British Columbia's Oil and Gas Reserves and Production Report

2020 | 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, we work closely with communities, First Nations, and land owners, and confirm industry compliance with provincial legislation.

We are committed to advancing reconciliation and establishing close working relationships with Indigenous peoples throughout the energy life cycle.

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 call 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, 2020. 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 Gas Anaylsis

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

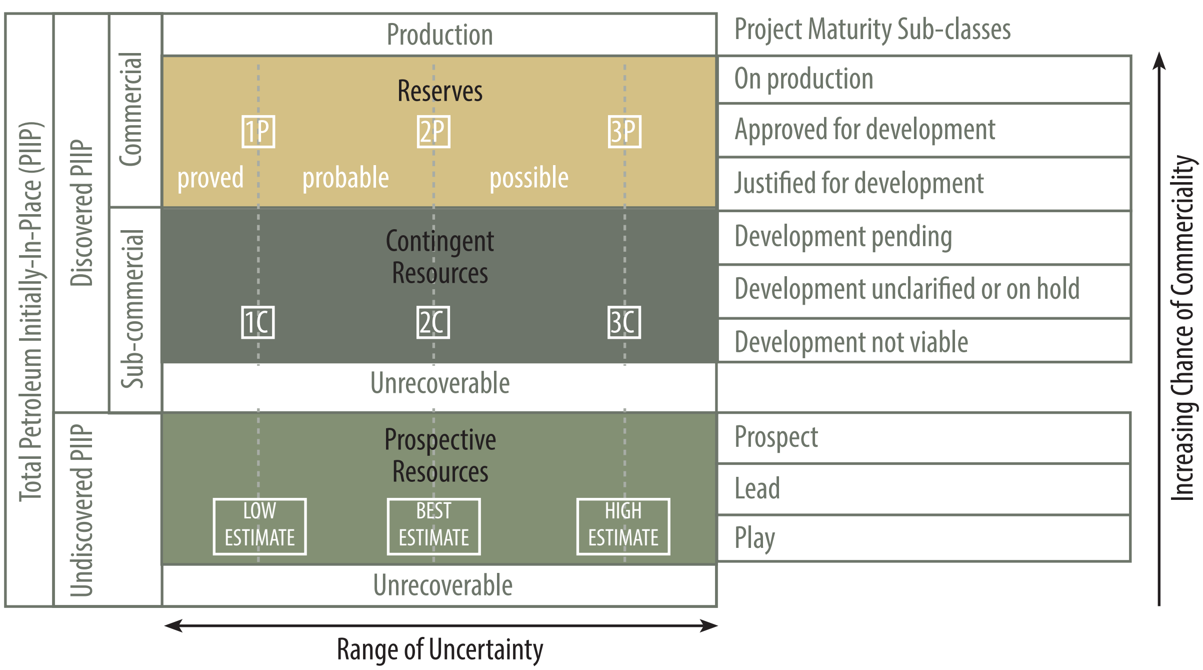
Difference Between Resources and Reserves

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 1,980 e^9m^3 (70.0 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

	RESOURCE				2020 RESERVES						
Basin/Play	Basin Total GIP Resource		Ultimate Resource Marketable		Initial Raw Gas Reserves		Remaining Reserves (Raw)		Cumulative Production (Raw)[6]		% Reserve per Resource
Unit	E^9M^3	Tcf	E^9M^3	Tcf	E^9M^3	Tcf	E^9M^3	Tcf	E^9M^3	Tcf	
Montney[1]	55,610	1,965	7,669	271	1,980	69.96	1,633.45	57.72	346.55	12.25	3.56%
Liard Basin[2]	23,998	848	4,726	167	2.93	0.10	0.80	0.03	2.13	0.08	0.01%
Horn River Basin[3]	12,678	448	2,207	78	78.99	2.79	43.01	1.52	35.97	1.27	0.62%
Cordova[4]	1,902	67	249	9	3.11	0.11	1.20	0.04	1.91	0.07	0.16%
Deep Basin Cadomin, Nikanassin[5]	255	9	207	7	28.99	1.02	8.66	0.31	20.34	0.72	11.38%
Total	94,443	3,337	15,058	532	2,094.02	73.99	1,687.12	59.62	406.90	14.38	2.22%

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
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, 2020.

Executive Summary

Demand for hydrocarbons saw a significant reduction in 2020 due to the COVID-19 pandemic, though the province's industry fared relatively well as natural gas prices did not experience the same extreme drop as oil prices.

As shown in Table 2, estimated remaining gas reserves increased 5.2 per cent due to added Montney development wells. Remaining oil reserves decreased 10.2 per cent due to oil pool depletion, cessation of waterflood operations in some pools, low prices, and lack of new oil discovery. Hydrocarbon liquids reserves continue to increase as development is largely focused on the Montney play, where many operators are targeting liquids rich areas and layers of the Montney. Sulfur reserves increased 10 per cent, driven by heightened reserves in the Heritage and revisions in the Bullmoose and Brazion fields.

371 wells were drilled in 2020, slightly increased from the 361 wells drilled in 2019. The number of active rigs in the summer of 2020 was very low compared to previous years but later returned to normal levels. The temporary decreased rig activity led to a decline in hydraulic fracturing, as most operators delayed hydraulic fracturing operations to the fall. Activity returned to normal levels in the final months of 2020.

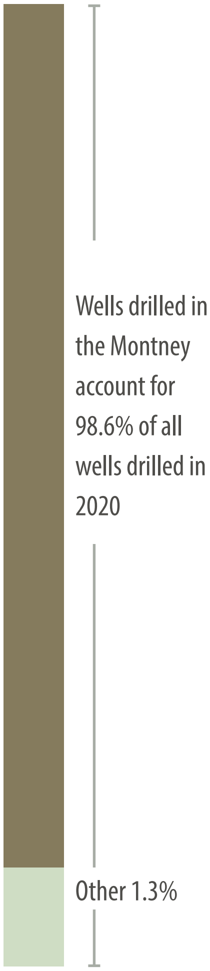
As shown in figure 2, of the 371 wells rig released in 2020, 98.6 per cent were drilled in the Montney. The remaining wells include 2 service wells, and 3 wells in other areas.

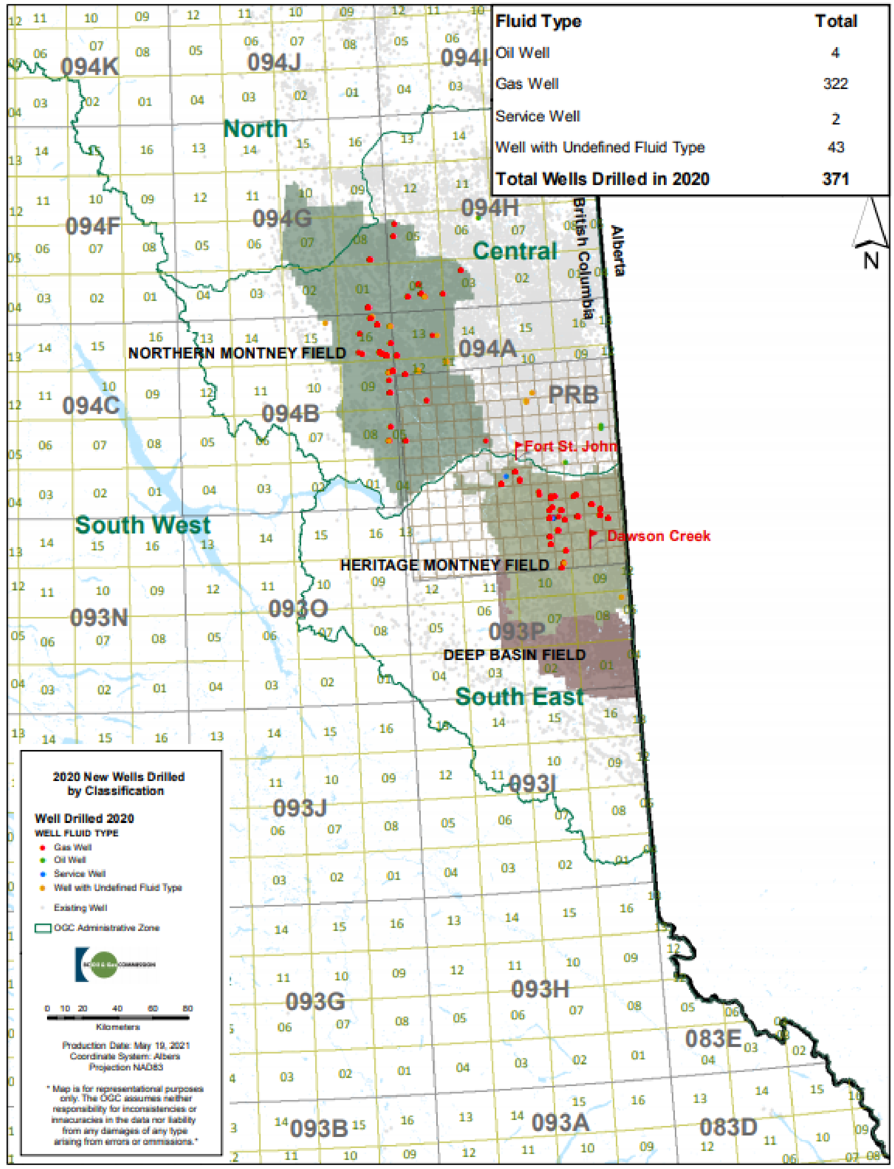
The Montney continues to dominate drilling activity, production, and reserves growth. Additionally, best practices for hydraulic fracturing continue to evolve, and demand for deep disposal for geological storage of flowback water remains high. New sections on both hydraulic fracturing and deep disposal can be found at the end of this report. The Commission completed a multi-year review of oil pool waterflood operations, which is also summarized in this report.

Table 2: B.C. Remaining Reserves as of Dec. 31, 2020

	2020		2019		Percent Change
Gas (raw)	1,912.5 10^9m^3	67.6 Tcf	1,818.7 10^9m^3	64.3 Tcf	5.2 %
Oil	14.9 10^6m^3	94.0 MMSTB	16.6 10^6m^3	104.7 MMSTB	-10.2 %
Pentanes$^+$	105.2 10^6m^3	661.3 MMSTB	86.0 10^6m^3	540.7 MMSTB	22.3 %
LPG	123.5 10^6m^3	776.3 MMSTB	105.8 10^6m^3	665.3 MMSTB	16.7 %
Sulphur	6.6 10^6 tonnes	6.5 MMLT	6.0 10^6 tonnes	5.9 MMLT	10.0 %

Figure 2: 2020 Wells Drilled by Fluid Type





Discussions: Gas Reserves and Production

As of December 2020, unconventional gas zones accounted for 89.0 per cent of all remaining reserves and 91.1 per cent of annual gas production in the province.

As of Dec. 31, 2020, the province's remaining raw gas reserves were 1,912.5 e^9m^3, a 5.2 per cent increase from the 2019 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 85.4 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 of December 2020). The majority of production in the province originates from the Montney.

Figure 3: 2020 Remaining Gas Reserves

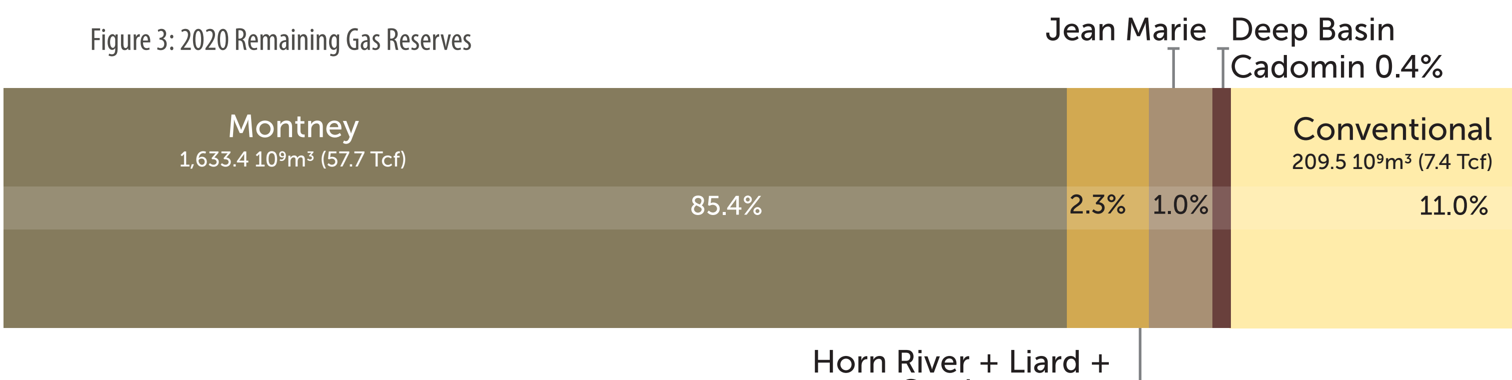
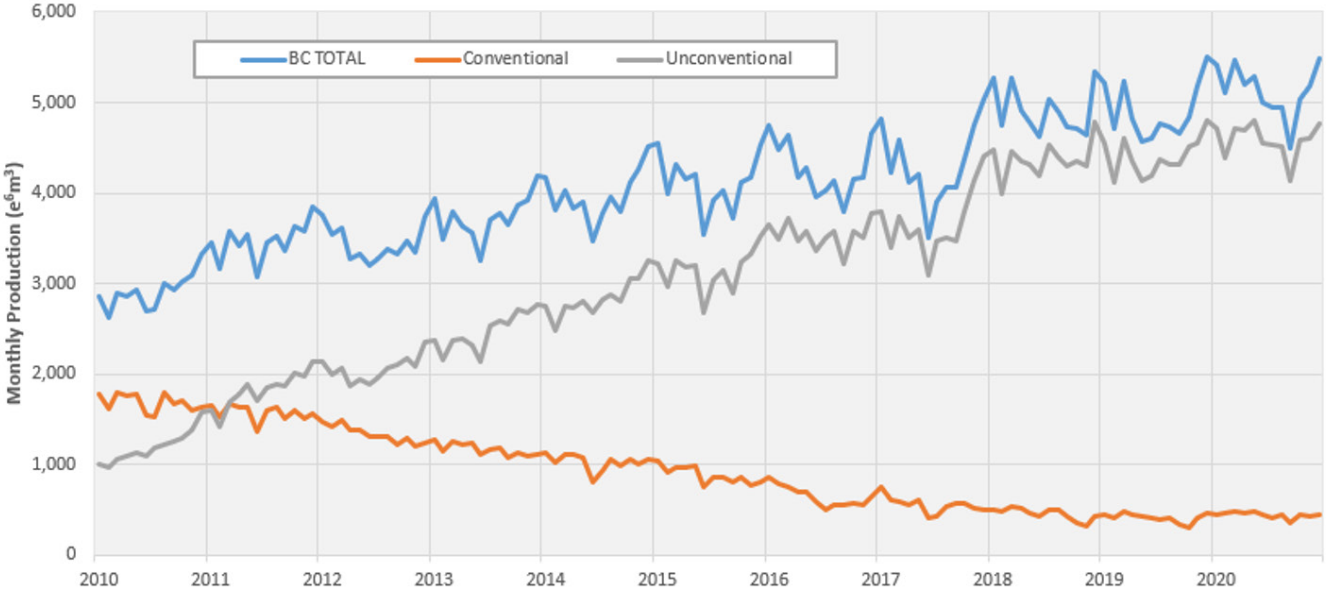


Figure 4: 2020 Annual Gas Production Split by Source

Discussions: Gas Reserves and Production

Figure 5: Unconventional vs. Conventional Raw Gas Production 2010 to 2020



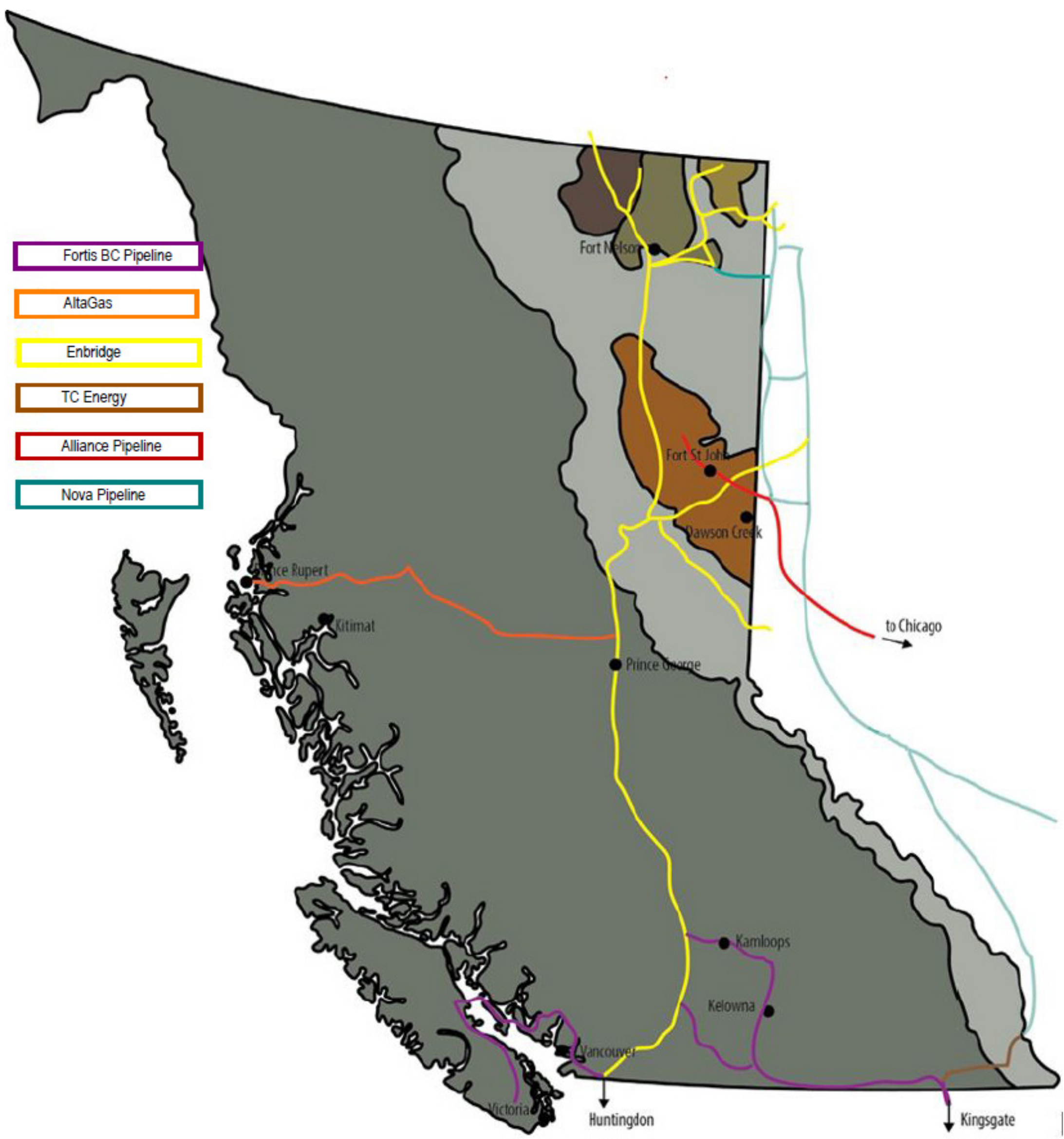
Discussions: Gas Reserves and Production

While the COVID-19 pandemic negatively impacted oil and gas demand, North American gas prices increased in 2020. The decreased demand and price for oil led operators, notably in the Bakken (North Dakota) and the Permian (Texas) plays, to shut in oil wells. Because associated gas is produced along with this oil, shutting in these wells removed significant supply of natural gas from the market. This drop in supply has more than cancelled out the drop in demand and thus gas prices saw an increase.

In the last five years, gas production in the province has increased by 20.3 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 System



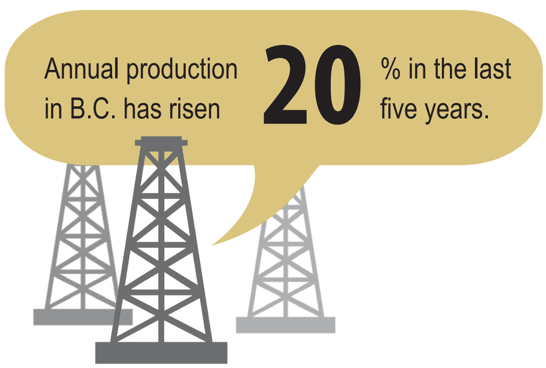
Discussions: Gas Reserves and Production

Figure 7 represents the Commission's raw gas reserves bookings from 2010 to 2020, 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 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, the onset of Montney horizontal drilling with hydraulic stimulation created a significant new supply of gas. This was followed by Liard Basin development in 2008 and Horn River development in 2010. Further development of the Horn River basin has now ceased, with decreasing production, awaiting increased gas prices. In 2020, Liard Basin suspended production completely.

Triggered by the pandemic, gas production declined from April 2020 to September 2020 due to the lack of new wells coming online and a higher-than-normal number of shut-in wells, with September 2020 dipping below its 2019 value (see figure 7.5). The low production in September is largely attributable to the McMahon gas plant, in Taylor, B.C., maintenance shutdown. Since September, production has steadily increased. Excluding September, all other months saw gas production above historic values. Raw gas production for the province in December 2020 was 177.2 e^6m^3 per day (6.26 Bcf/d).



Discussions: Gas Reserves and Production

Figure 7: Historical Development in B.C. 2010 to 2020

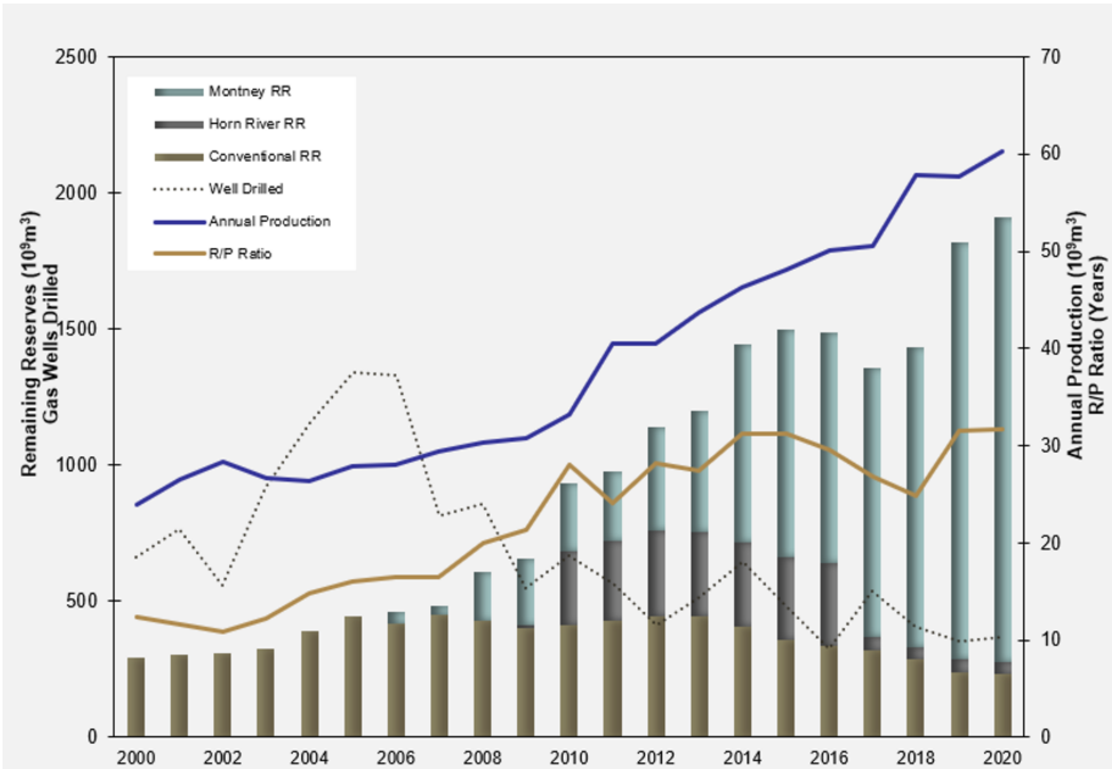
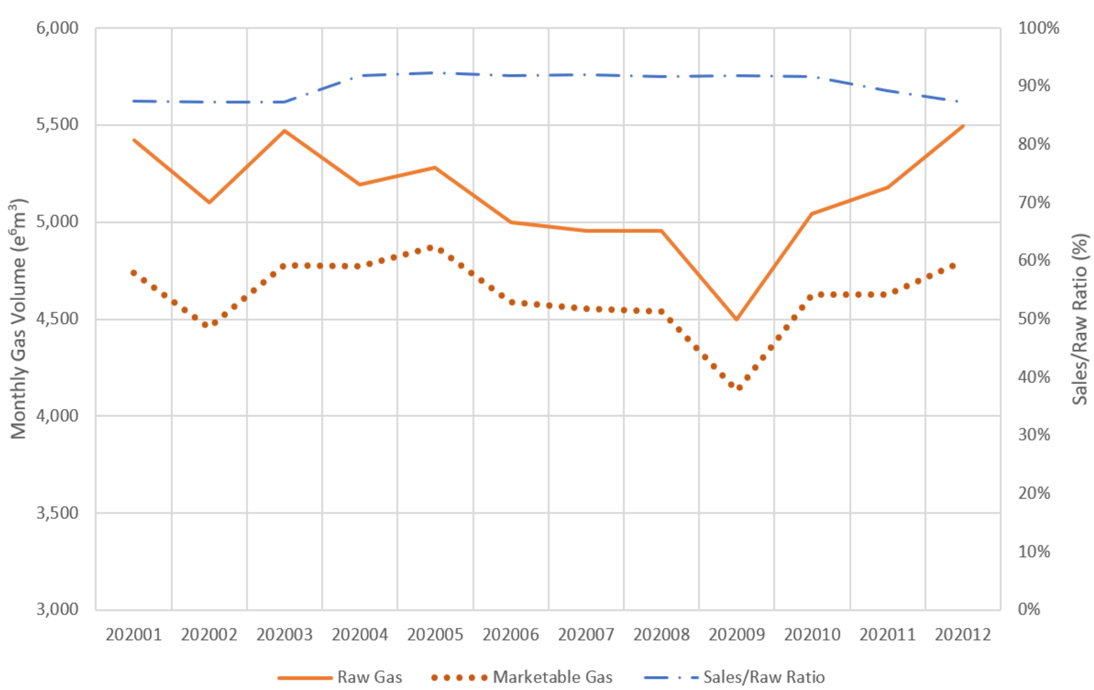


Figure 7.5: 2020 Raw Gas and Marketable Gas



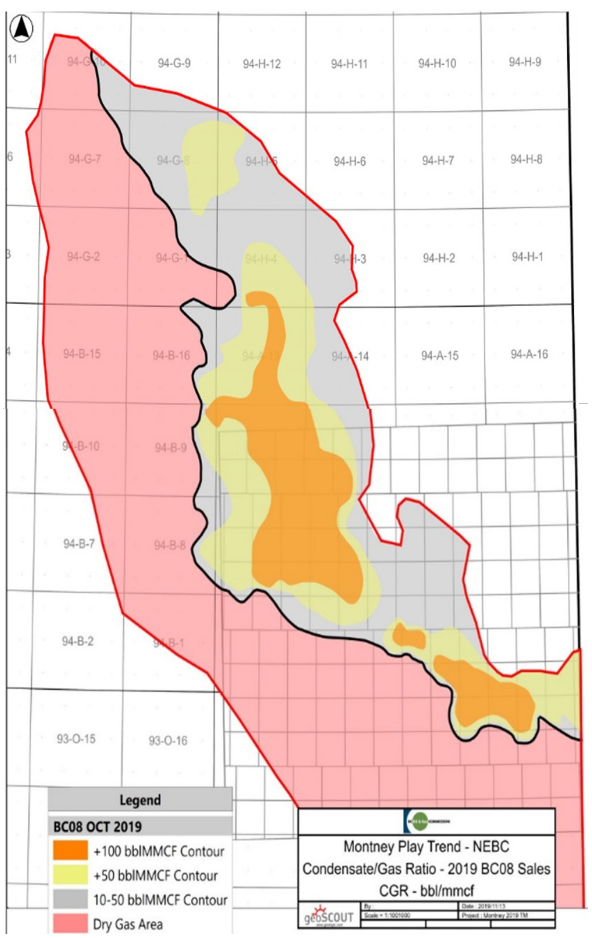
Montney Unconventional Gas Play

The Montney contains 85.4 per cent (57.7 Tcf) of the province's remaining raw gas reserves and contributed 86.3 per cent (5.05 Bcf/d; annual average rate) of the province's 2020 production.

Significant development of the Montney began in 2005 and the area has since become the largest contributor to natural gas production volumes in the province. Since 2019, drilling has focused on the liquid rich gas portions of the play trend. As a result, production of liquified petroleum gas (LPG) 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 2020, of the 8,425 producing wells in the province, 4,115 wells 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 Dry/Wet/Oil Distribution



In December 2020, the Northern Montney gas production was 54.7 e^6m^3 per day (1.94 Bcf/d) while the Heritage field gas production was 91.8 e^6m^3 per day (3.26 Bcf/d).

Montney Unconventional Gas Play

As of Dec. 31, 2020, the remaining gas reserves for the Montney formation is 1,633.4 e^9m^3 (57.7 Tcf) (raw). The initial reserves of 1,980.0 e^9m^3 represents a 3.6 per cent recovery of the estimated total basin gas-in-place of the Montney resource. Both reserves and recovery factor will increase with additional drilling and production. A detailed record of remaining reserve estimates for each Montney pool/sub-zone can be found in Table 3 below.

Table 3: Montney Remaining Reserves as of Dec. 31, 2020

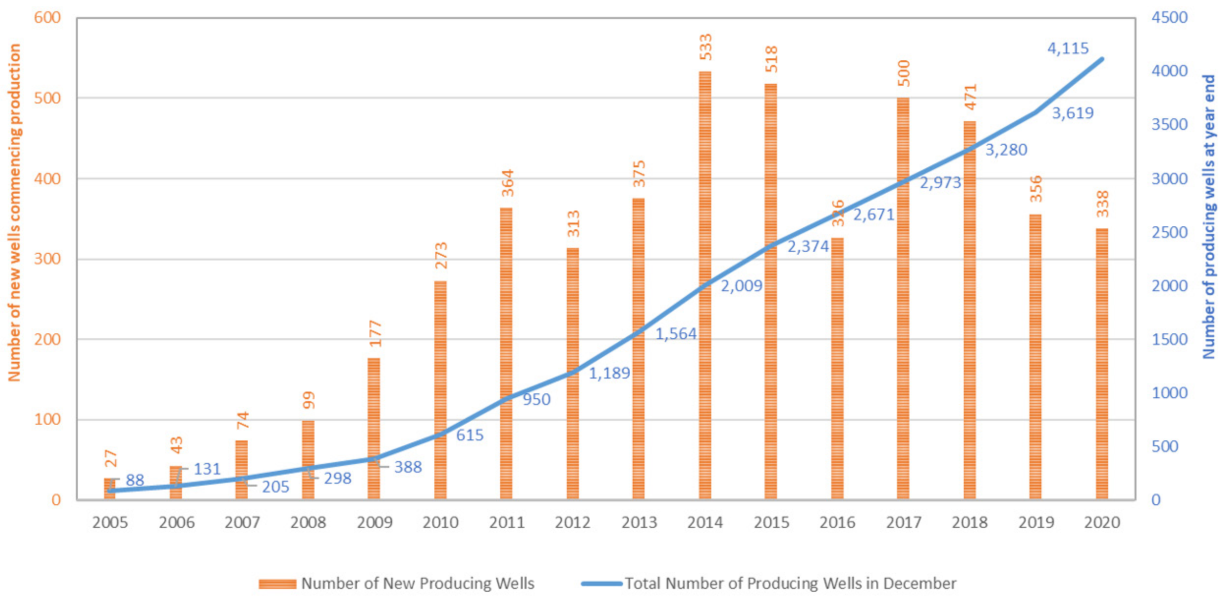
Field/Pool	Subareas/Layers	Horizontal Well EUR (Bcf) per well				Initial Reserves (Raw) Bcf	Remaining Reserves (Raw) Bcf	Existing	PUDs	Development Phase
			P90	P50	P10					
Heritage - Montney A	Dry/Ultra Dry Upper	6.77	1.89	5.70	12.41	25,639.9		1,153	2,643	Statistical
	Dry Lower	6.06	2.13	4.95	11.68	7,054.4		497	634	Statistical
	Liquid Upper	3.83	1.00	3.51	7.02	5,849.8		806	727	Statistical
	Liquid Lower	2.57	1.03	2.20	4.50	2,186.8		170	680	Intermediate
	Area Total	5.4	1.39	4.35	10.57	40,785	32,675	2,626	4,684	
Northern Montney - Montney A	NW - Upper	5.11	1.46	4.96	9.05	5,279.5		207	820	Intermediate
	NW - Lower	3.16	0.94	3.04	5.90	3,234.6		205	820	Intermediate
	SW - Upper	4.83	1.15	4.26	9.52	3,302.2		137	548	Intermediate
	SW - Lower	4.43	1.31	3.91	8.23	3,286.9		148	592	Intermediate
	NE - Upper	5.18	2.09	5.00	8.22	4,476.1		403	464	Statistical
	NE - Lower	3.53	1.02	3.07	6.34	5,468.7		310	1,240	Intermediate
	SE - Upper	2.77	0.63	2.28	5.41	1,810.4		131	524	Intermediate
	SE - Lower	2.56	0.57	2.08	5.03	1,622.9		127	504	Intermediate
	Area Total	4.15	1.05	3.62	7.82	28.481.3	24,706.0	1,668	5,516	

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. For maps with outlined areas see Appendix B.

Montney Unconventional Gas Play

Figure 9 compares the number of new Montney wells drilled to the number of Montney producing wells from 2005 to 2020. The number of wells producing from the Montney increased year-over-year, from 88 in 2005 to 4,115 by the end of 2020. Annual producing well additions peaked in 2014 and declined thereafter, however gas production has increased, illustrating improvements in per well performance due to evolving completion techniques and horizontal drilling.

Figure 9: Number of New Wells added and Producing Wells in Montney Play 2005 to 2020



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 has been divided into four subgroups, based on liquid content and targeted Montney layer, with P50 EURs ranging from 2.2 to 5.7 Bcf per well. The Northern Montney has been divided into eight subgroups, by geographic area and targeted Montney layer, with P50 EURs ranging from 2.1 to 5.0 Bcf per well. These variations occur due to a number of factors, from formation (zone) characteristics and completion techniques, to stage of development. For maps of sub-area locations, see Appendix B.

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

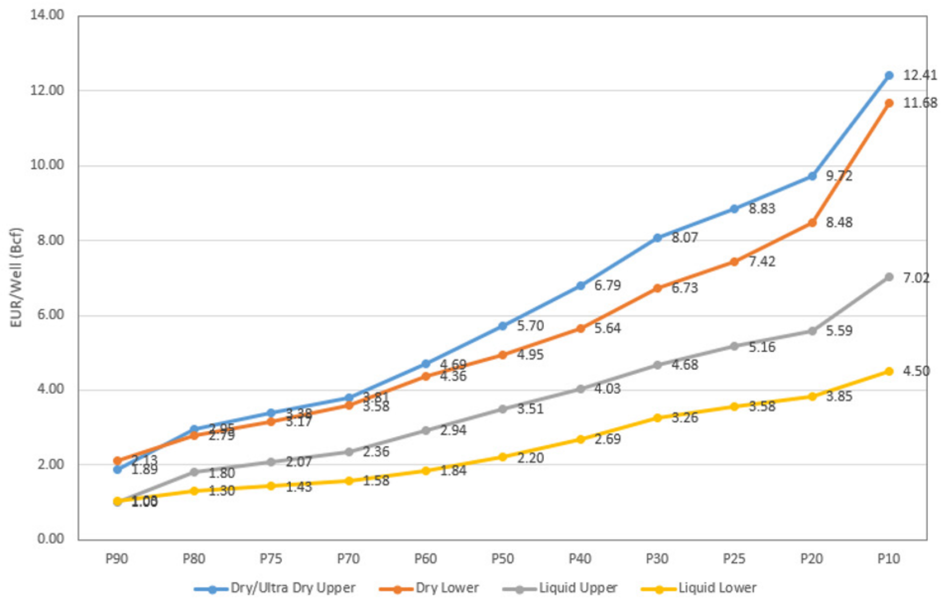
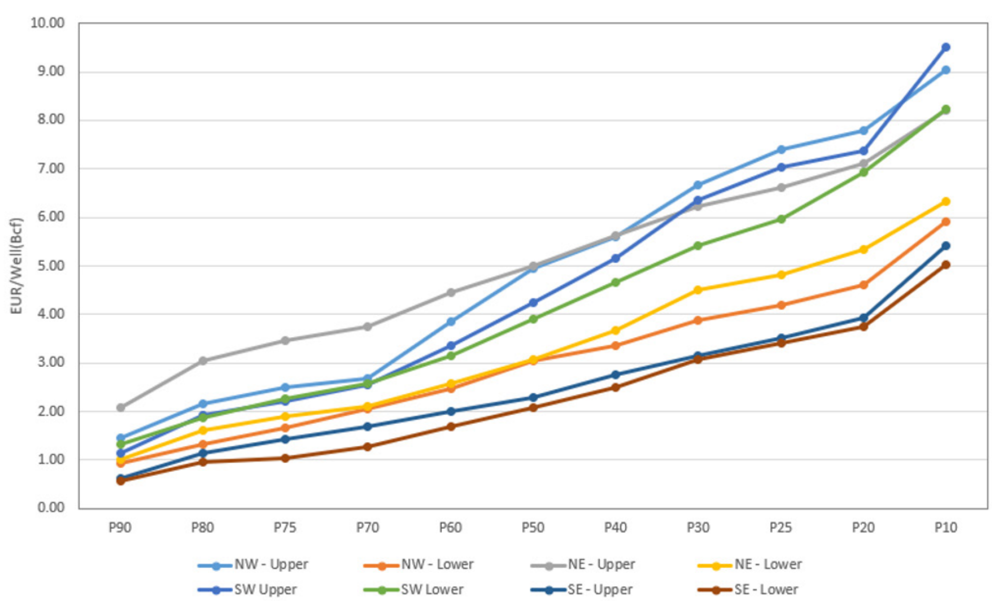


Figure 10B: Northern Montney EURs Distribution by Subareas/ Zones



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 operating, infrastructure and facility costs. Limited wells are now drilled outside of these focus areas for reserves delineation and land continuation obligations. Gas production volume and condensate production saw an increase, and LPGs saw a minor decrease. The trend in the industry is production company ownership and operation of infrastructure and plants, a shift from previous reliance on midstream companies. Mergers and acquisitions have reduced the number of Montney operators while contributing to the growth of established larger 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 2020

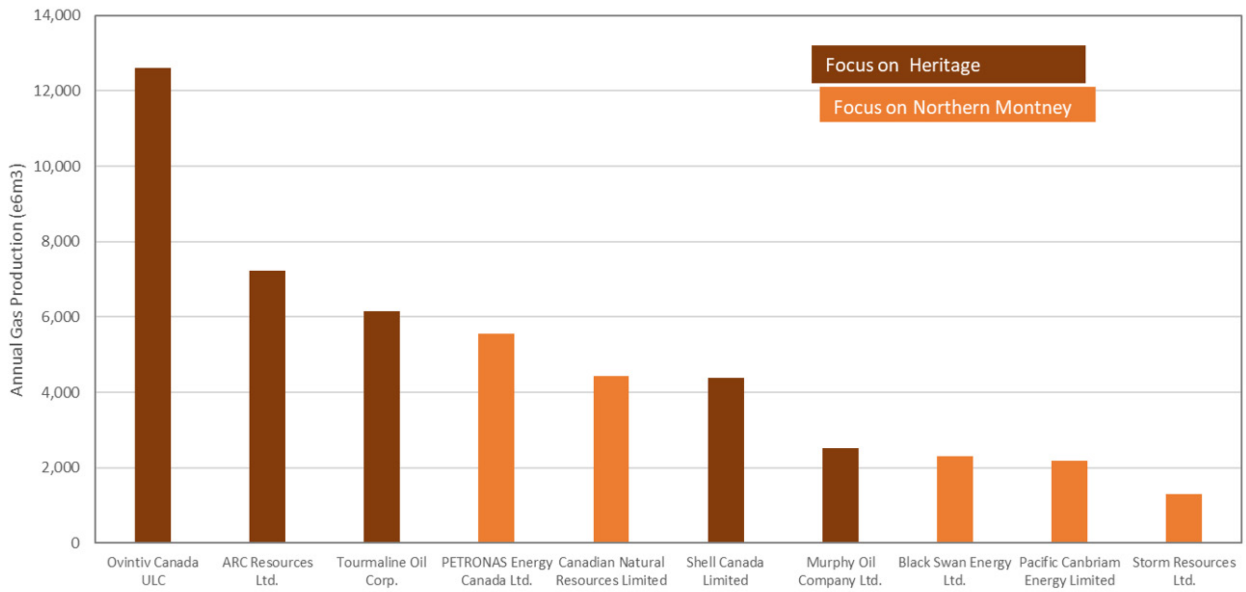
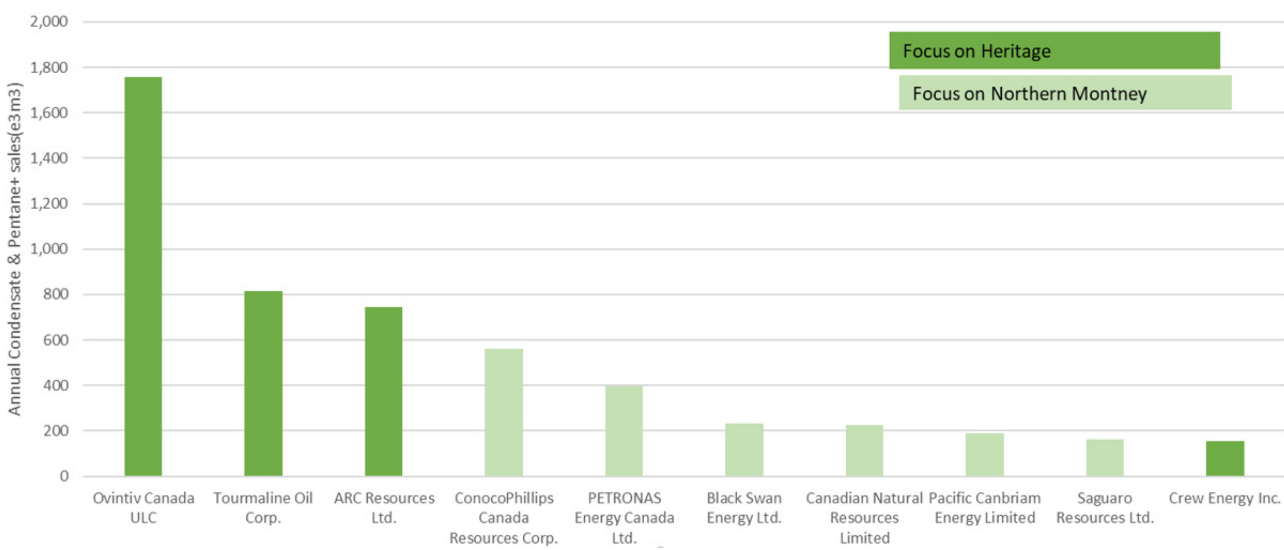


Figure 12: Top 10 Condensate & Pentanes+ Producers in Montney Play 2020



Other Unconventional Gas Plays
Liard, Horn River and Cordova

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

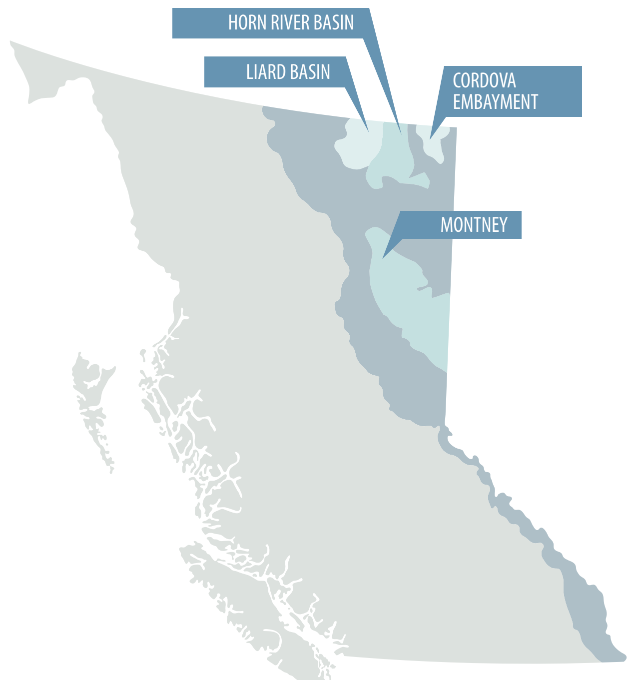
British Columbia has seen significant activity in the exploration and development of unconventional natural gas resources, beginning in the mid 1990's with horizontal drilling in the Devonian carbonates of the Jean Marie. Starting in 2006, unconventional tight gas resource development shifted to shale gas in the Devonian Muskwa, Otter Park and Evie shales in the Horn River Basin and the Triassic aged siltstones of the Montney formation. Later, 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 kilometres deep, 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. However, the pay zone depth and remote location have resulted in high costs which has stopped new activity in the current low gas price environment.

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 in the developed locations, a small fraction of the resource potential. 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 it was shut-in in June 2019. Estimated recoverable gas is 2,600 e^6m^3 (92 Bcf) from this single well. The 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 3.25 e^6m^3/d (114.7 MMcf/d) in December 2020, down 21.7 per cent from the previous year (December 2019). Operators have continued to shut-in wells that are 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. Due to lack of drilling activities since March 2015, a detailed evaluation, shown in the 2018 Reserves Report, resulted in a reduction in recovery factor for initial raw gas reserves. At the end of 2020 there were 99 wells producing from the Horn River Basin shales, down 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 2020, there were 15 wells producing from the Cordova Basin shale play, with a total production rate of 333.4 e^3m^3/d (11.8 MMcf/d). Further background information on the Horn River and Cordova fields is available in the 2014 Reserves Report.

Summary

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 significantly higher than 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 have been the focus of development, due to gas charging and their 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", however further development has ceased due to the significant capital and operating expenses due to the depth and remote location.

Figure 13:
Pressure vs. Temperature Plot

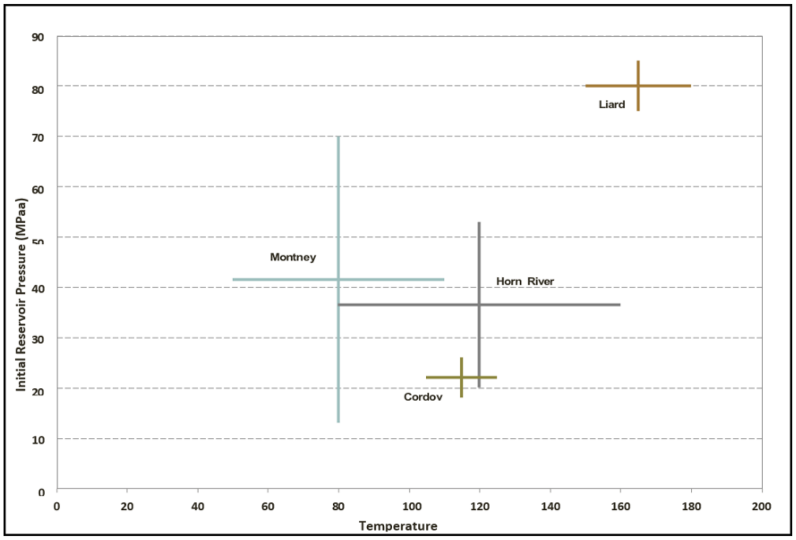
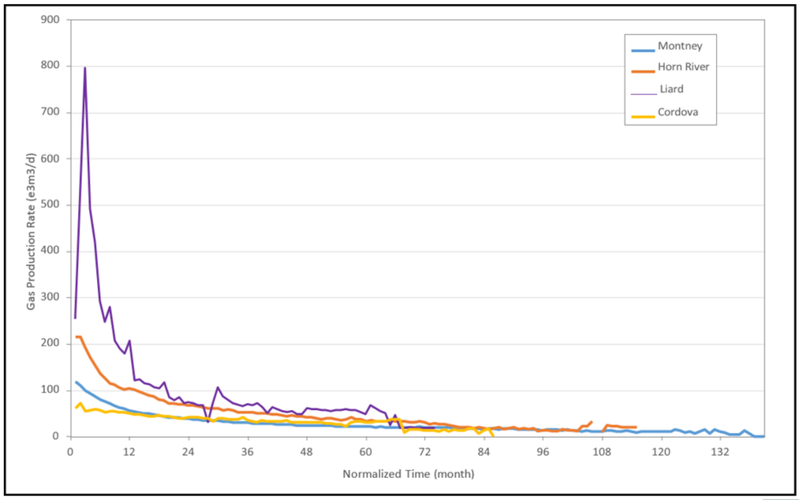
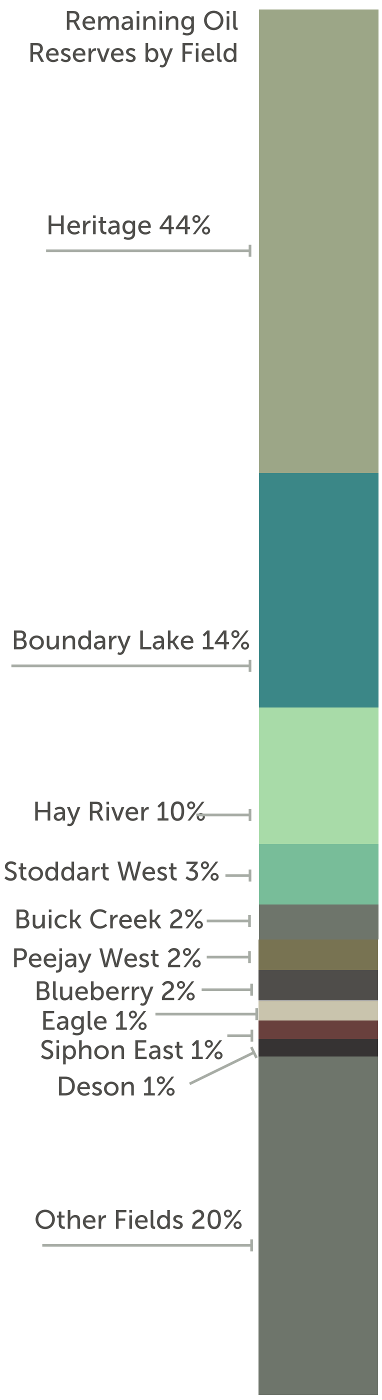


Figure 14:
Comparison of Montney, Horn River, Liard & Cordova Production Typewells



Discussions: Oil Reserves

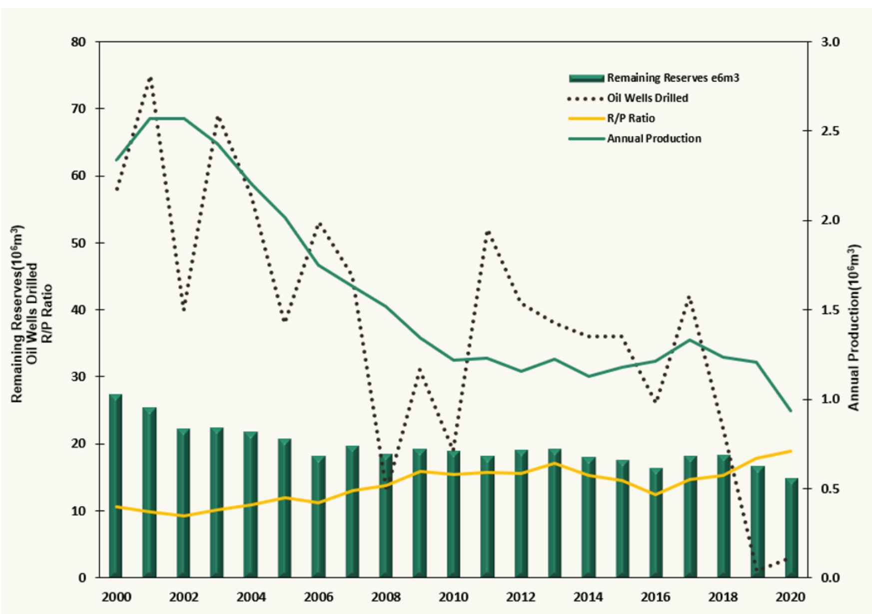
Annual oil production decreased 15.5 per cent from 935.2 to 790.3 10^3m^3 (4.97 MMSTB) in 2020.



Remaining oil reserves decreased 10.2 per cent from 2019 to 2020 resulting in total remaining reserves of 14.9 10^6m^3 (94.0 MMSTB). This reserves decrease is mainly due to the lack of new oil wells drilled. In 2020, only 3 additional oil wells came on production. Optimization of waterflood projects with injection locations, which support the large majority of conventional pool oil 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 pools with exceptional reservoir quality, with an average of approximately 35.7 per cent, showing good production management of conventional oil pools in the province. Reserves have been readjusted for waterflood pools which have ceased injection and several approvals were cancelled in 2020. Details can be found in the section of the report titled "Waterflood Projects Review" on page 33.

The 2020 R/P ratio is at its highest point in over 30 years, at a value of 18.9 years. The ratio had previously peaked in 2013 at 17.1 years before declining to a minimum of 12.4 years in 2016. The R/P ratio has remained relatively steady since 2007 at between 12 and 19 years. The recent trend of increasing R/P is due to relatively significant drops in annual production, with only moderate drops in reserves. The pool with the largest remaining reserves, as with previous years, is the Heritage Montney oil pool.

Figure 15: Historical Oil Development 2000 to 2020



29.2 per cent of the remaining oil reserves in B.C. are located in pools with secondary recovery pressure maintenance waterflood projects. These oil pools are listed in Table A-4: Oil Pools Under Waterflood. Gas injection recovery schemes account for 0.4 per cent of remaining oil reserves, occurring in six 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. In 2019, the Commission changed the policy for how the primary product is determined for wells producing from the Montney formation. New wells are predominantly classified as gas wells, in some cases with high associated hydrocarbon liquid volumes. Montney oil production peaked at 11,817 bbl/d (1,879 m^3/d) in August 2018 before demonstrating a significant decline from September 2018 to mid-2019, following which the production decline rate leveled out, as shown in Figure 16.

One additional Montney oil well came on production in 2020, 100/04-03-083-16W6/00, in the Two Rivers area. No new oil wells were drilled in the Heritage area nor the Northern Montney area in 2020.

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

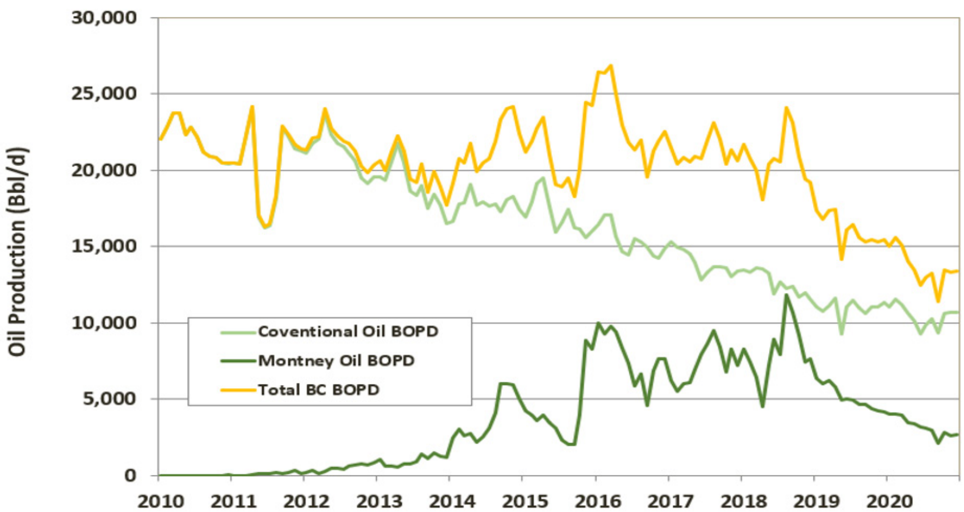


Figure 16: B.C. Oil Production 2010 to 2020

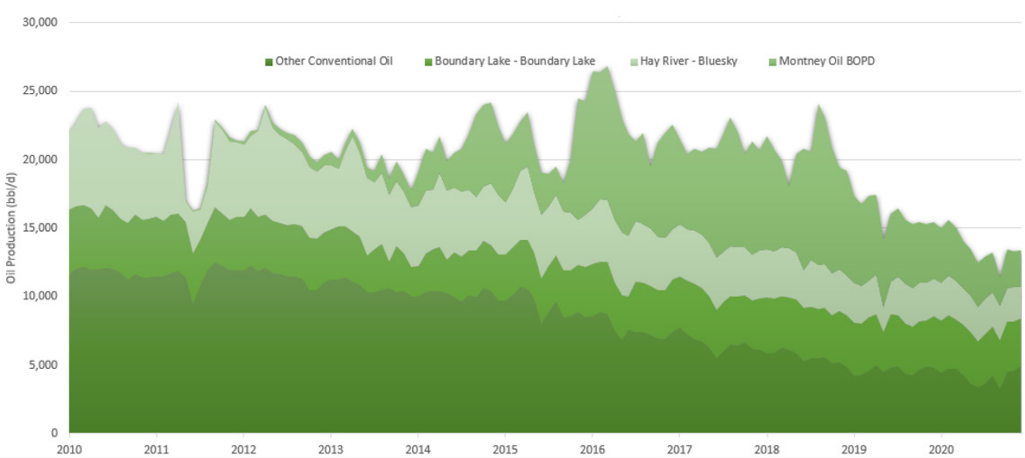


Figure 17: B.C. Oil Production by Source 2010 to 2020

Discussions: Condensate, Pentanes+ and NGLs

Production of condensate/pentanes+ and LPG in 2020 remained at approximately 2019 levels.

Overall liquid by-products production in 2020 remained at approximately the same level as 2019. In 2019, the focus of development shifted to include not only the upper Montney zone, but also the middle and lower Montney zones. In some areas, operators developed the entire 'stack' of the Montney formation (upper, middle, and lower zones).

Ethane annual sales had been relatively constant at around 950 e^3m^3 since 2012 but have seen a significant decrease in 2019 and 2020, at just 723 e^3m^3 and 357 e^3m^3 respectively. This reduction in ethane sales suggests that the ethane remains in plant outlet gas streams, to be extracted in other jurisdictions, closer to end markets. Butane and propane sales have been on an upward trend since 2008, although 2020 butane sales did decrease by a small margin of four per cent while 2020 propane sales had an minor increase of six per cent. The general increase in butane and propane sales volume in recent years is a result of some companies now having the capability to extract propane and butane from the gas stream within the province for export.

Both condensate/pentanes+ and LPG production have been on an upward trend for the past decade. In 2020, condensate/pentanes+ production increased by four per cent to 5,728.4 e^3m^3 whereas LPG production decreased by eight per cent to 4,278.6 e^3m^3 (Figure 18), mostly due to the aforementioned decreased ethane production.

The general increase in liquids production is in part due to a shift towards development of liquids-rich Montney areas in recent years. This is also due to a change in policy for determining the primary product of Montney formation wells 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.

Depressed oil prices in 2020 resulted in less demand for heavy oil production in Alberta and thus less demand for B.C. condensate, which is used as a solvent for heavy oil. As a result, some operators in B.C. shifted their focus to "dry gas" in 2020. This may explain the merely modest increase in condensate production in 2020 versus the significant increases in 2018 and 2019.

Similarly, reflecting Montney "rich gas" development, remaining reserves of pentanes+ in 2020 is 105.2 e^6m^3, an increase of 22.3 per cent from last year. LPG remaining reserves increased by 16.7 per cent versus last year to 123.5 e^6m^3. Drilling is currently 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 2010 to 2020 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 has been on an increasing trend for the past decade, indicating operators are able to increase the liquids yield in their area by further optimizing well location, completion techniques and operations. In 2020, CGR in the Heritage region decreased by 11 percent while CGR in the Northern Montney region increased by 18 per cent.

Figure 18: Annual Oil, Condensate and NGL Production 2010 to 2020

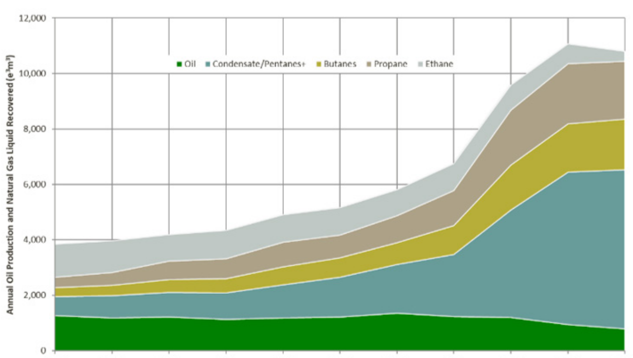
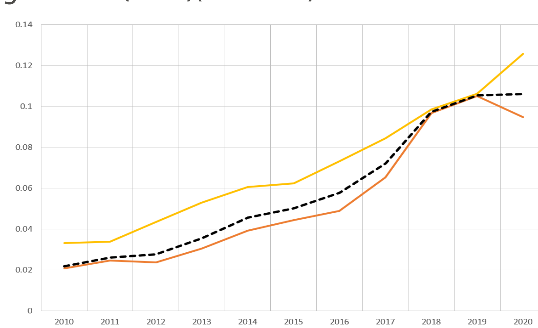


Figure 19: Condensate/Pentanes+ and Raw gas Ratio (CGR)(m^3/e^3m^3) 2009 to 2020



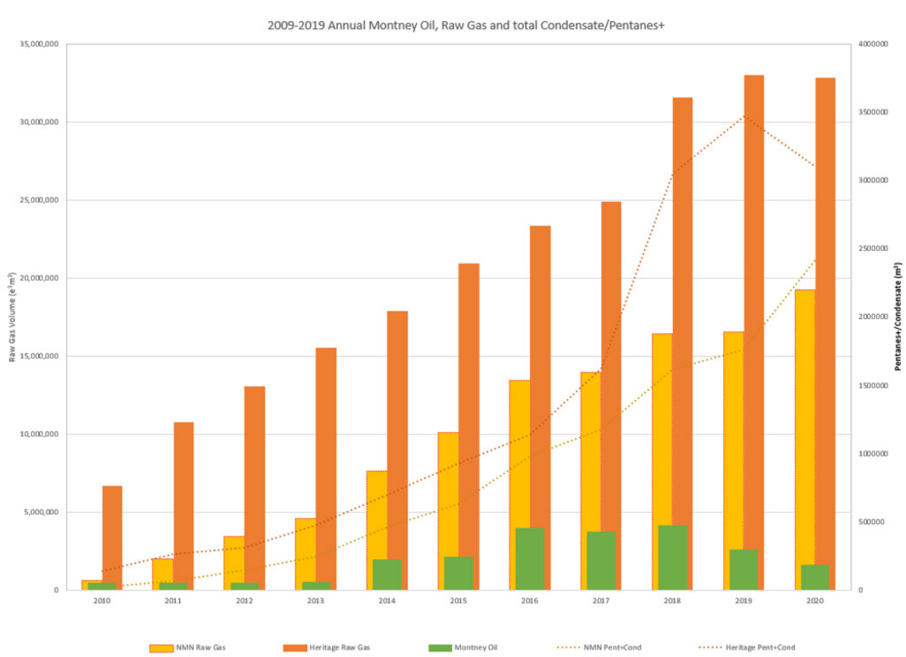
Discussions: Condensate, Pentanes+ and NGLs

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 have invested in upgrading existing 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.

In 2020, there was continued significant capital investment in gas processing, pipelines, and gas and associated liquids export facilities. Liquid propane and butane arriving via rail at the AltaGas Ltd. Ridley Island terminal (RIPET) near Prince Rupert is exported as LPG. The output from RIPET increased to 50,000 bbl/d by year end 2020, partly due to AltaGas' expanded Townsend 2B and North Pine facilities. A second LPG terminal on Watson Island near Prince Rupert, operated by Pembina, is coming on-service in April of 2021, with a capacity of 25,000 bbl/d. Pembina's northeast B.C. pipeline also connects liquids volumes from the Montney into Edmonton. This northeast expansion has a capacity of 75,000 bbls/d and has been in service since October 2017.

In 2020, there was an 11 per cent decrease in condensate/pentanes+ production in the Heritage region (Figure 20), whereas in 2019 the Northern Montney region saw a 38 per cent increase. This is a result of the decreased gas production and CGR in the Heritage, and the converse is true for Northern Montney.

Figure 20: Annual Montney Oil, Raw Gas and Condensate/Pentanes+ Production 2010 to 2020



Discussions: Condensate, Pentanes+ and NGLs

Figures 21 and 22 show the condensate type curves for each subarea and layer for the Heritage and Northern Montney areas. At the current level of development (not including PUDs), the estimated condensate P50 EUR using the typewells in Figure 21 is 1.5 to 3.1 e^3m^3 per well in dry and ultra dry areas, and 13.9 to 35.0 e^3m^3 per well in liquid rich areas of Heritage Montney. For the Northern Montney from the east liquid rich area to the west dry area, the P50 EUR ranges from 1.7 to 16.0 e^3m^3/well.

Figure 21 Heritage Condensate Typewell by Subareas and Layers

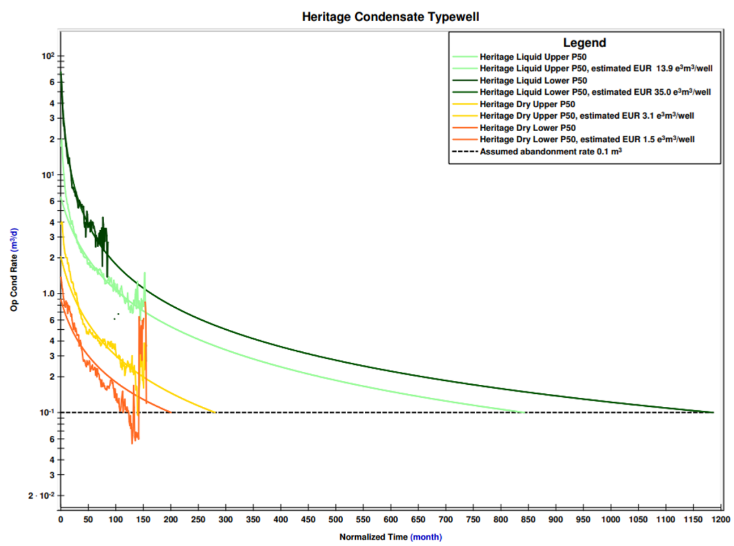
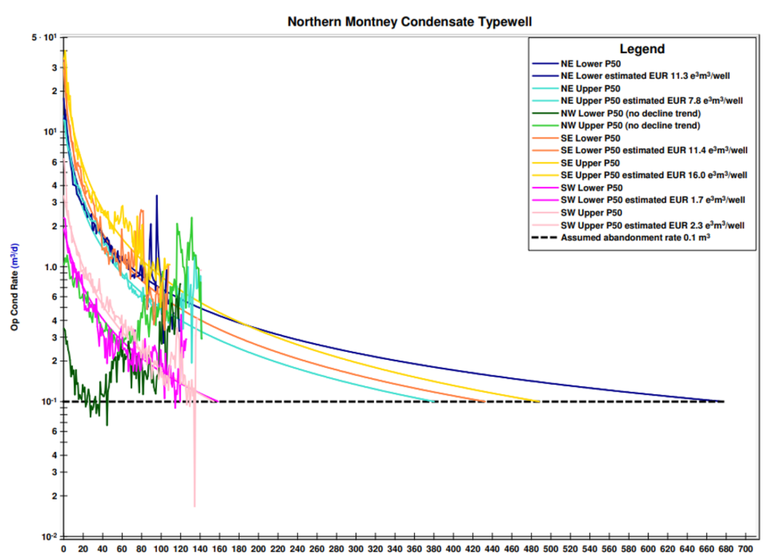


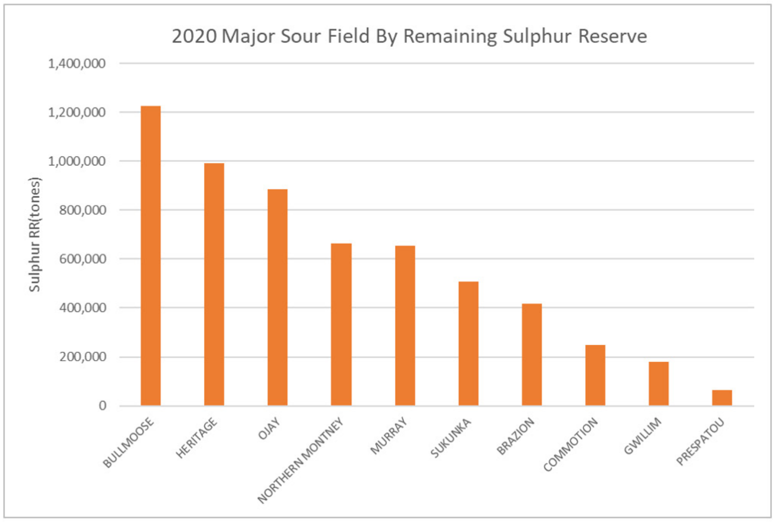
Figure 22: Northern Montney Condensate Typewell by Subareas and Layers



Sulphur sales increased slightly in 2020

As of Dec. 31, 2020, recoverable sulphur remaining reserves was 6.6 106 tonnes (6.0 MMLT). Sulphur reserves saw a modest 10 per cent increase in 2020, breaking the previous trend of year over year decreases. This increase is largely due to a significant increase in the reserves of the Heritage, and amendments to the Bullmoose and Brazion fields, 76 per cent, 38 per cent and 154 per cent, respectively. Figure 23 shows the breakdown as of Dec. 31, 2020.

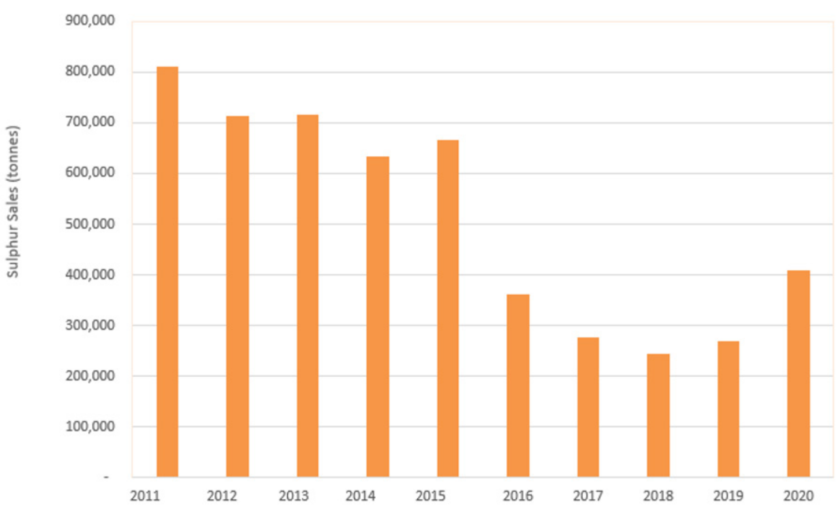
Figure 23: 2020 Major Sour Field by Remaining Sulphur



Operators continue to shut-in wells in these areas where acid gas levels are high, as continued production is often uneconomic. Sulphur sales, as illustrated in Figure 24, decreased significantly between 2015 and 2018. Sales saw a minor increase in 2019 and then a significant increase of 52 per cent in 2020. However, annual sales continue to remain well below historic levels.

Most of the natural gas recovered from the unconventional Montney Play Trend in B.C. has little to no H_2S content. However, even with minimal H_2S content, the immense volumes of natural gas recovered from the Norther Montney play results in a considerable amount of sulfur. Additionally, the are some cases where the percentage of H_2S can be significant in Montney gas (Figure 25).

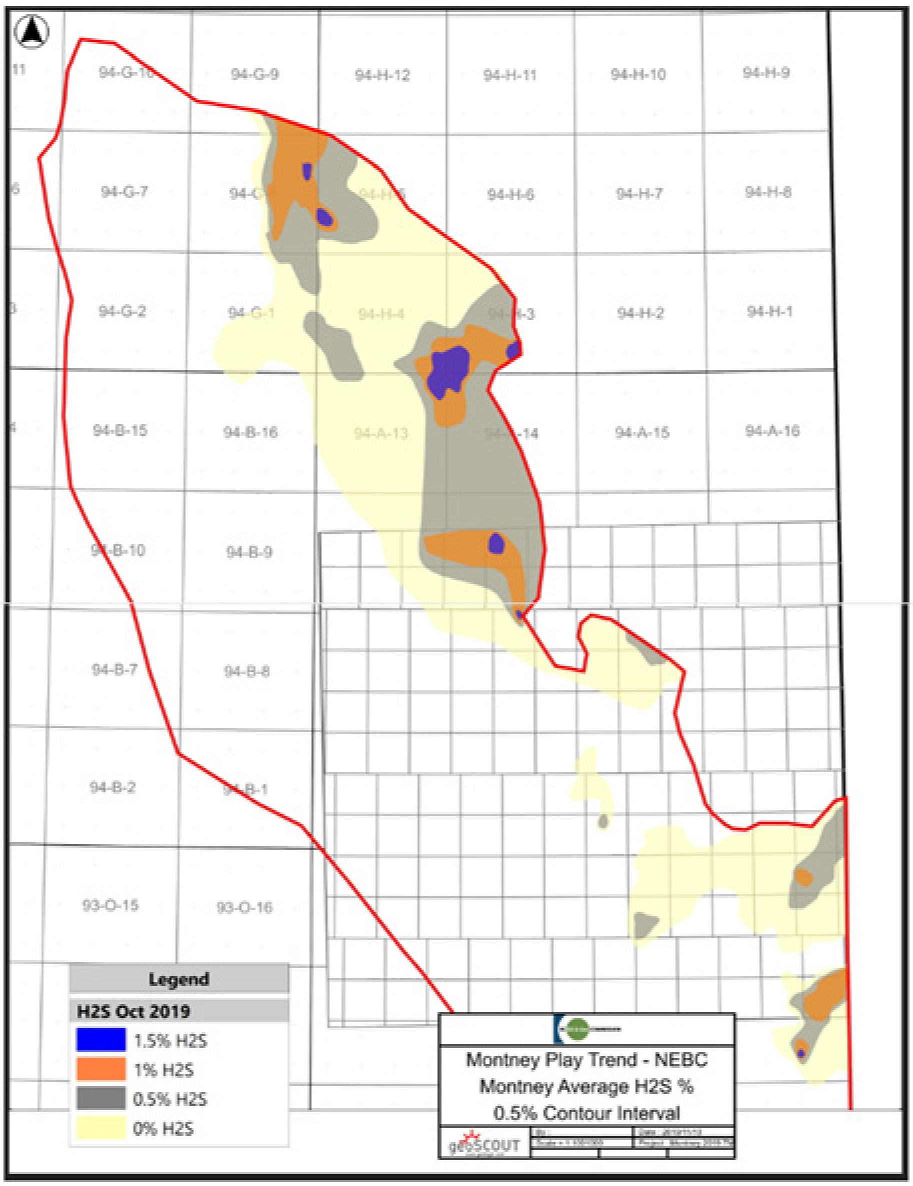
Figure 24: 2020 Annual Sulphur Sales



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 25: 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 sulfur reserves. The trend in Montney gas plants is dedicated H_2S (acid gas) disposal wells, in which the sulfur is sequestered for deep storage, rather than sold.

Discussions: Deep Disposal

Disposal wells inject undesired fluid by-products of oil and gas production into deep subsurface geological formations for long term storage. Disposal fluids fall into three categories: produced water (including flowback water from hydraulic fracturing), non-hazardous waste (NHW), and acid gas (CO_2 and H_2S). Formations used for disposal storage are either wet non-hydrocarbon bearing or depleted oil or gas pools. Disposal availability is key to economic production and reserves.

The most common type of disposal fluid is produced water. Production of oil and gas brings to the surface saline water trapped in the same formation. By regulation, this associated produced water must be disposed back into the subsurface. For oil waterflood projects, the produced water is re-injected back into the producing pool.

Nearly all new production wells target unconventional resources, with an initial multi-stage hydraulic fracture stimulation creating a significant amount of highly saline stimulation flowback fluid. A large portion of this fluid is re-used for subsequent hydraulic fracturing; however, the remainder is injected into produced water disposal wells. As a result, produced water disposal activity is now highly correlated with new well stimulations.

Oilfield non-hazardous waste, which includes fluids such as landfill leachate water, spend acid, and tank wash, makes up a small amount of total disposal. Wells approved for NHW disposal usually also dispose of produced water, and the combined monthly volume is reported as a single value.

Figure 26: Monthly Water Disposal Well Count and Volume 2005-2020

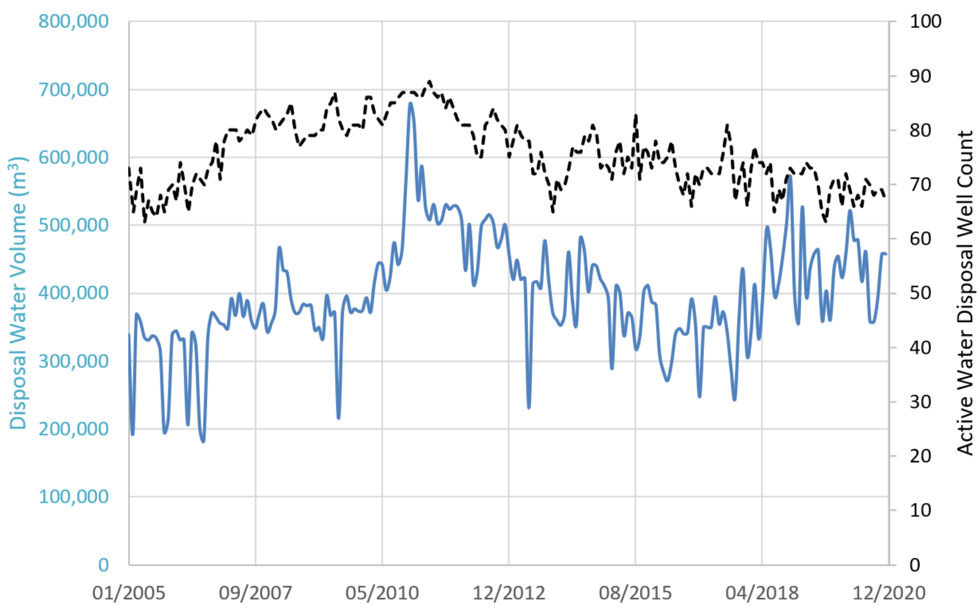


Figure 26 shows the monthly active water disposal well count and volume from 2005 to 2020. Total water disposal volume has mostly remained in the range of 400 $\pm$ 100 e^3m^3/month over this 15-year period, as disposal of fracture flow-back water has been replacing conventional formation produced water. The large spike in water disposal occurring from 2010 to 2014 is attributed largely to increased development (and thus increased wastewater from hydraulic fracturing) in the Horn River basin.

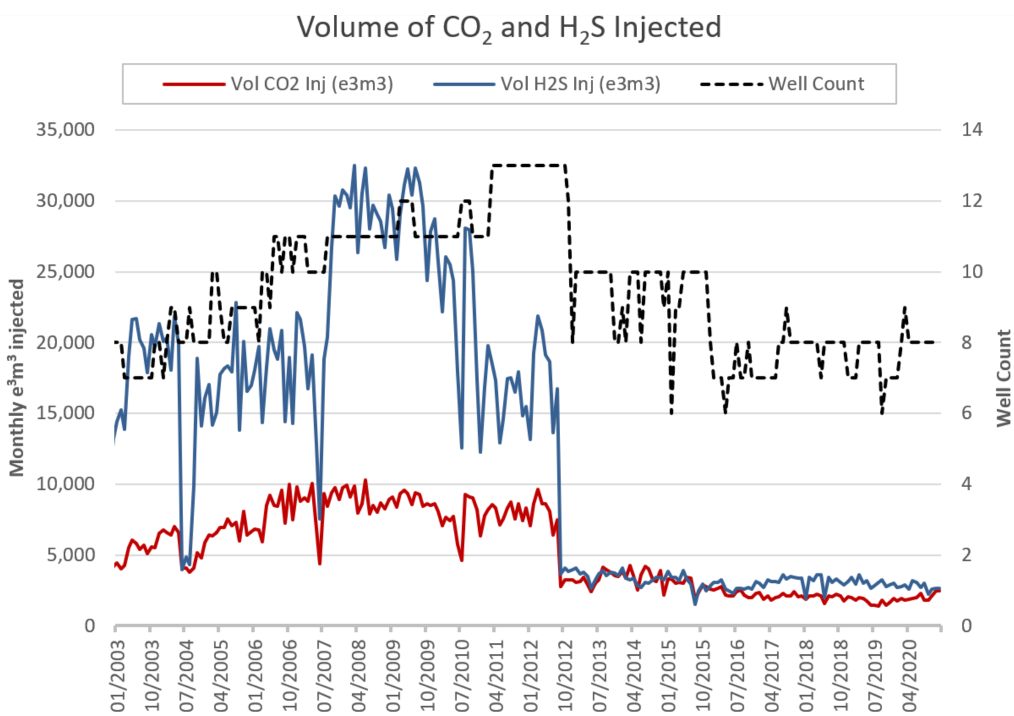
Discussions: Deep Disposal

Development of this area ceased in 2014. The recent increase in water disposal starting in 2018 is due to increased development of the Montney, as more fluid is being used on average for each well completion. Development activity not only affects disposal volume but also the location of the active disposal wells. Currently there is a significant demand for additional disposal capacity in the Montney fairway, while disposal wells in other areas with no current development have largely reduced or ceased operations despite having significant remaining disposal ability. A map of disposal well locations and information is available [here.]

Finally, the CO_2 and H_2S that constitute acid gas are the by-products from upgrading of some raw natural gas. The process for removal of H_2S also captures CO_2. Acid gas disposal is an environmental alternative to flaring and the atmospheric release of SO_2 and CO_2.

Figure 27 shows the active monthly acid gas disposal well count and CO_2 and H_2S volumes from 2003 to 2020. Total acid gas disposal volume averaged around 25-40 e^6m^3/month from 2006 to 2012 before decreasing to the current approximate value of 5 e^6m^3/month. The large drop was a result of the cessation of disposal operations of three acid gas disposal wells, all in the Foothills sour gas Sukunka, Burnt River and Brazion fields.

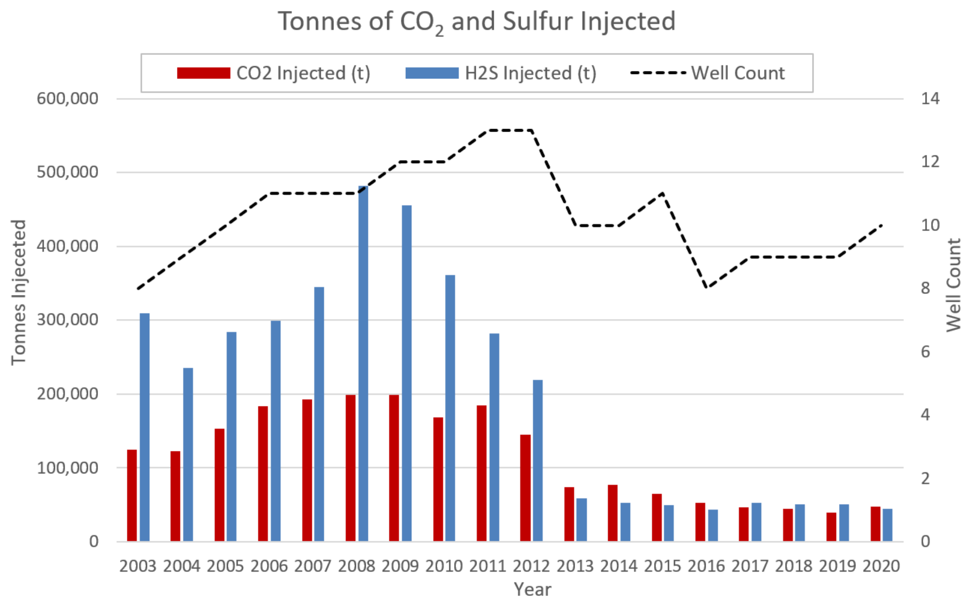
Figure 27: Monthy Acid Gas Disposal Well Count and Volume 2003-2020



The current trend in acid gas disposal is the installation of smaller rate acid gas disposal wells for plants processing Montney gas, which varies from sweet to around 1.5 per cent H_2S content.

Discussions: Deep Disposal

Figure 28: Annual Acid Gas Disposal Well Count and Volume 2003-2020



It should be noted that a total of 2.566 megatonnes of CO_2 have been sequestered as of December 2020 since acid gas disposal began in 1996. Additionally, during this time period, acid gas disposal has diverted the atmospheric release of 8.599 megatonnes of SO_2, if the gas had instead been flared.

In summary, 2020 disposal represented a continuation of existing trends for both water and acid gas disposal. Total water disposal for 2020 was within five per cent of 2018 and 2019 values and total acid gas disposal volume for 2020 was within five per cent of total volume for each year since 2016. The location of new disposal demand continues to be in the Montney fairway. Seven of the eight water disposal wells approved in 2020, and all of the operating acid gas disposal wells were located in the Montney fairway.

Additional information regarding disposal wells can be found on the Commission's website. Chapter 3 of the Water Service Wells Summary Information Document and Acid Gas Disposal Wells Summary Document provide comprehensive guides on the regulation of disposal wells in B.C. Individual disposal well approvals (and other reservoir engineering project approvals) can be found here. Disposal data for each well, monthly volume and injection pressure, can be downloaded in .csv or .txt format from the Commission's data centre, Drilling Data for All Wells in B.C. zip, water_gas_disposal file.

The Commission regulates disposal wells with conditions for monitoring, measurement, testing and reporting. The requirement for annual disposal reservoir pressure testing together with volume reporting allows the calculation and management of remaining disposal capacity "reserves" for existing wells.

Discussions: Hydraulic Fracturing Activity and Trends

Horizontal drilling and hydraulic fracture stimulation, or "fracking", have been the key to unlocking the vast unconventional resources of the province, supporting reserves and production growth. Natural gas and oil trapped in the Montney formation, the target of 98.6 per cent of wells drilled in 2020, requires hydraulic fracture stimulation to achieve economic production rates. The fracking process is described in the 'Hydraulic Fracturing' Factsheet found on our website.

Hydraulic fracturing technology has been utilized in wells in the province since the 1950's. Applied to vertical wells, these were typically small in comparison to modern programs. Beginning around 2004, when coupled with horizontal drilling, much larger areas of the deep target formations could be stimulated, as had been proven in other North American plays. While early Montney development using this method began in the Heritage field south of Dawson Creek, drilling and hydraulic fracturing activity also accelerated in the far north Horn River and later Liard deep shale plays. As outlined in other sections of this report, new activity including hydraulic fracturing in those areas has now ceased. Over 10,000 wells in the province have been hydraulic fracture stimulated.

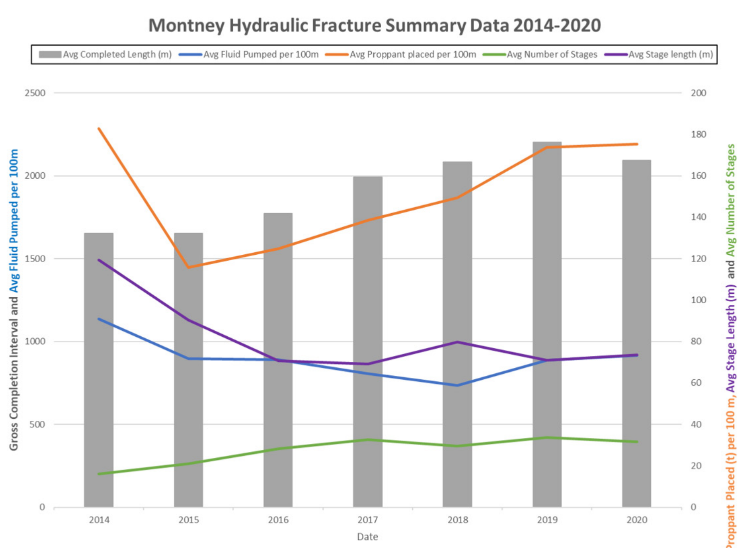
The Commission maintains records of all well completions and hydraulic fracture operations in the province. Data collection in electronic format began in 2014, providing more detailed information in a consistent format for comparison analysis.

The Montney formation covers a vast area, as illustrated in Figure 2. Through that fairway, reservoir quality varies significantly, with factors such as hydrocarbon content, reservoir pore pressure, rock stress and potential for induced seismicity being a few of the variables which influence fracture stimulation design. Wells from a common pad are completed in different Montney sub-units, each with these variations. The following graphs include data for all Montney wells and thus represent an averaging of values and trends, which will vary by sub-region.

Figure 29 shows the horizontal well lengths, or gross completion interval (GCI), has been increasing since 2014. The proppant placed has also increased slightly, both total amount due do longer wells but also intensity as shown in tonnes per 100 metre length. Water injected has varied and the number of frac intervals, or stages, has remained rather constant.

Data on water use for oil and gas activities is outlined in other Commission reports.

Figure 29: Annual Fracture Data 2014-2020

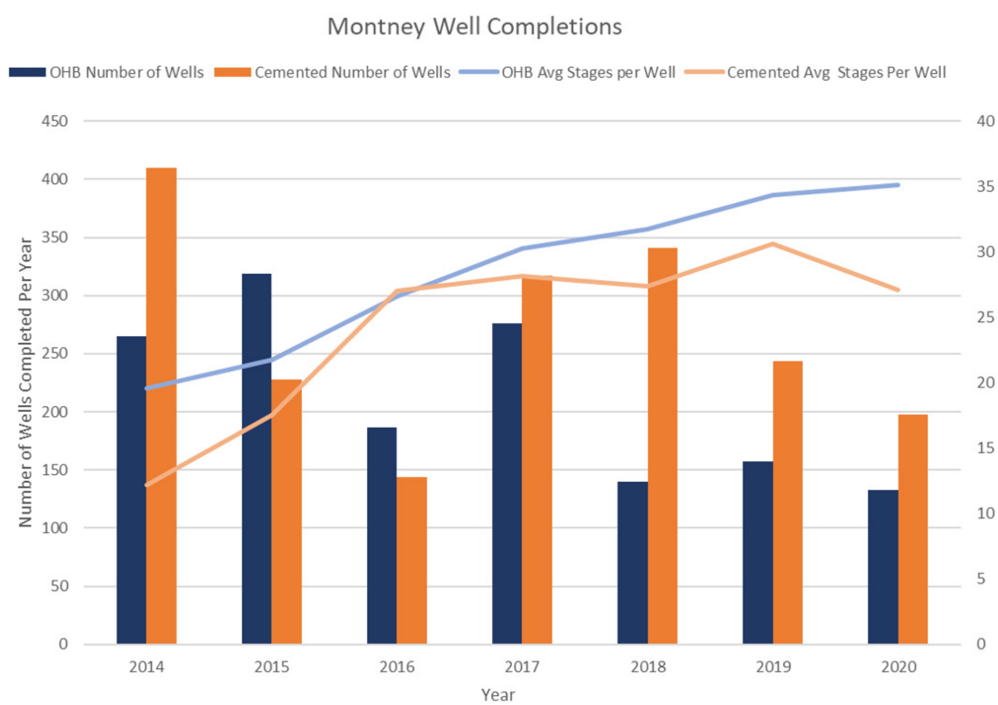


Discussions: Hydraulic Fracturing Activity and Trends

Varying water use and well lengths can be an indication of the activity from different operators and is a sign of continued optimization efforts. Also, water use, stage and well length vary when targeting liquid-rich versus dry natural gas – liquids require maximum fracture surface area in a limited area in order to optimize production. Fractures in dry gas are designed to maximize fracture extent of stimulated rock volume. The distance between horizontal wells is balanced with the ability to effectively open or stimulate the rock between wells while limiting “frac hit” contacts.

Figure 30 below shows the variation in stages completed using open hole frac assemblies (no cement with external packers) and cased type completions (cemented). From this plot, it becomes clear that the beginning of 2017 there was a reversal of preference, with cemented stage completions outnumbering open hole completions, however the closing gap in 2020 shows a closer to equal populations.

Figure 30: Well Completion Types



Additional information on hydraulic fracturing is available on our [website.](website)

The detailed hydraulic fracturing database, the source for graphs in this section, is available on the Commission’s website [Data Centre.](Data Centre)

Discussions: Waterflood Project Review

In 2020, the Commission completed a review of all pressure maintenance waterflood approvals in the province. All active waterfloods received approvals amended to conform to current requirements, including conditions for reservoir pressure testing, maximum injection pressures on injections wells, a maximum reservoir pressure equal to discovery pressure, and a requirement to cease injection upon cessation of production.

For projects where injection operations have ceased, the Commission has cancelled the approvals and adjusted recovery factors as appropriate. For those where production from the project area has ceased, the recovery factors have been adjusted to remove any remaining reserves. This oil volume reserves write-down totaled 376 e^3m^3. The cancelled waterflood projects are listed below in table 4.

Table 4: Cancelled Waterflood Projects

Waterflood Area – Pool and Project #	2020 RF	2020 RR (e^3m^3)	Initial Resrvs (2019) (m^3)	Initial Resrvs (2020) (m^3)	Delta Resrvs 2019-20 (m^3)
Beatton River - Halfway 'A' Pool Project 2	47%	271	1,616,512	1,616,512	0
Beatton River - Halfway 'G' Pool Project 5	30%	150	431,534	425,924	-5,610
Beatton River West - Bluesky 'A' Pool Project 2	37%	233	1,123,329	1,098,497	-24,832
Bubbles North - Coplin 'A' Pool Project 2	29%	27	43,141	41,703	-1,438
Bulrush - Halfway 'C' Pool Project 2	5%	181	4,335	4,335	0
Crush - Halfway 'A' Pool Project 2	35%	110	510,139	503,327	-6,812
Crush - Halfway 'B' Pool Project 2	34%	0	49,941	49,941	0
Currant - Halfway 'A' Pool Project 2	53%	0	419,350	418,950	-400
Currant - Halfway 'D' Pool Project 2	7%	0	8,046	8,038	-8
Halfway - Debolt 'A' Pool Project 3	10%	299	95,000	95,000	0
Inga - Inga 'A' Pool Project 6	31%	347	2,335,354	2,335,354	0
Inga - Inga 'A' Pool Project 7	45%	131	637,273	627,609	-9,664
Inga - Inga 'A' Pool Project 8	32%	170	583,598	557,851	-25,747
Lapp - Halfway 'C' Pool Project 2	44%	139	451,980	451,876	-104
Lapp - Halfway 'D' Pool Project 2	42%	24	166,010	165,852	-158
Milligan Creek - Halfway 'A' Pool Project 2	53%	828	6,423,194	6,377,141	-46,053
Milligan Creek - Halfway 'A' Pool Project 3	48%	10,566	1,079,802	1,036,610	-43,192
Muskrat - Lower Halfway 'A' Pool Project 3	23%	114	109,158	107,067	-2,090
Oak - Cecil 'B' Pool Project 2	24%	0	100,182	99,752	-430
Owl - Cecil 'A' Pool Project 3	45%	38	322,631	320,337	-2,294
Peejay - Halfway Project 2	38%	512	2,228,180	2,227,600	-580
Rigel - Halfway 'C' Pool Project 3	39%	56	293,395	292,041	-1,354
Rigel - Halfway 'C' Pool Project 2	27%	0	196,698	196,640	-57
Rigel - Dunlevy 'A' Pool Project 2	10%	19	19,024	19,024	0
Rigel - Halfway 'Z' Pool Project 2	7%	0	6,859	6,853	-6
Squirrel - North Pine 'C' Pool Project 3	30%	69	412,944	408,952	-3,992
Stoddart - North Pine 'G' Pool Project 4	35%	32	77,032	75,449	-1,583
Stoddart West - Bear Flat 'D' Pool Project 3	35%	43	158,180	156,011	-2,169
Sunset Prairie - Cecil 'A' Pool Project 2	37%	190	352,920	329,098	-23,822
Sunset Prairie - Cecil 'C' Pool Project 2	29%	392	147,070	120,597	-26,473
Sunset Prairie - Cecil 'D' Pool Project 2	1%	52	152,120	5,286	-146,834
Weasel - Halfway '' Pool Project 3	58%	156	1,005,838	1,005,838	0
Wildmint - Halfway 'A' Pool Project 2	54%	286	1,542,904	1,542,618	-287

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)
LPG consists primarily of propane and butane with minor components ranging from ethane to normal hexane. It is produced either as a by-product of natural gas processing or during refining and processing operations. For the purposes of this report, reported LPG include all ethane, propane, and butane.

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 (NGL)
Components of natural gas in a liquid state at surface and include propane, butane, pentane and heavier hydrocarbons.

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.

Definitions

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

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, 2020

	Oil (10^3m^3)	Raw Gas (10^6m^3)
Initial Reserves, Current Estimate	139,666	3,202,111
Discovery 2020	31	0
Revisions 2020	-947	154,061
Production 2020	790	60,282
Cumulative Production Dec. 31, 2020	124,728	1,289,624
Remaining Reserves Estimate Dec. 31, 2020	14,938	1,912,487

Appendix A

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	843,616	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
2020	3,202,111	0	154,061		60,282	1,289,624	1,912,487

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 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
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
2020	139,666	31	-947		790	124,728	14,938

Appendix A

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	G	05	1,438.4	29.6	425.9	425.8	0.1
BEATTON RIVER	HALFWAY	A	02	3,429.9	47.1	1,616.5	1,616.2	0.3
BEATTON RIVER WEST	BLUESKY	A	02	2,956.1	37.2	1,098.5	1,098.3	0.2
BEAVERTAIL	HALFWAY	B	06	499.0	17.6	87.8	87.2	0.7
BEAVERTAIL	HALFWAY	H	05	874.1	20.0	174.8	172.3	2.5
BIRCH	BALDONNEL	C	03	2,058.1	49.0	1,008.5	941.3	67.2
BLUEBERRY	DEBOLT	E	03	1,211.5	30.0	363.4	354.2	9.2
BOUNDARY LAKE	BOUNDARY LAKE	A	04	5,769.2	60.0	3,461.5	3,171.8	289.7
BOUNDARY LAKE	BOUNDARY LAKE	A	02	43,666.1	48.0	20,959.7	19,973.1	986.6
BOUNDARY LAKE	BOUNDARY LAKE	A	05	1,587.4	65.0	1,031.8	989.3	42.5
BOUNDARY LAKE	BOUNDARY LAKE	A	03	30,218.0	44.0	13,295.9	12,888.8	407.1
BOUNDARY LAKE NORTH	HALFWAY	I	04	1,085.8	40.0	434.3	363.2	71.1
BOUNDARY LAKE NORTH	HALFWAY	D	03	561.7	20.0	112.3	105.9	6.5
BUBBLES NORTH	COPLIN	A	02	143.8	29.0	41.7	41.7	0.0
BULRUSH	HALFWAY	C	02	96.3	4.5	4.3	4.2	0.2
CRUSH	HALFWAY	A	02	1,449.3	34.7	503.3	503.2	0.1
CRUSH	HALFWAY	B	02	148.6	33.6	49.9	49.9	0.0
CURRANT	HALFWAY	A	2	793.0	5,290.0	419.0	419.0	0.0
CURRANT	HALFWAY	D	2	122.0	660.0	8.0	8.0	0.0
DESAN	PEKISKO		03	5,388.1	20.0	1,077.6	903.8	173.8
EAGLE	BELLOY-KISKATINAW		02	6,928.9	40.0	2,771.5	2,589.5	182.0
EAGLE WEST	BELLOY	A	03	20,337.5	31.0	6,304.6	6,261.9	42.7
ELM	GETHING	B	04	1,772.6	7.3	129.4	129.2	0.2
HALFWAY	DEBOLT	A	03	950.0	10.0	95.0	94.7	0.3
HAY RIVER	BLUESKY	A	05	36,992.5	20.0	7,398.5	5,955.2	1,443.3
INGA	INGA	A	04	8,356.0	39.9	3,334.0	3,329.8	4.2
INGA	INGA	A	06	7,521.3	31.0	2,335.4	2,335.0	0.3
INGA	INGA	A	08	1,716.5	32.5	557.9	557.7	0.2
INGA	INGA	A	07	1,400.6	44.8	627.6	627.5	0.1
LAPP	HALFWAY	D	02	395.3	42.0	165.9	165.8	0.0
LAPP	HALFWAY	C	02	1,036.9	43.6	451.9	451.7	0.1
MICA	MICA	A	04	1,128.7	40.0	451.5	334.9	116.5
MILLIGAN CREEK	HALFWAY	B	04	509.7	30.0	152.9	113.6	39.3
MILLIGAN CREEK	HALFWAY	A	02	12,119.2	52.6	6,377.1	6,376.3	0.8
MUSKRAT	LOWER HALFWAY	A	03	2,159.6	48.0	1,036.6	1,026.0	10.6
MUSKRAT	BOUNDARY LAKE	A	03	1002.5	40.0	401.0	383.2	17.8
OAK	CECIL	A	03	464.5	23.0	107.1	107.0	0.1
OAK	CECIL	C	03	907.7	55.0	499.3	445.0	54.2
OAK	CECIL	E	03	1,264.5	48.0	607.0	603.4	3.6
OAK	CECIL	B	2	424.0	2,350.0	100.0	100.0	0.0

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 (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	7,17.0	44.7	320.3	320.3	0.0
PEEJAY	HALFWAY		04	10,137.3	44.3	4490.8	4,471.4	19.4
PEEJAY	HALFWAY		03	8,937.6	43.0	3843.2	3,813.7	29.5
PEEJAY	HALFWAY		02	5,802.6	38.4	2227.6	2,227.1	0.5
PEEJAY WEST	HALFWAY	A	03	1,560.6	40.0	624.3	530.7	93.5
PEEJAY WEST	HALFWAY	C	02	510.9	40.0	204.4	163.9	40.5
RED CREEK	DOIG	C	03	609.3	30.0	182.8	151.3	31.4
RIGEL	CECIL	H	03	1,820.9	50.0	910.4	888.8	21.6
RIGEL	DUNLEVY	A	02	195.5	9.7	19.0	19.0	0.0
RIGEL	CECIL	I	02	1,962.0	40.0	784.8	776.9	7.9
RIGEL	CECIL	G	02	952.7	45.0	428.7	419.0	9.7
RIGEL	CECIL	B	02	1,502.6	40.0	601.1	596.8	4.3
RIGEL	HALFWAY	C	03	752.3	38.8	292.0	292.0	0.1
RIGEL	HALFWAY	C	2	739.0	2,620.0	196.6	196.6	0.0
RIGEL	HALFWAY	Z	2	104.0	657.0	6.9	6.9	0.0
SQUIRREL	NORTH PINE	C	03	1,376.5	29.7	409.0	408.9	0.1
STODDART	NORTH PINE	G	04	214.0	35.3	75.4	75.4	0.0
STODDART WEST	BELLOY	C	05	5,784.4	25.0	1446.1	1,381.2	64.9
STODDART WEST	BEAR FLAT	D	03	451.9	34.5	156.0	156.0	0.0
SUNSET PRAIRIE	CECIL	A	02	882.3	37.3	329.1	328.9	0.2
SUNSET PRAIRIE	CECIL	C	02	420.2	28.7	120.6	120.2	0.4
SUNSET PRAIRIE	CECIL	D	02	380.3	1.4	5.3	5.2	0.1
TWO RIVERS	SIPHON	A	03	1,475.6	19.0	280.4	262.5	17.9
WEASEL	HALFWAY		02	3,720.0	65.0	2418.0	2,383.3	34.7
WEASEL	HALFWAY		03	1,729.4	58.2	1005.8	1,005.7	0.2
WILDMINT	HALFWAY	A	02	2,867.9	53.8	1542.6	1,542.3	0.3
WOODRUSH	HALFWAY	E	02	880.6	16.0	140.9	127.3	13.6
Total						**103,381.5**	**99,013.6**	**4,367.8**
% of Total British Columbia Oil Reserves						**74.0**		**29.2**

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)
Bulrush	Halfway	A	02	854.2	40.0%	341.7	335.7	5.9
Cecil Lake	Cecil	D	03	1,091.3	38.0%	414.7	368.0	46.7
Stoddart West	Belloy	C	03	1,525.5	25.5%	389.0	384.9	4.1
Rigel	Halfway	H	03	702.9	12.9%	90.7	90.7	0.0
Brassey	Halfway	A	02	94.5	14.6%	13.8	13.8	0.0
Brassey	Artex	G	02	353.4	42.3%	149.3	149.3	0.0
Total				4621.7		1,399.2	1,342.4	56.8
% of Total British Columbia Reserves						1.0%		0.4%

Appendix B

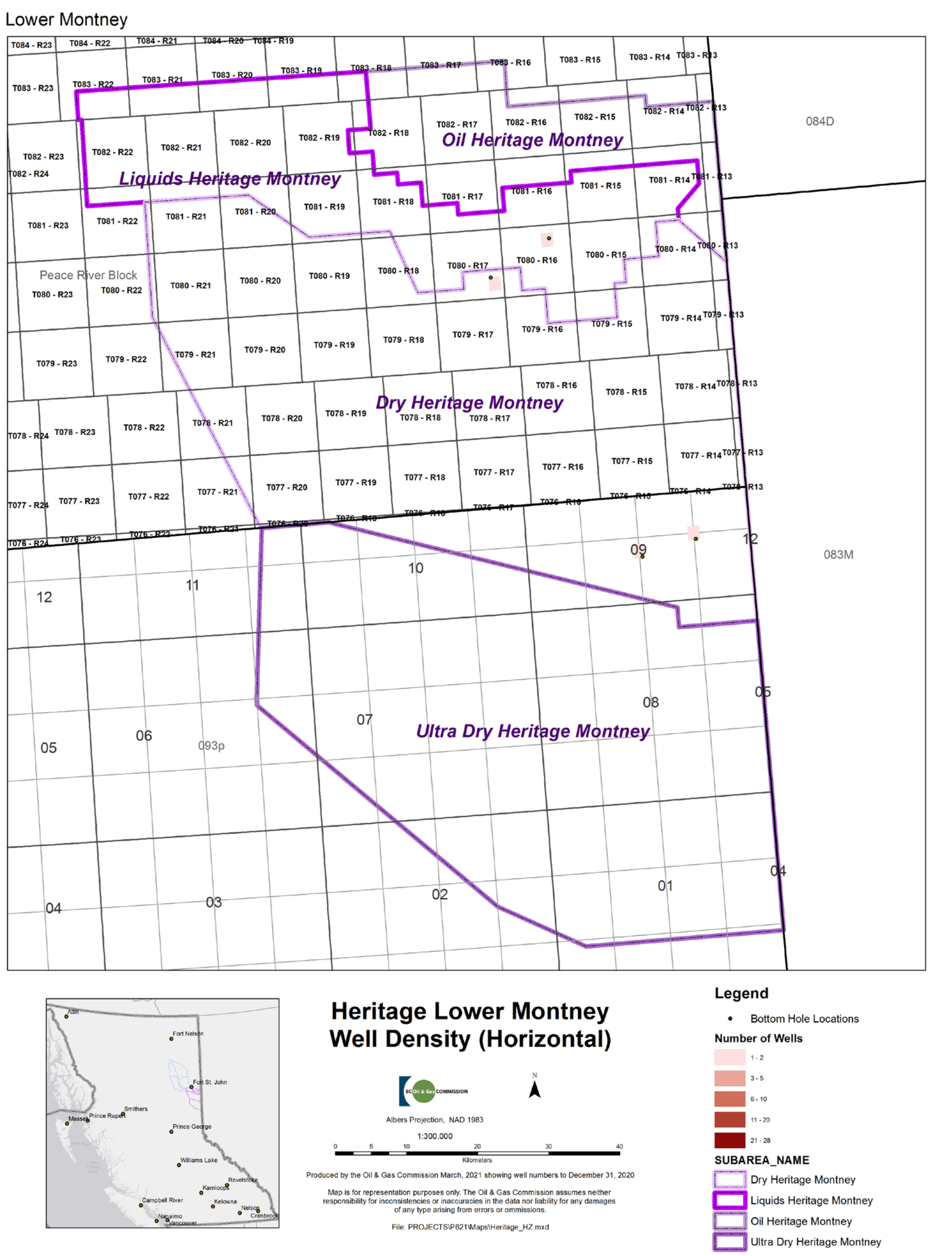
Current Montney Play Development and EUR Distribution

Well density is an indicator of the current phase of Montney development and the number of wells per gas spacing unit is used to determine the number of PUD locations for the estimation of recoverable reserves. For regulatory purposes, the Commission has split the Montney Regional field into the Heritage Montney A, Northern Montney Montney A and Northern Montney Doig Phosphate Montney A pools.

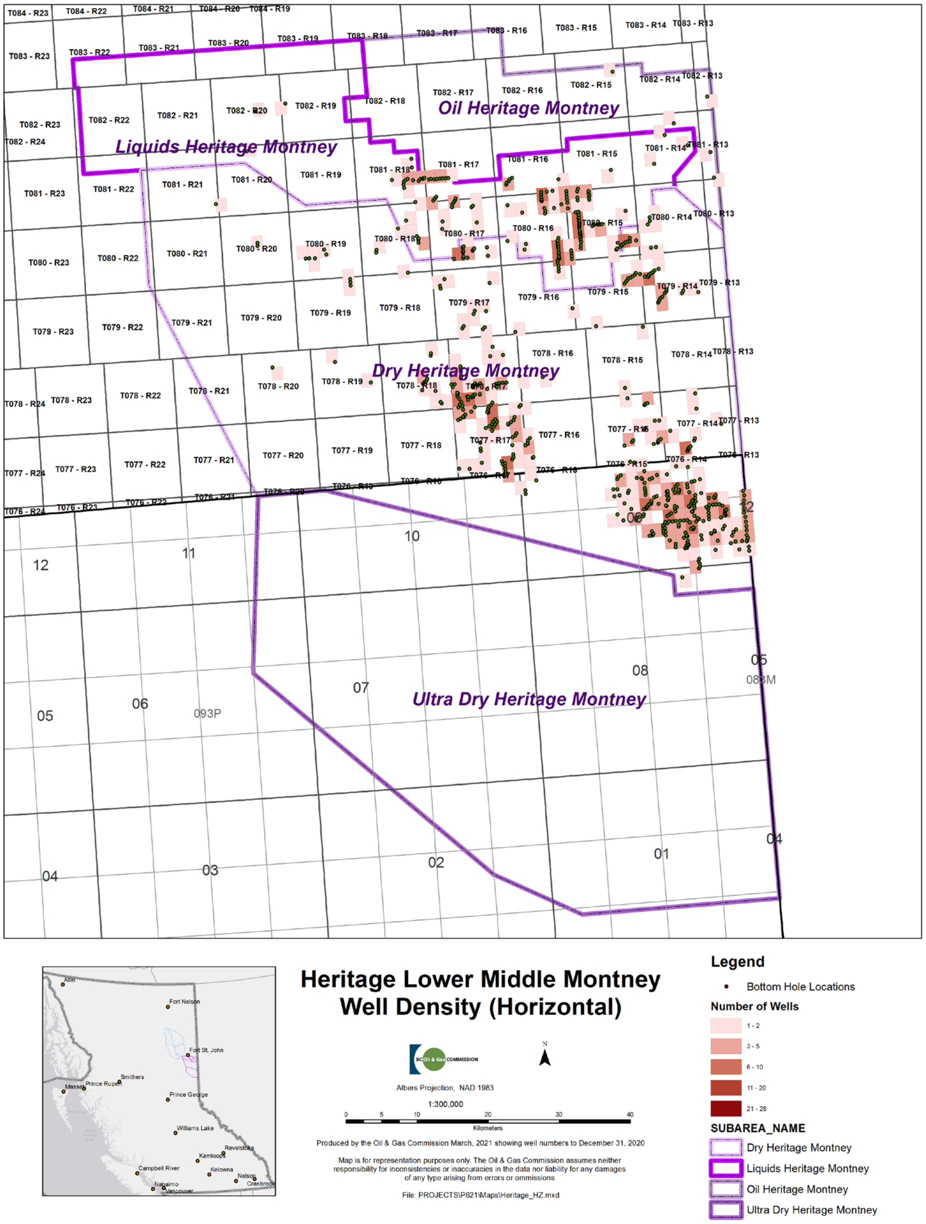
The following well density maps are for the three Montney areas. As illustrated, the variable density and coverage of wells in the areas reflects the current ability to establish proven reserves.

Note the majority of the wells in the Doig Phosphate pool have been merged into the Montney A pool resulting in changes to Montney A well density.

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



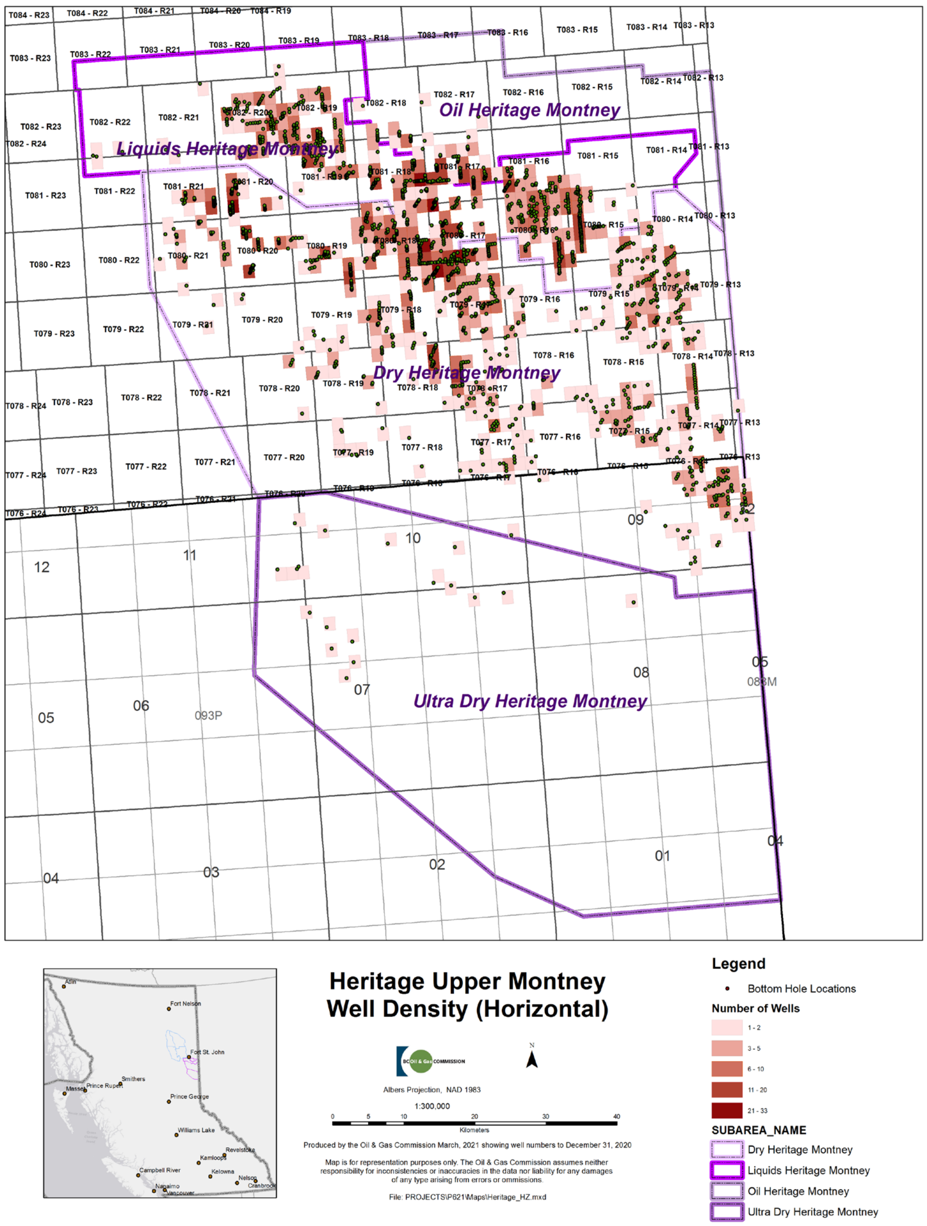
Lower Middle Montney



Appendix B

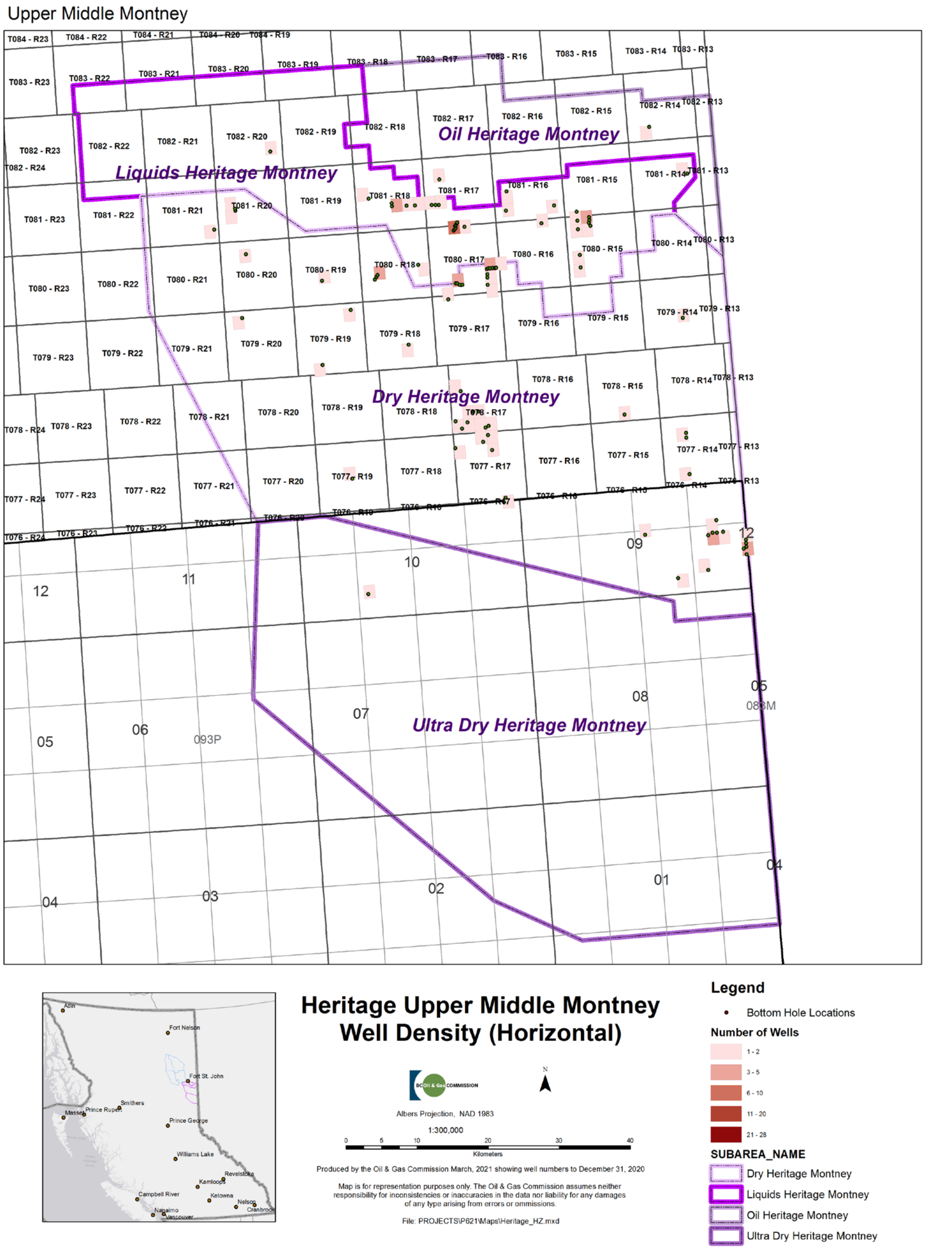
Current Montney Play Development and EUR Distribution

Upper Montney



Appendix B

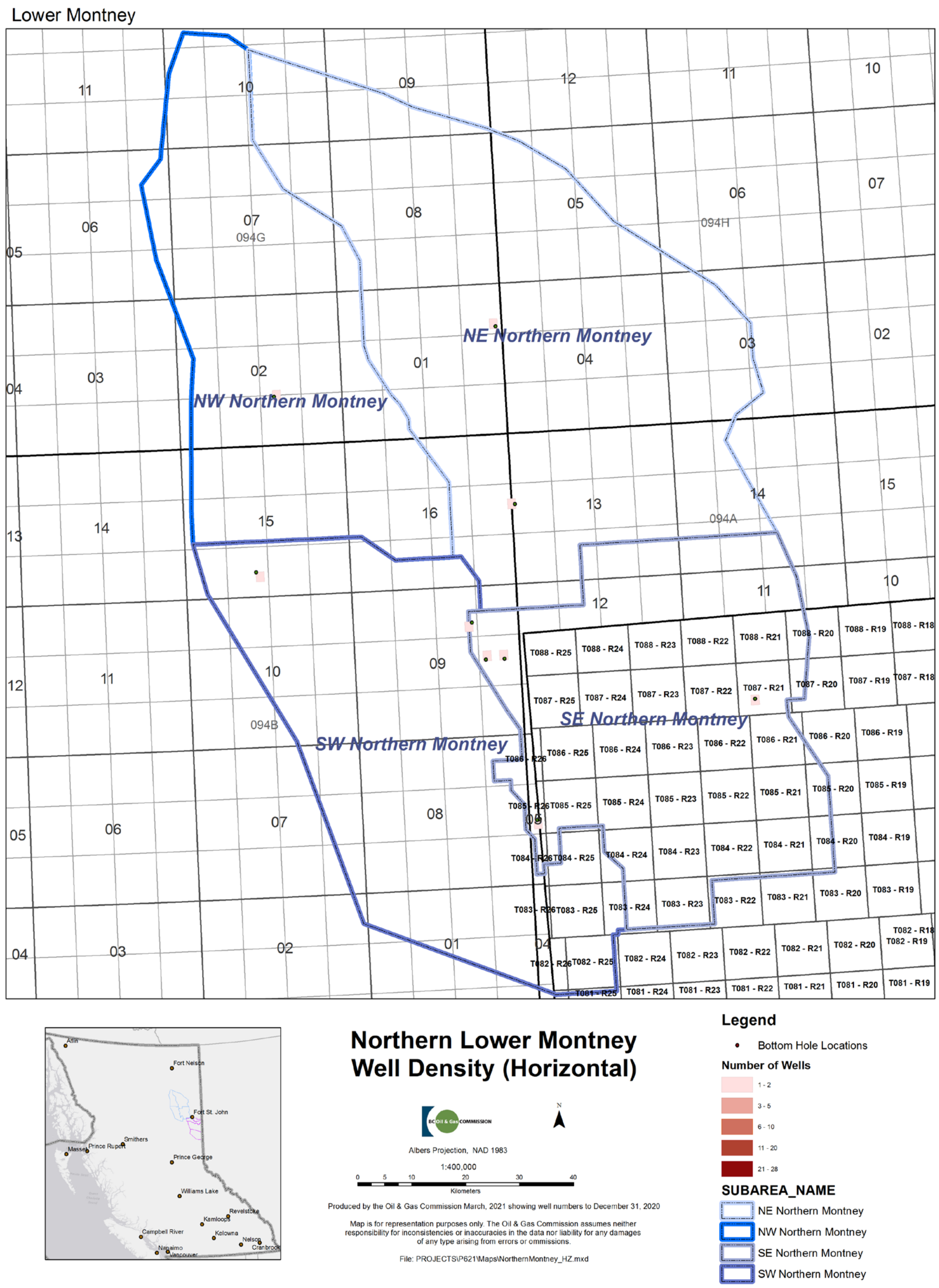
Current Montney Play Development and EUR Distribution

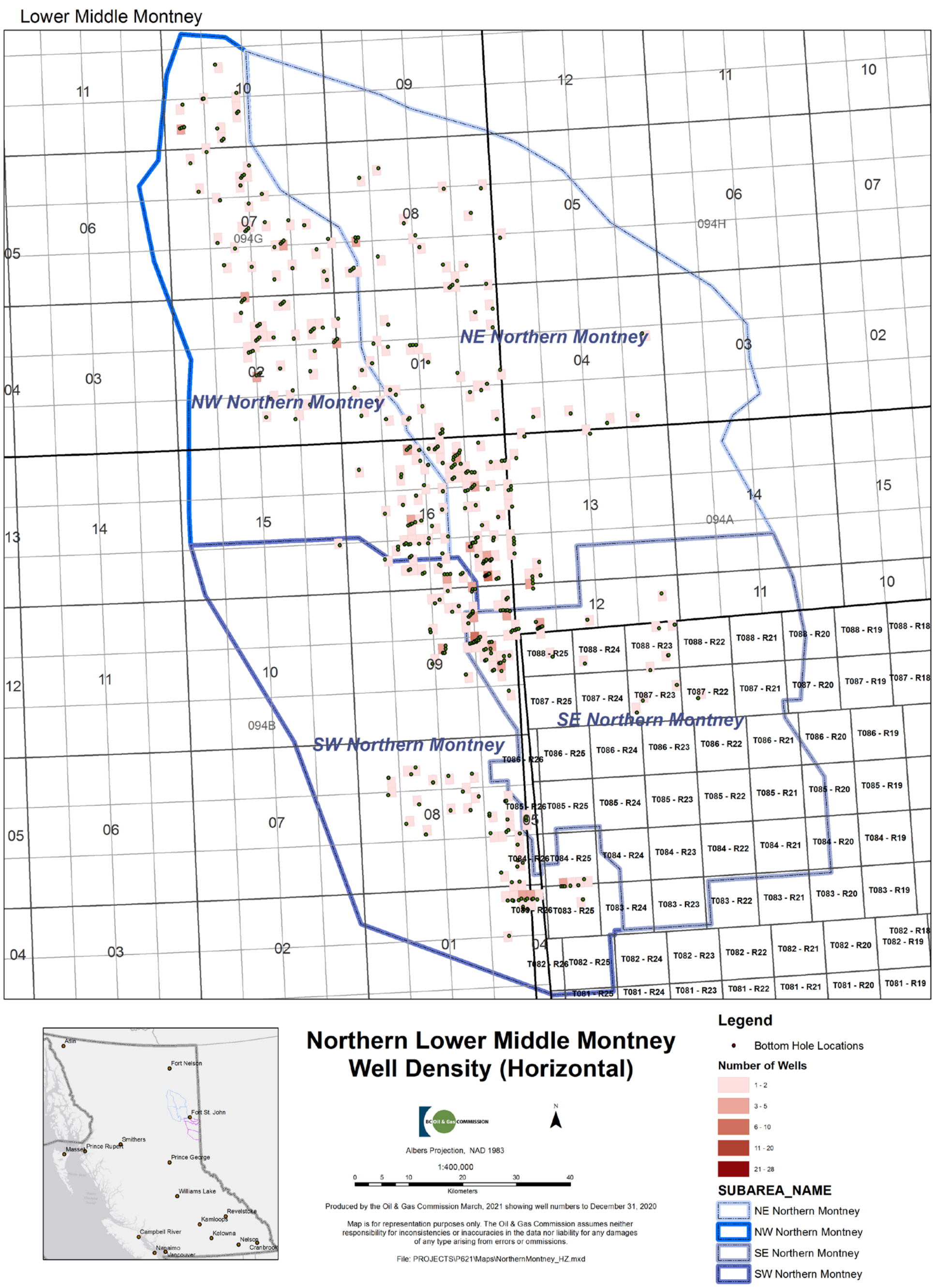


Appendix B

Current Montney Play Development and EUR Distribution

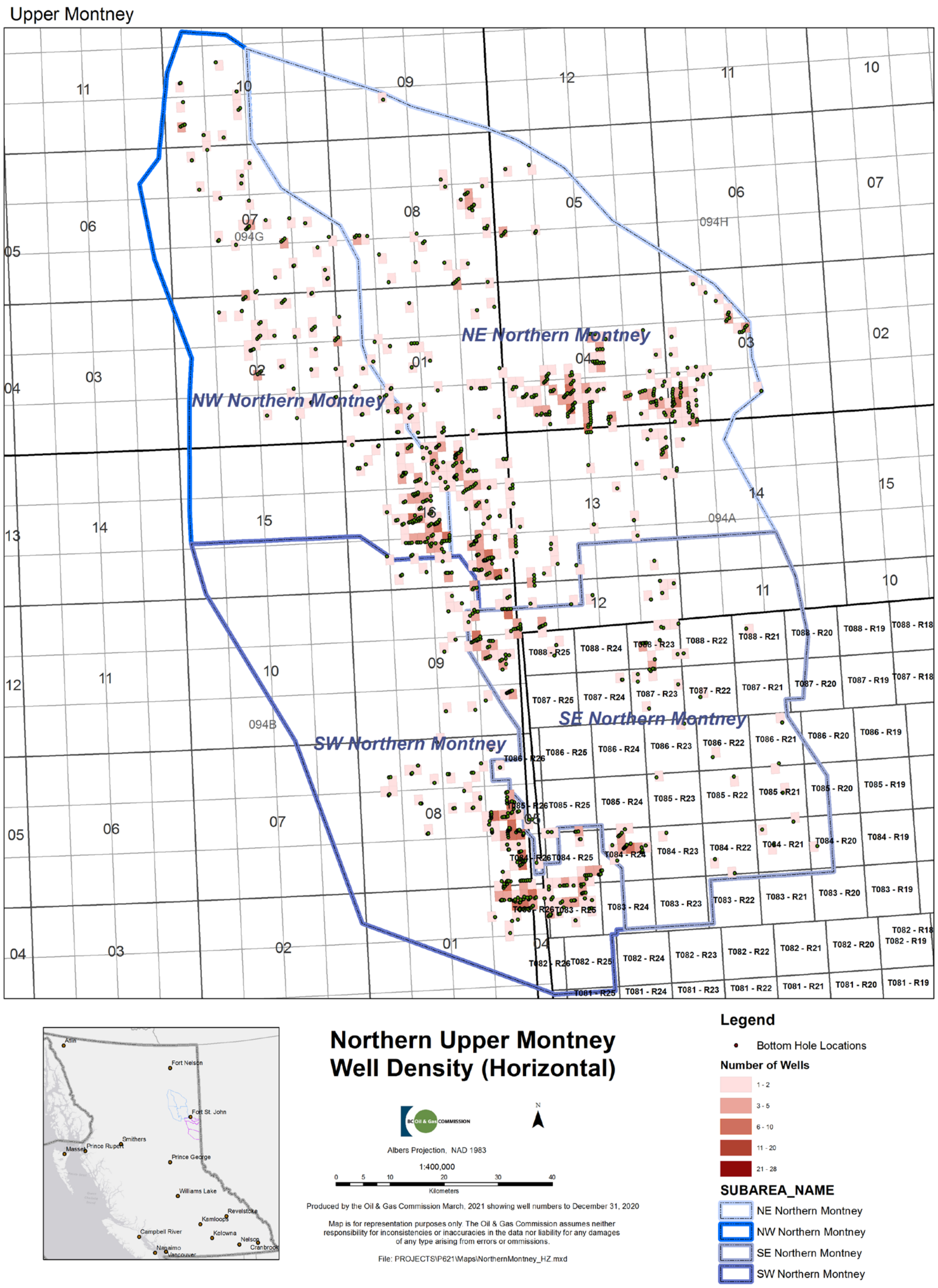
Map B-2: Northern Montney - Montney "A" And Doig Phosphate Well Density Maps




Lower Middle Montney
NE Northern Montney
NW Northern Montney
SE Northern Montney
SW Northern Montney
094G
094H
094A
094B
Northern Lower Middle Montney
Well Density (Horizontal)
Albers Projection, NAD 1983
1:400,000
Kilometers
Produced by the Oil & Gas Commission March, 2021 showing well numbers to December 31, 2020
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
Fort Nelson
Fort St. John
Prince George
Prince Rupert
Smithers
Williams Lake
Kamloops
Kelowna
Revelstoke
Campbell River
Vancouver

Appendix B

Current Montney Play Development and EUR Distribution



Current Montney Play Development and EUR Distribution

Upper Middle Montney

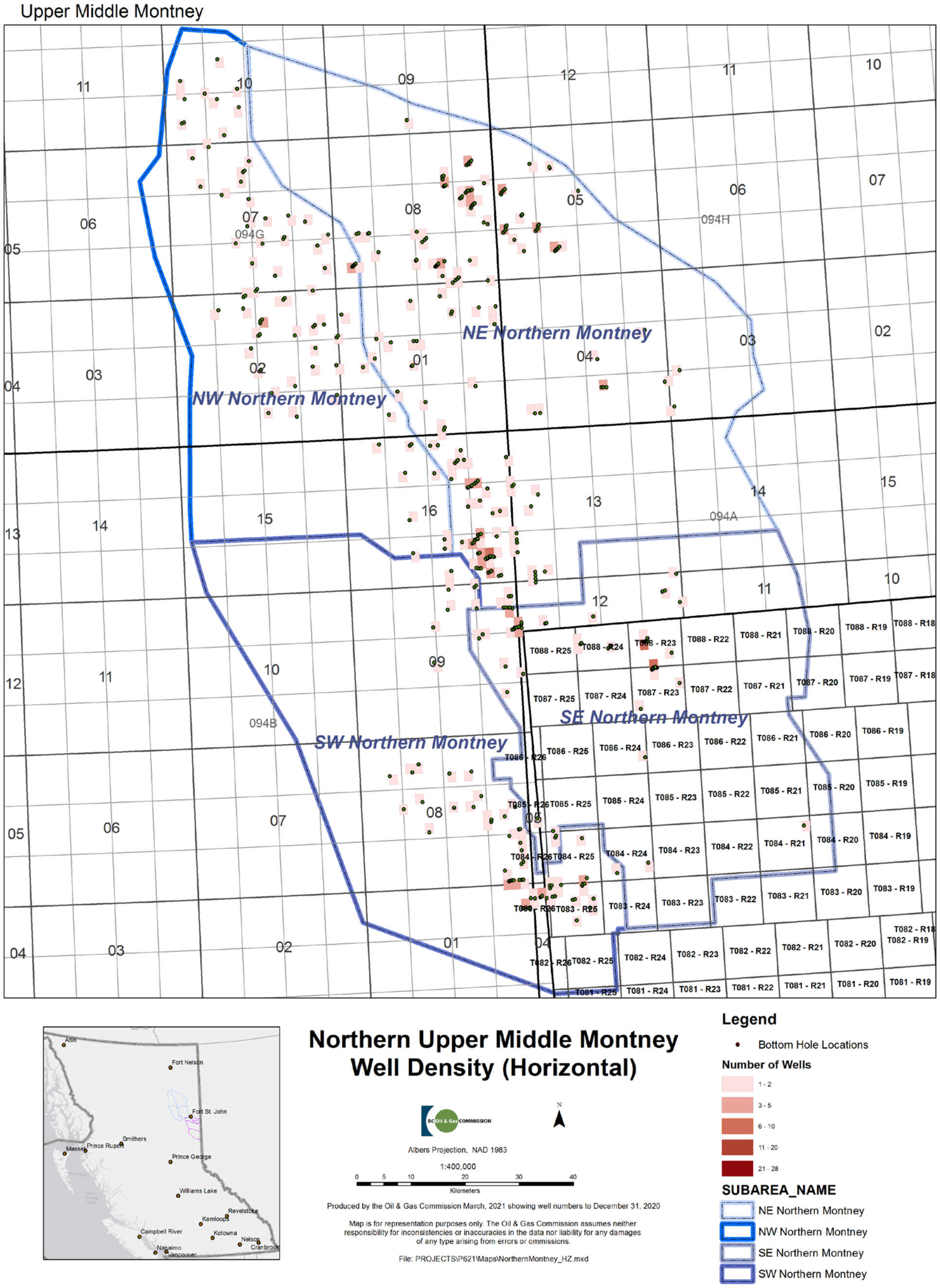


Figure B-1 below, shows overall Montney well population EUR values; P90 of 34 e^6m^3, P10 of 262 e^6m^3, mean of 139 e^6m^3, and median of 115 e^6m^3.

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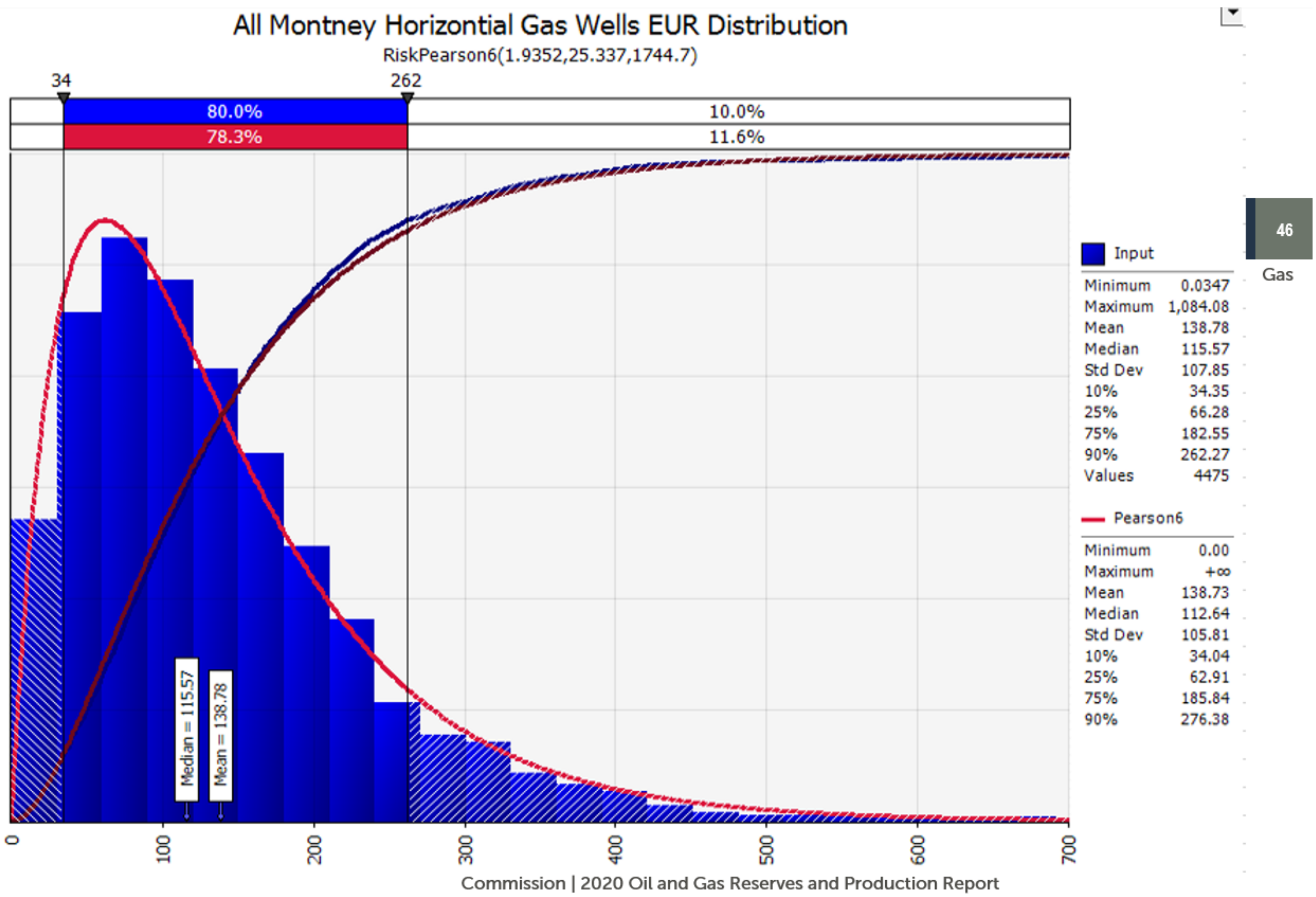
Figure B-1



Professional Authentication

Authenticating Engineer	Responsible Registrant
Association of Professional Engineers and Geoscientists of the Province of British Columbia R. G. STEFIK PROFESSIONAL LICENSEE ENGINEERING Licence 155171 2021-09-08	PERMIT NUMBER: 1000398 BC OIL AND GAS COMMISSION Date: 2021-09-10
Date: 2021-09-02	Date: 2021-09-02
Company: BC Oil and Gas Commission	Company: BC Oil and Gas Commission
Title: Supervisor, Reservoir Engineering	Title: Vice President, Reservoir, Drilling Engineering, and Technical Services
Name: Ron Stefik, P.L.Eng.	Name: Richard Slocomb, M.A.Sc., P.Eng.

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