13	0.237	-0.187	0.469
Vertical Rigs	226.13	51133.84	-0.247	0.237	0.265	0.469
Brent Crude Oil Price	34.51	1190.82	0.806	0.237	-0.759	0.469
Steel Demand	50.48	2548.25	0.535	0.237	-1.102	0.469
Frac.	45.24	2046.90	0.407	0.237	-0.743	0.469

QQ Plots are also developed; please see Appendix A.

Table 9 Pearson's Correlation between Brent Crude Oil Price and Horizontal Rig Demand.

		Horizontal Rigs	Brent Crude Oil Price
Horizontal Rigs	Pearson Correlation	1	0.895**
	Sig. (2-tailed)		.000
	N	104	104
Brent Crude Oil Price	Pearson Correlation	0.895**	1
	Sig. (2-tailed)	.000	
	N	104	104

Table 10 Pearson's Correlation between Brent Crude Oil Price and Vertical Rig Demand

		Brent Crude Oil Price	Vertical Rigs
Brent Crude Oil Price	Pearson Correlation	1	0.020
	Sig. (2-tailed)		0.838
	N	104	104
Vertical Rigs	Pearson Correlation	0.020	1

	Sig. (2-tailed)	0.838	
	N	104	104

Table 11 Pearson's Correlation between Brent Crude Oil Price and Fracturing Sand Demand

		Brent Crude Oil Price	Frac.
Brent Crude Oil Price	Pearson Correlation	1	0.812
	Sig. (2-tailed)		0.000
	N	104	104
Frac.	Pearson Correlation	0.812	1
	Sig. (2-tailed)	0.000	
	N	104	104

Table 12 Pearson's Correlation between Brent Crude Oil Price and Steel Demand

		Brent Crude Oil Price	Steel Demand
Brent Crude Oil Price	Pearson Correlation	1	0.947**
	Sig. (2-tailed)		0.000

	N	104	104
Steel Demand	Pearson Correlation	0.947**	1
	Sig. (2-tailed)	0.000	
	N	104	104

The above correlation results in table 9 to 12 are generally modelled applying two-tailed (as the directional hypothesis on these relationships is unknown) and Pearson's correlation in equation 21. The results suggest that there is a significant correlation with Brent Crude Oil price with horizontal rig demand (HRD), Steel demand (SD), and Hydraulic Fracturing Sand demand (Frac). A Person correlation coefficient (r) of 0.90 for the horizontal rig, 0.95 for steel demand, and 0.81 for hydraulic fracturing sand demand all at the 0.01 level. However, for vertical rigs, the correlation coefficient is 0.02 and thus insignificant.

4.6.2 Coefficient of Determination

The coefficient of determination r^2 aims to measure the variability in a variable shared by another variable. In this study, measuring how much the uncertainty in oil prices impacts horizontal and vertical rigs activity and steel and hydraulic fracturing sand demand.

$$\boldsymbol{r} = \boldsymbol{r}^{2} \quad \textbf{Equation 22}$$

Where r= correlation coefficient

Table 13 Coefficient of Determination

Independent Variable	r^2 (Coefficient of Determination)
Horizontal Rig Activity	0.80
Vertical Rig Activity	0.0004
Steel Demand	0.90
Hydraulic Fracturing Sand Demand	0.65

- Dependent Variable is Brent Crude Oil Price

Converting the above values of *r* to percentage shows that horizontal rig activity shares 80% of its variability with Brent Crude Oil Price, Vertical Rigs much less at less than 1% (0.045), 90% variability of steel demand is shared with crude oil price while Hydraulic fracturing sand shares 65% with the oil price index.

4.6.3 Adjusted R^2

$$\overline{\boldsymbol{R^2}} = \mathbf{1} - (\mathbf{1} - \boldsymbol{R^2})\left(\frac{\boldsymbol{n-1}}{\boldsymbol{n-k}}\right) \quad \textbf{Equation 23}$$

4.6.4 Empirical Results

$$\boldsymbol{Y_i} = \boldsymbol{B_1} + \boldsymbol{B_2 X_i} + \boldsymbol{u_I} \qquad \textbf{Equation 24}$$

Equation 24 above is the simple two-variable linear regression model, where is known as the stochastic or random error term. This error term's value cannot be controlled as such it is also a random variable usually characterized by its probability distribution. The $\boldsymbol{B_1} + \boldsymbol{B_2 X_i} + \boldsymbol{u_I}$ section in equation 24 relates to the average value of the dependent variables (HRD, VRD, HFSD, and SD) matching to a value of the independent variable (BCOP). The equation reveals how an average value of y (dependent variable) relates to each X (independent variable). $\boldsymbol{B_1}$ and $\boldsymbol{B_2}$ are parameters known as the regression coefficients; $\boldsymbol{B_1}$ is the intercept, while $\boldsymbol{B_2}$ is the slope that measures the rate of change of the dependent variable as for every unit change in X.

4.6.4.1 Empirical Results Applying Horizontal Drilling Demand (HRD) as a dependent variable

Table 14 HRD Dependent Variable Model Criteria

Model	Variables Entered	Variables Removed	Method
1	Brent Crude Oil Price		Stepwise (Criteria: Probability-of-F-to-enter <= .050, Probability-of-F-to-remove >= .100).

a. Dependent Variable: Horizontal Rigs

Table 15 Model Summary HRD Dependent Variable

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	0.895[a]	0.800	0.798	182.92

a. Predictors: (Constant), Brent Price

Table 16 ANOVA[a] Results with HRD Dependent Variable Scenario

Model	Sum of Squares	Df	Mean Squares	F	Sig.
Regression	13,680,570.5	1	13,680,570.5	408.977	0.000[b]
Residual	3,412,803.48	102	33,458.858		
Total	17,093,374.0	103			

a. Dependent Variable: Horizontal Rigs

b. Predictors: (Constant), Brent Price

Table 17 Coefficients[a] of Determination with HRD as Dependent Variable

Model	Unstandardized Coefficients		Standardized Coefficients	T	Sig.
	B	Std. Error	Beta		
(Constant)	-151.895	30.953		-4.907	0.000
Brent Crude Oil Price	10.561	0.522	0.895	20.221	0.000

a. Dependent Variable: Horizontal Rigs

The model summary table above further confirms our coefficient of determination, which suggests that 80% of the variability in horizontal drilling activity can be associated with Brent crude oil price uncertainty. The analysis of variance (ANOVA) table indicates F ratio of approximately 409 significant at p less than .001.

$$\boldsymbol{HRD = -151.9 + 10.56BCOP} \quad \textbf{Equation 25}$$

Equation 25 above is based on the model parameter table; it indicates that US$1 increase in Brent oil price will result in 11 more rigs being demanded or active.

4.6.4.2 Empirical Results Applying Vertical Drilling Demand (VRD) as the dependent variable

Table 18 Vertical Drilling Dependent Variable Model Parameters

Model	Variables Entered	Variables Removed	Method
1	Brent Crude Oil Price[a]		Enter

a. Dependent Variable: Vertical Rigs

b. All Requested variables entered.

Table 19 Coefficients[a] of Determination with VRD as Dependent Variable

Model	Unstandardized Coefficients		Standardized Coefficients	t	Sig
	B	Std. Error	Beta		
(Constant)	589.070	38.445		15.323	0.000
Brent Crude Oil Price	0.133	0.649	0.020	0.205	0.838

Table 20 Coefficient Confidence Interval for VRD Dependent Variable

Model	95.0% Confidence Interval for B	
	Lower Bound	Upper Bound
(Constant)	512.815	665.325
Brent Crude Oil Price	-1.154	1.420

a. Dependent Variable: Vertical Rigs

Table 19 above gives a low coefficient of determination for Vertical rig demand, which is further confirmed in equation 26 below; a US$ 1 increase in Brent oil price results in 0.13 Vertical rig demand. As such, a US$ 10 increase in Brent oil prices relates to 1 additional vertical rig demand.

$$\boldsymbol{VRD = 589 + 0.133BCOP} \quad \textbf{Equation 26}$$

4.6.4.3 Empirical Results Applying Steel Demand as dependent variable

Table 21 SD Dependent Variable Model Criteria

Model	Variables Entered	Variables Removed	Method
1	Brent Crude Oil Price		Stepwise (Criteria: Probability-of-F-to enter <=.050, probability-of-F-to-remove>=.100).

a. Dependent Variable: Steel Demand

Table 22 Coefficients[a] of Determination with SD as Dependent Variable

Model	Unstandardized Coefficients		Standardized Coefficients	t	Sig.
	B	Std. Error	Beta		
1 (Constant)	96.683	2.764	0.947	34.984	0.000
Brent Crude Oil Price	1.385	0.047		29.699	0.000

Table 23 Coefficient Confidence Interval for VRD Dependent Variable

Model	95.0% Confidence Interval for B	
	Lower Bound	Upper Bound
1 (Constant)	91.202	102.165
Brent Crude Oil Price	1.292	1.477

a. Dependent Variable: Steel Demand

The coefficient of determination in for steel demand concerning Brent crude oil price in table 22 above is 0.90, suggesting that Brent crude oil prices drive 90% variation in steel demand index. The empirical results in equation 27 below show that for US$1 increase in Brent crude oil price, the steel demand index rises by 1.385.

$$SD = 96.683 + 1.385BCOP \quad \textbf{Equation 27}$$

4.6.4.4 Empirical Results Applying Hydraulic Fracturing Sand Demand as dependent variable

Table 24 HFSD Dependent Variable Model Criteria

Model	Variables Entered	Variables Removed	Method
1	Brent Crude Oil Price		Stepwise (Criteria: Probability-of-F-to-enter <= .050, Probability-of-F-to-remove >= .100).

a. Dependent Variable: Hydraulic Fracturing Sand Demand (Frac.)

Table 25 Coefficients[a] of Determination with HFSD as Dependent Variable

Model	Unstandardized Coefficients		Standardized Coefficients	T	Sig.
	B	Std. Error	Beta		
1 (Constant)	104.502	4.492		23.264	0.000
Brent Crude	1.064	0.076	0.812	14.043	0.000

Table 26 Coefficient Confidence Interval for HFSD Dependent Variable

Model	95.0% Confidence Interval for B	
	Lower Bound	Upper Bound
1 (Constant)	95.592	113.411
Brent Crude Oil Price	0.914	1.215

a. Dependent Variable: Hydraulic Fracturing Sand Demand (Frac.)

Hydraulic fracturing sand's coefficient of determination in the table above 25 is 0.65, which suggests that Brent crude oil price changes drive 65% of this index. Equation 28 below also notes that for every US$1 rise in Brent crude oil prices, the HFS index/demand increases by 1.064.

$$\boldsymbol{HFS = 104.502 + 1.064BCOP}$$ **Equation 28**

The results of the correlation and coefficient of determination in the table overhead based on data applied seem quite optimistic and high for the following dependent variables, horizontal rigs, steel demand, and hydraulic fracturing demand. This research is bothered about conducting spurious regression that can be caused by data manipulation and seasonality. Data averaging during analysis introduces smoothness which dampens fluctuations in monthly data (Gujarati and Porter 2010). Raw data is altered into quarterly averages from daily, monthly, and other periods for this study.

Hilmer and Hilmer, 2013 also further highlight that quarterly seasonality is likely present in time series based on quarterly data.

4.6.5 First Difference Method

The remedial methodology applied in this study to account for the seasonality in data is the first difference method. The generalized regression equation (Equation 25) is reduced to the first different equation thus:

$$\boldsymbol{Y_t - Y_{t-1} = B_2(X_t - X_{t-1}) + \gamma_t} \quad \textbf{Equation 29}$$

Or

$$\Delta Y_t = B_2 \Delta X_t + \gamma_t \qquad \textbf{Equation 30}$$

Where is the first difference operator, which is formed for both the independent variable (Brent crude oil price) and dependent variables (Horizontal Rig Demand, Vertical Rig Demand, Steel Demand, and Hydraulic Fracturing Sand Demand) The regression is then run on these transformed variables.

4.6.5.1 Transformed First Difference Data-Driven Correlation

Table 27 Pearson's Correlation between Brent Crude Oil Price and Horizontal Rig Demand on Transformed First Difference Data

		dBCOP	dHRD
dBCOP	Pearson Correlation	1	0.128
	Sig. (2 tailed)		0.198

	N	103	103
dHRD	Pearson Correlation	0.128	1
	Sig. (2 tailed)	0.198	
	N	103	103

Table 28 Pearson's Correlation between Brent Crude Oil Price and Vertical Rig Demand on Transformed First Difference Data

		dBCOP	dVRD
dBCOP	Pearson Correlation	1	0.183
	Sig. (2 tailed)		0.065
	N	103	103
dVRD	Pearson Correlation	0.183	1
	Sig. (2 tailed)	0.065	
	N	103	103

The results in tables 27 and 28, respectively above, indicates the Pearson correlation coefficient is 0.128 for the transformed data for Horizontal rig activity (dHRD) and Brent Crude Oil price (dBCOP) whiles the correlation with Vertical rig activity (dVRD) has a Pearson correlation coefficient of 0.183.

Table 29 Pearson's Correlation between Brent Crude Oil Price and Steel Demand on Transformed First Difference Data

		dBCOP	dSD
dBCOP	Pearson Correlation	1	0.674**
	Sig. (2 tailed)		0.000
	N	103	103
dSD	Pearson Correlation	0.674**	1
	Sig. (2 tailed)	0.000	
	N	103	103

** correlation is significant at the 0.01 level (tailed).

Table 30 Pearson's Correlation between Brent Crude Oil Price and Hydraulic Fracturing Sand Demand on Transformed First Difference Data

		Dbcop	dHFS
dBCOP	Pearson Correlation	1	0.092
	Sig. (2 tailed)		0.355
	N	103	103

dHFS	Pearson Correlation	0.092	1
	Sig. (2 tailed)	0.355	
	N	103	103

The Pearson correlation coefficient is significant for transformed steel demand data (dSD) and Brent crude oil price (dBCOP) at 0.67 in table 29 on top while the transformed data for hydraulic fracturing sand (dHFS) Pearson correlation coefficient is 0.092 in table 30 above.

4.6.5.2 Empirical Results of Transformed First Difference Horizontal Rig Demand and Brent crude oil price

Table 31 First Difference Horizontal Rig Demand Dependent Variable Model Criteria

Model	Variables Entered	Variables Removed	Method
1	dBCOP[b]		Enter

a. Dependent Variables: dHRD

b. All requested variables entered.

Table 32 Model Summary First Difference Horizontal Rig Demand Dependent Variable

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	0.128[a]	0.016	0.007	63.62562

a. Predictors (Constant), dBCOP

Table 33 ANOVA[a] Results with dHRD Dependent Variable

Model	Sum of Squares	df	Mean Squares	F	Sig.
Regression	6787.01	1	6787.01	1.677	0.198[b]
Residual	408870.216	101	4048.22		
Total	415657.226	102			

a. Dependent variable: dHRD

b. Predictors: (Constant), BCOP

Table 34 Coefficients[a] of Determination with dHRD as Dependent Variable

Model	Unstandardized Coefficients		Standardized Coefficients	t	Sig
	B	Std. Error	Beta		
1 (Constant)	3.425	6.272		0.546	0.586

dBCOP	0.875	0.676	0.128	1.295	0.198

a. Dependent variable: dHRD

As demonstrated by the regression result above, it is estimated that each US$1 rise in Brent crude oil price results in about a 0.9 rise in Horizontal rig demand/activity.

4.6.5.3 Empirical Results of Transformed First Difference Vertical Rig Demand and Brent Crude Oil Price

Table 35 First Difference Vertical Rig Demand Dependent Variable Model Criteria

Model	Variables Entered	Variables Removed	Method
1	dBCOP[b]		Enter

a. Dependent variable: dVRD

b. All requested variables entered

Table 36 Model Summary First Difference Vertical Rig Demand Dependent Variable

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	0.183[a]	0.033	0.024	70.83811

a. Predictors: (Constant), dBCOP

Table 37 ANOVA[a] Results with dVRD Dependent Variable

Model	Sum of Squares	Df	Mean Square	F	Sig.
1 Regression	17466.066	1	17466.066	3.481	0.065[b]
Residual	506821.817	101	5018.038		
Total	524287.883	102			

a. Dependent Variables: dVRD

b. Predictors: (Constant), dBCOP

Table 38 Coefficients[a] of Determination with dVRD as Dependent Variable

Model	Unstandardized Coefficients		Standardized Coefficients	T	Sig.
	B	Std. Error	Beta		
1 (Constant)	-7.313	6.983	0.183	-1.047	0.297
dBCOP	1.404	0.753	0.753	1.866	0.065

a. Dependent variable: dVRD

The coefficient of correlation in the model summary shown above is 0.183, while the coefficient of determination is 0.33. The correlation is not significant. Furthermore, the F ratio is 3.481 significant at p<0.7. The empirical model derived indicates that for every US$1 increase in Brent Crude Oil Price, there is a 1.404 increase in vertical rig demand.

4.6.5.4 Empirical Results of Transformed First Difference Steel Demand and Brent crude oil price

Table 39 First Difference Steel Demand Dependent Variable Model Criteria

Model	Variables Entered	Variables Removed	Method
1	dBCOP[b]		Enter

a. Dependent variable: dSD

b. All requested variables entered.

Table 40 Model Summary First Difference Steel Demand Dependent Variable

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	0.674[a]	0.455	0.449	8.87615

a. Dependent Variable: dSD

b. Predictors (Constant), dBCOP

Table 41 ANOVA[a] Results with dSD Dependent Variable

Model	Sum of Squares	df	Mean Squares	F	Sig.
Regression	6631.792	1	6631.792	84.175	0.000[b]
Residual	7957.388	101	78.786		
Total	14589.180	102			

Table 42 Coefficients[a] of Determination with dSD as Dependent Variable

Model	Unstandardized Coefficients		Standardized Coefficients	T	Sig
	B	Std. Error	Beta		
1 (Constant)	0.486	0.875		0.555	0.580
dBCOP	0.865	0.094	0.674	9.175	0.000

The coefficient of correlation the model summary shown above 0.183, while the coefficient of determination is 0.33. The correlation is not significant. Furthermore, the F ratio is 3.481 significant at p<0.7. The empirical model derived indicates that for every US$1 increase in Brent Crude Oil Price there is a 1.404 increase in vertical rig demand.

4.6.5.5 Empirical Results of Transformed First Difference Hydraulic Fracturing Sand Demand (dHFSD) and Brent crude oil price

Table 43 First Difference First Difference Hydraulic Fracturing Sand Demand Dependent Variable Model Criteria

Model	Variables Entered	Variables Removed	Method
1	dBCOP[b]		Enter

a. Dependent Variables: dHFSD

b. All requested variables entered

Table 44 Model Summary First Difference Hydraulic Fracturing Sand Demand Dependent Variable

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	0.092[a]	0.008	-0.001	15.02388

Table 45 ANOVA[a] Results with dHFSD Dependent Variable

Model	Sum of Squares	df	Mean Squares	F	Sig.
Regression	194.500	1	194.500	0.862	0.355[b]

Residual	22797.410	101	225.717		
Total	22991.910	102			

Table 46 Coefficients[a] of Determination with dHFSD as Dependent Variable

Model	Unstandardized Coefficients		Standardized Coefficients	T	Sig
	B	Std. Error	Beta		
1 (Constant)	-0.408	1.481		-0.275	0.784
dBCOP	0.148	0.160	0.092	0.928	0.355

a. Dependent Variables: dHFSD

The model summary results above in table 40 show a 0.128 coefficient of correlation and coefficient of determination of 0.016; the empirical model does not consider the correlation significant based on the data input for transformed horizontal rig demand and Brent crude oil price. The f ratio is given as 1.68 and significant at p < 0.3.

The demonstrated model results above for the correlation coefficient is 0.92, while the coefficient of determination is 0.008. Resultant F-ratio is 0.862 which is significant at p<0.3. Overall, the empirical model states that a US$1 rise in Brent crude oil price results in a 0.148 in hydraulic fracturing sand index.

The resultant empirical models in equation form are illustrated below:

Transformed (BCOP & HRD) ….Equation 31

Transformed (BCOP & VRD) ….Equation 32

Transformed (BCOP & SD) …...Equation 33

Transformed (BCOP & HFS) ….Equation 34

4.7 Discussion

The unconventional development cost analysis commenced with the use of disaggregated data from Kaiser and Yu (2015). The comprehensive cost analysis suggests that the significant well development costs are 30 % sand and stimulation based, 13 % drilling and 10% casing (Figure 20). The result of a decomposed cost analysis focusing on drilling operations is highlighted in figure 20, which reveals that the costs of casings and drilling rigs represent the major cost parameters in developing unconventional resources. A further similar analysis focused on the completion phase of development shows that the principal expense is the water, sand, and stimulation (Hydraulic Fracturing Process) in figure 21. These results are consistent with a recent study by the US Energy Information Administration (USEEIA, 2016) focusing on the trends in US oil and natural gas upstream costs focusing on four unconventional resource plays.

Aguilera (2014) identifies that oil and gas costs can be affected by geological conditions, depth of accumulations, regulatory environments, and project lengths. The analysis (Figures 20,21 & 22) shows the cost component but does not incorporate the following factors that impact development costs; rig specification, reservoir porosity/permeability, and speed. In addition, reservoir depth and heterogeneity of unconventional gas reservoirs need to be considered. The USEIA 2016 study states that changes in development cost can also be attributed to changes in well and completion design leading to variations in primary cost drivers. The cost of drilling unconventional wells is correlated to formation depth, while completion depends linearly on the amount of water and proppant used (Sand and stimulation costs).

Consequently, in estimating the cost of unconventional gas production, this study applies a bottom-up approach based on work breakdown and activity cycles. Equation 18 focuses on the cost of drilling, while equation 20 estimates the cost of completion. Additionally, a material cost equation is introduced to account for water and other materials. Equation 18 addresses the drilling rate via the rate of penetration (ROP); the ROP addresses the type of rig applied and geological conditions of the reservoir. Additionally, the rig rate accounts for rig specification, which differs based on type and demand for rig activity. Kaiser (2007) identifies the formation geology as an essential factor along with the well characteristics such as drilling bit type. The developed drilling and completion cost functions in equations 18 & 20 address the essential cost components and parameters that affect the cost of developing unconventional gas wells as such, providing a bottom-up cost estimation approach. The total well construction cost is shown to be highly related to measured depths while drilling cost is associated with vertical and measured depth; similarly, completion costs correlate with horizontal displacement (Kaiser and Yu, 2015).

The expense breakdown, as well as the cost estimation functions reveals critical production inputs. Asides the well characteristics, other factors affect the costs of developing oil and gas wells. The difference between natural gas production from conventional and unconventional sources is the use of horizontal drilling and hydraulically fracturing the source rock. As rig rates will differ between types, regions, and technology, the rig demand index provided by Baker Hughes is decomposed into vertical and horizontal wells demand. In addition to drilling, casing expenses forms an essential part of overall drilling expenses. Consequently, the steel and iron demand index is applied as a proxy for steel prices. Finally, the significant completion cost is the hydraulic fracturing represented in this analysis by stimulation sand demand index.

All these indices are all manipulated into quarterly time series over 25 years (1991-2016) based on various indices and Brent crude oil prices. The descriptive statistics in Table 8 displays the statistical characteristics of the variables over the time frame. An examination of the model summary in sections (4.6.4.(1-4)) shows a significant correlation relationship between BCOP, steel, hydraulic stimulation sand, and horizontal rig demand. However, vertical rig demand shows a very weak correlation with BCOP. However, the empirical results may be due to spurious regression due to stationarity.

Additionally, due to manipulation involving converting daily or monthly data into quarterly data, the averaging is known to dampen the fluctuations in the monthly data (Hilmer and Hilmer, 2013). Consequently, the data are transformed using the first difference method expressed in equation 29 & 30. The resultant model summary in section 4.6.5.1 indicates no significance in the relationship between BCOP, horizontal drilling activity, vertical drilling demand, and hydraulic fracturing sand. However, the steel demand correlation coefficient remains significant in this transformed data scenario.

The resultant empirical equations 31-34 express the impact of a US$1 increase in Brent crude oil price on the production inputs (dependent variables) for shale oil and gas production, steel demand, horizontal and vertical rig demand, as well as steel demand. The equations are oil price relationships with unconventional shale resource development cost indicators, the "oprurci" model. However, caution is advised in applying the model universally due to varying macroeconomic factors and thus probable impact on dependent and independent variable correlation, coefficient of determination, and thus resultant model characteristics.

4.8 Conclusion

This chapter begins with defining cost about this study, focusing on the capital cost of developing a petroleum resource. The cost structure literature in petroleum economic appraisal is review; dynamic cost modelling, which accounts for uncertainty, is suggested. Consequently, a cost analysis is conducted, which identifies relevant parameters. The most relevant cost parameter in shale gas production is the cost of hydraulic fracturing, which relies on sand water, the simulation technology, and other chemicals and additives. The drilling and casing costs also have a high impact on the development cost. Additionally, based on the established work breakdown structure and the technology currently applied in developing shale resources, a cost estimation model is developed for shale resource development stages.

However, as highlighted in the literature reviewed, the relevant cost parameters vary over time due to uncertainty. The 25-year time trend for the cost parameter proxies is presented as descriptive statistics and Brent crude oil prices; previous studies state that oil price uncertainty has a significant impact on production cost fossil fuel technologies due to the correlation between production cost and oil price. An econometric analysis of the real data and transformed data reveals two different results. The untransformed data reveals a high correlation between oil prices and other cost parameters except with vertical drilling prices, while the transformed data shows an insignificant correlation in most cost parameters except steel prices. Overall, the econometric model also reveals the relative impact of US$1 increase in oil prices (BCOP) on all cost parameters. The insignificant correlation of cost parameters with oil prices suggests that additional factors need to be analysed. These results suggest that the market oil price impact on shale gas production cost, although important, might be restrained by other factors which may include financial revenue hedging programs aimed at securing higher revenues or endogenous efficiency gains which direct production strategy in low oil prices situations.

5 The Impact of Efficiency Gains on Shale Resource Development Cost

5.1 Introduction

This chapter aims to estimate efficiency gains in shale resource production over the last decade. In doing this, the approach to the production technology and historical production addressed in chapter 3 and cost parameters and production phases are highlighted in chapter 4. Thus, combining costs and production data to review empirical progression based on technological advancement, endogenous circumstances, or production approach over time.

This analysis commences by reviewing the learning curve theory in section 2, summarizing learning curve applications to energy production technology in section 3 while proposing a new approach in section 4. Data from US located shale production plays are applied in section 4. Finally, the results are discussed in section 5 and the conclusion drawn in the last section.

5.2 Learning Curve Theory

Cost decline and performance improvements through technological progress are essential considerations in energy system design, evaluation, and policy decision making (Nakata et al., 2011 and Nemet 2006). The learning curve theory was developed empirically by Wright's 1936 study observing the decline of assembly costs in airplanes due to task repetitions (Anzanello and Fogliatto, 2011). Also referred to as experience curves, learning curves are characterized by cost reduction by a constant percentage with a two-fold increase in the total number of units produced (Neij, 1997). Learning effects are due to accumulated experience over time, which results in reduced labour input required to produce a given level of output, process management improvements due to modified work task assignment, and technical progress due to application repetition (Berglund and Soderholm, 2006). The repetitive use enables adoption, which involves advancing the technology from one developmental stage until maturity (Kahouli-Brahmi, 2009). Thus, the learning curve theory states that unit costs decrease by a constant percentage called the learning rate for each doubling of experience (McDonald & Schrattenholzer; 2000, Neij; 1997, Junginger et al., 2010). A typical learning curve reveals the observed relationship between costs and accrued production or capacity from a technological system (Ibenholt; 2002, Rout et. al.: 2009) and operationalizes the explanatory variable experience applying a cumulative degree of production or use exhibited most notably in the log-linear function (Nemet, 2006).

The learning curve model is numerically expressed as follows:

$$\boldsymbol{SC = a * \left(cc^{-b}\right)} \quad \textbf{Equation 35}$$

Log-linearly presented as

$$\boldsymbol{log(SC) = \log(a) + (-b) * \log(CC)} \ \textbf{Equation 36}$$

Where *SC* is the specific cost; Cost per unit capacity (normalized by an indicator of performance). *"a"* represents the unit-specific cost once the cumulative production output attains unit value; *CC* is the cumulative production capacity at any time *(t)* while –*b* is the main parameter and exponent defining the slope of a power function.

The Progress Ratio *(PR)*, which is used to specify the cost reduction over time is:

$$\boldsymbol{PR = 2^{-b}} \quad \textbf{Equation 37}$$

And the overall learning rate (LR)

$$\boldsymbol{LR = (1 - PR)} \textbf{ Equation 38}$$

The characteristics of the learning curve model in equation 35 and addressed in Nemet (2006); are based on the empirical time series of the experience via production and unit cost. However, discontinuities in learning rates are not incorporated and uncertainty accounting applying empirical variance between cost and cumulative capacity, which might change in the future. Finally, the study also notes that due to the theory's application in planning and forecasting, the model assumes knowledge spillovers among firms in the same industry while also identifying that the only determinant of cost reduction is cumulative capacity, whereas other factors might impact cost reduction. This suggests that the empirical procedure might be biased due to the omitted variable(s) bias. The methodology in equation 35 is termed the one/single factor learning model due to the only variable/factor.

The other factors that can impact the rate of learning are; research and development funding, technology pull policies, change in input prices due to spillovers from suppliers' market, economies of scale, and technology-specific variables (Ibenholt, 2002; McDonald and Schrattenholzer, 2001).

The introduction of a second variable in learning curve modelling is termed; the two-factor learning curve. The most frequently introduced variable in the two factors learning method is the impact of research and development (R&D), which aims to incorporate the knowledge stock into the model. The theory stipulates that cost reduction over time is a factor of more production and investments in research that aids efficiency. The R&D two-factor learning curve is highlighted in studies by Klaasen et al., (2005); Rout et al., (2009) & Jamasb (2006). Rout et al., 2009 show R & D's potential contribution to the learning sphere theory, identifying the factor as significant, meaningful, and relevant. Jamasb (2006) finds that capacity addition and R & D are significant independent variables in the learning curve theory. Klassen et al. (2005) suggests that a learning curve incorporating the R&D factor presents a great potential to influence the impact appraisal of R&D expenses on technology costs. The model is defined thus:

$$\boldsymbol{SC = a * \left(CC^{-b}\right) * (KS^{-c})}$$ **Equation 39**

$$\boldsymbol{PR(lbd) = 1 - LR(lbd) = 2^{-b}}$$ **Equation 40**

$$\boldsymbol{PR(lbs) = 1 - LR(lbs) = 2^{-c}}$$ **Equation 41**

Where *SC* is the specific cost per unit of capacity; *a* is the unit-specific cost with cumulative capacity, and R&D expenses reach unity; *CC* refers to cumulative capacity at the point *–b;* the learning by doing *(lbd)* elasticity; *-c* the learning by searching *(lbs)* elasticity. *PR (lbd)* and *PR (lbs)* are the progress ratios for learning by doing and learning by searching. The impact of *lbs* plays a more critical factor during a technology's innovation stage (Pan & Kohler (2007). The impact of a technology's developmental stage also correlates with the factor affecting its learning curve. Kahouli-Brahmi (2009) states that at the emerging, evolving, and mature stages, technology is impacted more by diseconomies of scale, capacity expansion, and R&D, and return to scale, respectively. However, the application of the two-factor learning curve depends on the availability of research funding data. NRC (2010) and Wiesenthal et al. (2010) mention that private and public R&D costs are needed in two-factor learning models; however, private R&D investment data are not made available to the public. Rubin et al. (2015) stipulates that the difficulty of data acquisition for R & D limits applying the two-factor model in technology adoption.

5.3 Energy Technology Learning Curves

Nevertheless, different industries have applied various types of learning curves. Wright (1936) develops and applies learning curves to the aviation industry, focusing on aeroplane manufacturing. Learning curves were applied to the appraisal of service companies by Chambers and Johnston (2000), manufacturing by Roth et al., (2010), consumer goods by Teng and Thompson (1996), clean coal technologies by Nakata et al., (2011) and to US Iron & Steel sector by Karali et al., (2017). The learning curve theory (one and two factors) has been applied in the energy industry. Neij (1997) applies experience curves to analyse the potential for renewable energy technology (PV modules and Wind turbines adoption against conventional power plants (Coal to Gas, Gas-fired, Nuclear, and Hydroelectric plants). Neij (1999), Klassen et al. (2005), and Ibenholt (2002) focus on the cost dynamics and learning curves of Windpower, Zhao (2000) on the development of international Gas transmission lines. Nemet (2006) uses the methodology to investigate factors impacting cost reduction in photovoltaic technology, while Huenteler et al. (2014) compares local and global learning impacts of renewable energy in Thailand. Soderholm and Sunderqvist (2007) model the impact of cost reduction on renewable energy technologies in four western countries using learning rates while Isoard and Soria (2001) compare the learning rates of Photovoltaic and Wind (Both renewable energy sources. Rubin et al., (2015) reviews power plant learning rates; coal-based, natural gas-fired, nuclear, hydro, wind (onshore and offshore), solar photovoltaic, biomass and Geothermal; Brahmi (2009) and Jamasb (2006) also apply the methodology to power production energy technologies

Overall, the application reveals depth in the application of the learning curve method in energy technology appraisal. However, there is limited research concerning oil and gas production. The learning curve's relevance in both bottom-up and top-down energy technology assessment is not doubtful. McGlade (2012) notes that the learning curve is an essential factor in oil and gas cost analysis. McDonald and Scrattenholzer (2001) identify the use of a learning curve approach in Blackwood (1997) and Fisher (1974) to crude oil production cost; 25% learning rate for the North Sea region and 5% for United States cumulative production, respectively. These results suggest geological and location impact. Additionally, while the North Sea data is attributable to offshore production, the United States might contain all production types, which does not correlate with the theory, a technology learning curve.

5.4 Unconventional Oil and Gas Efficiency Gains

A 2019 study by the Council of Economic Advisers (CEA) on the value of US energy innovation and policies supporting the Shale revolution finds that from 2007 to 2019 innovation in shale production techniques has brought an eight-fold increase in extraction productivity for natural gas and a nineteen for oil; productivity gains. The well productivity gains are associated with shale operator's logistics optimization, well configuration leading to ever-longer lateral lengths and higher proppant loads, leading to more significant volumes from fewer wells in Eagle Ford and Permian shale plays. Besides, impressive drilling gains and average drill days per well (Patel & Vaucher, 2018). Melodie et al. (2017) studies the historical development and outlook of shale gas production costs, highlighting that technological parameters play a significant role by enabling to reduce costs directly or by contributing to improving the performance and production of the well lowers the well's unit cost. About unconventional hydrocarbon resources, Mejean and Hope (2008) model the cost of Canadian bitumen estimating a 42% learning rate. The study considers the resultant learning rate high compared to other technologies and thus attributes the elevated value to previous learning from similar technologies, an unaccounted spillover effect. In a 2017 study, Fukui et al. conclude that the US shale gas industry's basis for learning curves needs to be further studied to determine the drivers. Rubin et al. (2015) suggest improving learning curve modelling by incorporating better; data, econometric approaches that consider other factors that influence technology change, technology decomposition to hedge against spillover effects, other cost components with varying properties, and finally,,, geographic criteria. West (2019) assesses the shale industry's innovation based on technical papers from 2018 to 2019, and the studies imply continued productivity gains with innovation ongoing in enhanced oil recovery, digital instrumentation, machine learning, and advanced modelling.

5.5 An Alternative Learning Curve

A single technology unique learning curve is not proper; instead of learning, rates can be context-dependent and driven by model specification, variables, aggregation level, and time (Jamasb, 2006). This study proposes a new approach in estimating learning curves, which accounts for geological/location-specific factors, spillover effects from applied industries by applying a disaggregated approach suitable to Shale hydrocarbon but applicable to other industries.

About cumulative production *"CC"* in equation 35 above, the impact of technology displacement and industry demand is not incorporated in the present form. As such current analysis might suggest an increase in cumulative production while demand for the product has increased but supplied by other technologies. For instance, if the cumulative installed capacity of electricity generated from offshore wind in a region grows from 3,000MW to 3,5000MW within a time frame however the total cumulative capacity of electricity generated from all electricity generation technologies increases from 40,000MW to 55,000MW within the same time frame, the learning curve calculated without recognizing other technologies production as well as overall production could overstate the technologies advancement, learning curve and lock-in. Berglund & Soderholm (2006) notes that bottom-up models with endogenous learning do not readily account for technology diffusion. The technology diffusion stages are noted as emerging, evolving, and mature (Kahouli-Brahmi, 2009), identifying the stages based on correlation values. This study proposes that in the learning curve of technology, the production volume is a factor of total products in the macroeconomic, with the production volumes increasing as the technology moves from emerging, evolving, and finally mature. Spence (1981), Bhattacharya (1984) reported that the learning curve eventually creates entry barriers and protection from competition by conferring cost advantage on early entrants and those who achieve a large market share. As such, market share is a better indicator for technology advancement or adoption and a factor for consideration in cumulative production. The application of the cost and production theories above can be referred to as a multiple factor disaggregated technology diffusion cost curve.

5.6 Application to Shale Hydrocarbon Production

The cost analysis of shale gas production in chapter 4 already identifies the key cost parameters and the work breakdown structure; both can be used further to aggregate the cost component of the learning curve. The applied sub-sectors are drilling and Hydraulic stimulation.

Drilling technology Specific cost trend equation:

$$\boldsymbol{Rig\ Specific\ Cost = DC/F_{t} + DC/F_{t+1} + DC/FR_{t+2} + RDC/F_{t+n}}$$

Equation 42

Where DC/F= Drilling Cost per Feet (applicable to both horizontal and vertical rigs) *t* is a timeframe (Months or Years)

Hydraulic Stimulation Technology Specific cost trend equation:

$$\boldsymbol{Hydraulic\ Stimulation\ Specific\ Cost = \sum_{t1\ldots tn} SSV}$$ **Equation 43**

SSV= is the stimulation sand volume applied as a proxy for cost; an alternative scenario is using the stimulation sand price index (SSPI).

On production for the drilling segment, this can be analysed by the rate of penetration (ROP); as technology improves, the rate of penetration should increase. Consequently, for Hydraulic stimulation, the production index is hydrocarbon production due to completion of the well as sand is used in the stimulation process, which leads to hydrocarbon production.

The production equation for the three technologies applied is

$$\frac{Vertical}{Horizontal} Driiling\ Cummulative\ Capacity = \quad ROP_t + ROP_{t+1} + ROP_{t+2} \ldots \ldots .. ROP_{t+n} \quad \textbf{Equation 44}$$

Where ROP is the rate of penetration; t is the time in months/year

$$Hydraulic\ Fracturing\ Adoption\ Cummulative\ Production\ \ Capacity = (\frac{sp}{tp})_t + (\frac{sp}{tp})_{t+1} + (\frac{sp}{tp})_{t+2} + (\frac{sp}{tp})_{t+n} \quad \textbf{Equation 45}$$

Here sp is the production from shale; tp is overall industrial production,

$$TACPC = \quad \frac{sp}{tp} \ \textbf{Equation 46}$$

The technology adoption cumulative production capacity (TACPC) is the introduced parameter that accounts for a specific technology’s production within an industry or sector. The TACPC measures adoption by recognizing that production from a given technology is a fraction of the overall production of goods by all operational technologies in the sector.

5.6.1 Resultant Overall Technological Change Model

The learning curve theory expressed in equation 35 to 38 above is thus applied to the identified technologies below by combining equation 42 and 43 for the drilling technologies (Horizontal and Vertical) and then for the hydraulic fracturing technology (Well completion) which results in hydrocarbon production equation 44 to 46; combined to estimate the:

I.Drilling Technology Learning Curve Equations

$$\boldsymbol{DC/F = a * \left(ROP^{-b}\right)} \quad \textbf{Equation 47}$$

Log-linearly presented as

$$\boldsymbol{log(DC/F) = \log(a) + (-b) * \log(ROP)} \quad \textbf{Equation 48}$$

II.Hydraulic Fracturing Learning Curve Equations

$$\boldsymbol{SSV = a * \left(ACPC^{-b}\right)} \quad \textbf{Equation 49}$$

Log-linearly presented as

$$\boldsymbol{log(SSV) = \log(a) + (-b) * \log(ACPC)} \quad \textbf{Equation 50}$$

The overall learning elasticity *"b"* for unconventional hydrocarbon production is estimated by applying the weighted cost contribution previously revealed in chapter 4 of this study. Finally, the progress and overall learning rates are determined based on equations 37 and 38 above, respectively.

5.7 Data

Based on the proposed learning theory in this chapter, the following data are required to estimate unconventional hydrocarbon progress rate.

I.Cost:

Drilling Cost; Drilling Cost per Feet (Vertical & Horizontal)

Source: USEIA (2016)

Hydraulic Fracturing Cost.

Option 1: Stimulation Sand Volume

Source: USEIA (2016)

II. Cumulative Capacity

Drilling Cumulative Capacity; Rate of Penetration

Source: USEIA (2016)

Technology Adoption Cumulative Production Capacity

Hydraulic Stimulation Cumulative Capacity; Unconventional Well production

Source: USEIA Monthly Rig Productive Report

Overall industry cumulative production

Source: USEIA Crude Oil Domestic Production (US Data)

5.7.1 Disaggregation

The diverse nature of shale reservoirs is a significant characteristic highlighted in chapter 3 of this study concerning production profiles. The variance in geological conditions in different shale plays is expected to impact technical efficiency. The cost difference might be associated with different operators using different sand type mixtures and volumes and the impact of permeability of rocks that vary drilling speed and thus expense in various shale plays. The US Energy Information Administration's drilling productivity report is a monthly account that includes data on prominent shale plays in the United States.

5.7.2 US Unconventional Oil and Gas Plays

Shale resources in the United States produce both oil and gas. The oil from shale rock in the United States is termed tight oil. As of 2019, the major tight oil plays were

Permain, Bakken, and Eagle Ford, which provided 48%, 18%, and 16% of total tight oil production in the United States. The Bakken play in North Dakota, and eastern Montana was the first significant tight oil development while the Eagle Ford play in southern Texas ascended from producing less in 2008 to become the most extensive tight oil play by March 2015 (its peak) then again the Permian play of northwest Texas and southeast New Mexico is a vast oil-producing region with the most productive wells in Delaware and Midland basins. Shale gas, shale gas predominantly produced from the Barnett shale, Eagle Ford, Marcellus, and Utica plays with associated gas from the Permian shale play. The data presented include rig counts, production per rig and drilled but uncompleted (DUC) well count for individual shale plays; Permian, Bakken, Eagle Ford, Haynesville, Marcellus, Niobrara, and Utica. The end of May 2017 rig distribution report by the USEIA is revealed in figure 26 below.

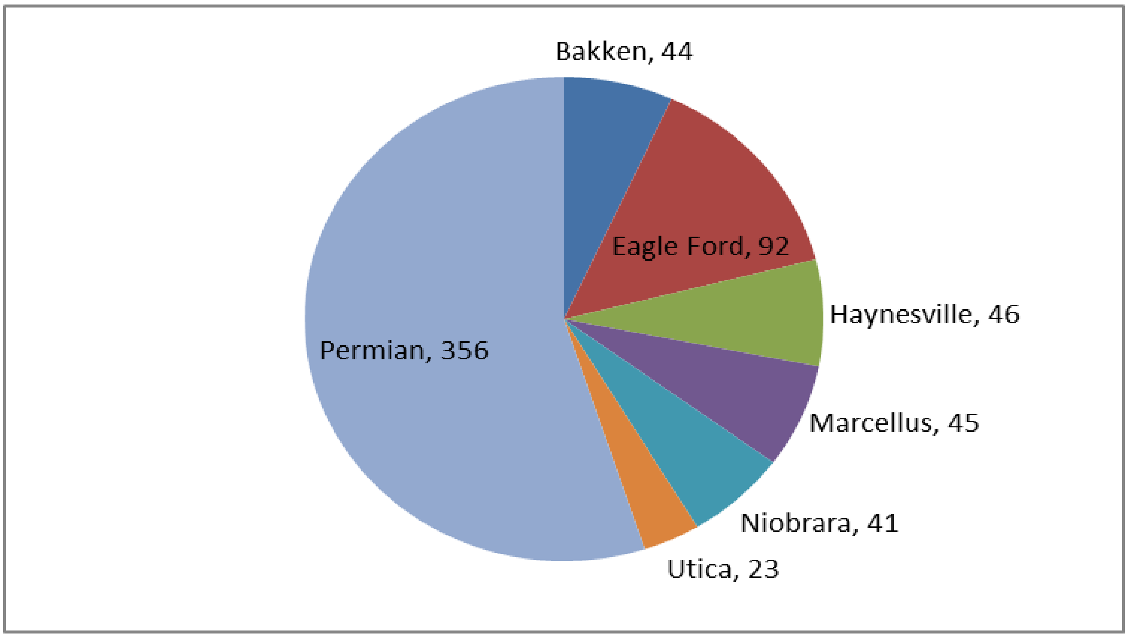


Figure 27 Rig Count by Shale Play (Source: USEIA, Drilling Productivity Report May 2017)

Consequently, the technological change study on £oil and shale gas plays applying micro-level data specified in equation 42-50. The data trend for each parameter on a micro-level is presented in figure 28-31 and then the technological change model developed.

5.7.3 Data Trends

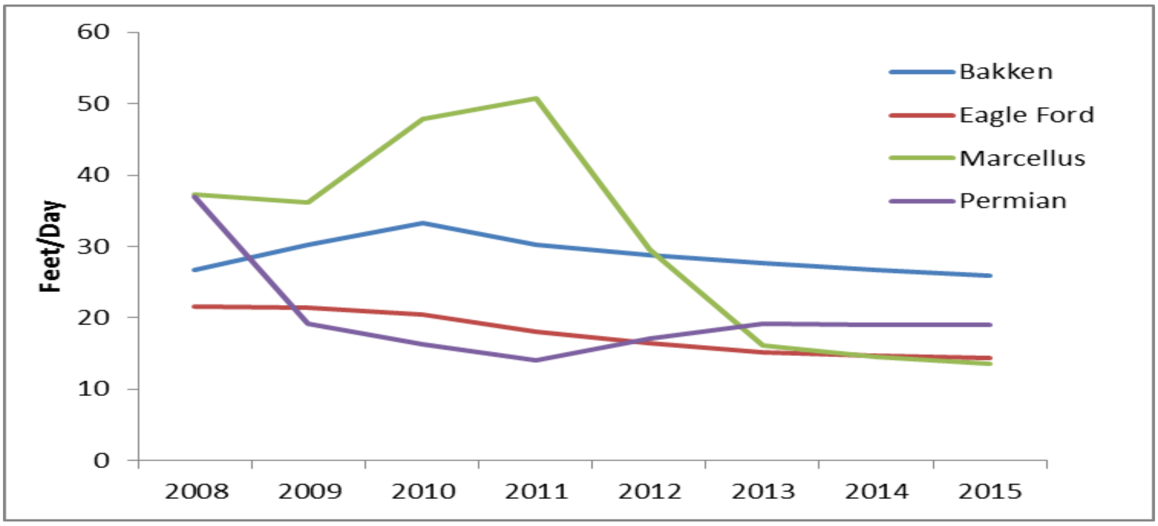


Figure 28 Rate of Penetration Trend by Rigs in the Major Shale Plays

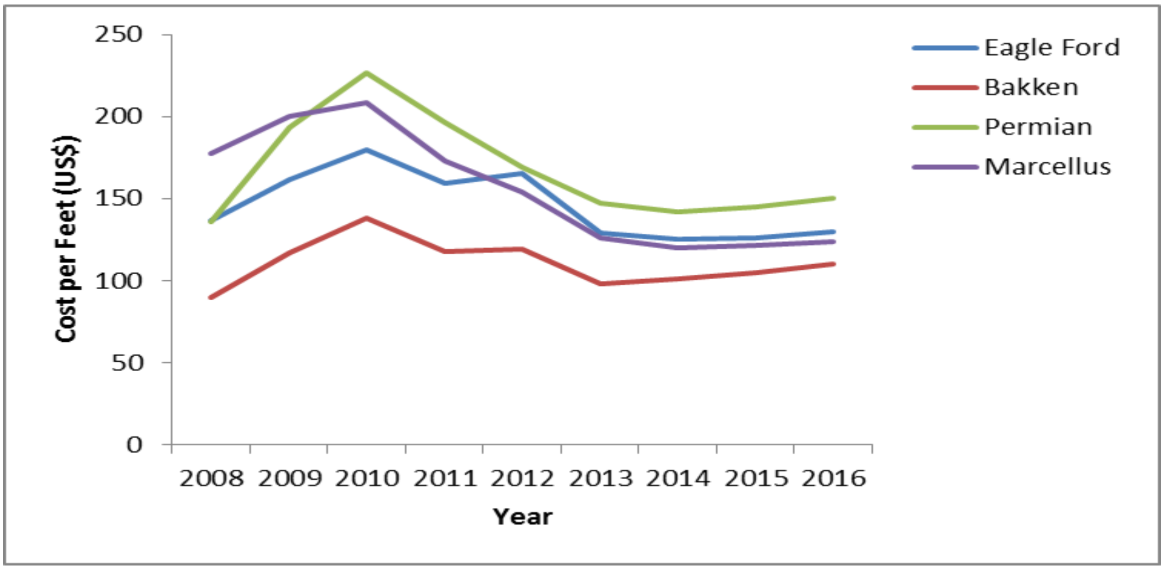


Figure 29 Drilling Cost Trend in the Major Shale Plays

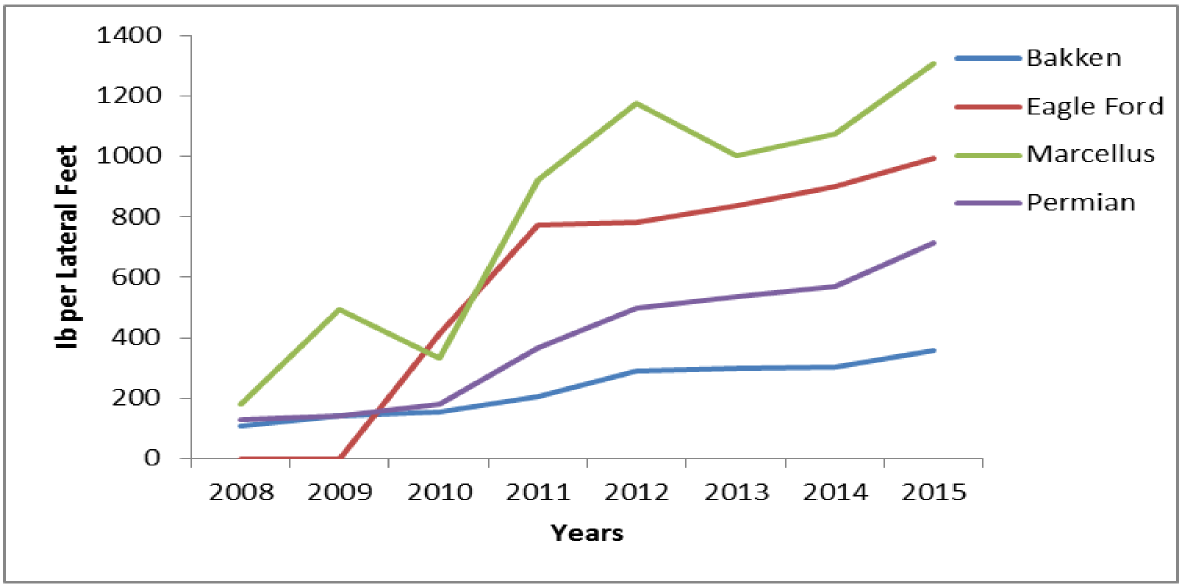


Figure 30 Liquid Load Trend during Hydraulic Fracturing in the Major Shale Plays

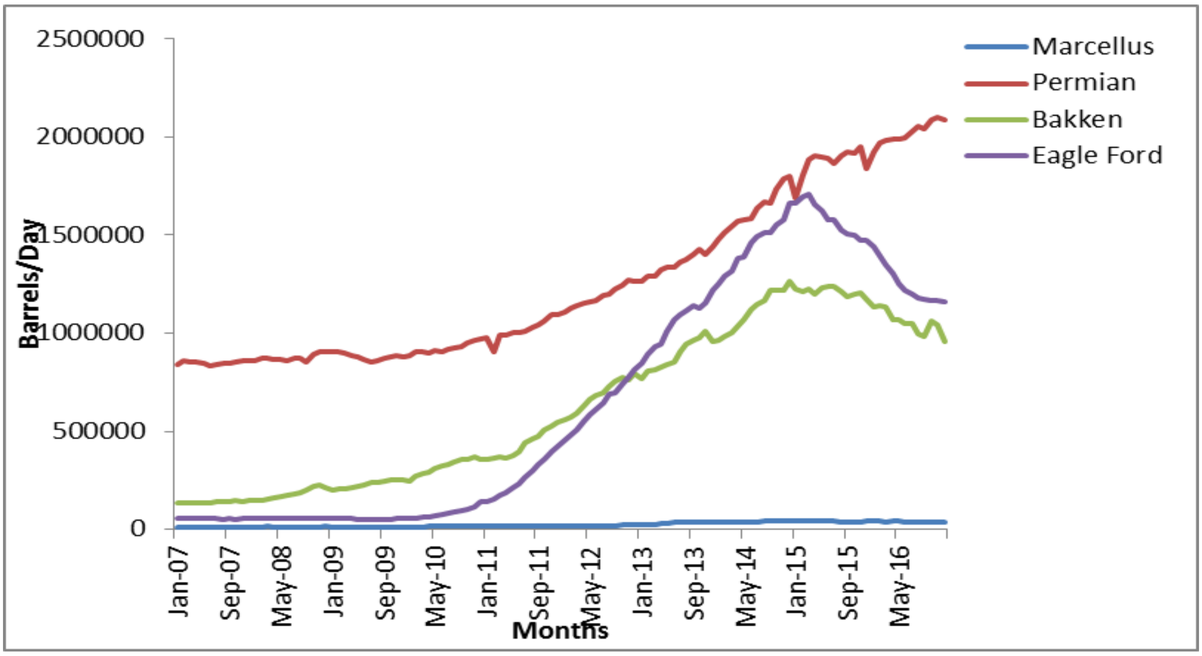


Figure 31 Production Volume Trend in the Major Shale Plays

5.8 Results

This section reveals the following results: subsection 5.7.1 focuses on the Eagle Ford play's drilling cost and efficiency, hydraulic fracturing proppant use/cost and production, and adoption to global oil demand based on the developed approach. The results for Bakken and Permian shale plays are revealed in section 5.7.2 and 5.7.3, respectively. The Marcellus shale is not included in this study.

The results are presented in three phases.

I. Drilling cost change as a dependent variable and efficiency measured as the rate of penetration change over 8years (2008-2015); equation 47.

II. Proppant Use change as a dependent variable and cost proxy against efficiency measured as the production rate change over 8years (2008-2015) not considering demand changes and as such Global production share (Adoption).

III. Proppant Use change as a dependent variable and cost proxy against efficiency measured as the production rate change over 8years (2008-2015) considering demand changes and as such Global production share (Adoption); equation 49.

5.8.1 Eagle Shale Play Technology Change Results

I. Drilling Cost change as a dependent variable and efficiency measured as the penetration rate over 8years (2008-2015); equation 48.

Table 47 Eagle Ford Shale Drilling Cost Dependent Variable Model Criteria

Model	Variables Entered	Variables Removed	Method

1	LogROP[b]		Enter

a. Dependent Variable: LogDrillingCost

b. All requested variables entered.

Table 48 Eagle Ford Shale Drilling Cost Dependent Variable Model Summary

Model	R	R Square	Adjusted R Square	Std. Error The Estimate
1	0.634[a]	0.402	0.302	0.05147

a. Predictors: (Constant), LogROP

Table 49 Eagle Ford Shale Drilling Cost Dependent Variable ANOVA

Model	Sum of Squares	df	Mean Squares	F	Sig.
Regression	0.011	1	0.011	4.026	0.092[b]
Residual	0.016	6	0.003		
Total	0.027	7			

a. Dependent Variable: LogDrillingCost

Table 50 Coefficient of Determination Eagle Ford Shale Drilling Cost Dependent Variable

Model	Unstandardized Coefficients		Standardized Coefficients	T	Sig.
	B	Std. Error	Beta		
`(Constant)	1.515	0.325		4.666	0.003
LogROP	0.523	0.261	0.634	2.007	0.092

a. Dependent Variable: LogDrillingCost

The R-value above (0.634) in the model summary table indicates that the penetration rate determines or impacts the drilling cost in the Eagle Ford shale play by 63%; 63% of the variation in drilling cost can be attributed to the rate of penetration. The analysis of variance (ANOVA) shows a p-value of 0.092 significant at the 0.1 level. The resultant regression model based on the coefficient result above is:

$$\mathbf{LogDrillingCost} = \mathbf{1.516} + \mathbf{0.523}\ (\mathbf{LogROP}) \quad \textbf{Equation 51}$$

An elasticity of 1.516 and 0.523 for capacity and learning respectively; applying equation 37 & 38 results in a 69% progress rate and thus a learning rate of about 31% over the timeframe.

II. Proppant Use change as a dependent variable and cost proxy against efficiency measured as the production rate change over 8years (2008-2015) not considering demand changes and as such global production share (Adoption).

Table 51 Eagle Ford Shale Proppant Use Dependent Variable Model Criteria

Model	Variables Entered	Variables Removed	Method
1	LogProduction[b]		Enter

a. Dependent Variables: LogProppantLF

b. All requested variables entered.

Table 52 Eagle Ford Shale Proppant Use Dependent Variable Model Summary

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	0.962[a]	0.925	0.913	0.05775

a. Predictors: (Constant), LogProduction

Table 53 Eagle Ford Shale Drilling Proppant Use Dependent Variable ANOVA

Model	Sum of Squares	Df	Mean Square	F	Sig.
Regression	0.248	1	0.248	74.393	0.000[b]

Residual	0.020	6	0.003		
Total	0.268	7			

a. Dependent Variable: LogProppantLF

b. Predictors (Constant), LogProduction

Table 54 Coefficient of Determination Eagle Ford Shale Proppant Use Dependent Variable

Model	Unstandardized Coefficients		Standardized Coefficients	T	Sig.
	B	Std. Error	Beta		
1 (Constant)	1.161	0.190		6.103	0.001
LogProduction	0.297	0.034	0.962	8.625	0.000

a. Dependent Variable: LogProppantLF

About the hydraulic fracturing process/technology at the Eagle Ford Shale play, the developed model summary shows 0.962 R-value. This suggests that about 96% of productivity/production is associated with the cost of stimulation using the proppant use volume as a proxy. Secondly, the ANOVA analysis a p-value of 0, which is statistically significant.

The model also presents the following equation:

$$\boldsymbol{LogProppant = 1.161 + 0.297\ (LogProduction)}$$ **Equation 52**

Equation 52 above reveals the elasticity of 1.161 and 0.287 for capacity and learning. The application of equation 37 & 38 yields a progress rate of 81% and 20% learning rate during the review period.

III. Proppant Use change as a dependent variable and cost proxy against efficiency measured as the production rate change over 8years (2008-2015) considering demand changes and as such Global production share (Adoption); equation 49.

Table 55 Eagle Ford Shale Proppant Use Dependent Variable Model Criteria Adoption Case

Model	Variable Entered	Variables Removed	Method
1	LogAdoption[b]		Enter

a. Dependent Variable: LogProppantLF

b. All requested variables entered

Table 56 Eagle Ford Shale Proppant Use Dependent Variable Model Criteria Adoption Case

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	0.961[a]	0.924	0.912	0.05812

a. Predictors: (Constant), LogAdoption

Table 57 Eagle Ford Shale Drilling Proppant Use Dependent Variable ANOVA Adoption Case

Model	Sum of Square	df	Mean Square	F	Sig.
Regression	0.248	1	0.248	73.367	0.000[b]
Residual	0.020	6	0.003		
Total	0.268	7			

a. Dependent Variable: LogProppantLF

b. Predictors: (Constant), LogAdoption

Table 58 Coefficient of Determination Eagle Ford Shale Proppant Use Dependent Variable Adoption Case

Model	Unstandardized Coefficients		Standardized Coefficients	T	Sig.
	B	Std. Error	Beta		
1 (Constant)	3.547	0.090		39.273	0.000
LogAdoption	0.306	0.036	0.961	8.565	0.000

a. Dependant Variable: LogProppantLF

The model summary results above in this scenario (Adoption Case) this instance reveals an R-value of 0.961 to proppant use/cost, production, and global demand. This suggests that 96% of proppant use drives shale resource adoption. The p-value under the ANOVA analysis is 0.000, which is considered statistically significant. The coefficients estimated by the developed model are represented in the equation below:

$$\boldsymbol{LogProppant = 3.547 + 0.306(LogAdoption)}$$ **Equation 53**

Applying equation 37 and 38 results in an 81% Progress Rate and 19% learning rate.

5.8.2 Bakken Shale Play Technology Change Results

I. Drilling Cost change as a dependent variable and efficiency measured as the penetration rate over 8years (2008-2015); equation 47.

Table 59 Bakken Shale Drilling Cost Dependent Variable Model Criteria

Model	Variables Entered	Variables Removed	Method
1	LogROP[b]		Enter

a. Dependent Variable: LOGDrillingCost

b. All requested variables entered.

Table 60 Bakken Shale Drilling Cost Dependent Variable Model Summary

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	0.881[a]	0.777	0.739	0.02997

a. Predictors: (Constant), LogROP

Table 61 Bakken Shale Drilling Cost Dependent Variable ANOVA

Model	Sum of Squares	Df	Mean Square	F	Sig.
1 Regression	0.019	1	0.019	20.850	0.004[b]
Residual	0.005	6	0.001		
Total	0.024	7			

a. Dependent Variable: LogDrillingCost

b. Predictors: (Constant), LogROP

Table 62 Coefficient of Determination Bakken Shale Drilling Cost Dependent Variable

Model	Unstandardized Coefficients		Standardized Coefficients	T	Sig.
	B	Std. Error	Beta		
1 (Constant)	-0.032	0.454		-0.069	0.947
LogROP	1.423	0.312	0.881	4.566	0.004

The developed model summary results in an R-value of 0.881, which indicates that in the Bakken Shale play, the penetration rate impacts 88% of the cost of drilling. The ANOVA also results in a statistically significant p-value of 0.004. Lastly, the created regression model is:

$$\boldsymbol{LogDrillingCost} = -\mathbf{0.032} + \mathbf{1.423}(\boldsymbol{LogROP})$$ **Equation 54**

Application of the progress and learning rate equations (Equations 37 & 38) yields 0.37 and 62%, respectively.

II. Proppant Use change as a dependent variable and cost proxy against efficiency measured as the production rate change over 8years (2008-2015) not considering demand changes and as such Global production share (Adoption).

Table 63 Bakken Shale Proppant Use Dependent Variable Model Criteria

Model	Variables Entered	Variables Removed	Method
1	LogProduction[b]		Enter

a. Dependent Variable: LogProppant

b. All requested variables entered

Table 64 Bakken Shale Proppant Use Dependent Variable Model Summary

Model	R	R Square	Adjusted Square	Std. Error of the Estimate
1	0.982[a]	0.965	0.959	0.03812

Table 65 Bakken Shale Drilling Proppant Use Dependent Variable ANOVA

Model	Sum of Squares	Df	Mean Square	F	Sig
1 Regression	0.240	1	0.240	165.239	0.000[b]
Residual	0.009	6	0.001		

Total	0.249	7			

a. Dependent Variable: LogProppant

b. Predictors: (Constant), LogProduction

Table 66 Coefficient of Determination Bakken Shale Proppant Use Dependent Variable

Model	Unstandardized Coefficients		Standardized Coefficients	T	Sig
	B	Std. Error	Beta		
1 (Constant)	-1.012	0.261		-3.882	0.008
LogProduction	0.586	0.046	0.982	12.855	0.000

a. Dependent Varaible: LogProppant.

The resultant R-value from the model summary in this scenario in the Bakken Shale play is 0.982 for the impact of proppant use on production and ANOVA p-value of 0.000, which is significant statistically. Lastly, the developed regression coefficients are detailed in equation 55 below:

$\boldsymbol{LogProppant = -1.012 + 0.586}(\boldsymbol{LogProduction})$ **Equation 55**

Consequently, the resultant progress and learning rate (equation 38 & 39) developed are 0.67 and 34% in that order.

III. Proppant Use change as a dependent variable and cost proxy against efficiency measured as the production rate change over 8years (2008-2015) considering demand changes and as such global production share (Adoption); equation 50.

Table 67 Bakken Shale Proppant Use Dependent Variable Model Criteria Adoption Case

Model	Variables Entered	Variables Removed	Method
1	LogAdoption		Enter

a. Dependent Variable: LogProppant

b. All requested variables entered

Table 68 Bakken Shale Proppant Use Dependent Variable Model Criteria Adoption Case

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	0.983[a]	0.967	0.961	0.03725

a. Predictors: (Constant), LogAdoption

Table 69 Bakken Shale Drilling Proppant Use Dependent Variable ANOVA Adoption Case

Model	Sum of Squares	Df	Mean Square	F	Sig.

1 Regression	0.241	1	0.241	173.332	0.000[b]
Residual	0.008	6	0.001		
Total	0.249	7			

a. Dependent Variable: LogProppant

b. Predictors: (Constant), LogAdoption.

Table 70 Coefficient of Determination Bakken Shale Proppant Use Dependent Variable Adoption Case

Model	Unstandardized Coefficients		Standardized Coefficients	T	Sig.
	B	Std. Error	Beta		
1 (Constant)	3.724	0.106	0.983	35.002	0.000
LogAdoption	0.620	0.047		13.166	0.000

a. Dependent Variable: LogProppant

R-Value's adoption consideration case about proppant use and technology adoption is 0.983; the proppant use volume impacts 98% of shale gas production and adoption. The ANOVA results in a 0.000 p-value. Consequently, the regression model/equation is expressed below:

$$\boldsymbol{LogProppant = 3.724 + 0.62(LogAdoption)}$$ **Equation 56**

The progress and learning rate are estimated as 0.65 and 34% correspondingly based on equation 37 & 38.

5.8.3 Permian Shale Play Technology Change Results

I. Drilling Cost change as a dependent variable and efficiency measured as the penetration rate over 8years (2008-2015); equation 47.

Table 71 Permian Shale Drilling Cost Dependent Variable Model Criteria

Model	Variables Entered	Variables Removed	Method
1	LogROP		Enter

a. Dependent Variable: LOGDrillingCost

b. All requested variables entered.

Table 72 Permian Shale Drilling Cost Dependent Variable Model Summary

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	0.626[a]	0.392	0.291	0.06845

a. Predictors: (Constant), LogROP

Table 73 Permian Shale Drilling Cost Dependent Variable ANOVA

Model	Sum of Squares	df	Mean Square	F	Sig.
1 Regression	0.018	1	0.018	3.875	0.097[b]
Residual	0.028	6	0.005		
Total	0.046	7			

a. Dependent Variable: LogDrillingCost

b. Predictors: (Constant), LogROP

Table 74 Coefficient of Determination Permian Shale Drilling Cost Dependent Variable

Model	Unstandardized Coefficients		Standardized Coefficients	T	Sig.
	B	Std. Error	Beta		
1 (Constant)	2.750	0.269		10.210	0.000
LogROP	-0.411	0.209	-0.626	-1.969	0.097

a. Dependent Variable: LogDrillingCost

II. Proppant Use change as a dependent variable and cost proxy against efficiency measured as the production rate change over 8years (2008-2015) not considering demand changes and as such global production share (Adoption).

Table 75 Permian Shale Proppant Use Dependent Variable Model Criteria

Model	Variables Entered	Variables Removed	Method
1	LogProduction[b]		Enter

a. Dependent Variable: LogProppant

b. All requested variables entered.

Table 76 Permian Shale Proppant Use Dependent Variable Model Summary

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	0.907[a]	0.822	0.792	0.13540

a. Predictors: (Constant), LogProduction

Table 77 Permian Shale Drilling Proppant Use Dependent Variable ANOVA

Model	Sum of Squares	df	Mean Square	F	Sig.
1 Regression	0.0507	1	0.507	27.659	0.002[b]

Residual	0.110	6	0.018		
Total	0.617	7			

a. Dependent Variables: LogProppant

b. Predictors (Constant), LogProppant

Table 78 Coefficient of Determination Permian Shale Proppant Use Dependent Variable

Model	Unstandardized Coefficients		Standardized Coefficients	T	Sig.
1 (Constant)	-10.395	2.455		-4.234	0.005
LogProduction	2.127	0.404	0.907	5.259	0.002

a. Dependent Variable: LogProppant

III. Proppant Use change as a dependent variable and cost proxy against efficiency measured as the production rate change over 8years (2008-2015) considering demand changes and as such global production share (Adoption); equation 49.

Table 79 Permian Shale Proppant Use Dependent Variable Model Criteria Adoption Case

Model	Variables Entered	Variables Removed	Method
1	LogAdoption		Enter

a. Dependent Variable: LogProppant

b. All requested variables entered

Table 80 Permian Shale Proppant Use Dependent Variable Model Criteria Adoption Case

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	0.893[a]	0.797	0.763	0.144

a. Predictors: (Constant), LogAdoption

Table 81 Permian Shale Drilling Proppant Use Dependent Variable ANOVA Adoption Case

Model	Sum of Square	Df	Mean Square	F	Sig
1 Regression	0.492	1	0.492	23.582	0.003[b]
Residual	0.125	6	0.21		
Total	0.617	7			

a. Dependent Variable: LogProppant

b. Predictors: (Constant), LogAdoption

Table 82 Coefficient of Determination Permian Shale Proppant Use Dependent Variable Adoption Case

Model	Unstandardized Coefficients		Standardized Coefficients	T	Sig.
	B	Std. Error	Beta		
1 (Constant)	7.081	0.942		7.520	0.000
	2.426	0.500	0.893	4.856	0.003

a. Dependent Variable: LogProppant

5.8.4 Developing the Progress and Learning Rates

The progress and learning rates are developed by applying equation 37 & 38 above to the resultant coefficients from the regression for the shale plays on the drilling technology and two hydraulic fracturing technology scenarios: production and adoption.

Table 83 Drilling and Hydraulic Fracturing Production & Adoption Learning Rates for Three Shale Plays

Technology	Drilling (%)	Production by Hydraulic Fracturing (%)	Hydraulic Fracturing Product Adoption (%)
Eagle Ford	31	20	19
Permian	-32	77	81
Bakken	62	34	34

5.9 Discussion

Mc Glade (2013) notes the difficulty in learning curve determination. However, the need to appraise cost reduction and production trend impact time on energy production technology is essential. Moreover, Karali et al. (2017) suggest improvements to learning curve determination, suggesting a robust methodology should include decomposed process learning rates, geography, and better econometric models to reveal the underlying parameters that impact technological innovation and penetration. This chapter develops and applies a decomposed learning rate estimation model that accounts for geography; the methodology is applied to unconventional resources development technologies and shale plays (which reveals geographical and geological considerations).

This study reports the decomposed learning curve of the two predominant technologies applied to unconventional resource development across the different locations/plays: Eagle Ford, Permian, and Bakken. The drilling technology estimated learning rates indicate that as the rate of penetration doubles, the rig day cost reduces by 31%, -32%, and 62% for the Eagle Ford, Permian, and Bakken playtime trend. The -32% drilling learning ratio in the Permian basin is quite remarkable compared to other positive learning rates; the negative values indicate that drilling cost increased during the period. In any case, negative learning rates are not uncommon in other energy learning curves; Rubin et al.,'s 2015 review identifies scenarios of -10% learning curve in natural gas closed cycle power plants, -38% in nuclear power plants and a -11% to 35% range in onshore wind power generation. However, our results are unique as other shale plays applying similar technology have positive learning rates during the same period, Eagle Ford and Bakken. Trappey et. al. (2013), focusing on wind power in Taiwan, approximates -11.4% and -5.6% learning rates based on different learning models. Overall, the results indicate an increase in development cost by 11% and 5.6% for every doubling of capacity. These cost increases can be attributed to capacity increases, additionally environmental, technical, and health risks or other supply chain limitations (McDowall, 2012), exogenous circumstances beyond technology but dependant on material consumption.

Concerning the completion and hydraulic fracturing operation/process/technology, the estimated learning rates in a similar order are 20%, 77%, and 34% in the production case. While the adoption case has similar estimated learning rates of 19%, 81%, and 34% in referenced play order above, indicating cost reduction based on cumulative doubling in production. The higher learning rates in the Permian play, compared to the other shale plays analysed, explain figure 18, which shows the apparent preference by investors and producers for the region. Thus, the preference can be attributed to the cost and benefits of producing hydrocarbon over time from the Permian basin.

The primary production cost drivers are impacted the drilling and completion cost. Over the past ten years, drilling technology has evolved, enabling a faster penetration rate dependent on longer lateral lengths, while increased liquid load and usage in the completion design are typical.

Using the Permian as an analogy in analysing unit costs of production, in terms of production to drilling unit cost, between 2010 to 2014 drilling efficiency improved; 416ft/day to 532ft/day, lateral length increased from an average of 4,000ft to 5,100ft and proppant use from 2millionlbs to 5.3millionlbs but with vertical drilling cost increasing from USD66/ft to USD69/ft while horizontal drilling reduced from USD370/ft to USD295/ft while proppant cost reduced from USD0.11/lbs to USD0.08/lbs. Consequently, unit production cost decrease from USD101,500/scf to USD63,800/scf. The impact of production size on this is apparent with oil production progressing from 1,000bbl/day to 2,000bbl/day (2010 to 2014) and now 4,500bbl/day, gas production increasing from 4,000mcf/day to 7,000mcf/day (2010 to 2014) and 18,000mcf/day in 2019.

An analysis of the data above provides guidance, drilling efficiency, and lateral length increased by 27% and proppant use by 165%. Also, vertical cost per foot increased 4% while horizontal drilling on the same indicators reduced by 20% and proppant per pound had a 23% decline. Therefore, the overall cost of unit production drops by 38%. Moreover, oil production improved by 100% and gas production by 75%. The cost profile per unit production reduced due to increased efficiency but with more drilling length and material use aided by about 90% increased production size. Technology innovation with cost implications that lead to enhanced production units leads to scaling/capacity of the well. This production capacity is considered in this research by the technology adoption cumulative production capacity (TACPC).

In 2018 and 2019, USD97billion and USD105billion were the US Onshore capital expenses; 41% was deployed in the Permian Basin. However, other play dependent cost parameters exist, regulatory imposed expenses, and fiscal regimes.

Mejean and Hope (2008), focusing on non-conventional oil produced from bitumen in Canada (Oil sands), reveals a 42% learning rate over five years (1983 to 1998) based on a methodology subject to production, oil in place and recovery factor. However, the recovery factor applicable to resource extraction changes with improved technology efficiency, thereby challenging the applied method. Concerning conventional oil and gas production, Fisher (1974) proposes a 5% learning rate for crude oil at the well level between 1969 and 1971. While Blackwood (1997), focusing on the North Sea in Europe, approximates a 25% learning rate. The methodology applied in this study, a technology decomposed, location disaggregated micro-level learning rate model can be applied to other hydrocarbon production industries to provide policy and investment guidance. This study is the first learning ratio focused on unconventional petroleum resources based on empirical United States derived data.

As mentioned, although the cost of drilling has reduced, there has been increased stimulation of sand demand also accompanied with increased production. The drilling learning rate in Bakken play is more than the hydraulic fracturing process. Furthermore, in the Eagle Ford play, a similar trend exists were the technological change in drilling is observed more than hydraulic fracturing. However, for the Permian play, this analysis shows that lateral length increased from 2500ft to 6000ft, 1000ft to 6000ft, and 5000ft to 9000ft in the Permian, Eagle Ford, and Bakken plays, respectively. Furthermore, proppant use per lateral foot increased from 100ibs to 700ibs, 400ibs to 1300ibs and 150ibs to 1000ibs for the plays in a similar order (USEIA, 2016).

5.10 Conclusion

This chapter has reviewed the learning curve theory, energy technology learning curve literature, developed and applied a one-factor technology-specific and multi-component learning curve model for prominent shale plays in the United States, thereby accounting for location biases. This study provides an improved knowledge of the impact of technological efficiency on different shale plays. It is concluded that for a doubling in drilling capacity, the Eagle Ford has experienced a 31% reduction in drilling cost and a 20% reduction in production expenses with similar capacity change. For the Bakken shale, cost reduction in drilling and production with doubling in capacities is 62% and 34%. However, with a doubling in the drilling capacity for the Permian shale, the cost has increased by 32%, while an impressive 77% reduces the production cost. Thus also gives insight into recent development interest in the Permian shale region. The Permian learning curves in production and adoption are 385% and 426% of the Eagle ford but 230% and 340% for the Bakken shale play.

Nevertheless, in relating to drilling, the Permian is 100% less than the Eagle Ford and 200% less than the Bakken shale play. Sweet spots are attributed to shale wells or areas with exceptional production profiles. Perhaps, cost profiles can also determine sweet spots. Sweet spots can thus be redefined as shale plays with enhanced production to cost profile. Perhaps for the Permian shale, due to a 70% production cost reduction, operators were prepared to pay a premium to attract drilling rigs, equipment, and personnel from other shale plays. The results show that with has haven varied learning outcomes bias within the US ed on either efficiency gains in the hydraulic fracturing technology or completions (lateral length and associated outcomes). As such, we expect learning curves to vary outside the US, but initial technology application will most likely rely on the most recent being applied in the current US wells.

The methodology can thus guide the cost of future shale resource development in plays, regions, and countries, and results show that drilling technology and increased lateral lengths have driven cost reduction. In contrast, the hydraulic fracturing technology has relied on more material use volumes. The additional demand in stimulation sand and other production materials and their disposal can lead to exogenous cost implications. These expected exogenous cost implications are environmental, regulation, and fiscal regimes, which can aid or deter technology adoption in different regions. Therefore, it is suggested that although the developed method, results, and analysis are moderately accurate, the impact of energy and environmental policy on development costs needs to be evaluated and incorporated into economic feasibility analysis.

About future/undeveloped shale plays, a detailed report of the correlation between empirical cost and cumulated production is provided by learning curve analysis, which can provide a foundation for future cost reduction by simple extrapolations (Ferioli et al., 2009). As such, the applied methodology can guide future shale development cost estimation as well as aid appropriate macroeconomic impact assessment.

6 Economic Appraisal of Undeveloped Unconventional Gas; The Bowland United Kingdom Case

6.1 Introduction

The study section applies the previously developed production, modelling, and cost and anticipated policy and fiscal regime to appraise the economic viability relying on various parameters.

The chapter begins with the review of scenario development in energy systems and establishing the modelling framework along with scenarios. Consequently, gas production scenarios established in chapter 4 guide the development of future situations for other input parameters and thus the model output.

In respect to input parameters, the following scenarios are developed, gas price, drilling cost, completion cost, and fiscal policy. Finally, the basis and model for commercial evaluation is established.

6.2 Scenarios Design and Modelling Framework

Based on perceived uncertainty, the production function and profiles developed in chapter 4 are based on scenarios as such scenarios are developed and designed for input parameters and consequently results. WEC (2016) notes that scenarios are used in strategy development to consider potential future implications. Also, scenario generation applies rigorous research and analysis to envisage possible futures. Consequently, scenario development is a tool that enables better understand and challenges of the future. Each scenario describes a certain way an uncertainty parameter could play out, future values of various input and output parameters.

In energy research, the IRENE 40 project proposes five electricity demand scenarios and generation in 29 European countries until 2050 (Pudjianto et al., 2016). Fawcett et al. (2009) review the energy modelling forum 22 study of the United States transition scenarios of potential climate change policy goals. Akashi et al. (2012) use scenarios to study Green House Gas (GHG) emissions up until 2050 in Asia and the World. Concerning low carbon and clean energy for India, four scenarios are also applied (Shukla and Chaturvedi, 2012). Sbroiavacca et al. (2016) also apply scenarios guided by a standard protocol defined by a previous project (CLIMACAP-LAMP) to appraise climate change policy options in Argentina. The methodology used to model Russian natural gas exports until 2050 uses an emissions prediction and policy analysis model based on scenarios (Paltsev, 2014). Lucena et al., (2016), compares modelling scenarios based on GDP, population, energy costs, and technological development assumptions relating to climate change policy in Brazil. Olaleye and Baker (2015) assist near term energy policy by conducting a scenario evaluation of potential technological advancements in low carbon technologies while Mahumane and Mulder (2016) use the Long-range Energy Alternatives Planning (LEAP) model which presents energy planning scenarios on energy transformation and production in the emerging Mozambique energy market. In exploring alternative renewable energy futures, Luderer et al., (2017) consider different climate policy and technology scenarios focusing on wind and solar using an Integrated Assessment Model (IAM). Cohen and Caron (2018) also apply scenarios to study the economic impacts of high wind penetrations in the United States. Furthermore, in a combined study of the economic viability of the gas to liquid technology and the oil-natural gas price relationship, Ramberg et al., (2017) analyzes scenarios using different parameters of essential inputs into the computable general equilibrium model.

Therefore, this study based its modelling approach on scenarios developed in Anandarajah and Nwaobi (2018)'s production estimation study of shale gas wells in the Bowland Shale in England developed in chapter 3 of this thesis. The following input parameter need scenario design and development to guide the modelling framework and structure, gas prices, cost indices for steel, stimulation sand, water, future inflation, fiscal, regulatory environment, and policy.

6.2.1 Gas Prices Scenarios

Unlike the crude oil market, the natural gas market is fragmented into regional markets (IEA, 2012). The crude oil market is referenced against the Brent Crude Oil in Europe and West Texas Intermediary in the United States. Concerning natural gas, price setting in the United States is via gas on gas competition with the gas traded over various time frames and at different trading hubs; the henry hub is the largest with pricing being guided by supply and demand (Saussay, 2018).

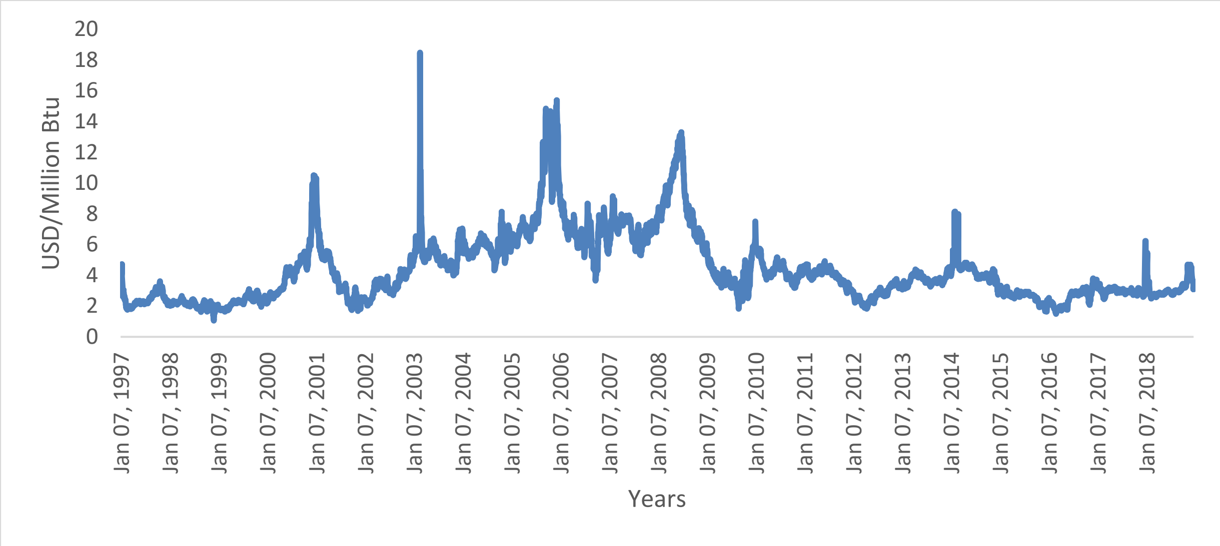


Figure 32 Natural Gas Price Trend over 21 Year at the Henry Hub (Source: USEIA)

The USEIA provides gas price trends in the henry hub over 20 years above. The descriptive statistics suggest that over time trend gas prices range between a low of USD1.05/MMBtu and 18.48MMBtu while averaging USD3.72MMBTU. A review of the price trend shows that as gas production from shale became significant in 2008, henry hub prices declined with periodic spikes in 2014 and 2018. Ji et al., (2018) notes that natural gas prices have become more critical in the energy economics research after the US Shale gas revolution.

A 2018 report by the International Gas Union notes that gas to gas pricing mechanism which is a methodology that relies on the interplay between demand and supply, traded over a variety of periods (daily, monthly, quarterly and annually) and occurring in physical trading hubs represent 46% of global consumption (IGU,2018). The National balancing point (NBP) is the physical hub and trading index for the United Kingdom.

BEIS (2017) provides short, medium- and long-term projections applying options, forward prices, interpolation, and various International Energy Agency (IEA) policy scenarios for future NBP prices shown in figure 32 and table 82.

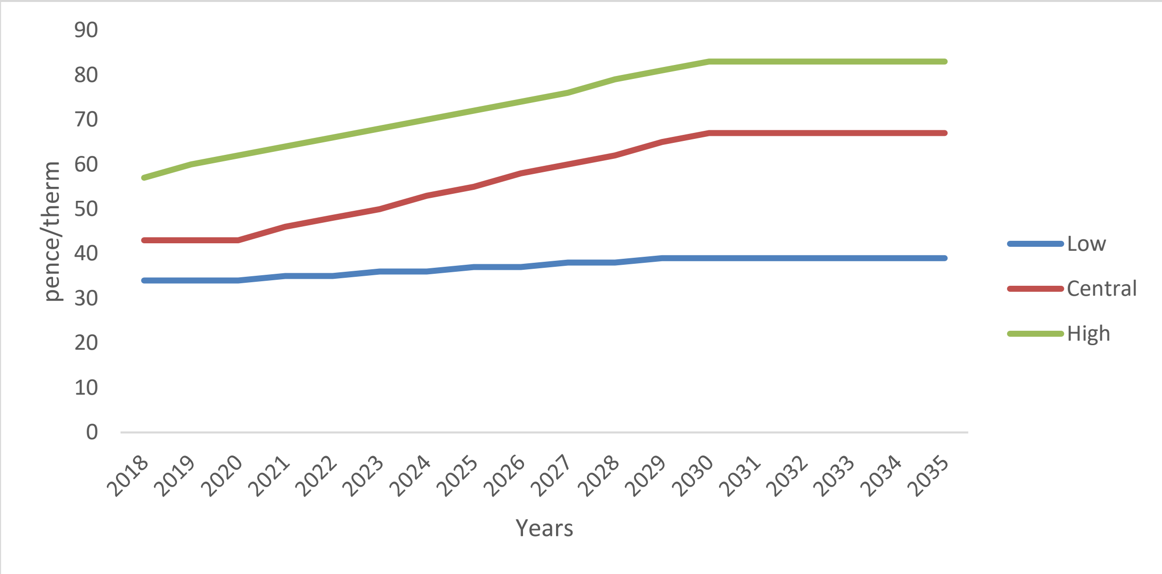


Figure 33 18 Year NBP Wholesale Gas Prices (Source: BEIS 2017)

Table 84 BEIS (2017) Gas Price Projections

Yearly Price in p/therm	Low	Central	High
2018	34	43	57
2019	34	43	60
2020	34	43	62
2021	35	46	64
2022	35	48	66

2023	36	50	68
2024	36	53	70
2025	37	55	72
2026	37	58	74
2027	38	60	76
2028	38	62	79
2029	39	65	81
2030	39	67	83
2031	39	67	83
2032	39	67	83
2033	39	67	83
2034	39	67	83
2035	39	67	83

6.2.2 Currency Exchange Risk Assessment

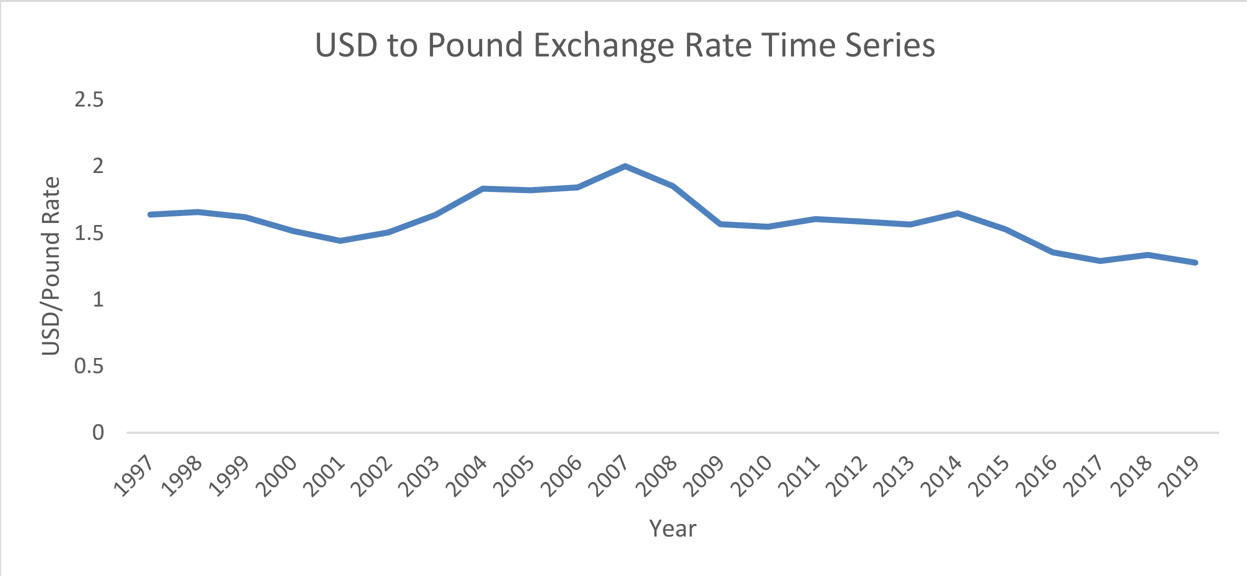


Figure 34 12 Year USD/Pound Exchange rate trend; Source UK Office of National Statistics

The figure above is the United States Dollars' exchange rate trend (USD) to British Pounds, which has averaged 1.59USD/1GBP (£) and a range of 1.27 to 2 over the time frame. However, more recent 10-year (2020-2019) data suggest 1.5USD/1GBP averagely. A lot of uncertain macroeconomic parameters impact the fluctuation of the exchange rate between currencies. However, the data above shows that economic and monetary policy has kept the exchange rate between the USD and GDP relatively stable over the past ten years, suggesting little uncertainty in the mid-term assessment. In this study, a USD to GBP 1.4 exchange rate is applied.

6.2.3 Cost Scenarios

The scenario framework relating to cost in this study depends on the analysis in chapter 4 and 5. The results in chapter 4 conclude that unconventional gas development costs comprise mainly 30% sand and stimulation, 13% drilling, and 10% casing cost; these three components represent 53%. Our scenario design and development thus focus on these parameters. As stated earlier stated, Aguilera (2014) identifies that oil and gas costs can be affected by geological conditions, depth of accumulations, regulatory environments, and project lengths. In terms of geological conditions, the porosity and permeability data, well depth and lateral length guidance is derived from chapter 3 of this study. The cost of drilling unconventional wells is correlated to formation depth, while completion depends linearly on the amount of water and proppant used (Sand and stimulation costs).

6.2.3.1 Drilling Cost Scenarios:

Table 85 Well Depth in The Bowland Shale Source: Andrew, 2013; Smith et al., 2010

Well Name	**Depth (ft^2)**
Blacon East	7431.80
Bosley	6568.00
Grove Well	7564.60
Heywood Well	5260.00
Long Eaton	5901.00

Roddlesworth	4226.00
Swinden	2038.00
Wessesnden	3505.00

Table 85 provides a depth overview of the wells in the Bowland Shale being analysed; in addition, research in chapter 4 provides the lateral length (horizontal length) of shale gas wells, which is considered to have increased from an average of 3500ft to 7500ft between 2013 and 2016. Saussay (2018) notes that public data on drilling costs are scarce, which makes approximation difficult. The following postulations are applied:

- Vertical Rig Mobilization Cost (VRMC) and Horizontal Rig Mobilization cost are USD350,000 individually.

- Horizontal and Vertical Rig Day rate is estimated as USD35,000.

- Rate of Penetration (Vertical and Horizontal) are derived by applying data from four shale plays in the US from USEIA, 2016; 532ft/day in Permian Shale, 994ft/day in the Eagleford, 710ft/day in the Bakken and 810.48ft/day in the Marcellus. Thus, drilling Penetration scenarios are developed applying 532ft/day as the P10, 763ft/day as the P50, and 994ft/day as the P90 scenarios.

- Individual well depth is based on table 85 above while the lateral and horizontal length is 7,500ft based on USEIA, 2016

- A USD100/Ft casing cost is applied based on USEIA, 2016 averages.

6.2.3.2 Completion Cost Scenarios

This study's completion cost estimation comprises Proppant, Fluid, Gels, Chemical Gels/Water, Pumping, and String expenses.

- Proppant use scenarios are developed based on the volume use per lateral foot (ib/lateral ft), the length of laterals, and the cost per amount (USD/ib). The proppant applied per lateral foot relies on USEIA, 2016's estimate for prominent shale plays; The averages for these plays yield 1295ib/lateral ft in 2018. Additionally, USEIA 2016 also develops cost per ib scenarios (P10, P25, Average, P75, and P90) for these shale plays. Thus, the averages on a scenario basis for P10, and the average scenario is applied as the P50 case and P90 cases. The output results in a P10 cost of USD0.12/lb and USD0.11 for both P50 and P90 cases.

- Fluid use scenarios are also based on a scenario developed above by USEIA 2016 for shale plays in the United States relating to gallons used and price/gallon. The scenarios yield a gallon use average range of 10.4Million gallons, 6.4 Million gallons, and 3.1Million gallons for P10, P50, and P90, respectively. A similar approach is applied to develop the Price per gallon.

- The method and scenarios established are thus used on the Gels, Chemical, and Water input costs.

- The cost of pumping, strings, and other costs comprising maintenance is applied on a flat basis; USD1.5Million, USD0.75Million, and USD0.6 Million separately.

- UK premium: A cost escalation index of 1.5 times is applied to all completion costs asides pumping, strings, and others. The cost escalation index's objective is to estimate UK specific costs on production parameters (except tax, regulatory and fiscal regime constituents) due to the infant nature of the shale gas industry.

The cost modelling yields a diverse set of results for each well, three scenarios for drilling and completion individually.

6.3 Fiscal Regime

Her Majesty’s Revenue and Customs (HMRC) provides guidance for UK oil and gas fiscal policy in the oil and gas industry's oil taxation manual. HMRC, 2016 notes that the UK oil and gas fiscal regime currently consists of three elements. The elements are Petroleum revenue tax, Corporation tax, and Supplementary charge (HMRC, 2019).

- Petroleum Revenue Tax (PRT): The PRT is a field-based tax/levy on profits from individual fields and not from all oil fields owned by an entity. The PRT rate was reduced to 0% by Finance Act 2016 beginning on or after 1 January 2016. The previous rate was 50% but applied to fields operational before 16 March 1993.

- Corporation Tax: The applicable corporation tax to upstream oil and gas in the UK is termed the Ring Fence Corporation Tax (RFCT) currently charged at 30% of profits. The Ring Fence term relates to the regime's ability or characteristics to prevent taxable profits from the industry being reduced by a corporation's losses in other activities and excessive interest payments. The RFCT is also designed to provide 100% relief on capital expenditure; ring-fenced losses can be uplifted by 10% annually for up to 10 accounting periods.

- Supplementary Charge (SC) is currently an additional 10% charge on a company's ring fence profits, excluding finance costs introduced from 17 April 2002. The SC rate has changed over time to reflect the prevailing oil and gas economic climate; 10% in 2002, 20% in 2006, 32% about profits accruing after 23 March 2011, 20% for accounting periods beginning on or after 1 January 2015. The current 10% charge commenced on or after 1 January 2016.

6.4 Economic Appraisal

The overarching economic appraisal applies a cost-benefit appraisal within a discounted cash flow model over 150 months.

$$\boldsymbol{NPV} = \sum_{t-0}^{t-T} (\boldsymbol{R_t} - \boldsymbol{V_t} - \boldsymbol{A_t} - \boldsymbol{SR_t}) / (\mathbf{1} + \boldsymbol{i})^{\boldsymbol{t}} \quad \textbf{Equation 57}$$

Where: R_t is gross revenue in per month t, V_t is the cost of development (drilling, completion & operational) in year t; A_t is the summation of fiscal regime cost, social responsibility commitments all in year t, *t* is time in months (0-150 Months) and “I” the discount rate.

These parameters or factors mostly differ due to well heterogeneity.

$\boldsymbol{V_t}$ is the capital expenditure is spread over two months while royalties and $\boldsymbol{SR_t}$ the community social responsibility and fiscal payments. $\boldsymbol{A_t}$ are accrued monthly.

R*t* (gross revenue) is modelled, relying on the daily production results based on the DDCM, the numerical model, and the monthly gas price estimate. The result is an economic appraisal model incorporating commercial returns and costs to represent the proposed gas wells' total economic value using the NPV criterion. Over the 150 months evaluation period, benefits were considered to outweigh costs if the NPV > USD0. The model's revenue data were obtained applying the reference gas price projections from the above to the central production price scenario and cost scenarios as defined above also for each gas well.

Other scenarios considered and modelled are 150% development cost increase on the most pessimistic case, 50% and 60% fiscal regime scenarios, and breakeven gas price for the cost base case on all wells. Additionally, the impact of short-term oil price movements, carbon constraints, and climate change abatement scenarios are appraised. The resultant model is an undeveloped shale gas investment decision model (USHIDM).

7 Results and Discussion

Overview

This section reveals the results from undeveloped shale gas investment decision model (USHIDM); which focuses on the commercial viability of undeveloped shale gas wells incorporating the reference gas production scenario from the developed depth-dependent correlation matrix (DDCM) and established cost scenarios both on a per well basis to account for established heterogeneity of shale gas wells in the Bowland region of North England.

The section begins with analysing the cost estimate for each shale well and the commercial viability over 150 months based on scenarios and projections.

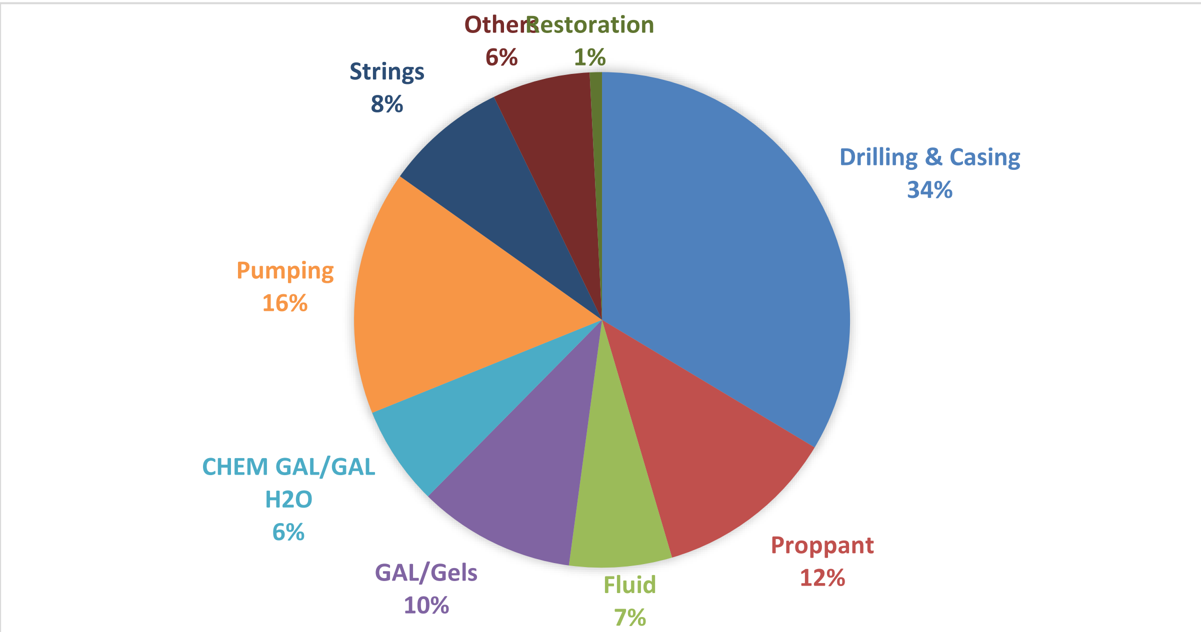


Figure 35 Cost Estimate Analysis of the Blacon East Well in the Bowland Shale

The cost breakdown in figure 35 shows that drilling and casing cost make up 34% of the development cost while the cost of proppant, fluids, GAL/Gels, CHEM GAL, Pumping and strings (which are associated with the stimulation process) summed up together represent 53% of the overall cost.

7.1 Drilling and Casing Cost Scenarios

Drilling costs are impacted by day hire rates for rigs, mobilization rate, penetration (dependent on geology and rig type), and well depth or vertical length (applicable to horizontal wells/drilling).

Table 86 Blacon East Well Drilling and Casing Cost

Scenarios	Horizontal Drilling Cost (USD)	Vertical Drilling Cost (USD)	Total Drilling & Casing Cost
Low	611,654.93	610,563.38	2,705,318.31
Mid	690,871.56	689,449.54	2,863,421.10
High	838,881.58	836,842.11	3,158,823.68

Table 87 Bosley Well Drilling and Casing Cost

Scenarios	Horizontal Drilling Cost (USD)	Vertical Drilling Cost (USD)	Total Drilling & Casing Cost
Low	581,267.61	610,563.38	2,588,630.99
Mid	651,284.40	689,449.54	2,737,533.94
High	782,105.26	836,842.11	3,015,747.37

Table 88 Grove Well Drilling & Casing Cost

Scenarios	Horizontal Drilling Cost (USD)	Vertical Drilling Cost (USD)	Total Drilling & Casing
Low	616,359.15	610,563.38	2,723,382.54
Mid	697,000.00	689,449.54	2,882,909.54
High	847,671.05	836,842.11	3,180,973.16

Table 89 Heywood Well Drilling and Casing Cost

Scenarios	Horizontal Drilling Cost (USD)	Vertical Drilling Cost (USD)	Total Drilling & Casing
Low	535,211.27	610,563.38	2,411,774.65
Mid	591,284.40	689,449.54	2,546,733.94
High	696,052.63	836,842.11	2,798,894.74

Table 90 Roddleworth Well Drilling and Casing Cost

Scenarios	Horizontal Drilling Cost (USD)	Vertical Drilling Cost (USD)	Total Drilling & Casing
Low	498,802.82	610,563.38	2,271,966.20
Mid	543,853.21	689,449.54	2,395,902.75
High	628,026.32	836,842.11	2,627,468.42

Table 91 Long Eaton Drilling and Casing Cost

Scenarios	Horizontal Drilling Cost (USD)	Vertical Drilling Cost (USD)	Total Drilling & Casing
Low	577,781.69	610,563.38	2,498,445.07
Mid	620,688.07	689,449.54	2,640,237.61
High	738,223.68	836,842.11	2,905,165.79

Table 92 Swinden Well Drilling and Casing Cost

Scenarios	Horizontal Drilling Cost (USD)	Vertical Drilling Cost (USD)	Total Drilling & Casing
Low	421,760.56	610,563.38	1,976,123.94
Mid	443,486.24	689,449.54	2,076,735.78
High	484,078,95	836,842.11	2,264,721.05

Table 93 Wessesden Well Drilling and Casing Cost

Scenarios	Horizontal Drilling Cost (USD)	Vertical Drilling Cost (USD)	Total Drilling & Casing
Low	123,415.49	260,563.38	2,174,478.87
Mid	160,779.82	339,449.54	2,290,729.36
High	230,592.11	486,842.11	2,507,934.21

Scenarios	Horizontal Drilling Cost (USD)	Vertical Drilling Cost (USD)	Total Drilling & Casing

Low	123,415.49	260,563.38	2,174,478.87
Mid	160,779.82	339,449.54	2,290,729.36
High	230,592.11	486,842.11	2,507,934.21

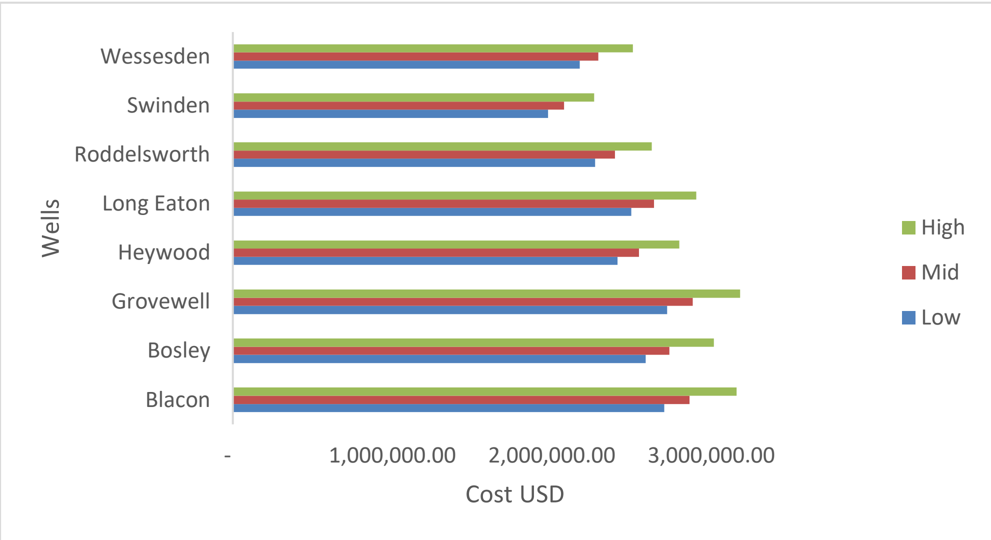


Figure 36 Drilling Cost Scenarios in the Bowland Shale Play

The drilling (vertical and horizontal) and casing cost scenario revealed in figure 36 above reveal that the Grovewell and Blacon wells have the highest cost while Swinden has the lowest development cost in this category. In the high-cost scenario, expense ranges from USD2.2 Million to f USD3.2 Million while the range in the low case is between USD1.9Million and USD2.7Milion. This study's reference and mid-case has a cost range of USD2.1Million and USD2.8Million. The averages are USD2.4Million, USD2.5Million, and USD2.8Million for the low, mid/reference, and high scenarios. In comparison, the EIA estimates the 2018 drilling costs are USD2.1Million, USD2Million for the Bakken, and Eagle Ford in the United States. As expected, drilling and casing costs are higher in the United Kingdom by about 13% primarily due to expected higher rig day hire rates due to a limited supply of onshore rigs in continental Europe and USD100/ft steel pricing the casing cost estimates.

7.2 Completion Cost Scenarios

The completion cost estimated for wells in the Bowland shale applies 7,400ft as lateral length. The modelling results for completion relies on the average 2018 volume and cost (low, average, and upper boundaries) for various inputs; proppant, fluids, Gels, and water for the analysed shale wells in USEIA 2016. Thus, the results for all inputs are represented by a low, mid, and upper case, escalated by 50% aiming to account for UK economic premium due to the value chain industry's infant nature.

Table 94 Results of Material Input Cost Estimates in Scenarios

Input	Proppant (USD)	Fluid (USD)	GAL/Gels (USD)	CHEM. GAL/GAL H_20 (USD)
Low Case	1,017,066.28	287,908.13	416,927.35	411,787.58
Mid Case	1,088,960.69	598,637.94	497,405.23	583,236.68
High Case	1,112,925.49	628,701.13	963,328.40	610,664.81

Table 94 shows the material cost scenarios during completion based on the lateral length and USEIA, 2016. However, Weijemars (2013) and Saussay (2017) all suggest that the UK's cost will be higher compared to the United States due to various reasons. Consequently, the resultant overall completion costs are represented below in figure 35.

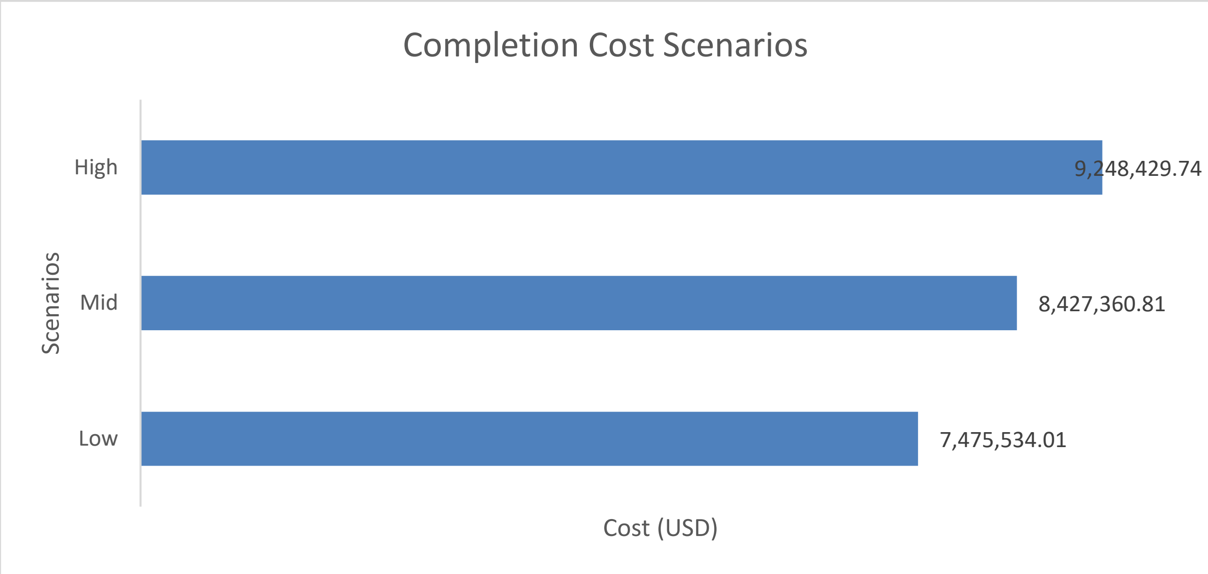


Figure 37 Completion Cost Scenarios applied in the Bowland Shale

7.3 Discounted Cashflow Analysis

The discounted cash flow (DCF) analysis relies on the depth-dependent correlation matrix (which estimates gas production potential) and the anticipated gas price to determine the benefits. Concerning expenses, the cost of drilling, completion, and operating the wells, the fiscal regime in place, the firm's corporate social responsibility to the immediate community and environmental levies or commitments are also considered.

A discount rate is applied to account for the time value of money and normalize the cashflow corresponding to each month, and hence all these monthly discounted net cashflows are summed to reveal the well’s or development’s NPV.

Applying a discount rate is essential to introduce the time value of money as its application normalizes cash flow resulting in monthly discounted net values summed to reveal the net present value (NPV) of a project (Tujan and Sinayuc, 2018). A discount rate is applied to both the income and cost estimates. The discount rate is a parameter applied to mark down future income to its present value. The discount rate used by authors and researchers are mostly the weighted average cost of capital (WACC) for the specific industry. The WACC incorporates inflation, associated industry risk, and expected equity returns. Gustavson (2000) proposes a 7% risk premium for oil and gas properties to reach its targeted return rate based on perceived quantity, price, and cost uncertainties. However, a 10% discount rate is suggested to reflect future net cash flow timing concerning proven oil and gas reserves (FASB, 2010). In the appraisal of the Barnet shale in Texas, an inflation rate of 2.5% is applied. Wejeimars (2013) applies a 5% discount rate to shale gas basins in Europe, while Saussay (2018) applies 7%. Although a 7% discount rate is applied in this study, a sensitivity and breakeven discount rate is also considered. The assumption is that capital expenditure is all debt, while equity is applied to predevelopment expenses.

The approach above is applied to 8 wells in the Bowland shale in the United Kingdom to account for heterogeneity in production and cost profiles. Thus, the results below on individual wells and focus on the commercial viability over the three cost scenarios address the impact of a 50% cost increase, 50% and 60% fiscal regime impact, and the specific breakeven gas prices.

7.3.1 The Blacon East Well Discounted Cash Flow Analysis

The gas production is well known as "Blacon East" provides a net present value of USD56.8 Million over 150 months by the discounted cash flow method in the reference cost scenario while in the low and high case the well yields USD55.7 Million and USD57.9Million respectively. To further investigate the impact of the cost of the well's development prospects, costs are modelled to increase by 50%, which results in about a 13% reduction in net present value. The fiscal regime is also increased from 30% of revenue take to 50% and 60%. The 50% fiscal regime results in a 34% reduction in net present value, while the 60% fiscal regime scenario suggests a 27% reduction in net present value. Finally, in terms of sustainability and duration of commercial viability, the impact of shorter well life is examined by reducing the reference model period from 150 months to 60months and increase the duration to 240months. The 60Months scenario causes a 37% reduction in NPV to USD35.7Million while the 240month case yields a 10% increase in NPV to USD62.2Milion.

7.3.2 The Bosley Well Discounted Cash Flow Analysis

The discounted cash flow (DCF) analysis on Bosley well suggests USD39.3Million net present value in the reference cost case while the low and high-cost scenarios provide NPVs of USD40.5Million and USD38.3Million, respectively. The impact of a 50% increase in production gives a USD32.1Million; an 18% reduction in NPV in comparison to the reference case. On the fiscal regime impact analysis for the Bosley well, a 67% increase from 30% to 50% of revenue take causes an 18% reduction in NPV to USD36.2Million. While a further 100% increase in fiscal regime to 60% causes a 33% NPV decrease to USD26.3Million. Furthermore, a 60-month discounted cash flow appraisal results in NPV reduction by 40% (relative to the reference case) to USD23Milliion while a 240-month review yields increased NPV by 11% USD43Million.

7.3.3 The Gove Well Discounted Cash Flow Analysis

The DCF results for Grove well show USD0.6 Million NPV in the mid-cost case, USD1.8Million in the low-cost case, and a no development result due to negative USD0.4Million NPV the high-cost scenario. As expected, a further 50% cost increase from the reference cost case yields negative USD5Million NPV. An increase in the fiscal regime impact from 30% to 50% on the Grove well causes about 400% change, while a 60% fiscal regime scenario results in an 800% change in NPV. It must be highlighted that under the 50% and 60% fiscal regimes, this well's NPV is negative and thus not to be developed. Furthermore, when the analysis tenor is reduced to 60-month, the NPV is negative at USD3Million with a no-drill recommendation. However, if analysed over 240 months, the NPV is USD1.6Million.

7.3.4 The Heywood Well Discounted Cash Flow Analysis

Discounted cash flow analysis of the Heywood well shows USD22.8Million NPV over the reference cost and time scenario. The low and high-cost scenarios also result in positive development decisions with NPVs of USD 23.9Million and USD 21.8Million. Furthermore, a 50% cost rise results in a 23.9% reduction in NPV to USD17.3Million. In terms of fiscal regime impact, a 30% to 50% increase causes a 43% reduction in NPV to USD13Million while a further growth to 60% of revenue fiscal regime causes a 113% reduction in NPV to USD8Million. Finally, for the Heywood well, reducing the DCF analysis tenor to 60months and extension to 240months gives a USD12.3Million and USD 25.8Million, respectively.

7.3.5 The Long Eaton Well Discounted Cash Flow Analysis

The Long Eaton well's discounted cash flow analysis in the reference case gives an NPV of USD31.6Million. Besides, the low and high-cost scenarios yield USD32.6Million and USD30.7Million in that order. Also, a 50% cost inflation in the mid-case scenario causes a 17% decrease in NPV value to USD26.2Million. An increase in the fiscal regime's take value from 30% to 50% causes a 38% reduction in NPV to USD19.2Mllion while a further increase in fiscal take to 60% results in a 58% reduction in NPV to USD13.1Million accordingly. Conversely, a reduction in the analysis timeframe from 150 Months to 60 Months and an increase to 240 Months yield NPVs of USD18Million and USD35Million correspondingly.

7.3.6 The Roddelsworth Well Discounted Cash Flow Analysis

Roddelsworth well's discounted cash flow analysis yields an NPV USD11Million in the reference scenario, USD13Million, and USD4Million in the low and high-cost case scenarios. An additional 50% increase in the reference case cost results in a 41% reduction in NPV to USD7.6Million. The fiscal regime impact assessment from 50% to 60% compared to the reference 30% both cause 62%, and 89% NPV decreases to USD4.8Million and USD1.4Million. A timeframe reduction to 60months causes the NPV to reduce to USD4.4Million while an increase to 240months causes an increase to USD13Million.

7.3.7 The Swinden Well Discounted Cash Flow Analys**is**

The discounted cash flow analysis for Swinden is negative for all scenarios considered; USD7.4Million for the reference case. The low-cost case scenario results in minus USD6.3Million, while the high-cost scenario also yields minus USD8.3Million.

As expected, a further 50% increase in cost relative to the reference case results in minus USD12.6Million NPV. Concerning fiscal regime changes, under a 50% and 60% take, the NPVs are minus USD8.3Millon USD8.8Million accordingly. The analysis tenor relating to 60 months and 240 months presents minus USD7Million and USD8.3Million, respectively. All scenarios studied do not justify developing the Swinden shale gas well.

7.3.8 The Wessesden Well Discounted Cash Flow Analysis

The Wessesden well's discounted cash flow analysis delivers a net present value of USD6Million in the reference case scenario. The low and high-cost scenarios deliver net present value results of USD7.1Million and USD5Million, respectively. An NPV of USD0.7Million is the impact of a 50% cost escalation consequence. The fiscal regime scenarios of 50% and 60% government take suggests net present values of USD1.1Million and minus USD1.3Million in that order. The impact of tenor reduction to 60months and escalation to 240months on the well study are NPVs of USD 0.8Million and USD 25.7Million.

7.3.9 Discussion of the DCF Analysis Results

The discounted cash flow analysis scenarios in this study yield 72 alternative net present values/scenarios. In relation to the low, reference, and high cases yields 24 NPV results that range between USD57Million to -USD8.3Million. The average NPV within the eight appraised wells is USD20Million while the cumulative net present value, and thus commercial value, is USD163Million. Nevertheless, total cumulative undiscounted revenue is USD544Million all in the reference case for wells examined.

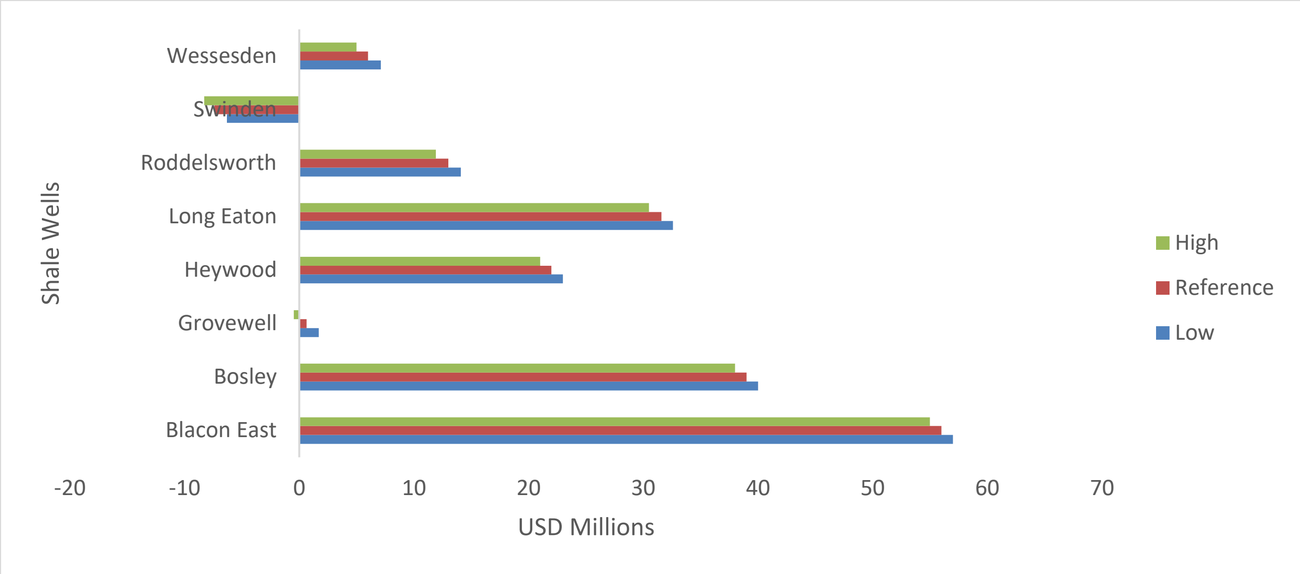


Figure 38 Scenario Net Present Values of Analysed Shale Well

Figure 38 above shows the well's NPV scenarios, which indicates the "sweet spot" (locations with higher productivity) within the region. Sweet spots are wells with higher productivity and commercial viability than other wells in the same region. Weijemars (2013) concludes that a play's productivity can be increased by focusing on drilling on sweet spots in developing shale plays. The results of the production estimates and discounted cash flow analysis suggest that the Blacon East, Bosley, and Long Eaton are sweet spots in our study. Figure 37 shows that the three sweet spot wells identified contribute 66% of total commercial value from our analysis. The "unsweet spots" of the wells studied are the Swinden and Grovewell wells; Swinden has a negative NPV in all cases, while Grovewell has a USD0.6Million value.

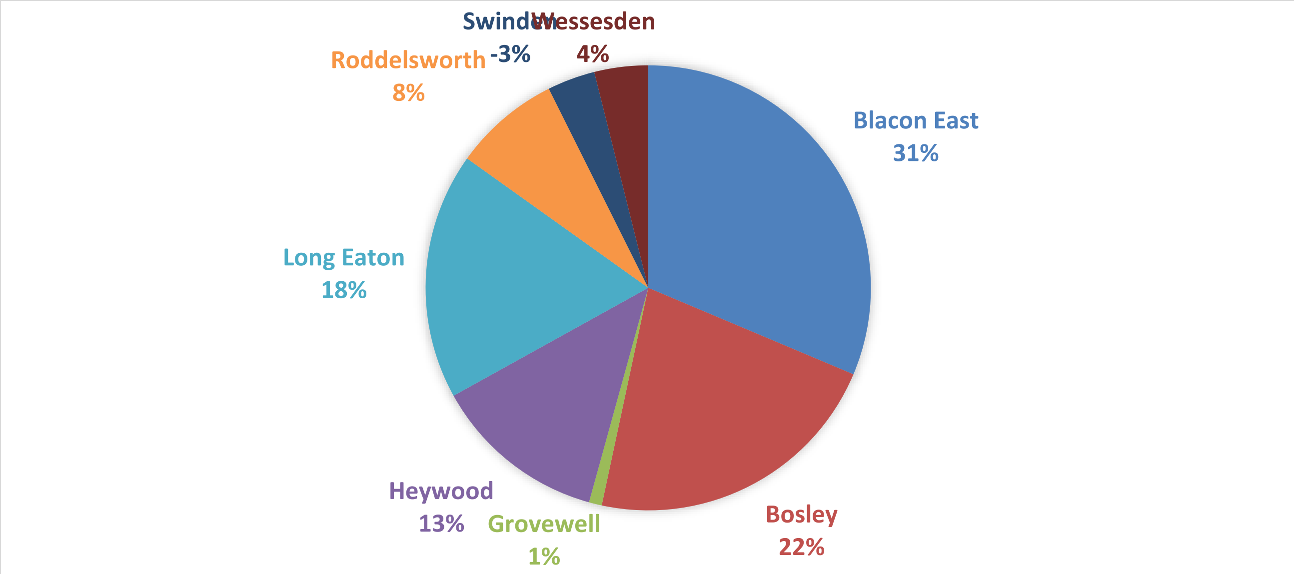


Figure 39 Well Share of Total NPV

Concerning cost, which depends on inputs from service industries and related entities and tax and commitment to local authorities, the total development cost is USD87Million. In contrast, overall tax and proposed community social corporate responsibility commitments are USD163Million and USD5.4Million, respectively, over 150 months in the reference case.

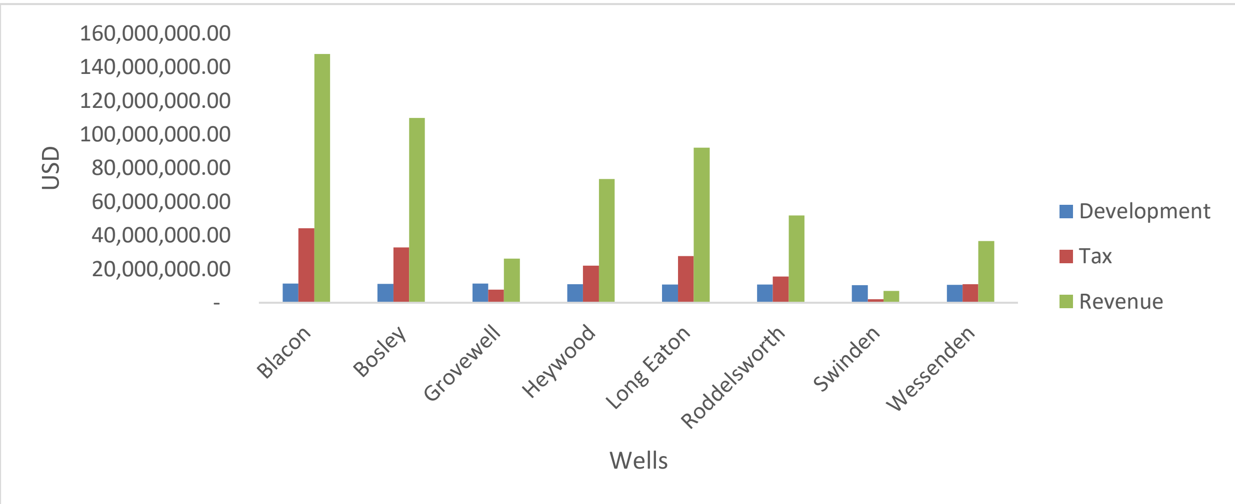


Figure 40 Development, Tax and Revenue Results from Wells Evaluated

7.4 Internal Rate of Return

The internal rate of return (IRR) is the mean rate of payback over a project's lifecycle; the IRR is the specific rate of discount where the net present value is equivalent to 0 (Wejeimars,2013). The IRR is an alternative project final investment decision ranking and making parameter. The IRR is the discount rate that achieves NPV of 0 in a specific scenario. Consequently, the IRR is determined for the eight wells appraised.

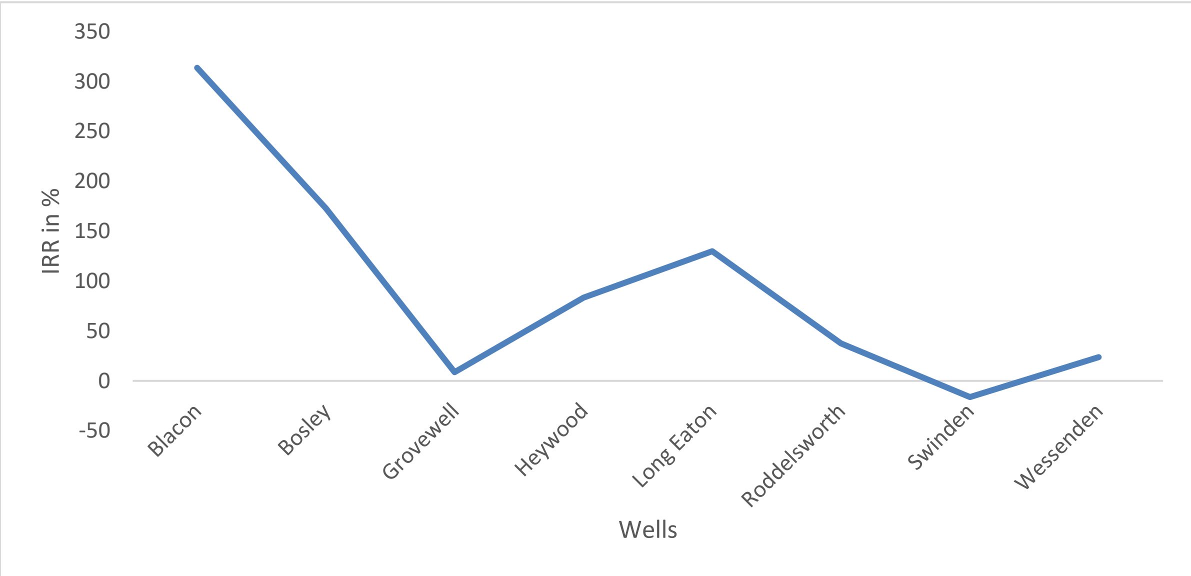


Figure 41 Internal Rate of Return of the Appraised Wells

The figure shows that the Blacon gas well had the highest IRR; 314%, Bosley gas well displays an IRR of 173%, Long Eaton 130% IRR, Heywood 83.3% IRR, 38% IRR for Roddelsworth, 24% IRR in Wessesden, 8.4% IRR in Grovewell and -16% IRR in the Swinden well. The IRRs output thus correlates with the results and ranking of the discounted cash flow analysis.

7.5 Sensitivity Analysis and Breakeven Gas Prices

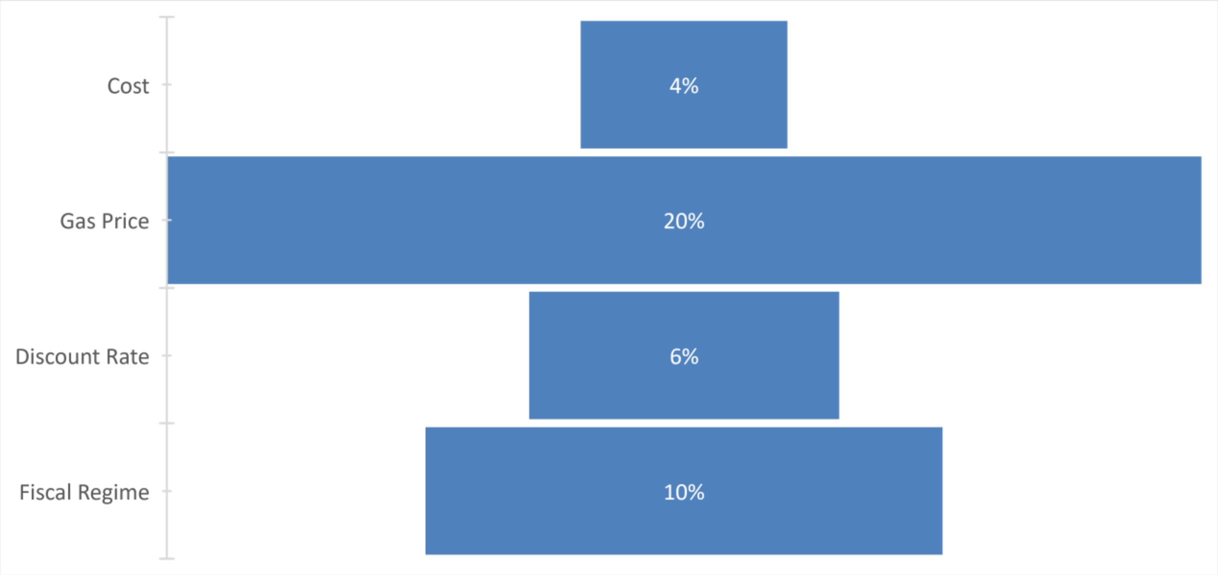


Figure 42 Input Parameter Sensitivity Impact Results

The impact of a 20% increase in development cost while keeping other parameters unchanged is a 4% decrease in net present value. A similar approach is applied to the discount rate and fiscal regime while keeping other parameters unchanged; the result is a 6% and 10% change in net present value. In this instance, the gas price is reduced by 20% while keeping other variables unchanged. The impact of a 20% gas price change on the net present value is a remarkable 20% also: a quite surprising output.

Furthermore, about the gas price, the price projections in table 13 are equivalent to an average price of USD53/therm. An examination of the gas price at which the net present value of each well in the reference case breaks even; NPV equals zero. Consequently, the breakeven price for the Blacon East well yields USD8.3/therm average price while that for Bosley is USD10/therm. A similar analysis for the Grovewell, Heywood, Long Eaton, Roddelsworth, Swinden, and Wessesden delivers the following average breakeven gas prices; USD34/therm, USD15/therm, USD12/therm, USD24/therm, USD152/therm and USD30/therm respectively.

7.6 Oil Price Impact Scenario

Chapter 4 of this study studies and develops an oil price impact model relating to unconventional shale gas. The oil price impact section focuses on demand for cost indicators, horizontal rigs, vertical rigs, steel prices, and hydraulic stimulation materials (sand and water). The results from the empirical study using transformed data based on the first difference methodology which accounts for seasonality corrects for manipulated data suggests that based on the derived Pearson correlation coefficient, oil price shocks or movements have an insignificant impact on the demand for horizontal rigs, vertical rigs or hydraulic fracturing sand demand. However, about steel prices, the regression analysis indicates a significant correlation; 67%. Chou et al. (2012) identify a unidirectional relationship between crude oil price and global steel price index, which infers that crude oil price movements impact the global steel price index. However, the crude oil price movement is not impacted by changes in the global steel price index. Amadi (2015) examines oil price shock's impact on the financial markets and industries and concludes that an increase in oil price increases the demand for steel in sectors like rig and pipeline construction. The study also highlights the importance of the correlation and connection between oil price and micro and macroeconomic subsectors.

Although the studies above identify the impact of oil price, research on the impact's estimation is limited. However, chapter 4 of this study examines the impact of oil prices on the demand for steel in the United States, which is currently producing oil and gas from shale resources via the hydraulic fracturing technology and process. The empirical dependent analysis, which relied on a first difference regression method, estimates that a USD1 change in oil price leads to a 0.87 change in steel demand index. Nevertheless, the impact of a 0.87 change in steel demand index has no empirical study. As such, to apply these resultant equations termed oil price relationships with unconventional shale resource development cost indicators; the "oprurci" model, I adopt a simple economic theory to represent price dynamics; that a unit change in steel demand index results in a corresponding and associated 1% cost/price change in the following cost input parameters; rig mobilization rate, rig day rate, casing cost/ft. Ni and Lee (2011) also note the impact of crude oil prices on steel in energy-related sectors; rigs and pipeline construction.

Crude oil price analysis suggests that the average price of crude in 2016 was USD43.55/barrel, 2017 price was USD54.25/barrel while in 2018, the price was USD71.06/barrel on the average; the price has a USD27.51 range over two years. Consequently, our estimation of the impact of oil price change over two years on the cost of development guided by equation 33, which is resultant from the oprurci model, is applied to the developed, undeveloped shale gas investment decision model (USHIDM). The impact of the drilling and casing cost, total development cost, and net present value on the Blacon East well compared to the reference case is shown in table 95 below:

Table 95 Oil Price Change Impact on Development Cost & Net Present Value

Scenario	Drilling &Casing Cost (USD Million)	Total Cost (USD Million)	Net Present Value (USD Million)
Reference	2.86	11.40	61.91
Oil Price Impact	3.56	12.10	62.61

As expected, the change in oil price and eventual change in steel prices, which impacts rig mobilization costs, rig hire day rates, and casing cost, result in a 25% change in drilling and casing cost, but the oil price impact on total development cost is 6%. This result draws a parallel with our findings in chapter 4 of this study and the cost estimation results earlier in this chapter; drilling and casing costs are about 34% of the total cost. Consequently, the impact 25% increase in drilling and casing cost impacts the overall economic viability in this instance by 1%, resulting in a change in NPV from USD62.6Million to USD61.9Million.

7.7 UK Carbon Constraint Scenario

The viability of UK Shale gas is appraised under a carbon-constrained scenario, especially under a net-zero emissions policy by 2050. The aim is to ensure that by 2050, the amount of greenhouse gases emitted into the atmosphere is no more than the amount taken out.

First, assuming that a carbon constraint is aimed at eventual net zero emissions, the demand for oil, gas, and its derivatives will be reduced, hence the market prices. The long-term low scenario of BEIS's projections is characterized and based on the International Energy Agency's 450 scenario demand intersected with BEIS, high supply yields a 38p/therm average. However, the BEIS high supply in a UK carbon-constrained situation seems implausible, but due to continued supply from continental Europe, LNG from the United States gas market, and the middle east, supply remains high.

Secondly, in a carbon-constrained scenario, it is expected that regulation and standards will be advanced to mitigate pollution and investment in carbon-emitting industries. The regulatory advancement is expected to include the application of reduced emissions completions (RECs) technology and other technologies stated in chapter 6 of this study. Also acknowledged is that best practices could increase the cost of a typical well by about 7% (Wang et al., 2014); this study in relation to carbon emissions abatement via RECs applies the pessimistic upper-cost range in the table below:

Table 96 Typical Cost for RECs (Source; USEPA, 2011)

One-Time Transportation and Incremental Set-Up Costs (USD)	Incremental REC Equipment Rental and Labour Costs (USD)	Well Clean-Up Time (Days)
600 per well	700-6500 per day	3-10

Thirdly, we expect a carbon tax regime and policy to be in place during this scenario. As such, industries will be taxed based on the estimated carbon emissions produced. Additionally, the price/cost of carbon is guided by the USEPA (2016) which estimates the cost between USD41/ tCO2e and USD64/tCO2e; the upper range is applied which is approximately £50/ tCO2e and 64% above the UK carbon price floor (CPF) guidance of £18/t tCO2e for 2019 but 40% less than 2030's £70/ tCO2e CPF (Hirst, 2018).

In this analysis, the carbon emissions from fugitive emissions are considered, and carbon emissions from the utilization of gas in electricity generation as an assumption. The fugitive emissions from shale gas production have been discussed earlier with a range guided by different studies, but prominently, Tollefson (2012) and Hashem (2016) both propose 4% of gas produced is lost to the atmosphere while Ecoinvent (2010) and USEPA (2012) propose a range of $4.1m^3$ to $54m^3$ gas vented per metre drilled. In relation to the carbon coefficient, 53.12kg CO_2/tcf is applied based on USEIA (2019) in Appendix C. However, note that Methane is considered 25 times more potent than CO^2 on a 100-year basis and apply this impact to the appraisal of production vented emissions.

7.7.1 Results

The modelling above impacts the development cost via increased drilling cost and tax expense. Other impacts are on breakeven gas price and the net present value of the proposed well development. Initially, the impact on development cost is analysed. The average impact of reduced emissions completions on drilling costs ranges from 0.57% to 0.81% and a 0.60% average. The maximum drilling cost impact occurs on the Roddelsworth well while the minimum impact is on the Blacon east. Overall, reduced emissions completions increase the wells' drilling cost by about half a million dollars from USD88.9Million to USD89.4Million. In relation to carbon taxes, the impact on tax increase ranges from a low of 3.2% to a high of 7.2% with an average impact of 4% on the developed wells, which results in an overall increase from USD118Million to USD124Miilion, a subjective impact. Considering gas prices, the average impact is a 10% increment in the required breakeven price. The highest gas price impact is on the Bosley located well, resulting in a 16% change between the reference and carbon-constrained cases.

Furthermore, the discounted cash flow analysis over 150month reveals the REC and carbon taxes' combined influence on commercial viability. The net present value of the Grovewell well is altered from USD0.655Million to a negative (USD2.5Million), and thus the well is not developed while the Blacon well's NPV reduces by 25%, Bosley decreases by 27%, Heywood is lowered by 32%, Long Eaton's NPV also declines 29%, there is also a 41% downgrade in the NPV of Roddelsworth while Wessesden's NPV decline is 33%. The Swinden well NPV reduces from a negative of USD7.4Million to USD8Million, which changes the commercial viability. Finally, the carbon floor price required to dismiss the development of analysed shale wells is USD573/ tCO2e, equivalent to £440/tCO2e based on the scenarios and modelling approach. The resultant carbon price is untenable in the short, medium, and long term; DECC's Global Carbon Finance (GLOCAF) model estimates an average global carbon price of £65/tCO2e for 2030 and £255/tCO2e by 2050.

7.8 Summary

Chapter 7 of this study integrates models developed in earlier chapters to a discounted cash flow examination to yield the undeveloped shale gas investment decision model (USHIDM)). Thus, the USHIDM consists of the depth-dependent correlation matrix (DDCM), which applies a well specific and micro-level production profiles, cost estimation model based on work breakdown estimation, fiscal regime parameters, and advanced unit metrics. Finally, the results of micro models are incorporated into the discounted cash flow model. The sensitivity of the results to input and out parameters is evaluated and the impact of oil price using the developed empirical opruci model. Based on the results, shale gas wells' heterogeneity applies to most economic aspects; production, costs, sensitivity, and response to exogenous events and macro-level appraisal will not account for this property.

The drilling and completion expense on the average accounts 34% and 53% respectively in the examined Bowland shale gas wells, this cost breakdown results show that the average of drilling costs between USD2.4Million and USD2.8Million while USEIA 2016 notes that US-based wells had a range of US1.8Million to USD2.6Million. Considering completion costs, the wells examined are between USD7.4Million and USD9.2Million, but that of the US wells had an average range of US2.9Million and US5.6Million. Cooper et al., (2018) applies an estimated shale development capital cost of GBP10.16Million and eventual total cost of GBP18.63Million which is equivalent to about USD23.2Million; 47% more than this study's high case scenario and 60% more than that of USEIA (2016). Cooper et al. (2018) is a macro level cost estimate and relies on Lewis et al. (2014), Amion (2014), Taylor and Lewis (2014), and Cronin (2013). The joint research objective of Taylor and

Lewis (2014), Amion (2014) as well as Lewis et al., (2014) is the economic impact analysis which relies on gross value added aimed at estimating the macroeconomic impact of shale gas development based on expenditure/costs. Secondly, the studies are authored by industry bodies aimed at positively influencing shale gas policy. These studies, mostly authored in 2014, rely on older data, which does not account for learning curve rates studied and developed in chapter 5. The learning rate is estimated to be between 20% to 77%, resulting in faster rates of drilling penetration. The application of an appropriate cost model is essential for comprehensive commercial evaluation and policy guidance. This study applies a developed micro level, work breakdown, material use per depth, and lateral length cost model, which gives well specific cost estimates that account for depth, geology, and technical efficiency in the rate of drilling penetrations and other parameters that impact development capital cost. Also, to account for uncertainty, the cost estimation applies scenarios to both the drilling and completions costs; average cost under these (low, mid, and high); USD9.9Million, USD10.9Million, and USD12Million respectively for the wells considered.

The examined wells' net present values are the first micro-level commercial appraisal of undeveloped shale gas wells as at date. The net present values are on a per well basis as against play level and country/play broad analysis provided by Weijermars (2013), Saussay (2018), and Cooper et al., (2018). The methodology's justification is further provided in the divergent internal rate of return, sensitivity response to changes in input and output parameters, and gas breakeven prices of all wells analysed.

Furthermore, the impact of oil price fluctuation on shale undeveloped gas's economic assessment is the examination and demonstrated based on the earlier empirical study in chapter 4. It is concluded that oil price fluctuations have had a nominal impact on shale gas development costs. About carbon emissions reductions, this study concludes that Figure 43 below shows that the overarching impact of reduced emission completions on the development of shale gas well based on the scenarios and input parameters is about 33% reduction in net present value from about USD160Million to USD107Million on the wells over 150 months.

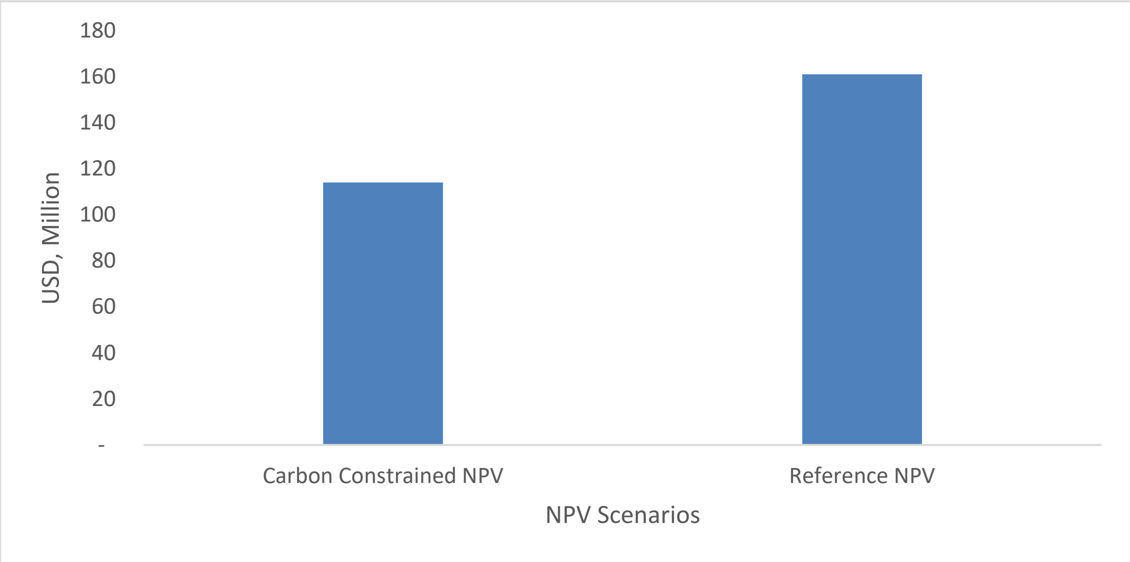


Figure 43 NPV Scenarios of Wells Examined

Based on the model parameters, results, scenario generation capabilities and heterogeneous characteristics of shale gas wells, concluding that shale gas commercial valuation should be as much as possible based on bottom-up well specific evaluation models such as the USHIDM which relies on work breakdown cost estimation and the developed depth-dependent correlation matrix numerical production approach.

8 Conclusion

8.1 Introduction

In concluding this study, reference is made to the objectives and research questions highlighted in chapter 2 of this study and provide the relevant findings based on the methods, results, and discussions. The overarching aim was to review and address the parameters that affect the economic appraisal of undeveloped unconventional gas, focusing on production benefits, cost, and regulation based on risks and externalities. This concluding chapter consists of five sections, production, costs, limitations of the study, future research opportunities, and overarching remarks.

8.2 Production

The first research question inquiries about the appropriate production forecast approach for undeveloped unconventional gas wells to address the following:

a. What impact does geological reservoir parameters, gas properties, and production efficiency have on initial gas flow and estimated ultimate recovery?

b. How can the initial flow rates and estimated recoveries be estimated?

c. How could uncertainty in reservoir conditions be addressed?

d. What could production scenarios be modelled to emulate eventual well production in the UK?

This research objective and questions are addressed in chapters 2 and 3. A detailed literature reviewed reveals the present shortcoming of methods and models applied to production estimation from unconventional gas sources in chapter 2. The following are concluded:

a. Seven parameters impact production based on the model adopted: formation volume factor, pressure, viscosity, permeability, porosity, and compressibility. A 10% decrease in input values for permeability, porosity, and compressibility yields a 20% decrease in estimated recovery, while a 10% reduction in the viscosity value increases gas recovery by 20%: an inverse relationship. In the rock extractive index, a 10% increase in input value results in a 40% estimated gas recovery growth; however, for the formation volume factor, a 40% production decrease yields a 10% value increase. Finally, for gas pressure, a 10% input value increment leads to a 40% increase in estimated production. The formation volume factor has the most impact on production estimates; it is the rock exposure index and accounts for the technology/hydraulic fracture process's production efficiency. Pressure and viscosity are subsequent and have a similar impact. While permeability, porosity, and compressibility have the least and similar impacts on production estimation.

b. Initial flow rates and estimated recoveries are evaluated via a developed depth-dependent correlation matrix numerical method applied to the prospective wells in the Bowland shale located in England to yield initial flow rates on a per well basis. It is determined that these wells in the reference scenario can produce an average of 147,00scf natural gas daily, while the EUR over 12 years is estimated as 1.1bcf of natural gas. The study proposes the application of a bottom-up well-based production estimation, which can account for heterogeneity and uncertainty in shale wells.

c. Concerning the uncertainty in the reservoir, permeability, and porosity, which are applied as scenarios due to data unavailability and based on data range in this study, have the least impact on recoverable reserve estimation. The results account for below ground uncertainty and heterogeneity of wells. A sensitivity analysis is applied to consider the relative impacts of individual parameters on production potential. A hybrid approach is also necessitated to address the high uncertainty introduced into the production estimation by the absence of porosity and permeability values in an undeveloped shale gas well. This lack of empirical evidence also impacts the first step and requirement to propose a distribution characteristic. Consequently, the uniform and normal distribution outlines are applied in this approach; the characteristic high and low values are thus interpreted as either the maximum or minimum values. A risk analysis using a Monte Carlo simulation is applied to randomly estimate the value of porosity and permeability for both the lognormal and uniform distributions using the @Risk software by Palisade. The random sampling and selection process requires many iterations; 5×10^3 over 100 times. The results yield the most probable values for these parameters under these distributions and conditions.

d. Four production scenarios are developed for the UK based on relevant parameter ranges (low and high) based on the average values (mid) and based on the hybrid approach, which applies a Monte Carlo model and the numerical approach.

8.3 Costs

The second research question focuses on estimating unconventional gas development costs, focusing on an appropriate methodology. The subordinate research questions are:

a. What are the cost drivers of unconventional gas development?

b. What is the impact of oil price uncertainty on unconventional gas cost parameters and the short, medium, and long-term development outlook?

c. What are the possible range and distribution of cost factors based?

d. What influence would different regulatory regimes have on unconventional gas development costs?

The enquiries above are resolved in chapters establish scenarios establishes scenarios, and 7 provides an overarching view of the research. Based on the guidance provided above in the research questions, principal findings are detailed below:

a. This study applies a hybrid of a bottom-up assessment and a parametric estimation method that aims to account for uncertainties and ensure the developed method is dynamic. The parameters that drive unconventional gas projects are classified into endogenous and exogenous. Based on data from the United States, the endogenous cost drivers of shale gas production are the cost of stimulation (hydraulic fracturing), drilling and casing; stimulation by hydraulic fracturing being the major endogenous cost factor.

The application of a developed work breakdown method to undeveloped shale gas wells in the Bowland shale also reveals a similar trend with hydraulic fracturing determining about 50% of total development cost. The cost of hydraulic fracturing which relies mostly on sand and water input. Secondly, the cost of drilling and casing shale wells also greatly impacts the total development cost of shale gas wells.

b. Concerning the impact of oil prices, an econometric analysis of the real data and transformed data reveals two different results. The untransformed data reveals a high correlation between oil prices and other cost parameters except with vertical drilling prices, while the transformed data shows an insignificant correlation in most cases except steel prices. Overall, the econometric model also reveals the relative impact of US$1 increase in oil prices on all parameters. The insignificant correlation of cost parameters with oil prices suggest that additional factors need to be analysed. Based on the inconclusive and insignificant impact of oil price on the cost of unconventional gas development, reviewed the learning curve theory, energy technology learning curve literature, developed and applied a one-factor technology-specific learning curve model to prominent shale plays in the United States thereby accounting for location biases.

I conclude that as the rate of penetration doubles the rig day cost reduces between 31% to 62% in the appraised shale plays while for completion or hydraulic fracturing operation, the estimated learning rates are between 20% and 77% and adoption case estimated learning rates between 19% to 81%. The cost of producing shale gas has reduced over time due mostly to a cumulative doubling in production.

This study provides a foundation and base knowledge on the impact of technological efficiency on different shale plays, giving insight into recent development interest in the Permian shale region. Sweet spots are attributed to shale wells or areas with exceptional production profiles. Perhaps, cost profiles can also determine sweet spots. Sweet spots can thus be defined as shale plays with enhanced production to cost profile. The methodology can thus guide the cost of future shale resource development in plays, regions, and countries.

c. In terms of location-specific cost, drilling and casing costs are considered and expected to be higher in the United Kingdom by about 13%. Within the United Kingdom, I focus on the Bowland shale. Cost projections are based on scenarios and factors broadly drilling, and completions derived. In the high-cost scenario, the estimated drilling expense ranges between USD2.2 Million and USD3.2 Million, while the range in the low case is between USD1.9Million and USD2.7Milion. This study's reference mid-case has a drilling cost range of USD2.1Million and USD2.8Million. The averages are USD2.4Million, USD2.5Million, and USD2.8Million for the low, mid/reference, and high scenarios. I assume a 50% UK premium escalation and continuous 7400ft lateral length and material consumption based on empirical data about completions. Relying on these scenarios and assumptions, our cost model suggests that completion cost ranges between USD7.4Million and USD9.2Million across the appraised shale wells in the United Kingdom.

d. The impact of fiscal and regulatory regimes on the cost and the commercial viability of the examined shale gas wells is examined via the application of a discounted cash flow model and a sensitivity analysis. The current fiscal regime in the United Kingdom is 30% of gross revenue take. Thus, the impact of a 20% rise is reviewed while keeping other parameters unchanged; this results in a 10% change in net present value while direct development costs cause a 4% change in net present values. The fiscal regime is a significant endogenous cost parameter.

Based on the result of the cost, production, and fiscal regime analysis, sweet spots are identified in the undeveloped Bowland shale. The Blacon east well has higher commercial prospects due to better productivity, although higher developmental and fiscal costs. The well provides satisfactory outcomes on all pessimistic scenarios analysed along with the Bosley, Long Eaton, and Heywood wells in that order while the Roddelsworth and Wessessden wells are marginal. However, the Grovewell and Swinden wells are likely to be undeveloped under the applied cost structure, gas price, and fiscal regime. Additionally, an additional regulatory regime impact due to greenhouse gas mitigation via carbon taxation and reduced emissions completions is assessed. The carbon-constrained scenario reduces commercial viability by 33%, resulting in displacement by other energy sources, renewable or non-renewable.

The natural gas outlook is uncertain, with options as either a relative or absolute bridge in the energy transition dynamics. BP energy outlook 2019 notes that global energy requirements increase, and natural gas demand grows much faster than other fossil fuels in all scenarios. Also, implementing a carbon tax regime and carbon prices are expected to further shift from coal to gas. Furthermore, an emissions reduction will be likely based on the development of a circular economy, energy efficiency improvements, decarbonized power generation, hydrogen deployment, and fossils fuels with carbon capture and storage technology.

Nonetheless, OECD energy demand is expected to decline while non-OECD's increase mainly in China and India but with the transition from coal to gas and renewable sources. This transition is expected to pressure global gas prices and security, leading to greater competition between pipeline and LNG gas in Europe and China. The Digest of UK Energy Statistics (2020) highlights a 21% reduction in pipeline imports from Norway but an increase in LNG importation from the US: a shale gas producer.

McGrade et al. (2018), in the net-zero UK energy system, all coal-fired generation is removed by 2025. However, a delayed deployment of carbon capture and storage technology through lack of policy support or/and limited global commercial progress will result in a replacement capacity issue for the UK energy policy. The study notes that a "second dash for gas" may provide short term gains in reducing emissions; in this scenario, the primary question will be UK produced or Imported gas. In the UK Imported gas scenario, conventional and unconventional gas will be the options. Furthermore, in the UK, fugitive emissions from produced natural gas are included within its territorial emissions but imported natural gas (Liquified or Pipeline Sourced) is effectively considered carbon-neutral, this approach favours imported conventional or unconventional gas. Andrew (2013) highlights that an increase in domestic gas production might have lower life-cycle emissions than other sources of imports, such as liquified natural gas (McKay and Stone, 2013).

8.4 . Research Contribution

The study has appraised the commercial viability of undeveloped shale gas appraisal in the United Kingdom. The appraisal began focusing on the various production estimation models, recommending the utilization of a rate transient analysis-based methodology that relies on geological and reservoirs parameters. Consequently, a depth-dependent correlation matrix model is developed to provide parameter data that drives a numerical model. This is the first attempt to apply a numerical model that accounts for well heterogeneity and uncertainty; results show that wells examined can produce an average of 147,00scf natural gas daily while the EUR over 12 years is estimated 1.1bcf of natural gas. This provides insight into the potential energy security contribution from the wells into the UK energy mix.

Secondly, a cost analysis guides the development of a depth-related bottom-up cost estimation methodology based on work breakdown. Besides, an initial research attempt on the impact of oil prices on shale gas development costs is analysed. The results identify cost parameters and use the developed empirical model, which suggests that there is limited correlation between oil prices and most major cost parameters except steel.

Thirdly, the impact of technological change and innovation on the shale resource development cost is studied. The study yields novel learning curve models for shale resources, which presents that drilling technology and increased lateral lengths have driven cost reduction while the hydraulic fracturing technology has relied on more material use volumes and, therefore, more sustainability concerns. This outcome presents that the UK shale industry, if/when developed, benefits reduced development cost due to learning, technological change, innovation, and research in the United States shale industry. As such, the anticipated high cost that was expected to impact the process's commercial viability is no longer relevant. The application of previous analogous cost estimates on the current assessment of UK shale gas cost will lead to overestimation. Equally, the reduction in cost identified in this study also queries the top-down macroeconomic impact assessment justification methods applied, which rely on high development cost estimation and multiplier effects. Consequently, the development cost and direct economic impact based on anticipated expenses from shale gas development have reduced over time.

The wells' commercial feasibility in the Bowland shale play is assessed by integrating the production, cost, and fiscal model. The integrated model is designed to account for carbon emission mitigation and carbon taxes, addressing some sustainability issues. The carbon mitigation cost and carbon tax expense over 150 months result in a 33% commercial value decline, leading to a corresponding transition to renewable energy in electricity generation. However, asides carbon emissions other environmental concerns exist.

8.5 Limitations of the study

Although the overall and specific research conducted presents many advantages and contribution to their relevant fields, some limitations need to be addressed to improve the output while also reducing uncertainty. The limitation section is detailed based on research sub-themes; production estimation, empirical cost parameters, environmental issues, and bottom-up cost estimation model.

Initially, a literature review is conducted focusing on shale resources' production estimation and developed an alternative numerical approach based on the depth-dependent correlation matrix (DDCM). The DDCM estimates four of the six required parameters for the numerical approach, while the other two parameters (porosity and permeability) are estimated based on established ranges and a probabilistic method; I apply the ranges and results as scenarios. Further study into estimating porosity and permeability will reduce uncertainty and provide additional clarity to policymakers and investors.

Secondly, relating to cost analysis and its empirical relation with oil price, horizontal and vertical rig demand indices and hydraulic fracturing sand demand index in the United States are applied. The application of demand indices as an analogy for the cost of vertical and horizontal rigs and hydraulic sand demand for these cost parameters cost was due to unavailability of data for the rigs, and available but short empirical stimulation sand data introduces a level of prejudice to our regression model. The objectivity of the model and empirical study will benefit from cost data for the three cost parameters over the study time framework. Additionally, the possibility of including other regression analysis variables will reduce omitted variable biases if present in this study.

Thirdly, in the case of environmental and sustainability concerns about the development of shale resources, we review studies focused on the United States for water, air, properties, and wildlife habitat concerns. Other risks, externalities, and consequences of developing shale gas include the impact on real estate value, seismic risk, and other industries' crowding due to increased demand. This commercial appraisal has incorporated the mitigating cost of carbon emissions (reduced emission completions) as well as a carbon emissions tax. About seismic risk, in 2011 there was an earthquake with a maximum magnitude of $2.3M_L$ recorded to have been caused by direct fluid injection into an adjacent fault zone during operations; Green et al., (2012) propose a protocol for controlling operational activities which depends on extensive enhanced geothermal system experience and a traffic light system with a recommended lower limit of $0.5M_{L.}$

Additionally, the validity of applying US development, operational methods to the UK framework introduces certain limitations. The limitations include the unique macroeconomic, currency, regulatory, fiscal regime and physical/play characteristics that vary between economic zones and countries. Although this research addresses some of these factors, the macroeconomic, political, and fiscal features are dynamic and vary subject to uncertainty and other conditions. Consequently, attention is recommended for researchers to review the location of the resources being analysed when applying the developed models.

Furthermore, the hydraulic fracturing process's production analysis and cost estimation applies a lateral length of 7500ft. Although the applied lateral length is based on empirical evidence, the application of an assumed lateral length on production could either lead to reduced or increased production profile thereby overestimating or underestimating the probable production from the well over time. A similar impact can be expected on the cost estimation. The cost estimation based on longer laterals will exaggerate costs while shorter laterals will reduce costs. However, the benefits from a longer lateral in production will be offset by increased costs.

Lastly, with the impact of oil price on cost parameters I assume steel demand is directly proportional in steel prices. The study is limited by this assumption, which could undermine the related results.

8.6 Further Research Opportunities

The apparent future research opportunities from this study relate to production, cost estimation, empirical studies, regulation, and economic impact assessment.

I. Production: What is the appropriate methodology to estimate porosity and permeability in shale gas wells?

Further research focusing on well specific porosity and permeability values on the wells being appraised will reduce production estimation uncertainty and the gap between the presented production scenarios.

II. Cost Estimation: What factors determine lateral length during hydraulic factoring, and how can these be estimated?

As detailed in this study, the completion of a significant cost component in shale gas development. However, empirical lateral lengths for all shale wells, research on lateral length determines factors, and hydraulic fracturing design will provide an appropriate and comprehensive input parameter for commercial evaluation and analysis.

III. Empirical Studies: What impact does steel demand have on steel prices?

Are there omitted variables in this study's empirical studies and regression analysis?

Although the impact of steel prices in macro and microeconomics and industries are studied, our literature search on the impact of steel demand on steel prices results in limited results. Perhaps further studies on this subject will guide our correlation analysis. The regression analysis applies singular variables about omitted variables, and perhaps the inclusion of other variables will impact the results will provide further insight and an enhanced regression model.

IV. Regulations: What are the additional regulatory/economic/social costs due to shale gas development?

The impact of shale gas resource development processes on the economy where wells are domiciled, and other regulatory issues need further enquiry and examination.

For the United Kingdom and other shale prospect regions, the sustainability criteria and other environmental issues need to be addressed other than carbon emissions.

V. Economic Impact Assessment: what would be the economic impact of shale gas based on a bottom-up well specific cost estimation?

Economic impact assessment of the UK shale or emerging shale plays needs to be examined based on unique economic characteristics either via a gross value-added approach or into a macroeconomic input-output model, which will reveal the interaction of the energy production technology other economic sectors supported by the research's output and modelling approach.

8.7 Concluding Remarks and Policy Impact

This thesis suggests that commercial and policy decision making in shale gas development should be modelled via well specific production profile establishment and disaggregated bottom-up cost modelling via scenarios to address uncertainties by capturing inherent variability in production, cost, and fiscal regime parameters. The results give the estimated ultimate recovery, internal rate of return, and net present value estimates for each well analysed; these are essential parameters in assessing a prospective shale's overall commercial viability well. Moreover, incorporating the carbon emission mitigation strategy via green completions and provision for a carbon tax gives a rigorous economic assessment.

Although unconventional exploration possesses a legal license to operate, the development probability of unconventional wells in the United Kingdom is highly uncertain due to reduced social and political license. Unconventional resource's social license has been impacted by seismic activities, climate change awareness, and peculiar land-use policy. In relation to political license, the current conservative government's unconventional development policy has changed over time from promotion as an energy source option to a moratorium based on seismic activity but before a general election.

Policy and support for natural resource development consider tax revenue as an economic benefit. This research provides insight into the potential tax revenue from developing the wells appraised based on the model. The wells provide approximately £9.3Million in taxes annually, equivalent to 1% of total oil and gas fiscal contribution: £931Million. In a development scenario, upon establishing appropriate exploration and production regulatory guidelines, tax revenue could aid and fund further development of low carbon and renewable energy technologies.

This research's output questions the basis of the top-down macroeconomic modelling, which relies on cost estimates to yield job creation potential. The economic impact assessment is driven by jobs created and material use. Nevertheless, the learning curve analysis result shows that there has been cost reduction over the past decade which thus totally invalidates impact modelling based on redundant cost estimation. Consequently, cost reduction also shows less economic consumption in an input-output model due to less value between industries. However, unconventional gas development will increase gas specific energy security in the United Kingdom and improve the balance of payments due to less import dependency.

Global economic uncertainty is associated with heightened political, trade, terror, war, and indeed health/pandemics risk, and their adverse impact of global economic uncertainty on a country, sector, and industry level is an essential consideration in energy policy development. Global uncertainty generally results in a sharp decline in inflation, growth, and interest rate. This elevated uncertainty causes firms and investors to delay investment and, thus, procurement of material and services, leading to corporate and sovereign credit rating downgrades. However, an interest rate cut is the most common fiscal and monetary policy during high uncertainty regimes. The interest rate decline improves financing appetite for consumers and businesses as well as public institutions, which leads to increased consumption and investment to offset the lower product demand. As such, subject to other parameters being satisfactory, the development of unconventional gas resources during global economic uncertainty with characteristic low input price and interest rates improves the short-term economic feasibility marginally due to low wholesale commodity prices (gas). The development could also provide partial macroeconomic benefits while the mid and long-term feasibility improves with commodity price rebound subject to climate change policy and environmental concerns.

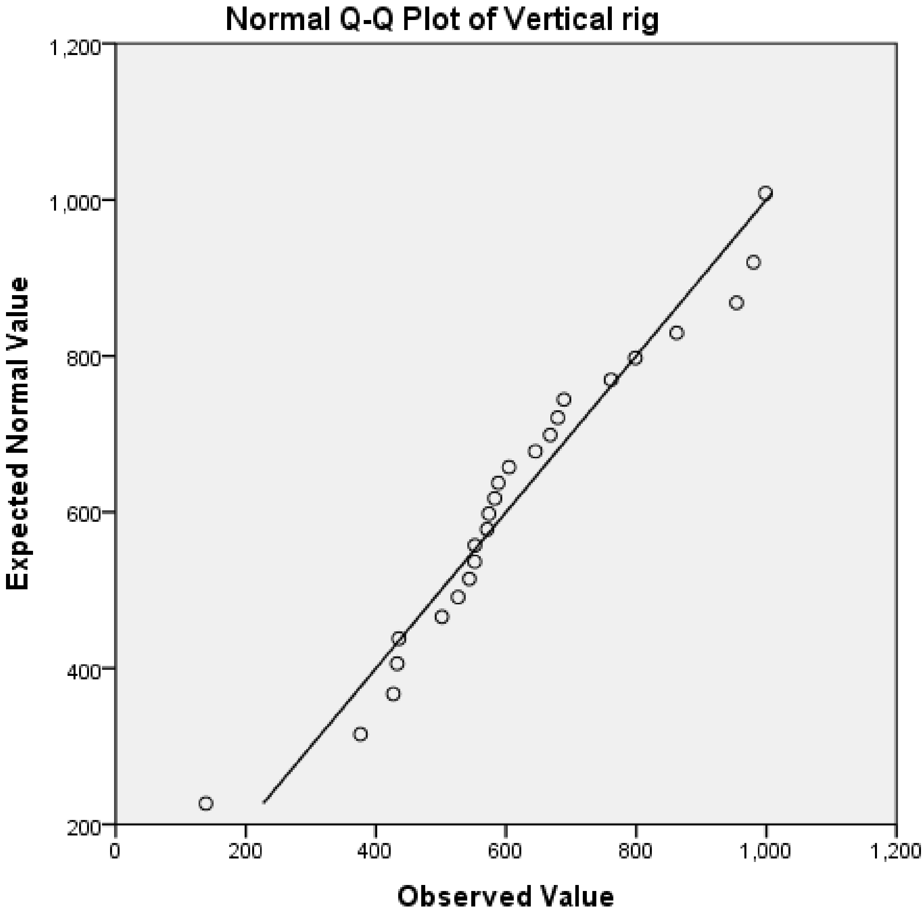
The current global energy policy is guided by affordability, sustainability/environmental concerns, and energy security. The development concerns of shale gas in Europe has been mostly environmental and risk factors. In the United Kingdom, development opposition dialogue has mainly focused on developmental risks (mainly seismic), while supportive dialogue has reiterated the UK's energy security gap and probable economic impact focusing on jobs. This study's result highlights the reduction in development cost due to technological innovation, which questions the probable economic impact on job creation, procurement from other industries, and employment. However, as of 2019, in the UK, natural gas accounts for 29% of UK energy production, meet 40% of the power plant fuel requirement, two-third of total energy demand, and provided space heating fuel. Natural gas is an essential component of the UK energy mix.

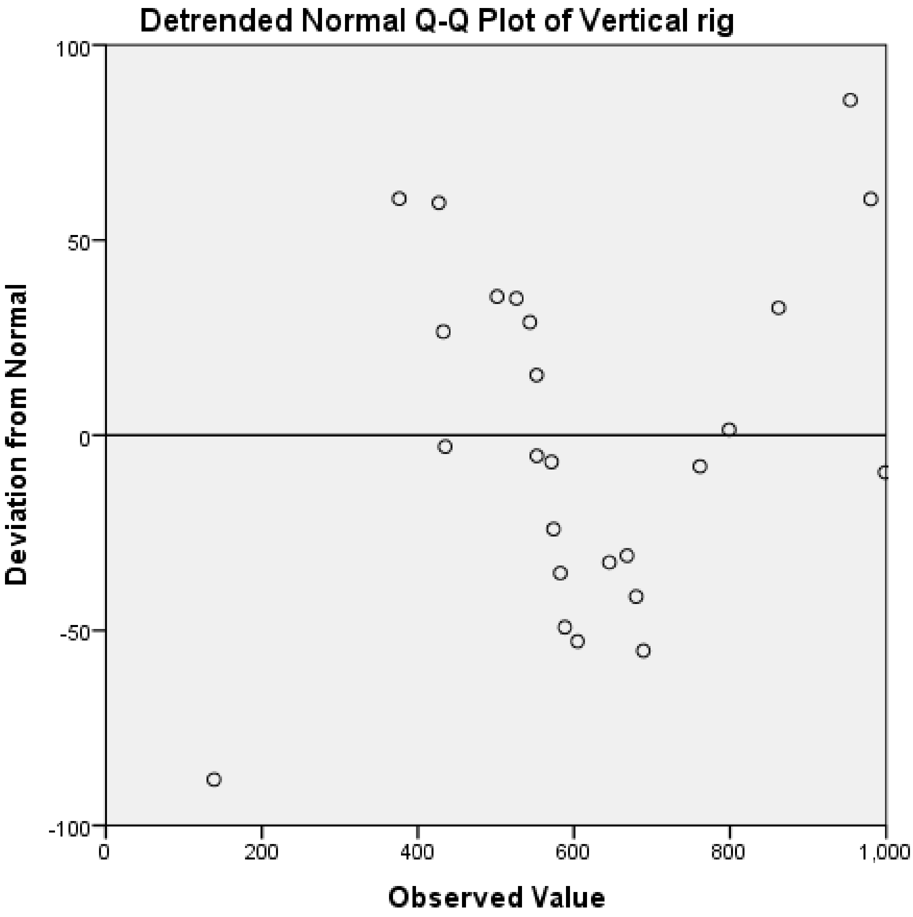
Nevertheless, natural gas production decreased by 2.9% in 2019 yearly, while demand lowered by 0.7%. On the other hand, the UK import of liquified natural gas (LNG) increased three-fold due to diversified supply options. In 2019, the United States supplied 20% of the UK's LNG demand, while shale gas contributed 90% overall natural gas production in the United States. Thus, the UK energy mix is supplied LNG produced from shale gas developed in the United States, leading to more life cycle emissions and carbon intensity. In conclusion, energy policy and developers have been unable to explore or develop shale gas resources but rely on similar resources developed abroad to meet demand. This research provides a more realistic bottom-up economic decision modelling, which considers the below and above ground uncertainties as well as innovation impact, thereby providing clarification and further understating for policy development while exploring climate change policy.

In conclusion, this thesis contributed to existing knowledge by providing an alternative micro-economic appraisal of geological, physical, technological, commercial, and sustainability parameters. The results show the scenario of production, development cost, and sustainability criteria, which could inform effective policies based on modelling output and investment decision characteristics. The policies could guide the short/mid-term energy transition policy relating to the UK gas sector. Additionally, the approach could also be relevant to international energy policy while guiding investors along the value chain. Overarching Energy policy is complex as it seeks to balance energy security, affordability, and sustainability to ensure natural capital preservation and a conducive climate for future generations while providing present resource requirements. The study and its results provide insight and potentials of a probable alternative mid carbon energy resource.

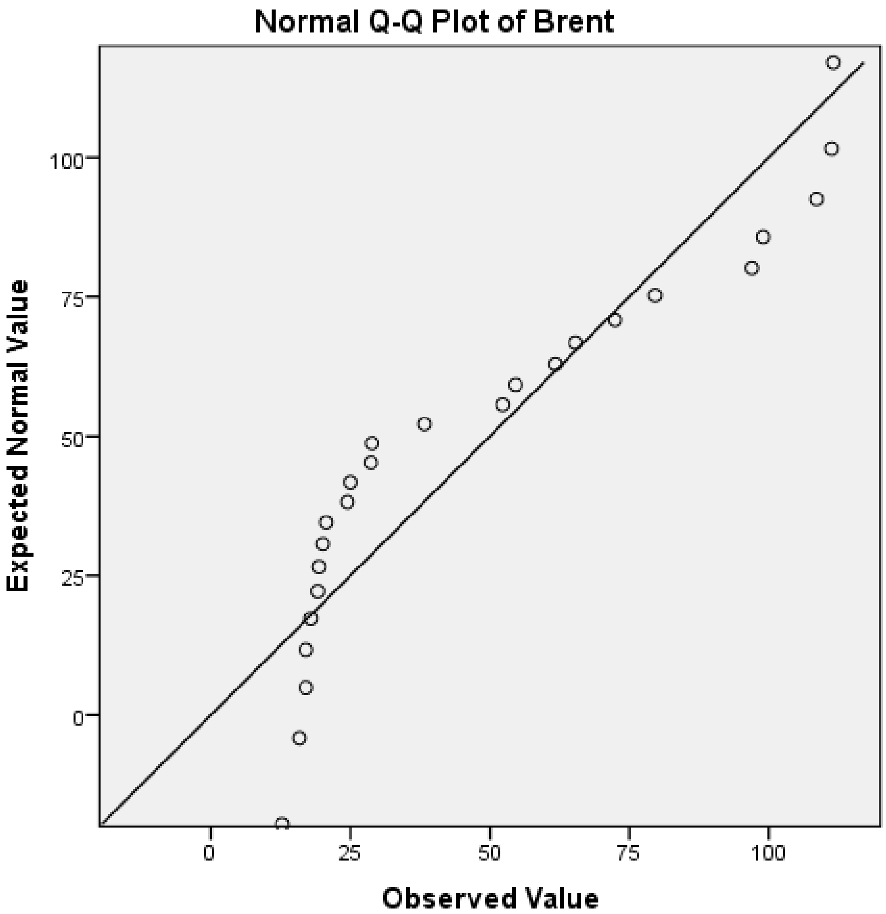
9 Appendix A

Vertical rig

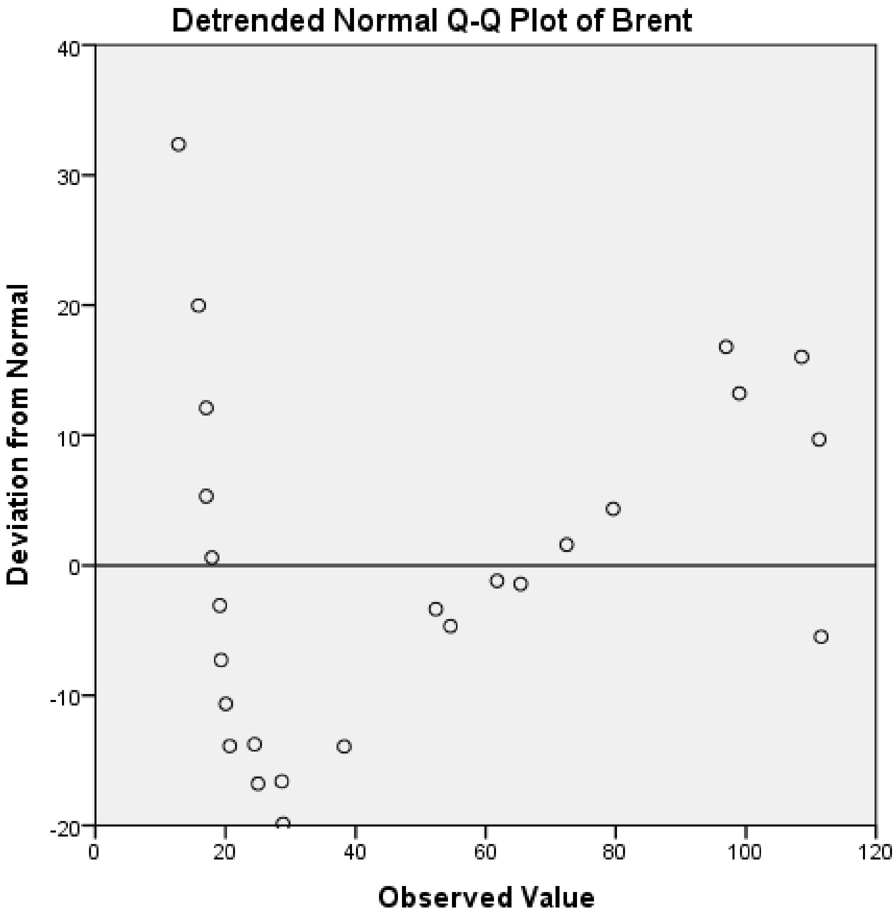


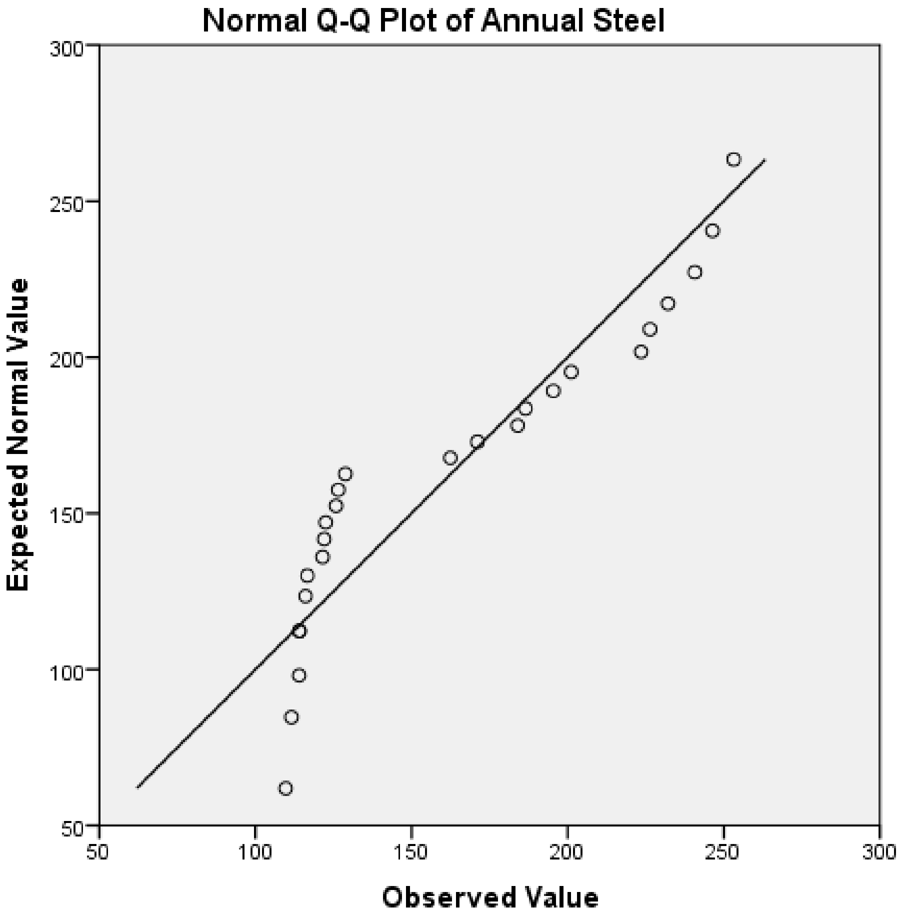

Detrended Normal Q-Q Plot of Vertical rig
Deviation from Normal
Observed Value
100
50
0
-50
-100
0
200
400
600
800
1,000

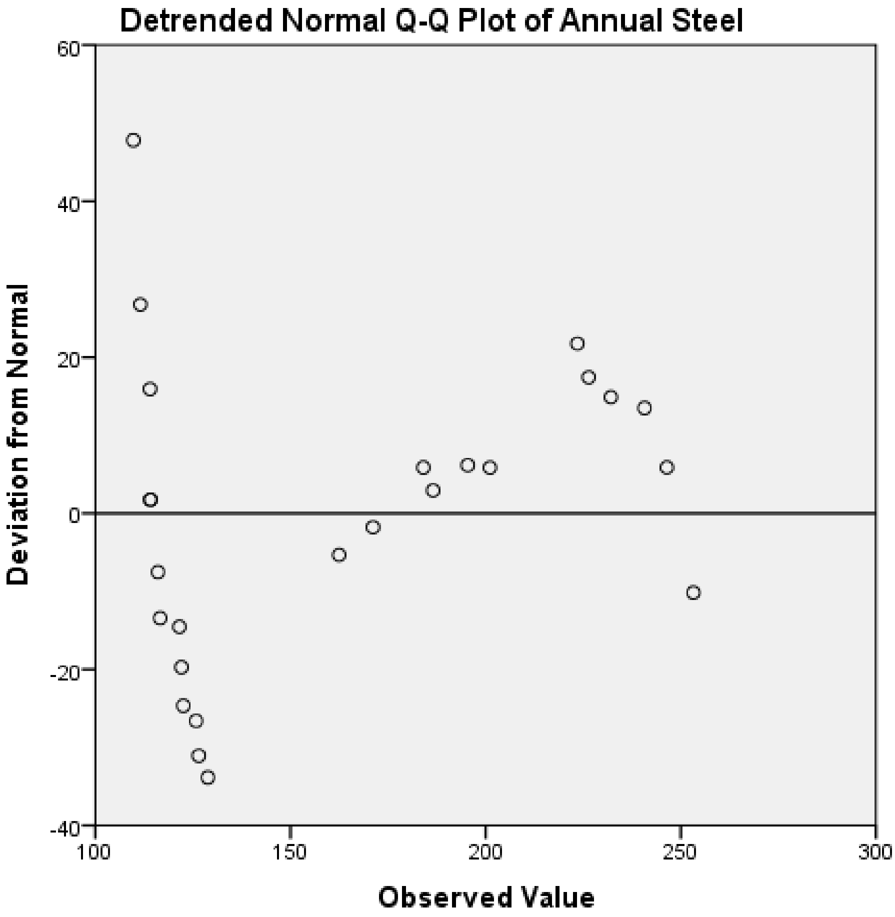
Brent

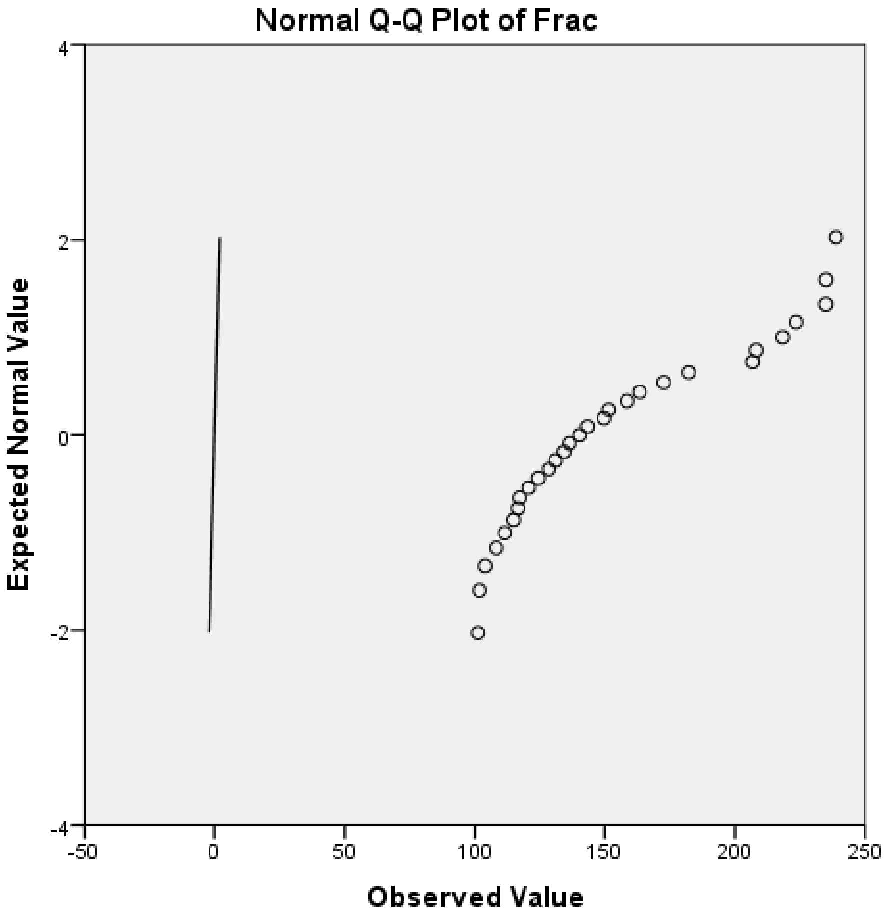


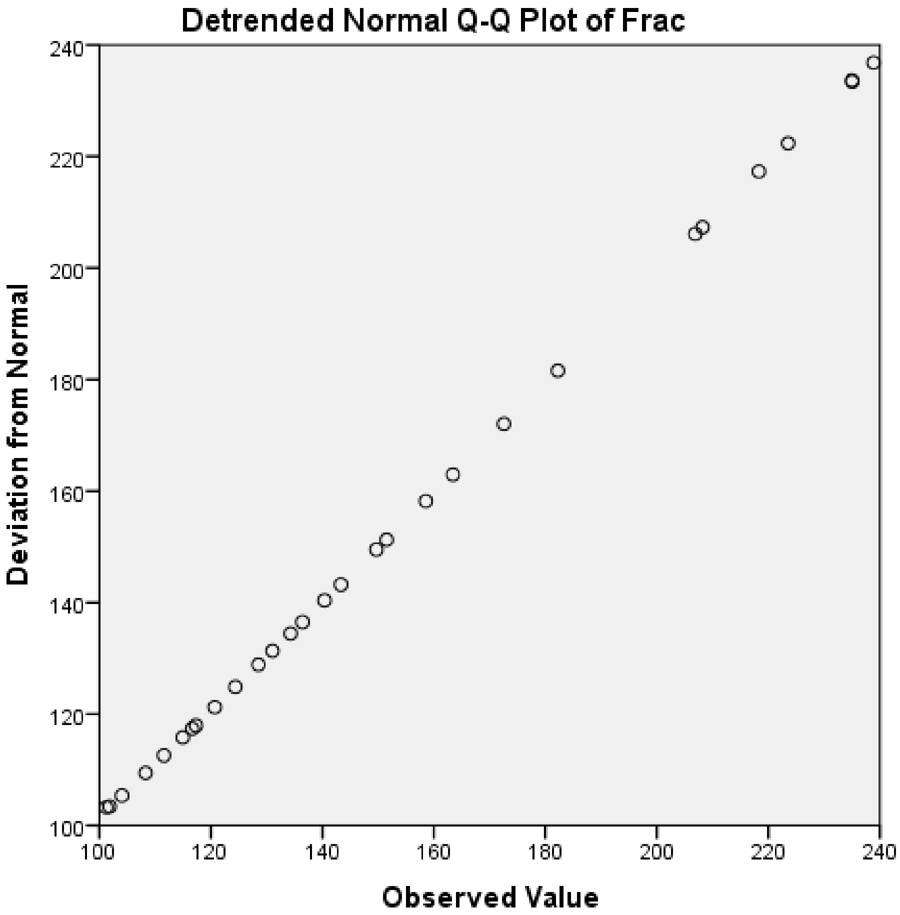
Normal Q-Q Plot of Brent
Expected Normal Value
Observed Value
100
75
50
25
0
0
25
50
75
100


Detrended Normal Q-Q Plot of Brent
Deviation from Normal
Observed Value
40
30
20
10
0
-10
-20
0
20
40
60
80
100
120


Normal Q-Q Plot of Annual Steel
Expected Normal Value
Observed Value
300
250
200
150
100
50
50
100
150
200
250
300

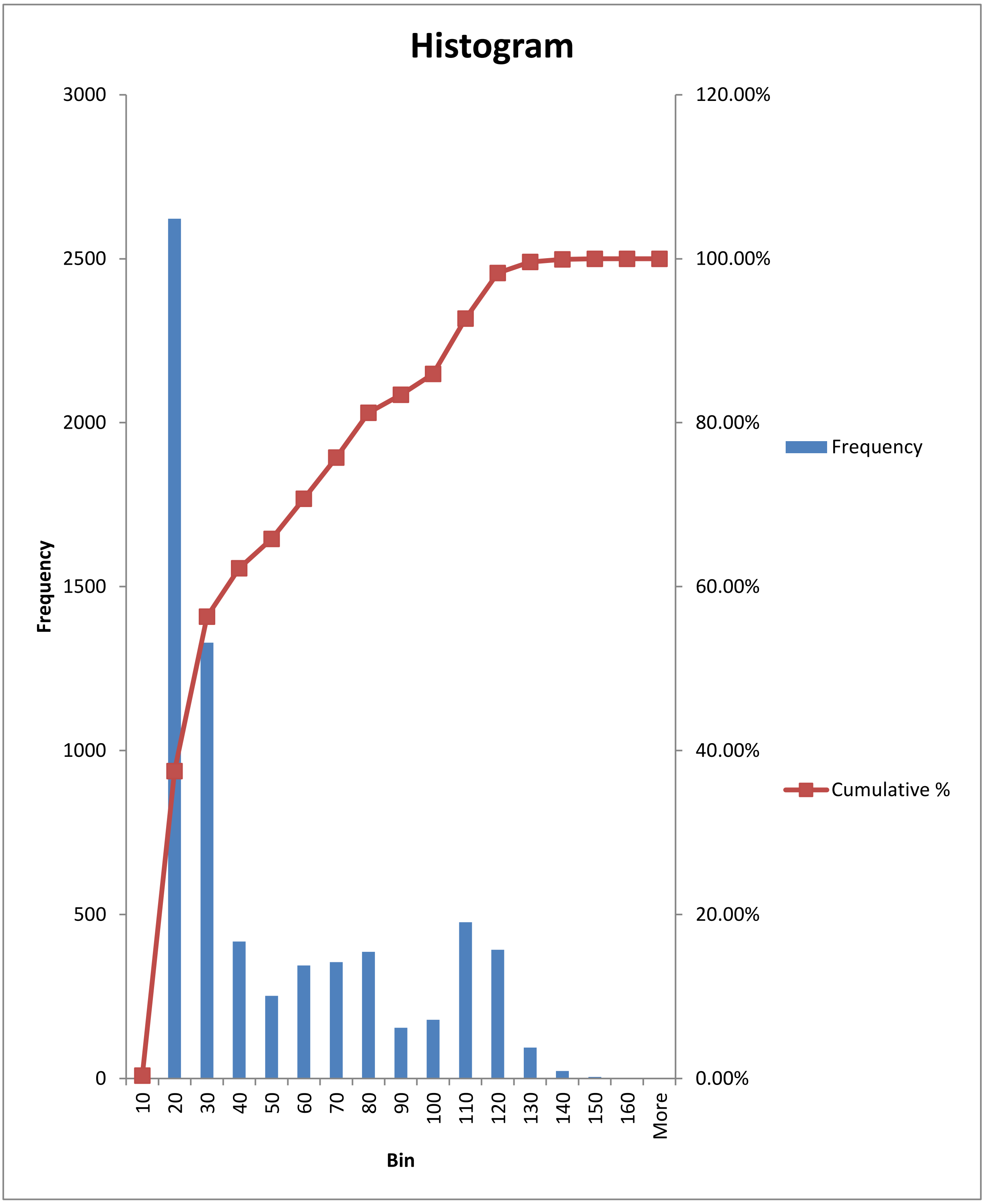

Detrended Normal Q-Q Plot of Annual Steel
Deviation from Normal
Observed Value
60
40
20
0
-20
-40
100
150
200
250
300


Normal Q-Q Plot of Frac
Expected Normal Value
Observed Value
4
2
0
-2
-4
-50
0
50
100
150
200
250


Detrended Normal Q-Q Plot of Frac
Deviation from Normal
Observed Value
100
120
140
160
180
200
220
240
100
120
140
160
180
200
220
240

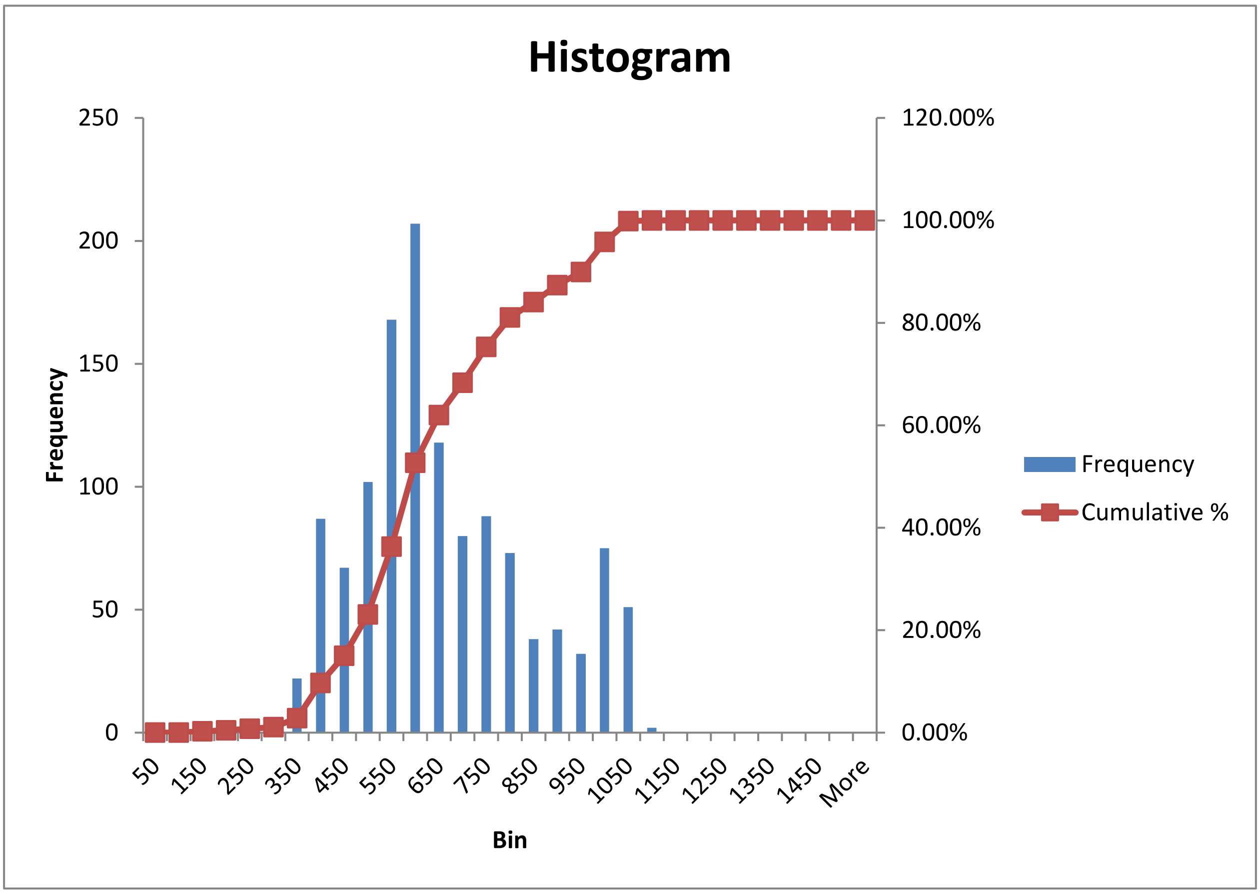
10 Appendix B

Brent Crude Oil Price Data Distribution



Bin	*Frequency*	*Cumulative %*
10	24	0.34%
20	2622	37.49%
30	1329	56.33%
40	418	62.25%
50	252	65.82%
60	345	70.71%
70	355	75.74%
80	386	81.21%
90	155	83.41%
100	179	85.94%
110	477	92.70%
120	393	98.27%
130	94	99.60%
140	23	99.93%
150	5	100.00%
160	0	100.00%
More	0	100.00%

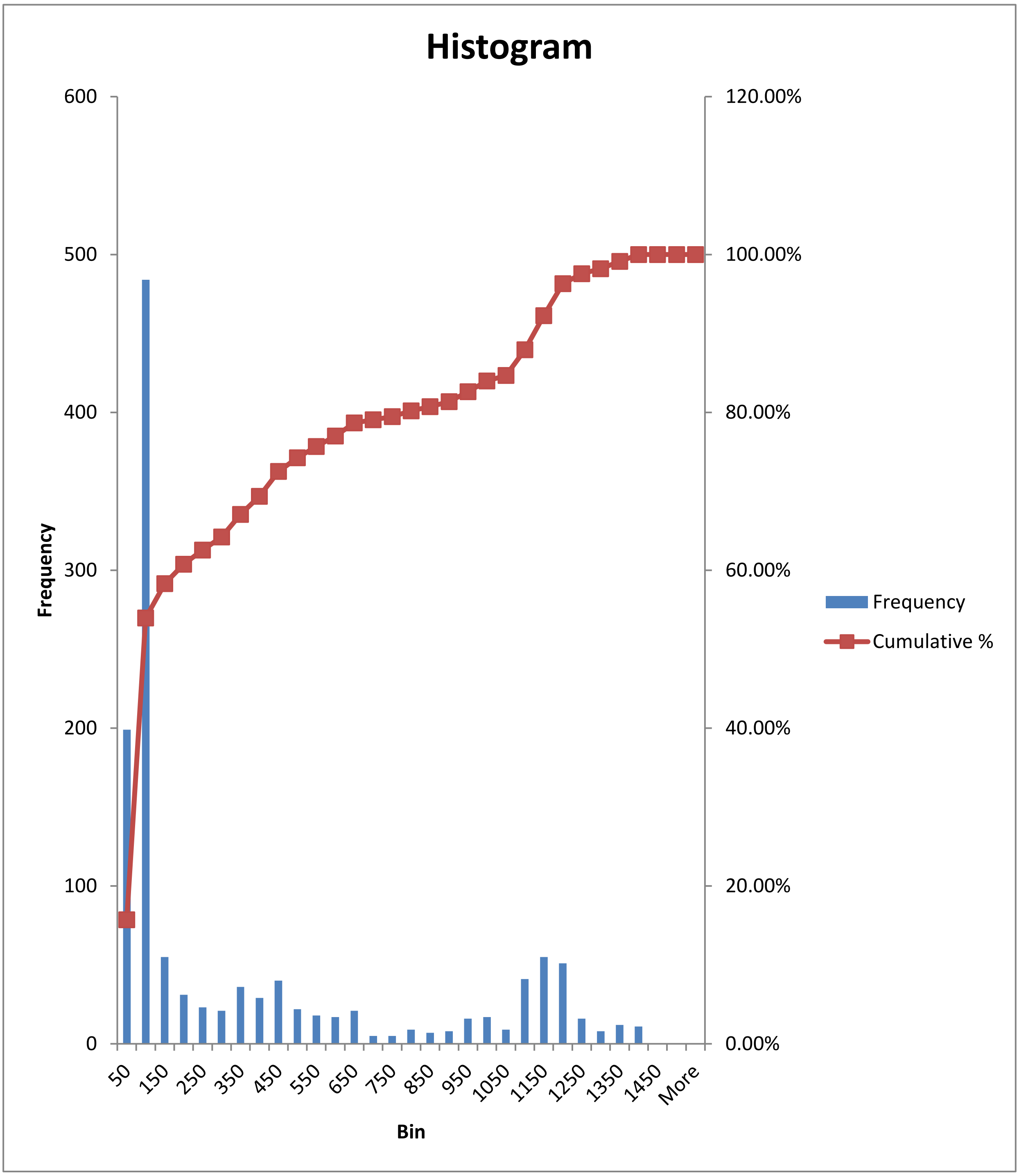
Vertical Rig Demand Data Distribution



Bin	*Frequency*	*Cumulative %*
50	0	0.00%
100	0	0.00%
150	3	0.24%
200	3	0.47%
250	4	0.79%
300	4	1.11%
350	22	2.84%
400	87	9.72%
450	67	15.01%
500	102	23.06%
550	168	36.33%
600	207	52.69%
650	118	62.01%
700	80	68.33%
750	88	75.28%
800	73	81.04%
850	38	84.04%
900	42	87.36%
950	32	89.89%
1000	75	95.81%
1050	51	99.84%

1100	2	100.00%
1150	0	100.00%
1200	0	100.00%
1250	0	100.00%
1300	0	100.00%
1350	0	100.00%
1400	0	100.00%
1450	0	100.00%
1500	0	100.00%
More	0	100.00%

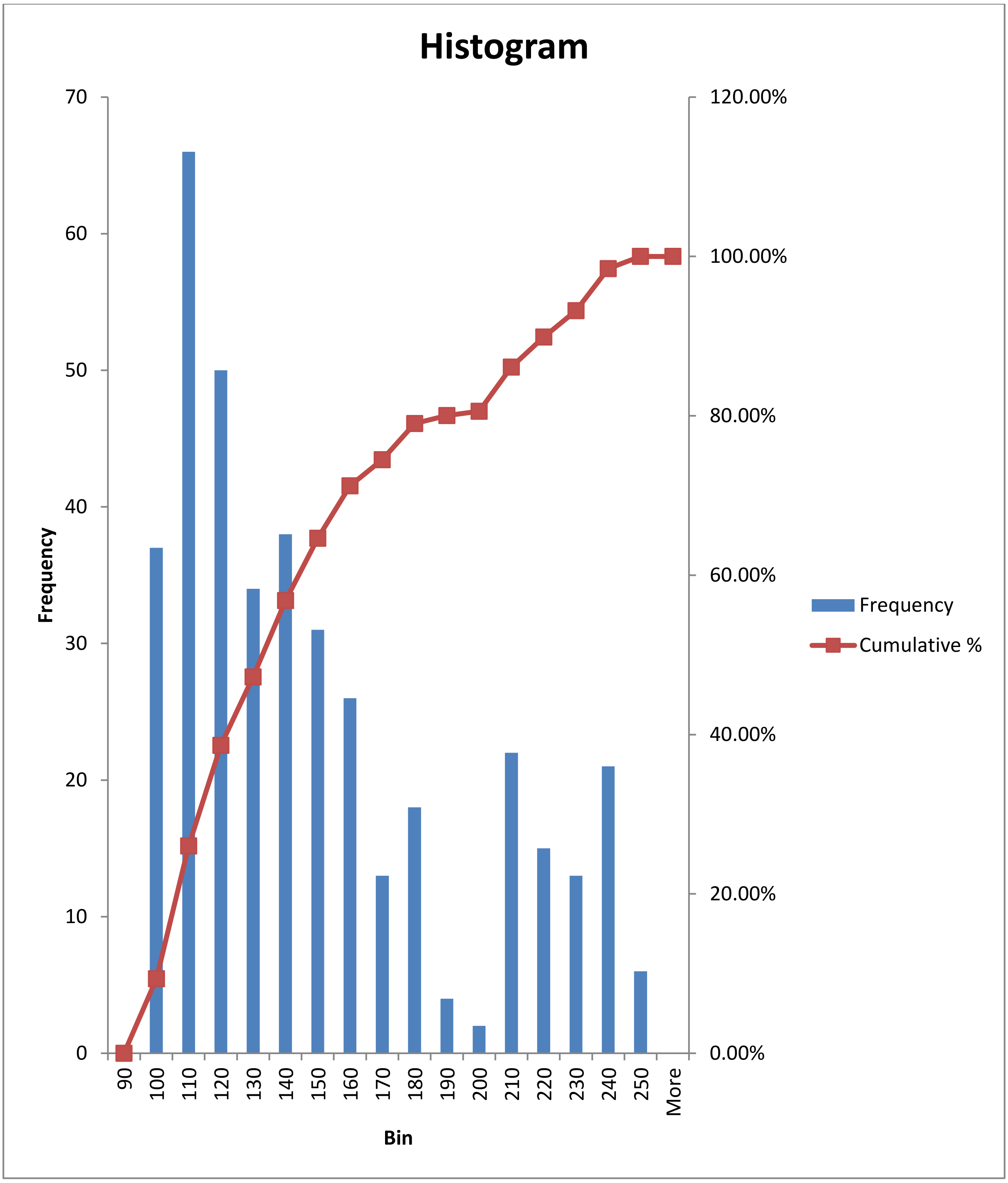
Horizontal Rig Demand Data Distribution



Bin	*Frequency*	*Cumulative %*
50	199	15.72%
100	484	53.95%
150	55	58.29%
200	31	60.74%
250	23	62.56%
300	21	64.22%
350	36	67.06%
400	29	69.35%
450	40	72.51%
500	22	74.25%
550	18	75.67%
600	17	77.01%
650	21	78.67%
700	5	79.07%
750	5	79.46%
800	9	80.17%
850	7	80.73%
900	8	81.36%
950	16	82.62%
1000	17	83.97%
1050	9	84.68%
1100	41	87.91%

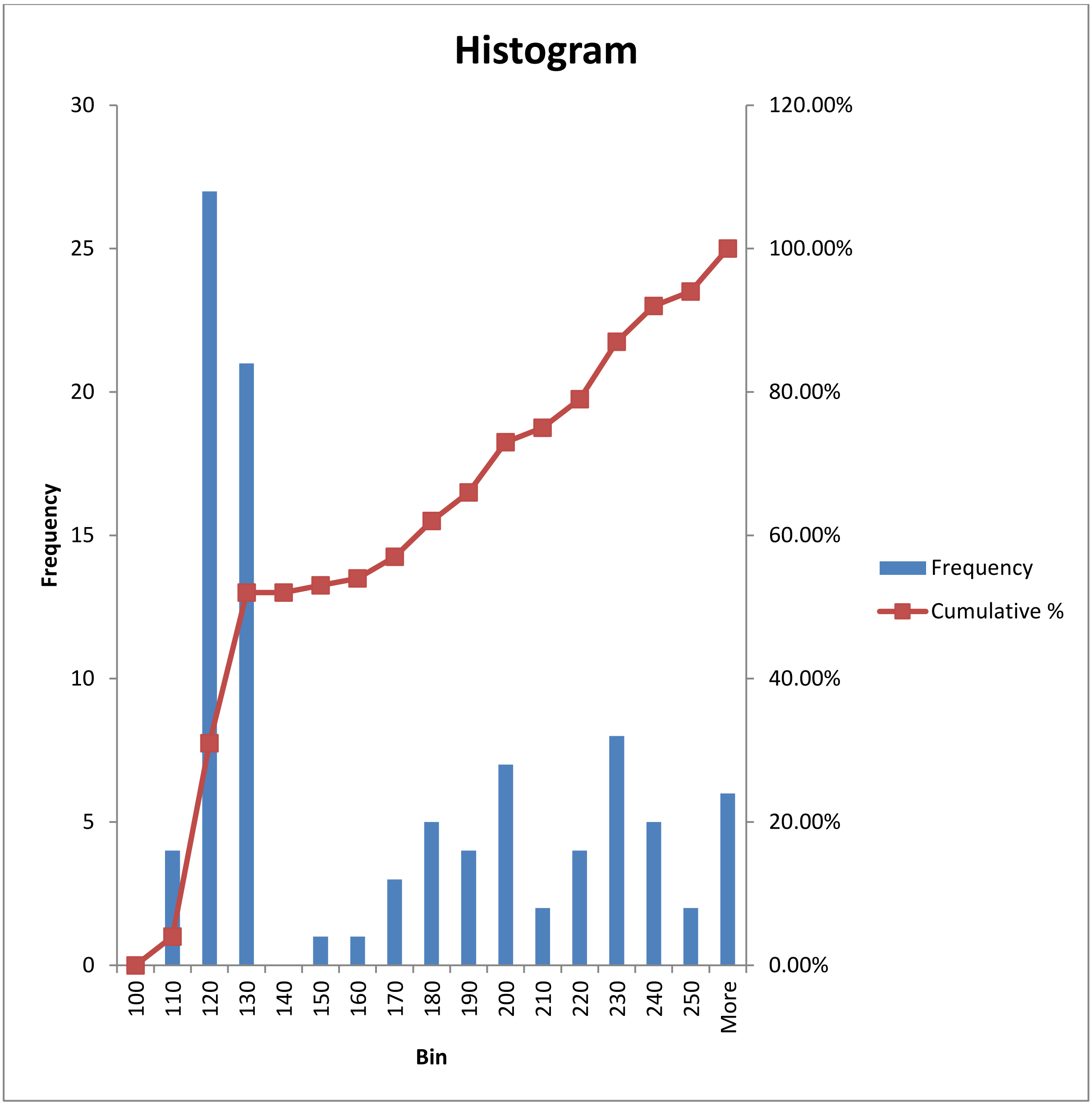
1150	55	92.26%
1200	51	96.29%
1250	16	97.55%
1300	8	98.18%
1350	12	99.13%
1400	11	100.00%
1450	0	100.00%
1500	0	100.00%
More	0	100.00%

Sand Demand Data Distribution


Histogram
Frequency
Bin
70
60
50
40
30
20
10
0
120.00%
100.00%
80.00%
60.00%
40.00%
20.00%
0.00%
90
100
110
120
130
140
150
160
170
180
190
200
210
220
230
240
250
More
Frequency
Cumulative %

Bin	*Frequency*	*Cumulative %*
90	0	0.00%
100	37	9.34%
110	66	26.01%
120	50	38.64%
130	34	47.22%
140	38	56.82%
150	31	64.65%
160	26	71.21%
170	13	74.49%
180	18	79.04%
190	4	80.05%
200	2	80.56%
210	22	86.11%
220	15	89.90%
230	13	93.18%
240	21	98.48%
250	6	100.00%
More	0	100.00%

Sand Demand Data Distribution


Histogram
Frequency
Bin
Frequency
Cumulative %
0
5
10
15
20
25
30
0.00%
20.00%
40.00%
60.00%
80.00%
100.00%
120.00%
100
110
120
130
140
150
160
170
180
190
200
210
220
230
240
250
More

Bin	*Frequency*	*Cumulative %*
100	0	0.00%
110	4	4.00%
120	27	31.00%
130	21	52.00%
140	0	52.00%
150	1	53.00%
160	1	54.00%
170	3	57.00%
180	5	62.00%
190	4	66.00%
200	7	73.00%
210	2	75.00%
220	4	79.00%
230	8	87.00%

240	5	92.00%
250	2	94.00%
More	6	100.00%

11 Appendix C

Carbon Calculation

Carbon dioxide emissions per therm are determined by converting million British thermal units (mmbtu) to therms, then multiplying the carbon coefficient times the fraction oxidized also multiplies by the ratio of the molecular weight of carbon dioxide to carbon (44/12).

mmbtu equals one therm (EIA 2018). The average carbon coefficient of natural gas is 14.46 kg carbon per mmbtu (EPA 2018). The fraction oxidized to CO_2 is 100 percent (IPCC 2006).

Note: When using this equivalency, please keep in mind that it represents the CO_2 equivalency for natural gas burned as a fuel, not natural gas released to the atmosphere. Direct methane emissions released to the atmosphere (without burning) are about 25 times more powerful than CO_2 in terms of their warming effect on the atmosphere.

Note: Due to rounding, performing the calculations given in the equations below may not return the exact results shown.

mmbtu/1 therm × 14.46 kg C/mmbtu × 44 kg CO_2/12 kg C × 1 metric ton/1,000 kg = 0.0053 metric tons CO_2/therm

Carbon dioxide emissions per therm can be converted to carbon dioxide emissions per thousand cubic feet (Mcf) using the average heat content of natural gas in 2016, 10.39 therms/Mcf (EIA 2018).

0.0053 metric tons CO_2/therm x 10.39 therms/Mcf = 0.0551 metric tons CO_2/Mcf

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