UNIVERSITY OF CALGARY

An Economic Assessment of Using Aqua Pure Technologies' PROH$_2$O® System to Treat Produced Fluids from Hydraulic Fracturing Operations for Reuse in Alberta, Canada

By:

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Abstract

As conventional forms of oil and gas mature, unconventional resources are becoming desirable. Unconventional resources, found in tight rock formations, require hydraulic fracturing to extract the resource. Large quantities of water are required and produce vast amounts of contaminated wastewater. Currently, wastewater must be locked away permanently, deep underground. This paper provides an economic assessment of using Aqua Pure Technologies' PROH$_2$O® system to treat wastewater for reuse. The aim is threefold; can the impact on water resources be reduced, can cost savings be achieved, and should Dragos Energy Corporation initiate investment in the technology? To complete the economic assessment, a hypothetical hydraulic fracturing operation is modeled and analyzed. Although a number of assumption have been made to complete this analysis, the author shows that the technology can be used to create significant economic and environmental benefits which could lead to a competitive advantage for Dragos Energy Corporation.

Acknowledgement

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List of Abbreviations and Vocabulary

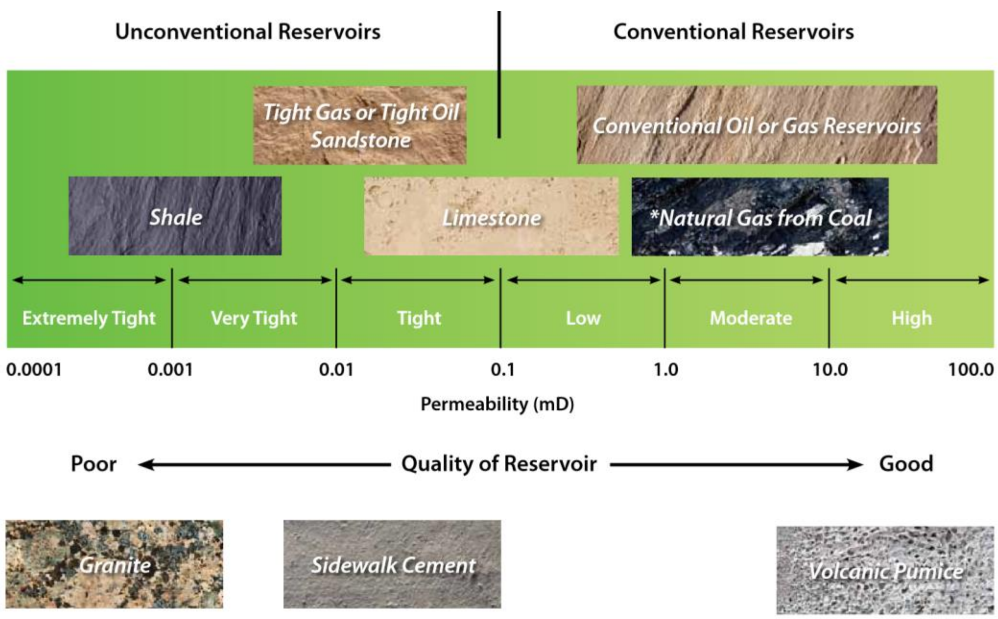
AER	Alberta Energy Regulator
AEP	Alberta Environment and Parks
APT	Aqua Pure Technologies' PROH2O® Technology
bbls	Billion Barrels
CEPA	Canadian Environmental Protection Act
CUSR	Canadian Society of Unconventional Resources
CIP	Clean-in-place
CBM	Coalbed Methane
dam3	Cubic Decameters
EOR	Enhanced Oil Recovery
FITFIR	First in Time, First in Right
m3	Cubic Meters
Dragos	Dragos Energy Corporation
EOR	Enhanced Oil Recover
ESRD	Environment and Sustainable Resource Development
EPA	Environmental Protection Agency
EPEA	Environmental Protection and Enhancement Act
HF	Hydraulic Fracturing
km	Kilometers
NGL	Natural Gas Liquid
NGO	Nongovernmental Organization
O&G	Oil and Gas
SAGD	Steam Assisted Gravity Drainage
TDL	Temporary Diversion License
the Act	The Alberta Water Act
TDS	Total Dissolved Solids
TSS	Total Suspended Solids
WCSB	Western Canadian Sedimentary Basin

CHAPTER 1. Introduction

As conventional forms of oil and gas (O&G) mature, the O&G industry is looking to unconventional resources. However, these unconventional resources are often more difficult and costly to extract. Some of these resources are; tight oil, tight and shale gas, and coal bed methane (CBM).

These resources are found in low-permeability rock including; sandstone, siltstone, shale, and carbonates (AER, 2016a). Due to low permeability, these resources require stimulation techniques such as hydraulic fracturing (HF) to create pathways in the rock for the resource to move (AER, 2016a).

Figure 1 - Unconventional Resources and Permeability



SOURCE: (CSUR, 2012, p. 7)

Large quantities of water are required for HF operations. Once a well is fracked, large volumes of wastewater are recovered at the well head and are known as produced fluids. This wastewater is highly contaminated. Currently, re-injection of wastewater into disposal wells is the primary way of handling produced fluids. This practice locks the water away permanently, deep underground, in an impermeable formation (Alberta Energy, 2015a). With that said, water scarcity is becoming an increasingly economic, social, and environmental concern for Albertans. Therefore, a number of water treatment and recycling options are being explored.

Technologies are currently being developed to treat or purify produced fluids from HF operations. This project provides an economic assessment of using Aqua Pure Technologies' PROH$_2$O® (APT) system to treat produced fluids for reuse. The aim is to examine the possibility for reducing the impact of HF on fresh water resources through conserving water. With that said, this paper also aims to determine if conditions exist where cost savings could be realized by treating wastewater from HF operation for reuse. Finally, this paper aims to determine if the savings realized provide an incentive to make the APT system economically worthwhile for Dragos Energy Corporation (Dragos) and its partners to initiate investment and add the technology to the services it provides.

1.1 Research Purpose

Accessing water for HF and other oil extraction operations is becoming a concern for companies in the O&G industry. These concerns, already being realized in parts of Alberta and the United States, have led to increased costs for companies operating in the industry. Additionally, companies are under increasingly more pressure from boards, the public, and nongovernmental organizations (NGO) to operate in a more environmentally conscious manner. Companies that fail to do so face reputational risk and may lose their social license-to-operate.

1.1.1 Growing Water Demand

As industry and populations grow in Alberta, so does the demand for fresh water and HF uses more water than traditional oil extraction technologies (AEP, 2015a). Fortunately, other than some ongoing challenges in the south, water is not scarce in Alberta. However, “variations in geography, climate, and the hydrologic cycle create regions and periods of water scarcity” (AEP, 2010, p. 5).

Alberta has used a "first in time, first in right" (FITFIR) allocation system for over a 100 years (AEP, 2015b). This system creates a situation where “during times of scarcity, senior (older) license holders can access a portion of their water allocation before junior (more recent) license holders” (AEP, 2015b). This situation could pose a problem for operators in the O&G industry because without access to water, production would have to be halted or producers may need to purchase water on an emerging water-license market. These activities lead to reduced revenues and increased expenses.

1.1.2 Increasing Regulation

Alberta has strict requirements in place to manage water withdrawal, water reuse, and the safe disposal of produced fluids. The Alberta Energy Regulator (AER) does not allow produced fluids to be sent to municipal wastewater treatment facilities (Alberta Energy, 2015a). Once water is used in O&G operations, it cannot be used for any other activity or be discharged back into the environment (CSUR, 2016). Therefore, produced fluids that cannot be recycled must be disposed of by re-injection into approved disposal wells.

1.1.3 Costs Associated with Disposal

Currently, it costs approximately $12 to $15 per cubic meter ($m^3$) to dispose of produced water and $22 to $25 per m^3 to dispose of flowback (Personal communication – Clint Jensen – July 20, 2016). Additionally, it can cost from $7 to $10 per barrel or approximately $53.46 per m^3 to truck wastewater off-site (Dicenzo, 2014).

Although wastewater levels produced at each wellhead can vary, for a newly fracked well in North America, the cost could be upwards of $119,000 for transporting 14,000 barrels [2,225 m^3] of flowback (Easton, 2015). Additionally, up to 3,400 barrels [541 m^3] of produced water would have to be transported each day, at $28,900 per day (Easton, 2015). For removing wastewater off-site for disposal, over the 20-year life of a HF well-project, it has been estimated to cost over $160 million (includes trucking costs, water disposal costs and labor) (Easton, 2015).

CHAPTER 2. Methodology

For this report, the author worked closely with Dragos and its partners to assess the aforementioned issues surrounding the industrial, ecological, regulatory and economic environments. This report has been completed using technical and industry information from Dragos and its partners. Additionally, the author completed a thorough review and assessment of available literature from peer-reviewed journal articles as well as government and corporate websites.

In order to complete the economic assessment, a hypothetical HF operation has been used. Due to the variability of HF operations it is impossible to predict the exact conditions. Therefore, a number of assumptions have been derived from field test data, industry experience, averages and ranges data, and the literature review to create a representative model. A list of all the assumptions is available in Appendix A.

Although this paper is intended for understanding the Alberta O&G environment, examples from the United States have been used to provide context and to understand practices. Furthermore, it is important to note here that the benefits realized with this technology will be dependent on the specific conditions of each well, operation, and resource formation.

2.1 Interdisciplinary Aspects

In order to achieve a rounded understanding of the issues faced, this paper will develop an understanding on four grounds;

2.1.1 Energy and the O&G Industry

The petroleum industry in Alberta has suffered plummeting oil prices and continued low natural gas prices. Yet the provinces resource extraction industry is positioned to return once the cyclical nature of these commodity prices eventually rise. Therefore, unconventional O&G resources such as tight oil, tight and shale gas, and CBM have the potential to make a significant contribution to Alberta's future O&G supply.

2.1.2 Environmental Considerations

Although there are other environmental concerns associated with HF operations, this report will only focus on concerns related to the impacts on water in Alberta. Specifically, those impacts associated with re-injection of produced fluids as compared to treatment for reuse. Furthermore, this report examines the impacts of HF operations on water availability and water quality.

2.1.3 Regulatory Setting

Government of Alberta websites and a review of the available literature have been used to assess the regulatory framework and environment. Additionally, the author communicates an understanding of regulatory expectations around water reuse and disposal.

2.1.4 Economic Environment

As advancements in drilling and completion technologies continue, Alberta's resources are becoming more economically developable (Alberta Energy, 2015a). This project investigates if cost savings can be realized in operations by using APT to treat produced fluids. In order to provide an economic assessment of the APT system, the author undertakes a financial comparison of using the APT system to reduce expenses and generate revenue by treating produced fluids rather that disposing them by re-injection.

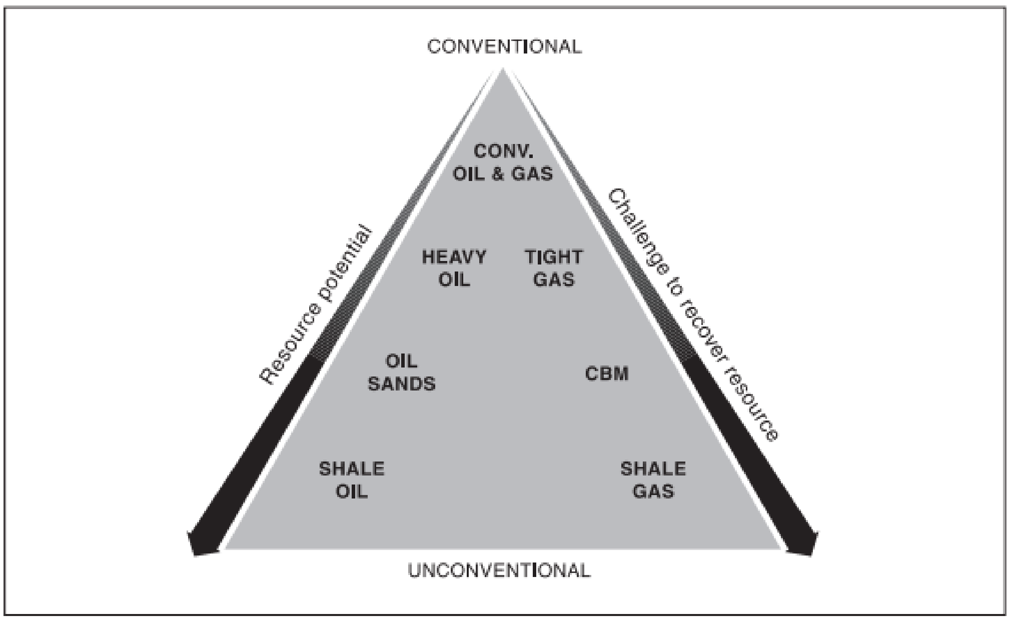
Finally, as water resources become strained, water restrictions are becoming more likely. The author develops an understanding of this threat and incorporates it into the economic analysis. For instance, the APT system reduces the need for water purchases. Could it then be used to gain a competitive advantage in times of water scarcity?

CHAPTER 3. Background

3.1 Unconventional Resources

Unconventional resources are often more difficult and costly to extract than conventional resources. However, there are significant deposits available in Alberta and they continue to provide an economic opportunity for Albertans.

Figure 2 - Unconventional Resource Pyramid



SOURCE: (Energy Resource Conservation Board, n.d, p. 7)

3.1.1 Tight Oil

Currently, the most economically desirable unconventional resource is tight oil. Tight oil is oil found in low-permeability rock. The oil found in these reservoir rocks does not typically flow to the head of the well without advanced drilling and completion technologies (CSUR, 2012). The main advantage of tight oil is that it is of higher quality and needs less refining than other unconventional oil resources available in Alberta such as bitumen (CSUR, 2012).

Additionally, by using existing surface infrastructure, capital investment and surface impacts can be reduced. As extraction techniques and technology improve, the oil locked away in these tight formations offers significant economic potential for Alberta O&G companies.

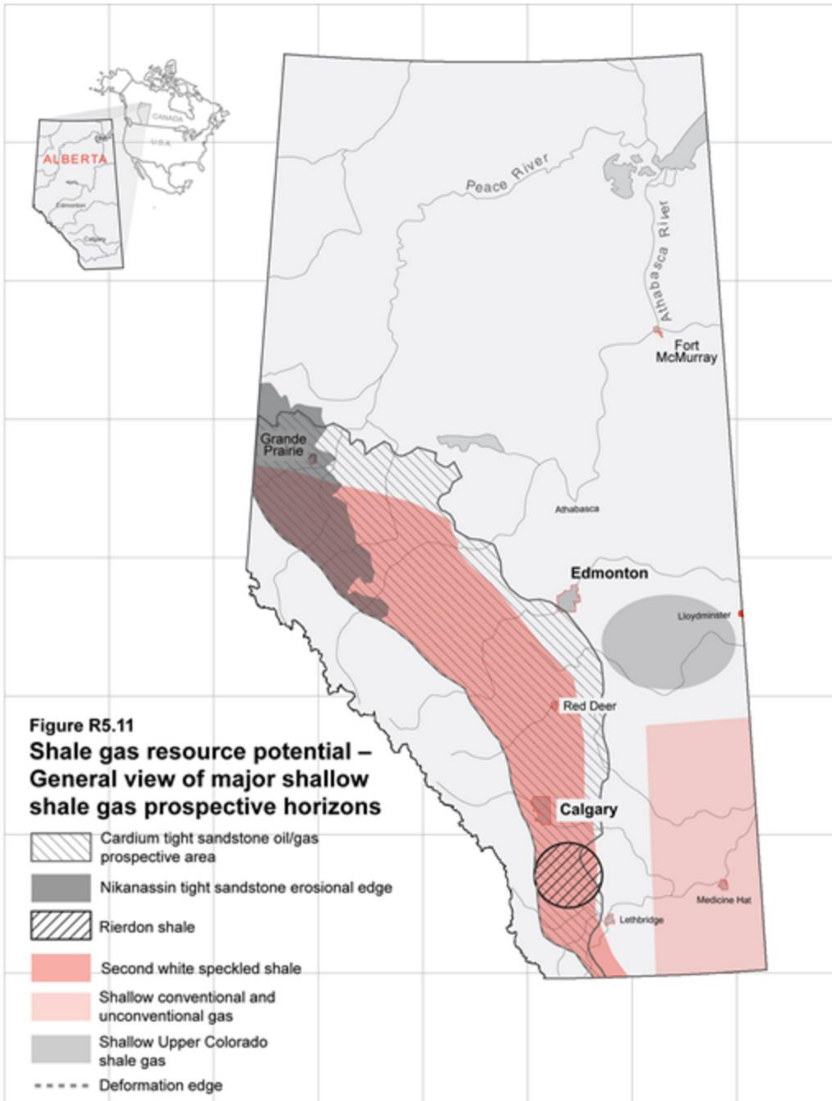
3.1.2 Tight and Shale Gas

Another economically desirable unconventional resource in Alberta is tight and shale gas specifically wells with large quantities (Personal Communication – Joe Gay – July 15, 2016). In 2014, of total Canadian natural gas production, shale and tight gas accounted for approximately 4 percent and 47 percent respectively (Natural Resources Canada, 2016).

In addition to gas, Alberta formations hold condensates or natural gas liquids (NGL) which can sell at a 10 percent premium to crude and command a lower 5 percent royalty rate (Schaefer, 2013). These liquids are formed as a result of the depth of the formation and the pressure experienced.

“Shale gas is natural gas that is attached to, or ‘adsorbed’ onto, organic matter or is contained in thin, porous silt or sand beds interbedded in shale” (Alberta Energy, 2015a). Production of shale gas can be accomplished through either vertical or directional wells (Alberta Energy, 2015a). However, shale formations normally have low permeability, which means that gas and other fluids do not easily flow through the formation (Alberta Energy, 2015a). Like tight oil, tight and shale gas normally require HF to extract the gas (Alberta Energy, 2015a).

Figure 3 - Shale Gas Resource Potential in Alberta.



SOURCE: (Alberta Energy, 2015a)

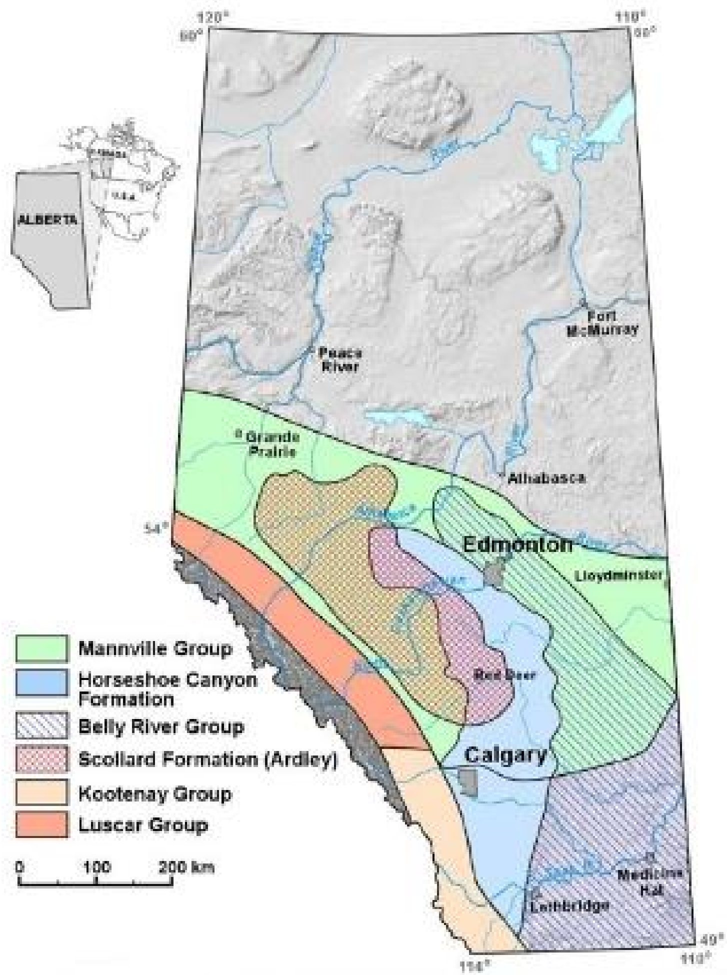
3.1.3 Coalbed Methane

Another potential unconventional resource available in Alberta is CBM. As coal is formed over time, the decomposing organic material produces methane gas (Alberta Energy, 2015b). The burial process puts pressure on the coal, decreasing permeability, which keeps much of the gas locked in the coal.

CBM does not contain hydrogen sulphide and is therefore considered to be sweet gas (Alberta Energy, 2015b). When the gas is recovered it requires less refining. CBM is contained in difficult-to-produce reservoirs, which require special completion, stimulation, and production techniques to achieve economic production (Alberta Energy, 2015b).

The Alberta Geological Survey estimates a potential 14.2 trillion m^3 of natural gas in Alberta's coal (Alberta Energy, 2015b). That said, at the current prices for gas, CBM is the least economically desirable unconventional resource in Alberta.

Figure 4 - CBM Resource Potential in Alberta.



SOURCE: (AER, 2016b)

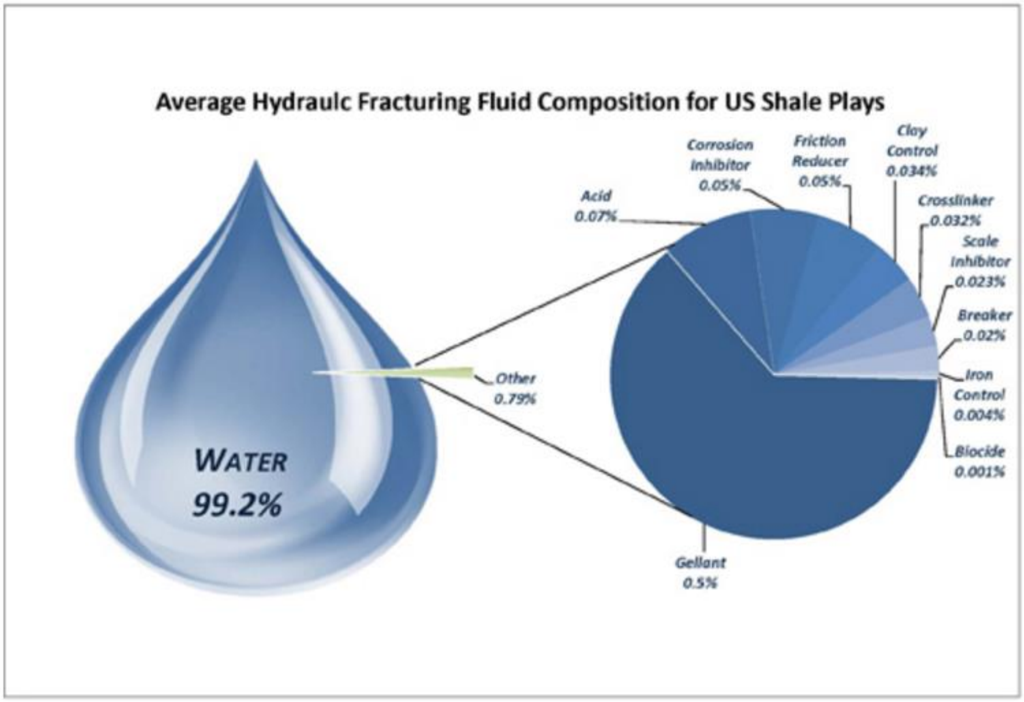
3.2 Hydraulic Fracturing

HF is a process in which fluid is pumped downhole into a rock formation, with enough pressure to crack or fracture a targeted rock layer (Alberta Energy, 2015c). There are two classifications of HF operations. Single stage HF is a fracturing treatment that involves the use of one stage of fracturing in the formation. Furthermore, "the process of multistage hydraulic fracturing uses stages to fracture the rock layer, starting at the far end of the horizontal section and working backwards to the vertical portion" (Alberta Energy, 2015c, p. 1). In Alberta, over 180,000 wells have been drilled using HF technologies (Alberta Energy, 2015c). In addition, "since 2008, more than 10,000 wells have been drilled in Alberta using the combination of multistage HF and horizontal drilling" (Alberta Energy, 2015c, p. 2).

A typical HF program will follow four stages. First, water with diluted acid is used to "clear debris that may be present in the wellbore providing a clear pathway for fracture fluids to access the formation" (Frac Focus, 2016a). Then, carrying fluid without proppant "is used to break the formation and initiate the hydraulic fracturing of the target formation" (Frac Focus, 2016a). Once this is complete, water mixed with a proppant is fed into the wellbore. Proppants are a non-compressible material, such as sand, that will be carried by the HF fluid into the formation and deposited there (Frac Focus, 2016a). "The proppant will remain in the formation once the pressure is reduced and prop open the fracture network. Thus, maintaining the enhanced permeability created by the hydraulic fracture program" (Frac Focus, 2016a). Finally, "fresh water is pumped down the wellbore to flush out any excess proppant that may be present in the wellbore" (Frac Focus, 2016a).

"A typical HF treatment will use very low concentrations of between three and twelve additive chemicals, depending on the characteristics of the water and the formation being fractured. Each component serves a specific, engineered purpose" (Frac Focus, 2015). Overall, the concentration of additives in most HF fluid is usually 0.5 percent to two percent, with water making up 98 percent to 99.2 percent of the total (Frac Focus, 2015).

Figure 5 - Typical make-up of HF fluid.



SOURCE: (Frac Focus, 2015)

3.3 Water Requirements for Hydraulic Fracturing

In HF, water typically acts as the primary carrier fluid. Furthermore, there is no such thing as a typical fractured well. The water used depends on the specifics of the rock formation, the operator, the well length, the number of stages in the HF operation, and whether the well is vertical or horizontal. However, the United States' Environmental Protection Agency (EPA) estimates that between 265m^3 and 530m^3 of water are used to fracture approximately 35,000 wells annually (Hunt, 2014). This suggests that a typical well requires around 7,600m^3 to 15,100m^3 of water to frac. Similarly, in Alberta, the typical well requires 10,000m^3 to 20,000m^3 of water, with the upper limit reaching as high as 70,000m^3 (CSUR, 2016).

3.4 Produced Fluids

During HF operations, when the well pressure is released, two flows of wastewater are returned to the well head and together are known as produced fluids (Alberta Energy, 2015a). Produced fluids can be broken down further into flowback and produced water.

3.4.1 Flowback Defined

Flowback can be comprised of as little as 3 percent or more than 80 percent of the total amount of water and other material used to fracture the well (Frac Focus, 2016b). “Besides the original fluid used for fracturing, flowback can also contain fluids and minerals that were contained within the fractured formation” (Frac Focus, 2016b).

3.4.2 Produced Water Defined

The water that is produced from the fractured formation is known as produced water. As O&G were formed over millions of years, the reservoir rocks often contained water. This water pushes the lighter O&G upward until they hit an impermeable rock (Shell, n.d). When the O&G is removed from a formation, some of this water moves along with it. Produced water is typically recovered from the well for the entire life of the well.

3.5 Handling Produced Fluids

Produce fluids can be dealt with in several ways, disposal by underground injection, reuse in HF operations or reuse in other O&G operations.

3.5.1 Understanding Disposal by Underground Injection

Traditionally, O&G wastewater is injected into underground porous rock formations not producing O&G, which is isolated from useable quality groundwater. Then, it is sealed above and below by unbroken and impermeable means (Hunt, 2014). Wastewater can also be disposed of by injection back into the productive zone where it originated, with or without the benefit of additional resource recovery (Hunt, 2014).

3.5.2 Understanding Reuse in HF Operations

Produced fluids cannot be reused in HF operations without treatment. Currently, a number of treatment options exist. However, one of the most significant challenges faced when determining which treatment option to use is the water quality requirements of the HF operator. This challenge exists because HF fluid formulas are closely guarded trade secrets. O&G water services companies can be hired to treat almost any quality of water to meet HF operators' requirements. Furthermore, due to the variable nature of produced fluids and HF facilities the best treatment technologies are flexible, tough, reliable, mobile and modular. A list of treatment options is available in Appendix B.

The advantage of reusing the treated water for other HF jobs is that a number of HF operations will typically take place in close geographic proximity. The close proximity would help to limit transportation costs.

3.5.3 Understanding Other Reuse Options

Other opportunities for reuse are enhanced oil recovery (EOR), thermal EOR or in-situ steam assisted gravity drainage (SAGD), and oil sands operations.

Conventional EOR, also known as the water flood method, “is a process in which saline or non-saline water is injected to displace the remaining oil in a pool by increasing or maintaining the fluid pressure” (Government of Alberta, 2014a, p. 8). In-situ or thermal EOR “is a process that injects water as steam directly into oil sand deposits or conventional heavy oil pools” (Government of Alberta, 2014a, p. 9). Finally, in oil sands mining, warm water is used to separate the bitumen from the clay and sand.

In-situ operations use about 0.4 barrels (bbls) of water for every oil barrel they produce (Cattaneo, 2013). Currently, 50 percent of the water used by in-situ is saline water rather than fresh water (Querengesser, 2014). Additionally, oil sands mines use an average of about 3.1 bbls of fresh water for every barrel of oil they produce (Cattaneo, 2013).

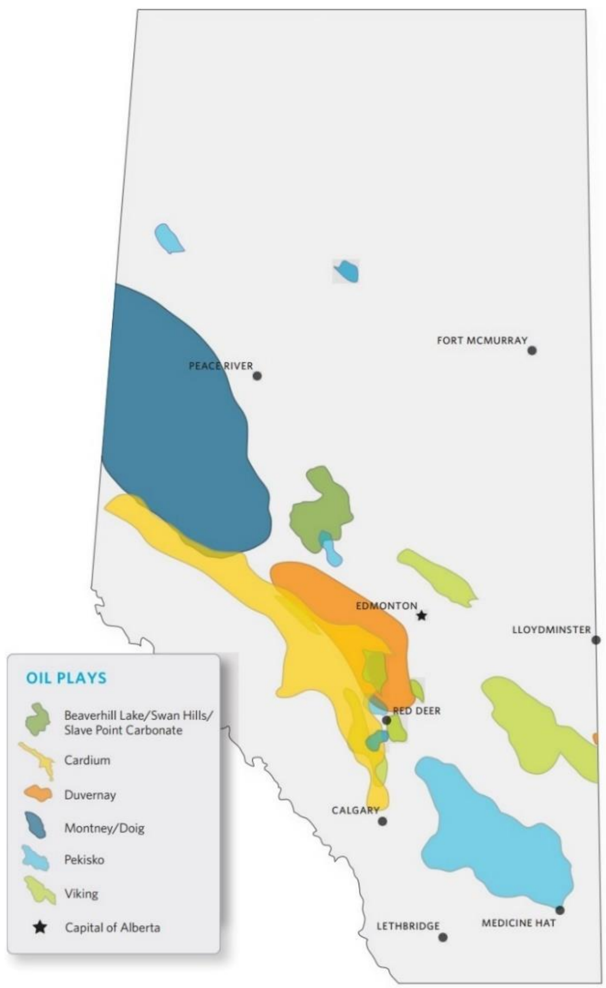
As discussed here, there are a number of other options that exist for the reuse of produced fluids. However, treatment before use is just as necessary as with reuse in HF. Again, water quality requirements for other operations depend on the operator, suggesting that flexibility of water treatment technology is key.

The major downside here is that other reuse option may incur significant transportation costs depending on geographic proximity. Therefore, economic incentive for reuse may not be present.

3.6 Relevant Formations and Plays in Alberta

The primary formation of interest for Alberta O&G producers is the Western Canadian Sedimentary Basin (WCSB). The WCSB extends from the Canadian Shield to the Rocky Mountains through Manitoba, Saskatchewan, Alberta, and northeastern British Columbia. That said, with prices the way they are now, the majority of the drills in Alberta focus on the deep-basin areas such as the Duvernay and Montney plays (Personal Communication - Joe Gay – May 27, 2016).

Figure 6 - Major Oil Plays in Alberta



SOURCE: (Government of Alberta, 2015)

3.6.1 Duvernay

The Duvernay formation is an emerging oil and NGL-rich gas formation in the WCSB. It is between 35 to 60 meters thick and extends over 400 kilometers (km) from the northwest to the southeast of Central Alberta (Hammermaster, et al., 2012).

The Duvernay formation is thought to hold 12.5 trillion m^3 of natural gas, 11.3 billion bbls of NGL, and 61.7 billion bbls of oil (Natural Gas Intel, 2016a). Additionally, this formation is of particular interest because it produces the NGL discussed earlier (Schaefer, 2013).

Between 2009 and 2011, prospective operators spent $1.4 billion to purchase more than 1 million acres in Alberta with access to the Duvernay formation (Natural Gas Intel, 2016a). Consulting firm, Wood Mackenzie Ltd. reported that the industry has drilled over 80 wells as of October 2012 (Natural Gas Intel, 2016a). That said, even though the Duvernay play has been known to have significant reserves of unconventional resources, full development has been limited due to its remote location (Natural Gas Intel, 2016a).

3.6.2 Montney

The Montney formation extends from British Columbia into Northwestern Alberta and is approximately 130,000 square km (Natural Gas Intel, 2016b). Generally, it is 1.7 to 4.0 km deep and typically ranges from 100 to 300 meters thick (Natural Gas Intel, 2016b).

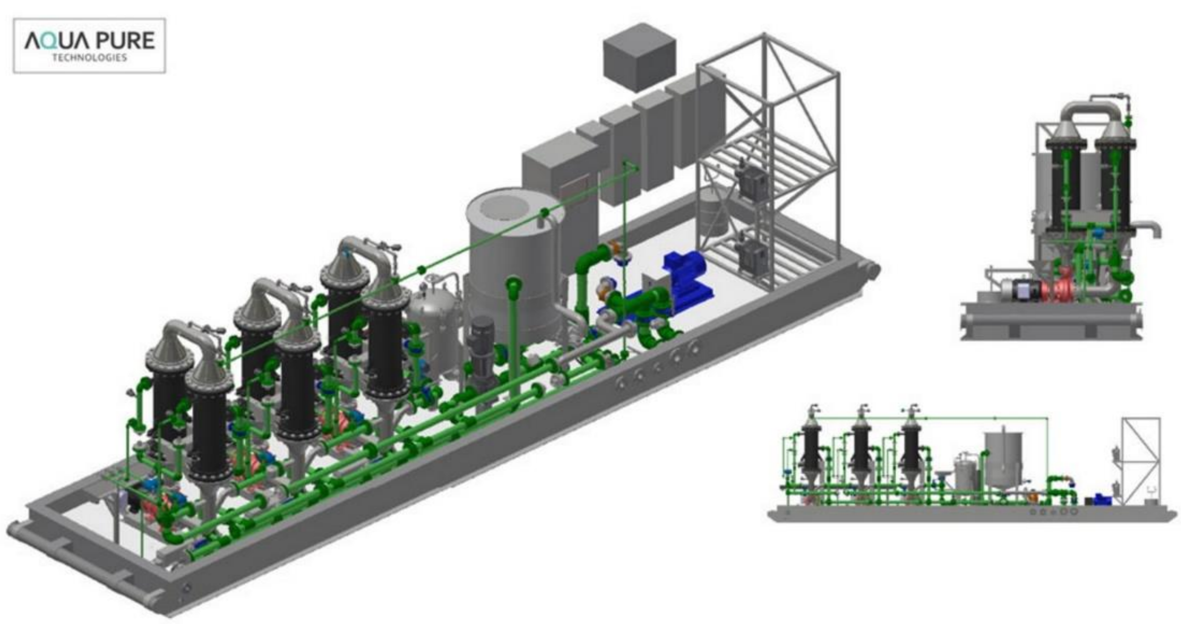
It is estimated that the Montney formation holds between 2.3 to 19.8 trillion m^3 of natural gas (Natural Gas Intel, 2016b). However, a 2013 AER report indicated that a conservative scenario for most likely recoverable reserves in Montney were 12.7 trillion m^3 of natural gas, 14.9 billion bbls of liquid byproducts and 1.1 billion bbls of oil (Natural Gas Intel, 2016b).

Although the Montney play was initially characterized as uneconomic, horizontal drilling and multi-stage HF has reversed this characterization. In the first three quarters of 2015, nearly 500 horizontal well-licenses were issued for the Montney formation (Natural Gas Intel, 2016b). This was despite an industry-wide drop of 54 percent (Natural Gas Intel, 2016b).

CHAPTER 4. Aqua Pure Technologies' PROH$_2$O® Technology

Aqua Pure Technologies Inc. is a privately owned, Canadian company operating out of Calgary, Alberta. The company develops, manufactures, and operates water filtration solutions for industrial applications (Aqua Pure Technologies Inc., 2016). The APT units are built in Canada and are exclusively patented in Canada and around the globe (Aqua Pure Technologies Inc., 2016). All of the systems sold and rented are accompanied with field service support and trained operators (Aqua Pure Technologies Inc., 2016).

Figure 7 - APT Typical Model



SOURCE: (Aqua Pure Technologies Inc., n.d.)

A standard APT unit has a capacity of 1,000 m^3 per day for traditional produced fluids (Aqua Pure Technologies Inc., 2015). However, APT units can be used for all types of produced fluids and can be customized to clients' specifications (Aqua Pure Technologies Inc., 2015). The system is fully scalable and can be fabricated to handle any volume (Personal Communication – Joe Gay – May 27, 2016).

The systems are relatively easy to use and mobile (Aqua Pure Technologies Inc., 2015). Additionally, APT units are multifunctional in that they can treat fresh water if needed as well as treat produced fluids for reuse (Aqua Pure Technologies Inc., 2015).

Furthermore, APT units can be used in combination with high speed separators, decanters, hydro-cyclones or desalting technologies depending on the clients' requirements (Aqua Pure Technologies Inc., 2015). See Appendix C for a detailed illustration of the APT system.

Figure 8 - APT System Size

SOURCE: (Aqua Pure Technologies Inc., 2015, p. 2)

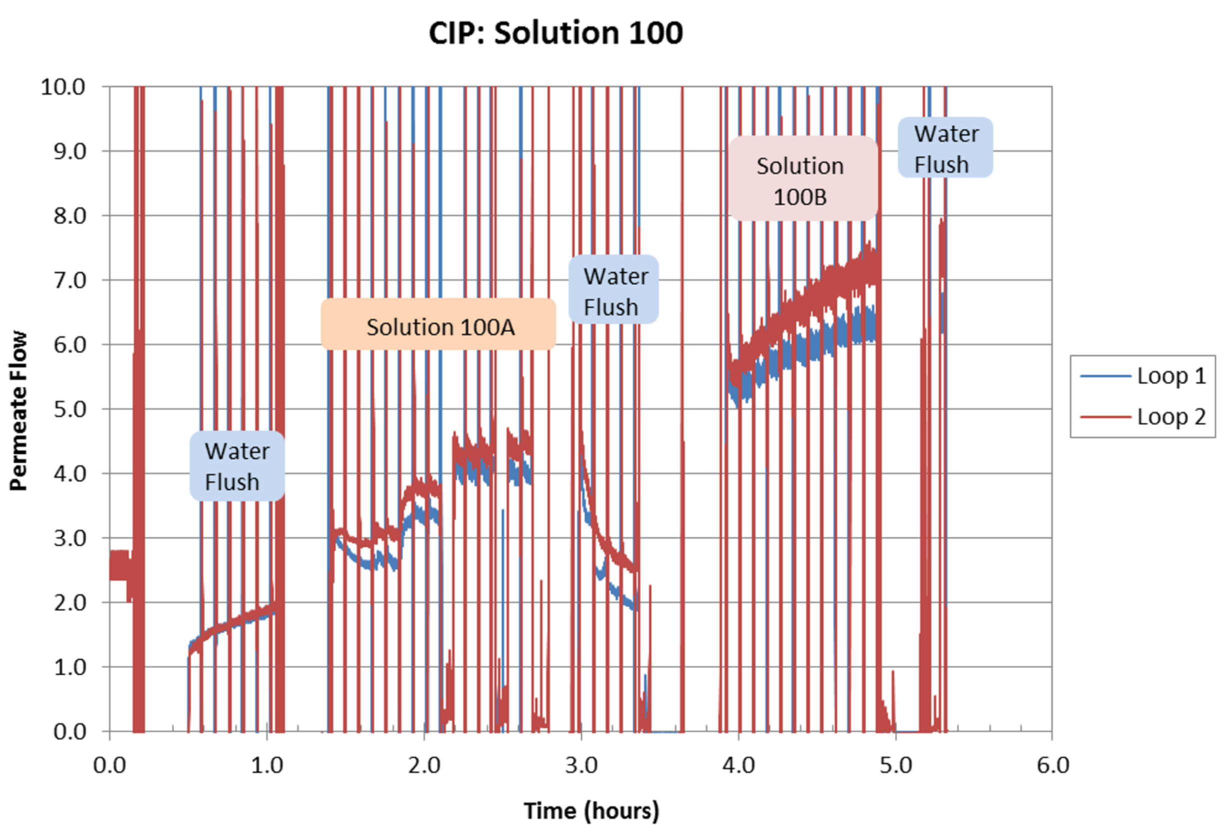
4.1 Technology Description

The APT system uses a ceramic membrane which has high strength, chemical and thermal stability (Aqua Pure Technologies Inc., 2015). Fresh water or produced fluid are cycled across the face of a ceramic membrane to achieve a given pressure differential. The pressure differential between the outer and inner faces of the membrane is the driving force for moving the fluid through the membrane. The ceramic membrane creates a physical barrier that cannot be penetrated by oil, suspended solids, or bacteria (Aqua Pure Technologies Inc., 2015). The membranes are also tolerant to harsh chemicals, temperatures, and environments (Aqua Pure Technologies Inc., 2015, p. 5). Membranes can be sized according to the required water specification, allowing for optimized efficient fluid processing (Personal Communication – Joe Gay – July 18, 2016)

The system has an automated backflush to clean the face of the membrane and an automated clean-in-place (CIP) system for detailed cleaning of a fouled membrane (Personal Communication – Joe Gay – May 27, 2016). Backflush only takes a few seconds and takes place while the system is online (Personal Communication – Joe Gay – May 27, 2016). CIP takes about an hour and requires the individual filter trains to be taken offline (Personal Communication – Joe Gay – May 27, 2016). Fortunately, redundancy is built into the system. There are multiple trains so that CIP has minimal effect on throughput (Personal Communication – Joe Gay – May 27, 2016). This offers a major advantage of this system, the multiple train design means that it does not need to be taken offline for maintenance, one train at a time can be maintained while the others are operating.

The CIP process uses three special, APT developed, cleaning chemicals. Transportation solution T40 eliminates freezing damage to the membranes and deep-cleans the membranes while being transported (Aqua Pure Technologies Inc., 2015). Solution 100A pre-cleans the membranes with an alkaline solution (Aqua Pure Technologies Inc., 2015). Finally, Solution 100B deep-cleans the membranes and recovers 100 percent of membrane flux (Aqua Pure Technologies Inc., 2015).

Figure 9 - Clean-in-place Process



SOURCE: (Aqua Pure Technologies Inc., 2015, p. 9)

In order to reduce fouling of the system, prior to entering the APT system, solids can be settled out of solution in a tankage system. There is also a bag-filter unit upstream of the membranes that is used to capture solids and sludge (Personal Communication – Joe Gay – July 18, 2016).

The system is set up to draw fresh water or produced fluids from tankage and then pump effluent to additional tankage. However, the unit can be designed to transfer directly to injection but this would typically only apply to produced fluid treatment at a water treatment facility.

4.1.1 Technology Capabilities

Up to 98 percent of water that goes through this system is recovered with approximately 99.9 percent of oil, 99.9 percent of total suspended solid (TSS) particles and 99.999 percent of bacteria is removed (Aqua Pure Technologies Inc., 2015). However, one of the limitations of the APT system is that it has almost no ability to remove total dissolved solids (TDS). Appendix D shows a visual representation of treatment results from a produced fluid field test.

4.1.2 Field Test Results

Two field tests were completed to determine the capabilities of the APT system in the field. The first test was completed in December 2015 and the second in February 2016. The tests were done on produced fluids that have been settled in a aboveground water storage system for an unknown period of time (Personal Communication – Stephen Brodie – August 9, 2016).

In the December 2015 test, feed water oil and grease levels were reported as 109 milligrams per liter (mg/L), after treatment they were reduced by 98.99 percent to 1.1 mg/L (AGAT Laboratories, 2015). TSS was reduced by 80.36 percent from 112 mg/L to 22 mg/L. Finally, TDS was reduced slightly by 2.60 percent from 192,000 mg/L to 187,000 mg/L (AGAT Laboratories, 2015). Specific water chemistry analysis and water quality assurance from the December 2015 field test are available in Appendix E.

In the February 2016 test, feed water oil and grease levels were reported as 464 mg/L, after treatment they were reduced by 99.61 percent to 1.8 mg/L. (AGAT Laboratories, 2016) . TSS was reduced by 94.55 percent from 605 mg/L to 33 mg/L. Finally, TDS was not affected and remained at 194,000 mg/L (AGAT Laboratories, 2016).

4.2 The APT and Dragos Relationship

Dragos is located in Calgary, Alberta and provides the Western Canadian O&G industry with a variety of specialized modular skids (Dragos Energy Corporation, 2015). Dragos facility applications range from but are not limited to;

- Portable/Permanent water injection “Turn Key” Facilities
- Pump packages for all process requirements
- Train/Truck offloading packages
- Motor control center building packages
- Generator packages
- Tank Packages
- Regulatory/Environmental applications and documentation

Dragos aims to incorporate the APT system into its fleet of modular units. The units can be offered to treat either produced fluids or fresh water for HF or other O&G operations.

Considering the large volumes of water required for HF, the primary purpose of offering clients the APT system is that it offers the potential to treat produced fluids for reuse. This could lead to reduced water withdrawal requirements, leading to reduced water withdrawal and transportation costs.

Additionally, companies involved in HF must normally improve a water's quality before it can be used. The initial water quality varies widely and the water quality needed for HF is a closely guarded secret. Another possibility here is to reduce the costs associated with treatment of source water. The assumption is that cleaner water requires less chemistry and additives in order to accomplish the goals of the frac and could lead to cost savings.

4.2.1 The Partnership

The details of this partnership have yet to be negotiated. However, APT will likely retain ownership of the units. On the other hand, Dragos would be responsible for marketing and leasing the technology and would obtain contracts with a shared interest in profits (Personal Communication – Clint Jensen – May 27, 2016).

CHAPTER 5. Environmental Considerations

5.1 Water in Alberta

Alberta holds approximately 2.2 percent of Canada's freshwater supply (Government of Alberta, 2010). Much of the surface water in Alberta is held in large rivers and numerous lakes. Furthermore, groundwater exists in aquifers throughout Alberta.

Surface water refers to water found on the surface of the earth that is collected in a river, lake, or wetland (Government of Alberta, 2010). "The majority of Alberta's population and industries get their water from surface water sources" (Government of Alberta, 2010, p. 6).

Groundwater is found beneath the earth's surface in gaps and pore spaces between consolidated or unconsolidated materials (Government of Alberta, 2010). "It is estimated that more than 90 percent of rural Albertans depend on wells for their water supply" (Government of Alberta, 2010, p. 22).

Table 1 - Classifications of Water in Alberta

Drinking Water (Potable)	Water used for drinking, cooking, dishwashing or other domestic purposes requiring water that is suitable for human consumption
Ground Water (Non - saline)	Groundwater having TDS less than or equal to 4000mg/L
Ground Water (Saline)	Water from wells greater than 150 meters deep (TDS greater than 4000mg/L)
Surface Water	Surface water means all water on the ground surface, whether in liquid or solid state

SOURCE: (CSUR, 2016)

The majority of the water supply in Alberta is located in the north with the majority of the water demand in the south. There are three main reasons for this discrepancy; the size of drainage basin, the location of headwater systems, and the variation in climate (Alberta Water Portal, 2013a).

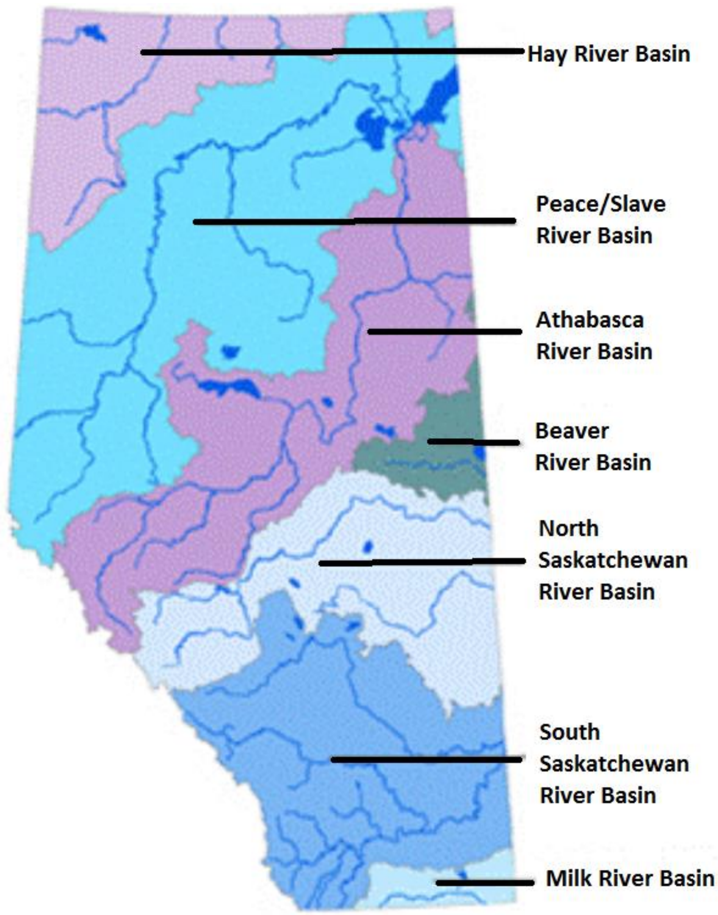
Northern basins are generally larger, receive more precipitation at their headwaters, and experience lower temperatures and less evaporation (Alberta Water Portal, 2013a). Furthermore, in the south, populations are greater and water use is higher (Alberta Water Portal, 2013a).

5.1.1 Alberta's Water Supply

A watershed, or basin, is "the area of land that catches precipitation and drains it to a water body, such as a marsh, lake, stream or river" (AEP, 2015c). In Alberta, there are seven major watersheds or river basins; Hay River Basin, Peace/Slave River Basin, Athabasca River Basin, Beaver River Basin, North Saskatchewan River Basin, South Saskatchewan River Basin, and Milk River Basin (AEP, 2015c).

As mentioned earlier, the primary areas of focus for this paper are the Duvernay and Montney plays. These plays are located in the Peace/Slave, Athabasca and North Saskatchewan River basins.

Figure 10 - Alberta's Major River Basins



SOURCE: *Adapted from* (AEP, 2015c)

5.1.1.1 Peace/Slave River Basin

The Peace River's headwaters are located in the mountains of British Columbia, the river then flows northeast across Alberta and ends up in the Slave River. The Peace/Slave river basin is the largest in Alberta, covering an area of 180,000 km^2, occupying approximately 30 percent of the province (Alberta Water Portal, 2013b). The mean annual natural river discharge of the Peace/Slave River is 108,000,000 cubic decameters (dam^3) (Alberta Water Portal, 2013b). The water flowing to Alberta is controlled by the W.A.C. Bennett Dam, located in British Columbia.

The Peace/Slave river basin has a population density of less than one person per km^2 (Alberta Water Portal, 2013b). It covers all or parts of 17 rural municipalities, 22 urban municipalities and 15 Aboriginal settlements (Alberta Water Portal, 2013b).

Water allocations to the industrial sector account for 37 percent, the municipal sector accounts for 11 percent, and the petroleum sector accounts for another 8 percent (Alberta Water Portal, 2013b).

5.1.1.2 Athabasca River Basin

The Athabasca River originates in Alberta's Rocky Mountains. The river flows northeast through the province and ends in Lake Athabasca. The Athabasca Basin covers about 140,000 km^2 in area and occupies approximately 23 percent of Alberta (Alberta Water Portal, 2013c). The mean annual natural river discharge of the Athabasca River is 24,000,000 dam^3 (Alberta Water Portal, 2013c).

The Athabasca river basin has a population density just over one person per km^2 (Alberta Water Portal, 2013c). It includes all or parts of 22 rural municipalities, 23 urban municipalities and 14 Aboriginal settlements (Alberta Water Portal, 2013c).

Water allocations to the industrial sector account for 17 percent, the municipal sector accounts for 7 percent, and the petroleum sector accounts for another 68 percent (Alberta Water Portal, 2013c).

5.1.1.3 North Saskatchewan River Basin

The North Saskatchewan River basin begins in the glaciers of Banff and Jasper National Parks and flows eastward towards the Alberta-Saskatchewan border. The North Saskatchewan Basin covers about 55,000 km^2 in areas and occupies approximately 9 percent of Alberta

(Alberta Water Portal, 2013d). The mean annual natural river discharge of the North Saskatchewan River is 7,277,000 dam^3 (Alberta Water Portal, 2013d).

The North Saskatchewan River basin has a population density of 41 people per km^2 (Alberta Water Portal, 2013d). It consists of all or parts of 25 rural municipalities, 68 urban municipalities and 12 Aboriginal settlements (Alberta Water Portal, 2013d).

Water allocations to the industrial sector account for 82 percent, the municipal sector accounts for 8 percent, and the petroleum sector accounts for another 5 percent (Alberta Water Portal, 2013d).

5.1.2 Understanding Water Use

Water allocation volume is made up of three components in a license; consumption, losses, and return flows (Government of Alberta, 2010). This is an important distinction because many water users will return diverted water back, usually at a reduced quality, to the source after use. Therefore, in order to fully understand the impacts of water use in O&G operations on water availability, it is important to understand the difference between water withdrawal and water consumption.

Water withdrawal refers to the actual volume of water diverted from a surface water or groundwater source. Conversely, water consumption refers to the water that is permanently withdrawn from the water source. For instance, water that is no longer available because it has been consumed by people or livestock, incorporated into a product, evaporated, or otherwise permanently removed. This concept also applies to water that is sufficiently contaminated so that it cannot be returned to the environment.

5.1.3 Water & Wastewater Quality

HF operators each have closely guarded and specific requirements for the water that is used in the creation of HF fluid. Therefore, for the purposes of this paper, it is not only important to consider the water quality after use but also prior to being used in HF operations.

5.1.3.1 Source Water Quality

Water quality varies naturally throughout Alberta according to local environmental conditions and human activity. There are three major factors that affect water quality; water quantity, point source contamination, and non-point source contamination (Government of Alberta, 2010).

The amount of water available affects its quality. High levels of precipitation and water flows wash sediment, nutrients, pesticides, bacteria, and other substances off the land and into rivers, thus lowering water quality. Equally, when precipitation and water flows are low, the capacity of a water body to dilute pollutants is reduced, again lowing water quality.

Point source and non-point source contamination are a result of human activity. The difference is that point source contamination results from discharge of treated or untreated wastewater and is easily traced (Government of Alberta, 2010). On the contrary, non-point source contamination is difficult to trace as it comes from the uptake of pollutants by precipitation which then enter rivers (Government of Alberta, 2010).

5.1.3.2 Wastewater Quality

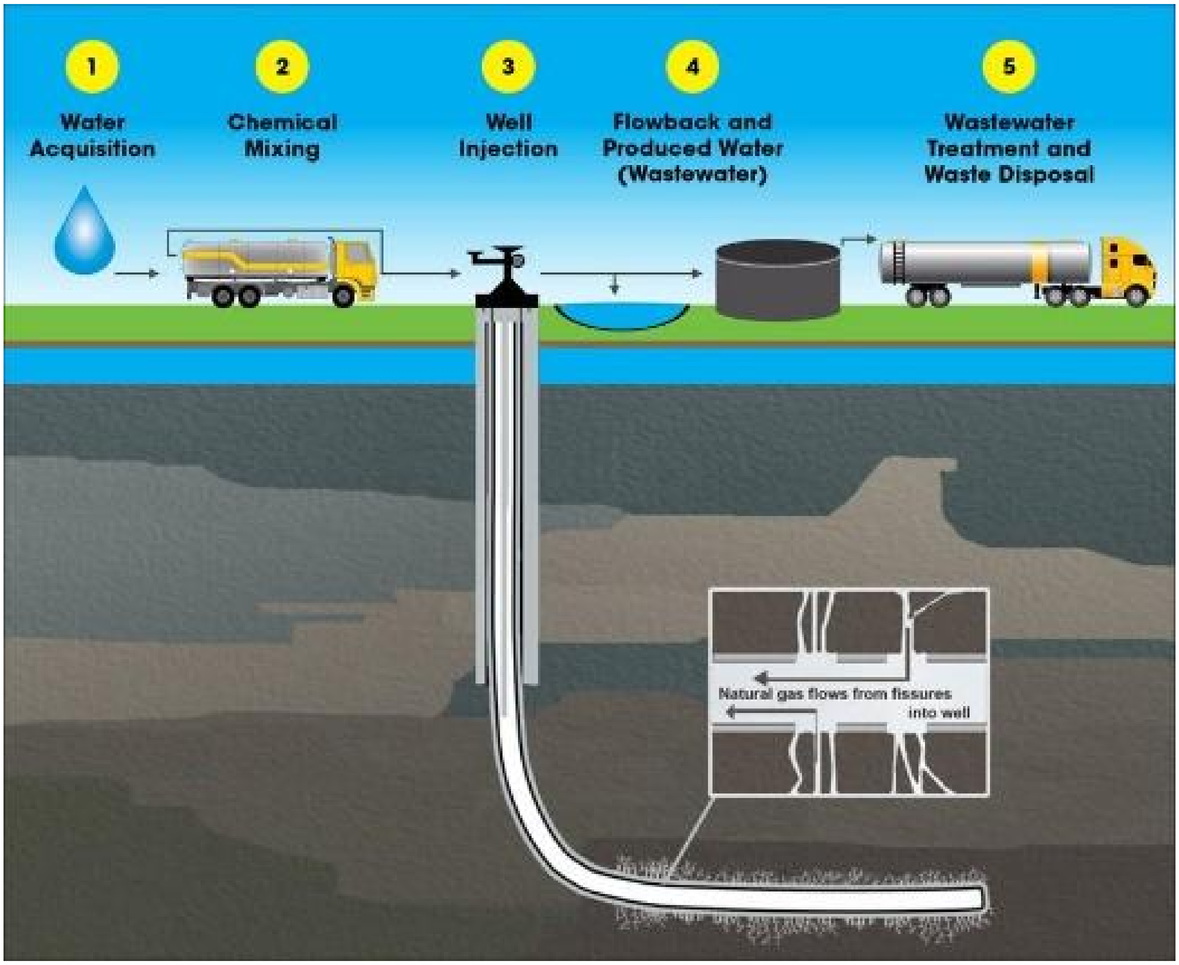
After the source water is used as HF fluid and returns to the well head as produced fluids it can be considered wastewater. Again, depending on the specifics of the HF operation, the wastewater quality from each well varies. However, the wastewater produced from HF wells contains pollutants both from HF fluids and from natural sources underground. The combination of fluids will typically contain TSS, TDS, proppant, heavy metals, chemicals and additives, hydrocarbons, sediment, bacteria, and naturally occurring radioactive substances.

One study looked at the concentration of 160 chemicals in produced fluids, it reported chemical oxygen demand ranging from 195 to 36,600 mgL^{-1}, Chlorine concentration from 64.2 to 196,000 mgL^{-1}, Sodium concentration from 69.2 to 117,000 mgL^{-1}, $Radium^{226}$ concentration from 2.75 to 9,280 $pCiL^{-1}$, and $Uranium^{238}$ concentration from 0 to 497 $pCiL^{-1}$ as some of the prominent chemicals of concern (Saba, 2014). Another study found oil and grease content in the range of 40 to 2,000 mgL^{-1} and TDS ranging from 1000 to 400,000 mgL^{-1} (Saba, 2014).

5.2 Potential Impacts on Water from HF

The primary concern when understanding impacts on water from HF operations is the impact it could have on drinking water resources. Another concern is the potential impact of contaminants entering the eco-system and the associated impacts to flora and fauna. The American EPA suggests five points of concern for potential impacts to drinking water from HF at each stage of the HF water cycle.

Figure 11 - HF Water Cycle



SOURCE: (EPA, 2016)

5.2.1 Water Acquisition

As discussed above, large amounts of water are required for HF operations. The primary concerns here are reduced availability in the quantity of drinking water. Also, the degradation of water quality due to reduced flow.

5.2.2 Chemical Mixing

When chemicals and additives are mixed with water prior to commencing a HF operation, there is a risk of leaks and spills. This could lead to toxic chemicals entering surface and groundwater sources.

5.2.3 Well Injection

When HF fluid is injected into the formation, there is a risk that it could escape into groundwater resources. Although the risk is low, poor well construction or operation could lead to HF fluid escaping through manmade or natural features in the formation (EPA, 2016). There is further concern that natural substances found underground, such as heavy metals or radioactive materials, could be mobilized as a result of HF and contaminate ground water (EPA, 2016).

5.2.4 Flowback and Produced Waste

When the pressure in the well is released produced fluids flow back up the well. This combination of fluids, containing HF chemical additives and naturally occurring substances, must be stored or treated on-site (EPA, 2016). There is potential for the release of this fluid to surface or ground water through spills or leaks during on-site storage (EPA, 2016).

5.2.5 Water Treatment and Water Disposal

As discussed above, wastewater is dealt with by either disposal through underground injection or treatment. Contaminants may be released into ground water if injection wells are improperly selected (EPA, 2016). Additionally, if wastewater is reused, releases similar to those experienced during the Well Injection section are possible.

CHAPTER 6. Regulatory Setting

6.1 Federal

In Canada, the regulation of onshore O&G operations falls under provincial jurisdiction. This mandate is set out by the Constitution Act of 1867 in section 92(A). However, the federal government still holds jurisdiction for regulating O&G operation on Aboriginal lands as set out by the Indian Oil and Gas Act of 1985.

When it comes to water governance in Canada, the federal government has jurisdiction related to fisheries, navigation, federal lands, and international relations. Furthermore, it plays a significant role in agriculture, health and the environment, ensuring national policies and standards are in place on environmental and health-related issues.

“Within the federal government, over 20 departments and agencies have unique responsibilities for fresh water” (Governement of Canada, 2016). However, the primary department of concern is the department of Environment and Climate Change Canada.

Key legislation administered by this department as it relates to water-related activities include “the Canada Water Act, which contains provisions for formal consultation and agreements with the provinces; the International River Improvements Act, which provides for licensing of activities that may alter the flow of rivers flowing into the United States; and, the Department of the Environment Act, which assigns the national leadership for water management to the Minister of the Environment” (Governement of Canada, 2016).

Another key piece of federal legislation that relates to water is the Canadian Environmental Protection Act (CEPA) of 1999. Specifically, Part 7 – Division 1 and 2, which highlight the Federal government’s responsibility for controlling pollution and managing waste.

6.2 Provincial

In November 2003, in response to the worst multi-year drought in recorded history, the Government of Alberta released the Water for Life action plan. The plan was designed as an overarching government-wide strategy for managing water in Alberta. The primary goals held within the policy are safe drinking water, healthy aquatic ecosystems, and reliable water supplies for a sustainable economy (Government of Alberta, 2008).

Within this plan, the Government of Alberta uses a number of tools to regulate and protect water resources. Furthermore, as knowledge, research, and understanding become more available, the tools are constantly evolving. These tools are made up of formal legislation and regulation, directives, codes of practice and guidelines.

6.2.1 Legislation and Regulation

The primary piece of legislation in Alberta that governs the use of water is the Alberta Water Act (the Act). The Act was proclaimed in 1999 following a comprehensive review of legislation in other jurisdictions and input from Albertans. However, the most recent vision of the Act came into force on December 17, 2014. Section 2 of the Act states that, “the purpose of this Act is to support and promote the conservation and management of water, including the wise allocation and use of water” (Government of Alberta, 2014b).

The AER has Water Act authority over all energy resource activities including, approvals, licenses, and codes of practice (AER, 2016c). However, Environment and Sustainable Resource Development (ESRD) retain Water Act authority over all other sectors and administration of priority in the event of a shortage (AER, 2016c).

In order to achieve its objectives, the Act sets out a number of regulations, the relevant regulations are listed below;

- Bow, Oldman, and South Saskatchewan River Basin Water Allocation Order
- Oldman River Basin Water Allocation Order
- Water (Ministerial) Regulation
- Water (Offences and Penalties) Regulation

These regulations have been issued in order for the AER and ESRD to carry out the intent of the Act. As highlighted, the intent of the Act is to manage the availability of water and quantities of water being allocated. However, this alone is not enough.

Another dimension that is legislated is the quality of the water in Alberta. The primary piece of legislation that governs the quality of water in Alberta is the Environmental Protection and Enhancement Act (EPEA). EPEA was proclaimed in 1993 after extensive consultation with industry, communities, NGOs, and the general public. However, the most recent version of EPEA came into force on June 30, 2016. Section 2 of EPEA states that, "the purpose of this Act is to support and promote the protection, enhancement and wise use of the environment" (Government of Alberta, 2016).

Beginning in March 2014, the AER began accepting applications under EPEA. Again, this responsibility was previously held by the ESRD. EPEA and its accompanying regulations identify which activities require regulatory approval and the requirements for obtaining it. Furthermore, EPEA is designed to support the coordination and integration of the review of potential environmental impacts of proposed projects. A list of regulation relevant to this paper is listed below;

- Activities Designation Regulation
- Administrative Penalty Regulation
- Approvals and Registrations Procedure Regulation
- Conservation and Reclamation Regulation
- Disclosure of Information Regulation
- Environmental Appeal Board Regulation
- Environmental Assessment (Mandatory and Exempted Activities) Regulation
- Environmental Assessment Regulation
- Environmental Protection and Enhancement (Miscellaneous) Regulation
- Potable Water Regulation
- Release Reporting Regulation
- Remediation Certificate Regulation
- Substance Release Regulation
- Waste Control Regulation
- Wastewater and Storm Drainage (Ministerial) Regulation
- Wastewater and Storm Drainage Regulation

6.2.2 Directives

Directives are documents released by the AER that set out new or amended requirements or implementation procedures. "Licensees, permittees, and other approval holders under the jurisdiction of the AER are required to obey all directives" (AER, 2016d).

In August 21, 2013, the AER released Directive 083: Hydraulic Fracturing – Subsurface Integrity. The directive sets out the “requirements for managing subsurface integrity associated with hydraulic fracturing subsurface operations” (AER, 2013, p. 2). The primary objectives of this directive are; prevent the loss of well integrity at a subject well, reduce the likelihood of unintentional inter-wellbore communication between a subject well and an offset well, manage well control at an offset well in the event of inter-wellbore communication with a subject well, prevent adverse effects to non-saline aquifers, prevent impacts to water wells, and prevent surface impacts (AER, 2013).

Additionally, a number of other directives, that supplement Directive 083, have been set out by the AER which impact HF operations;

- Directive 008: Surface Casing Depth Requirements
- Directive 009: Casing Cementing Minimum Requirements
- Directive 020: Well Abandonment
- Directive 027: Shallow Fracturing Operations – Restricted Operations
- Directive 044: Requirements for the Surveillance, Sampling and Analysis of Water Production in Oil and Gas Wells Completed Above the Base of Groundwater Protection
- Directive 050: Drilling waste management
- Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirement
- Directive 055: Storage requirements for the Upstream Petroleum Industry
- Directive 058: Oilfield Waste Management Requirements for the Petroleum Industry
- Directive 059: Well Drilling and Completion Data Filing Requirements

6.2.3 Codes of Practice and Guidelines

In addition to the legislation and directives, there are a number of other key tools worth mentioning. The Water Conservation and Allocation Policy for Oilfield Injection “provides direction for regulatory agencies and developers where the use of non-saline water resources may be essential to an enhanced oil recovery scheme” (Government of Alberta, 2006). This policy also requires O&G operators to investigate non-water alternatives and alternative sources of water before an application to use non-saline groundwater is made (Government of Alberta, 2014a).

Alberta Environment and Parks’ (AEP) Guide to Groundwater Authorization details the groundwater quantity limitations and evaluation requirements. Additionally, AEPs Desk-top Method for Establishing Environmental Flows in Alberta Rivers and Streams provide a technique for calculating environmental flow requirements in the absence of site-specific assessments or recommendations (CSUR, 2016).

In order to monitor groundwater, AEP manages the Groundwater Observation Well Network that consists of over 250 active monitoring wells (Alberta Energy, 2016). These monitoring wells have been installed to monitor groundwater quality and water levels throughout the province.

6.2.4 HF and Water Regulatory Requirements - Summary

Provincial regulatory requirement, specific to HF, fall under four broad categories;

6.2.4.1 Sourcing

As discussed above, quantities of water available and rates of diversion are governed by the Act. Limits may be imposed to satisfy water conservation objectives, aquatic ecosystem protection, environmental and in-stream flows, trans-boundary apportionment agreements, and allocations granted to previous licenses.

6.2.4.2 Using

As highlighted earlier, the fluid used in HF operations has raised concerns about surface water and groundwater contamination, both during and after the fluid has been injected into the resource reservoir. The AERs Directive 083 is designed to prevent HF fluid from mixing into groundwater and surface water (Alberta Energy, 2016). Additionally, Directives 008 and 009 set out strict requirements for cement casing and wellbore construction to provide a barrier between the wellbore and any nearby water sources (Alberta Energy, 2016).

The AERs Directive 059 requires disclosure of HF fluid composition, water source and volume data on a well-to-well basis (Alberta Energy, 2016). Fluids and waters that have been used or produced in O&G operations may only be reused in other O&G operations. Currently, they cannot be reused for any other purpose (CSUR, 2016).

6.2.4.3 Reporting

Directive 035 is designed to capture baseline conditions for water wells, prior to the drilling of nearby CBM wells. This directive will be expanded to include baseline water well testing in proximity to multi-stage HF operations in horizontal wells (Alberta Energy, 2016).

Directive 059 sets out the requirements for reporting related to HF. Information on HF fluid composition and water source must be submitted to the AER for each well undergoing HF within 30 calendar days from the conclusion of an operation (CSUR, 2016).

Water source submissions requirements include; type of water, volume, location, and timing of water withdrawal. Additionally, water licenses have monitoring requirements as a condition of the license. Typically, these requirements are based on the source and volume required.

6.2.4.4 Disposal

In Alberta, no fluids used or produced in O&G operations, even those that have been treated, may be released to natural water bodies. Once used, fluids and waters must be disposed deep underground or deep saline groundwater zones that are below the base of groundwater protection (CSUR, 2016).

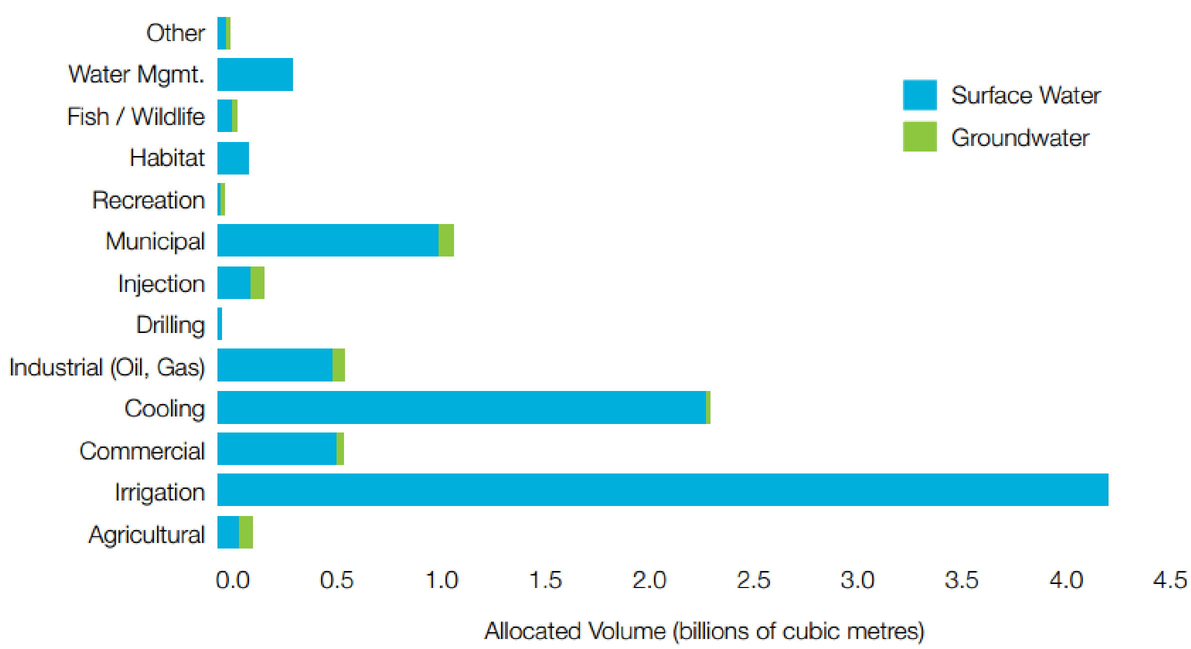
Directives 051, 055 and 058 detail strict guidelines for the storage and management of produced fluids (Alberta Energy, 2016). Furthermore, it is important to note that while the produced fluids are not regulated by the Transportation of Dangerous Goods regulations, the residue of crude that is contained within is regulated (Government of Alberta, 2012).

6.2.5 Understanding Water Diversion and Allocation

Despite the water cycle's ability to replenish water sources, the quantity of water available for human use is finite. In order to use water in Alberta, municipalities, industry and individuals can apply for a license to divert under the Act. "Diverted water is the amount of water a license holder is permitted to withdraw from a water source in one year" (Government of Alberta, 2010, p. 34). The amount is usually expressed as an allocation, consisting of a volume, a maximum pump rate, and timing when a licensee is allowed to pump (Government of Alberta, 2010). That said the total withdrawal over the year cannot exceed the volume of water specified in a license.

In Alberta, irrigation and cooling for thermal power generation account for the majority of surface water allocations (Government of Alberta, 2010). In contrast, O&G and agriculture account for the majority of ground water allocations (Government of Alberta, 2010).

Figure 12 - Water Allocation in Alberta by Specific Purpose (2009)



SOURCE: (Government of Alberta, 2010, p. 35)

It is important to note here that water allocations do not necessarily directly reflect actual water use. Allocation only represents the maximum amount of water permitted to be used.

6.2.5.1 First in Time, First in Right

The FITFIR model has been in existence since 1894 and was passed on from the federal government in 1930 when the provincial government received power over natural resources. Initially, it was designed to enable agriculture and encourage settlement as Alberta grew. Now, it is considered to be an antiquated and wasteful system.

As discussed earlier, Alberta's water priority is based on the seniority of the water license. This means each water license is given a priority number based on when the application was received. Again, other than household use, licenses are ranked according to priority not purpose of use. Each water license is composed of five components; priority, maximum annual water volume, maximum diversion rate, source and location, and purpose for use (Government of Alberta, n.d.)

Issues surrounding this system typically only present themselves when there is not enough water in a particular basin to meet all the licensee needs. Monitoring and enforcement of the FITFIR system is known as waster mastering. Water mastering ends or limits water diversion of junior, low priority; water licensees in order satisfy the water requirements of the senior licensees (Government of Alberta, n.d.). This priority action is known as a priority call under Section 30 of the Act (Government of Alberta, n.d.).

Alternatively, in situations of water shortage, under Section 33 there is a provision for water users to share water through assignment agreement. Furthermore, Section 81 allows for the transfer of an allocation.

Two types of water allocation transfers exist, a temporary transfer and a permanent transfer. "A temporary transfer refers to a licence transferring back to the original licence-holder from the transferee automatically upon a chosen date" (Alberta Water Portal, 2013e). "A permanent transfer is when a new licence transfer remains in place" (Alberta Water Portal, 2013e).

Licences can only be transferred if the licence is considered to be in good standing. Therefore, the "licence must explain all conditions and there must be no outstanding compliance issues" (Alberta Water Portal, 2013e). That said a 10 percent holdback of the water in an allocation transfer may be applied to achieve water conservation objectives (Alberta Water Portal, 2013e).

CHAPTER 7. Economic Environment

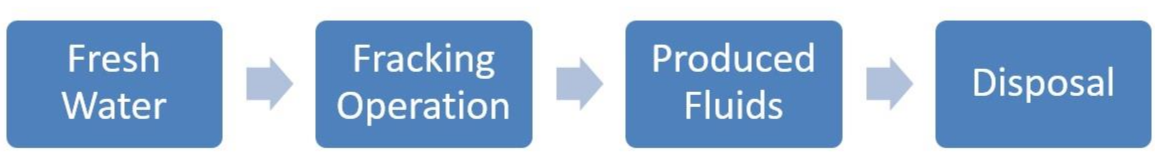
7.1 Water Demand

To date, Alberta's economy has been built with a subsidy of cheap water. However, a water-scarce environment could become Alberta's reality sooner than expected. Alberta's population is growing annually at around 3.5 percent and could top 7.5 million by 2050 (Querengesser, 2014).

By 2025, Alberta's water demand is forecasted to increase by 21 percent, meaning municipal demand will grow by a quarter (Querengesser, 2014). Additionally, water usage in both the agricultural and energy industries is expected to increase by 50 percent (Querengesser, 2014). This situation will set growing human water needs against the desire for economic growth in the province.

That said, it has been speculated that in order to overcome this dilemma, Alberta needs to govern water by attaching a price to it. Not just a price per m^3 withdrawn but for how much of that water is returned. As discussed earlier, water used in the O&G industry cannot be returned. Therefore, as a price for water becomes more likely, it is necessary for companies in the O&G industry to start rethinking how they use water.

Figure 13 - Current Configuration of Water Use in HF



7.1.1 Water Withdrawal is Already Being Limited

In 2006, the government closed water licenses on the South Saskatchewan basin, as a way to rationalize distribution of the nine billion m^3 of water allocated under the province's FITFIR system (Querengesser, 2014). In July, 2015, AEP issued a low flow advisory for the Upper Athabasca River basin (AER, 2016e). "The advisory notified water users in the Upper Athabasca Region that current temporary diversion licenses (TDL) are suspended and no new applications will be accepted" (AER, 2016e). The AER has applied this restriction to O&G operators in the region and has encouraged operators to voluntarily reduce their consumption in areas with no mandatory restrictions.

Later in 2015, due to dry weather and low flow conditions in rivers across Alberta, the AER took steps to further restrict water withdrawals (AER, 2016e). The following restrictions on TDLs for watercourses have been put in place for other river basins in Alberta;

- Battle River basin – no TDL applications are being accepted.
- South Saskatchewan River basin – no TDL applications are being accepted; in some sub-basins all TDLs have been suspended.
- Milk River basin – no TDL applications are being accepted.
- Peace River basin – no TDL applications are being accepted; in some sub-basins all TDLs have been suspended.
- North Saskatchewan River basin – no TDL applications are being accepted; in some sub-basins TDLs are in the process of being suspended.

SOURCE: (AER, 2016e)

7.1.2 Emerging Water-License Market

Water and energy production share a close relationship, in that all types of energy production consume water. Meaning, access to water is necessary for energy resource production. Therefore, in these times of water restriction, water begins to resemble something approaching a commodity. For instance, for a recent development north of Calgary, the Rocky View County purchased licenses granting it access to 2.47 million m^3 of water for $15 million (Querengesser, 2014).

This purchase suggests that the cost of purchasing water without an allocation on the emerging water-license market is at least $37 per m^3. Furthermore, without access to a water license, one of Dragos' clients reported spending close to $70 per m^3 to purchase the water required for its operations (Personal Communication – Clint Jensen – July 20, 2016).

7.2 Transportation

In Alberta's oil patch there are two major means of transportation, namely by pipelines or by truck. The primary means of transportation of water and produced fluids is by truck. Water hauling trucks come in all different sizes. However, one water hauling company in Alberta offers trucks that can hold approximately 19 m^3 of water (Lonestar West Inc., 2016). Similarly, it offers vacuum trucks that are used for fluid removal and disposal, that can hold 16 m^3 of fluid (Lonestar West Inc., 2016). That said, operations in Alberta that require HF volumes of water hauling typically use water trailers with a capacity of 30m^3 (Personal Communication – Clint Jensen – August 9, 2016).

As mentioned earlier, trucking costs can be as high as $63 per m^3. Dragos has indicated that trucking in Alberta typically costs around $200 per hour, including truck and driver

(Personal Communication – Clint Jensen – July 26, 2016). Therefore, transportation of fresh water to site and produced fluids off of site, offers significant operational expense. One estimate puts trucking at between 65 percent and 85 percent of total oilfield water management expenditures (Calvert, 2015).

7.3 Disposal by Re-injection

Currently, the costs of re-injection are between \$22 to \$25 per m^3 for disposing flowback and \$12 to \$15 per m^3 for produced water (Personal Communication – Clint Jensen – July 20, 2016). These numbers do not include the price of transporting the wastewater to the disposal site.

7.4 Water and Wastewater Treatment

If water scarcity is now becoming a problem, there is a need to consider reuse options for produced fluids. That said, in order for water to be reused in HF operations, it is necessary for the water to be treated to meet HF and other O&G operators' requirements.

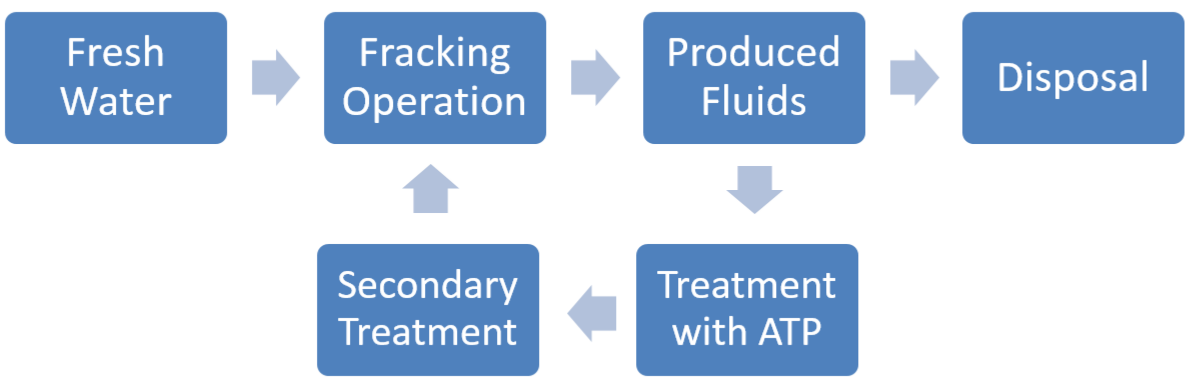
In 2010, treating water from North American O&G wells was a \$2.5 billion industry and is expected to grow about 10 to 20 percent annually (Hunt, 2014). Considering the aforementioned water scarcity challenges to come, this offers a significant economic opportunity for Dragos and its partners.

CHAPTER 8. Economic Analysis

8.1 Using APT to Treat Produced Fluids - Business Model

Using APT to treat produced fluids for reuse is carried out with the purpose of reducing wastewater streams and fresh water consumption over current practices. As highlighted earlier, both activities have costs associated with them. The goal here is to quantify the cost savings associate with using the APT system in a HF operation. From there, justification for the capital and operational expenditure for the filtration system can be provided.

Figure 14 - Proposed Configuration of Water Use in HF



8.1.1 Target Market

Dragos has identified a number of potential customers for the APT technology. The end users of the APT system and the treated water are water management companies, disposal companies, and O&G producers (Personal Communications – Clint Jensen – May 27, 2016). Dragos would offer the APT system as an add-on service where it would market APT's filters to its client base or to utilize at its facilities.

8.2 Economic Assessment Assumptions

8.2.1 The Hypothetical Operation

A number of assumptions have been made regarding a hypothetical HF operation for analysis in this paper. The hypothetical HF operation, located in the Montney formation of Alberta, consists of a well pad with two identical wells. Each of these well has a well-life of 10 years. The well pad is located 50 km from the fresh water source and the disposal well. The first well is fracked using traditional water sources, any additional wells recycle APT treated water.

8.2.2 Cost of Water

An AER representative quoted that the cost of water withdrawal, not including transportation, for operators with a water allocation ranges from \$1 to \$5 per m^3 (Personal Communication – Rohit Sharma – July 26, 2016). An average of \$3 per m^3 has been used in this analysis.

Furthermore, for the purposes of this analysis the cost of water withdrawal, not including transportation, for operators without a water allocation has come from the Rocky View County case discussed earlier. The cost of water withdrawal without a water allocation is assumed to be \$37 per m^3.

8.2.3 Pre-Treatment

For the purposes of this analysis, the source water is assumed to be of sufficient quality that it can be used to produce HF fluid. This assumption holds that there is no cost associated with the pre-treatment of source water.

8.2.4 Transportation and Storage

The cost of transportation is assumed to be \$200 per hour with an average truck load of 23 m^3. Furthermore, for this analysis, it is assumed that it takes one hour to load trucks and one hour to unload trucks. Additionally, it is assumed to take one and a half hours in return driving time to travel the 50 km distance to the source water or the disposal well (Personal Communication – Clint Jensen – July 26, 2016). Therefore, the average cost of trucking is around \$30 per m^3 for fresh water from source and wastewaters to the injection site.

Figure 15 - Calculation of Trucking Cost

$$(3.5\text{hrs}/23\ m^3) \times \$200.00/\text{hour} = \$30/m^3$$

With that said, an assumption is made that the transportation costs from well-to-well in the same operation are negligible. This assumption is due to the close proximity of wells in HF operations.

Additionally, the cost of water storage on-site is considered to be equal in both current and reuse scenarios. This assumption is made because water storage tanks are necessary in both.

8.2.5 Water Quantities

Dragos has reported that its clients in the identified region typically require 20,000 m^3 to 50,000 m^3 of water for each well that is fracked (Personal Communication – Clint Jensen – July 20, 2016). Therefore, an average of 35,000 m^3 of water per well is used.

Furthermore, although the literature indicates flowback recovery of anywhere between 3 percent to 80 percent, Dragos has indicated that in the field it is experiencing between 10 percent and 15 percent recovery (Personal Communication – Clint Jensen – July 20, 2016). Therefore, an average of around 13 percent recovery of flowback is used.

Figure 16 - Calculation of the Amount of Flowback Recovered per Well

$$35{,}000\ m^3 \times 12.5\% = 4{,}375\ m^3 \text{ per Well}$$

The produced water volumes that Dragos typically sees are 25 m^3 to 100 m^3 per day for the life of the well (Personal Communication – July 25, 2016). Therefore, produced water volumes are assumed to be an average of around 62 m^3 per day, per well.

8.2.6 Cost of Treatment with APT

Although lease rates for the APT system are yet to be determined, initial estimates for treating produced fluids using the APT system range from \$8 to \$10 per m^3 (Personal Communication – Clint Jensen – July 15, 2016). For this analysis, an average of \$9 per m^3 is used.

8.2.7 Secondary Treatment

As discussed above, the APT system suffers from its inability to remove TDS. However, a 2013 publication by the Society of Petroleum Engineers showed that brackish water can be an effective substitute for freshwater in HF fluids (Hunt, 2014). With that said, an anonymous HF operator indicated that the “sweet spot” for brackish water reuse in HF is 140,000 mg/L of TDS (Personal Communication – Anonymous – August 9, 2016).

As mentioned above, the field test data indicated that TDS after APT treatment ranged from 187,000 mg/L to 194,000 mg/L. For the purpose of this paper, the “sweet spot” concentration of TDS will be accomplished by diluting the APT effluent with fresh source water.

AEP operates a network of river water quality monitoring stations. Water quality data, collected from March 2013 to March 2015, from a monitoring station located on the Peace River has been used as representative source water for diluting TDS concentrations. The monitoring station is located in the Montney play, northeast of Grand Prairie and southwest of the town of Peace River. Over the two-year period, the average TDS concentration was around 113 mg/L (AEP, 2016). Furthermore, this source water is assumed to be otherwise pure. TDS is the only water quality parameter being taken to account here.

In order to determine the volume of this fresh source water required to dilute the APT effluent, the following formula was used;

Figure 17 - Dilution of APT Effluent with Source Water Calculation

$$\text{Volume}_{\text{Effluent}} \times \text{Concentration}_{\text{Effluent}} + \text{Volume}_{\text{Source}} \times \text{Concentration}_{\text{Source}} = \text{Volume}_{\text{ReusableWater}} \times \text{Conentration}_{\text{ReusableWater}}$$

$$\text{Since, Volume}_{\text{ReusableWater}} = \text{Volume}_{\text{Effluent}} + \text{Volume}_{\text{Source}}$$

$$\text{Volume}_{\text{Source}} = \frac{\text{Volume}_{\text{Effluent}} \times (\text{Concentration}_{\text{Effluent}} - \text{Conentration}_{\text{ReusableWater}})}{(\text{Conentration}_{\text{ReusableWater}} - \text{Concentration}_{\text{Source}})}$$

Table 2 - Source Water (Peace River) TDS Over Two Years

Peace River Sample TDS (mg/L)	Date (mmm-yy)
100	Mar-13
110	Apr-13
110	May-13
120	Jun-13
130	Jul-13
130	Aug-13
110	Sep-13
120	Oct-13
100	Nov-13
110	Dec-13
110	Jan-14
120	Feb-14
100	Mar-14
140	Apr-14
120	May-14
120	Jun-14
120	Jul-14
110	Aug-14
99	Sep-14
110	Oct-14
98	Nov-14
110	Dec-14
110	Jan-15
120	Feb-15
110	Mar-15
113.48	mg/L

SOURCE: *Adapted from* (AEP, 2016)

8.2.8 Wastewater Disposal

The cost of re-injection is assumed to be an average of around $24 per m^3 for disposing flowback and an average of around $14 per m^3 for produced water. Additionally, an assumption is made that the sludge that is recovered from the APT treatment process will be disposed of through re-injection at the same price as the disposal of flowback.

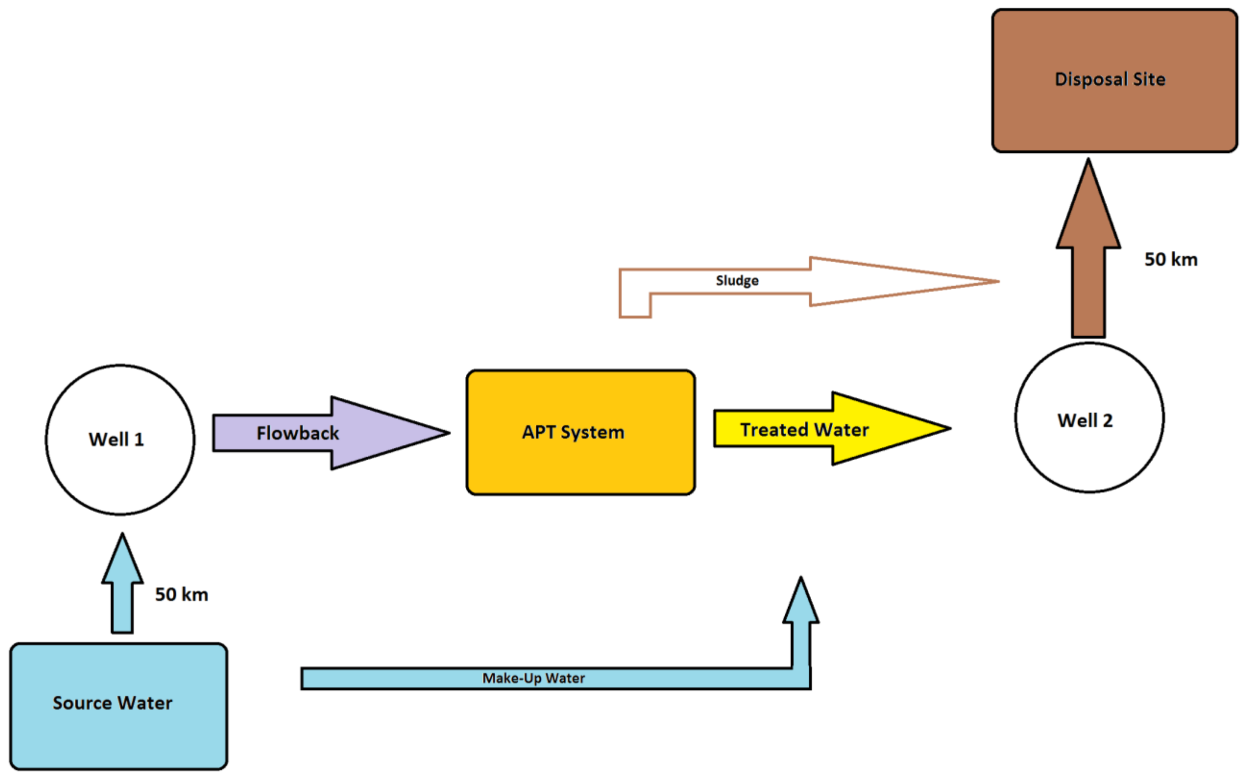
8.2.9 The Assessment Models

Three assessment models have been completed. Additionally, the first two assessments are used to compare cost saving potential in scenarios of water abundance and water scarcity. Therefore, these two assessments where run using the cost of water withdrawal with and without a water allocation. The third assessment assumes water scarcity and a market for usable treated water. Therefore, this third assessment was only run using the cost of water withdrawal without an allocation. Operating and treatment expenses in all three assessments are recorded on a volumetric basis.

8.2.9.1 Assessment 1

The first assessment assumes only flowback wastewater is reused within the HF operation. Furthermore, it is assumed that no water is produced from the wells. This assessment was completed to capture the effects of treating flowback alone. Additionally, because of the fact that produced waters becomes available over time and may not be available for treatment and reuse.

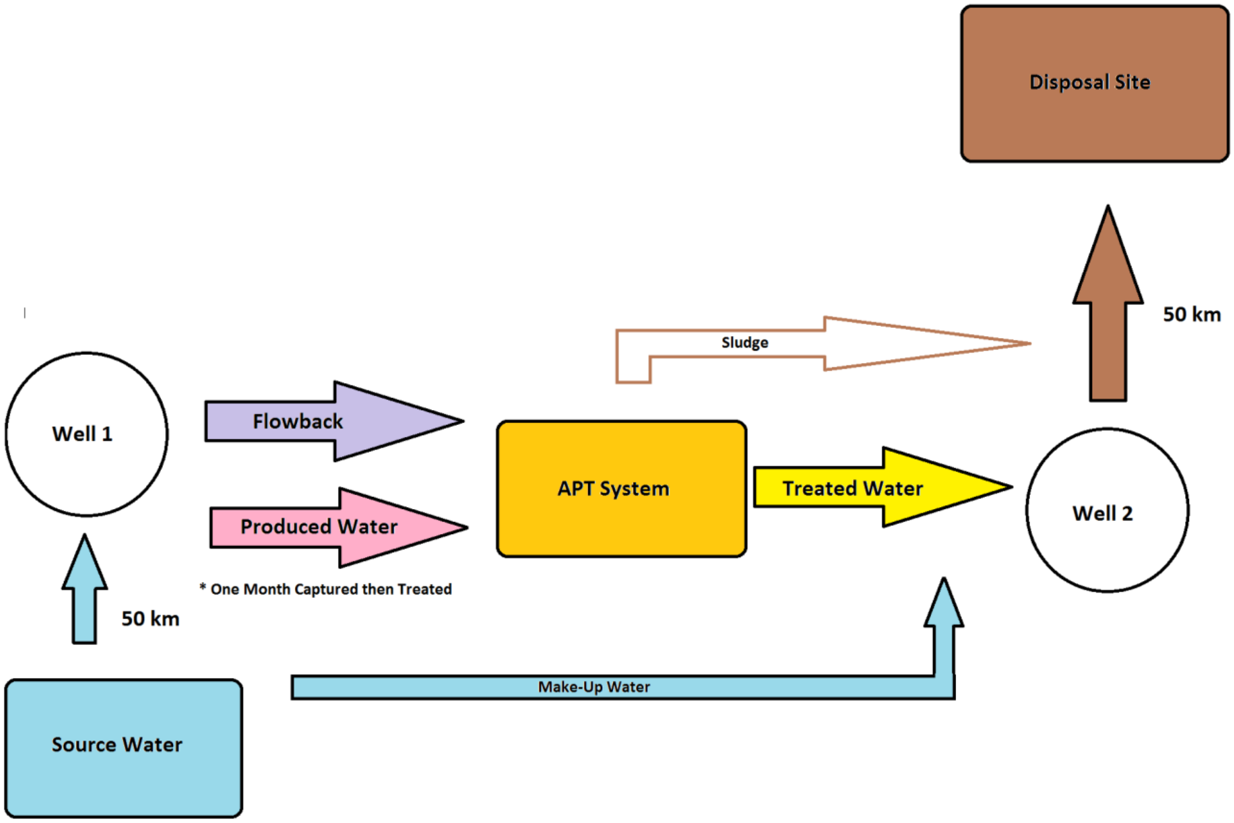
Figure 18 - Flow Diagram of Assessment 1



8.2.9.2 Assessment 2

In order to provide clarity on how adding the treatment and reuse of produced water impacts the economics, a second and third assessment have been completed. The second assessment assumes that the flowback and one month of produced water is captured, treated and reused within the HF operation. This timeframe is considered an acceptable amount of time for reuse of produced water in one HF operation.

Figure 19 - Flow Diagram of Assessment 2



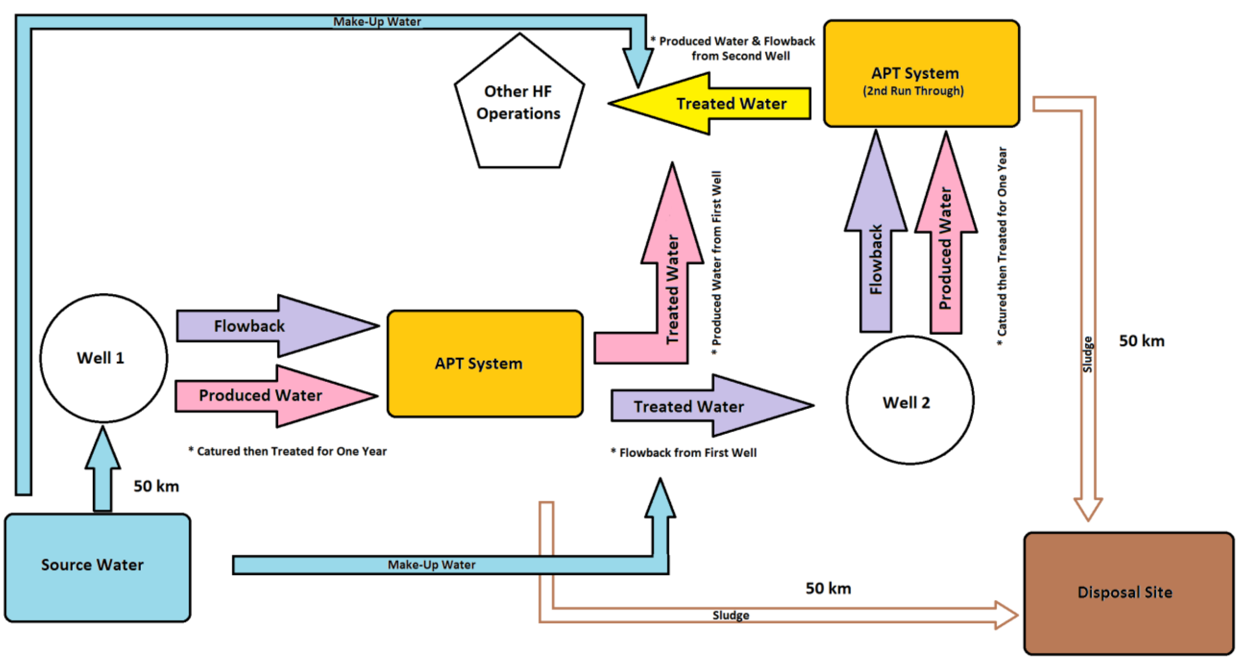
8.2.9.3 Assessment 3

The final assessment expands the scope to include using APT treated produced water for reuse in other HF operations. That said, all previous assumptions stand for these other HF operation.

Furthermore, this assessment only accounts for the reuse of APT treated flowback in the initial HF operation. Instead, all of the APT treated produced water will be sold for one year, using the cost of water withdrawal without an allocation, to identify the revenue potential that exists. In addition, the APT treated flowback for the last well that cannot be used in the initial HF operation, has been included for resale.

Finally, in the third assessment, the yearly income potential of treating produced water from subsequent years with the APT system, then selling the treated water to other HF operation was calculated. From there, the yearly income potential from resale was discounted, using a standard discount rate for O&G projects of 10 percent, in order to estimate of the net present value of the using the APT system over the 10-year life of the wells. Again, all previous assumptions stand.

Figure 20 - Flow Diagram of Assessment 3



8.2.10 Other Assumptions and Statements

All fluids used in this analysis are assumed to have the density of water. As a result, volumes are transferable when comparing all liquids. Similarly, due to lack of data, when referring to produced water, flowback or produced fluids, they are assumed to be of homogeneous water quality.

Moreover, all dollar values are expressed in Canadian currency. If an American dollar value was used in this analysis, no exchange rate was applied.

Table 3 - Summary of Water Use in Economic Assessments

Assessment	**Flowback**	**Produced Water**
Assessment 1	Well One: Treated and reused in initial HF operation. Well Two: Disposal by re-injection	None
Assessment 2	Well One: Treated and reused in initial HF operation. Well Two: Disposal by re-injection	Well One: One month captured, treated and reused in initial HF operation. Well Two: Disposal by re-injection
Assessment 3	Well One: Treated and reused in the second well of the initial HF operation. Well Two: Treated and sold to other HF operations	Captured for ten years, treated and sold to other HF operations.

8.3 Final Results

After completing the analysis of all three assessments, the APT system offers three key cost advantages over deep-well injection; reduced fresh water consumption, reduced transportation costs, and reduced disposal costs.

8.3.1 First Assessment

In the scenario for water withdrawal with a license, the overall cost savings of using APT to treat flowback only was around $290,000. Additionally, when considering the scenario of water withdrawal without a license, cost savings realized were around $434,000.

8.3.1.1 Reduced Water Consumption

In this assessment, water withdrawal was reduced by around six percent. This reduction led to about a $13,000 decrease in costs for water withdrawal in the scenario with an allocation. This reduction is further compounded when considering the scenario of water withdrawal without an allocation which realized a cost savings of around $156,000.

8.3.1.2 Reduced Transportation Costs

Total transportation cost was reduced by around 11 percent. This reduction led to approximately a $257,000 decrease in costs for transportation.

8.3.1.3 Reduced Disposal Costs

Total disposal cost was reduced by over 48 percent. This reduction led to approximately a $99,000 decrease in costs for disposal.

Table 4 - Results Summary of Assessment 1

Assessment 1	**Current Scenario**		**Reuse Scenario**	
	With a Water Allocation	*Without a Water Allocation*	*With a Water Allocation*	*Without a Water Allocation*
Water Withdrawal	70,000 m^3	70,000 m^3	65,778 m^3	65,778 m^3
Water for Reuse	0 m^3	0 m^3	5,746 m^3	5,746 m^3
Water Withdrawal Costs	$210,000	$2,592,100	$197,334	$2,435,764
Fluids Transported	78,750 m^3	78,750 m^3	70, 306 m^3	70, 306 m^3
Transportation Cost	$2,397,739	$2,397,739	$2,139,755	$2,139,755
Produced Water Disposed	0 m^3	0 m^3	0 m^3	0 m^3
Flowback/Sludge Disposed	8,750 m^3	8,750 m^3	4,528m^3	4,528m^3
Disposal Costs	$205,625	$205,625	$106,411	$106,411
Cost of Treatment	$0	$0	$78,750	$78,750
<u>Total Costs</u>	$2,812,000	$5,196,464	$2,522,251	$4,760,680

8.3.2 Second Assessment

This scenario presents a "real world" case for the potential for reusing treated produced fluids in a HF operation. In the scenario for water withdrawal with a license, the overall cost saving of using APT to treat both produced fluids was around $397,000. Additionally, when considering the scenario of water withdrawal without a license, cost savings realized were about $603,000.

8.3.2.1 Reduced Water Consumption

In this assessment, water withdrawal was reduced by almost nine percent. This reduction led to around an $18,000 decrease in costs for water withdrawal in the scenario with an allocation. This reduction is further compounded when considering the scenario of water withdrawal without an allocation which realized a cost savings of over $224,000.

8.3.2.2 Reduced Transportation Costs

Total transportation cost was reduced by almost 15 percent. This reduction led to about a $369,000 decrease in costs for transportation.

8.3.2.3 Reduced Disposal Costs

Total disposal cost was reduced by about 48 percent. This reduction led to around a $123,000 decrease in costs for disposal.

Table 5 - Results Summary of Assessment 2

Assessment 2	**Current Scenario**		**Reuse Scenario**	
	With a Water Allocation	*Without a Water Allocation*	*With a Water Allocation*	*Without a Water Allocation*
Water Withdrawal	70,000 m^3	70,000 m^3	63,942 m^3	63,942 m^3
Water for Reuse	0 m^3	0 m^3	8,244 m^3	8,244 m^3
Water Withdrawal Costs	$210,000	$2,592,100	$191,827	$2,367,785
Fluids Transported	82,555 m^3	82,555 m^3	70,439 m^3	70,439 m^3
Transportation Cost	$2,512,533	$2,512,533	$2,143,808	$2,143,808
Produced Water Disposed	3,805 m^3	3,805 m^3	1,902 m^3	1,902 m^3
Flowback/Sludge Disposed	8,750 m^3	8,750 m^3	4,595 m^3	4,595 m^3
Disposal Costs	$256,988	$256,988	$133,657	$133,657
Cost of Treatment	$0	$0	$112,992	$112,992
Total Costs	$2,979,522	$5,361,622	$2582284	$4,758,243

8.3.3 Third Assessment

This final scenario presents a "perfect world" case for the potential for reusing treated flowback and then selling treated water on the emerging water-license market. In this scenario the cost saving achieved after year one are around $3,530,000 or about $3,210,000 discounted. Additionally, the present value of the savings and income achieved over a 10-year life of the wells is almost $7,000,000.

Figure 21 - Calculation of the Present Value of a Future Cost Savings and/or Income

$$\text{Present Value of a Future Cost Savings and/or Income} = \frac{\text{Annual Cost Savings + Income}}{(1+\text{ Interest Rate})^{\text{Year of Project}}}$$

Table 6 - Calculation of Net Present Value of Cost Savings and Income from Assessment 3

Year	Savings/Income	Net Present Value
1	3,530,471	$3,209,520
2	$650,310	$591,191
3	$650,310	$537,446
4	$650,310	$488,587
5	$650,310	$444,171
6	$650,310	$403,791
7	$650,310	$367,083
8	$650,310	$333,712
9	$650,310	$303,374
10	$650,310	$275,795
Net Present Value of Project		**$6,954,671**

8.3.3.1 Reduced Water Consumption

Total water withdrawal for the initial HF operation actually increased by about 17 percent. This increase came as a result of the additional source water needed to dilute the APT effluent. However, when the treated water that is used in other operations is factored in, water withdrawal was reduced by almost 69 percent for the first year.

8.3.3.2 Reduced Transportation Costs

In this scenario total transportation costs were reduced by around 33 percent for the first year. This reduction led to around a $1,242,000 decrease in costs for transportation in the first year.

8.3.3.3 Reduced Disposal Costs

In this scenario total disposal costs were reduced by almost 95 percent for the first year. This reduction led to approximately a $777,000 decrease in costs for disposal in the first year. The significant reduction here came as a result of only sludge needing to be disposed of and all other water being treated and reused.

Table 7 - Results Summary of Assessment 3

Assessment 3 (Year 1)	**Current Scenario**	**Reuse Scenario**	***In Subsequent Years (Produced Water Only)***
Water Withdrawal	70,000 m^3	81,683 m^3	15,905 m^3
Water for Reuse	0 m^3	5,746 m^3	0 m^3
Water for Resale	0 m^3	65,710m^3	59,964 m^3
Water Withdrawal Costs	$2,592,100	$3,024,738	$588,975
Fluids Transported	124,406 m^3	83,587 m^3	17,503 m^3
Transportation Cost	$3,786,277	$2,543,973	$532,710
Produced Water Disposed	45,656 m^3	0 m^3	0 m^3
Flowback/Sludge Disposed	8,750 m^3	1,904 m^3	1,598 m^3
Disposal Costs	$821,984	$44,749	$37,552
Cost of Treatment	$0	$489,656	$410,906
Revenue	$0	$2,433,227	$2,220,453
Net Costs	$7,200,361	$6,103,117	($650,310)

Table 8 - Summary of Assessment Results

Assessment	**Reduction in Water Consumption**	**Reduction in Transportations Costs**	**Reduction in Disposal Costs**
Assessment 1	6%	11%	48%
Assessment 2	9%	15%	48%
Assessment 3	69%	33%	95%

CHAPTER 9. Limitations, Recommendations and Concluding Remarks

9.1 Limitations

It cannot be stressed enough; every HF well and operation is unique. The source water and produced fluids quality, as well as the water quality requirements of customers vary widely. The results of this research were bases on a very specific set of assumptions. These assumptions include small sample sizes, representative data, as well as data from ranges and averages. With that said, the actual results achieved in the field cannot be exactly predicted.

The assumptions that were made were done so to limit variability to a couple of key criteria. Additionally, the assumptions made have been done in a conservative and realistic manner to represent typical operations as set out by Dragos.

9.2 Recommendations

This paper and the research presented were designed to be a starting point. This section is presented in order to provide opportunities for future researchers to improve the applicability of this research.

9.2.1 Variability of HF Operations

In order to improve the applicability of this research as it pertains to real world operations, future researchers could improve the economic assessment by comparing the results achieved from altering operational parameters. These parameters include; number of wells, volume of water required to frac each well, volumes of produced fluids that need to be treated, wastewater quality, water quality requirements for HF fluid, and the distance to the source water or disposal site.

This research used public information and Dragos' industry expertise and included small sample sizes, representative data, as well as ranges and averages to create a hypothetical operation. Future researchers could improve this model by analyzing ranges for each of the aforementioned parameters. Researchers could assess the impact of using APT to treat wastewater using a variety of scenarios for each parameter. This adjustment would highlight the best and worst case options for using the technology in the field.

9.2.2 Treatment of Source Water

For the purposes of this paper, it was assumed that treating source water before producing HF fluid was not necessary. However, in reality this is often not the case.

Future researcher could improve the economic assessment models to identify if cost savings could be realized by treating the source water with APT compared to traditional pre-treatment methods.

9.2.3 Treatment and Disposal of the Sludge

In the economic assessment presented in this paper, the sludge recovered from the treatment of produced fluids using the APT system is disposed of by re-injection. That said, a number of options exist for treatment and disposal of waste sludge from O&G operations.

Future researchers could examine these options to identify if any additional economic or environmental advantages exist over disposal through re-injection.

9.2.4 Prices for Water

This paper used a dollar value derived from a case study as the cost of water withdrawal without an allocation. Additionally, this same number was used as the price treated water could be sold at on the emerging water-license market. Although cost savings were realized without a market for treated water, the APT system achieved its best results when treated water was sold to other HF operations for reuse.

Future researchers will need to determine how water scarcity will impact O&G operators' ability to acquire the water necessary for operations. Simply put, could treated water even be sold? Furthermore, researchers could develop a more complex model for determining the price water allocations could be sold for on the emerging water-license market.

9.2.5 Examination of Other Environmental Concern

In this paper, only the potential environmental impacts to water from HF operations were explored. Additionally, the assessment model used suggests that the primary decision criteria for Dragos to initiate investment in the APT system are economically driven. However, it was discovered that using the ATP system offers both economic and environmental benefit.

Future researchers could examine whether the APT system offers both economic and environmental benefit in other areas of concern. For instance, the energy use and associate greenhouse gas emissions associated with using the APT system could be compared to those of other treatment options.

9.2.6 Comparison with Other Treatment Options

The purpose of this paper was to identify if there was cost saving potential for using the APT system to treat produced fluids. Although this paper has identified cost saving potential, it does not necessarily mean that it offers the best cost saving available.

The mobile, modular, durable and flexible nature of the APT system were aligned with the Dragos business model and offered advantages over other technologies that were explored.

Future research could identify other technologies that offer similar advantages and that fit into the Dragos business model and use the assessment model to determine which offers a cost advantage.

9.3 Other Opportunities for Future Research

This section is presented in order to speculate on other future research options related to HF operations, water treatment and water reuse.

9.3.1 Alternatives to Water Withdrawal

As the O&G industry gets better at reusing produced fluids, it may also be worthwhile exploring alternative sources of water. Alternatives include municipal wastewater, wastewater from other O&G operations or brackish ground water. Although using these alternative source waters could lead to additional transportation costs, a reduction in fresh water consumption, and water withdrawal costs could be realized.

9.3.2 Reusing ATP Treated Water in Other O&G Activities

The assumptions made in this paper focused reuse solely on HF operations. That said, cost saving and revenue may be available from selling treated water on the emerging water-license market.

Future researchers could alter the criteria of the assessment model to explore reuse options in other O&G activities such as EOR, SAGD or the oil sands. Additionally, some of these operations have large treatment facilities located close by. Future researchers could explore option for selling APT treated water to these facilities, removing the requirement for dilution with additional fresh water. This adjustment could lead to additional cost saving and reduced water consumption.

9.3.3 Secondary Water Treatment

Other O&G operations often require significantly higher quality feed water than HF. Therefore, instead of dilution, another option worth exploring would be to investigate alternative secondary water treatment options.

Produced fluids are often thermodynamically unstable (Vavra, Platt, & Burnett, 2015). Therefore, it becomes necessary to remove partially soluble products such as iron oxide and other scaling compounds through secondary treatment such as desalination (Vavra, Platt, & Burnett, 2015). Choosing a desalination method depends on TDS concentration and the ability of the treatment system to handle the extra contaminants that are present (Arthur, Langhus, & Patel, 2005). Options include evaporation, distillation, membrane filtration, electric separation and chemical treatments to remove TDS.

Thermal distillations may offer another solution to removing TDS. For instance, the PROCECO Éco-Smart® Mechanical Vapor Recompression evaporator can treat water TDS concentrations up to 400,000 mg/L, with water recovery efficiency up to 98 percent (PROCECO, 2016). The biggest systems offered by this company can treat upwards of 43 m^3 per day (PROCECO, 2016). Depending on the cost and the volume requirements of the operation, cost saving and revenue potential could exist due to the extremely high water quality provided by this technology. The water recovered with this technology would be ideal for use in other O&G operations that do not have the tolerance for TDS that HF does.

9.3.4 Water-License Market

As mentioned before, the FITFIR water allocation system used in Alberta is consider antiquated and wasteful. Future researchers could examine other jurisdictions' water allocation system to determine how Alberta could improve its water allocation efficiency. A regulated water-license market that takes water consumed and water returned into account has been suggested as a way to improve allocation and generate economic opportunity in Alberta.

9.3.5 Optimization of Water Management Program

Finally, future researchers could develop a model to determine the optimal reuse and HF schedule to minimize the costs associated with transportation, treatment, storage, and disposal. For instance, in developing a water reuse strategy, it is important to consider the segregation or mixing of produced fluids to be treated and then reused in the HF process. Optimizing the water reuse network could improve the results of these economic assessments in order to reduce costs, water consumptions and the total wastewater disposed.

9.4 Concluding Statements

Despite the assumption and limitations of this analysis, this author is convinced that the APT system can be used to offer Dragos and its partners economic benefit. Even in the scenario where the APT system was used the least and the cost of water withdrawal was the lowest, cost savings were realized. As the use of APT and the cost of water increased, so did the potential for cost savings and revenue generation.

These financial incentives for investment also translate to a reduction in fresh water consumption and impacts on the environment. This too will offer Dragos and its partners a competitive advantage. Positive environmental performance can protect an operator’s license-to-operate or generate goodwill.

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Appendix A – Economic Analysis Assumption List

Assumptions	Unit	Value
Cost of Water (Licence)	$/m3	$3.00
Cost of Water (No Licence)	$/m3	$37.03
Transportation		
Distance from Well to Source	Km	50.00
Distance from Well to Reinjection Site	Km	50.00
Trucking	$/m3	$30.43
Trucking	$/hr	$200.00
Typical Water Truck Volume	m3	23.00
Driving Time (Return)	hrs	1.50
Loading Time	hrs	1.00
Unloading Time	hrs	1.00
Operations		
Volume of Water Used per Fracking Cycle	m3	35,000.00
Number of Fracking Cycles	#	1.00
Number of Wells in Fracking Operation	#	**2.00**
Efficiency of HF Fluid Recovered as Flowback	%	12.50%
Produced Water Volume	m3	22,828.13
Flowback Volume	m3	4,375.00
Days of operation	days	365.25
Volume of Produced Water per day	m3/day	62.50
Source Water TDS (c2)	mg/L	113.48
APT Treated Water TDS (c1)	mg/L	190,500.00
Disposal		
Disposal - Flowback	$/m3	$23.50
Disposal - Produced water	$/m3	$13.50
Treatment		
Efficiency of water recovery APT	%	96.50%
Cost of Treatment with APT	$/m3	$9.00
"Sweet Spot" Concentration for HF (c3)	mg/L	140,000.00
Liters per Cubic Meter	L/m3	1,000.00
Other		
Disposing Sludge cost the same as flowback - Can be stored then mixed with final disposal		
Cost of transportation from well to well is negligible		
Source water does not need to be treated		
Density is consistent for all liquids		
TDS of Effluent from APT system is consistent regardless of feedstock (FB, PW or PF)		
v1c1+v2c2=v3c3 and v3=v1+v2 ; v2=((v1(c1-c3))/(c3-c2))		
Funds are recorded as Canadian dollar		
Discount rate of 10%		

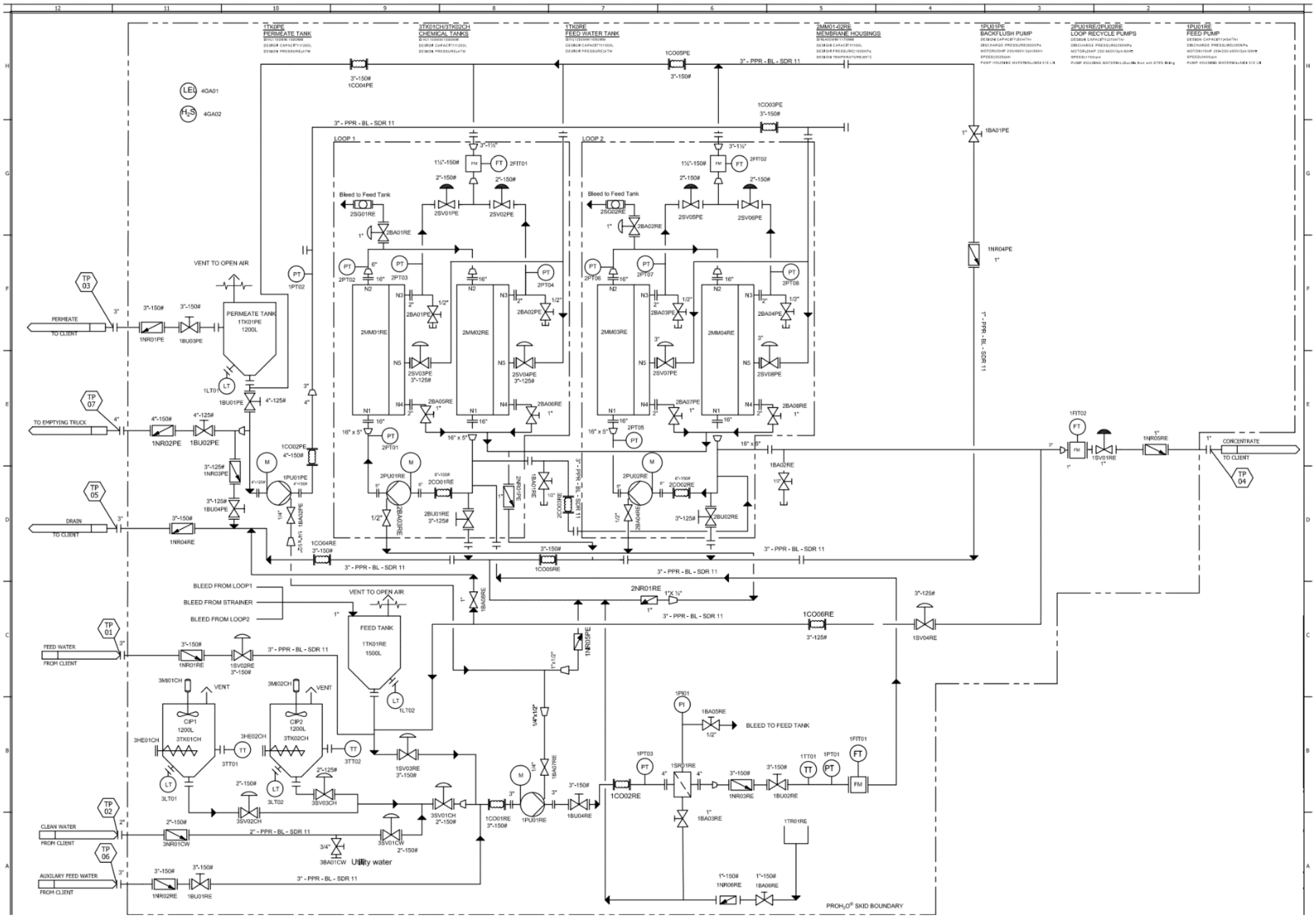
Appendix B – Options for Wastewater Treatment

Technique	Description	Use
Ion Exchange (SAC/WAC)	Vessels containing resin remove hardness ions (calcium and magnesium) as well as other multivalent ions.	- Hardness removal - Multivalent ion removal
Gravity Separation	Used for bulk hydrocarbon removal, a carefully designed gravity separation system ensures maximum effectiveness of installed residence capacities.	- Hydrocarbon removal
Induced Gas / Static Flotation	Gas bubbles introduced into a water stream facilitate the flotation of hydrocarbon within the unit. Commonly used as a secondary oil removal process	- Hydrocarbon removal
Evaporation	Uses thermal or mechanical energy to create a distilled water stream available for reuse.	- Total dissolved solids removal
Ion Exchange (SAC/WAC)	Vessels containing resin remove hardness ions (calcium and magnesium) as well as other multivalent ions.	- Hardness removal - Multivalent ion removal
Lime Softening (Warm & Hot)	Created using a combination of chemicals, a lime sludge bed reduces and removes a variety of contaminants from inlet water.	- Silica removal - Bulk hardness removal - Alkalinity reduction
Filtration	Removes particulate matter in water streams and in the final stages of hydrocarbon removal.	- Hydrocarbon removal - Iron removal - Suspended solids removal
Centrifuges	Removes bulk suspended solids from a water stream, resulting in a sludge and clean centrate stream.	- Suspended solids removal

Membranes	Strips dissolved gas from a water stream, a critical step in meeting water quality requirements for downstream equipment.	- Dissolved gas removal
Inclined Plate Settler (Lamellar Decanter)	Removes large volumes of solids / particulate matter from a water stream.	- Particulate removal
Chemical Treatment	Carefully prepared and measured chemicals injected upstream facilitate other separation methods required for the success of downstream processes	- Oxygen control Precipitation (e.g. oxidation of iron for filtration) - Chemical preparation for use (e.g. flocculants)

SOURCE: (Vista Projects, n.d.)

Appendix C – Detailed Drawing of APT System



Appendix D – Test Results from APT Pilot Unit

SOURCE: (Aqua Pure Technologies Inc., 2015, p. 9)

Appendix E – Field Test Results December 2015

AGAT Laboratories

Certificate of Analysis

AGAT WORK ORDER: 15C052757

PROJECT: CPL 01

2910 12TH STREET NE
CALGARY, ALBERTA
CANADA T2E 7P7
TEL (403)735-2005
FAX (403)735-2771
http://www.agatlabs.com

CLIENT NAME: MISC AGAT CLIENT AB
SAMPLING SITE:

ATTENTION TO: Trevor Noon
SAMPLED BY:

Routine Chemistry Water Analysis

DATE RECEIVED: 2015-12-14 | **DATE REPORTED: 2015-12-15**

			SAMPLE DESCRIPTION:	CPL Feed Water		CPL Permeate
			SAMPLE TYPE:	Water		Water
			DATE SAMPLED:	12/11/2015		12/11/2015
Parameter	**Unit**	**G / S**	**RDL**	**7283043**	**RDL**	**7283045**
pH	pH Units		0.02	6.80	0.02	6.87
p - Alkalinity (as CaCO3)	mg/L		5	<5	5	<5
T - Alkalinity (as CaCO3)	mg/L		5	82	5	78
Bicarbonate	mg/L		5	100	5	95
Carbonate	mg/L		5	<5	5	<5
Hydroxide	mg/L		5	<5	5	<5
Electrical Conductivity	uS/cm		50	312000	50	309000
Chloride	mg/L		40	116000	40	120000
Fluoride	mg/L		1	2	1	1
Nitrate	mg/L		8	<8	8	<8
Nitrate-N	mg/L		0.02	<0.02	0.02	<0.02
Nitrite	mg/L		4.0	<4.0	4.0	<4.0
Nitrite-N	mg/L		0.01	<0.01	0.01	<0.01
Nitrate+Nitrite - Nitrogen	mg/L		0.02	<0.02	0.02	<0.02
Sulfate	mg/L		6	309	6	304
Dissolved Calcium	mg/L		10	7590	1	7790
Dissolved Magnesium	mg/L		20	1330	2	1340
Dissolved Sodium	mg/L		20	56700	20	52500
Dissolved Potassium	mg/L		30	2870	3	3070
Dissolved Iron	mg/L		2	9	0.2	0.8
Dissolved Manganese	mg/L		0.05	9.98	0.005	9.14
Calculated TDS	mg/L		0.6	185000	0.6	185000
Sodium Adsorption Ratio	N/A			158		144
Hardness	mg CaCO3/L		1	24400	1	25000
Ion Balance	%		1	92	1	84

Comments: RDL - Reported Detection Limit; G / S - Guideline / Standard
7283043-7283045 < - Values refer to Report Detection Limits.

If sodium results in mg/L are less than detection, SAR is non-calculable and is reported as 0.

SOURCE: (AGAT Laboratories, 2015, p. 3)

AGAT Laboratories

2910 12TH STREET NE
CALGARY, ALBERTA
CANADA T2E 7P7
TEL (403)735-2005
FAX (403)735-2771
http://www.agatlabs.com

Quality Assurance

CLIENT NAME: MISC AGAT CLIENT AB
PROJECT: CPL 01
SAMPLING SITE:

AGAT WORK ORDER: 15C052757
ATTENTION TO: Trevor Noon
SAMPLED BY:

Water Analysis

RPT Date: Dec 15, 2015			DUPLICATE				REFERENCE MATERIAL			METHOD BLANK SPIKE			MATRIX SPIKE		
PARAMETER	Batch	Sample Id	Dup #1	Dup #2	RPD	Method Blank	Measured Value	Acceptable Limits Lower	Acceptable Limits Upper	Recovery	Acceptable Limits Lower	Acceptable Limits Upper	Recovery	Acceptable Limits Lower	Acceptable Limits Upper
Routine Chemistry Water Analysis															
pH	7283043		6.80	6.61	2.8%	< 0.02	101%	90%	110%						
T - Alkalinity (as CaCO3)	7283043		82	72	13.0%	< 5	101%	80%	120%						
Electrical Conductivity	7173419		33500	33700	0.6%	< 5	104%	80%	120%						
Chloride	7283043	7283043	116000	117000	0.1%	< 1	105%	80%	120%	97%	80%	120%	NA	80%	120%
Fluoride	7283043	7283043	<12	<12	NA	< 0.01	109%	80%	120%	90%	80%	120%	109%	80%	120%
Nitrate	7283043	7283043	<80	<80	NA	< 0.1	106%	80%	120%	99%	80%	120%	114%	80%	120%
Nitrite	7283043	7283043	<40	<40	NA	< 0.05	105%	80%	120%	99%	80%	120%	113%	80%	120%
Sulfate	7283043	7283043	287	286	0.0%	< 1	105%	80%	120%	100%	80%	120%	113%	80%	120%
Dissolved Calcium	7278280		5.2	5.4	3.3%	< 0.3	104%	80%	120%	114%	80%	120%	103%	80%	120%
Dissolved Magnesium	7278280		1.5	1.5	0.0%	< 0.2	98%	80%	120%	96%	80%	120%	96%	80%	120%
Dissolved Sodium	7278280		497	492	1.0%	< 0.6	92%	80%	120%	92%	80%	120%	NA	80%	120%
Dissolved Potassium	7278280		1.6	1.7	NA	< 0.6	100%	80%	120%	96%	80%	120%	100%	80%	120%
Dissolved Iron	7278280		<0.1	<0.1	NA	< 0.1	109%	80%	120%	105%	80%	120%	106%	80%	120%
Dissolved Manganese	7278280		0.008	0.008	NA	< 0.005	101%	80%	120%	103%	80%	120%	104%	80%	120%

Comments: If Matrix spike value is NA, the spiked analyte concentration was lower than that of the matrix contribution.
If the RPD value is NA, the results of the duplicates are under 5X the RDL and will not be calculated.

pH has been analyzed past the recommended holding time of 15 minutes from sampling (field measurement ideal if more accurate data required)

Nitrate and Nitrite: The regulatory hold time for the analysis of nitrate and/or nitrite in water is 48 hours in Alberta and 72 hours in British Columbia.

PARAMETER	Batch	Sample Id	Dup #1	Dup #2	RPD	Method Blank	Measured Value	Lower	Upper	Recovery	Lower	Upper	Recovery	Lower	Upper
Water Analysis - Total Solids															
Total Dissolved Solids	7275758		275	235	15.7%	< 5	83%	80%	120%						
Total Suspended Solids	189	1340	175	179	2.3%	< 2	85%	80%	120%				91%	80%	120%

Comments: If the RPD value is NA, the results of the duplicates are under 5X the RDL and will not be calculated.

PARAMETER	Batch	Sample Id	Dup #1	Dup #2	RPD	Method Blank	Measured Value	Lower	Upper	Recovery	Lower	Upper	Recovery	Lower	Upper
Water Analysis - COD															
Chemical Oxygen Demand	1037	043	1100	1110	0.9%	< 1	101%	80%	120%	101%	80%	120%	100%	80%	120%

Comments: If the RPD value is NA, the results of the duplicates are under 5X the RDL and will not be calculated.

SOURCE: (AGAT Laboratories, 2015, p. 8)