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Fracturing Fluid
Flowback Reuse Project

Prepared by M-I SWACO, a Schlumberger Company
for Petroleum Technology Alliance of Canada
and the Science and Community Environmental Knowledge (SCEK)
Fund

Decision Tree & Guidance Manual

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Executive Summary

This document is intended for:

- **Oilfield operators, hydraulic fracturing service companies, chemical manufacturers,** and **water treatment companies** in the design of fracturing processes and management of water needs and issues.
- **Regulators** who provide direction and develop policy regarding hydraulic fracturing operations and water management issues.
- **Other stakeholders** with an interest in water management, to understand the hydraulic fracturing process and the considerations that must be taken into account in the use and reuse of water for hydraulic fracturing operations.

Water has become a major economic factor in current fracturing technologies. The industry has learned that water need not be fresh, but may be reused if the chemistry is correct or can be adapted.

This study aims to identify a methodology, in the form of a Decision Tree and Guidance Manual, and supporting Appendices and Case Studies, so that producers can work with service companies to determine the limiting factors and mitigation or control scenarios for using water with high salinity or other undesirable constituents for making up fracturing fluid. The methodology and technologies that have been suggested incorporate the science and practice of hydraulic fracturing with fracturing fluid management and treatment technologies.

1.0 Introduction and Background

Previous projected recovery rates for shale gas-in-place were about 2%. Shale gas development has advanced so that this has increased to estimates of about 50%. [40] As shown in Figure 1.1, shale gas exists in many places in North America.

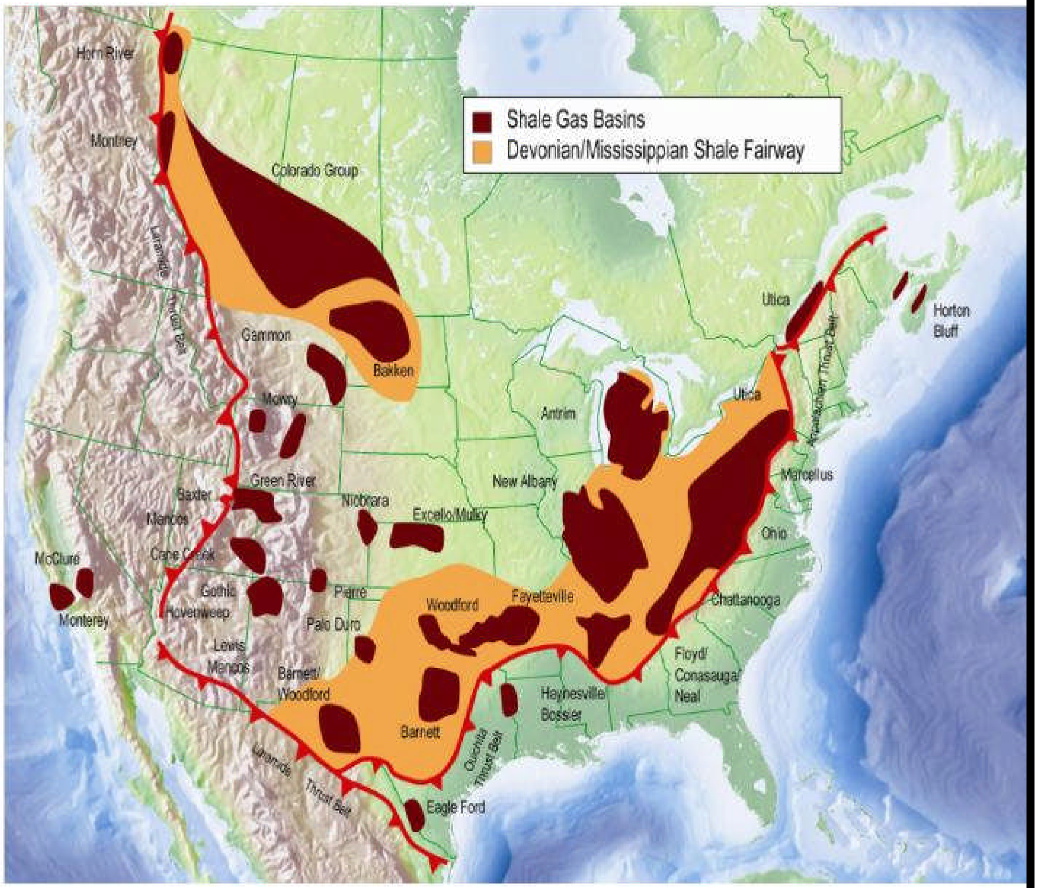


Figure 1.1 Shale Gas Development Areas of North America. [48]

Technologies that have been developed to increase the formation-face contact of the fracture system include:

- *multi-stage fracturing of horizontal wells,*
- *slickwater fluids with minimum viscosity,*
- *simultaneous fracturing.*

Future advances are likely to include

- *hybrid fracturing,*
- *fracture complexity,*
- *fracture flow stability,*
- *methods of re-using water.*

Newly advanced technologies mean that gas reserves that were completely unavailable only a few years ago can now be developed. However, these new technologies (see sidebar) all require large volumes of water.

Optimization of water use will require a thorough and accurate understanding of the factors that influence the reuse of fracturing flowback water in hydraulic fracturing operations, including the use and performance of water conditioners and hydraulic fracturing additives.

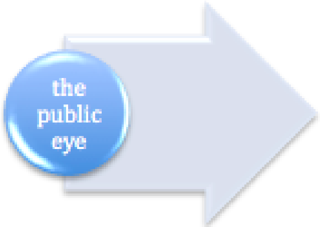
Cost-effective use of chemicals and water management will require intensive planning and engineering. Ultimately, the refinement of the science and experience with hydraulic fracturing will lead to the development of more formalized work flows and operating procedures. These, in turn, will evolve in response to continuing development and operating experience in shale gas and tight oil development.

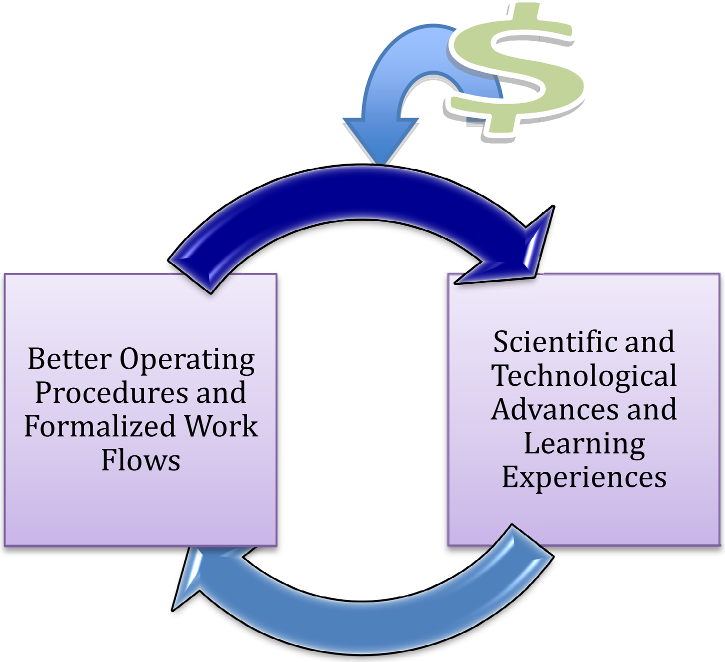
Reuse of fracturing flowback:

•reduces the demand for fresh water,

•reduces the amount of water that needs to be disposed,

•ideally, reduces overall production costs.





The recent call for more transparent operations also makes it desirable to outline the roles of the various conditioners and additives used in the various types of hydraulic fracturing methods.

As drilling and completion technologies have advanced, stimulation techniques have developed that are specifically effective in the stimulation of horizontal wells in shale gas zones.

The number of stages and the volume of fracturing fluids pumped per stage have increased. Completions have also been made more effective by the addition of combinations of specific chemical additives to the fracturing fluids.

Factors that influence the reuse of fracturing fluid flowback water must also be thoroughly researched to optimize the process. These include:

- Chemical additives likely to be used in hydraulic fracturing operations.
- A detailed evaluation of the physical and chemical composition and compatibility of the source water.
- Flowback water.
- Produced water.
- Chemical additives.
- Formation.

These factors and the methods of evaluation are discussed in the Decision Tree and the accompanying document.

Reuse and/or recycling practices require the selection of compatible additives (which means that they do not participate in chemical reactions that would be detrimental to any of the processes required for the hydraulic fracturing procedure).

Effort is focused on environmentally benign constituents.

Wise selection of additives may enhance the quantity and compatibility of fluids available and provide more options for use and disposal [17].

There are no optimum, one-size-fits-all completion or stimulation designs for fracturing or fracturing fluid configuration for shale gas wells because no two shales are alike. However, this paper aims to help formalize the logic and process of evaluating the needs for developing and designing cost-effective hydraulic fracturing fluid packages that optimize the use of water conditioners and fracturing additives, and reuse of flowback water.

2.0 Shale Gas Development and Hydraulic Fracturing Technologies

2.1 Introduction

A key element in the emergence of shale gas production has been the refinement of cost-effective horizontal drilling and hydraulic fracturing technologies. These two technologies, along with the implementation of protective environmental management practices, have allowed shale gas development to move into areas that previously would not have been economically developable.

There are now numerous different types of fracturing methods using a variety of fluids and proppant and injection techniques, which vary depending upon the reservoir characteristics.

Hydraulic fracturing technology was developed in the 1940s, and since then, about a million wells have been fractured and billions of cubic meters of natural gas and barrels of oil have been produced.

Hydraulic fracturing allows production from wells that were not previously available. Therefore, it will continue to be an important technology as production from conventional oil and gas fields continues to mature, and the shift in focus to non-conventional resources increases.

2.2 Horizontal Drilling Technology

Horizontal drilling involves drilling many (10+) wells from a single drilling pad. The use of the drilling pad concept reduces the footprint of drilling and completions operations and creates a cost-effective water management infrastructure.

Longer horizontal wells require more stages per well. Each stage receives a fracture treatment, which requires water, so there is an increase in the flowback volume that must be managed.

> *Horizontal drilling and hydraulic fracturing are costly compared to conventional vertical well completions and hydraulic fracturing, so companies engaged in shale gas development continue to commit significant engineering resources on an ongoing basis to monitor and optimize hydraulic fracturing procedures.*

The lengths of the horizontal wells, which began with wells on the order of a few hundred meters, have increased to several thousand meters as operator confidence in the drilling and completion process has grown.

Longer well lengths usually deliver a lower cost per foot as fracturing stages are increased to effectively break up the shale formation exposed by the extended wellbore reach. The increased length of the horizontal translates into more fracture stages and more fracturing fluid used per well completed.

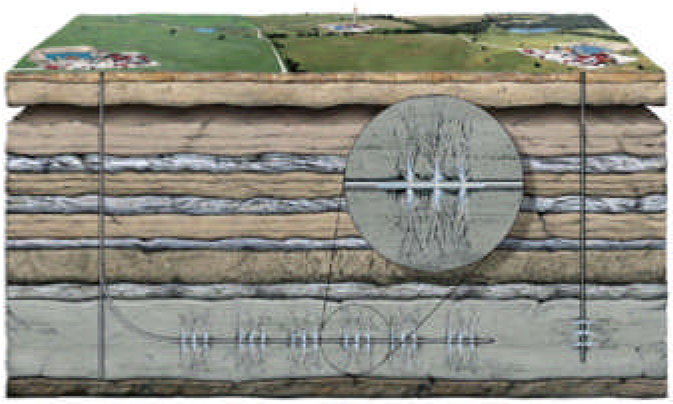


Figure 2.1 Vertical vs Horizontal Drilling with Hydraulic Fracturing [37].

2.3 Hydraulic Fracturing Technology

Hydraulic fracturing is widely used by the oil and gas industry to improve low permeability reservoirs. Fluid (often water, carbon dioxide, nitrogen gas, or propane) is pumped down the well until the pressure surpasses the rock strength and causes the reservoir to crack. The fracturing fluid pumped down the well is loaded with propping agent, or proppant, which infiltrates the formation and helps to prop the fractures open, as they are at risk of closing once the pressure is released. See Figure 2.2 for some common proppant materials currently in use in Canada.

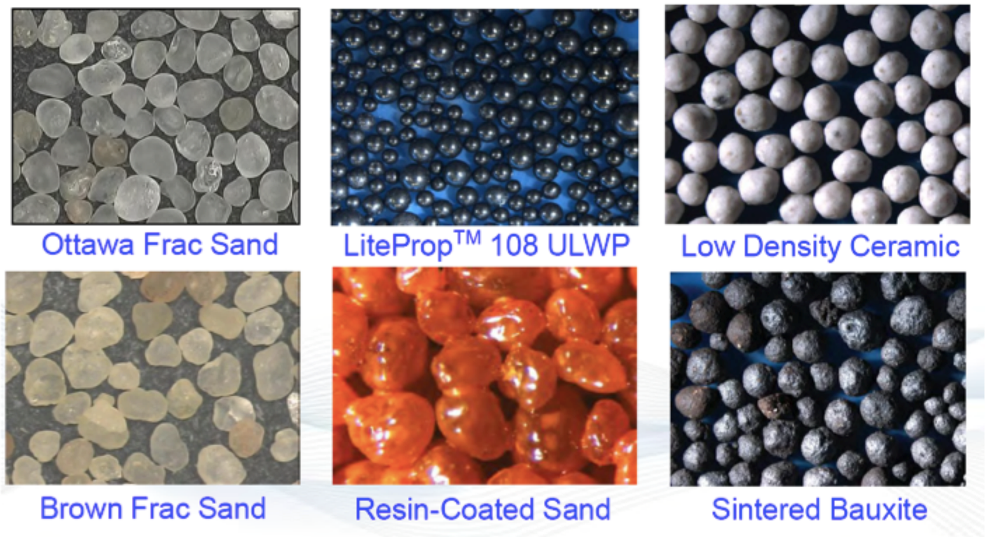


Figure 2.2 some common proppants used in hydraulic fracturing.

Hydraulic fracturing has traditionally been used in vertical wells that accessed only a specific portion of the producing zone. Multi-stage fracturing treatments in horizontal wellbores are now capable of accessing significantly larger producing zones, maximizing the amount of resources being recovered and minimizing the amount of surface space required [175].

2.4 Development of Shale Gas Areas

Much useful insight into water management needs and responses has been gained from experiences in the development of shale gas areas such as the Barnett Shale and the Marcellus in the United States, and the Horn River Basin and the Montney areas of Western Canada.

Each shale gas development area is substantially unique. As it undergoes its own development process, it will require its own set of field development procedures and water management approaches.

Shale gas development is occurring in British Columbia, Alberta, Saskatchewan, Quebec, New Brunswick, and thirty-four US states.

Normally, exploitation of a shale play proceeds through five distinct phases: discovery, drilling and reservoir evaluation, completion, production, and shut down and remediation [87].

1. Discovery

Discovery and planning is the stage during which all of the initial reservoir knowledge is gathered. Extensive analysis, including coring, establishes the economic viability of the play during this phase, and helps determine the techniques to be used to optimize the development. The effectiveness of planning in the discovery stage depends largely upon knowledge of the reservoir [87].

2. Drilling and Reservoir Evaluation

Drilling and reservoir evaluation is the operational phase. During this stage, the focus is on applying the planned techniques most efficiently to maximize reservoir contact and reduce the cost per unit. It is in this stage of development that the issues concerning infrastructure and practical efficiencies are addressed. This is the present state of several currently active shale plays [87].

3. Completion

Completion includes all of the activities and methods to prepare a well for production after drilling, including hydraulic fracturing and installation of equipment for production from a gas well.

4. Production

Production is the phase of development where commercial amounts of hydrocarbons are produced by the well. The production of a well typically lasts from a few years to a few decades [87].

5. Shut Down/Remediation

Shut down and remediation of wells that have produced all their economically viable petroleum must proceed in an environmentally responsible manner. This consideration should be taken into account at the outset of the project. Where will used flowback fluid be disposed of? Will any hazards be introduced by the production procedures? What reclamation procedures will be needed?

3.0 Integrated Water Management Plan

Water volumes for fracturing operations are on the rise, and it is essential to consider how much water will actually be available when planning operations. The cost of treatment and environmental issues are limiting factors that can be mitigated by smart use of water through treatment, reuse and recycling.

Application of advanced treatment technologies and chemical conditioners is expensive, and can easily reach to millions of dollars over the life of the project, so it is essential that the operator arrives at a rationalized decision regarding water management and chemical use early in the project development to minimize costs.

An Integrated Water Management Plan should include the following elements:

- Water Sourcing.
- Water Delivery and Logistics.
- Water Storage.
- Water Treatment and Reuse.
- Water Disposal.

A change in one of the elements of the water management plan is likely to have a significant impact on the other elements. A water needs assessment is a first step, but needs may be reduced or re-evaluated as innovative solutions arise.

An example of a change that would have an impact on other elements of the water management is a change in the decision regarding how much flowback will be reused for subsequent fracturing processes. This decision will affect the volume of water needed at source, and the volume of flowback fluid that must be disposed. This diagram is basically a brief introduction to the broad issues more thoroughly explained in the Decision Tree included in this report.

A graphic portrayal of an Integrated Water Management Plan is shown in Figure 3.1.

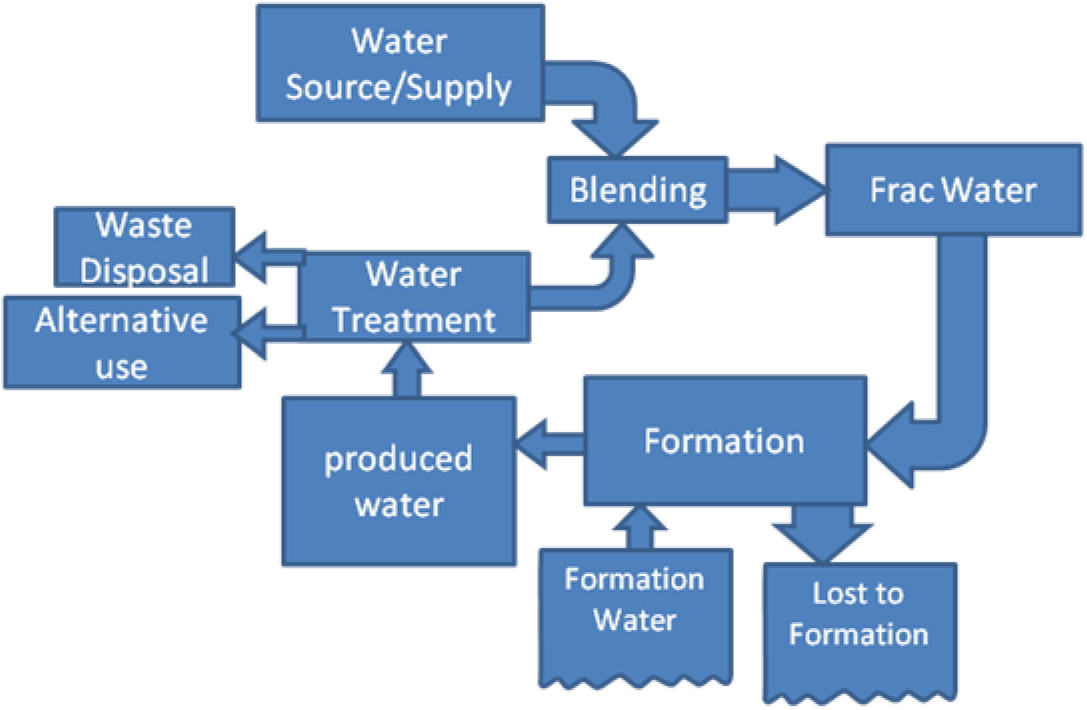


Figure 3.1 Elements of Integrated Water Management Plan.

Questions associated with such a plan include the following:

- **Source Water Acquisition**
    - Where will the water supplies needed for hydraulic fracturing operations be acquired [2]?
- **Transport**
    - How does the water get from the source to the well site and from the well site to the point of treatment and/or disposal [2]?
- **Storage**
    - What requirements and constraints exist for water storage on site, and how do source water considerations and fracture fluid requirements affect storage requirements [2]?
- **Use**
    - How will the water be used, what volume is required, over what period of time and what must be done (e.g. the addition of proppant and additives) to achieve the fracturing objectives [2]?

- **Treatment and Reuse/Recycle**
  - Can the water produced from the fracturing operation be treated and recycled for reuse [2]?
- **Treatment and Disposal**
  - If the water is not to be recycled and or reused, what must be done either prior to disposal or with any treatment byproducts [2]?

The drilling plan that is to be the basis for development of the Integrated Water Management Plan should include, as a minimum:

- Number and location of vertical wells to be drilled.
- Duration of drilling/fracturing season.
- Number of stages to be fractured in vertical wells.
- Type of fracturing for vertical wells.
- Volume of water to be used per vertical stage fractured.
- Expected flowback from vertical wells as percentage of pumped volume.
- Number and location of horizontal wells to be drilled.
- Number of stages to be fractured in horizontal wells.
- Type of fracturing for horizontal wells.
- Volume of water to be used per horizontal stage fractured.
- Expected flowback from horizontal wells as a percentage of pumped volume.
- Determination which wells are single well per lease or multi-well per pad.
- Identification where wells are to be drilled to identify where water is required.
- Projections of conceivable drilling scenarios in subsequent years.

The evaluation of water needs developed from this will be an iterative process worked out with the operator's drilling department. Since no drilling plan stays the same for very long, the water management plan must be capable of rapid and frequent adjustment.

Depending on the complexity and time duration of the drilling/completion plan, the projection of water needs may cover a time period of up to 15 – 20 years. The duration of the Water Management Plan will be driven by the necessary lead time to allow for fiscal planning and water infrastructure development.

A "do nothing" approach might be a valid option. Many factors need to be weighed.

The first option with regard to management of flowback water is to do nothing. Under this scenario, the operator may choose to use the flowback water directly in the next fracturing treatment, or to send all flowback water to disposal. If direct reuse is chosen, they may be subject to higher pumping costs, equipment failures, loss of viscosity, scale deposits on equipment and in the formation, and increased formation damage resulting from poorer fracturing fluid performance. The other “do nothing” approach is to dispose of the untreated flowback water as an oilfield waste. The volumes of fluid requiring disposal are often quite high (20 - 30% of the original volume of water used in the fracturing is in the order of 19,000 m^3). Assuming 40 m^3 per truck load, that equates to 4750 loads sent to the nearest disposal well. If an operator chooses this route, it should first consider the economic viability of other reuse alternatives.

3.1 Change Source Water

In cases where water quality issues arise because the source water contains constituents that are incompatible with the flowback, the formation water and/or the fracturing additives, it may be possible to address the incompatibilities by changing the chosen source water to a water that is more physically or chemically compatible with the fluids and additives being considered for the fracturing treatment, thus eliminating or reducing the need for using expensive conditioners or advanced treatment technologies.

Alternative water sources with more chemically suitable water are not always available. The evaluation of water source options and chemical compatibility is normally conducted as part of the planning process in the development of the Integrated Water Management Plan.

3.2 Blending or Dilution

The most basic solution for obtaining usable fracturing water from flowback fluids is to blend with fresh water. This option is commonly considered before more extensive and more costly remediation options.

3.3 Blending Process

The simplest treatment approach is to dilute or “blend” the poor quality water with a water of better chemical or physical quality until the desired concentration of troublesome chemical parameters is reached.

The kinds of scenarios that might be workable is if there is a desire to use flowback water that has a chloride content above 60,000 mg/L but that the high chloride pushes the cost of water conditioning and fracturing additives to unacceptable levels. If water of better quality is available, such as surface water from a nearby lake, then simple dilution of the flow back water with surface water will bring the mixed water, now to be used for fracturing, into a chloride range below 60,000 mg/L, in which case lower amounts of less expensive fracturing additives can be used. The economics of this scenario is improved by the fact that the flowback water is essentially free, except for the cost of storage and minimal costs associated with removal of solids.

Blending is most effective in situations where it is desirable to reuse flowback water. This is relatively straightforward when the salinity of the flowback is low to moderate and the flowback load recovery is low.

There are two drivers that lead to the consideration of blending to address water management issues:

- Reduce the need for source water.

In cases where there is a limited amount of source water available for hydraulic fracturing, or if the cost of source water is very high, consideration may be given to supplementing the source water (commonly a surface water or groundwater) with flowback water from hydraulic fracturing operations, or produced water that has been generated as part of ongoing oilfield production operations.

- Reduce the cost of disposal of flowback water.

Hydraulic fracturing operations generate flowback water that requires management. The volume of water that flows back from fracturing operations varies from well to well, but can be significant. Because the flowback must be disposed of if a use cannot be identified, it becomes a financial liability to the operator. By virtue of the volume of flowback water that is created, the liability is significant. Commonly, flowback water and other produced waters are disposed of by deep well injection. In cases where the cost of deep well injection is very high, consideration may be given to reducing disposal costs by using the flowback water, usually for subsequent hydraulic fracturing operations to reduce the need to dispose of produced water.

Similarly, the use of water from very saline aquifers where water salinities are in the order of 120,000 mg/L (such as in some of the Devonian zones) can be made attractive through the dilution with surface water. This approach minimizes the volume of fresh water required in a system, or makes using saline aquifers more economically attractive. This presupposes that there is a surface water supply that is available by permit, but there is either not enough surface water available either because of hydrologic factors or regulatory constraints to be a viable single source supply.

In scenarios where the original source water has high salinity and the flowback load recovery is high and formation fluid salinity is very high, the blending capacity may be limited.

An initial determination is a simple calculation of the dilution of one fluid in a second fluid. Simple calculations allow the determination of the concentration of blended constituents in the fixed proportions. Following the determination and selection of the constituents in the blended fluid, it is advisable to run the chemistry of the two fluids to be blended to determine if there are compatibility issues at the blending concentrations selected. If compatibility issues are present, some adjustment in using scale inhibitors may be necessary.

While blending water from multiple sources may resolve issues related to the volume of source water needed, blending waters from a variety of sources tends to create problems in water quality and compatibility that may require the application of advanced treatments after blending is completed.

Whereas blending is an effective mechanism to reduce the concentration of chlorides or other objectionable water constituents, blending may or may not be an effective mechanism to reduce scaling tendencies. Case studies conducted as part of this project suggest that scaling tendencies may in fact increase with blending of waters of differing chemical makeup.

In situations where access to source water is limited, and/or using produced water is compelling the source water being considered for fracturing purposes may be a mixture of water from a variety of sources, including produced water, surface water, or groundwater. This introduces the need to consider a formalized blending process in order to reduce concentrations of objectionable constituents, and to keep water quality as stable as possible. When blending flowback water, care must be taken in confirming that the chemistry used in the blending calculation matches the actual chemistry of the flowback water.

In settings where the salinity of the flowback fluids is high, and the flowback load recovery is high, the phenomena of “salinity creep“ may be observed whereby the salinity of the flowback of the source water increases with each successive fracturing event, requiring that the blending ratio be re-calculated prior to each time that the flowback is used.

For practical purposes, the reuse of flowback water can be accomplished for six to eight fracturing treatments before the quality of the flowback water deteriorates due to the presence of residual chemicals. These residual chemicals make its continued reuse unattractive. In such cases, the flowback water is commonly used in a “slickwater fracture” and new water is introduced to the fracturing process.

Advantages of blending techniques include:

- Only simple calculations are needed to determine effectiveness of blending.
- It can be very cost effective.

- No chemicals are needed beyond possible adjustment of pre-fracturing water conditioners.
- No waste products are made from the blending process.
- Only relatively simple logistics and oversight are needed.

Disadvantages of blending techniques include that they:

- May be limited by volume and concentration of flowback fluids produced.
- May require additional storage capacity for pre- and post-treatment storage.
- May have to be combined with using water conditioners or more advanced water treatment techniques.
- May not resolve scaling problems.

3.4 Pre-Fracture Treatment

During the pre-fracture treatment period, the water samples from the water sourcing options, detailed chemical analysis of water samples from the various surface waters, groundwater, produced water, and other sources will be evaluated against the chemical characteristics of the water in the formation that will be fractured. At this point, the primary consideration is the compatibility of the fluids. In addition to the fluid compatibility, the mineralogy of the formation to be fractured will be assessed to determine whether there are water sensitive clays that will require stabilization.

The outcome of the pre-fracturing assessment is the determination of the need for adjustment of water quality parameters through the application of water conditioners or water treatment technologies. The next step in the fracturing fluid planning process involves a comparison of the constituents in the “conditioned” source water against the fracturing additives that are proposed for the fracturing method selected.

Based on the results of the review of the sensitivities of the proposed fracturing additives to constituents in the conditioned source water, the conditioners and additives may require adjustment in terms of dosages, and types of additives being proposed for the fracture treatment.

The impurities that affect the desired fracturing fluid properties include:

- Chlorides increase demand for friction reducers and scale inhibitors.
- Scale potential.
- Suspended solids (> 25 microns).
- Bacterial growth.
- Crude oil effects on friction reducer.
- Scale & corrosive materials affect downhole and surface production facilities.
- Adding inhibitors affects friction reducers.

In a worst-case scenario, water quality issues identified at the planning stage may require a change in the choice of source water, or a change in the type of fracture treatment being proposed.

3.5 Flowback Period

If the reuse of flowback fluids is being considered, then a detailed characterization of the likely chemical constituents in the flowback, including the presence of fracturing additives that are included in the fracturing plan must be examined. The evaluation of flowback water includes the same parameters implicit in the pre-fracturing selection of source water for the fracture treatment, plus the additives and conditioners that have been added to the fracturing fluid including H_2S, CO_2 and temperature. This characterization and the characterization of the source water will be used to determine what, if any, supplemental water conditioning or treatment is needed before the fracturing flowback water can be reused for hydraulic fracturing purposes. Because the characteristics of flowback fluids changes with time, it is important that the characterization of flowback characteristics include a time series of analyses over the flowback period.

3.6 Pre-Disposal

Waters that do not meet water quality specifications for hydraulic fracturing and cannot be cost-effectively conditioned or treated become surplus to the needs of the hydraulic fracturing program (such as at the end of the fracturing season) and may require disposal. Determination of the chemical and physical characteristics of the waste stream must be considered as part of the disposal process. These disposal streams may include treatment wastes, and Naturally Occurring Radioactive Materials (NORM) bearing sludges for treatment processes. Different wastes and disposal technologies will determine the parameters that need to be quantified as part of this process.

The final step in the process is a compatibility check. All additives that have been identified throughout the process should be checked for incompatibilities and evaluated on the friction loop to confirm performance of the optimized fluid. If flocculation or incompatibilities result at this stage of the process, a different additive should be suggested and retested with the appropriate analytical tool.

4.0 Characterization of Source Water and Flowback

A detailed understanding of the chemical constituents present in source water, formation water, and fracturing flowback fluids is essential to effective management and decison making.

Samples of all waters to be involved in the hydraulic fracturing operations should be collected according to procedures and protocols that will ensure that results are representative and usable. These samples should include water present in the oil reservoir, as well as all available sources of potential injection water. The characterization of the source water chemicals must be adequate to understand any seasonal variability in water chemistry that might be inherent in the water source.

Often the only water analyses in formations above the oil reservoir that might be considered as supply water are those obtained from a drill stem test (DST) taken during drilling of the oil well. This emphasizes the importance of taking the necessary time and precautions essential to obtaining reliable DST water samples and information from existing databases.

Each hydraulic fracturing application will have its own set of water quality requirements. Water quality requirements are application and site specific. They may be set by industry or they may be determined by some regulatory agency.

4.1 Flowback Fluid Composition

Sampling programs have identified the typical components of shale gas fracturing flowback fluids. While proportions vary among formations, there is a consistent list of core components.

The range of total dissolved constituents varies from 10,000 - 250,000 mg/L; the salinity ranges are similar, pH typically ranges between 5.0 - 8.0, and most flowback contains:

- Additives used in fracturing.
- Products of reactions between different additives.
- Substances mobilized from within the formation.
- Substances contributed by multiple sources.

Flowback components detected in one set of analytical results included:

- Components of fracturing fluid.
- Dissolved solids (chlorides, sulfates, calcium).
- Metals (calcium, magnesium, barium, strontium).
- Suspended solids.
- Mineral scales (calcium carbonate; barium sulfate).
- Bacteria (acid producing bacteria; sulfate reducing bacteria).
- Friction reducers.
- Iron solids (iron oxide; iron sulfide).
- Dispersed solids (clay fines, colloids, silts).
- Acid gases (carbon dioxide; hydrogen sulfide).

Since flowback components are influenced by many different factors, they may vary over time. Limited time-series field data from Montney Shale flowback, taken at different times, showed:

- Increased concentrations of total dissolved solids, chloride, and barium.

- Increased radioactivity levels.
- Increased calcium and magnesium hardness.
- Increased concentrations of iron-controlling additives were not used.
- Decreased sulfate levels.
- Decreased alkalinity levels (likely due to acid use).
- Increased metal concentrations.

Fracturing fluids pumped into the well and materials mobilized within the shale contribute to changes in hardness, sulfate, and metals. Specific changes depend on the shale formation, the fracturing fluids used, and fracture operations control.

While some fracturing fluid additives are consumed in the well (e.g. strong acids) or react during fracturing to form different products (e.g. polymer precursors), most additives will be present in flowback water. The Generic Environmental Impact Statement (GEIS) identified several flowback components as significant environmental concerns:

- High Total Dissolved Solids (TDS).
- Chlorides.
- Surfactants.
- Gelling Agents.
- Metals.

Other additives of concern not identified in the GEIS include corrosion inhibitors, friction reducers, and microbiocides.

The physical and chemical characteristics that require quantification as part of the characterization of waters for sourcing purposes and for determining compatibility of formation fluids are listed below.

Table 4.1 Physical and Chemical Water Characteristics.

pH	Electrical Conductivity	Temperature (°C)	Specific Gravity	Fluid Density (kg/m^3)
Titrated Chlorides (mg/L)	Total Suspended Solids, TSS	Total Dissolved Solids, TDS (mg/L)	Salt %	Total Hardness (mg/L)
Sodium Na^+	Potassium K^+	Calcium as $CaCO_3$ (mg/L)	Calcium Ca^{2+} (mg/L)	Magnesium as $MgCO_3$ (mg/L)
Magnesium Mg^{2+} (mg/L)	Total Iron (mg/L)	Sulfates (mg/L)	Carbonate Alkalinity (mg/L)	Bicarbonate Alkalinity (mg/L)
Total Alkalinity (mg/L)	Scale Inhibitor (mg/L)	Barium, Ba^{2+}	Strontium P.S. (mg/L)	Bacteria
Petroleum Hydrocarbons	Dissolved Oxygen			

Other optional parameters that may be quantified as part of the water characterization include residual fracturing additives, dissolved metals, and radioactive constituents. Sampling plans and analytical protocols should consider the seasonal or temporal variability of the physical and chemical constituents in potential water sources.

Sequential flowback sampling (every 80 m^3 of flowback is recommended for the initial sequential testing) is a method to gain an understanding of the interactions between the fracture fluid, formation, and connate water. Figures 4.1, 4.2, and 4.3 are examples of sequential flowback analysis.

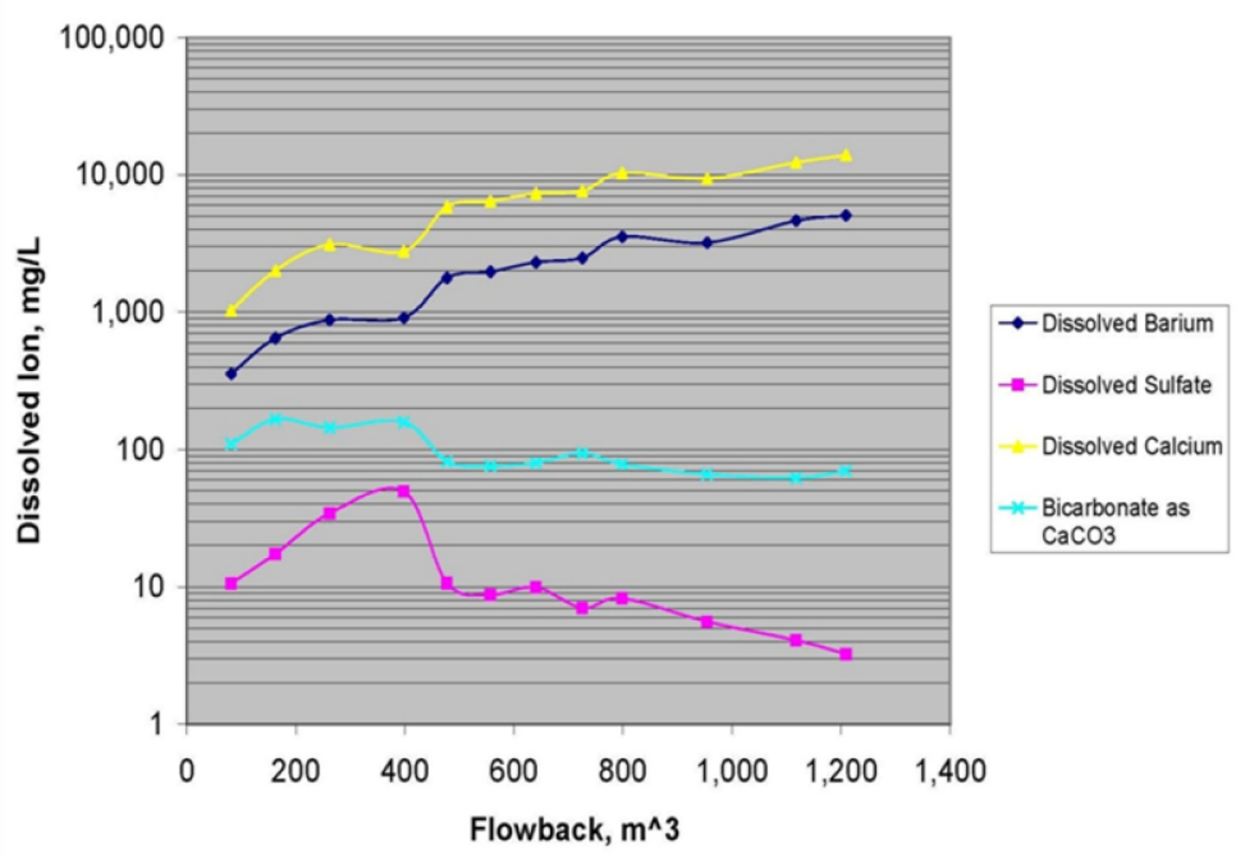


Figure 4.1 Concentrations of several typical scaling constituents in flowback fluid.

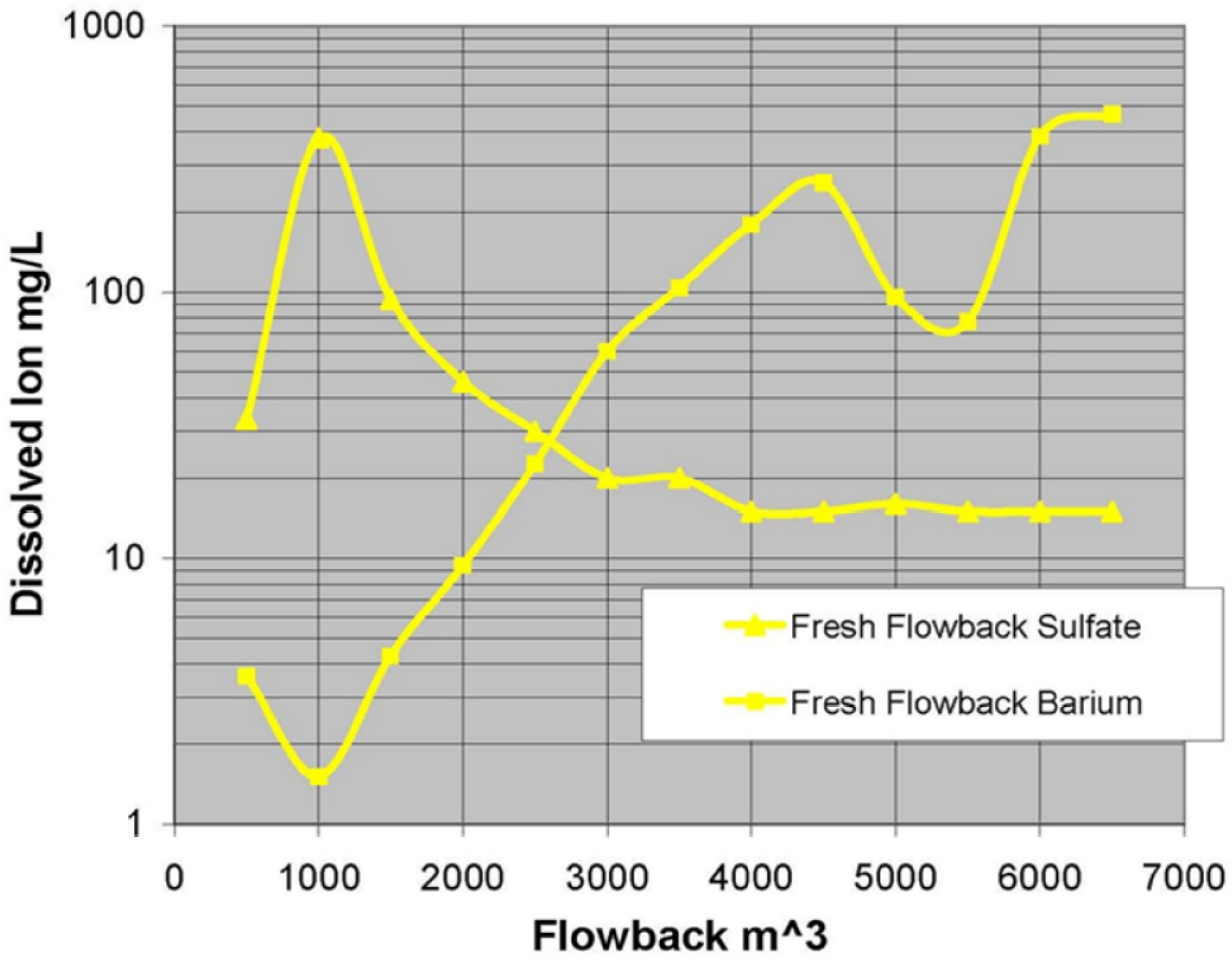


Figure 4.2 Flowback analysis of sulfate and barium from a fresh water based hydraulic fluid.

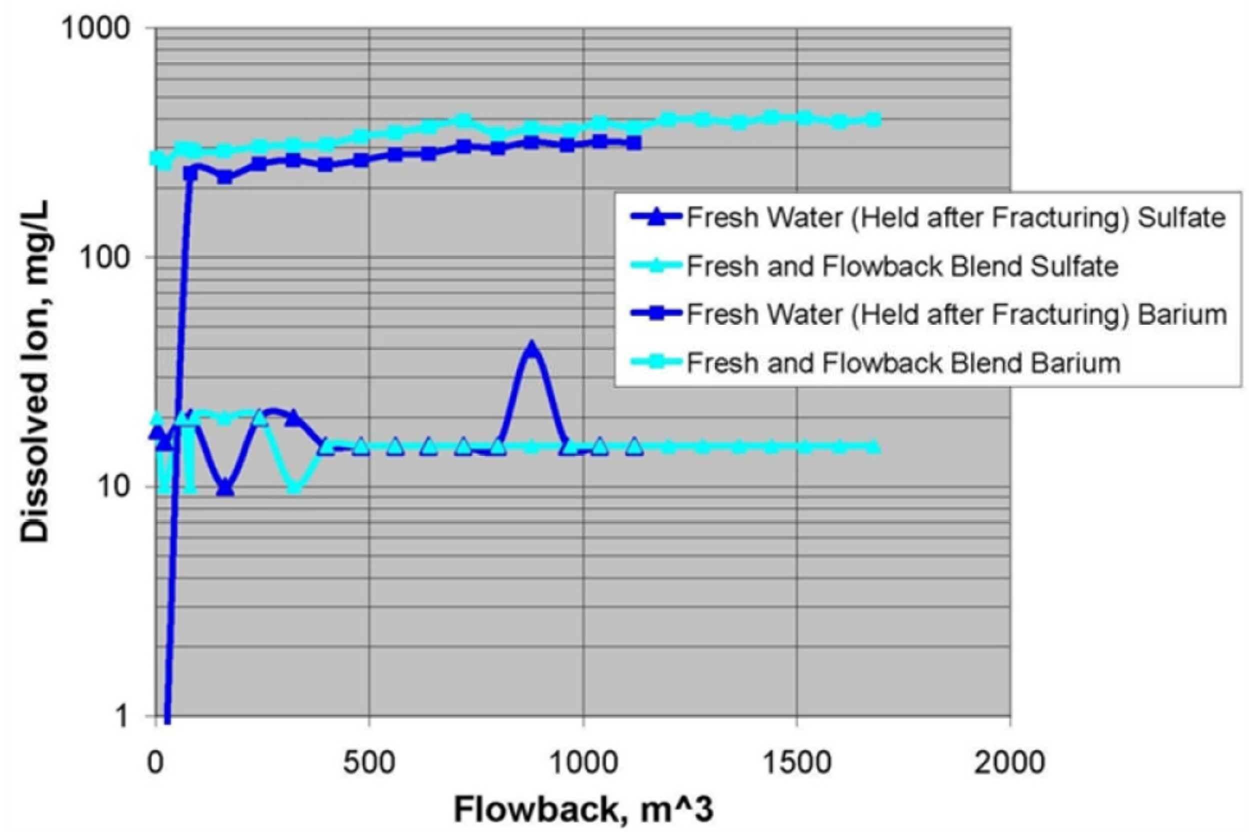


Figure 4.3 Flowback analysis of sulfate and barium from a blend of flowback and fresh water based hydraulic fluid.

4.2 Residual Fracturing Additives in Flowback

One concept for estimating the potential of chemical ingredients in additives to concentrate through successive reuse is that of concentration factor.

When we discuss concentration factor of residual additives we must first define it. Concentration Factor as we are going to define it is going to be the additive effect of a particular chemical ingredient, and its degradation products, in the fluid over successive reuse cycles.

An example of the impact of successive reuse is shown in Figure 4.4. The figure illustrates the accumulation of an additive when all of the flowback is reused for four wells (Wells 2 through 5). It is assumed that there is no degradation of additive and that none of the additive is absorbed or adsorbed in the formation. The volume of hydraulic fracture fluid in the example is 20,000 m^3

and additive is dosed at rate of 0.3 L/m^3. Flowback recovery is 50% of the hydraulic fracture fluid.

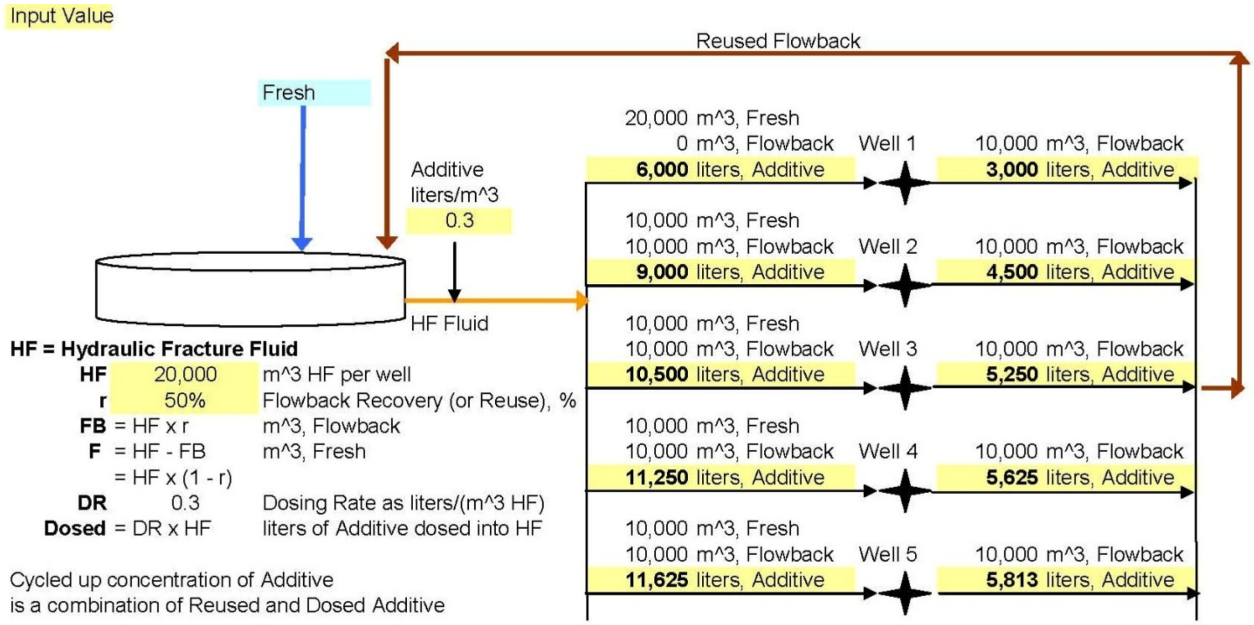


Figure 4.4 Impact of successive reuse.

The hydraulic fracture fluid for Well 1 is 20,000 m^3 of fresh water with 6,000 L of additive. Assuming no degradation of additive and that none of the additive is absorbed or adsorbed in the formation and that flowback recovery is 50%, then the flowback is 10,000 m^3 of fluid which has 3,000 L of additive. The other half of the fluid and additive remains in the formation. This fluid is mixed with fresh water for the fracturing of Well 2.

The hydraulic fracture fluid for Well 2 is 10,000 m^3 of fresh water and 10,000 m^3 of flowback. The flowback has 3,000 L of additive. Additive is dosed into this 20,000 m^3 blend at the rate of 0.3 L/m^3, which means that 6,000 L of fresh additive is added to the blend. The total additive in the blend is 9,000 L. Assuming no degradation of additive and that none of the additive is absorbed or adsorbed in the formation and that flowback recovery is 50%, then the flowback is 10,000 m^3 of fluid which has 4,500 L of additive. This fluid is mixed with fresh water for the fracturing of Well 3.

This process is repeated for Wells 3, 4 and 5. The blend fluid injected into Well 5 contains 11,625 L of additive. The loss of additive in the formation and the addition of fresh additive eventually reach a steady state balance. At this point there is 12,000 L of additive in the blend of fresh water and flowback. In this example the steady state concentration factor is 2. The steady state Concentration Factor can be expressed by the following formula:

$$\textbf{Steady State Concentration Factor} = \frac{\textbf{1}}{\textbf{(1 - \% Reused Flowback in Blend)}}$$

It is important to note that Concentration Factor does not depend on dosing rate of the additive. It depends only on the % of reused flowback in the blend.

Figure 4.5 shows the impact of % of reused fluid in the blend on Concentration Factor. It is also noted that the time required to reach steady state is longer at higher % reuse.

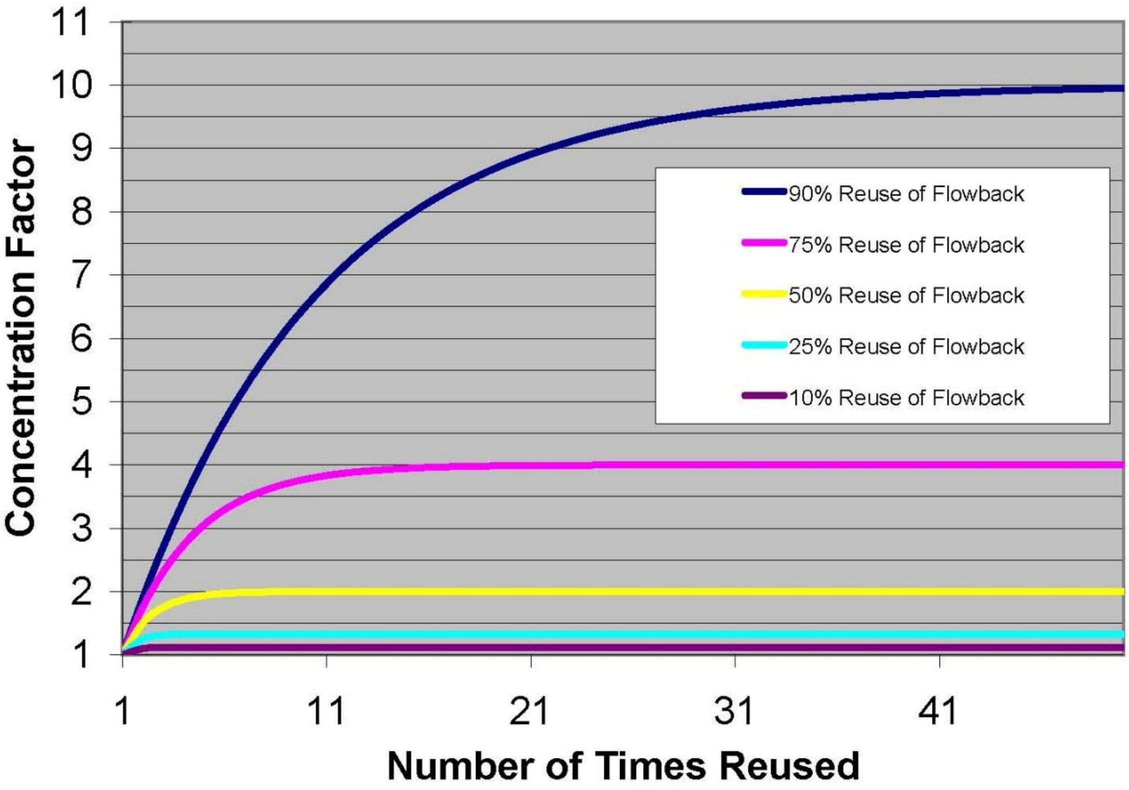


Figure 4.5 Impact of reused fluid.

The actual Concentration Factor of residual fracture additives is the result of a number of factors that all must be considered. The persistence of the additive itself is one of the main governing factors. That is the amount of a specific additive that does not either permanently associate with other components in situ or is degraded into a different form. The in situ associations can take the form of adherence to the rock through chemical interactions of active groups or phase associations with organic or inorganic states. Complexes can also be from dissolution products reacting with the additive to make new species. The complexes or associations can be temporary as environment changes such as temperature, pressure and fluid shear can act to remobilize these constituents resulting in different amounts being returned at different times during flowback cycle.

Additive degradation can occur through chemical reaction with fluid components, exposure to temperature and mechanical shear. These can all act to degrade the additive into a non usable form that may have nuisance or harmful side effects, or that might not have any impact.

The other factor effecting concentration is the differential mobility of carrier fluid to the component of concern. This is most prevalent in polymers that will be mechanically retained while allowing carrying fluid to leakoff. This is a result of molecular size of polymer being effectively filtered and carrying fluid to be removed from the cycle as a irretrievable filtrate.

This is important because as the component is concentrated a point can be reached that a maximum amount of component exists that the fluid will not be useful anymore due to interference of its function or side effects of high concentrations such as formation damage.

The additives which could be expected to accumulate to a measurable level include friction reducers, corrosion inhibitors, scale inhibitors and some biocides.

All these different species in the flowback water can have detrimental chemical affects on additives envisioned to be used for future treatments (e.g. disruption with biocide efficacy, ability of polymer to induce drag reduction, etc). This could lead to souring of the well or scaling of the wellbore.

There has been little or no discussion in the literature on how the residual additives can affect performance of these fracturing fluids and this is an area of further study.

As an example, reuse of flowback from crosslink fluids might create problems with fresh additives because two key components must be kept within a tight window. The crosslinker must be kept within a given concentration range, if this range is exceeded over crosslinking can occur that severely changes fluid performance. If this range is exceeded in base fluid before additive addition, it is impossible to get fluid performance without conditioning the water first. Likewise if too many buffering agents accumulate in flowback cycles a fluid of adequate performance is impossible to achieve. With all these factors it is very important to manage the residual additives and their concentration as part of the water management strategy.

4.3 Databases

In the early stages of planning the drilling and fracturing programs for shale gas development, a detailed understanding of the water quality of potential water sources or the formation characteristics of the formation to be fractured is frequently not known. Nonetheless, preliminary information regarding water chemistry and quality may be available from existing oilfield and environmental databases.

While water quality information available from these databases may be incomplete, it provides the basis for a first approximation of the water quality of the water sourcing options and the formation fluid. Identification of any prohibitively problematic water constituents identified during this initial characterization can result in significant savings in water development costs.

Databases that may provide initial insight into water quality include:

- Hydrogeological Databases maintained by provincial governments.
- Waterwell files (Alberta Environment, AE).

- Water Quality data reported by Facilities operating under Environmental Approvals (Alberta Environment, AE).
- Hydrogeological base maps (Alberta Geological Survey, AGS).
- Reports In Support of Application to Divert under Water Act (Alberta Environment, AE),
- Surface water databases.
- Oilfield databases (Energy Resources Conservation Board, ERCB).
- Oilfield databases (private by subscription).

5.0 Decision Tree

The Decision Tree is intended to provide a method for the evaluation of reusing flowback in hydraulic fracturing operations. The Decision Tree is not intended to serve a prescriptive method. It is intended to provide a method and framework for a consistent approach to answering a set of interdependent questions. The Decision Tree can also serve to evaluate the use of alternative sources of water, such as saline water or municipal wastewater.

Step 1 of the process presumes a certain amount of information, data, and knowledge about the formation and flowback water characteristics. This information will not likely be available in the early stages of development and forces the user to make assumptions until the data becomes available.

The Decision Tree is most useful when the characteristics of the formation, flowback fluid, and the presence of residual additives are well understood. The next sections describe that characterization.

Step 1. Select the percentage of flowback to blend with source water.

The initial step in the decision tree process is to collect the necessary information and assumptions required to develop an approach to managing the flowback water and managing the water issues.

Water management using the tree is an iterative process, and some initial assumptions regarding the fracturing are necessary. The information required in Step 1 includes assumptions regarding the hydraulic fracturing that is being proposed, including:

- Fracturing Treatment Type.
- Volume of Fluid to be Pumped.
- Water Conditioning and Fracturing Additives.
- Fracturing Fluid Recovery.
- Bottomhole Pressure and Temperature.
- Assumption of Blending Ratio.
- Chemical Analysis - Rock Core.

Fracturing Treatment Type

The provisional selection of the fracture type will allow the identification of sensitive constituents in the source, flowback, and formation waters to be identified and addressed. Dozens of fracturing types and hybrids are available, however, for the purposes of this decision making process, the four fracturing types most commonly applied in shale development have been integrated into the decision tree. These are:

- Slickwater.
- Linear Gel.
- Crosslinked Gel.
- Viscoelastic.

Each of the fracturing types requires different chemicals or additives, and has differing sensitivities to the chemical constituents in the source water, flowback water, and formation water.

Fracturing treatment types are discussed in Section 2.0 of Appendix C.

Volume of Water to be Pumped

The volume of water to be pumped during the fracturing is the basis for projecting the volume of flowback that will be generated, and which must be reused or otherwise managed.

For horizontal wells, the total volume pumped is the product of the number of stages pumped and the volume of fluid pumped per stage.

Water Conditioning and Fracturing Additives Likely to be Needed.

There are two types of chemicals used during a hydraulic fracturing operation:

1. Chemical additives are added to the hydraulic fluid to act as conditioners to modify the properties of the water to achieve a desired purpose (e.g. reduce friction, suspend proppant, reduce scaling, bacteria, and corrosion). These conditioners may include:
    - Acids.
    - Biocides.
    - Scale Inhibitors.
    - Iron Sequesters.

2. Certain chemical additives are required by each specific fracturing type. These additives include:
    - Friction Reducers.
    - Gels.
    - Crosslinkers.
    - Breakers.

These chemical additives are discussed in Section 1.0 of Appendix C.

Fracturing Fluid Recovery

The volume of fracturing fluid that flows back from a fractured well after pumping stops is known as flowback recovery and is commonly expressed as a percentage of the total volume of fracturing fluid pumped into the well during the fracturing operation. The flowback recovery is variable from formation to formation, and from area to area within a specific shale gas development area. The observed flowback recovery varies between 5% and 70%. A rule of thumb, in the absence of actual data, is a flowback recovery of 30%. As the history of fracturing and flowback recovery in any particular shale gas area becomes more extensive, trends begin to appear and the recovery percentage estimate can be adjusted.

An estimate of the flowback recovery is an essential part of the decision tree process. The flowback recovery becomes the basis for generating blending ratios, which determine the chemical characteristics of the hydraulic fluid.

Bottomhole Pressure and Temperature

Compatibility of source water, flowback, and formation water is a function of the chemical constituents and concentrations, as well as temperature and pressure. Bottomhole pressure and temperature are required to make a determination of compatibility. Water chemistry and geochemical simulators can be used to calculate scaling indices over a range of pressures and temperatures.

Assumption of Blending Ratio

The selection of the blending ratio that is initially being considered may be based on the objective of:

- Avoiding disposal costs of the flowback fluid.
- Reducing source water needs.

As an example, if the total fracturing volume is 20,000 m^3, and the flowback is expected to be 30%, that means that a blending ratio of 70% fresh and 30% flowback is needed to use all of the flowback. The blending ratio is often expressed as a percentage to facilitate determining the compatibility of fluids for a range of mixes using the geochemical simulator. The above blend would be expressed as 70:30.

The selection of a blending ratio is usually not relevant for the first fracturing treatment conducted in a drilling season when no flowback water is available, and the fracturing fluid is made from 100% source water. In this case, move to Step 2 without setting the blending ratio.

Chemical Analysis – Rock Core

In addition to the chemical analyses conducted on the fluid, it is necessary to determine the presence of sensitive clays (Section 5.0 Appendix A), which may be present in the rock formation. The common clays that account for most of the real and perceived clay problems are kaolinite, smectite (montmorillonite), illite and chlorite. Predicting the response of a certain clay to water flow is almost impossible without testing. The common technique for identifying the clay mineralogy is with a Scanning Electron Microscope. After identification of sensitive clay types, laboratory core flow tests are typically required to determine if clays are reactive with the fracturing fluid. The results of the analyses of rock core will be used to identify the need for clay stabilizers.

When the physical and chemical characteristics of the source water, flowback water, and formation water have been appropriately determined, and a provisional blending ratio has been selected, go to Step 2.

Step 2. Run compatibility model on the blend to check for fluid scaling.

The chemical analyses generated in Step 1 become the input that is used in this step. The scaling tendency of the source water, formation water, and the flowback water are determined using a geochemical simulator (see below). In addition to the scaling tendency of the individual fluids, the scaling tendency for a range of blends of fluids (source water blended with flowback, water) can be determined.

Examples of the output from a compatibility simulation are shown in the Case Studies section. Positive output from the geochemical simulator is indicative of a positive scaling tendency, while negative output is indicative of a corrosive condition. As a rule of thumb, for a scaling index of 1 or more for a carbonate scale, the use of a scale inhibitor is suggested. Any positive scaling index for a barite scale warrants consideration of the use of a scale inhibitor.

A standard set of geochemical simulations would include scaling indices for the following:

- Source water.
- Flowback water.
- Formation water.
- A blend of source water and flowback water.
- A blend of flowback water and formation water.
- A selected mix of blended source water and flowback water and formation water.

Geochemical Computer Modeling

A geochemical simulator may be used to predict the tendency for a wide range of geochemical precipitation from the shale completion flowback fluid. A geochemical simulator shows the tendency for specific mineral precipitates such as barium sulfate and iron carbonate to form. This process is used to ensure that the appropriate level of protection is being provided by the control chemical [14].

The software modeling program developed by Schlumberger contains an algorithm for scale prediction using information obtained from water analysis done on field mix water samples.

The concentration of each species detected in the water analysis is input into the software program along with the reservoir pressure and temperature.

The program then generates the different scaling species expected under such conditions and the relative amounts expected to scale out of solution.

This information is then used to recommend an appropriate scale inhibitor for treatment.

Because of the complexity of scale formation and the difficulty of the calculations, and the necessary thermodynamic and kinetic calculations to predict scaling, many computer programs have been produced to aid the user.

There are several general purpose geochemical models available in the public domain that can be used to predict formation of oilfield scale. Most of the models are available at no or minimal charge from the internet and have been extensively reviewed in texts on aqueous chemistry.

Geochemical models specifically adapted for oilfield scale prediction are also available but tend to be more expensive. An exception is the “Water Mixing and Scale Affinity Model” developed through the US Department of Energy. The databases of thermodynamic properties required for scale prediction tend to be better maintained and calibrated.

In addition to these models there are several proprietary scale prediction models that appear in the literature, but the access to these models is available through consulting agreement or with membership to the consortium of companies responsible for its development.

The geochemistry software programs/models available include the following:

- EQ3/6.
- PHREEQC and PHRQPITZ.
- MINTEQA2/Visual MINTEQ.
- The Geochemist’s Workbench.
- SOLMINEQ.88.
- ScaleChem.
- MultiScale.
- ScaleSoftPitzer.
- OKSCALE.
- Downhole.
- AquaChem.

Water Mixing and Scale Affinity Model

Once the scale indices are computed or scale analysis is completed, a comprehensive scale inhibitor program can be initiated if scale deposition is indicated. The type of scale inhibitor used in the system is based on the specific type of scale and the treating technique to be used.

Another way to evaluate compatibility is to mix the waters in definite proportion to test their compatibility. If an induction period is required before salt deposition occurs, it is important that the test be observed for a considerable length of time. If no reaction occurs that produces a deposit, it is advisable to seed the test waters with a crystal of the salt most likely to deposit. From the water analysis data of the individual waters, it is possible to calculate the composition of the mixed water. A prediction of which salt will be most likely to deposit can then be made. A few small crystals of this salt can be used to salt the test mixtures.

Step 3. Are the source water and flowback fluid compatible from scaling, bacteria, and corrosion perspectives?

Scaling

The results of the geochemical simulations in Step 2 are used to determine the compatibility of the source water and flowback water.

Bacteria

Bacteria in the fracturing fluid, if injected into the formation, can result in damage to the formation. In Section 2.0 of Appendix A, information about biocides is discussed to provide a basis for determining if the biocide of choice is compatible with the blend of source and flowback.

Corrosivity

Substances such as salts, acids, hydrogen sulfide, carbon dioxide and oxygen can result in damaging corrosion of tubular and surface equipment. Corrosion inhibition is discussed in Section 4.0 of Appendix A.

If the source water and flowback water are compatible, go to Step 9 to determine if the blend and the formation are compatible. If the source water and flowback water are not compatible with the formation, go to Step 4.

Step 4. Dilution.

Dilution is possible when disposal is inexpensive or storage is available.

Step 5. Water conditioning by chemical addition.

If the source water and the flowback are not compatible it is often possible to address the issues by chemical addition. Table A on the flow chart lists options for “Water Conditioning by Chemical Addition”. The chemical addition options are discussed in Appendix A.

Step 6. Is water conditioning by chemical addition a good option?

The use of chemicals as a conditioner in fracturing fluids is almost invariably a good option. As a rule of thumb, it is suggested that the least costly, simplest treatment technologies be used to meet treatment needs for fracturing fluids. There is a long history of the use of conditioners in the oil and gas sector, and the effectiveness of conditioners is well understood. Chemical conditioners have a wide range of uses and ultimately several conditioners are likely to be used in any fracturing job:

- Biocide.
- Corrosion Inhibition.
- Iron.
- Scale.
- Clay Stabilization.

Chemical conditioners are discussed in Appendix A.

The use of chemical conditioners may be integrated into a fracturing fluid design that includes pretreatment and or blending. In this step, the application of chemical conditioners in Table A is evaluated for the water issues expected during the fracture treatment, and the scaling tendencies identified in Step 2. This evaluation provides a basis for comparison to more treatment and management techniques identified in Step 8.

If the water conditioning by chemical additives is considered a good option, go back to Step 2 and confirm that the chemical addition addresses the incompatibility. If the water conditioning by chemical additives is not considered to be a good option, the use of more aggressive physical /chemical treatment techniques should be evaluated in Step 7.

Step 7. Evaluate water conditioning by physical/chemical water treatment to resolve identified problem.

If the source water and the flowback are not compatible and conditioning by chemical addition will not address the compatibility issues, then physical/chemical treatment options are evaluated. Table B lists options for “Water Conditioning by Physical/Chemical Treatment”. The treatment options are discussed in Appendix B.

Step 8. Is water conditioning by physical/chemical treatment a good option?

The use of physical/chemical treatment technologies becomes an option when other simpler or less costly techniques for achieving water quality objectives are not possible, and if there is a compelling need to reuse the flowback water.

The cost of the technologies must be evaluated against other options, such as disposal.

Application of advanced treatment technologies is expensive (easily in the millions of dollars over the life of the project) so it is essential that the operator arrive at rational decisions regarding water management and chemical use early in the project development to minimize costs. Implementation of an Integrated Water Management Plan, which is the recommended context for evaluating the implementation of physical/chemical treatment, is discussed in Section 3.0 of this manual.

Once the physical/chemical treatment technologies in Table B have been considered, and the water treatment technologies have been confirmed as a good option, return to Step 2 and confirm that the chemical addition addresses the incompatibility. If the physical /chemical treatment options are not considered good options, go to Step 19A.

Step 9. Are the blend and formation compatible?

Whenever there is a significant difference in either the composition or concentration of the injected water and the formation water that has been in contact with reservoir rocks for long periods of time, a potential for detrimental interactions exists. This is frequently the case when source water used for injection is different from the produced water.

Two types of compatibility or reactions related to water quality and water injection need consideration.

The first type of compatibility is concerned with precipitation reactions that might occur between the water that is being injected into the formation and the water that is already in the formation – this may be connate water or some other previously injected water. The testing described in Step 2 is appropriate for this compatibility evaluation. It is also noted that in the case of reused flowback, since the produced water came from the formation, it should be less damaging when re-injected into the same formation, particularly if care has been exercised to minimize chemical and physical changes in the water during production, separation, treatment and injection.

The second is concerned with chemical and physical reactions and interactions between the injection water and the formation rock in the injection zones. These reactions occur because of differences in chemical composition and concentration between the injection water and the water with which the rock has been in equilibrium.

There are two general mechanisms for formation damage or permeability impairment from injected water/formation rock interactions:

The first mechanism involves dissolution of formation minerals. In some cases, damage occurs when the dissolved minerals re-precipitate. In other cases, the dissolution of some minerals frees less soluble minerals that can move with the water flow and plug pore throats.

The second mechanism is concerned with the formation and liberation of fines. The fines then move with the water flow until they become lodged in a pore throat. Processes involved in this mechanism include: (1) clay swelling, (2) clay flocculation, (3) mica alteration, and (4) critical flow velocity.

There are a number of test procedures available to detect and identify possible damage. They include:

- Core flow tests (not to be confused with core flow tests to determine required water quality for injection).
- Mineral analysis of the formation rock.
- Chemical analysis of the waters involved in the fracture.
- Chemical analysis of the flowback.

The tests are usually run in the order listed. The rationale for this order is first to run the core flow tests to see if there is a problem. If there is, the mineralogical and chemical analyses can be used to determine the cause of the problem in the rock and water phases, respectively.

Step 10. Select hydraulic fracturing process.

The selection of the fracture fluid type is normally made by the completions team.

A mutual understanding between the water management team and the completions team improves the overall effectiveness of the program.

Step 11. Are the blend (including residual additives from flow back and added conditioners) and the hydraulic fracturing additives compatible?

The chemistry of recycled flowback becomes more complex with each successive cycle. Measuring the concentration of residual chemical ingredients and the degradation products against a high salinity background is a complicated task. The potential accumulation of residual chemical ingredients and their degradation products is discussed and a method for estimating the maximum concentration using the concept of concentration factor is presented in Section 2.0 of this document.

There is very limited information on the impact of residual chemical ingredients and their degradation products on fresh hydraulic fluid additives. Generally, slickwater fluids are the least sensitive, and cross-linked fluids are the most sensitive as noted in Appendix C.

Table 5.1 provides guidelines for evaluating the impact of concentrated residual chemical ingredients. Field testing is recommended for confirmation.

Table 5.1 Sensitivity of Fracture Fluids to Concentration Factor.

Hydraulic Fracture Fluid Type	Suggested Concentration Factor Threshold Requiring Additional Investigation	Additive or Additive Residuals which can impact fresh Fracture Fluid	Remedial Options
Slickwater Fluids	2	Friction Reducer	Breaker
Linear Gels	2	Polymer	Breaker
Cross Link Fluids	Field Tests Required	Borate	Disposal of Flowback or Physical/Chemical Water Treatment for Dissolved Solids
	2	Polymer	Breaker

	Field Tests Required	Buffers	Disposal of Flowback or Physical/Chemical Water Treatment for Dissolved Solids

Step 12. Conduct tests using field samples.

Once the conditioners and additives to be used in the fracturing are identified and provisional dosages are selected, the fracturing fluid design is tested using actual fluid samples collected from the field for the source water, formation water and flowback water using field samples. The objective of the test is to confirm that the fracturing fluid design will perform as predicted. These tests are routinely conducted by the hydraulic fracturing service provider or the operator's reservoir engineer. The tests may include bench scale tests, mixing or jar tests, and friction loop tests.

If field samples of the source water, flowback water, and formation water are not available, it is possible to recreate the chemical makeup of a fluid based on a historical analysis. These manufactured fluids then can be used to test the viability of the fracturing fluid design.

Friction Loop Testing

Friction Flow Loops are used for testing the effects of friction reducers by circulating at high rates through different pipe diameters. Friction Loop designs vary based on the application required. Data collected from friction loop tests can be used to predict and calculate friction pressures of the test fluid formulations in downhole conditions.

A friction loop consists of a pump, a pipe of known dimensions, a tank connected to the closed loop, and the tank feeds the pump and collects the effluent from the pipe section during pump operation (Figure 5.1). The friction loop allows for the measurement of the frictional pressure drop across the pipe section at different flow rates [19].

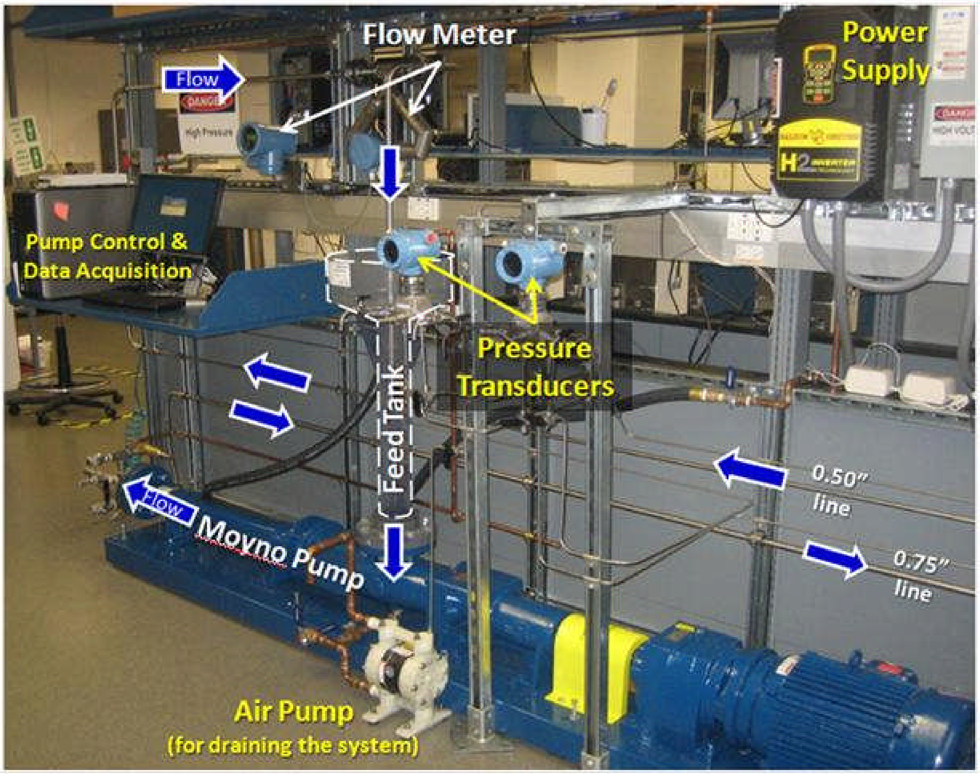


Figure 5.1 Friction Loop Tester.

For variable rate tests, a prepared fracturing treatment fluid is added to the friction loop hopper, and the test fluid is pumped for predetermined periods at incremental rates and drag reduction (%DR) is calculated using the following formula:

$$\%DR = (dP_{Water} - dP_{Fluid}) / dP_{Water} \times 100$$

Where;

dP_{Water} = differential pressure of water in 3/8 in. (0.952 cm) tubing, psi
dP_{Fluid} = differential pressure of the fluid in 3/8 in. tubing, psi
%DR = percent drag reduction with respect to water, dimensionless

Inversion Tests are used to quantify the length of time from polymer addition to evidence of reduced friction. For inversion tests, a selected amount of additive for the fracturing operation is mixed with the source water in a tank, and differential pressure gauges record the dP as time elapses.

Jar Tests

In spite of the power of existing geochemical models and the detailed analyses that are commonly conducted to identify water issues, questions regarding compatibility remain enormously complex, and it is common practice to conduct “mixing” tests in the lab or in the field using samples of the actual source water and conditioners and additives to verify the predicted chemical responses under operational conditions. The mixing tests, or “jar tests” are shown in Figure 5.2.

Water used for hydraulic fracturing usually contains a number of inorganic salts and sometimes organic salts in solution. It is common practice to test the compatibility of the injection water and water in the formation before starting an injection operation. Often this test is performed by mixing the injection water with the formation water in a glass container and observing to determine if a precipitate forms. The precipitate or scale can be analyzed to determine its composition. Waters are compatible if they can be mixed without producing chemical reactions between the dissolved solids in the waters that precipitate insoluble compounds.

Figure 5.2 Jar Test.

When the field testing work is complete, go to Step 13.

Step 13. Does HF fluid meet performance expectations?

The determination regarding the performance of the fracturing fluid is normally made by the fracturing service provider or the operator's reservoir engineer. If there are shortcomings in the performance of the fracturing fluid, adjustments may be made either based on pre-fracturing testing, or during the execution of the fracturing itself.

If the testing indicates that there are shortcomings in the performance of the fracturing fluid, the design of the proposed fracturing fluid is revisited (go to Step 11A). If the testing indicates that the performance of the fracturing fluid meets expectation, the execution of the fracturing can proceed (go to Step 14).

Step 14. Conduct HF process.

In Step 14, the hydraulic fracturing for which the fracturing fluid program is has been designed is executed using the fracturing fluid design. The elements of hydraulic fracturing are described in Section 2.0 of this manual.

When the fracturing is complete, go to Step 15.

Step 15. Collect flowback and as necessary perform analysis to characterize chemistry.

When the fracturing operation is complete, the next step is the completion of the well. The well test is conducted by a well testing contractor to determine the production characteristics of the well. The well is allowed to flow in a controlled manner for a period of time, which may extend several weeks.

In order to characterize the flowback process, it is desirable to monitor fluid production and collect water samples for analysis over the duration of the flowback test to establish the chemical characteristics of flowback with time (every 80 m^3 of flowback is recommended for the initial sequential testing). The parameters that should be analyzed are discussed in Section 4.0 of this manual. During initial sequential testing in a formation, field measurements of temperature, pH, conductivity, H_2S, flow rate and cumulative volume of water produced should be recorded hourly during the flowback period.

When the chemical and flow characteristics of the flowback have been documented, go to Step 16.

Step 16. Evaluate for health, safety and environmental considerations.

The sampling and monitoring of fluid properties produced should be conducted within the framework of a safety plan prepared and implemented by the operator's health and Safety Team. Thousands of shale gas wells have been drilled and completed using hydraulic fracturing techniques, and the need for safety measures and practices is well understood by the industry and regulators.

When health, safety, and environmental considerations have been identified, go to Step 17.

Step 17. Is the fluid nonflammable?

Fluids recovered from flowback commonly consist of a mixture of gas and fracturing fluid. Both the natural gas and the free phase hydrocarbon should be considered to be flammable (go to Step 17A). If the flowback is not considered flammable, go to Step 18.

Step 17A. Degas or treat with separator.

It is necessary to separate the gas from the fracturing fluid. If the produced fluids also contain free phase hydrocarbons it will be necessary to conduct phase separation of the flowback water and the liquid hydrocarbons as part of the fluid recovery process. Once flammable gases and liquids have been separated from the flowback water, go to Step 18.

Step 18. Is it sour by NACE MR-0175 requirements?

Flowback and produced water from the shale gas wells may contain H_2S gas. As a rule of thumb, if the H_2S is present in the gas phase, it will also be present in the liquid phase at a concentration approximately 1/10 of the concentration of H_2S in the gas phase.

If the water is considered to be sour, then go to Step 18A. If the water is not considered to be sour, go to Step 19.

Step 18A. Remove H_2S gas.

If H_2S is present in the water phase, the H_2S can be removed using chemicals or through stripping before it can be incorporated into a fracturing fluid. The requirement to remove H_2S from produced water is dictated by provincial regulation. Hydraulic fracturing service providers have established working limits for H_2S concentrations, above which the operator will not handle the fluid because of risk to pumping equipment. Refer to Section 4.0 of Appendix A.

Once the H_2S gas has been removed from the flowback water, go to Step 19.

Step 19. Can the flowback be reused safely?

Correct Health and Safety work practices should be used in handling chemicals and work practices. A safety plan should be prepared by the operator’s Health and Safety team to ensure that management of chemicals and fluids are handled appropriately. The major safety issues related to reuse of flowback fluid are:

- H_2S.
- Temperature.
- NORMS management.

The application of oilfield safety and best working practices should allow flowback water to be re-used in a manner that is safe and protective of the environment.

If a safety evaluation determines that the flowback water can be reused safely, return to Step 1 to begin the preparation of the next fracturing fluid design. If the flowback cannot be used safely or if no other use for the flowback is found, go to Step 19A.

Step 19A. Dispose as per local regulations.

If the flowback fluids cannot be reused safely, or the flowback fluids have no further use, such as at the end of a fracturing program, the fluids should be disposed of according to approved industry standards and procedures. The most likely scenario that would lead to disposal of fracturing flowback is when there is no further opportunity to reuse the flowback.

If the cost of source water is low, injection costs are low, and the cost of treatment is high, there is an economic disincentive to reuse the flowback water. There are still other considerations, such as the environmental benefit of reuse.

At the end of the drilling season, there may not be a need or ability to reuse flowback water, and other disposal methods must be considered. The most common practice is to inject the water fluid back into the formation.

PTAC Water Decision TREE

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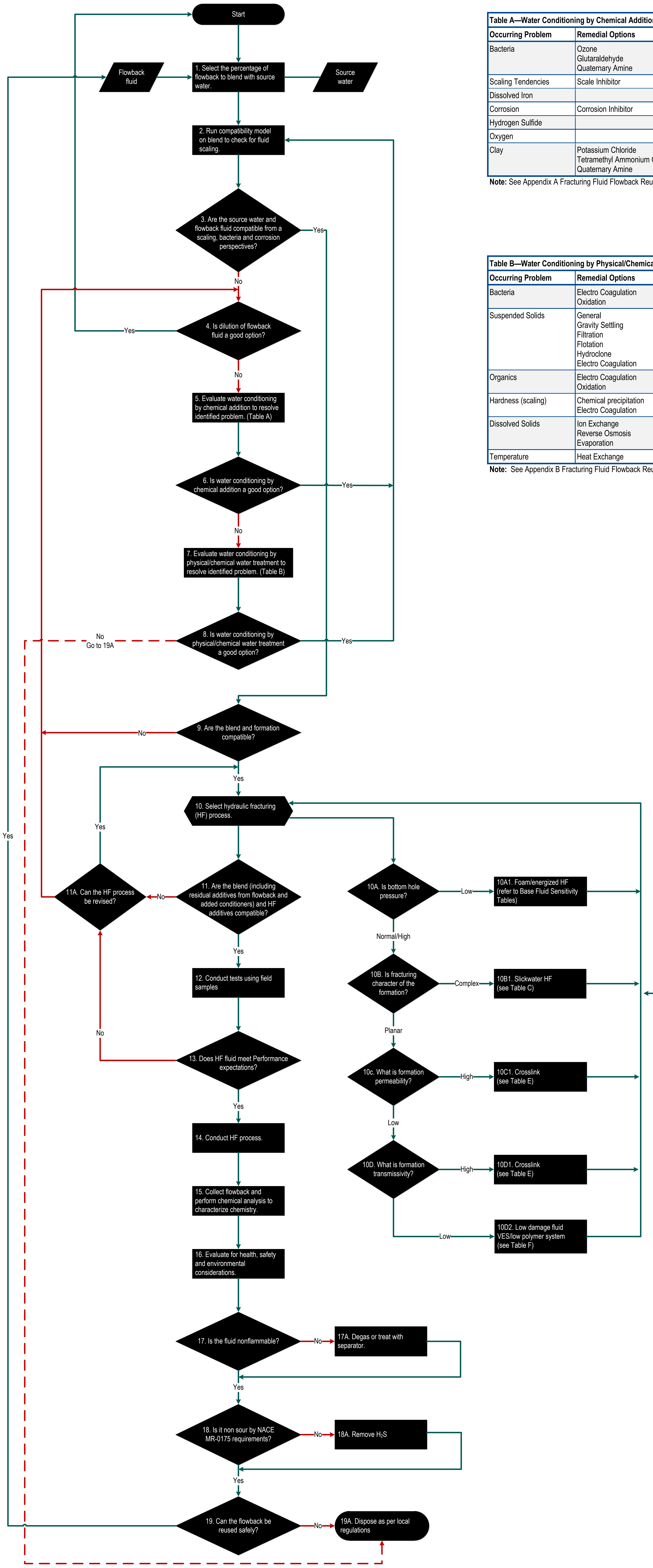

Table A—Water Conditioning by Chemical Addition	
Occurring Problem	**Remedial Options**
Bacteria	Ozone Glutaraldehyde Quaternary Amine
Scaling Tendencies	Scale Inhibitor
Dissolved Iron	
Corrosion	Corrosion Inhibitor
Hydrogen Sulfide	
Oxygen	
Clay	Potassium Chloride Tetramethyl Ammonium Chloride Quaternary Amine

Note: See Appendix A Fracturing Fluid Flowback Reuse Project

Table B—Water Conditioning by Physical/Chemical Treatment	
Occurring Problem	**Remedial Options**
Bacteria	Electro Coagulation Oxidation
Suspended Solids	General Gravity Settling Filtration Flotation Hydroclone Electro Coagulation
Organics	Electro Coagulation Oxidation
Hardness (scaling)	Chemical precipitation Electro Coagulation
Dissolved Solids	Ion Exchange Reverse Osmosis Evaporation
Temperature	Heat Exchange

Note: See Appendix B Fracturing Fluid Flowback Reuse Project

Table C—Slickwater			
Water Quality	**Range**	**Problem**	**Remedial Options**
Temperature (degC)	3–40	Temp for safe handling of fluid at surface lower temperatures may cause freezing problems	Use a hydration unit for mixing of water and friction reducer
pH	5.0–8.0	pH < 5 may cause prolonged hydration pH > 8.0 may result in inadequate gelling	NaOH or HCl
Chloride (mg/L)	<90,000	High chloride concentration inhibits hydration. Greater amounts of friction reducer maybe required.	Mechanical vapour recompression, ionization, reverse osmosis, electrocoagulation
Hardness (mg/L $CaCO_3$)	<15,000	Divalent cations inhibits hydration	flocculation and coagulation, ion exchange, electrocoagulation
Concentration Factor for Residual Additive Ingredients	2	Friction reducer impact on formation	Breaker
Suspended Solids (mg/L)	50 (< 100 um)	Possible damage to reservoir	Settling or filtration

Table D—Linear Gels			
Water Quality	**Range**	**Problem**	**Remedial Options**
Temperature (degC)	15–40	Lower temperatures may prolong the hydration of gel polymers	Passive cooling in tanks or ponds Heat exchanger
pH	6.0–8.0	A pH < 6 may cause prolonged hydration of gel A pH > 8 may result in inadequate gelling	NaOH or HCl
Chloride (mg/L)	<50,000	High chlorides concentration destabilizes the fluid and hydration	Mechanical vapour recompression (MVR), ionization, reverse osmosis (RO), electrocoagulation
Iron (mg/L)	<25	Iron degrades and breaks polymers in gels, causing premature breaking and crosslinking	Iron sequestration, oxidization
Sodium (mg/L)	<1000	Excess sodium destabilizes the fluid	Ion exchange, MVR, RO
Bacteria (CFU)	0	The presence of bacteria degrade the gel viscosity	Biocide, ozone
Concentration Factor for Residual Additive Ingredients	2	Polymer impact on formation and fresh additive	Breaker
Suspended Solids (mg/L)	50 (< 100 um)	Possible damage to Reservoir	Settling or filtration

Table E—Crosslink Fluids			
Water Quality	**Range**	**Problem**	**Remedial Options**
Temperature (degC)	15–40	Temperature range for safe handling of fluid at surface and hydration of gel.	Passive cooling in tanks or ponds. Heat exchanger.
pH	6.0–8.0	pH < 6 may cause prolonged hydration of gel pH > 8 may result in inadequate gelling	NaOH or HCl
Chloride (mg/L)	<30,000	High Cl^- concentration destabilizes the fluid and creates problems with crosslinking	Mechanical vapour recompression (MVR), ionization, reverse osmosis (RO), electrocoagulation
Iron (mg/L)	<25	Iron degrades and breaks polymers in gels, causing premature breaking. Iron can also create premature crosslinking	Iron sequestration, oxidization
Alkalinity (mg/L $CaCO_3$)	<600	Acts as a pH buffer, so high concentrations of crosslinking activator may be needed	Ionization, mechanical vapour recompression, scale inhibitor
Sodium (mg/L)	<1000	Excess sodium destabilizes the fluid	Ion exchange, MVR, RO
Silica (mg/L)	<35	Excess silica may inhibit the crosslinking of polymer gels	
Bacteria (CFU)	0	The presence of bacteria degrade the gel viscosity	Biocide, ozone
Concentration Factor for Residual Additive Ingredients	Field Tests Required	Borate impact on control of crosslinking	Disposal of flowback or physical/chemical water treatment for dissolved solids
	2	Polymer impact on formation and fresh additive	Breaker
	Field Tests Required	Buffers impact on control of crosslinking	Disposal of flowback or physical/chemical water treatment for dissolved solids
Suspended Solids (mg/L)	50 (< 100 um)	Possible damage to reservoir	Settling or filtration

Table F—Viscoelastic Fluids			
Water Quality	**Range**	**Problem**	**Remedial Options**
Temperature (degC)	20– 40	Temperature range for safe handling of fluid at surface	Passive cooling in tanks or ponds Heat exchanger
pH	5–12	Outside this range can effect properties of surfactants. Testing required	
Chloride (mg/L)	<33,000	Being outside of this range could affect the fluid quality and performance of standard chemistry. Alternative blends can be tested above this concentration.	Blending, mechanical vapour recompression, reverse osmosis, ionization, electrocoagulation
Suspended Solids (mg/L)	50 (< 100 um)	Possible damage to reservoir	Settling or filtration