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Ensuring the Safe Production of Natural Gas



A Major Qualifying Project Report

Submitted to the Faculty of WORCESTER POLYTECHNIC INSTITUTE In partial fulfillment of the requirements for the Degree of Bachelor of Science

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Submitted to:

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Abstract

Growing demand for natural gas in the U.S. has led to an increase in hydraulic fracturing in the Marcellus Shale region of PA. The goal of this project was to recommend best practices to the U.S. Department of Energy for hydraulic fracturing. First, industry practices for well drilling, cementing, and casing were analyzed. A System-Theoretic Process Analysis was used to identify weaknesses that could lead to loss of wellbore integrity; and a blowout preventer system was designed to mitigate this hazard. Second, contaminants in hydraulic fracturing fluids were identified and a mobile onsite wastewater treatment system using reverse osmosis was designed to remove fracturing chemicals, radium, and solids. Lastly, recommendations were made to improve the safety of natural gas recovery.

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Executive Summary

In his 2013 State of the Union Address, President Barack Obama highlighted the role of natural gas development in increasing United States energy independence and elaborated on the future of energy policy in the United States. His Administration plans to continue speeding up new oil and gas permits. "I also want to work with this Congress to encourage the research and technology that helps natural gas burn even cleaner and protects our air and water," he added (ABC News, 2013). While the strategy to reduce dependence of foreign oil in the United States is a politically divisive topic, the U.S. government supports the continued development of natural gas. From all of the energy sources that the U.S. utilizes, 22% comes from natural gas, and the U.S. Energy Information Administration (**EIA**) estimates that the United States holds a total of 1,744 trillion cubic feet of recoverable natural gas reserves (GWPC, 2013).

Advances in harvesting technology have led to development of horizontal well drilling, called unconventional wells, which can produce significantly more natural gas than traditional vertical wells, called conventional wells. Natural gas production using unconventional drilling increased by about 65% from 5.4 trillion cubic feet per year [tcf/yr] in 1998 to 8.9 tcf/yr in the United States in 2007 (GWPC, 2013). This project analyzed shale gas production in the state of Pennsylvania, which lies in the Marcellus Shale region. This region extends 95,000 square miles throughout six states in the Northeastern United States and holds a total of 262 tcf of recoverable natural gas. Pennsylvania produced approximately 6.1 billion cubic feet per day [Bcf/d] of natural gas in 2012, amounting to approximately 9% of the total national production of 68.71 Bcf/d (U.S. EIA, 2013). As shown in Figure 1, natural gas production in Pennsylvania rose 69% in 2012 despite a reduction in drilling activity (PA DEP, 2013b).



Figure 1: Annual Natural Gas Wells Starts and Production in Pennsylvania (U.S. EIA, 2013)

During the lifespan of a well, the casing and cementing should maintain its integrity; therefore, many tests are run to insure the safety of the well. Possible failures and violations from casing and cementing are linked to blowouts and environmental impacts; therefore, research was needed to insure safe production of natural gas. The first project goal was a model of safety control structure in the Marcellus Shale through the System-Theoretic Process Analysis (STPA), in order to show the interactions of the processes involved within drilling. STPA, developed by Nancy Leveson of MIT, focuses on the control structure of a process to improve its safety. There are five parts that are defined in a STPA: system boundaries, system safety goals, accidents, hazards, and safety control structures. For this project, the system boundary was the cementing process in the Marcellus Shale within the context of the Federal, State, and local regulations. The system goal was to produce natural gas safely, and potential accidents related to the goal and hazards that could lead to the accidents were identified. A few of the accidents identified that related to the other goals of the project were blowout and environmental contamination. The hazards that could lead to these are loss of secondary control barriers, elements that provide a backup to primary barriers, and improperly handled hydraulic fracturing wastewater. For safe operation, a model of safety control structure was created, consisting of the Federal government, the State government, standard organizations, well owner, cementing service contractor, and testing lab. Requirements and constraints were imposed in order for the safety control structure to function with all of the different interactions involved.

The STPA performed for Marcellus Shale drilling identified the significance of a blowout preventer (**BOP**) to work effectively so that blowouts, such as the Deepwater Horizon accident, do not occur. Blowout preventers are used throughout the Marcellus Shale and serve the same purpose as subsea blowout preventers, albeit on a lesser scale. Due to their large size and increased technicalities, there is more room for research in offshore BOPs than onshore BOPs. For this reason, the main focus of this part of the project were subsea BOPs. The second project goal was to redesign a critical component of a blowout preventer to make it more reliable, which would be used to insure well integrity. A blowout preventer is a complicated system, in that there are many subsystems that work together, and there are many ways that it can fail. All of the components need to work well together in order for the BOP to perform properly and prevent a blowout. To begin the redesign of a critical component, general information on BOPs and their components was researched. The next focus analyzed the materials that are suitable for a subsea BOP, since there are constraints to the temperatures and loadings that the BOP undergoes. Then, a blind shear ram and its casing were redesigned. A blind shear ram is responsible for shearing the drill pipe and then sealing it. The redesign is more efficient in that the component was both smaller and lighter than models currently used in the industry, while still producing enough force to shear and seal the pipe. Compared to Cameron's and Shaffer's unboosted rams, the redesigned component is designed to perform at a higher shear force at 3,000 psi and generates 98.5% of the shear force of the larger Hydril ram. Therefore, the redesign is intended to generate force comparable to major manufacturers and can shear drill pipe regardless of axial position. In addition, since the redesign is about 20% lighter than current rams, this would reduce handling difficulty of the BOP stack. The project redesign represents a significant development over traditional rams.

The identification of environmental contamination as a hazard to the safe production of natural gas in the PA portion of the Marcellus Shale region led to the third project goal: design of treatment technology units for safe management of hydraulic fracturing wastewater, for reuse in fracturing operations in other wells. Hydraulic fracturing enhances the flow of natural gas into a wellbore, since the small and infrequent pores of the Marcellus Shale formation limits its permeability. Hydraulic fracturing

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promotes the economic recovery of natural gas from these formations. During hydraulic fracturing, well operators perforate the casing and cementing, and then pump fluid additives along intervals of the well in order to achieve the required pressure to induce fractures along the entire length of the lateral portions of the well. The fracturing fluids used in Pennsylvania are approximately 90% water, 9% sand, and 1% chemical additives. Each fracturing interval may require upwards of 0.5 to 1 million gallons of water (PA DEP, 2013b).

During and after the hydraulic fracturing process, the internal pressure of the shale formation causes the injected fracturing fluids and natural formation water to rise to the surface through the well casing. Oil and gas operators first pump hydraulically fractured wastewaters from the well site to lined pits or fracturing tanks located on-site. From there, operators either treat the wastewater on-site, transport it for treatment at an off-site facility, or ship it for disposal to a Class II underground injection well. For treated waters, operators can transport the wastewater to another plant for additional treatment, discharge it to surface waters, or reuse it at a different well site. According to the biannual waste reports from the Pennsylvania Department of Environmental Protection (**PA DEP**) Oil and Gas Reporting Website, operators reported the disposal of 636 million gallons of hydraulic fracturing wastewater from July 1, 2011 to June 30, 2012. Between the second half of 2011 and the first half of 2012, the percent of total wastewater managed for reuse in other hydraulic fracturing operations increased from 60% to 81%. The centralized treatment plant option decreased from 22% to 9.4%, and the injection disposal well option decreased from 18% to 9.1%. Although the United States Geological Survey (USGS) did not conclusively prove that underground injections cause earthquakes, they identified a link between the two. Two main factors that impact the management of hydraulic fracturing are transportation and water usage. Increased transportation leads to increased costs for oil and gas operators as well as increased risk of spills. Pennsylvania oil and gas operators must incur increased costs to send their hydraulic fracturing wastewaters out of state since the Pennsylvania brine disposal wells cannot accommodate most of the wastewater produced. A single horizontal well can require an average of about 5 million gallons of water during the hydraulic fracturing process, which can put a strain on local water resources. On the other hand, reuse within

drilling operations management decreases fresh water usage and wastewater transportation while not requiring as stringent water quality standards as for drinking water treatment or surface water discharge. Therefore, this project provides a preliminary design for a mobile, on-site treatment system for reuse of hydraulic fracturing wastewater in other fracturing operations.

Treatment technologies were then evaluated to find the most suitable processes for fracturing fluid. FracFocus, a chemical disclosure registry for natural gas wells in Pennsylvania, was used to gather information on the chemical constituents of fracturing fluids by county and operator. The top four additives found were biocide/disinfectant, breaker, corrosive inhibitor, and friction reducer/scale inhibitor. Next, a USGS study was used to determine the concentrations of radium and total dissolved solids present in the wastewater produced in Pennsylvania. Based on the data collected in the study, the total radium activity values present in hydraulic fracturing wastewater ranged from 39 picocuries per liter [pCi/L] to 18,045 pCi/L, and the median was 1,552 pCi/L. The total dissolved solids (TDS) data for produced wastewater from the Marcellus Shale in PA ranged from 1,470 milligram per liter [mg/L] to 358,000 mg/L, and the median value was 88,500 mg/L (Rowan et al., 2011). There was a large range in the data, because the hydraulic fracturing wastewater that rises to the surface initially consists of the same constituents as the injected fluid. However, over time, it shifts towards TDS and inorganic chemical compositions that reflect the geochemistry of the formation. The Occupational Safety & Health Administration (OSHA) Chemical Sampling Information (CSI) online database was used to determine if any of the chemical constituents in the fracturing fluids could be regulated due to occupational exposure limits. The Environmental Protection Agency (EPA) National Primary Drinking Water Regulation Maximum Contaminant Level, version 2 (MCL2), was used to determine if any of the fracturing fluid constituents should be regulated because of potential health hazards to surrounding communities. There were five chemicals included in this list that were present in the wells analyzed: acrylamide, chlorine or chlorine dioxide, chlorite, epichlorohydrin, and xylenes. The EPA also has the Contaminant Candidate List 3 (CCL3), which are chemicals and microorganisms being evaluated for possible regulation. Within the list were four of the chemicals present in the wells analyzed, which could be included in drinking water regulations in the future: benzyl chloride, ethylene glycol, formaldehyde, and methanol.

To choose the best mobile, on-site treatment, a total of nine technologies were evaluated using six criteria, such as contaminant removal and mobile capability, each with a common scale rating and a distinct multiplier based on importance. The technology that generated the highest score (26.5 out of 30) was reverse osmosis (**RO**). A mobile, onsite wastewater treatment system using reverse osmosis was designed to treat for fracturing fluid chemicals, radium, and total dissolved solids. Sedimentation and microfiltration (MF) were used as a pretreatment for reverse osmosis to remove sand, bacteria, organics, and oil and grease. The MF unit will operate in a pressure-vessel configuration with a dead-end flow mode, and the pressure vessels will contain hollow fiber membrane modules with ceramic membranes. The effluent from the MF unit becomes the influent of the RO system where it passes through two stages. Stage I consists of three pressure vessels, and stage II consists of two. Each pressure vessel contains six membrane elements, thus the entire system includes thirty elements total. The concentrate from stage I is disposed as waste and the concentrate from stage II is added to the influent of stage I. The wastewater system was designed to treat according to the reuse standards of one of the top ten oil and gas operators in PA. The brine waste was recommended for disposal by a Class I hazardous waste disposal well and the sand waste for reuse in other fracturing operations. In choosing the management method, the team considered its effect on health and safety.

The project recommended safer procedures for the blowout preventer and wastewater management design, as well as changes to current policy regulations. To improve the ability to seal wells and prevent accidents in emergency conditions, the following were recommended for BOPs: increase shearing ability, require two blind shear rams for high risk deep-water wells, and maintain focus on early kick detection and respond measures. To protect water quality in the Marcellus Region, the following three main categories of actions were recommended: require reuse of wastewater in other fracturing operations, classify wastewater as hazardous under the Resource Conservation and Recovery Act (**RCRA**), and monitor wasters and wastewaters to avoid

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contamination. By incorporating these recommendations into natural gas development, the process can be conducted in a safe and efficient manner.

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Authorship

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Rebecca Newman	Chapters 5, 7; Formatting
Jacquelyn Tupper	Executive Summary; Chapters 1, 2, 3, 5, 7
Lee Joan Villafuerte	Executive Summary; Chapters 5, 7; References

List of Acronyms

AMF	Automatic mode function
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BOGM	Bureau of Oil and Gas Management
BOP	Blowout preventer
BP	British Petroleum
BSR	Blind shear ram
CAS	Chemical Abstract Service
CBL	Cement bond log
CCL 3	Contaminant Candidate List 3
CET	Ultrasonic cement mapping tools
CFR	Code of Federal Regulations
CMT	Cement mapping tools
CPP	Casing potential profile
CSGS	Critical static gel strength
CSI	Chemical sampling information
CWA	Clean Water Act
CWT	Centralized waste treatment
DOE	Department of Energy
DOT	Department of Transportation
EHS	Environmental Health and Safety
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FFKM	Perfluorocarbon elastomer
FIT	Formation integrity test
FKM	Fluorocarbon elastomer
FRAC	Fracturing Responsibility and Awareness of Chemicals
FTD	Fault tree diagram
HMI	Human-machine interface

HNBR	Hydrogenated nitrile butadiene rubber
HTHP	High temperature high pressure
HVOF	High velocity oxy-fuel
IOM	Installation, operation, and maintenance
ISO	International Organization for Standardization
LEFM	Linear elastic fracture mechanics
LMRP	Lower marine riser package
LOT	Leak off test
MCL	Maximum Contaminant Level
MCL2	Maximum Contaminant Level, version 2
MCLG	Maximum Contaminant Level Goal
MF	Microfiltration
MIC	Microbiologically influenced corrosion
MRDL	Maximum residual disinfectant level
MRDLG	Maximum residual disinfectant level goal
MUX	Multiplex
NACE	National Association of Corrosion Engineers
NBR	Nitrile butadiene rubber
NF	Nanofiltration
NORM	Naturally occurring radioactive material
NPDES	National Pollutant Discharge Elimination System
NPT	Nonproductive time
OD	Outer diameter
OKGS	Oklahoma Geological Survey
OSHA	Occupational Safety & Health Administration
PA DEP	Pennsylvania Department of Environmental Protection
PEL	Permissible exposure limit
PLC	Programmable logic controller
POTWs	Publicly owned treatment works
RCRA	Resource Conservation and Recovery Act
RO	Reverse osmosis

ROV	Remotely operated vehicle
SCC	Stress corrosion cracking
SCP	Sustained casing head pressure
SCS	Safety control structure
SDI	Silt Density Index
SDWA	Safe Drinking Water Act
SG	Specific gravity
SPE	Society of Petroleum Engineers
STP	Standard temperature and pressure
STPA	System-Theoretic Process Analysis
TDS	Total dissolved solids
TT	Treatment technique
TWA	Time weighted averages
UIC	Underground Injection Control
UF	Ultrafiltration
USGS	United States Geological Survey
XNBR	Carboxylated nitrile butadiene rubber

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Chapter 1: Introduction

As the demand for energy in the United States continues to increase, more energy must be supplied either through domestic or imported energy resources to meet growing demand. By eliminating the nation's dependency on foreign energy imports, and focusing on the production of domestic energy, the United States will in turn create jobs and bolster the economy. Since his inauguration speech in January 2013, President Barack Obama has highlighted the importance of research and investment in American energy. The Obama Administration has since called upon Congress to establish a new Energy Security Trust, which would invest \$2 billion over the course of 10 years to promote research towards the future of domestic energy, including alternative energies and natural gas (The White House, 2013). Some of this money would go towards researching more efficient vehicles and lowering the carbon emissions produced from them. This plan would also commit to moving towards cleaner methods of electricity production including renewable energy, nuclear power, and natural gas production. Part of the plan for cleaner natural gas production includes safer, more reliable drilling methods to decrease environmental impacts, including fewer carbon emissions produced. President Obama's budget will invest more than \$40 million in research to insure the safe production of natural gas, and also introduce a \$25 million prize for the first natural gas combined cycle power plant to integrate carbon capture and storage (The White House, 2013).

Shale gas is one rapidly increasing form of natural gas in the United States that has become popular due to advances in drilling technologies and more efficient hydraulic fracturing procedures. There are several shale gas basins located across the country, with the biggest basin being the Marcellus Shale with a total area of about 95,000 square miles (GWPC and ALL Consulting, 2009). This is more than double the second biggest shale basin, the New Albany Shale, which is about 43,000 square miles. The Marcellus Shale spans six states in the Northeast, extending from New York south to Virginia and west to Ohio. Previously, shale gas production made use of vertical drilling, however, this limited the amount of shale gas that could be extracted from a basin. With the introduction of horizontal drilling technology, shale gas production has become more efficient, causing

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the natural gas industry to grow. Drilling companies have established well sites in the Marcellus Shale since 2005, and moving forward with shale gas production, it is important that they are following regulations to keep the well safe over its lifetime as President Obama has stated. If safeguards are not used properly, wells are prone to loss in integrity, which can lead to leaks, blowouts, human injuries, and negative impacts on the surrounding environment.

One goal of this project was to analyze regulation violations and failures that arise from casing and cementing in the Marcellus Shale. To maintain well integrity, it is necessary for drilling companies to perform various tests on the casing and cementing. These tests include making sure the well does not fail and can stand the pressures at each depth of drilling. It is also essential to make sure the piping does not corrode from the materials in the ground where the well is drilled, leading to a gas leak or a blowout. Although testing is not always mandated, it is in the best interest of the drilling companies to do so, since it costs more to remedy failures than to perform the tests. Also, keeping the environment safe for species and further generations should be a top priority for these companies. For this reason, this project includes a model of a safety control structure in the Marcellus Shale. This shows the connections between each process, from the well up to the federal government, to insure the safety of drilling.

Blowouts are also causes for concern at a well site, and blowout preventers are another way to insure the integrity of a well. Blowout preventers (**BOPs**) are used on land and in subsea wells, since a blowout can occur onshore and offshore; however, offshore drilling poses more risks compared to land-based petroleum production. Another goal of this project was to analyze and redesign a component of a subsea blowout preventer, since the two largest accidental offshore oil spills resulted from a failed BOP. Looking at previous spills, such as the Deepwater Horizon spill in April 2010 and the Ixtoc I spill in June 1979, assisted in the analysis. These preventers are complicated machines since they are big, heavy, and experience a wide variety of loads. For example, the blowout preventer that failed during the Deepwater Horizon spill was about 50 feet tall, weighed about 300 tons, and was located about 5,000 feet below the surface of the ocean. A blowout preventer is comprised of numerous parts and systems, and it is critical to make sure each part is working properly together to insure that a blowout does not occur. This

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part of the project included the redesign of a shear ram and its seal with the goal of increased efficiency while still operation at the desired performance specifications.

Hydraulic fracturing can generate upwards of four million gallons per well of polluted wastewater that can threaten drinking water supplies, rivers, streams, and groundwater quality in the Marcellus region. One objective for this project was to design a treatment system for hydraulic fracturing wastewater from the Marcellus Shale wells in Pennsylvania to protect water quality. This was done by understanding and quantifying the constituents of hydraulic fracturing wastewater; researching and analyzing the current methods of wastewater treatment in the region; and designing cost-efficient treatment processes to remove contaminants in the wastewater for reuse of the wastewater in other fracturing operations.

Chapter 2: Well Life Cycle

This chapter covers the life cycle of a well from beginning to end. The process starts by first finding a suitable well site and ends with the abandonment of the well. Drilling companies first hire scientists and geologists to help them locate a potential site. Once data have been gathered and show a potentially profitable amount of shale gas, the drilling begins. When this is complete, hydraulic fracturing is then used to rupture the shale rock formation after which the shale gas can be pumped up from the ground. Throughout the process, many tests are run to insure the integrity of the well. When all of the gas has been extracted and the well is dry, drilling companies then begin the cleanup procedure. Here the piping is removed and the well is then sealed.

2.1 Site Selection & Development

Before a well can be drilled, a suitable area of land must be found. There are a number of criteria for selecting a site. First, there must be enough shale gas to give a positive return on investment. Second, the gas must be accessible. Third, the location where the well is drilled must be near other infrastructure to allow for transportation. To help drilling companies make a decision, scientists and geologists are hired to find a location for a well site. During this process, they follow a series of steps to find an appropriate location, as shown in Table 1 (Oil Industry International E&P Forum and UNEP IE, 1997). Beginning with the least costly method, scientists look at regional surveys and surface geology reports to find a region that looks promising based on the geography. These regions are then analyzed further to find the optimal spot for a well site. Scientists then survey these specific areas from the air in a low-flying aircraft to pinpoint further locations, keeping in mind the criteria for selecting a site. Once these locations have been picked, geologists perform seismic surveys to find the shale formation, which leads to the exact location for the well to be drilled. Running these tests and then analyzing the data takes between a few weeks and a few months.

Once an area has been tested and is shown to be a promising drilling site, the question is raised whether a conventional or unconventional well should be drilled. When this is determined, companies are then able to move on to the next stage where the

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negotiating begins. A lease between the developer and property owner(s) must be signed, including bonus and royalty payments over the lifetime of an active well (PIOGA, 2013).

Activity	Potential Requirement on Ground
 Geological review: identify major sedimentary basins 	None
2) Aerial survey: favorable features, such as faults or anticlines, revealed	Low-flying aircraft over study area
 Seismic survey: obtain detailed information on geology 	Access to onshore sites and marine resource areas; Possible onshore extension of marine seismic lines; Onshore navigational beacons; Onshore seismic lines; Seismic operation camps
 4) Exploratory drilling: verify the presence or absence of a hydrocarbon reservoir and quantify the reserves 	Access for drilling unit and supply units; Storage facilities; Waste disposal facilities; Testing capabilities

Table 1: Steps to Find a Suitable Well Site(Adapted from Oil Industry International E&P Forum and UNEP IE, 1997)

The first steps once an area is ready for drilling are clearing the land for a well site and creating access roads and reservoirs to hold the large amounts of water present during drilling. Figure 2 shows an aerial view of the reservoirs and access roads of a Marcellus drilling site in Upshur County, West Virginia.



Figure 2: Marcellus Shale Gas Well Site, West Virginia (WV SORO, 2012)

2.2 Drilling, Casing and Cementing

When the land has been cleared and the access roads have been created, the drilling equipment is transported to the site and set up. The initial drilling stages are the same for both conventional and unconventional drilling. The terminology of unconventional and conventional comes from the way the gas forms underground (PIOGA, 2013). The Marcellus Shale is an unconventional formation because the gas stays trapped within the source rock. To access the shale formation, horizontal drilling must be implemented. Conventional extraction occurs when gas forms in a source rock and then migrates to areas of lower pressure (PIOGA, 2013). As a result of the easy access of the shale gas, vertical drilling is used. Figure 3 shows the steps in drilling a vertical well (Smrecak and PRI Marcellus Shale Team, 2012).

To begin, a rotating drill bit cuts down through the ground until the first aquifer is reached as seen in Step 1. At this point, the first stage of cementing and casing begins so that the aquifer does not get contaminated from the drilling. Aided by a guiding shoe, the casing is then lowered into the hole as seen in Step 2. Next, cement is poured down the casing into the annulus as seen in Step 3. After the cement has finished pouring, a wiper plug is pushed down the well by a mixture of drilling muds, which lubricate the drill bit and help make the drilling easier, to clear the casing of leftover cement as seen in Steps 4 and 5. This process of casing is then repeated, with some wells having more than five casings and others only using three casing strings as seen in Steps 6 and 7. The number of strings is dependent on the stability of the piping, the depth of the shale formation, and protecting the surrounding underground.

The Marcellus Shale formation lies between 4,000 and 8,500 feet under the crust and thus the length of a vertical well is between those values. The drilling process for a vertical well takes about a month to complete (Smrecak and PRI Marcellus Shale Team, 2012). After the vertical piping reaches and penetrates the shale formation, which throughout the Marcellus Shale region can be between 50 and 200 feet, holes are punctured into the casing to allow the hydraulic fracturing fluid to flow into the shale formation (GWPC and ALL Consulting, 2009). The holes are created with a perforation gun (Smrecak and PRI Marcellus Shale Team, 2012). After being led into the piping by

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wire lines, the perforation gun shoots out charges or projectiles into the casing which puncture the casing and cementing and create holes for the fluid. With thousands of gallons of a specially designed fracturing fluid (each drilling company having its own mixture of chemicals, sand, and water) pumped into the well, the shale formation is then fractured, thus allowing the gas to flow upwards through the piping. For a vertical well, the average fluid required is between 20,000 and 80,000 gallons (Smrecak and PRI Marcellus Shale Team, 2012). Figure 4 shows an example of the hydraulic fracturing process in a conditional well. After the hydraulic fracturing process is complete, a vertical well is in its production stage, and gas will flow up through the pipe until the well site is abandoned.



Figure 3: Steps of Conventional Drilling (Adapted from Smrecak and PRI Marcellus Shale Team, 2012)



Figure 4: Hydraulic Fracturing in a Conditional Well (not to scale) (Adapted from Harper and Kostelnik, 2011)

Drilling a horizontal well differs slightly from drilling a vertical well. With advances in drilling technology, engineers are now able to drill horizontally in the shale formation at the end of a vertical well, allowing access to much more of the shale gas formation. To drill a horizontal well, workers begin the same process as used to drill a vertical well. They drill straight down; however, they stop about 1,000 feet short of the shale formation (Smrecak and PRI Marcellus Shale Team, 2012). At this point, the drilling gradually changes direction, until it is horizontal. A mud motor, seen in Figure 5, allows workers to drill at the angle required for horizontal drilling, starting at 0° and ending at 90° (Harper and Kostelnik, 2011). The motor is driven by the pressure of the drilling fluid circulating down the piping, which allows the bit to rotate while most of the drill pipe remains stationary. Drillers steer the motor by aligning the angle of the motor to the direction they want to drill (Harper and Kostelnik, 2011). With this technology, companies are able to drill down vertically to the Marcellus Shale formation (between 4,000 and 8,000 feet) and then continue to drill between 2,000 and 6,000 feet horizontally, increasing exposure of the piping to the shale reservoir and leading to more gas production (GWPC and ALL Consulting, 2009).



Figure 5: Mud Motor (Adapted from Harper and Kostelnik, 2011)

Figure 6 shows a cross-sectional view of a horizontal well. The point where the vertical drilling stops and the directional drilling begins is called the "kickoff point." As in a vertical well, once the piping is complete, holes are punctured at the end of the casing, and hydraulic fracturing fluid is pumped down into the well to fracture the shale formation. However, the volume of fluid used in each type of drilling differs: a horizontal well uses between 2 and 9 million gallons of fluid, with an average of about 4 million gallons per site, whereas a vertical well uses between 20 and 80 thousand gallons per site (Smrecak and PRI Marcellus Shale Team, 2012). A horizontal well uses about 80 times more fluid than a vertical well due to the increased length of piping.

Conventional and unconventional drilling can be compared based on cost, space, and feasibility. For cost, the drilling company looks for a positive return on investment. To maximize profits, companies seek to minimize the cost of drilling and find formations that will remain active for a lengthy period of time to maximize production. Excluding the pad and infrastructure, a vertical well is about one-third the cost of a horizontal well; however, production is often less. Comparing the average cost per well, excluding the pad and infrastructure, a vertical well costs about \$800,000 and a horizontal well costs about \$2.5 million (GWPC and ALL Consulting, 2009). A horizontal well costs more since it requires more cementing and casing as well as a different type of drilling method; however, more gas can be extracted faster, leading to a more efficient system.



Figure 6: View of Horizontal Drilling (not to scale) (Adapted from GWPC and ALL Consulting, 2009)

In Western Pennsylvania, drilling companies have implemented vertical wells throughout the Marcellus Shale region because of the shallow location of the shale formation (PIOGA, 2013). These wells are not only limited to producing shale gas: they can produce oil as well, and can remain in operation for decades. Although there are advantages with the longevity and lower cost of conventional drilling compared to unconventional drilling, in some cases a horizontal well is needed to access the shale formation. For instance, a portion of the Marcellus region lies in the Appalachian Basin. Because of the mountainous geography, it can be hard to reach the shale formation with only a vertical well, and thus a horizontal well provides better access to the shale formations. In another shale region, the Barnett Shale (located in the Fort Worth area of Texas), drilling companies make use of horizontal drilling in the area under the Dallas-Fort Worth International Airport (GWPC and ALL Consulting, 2009). Because there is an airport right above the shale formation, companies implement horizontal wells to reach the shale without interfering with the airport infrastructure. While the geography around a well influences which type of drilling is used, the amount of land designated for a well site is also a consideration. After a shale location has been confirmed, the excavation process begins. A typical vertical well requires between 1.5 and 3 acres of land and a horizontal well requires between 3 and 6 acres (Smrecak and PRI Marcellus Shale Team, 2012). At a vertical well site, the pads are spaced about 1,000 feet apart (WV SORO, 2012). With multiple vertical well pads each taking up approximately 2 acres of land, the amount of land used is one of the biggest disadvantages in vertical drilling. Horizontal drilling technology allows companies to drill multiple wells from one single pad as shown in Figure 7, and this eliminates a lot of surface disturbance (WV SORO, 2012).



Figure 7: Surface Disturbance during Drilling; including Access Roads, Drilling Pads, and Pipeline Infrastructure (Adapted from WV SORO, 2012)

In Figure 7, the smaller white boxes indicate vertical well pads spaced 1,000 feet apart from the other wells. The sole yellow box in the middle shows a horizontal well pad, and the yellow lines indicate the multiple wells that can be drilled from this pad. With the spacing (1,000 feet) and number of vertical wells given (45) in Figure 7, the total amount of land required for this vertical well site is about 1033 acres, as shown in the following equations:

Area =
$$L * W = 9000 \text{ ft} * 5000 \text{ ft} = 45000000 \text{ ft}^2$$
 (1)
Conversion: 1 acre =
$$43560 \text{ ft}^2$$
 (2)

Area =
$$45000000$$
ft² * $\frac{1 \text{ acre}}{43560 \text{ ft}^2}$ = 1033 acres (3)

Since there is spacing between vertical wells, not all of the acreage is used. While over 1000 acres would be needed for 45 wells, about 19% of the surface is disturbed (WV SORO, 2012). The same amount of shale formation can be accessed with one horizontal well, and results in an overall surface disturbance of about 1% (WV SORO, 2012). The decrease in access roads, drilling pads, pipeline infrastructure, and excavation all results in a less costly and more efficient system. As previously stated, a horizontal well (excluding the pad and infrastructure) is about 3 times more expensive than a vertical well. However, implementing one horizontal well would result in substantial savings because multiple vertical wells are needed for the same gas production.

2.2.1 Pressure Management

Pressure management of a well is necessary for numerous reasons that have effects on the entire drilling process. Managing the pressure increases the integrity of the well, increases safety for operators, increases drilling speeds, and limits the nonproductive time of the well (Rehm *et al.*, 2008). For these reasons, pressure must be carefully controlled during the drilling process to have a safe and effective production well. Otherwise, the well will be prone to an array of potential issues ranging from lost production time to serious harm to humans and the environment.

The main reason companies invest in strict pressure management of their drilling process is to limit the nonproductive time (**NPT**) of the well. Improper pressure management is the number one reason for NPT and accounts for approximately 45% of the NPT (Rehm *et al.*, 2008). This loss of production time is typically the result of lost circulation and differentially stuck pipe, both of which are caused by pressure issues. Hence, stringent pressure control plays a role in consistent production and makes the well economically viable.

The other vital benefit of pressure management is an immense increase of well integrity and safety. A properly balanced well allows for better control of the drilling process and enhanced monitoring of well conditions on a real-time system (Malloy, 2007). This then facilitates the ability of the control system to properly predict, monitor, and neutralize a kick and prevents a blowout (Lyons and Plisga, 2005). As a result, the well is a safer place for operators to work and potential environmental harm can be avoided.

Proper pressure management can have effects within the wellbore that can increase the integrity of the well due to the relationship between pressure and casing (Rehm *et al.*, 2008). A properly managed well increases the pressure gap between the pore pressure and fracture pressure. As a result, the casing can now be better seated within the well and the total number of strings can be greatly reduced (Malloy, 2007). This increases the overall integrity of the well and can facilitate the cementing process around the casing.

Pressure management also has other influences on the integrity of the well not directly related to casing. High pressures within the well can reduce the effective lifetime of certain components, like seals. Once these components wear out, they are no longer effective at performing their intended duty (Malloy, 2007). This then allows for leak pathways, or even catastrophic failure of main well components. By properly managing the pressure in the well, the components will be able to operate within their functional lifespan.

2.2.2 Basic Pressure Control

The basis behind pressure control is to keep the well pressure while drilling within the gap between pore pressure and fracture pressure. If the pressure in the wellbore exceeds the fracture pressure, then the formation will crack. Once the formation cracks, there is a pathway for the drilling mud and fluids to escape, and there is a loss of circulation (Rehm *et al.*, 2008). If the pressure in the wellbore goes below the pore pressure, then a kick will occur. If this kick is not properly managed, then a blowout is inevitable (Rehm *et al.*, 2008). For these reasons, pressure control plays a vital role in well completion.

Typically, the well is circulated as a closed-system. This is accomplished through the kill and choke lines at a pump rate required to keep constant pressure (Lyons and Plisga, 2005). The kill and choke lines are part of the drilling spool on the blowout

preventer. Mud is pumped into the annulus of the well through the kill line. The mud is then circulated back to the surface through the choke line. At the top of the choke line is the choke manifold, which is a series of valves. These valves are open and closed as needed to maintain the constant pressure at the bottom of the wellbore. The mud then flows to the separator, where the mud and natural gas are separated. The natural gas is then sent off to be sold while the mud gets pumped back down the well (Malloy, 2007).

2.2.3 Methods of Pressure Management

Pressure is managed by two methods: reactive and proactive. Reactive management entails dealing with pressure problems, such as kicks, when they arise. With reactive management, the technology used for pressure management is in place, but not activated until a pressure problem occurs. On the other hand, proactive management uses pressure control techniques and technology throughout the drilling process. With proactive, drillers have better control of the entire well and receive advanced warning of potential incidents (Malloy, 2007). This means faster drilling and less NPT.

The most common method of proactive pressure management is constant bottomhole pressure. The main objective of this method is to maintain a constant pressure at the bottom of the wellbore (Malloy, 2007). This is typically needed because the density of the drilling fluid changes near the bottom of the well, so the hydrostatic pressure column becomes unbalanced. To compensate for this, the pump rate of the drilling fluid is increased and the return valves are tightened to restrict flow. This will then balance the pressure at the bottom of the wellbore.

Another pressure control method typically used is mud capping. With mud capping, two drilling fluids are used, one high density and one low density (Malloy, 2007). With this technique, highly viscous mud is pumped down the annulus. This mud provides a barrier around the annulus while providing a constant static pressure. The lower density fluid is then pumped down the well and used for drilling at the bottom of the hole.

2.3 Hydraulic Fracturing

Unconventional gas shales are fine-grained sedimentary rocks where the gas occupies the pore spaces in the rock, and also absorbs onto the surface of organic matter that comprises a significant amount of the shale (Tiemann *et al.*, 2012). In the United States, at least 21 major shale basins lay beneath the surface of more than 20 states. Recent assessments of natural gas located in the United States reported approximately 1,836 trillion cubic-feet of the resource, an estimated one-third from shale gas. In its 2011 Annual Energy Outlook, the U.S. Energy Information Administration forecasted a 21% increase in shale gas production from 25% to 46% of total gas production in the United States by 2035 (Tiemann *et al.*, 2012).

The Marcellus shale formation underlies about 60% of Pennsylvania, and it contains trillions of cubic feet of natural gas reserves. However, the limited permeability of this formation due to its small and infrequent pores restricts the flow of the natural gas into the wellbore. Natural gas can easily flow though pore sizes of about 200 micrometers; Marcellus shale pore sizes range from 0.05 to 0.2 micrometers (Lestz, 2011). In order to overcome this restriction, a process called hydraulic fracturing is used. This process aims to increase the permeability of the rock formation to allow for the retrieval of enough gas for the process to be economically feasible. The process of hydraulic fracturing has already been implemented in Texas for harvesting natural gas from the Barnett shale, which has similar pore sizes to that of the Marcellus shale. The Marcellus shale covers an area nineteen times larger than the Barnett shale, at 95,000 square miles compared to 5,000. However, the net thickness in the Barnett shale ranges from 100 to 600 feet as opposed to the 50 to 200 feet net thickness of the Marcellus shale. Although exact estimates of natural gas reserves from each of the two shales vary by source, the Barnett shale is estimated to contain about half of the natural gas present in the Marcellus shale.

Gas production companies use engineered models known as hydraulic fracture simulations to design hydraulic fracturing treatments. These treatments use characteristics of the target formation such as shale thickness and stress regimes to develop a network of fractures in the rock that lead to maximum gas production (Arthur *et al.*, 2013). Companies use computer simulators to optimize fracture simulation design. These

programs use inputted formation characteristics to create a model that predicts fracture patterns in the rock formation using mathematical formulas of fracture propagation. Engineers can alter parameters in these simulation programs such as the volumes of proppant, fluids, and additives to evaluate developing fractures. Companies can utilize a variety of different models to predict fracturing in the formations (Arthur *et al.*, 2013).

Hydraulic fracturing occurs after drilling and all of the stages of cementing and casing of the wellbore are completed. Tests are first performed to insure that the well and all necessary equipment are in safe working order and can withstand the operational pressures from the fracturing procedure. Next, operators lower a perforating gun on a wireline. An electrical current passed through the wire from above stimulates the tool to create a hole in the casing and cement to the surrounding shale formation. These punctures allow fluids to enter the fractures created from the fracturing procedure as well as the gas to flow into the wellbore during the production phase of the well. The hydraulic fracturing procedure is performed over intervals along a well. These steps in the process are shown in Figure 8. Vertical wells are usually only divided into one interval whereas horizontal wells can consist of 4 to 20 intervals. This is necessary in order to achieve the required pressure to induce fractures along the entire length of the lateral portions of the well (PA DEP, 2013a). Mechanical plugs separate the different intervals, which are removed after the fracturing stage.



Figure 8: Well Perforation and Subsequent Fracturing along Well Intervals (Halliburton, 2013b)

Specific sequences of fluid additives are used along each interval of the well. The Marcellus wells in Pennsylvania use a water-based fluid referred to as a slickwater frac, because it contains more water than sand and chemical additives. Each fracturing interval may require upwards of 0.5 to 1 million gallons of water. Although vertical wells use similar slickwater solution compositions, they use two to three times more water than a horizontal well interval. However, in total, horizontal wells use significantly larger amounts of water than vertical wells, because they have multiple fracturing intervals. The term slickwater refers to the friction-reducing agents present in the fracturing fluid that reduce the pressure needed to pump the fluid into the wellbore. These chemicals may result in a 50 to 60% reduction in pipe friction.

Each interval along a well is subjected to four main stages during the hydraulic fracturing process: an acid stage, a pad stage, a prop sequence stage, and a flushing stage. In the acid stage, several thousands of gallons of water mixed with a dilute acid are pumped into the well. This fluid clears cement debris in the wellbore and opens fractures near the wellbore by dissolving carbonate minerals. The acid stage aims to create an open channel for the flow of the fracturing fluids used in the other stages. The pad stage uses around 100,000 gallons of slickwater without proppant material. Filling the wellbore with this fluid opens the formation, aiding in the flow and placement of proppant material used in the following step. Water combined with a proppant, such as a fine mesh sand or ceramic material, is pumped into the wellbore during the prop sequence stage. This stage uses several hundred thousand gallons of water, and is divided into several sub-stages of pumping. These sub-stages differ in the diameter of the proppant material used, ranging from fine particle size to a coarser one. The mixture of water and proppant material employed in the prop sequence stage props open the fractures created by the prior fracturing operation. During the final stage, called the flushing stage, an adequate amount of fresh water is pumped through the well in order to remove the excess proppant material from the wellbore (PA DEP, 2013a). Figure 9 provides an overview of the hydraulic fracturing process.



Figure 9: Hydraulic Fracturing Process (Grandberg, 2013)

There are seven main categories of chemicals that make up the fracturing fluid used in the Marcellus shale fracturing operations. **Figure 10** shows an example of the volumetric composition of a hydraulic fracturing fluid used in deep shale natural gas production. The components of each fracturing fluid vary on a well-to-well basis, and do not always include a chemical additive from every category. Two of these categories, dilute acid solutions and friction reducing agents, were described above. Biocides or disinfectants stop the growth of bacteria in the well that might disrupt the hydraulic fracturing procedure. A scale inhibitor reduces the precipitation of particular sulfate and carbonate minerals in the well. Iron control/stabilizing agents keep iron present in the formation water in a soluble form. Corrosion inhibitors prevent the steel well casing from degrading. Gelling agents thicken the fracturing fluid in order to facilitate the transport of the proppant material throughout the well. Cross-linking agents are sometimes added to improve the function of these gelling agents, which are later broken down in the fracturing stage by the addition of a breaker solution. This allows for an ease of removal of the material from the wellbore without carrying back the sand/proppant material (PA DEP, 2013a). Enhancements in the hydraulic fracturing process have focused on the characteristics of the chemical fracturing fluid additives and the propping agents in those fluids such as sand.



Figure 10: Hydraulic Fracturing Fluid Volumetric Composition Pie Chart (Kohl, 2013)

2.4 Well Abandonment

A well may be abandoned when it ceases to produce natural gas or is no longer being operated. When the well is ready to be abandoned, the operator has to file for the abandonment of the well with the state (Indiana General Assembly, 2010). When filing, the operator must provide a plan of how the well will be sealed and the materials that will be used. This plan then needs to be approved by the state commission, before any plugging can occur. Once approved, the operator will plug the well using the API standards. Upon completion of sealing and abandonment, the operator must then submit a final report of the exact methods and materials used.

Typical well sealing procedure involves filling the well with cement. In most cases, the cement is common water based cement, which must meet API standards. However, some special cement is needed based on the classification of the well

(Technology Subgroup of the Operations & Environmental Task Group, 2013). Wells that experience high exposure to salt, high pressure, or high temperature, need to be sealed with specialized cement. These cements have additives in them to combat the issues associated with the certain classification of the well. In addition to cement, wells are generally filled with drilling mud in locations where the cement is not required. Recent technology has also improved the well sealing sequence. Mechanical steel plugs are now available that can be used in conjunction with cement to reinforce the seal of the well.

There are environmental concerns that may arise over the integrity of the abandoned well. Over time, well casings might deteriorate and cracks in the cement can develop due to the pressure buildup of gases (Bishop, 2013). This now provides potential pathways for methane migration. Methane migration is the movement of methane gas from underground to new locations. The methane could potentially seep into fresh water supply, or reach the surface, causing environmental damage. The potential effects of such an event on human health and the environment are currently inconclusive.

Chapter 3: STPA of Natural Gas in the Marcellus Shale

3.1 Introduction to STPA

System-Theoretic Process Analysis (**STPA**) is a process analysis technique based upon control systems theory that was developed by Nancy Leveson, a Professor of Aeronautics and Astronautics at MIT. The model uses an accident investigation analysis that looks to ascertain the reasons for an accident in order to design safer engineering systems, rather than focusing on the cause of the accident to assign blame (Leveson, 2011). Leveson argues that event-based accident models fail to consider adaptation over time, human error, social and organizational factors, and system accidents and software errors (Leveson, 2011). STPA overcomes these limitations by considering the safety control structure itself because failure events result from inadequate control. Additionally, STPA directly identifies accidents occurring from interactions among components, inadequate management decision-making, and structural deficiencies in the organization rather than simply component failure (Leveson, 2011).

3.2 Application of STPA to Natural Gas Industry in Marcellus Shale

The STPA process begins with defining system boundaries. For this analysis, the natural gas extraction process in the Marcellus Shale was considered within the context of the federal, state and local regulations. The next step is to define the system safety goal, and accidents and hazards for the system. An accident is defined as an undesired or unplanned event that results in a loss. Losses include any loss unacceptable to stakeholders, which can be loss of human life, injury, property damage, and environmental pollution (Leveson, 2011). A hazard is a system configuration or set of conditions that, together with a particular set of worst-case environmental conditions will lead to an accident (Leveson, 2011). The system safety goal for this project was to produce natural gas safely and without environmental contamination. To identify accidents for the system, the group brainstormed a list of events unique to the process that could cause loss of life, injury, property damage, or environmental pollution. Accidents common to most industries, such as falls or electrocution, were omitted from the analysis. The list of accidents is presented in Section 3.2.1. Once the list of hazards was developed,

conditions responsible for causing each accident were researched and incorporated into the list of hazards in Section 3.2.2.

3.2.1 Accidents

The most catastrophic accident identified for the well system was a blowout, which is the uncontrolled release of hydrocarbons. Consequences of a blowout can be severe, including loss of life, complete loss of well assets, and environmental contamination. The next accident identified was loss of zonal isolation resulting in communication between different formations. Additionally, surface release of contaminants was considered. The complete list of accidents is shown below:

- Level 1: Complete Loss of Well Control
 - A1-1: Surface blowout
 - o A1-2: Sub-surface blowout
- Level 2: Loss of Zonal Isolation
 - A2-1: Groundwater contamination
 - A2-2: Formation damage
 - A2-3: Annular gas migration
 - A2-4: Sustained casing head pressure (SCP)
- Level 3: Surface release of environmental contaminants
 - o A3-1: Spills
 - o A3-2: Leaks
 - A3-3: Discharges

3.2.2 Hazards

The first hazard identified for the well system was the loss of primary well control elements. A primary well control element is one directly exposed to formation pressure, including the cement sheath, production tubing, and packers. The hydrostatic fluid pressure that balances the formation pressure and prevents influx of formation fluids was also considered a primary barrier. Secondary barriers are those that provide backup to primary barriers, and their failure was classified as the second hazard. The third hazard related to surface and water contamination due to improperly managed hydraulic fracturing wastewater.

- H1: Loss of primary well control barriers
 - Loss of hydrostatic barriers
 - Cementing failure
 - Production tubing failure
 - Packer failure
- H2: Loss of secondary well control barriers
 - BOP failure
 - Wellhead seal failure
 - Casing leakage
 - Christmas tree failure
- H3: Improperly handled hydraulic fracturing wastewater
 - Inadequate treatment
 - Loss of retention pit integrity
 - Transportation system failure

3.2.3 Organizational Structure and Interactions

Once the system boundaries, safety goals, accidents and hazards were defined, the next step was to develop a model of the Safety Control Structure (**SCS**). The safety control constraints are the rules that must be imposed on the system to insure safe operation under all conditions. The implementation of the safety constraints was by the safety control structure, which is displayed in Figure 11. Using research on natural gas extraction and interviews with industry representatives, a Safety Control Structure for natural gas extraction was developed. The SCS developed for natural gas extraction in the Marcellus Shale is shown in Figure 11.



Figure 11: Safety Control Structure

The same methodology used to develop the SCS was used in the development of the requirements and constraints on each entity identified in the SCS. The constraints that each entity identified in the Safety Control Structure must exert on the system to insure safe operation are discussed below.

The role of the Federal Government is to insure that natural gas extraction is completed in a safe and environmentally friendly manner on a nationwide scale through the establishment of regulatory bodies and through federal laws. The two main federal laws are the Safe Drinking Water Act (**SDWA**) and Clean Water Act (**CWA**), which regulate the disposal of wastewater by means of underground injection or surface water discharge. Under the SDWA, the Underground Injection Control (**UIC**) Program was initiated to prevent contamination of drinking water sources through the regulation of underground injection. However, the Energy Policy Act excludes hydraulic fracturingrelated activities from the SDWA except when diesel fuels are used. In 2009, the Fracturing Responsibility and Awareness of Chemicals (**FRAC**) Act was presented to Congress. Through the FRAC Act, the U.S. Environmental Protection Agency (**EPA**) would have authority over hydraulic fracturing activities under the SDWA, and the companies would be required to disclose hydraulic fracturing chemical constituents. It has been reintroduced to Congress, with the vote to be decided (as of April 2013).

There have been other actions to obtain more information on hydraulic fracturing, for example, President Barrack Obama initiated the "Blueprint for a Secure Energy Future" in 2011. Through this "Blueprint," the U.S. Department of Energy (**DOE**) Secretary identified recommendations on safety practices for public health and the environment through improved practices in shale gas production. Currently, EPA is conducting a study regarding the impacts of hydraulic fracturing on drinking water, with the release of the final report expected in 2014. Furthermore, the EPA regulates some aspects of hydraulic fracturing under the CWA. The effluent guidelines under the CWA prohibit on-site direct discharge of the hydraulic fracturing wastewater in U.S. navigable waterways (U.S. EPA, 2013d). If there is a direct discharge from unconventional drilling practices, then the discharge is subject to the EPA National Pollutant Discharge Elimination System (NPDES) permitting process as recorded in 40 Code of Federal Regulations (CFR) parts 122 through 125 and Part 435 (U.S. EPA, 2013f). If the hydraulic fracturing fluid waste is indirectly discharged via a Publicly Owned Treatment Works (**POTWs**), then the waste is regulated under the EPA General Pretreatment Regulations as recorded in 40 CFR Part 403 (U.S. EPA, 2013f). On the state level, some states have started requiring the disclosure of hydraulic fracturing fluid chemicals in order to more accurately monitor potential water contamination. There are ongoing changes to regulations on shale gas extraction, and there will be continued improvement as more analysis is conducted on potential effects.

The role of the State Government is to establish regulations that govern the natural gas extraction process, and enforce these regulations through state-level regulatory bodies. Currently, the standards for cementing and casing of wells in Pennsylvania are being revised by the Bureau of Oil and Gas Management (**BOGM**). The standards currently in place include language that "1) Allow affective control of the well at all times; 2) Prevent the migration of gas or other fluids into source groundwater; 3) Prevent pollution or diminution of fresh groundwater; and 4) Prevent the migration of gas or other fluids into source standards is to make them more specific to insure the structural well integrity through proper

casing/cementing. Current Pennsylvania standards that protect the environment from oil and gas wells can be found in *The Pennsylvania Code: Chapter 78. Oil and Gas Wells: Subchapter C. Environmental Protection Performance Standards.* The state is also responsible for issuing well permits.

Standards Organizations are non-government, private entities that establish standards and recommendations for best practice within the industry. The American Petroleum Institute (**API**) and the Society of Petroleum Engineers (**SPE**) are specific to the petroleum industry, but other standards organizations, such as American Society for Testing and Materials (**ASTM**), International Organization for Standardization (**ISO**), and National Association of Corrosion Engineers (**NACE**) publish recommendations and standards for the petroleum industry. It is important to note that because of the variability in downhole conditions, establishment of drilling procedures and design of wells to meet standards alone does not necessarily produce a safe design.

The well owner or well operator is the entity that serves as the overall manager and decision-maker of a drilling project. The operator commonly has the largest financial stake in the project (Schlumberger, 2013). The well operator is responsible for the well throughout its entire life cycle, beginning with obtaining well permits, and continuing through design, contracting and supervision of service contractors, and well abandonment. Oversight of the service contractors is typically accomplished by on-site representatives, often referred to as the "company man".

Service Contractors execute the plan for well construction developed by the well owner. Examples of service contractors include the drilling contractor, who owns and operates the drilling rig, and the cementing contractor, who executes implementation of the cement job. Service contractors may offer their services at a fixed daily rate, or as a turnkey operation, which may involve the assumption of significant risk (Schlumberger, 2013). The testing laboratory, which conducts specified testing services of cement slurries, may be considered to be a sub-entity of the cementing contractor. In the SCS, it is presented separately for clarity.

The well construction process consists of all steps of the well development life cycle, including processes for site selection, drilling, casing, cementing, hydraulic

fracturing, and production. The responsibilities of each entity within the SCS for natural gas development in the Marcellus Shale are summarized below:

Federal Government

• Insure that natural gas extraction is completed in a safe and environmentally friendly manner on a nationwide scale through the establishment of regulatory bodies

State Government

- Provide adequate resources to state-level regulatory bodies
- Establish regulations that govern the natural gas extraction process
- Issue well permits
- Enforce regulations

Standards Organizations

- Determine best practices and report findings
- Establish testing practices

Well Owner

- Responsible for obtaining appropriate well permits from regulatory bodies
- Operate in accordance to governing regulations
- Maintain control of well
- Design of well
- Contract and supervise implementation of service contractors
- Maintain well integrity over lifetime of the well

Service Contractor

- Complete drilling plan as specified by well owner
- Complete casing plan as specified by well owner
- Complete cement job as specified by well owner
- Provide testing services specified by well owner

Testing Laboratory

- Conduct specified testing services of cement slurries
- Provide test results in a timely manner

3.2.4 Identification of Focus Areas for Analysis and Design

The casing and cementing processes were selected for further analysis because of their contributions to hazards H1 and H2, loss of primary and secondary well control. Casing and cementing are well suited to the further application of STPA, because they are designed and installed as a process. The extension of STPA to the casing and cementing process can be found in the next chapter. The proper management of hydraulic fracturing wastewater was selected for further analysis, based off of the hazards in H3. Current management methods were analyzed, and a treatment design along with better management and handling methods are recommended in Chapter 5. A blowout failure was also a critical element identified in the initial analysis as contributing to hazard H2, loss of secondary well control. The physical components of a BOP are not processes, however, and are therefore not well suited to the application of STPA. Based on traditional failure analysis methodologies, which are well suited to component failures, the redesign of a blind shear ram BOP is presented in Chapter 6. A sub-sea operating environment was chosen due to the additional challenges, but many of the results and lessons learned in the design are fully applicable to a surface BOP such as those used in the Marcellus Shale.

Chapter 4: STPA of Casing and Cementing

This chapter presents relevant background information on the casing and cementing processes in the context of STPA, and identifies key failure mechanisms and interactions between entities, which directly influence the execution of the process. The casing and cementing process is implemented once a section of the well has been drilled. Casing and the surrounding cement sheath work together to insure wellbore integrity and zonal isolation. The casing serves as the primary conduit for fluid flow within the well, and the cement sheath seals the annular space around the casing while providing reinforcement and corrosion protection.

4.1 Introduction to Casing

Casing is the steel pipe that lines the borehole of a well and becomes a permanent part of the well once cemented in place. Pipes that can be removed from the well are collectively referred to as tubing. Casing comes in segments, ranging from 20 to 40 feet. When these segments are screwed together using threaded connections, the assembly is referred to as a casing string. The casing of a well serves three main functions: maintaining the structural integrity of the borehole, keeping formation fluids out of the borehole and keeping borehole fluids out of the formations (Byrom, 2007). Additional functions of casing include:

- 1. Preventing collapse or cave-in of the borehole
- 2. Serving as a foundation to support wellhead equipment.
- 3. Serving as a high strength flow conduit to surface for both drilling and production fluids
- 4. Protecting groundwater from contamination by drilling, fracturing and production fluids
- 5. Providing safe passage for running wireline equipment
- Allowing isolated access to selectively perforated formations of interest (Rahman and Chilingarian, 1995)

Historically, casing standards were set by the American Petroleum Institute (**API**). This role has been increasingly shared with the International Organization for

Standardization (**ISO**). Although most of the current ISO standards are adaptations of the API standards, they have not gained the same widespread use, and API standards remain dominant in the North American petroleum industry (Byrom, 2007). The API standards classify casing according to its method of manufacture, grade of steel, coupling method, dimensions and length (Cholet, 2008). It is convention to refer to casing by its outer diameter (**OD**) and nominal weight per foot, which is the theoretical calculated weight per foot for a 20 feet length of threaded and coupled casing joint.

4.1.1 Types of Casing

Casing is categorized into four different types, based primarily on functionality and depth. Aside from the four primary types of casing, most well completions include other important elements, such as liners and packers, to maximize production potential and minimize cost.

Conductor, or stove casing, is typically the first casing string cemented in place, and is therefore the largest, outermost casing. The conductor casing serves primarily to prevent the cave-in of unconsolidated formations near the surface, and to isolate shallow ground water. It may be used to support wellhead equipment, or simply cut off at the surface after the surface casing has been set. The conductor casing is not designed to be shut-in, or sealed using the BOP, and is therefore not capable of holding integrity under such pressures. To prevent contamination of shallow water sources, the hole for the conductor casing is either drilled using air or freshwater based drilling fluids, or driven into place like a structural pile (API, 2009). The proper setting depth of the conductor casing may be determined by soil bearing tests and coring, which determine the structural stability of the soil. A rule of thumb when determining the depth of conductor casings, in absence of soil tests, is to follow established practice in the region that has been shown to be effective (Byrom, 2007). A typical onshore well will use between 40 to 500 feet of conductor casing, depending upon geological conditions. Diameters vary from 7 to 20 inches. Generally, the deeper a well is, the larger diameter conductor casing it will use (Rahman and Chilingarian, 1995). In the Marcellus Shale, companies typically employ a 15-1/2 inch diameter conductor casing set to a depth of 40 feet (Anonymous, 2012).

Much like conductor casing, surface casing is primarily used to prevent the collapse of unconsolidated shallow formations, and to isolate freshwater-bearing formations. The surface casing, however, is set in a competent, consolidated formation, and is capable of holding pressure. For this reason, the BOP is most commonly installed on the surface casing string. For onshore wells, the surface casing is usually cemented to the surface. Cementing protects fresh-water formations from contamination, and forms a structural connection between the casing and formation (Lyons and Plisga, 2005). Setting depths for surface casing vary from a few hundred feet to as deep as 5,000 feet. Sizes of the surface casing vary from 7 to 16 inches in diameter, with 10 and 13 inches being the most common sizes (Rahman and Chilingarian, 1995). In the Marcellus Shale, companies typically employ an 11-3/4 inch diameter surface casing set to a depth of 700 feet (Anonymous, 2012).

Also called a protection string, intermediate casing is usually set to allow for drilling to total depth by isolating troublesome formations such as lost-circulation zones, zones with abnormal formation pressures, corrosive zones, or easily fractured shales or salt sections. Depending on sub-surface geology, the well may require two or more intermediate strings to reach total depth (Lyons and Plisga, 2005). Typical lengths for intermediate casing are between 7,000 to 15,000 feet and diameters range from 7 to 12 inches. It is common for the intermediate casing string to be hung from the surface casing as a liner, and cemented up to 1,000 feet from the casing shoe, but longer cement columns are sometimes needed to prevent buckling (Rahman and Chilingarian, 1995). In the Marcellus Shale, companies typically employ an 8-5/8 inch diameter surface casing set to a depth of 2000 feet (Anonymous, 2012).

Production casing is the casing string through which the well is produced and is usually the last casing string to be set in the well. The function of production casing is to provide zonal isolation between producing zones and other subsurface formations (API, 2009). The size of the production casing depends on the expected production rate from the well, with higher production rates requiring larger production casing strings. Common sizes range between 3 and 7 inch outside diameters (Serene Energy, 2012). In the Marcellus Shale, companies typically employ a 5-1/2 inch diameter production casing set to a depth of 7000 to 8000 feet (Anonymous, 2012).

In addition to the primary types of casing, there are other elements used to implement a casing string that warrant mention. The first is a liner, a string of casing that does not extend to the top of the well and is instead suspended inside the next largest casing string using a liner hanger (API, 2010). These devices are connected to the last casing string by setting slips or through expansion of the hanger against the inner wall of the previously set casing. Unless the liner is tied back to the surface, there is no need for an inner casing string above the hanger, which can greatly reduce the amount of casing required to complete the well. Liners are usually set to isolate troublesome sections of the well or producing zones, and for the economic benefit realized by reducing the amount of casing needed (Rahman and Chilingarian, 1995). Both intermediate and production casing are commonly set as liners. A scab liner is used to repair existing damaged casing and may be cemented or sealed with packers, or tied back to the surface, as shown in Figure 12.



Figure 12: Various Liner Types (Rahman and Chilingarian, 1995)

Packers are mechanical elements used to seal an annulus. There are many types of packers, and they are classified by use and retrievability. The two most common types of packers are production packers and inflatable packers. Production packers, or test

packers, are set in cased holes between the production tubing and the cased hole, which allows for controlled production. Production packers are typically set through forced extrusion of an elastomeric element (Schlumberger, 2013). Inflatable packers are typically set in open or cased holes, and are set by filling an elastomeric bladder with fluid, the expansion of which seals the annular space.

4.1.2 Joints

Joints are used to connect lengths of casing together to form the casing string. The process of connecting two lengths of casing is referred to as "making-up the joint." The amount of torque applied to make-up the joint has a direct impact on its sealing ability. Too little torque and the joint could leak, and too much torque can damage sealing surfaces and introduce large stresses into the sealing geometry that promote corrosion. There are many options available to the casing designer regarding the type of connection between lengths of casing. There are three main categories of connections:

- Coupling The most common connection type, a coupling has male threads on pipes connected by a female threaded coupler or collar. The end of the coupling that is installed during manufacture is called the mill end. The other end is referred to as the field end, as it is assembled in the field as the casing is being run.
- Integral An integral connection consists of pipe with two distinct ends. One side is fitted with male threads, called the pin end, and the other end is fitted with female threads, called the box end. Due to the internally threaded female threads, the casing must be thicker at that end. The increased wall thickness in this case is called an upset. Upsets may be internal or external, depending on if the inner or outer diameter is increased to accommodate the increased thickness. Most casing is externally upset to maintain a consistent inner diameter.
- Weld-on For a weld on connection, a threaded end is welded onto the pipe instead of being cut into the pipe body itself. This type of connection is most common on casing of large diameter (20" and larger), due to difficulty in cutting threads consistently (Byrom, 2007).

Within each category of casing connection types, there are various threadforms. Threadform refers to the actual geometry of the threads cut into the pipe, which is the cross-sectional shape of each individual thread. The threads also differ from one another in pitch, depth, diameter, and a number of other parameters. API 10 and 8 round thread forms are common, but there are many specialized threads for a given application (Lyons and Plisga, 2005). Aside from the standard connections, many companies offer premium connectors, typically used when additional features not found in standard connectors are needed. These additional features include larger clearances or less upset, increased sealing ability, and faster thread makeup. An example of a premium connector for thick walled casing is shown in Figure 13. Features of this particular connector include metal-to-metal seals for gas-tight sealing under load, a torque shoulder for accurate power-tight make-up, and flush ODs and IDs for minimal reduction in diameter.



Figure 13: TPCP TP-FJ Premium Connector (Byrom, 2007)

The seals achieved by the threaded connections are either interference type or metal-to-metal type. Interference seals require the use of pipe lubricant, referred to as "pipe dope", to seal completely. These connections are not recommended for use in gas well applications because improper application of the sealant during makeup or aging degradation over time has the potential to cause gas leakage (Byrom, 2007). Metal-tometal seals are formed when a tapered surface on the pin and box contact each other in compression. For metal-to-metal seals to be effective, the surfaces must be defect free. It is therefore very important that connections are not damaged during handling and correct make-up torque is used. Secondary elastomeric seals are sometimes used in addition to metal-to-metal seals to keep gas or corrosive fluids out of the threads.

4.2 Overview of Casing Process

The casing process begins with the design of the casing string, a complex optimization problem that requires careful consideration of many variables, including economics, safety, borehole stability, well completion aspects, and applicable regulations. Prior to beginning the casing design, important information such as fracture gradients, formation pressures, temperature profiles, maximum anticipated surface pressures, and produced fluid composition should be gathered (Hansen, 2013). The design process begins with the selection of the production casing size and depth by a petroleum engineer working alongside a geologist. With the depth and diameter of the production casing known, the borehole size and rock bit diameter are selected. From here, diameter selection of casing strings and boreholes proceeds in a bottom-up approach (Lyons and Plisga, 2005). Proper clearance between the casing stings and borehole must be maintained to promote good cementing.

With casing diameters determined, the next task is selection of the setting depth for each string. Many parameters influence the setting depth of casing, and most are out of control of the designer. These parameters include formation fluid pressures, fracture gradients, borehole stability problems, regulations, company policy and a company's experience in the area (Byrom, 2007). After the initial casing plan has been determined, it may be modified as the well is drilled based on measurements and data, such as drill logs, cuttings analysis, and analysis of pressures and drilling loads (API, 2009). Excluding

problem zones and regulations, the primary design criteria are the pore and fracture pressure gradients. While drilling, the drillers must maintain the pressure in the borehole between the formation pressure (also referred to as pore pressure) and fracture pressure, with an added safety margin on each parameter. Although this is explained in more detail in the section on pressure management, it plays an important role in casing design and setting depth.

To illustrate how casing set depth is determined based on pore and fracture pressure gradients, Figure 14 shows pore and fracture pressures verses depth for a theoretical well requiring the use of intermediate casing to reach a total depth of 12,000 ft. Starting at the bottom of the well, a mud density of 1.3 specific gravity (**sg**) is sufficient to contain the pore pressure plus the safety margin. However, at a depth of approximately 2,000 ft., a mud of 1.3 sg exceeds the kick margin. Therefore a string of casing must be set at that depth for drilling to continue from 2,000 feet to 12,000 feet. It is worth noting that the majority of wells drilled in the world have simple, linear pore and formation pressure gradients (Byrom, 2007).



Figure 14: Casing Depth Selection (Byrom, 2007)

Another important aspect of casing design is consideration of the loads applied to the casing and the resultant tri-axial stress. In service, casing will be subjected to burst loads, collapse loads, and tangential loads. Stress within the casing is composed of three principle components: axial stress (longitudinal), hoop stress (tangential) stress, and radial stress. Burst loads are applied when pressure inside the casing is greater than pressure external to the casing, such as during fracturing. Collapse loads are the opposite, and typically occur when the wellbore is empty and at atmospheric pressure. Collapse and burst loads result in hoop and radial stresses within the casing. Axial loads are caused by gravitational, frictional and buoyancy forces acting on the casing. These loads impose axial stress within the casing (Maurer Engineering Inc., 1996). The axial stresses imposed by tensile or compressive loads have an effect on the collapse and burst strength of the casing string. Tensile loads have the effect of increasing burst strength while decreasing collapse strength, compressive loads increase collapse strength while decreasing burst strength. This effect is shown quantitatively in Figure 15 for $7^{"} - 23$ lb/ft N-80 casing. In practice, loading calculations for casing are highly complex, and are often performed by computer programs making use of formulas outlined in API Bulletin 5C3.



Figure 15: Interaction of Axial Loads with Collapse and Burst Strength (TH Hill, 2010)

Proper material selection plays a vital role in the maintenance of well integrity, and is therefore a critical step in the design of a casing string. The two most important parameters involved in material selection for casing is the materials yield strength and corrosion resistance. The standard API Material designation encompasses both of these parameters. Casing and wellbore tubular grades are designated by a letter followed by a number, with the letter representing the composition of the steel, and the number approximate minimum yield strength of the material in ksi (1000 psi). The most common steels for casing include H40, J55, K55, N80-1, N80Q, and P110, with N80 being used most frequently (Renpu, 2011), and a comparison of their mechanical properties is shown in Table 2.

Grade	Yield Strength (ksi)		Tensile	Total
	Minimum	Maximum	Strength (ksi) Minimum	Elongation %
H-40	40	80	60	0.5
J-55	55	80	75	0.5
K-55	55	80	95	0.5
N-80	80	110	100	0.5
M-65	65	85	85	0.5
L-80	80	95	95	0.5
C-90	90	105	100	0.5
C-95	95	110	105	0.5
T-95	95	110	105	0.5
P-110	110	140	125	0.6
Q-125	125	150	135	0.65

Table 2: Mechanical Properties of API Casing Grades (Adapted from API Spec. 5CT/ISO 11960)

The borehole environment can be extremely hostile to steel, often containing Cl⁻, $HCO_3^-Mg^+$, CO_2 , and H_2S , all of which can corrode the cement sheath and the casing, possibly compromising wellbore integrity (Renpu, 2011). Materials have been developed which can resist the effects of some corrosive environments. For example, an L80-13Cr steel is well suited to an environment containing carbon dioxide, while grades like T95 and C95 are suited for environments containing H₂S (Renpu, 2011).

4.3 Introduction to Cementing

Once a string of casing has been landed, it is cemented into place. During this operation, referred to as primary cementing, cement slurry is pumped down the inside of the casing and is circulated back up through the annular space between the casing and formation (API, 2009). Proper cementing of the casing is critical to well integrity, and has been referred to as "the most important operation in the development of an oil and gas well" (Lyons and Plisga, 2005). The cement job serves three primary purposes: (1) zone isolation and segregation, (2) corrosion control, and (3) reinforcing formation stability and casing strength. For the cement job to be of high quality it must completely block the annular space and form a good bond between both the formation and the casing (Renpu, 2011).

Primary cementing is often a two-part process that uses a lower density "lead" cement followed by a higher density "tail" cement of higher compressive strength (API, 2009). The low density of the lead cement prevents fracture of the formation, and the higher density cement is used provide effective zonal isolation. In the Marcellus Shale, the high formation fracture pressures allow for completion of most cement jobs using a single density cement slurry (Anonymous, 2012). The primary cement job is typically conducted by service contractors, such as Halliburton or Schlumberger, using specifications developed by the well operator.

In addition to primary cementing, there are secondary or remedial operations, such as squeeze cementing and plug cementing (Lyons and Plisga, 2005). During squeeze cementing (sometimes called a squeeze job), pump pressure is used to inject cement slurry into a problematic portion of the well (Halliburton, 2013a). Squeeze cementing is a multi-purpose operation, and can be used to seal lost-circulation zones, repair casing leaks, and, most commonly, to remedy a deficient primary cement job. Plug cementing is a common operation used to seal portions of a well, and involves placing a volume of cement slurry over a larger volume of wellbore fluid (Halliburton, 2013a).

4.3.1 Cement Slurry Composition

Most wells use Portland-type, silicate based cement, often referred to as basic oil well cement and classified by the API. The primary constituent of Portland cements is

hydraulic calcium silicates, which hardens through reaction with water. Hardened silicate cement is built up from highly irregular grains of different minerals (Van Mier, 1997). The API classification of basic oil well cements by recommended use is shown in Table 3. In addition, there are also nonsilicate, resin-based or latex cements available for wells with challenging downhole conditions, such as high temperature and high pressure (**HTHP**), that could compromise the quality of the cement job (Lyons and Plisga, 2005). These are referred to as special oil well cements, and may be thixotropic (shear thinning), expanding or have increased corrosion resistance compared to standard API cements. Type H cement is commonly used for wells in the Marcellus Shale (Anonymous, 2012), and is appropriate for use from the surface to a depth of 8,000 feet (2,440 m) as manufactured.

			Туре		
Grade	Appropriate Well Depth (m)	Common	Medium Sulfate Resistance	High Sulfate Resistance	Remarks
А	0~1830	1	-	-	Common cement
В	0~1830	-	1	1	Sulfate-resisting cement
С	0~1830	1	1	1	High-early-strength cement
D	1830~3050	-	1	1	Medium-temperature medium-pressure conditions
Е	3050~4270	-	1	1	HTHP conditions
F	3050~4880	-	1	1	Super HTHP conditions
G	0~2440	-	1	1	Basic oil well cement
Н	0~2440	-	1	1	Basic oil well cement

Table 3: Uses of API Cement Types (Renpu, 2011)

A neat cement refers to a mixture of only cement and water, but in many applications the properties of the neat cement slurry must be modified for the specific application. The properties of basic API cement classes can be modified to meet certain performance requirements through the addition of additives and admixtures. Additives and admixtures exist for modifying each of the critical cement properties discussed in Section 4.3.2. For example, accelerants and retardants are used to modify thickening time, and lightening or weighting admixtures, can be used to change the density of the slurry (Renpu, 2011). Other additives include corrosion control elements such as hydrazine, and radioactive tracers.

4.3.2 Cement Slurry Properties

Proper slurry design is crucial to execution of a successful cement job, and encompasses many aspects, many of which are dependent on the well in question. The constraints and goals of the cement job determine which properties are most critical. For example, density control is paramount for a well with a narrow margin between pore pressure and fracture pressure. Properties that should be considered for every well are referred to as primary or critical slurry properties. Properties that not critical for most applications (but certainly can be in some wells) are collectively called secondary properties. Properties commonly considered to be primary are slurry density, thickening time, rheology, filter loss, stability, set compressive strength, and fluid compatibility. Secondary properties include set permeability, static gel strength development, mechanical properties other than set compressive strength, and expansion and shrinkage.

<u>Slurry density</u>– Achieving the correct cement slurry density, or specific weight, is critical to the cementing operation. Just as in drilling operations, the density of the cement slurry must be high enough to prevent the influx of formation fluids, but not so high as to fracture exposed formations. Fluctuations in the slurry density have an adverse effect on almost all slurry properties, and can lead to loss of well control (API 65-2). In most cases, the densities of all the neat slurries of API cements are high enough to cause most exposed formations to fracture, and are generally much higher than the density of drilling fluid. It is therefore necessary to lower the density of nearly all cement slurries (Lyons and Plisga, 2005). This can be accomplished through various means.

The first method used to reduce density is to use a higher water-to-cement ratio. However, this is limited by the API standards governing allowable water-to-cement ratio ranges. If the ratio of water-to-cement is too high, the cement strength will be reduced when it sets, and there will be voids due to excess liquid in the cement column. If the ratio of water-to-cement is too low, the slurry can be too viscous to pump, and there can

be voids of dry cement in the column (Emerson Process Management, 2013). The reduction in cement density is normally accomplished through the addition of low specific gravity solids to the slurry (Lyons and Plisga, 2005). This gives a much greater range of control when compared to modifying the water-to-cement ratio. Some examples of common additives used to reduce slurry density include bentonite, diatomaceous earth, solid hydrocarbons, and expanded perlite. If these additives cannot reduce the cement slurry below the level needed not to fracture the formation, nitrogen aeration of the mud column above the cement slurry may be used. It is also important to consider the effects of downhole temperature and pressure on the density of the cement. High pressures downhole can lead to compressibility effects in some slurry, resulting in higher densities downhole than at the surface (API 65-2).

In modern cementing systems, the density of the slurry is measured continuously for better process control. This is typically accomplished through means of a coriolis densometer, but radioactive densometers are still used. Both instruments are discussed further in Section 4.4.2 on process control equipment. Density can also be measured through means of a mud balance, which is a fixed volume cup on a balance scale.

Thickening time – As cement hydrates, the slurry continuously thickens until it is no longer pumpable and then sets in place. It is important that thickening time is known before the cementing operation begins so that all work can be done within the window between mixing and setting. If the slurry has not reached the proper location before setting, the quality of the cement job can be compromised and surface equipment can be damaged. Thickening time is a function of the class of cement, additives and admixtures, and the temperature and pressure in the location where the cement is placed (Lyons and Plisga, 2005). In general, higher temperatures and pressures greatly decrease the thickening time for a given slurry. Thickening time (T_t) is typically expressed in hours, and is defined as the time it takes the slurry to reach a consistency of 100 Bc (Bearden unit of consistency) (Renpu, 2011). The thickening time for the cement should be longer than the time needed to complete the cementing operation, and typically includes a safety factor ranging from $\frac{1}{2}$ to 2 hours depending on well complexity (Lyons and Plisga, 2005). Well operators are cautioned not to use excessive safety factors in thickening time design, as it can lead to a higher potential for formation influx before the cement has set.

(API 65-2). Thickening time is measured using a pressurized consistometer, which simulates downhole temperature and pressure conditions.

<u>Rheology</u> – Rheology refers to flow deformation behavior of the slurry under an applied shear stress. Viscosity (a measure of the resistance of a fluid to deformation by either shear stress or tensile stress), is one of the most important aspects of the rheology of a cement slurry. The viscosity of the cement slurry effects the pumping requirements for the slurry and the ECD of the cement slurry during placement. A slurry with a viscosity that is too high can cause formation fracture and loss of circulation (Lyons and Plisga, 2005). Similarly, if the viscosity is to low, the slurry will not be able to efficiently displace the drilling fluid, leading to contamination and poor cement job quality (Renpu, 2011).

Measurement of viscosity can be accomplished using a marsh funnel. The marsh funnel is a cone with a short tube attached at the bottom. A sample of cement is loaded into the top of the cone, and the measured viscosity of the fluid is a function of the time it takes for the cone to empty. This time is often referred to as the marsh funnel time, or MF.

<u>Filter loss</u> – Filtration control additives are added to cement slurries to limit the loss of water from the slurry to permeable formations. This is important for several reasons. First, it prevents hydration of formations containing water sensitive formations that could be damaged. Second, filter loss additives minimize the increase in slurry viscosity as cement is placed in the well, as well as insuring there is sufficient water to be available for cement hydration (Lyons and Plisga, 2005). Some examples of filtration control additives include synthetic and natural polymers, copolymers, latex, and dispersed bentonite (API 65-2).

<u>Slurry Stability</u> – Slurry stability is comprised of two aspects. The first is free fluid behavior, which may also be referred to as bleeding behavior. Free fluid occurs when water drops out of the slurry and forms a continuous phase. Excessive bleeding can cause nonhomogeneous cement density, uncontrolled gelation, and changes in set strength and other properties. Excessive bleeding behavior can also lead to the formation of water channels in the cement job, compromising annular sealing integrity. This problem can be

particularly serious for horizontal sections of wells (Renpu, 2011). For wells where there is a potential for flow, control of free fluids is critical for a successful cement job (API 65-2).

Sedimentation of the cement slurry leads to a higher concentration of solids in the lower sections of the well, and reduced concentrations in upper sections of the well. Areas with a high concentration of solids have increased gelation, and areas with low solids concentration have reduced strength and higher permeability (API 65-2). It is therefore important that the slurry has properties that are sufficient to control flow zones at both the top and bottom of the cement column.

<u>Set compressive strength</u> – Compressive strength is a measure of a materials ability to withstand compressive stresses. For brittle materials like concrete, when a compressive stress in excess of compressive strength is applied, the material is crushed. Engineering stress is typically presented in the following form:

$$\sigma = \frac{F}{A} \tag{4}$$

Where σ , the stress, is equal to the force (F) divided by the area (A).

Portland type cements, without any type of aggregate added to the slurry, are most commonly used for well cementing. The lack of aggregate limits their compressive strength to a range of 200 to 3,000 psi. A set compressive strength of 500 psi has long been considered acceptable in the industry; however, recent studies have shown that the compressive strength needed for bearing the casing is very low, at approximately 100 psi (Renpu, 2011), and the API considers cement to be a barrier element upon developing 50 psi of compressive strength. The set compressive strength of cement slurry is a function of water-to-cement ratio used, the curing time, the curing temperature, and the curing pressure, as well as any additives used. Typically, compressive strength increases as curing time, temperature and pressure are increased. The use of accelerators, such as calcium chloride, also tends to increase set compressive strength. Basic compressive strength is tested by allowing a number of sample cement cubes to cure for a specified amount of time, and then placing them into a compressive strength testing machine. The average compressive strength for the samples is then reported as the compressive strength of the set cement (Lyons and Plisga, 2005).

Another vital aspect of set strength is the bond strength between the cement and the borehole, and the cement and the casing. For acidizing and fracturing operations, failure typically occurs at these interfaces, rather than in the cement itself. A high strength of the set cement typically correlates with high consolidation strengths between cement sheath and borehole wall and between cement sheath and casing (Repu, 2011). Due to difficulties in recreating downhole conditions, there is no standard test for consolidation strength. However, a shear bond strength test has been developed, where the cement slurry is allowed to cure in the annulus of two concentric steel cylinders, and the force needed to separate the cylinders can be obtained experimentally. This gives some measure of the strength of the bond between the casing and the cement.

<u>Fluid compatibility</u> – Fluid compatibility is an important aspect of all drilling operations, whether it be compatibility between two fluids, or between a fluid and the formation. Two materials are considered compatible if contact between them does not result in an adverse physical or chemical change. For cementing operations, the interaction between the cement slurry and any other fluid in the wellbore is usually the most important consideration.

<u>Set permeability</u> – The permeability of set cement is a measure of the ability for migration of liquids and gases through the material. Fluid flow through a porous material, such as set cement, is governed by Darcy's Law. In petroleum engineering, Darcy's law is commonly expressed in the following form:

$$Q = \frac{kA}{\mu} \left(\frac{\partial P}{\partial L}\right) \tag{5}$$

Where Q is the flow rate, k is the relative permeability of the material (usually given in millidarcies), A is cross sectional area, and $\frac{\partial P}{\partial L}$ is the pressure change per unit length of the material.

Cement permeability is typically no higher than 12 mD, and with additives can be reduced to the order of fractions of millidarcy. Even with high cement permeability, the timescale of annular gas migration through a continuous cement column is large. Depending on the length of the cement column and differential pressures, displacement of uncombined or free water in the pore throats of the cement matrix can take several hundreds or thousands of years (API 65-2). This does not eliminate permeability as a concern, as migration typically occurs through channels or high permeability pathways within the cement.

Static gel strength development – During cementing operations, maintenance of the primary barrier to flow from the formation is very important. During the initial cementing, this primary barrier consists of the hydrostatic pressure of the slurry column, which acts to counteract the formation pressure and prevent flow. As the slurry starts to set, it gains cohesive strength. This results in a steady decay of hydrostatic pressure. When the hydrostatic pressure has been reduced to a point equal to the pore pressure, the slurry is said to have reached its critical static gel strength (CSGS). It is important to note that CSGS is only a function of the slurry density, and to achieve a higher CSGS, the overbalance pressure on the potential flow zone must be increased. A static gel strength of 500 lbf/100 ft² is generally accepted by industry as the point at which gas cannot freely percolate through cement (API 65-2). If the calculated value of CSGS is lower than 500 lbf/100 ft², then there is a potential for gas to enter the wellbore while the cement is setting. In this case, the CSGS must either be increased, or the time which the static gel strength remains below 500 lbf/100 ft² must be minimized. This time period is referred to as the critical gel strength period (CGSP), and for wells with a high potential for flow, a maximum CGSP of 45 minutes is recommended (API 65-2).

<u>Mechanical properties</u> – The mechanical properties of set cement, exclusive of compressive or sonic strength, are typically considered to be secondary properties. These mechanical properties include Young's modulus, Poisson's ratio, tensile strength and cohesive strength. Cements that perform better under the complex in-situ loading experienced by the casing and cement system tend to have a low Young's Modulus, high tensile strength and high Poisson's Ratio (API 65-2).

<u>Expansion and Shrinkage</u> – As Portland cement hydrates, its volume is reduced unless it has access to external water. Under certain wellbore conditions, such as tieback casings or at liner over laps, there is a potential for this reduction in volume to occur. The cement shrinkage may be internal (leading to an increase in porosity and therefore gas influx during hydration), or external (which may lead to loss of annular sealing ability).

Expansion additives may be added to the slurry, but care must be taken to avoid excessive expansion, which is also detrimental to the sealing ability of the cement sheath (API 65-2).

4.4 Overview of Cementing Process

The objective of the cementing process is the successful implementation of the planned cement job. In the field, the key components of the process are the equipment and the personnel executing the job. The equipment can be further broken down to surface equipment and downhole equipment. The functional objective of the surface equipment is to deliver an accurate cement blend to the well, and the functional objective of the downhole equipment is to insure proper placement of the slurry. A hierarchical representation of the cementing process system is shown in Figure 16.



Figure 16: Hierarchical System Representation of the Cementing Process

4.4.1 Surface Equipment and Process

The cementing process begins at the surface with cement in bulk, powdered form. Dry additives can be added to the cement at this time (Lyons and Plisga, 2005). This cement is typically stored in bulk pneumatic conveying units, but can also be stored in hoppers and gravity fed to the recirculating mixer. For pneumatic conveying, jets of
pressurized air are used to pick up the cement powder and transport it to a mixing unit, which is referred to as a recirculating mixer or blender. When precise control of cement delivery rate is needed, special bulk conveying equipment may be used, such as the Halliburton steady-flow separator shown in Figure 17.



Figure 17: Halliburton Steady-flow Separator (Halliburton, 2013a)

As bulk cement enters the recirculating mixer, it passes through the mixing head. It is here that the bulk dry cement is combined with water and previously mixed cement slurry. High velocity water jets in the mixing head, combined with large volumes of recirculated cement, are used to provide adequate and uniform wetting of the cement powder.

After passing though the mixing head, the cement passes into the mixing tank. The mixing tank serves to further blend and de-aerate the slurry, so that the final product is as homogeneous as possible. From the mixing tank, a portion of the cement is pumped back into the mixing head, and another portion of the cement is sent to the downhole pumps. Another example of a recirculating blender combined with a cement hopper can be seen in Figure 18. Note that the assembly is mounted on a skid and includes a control panel and several electric motors for agitation and pumping purposes.



Figure 18: Cutaway Schematic of Halliburton RCMIII Mixing Head (Halliburton, 2013a)



Figure 19: Recirculating Blender (Lyons and Plisga, 2005)

Downhole cementing pumps are positive displacement pumps, typically of duplex or triplex plunger type. Positive displacement pumps offer many advantages for

downhole pumping applications. With positive displacement pumps, discharge volume is dependent only on the speed on the pump, not on discharge pressure. This allows for fairly precise control of the volume of cement pumped into the well. Downhole pumps are typically powered by diesel engines. For actual applications, one or more pumps are used to provide flexibility and redundancy during operations.



Figure 20: Halliburton HT-400 Pump (Halliburton, 2013a)

Cement is introduced into the well by means of a cementing head, which is also referred to as the plug container. The plug container holds the top and bottom wiper plugs. These plugs serve to separate the slurry from the drilling mud, preventing contamination.

4.4.2 Process Control Equipment

The computerized controller is the center of the modern process control system. The controller takes feedback from the process, provided by various sensors and instruments, and implements a control algorithm based on deviation (error) from the process set points. The controller then provides an actuation signal to control devices, such as the control valve on the water supply to the mixing head. By varying these parameters, the controller insures that the cement matches the consistency set point. For implementation of sequential tasks, a Programmable Logic Controller (**PLC**) is used in addition. User interface is provided by a control panel or a computer program. Densitometers monitor cement slurry density, one of the most critical process parameters. In the past, nuclear densitometers were very common. These instruments, however, had many drawbacks, such as high monetary costs due to licensing, transportation and disposal (MicroMotion, 2009). Due to the drawbacks of nuclear densitometers, many companies have been towards increasing use of non-nuclear densitometers making use of the Coriolis effect to measure both density and flow rate. Feedback from the densitometers is used to control the input rates of water and bulk cement.



Figure 21: Schematic of the Micro Motion Meter Used in the Cementing Process

Metering of chemical additives and admixture is another vital aspect of the cement process. As discussed earlier, additives and admixtures modify the critical cement properties to match those needed for a successful completion. The chemical metering system provides precise additions of chemicals to the slurry.

4.4.3 Downhole Equipment

Guide shoes are a tapered fitting attached to the first casing string that goes downhole. They function as a guiding device of the casing to keep the string in the center of the hole as the casing string is lowered deeper into the well (Schlumberger, 2013). They also absorb and deflect impact with rock ledges and washouts as the string is lowered to minimize damage that can occur to the casing liner and prevent sidewall cavein. Once Downhole, the guide shoes then enable fluid circulation around the tip of the casing string for mud conditioning and cement placement (Halliburton, 2013a). A guide shoe can be seen in Figure 22, showing how the tapered tip for guiding and how it fits into the casing string.



Figure 22: A Guide Shoe Attached to a Casing String (Halliburton, 2013a)

Centralizers are fitted onto casing strings to insure that the casing is centered in the borehole during the cementing process. If casing strings are cemented off-center, there is a chance that the cement will create an imperfect seal with the formation, which will weaken the integrity of the cement protection (Schlumberger, 2013). Centralizers, like the one shown in Figure 23, help to insure that the cement sheath is of uniform thickness and forms an adequate protective barrier. Centralization also prevents differential sticking of the casing, and reduces the risk of contamination and channeling during the cementing process (Transocean, 2013).



Figure 23: A Bowspring Centralizer (Transocean, 2013)

Scratchers are devices for cleaning gelled mud and filter cake from the wall of the wellbore when the casing string is inserted downhole. The cleaning of the wellbore that this device induces allows for a better bonding surface of the cement to the wellbore wall (Halliburton, 2013a). The scratchers are mainly composed of a steel band with wire brush fingers extruding from the band. With movement of the casing, the wire fingers scrape the caked mud from the wellbore and effectively create a cleaner surface for a better cement job (Schlumberger, 2013). An example of a scratcher can be seen in Figure 24. The circular fitting in the image is the band that is inserted into the wellbore and the extruded wires from the band represent the fingers that provide the cleaning.



Figure 24: A Mechanical Scratcher (Halliburton, 2013a)

Float collars are installed near the bottom of the casing string above the guide shoes. Float collars consist of a small piece of casing with an internally fitted check valve (Schlumberger, 2013). The purpose of this devise is to prevent back flow of cement slurry after the pumping has stopped. Without the float collar, the cement slurry pumped down the annulus would reverse direction and flow up through the inner diameter of the casing (Halliburton, 2013a). An example of a float collar fitted in a casing string can be seen in Figure 25, where the dark grey object in the center is the check valve that prevents back flow.



Figure 25: Float Collar in a Casing String (Halliburton, 2013a)

4.5 Verification of Wellbore Integrity

Once the cement job has been completed, it must be evaluated to determine if it was successful. The API recommends a three part analysis and evaluation procedure: (1) completion of a material inventory, (2) review of data collected prior to and during the cement job, and (3) direct evaluation of the cement. A material inventory should be conducted before and after the cement job to insure that the correct amount of cement and additives were used during the cement job. Differences in actual quantities of material used and those specified by the cement job plan can be a first indication of problems.

The data collected during the cement job execution can be used to confirm that the job was completed in accordance with design. The data can also be compared to predicted data to provide verification of placement, and is useful for investigating the cause of failures for cement jobs. Job data can be a useful tool for designing future cement jobs in the same area, providing insight into particular challenges in a given formation (API 65-2). To gain a complete picture of the quality of a cement job, all of the available well information must be thoroughly reviewed. This information includes not only the job execution data discussed above, but also drilling reports, drilling fluid reports, cement design and related laboratory reports, and open-hole log results (API, 2009).

To verify the integrity of a well, a series of tests are run. One way this is done is by testing the cement. There are various ways to test the cement, with the most common being Cement Bond Logs (CBLs), Cement Mapping Logs, (CMT), Ultrasonic Cement Mapping Tools (CET), and Ultrasonic Imaging Logs (USI, RBT) (Crain, 2013). Some companies that specialize in the sale of cement bond logs to drilling companies are Baker Hughes and Halliburton. Each company has their own cement bond log tools, but overall they are standard from company to company, in that they are used to evaluate the effectiveness of cementing operations (Halliburton, 2013a). These tools utilize one omni-directional transmitter and two or more omni-directional receivers to emit and receive acoustic signals from the well at various depths, and these signals indicate the quality of the cementing (Halliburton, 2013a). As shown in Table 26, the sound travels from the transmitter – which is indicated by the white box at the end of the tool – through the pipe and cementing until it reaches the mud (Crain, 2013). The signal then changes direction and is transmitted to the receivers, which are indicated by the maroon boxes. These signals are then processed and inspected to verify the integrity of the well.



(Crain, 2013)

The data gathered in a CBL include the amplitude measured in millivolts [mV] and the attenuation measured in decibels/foot [db/ft] (Crain, 2013). An example of the data received from a Cement Bond Log can be seen in Figure 27 The log is related to the depth of the well, so the data further down the log correlate to the measurements taken further down the well.



Figure 27: Cement Bond Log (Halliburton, 2013a)

There are three ways to evaluate CBL results: amplitude, attenuation, and bond index. Ideally, the amplitude should be low and both the attenuation and bond index should be high (Crain, 2013). Both the amplitude and attenuation are shown in the bond log. With this information the bond quality, or bond index, can be calculated with the recommendation of at least 0.8 or 80% for critical parts of the well. This is to make sure that the integrity of the well stays high and will not result in a break in the piping, thus contaminating the surrounding underground. The following equation shows how to calculate the bond index at any point in the well.

Bond Index =
$$\frac{A}{A_{max}}$$
 (6)

Where: A is the attenuation at any point on the log; A_{max} is the maximum attenuation throughout the whole log.

The maximum attenuation can be found from the cement bond log where the amplitude is the lowest, and from here the bond index can be calculated (Crain, 2013). For example, if the bond index is calculated to be 0.5 for a certain depth that means that 50% of the annulus at that depth is filled with good cement. Cement Bond Logs are just one of the ways to measure the integrity of the well and this is specific to the cementing portion of the well. Other tests are run to measure pressure, temperature, and flowback, and generally the same companies, Halliburton and Baker Hughes for example, can supply drilling companies with these tests too.

Although the material inventories and job data review are important, conducting a successful hydraulic pressure test remains the only way to completely confirm well integrity. The most common pressure tests are the leak off test (**LOT**) and the formation integrity test (**FIT**). A leak off test is usually conducted after drilling below a new casing shoe. To conduct the test, the well is shut in and fluid is pumped into wellbore. The pressure is gradually increased until fluid enters the formation. If the formation is fractured by the LOT, it usually requires less pressure to open the fractures back up, so a LOT is only performed when understanding formation failure point is critical. The LOT may be repeated after the initial test to determine the pressure at which the fractures reopen, which is typically less than the original fracture pressure. A formation integrity

test is similar to a LOT test, except the pressure is raised to a predetermined point and then bled down, which prevents damage to the formation and the casing shoe. FITs are more commonly used for this reason. In the Marcellus Shale, FITs have yielded fracture pressures of approximately 22 ppg. This is much higher than the standard mud weight of 13 ppg and the standard cement weight of 15 ppg, making fracture of the formation unlikely under most conditions (Anonymous, 2012). The high fracture gradient is one of the reasons special hydraulic fracturing procedures are needed to access the gas within the shale.

4.6 Casing and Cementing Failures

Well integrity is highly dependent on the casing and the reinforcing cement sheath of the well, and failures of this system can result in potentially catastrophic losses of well control. Interaction between the casing and cement is complex, with each element depending on the other. For instance, loads induced by internal pressures within the casing are transferred to and shared by the surrounding cement sheath through the bond between the two. This interdependence of the cement and casing makes separating their failure modes and causes difficult in all but a few cases, such as in unsupported lengths of casing. In this section, casing and the cement are separated to facilitate discussion and provide logical organization, but it is important to remember that in most circumstances, the casing and cement sheath act together to provide wellbore integrity. A Fault Tree Diagram (**FTD**) for the top event of loss of well integrity is presented in Figure 28. This Figure provides a generalized overview of the main failure modes of the casing and cementing system.



Figure 28: Well Integrity Fault Tree Diagram

In a FTD, the top event occurs when the conditions dictated by the controlling logic gates are met, and single lower level faults, or combinations of faults progress up the tree. The top event in the fault tree presented corresponds to H1 and H2 identified in the primary STPA analysis. More information on FTDs can be found in NUREG-0492, the Fault Tree Handbook published by the U.S. Nuclear Regulatory Commission.

4.6.1 Casing Failures

There are three primary functional objectives of the casing string: (1) maintaining the structural integrity of the borehole, (2) keeping formation fluids out of the borehole and (3) keeping borehole fluids out of the formation. The casing must therefore maintain both its structural and hydraulic integrity to maintain effectiveness, and if either aspect is compromised, the casing is considered to have failed. Figure 29 presents the failure modes for the casing string, grouped by the primary identified cause of failure. For example, collapse or burst failures are caused by pressure differentials acting on the casing string, and are therefore presented and discussed together. Joint failure is presented separately due to its high importance.



Figure 29: Casing Failure Modes in Fault Tree Format

The majority of casing failures occur at joints between segments of casing. Although joints make up as little as 3 percent of the casing string length, they account for over 90 percent of casing failures (Hansen, 2013). Joints are a weakness in casing for several reasons, the first being their increased vulnerability to corrosion. At the thread interface, highly localized stresses combined with crevice formation provide a favorable location for corrosion to occur. This corrosion can lead to joint failure, typically beginning with leaks (Renpu, 2011). Joints are also susceptible to mechanical failure. For wedge shaped threads, such as API 8-rd, high compression, tensile forces, or bending stresses due to wellbore curvature can cause the joint to fail through "jump out". During jump out, axial loads (F_t) are translated by the threadfrom to forces normal to the thread surface (F_n). This force has a component perpendicular to the casing centerline (F_r), which tends to pull the threads apart. These forces are shown on a round threadform loaded in tension in Figure 30. Once the normal force borne by the thread tip is too high, deformation occurs and the thread slips (TH Hill, 2010). In API tensile tests, jump out was the dominant failure mode for round threads, occurring in 148 of 162 tests (91%). For this reason, the API buttress thread was adopted. The API buttress thread has tangential load bearing tooth flanks that nearly parallel to the radial direction, greatly reducing the radial force component that causes jump out.



Figure 30: Forces During Thread Jump Out

Pressure and axial loading can cause failure in the body of the casing. The effect of loading considered here are of the failures resulting from loading in excess of casing capacity. When the pressure difference between the inside and outside of the casing exceeds the burst pressure or collapse pressure of the pipe, failure will occur. An example of each type of failure can be seen in Figures 31 and 32.



Figure 31: Burst Failure (TH Hill, 2010)



Figure 32: Collapse Failure (TH Hill, 2010)

In addition to burst and collapse, the casing string can also fail through buckling, which occurs when the forces destabilizing the casing string exceed the forces stabilizing the casing string (TH Hill, 2010). Casing stability in a given section can be determined through use of the following inequality:

$$F > (P_i * C_i) - (P_o * C_0) \tag{7}$$

Where *F* is tension (+) or compression (-) (lbs) in the casing section, P_o is the annular pressure (psi), C_0 is the outer circumference of the casing (in), P_i is the internal pressure (psi), and C_i is the inner circumference of the casing (in). If the inequality is true, then the casing string is stable.

The casing can also undergo brittle fracture in response to loading. Factors that increase the probability of brittle fracture include use of materials with low toughness and hydrogen embrittlement due to interaction with H_2S . The in-situ toughness of the casing is reduced during perforation of the casing by use of an explosive charge. The deflagration of the perforating charge imposes high transient loads on the casing, which reduces the materials toughness and causes axial cracking of the casing on the upper and lower edges of the perforation (Renpu, 2011). Crack propagation following perforation is controlled by the lateral impact toughness of the material, making consideration of this property important in selecting casing material in perforated sections.



Figure 33: Modes of Buckling in Unsupported Casing Sections (Rechard and Schuler, 1983)

It is important to note that the applied casing load can exceed casing load capacity for several reasons. First, the in-situ loading can exceed those that were considered in the design stage. This may be due to design error or uncertainty in downhole conditions, and is one of the reasons a safety factor is applied during design. Changes in in-situ loading can be caused by many factors, including temperature changes, declining reservoir pressure, and formation movement. The casings load capacity can also be lower than considered in the design. This may be due to many factors, including corrosion, casing wear, improper casing manufacture, or damage during installation. Again, during the design a safety factor is included to prevent failure caused by these uncertainties.

The single most common cause of casing failures is corrosion (Renpu, 2011). Corrosion is a complex electrochemical process that can be difficult to predict and model accurately. Common causes of corrosion in the oilfield environment are H₂S and CO₂. Corrosion can occur on both the interior and exterior of casing strings, through varying modes of attack. The cement sheath surrounding a casing string retards the rate of corrosion, but does not eliminate it. Failure is most typically caused by external corrosion in an un-cemented segment of the well, often occurring at particular features that are particularly vulnerable, such as API/ISO standard threads, reducing nipples, stage collars, tie back tools, and casing wall above the drop-out point of condensate water (Renpu, 2011).

Corrosion occurring above a depth of 200 ft is typically due to the presence of oxygen, enhanced by chlorides or sulfates in the soil, while below that depth corrosion is due to formation water containing CO₂. Other factors leading to corrosion in well casing include galvanic cells, Microbiologically Influenced Corrosion (**MIC**) from anaerobic bacteria supported by drilling fluids, and stray-current corrosion (**Cramer and Covino**, 2006). The type of corrosion occurring and kinetics of the reaction are highly dependent on the downhole environment. NACE RP0186 recommends that well operators study the corrosion history of the well in question, and that of other wells in the area, to develop an understanding of the probability and/or rate of corrosion occurring in a given well. Studies of the downhole environment, such as resistivity logs, casing potential profile (**CPP**), geology, and drilling mud, will also provide useful information.

Prevention of corrosion typically accomplished through means of cathodic protection, which can be feasible up to depths of 13,000 ft. Cathodic protection may be achieved through use sacrificial anode type, or through an impressed-current cathodic protection system. Sacrificial anode systems are appropriate for shallow wells with low current requirements, but most wells require a larger amount of current for protection (Cramer and Covino, 2006). Coating systems are also used to protect casing from corrosion, but damage to the coating during installation remains a problem, as uncoated areas are subjected to increased rates of localized attack. In the Marcellus Shale, corrosion of casing strings is not usually an issue, because corrosive chemicals are "virtually non-existent" in the downhole environment (Anonymous, 2012). The natural gas produced is sweet (meaning it has low concentrations of CO₂ and H₂S) and producers only need to remove water vapor before the gas is ready for production.

Casing wear is a problem in many intermediate strings, especially in doglegged sections or horizontal wells. The primary cause of casing wear is the rotation of the drill pipe, and to a lesser extent, the repeated removal (tripping) and subsequent re-insertion of the drill string (Byrom, 2007). The wear on a given area of the casing is directly proportional the contact force of the drill pipe. If problematic wear is detected by caliper logs, the casing must either be re-run, or repaired with a scab liner, both unattractive

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options for the well owner in terms of cost, time and impact on future operations. Software can be used to accurately predict where critical wear areas of casing are, and the areas that have the greatest contact force between tool joints and casing can be protected by using thick protection liners.

A summary of casing failure modes and the recommended methods of mitigation is presented in Table 4. The relative risk of each failure mode was ranked on a scale from 1-5 depending on the frequency of occurrence and the ease of mitigation. Although no quantitative data could be found on the frequency of failure types, many sources included qualitative data on the relative frequency of failure occurrences.

Casing Failure Mode	Methods of Mitigation	Relative Risk
Corrosion	Materials selection, catholic protection, corrosion inhibitors, coatings	5
Seal Failure	Joint type selection, proper handling, proper assembly	5
Wear	Avoid doglegged sections, reinforce wear points	4
Fracture	Design with consideration of flaws, material selection	3
Buckling	Design for actual loading conditions	2
Burst	Design for actual loading conditions	2
Collapse	Design for actual loading conditions	2
Jumpout	Selection of buttress type threadforms	1

Table 4: Risk Ranking of Casing Failure Modes

For each failure mode presented in Table 4 there exists a known solution. The difficulty lies in recognizing the existence of downhole conditions that may lead to failure and properly quantifying their effect during the design stage, so that the design may be modified to mitigate potential hazards.

4.6.2 Cementing Failures

The cement sheath serves several purposes, which are to provide (1) zonal isolation and segregation, (2) corrosion control, and (3) reinforcing formation stability and casing strength. The failure that is of most concern is the failure to provide zone isolation and segregation. Loss of zonal isolation can have catastrophic consequences, including loss of well control (API 65-2). In gas plays, such as the Marcellus Shale, there is a high probability that failure of the cement sheath will result in annular gas migration

(Halliburton, 2013a). Failures of the cement sheath can be divided into two primary categories, failures that occur during the primary cementing process and those that occur after the cement has set. Again, this distinction is largely arbitrary, as defects in the cement sheath caused by deficiencies in the primary cementing process can lead to failure of the cement sheath during operation.

During the execution of the primary cement job, there are many potential causes of failure. One failure mode during cement placement is channeling. Channeling is a complex phenomenon, but a major cause is the development of gel strength and resulting loss of hydrostatic pressure. Undisplaced mud during slurry placement can result in a channel of high permeability mud, compromising the integrity of the cement sheath. Channeling can also be caused by bridging and poor centralization. If the casing is poorly centralized, the cement slurry will travel the path of least resistance in the wellbore, leaving the side of the casing close to the borehole wall with little or no cement sheath (Transocean, 2013). If the average fluid velocity of the cement slurry in the annulus is not above the velocity required to initiate flow in the narrowest part of the annulus, mud will not be displaced, causing channeling and possible contamination of the cement, which could result in failure to attain desired set properties. A diagram contrasting the effects on cement placement of poorly centralized casing to centralized casing is shown in Figure 34.



Figure 34: Poor Centralization versus Good Centralization of Casing (Transocean, 2013)

Excessive loading of the cement sheath during operations can cause multiple types of failures. This loading may be pressure induced during operations such as hydraulic fracturing, or induced due to temperature changes. These temperature or pressure fluctuations within the well can cause debonding of the cement sheath from the casing. This results in the formation of a small annular void (a microannulus) between the casing and cement sheath. In severe cases, the microannulus may encircle the entire casing circumference, possibly compromising hydraulic sealing ability of the cement sheath (Schlumberger, 2013). Varying degrees of microannulus formation can be seen in Figure 35.



Figure 35: Varying Degrees of Microannulus (Schlumberger, 2013)

Research conducted on steel to cement bonding in structural applications has high relevance to casing to cement sheath bonding. In a steel-reinforced concrete structure, load transfer between the steel cement occurs through the bond between the two materials. In structural applications, the three mechanisms of bond response are mechanical interaction, chemical adhesion, and friction, with mechanical interaction the dominant mechanism for load transfer. It has been shown that during cyclic shear loading, degradation of cement-steel bond occurs at small fractions of the fatigue life (Cao and Chung, 2001). Similarly, one would expect that in well applications that operations inducing cyclic shear loading on the casing to steel bond (such as hydraulic fracturing) would cause a decrease in bond strength and increased probability of

microannulus formation. Bond strength degradation may also be caused by corrosion of the casing. The effect of cyclic loading and corrosion on micro-annulus formation is an area that could benefit from further research and investigation.

Fractures in the cement result from loading occurring in the downhole environment in excess of the material strength. The fracture mechanics of concrete are best described as progressing through four stages: (1) the linear elastic regime, (2) precritical (stable) crack growth, (3) critical (unstable) crack growth, and (4) the bridging stage. Within stage 1, the linear elastic regime, Hooke's law is valid and can be used to model the behavior of the material. Hooke's law can be expressed as follows:

$$\sigma = \varepsilon * E \tag{8}$$

Where the stress (σ), is equal to the elongation (ϵ) multiplied by Young's Modulus (E), which is a material property that depends on cement composition.

For materials with small amounts of crack bridging, such as cement without aggregates, stages 2 and 3 of pre-critical and critical crack growth can be described using linear elastic fracture mechanics (**LEFM**):

$$K_{1C} = f(a,\theta) * \sigma * \sqrt{\pi * a}$$
⁽⁹⁾

Where K_{1C} is the critical stress intensity factor, $f(a, \theta)$ is the crack shape factor as a function of a and θ , and a is the length of a surface crack or half the length of an interior crack. The critical stress intensity factor, K_{1C} , is a material property that is dependent on composition of the cement.

In concrete, crack bridging by the aggregate has the effect of stabilizing the macro-crack growth to some extent, and must be modeled and included in analysis. However, for cement without aggregates, such as oil well cement, the bridging stage consists of the interaction of ligaments between overlapping crack tips and is typically negligible (Van Mier, 1997).

The stress-strain behavior of brittle and quasi-brittle materials is shown in Figure 36. Typical oil well cement behaves in a brittle manner, while concrete displays quasibrittle behavior. Important features to note in Figure 36 include the extremely small region of stable crack growth for brittle materials, and the almost complete lack of bridging. As aggregates are added, the region of stable crack growth and the effect of crack bridging increases.



Figure 36: Brittle and Quasi-brittle Crack Growth (Adapted from Van Mier, 1997)

Cracks that can be arrested by elements in the material structure are termed micro-cracks, while cracks that can only be delayed or arrested through structural measures at a larger scale than the material structure are termed macro-cracks (Van Mier, 1997). Under confined external compression, micro-cracking can be severe, but the increase in applied stress to cause crack growth criticality is typically large. Microcracking may increase the permeability of cement and enable gas migration through the cement sheath.

A summary of cementing failure modes and the recommended methods of mitigation is presented in Table 5. The relative risk of each failure mode was ranked on a scale from 1-5 depending on the frequency of occurrence and the ease of mitigation. Less qualitative data was available for raking the relative risk of cementing failure modes, so a risk value of 3 was assigned unless specific information was available.

Cementing Failure Modes	Methods of Mitigation	Relative Risk
Corrosion	Proper slurry design	4
Channeling	Proper slurry design, adequate centralization	3
Contamination	Adequate pre-treatment of the borehole	3
Microannulus formation	Design for actual loading conditions	3
Fracture	Design for actual loading conditions	2

Table 5: Risk Ranking of Cementing Failure Modes

Similar to the failures presented in the casing section, for each cementing failure mode there is a wealth of information on mitigation methods and techniques. The cementing process has developed to satisfy the needs of wells with more challenging downhole conditions than those found in the Marcellus Shale, and slurry properties can be tailored to address problems that may arise.

4.7 STPA Analysis

To extend the STPA analysis to the casing and cementing process, a safety control structure was developed using methodology similar to that used in Section 3.2. The control objective of this SCS is to prevent the development of H1 and H2, loss of primary and secondary well control due to cementing and casing failures, respectively. The majority of the failure modes identified in Section 4.6 are caused by interaction between the well system and the environment. The environment can be considered to be the primary source of excitement to the system, which must be handled by the SCS. Examples of failure modes that are a product of this interaction include corrosion and failures caused by in-situ loading exceeding design strength. Failures may also due to inadequate control of the casing and cementing process, for example the failure to properly centralize the well during cementing. The SCS developed for the casing and cementing process is presented in Figure 37. In addition to the SCS, Table 6 was developed to summarize the interactions between entities identified in the SCS. The safety control structure was focused on cementing so that more detail could be presented. A similar control structure could be developed for the casing process, but was not done due to time constraints.



Figure 37: SCS for the Cementing Process

Based on the research presented in Section 4.6, it can be concluded that the failure modes arising from interaction between the well and environment are not primarily the product of technical challenges in cement job execution or in development of a design that could provide zonal integrity in the Marcellus Shale. It follows that if the cement job is properly executed, but fails to provide wellbore integrity, the flaw lies within the design. There is plentiful material available on the technical aspects of casing and cement job design, and each failure mode identified in Section 4.6 has extensive literature devoted to presenting technical solutions to problems. To summarize, from communication with the Environmental Health and Safety Expert from one of the top ten natural gas production firms in PA, technical challenges downhole are virtually non-existent; there is not a high potential for corrosion, the vertical section of the well can be drilled with air, and the fracture gradient is much higher than the standard mud weight (Anonymous, 2012). These factors result in a fairly forgiving downhole environment.

Outputting Entity	Receiving Entity	Interaction Description		
Cementing Process	Well	Cement slurry into well		
Cementing Process	Well Operator	Cement job feedback		
Environment	Well	Loading conditions, corrosive fluids		
Raw Materials	Cementing Process	Water, cement, additives, etc.		
Service Contractor	Testing Lab	Tests to be conducted, test conditions		
Service Contractor	Cementing Process	Cement job execution		
Service Contractor	Well Operator	Cement job feedback		
Testing Lab	Service Contractor	Test results		
Well	Well Operator	Drilling logs, reports, integrity test results		
Well	Cementing Process	Surface returns		
Well	Environment	Formation fluids		
Well Operator	Cementing Process	Supervisory control of job completion by		
	Cementing 1 locess	contractor		
Well Operator	Service Contractor	Cement job specifications		
Well Operator	Well	Integrity tests to be performed,		
wen Operator	vv CII	monitoring of well		

Table 6: Interactions in the Cementing Safety Control Structure

Therefore, problems with casing and cementing in the Marcellus Shale likely do not stem from inadequate control of the execution of the process, but from inadequate control of the process of design. A full analysis of the process of designing a casing program and a cement job is outside the scope of this project, but several important factors are highlighted here. The challenge in the design of a casing string and cement job for a well lies in modifying the design to adequately address the unique conditions of a particular well. The design is modified based on feedback from drilling reports, log results, and integrity tests. For a particular casing and cementing program to be successful, it must be tailored to the downhole conditions encountered while drilling. This is one possible cause of the learning curve experienced when natural gas development begins in an area where the operators are unfamiliar with the formations present. There are also pressures within the company that influence the design, such as time and budgetary pressures, corporate policy and culture, and regulations and standards. It is recommended that the STPA analysis should be applied to the casing and cementing program design process to identify weaknesses that could lead to improper design.

Chapter 5: Hydraulic Fracturing Wastewater Management

During and after the hydraulic fracturing process, the internal pressure of the shale formation causes the injected fracturing fluids and natural formation water to rise to the surface through the well casing. Flowback is the wastewater that rises to the surface during and after the hydraulic fracturing process, and it consists of the fluid used to fracture the well. The majority of the flowback occurs within a few days of fracturing the well, but it can last for up to three or four weeks. Approximately 10 to 30% of the injected fracturing fluid returns to the surface while the rest remains in the shale formation (Schramm, 2011). After the hydraulic fracturing process is complete, produced water is the wastewater that rises to the surface over the entire lifespan of the well and consists of the naturally occurring water inside the shale formation. Flowback flows at a rate greater than 50 barrels per day (bpd) as opposed to that of produced water, which typically flows between 2 and 40 bpd (Schramm, 2011). These two terms are sometimes used interchangeably and their exact definitions can vary. This report refers to both flowback and produced water as "hydraulic fracturing wastewaters" (Schramm, 2011). This chapter identifies the constituents of hydraulic fracturing wastewaters, describes its management options, and develops a management strategy including a treatment system design.

5.1 Wastewater Constituents

The constituents of hydraulic fracturing wastewaters can vary significantly depending on the oil and gas company fracturing the well and where it is located in the Marcellus Shale region. This is because companies develop their own different fracturing fluids, and the Marcellus Shale geochemistry differs across the formation, resulting in varying compositions of natural formation water. This section describes the major constituents and their concentrations present in hydraulic fracturing wastewaters from the Marcellus Shale in Pennsylvania. It also provides a methodology for determining the chemical components of hydraulic fracturing fluid that in turn affects the flowback composition.

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5.1.1 Fracturing Fluids Disclosure Registry

FracFocus.com is a website that serves as the national chemical disclosure registry for hydraulic fracturing. Oil and gas companies can voluntarily register their hydraulically fractured wells along with the chemicals used in the fracturing fluid. The Ground Water Protection Council and Gas Compact Commission manage the FracFocus website, and they created it to serve as a public access forum that reports information on the chemicals used in hydraulic fracturing across the United States.

As of December of 2012, there were over 30,000 registered well sites on FracFocus, and the distribution of these registered wells across the United States is shown in Figure 38. The majority of hydraulically fractured wells in the United States lie from North Dakota to Texas through states such as Wyoming, Colorado, New Mexico, and Oklahoma. Pennsylvania, as well as seven other states, uses FracFocus as an official state chemical disclosure. FracFocus documents approximately 2,500 registered wells in Pennsylvania dispersed over the northeastern part of the state. Sixty-seven counties make-up Pennsylvania, and thirty-three of these counties have registered wells on FracFocus.



Figure 38: Map of Well Site Distribution in the United States (GWPC and IOGCC, 2012)

The Pennsylvania Department of Environmental Protection (**PA DEP**) regulates oil and gas drilling in the state and issues permits to operators. According to permits from January 2009 to June 30, 2012, there are almost 9,000 drilled wells in Pennsylvania from seventy-four different operators (Amico *et al.*, 2013). Records from FracFocus only include wells that were drilled in Pennsylvania after January 1, 2011. From the number stated by Amico approximately 28%, or 2,546, of the 9,000 hydraulically fractured wells in Pennsylvania are entered into the FracFocus system (2013). Table 7 and Table 8 identify the distribution of wells in Pennsylvania for the top ten counties and operators, respectively, as well as the number of wells and percent of the total wells reported on the FracFocus website for each of the top ten counties and operators in Pennsylvania. By county, the percentage of wells documented on FracFocus varies from 19 to 42%. By operator, the percentage of wells documented on FracFocus varies from 3 to 45%.

County	Number of Wells	FracFocus			
County	Number of wens	# of wells	% of wells		
Bradford	1,795	513	29		
Lycoming	846	356	42		
Susquehanna	858	317	37		
Tioga	1,197	295	25		
Washington	896	231	26		
Greene	650	204	31		
Westmoreland	342	92	27		
Fayette	290	68	23		
Butler	268	60	22		
Clearfield	284	53	19		
Totals	7,426	2,189	29		

 Table 7: Top Ten Counties in PA where Hydraulic Fracturing Wells are Drilled, Based on Number of Wells

 (Adapted from Amico. at al. 2013 and EracEocus. 2012)

Orrenation	Normhan of wolld	FracFocus		
Operator	Number of wens	# of wells	% of wells	
Chesapeake Appalachia LLC	1,355	369	27	
Range Resources Appalachia LLC	882	285	32	
Talisman Energy USA Inc	793	185	23	
Shell Western E&P Inc.	760	230	30	
Anadarko E&P Co Lp	418	187	45	
Atlas Resources LLC	398	11	3	
Eqt Production Co	376	71	19	
Cabot Oil & Gas Corp	368	155	42	
Chevron Appalachia LLC	315	122	39	
Eog Resources Inc	295	87	29	
Totals	5,960	1,702	29	

Table 8: Top Ten Hydraulic Fracturing Operators in PA, Based on Number of Wells (Adapted from Amico, *et al.*, 2013 and FracFocus, 2012)

5.1.2 Hydraulic Fracturing Fluids Used in Pennsylvania

As shown in section 5.1.1, there are 2,546 Pennsylvania wells registered on FracFocus (GWPC and IOGCC, 2012). Data from all of the registered wells could not be analyzed due to time constraints. This study analyzed the most recently hydraulically fractured wells from each operator in each PA County. This allowed for comparison of fracturing fluid constituents based upon county and company. The most recent wells were selected because over time, companies may change the components of their fracturing fluid in order to produce the most effective fluid with regard to cost and natural gas recovered. A total of 108 wells were analyzed using these criteria. The data were gathered on October 26, 2012, so any wells added or information updated past that date were not reflected in this study. Each well registered on FracFocus has a "Hydraulic Fracturing Fluid Component Information Disclosure" sheet. These sheets list identifying information for each well and information on the composition of the hydraulic fracturing fluid that was used in the well. An example sheet is pictured in Figure 39, as well as an example of how the information from the disclosure sheet was sorted using Microsoft Excel version 2010 in Table 9.

The data from all 108 wells was compiled in Microsoft Excel 2010 (refer to the supplementary document "Natural Gas Resources Development: Fracturing Fluid Data Sheets"). Then, the recorded Chemical Abstract Service (**CAS**) numbers of the hydraulic fracturing constituents were used to perform a frequency analysis. CAS numbers are unique numbers used as identifiers for a given chemical substance (CAS, 2013). The frequency analysis was performed using the count function on the Pivot Table in Microsoft Excel. The results showed that within the 108 wells analyzed, 158 different additives with registered CAS numbers were used. In total, 75.6% of the additives used in the wells had recorded CAS numbers. Thus, 24.4% of the additives did not have recorded CAS numbers and instead were listed as proprietary information/trade secret, not applicable, not recorded, or left blank. From this frequency analysis, it was also determined that of the 158 chemicals with recorded CAS numbers, 102 of these chemicals were found in more than one well.

Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient	Maximum		
Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient	Maximum		
Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient	Maximum		
Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient	Maximum		
Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient	Maximum		
Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient	Maximum		
Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient	Maximum		
Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient	Maximum		
Ingredients	Chemical Abstract Service Number (CAS #)	Maximum	Maximum		
Ingredients	Chemical Abstract Service Number (CAS #)	Maximum	Maximum		
Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient	Maximum		
Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient	Maximum		
ingredients	Service Number (CAS #)	Ingredient	Maximum	Commonte	
	(CAS #)		Ingredient	comments	
		Concentration	Concentration		
		in Additive	in HF Fluid		
		(% by mass)**	(% by mass)**		
	7647-01-0	37.00%	0.01934%		
i Alashal	0/-00-1	95.00%	0.00041%		
thyloxazolidine	51200-87-4	78.00%	0.00002%		
methyloxazolodine	75673-43-7	5.00%	0.00087%		
-2-methyl-1-propanol	124-68-5	1.00%	0.00017%		
ehyde Amine	56652-26-7	0.50%	0.00009%		
lehyde	111-30-8	50.00%	0.00378%		
1	67-56-1	0.50%	0.00004%		
Total Water Volume sources may include fresh water, produced water, and/or recycled water information is based on the maximum potential for concentration and thus the total may be over 100%					
Total Water Volume sources may include fresh water, produced water, and/or recycled water Total Water Volume sources may include fresh water, produced water, and/or recycled water " Total Water Volume sources may include fresh water, produced water, and/or recycled water " " Total Water Volume sources may include fresh water, produced water, and/or recycled water " " Total Water Volume sources may include fresh water, produced water, and/or recycled water " " Total Water Volume sources may include fresh water, produced water, and/or recycled water " Information is based on the maximum potential for concentration and thus the total may be over 100% Ingredient information for chemicals subject to 29 CFR 1910.1200(i) and Appendix D are obtained from suppliers Material Safety Data Sheets (MSDS)					

Figure 39: Example of "Hydraulic Fracturing Fluid Component Information Disclosure" Sheet from FracFocus (GWPC and IOGCC, 2012)

Operator	County Well Located In	API #	Well Name and #	Job Date	True Vertical Depth (TVD)	Total Water Volume (gal)	CAS #	Trade Name	Purpose	Ingredients	Chemical Supplier	Max ingredient concentra- tion in additive (% by mass)	Max ingredient concentra- tion in HF (% by mass)
Range Resources	Beaver	37- 007- 20339	Noss Unit #2-H	7/22/2012	5,439	10,442,756	7647- 01-0	37% HCL	Cleans perforation	HCl	Frac Tech	0.37	0.00019
Range Resources	Beaver	37- 007- 20339	Noss Unit #2-H	7/22/2012	5,439	10,442,756	67-56- 1	CI- 100	Corrosion Inhibitor	Methanol	Frac Tech	0.95	0.00000
Range Resources	Beaver	37- 007- 20339	Noss Unit #2-H	7/22/2012	5,439	10,442,756	107- 19-7	CI- 100	Corrosion Inhibitor	Propargyl Alcohol	Frac Tech	0.05	0.00000
Range Resources	Beaver	37- 007- 20339	Noss Unit #2-H	7/22/2012	5,439	10,442,756	51200- 87-4	MC B- 8520	Antibacterial Agent	4,4- Dimethylo- xazolidine	Multichem	0.78	0.00013

Table 9: Sorted Data from Example of "Hydraulic Fracturing Fluid Component Information Disclosure" Sheet(Adapted from GWPC and IOGCC, 2012)

Research was done on each of the chemicals with recorded CAS numbers to determine if their use might be regulated due to occupational exposure limits or to drinking water contaminant standards. The occupational exposure limits of the chemicals were determined by the Occupational Safety & Health Administration (OSHA) Chemical Sampling Information (CSI) online database. The database was searched using the 158 CAS numbers of the chemicals found in the wells. Of these 158 chemicals, 58 appear in the OSHA CSI online database, and 38 of these have recorded exposure limits. Most of the exposure limits recommended by OSHA are for contact via air. The purpose of this project was to design a treatment system for the flowback fluid so it is capable of being reused in other fracturing operations. Switching to reuse reduces the amount of chemicals from the flowback that are discharged into the environment due to other flowback fluid waste management practices. Therefore, exposure from the chemicals in the hydraulic fracturing industry would primarily be through skin exposure during handling or treatment of the hydraulic fracturing fluid and flowback. Thus, this project was primarily concerned with the chemicals in the OSHA CSI database that have a Permissible Exposure Limit (PEL) for exposure via skin contact. Table 10 displays the six chemicals that have skin exposure limits in the OSHA CSI online. The PELs are measured as time weighted averages (TWA) with the units of either parts per million (ppm) or milligrams per meter cubed (mg/m3).

		(0.01202,2010)	
CAS Number	Chemical Name	Number of analyzed wells that contain the chemical	OSHA Permissible Exposure Limit
107-19-7	Propargyl Alcohol	58	For Construction Industry: 1 ppm TWA; Skin
111-76-2	2-Butoxyethanol	30	For General Industry: 50 ppm, 240 mg/m ³ TWA; Skin
68-12-2	Dimethylformamide	7	For General Industry: 10 ppm, 30 mg/m ³ TWA; Skin
79-06-1	Acrylamide	2	For General Industry: 0.3 mg/m ³ TWA; Skin
106-89-8	Epichlorohydrin	2	For General Industry: 5 ppm, 19 mg/m ³ TWA; Skin
98-82-8	Cumene	1	For General Industry: 50 ppm, 245 mg/m ³ TWA; Skin

Table 10: Chemicals, from Analyzed Wells, which have Permissible Exposure Limits for Skin Contact (U.S. DOL, 2013)

Another environmental factor to consider is whether the fracturing fluid chemicals are regulated under drinking water standards. Drinking water standards should be considered for possible travel of fracturing fluid to a drinking water source. The Environmental Protection Agency (**EPA**) regulates drinking water contaminants, and Table 11 lists five of these chemicals that are present in the 108 wells analyzed. The table also contains the level of contaminant allowed in drinking water and its potential health effects according to the *National Primary Drinking Water Regulations*.

Table 11: Chemicals, from Wells Analyzed, which are on the National Primary Drinking Water Regulation

(Adapted from U.S. EPA, 2009)

TT stands for Treatment Technique; MRDL stands for Maximum Residual Disinfectant Level; MRDLG stands for Maxim Residual Disinfection Level Goal

Number of analyzed wells that contain the chemical	CAS Number	CAS NumberCommon NameMaximum Contaminant LevelMaximum Contaminant Level Goal		Potential health effects from long- term exposure above the MCL	
3	7758- 19-2	Chlorite	1.0 mg/L	0.8 mg/L	Anemia; nervous system effects on young children and fetuses
2	79-06-1	Acrylamide	(TT) 0.05 percent dose at 1 mg/L	0 mg/L	Nervous system problems; blood problems; increased risk of cancer
	10049-	Chlorine	(MRDL) 4.0 mg/L	(MRDLG) 4 mg/L	Eye irritation; nose irritation; stomach discomfort
2	04-4	Chlorine dioxide	(MRDL) 0.8 mg/L	(MRDLG) 0.8 mg/L	Anemia; nervous system effects on young children and fetuses
2	106-89- 8	Epichlorohydrin	(TT) 0.01 percent dose at 20 mg/L	0 mg/L	Increased risk of cancer; stomach problems
1	1330- 20-7	Xylenes	10 mg/L	10 mg/L	Nervous system damage

If the chemical is a regulated drinking water contaminant, it is usually because of its negative health effects, which industry should aim to prevent. This criterion is known as the Maximum Contaminant Level (MCL) and is expressed in milligrams per liter (mg/L). A MCL is "the highest level of a contaminant that is allowed in drinking water, and is set as close to [Maximum Contaminant Level Goals (MCLGs)] as feasible using the best available treatment technology and taking cost into consideration" (U.S. EPA,

2009). A MCLG is "the level of a contaminant in drinking water below which there is no known or expected risk to health, including a margin of safety" (U.S. EPA, 2009). Treatment Technique (**TT**) is a requirement of a treatment process that is intended to reduce the level of the contaminant; the limit in Table 11 is the level of the chemical that must not be exceeded in the effluent water (U.S. EPA, 2009). Some chemicals are also used to control microbial contaminants causing a residual amount to remain. Known as Maximum Residual Disinfectant Level (**MRDL**), this is the maximum level of these disinfectants allowed in drinking water (U.S. EPA, 2009). Of the 158 chemical additives that have registered CAS numbers from the 108 wells analyzed, five are regulated drinking water contaminants according to the *National Primary Drinking Water Regulations* set forth by the EPA (2009).

The EPA also has a list of chemicals and microorganisms that are being evaluated to determine if they should be regulated. In the future, the EPA could regulate other chemicals present in fracturing fluid as drinking water contaminants if they are on this list. This list is called the Contaminant Candidate List 3 (**CCL 3**). Of the 158 chemical additives in this analysis, four are on the CCL 3, and therefore may be regulated as drinking water contaminants in the future (U.S. EPA, 2009). The four chemicals are shown in Table 12.

Common Name	CAS #	Number of analyzed wells that contain the chemical
Methanol	67-56-1	97
Ethylene glycol	107-21-1	76
Benzyl chloride	100-44-7	3
Formaldehyde	50-00-0	3

Table 12: Chemicals, from Wells Analyzed, which are on the CCL 3

5.1.3 Naturally Occurring Radioactive Materials and Total Dissolved Solids

The Marcellus Shale began forming about 390 million years ago in a shallow sea that once covered the region of Ohio, West Virginia, and Pennsylvania (Perry, 2011). Shale is a finely grained sedimentary rock that forms from clay subjected to high pressure, and it is composed of tiny mud particles as well as organic matter. This organic
matter produces the natural gas, and naturally occurring radioactive material (**NORM**) already present in the Marcellus formation preferentially bonds to this organic matter when submerged in seawater. Since the Marcellus shale formed from sediment laid down by a shallow sea, water resides within the fractures and cracks of the underground rock formation. This water is classified as brine due to the presence of dissolved metals and salt, and is referred to as formation water. Since formation water can remain in the underground rock for centuries, radionuclides can concentrate in it. When hydraulic fracturing fluid is pumped through a well into the rock fractures, formation water can mix with it. Therefore, when water is pumped back out to the surface after the hydraulic fracturing process, the radionuclides present in the formation water can travel to the surface (Resnikoff and Alexandrova, 2010). Radium only appears in hydraulic fracturing wastewater if the fracturing fluid mixes with pre-existing brine when injected into the well because this injection process is not long enough for the direct migration of radium from the Marcellus Shale to the hydraulic fracturing fluids (Perry, 2011).

The primary radioactive substances found in the Marcellus shale are potassium-40, uranium-238, and thorium-232 – 40 K, 238 U, and 232 Th, respectively – and their decay products. However, since these materials have half-lives of over a billion years, their radioactivity levels are low. Additionally, the general insolubility of uranium and thorium cause them to adhere to rocks and soils as opposed to being incorporated into formation water. 40 Ar and 40 Ca, the decay products of 40 K, are not a radioactive threat since they are stable isotopes. The decay products of 238 U and 232 Th are 226 Ra and 228 Ra, respectively. These decay products are water-soluble, and therefore, they migrate into nearby brine solutions (Perry, 2011). Radium primarily occurs as Ra⁺² ions when dissolved in water, but it also forms complexes with carbonate, chloride, and sulfate ions (Rowan *et al.*, 2011).

Numerous studies since the 1980s document the relationship between salinity and radioactivity. Ra^{+2} competes with other multivalent ions in formation water for adsorption onto clay minerals. In low-salinity water, radium preferentially adheres to mineral surfaces, whereas in water with a high salinity, radium detaches from these minerals into the solution. Clay minerals absorb less radium at high salinities, therefore leaving more in the water (Rowan *et al.*, 2011).

Rowan *et al.*, (2011) from the United States Geological Survey (**USGS**) compiled radium activity data – and total dissolved solids (**TDS**) data when available – from sources outside of the USGS, such as the New York Department of Environmental Conservation, for waters produced from oil and gas wells in New York and Pennsylvania. This section discusses the data compiled by the USGS from the PA DEP for hydraulic fracturing wastewaters from the Marcellus Shale in PA, as well as data for six Marcellus Shale gas wells in PA collected by the USGS. The data collected by the USGS comes from two separate sources: a USGS study by Pritz (2010) and a joint effort by the USGS, U.S. Department of Energy (**DOE**), and industry collaborators (Rowan *et al.*, 2011). Data from the Pritz study includes one hydraulic fracturing wastewater sample for each of the five different gas wells studied in Bradford County, PA during April 2009. The USGS, U.S. DOE, and industry collaborators jointly collected nine samples of hydraulic fracturing wastewater from one gas well in Greene County, PA between December 8, 2010 and January 17, 2011. Table 13 displays the collected data for the six gas wells and 14 hydraulic fracturing wastewater samples provided by the USGS.

(Rowan <i>et. al</i> , 2011)						
PA DEP (2009-2010)						
Well number/sample ID	PA County	Total radium (pCi/L)	Ra-228/Ra-226			
1	Clinton	556	0.28			
3	Bradford	87	0.73			
4	Lycoming	482	0.12			
5.1	Lycoming	68	0.03			
5.2	Lycoming	277	0.16			
6	Tioga	18,045	0.07			
7	Tioga	12,407	0.12			
8	Centre	2,182	0.43			
9	Forest	5,258	0.26			
10	Potter	8,510	0.16			
11.1	Washington	1,654	0.74			
11.2	Washington	2,390	0.87			
12	Tioga	1,210	1.15			

Table 13: Radium Activity Data for Hydraulic Fracturing Wastewater from Natural GasWells in PA Compiled and Collected by USGS

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PA DEP (2009-2010)					
Well number/sample ID	PA County	Total radium (pCi/L)	Ra-228/Ra-226		
13	Tioga	3,481	2.90		
15	Clearfield	1,374	0.08		
16	Westmoreland	271	1.63		
17	Westmoreland	1,340	0.29		
18	Westmoreland	1,552	0.50		
19	Westmoreland	559	0.01		
20	Westmoreland	67	0.02		
21	Indiana	99	0.30		
22	Westmoreland	39	0.08		
23	Westmoreland	285	0.25		
	USGS (20	10-2011)			
Well number/sample	PA County	Total radium (nCi/I)	Ra-228/Ra-		
ID	TA County		226		
127	Bradford	2,971	0.120		
128	Bradford	4,018	0.303		
129	Bradford	2,530	0.292		
130	Bradford	1,957	0.317		
131	Bradford	2,133	0.215		
132.1	Greene	1,612	0.229		
132.2	Greene	3,905	0.161		
132.3	Greene	4,949	0.132		
132.4	Greene	5,491	0.122		
132.5	Greene	5,736	0.123		
132.6	Greene	5,824	0.118		
132.7	Greene	3,791	0.221		
132.8	Greene	6,266	0.151		
132.9	Greene	6,118	0.160		

The USGS study compiled unpublished data reports from 2009-10 from the PA DEP (Rowan *et al.*, 2011). These reports were annually filed "26R" forms (Chemical Analysis of Residual Waste, Annual Report by Generator) related to shale gas production, and the USGS study compiled TDS and radium activity information for 25 samples from 23 wells in 11 counties in PA using the 26R forms (Rowan *et al.*, 2011). Table 8 includes these compiled data. Two samples only included TDS values. The TDS data for produced wastewater from the Marcellus Shale in PA ranged from 1,470 mg/L to 358,000 mg/L, and the median value was 88,500 mg/L (Rowan et al., 2011). This large range is because the hydraulic fracturing wastewater that rises to the surface initially consists of the same constituents as the injected fluid. However, over time, it shifts towards TDS and inorganic chemical compositions that reflect the geochemistry of the formation. For example, in well number 11, the TDS measured 14 days after hydraulic fracturing was 157,000 mg/L compared to 200,000 mg/L after 90 days. Similarly, the TDS values for well number 5 increased from 38,200 mg/L to 82,600 mg/L within 17 days. For these two wells, two samples of the hydraulic fracturing wastewater were taken, as opposed to the rest of the wells from the PA DEP 2009-10 unpublished reports, where only one sample was taken from the wells. Data from Hayes (2009) showed that within 90 days of the injection of the fracturing fluid, TDS increased from median values of less than 1,000 mg/L to values greater than 200,000 mg/L TDS. Rowan et al. (2011) hypothesized that the major source of TDS in the Marcellus Shale production waters originated as seawater concentrated by evaporation, as evidenced by the elevated bromide concentrations as well as the Na-Cl-Br relations.

Considering the data from USGS and PA DEP, the total radium activity values ranged from 39 pCi/L to 18,045 pCi/L, and the median was 1,552 pCi/L. In cases where multiple samples were taken from the same well, the total radium activity of the well was determined by averaging the sample values. Similar to TDS, radium levels in hydraulic fracturing wastewaters increase over time, as exemplified by the radium data collected by the USGS for the sixth well, located in Greene County, PA. Within 20 days from hydraulic fracturing of the well, the total radium activity of wastewater went from 1,612 pCi/L on day 0 to 6,118 pCi/L on day 20, a 26% increase. The increase in salinity and radiation over time relates to the decrease in injected hydraulic fracturing fluid and increase in the amount of formation water that rises to the surface. The low salinity and radiation levels present in the injected fracturing dilute the high salinity and radiation levels present in the sample collection was reported for only a few cases in the data collected and compiled by USGS, which explains the large range of radium concentrations present in the wastewaters.

In addition to the total radium activity, the USGS and PA DEP data included amounts of Ra-228 and Ra-226. With a median Ra-228/Ra-226 ratio of 0.26, Ra-228 is present in larger quantities than Ra-226 in the hydraulic fracturing wastewaters from the Marcellus Shale in PA. This difference characterizes the Th/U ratio in the Marcellus Shale lithology since Ra-226 and Ra-228 are the decay products of U-238 and Th-232, respectively (Rowan *et al.*, 2011).

5.2 Wastewater Management Options

Well permits require the removal of all hydraulic fracturing wastewaters from a well site. Figure 40 depicts the management practices employed by well operators in order to meet this requirement. Oil and gas operators first pump hydraulically fractured wastewaters from the well site to lined pits or fracturing tanks located on-site. From there, operators either treat the wastewater on-site, transport it for treatment at an off-site facility, or ship it for disposal to a Class II underground injection well. For treated waters, operators can transport the wastewater to another plant for additional treatment, discharge it to surface waters, or reuse it at a different well site. All of the stages in this process require permits by the PA DEP. The choice of management depends mainly on costs and logistics as far as permitting and following regulations (Hammer *et al.*, 2012). This section describes the management practices used by oil and gas operators in the Marcellus Shale region of PA.



Figure 40: Flowchart of Management Practices for Hydraulic Fracturing Wastewater

5.2.1 Waste Reports

Unconventional well operators must submit waste reports to the PA DEP on a biannual basis as a part of the Pennsylvania Oil and Gas Act. The submission dates are August 15 for the January 1 to June 30 period of the same calendar year, and February 15 for the July 1 to December 31 period of the previous calendar year. The PA DEP posts the data from operators exactly as it was received on the PA DEP Oil and Gas Reporting Website. Data on waste type, waste quantity in barrels (bbl), and disposal method were taken from the July 1 to December 31, 2011 and January 1 to June 30, 2012 waste reports. Figures 41 and 42 provide the percent of total volume of hydraulic fracturing wastewaters for each disposal method. Figure 41 corresponds to the 2011 data, and Figure 42 to the 2012 data. In Figure 41, the other category "Other" consists of "Identify method in comments" (0.045%), "Landfill" (0.014%), "Public sewage treatment plant" (0.004%), and "Storage pending reuse or disposal" (0.075%).



Figure 41: Disposal Method, by Percent Volume of Total Hydraulic Fracturing Wastewater Disposed, Between July 1 and December 31 of 2011 in PA (Adapted from PA DEP, 2013b)



Figure 42: Disposal Method, by Percent Volume of Total Hydraulic Fracturing Wastewater Disposed, Between January 1 and June 30 of 2012 in PA (Adapted from PA DEP, 2013b)

Oil and gas operators reused hydraulic fracturing wastewater more than any other management option between July 1, 2011 and June 30, 2012. Between the second-half of 2011 and the first half of 2012, the percent of total wastewater managed by reuse for other hydraulic fracturing operations increased from 60% to 81%. The centralized treatment plant option decreased from 22% to 9.4%, and the injection disposal well option decreased from 18% to 9.1%. For both the 2011 and 2012 data, oil and gas companies shipped their hydraulic fracturing wastewater to underground injection wells in Ohio, West Virginia, and Pennsylvania. From the data for the second-half of 2011, 97% of the wastewater disposed by underground injection was shipped to Ohio, 2.6% to West Virginia, and 0.03% to Pennsylvania. From the combined data for the second half of 2011 and the first half of 2012, 99% of the wastewater disposed by underground injection was shipped to Ohio, 1.1% to West Virginia, and 0.03% to Pennsylvania.

5.2.2 Lined Pits

Oil and gas companies pump hydraulic fracturing wastewater into lined pits, where it can evaporate. Given the toxic chemicals present in the wastewater, this evaporation can cause air pollution problems (Green, 2013). Additionally, the high levels

of radium in the wastewater can form radon gas, which when inhaled can decay in compounds such as polonium, bismuth, and lead, causing lung cancer (Resnikoff, 2013). A an example of a lined pit in a well site is presented in Figure 43. As shown, these pits are open to the atmosphere. The climate of Pennsylvania is categorized a humid continental, and the state receives an average of 41 inches of precipitation a year (The PA State Climatologist). Therefore, periods of heavy rainfall can cause the pits to overflow. The *PA Code Chapter 78. Oil and Gas Wells Section 56*, requires the lining of these pits (PA DEP, 2010). However, the liners used are made of a thin, plastic material, introducing the risk of liner puncture and leaking of wastewater through of the liner (Swarthmore College, 2013). Wastewater that is pumped into these lined impoundments is later pumped to holding tanks used to transport the wastewater off-site.



Figure 43: Lined Impoundments Store Hydraulic Fracturing Wastewater

(NETL, 2013)

5.2.3 Underground Injection

Oil and gas companies can dispose of hydraulic fracturing wastewater off-site by pumping it thousands of feet underground into porous rock formations, known as underground injection wells. In 1974, the creation of the Safe Drinking Water Act (**SDWA**) required the EPA to start reporting to Congress about waste disposal practices and set federal requirements for injection wells to prevent drinking water contamination. In order to regulate injection wells, the EPA uses the Underground Injection Control (**UIC**) Program. The SDWA mandates that each state have a UIC program, but EPA implements UIC programs for some states that do not adopt primary enforcement responsibility. Thirty-three states have primacy UIC programs, seven states share the responsibility with the EPA, and ten states have UIC programs run by the EPA. Pennsylvania has an UIC program implemented by the EPA, and Ohio and West Virginia enforce their own UIC programs (U.S. EPA, 2012).

Underground injection wells are divided into six classes: class II injection wells are used to dispose of fluids relating to oil and gas production. Oil and gas companies transport hydraulic fracturing wastewaters from PA to class II disposal wells in PA, Ohio, and West Virginia for underground injection disposal (PA DEP, 2013b). As of August 2012, there were 172,068 class II injection wells throughout the United States, including 1,855 in Pennsylvania, 2,455 in Ohio, and 759 in West Virginia (U.S. EPA, 2012).

There are three types of class II injection wells: enhanced recovery, disposal, and hydrocarbon storage. Operators use enhanced recovery wells to inject carbon dioxide, brine, steam or water into oil-bearing, underground rock formations in order to recover residual oil. They represent as much as 80% of all class II wells. Operators use disposal wells to inject brine and other fluids associated with oil and gas production, and they comprise about 20% of class II wells located across the state. Most of the Class II brine disposal wells are located in California, Kansas, Oklahoma, and Texas where hydraulic fracturing has occurred for over 50 years. Operators use hydrocarbon storage wells to inject liquid hydrocarbons; there are over 100 of these types of wells in the US (U.S. EPA, 2012). In 2012, the Ohio Department of Natural Resources reported that class II injection wells average a depth of 4,000 feet and can extend up to 13,000 feet deep.

As of June 2012, eight of the 1,855 class II injection wells in PA are disposal wells, all located in the western-half of PA, and four of them are in use. Three of the eight wells are commercial, so the operator can inject fluids from any energy company (Phillips, 2013). Bear Lake Properties had permits pending for two disposal wells in Warren County, which were approved in 2012 by the EPA. Despite appeals by PA citizens against the permit approval, the decision was not overturned (U.S. EPA, 2012). Table 14 describes the disposal wells in PA. The monthly injection allowance for each well ranged from 4,200 barrels to 45,000 barrels, with a median value of 27,000 barrels and an average of about 20,000 barrels. An effective and affordable underground injection well for brine disposal requires a permeable layer of earth that can absorb the brine waste as well as an impermeable earth layer to trap the fluids – both located at least 4,000 to 5,000 below the surface. Although the PA subsurface contains these rock layers, most of them are already being used for gas extraction or gas storage. Oil and gas operators would need to drill 12,000 to 15,000 feet below the surface in order to find a place for brine disposal, which costs significantly more than trucking the waste to the neighboring state of Ohio (Puko, 2013).

In 2011, 177 of the 2,455 class II injection wells in Ohio were disposal wells, and operators injected 368.3 million gallons of hydraulic fracturing wastewater into them. Ohio increased the fees for underground injection disposal for out-of-state users in 2011 (ODNR, 2012). As of January 2011, West Virginia had nine commercial class II disposal wells and 62 private wells for brine disposal out of the 759 total class II injection wells in the state (Hammer *et al.*, 2012). The Ohio subsurface contains ample shallow, unused, and permeable space for underground injection. The number of Class II brine disposal wells is low in Ohio because the state does not have as much shale drilling as PA yet, but the number continues to increase rapidly from the demand by PA fracturing operations (Puko, 2013).

In order to reduce formation clogging and well plugging from microbial growth or scale-forming chemicals, oil and suspended solids are removed from the wastewaters at the disposal site before injection into the well. Without this treatment, periodic downhole workovers are necessary to remove formation clogs (Hammer *et al.*, 2012).

Operator	Status	County	Injection formation	Monthly injection allowance (barrels)
Range Resources	Plugged, no longer operating	Erie	Gatesburg	45,000
Bear Lake Properties	Permit being challenged	Warren	Medina Whirlpool Sands	30,000
CNX Gas Company	Active	Somerset	Huntersville/Oriskany	30,000
Cottonwood	Active	Somerset	Oriskany	27,000
Columbia Gas	Active	Beaver	Huntersville/Oriskany	21,000
EXCO Resources	Shut down, pending EPA approval for future operations	Clearfield	Oriskany	4,260
EXCO Resources	Active	Clearfield	Oriskany	4,200
XTO Energy	Out of service: plugged and abandoned in 2009	Indiana	Balltown	N/A

Table 14: Characteristics of the Eight Permitted Class II Disposal Wells in PA (Adapted from Phillips, 2013)

In 1967, the U.S. Army Corps of Engineers and the U.S. Geological Survey concluded that injecting fluid into underground rock formations could cause earthquakes when they determined that a disposal well at the Rocky Mountain Arsenal caused "significant" seismic events near Denver, Colorado. The largest earthquake resulting from underground fluid injection shook the city of Colorado in 1967 with a magnitude of 5.5, followed by a series of smaller ones (Nicholson and Wesson, 1990). On November 5, 2011, a 5.6-magnitude earthquake hit Oklahoma, and was felt as far away as Illinois. There were three deep injection wells located under two and a half miles from the epicenter of the earthquake. According to the Oklahoma Geological Survey, approximately 50 measurable earthquakes per year occurred in the state prior to 2009, and only a few had a magnitude high enough to be felt. In 2010, 1,047 earthquakes

occurred in Oklahoma (Oklahoma Geological Survey, 2010). As of January 2013, there were approximately 10,400 Class II underground injection wells active in Oklahoma – about 6,000 are for enhanced oil recovery and the other 4,400 for storage of drilling waste (OCC, 2013). Most of the disposal wells store waste between 10,000 and 20,000 feet underground. As of January 2013, Oklahoma does not regulate injection wells in relation to fault lines (StateImpact, 2013).

In 2011, the Oklahoma Geological Survey released a report entitled "Examination of Possibly Induced Seismicity from Hydraulic Fracturing in the Eola Field, Garvin County, Oklahoma." The paper studied approximately 50 earthquakes that occurred in the area on January 18, 2011, and it also looked at a hydraulic fracturing operation in Eola Field of southern Gavin County that began on January 17, 2011. The well where the hydraulic fracturing process occurred is named Picket Unit B well 4-18, and earthquakes started seven hours after the first hydraulic fracturing stage. Out of the 50 earthquakes, 43 were large enough to be measured, and they ranged in intensity from 1.0 to 2.8milliDarcies. According to the report, most of the earthquakes occurred within 3.5 kilometers of the well that was hydraulically fractured. The earthquakes started seven hours after the first and deepest stage of hydraulic fracturing. The Oklahoma Geological Survey (OKGS) report concluded that there was a "possibility" that the January 18, 2011 earthquakes "were induced by" hydraulic fracturing, and that the "uncertainties in the data make it impossible to say with a high degree of certainty whether or not these earthquakes were triggered by natural means or by the nearby hydraulic-fracturing operation" (Holland, 2011).

In March 2011, a series of earthquakes started shaking Youngstown, Ohio, and earthquakes continued to occur in the area for nine months. By November 2011, Ohio authorities requested for scientists at Columbia University to monitor the earthquakes. A 2.7 quake hit the area on December 24, 2011 followed by one with a 4.0 magnitude on December 31, 2011. The seismologists at Lamont-Doherty Earth Observatory, a part of Columbia University, said that the earthquakes were "likely linked" to a disposal well used for injection of hydraulic fracturing wastewaters. One seismologist noted that the chance of disturbing an ancient fault by injection fluid underground is about 1 in 200 (LDEO, 2013). Over the nine months, 12 earthquakes struck the area with magnitudes from 2.1 to 4.0. They occurred in a cluster, less than one mile from and 2,500 feet below the Northstar 1 injection well in Youngstown owned by D&L Energy. In January of 2012, the governor of Ohio closed the Northstar 1 injection well, halted the applications for four proposed injection wells, and stopped the use of three other injection wells drilled by D&L Energy (LDEO, 2013 and Funk, 2013). The Ohio Department of Natural Resources published a preliminary report in March 2012 on the quakes that occurred in Youngstown, Ohio. It also linked the earthquakes to a nearby injection well, and established a set of permit requirements for brine disposal wells. One requirement includes adding a pressure-monitoring system to the well with an automatic shutoff if the well exceeds permitted pressure by the state (Ohio Department of Natural Resources, 2012). Additionally, injection wells are not allowed to penetrate Precambrian rock, and all wells currently penetrating the formation will be plugged (Smyth, 2013).

An energy geophysicist at Lamont-Doherty, who did not work on the Youngstown earthquake study, claimed that earthquakes "triggered by waste injection wells can potentially be more powerful" than earthquakes caused by hydraulic fracturing due to the injection of larger amounts of fluid for longer periods of time. The hydraulic fracturing process creates smaller earthquakes by fracturing rock from the injection of fluid at high pressures. However, the process occurs in "relatively weak, shallow shales that crack before building up much strain" (LDEO, 2013).

In 2011, the USGS issued a report that studied changes in seismic activity in areas of the midcontinent United States, such as Oklahoma. The USGS concluded:

"A naturally-occurring rate change of this magnitude is unprecedented outside of volcanic settings or in the absence of a main shock, of which there were neither in this region. While the seismicity rate changes described here are almost certainly manmade, it remains to be determined how they are related to either changes in extraction methodologies or the rate of oil and gas production" (Ellsworth, 2012).

None of the reports mentioned in this section claimed to have absolute certainty or overwhelming evidence to prove that underground injection wells cause earthquakes.

5.2.4 Treatment

Oil and gas companies can treat hydraulic fracturing wastewater either on-site or off-site. Two widely used off-site options are publicly owned treatment works (**POTWs**) and centralized waste treatment (**CWT**) facilities. POTWs are designed to mainly treat municipal wastewater; therefore, industrial wastewater is usually pretreated to prevent interference with the conventional, POTWs treatment processes. Permits limit the amount of hydraulic fracturing wastewater to less than 1% of the average daily flow in order to prevent high salt concentrations from disrupting biological treatment in POTWs (Hammer *et al.*, 2012). POTWs can remove suspended solids, some metals, and biodegradable organics, with or without pretreatment, but cannot remove salts or organics resistant to microbial degradation.

CWT facilities are dedicated to the treatment of brine or industrial wastewater. In order to remove these contaminants, CWT incorporates additional units to those used by POTWs for further treatment. For example, the use of pH control and the addition of chemicals to facilitate precipitation can remove iron, barium, or radium salts (Hammer *et al.*, 2012). Following treatment, CWT facilities can do the following with the wastewater: discharge to surface water with a discharge permit, discharge to sewers with a pretreatment permit for subsequent treatments at POTWs, or send to additional treatment facilities for salt removal.

On August 21, 2010, Pennsylvania Chapter 95 regulation created a guideline for oil and gas companies to treat hydraulic fracturing wastewater to the drinking water standard of 500 mg/L of TDS. 15 facilities out of 17 were exempt from this regulation by application through permits, and nine of the 15 were POTWs and the other 6 were dedicated brine treatment facilities. In April of 2011, however, the PA DEP gave notice to public wastewater treatment plants, telling them to stop handling wastewater from hydraulic fracturing operations (Rassenfoss, 2011). As of April 2011, 25 new dedicated brine facilities applied for permits from the PA DEP, and many of these plants plan to have desalination unit operations. Due to the large cost associated with the desalination process, oil and gas companies will not treat hydraulic fracturing wastewater for reuse unless the company deems the wastewater to be ineffective for reuse in hydraulic fracturing at other well sites (Hammer *et al.*, 2012). For example, the wastewater that

flows up to the surface within the first few days of fracturing, termed flowback, does not contain elevated levels of TDS. Therefore, this wastewater could meet the reuse standards of the oil and gas company and require no treatment prior to reuse.

More oil and gas companies are investing in research for new treatment methods to manage wastewaters from hydraulic fracturing activities in the Marcellus shale region. These new technologies involve crystallization and evaporation of salts, and some companies, such as General Electric, are developing mobile evaporator units. A drawback of this technology is the production of large amounts of the solid waste residual, such as salts (Abdalla *et al.*, 2011). Two main factors complicate treatment of hydraulic fracturing wastewaters: the variability in composition over time since the fracturing of the well and the variability in composition across the state of PA due to the use of different types and amounts of chemicals in fracturing fluids across the PA state (Abdalla *et al.*, 2011).

5.2.5 Reuse within Drilling Operations

The Pennsylvania DEP notice for public wastewater treatment plants to stop treating hydraulic fracturing wastewater became a mandate in May of 2011, which provided an incentive for companies to reuse their hydraulic fracturing wastewater (Rassenfoss, 2011). Oil and gas companies in the Marcellus Shale region can reuse the hydraulic fracturing wastewaters either with or without treatment as part of the fracturing fluid at other well sites. Wastewater that rises to the surface during and within a few days after the hydraulic fracturing of the well can be reused without treatment. Although flowback water contains significantly less TDS than produced waters, continual reuse of flowback water results in the increased concentration of TDS. When TDS reach a certain amount, then the wastewater requires treatment before additional reuse. This treatment can occur through an on-site pretreatment plant or by trucking it to an approved treatment facility. On-site plants consist of a trailer that can move from site to site. Pretreatment processes filter out sediment and remove metals such as barium and strontium, but do not remove the salts in the wastewater that contribute to the majority of the TDS. Treating hydraulic fracturing wastewater for reuse and on-site reduces the cost of transportation,

the risk of spills, and the amount of freshwater needed for a fracturing operation (Abdalla *et al.*, 2011).

Some companies that recycle a significant portion of the fracturing wastewater from their operations in the Marcellus Shale include: Chesapeake Energy, Range Resources, and Anadarko Petroleum Co. Chesapeake Energy reuses nearly 100% of the initial produced water from their Marcellus Shale hydraulic fracturing operations (Mantell, 2011). Range Resources has been using a mixture of fresh water and recycled flowback water since August 2009; and as of 2010 they "reused 96% of [their] produced water in Pennsylvania" (Rassenfoss, 2011). Range Resources's quick transition from beginning reuse in 2009 to 96% reused in 2010 is evidence that it is possible for companies in the Marcellus region who hydraulically fracture to switch to reuse.

5.2.6 Transportation

As shown in by the flowchart in Figure 40 from Section 5.2, several phases of the hydraulic fracturing wastewater management process include transportation. Trucking from natural gas production sites in PA can lead to increased costs for gas companies, harmful air emissions, road degradation, and noise and light pollution. Mitchell (2013) estimated that truck traffic averaged between 890 and 1,350 trips per well in the Marcellus Shale region of PA. These trips included transporting wastewater, fracturing fluid, and drilling supplies. These trucks weigh over 8,000 pounds, and their impacts to the surrounding area equate to 3.5 million car trips (Reynolds and Northrup, 2013 and Christopherson and Rightor, 2013). The lifespan of country roads and town roads in PA is approximately 30 and 13 years, respectively. Every extra 1,000 trucks on these roads decreases their lifespan by 13% and 2%, respectively. By 2010, in Bradford County, trucking traffic from natural gas development has damaged 1,000 to 1,300 miles of roadways (Mitchell, 2013). In some cases, local officials have allowed gas companies to exceed posted weight limits on roads if they fund repairs for those roads caused by their use (NADO Research Foundation, 2013). From 2008 to March 2012, gas-drilling companies have invested 411 million USD in repair for PA roads. Scott Christie, deputy secretary for highway administration for the PA Department of Transportation (**DOT**),

told the Pittsburgh Post-Gazette that he was not able to answer whether that amount of money was sufficient for the repairs (Schmitz, 2013).

Since January 2010, the PA DOT conducted 5,800 roadside inspections of fracturing-industry trucks. They found 13,000 driver and vehicle safety violations with 2,800 violations that could put the driver or truck out of service. 42% of the inspections resulted in pulling the driver or vehicle out of service, compared to the national average for all truck inspections of 24%. The top reason for pulling drivers off of the roads had to do with paperwork, and the most common vehicle deficiencies were faulty brake tubing and hoses, lighting, poorly adjusted and defective brakes, and improperly secured cargo (Schmitz, 2013). Table 15 quantifies the number of trucks required to bring a single well into production. The information from the previous paragraphs encompasses all truck traffic related to fracturing a well. Transporting the water used to fracture the well to the well site and removing the wastewater from the well site requires the largest number of trucks. Anywhere from 120 to 480 truckloads are required to remove hydraulic fracturing wastewater from a well site. Although reducing the amount of water used to fracture a well is not in the scope of this project, wastewater management options can reduce the impacts of trucking. For example, longer transportation distances can significantly increase monetary costs to the gas operators and the risk of environmental contamination from spills. The reuse option treats the hydraulic fracturing wastewater on-site, so it only requires transport from the well site where the wastewater was produced to the well site where the treated water will be reused.

Phase in well life cycle	Item transported	Truckloads
Drilling	Completion fluid and materials	10 - 20
Casing and cementing	Completion equipment (pipe, wellhead)	5
Fracturing	Hydraulic fracture equipment	150 - 200
	(pump trucks, tanks)	
Fracturing	Hydraulic fracture water	800 - 2,400
Fracturing	Hydraulic fracture sand	20 - 25
Fracturing	Flowback water removal	120 - 480
Well production	Well production equipment	5 - 10

Table 15: Trucking Needed for a Single Well Completion and Production (Bureau of Oil & Gas Regulation and NYSDEC, 2009)

5.2.7 Water Usage

Section 5.1.2 discussed the use of "Hydraulic Fracturing Fluid Component Information Disclosure" sheets from FracFocus. In addition to disclosing the chemical composition of the fracturing fluid, the sheets included the total water volume in gallons used in the hydraulic fracturing process for the well. For the 108 wells studied, the total volume of water used per well ranged from 689 gallons to 18.7 million gallons, with an average of 4.52 million gallons and a median of 4.39 million gallons. In order to estimate the water usage from hydraulically fractured wells in Pennsylvania, the median value can be multiplied by the number of unconventional wells drilled in 2012 in the state. Unlike conventional wells, unconventional wells utilize the hydraulic fracturing process to produce natural gas. The PA DEP issued 4,090 total well permits between January and December 2012. 1,606 were for conventional wells and 2,484 were for unconventional wells. Of the 2,390 wells drilled in that time period, 1,365 wells were unconventional (PA DEP, 2013c). Therefore, the median water usage for unconventional drilling in PA in 2012 amounted to approximately 6 billion gallons.

In order to perform the hydraulic fracturing process on a well, operators must first obtain the water resources necessary to complete the job. If the well is located in a region with a small water supply or if the area is under drought conditions, then obtaining the water necessary for hydraulic fracturing could be difficult (Soeder and Kappel, 2009). Furthermore, water withdrawals required for hydraulic fracturing could put a strain on the local water resources. For example, if water is taken from a stream during a low flow period, it could impact the municipal drinking water supply, other industry supply, recreational uses, aquatic life, and the local ecosystem that is dependent on the river (Arthur *et al.*, 2013). If the local watershed cannot supply the needed water, then it must be trucked or piped to the well location. As discussed in section 5.2.6, transportation via trucking can have a significant negative impact on local infrastructure and environment. In Pennsylvania, if water is withdrawn in excess of 10,000 gallons per day as averaged over 30 days, then the entity withdrawing the water must register and report their water withdrawal as well as submit a Water Management plan to the PA DEP (Arthur et al., 2013). If the water is withdrawn from a fish-inhabited body of water in PA, then the operator must also acquire a permit from the PA Fish and Coat Commission (PFBC).

Water use and availability is therefore an important consideration upon siting a well. The water used for the hydraulic fracturing process must requires management when it flows up to the surface as wastewater – focus of this chapter.

5.3 Wastewater Treatment Design

Based on the discussion of current hydraulic fracturing wastewater management practices in Section 5.2 of the report, the project team designed an on-site treatment plant that produces water for reuse in hydraulic fracturing operations by gas companies in the Marcellus Shale region of PA. This section describes the quality and quantity of the wastewater to treat, evaluates the treatment technology alternatives, and provides a design proposal to treat the wastewater.

5.3.1 Wastewater Volume

As explained in the introduction to this chapter, hydraulic fracturing wastewaters can be broken down into two parts: flowback and produced water. Flowback mainly consists of the fracturing fluid that oil and gas companies inject into a well during the fracturing process, and produced water mainly consists of natural formation water present in the shale development. Operators from the Marcellus Shale region of PA recover 9 to 35% of fracturing fluid pumped into the well as flowback, and the majority of it returns to the surface within two to eight weeks of the fracturing of the well. Approximately 60% of the flowback that will return to the surface does so with four days of the fracturing of the well. After this time period, production of the wastewater, referred to as produced water, sharply declines to a few barrels per day for the remainder of the lifespan of the well (Bureau of Oil & Gas Regulation and NYSDEC, 2009).

Section 5.2.1 introduced the data from 2011 and 2012 waste reports submitted by oil and gas operators to the PA DEP. Designing an on-site treatment system requires knowing the volume of hydraulic fracturing wastewater produced per site. The PA DEP waste reports compiled waste data by disposal method. Therefore, each well that produces wastewater could be listed several times on the waste report if the operator divided the wastewater amongst several different management options. In order to

determine the volume of hydraulic fracturing wastewater per site, the data were imported to Microsoft Excel where the subtotal function summed the wastewater quantities by well permit number. Table 11 contains the results of the analysis.

(Adapted Holl 1 A DEL, 2013)					
Type of well			All types	Horizontal	Vertical
# of wells		3,235	2,658	577	
Total volume	million barre	els (bbl)	20.2	18.2	2.02
	million gallo	ns (gal)	636	573	63.6
Volume per well	Minimum	bbl	0.02	0.02	0.84
		gal	0.63	0.63	26.5
	Median	bbl	2.95×10^3	3.37×10^3	$1.06 \ge 10^3$
		gal	9.30×10^4	$1.06 \ge 10^5$	3.33×10^4
	Average	bbl	6.25×10^3	6.84×10^3	3.50×10^3
		gal	1.97 x 10 ⁵	2.15×10^5	$1.10 \ge 10^5$
	Maximum	bbl	1.29×10^5	1.29×10^5	6.36×10^4
		gal	4.05×10^6	4.05×10^6	2.00×10^6

Table 16: Hydraulic Fracturing Wastewater Production Amounts, from Wells Analyzed, Based on Type of Well (Adapted from PA DEP, 2013)

As shown, the median volume of wastewater produced per well ranges from 33,000 gallons for a vertical well to 106,000 gallons for a horizontal well. Vertical wells can produce up to 2 million gallons, and horizontal wells up to 4 million gallons. The amount of wastewater produced by an individual well decreases over time. Therefore, the extreme values could be explained by the time since the well was fractured. For example, larger amounts of wastewater produced may correspond to wells that were recently fractured. The waste report data analyzed showed that 3,235 wells produced hydraulic fracturing wastewater over the course of a year. The PA DEP did not specify between conventional and unconventional wells drilled in 2011. However, in 2012 the PA DEP reported that 1,365 unconventional wells were drilled. This could mean that thousands of wells are still producing wastewater years after being hydraulically fractured.

5.3.2 Wastewater Characteristics

Section 5.1.2 analyzed the use of chemicals in the hydraulic fracturing fluids disclosed by oil and gas companies through FracFocus. For the 108 wells studied, oil and gas companies used 158 different chemical additives with registered CAS numbers. Oil and gas companies divide the chemical components of their developed fracturing fluid into additive types named after the purpose of the chemical in the fluid. While oil and gas companies may choose different chemicals within each purpose, these chemicals all share similar chemical composition and characteristics that allow them to achieve the intended purpose.

Table 17 lists the eleven chemical additives based upon the designations on the "Hydraulic Fracturing Fluid Components Information Disclosure" sheets from FracFocus for the 108 wells studied. The second column includes the number of chemicals listed on the FracFocus data sheets that fall into the corresponding additive. Figure 44 shows a graphical representation of the chemical additives presented in Table 17. The category proppant or water/base fluid are not included in Figure 44 or in Table 17 because they are not chemical additives. The purpose of the proppant, described in section 2.3, is to hold open the fractures formed in the shale, allowing the gas to travel through the fractures for capture. Through this analysis, it was found that crystalline silica/quartz sand/silicon dioxide, CAS number 14808-60-7, was the most frequently used proppant.

Chemical additive	Most frequently used chemical	Chemical CAS Number	Frequency	Concentratio n range (mg/L)	Median concentration (mg/L)
Biocide/ disinfectant	Ethylene Glycol	107-21-1	76	0.0 - 8,900	43
Friction reducer/ scale inhibitor	Petroleum Distillates	64742-47- 8	86	0.0 - 1,700	220
Corrosion inhibitor	Propargyl Alcohol (2- Propynol)	107-19-7	58	0.0 - 8.4	0.65
Breaker	Hemicellulas e enzyme	9012-54-8	19	0.0 - 2.59	0.20
Acid	Hydrochloric acid	7647-01-0	120	0.0 - 9,300	560
Surfactant	Citrus Terpenes	94266-47- 4	6	1.7 – 570	140
Iron control/ stabilizing agent	Citric Acid	77-92-9	23	0.5 - 90	17
Gelling agent	Guar Gum	9000-30-0	28	0.0 - 160	16
pH adjusting agent	Potassium Carbonate	584-08-7	10	0.0 - 160	2.7
Cross linker	Ethoxylated Oleylamine	26635-93- 8	4	Concentration not recorded	
Oxygen scavenger	Ammonium Bisulfite	10192-30- 0	2	1.00 - 940	119.76

Table 17: Frequency of Chemical Additives, from Wells Analyzed (Adapted from FracFocus, 2012)



Figure 44: Frequency of Chemical Additive Purposes from Wells Analyzed (Adapted from FracFocus, 2012)

Some of the wells analyzed listed the same chemical multiple times on its well data sheet, such as hydrochloric acid which was recorded as being used 120 times throughout the 108 well data sheets. The five main chemical additives found to be present in hydraulic fracturing wastewater are: biocide/disinfectant, friction reducer/scale inhibitor, corrosion inhibitor, breaker and acid. The majority of the 108 wells studied contain one or more of the chemicals from these five additive types. Furthermore, the chemicals from each additive type can affect the appropriate treatment technology to use in treating the hydraulic fracturing wastewater. These issues are introduced in Table 18 along with the purpose of each additive type, which plays a role in the characteristics of the chemicals that fall into each of the additive types. The treatment system developed in this report is intended to treat the fracturing fluid chemicals that fall under the additive types identified.

Table 18: Impacts of Top Additive Types on Potential Treatment Technologies
(Adapted from Green Frac, 2013; GWPC and IOGCC, 2012)

Additive type	Purpose	Potential treatment technology concerns
Acid	Helps dissolve minerals and create cracks in rock formations	Certain pHs can foul membranes
Biocide/disinfectant	Eliminates bacteria in water that produces corrosive byproducts	May contain hazardous constituents
Breaker	Allows delayed breakdown of gel polymer chains	Reaction with other additives produces ammonia and sulfate salts
Corrosion inhibitor	Prevents corrosion of pipes	Bonds to metal surfaces downhole
Friction reducer/scale inhibitor	Minimizes friction between fluid and pipe	Product attaches to formation downhole

In order to determine the concentrations of the top fracturing fluid chemical within each additive type, a frequency analysis was performed to find the most commonly used chemicals for each. A table was created for each purpose that lists all of the fracturing fluid chemicals by CAS number from that purpose as well as the number of times that the chemical appeared in the studied "Hydraulic Fracturing Fluid Components Information Disclosure" sheets from FracFocus, explained in Section 5.2.2. These datasheets are located in the supplementary document. Table 19 includes the top chemical from each purpose as well as their respective concentration ranges and median concentration in the various fracturing fluids rounded to two significant digits. The chemical disclosure sheets from FracFocus provided the maximum concentrations of each chemical in the hydraulic fracturing fluid by percent mass. The top chemical concentrations were estimated using this information, and the calculations are shown in the supplementary Microsoft Excel document.

CAS number	Purpose in fracturing fluid	Chemical name	Concentration range (mg/L)	Median concentration (mg/L)
7647-01-0	Acid	Hydrochloric Acid	0.0 - 9,300	560
107-21-1	Biocide/ disinfectant	Ethylene Glycol	0.0 - 8,900	43
9012-54-8	Breaker	Hemicellulase enzyme	0.6 - 440,000	110,000
107-19-7	Corrosion inhibitor	Propargyl Alcohol (2-Propynol)	0.0 - 8.4	0.65
64742-47-8	Friction reducer/ scale inhibitor	Petroleum Distillates	0.0 - 1,700	220

Table 19: Top Chemical within Each of the Top Five Chemical Additives, from Wells Analyzed (Adapted from FracFocus, 2012)

As stated in Section 5.3.1, operators from the Marcellus Shale region of PA recover 9 to 35% of fracturing fluid pumped into the well as flowback. Another estimate, from the introduction to this chapter, for the volume of flowback fluid recovered is 10 to 30% of that injected. The proposed treatment system will use the liberal estimate of 30% flowback recovery. Therefore, the concentration of the top chemical in each additive types from Table 19 were multiplied by 0.30 to determine concentrations for the wastewater produced from hydraulic fracturing. The treatment system developed in this project report is intended to treat hydraulic fracturing wastewater with the characteristics detailed in Table 20. The table includes constituents from the injected fracturing fluid, as explained in this Section 5.3.2, and the natural formation water already present in the shale, described in Section 5.1.3.

Constituent	Unita	Concentration	Median
Constituent	Units	range	concentration
Hydrochloric Acid	(mg/L)	0.0 - 2,800	170
Ethylene Glycol	(mg/L)	0.0 - 2,700	13
Hemicellulase enzyme	(mg/L)	0.6 - 440,000	110,000
Propargyl Alcohol (2-Propynol)	(mg/L)	0.0 - 2.5	0.2
Petroleum Distillates	(mg/L)	0.0 - 510	66
Crystalline Silica (Quartz Sand, Silicon Dioxide)	(mg/L)	0.06 - 39,000	9,900
Total dissolved solids	(mg/L)	1,470 - 358,000	88,500
Radium	(pCi/L)	39 - 18,045	1,552

Table 20: Wastewater Characteristics of Treatment System Influent

5.3.3 Wastewater Treatment Goals

The goal of treating the hydraulic fracturing wastewater is to make it reusable in other hydraulic fracturing operations. Therefore, guidelines for what is acceptable for reuse are required. Through correspondence with an Environmental Health and Safety (**EHS**) expert from one of the top ten hydraulic fracturing operators in PA, who prefers to remain anonymous, the team of students acquired and gained permission to use the company's internal guidelines for reuse of fracturing wastewater. These guidelines were used for the effluent goal of the treatment deign proposed in this project, and are shown in Table 21.

The goals for the treatment system developed in this project report are shown in Table 22. The table connects the wastewater characteristics provided in Table 20 in Section 5.3.2 to the reuse standards from Table 21, above. Some cells are left blank on purpose, as there was no connection found between the chemical constituent and the reuse standards. Another treatment goal is the complete removal of the proppant (sand) from the wastewater.

Table 21: Reuse Standards

(Adapted from One of the Top Ten Hydraulic Fracturing Operators in PA Internal Reuse
Guidelines)

Charact	Goal	
	Specific gravity	< 1.08
	Total dissolved solids	< 120,000 ppm
Overall criteria	Total hardness as CaCO ₃	< 26,000 ppm
	Suspended solid size	< 10 micron
	pH	5 –7
Anions (ppm)	Bicarbonate	< 300
	Sulfate	< 50
	Chloride	< 70,000
	Sodium	< 36,000
	Calcium	< 8,000
Cations (ppm)	Magnesium	< 1,200
	Potassium	< 1,000
	Iron	< 10

Table 22: Parameters to be Monitored that Affect Reuse Standards

Constituent	Identifie	d as con	cern	Median expected influent concentration		Effluent goal	
	FracFocus	USGS	Reuse	Range	Units		
Hydrochloric Acid	\checkmark		~	170	(mg/L)	pH 5 – 7	
Ethylene Glycol	~			13	(mg/L)	Sulfate <50ppm; Calcium <8,000ppm; Magnesium <1,200ppm;	
Hemicellulase enzyme	\checkmark			33,00 0	(mg/L)	pH 5 – 7	
Propargyl Alcohol (2- Propynol)	~			0.2	(mg/L)		
Petroleum Distillates	~			66	(mg/L)		
Total dissolved solids		~	~	88,50 0	(mg/L)	< 120,000 ppm	
Radium		~		1,552	(pCi/L)	Sulfate <50ppm	

5.3.4 Evaluation and Selection of Treatment Technologies

To generate a list of treatment technologies, the group gathered information from numerous sources: information on water, wastewater, and industrial water treatment from industrial organizations; fact sheets on drinking water treatments from public organizations; publications on water treatment processes from professional societies; reports on wastewater and produced water treatment from nonprofit organizations; and PowerPoint presentations on produced water treatment from a university department and an industrial organization. In total, there were 15 treatment technologies included in the preliminary list. The complete list and evaluation details can be seen in Appendix A: Treatment Technology Data. From this primary list, six were eliminated: capacitive deionization due to it being a "novel desalination technology" (Xu et al., 2011), forward osmosis and membrane distillation due to them being "novel membrane processes" (Xu et al., 2011), nanofiltration due to it being an "inappropriate standalone technology" for produced water (Xu et al., 2011), electrodionization due to it being a poor treatment technology for produced water (CSM, 2009), and ion exchange due to its inability to treat high TDS levels (Clifford et al., 1986). Thus, the narrowed list contained 9 treatment technologies for further evaluation.

Six criteria were used to evaluate potential treatment technologies for removing the chemical constituents from the wastewater. Each criterion had its own multiplier based on importance. A summary of the point system is presented in Table 23, with more details to follow. The criteria are presented by the most important, with the highest weighting, to the least important, with the lowest weighting.

Criterion	Rating	Weight
Contaminant removal	1 - 3	2.5
Mobile capability	1 - 3	2.5
Energy efficiency	1 - 3	1.5
Low O&M cost	1 - 3	1.5
Low capital cost	1 - 3	1
Life cycle period	1 - 3	1

Table 23: Criteria Used for Treatment Evaluation

The group discussed and decided on the weighting for each criterion. Since the purpose was to create on-site, mobile units to treat wastewater for reuse for fracturing other well sites, the most important criteria were contaminant removal and mobile capability. Next, the group chose energy efficiency and low operation and maintenance cost as the next most important criteria since these dictate the long-term cost benefit of investing in the unit. While the energy efficiency overlaps with operation and maintenance cost, the overall O&M cost provided by the Colorado School of Mines (2009) included other components, such as "levels of monitoring and control required." Lastly, low capital cost and life cycle period were given the lowest weighting, since the capital cost is paid only once and the unit can be replaced. Each criterion was weighted such that the total of the weights summed to 10.

Each criterion used a uniform scale rating: 1 is for low, 2 is for medium, and 3 is for high. For the first criterion of contaminant removal, a technology received a higher rating if it can remove multiple contaminants being targeted. The four chemical categories, along with chemical examples, that the contaminants belonged to were dissolved inorganics (acids); dissolved monovalent ionic species (Na, K, Cl, Br, NH₄); dissolved multivalent ionic species (Ca, Mg, Fe, Sr, NORMs); and suspended solids (sand, bacteria). If a technology could treat all of them, it received a rating of 3; if a technology could treat two or three of them, it received a rating of 2; and if a technology could treat only one of them, it received a rating of 1. Table 24 shows the list of treatment technologies, the chemical category each is able to treat (denoted by x), the raw rating, and the weighted rating. The treatment technology that received the highest weighted rating was reverse osmosis, at 7.5, and the treatment technologies that received the lowest weighted rating were crystallizer, evaporation, and wind aided intensified evaporation, at 2.5.

Table 24: Contaminant Removal Criterion Evaluation (¹Hammer *et al.*, 2012. ²CSM, 2009. ³ Haggstrom, 2011. ⁴ NDWC, 1999. ⁵ SDWF, 2013. ⁶ Xu, *et al.*, 2011)

Technology	Dissolved inorganics	Dissolved monovalent ionic species	Dissolved multivalent ionic species	Suspended solids	Raw rating	Weighted rating
Electrodialysis	\mathbf{x}^1	\mathbf{x}^{1}			2	5
Electrodialysis reversal	\mathbf{x}^{1}	\mathbf{x}^{1}			2	5
Microfiltration	\mathbf{x}^2		x ³	\mathbf{x}^4	2	5
Multi-effect distillation	x ³	\mathbf{x}^{1}			2	5
Multi-stage flash	x ³	\mathbf{x}^{1}			2	5
Reverse osmosis	\mathbf{x}^{1}	\mathbf{x}^{1}	\mathbf{x}^{1}	x ⁵	3	7.5
Ultrafiltration	\mathbf{x}^2		x^3	x^4	2	5
Vapor compression	x ³	x ¹			2	5
VSEP	x ⁶	x ¹			2	5

For mobile capability, a unit received a higher rating if it is more portable. Portability was evaluated based on the infrastructure needs, compactness of the required parts, and the transportability of the whole unit. Table 25 shows the list of treatment technologies, details on their mobile capability, the raw rating, and the weighted rating.

Technology	Fachnology Datails		Weighted
Technology	Details	rating	rating
Electrodialysis	NO special infrastructures needed; Requires		5
	housing or shed		
Electrodialysis	NO special infrastructures needed; Requires	2	5
reversal	housing or shed	2	5
Microfiltration	Requires feed tank, feed pump, coagulant dosing	2	5
whereintration	pump, rack structure for membrane modules	2	5
Multi offoot	Requires large physical plant size, low-pressure		
distillation	steam from dedicated generation or cogeneration	1	2.5
distillation	with adjacent power plants		
Multi staga	Requires large physical plant size, low-pressure		
flach	steam from dedicated generation or cogeneration	1	2.5
118511	with adjacent power plants		
Reverse	Reverse Can be automated and mobile		75
osmosis	Can be automated and mobile	,	1.5
Illtrafiltration	Requires feed tank, feed pump, coagulant dosing	2	5
Ontaintration	pump, rack structure	4	5
Vapor	Requires large physical plant size, low-pressure		
vapor	steam from dedicated generation or cogeneration	1	2.5
compression	with adjacent power plants		
VSEP	Requires about 17' ceiling clearance; Compact	2	5

Table 25: Mobile Capability Criterion Evaluation (CSM, 2009)

If a technology cannot be built on-site due to its requirements, then it received a rating of 1. For example, multi-effect distillation, multi-stage flash, and vapor compression require power plants to support their processes, which would require a large investment in time and money. If a technology can be build on-site and has the potential of mobility, then it received a rating of 2. For example, electrodialysis requires housing and VSEP requires a certain ceiling clearance, so both have some limitations to where they can be relocated. The technology that received the highest rating of 3 was the one that was compact and mobile. The treatment technology that received the highest weighted rating of 7.5 was reverse osmosis.

For energy efficiency, the theoretical minimum energy requirement to desalinate seawater by osmosis is 1 kWh/m³ of produced water or 3.8 kWh/kgal (Water Reuse

Desalination Committee, 2011). If a technology consumes equal to or less than this amount of energy, it received a higher rating and vice versa. Table 26 shows the list of treatment technologies, the amount of energy each consumes, the raw rating, and the weighted rating. Most of the technologies received a high rating of 3. There was one outlier, multi-stage flash, which received a rating of 1 due to its high-energy consumption of 91 kWh/kgal. The technologies that consumed energy greater than the minimum energy requirement, but much less than the highest energy amount, received a rating of 2.

Technology	Average energy consumption (kWh/kgal)	Raw rating	Weighted rating
Electrodialysis	1.89 ¹	3	4.5
Electrodialysis reversal	1.89^{1}	3	4.5
Microfiltration	$< 2^{2}$	3	4.5
Multi-effect distillation	38 ³	2	3
Multi-stage flash	91 ³	1	1.5
Reverse osmosis	18.0^{1}	2	3
Ultrafiltration	$< 2^2$	3	4.5
Vapor compression	30^{3}	2	3
VSEP	0.27^{3}	3	4.5

Table 26: Energy Efficiency Criterion Evaluation (¹ Hammer *et al.*, 2012. ² NDWC, 1999. ³ CSM, 2009)

For Operation and Maintenance cost, each technology received a higher rating if it requires a lower cost. Table 27 shows the list of treatment technologies, each of their operation and maintenance cost, the raw rating, and the weighted rating. O&M costs were obtained from CSM (2009). From the amount for each cost listed in the table, the average was calculated to be \$2.47 per 1000 gallons. Ratings were 1 for technologies with costs greater than the average and 3 for costs lower than the average.

Technology	O&M cost	Raw rating	Weighted rating
Electrodialysis	<\$3.6/kgal	1	1.5
Electrodialysis reversal	<\$3.6/kgal	1	1.5
Microfiltration	\$1.5/kgal	3	4.5
Multi-effect distillation	\$2.6/kgal	2	3
Multi-stage flash	\$3/kgal	1	1.5
Reverse osmosis	\$0.70/kgal	3	4.5
Ultrafiltration	\$1.5/kgal	3	4.5
Vapor compression	\$1.8/kgal	3	4.5
VSEP	\$0.37/kgal	3	4.5

Table 27: Low O&M Cost Criterion Evaluation (CSM, 2009)

For low capital cost, each technology was rated in the same manner as O&M cost. If a treatment technology requires a lower amount to be paid, it received a higher rating. Table 28 shows the list of treatment technologies, each of their capital cost, the raw rating, and the weighted rating. Capital costs were determined from Hammer *et al.* (2012) and CSM (2009). For the capital costs of each treatment technology obtained from the sources mentioned, all of the costs were added and the overall average calculated as \$4.06/gpd. If a technology capital cost was approximately the same as the average amount, it received a rating of 2. Higher costs were rated 1, and lower costs 3.

Technology	Capital cost	Raw rating	Weighted rating
Electrodialysis	\$2.4/gpd; Same as RO ¹	2	2
Electrodialysis reversal	\$2.4/gpd; Same as RO ¹	2	2
Microfiltration	\$1.5/gpd ²	3	3
Multi-effect distillation	\$7/gpd ²	1	1
Multi-stage flash	\$7.3/gpd ²	1	1
Reverse osmosis	\$2.4/gpd ²	2	2
Ultrafiltration	\$1.5-2.4/gpd; More expensive than MF, less expensive than RO ¹	2	2
Vapor compression \$4.65/gpd ²		1	1
VSEP	< \$7/gpd; Less expensive than MED ²	1	1

Table 28: Low Capital Cost Criterion Evalution (¹ Hammer *et al.*, 2012. ² CSM, 2009)

For the life cycle period, the overall average number of years of the lifetime of each treatment technology was calculated as 11.2 years. Table 29 shows the list of treatment technologies, details on their life cycle with the average in parenthesis, the raw rating, and the weighted rating. If a technology life cycle period was approximately the same as the average number of years, it received a rating of 2. Lower lifetime was rated 1, and higher lifetime 3.

Technology	Life cycle period (years)		Weighted rating
Electrodialysis	4 - 5	1	1
Electrodialysis reversal	4 - 5	1	1
Microfiltration	7 - 10	2	2
Multi-effect distillation	20	3	3
Multi-stage flash	20-30	3	3
Reverse osmosis	3 - 7	2	2
Ultrafiltration	7 - 10	2	2
Vapor compression	20	3	3
VSEP	< 3 – 7; Shorter than conventional membranes due to high sheer force	2	2

Table 29: Life Cycle Period Criterion Evaluation (CSM, 2009)

Appendix A includes additional details and references for the criteria rating of each technology. The data for each treatment technology was input into Microsoft Excel 2010 to evaluate the scores based on the criteria stated above. Table 30 shows a summary of the analysis described above. The table lists each treatment technology, the criterion which it received the highest rating (denoted by x), and its total number of points. From Table 30, the treatment technologies that received the highest total points were microfiltration and reverse osmosis with 26.5 and 24, respectively, out of the maximum possible 30 points. Furthermore, each of these technologies was ranked the highest or among the highest technologies for three different criteria: microfiltration for energy efficiency, low O&M cost, and low capital cost, reverse osmosis for contaminant removal, mobile capacity, and low O&M cost. Therefore, reverse osmosis was chosen as the desalination treatment and microfiltration as the pretreatment to avoid membrane fouling. Both of the treatments are membrane processes

Treatment	Contaminant removal	Mobile capability	Energy efficiency	Low O&M cost	Low capital cost	Life cycle period	Total
Electrodialysis			Х				19
Electrodialysis reversal			x				19
Microfiltration			Х	Х	Х		24
Multi-effect distillation						х	17.5
Multi-stage flash						X	14.5
Reverse osmosis	х	Х		X			26.5
Ultrafiltration			Х	Х			23
Vapor compression						X	17.5
VSEP			Х	Х			22

Table 30: Summary of Treatment Technology Evaluation

Membrane processes are unit operations in which water passes through a porous membrane. A porous medium is a solid material that consists of multiple holes or pores of various sizes. The location of the pores within the solid material, the size and shape of the pores, and the connectivity of the pores characterize the porous medium. The surface and/or pores of the medium trap the solid particles present in the water, while the fluid, referred to as the filtrate, passes through. Therefore, membrane processes separate suspended particles from water (Cheremisinoff, 2002). Water that passes through a membrane is called the permeate; the retentate does not pass through the membrane (Crittenden *et al.*, 2005).

Microporous membranes were first patented in the 1920s, and were not used on an industrial scale until the 1950s for applications such as waste treatment and sterilization of pharmaceuticals. Drinking water utilities began designing membrane filtration units to remove microbiological contaminants in the 1980s (Crittenden *et al.*, 2005). Municipal water treatment utilizes four different types of pressure-driven membranes: microfiltration (**MF**), ultrafiltration (**UF**), nanofiltration (**NF**), and reverse osmosis (**RO**) membranes. These four types can be further divided into two physiochemical processes: membrane filtration and reverse osmosis (Crittenden *et al.*, 2005). The different types are distinguished by the pore sizes of the filter and the materials filtered out, as outlined in Table 31.

Physiochemical process	Membrane type	Pore size (µm)	Materials rejected
Membrane filtration	Microfiltration	0.1	Particles, sediment, algae, protozoa, bacteria
Membrane filtration	Ultrafiltration	0.01	Small colloids, viruses
Reverse osmosis	Nanofiltration	0.001	Dissolved organic matter, divalent ions (Ca ²⁺ , Mg ²⁺)
Reverse osmosis	Reverse Osmosis	Nonporous	Monovalent species (Na ⁺ , Cl ⁻)

Table 31: Main Types of Pressure-Driven Membrane Processes(Adapted from Crittenden, et al., 2005)

Membrane filtration utilizes MF and UF membranes, and it aims to completely remove the targeted solids from a waste stream. The feed stream of membrane filtration is a suspension, or two-phase system, and the solid phase to be removed can consist of: algae, bacteria, colloids, sediment, and viruses. Osmosis is when water preferentially diffuses through a semipermeable membrane due to a concentration gradient. In water treatment, reverse osmosis is used to remove specific dissolved contaminants, such as pesticides, arsenic, and radionuclides, and produce potable water from seawater. Nanofiltration membranes are used to soften hard waters by removing calcium and magnesium, as well as remove naturally occurring materials in order to reduce the concentration of disinfection byproducts. Membrane filtration mainly removes solids by straining, or size exclusion, regardless of the influent concentration and pressure as well as other operational parameters. Reverse osmosis, on the other hand, depends on the pressure, solute concentration, and water flux rate of the influent because RO utilizes a diffusion mechanism for removal (Crittenden *et al.*, 2005).
5.3.5 Treatment Process Overview

Figure 16 outlines the proposed treatment system design for the hydraulic fracturing wastewaters detailed in sections 5.3.1 - 5.3.3. First, operators pump the wastewater from the well to a holding tank. Sedimentation occurs in the holding tank in order to remove the sand from the wastewater as a pretreatment to the next stage: microfiltration. Microfiltration acts as a pretreatment to reverse osmosis. Reverse osmosis removes dissolved solutes such as sodium, chloride, and calcium from a solution. The product water is returned to a holding tank for transport to another well site in PA for reuse in the hydraulic fracturing process. The system therefore consists of three main units: sedimentation, microfiltration, and reverse osmosis. The next three sections, explain these units in detail.

As shown in Figure 45, the system will treat the wastewater from hydraulic fracturing as a batch system based upon the volume and characteristics of wastewater in a holding tank. The holding tank will be filled to full then treated; therefore, a well site will utilize multiple holding tanks. These tanks are already present on a well site as shown in Figure 2 from section 2.1. This was done for two main reasons. First, the volume of hydraulic fracturing wastewater varies significantly on a well-to-well basis as presented in section 5.3.1. Furthermore, the volume of wastewater produced by the well can differ dramatically over the lifespan of the well as explained in the introduction to chapter 5. Treating the wastewater per holding tank volume provides a consistent volume to develop the design from and for the system to function independent of the total volume that the well produces over its lifespan. The second reason is that the wastewater composition changes over the lifetime of the well. The wastewater that initially rises from the well mostly consists of the composition of the injected fracturing fluid, but over time will shift to a composition resembling the natural formation present in the Marcellus Shale Formation. Again, running the treatment process per holding tank volume allows for minor adjustments in the process based upon the wastewater composition. For example, sand is injected into the well as part of the fracturing fluid during the hydraulic fracturing process. Therefore, it is present in the wastewater within the weeks following the

fracturing procedure, but it may not be present later on in the well lifespan when the wastewater composition shifts to that of the natural formation water in the shale.



Figure 45: Schematic of Treatment System

5.3.6 Pretreatment to Reverse Osmosis

Proper pretreatment to a RO system protects membrane integrity, resulting in increased effectiveness and longevity of the process. Membrane performance efficiency decreases when substances from the feed water chemically alter the RO membrane. Oxidation and hydrolysis are two of the main chemical reactions that alter membranes, but the susceptibility of membranes to chemical reactions depends on their chemical composition. Membrane fouling refers to the loss of performance of a membrane, and it can result from the accumulation of substances in the feed water. When this happens, a higher operating pressure is required to maintain the flux and quality of the product water, which leads to increased energy consumption and cost of the system. Four main mechanisms induce membrane fouling: deposition of suspended solids, inorganic scale deposits from soluble salt precipitation, excessive biological growth, and organic interaction with the membrane (AWWA, 2007). Scaling occurs when particles precipitate onto the membrane surface. The dissolved salt concentration is highest at the surface of the membrane because as feed water passes through it, dissolved salt particles are left near its surface. When the concentration of a dissolved salt reaches a certain level, the solubility of the salt "can be exceeded," causing it to precipitate. Scaling can cause a decrease in feed water flow rates as well as irreversibly damage the membrane. For feed waters with high levels of salts, "the concentration of salts in the concentrate stream is limited to the point at which the membrane process becomes uneconomical without pretreatment," especially in waters with high levels of barium, calcium, carbonates,

strontium, and sulfates (AWWA, 2007). Sand, used as a proppant in fracturing fluid, represents the suspended solids present in hydraulic fracturing wastewaters. The treatment system developed in this project utilizes the sedimentation process to remove sand from the wastewater prior to the membrane filtration processes of MF and RO.

5.3.7 Sedimentation Unit Design

The purpose of a sedimentation basin is to remove larger suspended solids in water, thereby preventing the filters in the microfiltration unit that follows the sedimentation unit in the treatment process from clogging. Clarification of the water occurs when larger particles settle due to gravity to the bottom of the tank where they accumulate and are removed as sludge. Figure 46 highlights the individual unit. Refer to Figure 45 for the location of the sedimentation unit in the treatment process. The primary purpose of a sedimentation tank is to remove the proppant and other larger particles from the hydraulic fracturing wastewater. Since the primary purpose is the removal of sand, which as explained in the below calculations, will settle out in a reasonable time frame without the use of coagulants, no coagulants were used in this design.



Figure 46: Schematic Drawing of Settling Tank Unit

This rest of this section describes the steps used to develop the proposed design for the sedimentation unit. The sedimentation process will take place once the operator pumps the hydraulic fracturing wastewater from the well to the holding tank. The tank will start working once full of the pumped wastewater. The standard capacity of a holding tank is 500 barrels or 21,000 gallons of water (McGrath RentCorp, 2013 and Global Tank, 2013). An example of a holding tank for fracturing wastewater is shown in Figure 47. As shown, holding tanks are rectangular with a wheel cutting into the back corner for ease of transport when attached to an oil and gas industry truck. A staircase is attached to the opposite side as well as an opening used to drain the contents. The exact dimensions of a holding tank vary by operator.



Figure 47: Example of Liquid Storage Tank (Frac-N-Vac Tanks, 2013)

This preliminary design uses the size of 46' by 8' by 11'and volume of 21,000 gallons, which was found to be used by two companies that provide fracturing fluid tanks (McGrath RentCorp, 2013 and Global Tank, 2013). The sedimentation unit is batch process. The tank is filled up and then is sits for the calculated detentions time to allow the proppant to settle out. In order to determine the detention time of the unit, the first step involves calculating the settling velocity of the sand. The settling properties of the sand particles fall into type I sedimentation where particles settle discretely at a constant velocity (Davis and Masten, 2009). Terminal settling velocity of a sand particle is modeled according to Stokes' law, shown in Equation 10.

$$\nu_s = \frac{g(\rho_s - \rho)d^2}{18\mu} \tag{10}$$

Where: v_s is the particle's settling velocity expressed in m/s, g is the acceleration due to gravity in m \cdot s⁻², ρ_s is the density of the particle in kg \cdot m⁻³, ρ is the density of the fluid

in kg·m⁻³, d is the diameter of the particle in m, 18 is a constant, and μ is the dynamic viscosity in Pa-s (Davis and Masten, 2009).

From the analysis of the 108 well data sheets it was found that crystalline silica/quartz sand/silicon dioxide, CAS number 14808-60-7, was the most frequently used proppant, and was therefore used in these calculations. Gravity is 9.81 m \cdot s⁻². The density of crystalline silica is 2.6 g/mL at 25°C, which equates to 2600 kg \cdot m⁻³ (ChemicalBook Inc., 2013). If a breaker other than Crystalline Silica was used, the setting velocity for the actual breaker used can be found by substituting the density of that breaker into Equation 9. The wastewater to be treated has a high salinity, so the density for seawater at standard temperature and pressure (STP), 1027 kg/m³, was assumed (Bergman, 2013). The actual hydraulic fracturing wastewater will have a higher density because seawater TDS averages around 35,000 ppm whereas the wastewater to be treated range from 130,000 to 300,000 ppm. Higher density decreases the settling velocity. Using the same assumption, the dynamic viscosity of seawater is 1.08×10^{-3} Pa \cdot s. The diameter of proppant types range from 106 micrometers to 212 micrometers (HORIBA, 2013). Crystalline silica were found at sizes of 100 mesh, 40-70 mesh (212 – 420 micrometers), and 30-50 mesh (300 - 600 micro meters) in the gathered well data sheets. To find the lowest settling velocity, the lowest crystal silica diameter, 212 micrometers, was used. Using these values for water the settling velocity of crystalline silica with a 2.12×10^{-4} m diameter, is 128 m/hr.

$$v_{s} = \frac{9.81 \frac{m}{s^{2}} (2,600 \frac{kg}{m^{3}} - 1,027 \frac{kg}{m^{3}}) (2.12x10^{-4} m)^{2}}{18(1.08x10^{-3} Pa \cdot s)}$$
$$v_{s} = 0.0356 \frac{m}{s}$$
$$v_{s} = 128.16 \frac{m}{hr} = 420.47 \frac{ft}{hr}$$

Using this calculated settling velocity and the height of the water in the setting tank, the time (t) it takes for the particles to settle was determined using Equation 11 (Droste, 1997).

$$t = \frac{h}{v_s} \tag{11}$$

The total height of a standard holding tank is 11 feet, therefore the waterline height has to be less. A water height of 10 feet was chosen for this sedimentation design.

$$t = \frac{(10ft)}{\left(420.74\frac{ft}{hr}\right)}$$

$$t = 0.024 hr = 1.44 minutes$$

Varying water conditions can cause the settling velocity and therefore the time the particles take to settle, also known as detention time, to vary. A safety factor of 1.25-1.75 can be applied to the detention time (Droste, 1997). For this design, a safety factor of 1.75 was chosen to help compensate for the various water densities that the sedimentation will treat, giving a settling time of 2.52 minutes.

The flow rate (Q) in gallons per hour (gal/hr) for the sedimentation unit can be found with the volume (V) of the tank and the detention time (settling time, t) using Equation 12 (Droste, 1997).

$$Q = \frac{v}{t} \tag{12}$$

The volume of water used for this sedimentation tank design was the standard capacity discussed earlier in the section, 21,000 gallons of water. Using 21,000 gallons of water for the volume and the calculated settling time of 2.52 minutes, the flow rate was calculated to be 500,000 gal/hr, which equates to 12 MGD (million gallons per day). This flow rate is the maximum flow rate through the sedimentation tank for 100% removal of the particles with a maximum settling time of 2.52 minutes. The detention time in typical sedimentation basins is normally two to four hours (Davis and Masten, 2009). A typical detention time of 2 hours and volume of 21,000 gallons were used to find this sedimentation unit's average flow rate (Q_{avg}), 10,500 gallons/hour. Since this flow rate is lower than the maximum flow rate needed to settle out particles with 2.52 minute settling time, the proppant particles will settle out completely in this sedimentation tank design.

5.3.8 Microfiltration Unit Design

This unit will serve as a pretreatment for the reverse osmosis unit. The influent to the unit comes from the holding tank following the sedimentation process. The MF unit will operate in a pressure-vessel configuration with a dead-end flow mode. The pressure vessels will contain hollow fiber membrane modules with ceramic membranes.

A fluid undergoes microfiltration when passed through a thin wall of a porous material. The porous material is a solid mass with interconnecting voids, or pores. The pore sizes of microfiltration membranes range from 0.05 to 5 µm (Li et al., 2008). As water passes through the membrane and solids accumulate, the head across the membrane needs to increase in order to maintain the transmembrane pressure. MF systems commonly operate at a transmembrane pressure of 0.2 to 1 bar, or 3 to 15 psi. Keeping the transmembrane pressure below 1 bar minimizes membrane fouling, meaning a loss of performance. Fouling significantly affects the cost of membrane filtration, and it results from the clogging of material in the membrane that backwashing does not remove. MF consists of repeating cycles, where after a prespecified amount of time of filtration, a backwash cycle removes the accumulated solids from the membrane and the cycle repeats. Fouling occurs gradually and continually over time, and is removed by periodic cleaning. Operators clean membranes once every few days to several months depending on the membrane material, operating conditions, and influent quality; and it entails soaking the membranes in a solution containing chemicals such as surfactants, acids, and bases. Membranes can degrade over time and may require replacement in 5 to 10 years (Crittenden et al., 2005).

MF systems use two basic configurations: pressure-vessels and submerged. Pressure-vessel modules generally range from 100 to 300 mm in diameter and 0.9 to 5.5 m in length, and consist of thousands of fibers for a surface area of 8 to 70 m². The modules operate simultaneously in parallel, and are arranged in racks. A rack, shown in Figure 48, can hold anywhere from 2 to 300 modules that each individually receive a water feed stream by pumps through a piping system. A pressure-vessel module maintains transmembrane pressure by increasing the feed water pressure with pumps as the membrane stays at near-atmospheric pressure, and it can operate at transmembrane pressures between 0.4 and 1 bar. Membrane filtration using a submerged system, also

called immersed membranes, involves modules immersed in a basin of feed water. The water column develops the pressure on the influent side since the basin is open to the atmosphere. A pump at the top of the unit develops transmembrane pressure by pulling the water through the membrane from the permeate side, and therefore the system can function at transmembrane pressures between 0.2 and 0.4 bar (Crittenden et al., 2005). An example of a submerged membrane system is shown in Figure 49. This MF unit utilizes a pressure-vessel configuration. Pressure-vessel systems operate at a larger and higher pH range than that of submerged systems. This allows the system to better adapt to changing conditions such as temperature. Pressure-vessel systems are safer and easier to clean because the cleaning chemicals are contained in the modules as opposed to a tank open to the atmosphere where toxic fumes are released. Pressure-vessel systems cost less because they do not need a costly hoisting mechanism to move membrane cassettes or basins to hold the water that submerged systems require for operation. They instead have individual modules that can be removed manually and the rack needs to rest on a concrete slab. Also, operating at pressures and consequently higher fluxes allows for less membrane surface area and smaller systems (Martinez, 2005).



Figure 48: Pressure-vessel Membrane System Configuration (Wigen Water Technologies, 2013)



Figure 49: Submerged Membrane System Configuration (KSM, 2013)

MF membranes are made out of organic polymers or inorganic materials, such as ceramic, glass, and metal. Polymeric membranes can be either hydrophilic or hydrophobic. Hydrophilic polymers, like cellulose, are "sensitive to acid or alkaline hydrolysis, temperature, and biological degradation" (Li et al., 2008). Three major membrane materials used in water treatment applications are polysulfone (PS), polyethersulfone (PES), and polyvinylidene (PVDF); all three materials are hydrophobic. PS is one of the most widely-used membrane materials in MF systems due to its resistance to oxidants and ability to operate under pH conditions. Most ceramic membranes resist water transport, and consequently require high transmembrane pressures to operate at a higher flux. Ceramic membranes can withstand feed water with high temperatures and pHs as well as high pressure – up to 2 kPa. They can also cost less to operate than polymeric membranes since they are easier to clean and maintain (AWWA, 2005). Studies conducted indicate that ceramic membranes are more suitable for treating produced waters that contain oil, in addition to being more durable than polymeric membranes (CSM, 2009). For this reason, the MF unit will consist of a ceramic membrane.

The most common membrane configuration for MF systems is hollow fiber. These modules, see Figure 50, consist of thousands of hollow fibers between 0.5 and 1.5 millimeters (mm) in diameter. They can be backwashed automatically by reversing the direction of the permeate stream to flush out the accumulated particles on the surface of

the membrane. Backwashing eliminates the need for extensive pretreatment prior to using a hollow fiber membrane. Fluid can flow through a hollow fiber membrane module in two different modes based upon the direction of the flow: inside-out or outside-in. In the inside-out configuration, feed water flows through the bore in the center of the module and the permeate is collected from the outside of module. The outside-in configuration works in the opposite way: feed water flows through the outside of the module to the bore in the center of the module for collection as the permeate. Pressure-vessel systems use inside-out hollow fiber membranes. Another type of membrane module configuration is tubular. Tubular modules, shown in Figure 51, have diameters up to 25 mm and the flow operates inside-out. The large diameter allows for the treatment of a feed water with higher levels of suspended solids and makes the configuration easier to clean mechanically. Tubular membranes cost more than hollow fiber membranes and are most commonly used in industrial wastewater treatment as well as the food and beverage industry (Li et al., 2008). Lastly, Figure 52 illustrates the spiral-wound membrane configuration. Spiral-wound membranes require extensive pretreatment since they cannot be backwashed. They consist of several assemblies wrapped around a plastic tube that collects the permeate from the assemblies. Each assembly is made up of two flat sheets of membranes with a permeate collection material in between. Spiral-wound elements therefore have a high packing density. The average commercial dimensions are 1 to 1.5 m in length and 0.2 m in diameter (Li et al., 2008). The MF unit designed in this project uses hollow fiber membrane configuration module. Hollow fiber membranes take up less space than other modules because of the surface area to volume ratio, or packing density (AWWA, 2005). Hollow fiber membranes have a larger packing density, 1,200-1,700 m^2/m^3 , than tubular modules, 140-310 m^2/m^3 , and spiral-wound modules, 700-1,000 m^2/m^3 , which is an important design consideration in developing a mobile, on-site treatment system. Spiral-wound modules are more commonly used in NF and RO applications because of clogging problems from the particulate matter in the feed water of MF and UF systems (Crittenden, 2005). Hollow fiber membrane modules can be backwashed in order to prevent fouling and increase the lifespan of the membrane. Lastly, they can operate at low transmembrane pressures, which reduce energy consumption and costs (AWWA, 2005).



Figure 50: Hollow Fiber Membrane Module (Qrbitz, 2013)



Figure 51: Tubular Membrane Module (Xylem, 2013)



Figure 52: Spiral-wound Membrane Module (MTR, 2013)

Membrane filtration systems operate in two different configurations: cross-flow and dead-end. In a cross-flow configuration, a pump transfers the feed water tangential to the membrane. The water that does not pass through the membrane is recirculated to the feed stream (Li *et al.*, 2008). In dead-end filtration, pumps transfer the water normal to the membrane, so all of the feed water passes through it. However, the flow path in deadend filtration causes solids to accumulate on the membrane, increasing the rate of membrane fouling as opposed to the tangential flow path used in a cross-flow configuration (AWWA, 2007). Dead-end filtration consumes less energy than cross-flow because the cross-flow configuration needs to maintain a higher cross-flow velocity to prevent fouling, and dead-end filtration does not recirculate concentrate (Li *et al.*, 2008). Capital cost for dead-end filtration are lower since it does not require pumps or piping for concentrate recirculation (AWWA, 2007). Due to its reduced costs, this MF unit uses a dead-end flow configuration.

Pilot testing is an essential tool used to design a membrane system. It provides a way to test various operating parameters in order to determine design criteria that achieve the product water quality goals (AWWA, 2005). Pilot testing is not in the scope of this project, and therefore this report includes only a preliminary MF unit design. Typical operating parameters for a MF pressure-vessel system are given in Table 32.

Parameter	Units	Typical values
Permeate flux	L/m ² ·h	30-170
Average transmembrane pressure	bar	0.4-1
Maximum transmembrane pressure	bar	2
Recovery	%	>95
Filter run duration	min	30-90
Backwash duration	min	1-5
Time between chemical cleaning	days	5-180
Duration of chemical cleaning	hours	1-6
Membrane life	years	5-10

 Table 32: MF Operating Characteristics for Pressurized Systems

 (Adapted from Crittenden, 2005)

5.3.9 Reverse Osmosis Unit Design

Figure 53 provides an overview of the proposed reverse osmosis system. The effluent from the MF unit becomes the influent of the RO system where it passes through two stages. Stage I consists of three pressure vessels, and stage II consists of two. Each pressure vessel contains six membrane elements, meaning that the total system includes thirty total elements. The concentrate from stage I is disposed of and the concentrate from stage II is added to the influent of stage I.



Figure 53: Schematic Drawing of Reserve Osmosis System

The processes of reverse osmosis and nanofiltration primarily separate dissolved constituents from water by diffusion across semipermeable membranes. The membrane can quickly foul based upon particle loading rates. The system works by applying pressure to the feed side of the membrane, thereby forcing the water through the semipermeable membrane. The hydraulic pressure required to do so depends on the osmotic pressure of the feed, the feed temperature, the membrane thickness, and the membrane material. Osmotic pressure is the pressure created by the natural tendency of water to flow from a dilute solution to a more concentrated solution. The hydraulic pressure acts against this pressure as well as the physical resistance of the membrane itself (AWWA, 2007).

In the reverse osmosis process, water is forced through a semipermeable membrane by a pressure differential. Feed water is pumped through the system and separated into a product stream, called the permeate, and a reject stream, called the concentrate. Figure 54 illustrates the basic concepts of a RO element design. K_w and K_s represent the water permeation coefficient, or water mass transfer coefficient, and solute permeation coefficient, or solute mass transfer coefficient, respectively (AWWA, 2007). Both coefficients vary for different types of membranes, and are based on membrane characteristics such as materials, permeability, and thickness (Kucera, 2010). Equation 13 provides the corresponding mass balance for the system.



Figure 54: RO Element Diagram (Adapted from AWWA, 2007)

$$Q_f C_f = Q_p C_p + Q_c C_c \tag{13}$$

Where: Q_f , Q_p , and Q_c are the flow rates in units of volume per time of the feed water, permeate, and concentrate, respectively. C_f , C_p , and C_c are the solute concentrations in units of mass per volume of the feed water, permeate, and concentrate, respectively.

In a reverse osmosis system, flux is the volumetric flow rate of feed water across a membrane. The flux is directly proportional to the mass transport coefficient, K, and the net pressure driving force applied to the feed water, as shown in Equation 14. The mass transfer coefficient can vary with temperature and pH of the water; it is unique to a given membrane (Kucera, 2010 and WEF, 2006).

$$J = K(\Delta P - \Delta \pi) = \frac{Q_p}{A_{Sys}}$$
(14)

Where: J is the flux expressed in units of volume per unit time over an area, K is the mass transfer coefficient, ΔP is the pressure differential, $\Delta \pi$ is the change in osmotic pressure across the membrane, Q_p is the permeate flow rate, and A_{Sys} is the surface area of the membrane system.

Two major design parameters for a reverse osmosis system are the recovery and rejection. The recovery of a RO membrane system is the percentage of the feed water that is converted to permeate. Unlike in MF and UF systems, not all of the feed water will pass through the membrane in a NF or RO system. Membrane systems aim for a high recovery since it reduces the waste stream. However, systems that operate at elevated recoveries run the risk of increased fouling rates and cleaning frequencies (WEF, 2006). A system recovery can be calculated using Equation 15.

$$R = \frac{Q_p}{Q_f} \times 100\% \tag{15}$$

Where: R is the percent recovery, Q_p is the permeate flow rate, and Q_f is the feed flow rate. Rejection, also called contaminant removal, can be calculated for any parameter, such as TDS and radium, and it is defined as percent of contaminant removed from the feed stream by the membrane (WEF, 2006).

$$R_{Cont} = \frac{c_f - c_p}{c_f} \times 100\% \tag{16}$$

Where: R_{cont} is the contaminant removal (%), C_f is the feed water contaminant concentration, and C_p is the permeate contaminant concentration.

This subsection outlines the process and necessary steps to design a reverse osmosis filtration system for hydraulic fracturing wastewaters. A membrane filtration system requires pilot testing before implementation, which was beyond the scope of this project. The hydraulic fracturing wastewater treated with this design consists of TDS values between approximately 130,000 mg/L to 300,000 mg/L. Available reverse

osmosis membrane technology can treat for TDS in that of seawater: around 35,000 mg/L. This subsection therefore explains the design process for treating seawater while including considerations for a hydraulic fracturing wastewater.

The feed water quality must be considered prior to the design of a reverse osmosis filtration system. The factor with the greatest influence on the membrane system design is the tendency of the feed water to cause fouling. Suspended and dissolved particles in the feed water can cause membrane fouling (Dow, 2013b).

The Silt Density Index (**SDI**) is an empirical test used to assess particulate fouling. It is conducted by passing the feed water through a gridded membrane filter for three timed intervals. The membrane filter has a diameter of 47 mm, mean pore size of 0.45 ± 0.02 micrometers, and a constant applied pressure of 2.07 bars. The first time interval represents the time to collect 500 mL of permeate. Filtration continues after this collected amount for a second interval that stops when the total filtration time for both intervals is 15 minutes. A volume is not collected during the second time interval. Sometimes a time duration of less than 15 minutes is used if the water has a high fouling tendency. The third time interval is recorded when 500 mL of permeate is collected following the end of the second time interval. SDI is calculated using Equation 17 (Crittenden, 2005).

$$SDI = \frac{100(1-t_I/t_F)}{t_T}$$
 (17)

Where: t_I is the time to collect the first 500 mL sample in minutes, t_F is the time to collect the final 500 mL sample in minutes, and t_T is the duration of the first two test intervals.

The first step in designing an RO system is to choose the flow configuration and number of passes. Plug flow, where the feed water passes through the system once, is the standard flow configuration for a membrane system. In concentrate recirculation, a fraction of the concentrate stream is fed to the influent feed water (Dow, 2013b). Figure 55 depicts a plug flow configuration and Figure 56 a concentrate recirculation configuration. Concentrate recirculation is commonly "used in smaller RO systems, where the cross-flow velocity is not high enough to maintain good scouring of the membrane surface." Recirculating the concentrate increases the cross-flow velocity, and therefore reduces the risk of fouling by reducing the individual module recovery (Kucera, 2010). The application of concentrate recirculation is also common in larger systems when the number of elements cannot achieve a high enough system recovery using plug flow (Dow, 2013b). Concentrate recirculation systems have three main disadvantages: a lower overall product quality from a highly-concentrated reject being added to a lower-concentration influent; a larger feed-pump requirement from the need to pressurize both the influent feed and the recirculated rejection feed; and a higher energy consumption and capital cost from the larger feed-pump requirement (Kucera, 2010).



Figure 55: Plug Flow RO System Diagram



Figure 56: Concentrate Recirculation RO System Diagram

In multipass systems, two RO systems are run in series, and the permeate from the first unit becomes the influent feed stream for the second unit (AWWA, 2007). Figure 57 shows an example of a double pass RO system. The design concepts for a multipass system remain the same as for a single pass (Kucera, 2010). However, the second pass RO unit can be operated at higher fluxes (around 20 gpd) and recoveries (as high as 90%)

(AWWA, 2007). The low concentration of dissolved and suspended solids in the influent allows for a higher influent flow and lower concentrate flow. Since the reject from the second pass is of a higher quality than the influent to the first pass, it can be recycled to the front of the first pass to minimize waste and improve feed water quality. A tank is usually installed between the first pass and second pass in order to equalize the pressure, but it might be unnecessary if the number of first-pass skids equals that of the second-pass (Kucera 2010). In potable water treatment, multipass systems are most often used in seawater desalination systems to address TDS concerns (AWWA, 2007). The RO system for this project was designed to utilize a plug flow, double pass system to increase the product quality and recovery as well as reduce the energy consumption and costs.



Figure 57: Double Pass RO System Diagram

Next in the design of a RO system is the selection of the membrane and element type. Considerations to take into account include: feed water salinity, feed water fouling tendency, energy requirements, and required rejection. The RO will utilize membranes and design specifications provided by Dow Water & Process Solutions, a purification and separation technology supplier. The standard length of a membrane element is 40 inches, and the standard diameters are 25, 4, and 8 inches. Dow seawater membranes treat the largest TDS feed concentrations, ranging from 10,000 to 50,000 mg/L down to <500 mg/L (Dow, 2013b). Figure 58 shows a FILMTEC, seawater membrane product selection guide provided by Dow, and Table 28 outlines the operating parameters and benefits unique to a series of FILMTEC seawater membranes detailed in the product information catalog. The product specification values are based on testing with the following

parameters: 32,000 ppm NaCl, 5.5 MPa, 77°F, pH 8 and 8% volume recovery per module (Dow, 2013b). Both Figure 58 and Table 33 provide information on six different membranes. All of them have polyamide thin-film composite membranes. Although certain membranes achieve a higher rejection, as shown in Figure 58, all of the five membranes in Table 33 have salt rejection values greater than 99%. Hydraulic fracturing wastewater has a high fouling potential due to the constituents such as suspended solids and acid; however, these parameters are treated for in the stages prior to the reverse osmosis unit. Therefore, the best FILMTEC membrane element for the RO system design of hydraulic fracturing wastewaters would be the SW30XLE-400 because its low energy consumption reduces system costs. The SW30XLE-400 also has one of the higher permeate flow rates and maximum operating pressure, which is beneficial when treating wastewater with high TDS levels that increase the osmotic pressure of the membrane. While the membrane system for treating hydraulic fracturing wastewater would need to remove larger amounts of TDS, upwards of 100,000 mg/L as opposed to a maximum of 50,000 in seawater applications, the percent rejection does not need to be as high, with an upwards of 50% for hydraulic fracturing wastewaters and close to 100% for seawater in potable water treatment applications. This is because seawater applications treat the water with the goal of producing potable water (TDS < 500 ppm). The TDS treatment goal of hydraulic fracturing wastewater is based upon oil and gas company reuse standards, explained in section 5.3.3, of a TDS level less than 120,000 ppm.



Figure 58: Dow, FILMTEC Seawater Membrane Selection Diagram (Adapted from Dow, 2013)

		GUUQOUD	CILICOLID		
Membrane	SW30XLE-	SW30HR	SW30HR-	SW30XHR-	SW30ULE-
element	400	LE-400	380	400	400
Active area (ft ²)	400	400	380	400	400
Maximum					
operating	83	83	55	83	83
pressure (bar)					
Permeate flow	0.000	7,500	6,000	6,000	11,000
rate (gpd)	9,000				
Minimum salt	00.55	99.60	99.60	99.60	99.55
rejection (%)	77.33				
Stabilized salt	00.70	00 75	00.7	00 75	00.70
rejection (%)	<i>99.1</i> 0	99.15	<i></i>	<i>>></i> . <i>\J</i>	99.70
Maximum					
element	1.0	1.0	1.0	0.9	0.9
pressure drop	1.0	1.0	1.0	0.9	0.9
(bar)					

Table 33: Differing Characteristics of Dow, FILMTEC Product Catalog Seawater Membranes (Adapted from Dow, 2013)

After the selection of the membrane and element types, the next requirement in the design of an RO system is the membrane or design flux. This selection is done using pilot data, customer experience, or typical design fluxes based upon feed water source. This project design implements the third option using Dow membrane system design guidelines (Dow, 2013b). Table 34 gives ranges for average system fluxes and corresponding maximum membrane element recoveries based about feed source quality for 8-inch diameter FILMTEC seawater membrane elements. The design parameters applicable to the system in this report are based upon a feed source of seawater with MF pretreatment. Table 35 provides additional design parameters based upon a feed source of seawater with a MF pretreatment, including the permeate, concentrate, and feed flow rates of system as well as the active area of the membrane. The design parameters from Tables 34 and 35 inform the next steps in the design process.

Feed source		SDI	Average system flux (gpd)	Maximum element recovery (%)
RO perme	eate	< 1	21-25	30
Well wat	ter	< 3	16-20	19
Surface supply		< 3	13-17	17
		< 5	12-16	15
Wastewater	MF	< 3	10-14	14
(Filtered municipal effluent)	Conventional	< 5	8-12	12
Seawater	Well or MF	< 3	8-12	15
	Open intake	< 5	7-10	13

Table 34: Design Parameters for 8-in Diameter, FILMTEC Membranes (Adapted from Dow, 2013)

Table 35: Design Guidelines for 8-in Diameter, FILMTEC Membrane with Seawater and Well for MF as Feed Source (Adapted from Dow, 2013)

Element type	Seawater	
Active membrane area (ft ²)	320	380
Maximum permeate flow rate (gpd)	6,700	7,900
Minimum concentrate flow rate (gpm)	13	
Maximum feed flow rate (gpm)	63	70

 Minimum concentrate flow rate (gpm)
 0,700
 7,900

 Minimum concentrate flow rate (gpm)
 13

 Maximum feed flow rate (gpm)
 63
 70

 The next step in the RO treatment design is to calculate the number of membrane elements, pressure vessels, and stages needed for the system as well as the staging ratio selection. Large treatment systems utilize 6-element pressure vessels as a standard, but 8-element vessels are available. Smaller or compact systems (only a few elements) may

element vessels are available. Smaller or compact systems (only a few elements) may utilize shorter vessels. The number of stages in a RO system correlates with the system recovery and the number of serial element positions. This relationship is shown in Table 36 (Dow, 2013b). The number of serial element positions refers to the number of pressure vessels in parallel. For example if 6-pressure vessels were used in both the first and second stage of a two-stage system, then the system would have 12 serial element positions. This RO system aims to maximize the amount of product water, which for the hydraulic fracturing wastewater treatment system means more water available for reuse. This corresponds to less fresh water usage and smaller system costs associated with more waste. Therefore, this system uses 6-element vessels in two stages, creating 12 serial element positions.

Number of stages		Number of sorial element	System recovery	
6-element vessels	7-element vessels	positions	(%)	
1	1	6	35 - 40	
2	1	7-12	45	
2	2	8-12	50	
2	2	12-14	55 - 60	

Table 36: Number Stages in a Seawater RO System(Adapted from Dow, 2013b)

The typical staging ratio of a two-stage, seawater system with 6-element vessels is 3:2 (Dow, 2013b). This array ratio means that the system would contain 3 vessels in the first stage and 2 in the second stage; therefore, the system would have a minimum of 30 elements.

Equation 18 can be used to back-calculate the permeate flow rate of the system using the number of elements.

$$\# of \ elements = \frac{Q_p}{J \times A_m} \tag{18}$$

Where: Q_p is the design permeate flow rate, J is the design flux, and A_m is the active surface area of the selected membrane element.

The design permeate flow rate for one element in a seawater system is 7,900 gpd for an active membrane surface area of 380 ft^2 , as given by Table 35. A higher permeate flow rate allows for a higher element recovery, as shown in Equation 15. The design flux is 10 gfd, as given in Table 34 for seawater with a MF pretreatment. The aforementioned FILMTEC membranes all have a 400-ft² active membrane surface area.

After performing these calculations, it was determined that the permeate flow rate of the RO design was 120,000 gpd. Since the system would consist of 30 elements, the permeate flow rate per element would be 4,000 gpd – about half of the maximum flow rate mentioned in the last paragraph for a membrane with an active area of 380-ft². Assuming a system recovery of 0.6 (the highest achievable in a two-stage seawater

system), Equation 14 shows that the feed water flow rate would be 200,000 gpd. Section 5.3.1 discussed water quantity for hydraulic fracturing. This treatment system will treat volumes of water per holding tank, which averages approximately 20,000 gallons. This RO system could therefore treat the hydraulic fracturing wastewater in a holding tank in approximately two and a half hours. After the tank is treated, it will be filled with wastewater again to prepare it for the next treatment. Based upon total volume of wastewater that a hydraulically fractured well can produce, the system design would need to be capable of treating upwards of 1,000s of holding tanks throughout the lifespan of a well. The treatment time per holding tank is based upon the number of elements and the feed water flow rate. The system configuration uses a total of thirty membrane elements in order to achieve high recovery rates, and the feed water flow rate depends on the high TDS levels and resulting osmotic pressures. The feed water flow rate needs to be high enough to overcome the osmotic pressure from the dissolved salts. Since operating times for the RO system are not a limiting parameter, reducing the system capacity is an option for lowering costs. However, the two aforementioned variables of membrane elements and feed water flow rate prevent this option in order to achieve other necessary design specifications such as percent recovery.

The ultimate goal of a RO system is to treat a feed source by removing dissolved contaminants to produce a permeate with a specified water quality, in other words reduce the concentration of dissolved contaminants in the feed water, C_f , to a certain concentration in the product stream, C_p . Equation 19 expresses permeate concentration according to homogenous solution diffusion model. As shown in Equation 19, the permeate concentration is a function of five independent variables: C_f , K_w , K_s , R and P (AWWA, 2007).

$$C_p = \frac{K_s C_f}{K_w \Delta P + \Delta \pi \left(\frac{2-2R}{2R}\right) + K_s} \tag{19}$$

Where: C_p is permeate solute concentration, K_s is the solute mass transfer coefficient, and C_f is the feed water solute concentration, K_w is the water mass transfer coefficient, ΔP is the pressure differential, $\Delta \pi$ is the change in osmotic pressure across the membrane, and R is the fractional recovery.

Table 37 summarizes the relationship between each of the five independent variables and the permeate concentration of a RO system. C_f , the feed water concentration, can be altered by changing the water source or through pretreatment. As stated in the background subsection, the mass transfer coefficients depend on the membrane, and they can be determined through pilot testing. Membranes with a very high K_w and very low K_s can treat high-TDS water inexpensively. Increasing the pressure of a RO system forces more water through the membrane, thereby diluting the permeate (AWWA, 2007). A higher recovery percentage means that more feed water is converted to permeate rather than leaving the RO system in the concentrate stream. Increasing the recovery of an RO element increases the risk of membrane scaling or fouling (Puretec Industrial Water, 2013).

Table 37: Effects of RO System Variables on Permeate Concentration (Adapted from AWWA, 2007)

Variable	To reduce permeate concentration, C_p
Feed water concentration, C_f	Decrease
Water mass transfer coefficients, K_w	Increase
Solute mass transfer coefficient, K_s	Decrease
Recovery, R	Decrease
Pressure, P	Increase

5.3.10 Waste Disposal

The treatment system designed throughout section 5.3 produces waste as explained in section 5.3.5. The waste from the sedimentation process, outlined in Section 5.3.6, is sludge. The MF process, section 5.3.8, removes bacteria, organics, and oil and grease in the waste stream, and the RO system produces ions, radium, total dissolved solids in a brine as waste. Section 5.2.1 elaborated on the biannual waste reports from the PA DEP. In addition to hydraulic fracturing wastewaters, these reports detail the generated amounts and disposal of the sand used in hydraulic fracturing. Figure 59 shows the disposal methods of "flowback fracturing sand" by percent volume from July 1, 2011 to June 30, 2012. Of the 3,235 wells with reported waste during this time period, 370 were reported as having disposed of sand from fracturing wastewaters. The largest amount of sand was sent to a landfill for disposal, comprising 94.1% of the total volume. 5.88% of the total volume of sand was sent to centralized treatment plants for recycle, 0.02% was in storage pending disposal or reuse, and 0.03% was treated on-site with a NPDES discharge. This treatment system will reuse sand component of the sludge to the largest extent possible, and dispose of the rest in a landfill.



Figure 59: Disposal Method by Percent Volume of Total Sand from Fracturing Disposed Between July 1, 2011 and June 30, 2012 (Adapted from PA DEP, 2013b)

The waste produced by the MF and RO process is termed brine, meaning a solution of salt in water. As discussed in section 5.1.3, hydraulic fracturing wastewaters contain radium, a radioactive, hazardous substance. Congress exempted oil and gas wastes from being regulated as hazardous wastes in the Solid Waste Disposal Act Amendments of 1980 to the Resource Conservation and Recovery Act (**RCRA**) of 1976 even if the wastes contained hazardous contaminants (U.S. EPA, 2013e). In order to protect public health and safety, the waste from the MF and RO units is disposed of according to hazardous waste regulations. The main types of land disposal units for hazardous wastes are: landfill, surface impoundment, waste pile, land treatment units, and injection wells. Landfill and waste piles do not dispose of liquid hazardous wastes, and therefore are not discussed further. Surface impoundments hold liquid, hazardous wastes in either a natural depression in the Earth or a man-made pit for temporary storage or

evaporative treatment. The pits are lined with a plastic material to prevent leaking (U.S. EPA, 2013c). Surface impoundments run the risk of wastewater leaching into the ground and contaminating groundwater or surface water sources. Injection wells are discussed in section 5.2.2, and will be used to dispose of the brine produced by this treatment system. Since the RO unit will operate at a recovery of 60%, 40% of the wastewater treated will need disposal. However, the waste will be disposed of in a Class I hazardous waste disposal well rather than a Class II brine disposal well. Unlike Class II brine disposal wells, Class I injection wells are subject to stricter regulations to insure public safety. For example, Class I wells require continuous pressure testing and monitoring for leaks at least once a year, as opposed to once every five years for Class II wells. For Class I wells, operators must inspect the surrounding area within a certain radius in order to insure no avenue exists for the injected fluid to travel to underground aquifers; the inspection radius for class II well operators is significantly less with a minimum of one mile (U.S. GPO, 2013).

5.3.11 Treatment Design Summary

Pre-treatment of the hydraulic fracturing wastewater was needed to prevent membrane fouling and scaling. First, sedimentation is proposed to remove large suspended solids, primarily the proppant, from the wastewater in order to prevent the clogging of the units that follow. The design consisted of a holding tank with dimensions of 46' x 8' x 11', with a volume capacity of 21,000 gallons. Second, microfiltration is proposed to prevent membrane fouling to insure effectiveness of the process and longevity of the process. The designed unit uses a pressure vessel system configuration with hollow fiber membrane modules made out of ceramic membranes. These design specifications allow the system to be better adept to changing conditions and the cost to be less from the individual modules. Lastly, the desalination technology chosen was reverse osmosis. It separates dissolved constituents from the wastewater by diffusion across semipermeable membranes. The design consists of two stages, with a total of 30 elements. The designed unit will is a plug flow, double-pass system made out of polyamide, thin-film composite. With the increased product quality and recovery from the plug flow configuration, energy consumption and costs are reduced. The double pass capability allows for operation at higher fluxes and recoveries. The units presented are preliminary designs, and therefore require testing for future implementation.

Chapter 6: BOP Improvement

In both land based natural gas extraction and offshore oil drilling, blowout preventers are used to control and, in cases of failure, seal the well. While blowouts happen in both instances, subsea blowouts have more consequences than blowouts on land in terms of environmental impacts, cleanup costs, and overall reliability issues. This is because offshore BOPs are bigger, heavier systems and have more components than onshore BOPs, and experience many different loading conditions. Blowout preventers are used throughout the Marcellus Shale, and serve the same purpose as subsea blowout preventers, albeit on a lesser scale. Due to their large size and increased technicalities, there is more room for research in offshore BOPs than onshore BOPs. For this reason, the main focus of this part of the project were subsea BOPs.

Today approximately 30% of oil produced by the United States comes from offshore drilling on the Outer Continental Shelf. In 2010 alone, offshore drilling produced 589 million barrels of oil, and 2.3 trillion cubic feet of natural gas (BOEMRE, 2013). Offshore drilling represents a huge potential source of future energy, but there remain significant risks when compared to land-based petroleum production. One such risk, present in almost all well drilling applications, is the total loss of well control. This is referred to as a blowout, and results in uncontrolled release of crude oil or natural gas. To date, the two largest accidental offshore oil spills have been caused, in part, by a failure of the BOP to close and seal. The largest release occurred during the Deepwater Horizon oil spill, also known as the Macondo blowout, which began on April 20, 2010. The blowout resulted in the loss of the drilling platform and 11 lives; and over the span of the following months until July 2010, led to the release of an estimated 4.9 million barrels of crude oil (Hoch, 2013). During the subsequent investigation of the accident, it was found that the blowout preventer failed to seal the well as intended, resulting in the loss of control of the well (Kenney et al., 2011). The effect of the blowout and subsequent explosion on the Deepwater Horizon is shown in Figure 60.



Figure 60: Deepwater Horizon Blowout, April 20, 2010 (DHSG, 2011)

Failure of the blowout preventer also led to the Ixtoc I blowout off of the Gulf of Mexico in 1979. While removing the drill sting from the exploratory well, a kick occurred and the shear rams were activated, but they failed to shear and seal, and control of the well was lost. The blowout resulted in the release of an estimated 3.5 million barrels of crude oil into the ocean. An aerial photo of the blowout is shown in Figure 61.



Figure 61: Ixtoc I Blowout and Spill (West, 2004)

During drilling, casing, and work overs, the blowout preventer (**BOP**) is attached to the wellhead and serves as the last barrier preventing catastrophic loss of well control. The main function of the BOP stack is to confine well fluids or gas to the borehole until primary control of the well can be restored (Bai and Bai, 2012). Blowout preventers are highly complex systems, consisting of many mechanical, hydraulic, and electrical subsystems, all of which play a critical role in successful operation of the device. Although much work has been done in the past to make BOPs as reliable as possible, there are still outstanding issues and room for future improvement. This chapter presents background on blowout preventer systems, potential failure modes of BOP systems, and design recommendations to improve BOPs.

6.1 Blowout Preventer

The functional objective of the blowout preventer system is to seal the well while primary well control is regained. Sealing the well prevents the uncontrolled release of wellbore fluids into the ground (onshore drilling) or the ocean (offshore drilling). The BOP must have the ability to seal-in the well regardless of what is in the wellbore at the time; such as the piping, casing, or wire-line equipment. The BOP consists of three primary sub-systems: controls, hydraulics, and rams. Figure 62 depicts a simplified hierarchical diagram of the BOP and major sub-systems.



Figure 62: BOP Hierarchical System Composition

In addition to the major sub-systems identified, subsea BOPs also consist of structural components, choke and kill manifolds, and riser connectors. The subsea BOP stack used by the Deepwater Horizon can be seen in Figure 63. The BOP stack employed by British Petroleum (**BP**) was approximately 54 feet in overall height with a weight of approximately 400 tons (Kenney *et al.*, 2011).



Figure 63: Deepwater Horizon BOP Stack (Transocean, 2013)

6.1.1 BOP Controls

The main source of control and feedback for a subsea BOP starts with two pods attached to the Lower Marine Riser Package (**LMRP**). These units are known as the yellow and blue pods and their exact location on the BOP stack can be seen in Figure 64. From this location, the control pods communicate with the lower BOP stack and the above sea operator. **Figure 64** illustrates the process sequence from the control pods to the drilling operator.



Figure 64: Driller's Control Sequence (Shanks *et al.*, 2003)

The yellow and blue pods communicate with the surface vessel through the use of Multiplex (**MUX**) cables, which is indicated in the diagram above as black lines (Shanks *et al.*, 2003). The MUX cable is composed of fiber optic lines for data communication and copper lines for power transmission to the BOP (Springett and Franklin, 2013). From the control pods, the MUX cables feed to the driller's control panels located above sea. With the feedback and communication from the control pods, the operator is able to closely monitor the wellbore pressure, the hydraulic pressure, and manually close BOP rams as necessary. Through this process, the driller's control panel sends signals back to

the yellow and blue pods, which can then be relayed to the hydraulic system in the event hydraulic pressure and actuation is needed.

The yellow and blue pods also control and give feedback to the rams located on the lower BOP stack. Figure 65 illustrates the contents of the control pods and the process sequence from the pods to the lower BOP stack. Red components are those that failed during the Macondo blowout.



Figure 65: Pod Contents and Lower Stack Communication

The control pods each consist of two 9-volt batteries and a 27-volt battery. The 9volt batteries power the Automatic Mode Function (**AMF**) processor and the 27-volt battery powers the pressure transducer and the solenoid valve (BP, 2010). The solenoid valve receives inputs from the driller's control panel from Figure 65. If activated, the solenoid valve will open and pressure will be supplied from the accumulator racks, and in turn the rams will start to close. The AMF is a safety feature added to the control pods to activate the rams in the case of a fire or explosion. Within the control pods, the AMF will initiate when electrical power, communication, and hydraulic pressure is lost to both pods (BP, 2010). If any of the three services have not failed, then the AMF will not activate and the control system will operate as normal.

6.1.2 BOP Hydraulics

The functional objective of the hydraulic system of a subsea blowout preventer is to take the fluid energy stored in accumulator banks, and deliver this energy to the ram pistons through a series of interconnected tubes, hoses, valves and other hydraulic components. A simplified hydraulic schematic for a ram-type BOP is shown in Figure 66. Fluid flows from a bank of accumulators, through a shuttle valve, to a bank of solenoids, shown in this diagram as a single multi-position, multi-port valve. The pressurized hydraulic fluid is used to actuate two opposed hydraulic pistons (referred to in this diagram as 'right' and 'left' pistons), which close or open the rams. Ram preventers should be equipped with an integral or remotely operated locking system to prevent unintended opening if hydraulic pressure is lost (API Recommend Practice 53).



Figure 66: Simplified Hydraulic System Schematic

The American Petroleum Institute publishes recommended practices for the hydraulic system to insure proper functioning and safety. A minimum of two hydraulic pumps are required and each pump should be protected from overpressure by limit switches and relief valves (API Recommended Practice 53). The hydraulic accumulators, in conjunction with the control system, must be capable of closing each BOP ram in 45 seconds or less.

6.1.3 BOP Stacks

There are a few major BOP designs that are employed on a subsea BOP stack: Annular BOPs, blind shear rams, casing shear rams, and pipe or test rams. The main ram types of a subsea BOP are each discussed in greater detail in the following section, with emphasis on the functionality and design of Blind Shear Rams (BSRs). A subsea BOP consists of a stack of multiple rams of different types, usually with some redundancy between rams of the same type. An example of ram configurations for subsea installations recommended by the API is shown in Figure 67. A BOP stack may be identified by its pressure rating, throughbore diameter and ram configuration. For
instance, a BOP stack could be identified as follows: $10K - 18-3/4 - C_w R_d R_d A_L C_R A_U$. This BOP stack would be rated to 10,000 psi, have an 18-3/4" throughbore, and be arranged as in Figure 67.



Figure 67: Example Stack Arrangements for 10K Subsea BOP Stacks (Adapted from API, 2000)

Annular preventers are designed to seal around drill pipe or casing within the bore of the preventer by extruding an elastomeric packing element reinforced by steel ribs or inserts (Transocean, 2013). They are also able to seal the well if there is no pipe in the hole. Although capable of sealing an open borehole, annular preventers are not typically used in this manner during day to day operations. Stripping of the annular preventer can occur in the preventer if it is closed around the pipe, and the pipe is then moved up or down. In order to prevent this, a suitable material should be selected for the annular element; one which will not strip under these conditions. Figure 68 illustrates the major components of an annular preventer.



Figure 68: Cameron DL Annular Preventer (Transocean, 2013)

The head of the annular preventer serves as an attachment point for other elements of the BOP stack. The annular element consists of a steel reinforced elastomeric packing element that closes around objects in the throughbore of the preventer when activated. The extrusion of this packing element is accomplished by means of a hydraulic piston, similar to those found in ram BOPs. The annular body houses all of the internal components, providing structural integrity and isolating the internal components from seawater exposure. Casing shear rams are designed to shear through large diameter, heavy walled casing and drill pipe that may be in the well. Casing shear rams are not designed to seal, and when closed provide little resistance to flow (Kenney *et al.*, 2011). Two double "V" casing shear rams are illustrated in Figure 69.



Figure 69: Casing Shear Ram

Pipe rams are used to close and seal around a drill pipe to restrict flow in the annulus between the drill pipe and the borehole. When the pipe ram is activated, fluid cannot flow through the annulus but there is no restriction within the drill pipe (Tekin, 2010). Pipe rams can accommodate either a fixed or variable diameter, which may be needed if different drill string diameters are used during the drilling process. A variable bore pipe ram is shown in Figure 70.

⁽Transocean, 2013)



Figure 70: VBR Pipe Ram (Transocean, 2013)

Blind shear rams is the last line of defense in a blowout, and are designed to accomplish two objectives: shear the drill pipe within the BOP unit, and seal the well. Figure 71 shows a BSR configuration commonly used in subsea BOP installations. The shear blades cut the drill pipe, and sealing is accomplished by the elastomeric material on the shear blades, ram tops, and packers on the sides of the rams. However, the rams are not able to cut through the joints in the piping, and therefore, the joints cannot be placed in the way of these rams. The Deepwater Horizon BOP used two shear blades in its system; one for the piping and one for the casing (DHSG, 2011).



Figure 71: Blind Shear Ram (Transocean, 2013)

6.1.4 Installation of the BOP Stack

Installation of equipment to the seabed is generally done using tensioned guidelines attached to guide sleeves on the subsea structure which orient and guide the equipment into position, or with a dynamic positioning reference system that positions the surface vessel over the landing point, after which the equipment is lowered into place (Bai and Bai, 2012). For both types of guidance systems, the installation of the wellhead equipment proceeds as follows:

- After installation of the conductor casing string, the conductor housing is installed. This serves as a structural base for elements connected to the wellhead, but is not a pressure containing device. This is shown in Figure 72, along with the other equipment discussed.
- The permanent guide base (PGB) is installed on the conductor housing. The permanent guide base provides guidance and support during the installation of the BOP stack or the subsea tree, and establishes structural support and final alignment once the equipment has landed.

- 3. The wellhead housing is attached to the conductor housing, and provides pressure integrity for the well.
- 4. A subsea BOP stack is attached to the wellhead housing, and is supported by the permanent guide base.
- 5. The wellhead housing is attached to the conductor housing, and provides pressure integrity for the well.
- 6. A subsea BOP stack is attached to the wellhead housing, and is supported by the permanent guide base.



Figure 72: 18 3/4-in. Subsea Wellhead System (Bai and Bai, 2012)

6.1.5 Maintenance of the BOP Stack

Manufacturers of BOP equipment establish their own installation, operation, and maintenance (IOM) protocols, which should be followed by the operator. After each well is drilled, and the BOP equipment removed, it should be cleaned, inspected. Following

preventive or remedial maintenance, the BOP should be pressure tested. In addition, after every 3-5 years of service, the BOP stack should be disassembled and inspected in accordance to the manufacturer's guidelines. During this teardown and rebuild, elastomeric elements should be changed out at and all components should be examined for wear, corrosion, or any abnormalities. Critical dimensions should be checked against the wear limits set by the manufacturers (API Recommended Practice 53).

Spare parts for the BOP components should be kept on hand and stored according to manufacturer's recommendations. The API recommends that at minimum the following parts be available:

- A complete set of elastomeric sealing elements for each ram
- A complete set of bonnet seals for each ram
- Ring gaskets for end connections
- A spare annular BOP packing element

Testing of the BOP stack is used to verify that the equipment is functioning as intended. The API recommends that testing be conducted on the surface prior to installation, and subsequent testing be performed following installation. There should be at least two subsequent tests, one immediately after installation, and the next within 21 days of that test. A breakdown of these testing procedures can be found Appendix C.

Retrieval of a BOP stack to the surface for maintenance is a costly and time consuming exercise, and is not usually done during drilling unless there is a problem. Pulling the stack is a multi-million dollar operation, and is one of the single most expensive operations during drilling. The high opportunity cost of conducting maintenance during operations is part of the reason for the high redundancy found in BOP systems. Commercial software exists to help operators analyze the risks associated with particular malfunctions, and decide whether the stack must be pulled for maintenance.

6.2 Design Theory of Blind Shear Rams

The deployment sequence of a BSR is shown in Figure 73. During normal operations, the BSR is open, and the wellbore is free from obstruction, as in Figure 73 (a). Upon activation of the BSR, pressurized hydraulic fluid exerts a force on the ram

piston, shearing the drill pipe as shown in Figure 73 (b). Once shearing is complete, the pressure differential in the wellbore creates a sealing force on the ram, and the lower portion of drill string is suspended by a folded over portion in the BSR, shown in Fig 73 (c).



Figure 73: Blind Shear Ram Shearing Process (a) Shear rams open, (b) Shear rams closing, and (c) Shear rams closed and sealed the wellbore (Tekin, 2010)

6.2.1 Shearing

To be effective, a BSR must shear through drill pipe within the wellbore, and then create a seal to prevent the flow of wellbore fluids. The shearing of the drill pipe as the ram blades close is accomplished through the interaction of two continuous processes. First, as the shear blades crush the drill pipe a stress concentration is created and the drill pipe is slightly collapsed. Second, the tensile force exerted on the drill pipe by the rake surfaces of the shear rams, combined with the stress concentration within the drill pipe, shears the drill pipe (West, 2004). This is shown in Figure 74.



Figure 74: Stress in Blades (West, 2004)

The Distortion Energy Theory shear force equation gives a reasonable first approximation for the force needed to shear the pipe within a BOP. The equation is shown below:

$$F_{\rm s} = 0.577 * A * \sigma_{\rm Y} \tag{20}$$

Where: F_S is the shear force, A is the cross-sectional area of the pipe, and σ_Y is the yield strength of the pipe material. Several studies have shown that shear forces predicted by this equation can differ significantly from actual shear forces. These studies attempted to either modify the equations or use a different method, such as FEA, to predict the shear forces.

West Engineering Services (2004) reviewed shearing data for E-75, G-105, and S-135 drill pipe, and performed linear regression analysis on the data, using elongation percentage as well as yield strength as independent variables effecting shear force. A generic form of the modified Distortion Energy Theory Equation that was derived is shown below:

$$F_{s} = A * (0.577 * A_{c} * \sigma_{Y}) + B * (Elongation \%) + C + 2 * StdErr$$
(21)

Where: F_S is the shear force, A is an experimentally derived constant, A_c is the crosssectional area of the pipe, σ_Y is the yield strength of the material, B is an experimentally derived constant, C is an experimentally derived constant, and StdErr is the standard error of the estimate. Values obtained by West Engineering Services can be found in the report.

Tekin (2010) used FEA to calculate the force needed to shear drill pipe and compared these data to the shear force predicted by the Distortion Energy Theory and the actual values obtained by West (2004). Tekin (2010) concluded that Finite Element Method simulations can be used as a tool to estimate actual shear force with high accuracy, and that the results were more accurate than the values predicted by the Distortion Energy Theory Equation.

The capacity of the shear ram preventer and ram operator should be verified with the manufacturer of the planned drill string to confirm that the given system will successfully shear the drill pipe, as metallurgical differences among drill strings may necessitate higher pressure shearing operations (API Recommended Practice 53).

The two basic types of sealing shear ram designs are single and double "V" blades. The "V" designation refers to a non-zero blade angle. In reviews of manufacture's shear force data, it appears that rams with double "V" blades have 15% to 20% lower shear forces than single "V" blade designs (West, 2004). For this reason, double "V" blades are used for casing shear rams, which must shear thick sections of casing.

6.2.2 Sealing

Due to their wide range of properties, elastomers are the most commonly used material class for seals; covering the full range of static and dynamic seals (Flitney, 2007). The characteristics of these materials enable them to seal so effectively, and having only a few limitations allows them to also be very versatile. One mechanical property that sets elastomers apart from other material classes, such as metals and plastics, is their low elastic modulus (or Young's modulus). The elastic modulus, E, of a material is equal to the stress, measured in Pa or psi, over the strain, which is dimensionless, and can be seen in the following equation:

$$E = \frac{\sigma}{\varepsilon} = \frac{\text{Stress}}{\text{Strain}}$$
(22)
F Force

Where:
$$\sigma = \frac{F}{A} = \frac{Force}{Area}$$
 and $\varepsilon = \Delta L$ = Change in Length

Elastomers generally have a low elastic modulus (approximately 5.5 MPa or 800 psi), and this is seen compared to plastics (approximately 1 GPa or 145 kpsi) and metals (approximately 100 GPa or 14500 kpsi). Having a low elastic modulus means that they only require a low stress to produce a large deflection (CES EduPack, 2012). Figure 75 shows the stress/strain properties of several elastomers (light blue), plastics (dark blue), non-ferrous metals (red), and ferrous metals (teal) plotted in CES EduPack. The x-axis is a measure of elongation (or strain) and the y-axis is a measure of tensile strength (or stress). Each bubble in the graph represents a material and shows the range of properties for that material. This figure shows that elastomers require the least amount of stress to result in a large strain, whereas both types of metals require a large amount of stress resulting in a small strain. Plastics are scattered generally in between the two, and are average compared to the other classes.



Figure 75: Elongation (Strain) & Tensile Strength (Pa)

From the previous equations the elastic modulus (or Young's modulus) is equal to the stress divided by the strain. Plotting the Young's modulus of the materials shows a clearer picture of what was represented in Figure 76. Seen in Figure 77 is the Young's modulus of the materials plotted in CES EduPack 2012. Contrary to the stress/strain graph, this graph shows the gaps between the various material classes. Each bar represents a material, and shows the range of Young's Modulus for that material. The elastomer class (light blue) can be seen towards the left of the graph with a lower Young's modulus, and the metal class (teal and red) can be seen towards the right of the graph with a higher Young's modulus. The plastic class (dark blue) can be seen grouped in the middle with an average Young's modulus compared to the other classes.

A stiff material is one that has a high elastic modulus, and therefore only slightly deforms under high stress. For this reason, it is not suitable to use metals and plastics for O-ring type applications. Materials in the elastomer class have a low elastic modulus, resulting in a flexible material; making them ideal for the most effective seals.



Figure 76: Young's Modulus (Pa)

The Poisson's ratio of elastomers is another reason why they are a favored material for seals. Poisson's ratio, v, is defined as "the negative of the ratio of the lateral or transverse strain, ε_{tr} , to the axial strain, ε_{ax} , in tensile loading" and can be seen expressed in the following equation (CES EduPack, 2012):

$$v = -\frac{\varepsilon_{\rm tr}}{\varepsilon_{\rm ax}} \tag{23}$$

Due to limitations the maximum Poisson's ratio in a linear elastic material is 0.5 and the minimum ratio is -1. Materials with a negative Poisson's ratio will stretch in directions perpendicular to the direction of the pulling force, whereas materials with a positive ratio will do the opposite. A perfectly incompressible material will have a Poisson's ratio of 0.5. Figure 77 shows the materials plotted with the x-axis as the shear modulus [Pa] and the y-axis as the Poisson's ratio. This graph shows the elastomers having the highest Poisson's ratios, very close to 0.5, and the metals having the lowest Poisson's ratios, close to 0.3. Plastics tend to have a Poisson's ratio of close around 0.4 (CES EduPack, 2012). Elastomers have ratios very near 0.5, meaning that they are very nearly incompressible. The combination of a high Poisson's ratio and low shear modulus create a material that is nearly incompressible and easily deformed. This results in elastomers behaving similarly to a liquid, enabling them to distribute pressure evenly throughout the seal (Flitney, 2007).



Figure 77: Poisson's Ratio & Shear Modulus (Pa)

However, elastomers also have limitations due to their makeup, and these add constraints to the design of the seal. One limitation is that they are a soft material and can tear easily. For this reason the design of the seal must be carefully constructed to account for the constraint. Elastomers also have a high coefficient of friction, which results in stripping of the material if there is a force acting along it, such as the pipe in a BOP. After the Deepwater Horizon incident, researchers concluded that he upper annular preventer may have been weakened at the time of the spill due to the stripping that occurs when the annular preventer is closed and the drill pipe moves up or down (DHSG, 2011). The biggest limitation of elastomers is their limited temperature range and highly temperature dependent behavior (Flitney, 2007). High temperatures cause elastomers to get softer, and tear more easily, and low temperatures cause them to get harder and less able to conform to create a seal. Generally, elastomers that are able to seal at extremely high temperatures are less likely to provide a successful seal at extremely low temperatures (West, 2009).

6.3 Reliability Issues

It is important to make sure that each part in a BOP stack is reliable, so that major accidents such as the Deepwater Horizon and Ixtoc I do not occur again. Increasing the reliability of critical parts will result in an overall safer and more robust system. As seen in the two major Gulf of Mexico oil spills, problems can arise from the rams and the sealing. Shear rams in a BOP are subjected to many factors that can affect their capability, and rams in a subsea stack are even more complicated due to the various temperatures, pressures, and loadings they experience. One factor affecting shear rams is the axial position of the drill pipe, which was one of the reasons for the failure of the BOP in the Deepwater Horizon spill. As seen in Figure 78, in order for the ram to fully close, the drill pipe must be centered. If the pipe is off-centered, there may not be enough force to completely shear through the pipe, and the likelihood of a leak or blowout increases, since the maximum shearing force occurs at the center of the ram.



Figure 78: BSR Configuration (Kenney *et al.*, 2011)

Not having the maximum force for the rams is also a reason for why the Ixtoc I spill happened. Here, the shearing failed because drill collars were in the way of the rams, and not enough force was exerted to completely shear through the pipe (West,

2004). As the drill pipe is assembled piece-by-piece, joints are attached at the end of the pieces in order to connect them together and create one long pipe. It is important that these joints to do get in the way of the rams, for if they do, the rams may not have enough force behind them to completely shear through both the pipe and joint. In the case of Ixtoc I, there was a joint in the way of the ram, and as a result, the ram did not shear through both pieces and a blowout ensued.

Since the Deepwater Horizon blowout happened due to an off-centered pipe, a way to fix this would be to design a ram that can still shear through piping even if it is off-centered. Changing the design of the blade could lead to this. Having two shear rams spaced a distance apart would solve the problem of there being a joint in the way of one of the rams, and many companies are utilizing this design. Spacing them apart could insure that if one of the rams were to fail the other could still be able to shear through the piping and create an effective seal, preventing a blowout.

The sealing ability of a blowout preventer also plays a vital part in the reliability of the system, and there are a few factors that can affect the ability to seal effectively. The material of the seal plays an important role in the sustainability of the sealing, since these material properties govern how the seal will react under a range of temperatures, high pressures, and loadings. Erosion or stripping of the elastomer seal can cause the seal to fail, and many factors can influence this. Stripping can occur in an annular preventer if it is closed around the pipe, and the pipe is then moved up or down. During the Deepwater Horizon incident, witnesses saw pieces of rubber floating in the ocean, presumably from the annular preventer. This led researchers to believe that the annular preventer had weakened, and was another cause of the blowout (DHSG, 2011). Each failure alone was minor, however, in conjunction all of the failures led to a blowout. The low temperature of the seawater at the depth of the BOP causes elastomers to become stiff and not able to seal as well. This is another factor that plays a role in the sustainability of the seal. As temperature decreases the thermal energy of elastomers also decreases, leading to a decrease in resilience (Flitney, 2007). It is important that the seal does not reach the glass transition temperature, for if it does, the material will not be able to fully recover and the seal will become ineffective. Testing is imperative to insure the seal will not fail under these conditions, and it is essential to note that generally,

elastomers that are able to seal well at extremely high temperatures are less likely to seal as well at extremely low temperatures (West, 2009). Resistance to the fluid in a seal's environment is also a factor that can affect the reliability of the seal. Due to the chemical makeup of various materials, it is critical to test whether the material will fail while operating in the fluid. One way to test this is by soaking the material in fluids with temperatures ranging from low to high (Flitney, 2007). During this process the change in physical properties of the seal is noted. When the material is done soaking it is then tested again outside of the fluid to see how its physical properties change. These tests will insure that the seal will not fail in the various environments it will be put to use in. The various environments will affect the reliability of the seal, and for this reason it is important to pick a suitable material; one that can handle the environment of a subsea BOP. Looking towards a material selection, it is found that NBR, XNBR, HNBR, FKM and FFKM are suitable materials for this kind of BOP. This is referred to later in the chapter.

The investigation conducted by DNV following recovery of the BOP that failed during the Macondo blowout extensively documented the as-recovered condition of the blind shear ram. In particular, the extent of the erosion and damage to sealing surfaces:

"Material was missing from both the starboard and port side BSRs due to erosion. The elastomer of side packers was totally missing and metallic components partially eroded. The elastomeric blade seal on the upper (starboard) ram block was missing [and] the metallic packer components were also eroded" (Kenney *et al.*, 2011).

The DNV investigators performed laser scanning of recovered BOP components to quantify the extent of the erosion damage, as shown in Figure 79. This geometry was then compared to the geometry of the ram as initially produced, in order to generate a plot deviation from the original, which provides a visual scale of the magnitude of the damage.

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Figure 79: Deviation Plot of the Lower BSR Block (Kenney *et al.*, 2011)

6.4 Engineering Design

The goal of the student team was to design a blind shear ram BOP to address the reliability issues presented in the Section 4.3. In addition, the design had to be similar to other industry leading designs in terms of mass and cost of raw materials to be a competitive and viable design. The two main objectives for this design are outlined below:

- 1. Increase shearing ability for off-center, buckled drill pipes
 - a. Shear blades must span the entire throughbore
 - b. Shearing force must be equal to or greater than competing designs
- 2. Increase sealing capability under adverse conditions
 - a. Side packers must be protected from flow induced erosion
 - b. Face packers must be protected from flow induced erosion

The design objectives above address the major flaws found in current designs. In addition, a set of design parameters were developed through examination of literature published by major BOP manufacturers (Hydril, Shaffer and Cameron) and the API. Tables of these design parameters are presented below:

Table 38: BOP Design Parameters

Operating Conditions

Close Pressure	4,000 psig
HP Close Pressure	5,000 psig
Max Wellbore Pressure	10,000 psig
Max Operating Depth	12,000 ft.
Hydrostatic Pressure at Depth	5,350 psig
Max Temperature	250 F
Min Temperature	40 F

BOP Design Goals

Bore Diameter	14"
Overall Height	< 50 in.
Overall Length	< 200 in.
Overall Weight	< 11,000 lb.
Connection Type	Flanged
Close Time	< 45 Seconds

The design that was developed is presented in the following section. Additional material related to the design of the BOP, such as dimensioned parts, analysis results, and material information is located in Appendix C.

6.4.1 Blind Shear Ram Design

There are two main assemblies that shear and seal the wellbore. These are the upper and lower blind shear ram assemblies. The blades are of single "V" design, balancing shear force requirements with sealability. Both rams are hydrostatically balanced, so the wellbore pressure exerts a force on each ram that tends to assist in closing, rather than acting against the hydraulic pistons. This is accomplished by the 1" X 3" channel through the bottom of each ram. The lower shear ram assembly is shown in Figure 80. A detailed engineering drawing of the LSR assembly is shown in Figure 81. The lower shear ram consists of five components:

- 1. Main LBSR Body (1)
- 2. LBSR Side Packers (2)
- 3. LBSR Top Packer (1)
- 4. LBSR Face Packer (1)
- 5. Lower Shear Blade (1)



Figure 80: Lower Shear Ram Assembly



Figure 81: Detailed Engineering Drawing of LSR Assembly

The upper blind shear ram assembly is shown in Figure 82. A detailed engineering drawing of the USR assembly is shown in Figure 83. The upper blind shear ram consists of five components:

- 1. Main UBSR Body (1)
- 2. Upper Shear Blade (1)
- 3. UBSR Top Packers (1)



Figure 82: Upper Blind Shear Ram



Figure 83: Detailed Engineering Drawing of USR Assembly

The material for the shear blade must have very high hardness and strength. In most BOP applications, a high-strength tool steel is used. However, these materials are highly susceptible to hydrogen embrittlement and could fail catastrophically in environments containing H₂S or other corrosive fluids. To achieve the highest reliability, the design group selected an alloy that would not be vulnerable to embrittlement and sudden failure. The multiphase UNS R30035 alloy was chosen as the cutting edge because of its unique combination of high mechanical strength, hardness and corrosion resistance. This multiphase alloy is a quaternary alloy system, consisting of 35% Ni, 35% Co, 20% Cr, and 10% Mo, that can be strengthened to 260,000-psi tensile strength with good ductility and a hardness between 48 to 55 HRC (Canal and Shaffer, 1989).

For increased reliability over bolted shear ram assemblies, a welded assembly was designed. The electron-beam welding (EBW) process was selected because it permits the joining of metals that depend on hardening by cold-working for their strength without significant deterioration of their mechanical properties at the welded joint (Canal and Shaffer, 1989). In electron-beam welding, heat is generated by a narrow beam of high velocity electrons. As electrons strike the work piece, their kinetic energy is converted into heat. Weld depths of up to 6" can be achieved, and depending on the amount of

vacuum, depth-to-width ratios can range from 10-30. Welds made through the EBW process are of high quality, with minimal distortion in the weld area and a very small heat affected zone (Kalpakjian and Schmid, 2005). To weld the shear blade to the main shear body, the materials had to be compatible, and exhibit similar strength and fluid resistance characteristics to the BOP housing. For this reason, an iron-based super alloy, ASTM A638 (UNS S66286) was selected. ASTM A638 is a is a precipitation hardening austenitic stainless steel with a composition of 27% Ni, 16% Cr, 1% Mo, 2% Ti, 02.5% V and an Fe base metal.

The design of the blind shear ram assemblies is a significant improvement over the design employed by BP on the Deepwater Horizon, and addresses one of the causative issues of the blowout. The geometry of the ram housing and ram designs are shown in Figure 84. The UBSR rendered in green, with the cutting blade a slightly deeper shade. The LBSR rendered in red, with the cutting blade a slightly deeper shade. A 5" OD drill pipe is shown in blue, and the BOP housing is a transparent gray.



Figure 84: Geometry of Housing and Ram Design

From Figure 84 it can be seen that blades of the shear ram span the entire throughbore, unlike the BSR employed by the Deepwater Horizon. This means that there is no potential for off-center, buckled drill pipes to be located outside the shearing range of the ram. Although difficult to numerically estimate the reliability increase through use of a full-bore ram configuration, the team recommends that this type of design is incorporated in the next generation of shear rams.

6.4.2 Hydraulic System Design

The BSR rams are closed and opened by two opposed pairs of double acting hydraulic cylinders. The WPI design utilizes a dual piston assembly for ease of manufacturability and even distribution of closing force over the entire shear blade. In addition, because of the longer shear blade length, a double piston design takes advantage of the large width to height ratio. A single piston design would require the housing to be modified by adding more material in the height direction to attach the piston. The double ram design achieves significant weight savings by not requiring extra material in the height direction to accommodate the pistons. A cutaway view of the main hydraulic components is shown in Figure 85. A cutaway side view of the hydraulic system in the fully open position is shown in the top part of Figure 85. On the left side, the fluid chambers are illustrated with red for closing pressure and blue for opening pressure. On the right side, the major components of the hydraulic system are identified. A top cutaway view of the hydraulic system in the fully closed position can be seen in the bottom portion of Figure 85. This view illustrates the dual opposed piston design, with two pistons for each ram.



Figure 85: Cutaway View of Main Hydraulic Component

The geometry of the piston was designed to achieve a closing force equal to or greater than un-boosted rams of similar throughbore. Dimensioned drawings of the piston assembly are shown in Figure 86.



Figure 86: Dimensional Drawing of Piston Assembly

For high wear resistance and sealing ability, the hydraulic shaft and piston bore should be coated with a very smooth, high hardness material. The coating selected for this application is Hardide-A, a proprietary chemical vapor deposition coating with a hardness of 800-1200HV (upwards of 70 HRC) and a typical thickness of 100 μ m. Developed as a replacement for hard chrome treatments, the coating outperforms hard chrome in several key properties, including enhanced protection against corrosion and wear in chemically aggressive media such as seawater and fluids containing H₂S. The coating is made of Tungsten with nano-structured Tungsten Carbide, and can be polished to a surface finish between 0.2 to 0.3 mircons Ra (Hardide Coatings, 2013).

To verify that the piston assembly could withstand the loads applied, FEA was performed using SolidWorks SimulationXpress. The results of an FEA simulation of a 5,000 psi load on both the piston and piston shaft in shown in Figure 87. The Von Mises yield criterion was used to determine if the material would yield. The Von Mises stress, σ' , is calculated as follows:

$$\sigma' = \frac{1}{\sqrt{2}} \Big[\left(\sigma_x - \sigma_y \right)^2 + \left(\sigma_y - \sigma_z \right)^2 + \left(\sigma_z - \sigma_x \right)^2 + 6 \left(\tau_{xy}^2 + \tau_{yz}^2 + \tau_{zx}^2 \right) \Big]$$
(24)

where σ_x , σ_y , and σ_z , are the normal stresses, and τ_{xy} , τ_{yz} , and τ_{zx} , are the shear stresses. The part was considered to fail if the calculated Von Mises stress at a point exceeded the materials yield strength.



Figure 87: FEA Simulation of a 5,000 psi Load on Both the Piston and Piston Shaft

The piston shaft assembly withstood the 5,000 psi load and the maximum von Mises stresses in the part less than half of the materials yield strength. The assembly has a factor of safety of 2.8 for a 5,000 psi working load, and the recommended operating pressure of the BOP is 4,000 psi.

The accumulators selected for the hydraulic system are depth compensated accumulator tanks. These tanks are specially designed with 4 chambers within the tank, instead of the traditional 2 chambers. The four chambers consist of a vacuum, seawater, hydraulic fluid, and nitrogen. These accumulators work by using the seawater combined with a vacuum chamber to create strong suction forces that create pressures of about 5,350 psi. Then the nitrogen on the opposite side of the hydraulic fluid is pressurized to 5,000 psi. Combined, this creates 10, 350 psi of pressure on the hydraulic fluid to be distributed to the system (Springett and Franklin, 2013). Typically, 98 accumulators will be used in a BOP hydraulic system; however, 7 depth compensated accumulators can

produce the same pressure as the 98 tanks. The layout and attachment of the depth compensated accumulators can be seen in Figure 88. As shown, these tanks can be mounted around the shear rams in a confined package. This will allow for a much more compact hydraulic system, which as a result will reduce the size and weight of the BOP.



Figure 88: Depth Compensated Accumulators (Springett and Franklin, 2013)

In addition to the accumulator tanks, the hydraulic system is designed with a hydraulic booster to increase pressure to system when necessary. The hydraulic booster can be automatically or manually activated in instances when the wellbore pressure is extremely high or if the shear ram is not closing fast enough and the velocity needs to be increased.

There are two options that were considered for booster pump selection. The first design is the standard booster pump. In this design, a high-pressure booster pump is supplied from a hydraulic reservoir tank and is tied into the main hydraulic lines through a series of valves. The control system would then recognize the need for additional pressure, and the series of valves would open proportionally to supply the necessary amount of pressure. However, the downside to this system is the need of a pump and a

relatively large reservoir tank. The second design is known as a tandem booster. The tandem booster is a small nitrogen charged accumulator tank that is mounted directly on the bonnet of both sides of the BOP. The tandem booster has the capability of adding nearly 3,000 psi of pressure to the system when activated (Springett and Franklin, 2013). This booster is much smaller than the pump booster, and is easy to mount right on the BOP. For this reason, the design will incorporate the tandem booster to supply auxiliary pressure when necessary while incorporating weight savings in the BOP design.

Medium pressure Swagelok fittings are used in the hydraulic system. The fittings are made from SAF 2507 (UNS S32750) super duplex stainless steel and rated for a working pressure of 15,000 psi. Sealing of Swagelok fittings is accomplished by the mechanical action of the threads applying force to the ferrules, which affect a metal-to-metal seal. The seals can be made and re-made multiple times, resulting in easier maintenance of the hydraulic system. In addition, the fittings are gaugeable, meaning they can be tested for proper installation, insuring that leaks do not occur. A Swagelok medium-pressure tube fitting can be seen in Figure 89.



Figure 89: Swagelok Medium-Pressure Tube Fitting (Swagelok, 2013)

6.4.3 Housing Design

The largest component of the BOP assembly is the ram housing. There are two primary loads applied to the housing: (1) the hydrostatic pressure at the operating depth, and (2) the wellbore pressure. In the design specifications these were 5,350 psig and 10,000 psig, respectively. To predict the potential for failure at the expected pressure loading, Finite Element Analysis was performed using SolidWorks SimulationXpress, shown in Figure 90. The most extreme loading that the housing would experience would be exposure to wellbore pressure at the surface, as there is no balancing hydrostatic force. The housing was tested at a 15 ksi internal pressure to introduce a factor of safety into the design.



Figure 90: FEA Simulation on Ram Housing

The large size of this component and limited production makes sand casing the most viable manufacturing process. Machining following casing would need to take place to achieve the desired surface roughness in the ram cavities.

To select a suitable material for the housing, four primary factors were considered:

- 1. Fluid resistance to both seawater and hot hydrocarbons
- 2. High strength and hardness
- 3. Ability to be cast
- 4. Dimensional stability at elevated operating temperatures and pressures

Using CES EduPack, multiple candidate material were found. The strongest material was CB-7Cu H900 (17-4PH H900), a chromium-nickel-copper precipitation hardening stainless steel used in application requiring high strength and corrosion resistance. The steel would be heat treated at 900 F for 1 hour, resulting in a yield strength of 170,000 psi (ATI, 2013). Increased fluid resistance would be achieved through High velocity oxy-fuel (HVOF) application of thin aluminum coating on the surface of the casting. A 6 mil thick coating of sealed Al can provide corrosion resistance in immersed seawater environments of up to 20 years (Cramer and Covino, 2005). However, upon detailed review, it was found that this alloy is particularly susceptible to pitting and stress corrosion cracking (SCC) in chloride containing environments (such as seawater). This could result in sudden, catastrophic failure, and therefore was an unacceptable material choice.

A better material was determined to be a cast duplex or super-duplex stainless steel. Although lower in strength than some other cast stainless steel alloys, they exhibit excellent resistance to corrosion in seawater environments, including pitting and SCC. In addition, the combination of high hardness and good corrosion resistance found in duplex stainless steels gives them a high resistance to erosion-corrosion if exposed to high velocity flowing media containing abrasive solid particles (Sandvik, 2013).

The material selected for the BOP housing was ASTM CD-4MCu (UNS J93370), a cast, duplex stainless steel. The material composition is 66.4% Fe, 26.5% Cr, 2.7% Cu, 2.3% Mo, and 0.04% C. The material has a yield strength between 73.2 to 89.9 ksi, and an elastic modulus of 28.9E6 psi. A comparison of the yield strength vs. cost for the stainless steel alloys considered for the BOP housing is found in Appendix C. In addition, the material has a pitting resistance equivalent number (PREN) equal to 34. The PREN is defined by the following formula:

$$PREN = 1 \times \%Cr + 3.3 \times \%Mo + 16 \times \%N$$
(25)

The PREN can be used to compare the corrosion resistance of stainless alloys. NACE MR01751 establishes a maximum H_2S partial pressure of 1.5 psia (10 kPa abs) for solution-annealed duplex stainless steel with a PREN between 30 and 40. If a higher resistance to H_2S corrosion was needed, a castable, super-duplex alloy could be used, such as Sandvik SAF 2707 HD, which has a PREN of almost 50.

6.4.4 Locking Mechanism

In the event the BOP loses hydraulic pressure after closing, the rams must remain sealed. This is accomplished through a locking assembly attached to the BOP bonnet. The locking mechanism operates as follows: pressurized hydraulic fluid is provided to a hydraulic motor, which converts the hydraulic energy into rotational motion. An Acme Screw assembly translates the rotational motion into linear motion, driving a block into the path of the hydraulic piston of the BOP. The locking assembly is shown in Figure 91. More detailed drawings of the locking mechanism assembly can be found in Appendix C.



Figure 91: Locking Mechanism Assembly

The application would require the hydraulic motor to operate at low speeds and output high torque, so a gerotor-type design would be appropriate. One such design is the TC Series of Nichols motors manufactured by Parker. The design group selected a TC0080 Motor for use in the locking mechanism. The motor outputs 539 lb-in of torque, with a fluid displacement of 5 cubic inches per revolution (Parker Hannifin Corp, 2013). A schematic of this motor is shown in Appendix C.

6.4.5 Control Design

Having reliable control and feedback of the hydraulic system of a BOP can increase safety and immensely help prevent disasters. The control design is based mainly on the ability of the system to give constant feedback to the operator, as well as give the operator manual control of the system in the event it is needed. All of the feedback, inputs, and outputs are generated in the yellow and blue control pods. Within the control pod, our design will add a MTS transducer and 18 pressure transducers. The battery packs, AMF controller, and solenoid driver board features will remain to function in their traditional manner and will not be updated with our design. The control pods will then transmit this data above sea to the operator through the use of traditional MUX cables. The operator will then be able to view this feedback and give output signals to the control pods through the use of a Human-Machine Interface (HMI) screen. The design of the interactive HMI screen can be seen in Figure 92, which directly corresponds with our design of the shear rams and the hydraulics system.



Figure 92: Shear Ram HMI Screen

On the HMI screen, the operator can easily view all pressures of the hydraulic system as it interacts with the shear ram. Such pressures include open and close pressures at every port, accumulator pressure supplied, and the pressure supplied from the booster. The ability to view the pressure within the wellbore is also displayed in the center of the screen, and that reading plays a major role in the ability to predict a blowout. These pressure readings are an output from the 18 pressure transducers located within the control pods. In addition to the pressures, the operator has the ability to monitor the position of the shear ram through the position indicator located at the top of the screen. The position indicator gives feedback to the operator when the ram is fully open, fully closed, and any incremental position in between. The position indicator gives the reading from the MTS transducer located in the control pods. The MTS transducer is a precision linear hydraulic sensor that measures the displacement and velocity of the piston, and this feedback is then used to give the position of the ram. Finally, there is an interface on the bottom right of the screen that allows the operator to manually send signals to the control

pods to activate certain function. The operator has the ability to open or close the ram, activate the boosters, or enable ROV intervention by either touching on or off on the HMI screen. When the green light is on, that would indicate the feature if on. When the red light displays, that would indicate the feature is off. These features are off by default, and will either activate manually through the HMI or automatically through the control logic used in the pods.

The designed control system will also have a Remotely Operated Vehicle (ROV) connection point on the control pod for maintenance and manual control purposes. When the ROV attached to the control pod, it will have the ability to remotely apply hydraulic pressure to the shear rams. However, this feature must first be activated through the HMI screen for the ROV to have the ability to connect to the control system and function.

6.4.6 Seal Design

Seal design for a subsea BOP is a challenging task. There are high pressures, large temperature shifts, and many different fluids that may be flowing at high velocity and contain abrasive particles. Design of seals that will not fail under adverse conditions requires adequate background knowledge on this complex topic, which will be presented in this section.

The formation of a seal is due to the unique properties of an elastomer. At normal working temperatures elastomers have a very low modulus of elasticity and are virtually incompressible. This means that they are highly deformable, but still maintain a nearly constant volume, as the Poisson's ratio of elastomers is close to 0.5 (Flintley, 2007). A schematic of a simple O-ring type seal is shown in Figure 93. In part (a), the seal is shown in its compressed, but energized state. This means the seal is in position, but not subjected to fluid pressure. In part (b), the seal is energized by the system pressure, and deforms to seal the grove. Extrusion of the seal can be seen in the rightmost gap, and if repeated this can lead to damage of the seal and possibly failure.



Figure 93: Schematic of a Simple O-Ring Type Seal

Increasing the reliability of the BOP system under adverse conditions is our project's objective, and preventing failure of the seals is one of the core design goals to achieve in the end. In our case, the primary failure causes of interest are:

- 1. Movement of counter-faces reducing the amount of squeeze on the seal
- 2. Extrusion of the seal
- 3. Aging of the seal changing elastomeric properties
- 4. Temperature effects

Each seal in the BOP assembly will be designed with these failure mechanisms in mind, so that reliability is maximized. In addition to the above criteria, there are other important points that must be considered when selecting an appropriate elastomer material for a subsea BOP seal. Some of these include (Flitney, 2007):

• How and where will the seal be used?
- What is the environment in which the seal will operate; including liquids, gases, contaminants, pressures, temperatures, etc.?
- What forces/pressures are experienced?
- Factors to be considered:
 - The primary fluids to which the elastomer will be exposed
 - Secondary fluids; such as assembly lubricants, cleaning fluids
 - The temperature extremes, both hot and cold
 - The presence of abrasive external contaminants

The first two bullets address the ocean as the environment it will be used in, and as part of a BOP as how it will be used. Due to the limited sunlight at the depths of which a BOP lays, the seal will experience low temperatures. However, if there are flowing hydrocarbons the temperature will increase and therefore, the seal can experience a wide range of temperatures from low to high. The biggest concern in elastomers at low temperatures is the change in their properties. At low temperatures elastomers become stiff and brittle; which is not acceptable for an efficient seal (Flitney, 2007). The elastic modulus of elastomers increases as the temperatures. Since the BOP will continuously operate at low temperatures over its entire lifetime, it is critical to make sure the seal will not fail due to these conditions.

Elastomeric materials are narrowed down from the application factors mentioned, in order to find the best suitable material for a subsea BOP seal. There are many different elastomer types, each having a wide range of properties. Within each type a seal manufacturer can have between 15 and 20 various grades of material to meet the operating requirements in a specific environment (Flitney, 2007).

The best suited material for a subsea BOP seal is nitrile butadiene rubber (**NBR**), fluorocarbon elastomer (**FKM**) and perfluorocarbon elastomer (**FFKM**) each of which has various grades to provide the best sealing for its environment. Nitrile is widely used in general sealing materials for both static and dynamic seals. This is due to its good mechanical properties, resilience, wear, and resistance to many mineral based oils (Flitney, 2007). It is also suitable for use with water and diluted acids; making it a good material for a BOP seal. In order to have the best mix of properties, the appropriate grade

of nitrile must be selected. One grade of nitrile is carboxylated nitrile butadiene rubber (**XNBR**), and this is made with the addition of carboxylic acid to nitrile polymers. This addition creates a polymer with increased strength, in turn producing an elastomer with better tear properties and abrasion resistance. But, there are also negative effects to this, thus not being as widely usable as NBR. Some of these effects are a decrease in water resistance, resilience, and low temperature properties. However, the increased strength and abrasion resistance are needed for high pressure reciprocating seals, as is experienced in subsea BOPs. Another grade of nitrile is hydrogenated nitrile butadiene rubber (**HNBR**), and this is made when the nitrile polymer undergoes a hydrogenation process (Flitney, 2007). This process increases the resistance to chemicals attacks, and creates a material with good mechanical properties and increased temperature resistance. This is a useful material, in that HNBR has a high strength and high elongation to break, however, it has a higher cost associated with it than NBR. This material is widely used in the oil and gas industry, because of its high strength, better fluid resistance, and high temperature capability (Flitney, 2007).

FKM is created when fluorine is added to the polymer chain, creating a material with wide chemical properties at temperatures up to 200°C (Flitney, 2007). The addition of fluorine forms a strong bond, with most of these elastomers having 65% fluorine content. Increasing the amount of fluorine in the polymer results in a material with improved fluid resistance, however, in turn, there is a decrease in the physical properties. As a result, the material is susceptible to compression and extrusion problems. FFKM is created when the polymer chain is fully fluorinated, and there is no hydrogen present in the chain (Flitney, 2007). This produces a material with high temperature capabilities and has a high degree of chemical resistance. One downside to FFKM is that the materials required to produce this polymer are very expensive, generating an expensive final product. As previously stated, increasing the fluorine content results in a decrease in the physical properties, so FFKM usually has poor resilience. There are, however, special grades that combat this problem, but they are costly. Some applications require the use of FFKM, since it is the only material suitable for a seal. These applications include the oil and gas industry and chemical processing industry. Although FFKM is

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costly, this is sometimes the most cost efficient solution, since a seal design without the use of elastomers could be much more expensive (Flitney, 2007).

These materials (NBR, XNBR, HNBR, FKM, and FFKM) are advanced materials, and therefore, are not shown in the previous CES EduPack graphs. To show these materials and their properties, an advanced material class is needed to graph them. The following graphs show the advanced elastomer class, including NBR, XNBR, HNBR, FKM, and FFKM; along with other advanced elastomers. These graphs show the same properties as the previous graphs: Stress & Strain, Young's Modulus, and Poisson's Ratio & Shear Modulus (CES Edupack, 2012). In each graph the entire elastomer class is narrowed down to thermoset elastomer rubbers. These are the light blue bubbles and each bubble indicates the range of properties for each material. The greyed out bubbles are various elastomers that do not pertain to the seal material; in particular thermoplastics. The red bubbles are the most important ones and are various grades of NBR, XNBR, HNBR, FKM, and FFKM.



Figure 94: Stress & Strain Graph for Selected Materials



Figure 95: Young's Modulus for Selected Materials



Figure 96: Poison's Ratio and Shear Modulus for Selected Materials

Sealing of the entrance of the hydraulic piston shafts into the ram cavity was achieved through use of a three part sealing system. The outermost seals were fluid wipers, designed to remove both oil films and abrasive particulates from the shaft before the main seal. The inner seal was based on a two-part seal system to prevent extrusion of the elastomer. A schematic of this type of design is shown in Figure 97.



(Flintney, 2007)

Pressure sealing was achieve through use of a Hallite type 735 seal, a compact double acting piston seal assembly designed for one piece pistons. The Hallite 735 seal is suitable for high pressure, heavy-duty applications. The assembly comprises as standard a self-lubricating wear resistant, glass and MoS_2 filled PTFE cap ring, which is loaded by an NBR energizer. Split thermoplastic anti-extrusion rings support the seal on both sides and prevent contamination of the energizer and cap ring (Hallite, 2013).



Figure 98: Hallite 735 Seal

6.5 Design Summary and Benchmarking

The design achieves significant weight and size savings over other models of comparative size and capacity, while improving both shearing and sealing capability under adverse conditions such as a buckled drill pipe and a flowing well. Figure 99 depicts a rendering of the final design. A dimensioned engineering drawing of the assembly is shown in Figure 99. An exploded rendering of the BOP assembly is shown in Figure 100.



Figure 99: Design Render



Figure 100: Dimensioned Engineering Drawing of the Assembly



Figure 101: Exploded Rendering of BOP Assembly

The BOP assembly consists of many components. Important statistics and measurements for the BOP design are presented in Table 39.

Overall Dimensions and Mass									
Bore Diameter	14"								
Overall Height	36 in.								
Overall Length - Rams Open	113.05 in.								
Overall Length - Rams Closed	98.8 in.								
Overall Width	30.92 in.								
Overall Weight	9223 lb.								
Connection Type	Flanged								
Bore Diameter	14"								

Table 39: BOP Design Summary

•					
Pistons per ram	2				
Stroke	9.4 in.				
Piston alosa area	78.5 sq.				
Fision close area	in.				
Total niston close area	157.08				
Total piston close area	sq. in.				
Riston open area	68.9 ² sq.				
Fiston open area	in.				
Total niston open area	137.8 sq.				
Total piston open area	in.				
May close force (3,000 psi)	471,238.5				
Max close loree (5,000 psi)	lb				
Max close force (4,000 psi)	628,318				
Wax close loice (4,000 psi)	lb				
May close force (5,000 psi)	785,397.5				
Wax close loice (5,000 psi)	lb				

Hvdraulics

The Blowout Preventer design compares favorably to other similar models by leading industry manufactures. Table 40 takes information gathered from Cameron, Hydril, and Shaffer and compares it to the team's final design specifications. The WPI BSR design achieves a higher shear force at 3,000 psi than both the unboosted Cameron and Shaffer rams, and generates 98.5% of the shear force of the larger Hydril ram. Therefore, the WPI BOP generates shearing force comparable to all major manufacturers, and has full bore shear blades, meaning that it can shear drill pipe regardless of axial position. This represents a significant improvement over traditional rams. In addition, the seal configurations of the WPI BSR protect the seals from erosion in a flowing wellbore. This is accomplished by the removal of face packers and side packers from the top ram, which were located in high velocity flow zones.

Manufacturer, BOP and Operator Type	Close Area (sq. in.)	Shear Force (lb) @ 3,000 psi	Mass (lb)	Overall Open Length (in.)	Height (in.)	Width (in.)	
Cameron 13-5/8" 10K	110.15	330,450	10,300	201	41.688	30.25	
Cameron 13-5/8" 10K w/							
LB shear bonnets and boosters	224	672,000	11,600	235.875	41.688	30.25	
Hydril 14.25"	159.5	478,500					
Shaffer 14"	153.9	461,700					
Shaffer 14" w/ 14" booster	293.7	881,100					
Shaffer 14" w/ 16" booster	340.8	1,022,400					
Shaffer 14" w/ 18" booster	394	1,182,000					
WPI 14" 10K Ram Type 1	157.1	471,239	8,500	84	34	28	

Table 40: Benchmarking Data

Due to the dual piston design, the BOP design is significantly lighter and shorter than the Cameron 13-5/8" 10K rams. This would reduce handling difficulty of the BOP stack, decreasing logistical problems and increasing safety for the riggers during installation, maintenance and retrieval. Although no information could be found on the dimensions of the Hydril and Shaffer rams, there is confidence that the redesigned ram is of similar dimensions and would be highly competitive.

Chapter 7: Conclusion

The extraction of natural gas from shale gas reserves and oil from deepwater oil reserves is becoming more prevalent as the U.S. national demand for energy increases. With this increase in the extraction of natural resources, it is essential to maintain and increase the safety and reliability of the extraction and management processes. From this project, conclusions were drawn and recommendations given to help maintain and increase safety and reliability for natural gas and oil extraction. STPA was used to determine further areas of research into natural gas development. The further areas of interest that this project focused on were casing and cementing during the drilling process, the management and treatment of hydraulic fracturing fluid wastewater, and the reliabilities of blowout preventers. Research in each of these topics produced an in-depth analysis of the casing and cementing process, along with a safety control structure of the process; an on-site wastewater treatment system preliminary design; and an improved, higher-reliability, redesigned critical component of a blowout preventer.

The Systems-Theoretic Process Analysis framework provided clarity and organization during the analysis of casing and cementing in the Marcellus Shale, and helped to highlight the entities and interactions involved in preventing accidents during the life cycle of a well. Although no quantitative data was found on the number of failures of casing and cementing systems in the Marcellus Shale, the analysis resulted in insight into the probable cause of failures, and the largest weaknesses within the process. Based on initial research and application of the STPA framework, the student team reached the following conclusions:

- A) The downhole conditions of the Marcellus Shale are benign compared other formations and locations found within the industry.
- B) Current technology is more than adequate to address any technical challenges downhole if they are identified before well completion
- C) The majority of challenges faced are on the surface, such as the treatment of wastewater or the reduction the amount of truck traffic due to the well locations

The casing and cementing STPA also concluded that it was likely that any problems with casing and cementing in the Marcellus Shale likely stem from inadequate control of the process or design. The challenge in the design of a casing string and cement job for a well lies in modifying the design to adequately address the unique conditions of a particular well. The design is modified based on feedback from drilling reports, log results, and integrity tests. For a particular casing and cementing program to be successful, it must be tailored to the downhole conditions encountered while drilling. This is one possible cause of the learning curve experienced when natural gas development begins in an area where the operators are unfamiliar with the formations present. There are also pressures within the company that influence the design, such as time and budgetary pressures, corporate policy and culture, and regulations and standards. It is recommended that the STPA analysis should be applied to the casing and cementing program design process to identify weaknesses that could lead to improper design. Work should also be conducted quantifying casing and cementing regulatory violations in the Marcellus Shale in terms of their technical content, separating paperwork violations from errors in the design and construction of the well, and identifying why these errors occurred using the STPA framework.

Creating regulations to insure that the correct design is used for a particular well is a difficult task. The large variability in downhole conditions, even between wells within the same formation, means that designing and constructing a well to the standards alone does not necessarily produce a safe design. It is therefore difficult to address the effect of policies that require wells to meet certain design specifications, such as requiring the top of cement to be a certain distance above the top of the formation. For one well this may be more than enough, but for other wells it may be inadequate. Therefore, creating a set of nationwide regulations and standards for casing and cementing design that accounts for the variability between formations would be an extremely difficult task.

The chapter on hydraulic fracturing wastewater management discussed the composition of hydraulic fracturing wastewater and the current methods for managing that waste for Pennsylvania. In order to protect the health and safety of its inhabitants, the team recommends the following:

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- A) Require reuse of wastewater in other fracturing operations
 - Stop usage of pits; Minimize fresh water withdrawals
- B) Classify wastewater as hazardous under RCRA
 - Require registration of all chemicals used in fracturing fluids
- C) Monitor waters and wastewaters to avoid contamination
 - Establish baseline water quality; Test surface waters post-fracturing

Improper management of hydraulic fracturing wastewaters poses potential risks including environmental contamination due to spills, leaks, or inadequate treatment before discharge, or improper disposal. Hydraulic fracturing in Pennsylvania produces millions of gallons per well of wastewater that can contain hazardous substances such as radium. Although practicing safe management methods for this wastewater can reduce the hazards associated with it, the best way to protect human health is to minimize the amount of wastewater that is disposed of. Ultimately, the team recommends future research into changing the hydraulic fracturing process to use less water.

From the research conducted in blowout preventers (BOPs) it was found that current blowout preventer technology encounters critical issues that compromise the ability to seal the well under emergency conditions. These design issues have resulted in deadly accidents when BOP stacks failed to maintain the integrity of the well; the most recent of which was the Deepwater Horizon Spill in April, 2010 that resulted in 11 deaths and led to the release of an estimated 4.9 million barrels of crude oil. During the component redesign, information was learned that allowed for recommendations for BOP designs. The first recommendation is to increase BOP shearing ability. This is based on addressing the issues that have caused the two largest subsea blowouts to date. In both incidents, the blades required to cut through the drill pipe we not successful in cutting through the drill pipe; resulting in blowouts. In addition, BOPs should be able to shear off-center, buckled drill pipes. This was the case in the Deepwater Horizon Spill, where the blind shear rams were not able to shear the off-center pipe. Another recommendation is to require two Blind Shear Rams (**BSRs**) for high risk deep-water wells. Current BOPs are also not designed to shear though tool joints; however, during emergencies the operators may not be certain where the tool joints are located within the BOP stack. With tool joints forming almost 5% of the drill string, this is a large and unacceptable risk that

the BOP will fail to close and seal. Therefore, it is recommended that two blind shear rams be included on all subsea BOP stacks used on high risk deep-water wells. This adds redundancy in case one BSR encounters a tool joint, and also decreases the chance that a buckled pipe will prevent the sealing of the wellbore.

A final recommendation given to increase the safety and reliability of blowout preventers is to maintain focus on early kick detection and response measures. Blowout preventers are not failsafe, and although a lot of research and engineering goes into designing one, they are still prone to critical issues. For this reason, well operators must maintain vigilant focus on kick detection, prevention, and response measures. This can be accomplished through an improved control system with extensive feedback to the operator. The Deepwater Horizon Spill occurred, in part, because operators missed warning signs that the well was flowing, and failed to take appropriate action within the brief window of opportunity. It is recommended that all stages of well development are conducted under automated supervision, so that costly human errors can be avoided.

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Appendices

Appendix A: Treatment Technology Data

A.1 Complete Technology List

- Capacitive deionization
- Electrodialysis
- Electrodialysis reversal
- Electrodionization
- Forward osmosis
- Ion exchange
- Membrane distillation
- Microfiltration
- Multi-effect distillation
- Multi-stage flash
- Nanofiltration
- Reverse Osmosis
- Ultrafiltration
- Vapor compression
- VSEP

A.2	Complete	Analysis
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Technology																	Total		
	Contaminant removal		Mobile capability		Energy efficiency		Low O&M cost			Low capital cost			Life cycle period						
	RR	W	WR	RR	W	WR	RR	W	WR	RR	W	WR	RR	W	WR	RR	W	WR	
Electrodialysis	2	2.5	5	2	2.5	5	3	1.5	4.5	1	1.5	1.5	2	1	2	1	1	1	19
Electrodialysis reversal	2	2.5	5	2	2.5	5	3	1.5	4.5	1	1.5	1.5	2	1	2	1	1	1	19
Microfiltration	2	2.5	5	2	2.5	5	3	1.5	4.5	3	1.5	4.5	3	1	3	2	1	2	24
Multi-effect distillation	2	2.5	5	1	2.5	2.5	2	1.5	3	2	1.5	3	1	1	1	3	1	3	17.5
Multi-stage flash	2	2.5	5	1	2.5	2.5	1	1.5	1.5	1	1.5	1.5	1	1	1	3	1	3	14.5
Reverse Osmosis	3	2.5	7.5	3	2.5	7.5	2	1.5	3	3	1.5	4.5	2	1	2	2	1	2	26.5
Ultrafiltration	2	2.5	5	2	2.5	5	3	1.5	4.5	3	1.5	4.5	2	1	2	2	1	2	23
Vapor compression	2	2.5	5	1	2.5	2.5	2	1.5	3	2	1.5	3	1	1	1	3	1	3	17.5
VSEP	2	2.5	5	2	2.5	5	3	1.5	4.5	3	1.5	4.5	1	1	1	2	1	2	22

RR = Raw Rating

W = Weight

WR = Weighted Rating

Appendix B: General Regulations

B.1 Federal Agencies

- Bureau of Land Management and U.S. Forest Services manages natural gas drilling process for federally owned land.
- Environmental Protection Agency (EPA) primary agency that oversees federal laws relating to natural gas drilling.

B.2 Federal Laws

- Clean Air Act (CAA) limits impact of air emissions to the iar quality, from sources such as engines and gas processing equipment)
- Clean Water Act (CWA) primary law that regulates pollution to surface water. It was established to protect the quality of water, and it goes through the National Pollutant Discharge Elimination System (NPDES) permitting process.
- National Environmental Policy Act (NEPA) requires a thorough analysis for environmental impacts from exploration and production on federal lands.
- Safe Drinking Water Act (SDWA) regulates underground injection of fluids.

B.3 State Agencies

- Each state has a primary agency responsible for permitting and overseeing well operations.
- Interstate Oil and Gas Compact Commission (IOGCC) used to conduct state reviews prior to the formation of STRONGER.
- State Review of Oil and Natural Gas Environmental Regulation, Inc. (STRONGER) – develops guidelines for reviewing state oil and gas environmental programs.

B.4 State Laws

- Several states have their adjusted NEPA law, with additional state reviews needed prior to gaining approval.
- Prior to drilling a well, an application for a permit is required that outlines every aspect of the procedure (ie. location, construction, operation, etc.).
- Interstate Oil and Gas Compact Commission represents oil and gas producing states.
- Underground Injection Control (UIC) Program optional voluntary review process that states can conduct, created by the Ground Water Protection Council (GWPC).

Appendix C: BOP Supplemental Material



C.1 FEA Testing of BOP Housing

FEA Testing of BOP Housing, Rev. A

Test Pressure: 15 ksi Material: Low Alloy Steel



FEA Testing of BOP Housing, Rev. M

Test Pressure: 15 ksi Material: CD-4MCu



FEA Testing of BOP Housing, Rev. N Test Pressure: 10 ksi – System Pressure Material: CD-4MCu Factor of Safety: 1.85 Changes from Rev. M: Thickened flange connections and reinforced failure points


FEA Testing of BOP Housing, Rev. N Test Pressure: 10 ksi – System Pressure Red areas indicate FOS below 3



Piston Rev. B von Mises Stresses, 5 ksi test

C.2 Assembly Visualization



Major parts and assemblies of the BOP colored by total mass – top cutaway



Major parts and assemblies of the BOP colored by total mass – side cutaway



All parts of the BOP colored by mass – top cutaway



All parts of the BOP colored by mass – side cutaway

Previous Revisions:

BOP Rev. L





Yield strength (elastic limit) (ksi) g 12 いたの日 Tanless steel martenetic, ASTM CB-7Cu, cast, aged at SSOPC Price (USD/lb) Startless steel, See. CICCOLDING OF LITEL DE LE CONTRACTÓN DE LE CONTRACTÍN 日本美 日本 R niess steel, duplex, Tum PD, cast, H2O quenched & aged aloy, IW/AR, cold worked, hard

C.3 Housing Material Selection

Material Key:

Red – Nickel based alloys

Aqua – Stainless Steels

Yellow – Duplex Stainless Steels

Lime – Cast Duplex Stainless Steels

Magenta – Cast 17-4PH Blue – Cast ASTM CA-15 and CA-40 Orange – Cast CB-7Cu



Rendering of the Locking Assembly



Locking Assembly Cutaway Mass Visualization View



Locking Assembly Exploded View



Parker Hydraulic Motor Cutaway View

C.4 Recommended Test Practices for Subsea BOP Stacks (API, 2000)

Initial Test – Prior to Installation

Component to be Tested	Recommended	Recommended Pressure Test High
	Pressure Test, Low	Pressure (psig)
	Pressure (psig)	
Annular Preventer(s)	200-300	Minimum 70% BOP working pressure
Operating Chambers	N/A	Minimum of 1500
Ram Preventers		
Pipe Rams	200-300	Working pressure of ram BOPs
Blind Shear Rams	200-300	Working pressure of ram BOPs
Casing Rams	200-300	Working pressure of ram BOPs
Operating Chambers	N/A	Maximum operating pressure
BOP Control System		
Manifold and BOP Lines	N/A	Minimum of 3000
Accumulator Pressure	Verify Precharge	N/A
Close Time	Function Test	N/A
Pump Capacity	Function Test	N/A
Control Stations	Function Test	N/A

Subsequent Tests:

Component to be	Recommended	Recommended Pressure Test,
Tested	Pressure Test, Low	High Pressure (psig)
	Pressure (psig)	
Annular Preventer(s)	200-300	Minimum 70% BOP working
		pressure
Operating Chambers	N/A	N/A
Ram Preventers		
Pipe Rams	200-300	Greater than MASP**
Blind Shear	200-300	Greater than MASP**
Rams		
Casing Rams	200-300	Greater than MASP**
Operating Chambers	N/A	N/A
BOP Control System		
Manifold and BOP	N/A	Optional
Lines		
Accumulator	N/A	N/A
Pressure		
Close Time	Function Test	N/A
Pump Capacity	Function Test	N/A
Control Stations	Function Test	N/A
*Pressure tests should be stable for at least		
5 minutes.		
**Maximum Anticipated Surface shut-in		
Pressure		

