British Columbia's Oil and Gas Reserves and Production Report

2019 | BC Oil and Gas Commission

About the

BC Oil and Gas Commission

The BC Oil and Gas Commission (Commission) protects public safety and safeguards the environment through the sound regulation of oil, gas and geothermal activities in B.C. From exploration through to final reclamation, the Commission works closely with First Nations, land owners and rights holders, and ensures industry complies with provincial legislation.

With more than 20 years' dedicated service, the Commission is committed to safe and responsible energy resource management for British Columbia.

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

The Commission's seven office locations plus major oil and gas plays in Northeast B.C.

Purpose of Report

British Columbia's Oil and Gas Reserves and Production Report

This annual report summarizes provincial oil and gas production and remaining recoverable reserves in British Columbia, providing assurance of supply for the development of policy, regulation and industry investment. The report also qualifies 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 are presented in this report as of Dec. 31, 2019. The estimates have been prepared by the BC Oil and Gas Commission (Commission) using the principles of accepted engineering methods (including the Canadian Oil and Gas Evaluation Handbook (COGEH), the SPEE Monograph 3: Guidelines for the Practical Evaluation of Undeveloped Reserves in Resource Plays, and SPEE Monograph 4: Estimating Ultimate Recovery of Developed Wells in Low-Permeability Reservoirs). This report is not subject to the audit requirements of publicly traded companies and is not intended for the evaluation of individual companies.

The reserve numbers represent proved plus probable (2P) recoverable reserves using current technology. The proved reserves reflect a "reasonable certainty" to be commercially recoverable. Probable reserves are less likely to be recovered than proved reserves and are interpreted from geological data or engineering analyses.

Table of Contents

Available on the Commission website:

Detailed Gas Reserves By Field and Pool

Detailed Oil Reserves by Field and Pool

Detailed Condensate and By-Product Reserves by Field and Pool

Difference Between Resources and Reserves

The terms "Resources" and "Reserves" are not interchangeable. This section highlights the significant differences in the criteria associated with their classification.

Resources

Resources are the total quantity of oil and natural gas estimated to be contained in subsurface accumulations. The term resource is applied to a geologic formation in a large geographic region or a specific geologic basin. Resource estimates include proven reserves, produced quantities and unproven resources which may not be recoverable with current technology and economics.

The Commission cautions those using resources (prospective or contingent) as an indicator of future production.

Reserves

Reserves are quantities of oil and natural gas that are commercially recoverable with development projects from a given date under defined conditions. To be classified as reserves, the oil or gas must meet these criteria:

- Penetrated by a wellbore.
- Confirmation the well will produce (either a production test, or on production).
- Meets regulatory requirements (production or development not prohibited by government policy or legislation).
- Marketable to sell (viable transportation to sales point available either through pipelines, rail or trucking).
- Developed within a reasonable time frame (up to five years for probable reserves).
- Economic to recover, considering development costs, sales price, royalties, etc.

Dawson Creek Resource Centre

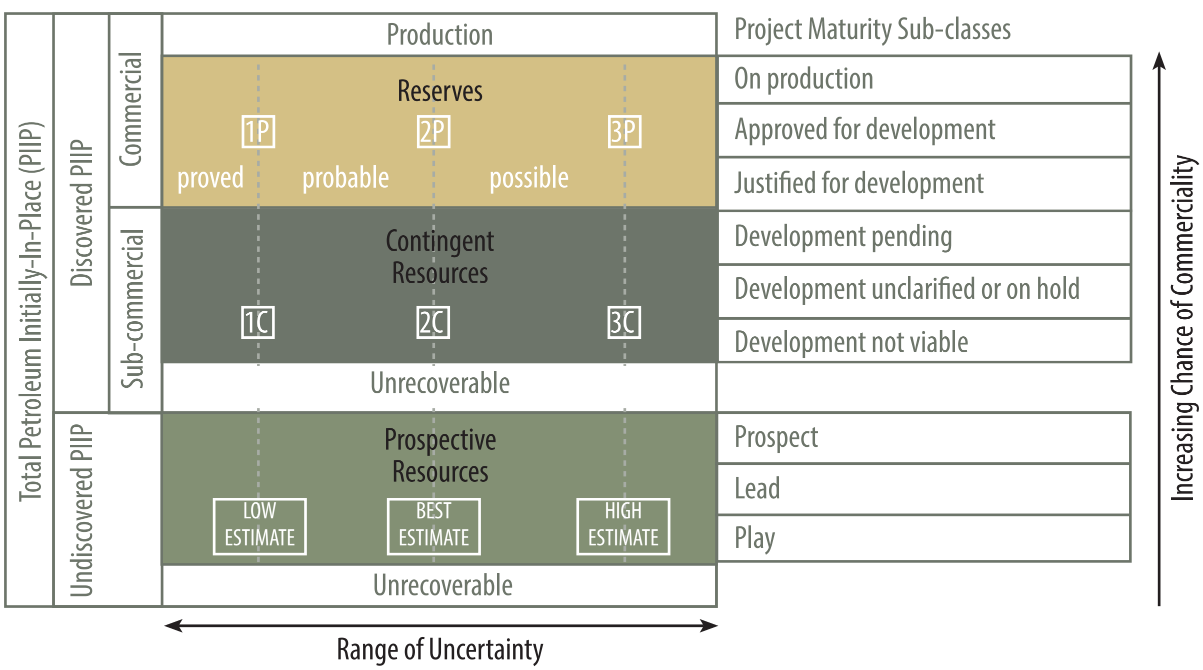
Difference Between Resources and Reserves

The Petroleum Resources Classification Framework published by the Society of Petroleum Engineers (Figure 1) provides a detailed analysis of the differences between resources and reserves.

The resources classification system is based on project maturity. This classification system uses an increasing chance of commerciality to categorize the petroleum initially-in-place (PIIP) as prospective resources (undiscovered resources), contingent resources (discovered but sub-commercial) or as reserves (commercial).

Along the horizontal axis, prospective resources are sub-divided into three uncertainty categories providing a low estimate, best estimate, or high estimate. Contingent resources are sub-divided into 1C, 2C and 3C estimates of recovery with 3C having the highest number of resources. Reserves have a comparable system to that of contingent resources with 1P, 2P and 3P to represent proved, probable and possible reserves.

Figure 1: Resources Classification Framework and Sub-classes Based on Project Maturity
Sourced from: Petroleum Resources Management System (no scale inferred).



Difference Between Resources and Reserves

Reserves: What we can get.
Resources: What is there.

The resource volume provides an understanding of the size of these accumulations and potential for further development. An often used graphic when comparing resources and reserves is the iceberg image to the right. It shows the vast quantity of hydrocarbons available (resources) versus the known established reserves.

A comparison between the resource estimate and remaining reserves (Table 1) illustrates the large differences in gas volumes between the two categories. For example, in the Montney basin the resource estimate (P50) is 55,610 e^9m^3 (1,965 Tcf); however, currently recoverable initial raw gas reserves of 1,827.53 e^9m^3 (64.58 Tcf) are approximately three per cent. This reserves percentage is expected to increase with continued development of the play.

Table 1: Unconventional Gas Resource, Reserves and Cumulative Production

Basin/Play	Resource: Basin Total GIP Resource		Resource: Ultimate Resource Marketable		Reserve: Initial Raw Gas Reserves		Reserve: Remaining Reserves (Raw)		Reserve: Cumulative Production (Raw)[6]		% Reserve per Resource
Unit	10^9m^3	Tcf	10^9m^3	Tcf	10^9m^3	Tcf	10^9m^3	Tcf	10^9m^3	Tcf	
Montney[1]	55,610	1,965	7,669	271	1,827.53	64.58	1,532.95	54.17	294.60	10.41	3.29%
Liard Basin[2]	23,998	848	4,726	167	2.93	0.10	0.80	0.03	2.14	0.08	0.01%
Horn River Basin[3]	12,678	448	2,207	78	78.99	2.79	44.39	1.57	34.60	1.22	0.62%
Cordova[4]	1,902	67	249	9	3.11	0.11	1.32	0.05	1.79	0.06	0.16%
Deep Basin Cadomin, Nikanassin[5]	255	9	207	7	28.99	1.02	9.16	0.32	19.83	0.70	11.38%
Total	94,443	3,337	15,058	532	1,941.55	68.61	1,588.61	56.13	352.96	12.47	2.06%

1. NEB/OGC/AER/MNGD Energy Briefing Note - The Ultimate Potential for Unconventional Petroleum from the Montney Formation of BC and Alberta (Nov. 2013).
2. NEB/OGC/ NWT/Yukon Energy Briefing Note - The Unconventional Gas Resources of Mississippian-Devonian Shales in the Liard Basin of British Columbia, The Northwest Territories and Yukon (March 2016).
3. NEB/MEM Oil and Gas Reports 2011-1, Ultimate Potential for Unconventional Natural Gas in Northeastern BC's Horn River Basin (May 2011).
4. MNGD/OGC Cordova Embayment Resource Assessment (June 2015).
5. MEMPR/NEB Report 2006-A, NEBC's Ultimate Potential for Conventional Natural Gas.
6. Cumulative production to Dec. 31, 2019.

Executive Summary

The 361 wells drilled in 2019 were a 23 per cent decrease from the 471 wells in 2018, as operators deferred drilling activity on well permits issued. The Montney remains the dominant play for provincial drilling activity, production and reserves growth.

An overall increase in remaining gas reserves in the province resulted from additions, especially in the Montney. In other plays, such as the Horn River regional field, natural production decline and the lack of activity continue to deplete the local reserves inventory.

Reserve estimates, as shown in Table 2, indicate a significant shift from dry gas to liquids rich production. Liquid by-product production (Pentanes+ and LPG) increased by 21 per cent in 2019 (Figure 18). This increase partially reflects a policy change in determination of the primary product of Montney formation wells, with most new wells qualifying as gas wells with associated hydrocarbon liquids, rather than oil. In 2019, the focus of development shifted to exploring the middle and lower portions of the Montney, in addition to the already active upper Montney zone. In some areas operators developed the entire stack of the Montney formation (upper, middle, and lower zones), referred to as a 'cube' development, that optimizes drilling and completion activity at a location within a single period of time. This approach also shortens the period of initial social and environmental impact in the area of operations.

However, the Pmean gas EUR (estimated ultimate recovery) per well including all zones in the Heritage and Northern Montney showed a slight decrease compared to the previous year, in part due to operators developing the entire stack of the Montney with variable results.

A 2019 statistical analysis divided the Heritage and Northern Montney fields into subareas, as well as vertically grouping wells to either the upper or lower Montney zones, to more accurately aggregate reserves. Within the Northern Montney, the northern sub-area shows higher gas and liquid EURs than for the southern sub-area. For the Heritage field, wells horizontally located in upper and lower zones have similar gas EURs within the same identified dryer or liquid rich subareas (Table 3). The main difference between upper and lower zones is seen in the liquid content (Figure 21 through 23). As stated above, hydrocarbon by-products production increased in 2019. Similarly, condensate/pentantes+ reserves showed a strong increase, while LPG reserves were negatively affected primarily due to reporting and calculation changes.

The decrease in oil reserves was due to a combination of downward reserve revisions combined with the lack of new oil wells drilled in 2019. Reserve revisions are shown in Appendix A Table A-1.

Sulphur production increased by 10.3 per cent from the previous year but stayed below historic higher volumes. However, a decrease in sulphur reserves reflects ongoing depletion of gas reserves producing to sulphur recovery plants.

Table 2: B.C. Remaining Reserves as of Dec. 31, 2019

	2019		2018		Percent Change
Gas (raw)	1,818.7 $10^9 m^3$	64.3 Tcf	1,434.1 $10^9 m^3$	50.7 Tcf	26.8 %
Oil	16.6 $10^6 m^3$	104.7 MMSTB	18.3 $10^6 m^3$	115.5 MMSTB	-9.3 %
Pentanes$^+$	86.0 $10^6 m^3$	540.7 MMSTB	48.0 $10^6 m^3$	301.8 MMSTB	79.2 %
LPG	105.8 $10^6 m^3$	665.3 MMSTB	143.4 $10^6 m^3$	901.7 MMSTB	-26.2 %
Sulphur	6.0 10^6 tonnes	5.9 MMLT	9.8 10^6 tonnes	9.6 MMLT	-38.8 %

As shown in Figure 2, well drilling activity was concentrated in the Montney formation. Of the 361 wells drilled in 2019, approximately 98.6 per cent (356 wells) were drilled in the Montney formation. The remaining 1.3 per cent included three disposal wells, one injection and one production well, all targeting other formations.

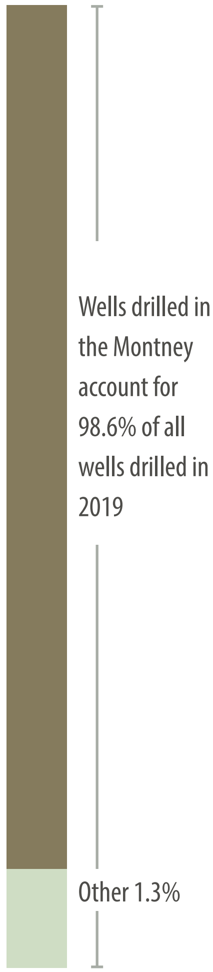
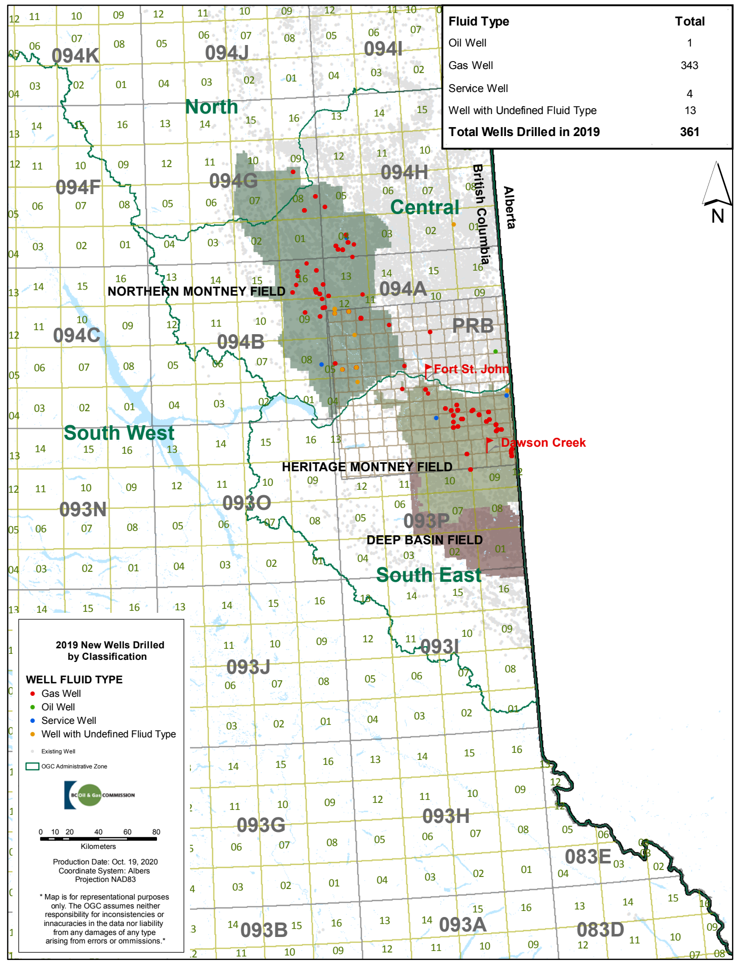


Figure 2: 2019 Wells Drilled by Fluid Type



Discussions: Gas Reserves and Production

As of December 2019, unconventional gas zones accounted for 88.3 per cent of all remaining reserves and 91.4 per cent of annual gas production in the province.

As of Dec. 31, 2019, the province's remaining raw gas reserves were 1,818.7 e9m3, a 26.8 per cent increase from the 2018 remaining reserves. The increase in reserves occurred primarily due to Montney revisions with additional PUD (proven undeveloped) locations.

Figure 3 illustrates the distribution of remaining conventional and unconventional gas reserves, with 84.3 per cent of the remaining recoverable reserves held in the Montney basin.

Figure 4 echoes the distribution of remaining reserves by showing the gas production split by source (as at December 2019). The majority of production in the province now originates from the Montney.

Figure 3: 2019 Remaining Gas Reserves

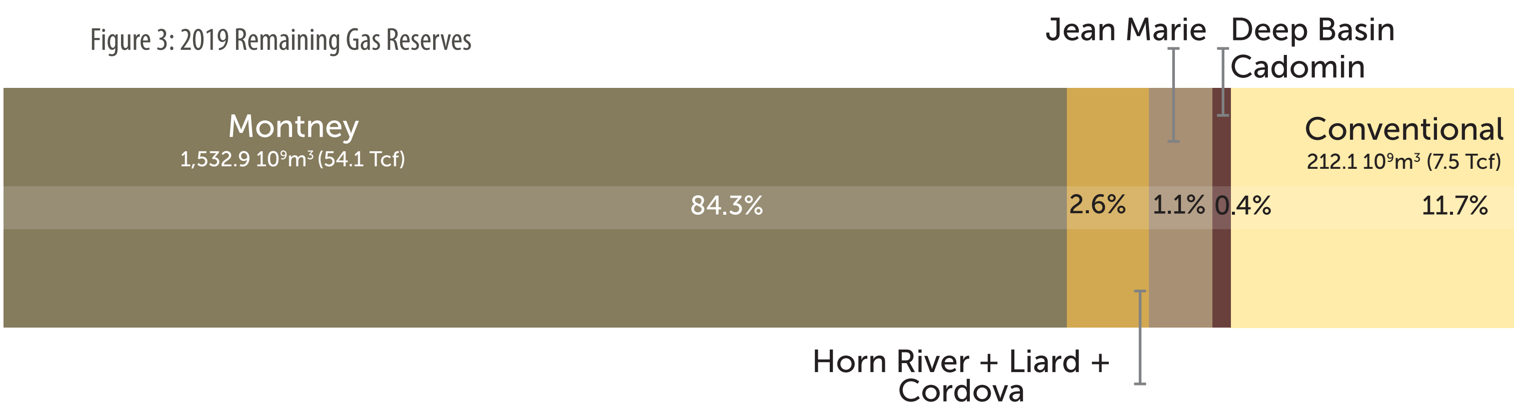
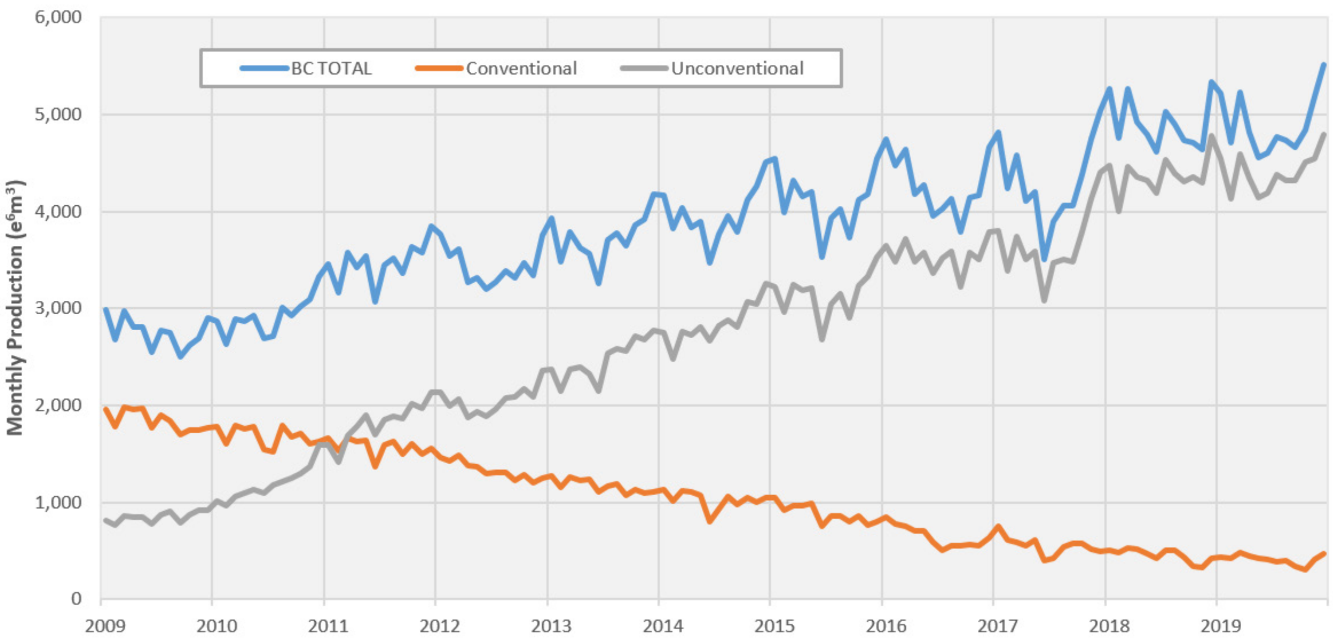


Figure 4: 2019 Annual Gas Production Split by Source

Discussions: Gas Reserves and Production

Figure 5: Unconventional vs. Conventional Raw Gas Production 2009 to 2019



Discussions: Gas Reserves and Production

In the last five years gas production has increased by 22 per cent resulting in increased loads within the existing pipeline delivery points for the Montney. Gas within these regions is transported by pipelines to Station 2 (shipped on Enbridge, formerly Spectra), AECO (shipped on TC Energy Pipeline) and Chicago (shipped on Alliance). See Figure 6.

TC Energy construction of the North Montney Mainline will provide a significant increase in capacity.

Figure 6: British Columbia's Gas Pipelines

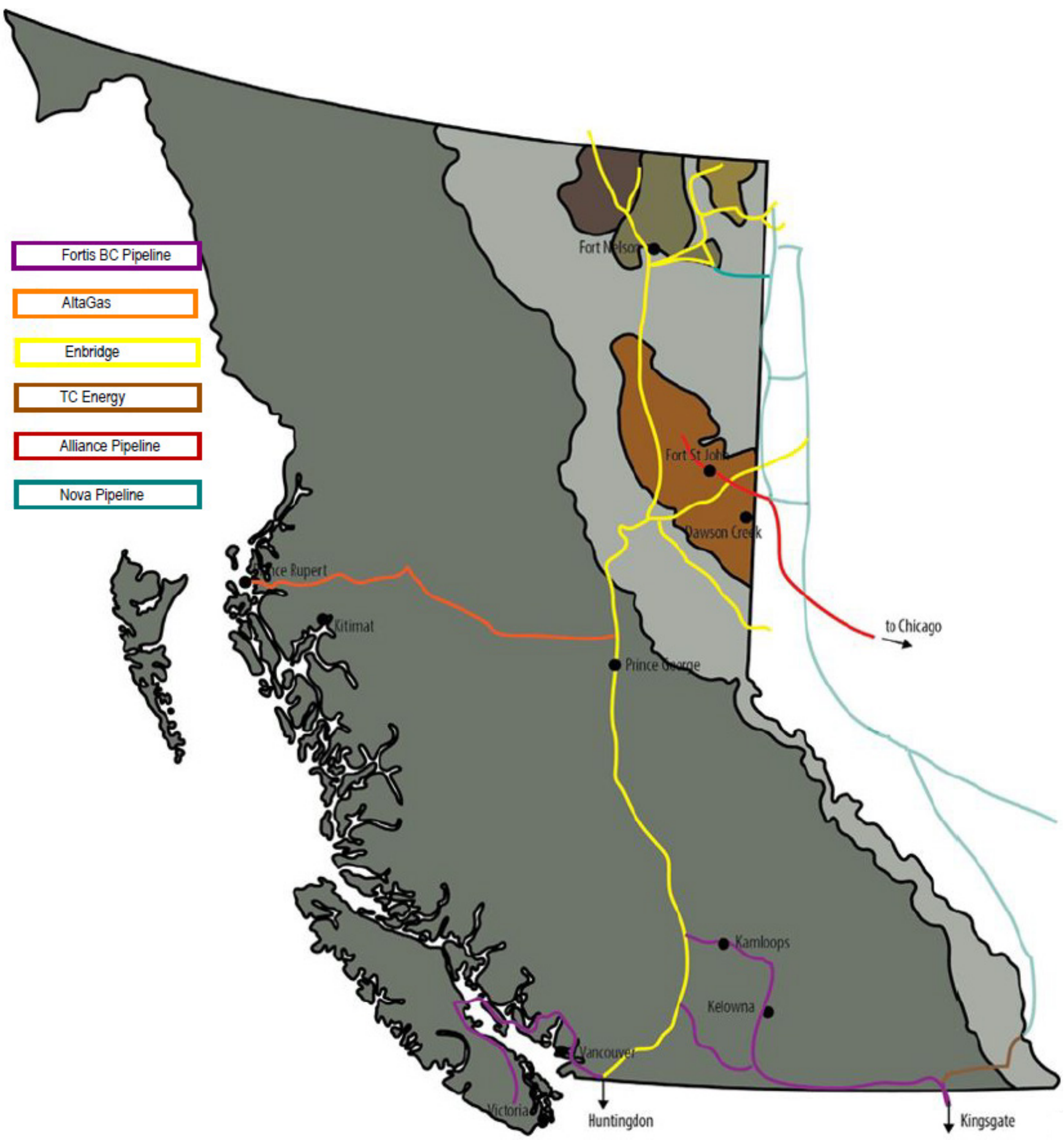


Figure 7 represents the Commission's raw gas reserves bookings from 1999 to 2019, highlighting unconventional Montney and Horn River reserves versus all other reserves grouped together.

Remaining reserves were consistent for a decade prior to 2003, then increased due to a number of factors including Deep Basin development followed by horizontal unconventional development. Between 2003 and 2006, activity reached record levels (1,300 gas wells drilled in 2006), with predominant targets such as 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, the onset of Montney horizontal drilling with hydraulic stimulation created a new supply of gas. This was followed by Horn River development in 2010. Further development of the Horn River basin has now ceased, with decreasing production, awaiting economic gas demand.

Raw gas production for the province in December 2019 was 177.7 e6m3 per day (6.27 Bcf/d).

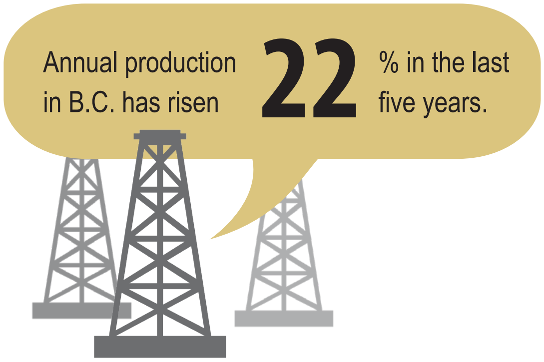
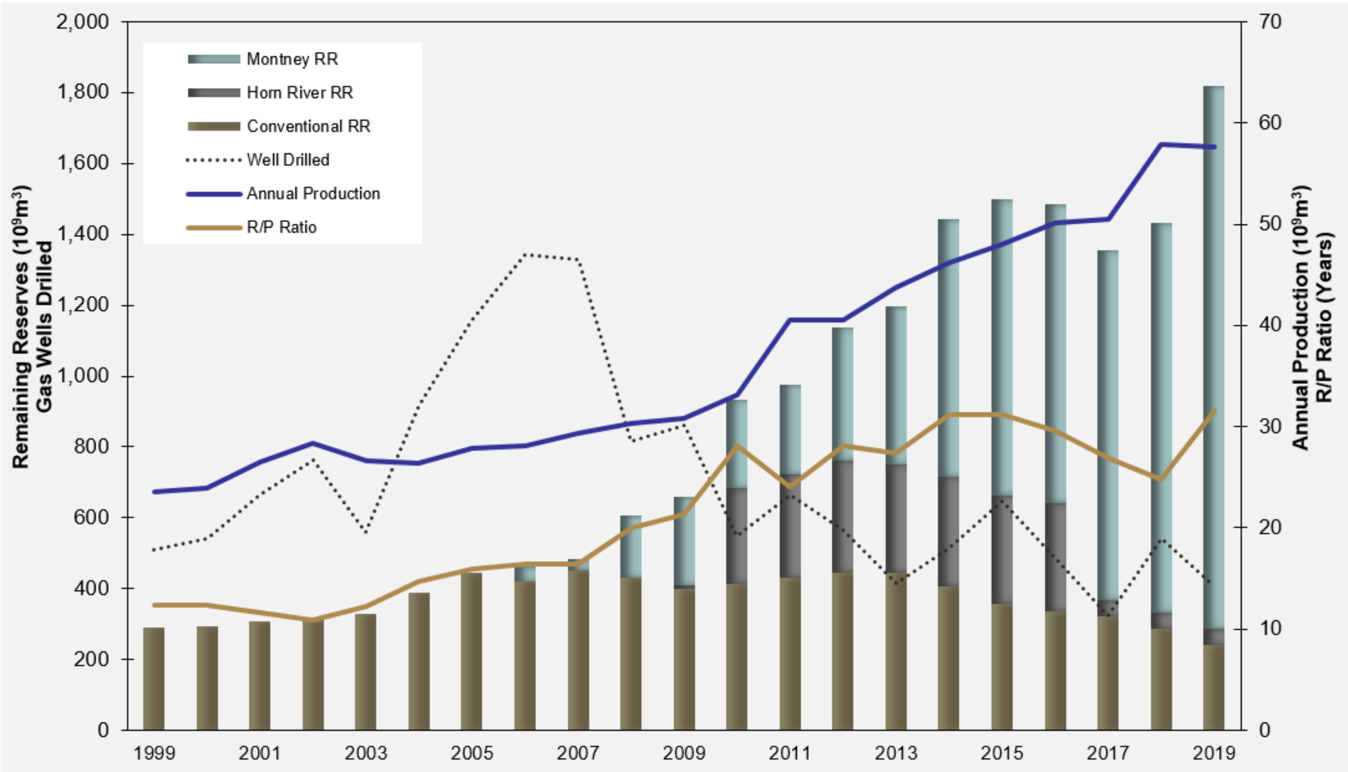


Figure 7: Historical Development in B.C. 1999 to 2019



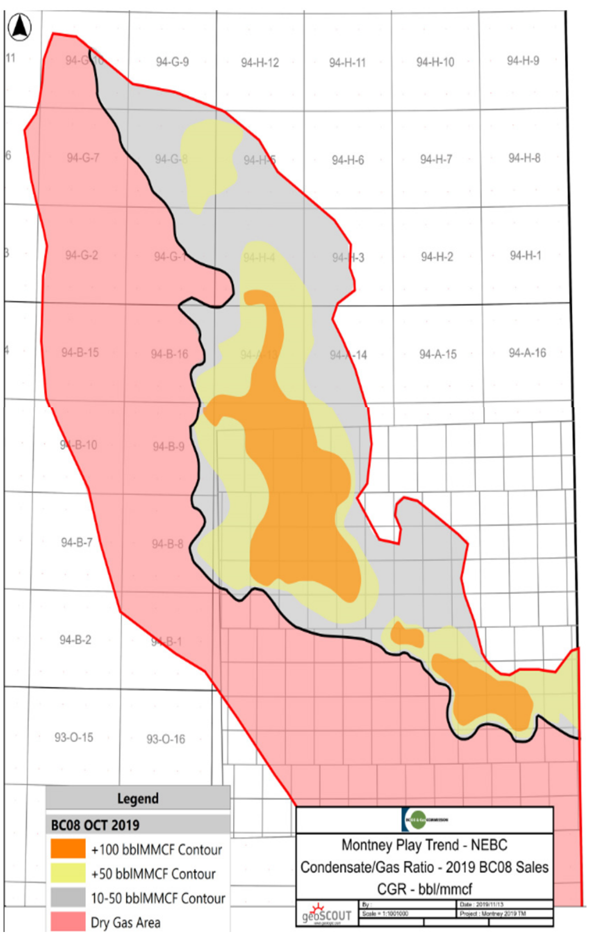
Montney Unconventional Gas Play

The Montney contains 84.3 per cent (54.1 Tcf) of the province's remaining raw gas reserves and contributed 85.8 per cent (5.11 Bcf/d; annual average rate) of the province's 2019 production.

Significant development of the Montney began in 2005 and the area has become the largest contributor to natural gas production volumes in the province. In 2019, drilling was focused on the liquid rich gas portions of the play trend. As a result, production of natural gas liquids and condensate increased significantly. This increase is also a reflection of Commission policy in assigning well primary product, with few new wells with high liquid hydrocarbon content qualifying as oil wells. At the end of December 2019, of the 8,203 producing wells in the province, 3,619 were producing from the Montney formation.

Figure 8 displays the identified dry gas, rich gas and oil trends within the greater Montney Play trend. In the eastern area of the play trend a prolific high quality condensate window exists. Drilling continues along the eastern side of this super-condensate rich area where this window continues for a considerable distance on the north-eastern side of the Montney play.

Figure 8: Montney 2018 Dry/Wet/Oil Distribution



In December 2019 the Northern Montney gas production was 52.3 e^6m^3 per day (1.86 Bcf/d) while the Heritage field gas production was 93.6 e6m3 per day (3.33)Bcf/d).

Montney Unconventional Gas Play

As of Dec. 31, 2019, the remaining gas reserves for the Montney formation is 1,532.9 e9m3 (54.1 Tcf) (raw). The initial reserves of 1,827.53 e9m3 represents a 3.3 per cent recovery of the total basin gas-in-place of the Montney resource estimate. Both reserves and recovery factor will increase with additional drilling and production. A detailed record of remaining reserve estimates for each Montney pool/zone can be found in Table 3 below.

Table 3: Montney Remaining Reserves as of Dec. 31, 2019

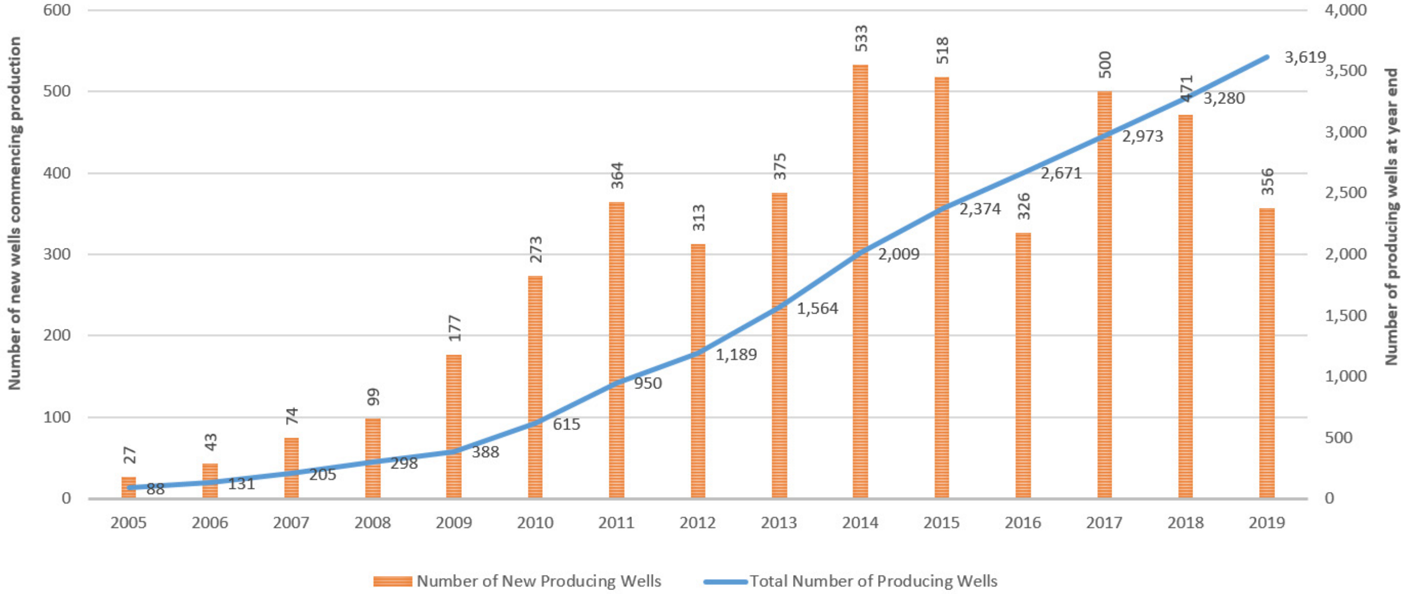
Field/Pool	Subareas/Layers	Horizontal Well EUR (Bcf) per well			
		Pmean	P90	P50	P10
Heritage - Montney A	Dry/Ultra Dry Upper	6.36	1.98	5.68	11.66
	Dry Lower	5.96	2.16	5.01	11.41
	Liquid Upper	3.70	0.92	3.34	6.87
	Liquid Lower	2.82	0.94	2.53	5.24
	Region/Total	5.31	1.49	4.55	10.10
Northern Montney - Montney A	NW - Upper	5.26	1.57	5.14	9.48
	NW - Lower	3.49	1.12	3.10	6.57
	NE - Upper	5.47	2.15	5.38	8.75
	NE - Lower	3.63	1.32	3.23	6.24
	SE - Upper	2.79	0.46	1.82	7.30
	SE - Lower	1.94	0.57	1.56	3.81
	Region/Total	4.34	1.24	3.87	7.98
Northern Montney - Doig Phosphate - Montney A	SW - Upper	4.64	1.17	4.06	8.92
	SW - Lower	4.23	1.24	3.63	7.91
	SE - Upper	2.79	1.04	2.48	5.18
	SE - Lower	3.72	1.33	3.23	7.21
	Region/Total	4.27	1.22	3.52	8.03

The initial reserves and remaining reserves do not include solution gas reserves. Due to limited well count, the upper-middle, the middle, and the lower-middle were combined with the lower Montney wells.

Figure 9 shows the number of new wells drilled versus the number of producing wells in the Montney play from 2005 to 2019. Producing wells continuously increased over the years, from 88 in 2005 to 3,619 by the end of 2019. Annual producing well additions peaked in 2014 and declined thereafter, however gas production has increased, illustrating improvements in per well performance.

Initial Reserves (Raw) Bcf	Remaining Reserves (Raw) Bcf	Existing Horizontal Wells	PUDs	Development Phase
22,996.1		1,126	2,069	Statistical
6,080.6		470	614	Statistical
5,411.5		810	732	Statistical
2,058.2		144	576	Intermediate
36,546.4	29.527.7	2,550	4,531	
5,648.9		216	864	Intermediate
3,572.6		220	880	Intermediate
4,238.4		350	435	Statistical
4,381.2		247	988	Intermediate
466.4		63	126	Early
327.2		60	120	Early
18,814.7	16,657.4	1,156	3,413	
5,059.3		244	896	Intermediate
2,689.9		131	524	Intermediate
354.1		44	88	Early
414.0		39	78	Early
8,517.3	7,556.1	458	1,586	

Figure 9: Number of New Wells added and Producing Wells in Montney Play 2005 to 2019



As shown in Figure 10A and 10B, the Montney's various subareas and zones differ in their gas Estimated Ultimate Recovery (EUR) volumes. The Heritage field shows four subareas with distributions in the P50 category ranging from 2.5 to 5.7 Bcf per well, whereas the Northern Montney shows six subareas with distributions in the P50 category ranging from 1.6 to 5.4 Bcf per well. These variations occur due to a number of factors, from formation characteristics (zone) and completion techniques, to stage of development.

Figure 10A: Heritage Montney EURs Distribution by Subareas/ Zones

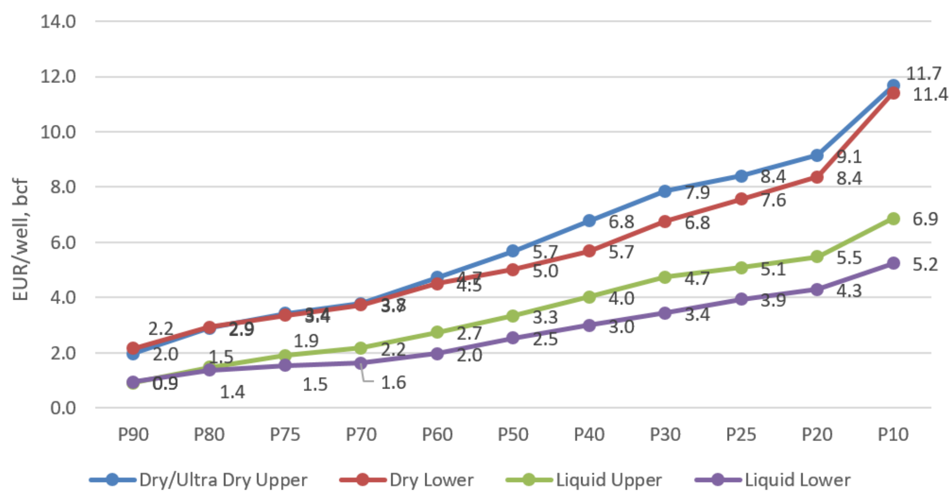
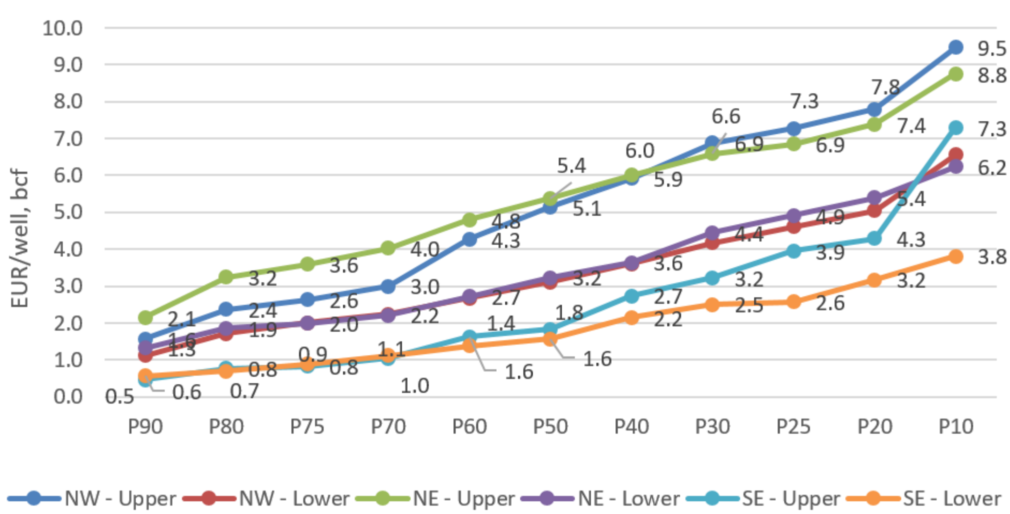


Figure 10B: Northern Montney EURs Distribution by Subareas/ Zones



Montney Unconventional Gas Play

As seen in Figure 11, the top gas producers in the Heritage field by production (Ovintiv, ARC and Tourmaline) differ from those in the Northern Montney (Petronas, Painted Pony and Pacific Canbriam). Operators focus within specific areas to optimize on operating, infrastructure and facility costs. Limited wells are drilled outside of these focus areas for reserves delineation and land continuation obligations. Production for most operators increased significantly in 2019, supported by improved completion techniques and new facilities. The trend in the industry is production company ownership and operation of infrastructure and plants, a shift from previous reliance on midstream companies. Operators are actively pursuing reduction of their environmental footprint by such actions as installing solar panels at the wellsite, reducing trucking operations by building liquid pipelines, and including green initiatives such as waste heat recovery in the design and construction of new facilities.

Figure 11: Top 10 Gas Producers in Montney Play 2019

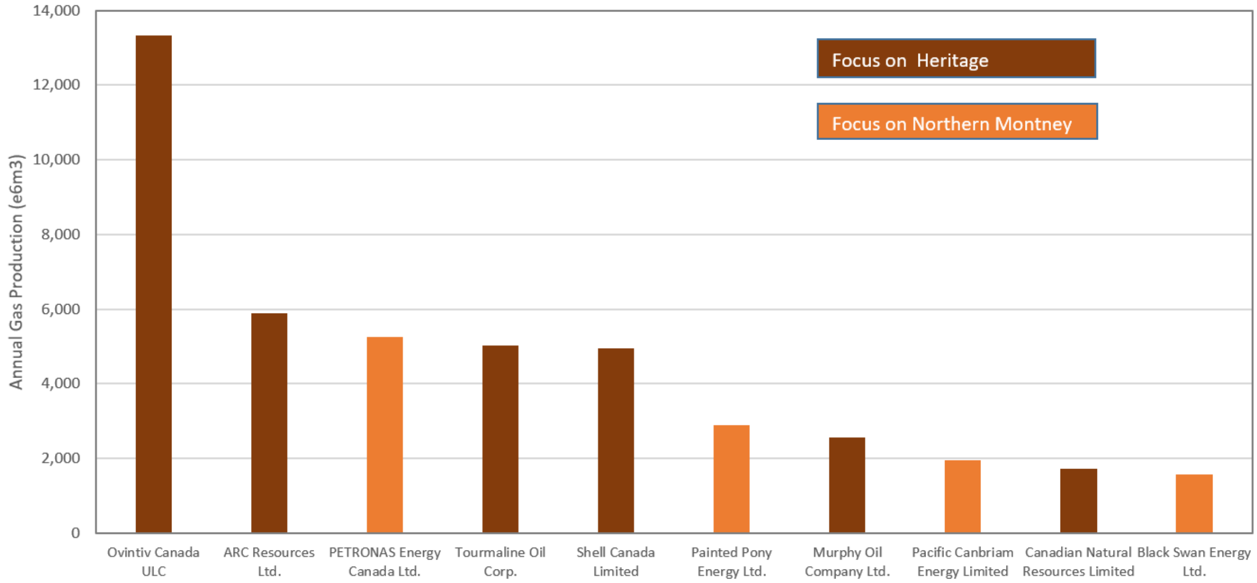
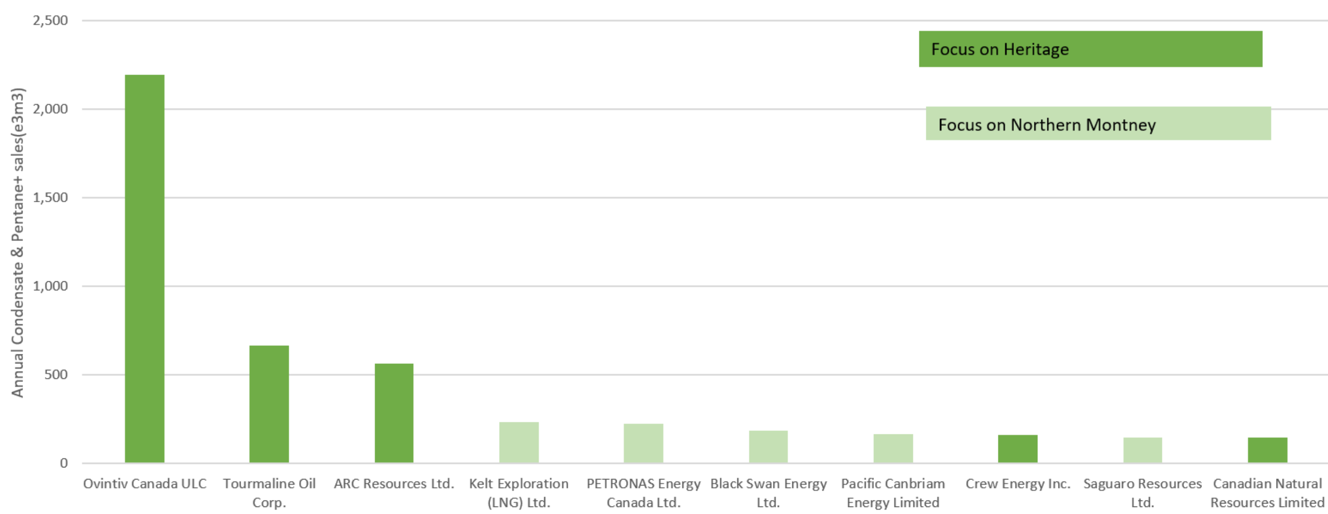


Figure 12: Top 10 Condensate & Pentanes+ Producers in Montney Play 2019



Other Unconventional Gas Plays Liard, Horn River and Cordova

Other plays also demonstrate the province's natural gas potential.

British Columbia has seen significant activity in the exploration and development of unconventional natural gas resources, beginning in the mid 1990's with horizontal drilling in the Devonian carbonates of the Jean Marie. Beginning in 2006, continued unconventional tight gas resources followed with shale gas development in the Devonian Muskwa, Otter Park and Evie shales in the Horn River Basin and the Triassic aged siltstones of the Montney formation. Drilling and production in the Liard Basin resulted in proving of a new play. Resource and reserve data for each gas play is contained in Table 1, page 6 of this report.

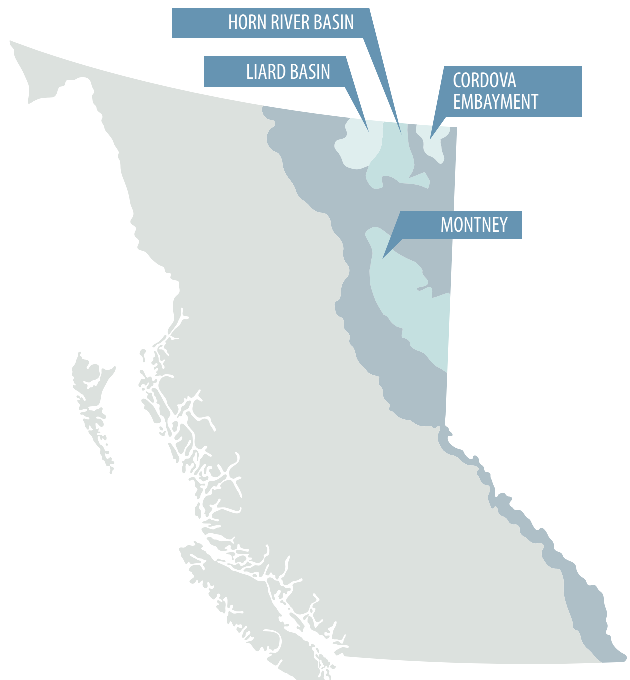
Liard Basin

Exploration in the Liard Basin started in 2008. Initial raw gas reserves are 2,933 e^6m^3 (0.1 Tcf) based on production from seven wells (two vertical and five horizontal wells).

The Exshaw-Patry shales within the B.C. portion of the Liard Basin, while depositionally similar, are significantly deeper, ranging from 3.5 to 5 kilometre depth, than the productive shales of the adjacent Horn River Basin. Net pay ranges from 30 metres near the Liard Basin's eastern edge to over 250 metres in the basin interior. The reservoir pressure is at approximately double the value of normal hydrostatic pressure gradient. The brittle nature of the siliceous shales allows them to be effectively stimulated by hydraulic fracturing which, combined with the elevated reservoir pressure, yields high initial gas production rates. The pay zone depth and remote location have resulted in high costs which has stopped new activity in the current low gas price environment.

Seven wells were evaluated in 2019 for reserves in the Liard Basin. This included four producing wells and three shut-in wells. By June 2019 all wells in the Liard were shut-in, resulting in a recovery factor to-date of approximately 7.3 per cent of the estimated initial recoverable reserves. The most significant production well, 200/c-016-K/094-O-12/00, peaked production at 1.57 e^6m^3/d (55.7 MMscf/d) in March 2016, then declined to 0.53 e^6m^3/d (18.7 MMscf/d) when shut-in in June 2019. Estimated recoverable gas is 2,600 e^6m^3 (92 Bcf) from this single well.

Well 200/c-050-B/094-O-12/03 also has high performance; initial production peaked at 0.71 e^6m^3/d (6.74 MMcf/d) in May 2019, then declined to 0.19 e^6m^3/d (8.83MMcf/d) by June 2019.



Horn River Basin

Production from the Horn River Basin was 4.15 e^6m^3/d (146.7 MMcf/d) in December 2019 down 30.2 per cent from the previous year (December 2018). Operators continued to shut-in wells no longer economic to produce, and no new wells have been drilled or completed since 2015. Continued production without new drilling resulted in a significant decrease in reserves from the previous year. A detailed evaluation in the 2018 Reserves Report resulted in a reduction in recovery factor for initial raw gas reserves, due to lack of drilling activities since March 2015. At the end of 2019 there were 123 wells producing from the Horn River Basin shales, from a peak of 222 wells in January 2015.

Other Unconventional Gas Plays
Liard, Horn River and Cordova

Cordova Basin

Development activity in the Cordova Basin ceased in February 2014 when the last new well was drilled. At the end of 2019 there were 17 wells producing from the Cordova Basin shale play, at a production rate of 359.3 e^3m^3/d (12.7 MMcf/d). Further background information on the Horn River and Cordova fields is available in the 2014 Reserves Report.

Figure 13 shows the initial reservoir pressure versus temperature plot for the Montney, Horn River, Cordova and Liard areas. The temperatures of these fields fall within expected ranges for depth except for Liard, which is also significantly higher than that of the Horn River, Cordova or Montney fields. The wide range in values reflects the large geographic area and depths of deposits. The over-pressured areas of these formations has been the focus of development, for gas charging and favourable response to hydraulic fracture stimulation.

Figure 14 illustrates "typewells" for the Montney, Horn River, Liard and Cordova fields. The most prolific wells are in the Liard Basin where operators have stated "exceptional results from two proof-of-concept horizontal wells" and "world-class deliverability of the basin".

Figure 13:
Pressure vs. Temperature Plot

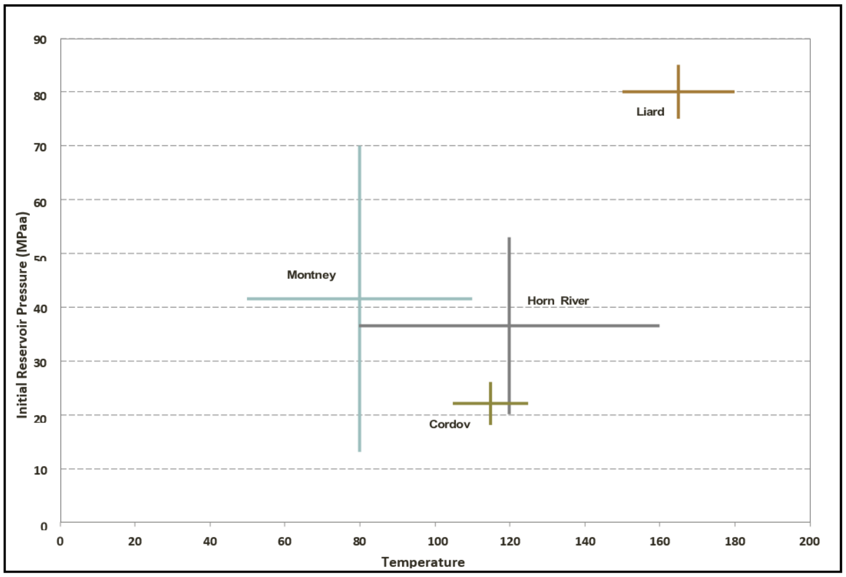
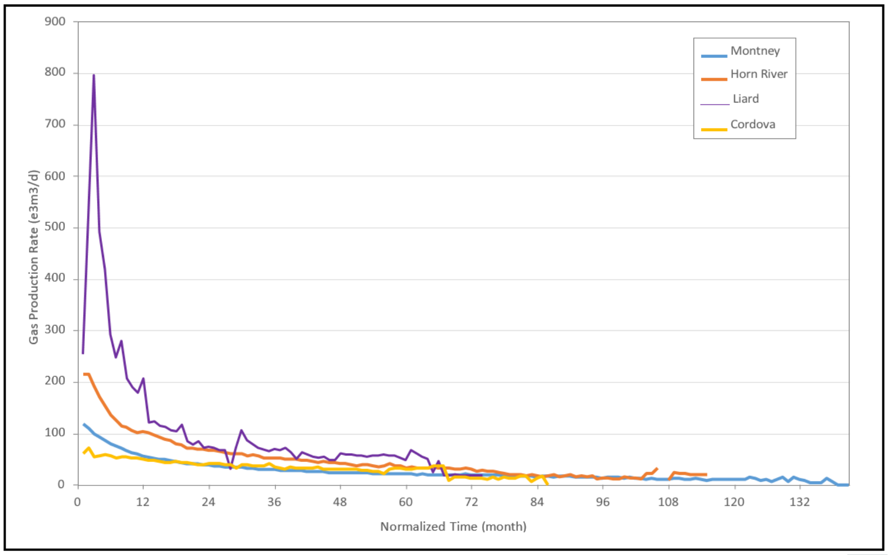
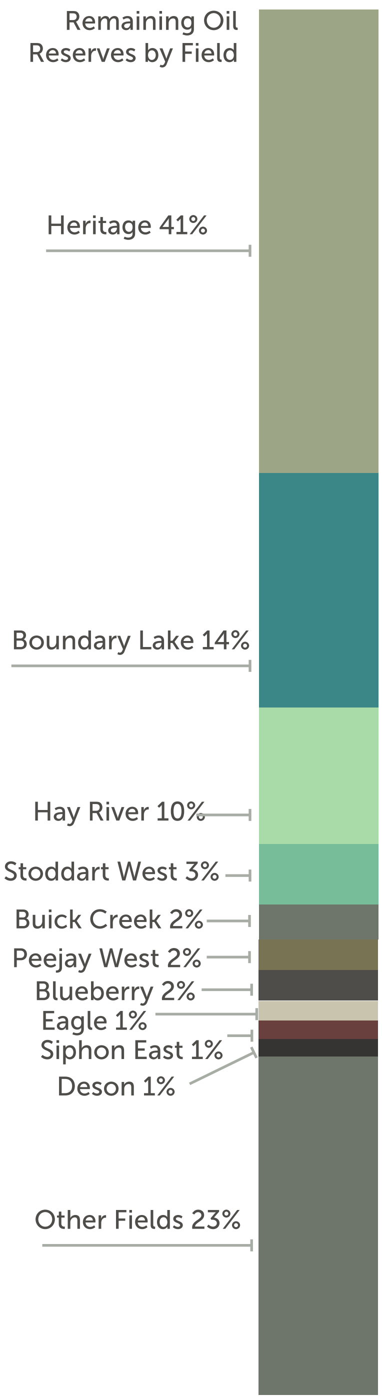


Figure 14:
Comparison of Montney, Horn River, Liard & Cordova Production Typewells



Discussions: Oil Reserves

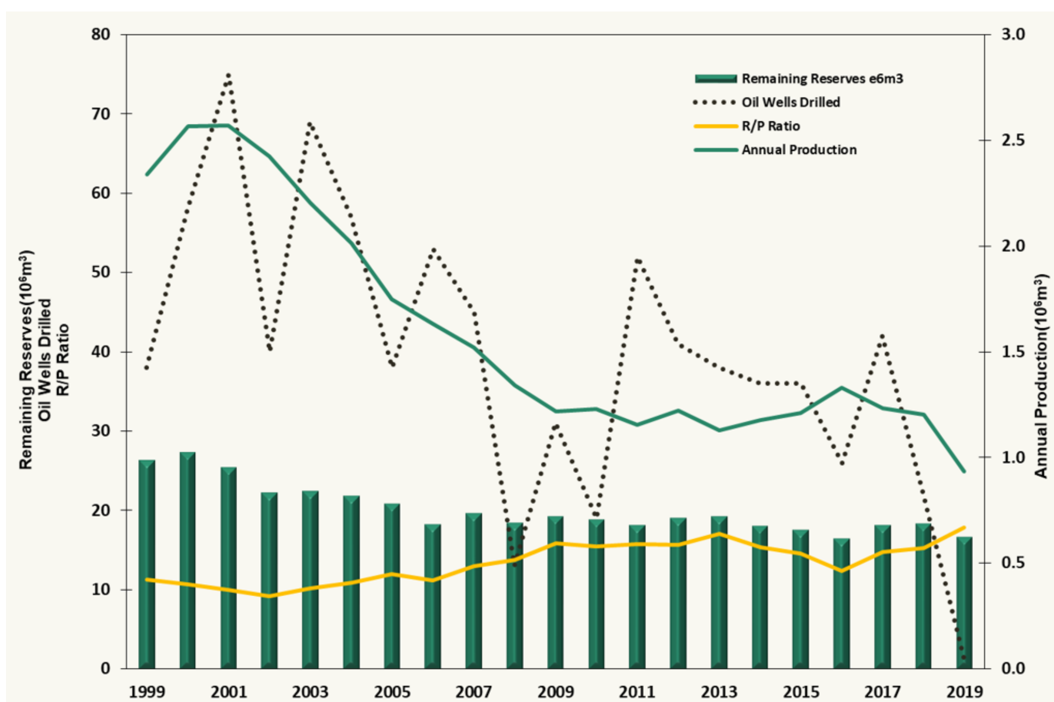
Annual oil production decreased 28.8 per cent from 1.20 to 0.93 10^6m^3 (5.88 MMSTB) in 2019.



Oil remaining reserves decreased 9.3 per cent in 2019 for total remaining reserves of 16.6 10^6m^3 (104.7 MMSTB). This reserves decrease is mainly due to the lack of new oil wells drilled. In 2019 only one additional conventional oil well came on production in comparison to a total of 22 oil wells in 2018. Optimization of waterflood projects with injection locations, which support the large majority of conventional pool production, is still taking place, but is limited due to the lower price environment. The estimated recovery factors for waterflood projects ranges from 4.5 per cent in tight rock to 65 per cent in exceptional reservoir quality pools, with an average of approximately 35.7 per cent, showing good production management of conventional oil pools in the province.

The R/P ratio has been steady since 2009 with approximately 15 years of reserve life. In 2019, the R/P ratio increased by 16.8 per cent, due principally to production rate decline. Heritage Montney oil remaining reserves continue to be the largest oil pool in B.C.

Figure 15: Historical Oil Development 1999 to 2019



31.4 per cent of the remaining oil reserves in B.C. are located in pools with secondary recovery pressure maintenance schemes, predominantly waterfloods. These oil pools are listed in Table A-4: Oil Pools Under Waterflood. Gas injection recovery schemes account for 0.6 per cent of remaining oil reserves, occurring in five oil pools (see Table A-5: Oil Pools Under Gas Injection).

Discussions: Oil Reserves

Montney A Oil

The regional Triassic Montney in northeast B.C. consists generally of dry gas in the west transitioning to oil in the east. Significant oil reserves are present in the Tower Lake area of the Montney play trend. The Commission implemented a change in policy in January 2019 for determination of the primary product of wells producing from the Montney formation. New wells are predominantly classified as gas wells, in some cases with high associated hydrocarbon liquid volumes. 2019 oil production, Figure 16, demonstrated a significant decline that started in September 2018 and continued until September 2019 when the production stabilized at approximately 15,300 bbl/d. Peak Montney oil production was reached in August 2018. No additional Montney oil wells came on production in 2019, partially a reflection of the change in primary product determination for Montney formation wells as mentioned previously. In the second half of 2019, the Montney oil decline was partially offset with an increase in conventional oil production from the Boundary Lake 'A' pool and the Hay River Bluesky pool. In May 2019 a significant reduction in conventional oil production was a reaction to lower than anticipated oil prices. This marked the start of the lower oil prices trend.

Conventional oil production continued to decline from 2006; however growth from the unconventional Montney became significant commencing in late 2013 as shown in Figure 16 and 17.

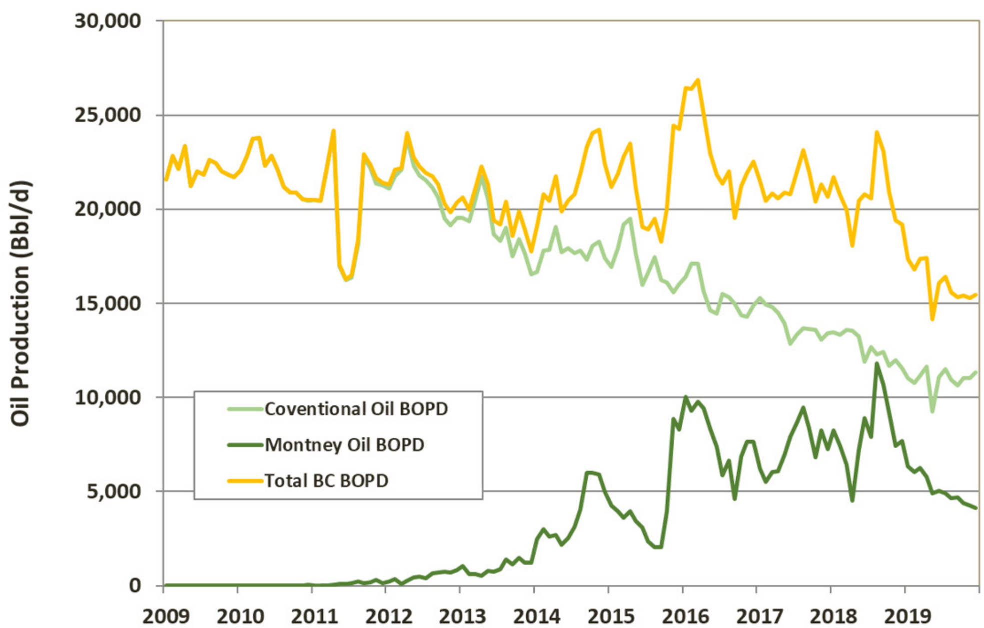


Figure 16: B.C. Oil Production 2009 to 2019

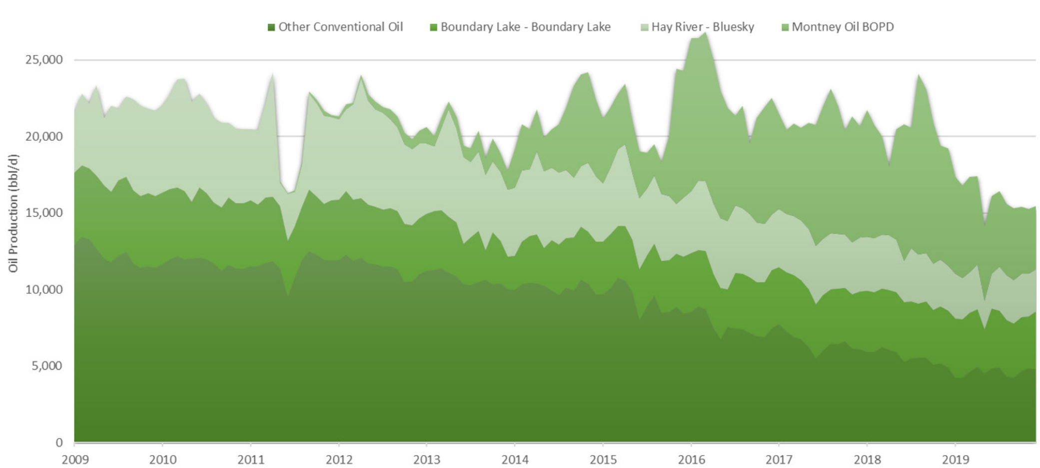


Figure 17: B.C. Oil Production by Source 2009 to 2019

Discussions: Condensate, Pentanes+ and NGLs

Production of condensate/pentanes+ and LPG increased in 2019.

Liquid by-product production increased in 2019, even though there was a reduction in drilling activity of 23.3 per cent. In 2019, the focus of development shifted to including not only the upper Montney zone, but the middle and lower Montney. In some areas operators developed the entire 'stack' of the Monteny formation (upper, middle, and lower zones). Butane and propane production continue to increase in B.C., while ethane sales decreased slightly. The increase in butane and propane sales volume is a result of some of the companies having the capability to extract propane and butane from the gas stream within the province for export. Ethane sales reduction indicates ethane remains in plant outlet streams, for extraction closer to markets.

Provincial condensate/pentanes+ production increased 42 per cent over last year whereas LPG increased by 2.9 per cent (Figure 18). The increase in liquids production is in part due to a shift towards development of liquid-rich Montney areas and a change in policy to determine the primary product of Montney formation wells, that has allowed for a primary product review of oil wells producing since mid-2018. Hydrocarbon liquids which may have previously been recognized as oil are now reported as condensate/pentane+ volumes.

Similarly, reflecting Montney "rich gas" development, remaining reserves of pentanes+ in 2019 is 86.0 e^6m^3, an increase of 79.2 per cent from last year. LPG remaining reserves of 105.8 10^6m^3 are a decrease of 26.2 per cent. The decrease in LPG volume is in part due to the change in reporting required for the implementation of the Petrinex volumetric reporting system and a change in methodology resulting from a new Commission reserves management system. Drilling is generally concentrated in liquid rich areas in the eastern side of the Montney play, with ratios reaching as high as 100+ bbl/mmcf.

The Commission identifies an oil leg and several "oily" areas, as illustrated earlier in Figure 8. Annual natural gas, liquid and oil production from 2009 to 2019 is shown in Figure 18.

Figure 19 shows the condensate/pentane+ to raw gas ratio (CGR) for the Heritage and Northern Montney regions. The CGR of both areas converges over the years to a similar liquids ratio, reaching CGR values of 0.105 and 0.106 for the Heritage and Northern Montney respectively in 2019. This represents an increase in CGR of 8.8 per cent and 7.7 per cent from the previous year for the Heritage and Northern Montney respectively, indicating operators are able to increase the liquids yield in their area by further optimizing well location, completion techniques and operations.

Figure 18: Annual Oil, Condensate and NGL Production 2009 to 2019

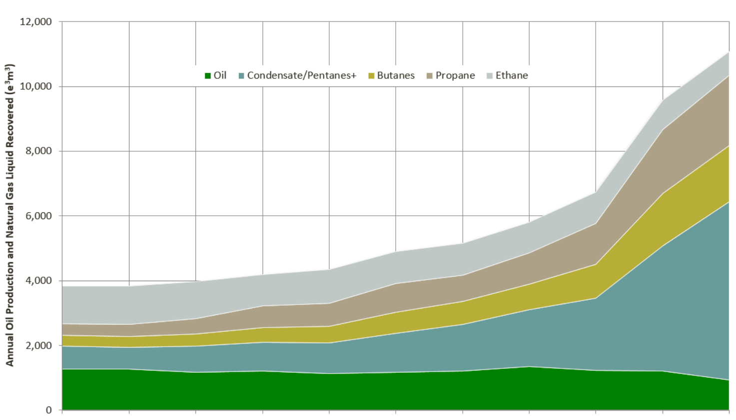
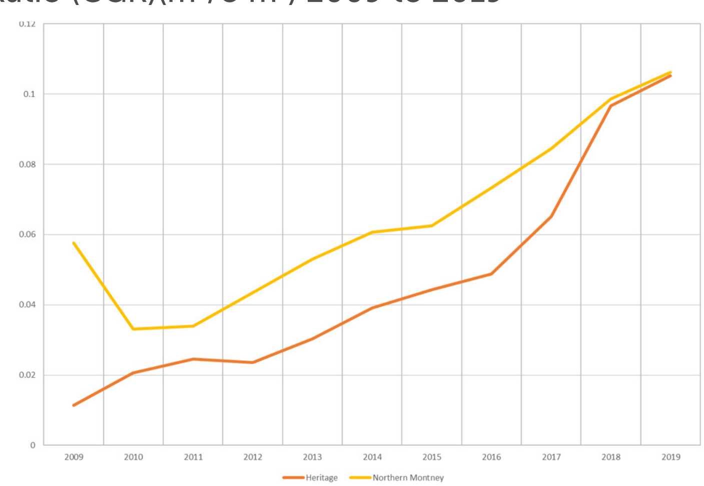


Figure 19: Condensate/Pentanes+ and Raw gas Ratio (CGR)(m^3/e^3m^3) 2009 to 2019



Discussions: Condensate, Pentanes+ and NGLs

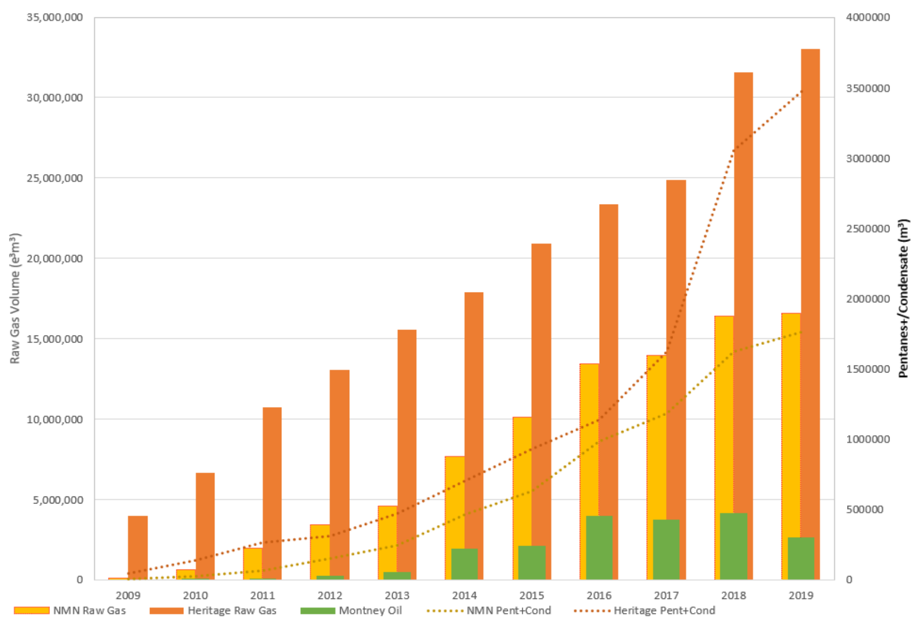
The majority of the NGL volumes are captured as an increase in marketable gas heating value with liquids being recovered at the pipeline delivery point. To be more resilient towards changing market conditions, operators invested in upgrading current facilities or building additional deep-cut facilities to capture these NGL volumes. Plant liquid recovery may fluctuate from month-to-month based on the market price and the current take-away capacity for a product.

Liquid propane and butane arriving via rail at the AltaGas Ltd. Ridley Island terminal near Prince Rupert is exported as LPG to markets. A second LPG terminal is planned by Pembina on Watson Island near Prince Rupert to be operational by early 2021. Current export capacity at the Ridley Island LPG facility is up to 1.2 million tonnes of propane and butane per year. Pembina Watson Island will have a capacity of approximately 25,000 bbls per day of LPG. Pembina northeast B.C. pipeline also connects liquids volumes from the Montney into Edmonton via Pembina’s downstream system. This northeast expansion has a capacity of 75,000 bbls/d and has been in service since October 2017.

2019 saw an increase in condensate production (Figure 20) relative to 2018 volumes of approximately 8.6 per cent for the Northern Montney and approximately 13.7 per cent for the Heritage Montney, highlighting the focus on liquid rich Montney development. As more wells are added in the liquid rich areas, condensate should continue to increase in the future.

Figures 21 through 23 show the condensate type curves for each of the regions and layers. The data shows there is a significant difference between the P50 and the Pmean type curves for the same region and layer, indicating high variations in liquid content between wells as expected in an early stage of development. As the well count increases in the liquid rich regions, condensate type curves will become more refined.

Figure 20: Annual Montney Oil, Raw Gas and Condensate/Pentanes+ Production 2009 to 2019

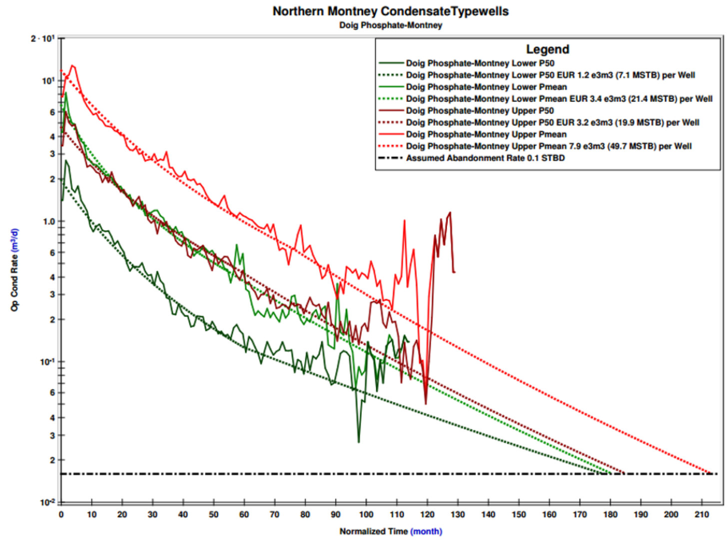


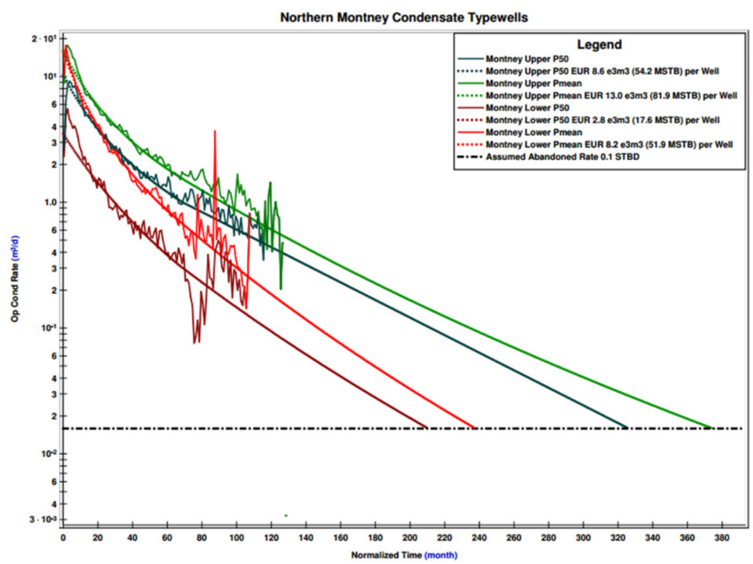
At current level of development (not including PUDs), estimated recoverable condensate reserves using the type curves in Figures 21 to 23 is 15,099 e^3m^3 for the Northern Montney and 17,797 e^3m^3 for the Heritage Montney. This is an increase in recoverable condensate reserves relative to 2018 volumes of approximately 9.5 per cent for the Northern Montney and a slight decrease of approximately 3.4 per cent for the Heritage Montney. The variations seen in condensate reserves are a result of dividing the data into sub areas and upper and lower Montney zones which reduces the well count for each zone prediction.

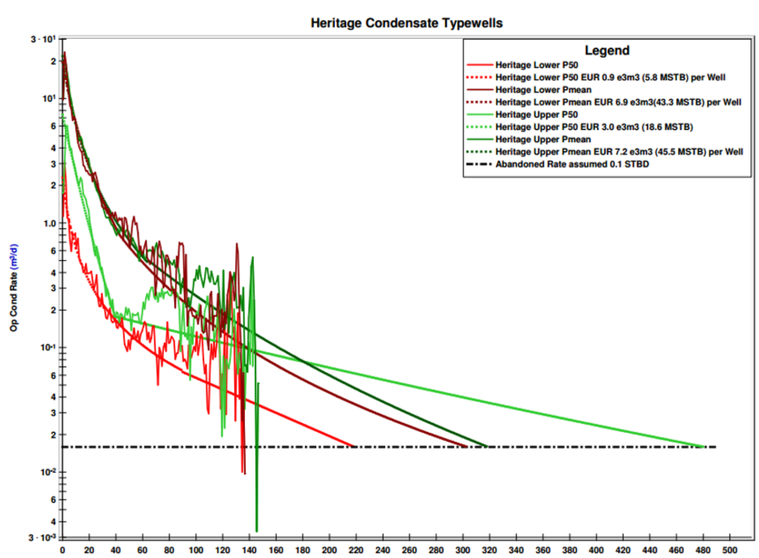
Due to technical limitations, the condensate type curve was generated by first creating a statistical distribution followed by developing the type curve. The gas type curves were created by declining each well to determine the individual well EUR followed by a statistical distribution to generate the type curve for each region/zone.

Discussions: Condensate, Pentanes+ and NGLs

Figures 21, 22 & 23: Condensate Type Well at Northern Montney and Heritage Regional Pools







Discussions: Sulphur

Sulphur production has decreased from 2015 level.

As of Dec. 31, 2019, recoverable sulphur remaining reserves was 6.0 106 tonnes (5.9 MMLT). Sulphur reserves continue to decrease year over year due to no new sales sources and a natural decline in production from the sour gas Bullmoose (> 30 per cent H_2S), Sukunka (> 20 per cent H_2S) and Ojay fields, where significant sulphur production occurs. Figure 24 shows the breakdown as of Dec. 31, 2019.

Figure 24: Major Sour Field by Remaining Sulphur Reserve

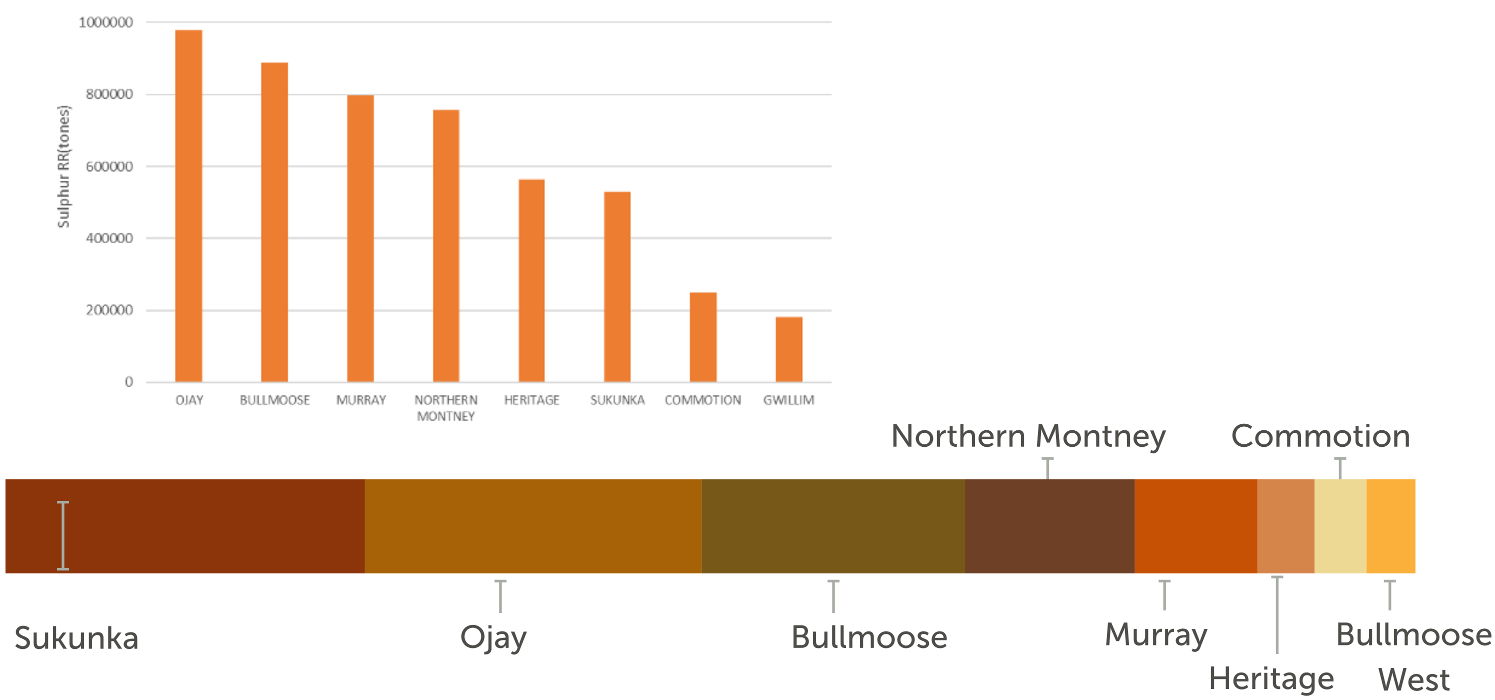
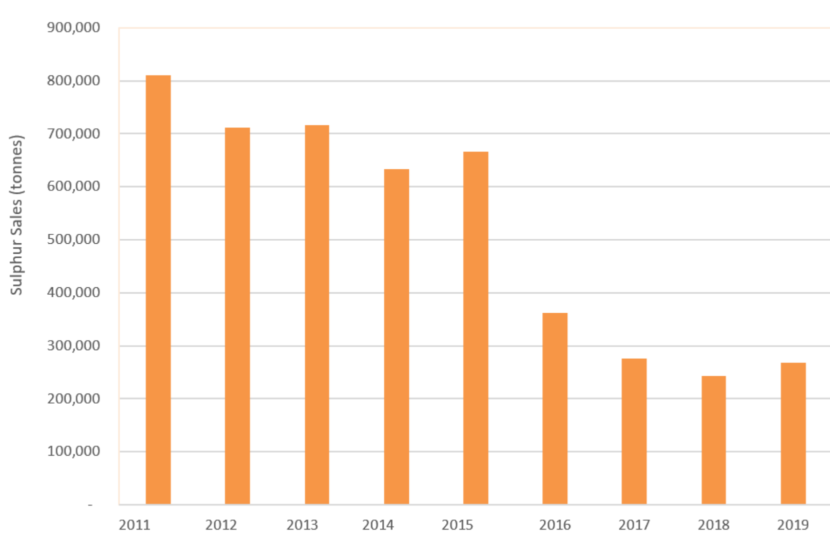


Figure 25: Annual Sulphur Sales



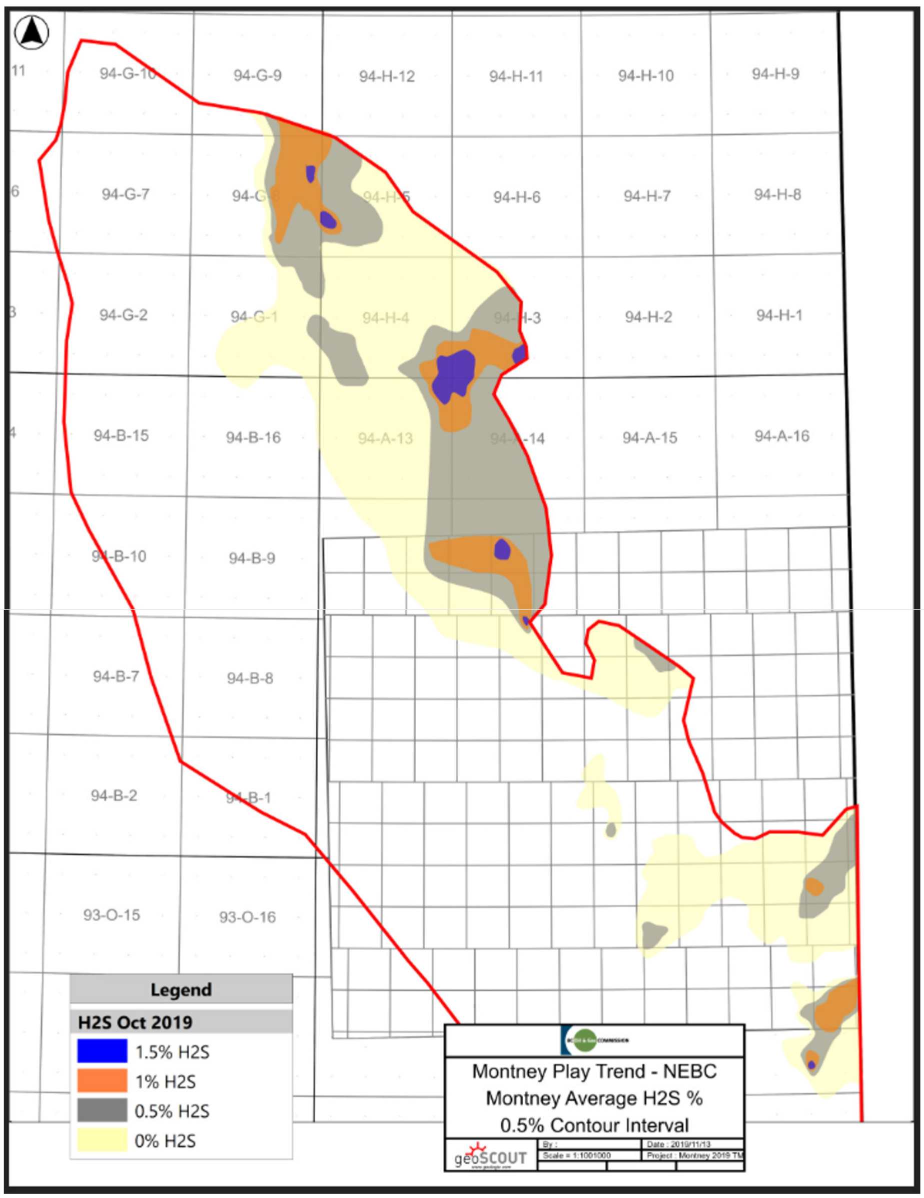
Operators continue to shut-in wells in these areas where acid gas levels are high, as continued production is no longer economic. Sulphur sales, as illustrated in Figure 25, decreased between 2015 and 2018, but saw an increase of 10.3 per cent in 2019, still remaining below historic annual Sulphur sales volumes.

Most of the natural gas recovered from the unconventional Montney Play Trend in B.C. has very little to no H_2S component. There are exceptions however, where the percentage of H_2S can reach significant levels (Figure 26).

Discussions: Sulphur

In the Doe-Dawson area of the regional Heritage Field average H_2S concentrations are 0.1 per cent but levels have been recorded at over 0.5 per cent. In the Northern Montney Field, the Birch-Nig-Umbach area has a more significant H_2S presence as concentration levels average over one per cent, with some recorded values as high as 2.2 per cent.

Figure 26: Average H_2S in the Montney Field



The most active areas in the Montney contain little to no H_2S and are expected to have a minimal effect on future sulphur reserves. The trend in Montney gas plants is dedicated H_2S (acid gas) disposal wells, resulting in no increase in sulphur recovery source.

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 throughout 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+ (equilibrium pressure and 15° Celsius)	=	6.292 9 Canadian barrels of oil or pentanes+ (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])

Definitions

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+.

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.

Definitions

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).

Maturity of Resource Play Development
is divided into four phases:
Early phase: exploration phase with minimal well density. Statistical evaluation unreliable due to less than minimum well count.
Intermediate phase: exploration drilling/ delineation drilling is less than 50 per cent of total well count. Statistical analysis difficult.
Statistical phase: development phase is reached, some uncertainty remains regarding choice of completion techniques. Statistical analysis of the interior proved area possible.
Mature phase: delineation complete, well defined well density. Possible production interference seen. Well count sufficient for statistical analysis.

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+, 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.

Definitions

Pentanes+
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 (IER) less cumulative production.

Definitions

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

Society of Petroleum Evaluation Engineers -- Guidelines for the Practical Evaluation of Undeveloped Reserves in Resource Plays.

SPEE Monograph 4

Society of Petroleum Evaluation Engineers -- Guidelines for the Practical Evaluation of Undeveloped Reserves in Resource Plays. Estimating Ultimate Recovery of Developed Wells in Low-Permeability Reservoirs. Provides an understanding of current available methods to analyze well performance of these now developed unconventional plays and to estimate the associated recoverable volumes.

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.

Ultimate Potential

Defined in the NEB/MEM Oil and Gas Reports 2011-1, Ultimate Potential for Unconventional Natural Gas in Northeastern BC's Horn River Basin (May 2011): A term used to refer to an estimate of the marketable resources that will be developed in an area by the time exploratory and development activity has ceased, having regard for the geological prospects of an area, known technology and economics. It includes cumulative production, remaining reserves and future additions to reserves through extension and revision to existing pools and the discovery of new pools. For most of this report it is used as a short form of "ultimate potential of natural gas."

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.

Unconventional Gas

Natural gas and associated hydrocarbon liquids from a geologic formation not previously capable of economic production rates, but with horizontal drilling and hydraulic fracture stimulation technology is now a development objective.

Zone

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

Appendix A

Table A-1: Established Hydrocarbon Reserves (SI Units) at Dec. 31, 2019

	Oil (10^3m^3)	Raw Gas (10^6m^3)
Initial Reserves, Current Estimate	140,582	3,048,050
Discovery 2019	0	0
Revisions 2019	-735	442,951
Production 2019	935	58
Cumulative Production Dec. 31, 2019	123,937	1,229
Remaining Reserves Estimate Dec. 31, 2019	16,645	1,818,749

Appendix A

Table A-2: Historical Record of Raw Gas Reserves

Year	Estimated Ultimate Recovery 10⁶m³	Yearly Discovery 10⁶m³	Yearly Revisions 10⁶m³	Yearly Other 10⁶m³	Annual Production 10⁶m³	Cumulative Production at Year-End 10⁶m³	Remaining Reserves at Year-End 10⁶m³
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	843,616	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	426	101,754		43,722	919,007	1,197,229
2014	2,408,673	0	292,437		46,222	964,803	1,443,870
2015	2,517,904	0	10,231		48,106	1,013,247	1,504,657
2016	2,547,406	0	29,502		50,131	1,062,296	1,485,110
2017	2,467,579	0	-79,827		50,511	1,112,807	1,354,772
2018	2,605,099	0	137.520		57,881	1,171,010	1,434,089
2019	3.048,050	0	442,951		57,683	1,229,301	1,818,749

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

Tab	Estimated Ultimate Recovery 10³m³	Yearly Discovery 10³m³	Yearly Revisions 10³m³	Yearly Other 10³m³	Annual Production 10³m³	Cumulative Production at Year-End 10³m³	Remaining Reserves at Year-End 10³m³
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
2015	136,691	0	1,034		1,210	119,138	17,553
2016	136,956	0	256		1,331	120,473	16,483
2017	139,952	0	2,996		1,233	121,752	18,200
2018	141,317	0	1,365		1,196	122,968	18,349
2019	140,582	00	-735		935	123,937	16,645

Table A-4: Oil Pools Under Waterflood

FIELD	POOL	POOL	PROJECT CODE	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cumulative Oil (10^3m^3)	RR (10^3m^3)
BEATTON RIVER	HALFWAY	A	02	3,430.0	47.1	1,617	1,616.0	1.0
BEATTON RIVER	HALFWAY	G	05	1,438.0	30.0	432.0	426.0	6.0
BEATTON RIVER WEST	BLUESKY	A	02	2,956.0	38.0	1,123.0	1,098.0	25.0
BEAVERTAIL	HALFWAY	B	06	499.0	17.5	87.0	87.0	0.0
BEAVERTAIL	HALFWAY	H	05	874.0	20.0	175.0	171.0	4.0
BIRCH	BALDONNEL	C	03	2,058.0	50.0	1,290.0	904.0	125.0
BLUEBERRY	DEBOLT	E	03	1,211.0	30.0	363.0	354.0	9.0
BOUNDARY LAKE	BOUNDARY LAKE	A	05	1,587.0	65.0	1,032.0	984.0	48.0
BOUNDARY LAKE	BOUNDARY LAKE	A	02	43,666.0	48.0	20,960.0	19,724.0	1,236.0
BOUNDARY LAKE	BOUNDARY LAKE	A	04	5,769.0	60.0	3,462.0	3,133.0	329.0
BOUNDARY LAKE	BOUNDARY LAKE	A	03	30,218.0	44.0	13,296.0	12,783.0	513.0
BOUNDARY LAKE NORTH	HALFWAY	I	04	1,086.0	40.0	434.0	334.0	100.0
BOUNDARY LAKE NORTH	HALFWAY	D	03	562.0	20.0	112.0	101.0	11.0
BUBBLES NORTH	COPLIN	A	02	144.0	30.0	43.0	42.0	1.0
BULRUSH	HALFWAY	C	02	96.0	4.5	4.0	4.0	0.0
CRUSH	HALFWAY	A	02	1,449.0	35.2	510.0	503.0	7.0
CRUSH	HALFWAY	B	02	149.0	37.5	56.0	50.0	6.0
CURRANT	HALFWAY	A	02	793.0	52.9	419.0	419.0	0.0
CURRANT	HALFWAY	D	02	122.0	20.0	24.0	8.0	16.0
DESAN	PEKISKO	NULL	03	5,388.0	20.0	1,078.0	880.0	198.0
EAGLE	BELLOY-KISKATINAW	NULL	02	6,929.0	40.0	2,772.0	2,564.0	208.0
EAGLE WEST	BELLOY	A	03	20,337.0	31.0	6,305.0	6,252.0	53.0
ELM	GETHING	B	04	1,773.0	7.4	131.0	129.0	2.0
HALFWAY	DEBOLT	A	03	950.0	10.0	95.0	95.0	0.0
HAY RIVER	BLUESKY	A	05	36,992.0	20.0	7,398.0	5,647.0	1,751.0
INGA	INGA	A	04	8,356.0	40.0	3,342.0	3,328.0	14.0
INGA	INGA	A	06	7,521.0	31.1	2,335.0	2,335.0	0.0
INGA	INGA	A	07	1,401.0	45.5	637.0	627.0	10.0
INGA	INGA	A	08	1,716.0	34.0	584.0	558.0	26.0
LAPP	HALFWAY	C	02	1,037.0	45.0	467.0	452.0	15.0
LAPP	HALFWAY	D	02	395.0	42.5	168.0	166.0	2.0
MICA	MICA	A	04	1,129.0	40.0	451.0	309.0	142.0
MILLIGAN CREEK	HALFWAY	A	02	12,119.0	53.0	6,423.0	6,376.0	47.0
MILLIGAN CREEK	HALFWAY	A	03	2,160.0	50.0	1,080.0	1,022.0	58.0
MUSKRAT	LOWER HALFWAY	A	03	1,003.0	40.0	401.0	370.0	31.0
MUSKRAT	BOUNDARY LAKE	A	03	465.0	23.5	109.0	107.0	2.0
OAK	CECIL	B	02	424.0	23.6	100.0	100.0	0.0
OAK	CECIL	C	03	908.0	60.0	545.0	437.0	108.0
OAK	CECIL	E	03	1,264.0	48.0	607.0	603.0	4.0
OAK	CECIL	I	03	616.0	40.0	246.0	237.0	9.0

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

FIELD	POOL	POOL	PROJECT CODE	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cumulative Oil (10^3m^3)	RR (10^3m^3)
OWL	CECIL	A	03	717.0	45.0	323.0	320.0	3.0
PEEJAY	HALFWAY	NULL	02	5,803.0	38.4	2,228.0	2,227.0	1.0
PEEJAY	HALFWAY	NULL	03	8,938.0	43.0	3,843.0	3,802.0	41.0
PEEJAY	HALFWAY	NULL	04	7,897.0	44.3	3,498.0	3,485.0	13.0
PEEJAY	HALFWAY	NULL	06	2,836.0	35.0	992.0	982.0	10.0
PEEJAY WEST	HALFWAY	A	03	1,561.0	40.0	624.0	520.0	104.0
PEEJAY WEST	HALFWAY	C	02	511.0	40.0	204.0	158.0	46.0
RED CREEK	DOIG	C	03	609.0	25.0	152.0	149.0	3.0
RIGEL	CECIL	B	02	1,503.0	40.0	601.0	595.0	6.0
RIGEL	CECIL	G	02	953.0	45.0	429.0	419.0	10
RIGEL	CECIL	H	03	1,821.0	50.0	910.0	887.0	23.0
RIGEL	CECIL	I	02	1,962.0	40.0	785.0	775.0	10.0
RIGEL	HALFWAY	C	02	739.0	27.5	203.0	197.0	6.0
RIGEL	HALFWAY	C	03	752.0	39.0	293.0	292.0	1.0
RIGEL	HALFWAY	H	03	703.0	15.0	105.0	91.0	14.0
RIGEL	HALFWAY	Z	02	104.0	20.0	21.0	7.0	14.0
SQUIRREL	NORTH PINE	C	03	1,376.0	30.0	413.0	409.0	4.0
STODDART	NORTH PINE	G	04	214.0	36.0	77.0	75.0	2.0
STODDART WEST	BELLOY	C	05	5,784.0	25.0	1,446.0	1,369.0	77.0
STODDART WEST	BEAR FLAT	D	03	452.0	35.0	158.0	156.0	2.0
SUNSET PRAIRIE	CECIL	A	02	882.0	40.0	353.0	329.0	24.0
SUNSET PRAIRIE	CECIL	C	02	420.0	35.0	147.0	120.0	27.0
SUNSET PRAIRIE	CECIL	D	02	380.0	40.0	152.0	5.0	147.0
TWO RIVERS	SIPHON	A	03	1,476.0	17.8	263.0	261.0	2.0
WEASEL	HALFWAY	NULL	03	1,729.0	58.5	1,012.0	1,006.0	6.0
WEASEL	HALFWAY	NULL	02	3,720.0	65.0	2,418.0	2,377.0	41.0
WILDMINT	HALFWAY	A	02	2,868.0	53.8	1,543.0	1,542.0	1.0
WOODRUSH	HALFWAY	E	02	881.0	16.0	141.0	125.0	16.0
Total						103,786.0		5,771.0
% of Total British Columbia Oil Reserves						73.4		31.5

Appendix A

Table A-5: Oil Pools Under Gas Injection

Field	Pool	Pool Sequence	Project Code	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cum. Prod. (10^3m^3)	RR (10^3m^3)
Cecil Lake	Cecil	D	03	1,091.3	38.0%	414.7	363.2	51.5
Stoddart West	Belloy	C	03	1,525.5	25.5%	389.0	384.5	4.5
Bulrush	Halfway	A	02	854.2	40.0%	341.7	333.7	7.9
Brassey	Artex	G	02	353.4	42.3%	149.3	149.3	0.0
Rigel	Halfway	H	03	702.9	15.0%	105.4	90.7	14.8
Brassey	Artex	A	02	94.5	16.0%	15.1	13.8	1.3
Total						1,415.2	1,335.3	79.9
% of Total British Columbia Reserves						1.0%		0.5%

Appendix B

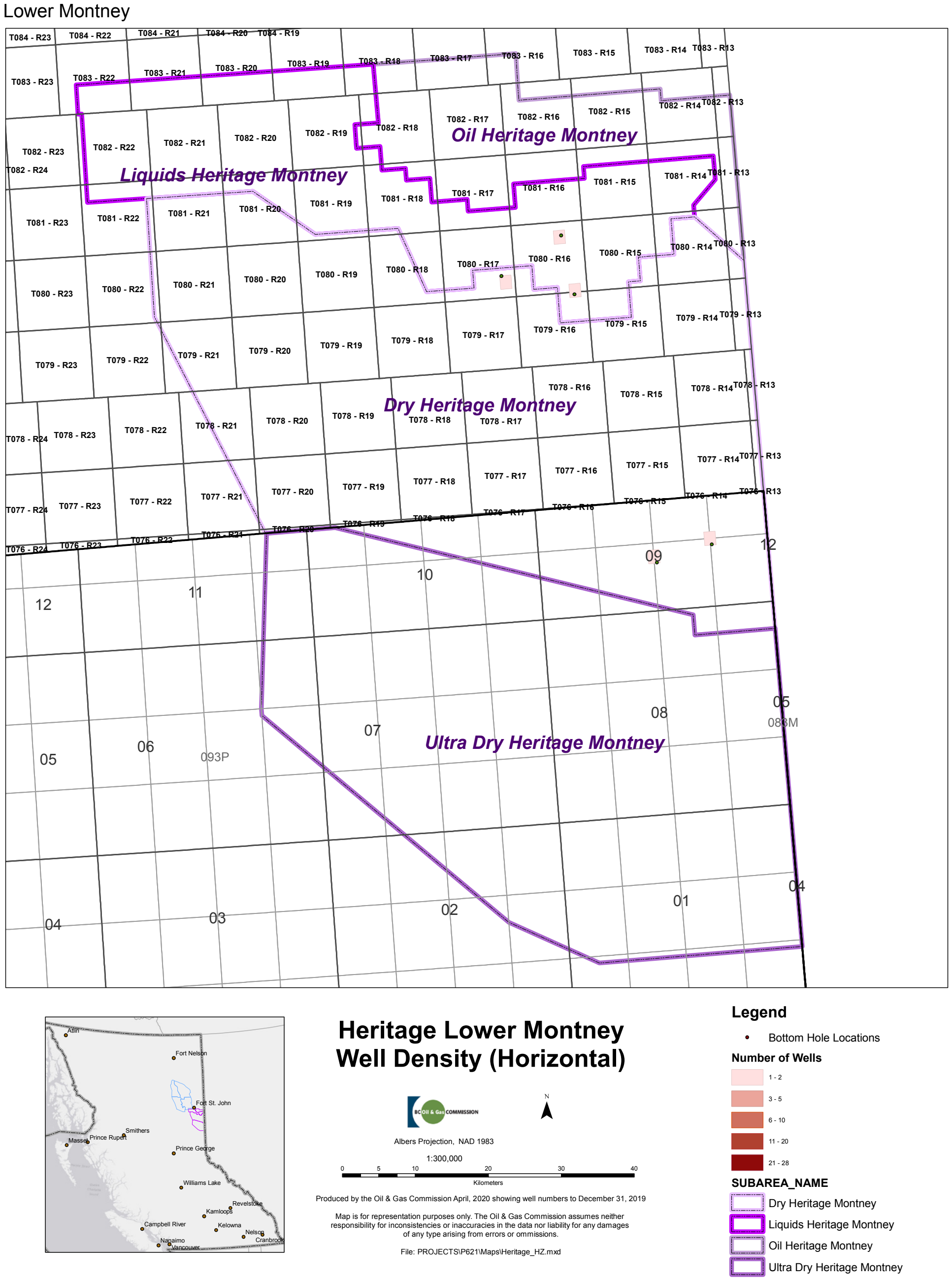
Current Montney Play Development and EUR Distribution

Well density reflects the stage of Montney development. The number of wells per gas spacing unit is utilized to determine the number of PUDs in the estimation of recoverable reserves. For regulatory purposes, the Commission split the Montney Regional field into Heritage Montney A and Northern Montney Montney A and Northern Montney Doig Phosphate Montney A 3 pools.

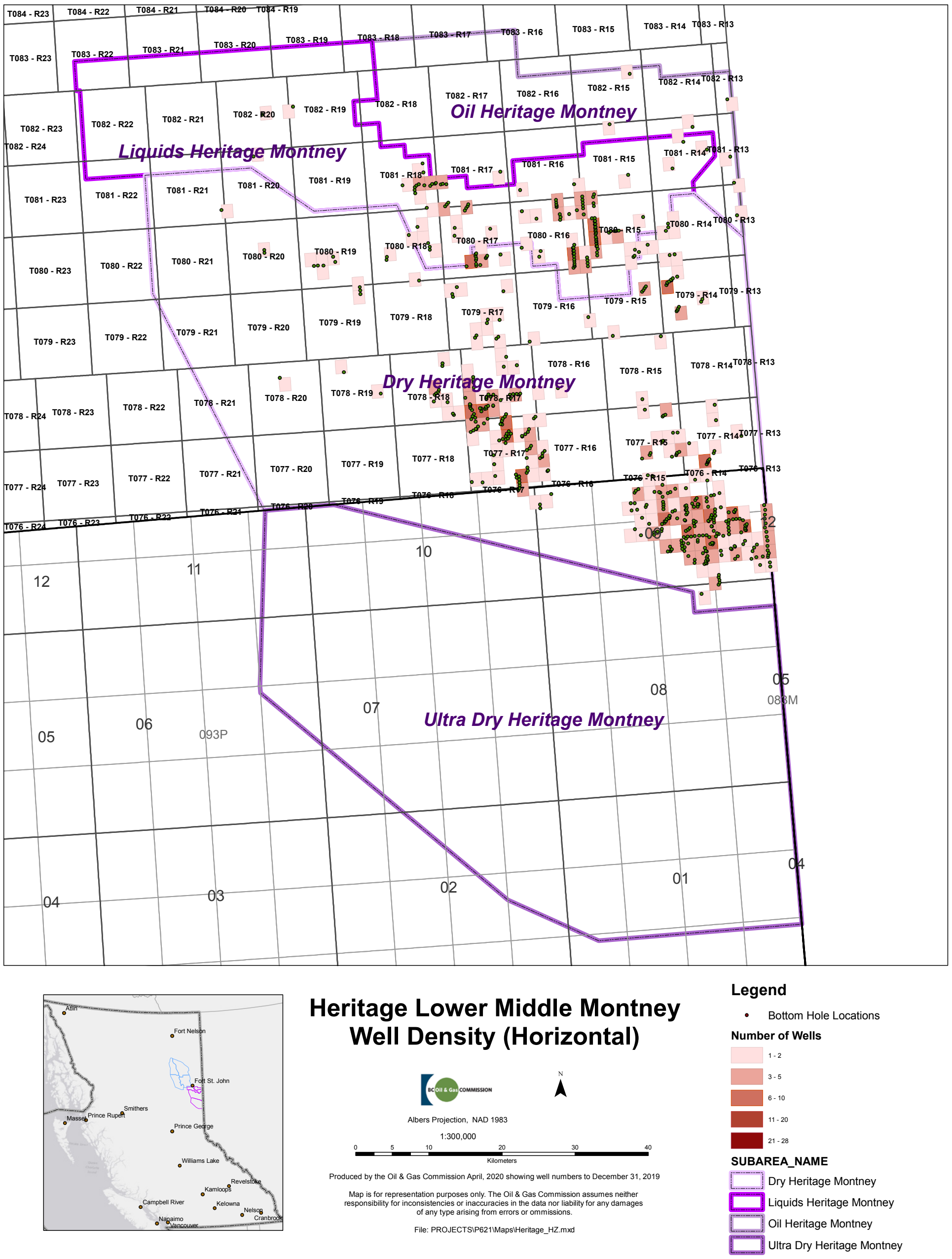
The following well density maps are for three Montney areas. As illustrated, the variable density and coverage of wells in the areas reflects current ability to establish proven reserves.

Map B-1: Heritage Montney - Montney "A" Well Density Maps

Lower Montney



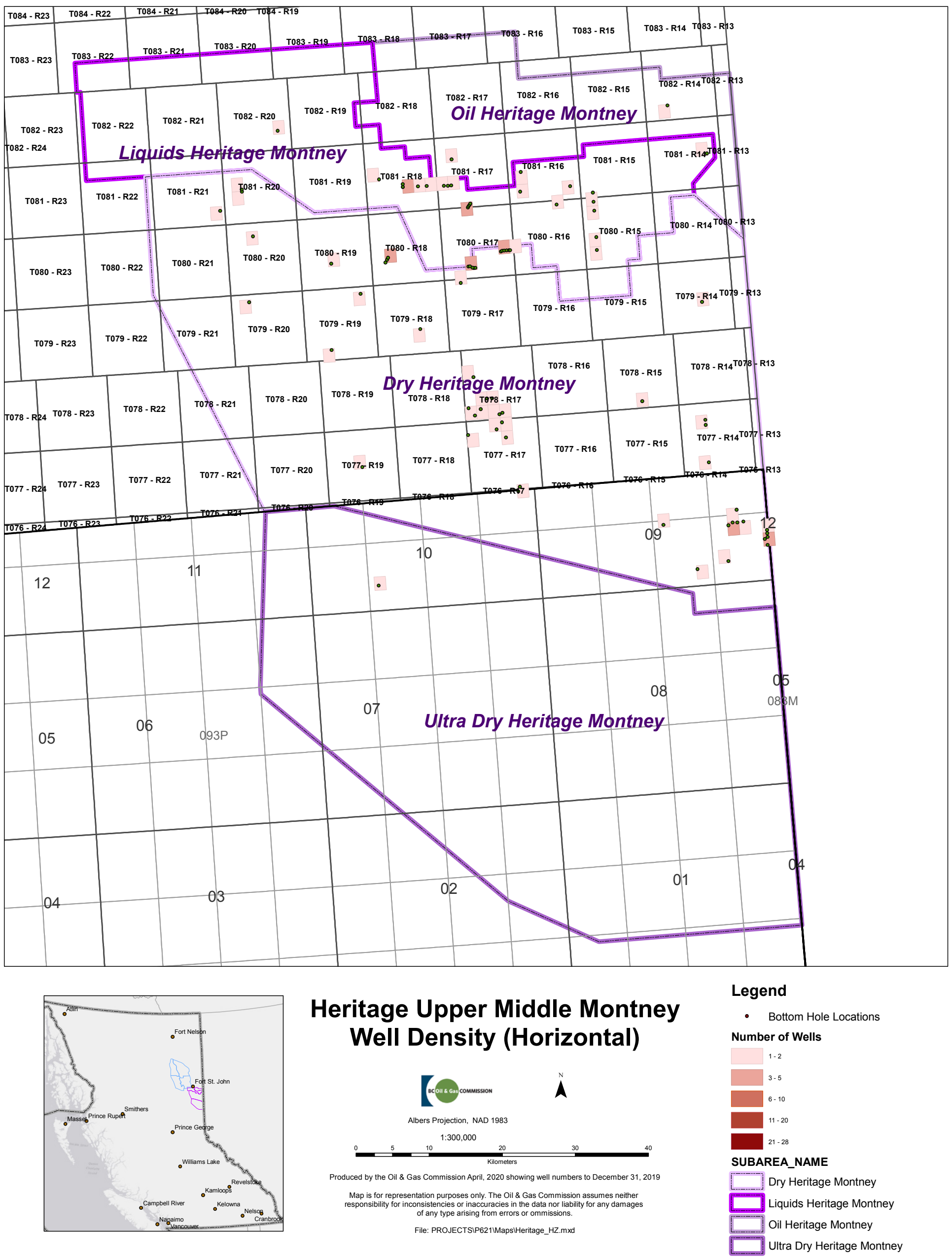
Lower Middle Montney



Appendix B

Current Montney Play Development and EUR Distribution

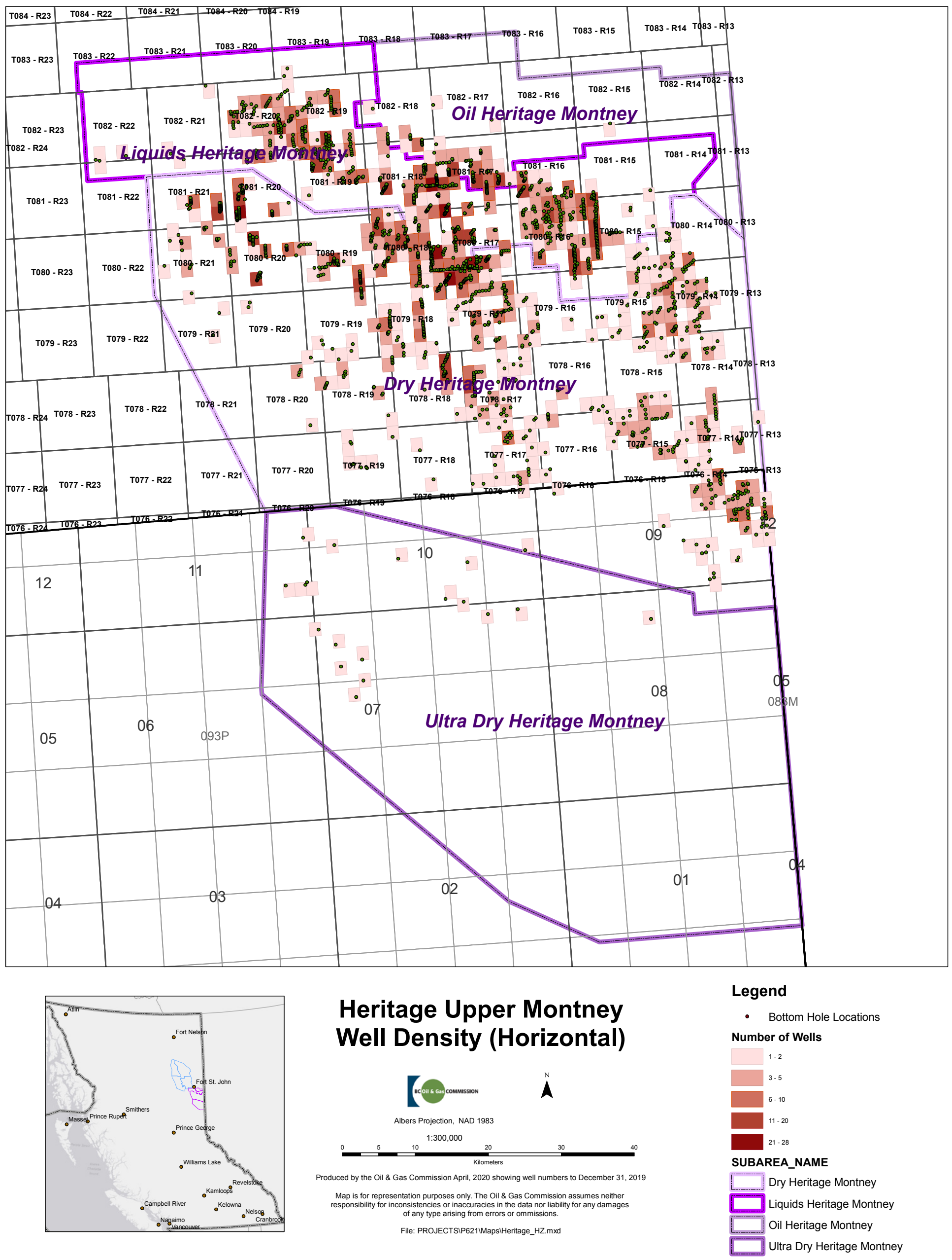
Upper Middle Montney



Appendix B

Current Montney Play Development and EUR Distribution

Upper Montney

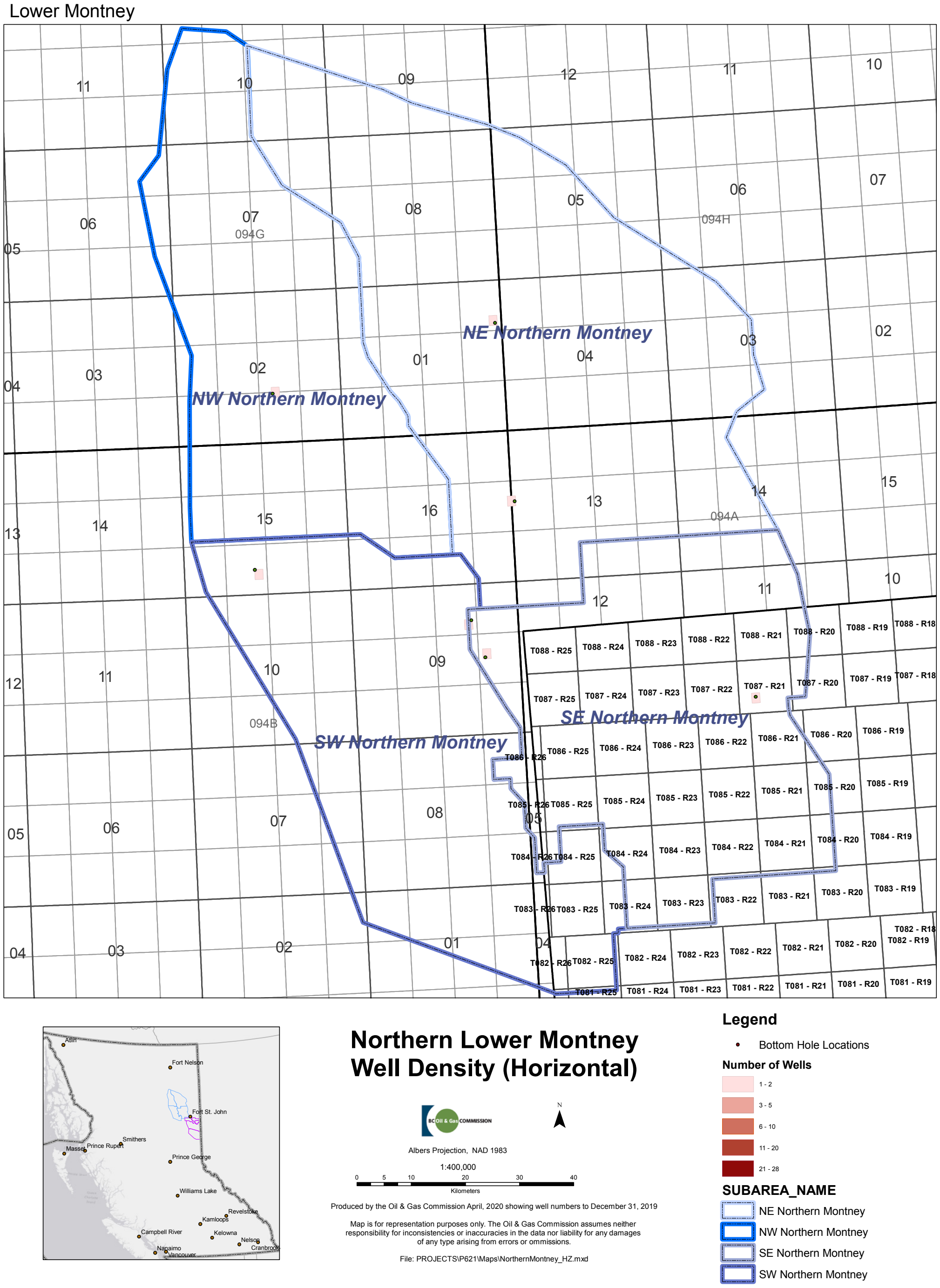


Appendix B

Current Montney Play Development and EUR Distribution

Map B-2: Northern Montney - Montney "A" And Doig Phosphate Well Density Maps

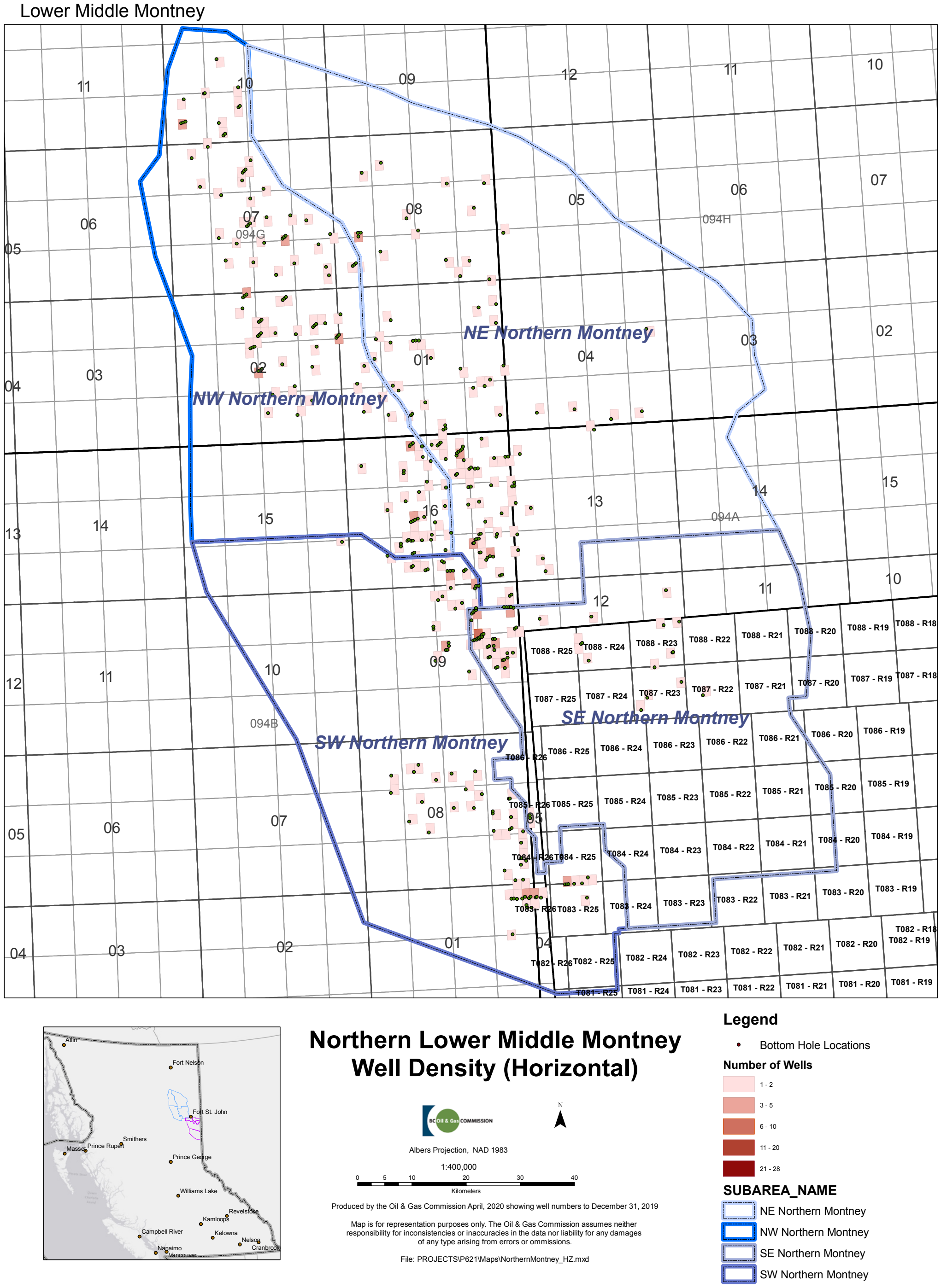
Lower Montney



Appendix B

Current Montney Play Development and EUR Distribution

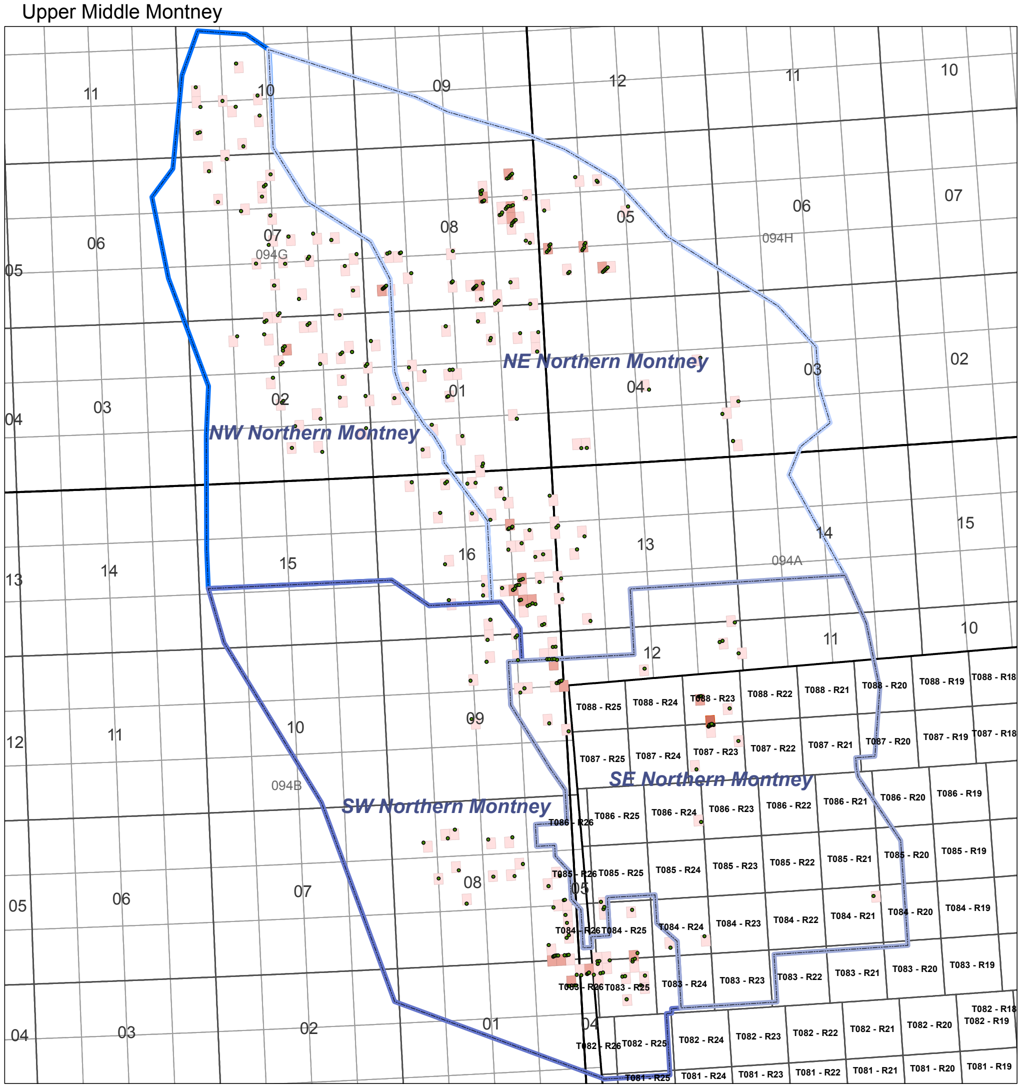
Lower Middle Montney

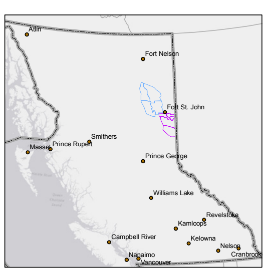


Appendix B

Current Montney Play Development and EUR Distribution

Upper Middle Montney





Northern Upper Middle Montney Well Density (Horizontal)

Albers Projection, NAD 1983

1:400,000

0 5 10 20 30 40

Kilometers

Produced by the Oil & Gas Commission April, 2020 showing well numbers to December 31, 2019

Map is for representation purposes only. The Oil & Gas Commission assumes neither responsibility for inconsistencies or inaccuracies in the data nor liability for any damages of any type arising from errors or omissions.

File: PROJECTS\P621\Maps\NorthernMontney_HZ.mxd

Legend

- Bottom Hole Locations

Number of Wells

- 1 - 2
- 3 - 5
- 6 - 10
- 11 - 20
- 21 - 28

SUBAREA_NAME

- NE Northern Montney
- NW Northern Montney
- SE Northern Montney
- SW Northern Montney

Appendix B

Current Montney Play Development and EUR Distribution

Upper Montney

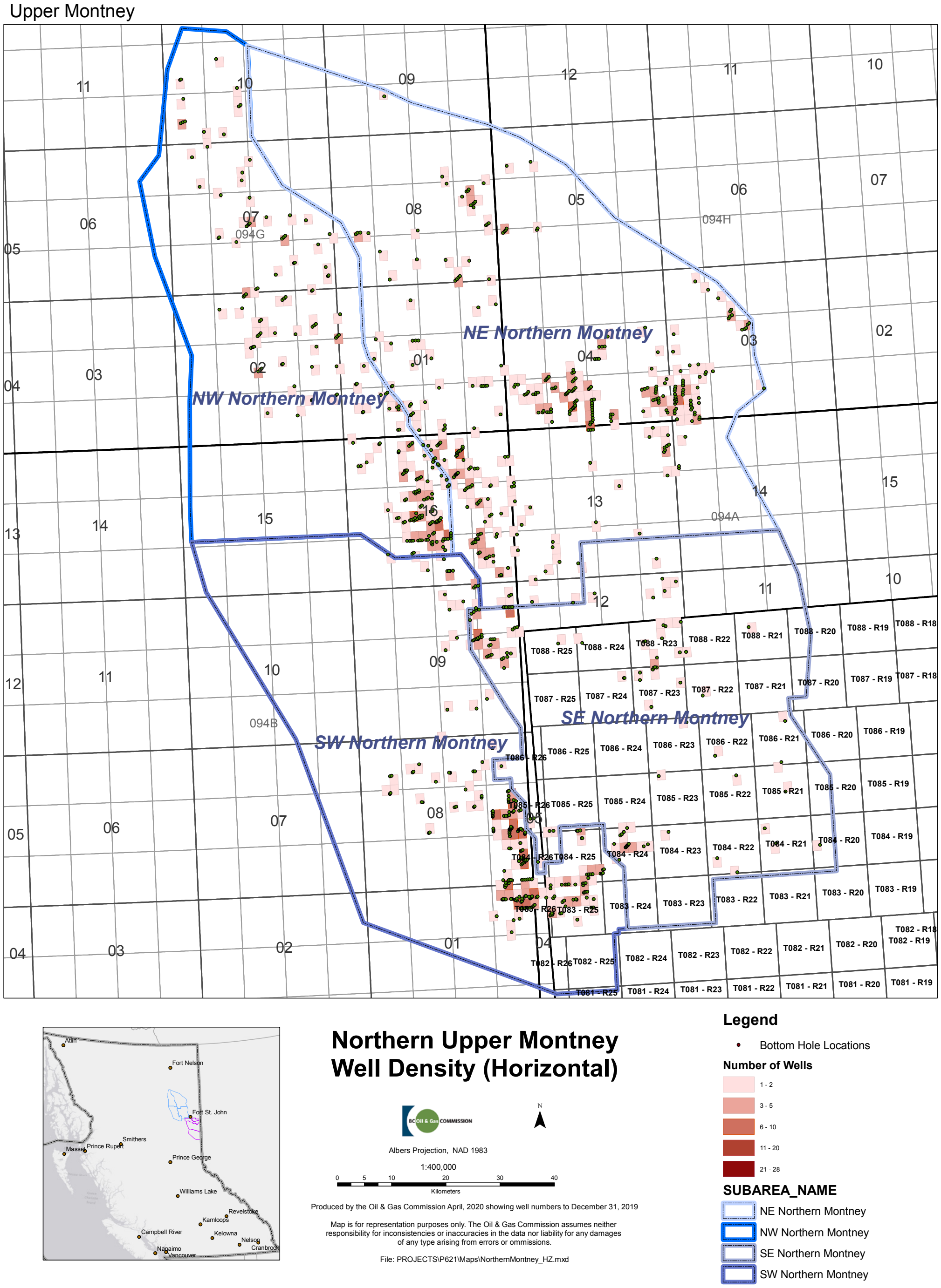
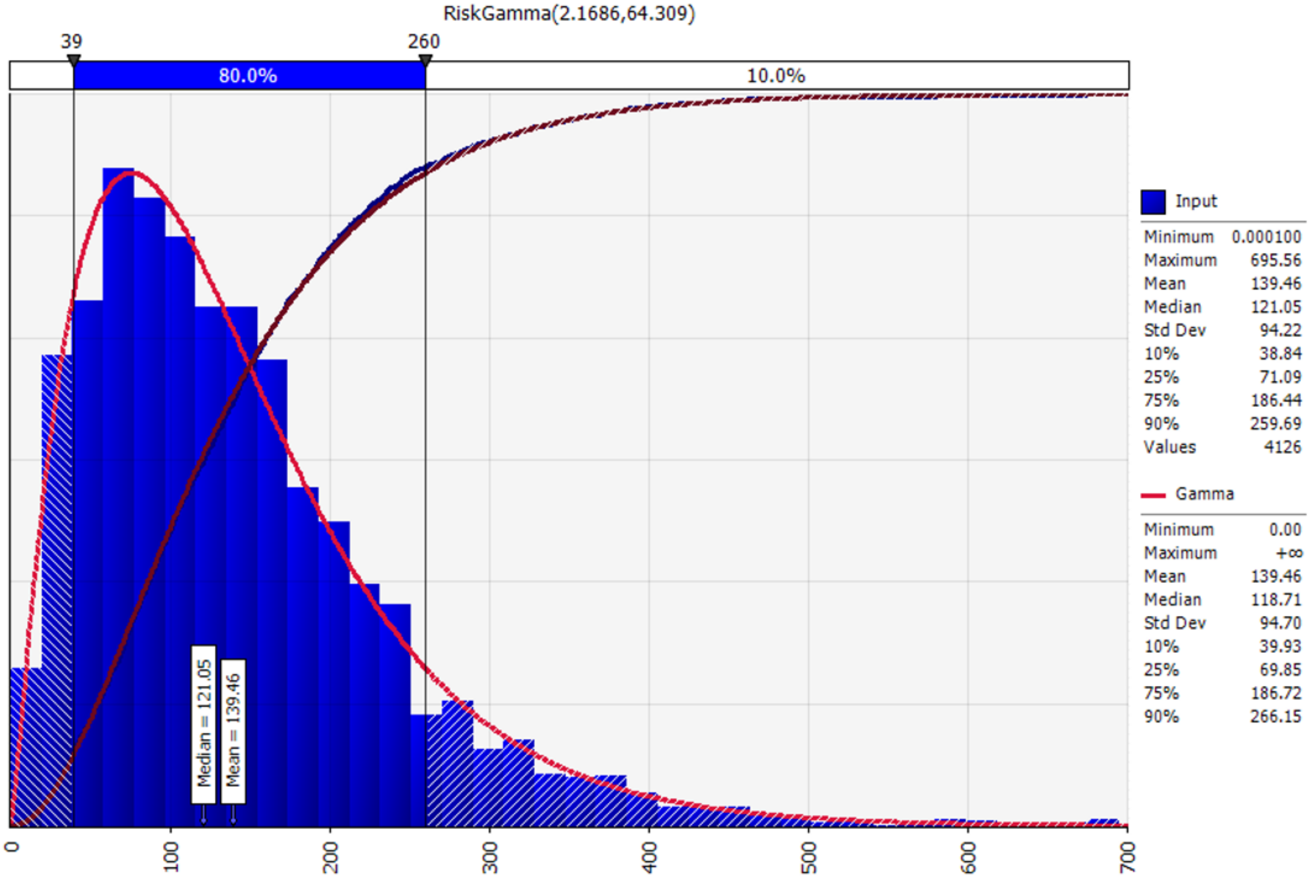


Figure B-1 below, shows overall Montney well population EUR values; P90 of 38.84 e^6m^3, P10 of 259.69 e^6m^3, mean of 139.46 e^6m^3, and median of 121.05 e^6m^3.

.

Figure B-1: All Montney Horizontal Gas Well EUR Distribution.



More information

www.bcogc.ca

This report was published in November 2020.
It is updated annually.

For specific questions regarding this document please contact:

Reservoir@bcogc.ca
Reservoir Engineering Department
BC Oil and Gas Commission
2950 Jutland Rd.
Victoria, B.C. V8T 5K2