AN INTEGRATED APPROACH TO MOBILE TREATMENT OF FLOWBACK WATER FROM SHALE GAS PRODUCTION

A Thesis

by

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ABSTRACT

Advancements in horizontal drilling and hydraulic fracturing technologies and methods have resulted in tight shale formations becoming viable for oil and gas production. A necessary resource for any hydraulic fracturing project is fresh water to form the fracturing fluid. Most of the used water is discharged in the form of a flowback wastewater. In principle, the flowback wastewater can be treated and reused to reduce freshwater consumption. The objective of this research is to develop a framework for the logistics and scheduling of a mobile treatment system for multiple producing wells. Several treatment technologies were studied, including coagulation/ultrafiltration, lime softening, and membrane treatment. In order to perform a case study on Marcellus well data, thermal membrane distillation technology (TMD) was chosen due to its modularity and compatibility for use in a mobile rig. An optimization approach was used in order to determine the number of membrane units needed at each well for each of the twenty-eight days. Results show that the use of TMD for flowback treatment is economically competitive with conventional disposal methods. The application of this framework can be scaled to any number of wells, allowing for efficient and accurate allocation of mobile units to meet desired treatment thresholds.

CONTRIBUTORS AND FUNDING SOURCES

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. INTRODUCTION

In recent years, advancements in horizontal drilling and hydraulic fracturing have resulted in rapid growth of fracking projects. New technologies have made previously inaccessible oil and gas plays exploitable, and companies have started to produce this available supply. One of the predominant resources needed in a fracking project is fresh water. It is utilized in large quantities to frack the formation, and is then returned to the surface as flowback and produced water. Most of this water ends up as waste, since there are few treatment options that can compete with the economic benefits of deep well injection. This mass wasting of fresh water not only creates environmental concerns, but also provides an opportunity for businesses to exercise greater economic efficiency and cut their costs. The primary objective of this project is to analyze treatment options for produced water in shale gas production, and provide cost-effective options for on-site water treatment and reuse. The aim of this project is to develop a water treatment option for shale gas production that is cost effective and viable in today's fracking developments.

1.1 Background

Today's oil and gas market has seen a rise in production that is due largely to advancements in horizontal drilling and hydraulic fracturing. Horizontal drilling differs from traditional vertical wells in the way that it turns the well laterally through the productive formation. This enables the well to be in contact with more of the formation and increases its effective producing area (Figure 1).

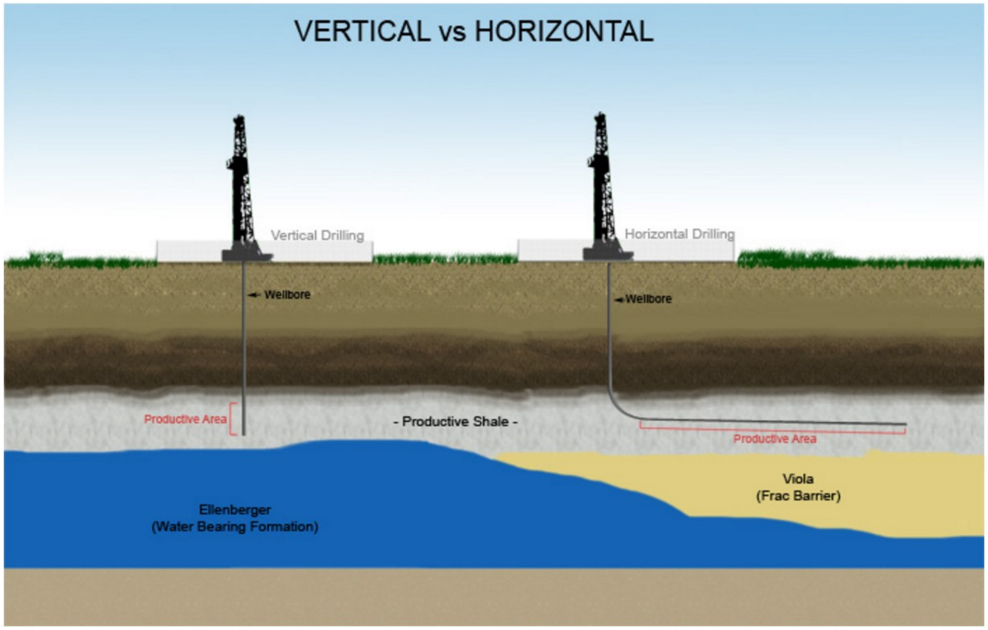


Figure 1: *Horizontal and Vertical Wells (Keystone Exploration)*

Horizontal wells paired with hydraulic fracturing techniques enable economically viable production from tight shale formations. Fracturing fluid is created with a mixture of fresh water, chemicals, and proppant. After the horizontal well has been drilled, stages of fracturing produce a series of cracks in the shale formation. The fracking fluid leaves behind the proppant particles, most commonly sand grains, to keep these cracks open. This increases permeability and allows the oil or natural gas to flow into the fractures where it can be brought to the surface. By hydraulically fracturing along the lateral portion of a well, a large area of the formation can be accessed and produced from a single drilling project (Figure 2.)

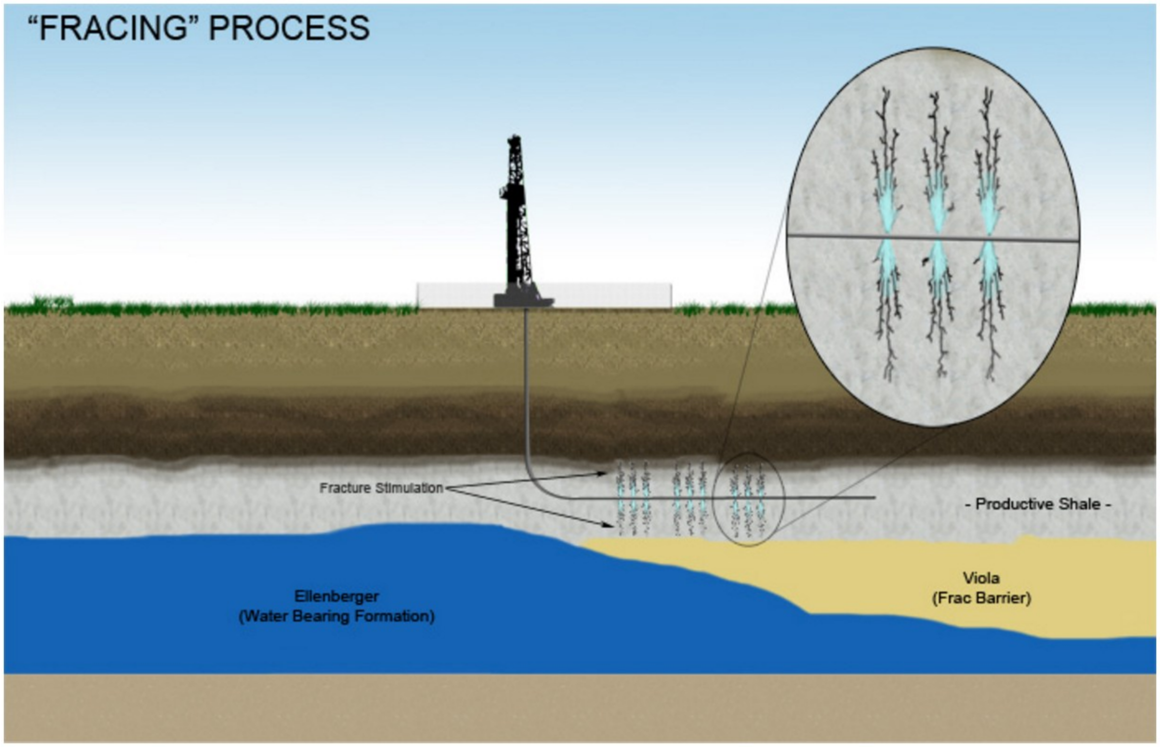


Figure 2: *Hydraulic Fracturing (Keystone Exploration)*

Following the completion of the fracking stages, water that was used during this process returns to the surface. The initial water that is recovered is referred to as flowback water, and once production begins on the well it is called produced water. The detailed compositions of this water are unique to each well, but the general makeup is a mixture between the fracturing fluid, minerals, and dissolved solids from the formation (Haluszczak, 2013). Produced water tends to have higher amounts of minerals and dissolved solids due to its longer residence time underground. The recovery rates for this fluid can vary greatly depending on the geologic structure of the formation. Studies within the Marcellus Shale have experienced anywhere from 10-40% recovery rates of the water used to fracture the well. Considering today's fracturing wells require millions of barrels of water to complete, effective treatment of this flowback and produced water is increasingly important (Karapataki, 2010).

To recycle flowback water for use in subsequent fracking projects, the fluid must undergo some form of treatment. The various chemicals, particles and contaminants present in flowback water present an array of potential problems for equipment and environmental safety if they are not removed before reuse. Figure 3 illustrates several examples of these issues.

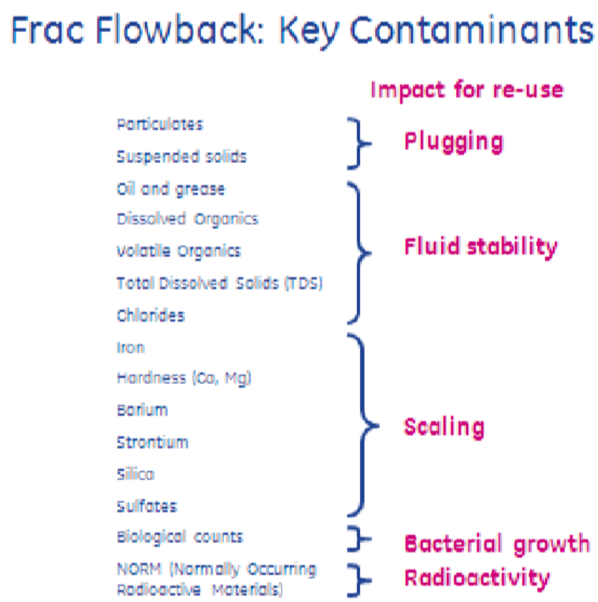


Figure 3*: Flowback Contaminants (Adapted from Acharya, 2011)*

Particulates include clays, silts, sand grains from proppant material, and other solid pieces that entered the flowback water in the well bore. This is a relatively simple contaminate to remove, and requires only sufficient filtration to separate it from the fluid. Hardness and the Total Dissolved Solids (TDS) are both indicators of mineral levels in the water. Hardness ions have the potential to cause scaling and include ions such as calcium and magnesium. TDS measures the level of all inorganic dissolved solids within the water, which include hardness ions as well as other ions such as silica and sodium. This value gives a more complete assessment of the total mineral content of the fluid.

There are numerous water treatment technologies that can be separated into three main categories: primary, secondary and tertiary treatment. Primary treatment focuses on the removal of particulate matter and suspended contaminants in the fluid. Secondary treatment serves to soften the water, namely removing ions like Ba^{2+}, Sr^{2+}, Ca^{2+}, and others. Tertiary treatment involves desalination of the water, and can be implemented at various degrees of discretion, depending on the intended use of the treated fluid. Each level of technology is implemented to remove specific contaminants from the flowback fluid, and will create an end product that is suitable for reuse in various ways (Figure 4).

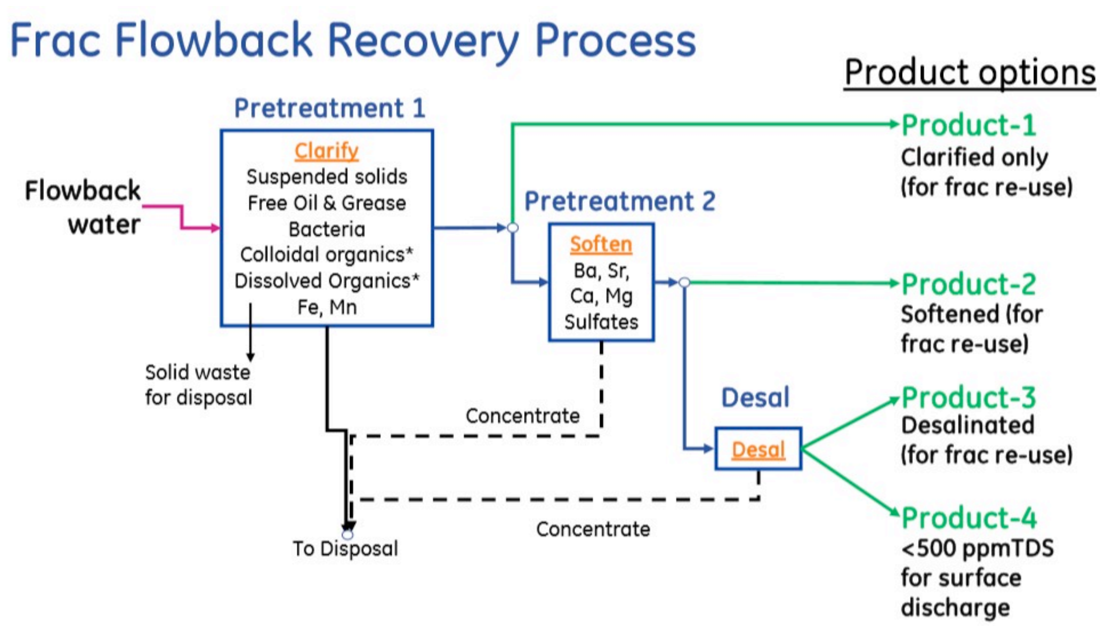


***Figure 4**: Flowback Recovery Process.(Acharya, 2011)*

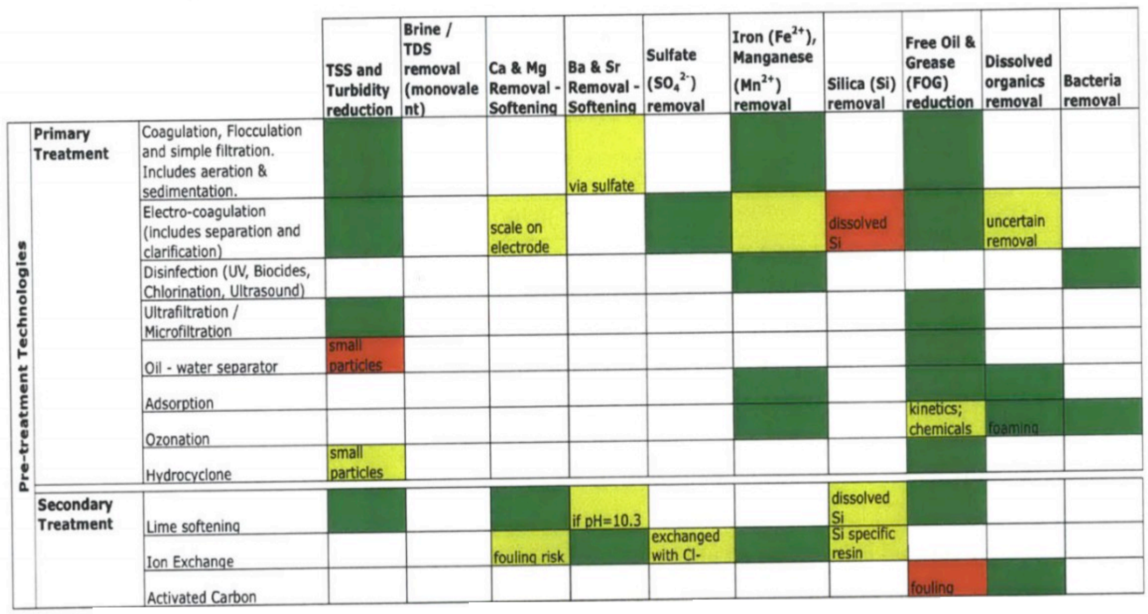
What is done with the water after treatment is dependent on the level to which it has been purified. Certain shale plays, such as the Marcellus, have set standards of contaminant levels that must be reached to use a fluid for fracking. To achieve these set concentrations, flowback/produced waters can either be subjected to high levels of treatment, or companies can implement blending. Blending is simply mixing fresh water in with the partially treated flowback water to bring down the overall concentrations of contaminants to within acceptable levels. While either of these pathways can end with the same result, there are tradeoffs to be considered for each case. Blending requires additional fresh water to be brought in, which could be costly in a region that is challenging to transport water to. However, depending on the composition of the flowback/produced water, high level technologies may have to be utilized in order to clean the water to meet the standards. This obviously becomes more expensive as you use increasingly advanced treatment technologies.

2. TREATMENT TECHNOLOGIES

According to the case study performed by Acharya in 2011, on-site primary and secondary treatment of flowback water can be economically beneficial and cost effective when compared to deep well injection. Therefore, various treatment options of the primary and secondary levels are under consideration that could be implemented on-site, and if blended with a smaller amount of fresh water, could be reused in subsequent hydraulic fracturing projects. The following will provide a more robust discussion of several water treatment technologies, and their applications in the scope of this project.

Within primary technologies, one potential technology option is a coagulation/ultrafiltration unit to serve as the clarification step. This is a method that utilizes a membrane to filter out total suspended solids (TSS) and free oil/grease from the well operations. It can also be utilized to remove iron from the solution, which if left untreated could result in fouling of subsequent treatment technologies.

For secondary technologies, lime softening is implemented to treat the flowback water. Lime softening serves to remove hardness minerals such as calcium and magnesium. It is a cheap and robust technology that has lasted the test of time. It is necessary to soften the fluid as hardness ions can cause plugging of drilling equipment if present in the fracturing fluid during reuse in subsequent projects. These ions can also cause issues with membranes in later treatment steps, and thus need to be removed. Figure 5 illustrates various primary and secondary treatment technologies.



Pre-treatment Technologies		TSS and Turbidity reduction	Brine / TDS removal (monovalent)	Ca & Mg Removal - Softening	Ba & Sr Removal - Softening	Sulfate (SO_4^{2-}) removal	Iron (Fe^{2+}), Manganese (Mn^{2+}) removal	Silica (Si) removal	Free Oil & Grease (FOG) reduction	Dissolved organics removal	Bacteria removal
Primary Treatment	Coagulation, Flocculation and simple filtration. Includes aeration & sedimentation.				via sulfate						
	Electro-coagulation (includes separation and clarification)			scale on electrode				dissolved Si		uncertain removal	
	Disinfection (UV, Biocides, Chlorination, Ultrasound)										
	Ultrafiltration / Microfiltration										
	Oil - water separator	small particles									
	Adsorption										
	Ozonation								kinetics; chemicals	foaming	
	Hydrocyclone	small particles									
Secondary Treatment	Lime softening				if pH=10.3			dissolved Si			
	Ion Exchange			fouling risk		exchanged with Cl-		Si specific resin			
	Activated Carbon								fouling		

Figure 5*: Primary and Secondary Treatment Technologies (Karapataki, 2012)*

For desalination, a membrane treatment unit is implemented. The membrane serves to remove NaCl ions from the fluid, and decrease salinity to a level appropriate for reuse. Acharya defined a TDS level of less than 20,000 ppm as the threshold for reuse in fracking projects. This level will also be upheld in this case study.

The implementation of these technologies in conjunction with one another has been proven capable of obtaining water concentration levels that are suitable for reuse in fracking projects, as seen in the 2011 Acharya study. An example of Marcellus shale requirements is shown below (Figure 6). Tests have yielded costs of the above treatment unit to be less than \$2/bbl of water in a 50 gallon/minute mobile treatment unit (Acharya, 2011). By utilizing primary and secondary treatment, 20% less makeup water is required to get back to proper levels of reuse. If this savings can be applied to each individual hydraulic fracturing project, the environmental and economic benefits will add up substantially.

Untreated flowback blended for reuse	Fresh water used TDS Chlorides	85% 20,510 ppm 13,839 ppm	Limits for water reuse TDS < 50000ppm Cl < 26000ppm
Flowback blended for reuse after primary and secondary treatment	Fresh water required TDS Chlorides	65% 45,330 ppm 25,314 ppm	Limits for water reuse TDS < 50000ppm Cl < 26000ppm

Figure 6: *TDS and Chloride Requirements (Karapataki, 2012)*

A membrane treatment option that has been researched for applications to flowback water is a thermal membrane distillation (TMD) system. This technology has been around since the 1960s, however it was not until recent years that it has been more extensively researched and developed. Advances in membrane materials, as well as lowered costs have made TMD systems economically competitive with reverse osmosis treatment options. (Camacho, 2013)

Numerous benefits exist by implementing a TMD unit. In theory, the design of a TMD system provides complete separation of non volatiles and ions. Physical systems operate near this level and are able to generate highly pure permeate end products. Another advantage of thermal membrane distillation is its capacity for high TDS level feedstock, as well as low pretreatment needs. These membrane units can treat a wide range of salinities which are found across shale plays, and experience very few issues with fouling.

In addition to these advantages, TMD systems have qualities that make them well suited for applications in flowback water treatment. One advantage is the relatively low heating requirements to drive the process. Temperatures for water treatment need to be in the range of 325-360 K, which can be accounted for by utilizing process heat from on-site flaring. The size and modular capabilities of TMD units are also advantageous to water treatment applications, as unit sizes are small enough to be configured in a mobile treatment array. A system can also increase its capacity by adding additional membrane modules, and maintenance can be conducted without necessitating the shutdown of the entire unit.

Several configurations of TMD systems exist, including Direct Contact Membrane Distillation (DCMD) which will be expanded upon in this section. The direct contact system operates by utilizing the vapor pressure differential across the membrane. The feed is heated and enters the area containing the membrane. This contact between liquid and membrane is the reason for the name “direct contact.” Due to its hydrophobic nature, the water vapor passes through the membrane to the other side. This also helps prevent condensation inside the membrane structure. Then a sweeping stream of permeate is passed through, which condenses the vapor and flows out of the system. (Elsayed, 2015)

The Acharya, 2011 study also examined membrane technologies for flowback water treatment and reuse. In their case study calculations it was found that not only is a mobile membrane unit able to produce treated water of suitable qualities for reuse, but at costs of approximately $2.00 per barrel of feed. This amount was set forth as the success criteria for system design in order to be considered economically viable in comparison to disposal methods such as injection. Additionally, in the breakdown of cost associated with the mobile treatment rig, 75% of operating costs are associated with fixed capital investment of the system (Figure 7). This means that after the investment is made to construct and purchase the mobile system, the actual operating costs are not very high. In fact, the membranes themselves are only 2% of the overall cost, which shows why they are desirable for applications in the field of flowback water treatment.

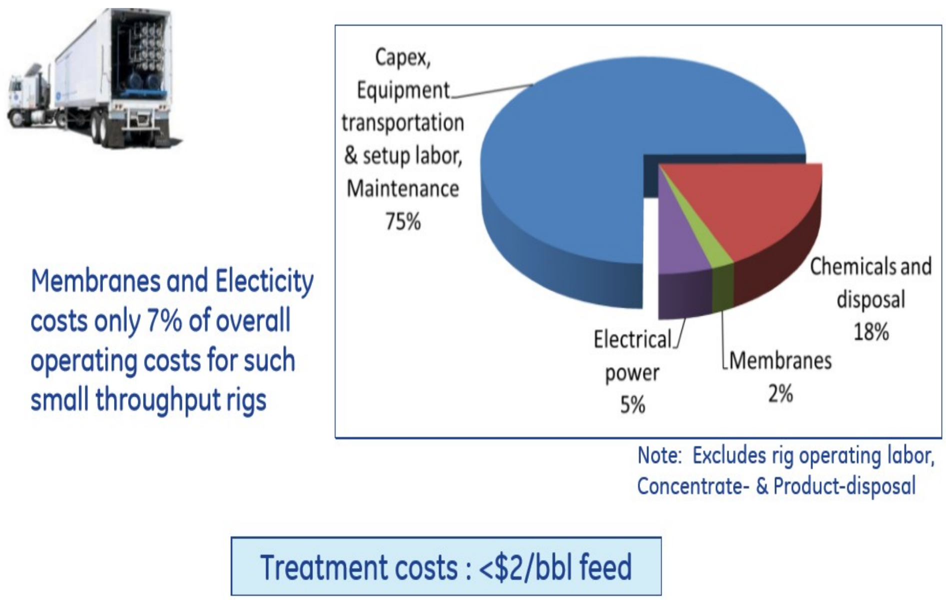


Figure 7: *Cost Breakdown of Mobile Membrane Unit (Acharya, 2011)*

3. ECONOMIC ANALYSIS

When looking at today's shale gas industry, one of the most important deciding factors for choosing technology options is cost. In general, it is more expensive to treat water on site than dispose of it or ship is someplace else. For this reason, most companies elect to dispose of their flowback and produced water via deep-well injection or transport it to an offsite centralized water treatment facility rather than treat it themselves for reuse. The way prices have been aligned has made it more economical to bring in all new fresh water for continued fracking developments instead of attempting to treat flowback water to sufficient levels of cleanliness. Because oil and gas is a business, if there is to be any significant breakthrough in the area of water reuse, on-site treatment technology and methodology must reach a level that is economically competitive with the current practices.

During literature research, several studies were examined that took an in depth look at numerous water treatment technologies. The MIT report by Karapataki will be the main reference for economic data presented in this section.

When analyzing options for water reuse, the simplest path would be blending flowback water without any treatment and using this fluid in subsequent fracking. Although this would be the most cost effective option, it is not smart because all the contaminants within the flowback/produced water will damage the equipment it passes through. Therefore, this option will not be considered for cost analysis and comparison of treatment options. The focus of this research is the comparison of deep-well injection and primary/secondary treatment with blending for reuse.

Deep-well injection is oftentimes the most cost effective option for flowback/produced water. However, there are many factors that affect the economics of injection, and the price of this process can vary considerably depending on the location of the hydraulic fracturing project. Distances from the well to the disposal facility, as well as disposal costs are highly variable factors that can result in a wide spread of pricing ranges for injection.

According to the economic analysis of the Karapataki study, primary/secondary treatment with blending for reuse has the potential to be competitive with injection costs (Figure 7). In areas that experience high costs for water transportation, this method is attractive because of the previously mentioned 20% reduction in necessary make up water. Savings on trucking, fresh water, and disposal fees enable this treatment option to be both economically advantageous, and environmentally friendly.

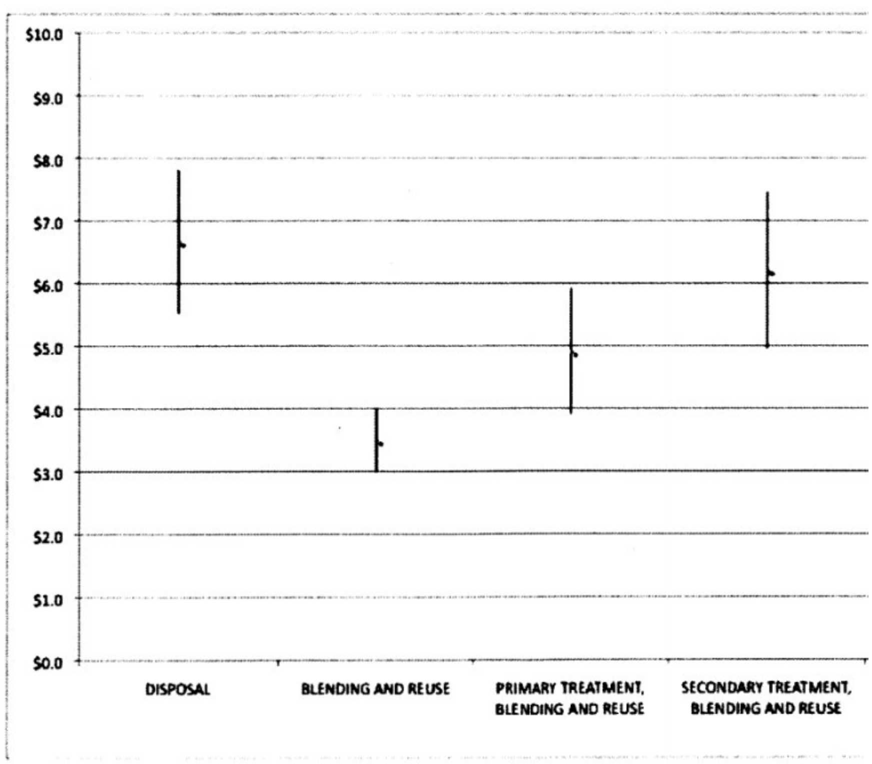


Figure 8: *Cost Analysis of Treatment Options (Karapataki, 2012)*

4. METHODOLOGY

The aim of this project is to construct a framework that can be applied to solve a logistic/supply chain optimization problem when dealing with water treatment in hydraulic fracturing projects. For this study, the following scenario will be considered:

Three different wells are operating fracking projects and want to implement treatment in order to reuse water in subsequent fracturing processes. At each well site, a water storage tank will be placed in order to house the flowback water during production. This study uses a 200,000 gal mobile storage tank, comparable to the HydroTec MB model produced by CST Storage. A fleet of water treatment trucks will be deployed in order to treat the flowback water from the storage tanks to levels appropriate for reuse. The overall objective is to determine the minimal number of treatment units needed daily at each well for a period of twenty-eight days. Cost estimations will also be performed on the treatment units.

4.1 Case Study

Well data was taken from the Hayes, 2009 study on water streams from the Marcellus Shale. Figures 9 and 10 show a map of the sampling locations in Pennsylvania and West Virginia. In this study, data from Wells C, E, and F were utilized. These specific wells were chosen for the case study for a few reasons. First, they are all horizontal, hydraulically fractured wells. They also represented a wide range in terms of total amount of fracturing fluid used and percentage of recovered fluid. By selecting these wells, a network can be created that provides a thorough representation of the variability that is present through wells in a shale play. Figure 11 is taken from the Hayes study, and contains measured data on all of the wells.

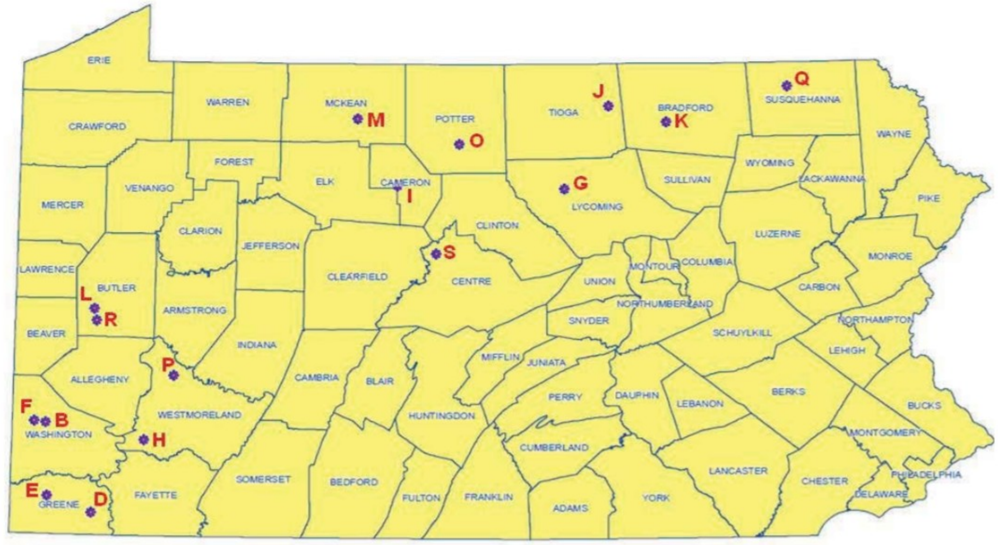


Figure 9: *Pennsylvania Sampling Locations (Hayes, 2009)*

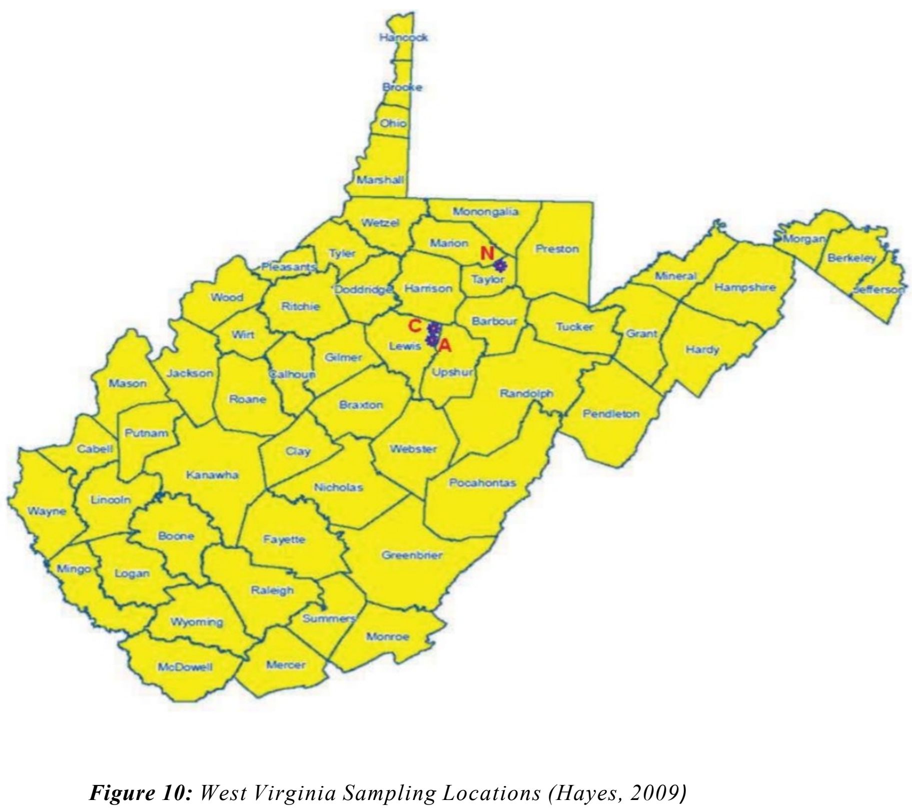


Figure 10: *West Virginia Sampling Locations (Hayes, 2009)*

Location	Well Type	Total Vol. Frac Fluid Used, bbls	Cumulative Volume of Flowback Water, bbls				Percent Collected
			1 Day*	5 Days	14 Days	90 Days	
A	Vertical	40,046	3,950	10,456	15,023		37.5
B	Vertical	94,216	1,095	10,782	13,718	17,890	19.0
C	Horizontal	146,226	3,308	9,652	15,991		10.9
D	Horizontal	21,144	2,854	8,077	9,938	11,185	52.9
E	Horizontal	53,500	8,560	20,330	24,610	25,680	48.0
F	Horizontal	77,995	3,272	10,830	12,331	17,413	22.3
G	Horizontal	123,921	1,219	7,493	12,471	18,677	15.1
H	Vertical	36,035	3,988	16,369	21,282	31,735	88.0
K	Horizontal	70,774	5,751	8,016	9,473		13.4
M	Horizontal	99,195	16,419	17,935	19,723		19.9
N	Vertical	11,435	2,432	2,759	3,043	3,535	30.9
O	Horizontal	96,706	5,131	19,202			19.8
Q	Vertical	23,593	1,315	3,577	5,090		21.6
S	Vertical	16,460	2,094	7,832	9,345	10,723	65.1
			Weighted Average % Collected ➔				24.3

* Days from the hydraulic fracturing event.

Figure 11: Well Data (Hayes, 2009)

After selecting C, E, and F as the wells to be used for this study, the flowback data was imported into Excel. Regression calculations were performed on this data in order to determine functions for each well, with *t* indicating the number of days that have passed since the hydraulic fracturing began:

Well C: Cumulative Flowback Water (BBL) = 4729.9*ln(*t*) + 2952

Well E: Cumulative Flowback Water (BBL) = 6190*ln(*t*) + 9067.3

Well F: Cumulative Flowback Water (BBL) = 3543.7*ln(*t*) + 3792.5

With these equations, the daily amount of flowback water for each well was constructed over a period of twenty-eight days. The values are displayed in Table 1:

Daily Flowback Calculations in BBL

Day	Well C	Well E	Well F
1	2952	9067.3	3792.5
2	3278.516849	4290.581048	2456.305664
3	1917.809415	2509.829019	1436.846704
4	1360.707434	1780.752028	1019.45896
5	1055.446683	1381.258583	790.7538028
6	862.3627315	1128.570437	646.0929008
7	729.1173005	954.1927081	546.2637641
8	631.590134	826.5593203	473.195196
9	557.1019804	729.0769907	417.3877435
10	498.344703	652.1815919	373.3660593
11	450.8076195	589.970013	337.7506842
12	411.555112	538.6004236	308.3422166
13	378.594003	495.4643605	283.6473432
14	350.5232975	458.7283476	262.6164209

Table 1: *Daily Flowback Calculations in BBL*

Day	Well C	Well E	Well F
15	326.3293828	244.4900387	427.0658745
16	305.2607511	228.7051574	399.4934458
17	286.7483987	214.8354723	375.266409
18	270.3535816	202.5522711	353.8105817
19	255.7325499	191.598012	334.6760997
20	242.6121531	181.7680473	317.5054923
21	230.7725975	172.8977048	302.0111162
22	220.035022	164.8529794	287.9588968
23	210.2523918	157.523711	275.1564103
24	201.3027202	150.8185056	263.4440133
25	193.0839519	144.660902	252.6881461
26	185.5100511	138.9864412	242.7762144
27	178.5079773	133.7404003	233.6126302
28	172.0153202	128.8760206	225.1157174

Table 1: *Continued*

4.2 Treatment Calculations

Once the daily flowback volumes were determined, the next step was to begin analysis of treatment requirements for these amounts of fluid. While many viable treatment options exist and were touched upon in this research, for the purpose of calculating treatment capacities and cost estimations, the selected technology was a direct contact thermal membrane distillation system. This method benefits from traits such as modular configuration and high selectivity, which make it well suited for applications in mobile rigs used in shale gas plays.

The optimization of this system was based upon the methods presented in the Elsayed *et al*. 2015 paper. Key equations are well documented in this reference, and can be found in detail there. The differences in the scope of this project lie in the application of the methodologies. Where the Elsayed paper formulated an optimized pathway for an individual well, this project establishes a means to calculate the number of treatment units needed daily in a series of wells within a formation.

For these calculations, four different flow rates were considered for the treatment units. These flow rates, in gallons per minute, were 5, 10, 15, and 20. A constraint was applied on the calculations to provide that at least fifty percent of the daily amount of flowback water produced would be treated by a mobile unit. This constraint ensures that the mobile units are being utilized efficiently, and the overall water treatment would be completed in a timely fashion. The equations were formatted in order to provide answers in terms of number of 180 m^2 surface area membrane units necessary. The results of the daily number of membrane units needed at each well, for the four flow rates can be found in Tables 2-5. The numbers were rounded up to the next whole number, to represent the necessity of purchasing full membrane units.

Day	Well C	Well E	Well F
1	12	36	15
2	13	17	10
3	8	10	6
4	6	7	4
5	5	6	4
6	4	5	3
7	3	4	3
8	3	4	2
9	3	3	2
10	2	3	2
11	2	3	2
12	2	3	2
13	2	2	2
14	2	2	2

Table 2: *Number of Membranes for 5 gpm Unit*

Day	Well C	Well E	Well F
15	2	2	1
16	2	2	1
17	2	2	1
18	2	2	1
19	1	2	1
20	1	2	1
21	1	2	1
22	1	2	1
23	1	2	1
24	1	2	1
25	1	1	1
26	1	1	1
27	1	1	1
28	1	1	1

Table 2: *Continued*

Day	Well C	Well E	Well F
1	7	18	8
2	7	9	5
3	4	5	3
4	3	4	2
5	3	3	2
6	2	3	2
7	2	2	2
8	2	2	1
9	2	2	1
10	1	2	1
11	1	2	1
12	1	2	1
13	1	1	1
14	1	1	1

Table 3: *Number of Membranes for 10 gpm Unit*

Day	Well C	Well E	Well F
15	1	1	1
16	1	1	1
17	1	1	1
18	1	1	1
19	1	1	1
20	1	1	1
21	1	1	1
22	1	1	1
23	1	1	1
24	1	1	1
25	1	1	1
26	1	1	1
27	1	1	1
28	1	1	1

Table 3: *Continued*

Day	Well C	Well E	Well F
1	4	12	5
2	5	6	4
3	3	4	2
4	2	3	2
5	2	2	2
6	2	2	1
7	1	2	1
8	1	2	1
9	1	1	1
10	1	1	1
11	1	1	1
12	1	1	1
13	1	1	1
14	1	1	1

Table 4: *Number of Membranes for 15 gpm Unit*

Day	Well C	Well E	Well F
15	1	1	1
16	1	1	1
17	1	1	1
18	1	1	1
19	1	1	1
20	1	1	1
21	1	1	1
22	1	1	1
23	1	1	1
24	1	1	1
25	1	1	1
26	1	1	1
27	1	1	1
28	1	1	1

Table 4: *Continued*

Day	Well C	Well E	Well F
1	3	9	4
2	4	5	3
3	2	3	2
4	2	2	1
5	2	2	1
6	1	2	1
7	1	1	1
8	1	1	1
9	1	1	1
10	1	1	1
11	1	1	1
12	1	1	1
13	1	1	1
14	1	1	1

Table 5: *Number of Membranes for 20 gpm Unit*

Day	**Well C**	**Well E**	**Well F**
15	1	1	1
16	1	1	1
17	1	1	1
18	1	1	1
19	1	1	1
20	1	1	1
21	1	1	1
22	1	1	1
23	1	1	1
24	1	1	1
25	1	1	1
26	1	1	1
27	1	1	1
28	1	1	1

Table 5: *Continued*

5. COST ESTIMATION

The calculations performed in this study were based upon the TMD cost model presented in Elsayed *et al.* 2013. Some key equations are as follows:

1.) The annualized fixed cost of the treatment system, AFC is given by:

$$AFC = 58.5*A_m + 1,115*W_{FB}$$

The membrane area in square meters is indicated by A_m , while W_{FB} represents the flow rate of water into the treatment unit.

2.) The annual operating cost of the treatment system, AOC is given by:

$$AOC = 3438*W_{FB}$$

Where AOC is in terms of dollars per year.

3.) The non-membrane fixed capital investment, NMFCI is given by:

$$NMFCI = 11,150*W_{FB}$$

Where NMFCI is in terms of dollars per year.

4.) The membrane fixed capital investment, FCI is given by:

$$FCI = 450*A_m$$

6. RESULTS AND DISCUSSION

The motivation behind this research project was to examine the status of water use in shale gas hydraulic fracturing wells, in hopes of proposing an economically viable method for treatment and reuse of fracking fluid. During a ten month timeframe, literature review, case study, cost estimation, and calculations were performed. Results from these procedures indicate that with today's technology and available treatment methods, it is possible to treat flowback water in a manner that is economically competitive with established disposal or injection methods.

Several projects have been conducted that examined membrane treatment in the context of flowback water treatment. Results in the literature suggest that this method is economically viable and competitive with conventional wastewater disposal. This is especially true in areas that are farther away from disposal sites and would incur high costs for water transportation. The Elsayed et al, 2015 study showed that a thermal membrane distillation system could effectively serve as the treatment technology in a mobile treatment rig, resulting in a cost of $2.60 per cubic meter of permeate. This study utilized their contributions in order to apply the system to a series of producing wells in different geographic locations.

Analysis of the treatment results indicate that TMD systems, arranged in a fleet of mobile treatment trucks, are a viable way to achieve the reuse of flowback water in shale gas production. The fact that TMD systems can be suited for various flow rates means that they can be adaptable to meet the specific needs of a certain well or company desires for treatment scheduling. This study analyzed relatively low throughput membrane systems in use at three different wells that represented low, medium and high amounts of recovered fracturing fluid.

The results of this project provide a means of creating an optimized design for a TMD treatment network for flowback water. Additionally, a methodology has been constructed in order to expand the scope of the network to multiple, simultaneously producing wells. This approach is scalable, and can be applied to any number of wells that fall within the scope of a given treatment objective. By utilizing this framework, companies would be able to calculate and visualize their own needs in terms of number of treatment trucks and overall cost, as well as schedule how many membrane units are necessary at each well for each day over the time period that operations are taking place.

6.1 Future Works

There are a few suggested pathways to take in order to expand upon the framework presented in this research. One is to adapt the formulation in such a way as to allow for the mixed usage of treatment units with different flow rate capacities. This project was designed to deal with a treatment network that utilized mobile treatment units that all had the same capacity. While this is a viable approach, and allows for some simplification in the process, it can also result in a loss of efficiency for certain wells. If additional work was directed towards this topic and enabled an optimal design for any given flow rate, a treatment network could be constructed that would more accurately account for the wide variation found in the flowback characteristics of shale gas production.

Another area of study that could build upon this research would be addressing the concept of the Energy-Water-Food Nexus. The consumption of water in efforts to produce energy is one of the most important relationships to consider as society continues to progress. It is vitally important that we find a sustainable way to have these three elements interact and coexist. Further study of flowback water treatment and reuse could focus on Nexus thinking, and provide quantitative results for how the adoption of this treatment practice could have positive impacts on the energy sector.

7. CONCLUSIONS

This study has implications both in the oil and gas industry, and environmental sector. Businesses that are engaged in shale gas production would be able to utilize the design of this mobile treatment network to drive the costs down on their fracking projects. This would benefit both profit margins and efficiency of the oil and gas companies that use this unit.

From an environmental viewpoint, the results of this project also have major benefits. By making treatment and reuse economically viable, less fresh water is needed to pump into the well site. Additionally, there would be less of a need for deep-well injection practices which are concerning to many environmental groups. More widespread utilization of water treatment units in shale plays would create a significant drop in the amount of fresh water usage in the development of new fracking wells. This would be a major step forward in the area of thinking known as the Energy-Water-Food Nexus, as it would help reduce the amount of water that is needed for energy production from shale formations.

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