

REUSE OF FLOWBACK & PRODUCED WATER FOR HYDRAULIC FRACTURING IN TIGHT OIL

PREPARED FOR: THE PETROLEUM TECHNOLOGY ALLIANCE CANADA (PTAC)

PREPARED BY: ROBERTA WASYLISHEN, WASTE WATER TECHNOLOGIST
SARAH FULTON, WATER COORDINATOR, ENVIRONMENT AND RECLAMATION

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ABSTRACT

The objective of the Reuse of Flowback & Produced Water for Hydraulic Fracturing in Tight Oil assessment is to evaluate potential opportunities to reduce freshwater consumption and waste through reuse of produced and/or flowback waters as sources of base fluid for hydraulic fracturing. The evaluation requires quantification and characterization of various tight oil hydraulic fracturing flowback and produced waters and characterization of the desired quality of the base fluid for reuse. This information is used to evaluate integrated treatment technology objectives for water reuse in multi-stage hydraulic fracturing applications within tight oil resource plays. This evaluation framework will assist industry peers in developing enhanced water treatment and recycling best practices in similar applications.

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PREFACE

The findings of this paper are intended to specifically appeal to individuals with a completions background seeking to expand their understanding of flowback and produced water reuse as it pertains to hydraulic fracturing in tight oil as well as individuals with a water treatment background seeking to further expand their understanding of the hydraulic fracturing requirements within tight oil. Additional audiences that may benefit from the research findings include hydraulic fracturing service companies, chemical manufactures, water treatment service companies, regulators and other stakeholders with a general interest in water management as it pertains to hydraulic fracturing within tight oil.

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1.0 INTRODUCTION

Technological advances in horizontal drilling and multi-stage hydraulic fracturing are the primary mechanisms facilitating tight oil production within low permeability reservoirs throughout the Western Canada Sedimentary Basin (WCSB) (National Energy Board, 2011). The combination of technological innovation, an improved royalty scheme within Alberta and regulatory changes permitting tighter down-spacing of wells has accelerated industry's interest in the development of tight oil reserves (Stonehouse, 2011). However, the expedited rate of tight oil development is creating new challenges, including identifying sustainable supplies of source water for hydraulic fracturing and management of water-based hydraulic fracturing flowback fluids. Recycling flowback can offset hydraulic fracturing fresh water source requirements while avoiding the cost associated with flowback disposal. In geographic areas where hydraulic fracturing coincides with existing oil production, the opportunity to incorporate produced water recycling may further reduce industry's reliance on fresh source waters for hydraulic fracturing.

The magnitude of treatment required to facilitate water reuse is defined by the difference between the quality of the initial flowback and/or produced waters in comparison to the desired hydraulic fracturing source water specifications. By characterizing the quality of these fluids in detail and evaluating the technologies available to achieve the treatment objective, this assessment identifies various treatment approaches for reuse of tight oil hydraulic fracturing flowback and produced waters within the WCSB.

2.0 TIGHT OIL INDUSTRY OVERVIEW

The advancements in both horizontal drilling and multi-stage fracturing technologies combined with higher oil prices have "given new life to previously low-producing or unproductive (tight) oil reservoirs in the WCSB" (National Energy Board, 2011). At present, the key resource plays targeted for tight oil development within Canada spanning across the WCSB include the Bakken/Exshaw, Cardium, Viking, Lower Shaunavon, Montney/Doig, Duvernay/Muskwa, Beaver Hill Lake Group and Lower Amaranth. The respective formation locations, typical depths, reported reserves and typical production rates per well are outlined below in Table 1.

TABLE 1: WESTERN CANADA SEDIMENTARY BASIN TIGHT OIL FORMATIONS

FORMATIONS	TYPE	LOCATION	TYPICAL DEPTHS (M)	REPORTED RESERVES (MILLION BARRELS)	TYPICAL INITIAL PRODUCTION RATES PER WELL (BARRELS PER DAY)
BAKKEN/EXSHAW	TIGHT	MB, SK, AB & BC	900-2,500	225	120-250
CARDIUM	TIGHT	AB	1,200-2,300	130	150-500
VIKING	TIGHT	AB & SK	600-900	58	100-200
LOWER SHAUNAVON	TIGHT	SK	1,300-1,600	93	100-250
MONTNEY/DOIG	TIGHT	AB	800-2,200	NR	200-600
DUVERNAY/MUSKWA ¹	SHALE	AB	2,000+	NR	UNKNOWN
BEAVER HILL LAKE GROUP	TIGHT	AB	2,000-2,900	NR	250-2,000
LOWER AMARANTH	TIGHT	MB	800-1,000	NR	100-200

¹DUVERNAY/MUSKWA FORMATION EXPANDS INTO BC, ALTHOUGH THE SHALE OIL PORTION OF THE FORMATION RESIDES PREDOMINANTLY WITHIN AB

BC: BRITISH COLUMBIA

AB: ALBERTA

SK: SASKATCHEWAN

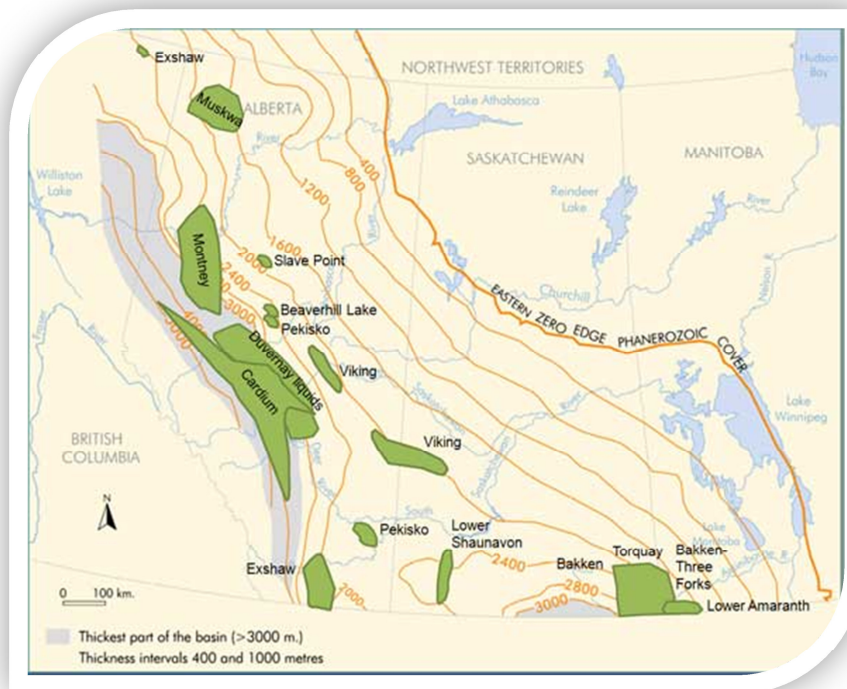
MB: MANITOBA

NR: NOT REPORTED

SOURCE: NATIONAL ENERGY BOARD. (2011, DECEMBER). *TIGHT OIL DEVELOPMENTS IN THE WESTERN CANADA SEDIMENTARY BASIN*. RETRIEVED JANUARY 13, 2012, FROM NATIONAL ENERGY BOARD: [HTTP://WWW.NEB-ONE.GC.CA/CLF-NSI/RNRNGYNFMTN/NRGRYPRPT/L/TGHTDVLPMNTWCSB2011/TGHTDVLPMNTWCSB2011-ENG.HTML](http://www.neb-one.gc.ca/clf-nsi/rnrngynfMTN/NRGRYPRPT/L/TGHTDVLPMNTWCSB2011/TGHTDVLPMNTWCSB2011-ENG.HTML). REPRODUCED WITH THE PERMISSION OF PUBLIC WORKS AND GOVERNMENT SERVICES, 2012.

As the development of tight oil resources progresses, it is anticipated that additional formation will be targeted. Further prospective tight oil formations as outlined by the National Energy Board include Second White Specks, Nordegg, and Pekisko. Figure 1 outlines the geographic landscape of current tight oil development activities.

FIGURE 1: MAP OF WESTERN CANADA SEDIMENTARY BASIN TIGHT OIL FORMATIONS



SOURCE: NATIONAL ENERGY BOARD. (2011, DECEMBER). *TIGHT OIL DEVELOPMENTS IN THE WESTERN CANADA SEDIMENTARY BASIN*. RETRIEVED JANUARY 13, 2012, FROM NATIONAL ENERGY BOARD: [HTTP://WWW.NEB-ONE.GC.CA/CLF-NSI/RNRGYNFMTN/NRGRPRPT/L/TGHTDVLPMNTWCSB2011/TGHTDVLPMNTWCSB2011-ENG.HTML](http://www.neb-one.gc.ca/CLF-NSI/RNRGYNFMTN/NRGRPRPT/L/TGHTDVLPMNTWCSB2011/TGHTDVLPMNTWCSB2011-ENG.HTML). REPRODUCED WITH THE PERMISSION OF PUBLIC WORKS AND GOVERNMENT SERVICES & THE UNIVERSITY OF REGINA, 2012.

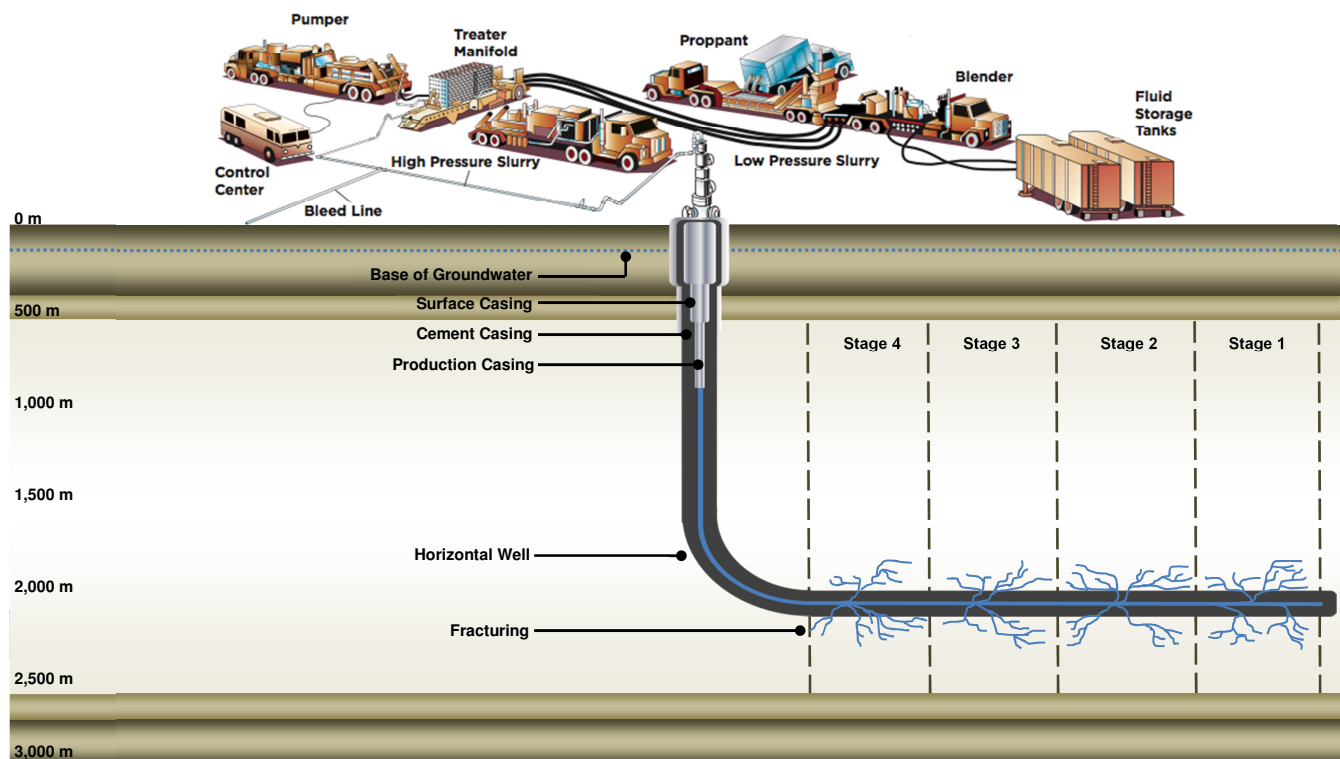
Although exploration of tight oil reservoirs in Canada remains in its infancy, preliminary data suggests more than 506 million barrels of reported reserves remain within the WCSB Bakken/Exshaw, Cardium, Viking and Lower Shaunavon formations (National Energy Board, 2011). As tight oil developments evolve and additional information is compiled, the projected tight oil reserves in place “may very well add billions of barrels to Canada’s oil reserves” (U.S. Energy Information Administration, 2011).

3.0 HYDRAULIC FRACTURING PROCESS

The purpose of hydraulic fracturing is to “increase the exposed flow area of the productive formation and to connect this area to the well by creating a highly conductive path extending a carefully planned distance outward from the well bore into the targeted hydrocarbon-bearing formation” (American Petroleum Institute, 2010, p. 6). This may be achieved by pumping a base fluid consisting of water, foam or oil containing small concentrations of chemical additives as well as proppant material.

As the pressurized fluid is pumped into the well, “narrow cracks (fractures) expand outward... that serve as flowing channels for... hydrocarbons trapped in the formation to move to the wellbore” (American Petroleum Institute, 2010, p. 6). The newly formed fractures are supported by the proppant material which ensures enhanced permeability as the well transitions to production mode (American Petroleum Institute, 2010, p. 5). Once the hydraulic fracture stimulation is complete, a portion of the original frac fluid combined with comingled constituents from the formation water flows back to the surface where it is either treated for reuse or trucked off site for disposal. The process of multi-stage hydraulic fracturing as it applies to horizontal wells is outlined in Figure 2.

FIGURE 2: MULTI-STAGE HYDRAULIC FRACTURING IN A HORIZONTAL WELL



SOURCES: ADAPTED FROM NATIONAL ENERGY TECHNOLOGY LABORATORY. (2000, AUGUST 24). HYDRAULIC FRACTURING. RETRIEVED MAY 17, 2012 FROM NETL: [HTTP://WWW.NETL.DOE.GOV/TECHNOLOGIES/OILGAS/PUBLICATIONS/EORDRAWINGS/BW/BWHF.PDF](http://www.netl.doe.gov/technologies/oilgas/publications/eordrawings/BW/BWHF.PDF)
 CANADIAN SOCIETY FOR UNCONVENTIONAL RESOURCES. (2012, MAY 9). UNDERSTANDING HYDRAULIC FRACTURING. RETRIEVED MAY 17, 2012 FROM CSUR: [HTTP://WWW.CSUR.COM/IMAGES/CSUG_PUBLICATIONS/HYDR_FRAC_FINAL_CSUR.PDF](http://www.csur.com/images/CSUG_PUBLICATIONS/HYDR_FRAC_FINAL_CSUR.PDF)

4.0 HYDRAULIC FRACTURING FLUID SELECTION

Selection of the base fluid for hydraulic fracturing is dependent upon numerous variables including, but not limited to: reservoir temperature, reservoir pressure, the expected value of fracture half-length, and a determination if the reservoir is water sensitive (U.S. Department of Energy, 2004, p. 16). Examples of fracturing fluids and conditions for their use have been summarized below in Table 2.

TABLE 2: EXAMPLES OF FRACTURING FLUIDS & CONDITIONS FOR THEIR USE

BASE FLUID	FLUID TYPE	MAIN COMPOSITION	USED FOR
WATER BASED	LINEAR FLUIDS	GELLED WATER, GUAR, HPG, HEC, CMHPG	SHORT FRACTURES, LOW TEMPERATURES
	CROSSLINKED FLUIDS	CROSSLINKER + GUAR, HPG, CMHPG, CMHEC	LONG FRACTURES, HIGH TEMPERATURES
	ENERGIZED CROSSLINKED FLUIDS	FLUIDS WITH UP TO 40% N ₂ OR CO ₂	IMPROVED FLOWBACK
	POLYMER FREE FLUIDS	WATER + VES SURFACTANT	REDUCED FRACTURE FACE DAMAGE
FOAM BASED	SLICKWATER FLUIDS	WATER + POLY ACRYLAMIDE	MULTIPLE FRACTURES
	WATER-BASED FOAM	WATER AND FOAMER + N ₂ OR CO ₂	LOW PRESSURE FORMATIONS
	ACID-BASED FOAM	ACID AND FOAMER + N ₂	LOW PRESSURES, WATER SENSITIVE FORMATIONS
OIL BASED	ALCOHOL-BASED FOAM	METHANOL AND FOAMER + N ₂	LOW PRESSURE FORMATIONS WITH WATER BLOCKING PROPERTIES
	LINEAR FLUIDS	OIL, GELLED OIL	SHORT FRACTURES, WATER SENSITIVE FORMATIONS
	CROSSLINKED FLUIDS	PHOSPHATE ESTER GELS	LONG FRACTURES, WATER SENSITIVE FORMATIONS
	WATER EXTERNAL EMULSIONS	WATER + OIL + EMULSIFIER	GOOD FOR FLUID LOSS CONTROL

HPG: HYDROXYPROPYL GUAR
 HEC: HYDROXYETHYLCELLULOSE
 CMHPG: CARBOXYMETHYLHYDROXYPROPYL GUAR
 CMHEC: CARBOXYMETHYLHYDROXYETHYLCELLULOSE

SOURCE: ADAPTED FROM UNITED STATES DEPARTMENT OF ENVIRONMENTAL PROTECTION AGENCY APPENDIX A HYDRAULIC FRACTURING WHITE PAPER EPA 816-R-04-003, P. A-6

The optimum hydraulic fracturing fluid for each well is normally determined “after reviewing the treatment objectives and evaluating the adequacy of the fluid system’s performance in fluid-loss control, fracture conductivity, and proppant transport, as well as in the amount of formation permeability damage” (Dusterhoft, McGowen, & Ghalambor, 2009, p. 33). Ideally, the selected fluid system should promote “placement of the frac-pack treatment, minimize associated risks, and maximize post-treatment production economics” (Dusterhoft, McGowen, & Ghalambor, 2009, p. 33).

Although both foam and oil based hydraulic fracturing fluids may be utilized within tight oil developments, for the purpose of this paper, the authors will be focusing exclusively on the usage of water as the base-fluid for hydraulic fracturing as it applies within tight oil developments throughout the WCSB.

5.0 METHODOLOGY

In order to evaluate the reuse of flowback and produced water for hydraulic fracturing in tight oil as it applies to industry, the authors of this paper focused on Penn West Exploration’s four primary tight oil resource plays: Cardium, Carbonates (Slave Point), Colorado Group (Viking), and Waskada/Spearfish (Lower Amaranth). The methodology applied encompasses:

- Quantification of tight oil water-based hydraulic fracturing water requirements
- Quantification of anticipated flowback volumes per resource play
- Characterization of water-based crosslinked hydraulic fluids
- Evaluation of target constituents requiring treatment
- Characterization of frac (source), flowback and produced waters

5.1 WATER REQUIREMENTS

Understanding that the volume of water required for hydraulic fracturing throughout the WCSB will vary extensively depending on the “formation depth, formation permeability, in-situ stresses in the pay zone, in-situ stresses in the surrounding layers, formation modulus, reservoir pressure, formation porosity, formation compressibility, and the thickness of the reservoir” (U.S. Department of Energy, 2004, p. 3), the average tight oil development water requirements utilized by Penn West Exploration are provided in Table 3.

TABLE 3: PENN WEST EXPLORATION TIGHT OIL DEVELOPMENT SUMMARY & HYDRAULIC FRACTURING WATER REQUIREMENTS

RESOURCE PLAY	FORMATION	VERTICAL DEPTH (M)	PAY THICKNESS (M)	HZ LATERAL LENGTH (M)	FRAC REQUIREMENTS			2011 HZ WELLS DRILLED	AVERAGE API (°)	90 DAY EXIT RATE BOE/D/WELL
					# OF STAGES	TONS PER STAGE	WATER (M ³ /WELL)			
CARDIUM	TIGHT SANDSTONE	1,800	20	1,400	20	20	1,000	10 ¹	40	165
CARBONATES (SLAVE POINT)	TIGHT CARBONATES	2,300	NR	1,400	20	30	2,400	40	40	190
COLORADO GROUP (VIKING)	TIGHT SANDSTONE	700	15	800	14	10	500	85	34	55
WASKADA/SPEARFISH (LOWER AMARANTH)	TIGHT SANDSTONE	900	25-30	800	20	5	700	95	31	95

¹ A TOTAL OF 100 HORIZONTAL WELLS WERE DRILLED WITHIN THE CARDIUM IN 2011, HOWEVER ONLY 10 OF THESE WELLS WERE COMPLETED WITH WATER-BASED FLUIDS.

HZ: HORIZONTAL WELLS

BOE/D/WELL: BARREL OF OIL EQUIVALENTS PER DAY PER WELL

NR: NOT REPORTED

TONS PER STAGE: PROPPANT ONLY

For comparative purposes, Penn West Exploration’s average shale gas hydraulic fracturing water requirements for the Cordova resource are outlined in Table 4.

TABLE 4: PENN WEST EXPLORATION SHALE GAS DEVELOPMENT SUMMARY & HYDRAULIC FRACTURING WATER REQUIREMENTS

RESOURCE PLAY	FORMATION	VERTICAL DEPTH (M)	PAY THICKNESS (M)	HZ LATERAL LENGTH (M)	FRAC REQUIREMENTS			2011 HZ WELLS DRILLED	AVERAGE API (°)	90 DAY EXIT RATE BOE/D/WELL
					# OF STAGES	TONS PER STAGE	WATER (M ³ /WELL)			
CORDOVA	TIGHT SHALE	1,800	150	2,000	20	250	70,000	24	N/A	500 ¹

HZ: HORIZONTAL WELLS
 BOE/D/WELL: BARREL OF OIL EQUIVALENTS PER DAY PER WELL
 NR: NOT REPORTED
 TONS PER STAGE: PROPPANT ONLY
¹Dry Gas

Although the hydraulic fracturing water requirements per tight oil well are significantly less than those for shale gas, the increased tight oil development activity represents a potentially significant opportunity for innovation in alternative sources of water. Consequently, consideration of developing flowback and produced water treatment strategies to facilitate reuse in hydraulic fracturing represents a considerable opportunity to further reduce Penn West Exploration’s reliance on fresh water resources.

5.2 FLOWBACK

The volume of water and sand (flowback) that returns through the borehole to surface from hydraulic fracturing stimulations varies predominantly due to the type of fracturing fluid used, the formation’s geology and the length of well shut-in time between when the well is stimulated and when fluids are flowed back (Environmental & Regulatory Subgroup of the Operations & Environment Task Group, 2011, p. 11). Across Penn West Exploration operations, these flowback volumes range between 5 and 50% of the original fluid volume. Based upon the combination of average water requirements and average flowback volumes per resource play, the cumulative water requirements and flowback volumes anticipated from each tight oil resource play are summarized in Table 5.

TABLE 5: PENN WEST EXPLORATION 2011 TIGHT OIL DEVELOPMENT WATER-BASED HYDRAULIC FRACTURING OVERVIEW

RESOURCE PLAY	2011 HZ WELLS	AVERAGE WATER REQUIREMENTS (M ³ /WELL)	CUMULATIVE WATER REQUIREMENTS PER RESOURCE PLAY (M ³)	AVERAGE FLOWBACK VOLUMES ² (M ³ /WELL)	CUMULATIVE FLOWBACK VOLUMES PER RESOURCE PLAY (M ³)	WATER-BASED FRAC FLUID TYPE
CARDIUM	10 ¹	1,000	10,000	500	5,000	ENERGIZED CROSSLINKED
CARBONATES (SLAVE POINT)	40	2,400	96,000	960	38,400	CROSSLINKED
COLORADO GROUP (VIKING)	85	500	42,500	100	8,500	ENERGIZED CROSSLINKED
WASKADA/SPEARFISH (LOWER AMARANTH)	95	700	66,500	35	3,325	CROSSLINKED
TOTAL	230		217,452		86,955	

¹ A TOTAL OF 100 HORIZONTAL WELLS WERE DRILLED WITHIN THE CARDIUM IN 2011, HOWEVER ONLY 10 OF THESE WELLS WERE COMPLETED WITH WATER-BASED FLUIDS.
² BASED ON AVERAGE FLOWBACK VOLUME PER RESOURCE PLAY

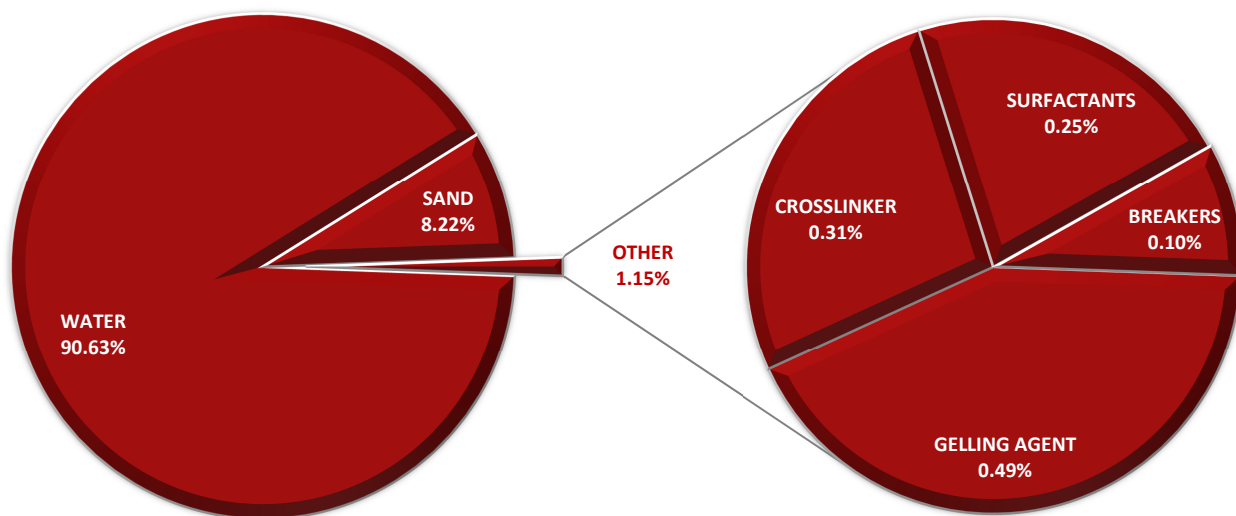
From this data, the Carbonates (Slave Point) suggests the greatest potential opportunity for flowback reuse as this resource play presently represents the largest cumulative water requirements and the greatest volume of cumulative flowback. Assuming 2011 drilling activities are representative of future operations, implementation of a flowback water reuse strategy within the Carbonates (Slave Point) suggests a potential opportunity to reduce Penn West Exploration’s overall fresh water dependency for hydraulic fracturing by up to 17%¹, assuming reuse of all flowback.

¹ $\frac{\text{Carbonates (Slave Point) Cumulative Flowback Volume}}{\text{Total Cumulative Water Requirements for Tight Oil Hydraulic Fracturing}} \times 100 = \% \text{ Opportunity to Reduce Fresh Water Dependency}$

5.3 FLUID COMPOSITION

From evaluation of various frac programs for each Penn West Exploration tight oil play, the most commonly applied stimulation chemistry consists of a water-based crosslinked fluid. On average, the water-based crosslinked hydraulic fluid composition was determined to consist of approximately 90.63% water, 8.22% proppant (sand) with the remaining 1.15% fluid volume consisting of additional frac chemistries. The additional fracturing fluid chemistries may include any combination of the following: gelling agents, crosslinkers (boron, zirconium, iron or titanium), surfactants, scale inhibitors, pH buffers, breakers, iron control agents, corrosion inhibitors and/or biocides (Canadian Society for Unconventional Resources, 2012, p. 23). A summary of the Tight Oil Development Water-Based Crosslinked Hydraulic Fracturing Fluid Composition is provided in Figure 3.

FIGURE 3: TIGHT OIL DEVELOPMENT WATER-BASED CROSSLINKED HYDRAULIC FLUID COMPOSITION



Although the overall percentages of water-based crosslinked hydraulic fluid chemistries are quite low, the impact of these residual chemistries within flowback waters must be considered. Recycled flowback containing residual crosslinker and/or breaker chemistries may result in gel degradation potentially compromising the desired hydraulic fracturing fluid integrity required for subsequent stimulations. In addition to fluid compatibility concerns, residual gelling agents present within flowback waters may impede the technological efficiencies of the water treatment equipment.

5.4 TARGET CONSTITUENTS REQUIRING TREATMENT

The decision regarding which water constituents should be targeted for flowback/produced water reuse is driven by two factors. Firstly, any treated water source must remain compatible with the desired fluid system for the respective tight oil development area. Secondly, removal of constituents within the flowback and produced water sources may be required to mitigate the fouling, scaling and corrosion potential certain species may have both within the reservoir as well as on the selected water treatment equipment.

Presently, where hydraulic fracturing operations rely solely on fresh water sources, limited pre-treatment is required to ensure hydraulic fracturing fluid compatibility. In most cases, pre-treatment is limited to the application of biocide and filtration to eliminate bacteria and remove suspended solids that may be present within the fresh water. During the stimulation process, the hydraulic fracturing fluids comingle with the formation water to create a flowback water containing potentially elevated concentrations of contaminants. The potential flowback water contaminants include residual hydraulic fracturing fluid chemistries, iron, total hardness, alkalinity, silica, bacteria and solids. The increase in concentration of these species is known to have detrimental impacts on the fluid compatibility of water-based crosslinked hydraulic fracturing fluid systems. In most cases, the desired viscosity and thermal stability of the water-based crosslinked

fluid is compromised either through chemical, mechanical or biological degradation resulting in hindered proppant carrying capacity of the hydraulic fracturing stimulation fluid (Aqualon, 2007, pp. 15-24). An inability to achieve the desired fluid viscosity and the required proppant carrying capacity of the water-based crosslinked fluid will hinder the effectiveness of the stimulation. Without the appropriate distribution of proppant into the opened fractures, the newly formed fractures may close once the fracturing pressures are released (LaFollette, 2010, p. 13). Consequently, to mitigate water-based crosslinked fluid compatibility concerns, Table 6 outlines water quality guidelines for preventing undesired hydration rate reactions, overcrosslinking, delayed crosslinking, thermal destabilization, viscosity inhibition, gelling agent precipitation as well as chemical and biological degradation.

TABLE 6: WATER QUALITY GUIDELINES TO MITIGATE HYDRAULIC FRACTURING FLUID COMPATIBILITY ISSUES FOR CROSSLINKED FLUIDS

WATER QUALITY PARAMETER	UNITS	TARGET	RATIONALE
pH	N/A	6-8	<ul style="list-style-type: none"> pH >8 may impede the rate and quality of hydration of the water-based crosslinked fluid. pH <6 may accelerate the rate of hydration of the water-based crosslinked fluid, creating gel balls, lumping or 'fish eyes'.
Iron	mg/L	<25	<ul style="list-style-type: none"> >25 ppm iron may alter the valence state of certain crosslinkers or act as a catalyst for oxidizing polysaccharide gelling agents resulting in chemical degradation of the water-based crosslinked fluid. Excessive iron concentrations may also result in over crosslinking of the fluid, premature breaking of oxidative breakers, and/or loss of thermal stability of the water-based crosslinked fluid.
Total Hardness	mg/L (as CaCO ₃)	<15,000	<ul style="list-style-type: none"> Total hardness concentrations >15,000 ppm may prevent desired water-based crosslinked fluid viscosity, crosslinking effectiveness, as well as thermal and shear stability.
Oxidizing Agents	N/A	0	<ul style="list-style-type: none"> May result in chemical degradation of the water-based crosslinked fluid. Oxidizing agents may include residual breaker chemistries (sodium hypochlorite) present within the flowback waters.
Reducing Agents	N/A	0	<ul style="list-style-type: none"> May result in chemical degradation of the water-based crosslinked fluid. Reducing agents may include residual crosslinker chemistries (boron, iron, titanium, zirconium, etc.) present in flowback waters.
Carbonate	mg/L (as CaCO ₃)	<600	<ul style="list-style-type: none"> HCO₃⁻ >600 ppm may delay crosslinking of some fluids.
Bicarbonate	mg/L (as CaCO ₃)	<600	<ul style="list-style-type: none"> CO₃²⁻ >600 ppm may delay crosslinking of some fluids.
Silica	mg/L	<35	<ul style="list-style-type: none"> May inhibit the crosslinking effectiveness of water-based crosslinked fluids.
Bacteria	CFU/mL	0	<ul style="list-style-type: none"> May result in biological degradation of water-based crosslinked fluids. Fluids are generally heated to temperatures of 30-35°C to enhance gel hydration, however this temperature range is also ideal for promoting bacteria growth. Bacteria are capable of ingesting polysaccharide gelling agents as a food source and can double in population in as little as 20 minutes.
Total Dissolved Solids	mg/L	50,000	<ul style="list-style-type: none"> Excessive total dissolved solids concentrations may prevent the gelling agent from fully uncoiling and hydrating which in turn may result in the formation of 'fish eyes', insolubilities of the gelling agents and/or potential precipitation within the water-based crosslinked fluid.
Total Suspended Solids	mg/L	50	<ul style="list-style-type: none"> Solids are often a source of bacteria which may result in biological degradation of the water-based crosslinked fluid.

SOURCES: UNITED STATES DEPARTMENT OF ENVIRONMENTAL PROTECTION AGENCY. (2004, JUNE). *APPENDIX A HYDRAULIC FRACTURING WHITE PAPER EPA 816-R-04-003*. RETRIEVED JANUARY 23, 2012, FROM UNITED STATES ENVIRONMENTAL PROTECTION AGENCY: [WWW.EPA.GOV/.../UIC/.../CBMSTUDY_ATTACH_UIC_APPEND_A_DOE_WHITEPAPER.PDF](http://www.epa.gov/.../uic/.../CBMSTUDY_ATTACH_UIC_APPEND_A_DOE_WHITEPAPER.PDF)

VAN GUTENBEK, K., PAVLYKUCHENKO, V., RUDNITSKY, A., & PONGRATZ, R. (2006). *STRINGENT QUALITY CONTROL AND QUALITY ASSURANCE PROCESS: KEY TO SUCCESSFUL FRACTURING TREATMENTS IN WESTERN SIBERIA. SPE 100772*. SOCIETY OF PETROLEUM ENGINEERS.

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AQUALON. (2007). *GUAR AND GUAR DERIVATIVES OIL AND GAS FIELD APPLICATIONS*. RETRIEVED APRIL 18, 2012, FROM ASHLAND: [HTTP://WWW.ASHLAND.COM/ASHLAND/STATIC/DOCUMENTS/AAFI/PRO_250-61_GUAR.PDF](http://www.ashland.com/ashland/static/documents/AAFI/PRO_250-61_GUAR.PDF)

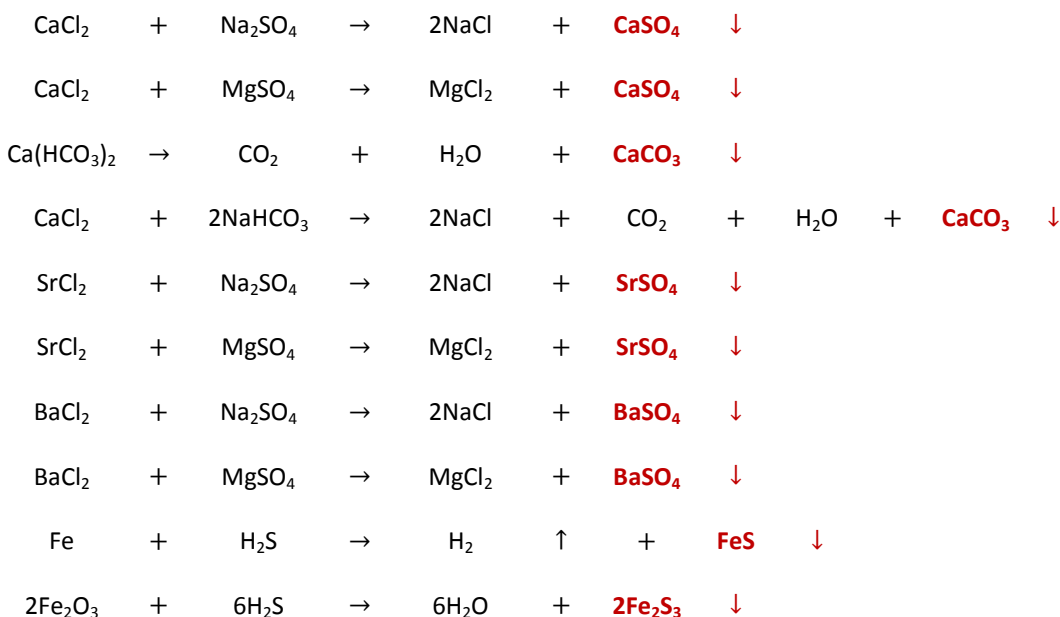
M-I SWACO. (2012, MAY 17). *FRACTURE WATER RECYCLING FEASIBILITY STUDY AND DECISION TOOL*.

Furthermore, to mitigate potential water-based crosslinked fluid compatibility concerns, other constituents present in the frac (source), flowback and produced waters may contribute to the fouling, scaling and corrosion potential these waters may have both within the reservoir and the selected water treatment equipment. These constituents are:

- Total Dissolved Solids (TDS)
- Total Suspended Solids (TSS)
- Emulsions
- Dissolved Gases

TOTAL DISSOLVED SOLIDS

Formation waters contain dissolved solids concentrations ranging from brackish (5,000 mg/L to 35,000 mg/L) to supersaturated brines (50,000 mg/L to >200,000 mg/L) (Collins, 1977, p. 4; American Petroleum Institute, 2010, p. 27). So long as the reservoir pressure, temperature and fluid composition remain constant, the dissolved solids concentrations of the formation waters will remain in solution (Collins, 1977, p. 4 & 7). However, during the hydraulic fracturing stimulation process, the comingling of fresh water, and/or recycled waters including flowback and/or produced waters with the formation waters under increased pressures represents the potential for a shift in subsurface water compatibility. Consequently, the comingling of waters containing lower dissolved solids concentrations with those of elevated dissolved solids concentrations may result in the precipitation of various solids (Collins, 1977, p. 4). Common ions frequently present within formation, frac (source), flowback and produced waters that are likely to contribute to precipitation in incompatible waters include calcium (Ca²⁺), strontium (Sr²⁺), barium (Ba²⁺), iron (Fe²⁺), bicarbonate (HCO₃⁻) and sulphate (SO₄²⁻). The reaction of these ions may result in the following precipitants (Collins, 1977, p. 9):



The precipitation of the species outlined above have the potential to hinder both the well production as well as downstream water treatment equipment. Depending on the concentration of the scaling constituents, the treatment approach may be managed either by the application of scale inhibitor chemistries or by depressing the concentration of the scaling species of greatest concern by integrating ion selective water treatment technologies.

Another challenge associated with elevated concentrations of dissolved solids is water treatment technological limitations. As the concentration of dissolved solids increases, the number of treatment technologies capable of effectively processing the comingled waters to the desired water quality parameters as outlined in Table 6 becomes more limited.

TOTAL SUSPENDED SOLIDS

In addition to dissolved solids concentration concerns, the second parameter of interest likely to impact the fouling potential within both the reservoir and the selected water treatment equipment is the total suspended solids concentration and composition. Suspended solids include precipitated solids as outlined above, sand, clay, plant matter, animal debris, and bacteria. Ideally, any water injected subsurface should be free of all particles in suspension to mitigate the potential for formation damage (Collins, 1977, p. 6). In the case of hydraulic fracturing, an excess concentration of total suspended solids may result in damage to the proppant pack, inhibiting reservoir permeability. In most cases, total suspended solid concentrations may be mitigated by mixing the waters with an alternate source containing a lower total suspended solids concentration, allowing the suspended solids to settle by using ponds or tanks, or removing the suspended solids by applying filtration technologies. Should the composition of the suspended solids be microbiological in nature, a combined treatment approach encompassing biocide application and filtration may be required to mitigate the fouling, microbiological influenced corrosion and souring potential the microbes may have within the reservoir.

EMULSIONS

Specific to the hydraulic fracturing of tight oil wells, the third parameter of interest likely to impact the fouling potential within both the reservoir and the selected water treatment equipment is the concentration and composition of emulsions. As the hydraulic fracturing fluid (fresh, recycled flowback and/or produced water) comes into contact with the formation water, the fluid is likely to come into contact with oil within the reservoir. Depending on the API gravity of the oil, the concentration and composition of suspended solids present, the base-fluid of the hydraulic fracturing fluid being used, and the turbulence encountered, the oil may form a normal or reverse emulsion with the frac fluid. Emulsions can damage the proppant pack, inhibit formation permeability and cause formation damage. At the surface, these emulsions require treatment prior to processing the fluid through downstream water treatment equipment. Depending on the oil droplet size, oil and grease concentration, concentration of suspended solids, and nature of the emulsion, the oil may separate with gravity separation within either a retention pond or tank. For stable emulsions containing smaller oil droplets, lower concentrations of oil and higher concentrations of suspended solids, combinations of mechanical, chemical and thermal treatment may be required to liberate the oil from the fluid. Ideally, it is in the company's best interest to recover this oil and transport to a local battery for further processing as opposed to disposing the isolated oil as a waste stream and thereby failing to recover its economic value.

DISSOLVED GASES

The fourth parameter of interest likely to impact both the corrosion and fouling potential within the reservoir and selected water treatment equipment is the concentration of dissolved gases. Formation, frac (source), flowback and produced waters are all likely to contain dissolved gases including oxygen (O_2), hydrogen sulfide (H_2S) and carbon dioxide (CO_2). The corrosion potential of these waters increases under conditions where either or both the dissolved solids and dissolved gases concentrations increase. In subsurface situations, carbon dioxide and hydrogen sulfide are anticipated to be of greater concern. The degree of solubility for both carbon dioxide and hydrogen sulfide is dependent upon temperature, pressure and dissolved solids concentration (Collins, 1977, p. 8). When dissolved in water, both carbon dioxide and hydrogen sulfide are present as carbonic and sulfuric acids, respectively. As the concentration of dissolved gases increases, the greater the potential for a shift in formation water pH. In waters with a greater concentration of bicarbonate alkalinity, a shift in pH may be enough to convert the bicarbonate alkalinity to carbon dioxide, further increasing the corrosivity of the formation water (Collins, 1977, pp. 7-8). Alternatively, if the pH of the water is adjusted to above 7 to compensate for elevated concentrations of both carbon dioxide and bicarbonate alkalinity, the end result may equate to increased risk of scaling, precipitated carbonates, and clay swelling within the reservoir (Collins, 1977, pp. 7-8). In both situations, the corrosion potential for subsurface equipment and downstream water treatment equipment increases as the dissolved gas concentrations increase. Consequently, the corrosion by-products produced can damage the proppant pack, inhibit formation permeability and cause formation damage.

The favourable solubility of hydrogen sulfide in water presents additional safety concerns when these waters are pumped to the surface as flowback or produced water. Hydrogen sulfide is not only extremely corrosive; it is highly toxic. Liberation of the hydrogen sulfide from the flowback and produced waters is therefore a potentially significant concern. To ensure the safety of all personnel, the concentration of hydrogen sulfide should be closely monitored and treated accordingly, particularly if these waters are being considered for reuse in subsequent hydraulic fracturing stimulations. The treatment

approach for hydrogen sulfide will vary from chemical oxidation to desorption depending on the concentration of dissolved gas present.

In summary, the identified constituents commonly present in the formation, frac (source), flowback and produced waters most likely to contribute to the fouling, scaling and corrosion potential within both the reservoir and the selected water treatment equipment are summarized in Table 7.

TABLE 7: WATER QUALITY PARAMETERS CONTRIBUTING TO FOULING, SCALING & CORROSION CONCERNS

WATER QUALITY PARAMETER	RATIONALE
Dissolved Solids (TDS)	<ul style="list-style-type: none"> • Dissolved inorganic constituents have the potential to form precipitated solids. • Elevated concentrations of total dissolved solids may be limiting to certain water treatment/conditioning technologies.
Precipitated Solids (Scales)	<ul style="list-style-type: none"> • Ions that react to form precipitates when pressure, temperature or composition changes include CaCO₃, MgCO₃, FeS, CaSO₄, BaSO₄, and SrSO₄. • These precipitated species may have a scaling/fouling tendency on both the formation (loss of permeability) as well as water treatment equipment.
Suspended Solids (TSS)	<ul style="list-style-type: none"> • The physical characteristics and electric charge of the suspended solids may result in attraction to dispersed oil droplets which can result in stabilized emulsions preventing coalescence and oil separation. • Particle size of the suspended solids in addition to total solids loading concentration will potentially damage the formation; resulting in loss of formation permeability and impacting water treatment technology selection. • Solids are often a source of bacteria, clays, ferric hydroxide, and/or soluble iron complexes and can create emulsions, damaging the proppant pack and formation permeability.
Dissolved Gases	<ul style="list-style-type: none"> • Of particular concern is the potential presence of H₂S as it is extremely toxic, corrosive, and can cause iron sulfide scaling. • Flowback and produced waters brought to the surface and exposed to atmosphere will absorb oxygen which may lead to sever and rapid corrosion as well as solids generation from oxidation reactions.
Emulsions	<ul style="list-style-type: none"> • Can consist of normal emulsions (water-in-oil emulsions) or reverse emulsions (oil-in-water) in either unstable or stable conditions. • Normal emulsions consist of water droplets ranging from 100 to 400 microns in diameter dispersed within the oil phase. • Reverse emulsions consist of oil droplets typically ranging in less than 150 microns in diameter dispersed within the water phase; the smaller the oil droplet, the more challenging the dispersed oil is to be removed and recovered with de-oiling technologies. • Unstable emulsions readily break within a few minutes and typically do not require any type of treatment. • Stable emulsions may remain for days or weeks if left untreated and often require a combination of chemicals, heat, settling time and electrostatics treatment to cause the emulsion to breakdown. • Oil droplet size distribution must be considered when selecting and sizing de-oiling technologies.
Dissolved Oil Concentrations	<ul style="list-style-type: none"> • Represents all hydrocarbons and other organic compounds that have some solubility in flowback and produced waters.
Bacteria	<ul style="list-style-type: none"> • Several types of bacteria can cause formation damage, microbiological induced corrosion, suspended solid byproducts, and H₂S gas production.

SOURCES: STEWART, M., & ARNOLD, K. (2011). *PRODUCED WATER TREATMENT FIELD MANUAL*. WALTHAM: ELSEVIER INC. PP. 4-13
 M-I SWACO. (2012, MAY 17). *FRACTURE WATER RECYCLING FEASIBILITY STUDY AND DECISION TOOL*.

5.5 ANALYTICAL RESULTS

To evaluate the potential magnitude of water treatment requirements, samples were collected from frac (source), flowback and produced water sources throughout 2011 & 2012 from Penn West Exploration’s Cardium, Carbonates (Slave Point), Colorado Group (Viking), and Waskada/Spearfish (Lower Amaranth) operating locations. Frac (source) water samples were collected from the shown Treater Manifold in Figure 2, flowback samples were collected from Testers Manifold and produced water samples were collected from either the Treaters at various batteries and/or Wellheads.

The collected frac (source), flowback and produced water samples were analyzed by an accredited third party laboratory utilizing the analytical methodologies outlined in Table 8.

TABLE 8: ANALYTICAL METHODS UTILIZED TO EVALUATE FRAC WATER, FLOWBACK & PRODUCED WATER SAMPLES

PARAMETER	METHODS	DETECTION LIMIT
Metals and Metalloids	Standard Methods 21 st ed. 3120 B: Metals by Plasma Emission Spectroscopy Inductively Coupled Plasma (ICP) Method	Sodium 0.0300 mg/L
		Potassium 0.1000 mg/L
		Calcium 0.0100 mg/L
		Magnesium 0.0300 mg/L
		Barium 0.0020 mg/L
		Strontium 0.0005 mg/L
		Iron 0.0070 mg/L
		Manganese 0.0020 mg/L
		Chloride 0.1000 mg/L
		Sulphate 0.1000 mg/L
Alkalinity	Standard Methods 21 st ed. 2320 B: Alkalinity – Titration method	Bicarbonate 2 mg/L as CaCO ₃
		Carbonate 2 mg/L as CaCO ₃
		Hydroxide 2 mg/L as CaCO ₃
Hydrogen Sulfide	Standard Methods 21 st ed. 4500 A: S ²⁻ Sulfide – Qualitative Tests Lead Acetate Paper & Silver Foil Tests	5 mg/L
pH	Standard Methods 21 st ed. 4500 B: H ⁺ pH Value – Electrometric Method	.001 SU
Total Dissolved Solids	Calculated Value	N/A
Total Suspended Solids	Standard Methods 21 st ed. 2540 D: Solids – Total Suspended Solids Dried at 103-105°C	0.1 mg/L

The respective analytical results characterizing the frac (source), flowback and produced waters are as follows:

TABLE 9: PENN WEST EXPLORATION TIGHT OIL DEVELOPMENT FRAC WATER SAMPLE SUMMARY

NUMBER OF SAMPLES	UNITS	CARDIUM FRAC WATER				CARBONATES (SLAVE POINT) FRAC WATER				COLORADO GROUP (VIKING) FRAC WATER				WASKADA/SPEARFISH (LOWER AMARANTH) FRAC WATER			
		TOTAL				TOTAL				TOTAL				TOTAL			
COUNT	N/A	1				1				34				6			
CATIONS	UNITS	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.
SODIUM (Na)	mg/L	1,000	N/A	N/A	N/A	26	N/A	N/A	N/A	594	94	6,250	1,036	128	27	318	128
POTASSIUM (K)	mg/L	18	N/A	N/A	N/A	2	N/A	N/A	N/A	14,614	770	40,900	7,466	17	11	24	5
CALCIUM (Ca)	mg/L	9	N/A	N/A	N/A	52	N/A	N/A	N/A	62	11	227	46	69	51	94	15
MAGNESIUM (Mg)	mg/L	9	N/A	N/A	N/A	18	N/A	N/A	N/A	64	3	384	89	43	22	59	15
BARIUM (Ba)	mg/L	1.50	N/A	N/A	N/A	0.04	N/A	N/A	N/A	0.36	0.03	7.70	1.29	0.06	0.05	0.09	0.01
STRONTIUM (Sr)	mg/L	0.50	N/A	N/A	N/A	0.20	N/A	N/A	N/A	2.10	0.10	42	7.44	0.26	0.18	0.36	0.07
IRON (Fe)	mg/L	17	N/A	N/A	N/A	<0.007	N/A	N/A	N/A	2.45	0.02	24	6.05	0.04	0.04	0.04	0.00
MANAGNESE (Mn)	mg/L	0.17	N/A	N/A	N/A	0.16	N/A	N/A	N/A	0.34	0.02	2.20	0.52	0.04	0.04	0.04	0.00
ANIONS	UNITS	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.
CHLORIDE (Cl)	mg/L	720	N/A	N/A	N/A	<0.1	N/A	N/A	N/A	13,855	896	35,728	6,184	16	11	25	6
SULPHATE (SO ₄)	mg/L	270	N/A	N/A	N/A	21	N/A	N/A	N/A	566	15	4,150	887	331	137	720	265
BICARBONATE (HCO ₃)	mg/L	520	N/A	N/A	N/A	305	N/A	N/A	N/A	471	<2	1,117	252	359	214	493	101
CARBONATE (CO ₃)	mg/L	<2	N/A	N/A	N/A	<2	N/A	N/A	N/A	28	<2	305	76	<2	<2	<2	<2
HYDROXIDE (OH)	mg/L	<2	N/A	N/A	N/A	<2	N/A	N/A	N/A	8	<2	224	38	<2	<2	<2	<2
PHYSICAL PROPERTIES	UNITS	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.
HYDROGEN SULFIDE (H ₂ S)	FREQUENCY PRESENT (%)	0.00%	N/A	N/A	N/A	0.00%	N/A	N/A	N/A	0.00%	N/A	N/A	N/A	0.00%	N/A	N/A	N/A
pH	STANDARD UNIT (SU)	6.98	N/A	N/A	N/A	7.90	N/A	N/A	N/A	8.29	7.40	12.30	1.05	8.05	7.90	8.20	0.10
TOTAL DISSOLVED SOLIDS (TDS)	mg/L	2,000	N/A	N/A	N/A	425	N/A	N/A	N/A	30,263	2,363	78,774	13,834	963	508	1,701	513
TOTAL SUSPENDED SOLIDS (TSS)	mg/L	320	N/A	N/A	N/A	62	N/A	N/A	N/A	196	22	1,142	228	45	5	227	81

VALUES ARE GREATER THAN THE ACCEPTABLE UPPER LIMITS OUTLINED IN TABLE 6
 MORE LIKELY TO PROMOTE FORMATION OF PRECIPITATED SOLIDS OUTLINED IN TABLE 7

SAMPLES COLLECTED: JULY 8, 2011 - FEBRUARY 18, 2012

ADDITIONAL NOTES:

- Variability in potassium & chloride concentrations is due to hydraulic fracturing programs combining up to 4% KCl with fresh water sources.
- The larger variability in standard deviation as observed for the Colorado Group (Viking) is defined in the Appendix where this data is further disseminated into Avon Hills, Dodsland, Esther and Provost.

TABLE 10: PENN WEST EXPLORATION TIGHT OIL DEVELOPMENT FLOWBACK WATER SAMPLE SUMMARY

NUMBER OF SAMPLES	UNITS	CARDIUM FLOWBACK WATER				CARBONATES (SLAVE POINT) FLOWBACK WATER				COLORADO GROUP (VIKING) FLOWBACK WATER				WASKADA/SPEARFISH (LOWER AMARANTH) FLOWBACK WATER			
		TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL		
COUNT	N/A	3				12				45				68			
CATIONS	UNITS	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.
SODIUM (Na)	mg/L	1,667	1,100	2,700	732	16,392	12,230	18,270	1,785	5,738	341	20,330	4,477	41,588	14,880	55,060	11,594
POTASSIUM (K)	mg/L	33	20	53	14	270	218	403	48	5,128	342	16,270	5,138	411	129	605	129
CALCIUM (Ca)	mg/L	45	31	65	15	4,089	3,230	4,660	418	256	7	1,100	219	2,510	1,150	3,340	505
MAGNESIUM (Mg)	mg/L	3	<0.03	6	2	961	762	1,130	100	145	7	559	121	626	212	1,100	184
BARIUM (Ba)	mg/L	2.13	1.40	3.20	0.77	0.52	0.32	1.10	0.22	5.70	0.05	42.00	8.65	0.08	0.02	0.23	0.05
STRONTIUM (Sr)	mg/L	1.13	0.60	2.10	0.68	87.58	65.00	103.00	12.09	17.88	0.22	90.00	18.98	58.17	22.00	76.00	14.84
IRON (Fe)	mg/L	9.43	8.00	11.00	1.23	12.49	0.76	28.00	10.84	3.60	0.01	46.00	9.62	9.92	0.11	80.00	15.63
MANAGNESE (Mn)	mg/L	0.15	0.13	0.18	0.02	1.58	1.10	2.50	0.50	1.09	0.03	4.00	0.97	0.98	0.19	2.80	0.48
ANIONS	UNITS	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.
CHLORIDE (Cl)	mg/L	1,447	940	2,100	485	35,396	27,923	38,651	3,418	14,279	1,100	36,550	5,942	69,061	24,486	93,082	19,172
SULPHATE (SO ₄)	mg/L	317	270	380	46	1,443	1,207	1,810	210	665	24	2,070	504	3,029	1,657	3,570	403
BICARBONATE (HCO ₃)	mg/L	583	440	770	138	682	299	892	229	487	<2	995	228	446	133	1,134	124
CARBONATE (CO ₃)	mg/L	<2	<2	<2	<2	<2	<2	<2	<2	4	<2	90	14	<2	<2	<2	<2
HYDROXIDE (OH)	mg/L	<2	<2	<2	<2	<2	<2	<2	<2	3	<2	150	22	<2	<2	<2	<2
PHYSICAL PROPERTIES	UNITS	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.
HYDROGEN SULFIDE (H ₂ S)	FREQUENCY PRESENT (%)	66.67%	N/A	N/A	N/A	66.67%	N/A	N/A	N/A	2.22%	N/A	N/A	N/A	48.53%	N/A	N/A	N/A
pH	STANDARD UNIT (SU)	7.47	7.42	7.52	0.04	6.87	6.60	7.10	0.18	7.92	7.10	11.90	0.70	6.84	5.20	7.80	0.60
TOTAL DISSOLVED SOLIDS (TDS)	mg/L	3,267	2,300	4,600	974	59,335	46,476	64,673	5,659	27,228	2,187	64,522	10,828	116,182	13,346	156,422	33,673
TOTAL SUSPENDED SOLIDS (TSS)	mg/L	433	340	500	68	454	214	686	157	3,628	34	55,130	9,906	882	61	6,763	1,251

VALUES ARE GREATER THAN THE ACCEPTABLE UPPER LIMITS OUTLINED IN TABLE 6
 MORE LIKELY TO PROMOTE FORMATION OF PRECIPITATED SOLIDS OUTLINED IN TABLE 7

SAMPLES COLLECTED: JULY 9, 2011 - MARCH 2, 2012

ADDITIONAL NOTES:

- Variability in potassium & chloride concentrations is due to hydraulic fracturing programs combining up to 4% KCl with fresh water sources.
- The larger variability in standard deviation as observed for the Colorado Group (Viking) is defined in the Appendix where this data is further disseminated into Avon Hills, Dodsland, Esther and Provost.
- Variability in flowback water quality is expected to be predominantly related to variability in formation geologies and contact of frac fluids with formation waters.
- Flowback sample frequency throughout the evaluation was highly variable with as few as one sample being collected for some hydraulic jobs and up to six samples for others.
- The average flowback period per well may be generalized as a variable (both volume and composition) non-continuous stream occurring over two days.
- Limited numbers of samples were collected for the Cardium as 90% of the wells within this resource play are hydraulically fractured with oil based fluids.
- H₂S presence reported may be higher than actual field concentrations due to the turnaround time between when the sample was collected and when it was analyzed.

TABLE 11: PENN WEST EXPLORATION TIGHT OIL DEVELOPMENT PRODUCED WATER SAMPLE SUMMARY

NUMBER OF SAMPLES	UNITS	CARDIUM PRODUCED WATER				CARBONATES (SLAVE POINT) PRODUCED WATER				COLORADO GROUP (VIKING) PRODUCED WATER				WASKADA/SPEARFISH (LOWER AMARANTH) PRODUCED WATER			
		TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL	TOTAL		
COUNT	N/A	24				4				22				14			
CATIONS	UNITS	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.
SODIUM (Na)	mg/L	2,431	93	10,000	2,132	37,325	32,400	50,000	7,333	15,547	1,710	35,900	9,007	53,593	38,300	61,900	6,220
POTASSIUM (K)	mg/L	169	7	1,750	358	503	336	639	131	208	10	442	98	585	236	758	132
CALCIUM (Ca)	mg/L	934	6	11,000	2,346	11,793	9,270	14,100	2,091	641	33	1,760	460	2,551	1,890	2,920	264
MAGNESIUM (Mg)	mg/L	143	2	858	229	3,053	1,910	4,050	807	367	9	865	242	746	356	990	160
BARIUM (Ba)	mg/L	10.49	0.01	120.00	24.23	0.34	0.27	0.41	0.05	29.64	0.02	74.40	22.56	0.08	0.05	0.11	0.02
STRONTIUM (Sr)	mg/L	26.06	0.35	307.00	62.12	250.75	170.00	335.00	76.98	52.50	1.09	124.00	35.68	59.09	45.30	63.30	4.45
IRON (Fe)	mg/L	15.67	0.15	145.00	33.64	6.98	2.77	13.40	4.30	1.05	0.12	5.53	1.24	1.49	0.86	3.75	0.70
MANAGNESE (Mn)	mg/L	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
ANIONS	UNITS	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.
CHLORIDE (Cl)	mg/L	5,104	211	24,130	5,883	88,435	74,450	107,500	12,114	27,000	2,805	62,660	16,045	93,581	65,200	106,000	11,295
SULPHATE (SO ₄)	mg/L	226	<0.1	1,130	301	969	334	1,790	547	152	<0.1	3,190	663	2,104	143	3,840	1,499
BICARBONATE (HCO ₃)	mg/L	1,098	240	2,700	758	164	14	290	99	463	210	800	184	389	170	520	73
CARBONATE (CO ₃)	mg/L	<2	<2	<2	<2	<2	<2	<2	<2	<2	<2	<2	<2	<2	<2	<2	<2
HYDROXIDE (OH)	mg/L	<2	<2	<2	<2	<2	<2	<2	<2	<2	<2	<2	<2	<2	<2	<2	<2
PHYSICAL PROPERTIES	UNITS	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.	AVERAGE	MIN.	MAX.	STND. DEV.
HYDROGEN SULFIDE (H ₂ S)	FREQUENCY PRESENT (%)	0.00%	N/A	N/A	N/A	0.00%	N/A	N/A	N/A	4.55%	N/A	N/A	N/A	50.00%	N/A	N/A	N/A
pH	STANDARD UNIT (SU)	7.36	5.47	8.24	0.60	6.33	5.97	6.71	0.27	7.52	6.78	8.20	0.33	6.59	5.35	7.36	0.52
TOTAL DISSOLVED SOLIDS (TDS)	mg/L	9,576	610	39,000	9,609	140,000	120,000	170,000	18,708	44,082	4,800	100,000	25,452	153,571	110,000	170,000	17,971
TOTAL SUSPENDED SOLIDS (TSS)	mg/L	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

VALUES ARE GREATER THAN THE ACCEPTABLE UPPER LIMITS OUTLINED IN TABLE 6
 MORE LIKELY TO PROMOTE FORMATION OF PRECIPITATED SOLIDS OUTLINED IN TABLE 7

SAMPLES COLLECTED: FEBRUARY 10, 2011 - FEBRUARY 28, 2012

ADDITIONAL NOTES:

- Variability in potassium & chloride concentrations is due to hydraulic fracturing programs combining up to 4% KCl with fresh water sources.
- The larger variability in standard deviation as observed for the Colorado Group (Viking) is defined in the Appendix where this data is further disseminated into Avon Hills, Dodsland, Esther and Provost.

6.0 TECHNOLOGY EVALUATION

A six-stage treatment process for flowback and produced water is proposed based on:

- Chemical analyses of frac (source), flowback and produced waters from multiple resource plays
- Fouling, scaling and corrosion potential of frac (source), flowback and produced waters
- Fracturing fluid chemistry compatibility with residual additives or other water constituents
- Tight oil hydraulic fracturing water requirements
- Flowback availability for each resource play

The six proposed treatment objectives include: de-oiling and solids removal, pre-treatment, solids and soluble organics removal, selective ion reduction, desalination and disinfection. These treatment objectives are defined in the following sections:

DE-OILING & SOLIDS REMOVAL: De-oiling and solids removal is proposed as the first treatment objective in order to reduce the solids loading and emulsion concentration the flowback and produce waters may have on the downstream treatment equipment. By reducing the solids loading and targeting oil recovery, the isolated fluid may be transfer to a local battery for further processing with reduced risk of battery upset. Removal of free oil, dispersed oil (small oil droplets), emulsions and suspended solids (>25 μm particle size diameter) may be achieved using technologies like API separators, skim tanks, treaters, clarifiers, plate or enhanced coalescence, gas floatation, hydrocyclones, and micro-filtration (MF).

PRE-TREATMENT: Pre-treatment is proposed as the second treatment objective due to the need to degrade residual gelling agents and remove dissolved gases upstream of any water treatment equipment. Removal of light hydrocarbon gases, carbon dioxide, hydrogen sulfide, etc. may be achieved using technologies like desorption (air stripping), membrane filtration (gas transfer membranes), biological treatment (suspended growth & fixed growth), and chemical oxidation (ozone & hydrogen peroxide). Removal of residual gelling agents may be achieved using technologies like biological treatment (suspended growth & fixed growth), chemical oxidation (ozone & hydrogen peroxide), and UV radiation. In certain situations where dissolved gases (H_2S) concentrations are greater than 25 mg/L, consideration of incorporating the pre-treatment objective between the flowback and/or produced water storage tanks and the primary de-oiling technology may be beneficial. Increased turbulence within the de-oiling technologies may liberate excess concentrations of hydrogen sulfide and increase the atmospheric concentration compromising the safety of the working environment. By incorporating the pre-treatment objective upstream of the de-oiling technologies like plate or enhanced coalescence, gas floatation, hydrocyclones, and micro-filtration (MF), the atmospheric exposure risk is expected to be further mitigated.

SOLIDS & SOLUBLE ORGANICS REMOVAL: Depending on the particle size distribution, the targeted total suspended solids concentration and downstream water treatment equipment selection, a second phase of solids and soluble organics removal may be required. Removal of dissolved hydrocarbons and suspended solids (<25 μm particle size diameter) may be achieved using technologies like electrocoagulation, media filtration (quartz sand, silica sand & anthracite coal), membrane filtration (ultra-filtration), adsorption filtration (activated carbon & walnut shell media), and chemical oxidation (ozone & hydrogen peroxide).

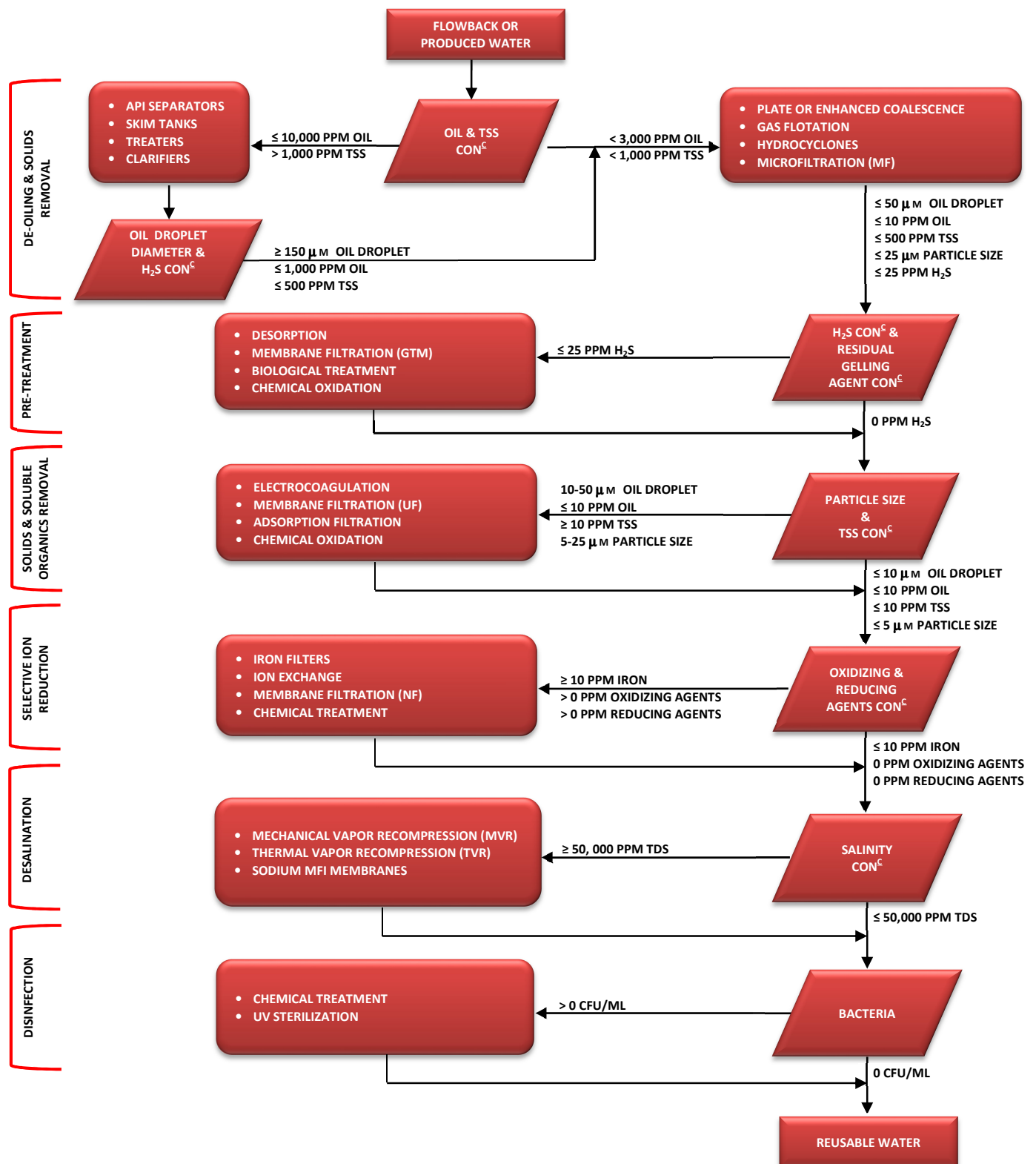
SELECTIVE ION REDUCTION: Depending on the flowback and produced water quality, certain species such as iron, calcium, magnesium and bicarbonate alkalinity may require treatment. Reduction of these selective ions may be achieved using technologies like ion exchange, iron filters, membrane filtration (nano-filtration), and chemical treatment (coagulation & flocculation).

DESALINATION: Removal of dissolved solids and salts may be achieved using technologies like evaporation (mechanical vapor recompression & thermal vapor recompression), distillation, and membranes (sodium MFI).

DISINFECTION: Removal of bacteria, viruses, micro-organisms, algae, etc. may be achieved using technologies like chemical treatment (preferably non-oxidizing biocides such as gluteraldehyde, isothiazoline and/or DBNPA) and may be supplemented with UV sterilization. Disinfection is expected to be a required treatment objective in all hydraulic fracturing applications, regardless of the water source being used to prevent formation damage, microbiological induced corrosion, suspended solid by-products, and H_2S gas production commonly attributed to sulfate reducing and acid producing bacteria.

Keeping in mind these six treatment objectives and the limitations of various treatment technologies, the following Flowback & Produced Water Treatment Decision Tree methodology is proposed:

FIGURE 4: FLOWBACK & PRODUCED WATER TREATMENT DECISION TREE



CON^c: CONCENTRATION

By applying the decision tree (Figure 4) with the analytical data obtained from each Penn West Exploration tight oil development play (Tables 9, 10 & 11); the authors evaluated which treatment objectives are potentially required to condition the flowback and produced waters for reuse in tight oil hydraulic fracturing throughout the various resource plays. Results from the Flowback & Produced Water Treatment Technology Evaluation are outlined in Table 12.

TABLE 12: FLOWBACK & PRODUCED WATER TREATMENT TECHNOLOGY EVALUATION

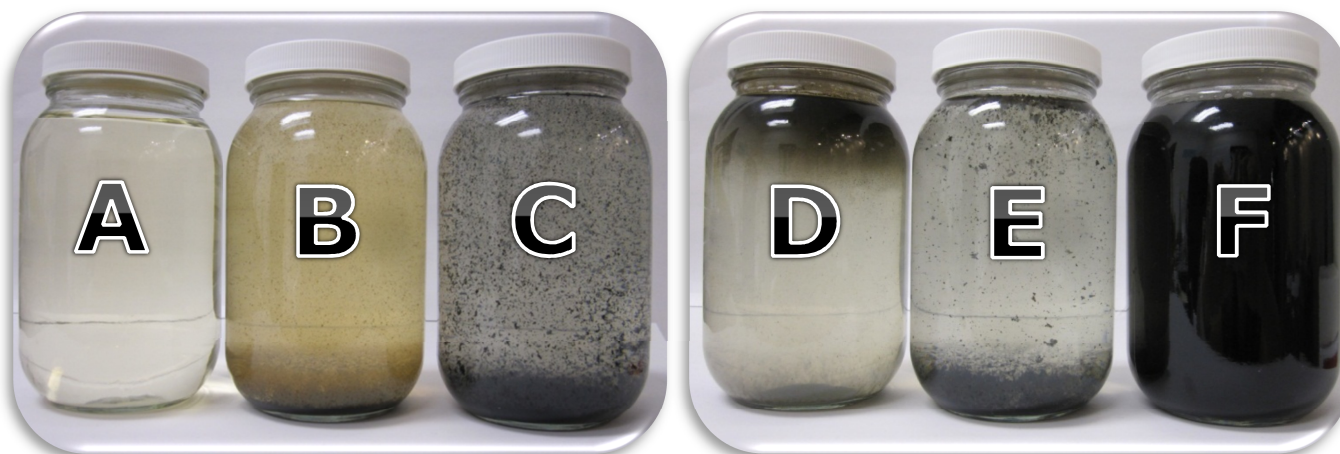
RESOURCE PLAY	RE-USE SOURCE	DE-OILING & SOLIDS REMOVAL	PRE-TREATMENT	SOLIDS & SOLUBLE ORGANICS REMOVAL	SELECTIVE ION REDUCTION	DESALINATION	DISINFECTION
CARDIUM	FLOWBACK	✓	✓	✓	✗	✗	✓
	PRODUCED WATER	✓	✗	✓	✓	✗	✓
CARBONATES (SLAVE POINT)	FLOWBACK	✓	✓	✓	✓	✗	✓
	PRODUCED WATER	✓	✗	✓	✓	✓	✓
COLORADO GROUP (VIKING)	FLOWBACK	✓	✓	✓	✓	✗	✓
	PRODUCED WATER	✓	✓	✓	✓	✗	✓
WASKADA/SPEARFISH (LOWER AMARANTH)	FLOWBACK	✓	✓	✓	✓	✓	✓
	PRODUCED WATER	✓	✓	✓	✓	✓	✓

✓ TREATMENT OBJECTIVE IS EXPECTED TO BE REQUIRED
 ✗ TREATMENT OBJECTIVE IS NOT EXPECTED TO BE REQUIRED

Flowback and produced waters from tight oil development plays in the WCSB region are expected to contain residual soluble and insoluble hydrocarbons, suspended solids (particle diameter greater than 25 µm) and bacteria. As a result, it is expected that solids and soluble organic removal technologies as well as disinfection will be critical treatment steps before these waters will be suitable for reuse in subsequent hydraulic fracturing applications.

While average values of fluid characterization were used to devise the water treatment technology evaluation, it is valuable to note the degree of visual water quality variability that can be expected. Figure 5 shows a set of samples that were obtained during various phases of the hydraulic fracturing process in October of 2011 from the Carbonates (Slave Point) resource play.

FIGURE 5: FLOWBACK WATER QUALITY VARIABILITY



Sample A represents fresh water that has been filtered and disinfected with biocide prior to the addition of the hydraulic fracturing crosslinked chemistries. This sample provides a baseline representing the current quality of water typically being utilized for tight oil hydraulic fracturing across the WCSB. The wide range in flowback water quality is observed with samples B through F. Sample B is flowback water with very little oil and grease content, however the residual gelling agent concentration is preventing the very fine suspended solids from settling out of the solution. Similar to sample B, sample C is observed to have an even greater concentration of oil coated solids remaining in solution which is also likely attributed to

an excess concentration of residual gelling agent present within the flowback water. In contrast to samples B & C, the distinct stratification layers of sample D suggest very little residual gelling agent present within the flowback sample. The solids present in sample D readily settled out of solution and the free oil has accumulated as the top layer within the sample. The layer of oil and fine solids at the surface of sample E, combined with the distinct layer of oil-coated solids at the bottom of the sample, suggests a lesser concentration of residual gelling agent within this flowback sample compared to samples B and C. Lastly, the homogenous nature of sample F suggests a very stable reverse (oil-in-water) emulsion.

The magnitude of fluid variability must be taken into consideration as fluctuations in residual gelling agent concentration, solids loading, particle size, oil content, oil droplet size, and general water quality will add further strain to downstream water treatment technologies. Processing a fluid of a known quality is far more manageable than treating a fluid that is in a constant state of flux. When applying the decision tree methodology outlined in Figure 4, it is recommended to collect and retain multiple samples from various phases during the hydraulic fracturing stimulation for both analytical and visual assessment. The combination of results obtained from the analytical and visual assessments will aid in ensuring all of the necessary treatment objectives are incorporated.

In summary, it is apparent that the treatment objectives throughout the various tight oil developments across the WCSB are variable, demanding slightly different technological treatment approaches within each respective resource play. Similar water treatment regimes may be effective for both the Carbonates (Slave Point) and Waskada/Spearfish (Lower Amaranth) whereas a slightly less technologically demanding treatment approach may be applicable to both the Cardium and the Colorado Group (Viking). A decision to apply a standardized treatment approach across all four tight oil development plays would result in unnecessary over treatment of some waters and the potential under treatment of others. In either case, failure to modify the technological treatment approach for each area may result in either the unnecessary allocation of OPEX and CAPEX costs or alternatively, a compromise in the quality of recycled flowback and produced waters potentially impeding the effectiveness of subsequent hydraulic fracturing stimulations.

7.0 PHASE I: LESSONS LEARNED

Throughout the preparation of this paper, numerous lessons have been learned that will add value to both Penn West Exploration and our industry peers should the findings of this evaluation be further expanded upon. The lessons learned include the following:

1. SAMPLE COLLECTION

Ensuring data quality was a challenge in this study and would be remedied by refining the current sampling protocol. A refined protocol would include enhanced training for those collecting/labeling samples, a combination of field and laboratory analysis, as well as a chain of custody system to ensure timely delivery of samples and results.

2. SAMPLE ANALYSIS

Due to an absence of peer-reviewed data on water treatment criteria for tight oil hydraulic fracturing, the species selected for analysis were based upon the water quality parameters outlined by the US EPA for Coalbed Methane and Shale Gas hydraulic fracturing applications (Table 6). Future studies would also include the following analysis: oil & grease, residual crosslinker concentration, residual gelling agent concentration, bacteria, H₂S, silica, oil droplet size and distribution, particle size and distribution and sample profiles over time. The extended analysis will further aid in the selection of specific treatment objectives outlined in the Flowback & Produced Water Treatment Decision Tree (Figure 4).

3. TECHNOLOGY EVALUATION

Additional considerations within the technology evaluation include how well suited the technology is at processing the flowback and produced water volumes (Table 5) to satisfy water-based hydraulic fracturing requirements within the WCSB. With flowback volumes occurring in batches, certain water treatment technologies are anticipated to have greater sensitivities to flow fluctuations and may not be considered suitable for flowback treatment applications. The logistics of water treatment as it applies to hydraulic fracturing has not been assessed in this study, but is a fundamental factor for consideration in commercial field application of technology.

Equipment that cannot process volumes in a timely and cost effective manner to facilitate reuse will not find broad application, despite their ability to meet the treatment quality objectives.

Once the technological selection is further refined, evaluation of variables including percent recovery, CAPEX, OPEX, scalability, footprint, energy requirements, percent uptime, mobility, degree of Operator intervention required, and level of Operator knowledge required to operate the equipment will require evaluation.

8.0 CONCLUSION

In summary of the Reuse of Flowback & Produced Water for Hydraulic Fracturing in Tight Oil evaluation, the authors have identified the technological treatment intensity anticipated to treat flowback and produced waters for reuse in multi-staged hydraulic fracturing operations within tight oil resource plays. This evaluation suggests both the Cardium and the Colorado Group (Viking) require less intense water treatment of both flowback and produced waters than the Carbonates (Slave Point) and Waskada/Spearfish (Lower Amaranth). With the combined technology evaluation, analytical results, cumulative hydraulic fracturing water requirements and flowback volumes, Penn West Exploration is favorably positioned to prioritize a flowback and produced water treatment strategy within each respective tight oil resource play.

The conclusions of this paper are constrained by the authors' interpretation of a limited number of technical papers which examine the water reuse requirements for flowback and produced water as it applies to hydraulic fracturing stimulations. From the limited technical information available within the public domain, the authors strived to identify additional parameters, water constituents, and treatment challenges that may be unique to water reuse requirements for hydraulic fracturing in tight oil. Based upon Penn West Exploration's preferred hydraulic fracturing fluid programs, the research findings of this paper focused exclusively on the water reuse requirements for water-based crosslinked fluids in tight oil resource plays.

Future research evaluating the reuse requirements of flowback and produced waters for hydraulic fracturing in tight oil might examine the reuse requirements for alternate water-based hydraulic fracturing fluid systems (Table 2). In doing so, the researcher will be able to identify potential variances in treatment intensity requirements for multiple water-base fluid systems. Additional research might also choose to investigate the validity of the proposed Flowback & Produced Water Treatment Decision Tree (Figure 4). The validity of the proposed treatment approach might be investigated by conducting field-based water reuse trials incorporating various treatment technologies. Through field-based water reuse trials, additional treatment challenges and alternate treatment approaches are anticipated to become more apparent. An additional research outcome anticipated to be achievable through the application of field-based water reuse trials is the refined examination of the identified constituents expected to have the greatest impact on hydraulic fracturing fluid compatibility. Field-based water reuse trials are anticipated to provide the research platform necessary to determine other potential constituents that may hinder hydraulic fracturing fluid compatibility while either confirming or disproving the current parameters and upper threshold limits as identified within this paper.

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