PTAC PETROLEUM TECHNOLOGY ALLIANCE CANADA

Tight Oil and Shale Gas Innovation Roadmap

May 8, 2017

ALBERTA INNOVATES

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EXECUTIVE SUMMARY

Background

Production from tight and shale oil and gas resources has surged in North America due to new multistage hydraulic fracturing technologies, and this development has profound implications for Canada. In Alberta, light oil production has increased due to contributions from tight zones in formations such as the Cardium and Viking; in addition, significant growth could take place in the Montney and Duvernay formations if development at a large scale is found to be economic. In Saskatchewan, tight oil production from the Bakken formation has been significant. In British Columbia, prolific production of shale gas, particularly from the Montney formation, has created new opportunities for export of Liquefied Natural Gas (LNG).

While hydraulic fracturing has been deployed successfully by many operators in several regions, it has raised concerns about environmental impact, particularly concerning water management, greenhouse gas (GHG and air emissions, social impact from truck traffic and industrial activity, and the possibility of triggering earthquakes. As a result, the technology has been subject to regulatory reviews in several jurisdictions nationally and internationally. Thus, it is of high value for industry and government to study challenges and opportunities from the increasing production of tight and shale oil and gas from hydraulic fracturing, and understand the role that innovation could play in addressing them.

Purpose and Scope

The purpose of the Tight Oil and Shale Gas Innovation Roadmap (the “Roadmap”) is to provide knowledge for industry, government and academia to address current and anticipated research and technology challenges and opportunities related to the development by multistage hydraulic fracturing of unconventional tight and shale oil and gas resources. The outcome will be to deepen the understanding of the potential for scientific research and technology development to provide solutions in this industrial sector, and to propose an initial blueprint for future technology investments.

The Roadmap is not focused on any specific company or play, and recognizes that individual producers and service companies have an excellent understanding of technology challenges and opportunities related to their business. It does not enter the realm of government policy and regulatory frameworks, and acknowledges that several government organizations may have studied internally technology gaps and possible futures.

The Roadmap is focused on issues directly related to hydraulic fracturing technology. As such, challenges, gaps and opportunities that apply generally to conventional oil and gas activities are only briefly mentioned, if at all. One such area is well integrity and the potential occurrence of wellbore leakage, which is analysed in reports from the Council of Canadian Academies and of the Canadian Gas Migration Society and will be the topic of a future technology roadmap by Natural Resources Canada.

PTAC formed and facilitated the Tight Oil and Gas Innovation Network (TOGIN) with participation from industry, government, and academia to guide and support the development of the Roadmap. TOGIN held 19 committee meetings and three workshops over a 12 month period. A summary of TOGIN activities is found in Appendix A.

The Roadmap is a conceptual document that:

- Provides an introductory technical primer on hydraulic fracturing technology (Appendix B);
- Describes the opportunity in Western Canada through a review of major geological formations and petroleum plays (Section 2);
- Addresses the major challenges and opportunities that face the widespread deployment of the technology in Western Canada:
    - Sustainable production (Section 3)
    - Water management and treatment (Section 4)
    - GHG and air emissions management (Section 5);
- Analyses industry needs and challenges in a matrix of gaps that are addressable with new research and technology development (Section 6);
- Identifies potential future directions for technology investments (Section 7).

Geological Formations and Petroleum Plays in Western Canada

Multistage hydraulic fracturing is being applied to an ever growing number of formations and plays in Western Canada and around the world. These formations range from very deep thermogenic gas production from "over-mature" shale formations, which were rarely drilled in the past, to relatively shallow "tight" extensions of conventional oil reservoirs that have been under production for over 60 years from the permeable zones. Alberta has the greatest number of relevant plays. These are often overlying formations with some plays containing 10 or more conventional and unconventional oil, gas, or even coal formations under the same area of land, making development complex. Many of these layers may also have different mineral rights owners, ultimate production potential, ecological settings, and a wide variation in the amount of geological information available about them. Saskatchewan has fewer gas plays, but has conventional and unconventional oil plays in the southern part of the province, some of which overlap and some of which are found in analogous formations in Alberta and Manitoba, and in neighboring U.S. states. Unconventional resources plays in northeastern British Columbia are under development primarily for natural gas production and LNG exports, with some plays extending into the Yukon and the Northwest Territories.

While the basic hydraulic fracturing technology being used is similar for all these resources, the characteristics of the formations require significantly different development patterns, input resources, and application methods, and, as a result, the needs, gaps and solutions may differ significantly between formations. Formation depth is a key parameter for cost. Deeper wells, which are typically required to reach shale formations, can be significantly more expensive. Formation thickness and areal uniformity drive the magnitude of the opportunity, and shape the approach to development, with thick, aerially extensive shale formations offering the greater amount of in place resources. In general, deep shales are being developed with big long wells and large wellpads in order to generate economies of scale. By contrast, the shallow tight zones of conventional reservoirs are challenged with geological heterogeneity and are being developed on a smaller local scale. Production technology and economic returns are also greatly dependent on whether the targeted resource is dry gas, wet gas (gas with light hydrocarbon liquids), condensate or oil. In addition, the reservoir locations range from farmland with good access to services to very remote areas only accessible seasonally. The availability of services affects the type of technology that can be reliably and economically deployed. Finally, the presence of transportation infrastructure impacts the pace, scale and economics of development. For example, the Saskatchewan Bakken would benefit from more pipeline availability, and the B.C. gas shales are still waiting for the first LNG export terminal. Therefore, innovation in multistage hydraulic fracturing takes place in a complex set of circumstances, and a technology embodiment found successful in one formation or region may not be equally successful elsewhere. Despite early successes, hydraulic fracturing remains an emerging technological trend which will require further investments to fully address the range of challenges and opportunities.

Sustainable Production

On a global basis, the extremely large volumes of petroleum resources found in shale formations are larger than, for example, those of the Alberta oil sands, particularly if unconverted organic materials in shale formations are considered to be potentially recoverable. Thus, the objectives of improving economics, reducing environmental impacts, and providing a secure supply of jobs and energy to Canada must be addressed to make production of these resources sustainable.

This section highlights technological challenges which are specific to play types such as tight oil, shale oil, shale gas and tight gas. These play types produce different products from different rocks, and use different embodiments or application methods of hydraulic fracturing. Given that deployment at scale of hydraulic fracturing is a recent development, needs and opportunities can only be analysed based on limited data from recent years for economic value, activity levels and environmental impact. Technology is fast evolving and, in some plays, the application methods of a few years ago have already been adapted to new and better ones. Therefore, the identification of dominant trends and of long term needs is difficult. Play specific needs range from improving the basic understanding of the properties of deep source rock formations, to the potential challenges of attempting to expand conventional Enhanced Oil Recovery (EOR) methods in tight oil formations.

The section also addresses generic hydraulic fracturing needs, which may apply to a number of different plays at different times as the development of the resources progresses. Generic options range from hardware development needs to allow increased recovery, to the potential for accelerating in-situ conversion of the organic carbon (kerogen) in the source rocks.

While there is a large number of individual needs and opportunities coming from the wide variety of formation characteristics and environmental settings, the needs and opportunities can be aggregated in the following science and engineering areas:

> <u>Reservoir characterization</u>, including rock and fluid geochemistry and thermodynamic properties. The efficiency of any recovery process is highly dependent on a complete understanding of the reservoir. Given that the exploitation of tight rocks and shale resources is a relatively recent undertaking, much characterization work of the zones of interest remains to be done.
>
> <u>Optimization of completion and production processes</u>. Operators are still actively experimenting with various completions and production variables such as well spacing, stage spacing, length of laterals, number of stages, multilateral schemes, proppant type and quantity, fracturing fluid type and chemical formulation, and production rate control schemes.

It is well understood that the optimum mix of these variables will vary considerably between formations and surface environmental settings, with great impact on total recovery, economics and environmental impact.

It is also noted that seismic events have been associated with hydraulic fracturing completions in Alberta and ongoing research by the University of Calgary has elucidated potential mechanisms.

Refracturing and well re-stimulation. In hydraulic fracturing, production decline is very steep and the recovery rate is relatively low. Thus, the opportunity exists for refracturing or re-stimulating existing wells some years after initial production to re-energize production and to access bypassed resources. However, results of trials and field campaigns by operators have been uneven, and there remains considerable uncertainty as to the outcome of a recompletion program. Thus, new knowledge is required to guide the selection of well candidates for refracturing programs, and new completion technologies are needed to facilitate refracturing to reduce cost and financial risk.

Enhanced Oil Recovery. As an alternative to refracturing individual wells, EOR can also coax more production from an existing field. EOR is generally applicable at a field or section level and involves the injection of water or gas (e.g. CO_2, methane) to increase reservoir pressure, provide a sweep or drive mechanism, and to reduce oil viscosity in some cases, in order to generate more production and recovery. Laboratory work and field pilots have taken place but full commercial deployment remains a future possibility.

Improving the economic and environmental sustainability of tight and shale oil and gas recovery and production covers a broad front of challenges and opportunities from new knowledge from rock characterization and data analytics, to novel equipment design and innovative processes. The industrial nature of these needs and opportunities will require close collaboration with operators for the successful outcome of the most prospective research and technology investments.

Water Management and Treatment

The environmental challenges with water management and treatment are a dominating concern associated with hydraulic fracturing. Key environmental issues include:

- Consumption of vast quantities of water which may deplete scarce surface sources of fresh water and/or compete with population needs, agriculture and other economic activities in the region;
- Risk to ground water from potential contamination from injected or produced fluids; and
- Risk of land contamination from potential spills of transported or stored fluids.

In addition, water chemistry is complex and compatibility issues present cost, logistics and process challenges during completion and production.

Water Management

The challenges with water management include a wide array of issues from ground water and surface water interactions to flowback reuse, to disposal. Presently, most water sources for hydraulic fracturing operations, excluding reused water, range from surface waters (e.g. rivers, lakes, ponds) to ground waters (saline and non-saline). The interactions between surface and ground waters within and between watershed basins as well as the supply-demand for water on a watershed basis are not well understood in all cases. Ongoing watershed modelling efforts have taken place to gauge the impacts of withdrawals from multiple users on watershed health and water availability. Several initiatives are underway, focused primarily on surface water resources. Additional studies are required to increase the knowledge base of ground water resources in Western Canada, particularly saline aquifers.

When saline or non-saline water sources are used for the first time for hydraulic fracturing, a thorough characterization of these waters is key for determining compatibility impacts. Chemicals and minerals in a water stream may react with chemicals and minerals from reservoir rock, other waters or fracturing fluid chemicals, resulting in adverse impacts such as precipitation in reservoir pores or scaling of process equipment. Thorough water characterization will also allow efficiency improvements such as comingling of different waters, and recycling of flowback and produced water. Improved water characterizations through standardized methodologies would allow for water chemistry data that is comparable between different laboratories, which is crucial for supporting operations.

The reuse of flowback and produced water relies on a sound understanding of the interactions between these waters and makeup water, fracture fluid chemicals, formation waters, and freshly fractured rock faces. Flowback and produced water may contain trace amounts of additives (e.g. residual crosslinkers) that could interfere with subsequent additions of chemicals during reuse. Compatibility is also a concern when blending flowback or produced water with make-up water. If the completions fluid and downhole water and rock chemistries are incompatible, reservoir plugging precipitates may form. Flowback and produced water may also contain Naturally Occurring Radioactive Material (NORMs). Under certain operating conditions, NORMs can precipitate to form solids that settle and accumulate or solids that adhere to equipment surfaces. Flowback and produced water are often nutrient rich. Re-injection of bacteria-containing flowback or produced water can cause further subsurface bacterial growth resulting in reservoir damage, microbiologically induced corrosion, plugging of the near wellbore, and souring of a well with the formation of hydrogen sulfide. Whether the objectives include preventing scale formation, mitigating the precipitation of NORM contaminated solids or avoiding bacteria-induced corrosion, detailed flowback and produced water characterizations are crucial for assessing the reusability and compatibility of these waters with fracture fluid chemicals, make-up sources and the producing formation.

When reuse is not possible, these wastewaters are typically injected into deep wells for disposal. The comingling of multiple wastewaters at disposal wells has led to blending of incompatible waters and the consequential plugging of the disposal zone with precipitated solids. Detailed wastewater characterizations together with best practices and guidelines for preventing the comingling of incompatible waters could help prevent injectivity losses and the potential for permanent formation damage within disposal wells.

A final challenge is the logistical aspects of storage and transport of water, which is determined by the supply-demand relationship for water at one or multiple locations. The storage capacities, transport distances, available transfer equipment, means of transport, completions schedules make for complex logistics. In addition, flowback and produced water transport and storage requirements include safety and environmental considerations due to the potential presence of contaminants including hydrocarbons, bacteria, volatile organic compounds, polyaromatic hydrocarbons, hydrogen sulfide, suspended solids, and NORMs.

Water Treatment

Water treatment includes processes to remove contaminants from water in order to improve its quality and allow its use in desired applications. Overall treatment intensity is anticipated to be the lowest with non-saline water management processes with progressively more treatment intensity required for saline and reuse applications. The current technology gaps lie in the treatment for key water quality parameters that influence reuse challenges. While the water treatment needs will depend on the individual characteristics of the resource play, source waters, completions programs, etc., the parameters most likely to create reuse challenges include sulphates, residual crosslinkers and polymer, bacteria, and NORMs. The treatment gaps related to these issues include sulfate removal to avoid hardness and NORM-based scale precipitation, developing best practices for bacteria management during treatment and storage, and determining the maximum allowable concentrations of residual crosslinkers and polymer without impacting the compatibility with fracturing fluids.

GHG and Air Emissions Management

Surface facilities associated with hydraulically fractured wells are generally similar to surface facilities in conventional oil and gas operations. However, key differences are that hydraulic fracturing involves significant consumption of energy and fuel during completion operations, with resulting GHG emissions (primarily CO_2 in combustion gases), and that hydraulically fractured wells exhibit a high initial production rate followed by a steep rate decline, creating operational challenges which may result in increased emissions in some circumstances (primarily flaring and venting). The Roadmap focused on needs and gaps specifically related to multistage hydraulic fracturing, and highlighted potential technology solutions.

The following emission sources have the most relevance in hydraulic fracturing operations:

- Fuel consumption during production, generally for electricity generation and heat.
- Venting from pneumatic equipment, particularly related to chemical injection pump emissions.
- Completion venting and flaring of flow-back gases prior to production, which can last 3 to 7 days.
- Completion operations, which mostly involves fuel consumption for pumping the fracturing fluid and can last one to several days.
- Flaring during production, related to the disposal of solution gas after the well has come on stream; may be a significant emission source when pipeline infrastructure is lacking.

In summary, existing gaps related to tight and shale oil and gas operations generally involve fuel consumption, venting and flaring associated with completions, pneumatic equipment, and production operations, as well as advanced Leak Detection and Repair (LDAR). Addressing these challenges will likely best take place in the context of relevant programs and initiatives covering both conventional and unconventional operations.

Gap Analysis

Knowledge gaps are barriers between the current status and the desired future state. The identification of gaps and technology opportunities is necessary to formulate a pathway to solutions. In this Roadmap process, gap analysis was informed by three workshops related to sustainable production, water management, and GHG emissions, as well as by the subject matter experts who contributed chapters to this report. Each of the three workshops was attended by representatives from oil and gas companies, service and supply companies, technology innovators, academia and governments.

Through the Roadmap process and workshop discussions, 24 specific gaps were identified, documented and aggregated in the areas of sustainable production (13 gaps), water management and treatment (6 gaps) and GHG and air emissions management (5 gaps). The gaps were analysed according to a prescribed framework in an effort to provide structure and support to the development of planning and decision-making by users of the Roadmap. The gaps were assessed from two perspectives:

- Impact on industry needs and environmental management; and
- Current level of innovation activity, gauging the magnitude of existing research and technology investments targeting the subject gap.

The representation of gaps in a matrix according to the two above dimensions will allow decision-makers to target scarce technology budgets in a manner that will create the most value: prioritizing areas with high impact that are not adequately addressed by existing programs.

Technology Directions

Gap analysis provides the targets for research and technology development. The next step is to identify potential technology avenues or directions that could close the gaps if successful. The Roadmap process identified and listed 49 potential areas for research studies and technology development that were assembled into three portfolios: sustainable production (21 opportunities), water management and treatment (13 opportunities), and GHG and air emissions management (15 opportunities). These portfolios constitute a well-defined starting point for the design of research and technology investment programs. Steps, beyond the scope of the Roadmap, include deeper analysis of the research and technology development opportunities with respect to questions such as degree of novelty, alignment with industry processes, probability of success, preliminary economics, and the cost and schedule for R&D investments.

Conclusion

It is only during the last 10 years that multistage hydraulic fracturing has been applied at industrial scale to tight and shale oil and gas resources in Western Canada. The technology is at an emerging stage and innovation is still advancing at a rapid pace. The size of the Canadian resources that could be unlocked with this technology has yet to be fully delineated but the potential for the resource is impressive and could rival the Alberta oil sands. However, hydraulic fracturing technology faces significant challenges with respect to environmental impact particularly in the areas of water management and GHG emissions. In addition, the dramatic fall in oil prices since 2014 will require innovative technologies to reduce cost and increase recovery in order for the sector to remain internationally competitive.

Innovation is a powerful force to address economic and environmental challenges, particularly in the areas of sustainable production, water management and treatment, and GHG and air emissions management. The Roadmap process unfolded over a period of approximately one year through meetings, workshops and network consultations, as well as analysis and reporting by subject matter experts. The output was the identification of 24 specific gaps addressable through research and technology innovation, as well as 49 opportunities for projects and studies. These are represented in a matrix to allow prioritization by decision-makers and aggregated in portfolios that offer a foundation for the design of new research and technology development programs.

Learnings from the Roadmap are that the context for innovation in multistage hydraulic fracturing is very complex; challenges and opportunities exist on a number of fronts as described earlier, all of which could proceed simultaneously rather than in a sequential manner. Sustainable production opportunities include reservoir characterization studies, innovative completion technologies such as multilateral wells, optimization of completion programs and production strategies, and secondary recovery strategies such as refracturing and EOR. Studies and best practices in water management would benefit all stakeholders and technology development focused on water treatment for specific contaminants such as sulfates and NORMs would improve economics and environmental performance. In the area of GHG and air emissions management, solutions for hydraulic fracturing operations are similar to those applicable to the conventional oil and gas sector, such as enclosed combustors, electrification alternatives to pneumatic equipment, waste gas capture and utilization, and advanced LDAR.

The Roadmap was informed by a thorough review of needs, gaps, challenges, and opportunities performed by a team of subject matter experts, in consultation with industry, government and academic stakeholders. The outcome is a conceptual blueprint for consideration by oil and gas operators, service and technology companies, governments, regulators, and academic institutions that provides a strategic framework for innovation in hydraulic fracturing technology. Action and investments will lead to technology solutions that will respond to needs expressed by stakeholders and to opportunities identified by industry, in a way that leverages the resources of individual organizations for the benefit of the sector as a whole.

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ACRONYMS AND ABBREVIATIONS

AER	Alberta Energy Regulator
AI- Clean Energy	Alberta Innovates – Clean Energy
AUPRF	Alberta Upstream Petroleum Research Fund
Bbls	Barrels
Bcf	Billion cubic feet
BHA	Bottomhole assembly
BOE	Barrel of oil equivalent
BROM	Bow River Operational Model
CAPP	Canadian Association of Petroleum Producers
CLIP	Cement left in pipe
CT	Coiled-tubing
D&C	Drilling and Completions
DHM	Dual element, hydraulic-set, mechanical
DRBC	Delaware River Basin Commission
DST	Drillstem test
EOS	Equation-of-state
EUR	Estimated ultimate recovery
GIS	Geographic information systems
GoA	Government of Alberta
GHG	Greenhouse gas
GOR	Gas/oil ratio
HJAF	Hydrajet-assisted fracturing
HPHT	High pressure high temperature
IOR	Improved oil recovery
KOP	Kick-off point
LCM	Loss circulation materials
LNG	Liquefied natural gas
LWD	Logging-while-drilling
ME FSS	Multi-entry fracturing sleeve system
MEM	Mechanical Earth Model
MIC	Microbiologically induced corrosion
MMcf	Million cubic feet
MMP	Minimum miscibility pressure
MSHF	Multistage hydraulic fracturing
MWD	Measurement-while-drilling
NEB	National Energy Board
NFR	Naturally fractured reservoirs

NGLs	Natural gas liquids
NORMs	Naturally Occurring Radioactive Materials
NPV	Net present value
NRCan	Natural Resources Canada
NSPS	New Source Pollution Standards
NSR	North Saskatchewan River
GOWN	Groundwater Observation Well Network
OHMS	Open-hole, multistage fracturing system
OOIP	Original Oil-In-Place
OSSK	Oldman and South Saskatchewan Model
PAWF	Predicting Alberta's Water Future
PTAC	Petroleum Technology Alliance Canada
PVT	Pressure, Volume, Temperature
QA/QC	Quality assurance/Quality control
ROI	Return on investment
ROP	Rate of penetration
RSS	Rotary steerable system
SE FSS	Single-entry fracturing sleeve system
SPWB	Synthetic polymer water based
SRV	Stimulated reservoir volume
SSRB	South Saskatchewan River Basin
STB	Stock tank barrels
Tcf	Trillion cubic feet
TDS	Total dissolved solids
TEREE	Technology for Emissions Reduction and Eco-Efficiency
TOC	Total organic content
TOGIN	Tight Oil and Gas Innovation Network
TVD	True Vertical Depth
VOC	Volatile organic compound
WAG	Water-alternating-gas
WCSB	Western Canada Sedimentary Basin
WOB	Weight on bit
WOR	Water/oil ratio
ZLD	Zero Liquid Discharge

1. PURPOSE AND SCOPE

1.1. Motivation

The advent of hydraulic fracturing technologies has resulted in dramatic increases to the production of oil and gas in North America, particularly from tight oil and shale gas resources. Canada has benefited with the development of Bakken tight oil in Saskatchewan, increases in production from the Cardium and Viking formations in Alberta and production of shale gas in British Columbia that has created the opportunity for natural gas exports through LNG facilities on the Pacific coast.

The full understanding of the environmental impact of hydraulic fracturing is still the object of studies. Environmental concerns have caused some jurisdictions to implement a moratorium until uncertainties are clarified or improved production methods are developed. Of primary concern is that hydraulic fracturing requires vast quantities of water which must be sourced, used and eventually disposed. In addition, the GHG impact of hydraulic fracturing methods requires further analysis to be fully understood.

It has been well publicized that the significant increases in production of oil and gas attributed to hydraulic fracturing have been one of the key causes of present low prices for oil and for natural gas. Producers have responded by reducing costs in order to remain competitive, but it appears that further cost reductions will be required for long-term sustainability.

Investments in innovation and technology development could result in solutions to the complex production, cost and environmental challenges faced by the tight oil and shale gas sector. This Roadmap project was initiated to explore such technology opportunities.

1.2. Scope

This project progressed in phases which built on information and understanding gained in previous phases and was guided by a PTAC Steering Committee composed of the funding organizations.

The domain of this Roadmap is technology innovation. Therefore, the scope excludes solutions that could arise from government policy and regulations, business strategy and management, and stakeholder consultations and public relations.

The development of the Roadmap proceeded by identifying sources of expertise and of technology capability; describing the current state of knowledge; scanning for issues; identifying strategic drivers and the desired future state; determining knowledge gaps and research needs; and by proposing technology directions to fill gaps and generally advance knowledge toward the desired future state.

The project proceeded in 5 phases as follows:

- Phase 1: Kickoff and Scope Finalization. PTAC formed a Steering Committee and assembled a project team. The scope was then reviewed and finalized to ensure that all project participants were well aligned.
- Phase 2: Current Situation. The project described prospective unconventional resources, modern practices of hydraulic fracturing, and the current level of activity and production. It also scanned for issues raised by producers and stakeholders. Stakeholder workshops also assisted the process.

- Phase 3: Gap Analysis. Gaps arise from the distance between the current situation and the desired future state. Thus, the project identified improvements sought by industry, government and other stakeholders. Subject matter experts from the project team identified and described gaps. Gaps were reviewed and aggregated in domain areas in workshops.
- Phase 4: Roadmap. Once knowledge gaps were identified, research needs and programs were identified to guide future technology developments. The deliverable resulted in a roadmap that acts as a starting point for research initiatives to bridge the knowledge gaps.
- Phase 5: Final Report. This report accounts for the roadmap development process and the key messages and conclusions.

1.3. Audience for this Report

This report was developed to inform industry, government and academia about research needs and technology investment opportunities in tight oil and shale gas innovation to support continuous improvement in reliability, integrity and environmental impact, and to address concerns raised by the public and regulators in recent years.

The primary value of this report is to aggregate and structure information about needs and opportunities. It is aimed at the overall sector in a Canadian context. It is not aimed at any specific company or hydraulic fracturing project, and it fully recognizes that individual operators do have a deep understanding of technology challenges and opportunities related to their business. It also does not enter the realm of government policy and regulatory frameworks, and fully acknowledges that several government organizations have already studied technology gaps and possible futures. Finally, the report is aware of related initiatives undertaken by other industry associations and has accessed publicly available information on same in order to identify opportunities for collaboration and to avoid duplication.

As noted, the unique contribution of this report is to provide an overall and aggregated perspective with emphasis on Canada. It notes research needs and technology opportunities that may not be fully addressed elsewhere, and identifies directions for collaboration in areas where research is already active. Importantly, it delivers content for consideration by Canadian federal and provincial government organizations, oil and gas producers, technology developers, and learning institutions for leveraging their expertise, infrastructure capabilities and financial resources to jointly deliver technology solutions that would benefit the sector as a whole.

2. PLAYS AND FORMATIONS IN WESTERN CANADA

Assessment of potential technology needs and opportunities in Western Canada's Tight and Shale Plays is complicated by the sheer number of potential resources, of varying size, depth, hydrocarbon content, rock types, perceived production rates and recoveries found across the region. Unlike conventional oil and gas resources, which are usually limited to well-defined high permeability "traps" into which oil and gas migrated from deeper source rocks[i], like the U.S. Bakken or Duvernay/Muskwa, many of the new tight/shale plays are often continuous over large portions of the Western Canadian Sedimentary Basin (WCSB). The shale formations may have "pay zones" hundreds of meters thick, which could contain oil, gas, natural gas liquids (NGLs) in mature or over-mature areas of the play, or organic rich rock in immature areas[ii]. In addition to the geological variability, there is also the issue of resource control and maintenance of oil and gas leases by oil and gas producers with a wide range of assets, development opportunities and financial strategies to maximize shareholder value. Often different producers will have the rights to explore and develop formations under the same geographic area, resulting in considerable potential for either conflict or collaboration.

This chapter of the Roadmap is intended to provide a brief, high-level overview of the range of tight and shale oil and gas plays in the region which have become economically accessible for development through the application of horizontal multistage hydraulic fracturing technology.

2.1. Alberta

Authored by New Paradigm Engineering

Alberta has the largest and most diverse tight and shale resources in the WCSB and even in North America as a whole, with many other potential shale or tight formations remaining unassessed for in-place resources. Most of the province is underlain by many layers of sedimentary rock, from source rock formations like the Duvernay/Muskwa, to large reef structures like the Leduc/Nisku trend, to shallow formations containing biogenic gas in the eastern part of the province. Most of the areas containing tight and shale formations have already been producing from conventional oil and gas pools in those regions, so the province has the advantage of already having a great deal of production infrastructure in place with spare capacity. Infrastructure includes gas plants, oil, condensate and gas transmission pipelines which are already connecting to operations in communities which have been service and support centres for conventional oil and gas for decades.

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[i] Source rocks are deep shales like the Duvernay and Bakken where oil and gas form over time and can migrate through high permeability aquifers into traps.

[ii] Maturity refers to the degree to which organic materials deposited in sedimentary rocks have been thermally converted into hydrocarbons over time, through natural heating and pressure. "Immature" formations contain organic carbon which has not been heated enough to turn into hydrocarbons, "mature" formations contain oil which formed from the organic carbon, while "over-mature" formations are usually deeper and the organic carbon has been transformed into natural gas. Between "mature" and "over-mature" regions NGLs are found which are produced with a rich stream of gas.

The same areas also contain many layers of conventional oil and gas

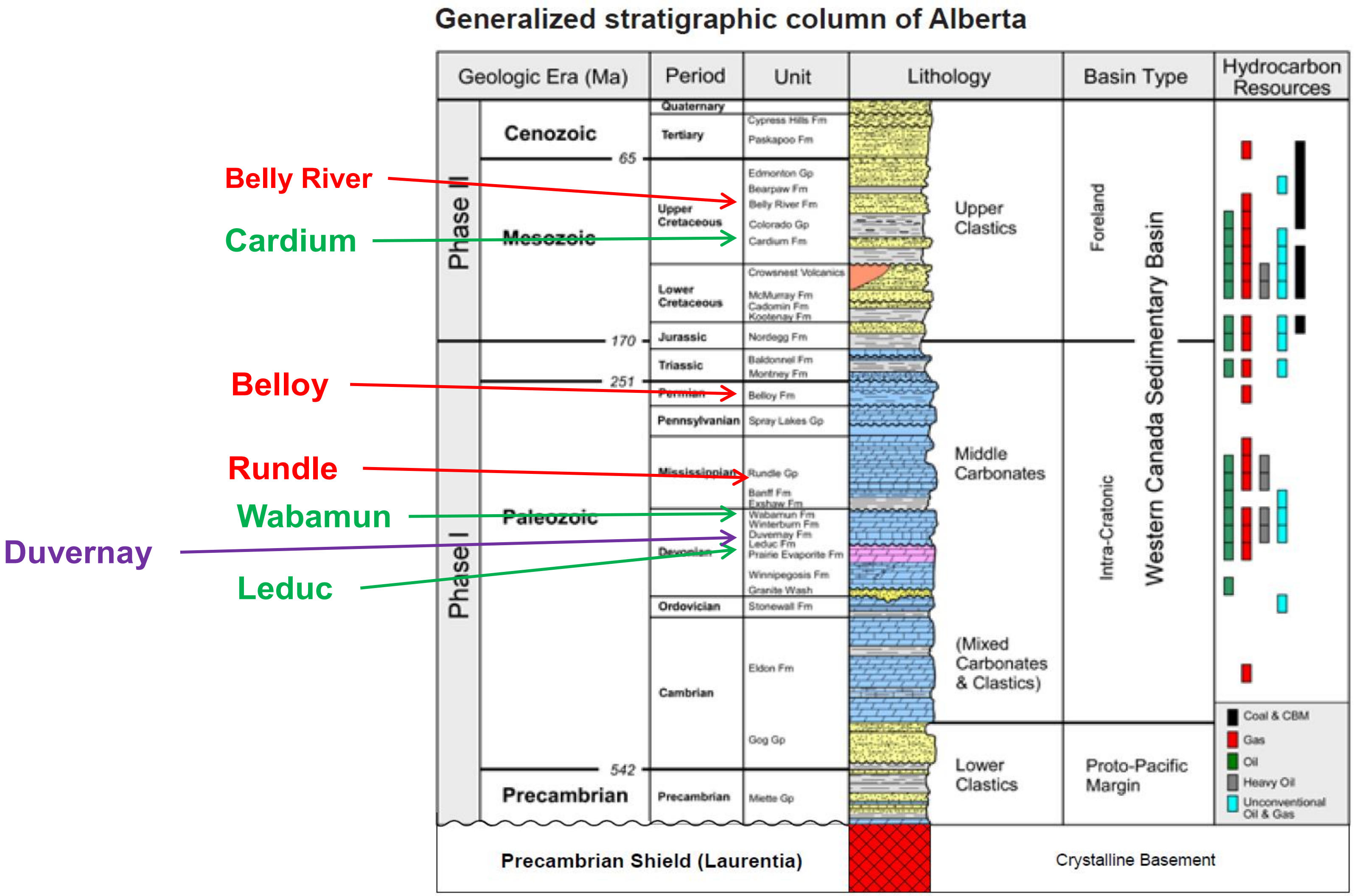

Figure 1. Wide Range of Tight Oil and Gas Formations in Alberta

Source: Alberta Energy Regulator[1]

2.1.1. Alberta Horizontal Oil Wells

The high level distribution of wells, production, and resources in Alberta shows that drilling activity and production of oil and liquids, in the last six years, has been higher in the shallower tight formations like the Cardium, than in deeper formations, due to the relatively lower costs to drill shallow formations. Deeper formations can be economic at high oil prices, but may not be able to compete with shallower wells which may have similar oil production rates. As economics drives drilling activity, there may be a continuing focus on shallow tight oil wells, rather than deep shales even though the amount of resource contained in the shales is higher, so they are of more interest in the long-term. Much of the shallower development is also being carried out by smaller producers who generally retain mineral rights to those formations, and could not afford the high cost of obtaining deep shale rights in highly competitive land sales for the deep shales. As of 2016, there is no estimate available for tight oil resources in place in the province, even though there is one for the deep shales.[2]

Figure 2 and Figure 3 show the distribution of horizontal oil wells (includes horizontal conventional heavy oil wells; bitumen wells are excluded) drilled in Alberta between January 2009 and November 2015 and the relative contribution to Alberta liquids production of wells from each age of formation, as well as condensate (NGLs) from horizontal gas wells.

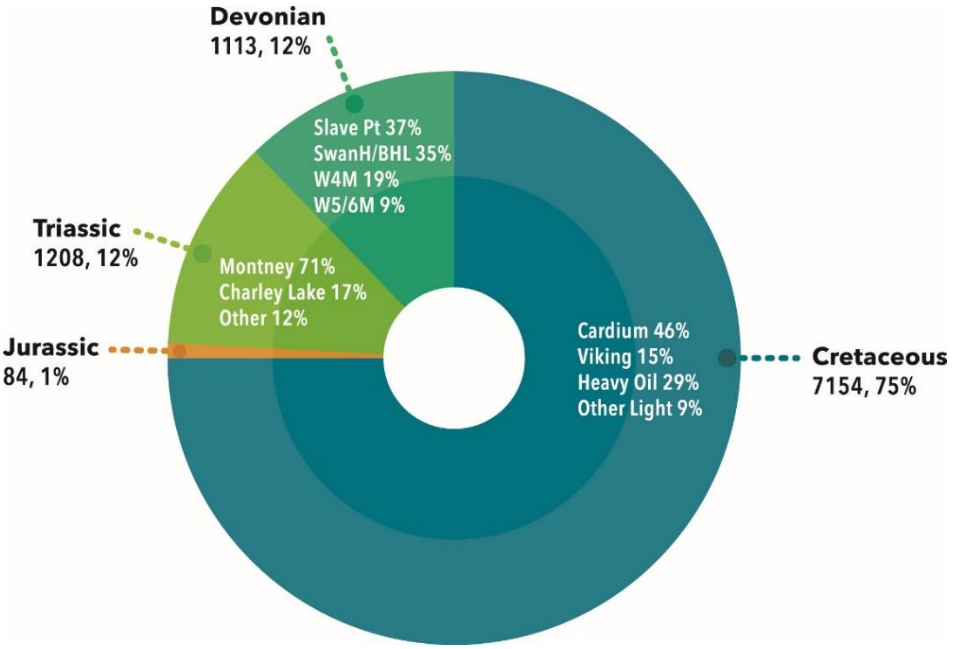

Figure 2. Alberta Horizontal Oil Well Drilled by Formation Age

Notes:
- For 2009 to 2015
- Excludes oil sands horizontal wells which are not fractured.
- Source: New Paradigm Engineering (2013) from analysis of well data from the Alberta Energy Regulator database through geoSCOUT.

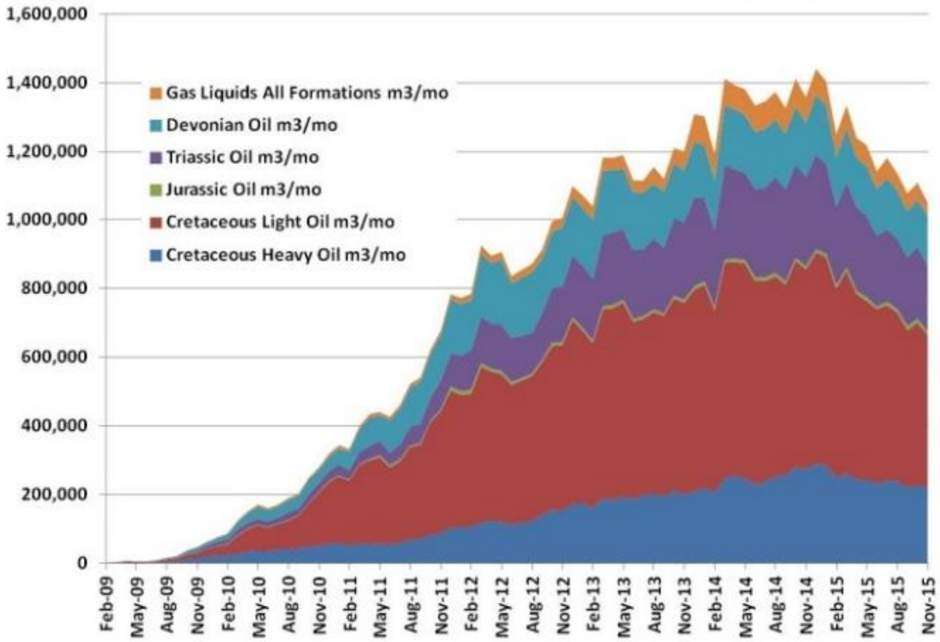

Figure 3. Alberta Production from Horizontal Oil Wells by Formation Age

Notes:

- For 2009 to 2015
- Excludes oil sands horizontal wells which are not fractured.
- Source: New Paradigm Engineering (2013) from analysis of well data from the Alberta Energy Regulator database through geoSCOUT.

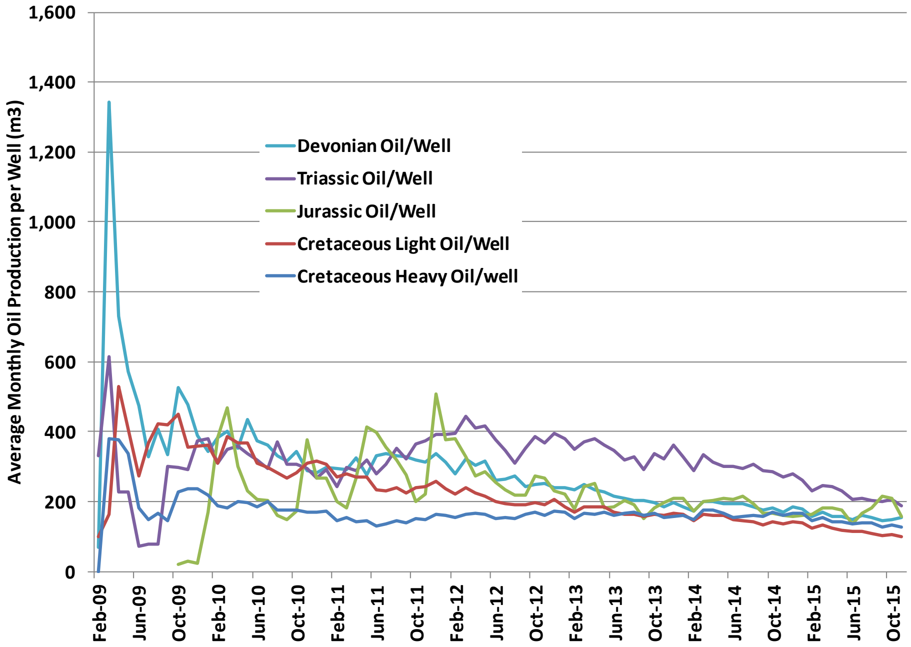

Figure 4. Alberta Horizontal Oil Well Average Monthly Production per Well by Formation Age

Notes:

- For 2009 to 2015
- Excludes oil sands horizontal wells which are not fractured.
- Source: New Paradigm Engineering (2013) from analysis of well data from the Alberta Energy Regulator database through geoSCOUT.

Figure 4 and Table 1 show that although deeper shale (Triassic and Devonian) wells are more expensive to drill (Duvernay and Montney), their production performance may not be markedly different from shallower tight oil wells except in the early months.

Table 1. Comparison of Alberta Oil Metrics by Formation

	Duvernay Shale	Montney Shale	Cardium Tight	Beaverhill L. Tight
Resources in Place (Liquids)	~73 Bbbls (P50)	~163 Bbbls (P50)	~1-3 Bbbls?	~2.5 Bbbls?
Hz Multi-stage Wells/yr (2014)	~60	~200	~700	~40
Fracturing Water per Well m^3	20,000 – 60,000	2,000-6,000	2,600	2,000-3,000
Cost/Well D&C	\$10M-\$25M	\$4M-\$6M	\$2.5M-\$4M	~\$5.8M
Liquids Production BPD total	~7,200	~10,000	~82,000	~20,000
Some Key Operators	Shell, Encana, Chevron	ARC, Trilogy, RMP, 7G	Whitecap, Lightstream, PennWest, Vermillion	Pengrowth, PennWest, Arcan, Nuvista Lightstream

Source: Corporate presentations and Alberta Energy Regulator information [iii]

Cretaceous Cardium Tight Oil

The main Cretaceous age formation being developed in west central Alberta, surrounding Drayton Valley, is the Cardium formation. Higher permeability portions of this sandstone formation, characterized by layers of agglomerates, have been under production since the 1950s with vertical wells and water floods which have recovered, on average, about 20% of the original oil in place. Surrounding the conventional pools, are areas of lower permeability fine grained sandstone which are the targets for horizontal well drilling and multistage fracturing. These Cardium oil developments were assessed through an earlier (2014) PTAC backgrounder[3] which contains more details on the history and potential opportunities for this formation. At that time it was identified that further production increases would

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[iii] Economic data in the table is summarized from a review of producer corporate presentations, AER production data and rough estimates of resources in place from AGS and other sources.

be limited by the capacity of the oil transmission pipeline out of the region, but there appeared to be at least enough locations identified by operators to allow for at least 7-9 years of steady drilling at 450-500 wells per year. With lower prices, the pace of new well drilling will likely be reduced. The main producers in the Cardium are Lightstream, Whitecap, Penn West and Pengrowth, with about two-thirds of the Cardium wells drilled in the Pembina field, and many of the remainder drilled in Willesden Green and Garrington fields.

Cardium Fracturing Technology – The main types of fracture treatments used in the tight Cardium, based on a sample of 200 wells, are:

  - **Slickwater Fracture (<10% nitrogen) –** The majority (almost 75% of the 200 well sample analyzed) of the Cardium wells were completed using this method. Water use per well ranges from about 1,500-4,300 m^3/well, or about 50-250 m^3/fracture stage and an average water use per well of 2,600 m^3 water per well with an average of 4% nitrogen and 17% proppant. The average number of fracture stages per well was ~17. On a mass basis: Water ~2,600 tonnes/well; Sand ~500 tonnes/well; Nitrogen ~120 tonnes/well.
  - **Nitrogen Energized (10 to 80% nitrogen) –** From the same analysis, approximately 25% of the 200 wells used larger volumes of nitrogen and required less water, with between 250-600 m^3 water used per well, or about 15-75 m^3/fracture stage and an average water use per well of 500 m^3 water per well with an average of 22% nitrogen and 31% proppant. The average number of fracture stages per well was ~18. On a mass basis: Water ~500 tonnes/well; Sand ~350 tonnes/well; Nitrogen ~250 tonnes/well.

- **Oil Carrier Fluid** – In the early years (2009-2011) many of the horizontal Cardium wells drilled were fractured with oil. For example, Penn West reported that in 2011 only 10 out of 100 wells completed in that year were fractured with water-based carrier fluids[4]. In recent years the trend has shifted to slick water and nitrogen energized fracturing, with only a few wells being fractured with oil based carrier fluid.

Viking and Other Cretaceous Tight Oil in Alberta

The Viking play spans both Alberta and Saskatchewan with about 1100 Viking wells in Alberta and about 600 in other tight light oil formations (Dunvegan approximately 300 wells mainly in Fox Creek region). About 90% of the Alberta Viking wells are found in the Redwater field (northwest of Edmonton) and the Provost Field. The main Viking operators in Alberta are Long Run, Crescent Point and Husky.

Viking Fracturing Technology – The main types of fracture treatments used in the tight Viking oil, have not been evaluated in detail for this report, but appear to be mainly cross-linked polymer gel fractures with 15-25 stages and a fracture water demand of 600-1,400 m^3/well depending on the field and the operator.

Triassic Montney/Charley Lake Shale Oil

A few operators are drilling commercial oil development wells in the Montney/Charley Lake Triassic Shale formations, which can be variable in composition between shale, sandstone, and siltstone. Even prior to the use of multistage fracturing, some conventional production with vertical or more conventional horizontal wells was possible. Key producers active in the Montney formation are Long Run Exploration, ARC Resources, Trilogy Energy, CNRL and Spyglass Resources with most of the development in the Kaybob, Ante Creek North and Dixonville Fields. While the Charley Lake formation is mainly being developed by Exshaw, Birchcliff and Harvest Operations in the Valhalla, Worsley and Cecil fields. Based on the average well's monthly production plot, shown earlier in this section, Triassic oil wells appear to be more productive than wells in other formations, but performance can vary widely between operators and field areas.

Montney Oil Fracturing Technology – Several types of fracture treatments are used in the Montney oil play by different operators in different fields. These have not been evaluated in detail for this report, but cover a wide range with some producers preferring gelled oil fracturing with no water and 7-10% N_2, others use gelled water with 750-1000 m^3/well, while still others are using nitrogen energized fracturing with over 20% N_2 and 300-500 m^3 of water per well. Most have 20-30 fracture stages per well. The variation in completion practices may be due to variations in reservoir composition as the Montney can contain sandstone, siltstone, or dolostone, which may react differently to fracturing fluids or may be a company preference based on observed variation in cost and production performance.

Devonian Slave Point/Swan Hills/Beaverhill Lake Tight Oil

These formations are the main tight oil wells being drilled into carbonate reef formations in sections of the reefs adjoining some of the most prolific light oil pools in the province. These reef formations are considerably different in characteristics than the clastic (sandstone/siltstone) formations, and are generally thicker but not as aerially extensive, so tend to be more distributed than the Cardium and Montney developments since the formations are not as large. The main operators in the Devonian tight oil developments are Crescent Point, Penn West, Lone Pine and Pengrowth in the Swan Hills (Beaverhill Lake) and Evi (Slave Point) fields. Other producers are now focusing on similar types of formations in eastern Alberta such as Repsol targeting Leduc reefs in the Chauvin South field and NEP Canada in the Leduc-Woodbend D-2 formations SW of Edmonton.

Devonian Oil Fracturing Technology – The main types of fracture treatments used in the tight Devonian oil, have not been evaluated in detail for this report, but appear to be mainly cross-linked polymer water fractures, usually with acid added to react with the limestone in the formation. Wells may have 10-25 fracture stages and use 750-1,500 m^3/well of water.

2.1.2. Alberta Horizontal Gas Wells

Shallower gas formations also have seen more drilling of horizontal wells than deeper shale formations. With the low price for gas in current markets, gas well drilling of all types has dropped off, but some gas wells are still being drilled and completed in a number of formations for a range of reasons depending on the lease holders assets, degree of hedging on prices and other factors. Some of the drivers for continued drilling are:

- Large leases in over-mature portions of Triassic and Devonian formations still require wells to be drilled to retain the leases;
- Producers delineating the high grade portions of their leases so that lower quality leases can be allowed to revert to the crown;
- Some companies in the Duvernay formation have entered into large farm-in agreements which require expenditures to be made over a fixed timeframe;

- High condensate prices were encouraging drilling of rich gas wells until oil prices dropped in 2015;
- Some companies have gas plants which are more economic to operate than to shut down; and
- Favourable royalty rates and well drilling credits for new wells.

Figure 5 and Figure 6 below show the distribution of horizontal gas wells drilled in Alberta between January 2009 and November 2015 and the relative contribution to Alberta horizontal gas production of wells from each age of formation, as well as solution gas from oil wells. Almost 50% of the gas production from horizontal multistage fractured wells is coming from shallow formations, while about 40-45% is coming from Triassic age formations and solution gas. Note that due to confidential production from shale wells, some of the actual volumes for shale formations could be higher than shown here.

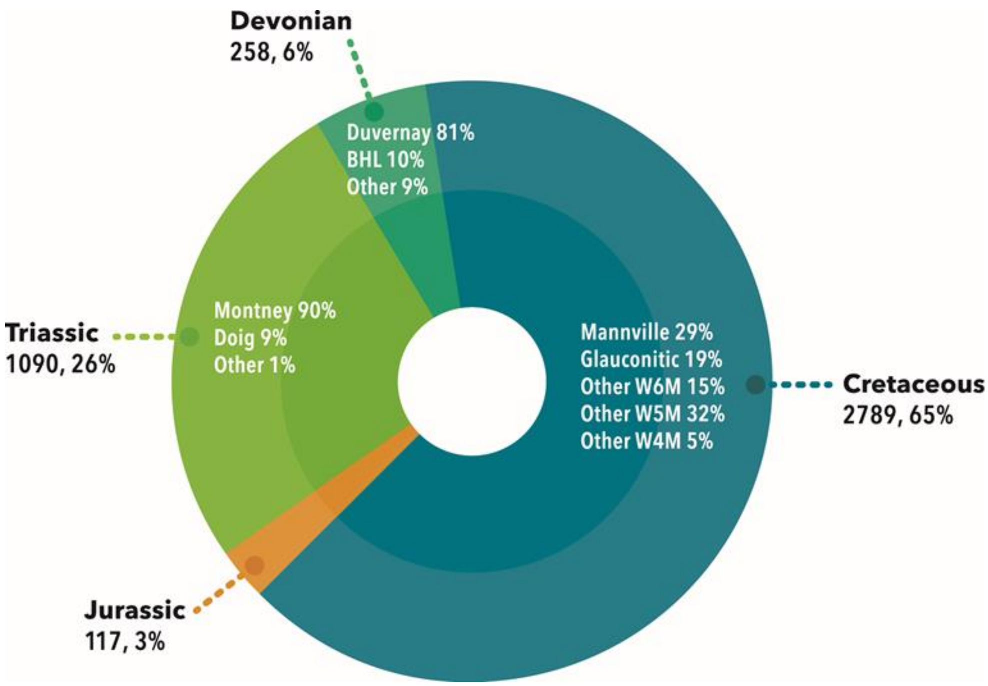


Figure 5. Alberta Horizontal Gas Well Drilled by Formation Age

Notes:

- For 2009 to 2015
- Also Showing Solution Gas Produced from Hz Oil Wells.
- Source: New Paradigm Engineering (2013) from analysis of well data from the Alberta Energy Regulator database through geoSCOUT.

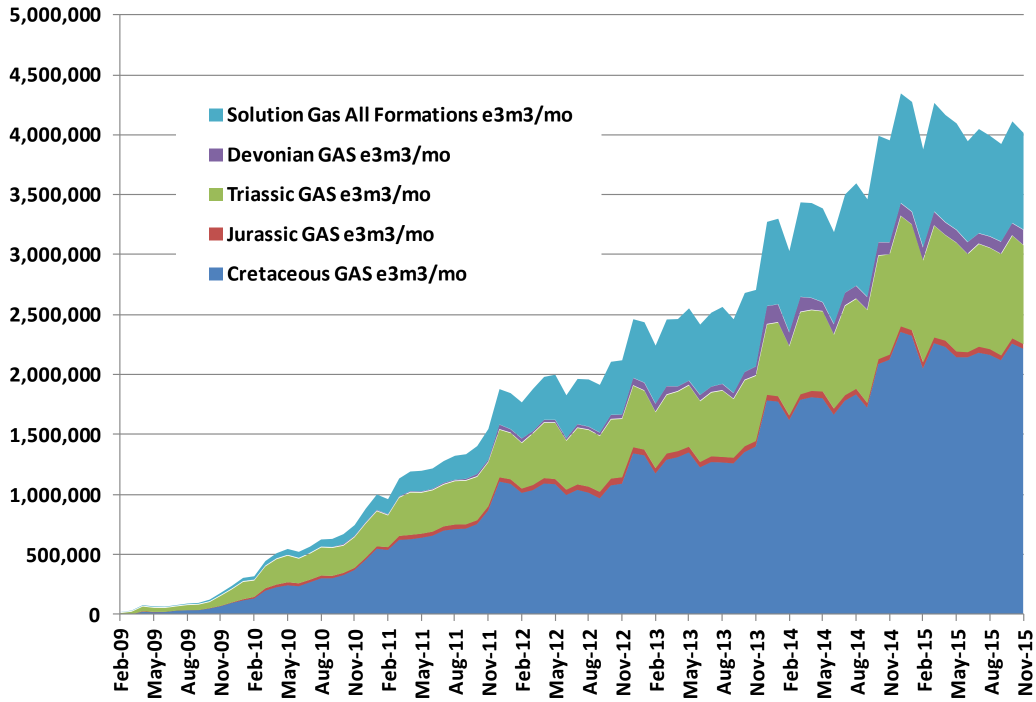


Figure 6. Alberta Horizontal Gas Well Production by Formation Age

Notes:

- For 2009 to 2015
- Also Showing Solution Gas Produced from Hz Oil Wells.
- Source: New Paradigm Engineering (2013) from analysis of well data from the Alberta Energy Regulator database through geoSCOUT.

Figure 7 presents a graphical relationship of the average well production for gas wells in Alberta per well by formation age. From an average well productivity point of view for natural gas, the shallower Cretaceous and Triassic formations in Alberta appear to be more productive per well than wells in the deeper Devonian age formations. However, the deeper formations produce more natural gas liquids, which, at least at higher oil prices, make up for the higher costs of drilling the deeper wells. Figure 8 shows the relationship between liquids production per well by formation age for Alberta horizontal gas wells. Generally, wells with higher liquids production, will have lower natural gas production. As can be seen, liquids production from the rich parts of the Duvernay greatly exceeds liquids from other formations. As in the case of oil wells, some of the newer shale gas wells are still confidential so average rates in later months could be higher than those shown. The cyclic increase and decrease in average gas rates in Devonian wells is due to the high initial production and rapid declines seen in these wells combined with the impacts of seasonal drilling, which results in more wells starting up in December-February of each year.

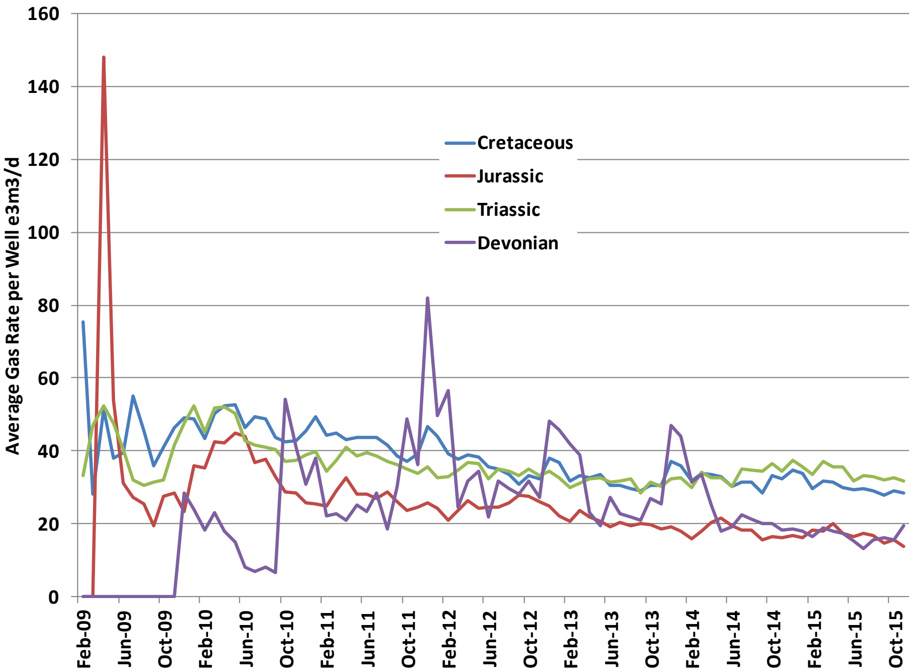


Figure 7. Alberta Horizontal Gas Well Average Production per Well by Formation Age

Notes:

- For 2009 to 2015
- Also showing solution gas produced from Hz oil wells.
- Source: New Paradigm Engineering (2013) from analysis of well data from the Alberta Energy Regulator database through geoSCOUT.

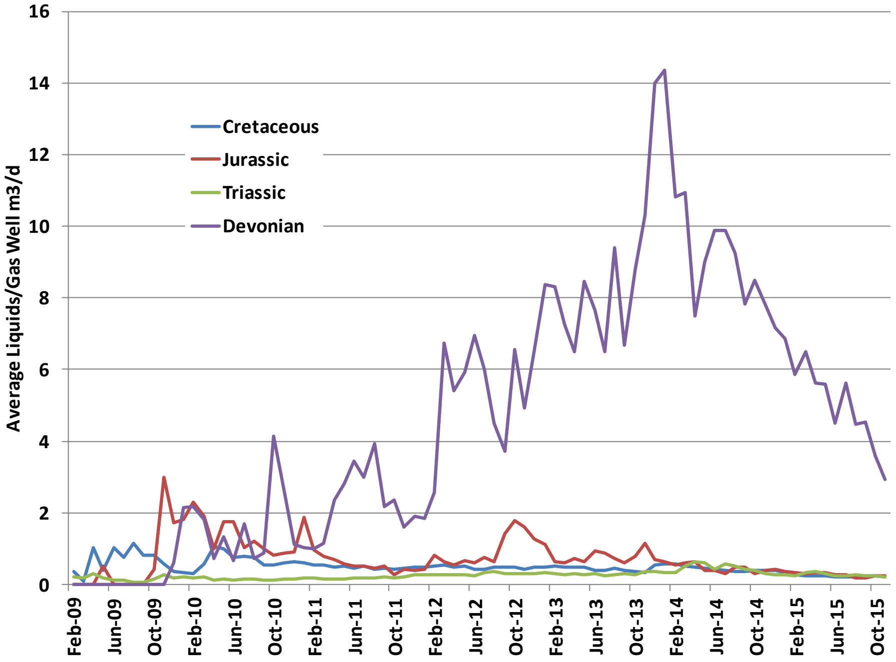


Figure 8. Alberta Horizontal Gas Well Liquids Production per Well by Formation Age

Notes:

- For 2009 to 2015
- Source: New Paradigm Engineering (2013) from analysis of well data from the Alberta Energy Regulator database through geoSCOUT.

Cretaceous Mannville/Glauconitic Tight Gas

These two main shallow gas formations, along with the Fahler, Cardium, Bluesky and other Cretaceous formations, contain mainly lean, sweet natural gas which generally requires little processing except for dehydration. They are relatively low cost to drill and produce. Since much of this gas does not require extensive processing for liquids recovery, it is generally less restricted by infrastructure than the deeper rich gas and solution gas is. In the Mannville, the main operators are Peyto Exploration and Development, Bellatrix Exploration, and Tourmaline Oil Corp, with the main fields of interest being Sundance, Edson and Pembina. For the Glauconitic gas play the main operator is Bonavista Energy in the Willesden Green and Wilson Creek fields.

> **Cretaceous Gas Fracturing Technology** – The main types of fracture treatments used in the tight Cretaceous gas, have not been evaluated in detail for this report, but appear to be mainly slickwater fractures with 7-11 stages, 4-11% nitrogen and a fracture water demand per well of 2,000-2,500 m^3/well.

Triassic Montney Shale Gas

Much of the Montney gas development has been lean gas similar to the shallower formations, however, the wells are more expensive to drill and complete, making them less economic if liquids production is low. The main operators are Birchcliff, Advantage and Paramount with a large percentage of the wells in the Pouce Coupe South field, with smaller numbers of wells in the Kaybob South, Kakwa and Elmsworth fields.

> **Triassic Gas Fracturing Technology** – The main types of fracture treatments used in the tight Triassic gas have not been evaluated in detail for this report, but appear to be mainly slickwater fractures with 14-17 stages, 3-4% nitrogen and a fracture water demand per well of 6,500-7,500 m^3/well.

Devonian Duvernay Shale Gas

As was indicated earlier, the main prize in the Duvernay formation are the relatively large volumes of light hydrocarbon liquids produced from these wells. While their greater depth makes Duvernay wells more costly, higher price for liquids and lower drilling costs, mainly through pad drilling and faster drilling and completion times, can yield positive economics. Most of the liquids rich gas wells are found within the designated Duvernay Regulatory Pilot Area around Fox Creek. In 2015, PTAC developed a background report on Duvernay Shale Gas.[5] There are three major producers active in the Duvernay: Encana, Shell and Chevron who are drilling mainly in the Kaybob South, Kaybob and Waskahigan fields. Development strategies and practices are different between the three companies with Encana drilling longer, but variable length wells with larger fracture treatments on a northwest-southeast orientation, Shell drilling wells of more standard length in a north-south orientation with smaller fracture treatments, and Chevron experimenting with both options.

> **Duvernay Shale Gas Fracturing Technology** – The main types of fracture treatments used in the Duvernay shale gas, were evaluated in the PTAC report and are mainly slickwater fractures with anywhere from 2 to over 60 fracture stages and fracturing water demands per well ranging from 15,000 to 125,000 m^3/well depending on the well and the operator. Encana tends to drill longer wells with 20-40 fracture stages and 30,000 to 60,000 m^3/well of water. Shell appears to have standardized their well length and uses 16-18 fracture stages and about 20,000 m^3/well of water

injected for fracturing. As relatively few Duvernay wells have been made public as of 2016, it is difficult to evaluate the impacts of well completion practices vs. production as the two companies also operate in different areas of the play, and Shell's wells tend to produce more condensate.

2.2. Saskatchewan

Authored by the Saskatchewan Research Council

The Saskatchewan portion of the WCSB is generally shallower than similar formations to the west in Alberta or to the south in North Dakota. In fact much of the oil in the Saskatchewan Bakken in the southeast portion of the province migrated in from deeper source rocks in the U.S. part of the formation, so it behaves more like a tight reservoir than a shale. In southwest Saskatchewan, there are additional tight oil resources in the Shaunavon and Viking formations. Often tight oil formations are found in the same regions as conventional heavy and medium oil in formations like the Mannville.

2.2.1. Saskatchewan Horizontal Oil Resource Plays

In the early years, Saskatchewan's Bakken oil production was limited to several pools such as the Rocanville-Welwyn, Viewfield, Ceylon, Hummingbird, and Roncott pools. Primary production is often related to natural fractures[6] [7]. Oil flow during primary production is dependent on the transmissibility and connectivity of these natural fractures that intersect with production wells[8]. In general, the Bakken production was considered uneconomic until the introduction and application of innovative drilling and completion technologies since 2004. In recent years, drilling activities have been focused on the Viewfield–Midale region and have spread to other fields.

The boom in Saskatchewan Bakken production activity generally started in mid-2000, and was triggered by application of long horizontal wells, which allow maximum exposure to the reservoir, and new conceptual stackfrac techniques, which allow fracturing of siltstone along the extent of the wellbore. At the largest Viewfield field in the Saskatchewan Bakken, the average true vertical depth (TVD) is 1,500 m and the average lateral lengths is 1,600 m.

According to a 2015 report published by Saskatchewan Ministry of the Economy and the National Energy Board (NEB)[9], about 1.4 billion bbl of oil and 2.9 trillion cubic feet of natural gas are economically recoverable from the Canadian Bakken formation. With cumulative production of 160 million barrels up to the end of 2014, there are still 1.24 billion barrels of recoverable oil remaining based on today's technology. General industry trends indicate that advancements in drilling, completion, and completion technologies will further add to these reserves.

2.2.2. Devonian Bakken Tight Oil

The late Devonian–early Mississippian Bakken formation was deposited about 360 million years ago. It spreads in the central and deeper portion of the Williston Basin, which is a large, roughly circular depression on the North American craton. The thickest area of the Bakken formation reaches 145 to 150 feet southeast of Tioga, North Dakota, where it is located at the eastern base of the Nesson Anticline. The formation generally thins evenly toward the margins of the Williston Basin. The formation is over 3,350 m (11,000 feet) in depth at the center of the formation and rises to 900 m (3000 feet) on the Canadian side. Figure 9 depicts the locations of the main shale formations in Saskatchewan.

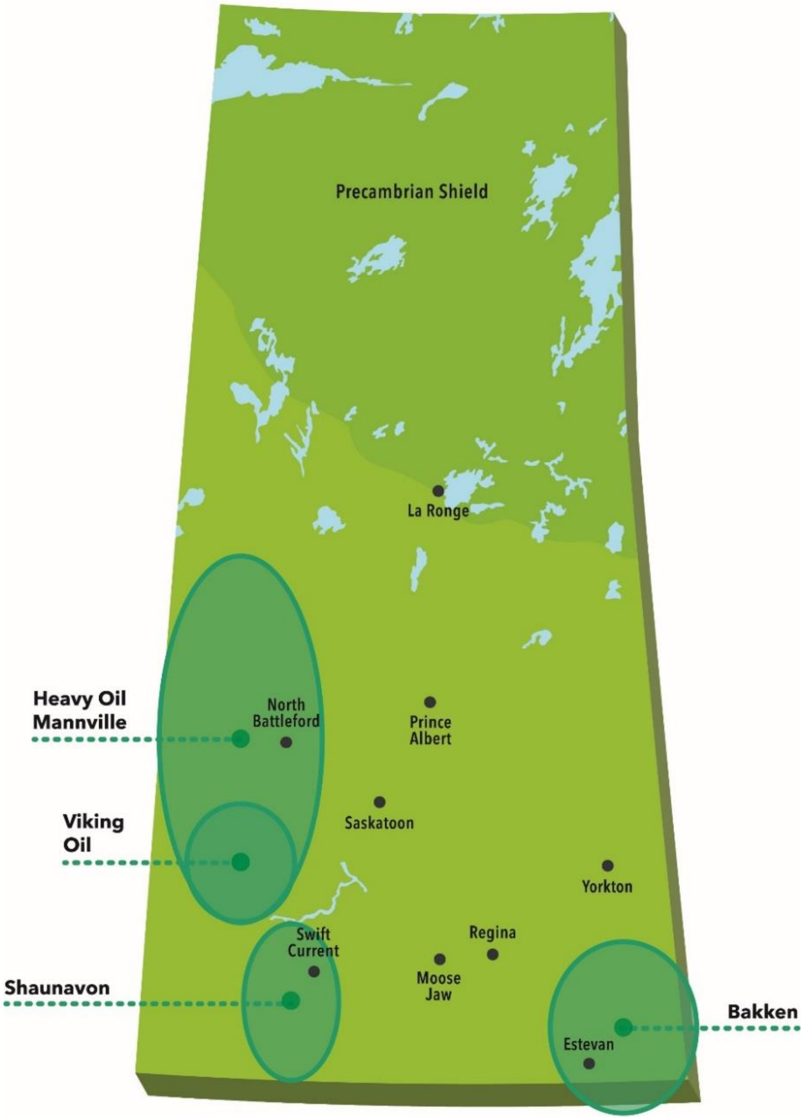


Figure 9. Location of the Main Tight/Shale Formations in Saskatchewan

Notes:

- Source: Saskatchewan Ministry of Economy [10]
- Mainly oil

The Bakken formation has three members: black, organic-rich shales for the Upper and Lower Members, which are generally one to ten meters thick, and siltstones and sandstones in the Middle Bakken Member[11]. The productive middle member contains mainly very fine to fine grained, argillaceous, dolomitic sandstone to siltstone, and can be further divided into three units and five lithofacies [9] [11] [12]. Matrix permeability is in the range of 0.01 to 0.5 md and porosity is from 5% to 12%. Figure 10 provides visual representation for Saskatchewan's southeast stratigraphy.

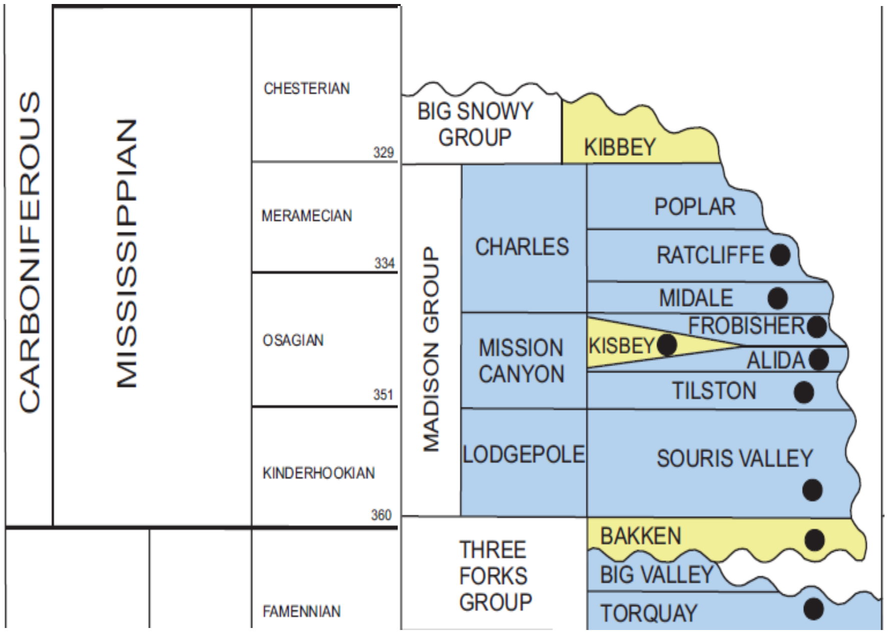


Figure 10. Southeast Saskatchewan Stratigraphy

Notes:

- Source: Saskatchewan Ministry of Economy [10]
- Late Devonian Early Mississippian

2.2.3. Shaunavon Tight Oil

The Shaunavon formation is located in Southwest Saskatchewan and has approximately 1300 horizontal wells drilled into it, 500 of which were drilled into the low permeability reservoirs since late 2007, accounting for more than 15.1 million barrels of total oil production. Between 2010 and 2015, Shaunavon horizontal wells have produced approximately 28.5 million barrels of oil.[13] This formation has not been evaluated in detail for this report, but appears to be similar to other formations mentioned in this section such as: Beaverhill Lake and Slave Point.

2.2.4. Viking Tight Oil

Geology and Oil Production

The Viking formation lies within the Lower Colorado Group of the early Cretaceous and is extensively found within a wedge-shaped area throughout most of the WCSB. The formation is conformably overlain by the marine shale Westgate formation and regionally underlain by the Joli Fou Formation. The formation occurs in the Redwater area of central Alberta and the Provost area of eastern Alberta and extends to west-central Saskatchewan. It reaches a maximum thickness of 50 metres (160 feet) in central Alberta, thins out to 40 metres (130 feet) in west-central Saskatchewan, and pinches out in central Saskatchewan and along the Saskatchewan-Manitoba border.

Viking geology is complex. It is recognized that several major sea-level transgression and regression cycles of the Western interior seaway occurred in the formation during Cretaceous time. Along the long, narrow northwest-southeast trend across Alberta and Saskatchewan, the shoreline moved back and forth to create subaerial exposure and erosion of previous marine deposits. Such sea-level fluctuations have been preserved in the Viking sedimentary record represented by complex lithology of fine- to medium-grained interbedded sandstones, siltstones, and mudstones.

Compared to its more studied Alberta counterpart, the Saskatchewan Viking formation has been the subject of considerably less research, partly due to the formation's different geological settings and reservoir qualities. One petrographic study [14] examined 32 oil and gas wells in Alberta and Saskatchewan to discuss secondary porosity generation from these reservoirs. Another study [15] reviewed 100+ cores throughout the Verendrye, Plato, and Forgan pools in the Kindersley area and identified nine facies of various sedimentary bedforms, biological structures, and lithology. The extent of understanding of the Viking geology is largely dependent on the quality of core and logs in the area. Unfortunately, due to its fragile argillaceous nature, cores available at the Saskatchewan Geological Survey are often broken and rubbled. In addition, the finely laminated and highly bioturbated nature of the sand and shale interbeds complicates the net-to-gross reservoir ratio determination such that it cannot be accurately calculated from log analysis. The resolution of the geophysical well logs is not fine enough to accurately quantify net pay in such reservoirs.

The Viking formation bears abundant hydrocarbon resources with proven Original Oil-On-Place (OOIP) of 3.0 billion barrels (478 million m^3), second only to the Cardium formation in western Canada. In Saskatchewan, the depth of the Viking production is the range of 600 to 750 metres. Oil and gas production with vertical drilling in west-central Saskatchewan started in 1951. The formation is divided into an upper zone of conventional vertical well production and a lower tighter zone that was deemed to be uneconomic until the recent application of horizontal well drilling technology. The recoverable reserves based on conventional vertical wells and waterflooding technology are estimated at 296 million barrels (47.1 million m^3), or a 10% recovery factor. Figure 11 shows major oil and gas pools in west-central Saskatchewan and Viking. The five biggest oil pools in Saskatchewan in terms of cumulative oil production to date are Dodsland, Smiley Dewar, Kerrobert, Eureka, and Plato North.

The Viking produces high-quality oil of 36°API gravity. Compared to the Bakken formation in southeast Saskatchewan, which is another prolific tight oil play, the Viking in the Dodsland area is much shallower, at only 700 to 750 m in depth. This results in significantly lower cost for drilling and completion but also presents lower reservoir pressure, which translates into lower production rates and ultimate oil recovery. Furthermore, due to its low-permeability and low-pressure nature, its oil recovery factors are also generally low (5–15%).

The revitalization of the Viking since 2010 is strongly associated with increasing implementation of horizontal well technology in the play. However, numerous challenges were encountered during the early days of horizontal well drilling, completion, and production in the geologically complex formation. These include reservoir rubblization, swelling and migrating clays, wax precipitation, and so on. Recent advancement of multistage fracturing and other technologies have resulted in significantly better recovery performance than for earlier horizontal wells in the play. Designing a compatible drilling/fracturing fluid system requires systematic evaluation and understanding of the formation geology and fluid chemistry.

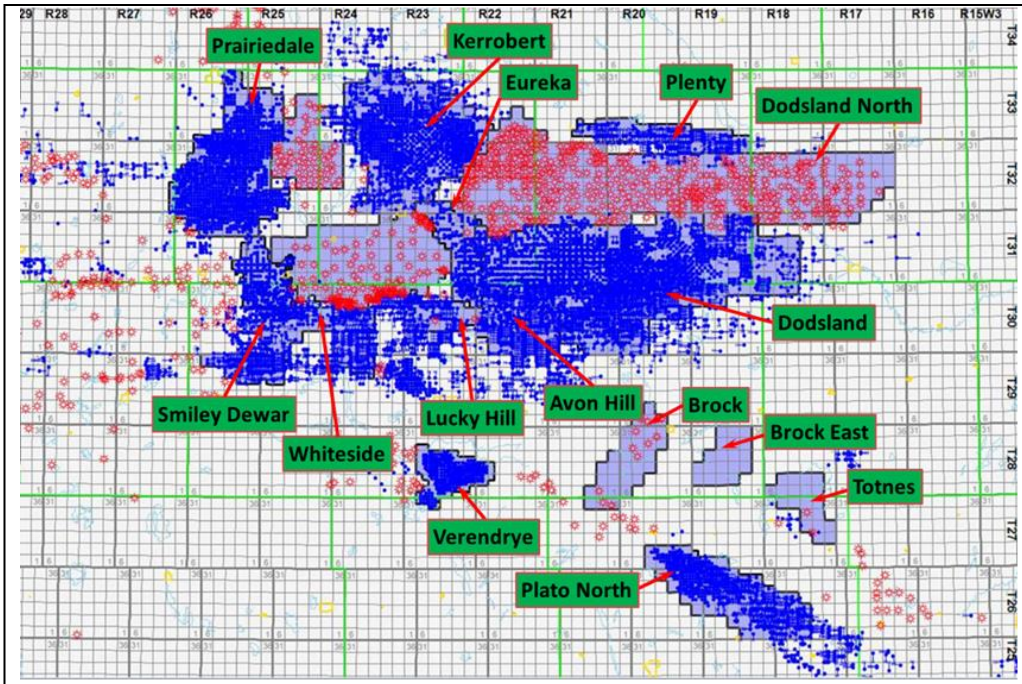


Figure 11. Viking Pools with Oil and Gas Wells in West-Central Saskatchewan

Notes:

- Oil production: blue dots
- Gas production: red dots
- Source: Saskatchewan Research Council is using information retrieved from AccuMap and geoSCOUT

According to Dr. Melinda Yurkowski[16], the assistant chief geologist at the Saskatchewan Ministry of Economy, considerably more wells were drilled in the Viking Formation in the last three years than the other two hot plays in Saskatchewan, Bakken light oil and Mannville heavy oil. As shown in Figure 12, until December 2016, there are approximately 9,950 producing wells in Saskatchewan Viking, 5,100 of which were horizontal wells that had been drilled since December 2007. In December 2016, the Viking oil production from horizontal wells only (not counting vertical production) averaged 56,000 barrels per day, out of 58,000 barrels per day of total production; and the cumulative production was approximately 44 million barrels of oil (7.0 million m^3) and 45.2 billion scf of gas (1,274 million m^3). Furthermore, with the increasing application of multistage fracturing technology in Viking horizontal wells, the profitability of the play is anticipated to increase in the future.

The technical priorities for the Viking formation in the future include developing and applying emerging technologies and optimizing the current production practice to slow down decline rates and improve recovery factors. Multistage fracturing has been emerging as a worldwide game-changer in unconventional tight oil/shale gas/shale oil reservoirs. In the Saskatchewan Viking, a large number of vertical well waterfloods have been implemented since the 1960's. Waterflooding has been well proven as a feasible improved recovery method in the play. Current focus is on an effective design and implementation of the waterflooding projects that employ multistage fracturing in horizontal wells. Significant productivity improvement in the Viking formation relies on several factors: (1) comprehensive and accurate reservoir characterization in terms of stratigraphy, lithology, clay mineralogy, water chemistry, and log analysis; (2) evaluation of formation damage due to water compatibility, swelling and migration clays, and wax precipitation; (3) design and optimization of horizontal well placement and lengths; (4) design and optimization of multistage fracturing operations, such as fracturing fluid with additives, proppant sizes and concentrations, fracture size and spacing; and (5) production optimization through continuous field operation monitoring and analysis.

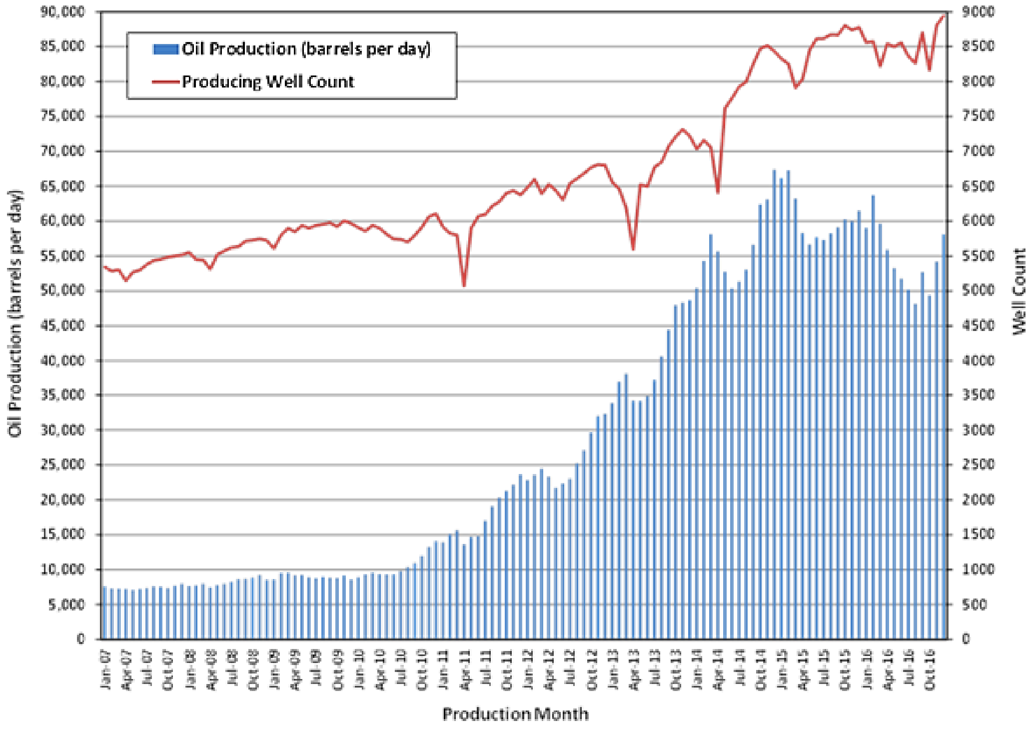


Figure 12. Saskatchewan Viking Total Oil Wells and Production

Source: Saskatchewan Research Council is using information from AccuMap and geoSCOUT

2.3. British Columbia

British Columbia ranks second for natural gas production among Canadian provinces. Production in 2015 was 4.3 Bcf per day for natural gas and 20,900 bbls per day for crude oil. Remaining natural gas reserves in 2014 were 1.4 billion m³ (51 Tcf)[17] and ultimate natural gas reserves were estimated at 349 Tcf.[18] Approximately three quarters of natural gas production originates from unconventional plays, the two most prospective being the Montney Play Trend and the Horn River Basin.[19] (See Figure 13). In 2014, 697 wells were drilled in British Columbia and approximately 90% of these wells were in the Montney Play Trend.[20]

British Columbia was one of the first areas to experience a development boom for deep shale gas starting in the Horn River Basin, Laird Basin and Cordova Embayment in the far northeast corner of the province. However, in recent years much of the development effort has moved further south into the B.C. portion of the Montney formation which contains large volumes of liquids rich gas.

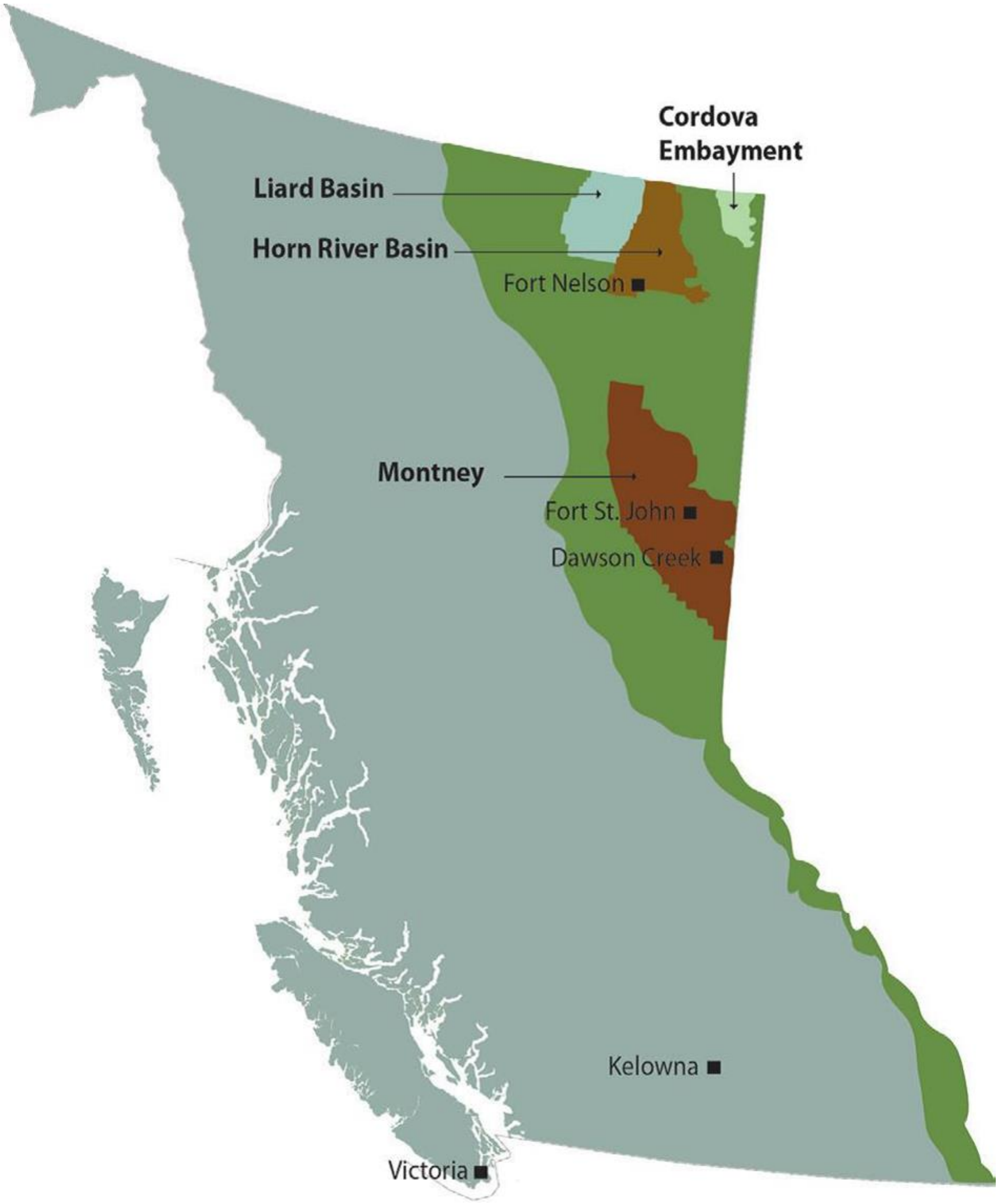


Figure 13. Tight/Shale Gas in British Columbia

Source: National Energy Board [19]

An overview of the principal unconventional gas plays in British Columbia is presented in Table 2 and each play is further discussed in the following sections.

Table 2. Overview of Major Unconventional Gas Plays in British Columbia

Play	Typical Associated Geological Formations	2014 Cumulative Gas Production (MMcf)	2014 Average Daily Gas Production (MMcf per day)
Montney Play Trend	Triassic Montney and Doig Phosphate formations	1,600,000	2,500
Horn River Basin	Lower Mississippian Exshaw shale; Upper to Middle Devonian Muskwa, Otter Park and Evie formations	800,000	500
Greater Sierra	Upper Devonian Jean Marie formation (tight gas)	663,000	200
Cordova Embayment	Devonian shales in the Muskwa, Otter Park and Evie formations; (prior to shale gas: Upper Devonian Jean Marie and Middle Devonian Slave Point and Keg River Formations)	32,300	25.3
Liard Basin	Current focus on the Middle Devonian to Lower Mississippian Besa River formation	12,200	4.1
Bivouac-Hay River	Middle Devonian Muskwa formation	269	1.1

Source: British Columbia Ministry of Natural Gas Development [20]

2.3.1. Montney Play Trend

The Triassic age Montney formation is a thick and geographically extensive geological formation, present in British Columbia and Alberta (see Figure 14). It covers approximately 130,000 km^2 and its thickness ranges from 100 to 300 meters. A recent study led by the NEB rated its ultimate potential as very large, containing estimated volumes of 449 Tcf of marketable gas, 14.5 billion bbls of NGLs and 1.1 billion bbls of marketable oil. [21] The NEB study concluded that the Montney is one of the world's largest resources for marketable natural gas, enough to satisfy 145 years of Canada's gas consumption. The distribution of resources between British Columbia and Alberta is shown in Table 3. British Columbia holds 60% of the natural gas, 87% of NGLs and 3% of the oil in the Montney Formation.

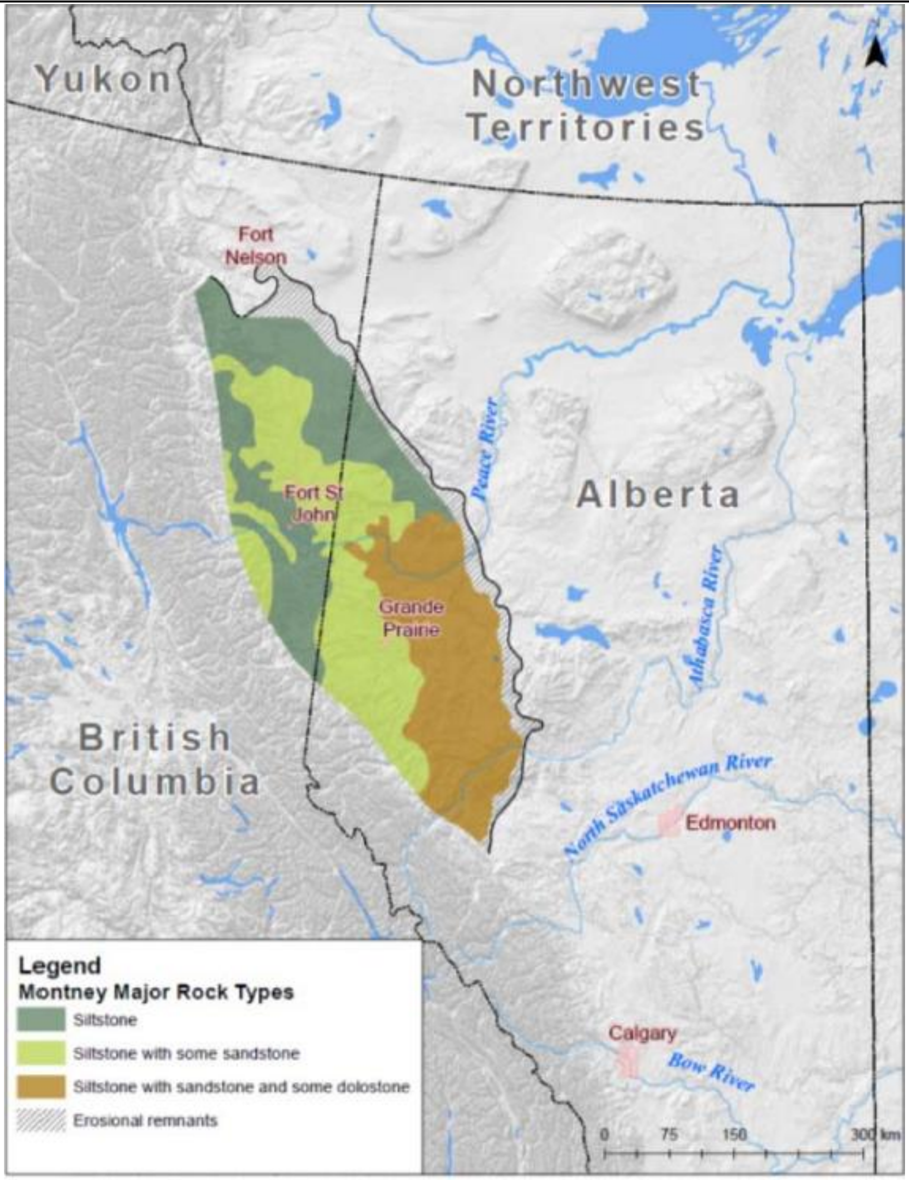


Figure 14. Location of the Montney Formation

Source: National Energy Board [21]

Major operators in the B.C. Montney in 2014 were Progress Energy, Shell, ARC Resources, Encana, Tourmaline, Canadian Natural Resources, Murphy Oil and Crew Energy. In 2014, it is estimated that 1585 wells were producing 2.5 Bcf per day from the B.C. Montney formation.

Development of the B.C. Montney has shown a different pattern to development in Alberta. Alberta producers focus on either oil or leaner gas production, while in B.C. the Montney gas play is richer in liquids than most Montney gas wells in Alberta. The main types of fracture treatments appear to be slickwater fractures with 15-20 stages and a fracture water demand of 6,500-10,000 m^3/well.

Table 3. Montney Expected Marketable Resources

	British Columbia	Alberta	Total
Natural Gas			
(billion m^3)	7,677	5,042	12,719
(Tcf)	271	178	449
Natural Gas Liquids			
(million m^3)	2,010	298	2,308
(million barrels)	12,647	1,874	14,521
Oil			
(million m^3)	5	174	179
(million barrels)	29	1,096	1,125

Source: National Energy Board [21]

2.3.2. Horn River Basin, Liard Basin and Cordova Embayment

The Horn River Basin, Liard Basin and Cordova Embayment are located in the far northeast corner of British Columbia, with the Liard Basin extending into the Yukon and Northwest Territories.

Horn River Basin

The Horn River Basin was the first to see oil petroleum development. In British Columbia, it covers 11,460 km^2 in the region north of Fort Nelson, between the Liard Basin to the west and the Cordova Embayment to the east. The main producing formations are the dry gas bearing Muskwa, Otter Park and Evie formations which, in some areas, overlay each other allowing for vertically stacked developments.

A study led by the NEB estimated marketable natural gas in the Horn River Basin at 2,198 billion m^3 (78 Tcf).[22]Drilling and production activities increased rapidly around 2010 and 2011, but, due to low prices for natural gas, drilling activity has slowed down considerably in 2014. In December 2014, 224 wells were producing approximately 500 MMcf per day.

Liard Basin

The Liard Basin is located at the far northwest corner of the Western Canada Sedimentary Basin (WCSB) and is present in British Columbia, the Yukon and the Northwest Territories. Conventional natural gas has been produced in the Liard Basin since the 1960s and gas processing and pipeline infrastructure is in place. However, the region remains largely unexplored, particularly for unconventional resources. As of April 2015, there were only two wells producing gas from the Besa River formation at a combined rate of 4.1 MMcf per day.

The primary shale gas target is the Besa River formation of Middle Devonian to Middle Mississippian age, particularly the Exshaw and Patry shales. A study led by the NEB estimated marketable natural gas at 6.2 trillion m^3 (219 Tcf).[23]

Cordova Embayment

The Cordova Embayment is located east of the Horn River Basin and covers an area of approximately 2,400 km^2 in British Columbia. The area has seen natural gas development from the conventional Jean Marie formation and this has resulted in the presence of pipeline infrastructure. However, the current interest is in recovering shale gas from the Muskwa, Otter Park and Evie Formations. A 2015 study from the British Columbia Ministry of Natural Gas Development estimated that the marketable natural gas from shale formations in the Cordova Embayment at 249 billion m^3 (8.8 Tcf), are distributed as follows: Muskwa (37%), Otter Park (27%) and Evie (36%). [24]

2014 production of 25.3 MMcf per day was from 20 wells.

Bivouac-Hay River

The Bivouac-Hay River field is located east of the Horn River Basin and south of the Cordova Embayment. In 2014, 18 wells were drilled in the area, making it the second most active shale gas area in British Columbia. In the Horn River Basin, the Muskwa formation produces dry gas, while in the Bivouac-Hay River field, the same formation also contains condensate. The area also has well established gas production from the conventional Debolt and Jean Marie carbonate formations. 2014 production from shale formations was 1.1 MMcf per day of natural gas and 22 barrels per day of condensate from one well.

Greater Sierra

The area referred to as Greater Sierra encompasses the Gunnel Creek, Yoho, Sierra, Elleh and Eskai areas located east of Fort Nelson in the south east corner of the Horn River Basin and further south of the Basin. The area has been in production using horizontal wells since the mid-1990s's but has seen renewed interest in tight gas development from the Jean Marie Reef Play.

Production in 2014-15 was from 617 wells producing from the Jean Marie formation at a rate of approximately 200 MMcf per day.

2.4. Yukon and Northwest Territories

Portions of shale and tight gas deposits found in northern B.C. also extend into the Yukon and Northwest Territories with some drilling and production from the Liard Basin.

There has been minimal oil and gas production from unconventional resources in the Yukon. The Liard Basin in the Yukon Territory saw production from only 3 wells between 1991 and 2012.[25]

In 2015, there was no gas production from the Liard Basin (Cameron Hills field) in the Northwest Territories. Production had been declining from 35 thousand m^3/day in 2002 to 6.5 thousand m^3/day in 2014. Similarly, NWT Liard Basin oil production declined from 14 m^3/day in 2003 to none in 2015.[26]

3. SUSTAINABLE PRODUCTION FROM MULTISTAGE HYDRAULIC FRACTURING OF HORIZONTAL WELLS

Authored by New Paradigm Engineering, with contributions (section 3.2) from Saskatchewan Research Council

3.1. Section Overview

This section is focused on needs and gaps shared by most tight or shale oil and gas developments related to enhancing production rates and Economic Ultimate Recovery (EUR). In recent years, with oil and NGLs prices being relatively higher than gas prices, the focus in Western Canada has been mainly on liquids production; it is assumed this will continue even with lower commodity prices, especially for low cost light tight oil and NGL, which can be used as diluent for bitumen exports.

The first four sub-sections are focused on reservoir and production needs and gaps associated with specific resource types, as follows:

- Tight oil
- Shale oil
- Shale (rich) gas
- Tight (lean) gas

The resource specific sub-sections have been ordered as above based on the relative current activity levels and market drivers for these resource types, indicative of short-term needs. This order would be different if the focus was on the long term and total resource in place in the various plays. However, it was felt that the technologies are too new to adequately assess factors influencing long term total resource recoveries in some of the huge and deep shale plays, where there has been insufficient experience, and where current economics do not appear to be favourable for near-term development.

Needs and gaps based on the type of resource tend to be areas where producers would be the primary entities involved with using the results, to make development decisions, to analyze reservoir/well performance, and to address key production issues. Governments, as resource owners, would also have interest in order to assess potential locations, relative desirability and sustainability impacts of development.

Section (3.6) focuses on the hardware, materials and methods for conducting hydraulic fracturing, which are generally common to all resource types. The technologies to address these gaps are usually developed by service and supply companies, in highly competitive proprietary product development settings.

It is also noted that, while the focus of this Roadmap is on hydraulic fracturing, novel fracturing approaches, such as electrical pulse and the Kiel Process, are emerging as alternative techniques to improve the rock fracture network.

3.2. Tight Oil

This section addresses tight oil formations where the reservoir is not a source rock; so oil contained in the formations has migrated in from a lower formation. While these formations are considered “tight” with low permeability to flow and low porosity, they are similar to conventional oil reservoirs and are sometimes tight areas of formations that have been under production for decades. Tight formations can also be divided into carbonates (Saskatchewan Bakken, Swan Hills/Beaverhill Lake Slave Point, Leduc, Nisku, Wabamun) and clastics (Cardium, Viking).

This section focuses on the Bakken formation, but the issues identified are applicable to other tight oil formations. Furthermore, tight oil formation issues are not limited to those included in this section.

3.2.1. Reservoir Characterization

Reservoir characterization provides important geological and engineering parameters for economically evaluating and exploring formations. For example, the reservoir rocks located in the Bakken formation are highly complex and variable. There are many stratigraphic targets and sweet spots for lateral drilling around the basin. Variables such as thermal maturity and facies distribution are primary controls on the distribution of the overall play. Natural fracturing of the reservoir is also key to success, and ranges from microfracturing, to diagenetically enhanced fracturing, to hydraulic fracturing due to hydrocarbon generation, and finally to tectonic fracturing of brittle rock types. Facies-controlled lithologies and subsequent diagenesis also influence reservoir quality. Finally, reservoir pressure and water saturation play a role in the ultimate recoveries. Understandably, these variables yield a wide range of reservoir targets and production characteristics around the Williston Basin.

Petrophysical and Geomechanical Properties

Proper measurement of the petrophysical properties, e.g., porosity, permeability, and pore throat distribution, is critical for design and implementation of the production processes. That is because tight oil production performance is strongly dependent on interconnected natural and hydraulic fractures in the drainage volume of the horizontal well, i.e., stimulated reservoir volume. When fractures are created or regenerated as a result of in-situ stress and strain change, the distribution and permeabilities of these fractures have determining effects on the tight oil production performance and ultimate recovery. It is currently difficult to measure the changes in geomechanical properties of the reservoir, rock type, degree of fracturing, density etc. as the fractures are initially developed and as they change over time when the well is put on production. In general, lab testing, core analysis, and well log correlations are three major ways to determine geomechanical properties[27], each of which has its advantages and limitations. Lab testing is the most direct and reliable means, though many tests are labour- and time-intensive. Core analysis is another direct method, but it can only be conducted in cored wells. Well logging is an indirect method that reflects petrophysical and geomechanical properties of the formation and regional geology.

Some commonly measured/estimated geomechanical properties for the Bakken formation and other unconventional resources are listed in Table 4 below.

Table 4. Geomechanical Properties Studied for Bakken Reservoirs

Property	Details
Maximum horizontal principal stress and its orientation	Determined using an elastic strain recovery and acoustic anisotropy velocity method, and induced tensile fractures in oriented cores
Dynamic elastic properties	Young's modulus, Poisson's ratio, etc., determined from wireline data
Static elastic modulus	Converted from dynamic elastic properties using empirical correlations and calibrated to available core data, or determined from tri-axial test
Rock strength	Laboratory tests, if available, to fit a number of empirical correlations
Vertical stress (overburden)	Integrating bulk density to the depth of interest
Horizontal stress	Determined from poroelastic horizontal strain model, which incorporates pore pressure and static elastic properties to calculate the minimum and maximum horizontal stresses
Pore pressure	Difficult to measure, usually estimated from drilling events (e.g., kicks, influxes, and connection gas), fracture injection tests, and build-up curves
Fracture gradient	Estimated with laboratory tests
Static Poisson's ratio	Determined from tri-axial test
Dynamic Poisson's ratio	Determined from P- and S-velocity (sonic) and density logs
Biot's coefficient	Describes the ability of the pore pressure to counteract the stresses on the rock, can be calculated using the dry rock stiffness tensor and estimate of the mineral bulk modulus

Fluid Pressure, Volume, Temperature (PVT) Properties

When pore spaces shrink to the scale of nanometers for shale or ultra-tight reservoirs, capillary pressure, electrostatic, and van der Waals forces result in amplified effects, which can cause the phase behaviour of reservoir fluids to deviate from classic thermodynamics. In addition, Bakken formation brine has significant total dissolved solids (TDS), hardness (mainly caused by the presence of calcium and magnesium), and iron and strontium concentrations. This requires increased attention to water chemistry, such as the high tendency for scaling problems and incompatibility of injection water/drilling fluid/fracturing fluid with formation water. Research and development in scale inhibitors with high iron- and temperature-tolerance is critical. Water-related gaps are further discussed in Section 4.

3.2.2. Drilling and Completion

Bakken well activity and oil production have increased dramatically in recent years, largely because of technological advancements in drilling, completion, and hydraulic fracturing. In addition to horizontal drilling, one of the key drivers in the Bakken oil boom is the game-changing multistage hydraulic fracturing technology. While drilling and casing programs have become generally standardized in the Bakken Middle Member, there are wide variations in the completion and stimulation practices, which continue to evolve as production enhancements translate into new best practices for a producing area. Details can vary significantly depending on specific reservoir properties, such as permeability, stress, and natural fractures. A successful drilling and completion strategy needs to consider many aspects, such as geological settings, geochemistry, geomechanics, petrophysics, logistics, economics, and environment. In southeast Saskatchewan, drilling and completion of a horizontal well can encounter several specific geological hazards[28]. These include localized thinning of the reservoir, extreme salt collapse, and structural lows related to salt dissolution. The major concern for completion is the fracture growth into the overlying limestone Lodgepole Formation. Within 10 to 50 meters above the Bakken reservoir there is often a higher permeability water-bearing interval in the Lodgepole. Therefore, hydraulic fracturing in the Bakken oil reservoirs in Saskatchewan involves a risk of connection to these overlying water-bearing zones. To minimize the potential negative impact of partial hydraulic fracture growth out of zone, some strategies, such as reduction of pump rate, slurry volume and fluid viscosity, are implemented.

Some of the most challenging aspects of the drilling and completions include a better control in thin tight formations to avoid water production and communication between wells, as well as achieving an optimum balance of well or lateral spacing vs. fracture numbers, spacing and size in tight zones.

Table 5 provides an overview of the various drilling technologies used in Bakken and their relative advantages. Table 6 summarizes the advantages and disadvantages of various completion methods.

Table 5. Bakken Drilling Field Cases

Field/ County	Technology/Best Practice Highlights	Findings and Technology Advantages	Reference
Sanish field, Mountrail County, ND	• Real-time downhole dynamics tool to help optimize drilling activity. • Practical use of directional information from bending moment and bending tool face close to the bit.	• Save time and increase the successful rate of one-run laterals. • Allow the directional driller to make better real-time decisions whether wellbore correction is needed.	29

Table 5. Bakken Drilling Field Cases

Field/ County	Technology/Best Practice Highlights	Findings and Technology Advantages	Reference
Mountrail County, ND	• Conventional mud motors and measurement/logging while drilling (MWD/LWD) systems together with onsite geological analysis to drill the curve and lateral section. • Electromagnetic (EM) MWD/LWD. • GeoSteering in the lateral section.	• Landing curve: cost effective with adequate results. • EM MWD/LWD: faster data rate than conventional mud-pulse; signal transmission is independent of wellbore hydraulics; allows more lost circulation material (LCM) to be pumped downhole when necessary. • GeoSteering: constantly monitors drilling parameters and cutting samples to avoid undesirable penetration of shale formation.	30
Burke County, ND	• Rotary steerable system (RSS), "push-the-bit" tool applies force outwards against the wellbore to push the bit in the opposite direction. • Conditioning the borehole with reamer run.	• RSS: simplicity and full rotating capability to effectively clean the wellbore. It is also used to maintain hole verticality above the kick-off point (KOP). • Reamer run: improve borehole trajectory condition by reducing borehole rugosity, spiral boreholes, and porpoising effects.	31
Not disclosed	• Holistic optimization technique to analyze the entire drilling and all BHA components back to surface. • The results were analyzed as a whole to determine the best drilling solution. • An optimization "roadmap" is generated to include a mainline strategy in addition to several contingency plans.	• Proper drill bit selection and wear pattern emulation to improve drilling efficiency and ROP. • Appropriate liquid and mechanical drillstring lubrications were implemented for effective weight-on-bit (WOB) transfer. • Continuous well monitoring and streamlining of decisions. • 34% reduction in drilling days than projected and established average days.	

Table 6. Summary of Common Completion Methods in Bakken Formation

Method	Advantage	Disadvantage	References

Table 6. Summary of Common Completion Methods in Bakken Formation

Method	Advantage	Disadvantage	References
Cemented liner	• Allows control of wellbore stability, direct control of fracture initiation, and greater well serviceability. • Cemented liner and hydrajet perforations placing the fracture treatment with coil tubing.	• A primary concern with conventional liner methods is being assured of where the fracture is being placed. • Impossible to determine that there was adequate annular isolation to ensure where any of the planned fracture treatments were placed. • Potential for formation damage during completion. • Potential isolation of natural fractures that would otherwise contribute to conductivity in the open hole.	32 33 34
Open hole, multistage system (OHMS) completions	• All fracturing treatments can be conducted in a single, continuous pumping operation. Drilling rig or wireline/CT services are not needed, relatively quick and inexpensive. • Less fracturing fluid is used because bridge plugs are not pumped down the tubing; this removes need to clean out all proppant to avoid a plug getting stuck before it reaches desired setting depth. • Has good potential for improved recovery from refracturing techniques.	• Single-stage fracturing in the open hole provides little control over fracture initiation and propagation. • Other methods of open hole completions include the insertion of liners and ball-actuated sliding sleeve systems for multistage fracturing.	32

Table 6. Summary of Common Completion Methods in Bakken Formation

Method	Advantage	Disadvantage	References
Ball drop (ball-on-seat) systems and open hole packers	• One operator's approach was to complete wells using ball drop systems and open hole packers, leaving the balls and ball seats in the wellbore and milling them out later based on well-by-well analysis. Production performance dictates the decision of when to mill out the ball seats.	• Long laterals drilled with conventional bent assemblies need to run time-consuming reamer to remove tortuosity and hole rugosity. • This does not allow further workover operations or refrac opportunities without removing the restrictions. • Other drawbacks include additional cost, loss of production during the operation, longer operation time and excessive fluid losses.	28 31
Plug-and-perf	• Uses wireline intervention to set composite fracturing plugs for stage isolation and to perforate individual stages. • Creates distinctly distributed initiation points along each stage’s section in the lateral. • Perforation with high injection rate helps distribution of fluid and proppant along the lateral.	• Premature setting of bridge plugs requires additional remedial services. • Each stage needs to be flushed with a minimum of two stages volumes to clear the wellbore of residual proppant and displace the next plug and gun. • Multiple intervention increases the chances of operational and safety issues. • Typically 20% more expensive than ball-on-seat system.	35 31 32
Single entry fracturing sleeve systems (SE FSS)	• Ball activated fracturing sleeves are installed with the completion liner string and offer a single entry point per stage. • Remove the need for wireline intervention, thereby increasing completion efficiency.		35

Table 6. Summary of Common Completion Methods in Bakken Formation

Method	Advantage	Disadvantage	References
Multi-entry fracturing sleeve systems (ME FSS) completions	• Also ball activated, but a single ball opens multiple fracturing sleeves. • Do not require wireline intervention, and allow for multiple entry points per stage to be simultaneously stimulated.		35
Barefoot completion	• Utilizing an inflatable packer straddle system, has allowed all potential pay intervals to be effectively stimulated, as compared with traditional methods. This new approach of stimulating the open hole, without having permanent packers and frac sleeves or a cemented liner has resulted in reduced completion costs and improved production results.		34 36

3.2.3. Refracturing

Due to the tight nature of these reservoirs, the drainage area is largely defined by the size and shape of the hydraulic fractures. As a consequence, tight oil wells usually have steep decline curves with production rate declines of up to 70% in the first year. Common strategies to arrest this decline are drilling new wells, optimizing production to avoid water breakthrough or interwell communication and re-stimulating (refracturing) existing wells. In the current low oil price environment, technologies that revitalize old wells are gaining increasing popularity because of the lower costs resulting in improved economic benefit.

Refracturing has been applied to Bakken formation only in recent years but to a very limited extent. Currently, it accounts for less than 1% of the overall hydraulic fracturing market, according to Christopher Robart, managing director at IHS Energy[37]. The first key challenge for refracturing is to identify the right candidates. While the refracturing operation itself is not so different from the original fracturing, not all wells are inherently good candidates for the technology. Another challenge is that the refracturing performance, as judged by production increase, is more unpredictable than with newly fractured wells, which makes operators more hesitant to adopt this technology. To reduce risks for customers, services companies are relying on production risk-based business models.

3.2.4. Enhanced Oil Recovery Processes

As mentioned above, the production rate of tight oil wells can drop by 70% of its peak value after the first year. Under this circumstance, pressure maintenance is needed to keep the reservoir producing. Water and natural gas have been used for this purpose.

Waterflooding

Waterflooding is the most widely used EOR technique after primary production. Crescent Point Energy is the pioneer in conducting waterflooding pilot tests in the Canadian Bakken; the company has done eight tests to evaluate the production and injection response, various completion techniques, lateral length, well spacing, and the design (i.e., the number of producer and injector wells) of each pilot. In early 2015, Crescent Point completed the unitization of its first waterflood in its Stoughton unit, and continued to move forward with the unitization of three more units in the Viewfield field. Based on production history, the company estimates that waterflooding has reduced decline rates by up to 10% in swept areas, compared to areas under primary production only.

The efficiency of waterflooding depends on spontaneous imbibition of water into the oil-bearing matrix in fractured reservoirs. However, Bakken reservoirs are characterized as intermediate- to oil-wet wettability, which significantly limits the performance of waterflooding. As a result, methods that can alter rock wettability and improve the performance of injected water are being sought.

In tight oil reservoirs, wettability alteration from surfactants can play an important role in oil recovery. Sufficiently high imbibition rates along with relatively low surfactant adsorption need to be achieved for an economic surfactant injection process. For example, Dawson et al. (2015)[38] studied a novel non-ionic surfactant production enhancer (PE) blended with other chemical additives such as corrosion inhibitor, scale inhibitor, and biocide. Spontaneous tests showed that the PE performed significantly better than an alternative surfactant used in previous Bakken studies. Nevertheless, economic-sensitivity studies indicated that the implementation of a surfactant flooding field project would be unlikely due to the currently low oil price and high surfactant costs.

Although extensive laboratory studies have been conducted, including searching for the best formula for surfactants, and investigating surfactant–rock reactions, water chemistry and compatibility, there is still a long way to go before applying surfactant flooding projects in the Bakken fields.

Gas Flooding

Despite the advantages of enhanced waterflooding, it is believed that imbibition efficiency from surfactant injection is uneconomically slow if fractures are not fully developed[39]. Another obvious challenge for (enhanced) waterflooding is unfavorable injectivity, due to the extreme low permeability of Bakken reservoirs. Moreover, the high temperature of Bakken reservoirs (65–100°C in southeast Saskatchewan Bakken and above 100°C in the US Bakken) and their high salinity significantly limit the selection of available surfactants.

To further improve the development of Bakken oil reservoirs, gas flooding has been proposed as another EOR technology for these reservoirs. Compared with a traditional waterflooding process, gas flooding has its own advantages. Injected gas is much less viscous than water, so the injectivity is significantly improved. Moreover, gas flooding provides multiple mechanisms, such as oil swelling, viscosity reduction, and interfacial tension reduction, rather than just pressure maintenance.

Gas flooding typically refers to CO_2, natural gas or nitrogen injection, and the injection scheme can be direct gas injection, water-alternating-gas (WAG) injection, gas huff-n-puff, or water-gas co-injection. It is applied as either a miscible or an immiscible process. Miscible gas flooding aims at creating a miscible condition in which the interfacial tension between the injection gas and the reservoir oil is completely eliminated, whereas the main mechanism for immiscible gas flooding is normally pressure maintenance.

CO_2 flooding has been a mature EOR technology for conventional carbonate and sandstone reservoirs for several decades. The feasibility of CO_2 flooding for the Bakken formation was evaluated through numerical simulations, experimental work, and field pilots[40 41]. The Energy & Environmental Research Center (EERC) in North Dakota is leading a research consortium of government agencies and several oil companies to study CO_2 flooding for Bakken reservoirs[42]. Understanding of fluid mass transfer and movements through tiny pores, microfractures and macrofractures are the key to CO_2 EOR in tight formations. The consortium used a wide range of technologies including scanning electron microscopy and computed tomography (CT) to identify rock characteristics. Recovery tests were conducted using CO_2 for a low permeability Middle Bakken sample, ultra-low permeability Upper and Lower Bakken member samples, as well as a conventional reservoir sample. When oil-saturated Bakken rock samples were placed into a high-pressure, high-temperature cell filled with CO_2, up to 80 to 100% of the oil could be extracted in a 24-h period.

In the past, the majority of Bakken produced gas in both the United States and Canada was flared due to insufficient capacity of the gathering system and pipelines. Interest has grown and research has been undertaken in recent years to reinject this otherwise flared produced gas into the reservoirs as an EOR agent[43]. In terms of recovery mechanisms, though not as effective as CO_2, the methane- and ethane-enriched produced gas can still serve for pressure maintenance purposes and reduce oil viscosity considerably. Compared to CO_2, the use of enriched produced gas does not have any corrosion concerns for facilities and is readily available. Detailed laboratory measurements and numerical simulations need to be conducted to evaluate the technical viability and economic profitability of a produced gas reinjection process.

In 2011, Lightstream Resources started a dry-gas injection pilot in the Viewfield Bakken field[44]. The dry gas, which was primarily methane, was taken from produced solution gas, processed at Lightstream's gas plant, and transported via a 10.5-mile pipeline to the injection site. The pilot project covers 1,280 acres with combinations of 80- and 160-acre spacing. A one-mile horizontal well in the centre was used as the injection well to displace oil to the nine perpendicular horizontal wells. The dry gas was injected in an immiscible and continuous scheme at varied rates of 350 mcf/d to 1,000 mcf/d. At the time of publication, oil production from the pilot project had increased from 135 bbl/day to a peak rate of 295 bbl/d in 12 months from the start of gas injection. Compared to CO_2, injection of dry gas has advantages of (1) abundant and cost-effective supply of processed solution gas from nearby gas plant; (2) elimination of corrosion risk; (3) much less facility cost. Nevertheless, the pilot had also faced several major challenges including gas breakthrough, legacy well design, and down-hole pump failures.

3.2.5. Numerical Simulation

Due to widespread natural fractures, a dual-porosity model is often employed for simulation of tight oil or shale gas reservoirs. In dual-porosity systems, different porosities and permeabilities are assigned to the matrix and natural fractures, and the oil in the reservoir is produced by flowing from the matrix to the fractures. Understanding the contributions of the matrix and fractures to the oil production rate is the key to identifying oil recovery mechanisms affecting the productivity of the well over its lifetime. The introduction of secondary (hydraulic) fractures makes the fluid flow physics even more complicated to understand and model. Current reservoir simulators need to be adapted and further developed for dealing with tight oil and gas formations.

The ability to conduct adequate numerical simulations for the tight oil reservoirs is important not only for the optimal technical design of the field development, but also to provide the data necessary for building an economic model. Long-term economic viability and profit maximization are always the goals for every hydrocarbon production company. These goals are much harder to realize for tight oil producers. Horizontal or multi-lateral well drilling costs more than conventional vertical well drilling; hydraulic fracturing is a significant extra expense. During the initial oil production, the steep production decline quickly reduces the cash flow. If infill well drilling or EOR is required, the return and cost associated with them need to be carefully analyzed.

3.2.6. Produced Water Recycling Reservoir Impacts

In recent years, recycling of produced formation water is gaining increasing attention. Fresh water supply has become a concern, as the fluid volume requirement in fracturing treatment has increased significantly. Rather than looking for fresh water sources and disposing of produced and flowback water, partial or full reuse of produced brine for well stimulation can reduce the environmental footprint, preserve more fresh water sources, and save the cost of a central gathering system and water transportation. However, the impact of water quality issues when using treated recycled water in fracturing fluids or for waterfloods needs to be carefully studied. Incompatibilities between chemical constituents in different water sources may negatively impact reservoir rock, oil and gas production and surface facilities. A detailed discussion of water related challenges is found in Section 4.

3.2.7. Bakken Oil Transport

Despite large differences in production scale, the Canadian and US Bakken have similar challenges with the shortage of oil pipeline infrastructure to transport Bakken crude oils to market. Currently, rail is an important means of transportation. However, shipment by rail is more expensive than pipeline transportation. Furthermore, several recent train derailment tragedies related to the shipping of highly flammable Bakken crude oil have posed severe railroad safety concerns.

In the United States, the Energy Information Administration[45] stated that, in addition to other technical factors, pipeline transportation capacity issues could hinder further development of the Bakken Formation. If production in Montana and North Dakota increases, the existing transportation system will become a bottleneck. However, new pipeline infrastructure is progressively being installed. For example, the Government of Canada announced a Bakken Pipeline Project that will transport crude oil from a new pump station near Steelman, Saskatchewan, to the existing Enbridge Pipeline Cromer Terminal near Cromer, Manitoba. This project will involve the construction of a 123.4-km-long crude oil pipeline and associated facilities.

3.2.8. Associated Gas Utilization

Due to the lack of gas pipeline transportation infrastructure, much of the solution gas produced along with Bakken tight oil has to be flared. There are several factors affecting capture and utilization of associated gas, including government regulations and the reluctance of landowners to tolerate further requests for easements on their land. In order to support oil producers with flaring solution technology, the EERC provides a database containing vendor-supplied technical and economic information about gas utilization technologies. In 2011, the Saskatchewan Ministry of Economy developed Directives S-10 and S-20 for regulating gas conservation and flaring requirements. This drives development of cost-effective technologies in the Bakken formation to reduce gas flaring and promote utilization. At the national level, in late 2015, the Canadian Government set a policy goal of reducing methane emissions by 40 to 45% below 2012 levels by 2025.[46]

Rapid oil development has exposed producers to the inadequacies of the regional gas processing and transportation infrastructure in the Bakken[47]. To meet these gas-flaring reduction goals in the short term, a number of companies have turned to well site compressed natural gas (CNG) technology. More recently the flaring restrictions imposed by the North Dakota Industrial Commission (NDIC) have motivated development of mobile technology to address flaring concerns and to monetize associated gas. Wallace[48] discussed the technical feasibility of replacing diesel with Bakken produced gas for powering drilling and hydraulic fracturing operations. The analysis of average energy generated from the volume and composition of the produced gas showed that it is sufficient for supplying the energy required for powering the drilling rig and fracture spreads. Hoffman[49] evaluated the recovery potential along with the costs of reinjecting gas to determine the economic value of this process. A dual-porosity, compositional flow simulator was used to model the gas injection process into a well surrounded by producers and to determine the amount of incremental oil and gas produced. The handling of associated gas can be complicated by the presence of H_2S.

3.3. Shale Oil

This section addresses needs and gaps mainly associated with shale, siltstone or carbonate shale source rock formations, (Montney, Duvernay), containing oil where low permeability and the presence of solid kerogen, absorbed gas, rock wettability, high pressures/temperatures or other factors may impact the ability of fluid to flow through the reservoir and fractures.

3.3.1. Reservoir Geochemistry

Reservoir geochemistry is a concern in the true oil shales (Duvernay and Montney) where the presence of kerogen may impact production by blocking pore spaces; it is also possible that fractures may close if the rock or kerogen is soft or brittle. Due to the depths and pressures at which shale oil and gas source rocks are found, it is still unclear as to the state in which the oil, gas and NGL exist at reservoir conditions, often 2,000 to 4,000 meters underground. This leads to considerable speculation and questions concerning the potential recovery issues, especially in the liquid rich gas areas around Fox Creek and Grand Prairie in Alberta, and the Montney oil in Alberta and rich gas play in B.C.

Recovery Mechanisms for Liquids

In each play, different geographical areas of the formations can contain NGL, gas condensate or very light oil (depending on the criteria used for defining these). The NGL are produced at a higher rate than oil, as they are low viscosity and the high gas to liquid ratios assist in the production rates and recoveries. The basic information on whether the target area of the formation contains NGL, light oil, a retrograde condensate, or if it is a liquid being desorbed from kerogen, impact which basic recovery mechanisms will exist in the reservoir, and the potential content and behaviour of pores and flow channels in the reservoir, and are difficult to assess when only looking at initial primary production and core from a limited number of wells.

Definition of Oil vs. Gas

In deep shale formations, it is uncertain what form the oil, gas and NGL take in the reservoir. This may impact how the production is treated from a royalty point of view as in conventional reservoirs the royalty regime used for calculations is normally based on what form the hydrocarbons are found in the reservoir. There has been some controversy and inconsistencies already noted in how Montney/Duvernay wells are handled for royalty purposes. These issues are not commonly encountered in lean gas or more conventional oil reservoirs.

Petrophysical and Geochemical Properties

Duvernay carbonate rocks are relatively weak and soft so they may already contain significant natural fracture networks due to stresses encountered during burial, and may also be soft enough to fail in areas around proppants and allow propped fractures to close over time. This aspect is potentially more important in carbonate dominated formations like the Duvernay. The geochemical properties of the rock are important for fracturing and stimulating the wells. Carbonate rocks can be reduced through use of acid in the stimulating fluids, while clays or silts may be adversely affected by water injection.

Impact of Immature Kerogen on Production

Source rocks still contain significant amounts of organic material, or kerogen, in the rock structure, which would be expected to alter the characteristics of the surrounding mineral matrix and pore structure. The solid kerogen particles or strata could shrink if adsorbed gas escapes, expand if the gas is depressured but contained in viscous material, or potentially be broken up as absorbed gases desorb under reduced pressures, which could weaken the rock structure, cause plugging of pore throats or microfractures, and generally reduce the permeability of the formation in some areas. Research into the properties of various types of this material in a range of hydrocarbon fluids, temperatures and pressures would assist in trying to assess potential limits to shale production.

3.3.2. Water/Fracturing Fluid and Fate in the Reservoir

There are many questions about where the water and other fracturing fluids go when injected in shale formations. In some cases, like the Duvernay, some appears to go down and enter faults in the basement rock, which are believed to cause seismic events in the Fox Creek area. A recent study by Dr. David Eaton of the University of Calgary analysed seismic events going back to the winter of 2015 in the Fox Creek area of Alberta where hydraulic fracturing takes place.[50] The study identified a basement fault system running parallel to two horizontally drilled wells. Hydraulic fracturing of the two wells triggered small earthquakes by imposing mechanical stresses on the rock formations beneath the hydrocarbon bearing zone, causing the fault to slip. In this case, the seismic event stopped when hydraulic fracturing was interrupted. However, in another strand of the fault, additional seismic events occurred more than two weeks after the interruption of fracturing operations. These events were attributed to the later infiltration of fracturing fluids into that strand of the fault. The study paves the way to assess and mitigate the risk of seismic events.

In other formations, it may be widely distributed throughout the rock matrix, potentially blocking flow of oil to the wellbore or just gravity segregate to the lower portions of the fractures where it will stay. Even in similar formations there are questions about what fracturing fluid to use. For example, Table 7 and Figure 15 indicate that some producers in the Montney are using oil to fracture and seem to achieve higher production rates than those using slickwater.

Methods to Detect Water or Fracture Fluid Distribution Pre- and Post-Fracturing

The path followed by injected water, and its eventual fate will have a significant impact of the success of the completion program and on the associated risks such as seismic events. Due to the great depth of shale wells and the absence of instrumentation beyond the wellbore, it is difficult to image the distribution of injected water. Further utilization of established technologies such as time lapse 3-D seismic could continue to be explored. Tracers or yet to be developed nano detectors could also be thought of as tools to gather information on the fate of injected water. Closing this knowledge gap would inform choices for completion parameters such as fracturing fluids, additives, and proppant, would assist in improving the design of fracture programs and would allow for improved analysis of the effectiveness of fracturing methods.

Table 7. Range of Fracturing Treatments Used in Alberta Montney Oil Wells

Well Group (# Wells)	Average True Vertical Depth (m) (Range m)	Average Dev't Depth (m) (Range m)	Completion Services Supplier (# Wells)	Carrier Fluid Type (Water use m^3/well)	Fracture Stages Per Well (Range)	Proppant (Mass %) (Range %)
Trilogy Kaybob (18)	1835 (1821-1850)	3710 (3510-4118)	Calfrac	Oil + 10% N_2 (0)	23 (21-29)	24 (20-27)
Trilogy Kaybob (5)	1828 (1788-1845)	3592 (3523-3653)	Calfrac	Water + 10% N_2 (785)	22 (21-29)	20 (19-22)
Trilogy Kaybob S (1)	2043	3756	Calfrac	Oil +10% N_2 (0)	21	20
ARC Ante Creek N (6)	1916 (1873-1969)	3729 (3370-4150)	Schlumberger (1); Sanjel (3); Haliburton (2)	Water (642)	17 (13-21)	25 (21-30)
ARC Ante Creek (4)	1917 (1873-1968)	3790 (3007-4350)	Schlumberger (3); Sanjel (1)	Water + 20% N_2 (274)	20 (11-28)	32 (29-38)
ARC Ante Creek (2)	2077 (2076-2077)	3630 (3501-3759)	Schlumberger	Water (456)	17.5 (17-18)	19 (15-23)
ARC Ante Creek (1)	2079	3400	Schlumberger	Water + 20% N_2 (198)	16	34
RMP Ante Creek (1)	1966	3672	Calfrac	Oil +10% N_2 (0)	18	30
RMP Waskahigan (4)	2182 (2137-2261)	3789 (3404-3974)	Calfrac (4); Canyon (1)	Oil + 10% N_2 (0)	19 (18-23)	30 (27-32)

Source: New Paradigm Engineering (2013) from analysis of Montney well data from the Alberta Energy Regulator database through geoSCOUT and of associated completion information from the FracFocus Chemical Disclosure Registry (www.fracfocus.ca)

Controlled Testing of Fracturing Fluids with Changes in Geochemistry

Understanding the details of the interactions between of rock geochemistry and the chemistry of injected fluids is a key issue in effectively recovery hydrocarbons from shale formations. Minerals present in injected water can react with rock compounds and block pore space. Minerals extracted from the reservoir rock and entrained with produced water can cause scale and buildups in processing equipment.

A typical workflow for examining rock geochemistry interactions involves using core samples and exposing these samples to experimental conditions. However, challenges with this approach are the limited availability of core samples which are costly to obtain, variations in characterization parameters between core samples as they are all unique rock samples, as well as their ability to act as representative samples of the field as a whole. One novel proposed approach is to print cores using 3D printers that have become available in recent years. This approach would allow researchers to conduct repeatable tests on the required population of identical printed core analogues to ensure reliable and statistically meaningful results to examine key variables, and to more clearly distinguish research results due to variations of experimental parameters to those due to variations in sample quality. The University of Alberta Geomechanical Reservoir Experimental Facility led by Dr. Rick Chalaturnyk is currently experimenting with 3D printed cores for the purpose of improving the repeatability of core testing.

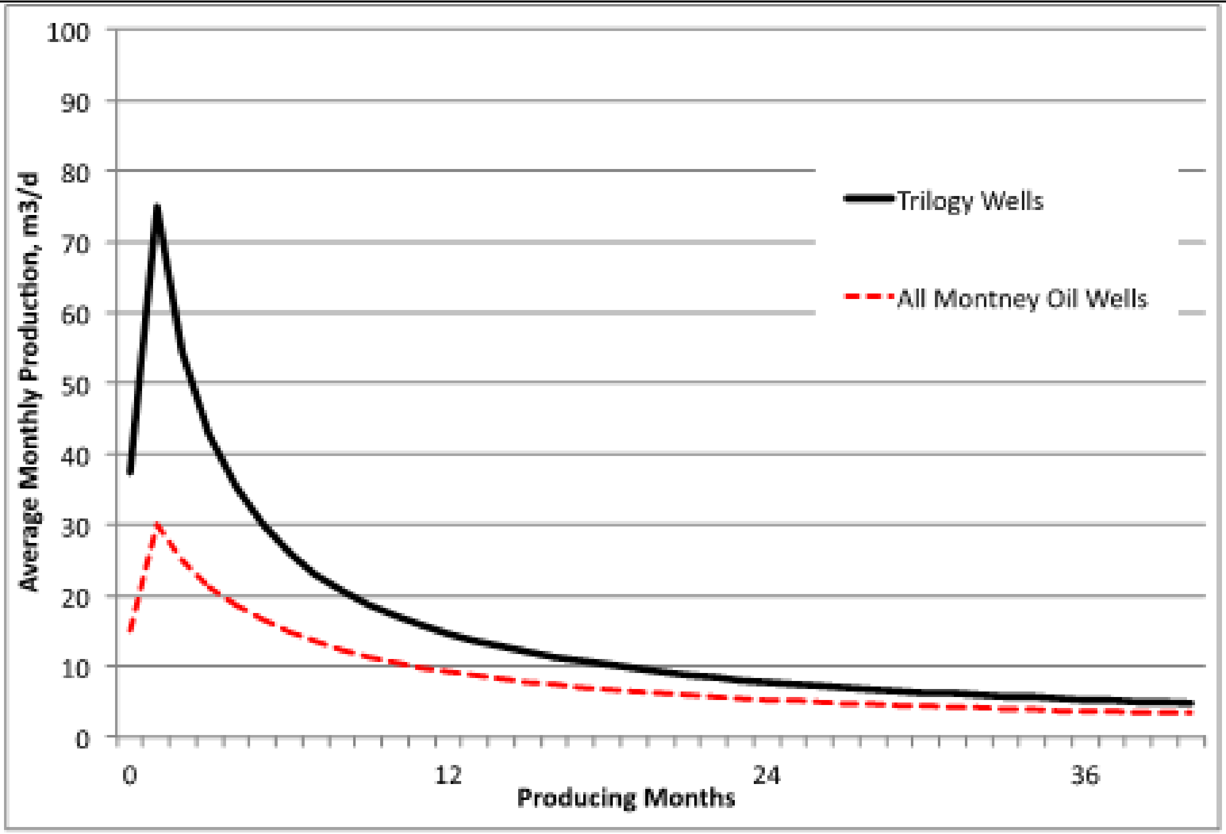


Figure 15. Best in Class Performers using Oil Fracture Fluid vs. all Montney Oil Wells

Source: New Paradigm Engineering (2013) from analysis of well data from the Alberta Energy Regulator database through geoSCOUT.

3.3.3. Shale Drilling and Completions

As development moves from exploration and resource delineation, to full scale commercial development, the emphasis shifts to understanding inter-well effects and ensuring that a high percentage of the resource in place is being accessed. This is especially critical in thick source rock formations which may be hundreds of meters thick so it is unlikely that a single layer of fractured horizontal wells is going to be able to effectively deplete the whole thickness. Determining optimum vertical and lateral or offset spacing for multi-laterals drilled concurrently or sequentially will likely result in a trade-off of larger fracture treatments vs. more laterals. These are general development issues that would normally be considered proprietary, however, given the range of operations and the large size of the resources it may be advantageous for the industry to learn together and collaborate to speed up this analysis and assist in the development of tools to optimize well locations and designs.

Development of Fracturing "Test" Sites

A challenge in assessing fracturing fluids, and potential monitoring methods, is that it is difficult to determine if a difference in well performance is due to a difference in the fracturing fluids, fracturing procedures, or in the geochemistry or geology in a given area. In a previous PTAC report "Filling the Gap"[51] the potential to work with governments to develop test sites for side by side comparisons of well drilling, completion and fracturing methods was discussed for shale gas, and could be of value in tight/shale oil formations.

Placement of Wells in Thick Formations

Many shale oil formations are thick (100s of meters) and laterally continuous. To date there appears to be little science behind well placement for development, both vertically and laterally, with many opting for a single layer of horizontal wells with 4 wells per section or 8 wells per 3-4 sections depending on orientation and well length selected. A few producers have begun overlapping wells vertically in the same formation, with some drilling the laterals at the same time and others drilling them sequentially. Analysis of public data could be done to start to assess these factors, but would require commissioning of reservoir studies potentially by third party consultants.

Trade Off of Larger Fracture Stages vs. More Laterals

Knowledge is beginning to grow on the extent of fractures as a result of hydraulic fracture treatments, mainly as a result of micro-seismic monitoring, and also later evidence showing low or no inter-well communication if some type of EOR is applied. There could be a benefit in economic studies to determine the trade-off between larger volume (sand and fluid) fracture stages vs. drilling more laterals to access the formation.

3.3.4. Production Rate Optimization

Some recent indications in literature are that low initial rates, or throttled flow, in shale oil wells will result in higher recoveries of oil per well and result in improved overall economics, even though initial rates may be lower and a slightly longer payout may be the result. A number of theories, from high rates flushing out proppant, fractures closing around proppants as a result of high draw down differentials into the wells. However, this also impacts downstream facilities requirements as production volumes grow.

Economic Trade-off Initial Rate vs. Total Production

At $90-$100/bbl oil the economics of initial rate vs. higher total recovery might favour rate and make it worthwhile to spend more capital to achieve a higher initial rate. However, at lower prices it may be more economic to reduce capital. This trade-off is illustrated below in an analysis for Cardium tight oil type curves. Year to year rate increases are achieved generally by adding more fracture stages, however, over the longer term (3-4 years) the number of fracture stages may not greatly impact total oil recovered per well (See Figure 16 and Figure 17). Collecting data on this may take some time as it is still uncertain what the behaviour of shale oil wells will be over a number of years.

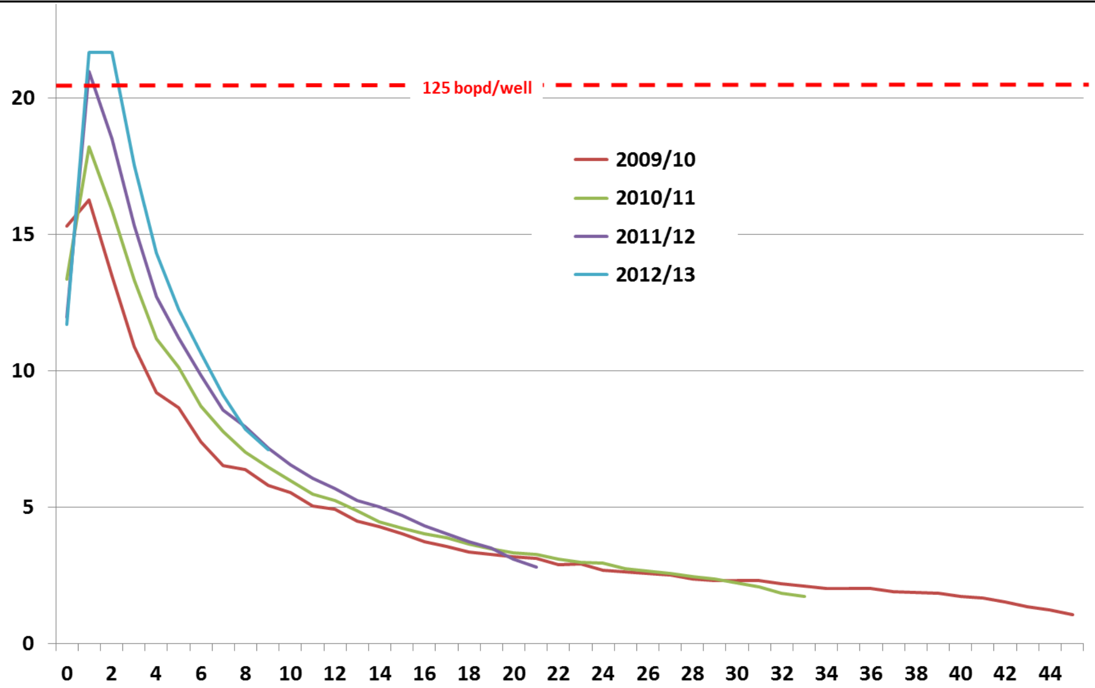


Figure 16. Type Curves for Cardium Tight Oil Wells by Drilling Season

Source: New Paradigm Engineering (2013) from analysis of well data from the Alberta Energy Regulator database through geoSCOUT.

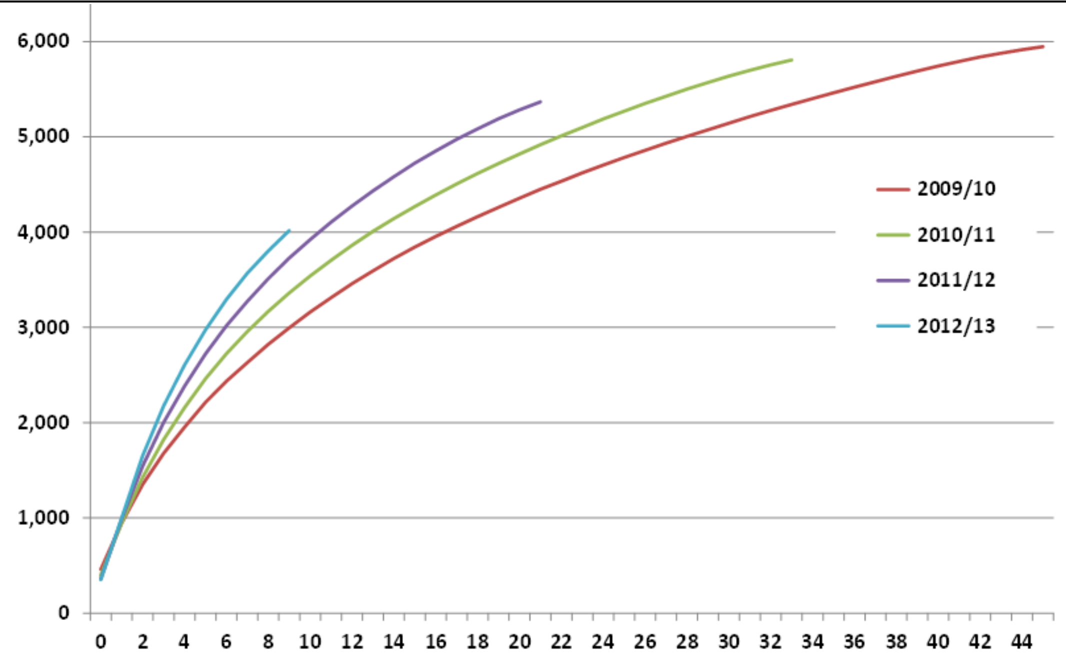


Figure 17. Cumulative Production for Cardium Tight Oil Wells by Drilling Season

Source: New Paradigm Engineering (2013) from analysis of well data from the Alberta Energy Regulator database through geoSCOUT.

Lease and Flowline Costs for Long-term Development

High initial flow rates from shale oil wells requires the installation of larger capacity surface facilities on the leases to handle the short-term peak flows and allow production testing. At higher oil prices trucking of production may be economic, but at lower prices flowlines could increase per barrel netbacks over the longer-term.

Light Crude Stabilization

Producers are often installing high temperature (160°C) crude stabilization units which increase the volume and liquids content of produced solution gas. This may require changes in downstream gas plant facilities to take advantage of light oil vs. condensate as volumes increase, but this investment will be highly impacted by oil prices and relative demand and spreads between light crude and condensate. So studies may be of value in optimizing this decision making process as economic conditions change.

3.3.5. In-Situ Conversion of Shales

A longer-term target (next 10-15 years) should be to accelerate the rate of natural conversion of kerogen in shales into oil to maximize production of oil/liquids from existing wells, as only a small portion of the organic carbon in the shales has been converted and only a small portion of the converted volumes is being recovered. ExxonMobil, Shell and Chevron are working on in-situ conversion technologies using respectively: electrical heating through fractures, in well electric heaters, and high temperature CO_2 injection. These processes indicate that there is potential to manufacture oil and liquids, in shale wells, rather than simply produce what is there naturally. Conditions are already suitable in mature shale, so a small increase in energy or presence of water or hydrogen could accelerate the rates of conversion. This type of process may also mitigate any plugging or permeability reduction in the formations due to mobile kerogen.

3.4. Shale Gas

There has been considerable development of lean gas wells in shale formations like the Montney and Duvernay, which are over-mature source rocks. While part of the Duvernay liquids rich area has been designated as a regulatory pilot, a much larger number of wells are being drilled into the Montney formation in Alberta and British Columbia where liquid yields are not as high as in the Duvernay, yet wells are lower in cost and less water is required for fracturing.

3.4.1. Fate of Water in the Reservoir

As in the case of shale oil, the fate and role of fracturing water in the reservoir is still an area of debate. Some initial observations in the Horn River Basin were that gas production from a well is proportional to the volume of water used for fracturing. If this response is the same for all deep shale gas formations, it may indicate that the gas in the reservoir is behaving more like a fluid.

3.4.2. Shale Drilling and Completions

Work is required to evaluate the impact of initial well location and completions in thick formations, to determine if and how nearby wells impact gas productivity. As drilling moves from evaluation to high density development, as it has for the Montney in B.C., there will likely be some optimum arrangement of vertical and lateral or offset spacings for multi-laterals, and optimum development strategies in drilling laterals or well concurrently or sequentially on pads. There may also be a trade-off between larger fracture treatments vs. more laterals to achieve higher gas recoveries.

3.4.3. Reservoir Geochemistry

Reservoir geochemistry is a mainly a concern in rich gas shales with high NGL yields (Duvernay and Montney) where the presence of kerogen may impact production through blocking pore spaces. This is also important to possibly predict condensate yields from planned wells to optimize development of rich gas regions, by researching how condensate yield may vary with depth and geochemistry.

3.4.4. Production Rate Optimization

Recent observations may indicate that lower initial rates, achieved by throttling well flows in shale oil wells, result in higher recoveries of oil per well. Some rich Duvernay gas wells also appear to have been throttled back, so this effect may also be a factor in rich gas, which may indicate that operators believe this operating strategy might increase condensate yields. In order to optimize production rates over the short and long-term, and to maximize total recovery, basic research work is needed to determine what mechanism controls production rates and total recovery. This analysis could be an important contribution in optimizing net present value and resource recovery, especially with lower commodity prices.

3.5. Tight Gas

Tight gas is found in thinner formation such as the Mannville, Glauconitic, Fahler, Cardium, and other sandstone (clastic) formations. Some gas in the shallower areas may be biogenic in origin and may even be coal bed methane which migrated in from deeper coal seams. In the case of tight gas, not all horizontal wells may be fractured.

3.5.1. Tight Gas Drilling and Completions

Prior to the use of horizontal, multistage fracturing there were a relatively large number of horizontal wells drilled for gas in some of these formations in western Alberta. A key need may be to define the incremental benefit of fracturing vs. simply drilling horizontal wells and the relative impacts on rate vs. recovery in these gas wells.

3.5.2. Potential Gas Recharge from Coal Formations

Many of the shallower formations (e.g. Mannville) may be connected to coal beds within the same strata. Understanding any connection between coal seams and nearby tight formations may help indicate if the tight formations might be a way to recover coal bed methane. Analysis could also be done to determine whether or not horizontal wells with multistage fractured completions are penetrating to coal seams and accessing coal bed methane resources.

3.6. General Hydraulic Fracturing

While the specific recovery needs of the different types of formations have greater importance for some plays than others, a common area of need for new technology is to improve the completion hardware, fluids, proppant and other materials needed for these types of completions. Improvements depending on the specific innovation or need being met may have application in more than one formation and commodity type.

3.6.1. Stage Isolation

An important need related to equipment and hardware installed downhole is the ability to isolate fracture stages, even when there is equipment left over from the prior fracture job which can restrict the diameter of the wellbore. This is particularly a problem when refracturing a well which was completed and fractured using a ball-drop system and sliding frac sleeves (see Figure 18); the sleeves cannot be removed because they are pre-installed in the liner, and the decreasing diameters of the sleeves can result in high costs and delays. It is also difficult, or impossible, to get an isolation device such as a packer past the sleeve and in oil wells this may limit the ability to install artificial lift to remove liquids from the wells. Overcoming this challenge represents a significant opportunity for accessing new production, since ball-drop systems are commonly used in large scale developments, such as multi-well pads, due to their simple logistics and the fact that they allow continuous fracturing operations without moving a service rig.

Another way to potentially simplify stage isolation during refracturing treatments would be to use completions which do not limit the inner diameter once the well is completed. Although there are completion methods which leave behind a bare casing, these lack the logistical advantages of a ball-drop system, since they require service rigs and packers to be moved in between stages. A new completion system offering the logistics and ease of operation of a ball activated system, but ultimately leaving behind an unobstructed inner diameter would simplify refracturing and lower costs.

Although a method of isolating stages is still required, diverters can isolate the refracture treatment from re-entering existing fractures, which are the “path of least resistance.” Diverters are particles, larger than proppant, which are pumped downhole to plug the channels and pathways with the largest pressure drop (indicating high flows of fracturing fluid), allowing a treatment to be diverted to areas with less productive fractures. It can also allow for existing fractures to be temporarily closed during a refracture job, encouraging the creation of new fractures. Once the refracturing treatment is complete, the diverters dissolve in the well, leaving behind a larger and more complex fracture network. Other methods of diversion have been proposed which may preferentially restrict flows into upper or lower portions of fracture networks.

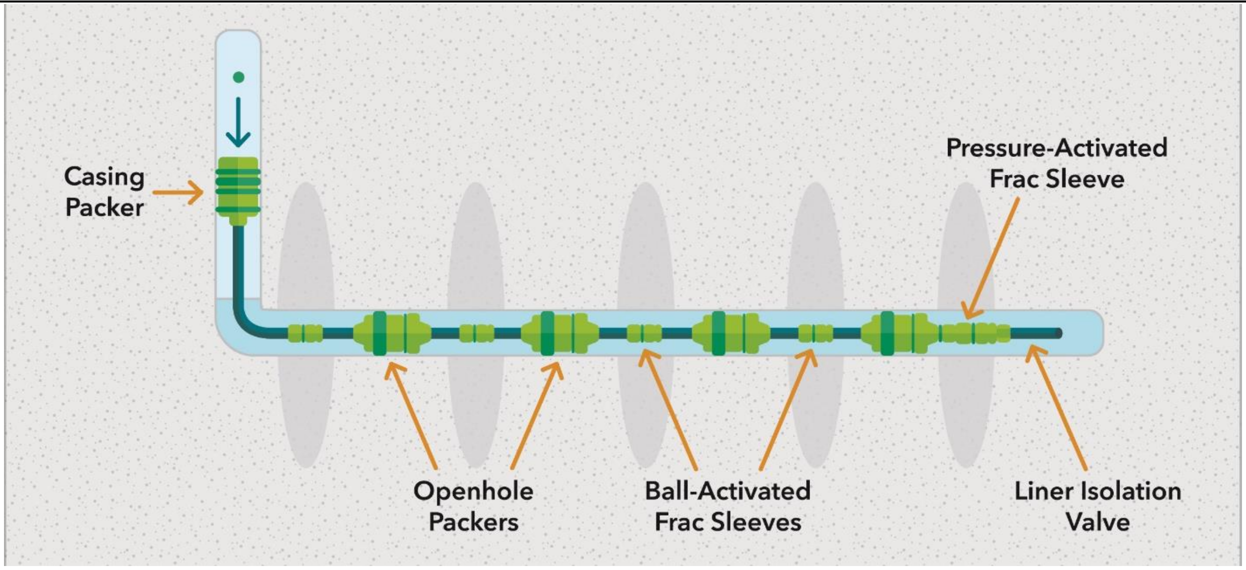


Figure 18. Ball Activated Completion System Diagram

3.6.2. Lateral Isolation

Due to their higher complexity compared to a normal multistage horizontal well, achieving isolation before fracturing in a multilateral horizontal well is more difficult. Not only is it necessary to fracture one stage at a time, but the other lateral(s) must also be isolated either temporarily or permanently. This requires a method to reliably seal at the junction, where the branches of the well split. It can also be difficult to install equipment in a multilateral well. If the junction is cased, a window must be cut in the casing to allow communication between the lateral and the main wellbore. Improper installation or placement of this window could result in a sharp metal lip, which can damage other tools or equipment being placed in the well or inhibit production.

3.6.3. Proppant

Proppant is a generic term for the small particles which are carried into the fracture network by the fracture fluid, to hold the fractures open when the treatment is over. Improper selection, or flowback of proppant during high initial rates, may be a contributing factor for the rapid production drop in new multistage hydraulically fractured wells. Also hard proppants could embed in softer rock/formations allowing the fractures to close, or brittle proppant or soft proppants could break or deform, leading to the same outcome. Another reason for the steep decline in production could be that the open fracture network does not extend as far as first thought, especially in areas using less viscous fracturing fluids, such as slickwater, since its ability to carry proppant particles is low. Therefore, the proppant pack may not extend all the way to the tips of the fractures. Both these cases would result in lower contact area between the formation and the well. Some technologies proposed to help to address these issues include: i) buoyant proppants, which are lightweight, plastic, non-deformable proppant which could be more easily carried by low density and low viscosity fracturing fluids, such as water or gases; or ii) ceramic proppants to increase the strength of the proppant and avoid its deformation or destruction; iii) improved “tracer” to track and potentially map fractures and diagnose problems, such as communication between wells, short circuits, or the fracturing treatment leaving the zone of interest; iv) proppant injection profiling, or “channel fracturing”, alternating between proppant-less and proppant-laden fracturing fluid to form higher permeability channels in the proppant.

3.6.4. Carrier Fluids

An area which is particularly visible and a concern to the public is the amount and type of fracturing fluids and additives used in fracturing treatments[iv]. Less obvious, but still of concern, is the fate of the fracturing fluids and chemicals when they flowback to surface. The main fluid used is water which will be covered in Section 4, so this section will focus on other components found in fracturing fluids.

Non-hydrocarbon Gases in Carrier Fluids

Many water based fracturing fluids contain a small amount of N_2, or CO_2, usually between 5%-15%, as an energizing fluid. Other applications can use substantially more and some fracturing uses pure gas streams. The energizing fluid helps to clean out the fractures and well bore when the fracturing fluids flow back to the surface, ensuring connectivity and open flow paths. The advantage of using fracturing fluid made up of large portions of these gases is that water use is significantly reduced. However, the challenges include corrosion, the contamination of produced gas, and increased flaring and/or venting to purge the gas. One technology gap identified is for methods to efficiently separate nitrogen and carbon dioxide from produced hydrocarbons at low cost. Methane gas which is contaminated with N_2 or CO_2 is difficult to use as a fuel gas, and must be treated to meet sales gas specifications, and therefore often must often be flared. Separating the energizing gases from the hydrocarbons could also potentially allow re-use N_2 and CO_2, which could reduce overall costs. There have been technologies proposed, for example by Ferus, which use a membrane to separate the CO_2 or N_2, allowing it to be reused, stored, or pipelined. This topic is further discussed in Section 5.

[iv] www.fracfocus.ca provides this information as well as completion chemicals.

3.6.5. Fracture Job Design Factors

For designing broader well development and fracturing programs a number of issues can impact the technology needs to allow economic and efficient design. Tools to assist with this pre-design would be of great use to resource developers.

Performance Evaluation across Development Areas

Predicting the performance of future wells to optimize investments is an area where performance improvements are needed in a low commodity price environment. In a high price “manufacturing” mode, it may be more cost effective to mass drill wells on a pattern and accept large variations in performance, but eventually optimization requires more selective methods. Technologies or methods of mapping the formation have been suggested by Chemostrat[52] and others, who have technologies capable of analyzing the elements and minerals from drill cuttings. The benefits of this data could include knowledge of the mineralogy changes along the wellbore to accurately design fracturing treatments; avoid softer areas, targeting spots most likely to create efficient fractures. It would also provide knowledge of any sections which deviated from the zone of interest, and help build a 3D model of the area, which can then be combined with production data to develop performance prediction tools.

Artificial Lift Requirements

With much of the focus of tight and shale developments being placed on the initial few months of production, often little provision is made for artificial lift techniques during the later life of the well. It can include the use of pumps, or other means, to decrease the pressure acting on the reservoir and extend late life production. A challenge is to design and develop artificial lift equipment which can be efficiently operating in deep horizontal wells were the internal well diameter is reduced by the fracturing tools left in the wells.

Lease Equipment

When sizing equipment for new multistage hydraulically fractured well leases, the equipment is initially sized to handle the large initial volumes expected. However, after the production drops off later over the next 2-12 months, this equipment is then oversized. One solution could be to develop efficient multi-purpose, portable production facilities designed to be relocated and reused as lease production needs change. Functions could include: pumping, phase separation, power generation, metering, pumping, liquids stabilization, and gas analysis.

Infrastructure for Solution Gas Collection

A challenge for shale tight oil wells is the need to handle solution gas produced with the oil, which may not be economic to capture and collect if the volumes are relatively small and the wells are remote from gathering lines. Because the highest production rates of a hydraulically fractured horizontal oil well occur within the first year, most of the solution gas is also produced during this time. If a well is too remote to economically tie in to a pipeline network, part of this gas is often vented or flared, while the oil is trucked. One proposed solution could be using a mobile compressor, mounted on a trailer with other trailers dedicated to gas storage cylinders to allow compressed gas transfers off the leases. The gas could then be transported to its final destination instead of released into the atmosphere. Liquids separated during compression might be stored in pressurized bullets and transported separately.

3.7. Section Summary

This section described technology needs specific to each play types: tight oil, shale oil, shale gas and tight gas, as well as generic hydraulic fracturing needs, which may apply to a number of different plays at different times. While there is a large number of individual needs and opportunities coming from the wide variety of formation characteristics and environmental settings, the needs and opportunities can be aggregated in the following areas:

> Reservoir characterization, including rock and fluid geochemistry and thermodynamic properties. The efficiency of any recovery process is highly dependent on a complete understanding of the reservoir. Given that the exploitation of tight rocks and shale resources is relatively recent, much characterization work of the zones of interest remains to be done.
>
> Optimization of completion and production processes. Operators are still actively experimenting with various completions and production variables such as well spacing, stage spacing, length of laterals, number of stages, multilateral schemes, proppant type and quantity, fracturing fluid type and chemical formulation, and production rate control schemes. The optimum mix of these variables will vary considerably between formations and surface environmental settings.
>
> Refracturing and well re-stimulation. In multistage hydraulic fracturing, production decline is very steep and the recovery rate is relatively low. Thus, the opportunity exists to re-energize production and to access bypassed resources by an intervention some years after initial production, such as refracturing or re-stimulating existing wells. Trials and field campaigns have been undertaken by operators, mostly in the United States. However, outcomes have been uneven, and there remains considerable uncertainty as to the success of a recompletion program. Thus, new knowledge is required to guide the selection of well candidates for refracturing programs, and new completion technologies are needed to facilitate refracturing to reduce cost and financial risk.
>
> Enhanced Oil Recovery. As an alternative to refracturing individual wells, EOR can also recover more production from an existing field. EOR is generally applicable at a field or section level and involves the injection of water or gas (e.g. CO_2, methane) to increase reservoir pressure, provide a sweep or drive mechanism, and to reduce oil viscosity in some cases, in order to generate more production and recovery. Laboratory work and field pilots have taken place but full commercial deployment remains a future possibility.

The opportunity, and indeed the need, to improve the economic and environmental sustainability of tight and shale oil and gas recovery and production is applicable to a broad front from new knowledge about rock characterization and data analytics, to novel equipment design and innovative processes. The industrial nature of these opportunities will require close collaboration with operators in order to ensure successful research outcomes and widespread deployment.

4. WATER MANAGEMENT

Authored by Third Bay and Fluid Intelligence

Section Overview

This section of the roadmap will capture the water-related gaps impacting tight oil and gas developments within Western Canada. Topics of particular interest will include gaps related to water sourcing, characterization of various waters, water reuse, treatment technologies, transportation, storage, and disposal. The intent of this section will be to document the identified gaps along with recommendations for next steps in order to overcome the existing challenges as the roadmap development plans progress.

As stated in the Executive Summary, the focus of the Roadmap, and of this section, is on issues directly related to hydraulic fracturing technology. As such, challenges, gaps and opportunities that apply generally to conventional oil and gas activities are only briefly mentioned, if at all. One such area is well integrity and the potential occurrence of wellbore leakage. Under certain circumstances, poorly installed or damaged cement can lead to leakage pathways from the subsurface. These pathways could cause subsurface fluids including methane gas and contaminated water to migrate upwards into freshwater aquifers and to the surface. These issues are fully covered elsewhere, particularly in reports from the Council of Canadian Academies[53], and of the Canadian Gas Migration Society.[54]

Definitions

The terms flowback and produced water are used extensively in the hydraulic fracturing industry. While definitions for these fluids may vary from operator to operator, the following basic distinction can be made:

- Flowback is the water which initially flows back from the well during the time that the completions crew is on site before the facilities are tied in. In this stage, the water quality is highly variable and reflects a mixture of the injected water and subsurface waters.
- Produced water flows from the well after the completions crew has turned over the well to operations and often resembles the characteristics of the formation waters.

4.1. Water Management and Treatment

Water management covers a wide array of issues from ground water-surface water interactions to flowback reuse to disposal. In the arena of water management for hydraulic fracturing, the following sections outline the gaps and proposed next steps for water sourcing, first water use, reuse, and disposal.

4.1.1. Water Sourcing

The amount and quality of water used in hydraulic fracturing is of interest to operators, regulators and the general public. A sound understanding of this usage in the context of availability, renewability and downstream uses is critical for preserving water resources.

Presently, most water sources for hydraulic fracturing operations, excluding reused water, range from surface waters (rivers, lakes, ponds) to ground waters (saline and non-saline). The interactions between surface and ground waters within and between watershed basins as well as the supply-demand for water on a watershed basis are not well understood in all cases. Ongoing watershed modelling efforts have been developed to gauge the impacts of withdrawals from multiple users on the watershed health and water availability. In general, the existing and available hydrology and hydrogeology mapping tools have currently not been widely implemented as support for decision-making.

There are several initiatives either completed or underway for improving the understanding of hydrology and hydrogeology in Western Canada. These include, but are not limited to the initiatives listed in Table 8.

Table 8. Initiatives Completed or Underway for Improving the Understanding of Hydrology and Hydrogeology in Western Canada

Project	Developer	Details	Status	Availability
Cumulative effects water allocation tool[55]	Alberta Energy Regulator (AER)	Comparison between fresh surface water allocations and threshold limits by watershed to assess current state of water usage; coordination with AER's play based regulation study pilot[56] for impacts on ground water	Ongoing	AER Internal use
Baseline ground water well data[57]	Applied Geochemistry Group, Department of Geoscience, University of Calgary	Fingerprinting tool based on isotopic analyses to differentiate between methane formed biogenically in shallow aquifers vs. methane, ethane and propane derived from thermogenic sources in deeper formations.	1. Ongoing and in publication for GOWN 2. 2016 AUPRF project application through PTAC	Public
BROM, OSSK, SSRB[58]	University of Lethbridge, Hydrologics, Alberta Innovates, Alberta WaterSMART (AER support)	Watershed models for fresh surface water supply/demand, risks, and ability to factor for climate change. Models were developed based on a collaborative approach for integrated water management decision-making.	Completed: BROM, OSSK Ongoing: SSRB	Public

Table 8. Initiatives Completed or Underway for Improving the Understanding of Hydrology and Hydrogeology in Western Canada

Project	Developer	Details	Status	Availability
Athabasca River Basin[59]	Alberta WaterSMART (Alberta Innovates, GoA, industry support)	Multi-phased project, including hydrogeologic models, to assess current and future water management issues and opportunities in the Athabasca River Basin (ARB) and will expand to include the whole Slave River system (Athabasca River Basin, Peace River Basin, Peace-Athabasca Delta, and Slave River Basin)	Initial stakeholder consultations	Public
North Saskatchewan River (NSR) Water Quality Model[60]	TetraTech (North Saskatchewan Watershed Alliance support)	In-stream hydrodynamic and water quality model for a portion of the NSR (surface water)	Completed	Unknown
WCAB[61] (Integrated Assessment of Water Resources, West-Central Alberta)	Foundry Spatial, Integrated Water Resources Group	Mapping for surface, ground water and deep saline water resources over 140,000 km^2 (includes Montney, Duvernay)	Release date: Q2 2016	Fee for license
Predicting Alberta's Water Future (PAWF)[62]	University of Alberta (Alberta Innovates support)	Hydrologic model, climate change model and risk assessment map to conduct supply-demand analysis, management scenarios and economic analysis for Alberta's water over the next 50 years.	2017 with possible extension	Public

While these initiatives range in complexity and scope, their focus is primarily on surface water resources and it is clear that the understanding of ground water quantities, qualities and variability is limited, in particular with respect to saline water resources. Further research and study to increase the knowledge base of Western Canada’s ground water resources would benefit all stakeholders.

In addition to the water resource studies in Western Canada, there are many examples of water management from the United States to reference. These are too numerous to summarize in this report, however, two projects are noteworthy. Firstly, an interactive mapping database from Ditigal H2O[63] provides Texas well users with detailed information on produced water volumes and transportation logistics on a well-by-well and aggregated basin basis. Secondly, when the Delaware River Basin Commission (DRBC) was created in 1961, 43 state agencies, 14 interstate agencies, and 19 federal agencies exercised a multiplicity of splintered powers and duties within the watershed.[64] The DRBC was granted the legal authority to oversee a unified approach to managing a river system without regard to political boundaries. Both of these examples provide creative approaches to water management from detailed data compilations from oil and gas operations to river water management that brings inter-jurisdictional parties together.

Water sourcing is also intricately tied to regulatory policies and agreements. Although a detailed discussion on this topic is outside the scope of this report, it is worth briefly mentioning that future water sourcing and competing users could be impacted if water is commoditized. Furthermore, since climate change policies are also linked to water sourcing, comprehensive and current data is required for the climate change inputs used in modelling efforts.

Gaps and Next Steps

- A collaborative initiative between all industries, government, Watershed Planning and Advisory Councils and other interested parties to develop a methodology and tools for managing Western Canada's water resources at a watershed basin level, drawing on the studies and work currently underway or completed in the province.

4.1.2. First Use (Saline or Non-saline)

When saline or non-saline water sources are used for the first time for hydraulic fracturing, a thorough characterization of these sources is key for ensuring overall comingling compatibility with different fracturing fluid chemicals, formation waters, and freshly fractured rock faces. The sampling and characterization is frequently performed through Third Party laboratories which may or may not have an understanding of the water source, potential trace species and operational, seasonal or environmental impacts. For these reasons, it becomes difficult to compare water chemistry information taken at different times during operations, by different groups, for a broad array of species. Comparable water chemistry data is crucial for supporting operations when evaluating different potential water sources and determining both comingling compatibility and compatibility with different fracture fluid chemicals.

Another challenge faced by industry is the logistical aspects of storage and transport of water. Current water storage options within Western Canada include ponds, C-rings or tanks. Saline water infrastructure requires additional operational and monitoring considerations. An initial study on lined pond solutions has been completed for PTAC which outlines future research opportunities and highlights the benefits of existing guidelines, including QA/QC programs, for the design, application and construction of lined ponds.[65]

Gaps and Next Steps

1. The water quality guidelines developed for the 2011 PTAC project, *Fracturing Fluid Flowback Reuse Feasibility Study and Decision Tool*[66], for different types of fracturing fluids should be updated to reflect current operational practices and research. The objective of the study was to assist oil and gas operators, when collaborating with service companies, to determine mitigation strategies for use of water with high salinity content for the makeup of fracturing fluid. The 2011 study is somewhat dated and would benefit from an update, as perspectives of oil and gas operators may have changed and new mitigation methods may be available.
2. Development of a standardized testing method for determining fracturing fluid compatibility with source waters prior to first use in the field.
3. Development of a standardized water chemistry characterization matrix for varying water sources and different types of fracturing fluids to support operational decisions in water sourcing.
4. Development of a guideline for water sampling frequency and methods to ensure that water chemistry data is comparable.
5. Establish or utilize existing collaborative efforts between operators in specific regions (e.g. Montney) to develop water analyses databases for different water sources. These databases are ideally 'living' documents with the intention of being able to provide historical data for the future. Development of industry best practices for water storage and transport, particularly for saline water sources.

Note

a) The gaps and needs identified regarding water characterization builds on the following Guiding Principles from CAPP's Guiding Principles[67]

  - #2: Fracturing Fluid Additive Risk Assessment and Management
  - #5. Water Sourcing, Measurement and Reuse
  - #6: Fluid Transport, Handling, Storage and Disposal

4.1.3. Reuse

The reuse of flowback and produced water for hydraulic fracturing operations relies on a sound understanding of the interactions between these waters and makeup water, fracture fluid chemicals, formation waters, and freshly fractured rock faces.

Water Characteristics

The chemical composition of flowback and produced water can vary from one well to the next and throughout the lifecycle of the well. This includes variability in the Total Dissolved Solids (TDS) concentration over time, shifts in alkalinity and pH as reservoir pressure declines, and swings in total suspended solids composition and concentration depending on mineral solubility. The dissolved mineral species in the water may change with adjustments within the surrounding environment.

Flowback and produced water may contain trace amounts of additives (e.g. residual crosslinkers) that could interfere with subsequent additions of fracturing fluid chemicals during reuse. Compatibility is also a concern when blending flowback or produced water with make-up water. For example, non-saline make-up water with high levels of sulphate could cause precipitation of barium sulphate or calcium sulphate scale when blending with produced water with high hardness concentrations. Identification of an appropriate flowback/make-up water/fracturing fluid chemicals combination also depends on the interaction between the mixture and formation waters or freshly fractured rock facies. Furthermore, the formation waters and freshly fractured rock facies may have a different chemical composition than the prepared completions fluid. If the completions fluid and downhole water and rock chemistries are incompatible, reservoir plugging precipitates and solids may form.

Flowback and produced water may also contain Naturally Occurring Radioactive Material (NORMs). Under certain operating conditions, NORMs can precipitate to form solids that settle and accumulate or solids that adhere to equipment surfaces. Depending on the degree of NORM contamination, these solids and scales may present a potential safety hazard along with increased difficulty and costs with associated disposal.

Flowback and produced water are often nutrient rich and are frequently inoculated at the surface once exposed to the atmosphere or to bacteria originating from other water sources. Re-injection of bacteria-containing flowback or produced water can cause further subsurface bacterial inoculation resulting in reservoir damage, including microbiologically induced corrosion (MIC), plugging of the near wellbore, and souring of a well with the formation of hydrogen sulfide. Industry practices tend to incorporate a biocide added on the fly to the injection water during the pressure pumping schedule. This may or may not be the best approach for managing bacteria particularly when flowback and produced waters are stored for extended periods of time between well stimulations.

Whether the objectives include preventing scale formation from occurring, mitigating the precipitation of NORM contaminated solids or avoiding bacteria-induced corrosion, detailed flowback and produced water characterizations are crucial for assessing the reusability and compatibility of these waters with fracture fluid chemicals, make-up sources and the producing formation.

Transport and Storage

The transport and storage of flowback and produced water is determined by the supply-demand relationship for water at one site or between multiple locations. The storage capacities, transport distances, available transfer equipment (pumps, pipes and hoses), means of transport, completions activity, and completions schedule all impact the availability of these waters for reuse.

The water volumes that must be managed are strongly dependent on the type of completions fluid used. Reuse of flowback and produced water from slickwater fracturing is perceived as more favourable as chemical residuals tend to cause less interference when mixing with fracturing fluid chemicals. However, the water demand requirements needed to support slickwater operations are much greater, presenting more logistical challenges for transport and storage. Conversely, reuse of flowback and produced water from gelled or crosslinked fluids are perceived as more challenging as chemical residuals have a much greater potential to negatively impact the completions fluid characteristics. Despite the increased reuse challenges, the overall water demand requirements to support gelled or crosslinked completions fluid programs is often much lower.

In addition to logistical challenges for managing large volumes of water at the surface, flowback and produced water transport and storage requirements include the same considerations as highly saline water with the potential presence for contaminants including hydrocarbons, bacteria, volatile organic compounds, polyaromatic hydrocarbons, hydrogen sulfide, suspended solids, and NORMs.

Gaps and Next Steps

1. Development of a standardized testing method for determining fracturing fluid additive compatibility with flowback and produced waters.
2. Development of a standardized water chemistry characterization matrix for flowback and produced waters from different types of hydraulic fracturing fluids. In particular, this characterization needs to include residual fracturing fluid chemicals that impact reuse and bacteria concentration analyses.
3. Development of a guideline for flowback and produced water sampling frequency and methods to ensure that water chemistry data is comparable.
4. Developing guidelines and practices for managing bacterial growth in surface storage.
5. Development of industry best practices for water storage and transport of flowback and produced waters, taking into account the potential presence of bacteria, NORMs and hydrocarbons. Best practices for water storage and transport should also be developed for cases where water reuse may be shared by more than one operator or from more than one facility at water hubs.

Notes

a) Gaps #3, #5-#7 from the previous section (First Use) are also applicable to this section (Reuse)

b) The gaps and needs identified regarding water characterization builds on the following Guiding Principles from CAPP's Guiding Principles [67]

- #2: Fracturing Fluid Additive Risk Assessment and Management
- #5. Water Sourcing, Measurement and Reuse
- #6: Fluid Transport, Handling, Storage and Disposal

4.1.4. Disposal

When reuse of flowback or produced water is not possible, these saline wastewaters are typically injected into deep wells for disposal. Many operators rely on trucking to transport these wastewaters to disposal wells at offsite facilities which may or may not be located near operations. Depending on the magnitude of activity within the surrounding area, extended wait times to offload the wastewater may also be encountered. The combination of accessibility to disposal facilities and wait time can lead to increased disposal costs and liabilities associated with trucking of the wastewater.

Furthermore, the comingling of multiple wastewaters at disposal wells has led to blending of incompatible waters and the consequential plugging of the disposal zone with unwanted precipitated solids. Detailed wastewater characterizations together with best practices and guidelines for preventing the comingling of incompatible waters could help prevent injectivity losses and the potential for permanent formation damage within these disposal wells.

Alternatives to deep well disposal include Zero Liquid Discharge (ZLD) systems. Current ZLD technology is cost-prohibitive, energy-intensive and generally creates a waste steam which is more difficult to dispose of. While ZLD treatment can recover more water for reuse, the by-products – typically large volumes of salt – create further disposal challenges. Where disposal options are limited, low cost ZLD technologies, which lower energy requirements or utilize waste heat, and provide solutions for the waste stream could be beneficial.

Gaps and Next Steps

1. Disposal zone mapping by region (e.g. Montney, Duvernay, Bakken) to provide information on disposal locations and volumes.
2. Development of guidelines and a Risk Assessment Tool for disposal well management based on water compatibilities.
3. Research and/or development of low cost ZLD systems for flowback and produced water.
4. Assess the limitations and challenges (regulatory, technical, risk and liability, cost) to the treatment and then surface discharge of produced water.

Note

a) The gaps and needs identified regarding water characterization builds on the following Guiding Principles from CAPP's Guiding Principles[67]
    - #6: Fluid Transport, Handling, Storage and Disposal

4.2. Water Treatment Technology

The drivers for water treatment requirements can vary from one basin to another and are further influenced by local policy, the ease of water transfer and storage, accessibility to water, accessibility to disposal, the type of completions fluid chemistry being utilized, mineralogy of the formation, and production conditions. The drivers for water treatment requirements reflect overall risk tolerance by the operator, regulator, and stakeholders:

- What quality of water is acceptable for completions fluid compatibility?
- What quality of water is acceptable for the reservoir?
- What quality of water is acceptable for surface transfer?
- How can production related issues be mitigated?
- How can environmental liability be managed?

The answers to these questions are variable, which makes industry standardization challenging. In addition to variable water quality targets, most treatment technologies generate one or more waste streams. These streams require management or additional environmental tradeoffs that need to be considered. For the purpose of this chapter, a high level evaluation of the treatment priorities and technology gaps are presented.

4.2.1. Treatment Prioritization Matrix

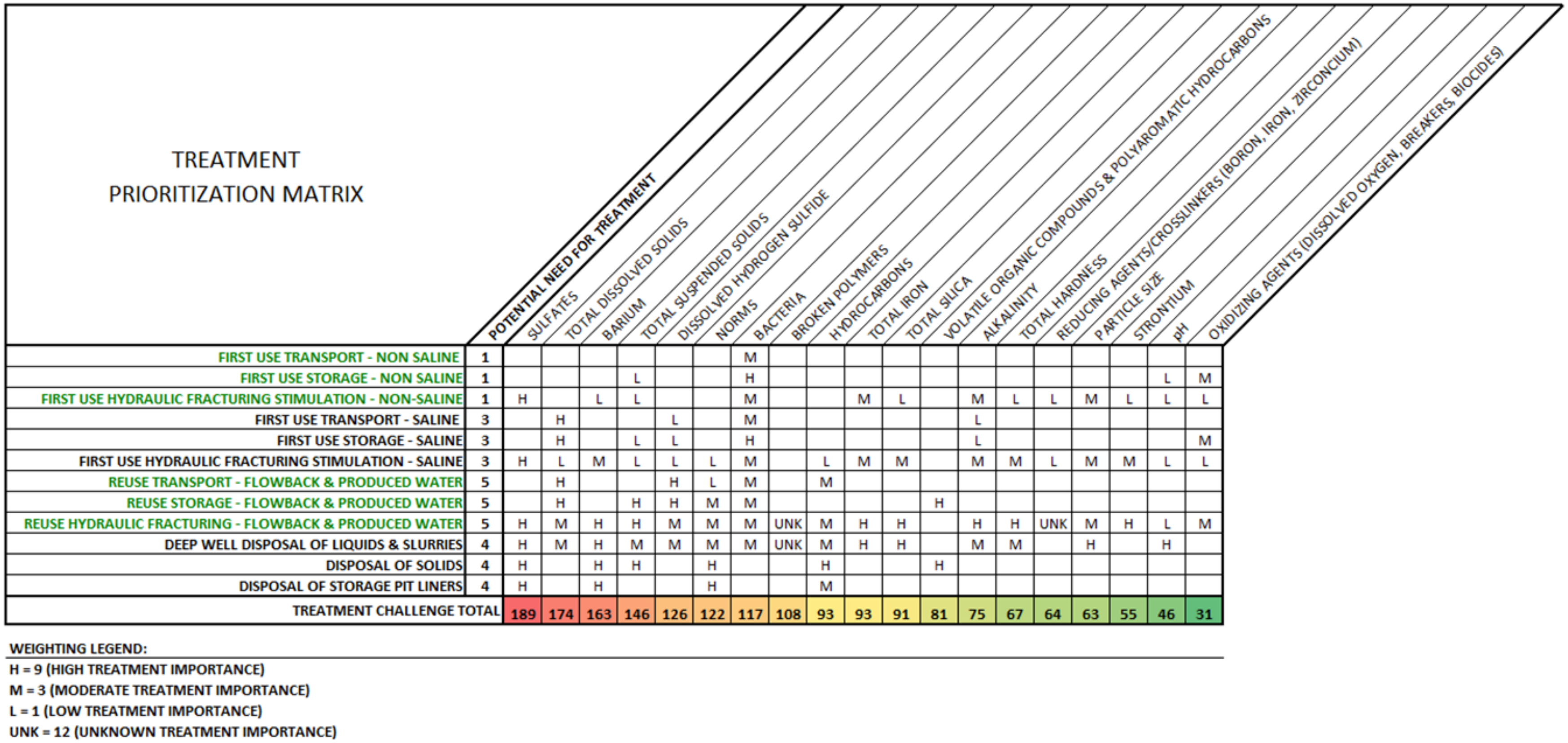
A matrix was developed to determine which water quality parameters require the most attention from a water treatment perspective (See Table 9). This matrix illustrates the increase in treatment need as the composition of the water increases in complexity. Overall treatment intensity is anticipated to be the lowest with non-saline water management processes with progressively more treatment intensity required for saline applications. Consequently, water management processes utilizing produced water and flowback are anticipated to require the greatest overall need for treatment throughout the water management cycle. For this evaluation, treatment was defined as any chemical or technology applied to modify the chemical or physical composition of the water.

The prioritization matrix was developed in two steps. First, the importance of water treatment for different categories of use was identified. Second, the difficulty of treating the water to achieve the desired water quality was identified. The value for treatment challenge was multiplied by the treatment need ranking and then summed to indicate the prioritization in the matrix.

In order to rank the importance of water treatment for each of the categories for first use, reuse, storage, transportation, and disposal, each category was ranked between 5 and 1, where 5 applies to categories with the greatest potential need for treatment down to 1 for categories with the lowest potential need for treatment.

For each category, the applicable water quality parameters were ranked based on the difficulty in treating the water to achieve the desired water quality for that parameter. The rankings are High, Moderate, Low, Unknown or left blank if treatment challenges are not anticipated.

Table 9. Treatment Prioritization Matrix



TREATMENT PRIORITIZATION MATRIX	POTENTIAL NEED FOR TREATMENT	SULFATES	TOTAL DISSOLVED SOLIDS	BARIUM	TOTAL SUSPENDED SOLIDS	DISSOLVED HYDROGEN SULFIDE	NORMS	BACTERIA	BROKEN POLYMERS	HYDROCARBONS	TOTAL IRON	TOTAL SILICA	VOLATILE ORGANIC COMPOUNDS & POLYAROMATIC HYDROCARBONS	ALKALINITY	TOTAL HARDNESS	REDUCING AGENTS/CROSSLINKERS (BORON, IRON, ZIRCONCIUM)	PARTICLE SIZE	STRONTIUM	pH	OXIDIZING AGENTS (DISSOLVED OXYGEN, BREAKERS, BIOCIDES)
FIRST USE TRANSPORT - NON SALINE	1							M												
FIRST USE STORAGE - NON SALINE	1				L			H											L	M
FIRST USE HYDRAULIC FRACTURING STIMULATION - NON-SALINE	1	H		L	L			M			M	L		M	L	L	M	L	L	L
FIRST USE TRANSPORT - SALINE	3		H			L		M						L						
FIRST USE STORAGE - SALINE	3		H		L	L		H						L						M
FIRST USE HYDRAULIC FRACTURING STIMULATION - SALINE	3	H	L	M	L	L	L	M		L	M	M		M	M	L	M	M	L	L
REUSE TRANSPORT - FLOWBACK & PRODUCED WATER	5		H			H	L	M		M										
REUSE STORAGE - FLOWBACK & PRODUCED WATER	5		H		H	H	M	M					H							
REUSE HYDRAULIC FRACTURING - FLOWBACK & PRODUCED WATER	5	H	M	H	H	M	M	M	UNK	M	H	H		H	H	UNK	M	H	L	M
DEEP WELL DISPOSAL OF LIQUIDS & SLURRIES	4	H	M	H	M	M	M	M	UNK	M	H	H		M	M		H		H	
DISPOSAL OF SOLIDS	4	H		H	H		H			H			H							
DISPOSAL OF STORAGE PIT LINERS	4	H		H			H			M										
TREATMENT CHALLENGE TOTAL		189	174	163	146	126	122	117	108	93	93	91	81	75	67	64	63	55	46	31

WEIGHTING LEGEND:

H = 9 (HIGH TREATMENT IMPORTANCE)
M = 3 (MODERATE TREATMENT IMPORTANCE)
L = 1 (LOW TREATMENT IMPORTANCE)
UNK = 12 (UNKNOWN TREATMENT IMPORTANCE)

The Treatment Challenge Totals from the Prioritization Matrix are also presented graphically in Figure 19.

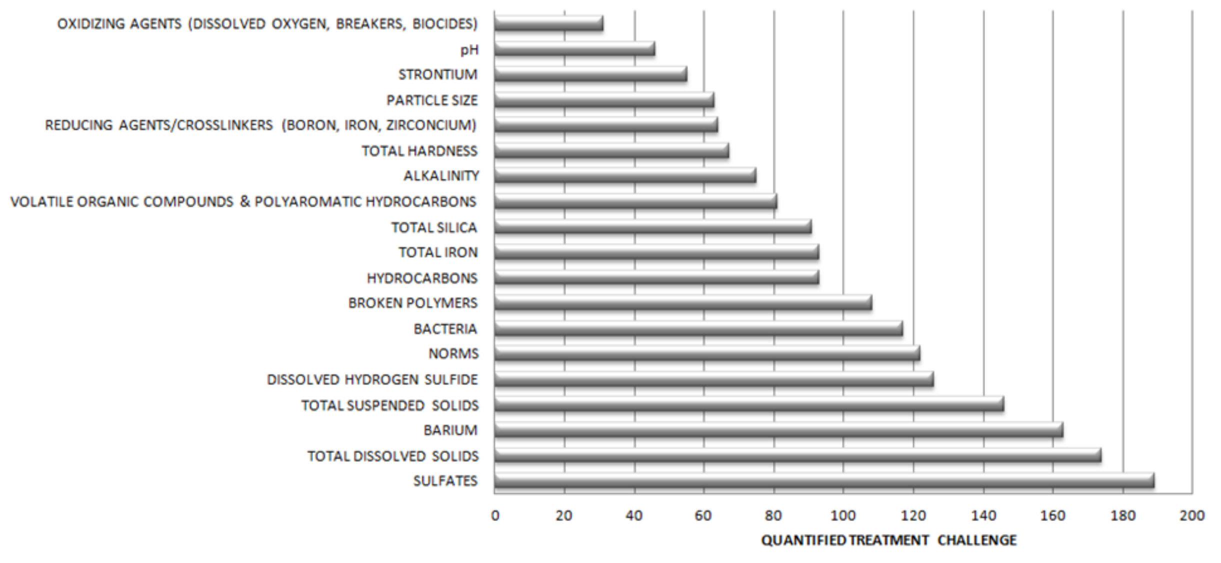


Figure 19. Treatment Challenge Totals

4.2.2. Treatment Technology Gaps

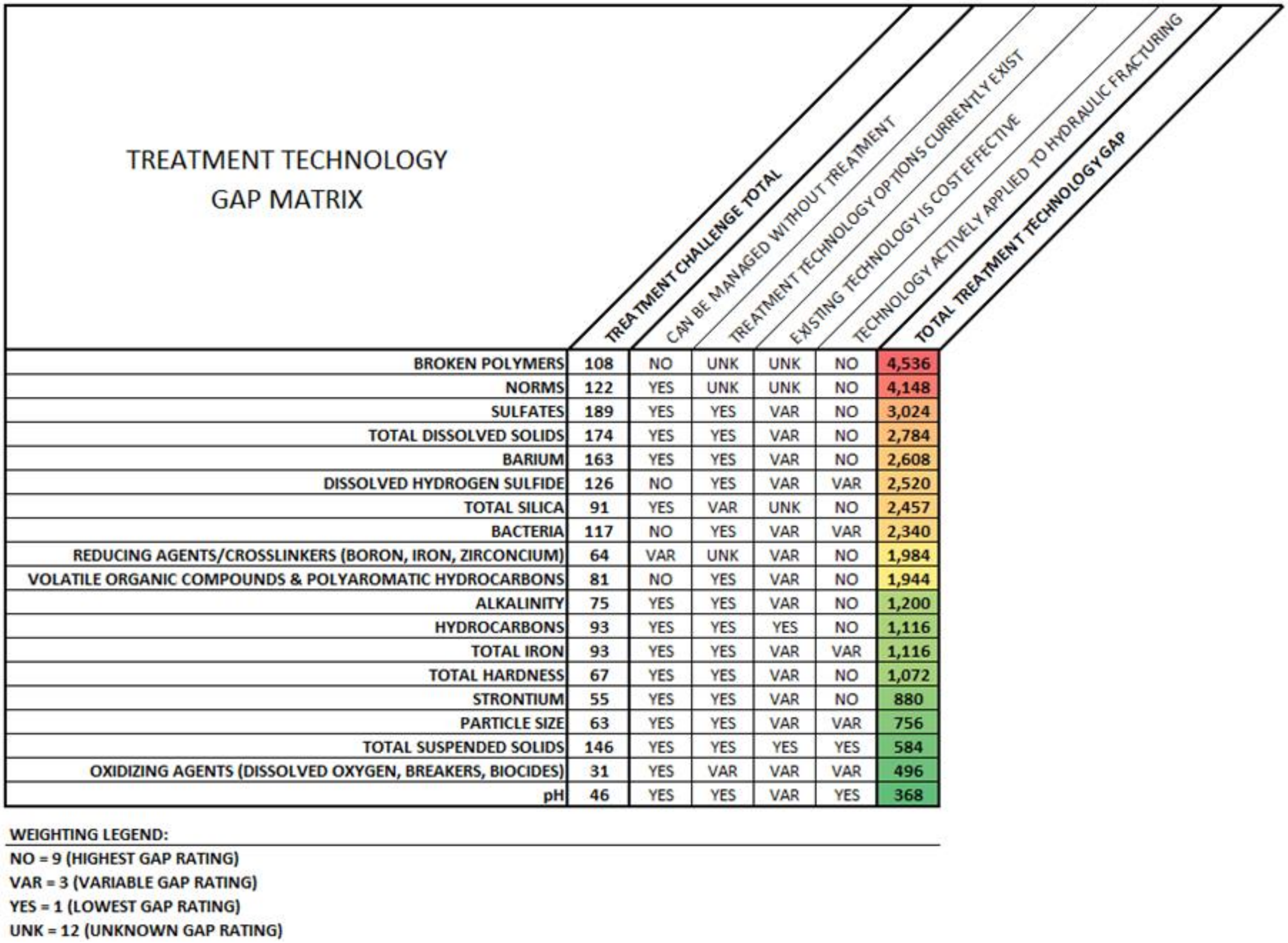
The outcomes of the Treatment Prioritization Matrix were then expanded to further identify technology gaps as they pertain to the water quality parameters requiring treatment. The matrix includes four categories to evaluate if:

1. The water quality parameter can be managed without treatment.
2. Treatment technology options currently exist.
3. The existing technology is cost effective; and
4. The treatment technologies are actively being applied to hydraulic fracturing operations within Canada.

Examples of alternate approaches to managing the water quality parameters without treatment include dilution using make up water sources or leveraging effects of gravity separation of solids within existing water management infrastructure such as surface impoundments or storage tanks.

Each category was ranked with Yes, No, Variable, or Unknown in contrast to the listed water quality parameters. Each ranking was weighted with the heaviest weightings applied to Unknown and the lowest to Yes. The results from each category were then multiplied by the Total Treatment Challenge Values carried forward from the first matrix (Treatment Prioritization Matrix). The Treatment Technology Gap Matrix (Table 10) highlights the combined results of which water quality treatment parameters are the most important to treat along with the technology gaps.

Table 10. Treatment Technology Gap Matrix



TREATMENT TECHNOLOGY GAP MATRIX	TREATMENT CHALLENGE TOTAL	CAN BE MANAGED WITHOUT TREATMENT	TREATMENT TECHNOLOGY OPTIONS CURRENTLY EXIST	EXISTING TECHNOLOGY IS COST EFFECTIVE	TECHNOLOGY ACTIVELY APPLIED TO HYDRAULIC FRACTURING	TOTAL TREATMENT TECHNOLOGY GAP
BROKEN POLYMERS	108	NO	UNK	UNK	NO	4,536
NORMS	122	YES	UNK	UNK	NO	4,148
SULFATES	189	YES	YES	VAR	NO	3,024
TOTAL DISSOLVED SOLIDS	174	YES	YES	VAR	NO	2,784
BARIUM	163	YES	YES	VAR	NO	2,608
DISSOLVED HYDROGEN SULFIDE	126	NO	YES	VAR	VAR	2,520
TOTAL SILICA	91	YES	VAR	UNK	NO	2,457
BACTERIA	117	NO	YES	VAR	VAR	2,340
REDUCING AGENTS/CROSSLINKERS (BORON, IRON, ZIRCONCIUM)	64	VAR	UNK	VAR	NO	1,984
VOLATILE ORGANIC COMPOUNDS & POLYAROMATIC HYDROCARBONS	81	NO	YES	VAR	NO	1,944
ALKALINITY	75	YES	YES	VAR	NO	1,200
HYDROCARBONS	93	YES	YES	YES	NO	1,116
TOTAL IRON	93	YES	YES	VAR	VAR	1,116
TOTAL HARDNESS	67	YES	YES	VAR	NO	1,072
STRONTIUM	55	YES	YES	VAR	NO	880
PARTICLE SIZE	63	YES	YES	VAR	VAR	756
TOTAL SUSPENDED SOLIDS	146	YES	YES	YES	YES	584
OXIDIZING AGENTS (DISSOLVED OXYGEN, BREAKERS, BIOCIDES)	31	YES	VAR	VAR	VAR	496
pH	46	YES	YES	VAR	YES	368

WEIGHTING LEGEND:

NO = 9 (HIGHEST GAP RATING)
VAR = 3 (VARIABLE GAP RATING)
YES = 1 (LOWEST GAP RATING)
UNK = 12 (UNKNOWN GAP RATING)

The Treatment Technology Gap Totals from the Treatment Technology Matrix are also presented graphically in Figure 20.

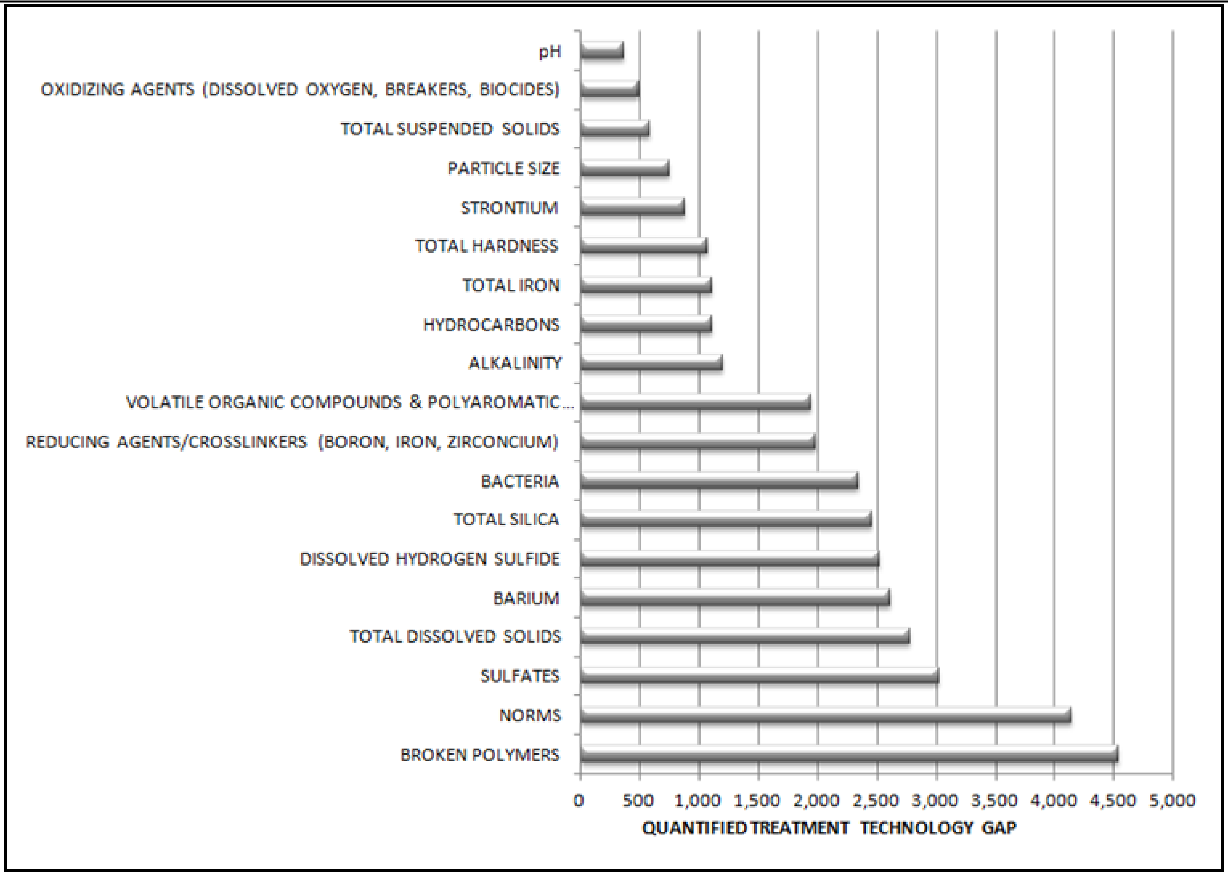


Figure 20. Treatment Technology Gap Totals

To aid in the interpretation of this matrix, a selection of the highest rated areas for technology gaps (broken polymers, NORMs, sulfates, TDS and bacteria) is discussed in more detail. Other high-ranking areas include barium, hydrogen sulfide (H_2S) and silica. Since barium and NORMs concentrations and chemical interactions are related, the following discussion on NORMs applies equally to barium. Silica may present a technology gap for certain fracturing fluids but the lack of water characterization data for silica means that its impact is unknown and therefore the ranking is high. Consistent and comprehensive water characterizations, as discussed previously in this chapter, will help to shed light on whether or not silica treatment presents a real technology gap. Hydrogen sulfide (H_2S) also ranked high in the matrix due to the fact that the management and treatment of H_2S-laden waters is variable depending on concentration and location. However, the technology and methods to treat H_2S are established, presenting no significant gaps.

The parameter identified with the greatest overall technology gap rating is listed as Broken Polymers. Although chemical breakers are added to the completions program to chemically degrade the polymers used, residual broken polymer is commonly detected at the surface in flowback waters. The presence of residual broken polymer has an unknown impact on completions fluid compatibility for reuse applications and may present additional risks within the formation and to other water treatment processes such as filtration by causing filter blinding.

Gaps and Next Steps (Broken Polymers)

1. Research on effects of various residual Broken Polymers chemistry on completions fluid compatibility.
2. Research methods including chemical, thermal, and microbiological approaches that facilitate the reduction of Broken Polymer chemistry.

The second parameter identified with a significant technology gap rating is Naturally Occurring Radioactive Material (NORM). In most cases where NORMs may be detected in water, the NORMs remain soluble until the water is mixed with an incompatible source, resulting in the co-precipitation of NORMs with the precipitated solids. A common example of when this situation may occur is at the point of flowback and make-up water comingling. The precipitation and accumulation of NORM-contaminated solids may increase operational exposure risks when removing tank bottom sludge or conducting work on surface equipment containing NORM contaminated scale. In situations where the comingling of the incompatible waters cannot be avoided, alternate treatment approaches may be of value. The primary driver supporting further development in NORM treatment technologies is to alleviate health and safety issues that may arise over time, mitigating negative environmental impacts, and reducing final costs associated with proper NORMs solids and slurry disposal.

Gaps and Next Steps (NORMs)

1. Evaluate technologies to cost effectively remove sulphate from source waters.
2. Development of a bench scale test for assessing the precipitation potential of NORMs under varying surface handling and storage conditions.
3. Research opportunity to develop thermally stable scale inhibitor chemistry.
4. Research opportunity into NORM removal methods suitable for flowback and produced water treatment applications.

Similar to the challenges associated with NORMs, the impact of sulphates on the water management cycle tends to be under estimated. Industry’s reliance on non-saline sources in the past may have contributed to this interpretation, however as flowback and produced water reuse applications become more common, the importance of sulphates is expected to shift significantly. Depending on process conditions, an increase in sulphates may result in sulphate-based scale deposition at the surface at the point of water comingling or be delayed resulting in subsurface deposition within the formation and production tubing. In situations where the comingling of incompatible waters cannot be avoided, alternate treatment approaches may be of value. There are chemical, ion exchange, and membrane options available to treat sulphates within the water. However, depending on the final sulphate concentration and other water quality characteristics, there may be more economical approaches for effective sulphate treatment.

Gaps and Next Steps (Sulphate)

1. Evaluate technologies to remove sulphate from source waters.
2. Research opportunity to develop thermally stable sulphate scale inhibitor chemistry.

The importance of Total Dissolved Solids (TDS) treatment reflects leakage issues that may arise with fluid transfer and storage rather than fluid compatibility concerns associated with flowback and/or produced water reuse. Removal of TDS is costly and is unnecessary for most fracturing fluids. Water storage and transport related issues were previously discussion in Section 1) c).

Gaps and Next Steps (TDS)

1. Research opportunity to work with regulatory bodies to select materials suitable for transfer and storage of saline, flowback, and produced waters to facilitate water reuse opportunities.
2. Identification of cost-effective double containment saline water storage options and leakage detection for hydraulic fracturing.
3. Identification and implementation of leak detection methodologies before storage water contacts ground and surface water.

Reducing agents including residual crosslinkers such as iron, boron, and zirconium have been identified as potential risks to fluid compatibility in situations where flowback and produced water are being considered for reuse applications. Although the acceptable amount of reducing agents/residual crosslinkers that may be present in flowback or produced water in reuse applications vary, it is anticipated that concentrations as low as 10 ppm may result in over crosslinking of future fluids.

Gaps and Next Steps (Crosslinkers)

1. Research opportunity to quantify maximum concentration of reducing agents/residual crosslinker that can be present without affecting crosslinking of future fluids. This may result in the identification of different limits for different reducing agent/residual crosslinker constituents.

4.3. Section Summary

Water management covers water sourcing, transportation, storage, flowback reuse, and disposal. Presently, most water sources are surface waters (e.g. rivers, lakes, ponds) and, to a lesser extent, ground waters (saline and non-saline). The interactions between surface and ground waters within and between watershed basins as well as the supply-demand for water on a watershed basis are not well understood in all cases. Ongoing watershed modelling efforts have taken place to gauge the impacts of withdrawals from multiple users on watershed health and water availability. Several initiatives are underway, focused primarily on surface water resources. Additional studies are required to increase the knowledge base of ground water resources in Western Canada, particularly saline aquifers. In addition, improved water characterizations through standardized methodologies would allow for water chemistry data that is comparable between different laboratories, which is crucial for supporting operations.

The reuse of flowback and produced water relies on a sound understanding of the interactions between these waters and makeup water, fracture fluid chemicals, formation waters, and freshly fractured rock faces. If the completions fluid and downhole water and rock chemistries are incompatible, reservoir plugging precipitates may form. Flowback and produced water may also contain NORMs which can precipitate to form solids that settle and accumulate or that adhere to equipment surfaces. Flowback and produced water are often nutrient rich and re-injection of bacteria-containing waters can cause further subsurface bacterial growth resulting in reservoir damage, microbiologically induced corrosion, plugging of the near wellbore, and souring of a well. Detailed flowback and produced water characterizations are crucial for assessing the reusability and compatibility of these waters with fracture fluid chemicals, make-up sources and the producing formation.

Wastewaters are typically injected into deep wells for disposal. Detailed wastewater characterizations together with best practices and guidelines for preventing the comingling of incompatible waters could help prevent injectivity losses and the potential for permanent formation damage within disposal wells.

The logistical aspects of water storage and transport are determined by the supply-demand relationship for water at one or multiple locations, which are typically complex. Flowback and produced water transport and storage create additional safety and environmental considerations due to the potential presence of contaminants.

Water Treatment

Water treatment is the process of removing contaminants from water in order to improve its quality and allow its use in desired applications. Overall treatment intensity is anticipated to be the lowest with non-saline water management processes with progressively more treatment intensity required for saline and reuse applications. The current technology gaps lie in the treatment for key water quality parameters that influence reuse challenges such as sulphates, residual crosslinkers and polymer, bacteria, and NORMs.

5. GHG AND AIR EMISSIONS MANAGEMENT

Authored by Cap-Op Energy

A variety of emission sources exist at multistage hydraulic fracture sites. A transparent and systematic method for categorizing and prioritizing emission sources is presented below. This systematic approach is used to justify the gaps and needs that are identified from the report. Needs are first defined by categorizing the emissions. Gaps are identified and discussed in the context of potential technology solutions and their attributes.

The intent of this report is to identify gaps and needs so as to guide further industry efforts in reducing emissions related to Multi-Stage Hydraulic Fracturing (MSHF). Therefore, challenges, gaps and opportunities that apply generally to conventional oil and gas activities are only briefly mentioned, if at all. Such areas include the use of pneumatic equipment and associated methane venting. Completion, well testing and production flaring are discussed in this section in terms of differences attributable to hydraulic fracturing operations. Another general area of environmental impact is surface casing vent flows which is the potential for methane gas to migrate to the surface as a result of poorly installed or damaged cement that cause leakage pathways from the subsurface. Well integrity and wellbore leakage issues are discussed elsewhere, particularly in reports from the Council of Canadian Academies[53], and of the Canadian Gas Migration Society[54].

5.1. Emission Source Categorization to Define Needs

Emissions have been categorized in Table 11 as they pertain to the life cycle of wells where MSHF completions have been employed. A survey of limited participants in the Technology for Emissions Reduction and Eco-Efficiency (TEREE) Committee convened by PTAC was conducted to provide information to complete the table. Relevance of emission categories is defined according to whether they are specific to hydraulic fracturing, their relative magnitude, and relative duration.

It is acknowledged that the survey results are subjective and should only be used to define gaps and needs. The emission profile (magnitude and duration) of each well will differ and the intent here is to broadly characterize relative emission rates to prioritize areas of further study. Further work may be required to quantify actual emissions and accurately discern relative or absolute emission magnitudes, durations and relevance.

MSHF Specific: Denotes whether an emission source or emission profile is unique or distinct at hydraulically fractured wells or whether it is characteristically similar to conventional well emission profiles. Checked boxes denote unanimous or a majority of responses to the survey replied that this emission was distinct for MSHF wells.

Magnitude: Emissions are characterized by their relative magnitude in a subjective manner with ‘Significant’, ‘Moderate’ and ‘Low’:

- Significant denotes that on average, respondents to the survey ranked this category in the top third.
- Moderate denotes that on average, respondents to the survey ranked this category in the middle third.

- Low denotes that on average, respondents to the survey ranked this category in the bottom third.

Duration: Emission sources are characterized by their relative duration in a subjective manner with 'Short, 'Medium' and 'Long':

- Long denotes that on average, respondents to the survey ranked this category in the top third.
- Medium denotes that on average, respondents to the survey ranked this category in the middle third.
- Short denotes that on average, respondents to the survey ranked this category in the bottom third.

Table 11. MSHF Emissions Relevance Matrix

Phase	Life Cycle Emission Description	Gases	MSHF Specific	Magnitude	Duration
Pre-Production	Development of Site	CO_2, CH_4, N_2O		Low	Short
	Construction of Site	CO_2, CH_4, N_2O		Low	Short
	Fluid/Fuel Delivery	CO_2, CH_4, N_2O	✓	Low	Short
	Drilling Operations	CO_2, CH_4, N_2O	✓	Significant	Medium
	Completions Operations	CO_2, CH_4, N_2O	✓	Significant	Medium
	Completions venting / flaring	CO_2, CH_4, N_2O	✓	Significant	Medium
Production	Electricity consumption	CO_2 Equivalent		Moderate	Long
	Fuel consumption	CO_2, CH_4, N_2O	✓	Significant	Long
	Pneumatic venting	CH_4	✓	Moderate	Long
	Flaring	CO_2, CH_4, N_2O	✓	Significant	Short
	Transport of personnel and equipment	CO_2, CH_4, N_2O		Low	Short
	Tank top emissions	CH_4		Low	Long
	Fugitive emissions	CH_4	✓	Moderate	Long
Post Production	Gas Migration	CH_4		Moderate	Medium
	Surface Casing Vent Flows	CH_4		Moderate	Short

As a result of the categorization matrix shown above, the following emission sources represent areas that ranked highest for relevance, duration and magnitude, and are used to discuss gaps and potential technology solutions:

1. **Fuel Consumption During Production** – Fuel used onsite during production is for electricity generation and heat. Fuel consumption that is vented (pneumatic fuel gas supply) is not considered here.
2. **Pneumatic venting** – Pneumatic venting, particularly related to chemical injection pump emissions just after the well has come on stream, may be a significant emission source.
3. **Completion Venting / Flaring** – Venting and flaring of flow-back gases typically occurs prior to production and can last 3 – 7 days.

4. **Completion Operations** – Fuel consumption related to MSHF is driven by thousands of horsepower of pumping power and can last one to several days.
5. **Flaring During Production** – Flaring during production, particularly just after the well has come on stream, may be a significant emission source related to the disposal of solution gas.

5.2. Gaps and Possible Technology Solutions

5.2.1. Fuel Consumption during Production

Fuel consumption onsite may include power generation, compression, heating and combustion of pilot fuel. It does not include fuel gas use for pneumatic devices that vent. Fuel consumption can be a form of utilization of solution gas as it is an alternative to flaring or venting. In the absence of solution gas conservation, fuel consumption onsite during production represents an emission source.

Existing constraints, common practices or gaps include:

- Energy efficiency of buildings, processes and equipment that consume fuel at upstream oil and gas facilities has not traditionally been a priority.

Technologies that may offer emission abatement options for fuel consumption during production are listed below.

- **Combustion Control:** Efficiency initiatives often involve improved combustion control devices and does not necessarily impose a large cost or change in standard equipment or operating procedures. In addition to reducing energy consumption and emissions, improved efficiency may improve production of facilities.

5.2.2. Pneumatic Venting

Pneumatically actuated valves may be powered by fuel gas or process gas available at well sites. Chemical injection pumps dose pipelines with anti-freeze and anti-corrosion chemicals and are typically powered with available fuel gas as well. Both types of pneumatic devices vent gas as a result of their operation. Chemical injection pumps may have more significant vent rates due to large flow rates early on in production from hydraulically fractured wells.

Existing constraints, common practices or gaps include:

- Concern, or unfamiliarity with the reliability of certain alternatives to pneumatic venting devices.
- Theft and high costs are concerns, especially for solar equipment.

Technologies that may offer emission abatement options for pneumatic venting devices are listed below.

- **Conversion to pneumatic air:** A compressed air system can be installed and used to furnish pneumatic pressure. Since hydraulically fractured wells are often in a pad, there are a number of pneumatic devices that could share the compressed air system costs.
- **Low bleed pneumatic control devices:** Economics can be favorable for implementing this proven technology and it is common throughout industry at new facilities.

- **Solar Electrification:** Solar electrification offers emission free actuation control and chemical dosing. Solar components can be expensive and impose a higher capital cost than alternatives, but can have a net positive economic return.

5.2.3. Completion Venting / Flaring

Flow-back emissions occur after a well fracture is completed and the mud, hydraulic fluids, plug grindings and other fluids in the well bore are cleared out through high rate production. Flow-back fluids are typically produced into large pools or basins. Gases may be separated in a separator, and then flared and/or vented.

Existing constraints, common practices or gaps include:

- There are many locations where no pipeline is available nearby to receive the flowback gases and/or the gas may not be at appropriate pressure and quality.
- The presence of gases, typically nitrogen, which is inert, and CO_2, which may be corrosive, in flowback fluids pose challenges to downstream equipment and prevent in-line production when it might otherwise be possible. Few technologies are cost effective to remove nitrogen and carbon dioxide from flowback fluids to allow flowback to be produced in-line.
- Onsite, permanent equipment for processing gas may not be appropriate for processing flowback gas. Separators, dehydrators and compressors may be undersized for flowback flows if sized to handle production volumes.

Technologies that may offer emission abatement options for completion venting/flaring are listed below.

- **Pipeline tie-in:** This is also known as ‘green completions’ or ‘reduced emissions completions’ and conserves gas through pipeline infrastructure.
- **Inert Gas Separation:** Nitrogen and carbon dioxide separation technologies of appropriate capacity and cost are needed to process flowback fluids. Since completion operations are temporary, this equipment needs to be mobile. Membranes, pressure swing absorption and cryogenics are different approaches that exist, each with positive and negative attributes related to their application to hydraulic fracturing flowback gas. More upfront consideration of the cost and emissions implications of using these energizing gases during flowback versus the benefit may also lead to emission reductions by designing hydraulic fractures with less inert gases.
- **Flaring of flow-back fluids:** Destruction of the methane component in flow-back gases is an emission reduction compared to venting. Initial flow-back fluids may not be able to sustain flames in conventional flares, and more advanced control systems or combustor / incinerator type devices may allow improved destruction of flowback gases.
- **Utilization of flow-back gas**: The utilization of gases produced during completions through power, heat, or electricity.

5.2.4. Completion Operations

Hydraulic fracturing operations require significant pumping power, typically achieved with mobile pumping equipment. These pumps can be up to 2,500 bhp each and a hydraulic fracture operation may require dozens of units networked together. They often consume diesel fuel and produce emissions only when the wells are being completed.

Existing constraints, common practices or gaps include:

- The hydraulic fracturing operation itself is energetically intense and few other fuels or power supplies would be sufficient.
- Fracture pumps are often operating in cold conditions in Canada and some fuels have challenges related to engine starting and operating reliability in cold weather.
- Economics of fuels make alternative sources of energy for fracturing challenging because diesel is a common industrial fuel available without pressurized equipment and tanks, and can be transported to remote sites with relative ease and low cost.

Technologies that may offer emission abatement options for completions are listed below.

- **Fuel switching to natural gas:** Pipeline gas available onsite may be used with bi-fuel equipment for pumping. Bi-fuel equipment includes engines that have the ability to switch from a pure diesel fuel to partial gas and diesel fuel during operations. They typically have a maximum displacement, which may be up to 70% displacement of diesel with gas.
- **Fuel switching to bio-diesel:** Biodiesel can have life cycle carbon emission intensities significantly lower than those of petroleum based diesels. Blending small amounts of bio-diesel is currently required for transportation fuels and may be relevant for diesel fuel in hydraulic fracture operations. Cold weather poses challenges to biodiesel operation and this may limit its applicability in hydraulic fracture operations.

5.2.5. Flaring During Production

Routine flaring at oil producing sites disposes of unwanted associated gas or solution gas. This activity is the result of economic barriers or the technical inability to conserve the gas. Gas is conserved when there is an economic incentive or relatively small cost associated with doing so. Non-routine flaring at oil and gas sites is mainly due to well workovers and maintenance of pipelines.

Existing constraints, common practices or gaps include:

- The technologies required to conserve gas during production exist and are relatively mature, however due to the high rate of decline in production it is difficult to properly size utilization equipment.
- Onsite gas utilization may be infeasible because gas quality is too low for direct use in onsite equipment and gas processing equipment is impeded by an economic barrier.

Technologies that may offer emission abatement options for flaring during production are listed below.

- **Onsite Consumption:** These technologies consume solution gas to generate heat, mechanical work, onsite electricity or electricity for export to the grid. These technologies are commercial and may be economic depending on the location, characteristics of the flow, and process demands. Gas quality during the production phase may be a technical concern.

- **In-line Production:** The reservoir may generate sufficient pressure for direct tie-in, or a compressor may be required to boost pressure. Liquids knock-out and dehydration may be required to meet gas quality specs. Gas quality during the production phase may be a technical concern.

5.3. Regulatory Review

In Canada, no national or regional emission standards or regulations exist which pertain specifically to the reduction of GHG emissions from MSHF well drilling, completion, and operation.

At the provincial level, the following regulatory documents relate to such activities:

- Alberta Energy Regulator - Directive 60 - Upstream Petroleum Industry Flaring, Incinerating, and Venting,
- British Columbia Oil and Gas Commission - Flaring and Venting Reduction Guideline; and,
- Saskatchewan Ministry of Economy - Directive S-10 - Saskatchewan Upstream Petroleum Industry Associated Gas Conservation Directive and Directive S-20 Saskatchewan Upstream Flaring and Incineration Requirements

All three documents define limits for venting and flaring gas at upstream oil and gas production facilities. Requirements and guidance are provided in the form of thresholds and decision trees for how to determine appropriate avenues for disposing or conserving gas. There are no requirements specific to hydraulically fractured wells. Venting and flaring emissions specific to hydraulic fracturing may be reported under these regulatory documents broadly as 'Testing'.

In the US, the EPA has mandated certain emission control techniques for the purposes of reducing or eliminating Volatile Organic Compounds (VOCs) from flow-back emissions related to completions in multi stage fractured wells. These standards are applicable to many types of gas wells and have the ancillary benefit of reducing GHG emissions. These regulations are part of New Source Pollution Standards (NSPS) 40 CFR Part 60, Subpart OOOO Emission Standards and came into force in 2012.

On March 10th 2016, the US and Canada made joint commitments to reduce methane emissions by 40-45% by 2025 in the oil and gas industry. Few details are available at the time of writing, however it is likely that a significant fraction of those emission reductions would be achieved by the upstream oil and gas sector and hydraulic fracturing could contribute a component therein.

5.4. Section summary

GHG and air emissions in oil and gas operations arise from surface operations and facilities, which are generally similar between multistage hydraulic fracturing and conventional oil and gas operations. Two differences are that hydraulic fracturing involves significant consumption of energy and fuel during completion operations, with resulting GHG emissions (primarily CO_2 in combustion gases), and that hydraulically fractured wells exhibit a high initial production rate followed by a steep rate decline, creating operational challenges which may result in increased emissions in some circumstances (primarily flaring and venting). The following emission sources have the most relevance in hydraulic fracturing operations:

- Fuel consumption during production, generally for electricity generation and heat;
- Venting from pneumatic equipment, particularly related to chemical injection pump emissions;
- Completion venting and flaring of flow-back gases prior to production;
- Completion operations, which mostly involves fuel consumption for pumping the fracturing fluid;
- Flaring during production, related to the disposal of solution gas after the well has come on stream; may be a significant emission source when pipeline infrastructure is lacking.

Addressing these challenges will likely best take place in the context of relevant programs and initiatives covering both conventional and unconventional operations. The principal gaps involve fuel consumption during completion operations, flaring, venting from pneumatic equipment, and leak detection.

6. GAP ANALYSIS AND TECHNOLOGY OPPORTUNITIES

6.1. Gap Identification

Gaps and barriers stand between the current state of technology and the desired future state. In addition, technology opportunities arise from advances in fundamental science and engineering, in tight oil and shale gas technology, and in related fields. The gap analysis in this section is specific to hydraulic fracturing in tight oil and shale gas, and focuses on sustainable production, water management, GHG and air emissions, which are the key topics discussed earlier. Generic gaps and gaps broadly applicable to the oil and gas industry are not covered. For example, the opportunity for advanced sensors and analytics to detect and quantify GHG gases and air pollutants is applicable to all segments of the oil and gas industry and is only touched upon in the document.

Identifying gaps and opportunities involves comparing the current situation to what could be possible with future investment in research and development. Gaps and potential technology solutions identified in TOGIN workshops and meetings, and discussed by Roadmap section authors were analyzed using a standard gap worksheet which first listed the gap title and the relevant technology area. The gap worksheet also provided a summary description of the industry need and of the associated research and technology opportunity, as well as ratings for the future beneficial impact of closing the gap and of the estimated level of current research activity with respect to this gap or opportunity.

Project team members prepared 24 gap worksheets based on their experience and expertise using inputs from TOGIN workshops and meetings and the issues discussed in earlier sections. It should be noted that the gap worksheet are meant as a useful starting point for planning and for exploring opportunities and it is acknowledged that another project team could arrange the information differently. The gaps are listed and briefly described in Table 12. All individual gap worksheets provided in Appendix C.

Table 12. Overview of Technology Gaps

Gap Title	**Description of Need or Challenge**
Technology Area: Sustainable Production (13 gaps)	
Reservoir Characterization (General)	Minimizing environmental impact and maximizing production require detailed and accurate reservoir characterization. Petrophysical, geomechanical and PVT properties are critical for the design and implementation of the drilling, completion and production processes. In tight oil and shale gas resources, production performance strongly depends on the distribution and interconnectedness of natural and hydraulic fractures, and, thus, the reservoir characterization plays a crucial role.

Table 12. Overview of Technology Gaps

Gap Title	Description of Need or Challenge
Reservoir Geochemistry (Shale Formations)	In oil shale formations such as the Duvernay and the Montney, there is a need to better understand reservoir geochemistry because of the presence of kerogen which may impact production by blocking pore space or fractures. Also, due to the depths and pressures in these deep formations, the state in which oil, gas and condensate exist at reservoir condition may be unclear.
Fate of Injected Water in Shale Formations	In hydraulic fracturing, only a fraction of the injected water is recovered with production. There are many questions about the fate of the injected water that is not recovered and whether its presence supports or hinders production.
Refracturing Well Selection and Performance	In tight oil and shale gas, production decline is very steep, up to 70% in the first year. There is thus an opportunity to re-stimulate or refracture an existing well in order to revitalize production and increase recovery from the target drainage area. Refracturing has taken place mostly in the United States with the outcome that production from refractured wells is more unpredictable than from newly fractured wells. Understanding key criteria for identifying highly prospective refracturing candidates would reduce uncertainty and improve economic and recovery outcomes.
Refracturing Well Completion	Refracturing is an attractive opportunity to extract more oil or gas from a reservoir using an existing wellbore, thus reducing costs and minimizing environmental impact by avoiding the drilling of a new well. However, a number of initial hydraulic fracturing completion techniques substantially increase the cost of refracturing due to the need to remove completion equipment left in the well. New completion technologies used for refracturing that leave a clean wellbore behind would be beneficial.
Enhanced Waterflooding	Waterflooding is a well-known recovery method to increase production after the decline of primary production. However, the characteristics of unconventional reservoirs such as the Bakken significantly limits the performance of waterflooding. Adapting conventional waterflooding to tight formations will require investments in research and technology development.
CO_2 Gas Flooding	CO_2 EOR is a mature technology for conventional oil reservoirs that results in the recovery and production of additional oil. It has yet to be adapted and implemented in tight oil formations, but the potential may be worth investigating.
Understanding the Decline Curve	In unconventional reservoirs, production decline is very steep, up to 70% in the first year. Understanding the precise causes of this phenomenon and how to mitigate it could provide significant opportunities.

Table 12. Overview of Technology Gaps

Gap Title	Description of Need or Challenge
Completion Optimization (General)	Hydraulic fracturing completions programs have continually evolved in the last decade. However questions remain particularly with respect to optimal well placement, lateral and vertical spacings, stage density, fluid volumes and sand volumes. Furthermore, designs will vary between formations. Continuous improvement should continue to provide benefits in terms of lower costs and environmental impact.
Production Rate Optimization	High commodity prices of the recent past created an incentive to maximize short-term production. However, there is some evidence that would indicate that maximizing the initial production rates could come at the expense of a steeper decline curve and lower total recovery.
Multilateral Completions	Multilateral wells have one vertical wellbore that separates into more than one horizontal wellbore in the reservoir, thereby reducing drilling costs and maximizing exposure to the reservoir. While this completion is advantageous, it is also complex and costly.
Novel Proppants	The most commonly used proppant is sand. However, in certain formations, sand may not be strong enough to resist formation pressure. Sand is also much heavier than water and tends to settle quickly in fractures, thereby not propping open deeper areas of the fracture.
Improved Well Characterization while Drilling	Existing well logging and measurement while drilling (MWD) technologies acquire some information about the wellbore that is being drilled. However, new technologies to acquire more data at a greater precision could improve the design of the completions program leading to efficiency and productivity improvements
Technology Area: Water Management and Treatment (6 gaps)	
Standardized Water Characterizations Method and Guideline Development	In Western Canada, there is a need to develop standardized testing methods for determining fracturing fluid compatibility and a standard for water chemistry characterization (i.e. potentially a type of matrix) for varying water sources and fracturing fluids. Specifically, there is a need for water characterization to include residual fracturing fluid chemicals that impact reuse and bacteria concentration analyses. Guidelines must also be developed for source water, flowback, and produced water sampling. As the use of hydraulic fracturing for the extraction of unconventional resources continues to grow, characterization methods and guidelines must be defined and implemented to ensure that industry is referencing universal information when making decisions in the field.
Saline Surface Storage Technologies	In most cases, hydraulic fracturing operations require a large amount of water for functional purposes. Storage of flowback and produced water is an ongoing challenge for hydraulic fracturing sites and addressing this challenge through identification of additional effective storage options and implementation of new leak detection methodologies is essential.

Table 12. Overview of Technology Gaps

Gap Title	Description of Need or Challenge
Managing Sulphate and NORMs	Evaluation of cost effective technologies for removal of sulphate from source waters and research on NORM removal methods for flowback and produced water treatment applications. During hydraulic fracturing, flowback is the part of the process that brings contaminants to the surface. Removal of these contaminants is a necessary step in mitigating contamination caused by this production method.
Disposal Well Management	Development of guidelines and a Risk Assessment Tool for disposal well management based on water compatibilities. In hydraulic fracturing operations, the reuse of flowback or produced water is not always an option and there is a need to have effective tools in place to help operators deal with the need for proper disposal when it arises.
Availability of Water Samples	There is a need to create a more efficient way for technology providers to obtain water samples for technology testing by developing a centralized facility with involvement from multiple operators. Currently, it is difficult for technology providers to obtain samples for testing technologies related to water management, which delays the progression of new technologies for industry use. One option could be a “water bank” or cooperative network which shares data and samples.
Saline Storage and Transport	The water volumes that must be stored and transported are strongly dependent on the type of completions fluid used and logistics. Reuse of flowback and produced water is perceived as favourable. However, the water demand requirements present logistical challenges for transport and storage. In addition, flowback and produced water transport and storage requirements include the same considerations as highly saline water with the potential presence for contaminants including hydrocarbons, bacteria, volatile organic compounds, polyaromatic hydrocarbons, hydrogen sulfide, suspended solids, and NORMs.
Technology Area: GHG and Air Emissions Management (5 gaps)	
Fuel Consumption During Production	There is a need for industry to develop energy efficient processes and equipment for fuel consumption at upstream oil and gas facilities to reduce emissions from operating activities. In particular, efficiency initiatives aimed towards improved combustion control devices is needed to reduce energy consumption and emissions.
Alternatives to Pneumatic Equipment	There is a need to look into alternatives to pneumatic venting devices to determine if options are available with improved reliability, robustness, security and cost effectiveness.

Table 12. Overview of Technology Gaps	
Gap Title	**Description of Need or Challenge**
Completion Venting / Flaring	During the completion process, it is important to properly handle flowback from production. Thus, there is a need to develop pipeline infrastructure in areas lacking the equipment required to receive flowback fluids. There is also currently a lack of appropriate equipment available to process flowback gas. Additionally, identifying cost effective technologies for the removal of N_2 and CO_2 flowback fluids should be a priority as it would allow flowback to be produced in-line.
Completion Operations	Hydraulic fracturing completion operations require energetically intense equipment and fuels for the process to successfully run. Thus, there is a need to identify more sufficient fuels and power supply options for these operations. Furthermore, the operability of equipment on the sites of completions operations will vary based on fluctuating/cold weather in Canada. Therefore, there is a need to address challenges related to these weather fluctuations and to search for alternative energy sources to overcome the challenges of fuel economics.
Flaring During Production	The production trends for hydraulic fracturing tend to have a high decline rate, which causes a need for proper sizing and utilization of equipment. Gas quality issues for direct use in onsite equipment must be overcome by assessing available methods to address them.

6.2. Gap Analysis

The 24 gaps were reviewed were analysed in an effort to provide structure and support to the development of planning and decision-making by users of the Roadmap. Each gap was assessed with the potential beneficial impact of addressing it. This would provide a starting point for prioritization. In addition, the gaps were reviewed for the level of effort of active research programs which are aimed at addressing it; this would assist decision-makers in allocating scarce funds to areas of greatest leverage and to avoid duplication.

The gaps were then placed in a matrix capturing the impact of the gap on the vertical axis and the extent to which it may already be addressed on the horizontal axis. The Tight Oil and Shale Gas Research Gap Matrix is shown in Figure 21. The vertical axis gauges the impact on industry needs, in other words the impact on reducing costs, improving production and reducing environmental impact. The scale rates such impact as low, medium or high, as follows:

- Low impact. Closing the gap will have a positive impact on some industry needs.
- Medium impact. Closing the gap will have a significant impact on industry needs; prior research may have already partially closed the gap or harnessed the opportunity, thus reducing the impact of new research.
- High impact. Closing the gap would result in a profound impact on industry needs. There may be existing research programs but much work remains to be done to close the gap and realizing the benefits.

The horizontal axis is informed by knowledge of existing research and technology development programs in industry, government laboratories and academia. The existence of research programs will inform the priority for allocating new resources to the topic but, most importantly, the method by which such investment could be made whether it is leadership for a new research initiative or participation and collaboration in existing programs nationally or internationally.

It is important to note that the analysis of the gaps is only one of the factors that would lead to future investment decisions. Factors such as value (which combines impact and costs) and technology maturity (which encompasses probability of success, time horizon, cost of research and other factors) will also need to be considered. Thus, analysis of gaps is only a first screening mechanism and other filters must be subsequently applied.

The Tight Oil and Shale Gas Research Gap Matrix (Figure 21) distributes the gaps according to their respective impact and level of current activity. The interpretation is as follows:

- Gaps with high impact but addressed by few research organizations represent an opportunity or a need for future investment in new research initiatives.
- High impact gaps that are the object of a high level of effort represent opportunities for collaboration and partnerships with the research programs already addressing the gap.
- Medium and low impact gaps are of lower overall priority but some aspects may be of higher interest to specific participants in the innovation system.

Figure 21. Tight Oil and Shale Gas Research Gap Matrix

Impact/Value on Operations and the Environment	**High**	• CO_2 Gas Flooding • Novel Proppants	• Refracturing Well Selection • Enhanced Waterflooding • Understanding the Decline Curve • Multilateral Completions • Saline Surface Storage Technologies • Completion Venting / Flaring	• Refracturing Well Completion
	Medium	• Standardized Water Characterizations Method and Guideline Development • Fuel Consumption During Production	• Reservoir Characterization (general) • Completion Optimization (general) • Production Rate Optimization • Managing Sulphate and NORMs • Alternatives to pneumatic equipment • Completion Operations	• Disposal Well Management • Availability of Water Samples • Saline Storage and Transport • Flaring During Production
	Low		• Improved Well Characterization while Drilling	• Reservoir Geochemistry (Shale Formations) • Fate of Injected Water in Shale Formations
		Many	**Medium**	**Few**
		Current Level of Innovation Activity		

7. TECHNOLOGY DIRECTIONS

7.1. Objective

The purpose of the Roadmap is to provide a blueprint for future investments in research and innovation for the development of technology solutions that would address stakeholders concerns. Subsequently, the Roadmap may lead to an action plan to implement a portfolio of technology opportunities. The gap analysis is an exercise in scanning the landscape for needs and opportunities to capture the significant issues. It is a necessary precondition and foundation for the Roadmap.

The final element of project workflow is to propose initial portfolios for investments in research, technology development and innovation that would be aimed at filling gaps and harnessing opportunities. The Roadmap is best described as a conceptual blueprint that captures a consensus among stakeholders about the motivation for improvement and potential directions for achieving them. This blueprint is prepared for consideration by industry, government and academia, and may be a basis for improved dialogue and planning that could subsequently lead to a full strategic implementation plan with concomitant allocation of resources with the objective to make significant improvements in the production, recovery and environmental impact of tight oil and shale gas resources.

7.2. Technology Portfolios

In general, investment in technology development would favor high-value projects in a mature technology space, in other words high reward/low risk technology investments. If one had perfect knowledge, one would always select high reward/low risk technology projects. In practice, a number of uncertainties cloud the selection process. Thus, research and technology decision-makers adopt a portfolio approach to manage risk and maximize total expected returns. A technology development portfolio typically attempts to balance investment risk with potential returns in a continuum from incremental improvement (low risk but low value; typical of mature technologies) to game changing technologies (high risk but high reward; typical of low maturity technologies).

At the strategic level of a roadmap, one would not be concerned with discrete specific projects or technologies, but would rather be considering areas of research or technology development which represent the aggregation of individual technologies aimed at the same outcome and requiring a convergent set of skills and capabilities. For example, in GHG and air emissions, alternatives for pneumatic instruments and equipment was identified as a gap. A technology solution area would be instrument air technologies as an aggregation of specific instrument air solutions proposed by individual researchers or technology developers.

As part of workshop discussions and the gap analyses done by subject matter experts, potential areas for research studies and technology development were also identified with the objective of addressing the gaps. 49 potential areas for research studies and technology development were assembled into three portfolios: Sustainable Production (Table 13), Water Management and Treatment (Table 14), and GHG and Air Emissions Management (Table 15).

Table 13. Overview of Sustainable Production Research and Technology Opportunities

Title	Description of the Research and Technology Opportunity	Technology Readiness
Studies of tight oil and shale gas rocks for characterization of petrochemical, geomechanical and PVT properties	Studies to generate a greater amount of analysis of reservoir samples from target resources, as well as improved laboratory methods for the characterization of petrochemical, geomechanical and PVT properties for tight oil and shale gas resources.	Studies
In-situ nanoscale devices	In-situ nanoscale devices to help understand the reservoir mechanisms, responses, and fracture behavior, to act as tracers, and compile data to create models.	TRL 1 to 3
Geochemical studies of reservoir cores from the Duvernay and the Montney	Studies to increase the public knowledge base and support an improved understanding of the recovery mechanisms for gas, liquids and oil in shale formations which could lead to novel recovery technologies.	Studies
Studies of the interaction of water with shales at reservoir conditions	Studies to understand mechanisms that would cause retention of water in shales.	Studies
Sensing technology to gather information on the fate of water in different formations	Development of in situ sensors to identify the path followed by injected water and its ultimate location in the reservoir.	TRL 1 to 3
3-D printed cores allowing for repeatable testing of water interaction with different rocks and formation fluids	Development of laboratory methods to model water-shale interactions at reservoir conditions.	TRL 4 to 6
Studies of reservoir characteristics, refracturing method and production data	Studies to determine key success criteria, to develop new well selection strategies and to validate through implementation.	Studies
A model or algorithm for refracturing candidate wells	A model allowing for rapid well selection without depending on production history.	Studies
Improved completion technologies	Development of completion technology that would optimally fracture a reservoir (e.g. preserving the simple logistics of ball drop systems) while at the same time leaving behind a clean wellbore in anticipation of the need for future refracturing.	TRL 4 to 8

Table 13. Overview of Sustainable Production Research and Technology Opportunities

Title	Description of the Research and Technology Opportunity	Technology Readiness
Improved waterflooding technologies	Investigations of surfactant–rock reactions, water chemistry and compatibility; development of methods to alter rock wettability and/or to improve the performance of water by, for example, the addition of chemicals such as surfactants.	TRL 4 to 8
Improved CO_2 gas flooding technologies	Laboratory work based on Bakken cores indicates that under appropriate conditions high levels of oil recovery can be achieved with CO_2. However, detailed laboratory measurements need to be continued and results used in numerical simulations to evaluate the technical and economic feasibility of CO_2 EOR in Bakken tight oil formations.	TRL 4 to 8
Numerical simulation analysis of production phenomena in unconventional reservoirs	Studies to identify the root causes of production decline and identify appropriate mitigation methods.	Studies
Improved reservoir simulators that can handle the complex fluid flow physics of introduced hydraulic fractures	Development of reservoir simulators with improved capability to model tight and shale rocks in order to account for the parameters that affect the contribution of matrix and fracture flow to oil production over the lifetime of the well.	TRL 4 to 6
Study of the potential of artificial lift	Studies of the potential of artificial lift to economically increase production after the high initial rate drops off.	Studies
Field pilots and analysis of new completion programs	Piloting and demonstration trials to support and maintain innovation and continuous improvement in production optimization and cost reduction.	TRL 7 to 8
Numerical simulation studies and field data analysis of production strategies	Studies to optimize production and maximize recovery, such as, for example, a study of the long term effects on total recovery of choking initial production to preserve wellbore-fracture connectivity.	Studies
Development and piloting of novel multilateral completions	Development, piloting and demonstration of novel multilateral completion equipment to reduce capital and operating costs, as well as environmental impact.	TRL 4 to 8
Development of novel ceramic proppants	Development, piloting and demonstration of novel ceramic proppants with improved properties and higher performance features as compared to sand.	TRL 4 to 8

Table 13. Overview of Sustainable Production Research and Technology Opportunities

Title	Description of the Research and Technology Opportunity	Technology Readiness
Development of novel lightweight proppants	Development, piloting and demonstration of novel light-weight proppants, using different materials (including polymers) with better buoyancy and improved ability to be carried deeper into fractures, so to increase propped fracture length and to increase conductivity and production.	TRL 4 to 8
Improved well logging and/or measurement while drilling (MWD) technologies	Development, piloting and demonstration of novel MWD tools to increase the accuracy of well placement and the appropriate selection of fracture initiation locations.	TRL 4 to 8
Improved technologies for characterizing drill cuttings	Development, piloting and demonstration of ruggedized, small footprint chemical analysis instruments to better characterize reservoir rock while drilling.	TRL 4 to 8

Table 14. Overview of Water Management and Treatment Research and Technology Opportunities

Title	Description of the Research and Technology Opportunity	Technology Readiness
Development of a standardized testing method for determining fracturing fluid compatibility with source waters	Development of a standardized testing method for determining fracturing fluid compatibility with source waters prior to first use to improve and optimize fracturing fluid performance and quality	Best practices
Development of a standardized water chemistry characterization matrix for varying water sources and different types of fracturing fluids	Development of a standardized water chemistry characterization matrix for varying water sources and different types of fracturing fluids to support operational decisions in water sourcing	Best practices
Development of a standardized water chemistry characterization matrix for flowback and produced waters	Development of a standardized water chemistry characterization matrix for flowback and produced waters from different types of hydraulic fracturing fluids. In particular, this characterization needs to include residual fracturing fluid chemicals that impact reuse and bacteria concentration analyses.	Best practices

Table 14. Overview of Water Management and Treatment Research and Technology Opportunities

Title	Description of the Research and Technology Opportunity	Technology Readiness
Development of guidelines for source water, flowback and produced water sampling frequency and methods	Development of guidelines for source water, flowback and produced water sampling frequency and methods to ensure that water chemistry data is comparable	Best practices
Enhanced storage options for flowback and wastewater	Development, piloting and demonstration of novel storage options for flowback and wastewater with enhanced integrity, such as cost effective double containment saline water storage systems.	TRL 4 to 8
Enhanced leak detection methods for flowback and wastewater	Development, piloting and demonstration of novel leak detection methods with enhanced performance to prevent stored flowback and wastewater from contacting ground and surface water.	TRL 4 to 8
New technologies to improve the effectiveness of existing sulphate removal methods	Development, piloting and demonstration of new technologies to improve the effectiveness of existing sulphate removal methods for cost effective treatment of flowback and produced water.	TRL 4 to 8
New technologies to improve the effectiveness of NORM removal methods	Development, piloting and demonstration of new technologies to improve the effectiveness of NORM removal methods for flowback and produced water treatment applications.	TRL 4 to 8
Development of improved disposal well management procedures and tools	Development of improved disposal well management procedures and tools based on water compatibilities to manage risk, optimize operations and extend well life.	Best practices
Development of a centralized facility for flowback water samples	Development of a centralized facility for flowback water samples with involvement from multiple operators for accessible distribution of samples to technology providers.	Best practices
Best practices for water storage and transport of flowback and produced waters	Best practices for water storage and transport of flowback and produced waters, taking into account the potential presence of bacteria, NORMs and hydrocarbons.	Best practices
Best practices for cases where water reuse may be shared by more than one operator	Best practices for cases where water reuse may be shared by more than one operator or from more than one facility at water hubs to improve industry-wide efficiency and reduce overall environmental impact.	Best practices

Table 14. Overview of Water Management and Treatment Research and Technology Opportunities

Title	Description of the Research and Technology Opportunity	Technology Readiness
Best practices for managing bacterial growth	Best practices for managing bacterial growth in surface storage to improve water quality and reliability.	Best practices

Table 15. Overview of GHG and Air Emissions Management Research and Technology Opportunities

Title	Description of the Research and Technology Opportunity	Technology Readiness
Energy efficiency best practices in upstream facilities	Energy efficiency best practices in upstream facilities, such as energy efficient buildings, processes and equipment to minimize fuel consumption and associated GHG emissions.	Best practices
Combustion control and efficiency best practices	Combustion control and efficiency best practices for optimal operation of combustion devices to reduce energy consumption and emissions, improve efficiency, and potentially improve production.	Best practices
Solar powered instrument air systems	Development, piloting and demonstration of new solar powered instrument air systems with improved reliability and reduced costs.	TRL 4 to 8
Solar powered electric controls and equipment	Development, piloting and demonstration of new solar powered electric controls and equipment with improved reliability and reduced costs.	TRL 4 to 8
Solar panels with lower costs and improved theft prevention	Development, piloting and demonstration of new solar panels with lower costs and improved theft prevention, to enhance accessibility and reliability.	TRL 4 to 8
Capture and utilization of low pressure and low flow rate gas from gas powered systems	Development, piloting and demonstration of new systems for capture and utilization of low pressure and low flow rate gas from gas powered systems, such as thermoelectric generators and catalytic converters.	TRL 4 to 8
Detection and monitoring sensors	Development, piloting and demonstration of new detection and monitoring sensors with lower operating costs and improved accuracy and precision.	TRL 4 to 8

Table 15. Overview of GHG and Air Emissions Management Research and Technology Opportunities

Title	Description of the Research and Technology Opportunity	Technology Readiness
Mobile equipment to capture and utilize produced gas	Development, piloting and demonstration of new mobile equipment to capture and utilize produced gas with lower cost at smaller scale for temporary service until production operations are fully in place.	TRL 4 to 8
Separation technologies for removing N_2 and CO_2 from flowback gas	Development, piloting and demonstration of new mobile and small footprint separation technologies for removing N_2 and CO_2 from flowback gas to allow the non-condensable gas to be re-used onsite and the methane to be produced and shipped to market.	TRL 4 to 8
Gas sweetening technologies	Development, piloting and demonstration of new gas sweetening technologies, at smaller scale and lower cost to allow the onsite processing of produced sour gas.	TRL 4 to 8
Studies of pipeline access logistics and costs	Studies of pipeline access logistics and costs, to optimize the construction of pipeline infrastructure.	Studies
Fuel switching for hydraulic fracturing operations	Development, piloting and demonstration of new technologies to enable fuel switching in hydraulic fracturing operations in order to use the best fuels and power supply options to minimize the use of diesel while controlling costs.	TRL 7 to 8
Practices to address cold and fluctuating weather impacts on equipment functionality	Practices to address cold and fluctuating weather impacts on equipment functionality to provide for energy efficient operations in cold weather.	Best practices
Mobile units that can be relocated easily to allow correct production equipment sizing	Development, piloting and demonstration of new mobile units that can be relocated easily to other wellsites to allow correct production equipment sizing to maintain energy efficiency in the context of a rapid production decline curve.	TRL 4 to 8
Technologies to allow onsite direct use of produced gas	Development, piloting and demonstration of new technologies to allow onsite direct use of produced gas to fuel onsite equipment, in order to minimize use of other fuels such as propane and diesel.	TRL 4 to 8

The portfolio listed above were informed by TOGIN network discussions and form a starting point for consideration by industry and government when making research and technology investment decisions.

When evaluating specific investment opportunities, the concepts of value and technology maturity must be considered when analysing the details of the research or technology opportunity.

The concept of value embedded in a prospective technology builds from the beneficial impact of closing the gap or harnessing the opportunity, but adds the consideration of development and implementation costs and the potential for disruption to existing systems when implementing the solution. Technology maturity describes how probable and how imminent a technology solution is to translation to widespread industrial use. It encompasses variables such as:

- Probability of technical success;
- Ease of market uptake;
- Cost of research and development;
- Time horizon for complete development and commercialization.

For example, a low maturity technology would exhibit one or more of the following characteristics:

- Technically challenging (Could need one or more inventions.);
- Market disruptive (The sector would need to acquire new skills or capabilities, change procedures or regulations, invest in new infrastructure, etc.);
- High technology development expenditures;
- Long technology development timelines.

A mature technology would exhibit converse characteristics to the attributes listed above.

Thus the portfolios shown were designed as starting points for readers and users of the Roadmap, but careful decision-making will require consideration of some of the additional factors mentioned above.

8. CONCLUSION

Tight and shale oil and gas resources offer a significant opportunity for Canada, particularly in the western provinces. The amount of in-place resources is very large and has yet to be fully delineated and assessed. The recovery at scale of these resources is a relatively recent development and considerable potential exists for further innovation to address economic and environmental challenges.

Key challenges that are addressable through research and technology development are principally in the areas of:

- Sustainable production: technologies and processes to improve recovery and production, and to reduce costs.
- Water management and treatment: hydraulic fracturing requires substantial quantities of water which must be sourced, treated, transported, formulated, injected, recovered and recycled or disposed. Water chemistry is critical for the sustainability and cost-effectiveness of water management and treatment, and for the economic deployment at scale of alternatives to fresh water sources such as reuse and saline aquifers.
- GHG and air emissions management: in general, air emissions issues from surface facilities used in tight and shale oil and gas are similar to those experienced in conventional oil and gas operations which are the minimization of GHG emissions from fuel combustion, flaring and venting.

The Roadmap process allowed for the identification and documentation of specific gaps and their representation in a matrix which prioritize gaps according to their potential impact and to the level of existing research and technology development activity. The Roadmap process also included the identification of specific opportunities for research or technology development projects or studies, which were aggregated in portfolios for sustainable production, water management and treatment, and GHG and air emissions management.

Learnings from the Roadmap are that, while the opportunity for tight and shale oil and gas development is substantial, the context for innovation is very complex and innovation would be prospective on a number of fronts simultaneously. In sustainable production, key opportunities include further investments in reservoir characterization studies, including rock description, geochemistry and thermodynamics properties likely through joint industry projects with relevant operators and government organization. Technology strides in completion technologies hold meaningful potential for cost reduction and increased recovery and production. Examples include multilateral wells and simplified multistage completions. Optimization of completion programs and of production strategies also offer promises with a high probability of delivery. Finally, technological approaches for extracting more resources from the same wellbore after initial production decline represent a sizable opportunity either through improved understanding of refracturing approaches or through EOR schemes.

With respect to water management, studies and best practices would assist industry and stakeholders to better understand the impacts of withdrawals from multiple users on watershed health and to increase the knowledge base of ground water resources, particularly saline aquifers. Improved and focused water treatment technologies are required for specific contaminants such as sulfates and NORMs, in order to reduce costs and improve performance, particularly for allowing the economic use of aquifer brines. Environmental performance would be enhanced by novel storage and transportation technologies for saline waters and for the management of disposal wells.

GHG and air emissions management remains a critical aspect for any oil and gas operations, particularly in the context of Canada’s commitment to the Paris Agreement. In general, the surface facilities associated with hydraulic fracturing operations are of the same type and nature as facilities in conventional oil and gas. The generic challenges are similar: reduced fuel consumption, flaring and venting. Hydraulic fracturing operations presents some additional challenges with respect to fuel use during completion operations and operational process adjustments during the step production decline from high initial production rates. Solutions will be generally be analogous to those applicable to conventional operations such as enclosed combustors, electrification alternatives to pneumatic equipment, waste gas capture and utilization, and advanced LDAR.

The Roadmap was built on the foundation of a thorough review of needs, gaps and opportunities, through workshops and meetings coordinated by TOGIN and was also informed by the knowledge and expertise of subject matter experts, in consultation with industry, government and academic stakeholders. It provided a mission-oriented framework to maximize the tight oil and shale gas opportunity and to minimize environmental impact. It is being proposed for consideration by oil and gas industry operators, service and technology companies, governments and regulators, and academic institutions. Action on this framework will lead to technology solutions that will respond to needs expressed by stakeholders and to opportunities identified by industry, in a way that leverages the resources of individual organizations for the benefit of the sector as a whole.

APPENDIX A METHODOLOGY

A1) Project Organization

The organizational structure of the roadmap project includes the TOGIN Steering Committee, and committees for water, air emissions and GHGs, and sustainable production. PTAC facilitated work sessions and workshops, and the production of various work products such as section reports and the Final Roadmap Report by working with partners New Paradigm Engineering, Third Bay, the Saskatchewan Research Council and Cap-Op Energy.

The TOGIN Steering Committee provided governance and direction to the project. It was comprised of representatives from Husky Energy, Encana, ConocoPhillips, Progress Energy, Quicksilver Resources, Unconventional Gas Resources, Alberta Innovates - Clean Energy, Alberta Environment and Parks, Alberta Energy, Alberta Economic Development and Trade, the Saskatchewan Research Council, the BC Innovation Council, and Natural Resources Canada (NRCan).

Husky Energy is one of Canada's largest integrated energy companies and has operations worldwide with upstream and downstream business segments[68]. Encana is a leading North American energy producer that is focused on growing its portfolio of diverse resource plays producing natural gas, oil and natural gas liquids[69]. ConocoPhillips is a producer committed to the efficient and effective exploration and production of oil and natural gas[70]. Progress Energy is a leader in Canadian natural gas development[71]. Prior to April 2016, Quicksilver Resources was a leader in the development and production of unconventional reservoirs including shale gas and coal bed methane[72]. Unconventional Gas Resources is a private company focused on the development of unconventional resources in North America.

Alberta Innovates is an important investment in the growth and diversification of Alberta’s economy. The corporation builds on provincial strengths in health, environment, energy, food, fibre and emerging technologies to produce results that contribute to the province’s health, social and economic future. Alberta Innovates delivers the kind of cross-sectoral support and leadership that Alberta’s world-class researchers, entrepreneurs and industry innovators need to thrive in a globally competitive research and innovation context. Services, tools, expertise, partnerships and funding from Alberta Innovates support a broad range of research and innovation activity, from discovery to application, with the focus on accelerating commercial outcomes.

Alberta Environment and Parks is a ministry of the government of Alberta which includes stewards of air, land, water, and biodiversity, and has the goal of achieving the desired environmental outcomes and sustainable development of natural resources for Albertans[73]. Alberta Energy manages the province’s development of non-renewable resources and renewable energy[74]. Alberta’s Ministry of Economic Development and Trade provides leadership on the government’s economic development efforts and access to information and support for businesses and investors[75]. The Saskatchewan Research Council is one of Canada’s leading providers of applied research, development and demonstration and technology commercialization[76]. The BC Innovation Council supports startups and developing entrepreneurs to accelerate technology commercialization[77]. NRCan is an established leader in science and technology in the fields of energy, forests, and minerals and metals and use our expertise in earth sciences to build and maintain an up-to-date knowledge base of our landmass. NRCan develops policies and programs that enhance the contribution of the natural resources sector to the economy and improve the quality of life for all Canadians. NRCan conducts innovative science in facilities across Canada to generate ideas and transfer technologies[78].

PTAC provided project management and administrative services to the project and was the entity responsible for delivering it. PTAC is a 20 year old not for profit organization that was created to promote collaborative research and technology development for the Canadian hydrocarbon energy industry. PTAC's network is comprised of approximately 200 member organizations, including oil and gas producers, who produce approximately 80% of Canadian conventional oil and gas, transporters, government bodies, research providers, venture capital firms, academic institutions, individuals, as well as service and supply companies.

The project team was tasked with producing the work products required for the execution and delivery of the project. It was composed of New Paradigm Engineering (Bruce Peachey), Saskatchewan Research Council (Petro Nakutnyy, Peng Luo, Paul Paynter, and Mike Crabtree), Third Bay Ltd. (Jana Vander Kloet, Roberta Wasylishen, and Keith Minnich), and Cap-Op Energy (Ian Kuwahara).

A2) Key Network Events

The roadmap project involved a number of meetings and events, the most notable of which were three workshops in the areas of water management, GHG and air emissions, and sustainable production related to hydraulic fracturing, which are described below. The meetings were designed to review and integrate various individual assignments and obtain feedback from the Steering Committee regarding project contents and key messages. The workshops presented key project findings and outcomes to a broad expert audience composed of invited industry stakeholders from production companies, government and regulatory bodies, consulting firms, research organizations, and technology providers.

Within TOGIN, PTAC created 3 sub-committees whose purpose was to provide expertise in more specified areas related to tight oil and gas. All committees included representatives from government organizations, oil and gas producers, and technology providers to provide expertise from a range of industry stakeholders. Committees provided guidance to PTAC when planning the workshops and are listed below:

2a) TOGIN Water Management Committee

This was the largest committee formed under the TOGIN and the group provided coverage in the area of water management. The committee included thirty-nine attendees who met 11 times (June 22, July 27, September 8 and 24, October 14 and 28, November 17, December 2, January 7 and 18, and February 16) to help PTAC plan the workshop entitled: "Water Management for Multi-Stage Hydraulic Fracturing of Horizontal Wells," and also selected a water management subject matter expert to write relevant chapters in this final report. Following the water workshop, this committee expanded to sixty-eight members with additions from water experts who expressed interest in joining after attending the event.

The Water Management for Multi-Stage Hydraulic Fracturing of Horizontal Wells Workshop was held on December 9, 2015 and was only attended by those who were considered experts in the field of water management related to hydraulic fracturing. The workshop resulted in the identification of the top challenges and respective solutions by workshop attendees, as outlined in Table A1 and Table A2.

Table A1. Top Water Management Challenges

Challenges	Votes
1. Regulatory issues: classification gaps; Regulations that promote water efficiency; improved clarity; risk-based vs. prescriptive	41
2. Basin knowledge or lack thereof; water supply	27
3. Data information and communications; Effective water communications	22
4. Economics	11
5. Alternative for volume management; Saltwater storage and transport	7
6. Lack of technology sandbox	6
7. Water Treatment	4
8. Water availability at the right time and place (regulatory issues)	3

Table A2. Top Water Management Technologies and Solutions

1. Basin Knowledge or Lack Thereof; Water Supply
- Centralized databank, share for everyone to access
- Excess capacity usage
- Basin model

2. Regulatory Issues; Classification Gaps; Regulations that Promote Water Efficiency; Improved Clarity; Risk-Based vs. Prescriptive
- Modernize the water act
- Regulatory harmonization – regulatory champion
- Public transparency in data – water information availability
- Decentralize semi-central facility, remove roadblocks, enable transportation between facilities
- Lower risks to companies to enable collaboration to blend water. Share with neighbor.
- Regulators not limiting the technology

3. Data Information & Communications; Effective Water Communications; Credible organizations to archive data and broadcast our communications
- Duplicate the CASA framework
- CAPP change the way they communicate to the public
- Transparency to the public
- Communications to those who use and manage water
- Big data management – what is relevant and what isn't
- What data is available – historical and current
- What data do we want – quality, who would be leading the charge?

Table A2. Top Water Management Technologies and Solutions

4. Economics
    - Water bank – sharing risk and cost. E.g. cooperative network that has shares and data credits.
    - Centralized facility with multi-operator
    - Blending relaxed regulations
    - Mobile technology

The workshop received positive reviews overall and as mentioned above, generated interest from attendees to join TOGIN. PTAC also worked with the committee towards forming potential new projects based on workshop results.

2b) TOGIN Sustainable Production Committee

PTAC formed a committee of 8 industry stakeholders to help plan a workshop entitled: Sustainable Production from Tight Oil and Shale Gas Plays. The committee met 4 times (November 25, December 16, January 20, and February 16) to guide PTAC in the planning process of this workshop. The workshop was modelled after the previous TOGIN water workshop, due to its positive reception, and took place on February 22, 2016. The workshop resulted in the identification of the top challenges and respective solutions by workshop attendees, as outlined in Table A3and Table A4.

Table A3. Top Sustainable Production Challenges

1. Collaboration – Data and Technology Sharing
2. Understanding Reservoirs & Increasing EOR
3. Prioritizing Formations for R&D
4. Increasing Speed of Technology Adoption
5. Market Access
6. Improvement of Public relations
7. Revive Existing Infrastructure
8. Decline – Economics of capturing late life Reserves
9. Body to Keep R&D Going Even When Prices are High
10. Collaboration – Research & Funding

Table A4. Top Sustainable Production Technologies and Solutions

1. Nanotechnology:
    - Reservoir Surveillance – Nano Sensors and Tracers
    - Understanding Interactions Within the Reservoir to Create a Cognitive Model
    - Use of Nano Particles as a Filter for GHG & Water Treatment
    - Nanotechnology Applications for EOR
    - Nanotechnology for Fracture Stimulation
2. Reviving Old Producers & Prolonging Well Life
3. Artificial Lift
4. Enhanced Oil Recovery
5. Collaboration tools to develop new technologies

2c) TOGIN Greenhouse Gas and Air Emissions Committee

PTAC formed another committee to help plan a workshop entitled: Greenhouse Gas and Air Emissions Related to Hydraulic Fracturing. The committee met 4 times (November 26, December 16, January 11, and March 7) to guide PTAC in the planning process of this workshop. The workshop was modelled after the previous TOGIN workshops, due to their positive reception, and took place on March 16, 2016. The workshop resulted in the identification of 7 specific breakout group topics during the morning panel discussion and the corresponding challenges per topic from the workshop attendees. The results are shown below in Table A5 and Table A6.

Table A5. GHG and Air Emissions Morning Breakout Topics

Group	Topic
1	• Lack of infrastructure and access to gathering systems • Challenges with sizing equipment for varied flow rates (initial vs. late life) • Issues with nitrogen/CO_2/ HC and alternative frac types
2	• How to measure and break down emissions data and define a baseline • Can actions be taken from a desktop to reduce GHGs: Data accuracy, measurement? What data is needed? • How information can support collaboration for solutions
3	• Lack of protocol for: green completions, reporting, others • Ways to make money and reduce GHGs at once – Resource sharing, better CO_2 and N_2 stripping, tie in wells quicker to capture the early flaring/venting
4	• Region specific regulations to balance more challenging areas • Looking at geographic and temporal distributions and what constraint imposes on technologies? Usually they will become mobile
5	• Incentives to use bi-fuel/electric/solar instead of diesel.

Table A5. GHG and Air Emissions Morning Breakout Topics

Group	Topic
	• Security on sites to avoid equipment theft. Technological issues (HP, etc.)
6	• Understanding abatement costs. How addressing these issues may compete with other issues in the upstream oil and gas sector
7	• Alternative energy (e.g. solar pumps) • Incorporating solar/electric alternatives into high pressure applications/wells

Table A6. Top GHG and Air Emissions Challenges

Group	Challenges
1	• Formation considerations (e.g. formations with high CO_2). What factors affect the time it takes to clean up the well • Methane injection possible? Infrastructure to reduce dangerous handling at surface • Nitrogen is preferred over other gasses (CH_4). Therefore, we must find ways to deal with N_2 in our operations • Reinjection – A disposal well. Sometimes could have the luxury of having one near • Current technology for N_2, CO_2 separation is not up to speed • Access to infrastructure /capacity is challenging, especially for new areas
2	• Current data infrastructure is based on crude emission factors. Can lead to a sloppy baseline • Can actions be taken from a desktop to reduce GHGs? • Need clean data and collection methodology – consistent data, transparency of data standards vs comparing standards between companies • Greater social push of successes – Support changes and improve overall image • Stick and carrot approach – Incentivize (up front) and enforce (backstop). Reward early action – Early data would help forecasting • Barrier with sharing info. Coalitions or commitment to share knowledge
3	• Silos between players operating in similar areas • Multiple operators tripping over each other. Unitizing the field/JV operatorship of treating facility- clustering • Value proposition of adding enhanced recovery compression via gas reinjection. Economics could get better over a longer period of time. • Understand economics of GHG/barrel of oil and how to communicate that to investment groups • Incentivize service providers to spend capital to meet producers needs

Table A6. Top GHG and Air Emissions Challenges

Group	Challenges
4	• What are the technology needs for each formation • For existing inert fluid fracs – Improve stripping technologies (membrane technologies on site or downstream for removing N_2 and CO_2 • Look for alternative fluids – Propane to replace CO_2, LNG to replace N_2. • Pull together a consortium to test the #3 • Develop a benchmark and then a metric - E.g. To measure flare volume vs length of well for a formation type. Incentives for companies to introduce these new technologies • Regulations/Incentives for bi-fuels, a minimum standard for tier 2+ engine controls
5	• Industry is being driven in this direction by cost considerations in the current environment • Carbon tax and potential royalty breaks will promote adoption • Technology must be “at least break even” to gain corporate acceptance • Social license perspective – Publicize successes and our track record/evolution of fracturing methods
6	• Retrofit of legacy (higher pollution) equipment that is presently sub-economic. Royalty breaks/carbon tax? • Accelerate adoption of low emission/high technology protocols for future wells • Current efficiency drives are also driving emissions reduction (e.g. larger, lower slippage compressors on multi well pads) • Data quality – Suspicion that fugitives are significantly less than current assumptions, including background (natural) levels
7	• Regulations impede adoption of new technologies • Information on capabilities of solar pumps and other pneumatic controls • Flexibility in regulations so in the initial phase (high volume, high pressure) we might need a mobile system which could be moved to other wells • Purchasing systems in large companies – Looking at price but not lifecycle costs. Incomes generated from large scale conversions can be quite reasonable

After establishing the top challenges, for each morning breakout topic associated with GHG and air emissions related to hydraulic fracturing, workshop attendees identified new breakout group topics related to the afternoon panel discussion and brainstormed the top solutions related to each topic. The results are shown in Table A7 and Table A8.

Table A7. GHG and Air Emissions Afternoon Breakout Topics	
Group	**Topic**
1	• Could existing protocols be adapted to suit well testing? Are the protocols facility-based, or too specific to adapt? Flexibility when developing new protocols • Carbon tax, like in B.C. Instead of paying it to the government, use it to fund projects. We would need to add incentives to make changes. Money from offsets could be used to reduce emissions further • Government fund for downturns (like right now) to fund innovation during those times
2	• Bringing on old producers – If we can economically increase well production, we are improving the emissions: production ratio. However since we are bringing on more wells, there will be more venting/flaring
3	• Infrastructure for hydrogen use: Could this be a focus in industry in the future?
4	• Micro-electric generators – If these are economic, they could help provide power to remote locations without transmission line losses • Micro LNG – Gathering many small emissions sources • Gas to liquids • Dump flooding • Increase flaring efficiency • Technology to Separate CO_2 and N_2 from flowback
5	• Baseline definition – Making meaningful comparisons between “apples to apples.” If someone has innovated already, should they get the early benefits? We don’t want to penalize early innovators. Simple, cost effective, flexible measurement that is accepted by everyone

Table A8. Top GHG and Air Emissions Technologies and Solutions	
Group	**Technology Solutions**
1	• Have offsets directly fund projects. No ambiguity in the offset protocol to encourage investment • Tax money put towards commercialization stage – Need stability in offsets programs to encourage investment. CCEMC too vague. Perhaps a 2 tier application process, one for SMEs and one for larger projects • Simplify protocol approval process – Currently involves too much consultation • What the government can do during a downturn: Royalty credit program to help fund new technologies. Royalty relief during hard times, so the money never leaves the hands of the producers. Upfront cash might be more effective?
2	• Was not discussed in a breakout group
3	• Was not discussed in a breakout group

Table A8. Top GHG and Air Emissions Technologies and Solutions

Group	Technology Solutions
4 #1	• Low capacity sites – Micro-tech needs a solution applying to low capacity sites, mobile, and can work without electricity. Multi-phase pumps? More efficient thermoelectric generators? • Dump flooding – Technical and regulatory complications to address: deal with initial spike of gas by dilution? • Flare efficiency – Consider mine facility incinerators, which use a lot of fuel gas (e.g. H_2S), plasma incinerators? • Nitrogen separation – Dilution could be a solution • Is there a possibility of methane to hydrates
4 #2	• Dump flooding – Hasn't been completed in AB, but could have potential. Has been done in the U.S. • Micro-gen – Use local natural gas to create electricity. Previous efforts have not been successfully up taken except on a large scale. Needs larger volumes and higher quality gas. N_2 flowback might not be compatible • Micro LNG – Promoting oil and gas to use their own product – energized fracs and bi fuel • Fracturing with LNG. • Social perception of risks involving LNG – high pressure hazard • CO_2 and N_2 stripping technology: Need better small scale systems for stripping. Effects of N_2 and CO_2 on downstream facilities/infrastructure • Many companies are bringing good technology into use but aren't recognized • Electric frac pumps – 50-150 MW gas turbines: what equipment would you need to install these
5	• Baseline and useable process leaving room for provisions which align with intent and spirit • Allow companies to use equivalent methods. Normalize the data and their methodology through a self-audit • Benchmark with signoff for equivalent methods of measurement and collection • Send a signal of acknowledgment and incentivize people to want to change • Use tax dollars to create a baseline. AER could store the data. This would allow industry and government to work together

The workshop received positive reviews overall and PTAC is looking to hold a follow up meeting with interested workshop attendees to potentially move forward with the top technologies and solutions developed.

2d) Other Committees Related to Tight Oil and Shale Gas

Outside of TOGIN, PTAC formed two small committees, one specific to the Duvernay formation and the other specific to the Bakken formation, to help write reports and plan events in relation to the respective formations. These committees are relevant to this roadmap, because the subject matter experts who authored those reports also wrote condensed chapters in this roadmap on the same topics.

The Duvernay Steering Committee and project team met 7 times (October 28, November 25, December 8, January 19, March 3, March 10, and April 4).

The Bakken Steering Committee and project team held 6 conference calls (August 5, September 18, September 22, November 12, December 2 and March 7).

A3) Fall 2016 Workshop

Upon completion of this Roadmap, there is to be a workshop held during fall 2016 to review the work that was completed and prioritize the identified technology solutions to work towards forming projects to advance existing technologies towards commercialization.

APPENDIX B WHAT IS HYDRAULIC FRACTURING?

Authored by New Paradigm Engineering

B1) Overview

Hydraulic fracturing is a process where some type of fluid is pumped into an oil or gas well at a higher pressure than the formation rock can withstand. This causes small fractures and cracks to open in the rock, extending away from the well and increasing access to more of the oil or gas containing rock. Since these rock fractures close again when the pressure is reduced, very small particles, usually sand, called proppant are added to the fracturing fluid. These particles enter the fractures, acting as doorstops to prevent the fractures from closing once the fracturing fluid pumping stops. These open channels then act as conduits through which oil and gas can flow back to the well.

Since the pressure acting on the formation via the fracturing fluid is what causes fractures to form, fluid losses or leak-off into the formation will reduce the pressure holding the fractures open. This is why modern hydraulic fracturing methods use a multistage approach, where the wellbore being fractured is divided into multiple stages, and each of the stages is isolated from the others and fractured one at a time. This has several advantages in that:

- Since each stage requires a lower flow rate of fracturing fluid to achieve the same pressure, fewer pumps are needed on the surface, and the total volume of fracturing fluid required is also reduced.
- If one section of the well has a high leak-off rate and is losing fluids faster than expected, then fracture development will be limited in the rest of the well. By staging, other sections of the well can be fractured separately and more efficiently. This means that maintaining adequate pressure to create fractures along the well will not be hampered by high leak-off encountered at a particular stage.
- Finally, the fracturing processes can be better controlled when completed in smaller pumping stages as the properties of the reservoir formation change along the horizontal well, so more stages help to ensure the fracturing occurs along the entire length of the well.

Not all wells will show improvements in oil and gas flow rates when they are fractured, so it is not a technology that can be applied on every well. Historically, the main use of fracturing in vertical wells was to break through near well damage caused by drilling and cementing operations, and later single fractures were done along horizontal wells to break through thin horizontal barriers in the rock which prevented complete reservoir drainage. So the main reason to fracture a well is if the permeability, or ability of fluid to flow through the rock is low. If a rock has high permeability, it will be easy for oil and gas to flow through it, and fracturing is probably not needed for an economic (profitable) operation. So hydraulic fracturing is used to increase flow in less permeable formations, because the fractures create significantly increased permeability, since it is easier to flow through a crack in a rock. As the fracture network grows, the amount of the reservoir which is open to flow increases, allowing the reservoir to be drained more efficiently.

1a) Short History of Hydraulic Fracturing

The first use of hydraulic fracturing for oil and gas production took place in the United States in the late 1940s, with the first Canadian use occurring in Alberta's Pembina Cardium field in the 1950s. Over the next 60 years, hydraulic fracturing was generally used to increase production from low productivity wells. In Alberta, almost 37% of over 450,000 wells drilled have been hydraulically fractured with around 10,000 of the fractured wells being horizontal multistage fracture completions, which were completed between 2009 and 2015 in a large number of low permeability formations[79]. Note that not all horizontal wells are fractured and many horizontal wells were drilled before 2009 in formations where permeability was high enough to make the wells economic without fracturing.

1b) Why Hydraulically Fracture Wells?

Conventional oil and gas resources, with high permeability and porosity (how much empty space, or pore space, makes up the rock), can be extracted from the reservoir using only the natural pressure in the reservoir and/or pumping operations. Conventional wells were the first type of well drilled, but as the number of undeveloped conventional resource plays dropped, oil and gas producers began looking at ways to develop unconventional resources. For the purposes of this report, unconventional includes low permeability and porosity light oil and gas formations, which conventional practices cannot produce economically, but excludes other oil, oil sands, heavy oil or coalbed methane wells which are either not fractured or are fractured without use of proppants. Producing from unconventional resources often requires more intensive and complicated techniques, such as fracturing.

Generally the properties of the unconventional reservoir rocks cannot be changed, so to compensate for their low permeability, the area of the rock connected to the well and open to flow must be changed by fracturing and injecting proppant. Drilling horizontal wells rather than vertical wells and fracturing the rock containing oil and gas creates new and larger channels through which fluids can flow, and also increases the area open to flow by millions of times over that of a single vertical well. The combination increases flow rates and improves well economics.

1c) Evolution of a "Game Changer" and Modern Practices

The technologies used in modern multistage hydraulic fracturing have all been present for many years. It is their combination which led to the recent development of hydraulic fracturing as a "game changer." The technologies which were combined to form present-day "multistage hydraulic fracturing" practices are briefly described below.

Horizontal Wells

Drilling horizontal wells rather than vertical wells into the formation increases the inflow area because more of the well contacts the formation. However, they are more expensive and difficult to fracture because the larger well length causes higher pressure losses. Compared to a vertical well, production increases generated by just horizontal drilling without fracturing usually did not yield enough additional production to justify their higher cost, but they do allow wells to be drilled from pads which reduces surface disturbance and allows drilling and completion activities to be concentrated on much fewer well sites, as illustrated in Figure B1.

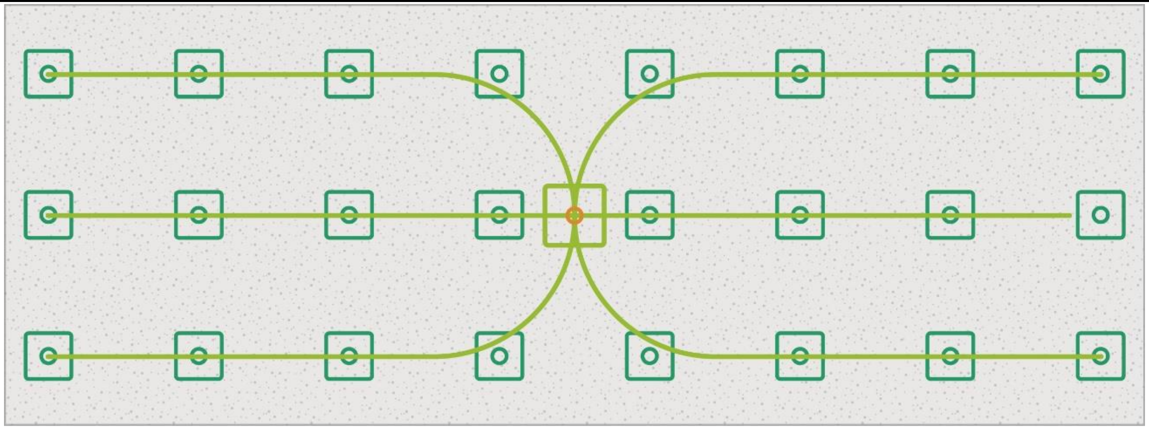


Figure B1. Multi-well Horizontal Pad

Showing how a single multi-well horizontal pad (light green) can replace 24 or more vertical wells (dark green) to access the same resource[80]

Orientation of Fractures

To increase fracture penetration in low permeability formations, producers began to orient the wells so that the fractures would preferentially form at a right angle to the horizontal well (See Figure B2). This significantly increased the penetration of the fractures into the formation before energy was lost through "leak off" of the hydraulic fracturing fluid.

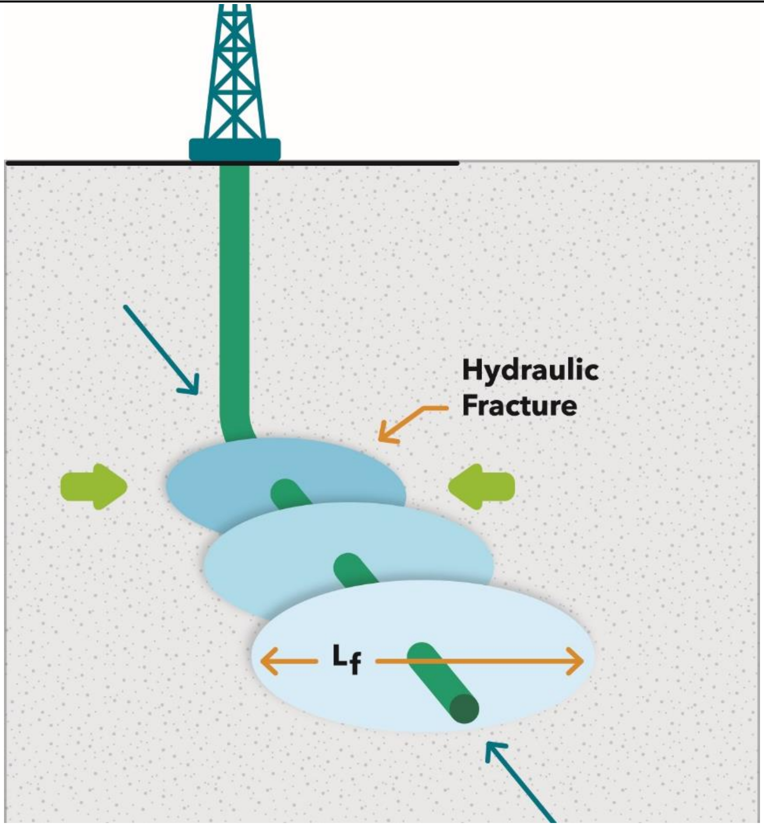


Figure B2. Orientation of Fractures Along Horizontal Wells
Source: Texas A&M University Presentation[81]

Stage Isolation

Dividing the horizontal well into a series of smaller fracturing stages shortens the length of the interval being fractured, minimizing pressure losses and allowing precise control over which sections of the well are fractured. Initially this required high costs to sequentially isolate different well intervals by setting packers (a tool with a rubber element on it designed to seal against the sides of the well). However, new methods were developed to isolate portions of the horizontal well and allow fracture stages to be fractured in series in less time. This significantly reduced multistage fracturing costs.

Multi-laterals

One of the most recent enhancements to the available technologies is to further expand reservoir access in thick reservoirs by drilling and fracturing additional “laterals” or “drainage wells” from other “mother” wells, which again increases access without increasing surface footprint (See Figure B3.)

B2) Resource Types

While the basic principles and tools of hydraulic fracturing may be used in any low permeability unconventional formation, the specific methods, fracturing fluid types, potential additives, numbers of fracture stages, and well designs are different between different types of resources. Choices in the technology used will be driven by the type of rock and hydrocarbon found in each formation.

2a) Oil Resources

Conventional Oil Reservoirs

The main feature distinguishing a conventional oil reservoir is the presence of permeable layers through which oil can flow relatively easily. Millions of years ago, before they were buried, they were layers of sediments such as ancient river beds or beaches (sandstones or clastic formations), or porous remains of coral reef structures (carbonates). Oil flowed into the porous rock, which must be “capped” by some impermeable feature of the formation preventing further upwards flow of oil, forming a trap. Sandstones may have alternating layers of high permeability gravel beds (aggregates), which allow production through vertical wells. Carbonates can also contain very high permeability caverns (“karst” features), natural fractures, and relatively large openings (“vugs”) in some portions of a buried reef structure which are easy to produce using vertical wells. Carbonate formations in Alberta, make up about two thirds of the original established conventional oil

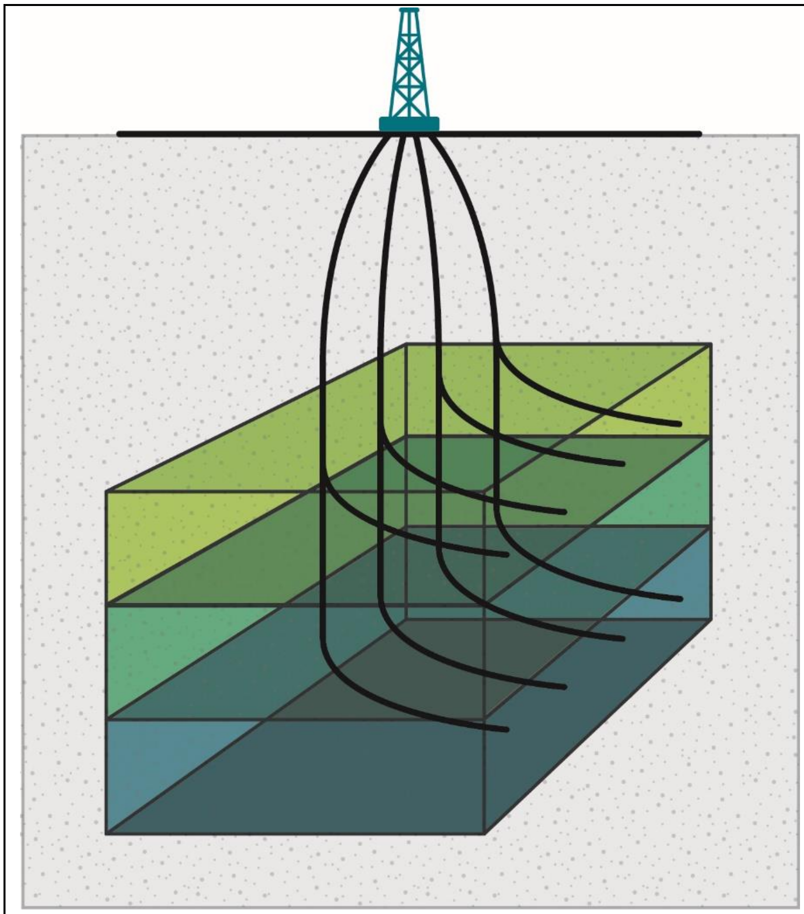


Figure B3. Spacing of Laterals in a Thick Shale Formation

Source: National Energy Board [82]

reserves in Alberta from large fields like Leduc, Redwater, Bonnie Glen, Swan Hills, Judy Creek and others, while the Pembina Cardium field, and other Cardium, Viking and conventional heavy oil fields are sandstone. Fracturing is not required for this type of resource if there is good natural porosity and they can be easily produced with vertical wells.

Tight Oil

The same formations containing conventional oil can also contain “tight” oil in portions of the formations which have lower permeability. Fine sandstones (light color in the photo in Figure B4) are the primary type of “tight” unconventional sandstone formations, often found in areas around the conventional portions of the formation, while “tight” carbonates may be less permeable limestone or sediments made up of coral sands adjacent to the conventional pools. Since these reservoir rocks have lower permeability, it is much harder for oil or water to flow through the rock into wells. The oil may seep out of the rock, very gradually, into a well, but often not at rates high enough to make the production economic. The lower permeability also means these formations are not in communication with underlying saline aquifers, which often provide pressure support by allowing water to flow in to replace the oil as it is recovered. Without some other fluid coming in, or being injected to replace the oil, formation pressures drop off quickly and further reduce or stop oil flow into the wells.

Figure B4. Examples of reservoir rocks

Note: Layered sandstone left[83], carbonate right[84]) indicating differences in natural permeability of the rocks.

Shale Oil

The voids in which the oil is trapped are thin sand layers sandwiched between layers of impermeable shales. Shales are fine-grained and have a laminated structure. Oil can flow in from the edges, and be trapped within a layer, but there is negligible flow or pressure communication between and along the layers. Completing un-fractured wells into these formations results in very low rates of production, and what flow that does occur will rapidly decline.

Oil Shale

These formations are very hard, fine grained shales with veins of greasy solid known as kerogen, which is oil mixed with organic matter, mixed in with the inorganic sediments (See Figure B5). Up to 20% of the shale material may be organic material, which was naturally deposited when the shale was originally formed at the bottom of an ancient sea or ocean, so the oil and kerogen are trapped together within a matrix of the inorganic material. As these types of rocks become more deeply buried over time, natural geothermal heating will cause the solid kerogen to be naturally “upgraded” or “mature” into light oil and gas, which will either remain trapped where it is or can then migrate over geologic time upwards through more permeable zones, and be trapped in the shallower conventional oil formations. As a result, oil shales are the “source rocks” for oil and gas found in conventional oil and gas pools.

Figure B5. Example of Oil Shale Reservoir Rocks

Note: The rocks are composed of fine layers of minerals and organic “kerogen” which has very little natural permeability to allow oil flow[85].

2b) Gas Resources

Conventional Gas

There are two different types of conventional gas reservoirs in Western Canada, differentiated by how the gas was formed. They can be economically produced without extensive hydraulic fracturing.

a) **Thermogenic Gas Reservoirs**. This gas was formed by the heating of the source rock, in which organic material (kerogen) was originally deposited and turned into hydrocarbons, before migrating into conventional traps with high porosity.

b) **Biogenic Gas Reservoirs**. These generally contain smaller amounts of organic sediments or coal, and are found at shallow depths and conditions where natural colonies of bacteria can survive. These microbes gradually turn the organic carbon in the rock sediments or underlying coal seams into methane with very few contaminants.

Tight and Shale Gas

This gas is trapped in formations similar to tight oil and shale oil. The reservoirs lack high porosity and permeability layers, hindering flow. The low viscosity of the gas can often allow flow to occur, but it may not be at commercially viable rates and pressures, and very little of the formation can be drained if only vertical wells are used. In some formations the thermogenic gas may contain various amounts of hydrogen sulphide or carbon dioxide, which will have to be removed from the produced gas before it can be sold. In the B.C. Horn River Basin the gas generally contains 10-20% CO_2, while much of the "tight" gas in the southern prairies around Medicine Hat is mainly biogenic methane and has been economically produced from vertical wells for over 100 years.

Rich Gas Shales

This gas is found in the same deep shale formations as the shale oil and gas, usually found at depths in between the shallow "mature" oil zones and the deep "over-mature" gas zones, but the kerogen in the shale has been heated to a higher temperature and converted to natural gas and natural gas liquids. Currently this is the primary type of production targeted for development as the liquids produced greatly increase the value of the production even at lower oil prices.

B3) Hydraulic Fracturing Design Considerations

3a) Rock Properties

To design a fracture stage, a completions engineer obtains data on the rock properties from core, rock samples, and other data collected during drilling. The rock strength, one of the collected parameters, is used to determine the required pressure to break the rock, and rock porosity and permeability are used to calculate the leak off rate of the fracturing fluid.

This leak off rate affects fracturing efficiency, and is a reason why hydraulic fracturing is impractical in rock formations with higher permeability. If the rate of fluid loss into the formation is too high, then building up enough pressure to fracture the formation becomes difficult. An analogy for this can be visualized as trying to blow up a balloon with a hole in it; much more air is needed to overcome the leak to make the balloon expand, and the larger the hole is, or becomes as the balloon expands, the higher will be the leak-off. Once the leak-off rate becomes equal to the pumping rate, the fractures will no longer grow.

3b) Formation Stresses

The natural rock stresses in the formation dictate the orientation in which the fractures will form. The wells for multistage fracturing are placed so that fractures are perpendicular, or at least at an angle to the wellbore to ensure maximum fracture penetration into the rock.

3c) Pump Design

Based on the thickness of the formation, the location of the horizontal well within the formation, the length of well for the stage, and the desired size of the fracture, an estimate can be made of the required pumping pressures, durations and flow rates. To minimize required flow rates, reduce the number of pumps required, and more accurately control where the fractures form in the horizontal well. Each stage is fractured separately.

3d) Well Type

These include vertical, horizontal, and multi-lateral, as shown in Figure B6:

- **Vertical wells** are drilled as directly as possible to the zone of interest. They are uncommon in unconventional applications because not enough area contacts the reservoir to compensate for the lower permeability.
- **Directional wells** are often used in conventional heavy oil wells or to access resources under surface features like lakes and rivers, so the bottom hole locations are off-set from the surface locations.
- **Horizontal wells** extend vertically into the ground similar to a vertical well, but at a certain point begin to deviate and eventually become horizontally, or nearly horizontal, in the target formation and can be drilled within the formation for anywhere from a few hundred to a few thousand meters. This well type is preferred in shale applications because it contacts a large area of the reservoir and can extend from central drilling pads to minimize land use and clearing.

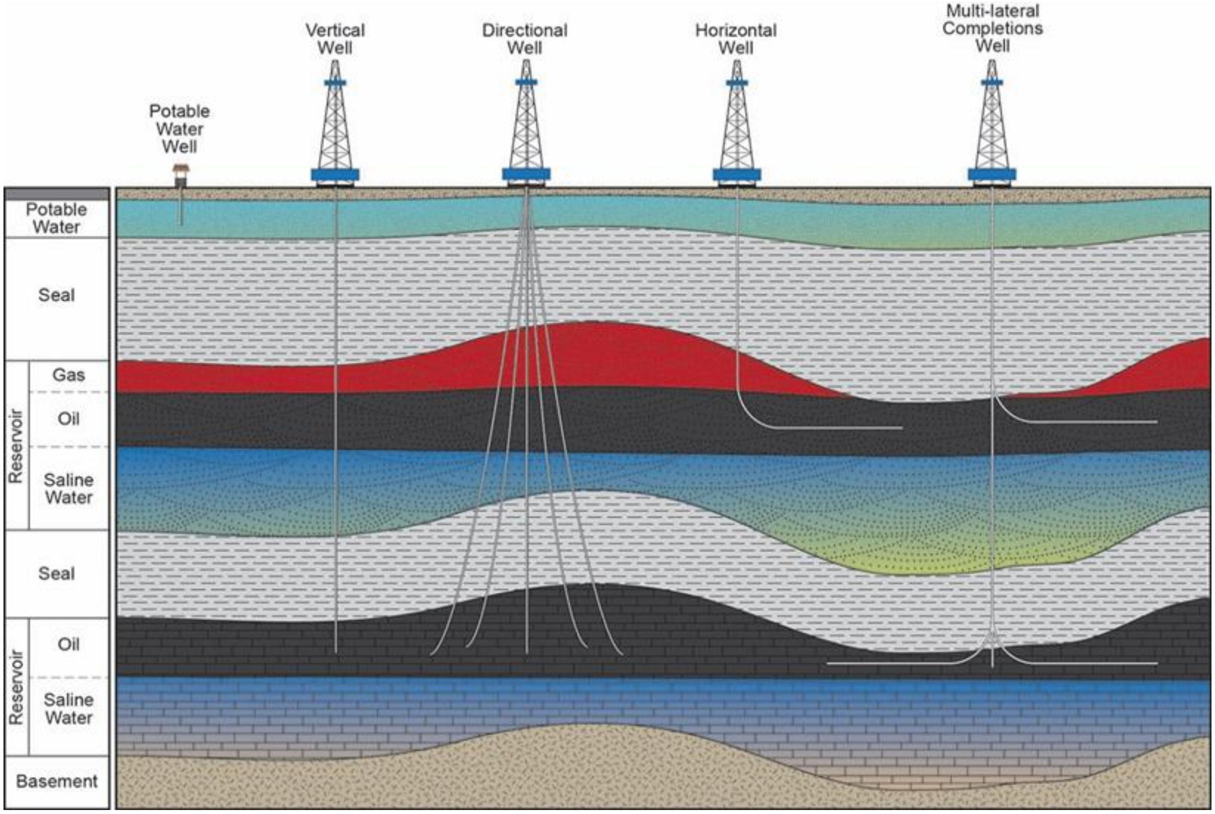


Figure B6. Basic well types for oil and gas wells

Note: Multistage fracturing is mainly done in horizontal and multilateral wells, but not all of these wells are fractured[86]

- **Multi-lateral wells** have more than one horizontal lateral ("leg") coming off the main "mother" wellbore, and sometimes may even have additional branches coming off these laterals. They are more complex than a horizontal well, and many different configurations exist. Hydraulic fracturing is a challenge in these wells since the other legs must be isolated, as well as the individual fracturing stages. They become more economically viable the deeper the target zone(s) are and in thick formations. They can be drilled with the initial well or added later as "re-entries".

3e) Well Completion Type

Once a well is drilled, it must be completed. This involves installing any equipment required before producing from the well. "Open" or "cased" hole completions refer to the presence of cement and steel casing in the well. In an open hole completion these components are absent, so the sides of the producing well in the formation are the formation itself. In a cased hole, a cemented liner or casing is cemented into the well along the horizontal length to help stabilize the wellbore and provide a uniform surface for downhole tools, such as packers, to seat properly and provide a seal. However, cemented casings, or liners, must then be perforated before production can begin; this process uses explosive shaped charges, or a jetting tool, to puncture the steel liner, allowing oil and gas to flow into the well. Open hole completions are cheaper to drill, due to the lack of materials installed in the well, however, the surface of a steel casing is much more likely to be consistent and smooth, whereas sections of an open hole well may "wash out" or collapse due to the lack of support. A solid and consolidated rock type is required for an open hole completion.

3f) Fracturing Fluids

There is a wide range of fluids, gels or foams which can be used as fracturing fluids. The first hydraulic fractures used gelled, or thickened, hydrocarbons (oil or kerosene), but very soon the industry switched to using water based fracturing fluids, and more recently fluids containing propane, nitrogen, or CO_2 as the base fracture fluid have been developed. Water is the most common fluid used as it is readily available in most regions. The industry has more experience using water and it is the least hazardous for the rig crews to handle. Other options may be flammable, toxic, and extremely cold or can cause asphyxiation if they are suddenly released into the air at a site. Types of fracturing fluid include water and oil based, as well as nitrogen, carbon dioxide, and propane based.

Water Based Fluids

The main challenge with using water as a fracturing fluid is its low viscosity, which results in high leak off rates (high rate of fluid loss into the formation), and therefore large volumes of water per well. The low viscosity also means that it cannot easily transport proppants into the fractures. To reduce the water volumes required, a number of chemicals can be added to form gels to increase the water viscosity during the fracturing. These will later break down on their own or with the addition of another "breaker" chemical, such as salt, so oil or gas can flow into the well without having to push a thick gel out first.

Thus, there is a trade-off off when using water based fracturing fluids: high water volumes and water transportation costs, vs. less water volume with more chemicals and chemical costs. Deciding which fracturing fluid to use in a given well type and formation, depends on geologic conditions (temperature), geochemistry (presence of clays, salinity, and oil or gas properties), and the availability of fracturing fluid ingredients. Generally the chemicals used will already be mass produced for other high volume purposes as this will result in lower costs. In many cases "proprietary" components are simply unique blends of chemicals is specific proportions.

The main water based fracturing additives used in Canada are:

- **Slickwater**. Slickwater fluids can be as much as 99% water. Since gel additives might plug up the natural fractures in some formations, other additives are used to reduce the pressure losses caused by the high water flow rates down the well. These chemicals could be mineral oil (often used in cosmetics or medicines) or petrochemical products like polyacrylamide, which might be found in nail polish remover. Large volumes of water in deep formations may also serve to help displace oil and gas from those formations where there is no other natural driving force or where it is difficult to reduce the pressure in the well.
- **Borate Salts**. These form "cross-linked" gels to maintain viscosities in higher temperature formations. They can be similar to laundry detergents, hand soaps or wood preservatives.
- **Guar Gum or Hydroxyethylcellulose**. These additives are used to thicken water to increase its viscosity. Both are biodegradable. Guar gum comes from guar plants which are mainly grown in India and Australia, and is a product used as a thickener in ice cream and other food products. Hydroxyethylcellulose is also used in food and other domestic products.
- **Breakers**. Breakers are injected after the fracture treatment to help break down the gels so they don't block flow into the well. The main chemical used is sodium chloride (table salt), or calcium chloride which is often used as road salt or to suppress road dust. Other types of breaker might be used that cause a slower breakdown of the gels.

Oil Based

Oil based fluids were some of the first fluids used for hydraulic fracturing. Oil based fluids minimize the likelihood of formation damage such as is caused by certain clays which swell in water. They can be used in almost any type of formation, with the oil being produced back with formation fluids.

Oil-based fluids include the following:

- **Oil Fracturing**. Oil and other hydrocarbon liquids are already more viscous than water, so they have lower leak-off rates and can create fractures with lower volumes of fracturing fluid. Since the oil will eventually be produced back it may not represent a major cost.
- **Gelled Oil**. As with gelled water, guar gum or other materials can be used to thicken oil or other hydrocarbons to further reduce leak-off.
- **Crosslinked Phosphate Ester Gels**. Allow for increased control of gel formation and are usually used with kerosene, diesel or other hydrocarbon liquids for higher temperature applications.
- **Oil Water Emulsions**. Surfactants can be added to oil and water to create an emulsion with higher viscosity than either oil or water on their own, and can then be broken down by demulsifiers. Surfactants include soaps which change the surface tension of oil droplets in water or water droplets in oil.

Nitrogen (N_2) Based Fluids

Nitrogen can be produced by chilling the air to a liquid and separating the nitrogen from oxygen, and is commercially manufactured by industrial gas suppliers who also supply it for many other purposes. Nitrogen has the advantage of being chemically stable, or inert, so it does not cause corrosion or other problems. A problem that can be encountered is that the nitrogen will dilute the first gas produced from a well, and while nitrogen is usually present in most natural gas, too much of it can lower the heating value of the natural gas and it is difficult to remove.

The main methods for using nitrogen as a fracturing fluid are:

- **Nitrogen Gas Fracturing.** Injects pure gaseous nitrogen into tight shallow formations, but the formations also have to be very brittle so that they will be “self-propping” as nitrogen gas is not viscous enough to carry proppants. As nitrogen can leak off quite easily, the formations must have very low permeability and porosity. This is the primary fracturing method used for vertical coal bed methane wells.
- **Nitrogen Energized Fracturing**. Consists of a mixture of water, additives and nitrogen with the nitrogen comprising under 50% of the total volume of fracturing fluid. It is generally used in deeper formations over 3,000m deep.
- **Nitrogen Foam Fracturing**. Uses a higher percentage of nitrogen (50-95% by volume) with water and alcohol based additives to cause foaming. Varying the composition changes the viscosity of the foam so the fluid so can be adjusted to match the formation, while at the same time requiring lower volumes or water and other chemicals.
- **Cryogenic Nitrogen**. Involves injecting cold liquid nitrogen which can fracture the rock by causing naturally present formation water to freeze. The freezing water expands, and freezing the rock makes it more brittle and easier to fracture or shatter. This method is rarely used as it requires special piping and equipment to handle the cryogenic nitrogen.

Carbon Dioxide (CO_2) Based Fluids

CO_2 based fluids can be used instead of nitrogen in less brittle formations, like the Montney Formation. This is only viable in some formations, and while water use is reduced, the CO_2 will eventually be released to the atmosphere as a GHG. Unlike nitrogen, CO_2 can be injected as a non-cryogenic liquid. Otherwise, CO_2 based treatments are similar to the nitrogen treatment methods discussed above. Like nitrogen, CO_2 will be a contaminant in the produced gases from the well, but is easier to process and is routinely removed by gas plants.

Propane/NGL Based Fluids

Since propane is a normal component of natural gas, it is available from almost any local gas processing plant in a given area, and the propane produced back after a fracturing treatment can be recovered at the same gas plants. Propane is neither as energy intensive nor as expensive to produce as nitrogen or carbon dioxide, so is a lower net cost replacement for water with potentially lower net air and GHG emissions impacts. However, it is flammable, so greater care and proper safety precautions must be taken in handling the propane prior to injection.

3g) Proppants

Proppants are the second largest volume of material used in hydraulic fracturing after water. They are usually a non-reactive, hard, granular solid material such as find sand, and are mixed with the fracturing fluid to hold open fractures after pumping stops. Some proppant sand might be coated with resin to change the density of the proppant to help it flow into the fractures, or to stick to the fracture walls to hold it in place. Other materials used include ceramic (glass) beads which can be manufactured to be of more consistent size and density, or high strength materials such as mineral oxides. Some innovative proppants have been proposed which can be "tagged" and tracked once they are in place so the well designers can see where the proppant went when it was injected. The size and strength required of the proppant is dependent on the application.

3h) Fracturing Techniques

Basic Multistage Hydraulic Fracturing Process

As discussed earlier, a major "game changer" for hydraulic fracturing was the development of methods to sequentially fracturing wells in "stages" without having to continually remove and replace packers to isolate sections of the well. The basic methods developed allow stages to be fractured one after the other, starting at the far end of the horizontal wellbore, and allow most of the fracturing to be completed in only 1-2 days for most wells (See Figure B7). Three main methods have been developed to isolate, perforate, and fracture each stage of a multistage horizontal well. While there are variations in design and features, the main methods used can generally be describes as: Plug and Perf (PNP), Ball Activated Completions Systems (BACS), and Coiled Tubing Activated Completion Systems (CTACS). All three can be used in cased or open hole applications, and each have advantages in different situations. The specific of each system are proprietary to the companies supplying the equipment.

Plug and Perforate (PNP)

PNP uses equipment mounted on a wireline[v] or coiled tubing (CT) unit to perforate a stage and isolate it from the rest of the well. The perforating/isolating unit is alternated with a hydraulic fracturing unit for each stage. Starting at the far end (toe) of the well and moving towards the vertical section (heel), each stage is perforated, isolated with a plug or a packer, and then fractured.

Ball Activated Completion Systems (BACS)

BACS uses sliding "fracture sleeves" already installed in the liner. Each fracture stage has a sleeve corresponding to a ball size, which increases towards the heel. The smallest ball is dropped first, plugging its corresponding seat and allowing the sleeve to slide open and the interval to be fractured. The subsequent ball catches in the next sleeve, allowing it to be opened while simultaneously cutting off flow to the stages behind them. This process is

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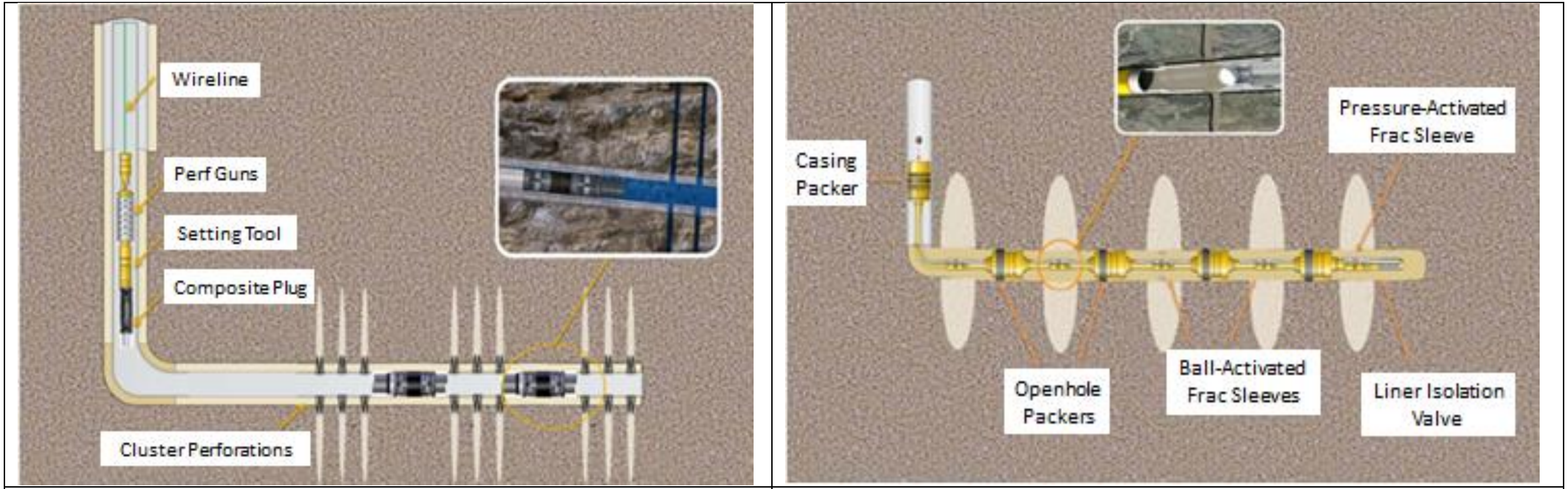
[v] A wireline unit is basically a spool of wire which is lowered into the well, while CT is similar but uses a flexible tube instead of wire

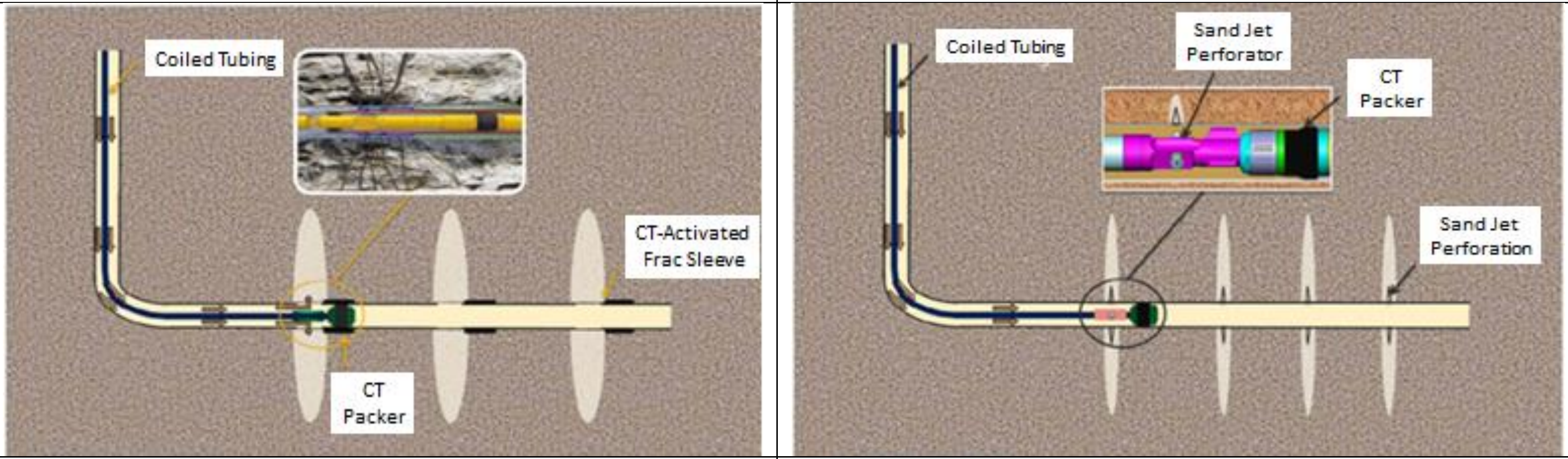
repeated for each fracture stage. Balls are then produced back during flowback or some are designed to dissolve.

Coiled Tubing Activated Completion Systems (CTACS)

CTACS uses coiled tubing (CT) and CT activated sleeves (similar to the sliding sleeves used in the BACS method) already installed in the liner. An isolating packer is set below the stage being fractured before the sleeve is opened and fracturing begins, again starting at the toe of the well and working towards the heel.



Plug-and-Perf Completion | **Ball-Activated Completion System**



Coiled Tubing-Activated Completion System | **CTACS Using SJP and CT Packer**

Figure B7. Basic Hydraulic Fracturing Methods

Source: Baker Hughes [87]

CTACS with Sand Jet Perforator (SJP)

This is another configuration of CTACS uses a sand jet perforator. It eliminates the need for pre-installed frac sleeves, since a jetting tool perforates the liner immediately before fracturing.

Hybrid Systems

Hybrid systems are also possible; for example, using PNP to fracture the toe before switching to BACS close to the heel of the well.

Refracturing

Once a hydraulically fractured horizontal well has been producing for a certain amount of time, say one to two years, the production rate often drops drastically. It is possible to re-enter the well with fracturing equipment in a process called “refracturing.” In the Eagle Ford, a shale gas formation in Texas, refracturing has boosted production back to initial levels while costing half the price of a new well. However, if the wellbore is cluttered with equipment from the initial fracturing job, it can be difficult to isolate the sections being refractured. Additionally, steps must be taken to ensure that this second fracturing treatment does not simply take the “path of least resistance” down the previous fractures, since forming new fractures leads to more efficient refractures.

Re-entry Drilling and Completions

Another option that is beginning to be seen is to “re-enter” depleted wells (2-3 years after initial production starts) to plug off the original horizontal portion of the well and drill a new lateral into a different part of the formation. The new lateral is then completed and fractured similar to the original one to re-establish production rates. The process could be repeated a number of times and avoids having to re-drill the upper portions of the well. This avoids problems with equipment left in the original well and is more likely to access new production by fracturing a different part of the formation. Once a number of laterals are completed all the original laterals might be reopened to complete draining hydrocarbons or for other uses.

Well Flowback

Once the fracturing treatment is over, the first fluids or gases produced back will be the ones used in the fracturing treatment or their reaction products. Many chemicals used in the treatments, such as acid, will have already reacted with the formation and won’t be present to a large extent in the flowback. As flowback continues, the produced fluids flowing from the wells will increasingly be hydrocarbons and water from the formation, with only trace amounts of fracturing chemicals. In Alberta and most jurisdictions, the flowback must be contained and handled to avoid environmental or health issues.

B4) Environmental Considerations

These factors are particularly visible to the public, with important environmental implications.

4a) Air

Methane and other GHGs, such as carbon dioxide, are released in all oil and gas operations. Automated valves, controllers, and pumps are all designed to release some gases as part of their normal function. Many horizontal and multi-lateral wells are drilled from pad locations, with their surface locations all in the same spot which could facilitate emissions capture from multiple wells using only one system.

4b) Water

Most fracturing operations use water as the fracturing fluid or as a component of a gel or foam mixture. Therefore, economics are highly affected by water sourcing, handling, and disposal costs. It is also a matter of concern for the general population, since it uses large amounts of surface water (lakes, rivers) or ground water (underground aquifers) over short periods of time, potentially when local supplies are limited, in winter. Containment and treatment of flowback water is also a concern.

4c) Chemicals

As described in the fracturing fluids section, many chemicals used in fracturing fluids are environmentally friendly, and several are used in the food industry. In Alberta, all chemicals and fracturing fluid compositions must be disclosed. This data is available on the www.fracfocus.ca website on a well by well basis, along with fracturing fluid and proppant volumes. Some fracturing fluid chemical additives are described below.

Acids

Hydrochloric acid (HCl) may be used to clean out residual cement or to enlarge natural flow paths in carbonate rocks in the producing zone. HCl is generally used in concentrations of around 15% in water, and quickly reacts and dissolves the cement or carbonate limestone turning into chloride salt or brine. As a result it must be handled with care when it is injected, but very little of it will be produced back to the surface.

Biocides

In the presence of water and organic chemicals such as guar gum, bacteria can grow and cause problems like plugging, formation of hydrogen sulphide, and corrosion. Biocides are used to control bacterial growth and are consumed as they kill the bacteria, so are rarely produced back.

Corrosion Inhibitors

Small amounts of chemicals may be added to protect downhole tubing and casing. The inhibitors work by forming a thin coating on steel which acts as a protective layer on the pipe.

Scale Inhibitors

Are used in fracture treatments to prevent the formation of scale when incompatible minerals in the formation water react with other chemicals to form precipitates which can form hard scale in the well.

pH Buffers

The most common types of pH buffers are sodium carbonate (often used as a water softener) and potassium carbonate (used in soaps) which are used to control the acidity of the fracturing fluid.

Surfactants

Are used to help normally incompatible fluids like oil and water mix or separate.

Clay Stabilizers

Some formations contain clays which will come apart in fresh water or swell which can block natural flow channels. Clay stabilizers are salts, which increase the salinity of the water to prevent swelling.

APPENDIX C GAP WORKSHEETS

<table>
<tr><td>Gap Title:</td><td colspan="4">Reservoir Characterization (General)</td></tr>
<tr><td>Technology Area:</td><td colspan="4">Sustainable Production</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">Minimizing environmental impact and maximizing production requires detailed and accurate reservoir characterization. Petrophysical, geomechanical and PVT properties are critical for the design and implementation of the drilling, completion and production processes. In tight oil and shale gas resources, production performance strongly depends on the distribution and interconnectedness of natural and hydraulic fractures, and thus the reservoir characterization plays a crucial role.
Additionally, shale formations contain organics such as kerogen which requires specialized characterization and is further discussed in the Reservoir Geochemistry Worksheet.</td></tr>
<tr><td>Impact</td><td colspan="4"><table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table>A more detailed and precise description of unconventional resources would incrementally improve the analysis and design of completion and production methods, but could also lead to understandings that could have a major impact.</td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="4"><table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table>Reservoir characterization is a well-established technical area and is already applied in tight oil and shale gas. The need to adopt existing methods to specific unconventional resources is recognized and some Joint Industry Projects (JIP) for characterization of reservoir cores are in existence.</td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">1. <u>Studies of tight oil and shale gas rocks for characterization of petrochemical, geomechanical and PVT properties</u>: A greater amount of analysis of reservoir samples from target resources, as well as improved laboratory methods for the characterization of petrochemical, geomechanical and PVT properties for tight oil and shale gas resources.
2. <u>In-situ nanoscale devices </u>to help understand the reservoir mechanisms, responses, and fracture behavior, to act as tracers, and compile data to create a model</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td>Piloting and demonstration
TRL 7-8</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="4">Reservoir Geochemistry (Shale Formations)</td></tr>
<tr><td>Technology Area:</td><td colspan="4">Sustainable Production</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">In oil shale formations such as the Duvernay and the Montney, there is a need to better understand reservoir geochemistry because of the presence of kerogen which may impact production by blocking pore space or fractures. Also, due to the depths and pressures in these deep formations, the state in which oil, gas and condensate exist at reservoir condition may be unclear.</td></tr>
<tr><td>Impact</td><td colspan="2">Improved geochemical characterization would improve understanding of the recovery mechanisms for gas, liquids and oil and help determine the recovery potential in shale formations.</td><td colspan="2"><table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table></td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="2">The development of the Duvernay and the Montney occurred only recently and the public knowledge base about the formation is not believed to be large.</td><td colspan="2"><table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table></td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4"><u>Geochemical studies of reservoir cores from the Duvernay and the Montney</u> to increase the public knowledge base and support an improved understanding of the recovery mechanisms for gas, liquids and oil in shale formations which could lead to novel recovery technologies.
In addition, further R&D would be important for developing novel approaches to characterize the organics and better understand the controls of organics on production in shale/tight reservoirs (many shale/tight reservoirs are source rock as well as reservoir rock).</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td>Piloting and demonstration
TRL 7-8</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="4">Fate of Injected Water in Shale Formations</td></tr>
<tr><td>Technology Area:</td><td colspan="4">Sustainable Production</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">In hydraulic fracturing, only a fraction of the injected water is recovered with production. There are many questions about the fate of the injected water that is not recovered and whether its presence supports or hinders production.
In addition, it is understood that under certain circumstances and reservoir configurations that injected water may cause local seismic events.</td></tr>
<tr><td rowspan="2">Impact</td><td rowspan="2">An improved understanding of the fate of injected water could lead to the optimization of completion programs.</td><td colspan="3">Rating</td></tr>
<tr><td>High</td><td>Medium</td><td>[✓ Low]</td></tr>
<tr><td rowspan="2">Current Level of Innovation Activity</td><td rowspan="2">Academic and industry research projects have taken place to a limited extent.</td><td colspan="3">Rating</td></tr>
<tr><td>High</td><td>Medium</td><td>[✓ Low]</td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">1. Studies of the interaction of water with shales at reservoir conditions to understand mechanisms that would cause retention of water in shales.
2. Sensing technology to gather information on the fate of water in different formations: development of in situ sensors to identify the path followed by injected water and its ultimate location in the reservoir.
3. 3-D printed cores allowing for repeatable testing of water interaction with different rocks and formation fluids: development of laboratory methods to model water-shale interactions at reservoir conditions.
4. Continued research and studies of relationships between water injection and seismic events.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>[✓ Characterization studies, analysis, and best practices]</td><td>[✓ Research
TRL 1-3]</td><td>[✓ Technology Development
TRL 4-6]</td><td>Piloting and demonstration
TRL 7-8</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="4">**Refracturing Well Selection and Performance**</td></tr>
<tr><td>Technology Area:</td><td colspan="4">**Sustainable Production**</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">In tight oil and shale gas, production decline is very steep, up to 70% in the first year. There is thus an opportunity to re-stimulate or refracture an existing well in order to revitalize production and increase recovery from the target drainage area. Refracturing has taken place mostly in the United States with the outcome that production increased is more unpredictable than with newly fractured wells. Understanding key criteria for identifying highly prospective refracturing candidates would reduce uncertainty and improve economic and recovery outcomes.</td></tr>
<tr><td>Impact</td><td colspan="4">Refracturing is an attractive proposition from both the economic and environmental perspectives; it utilizes an existing surface disturbance and wellbore to extract more oil or gas from the resource. Improving well selection would reduce uncertainty and increase the uptake of this completion approach.<table><tr><td colspan="3">Rating</td></tr><tr><td>**High**</td><td>Medium</td><td>Low</td></tr></table></td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="4">There has been a number of attempts at analysing refracturing data sets in the United States and this effort is likely to continue until a better understanding of well selection criteria is achieved.<table><tr><td colspan="3">**Rating**</td></tr><tr><td>High</td><td>**Medium**</td><td>Low</td></tr></table></td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">1. Studies of reservoir characteristics, refracturing method and production data to determine key success criteria, development of new well selection strategies and validation through implementation.
2. A model or algorithm for refracturing candidate wells, allowing for rapid selection without depending on production history</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>**Characterization studies, analysis, and best practices**</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td>Piloting and demonstration
TRL 7-8</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="4">Refracturing Well Completion</td></tr>
<tr><td>Technology Area:</td><td colspan="4">Sustainable Production</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">Refracturing is an attractive opportunity to extract more oil or gas from a reservoir using an existing wellbore, thus reducing costs and minimizing environmental impact by avoiding the drilling of a new well. However, a number of original hydraulic fracturing completion techniques substantially increase the cost of refracturing due to the need to remove completion equipment left in the well.</td></tr>
<tr><td>Impact</td><td colspan="4">The development and adoption of original fracturing techniques that would anticipate refracturing operations and reduce their costs (in other words refracturing ready) would increase the uptake of refracturing.<table><tr><th colspan="3">Rating</th></tr><tr><td>[✓ High]</td><td>Medium</td><td>Low</td></tr></table></td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="4">In the current industry downturn, fracturing of new wells has been kept to a minimum level and is focused on achieving optimal production from the initial completion. Refracturing activities are taking place but have to contend with the original completion hardware from years ago.<table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>[✓ Low]</td></tr></table></td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4"><u>Improved completion technologies</u>: Development of completion technology that would optimally fracture a reservoir (e.g. preserving the simple logistics of ball drop systems) while at the same time leave behind a clean wellbore in anticipation of the need for future refracturing.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>[✓ Technology Development
TRL 4-6]</td><td>[✓ Piloting and demonstration
TRL 7-8]</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="4">**Enhanced Waterflooding**</td></tr>
<tr><td>Technology Area:</td><td colspan="4">**Sustainable Production**</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">Waterflooding is a well-known recovery method to increase production after the decline of primary production. However, the characteristics of unconventional reservoirs such as the Bakken significantly limits the performance of waterflooding.</td></tr>
<tr><td>Impact</td><td colspan="4">Methods that would improve the performance of waterflooding in unconventional reservoir could significantly improve recovery, reduce unit costs and minimize environmental impact because they would enhance the existing waterflooding infrastructure.<table><tr><td colspan="3">**Rating**</td></tr><tr><td>**High**</td><td>Medium</td><td>Low</td></tr></table></td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="4">There is a large body of knowledge with respect to waterflooding in conventional reservoirs and this provides a foundation for adaptations and improvements in unconventional reservoirs.<table><tr><td colspan="3">**Rating**</td></tr><tr><td>High</td><td>**Medium**</td><td>Low</td></tr></table></td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">Improved waterflooding technologies: Investigations of surfactant–rock reactions, water chemistry and compatibility; development of methods to alter rock wettability and/or to improve the performance of water by, for example, the addition of chemicals such as surfactants.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>**Technology Development**
TRL 4-6</td><td>**Piloting and demonstration**
TRL 7-8</td></tr>
</table>

Gap Title:	**CO_2 Gas and Miscible Gas Flooding**			
Technology Area:	**Sustainable Production**			
Description of Need or Challenge	CO_2 EOR is a mature technology for conventional oil reservoirs that results in the recovery and production of additional oil. It has yet to be adapted and implemented in tight oil formations. CO_2 EOR can be deployed as immiscible or miscible flooding depending on depth and other reservoir characteristics.			
Impact	Methods to successfully deploy CO_2 EOR in tight oil formations could significantly improve recovery, and production while offering some environmental benefits.	**Rating**		
		High	Medium	Low
Current Level of Innovation Activity	The Energy & Environmental Research Centre in North Dakota is conducting research in the use of CO_2 EOR in Bakken formations in collaboration with government agencies and several oil companies.	**Rating**		
		High	Medium	Low
Description of the Research/ Technology Opportunity	Improved CO_2 gas flooding technologies: Laboratory work based on Bakken cores indicates that under appropriate conditions high levels of oil recovery can be achieved with CO_2. However, detailed laboratory measurements need to be continued and results used in numerical simulations to evaluate the technical and economic feasibility of CO_2 EOR in Bakken tight oil formations.			
Technology Readiness Level (TRL)	Characterization studies, analysis, and best practices	Research TRL 1-3	**Technology Development** **TRL 4-6**	**Piloting and demonstration** **TRL 7-8**

<table>
<tr><td>Gap Title:</td><td colspan="4">Understanding the Decline Curve</td></tr>
<tr><td>Technology Area:</td><td colspan="4">Sustainable Production</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">In unconventional reservoirs, production decline is very steep, up to 70% in the first year. Understanding the precise causes of this phenomenon and how to mitigate it could provide significant opportunities.</td></tr>
<tr><td>Impact</td><td colspan="4"><table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table>Reducing the rate of production decline could correspondingly increase ultimate recovery and prolong the economic life of producing wells, potentially without the need for additional investments in refracturing approaches and/or Enhance Oil Recovery.</td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="4"><table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table>There is continuous improvement in the performance of numerical simulators with respect to their ability to predict performance in unconventional resources.</td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">1. Numerical simulation analysis of production phenomena in unconventional reservoirs to identify the root causes of production decline and test appropriate mitigation methods.
2. Improved reservoir simulators that can handle the complex fluid flow physics of introduced hydraulic fractures are required to understand the parameters that affect the contribution of matrix and fracture flow to oil production over the lifetime of the well.
3. Study of the potential of artificial lift to economically increase production after the high initial rate drops off.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td>Piloting and demonstration
TRL 7-8</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="4">Completion Optimization (General)</td></tr>
<tr><td>Technology Area:</td><td colspan="4">Sustainable Production</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">Hydraulic fracturing completions programs have continually evolved in the last decade. However questions remain particularly with respect to optimal well placement, lateral and vertical spacings, stage density, fluid volumes and sand volumes. Furthermore, designs will vary between formations.</td></tr>
<tr><td>Impact</td><td colspan="4">The continuous improvement in completions programs has been largely responsible for the sustained gradual increases in production and recovery, as well as reductions in costs observed in recent years. This trend is likely to continue if there is steady investment in technology optimization.<table><tr><td colspan="3">Rating</td></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table></td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="4">Continuous improvement in completion programs is expected to continue albeit at a lower level of activity than previous years due to the current economic downturn.<table><tr><td colspan="3">Rating</td></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table></td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">Field pilots and analysis of new completion programs to support and maintain innovation and continuous improvement in production optimization and cost reduction.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td>Piloting and demonstration
TRL 7-8</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="4">Production Rate Optimization</td></tr>
<tr><td>Technology Area:</td><td colspan="4">Sustainable Production</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">High commodity prices of the recent past created an incentive to maximize short-term production. However, there is some evidence that would indicate that maximizing the initial production rates could come at the expense of a steeper decline curve and lower total recovery.</td></tr>
<tr><td rowspan="2">Impact</td><td rowspan="2">Identifying the optimum production rate over the life of a producing well would lead to the maximization of total recovery.</td><td colspan="3">Rating</td></tr>
<tr><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td rowspan="2">Current Level of Innovation Activity</td><td rowspan="2">Current low commodity prices have reduced the incentive to maximize initial production and some alternative production strategies have been attempted.</td><td colspan="3">Rating</td></tr>
<tr><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">Numerical simulation studies and field data analysis of production strategies to optimize production and maximize recovery, such as, for example, a study of the long term effects on total recovery of choking initial production to preserve wellbore-fracture connectivity.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td>Piloting and demonstration
TRL 7-8</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="4">Multilateral Completions</td></tr>
<tr><td>Technology Area:</td><td colspan="4">Sustainable Production</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">Multilateral wells have one vertical wellbore that separates into more than one horizontal wellbore in the reservoir, thereby reducing drilling costs and maximizing exposure to the reservoir. While this completion is advantageous, it is also complex and costly.</td></tr>
<tr><td>Impact</td><td colspan="4">Lowering the insulation and operational complexity and cost of multilateral wellbores would increase their uptake thereby improving economic and environmental outcomes.<table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table></td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="4">Multilateral completions are practised in offshore settings and relevant technologies could be migrated to onshore applications. However, development costs are high and thus develop and activities have been tempered during the industry downturn.<table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table></td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4"><u>Development and piloting of novel multilateral completions</u> to reduce capital and operating costs, as well as environmental impact.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td>Piloting and demonstration
TRL 7-8</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="4">Novel Proppants and Carrier Fluids</td></tr>
<tr><td>Technology Area:</td><td colspan="4">Sustainable Production</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">The most commonly used proppant is sand. However, in certain formations, sand may not be strong enough to resist formation pressure. Sand is also much heavier than water and tends to settle quickly in fractures, thereby not propping open deeper areas of the fracture.
The most commonly used carrier fluid is water. Innovation in water additives and in multiphase fluids can enhance the performance of proppant placement.</td></tr>
<tr><td>Impact</td><td colspan="4">Improved proppants and carrier fluids could lead to higher production rate and total recovery by improving fracture conductivity.<table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table></td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="4"><table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table>A number of technology companies and materials suppliers have developed and offered a wide range of ceramic and lightweight proppants and these improved proppants have been field tested with some degree of commercial deployment. Innovation is also active with respect to additive formulations for carrier fluids and for energizing liquid carrier fluids with gases such as nitrogen and CO_2.</td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">1. <u>Continued development of novel ceramic proppants</u> to improve efficiency vs. sand.
2. <u>Continued development of novel lightweight proppants</u> using different materials (including polymers) with better buoyancy and ability to be carrier deeper into fractures so to increase proppant distribution farther into fractures and increase conductivity and production.
3. <u>Continued development of improved carrier fluid</u> formulations.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td>Piloting and demonstration
TRL 7-8</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="4">Improved Well Characterization while Drilling</td></tr>
<tr><td>Technology Area:</td><td colspan="4">Sustainable Production</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">Existing well logging and measurement while drilling (MWD) technologies acquire some information about the wellbore that is being drilled. However, new technologies to acquire more data at a greater precision could improve the design of the completions program leading to efficiency and productivity improvements.</td></tr>
<tr><td>Impact</td><td colspan="2">A more precisely design completion program that is specific to each well would incrementally increase well productivity.</td><td colspan="2"><table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table></td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="2">A number of technology providers continually offer improvements in well logging and MWD technologies, driven and a large part by the increased ability to miniaturize sensors.</td><td colspan="2"><table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table></td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">1. Improved well logging and/or measurement while drilling (MWD) technologies to increase the accuracy of well placement and the selection of fracture initiation locations.
2. Improved technologies for characterizing drill cuttings to better characterize reservoir rock while drilling.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td>Piloting and demonstration
TRL 7-8</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="4">**Standardized Water Characterizations Method and Guideline Development**</td></tr>
<tr><td>Technology Area:</td><td colspan="4">**Water Management and Treatment**</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">In Western Canada, there is a need to develop standardized testing methods for determining fracturing fluid compatibility and a standard for water chemistry characterization (i.e. potentially a type of matrix) for varying water sources and fracturing fluids. Specifically, there is a need for water characterization to include residual fracturing fluid chemicals that impact reuse and bacteria concentration analyses. Guidelines must also be developed for source water, flowback, and produced water sampling. As the use of hydraulic fracturing for the extraction of unconventional resources continues to grow, characterization methods and guidelines must be defined and implemented to ensure that industry is referencing universal information when making decisions in the field.</td></tr>
<tr><td>Impact</td><td colspan="4"><table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>**Medium**</td><td>Low</td></tr></table>Standardized methods and guidelines to support operational decisions in water sourcing and will ensure that water chemistry data is comparable. This will result in improved operations and reduced environmental impact, and in the creation of a baseline to reflect current operational practices and research, which will be referenced throughout industry.</td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="4"><table><tr><th colspan="3">Rating</th></tr><tr><td>**High**</td><td>Medium</td><td>Low</td></tr></table>Water characterization and guideline development is an ongoing maintenance task to ensure that the most updated information is being used by all stakeholders. There is a need to incorporate new information to ensure industry awareness.</td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">1. Development of a standardized testing method for determining fracturing fluid compatibility with source waters prior to first use to improve and optimize fracturing fluid performance and quality
2. Development of a standardized water chemistry characterization matrix for varying water sources and different types of fracturing fluids to support operational decisions in water sourcing
3. Development of a standardized water chemistry characterization matrix for flowback and produced waters from different types of hydraulic fracturing fluids. In particular, this characterization needs to include residual fracturing fluid chemicals that impact reuse and bacteria concentration analyses.
4. Development of guidelines for source water, flowback and produced water sampling frequency and methods to ensure that water chemistry data is comparable.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>**Characterization studies, analysis, and best practices**</td><td>Research TRL 1-3</td><td>Technology Development TRL 4-6</td><td>Piloting and demonstration TRL 7-8</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="4">Saline Surface Storage Technologies</td></tr>
<tr><td>Technology Area:</td><td colspan="4">Water Management and Treatment</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">In most cases, hydraulic fracturing operations require a large amount of water for functional purposes. Storage of flowback and produced water is an ongoing challenge for hydraulic fracturing sites and addressing this challenge through identification of additional effective storage options and implementation of new leak detection methodologies is essential.</td></tr>
<tr><td>Impact</td><td colspan="4"><table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table>Improved storage methods will help to contain produced flowback and wastewater and reduce the environmental impact of hydraulic fracturing operations. Leak detection methodologies will prevent storage water from contacting ground and surface water, and thus will prevent contamination.</td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="4"><table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table>Hydraulic fracturing is a relatively new method of production compared to other oil and gas production methods. Thus, there is space for innovation and growth regarding the storage and leak mitigation methods for produced flowback from this production method.</td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4"><u>Enhanced storage options for flowback and wastewater</u> such as cost effective double containment saline water storage options.
<u>Enhanced leak detection methods for flowback and wastewater</u> such as leak detection for hydraulic fracturing, and implementing leak detection methodologies prior to storage water contacting ground and surface water.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td>Piloting and demonstration
TRL 7-8</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="4">Managing Sulphate and NORMs</td></tr>
<tr><td>Technology Area:</td><td colspan="4">Water Management and Treatment</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">Evaluation of cost effective technologies for removal of sulphate from source waters and research on NORM removal methods for flowback and produced water treatment applications. During hydraulic fracturing, flowback is the part of the process that brings contaminants to the surface. Removal of these contaminants is a necessary step in mitigating contamination caused by this production method.</td></tr>
<tr><td>Impact</td><td colspan="4">Validation of sulphate removal methods from source waters and improved understanding of NORM removal methods for flowback and produced water treatment applications to improve on site performance and potentially lead to impactful research findings.
<table>
<tr><th colspan="3">Rating</th></tr>
<tr><td>High</td><td>Medium</td><td>Low</td></tr>
</table></td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="4">Challenges and interpretations associated with the impact of sulphate and NORMs tend to be underestimated and the importance of sulphates is expected to shift significantly as the reuse of flowback becomes more common in hydraulic fracturing operations. There may be more economical approaches for effective sulphate treatment that haven’t been identified yet.
<table>
<tr><th colspan="3">Rating</th></tr>
<tr><td>High</td><td>Medium</td><td>Low</td></tr>
</table></td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">1. New technologies to improve the effectiveness of existing sulphate removal methods for cost effective treatment of flowback and produced water.
2. New technologies to improve the effectiveness of NORM removal methods for flowback and produced water treatment applications.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td>Piloting and demonstration
TRL 7-8</td></tr>
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<table>
<tr><td>Gap Title:</td><td colspan="4">Disposal Well Management</td></tr>
<tr><td>Technology Area:</td><td colspan="4">Water Management and Treatment</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">Development of guidelines and a Risk Assessment Tool for disposal well management based on water compatibilities. In hydraulic fracturing operations, the reuse of flowback or produced water is not always an option and there is a need to have effective tools in place to help operators deal with the need for proper disposal when it arises.</td></tr>
<tr><td>Impact</td><td colspan="4">Better procedures and tools in place to assist operators with disposal well management based on water compatibilities.<table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table></td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="4">Many operators currently rely on trucking to transport wastewater to disposal wells at offsite facilities and sometimes extended wait times to deposit the wastewater may occur leading to increased disposal costs and liabilities associated with trucking of the wastewater.<table><tr><th colspan="3">Rating</th></tr><tr><td>High</td><td>Medium</td><td>Low</td></tr></table></td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4"><u>Development of improved disposal well management procedures and tools</u> based on water compatibilities to manage risk, optimize operations and extend well life.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td>Piloting and demonstration
TRL 7-8</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="5">Availability of Water Samples</td></tr>
<tr><td>Technology Area:</td><td colspan="5">Water Management and Treatment</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="5">There is a need to create a more efficient way for technology providers to obtain water samples for technology testing by developing a centralized facility with involvement from multiple operators. Currently, it is difficult for technology providers to obtain samples for testing technologies related to water management, which delays the progression of new technologies for industry use. One option could be a “water bank” or cooperative network which shares data and samples.</td></tr>
<tr><td rowspan="2">Impact</td><td rowspan="2" colspan="2">Creation of a centralized facility used for distributing water samples would advance water management technology development by providing the necessary testing materials that innovators need.</td><td colspan="3">Rating</td></tr>
<tr><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td rowspan="2">Current Level of Innovation Activity</td><td rowspan="2" colspan="2">There is currently no centralized facility or sophisticated method used for the distribution of water samples.</td><td colspan="3">Rating</td></tr>
<tr><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="5"><u>Development of a centralized facility for flowback water samples</u> with involvement from multiple operators for accessible distribution of samples to technology providers.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td colspan="2">Piloting and demonstration
TRL 7-8</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="4">Saline Storage and Transport</td></tr>
<tr><td>Technology Area:</td><td colspan="4">Water Management and Treatment</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">The water volumes that must be stored and transported are strongly dependent on the type of completions fluid used and logistics. Reuse of flowback and produced water is perceived as favourable. However, the water demand requirements present logistical challenges for transport and storage. In addition, flowback and produced water transport and storage requirements include the same considerations as highly saline water with the potential presence for contaminants including hydrocarbons, bacteria, volatile organic compounds, polyaromatic hydrocarbons, hydrogen sulfide, suspended solids, and NORMs.</td></tr>
<tr><td rowspan="2">Impact</td><td rowspan="2">Best practices for water storage and transport would allow opportunities where water reuse may be shared by more than one operator or from more than one facility at water hubs.</td><td colspan="3">Rating</td></tr>
<tr><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td rowspan="2">Current Level of Innovation Activity</td><td rowspan="2">There are currently some localized efforts at standardization and best practices.</td><td colspan="3">Rating</td></tr>
<tr><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">1. Best practices for water storage and transport of flowback and produced waters, taking into account the potential presence of bacteria, NORMs and hydrocarbons.
2. Best practices for cases where water reuse may be shared by more than one operator or from more than one facility at water hubs to improve industry-wide efficiency and reduce overall environmental impact.
3. Best practices for managing bacterial growth in surface storage to improve water quality and reliability.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td>Piloting and demonstration
TRL 7-8</td></tr>
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<table>
<tr><td>Gap Title:</td><td colspan="4">Fuel Consumption During Production</td></tr>
<tr><td>Technology Area:</td><td colspan="4">GHG and Air Emissions Management</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">There is a need for industry to develop energy efficient processes and equipment for fuel consumption at upstream oil and gas facilities to reduce emissions from operating activities. In particular, efficiency initiatives aimed towards improved combustion control devices is needed to reduce energy consumption and emissions.</td></tr>
<tr><td>Impact</td><td colspan="4">Reduction of energy consumption, emissions, and improvement of efficiency and potentially production of facilities.
Rating
High | Medium | Low</td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="4">Emissions reduction, particularly methane emissions reduction, is a top priority of the Alberta government and thus, industry has responded by completing research and technology initiatives to meet the need for innovation.
Rating
High | Medium | Low</td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">1. Energy efficiency best practices in upstream facilities, such as energy efficient buildings, processes and equipment to minimize fuel consumption at upstream oil and gas facilities
2. Combustion control and efficiency best practices for optimal operation of combustion control devices to reduce energy consumption and emissions, improve efficiency, and potentially improve production of facilities.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td>Piloting and demonstration
TRL 7-8</td></tr>
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<table>
<tr><td>Gap Title:</td><td colspan="4">Alternatives to Pneumatic Equipment</td></tr>
<tr><td>Technology Area:</td><td colspan="4">GHG and Air Emissions Management</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">There is a need to look into alternatives to pneumatic venting devices to determine if options are available with improved reliability, robustness, security and cost effectiveness.</td></tr>
<tr><td>Impact</td><td colspan="4">Improved security of solar panels would reduce equipment theft on operational sites. Increased reliability and lower costs of alternative technologies would increase deployment by operators, therefore benefiting the environment.
Rating
High [✓ Medium] Low</td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="4">Alternatives to pneumatic equipment are available (particularly based on solar electricity) and are constantly being improved by technology developers.
Rating
High [✓ Medium] Low</td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">1. <u>Solar powered instrument air systems</u> with improved reliability and reduced costs
2. <u>Solar powered electric controls and equipment</u> with improved reliability and reduced costs
3. <u>Solar panels with lower costs and improved theft prevention</u>, to enhance accessibility and reliability
4. <u>Capture and utilization of low pressure and low flow rate gas from gas powered systems</u>, such as thermoelectric generators and catalytic converters.
5. <u>Detection and monitoring sensors</u> with lower operating costs and improved accuracy and precision</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>[✓ Technology Development
TRL 4-6]</td><td>[✓ Piloting and demonstration
TRL 7-8]</td></tr>
</table>

<table>
<tr><td>Gap Title:</td><td colspan="4">Completion Venting / Flaring</td></tr>
<tr><td>Technology Area:</td><td colspan="4">GHG and Air Emissions Management</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">During the completion process, it’s important to properly handle flowback from production. Thus, there is a need to develop pipeline infrastructure in areas lacking the equipment required to receive flowback fluids. There is also currently a lack of appropriate equipment available to process flowback gas. Additionally, identifying cost effective technologies for the removal of N_2 and CO_2 flowback fluids should be a priority as it would allow flowback to be produced in-line.</td></tr>
<tr><td rowspan="2">Impact</td><td rowspan="2">Ability to receive and process flowback fluids and remove N_2 and CO_2 to allow flowback to be produced in-line.</td><td colspan="3">Rating</td></tr>
<tr><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td rowspan="2">Current Level of Innovation Activity</td><td rowspan="2">There are sites that currently have pipeline infrastructure installed to handle produced flowback; However, it is recognized that many locations do not have the necessary equipment to handle flowback fluids. Similarly, methods for N_2 and CO_2 removal exist and are used in industry, but there is a need for continued research to find the most cost effective technologies to carry out this process.</td><td colspan="3">Rating</td></tr>
<tr><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">1. Mobile equipment to capture and utilize produced gas with lower cost at smaller scale for temporary service until production operations are fully in place
2. Separation technologies for removing N_2 and CO_2 from flowback gas to allow the non-condensable gas to be re-used in-line and the methane to be produced.
3. Gas sweetening technologies, at smaller scale and lower cost to allow the onsite processing of produced sour gas
4. Studies of pipeline access logistics and costs, to optimize the construction of pipeline infrastructure.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td>Piloting and demonstration
TRL 7-8</td></tr>
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<table>
<tr><td>Gap Title:</td><td colspan="4">Completion Operations</td></tr>
<tr><td>Technology Area:</td><td colspan="4">GHG and Air Emissions Management</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">Hydraulic fracturing completion operations require energetically intense equipment and fuels for the process to successfully run. Thus, there is a need to identify more sufficient fuels and power supply options for these operations. Furthermore, the operability of equipment on the sites of completions operations will vary based on fluctuating/cold weather in Canada. Therefore, there is a need to address challenges related to these weather fluctuations and to search for alternative energy sources to overcome the challenges of fuel economics.</td></tr>
<tr><td rowspan="2">Impact</td><td rowspan="2">Sufficient fuels and power supply options for hydraulic fracturing operations, dealing with operability challenges related to fluctuating/cold weather.</td><td colspan="3">Rating</td></tr>
<tr><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td rowspan="2">Current Level of Innovation Activity</td><td rowspan="2">Historically, hydraulic fracturing is a relatively new method of production being used in industry and thus there is room for new technologies with respect to fuel and power supply options and economic assessments.</td><td colspan="3">Rating</td></tr>
<tr><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">1. Fuel switching for hydraulic fracturing operations to identify the best fuels and power supply options to minimize the use of diesel while controlling costs.
2. Practices to address cold and fluctuating weather impacts on equipment functionality to provide for energy efficient operations in cold weather.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>Technology Development
TRL 4-6</td><td colspan="2">Piloting and demonstration
TRL 7-8</td></tr>
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<table>
<tr><td>Gap Title:</td><td colspan="4">Flaring During Production</td></tr>
<tr><td>Technology Area:</td><td colspan="4">GHG and Air Emissions Management</td></tr>
<tr><td>Description of Need or Challenge</td><td colspan="4">The production trends for hydraulic fracturing tend to have a high decline rate, which causes a need for proper sizing and utilization of equipment. Gas quality issues for direct use in onsite equipment must be overcome by assessing available methods to address them.</td></tr>
<tr><td>Impact</td><td colspan="2">Compatible equipment to match rapid production decline over time and improvement of operational efficiency by addressing gas quality issues.</td><td colspan="2">Rating
High [✓ Medium] Low</td></tr>
<tr><td>Current Level of Innovation Activity</td><td colspan="2">Flaring is a regulatory priority and there are many requirements and technologies that attempt to reduce flaring during production; However, flaring specific to hydraulic fracturing has not been focused on as much as flaring at conventional sites and therefore allows room for improvement on the current methods.</td><td colspan="2">Rating
High Medium [✓ Low]</td></tr>
<tr><td>Description of the Research/ Technology Opportunity</td><td colspan="4">1. Mobile units that can be relocated easily to allow correct production equipment sizing to maintain energy efficiency in the context of a rapid production decline curve.
2. Technologies to allow onsite direct use of produced gas to fuel onsite equipment, in order to minimize use of other fuels such as propane and diesel.</td></tr>
<tr><td>Technology Readiness Level (TRL)</td><td>Characterization studies, analysis, and best practices</td><td>Research
TRL 1-3</td><td>[✓ Technology Development
TRL 4-6]</td><td>[✓ Piloting and demonstration
TRL 7-8]</td></tr>
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