Independent Statistics & Analysis
U.S. Energy Information Administration

# Technically Recoverable Shale Oil and Shale Gas Resources:

## Canada

September 2015

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# Executive Summary

## Introduction

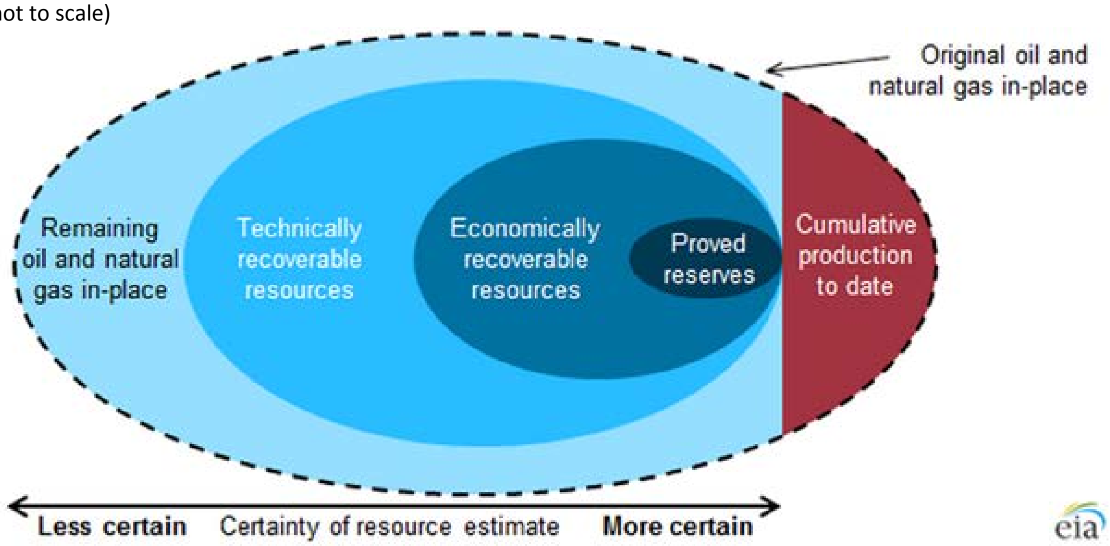
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically recoverable oil and natural gas resources. This chapter is from the 2013 EIA world shale report Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States.

## Resource categories

When considering the market implications of abundant shale resources, it is important to distinguish between a technically recoverable resource, which is the focus of this supplement as in the 2013 report, and an economically recoverable resource. Technically recoverable resources represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Economically recoverable resources are resources that can be profitably produced under current market conditions. The economic recoverability of oil and gas resources depends on three factors: the costs of drilling and completing wells, the amount of oil or natural gas produced from an average well over its lifetime, and the prices received for oil and gas production. Recent experience with shale gas and tight oil in the United States and other countries suggests that economic recoverability can be significantly influenced by above-the-ground factors as well as by geology. Key positive above-the-ground advantages in the United States and Canada that may not apply in other locations include private ownership of subsurface rights that provide a strong incentive for development; availability of many independent operators and supporting contractors with critical expertise and suitable drilling rigs and, preexisting gathering and pipeline infrastructure; and the availability of water resources for use in hydraulic fracturing. See Figure 1.

**Figure 1. Stylized representation of oil and natural gas resource categorizations**

(not to scale)




Source: U.S. Energy Information Administration
Note: Resource categories are not drawn to scale relative to the actual size of each resource category. The graphic shown above is applicable only to oil and natural gas resources.

Crude oil and natural gas resources are the estimated oil and natural gas volumes that might be produced at some time in the future. The volumes of oil and natural gas that ultimately will be produced cannot be known ahead of time. Resource estimates change as extraction technologies improve, as markets evolve, and as oil and natural gas are produced. Consequently, the oil and gas industry, researchers, and government agencies spend considerable time and effort defining and quantifying oil and natural gas resources.

For many purposes, oil and natural gas resources are usefully classified into four categories:

- Remaining oil and gas in-place (original oil and gas in-place minus cumulative production at a specific date)
- Technically recoverable resources
- Economically recoverable resources
- Proved reserves

The oil and natural gas volumes reported for each resource category are estimates based on a combination of facts and assumptions regarding the geophysical characteristics of the rocks, the fluids trapped within those rocks, the capability of extraction technologies, and the prices received and costs paid to produce oil and natural gas. The uncertainty in estimated volumes declines across the resource categories (see figure above) based on the relative mix of facts and assumptions used to create these resource estimates. Oil and gas in-place estimates are based on fewer facts and more assumptions, while proved reserves are based mostly on facts and fewer assumptions.

**Remaining oil and natural gas in-place (original oil and gas in-place minus cumulative production)**. The volume of oil and natural gas within a formation before the start of production is the original oil and gas in-place. As oil and natural gas are produced, the volumes that remain trapped within the rocks are the remaining oil and gas in-place, which has the largest volume and is the most uncertain of the four resource categories.

**Technically recoverable resources.** The next largest volume resource category is technically recoverable resources, which includes all the oil and gas that can be produced based on current technology, industry practice, and geologic knowledge. As technology develops, as industry practices improve, and as the understanding of the geology increases, the estimated volumes of technically recoverable resources also expand.

The geophysical characteristics of the rock (e.g., resistance to fluid flow) and the physical properties of the hydrocarbons (e.g., viscosity) prevent oil and gas extraction technology from producing 100% of the original oil and gas in-place.

**Economically recoverable resources.** The portion of technically recoverable resources that can be profitably produced is called economically recoverable oil and gas resources. The volume of economically recoverable resources is determined by both oil and natural gas prices and by the capital and operating costs that would be incurred during production. As oil and gas prices increase or decrease, the volume of the economically recoverable resources increases or decreases, respectively. Similarly, increasing or decreasing capital and operating costs result in economically recoverable resource volumes shrinking or growing.

U.S. government agencies, including EIA, report estimates of technically recoverable resources (rather than economically recoverable resources) because any particular estimate of economically recoverable resources is tied to a specific set of prices and costs. This makes it difficult to compare estimates made by other parties using different price and cost assumptions. Also, because prices and costs can change over relatively short periods, an estimate of economically recoverable resources that is based on the prevailing prices and costs at a particular time can quickly become obsolete.

**Proved reserves.** The most certain oil and gas resource category, but with the smallest volume, is proved oil and gas reserves. Proved reserves are volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves generally increase when new production wells are drilled and decrease when existing wells are produced. Like economically recoverable resources, proved reserves shrink or grow as prices and costs change. The U.S. Securities and Exchange Commission regulates the reporting of company financial assets, including those proved oil and gas reserve assets reported by public oil and gas companies.

Each year EIA updates its report of proved U.S. oil and natural gas reserves and its estimates of unproved technically recoverable resources for shale gas, tight gas, and tight oil resources. These reserve and resource estimates are used in developing EIA's Annual Energy Outlook projections for oil and natural gas production.

- Proved oil and gas reserves are reported in EIA's U.S. Crude Oil and Natural Gas Proved Reserves.
- Unproved technically recoverable oil and gas resource estimates are reported in EIA's Assumptions report of the Annual Energy Outlook. Unproved technically recoverable oil and gas resources equal total technically recoverable resources minus the proved oil and gas reserves.

Over time, oil and natural gas resource volumes are reclassified, going from one resource category into another category, as production technology develops and markets evolve.

Additional information regarding oil and natural gas resource categorization is available from the Society of Petroleum Engineers and the United Nations.

## Methodology

The shale formations assessed in this supplement as in the previous report were selected for a combination of factors that included the availability of data, country-level natural gas import dependence, observed large shale formations, and observations of activities by companies and governments directed at shale resource development. Shale formations were excluded from the analysis if one of the following conditions is true: (1) the geophysical characteristics of the shale formation are unknown; (2) the average total carbon content is less than 2 percent; (3) the vertical depth is less than 1,000 meters (3,300 feet) or greater than 5,000 meters (16,500 feet), or (4) relatively large undeveloped oil or natural gas resources.

The consultant relied on publicly available data from technical literature and studies on each of the selected international shale gas formations to first provide an estimate of the "risked oil and natural gas in-place," and then to estimate the unproved technically recoverable oil and natural gas resource for that shale formation. This methodology is intended to make the best use of sometimes scant data in order to perform initial assessments of this type.

The risked oil and natural gas in-place estimates are derived by first estimating the volume of in-place resources for a prospective formation within a basin, and then factoring in the formation's success factor and recovery factor. The success factor represents the probability that a portion of the formation is expected to have attractive oil and natural gas flow rates. The recovery factor takes into consideration the capability of current technology to produce oil and natural gas from formations with similar geophysical characteristics. Foreign shale oil recovery rates are developed by matching a shale formation's geophysical characteristics to U.S. shale oil analogs. The resulting estimate is referred to as both the risked oil and natural gas in-place and the technically recoverable resource. The specific tasks carried out to implement the assessment include:

1. Conduct a preliminary review of the basin and select the shale formations to be assessed.

2. Determine the areal extent of the shale formations within the basin and estimate its overall thickness, in addition to other parameters.
3. Determine the prospective area deemed likely to be suitable for development based on depth, rock quality, and application of expert judgment.
4. Estimate the natural gas in-place as a combination of *free gas*[1] and *adsorbed gas*[2] that is contained within the prospective area. Estimate the oil in-place based on pore space oil volumes.
5. Establish and apply a composite success factor made up of two parts. The first part is a formation success probability factor that takes into account the results from current shale oil and shale gas activity as an indicator of how much is known or unknown about the shale formation. The second part is a prospective area success factor that takes into account a set of factors (e.g., geologic complexity and lack of access) that could limit portions of the prospective area from development.
6. For shale oil, identify those U.S. shales that best match the geophysical characteristics of the foreign shale oil formation to estimate the oil in-place recovery factor.[3] For shale gas, determine the recovery factor based on geologic complexity, pore size, formation pressure, and clay content, the latter of which determines a formation's ability to be hydraulically fractured. The gas phase of each formation includes dry natural gas, associated natural gas, or wet natural gas. Therefore, estimates of shale gas resources in this report implicitly include the light wet hydrocarbons that are typically coproduced with natural gas.
7. Technically recoverable resources[4] represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Technically recoverable resources are determined by multiplying the risked in-place oil or natural gas by a recovery factor.

Based on U.S. shale production experience, the recovery factors used in this supplement as in the previous report for shale gas generally ranged from 20 percent to 30 percent, with values as low as 15 percent and as high as 35 percent being applied in exceptional cases. Because of oil's viscosity and capillary forces, oil does not flow through rock fractures as easily as natural gas. Consequently, the recovery factors for shale oil are typically lower than they are for shale gas, ranging from 3 percent to 7 percent of the oil in-place with exceptional cases being as high as 10 percent or as low as 1 percent. The consultant selected the recovery factor based on U.S. shale production recovery rates, given a range of factors including mineralogy, geologic complexity, and a number of other factors that affect the response of the geologic formation to the application of best practice shale gas recovery technology. Because most shale oil and shale gas wells are only a few years old, there is still considerable uncertainty as to the expected life of U.S. shale wells and their ultimate recovery. The recovery rates used in this analysis are based on an extrapolation of shale well production over 30 years. Because a shale's geophysical characteristics vary significantly throughout the formation and analog matching is never exact, a shale formation's resource potential cannot be fully determined until extensive well production tests are conducted across the formation.

## Key exclusions

In addition to the key distinction between technically recoverable resources and economically recoverable resources that has been already discussed at some length, there are a number of additional factors outside of the scope of this report that must be considered in using its findings as a basis for projections of future

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[1] Free gas is natural gas that is trapped in the pore spaces of the shale. Free gas can be the dominant source of natural gas for the deeper shales.

[2] Adsorbed gas is natural gas that adheres to the surface of the shale, primarily the organic matter of the shale, due to the forces of the chemical bonds in both the substrate and the natural gas that cause them to attract. Adsorbed gas can be the dominant source of natural gas for the shallower and higher organically rich shales.

[3] The recovery factor pertains to percent of the original oil or natural gas in-place that is produced over the life of a production well.

[4] Referred to as risked recoverable resources in the consultant report.

production. In addition, several other exclusions were made for this supplement as in the previous report to simplify how the assessments were made and to keep the work to a level consistent with the available funding.

Some of the key exclusions for this supplement as in the previous report include:

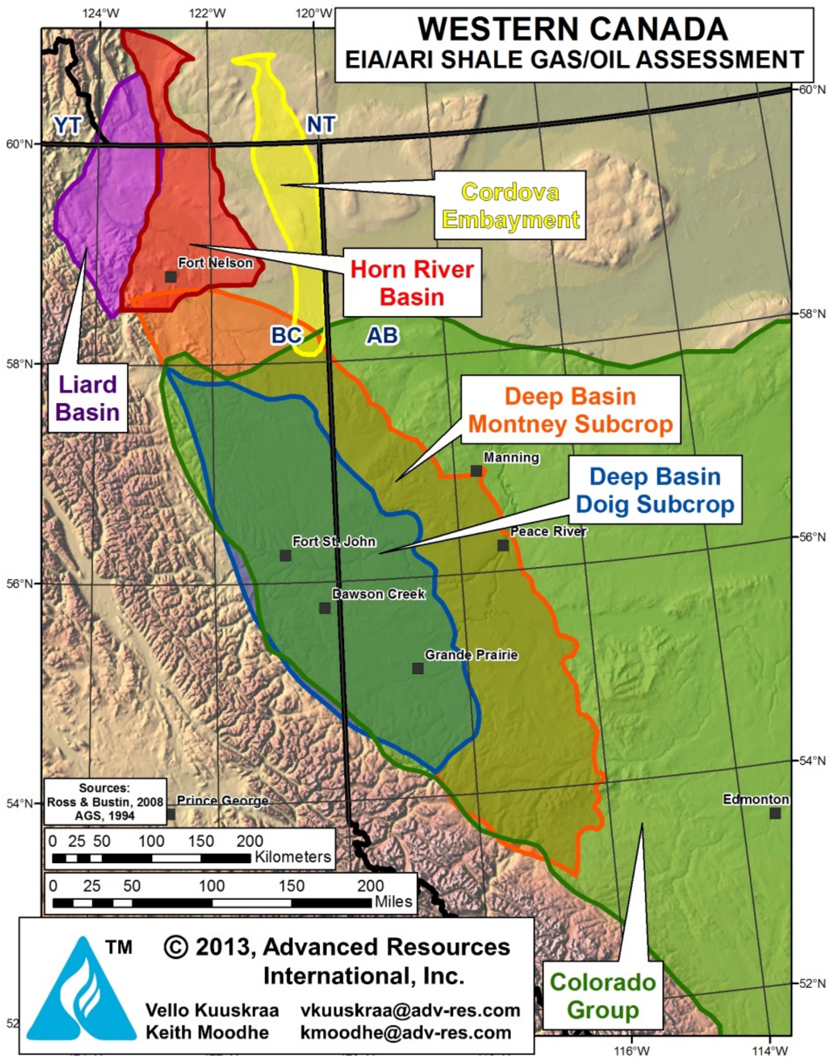
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas resources that may exist within these countries were also excluded from the assessment.
3. **Assessed formations without a resource estimate**, which resulted when data were judged to be inadequate to provide a useful estimate. Including additional shale formations would likely increase the estimated resource.
4. **Countries outside the scope of the report**, the inclusion of which would likely add to estimated resources in shale formations.  It is acknowledged that potentially productive shales exist in most of the countries in the Middle East and the Caspian region, including those holding substantial non-shale oil and natural gas resources.
5. **Offshore portions of assessed shale oil** and shale gas formations were excluded, as were shale oil and shale gas formations situated entirely offshore.

# I. CANADA

## SUMMARY

Canada has a series of large hydrocarbon basins with thick, organic-rich shales that are assessed by this resource study. Figure I-1 illustrates certain of the major shale gas and shale oil basins in Western Canada.

Figure I-1. Selected Shale Gas and Oil Basins of Western Canada




Source: ARI, 2012.

The full set of Canadian shale gas and shale oil basins assessed in this study include: (1) the Horn River Basin, the Cordova Embayment and the Liard Basin (located in British Columbia and the Northwest Territories) plus the Doig Phosphate Shale (located in both British Columbia and Alberta); (2) the numerous shale gas and shale oil formations and plays in Alberta, such as the Banff/Exshaw, the Duvernay, the Nordegg, the Muskwa and the Colorado Group; (3) the Williston Basin's Bakken Shale in Saskatchewan and Manitoba; and (4) the Utica Shale in Quebec and the Horton Bluff Shale in Nova Scotia.

Western Canada also contains the prolific and areally extensive Montney and Doig Resource Plays (in both British Columbia and Alberta) categorized primarily as tight sand and siltstone reservoirs. As thus, these two important unconventional gas resources are not included in this shale gas and shale oil resource assessment. In addition, Canada has a series of additional hydrocarbon-bearing siltstone and shale formations that are not included in the quantitative portion of this resource study either because of low organic content (Wilrich Shale in Alberta) or because of limited information (Frederick Brook Shale in New Brunswick).

We estimate risked shale gas in-place for Canada of 2,413 Tcf, with 573 Tcf as the risked, technically recoverable shale gas resource. In addition, we estimate risked shale oil in-place for Canada of 162 billion barrels, with 8.8 billion barrels as the risked, technically recoverable shale oil resource. Table I-1 provides a more in-depth, regional tabulation of Canada's shale gas and oil resources.

As new drilling occurs and more detailed information is obtained on these large, emerging shale plays, the estimates of the size of their in-place resources and their recoverability will undoubtedly change.

Table I-1. Shale Gas and Oil Resources of Canada

| Region | Basin / Formation | Risked Resource In-Place | | Risked Technically Recoverable Resource | |
|---|---|---|---|---|---|
| | | Oil/Condensate (Million bbl) | Natural Gas (Tcf) | Oil/Condensate (Million bbl) | Natural Gas (Tcf) |
| **British Columbia / Northwest Territories** | Horn River (Muskwa / Otter Park) | - | 375.7 | - | 93.9 |
| | Horn River (Evie / Klua) | - | 154.2 | - | 38.5 |
| | Cordova (Muskwa / Otter Park) | - | 81.0 | - | 20.3 |
| | Liard (Lower Besa River) | - | 526.3 | - | 157.9 |
| | Deep (Doig Phosphate) | - | 100.7 | - | 25.2 |
| | Sub-Total | **-** | **1,237.8** | **-** | **335.8** |
| **Alberta** | Alberta (Banff / Exshaw) | 10,500 | 5.1 | 320 | 0.3 |
| | E/W Shale (Duvernay) | 66,800 | 482.6 | 4,010 | 113.0 |
| | Deep Basin (Nordegg) | 19,800 | 72.0 | 790 | 13.3 |
| | N.W. Alberta (Muskwa) | 42,400 | 141.7 | 2,120 | 31.1 |
| | S. Alberta (Colorado) | - | 285.6 | - | 42.8 |
| | Sub-Total | **139,500** | **987.1** | **7,240** | **200.5** |
| **Saskatchewan / Manitoba** | Williston (Bakken) | **22,500** | **16.0** | **1,600** | **2.2** |
| **Quebec** | App. Fold Belt (Utica) | **-** | **155.3** | **-** | **31.1** |
| **Nova Scotia** | Windsor (Horton Bluff) | **-** | **17.0** | **-** | **3.4** |
| | **Total** | **162,000** | **2,413.2** | **8,840** | **572.9** |

*Less than 0.5 Tcf

# BRITISH COLUMBIA/NORTHWEST TERRITORIES

British Columbia (BC) and the Northwest Territories (NWT) hold three "world-scale" shale basins, the Horn River Basin, the Cordova Embayment and the Liard Basin. In addition, the organic-rich Doig Phosphate Shale exists on each side of the central Alberta and BC border. In addition to these shale resources, British Columbia also has portions of the massive tight sand and siltstone Montney Resource and Doig Resource plays. These two low organic content formations, classified as tight sands by Canada's National Energy Board, are not included in this shale gas and oil resource assessment.

This resource assessment study has benefitted greatly from the extensive geological and reservoir characterization work supported by the BC Ministry of Energy and Mines on the shale basins and formations of British Columbia.[1,2] In addition, this study has drawn on the extensive well drilling and well performance information provided by Canada's oil and gas industry. These two information sources serve as foundations for the assessment of the shale gas and oil resources of British Columbia and the Northwest Territories. The four BC/NWT shale oil and gas basins assessed by this study contain 1,238 Tcf of risked shale gas in-place, with 336 Tcf as the risked, technically recoverable shale gas resource, Table I-2.

Table I-2. Shale Gas Reservoir Properties and Resources of British Columbia/NWT

| | | | Horn River ($7{,}100\ mi^2$) | | Cordova ($4{,}290\ mi^2$) | Liard ($4{,}300\ mi^2$) | Deep Basin ($24{,}800\ mi^2$) |
|---|---|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | Horn River ($7{,}100\ mi^2$) | | Cordova ($4{,}290\ mi^2$) | Liard ($4{,}300\ mi^2$) | Deep Basin ($24{,}800\ mi^2$) |
| | Shale Formation | | Muskwa/Otter Park | Evie/Klua | Muskwa/Otter Park | Lower Besa River | Doig Phosphate |
| | Geologic Age | | Devonian | Devonian | Devonian | Devonian | Triassic |
| | Depositional Environment | | Marine | Marine | Marine | Marine | Marine |
| Physical Extent | Prospective Area ($mi^2$) | | 3,320 | 3,320 | 2,000 | 3,300 | 3,000 |
| | Thickness (ft) | Organically Rich | 420 | 160 | 230 | 500 | 165 |
| | | Net | 380 | 144 | 207 | 400 | 150 |
| | Depth (ft) | Interval | 6,300 - 10,200 | 6,800 - 10,700 | 5,500 - 6,200 | 6,600 - 13,000 | 6,800 - 10,900 |
| | | Average | 8,000 | 8,500 | 6,000 | 10,000 | 9,250 |
| Reservoir Properties | Reservoir Pressure | | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. | Highly Overpress. | Mod. Overpress. |
| | Average TOC (wt. %) | | 3.5% | 4.5% | 2.0% | 3.5% | 5.0% |
| | Thermal Maturity (% Ro) | | 3.50% | 3.80% | 2.50% | 3.80% | 1.10% |
| | Clay Content | | Low | Low | Low | Low | Low |
| Resource | Gas Phase | | Dry Gas | Dry Gas | Dry Gas | Dry Gas | Dry Gas |
| | GIP Concentration ($Bcf/mi^2$) | | 150.9 | 61.9 | 67.5 | 319.0 | 67.1 |
| | Risked GIP (Tcf) | | 375.7 | 154.2 | 81.0 | 526.3 | 100.7 |
| | Risked Recoverable (Tcf) | | 93.9 | 38.5 | 20.3 | 157.9 | 25.2 |

# 1. HORN RIVER BASIN

## 1.1 Geologic Setting

The Horn River Basin covers an area of 7,100 $mi^2$ in northern British Columbia and the Northwest Territories, Figure I-2. The basin's western border is defined by the Bovie Fault, which separates the Horn River Basin from the Liard Basin. Its northern border, in Northwest Territories, is defined by the thinning of the shale section, and its southern border is constrained by the pinch-out of the shale. Its eastern border is defined by the Slave Point/Keg River Uplift and the thinning of the shale deposit. We have defined a higher quality, 3,320-$mi^2$ prospective area for the Horn River Shale in the west-central portion of the basin, Figure I-3.

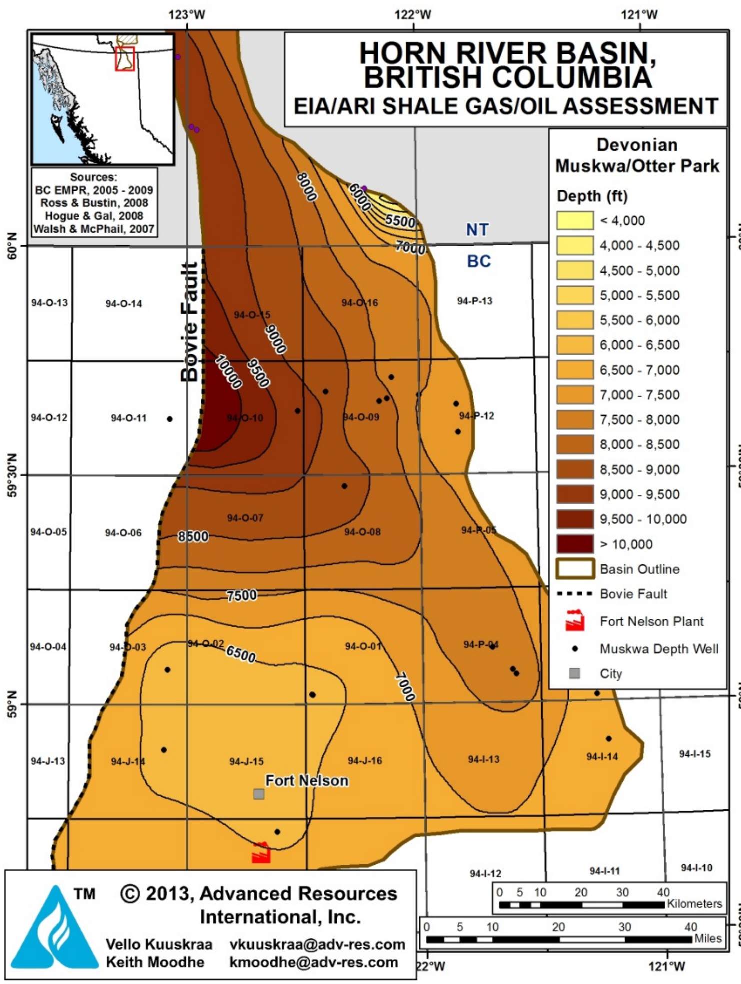
The Horn River Basin contains a series of organic-rich shales, with the Middle Devonian-age Muskwa/Otter Park and Evie/Klua most prominent, Figure I-4.[3] These two shale units were mapped in the Horn River Basin to establish a prospective area with sufficient thickness and resource concentration favorable for shale gas development. Other shales in this basin (but not included in the study) include the high organic-content, lower thermal maturity, poorly defined Mississippian Banff/Exshaw Shale and the thick, low organic-content Late Devonian Fort Simpson Shale.

## 1.2 Reservoir Properties (Prospective Area)

Two major shale gas formations, the Muskwa/Otter Park and the Evie/Klua, are included in the quantitative portion of our resource assessment.

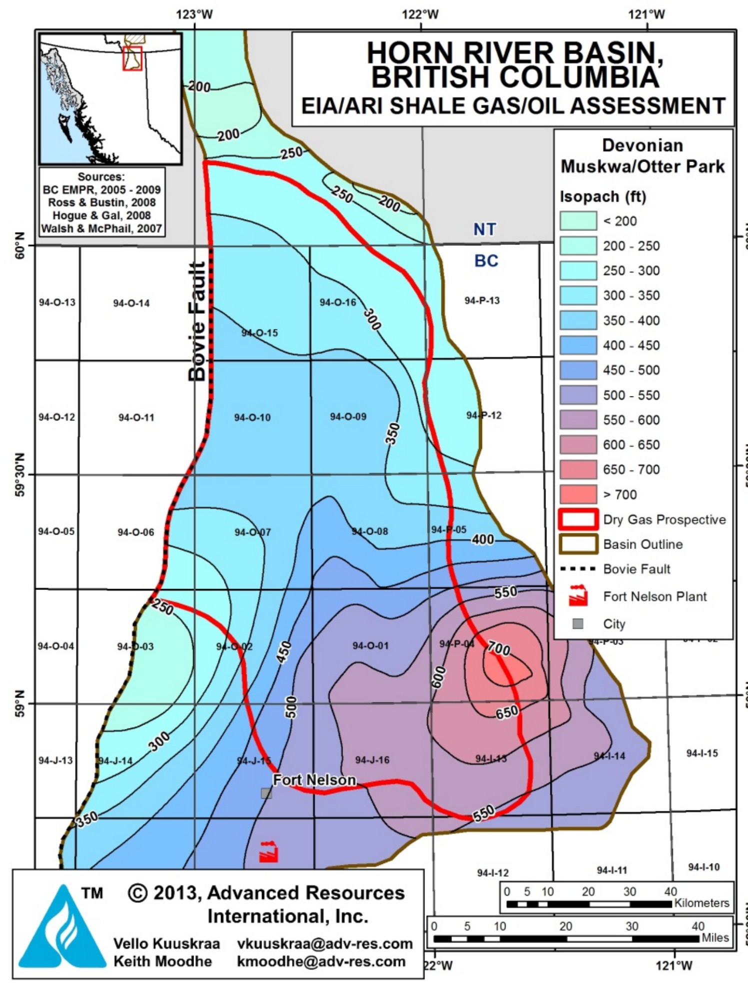
Muskwa/Otter Park. The Middle Devonian Muskwa/Otter Park Shale, the upper shale interval within the Horn River Group, is the main shale gas target in the Horn River Basin. Drilling depth to the top of the Muskwa/Otter Park Shale ranges from 6,300 to 10,200 feet, averaging 8,000 feet for the prospective area. The Muskwa/Otter Park Shale is moderately over-pressured in the center of the basin. With an organic-rich gross shale thickness of 420 feet, the Muskwa/Otter Park has a net pay of 380 feet. Total organic content (TOC) in the prospective area averages 3.5% for the net shale thickness investigated. Thermal maturity ($R_o$) is high, averaging about 3.5% and placing this shale gas in the dry gas window. Because of the high thermal maturity in the prospective area, the in-place shale gas has a $CO_2$ content of 11%. The Muskwa/Otter Park Shale has high quartz and low clay content.

Figure I-2. Horn River Basin (Muskwa/Otter Park Shale) Outline and Depth



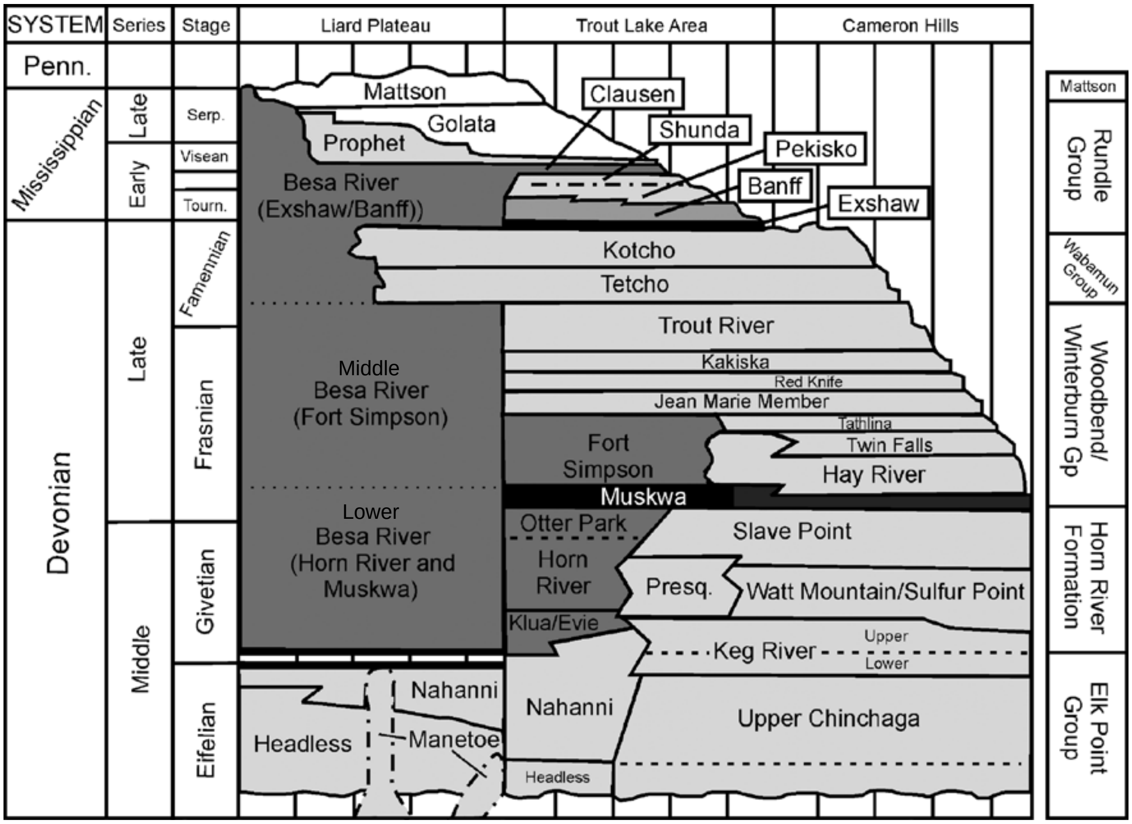

Source: ARI, 2013.

Figure I-3. Horn River Basin (Muskwa/Otter Park Shale) Isopach and Prospective Area




Source: ARI, 2013.

Figure I-4. NE British Columbia, Devonian and Mississippian Stratigraphy




Source: D. J. K. Ross and R. M. Bustin, AAPG Bulletin, v. 92, no. 1 (January 2008), pp. 87–125 JAF21300.AI

Evie/Klua. The Middle Devonian Evie/Klua Shale, the lower shale interval within the Horn River Group, provides a secondary shale gas target in the Horn River Basin. The top of the Evie/Klua Shale is approximately 500 feet below the top of the Muskwa/Otter Park Shale, separated by an organically-lean rock interval. The organic-rich Evie/Klua Shale, with an average TOC of 4.5%, has a thickness of about 160 feet (gross) and 144 feet (net). Thermal maturity ($R_o$) is high at about 3.8%, placing this shale gas in the dry gas window. The $CO_2$ content is estimated at 13%. The Evie/Klua Shale has a low clay content making the formation favorable for hydraulic stimulation.

Other Shales. The Horn River Basin also contains two shallower shales - - the Upper Devonian/Lower Mississippian Banff/Exshaw Shale and the Late Devonian Fort Simpson Shale. The Banff/Exshaw Shale, while rich in TOC (~5%) is relatively thin (10 to 30 feet). The massively thick Fort Simpson Shale, with a gross interval of 2,000 to 3,000 feet, is organically lean (TOC <1%). Because of these less favorable reservoir properties and limitations of data, these two shale units have not been included in the quantitative portion of the Horn River Basin shale resource assessment.

## 1.3 Resource Assessment

The prospective area for both the Horn River Muskwa/Otter Park Shale and the Evie/Klua Shale is approximately 3,320 mi$^2$.

Within this prospective area, the Horn River Muskwa/Otter Park Shale has a rich resource concentration of about 151 Bcf/mi$^2$ and a risked gas in-place is 376 Tcf, excluding $CO_2$. Based on favorable reservoir mineralogy and other properties, we estimate a risked, technically recoverable shale gas resource of 94 Tcf for the Muskwa/Otter Park Shale, Table I-2.

The thinner Evie/Klua Shale has a resource concentration of 62 Bcf/mi$^2$ and 154 Tcf of risked gas in-place, excluding $CO_2$. We estimate a risked, technically recoverable shale gas resource for the Evie/Klua Shale of 39 Tcf, Table I-2.

## 1.4 Comparison with Other Resource Assessments

In mid-2010, the Canadian Society for Unconventional Gas estimated 75 to 170 Tcf of marketable (recoverable after extraction of $CO_2$ and any NGLs) shale gas for the Horn River basin.[4] Subsequently, in 2011, the BC Ministry of Energy and Mines (BC MEM) and the National Energy Board (NEB) published an assessment for the shale gas resources of the Horn River Basin that identified 448 Tcf of gas in-place, with an expected marketable shale gas resource of 78 Tcf.[5]

We estimate a larger risked, technically recoverable shale gas resource of 133 Tcf for the two shale units assessed by this study, using a recovery factor of 25% of the shale gas resource in-place. Our recovery factor is consistent with the 25% recovery factor used by the BC Oil and Gas Commission in their 2011 hydrocarbon reserves report for the Horn River Basin.[6] The BC MEM/NEB Horn River Basin assessment report, with a lower 78 Tcf of marketable (recoverable) shale gas resource, implies a lower recovery factor of 17.4% of gas in-place. (The BC MEM/NEB assessment excluded $CO_2$ content and produced gas used as fuel from marketable shale gas.)

Consistent with the experience of shale gas development in the U.S., this study anticipates progressively increased efficiencies for shale gas recovery as industry optimizes its well completion and production practices. One example is Nexen's testing of advanced shale well completion methods in the Horn River Basin. These advanced methods are designed to increase EURs in the Horn River Basin shales from 11 Bcf/well to 16 Bcf/well.

## 1.5 Recent Activity

A number of major and independent companies are active in the Horn River Shale play, including Apache Canada, EnCana, EOG Resources, Nexen, Devon Canada, Quicksilver and others.

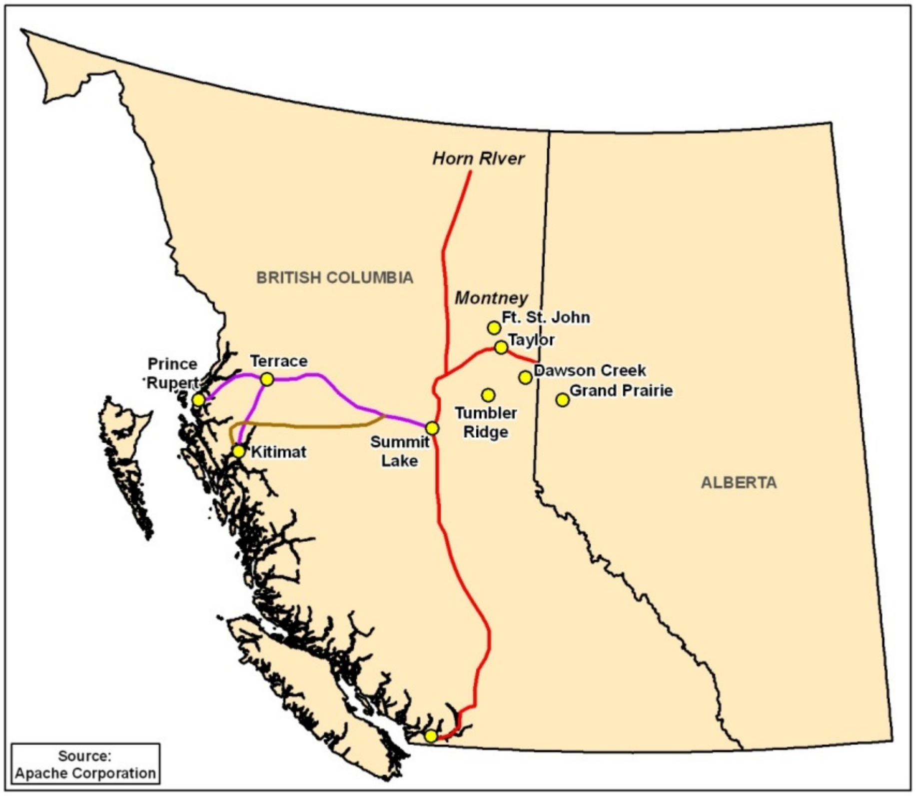
Apache Canada, the Horn River Basin's most active operator with 72 wells targeting shale gas in the basin, has full-scale development underway in the Two Island Lake area with net production of 90 million cubic feet per day (MMcfd). Apache estimates a net recoverable gas resource of 9.2 Tcf from its shale leases in the Horn River Basin. [7]

EnCana, with 68 long horizontal wells, produced a net 95 MMcfed in 2011 from its shale gas leases in the Horn River Basin. Devon, with 22 shale gas wells, is in the early stages of de-risking its 170,000 net acre lease position, which the company estimates contains nearly 10 Tcfe of net risked resource. EOG, with a 157,000 net acre lease position and 9 Tcf of potential recoverable resources, has drilled 35 shale gas wells and claims that the performance of its initial set of shale gas wells has met or exceeded expectations. Quicksilver has a 130,000 net acre lease position, 18 shale gas wells and a projected recoverable resource of over 10 Tcf. Nexen, with 90,000 acres, has drilled 42 horizontal wells and estimates 6 Tcf of recoverable resources from its lease area.[8]

Total natural gas production from the Horn River Basin was 382 MMcfd from 159 productive wells in 2011. In their 2010 report, the BC Oil and Gas Commission (BCOGC) estimated 10 Tcf of initial raw gas reserves from 40 Tcf of original gas in-place, equal to a 25% recovery factor. [8] In their 2011 report, the BCOGC increased the Horn River Shale initial recoverable raw gas reserves to 11.5 Tcf.

The gas processing and transportation capacity in the Horn River Basin is being expanded to provide improved market access for its growing shale gas production. Pipeline infrastructure is being expanded to bring the gas south to a series of proposed LNG export facilities. A 287-mile (480-km) Pacific Trail Pipeline is under construction to connect the Kitimat LNG export plant (due on line in 2017) with Spectra Energy's West Coast Pipeline System, Figure I-5. The Kitimat LNG terminal has an announced initial send-out capacity of 5 million tons of LNG per year (MTPA), expanding to 10 MTPA with a second train.

Figure I-5. Western Canada's LNG Export Pipelines and Infrastructure




TransCanada is proposing to build the 470-mile Prince Rupert Gas Transmission line with an initial capacity of 2 Bcfd (expandable to 3.6 Bcfd) to move Montney and Horn River gas to the Pacific Northwest LNG export terminal near Prince Rupert, BC. The planned in-service date is 2018. Earlier, TransCanada was selected by Shell Canada to build the 1.7 Bcfd Coastal GasLink Project, linking Horn River (and Montney) gas with Shell's planned 12 MTPA LNG export facility near Kitimat estimated to be in-service "toward the end of the decade".[9]

## 2. CORDOVA EMBAYMENT

### 2.1 Geologic Setting

The Cordova Embayment covers an area of 4,290 $mi^2$ in the extreme northeastern corner of British Columbia, extending into the Northwest Territories, Figure I-6. The Cordova Embayment is separated from the Horn River Basin on the west by the Slave Point Platform. The Embayment's northern and southern boundaries are defined by a thinning of the shale and its eastern boundary is the British Columbia and Alberta border. The dominant shale gas formation, the Muskwa/Otter Park Shale, was mapped to establish the 2,000-$mi^2$ prospective area, Figure I-7.

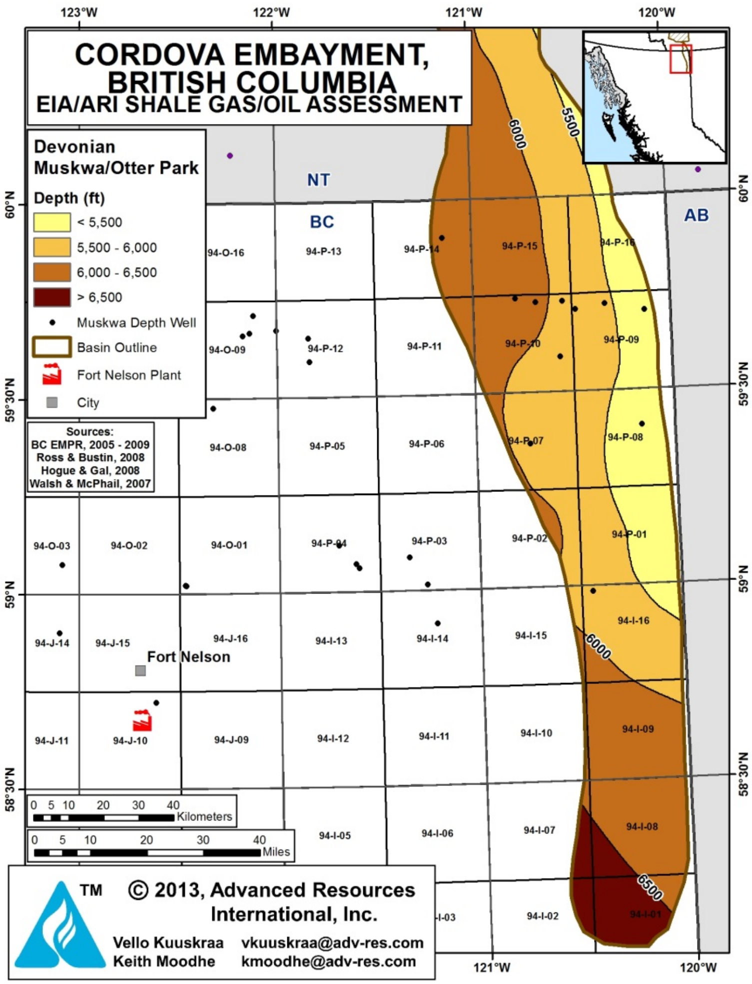
### 2.2 Reservoir Properties (Prospective Area)

One shale gas formation, the Muskwa/Otter Park, is included in the quantitative portion of our resource assessment.

Muskwa/Otter Park. The Middle Devonian Muskwa/Otter Park Shale is the main shale gas target in the Cordova Embayment. The drilling depth to the top of the Muskwa Shale in the prospective area ranges from 5,500 to 6,200 feet, averaging 6,000 feet. The reservoir is moderately over-pressured. The organic-rich gross thickness is 230 feet, with a net thickness of 207 feet. Total organic content (TOC) in the prospective area is 2.5% for the net shale thickness investigated. Thermal maturity averages 2.0% Ro, placing the shale in the dry gas window. The Muskwa/Otter Park Shale has a moderately high quartz content, favorable for hydraulic stimulation.

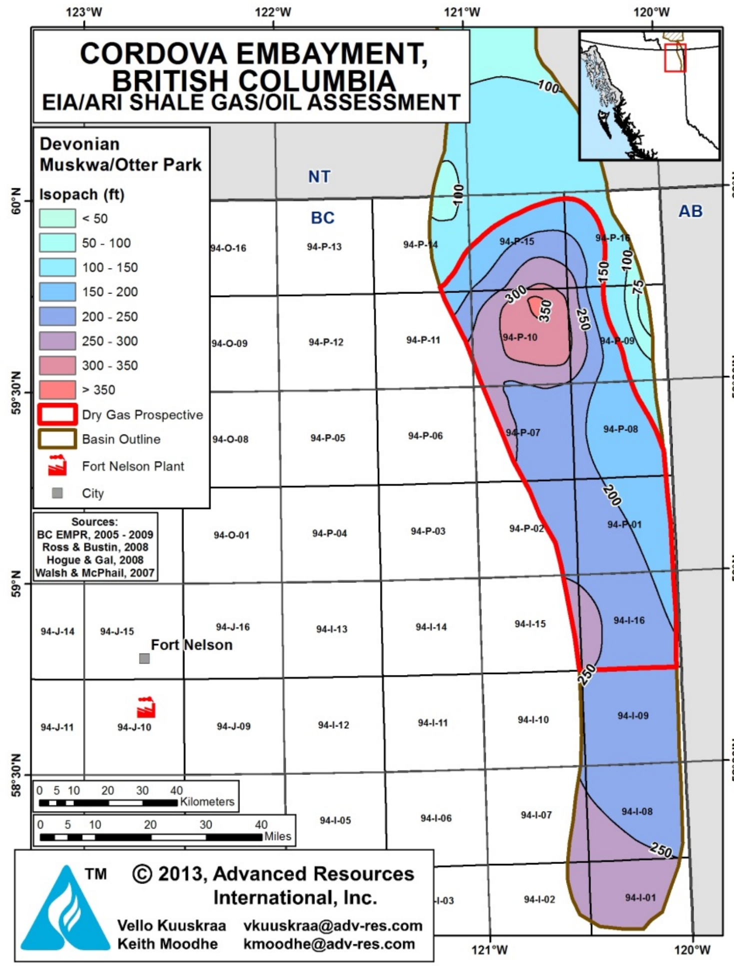
Other Shales. The deeper Evie/Klua Shale, separated from the overlying Muskwa/Otter Park by the Slave Point and Sulfur Point Formations, is thin, Figure I-8. The overlying Banff/Exshaw and Fort Simpson shales are shallower, thin and/or low in organics. These other shales have not been included in the quantitative portion of the Cordova Embayment resource assessment.

Figure I-6. Cordova Embayment (Muskwa/Otter Park Shale) Outline and Depth



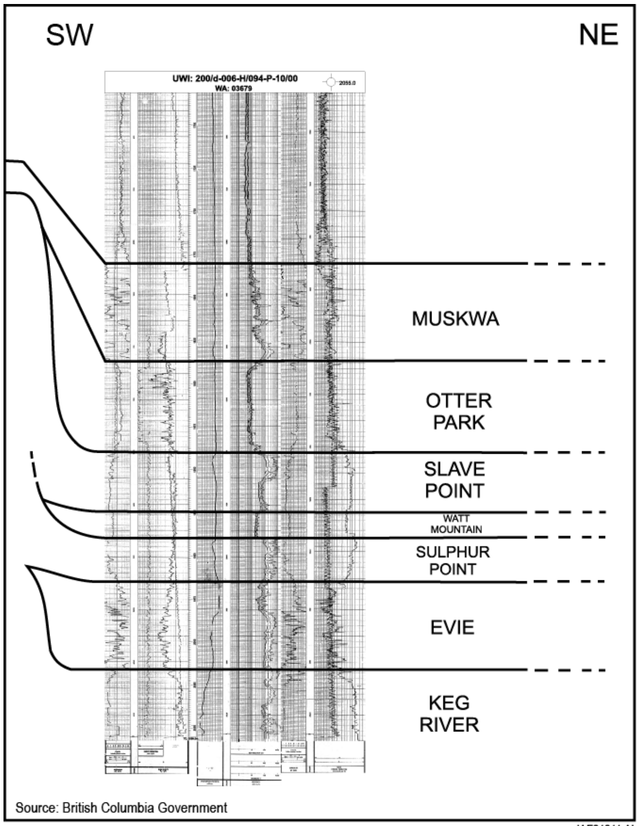

Source: ARI, 2013.

Figure I-7. Cordova Embayment - Muskwa/Otter Park Shale Isopach and Prospective Area




Source: ARI, 2013.

Figure I-8. Cordova Embayment Stratigraphic Column



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## 2.3 Resource Assessment

The prospective area of the Cordova Embayment's Muskwa/Otter Park Shale is approximately 2,000 mi$^2$. Within this prospective area, the shale has a moderate resource concentration of 68 Bcf/mi$^2$ and a risked gas in-place of 81 Tcf. Based on favorable reservoir mineralogy and other properties, we estimate a risked, technically recoverable shale gas resource of 20 Tcf for the Muskwa/Otter Park Shale in the Cordova Embayment, Table I-2.

## 2.4 Comparison with Other Resource Assessments

In mid-2010, the Canadian Society of Unconventional Gas (CSUG) estimated 200 Tcf of shale gas in-place and 30 to 68 Tcf of marketable (recoverable) shale gas for the Cordova Embayment.[4] In early 2012, the BC Ministry of Energy reported 200 Tcf of gas in-place for the Cordova Embayment, a number which appears to have been based on the CSUG study.[4]

## 2.5 Recent Activity

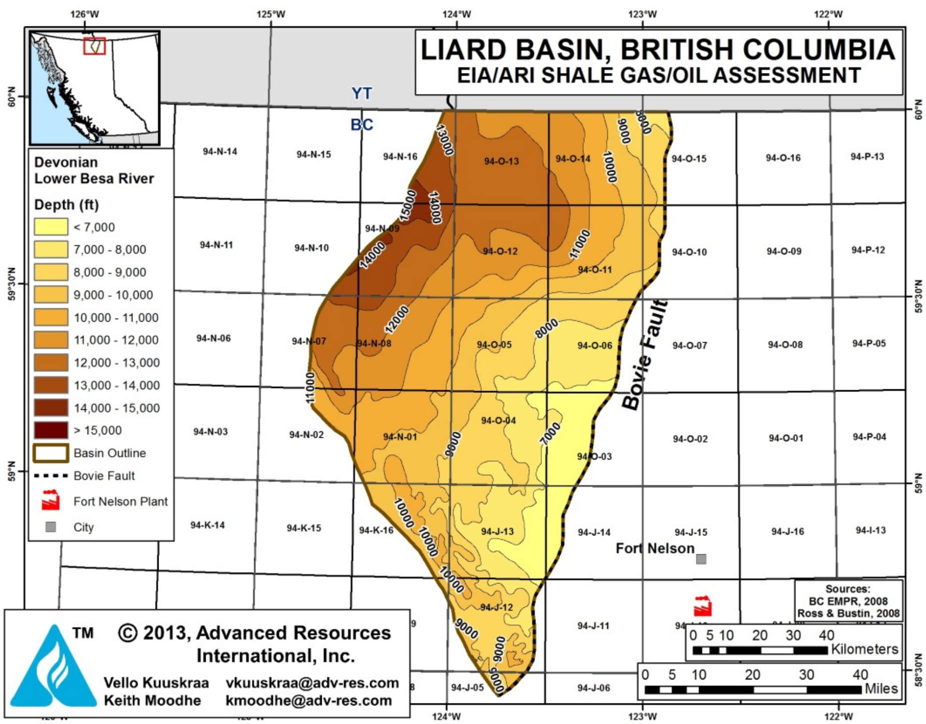
Nexen has acquired an 82,000-acre lease position in the Cordova Embayment and has drilled two vertical and two horizontal shale gas exploration wells. Nexen estimates a contingent resource of up to 5 Tcf for its lease position.[10] PennWest Exploration and Mitsubishi have formed a joint venture to develop the estimated 5 to 7 Tcf of recoverable shale gas resources on their 170,000-acre (gross) lease area.[11]

# 3. LIARD BASIN

## 3.1 Geologic Setting

The Liard Basin covers an area of 4,300 mi$^2$ in northwestern British Columbia, Figure I-9.[3] Its eastern border is defined by the Bovie Fault, which separates the Liard Basin from the Horn River Basin, Figure I-8. Its northern boundary is currently defined by the British Columbia and the Yukon/Northwest Territories border, and its western and southern boundaries are defined by structural folding and shale deposition.

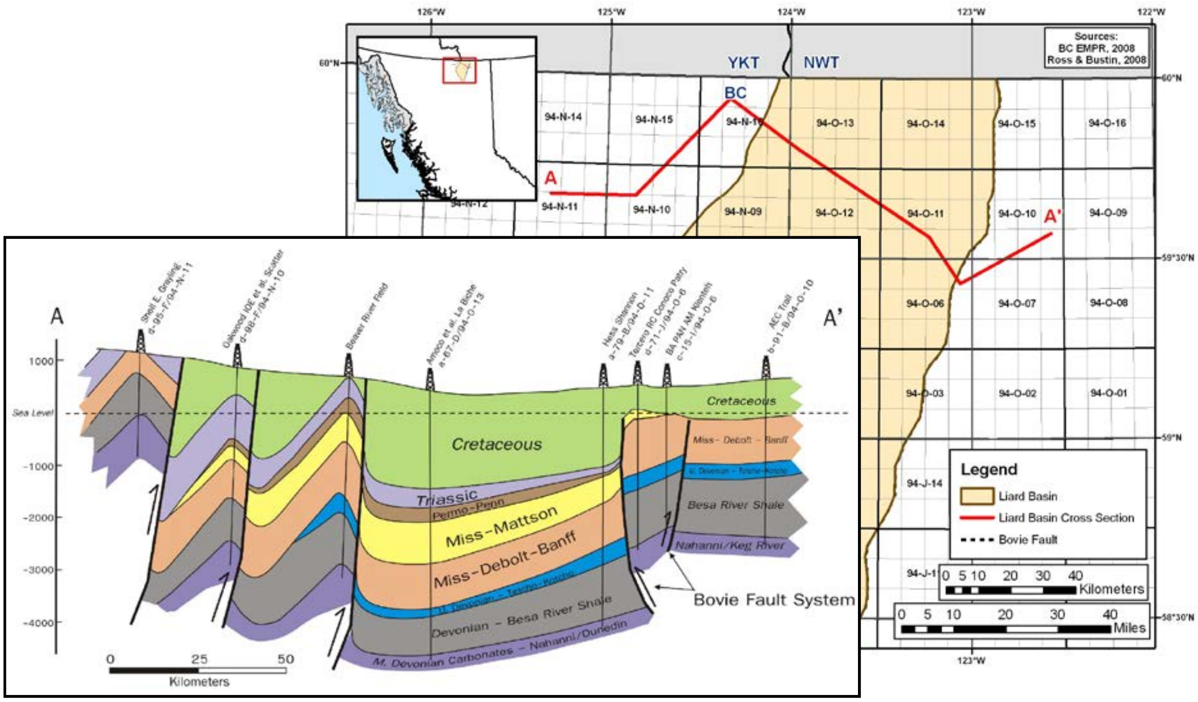
Figure I-9. Liard Basin (Lower Besa River Shale) Outline and Depth Map




Source: Modified from Ross and Bustin, 2008.

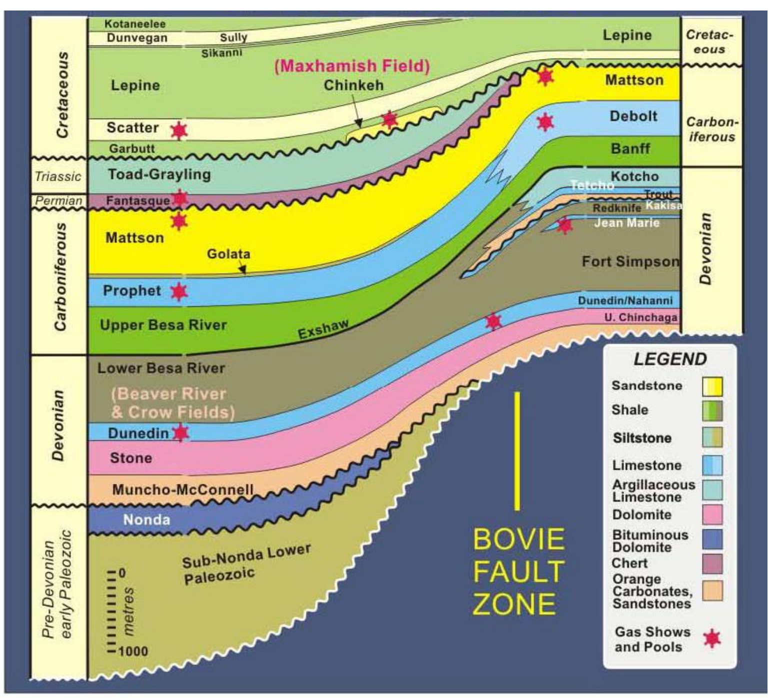
The dominant shale gas formation in the Liard Basin is the Middle Devonian-age Lower Besa River Shale, equivalent to the Muskwa/Otter Park and Evie/Klua shales in the Horn River Basin. Additional, less organically rich and less prospective shales exist in the basin's Upper Devonian- and Mississippian-age shales, such as the Middle Besa River Shale (Fort Simpson equivalent) and the Upper Besa River Shale (Exshaw/Banff equivalent), Figures I-10[12] and I-11.[13] Based on still limited data on this shale play, a prospective area of 3,300 mi$^2$ has been mapped for the Lower Besa River Shale in the central portion of the basin, Figure I-12.[3]

Figure I-10. Liard Basin Location, Cross-Section and Prospective Area



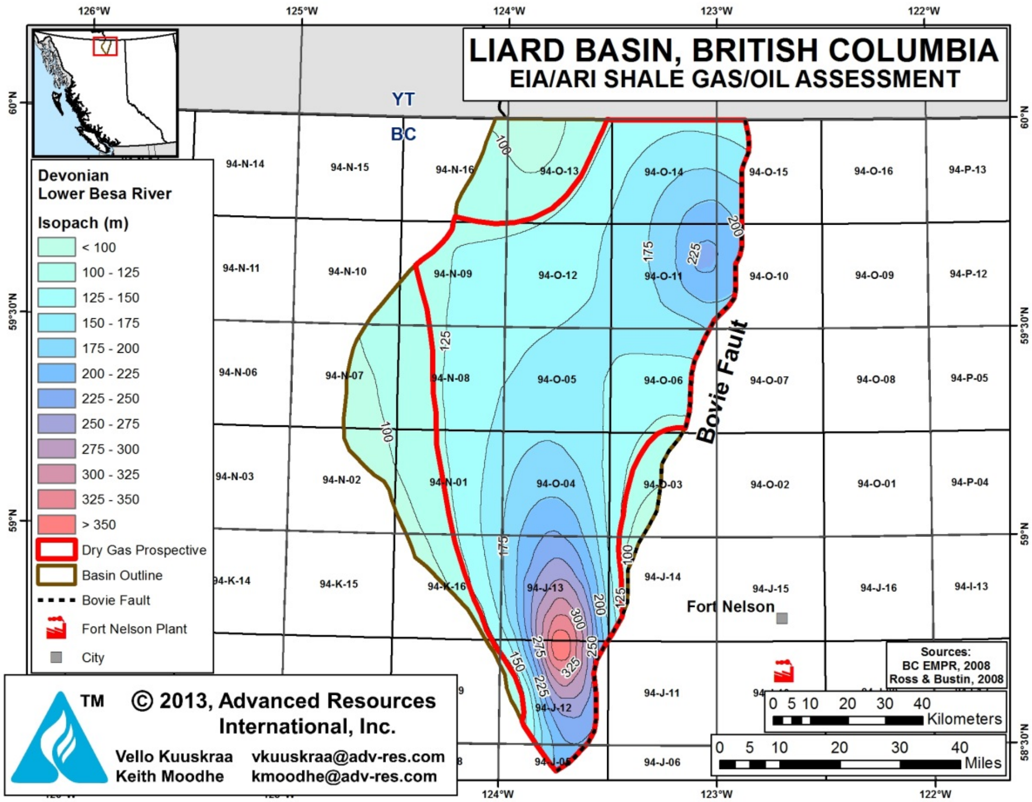

Source: Levson et al., British Columbia Ministry of Energy, Mines, and Petroleum Resources, 2009.

Figure I-11. Liard Basin Stratigraphic Cross-Section




Source: D. W. Morrow and R. Shinduke, "Liard Basin, Northeast British Columbia: An Exploration Frontier", Geological Survey of Canada (Calgary), Natural Resources Canada

Figure I-12. Liard Basin (Lower Besa River Shale) Isopach and Prospective Area




Source: Modified from Ross and Bustin, 2006.

## 3.2 Reservoir Properties (Prospective Area).

The Lower Besa River organic-rich shale is the main shale gas target in the Liard Basin. Drilling depths to the top of the formation in the prospective area range from 6,600 to 13,000 feet, averaging about 10,000 feet. The organic-rich Lower Besa River section has a gross thickness of 750 feet and a net thickness of 600 feet. Total organic content (TOC) in the prospective area, locally up to 5%, averages 3.5% for the net shale interval investigated. The thermal maturity of the prospective area is high, with an average Ro of 3.8%. Because of the high thermal maturity, we estimate the in-place shale gas has a $CO_2$ content of 13%. The geology of the Besa River Shale is complex with numerous faults and thrusts. The Lower Besa River Shale is quartz-rich, with episodic intervals of dolomite and more pervasive intervals of clay.

### 3.3 Resource Assessment

The Liard Basin's Lower Besa River Shale has a high resource concentration of 319 Bcf/mi$^2$. Within the prospective area of 3,300 mi$^2$, the risked shale gas in-place is approximately 526 Tcf. Based on favorable reservoir mineralogy but significant structural complexity, we estimate a risked, technically recoverable shale gas resource of 158 Tcf for the Liard Basin, Table I-2.

### 3.4 Recent Activity

Apache has a 430,000 acre lease position in the center of the Liard Basin's prospective area, estimating 210 Tcf of net gas in-place and 54 Tcf of recoverable raw gas (48 Tcf of marketable gas). Apache's D-34-K well, drilled to a vertical depth of 12,600 feet with a 2,900 foot lateral and 6 frac stages, had a 30-day IP of 21.3 MMcfd and a 12 month cumulative recovery of 3.1 Bcf. The well has a currently projected EUR of nearly 18 Bcf.[7]

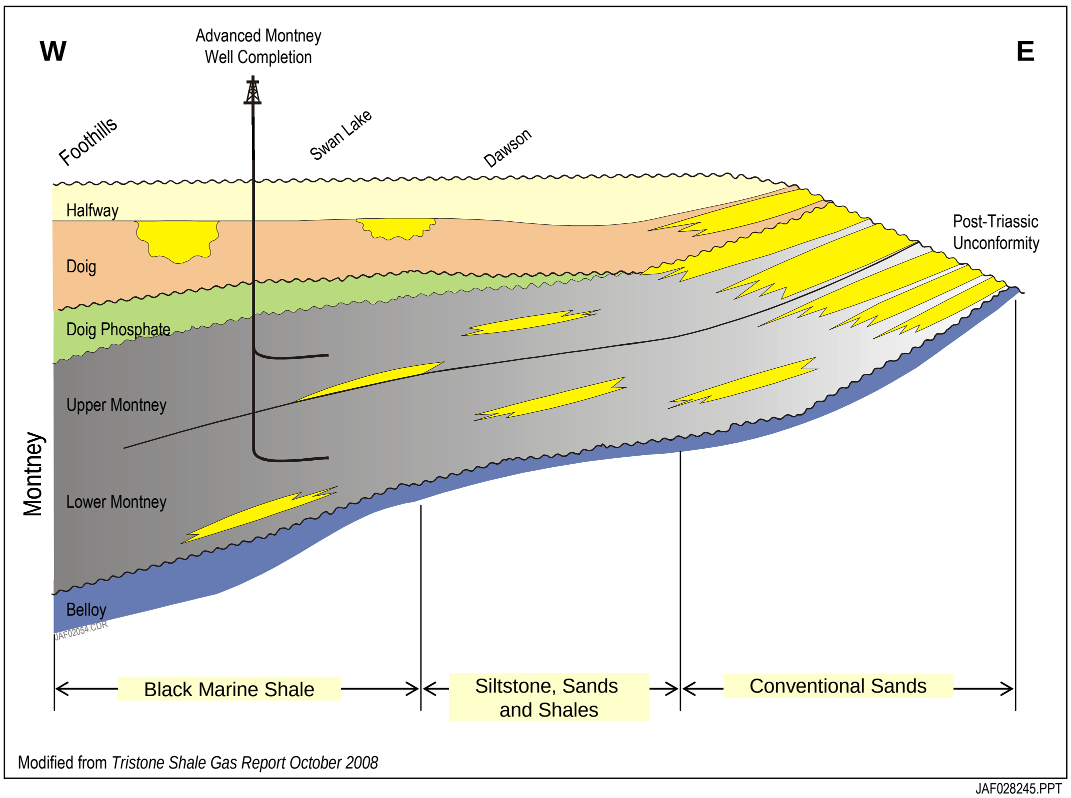
Nexen has acquired a 128,000-acre (net) land position in this basin, assigning up to 24 Tcf of prospective recoverable resource to its lease area.[10] Transeuro Energy Corp. and Questerre Energy Corp., two small Canadian operators, have completed three exploration wells in the Besa River and Mattson shale/siltstone intervals at the Beaver River Field.[14]

# 4. DOIG PHOSPHATE SHALE/DEEP BASIN

## 4.1 Geologic Setting

The Doig Phosphate Shale is located in the Deep Basin of Alberta and British Columbia. The Middle Triassic Doig Phosphate Formation serves as the base for the more extensive, predominantly siltstone and sand content Doig Resource Play, Figure I-13. The Doig Phosphate Formation, a high organic-content shale, has a prospective area of 3,000 mi$^2$ along the west-central portion of the Deep Basin.

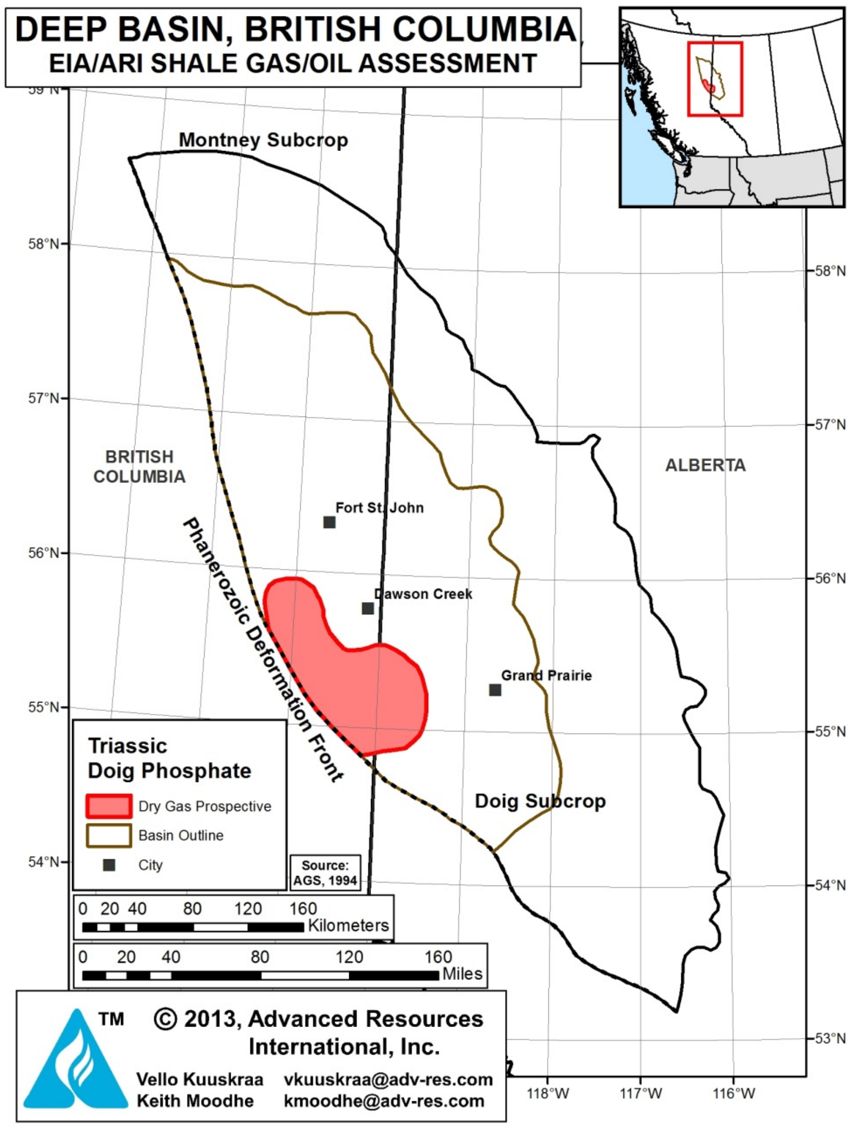
Figure I-13. Deposition and Stratigraphy of Doig Phosphate and Montney/Doig Resource Plays




## 4.2 Reservoir Properties (Prospective Area)

The Middle Triassic Doig Phosphate Shale has a thick section of organic-rich shale along the western edge of the Deep Basin that forms the prospective area, Figure I-14.[15,8] Drilling depth to the top of the shale averages 9,250 feet. The organic-rich Doig Phosphate Shale's thickness ranges from 130 to 200 feet, with a net thickness of 150 feet in the prospective area. The average thermal maturity (Ro of 1.1%) places the shale in the wet gas/condensate window. The total organic content (TOC) is moderate to high, averaging 5%. X-ray diffraction of cores taken from the Doig Phosphate Formation show significant levels of quartz with minor to moderate levels of clay and trace to minor amounts of pyrite and dolomite, making the formation favorable for hydraulic fracturing.

Figure I-14. Prospective Area for the Doig Phosphate Shale (Deep Basin)




Modified from Walsh, 2006.

### 4.3 Resource Assessment

The prospective area of the Doig Phosphate Shale is estimated at 3,000 mi$^2$, limited on the west by the Phanerozoic Deformation Fault and by the pinch-out of the shales to the north, east and south. Within the prospective area, the shale has a moderate resource concentration of 67 Bcf per mi$^2$ of wet gas and a risked resource in-place of 101 Tcf. Based on favorable mineralogy, we estimate a risked, technically recoverable shale gas resource of 25 Tcf for the Doig Phosphate Shale.

### 4.4 Comparison with Other Resource Assessments

In 2006, Walsh estimated a gas in-place for the Doig Phosphate Unit of ~70 Tcf.[15]

### 4.5 Recent Activity

The Doig Phosphate Shale reservoir overlies the Montney Resource Play. As such, much of the activity and appraisal of the Doig Phosphate is reported as part of exploration for the Montney and Doig Resource plays. Pengrowth Energy Corp, a small Canadian producer, tested the larger Doig interval with a vertical well in 2011 with a reported test rate of 750 Mcfd. The company plans to target the Doig with a horizontal well in 2012.[8]

## 5. MONTNEY AND DOIG RESOURCE PLAYS (BRITISH COLUMBIA)

The Deep Basin of British Columbia contains the Montney and Doig Resource plays. These are multi-depositional, Triassic-age hydrocarbon accumulations containing large volumes of dry and wet gas in-place in conventional, tight sand and shale formations.

The Canadian National Energy Board categorizes the Montney and Doig Resource plays as tight gas sands. Work by the BC Oil and Gas Commission, in their "Montney Formation Play Area Atlas NEBC",[16] shows that only a very small portion of the Montney Resource play contains oil/condensate, Figure I-15. As such, we have excluded the Montney and Doig Resource plays from the shale resource assessment of Canada. (In our previous shale gas resource assessment, we speculated that a shale-rich Montney area with higher TOC values may exist in BC along the northwestern edge of the Deep Basin. However, because of lack of data confirming this speculation, we have excluded this area and resource volumes from our current shale oil and gas assessment.)

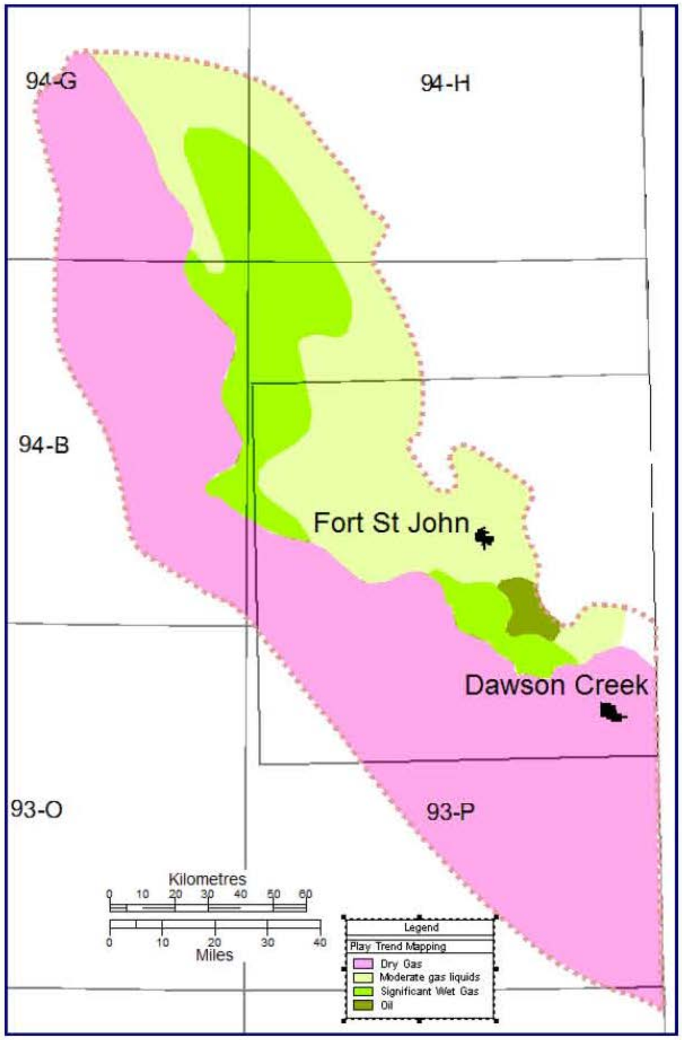
To put the potential volume of tight gas resource in the Montney and Doig Resource plays of British Columbia into perspective, the BC MEM reports a gas in-place for the BC portion of the Montney and Doig Resource plays at 450 Tcf and 200 Tcf respectively.[8]

## 6. CANOL SHALE

The Canol Shale is an emerging shale play located in the central Mackenzie Valley near Norman Wells, Northwest Territories. To date, only seismic and a handful of vertical wells have been drilled to explore this shale oil play. Work is underway on a multi-year study by the Northwest Territories Geoscience Office to better define this resource.

Husky Oil, having spent $376 million at the 2011 land auction, has drilled two vertical wells on its 300,000-net acre lease area and is planning on completing three wells in 2013.[17] MGM Energy Corp, with 470,000-net acres in this resource play, plans to drill one vertical well during the current winter exploration season. MGM (with Shell as its partner) withdrew plans to drill a horizontal well in 2012 to test the productivity of the Canol Shale play.[18] As information on the prospectivity of the Canol Shale is gained from the above wells, it would be timely to include this shale play in the assessment of Canada's shale gas and oil resources.

Figure I-15. Montney Trend – Identified Gas Liquids/Oil Distribution




Source: BC Oil and Gas Commission Montney Formation Play Atlas NEBC October 2012.

# ALBERTA

Alberta holds a series of significant, organic-rich shale gas and shale oil formations, including: (1) the Banff and Exshaw Shale in the Alberta Basin; (2) the Duvernay Shale in the East and West Shale Basin of west-central Alberta; (3) the Nordegg Shale in the Deep Basin of west-central Alberta; (4) the Muskwa Shale in northwest Alberta; and (5) the shale gas formations of the Colorado Group in southern Alberta. (In addition, Alberta holds the eastern portion of the Doig Phosphate Shale play, discussed previously.)

The study has benefitted greatly from the in-depth and rigorous siltstone and shale data in the ERCB/AGS report entitled, “Summary of Alberta’s Shale- and Siltstone-Hosted Hydrocarbon Resource Potential”.[19] This ERCB/AGS report helped define the boundaries for the oil, wet gas/condensate and dry gas play areas used by this study. This report also provided valuable data on key reservoir properties such as porosity and net pay.

To maintain consistency with the ERCB/AGS study for Alberta, our study used the same minimum criterion of 0.8% $R_o$ for the volatile/black oil window. However, our study used the criterion of >1.3% $R_o$ for the dry gas window, compared to the >1.35% $R_o$ in the ERCB/AGS study. Our study also expanded on the analytical data in ERCB/AGS’s report with our independently derived estimates of prospective areas as well as our assignments of pressure gradients, gas-oil ratios (as functions of reservoir pressure and temperature), and other reservoir properties to each shale play. (The ERCB/AGS assumed normal rather than over-pressured gradients in their Alberta resource assessment and linked a constant oil-gas ratio to each thermal maturity ($R_o$) value, independent of reservoir pressure and depth.)

The five Alberta basins assessed by this study contain 987 Tcf of risked shale gas in-place, with 200 Tcf as the risked, technically recoverable shale gas resource, Table 1-3. These five basins also contain 140 billion barrels of risked shale oil in-place, with 7.2 billion barrels as the risked, technically recoverable shale oil resource, Table I-4.

## Table I-3. Shale Gas Reservoir Properties and Resources of Alberta

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | Alberta Basin (28,700 $mi^2$) | East and West Shale Basin (50,500 $mi^2$) | | | Deep Basin (26,200 $mi^2$) | | | NW Alberta Area (33,000 $mi^2$) | | Southern Alberta Basin (124,000 $mi^2$) |
| | Shale Formation | | Banff/Exshaw | Duvernay | | | North Nordegg | | | Muskwa | | Colorado Group |
| | Geologic Age | | L. Mississippian | U. Devonian | | | L. Jurassic | | | U. Devonian | | Cretaceous |
| | Depositional Environment | | Marine | Marine | | | Marine | | | Marine | | Marine |
| Physical Extent | Prospective Area ($mi^2$) | | 10,500 | 13,000 | 7,350 | 2,900 | 6,900 | 4,000 | 1,500 | 12,500 | 6,600 | 48,750 |
| | Thickness (ft) | Organically Rich | 65 | 45 | 60 | 70 | 82 | 72 | 69 | 70 | 112 | 523 |
| | | Net | 15 | 41 | 54 | 63 | 37 | 31 | 29 | 25 | 78 | 105 |
| | Depth (ft) | Interval | 3,900 - 6,200 | 7,500 - 10,500 | 10,500 - 13,800 | 13,800 - 16,400 | 5,200 - 8,200 | 8,200 - 11,500 | 11,500 - 14,800 | 3,300 - 8,200 | 3,900 - 8,200 | 5,000 - 10,000 |
| | | Average | 4,800 | 9,000 | 11,880 | 15,000 | 6,724 | 10,168 | 12,464 | 6,100 | 4,602 | 6,900 |
| Reservoir Properties | Reservoir Pressure | | Normal | Highly Overpress. | Highly Overpress. | Highly Overpress. | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. | Underpress. |
| | Average TOC (wt. %) | | 3.2% | 3.4% | 3.4% | 3.4% | 11.0% | 11.0% | 11.0% | 3.2% | 3.2% | 2.4% |
| | Thermal Maturity (% Ro) | | 0.90% | 0.90% | 1.15% | 1.50% | 0.90% | 1.15% | 1.35% | 0.90% | 1.10% | 0.60% |
| | Clay Content | | Medium | Low | Low | Low | Low/Med. | Low/Med. | Low/Med. | Low | Low | Low/Med. |
| Resource | Gas Phase | | Assoc. Gas | Assoc. Gas | Wet Gas | Dry Gas | Assoc. Gas | Wet Gas | Dry Gas | Assoc. Gas | Wet Gas | Dry Gas |
| | GIP Concentration (Bcf/$mi^2$) | | 1.2 | 12.0 | 47.4 | 63.8 | 4.7 | 19.6 | 22.1 | 4.6 | 34.2 | 20.9 |
| | Risked GIP (Tcf) | | 5.1 | 109.1 | 244.1 | 129.5 | 16.2 | 39.2 | 16.6 | 29.0 | 112.7 | 285.6 |
| | Risked Recoverable (Tcf) | | 0.3 | 13.1 | 61.0 | 38.8 | 1.3 | 7.8 | 4.1 | 2.9 | 28.2 | 42.8 |

## Table I-4. Shale Oil Reservoir Properties and Resources of Alberta

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | Alberta Basin (28,700 $mi^2$) | East and West Shale Basin (50,500 $mi^2$) | | Deep Basin (26,200 $mi^2$) | | NW Alberta Area (33,000 $mi^2$) | |
| | Shale Formation | | Banff/Exshaw | Duvernay | | North Nordegg | | Muskwa | |
| | Geologic Age | | L. Mississippian | U. Devonian | | L. Jurassic | | U. Devonian | |
| | Depositional Environment | | Marine | Marine | | Marine | | Marine | |
| Physical Extent | Prospective Area ($mi^2$) | | 10,500 | 13,000 | 7,350 | 6,900 | 4,000 | 12,500 | 6,600 |
| | Thickness (ft) | Organically Rich | 65 | 45 | 60 | 82 | 72 | 70 | 112 |
| | | Net | 15 | 41 | 54 | 37 | 31 | 25 | 78 |
| | Depth (ft) | Interval | 3,900 - 6,200 | 7,500 - 10,500 | 10,500 - 13,800 | 5,200 - 8,200 | 8,200 - 11,500 | 3,300 - 8,200 | 3,900 - 8,200 |
| | | Average | 4,800 | 9,000 | 11,880 | 6,724 | 10,168 | 6,100 | 4,602 |
| Reservoir Properties | Reservoir Pressure | | Normal | Highly Overpress. | Highly Overpress. | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. |
| | Average TOC (wt. %) | | 3.2% | 3.4% | 3.4% | 11.0% | 11.0% | 3.2% | 3.2% |
| | Thermal Maturity (% Ro) | | 0.90% | 0.90% | 1.15% | 0.90% | 1.15% | 0.90% | 1.10% |
| | Clay Content | | Medium | Low | Low | Low/Med. | Low/Med. | Low | Low |
| Resource | Oil Phase | | Oil | Oil | Condensate | Oil | Condensate | Oil | Condensate |
| | OIP Concentration (MMbbl/$mi^2$) | | 2.5 | 7.1 | 0.5 | 5.5 | 0.4 | 6.4 | 0.7 |
| | Risked OIP (B bbl) | | 10.5 | 64.2 | 2.6 | 19.0 | 0.8 | 40.0 | 2.4 |
| | Risked Recoverable (B bbl) | | 0.32 | 3.85 | 0.16 | 0.76 | 0.03 | 2.00 | 0.12 |

# 1. BASAL BANFF AND EXSHAW SHALE/ ALBERTA BASIN

## 1.1 Geologic Setting

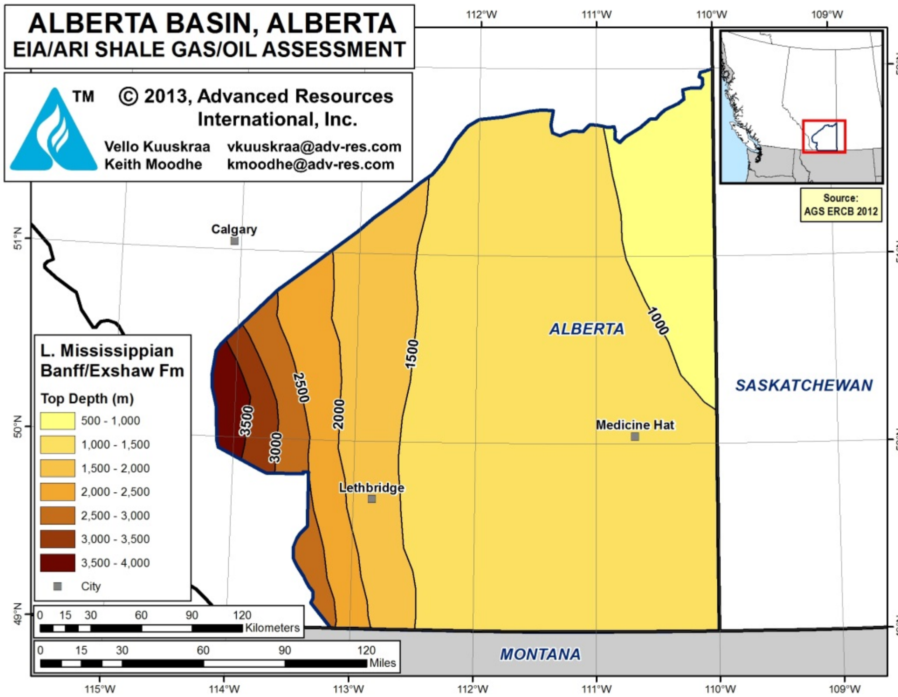
The basal Banff/Exshaw Shale assessed by this study is located in the southern Alberta portion of the Alberta Basin, Figure I-16.[19] The western boundary of this shale deposit is constrained by the Deformed Belt and its northern boundary is defined by the sub-crop erosional edge. Its eastern boundary is the Alberta and Saskatchewan border and its southern boundary is the U.S. and Canada border. Within the larger 15,360-mi$^2$ area of shale deposition, the Basal Banff/Exshaw Shale has a prospective area of 10,500 mi$^2$ for volatile/black oil, Figure I-17.[19] (The small dry gas and wet gas areas were not considered prospective.) The east to west cross-section (E-E') for the Lower Mississippian and Upper Devonian Basal Banff/Exshaw Shale shows its stratigraphic equivalence to the Bakken Formation in the Williston Basin, Figure I-18.[19]

## 1.2 Reservoir Properties (Prospective Area)

Similar to the Bakken Shale, the basal Banff/Exshaw Shale consists of three reservoir units. The upper and lower units are dominated by organic-rich shale. The middle unit contains a variety of lithologies including calcareous sandstone and siltstone, dolomitic siltstone and limestone. The primary reservoir is the more porous and permeable middle unit, sourced by the upper and lower organic-rich shales units. However, compared to the Bakken Shale, the prospective area of the basal Banff/Exshaw Shale is normally pressured (with higher pressures in the west) rather than over-pressured, and its middle unit appears to have considerably lower permeability and solution gas.

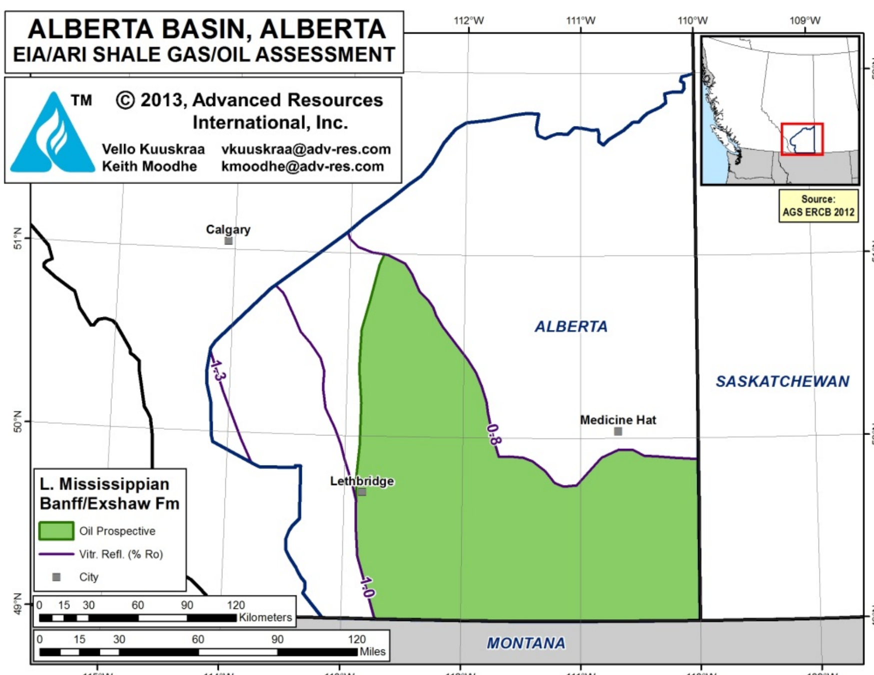
In the prospective area, the drilling depth to the top of the shale ranges from 3,300 feet on the east to about 6,600 feet on the west, averaging 4,800 feet. The upper shale unit is 3 to 5 feet thick and the lower shale unit has a gross thickness of 10 to 40 feet, providing a net, organic-rich shale pay averaging 15 feet.

Figure I-16. Outline and Depth of Basal Banff and Exshaw Shale (Alberta)



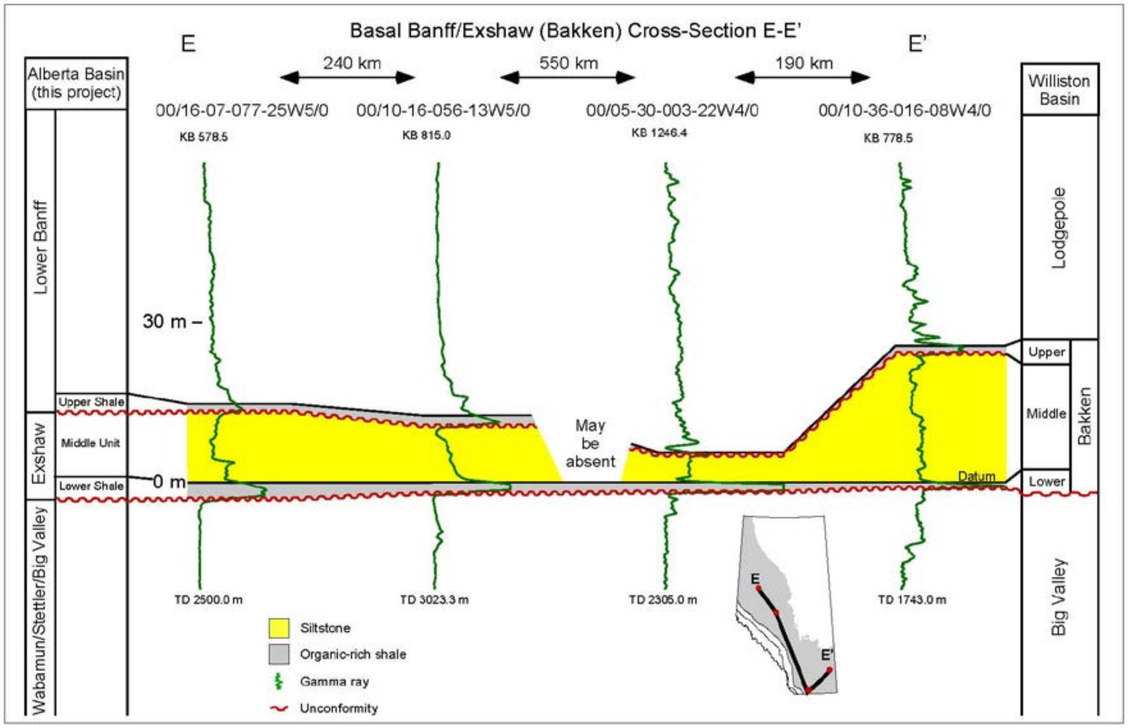

Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-17. Prospective Area for Basal Banff and Exshaw Shale (Alberta).




Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-18. Stratigraphic Cross Section E-E' of the Basal Banff and Exshaw Shale




Source: ERCB/AGS Open File Report 2012-06, October 2012.

The total organic content (TOC) in the prospective area averages 3.2% and ranges from lean to nearly 17%. The upper and lower shale units have high TOC values (3% to 17%), the middle unit has much lower TOC (lean to 3%). The thermal maturity ($R_o$) of the shale shows a progressive increase from immature (below 0.8% $R_o$) in the east to dry gas (over 1.3% $R_o$) in the west. However, in the western area where the thermal maturity exceeds 1.0% $R_o$, the shale is thin and thus has been excluded from the prospective area. As such, the basal Banff/Exshaw Shale has a prospective area for oil of 10,500 mi$^2$ (0.8% to 1.0% $R_o$) located in the center of the larger play area.

## 1.3 Resource Assessment

The prospective area for the Basal Banff/Exshaw Shale in the Alberta Basin is limited by depth and thermal maturity on the east and by shale thickness on the west. Within the 10,500-mi$^2$ prospective area for oil, the basal Banff/Exshaw Shale has a resource concentration of 2.5 million barrels of oil per mi$^2$ plus moderate volumes of associated gas.

The risked resource in-place for the oil prospective area is estimated at 10 billion barrels of oil plus 5 Tcf of associated natural gas. Based on recent well performance as well as reservoir properties that appear to be less favorable than for the Bakken Shale in the Williston Basin, we estimate a risked, technically recoverable resource of 0.3 billion barrels of shale oil and 0.3 Tcf of associated shale gas.

## 1.4 Comparison With Other Resource Assessments

The ERCB/AGS resource study, discussed above, calculated an unrisked oil in-place of 26,300 million barrels and an unrisked gas in-place of 39.8 Tcf for the basal Banff/Exshaw Shale.[19] The ERCB/AGS study did not use depth, net pay or other criteria to define a prospective area and did not estimate a risked recoverable resource.

## 1.5 Recent Activity

Considerable leasing occurred for the basal Banff/Exshaw Shale in 2010, sparking this southern Alberta shale play. Since then, a number of producers, such as Crescent Point and Murphy Oil, have drilled exploration wells to test the resource potential in this shale oil play. So far, of the 22 wells with reported production, only three wells have current producing rates of over 100 B/D; the remainder have rates of less than 50 B/D.

Crescent Point drilled two exploration wells into the Exshaw Shale in early 2012 with plans to drill additional wells in the area.[20] Murphy Oil has assembled a 150,000 net acre lease area. While its early exploration for this shale play has shown mixed results, Murphy's recent #15-21 well targeting the Exshaw Shale had an IP of 350 BOPD. Murphy Oil is examining the use of longer laterals, enhanced stimulation and lower costs to improve the economic viability of this shale play.[21]

# 2. DUVERNAY SHALE/EAST AND WEST SHALE BASIN

## 2.1 Geologic Setting

The East and West Shale Basin, covering an area of over 50,000 $mi^2$ in central Alberta, contains the organically rich Duvernay Shale, Figure I-19.[19] The western boundary of this shale deposit is defined by the Deformed Belt, the northern boundary by the Peace River Arch, the southern boundary by the Leduc Shelf, and the eastern boundary by the Grosmont Carbonate Platform. Within this larger area of shale deposition, the prospective area for the Duvernay Shale is 23,450 $mi^2$, primarily in the central and western portions of this basin, Figure I-20.[19]

The Upper and Middle Devonian Duvernay Shale is stratigraphic equivalent to the Muskwa Shale in northwest Alberta and northeast British Columbia. In the East Shale Basin, the Duvernay Shale is primarily an organic-rich limestone. In the West Shale Basin, the Duvernay Shale grades from a carbonate-rich mudstone in the east to an increasingly porous, organic-rich shale in the west, Figure I-21.[19]

## 2.2 Reservoir Properties (Prospective Area)

In the prospective area, the drilling depth to the top of the Duvernay Shale ranges from 7,500 feet in the east to 16,400 feet in the west. The gross shale thickness in the prospective area ranges from 30 feet to over 200 feet, with an average of 41 net feet in the oil prospective area, 54 net feet in the wet gas/condensate prospective area, and 63 net feet in the dry gas prospective area.

The total organic carbon (TOC) in the prospective area reaches 11%. Excluding the organically lean rock using the net to gross ratio, the average TOC is 3.4%. The thermal maturity ($R_o$) of the shale increases as the shales deepen, from immature (below 0.8% Ro) on the east to dry gas (1.3% to 2% $R_o$) in the west. As such, the Duvernay Shale has an extensive oil prospective area in the east, a wet gas/condensate prospective area in the center, and a smaller dry gas prospective area in the west.

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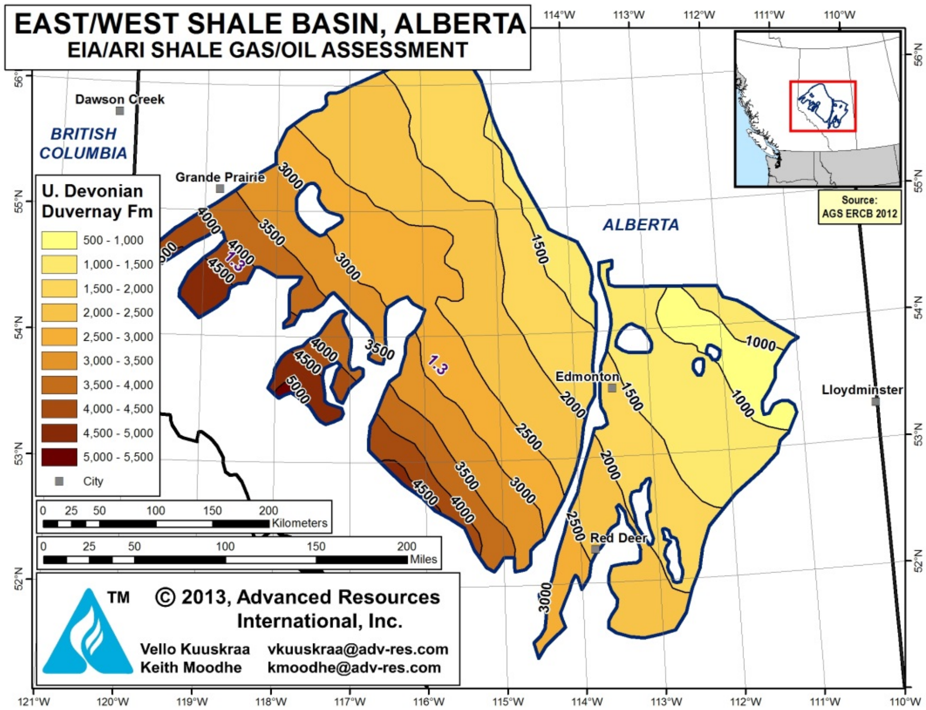
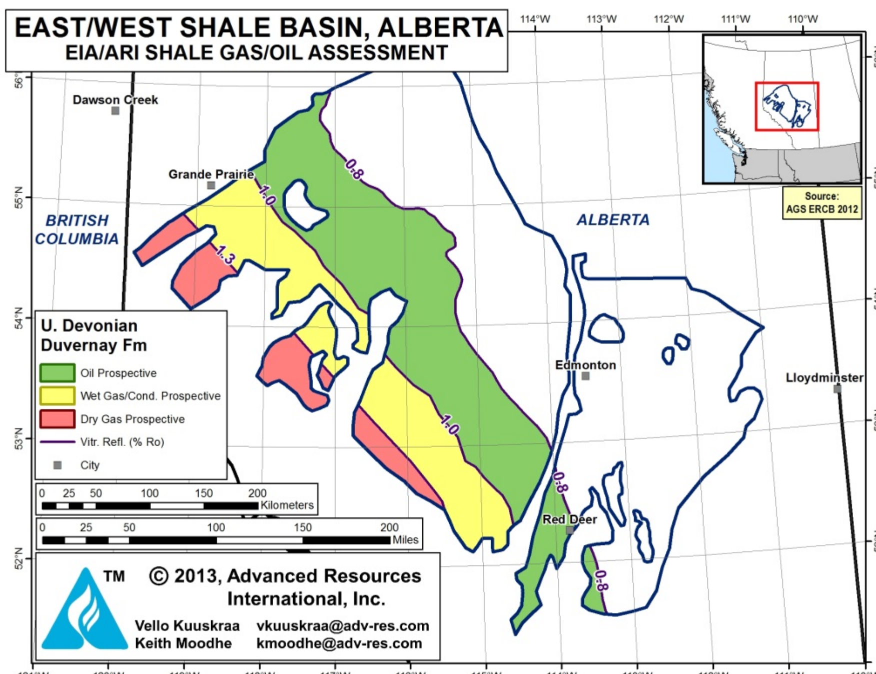
Figure I-19. Outline and Depth of Duvernay Shale (Alberta)



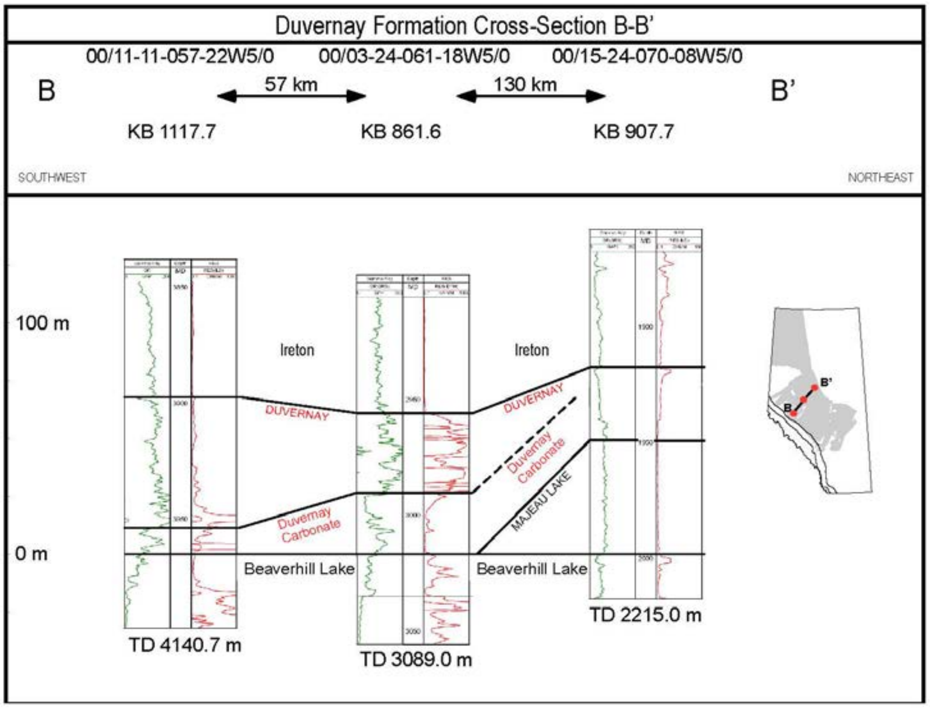

Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-20. Prospective Area for Duvernay Shale (Alberta)




Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-21. Stratigraphic Cross Section B-B' of the Duvernay Formation




Source: ERCB/AGS Open File Report 2012-06, October 2012.

## 2.3 Resources Assessment

The prospective area of the Duvernay Shale in the East and West Shale Basin covers 23,250 mi$^2$, limited on the east by low thermal maturity. Within the 13,000-mi$^2$ prospective area for oil, the Duvernay Shale has a resource concentration of 7.1 million barrels of oi/mi$^2$ plus associated gas. Within the 7,350-mi$^2$ wet gas/condensate prospective area, the Duvernay Shale has resource concentrations of 0.5 million barrels of condensate and 47 Bcf of wet gas per mi$^2$. Within the 2,900-mi$^2$ dry gas prospective area, the Duvernay Shale has a resource concentration of 64 Bcf/mi$^2$.

The risked resource in-place in the prospective areas of the Duvernay Shale is estimated at 67 billion barrels of shale oil/condensate and 483 Tcf of shale gas. Based on favorable reservoir properties and analog information from U.S. shales such as the Eagle Ford, we estimate risked, technically recoverable resources of 4.0 billion barrels of shale oil/condensate and 133 Tcf of dry and wet shale gas.

## 2.4 Recent Activity

The Duvernay Shale is the current “hot” shale play in Western Canada with over $2 billion spent (in 2010 and 2011) in auctions for leases. Athabasca Oil (with 1,000 $mi^2$) followed by Canadian Natural Resources (600+ $mi^2$), EnCana (580+ $mi^2$) and Talisman (560+ $mi^2$) have the dominant land positions. Twelve additional companies, ranging from Chevron to Enerplus, each hold over 100 $mi^2$ of leases.

Much of the current activity is in the Kaybob wet gas/condensate area. EnCana with 8 Hz wells plus one vertical well and Celtic with 7 Hz and 5 vertical wells are the most active operators. Since the first Celtic well in the Duvernay Shale in 2010, a total of 45 wells (Hz and vertical) have been drilled or are being drilled (mid-2012).

- EnCana reports that its Duvernay well tested at 2.3 MMcfd of wet gas and 1,632 barrels per day of condensate.
- Celtic’s best Duvernay well tested at 5.8 Mcfd of wet gas plus 638 barrels per day of condensate.

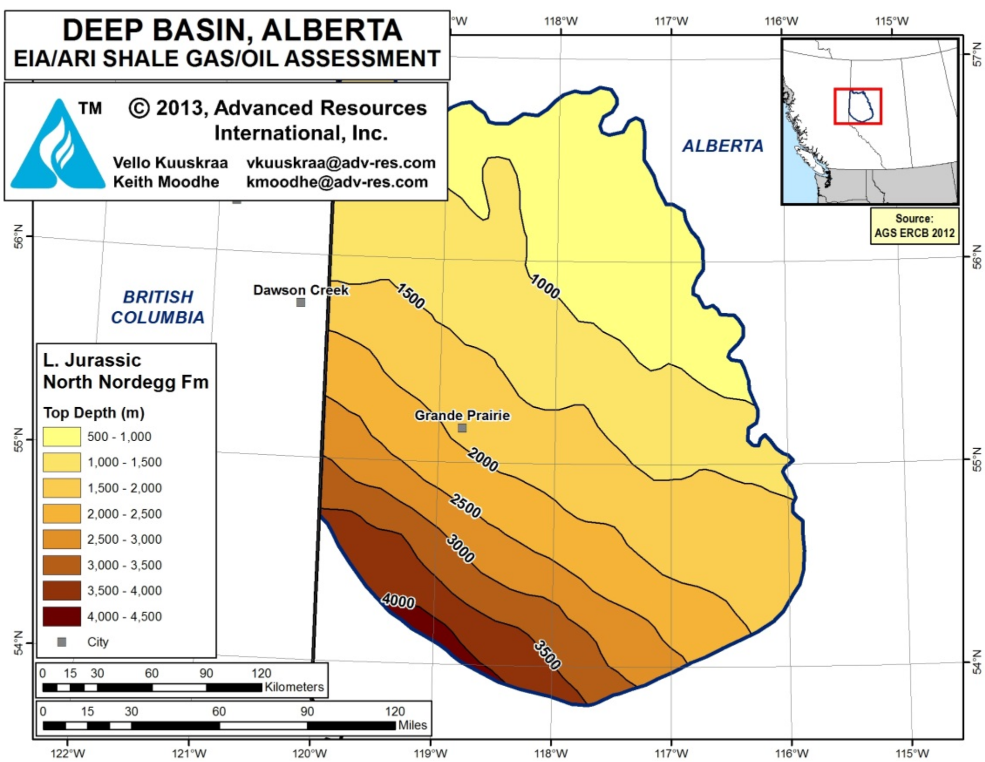
In the Pembina area, EnCana with four Hz wells and ConocoPhillips with three Hz wells are most active. In the Edson Area, where active leasing is still underway, Angle Energy, CNRL and Vermillion are drilling Duvernay Shale explorations wells.

## 3. NORDEGG SHALE/DEEP BASIN.

### 3.1 Geologic Setting.

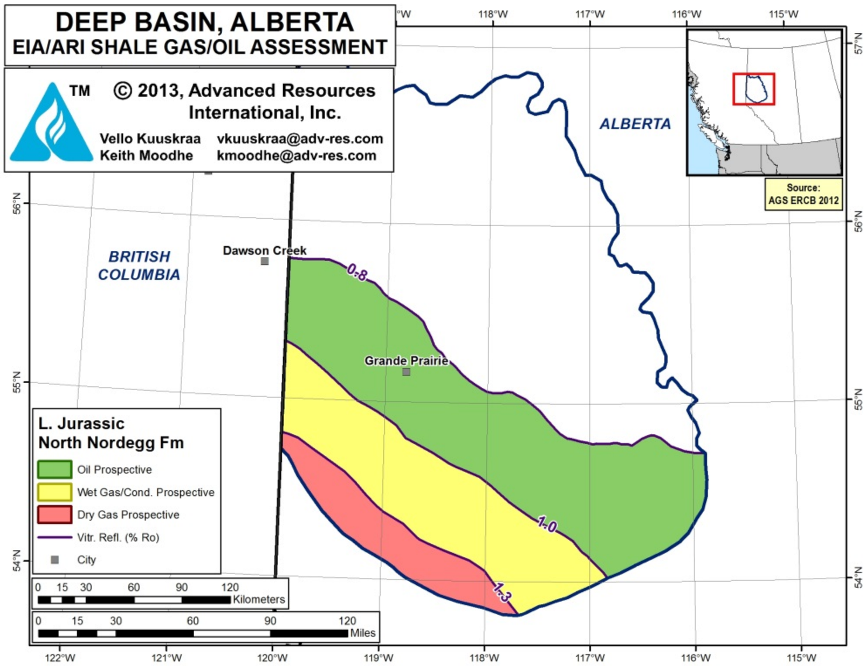
The Nordegg Shale assessed in this study is located within the Deep Basin of Alberta, Figure I-22.[19] The Lower Jurassic Nordegg Shale Member is located at the base of the Fernie Formation, shown by the cross-section on Figure I-23.[19] The Nordegg transitions from a carbonate-rich deposition on the south into a fine-grained rock on the north. In the northern area, where the shale interval is sometimes referred to as the Gordondale Member, the Nordegg Shale is an organic-rich mudstone (shale) which also includes cherty and phosphoric carbonates as well as siltstones and some sandstone, Figure 1-24.[19] The Nordegg Shale has served as a prolific source rock for shallower conventional hydrocarbon reservoirs in this portion of the Deep Basin.

Figure I-22. Outline and Depth of Nordegg Shale (Alberta).



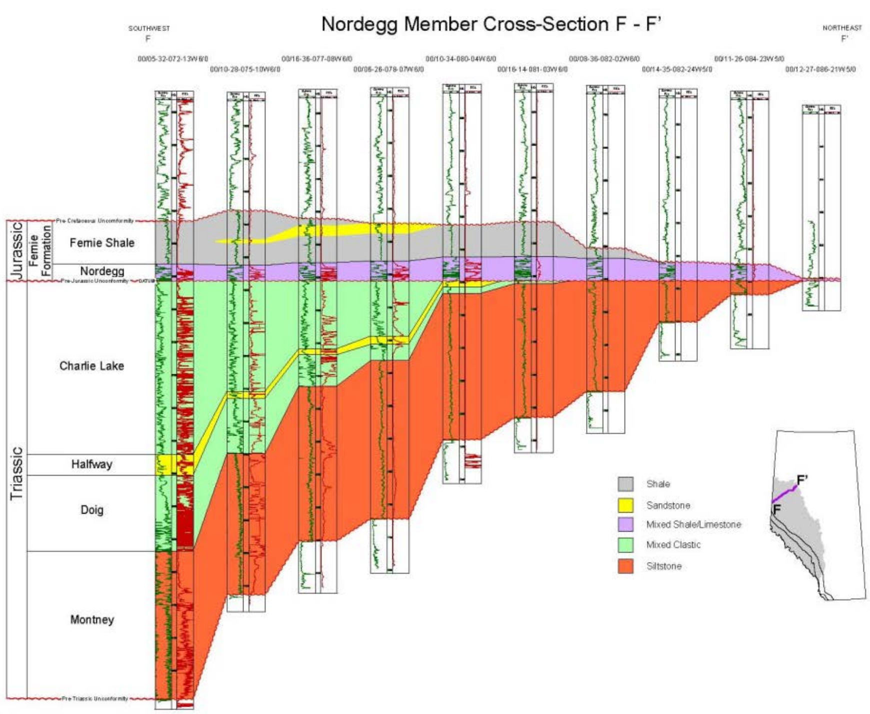

Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-23. Prospective Area for Nordegg Shale (Alberta)




Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-24. Stratigraphic Cross Section F-F' of the Nordegg Member




Source: ERCB/AGS Open File Report 2012-06, October 2012.

### 3.2 Reservoir Properties (Prospective Area).

In the Nordegg Shale prospective area, the drilling depth to the top of the shale ranges from 3,300 feet in the north-east to about 15,000 feet in the south. Within the overall prospective area of 12,400 mi$^2$, the volatile/black oil prospective area is 6,900 mi$^2$, the wet gas/condensate prospective area is 4,000 mi$^2$, and the dry gas prospective area is 1,500 mi$^2$. The shale thickness in the overall prospective area ranges from 50 feet to 150 feet and has a high net to gross ratio of about 0.8.

The total organic carbon (TOC) in the prospective area is high, at over 11%, based on 82 samples from 16 wells. The thermal maturity ($R_o$) of the shale increases to the southwest in line with increasing depth. The overall Nordegg Shale prospective area has an oil prone area ($R_o$ of 0.8% to 1.0%) on the north, a wet gas/condensate area in the center ($R_o$ of 1.0% to 1.3%) and a dry gas area ($R_o$ >1.3) on the south. While the data are sparse, industry information suggests that the Nordegg Shale is over-pressured.

### 3.3 Resource Assessment.

Within the 6,900-mi$^2$ oil prospective area, the Nordegg Shale has a resource concentration of 5.6 million barrels of oil per mi$^2$ plus associated gas. Within the 4,000-mi$^2$ wet gas and condensate prospective area, the Nordegg Shale has a resource concentrations of 0.4 million barrels of oil and 20 Bcf of wet gas per mi$^2$. Within the 1,500-mi$^2$ dry gas prospective area, the Nordegg Shale has a resource concentration of 22 Bcf/mi$^2$.

Combined, the risked resource in-place for the prospective area of the Nordegg Shale is estimated at 20 billion barrels of oil/condensate and 72 Tcf of natural gas. Based on moderate reservoir properties and analog information from U.S. shales, we estimate risked, technically recoverable resources of 0.8 billion barrels of oil/condensate and 13 Tcf of natural gas for the Nordegg Shale.

### 3.4 Comparison with Other Resource Assessments

The ERCB/AGS resource study, discussed above, calculated an unrisked mean oil in-place of 40,645 million barrels and an unrisked mean gas in-place of 164 Tcf for the Nordegg Shale.[19] The in-place resource values in our study are different than those reported in the ERCB/AGS study due to the following: (1) given the still emerging nature of the Nordegg Shale, we judge this resource area to be only 50% de-risked; (2) we find the Nordegg Shale to be moderately over-pressured; and (3) we have a significantly lower associated gas-oil ratio for the volatile/black oil prospective resource area than used in the ERCB/AGS study.

### 3.5 Recent Activity

Only a modest number of exploration wells have been completed in the Nordegg Shale. Recently, Anglo Canadian drilled a horizontal test well (Shane 07-11-77-03W6) and a vertical test well (Sturgeon Lake 05-10-68-22W5) which produced non-commercial volumes of moderately heavy, 25$^o$ API oil. Tallgrass Energy has since acquired Anglo Canadian and its large land position, with 272 mi$^2$ in the Nordegg Shale.[22] The literature reports that a company active in the Nordegg oil fairway has completed one Nordegg Hz well with a multi-stage frac that produced 500 BOED, with 80% oil (42$^o$ API), during its initial flow test and completed a second well that had a 30-day initial production rate of 78 barrels of 32$^o$ API oil.[23]

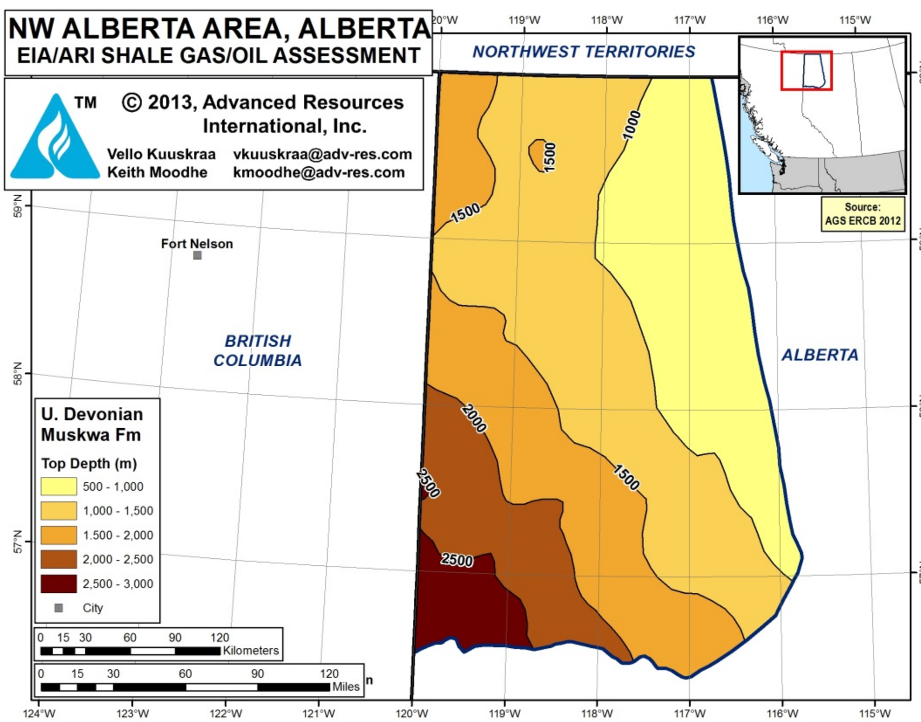
# 4. MUSKWA SHALE/NORTHWEST ALBERTA

## 4.1 Geologic Setting

The Muskwa Shale deposition in northwest Alberta is the northern continuation of the Duvernay Shale in central Alberta and the eastern continuation of Muskwa/Otter Park Shale in northeast British Columbia, Figure I-25.[19] The boundaries of the Muskwa Shale in northwest Alberta are the Alberta/British Columbia border on the west, the Alberta/NWT border on the north, the Peace River Arch on the south, and the Grosmont Carbonate Platform on the east. Within this larger depositional area, the Muskwa Shale has a prospective area of 19,100 mi$^2$, primarily in the western portion of the larger Muskwa Shale depositional area, Figure I-26.[19]

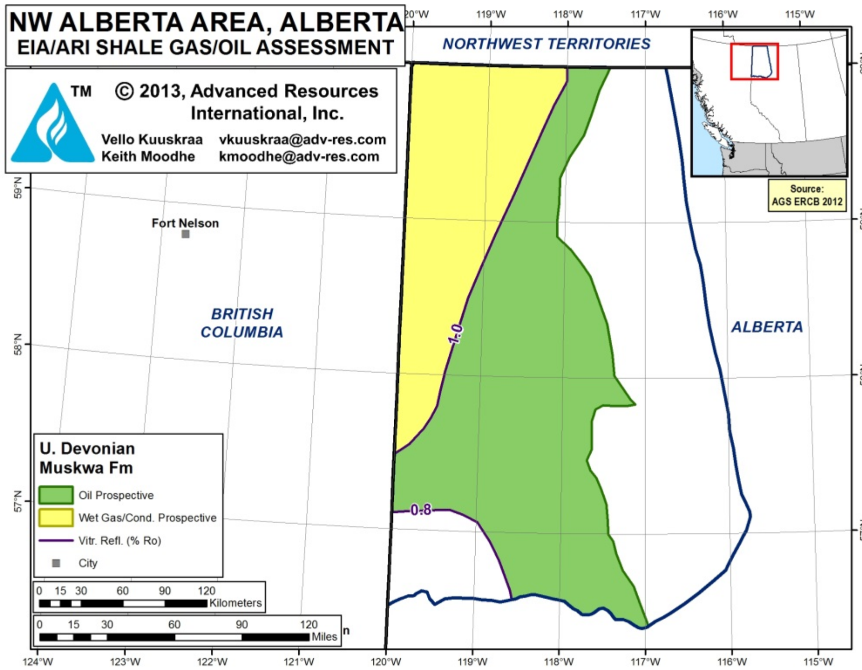
The Muskwa Shale is overlain by the Ft. Simpson Shale and is deposited on the Beaverhill Lake Formation, Figure I-27.[19] The Muskwa Shale is primarily an organic-rich limestone deposited in a deep-water marine setting.

Figure I-25. Outline and Depth of Muskwa Shale (Alberta).



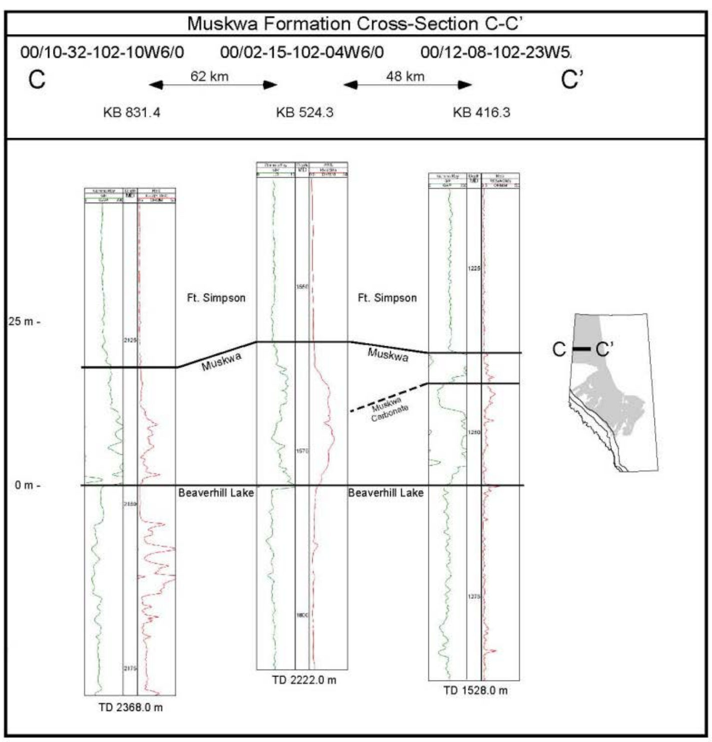

Source: ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-26. Prospective Area for Muskwa Shale (Alberta).




Source: ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-27. Stratigraphic Cross Section C-C' of the Muskwa Formation




Source: ERCB/AGS Open File Report 2012-06, October 2012.

## 4.2 Reservoir Properties (Prospective Area)

In the prospective area, the drilling depth to the top of the Muskwa Shale ranges from 3,300 feet in the northeast to 8,200 feet in the southwest. The gross shale thickness ranges from 33 feet to nearly 200 feet, with a high net to gross pay ratio.

The total organic content (TOC) ranges from less than 1 to over 10%, with the leaner TOC pay excluded by the net to gross pay ratio. Excluding the lean TOC segments, a sample of 47 TOC measurements from 5 wells provided an average TOC value of 3.2%. The thermal maturity ($R_o$) of the shale increases with depth, ranging from immature ($R_o$ < 0.8%) in the east to thermally mature for wet gas and condensate ($R_o$ of 1.0% to 1.2%) on the west. Based on thermal maturity, the Muskwa Shale has an oil-prone area with associated gas on the east and a wet gas/condensate area on the northwest.

## 4.3 Resources Assessment

The overall oil and gas prospective area of the Muskwa Shale in northwest Alberta is approximately 19,100 mi$^2$. Within the oil prospective area of 12,500 mi$^2$, the Muskwa Shale has a resource concentration of 6 million barrels of oil per mi$^2$ plus associated gas. Within the wet gas/condensate prospective area of 6,600 mi$^2$, the Muskwa Shale has a resource concentration of 1 million barrels of oil/condensate per mi$^2$ and 34 Bcf of wet gas per mi$^2$.

The risked resource in-place is estimate at 42 billion barrels of oil/condensate and 142 Tcf of shale gas. Given favorable reservoir properties and analog information from the Horn River and Cordova Embayment shales, we estimate a risked, technically recoverable resource of 2.1 billion barrels of shale oil/condensate and 31 Tcf of shale gas.

## 4.4 Comparison with Other Resource Assessments

The ERCB/AGS resource study, discussed above, calculated an unrisked mean oil in-place of 115,903 million barrels and an unrisked mean gas in-place of 413 Tcf for the Muskwa Shale study area in NW Alberta.[19] The in-place values in our study are different than those reported in the ERCB/AGS study due to the following: (1) given the limited exploration for the Muskwa Shale in NW Alberta, we judge this resource area to be only 50% de-risked; (2) we find the Muskwa Shale in this area to be moderately over-pressured; and (3) we have a lower associated gas-oil ratio for the shale.

## 4.5 Recent Activity

Husky Oil Canada, currently the most active explorer in Alberta's Muskwa Shale, has a concentrated 400,000-net acre land position in the Rainbow area. Husky drilled 14 Muskwa Shale wells in 2012, completing 4 wells, with the goal of de-risking its large land position and refining its well completion practices. Husky is currently looking for a JV partner to help finance the development of this shale oil play[17].

A smaller Canadian E&P company, Mooncor Oil and Gas, drilled a pilot test well into the Muskwa Shale in early 2009 (Well #06-34-94-12W6). The Muskwa zone was reported to be over-pressured and flowed 56$^{o}$ API condensate plus wet gas.[24]

## 5. COLORADO GROUP/SOUTHERN ALBERTA

### 5.1 Geologic Setting

The Colorado Group Shale covers a massive, 124,000-mi$^2$ area in southern Alberta and southeastern Saskatchewan. The western boundary of the Colorado Group is the Canadian Rockies Overthrust. The northern and eastern boundaries are defined by shallow shale depth and loss of net pay. The southern boundary is the U.S./Canada border. The Colorado Group encompasses a thick, Cretaceous-age sequence of sands, mudstones and shales. Within this sequence are two shale formations of interest - - the Fish Scale Shale Formation in the Lower Colorado Group and the Second White Speckled Shale Formation in the Upper Colorado Group, Figure I-28.[25] We selected the 5,000 to 10,000 foot depth contours for defining the 48,750-mi$^2$ prospective area, Figure I-29.

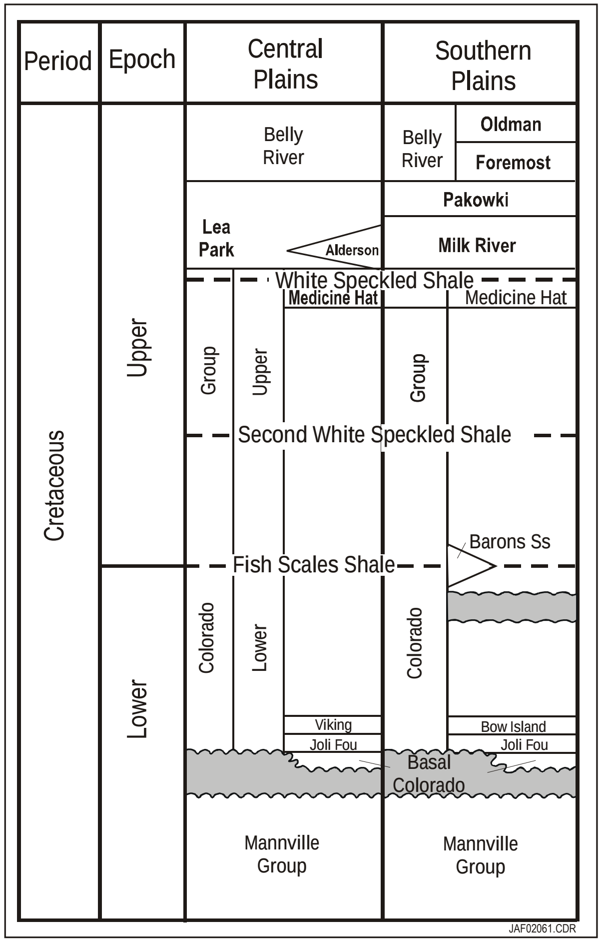
### 5.2 Reservoir Properties (Prospective Area)

In the prospective area, the depth to the Second White Speckled (2WS) and the Fish Scale shales ranges from 5,000 feet near Medicine Hat (on the east) to over 10,000 feet in the west. The Fish Scale Shale is generally about 200 feet deeper than the 2WS. The interval from the top of the 2WS to the base of the Fish Scales Shale ranges from 300 feet in the east to over 1,000 feet in the west, with an average gross pay of 523 feet. Assuming a conservative net to gross ratio of 20%, we estimate a net pay of 105 feet. Much of the Colorado Group Shale appears to be under-pressured, with a pressure gradient of about 0.3 psi/ft. The total organic carbon (TOC) content of the shale ranges from 2% to 3%. In the prospective area, the thermal maturity of the shale is low ($R_o$ of 0.5% to 0.6%). However, the presence of biogenic gas appears to have provided adequate volumes of gas generation. The rock mineralogy appears to be low to moderate in clay (31%) and thus favorable for hydraulic fracturing.

### 5.3 Resource Assessment

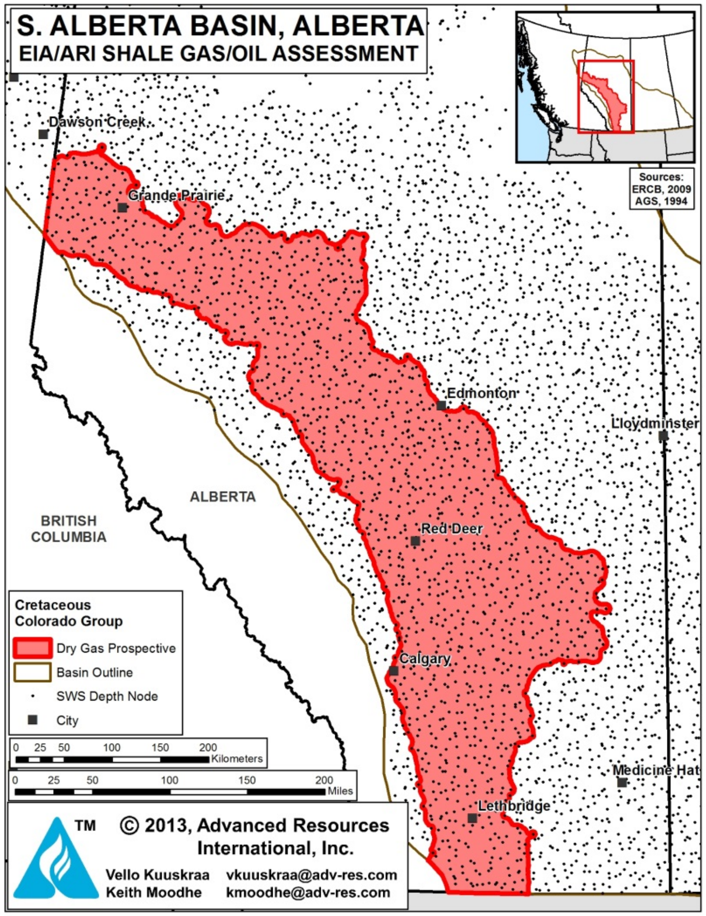
The 48,750-mi$^2$ prospective area of the Colorado Group Shale covers much of southwestern Alberta. Within this prospective area, the shale has a relatively low gas concentration of 21 Bcf/mi$^2$. The risked shale gas in-place for the Colorado Group Shale is estimated at 286 Tcf. Based on moderately favorable shale mineralogy, but other less favorable reservoir properties such as low pressure and an uncertain gas charge, we estimate a risked technically recoverable shale gas resource of 43 Tcf for the Colorado Group Shale.

Figure I-28. Colorado Group Stratigraphic Column




Source: Leckie, D.A., 1994.

Figure I-29. Colorado Group, Prospective Area




Source: ARI, 2013.

## 5.4 Comparison with Other Resource Assessments

In mid-2010, the Canadian Society for Unconventional Gas estimated 100 Tcf of gas in-place and 4 to 14 Tcf of marketable (recoverable) shale gas for the Colorado Shale.[4]

## 5.5 Recent Activity

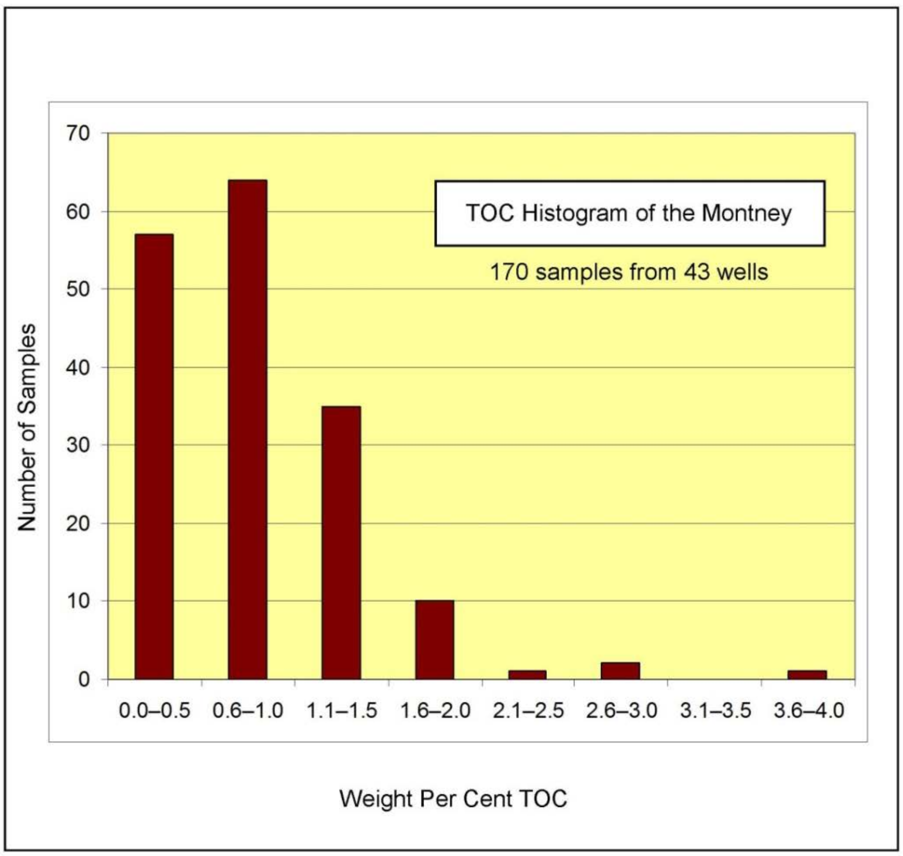
To date, the Colorado Group Shale has seen only limited exploration and development, primarily in the shallower eastern portion of the play area.

## 6. MONTNEY AND DOIG RESOURCE PLAYS (ALBERTA)

The Deep Basin of Canada also contains the Alberta portion of the Montney and Doig Resource plays. These multi-depositional Triassic-age hydrocarbon accumulations contain massive volumes of dry, wet and associated gas as well as oil/condensate.

We have excluded the Alberta portion of the Montney and Doig Resource Plays from our assessment because the reservoirs in the Alberta portion of the basin are generally classified as tight and conventional sands and because the organic-content (TOC) of the Montney and Doig Resource plays is low, averaging about 0.8%. Essentially all of the 170 samples taken from 43 Montney Formation wells have TOC values less than 1.5%, Figure I-30.[19] The basin average cut-off values for TOC in our study (for consistency with the USGS evaluations of shale oil and gas resources) is 2%, with individual reservoir rock intervals having to have at least 1.5% for inclusion in net, organic-rich pay.

Figure I-30. Histogram of Total Organic Carbon (TOC) of 170 Samples from the Montney Formation.




Source: ERCB/AGS Open File Report 2012-06, October 2012.

# SASKATCHEWAN/MANITOBA

## 1. WILLISTON BASIN/BAKKEN SHALE

### 1.1 Geologic Setting

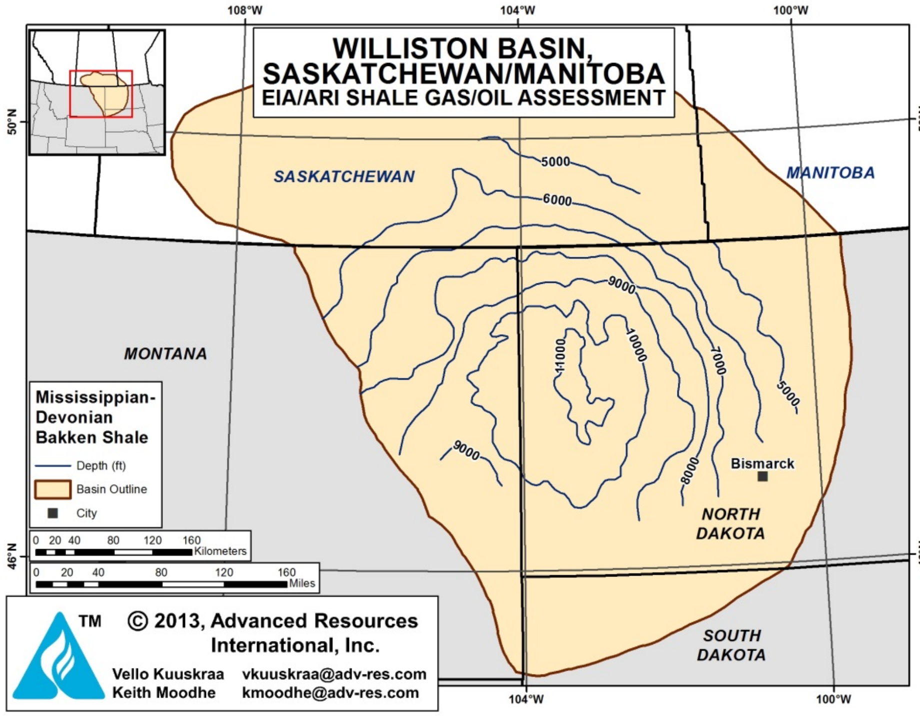
The Williston Basin of Canada extends northward from the U.S./Canada border into southern Saskatchewan and southwestern Manitoba and contains the Canadian portion of the Bakken Shale play, Figure I-31.[26] We estimate this basin contains 22 billion barrels of risked shale oil in-place, with 1.6 billion barrels as the risked, technically recoverable shale oil resource. The basin also contains 16 Tcf of associated shale gas in-place, with 2 Tcf as the risked, technically recoverable shale gas resource, Table I-5.

Table I-5. Shale Gas and Oil Reservoir Properties and Resources of Saskatchewan/Manitoba

| | | | Williston (110,000 mi²) | | | | Williston (110,000 mi²) |
|---|---|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | Williston (110,000 mi²) | Basic Data | Basin/Gross Area | | Williston (110,000 mi²) |
| | Shale Formation | | Bakken | | Shale Formation | | Bakken |
| | Geologic Age | | Devonian-Mississippian | | Geologic Age | | Devonian-Mississippian |
| | Depositional Environment | | Marine | | Depositional Environment | | Marine |
| Physical Extent | Prospective Area (mi²) | | 8,700 | Physical Extent | Prospective Area (mi²) | | 8,700 |
| | Thickness (ft) | Organically Rich | 50 | | Thickness (ft) | Organically Rich | 50 |
| | | Net | 20 | | | Net | 20 |
| | Depth (ft) | Interval | 5,500 - 8,000 | | Depth (ft) | Interval | 5,500 - 8,000 |
| | | Average | 6,000 | | | Average | 6,000 |
| Reservoir Properties | Reservoir Pressure | | Mod. Overpress. | Reservoir Properties | Reservoir Pressure | | Mod. Overpress. |
| | Average TOC (wt. %) | | 11.0% | | Average TOC (wt. %) | | 11.0% |
| | Thermal Maturity (% Ro) | | 0.64% | | Thermal Maturity (% Ro) | | 0.64% |
| | Clay Content | | Low/Medium | | Clay Content | | Low/Medium |
| Resource | Gas Phase | | Assoc. Gas | Resource | Oil Phase | | Oil |
| | GIP Concentration (Bcf/mi²) | | 3.1 | | OIP Concentration (MMbbl/mi²) | | 4.3 |
| | Risked GIP (Tcf) | | 16.0 | | Risked OIP (B bbl) | | 22.5 |
| | Risked Recoverable (Tcf) | | 2.2 | | Risked Recoverable (B bbl) | | 1.57 |

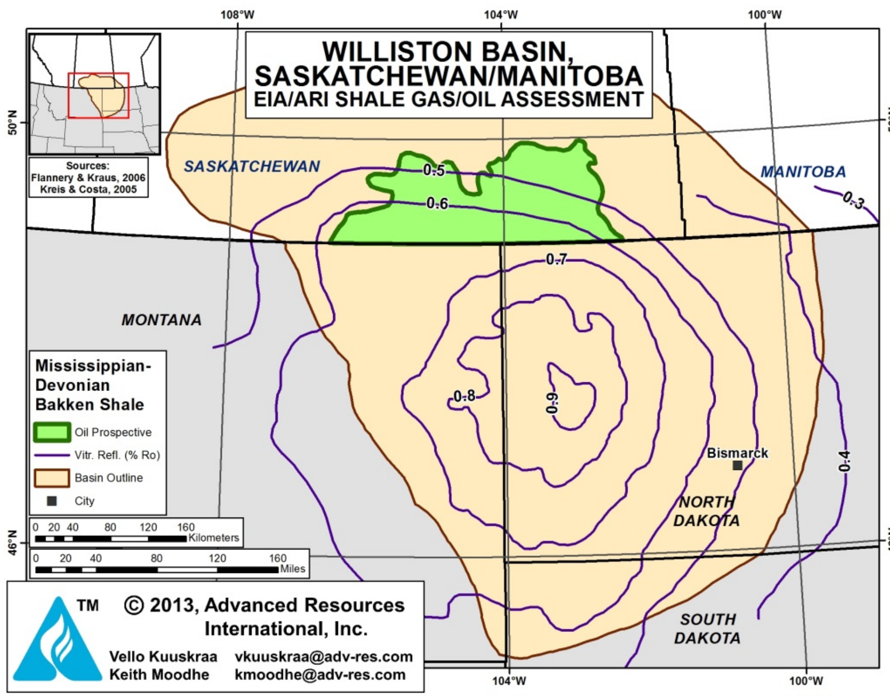
Within the larger Bakken Shale depositional area, we have defined a prospective area of 8,700 mi² where the shale appears to have more favorable reservoir properties and where past Bakken Shale drilling has occurred. The prospective area for the Bakken Shale in Saskatchewan and Manitoba is bounded on the north, east and west by the 30-foot shale interval contour and on the south by the U.S./Canada border, Figure I-32.[27]

Figure I-31. Outline and Depth of Williston Basin Bakken Shale (Saskatchewan/Manitoba)




Source: Modified from Saskatchewan Ministry of Energy Resources, 2010.

Figure I-32. Prospective Area for Williston Basin Bakken Shale (Saskatchewan/Manitoba)



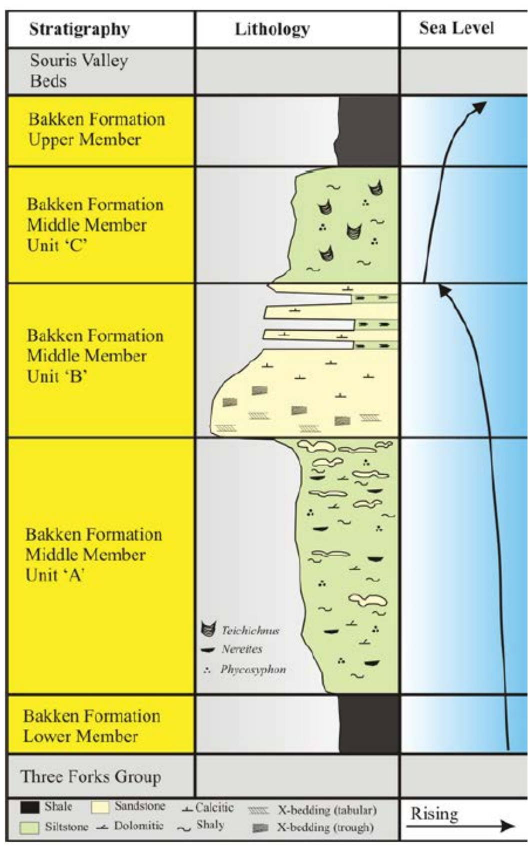

Source: AAPG Flannery & Kraus, 2006.

For this shale play, we have expanded our criteria for establishing the prospective area for oil to below our general cut-off of 0.7% thermal maturity (Ro) for two reasons. First, much of the oil in-place in this part of the Bakken Shale play is oil that has migrated from the deeper, more mature Bakken Shale in the center of the Williston Basin to the south.[28] Second, a considerable portion of the successful Bakken Shale well drilling in Canada has been in this thermally less mature area of the northern Williston Basin.

## 1.2 Reservoir Properties (Prospective Area).

Similar to the basal Banff/Exshaw Shale, the Late Devonian to Early Mississippian Bakken Shale consists of three reservoir units. The upper and lower units are dominated by organic-rich shale. The middle unit contains a variety of lithologies including calcareous sandstone and siltstone, dolomitic siltstone and limestone, Figure I-33.[26] The primary reservoir is the more porous and permeable middle unit, sourced by the upper and lower organic-rich shales. The Bakken Shale is over-pressured in much of its prospective area.

Figure I-33. Bakken Shale Stratigraphy (Saskatchewan)




Source: Saskatchewan Ministry of Energy Resources, 2010.

The drilling depth to the top of the Bakken Shale in the prospective area ranges from 5,500 feet on the north to about 8,800 feet on the south, averaging 6,600 feet in the prospective area. The Bakken Shale gross interval ranges from 30 to over 60 feet in the prospective area with an average net pay of about 20 feet, with favorable porosity of about 10%. The total organic content (TOC) in the prospective area averages 11% in the organic-rich upper and lower units. The Bakken Shale is prospective for oil plus associated gas.

## 1.3 Resource Assessment

Within the 8,700-mi$^2$ prospective area for oil and associated gas, the Bakken Shale has a resource concentration of 4 million barrels/mi$^2$ for oil plus moderate volumes of associated gas.

The risked oil resource in-place for the prospective area is estimated at 22 billion barrels plus 16 Tcf of associated natural gas. Based on recent well performance and reservoir properties, we estimate risked, technically recoverable resources of 1.6 billion barrels of oil and 2 Tcf of associated gas.

## 1.4 Recent Activity

The Bakken Shale in Canada is an active shale oil play with over 2,000 producing wells and about 75,000 barrels per day of oil production, as of mid-2011. The various companies active in the play have publically reported 225 million barrels of proved and probable reserves.[29]

# EASTERN CANADA

Canada has four potential shale gas plays - - the Utica and Lorraine shales in the St. Lawrence Lowlands of the Appalachian Fold Belt of Quebec, the Horton Bluff Shale in the Windsor Basin of northern Nova Scotia, and the Frederick Brook Shale in the Moncton Sub-Basin of the Maritimes Basin in New Brunswick. These shale oil and gas formations and basins are in an early exploration stage. Therefore, only preliminary shale resource assessments are offered for the Utica and Horton Bluff shales. Insufficient information exists for assessing the Lorraine and Frederick Brook shales.

The two assessed Eastern Canada shale gas basins assessed by this study contain 172 Tcf of risked gas in-place, with 34 Tcf as the risked, technically recoverable shale gas resource, Table I-6.

Table I-6. Shale Gas Reservoir Properties and Resources of Eastern Canada

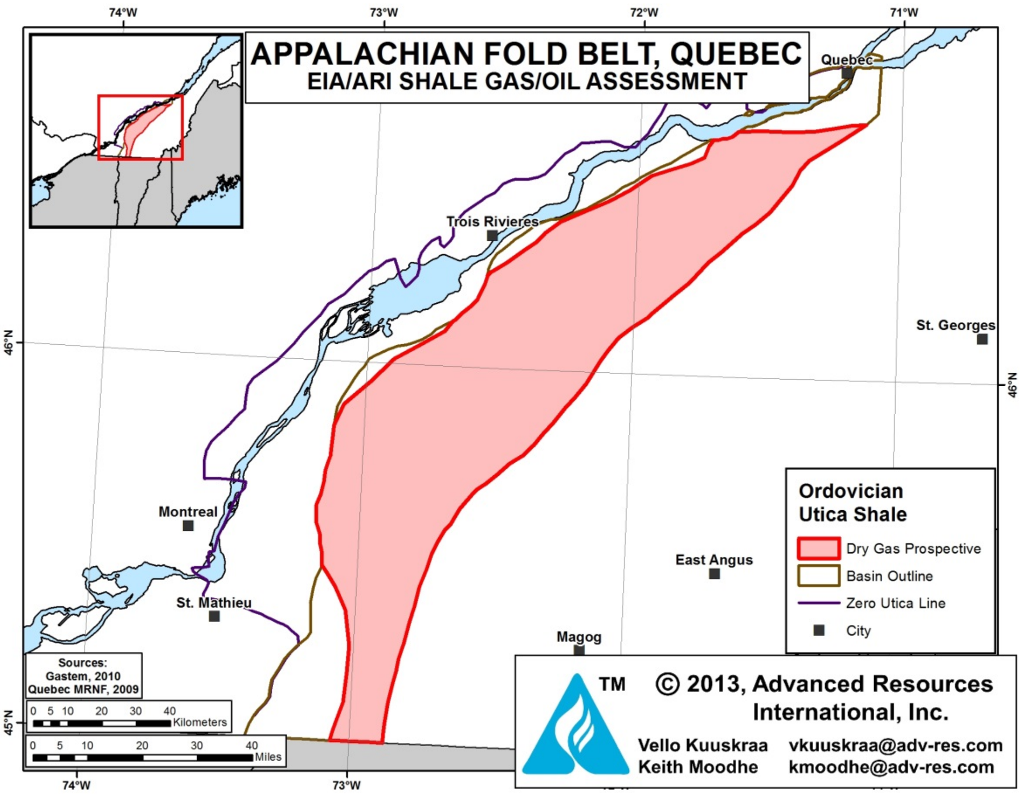
| | | | Appalachian Fold Belt | Windsor |
|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | Appalachian Fold Belt ($3,500\ mi^2$) | Windsor ($650\ mi^2$) |
| Basic Data | Shale Formation | | Utica | Horton Bluff |
| Basic Data | Geologic Age | | Ordovician | Mississippian |
| Basic Data | Depositional Environment | | Marine | Marine |
| Physical Extent | Prospective Area ($mi^2$) | | 2,900 | 520 |
| Physical Extent | Thickness (ft) | Organically Rich | 1,000 | 500 |
| Physical Extent | Thickness (ft) | Net | 400 | 300 |
| Physical Extent | Depth (ft) | Interval | 4,000 - 11,000 | 3,000 - 5,000 |
| Physical Extent | Depth (ft) | Average | 8,000 | 4,000 |
| Reservoir Properties | Reservoir Pressure | | Mod. Overpress. | Normal |
| Reservoir Properties | Average TOC (wt. %) | | 2.0% | 5.0% |
| Reservoir Properties | Thermal Maturity (% Ro) | | 2.00% | 2.00% |
| Reservoir Properties | Clay Content | | Low | Unknown |
| Resource | Gas Phase | | Dry Gas | Dry Gas |
| Resource | GIP Concentration ($Bcf/mi^2$) | | 133.9 | 81.7 |
| Resource | Risked GIP (Tcf) | | 155.3 | 17.0 |
| Resource | Risked Recoverable (Tcf) | | 31.1 | 3.4 |

# 1. APPALACHIAN FOLD BELT (QUEBEC)/UTICA SHALE

## 1.1 Introduction and Geologic Setting

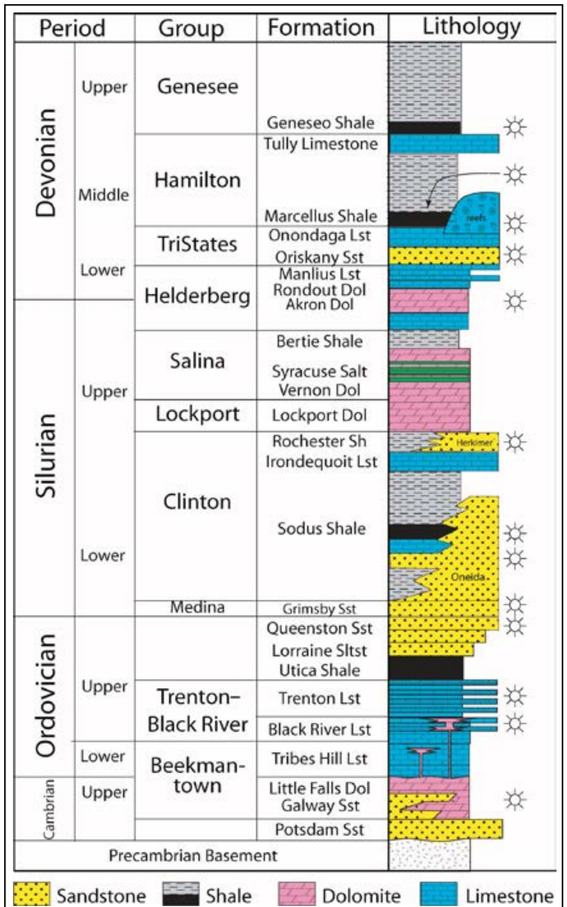
The Utica Shale is located within the St. Lawrence Lowlands of the Appalachian Fold Belt in Quebec, Canada, Figure I-34. The Utica is an Upper Ordovician-age shale, located above the conventional Trenton-Black River Formation, Figure I-35. A second, less defined, thicker but lower TOC Lorraine Shale overlies the Utica. Three major faults - - Yamaska, Tracy Brook and Logan's Line - - form structural boundaries and partitions for the Utica Shale play in Quebec.

Figure I-34. Utica Shale Outline and Prospective Area (Quebec)




Source: ARI, 2013.

Figure I-35. Utica Shale Stratigraphy (Quebec)




Source: L. Smith AAPG, AAPG Bulletin, v. 90, no. 11 (November 2006), pp. 1691–1718

JAF21299.AI

## 1.2 Reservoir Properties (Prospective Area)

The extensive faulting and thrusting in the Utica Shale introduces considerable exploration and completion risk. The depth to the top of the shale in the prospective area ranges from 3,000 to over 11,000 feet, shallower along the southwestern and northwestern boundaries and deeper along the eastern boundary. The Utica Shale has a gross interval of 1,000 feet. With a net to gross ratio of 40%, the net organic-rich shale is estimated at 400 feet. The total organic content (TOC) ranges from 1.5% to 3%, with the higher TOC values concentrated in the Upper Utica Shale. The thermal maturity of the prospective area ranges from an $R_o$ of 1.1% to 4% and averages 2%, placing the shale primarily in the dry gas window. Data on quartz and clay contents are not publicly available.



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## 1.3 Resource Assessment

The prospective area of the Utica Shale in Quebec is estimated at 2,900 $mi^2$. Within this prospective area, the shale has a gas in-place concentration of 134 Bcf/$mi^2$. As such, the risked shale gas in-place is 155 Tcf. Assuming low clay content, but considerable geologic complexity within the prospective area, we estimate a risked, technically recoverable shale gas resource of 31 Tcf for the Utica Shale.

## 1.4 Comparison with Other Resource Assessments

In mid-2010, the Canadian Society for Unconventional Gas (CSUG) cites a gas in-place of 181 Tcf (unrisked) for the Utica Shale in Canada with 7 to 12 Tcf of marketable (recoverable) shale gas resources.[30]

## 1.5 Exploration Activity

Two large operators, Talisman and Forest Oil, plus numerous smaller companies such as Questerre, Junex, Gastem and Molopo, hold leases in the Utica Shales of Quebec. Approximately 25 exploration wells have been drilled with moderate results. Market access is provided by the Maritimes and Northeastern pipeline as well as the TransCanada Pipeline to markets in Quebec City and Montreal. Currently shale gas drilling in Quebec is on hold, awaiting further environmental studies.

## 2. WINDSOR BASIN (NOVA SCOTIA)/HORTON BLUFF SHALE

### 2.1 Introduction and Geologic Setting

The Horton Bluff Shale is located in north-central Nova Scotia. It is a Carboniferous (Early Mississippian) shale within the Horton Group, Figure I-36. Because the Horton Bluff Shale rests directly on the pre-Carboniferous igneous and metamorphic basement, it has experienced high heat flow and has a high thermal maturity in northern Nova Scotia. The Horton Bluff Shale geology is complex, containing numerous faults.

### 2.2 Reservoir Properties (Prospective Area)

The regional extent of the Horton Shale play is only partly defined as the basin and prospective area boundaries are highly uncertain. A preliminary outline and 520-mi$^2$ prospective area has been estimated for the Horton Bluff Shale play, Figure I-37. The depth of the shale in the prospective area ranges from 3,000 to 5,000 feet. The shale interval is thick with 500 feet of gross pay and 300 feet of organically rich net pay. The TOC is 4% to 5% (locally higher). The thermal maturity of the prospective area ranges from a $R_o$ of 1.2% in the south to a $R_o$ of over 2.5% in the northeastern portion of the prospective area, placing the Horton Bluff Shale primarily in the dry gas window. Data from the Kennetcook #1, drilled to test the Horton Bluff Shale in the Windsor Basin, provided valuable data on reservoir properties.

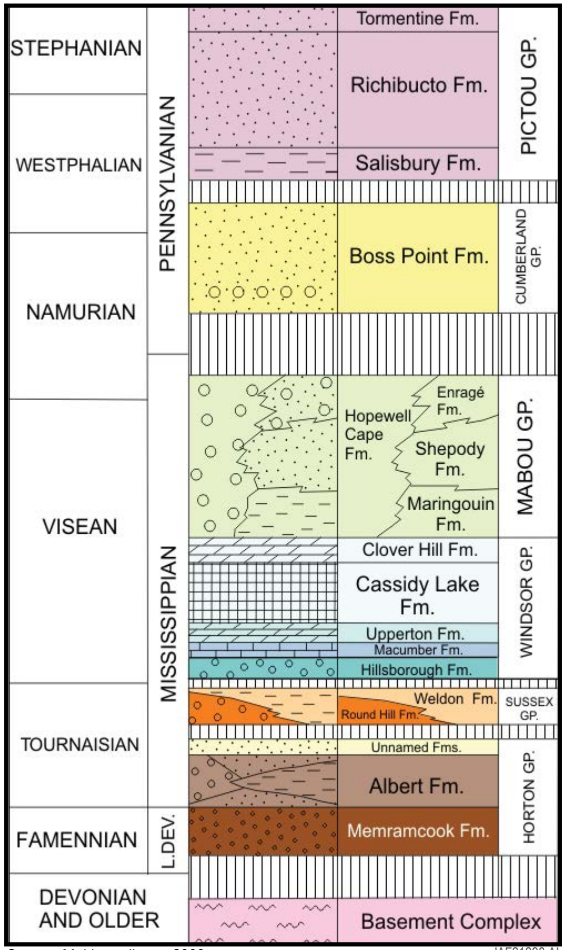
### 2.3 Resource Assessment

The 520-mi$^2$ prospective area of the Horton Bluff Shale in Nova Scotia is in the northern and eastern portions of the play area. Within this prospective area, the shale has an in-place resource concentration of 82 Bcf/mi$^2$. Our preliminary resource estimate is 17 Tcf of risked shale gas in-place. Given the geologic complexity in the prospective area, we estimate a risked, technically recoverable shale gas resource of 3 Tcf for the Horton Bluff Shale.

### 2.4 Recent Activity.

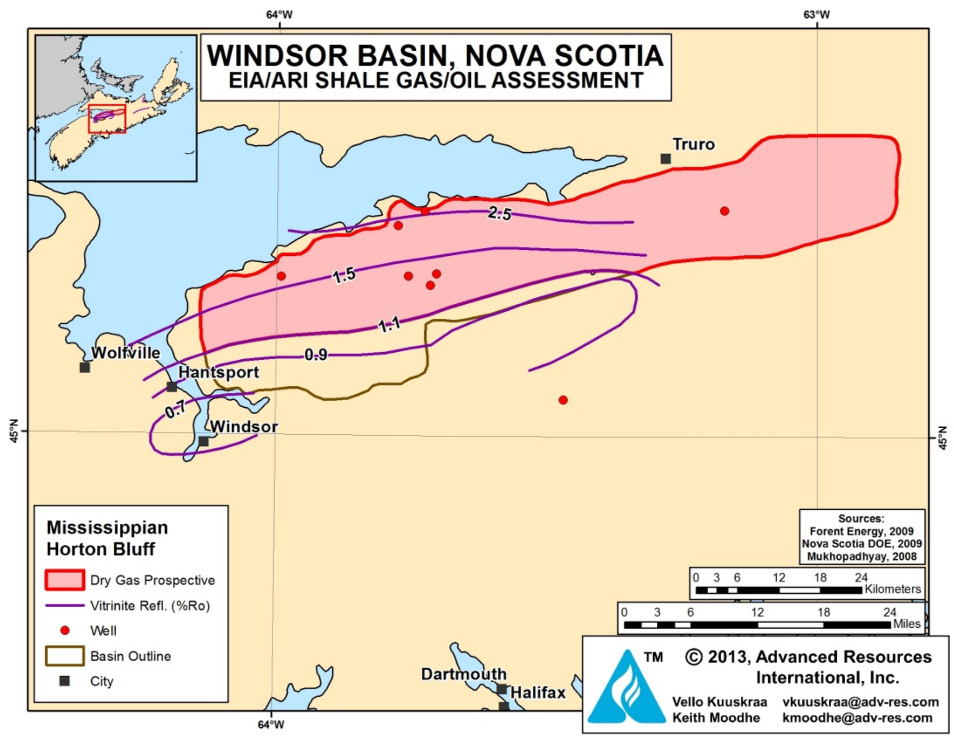
Two small operators, Triangle Petroleum and Forent Energy, have acquired leases and have begun to explore the Horton Bluff Shale.

Figure I-36. Horton and Frederick Brook Shale (Horton Group) Stratigraphy




Source: Mukhopadhyay, 2009

Figure I-37. Outline and Prospective Area for Horton Bluff Shale (Nova Scotia)

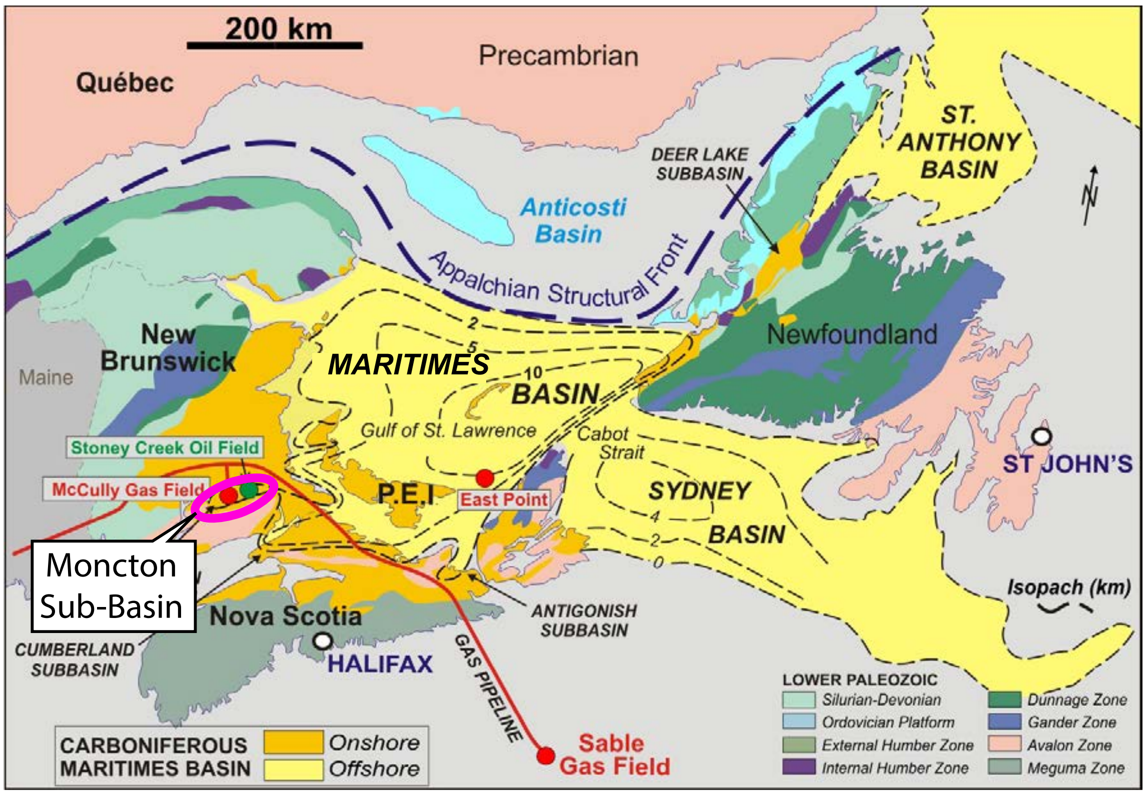



Source: ARI, 2013.

## 3. MONCTON SUB-BASIN (NEW BRUNSWICK)/FREDERICK BROOK SHALE

The Frederick Brook Shale is located in the Moncton Sub-Basin of the larger Maritimes Basin of New Brunswick, Figure I-38. This Mississippian-age shale is correlative with the Horton Group in Nova Scotia. The Moncton Sub-Basin is bounded on the east by the Caledonia Uplift, on the west by the Kingston Uplift, and on the north by the Westmoreland Uplift, Figure I-39. Because of limited data, the definition of the prospective area of the Frederick Brook Shale has yet to be established.

Figure I-38. Location of Moncton Sub-Basin and Maritimes Basin

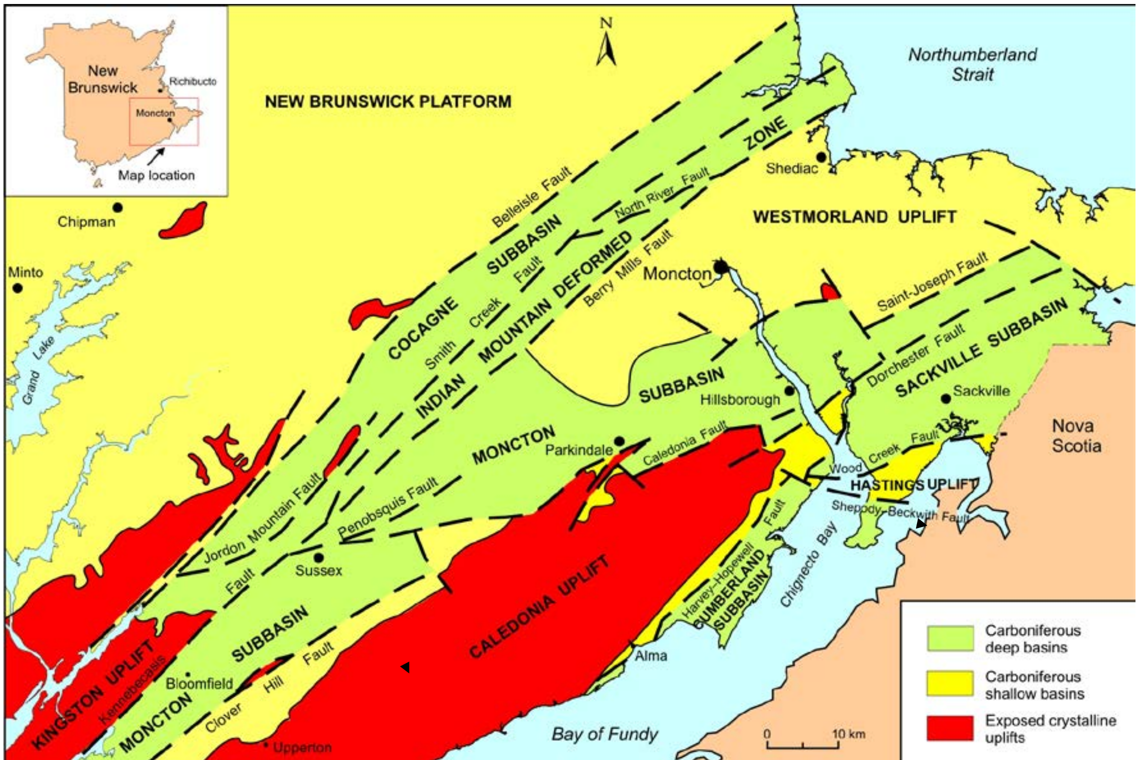



Source: Geological Survey of Canada, 2009 CSPG CSEG CWLS Convention, Canada JAF21297.AI

The Frederick Brook Shale in the Moncton Sub-Basin is structurally complex, with extensive faulting and deformation. Its depth ranges from about 3,000 feet along the basin's eastern edges to 15,000 feet in the north. The total organic content of the shale varies widely (1% to 10%), but typically ranges from 3% to 5%. No public data are available on the mineralogy of the shale. The thermal maturity ranges from immature $R_o < 1\%$ in the shallower portions of the basin to highly mature ($R_o > 2\%$) in the deeper western and southern areas of the basin.

Much of the data for this preliminary assessment of the Frederick Brook Shale is from the McCully gas field along the southwestern edge of the Moncton Sub-Basin and from a handful of vertical exploration wells. Other areas, such as the Cocagne Sub-Basin, Figure I-39, may also be prospective for the Frederick Brook Shale but have yet to be explored or assessed.

Figure I-39. Structural Controls for Moncton Sub-Basin (New Brunswick) Canada




Source: P.K. Mukhopadhyay, Search and Discovery Article #10167 (2008)

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