USING PROCESS AND LIFECYCLE ANALYSIS TO DELIVER ECONOMICALLY EFFECTIVE ENVIRONMENTAL HEALTH, SAFETY AND SUSTAINABILITY PUBLIC POLICY

A Dissertation

by

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ABSTRACT

The intense focus on the intersection of energy and the environment has led to extensive discussion of both environmental issues and energy practices. While the environmental health and safety (EHS) issues in oil and gas is a topic of concern for the industry, policy makers, and citizens, it is typically overshadowed by the economic viability of oil and gas operations. Many policy makers believe that EHS practices represent an increase in cost on capital businesses. As a result, they develop environmental policy using methods which force businesses to choose between costs and the environment.

This research proposes a systematic approach to process analyses, based on the lean – six sigma discipline. It analyzes the economic and environmental footprints of existing oil and gas operations using a series of case studies and recommends environmentally favorable solutions. It then evaluates the impacts of these substitutions on both costs and EHS, combining economically and environmentally favorable solutions for oil and gas operations. The results are used to recommend environmental policy that should encourage adoption of the proposed solutions.

Two types of processes were analyzed, a carbon capture and sequestration (CCS) operation associated with liquefied natural gas production, and shale gas production. In analyzing these operations, both environmentally and economically favorable solutions were reached. In addition, by looking at the microeconomic footprints of the operations, public policy recommendations were suggested to more effectively drive adoption of environmentally favorable technologies.

In the case of CCS, the net present value (NPV) for operators with the \$23/ton CO_2 proposed carbon price is about \$700,000,000. In the case of shale operations, environmental remediation options resulted in an NPV of \$20,000,000 to \$30,000,000, and a reduction of 20,000 to 40,000 tons of CO_2 for a single well cluster.

The lean-six sigma approach has demonstrated the ability to develop both economically and environmentally favorable solutions. With this understanding of the economics of oil and gas operations, more effective public policy can be recommended. This approach can be used across industries in a similar manner to drive effective global environmental policy and encourage environmental technology adoption.

DEDICATION

I would like dedicate this research to my mother, whose strength and perseverance have helped inspire me to pursue my passion. An additional dedication goes to my father, whose patience and quiet resilience have helped me to better understand others and see the many sides of any issue to develop better solutions. It is their combined love and support that has made me the person I am today, and has enabled me to pursue my goals relentlessly.

Deserving honorable mention, is my younger brother and his family. Their sense of humor and zest for life help to remind me, every day, not to take myself too seriously, remember to laugh and take some downtime to recharge and refocus. As my co-conspirator on many family vacations, his ability to make friends and lighten the mood of any situation reminds me that not all solutions are technical ones, and at times, relationships are just as important as the work itself.

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1 INTRODUCTION

The intensifying focus on the intersection of energy and the environment has led to extensive discussion of both environmental issues and energy practices. Whether through coverage in the traditional[1] and social media, recent religious doctrine[2] or extensive policy discussions among and within governments globally, the impact of the world's energy requirements on both the availability of energy sources and the sustainability of the global environment is receiving significant attention.

While energy security, in particular, the emergence of unconventional resources as viable energy options, tend to take the spotlight among these discussions, environmental issues tend to generate a significant amount of debate. At the center of these discussions is the United States development of unconventional resources and their potential long-term impacts on both energy security and the environment.

1.1 Unconventional Energy Sources and Energy Independence

Global demand for energy as well the global carbon footprint is expected to rise consistently through 2040.[3] United States energy demand/consumption continues to be among the largest in the world, as does its carbon footprint, especially when compared to other global economies.[3] The U.S. is expected to remain the largest consumer of energy and emitter of CO_2, after China, through 2040 as shown in Figure 1.

While it is true that both the energy and CO_2 intensities (per dollar of GDP) of the United States paints a much better picture[3], the issue still remains that the world and, specifically the US, will continue to need more energy and emit more carbon dioxide than most other countries on the planet. Although it is difficult to accurately characterize energy reserves globally, it is clear that United States demand is expected to outstrip what can be produced domestically from traditional sources, across all sectors of the economy.[4]

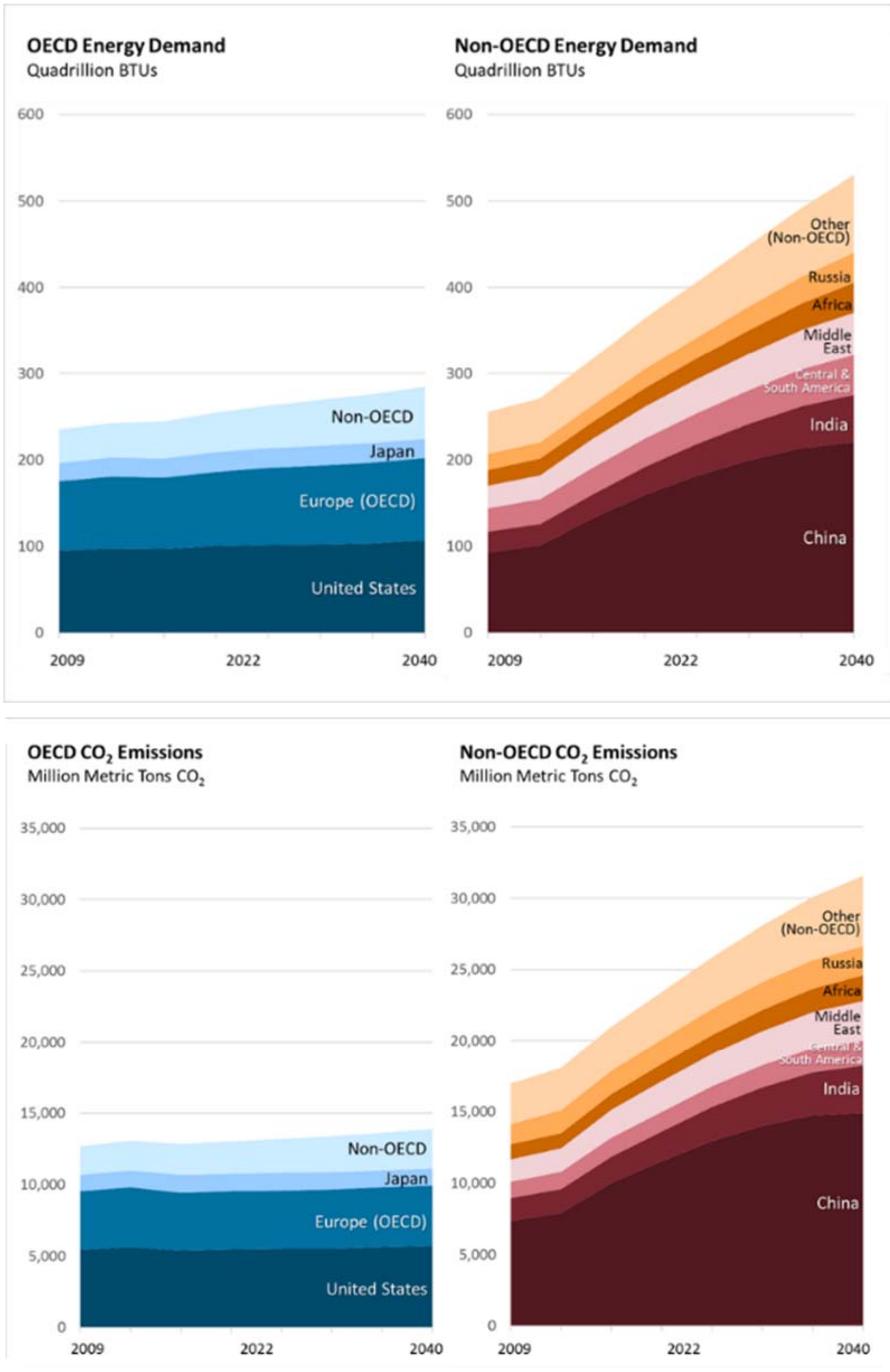

Figure 1: Projected Global Energy Demand and CO_2 Emissions[5]

In addition, the current United States energy mix sways heavily toward coal and oil, totaling about 56% of total fuel consumption[3], which have a high environmental tax as compared to cleaner sources. Electricity generation sways more towards coal while transportation relies heavily on petroleum. Without clean, domestic alternatives, to support this demand, the United States will continue to rely heavily on foreign energy sources and negatively impact the environment.

Although the current reserves of shale gas are expected to support US consumption for anywhere from 100-200 years, the current production process, specifically hydraulic fracturing, is perceived to negatively impact both the immediate and broader environment. Fracking is also believed to affect the health and safety of people in the immediate vicinity of the operation. The fracking process involves the injection of large amounts of water laden with chemicals and mud into the "well" and fracturing shale to release the gas. The gas is then captured and processed for use. Although fracking has been used for decades, to stimulate traditional oil and gas wells; the main issue with shale is scale. The size and number of fractures required to release the gas from shale is much more significant than those employed by the industry to date. In addition, the reach and production profile of a single well as compared with those of conventional operations, requires many more wells must be drilled to access the oil and gas from shale.

These requirements have led to environmental impacts in several areas including greenhouse gas emissions; water consumption and waste water management; and increased seismic activity: leading to "dirty production of a clean fuel". These issues are becoming more pronounced as we discover and characterize more and more shale deposits and have led to a growing opposition to shale gas exploration and production in many communities.[6] Shale gas, therefore, behaves as a public good and the negative externalities associated with its consumption as well as the information asymmetry associated with shale gas operations, lead to a price for natural gas that does not reflect the true cost of production.[7]

1.2 Environmental Impacts

In addition to the water and seismic, environmental impacts of shale operations, in particular, and oil and gas operations, in general, have a significant greenhouse gas component. The impacts[8] and risks[9] of greenhouse gas (GHG) emissions on the environment has been well documented. Governments rely on high quality data about greenhouse gas emissions to set environmental policy[10] and must verify these emissions to effectively determine their policy options.[11] It is expected that continued venting of greenhouse gases to the atmosphere will continue to increase the effect of global climate change as the atmosphere struggles to equalize in the face of anthropogenic sources of excessive greenhouse gas emissions.[12] The production and use of fossil fuels has been identified as a key source of excessive greenhouse gas emissions.[13] Of the many substances classified as greenhouse gases, perhaps the single most discussed gas is carbon dioxide, due to its importance and prevalence in many industrial processes.[14] It has been estimated that more that 70% of the greenhouse gas increases over the past 3 decades were composed of CO_2.[15]

As a result, a number of countries bound by the Kyoto Protocol[16] have taken measures to limit CO_2 emissions using a series of political instruments.[17] There are a number of political instruments which can be used to impact CO_2 emissions[18] including:

- **Carbon tax:** typically translated into a cost/ton of CO_2 emitted and applied to a project or plant

- **Cap and trade:** a market based policy which puts a cap on CO_2 and allows participants to trade its excess emissions with others who do not reach the limit

- **Carbon subsidies**: including both direct and indirect subsidies which involve some sort of monetary transfers to the recipient

Analyses of policies for carbon capture and sequestration (CCS) have demonstrated that there is a balance which must be developed between the flexibility required by policy makers and the predictability required by the private sector.[19] Three approaches to reducing CO_2 emissions are typically discussed[20]:

- **Reducing energy intensity** by focusing on more efficient use of energy

- **Reducing carbon intensity** by switching from fossil fuels to fuels that are based in the current carbon cycle

- **Enhancing the natural sequestration of CO_2** by developing and implementing technologies that capture and sequester more CO_2.

The process of CO_2 sequestration involves the capture and separation of CO_2 from an impure stream, compressing the gas to supercritical condition and pumping it into a secure reservoir for long term storage, and sequestration. Carbon capture is limited to stationary point sources[14] and in the case of LNG processing, for example, can happen pre-combustion on the hydrocarbon stream before liquefaction[21] and post-combustion where CO_2 is captured from whatever source provides power to the operation.[22]

Capture and separation of CO_2 can be accomplished using a number of methods including direct absorption,[23] membrane separation, adsorption or cryogenic distillation.[20] Current technologies tend to be expensive and energy intensive, using upwards of 30% of the power generated.[14] This poses a significant economic burden on the operation and new technologies, in this area, focus on reducing the cost and energy intensity of this process.

By modeling oil and gas operations, employing a step-by-step process analysis and understanding the micro-economic impacts of environmental solutions: environmental policy that balances energy security with environmental impacts can be proposed which addresses the market failures in the natural gas market.

1.3 Central Thesis

Many policy makers take the stand that environmental health, safety and sustainability represents an increase in cost on capital businesses and, as a result, develop public policy in that area using methods which force businesses to choose the lesser of two evils. This is typically ineffective and meets with a great deal of opposition from the private sector.

1.4 Problem Statements & Key Hypotheses

While the environmental health, safety and sustainability issues surrounding oil and gas production are topics of concern for the industry, policy makers and citizens, they are typically overshadowed by the economic viability of oil and gas operations. In many cases, technology exists that improves both the environmental footprint and, in many cases the inherent safety of these operations, however, the industry has been slow to adopt those technologies.

Many industrial processes include a significant amount of waste. In many cases, that waste also reduces the EHS&S of the overall process. While this waste typically involves a significant financial impact, as well, it is difficult to quantify and isolate, so businesses struggle with how to tackle these elements, improve the overall environmental health, safety and sustainability of these processes and realize the financial improvements. **Hypothesis: Integrated process analysis and improvement methodologies, such as lean six-sigma, can be applied to industrial processes to reduce waste AND improve process safety.**

In looking at industrial processes, specifically oil and gas processes, much of the process waste impacting sustainability introduces inefficiencies, which render the implementation of traditional environmental policy (e.g. carbon tax) economically infeasible for many operations. As a result, these policies meet with much opposition and are ultimately ineffective. **Hypothesis: Integrated process analyses can be applied to an isolated CCS process to improve the economic viability of sequestration and render a carbon policy more effective.**

While environmentally favorable technologies may also be economically more viable in the long term, many oil and gas operators are not willing to make the up-front capital investment required to explore the long-term economic and environmental benefits of the unproven technologies. **Hypothesis: Integrated process analyses can be applied to the shale gas exploration and production process to improve its economic viability and environmental footprint.**

Environmental policy has historically focused on developing a carbon scheme that puts a price on carbon. While successful energy policy has been multi-pronged, combining tax incentives with other policy instruments such as incentive pricing and research credits[24], environmental policy has not historically followed suit. Public policy in this area approaches the issue from the perspective of driving environmental improvements without an understanding of the micro-economic impact of the policy instrument. As a result, it either meets with opposition or is ineffective in driving adoption and less environmentally friendly solutions continue to be employed in the field leading to both a larger environmental footprint and more economic losses than required. **Hypothesis: By leveraging integrated process analyses, environmental policy can be developed that drives the adoption of technologies, which improve the long-term economic viability and environmental footprint of shale gas exploration and production.**

1.5 Research Objectives and Document Format

Using integrated process analyses, based on the lean six-sigma methodology and focused on the oil and gas industry, this research seeks to demonstrate, through a series of cases studies, the micro-economic viability of environmental health, safety and sustainability (EHS&S) practices. It then recommends alternate approaches to public policy to offset some of the hurdles of EHS&S technology adoption in oil and gas. While out of scope for this research, additional industries may be analyzed using similar approaches to enable the development of successful, industry specific, public policy in the area of EHS&S.

Sections of this manuscript have already been published with other co-authors and those individuals have been called out in the individual sections. Publication rights have also been obtained for previously published work. Finally, the references in this manuscript follow the style for the American Chemical Society.

2 METHODOLOGY AND APPROACH

This research utilizes a systematic approach to process analysis, similar to those used in the lean – six sigma discipline, to understand the economic and environmental footprints of existing oil and gas operations using a series of case studies. Direct field data and secondary data sources will be combined to develop a simulator, which models the economic and environmental footprints of each case. Proven, environmentally favorable solutions will then be substituted within the processes to examine the environmental and micro-economic impact of the substitutions on the operation. The long-term economic impacts will be assessed using standard net present value calculations to take into account the time value of money and results extrapolated to indicate the broader economic and environmental benefits that could be realized industry-wide. Finally, the research will propose a public policy approach that drives favorable environmental and economic outcomes to the operation, thereby incenting the adoption of the newer technology.

2.1 Application of Lean-Six Sigma

"Lean" is a production practice that considers the expenditure of resources for any goal other than the creation of "value" for the end customer to be wasteful, and thus a target for elimination. Working from the perspective of the customer who consumes a product or service, "value" is defined as any action or process that a customer would be willing to pay for.

The method was pioneered and developed by Toyota and is based on concepts which began to be developed in the early 1900's with Sakichi Toyoda's automatic loom which first demonstrated the concept of Jidoka. Armed with this concept, Taiichi Ohno and his autonomous study group, within the now incorporated Toyoda Motor Company (now Toyota), created the Toyota Production System (TPS) which is the basis for lean.

There are five core principles of Lean which can be systematically implemented to drive process improvement and execution excellence. These can be summarized as follows:

1. Define **value** from the end customer back
2. Identify the value stream
3. Establish **flow** in operations

4. Always **pull** from the customer where you cannot flow
5. Continuously improve the process to **perfection**

The fundamental basis of lean is a thorough understanding of the process that brings value to the customer and an identification of the core activities that truly contribute to that value. The value stream mapping process takes the approach that waste in the "production" process can be eliminated to ensure only value added activities are performed.

Six Sigma is a process improvement set of tools and strategies, which seeks to improve the quality of process outputs by identifying and removing the causes of defects (errors) and minimizing variability in manufacturing and business processes. It uses a set of quality management methods, including statistical methods, and creates a special infrastructure of people within the organization ("Champions", "Black Belts", "Green Belts", "Orange Belts", etc...) who are experts in these very complex methods. Each Six Sigma project carried out within an organization follows a defined sequence of steps and has quantified financial targets (cost reduction and/or profit increase).[25]

As six sigma is a highly quantitative approach, there is an underlying assumption that the defects (Ys) are driven by a number of basic causes (Xs) and that the Xs are related to the Ys via a known/understood transfer function f(X). This implies that by controlling the Xs, one can control the Y and therefore the process. This also implies that fundamental changes to the outcome (Y) can be achieved by making foundational changes to the critical Xs. Historically, process improvement initiatives have focused on addressing the Y while with six sigma, the focus is on the Xs. To get at this relationship, the six sigma process takes the practical problem, abstracts it to a numerical problem, develops a numerical solution then translates that back into a practical solution.

When combined with the value stream mapping approach of lean, this approach yields a powerful process analysis toolset that can be used to analyzed and address fundamental issues associated with complex processes. It is this approach which forms the foundation for the methodology used in this research. The focus here is to analyze oil and gas processes with a focus on addressing two outcomes (Ys): **EHS&S and Profitability**, by mapping the value stream and identifying the critical levers (Xs) which impact those outcomes. Alternative solutions are then developed to shift those levers and drive the process outcome. Those solutions are then analyzed in the context of the value stream map to determine the numerical impact on the outcomes. These analyses are then used to suggest an approach for public policy that drive the behavior required among the key stakeholders that will lead to the adoption of the improved processes and therefore improved outcomes.

2.2 A Note About Safety

While much of the analysis of the research will focus on quantifying the environment impact of oil and gas processes, the role of safety cannot be underestimated. While not always easily quantifiable, the safety aspects of EHS&S are critical considerations. Four main methods for achieving inherently safer process design are typically discussed[26, 27]:

- **Minimize:** Reducing the amount of hazardous material present at any one time, by using smaller batches or achieving single piece flow in the process

- **Substitute:** Replacing one material with another of less hazard

- **Moderate:** Reducing the strength of an effect by reducing temperature, pressure or diluting hazardous materials

- **Simplify:** Eliminating problems by design rather than adding additional equipment or features to deal with them or simplifying complex procedures by using kits or pre-measured packaging

Additional concepts include:

- **Error tolerance**: Equipment and processes can be designed to be capable of withstanding possible faults or deviations from design

- **Limit effects** by design, location or transportation of equipment so that the worst possible condition produces less danger

These concepts are very aligned to the lean-six sigma methodologies and will be used as part of the process analysis approach. In addition, a section discussing the broader application of lean-six sigma methodologies to improve the overall process safety will be developed which expands on the key lean-six sigma concepts and enables the use of the methodology for future work in this area.

2.3 Key Parameters for Application of Lean - Six Sigma to Case Studies

2.3.1 Case Study I: Carbon Sequestration in a Liquefied Natural Gas Operation

In the first case study that applies the lean-six sigma approach, an analysis of the technical, micro-economic and political impact of a carbon tax on carbon dioxide sequestration resulting from liquefied natural gas production was undertaken using the lean-six sigma process analysis approach. The case study looked at the Gorgon project in Australia, which is a subsea development project in which natural gas is produced from subsea wells, delivered to shore where it is processed and compressed to produce LNG for export. Natural gas from the Gorgon gas fields has a high carbon dioxide content and processing occurs in an environmentally sensitive area, therefore a commercial scale carbon sequestration facility was implemented to inject CO_2, separated from the natural gas prior to compression, into an underlying aquafer. In addition, during the time the project was being developed, Australia had implemented a carbon scheme to stimulate sequestration activity within its borders.

<u>Project Modeling</u>

In looking at the economics of the CCS project tied to Gorgon, a base case, which reflects the operation, needed to be developed. Given the complexity of the project, a simplified model was developed and a basic economic simulator was built to perform the scenario analyses presented in this research. The basic underlying assumption is that CO_2 is an inherent burden to LNG production and would need to be separated regardless of whether it is sequestered or vented. This allows us to isolate the carbon sequestration system and consider it on an incremental basis in the analysis.

Several methods were used to evaluate the impact of the carbon tax on the project economics and were built into the economic simulator. The **annual operating cost** of the project was initially considered to determine if the introduction of the current carbon tax could make carbon sequestration profitable on an annual basis. **Breakeven analyses** were then conducted to determine at what minimum carbon price the CCS operation would become profitable and to test the sensitivity of that to changes in the price of natural gas. Finally, **net present value** calculations were used to determine if investments in operational improvements today would yield long term benefits over the life of the project, in the context of the carbon tax.[28, 29]

In mapping the value stream, the following critical factors were found which drive the economic and environmental outcomes.

Table 1: Key Parameters for Carbon Sequestration

Outcomes (Y)	Critical Factors (Xs)
Y1: Project Profitability (as measured by annual operating costs; project breakeven & net present value)	**X1:** Carbon Price/Tax
Y2: Environmental Impact (as measured by carbon footprint)	**X2:** Equipment Efficiency (including the energy tax of the CCS System)
	X3: Equipment Reliability
	X4: Post combustion sequestration

2.3.2 Case Study II: Environmental Remediation of Shale Gas Operations

In the second case study, the lean six-sigma process analysis approach was applied to the environmental remediation of shale gas operations. The case study looked at a cluster of wells in the Barnett Shale play in Texas. The Barnett Shale was chosen as it is among the most established and most mature shale gas plays in the United States today and it plays a critical role in the U.S. natural gas landscape. As a result, a robust data set collected from operations in the Barnett could be used to conduct the analyses. The baseline process definition as well as the base case data was taken from actual field data in a Barnett well and used to model the current operation. In looking at the environmental impacts of shale gas, it was assumed that once the gas is produced and processed for transportation, its environmental footprint will be similar to that of natural gas from conventional sources. Therefore, the focus of this analysis is on the environmental footprint of the drilling and production processes associated with shale gas extraction, the "well" lifecycle, and not on the entire lifecycle of the shale gas itself. This lifecycle encompasses three stages: drilling, completion and production.

Project Modeling

The environmental footprint of the well across these three stages was evaluated and the critical factors were substituted for more environmentally friendly options. The environmental and microeconomic impacts were then analyzed again the base case and public policy proposed that is expected to drive operator behavior to better adopt these options. As with the previous case, the micro-economic impact was measured using a combination of annual operating costs, breakeven analyses and net present value. The case was divided into two separate areas of focus. Each focus was separated out and evaluated separately and then the two focus areas were combined to determine to total potential impact and inform the policy recommendations.

Part 1: Using natural gas to reduce greenhouse gases from combustion - The first focus area looked at the substitution of diesel and gasoline, used in both heavy duty and light duty equipment, with natural gas produced from the formation. The following table summarizes the major outcomes (Y's) and critical factors (X's).

Table 2: Key Parameters for GHG Remediation Shale Gas Production

Outcomes (Y)	Critical Factors (Xs)
Y1: Project Profitability (measured by annual operating costs; project breakeven & net present value)	**X1:** Type of fuel used to power equipment
	X2: Impact of fuel type on safe operations
Y2: Environmental Impact (measured by carbon footprint)	**X3:** Relative cost of fuels (diesel, gasoline, natural gas)
	X4: Comparative cost of natural gas processing (Raw Gas, CNG, LNG)
	X5: Greenhouse gas emissions from combustion (diesel vs. gasoline vs. natural gas)
	X6: Relative energy density of fuels & amount required to power equipment
	X7: Capital investment required

Part 2: Alternative technologies to reduce water and seismic impacts –The second focus area addressed the use of alternative fracturing fluids to eliminate the use of water in the hydraulic fracturing operation. This critical part of the completions phase is where the majority of water is used and contributes to the major seismicity issues associated with waste water injection. In particular, the research evaluated the use of both liquefied petroleum gas (LPG) and carbon dioxide (CO_2) as fracturing fluids. The following table summarizes the major outcomes (Y's) and critical factors (X's).

Table 3: Key Parameters for Water and Seismic Remediation Shale Gas Production

Outcomes (Y)	Critical Factors (Xs)
Y1: Project Profitability (as measured by annual operating costs; project breakeven & net present value) **Y2:** Environmental Impact (as measured by carbon footprint, water consumption & water disposal)	**X1:** Relative cost of fracturing fluids (water, LPG, CO_2) **X2:** Relative impact of fracturing fluids on the safety of operations **X3:** Relative amount of fluid required to complete a given fracture **X4:** Fluid flowback characteristics **X5:** Relative differences in production resulting from fluid characteristics **X6:** Amount of fluid flared/recycled (including sequestration in the formation) **X7:** Reductions in proppant usage

3 LEVERAGING LEAN – SIX SIGMA TECHNIQUES TO DRIVE THE ENVIRONMENTAL HEALTH, SAFETY AND SUSTAINABILITY OF INDUSTRIAL PROCESSES

3.1 Summary

In many process industries, safety incidents occur for a number of reasons, including process design, culture, leadership, employee competence. These can be broadly classified as errors in plant or process design and/or operation. By looking at and addressing some of these process issues one can address a significant portion of safety issues in these plants. Lean-Six Sigma is a discipline of process improvement that aims to reduce waste and eliminate defects from a production process. Although the disciplines of lean and six sigma are aimed at reducing waste, there is a safety component to the programs themselves. In addition, many of the tools and techniques contained therein can be used to drive safer processes across the board, especially in the area of plant/process design and operations.

This section of the research looks at how these principles can be used to develop inherently safer processes. These principles are then used as the fundamental methodology for conducting the research detailed herein. For each case study analyzed, various aspects discussed here are used to analyze the processes involved and recommend more environmentally favorable alternatives.

3.2 Introduction

In process industries, safety incidents occur for a number of reasons, including process design, culture, leadership, employee competence. These can be broadly classified as errors in plant or process design and/or operation. A study of 189 incidents in chemical process plants, in the UK, between 1962 and 1987, was undertaken. It was found that only 20% of the incidents which could be analyzed (about 169) could be attributed to a lack of knowledge or errors in the chemistry or thermo-chemistry. The remaining 80% were attributed to errors on plant design and operations with causes ranging from temperature control, agitation, mischarging, maintenance and so on.[30] By looking at and addressing some of these process issues one can address a significant portion of safety issues in these plants.

Lean-Six Sigma is a discipline of process improvement that aims to reduce waste and eliminate defects from a production process. It uses the combined techniques to Lean (as manifested in the Toyota Production System) and Six Sigma to systematically drive execution excellence.[31] Although the disciplines of lean and six sigma are aimed at reducing waste, there is a safety component to the programs themselves. In addition, many of the tools and techniques contained therein can be used to drive safer processes across the board, especially in the area of plant/process design and operations.

3.3 Overview of Lean-Six Sigma

3.3.1 Lean: The Relentless Pursuit of the Perfect Process Through Waste Elimination

Lean is a production practice that considers the expenditure of resources for any goal other than the creation of "value" for the end customer to be wasteful, and thus a target for elimination. Working from the perspective of the customer who consumes a product or service, "value" is defined as any action or process that a customer would be willing to pay for.

The method was pioneered and developed by Toyota and is based on concepts which began to be developed in the early 1900's with Sakichi Toyoda's automatic loom which first demonstrated the concept of Jidoka. Armed with this concept, Taiichi Ohno and his autonomous study group, within the now incorporated Toyoda Motor Company (now Toyota), created the Toyota Production System (TPS) which is the basis for lean.

TPS aims to achieve operational excellence via three fundamental pillars which are frequently represented in a house. These form the basis of a lean culture and are applied throughout the lean execution process:

- Heijunka (circa 1970): Stable processes which can accommodate variability in customer demand by aggregating demand into a single production line and structuring products in a way the meets customer variability while allowing standard production.

- Jidoka (circa 1900): Automated processes to reduce human error but with intelligence built into the automation which stops defects from passing on. This also includes enabling workers to stop a defect from passing and correcting at the source.

- Just in Time (circa 1940): aim for single piece flow through a line…if you can't flow pull from the customer. Establish standard takt (cycle) time and eliminate work in progress from the line.

Core principles of lean

There are five core principles of Lean which can be systematically implemented to drive process improvement and execution excellence. These can be summarized as follows:

1. Define value from the end customer back
2. Identify the value stream
3. Establish flow in operations
4. Always pull from the customer where you cannot flow
5. Continuously improve the process to perfection

This section attempts to briefly discuss each of these principles to provide an overview of the lean discipline so that the following discussion on process safety can be taken into context.

Define value form the end customer back

This is the process of clearly understanding the end customer requirements and having a relentless focus on exactly what the customer expects, not the organization's interpretation of those requirements. Customer requirement in the context of lean is everything that, and only what, the customer is willing to pay for. In many cases, getting at the underlying customer need versus the stated customer need is required. Lean tools like the 5 Whys approach can enable one to get at the implicit need of the customer.

Customer value is then delivering the right product or service, in the right quantity, to the right customer at the right place and time. "Value" changes the form and function of work that is in progress to bring it closer and closer to the end customer need. All activities that do not add value in the process are considered **waste**.

Lean recognizes seven (7) types of waste which contribute to increased cycle time and cost. By continuously eliminating waste, the lean process seeks to drive a process to entitlement. These wastes are classified as follows:

- **Over-processing** – Doing more work than is necessary to satisfy customers…excessive approvals/handoffs
- **Waiting** – Any delay between when one process step ends and the other begins
- **Motion** – Needless movement performed by people
- **Inventory** – Excess WIP vs what is needed by the customer
- **Moving Things** – needless movement of work, products or information
- **Over-production** - Production of items beyond what is needed for immediate use
- **Defects & Inspection** – defective work or excessively checking work

In the drive to eliminate these wastes, it can be demonstrated the processes not only become more efficient but also become inherently safer. This concept will be discussed in a later section of this paper.

Identify the value stream

Once end customer value is identified, that value is translated through the process and the steps required, to deliver that value, are identified. Each subsequent step should bring the delivered product closer to the customer's need. The value stream is therefore a time series of all activities & steps (both value add and non-value add) that are required to bring the final product or service to the customers. It includes R&D, new product introduction, go to market activities & product launch as well as the sales and order fulfillment processes

In analyzing the value stream it is useful to understand the cycle time or lead time of each process. To do this, Little's Law is used on each process step and the total cycle time is then calculated. Little's Law can be expressed as:

$$Cycle\ Time(Lead\ Time) = \frac{Work\ in\ Process}{Throughput} = Standard\ WIP * Takt\ Time$$

The value stream is typically identified/mapped by a cross functional team of experts who understand the as is process intimately and can envision a to-be process where waste is eliminated. Similar to the HAZOP process, the value stream mapping process is a systematic end to end mapping of the process (to define the as-is state) followed by a creative problem solving phase (to define the to-be state).

In identifying the value stream, a critical output is a summary of the key areas of waste in the process and in many cases the root causes of that waste. Then an action plan/project plan is put in place to systematically address those wastes to eliminate excess cycle and WIP.

Establish flow

Once the value stream is mapped and the key problem areas identified, measures are taken to establish flow in the process. Flow is the movement of products, services and/or information down the value stream without queues or wait time. Thus, flow is created by systematically eliminating those queues and stops, identified in the value stream, while improving process flexibility & reliability in order to keep them from reappearing as demand changes. The ultimate objective of flow is continuous, uninterrupted transformation of product, service or information by continuously adding value. The pace at which flow is kept is known as the takt time for the process.

Takt Time - Takt time is derived from the German word Taktzeit which translates to *cycle time*, and it is the unit of time that sets the pace for industrial manufacturing lines. For example, in automobile manufacturing, cars are assembled on a line, and are moved on to the next station after a certain time - the takt time. The time needed to complete work on each station has to be less than the takt time in order for the product to be completed within the allotted time to meet customer demand.

The takt time concept aims to match the pace of production with customer demand and the net available work time available. Assuming a product is made one unit at a time at a constant rate during the net available work time, the takt time is the amount of time that must elapse between two consecutive unit completions in order to meet the demand.

Takt time can be determined by the formula:

$$\mathrm{T} = \frac{\mathrm{T}_a}{\mathrm{T}_d}$$

where:

T = Takt time, e.g. [work time between two consecutive units]

T_a = Net time available to work, e.g. [work time per period]

T_d = Time demand (customer demand), e.g. [units required per period]

Net available time is the amount of time available for work to be done. This excludes break times and any expected stoppage time (for example scheduled maintenance, team briefings, etc.).

In reality, people and machines can never maintain 100% efficiency and there may also be stoppages for other reasons. Allowances should be made for these instances and thus the line will need to be set up to run at a faster rate to account for this.

Also, takt time may be adjusted according to requirements within the company. For example, if one department delivers parts to several manufacturing lines, it often makes sense to use similar takt times on all lines to smooth out flow from the preceding station. Customer demand can still be met by adjusting daily working time, reducing down times on machines and so on.

Moving towards Flow - To move a process towards flow, there are several concepts that are/can be applied. These are basic principles that are part of the lean framework that generally guide the thinking in the transformation to a lean process. These can be summarized as:

- Strive for single piece flow…one line one part
- No batch and queue ….just delivery of input materials at each stage of the process
- Poka yoke …designing error proof processes which do not depend on highly specialized operator skills
- Eliminate excess process steps, approvals and extraneous motion
- Combine/group consecutive/related processes together….physically

- Separate from critical path….separate sub-processes from the critical path in feeder lines and only deliver the output of these processes to the main line

- Mitigate the impact of shortages and errors…by setting up a marketplace where inbound inventory is kept, away from the line, and material is sorted, kitted (see next section) and prepped for use on the line using a “water spider” approach.

Pull from the customer where you cannot flow - In some cases, it may not be feasible to create flow. This is especially true in customer shops where the work is started only when customers place the order and is quite common in heavy industrial organizations. Aerospace, power generation equipment, oil and gas equipment all have environments where pure flow cannot be realistically achieved. In these cases, a pull system needs to be established and linked with a kanban.

Pull requires each step in the process to take the product, service or information it needs, only in the amount needed and at the moment needed from the proceeding process. This implies that no action is taken until the downstream process initiates it and that the pull process is initiated by end customer demand.

Kanban – Kanban (literally signboard or billboard) is a scheduling system for lean and just-in-time (JIT) production and it is one means through which JIT is achieved.[32] Contrary to popular belief, Kanban is not an inventory control system; it is a scheduling system that helps determine what to produce, when to produce it, and how much to produce.

The need to maintain a high rate of improvement led Toyota to devise the kanban system. Kanban became an effective tool to support the running of the production system as a whole. In addition, it proved to be an excellent way for promoting improvements because reduced numbers of kanban in circulation highlighted problem areas.

Kanbans maintain inventory levels; a signal is sent to produce and deliver a new shipment as material is consumed. These signals are tracked through the replenishment cycle and bring extraordinary visibility to suppliers and buyers.

In recent years, the kanban has evolved into the electronic kanban or e-kanban which is based on the same principles of kanban but used barcodes and electronics messages instead of kanban cards and leverages enterprise resource planning (ERP) applications and the internet for communication with suppliers and buyers.

<u>Continue to improve the process to perfection (Lean Execution)</u>

As waste is reduced, the process moves closer to the lean definition of perfection, single piece flow with no stops or queues. The closer a process is to perfection the more is revealed; as we reduce inventory and overproduction in the process, new wastes and new bottlenecks are exposed. The relentless pursuit of perfection means always keeping the customer in focus; and making waste and defects more and more visible. Within lean this is accomplished using a process of incremental step-wise improvements that cumulatively bring the process closer and closer to perfection. Making defects visible then using concepts like kaizen, root cause problem solving and genba/gemba, the ongoing lean journey continuously works towards a more and more effective process.

Make defects visible - This principle involves setting up a system where all defects/issues are made visible so that they can be worked on. The kanban system is one way we make signals visible but there are many others. A couple of these examples are illustrated here.

As mentioned previously, the use of a "marketplace" approach where there is a dedicated receiving area for inbound inventory which can then be sorted, inspected and kitted is a critical area where defects can be made visible to the "water spider". The "water spider" is a position in the lean process which takes material handling to new levels. The water spider position is considered a right of passage to becoming a plant supervisor and this role involves understanding the line or cell supported intimately, to the point of understanding the material required, the standard work, the sequence of operations and even being able to fill in on the line if required. Kitting and poka yoke are both tools used in the marketplace to make defects and shortages visible.

<u>Kitting</u> - In many cases, a process step may require the assembly of multiple components in a single step. The concept of "kitting" involves putting all of the components together on a tray or trolley in advance so that the operator has only what he/she needs at the time they need it in a convenient location which reduces motion waste. The kitting process in turn exposes material shortages or defects as the "kitter" or "water spider" assembles the kit, well in advance of it getting to the operator, and this can be corrected in advance of the kit being provided to the line.

<u>Poka Yoke</u> – In many cases, the amount of material on hand can be hard to determine if you are dealing with bulk material. Poka yoke, error proofing, is then used to develop custom approaches to quickly see and determine how much inventory is on hand and when a kanban card needs to be issued for more material. The example below shows how this is done in a manufacturing plant for things like buts and bolts. Frequently, a kanban mark is places on the tray or trolley to indicate when it is time to reorder.

Figure 2: Using Poka Yoke to Enable the Kanban Process

Kaizen: Identify Opportunities, Narrow the Focus & Prioritize - Kaizen translates roughly into "small change for the better" and is both a method and a mindset for continuous improvement of processes. Kaizen can be a daily process or a series of integrating events, the purpose of which goes beyond simple productivity improvement. It is also a process that, when done correctly, humanizes the workplace, eliminates overly hard work, and teaches people how to perform experiments on their work using the scientific method and how to learn to spot and eliminate waste in business processes. In all, the process suggests a humanized approach to workers and to increasing productivity: "The idea is to nurture the company's human resources as much as it is to praise and encourage participation in kaizen activities."[33]

The cycle of kaizen activity can be defined as:

- Standardize an operation and activities.
- Measure the operation (find cycle time and amount of in-process inventory)
- Gauge measurements against requirements
- Innovate to meet requirements and increase productivity
- Standardize the new, improved operations
- Observe results
- Identify next opportunity and begin again

This is also known as the Shewhart cycle, Deming cycle, or the Plan-do-Check-Act (PDCA) cycle.[34] In the *Toyota Way Fieldbook*, Liker and Meier discuss the kaizen blitz and kaizen burst (or kaizen event) approaches to continuous improvement.[35] A kaizen blitz, or rapid improvement, is a focused activity on a particular process or activity. The basic concept is to identify and quickly remove waste. Another approach is that of the kaizen burst, a specific kaizen activity on a particular process in the value stream. Kaizen events are not traditional workshops, they focus on change and speed and encourage participants to “try-storm” where new ideas are modeled and tried quickly and failures are improved until a solution is developed through a series of quick iterative cycles: quick improvement – modification – refinement. As companies increase in size and processes become more complex, kaizen “events” are repeated and tackle more and more of the complexity as both the process improves and kaizen becomes more and more engrained in the organization’s culture. The more complex the process the more the kaizen process is repeated getting more and more focused with each event, the following diagram demonstrates and example of how these successive events are used to drive incremental change in process. In each cycle, issues are identified and the process of root cause problem solving works to address the roots of the issues.

Root Cause Problem Solving - Root cause problem solving is used in conjunction with Kaizen to address the sources of waste. There are several tools using in this part of the lean execution process; including, but not limited to:

- **5 Whys** - which is a form of root cause analysis in which the user asks "why" to a problem and finds an answer five successive times; and

- **Fishbone diagram** - There are normally a series of root causes stemming from one problem, and they can be visualized using fishbone diagrams or tables. A fishbone diagram is used to identify all of the contributing root causes likely to be causing a problem.

- **Genba/Gemba** – the process of walking around, looking and seeing the issues in the environment vs. addressing them hypothetically in a conference room.

Genba (sometimes Gemba) - Genba is a Japanese term meaning "the real place". Japanese detectives call the crime scene *genba,* and Japanese TV reporters may refer to themselves as reporting from *genba.* In business, *genba* refers to the place where value is created; in manufacturing the *genba* is the factory floor. It can be any "site" such as a construction site, sales floor or where the service provider interacts directly with the customer.

In lean manufacturing, the idea of *genba* is that the problems are visible, and the best improvement ideas will come from going to the *genba.* The *genba* walk, much like 'Management by Walking Around (MBWA)', is an activity that takes management to the front lines to look for waste and opportunities to practice *kaizen*.

In quality management, *genba* means the manufacturing floor and the idea is that if a problem occurs, the engineers must go there to understand the full impact of the problem, gathering data from all sources. Unlike focus groups and surveys, *genba* visits are not scripted or bound by what one wants to ask.

Try-storming & Moonshine - Once the root causes are identified, the concept of trystorming and moonshine are applied to begin to address the key drivers of waste. As discussed earlier, trystorming is the concept of prototyping ideas quickly and trying them out and iterating until a solution is found. Moonshine is the customization of the process to the product using custom tools, machines etc. It is the creative element of lean that creates, for many lean factories, a competitive advantage in processes. New and improved tools and processes aimed at the specific line requirements can be used to fool proof a line or make it safer for the operator as well as reducing wasted cycle time in setup and processes. As batch and queue is replaced with single piece flow, standard machines and tools may not be well adapted for the smaller sizes and volumes, so a highly skilled and very creative moonshine team is critical to the design of specialized approaches to these issues.

3.3.2 Principles of Six Sigma

Core principles of six sigma

Six Sigma is a process improvement set of tools and strategies, which seeks to improve the quality of process outputs by identifying and removing the causes of defects (errors) and minimizing variability in manufacturing and business processes. It uses a set of quality management methods, including statistical methods, and creates a special infrastructure of people within the organization ("Champions", "Black Belts", "Green Belts", "Orange Belts", etc...) who are experts in these very complex methods. Each Six Sigma project carried out within an organization follows a defined sequence of steps and has quantified financial targets (cost reduction and/or profit increase).[36]

The term six sigma originated from terminology associated with manufacturing, specifically, terms associated with statistical modeling of manufacturing processes. The maturity of a manufacturing process can be described by a sigma rating indicating its yield or the percentage of defect-free products it creates. A six sigma process is one in which 99.9999966% of the products manufactured are statistically expected to be free of defects (3.4 defects per million).

The six sigma approach looks at process from the perspective of repeatable defect free production and generally corrects for two types of “defects”:

- Process off target which implies that on average production is off specification

- Excess variation which implies that, while the average product coming off the line is on specification, there is excessive variability in the line's production.

The premise is that customers will feel the variation in the product more the shift in the mean.

As six sigma is a highly statistical approach, there is an underlying assumption that the defects (Ys) are driven by a number of basic causes (Xs) and that the Xs are related to the Ys via a known/understood transfer function f(X). This implies that by controlling the Xs within a specific range, one can control the Y and therefore the process. Historically, process improvement initiatives have focused on addressing the Y while with six sigma, the focus is on the Xs. To get at this relationship, the six sigma process takes the practical problem, abstracts it to a statistical problem, develops a statistical solution then translates that back into a practical solution:

Practical Problem ➔ Statistical Problem ➔ Statistical Solution ➔ Practical Solution

<u>D-M-A-I-C: The 15 steps of six sigma</u>

When applied to an ongoing manufacturing process, the six sigma process is broken down into five phases and 15 steps. The five phases Design – Measure – Analyze – Improve – Control make up the DMAIC acronym which is typically associated with six sigma. The following table summarizes the 15 step approach and highlights some of the tools used at each step.

<u>Define customer expectations of the process</u>

The define phase of the DMAIC process is primarily used to make the case for action and scope the six sigma process. In this phase, the process to be improved is determined, customers are identified and customer needs are translated into CTQs (critical to quality elements to provide focus. Finally, the process is defined and a high level process maps is developed. In the case of process safety, the key safety CTQs can be determined based on a HAZOP and the rest of the process can then revolve around optimizing key safety metrics.

Table 4: The Steps of the DMAIC Approach

Step	Description	Focus	Tools
Define			
1	Identify CTQs (critical to quality)	Y	
2	Develop team charter		
3	Define process steps		
Measure			
4	Select CTQ characteristics	Y	Customer input, QFD, FMEA
5	Define performance standards	Y	Customer input, blueprints
6	Analyze measurement system	Y	Continuous gage R&R, test/retest, attribute R&R
Analyze			
7	Establish process capacity	Y	Capability indices
8	Define performance objectives	Y	Team expertise, benchmarking
9	Identify variation sources	X	Process analysis, graphical analysis, hypothesis testing
Improve			
10	Screen potential causes	X	DOE-screening
11	Discover variable relationships	X	Factorial designs
12	Establish operating tolerances	Y,X	Simulation
Control			
13	Define & validate measurement system in actual application	Y,X	Continuous gage R&R, test/retest, attribute R&R
14	Determine process capability	Y,X	Capability indices
15	Implement process control	X	Control charts, mistake proof, FMEA

<u>Measure the frequency of defects</u>

The measure phase is where the organization defines success and determines what the to-be situation looks like. The CTQs identified in the define phase are culled and the measureable CTQ that is to be improved is identified - focus is not on improving just one internal process element but the series of process elements that impact the specific CTQ which will become the “Y” in the process.

The CTQ/Y is then measured to baseline the process. Here takt time, variation and sources of variation are the key process parameters used to measure the CTQ/Y. Once the baseline is developed, the specification limits for the CTQ/Y are determined and confirmed. As part of this phase, a system is established for ongoing measurement that is adequate for measuring the Y without being burdensome to the business (using gauge R&R & DFMEA). The idea is to develop a measurement system that will enable as close to continuous monitoring as possible. The measurement system should have the following characteristics.

- Accuracy – the differences between observed average measure measurement and a standard

- Repeatability – variation when one person repeatedly measures the same unit with the same measurement equipment

- Reproducibility – variation when one or more people measure the same unit with the same measuring equipment

- Stability – variation obtained when the same person measure the same unit with the same equipment over an extended period of time

- Linearity – the consistency of the measurement system across the entire range of the measurement system

<u>Analyze why, when and where defects occur</u>

Based on the baseline process developed, the "Xs" which drive the specific CTQ/Y are defined. Probability and statistics are used to define and analyze the process capability. Process capability is then established and "entitlement" (the best the current process can deliver) is identified.

The performance objectives of the process are then statistically defined to adequately scope the improvement process – using a combination of the entitlement analysis and benchmarking others…with the ultimate benchmark as perfection. The key variation sources in the process are then identified by identifying and listing the statistically significant Xs, chosen based on the analysis of historical data. Tools typically used at this stage are cause & effect analysis, fishbone analysis, and pareto. Lean principles come into play at this stage as "flow" is evaluated and waste/non value added work is identified.

Improve how we fix the process

The improve phase requires high engagement across the organization to drive change. Cross functional involvement in the solution development using a workshop approach works best in this phase. In preparation for this workshop, the X → Y relationships need to be understood with the vital few Xs that are causing changes in Y exposed and then the transfer function that relates the vital few Xs quantitatively to the Y identified/established. Also, the optimal setting for the vital few Xs should be determined and several confirmation runs should be performed to ensure causality.

The Xs are then improved and improvements in Y are measured. Here tools such as standard work definition, material presentation-kitting & poka yoke, pull production, visual management, 3P-Production Preparation Process (using lean principles) are utilized to come up with ways of improving the Xs. Finally, the tolerances on the vital few Xs that will be controlled in the next phase are defined using simulation techniques.

Control and maintain the 'fixed' process

Control is typically established using a quality management system where work procedures are maintained and managed. This key tenet of this system is the establishment, monitoring and control of safe work practices. Regular quality and/or safety audits should be performed to ensure process are being followed and adhered to.

Specifically, a measurement system on Xs in actual production should be defined and validated, process capability determined and process controls implemented using control charts, FMEA, and risk management techniques. Process control software integrated with ERP systems can be used here where available.

Here, the lean aspect of mistake proofing or poka yoke comes into play. Mistake proofing takes into account and attempts to eliminate human error. Human error comes in many forms and the lean-six sigma framework identifies common human errors that need to be addressed. The following is a list of potential human errors poka yoke can address, all of which have, at one point or another, been associated with a major chemical disaster over the past several decades.

- Forgetfulness (not concentrating)
- Lack of Communication/Miscommunication (jumping to conclusions)
- Errors in identification (viewing incorrectly – too far away)
- Errors due to insufficient training
- Willful or intentional errors (ignoring the rules/sabotage)
- Inadvertent errors (distraction, fatigue)
- Errors due to slowness (delay in judgment)
- Errors due to a lack of standards (written, verbal and visual)
- Surprise errors (machine not capable, malfunctions)

DMAIC to DFSS

Six Sigma is traditionally divided into two key areas, DMAIC (Define – Measure – Analyze – Improve – Control) and DFSS (Design – For – Six – Sigma). DMAIC is the predominant branch and the most well-known as it focuses on the reduction of defects on existing designs/processes. DFSS focuses on the development and design of new products/processes using Six Sigma techniques to make them inherently higher quality and potentially, inherently safer.

What both approaches have in common is the relentless focus on customer driven metrics. By focusing on how the customer views the value we bring vs. how we view ourselves, we can design quality into products and processes. The DFSS process is summarized in the following table.

Table 5: The Steps of the DFSS Approach

Define	Step 1	Identify product/process performance and reliability CTQs and set quality goals
Measure	Step 2	Perform CTQ flow-down to subsystems and components
	Step 3	Measurement system analysis/capability
Analyze	Step 4	Develop conceptual designs (benchmarking, tradeoff analysis)
	Step 5	Statistical analysis of any relevant data to assess capability of conceptual designs
	Step 6	Build scorecard with initial product/process performance and reliability estimates and capability of conceptual designs
	Step 7	Develop risk assessment
Design	Step 8	Generate and verify system and subsystem models, allocations and transfer functions
	Step 9	Capability flow-up for all subsystems and gap identification
Optimize	Step 10	Optimize design ▪ Statistical analysis of variance drivers ▪ Robustness ▪ Error proofing
	Step 11	Generate purchasing and manufacturing specification and verify measurement system on Xs
Verify	Step 12	Statistically confirm that product process matches predictions
	Step 13	Develop manufacturing and supplier control plans
	Step 14	Document and transition

3.3.3 The Concept of Lean - Six Sigma

As seen in previous sections lean and six sigma concepts are highly complimentary and can be combined to attack process inefficiency holistically giving rise to the concept of Lean-Six Sigma. The following diagram attempts to highlight how the two concepts can work together to drive process efficiency and cycle time reduction.

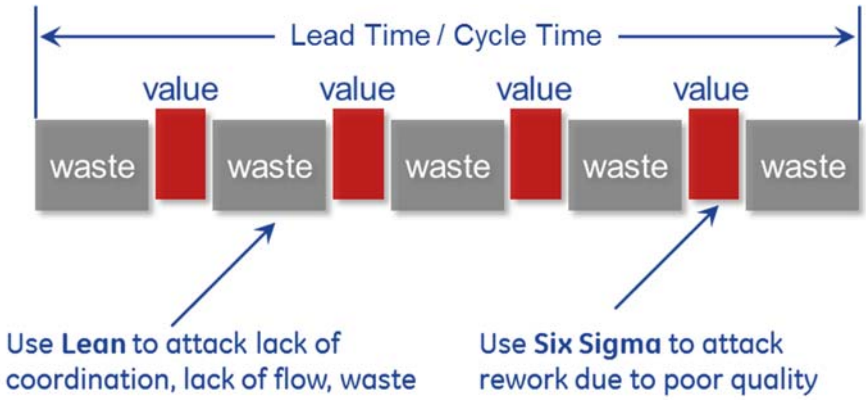

Figure 3: Integrated Lean Six-Sigma Approach

Additionally, lean principles can be embedded at various locations in the relatively extensive Six Sigma framework to turn statistical models into action in the organization.

3.4 Lean Six Sigma and Process Safety

The previous sections have discussed the concepts of lean-six sigma in their purest forms – as they relate to process efficiency and cycle and cost reduction. This section attempts to take these same concepts and discuss how, if the problem we are solving for is process safety, the basic principles of lean-six sigma can be used to develop inherently safer processes.

3.4.1 Key Principles of Process Safety

Process safety is a wide area covering several topics. This section attempts to summarize the key areas of process safety that could leverage the lean-six sigma approach to drive inherently safer processes and lend themselves well to the approach.

<u>Safety pyramid</u>

The concept of the safety pyramid already leverages the root cause analysis approach. The idea behind the safety pyramid is that by recording incidents and high risk behaviors, an organization can address the root causes of many more serious incidents before they result in significant impact to human life and property.

High risk behaviors and near misses lend themselves well to the kaizen approach within lean. The regular genba walks can begin to identify high risk behaviors and performing kaizen on near miss reports enables organizations to systematically address these issues early. In addition, by performing a root cause analysis (leveraging five whys), root causes can be exposed and the application of poka yoke and moonshine on these problem can begin to mistake proof the process preventing future incidents.

<u>Hierarchy of release prevention & mitigation approaches</u>

The hierarchy of release prevention and mitigation approaches shown below sets up layers of protection for safety. This approach has a strong affinity to lean-six sigma. Using DFSS to address the areas of inherent safety and design, DMAIC and a quality management system (QMS) for safety to address the management phase, and early detection and warning aligning to many of the lean principles like kaizen.

By leveraging the DFSS framework, with process safety as a CTQ and focusing only on customer requirements, processes can be built from the ground up with safety embedded in and the critical safety Xs defined and monitored. For existing processes, DMAIC can be used with safety, again as a CTQ, to redesign process elements and a safety based QMS can then be used to manage the tolerances. Finally, as with the safety hierarchy, standard early detection & warning systems can be supplemented by genba walks and kaizens to identify potential issues and behavior early. In this way, these invaluable tools can become an integral part of the early warning system for the process.

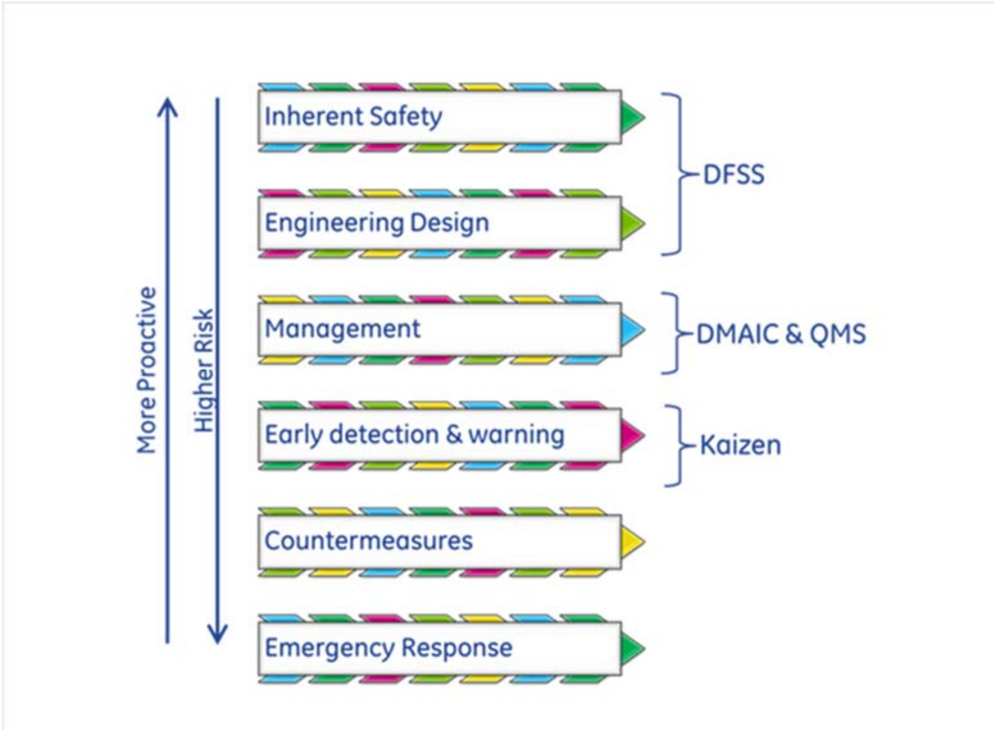

Figure 4: Applying Lean-Six Sigma to the Hierarchy of Release Prevention

Inherent process safety

Four main methods for achieving inherently safer process design are typically discussed[26, 27]:

- **Minimize**: Reducing the amount of hazardous material present at any one time, by using smaller batches or achieving single piece flow in the process
- **Substitute**: Replacing one material with another of less hazard
- **Moderate**: Reducing the strength of an effect by reducing temperature, pressure or diluting hazardous materials
- **Simplify**: Eliminating problems by design rather than adding additional equipment or features to deal with them or simplifying complex procedures by using kits or pre-measured packaging

Additional concepts include:

- **Error tolerance**: Equipment and processes can be designed to be capable of withstanding possible faults or deviations from design

- **Limit effects** by design, location or transportation of equipment so that the worst possible condition produces less danger

These concepts are very aligned to the lean-six sigma methodologies, specifically in the areas of the development of single piece flow. Single piece flow implies breaking the process down so that smaller batches flow through at a time which allows both minimization and moderation. In addition, the development of specialized handling equipment using the moonshine approach, and process enhancements using kitting and poka yoke ensure processes are simplified and increase the error tolerance of specific operations.

<u>Mechanical vs. Chemical Manufacturing Processes</u>

While Lean-Six Sigma is typically referred to in the context of traditional manufacturing processes, a clear analogy can be made to chemical processes. Incremental process steps, in a traditional manufacturing context, involve incrementally adding value to the finished product, modifying form and function to bring it closer and closer to customer requirements. In addition, intermediaries may be used and waste by-products may be generated which impact the safety of individuals. Consider a manufacturing process where a part goes through a rough machining process, a chemical treatment and a final machining process. The process to produce the one part may have machine chips as waste by products that could pose danger to operators, the chemical treatment process may use hazardous chemicals etc.

In a chemical process, a similar approach occurs. Each incremental step in a chemical process brings the final product closer to the finished product by reacting, refining, distilling, etc. One of the fundamental differences in a chemical process, is that any one chemical process may have a primary product and several very useful by-products and as a result the chemical engineer may be optimizing for multiple variables at once.

3.4.2 Leveraging Lean-Six Sigma to Improve Process Safety

Establishing flow and eliminating waste

The relentless focus on end customer requirement and the elimination of waste can be used to drive safer process. Waste in and of itself can create dangerous conditions whether it is physical waste of wasted motion. The concept of kitting and the water spider brings only what the process need to the line at the time the line needs it thereby reducing the risk of accidents due to WIP inventory of hazardous chemicals. The reduction of unwanted motion ensures that unnecessary movement of individuals, forklifts etc. do not create conditions where accidents can occur, for example, unnecessary motion toggling a valve or a forklift puncturing a vessel. Standard work and pre-defined forklift paths ensure that during line operation all motion is confined to the standard work procedure.

In addition, moving from batch and queue to semi batch or better yet flow processes ensure that only the amount of input material or intermediaries are produced when they are needed eliminating the massive storage of potentially hazardous materials and exposing them to the risk of causing an accident as in the case of the Bhopal incident. In the lean scenario, where only small amounts are produced, moved and used just in time for the process, even if a loss of containment or introduction of water occurs, the potential impact is reduced. Thus, by evolving the semi-batch process often used in chemical processes for improved safety to more and more of a flow process, more and more safety can be built into chemical processes.

Mapping the value stream/process

As mentioned earlier, the mapping of the value stream/process from end to end and identifying the key areas for improvement with process safety as the primary CTQ can form the beginning of a very thorough HAZOP analysis. When coupled with root cause analysis and what-if analysis, a very robust process can be put in place that identifies all potential safety risks in a process. In addition, the poke yoke, 3P and moonshine approaches can then be used to mistake proof those areas with the highest risk.

The key underlying principle of lean, automation without passing on defects, becomes a very potent mindset. The highest risk items in the HAZOP can then be viewed in this light and automated in a way that any potential breach of safety protocols **automatically** stops the process without human intervention.

Separating from the critical path and mitigating the impact

In many chemical processes intermediaries are used which can be hazardous if stored in large quantities or not well contained. The traditional production approach involves producing large quantities of the intermediary and storing on site as part of the critical production path. While an inherently safer design involves eliminating the intermediary when possible, it is not always possible. As mentioned above, the lean approach involves producing small batches of the intermediary only as it is needed by the process (flow). Adding to the flow approach a separation of the intermediary production process from the primary process line and producing it in a "feeder line" - which can then be isolated from the critical path process and contained to better ensure there is no accidental discharge can ensure containment of potentially hazardous intermediaries. In addition, it can limit the exposure of both the intermediary and main products from potential issues on either. That is to say, if a runaway reaction on the main line occurs, the feeder line can be contained so no downstream effects occur on that line due to an accident on the main line and vice versa.

This approach is balanced by the concept of grouping consecutive processes together physically. This ensures that potentially hazardous intermediaries are not required to travel large distances to be used. This not only improves the flow and effectiveness off a process but also improves the safety by minimizing the exposure of the intermediary to risks in transit. So feeder lines must be close but isolated and leveraging moonshine to achieve this through creative process customization can yield extraordinary results. For example, creative barriers can be designed and built which are very specific to the process and chemicals.

Kitting, material presentation, poka yoke and moonshine

Perhaps the most useful elements of lean involve customizing the process using kitting, material presentation, poka yoke and moonshine. The reason these elements typically have such a significant impact is that they are customized to the needs of the process. Trolleys with unidirectional slots and customer holders can be used to ensure material is placed in the way it is used with no room for error. Containers with specific attributes for containment can be mounted to trolleys and specific trolley measurements can be developed to ensure evaporation of any spilled chemical falls within the TLV-TWA.

In addition, using poka yoke to mistake proof valves within reach to ensure special toggles must be engaged to turn a valve to a potentially hazardous position can reduce the impact of so-called human error on the safety of the process.

Making it visible

Another key element of lean is to make the process so visible that a person who knows nothing about plant operations can discern the process and its status. Visible flags for part in maintenance physically located on the part and consistently used across the plant can help ensure that incidents like Piper Alpha are avoided. In addition, status boards and electronic status boards that can read machine status directly from equipment on the line (e.g. valves, pumps, heat exchangers, etc.) can be used to quickly see what equipment is down for scheduled or unscheduled maintenance to help ensure that sound decisions can be made quickly both on the line and in the control room.

In addition, to being designed with toggles to ensure only deliberate movement occurs, valves can also be modified via moonshine with highly visible flags to ensure that valve positions, for example, can be seen and identified from multiple reasonably accessible locations. One of the design CTQs can be that it is visible at least from several ground locations and the control room.

Kaizen and genba

As mentioned earlier, genba (walking the plant) and kaizen can be very powerful tools in early incident prevention. High risk behavior can be seen and identified quickly during a genba. When immediately followed by a kaizen to design out the opportunity for the behavior to occur, many issues can be addressed well before they reach a threshold where safety is compromised. The rigor and continuous focus of lean to improve the process, again with safety as a primary CTQ, can systematically and incrementally improve processes to make them safer and safer.

Root cause problem solving

One of the goals in developing safer processes is the identification of all of the potential hazard risks within the process and identifying their potential root causes. As discussed, this concept is critical in analyzing the learnings from near misses and minor incidents and applying them early to ensure more serious incidents do not occur. Many of the tools discussed here in root cause problem solving, such as five whys and fishbone diagrams, can be instrumental in identifying these risks and root causes.[37]

QMS and sustainable process safety

Process safety can only be sustained if the measures put in place are maintained. A quality management system (QMS) with safety as a CTQ is one method of achieving this. When merged with the safety management system and coupled with the management of change (MOC) process, a powerful combination of checks and balances can be put in place to ensure that investments in process safety are maintained, executed and institutionalized. The key differentiator here is that the QMS controls the Xs or root causes of potential safety issues. This ensures that the safety management system truly addresses the underlying safety issues and causes not the symptoms or intermediate causes. It also ensures that when an MOC event occurs, the control mechanism goes down to the Xs. Also, when kaizen is added to the mix, MOC events can also become kaizen events ensuring a closed loop lean – safety cycle.

3.5 Conclusion: The Lean-Six Sigma Mindset and the Culture of Safety

As with safety cultures, the lean-six sigma mindset is essentially a way of doing business with process excellence in mind. The vigilance and rigor that comes with lean-six sigma and the employee engagement and ownership can be powerful tools in building a culture of safety. Thus, buy leveraging lean-sigma tools and infrastructure, with safety as a CTQ for process excellence, a safety culture can begin to be developed within the organization. The following table gives examples of how lean thinking differs from traditional thinking in addressing key safety risk factors.

Table 6: Shifting from Traditional Thinking to Lean Thinking to Improve Safety

Risk Factor	Traditional Thinking	Lean Thinking
Material Handling	• Install Cranes/Hoists • Awareness/Technique Training • Specialized Carts	• Eliminate the need to lift
Noise Exposure	• Enclosure • Awareness Training • Audiometry • Personal Protection Equipment	• Eliminate source of noise
Industrial Hygiene Exposure	• Enclosure/Ventilation • Monitoring Programs • Eating/Drinking Policies • Personal Protection Equipment	• Eliminate need for material
Waste Streams	• Manage & Dispose • Treat & discharge	• Eliminate/reduce waste generation or recycle waste

In addition, there are already many similarities between the concepts of process safety and lean-six sigma. Alignment in metrics between sigma and FAR, the focus on quantifiable risks using statistics and probability and DMAIC and customer centric metrics are all examples of how these two approaches are highly complementary. It can therefore be concluded that, by extending process safety approaches to include lean six sigma concepts, an organization can improve the safety of its processes while simultaneously becoming more efficient in its operations.

4 ANALYSIS OF THE TECHNICAL, MICRO-ECONOMIC AND POLITICAL IMPACT OF A CARBON TAX ON CARBON DIOXIDE SEQUESTRATION RESULTING FROM LIQUEFIED NATURAL GAS PRODUCTION*

4.1 Summary

With increasing attention to the environmental impact of discharging greenhouse gases (GHG) in general, and CO_2 in particular, many are looking to carbon sequestration as an approach to reducing the carbon impact of stationary point sources of CO_2. Although much of the focus has historically been on capturing and sequestering post-combustion CO_2 from the burning of fossil fuels, there are many industrial processes that already require separation of CO_2 that also contribute to GHG emissions. This CO_2 can also be sequestered. One such process is the commercial production of liquefied natural gas which necessitates the separation of CO_2 from the hydrocarbon for liquefaction; resulting in a relatively pure CO_2 stream which can be sequestered.

The Gorgon project is one such commercial project. In the broader political environment of Australia's carbon tax system and government grants to offset the capital investment in carbon abatement technologies, the economics of the Gorgon project can be analyzed to determine the technical and economic parameters that make the carbon sequestration more or less feasible for this self-contained project. These findings can then be applied to any such project where a pure CO_2 is a necessary by-product and a carbon tax is either in effect or being considered. This analysis is the primary objective of this article.

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* Reprinted with permission from: Hasaneen, R.; Elsayed, N.; Barrufet, M.A. *Analysis of the technical, microeconomic, and political impact of a carbon tax on carbon dioxide sequestration resulting from liquefied natural gas production,* Clean Technologies and Environmental Policy, 16(8), 1597-1613 (2014) by Springer. The final publication is available at http://link.springer.com/article/10.1007/s10098-014-0735-6

In this context, a computer based simulator was developed to analyze the impact of technical, market and public policy factors on project economics. A base case was developed using the current project parameters and a number of alternative scenarios were then developed. Sensitivity analyses were conducted and a "best case" scenario was developed to look at what the appetite for investment could be to improve the sequestration of CO_2. The article demonstrates that CCS project competitiveness can be simulated to analyze the impact of key technological, market and policy changes on the project.

4.2 Introduction

4.2.1 CO_2 and the Environment

The impact[8] and risks[9] of greenhouse gas (GHG) emissions on the environment has been well documented. Governments rely on high quality data about greenhouse gas emissions to set environmental policy[10] and must verify these emissions to effectively determine their policy options.[11] It is expected that continued venting of greenhouse gases to the atmosphere will continue to increase the effect of global climate change as the atmosphere struggles to equalize in the face of anthropogenic sources of excessive greenhouse gas emissions.[12] The production and use of fossil fuels has been identified as a key source of excessive greenhouse gas emissions.[13] Of the many substances classified as greenhouse gases, perhaps the single most discussed gas is carbon dioxide, due to its importance and prevalence in many industrial processes.[14] It has been estimated that more that 70 % of the greenhouse gas increases over the past 3 decades are composed of CO_2.[15]

As a result, a number of countries bound by the Kyoto Protocol[16] have taken measures to limit CO_2 emissions using a series of political instruments.[17] There are a number of political instruments which can be used to impact CO_2 emissions[18] including:

- **Carbon tax:** typically translated into a cost/ton of CO_2 emitted applied to a project or plant

- **Cap and trade:** a market based policy which puts a cap on CO_2 and allows participants to trade its excess emissions with others who do not reach the limit

- **Carbon subsidies**: including both direct and indirect subsidies which involve some sort of monetary transfers to the recipient

Analyses of policies for CCS have demonstrated that there is a balance which must be developed between the flexibility required by policy makers and the predictability required by the private sector.[19]

Among the countries leading this charge is Australia. As a remote continent, Australia has an ecosystem that has evolved in relative isolation from the rest of the world. As a result, the Australian government has taken great care to ensure that environmental issues (including GHG emissions) are at the forefront of every project[38], especially those related to the energy industry[39]. As one of the largest natural gas projects in the country, Gorgon is no exception. The Australian government uses a carbon tax scheme to regulate CO_2 emissions across the energy industry and has a capital equipment subsidy to support carbon sequestration projects.

4.2.2 Reducing CO2 Emissions: CO2 Sequestration

Three approaches to reducing CO_2 emissions are typically discussed[20]:

1. **Reducing energy intensity**: by focusing on more efficient use of energy

2. **Reducing carbon intensity**: by switching from fossil fuels to fuels that are based in the current carbon cycle

3. **Enhancing the natural sequestration of CO_2**: by developing and implementing technologies that capture and sequester more CO_2.

The process of CO_2 sequestration involves the capture and separation of CO_2 from an impure stream, compressing the gas to supercritical condition and pumping it into a secure reservoir for long term storage, and sequestration. Carbon capture is limited to stationary point sources[40] and in the case of LNG processing, for example, can happen pre-combustion on the hydrocarbon stream before liquefaction[21] and post-combustion in the case where gas turbines are used to deliver power to the operation[22].

Capture and separation of CO_2 can be accomplished using a number of methods including direct absorption[23], membrane separation, adsorption or cryogenic distillation[20]. Current technologies tend to be expensive and energy intensive, using upwards of 30 % of the power generated[40]. New technologies focus on reducing the cost and energy intensity of this process.

Reservoirs for CO_2 sequestration range from direct deposit into seawater[13] to storage in forest ecosystems or agricultural lands[41] to depleted oil and gas reservoirs[42] to underground storage in saline aquifers[43]. There are a number of key issues associated with sequestration of CO_2 in underground reservoirs including storage capacity per reservoir[44] and across reservoirs globally[45] and leakage back into the atmosphere[46] throughout the duration of the storage period which extends to geological time horizons[47]. As a result, to ensure containment, extensive characterization and monitoring of the reservoir for extended periods of time is required.

In recent years, much attention has been paid to analyzing the economic and environmental impact of carbon capture and sequestration, in an effort to provide background for environmental policy. These studies range from analyzing the economic potential for agricultural greenhouse gas mitigation[48] to analyzing the techno-economic impacts of CCS on several industrial operations and technologies such as: petroleum refineries, chemical plants, hydrogen plants[49]; coal to liquid technologies[50]; distributed energy systems[51]; natural gas combined cycle with SEWGS[52]; poly-generation systems[53]; and pre-combustion power generation[54].

In an effort to model the long term economic and environmental impact of uncertain commercial scale CCS systems, researchers have taken input from analogous energy technologies[55]; conducted pinch analyses to match sources to sinks[56] and performed lifecycle analyses[57], environmental impact assessments[58] and systems analyses[59]. In addition, a wide body of research is focused on techno-economic analyses of CCS operations tied to specific economies where a carbon price may be in effect, proposed or being considered such as Denmark[60], the Netherlands[49], China[50], South Korea[61].

4.2.3 Scope & Methods

The Gorgon LNG Project, off the north-west coast of Western Australia, will be used to model the LNG system and provide a realistic basis for the development of the carbon capture and sequestration (CCS) model. Gorgon is considered the largest single resource project in Australia's history and is expected to position Australia as a major gas exporter, especially in Asia[62]. The project will also position Australia as the world leader in commercial scale greenhouse gas (i.e. carbon dioxide) injection.

The Gorgon received state approvals and licenses for the overall project – which has an estimated lifespan of at least 40 years – in September 2009 with first gas scheduled in 2014. The commercial-scale CCS demonstration project will capture and store between 3.4 and 4 million tonnes of CO_2 per year – a total of 120 million tons over the project's lifetime, and 40 per cent of its emissions[62].

This paper focuses on the CCS system in the context of the broader LNG project. A secondary overview of the overall operation, the environment and the geology of the area has been conducted and discussed with a particular focus on its impact on CCS. In addition, a review of the CCS system in detail including equipment, simulations and monitoring plans has been conducted as well as a discussion of the natural gas market dynamics and Australian political policy impacting the Gorgon project. In the analysis of the CCS operation, the separation of CO_2 from the impure stream of natural gas will be considered part of the gas liquefaction process and will be included in the base LNG production calculations. In addition, since the CO_2 is produced in the controlled LNG production environment, no additional effort is required to "capture" the gas. Thus, the key system burden to be considered in the analysis will be the carbon sequestration system.

A simplified economic simulator has been built and used to develop a set of potential project improvement scenarios for Gorgon including the market, policy and technical impacts. Finally, a best case technical scenario has been developed and its economic impact on the project discussed.

Out of scope for this paper is a full project economic analysis including all potential cost sources. Only cost drivers believed to be relevant to CCS have been considered. Also, extensive technical discussions on achieving the various proposed scenarios were not undertaken, nor has a sophisticated optimization process using advance software tools been conducted. This project could serve as a basis for such research in the future. Opportunities for such future work have been suggested in this paper as well.

4.3 Section I: Gorgon Project Summary

In looking at a complete system, it is useful to understand the context of the analysis and the constraints that the subject case places on the simulation. This section summarizes the Gorgon project, highlighting the key project element that will impact the analysis.

4.3.1 Environment

Barrow island, the home of the Gorgon project, has been a Class A nature preserve since 1910 with no freshwater aquifers. There are a number of coral reefs around the island and there is highly restricted access to the island. Due to the fragile nature of the Barrow Island ecosystem, extensive site screening and selection processes were undertaken for the CCS operation based on four key criteria: containment risk, storage capacity, injectivity and risk to other assets[63]. Both the gas processing and CO_2 injection facilities are co-located on Barrow Island to minimize potential transportation issues with the separated CO_2.

The **Barrow Island Dupuy Formation** (in the Carnarvon Basin) was the only site that adequately satisfied all criteria in 2002[64], based on the inherent characteristics of the basin and formation as well as the presence of over 40 years of existing petroleum exploration. This was further confirmed using rock samples, well logs and seismic data[65].

The Dupuy formation was deemed to be relatively inert, chemically, thereby excluding mineral trapping as a primary method and no large scale geometric traps were found (although smaller scale structural/stratigraphic trapping is expected to occur)[66]. Supercritical CO_2 in the formation will tend to rise vertically due to buoyancy forces.

At a depth of approximately 2200 meters the following parameters are expected:

Reservoir Pressure:	22 MPa
Reservoir Temperature:	100°C
Expected CO_2 Density:	550 kg/m^3
CO_2 State:	Supercritical (from CO_2 phase diagram)

Based on all of the site characteristics, the Dupuy storage formation was deemed to have adequate permeability to balance the requirements for both injection and residual gas trapping. It is considered an ideal CO_2 'container' with the appropriate baffles and seals. In addition, proximity to the LNG operation will minimize the transportation issues associated with CO_2 so only injection issues need be accounted for.

4.3.2 Gas Fields

The Greater Gorgon Fields lie 130-200 km offshore and consist of several gas fields, including Gorgon, Chandon, Geryon, Orthrus, Maenad, Eurytion, Urania, Chrysaor, Dionysus, Jansz/lo and West Tryal Rocks, situated in the Barrow sub-basin of the Carnarvon Basin. The Gorgon project covers natural gas extraction from the **Gorgon field** at about 130km/81mi offshore and at a water depth of ~200m/660ft; and the **Jansz/lo field** to the north at about 200km/124mi offshore (spanning an area of 2,000 km^2) and at a depth of 1,300m/4,300ft.[67]

The project comprises multiple offshore gas fields (a.k.a. the Greater Gorgon Fields) with the two main fields dubbed Gorgon and Jansz. Natural gas from the offshore fields will be piped back to Barrow Island for processing into liquefied natural gas (LNG). This transportation burden will be handled in the analysis as part of the LNG burden, not the CCS burden since the gas must be transported back to Barrow Island regardless of whether CO_2 vented or sequestered. The resulting LNG will be both exported by sea and piped back to the Australian mainland from there to connect with existing domestic pipelines for domestic use. Gas from the fields contains 14 %-16 % CO_2 which must be completely removed for the LNG operation. The separated CO_2 will be captured and stored in the Dupuy formation instead of being vented to the atmosphere.

The Gorgon processing facility is expected to deliver 15,000,000 tonnes of LNG per year, 300 tera joules per day from a domestic gas plant and sequester 3.4 - 4.0 Mt CO_2/y (~125 Mt CO_2 over the life of the project).[68]

4.3.3 Project Technical Details

The Gorgon project is a $43,000,000,000 capital project producing, in excess of, 2,000,000,000 cubic feet of natural gas per day (gross). It consists of four main areas of operation; (1) the subsea system, (2) the LNG system, (3) the carbon capture and sequestration (CCS) system and (4) the power generation system which powers the onshore processing plant.

Subsea System: Natural gas will be extracted from the Gorgon and Jansz fields via a subsea extraction system and piped back to Barrow Island for processing. The subsea system consists of clusters of subsea Christmas trees connected via manifolds; and the tree clusters are then connected via umbilicals to the subsea processing platform for transport to the island. The subsea system will consist of 5 manifolds and 18 trees (and wellheads) with their accompanying equipment.[69]

LNG System: The CO_2 laden (unprocessed) gas will then be piped back to the island where the CO_2 burden will be stripped using an amine system. Natural gas must be completely free of CO_2 for liquefaction to avoid freezing during the process. Air Products and Chemicals Incorporated (APCI) process for liquefaction will be used for LNG production and it is during this process that the CO_2 will be separated from the natural gas prior to liquefaction. In the first phase of the project, 3 LNG trains, each producing 5 million tonnes per annum (MMTPA), equaling 15MMTPA. Trains will produce 2,600,000,000 cubic feet of LNG/day. In phase 2, it is expected that a fourth compression train will be added bringing total production to 20MMTPA (subject to carbon tax outcomes and space constraints).[70]

CCS System: Rather than venting the stripped CO_2 to the atmosphere, carbon will be compressed and sequestered in the saline aquifers of the Dupuy formation. Six strings of electric motor driven barrel type-centrifugal compressors will be used to compress 3.4 - 4.0 million tonnes of stripped CO_2 per year to the 217 bara required for sequestration.[69]

Power Generation System: Power to the onshore facility will be supplied via five standard 100 MW gas turbines. No external power/electricity sources will be used. There are currently no plans to sequester post combustion CO_2 so all combustion gasses will be vented to the atmosphere.

Carbon Inventory: The Gorgon Joint Venture partners have estimated the greenhouse gas impact of both the construction and commissioning phases as well as the operations phase of the project[71]. These boundary conditions are shown in Tables 1 and 2 and will be useful in the economic analysis to come. These estimates represent the emissions which were expected for the project prior to equipment selection and will be updated, in this analysis, based on the actual equipment configuration chosen by the operators. The CO_2 impact of the operations phase is over and above the 3.4 - 4.0 Mt CO_2/y to be sequestered which represents about 40 % of the total emissions[72]. The tables below show the expected lifecycle greenhouse gas emissions for the life of the project divided into up front emissions due to construction and commissioning and ongoing emissions from operations[71].

Table 7: Greenhouse Emissions During Construction and Commissioning[*71]

Activity	Estimated GHG (tons CO_2e)
Offshore drilling activities (fuel consumption)	110 000 – 160 000 (over life of development)
Offshore drilling activities (well clean-up operations)	70 000 – 100 000 (over life of development)
Pipe laying operations – Gorgon field to Barrow Island	25 000
Multiple support vessel	45 000
Electrical power generation on Barrow Island	75 000 – 95 000
Mobile equipment and vehicle usage on Barrow Island	25 000
Dredging	75 000
LNG process commissioning operations	1 200 000
Pipe laying operations – Domestic gas pipeline	15 000
Total estimated greenhouse gas emissions related to construction and commissioning activities	1.64 – 1.74 million tons

* The emissions stated in this table should be considered as order of magnitude estimates.

Table 8: Predicted Annual Greenhouse Gas Emissions[71]

Source	LNG Processing (tons CO_2e/year)	Domestic Gas Processing (tons CO_2e/year)	Island Infrastructure Support (tons CO_2e/year)
Gas Turbine – Gas Processing Drivers	1 612 000	Nil	Nil
Gas Turbine – Power Generation	1 287 000	200 000	60 000
Fired Heaters	71 000	28 000	Nil
Flare – Events	60 000	Minor	Nil
Flare – Pilots	2 000	Minor	Nil
Fugitive Emissions	Less than 1 000	Less than 1 000	Nil
Transport	Nil	Nil	10 000
Diesel Engines	Less than 300	Minor	Minor
Reservoir CO_2 Vented	500 000	180 000	Minor
Total	3 534 000	409 000	70 000

4.3.4 Carbon Capture and Sequestration (CCS) Operation

Figure 5 shows a schematic of the CCS process designed for the Gorgon project[71]. All environmental impact assessments for the CCS operation have been and will continue to be made available for public review as part of the joint venture partners' commitment to environmental responsibility.

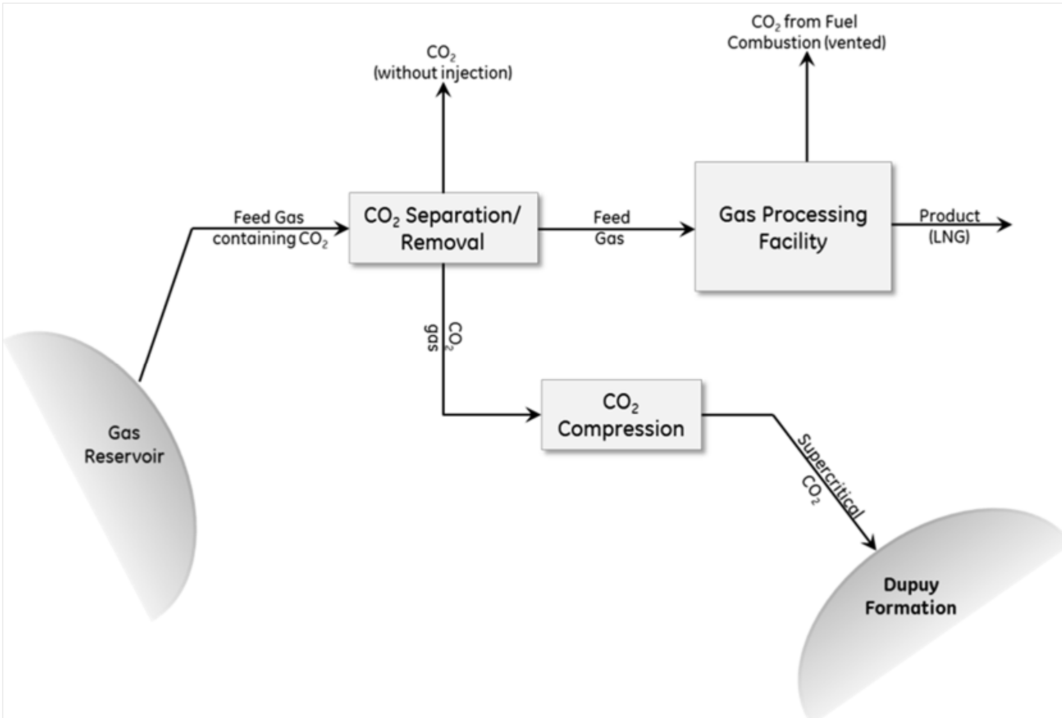


Figure 5: Schematic Diagram for Natural Gas Extraction, LNG Production and Carbon Capture & Sequestration

CO_2 separation

The comingled Gorgon and Jansz gas phase streams from the slug catchers and the condensate stabilization unit will be routed to three Acid Gas Removal Units (AGRU) for acid gas removal from the natural gas using a proprietary activated Methyl Di-ethanol Amine (a-MDEA) technology[23]. Acid gas must be removed from the natural gas to prevent it from freezing out at low temperatures in the cryogenic sections of the plant and to meet the LNG product CO_2 and sulfur specifications. Each AGRU is designed to process 33 % of the combined Gorgon and Jansz gas stream and consists of absorber and regenerator sub-systems to remove CO_2 and H_2S and regenerate a-MDEA for re-use.[73]

CO_2 compression and injection

The removed acid gas, containing 99.7 mole % of CO_2 and minor residual amounts of volatile organic compounds (VOCs) and H_2S, is to be compressed in the CO_2 Injection System and injected into the subsurface Dupuy Formation, or vented in the event of a compression and injection system failure. The CO_2 Injection System consists of 2 x 50 % CO_2 Injection units dedicated to each AGRU. Failure of any of the critical equipment inside each injection unit is likely to result in the immediate shutdown of that unit and local acid gas venting. The second CO_2 injection unit is expected to be able to operate normally during this time. The compressed acid gas will be injected via eight or nine CO_2 injection wells, drilled directionally from three or four CO_2 drill centers. An above-ground CO_2 pipeline will run from the CO_2 compressors on the north side of the Gas Treatment Plant to these drill centers.

CO_2 monitoring

Due to the fragile nature of the surrounding ecosystem, after injection is started, an extensive reservoir surveillance program will monitor movement of the injected CO_2 and track the effects of injection on the formation. The system consists of 4D seismic monitoring systems, a series of observation and pressure management wells and extensive soil flux sampling. This is primarily to ensure no adverse effects to the environment and to monitor any potential leakage of sequestered CO_2[72].

Well simulation - Growth of CO_2 plume over time

Plume movement is expected to be influenced by: water off-take, reservoir depositional trends and structure. Growth in plume area is expected to be rapid during injection, but limited following site closure. Plume management will be achieved by the use of mitigation signposts which are evaluated by reservoir surveillance. Acquired reservoir surveillance data should identify any negative signposts to allow mitigation in the deep subsurface. Integration of reservoir surveillance and reservoir simulation data will assist the demonstration of site integrity and assure project stakeholders of long term continued containment of the plume in the Dupuy Formation[74]. Extensive simulations have been completed to attempt to verify plume growth and migration and identify potential risks to injection.

4.4 Section II: The Market and Political Environment

4.4.1 Australia and the Global Energy Market

Australia is currently the world's largest exporter of coal and the fourth largest exporter of LNG. Recent major oil and gas discoveries have made Australia an up and coming hot bed for energy activity with a national forecast to rival Qatar for the number one spot in LNG by 2016, due to rapidly growing offshore and coal-steam gas industries[75]. Australia, in particular, has an advanced environmental policy with a total $13,200,000,000 investment in clean and renewable energy. Presently Australia exports around 20,000,000 tonnes per year of LNG representing around 9 % of the world LNG trade.

The demand for world energy is expected to be fueled by key emerging economies such as China and India which are placing substantial pressure on world suppliers to meet demand. As a result, energy markets have tightened considerably over the past period, and security of supply has become a priority for many economies, particularly those with high levels of import dependence. With Australia's proximity to the Asian market, which simplifies and reduces the cost of transportation, these developments represent a significant opportunity for Australia to become world leader in energy. This is especially true for natural gas, LNG in particular, due to the reliance on natural gas in the wake of Fukushima[76].

Fukashima did not just impact Japan's view on nuclear as a significant energy source. Nations in Europe and Asia are looking to expand gas imports as well, in some cases because of a turn away from nuclear power[77]. Rapid population growth, urbanization and industrialization added to declining supplies of domestic crude oil, are fueling demand from industrial and utility customers for large volumes of LNG and long-term contracts. In this environment, Australia has the opportunity to assume a leading role as producer of gas in the Asia Pacific Region. There are many factors which contribute to the likelihood of this scenario including: vast and growing reserves of natural gas; access to expanding energy-hungry markets; a world demanding cleaner energy; and the experience and skill in the development and execution of large resource projects[78].

4.4.2 Price of Natural Gas

The price of natural gas is typically set by market forces, based on local supply and demand for the commodity in the marketplace as well as local government policy. The standardized approach to price, similar to that for oil prices, is not available for the natural gas market[79].

Against the backdrop of energy instability in Asia and the follow on effects in Europe, the price of natural gas in these regions is significantly higher than that in the US. In Japan alone, at the time of the research, the price of natural gas had skyrocketed in the wake of Fukushima leveling off at about $16.80/mmBTU ($17.72/GJ) compared to spot prices of about $2.50/mmBTU ($2.63/GJ) in the US and $10-$12/mmBTU ($10.55-$12.66/GJ) in Europe. The Chinese government has historically regulated natural gas prices, however, new energy reform will allow natural gas prices to trade at higher prices hovering at about $5.00/mmBTU ($5.28/GJ). In addition, the price for natural gas domestically in Australia exhibits a similar price due to the spike in demand for exports. These prices were publically available from major outlets such as Bloomberg and the Energy Information Administration[77] at the time the research was conducted.

In their first quarter earnings, Chevron, the operator of the Gorgon project, quoted the average international price of natural gas was $5.88/mmBTU ($6.20/GJ)[80]. This is the price which will be assumed for the base scenario analysis. Given the volatility of the price of natural gas, the simulator will evaluate the impact of natural gas prices on the penalty or burden of the CCS operation on the profitability of the project.

4.4.3 Australia's Energy and Environmental Policies Impacting the Gorgon Project

Australia has an extensive energy and environmental policy governing energy production and usage. It ranges from residential incentives for carbon footprint reduction to an extensive national carbon mapping and infrastructure plan to a carbon price imposed on industry81. As part of this effort, the environmental impact plan tied to Gorgon has been and will continue to be available for public review and scrutiny. Figure 6 shows the history of the Gorgon project mapped against the evolution of the major policy decisions impacting the project.[64]

The Barrow Island Act 2003 (WA) (the Act) and the Gorgon Gas Processing and Infrastructure Project Agreement (the Gorgon State Agreement) outline the terms and conditions of the Gorgon Project, including access to the island, supply of domestic gas to the mainland, funding for net conservation benefits, storage of carbon dioxide and local content obligations. The Act regulates carbon dioxide capture activities occurring in the context of the Gorgon Project. Whilst the Act makes provisions for the injection and disposal of carbon dioxide on Barrow Island, it does not require it.[82]

In addition, to political mandates, the Australian government has a set of economic instruments for the reduction of carbon footprint. The Australian government will subsidize the capital investment in the CCS operation with a $60,000,000 commitment as part of the Low Emissions Technology Demonstration Fund (LETDF). In addition, Australia has instituted a carbon tax of \$23/tonne CO_2 emitted. Finally, there is currently a proposal to institute a credit of \$11/tonne CO_2 for LNG producers to continue to stimulate LNG production. These will all be taken into account as part of the economic analysis.

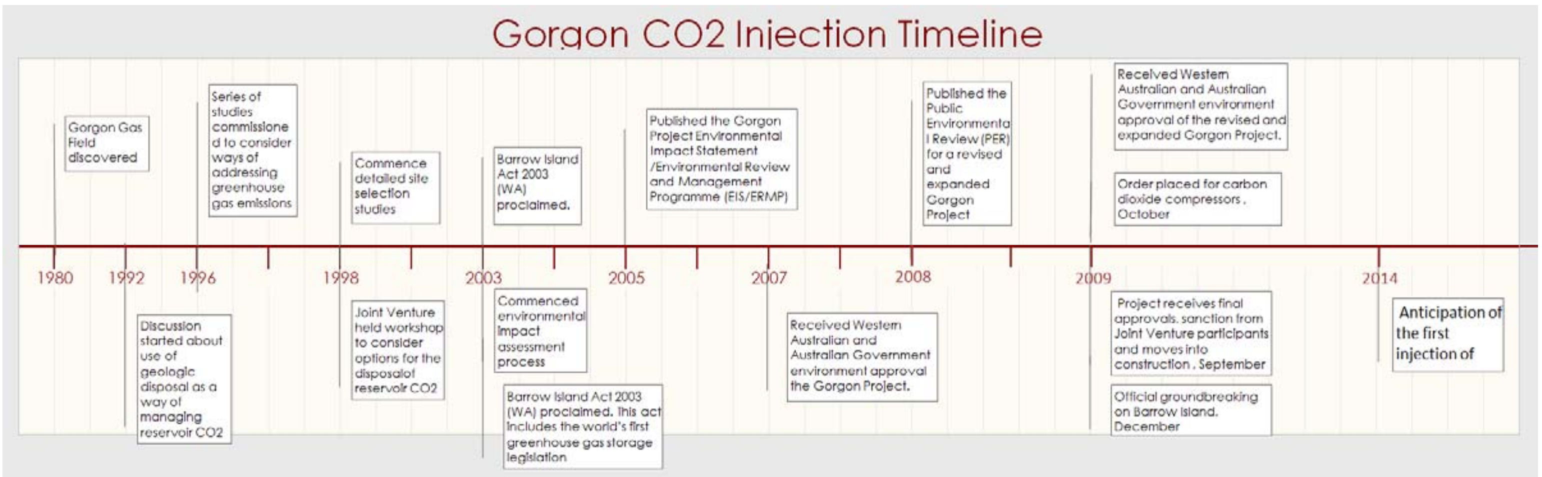


Figure 6: Timeline of Gorgon Project from Early Development Stages to Initial Injection of CO_2

4.5 Section III: Project Economics

In looking at the economics of the CCS project tied to Gorgon, a base case must be developed. Given the complexity of the project, a simplified model was developed and a basic economic simulator was built to perform the scenario analyses presented here. The basic underlying assumption is that CO_2 is an inherent burden to LNG production and would need to be separated regardless of whether it is sequestered or vented. This allows us to isolate the carbon sequestration system and consider it on an incremental basis in the analysis.

Several methods were used to evaluate the impact of the carbon tax on the project economics and were built into the economic simulator. The **annual operating cost** of the project was initially considered to determine if the introduction of the current carbon tax could make carbon sequestration profitable on an annual basis. **Breakeven analyses** were then conducted to determine at what minimum carbon price the CCS operation would become profitable and to test the sensitivity of that to changes in the price of natural gas. Finally, **net present value** calculations were used to determine if investments in operational improvements today would yield long term benefits over the life of the project, in the context of the carbon tax. The underlying assumptions, variables and equations tied to these principles are discussed in the following sections.[28, 29]

4.5.1 Simulation Assumptions

There are a number of basic assumptions taken into account when building the model upon which the economic simulator was designed.

- There are three major systems driving power requirements and carbon emissions. The LNG compression train, the CCS system and the power generation trains.

- All power required will be generated from within project using extracted natural gas, within the power generation trains. Thus the cost will be treated as the "opportunity cost" of using that natural gas for production instead of sales. As a result, the power required for carbon sequestration will be "carved out" of the total power generated. No extraneous electricity will be used.

- Sales of LNG from the Gorgon project will be skewed towards the Asia market with an expected sales mix of 40 % Asia, 20 % Australia, 20 % Europe and 20 % USA. The base case will be based on Chevron's average realized price of gas and the fuel mix will be taken into account as part of the scenario analyses. While the impact of the price of natural gas on the operation will studied, for time based calculations (e.g. net present value), the price of natural gas will be assumed constant throughout the life of the project.

- The primary operational variables in question are power and carbon.
    - Heat was considered, however, given the initial estimates for the project highlighted in Table 8, it was expected that the impact of all fired heaters in the operation would represent less than 2 % of the total contribution. As a result, fired heaters were not considered a key variable for the analysis. A final check, to ensure that this assumption continues to hold once the final numbers were run, was conducted and the total contribution of all fired heaters fell to less than 1 % of the total energy and greenhouse gas contributions.

    - Since only the carbon sequestration system will be analyzed as incremental to the operation, it is expected that all other operational variables would remain the same for the LNG operation whether CO2 is vented or sequestered.

    - The only additional boundary condition is the overall space constraint of 300 hectare maximum on space (all proposed scenarios must physically fit within this space constraint).

- The CO2 injection portion is an inherently nascent process using established technology ➔ a risk premium will be calculated to reflect this and will be reduced over time as the process becomes more stable.

- The capital expense of the CCS system is $2,000,000,000 (4.6 % of the total project cost) minus the $60,000,000 government subsidy.[68]

- As the CCS equipment represents less than 5 % of the total capital expenditure, incremental annual fixed costs tied to this system (e.g. equipment maintenance) are also expected to be a very small portion of the operation and are therefore assumed to be negligible when compared to the costs of power and carbon. This assumption was validated and confirmed during the simulation.

4.5.2 Variables and Key Equations

The key variables impacting the economics of the project are:

LHV:	The lower heating value of the natural gas extracted from the gas fields (kJ/kg)
P:	Market price of natural gas ($/mmBTU or $/tonne LNG)
N:	Number of power units employed in the system
Cap:	Power capacity of a power unit
ε:	Thermodynamic efficiency of the power unit
Load:	The load on the power unit
Reliability:	% of total time the power unit is operational
CP:	Carbon price ($/tonne CO_2)
CO_2 injection risk:	The % of CO_2 expected to be vented due to risk inherent in the operation

There are a number of key equations which were used to simulate the operation and the resulting economics. These equations are summarized here and were used to develop the economic simulator.

<u>Annual operating costs</u>

For each of the three systems: LNG production, CCS and power generation, the total operating costs can be expressed as follows:

Total Operating Cost = Cost of Power + Cost of Carbon

<u>Cost of Power</u>

The equations used in the simulator to calculate **cost of power** are:

Cost of Power=Fuel Consumption*P

Fuel Consumption: To calculate fuel consumption for the primary driver systems drivers, namely the gas turbines driving both the LNG and CCS compressors as well as the gas turbines used for power generation. For a gas turbine:

$$\textbf{Fuel Consumption (per tonne LNG)} = \frac{\text{Annual Fuel Consumption}}{\text{Annual LNG Production}}$$

Annual Fuel Consumption = Fuel Intake*Annual Operating Time = Fuel Intake*Reliability*365

$$\text{Fuel Intake (per second)} = \frac{\text{N*Cap*Load}}{\text{LHV*}\varepsilon}$$

For the analysis, it is useful to understand the power generated per ton of LNG produced.

Annual Power Generated = N * Cap * Load * ε * Annual Operating Time
= N * Cap * Load * ε * Reliability * 365 * 24

$$\textbf{Power per tonne LNG} = \frac{\text{Annual Power Generated}}{\text{Annual LNG Production}}$$

Cost of Carbon

The methodology and equations used for cost of carbon are as follows:

- CO_2 Generated: CO_2 generated in the carbon sequestration operation primarily comes from natural gas combustion within the gas turbines which deliver power to the compressors. Assuming natural gas can be approximated by methane (CH_4), the equations governing this process are:

$$CH_4 + 2O_2 \rightarrow CO_2 + 2\,H_2O$$
$$\therefore\ 1 \text{ mole } CH_4 = 1 \text{ mole } CO_2$$
$$1 \text{ mole } CH_4 = 16g \quad \underline{\text{and}} \quad 1 \text{ mole } CO_2 = 44g$$
$$\therefore\ 1g\ CH_4 \rightarrow 2.75g\ CO_2$$

- When applied to a continuous flow of methane consumed:

CO_2 Generated = Fuel (methane) Consumption*2.75

- Cost of Carbon=CO_2 Generated*CP*CO_2 Injection Risk

Net present value

The following equation was used, in the simulator, to calculate net present value (NPV):

$$\textbf{NPV} = -(CAPEX) + CF * \left[\frac{1-(1+i)^{-n}}{i}\right]$$

where: CAPEX = up-front capital investment
CF = annual net cash flows = expected revenue –total operating costs
i = discount rate
n = number of years of active development

4.5.3 Operations Base Case Model

Using these equations and the most likely scenario for operating conditions (derived from equipment configurations and the proposed, published operating plan for the project), the following project economics were calculated.

Operating Parameters/Assumptions:

- LHV = 38000 kJ/kg
- P = \$5.88/mmBTU = \$6.20/GJ
- ε = 33 %
- Reliability = 93 %
- Carbon Price = \$23/tonne CO2
- CO2 Injection Risk (separation) = 20 %
- CO2 Injection Risk (post combustion) = 100 %

Two subsystems will be used as a basis for operations/scenario analyses: the overall system and the isolated CCS system. For each case, the power impact, carbon impact and total impact of the LNG production system, the CCS system and the power generation system will be considered. The scenarios will look at market, policy and technology decisions and their impact on the overall project profitability.

Economics of the CCS system

By isolating the CCS System, we can look at the economics in the base case, and determine the economic viability of the sub-system, in the context of the existing carbon tax. Entering the equipment configurations, for LNG production, carbon sequestration and power generation, into the simulator and "carving out" the CCS system, yields the Base Case shown in Figure 7.

In Figure 7, we can see from the first bar, when looking simply at the cost of production of LNG, the carbon tax added significant cost to the operation (shown in red). The second bar in the graph quantifies the cost avoided due to carbon sequestration without taking into account the "energy tax" of the CCS system. The third bar looks at the total power required to power the entire operation and the cost of carbon tied to that. In the graph, the fourth bar isolates the CCS system by "carving out" the power required to run the CCS system from the power generation system (third bar) and combining it with the carbon cost avoided in a single bar to isolate the entire CCS system (including power).

From this analysis, it becomes clear that the net contribution of carbon sequestration to the profitability of the overall Gorgon project is negative, even with the current carbon price of \$23/tonne CO_2 (i.e. the carbon tax is not enough to offset the energy tax of the carbon sequestration system). Had the cost of carbon avoided completely offset the operating cost of the CCS system, the bar showing the isolated CCS system would be completely red and white.

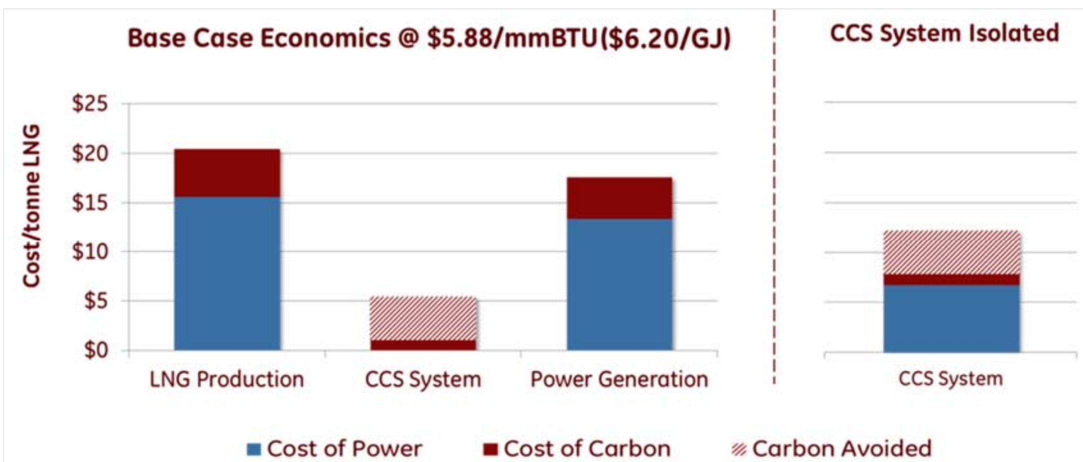


Figure 7: Base Case Economics for the Entire Project as well as the Isolated CCS System

This implies the decision to sequester carbon was not purely an economic decision, but was motivated by both corporate dedication to the environment to garner goodwill and strong political motivation driven by Australia's commitment to environmental responsibility, but not entirely reflected by the economic instruments (i.e. the \$3.50-\$6.00/tonne LNG produced delta, between the current state and what is required to breakeven, is the cost of doing business/producing on Barrow Island). This investment in the Gorgon project is also expected to drive favorable decisions on future developments in Australia thereby cementing the operators' presence in one of the most active natural gas regions in the world and ensuring future revenue in the region. By using this type of simulator as a tool, government policy makers can better determine the impact of environmental policies operations and set the appropriate levels to reach the desired results.

4.6 Section V: Operations and Scenario Analyses

As shown in the previous section, the net impact of overall annual project profitability of the CCS portion of the project is expected to be negative using the base scenario, even in the presence of the current carbon tax. Given the large up front capital investment it is clear that the net present value of the CCS portion of the project will heavily burden the natural gas operation. A series of "what-if" scenarios were developed to determine a set of conditions which could render the CCS operation accretive to the overall project. The simulator developed was used to run these scenarios. As stated previously, only power and carbon will be considered as part of the analysis. All other project costs will be considered common and incurred as part of the operation regardless of the presence of the CCS operation.

4.6.1 Impact of Changes in Carbon Price

The base scenario assumes a carbon price of \$23/tonne CO_2. Using the operator's average price of natural gas, the graph in Figure 8 shows the "breakeven" point of the CCS operation at about \$70/tonne CO_2 vented.

At \$70/tonne CO_2, the cost avoided completely offsets the energy tax of the operation on an annual basis. However, given that large up-front investment, a higher tax would be required to provide a net present value of zero. A net cash flow of \$13.23/tonne LNG would be required for a full investment recovery on the CCS project, which only occurs at a carbon tax of \$200/tonne CO_2.

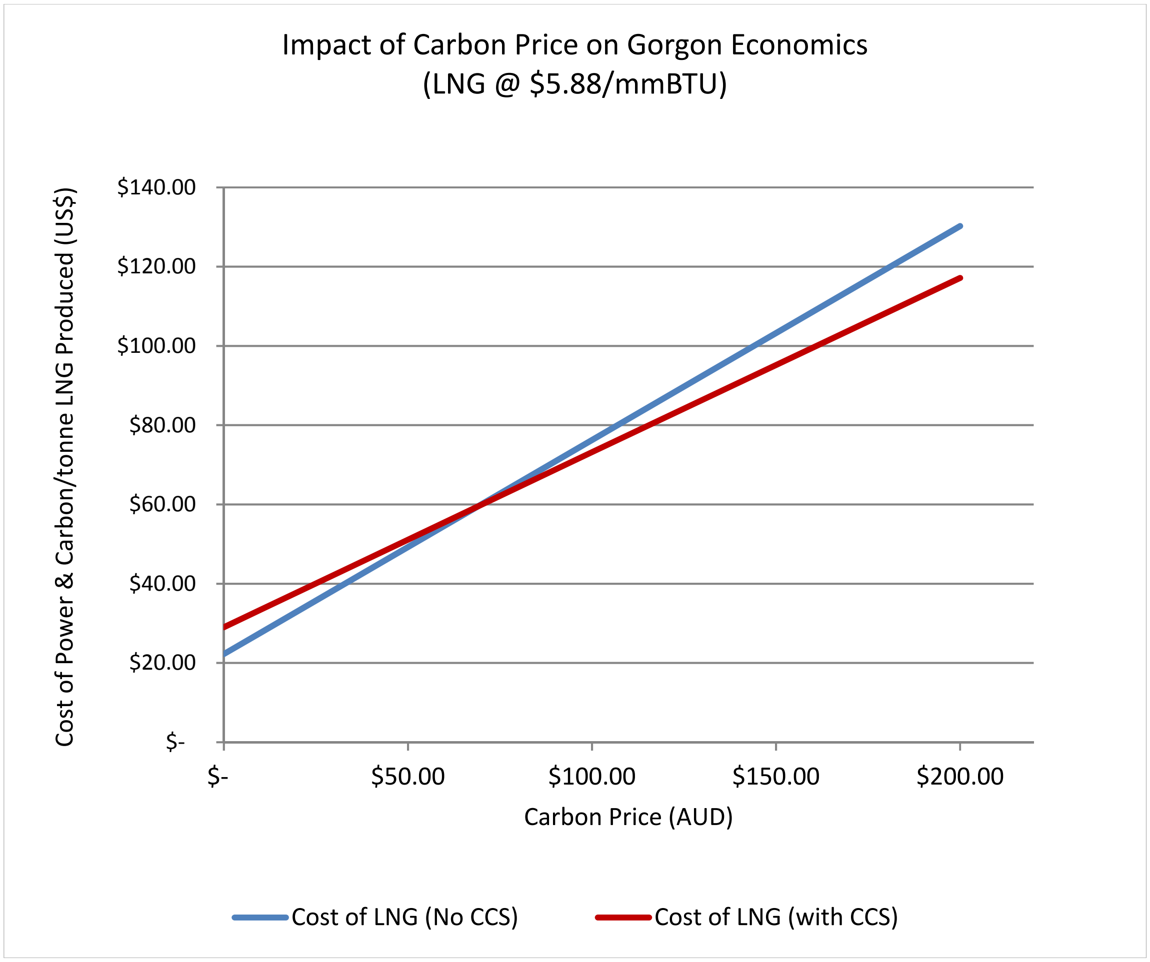


Figure 8: Impact of Carbon Price on Project Economics

Using the simulator to run this type of scenario analysis during the policy setting process, can help policy makers determine the appropriate tax levels which would yield an economically viable policy in the context of such large infrastructure projects.

4.6.2 Impact of Changes in Price of Natural Gas

The breakeven carbon price was found to be highly dependent on the price of natural gas as this impacts the cost of power dramatically. The higher the price of natural gas, the more expensive the energy tax of the operation. The Figure 9 shows the impact of natural gas price on the breakeven carbon price when the CCS operation is taken in isolation.

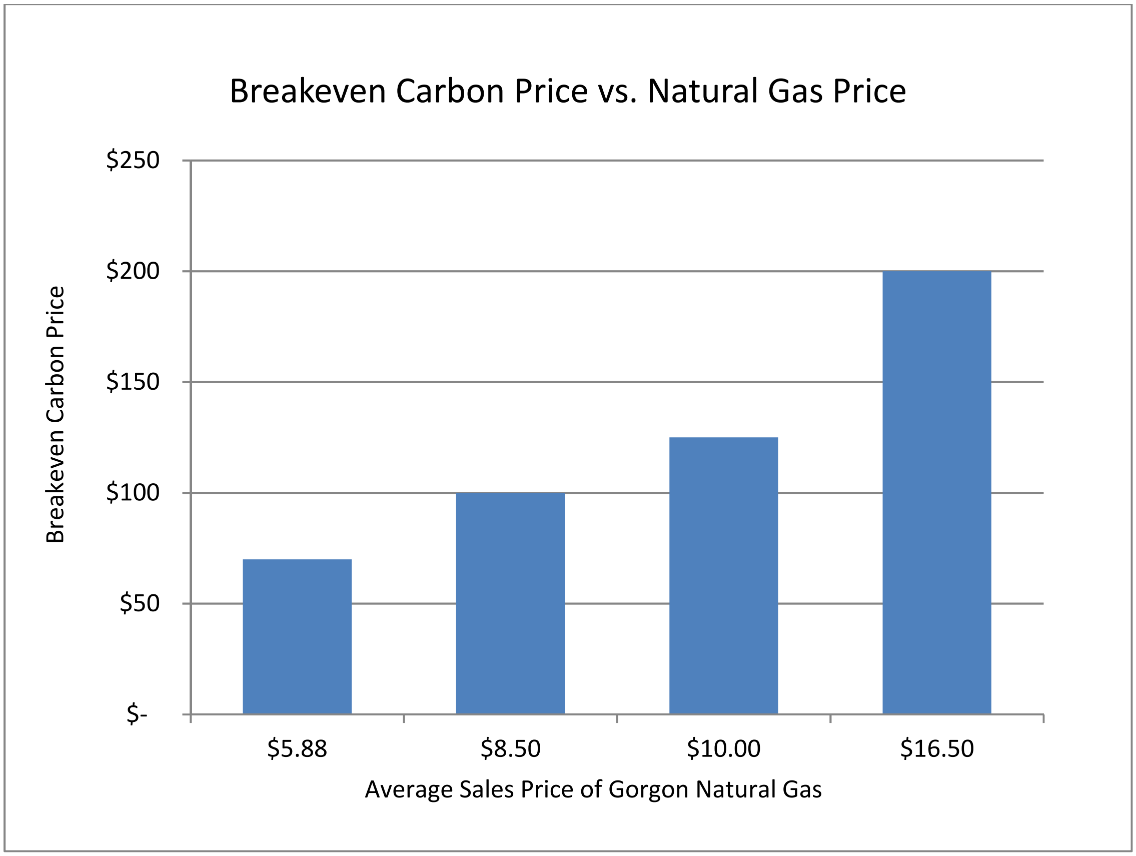


Figure 9: Relationship Between Price of Natural Gas and Breakeven Carbon Tax

In the economic analysis undertaken to make the decision to invest in the CCS system, the higher the expected price of natural gas, the higher the opportunity cost of using valuable natural gas in powering a CCS system, the higher the carbon price must be to offset this cost and make the decision to sequester economically viable. Having said that, the higher the price of the natural gas the more profit an operation can generate with the same capital investment and operating conditions. This implies that once the internal hurdle rate of the operator is reached and exceeded, the higher overall profitability of the project could enable the price of "goodwill" to supplement the pure economic impact of the carbon price and facilitate an annual investment in environmental responsibility, provided the annual cost doesn't drive the project back below the hurdle rate set by the operator. However, depending on the overall health of the operator, that places the CCS operation at risk of being terminated at the whim of the operator, when the extra profitability is required to offset losses in other areas of the business.

4.6.3 Impact of Efficiency Improvements in Existing Operations

The next potential scenario is to look at engineering efficiencies and their impact on the viability of the CCS operation. Two major variables are considered in the analysis. The first is the inherent efficiency of the CCS trains leveraging technologies which drive more complex, but more efficient, thermodynamic cycles. By augmenting or substituting traditional gas compression cycles with trains which leverage supercritical compression and pumping or refrigeration, the total absorbed power can be reduced. Reducing the 12.5MW/train of absorbed power to 11 MW/train and 9.5 MW/train respectively, was found to have a significant impact on the energy tax of the operation. These are shown by the blue bars in Figure 10. These represent the negative impact of the CCS subsystem on the total profitability of the LNG operation for the power absorption in question. The more negative the number the larger a negative impact it has on the total operation.

The second major area of engineering efficiency improvements is in the area of efficiency improvements in power generation units, both as part of the LNG trains as well as the units powering the operation. Improving the efficiency of the gas turbines by using, for example, a combined cycle process with waste heat recovery can yield significant improvements in the energy tax of the entire operation, especially in the CCS portion. A 7 % improvement in train efficiency was assumed and when combined with the absorbed power assumptions, it can be seen from the red bars in Figure 10, that the energy tax of the CCS operation on the project can be reduced significantly. In fact, the impact of improvements in power generation efficiency was found to have a much more dramatic improvement on project burden than the improvement in the power absorbed by the CCS system.

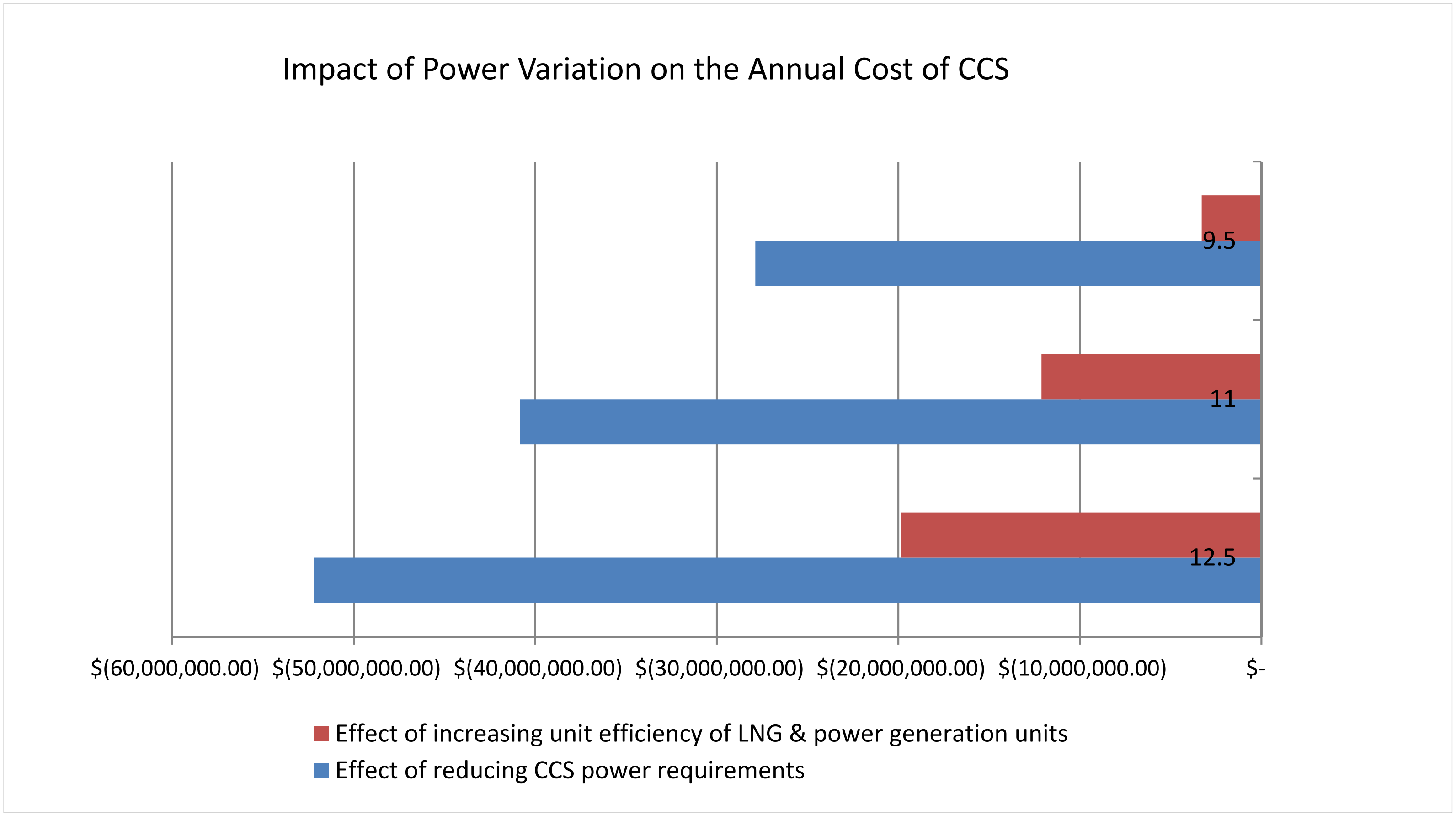


Figure 10: Net Present Value of Improvements in Equipment Efficiency

While these improvements continue to burden the project, the total burden is much reduced. A best case scenario, with improved power generation efficiency and an improved CCS process, reduces the project burden by $24,600,000 annually. The NPV of this improvement is $ 240,000,000 over the life of the reservoir. This represents the investment in technology that a rational consumer would be willing to make to break even on the benefits over the life of the project. This, however, does not include the risk of implementation of unproven technology. Based on the publicly available information, this risk could be as high as 20 % in the case of Chevron, or higher if this new technology puts the primary production trains at risk. With a 20 % risk included, the breakeven of initial investment is reduced to about $190,000,000.

A major technological breakthrough that should be mentioned, although not modeled here, would be in CO_2 separation from natural gas at high pressures. Should an industrially viable solution in this area be introduced, a dramatic reduction in compression costs could be realized, in terms of both capital investment and operating expenses. These would then need to be tempered with the appropriate risk factor associated with the implementation of untested technology in the field.[83]

4.6.4 Impact of Post Combustion Sequestration

Another obvious scenario is to look at a scenario in which post combustion carbon is also sequestered. A basic assumption in this portion of the analysis is that, the existing CCS system consisting of six compression units is already sequestering as much carbon as possible. Therefore, additional capacity will need to be added for post combustion sequestration and that capacity is added in a linear fashion. Relaxing this assumption and calculating the actual maximum sequestration opportunity of the existing system will only yield more favorable results.

Using this assumption and a crude optimization methodology (i.e. iterating in Excel) we find that we will need 22 CCS units and an additional two power generation units running at 95 % load to satisfy the post combustion compression scenario. In addition, this does not take into account any additional investment in post combustion separation and gas cooling technologies. Even if space constraints on the island allowed for this type of investment and we could mitigate all risk to LNG production, with the existing carbon tax, post combustion CCS consumes profitability and does not add to it. In the long term, not only is the NPV for this scenario in isolation negative, is has a negative impact on the annual profitability of the project by approximately $175,000,000/year with an increase of about 250 % of the power required for the base case. Thus, a rational consumer, not required by law to sequester post combustion gases, would not invest in this scenario in isolation of any other operational improvements, even in the presence of the current carbon tax. These impacts are shown in Figure 11 and Figure 12.

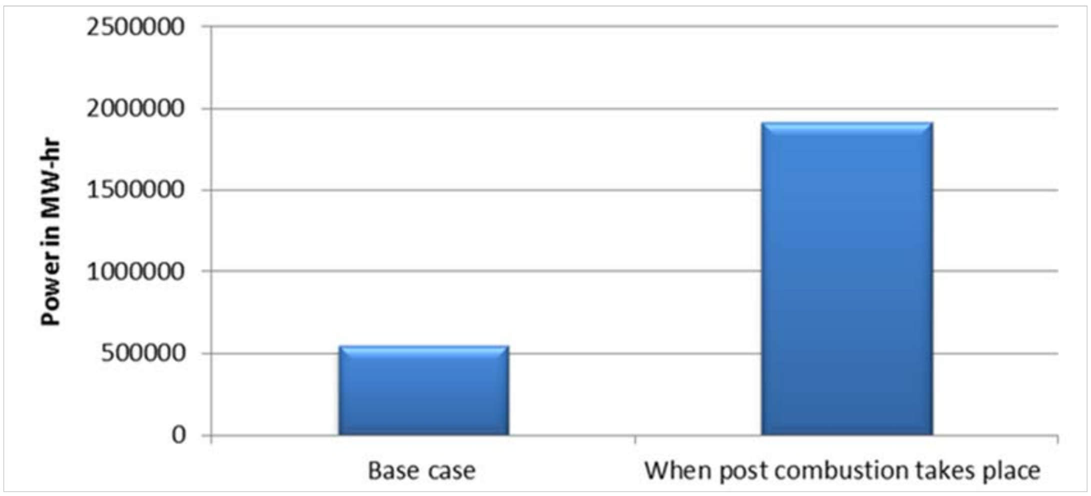


Figure 11: Impact of Post Combustion CCS on Power Consumption

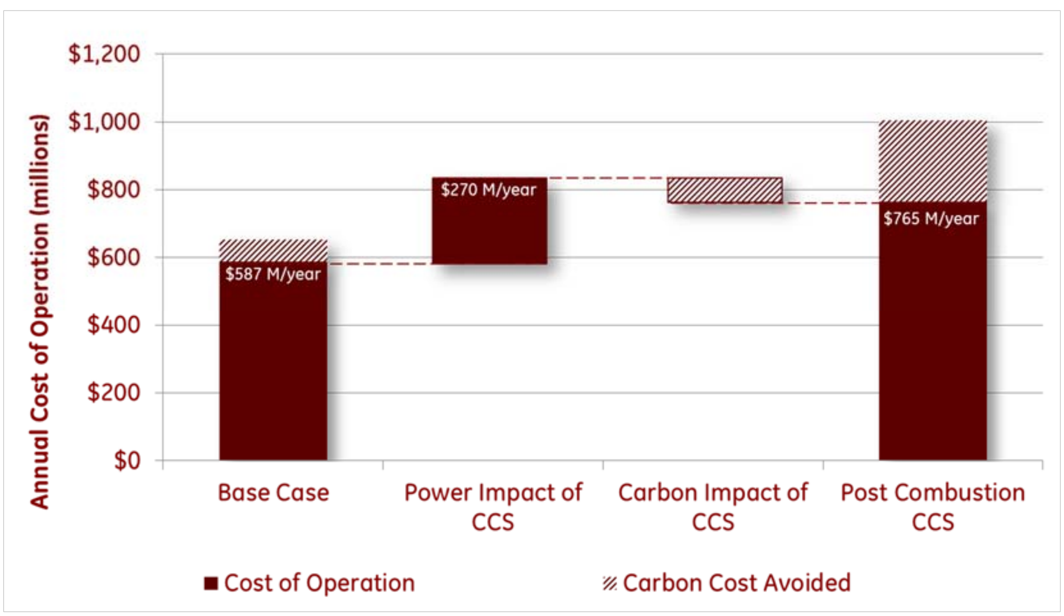


Figure 12: Impact of Post Combustion Sequestration on Profitability

4.6.5 Best Case Scenario

Using the approach above, each factor impacting the improvement in the performance of the CCS operation can be analyzed in isolation. An objective function can then be developed and optimized to determine the set of parameters which would render the CCS project a viable and accretive portion of the project using only economic considerations. For this analysis, each of the factors was tied to a series of technological and commercial opportunities and an overall "best case" scenario developed. Table 9 shows parameters used and the opportunities to improve those parameters. These were then used in the simulator to perform a crude optimization process.

Table 9: Technical and Commercial Opportunities for System Improvement

Improvement Factor	Improvement	Activity
System Reliability	93 % → 98 %	sign service agreements with vendors guaranteeing system reliability
CCS System Efficiency	+3 MW/train	leverage advanced compression systems
Power Generation Efficiency	+7 %	leverage technologies such as enhanced heat recovery systems/combined cycle gas turbines[22]
Risk of CO_2 injection	-15 %	gain experience with CO_2 over time and sign service agreements guaranteeing system reliability
Post Combustion Sequestration	+95 % post combustion CCS	leverage advanced technologies in separation and cooling, expanding the existing CCS system and leverage experience from separation CCS

This represents the best case scenario previously developed parameter by parameter. The following graphs show the impact of the improvements on the breakeven carbon price for two natural gas price points: the first is the operator's publicly stated company average price of natural gas, the second is the effective price of natural gas with sales skewed towards the Asia market. As shown in Figure 13 and Figure 14, with the investments in operational improvements, the breakeven cost of carbon drops to $11/tonne CO_2 for an effective price of gas of $211.78/tonne LNG ($5.88/mmBTU) and $15/tonne CO_2 for an $306.14/tonne LNG ($8.50/mmBTU) gas price. This means that at the $23/tonne CO_2 carbon tax would actually make the investment in CCS accretive to the overall operation.

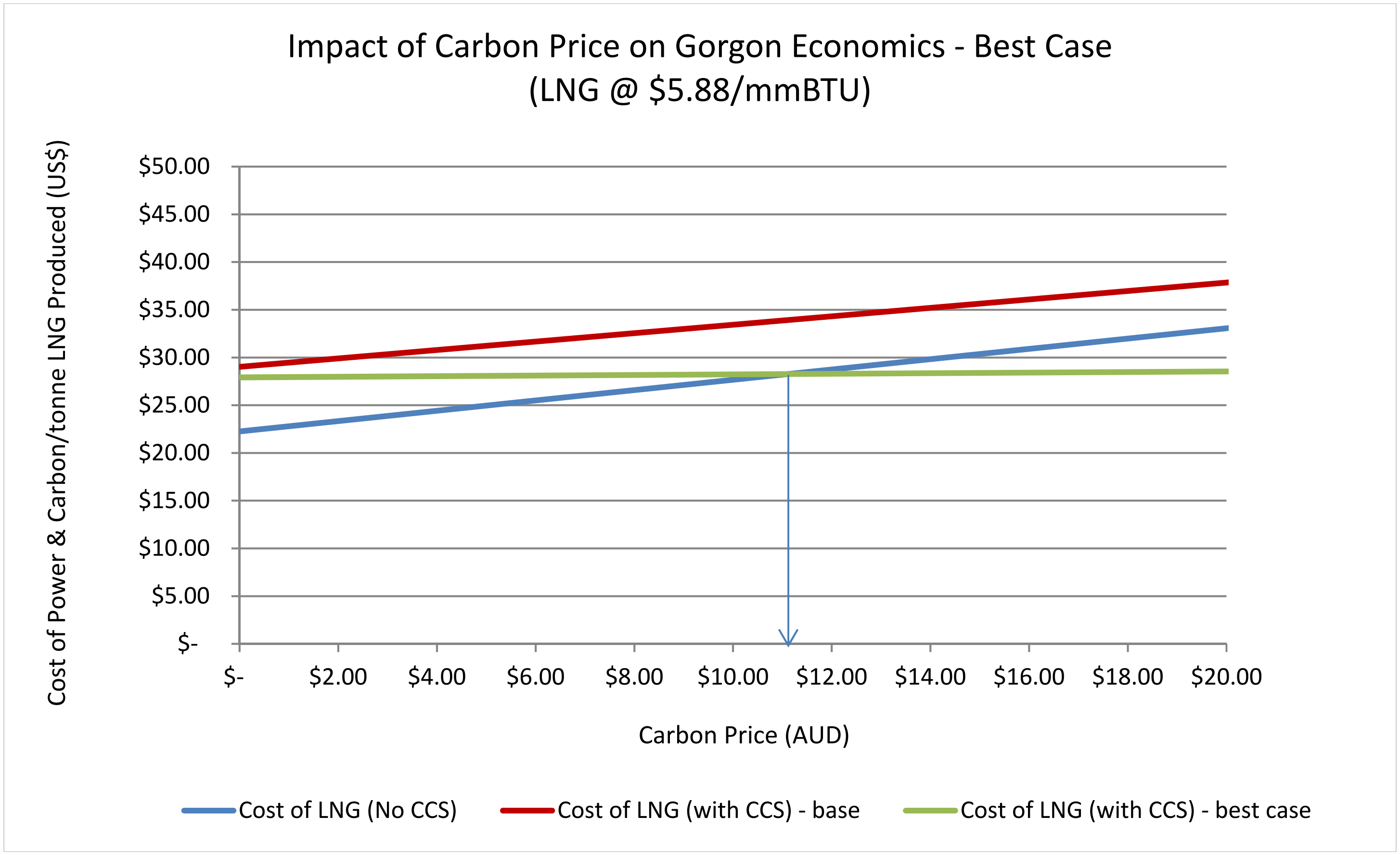


Figure 13: Impact of Carbon Price on "Best Case" Economics (LNG @ $5.88/mmBTU)

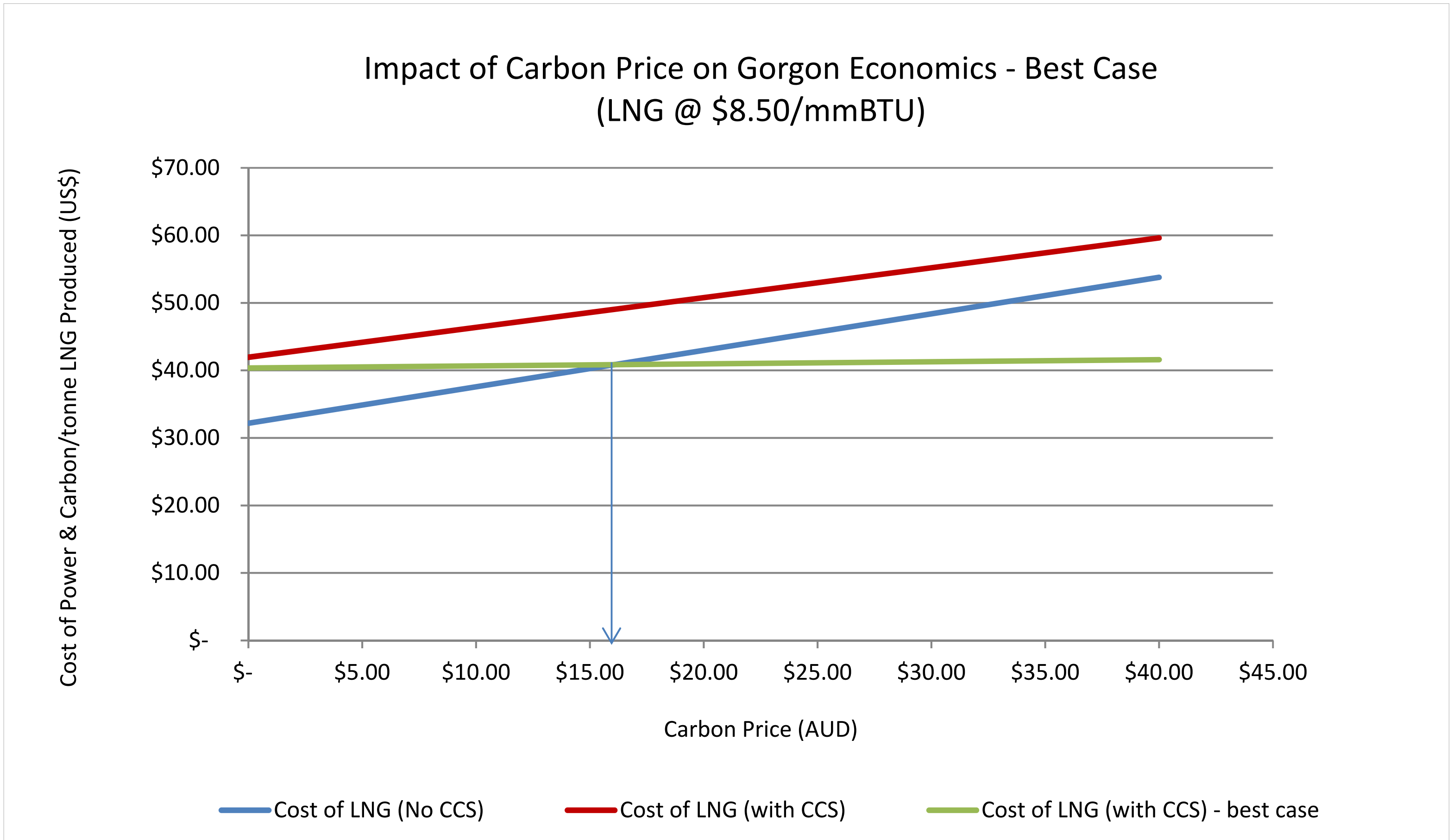


Figure 14: Impact of Carbon Price on "Best Case" Economics (LNG @ $8.50/mmBTU)

By looking at the impact on the total cost of the operation, it can be shown that investing in the operational improvements specified in the best case scenario has a net positive annual impact on the profitability of the operation at the \$23/tonne CO_2 carbon price. This impact is shown in the following graph.

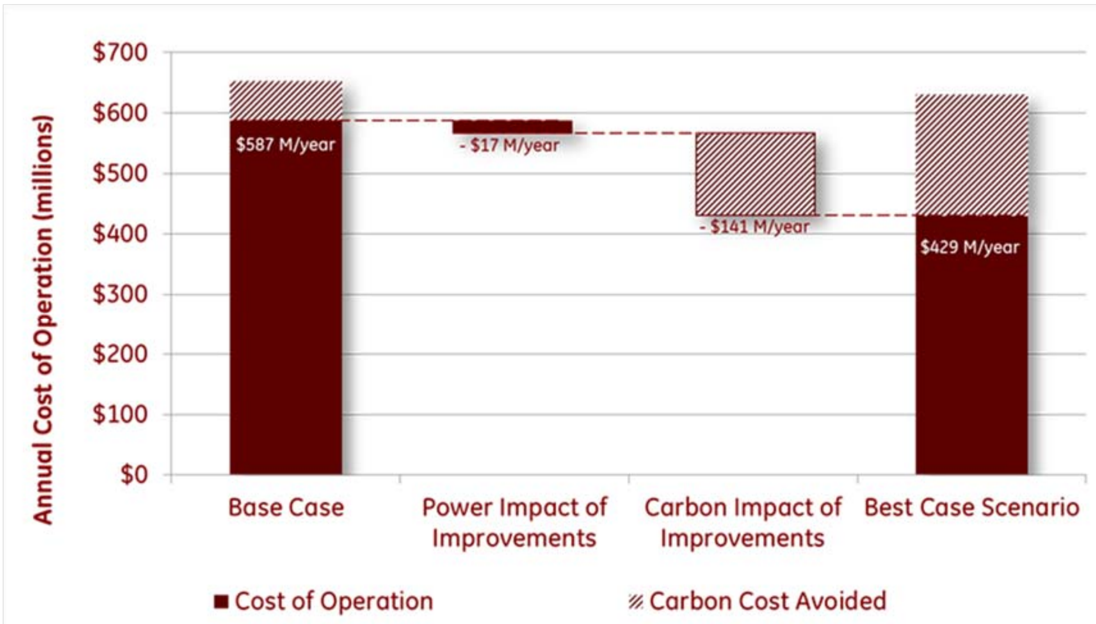


Figure 15: Best Case Economics – Annual Cost of Operation

Based on these simulations, the capital investment required to breakeven on the long term improvements is on the order of \$850,000,000 to \$920,000,000 (\$690,000,000 - \$735,000,000 with a 20 % risk premium). That is, a rational consumer would be willing to invest about \$700,000,000 in the short term to realize these long term profit improvements to the project. In addition, the higher the effective sales price of natural gas or the higher the carbon price, the more of an up-front investment the operator would be willing to make.

4.7 Conclusions & Recommendations

When setting environmental policy, it is critical that policy makers examine the impact of those policies in light of the micro-economic environment of the industries they are trying to impact. In the case of the environmental impact of LNG production, natural gas behaves like a public good with negative externalities, in the form of environmental impact. In many cases, a tax can be used to alleviate these externalities, however, the amount of tax needs to be high enough to incent LNG producers to act differently, i.e. sequester CO_2 produced as a natural consequence of LNG production.

This paper looked at a specific case, the Gorgon project, and modeled the carbon sequestration system in order to develop an economic simulator which can be used by policy makers to help determine the appropriate levels for a carbon tax on LNG production. The simulator was then used to model additional physical factors which might make carbon sequestration more affordable and the resultant target tax. This type of analysis can be used to determine other policy instruments by which to encourage LNG producers to sequester carbon.

The paper found that, without improvements in technology, the existing carbon tax imposed on the Gorgon project was inadequate to incentivize LNG producers to sequester carbon, based purely on economic drivers. In addition, it was found that the tax would have to be increased as the price of LNG rose to compensate for the opportunity cost of using natural gas to power carbon sequestration equipment, in lieu of selling it as LNG. In addition, the most significant driver of cost was the energy intensity of the power generation modules, by a wide margin, followed by CCS system efficiency. Additional drivers included overall system reliability and the risk of CO_2 injection. By improving the underlying technology of the system, it was discovered that a much lower carbon tax could be imposed to offset the negative externality of LNG production. As a result of looking at this analysis, policy makers might consider supplementing the carbon tax with a “best available technology” policy to drive these technological improvements into the project and increase the effectiveness of the carbon tax.

Although this analysis provides critical insight for policy makers, here are a number of limitations. These scenario analyses represent a very basic economic simulation using a simplified business model for the Gorgon project. In order to better model the operation, there are a number of potential opportunities that would increase the sophistication of the analysis and drive more comprehensive results, for example:

- **Expansion of cost model** – expanding the number of variables impacting project cost and more accurately modeling the impact of the CCS portion of the operation will provide a more accurate cause and effect analysis of decisions

- **Optimization of Operation** – the development of a true objective function and using a sophisticated modeling tool can derive a set of optimized operating conditions to better determine the most optimal set of investment decisions for long term project profitability.

- **Technology Selection** – selection of specific technologies for improvement and the specific costs and benefits tied to those technologies will more accurately determine the potential for true operational improvements.

- **Real Data** – use of real field data after first gas in 2014 will help tighten the operational model and provide more accurate predictions for decision making

- **Variable NPV model** – use of a year by year analysis of operational risk and the development of a variable net present value model, taking into account the variation of key variables, like the prices of natural gas and will allow the modeling risk reduction due to learning over time and enable a more accurate value for capital investment decisions.

- **Use of CO_2 for EOR** – given the proximity of the Gorgon oil fields, a simulation looking at a the economic and environmental impact of the use of CO_2 for EOR with a supporting value sharing scheme between operators can be conducted.

5 ENVIRONMENTAL REMEDIATION OF SHALE GAS WELLS IN THE BARNETT SHALES (PART 1): USING NATURAL GAS TO REDUCE GREENHOUSE GASES FROM COMBUSTION

5.1 Summary

Advances in horizontal drilling and hydraulic fracturing technologies have led to a rapid and widespread growth in natural gas production from shale formations in the United States. In addition to supplying a much larger portion of the U.S. energy needs domestically, natural gas promises to improve the United States environmental footprint as natural gas is considered a much cleaner burning fuel than both coal and oil. However, the drilling and production processes in shale gas operations have raised many debates as to the lifecycle footprint of shale gas and have driven many local governments to take policy actions to limit shale gas extraction. This series of papers will look at three of the most discussed environmental elements of shale gas operations, greenhouse gas emissions; water consumption and disposal; and seismicity. Using the Barnett Shale play as a case study and leveraging field data and market validated estimates, a simulator was built to determine environmental and microeconomic implications of selected environmental remediation techniques on the operation. In this first part of the series, reducing greenhouse gas emissions by substituting diesel and gasoline with natural gas as a fuel is examined. It was concluded that, although an up-front capital investment would be required to convert equipment to natural gas, the process would be both environmentally and economically beneficial for the operator in the long run in two out of the three evaluated scenarios.

5.2 Introduction

5.2.1 Framing the Issues: The Energy & Environmental Equation

Advances in horizontal drilling and hydraulic fracturing technologies have driven a rapid and widespread growth in natural gas production from shale formations in the United States. This development has narrowed the production-consumption gap in U.S. energy and is expected to turn the United States into a net exporter of natural gas by 2020[84, 85]. As natural gas is considered among the cleanest of conventional fuels, in terms of usage, this also promises a reduction of the carbon footprint of the United States[5], as many of the industries which are heavily reliant on coal and oil turn to natural gas as an alternative.[84, 86, 87]

While natural gas itself is considered a clean fuel, the extraction process, attributed to natural gas, derived from shale formations, has raised many debates as to the total lifecycle environmental footprint of the fuel[88-96]. Many argue that, the environmental impact of drilling and production processes employed in shale gas operations severely limit the environmental benefit of the use of shale gas as a clean fuel alternative.[97-99]

While research in this area is still developing, there are unique elements of shale gas drilling and production operations that inherently contribute to their environmental footprint. Shale reservoirs are massive, typically spanning multiple communities, many coming close to metropolitan areas and agricultural zones[96]. As a result, localized environmental impacts have less opportunity to dissipate and must be contained much more tightly. Also, as compared to vertical wells, in conventional oil and gas formations, unconventional wells tend to be more closely spaced and can take months to drill. They require horizontal drilling to access the formation and more fully drain the rock matrix and must employ hydraulic fracturing at extensive rates to stimulate production. The hydraulic fracturing process involves the injection of large amounts of chemical-laden water and mud into the well at high pressures, in order to fracture the rock and allow the gas to be produced[100]. Although hydraulic fracturing has been used for decades to stimulate traditional oil and gas wells; the main issue with shale is scale. The size and number of fractures required to release the gas from shale is much more significant than those previously employed by the industry.[101]

As the current boom in shale production is relatively new, there is still a fragmentation among operators in terms of drilling and production processes. Many of the producers typically operate using traditional techniques, which allow for minimal up front capital investment. Also, since the breakeven gas/oil price for unconventional resources is much higher than those in conventional reservoirs, these operators are very typically cost sensitive. This has led to operations which have proven to be sub-optimal from an environmental perspective.[91, 97, 102]

This issue is becoming more pronounced as we discover and characterize more and more shale gas deposits. The situation has led to a growing opposition to the hydraulic fracturing process with several bans and moratoria on shale gas extraction, led by local and municipal governments, both in the United States and across the world.[6] Without alternatives that reduce this environmental impact, shale gas production may have significant adverse effects on both immediate environmental health and safety as well as on the broader environment.

The process it takes to develop a gas well requires an extensive use of diesel fuel, fresh water, contingencies to local water supply, roads, and reinjection of waste water into deep wells for disposal. The environmental impacts of these activities[103, 104] include:

- **Land impacts** - Number of wells that need to be drilled; acreage & clearing for well pads & impoundments; clearing land for building new roads

- **Greenhouse Gas Emissions** - Fugitive methane emissions & flaring; release of pollutants from diesel and gasoline engines used in the operation

- **Impacts on water** - Overconsumption of fresh water for fracturing (millions of gallons per well) [100] and waste water management required due to the contamination of water with fracturing chemicals & methane (local streams/rivers & well water); pond fires due to wastewater pond negligence

- **Seismic impacts** – Increased seismic activity related to hydraulic fracturing [90], natural gas extraction and waste water re-injection [105]

- **Additional impacts** - Release of VOCs from well installation and radioactive particles in waste water

While these issues are common among unconventional gas plays, the unique composition of the gas in each play could require additional processes which would also need environmental remediation such as de-watering or CO_2 removal. As a result, looking at these issues can form a foundation for analysis of other plays, but cannot be applied directly without adaptation.

5.2.2 Focusing the Analyses: The Barnett Shale.

In order to focus the analysis, a specific shale gas play was evaluated. Depending on the underlying depositional system, different shale plays will require different remediation approaches, so limiting the analysis to a specific play enables a focused approach to the analysis. The Barnett Shale was chosen as it is among the most established and most mature shale gas plays in the United States today and it plays a critical role in the U.S. natural gas landscape. As a result, a robust data set collected from operations in the Barnett could be used to conduct the analyses.

The Barnett Shale is a geological formation, located in North Texas. It is estimated to extend 5000 square miles, across 25 counties with the core producing area located around Fort Worth.[88] The formation rests between 6,500 – 8,000 feet in depth, with an average thickness of 350 feet [106].

As of August 2014, there were over 17,500 wells, producing 4,856 million cubic feet per day of natural gas, according to the Texas Railroad Commission[107]. In addition, the Barnett Shale currently produces approximately 4,125 barrels per day of oil and 12,000 barrels per day of condensate, making it a considerable resource for Texas and placing it among the top five shale gas plays in the United States, with the success of horizontal drilling driving the success of the play. Today, horizontal well count is triple that of vertical wells in the formation, and horizontal well production dwarfs that of verticals wells in the play.[108, 109] Shale gas from the Barnett play does not require CO_2 and H_2O processing to make it usable and can therefore be used as a baseline for further analyses.

5.2.3 Well Lifecycle Analysis and Environmental Impacts

In looking at the environmental impacts of shale gas, it was assumed that once the gas is produced and processed for transportation, its environmental footprint will be similar to that of natural gas from conventional sources. Therefore, the focus of this analysis is on the environmental footprint of the drilling and production processes associated with shale gas extraction, the "well" lifecycle, and not on the entire lifecycle of the shale gas itself.

As discussed previously, there are a number of environmental issues tied to shale gas development. Issues around greenhouse gas emissions; water consumption and disposal during hydraulic fracturing; and seismicity are the most consistent among shale gas plays and have the most direct impact on the immediate environment. In addition, these elements are among the most difficult to manage and mitigate.

As a result, the well lifecycle analysis across this series of papers focuses these three elements and the proposed improvements to reduce the impact on the immediate environment were analyzed and discussed at length. In this first part, the analysis will focus on greenhouse gas emissions. Specifically, this paper focuses on emissions resulting from the burning of fuel to run drilling and production equipment rather than fugitive methane emissions which can also be a source of greenhouse gas emissions in the operations. In the second part of the series, the analysis will turn its focus towards the impacts on water consumption and disposal and seismicity which are inter-related.

5.2.4 Shale Gas Operations.

In order to analyze that environmental impact of the drilling and production processes associated with shale gas, it is useful to understand the overall operation, how the gas is extracted and how it differs from conventional operations. This is the basis for the well lifecycle analysis.

After the initial exploration, permitting and exploratory drilling stages are completed, an operator will begin drilling and production activities. Land is cleared for the operation and vertical wells are drilled into the shale formation through to the total formation depth. Conventional wells are typically drilled into sandstone and the natural permeability allows the fluids to flow to the low pressure wellbore, thus artificial stimulation, such as fracturing, is not necessary. In contrast, a wellbore in an unconventional reservoir may make contact with some natural fractures, but the hydrocarbons that could be produced from these are insufficient for economic production of gas. In order to bring enough fluid to the surface, the fracture network needs to be greatly expanded. Thus, a well needs to be designed in a way that will connect to the maximum number of fractures and allow induced fractures to expand as far as possible. This is achieved in the first two phases of the well's lifecycle: **drilling and completion**. The final phase of the lifecycle, the **production** phase, requires marginal effort, as it typically consists of a pumper making daily checks on the well or performing a workover, as required. Most new gas wells go through these three major phases in their life: drilling, completion/stimulation, and production.

The drilling and completion phases are relatively brief, typically one to two months in duration, but require a tremendous amount of energy and capital. It is during these phases that much of the environmental impacts occur. The production phase starts when the well begins flowing and continues until it reaches the end of its economic life. Since many unconventional wells can live for decades, the marginal environmental impact of the production phase can sum up to a material amount.

***Drilling* -** In the drilling phase, a well is drilled that descends into the targeted formation and bores through it, horizontally, increasing the contact area with the reservoir. Horizontal wells are drilled to a kick-off point (KOP) and the bit is driven in a soft angle until it reaches approximately 90^o and will continue to bore to the desired measured depth. As a well is drilled, the hole will be encased with steel pipes and cement will be pumped around it to improve isolation of the well from the subsurface zones. One of the advantages of horizontal wells is that multiple wells can be drilled into the targeted formation from a single well pad. This reduces the impact to the surface environment and reduces costs.

Completions - Once a well has been drilled, cased and cemented, the stimulation or completion process begins. In the completion phase, the well bore is perforated to establish communication with the reservoir and fractures are induced using hydraulic fracturing[100]. Hydraulic fracturing is a process that induces fractures into the rock, by pumping fluid down at very high rates. The fluid is often fresh-water-based and filled with proppant: a sandy or gel-like substance that fills in the newly created fractures and keeps them “propped” open to allow reservoir fluids to flow. This perforation and fluid pumping process is repeated several times in stages and connects the natural fractures within the reservoir. The combination of these fractures, creates a large network of interconnected pores to the wellbore and allow for economic flow of oil and gas[110, 111].

Production - The gas is then produced by allowing fluid to flow to the surface. The gas is collected for processing and transportation.

5.3 Environmental Remediation of Greenhouse Gas Emissions Using Natural Gas as a Fuel

To conduct the environmental impact analysis, a well by well approach was taken. Field data from Barnett Shale assets was obtained and compared with other public sources and research. The results were then extrapolated to encompass the entire play and develop the economic and environmental models, assuming that the shale gas wells across the play behaved and were produced in a similar manner. For each well, the step by step drilling and production processes were analyzed and alternatives with reduced environmental footprints were proposed to address the three major environmental factors: greenhouse gas emissions, water consumption & disposal and seismic impacts. These alternatives were then evaluated by looking at the environmental footprint improvement as well as the micro-economic implications to the operator. This environmental and economic model was then expanded to encompass the entire play and conclusions were drawn regarding the economic viability of investing in the alternatives for each of the major environmental factors.

This research discusses the greenhouse gas portion of the analysis, specifically focusing on greenhouse gas emissions resulting from the burning of fossil fuel for powering drilling and production equipment in the operation.

The process of drilling, completing and producing a well consumes a large amount of energy. Power for the engines that operate the extensive number of rigs and trucks that make a gas well possible is provided primarily by diesel fuel supplemented by gasoline. There are three major categories of equipment used to drill complete and produce a shale gas well. Heavy duty drilling rigs running primarily on diesel; heavy duty diesel trucks used for primarily for pumping; and light duty transport vehicles which are primarily standard gasoline powered vehicles. Although diesel and gasoline offer many technical and logistical advantages, the resultant emissions pose a serious environmental issue. The EPA sites the development of natural gas and petroleum systems as the leading producer of greenhouse gas.[87]

The abundance of natural gas, from the development of shale resources, has driven the price down to levels where using natural gas could provide significant cost savings over diesel and gasoline. Furthermore, the environmental impact of burning diesel versus natural gas is vastly in favor of natural gas. Therefore, in looking at reducing the greenhouse gas footprint of shale operations, one key focus would be on replacing diesel and gasoline usage with natural gas throughout the lifecycle of a typical Barnett Shale gas well.

5.3.1 Single Fuel, Bi-fuel or Dual Fuel

Replacing diesel and gasoline based engines with natural gas based ones has been examined for some time[112]. Natural gas can be implemented in single fuel, bi-fuel, and dual fuel modes. Single fuel mode involves an engine that only operates on natural gas. Bi-fuel engines have two independent engines, but can only be run one at a time, while dual fuel engines are two independent engines that can be run simultaneously.

Dual fuel rigs are seen as the best potential solution for natural gas utilization in the field, so an operator has the horse power available with diesel, but can switch to natural gas as power requirements diminish[113]. These alternatives are commercially available today and their energy tax and required capital investment is known. Dual fuel engines could also replace diesel engines used for trucking, hauling, and pumping. These engines offer improved economics over time, with current pricing spreads, and burn much cleaner [114,115,116].

For transport vehicles, single mode natural gas systems are assumed as conversion kits a readily available today and there are no specific power requirements that necessitate a bi-fuel or dual fuel mode. The benefits of natural gas based vehicles over gasoline vehicles are similar to their benefits over diesel.

5.3.2 Forms of Natural Gas

Natural gas as an engine fuel comes in three types: Raw Natural Gas, Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG). CNG offers opportunity as it can become compressed on site for fuel use. LNG is a denser form and carries more value for heavy engine use, but LNG compression trains are less portable and have more stringent requirements for compression that require pre-processing. Although the heating value of diesel is significantly higher than that of LNG, by factor of 1.72 to 1.00, it is also about four times of the cost, implying that LNG can be an economically favorable solution overall. Raw natural gas does not require any compression and therefore has no associated energy tax, however, not all natural gas engines can operate on raw natural gas without some sort of processing and it must be piped from location to location so transportation becomes an issue.

5.3.3 Environmental Impact

In order to quantify the environmental impact of using natural gas in place of diesel or gasoline, each phase of the well lifecycle will be examined and the opportunities present for natural gas utilization in operations determined. An assessment of the monetary and environmental impact of replacing traditional fuel based engines with natural gas based ones will then be made to determine the economic and environmental viability of the substitution. Compared to gasoline or diesel engines, natural gas engines typically demonstrate the following emission reductions:

Carbon dioxide (CO_2):	10%-20%
Carbon monoxide (CO):	80%-90%
Hydrocarbons & Volatile Organic Compounds (VOCs):	50%-70%
Nitrogen Oxides (NOx):	30%-40%
Sulfur Dioxide (SO_2):	~70%.

Moreover, these vehicles produce no carbon smoke and particulate matter (PM) emissions, and harmful substances are reduced by 90% [117]. These reductions will be evaluated using field data form the Barnett Shale operation and existing technologies for substitution.

5.4 Theoretical Calculations

5.4.1 Current Operations

As discussed, in order to determine the amount of energy a typical shale gas well operation requires, and therefore the amount of fuel to be consumed and greenhouse gases emitted, field data from Barnett Shale assets was obtained and compared with other public sources and research. The assumptions and equations detailed here were used to build a simulator that approximates the costs and greenhouse gas emissions of the operation. Greenhouse Gas emissions were evaluated by looking at heavy equipment usage of diesel and light duty truck usage of gasoline throughout the well lifecycle and then evaluating their conversion to fuel combinations with smaller environmental footprints.

5.4.2 Key Assumptions

- For a given well, there is a short term phase, drilling & completion, and a long-term phase, production
- The drilling and completion phase takes approximately 1 month for a Barnett Shale well (based on field data)
- The useful life of the equipment is uniform across equipment types and is assumed to be 5 years before a major overhaul which would require an additional capital investment. At that point, the cycle will be assumed to repeat.
- Wells will be drilled continuously with no downtime between completing one and drilling the next well
- Price of fuel remains constant throughout the life of the operation
- At one well/month; a given rig can drill and complete 12 wells/year and this will constitute the basic “unit or cluster” of calculation
- Transport Vehicles will be treated separately spanning the entire well lifecycle & one vehicle will cover a bundle of 12 wells
- All generators used in the drilling operation are assumed to be uniform in specifications and operating conditions
- All drilling generators use fuel at the same rate and operate at 80% load

Fuel usage by well

Heavy Equipment Usage: Drilling Rigs. From the field data, the average rig used in the drilling operation required a total of three 1250 horsepower diesel engines to deliver the necessary power for drilling a horizontal well of 3,500 feet. Over the 25 days, on average, required to drill the well, the engines each ran on average 351 hours at 80% load.

To calculate the total amount of diesel fuel consumed per rig, for each well drilled, the total energy consumed by the three engines was determined using the conversions inTable 10 and the following equation were used.

$$\text{Fuel Consumed per Well} = \frac{(\text{Engine Power})(\text{Number of Engines})(\text{Duration of Operation})}{\text{Energy Density of Target Fuel}}$$

Table 10: Energy Consumption - Conversions & Constants[118].

Element	Conversion Factor
1 horsepower (HP)	746 kilowatts (kW)
1 liter (L)	0.26417 gallons (G)
1250 HP @ 80% load	1000 HP
Energy Density of Diesel	35.8 megajoules/liter (MJ/L)
1 DGE	0.1395 MM BTU natural gas
1 DGE	143.94 standard cubic feet (SCF) natural gas 0.14394 MCF natural gas
1 DGE	1.68 gallons liquefied natural gas

Heavy Equipment Usage: Pumper Trucks for Completions. Fuel usage during the completions phase is concentrated in gathering and pumping water and proppant down hole at rates powerful enough to overcome the friction of the wellbore, the small punctures at the end, and break through long reaches of rock. Many pump trucks are typically gathered around the well site and work in series to add enough velocity to the water. The process of perforation and pumping of fracture fluid is repeated for all planned stages of the fracturing operation. From the field data, an average well covering 3,000 feet of lateral length is perforated in 12 stages, on average. Several pump trucks working for seven days intermittently consumed, on average, 31,000 gallons of diesel fuel to complete the operation.

Heavy Equipment Usage: Fresh and Waste Water Management. The hydraulic fracturing process uses several million gallons of water. That water must be hauled from fresh water sources. In addition, a portion of that water flows back to the surface as flowback or produced water. This water must then be hauled away from the site to a waste water disposal well. More detail on this topic is included in the second part of this series. Heavy duty trucks running predominantly on diesel fuel are used to for this process and pumper trucks typically dispose of the water into the disposal well. These trucks can carry approximately 8,000 gallons of water each.[119] To assess the amount of fuel used, it was assumed that the publicly available cost per barrel of water hauling and disposal was composed of the cost of fuel used. Those were used to determine the amount of diesel fuel used for these operations.

Transport Vehicles. During all major phases of the well lifecycle, transport vehicles are used for several purposes, making trips to and from the site to support the operation. In an effort to determine the environmental effects from truck mileage during the drilling, completion, and production phases, the North Central Texas Council of Governments [120], gathered data from operators, service companies, and regulatory authorities. Mileage assumptions were based on the expected number of vehicles utilized, the average number of trips taken, the average mileage per trip, and the average fuel efficiency. Table 11 summarizes those findings for each of the phases of the operation.

Table 11: Transport Vehicle Fuel Usage

Phase	No. of Trips per well	Distance/Trip (miles)	Total Mileage (miles)
Drilling	187	50	9,350
Completion	420	50	21,000
Production	3,613	0.5	1806.5
Total			32,157

Vehicles are assumed to be light duty gasoline powered trucks with a fuel efficiency of 20 miles/gallon. As the production phase can continue for many years, the transport vehicle calculations are annualized, using the 12 well assumption, to ensure consistency among the data.

<u>Annual fuel usage and costs</u>

In looking at the greenhouse gas footprint of the shale gas operation and the resultant economic impact of the environmental remediation techniques, it is useful to look at annual fuel usage across the three stages and the various applications using current technologies. To determine the microeconomic impact of the environmental remediation recommendations the annual operating costs of a diesel and gasoline based operation was determined and then compared to those of the alternative fuel options. Based on the field data, it takes approximately one month to drill and complete a single Barnett well. Thus, it can be assumed that a given "cluster" of equipment can be used to drill 12 consecutive wells per year.

Using the field data presented and applying the assumptions and equations listed here, the annual fuel consumption and resultant costs of the cluster of 12 wells was derived. To determine the annual operating costs of the equipment cluster, the price of fuel needed to be taken into account. In the case of diesel and gasoline, this is real cost to the operation as gasoline and diesel are not produced. In the case of natural gas, in its various forms, this represented the opportunity cost of selling that gas on the market rather than using it to drive the operation. Changes in these market prices would impact the results of the analyses.

Table 12: Fuel Prices

Fuel	Market Price (USD)
Diesel	\$3.61/DGE [121]
Gasoline	\$3.71/GGE[121]
Natural Gas	\$4.12/MM BTU[122]
CNG	\$1.68/DGE[123]
LNG	\$2.92/DGE[123]

Greenhouse gas emissions

Of the many substances classified as greenhouse gases (GHG), perhaps the most discussed is carbon dioxide, due to its importance and prevalence in many industrial processes.[14] It has been estimated that more than 70% of the GHG increases over the past three decades are composed of CO_2.[15] While the combustion of gasoline and diesel fuel emits GHG across the entire spectrum, calculations are focused on CO_2 which will serve as an indicator of the benefits which can be derived from the use of alternative fuels in the shale gas production process. The broader spectrum of greenhouse gases will be discussed at a high level to demonstrate the expected magnitude of the benefits.

The U.S. Energy Information Administration estimates that about 19.64 pounds of CO_2 are produced from burning one gallon of gasoline that does not contain ethanol, about 22.38 pounds of CO_2 are produced from burning a gallon of diesel fuel.[124] Table 13 summarizes the emissions factors from the technologies used in the field data. As these greenhouse gases can vary dramatically by technology the factors for the specific technologies studies are used here.

Table 13: Greenhouse Gas Emission Factors for Base Case Fuels

Fuel Type	NOx	CO	VOC	PM
Diesel (g/bhp-hr)[125]	8.15	4.69	0.43	0.27
Gasoline (g/mi)[126]	0.95	11.84	2.513	0.0094

Based on these figures, the annual GHG footprint of a "well cluster" can be calculated as a baseline for the environmental remediation process and can be extrapolated to express the broader environmental benefits.

5.4.3 Operations after Environmental Remediation

Conversion to dual fuel systems

Utilizing a dual fuel system implies that a portion of the diesel fuel consumed with natural gas and in this case, 70% of the diesel fuel consumed per well was replaced with natural gas in the form of CNG, LNG or raw natural gas. During this process, the energy density of these replacement fuels was taken into account in both the cost and environmental impact equations[127]. Table 10 includes the conversions used to determine these amounts. To determine the fuel consumption of natural gas, diesel and gasoline across the well lifecycle, the simulator used the fuel consumption assumptions in the "current operations" base case and substituted 70% natural gas for diesel engines and 100% for gasoline. The energy density conversions were used to derive the absolute amount of natural gas consumed and costs and greenhouse gas emissions were calculated off of that basis.

In addition, the energy burden of the CNG or LNG systems, to convert the reservoir gas to this form, must be taken into account as part of the overall calculation. This does not need to be taken into account when working directly with raw gas. This energy tax is accounted for in the price of these forms of natural gas which can vary dramatically due to the processing requirements[128]. By extrapolating the results and looking at the total number of wells drilled across the shale play, an expression for total annual cost and environmental footprint across the entire play can be calculated.

<u>Greenhouse gas improvements</u>

To determine the improvements in greenhouse gas emissions from substituting natural gas for diesel and gasoline, the proposed configuration was analyzed and compared with the baseline configuration. Representative technologies were evaluated for each scenario, while the final results will vary depending on the technology implemented, the results discussed here will provide directional guidance for expected benefits from the use of natural gas as an alternative fuel.

Based on the estimates provided by the U.S. Energy Information Administration, 119.0 pounds of CO_2 are produced from burning one thousand cubic feet (MCF) of natural gas.[124] In order to determine the reductions in other major pollutants specific technologies used in the field data and comparable alternative natural gas technologies were assumed.

Table 14: Emissions Factors for Technologies Used in Environmental Remediation

Technology	NOx	CO	VOC	PM
Heavy Duty Diesel Engine (g/bhp-hr)[125] (used for 30% of heavy duty operations)	8.15	4.69	0.43	0.27
Heavy Duty Natural Gas Engines (g/bhp-hr)[129, 130] (used for 70% of heavy duty operations)	0.5	1.4	5.88	0
Light Duty Natural Gas Trucks (g/mi)[131] (used for personal transport)	0.168	1.835	0.025	0
Heavy Duty Diesel Trucks (g/mi)[132] (used for 30% of heavy duty hauling)	8.613	2.311	0.900	0.421

5.4.4 Net Present Value and Expected Capital Outlay

The net present value (NPV) of the environmentally remediated operation was determined to identify the maximum capital outlay that would make the investment in environmental remediation economically viable for the operation. This was then compared against estimates for the up-front capital investment required for the technologies assumed in the environmentally improved case. The following equation was used to determine NPV:

$$NPV = -(CAPEX) + CF * \left[\frac{1-(1+i)^{-n}}{i}\right]$$

CAPEX = the up-front capital investment,

CF = annual net cash flows (or net savings),

i = the discount rate, and

n = the number of years before a major overhaul

Depending on whether the investment is for a green field application or for a conversion of existing rigs, the up-front capital investment can vary. In a green field application, the difference between the diesel investment and the natural gas investment would need to be taken into account. For a conversion project, the investment in diesel technology would be considered a sunk cost, so the up-front capital investment would be the total cost of the natural gas system without subtracting out the potential investment in diesel.

5.5 Results and Discussion

5.5.1 Improved Shale Gas Operations with Environmental Remediation

Table 15 summarizes the simulation results for the baseline, unremediated annual consumption, carbon footprint and total operating costs tied to fuel usage within the well cluster, based on the market prices of the related fuels at the time of the analysis. The average well cluster costs approximately $6.9 million in fuel costs and emits 24 tons of CO_2 annually. This is the ongoing operating cost of using traditional equipment.

Table 15: Baseline Annual Fuel Consumption, Costs & CO_2 for a Well "Cluster"

Fuel Type	Annual Fuel Consumption (gallons)	Fuel Market Price (USD)	Annual Costs (USD/yr)	CO_2 Emitted (lbs/gallon)	Annual CO_2 Emissions (tons)
Diesel	2,139,474	$3.61/DGE	$6,978,622	22.38	23,941
Gasoline	18,246	$3.71/GGE	$67,511	19.64	179
Total			$8,369,307		24,120

In looking at improving the greenhouse gas footprint of the shale gas operation, the three scenarios with 30% diesel and 70% natural gas (directly from the wellhead), CNG and LNG for the heavy duty equipment was looked at along with conversion of light duty vehicles to 100% compressed natural gas. Table 16 and Table 17 highlight the results of this analysis, demonstrating that although LNG has the highest energy density of the three natural gas alternatives, then CNG, then natural gas directly from the wellhead, the environmental improvements are similar while raw natural gas offers a much more attractive economic benefit annually. This is primarily due to higher opportunity cost of LNG and CNG compared to natural gas taken directly from the wellhead. Typically the market price of CNG and LNG take into account the ongoing cost of gas processing and compression required to get the gas to those states. Once a company invests in these processes it is typically more profitable to sell those products than to re-use them for power generation. The price of raw natural gas (or associated petroleum gas (APG) in shale oil operations) excludes these mark-ups and as a result becomes a more cost effective option for an operator.

Table 16: Cost and CO_2 Footprint Reductions Resulting from Environmental Remediation in a Well "Cluster"

Fuel Scenarios	Annual Fuel Consumption (gallons)	Fuel Market Price (USD)	Annual Costs (USD/yr)	Annual Savings (USD/yr)	Annual CO_2 Emissions (tons)	Annual CO_2 Reductions (tons)
Diesel Gasoline	2,139,474 DGE 18,246 GGE	$3.61/DGE $3.71/GGE	$7,046,133	---	24,120	---
Diesel LNG CNG	641,842 DGE 1,754,559 DGE (210,135 MCF) 18,246 GGE (2,311 MCF)	$3.61/DGE $2.92/DGE $1.68/GGE	$6,077,402	$968,731 14%	19,780	4,340 18%
Diesel CNG CNG	641,842 DGE 1,754,559 DGE (217,880 MCF) 18,246 GGE (2,311 MCF)	$3.61/DGE $1.68/DGE $1.68/GGE	$4,339,576	$2,646,557 38%	20,244	3,876 16%
Diesel Raw Natural Gas CNG	641,842 DGE 1,754,559 DGE (217,880 MCF) 18,246 GGE (2,311 MCF)	$3.61/DGE $4.12/MM BTU $1.68/GGE	$2,843,576	$4,202,557 60%	20,244	3,876 16%

Table 17: Annual Environmental Impact of Remediation on a Well "Cluster" (in tons/yr)

Fuel Scenarios	CO_2 Emissions	NO_x Emissions	CO Emissions	VOC Emissions	PM Emissions
Base Case Diesel & Gasoline	24,120	311	179	23	10
Remediated Cases Diesel (reduced) & Natural Gas (all forms)	19,780-20,244	93	54	7	3.1
Reductions	3,876 – 4,340 (16% - 18%)	218 (70%)	125 (70%)	16 (80%)	6.9 (70%)

Table 18 summarizes the cost improvements per million BTU of natural gas produced assuming an average annual production rate of 172,000 MM BTU/well derived from Browning et. al.[133]

Table 18: Cost Improvements per Million BTU of Natural Gas Produced

Fuel Scenarios	Cost Improvements per MM BTU (% of price @ $4.12/MM BTU))
Diesel LNG	$ 0.46 (11%)
Diesel CNG	$1.28 (31%)
Diesel Raw Natural Gas	$2.04 (49%)

The combined economic and environmental improvements for one well cluster (i.e. annual improvements) are shown graphically in Figure 16. In the case of APG, natural gas extracted during shale oil operations is typically not sold and constitutes a cost to the operation as gas must either be vented or flared. While this analysis is out of scope for this paper, it can be seen that both the environmental impact and economic impact would only be more significant than that for shale gas operations as it involves the recycling of process by-products to power the operation. In these cases the savings on diesel can be taken in their entirety rather than being offset by the opportunity cost of natural gas. In addition, the reduction of flared or vented greenhouse gases would have an additional positive impact on GHG footprint[134].

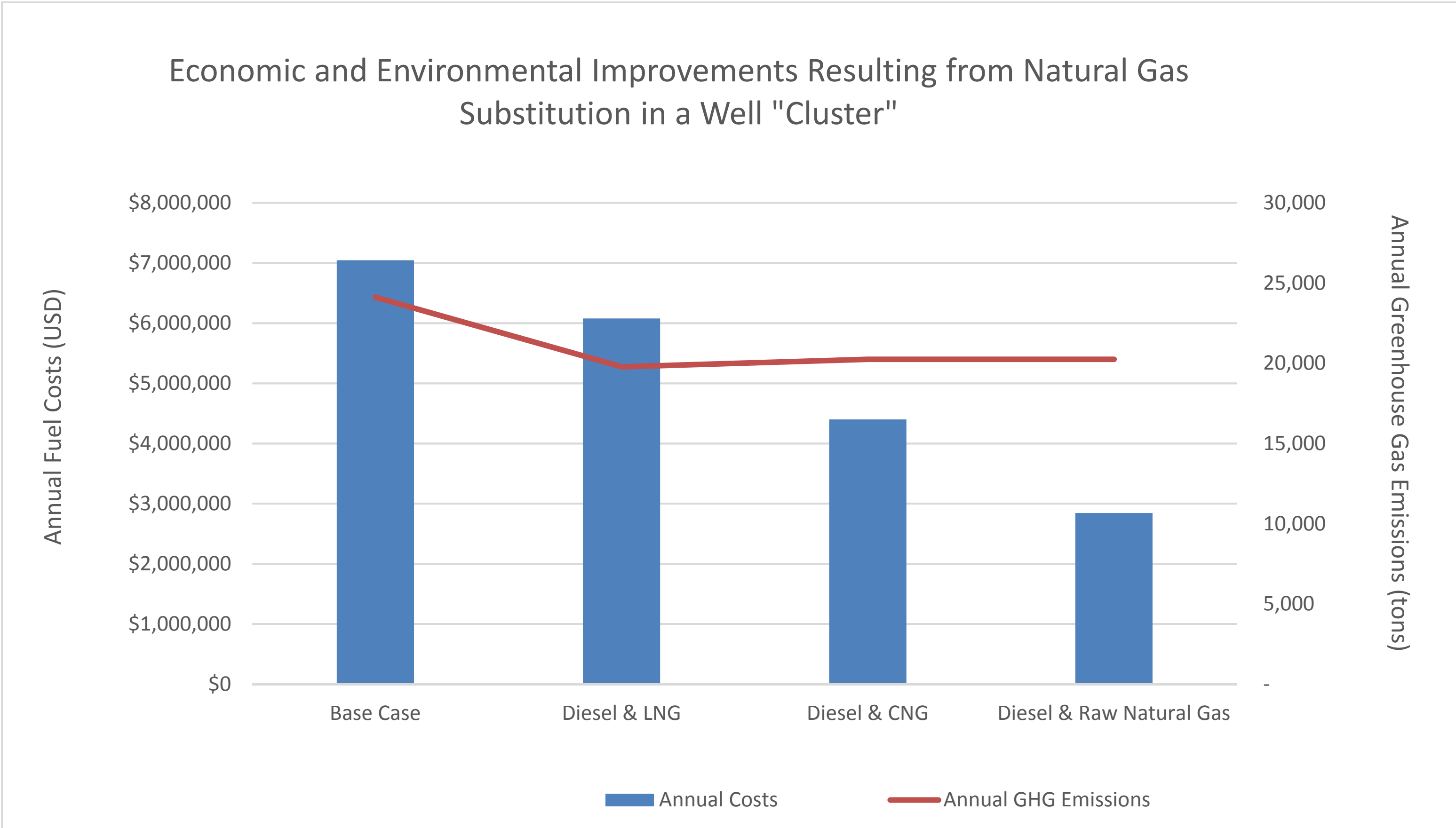


Figure 16: Economic and Environmental Improvements for a Well "Cluster"

5.5.2 Capital Investment Analysis

While the improved annual operating costs are a benefit, an additional up-front capital investment will be required. This is a much more expensive proposition for converting existing rigs than for building new rigs as the investment in traditional technologies is sunk already. For new rigs, the difference between the natural gas based technologies and the traditional diesel or gasoline based technologies would be considered as an investment would need to be made either way.

Based on the annual savings, the net present value calculations indicate the maximum up-front capital investment which can be made for the project to break even over the initial five years. This time period is used as all major equipment would need a major overhaul and repair typically after five years and an additional investment would need to be taken into account. This is a simplified assumption to enable comparison of existing technologies. A more sophisticated approach would be to understand the maintenance schedules of existing technologies over the useful life of the equipment and compare total lifecycle costs. As this field data is much more difficult to find, this simplified approach illustrates the approach which can be applied to the more sophisticated scenario in future work.

Based on the net present value, an operator can invest as much as $15.9 million in up-front capital and break even if natural gas directly from the wellhead is used. With CNG, that number decreases to $10.0 million and with LNG that number drops significantly to $3.7 million. To determine whether or not the required investment would be financially feasible an evaluation of the cost of representative technologies was evaluated. Using data from equipment manufacturers, retailers, operators and public information several technology options were evaluated.

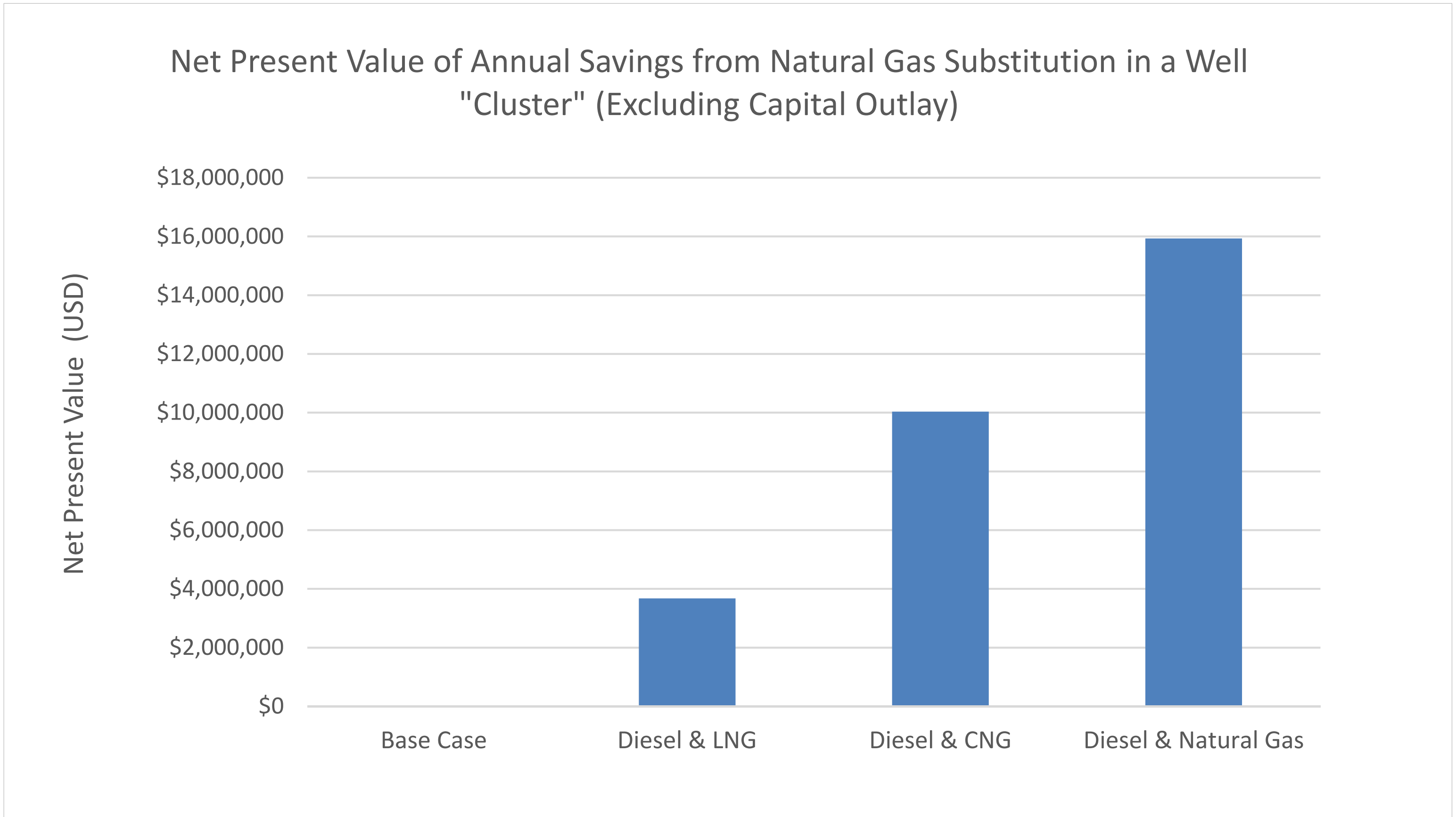


Figure 17: Net Present Value of a Well "Cluster" (Excluding Capital Outlay)

In looking at technologies, the major difference in technology among the three scenarios is in the drilling rigs.[127, 135] The lowest up-front investment is in the Diesel-CNG scenario as the operator will need to process and compress the wellhead gas to pipeline quality for transport, so no additional investment in a CNG compression train is required specifically for this application. In addition, since compressed natural gas is high quality a lower cost engine can be used to drive the drilling rig. For raw natural gas direct from the wellhead, a more robust engine must be used. In this case, the cost of the engine would be significantly higher, however, only two such engines could be used and in speaking with both the manufacturer and distributor of such engines, the resultant horsepower could potentially be used to displace all three diesel engines for most situation, so that the diesel engine is used for backup purposes only. For this analysis, however, a conservative scenario is used with the understanding that these engines would have a one to one replacement ratio, two diesel engines would be replaced with two natural gas engines and the third engine would remain and operate one-third of the time. Finally, while the engines scoped for the CNG scenario could be used for LNG, and additional investment in a small LNG compression train would be required to liquefy the natural gas. Typically, an operator does not need this level of compression to prepare natural gas for pipelines and LNG trains require a much higher level of purity for liquefaction, so additional gas processing, over and above pipeline quality, would also be required. This is modeled in the simulator as an LNG uplift to the CNG investment to cover the up-front capital cost of these systems. LNG trains typically have a much higher throughput than that required for one cluster, so the train would be shared among 5-6 clusters depending on throughput and the cost divided among the clusters to determine the effective investment.

Table 19:Estimated Capital Outlays for Environmental Remediation Scenarios for a Well "Cluster"

Scenario/Case	Heavy Equipment (Drilling)	Heavy Equipment (Completion)	Light Duty Passenger Vehicles	Total Investment
Diesel & LNG	$2,490,000	$65,000	$66,500	$2,621,500
Diesel & CNG	$800,000	$65,000	$66,500	$931,500
Diesel & Natural Gas	$2,000,000	$65,000	$66,500	$2,131,500

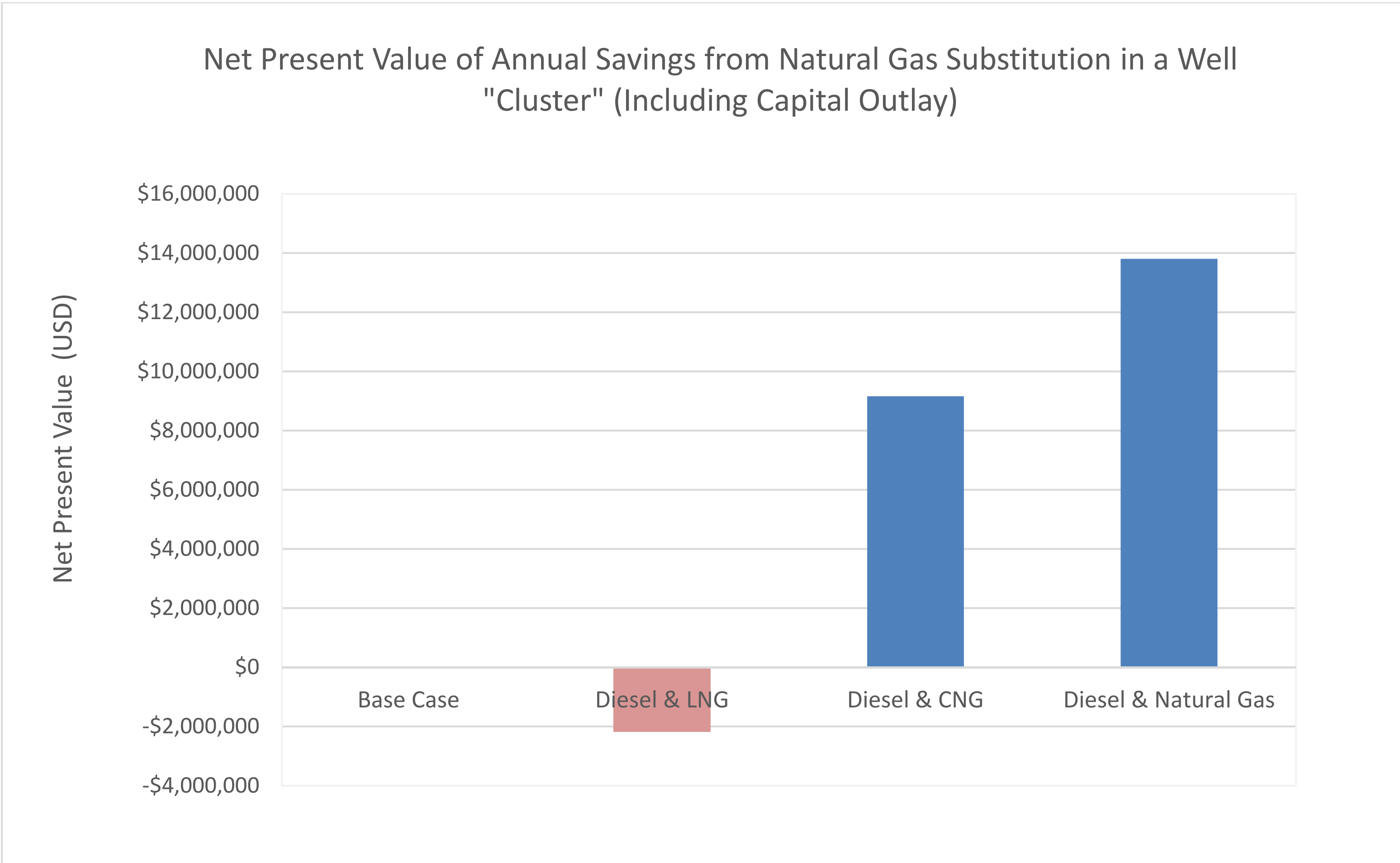


Figure 18: Net Present Value of a Well "Cluster" (Including Capital Outlay)

Based on these capital outlays, the net present value analysis indicates that the most feasible economic scenario is the use of raw natural gas directly from the wellhead. The higher up-front capital investment narrowed the gap between raw natural gas and CNG, however, the increased annual savings of the wellhead gas compensated for this over the five year period. Also, given the high up-front investment in LNG, the Diesel-LNG scenario actually yielded and negative net present value when the capital investment was taken into account.

5.5.3 Broader Economic and Environmental Benefits

Based on the well cluster analysis, it can be seen that the use of natural gas in place of diesel and gasoline can yield both an environmental and economic benefit for operators, provided either CNG or raw natural gas taken directly from the wellhead are used. Using the wellhead gas scenario and extrapolating these results to encompass the 1,000 -1200 new wells to drilled annually across the entire Barnett Shale play[136] and the ~3,700 new wells to be drilled annually across the United States[137], operators can reduce the environmental impact of natural gas extraction and save the industry money, as shown in the following table.

Table 20: Extrapolation of Results Across Barnett Shales and all U.S. Shale Plays

	Impact across Barnett Shale Play	Impact across all United States Shale Plays
Annual Savings (USD)	$385,234,346	$1,295,788,256
CO_2 Reductions (tons)	355,277	1,195,022
NOx Reductions (tons)	19,944	67,086
CO Reductions (tons)	11,487	38,638
VOC Reductions (tons)	1,494	5,026
PM Reductions (tons)	657	2,1211

While the long term financial impact of converting to natural gas is significant, as discussed earlier, the shale gas industry is highly cost sensitive and as a result, would be hesitant to invest heavily up front in the operation.

5.1 Conclusions and Recommendations

When looking at the environmental remediation of oil and gas processes, it is important to understand the microeconomic implications of the proposed technologies and their impact on the operators. Frequently, the more economic benefit that can be derived the more open an operator is to implementing the technology. However, sometimes those economic benefits are realized over a period of time and an up-front capital investment must be made to realize the long term savings. In these cases, when the operator is unable to make the up-front investment and the potential environmental benefits are significant enough, public policy can be implemented to lessen the financial burden on the operator and encourage adoption.

This paper examined the environmental remediation of greenhouse gases from combustion in shale gas operations in the Barnett Shale formation. An economic and environmental simulator was built to model the operation and it was found that the positive long term environmental impact was accompanied by a long term economic benefit which more than offset the initial capital investment in the first five years of implementation. This type of simulator could be used to inform policy decisions moving forward to improve the adoption of technologies for environmental sustainability. The next paper in this series will look at alternatives which are expected to improve the water consumption and disposal and seismicity aspects of the operation. Any additional greenhouse gas improvements associated with those technologies will also be examined. That paper will leverage and build on this paper.

6 ENVIRONMENTAL REMEDIATION OF SHALE GAS WELLS IN THE BARNETT SHALES (PART 2): ALTERATIVE TECHNOLOGIES TO REDUCE WATER AND SEISMIC IMPACTS

6.1 Summary

Advances in horizontal drilling and hydraulic fracturing technologies have led to a rapid and widespread growth in natural gas production from shale formations in the United States. In addition to supplying a much larger portion of the U.S. energy needs domestically, natural gas promises to improve the United States environmental footprint as natural gas is considered a much cleaner burning fuel than both coal and oil. However, the drilling and production processes in shale gas operations have raised many debates as to the lifecycle footprint of shale gas and have driven many local governments to take policy actions to limit shale gas extraction. The first paper in this series explored the impact of substituting natural gas for diesel and gasoline as a fuel during shale gas operations. This paper examines potential environmental alternatives water consumption and disposal and seismicity. Using the Barnett Shale play as a case study and leveraging field data and market validated estimates, a simulator was built to determine environmental and microeconomic implications of selected environmental remediation techniques on the operation. It was concluded that, although an up-front capital investment would be required to convert equipment to waterless fracturing or to invest in waterless fracturing in lieu of hydraulic fracturing for green field applications, the process would be both environmentally and economically beneficial for the operator in the long run in all scenarios.

6.2 Introduction

6.2.1 Framing the Issues: The Energy & Environmental Equation.

As discussed in the first part of this series, the potential for natural gas from shale formations to deliver more, clean energy for the United States, must be balanced with the environmental impacts of shale gas operations.[5, 84, 86-98] These environmental issues are becoming more pronounced as more shale gas deposits are discovered and characterized. The situation has led to a growing opposition to the hydraulic fracturing process with several bans and moratoria on shale gas extraction, led by local and municipal governments, both in the United States and across the world.[6] Without alternatives that reduce this environmental impact, shale gas production may have significant adverse effects on both immediate environmental health and safety as well as on the broader environment.

While research in this area is still developing, there are unique elements of shale gas drilling and production operations that inherently contribute to their environmental footprint. As compared to vertical wells, in conventional oil and gas formations, unconventional wells tend to be more closely spaced and can take months to drill. They require horizontal drilling to access the formation and more fully drain the rock matrix and must employ hydraulic fracturing at extensive rates to stimulate production. The hydraulic fracturing process involves the injection of large amounts of chemical-laden water and mud into the well at high pressures, in order to fracture the rock and allow the gas to be produced[100]. Although hydraulic fracturing has been used for decades to stimulate traditional oil and gas wells; the main issue with shale is scale. The size and number of fractures required to release the gas from shale is much more significant than those previously employed by the industry.[101]

Many of the producers typically operate using traditional techniques, which allow for minimal up front capital investment. Also, since the breakeven gas/oil price for unconventional resources is much higher than those in conventional reservoirs, these operators are very typically cost sensitive. This has led to operations which have proven to be sub-optimal from an environmental perspective.[91, 97, 102]

6.2.2 Focusing the Analyses: The Barnett Shale.

In order to focus the analysis, a specific shale gas play was evaluated. Depending on the underlying depositional system, different shale plays will require different remediation approaches, so limiting the analysis to a specific play enables a focused approach to the analysis. The Barnett Shale was chosen as it is among the most established and most mature shale gas plays in the United States today and it plays a critical role in the U.S. natural gas landscape. As a result, a robust data set collected from operations in the Barnett could be used to conduct the analyses.

The Barnett Shale is a geological formation, located in North Texas. It is estimated to extend 5000 square miles, across 25 counties with the core producing area located around Fort Worth [88]. The formation rests between 6,500 – 8,000 feet in depth, with an average thickness of 350 feet [106]. As of August 2014, there were over 17,500 wells, producing 4,856 million cubic feet per day of natural gas, according to the Texas Railroad Commission[107]. In addition, the Barnett Shale currently produces approximately 4,125 barrels per day of oil and 12,000 barrels per day of condensate, making it a considerable resource for Texas and placing it among the top five shale gas plays in the United States, with the success of horizontal drilling driving the success of the play. Today, horizontal well count is triple that of vertical wells in the formation, and horizontal well production dwarfs that of verticals wells in the play.[108, 109] Shale gas from the Barnett play does not require CO_2 and H_2O processing to make it usable and can therefore be used as a baseline for further analyses.

6.2.3 Well Lifecycle Analysis and Environmental Impacts.

In looking at the environmental impacts of shale gas, it was assumed that once the gas is produced and processed for transportation, its environmental footprint will be similar to that of natural gas from conventional sources. Therefore, the focus of this analysis is on the environmental footprint of the drilling and production processes associated with shale gas extraction, the "well" lifecycle, and not on the entire lifecycle of the shale gas itself.

As discussed previously, there are a number of environmental issues tied to shale gas development. Issues around greenhouse gas emissions; water consumption and disposal during hydraulic fracturing; and seismicity are the most consistent among shale gas plays and have the most direct impact on the immediate environment. In addition, these elements are among the most difficult to manage and mitigate.

As a result, the well lifecycle analysis across this series of papers focuses these three elements and the proposed improvements to reduce the impact on the immediate environment were analyzed and discussed at length. In this first part, the analysis focused on greenhouse gas emissions. This paper focuses on the impacts on water consumption and disposal and seismicity which are inter-related.

6.2.4 Shale Gas Operations.

In order to analyze the environmental impact of the drilling and production processes associated with shale gas, it is useful to understand the overall operation, how the gas is extracted and how it differs from conventional operations.

After the initial exploration, permitting and exploratory drilling stages are completed, an operator will begin drilling and production activities. Land is cleared for the operation and vertical wells are drilled into the shale formation through to the total formation depth. Conventional wells are typically drilled into sandstone and the natural permeability allows the fluids to flow to the low pressure wellbore, thus artificial stimulation, such as fracturing, is not necessary. In contrast, a wellbore in an unconventional reservoir may make contact with some natural fractures, but the hydrocarbons that could be produced from these are insufficient for economic production of gas. In order to bring enough fluid to the surface, the fracture network needs to be greatly expanded. Thus, a well needs to be designed in a way that will connect to the maximum number of fractures and allow induced fractures to expand as far as possible. This is achieved in the first two phases of the well's lifecycle: **drilling and completion**. The final phase of the lifecycle, the **production** phase, requires marginal effort, as it typically consists of a pumper making daily checks on the well or performing a workover, as required. Most new gas wells go through these three major phases in their life: drilling, completion/stimulation, and production.

The drilling and completion phases are relatively brief, typically one to two months in duration, but require a tremendous amount of energy and capital. It is during these phases that much of the environmental impacts occur. Specifically, it is during the completion phase that the well is hydraulically stimulated by fracturing the underlying matrix to release the gas. This hydraulic fracturing is focus for much debate as it relates to water usage, disposal and seismicity. The production phase starts when the well begins flowing and continues until it reaches the end of its economic life. During the production phase, much of the water that is used to fracture the well flow back and is "produced" with the natural gas. It must then be transported and disposed of. Since many unconventional wells can live for decades, the marginal environmental impact of the production phase can sum up to a significant amount. A detailed discussion of the overall shale gas extraction process can be found in the first part of this series.

6.2.5 Hydraulic Fracturing and Water Impacts.

Once a well has been drilled, cased and cemented, the stimulation or completion process begins. In the completion phase, the well bore is perforated to establish communication with the reservoir and fractures are induced using hydraulic fracturing[100].

Hydraulic fracturing is the process that induces fractures into the rock, by pumping fluid down at very high rates. The fluid is often fresh-water-based and filled with proppant: a sandy or gel-like substance that fills in the newly created fractures and keeps them "propped" open to allow reservoir fluids to flow. This perforation and fluid pumping process is repeated several times in stages and connects the natural fractures within the reservoir. The combination of these fractures, creates a large network of interconnected pores to the wellbore and allows economic flow of oil and gas[110, 111].

Fracturing fluid is typically a slurry of water, proppant, and chemical additives, typically, 90% of the fluid is water and 9.5% is sand, with chemical additives accounting to about 0.5%.[138, 139] The quality of the water used is critical as impurities can reduce the efficiency of the additives used in the process. An average well requires 3 to 8 million US gallons (11,000 to 30,000 m^3) of water over its lifetime,[138] while the average well in the Barnett Shale formation uses from approximately 2.8 million[140] to 5 million[141] gallons of water depending on horizontal fracture length and number of stages per well. Today, most water used in hydraulic fracturing comes from surface water sources such as lakes, rivers and municipal supplies. However, groundwater can be used to augment surface water supplies where it is available in sufficient quantities.

While the cost of water also varies, water can behave as a public good and water rights are typically granted with the land lease, along with mineral rights. In these cases, the cost of water represents the opportunity cost of selling that water on the market. In other cases, water is purchased from neighboring water authorities. This cost will vary dramatically based on the abundance of water in the region for alternatives such as farming, industrial operations and urban usage.

The use of vast amounts of potable, fresh water has raised concerns in communities neighboring shale gas operations. This is heightened by the fact that shale reservoirs span such large territories, many across rural areas where potable water is in high demand [142]. In addition, the transport of such large amounts of water requires the use of trucks which has both cost and greenhouse gas implications. This transportation element becomes critical in arid areas or areas of high water stress which have large shale formations.[143]

Slickwater fracturing has additional issues in terms of the expected ultimate recovery of oil and gas from shale resources. As, typically, less than 50% of the water injected is produced over the life of the well, it can actually act as a barrier to optimal production by impeding the flow of oil and gas back through the network of fractures created.[144, 145]

Perhaps as critical as the use of fresh water, is the disposal of produced water once the fracturing operation is completed. The fluid that returns to the surface through the wellbore is not only the chemically treated fracture water, but water from the rock formation that can contain salts, metals, and radionuclides. This water can contain hydrocarbons, high levels of total dissolved solids (TDS), suspended solids, and residual production chemicals. That wastewater must be captured and stored on site, and then is often shipped long distances for deep well injection. Produced water stored on the surface for long periods of time is subject to evaporation, which can further increase the salt concentration of the water. Additionally, flowback of produced water, generated during completion and production operations, could have catastrophic results on the underground drinking water supply, if done improperly. About 30% of injected water is returns to the surface as "produced" water in the first with another 20-30% returning over the life of the well. This implies that about 40-50% of the injected water remains in the rock matrix and in many cases impedes the flowback of natural gas through the well bore. A hydraulic fracture typically exhibits about 20% efficiency.[146]

6.2.6 Hydraulic Fracturing and Seismicity.

Induced seismicity, seismic activity whose frequency is increased or triggered by human activity, is a controversial term as it relates to production of oil and gas. With respect to production of oil and gas from unconventional sources, induced seismicity can be attributed to three primary types of activities: hydraulic fracturing [90], extraction of large amount of fluids from the subsurface and injection of large amounts of fluids (typically produced water) into the subsurface [147].

Hydraulic fracturing is known to produce a seismic response as it drives faults through the subsurface. However, this induced seismicity is more appropriately described as micro-seismicity, as it generally cannot be felt at the surface except by very sensitive instruments designed for that purpose to map the fracture propagation [90]. Many sources agree that a seismic event must generally be above a 3.0 on the Richter scale to have a chance of being felt on the surface, while others suggest a magnitude above 2.0 is sufficient. In any case, an event in this range (2.0-3.0) is not expected to cause damage on the surface. According to the Colorado Oil and Gas Association, there are only two known cases of seismic activity levels greater than 1.0 magnitude being induced by hydraulic fracturing; compared with the well over 1,000,000 fracture stimulations that have been done in the U.S. to date[90].

Induced seismicity with a magnitude of greater than 3.0 is known to be caused by other hydrocarbon production related activities, specifically massive extraction of fluid or fluid injection [147]. Although massive extraction of fluids has caused earthquakes in a few cases, it is not an issue specific to shale gas extraction. This is common to all operations that involve the extraction of large amounts of fluids. As a result, remediation of this cause will not be discussed here,

However, shale gas production does frequently necessitate the disposal of significant amounts of wastewater. It is this massive injection of fluid into the sub-surface that is the primary driver of induced seismicity related to shale gas production. There are several cases of water injection induced seismicity associated with shale gas plays, including cases associated with the Barnett Shale. Wastewater injection has been linked to induced seismicity since the early 1960s, when injection at the Rocky Mountain Arsenal led to an increase in seismic activity [148].

Seismicity can occur when water injected into a formation causes a rise in pore pressure. If this pressure increase occurs along a fault, this increase can reduce the force required to trigger movement along that fault and cause an induced earthquake. The increase in pore pressure in a formation due to injection is related to several factors, both controllable and uncontrollable. The most important of the controllable factors is injection rate. Any injection well that operates near a fault has the potential to increase the likelihood of earthquakes if the pore pressure increase is large enough [105].

It is the injection of massive quantities of produced water that is believed to be the primary driver for this induced seismicity. In 1987, Wesson and Nicholson prepared a report for the EPA looking at seismic activity tied to deep well injection [105]. At that time there were only two known cases of wastewater disposal wells triggering induced seismicity, while the cases of induced seismicity caused by injection wells used for secondary hydrocarbon recovery were much more numerous. With the recent shale gas boom in the U.S., the number of cases of wastewater injection induced seismicity has increased significantly. The United States Geologic Survey, shows a "hockey stick" style trend change in earthquakes of magnitude 3.0 or greater in the central and eastern U.S. starting in 2009 and continuing into 2015.[149] In recent years there has been a spike in earthquakes in the Denton, Texas area, which correlates with the well count in the Barnett Shale [150, 151]. This correlation suggests the presence of induced seismicity caused by injection wells disposing of the wastewater from Barnett Shale operations. Frohlich [152] highlighted this correlation, concluding that injection well locations, when compared with earthquake epicenters, proved a definitive link between the injection wells and the earthquakes. Other surface areas overlying the Barnett Shale have recently seen even more drastic upticks in seismic activity. The area around Azle, Texas experienced more than 30 earthquakes over a 5-month period from late 2013 to early 2014[153]. Additional studies have shown that areas with suspected anthropogenic earthquakes are more susceptible to earthquakes from natural transient stresses[154].

6.3 Environmental Remediation of Water and Seismic Impacts

To conduct the environmental impact analysis, a well by well approach was taken. Field data from Barnett Shale assets was obtained and compared with other public sources and research. The results were then extrapolated to encompass the entire play and develop the economic and environmental models, assuming that the shale gas wells across the play behaved and were produced in a similar manner. For each well, the step by step drilling and production processes were analyzed and alternatives with reduced environmental footprints were proposed to address the three major environmental factors: greenhouse gas emissions, water consumption & disposal and seismic impacts. These alternatives were then evaluated by looking at the environmental footprint improvement as well as the micro-economic implications to the operator. This environmental and economic model was then expanded to encompass the entire play and conclusions were drawn regarding the economic viability of investing in the alternatives for each of the major environmental factors.

This paper discusses on the water and seismic impact portion of the analysis, specifically focusing on changes to the hydraulic fracturing process and the impact of those changes on both environmental footprint and economic viability of the fracturing process. Two alternatives to traditional "slickwater" hydraulic fracturing were explored. The first involves the use of alternative fracturing fluids that would eliminate the need for water, termed waterless fracturing. The second, more conservative alternative, involves modifying the existing hydraulic fracturing process to improve the environmental footprint of that process with respect to water and managing the seismic impact through an array of sensors.

6.3.1 Waterless Fracturing

The use of alternative fracturing fluids has been a practice in the oil and gas industry since 1962.[145] Although historically used as additives to "energize" water based fracturing fluids, these fluids have shown promise as "slickwater" substitutes in the unconventional space due to their environmental and economic impact as well as their potential for improved oil and gas production.[144] Due to their physical characteristics and environmental significance, two fluid alternatives were evaluated: liquefied petroleum gas and carbon dioxide.

<u>Liquefied petroleum gas fracturing</u>

Fracturing with liquefied petroleum gas (LPG), known as gas fracturing, was developed in 2006[155] and over 1,300 wells have used this method for fracturing wells. The process involves the substitution of water with an LPG gel, mixing it with proppant and injecting it down the wellbore to induce fractures in the rock[146]. Once the gas fracturing fluid is mixed, the fracturing process mimics that used in hydraulic fracturing.

Gas fracturing fluid, as described by Tudor, et al. [156] and Lestz, et al. [157], is a mixture of LPG gases, including varying amounts of propane and butane, depending on the reservoir conditions. The LPG mixture components are designed in a way to achieve the desired hydraulic fracturing and clean-up performance. Propane is the most commonly used LPG product in fracture treatments, but there are temperature limits for its use. Fracturing fluids made of pure propane can be used with formation temperatures of up to 96°C. When the formation temperature is above 96°C, commercial butane must be mixed with the propane in increasing amounts as the temperature increases. Pure butane allows fracturing formations with temperatures up to 150°C [158]. Because the gel retains sand better than water, it is possible to get the same results with a much smaller volume of fluid and provides the ability to pump at a slower rate. Field tests have resulting in successful fracturing with one-fourth to one-eighth of the amount of fluid used in traditional hydraulic fracturing[146, 159]. When coupled with the lower specific gravity of propane, compared to water, the use of LPG would lead to additional benefits in transportation costs and the associated greenhouse gas implications[146].

Field studies have also shown that, unlike water based fracturing where gas was not observed until 5-20% of the load fluid had been recovered, propane based fracturing yielded observable reservoir gas immediately after the wellbore had been cleaned out.[158] In addition, propane fractured wells demonstrate 100% recovery of propane within 12-15 days of production[158] and an increase of 20-30% in expected ultimate recovery (EUR) of the well.[146]

Carbon dioxide fracturing

Liquid carbon dioxide (CO_2) fracturing systems were developed in 1981[145] and have been used as fracturing substitutes to "slickwater" in limited applications in North America since the early 1990s.[160] The broader use of carbon dioxide for the recovery of shale resources is being explored in a number of situations, most of these are for specific conditions such as water sensitive formations or partially depleted formations for enhanced gas recovery.[161, 162] As a fracturing fluid, carbon dioxide can be used in several forms, the most explored options include pumping CO_2 as a liquid or foam at high pressure[144] or, more recently, converting it to a super-critical fluid and pumping it at much lower pressures.[163] This implies that with minor modifications to existing hydraulic fracturing equipment, super-critical CO_2 can be used in place of water, while using high pressure liquid CO_2 would require some specialized equipment.[164] However, the technology required carbon dioxide supercritical through the wellbore currently has a cost and energy tax that would render its use expensive and potentially have a negative environmental impact. It is unclear whether its benefits over foamed CO_2 would warrant its use today but the approach shows potential for future applications. On the other hand, carbon dioxide foam has shown in field tests that it not only reduces clean-up effort, but also improves flowback performance, by enabling gas to be produced at saleable rates within 48 hours of start of production, with complete recovery within two weeks.[145] Similar to LPG, as carbon dioxide foam converts to gas in the formation, and as such does not contribute to formation damage or clay swelling which can inhibit the flow of hydrocarbons to the surface. As a result, CO_2 fracturing has also demonstrated improvements in natural gas production by 15-40%.[144] In addition, supercritical CO_2 has demonstrated superior fracturing network propagation in lab experiments and as a result, is expected to improve both production rates and expected ultimate recovery of reserves.[165]

Finally, carbon dioxide can have two to three times the affinity to adsorption in shale as methane under lab conditions[166] and as much as five time the affinity under reservoir conditions.[167] As such, it is expected that a portion of the carbon dioxide used for fracturing would replace methane in the formation supporting the additional natural gas production while sequestering the carbon dioxide in the formation. Carbon dioxide can also react with formation elements, depending on the chemical characteristics of the shale play, to further sequester in the formation. As approximately 30% of gas in shale reservoirs is believed to be adsorbed in place,[168] a 30% sequestration rate for carbon dioxide fracturing will be assumed in this analysis. It is expected that should additional chemical sequestration occur it would render these estimates conservative.

6.3.2 Recycling Produced Water

While the use of large quantities of fresh water is a critical environmental issue, the use of fresh water for fracturing in comparison to other sectors represents less than 2% of water used in the United States.[169] In the counties covered by the Barnett Shale, water for shale gas production accounts for less than 1% of total consumption.[170] In addition, it was found that, the use of purchased fresh water is not the major cost driver in the operation, given the low cost of water per gallon. While these costs can vary depending on the water scarcity level in vicinity of the shale play, in general, the cost of acquiring fresh water from water districts is a much smaller part of the operation.

The bigger environmental and economic issues arise with the management and disposal of produced water or wastewater. While the waterless fracturing techniques discussed above eliminate the need for both using and disposing of large quantities of water which addresses water and seismic for the entire operation, there are established solutions for addressing the most critical of these issues through wastewater management. Two alternatives to standard storage and reinjection of the large quantities of wastewater produced were evaluated: fracturing with produced water and wastewater treatment.

Fracturing with produced water

The first alternative includes repurposing produced water for use in hydraulic fracturing operations. In addition to reducing the need for water disposal and reducing fresh water consumption during the completion process, using produced water for hydraulic fracturing has economic benefits, since reinjection of produced water into disposal wells can cost an average of USD 0.75 to USD 1.00 per barrel of water.[171]

Field experiments have shown that the use of high-TDS (>270,000 PPM) produced water can be recycled to create a cross-linked, gel-based hydraulic fracturing fluid. During bench scale experiments cross-linked gels were formulated and results showed that the gel was capable of successfully creating a fracture network and transporting sand into that network. When compared to a control well, the well fractured with the high-TDS treatment exhibited a comparable production profile, leading to a reduction in total water consumed per well and an economic benefit to the operator with no compromise in production levels.[171]

In the Barnett Shale, produced water only accounts for 5-10% of water used for hydraulic fracturing due to the quality of water produced, the limited amount of water produced in the time immediately after fracturing to be re-used and the ready availability of salt water disposal infrastructure in the area.[141, 172] In particular, the use of produced water does not negate the costs of hauling to and from treatment sites or reduce pumping costs, nor does it eliminate the need for the use of additional fresh water, as not all of the water used for hydraulic fracturing flows back to the surface for re-use. In addition, water quality produced from the Barnett formation requires significant filtering to enable re-use for fracturing leading to an incremental cost for filtration and the disposal of solid waste which could have its own environmental issues.[172] When coupled with the abundance of salt water disposal wells and low cost fresh water in the area, the economics of using produced water as a fracturing fluid infeasible. Different economics exist for other plays where this option may be more feasible.[173]

<u>Treating wastewater</u>

There are a number of methods that can be used to treat wastewater. They can be as simple as filters or conventional thermal evaporation processes, or as complicated as treatment systems, which use positively charged ions and bubbles to remove particles from the water at the fracturing site.[174]

In the last few years, membrane distillation (MD) has proven its importance as a powerful solution for water treatment. As it is a thermally driven separation process, this system has received attention as a possible water and wastewater treatment technology in applications such as water desalination, re-use and recycling. Membrane distillation allows water to be reused without being diluted with freshwater.[175] The main benefit of using membrane distillation is that it is a thermally driven process and not a pressure driven process. It therefore does not need to overcome the high osmotic pressures that characterize produced waters in hydraulic fracturing operations. Also, since non-volatile solutes cannot move through the membrane barrier in an MD system, it is capable of achieving near 100% rejection of dissolved salts and minerals. [176]

There are a number of issues that make these solutions sub-optimal for the treatment of wastewater from hydraulic fracturing. For example, one of the issues is that some of the more traditional processes typically do not do a good job removing halides. Once this halide-rich water is treated for drinking purposes using conventional methods, such as chlorination or ozonation, toxic by-products can result.[177] In addition, membrane distillation imposes an energy tax on the operation, as the availability of a heat source is a prerequisite for the process. This could increase the cost of the operation dramatically to maintain the required temperatures for the process. For these reasons, membrane distillation is a promising technology that has gained attention as a treatment alternative for high salinity source waters[120, 176, 178] around the world; but that needs to be further evaluated for shale gas operations. These options also produce highly concentrated waste as the water is separated from the dissolved solids. This water can contain high concentrations of toxic and potentially radioactive waste which require disposal.

Based on the literature reviewed, the use of high-TDS water and waste water treatment appear to be partial solutions to the water issue with hydraulic fracturing and in many cases create an incremental cost with little incremental benefit, with the potential to create additional environmental, health and safety issues. As a result, this analysis will focus on waterless fracturing techniques and their potential use for both an economic and environmental gain.

6.4 Theoretical Calculations

In order to determine the environmental impact of a shale gas well, field data from Barnett Shale assets was obtained and compared with other public sources and research. The assumptions and equations detailed here were used to build a simulator that approximates the costs and environmental impacts of the operation as they relate to water and seismic. Greenhouse gas emissions were also evaluated by looking at heavy equipment usage of diesel and light duty truck usage of gasoline throughout the well lifecycle as they relate to water handling and management.

6.4.1 Key Assumptions

- For a given well, there is a short term phase, drilling & completion, and a long-term phase, production
- The drilling and completion phase takes approximately 1 month for a Barnett Shale well (based on field data)
- No produced water is re-used or recycled so each new well draws fresh water from the source

- The useful life of the equipment is uniform across equipment types and is assumed to be 5 years before a major overhaul which would require an additional capital investment. At that point, the cycle will be assumed to repeat.
- Wells will be drilled continuously with no downtime between completing one and drilling the next well
- Price of fuel, water and propane remains constant through the life of the operation
- At one well/month; a given rig can drill and complete 12 wells/year and this will constitute the basic "unit or cluster" of calculation
- The life of one well is assumed to be 25 years[133]

6.4.2 Current Operations.

The current hydraulic fracturing operation, using "slickwater" as a fracturing fluid, was analyzed to develop a baseline for comparison of various environmental remediation techniques. Table 21 summarizes the assumptions used to construct the baseline model for the economic simulator.

<u>Fresh water consumption</u>

Although it is difficult to generalize on water usage by well, by focusing on the Barnett Shale play, averages can be used to estimate the potential benefits of environmental remediation. Nicot and Scanlon estimate that an average well in the Barnett Shale uses 2.8 million gallons of water for hydraulic fracturing[140]. While the cost of water also varies, ground water typically behaves as a public good and water rights are typically granted with the land lease, along with mineral rights. Thus, the cost of water used in the simulator represents the publicly available price of water in the Barnett Shale area for "gas well class" water usage and represents cost of buying water from the various water authorities or the opportunity cost selling ground water on the market. This cost will vary dramatically based on the abundance of water in the region for alternatives such as farming, industrial operations and urban usage. A 20% uplift was added to the price of fresh water to account for treatment of the water to produce "slickwater" for fracturing.

Transportation & disposal of produced water

In looking at the disposal of produced water, rate of water production was taken into account as well as hauling & disposal costs per barrel of water produced. In addition, it is important to understand the cost of drilling a disposal well which, according to the EPA, must be a Class II well as well as the maximum allowable injection rate into each well[179]. This will help to determine the number of Class II wells required for safe disposal of produced water and the baseline capital investment for current operations. It is this maximum allowable injection rate that minimizes the seismic impact of deep water injection.

Fuel usage

Field data on heavy equipment fuel usage for the completion process, primarily for the operation of pumper trucks was taken into account as an additional cost in the model. These costs are consistent with those used in Part 1 of the series. Fuel usage costs for hauling and disposal are included in the overall cost of hauling and disposal assumptions discussed in the previous section.

Table 21: Baseline Water Assumptions

Water Consumption per well[141]	4,600,000 gallons
Cost of Water[180]	$6.43 USD/ccf $0.32 USD/barrel
Water Recovery in Production Year 1[181]	30%
Annual Water Recovery in Production Years 2-25[133, 181]	1%
Cost of Water Hauling[182]	$1.60 USD/barrel
Cost of Water Disposal[182]	$0.90 USD/barrel
Cost of Drilling a Class II Injection Well[183]	$2,500,000 USD
Proppant Consumption per well[184]	1,750 tons
Cost of Proppant[185]	$63 USD/ton
Amount of Natural Gas Flared[97]	159,087 MCF/yr
Water Injection Rate for each Class II Well[179]	~ 99,000,000 gallons/yr

Environmental impacts

The environmental implications of water consumption and disposal are inextricably linked with the greenhouse gas impacts discussed in the first paper of this series. For baseline operations, a combination of diesel fuel for heavy equipment used for pumping and hauling water with gasoline for light duty vehicles are used to develop the baseline environmental footprint of the hydraulic fracturing operation. The baseline fuel assumptions will be held constant for the analysis of alternative fracturing technologies to evaluate the true economic and environmental impact of the proposed remediation techniques.

6.4.3 Operations After Environmental Remediation.

The two environmental remediation options for waterless fracturing, LPG and CO2 fracturing, were analyzed and compared against the base case representing current operations. Table 22 summarizes the assumptions used in evaluating the economic and environmental impact of the two alternatives. For each of these fluids, the key levers which drive both the environmental footprint and micro-economic viability as they relate to the fracturing process were used to develop the simulation model.

Operational elements impacting environmental footprint

Total volume, properties and cost of alternative fluid – In addition to having a direct impact on the economics of the project, these parameters also have a follow-on impact on the amount of fuel used for pumping and hauling as well as potential pre-processing costs unique to the fluid.

Potential increase in production – As an offset to the cost implications, this lever has the effect of offsetting potential cost increases in the model. Each of the alternative fracturing fluids has physical properties which can potentially result in an increase in well production. Estimated production increases based on field studies of other shale plays will be used in the simulator to determine the total economic impact of the substitution.

Flowback/Recovery of fracturing fluid – The management of fluids during the flowback period has a direct impact on costs as well as greenhouse gas emissions in several ways. This factor also impacts direct post-production clean-up costs and can have a potential impact on operating costs in the event fluids can be recycled and re-used. The simulator assumes all flowback gasses will be flared to the legal limit of 10 days[186] and not vented or recycled. The impact of recycling fracturing fluids will be addressed in the discussion.

In the case of LPG fracturing two flaring options will be considered, flaring 100% of the flowback gas for the government allowed 10 day maximum. Based on available field data, it is expected that 100% of the propane would be flared during this period should the operator use this approach. This represents an extreme case, however, as gas processing facilities accommodating natural gas streams with up to 45% LPG are typically part of natural gas production operations and would therefore be used to separate LPG from the natural gas. As a result, the second case which involves flaring flowback gas until it falls below 45% LPG will be developed with flow directed to a processing plant after this point. Based on similar production profiles, it is expected that this point will occur on the 5th day of production.

In the case of CO_2, flowback volumes are directly impacted by the amount of CO_2 that can be sequestered during the completion phase. In this case, it was assumed that 30% of the fracturing fluid would remain in the formation, adsorbed to the shale, based on the affinity of shale to CO_2 compared to methane. In addition, based on related field studies, it is expected that 100% of the CO_2 will flow back to the surface within the 10 day flaring limit for natural gas.

Reduction in proppant volume – An increase in efficiency in the deposition of proppant in the fracture has a direct impact on the cost of the operation and an increase in proppant efficiency implies a reduction in the mining and use of sand, ceramics and other materials and a reduced environmental footprint.

Table 22: Waterless Fracturing Assumptions

Gas Fracturing	
Price of LPG[187]	$0.44 USD/gallon
Volume of fluid reduction[155]	75%
Increase in production[146]	30%
LPG flowback/recovery[158]	
5 days from start of production	55%
10 days from start of production	100%
Maximum	100%
Reduction in proppant	N/A
Amount of Natural Gas Flared[97]:	
100% LPG Flared	159,087 MCF
55% LPG Flared	86,978 MCF
Carbon Dioxide Fracturing	
Price of liquid CO_2[188]	$100 USD/ton
Volume of fluid reduction[144]	71%
Increase in production[144]	15% - 40%
CO_2 flowback/recovery[161, 189, 190]	70%
Reduction in proppant[144]	34%
Amount of Natural Gas Flared[97]	159,087

In determining the reductions in the above parameters, results from field studies in other plays were normalized and extrapolated to apply to the actual Barnett Shale operations. While this incorporates a level of uncertainty in the results, as compared to a full field study in the Barnett Shale it provides a directional comparison on costs and environmental impact among the options. All reductions are in direct comparison to slickwater fracturing and it is using that baseline that the comparisons are made.

Fuel consumption for the fracturing process is assumed to reduce linearly with fluid volume. This assumption could change depending on whether or not the fluid used has distinctive pumping characteristics. Literature implies that for both LPG and CO_2 these differences are minimal as they relate to the operation of the pumps although specialized pumping equipment may be required, leading to an increase up front capital required.

The effect of substituting natural gas for diesel and gasoline in both heavy duty and light duty vehicles will initially be excluded from the calculation to provide a consistent platform to evaluate the impact of fracturing fluids exclusively. The integrated results of both greenhouse gas and water impacts will be discussed separately to demonstrate the potential impact of an integrated policy strategy that addresses all of these elements simultaneously. In performing this analysis, the results and assumptions used in the first part of this series will be used and extrapolated to account for the total reduction in fuel consumed in the alternative fracturing fluid scenario.

Environmental improvements

Environmental improvements are classified into three categories, reduction water consumption and disposal, reduction in proppant usage and reduction in greenhouse gas emissions resulting from reductions in pumping, hauling and disposal activities. In the case of CO_2 fracturing, the additional carbon sequestration resulting from the use of CO_2 as a fracturing fluid will also be taken into account. The following table summarizes the CO_2 emissions of the alternative fuel options.

Table 23: CO_2 Emissions for Technologies Used in Environmental Remediation

Technology	CO_2 (lbs)
Diesel (per gallon)[191] - (used for heavy duty operations)	22.38
Gasoline (per gallon)[191] - (used for personal transport)	19.64
Natural Gas (per MCF)[124] - (flared during flowback)	119.9
Propane (per gallon)[192] - (flared during flowback)	12.7

6.4.4 Net Present Value and Expected Capital Outlay

The net present value (NPV) of the environmentally remediated operation was determined to identify the maximum capital outlay that would make the investment in environmental remediation economically viable for the operation. This was performed first by evaluating the NPV of cost implications tied to the alternative technologies exclusively, then by looking at the NPV including potential improvements in the production profile of the well to provide the overall picture. The following equation was used to determine NPV:

$$NPV = -(CAPEX) + CF * \left[\frac{1-(1+i)^{-n}}{i}\right]$$

where:

CAPEX = the up-front capital investment,

CF = annual net cash flows (or net savings)

i = the discount rate, and

n = the number of years in the life of a well

Depending on whether the investment is for a green field application or for a conversion of existing rigs, the up-front capital investment can vary. In a green field application, the difference between the base-case equipment and specialized equipment required for the environmentally remediated solutions would need to be taken into account. For a conversion project, the investment in existing technology would be considered a sunk cost, so the up-front capital investment would be the total cost of the specialized system without subtracting out the potential investment in existing technology.

6.5 Results and Discussion

6.5.1 Improved Shale Gas Operations with Alternative Fracturing Fluids

<u>Summary of results</u>

Table 24, Table 25 and Figure 19 summarize the economic and environmental impacts of alternative fracturing fluids on one well “cluster”, representing one year of hydraulic fracturing. In evaluating both LPG and CO_2 as alternative fracturing fluids, little appreciable difference in annual operating costs, compared to slickwater, was observed, with the cost of the fracturing fluids compensating for the additional water management expense of slickwater fracturing.

It is important to note that the Barnett Shale formation has high levels of formation water so a well may produce more than 100% of the water used for fracturing[141]. This additional water production is not taken into consideration in the simulation as it is not clear whether or not this water would ultimately be produced in the same volumes with alternative fracturing fluids. These results assume that the fracturing fluid is not recycled or resold.

Table 24: Economic Impact of Waterless Fracturing Options on a Well "Cluster"

Fracturing Fluid	Annual Costs (USD/yr)	Annual Savings (USD/yr)	Incremental Production (USD/yr)	NPV of Impact - Life of Well (USD)
Slickwater	$7,874,531	---	---	---
LPG (55% Flared)	$7,783,580	$90,952 1.15%	$2,551,104 (32%)	$23,247,425 (33%)
LPG (100% Flared)	$7,783,580	$90,952 1.15%	$1,988,235 (23%)	$18,138,240 (26%)
CO_2	$8,148,547	-$274,016 -3.36%	$1,275,552 - $3,401,472 (16% - 43%)	$11,304,221-$30,601,282 (16% - 44%)

Table 25: Environmental Impact of Waterless Fracturing on a Well "Cluster"

Fracturing Fluid	Fluid Consumed (gallons)	Proppant Consumed (tons)	Fuel Consumed (gallons)	Carbon Footprint – no sequestration (tons)	Carbon Footprint – with sequestration (tons)
Slickwater	55,200,000	21,000	1,959,513 DGE 12,600 GGE	31,588	22,051
LPG (55% Flared)	13,800,000	21,000	357,960 DGE 3,150 GGE	57,447	57,447
LPG (100% Flared)	13,800,000	21,000	357,960 DGE 3,150 GGE	105,071	105,071
CO_2	16,008,000	14,000	361,556 DGE 3,700 GGE	33,138	12,541

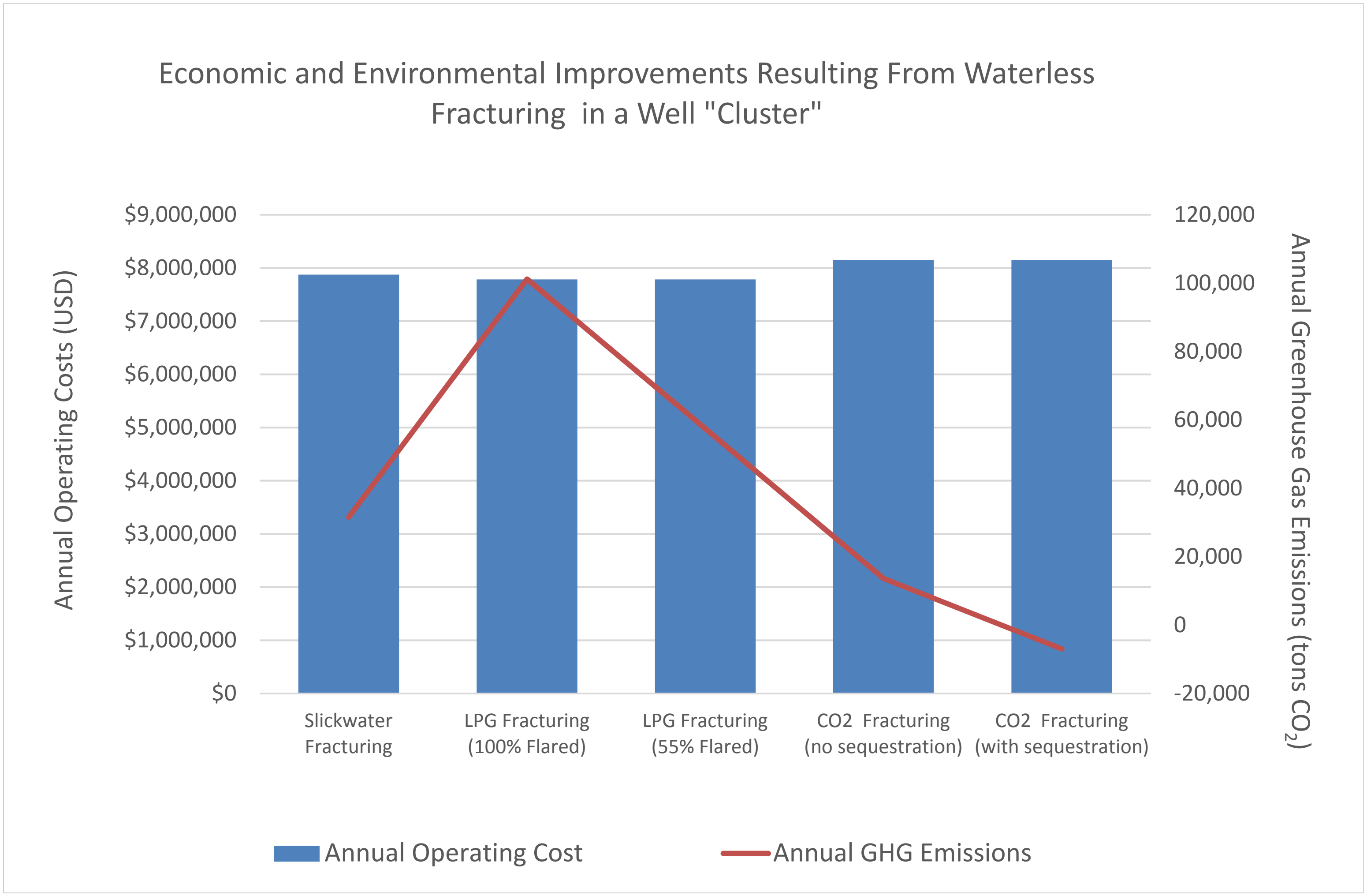
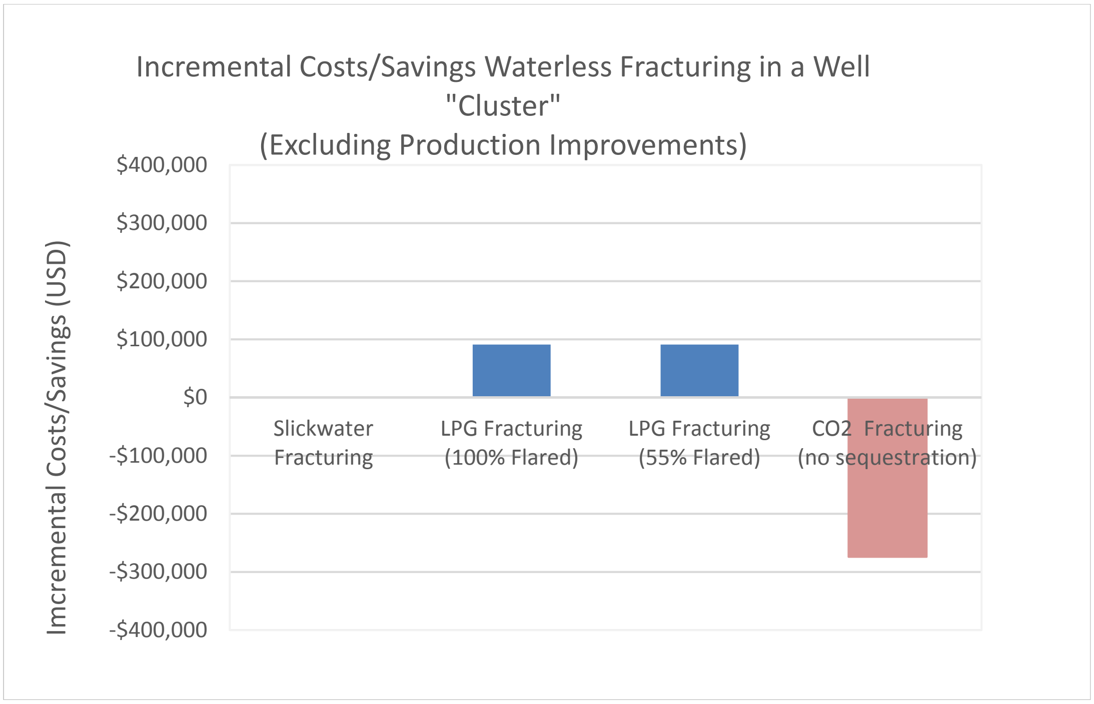


Figure 19: Impact of Waterless Fracturing on Annual Operating Costs and GHG Footprint

It is interesting to note that, although less diesel and gasoline are used in the process, the greenhouse gas footprint for LPG fracturing is actually higher than that of slickwater fracturing due to the large amount of natural gas and LPG that must be flared to get LPG concentrations below those required for transport and standard processing facilities. Although it represents the highest overall cost, CO_2 fracturing also has the lowest carbon footprint and once carbon sequestration is taken into account, the operation becomes carbon negative. This also implies that, based on cost savings alone, there is little economic incentive of operators to move to alternative fracturing fluids which could represent a higher risk to production.

The picture changes when the impact on production is taken into account. Based on observed production increases in other shale plays, and their application to the Barnett Shale, a significant economic impact can be realized when production is enhanced by using alternative fracturing fluids. This implies that operators should be willing to invest between \$10,000,000 and \$25,000,000 in these new technologies provided production improvements can be guaranteed. In the case of CO_2 fracturing, this converts a negative return on investment to a positive one.



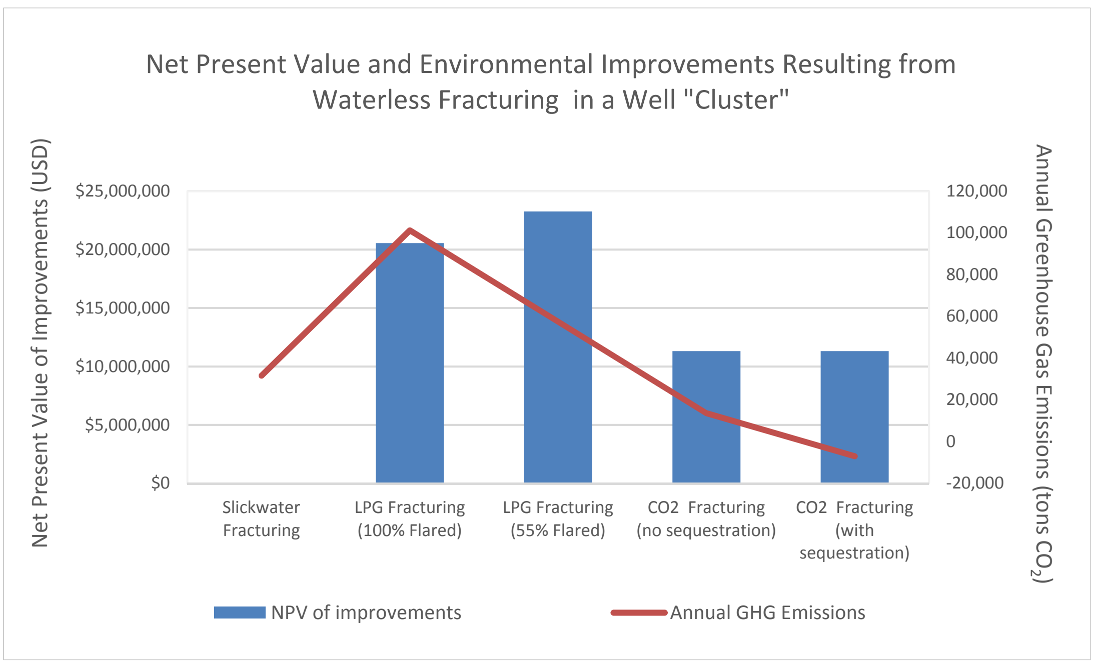


Figure 20: Impact of Production Improvements on the NPV a Well "Cluster"

As discussed previously, there are number of key factors influencing the outcome of this analysis, the most critical of these will be discussed here. While the remaining elements have an impact on the analysis, that impact is less pronounced and will not be discussed at length in this analysis.

<u>Cost of alternative fracturing fluids.</u>

Given the volumes of fluids used, a small change in the price of fracturing fluids has a significant impact on the economics of the operation. As the prices used in the simulation include transportation costs to the well site, their prices can be dependent on both the supply and demand of these fluids as well as the transportation costs of these fluids to the site. While the market dynamics of water and LPG pricing can be somewhat predictable and there is existing infrastructure to support the use of both of these fluids, the issue becomes more complex in the case of carbon dioxide.

While carbon dioxide itself is abundant, the availability of captured, separated and processed CO_2 can be limited. Also, the lack of infrastructure to transport CO_2 in large quantities makes its price vary quite dramatically across the country. Finally, most end consumers of liquid CO_2, such as the food and beverage industry, require high purity standards, thereby driving up the processing costs, and therefore the price, of available CO_2 supply. Therefore, carbon dioxide behaves as a public good and its current price does not accurately reflect supply and demand dynamics. As there is a market failure in the case of CO_2, the impact of public policy can be profound. A small improvement in the price of carbon dioxide has a significant implication on the economics of the case and can make the option economically more favorable than both LPG and water. The following graph shows the impact on net present value of a 10% reduction in CO_2 price. This is a critical component of the analysis as the CO_2 purity required for fracturing and other industrial processes is significantly lower than that for the other industries such as food and beverage and as a result could be less expensive the prevailing market prices assumed in the analysis and significantly impact the results.

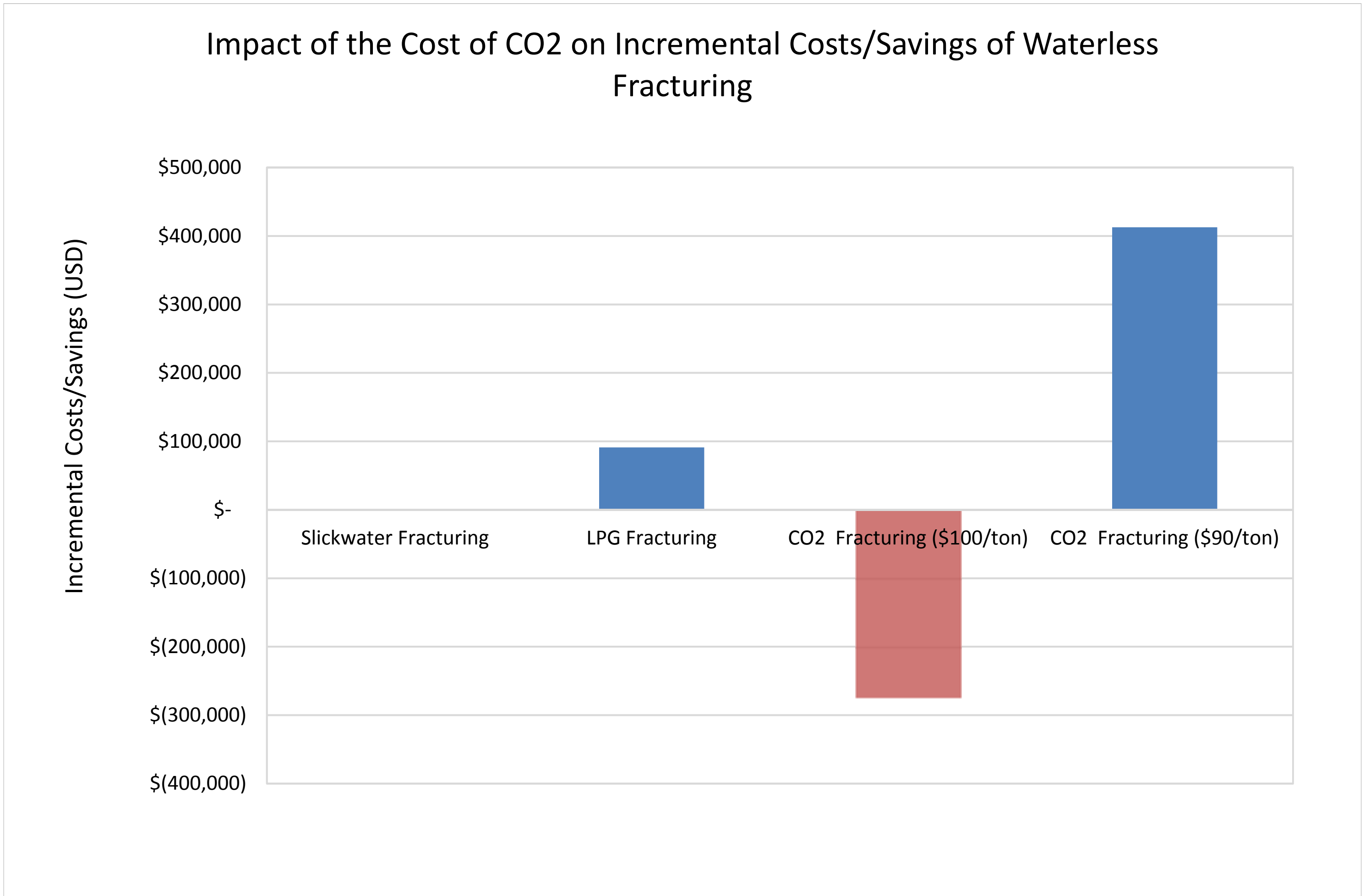


Figure 21: Impact of CO_2 Price on the Net Present Value of the Hydraulic Fracturing Operation (Excluding Production Improvements)

Availability of salt water disposal sites

The cost of water management is heavily dependent on the costs of hauling and disposal. These costs are dependent the price for fuel (typically diesel) used for hauling and how far water must be hauled both to the well from water sources and from the well to disposal sites. The price of fuel, has an impact on all scenarios as its cost also impacts the cost for transporting all fracturing fluids. The distance from water sources and the availability of salt water disposal sites, does however have a significant impact on the "slickwater" operation significantly.

Extensive salt water disposal infrastructure has been developed within the Barnett Shale play with deep water injection into the Ellenberger formation. As a result, the cost of wastewater hauling and disposal is much lower than that of other shale plays which can be between 2 and 5 times as expensive.[144, 181] In addition, the drilling and completion of Class II salt water disposal well, provided there is a viable disposal formation or aquafer, can range anywhere from $400,000[183] to more than $2.5 million[119], rendering the building of comparable infrastructure at other shale plays expensive for operators in those areas and in many cases prohibitive. The more the scarcity of salt water disposal sites, the clearer operating benefit of alternative fracturing fluids with or without production increases. The following graph shows the impact of these increases in hauling and disposal costs on the operation. Many of the fields where LPG and CO_2 fracturing have been employed, have had these higher cost profiles, rendering these alternative processes necessary for the profitability of the operations.

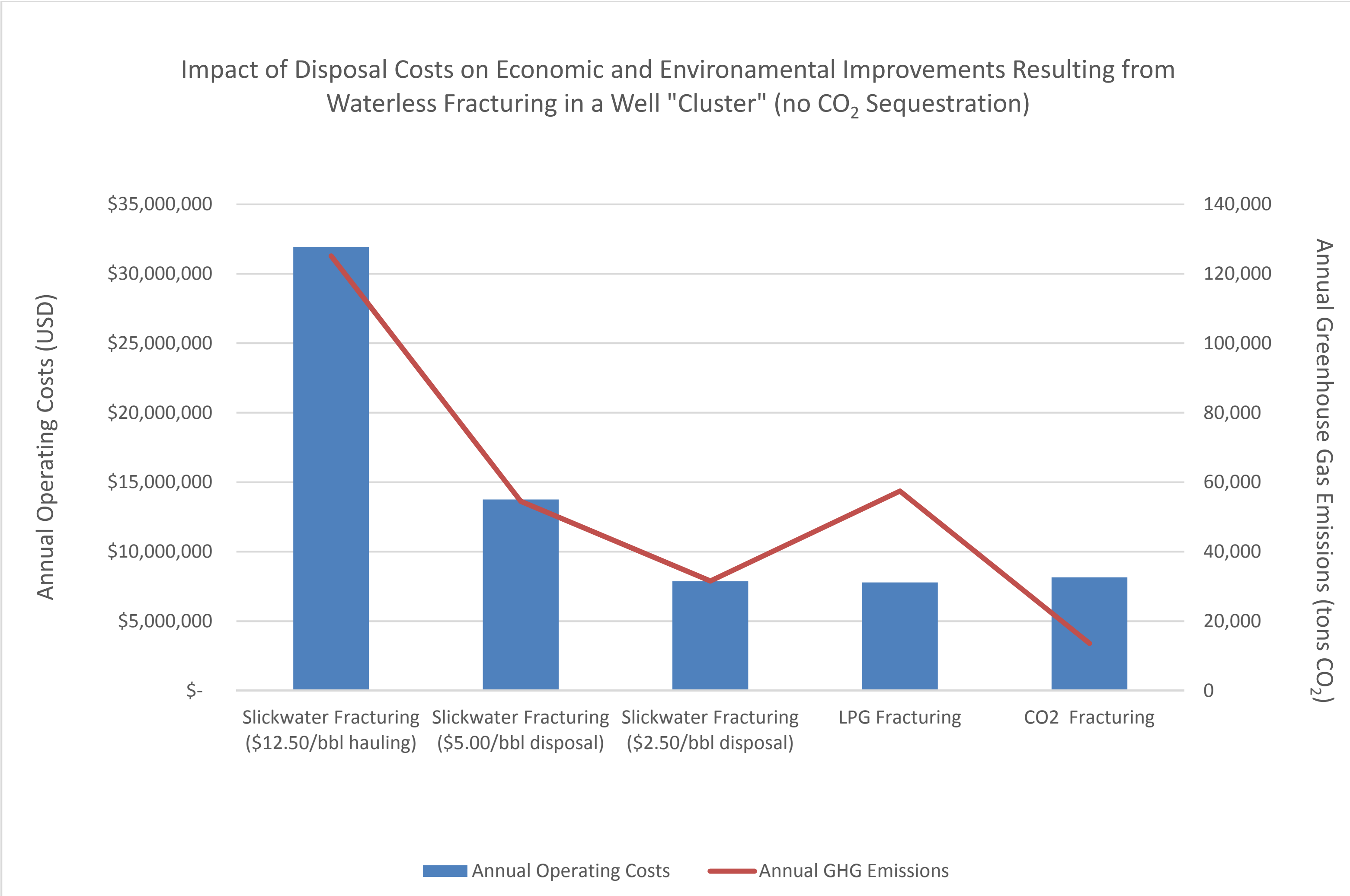


Figure 22: Impact of Hauling and Disposal Costs on the Economic and Environmental Benefits of Alternative Fracturing Fluids

6.5.2 Fracturing with CO_2 vs. LPG

In looking purely at the economics of the operation, it can be inferred that, while both waterless fracturing options offer economic benefits, LPG fracturing offers a larger economic incentive for operators.

Fracturing with liquefied petroleum gas has a number of benefits. Since the types of hydrocarbons in the fracturing gel are comparable to those in the formation, once exposed to the heat and pressures of the reservoir, the gel is broken down and propane vaporizes and can simply be produced with the reservoir flow. This minimizes clean up and maximizes well flowback. Unlike, carbon dioxide fracturing, no specialized separation equipment is required, natural gas processing plant used to produce dry gas from wellhead gas will ultimately remove propane with the stream where it can be reclaimed for re-use or resale. Also, since, LPG is electrically neutral and low in friction, many of the salts, heavy metals and radio-active components that rise to the surface with water remain in the formation. In addition, the transportation infrastructure for propane is relatively extensive and, as such, its transportation to the well site can be considered comparable to that of water.

However, there are several potential issues with the use of LPG as a fracturing fluid. The first is the obvious safety concern with substituting water with a significant volume flammable gel and pumping it at high pressure down the wellbore. The substitution of the nonflammable base fluid, water, with a flammable one, propane, decreases the inherent safety of the operation and therefore additional precautions must be taken to ensure the safety of the operation. In addition, every effort to run the operation remotely must be taken to minimize the impact of a potential fire hazard. The safety program for an operation which uses propane instead of water would be expected to be much more complex and prone to human error. Given the safety pre-cautions taken to handle the flowback of natural gas, the extension of the safety system to include that fracturing fluid needs to be evaluated. This is especially true of storage, liquefaction, pumping and transport units involved in the management of propane and/or butane before, during and after the fracturing operation.

Gas fracturing also requires highly specialized equipment[193] which could result in a significant capital investment by the operator. While the expected net present value of the operation seems to support this investment, risk averse, cost sensitive operators will be reluctant to make the investment. Finally, this is truly a new technology not widely proven in the industry. Unlike hydraulic fracturing and CO_2 fracturing which have been used in the oil and gas industry for decades and are used in shale gas extraction as a new "application", gas fracturing is truly a new and relatively unproven technology. As the shale gas market is highly competitive, operators who have taken a risk on the technology have kept the benefits tightly controlled, thereby creating a state of information asymmetry in the marketplace and reducing technology adoption. More traditional, risk averse operators, therefore, lack the data required to make informed decisions to adopt this technology.

In contrast, CO_2 fracturing has many of the same benefits of LPG fracturing in that it also does not damage the formation or dissolve salts, heavy metals and radio-active components that rise to the surface with water enabling them to remain in the formation. It also has comparable flowback characteristics and can drive similar increases in production. CO_2 has the added benefit of affinity to shale and its ability to displace methane in the shale formation leading to enhanced gas recovery. This is especially helpful as shale wells are depleted and workover rigs are needed to sustain production. The use of CO_2 to prolong the production of the well would be a natural extension of the fracturing process. In addition, supercritical CO_2 has been shown to produce more extensive three dimensional fractures, which is expected to further enhance production.[163, 194-196]

CO_2 is also inherently safer as a fracturing fluid than LPG, having similar flame retardant characteristics to water. It is safe to transport, store and pump and, therefore, does not introduce inherent safety risks to the operation. While creating foamed or supercritical CO_2 does impose an energy tax and, therefore a cost, on the operation, CO_2 in these forms does not require specialized pumping or monitoring equipment, nor does it require an extension of the safety management protocols in the operation. While flowback CO_2 can be vented to the atmosphere through a flaring process until concentrations reach pipeline levels, an incremental investment in a mobile CO_2 recovery system for the first two to three weeks after flowback is initiated would enable recovery and reuse/resale of CO_2.[145] For shale plays like the Barnett play, this would be an incremental investment to the operation, while for other plays where CO_2 is produced from the formations themselves, this would be an extension of the investment required to separate CO_2 from the formation gas. These costs, coupled with the higher market price of carbon dioxide make the alternative less attractive for operators than LPG or hydraulic fracturing.

Some of the most common drawbacks of CO_2 fracturing include the need to transport the fluid in a liquid state and store it in pressurized tanks; as well as the potential formation of ice on the hydraulic head and pipes during the fracturing operation should the wellhead pressure drop rapidly.[161]

From an environmental and safety perspective, it is clear that the use of CO_2 as a fracturing fluid could be much more attractive than any of the other options discussed here. In addition to the safety considerations and expected sequestration during hydraulic fracturing as well as the reduced amount of proppant required, the benefit of enhanced gas recovery and post-production sequestration in depleted shale wells with no incremental capital investment in equipment, render the potential environmental benefits much more appealing.

Several studies have evaluated the viability of depleted shale reservoirs for wide scale carbon sequestration and have recommended their use.[189, 190, 196] However, this long term sequestration comes at a cost of \$36 - \$73 per ton of CO_2, inclusive of enhanced gas recovery gains.[197] In the absence of any external incentives, oil and gas operators would not be likely undertake the longer term sequestration programs at this cost. In addition, the largest components of this cost are predicted to be transportation and injection costs with power supplied from an electric utility and pipeline based transportation which is not available in all areas. Thus, in the absence of public policy to drive these longer term programs, this level of sequestration will not likely be realized.

In fact, while CO_2 fracturing is considered a more preferred solution from an environmental perspective, the economics could drive operators to remains with hydraulic fracturing or move towards LPG as an alternative. The implementation of short term or temporary policy aimed at making the use of CO_2 more economically attractive could drive improvements in infrastructure that could sustain the alternative as economically viable even after the policy instruments have expired. This type of environmental policy has proven successful in driving technology adoption in the past with renewables policy or even the unconventional fuels development policy which spurred the current shale boom in the US.[24]

6.5.3 Flowback and Recycling of Fracturing Fluid

While the recycling of produced water may not be economically desirable in the Barnett Shale due to the abundance of water disposal infrastructure and the extended flowback periods, the recycling and re-use of alternative fracturing fluids are a different story. For LPG fracturing, field studies have shown that 100% of the propane used in fracturing is produced with the saleable natural gas within the first two weeks of production.[158] This implies that with separation and processing, a large portion of the LPG used in additional wells can be re-used or re-sold. In which case, the majority of the fuel need only be purchased once and the operator would just need to make additional purchases to replace process losses. A 10% loss rate is assumed for this analysis. Should recycling of propane be employed, flowback from the well could be processed on site or sent to the natural gas processing facility and then transported back to site rather than flaring the flowback gas until the propane level is reduced. This additional cost would need to be taken into account in the analysis.

A similar rationale applies to CO_2 fracturing, again flowback of CO_2 is completed within weeks of the start of production[198] with the exception that a portion of the CO_2 injected for fracturing will remain sequestered, so a 10% loss is assumed over and above the sequestered amount. The costs of CO_2 separation and fluid processing (either into foam or supercritical fluid) need to be taken into account as well.[199] The following figure shows the impact of recycling on the economics and greenhouse gas footprint of the operation. The profitability of the well cluster was analyzed including separation costs, reduced operating costs due to fluid recycling and incremental revenue from the excess natural gas recovered due to separation, rather than flaring.

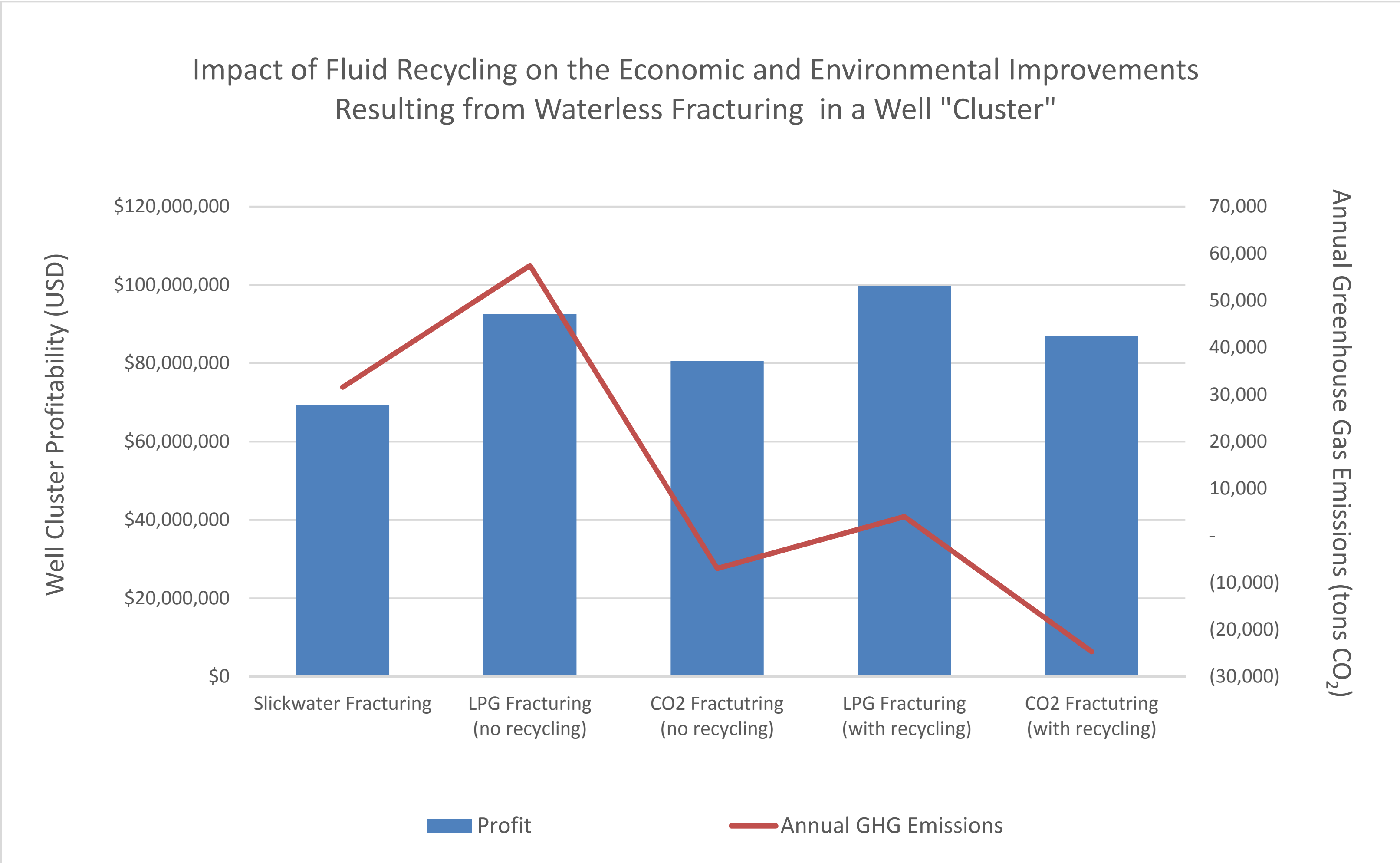


Figure 23: Impact of Recycling Fracturing Fluids on Profitability and Greenhouse Gas Footprint

Recycling has a threefold benefit for the operation. Firstly, it implies less fracturing fluid is purchased for each subsequent operation after the first. Secondly, it reduces the amount of natural gas flared thereby resulting in an increase in revenue. Finally, it reduces the overall greenhouse gas footprint of the operation significantly due to a reduction in flaring and fuel used for hauling fracturing fluid to the site. As a result of the sequestration of carbon dioxide in the formation, the economic impact of LPG recycling is much higher than that of CO_2. In this case, the more favorable economic solution is not the most favorable environmental solution due to the market failure attributed to CO_2 as a greenhouse gas.

6.5.4 Seismic Implications

One of the critical issues with hydraulic fracturing is the potential to trigger seismic activity during the re-injection of wastewater. As all fluids in the waterless fracturing process vaporize and flowback, re-injection is not required and therefore the risk of seismic activity from re-injection is eliminated in the remediated processes. As there is no evidence of significant seismic activity resulting from the fracturing process itself, the elimination of water from the process addresses the seismicity issues directly.

6.5.5 Broader Economic and Environmental Benefits

<u>US economic & environmental benefits</u>

Based on the well cluster analysis, it can be seen that the use of either CO_2 or LPG in place of water as a fracturing fluid can yield both an environmental and economic benefit for operators provided increases in production are taken into account, and especially when fluid recycling is employed. Using the scenario that includes both production impacts and fluid recycling and extrapolating these results to encompass the 1,000 -1200 new wells to drilled annually across the entire Barnett Shale play[136] and the ~3,700 new wells to be drilled annually across the United States[137], operators can reduce the environmental impact of natural gas extraction and save the industry money, as follows:

Table 26: Extrapolation of Results Across Barnett Shales and all U.S. Shale Plays

	Impact across Barnett Shale Play	Impact across all United States Shale Plays
CARBON DIOXIDE FRACTURING		
Annual Savings (USD)	$1,775,839,450	$5,475,504,969
Annual CO_2 Reductions (tons)	5,626,666	17,348,885
GAS FRACTURING		
Annual Savings (USD)	$3,040,524,683	$9,374,951,107
CO_2 Reductions (tons)	2,755,141	8,495,019

As demonstrated by the analyses, the economic benefits tied to LPG outweigh those of CO_2 in the substitution of water as a fracturing fluid, while the environmental benefits of CO_2 outweigh those of LPG. While both options drive economic and environmental benefits, driving the industry towards the safer, more environmentally friendly alternative requires the institution of policy that will incent the development infrastructure to drive down the price of CO_2 and create a sustained carbon economy. With the right type and duration of policy actions, a carbon economy can be developed that far outlasts the policy itself and encourages the capture and sequestration of carbon for years to follow.

<u>Unlocking arid and water sensitive shales</u>

In addition to improving the economics and environmental footprint of existing shale plays, an added benefit of waterless fracturing is unlocking additional shale plays that were previously infeasible either due to water scarcity or an under-saturation of the shale formation rendering it water sensitive. This not only unlocks a significant resource within the United States, but also provides a platform for countries like China, Mexico and South Africa that have a significant, characterized resource in very arid or water stressed parts of the country.[200] This could, in turn, have a significant impact on some of these developing nations' energy independence, or their dependence fuels such as coal and their greenhouse gas footprint. Again, for a country like China, that has a greenhouse gas footprint that is expected to surpass the United States this shift could significantly improve the global greenhouse gas profile and change the dynamics of the energy industry.[5]

6.6 Conclusions and Recommendations

When looking at the environmental remediation of oil and gas processes, it is important to understand the microeconomic implications of the proposed technologies and their impact on the operators. Frequently, the more economic benefit that can be derived the more open an operator is to implementing the technology. However, sometimes those economic benefits are realized over a period of time and an up-front capital investment must be made to realize the long term savings. In these cases, when the operator is unable to make the up-front investment and if the potential environmental benefits are significant enough, public policy can be implemented to lessen the financial burden on the operator and encourage adoption.

This paper examined the environmental remediation of the use of water in and the resultant greenhouse gas emissions of hydraulic fracturing in the Barnett Shale formation. An economic and environmental simulator was built to model the operation and it was found that the positive long term environmental impact was accompanied by a long term economic benefit which would more than offset the initial capital investment required to realize those gains. This paper built on the first paper in this series which looked at greenhouse gas remediation of combustion during a well's lifecycle in the Barnett Shale.

There are a number of opportunities for future research to validate and/or re-inforce the conclusions of this research. These areas include:

- The energy tax, and the costs, of producing foamed or supercritical CO_2 compared to LPG gel should be evaluated and added to the analysis if a true representation of environmental footprint is to be established. This paper assumed that the cost of producing LPG would be lower than that of producing carbon dioxide, thereby increasing the economic distance between the two alternatives.

- For the Barnett Shale, much of the water produced in hydraulic fracturing is formation water, therefore this was excluded from the analysis to make it more comparable to other plays. The production of formation water with LPG fracturing as well as CO_2 fracturing, compared to hydraulic fracturing, should be further investigated to determine if there are any additional considerations that need to be taken into account. In addition, the use of unconventional water treatment technologies such as advanced vapor compression desalination could be explored further and applied to both fracturing and produced water to determine if a water treatment option could be a feasible alternative.

- One of the most critical greenhouse gas issues with hydraulic fracturing is the leakage of methane directly into the atmosphere. Methane is known to have 25 times the greenhouse gas effect as carbon dioxide and leakage can have a significant impact on the greenhouse gas footprint of the operation. In this series of papers, methane leakage was assumed to be consistent among all scenarios and as a result excluded from the analysis. A similar analysis looking at the reduction of methane leakage could be conducted to supplement these results and develop a true representation of the greenhouse gas footprint of the operation.

- In these analyses, the prices of fuel consumed and natural gas produced were held constant throughout the life of the well. Sensitivity analyses taking into account changes in fuel prices and the price of natural gas over time could be conducted and included in the net present value calculations to provide a more accurate estimate of the economics over time.

- The amount of carbon dioxide sequestered during the CO_2 fracturing operation was estimated based on the amount of adsorbed methane expected in the formation. There are additional factors which impact the amount of CO_2 that can be sequestered including the shut-in time, the amount of moisture in the formation, and potential chemical sequestration that can occur should the CO_2 react with formation elements. Field experiments to verify actual sequestration amounts and flowback curves of carbon dioxide should be conducted to verify those assumptions.

- Much of the literature highlights the use of binary foam (carbon dioxide mixed with another gas such as nitrogen) to offset some of the drawbacks of carbon dioxide. The economic, environmental and safety impacts of the use of binary foam instead of pure CO_2 should be analyzed to determine if they have a significant impact.

7 USING INTEGRATED PROCESS AND MICRO-ECONOMIC ANALYSES TO ENABLE EFFECTIVE ENVIRONMENTAL POLICY FOR SHALE GAS IN THE UNITED STATES

7.1 Summary

As one of the largest consumers of energy and emitters of greenhouse gases (GHG) in the world, the US must balance energy demand and security with environmental responsibility. An emerging portfolio of energy resources and GHG reduction strategies must be considered. In the past several years, shale gas has emerged as a promising element towards a solution to this dilemma. Today, shale gas production is largely unregulated and involves small independent operators that typically endeavor to utilize the most cost effective extraction processes without necessarily prioritizing the environmental impact of their operations.

As a result of this situation, opposition to shale gas extraction, especially hydraulic fracturing, threatens the continuity and sustainability of the shale-gas industry. The negative externalities and information asymmetry associated with this market continue to be captured in a price of natural gas which is not inclusive of the environmental costs of the extraction processes.

In this analysis, four policy alternatives to the status quo are evaluated against the policy goals of:

- Economically efficient production of natural gas from shale plays
- Environmental, health, safety, and sustainability (EHSS) preservation of the immediate environment surrounding the shale operations
- Equity of Benefits to the many stakeholders in the shale gas debate
- Political Feasibility of each alternative in the current political climate

The four alternatives explore multiple policy mechanisms to alleviate the deadweight loss in the market around shale gas. The evaluated policy alternatives are:

- **Status Quo:-** which is equivalent to the existing policy for the conventional oil and gas industry
- **Stimulating Demand:-** which involves a carbon tax on supply and demand with forced greenhouse gas reductions

- **Most Effective Technology:-** which centers around tax reductions for use of the most effective technologies for environmental abatement
- **Plug the Loopholes:-** which involves removing all of the exception in place for the oil and gas industry and equating shale gas operations to other similar industries with respect to environment regulations
- **Comprehensive Policy:-** which builds on the "Most Effective Technology" alternative and uses elements of the other policy alternative to fill the gaps in that policy

The primary recommendation resulting from the analysis, the Comprehensive Policy alternative, uses a phased approach to drive ongoing innovation in the shale gas industry, stimulate demand for natural gas and reduce the information asymmetry. The implementation of this policy is then applied to an economic and environmental model of a cluster of wells in the Barnett Shale to determine how the policy would be implemented and further define the various policy elements.

7.2 Introduction

7.2.1 The Energy Equation: Assessing the Symptoms

The United States energy demand and consumption continue to be among the largest in the world, as does its carbon footprint, especially when compared to other global economies. The U.S. is expected to remain the largest consumer of energy and emitter of CO_2 after China through 2040. [5]

In addition, the current energy mix of the United States sways heavily toward coal and oil, totaling about 56% of total fuel consumption [3], which have a high environmental burden compared to cleaner sources. Electricity generation leans more towards coal while transportation relies heavily on petroleum. Without clean, domestic alternatives, to support this demand, the United States will continue to rely heavily on foreign energy sources and negatively impact the environment.

Among fossil fuels, natural gas is considered among the cleanest options. It also offers advantages over renewables in terms of expense and intermittency issues. Given the United States energy resource profile, as well as recent technological improvements in horizontal drilling and hydraulic fracturing, or *fracking*; natural gas and oil from shale rock (dubbed *shale gas* and *shale oil*) have emerged as significant potential contributors to the United States energy equation. These unconventional sources are expected narrow the production-consumption gap in the United States. [4] They have the potential to turn the United States into a net exporter of natural gas and have spurred major investments for downstream processing to produce fuels and value-added chemicals [201-204]. The success of shale gas production in the United States has spurred other economies to look at shale gas, and similar unconventional fuels, as potential energy options in their development.

Although the current reserves of shale gas are expected to support US consumption for anywhere from 100-200 years, the current production process, specifically hydraulic fracturing, is perceived to negatively impact both the immediate and broader environment. Hydraulic fracturing is also believed to affect the health and safety of people in the immediate vicinity of the operation. The hydraulic fracturing process involves the injection of large amounts of water laden with chemicals and mud into the "well" and fracturing shale to release the gas. As a result, water management strategies must be developed[205-207]. The gas is then captured and refined for use. Although hydraulic fracturing has been used for decades, to stimulate traditional oil and gas wells; the main issue with shale is scale. The size and number of fractures required to release the gas from shale is much more significant than those previously employed by the industry to date. In addition, the reach of a single well does not compare with that of conventional operations, so many more wells must be drilled to access the oil and gas from shale.

At present, shale production is spearheaded by a number of independent vendors who lack the robust environmental, health and safety practices of the more established oil and gas vendors. The lack of clear regulation in the industry enables independents to operate in the most cost effective manner, without necessarily prioritizing their impact on the surrounding environment.[208] This issue is becoming more pronounced as more shale gas deposits are discovered and characterized. Shale gas, therefore, behaves as a public good and the negative externalities associated with its consumption and the information asymmetry associated with shale gas operations, lead to a price for natural gas that does not reflect the true and total cost of extraction.

This situation has led to a growing opposition to the hydraulic fracturing process with several bans and moratoria on shale gas extraction both in the United States, led by local and municipal governments and across the world. In essence, many governments are taking a wait and see approach to the issue until they better understand the longer term implications of shale gas production. [6]

7.2.2 Focus on Hydraulic Fracturing: Framing the Issues

Given the fragmented nature shale gas production today, without federal regulation it will be difficult for the United States to realize the full potential shale gas may have in improving energy security and the environmental footprint of energy consumption. Leaving the current industry unchecked may have significant adverse effects on both the immediate environmental health and safety as well as on the broader environment.

Shale reservoirs are massive, typically spanning multiple communities, many coming close to metropolitan areas and agricultural zones [96]. As a result, the multiple wells that must be drilled to stimulate the gas, are frequently located on private properties. This situation leaves energy security in the hands of many private owners and municipalities and has led to inconsistent local regulation on shale gas production. This fragmentation of policy poses a risk for larger operators which are more environmentally conservative and narrows the market to smaller entrants with higher risk-reward profiles; ultimately reducing competition.

Currently shale gas operations, specifically hydraulic fracturing, are executed with the most cost effective approach but not necessarily the most ideal from the perspective of environmental health and safety. In many cases, the current lifecycle GHG emissions associated with shale gas can be higher than those of conventional gas and even coal [98, 102].

These practices have led to negative externalities associated with the consumption of natural gas, which behaves like a public good. In this case, the low price of natural gas does not reflect the additional cost of the environmental burden that the extraction process imposes. In addition, the lack of transparency between the shale gas operators and the public has led to information asymmetry around the true environmental impact and health hazards associated with the extraction process.

The list of environmental issues associated with shale gas extraction is broad. While many of these can be managed as part of the operation, there is no guarantee given current regulations:

- Number of wells that need to be drilled - acreage and clearing for well pads & impoundments
- Overconsumption of fresh water for hydraulic fracturing (2 million – 6 million gallons/well)[100]
- Contamination of water with hydraulic fracturing chemicals and methane (local streams/rivers and well water)
- Ponds fires due to wastewater pond negligence
- Fugitive methane emissions and flaring
- Release of volatile organic compounds (VOCs) form well installation
- Radioactive particles in waste water
- Release of pollutants from diesel and gasoline engines used in the operation (e.g. pumpers, trucks, etc.)

Without more consistent federal regulation around shale production, the fragmentation of policy will continue to be a barrier to larger more environmentally conservative entrants into the market as their cost of operation will be uncompetitive. This practice will continue to drive strong opposition to shale gas production, leading to more fragmentation, in a continuous cycle.

In addition to the energy security/independence and the environmental equation, shale gas production has the potential to drive jobs, exports and tax revenue both in its own right; and in support of other domestic industries; which can rely on inexpensive domestic energy for production. Solving the shale gas equation will help to provide a more stable and secure environment for these industries to operate.

Finally, since the United States is the global leader in the area of shale gas production, other economies are looking to the United States to determine how to set their own policies around shale reserves. This will have a domino effect on the environment and energy balance globally. By establishing policies that address both the negative externalities that arise from production of shale gas, and the information asymmetry in the market, the federal government can lay the foundation for other economies to effectively regulate this industry within their borders.

7.2.3 Current U.S. Policy Environment for Shale Gas Production

All development and production of oil and gas in the United States, including shale gas, are regulated under a complex set of federal, state and local laws that address every aspect of exploration and operation. All laws, regulations and permits that apply to conventional oil and gas exploration and production also apply to shale gas development[100]. As these regulations are extensive, the more salient points will be summarized here.

The U.S. EPA administers most of the federal laws and development on federally owned land is managed by the Bureau of Land Management and the US Forest Service. In addition, each state has one or more regulatory agencies that permit wells (design, location, spacing, operation and abandonment), as well as environmental activities and discharges (water, waste, air emissions, underground injection, wildlife impacts, surface disturbance and worker health and safety.

A series of federal laws govern most environmental aspects of shale gas development. Federal laws are implemented by the states under agreements and plans approved by federal agencies. Most of these have provisions for granting "primacy" to the states in which shale is being produced. The regulations include:

- **Clean Water Act** – regulates surface discharges of water associated with shale gas drilling and production as well as storm water runoff from production sites
- **Safe Drinking Water Act** – regulates the underground injection of fluids from shale activities, but excludes methane contamination

- **Clean Air Act** – limits air emissions from engines, gas processing equipment and other sources associated with drilling and production but does not include emissions of greenhouse gases
- **National Environmental Policy Act (NEPA)** – requires that exploration and production on federal land be thoroughly analyzed for environmental impact
- **Occupational Safety and Health Act (OSHA)** - regulations have provisions for handling naturally occurring radioactive material (NORM)to protect gas field workers

State agencies not only implement and enforce federal laws; they also have their own sets of state laws to administer. The states have broad powers to regulate, permit, and enforce all shale gas development activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well. States have implemented voluntary review processes to help ensure that the state programs are as effective as possible.

- **Ground Water Protection Council (GWPC)** – has a program to review state implementation of the Underground Injection Control (UIC) program
- **State Review of Oil and Natural Gas Environmental Regulation (STRONGER)** – has developed a set of a set of environmental guidelines against which state programs can be reviewed.
- **Interstate Oil and Gas Compact Commission (IOGCC)** – conducted state reviews against a set of similar guidelines before STRONGER was formed.

Much of the environmental policy, today, takes the stand that environmental health and safety represents an increase in cost on capital businesses. As a result, public policy in that area is developed using methods which force businesses to choose the lesser of two evils. This is typically ineffective and meets with a great deal of opposition from the private sector. In many cases, technology exists that improves both the environmental footprint **and** the inherent safety of these operations, however, the industry has been slow to adopt those technologies.

Much of the proposed environmental policy has focused on developing a carbon scheme that puts a price on carbon. While successful energy policy has been multi-pronged, combining tax incentives with other policy instruments such as incentive pricing and research credits [24], environmental policy has not historically followed suit. Public policy in this area approaches the issue from the perspective of driving environmental improvements without a thorough understanding of the micro-economic impact of the policy instrument. As a result, it either meets with opposition or is ineffective in driving adoption and less environmentally friendly solutions continue to be employed in the field leading to both a larger environmental footprint and more economic losses than required.

7.3 Methodology

In looking at environmental policy related to unconventional gas plays, the approach taken in this paper is to analyze the technical and micro-economic impacts of environmental remediation techniques and then take a multi-pronged approach to policy in this area which supports both the micro-economic and environmental health and safety goals. It is expected that this policy approach will enable adoption of new technology which also has a positive long term economic impact, by reducing the initial financial hurdles of an operation. This, in turn, should create both an economically and environmentally sustainable operation which would constitute a win-win scenario for the policy makers, the oil and gas operators and for the citizens of the United States. Figure 24 presents the methodology used for the development public policy using process and micro-economic analyses as a basis.

While many of the environmental and policy issues are common among unconventional gas plays, the unique composition of the gas in each play could require additional processes which would also need environmental remediation such as de-watering or CO_2 removal. In addition, the unique location of the play and the related local policy environment can dictate how the development of the resource is executed. As a result, looking at these issues for a specific play can enable a focused analysis of the issues and form a foundation for analysis of other plays. In order to apply the findings across other plays, additional analyses and adaptations must be applied.

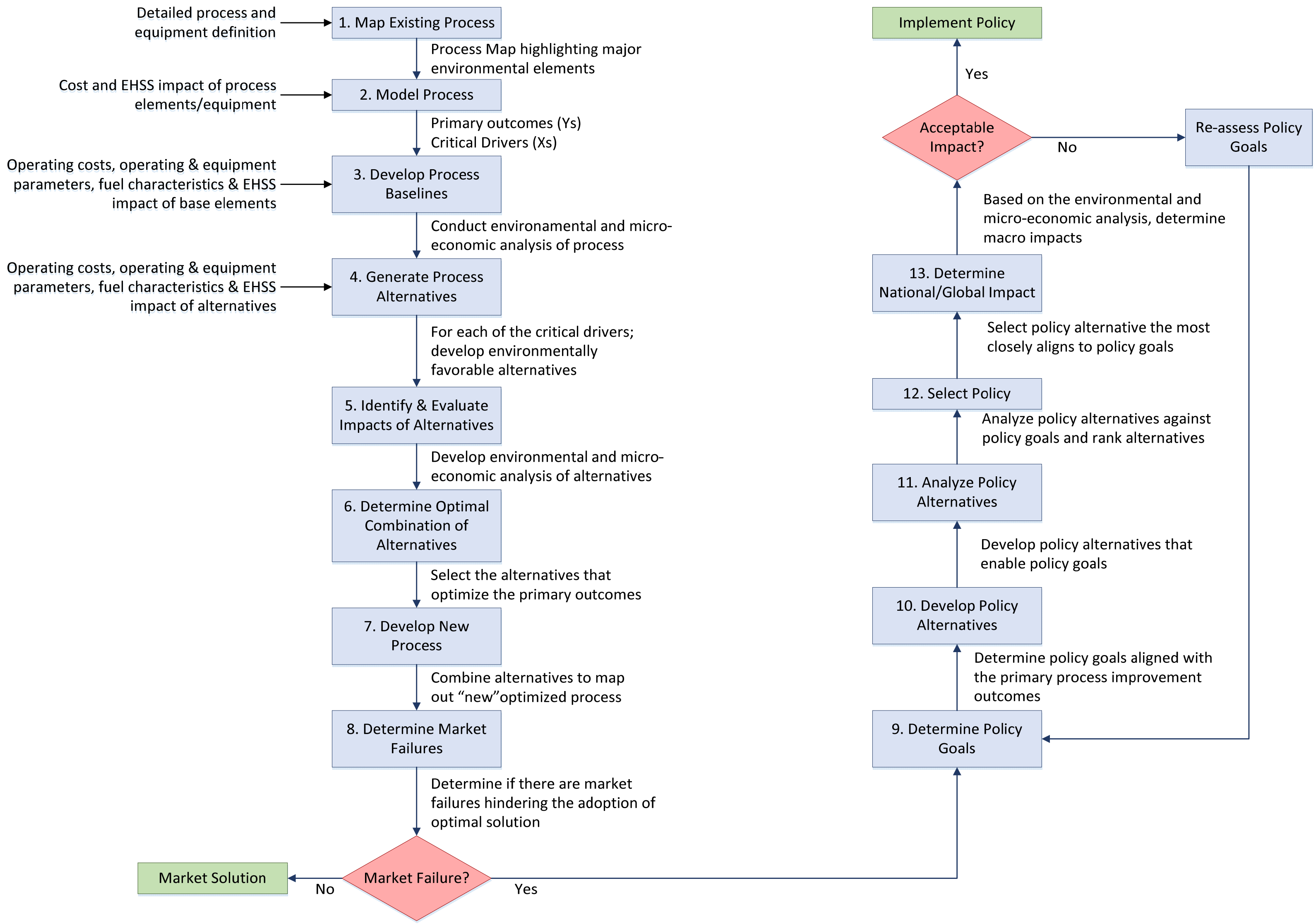


Figure 24: Process for Environmental Policy Development using Process and Microeconomic Analyses

1. The shale production process was mapped and the major elements impacting environmental impact were identified
2. The primary outcomes of profitability and environmental impact and their measures were identified. The critical drivers were then identified as: fuel type to power equipment (and its relative parameters), fracturing fluid (and its relative parameters) and impact of changes on the safety of operations.
3. Process baselines for the critical drivers was determined and the primary outcomes based on these were developed.
4. For each of the critical drivers, alternatives were developed which were expected to reduce the overall environmental impact of the operation.
5. These alternatives were substituted into the base process and the total environmental and profitability impacts were evaluated.
6. Combinations of alternatives which had the most favorable impacts were identified.
7. New processes using these alternatives were developed.
8. The EHSS impact of each alternative was compared against the impact on profitability to determine if a market failure was present
9. In the case where a market failure was found policy goals were determined to align profitability outcomes with EHSS ones.
10. Policy alternatives were then developed to attempt to reach the policy goals.
11. Each policy alternative was evaluated against each policy goal and the alternatives were ranked based on how well they aligned to the goals.
12. The policy which best aligns to the policy goals and closes the gap between the profitability and EHSS gaps was selected.
13. Based on the economic and environmental benefits of the individual case study, the results of policy implementation were extrapolated to determine the expected national impact of the policy to ensure a significant improvement over status quo.

Figure 24: Process for Environmental Policy Development using Process and Microeconomic Analyses (cont.)

7.3.1 Focusing the Analyses: The Barnett Shale

In order to focus the analysis and demonstrate its applicability and usefulness, a specific shale gas play was evaluated. Depending on the underlying depositional system, different shale plays will require different remediation approaches, so limiting the analysis to a specific play enables a focused approach to the analysis. The Barnett Shale was chosen as it is among the most established and most mature shale gas plays in the United States today and it plays a critical role in the U.S. natural gas landscape. As a result, a robust data set collected from operations in the Barnett could be used to conduct the analyses.

The Barnett Shale is a geological formation, located in North Texas.[209] It is estimated to extend 5000 square miles, across 25 counties with the core producing area located around Fort Worth [88]. The formation rests between 6,500 – 8,000 feet in depth, with an average thickness of 350 feet [106].

As of March 2016, there were over 17,500 wells, producing 4,018 million cubic feet per day of natural gas, according to the Texas Railroad Commission[107]. In addition, the Barnett Shale produces approximately 4,125 barrels per day of oil and 12,000 barrels per day of condensate, making it a considerable resource for Texas and placing it among the top five shale gas plays in the United States, with the success of horizontal drilling driving the success of the play. Today, horizontal well count is triple that of vertical wells in the formation, and horizontal well production dwarfs that of verticals wells in the play.[108, 109] Shale gas from the Barnett play does not require CO_2 and H_2O processing to make it usable and can therefore be used as a baseline for further analyses.

7.3.2 Well Lifecycle Analysis and Environmental Impacts

In looking at the environmental impacts of shale gas, it was assumed that once the gas is produced and processed for transportation, its environmental footprint will be similar to that of natural gas from conventional sources. Therefore, the focus of this analysis is on the environmental footprint of the drilling and production processes associated with shale gas extraction, the "well" lifecycle, and not on the entire lifecycle of the shale gas itself.

As discussed previously, there are a number of environmental issues tied to shale gas development. Issues around greenhouse gas emissions; water consumption and disposal during hydraulic fracturing; and seismicity are the most consistent among shale gas plays and have the most direct impact on the immediate environment. In addition, these elements are among the most difficult to manage and mitigate.

As a result, a well lifecycle analysis was conducted focusing on these three elements and the proposed improvements to reduce the impact on the immediate environment were proposed and analyzed. The total micro-economic and environmental impacts of the proposed options for environmental remediation were developed to form a basis for policy recommendations. The first was remediation of greenhouse gas emissions from the burning of fossil fuels in the operation. The second was reducing the impact on water resources both in terms of fresh water usage as well as wastewater management. The third was looking at the reduction of induced seismicity resulting from shale operations. A thorough review of the literature revealed that induced seismicity was inextricably linked to wastewater management, so these two areas were combined into a single analysis.

A systematic approach was used to analyze the key process elements in shale gas operation. An analytical model was then developed and an economic and environmental simulator was built. Alternative technologies were then substituted for the most impactful levers of the operation to reduce the environmental impacts. The remediated operations were then simulated and analyzed from both environmental and micro-economic perspectives.

7.3.3 Policy Goals and Analysis

Once the need for policy was established a series of policy goals were developed, in order to ensure that the policy alternative developed were evaluated objectively. Once the policy alternatives are developed, a series of metrics for each goal are defined and each alternative is analyzed against each of the policy goals to help determine the policy recommendations. In addition, a number of constraints were identified, within which the chosen policy will be bound.

Economic Efficiency

The first policy goal focuses on the *economic efficiency* of shale gas production as measured by the *cost to produce* and our ability to balance *production rate with demand* (energy security/independence). The policy must do this without infringing on the rights of land owners or attempting to fix the price of natural gas in the market. In order to preserve the health of the industry, the policy cannot be so restrictive as to indiscriminately drive value out of the industry. This policy goal is heavily influenced by a related policy around export restrictions for natural gas. Restricting the export of natural gas creates an insular market for natural gas where the dynamics are controlled by production rate. By allowing exports, the world market influences the market dynamics and that control is compromised. While this policy does not dictate one alternative or another, it is influenced by this dynamic.

Environmental Health and Safety Preservation

The second key policy goal is *environmental health and safety preservation* in shale production. The policy should reasonably protect the environment and the health and safety of neighboring communities as compared to alternative operations in the industry. In addition, it should encourage operators to continually improve the environmental impact over time as measured by the environmental footprint of production; impact on the health of citizens in the vicinity of production; safety of drilling operation. It must do this without infringing on the privacy of citizen health information (HIPAA). As we are interested in real improvements not perceived improvements, *implementation feasibility* is an element of this goal. The primary measures of implementation feasibility are *ease of enforcement* and *ease of monitoring*.

Equitable Distribution

Third, e*quitable distribution* of wealth and environmental benefits among land owners, corporations, citizens in vicinity of production facilities, and the average citizen is critical to ensuring success. As part of ensuring fairness among key stakeholders, it is critical to ensure equity is perceived and felt among these constituents. As a result, equitable distribution includes information dissemination as measured by brand awareness and citizen satisfaction measures.

Political Feasibility

Finally, *political feasibility* is relevant, especially in the context of the broader energy and environmental policies. In addition to evaluating likelihood of successful adoption of the policy, based on the current governing bodies, political feasibility can be determined by the similarity of the proposed policy to other programs executed in similar industries or countries.

When evaluating the political feasibility of the policy alternatives, various stakeholders were considered. The key actors considered are summarized here. In the analysis, the motivation, beliefs and resources of these stakeholders inform how feasible any given policy alternative will be. Public records are used to determine their position on the topic at the time of the research and their impact is consequently evaluated. The **House Committee on Energy and Commerce** has wide jurisdiction and a broad charter on both sides of the shale debate. This necessitates the prediction of the positions of specific, relevant actors on the Committee and its various Subcommittees and Agencies. **Local governments/municipalities and their officials** can support or hamper implementation of policy at a local level through additional local bureaucracy. **Shale gas operators/large utilities/industrial governments** have marketplace buyer and supplier power and house vocal and well-funded lobbies. **Land owners and neighbors** have a vested interest in both the local economy and environmental impacts. **Energy and environmental lobbies** are vocal and well-funded and sway local governments and public opinion. **Industry Associations** have strong oil and gas membership, are considered credible sources for accurate information and can be instrumental in the implementation and enforcement of policies. **Average citizens** are tangentially affected via the price of natural gas but can vote with their wallets on the shale gas issue by choosing providers based on their opinions.

7.4 Improving the Environmental Footprint of Shale Gas in the Barnett Shale

7.4.1 Environmental Remediation Techniques for Shale Gas Production

The first environmental remediation technique evaluated was the substitution of natural gas for diesel and gasoline in powering the shale gas operation. In evaluating several alternatives, the approaches which had the biggest economic and environmental benefit while continuing to meet the needs of the drilling and production operations included the use of dual fuel heavy duty equipment for drilling and completions. The equipment would burn raw natural gas directly from the well head 70% of the time and diesel for 30% of the time to satisfy periods of high power and torque requirements. In addition, the use of light duty compressed natural gas vehicles for transport reduced the use and emissions from gasoline.

The second environmental issue, water consumption and management, was addressed with two waterless fracturing options. These processes use substances that are naturally in a gaseous state but are either liquefied or foamed to enable fracturing, thereby limiting the amount of water used to drilling operations and limiting waste water management to management of water produced from the formation itself. Liquefied Petroleum Gas or LPG fracturing uses a cross linked gel made of largely propane and in some cases includes some butane. Carbon Dioxide fracturing uses CO_2 in a foamed or supercritical form. While supercritical CO_2 has had some experimental success, foamed CO_2 has been used in the field with quite a bit of success. While all of these alternatives have an initial upfront investment and some operational risk associated with their relative newness in this application, the economic benefits are expected to outweigh those costs.

7.4.2 Environmental and Microeconomic Impacts of Technology Alternatives

As much of the environmental impacts of the shale gas operation occur during the drilling and completion phases of the well lifecycle, and it take approximately one month to drill a well, a cluster of 12 wells was used as the unit of measure for the analysis. This represents an "annualized" cost model. The net present value of the remaining costs which run through the life of the well cluster (assumed to be 25 years) as well as the lifetime revenue of the cluster were then compared to this annualized cost to develop an expression for the lifetime profitability of the well.

In addition to a number of critical operating assumptions which were made in modeling the operation, the following assumptions were made to compare the key alternatives:

- The life of a well is, on average 25 years. Should the well life be shorter or longer, the well life is such that it would not change the outcome of the analysis significantly.

- All alternative fracturing fluids recovered from each well would be recycled in the following wells in the cluster and there would be approximately a 10% loss in fluid volume which would need to be replenished.

- Carbon dioxide used for fracturing is partially sequestered in the formation at a rate of 30%.

- Alternative fracturing fluids would yield enhanced gas production at a rate similar to that of other field studies using that fluid

Figure 25 highlights the combined environmental and microeconomic impact of the proposed technology alternatives.

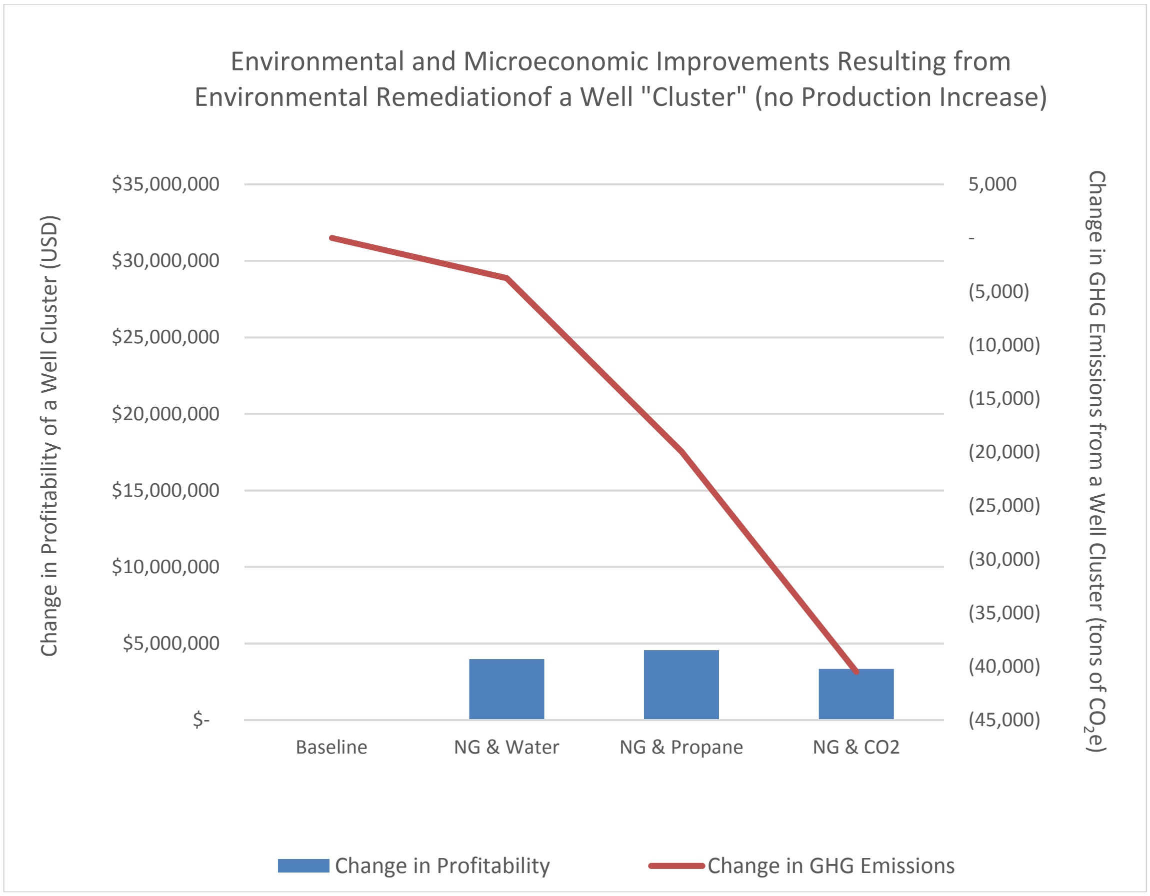


Figure 25: Environmental Improvements and Annual Savings of Technology Alternatives

While there is a reduction in operating costs resulting from each of the three alternatives, the largest cost reduction comes from the substitution of natural gas with diesel as a fuel, even though this option does not produce the most optimal greenhouse gas reduction. A different picture emerges when the increase in production resulting from the alternative fracturing fluids is taken into account, as shown in Figure 26.

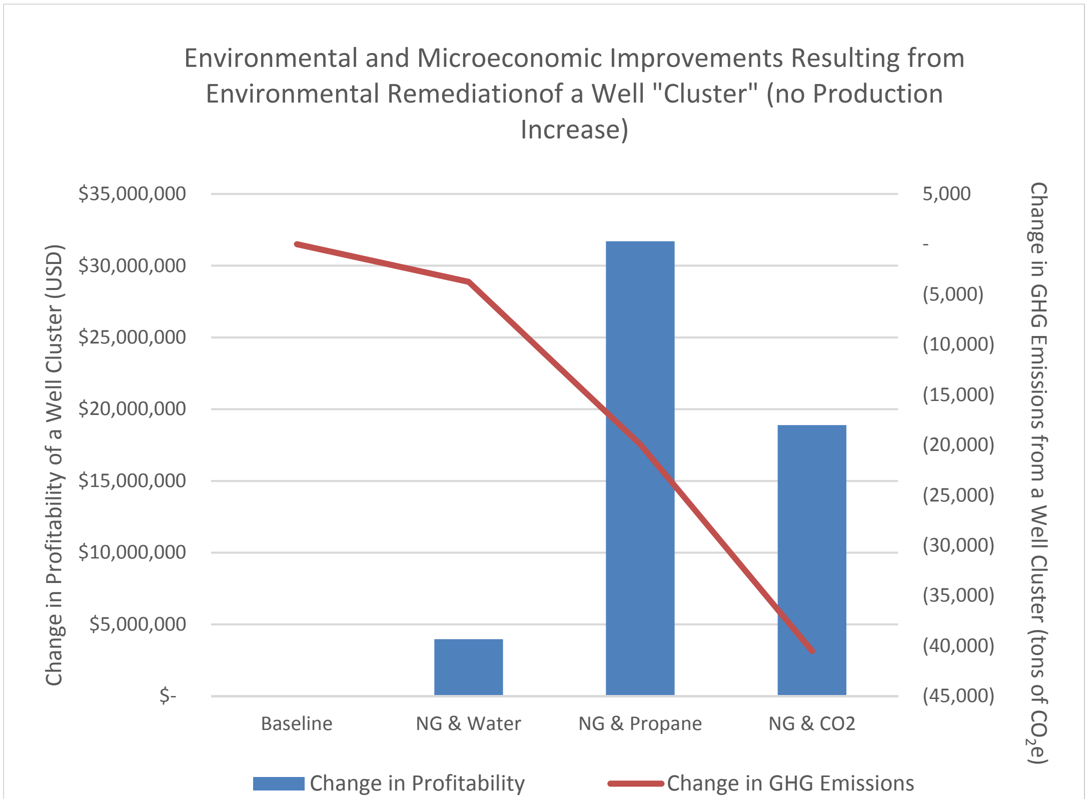


Figure 26: Environmental and Microeconomic Impacts of Technology Alternatives

The improvements in the overall microeconomic footprint of the operation is shown by looking at the overall profitability of the well cluster over its expected life. The increases in profitability resulting from the alternative fracturing fluids far outweigh the cost savings involved. If only the economic view was taken, it can be surmised that the use of natural gas as a fuel coupled with the use of LPG or propane as a fracturing fluid would yield the best solution. This option does not, however, lead to the most effective economic solution. This economic disparity results from a number of inherent issues, the most significant of which are:

- As more carbon dioxide is sequestered in the operation, a positive environmental outcome, more carbon dioxide must be purchased to compensate for the "loss"
- The cost of carbon dioxide is very high as there is a distinct lack of infrastructure to capture, process and transport carbon dioxide to site
- In field studies, carbon dioxide foam did not increase production by as large a percentage as LPG gel, thereby leading to a higher boost in revenues tied to LPG

This case study vividly demonstrates the negative externalities associated with many environmental issues. As a result, it lends itself well to the institution of public policy to eliminate or reduce the dead weight loss in the market and drive the desired economic and environmental outcomes. In short, the analysis shows that while all technology options offer both economic and environmental benefits, left to standard market dynamics, operators would gravitate towards the use of natural gas as a fuel and LPG as a fracturing fluid ("natural gas/LPG") rather than the safer, and more environmentally favorable, use of carbon dioxide as a fracturing fluid. Public policy is therefore recommended to support the natural gas and CO_2 ("natural gas/CO_2") solution as the more environmentally favorable option.

7.5 Environmental Policy Recommendations for Shale Gas Production

7.5.1 Policy Alternatives

The broad nature of the shale gas extraction issue lends itself to multiple policy alternatives. In reality, a multi-faceted approach is likely the best option. The challenge will be to keep the chosen policy framework simple enough to understand and implement while ensuring it is comprehensive enough to address the issues posed by the shale gas extraction issue. In addition, since the environmental issues have long term implications, it will be critical that the chosen policy withstand multiple administration changes. The goal of these alternatives is to internalize the negative externalities associated with shale gas production and resolve the information asymmetry.

Alternative I: Status Quo

The current regulatory environment for shale gas extraction, as for conventional oil and gas exploration and production, is complex and multi-layered. Today, the laws, regulations and permits associated with conventional oil and gas, apply to shale gas extraction.[100]

Many of the governing regulations set limits on environmental impact elements such a water pollutants or air pollutants. They manage compliance using permitting mechanisms and fines for non-compliance. Many have specific recordkeeping and reporting requirements for the operators to ensure monitoring and transparency. In it important to note, that there is no current regulation on greenhouse gas emissions for all but the very largest stationary sources. There are also no provisions in place for regulating methane (the primary component of shale gas) contamination of drinking water[210]. In fact, there are a number of exemptions for oil and gas producers in many of these regulations today, the Halliburton Loophole [98].

In addition, there are two major state, industry and environmental consortia that work to govern oil and gas producers at the state level. The Interstate Oil and Gas Compact Consortium (IOGCC) and State Review of Oil and Natural Gas Environmental Regulations (STRONGER) represent constituents responsible for 90% of onshore domestic production. They also update regulatory guidelines consistent with developing environmental and oilfield technologies and practices.

The Comprehensive Environmental Response Compensation and Liability Act (CERCLA or Superfund) taxes chemical and petroleum industries and funds a trust for the clean-up of hazardous waste sites. This excludes natural gas and oil but would apply to shale gas in the event other hazardous material is discharged. This is the only specific environmental tax element in today for shale gas producers.

Finally, the Emergency Planning and Community Right to Know Act (EPCRA) has disclosure requirements for all oil and gas producers regarding all hazardous material on site. The EPA's Toxic Release inventory (TRI), which is authorized as part of the EPCRA provides valuable information regarding chemical releases and waste management to the public but it currently does not include the oil and gas industry (part of the Halliburton Loophole). This specific element goes to the issue of information asymmetry.

Alternative II: Stimulate Demand

This alternative involves an environmental tax/cap and trade mechanism on both the supply (shale gas operators) and demand (large shale gas intermediaries) balanced by forced percentage reduction of greenhouse gas emissions for utilities and large energy consumers; equivalent to the difference between the greenhouse gas emissions for coal or oil and natural gas. Tax revenue goes to funding infrastructure investments (staff, management and technology) for monitoring and enforcement. This policy would be regulated by the Department of Energy and EPA to ensure balance and would mandate increased reporting requirements to support tax enforcement only [102, 211].

To approximate national emissions policies most actively pursued at present we would impose (1) a renewable energy standard (RES) requiring a 25% renewable share of electric generation by 2030, and (2) the retirement of 50% of current U.S. coal-fired generation capacity by 2030. [211]

Alternative III: Most Effective Technology

This alternative involves tax incentives for use of the most effective technology for abatement of environmental impact. To ensure continuous improvement, incentives are tiered and only continue at the highest level if organizations make year over year improvement in their environmental footprint. To implement this policy, there would be regional individual and co-op based environmental responsibility tied to drilling rights and enforced via drilling permits [212]. This includes infrastructure investments for monitoring environmental impact and reporting and disclosure; putting the onus on the operators for monitoring and reporting to get the tax incentives. Industry associations would be recruited to determine and enforce “best available technology” usage via their existing audit programs (a.l.a. API monogram program). The EPA and Department of Energy enforce regulation and tax rate reductions using the same mechanisms used for wind and solar credits. The reduction in tax rate would have to be enough to create a positive or neutral net present value on the initial investment in infrastructure by corporations.

Alternative IV: Plug the Loopholes

In this alternative, there is also regional individual and co-op based environmental responsibility tied to drilling rights and enforced via drilling permits. Regulations are put in place to plug the Halliburton loopholes on reporting, transparency and environmental impact using the current regulators and enforcement mechanisms in place for other industries. Revenue from the fines associated with increased regulation is invested in upgrading the infrastructure to accommodate the increased data load on the monitoring agencies and systems. [213]

Alternative V: Comprehensive Policy

In this alternative, there is, again, regional individual and co-op based environmental responsibility tied to drilling rights and enforced via drilling permits. The policy is based on the "most effective technology" policy with modifications to address the shortfalls of the original alternative. It involves a phased in approach starting with tax incentives and research funding for most effective technology to fund investment in infrastructure improvements to plug the associated informational and environmental (Halliburton) loopholes around the most critical of environmental factors (2-3 years). Again, industry associations would determine and enforce the "most effective technology".

Once a baseline environmental footprint is established, incentives would continue to be offered for continuous improvement and demand would be driven with environmental impact reduction policies on utilities and large energy customers with taxes/fines after the initial 2-3 year grace period. This ensures that demand for natural gas remains high enough to counter any potential oversupply with the tax incentives driving down costs.

Environmental tax would be imposed on all suppliers/operators those who, after 2-3 years do not employ the "most effective technology". The EPA and Department of Energy would invest up front in infrastructure and monitoring in preparation for the 2-3 year cutoff. Taxes and fines, in all cases, go to return the initial agency investment and fund ongoing monitoring and regulation enforcement after the initial 2-3 year period.

7.5.2 Analysis of Policy Alternatives

In order to adequately evaluate these alternatives and make a recommendation, each alternative was analyzed against each of the policy goals outlined in the previous section. Table 27 summarizes these results. Each of the impact categories is given metrics which help determine how the alternatives will be evaluated and the scale is highlighted as part of Table 27. For each impact category the high, low and median scores were given values and descriptors and then each alternative was evaluated against the status quo and given a relative and more qualitative score along the range from high to medium to low. Additional research will be required in order to better refine these values quantitatively and this is a recommendation for future work on this analysis.

Alternative I: Status Quo

Economic Efficiency - The status quo is the most economically efficient of the alternatives. In the status quo, shale gas is produced with the lowest cost of production. This low cost of production makes wells that would otherwise be unfeasible, at the current price of gas, feasible. This drives the highest potential production rate among all of the alternatives. It is this economic efficiency that drives the negative externalities in this market place as the cost and therefore the price does not adequately reflect the cost to the environment.

EHS Preservation – In contrast, the status quo is poorest in terms of EHS preservation as all environmental, health and safety elements of the regulation are voluntary. In order to facilitate the economic efficiency of current operations, operators do not invest in environmental preservation, even if that investment may result in economic efficiencies in the longer term. The only impact category of EHS preservation that does well in the status quo is safety of operation as OSHA requirements do still prevail.

Table 27:Policy Goals and Alternatives Matrix

Goals	Impact Category	Policy Alternatives				
		Status Quo	Stimulate Demand	Most Effective Technology	Plug the Loopholes	Comprehensive
Economically Efficient Shale Production[a]	Cost of Production					
	Production Rate					
EHS Preservation[b]	Environmental Footprint of Production					
	Year on year improvement of footprint					
	Citizen Health Index					
	Safety of Operation					
Implementation Feasibility[c]	Ease of Enforcement					
	Ease of Monitoring					
Equitable Distribution[d]	Fairness to land owners					
	Fairness to corporations					
	Fairness to neighbors					
	Fairness to the average citizen					
Information Dissemination[e]	Brand awareness					
	Citizen satisfaction					
Political Feasibility[f]	Likelihood of successful adoption					
	Program similarity					

[a]Economic Efficiency

Cost of Production: Impact of the policy on the cost to product natural gas		
No Impact	Impact does not affect well viability	Impact significantly reduces well viability
Production Rate: Impact of the policy on an operator's ability to produce at the current price of natural gas		
Remain at current high levels	Reduced but still competitive at current price	Uncompetitive at current price

Table 27:Policy Goals and Alternatives Matrix (cont.)

[b]Environmental Health and Safety Preservation		
Environmental Footprint of Production: Relative impact of operations on the immediate environment		
In line with green operations benchmark	In line with other (non-shale) industrial activities	Impact on environment greater than others
Year on year improvement of footprint: Measures impact of the policy on sustainable environmental improvements		
>5% improvement	1-5% improvement	No Improvement
Citizen Health Index: Measures our ability to develop root causes and solutions for impact on citizen health in the vicinity of operations		
No impact to citizen health	Causes of impacts to health known/resolving	Unknown impact on citizen health
Safety of Operation: Uses standard OSHA definitions for oil and gas to determine safety of operations		
Equal to other oil and gas operations	1-10% worse than oil and gas operations	>10% worse than oil and gas operations
[c]Implementation Feasibility		
Ease of Enforcement: Measures the need for investment in mechanisms for enforcement		
Uses existing mechanisms	Uses repurposed mechanisms	Requires new mechanisms
Ease of Monitoring: Measures the need for investment in infrastructure (technology, people, management) for monitoring		
Uses existing infrastructure	Uses repurposed/expanded infrastructure	Requires new infrastructure
[d]Equitable Distribution		
Fairness to land owners: Directly correlated to level of burden and personal gain (in the form of royalties received from operators…related to production rate)		
Low burden & high personal gain	High burden or low personal gain	High burden and low personal gain
Fairness to corporations: Directly related to company benefit (profitability and reputation) and level of burden (time and money)		
High benefit and low burden	Low benefit or high burden	Low benefit and high burden
Fairness to neighbors: Determined by personal gain from operations (in the form of jobs and consumption of local goods and services) and level of burden (health and safety)		
Low burden & high personal gain	High burden or low personal gain	High burden and low personal gain
Fairness to the average citizen: Manifested in the form of personal gain (cost/price of natural gas) and level of burden (impact on the larger environment)		
Low burden & high personal gain	High burden or low personal gain	High burden and low personal gain

Table 27:Policy Goals and Alternatives Matrix (cont.)

[e]Information Dissemination		
Brand awareness: Measures the awareness, understanding and acceptance of the average citizen of the issues and facts related to shale gas		
Aware and Understands facts	Aware of facts; may not understand issues vs. fiction	Unaware of facts, follows propaganda
Citizen satisfaction: Measures acceptance of and satisfaction with policies in place related to shale (% of people measured who are satisfied or better with policies and measures)		
>60% are satisfied or better	20%-60% are satisfied or better	<20% are satisfied or better
[f]Political Feasibility		
Likelihood of successful adoption: In the current climate, how aligned is it with stakeholder motivations and beliefs and is there a precedence of rejection of similar policies		
In line with all stakeholder motivations and beliefs	Aligned with many motivations and beliefs; no precedence of policy rejection	Aligned with minority motivations; precedence of similar policy rejections
Program similarity: Measures if there are any similar policies both domestically and/or internationally that have been successfully implemented		
Similarity in the US and internationally	Similarity in the US or internationally	No similarity in the US or internationally

Equitable Distribution – While the status quo is extremely fair to corporations and fair to land owners, who collect rents from these corporations, it is unfair to neighbors. These neighboring citizens are the primary recipients of the EHS fall out and have received no compensation as the land owners have. Fairness to the average citizen is mixed as the lower natural gas prices ensure more discretionary spending, but the aggregated impact to the environment could be detrimental in the long term. Information dissemination under this policy is extremely poor as operators are not required to disclose any information about their impact on the environment. This lack of transparency has led to the current opposition to shale gas extraction.

Political Feasibility – As this policy is currently in place it is the most politically feasible alternative. This is especially true as it mimics the existing policies for the remainder of the oil and gas industry.

Alternative II: Stimulate Demand

Economic Efficiency – This policy alternative is disadvantaged with respect to efficiency, when compared to the status quo. The environmental impact tax on both the supply and demand will hit "clean" producers less than others, but will impact the cost to produce natural gas nonetheless. The impact to efficiency is balanced by taxing energy consumers on their environmental impact, driving them away from more damaging fuels like oil and coal towards cleaner fuels like natural gas and renewables. By indiscriminately taxing environmental impact, we would also put natural gas in competition with renewables and other clean energy sources, which could negatively impact the economic efficiency of shale further.

This policy will stifle production rate in the short term, as it will make many marginal well uneconomical to produce at the prevailing price of natural gas. However, it will recover over time as the price of natural gas adjusts and it becomes economically feasible to go back and produce those wells.

EHS Preservation – This policy is expected to drive excellent reductions in the short term environmental footprint, especially as it makes renewable and other ultra clean fuel attractive, in addition to natural gas. There is, however, there is no guarantee that this policy has staying power to ensure long term year on year improvement. In addition, this policy does not address citizen health or operational safety at all. It is also very difficult to measure and monitor the environmental impact of an organization completely and fairly, especially when, like shale gas operations, the sources of environmental offenders are numerous and dispersed over large areas.

Equitable Distribution – This policy lacks equity to corporations who will take on the burden of the tax. It is also difficult to maintain equity within the category of "corporations" as some corporations, with more condensed footprints, will have an easier time monitoring and reducing their environmental footprint than others and will therefore not have an equal burden. These stakeholders have large and well-funded lobbies which will make the policy nearly impossible to implement effectively. In addition, this policy only partially addresses information dissemination, as corporations will fight to withhold as much information as possible to avoid paying the tax.

Political Feasibility – While there are similar successful programs internationally to model this after (e.g. Australia), the current political climate renders this policy politically infeasible. This policy runs completely at odds with a recent bill banning the EPA from establishing programs which tax carbon for any industry. In addition, key Committee members are heavily supported by fossil energy interests, are strongly in favor of shale gas and will be hesitant to support such a heavy handed approach with the industry.

Alternative III: Most Effective Technology

Economic Efficiency – With this policy, the introduction of tax incentives for the most effective technology ensures that the cost of production remains low driving an economically efficient approach. As the tax incentive will be large enough to ensure a reasonable payback period for the investment in technologies and the ongoing technological improvements will likely drive additional gains in the productivity of the shale gas operation, the cost of production is expected to stay at the same level as the status quo or even drop over time. The danger with this policy is with production rate. A reduction in production cost over time, after the initial infrastructure investment, can lead to oversupply in the market so balancing demand and supply in form of production rates, without price fixing, can drive the market into a tailspin, assuming limited natural gas exports. If the export limitations are removed, however, this issue is lessened considerably and this alternative becomes a very economically efficient one.

EHS Preservation – As it is a tax incentive approach, this policy is expected to stimulate and reward innovation among those operators who choose to take advantage of it. This continuous improvement in abatement technology will drive excellent EHS preservation. However, given that it is a tax incentive, some operators may choose to opt out of the incentive, as current operations are already profitable and, unlike wind and solar for example, the tax incentives serve to enhance profitability not ensure it. In these cases, no EHS preservation will be observed, so not all operations will be driven to improve.

The onus of implementation and monitoring will be on the operators, so it will be relatively easy to implement. However, an auditing program will need to be in place to ensure operators are realizing the environmental benefits they claim. While this auditing will be accomplished by expanding and enhancing existing industry associations, it will be imperfect and intermittent.

Equitable Distribution – Again, because it is an incentive (i.e. opt-in) based approach, those land owners and neighbors where operators have not taken advantage of the tax incentives will not realize the EHS benefits of their counterparts where these incentives are fully exercised. As a result, there will likely be an inequity felt among those groups. Also, information dissemination as it relates to the tax incentives will drive information symmetry but only for operators who choose to take advantage of it, so information asymmetry will likely be only partially addressed.

Political Feasibility – As this is a tax credit program, this policy aligns exceptionally well with all of the key actors in the arena. It also mimics the wind and solar tax credit programs so there is precedence on which programs can be designed and decisions can be made. Finally, the same mechanisms in place for wind and solar can be extended and used for this policy easing the way for implementation.

<u>Alternative IV: Plug the Loopholes</u>

Economic Efficiency – It is estimated that the economic impact of "plugging the loopholes" on the US "unconventionals" industry is expected to be between $1.5 and $3 billion annually leading to a 12% - 18% reduction in unconventional gas production [214]. This data indicates that both the cost of production and production rate would be severely impacted by this policy; leading to an economically inefficient policy.

EHS Preservation – This policy only partially addresses EHS preservation in that it only addresses current loopholes in the oil and gas policy but does not address any unique items related to shale gas extraction. It also does not drive any year on year improvements. As it brings the oil and gas industry even with other industries, the implementation mechanisms used for those industries can be used for this policy, making it easy to implement.

Equitable Distribution – Equity for this policy sways heavily towards the average citizens, neighbors and land owners and heavily against corporations as they would bear the burden of compliance. Information dissemination, in this policy, is very well satisfied as many of the loopholes center around reporting of environmental impacts publically.

Political Feasibility – Although this policy is identical to that for other industries, it goes against the grain of the current political climate within the Committee, in that it burdens shale gas operators and increases the cost burden on the industry significantly. That renders this policy politically infeasible.

Alternative V: Comprehensive Policy

Economic Efficiency - With this policy, the introduction of tax incentives for the most effective technology ensures that the cost of production remains low driving an economically efficient approach. As the tax incentive will be large enough to ensure a reasonable payback period for the investment in technologies and the ongoing technological improvements will likely drive additional gains in the productivity of the shale gas operation, the cost of production is expected to stay at the same level as the status quo or even drop over time. By balancing the incentives with a mandatory reduction on greenhouse gas emissions, corporations are driven to natural gas, a cleaner fuel, driving demand for natural gas and balancing the oversupply risk.

EHS Preservation – The risk associated the with the “opt out” aspect of the “most effective technology” policy is balanced with a phased in mandate for compliance with fines/taxes after the initial 2-3 year period. This approach ensures that operators take advantage of the incentives before they are forced to comply and that EHS is preserved across the industry not just for operators who “opt in”. As this is a more complex policy with a long term implementation strategy, there is a higher likelihood that implementation and monitoring will be more difficult.

Equitable Distribution – Again by phasing in fines for non-compliance, the equity issue for neighbors and land owners is alleviated in this comprehensive policy. This ensures that land owners and neighbors, regardless of the operator in their area, will realize the EHS benefits of the policy.

Political Feasibility – As there is little financial burden on the shale gas operators, the likelihood of adoption is high, but, since it is a multi-faceted, phased policy, objection to any one part of the policy could lead to the entire policy being rejected. In addition, the success of this policy relies on consistent administration and follow through which increases the riskiness of implementation. Finally, where there are similar policies domestically and abroad for portions of this policy, there is no precedent to a policy of this complexity being successful; which further increases the risk of success and moderates its political feasibility.

7.5.3 Policy Recommendations

Based on the evaluation of policy alternatives against the proposed policy goals, it can be seen that each of the alternatives has benefits and drawbacks. All of the alternatives are more favorable than the Status Quo on the EHS preservation aspect although not all can improve this aspect without significant degradation in economic efficiency. Therefore, it is concluded that the Status Quo is not an option when looking at the issue of shale gas extraction.

The Comprehensive proposal ranked highest among the remaining alternatives along all of the policy goals except for political feasibility where ranks second to the Most Effective Technology policy, due to its complexity and the longer term nature of the phased implementation. It is a close call among these two alternatives. It is our conclusion that the, more holistic and longer term impact of, the Hybrid policy warrants the potential risks.

The Comprehensive policy alternative, while more complex, is more aligned with successful energy policy and more effectively leverages public private partnerships to foster competition with in the marketplace and support innovation in more environmentally sustainable technologies for shale gas production. It is expected that the long term effects of this policy will continue to drive favorable environmental outcomes into the future, even should the administration discontinue the policy at some point.

Should the implementation risks associated with the Comprehensive policy be deemed too high, the Most Effective Technology policy is recommended as an alternative. It should be noted that, while it is expected that the initial impact of this policy will be positive, not all shale gas operators will be inclined to comply and without the checks and balances of the comprehensive policy, a sub-optimal position may be reached.

7.6 Environmental and Microeconomic Impacts of Policy Recommendations

The primary objective of the Comprehensive Environmental Policy is to drive technology adoption and support infrastructure development for the most environmental alternative for shale gas production. Based on the technical and microeconomic analysis, the solution the uses the "most effective technology" is that with natural gas a fuel and CO_2 as a fracturing fluid.

7.6.1 Tax Incentives to Offset Up-front Capital Investment

Based on the technology analysis, an up-front capital investment for brown field applications to convert operations for well cluster to natural gas and carbon dioxide was found to be in the neighborhood of $3,000,000. For green field applications, the difference in capital investment would be slightly less as the initial cost of the older technology would need to be taken into account and subtracted from the financial impact on the operator. The tax incentives tied to this value can be in the form of one-time tax credits at the time the equipment is purchased, or a cost per million cubic feet of natural gas over the life of the well. While the tax incentive over the life of the well cluster would offer a more economically feasible option for the public sector, a one-time credit aligned with the timing at which the cost was incurred would have a more favorable impact on the private sector and better support adoption. There are a number of variations which can be used to balance these interests. A partial up-front credit balanced with a per MCF credit over the life of the well cluster. Also, given the fact that there is a positive net present value (NPV) associated with the most effective technology option, it may be sufficient to offer a partial tax credit to stimulate adoption without offsetting the entire difference in investment.

7.6.2 Breakeven Carbon Price for Maximum Environmental Impact

After the capital investment incentive period of 2-3 years expires and to ensure adoption of the CO_2 fracturing option, a carbon tax on the less favorable alternative would be applied. This would ensure that the operating costs between the options are equalized. The target tax would need to be enough to bring operating costs of the CO_2 option to be equal or better than the LPG option. The tax may either be applied on the CO_2 emitted by the operation or on the natural gas produced using the less effective technologies. There are number of pros and cons to each approach. Taxing the CO_2 is the more accurate method as it taxes the actual environmental factor, however it raises the challenge of monitoring and verifying how much CO_2 is actually emitted. Also, because the CO_2 is emitted early in the operation, the tax burden is incurred by the operator all at once. While a tax on the natural gas is a less direct approach, it is easily auditable and operators already report how much is produced, so the enforcement would be less cumbersome. In addition, the tax is amortized throughout either part or all of the life of the well cluster which makes it more affordable to operators and aligns the tax to when they actually recognize the revenue. Table 28 demonstrates some carbon tax options which would bring the "natural gas/CO_2" option on par with that of "natural gas/LPG".

Table 28: Carbon Scheme for Recovering Economic Losses from CO_2 vs. LPG Fracturing

Policy Scenario	Breakeven Carbon Price**	% of Revenue*
Tax Applied to CO_2 (USD/ton CO_2e)		
Economic Recovery in 1 year	$628/ton	110%
Tax Applied to Produced Natural Gas (USD/MCF)		
Economic Recovery in 10 years	$ 0.47/MCF	11%
Economic Recovery in 15 years	$ 0.31/MCF	8%
Economic Recovery in 25 years	$ 0.19/MCF	5%

* This is the annual tax burden as a percent of revenue for the year(s) in which the tax is applied
**Based on 2,683,000 MCF annual production [133] and a price of $4.21/MMBTU for natural gas [122]

7.6.3 Research and Infrastructure Credits

Supporting the policy scheme targeted at operators, additional research credits targeted at developing technologies which further reduce the environmental footprint of shale operations would be offered. This would include the support of field testing of related technology with requirements to produce microeconomic and environmental impacts resulting from the research. Once technology resulting from this research is tested and proven to reduce the environmental impacts of shale operations, the core "most effective technology" policy would be updated to drive more rapid adoption.

In addition, credits could be introduced to build CO_2 infrastructure which would further reduce the price of CO_2 and reduce the disparity between LPG and CO_2 as fracturing fluids. This would allow the carbon tax to be phased out. This incentive would be for pipeline and CO_2 plant operators and should drive the building of an infrastructure to support the most effective technology over time.

7.6.4 Stimulating Demand

The final element of the policy approach is in stimulating demand for both natural gas as well as carbon sequestration among large carbon emitters such as large utilities and energy intensive industries. This is expected to increase the price of natural gas as well the supply of CO_2 for fracturing and thereby further bringing down the price of CO_2. This is expected to stimulate a market for commercial grade carbon dioxide that could be self-sustaining and would involve a series of carbon based policies for some of the largest emitting industries. To determine the nature of this scheme, a similar microeconomic approach, to the one used in this research, would need to be undertaken to ensure the carbon policy also has microeconomic viability. This would further enable CO_2 infrastructure development and help develop a self-sustaining marketplace.

7.6.5 Broader Economic and Environmental Benefits

US economic and environmental benefits

Based on the well cluster analysis, it can be seen that the use of natural gas for fuel and carbon dioxide as a fracturing fluid can yield both an environmental and economic benefit for operators provided increases in production are taken into account, and especially when fluid recycling is employed. When supported by a Comprehensive Environmental Policy, the potential benefits can result in a CO_2 marketplace the enables significant carbon sequestration in the industry. Using the scenario that includes the substitution of natural gas for gasoline and diesel for combustion, and CO_2 as a fracturing fluid, taking into account production impacts and fluid recycling; then extrapolating these results to encompass the 1,000 -1200 new wells to drilled annually across the entire Barnett Shale play [136] and the ~3,700 new wells to be drilled annually across the United States [137], operators can reduce the environmental impact of natural gas extraction and save the industry money of the life of their wells, as shown in Table 29.

Table 29: Extrapolation of Results Across Barnett Shales and all U.S. Shale Plays

	Impact across Barnett Shale Play	Impact across all United States Shale Plays
Annual Savings (USD)	$23,070,337,317	$71,133,540,060
CO_2 Reductions (tons)	47,565,437	146,660,097
NOx Reductions (tons)	19,944	67,086
CO Reductions (tons)	11,487	38,638
VOC Reductions (tons)	1,494	5,026
PM Reductions (tons)	657	2,1211

As demonstrated by the analyses, the economic benefits tied to LPG outweigh those of CO_2 in the substitution of water as a fracturing fluid, while the environmental benefits of CO_2 outweigh those of LPG. While both options drive economic and environmental benefits, driving the industry towards the safer, more environmentally friendly alternative requires the institution of policy that will incent the development infrastructure to drive down the price of CO_2 and create a sustained carbon economy. With the right type and duration of policy actions, a carbon economy can be developed that far outlasts the policy itself and encourages the capture and sequestration of carbon for years to follow.

Unlocking arid and water sensitive shales

In addition to improving the economics and environmental footprint of existing shale plays, an added benefit of waterless fracturing is unlocking additional shale plays that were previously infeasible either due to water scarcity or an under-saturation of the shale formation rendering it water sensitive. This not only unlocks a significant resource within the United States, but also provides a platform for countries like China, Mexico and South Africa that have a significant, characterized resource in very arid or water stressed parts of the country.[200] This could, in turn, have a significant impact on some of these developing nations' energy independence, or their dependence fuels such as coal and their greenhouse gas footprint. Again, for a country like China, that has a substantial GHG footprint this shift could significantly improve the global greenhouse gas profile and change the dynamics of the energy industry.[5, 215]

7.7 Conclusions and Recommendations for Future Work

When looking at the environmental remediation of oil and gas processes, it is important to understand the microeconomic implications of the proposed technologies and their impact on operators. Frequently, the more economic benefit that can be derived, the more open an operator is to implementing the technology. However, sometimes those economic benefits are realized over a period of time and an up-front capital investment must be made to realize the long term savings. In these cases, when the operator is unable to make the up-front investment and if the potential environmental benefits are significant enough, public policy can be implemented to lessen the financial burden on the operator and encourage adoption. Policy can also be used to neutralize economic discrepancies between less favorable technologies and encourage the maximum environmental benefit.

By applying principles similar to those used for energy policy to environmental policy, comprehensive policies addressing the various elements of the related environmental issues can be developed. In the case of shale gas production, a multi-pronged comprehensive policy which:

- offsets the capital investment hurdles for natural gas operated rigs and vehicles as well as CO_2 fracturing equipment;
- ensures that the economic discrepancy between CO_2 fracturing and LPG fracturing is eliminated;
- supports research and infrastructure investments; and
- stimulates the demand for natural gas and the supply of CO_2 from adjacent industries

can be developed. It is expected that this type of policy will stimulate competition and innovation in a way that sustains a market for CO_2 and enables more and more carbon sequestration in an economically viable fashion.

By extrapolating the environmental and micro-economic impacts of alternative technologies on a single well cluster in the Barnette shale play, it is estimated that public policy which enables the adoption of these technologies could result in a carbon reduction of over 146,000,000 tons of CO_2 and save the industry over $71,000,000,000.

It is further recommended, that additional research be conducted to further refine the impact category measures. This will enable more quantitative representations of how well each of the policy alternatives compares to the status quo along each of these categories. In addition, similar process analyses for operations in adjacent industries can be undertaken to further develop the demand stimulation aspect of the policy with various energy intensive industries. Finally, a more detailed analysis of the implementation process and how the proposed policy will be enforced can be undertaken to ensure the feasibility of the approach.

8 CONCLUSIONS

Environmental policy has historically generated a great deal of debate both among policy makers and within a number of public forums. As it typically takes the form of a carbon tax or carbon price levied on the private sector, it typically generates a great deal of opposition. In many cases, broad brush environmental policy is proposed which does not typically take into account the specific economics of a particular industry.

Using integrated process analyses, based on the lean six-sigma methodology and focused on the oil and gas industry, this research has demonstrated the micro-economic viability of several environmental health, safety and sustainability (EHSS) practices. It has also recommended alternate approaches to public policy to offset some of the hurdles of EHSS technology adoption in oil and gas. It demonstrates that by using the micro-economics of an industry to enable environmental improvements, policy can act in the benefit of all stakeholders involved and enable stronger public-private partnerships. Policy of this type, can drive innovation and competition and create a marketplace that encourages rather than discourages environmental preservation.

While out of scope for this research, additional industries may be analyzed using similar approaches to enable the development of successful, industry specific, public policy in the area of EHSS. When applied to adjacent industries, such as utilities and other large carbon producers, the proposed policy approach can be expanded to stimulate a broader carbon economy.

In addition, the impact of such a policy approach when applied globally, could stimulate a global reduction in carbon footprint while supporting the economic development of shale and conventional natural gas rich nation states. The unlocking of arid shales and the creation of virtual and physical natural gas and CO_2 pipelines could change the face of energy globally.

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