Hydrocarbon and By-Product Reserves in British Columbia

2014 | BC Oil and Gas Commission

BC Oil & Gas COMMISSION

About the

BC Oil and Gas Commission

The BC Oil and Gas Commission (Commission) is the provincial single-window regulatory agency with responsibilities for regulating oil and gas activities in British Columbia, including exploration, development, pipeline transportation and reclamation.

The Commission's core services include reviewing and assessing applications for industry activity, consulting with First Nations, cooperating with partner agencies, and ensuring industry complies with provincial legislation and all regulatory requirements. The public interest is protected by ensuring public safety, respecting those affected by oil and gas activities, conserving the environment, and ensuring equitable participation in production.

For general information about the Commission, please visit: www.bcogc.ca or phone 250-794-5200.

Mission

We regulate oil and gas activities for the benefit of British Columbians.

We achieve this by:

- Protecting public safety,
- Respecting those affected by oil and gas activities,
- Conserving the environment, and
- Supporting resource development.

Through the active engagement of our stakeholders and partners, we provide fair and timely decisions within our regulatory framework.

We support opportunities for employee growth, recognize individual and group contributions, demonstrate accountability at all levels, and instill pride and confidence in our organization.

We serve with a passion for excellence.

Vision

To provide oil and gas regulatory excellence for British Columbia's changing energy future.

Values

Respectful

Accountable

Effective

Efficient

Responsive

Transparent

Purpose of Report

Hydrocarbon and By-Product Reserves

The oil and gas production and remaining recoverable reserve numbers are a current reflection of the state of development in British Columbia. As drilling continues to define additional prospective lands, resource estimates become proven reserves, substantiated with production volumes and geological data.

This report summarizes oil and gas production and remaining recoverable reserves in British Columbia providing assurance of supply for the development of policy, regulation and investment. It also emphasizes the growth and future potential of unconventional resources as a long-term source of natural gas for the province.

Estimates of British Columbia's natural gas, oil, condensate, and associated by-product reserves as of Dec. 31, 2014 are presented in this report. The estimates have been prepared by the Commission using accepted geological and engineering practices (including the Canadian Oil and Gas Evaluation Handbook (COGEH) and the Guidelines for the Practical Evaluation of Underdeveloped Reserves in Resource Plays (SPEE Monograph 3)).

The reserve numbers represent proved plus probable (P_{50}) reserves recoverable using current technology. The proved reserves reflect "reasonable certainty" to be commercially recoverable, and are proven by drilling, testing and or production. Probable reserves are less likely to be recovered than Proven Reserves and are interpreted from geographical data or engineering analyses.

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Executive Summary

British Columbia's remaining reserves as of Dec. 31, 2014, together with a comparison of the Dec. 31, 2013 reserves, are summarized in Table 1.

In 2014 reserves increased for gas, condensate and pentanes, and natural gas liquids (NGL) due to significant drilling in the regional Montney formation. The oil reserves decrease was attributed to a reduction in the number of new drills and a write-down of remaining reserves in pools no longer producing. Continued drilling in oil-rich areas of the Montney is expected to be the strongest contributor to reserves growth in future years. These reserve revisions are shown in Appendix A, Table A-1.

Unconventional reservoirs have tremendous growth potential, with booked reserves (raw) representing less than two per cent of current resource estimates of 2,781 Trillion Cubic Feet (TCF) Oil and Gas in Place (OGIP). See Appendix B, Table B-1: Summary of Unconventional Plays.

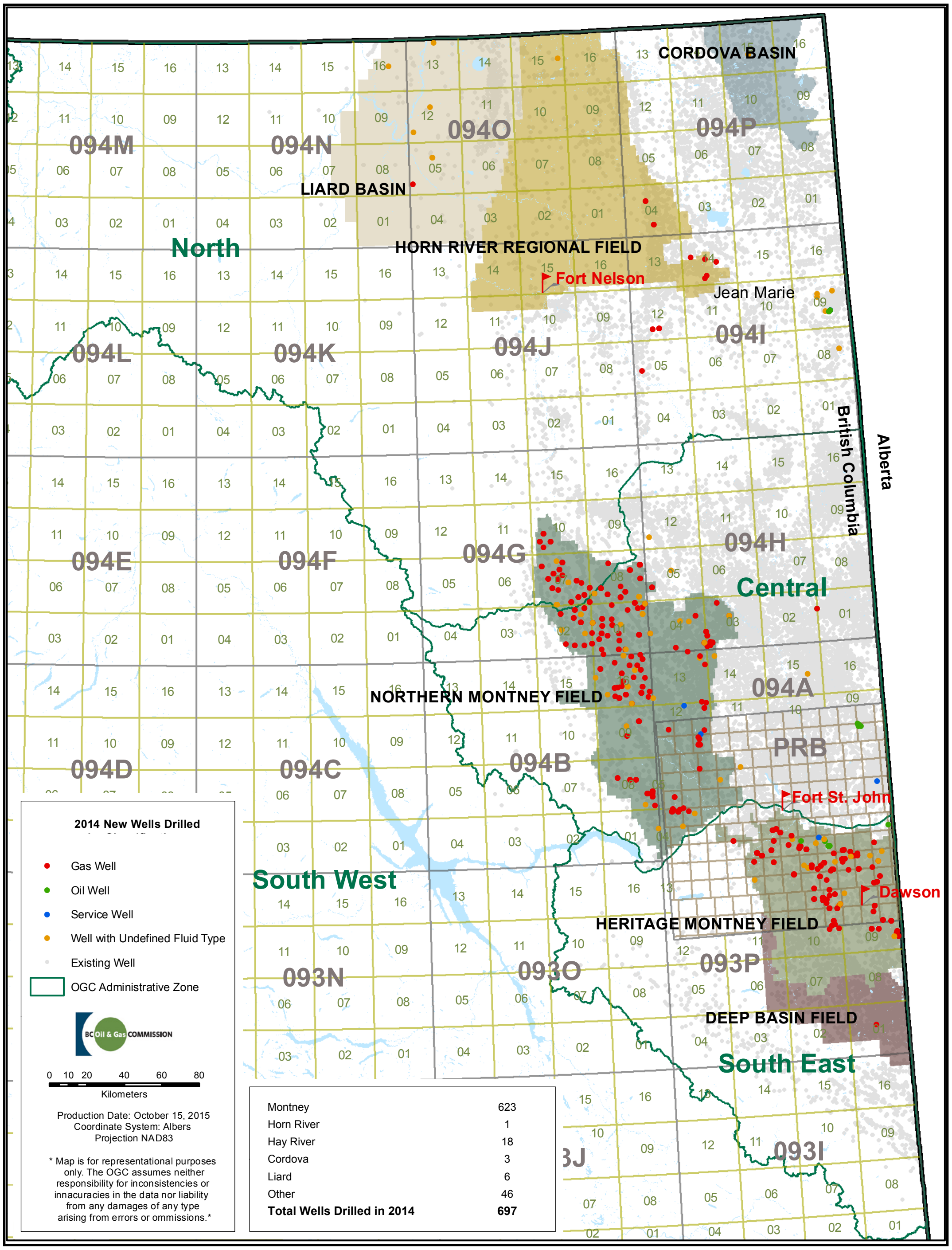
Historical data from previous hydrocarbon reports published by the Commission is summarized in Appendix A; Tables A-2 and A-3. Detailed information on the reserves and reservoir parameters for each field and pool in B.C. is available on the Commission website provided in the Table of Contents.

The lack of discoveries highlighted in Table A-1 reflects industry attention to regional accumulations of unconventional resources rather than exploration.

Table 1: Remaining Reserves as of December 31, 2014

Reserve Type	2014	2013	Percent Change
Oil	18.1 10^6m^3 (113.6 MMSTB)	19.3 10^6m^3 (121.4 MMSTB)	-6.2%
Gas	1,443.9 10^9m^3 raw (51.0 Tcf raw)	1,197.2 10^9m^3 raw (42.3 Tcf raw)	20.6%
Pentanes$^+$	29.7 10^6m^3 (186.8 MMSTB)	20.8 10^6m^3 (130.7 MMSTB)	42.8%
LPG	77.8 10^6m^3 (489.6 MMSTB)	53.6 10^6m^3 (337.1 MMSTB)	45.2%
Sulphur	14.8 10^6 tonnes (14.6 MMSTB)	17.7 10^6 tonnes (17.4 MMSTB)	-16.4%

Figure 1: 2014 Wells Drilled by Type



In Figure 1: Wells Drilled by Type, the location and areal extent of the major unconventional fields (Montney, Horn River, Liard, Cordova Embayment, Jean Marie and Deep Basin) are included on the map. There was a significant increase in drilling activity in 2014 with the drilling of 697 wells. The majority of the wells were drilled in the regional Montney formation (89 per cent) with less activity occurring in areas to the north: Liard Basin, Horn River Basin and Cordova Basin. Continued drilling within the oil leg in the Montney field accounted for 39 per cent (14 wells) of oil wells drilled in the province (36 wells). The most active area remains the Hay River Bluesky A pool with 14 oil wells drilled in 2014 (39 per cent of all oil wells).

There were also 11 service wells drilled in 2014.

Figure 2: 2014 Drilling Activity by Play Area

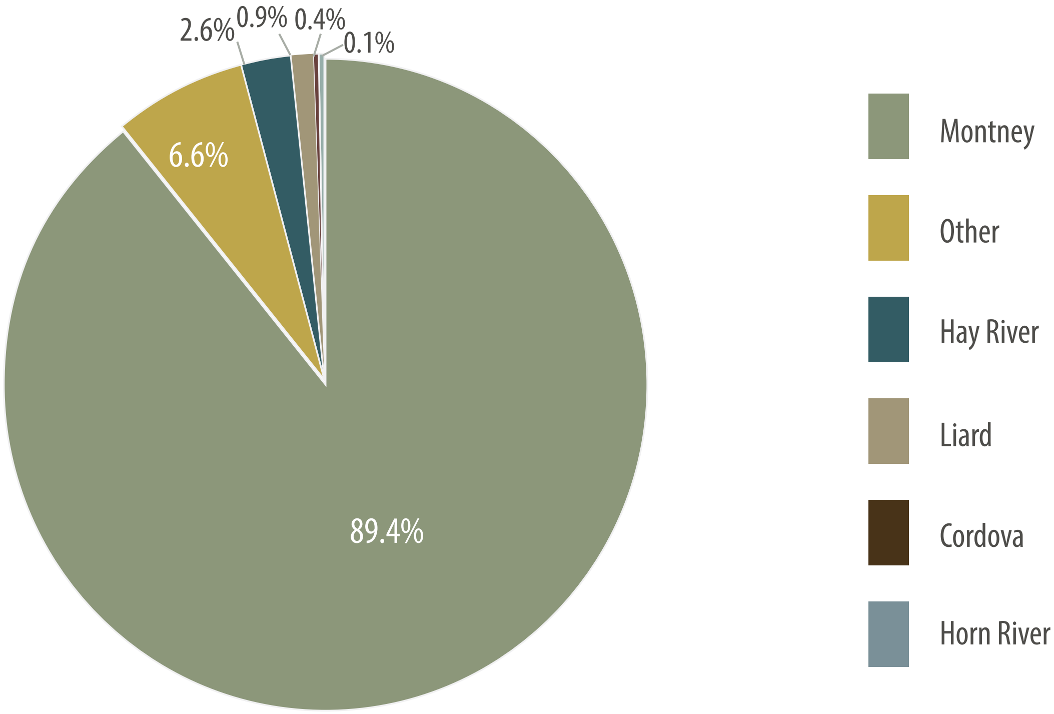


Figure 2 shows the 2014 drilling activity by well type and area. The Montney was the dominant zone with 89 per cent of the wells drilled in this area compared to 80 per cent in 2013 and 73 per cent in 2012.

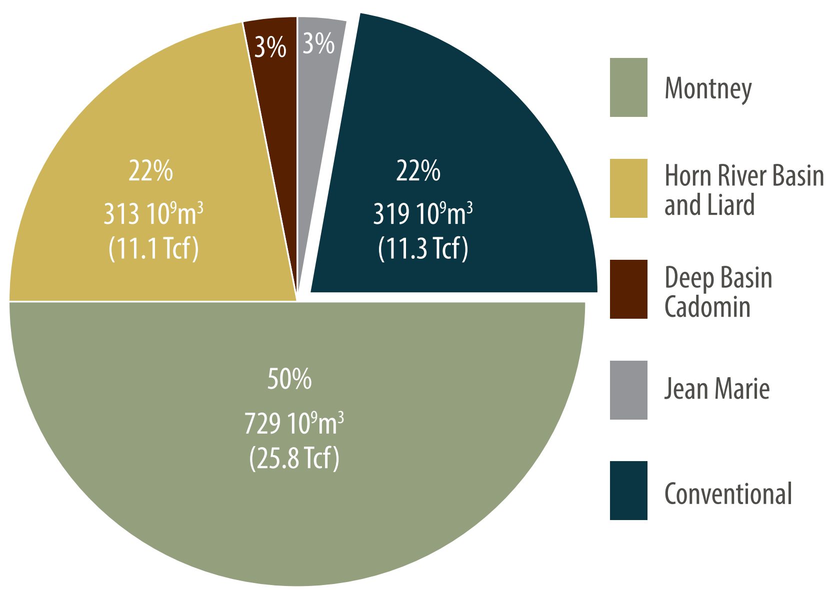
Discussion

A. Gas Reserves

As of Dec. 31, 2014, the province's remaining raw gas reserves were 1,444 10^9m^3, a 20.6 per cent increase over the 2013 volume. The upward trend of reserve revisions continues largely due to successful development of unconventional Montney tight gas in the province.

Figure 3 illustrates the distribution of remaining conventional and unconventional gas reserves per play. Approximately 50 per cent of the remaining recoverable reserves are in the Montney unconventional play, 22 per cent in the Horn River area and the conventional reserves accounting for an additional 22 per cent.

Figure 3: Remaining Gas Reserves - Conventional vs. Unconventional



In Figure 4, gas production was stable at approximately 3.0 Billion cubic feet per day (Bcf/d) from 2005 to 2010 as the majority of drilling in the province was for conventional high permeability reservoirs. It was not until 2005 that the first unconventional Montney well was drilled, followed by the drilling of Horn River wells in 2008. In 2011/2012, for the first time, unconventional production surpassed that of conventional production. In 2014, unconventional plays accounted for 73 per cent of British Columbia's total gas production. Total raw natural gas production for 2014 was 46.2 $10^9 m^3$ (1.6 Tcf), a 5.7 per cent increase over 2013 annual production.

Figure 5 presents the Commission's reserves bookings from 1994 – 2014, showing unconventional Montney and Horn River reserves versus all other reserves grouped together. Remaining reserves were fairly consistent for a decade prior to 2003, when the number of gas wells drilled increased dramatically. Between 2003 and 2006, activity reached record levels (1,300 gas wells drilled in 2006), with predominant targets being shallow Cretaceous (Notikewin, Bluesky and Gething) and Triassic (Baldonnel and Halfway), in the Deep Basin the Cadomin and Nikanassin, and the Jean Marie in the north east.

In 2005, however, the onset of Montney horizontal drilling with large hydraulic stimulation created a new supply of gas. This was followed by Horn River development in 2010.

Annual production in B.C. has risen 39 per cent in the last five years, with the majority, 73 per cent, now coming from unconventional reservoirs. The reserve life index, the current remaining reserve volume divided by the current production rate, has increased to 31 years in 2014, from 27 years in 2013. In 2014 the remaining raw gas reserves increased 20.6 per cent, due principally to a review of both the Northern Montney and Heritage Montney regional fields.

Figure 4: Gas Wells Drilled Per Year and Calendar Day Raw Gas Rate

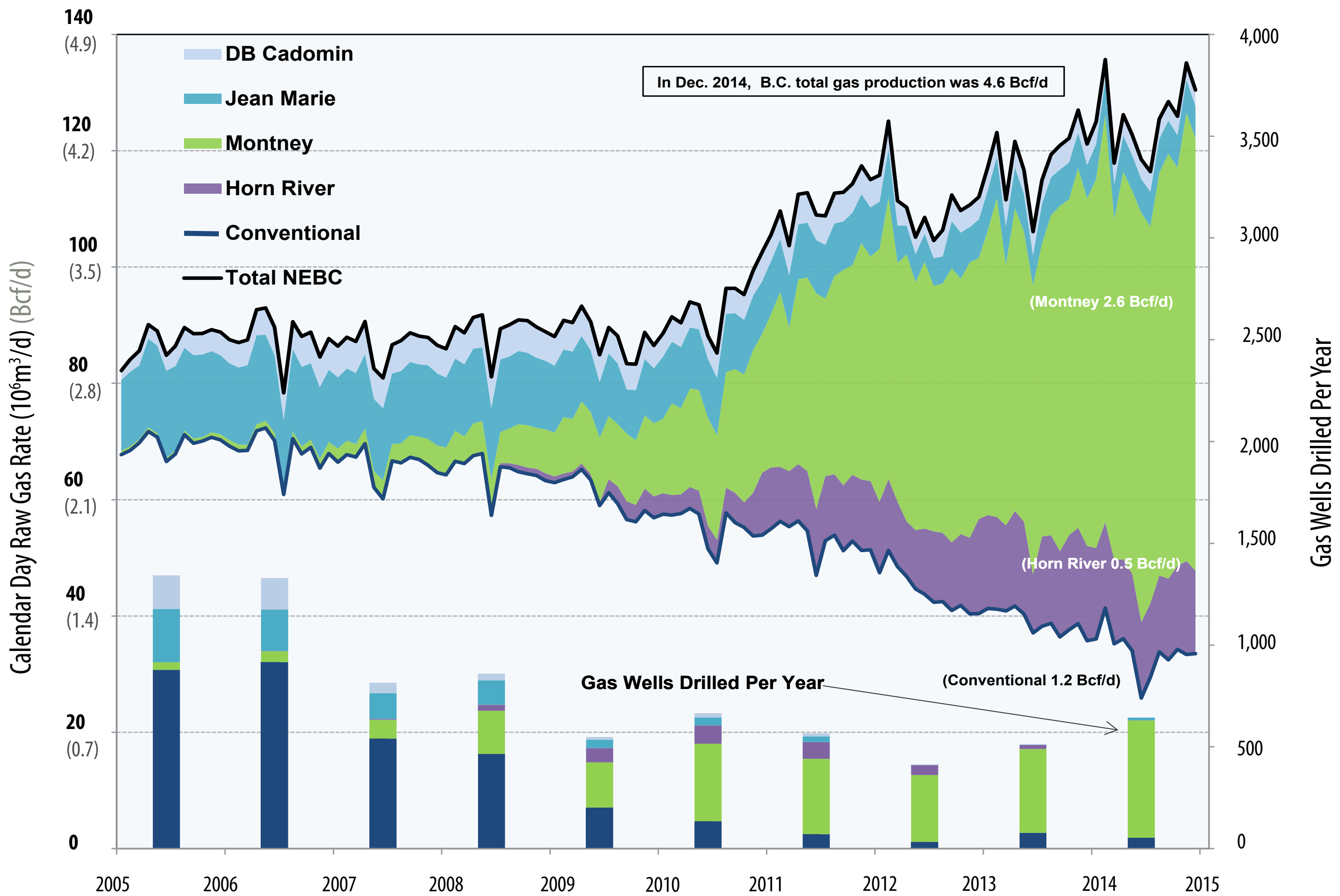


Figure 5: Historical Gas Development in B.C.

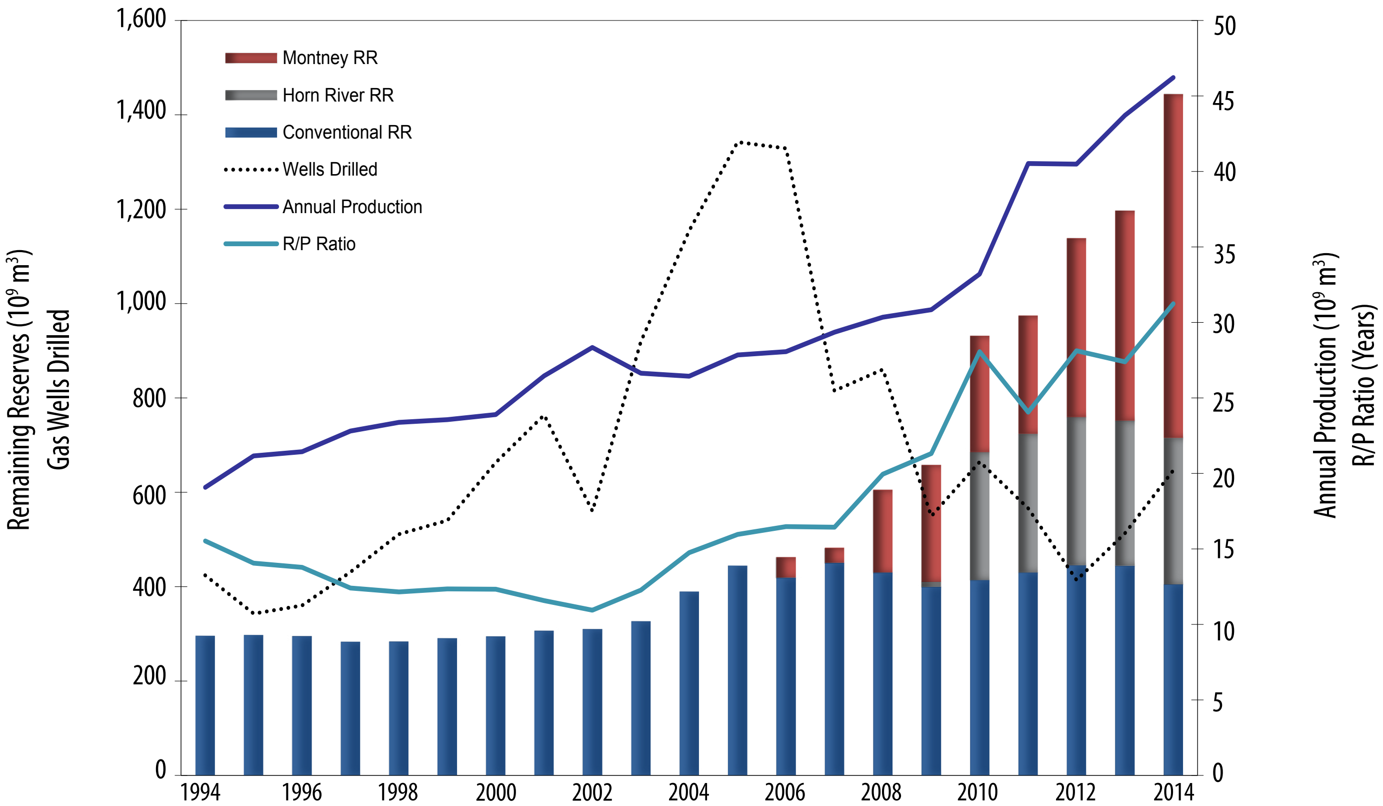


Figure 6 highlights the growth of hydraulic fracture stimulation operations, a key to developing unconventional reservoirs. The number of hydraulically fractured wells increased significantly after the year 2000, consisting of one or two stimulations per hydraulically fractured well.

Beginning in 2007, there was a significant increase in the number of hydraulic fracture stimulations for each, now horizontal, well. More recently it is not unusual to see as many as 20 fracture stimulations per well, with 95 to 130 tonnes per stage of proppant and a total fluid pumped of 7,240 m^3. A summary of the completion parameters for the Montney, such as number of fracture stages and fluid pumped, are included in later sections of this report.

Montney - Unconventional Tight Gas Play

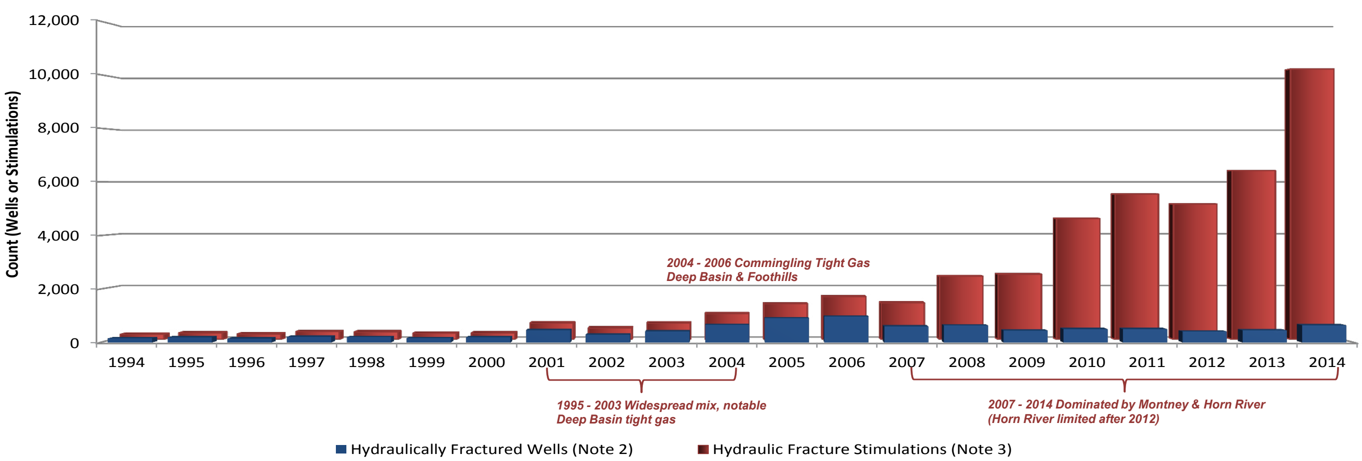
The Unconventional Montney Play Trend represents 50 per cent (25.8 Tcf) of the province's remaining recoverable raw gas reserves. In 2014, 0.9 Tcf was produced from the Montney, accounting for 55 per cent of total gas production in the province.

Geology

The unconventional Lower Triassic Montney play targets dry gas, liquids rich gas, and oil in over-pressured siltstones along an extensive 29,850 km^2 play trend that stretches northwest 200 km from the B.C.-Alberta border near Dawson Creek to the B.C. foothills (Figure 7a).

The unconventional Montney is confined to the northwest by outcrop and to the southwest by depth as it deepens to beyond 4,000 m True Vertical Depth (TVD). The eastern play limit is defined by the transition to a normal formation pressure regime. While hydrocarbon charge is pervasive throughout the play trend, local reservoir conditions can vary extensively. As such, preferred landing targets within the 300+m thick Montney formation as well as completion methodologies are also locally applied.

Figure 6: Hydraulically Fractured Wells and Hydraulic Fracture Stimulations



Note 1: The year indicates which year the hydraulic fracture stimulation took place. For hydraulically fractured wells, this is the year the first hydraulic fracture stimulation occurred.

Note 2: The count of wells with hydraulic fracture stimulation (counted once, by the year the first hydraulic fracture stimulation occurred).

Note 3: The count of individual hydraulic fracture stimulations. Vertical wells typically have one, horizontal wells may have more than 30.

Figure 7a: Unconventional Montney Play Trend

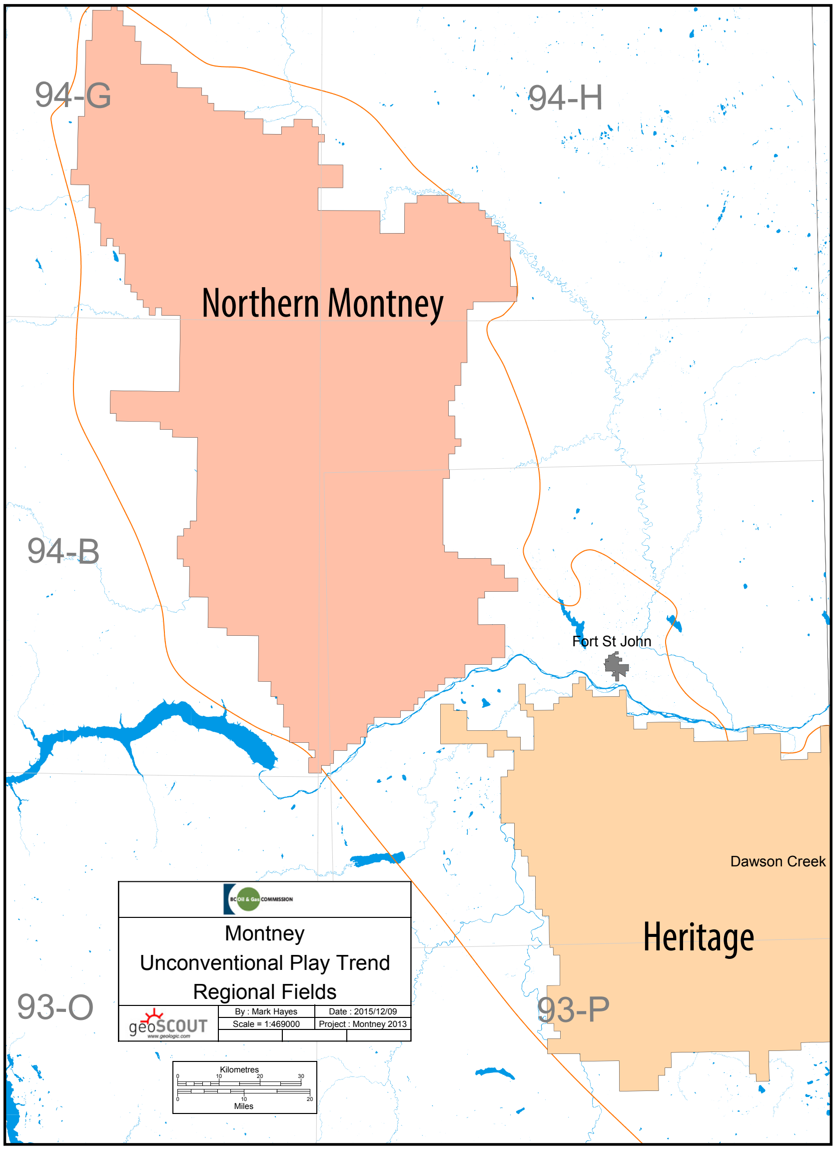


Table 2: Regional Heritage Field Reservoir Parameters

Reservoir Data	Heritage
Depth Range	1,400 – 3,200 m
Gross Thickness	30 – 300 m
TOC Range	~2%
Porosity	2 – 9%
Water Saturation	25%
Pressure	14 – 86 MPa
Pressure Regime	Over Pressure
Temperature	50 – 110° C
H_2S	0 - 1.0%
CO_2	Less than 1% (max 5%)

Table 3: Northern Montney Field Reservoir Parameters

Reservoir Data	Northern Montney
Depth Range	2,000 – 2,400 m
Gross Thickness	30 – 300 m
TOC Range	~2%
Porosity	2 – 9%
Water Saturation	25%
Pressure	14 – 53 MPa
Pressure Regime	Over Pressure
Temperature	51 – 83° C
H_2S	0 - 1.5%
CO_2	Less than 1% (max 5%)

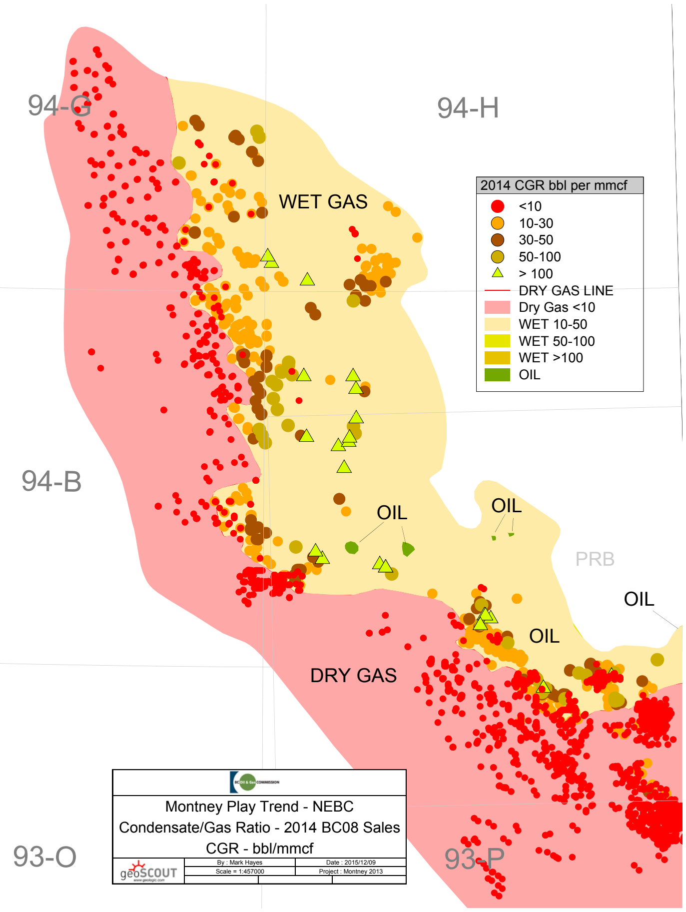
Development of the unconventional Montney began in 2007 and by 2014 the Montney has become the single largest contributor to provincial natural gas production volumes. The Montney production rate in 2014 was up 28 per cent over 2013, rising to 81.1 e^3m^3/d (2.87 Bcf/d) at year end. The number of producing wells in 2014 rose to 2,349, up from 1,555 in 2013. Cumulative production climbed to 91.0 e^9m^3 (3.2 Tcf).

In 2014, drilling continued to focus on the rich gas portion of the play trend. As a result, production of natural gas liquids and condensate has risen along with the increase in natural gas volumes.

Figure 7b displays the identified dry gas, rich gas and oil trends within the greater Montney Play trend. The relative rise of associated natural gas liquids and condensate production is detailed in Figure 8.

The Montney resource play is mapped as two formation-specific regional fields, the Regional Heritage Field to the south-east, and the Regional Northern Montney Field to the north-west. These regional fields overlie numerous pre-existing conventional fields that developed oil and gas in other formations. Well names continue to utilize these conventional fields, for geographic reference.

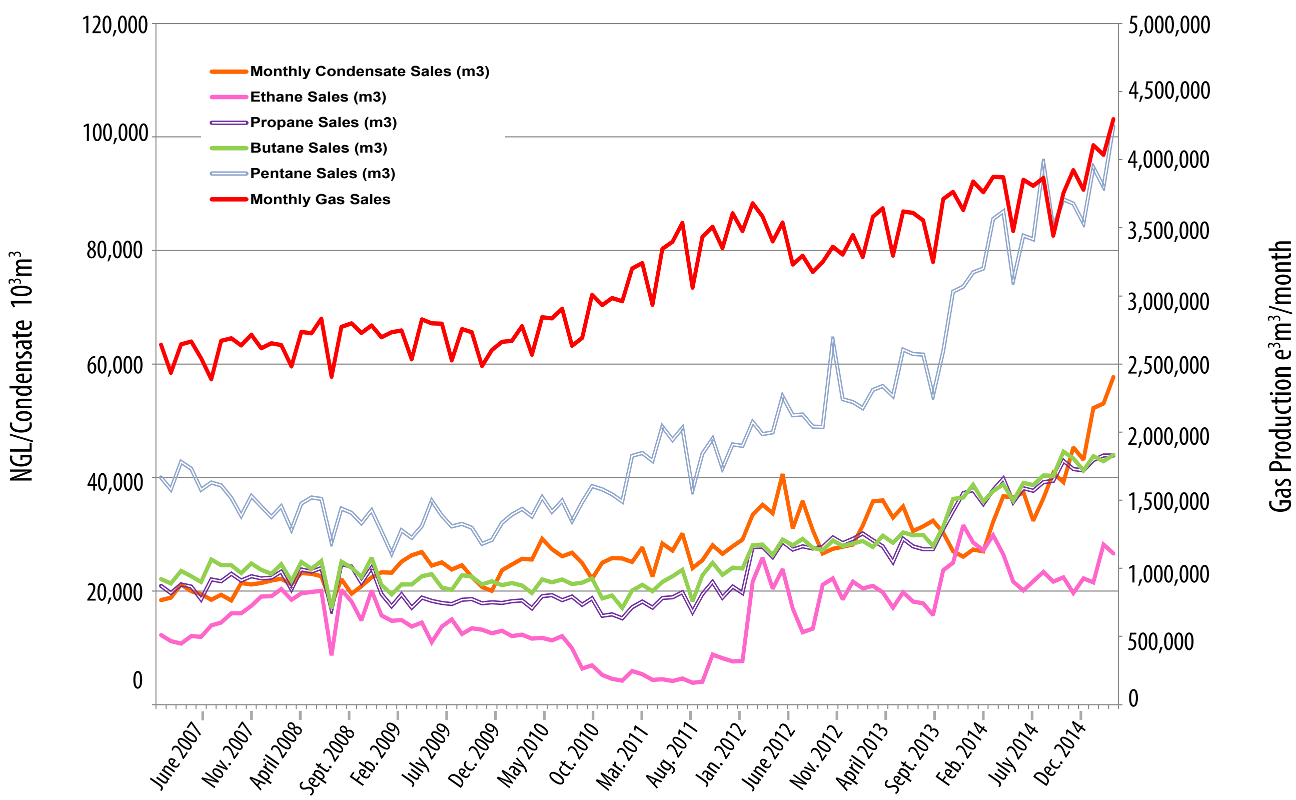
Figure 7b: Montney 2014 Dry/Wet/Oil Distribution



The Regional Heritage Field comprises a single pool (Montney A) with dry and rich gas areas, and an oil leg. The Heritage Field covers a large area with a significant range in reservoir parameters. As a general rule, porosity and permeability are better to the northeast while formation pressure increases with depth of burial to the southwest, especially where the play quickly transitions into the B.C. portion of the Deep Basin (Tables 2 & 3). There is a significant component of liquids in the Montney gas in the northeast part of the field (in the geographic areas of Septimus, Sunrise, Parkland and a defined oil leg in the area of Tower Lake). By the end of 2014, 42 oil wells were producing approximately 553 m^3/d (3,481 bbl/d). Cumulative oil production in 2014 was 283 e^3m^3 (1,780 mbbl).

The Regional Northern Montney Field contains three gas pools; Montney-Doig Phosphate A, Montney A and Montney B. The large areal size of the field translates into significant ranges for the reservoir parameters. Reservoir conditions are further complicated to the west where a portion of the Northern Montney resides within the disturbed belt of the Northern Rockies. As such, the western part of the field can be subject to substantial formation over-pressure, structural thickening and naturally occurring fractures and faults. There is also significant NGLs and condensate production, especially in the geographic areas of north Altares, Inga and Blueberry (Figure 7b).

Figure 8: Annual Montney NGL & Condensate Sales Volumes



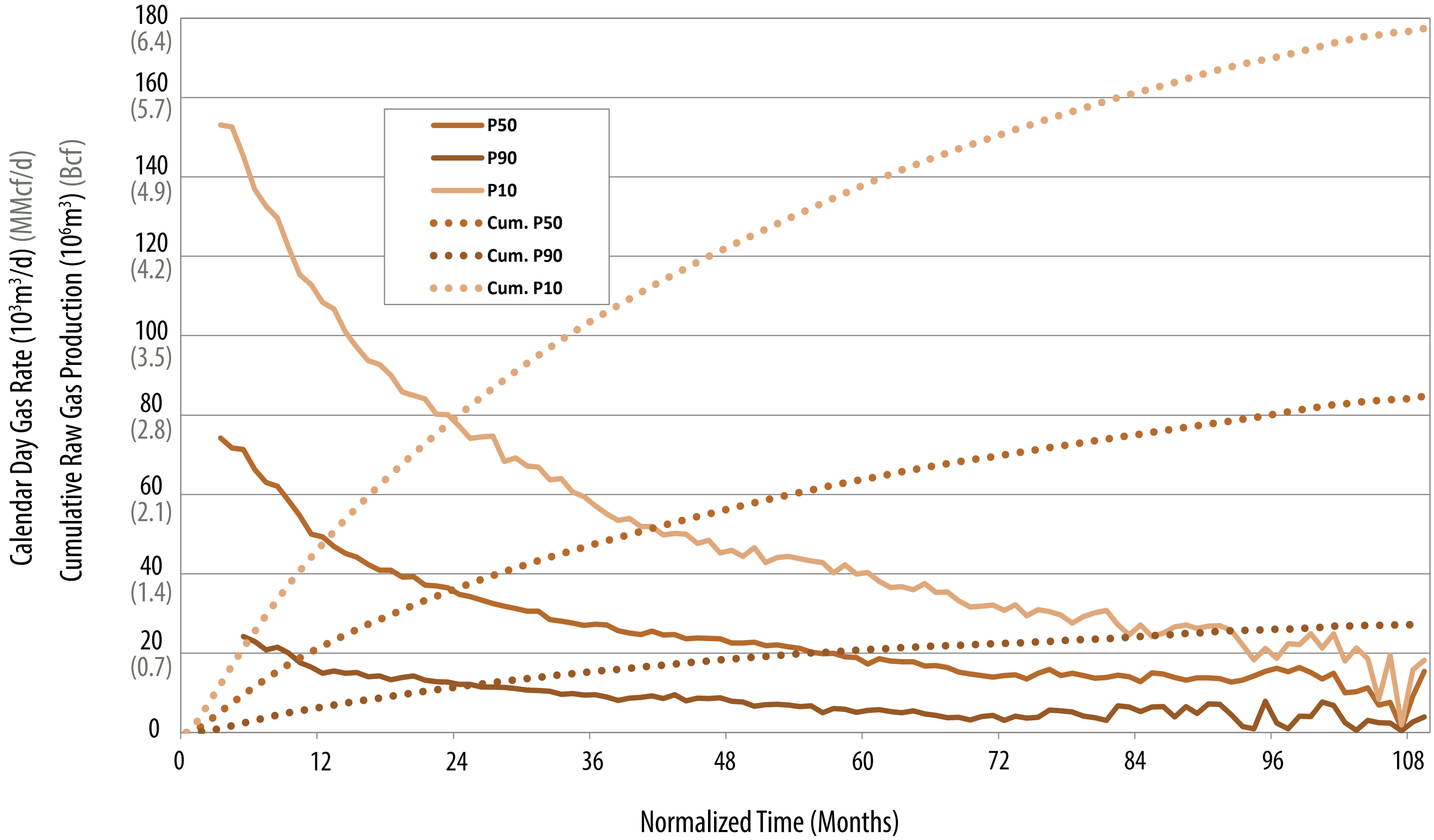
Montney Type Curves

Figure 9 presents type curves of Montney production across the Heritage and Northern Montney regional fields. Calendar day raw gas rate and cumulative gas production (dashed lines) are plotted versus normalized time (months). The type curves were generated to show the P10, P50 and P90 well performance. The type curve for the Montney has not changed significantly in 2014 from those published in the 2013 Report. The P50 well initial rate is approximately 75 $10^3m^3/d$ (2.7 MMcf/d), declining sharply to under 50 $10^3m^3/d$ (1.7 MMcf/d) in the first year. After seven years, the P50 well has produced a total of 75 10^3m^3 (2.6 Bcf). Interestingly, the P10 results show substantial cumulative production of over 160 10^3m^3 (5.7 Bcf) after seven years of production.

Table 4: 2014 Montney Completion Statistics
(Regional Heritage, Northern Montney; Gas Wells, 2014 average values)

Drilling Data	Regional Heritage	Northern Montney
Average Proppant Placed per Stage (t)	100	135
Total Fluid Pumped (m^3)	10,218	13,078
Average Fluid Pumped per Stage (m^3)	587	1,222
Number of Stages	19	13
Completed Length (m)	1,840	1,612
Average Frac Spacing (m)	121	168
Six Month Gas Rate per Stage (Mcf/d)	215	175

Figure 9: Montney Horizontal Well Production Type Curves



Reserve Methodology

Following the guidance in SPEE Monograph 3, proved undeveloped (PUD) reserves were assigned to the Regional Heritage and Northern Montney pools based on development maturity (calculated using P10/P90 ratios and well count). The Northern Montney falls into the Monograph's early to intermediate development stage while the Heritage Montney falls into the Monograph's mature phase of resource play development.

For the early to intermediate phase of development in the Northern Montney, three PUDs were assigned for every existing well. Monte Carlo simulations were performed to obtain aggregated P90 Estimated Ultimate Recovery (EUR). These values were used to assign reserves to PUDs.

In the Heritage Montney, where the field is in the mature phase of development, the number of PUDs is calculated using statistical methods. Reserves were assigned to each PUD using aggregated P90 EUR from Monte Carlo simulation.

Existing wells were assigned the P50 EUR in both the Regional Heritage and Northern Montney.

As of Dec. 31, 2014, the total booked EUR for the Montney is 29.0 Tcf, which represents a 12 per cent recovery factor (RF) of the "proved" gas in place (drilled spacing areas and immediate surrounding) and less than one per cent recovery of the total prospective resource estimate, including unproven sections of the play trend.

A complete record of the reserve estimates for each Montney pool can be found in Table 5 below and it is discussed in detail in Appendix B.

Figure 10: Montney EUR Statistics (e^3m^3/well)

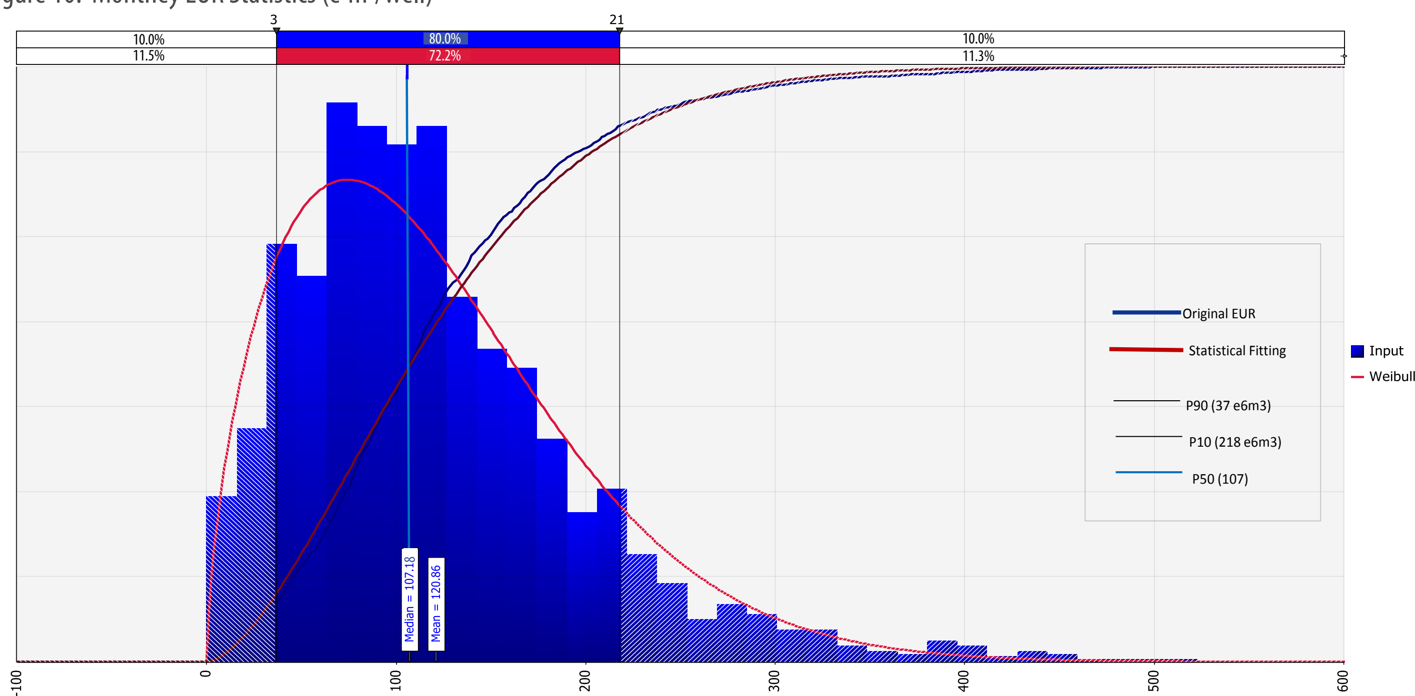


Table 5: Montney Reserves (as of Dec. 31, 2014)

Field	Pool	Horizontal Well EUR(Bcf) Per Well				Initial Reserves (Raw) Bcf	Remaining Reserves (Raw) Bcf	Existing HZ Wells	PUDs	Existing Vertical Wells
		Pmean	P90	P50	P10					
Heritage	Montney A	4.7	1.5	4.1	8.1	18,167	15,598	1,363	2,508	215
Northern Montney	Montney A	3.4	1.1	2.8	6.4	5,529	5,235	341	1,364	20
Northern Montney	Doig Phosphate-Montney A	3.6	1.3	3	6.8	4,450	4,143	245	980	14
Northern Montney	Montney B	3	0.5	2.7	6.2	807	762	98	196	6

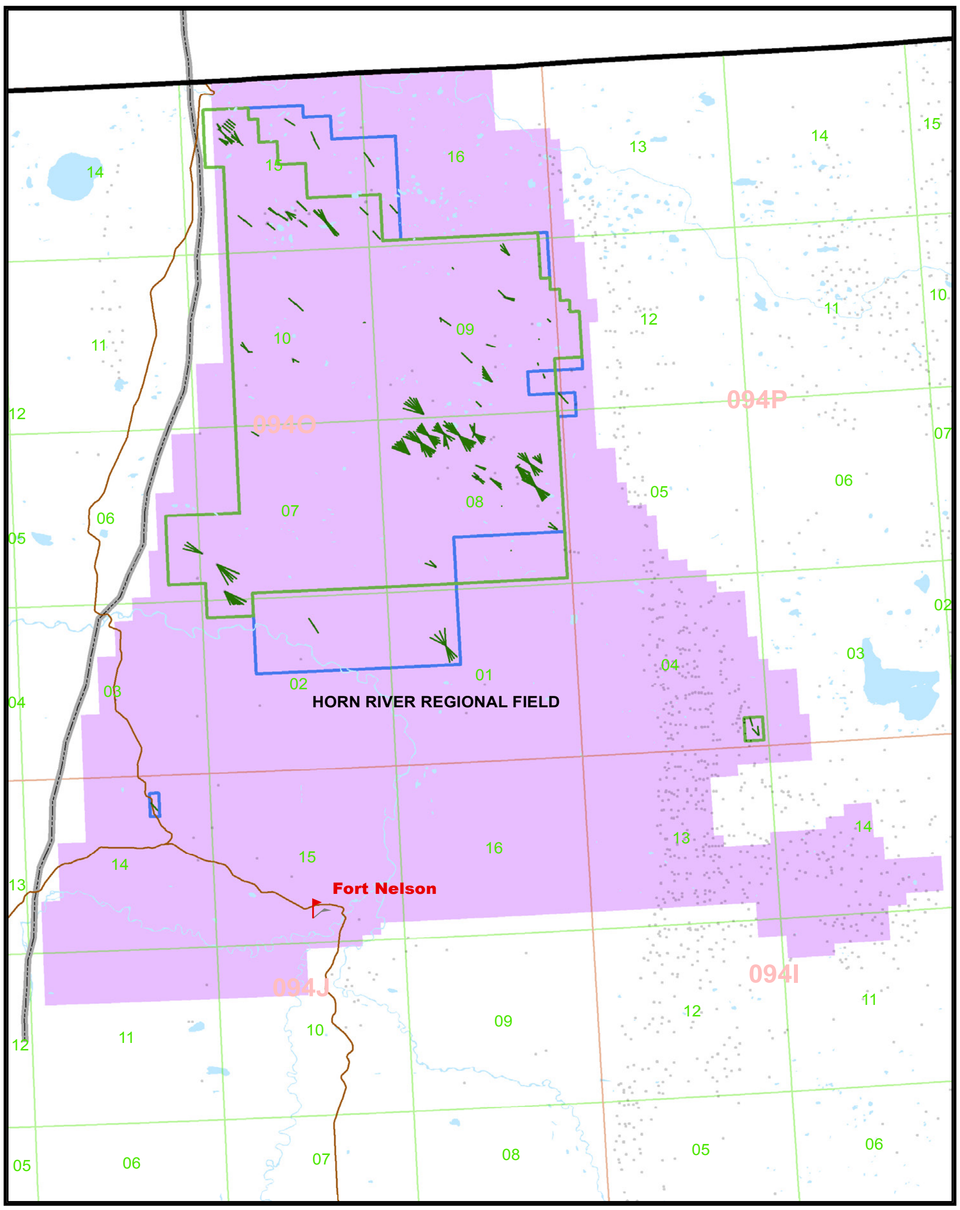
Horn River Basin - Unconventional Shale Gas Play

The Horn River Basin represents 21.7 per cent (11 Tcf) of the province's remaining recoverable raw gas reserves. In 2014, 0.18 Tcf of raw gas was produced from the Horn River Basin, accounting for 11 per cent of total annual production in the province.

Geology

The Horn River Basin is an unconventional shale play targeting dry gas from mid-Devonian aged overpressured shales of the Muskwa, Otter Park and Evie formations. Situated in the northeast of the province (see Fig 1 on page 5), the Horn River Basin is confined to the west by the Bovie Lake Fault Zone and to the east and south by the time equivalent Devonian

Figure 11: Pool Designation Areas (PDA) within the Horn River Basin



Carbonate Barrier Complex. Stratigraphically, the organic rich siliciclastic Muskwa, Otter Park and Evie shales of the Horn River group are overlain by the Fort Simpson shales and underlain by the Keg River platform carbonates.

Muskwa and Otter Park formations were mapped in combination and analyzed as one interval, with the Evie formation evaluated and mapped separately. A regional mapping project has been completed, and the Horn River Basin Unconventional Shale Gas Play Atlas was published in June 2014. Mapping completed thus far has defined areas of reservoir variability within the Horn River Basin, particularly within the Otter Park formation. Figure 10 (see page 13) denotes wells drilled and the pool designation areas (PDAs) for the Muskwa, Otter Park and Evie shale formations. A general range of reservoir parameters is provided in Table 6.

Due to the depths and corresponding high temperatures and pressures of the Muskwa, Otter Park and Evie shale formations in the Horn River Basin, the recoverable gas is sweet dry gas, >83 per cent methane, with trace amounts of ethane (0.2 per cent), and heavier hydrocarbon components, C_3+ (<0.1 per cent). The majority of gas analyses show no H_2S, or very low levels, with slightly higher values in the Evie (Table 7). CO_2 content in the recoverable gas averages 10 per cent in the Muskwa and Otter Park formations and 13 per cent in the Evie formation, generally increasing with depth in the Horn River Basin.

Table 6: Horn River Shale Reservoir Parameters

Reservoir Data	
Depth Range	1,900 – 3,100 m
Gross Thickness	140 – 280 m
TOC Range	1 – 5%
Porosity	3 – 6%
Water Saturation	25%
Pressure	20 – 53 MPa
Pressure Regime	Over Pressure
Temperature	80 – 160° C

Drilling and Completions

Continued advancements in horizontal well technology and hydraulic fracturing remain central to unlocking reserves in the Horn River Basin. On average, up to 20 horizontal wells per drilling pad have been stimulated, with as many as 25 stages per well (Table 8).

Microseismic monitoring is used extensively in the Horn River Basin to identify faults, optimize completion design and study fracture growth. To date, the overlying Fort Simpson shale has been demonstrated to be a highly effective fracture barrier.

Table 7: Horn River Gas Composition, Mole Percentage

Gas Composition, Avg (Min-Max) %	Muskwa-Otter Park	Evie
Methane (C_1)	89 (83 – 98)	85 (80 – 98)
Ethane (C_2)	0.16 (0 – 1)	0.1 (0.01 – 0.7)
NGLs (C_{3+})	0.05 (0 – 4)	0.09 (0 – 4)
CO_2	10 (0 – 14)	13 (0 – 18)
H_2S	0 (0 – 0.1)	0.02 (0 – 0.1)

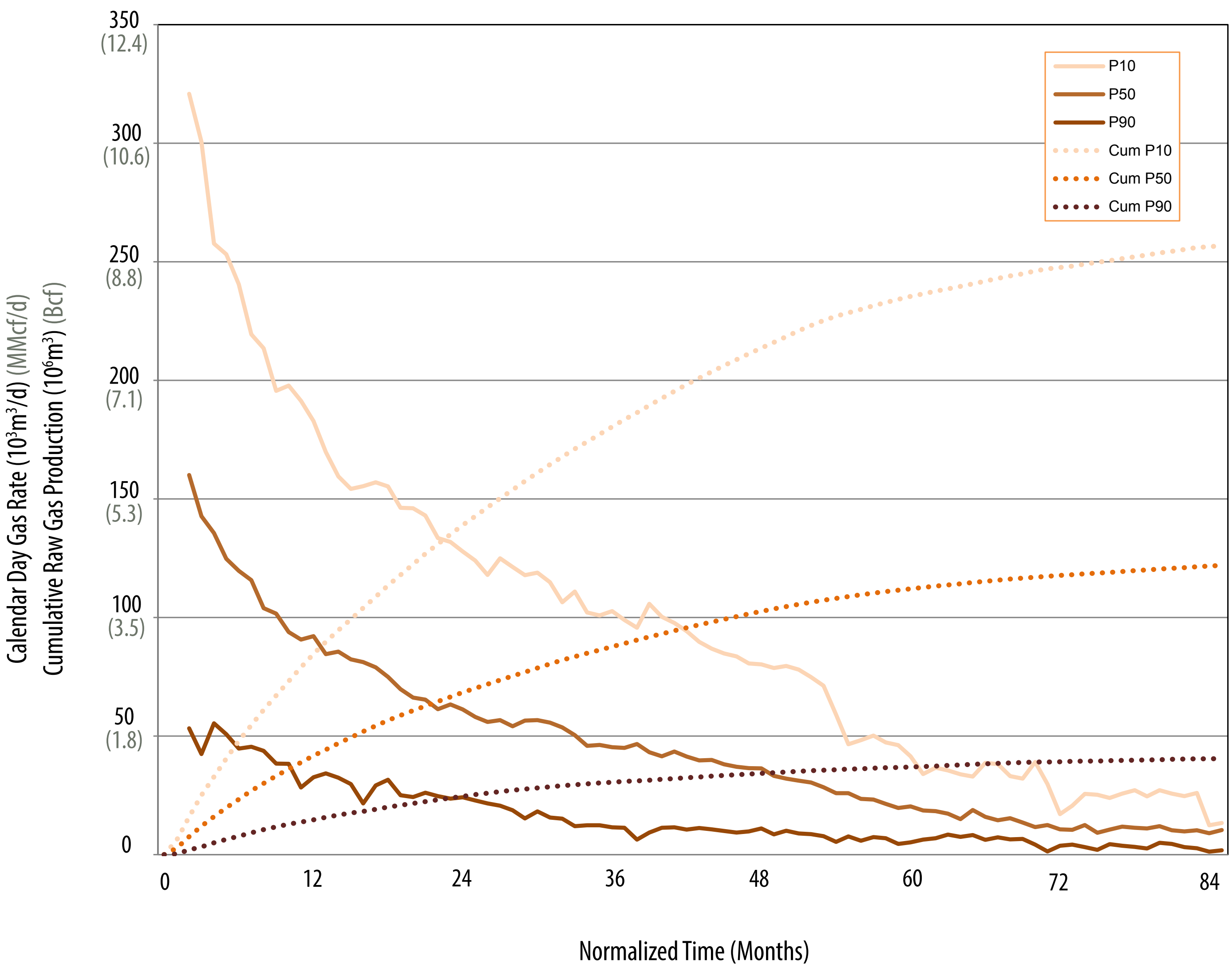
Table 8: 2014 Horn River Shale Completions Statistics (Gas wells, 2014 average values)

Drilling Data	
Average Proppant Placed per Stage (t)	170
Total Fluid Pumped (m^3)	79,920
Average Fluid Pumped per Stage (m^3)	3,296
Average Number of Stages	25
Completed Length (m)	2,232
Average Frac Spacing (m)	103
Six Month Gas Rate per Stage (Mcf/d)	227

Horn River Production - Type Curves

A typical horizontal well in the Horn River Basin exhibited an initial peak gas rate of 160 $10^3m^3/d$ (5.6 MMcf/d), declining 44 per cent in the first producing year, gradually reaching boundary dominated flow (after more than four years) due to the ultra-low permeability of the reservoir and complex fractures created from hydraulic stimulation. Figure 12 presents Horn River type curves of P10, P50 and P90 horizontal well performance. After 40 months, the P50 well has produced 90 10^6m^3 (3.2 Bcf).

Figure 11: Horn River Horizontal Well Type Curves



Liard Basin - Unconventional Shale Gas Play

Exploration in the Liard Basin started in 2008 and had a preliminary EUR of 2,933 $10^6 m^3$ (0.1 Tcf) booked in 2014, based on production from four existing wells (two vertical wells and two horizontal wells).

A major structural feature, the Bovie fault zone, separates the Liard from the Horn River Basin. The Liard Basin has more than five km thickness of sedimentary rocks preserved including thick, organic shales within the upper and lower Devonian Besa River strata.

Figure 13: Northeast B.C. Shale Basins - Liard, Horn River and Cordova Embayment

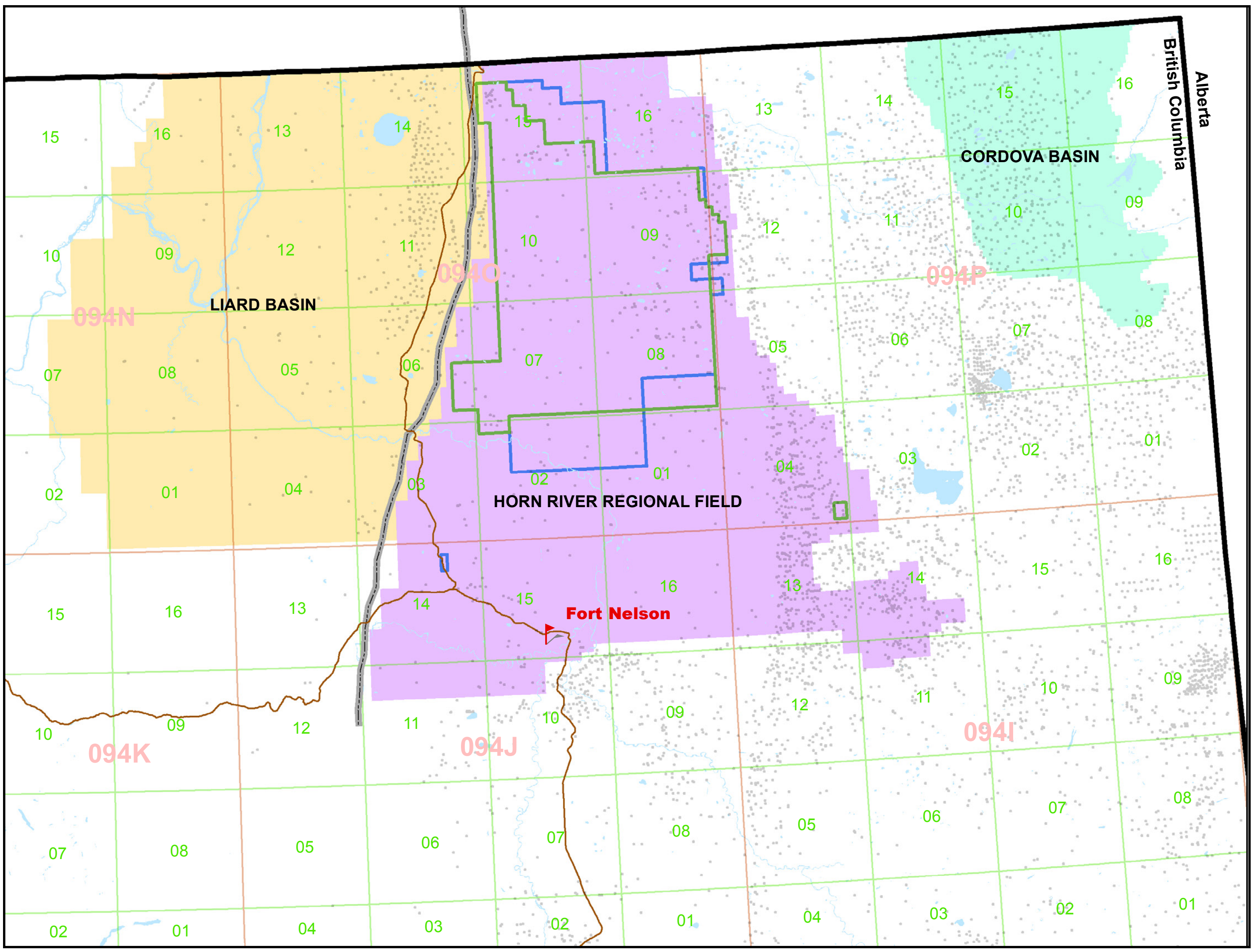
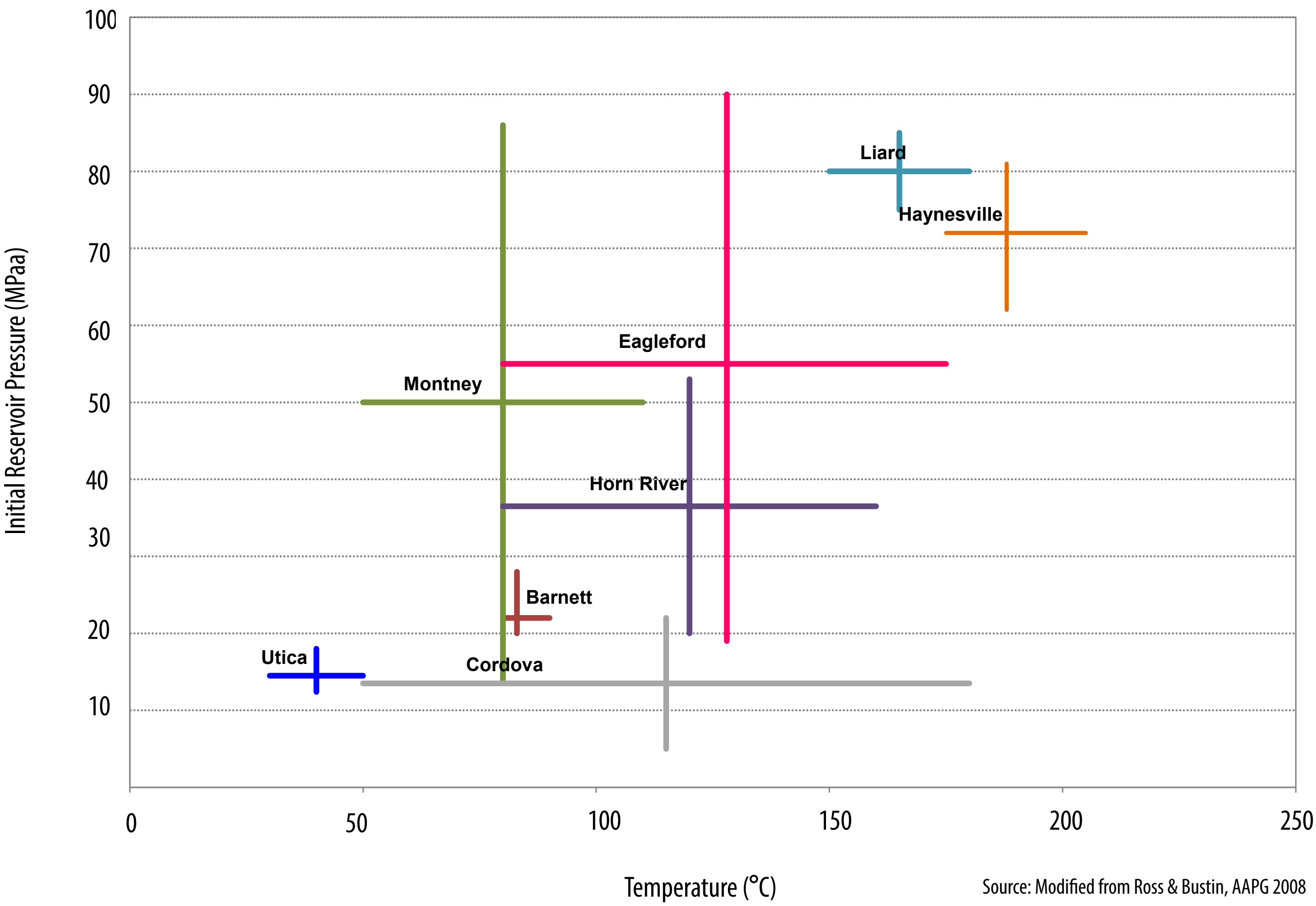


Figure 14: Pressure versus Temperature Plot



Source: Modified from Ross & Bustin, AAPG 2008

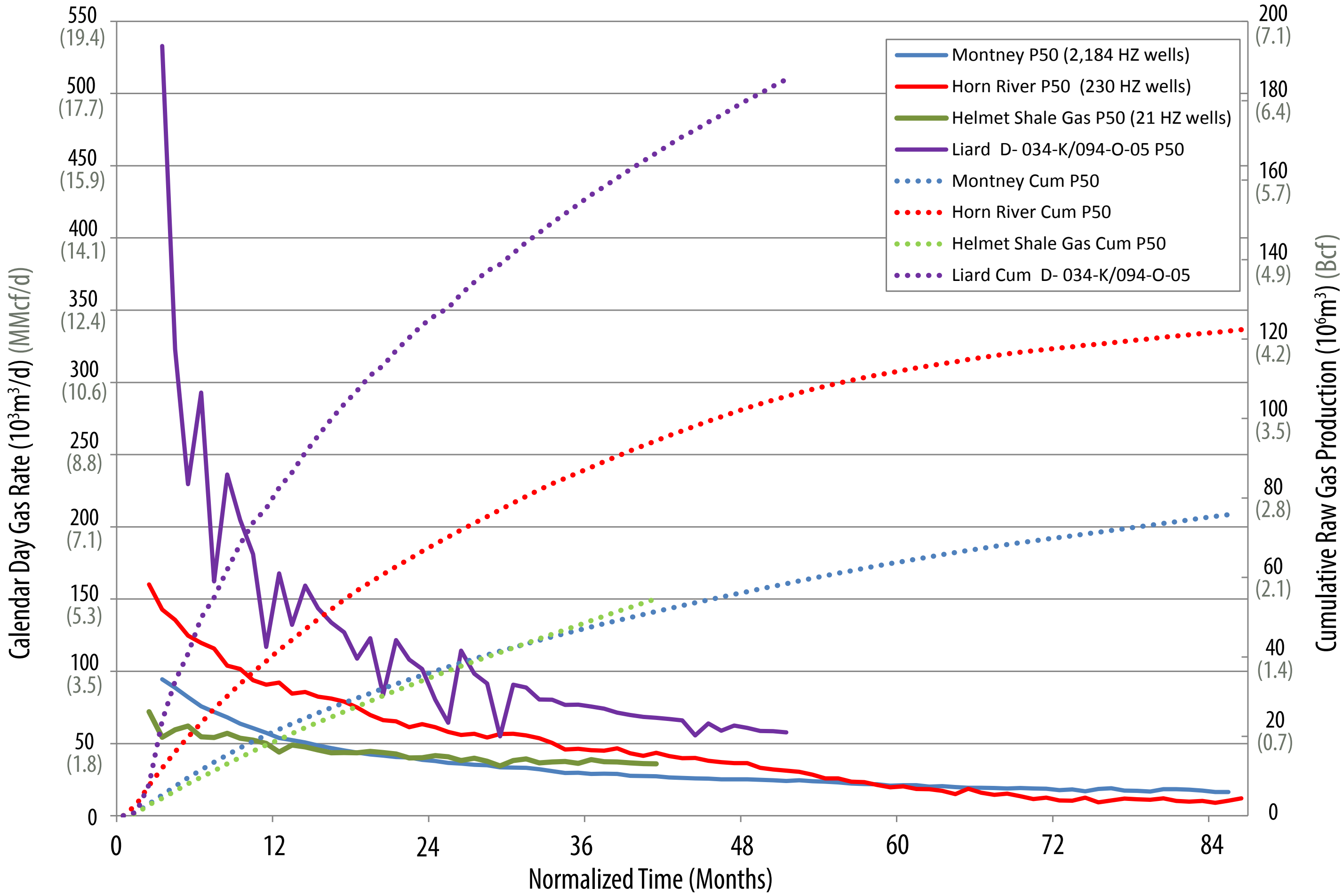
Gas analysis from the three Liard wells drilled to date indicates CO_2 content of approximately seven per cent; lower than the 13 per cent observed in the western portions of the Horn River. Preservation of the relatively high methane content of the gas may be due to a lower than expected temperature gradient. Although much deeper than even the deepest portions of the Horn River Basin, the temperatures at the upper Besa River level are similar to the maximum temperatures seen in the Horn River.

The shale gas potential of the Besa River formation was tested with the drilling and stimulation of three vertical wells and two horizontal wells in 2009-2014, in an area previously devoid of deep well tests. Test results (7 MMcf/d vertical well and 30 MMcf/d horizontal well) and production was very promising and among the best of any shale gas play in North America. The Commission forecasts an EUR of 8 Bcf/well to the vertical wells and 19 Bcf/well to the horizontal well. With six stimulations over a 900 m horizontal section, (1,500 t sand; 23,000 m^3 water), the Commission forecasts over 3 Bcf/frac for the horizontal Liard well, compared with 1 Bcf/frac for the Horn River and 0.5 Bcf/frac for the Montney, on average.

Figure 14 shows the Pressure versus Temperature plot for the Montney, Horn River, Cordova, and Liard areas compared to other major fields. The temperatures of these fields fall within expected ranges when compared to other fields, except for Liard, which is significantly higher than that of the Horn River, Cordova or Montney fields.

A comparison of the Montney, Horn River, Liard and Cordova P50 type curves are shown in Figure 15. The type curve peak initial rate from the Liard well is significantly higher than that of either the average Horn River or Montney well.

Figure 15: Comparison of Montney, Horn River, Liard and Helmet HZ Production Type Curves



Cordova Embayment - Unconventional Shale Gas Play

Exploration and development activity in the Cordova declined in 2014. While three new horizontal wells targeting Muskwa-Otter Park were drilled in the Cordova Embayment in 2014, they have not yet been completed.

A general range of reservoir parameters are provided in Table 9

Development History

The first gas wells in the Cordova Embayment targeting shale were rig released in 2008. The majority of the drilling to date occurred in 2012 (14 wells), with five and seven wells drilled in 2012 and 2013, respectively. Only three wells were drilled in 2014.

Drilling and Completions

The completions approach in the Cordova was comparable to the Horn River. The average values from the horizontal wells completed in 2012-2014 are summarized in Table 10. The average well has a 1,765 m horizontal cased hole lateral and received hydraulic stimulation with 15 slickwater fracture stages using approximately 43,500 m^3 of water and 225 tonnes of sand. Nitrogen (N_2) gas was employed in two wells as an energizer.

Production

The P50 horizontal type well for Cordova is shown in Figure 15 (page 19). Although initial rates are lower than the neighboring Muskwa-Otter Park and Evie shales of the Horn River Basin to the west, (despite similar completion techniques), the decline appears to be more stable. A significantly lower reservoir pressure is a dominant factor. More drilling and production is required to substantiate the Cordova type well.

Table 9: Cordova Shale Reservoir Parameters

Reservoir Data	
Depth Range	1,500 – 2,300 m
Gross Thickness	70 – 120 m
TOC Range	2 – 5%
Porosity	3 – 6%
Water Saturation	25%
Pressure	5 – 22 MPa
Pressure Regime	Under pressure to normal
Temperature	50 – 180° C

The average CO_2 content in the Cordova Embayment is eight per cent, slightly lower than the 10 -13 per cent present in the Horn Rriver Basin. There are trace amounts of H_2S (<0.6ppm).

Table 10: 2014 Cordova Shale Completion Statistics
(Gas wells, 2014 average values)

Drilling Data	
Average Proppant Placed per Stage (t)	220
Total Fluid Pumped (m^3)	43,513
Number of Stages	14
Completed Length (m)	1,794
Average Frac Spacing (m)	147
Six Month Gas Rate per Stage (Mcf/d)	134

B. Oil Reserves

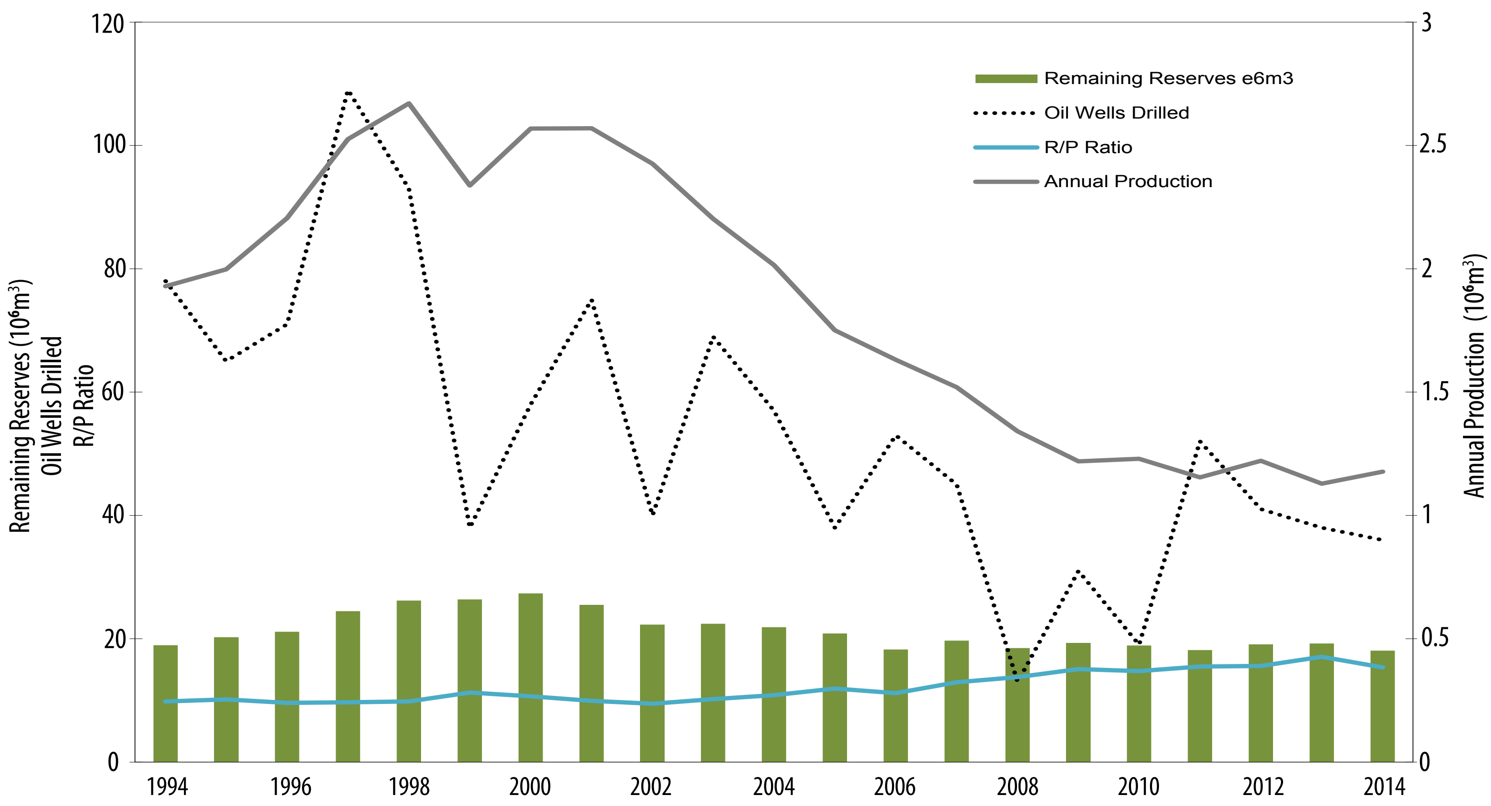
Oil reserves decreased 6.2 per cent in 2014, for a total of 18.1 10^6m^3 remaining. The major contributing factors for this drop were a reduction in the number of new drills (38 in 2013, compared to 36 in 2014) and a depletion of pools that had not produced in many years.

Annual oil production in 2014 was 1.2 10^6m^3, an increase of 4.3 per cent from 2013.

Historical oil reserves, drilling, production and reserves to Annual Production Ratio (R/P ratio) are plotted in Figure 16 below. Oil production reached a peak of 2.7 10^6m^3/year in 1998, then declined until 2010 when it began to stabilize with continued horizontal drilling and waterflood pressure maintenance. The R/P ratio has been steady since 2009, with approximately 15 years of reserve life booked.

The distribution of remaining oil reserves by field is shown in Figure 17. The Boundary Lake - Boundary Lake A pool, the Hay River - Bluesky A pool, and the Heritage Montney A pool are the largest contributing pools to overall remaining oil reserves in the province (18 per cent, eight per cent and seven per cent, respectively).

Figure 16: Historical Oil Development in B.C.



Forty-seven per cent of the remaining oil reserves in B.C. come from pools with secondary recovery pressure maintenance schemes, predominantly waterfloods. Those pools are listed in Table A-4: Oil Pools Under Waterflood.

Gas injection recovery schemes account for one per cent of remaining oil reserves and occur in seven oil pools. Further details can be found on Table A-5: Oil Pools Under Gas Injection.

Heritage Montney A Oil

A significant addition to oil reserves is the Heritage Montney A oil pool in the central Tower Lake area of the Montney Play trend (see Figure 7b). The regionally extensive Triassic Montney formation trends from dry to rich gas, but also includes an oil leg in the Heritage Field, in an area of lower pressure and shallower depth.

Figure 17: Remaining Oil Reserves by Field

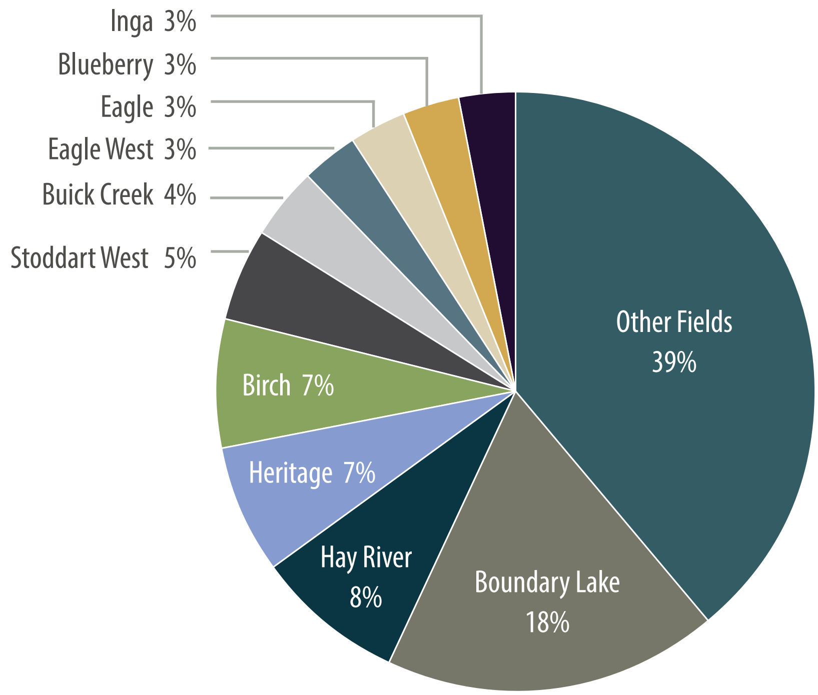


Table 11: Heritage Montney A Oil Pool Reservoir Parameters

Reservoir Data	Reservoir Parameter
TVD top to Montney	1,800 – 2,100 m
Initial Pressure	19 – 28 MPa
Pressure Regime	Slightly overpressure (10-12 kPa/m)
Temperature	60 – 70° C
API Gravity	45°
Solution GOR	200

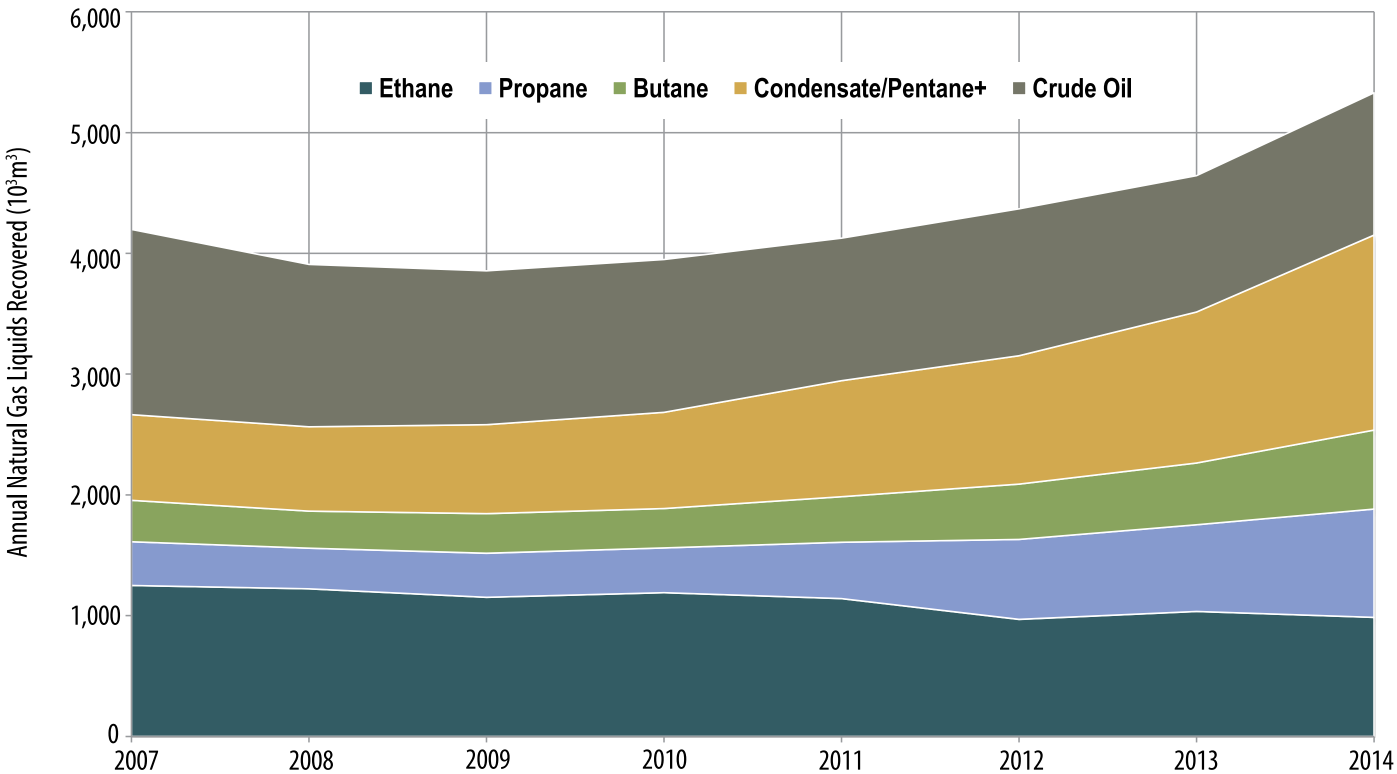
In 2014 there were 41 Heritage Montney oil wells on production. A forecasted total EUR assigned to the Heritage Montney A oil leg was 1,472 10^3m^3 (9.3 MMSTB), which represents only a fraction of the estimated original oil in place (OOIP) of 73,610 10^3m^3 (463 MMSTB). Given the potential of the resource and lack of analogous reservoirs, the Commission is focused on determining the best production practice for maximizing recovery. Reservoir parameters are provided in Table 11.

C. Condensate and Natural Gas Reserves

Condensate and natural gas liquid (NGL) production, in association with natural gas, is increasing in B.C. predominately due to the development of gas/liquids-rich portions of the Montney Play trend (see Figure 7b on page 11). Across all of B.C., the condensate and NGL production increased by 29.2 per cent and 18.1 per cent respectively, while oil production decreased by 4.3 per cent (Figure 18). The annual liquid volumes recovered in B.C. are shown in Figure 18. Significant volumes of NGL and condensate are recovered in the northeast section of the Heritage Montney field with ratios reaching as high as 50-100 bbl/MMcf. The Commission identified an oil leg and several new "oily" areas, which are under investigation.

Liquid petroleum gas (LPG) remaining reserves increased 45.1 per cent in 2014 (53.6 10^6m^3 in 2013 to 77.8 10^6m^3 in 2014) and is indicative of the activity in the liquids-rich areas in B.C.

Figure 18: 2014 Annual Oil, Condensate and NGL Production



D. Sulphur

In B.C. most by-product H_2S along with CO_2 extracted from raw gas is disposed of in approved disposal wells. Recovered sulphur is not a significant resource in British Columbia. Of significance, the areas that contribute the majority of sulphur reserves are the Bullmoose, Sukunka and Ojay fields (Figure 19). As of Dec. 31 2014, the remaining recoverable sulphur reserves are 14.8 10^6 tonnes; a decrease of 16.5 per cent from 2013 (Table 1 on page 4), due to a natural decline in production from the Bullmoose, Sukunka and Ojay fields, where the majority of the sulphur production occurs in B.C.. The sulphur sales volume decreased 11.5 per cent from 2013 to 2014 (Figure 20).

Figure 19: Major Sour Field by Remaining Sulphur Reserves

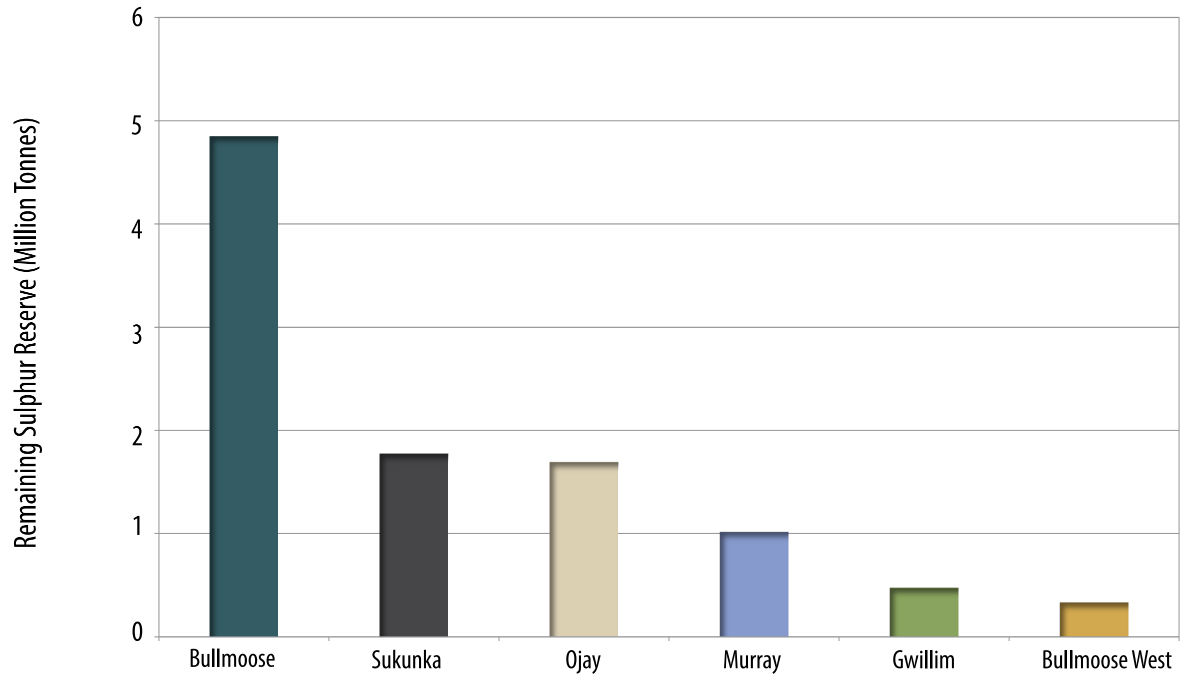
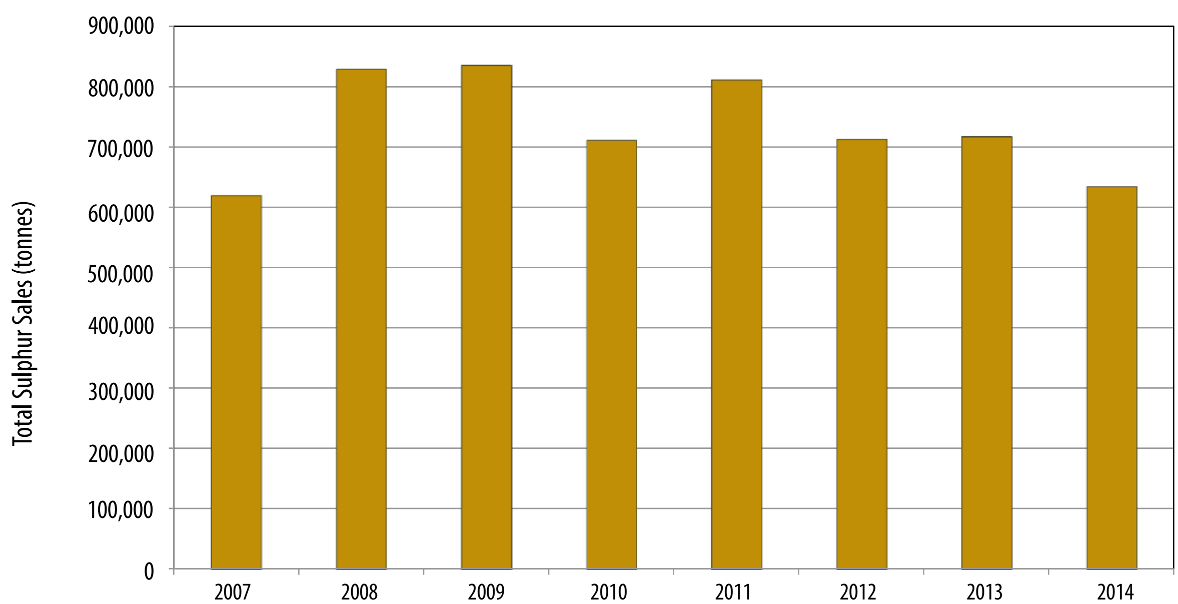


Figure 20: B.C. Sulphur Annual Sales



Definitions

SI Units

British Columbia's reserves of oil, natural gas liquids and sulphur are presented in the International System of Units (SI). Both SI units and the Imperial equivalent units are used through this report. Conversion factors used in calculating the Imperial equivalents are listed below:

1 cubic metre of gas (101.325 kilopascals and 15° Celsius)	=	35.493 73 cubic feet of gas (14.65 psia and 60° Fahrenheit)
1 cubic metre of ethane (equilibrium pressure and 15° Celsius)	=	6.330 0 Canadian barrels of ethane (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of propane (equilibrium pressure and 15° Celsius)	=	6.300 0 Canadian barrels of propane (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of butanes (equilibrium pressure and 15° Celsius)	=	6.296 8 Canadian barrels of butanes (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of oil or pentanes plus (equilibrium pressure and 15° Celsius)	=	6.292 9 Canadian barrels of oil or pentanes plus (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of water (equilibrium pressure and 15° Celsius)	=	6.290 1 Canadian barrels of water (equilibrium pressure and 60° Fahrenheit)
1 tonne	=	0.984 206 4 (U.K.) long tons (2,240 pounds)
1 tonne	=	1.102 311 short tons (2,000 pounds)
1 kilojoule	=	0.948 213 3 British thermal units (Btu as defined in the federal Gas Inspection Act [60°- 61° Fahrenheit])

Aggregated P90
The 90 per cent probability of a distribution that forms as a result of an aggregation of outcomes.

Area
The area used to determine the adjusted bulk rock volume of the oil, or gas-bearing reservoir, usually the area of the zero isopach or the assigned area of a pool or deposit.

Butane
(C_4H_{10}) An organic compound found in natural gas. Reported volumes may contain some propane or pentanes plus.

COGEH
Canadian Oil and Gas Evaluations Handbook (Volume 1, 2 and 3). First published in 2002 by the Calgary Chapter of the Society of Petroleum Evaluation Engineers (SPEE) to act as a standard for the evaluation of oil and gas properties.

Compressibility Factor
A correction factor for non-ideal gas determined for gas from a pool at its initial reservoir pressure and temperature and, where necessary, including factors to correct for acid gases.

Condensate
A mixture mainly of pentanes and heavier hydrocarbons (C_5^+) that may be contaminated with sulphur compounds that is recovered at a well or facility from an underground reservoir and that may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured.

Density
The mass or amount of matter per unit volume.

Density, Relative (Raw Gas)
The density, relative to air, of raw gas upon discovery, determined by an analysis of a gas sample representative of a pool under atmospheric conditions.

Discovery Year
The year in which the well that discovered the oil or gas pool finished drilling.

Estimated Ultimate Recovery (EUR)
Total volume of oil or gas recoverable under current technology and present and anticipated economic conditions, specifically proven by drilling, testing, or production; plus contiguous undeveloped reserves that are interpreted from geological, geophysical, and/or analogous production, with reasonable certainty to exist. Also referred to as Initial Reserves in the detailed reserves tables listed in Appendix A.

Ethane
(C_2H_6) An organic compound in natural gas and belongs to the group of natural gas liquids (NGLs). Reported volumes may contain some methane or propane.

Formation Volume Factor
The volume occupied by one cubic metre of oil and dissolved gas at reservoir pressure and temperature, divided by the volume occupied by the oil measured at standard conditions.

Gas (Non-associated)
Gas that is not in communication in a reservoir with an accumulation of liquid hydrocarbons at initial reservoir conditions.

Gas Cap (Associated)
Gas in a free state in communication in a reservoir with crude oil, under initial reservoir conditions.

Gas (Solution)
Gas that is dissolved in oil under reservoir conditions and evolves as a result of pressure and temperature changes.

Gas (Raw)
A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium, and minor impurities, or some of them, which is recovered or is recoverable at a well from an underground reservoir and which is gaseous at the conditions under which its volume is measured or estimated.

Gas (Marketable)
A mixture mainly of methane originating from raw gas, if necessary, through the processing of the raw gas for the removal or partial removal of some constituents, and which meets specifications for use as a domestic, commercial, or industrial fuel or as an industrial raw material.

Gas-Oil Ratio (Initial Solution)
The volume of gas (in thousand cubic metres, measured under standard conditions) contained in one stock-tank cubic metre of oil under initial reservoir conditions.

Gross Heating Value (of dry gas)
The heat liberated by burning moisture-free gas at standard conditions and condensing the water vapour to a liquid state.

Initial Reserves
Established reserves prior to the deduction of any production. Also referred to as Estimated Ultimate Recovery (EUR).

Liquid Petroleum Gases (LPG)
A hydrocarbon mixture comprised primarily of propane and butanes. Some ethanes may be present. Also referred to as natural gas liquids (NGLs).

Mean Formation Depth
The approximate average depth below kelly bushing of the mid-point of an oil or gas productive zone for the wells in a pool.

Methane
In addition to its normal scientific meaning, a mixture mainly of methane which ordinarily may contain some ethane, nitrogen, helium or carbon dioxide.

Natural Gas Liquids
Ethane, propane, butanes, or pentanes plus, or a combination of them, obtained from the processing of raw gas or condensate.

Oil
A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir, and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas or condensate.

Original Gas and Original Oil in Place (OOIP)
The volume of oil, or raw natural gas estimated to exist originally in naturally occurring accumulations, prior to production.

Pay Thickness (Average)
The bulk rock volume of a reservoir of oil or gas, divided by its area.

Pentanes Plus
A mixture mainly of pentanes and heavier hydrocarbons, (which may contain some butane), that is obtained from the processing of raw gas, condensate, or oil.

Pool
A natural underground reservoir containing or appearing to contain an accumulation of liquid hydrocarbons or gas or both separated or appearing to be separated from any other such accumulation.

Porosity
The effective pore space of the rock volume determined from core analysis and well log data, measured as a fraction of rock volume.

Pressure (Initial)
The reservoir pressure at the reference elevation of a pool upon discovery.

Probabilistic Aggregation
The adding of individual well outcomes to create an overall expected reserve outcome.

Project/Units
A scheme by which a pool or part of a pool is produced by a method approved by the Commission.

Propane
(C_3H_8) An organic compound found in natural gas. Reported volumes may contain some ethane or butane.

Proved Plus Probable Reserves
Proved plus probable reserves are estimates of hydrocarbon quantities to be recovered. There is at least a 50 per cent probability that the actual quantities recovered will equal or exceed the estimated proved plus probable reserves.

PUD (Proved Undeveloped)
Proved undeveloped reserves that are assigned to undrilled well locations that are interpreted from geological, geophysical, and/or analogous production, with reasonable certainty to exist.

P10
There is a 10 per cent probability (P10) that the quantities actually recovered will equal or exceed this value.

P50
There is a 50 per cent probability (P50) that the quantities actually recovered will equal or exceed this value.

P90
There is a 90 per cent probability (P90) that the quantities actually recovered will equal or exceed this value.

Pmean
The expected average value or risk-weighted average of all possible outcomes.

Recovery
Recovery of oil, gas or natural gas liquids by natural depletion processes or by the implementation of an artificially improved depletion process over a part or the whole of a pool, measured as a volume or a fraction of the in-place hydrocarbons so recovered.

Remaining Reserves
Initial established reserves (EUR) less cumulative production.

Reserves
Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be sub classified based on development and production status (from COGEH).

Resource
Resources are those quantities of hydrocarbons estimated to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development (adapted from COGEH).

Saturation (Water)
The fraction of pore space in the reservoir rock occupied by water upon discovery.

SPEE Monograph 3
An established guideline published by the Society of Petroleum Evaluations Engineers (2010) which discusses evaluation of undeveloped reserves in resource plays.

Surface Loss
A summation of the fractions of recoverable gas that are removed as acid gas and liquid hydrocarbons, used as lease or plant fuel, or flared.

Temperature
The initial reservoir temperature upon discovery at the reference elevation of a pool.

Unconnected Reserves
Gas reserves which have not been tied-in to gathering facilities and therefore do not contribute to the provincial supply without further investment.

Zone
Any stratum or any sequence of strata that is designated by the Commission as a zone.

Appendix A

2014 Hydrocarbon Reserves (SI Units)

Table A-1: Established Hydrocarbon Reserves (SI Units) by December 31, 2014

	Oil (10^3m^3)	Raw Gas (10^6m^3)
Initial Reserves, Current Estimate	135,657	2,408,673
Discovery 2014	0	0
Revisions 2014	-226	292,437
Production 2014	1,177	46,222
Cumulative Production Dec. 31, 2014	117,598	964,803
Remaining Reserves Estimate Dec. 31, 2014	18,059	1,443,870

Table A-2: Historical Record of Raw Gas Reserves

Year	Estimated Ultimate Recovery 10^6m^3	Yearly Discovery 10^6m^3	Yearly Revisions 10^6m^3	Yearly Other 10^6m^3	Annual Production 10^6m^3	Cumulative Production at Year-End 10^6m^3	Remaining Reserves at Year-End 10^6m^3
1977	376,960	18,119	-14,107		11,039	143,958	233,002
1978	399,535	21,190	1,386		9,943	153,900	245,635
1979	424,805	26,142	-872		11,394	165,294	259,511
1980	462,596	28,909	8,882		8,968	174,262	288,334
1981	478,689	13,842	2,251		8,293	182,555	296,134
1982	488,316	7,765	1,862		7,995	190,550	297,766
1983	490,733	2,550	-133		7,845	198,395	292,338
1984	496,703	1,798	4,172		8,264	206,659	290,044
1985	505,233	2,707	5,823		8,799	215,458	289,775
1986	501,468	4,822	-8,463		8,506	223,964	277,628
1987	497,466	1,986	-5,940		9,810	233,794	263,777
1988	500,738	6,083	-1,661		10,275	244,249	256,483
1989	513,662	12,193	-2		13,276	257,862	255,782
1990	547,058	27,683	5,888		13,226	271,344	275,685
1991	574,575	24,708	3,812		15,162	285,965	288,582
1992	591,356	6,377	10,404		16,510	302,916	288,408
1993	617,379	22,901	3,122		18,202	321,090	296,246
1994	635,774	22,004	-3,301		19,069	339,861	295,885
1995	657,931	21,065	1,051		21,157	361,106	296,825
1996	677,769	16,083	3,852		21,435	382,332	295,437
1997	688,202	12,835	-2,394		22,811	405,157	283,045
1998	712,677	9,957	14,502		23,375	428,822	283,855
1999	743,816	13,279	17,824		23,566	453,000	290,816
2000	772,221	13,832	14,571		23,894	477,381	294,800
2001	811,146	7,199	31,690		26,463	504,620	306,526
2002	843,612	19,004	13,462		28,348	533,548	310,064
2003	889,488	19,317	26,282		26,639	562,560	326,928
2004	973,771	6,412	65,149	12,897	26,430	584,033	389,738
2005	1,065,288	8,974	63,268	19,104	27,854	620,696	444,592
2006	1,114,562	15,356	33,912		28,056	652,137	462,425
2007	1,172,136	21,468	36,109		29,362	689,209	482,927
2008	1,328,729	6,559	150,167		30,346	722,769	605,280
2009	1,415,172	30,331	56,133		30,846	757,291	657,881
2010	1,724,769	275,942	33,691		33,202	792,798	931,971
2011	1,809,591	7,909	76,934		40,519	834,715	974,876
2012	2,014,054	1,646	202,809		40,482	875,580	1,138,474
2013	2,116,236	428	101,754		43,722	919,007	1,197,229
2014	2,408,673	0	292,437		46,222	964,803	1,443,870

These values are taken from previously published ministry reserve estimates. This compilation is provided for historical value and to aid in statistical analysis only. Values shown for any given year may not balance due to changes in production and estimates over time.

Table A-3: Historical Record of Oil Reserves

Year	Estimated Ultimate Recovery 10^3m^3	Yearly Discovery 10^3m^3	Yearly Revisions 10^3m^3	Yearly Other 10^3m^3	Annual Production 10^3m^3	Cumulative Production at Year-End 10^3m^3	Remaining Reserves at Year-End 10^3m^3
1977	72,841	4,159	-84		2,201	46,318	26,523
1978	77,826	2,650	2,376		2,004	48,280	29,546
1979	78,882	427	629		2,140	50,397	28,485
1980	80,043	234	927		2,002	52,399	27,644
1981	79,968	143	-218		2,060	54,459	25,509
1982	80,760	126	666		2,095	56,554	24,206
1983	82,149	661	727		2,079	58,634	23,515
1984	79,551	781	-3,378		2,113	60,747	18,805
1985	82,887	1,767	1,569		1,944	62,691	20,196
1986	83,501	456	144		2,010	64,701	18,786
1987	84,201	631	68		2,084	66,793	17,361
1988	85,839	1,238	-50		1,937	68,759	16,623
1989	89,899	2,306	-2,402		1,978	70,737	19,129
1990	90,650	569	181		1,954	72,714	17,823
1991	91,606	233	630		1,974	74,689	16,911
1992	94,030	823	1,596		2,017	76,750	17,273
1993	96,663	803	1,830		1,976	78,726	17,925
1994	99,619	1,477	1,482		1,929	80,664	18,956
1995	102,823	2,887	290		1,997	82,658	20,167
1996	106,009	1,306	1,878		2,205	84,856	21,153
1997	110,765	3,199	1,561		2,525	87,401	23,364
1998	116,294	815	4,717		2,670	90,105	26,189
1999	118,840	345	2,201		2,338	92,453	26,388
2000	122,363	504	3,018		2,568	95,031	27,357
2001	123,048	106	582		2,569	97,591	25,478
2002	122,245	427	-1,233		2,426	99,977	22,313
2003	124,660	424	1,990		2,203	102,234	22,426
2004	125,953	154	947	188	2,015	104,104	21,873
2005	126,941	247	636	110	1,750	106,086	20,857
2006	125,845	222	-1,322		1,631	107,603	18,244
2007	128,971	266	2,859		1,520	109,283	19,692
2008	129,117	162	25		1,341	110,632	18,485
2009	131,172	289	1,766		1,282	111,924	19,252
2010	131,840	643	28		1,270	113,197	18,653
2011	132,414	99	475		1,154	114,253	18,161
2012	134,600	537	1,614		1,222	115,492	19,108
2013	135,883	0	1,278		1,129	116,633	19,250
2014	135,657	0	-226		1,177	117,598	18,059

These values are taken from previously published ministry reserve estimates. This compilation is provided for historical value and to aid in statistical analysis only. Values shown for any given year may not balance due to changes in production and estimates over time.

Table A-4: Oil Pools Under Waterflood

FIELD	POOL	PROJECT CODE	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cum Oil (10^3m^3)	RR (10^3m^3)
Beatton River	Halfway A	02	3,429.9	47.1	1,616.5	1,616.2	0.3
Beatton River	Halfway G	05	1,438.4	30.0	431.5	425.8	5.8
Beatton River West	Bluesky A	02	2,956.1	40.0	1,182.5	1,097.7	84.7
Beavertail	Halfway B	06	909.3	20.0	181.9	166.5	15.4
Beavertail	Halfway H	05	503.0	18.0	90.5	86.0	4.5
Birch	Baldonnel C	03	4,070.0	50.0	2,035.0	740.9	1,294.1
Boundary Lake	Boundary Lake A	02	43,666.1	45.4	19,824.4	19,252.0	572.4
Boundary Lake	Boundary Lake A	04	31,026.6	45.3	14,055.1	12,592.7	1,462.3
Boundary Lake	Boundary Lake A	05	5,355.8	60.0	3,213.5	3,035.3	178.2
Boundary Lake	Boundary Lake A	03	1,548.3	65.0	1,006.4	963.7	42.7
Bubbles North	Coplin A	02	143.8	40.0	57.5	40.1	17.4
Bulrush	Halfway C	02	96.3	4.5	4.3	4.2	0.2
Crush	Halfway A	02	1,449.3	35.2	510.1	503.2	6.9
Crush	Halfway B	02	148.6	37.5	55.7	49.9	5.8
Currant	Halfway A	02	792.7	52.9	419.3	419.0	0.4
Currant	Halfway D	02	121.9	20.0	24.4	8.0	16.3
Desan	Pekisko	03	5,388.1	18.0	969.9	758.8	211.1
Eagle	Belloy-Kiskatinaw	02	6,928.9	40.0	2,771.5	2,305.2	466.3
Eagle West	Belloy A	03	20,337.5	32.3	6,569.0	6224.7	344.3
Elm	Gething B	04	1,772.6	7.5	132.9	129.0	4.0
Halfway	Debolt A	03	950.0	10.0	95.0	94.7	0.3
Hay River	Bluesky A	05	31,032.8	20.0	6,206.6	4,744.6	1,462.0
Inga	Inga A	06	8,236.6	40.9	3,368.8	3,319.6	49.1
Inga	Inga A	07	7,521.3	34.1	2,564.8	2,335.0	229.8
Inga	Inga A	04	1,400.6	50.0	700.3	625.2	75.1
Inga	Inga A	08	1,716.5	34.0	583.6	557.7	25.9
Lapp	Halfway C	02	1,075.5	45.0	484.0	445.2	38.8
Lapp	Halfway D	02	407.4	45.0	183.3	162.2	21.1
Milligan Creek	Halfway A	03	12,119.2	53.0	6,423.2	6,376.3	46.9
Milligan Creek	Halfway A	02	1,972.5	54.0	1,065.2	1,015.2	50.0
Muskrat	Boundary Lake A	03	1,002.5	40.0	401.0	333.2	67.8
Muskrat	Lower Halfway A	03	464.5	25.0	116.1	106.9	9.2
Oak	Cecil B	03	1,313.9	48.0	630.7	598.5	32.2
Oak	Cecil C	03	907.7	60.0	544.6	386.4	158.3
Oak	Cecil E	03	1,334.6	20.0	266.9	231.9	35.0
Oak	Cecil I	02	424.5	30.0	127.3	99.3	28.1
Owl	Cecil A	03	784.7	45.0	353.1	318.9	34.2
Peejay	Halfway	06	8,937.6	42.5	3,798.5	3,782.1	16.4

Table A-4: Oil Pools Under Waterflood (continued on next page)

Table A-4: Oil Pools Under Waterflood (continued)

FIELD	POOL	PROJECT CODE	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cum Oil (10^3m^3)	RR (10^3m^3)
Peejay	Halfway	02	7,897.0	45.0	3,553.6	3,477.7	75.9
Peejay	Halfway	03	5,802.6	38.5	2,234.0	2,226.2	7.8
Peejay	Halfway	04	2,835.6	35.0	992.5	977.0	15.5
Peejay West	Halfway A	03	1,050.2	50.0	525.1	469.9	55.2
Peejay West	Halfway C	02	510.9	40.0	204.4	118.1	86.3
Red Creek	Doig C	03	4,358.9	5.0	217.9	148.6	69.4
Rigel	Cecil B	02	1,820.9	50.0	910.4	878.1	32.4
Rigel	Cecil I	02	2,146.0	40.0	858.4	763.4	95.0
Rigel	Dunlevy A	02	1,225.4	52.0	637.2	584.7	52.5
Rigel	Halfway C	03	952.7	45.0	428.7	418.1	10.6
Rigel	Halfway Z	02	752.3	39.0	293.4	292.0	1.4
Rigel	Cecil G	02	738.9	27.5	203.2	196.6	6.6
Rigel	Cecil H	03	104.4	20.0	20.9	6.9	14.0
Rigel	Halfway C	02	195.5	10.0	19.0	19.0	0.0
Squirrel	North Pine C	03	1,376.5	30.0	412.9	408.9	4.1
Stoddart	North Pine G	04	390.0	40.0	156.0	74.2	81.8
Stoddart West	Bear Flat D	03	5,784.4	25.0	1,446.1	1,343.8	102.3
Stoddart West	Belloy C	05	451.9	35.0	158.2	153.8	4.4
Sunset Prairie	Cecil A	02	882.3	40.0	352.9	328.9	24.0
Sunset Prairie	Cecil C	02	380.3	40.0	152.1	5.2	146.9
Sunset Prairie	Cecil D	02	420.2	35.0	147.1	120.2	26.9
Two Rivers	Siphon A	03	1,370.0	20.0	274.0	252.3	21.8
Weasel	Haflway	02	3,734.4	65.0	2,427.4	2,348.4	79.0
Weasel	Halfway	03	1,729.4	58.5	1,011.7	1,005.7	6.0
Wildmint	Halfway A	02	2,877.8	54.0	1,554.0	1,540.6	13.4
Woodrush	Halfway E	02	579.4	20.0	115.9	87.1	28.7
Total					102,372.1		8,174.8
% of Total British Columbia Reserves					75.5		45.3

Table A-5: Oil Pools Under Gas Injection

FIELD	POOL	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cum Oil (10^3m^3)	RR (10^3m^3)
Brassey	Artex A	353	42.5	149	149	0
Brassey	Artex G	94	16	15	14	1
Bulrush	Halfway A	820	45	369	320	49
Cecil Lake	Cecil D	893	40	357	338	19
Mica	Mica A	1,129	30	339	253	86
Rigel	Halfway H	703	15	105	91	14
Stoddart West	Belloy C	1,701	25	425	379	46
Total				1,759		215
% of Total British Columbia Reserves				1.3		1.2

Table A-6: Well Permitting Data

2014 Activity	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec	2014 Total	Total Since April 2005
Wells Permitted[1]	333	255	242	306	970	10,093
Wells Permitted - Conventional	40	25	25	58	148	4,707
Wells Permitted - Unconventional	293	230	217	248	822	5,386
Montney Trend	281	230	204	231	762	3,498
Horn River Basin	--	--	--	--	26	522
Cordova Embayment	--	--	--	3	3	70
Liard Basin	9	--	1	3	11	22
Jean Marie	3	--	12	9	9	968
Deep Basin Cadomin	--	--	--	2	11	306
Total	959	740	701	1,217	3,617	

[1] Wells permitted are reflective of wells authorized at all statuses.

Appendix B

Unconventional Reserves Evaluation Method

In 2013, drilling and production activities in British Columbia focused on unconventional resource plays. Therefore, the Commission adopted an evaluation methodology suitable for evaluating unconventional reserves and resources by following the methodology outlined in the Canadian Oil and Gas Evaluation Handbook (COGEH) and the Society of Petroleum Evaluation Engineers (SPEE) Monograph 3, “Guidelines for the Practical Evaluation of Undeveloped Reserves in Resource Plays”.

Using these guidelines, the Heritage Regional field remained in the mature phase of development while the Northern Montney Regional field has shifted its development phase from “Early” to an “Intermediate” stage. As a result of this shift in the phase of resource play development, the Commission focused on reviewing and updating the Northern Montney reserves.

Within the Northern Montney Regional field, there are three PDAs (Pool Designation Areas); i) the Doig Phosphate–Montney in the SE; ii) the Montney B field in the north; and iii) the Montney A field. Within each field a modified Arps decline analysis was employed using two segments.

a). The first segment matched the transient flow, using decline exponent b of 1.5 to 2 for three to six years. The initial decline rate was adjusted manually to best fit the production curve. In liquid rich areas, boundary dominated flow appears earlier.

b). In the second segment matching of the boundary dominant flow used a b of 0.3 to 0.5 and decline rate of approximately 10 per cent/year.

c). The assumed abandonment rate was 100 Mcf/d.

Applying the guidelines outlined in the SPEE Monograph 3, the Northern Montney is in the Intermediate phase of development. Therefore, three PUDs were assigned to each existing well.

In assigning reserves to each PUD, a Monte Carlo simulation was performed as follows:

a) A decline forecast was obtained for every Montney gas well.

b) A simulation was run on the aggregated EURs to get outcome of P90, P50, P10 and Mean.

c) The aggregated P90 EUR was applied to each PUD as an expected result. The sum of (aggregated P90 EUR x the number of PUD’s) + (P50 EUR x the number of existing wells) resulted in the Pool EUR for the Montney North field.

d) The methodology for determining the Regional Heritage EUR can be found in the 2012 Hydrocarbon and By-Product Reserves in British Columbia report (Appendix B - Unconventional Reserves Evaluation Method).

Table B-1: Summary of Unconventional Plays

	Montney	Horn River	Liard	Cordova
PROSPECTIVE RESOURCES				
Potential Resource (TCF)	1,965	448	Evaluation ongoing	Evaluation ongoing
Source	Joint 2013 report: Commission, Alberta Energy Regulators, BC Ministry of Natural Gas Development, National Energy Board	Joint 2011 report: National Energy Board, BC Ministry of Energy and Mines	Commission evaluation ongoing (limited data)	Preliminary Commission estimate
PROVEN RESERVES				
OGIP (TCF)	241.3	46.9	1.0	0.4
RR (TCF)	25.7	11.0	0.09	0.08
Cum Gas (TCF)	3.2	0.8	0.012	0.03
Existing Wells Drilled	2520	375	12	39
RESERVES METHODOLOGY				
Evaluation Method	Decline Statistics	Decline	Decline	Volumetric
Average Reserves per HZ Well (BCF)	4.5	6.4	8.0	4.0
Recovery Factor (%)	12	25	10	25
RESERVOIR DATA				
Depth Range (m)	1,400-3,200	1,900-3,100	3,900-4,800	1,500-2,300
Gross Thickness (m)	30-300	140-280	100-200	70-120
TOC Range (%)	~2	1-5	3-6	2-5
Porosity (%)	2-9	3-6	3-6	3-6
Water Saturation (%)	25	25	15-20	25
Pressure (MPa)	14-86	20-53	75-85	5-22
Pressure Regime	Over Pressure	Over Pressure	Over Pressure	Under to Normal Pressure
Temperature (°C)	50-110	80-160	150-180	50-180
Average H_2S (%)	0-1.5	0 Muskwa-Otter Park 0.02 Evie	0.002	0.004
Average $C0_2$ (%)	< 1.0 (max 5)	10 Muskwa-Otter Park 13 Evie	7	8
COMPLETION DATA (based on 2010-2014 results)				
Average Proppant Placed per Stage (t)	120	170	193	220
Total Fluid Pumped (m^3)	11,648	79,920	20,431	43,513
Number of Stages	16	25	10	14
Completed Length (m)	1,726	2,232	1,200	1,794
Average Frac Spacing (m)	145	103	133	147
Six Month Gas Rate per Stage (Mcf/d)	195	227	158	134

More information

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