British Columbia's 2021 Oil and Gas Reserves and Production Report

September 2022

BC Oil and Gas Commission

BC Oil & Gas COMMISSION

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Vision, Mission and Values

Vision

A resilient energy future where B.C.'s energy resource activities are safe, environmentally leading and socially responsible.

Mission

We regulate the life cycle of energy resource activities in B.C., from site planning to restoration, ensuring activities are undertaken in a manner that:

- Protects public safety
- Safeguards the environment
- Supports meaningful reconciliation
- Advances the public interest and contributes to B.C.'s economy

Values

Transparency is our commitment to be open and provide clear information on decisions, operations and actions.

Innovation is our commitment to learn, adapt, act and grow.

Integrity is our commitment to the principles of fairness, trust and accountability.

Respect is our commitment to listen, accept and value diverse perspectives.

Responsiveness is our commitment to listening and timely and meaningful action.

Role of the BC Oil and Gas Commission

As a provincial Crown agency, we protect public safety and safeguard the environment through the sound regulation of oil, gas and aspects of geothermal activities in B.C. while balancing a broad range of environmental, economic and social considerations.

We regulate resource activity through the Oil and Gas Activities Act (OGAA), the Petroleum and Natural Gas (PNG) Act, and other associated laws related to heritage conservation, roads, land and water use, forestry, and other natural resources.

Through combined authority and working with partner agencies, we regulate activities on Crown land, private land, and the Agricultural Land Reserve. When oil, gas, or geothermal permits are granted, we are responsible for ensuring industry compliance with provincial legislation from initial exploration to final reclamation.

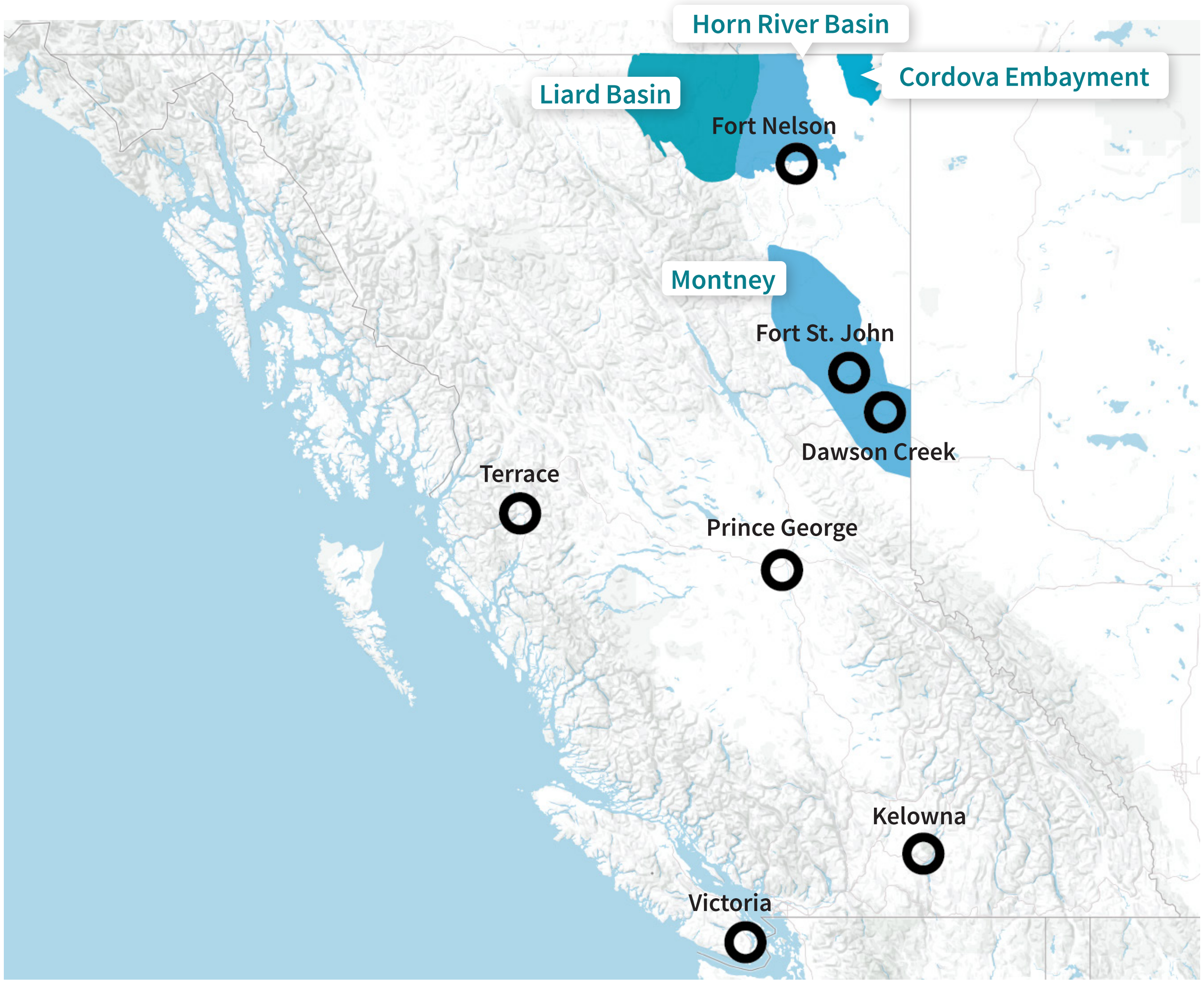
As more resources have been discovered, techniques for accessing them have advanced, environmental awareness has increased, and stakeholders have let us know they are interested in providing more input.

During our review and decision-making processes, we work closely with land owners, rights holders, and Indigenous communities.

The Commission currently has over 280 employees operating out of seven locations: Fort Nelson, Fort St. John, Dawson Creek, Terrace, Prince George, Kelowna and Victoria. The largest number of employees are in the Fort St. John office.

With more than 20 years' dedicated service, we're committed to ensuring safe and responsible energy resource management for British Columbia.

Commission Office Locations Throughout B.C.



Territorial Acknowledgement

We acknowledge and respect the many Indigenous Territories and Treaty areas, each with unique cultures, languages, legal traditions and relationships to the land and water, which the BC Oil and Gas Commission's work spans. We also respectfully acknowledge the Métis and Inuit people living across B.C.

About 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, 2021. 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.

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 Analysis

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.

Dawson Creek Resource Centre

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:

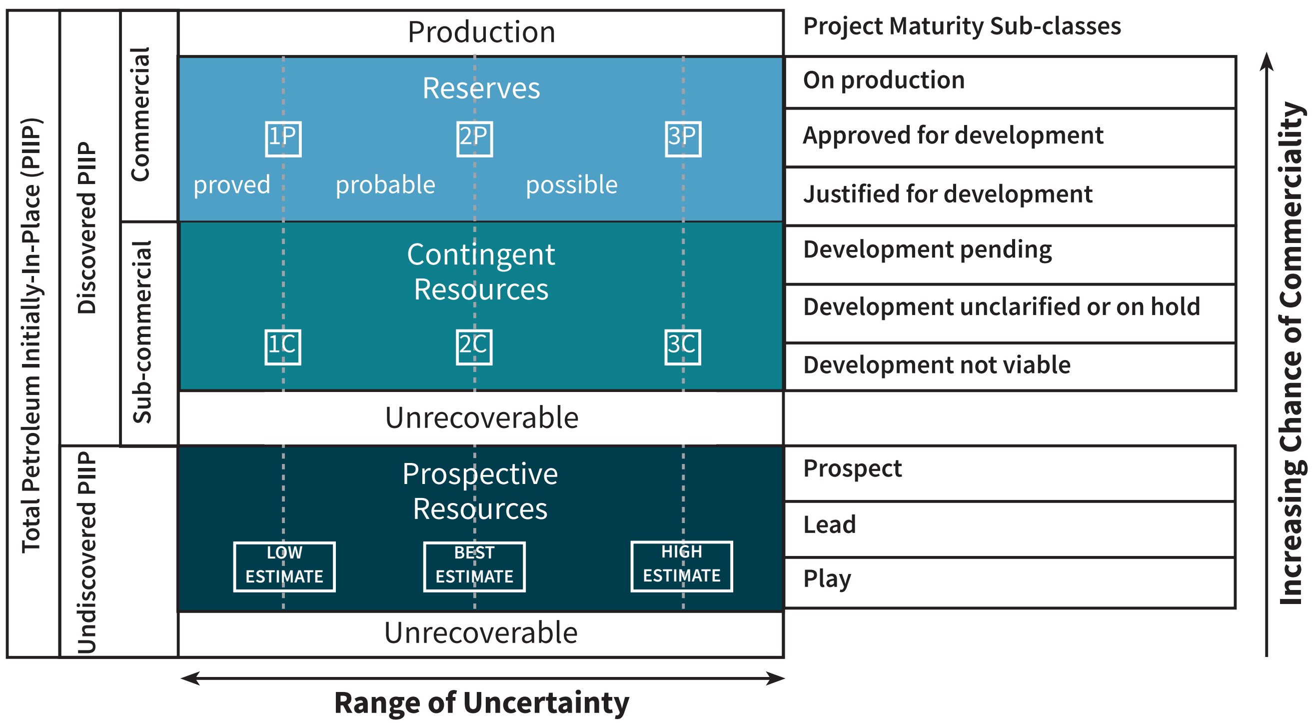
- Penetrated by a wellbore.
- Confirmation the well will produce (either a production test, or on production).
- Meets regulatory requirements (production or development not prohibited by government policy or legislation).
- Marketable to sell (viable transportation to sales point available either through 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.

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).



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 (1,965Tcf); however, currently recoverable initial raw gas reserves of 2,307.7 e^9m^3 (81.5 Tcf) are approximately four per cent of the resource estimate. This reserves percentage is expected to increase with continued development of the play.

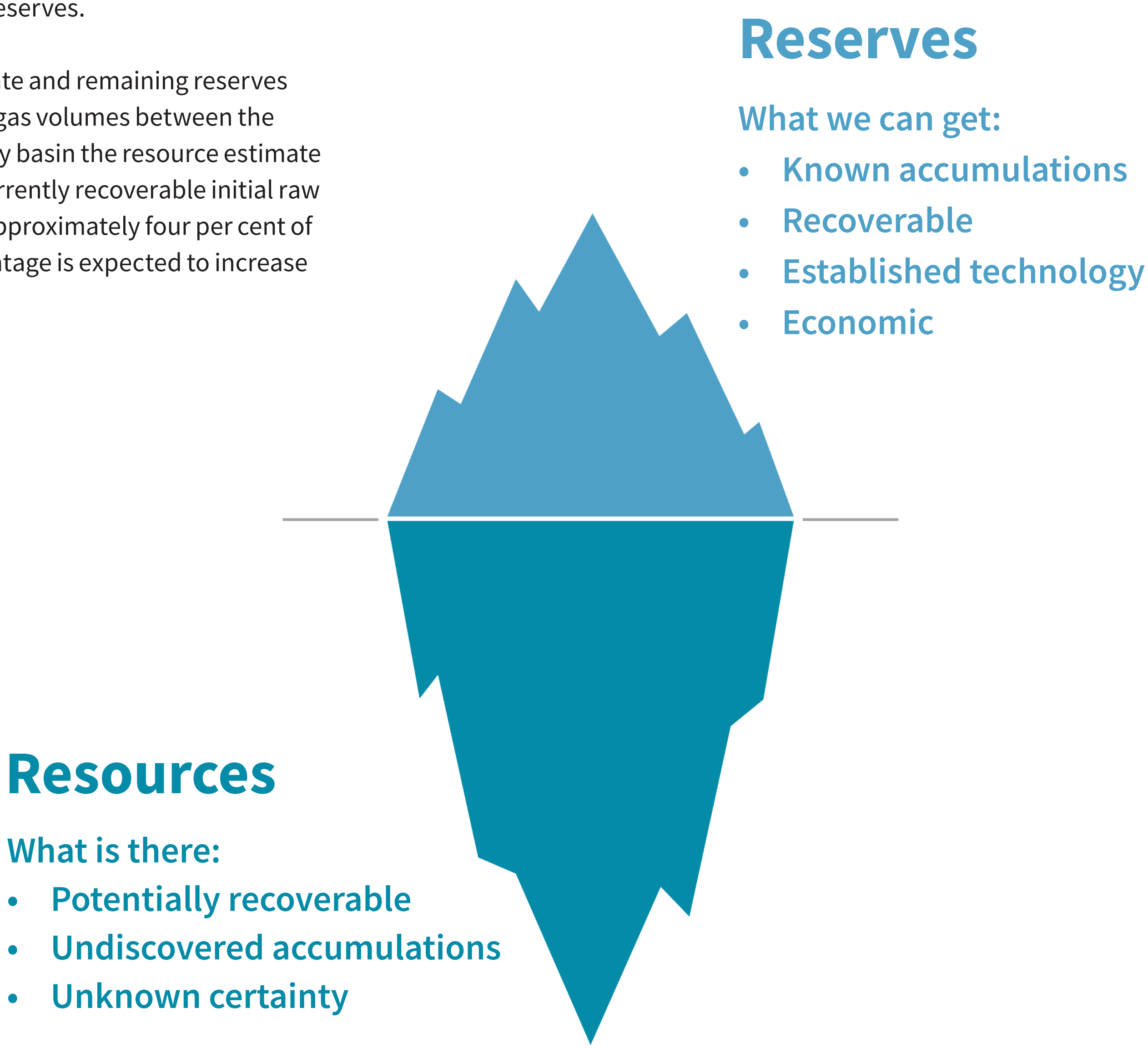


Table 1: Unconventional Gas Resource, Reserves and Cumulative Production

	RESOURCE				2021 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]	55,609.50	1,965.00	7,669.30	271.00	2,307.73	81.55	1,903.46	67.26	404.28	14.29	4.15%
Liard Basin[2]	23,998.40	848.00	4,726.10	167.00	2.93	0.10	0.80	0.03	2.13	0.08	0.01%
Horn River Basin[3]	12,678.40	448.00	2,207.40	78.00	78.99	2.79	41.80	1.48	37.19	1.31	0.62%
Cordova[4]	1,901.76	67.20	249.04	8.80	3.06	0.11	1.04	0.04	2.02	0.07	0.16%
Deep Basin Cadomin, Nikanassin[5]	254.70	9.00	206.59	7.30	28.62	1.01	7.80	0.28	20.82	0.74	11.24%
Total	94,443.00	3,337.00	15,058.00	532.00	2,421.33	85.56	1,954.90	69.08	466.44	16.48	2.56%

[1] NEB/OGC/AER/MNGD Energy Briefing Note - The Ultimate Potential for Unconventional Petroleum from the Montney Formation of B.C. 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 B.C.'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, 2021

Executive Summary

In December 2021, there were 8,709 producing wells—7,969 gas wells and 740 oil wells. The remaining 414 active wells are a mixture of observation (77), water source (10), water injection (249), deep disposal (69), and storage (9).

In 2021, there were 307 new well applications approved and 468 wells drilled—primarily in the Montney basin, the continued focus of activity. The number drilled exceeded approvals in 2021, due to a pause in the Commission issuing new approvals and industry utilizing previously approved well permits. The number of wells drilled increased by 26 per cent versus 371 wells drilled in 2020. The increase in drilling led to a 31 per cent increase in hydraulic fracturing activity from 2020, with 467 wells hydraulically fracture stimulated.

Demand for hydrocarbons saw a significant reduction in 2020 and early 2021 due to the COVID-19 pandemic, though demand recovered sharply in 2021, leading to oil and gas prices which exceeded pre-pandemic levels. Strong present and forecasted natural gas prices drove activity in 2021, with exports supporting U.S. domestic gas needs and U.S. LNG exports.

As shown in Table 2, estimated remaining gas reserves increased 9.4 per cent due to added Montney development wells. Remaining oil reserves decreased 11.4 per cent due to oil pool depletion, cessation of waterflood operations in some pools, and lack of new oil discoveries. 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 decreased 28.8 per cent, driven by diminished reserves in the Ojay, Bullmoose, and Brazion fields.

As shown in figure 2 and figure 3, of the 468 wells rig released in 2021, 98.7 per cent were drilled in the Montney. The remaining wells include three service wells, and three 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. Sections on both hydraulic fracturing and deep disposal can be found at the end of this report. The Commission completed a review of conventional remaining reserves and production activity, resulting in many pools being identified as depleted, which is also summarized in this report. Additionally, new sections on deep water sourcing, facilities and a high-level review of Carbon Capture and Storage opportunities in depleted pools are included at the end of this report.

Table 2: B.C. Remaining Reserves as of Dec. 31, 2021

	2021		2020		Percent Change
Gas (raw)	2092.9 $10^9 m^3$	74.0 Tcf	1912.5 $10^9 m^3$	67.6 Tcf	9.43%
Oil	13.2 $10^6 m^3$	83.0 MMSTB	14.9 $10^6 m^3$	94.0 MMSTB	-11.41%
Pentanes+	117.5 $10^6 m^3$	739.4 MMSTB	105.2 $10^6 m^3$	661.3 MMSTB	11.69%
LPG	149.1 $10^6 m^3$	939.4 MMSTB	123.5 $10^6 m^3$	773.3 MMSTB	20.73%
Sulphur	4.7 10^6 tonnes	6.5 MMLT	6.6 10^6 tonnes	6.5 MMLT	-28.79%

Figure 2: 2021 Number of Wells Drilled in Montney vs. Other Areas

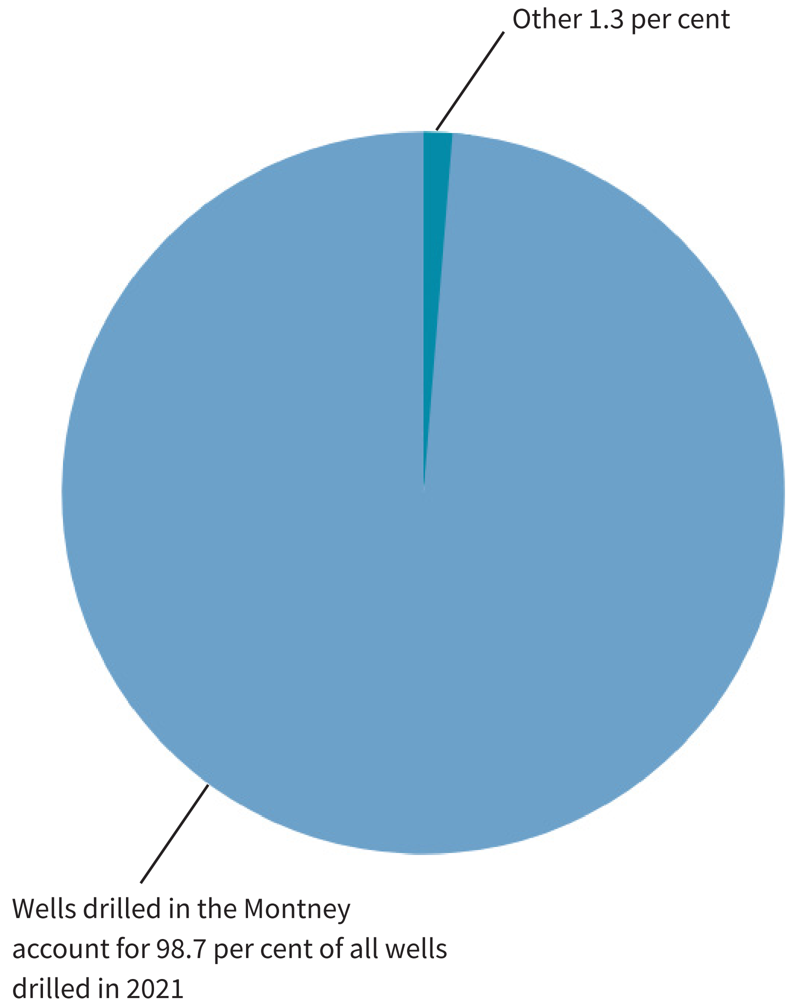
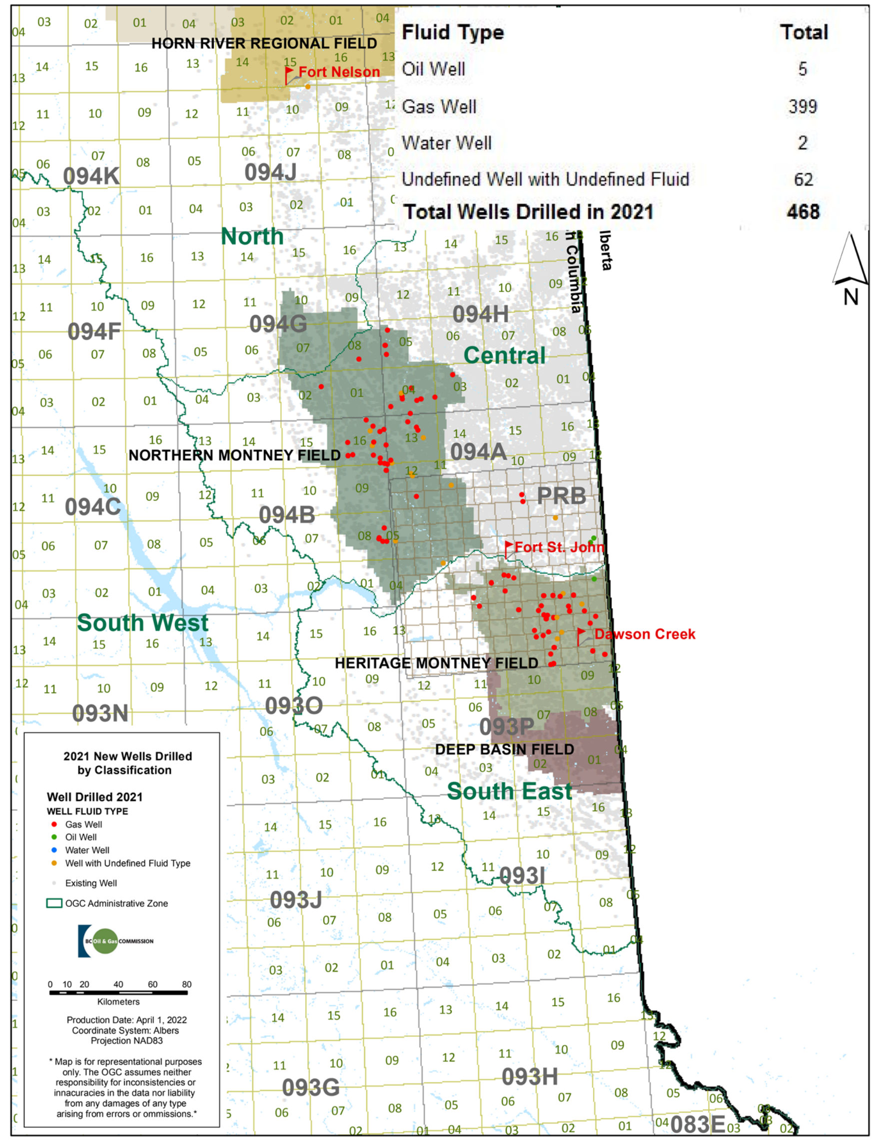


Figure 3: 2021 Wells Drilled by Fluid Type



Discussions: Gas Reserves and Productions

As of December 2021, unconventional gas zones accounted for 91 per cent of all remaining reserves and 88.9 per cent of annual gas production in the province.

As of Dec. 31, 2021, the province's remaining raw gas reserves were 2,092.9 e^9m^3, a 9.4 per cent increase from the 2020 remaining reserves. The increase in reserves occurred primarily due to Montney revisions with additional PUD (proven undeveloped) locations.

Figure 4 illustrates the distribution of remaining conventional and unconventional gas reserves, with 91 per cent of the remaining recoverable reserves held in the Montney basin.

The distribution of remaining reserves is echoed by Figure 5, which shows gas production split by source (as of December 2021). The majority of production in the province originates from the Montney.

Dawson Creek Resource Centre

Figure 4: 2021 Remaining Gas Reserves by Sources

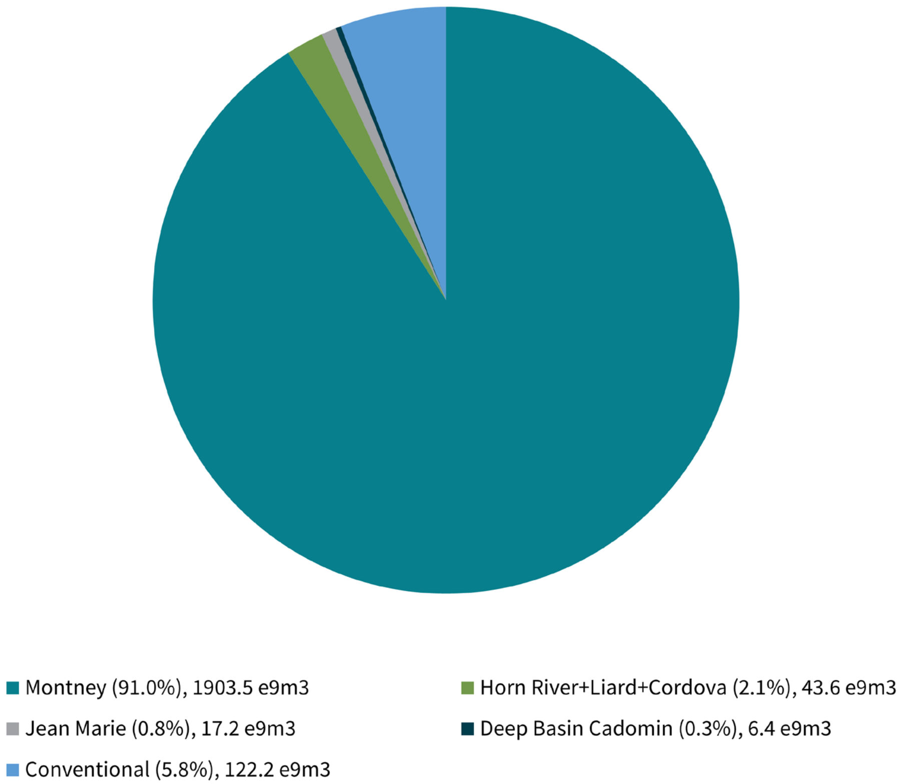


Figure 5: 2021 Annual Gas Production by Source

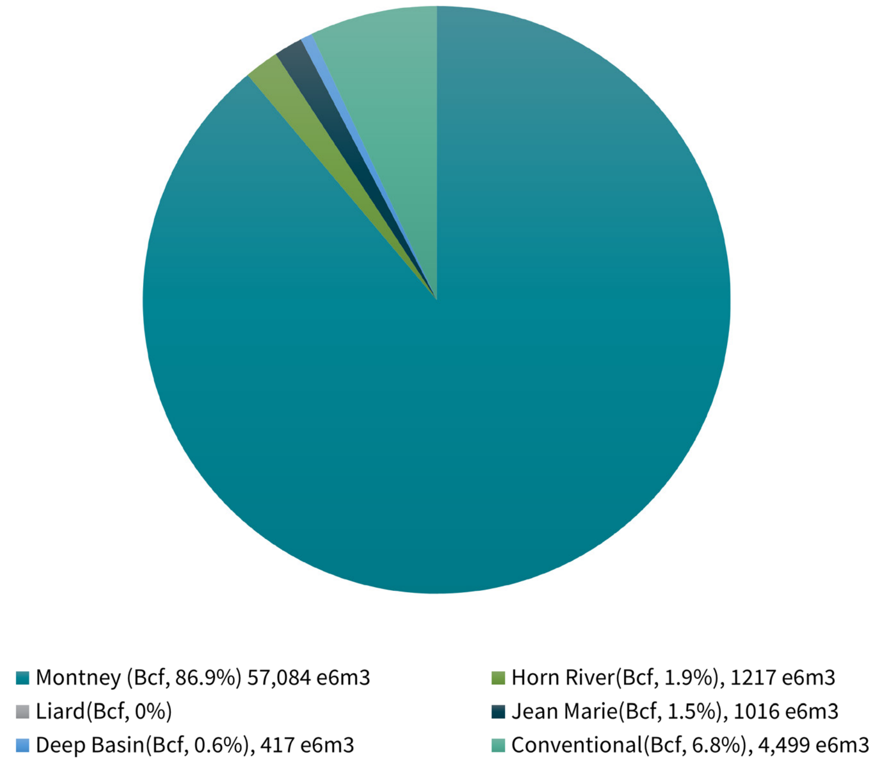


Figure 6: Unconventional vs. Conventional Raw Gas Production 2011 to 2021

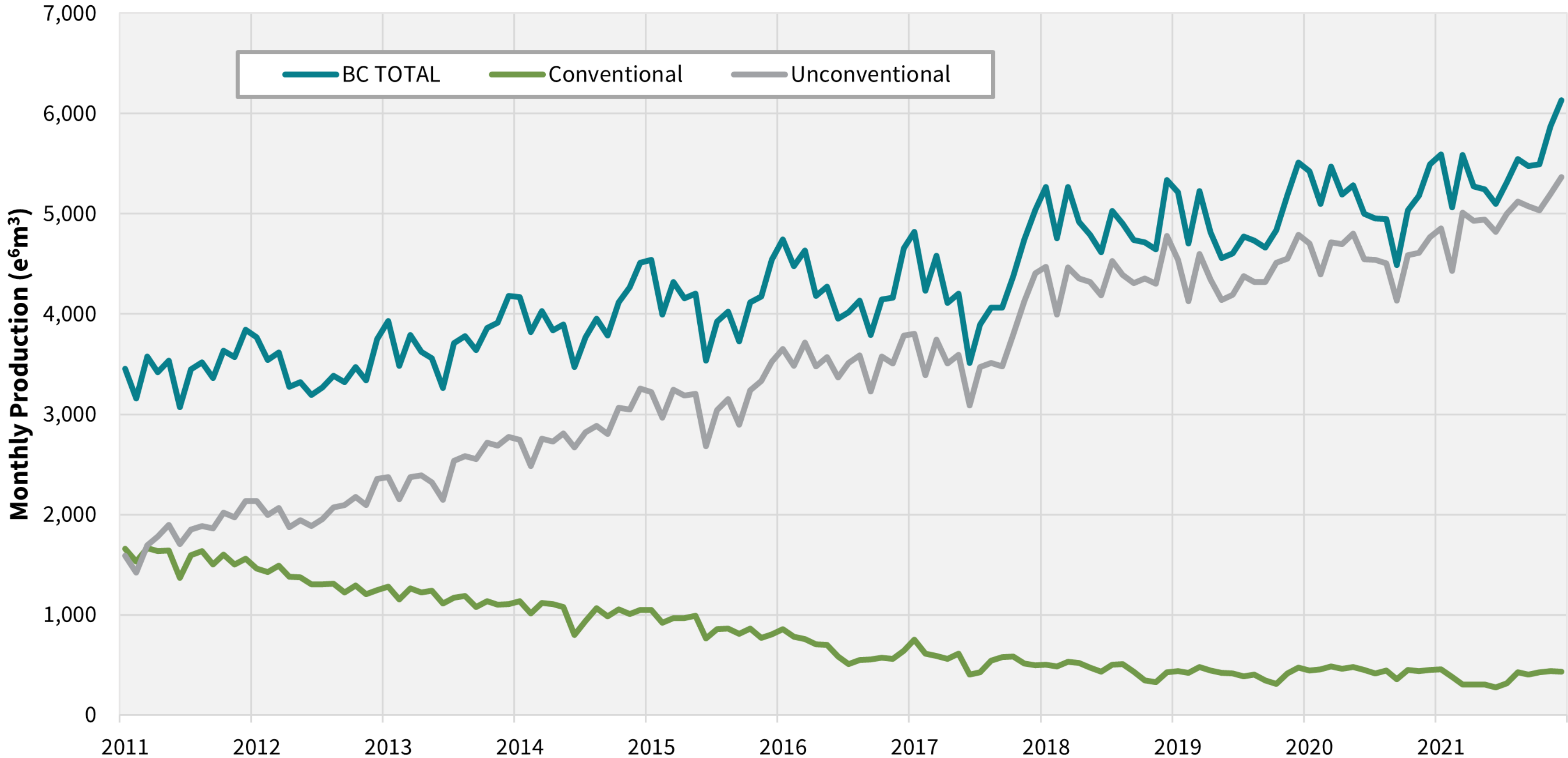
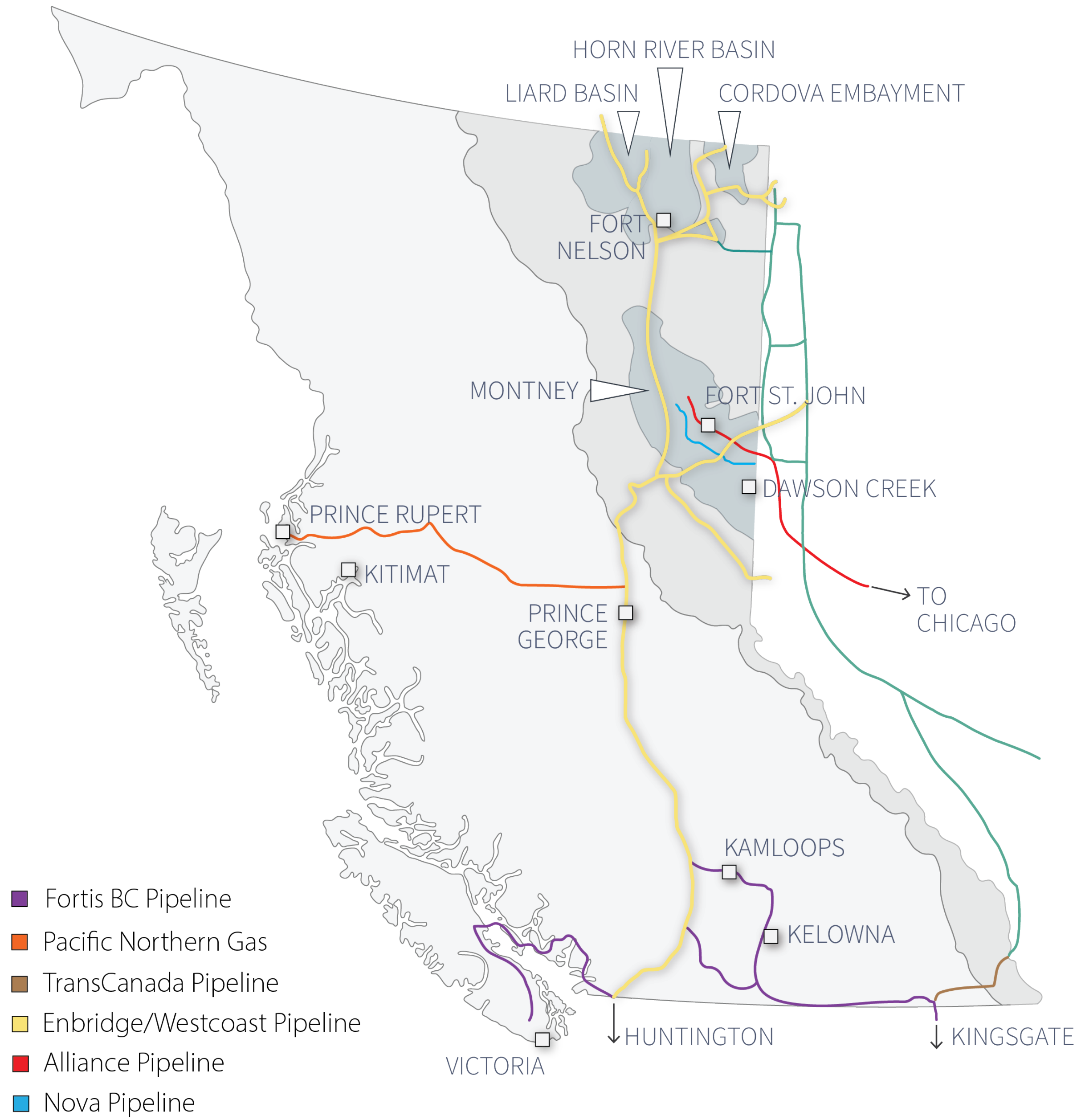


Figure 7: British Columbia's Gas Pipelines Systems



Oil and gas demand began to bounce back in early 2021, with oil prices returning to pre-pandemic levels and gas prices continuing their rise. By year end 2021, both oil and gas prices far exceeded pre-pandemic levels due to high demand and limited supply.

In the last five years, gas production in the province has increased by 28.4 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 7.

The TC Energy North Montney Mainline (NMML), connecting from the Bucking Horse River Area to the Dawson Creek area, came into service in 2020, providing a significant increase in capacity.

Annual production in B.C. has risen 28 per cent in the last five years.

Figure 8 represents the Commission's raw gas reserves bookings from 2001 to 2021, 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. In 2021, production in the Liard Basin remains completely suspended and further development of the Horn River Basin has ceased, with decreasing production.

The province's monthly raw and marketable gas volumes for 2021 can be seen in figure 9. Raw gas production for the province in December 2021 was 197.8 e^6m^3 per day (6.99 Bcf/d).

Table 3: 2021 Raw Gas Production by Basin

BASIN	Bcf (billion cubic feet) 2021 Annual Raw Gas	Tcf (trillion cubic feet) 2021 Annual Raw Gas	Cumulative (Bcf)	Cumulative (Tcf)	% of 2021 Production
All Conventional	159.7	0.1597	29,336.6	29.3	7.0%
Unconventional					
Heritage	1,253.5	1.2535	9,857.6	9.9	55.0%
Northern Montney	772.6	0.7726	4,675.7	4.7	33.9%
Horn River	43.2	0.0432	1,323.9	1.3	1.9%
Liard	0.0	0.0000	75.8	0.1	0.0%
Jean Marie	36.1	0.0361	2,595.9	2.6	1.6%
Deep Basin Cadomin	14.8	0.0148	683.4	0.7	0.6%
Total Raw Gas	**2,279.9**	**2.2799**	**48,548.9**	**48.5**	**100%**

Not including Aitken gas storage

Figure 8: Historical Development in B.C. 2001 to 2021

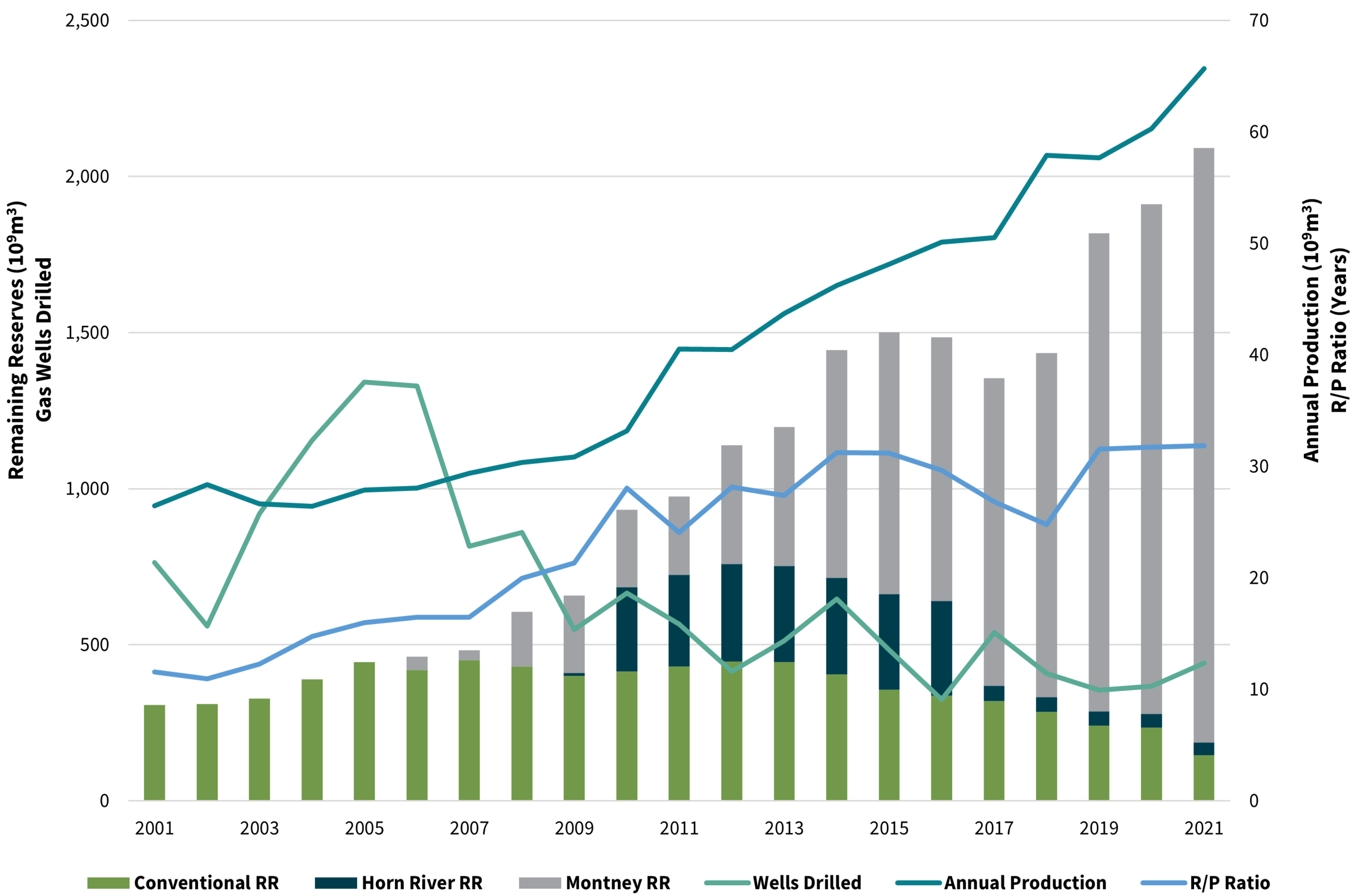
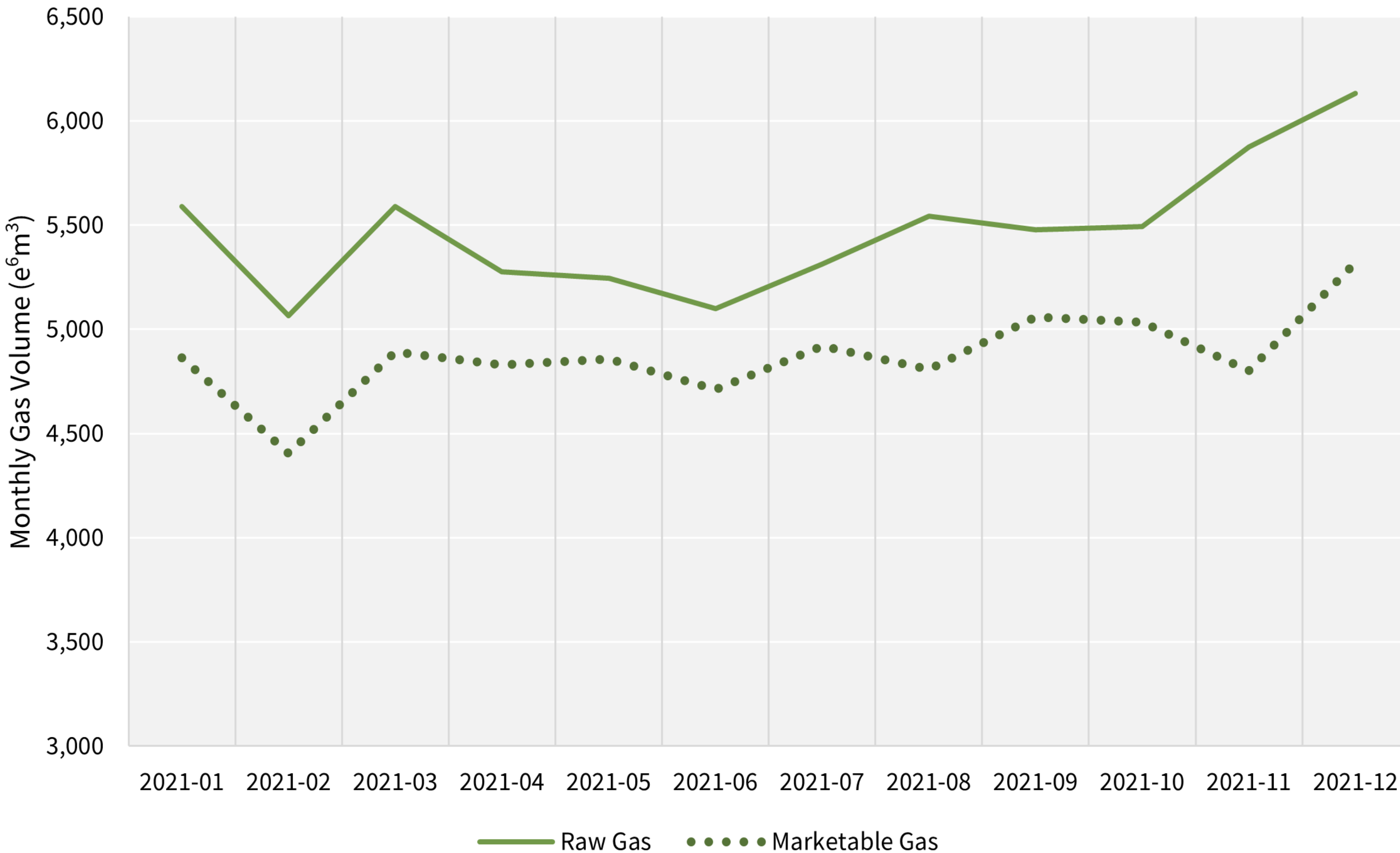


Figure 9: 2021 Raw Gas and Marketable Gas



Montney Unconventional Gas Play

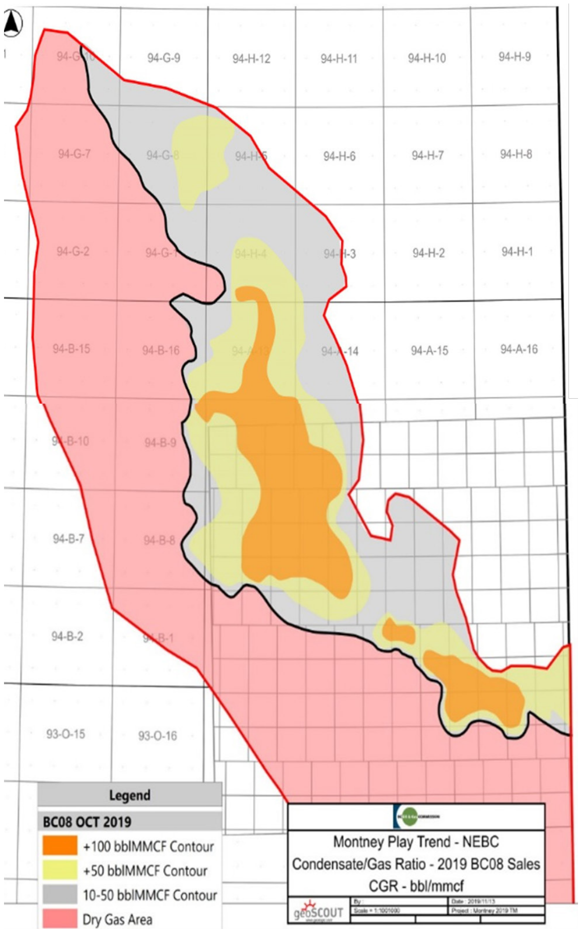


Figure 10: Montney Dry/Wet/Oil Distribution

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 2021 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 2021, of the 8,731 producing wells in the province, 4,481 wells were producing from the Montney formation.

Activity in dry gas areas provided a rapid increase in gas supply in response to market demand. Figure 10 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 northeastern side of the Montney play.

In December 2021, Northern Montney gas production was 65.5 e^6m^3 per day (2.31 Bcf/d) while Heritage field gas production was 100.9 e^6m^3 per day (3.56 Bcf/d).

As of Dec. 31, 2021 the remaining gas reserves for the Montney formation is 1,903.5 e^9m^3 (67.3 Tcf) (raw). The initial reserves of 2,307.7 e^9m^3 represents a 4.2 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 4 below.

Table 4: Montney Remaining Reserves as of Dec. 31, 2021

Field/Pool	Subareas/Layers	Horizontal Well EUR(Bcf) Per Well				Initial Reserves (Raw) Bcf	Remaining Reserves (Raw) Bcf	Exisiting HZ Wells	PUDs	Development Phase
		Pmean	P90	P50	P10					
Heritage - Montney A	Dry/Ultra Dry Upper	7.28	2.11	6.36	13.86	27,211.1		1,215	2,523	Statistical
	Dry Lower	6.88	2.30	5.53	13.77	9,292.3		563	788	Statistical
	Liquid Upper	4.29	1.25	3.77	7.87	7,900.5		848	925	Statistical
	Liquid Lower	3.17	1.25	2.78	5.57	2,062.8		210	840	Intermediate
	Area Average/Total	**5.67**	**1.83**	**5.16**	**11.44**	**46,467**	**36,650**	**2,836**	**5,076**	
Northern Montney - Montney A	NW - Upper	5.65	1.60	5.25	10.39	5,729.3		207	828	Intermediate
	NW - Lower	3.53	1.10	3.35	6.29	3,487.0		205	820	Intermediate
	SW - Upper	5.51	1.50	4.85	10.17	6,081.5		137	548	Intermediate
	SW - Lower	4.90	1.47	4.24	9.65	3,317.7		148	592	Intermediate
	NE - Upper	6.10	1.97	7.72	10.74	5,458.8		403	464	Statistical
	NE - Lower	4.27	1.2	3.72	8.02	7,202.6		310	1,240	Intermediate
	SE - Upper	3.31	0.49	2.63	6.76	1,474.0		131	524	Intermediate
	SE - Lower	2.87	0.75	2.27	5.91	1,907.1		127	508	Intermediate
	Area Total	**4.29**	**1.17**	**3.83**	**7.91**	**34,657.8**		**1,668**	**5,524**	

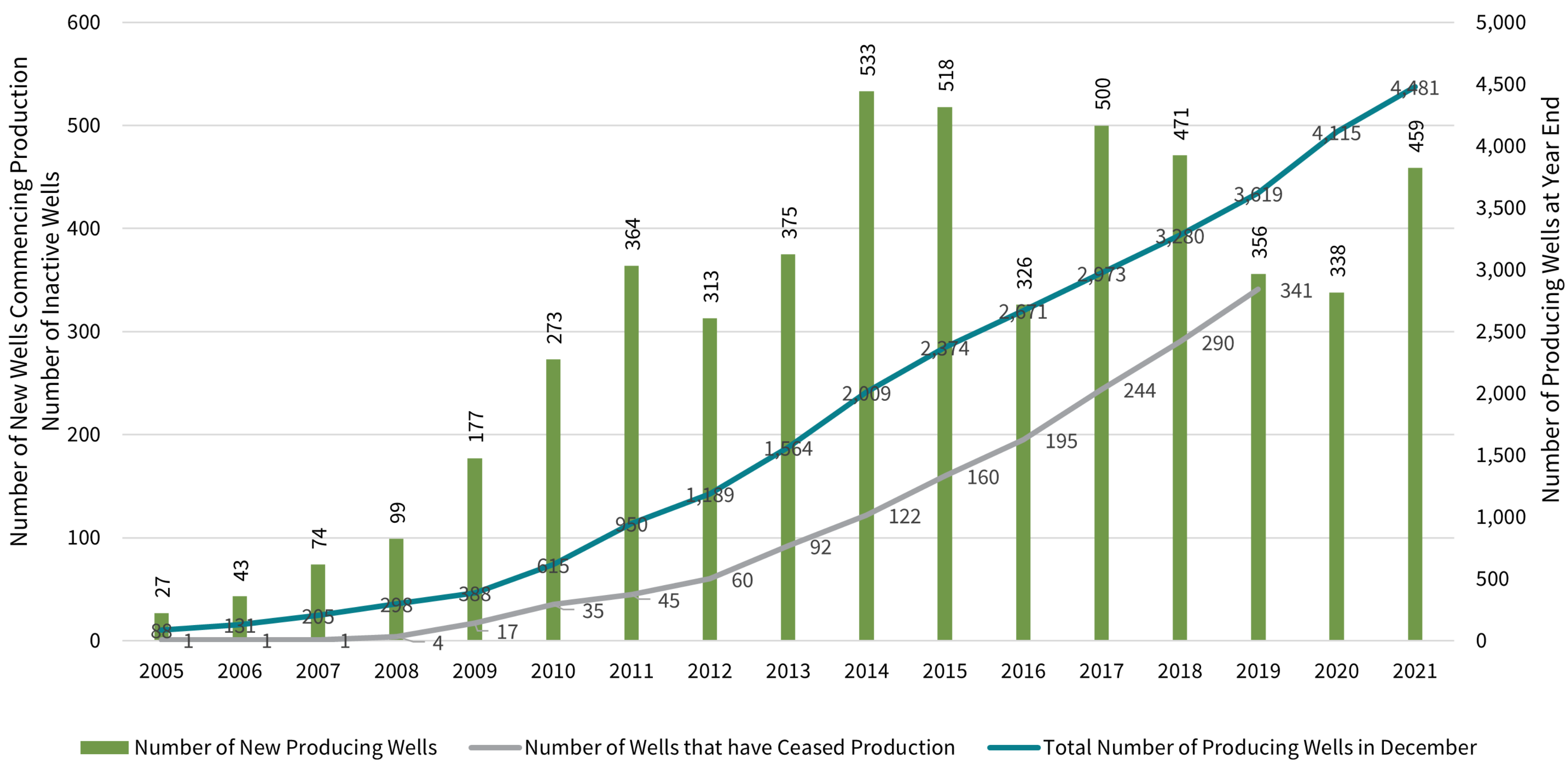
The initial reserves and remaining reserves do not include solution gas reserves. Due to limited well count, the upper-middle, the middle, and the lower-middle were combined with the lower Montney wells. For maps with outlined areas see Appendix B.

Figure 11 compares the number of new Montney wells drilled to the number of Montney producing wells from 2005 to 2021. The number of wells producing from the Montney increased year-over-year, from 88 in 2005 to 4,481 by the end of 2021. 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.

The line “Ceased Production” in Figure 11 is a cumulative count of wells which had produced for six months or more but have since ceased production for over two years and may be presumed to have reached the end of economic life in their present state. The reasons for suspension vary, from poor initial completion to reservoir damage from subsequent frac “hits” from offsetting wells. The majority of Montney wells have an anticipated economic life of decades, however this illustrates that not all are successful. Approximately one-third of these suspended Montney wells are vertical wells, while the rest are horizontal. The average cumulative production of these wells is $27e^6m^3$ ($29e^6m^3$ in the Heritage and $23e^6m^3$ in the Northern Montney).

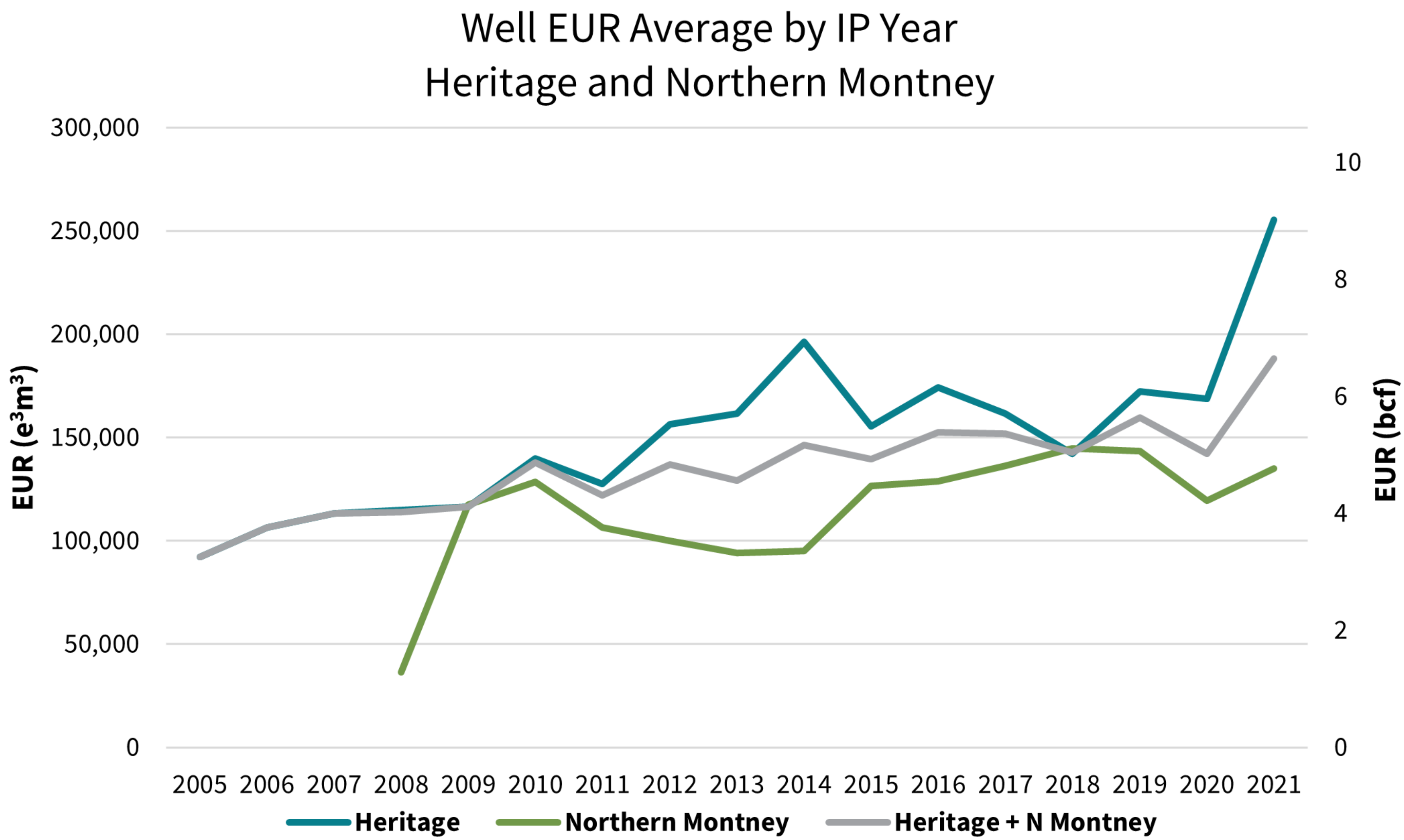
A general upward trend in average new well EUR over the course of play development is shown in Figure 12. Heritage area wells have shown consistently superior gas reserves EUR. Annual variations over the period are due to a number of factors, including focus by different companies at different times in specific areas and Montney sub-layer, changes in well spacing and length, and variations in well completion types and hydraulic fracture stimulations to find the optimum combination of factors for reserves recovery and economic return. A significant factor in the 2021 upswing in EUR is the increase in well length, as shown in Figure 36.

Figure 11: Number of New Wells, Wells that Ceased Production, and Producing Wells in Montney Play 2005 to 2021



Note: "Ceased Production" count ceases in 2019 as two years of history are required to be counted as inactive.

Figure 12: Well EUR Average by IP Year – Heritage & Northern Montney



As shown in Figure 13 and 14, 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 2.8 to 6.4 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 13: Heritage Montney EUR Distribution by Subareas/ Zones

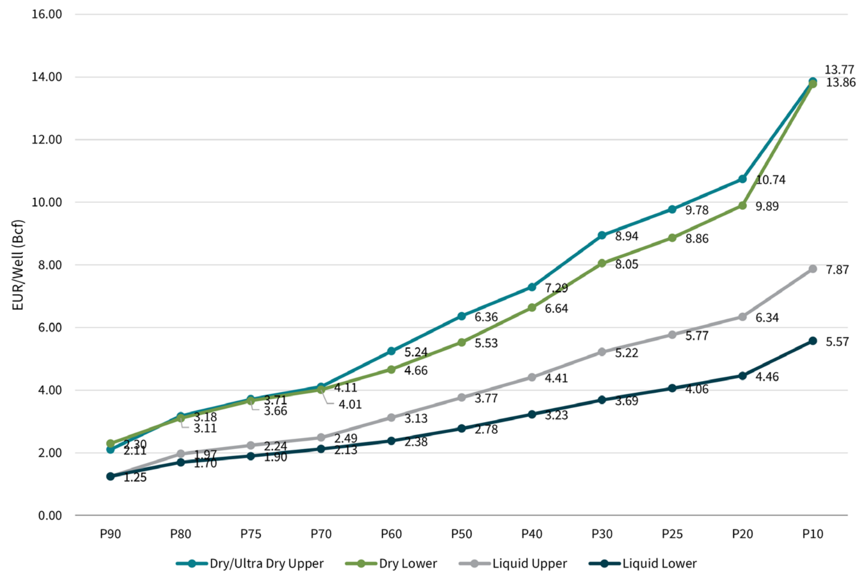
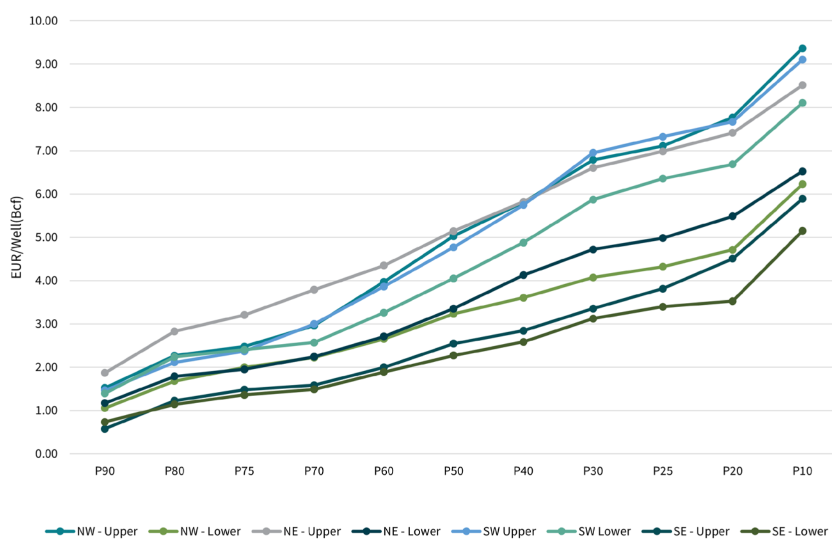


Figure 14: Northern Montney EUR Distribution by Subareas/ Zones



As seen in Figures 15 and 16, the top gas producers in the Heritage field by production (Ovintiv, ARC and Shell) differ from those in the Northern Montney (Tourmaline, CNRL, and Petronas). 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 and LPG production saw an increase in 2021, and condensate 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.

Figure 15: Top 10 Gas Producers in Montney Play 2021

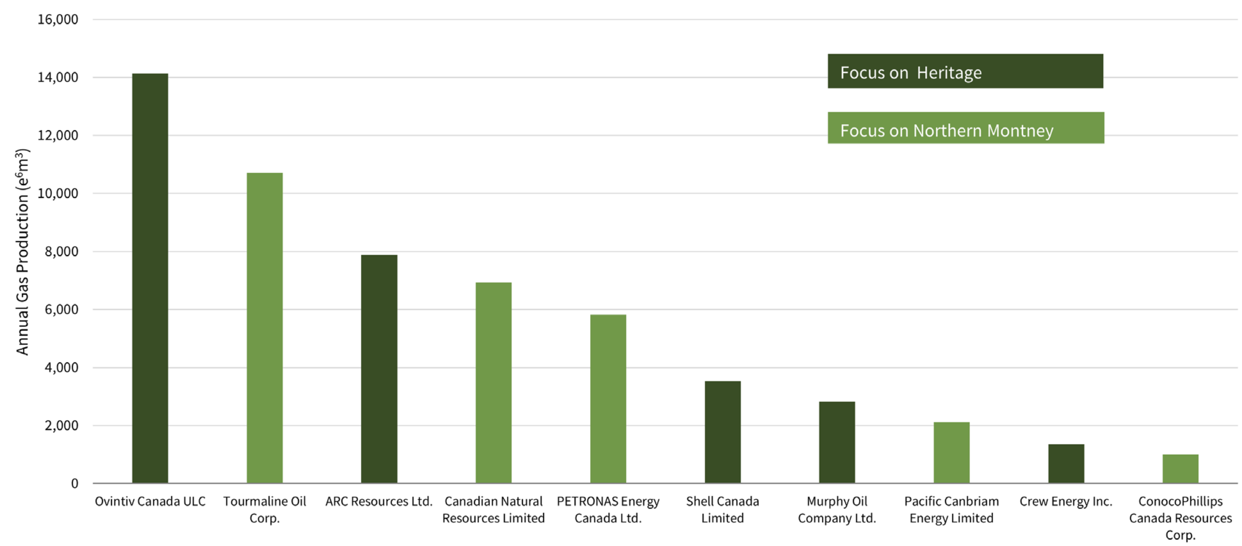
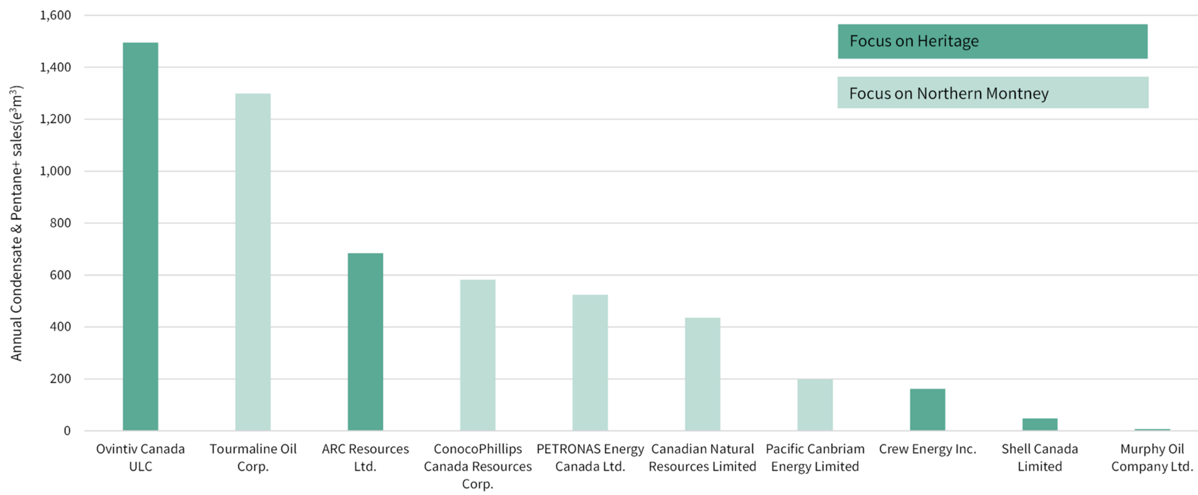


Figure 16: Top 10 Condensate & Pentanes+ Producers in Montney Play 2021



Other Unconventional Gas Plays

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 10 of this report.

Figure 17: British Columbia's basins

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 than the productive shales of the adjacent Horn River Basin. Despite very high individual well production rates, economics were severely hampered by the remote location and deep drilling depth.

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. Additional information on this play is available in previous versions of this report.

Horn River Basin

Production from the Horn River Basin was 3.37 e^6m^3/d (131.1 MMcf/d) in December 2021, up 3.7 per cent from the previous year (December 2020). While Horn River production and reserves have been declining since 2015 due to the shut-in of uneconomic wells and lack of new wells, production has leveled off since October of 2020. This is both due to the production decline profiles of the wells leveling off as they deplete, and four previously inactive wells being reactivated due to improved gas prices. 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 2021, there were 100 wells producing from the Horn River Basin shales, down from a peak of 222 wells in January 2015. Previous versions of this report contain additional overview of this play.

Cordova Basin

Development activity in the Cordova Basin ceased in February 2014 when the last new well was drilled. At the end of 2021, there were 16 wells producing from the Cordova Basin shale play, with a total production rate of 296.1 e^3m^3/d (11.7 MMcf/d). Further background information on the Horn River and Cordova fields is available in the 2014 Reserves Report.

Summary

Figure 18 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 19 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 18: Pressure vs. Temperature Plot

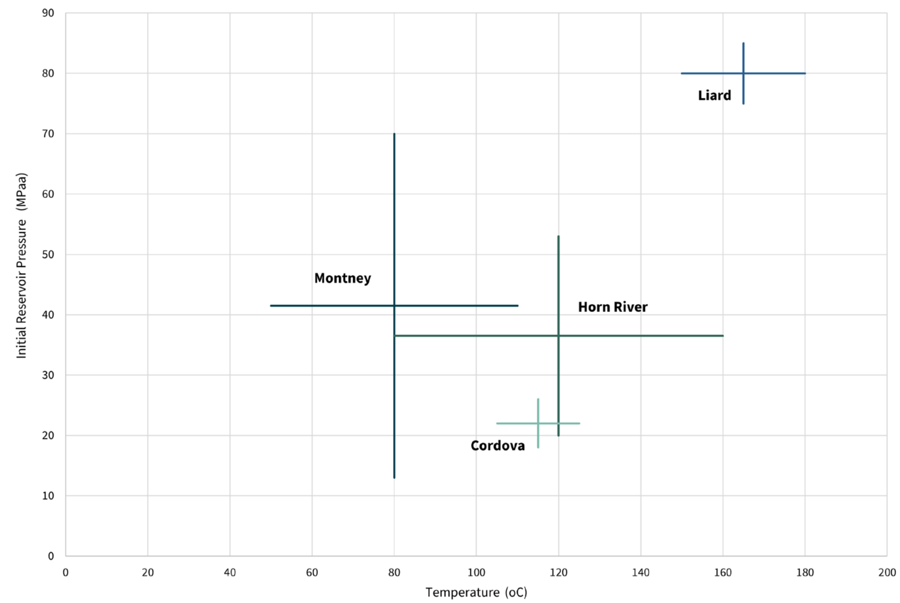
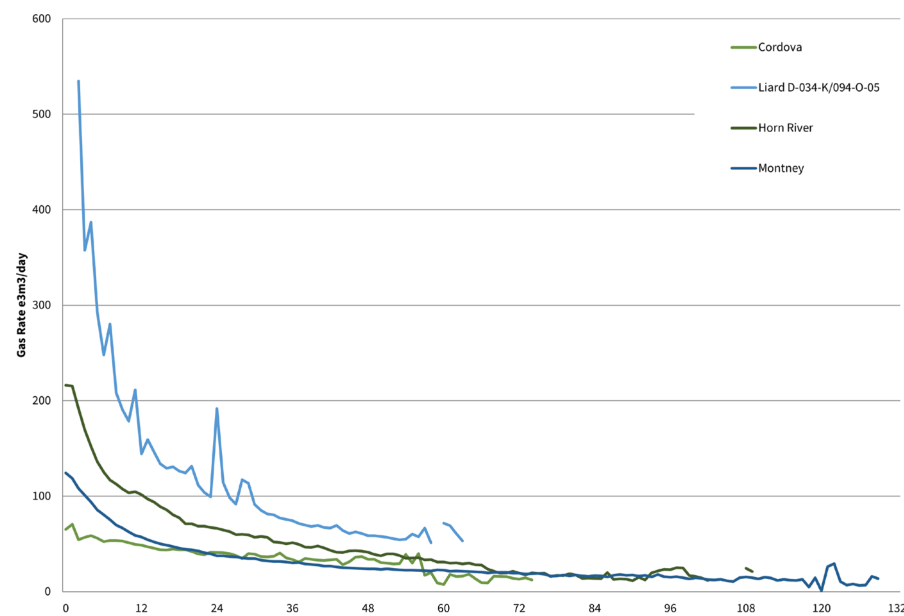


Figure 19: Comparison of Montney, Horn River, Liard and Cordova Production Type Wells



Discussions: Oil Reserves

Annual oil production decreased 13.9 per cent from 790.3 to 680.0 10^3m^3 (4.28 MMSTB) in 2021.

Remaining oil reserves decreased 11.3 per cent from 2020 to 2021, resulting in total remaining reserves of 13.2 10^6m^3 (83.3 MMSTB). This reserves decrease is mainly due to the lack of new oil wells drilled. In 2021, only five additional oil wells came on production. Optimization of waterflood projects with injection locations, which support the large majority of conventional pool oil production, is also still taking place. 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 "Waterflood Projects Review" section of the 2020 reserves report.

The 2021 R/P ratio is 19.6 years. The ratio had previously peaked in 2013 at 17.1 years before declining to a minimum of 12.4 years in 2016. The recent trend of increasing R/P is due to production decreasing at a higher rate than the reduction in reserves. The pool with the largest remaining reserves, as with previous years, is the Heritage Montney oil pool.

Figure 20: Remaining Oil Reserves by Field

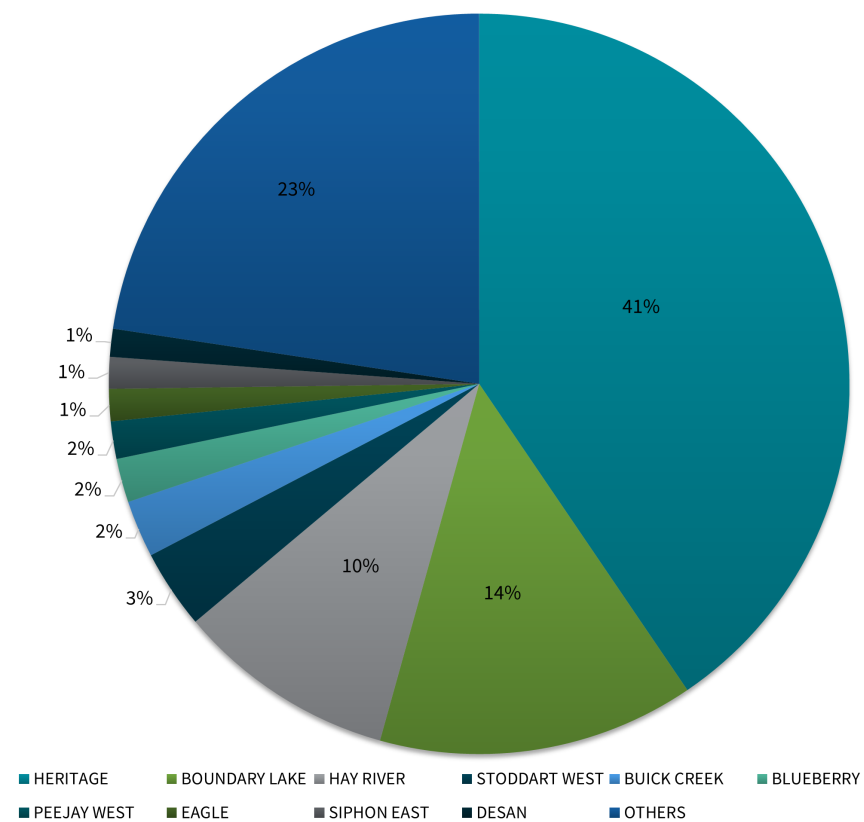
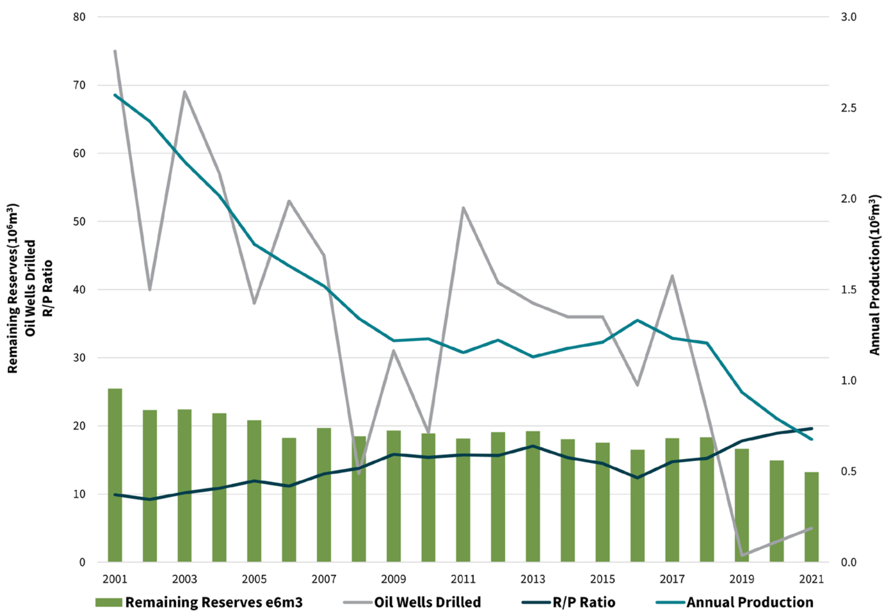


Figure 21: Historical Oil Development 2001 to 2021



30.3 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 0.6 per cent of remaining oil reserves, occurring in six oil pools (see Table A-5: Oil Pools Under Gas Injection).

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 22.

Leucrotta's 4-well Montney Phase 1 Mica Test Pad came on full production at the end of 2021 and produced an average rate of approximately 1,700 barrels of light oil per day and 10 mmcf/d of liquids-rich gas per day, demonstrating development opportunities.

Conventional oil production has continued to decline since 2006; however, growth from the unconventional Montney became significant, starting in late 2013 as shown in Figure 22 and 23.

Figure 22: B.C. Oil Production 2011-2021

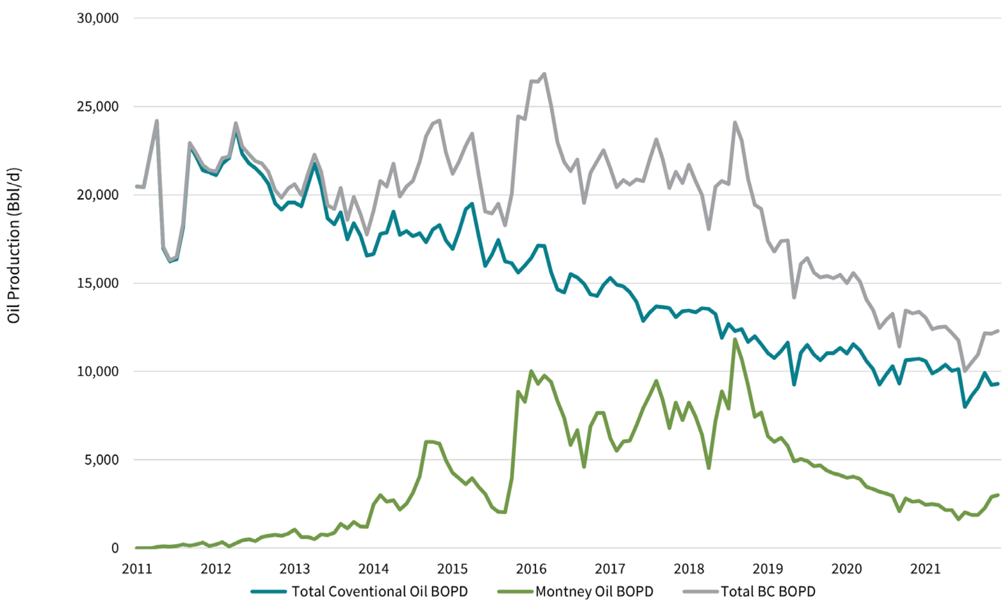
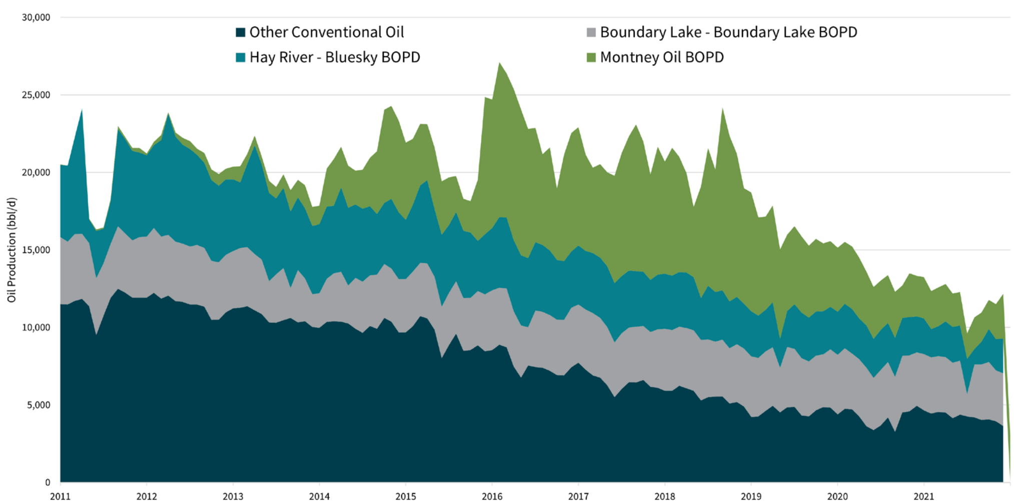
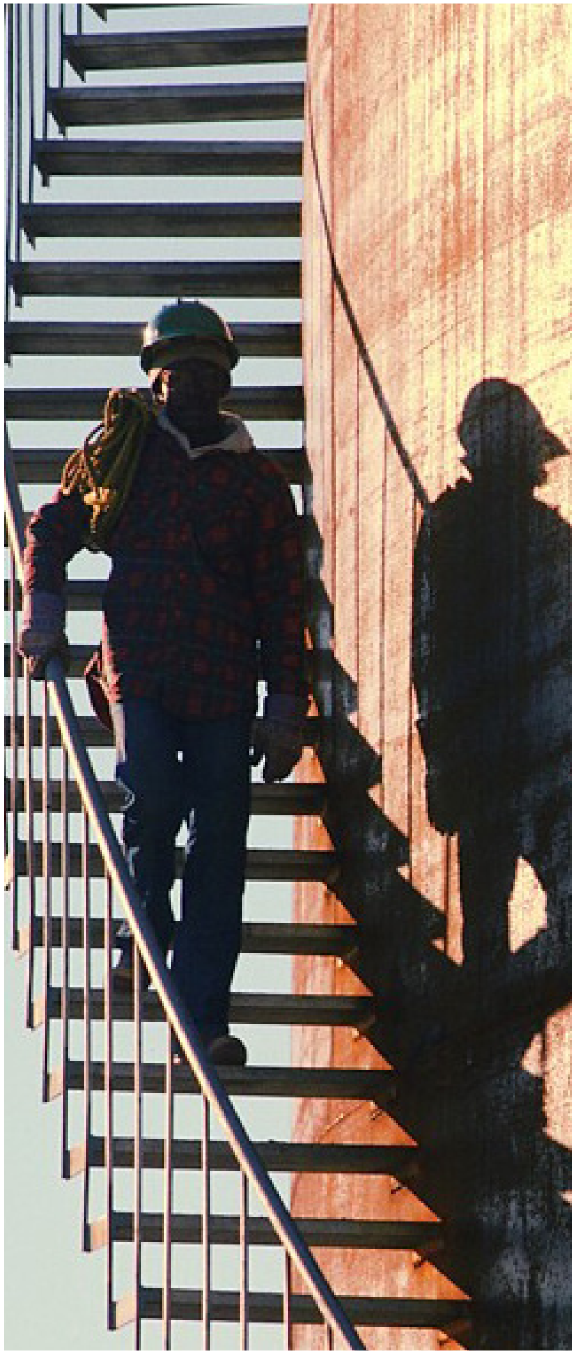


Figure 23: B.C. Oil Production Sources by 2021-12





Discussions: Condensate, Pentanes+ and NGLs

Production of condensate/pentanes+ and LPG in 2021 remained approximately at 2020 levels.

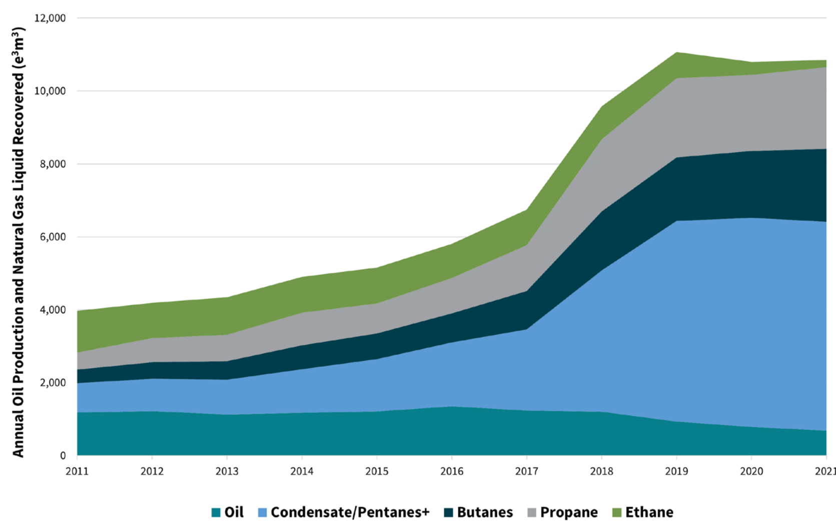
Overall liquid by-products production in 2021 remained at approximately the same level as 2020. In 2019, the focus of development shifted to include not only the upper Montney zone, but also the middle and lower Montney zones. In some areas, operators developed the entire 'stack' of the Montney formation (upper, middle, and lower zones).

Ethane annual sales had been relatively constant at around 950 e^3m^3 since 2012 but have declined significantly year-over-year since 2019 and were only 199.2 e^3m^3 in 2021. This reduction in ethane sales suggests 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, which continued in 2021 with a nine per cent and eight per cent increase respectively over 2020. 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, though they have largely leveled off since 2019. In 2021, condensate/pentanes+ production decreased by 0.1 per cent to 5,722.9 e^3m^3, whereas LPG production increased by four per cent to 4,278.6 e^3m^3 versus 2020 (Figure 24).

Figure 24: Annual Oil, Condensate and NGL Production 2010-2020



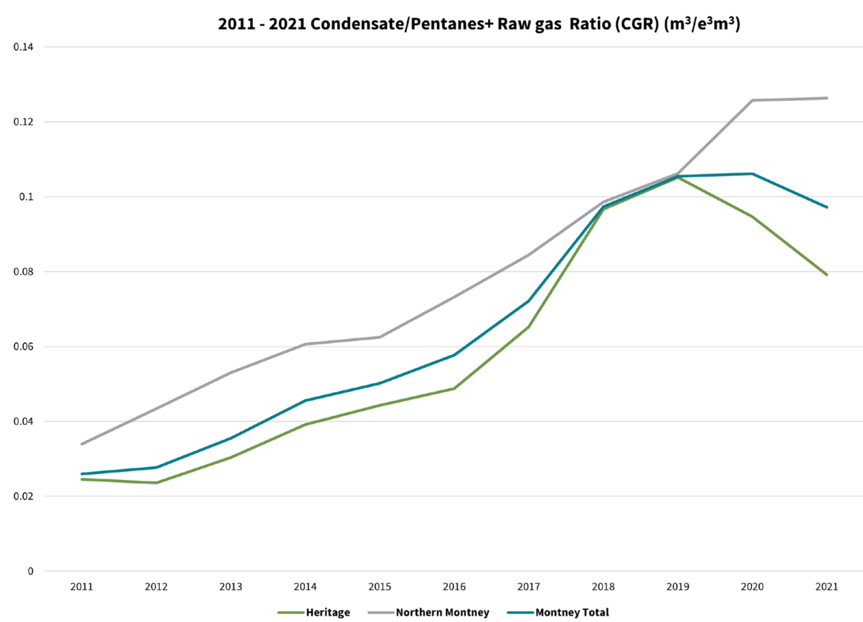
The general increase in liquids production is in part due to a shift towards development of liquids-rich Montney areas in recent years. This is also due to a change in policy for determining the primary product of Montney formation wells which has allowed for a primary product review of oil wells producing 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 2021 is 117.5 e^6m^3, an increase of 11.7 per cent from last year. LPG remaining reserves increased by 20.7 per cent versus last year to 149.1 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 10. Annual oil and natural gas liquids production from 2011 to 2021 is shown in Figure 24.

Figure 25 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 2021, CGR in the Heritage region decreased by 16 per cent, due to a shift to dry gas to meet market gas demand, while CGR in the Northern Montney region increased by 0.5 per cent.

Figure 25: Condensate/Pentanes+ and Raw gas Ratio (CGR)(m^3/e^3m^3) 2011 to 2021



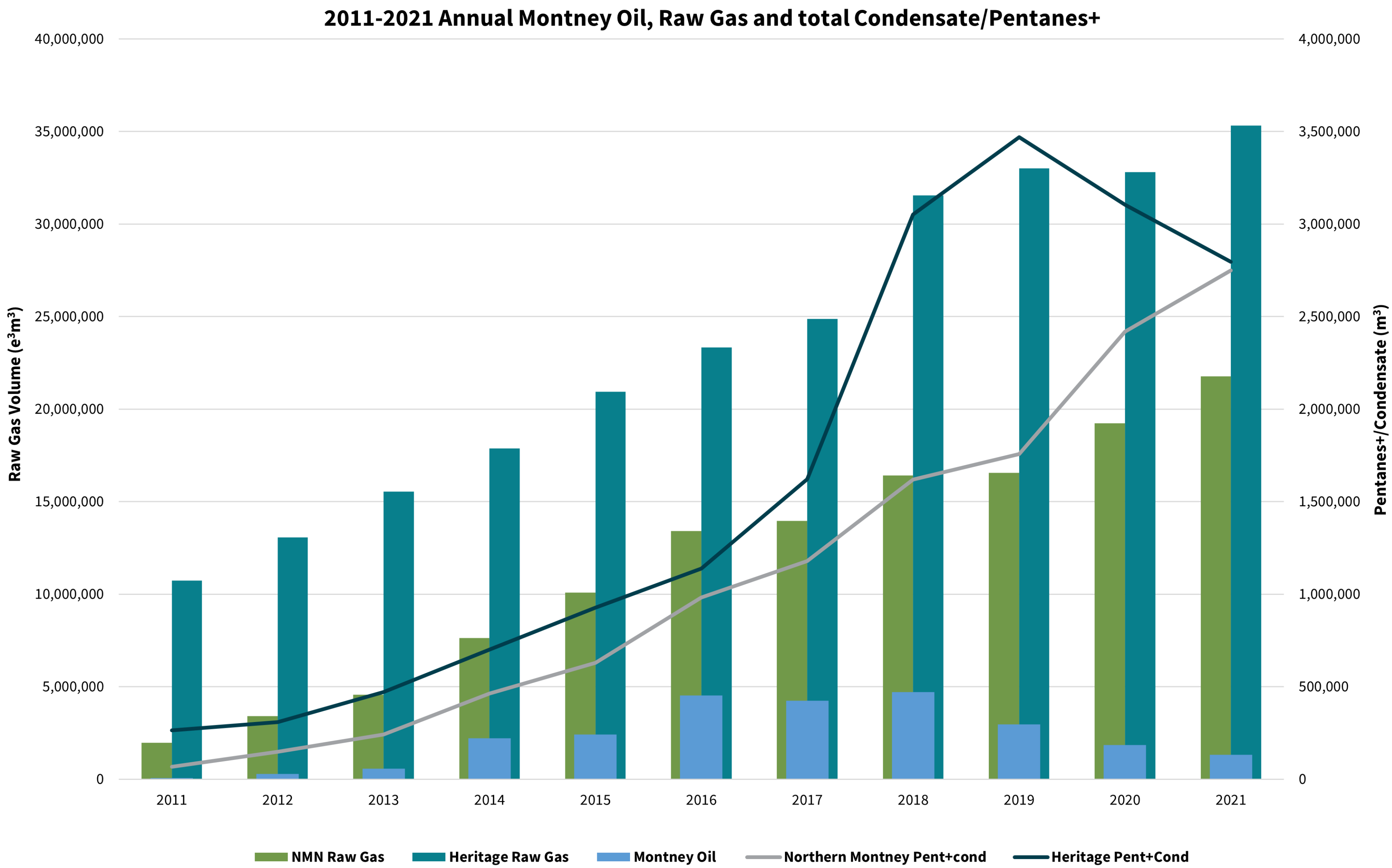
The majority of the NGL volumes are captured as an increase in marketable gas heating value with liquids being recovered at the pipeline delivery point. To be more resilient towards changing market conditions, operators have invested in upgrading existing facilities or building additional deep-cut facilities 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.

Western Canadian condensate prices are likely to remain high and continue to track the WTI benchmark for the foreseeable future. Much of the demand for condensate is for use as a diluent for heavy oil and bitumen, which allows it to be moved by pipeline. This demand has been heightened due to increased oil prices and production, as well as the completion of the Enbridge Line 3 expansion in late 2021.

In 2021, there was continued significant capital investment in gas processing, pipelines, and gas and associated liquids export facilities. A new LPG export terminal on Watson Island near Prince Rupert, operated by Pembina, came into service in April 2021, with a capacity of 25,000 bbl/d and an expected throughput of 20,000 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 bbl/d and has been in service since October 2017. Additionally, liquid propane and butane arriving via rail at the AltaGas Ltd. Ridley Island terminal (RIPET) near Prince Rupert is exported as LPG, with a capacity of 77,500 bbl/d.

In 2021, there was a 10 per cent decrease in condensate/pentanes+ production in the Heritage region versus 2020 (Figure 26), whereas the Northern Montney region saw a 14 per cent increase. This is a result of the decreased CGR in the Heritage, and increased gas production and CGR in the Northern Montney.

Figure 26: Annual Montney Oil, Raw Gas and Condensate/Pentanes+ Production 2011 to 2021



Figures 27 and 28 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 average EUR using the typewells in Figure 27 is 8.9 to 9.7 e^3m^3 per well in dry and ultra dry areas, and 18.0 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 average EUR ranges from 3.6 to 33.6 e^3m^3/well.

Figure 27: Heritage Condensate Typewell by Subareas and Layers

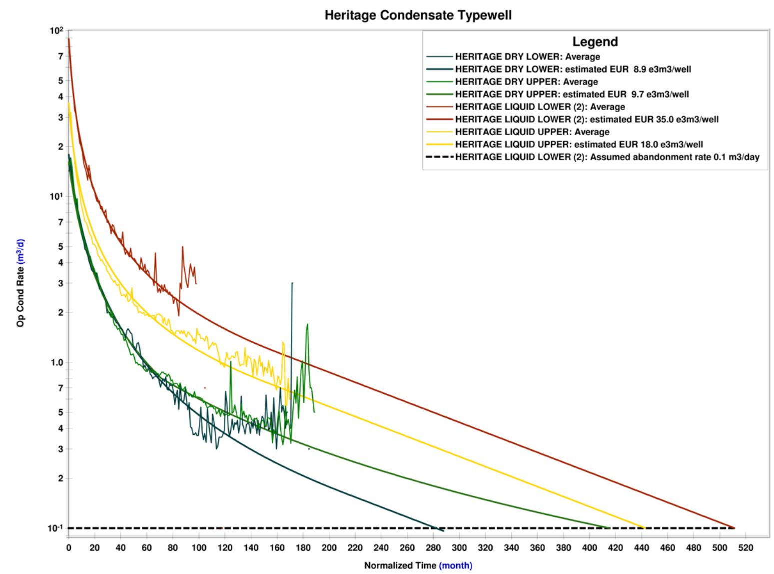
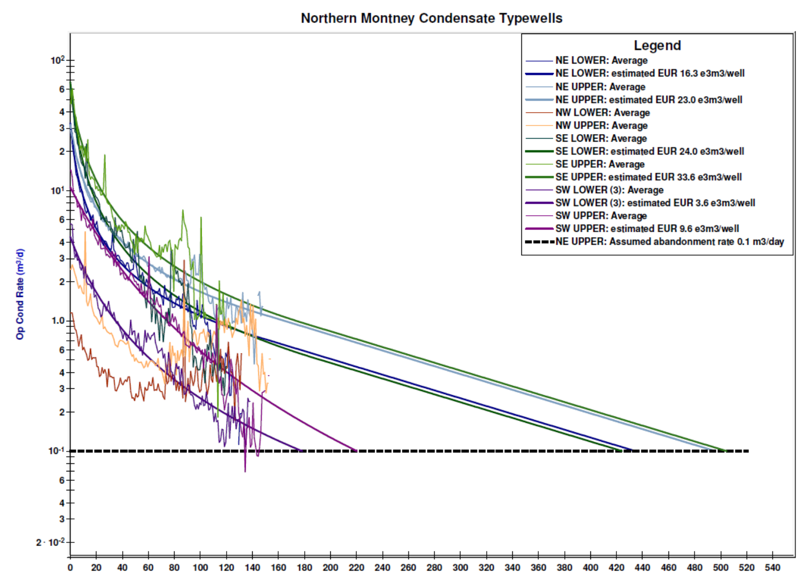


Figure 28: Northern Montney Condensate Typewell by Subareas and Layers



Discussions: Sulphur

Sulphur sales decreased in 2021

As of Dec. 31, 2021, recoverable sulphur remaining reserves was 4.7 10^6 tonnes (4.6 MMLT). Sulphur reserves saw a 27.7 per cent decrease in 2021, returning to the previous trend seen from 2016 to 2019. Figure 29 shows the breakdown of remaining sulfur reserves in the major sour fields as of Dec. 31, 2021.

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 30, decreased significantly between 2015 and 2018. Sales saw a relatively large increase in 2020 but in 2021 they decreased by 47 per cent to 218 10^3 tonnes, the lowest point in over a decade.

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 an appreciable amount of sulfur. Sulfur production occurs at the McMahon gas plant in Taylor, B.C. Additionally, there are some cases where the percentage of H_2S can be significant in Montney gas (Figure 31).

Figure 29: 2021 Major Sour Field by Remaining Sulphur

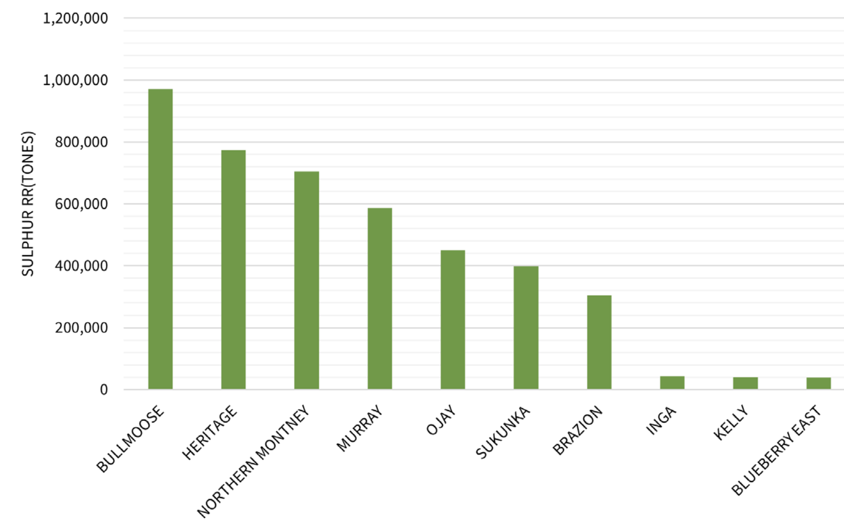
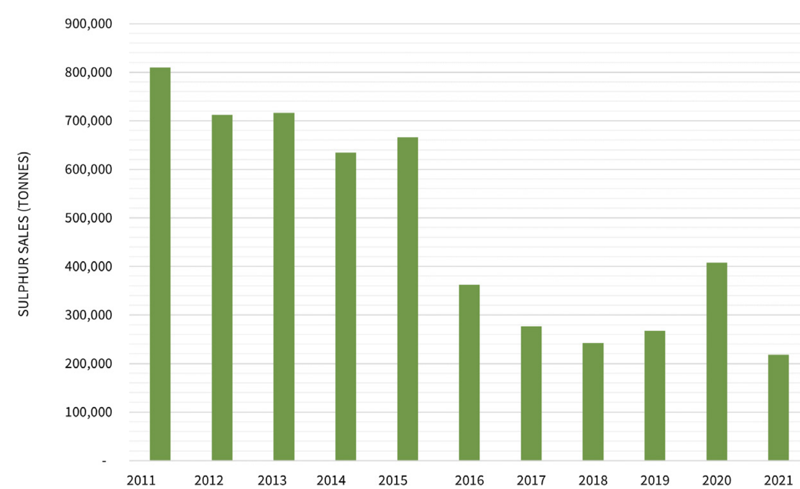


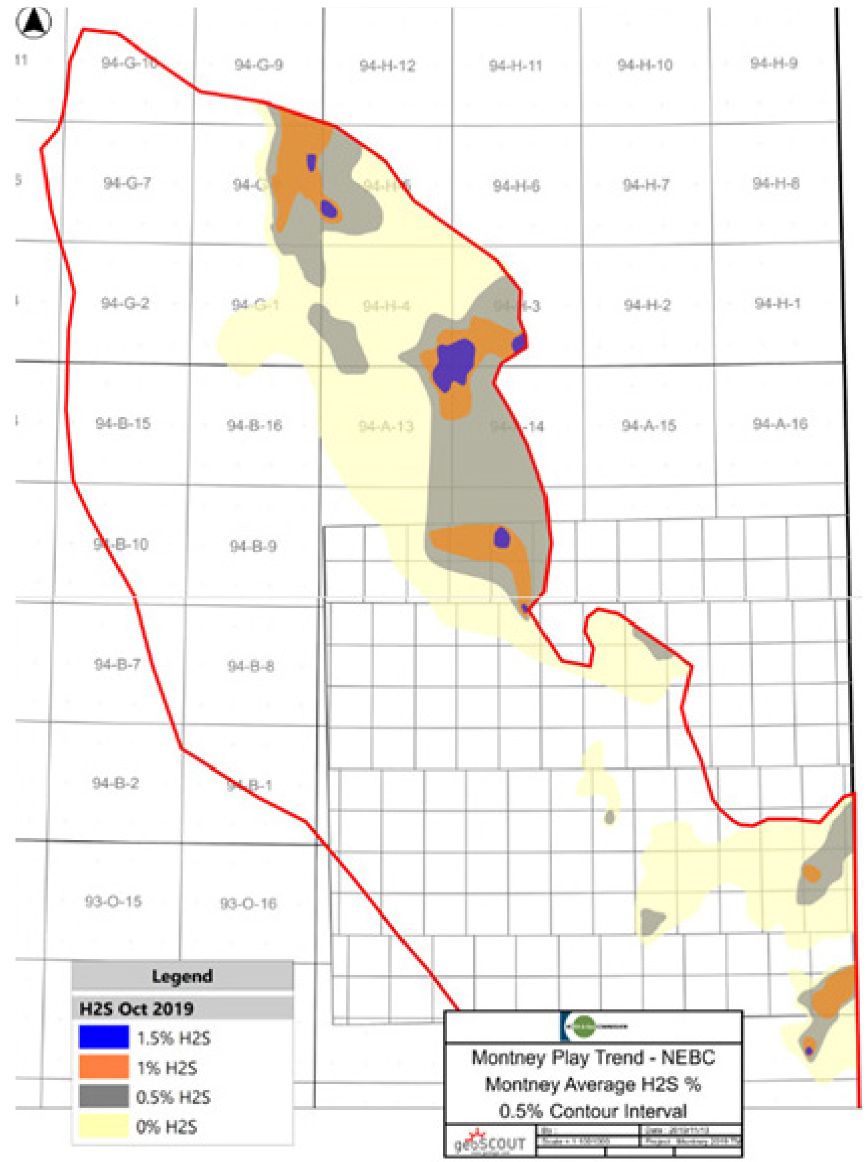
Figure 30: Annual Sulphur Sales 2011-2021



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.

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.

Figure 31: Average H_2S in the Montney Field



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.

Produced Water Disposal

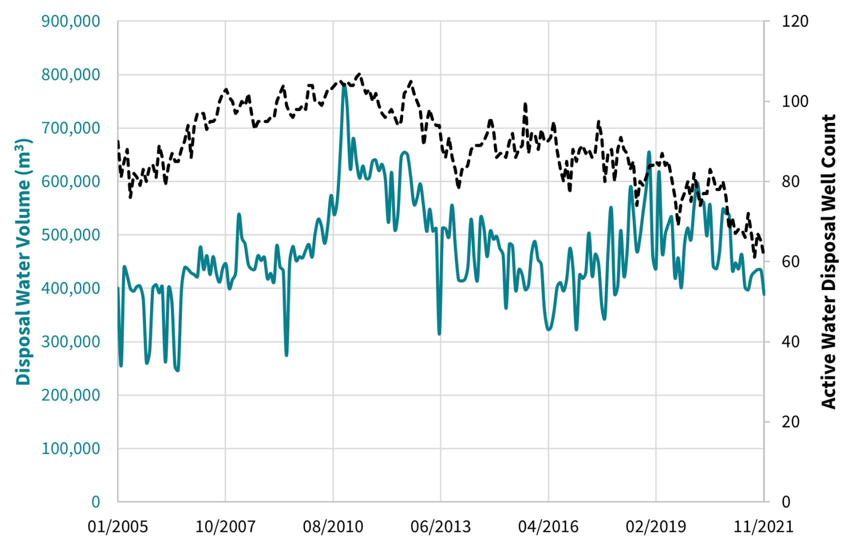
The most common type of disposal fluid is produced water. Production of oil and gas brings to the surface saline water trapped in the same formation. By regulation, this associated produced water must be disposed back into the subsurface. For oil waterflood projects, the produced water is re-injected 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, spent acid, and tank wash, makes up a small amount of total disposal. Wells approved for NHW disposal usually also dispose of produced water, as the majority of the fluid, and the combined monthly volume is reported as a single value.

Figure 32 shows the monthly active water disposal well count and volume from 2005 to 2021. Total water disposal volume has mostly remained in the range of 400 ± 100 e^3m^3/month over this 16-year period, as disposal of fracture flow-back water has been replacing conventional formation produced water. The large spike in water disposal occurring in 2010 is attributed largely to increased development (and thus increased wastewater from hydraulic fracturing) in the Horn River basin.

Figure 32: Monthly Water Disposal Well Count and Volume 2005-2021



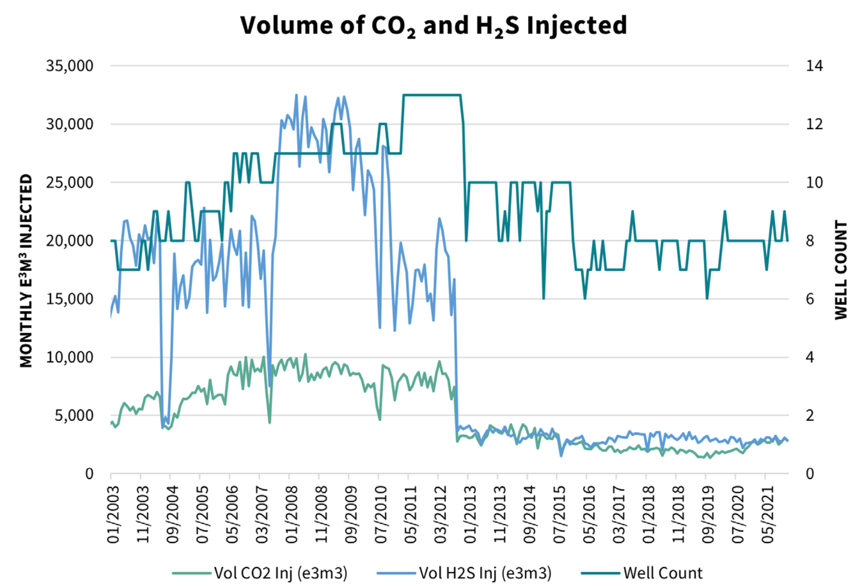
Development of this area ceased in 2014. The recent increase in water disposal starting in 2018 is due to increased development of the Montney, as more fluid is being used on average for each well completion. Development activity not only affects disposal volume but also the location of the active disposal wells. Currently there is a significant demand for 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 in some cases. A map of disposal well locations and information is available here.

Acid Gas Disposal

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

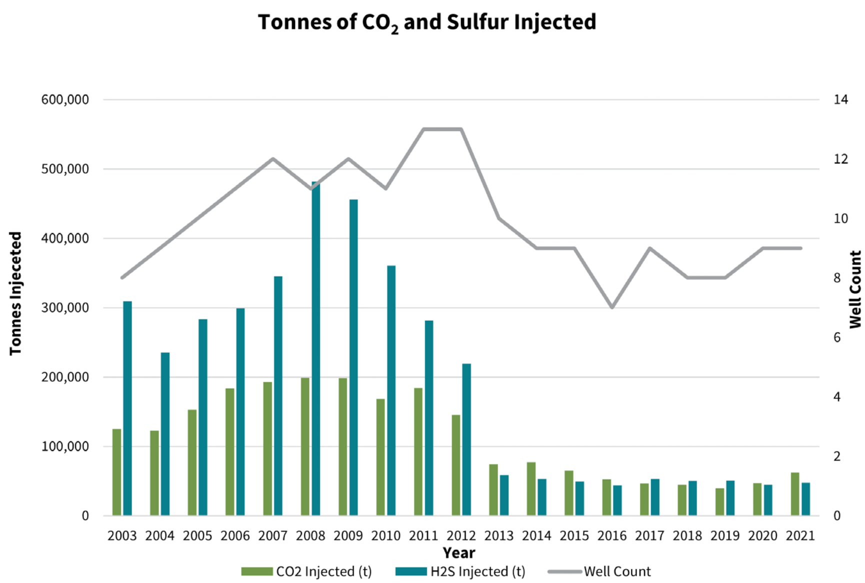
Figure 33 shows the active monthly acid gas disposal well count and CO_2 and H_2S volumes from 2003 to 2021. Total acid gas disposal volume averaged around 25-40 e^6m^3/month from 2006 to 2012 before decreasing to the current approximate value of 5 e^6m^3/month. The large drop was a result of the cessation of disposal operations of three acid gas disposal wells in the Foothills sour gas Sukunka, Burnt River and Brazion fields.

Figure 33: Monthly Acid Gas Disposal Well Count and Volume 2003-2021



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.

Figure 34: Annual Acid Gas Disposal Well Count and Tonnage 2003-2021



It should be noted that a total of 2.630 megatonnes of CO_2 have been sequestered as of December 2021 since acid gas disposal began in 1996. Additionally, during this time period, acid gas disposal has diverted the atmospheric release of 8.695 megatonnes of SO_2, if the gas had instead been flared.

Disposal Summary

In summary, 2021 disposal represented a continuation of existing trends for both water and acid gas disposal. Total water disposal for 2021 averaged 435 e^3m^3/month which was within the historical range, though below 2018, 2019, and 2020. In recent years, the location of new disposal demand has been in the Montney fairway, however all three water disposal wells approved in 2021 were located outside the Montney Fairway. All of the operating acid gas disposal wells were located in the Montney fairway.

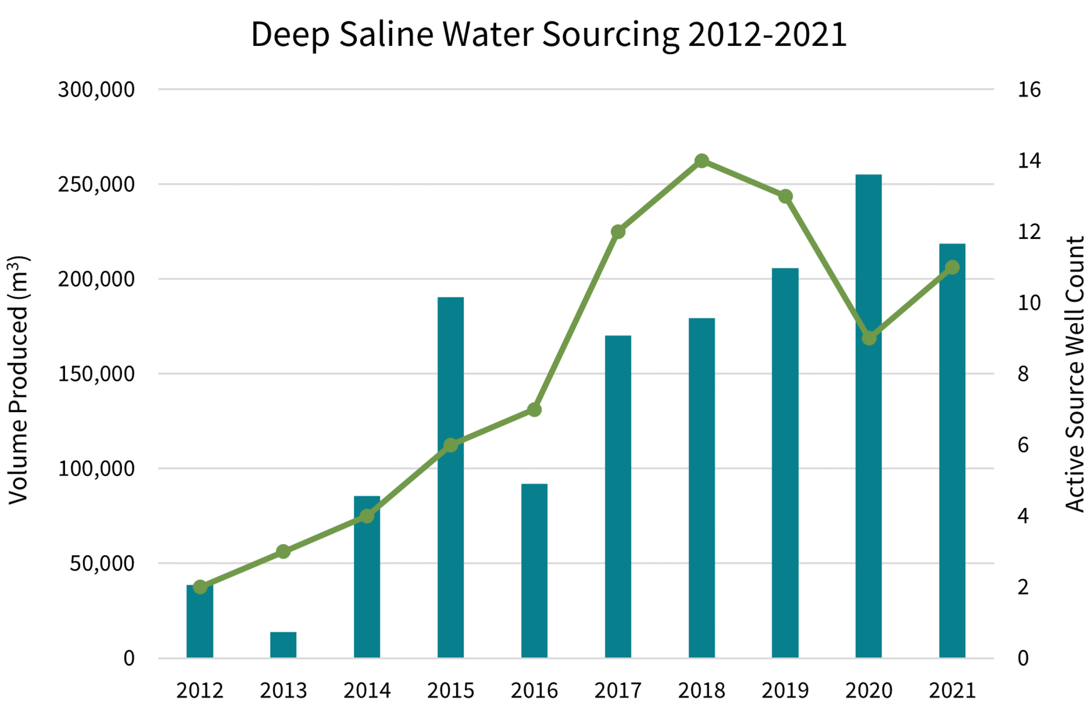
Additional information regarding disposal wells can be found on the Commission's website. Chapter 3 of the Water Service Wells Summary Information Document and Acid Gas Disposal Wells Summary Document provide comprehensive guides on the regulation of disposal wells in B.C. Individual disposal well approvals (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 Center**, Drilling Data for All Wells in B.C. zip, water_gas_disposal file. A new **Disposal Dashboard** provides a concise view of the performance of each well as well as the projected remaining disposal capacity.

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.

Discussion: Deep Saline Water Production

Deep saline water source wells extract “deep groundwater”, as defined in the Water Sustainability Regulation and operate primarily to supply hydraulic fracture stimulation fluid, as an alternative to the use of surface water. Deep water source wells producing salt water are excluded from the requirements of the Water Sustainability Act for a water production licence, however, these wells are subject to normal Commission regulation for well lifecycle permitting and monthly volumetric reporting. In some cases, deep water source reservoirs contain small amounts of natural gas in solution at reservoir conditions, which is separated at surface upon production, and for royalty purposes, the wells are designated as gas wells. These wells remain in internal well counts as Source, based on the permit intent. The following Figure 35 illustrates the trend in deep saline water source well activity. Some source wells withdraw from the same reservoir utilized for active disposal, with the deep subsurface acting as effective storage. The Commission does not maintain an inventory for deep saline reservoir ‘reserves’, however, understanding of the location and potential reservoir size is informed from the extensive data obtained from disposal wells.

Figure 35: Annual Deep Saline Water Data 2012-2021



Discussion: 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 over 98 per cent of wells drilled in 2021, requires hydraulic fracture stimulation to achieve economic production rates. The fracking process is described in the Factsheet ‘Hydraulic Fracturing’.

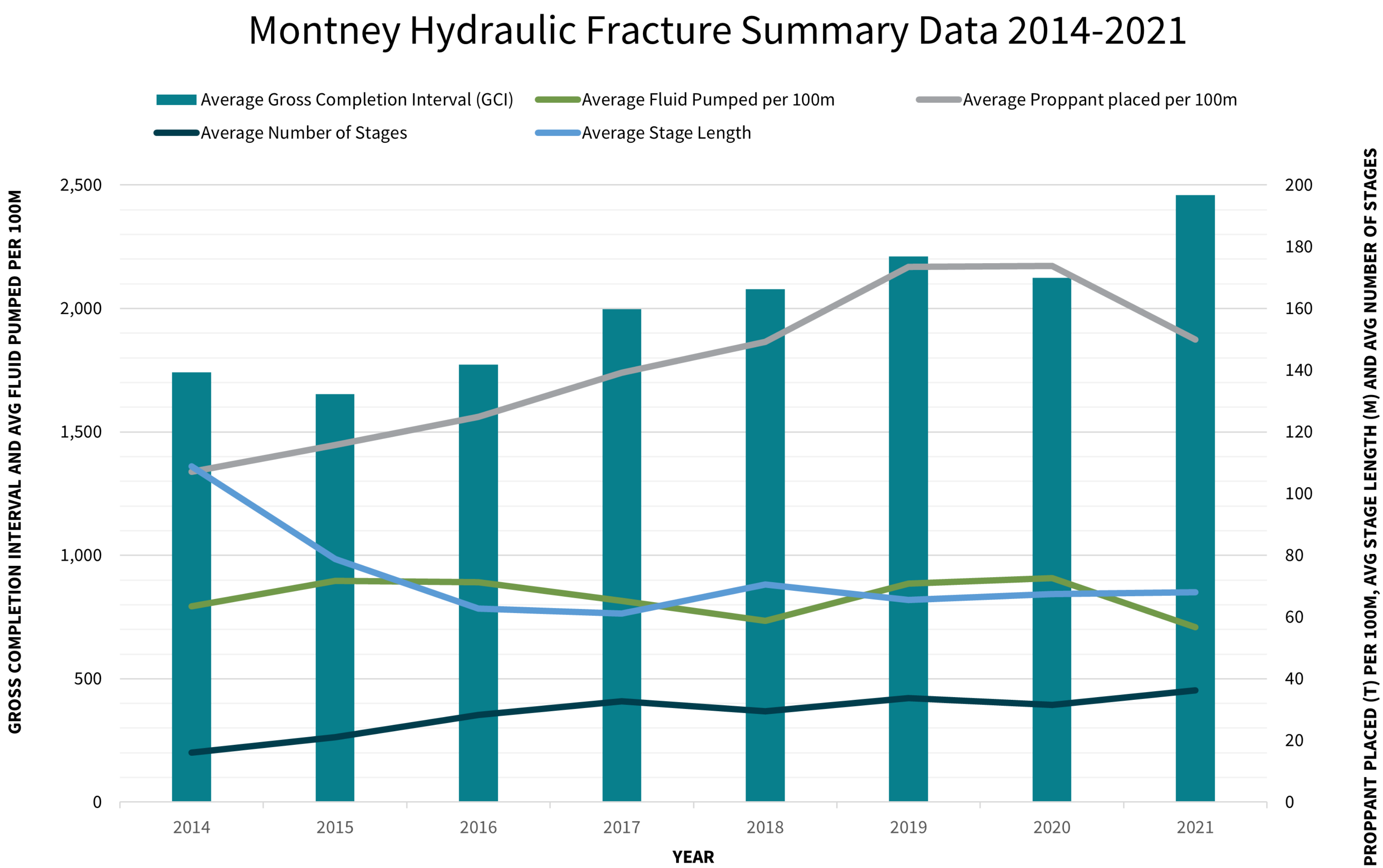
Hydraulic fracturing technology has been utilized in wells in the province since the 1950’s. Applied to vertical wells, these were typically small in comparison to modern programs. Beginning around 2004, when coupled with horizontal drilling, much larger areas of the deep target formations could be stimulated, 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, has now ceased in the Liard and Horn River. Over 11,000 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 the map of B.C.’s oil and gas plays on page 5. Through the 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 layer sub-units, each with these variations. The following graphs include data for Montney wells representing average values and trends, unless specified as data for specific sub-layer or region. The Montney is recognized as a single formation for regulatory purposes, however, is commonly subdivided into Upper, Upper Middle and Lower Middle for development and analysis.

Figure 36 shows horizontal well lengths, or gross completion interval (GCI), has been increasing since 2014 with a jump of several hundred metres, on average, in 2021. The proppant placed per 100m decreased slightly in 2021. Advances in fracking optimization may allow for less proppant to accomplish similar or better production and EUR. Water injected dropped similarly to the proppant placed, possibly indicating frac volume placed has been reduced to achieve a similar number of frac intervals, or stages, which have remained rather constant. Data on water sources and use for oil and gas activities is outlined in other Commission reports.

Figure 36: Montney Hydraulic Fracture Summary Data 2014-2021



In closer detail, Figure 37 shows the average proppant and pumped fluid by Montney stratigraphic layer. While the water pumped in the Upper Montney has varied little, the Middle Montney targets have seen varying fluid use since 2014. All three targets have settled in around 700 m3/100m of well length. Proppant placed per 100m of well length has increased for all three targets. Overall, the proppant to fluid ratio has gone down, meaning the injection slurry is denser (see figure 38).

Figure 37: Annual Average Proppant Placed and Fluid Pumped 2014-2021

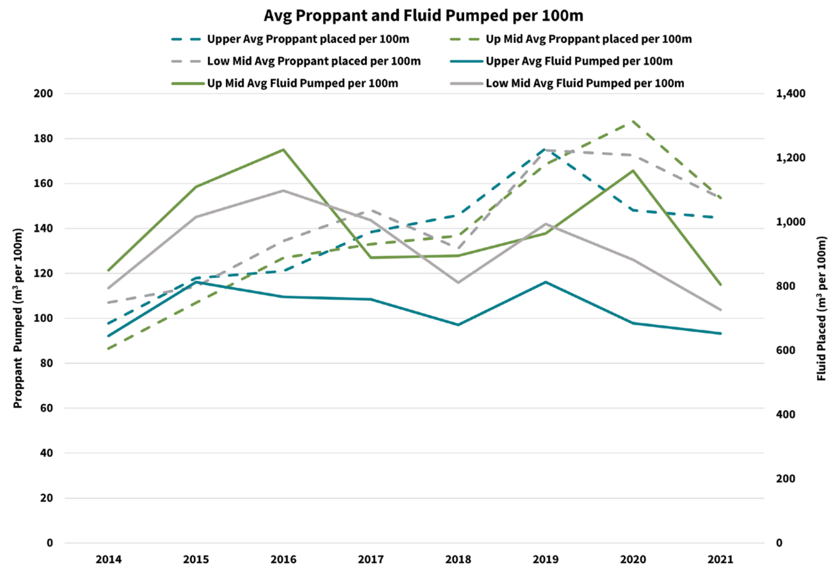
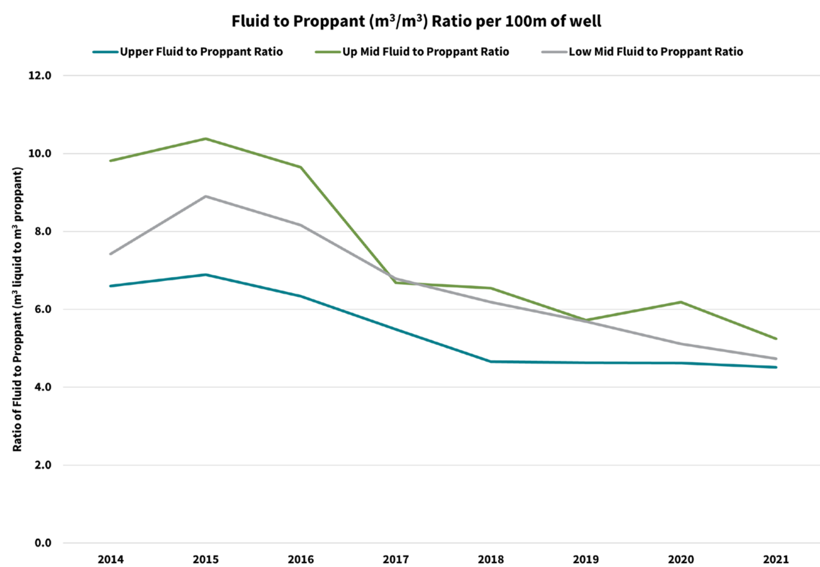


Figure 38: Annual Fluid Ratio 2014-2021



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 to optimize production. Fractures in dry gas are designed to maximize fracture extent, whereas recovery of wet gas, relies on fracture density. Optimizing the distance between horizontal wells demands effective access to and stimulation of the rock between wells, while limiting "frac hit" contacts.

Figure 39 depicts the length of horizontal completion interval and the average length of the stages in each stratigraphic interval. Stage lengths have reduced over the years with all three layers settling around 70m. The well gross completion lengths (GCI) have steadily risen throughout the years, as wells have gotten longer. This indicates less surface disturbance with more resource reach.

Figure 39: Annual Well and Stage Lengths by Montney Stratigraphy 2014-2021

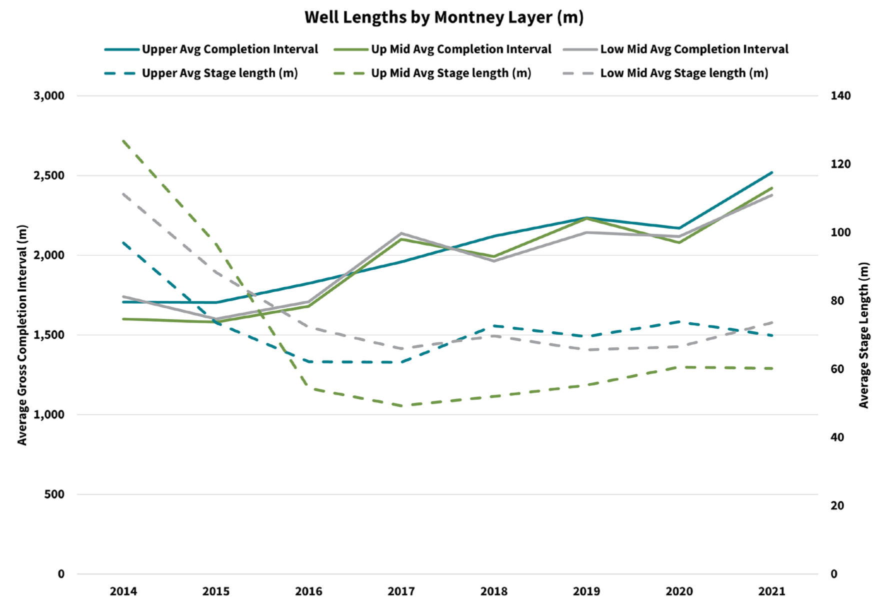


Table 5: Average Montney Well Lateral Length by Well Vintage

Rig Release Year	Average Lateral Length (m)
2014	1,784
2015	1,850
2016	1,986
2017	2,164
2018	2,275
2019	2,310
2020	2,406
2021	2,684

Figure 40 below shows the variation in stages completed using open hole frac assemblies (no cement, external packers) and cased type completions (cemented). From this plot, it becomes clear in the beginning of 2017, there was a reversal of preference, with cemented stage completions outnumbering open hole completions. However, the closing gap in 2020 and 2021, shows a closer to equal populations. Again, this may reflect which operators have been the most active during the past two years, since each operator tends to complete their wells in a consistent manner.

Figure 40: Well Completion Types

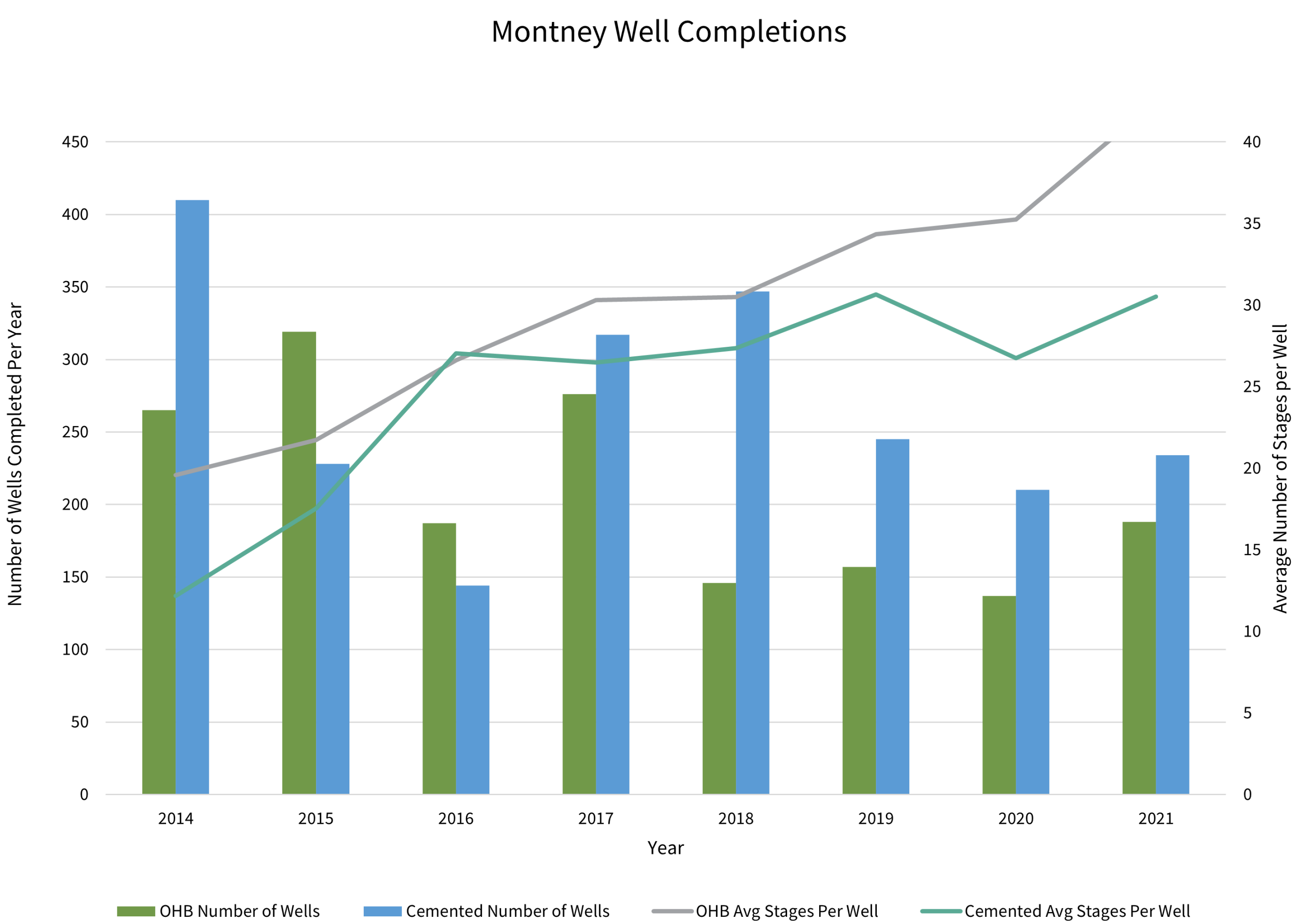
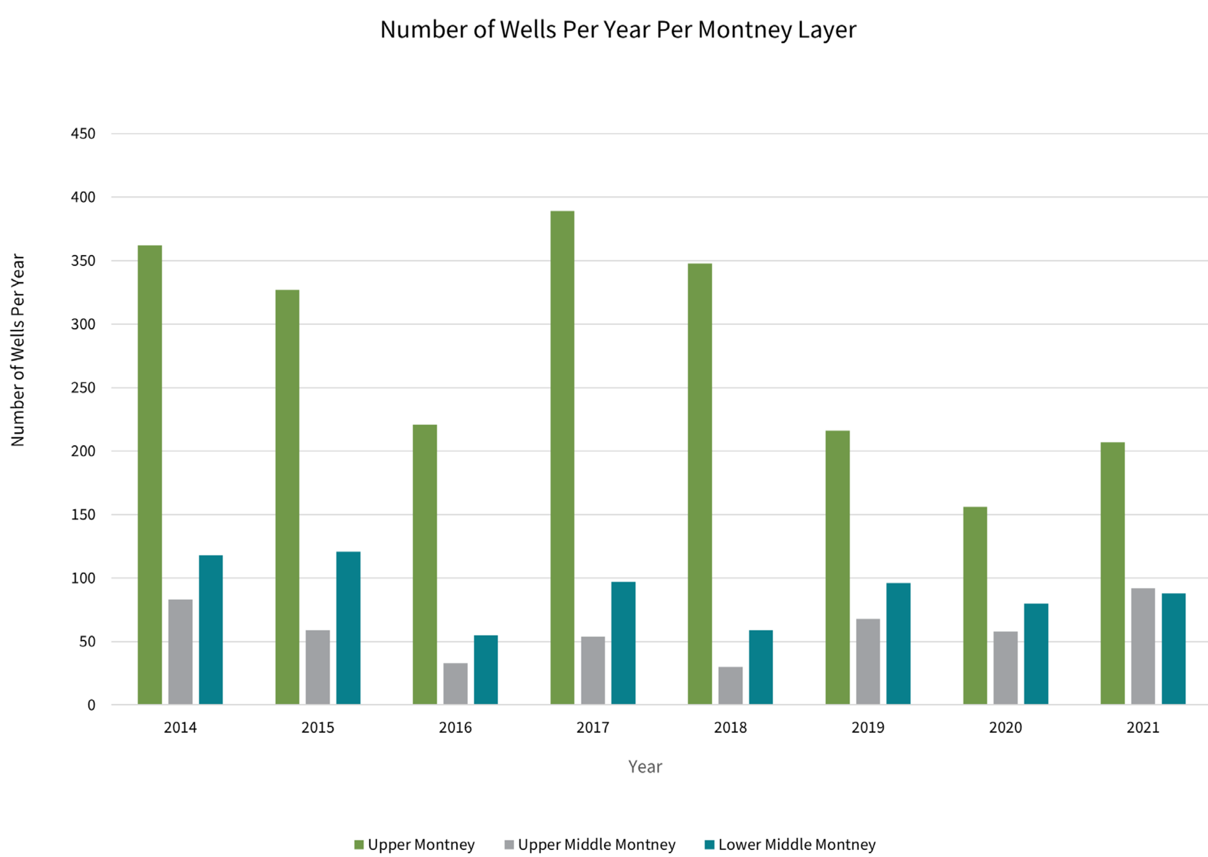


Figure 41 below shows the Montney layer targets each year. From this plot, it becomes clear the Upper Montney (U) is the most targeted layer with over 2,200 wells completed since 2014. Next is the Lower Middle (LM) layer with over 700 wells and the Upper Middle (UM) has the fewest wells at approximately 475 wells. As mentioned above, the various Montney layers bear different hydrocarbon products – from dry gas to light oil. Operators choose targets depending on the market price and ability to ship these products.

Additional information on hydraulic fracturing is available at [Hydraulic Fracturing | BC Oil and Gas Commission (bcogc.ca)]

The Commission's detailed hydraulic fracturing database, the source for graphs in this section, is available in the Commission's Data Centre (Hydraulic Fracture Summary Data). Additionally, information regarding frac fluids can be found in the Commission's FracFocus report.

Figure 41: Montney Stratigraphic Targets per year



Discussion: Depleted Pool Review

A special focus for this 2021 report was a review of the remaining reserves of inactive gas and oil pools. A review of production activity resulted in hundreds of gas and oil pools being assigned a reserves status of "pool depleted", as noted in the Gas Reserves and Oil Reserves tables. A criteria of no production for over 10 years was utilized, as there have been virtually no cases of pool production reactivation following this period of inactivity. In some pools, all wells have been decommissioned (abandoned), though this was not a requirement for the change in reserves status.

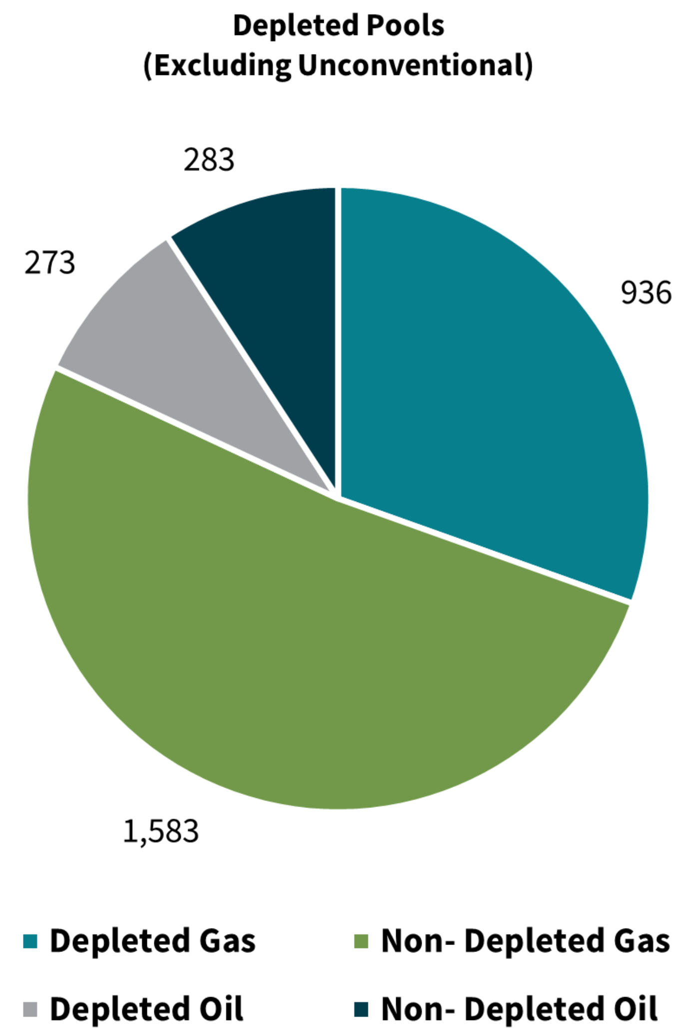
As a result of this review project, 620 pools were changed to depleted status, adding to the 589 distinct pools previously noted in this category for a total of 1,209 gas and oil pools with a status of depleted. All pools in this category are "conventional" type.

The remaining reserves of each of these pools is now zero. In most cases, the OGIP or OOIP value was left unchanged, and the recovery factor was adjusted to match recoverable reserves to cumulative production. The pools range in size from a single well to many wells.

The depletion of conventional pools reflects the shift in development activity over the past 16 years to unconventional resources. Existing conventional wells have been reaching economic production limits, and the lack of exploration has reduced new conventional pool discoveries to near zero.

The following graph compares the number of conventional pools with remaining reserves to the number of depleted pools.

Figure 42: Number of Conventional Pools with Remaining Reserves to the Number of Depleted Pools



Unconventional reserves are generally mapped as large regional pools. However, production and pressure depletion often indicate limited effective drainage contact between wells, effectively “single-well pools” aggregated for reserves methodology purposes, as noted in the Gas Reserves section of this report.

The result of this review has been a limited impact to total provincial remaining reserves, due to strong growth in Montney reserves in comparison to remaining conventional contribution.

The identification of depleted pools aids in the assessment of potential produced water disposal, acid gas disposal, and carbon dioxide storage (CCS) opportunities. The CCS section of this report contains estimates of storage potential based on the voidage pore space of depleted pools, in addition to consideration of future storage space in depleting unconventional zones.

Discussion: Carbon Capture Utilization and Storage

As of December 2021, British Columbia does not yet have an operating dedicated carbon capture utilization and storage (CCUS) project, however, significant interest has been shown by a variety of proponents. As noted in the Acid Gas Disposal section of this report, the injection of CO_2 in association with H_2S, has been ongoing in the province for decades as a proven technology. The Commission provides a guideline for CCUS applications, which aligns with acid gas disposal requirements and the Canadian Standards Association (CSA) Standard Z741.

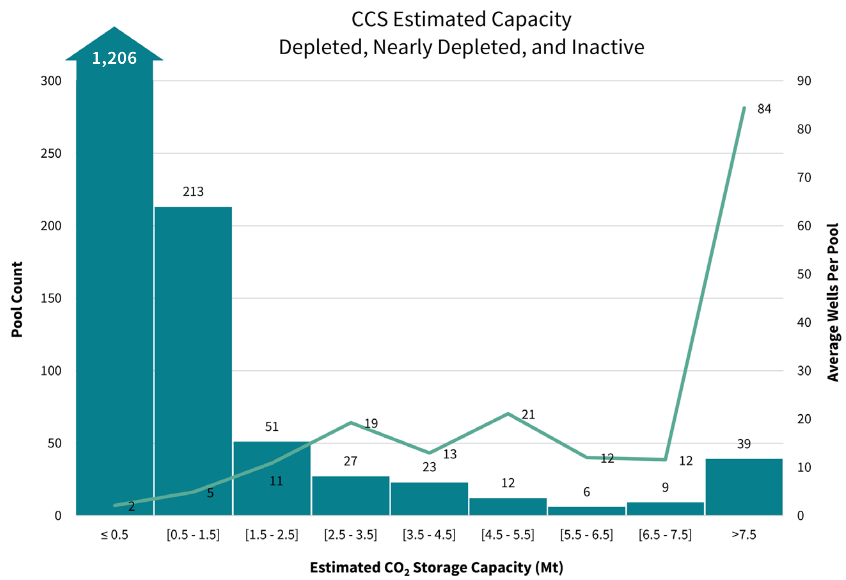
As noted in the Depleted Pools feature section in this report, the Commission has highlighted gas and oil pools which have reached the end of their economic life. While some of these pools are suitable for CCUS, many are challenged for this purpose due to location, depth, age of existing well penetrations, etc. Isopach net pay maps of conventional pools are published by the Commission, which provide the location and extent of each pool.

The Commission has undertaken a cursory calculation of CCUS "reserves", based on depleted pools reservoir voidage space. An estimate of 1,821Mt may be available. This number is provided as an estimate only, as it includes a number of assumptions and does not include any economic analysis.

Deep saline aquifers are another target for CCUS potential. Utilized by numerous water disposal wells, the Commission has been gathering and publishing data on the performance of these wells and reservoirs, which will assist with CCUS evaluation. See the Water Disposal Wells section of this report for further information.

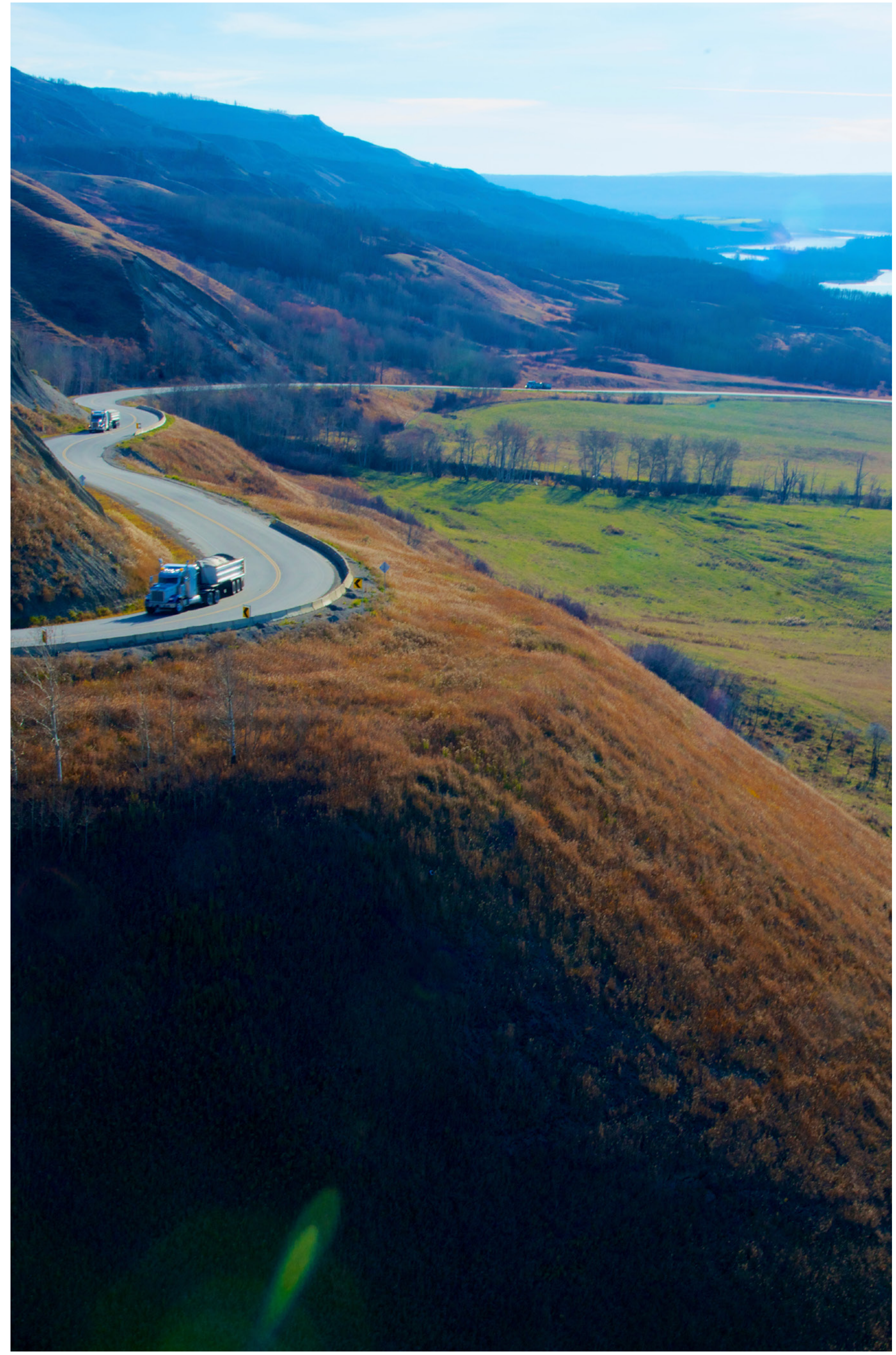
Histogram figure 43 illustrates the distribution of CO_2 storage capacity of pools with present potential for CCS study. Of the number of pools identified, 59 per cent have a capacity equal to or less than 0.5 Mt of CO_2, representing seven per cent of the total capacity of the population of pools.

Figure 43: CCS Estimated Capacity Pool Histogram



While small pools represent limited individual storage capacity, a close geographic aggregation of pools may be a suitable target of a project. A limited capacity pool may be suited for a fit-for-purpose CCS opportunity. An advantage of small pools is the limited number of well penetrations, lessening potential well integrity issues that may be encountered in a large pool with dozens of legacy wells. Smaller pools also represent a smaller area of concern for later drilling to access deeper resources.

Finally, CO_2 injection is utilized in numerous North American oil pools to increase production as enhanced oil recovery (EOR) projects. None of these have operated in British Columbia. The Oil Reserves table in this report identifies remaining pool reserves. All major pools have been subject to waterflood oil recovery, and some may respond favourably to EOR projects, however detailed analysis would be required.



Discussion: Facilities and Pipelines

In the midst of the COVID challenges, the 2020 calendar year was busy for gas plant construction and start-ups in B.C. As shown in green below, during 2020 there were three new gas plants brought on stream along with three plant expansions. The new plants increased processing capacity by 15,420 e^3m^3/d (547 mmscf/d), and the expansions added 12,624 e^3m^3/d (448 mmscf/d). As shown in yellow below, in 2021 the B.C. gas plant processing capacity increased by 9,136 e^3m^3/d (324 mmscf/d) and this was only through expansions of two existing gas plants.

There are currently 72 active gas plants in B.C., and 16 of these are connected to the hydro grid with 12 of those being fully electrified from that grid. It is important to note these 16 electrified gas plants are currently processing approximately 40 per cent of the total natural gas being processed in B.C. The majority of recently permitted, or new applications for gas plants and expansions are proposing to be fully electrified from the hydro grid, or on temporary site power generation until connected to the grid.

Table 6: B.C. Gas Plant Capacity Additions 2020-2021

FAC Code	Operator Name	Plant Name & Location	New/Previous Licensed Inlet Capacity e^3m^3/d	New (N) or Amended/ Expanded (A)	New Capacity e^3m^3/d	Capacity increase via Expansion	Electrification	On/Off the Grid
18246	Altagas	Townsend a-33-J/94-B-16	11,213	A	15,581	4,368	No	Off
18270	ARC	Dawson 13-7-80-14W6	2,760	A	5,947	3,187	Yes	On and Off
17909	Canbriam	Altares b-72-A/94-B-8	4,814	A	8,354	3,540	No	Off
7808	NorthRiver	Tupper West 5-1-77-17W6	6,760	A	11,829	5,069	Yes	On and Off
18309	Petronas	Town North b-89-J/94-B-16	9,910	N	9,910		No	Off
26427	Tourmaline	Gundy c-60-A/94-B-16	5,596	A	11,192	5,596	No	Off
26801	CNRL	Nig Creek b-48-G/94-H-4	2,119	N	2,119		No	Off
26856	Conocophillips	Inga 2-10-88-23W6	3391	N	3,391		No	Off

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])

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.

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.

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 Reserves (IR) less cumulative production.

Reserves

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable.

Reserves are further classified according to the level of certainty associated with the estimates and may be sub classified based on development and production status (from COGEH).

Resource

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

Saturation (Water)

The fraction of pore space in the reservoir rock occupied by water upon discovery.

SPEE Monograph 3

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.

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, 2021

	Oil ($10^3 m^3$)	Raw Gas ($10^6 m^3$)
Initial Reserves, Current Estimate	138,660	3,447,399
Discovery 2021	0	0
Revisions 2021	-1,006	245,363
Production 2021	676	64,222
Cumulative Production Dec. 31, 2021	125,403	1,354,545
Remaining Reserves Estimate Dec. 31, 2021	13,257	2,092,854

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	-8463		8,506	223,964	277,628
1987	497,466	1,986	-5940		9,810	233,794	263,777
1988	500,738	6,083	-1661		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	-3301		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	-2394		22,811	405,157	283,045
1998	712,677	9,957	14,502		23,375	428,822	283,855
1999	743,816	13,279	17,824		23,566	453,000	290,816
2000	772,221	13,832	14,571		23,894	477,381	294,800
2001	811,146	7,199	31,690		26,463	504,620	306,526
2002	843,612	19,004	13,462		28,348	533,548	310,064
2003	889,488	19,317	26,282		26,639	562,560	326,928
2004	973,771	6,412	65,149	12,897	26,430	584,033	389,738
2005	1,065,288	8,974	63,268	19,104	27,854	620,696	444,592
2006	1,114,562	15,356	33,912		28,056	652,137	462,425
2007	1,172,136	21,468	36,109		29,362	689,209	482,927
2008	1,328,729	6,559	150,167		30,346	722,769	605,280
2009	1,415,172	30,331	56,133		30,846	757,291	657,881
2010	1,724,769	275,942	33,691		33,202	792,798	931,971
2011	1,809,591	7,909	76,934		40,519	834,715	974,876
2012	2,014,054	1,646	202,809		40,482	875,580	1,138,474
2013	2,116,236	428	101,754		43,722	919,007	1,197,229
2014	2,408,673	0	292,437		46,222	964,803	1,443,870
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
2021	3,447,399	0	245,363		64,227	1,354,622	2,092,853

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

Table A-3: Historical Record of Oil Reserves

Year	Estimated Ultimate Recovery 10^3m^3	Yearly Discovery 10^3m^3	Yearly Revisions 10^3m^3	Yearly Other 10^3m^3	Annual Production 10^3m^3	Cumulative Production at Year-End 10^3m^3	Remaining Reserves at Year-End 10^3m^3
1977	72,841	4,159	-84		2,201	46,318	26,523
1978	77,826	2,650	2,376		2,004	48,280	29,546
1979	78,882	427	629		2,140	50,397	28,485
1980	80,043	234	927		2,002	52,399	27,644
1981	79,968	143	-218		2,060	54,459	25,509
1982	80,760	126	666		2,095	56,554	24,206
1983	82,149	661	727		2,079	58,634	23,515
1984	79,551	781	-3,378		2,113	60,747	18,805
1985	82,887	1,767	1,569		1,944	62,691	20,196
1986	83,501	456	144		2,010	64,701	18,786
1987	84,201	631	68		2,084	66,793	17,361
1988	85,839	1,238	-50		1,937	68,759	16,623
1989	89,899	2,306	2,402		1,978	70,737	19,129
1990	90,650	569	181		1,954	72,714	17,823
1991	91,606	233	630		1,974	74,689	16,911
1992	94,030	823	1,596		2,017	76,750	17,273
1993	96,663	803	1,830		1,976	78,726	17,925
1994	99,619	1,477	1,482		1,929	80,664	18,956
1995	102,823	2,887	290		1,997	82,658	20,167
1996	106,009	1,306	1,878		2,205	84,856	21,153
1997	110,765	3,199	1,561		2,525	87,401	23,364
1998	116,294	815	4,717		2,670	90,105	26,189
1999	118,840	345	2,201		2,338	92,453	26,388
2000	122,363	504	3,018		2,568	95,031	27,357
2001	123,048	106	582		2,569	97,591	25,478
2002	122,245	427	-1,233		2,426	99,977	22,313
2003	124,660	424	1,990		2,203	102,234	22,426
2004	125,953	154	947	188	2,015	104,104	21,873
2005	126,941	247	636	110	1,750	106,086	20,857
2006	125,845	222	-1,322		1,631	107,603	18,244
2007	128,971	266	2,859		1,520	109,283	19,692
2008	129,117	162	25		1,341	110,632	18,485
2009	131,172	289	1,766		1,282	111,924	19,252
2010	131,840	643	28		1,270	113,197	18,653
2011	132,414	99	475		1,154	114,253	18,161
2012	134,600	537	1,614		1,222	115,492	19,108
2013	135,883	0	1,278		1,129	116,633	19,250
2014	135,657	0	-226		1,177	117,598	18,059
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	0	-735		935	123,937	16,645
2020	139,666	31	-947		790	124,728	14,938
2021	138,660	0	-1006		676	125,403	13,257

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

Table A-4: Oil Pools Under Waterflood

FIELD	POOL	POOL SEQUENCE	PROJECT CODE	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cum Oil (10^3m^3)	RR (10^3m^3)
BEATTON RIVER	HALFWAY	A	02	3430.1	47.1%	1616.2	1616.2	0.0
BEATTON RIVER	HALFWAY	G	05	1438.4	29.6%	425.8	425.8	0.0
BEATTON RIVER	BLUESKY	A	02	2956.3	37.1%	1098.3	1098.3	0.0
BEAVERTAIL	HALFWAY	B	06	499.0	18.0%	89.8	87.4	2.4
BEAVERTAIL	HALFWAY	H	05	874.1	20.0%	174.8	172.5	2.3
BIRCH	BALDONNEL	C	03	2058.1	49.0%	1008.5	957.7	50.8
BLUEBERRY	DEBOLT	E	03	1211.5	30.0%	363.4	354.2	9.2
BOUNDARY LAKE	BOUNDARY LAKE	A	02	43666.1	48.0%	20959.7	20087.3	872.4
BOUNDARY LAKE	BOUNDARY LAKE	A	03	30218.0	44.0%	13295.9	12934.1	361.8
BOUNDARY LAKE	BOUNDARY LAKE	A	04	5769.2	60.0%	3461.5	3191.6	270.0
BOUNDARY LAKE	BOUNDARY LAKE	A	05	1587.4	65.0%	1031.8	993.2	38.6
BOUNDARY LAKE	HALFWAY	D	03	561.7	20.0%	112.3	108.0	4.4
BOUNDARY LAKE	HALFWAY	I	04	1085.8	40.0%	434.3	376.2	58.1
BUBBLES NORTH	COPLIN	A	02	143.8	29.0%	41.7	41.7	0.0
BUICK CREEK	LOWER HALFWAY	C	19	2761.8	25.0%	690.4	667.3	23.2
BULRUSH	HALFWAY	C	02	96.4	4.3%	4.2	4.2	0.0
CRUSH	HALFWAY	A	02	1449.4	34.7%	503.2	503.2	0.0
CRUSH	HALFWAY	B	02	148.6	33.6%	49.9	49.9	0.0
CURRANT	HALFWAY	A	02	792.7	52.9%	419.0	419.0	0.0
CURRANT	HALFWAY	D	02	121.8	6.6%	8.0	8.0	0.0
DESAN	PEKISKO		03	5388.1	20.0%	1077.6	932.0	145.6
EAGLE	BELLOY-KISKATINAW		02	6928.9	40.0%	2771.5	2601.6	170.0
EAGLE WEST	BELLOY	A	03	20337.5	31.0%	6304.6	6266.5	38.1
ELM	GETHING	B	04	1772.6	7.3%	129.4	129.2	0.2
HALFWAY	DEBOLT	A	03	949.9	10.0%	94.7	94.7	0.0
HAY RIVER	BLUESKY	A	05	36992.5	20.0%	7398.5	6071.8	1326.6
INGA	INGA	A	04	8356.0	39.9%	3334.0	3330.6	3.5
INGA	INGA	A	06	7521.3	31.0%	2335.4	2335.0	0.3
INGA	INGA	A	07	1400.6	44.8%	627.5	627.5	0.0
INGA	INGA	A	08	1716.5	32.5%	557.7	557.7	0.0
LAPP	HALFWAY	C	02	1036.8	43.6%	451.7	451.7	0.0
LAPP	HALFWAY	D	02	395.3	41.9%	165.8	165.8	0.0
MICA	MICA	A	04	1128.7	40.0%	451.5	348.3	103.2
MICA	DOIG	B	04	509.7	30.0%	152.9	123.0	29.9
MILLIGAN CREEK	HALFWAY	A	02	12120.0	52.6%	6376.3	6376.3	0.0
MILLIGAN CREEK	HALFWAY	A	03	2159.6	48.0%	1036.6	1028.3	8.3
MUSKRAT	BOUNDARY LAKE	A	03	1142.8	40.0%	457.1	389.3	67.8
MUSKRAT	LOWER HALFWAY	A	03	464.4	23.0%	107.0	107.0	0.0
OAK	CECIL	B	02	424.3	23.5%	99.8	99.8	0.0
OAK	CECIL	C	03	907.7	55.0%	499.3	449.0	50.3
OAK	CECIL	E	03	1264.5	48.0%	607.0	603.4	3.6
OAK	CECIL	I	03	616.1	39.0%	240.3	237.5	2.8
OWL	CECIL	A	03	717.0	44.7%	320.3	320.3	0.0
PEEJAY	HALFWAY		02	5802.7	38.4%	2227.1	2227.1	0.0
PEEJAY	HALFWAY		03	8937.6	43.0%	3843.2	3818.4	24.7
PEEJAY	HALFWAY		04	10137.3	44.3%	4490.8	4472.6	18.2
PEEJAY WEST	HALFWAY	A	03	1560.6	40.0%	624.3	532.1	92.2
PEEJAY WEST	HALFWAY	C	02	510.9	40.0%	204.4	166.3	38.1
RED CREEK	DOIG	C	03	609.3	30.0%	182.8	152.0	30.8
RIGEL	DUNLEVY	A	02	195.5	9.7%	19.0	19.0	0.0
RIGEL	CECIL	B	02	1502.6	40.0%	601.1	596.8	4.3
RIGEL	HALFWAY	C	02	738.7	26.6%	196.6	196.6	0.0
RIGEL	HALFWAY	C	03	752.3	38.8%	292.0	292.0	0.0
RIGEL	CECIL	G	02	952.7	45.0%	428.7	419.0	9.7
RIGEL	CECIL	H	03	1820.9	50.0%	910.4	888.8	21.6
RIGEL	CECIL	I	02	1962.0	40.0%	784.8	776.9	7.9
RIGEL	HALFWAY	Z	02	104.3	6.6%	6.9	6.9	0.0
SQUIRREL	NORTH PINE	C	03	1376.7	29.7%	408.9	408.9	0.0
STODDART	NORTH PINE	G	04	214.0	35.2%	75.4	75.4	0.0
STODDART WEST	BELLOY	C	05	5784.4	25.0%	1446.1	1387.5	58.6
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%	328.9	328.9	0.0
SUNSET PRAIRIE	CECIL	C	02	420.2	28.6%	120.2	120.2	0.0
SUNSET PRAIRIE	CECIL	D	02	379.3	1.4%	5.2	5.2	0.0
TWO RIVERS	SIPHON	A	03	1475.6	19.0%	280.4	262.8	17.6
WEASEL	HALFWAY		02	3720.0	65.0%	2418.0	2383.3	34.7
WEASEL	HALFWAY		03	1729.5	58.1%	1005.7	1005.7	0.0
WILDMINT	HALFWAY	A	02	2867.9	53.8%	1542.3	1542.3	0.0
WOODRUSH	HALFWAY	E	02	880.6	16.0%	140.9	127.3	13.6
Total				**270,890.3**		**104,125.2**	**100,109.9**	**4,015.3**
% of Total British Columbia Oil Reserves						**75.1%**	**79.8%**	**30.3%**

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)
BRASSEY	ARTEX	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
BULRUSH	HALFWAY	A	02	935.5	40.0%	374.2	338.1	36.1
CECIL LAKE	CECIL	D	03	1,091.3	38.0%	414.7	371.4	43.3
RIGEL	HALFWAY	H	03	702.8	12.9%	90.7	90.7	0.0
STODDART WEST	BELLOY	C	03	1,525.5	25.3%	385.9	384.9	1.1
TOTAL				**4,702.9**		**1,428.6**	**1,348.1**	**80.5**
% OF TOTAL BRITISI COLUMBIA RESERVES						**1.0%**		**0.6%**

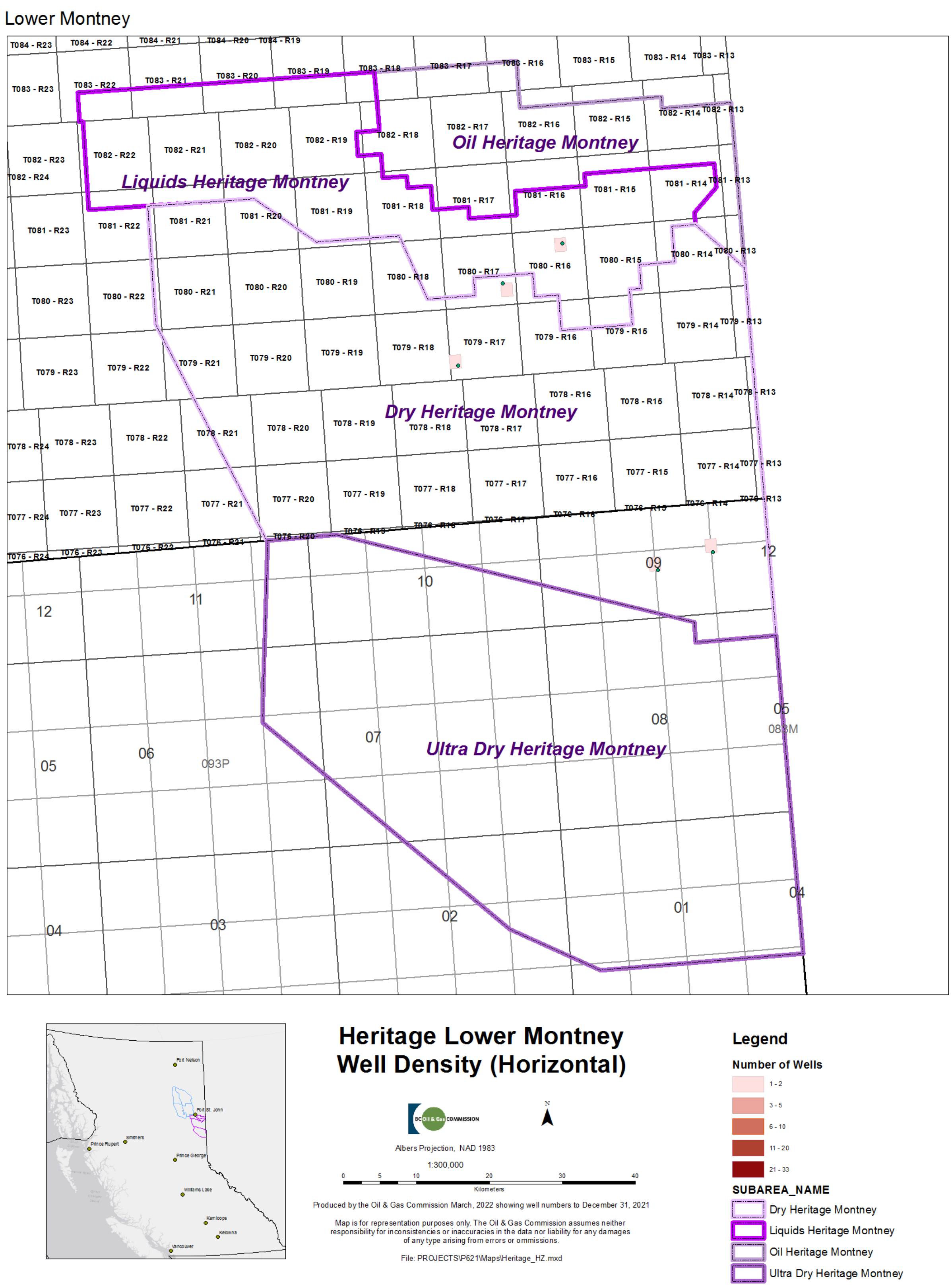
Appendix B

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.

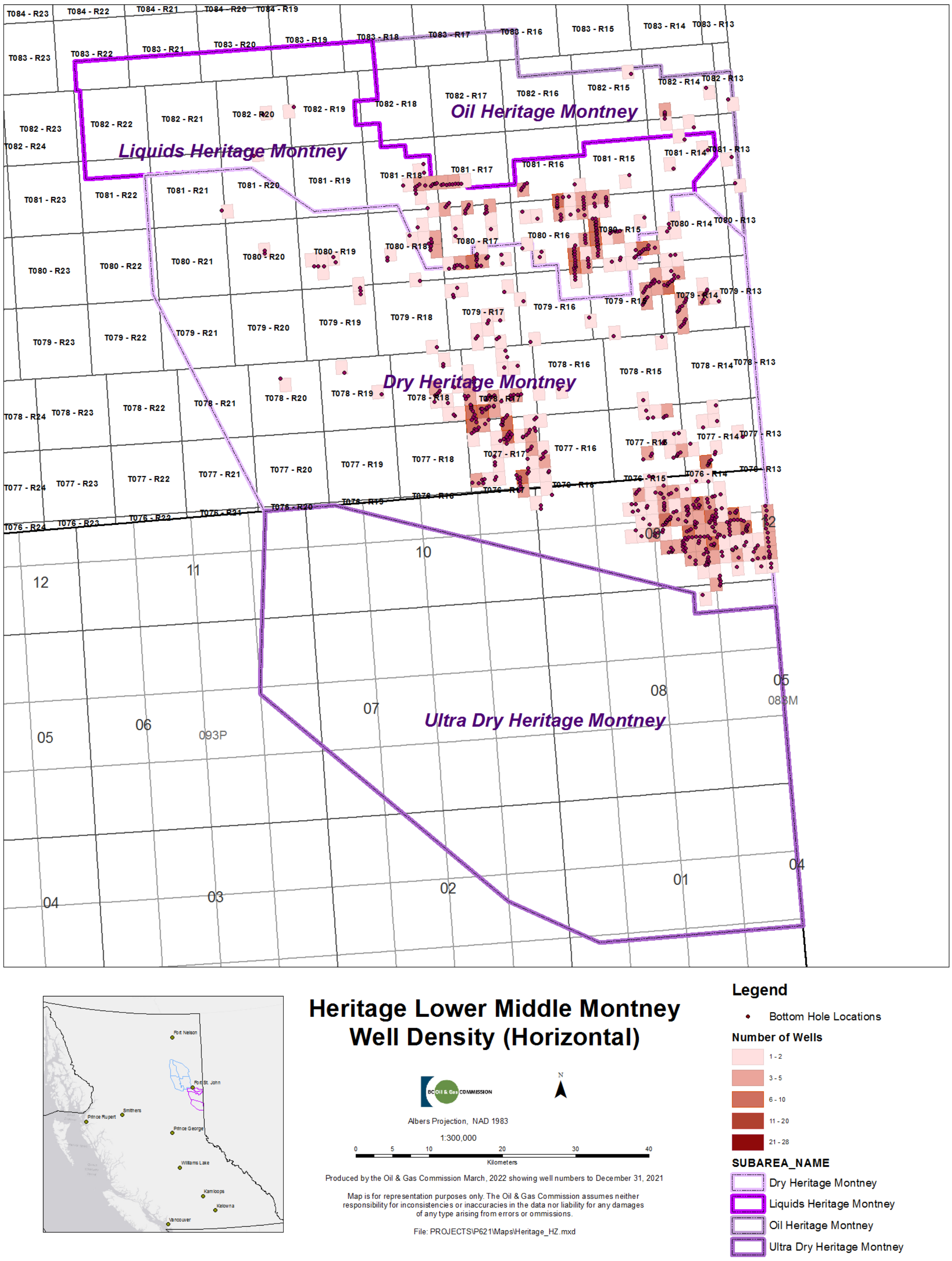
The following well density maps are for the three Montney areas. As illustrated, the variable density and coverage of wells in the areas reflects the current ability to establish proven reserves.

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.

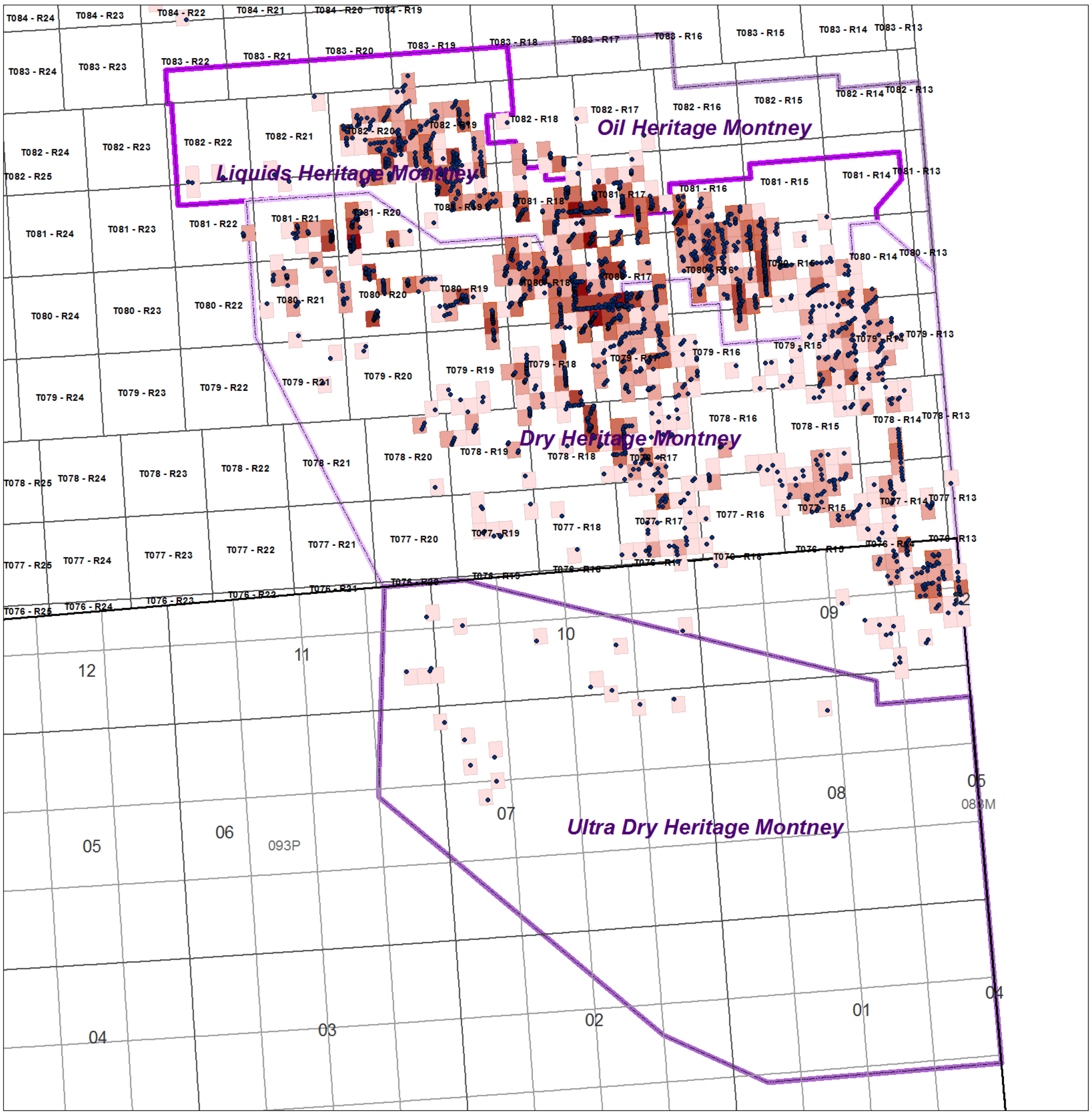
Map B-1: Heritage Montney - Montney “A” Well Density Maps

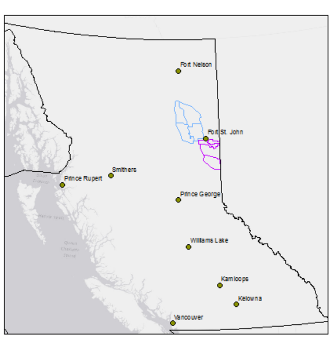


Lower Middle Montney



Upper Montney





Heritage Upper Montney Well Density (Horizontal)

Albers Projection, NAD 1983

1:300,000

0 5 10 20 30 40

Kilometers

Produced by the Oil & Gas Commission March, 2022 showing well numbers to December 31, 2021

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\Heritage_HZ.mxd

Legend

Bottom Hole Locations

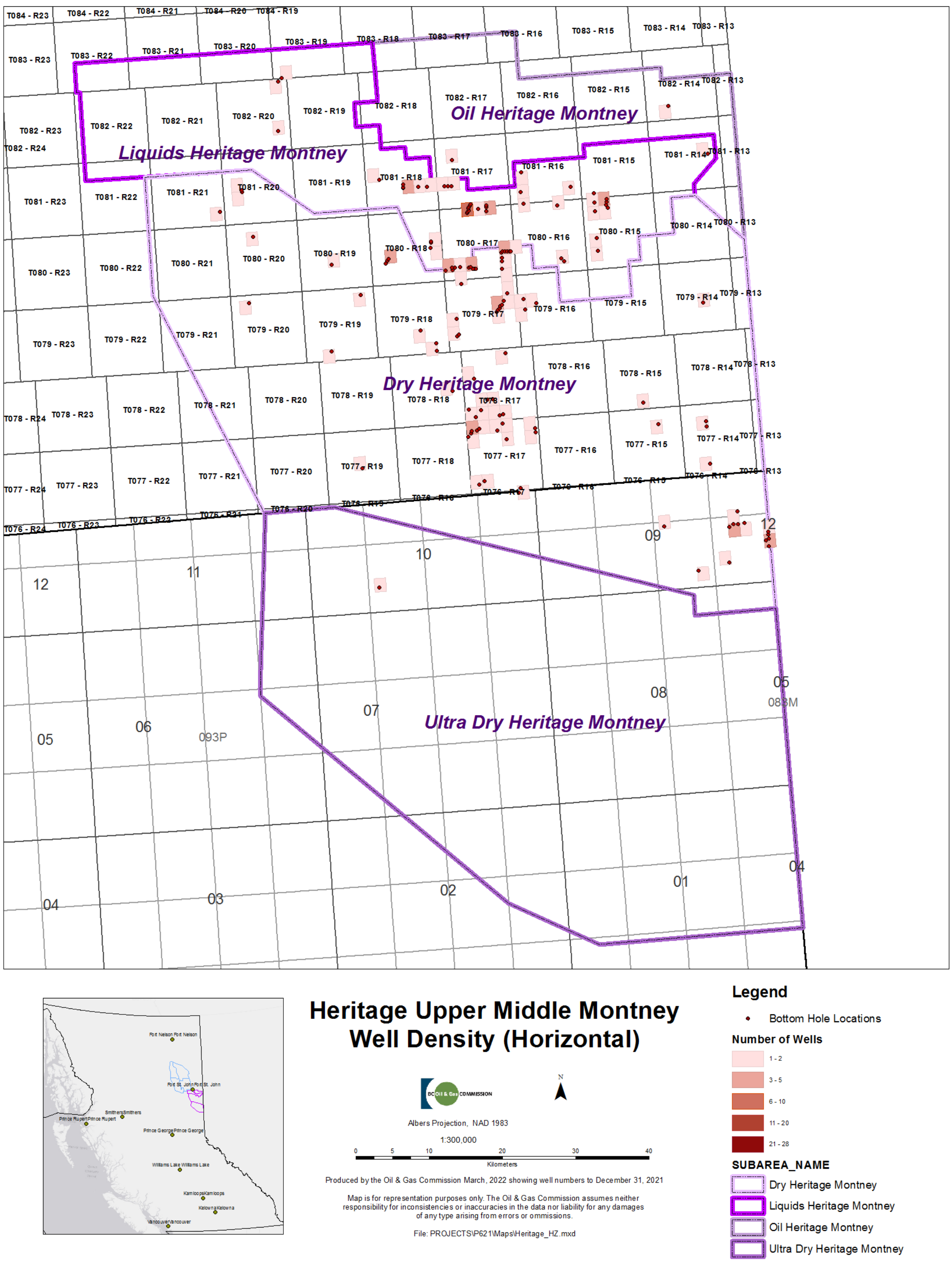
Number of Wells

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

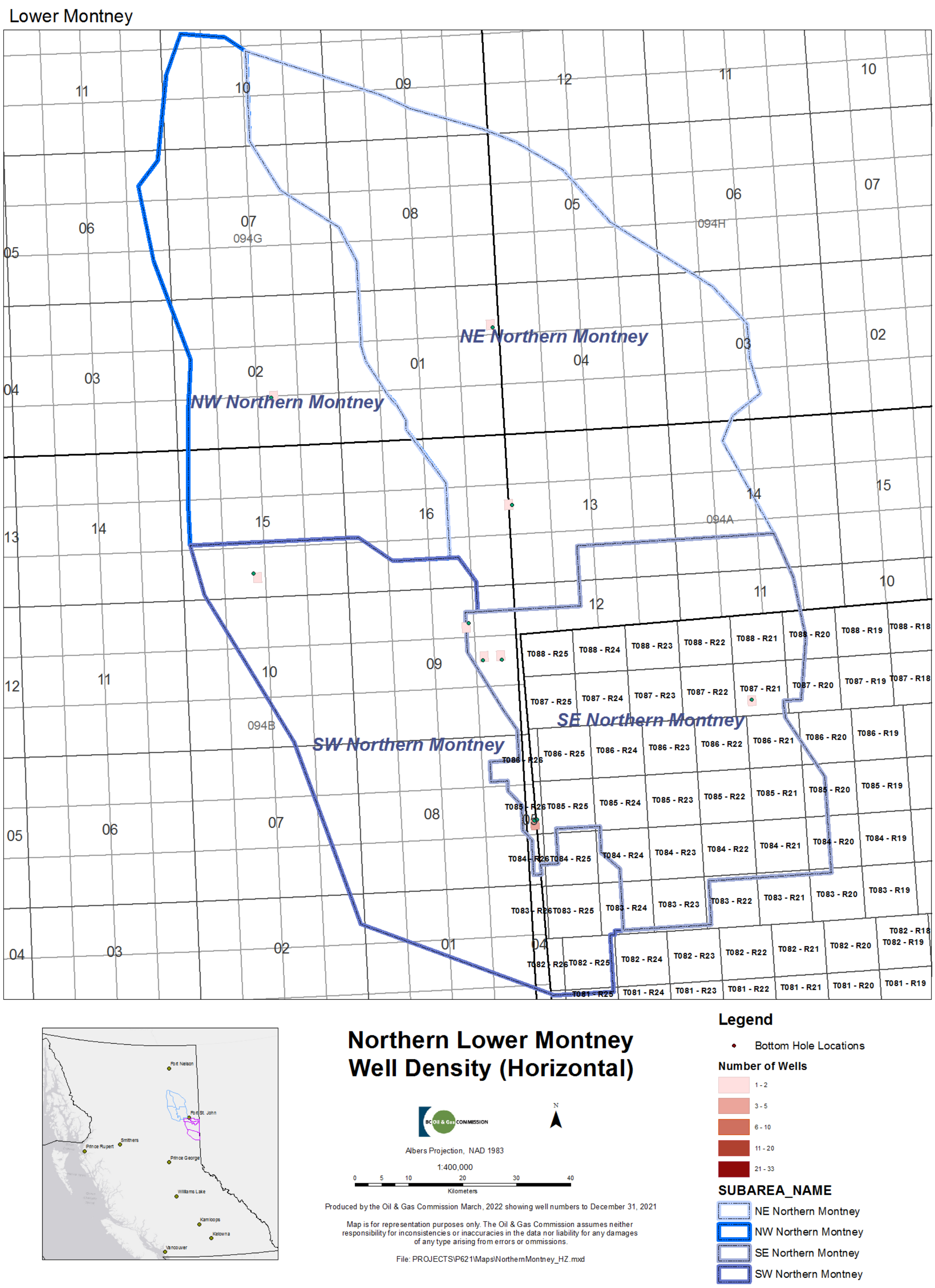
SUBAREA_NAME

Dry Heritage Montney
Liquids Heritage Montney
Oil Heritage Montney
Ultra Dry Heritage Montney

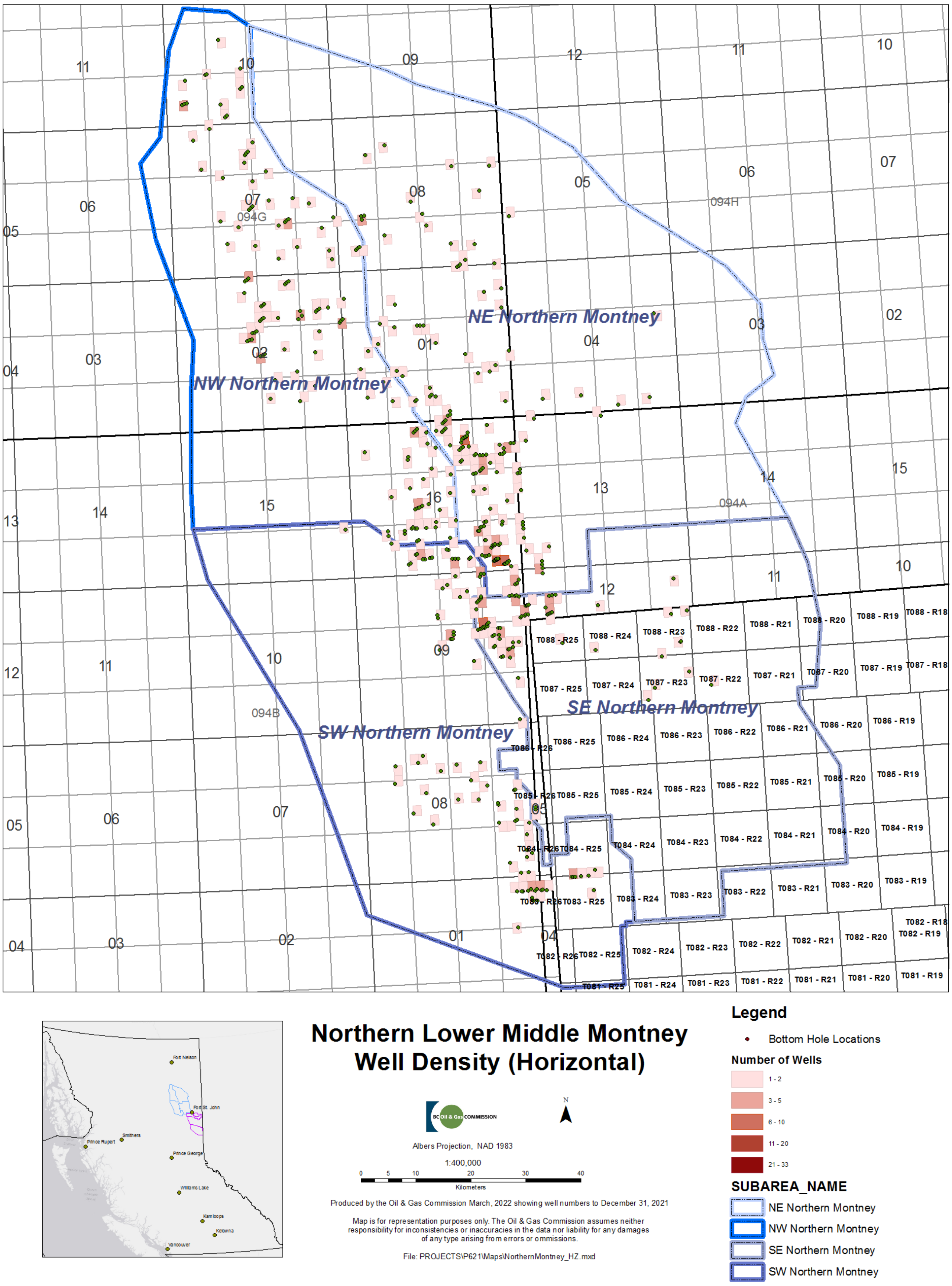
Upper Middle Montney



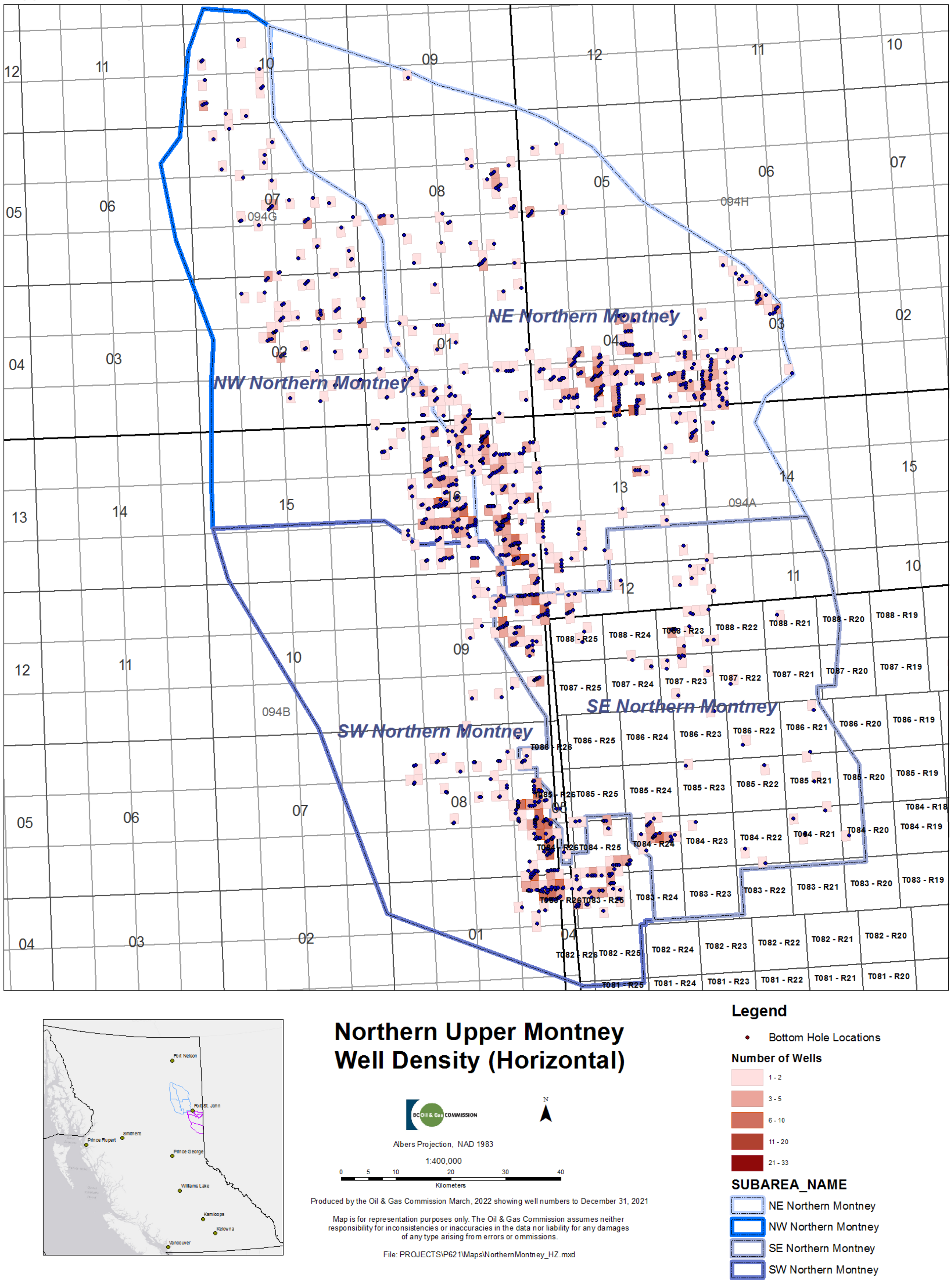
Map B-2: Northern Montney - Montney “A” and Doig Phosphate Well Density Maps



Lower Middle Montney



Upper Montney



Upper Middle Montney

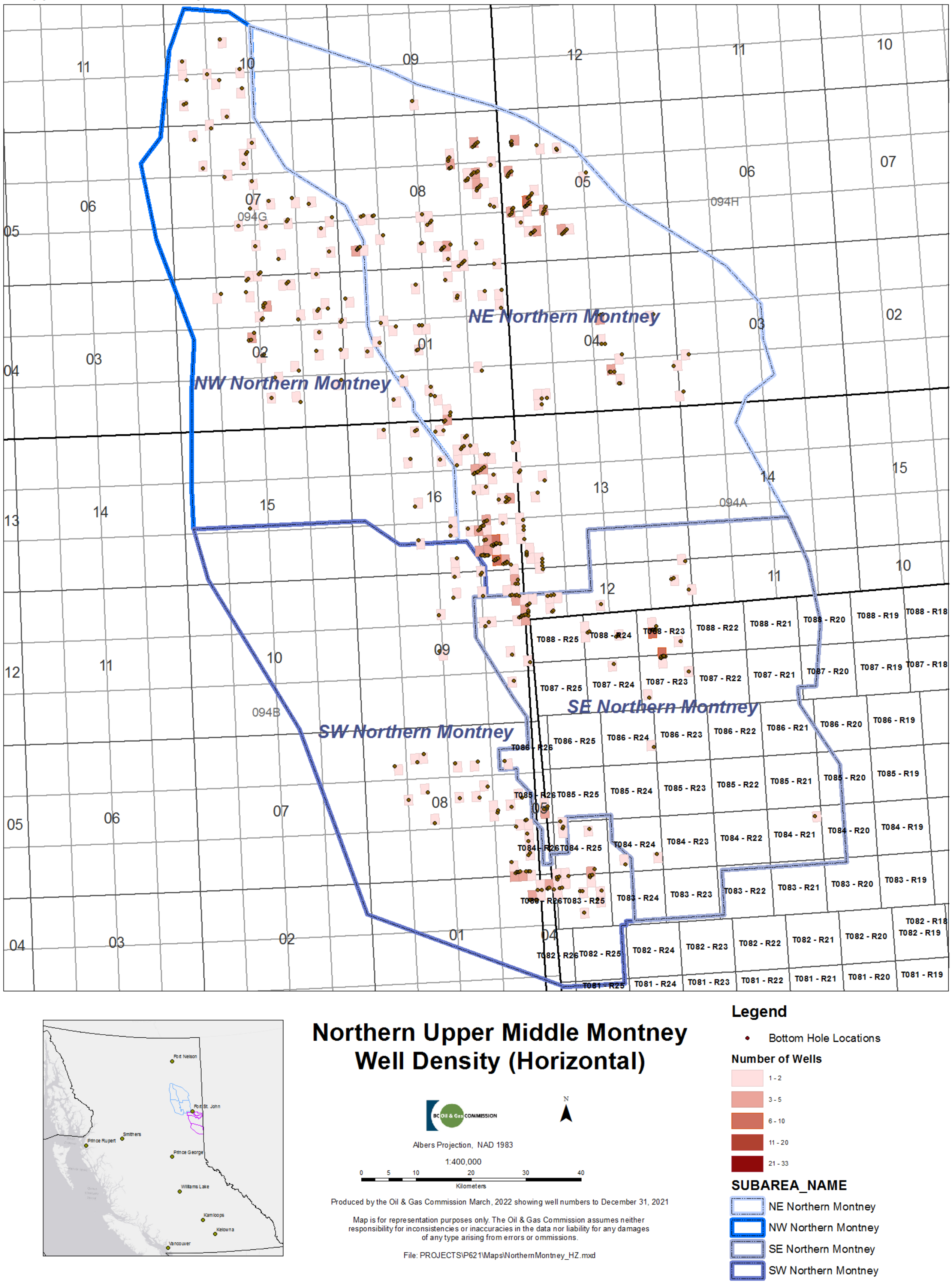


Figure B-1 below, shows overall Montney well population EUR values; P90 of 34 e^6m^3, P10 of 262 e^6m^3, mean of 139 e^6m^3, and median of 115 e^6m^3.

Figure B-1: Heritage Montney HZ Gas Well EUR Distribution

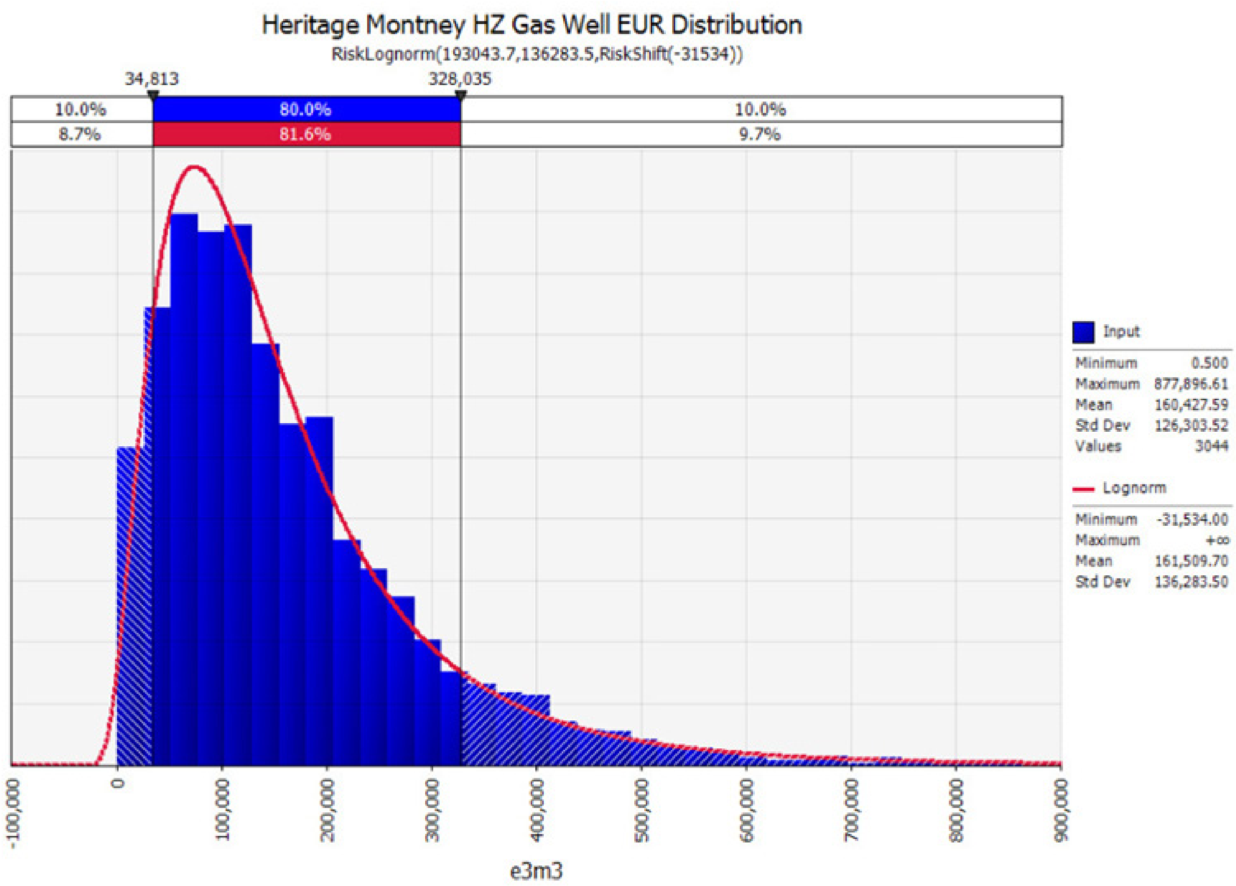
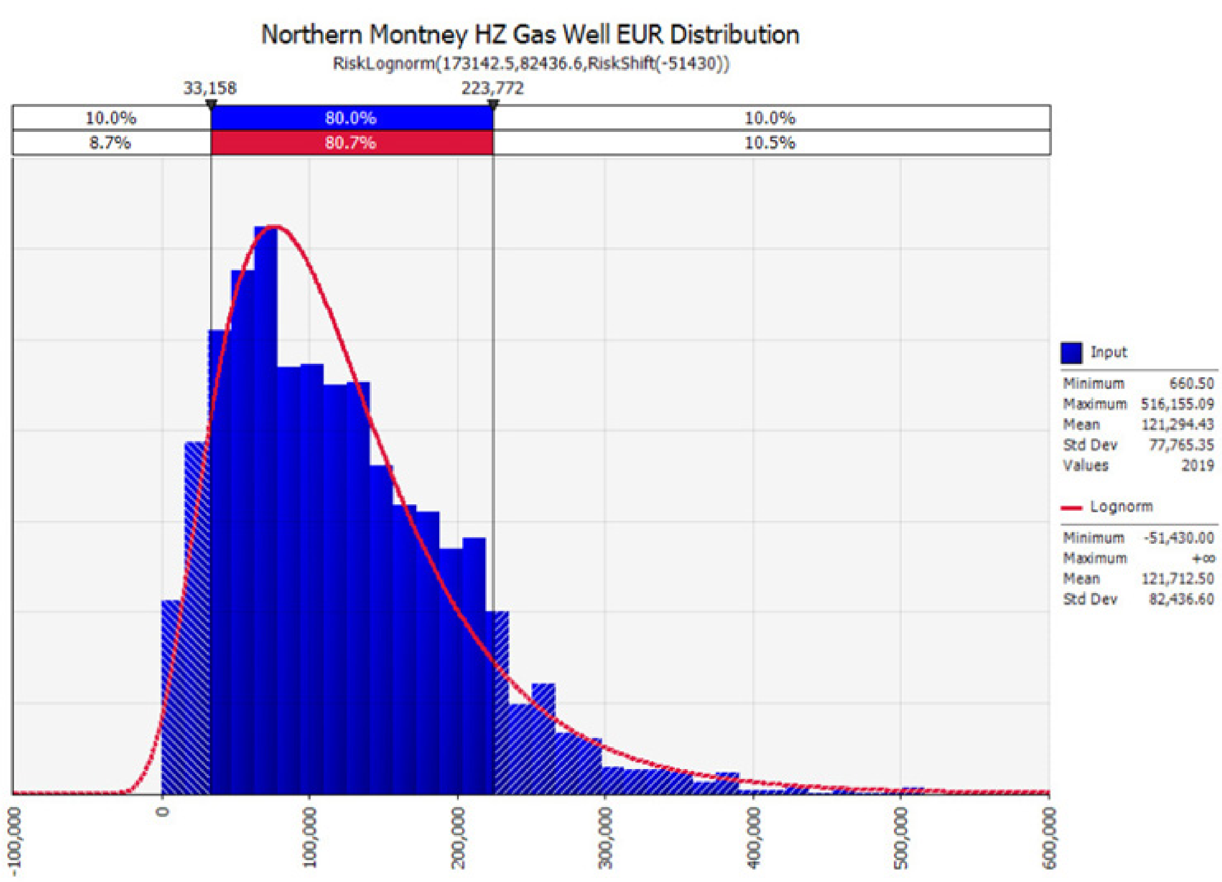


Figure B-2: Heritage Montney HZ Gas Well EUR Distribution



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Name: Ron Stefik, P.L.Eng.	Name: Richard Slocomb, M.A.Sc., P.Eng.

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