British Columbia’s 2022 Oil and Gas Reserves and Production Report

August 2023

BC Energy Regulator

Revision 1 January 2024

BRITISH COLUMBIA **ENERGY REGULATOR**

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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 and the environment
- Supports reconciliation with Indigenous peoples and the transition to low-carbon energy
- Conserves energy resources
- Fosters a sound economy and social well-being

Values

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

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

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.

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

Role of the BC Energy Regulator (BCER)

The British Columbia Energy Regulator oversees the full life cycle of energy resource activities in B.C., from site planning to restoration. We ensure activities are undertaken in a manner that protects public safety and the environment, supports reconciliation with Indigenous peoples, conserves energy resources and fosters a sound economy and social well-being. Our role includes the management of natural gas, hydrogen, ammonia, methanol, oil and aspects of geothermal resources, with an expanded role in carbon capture and storage (CCS).

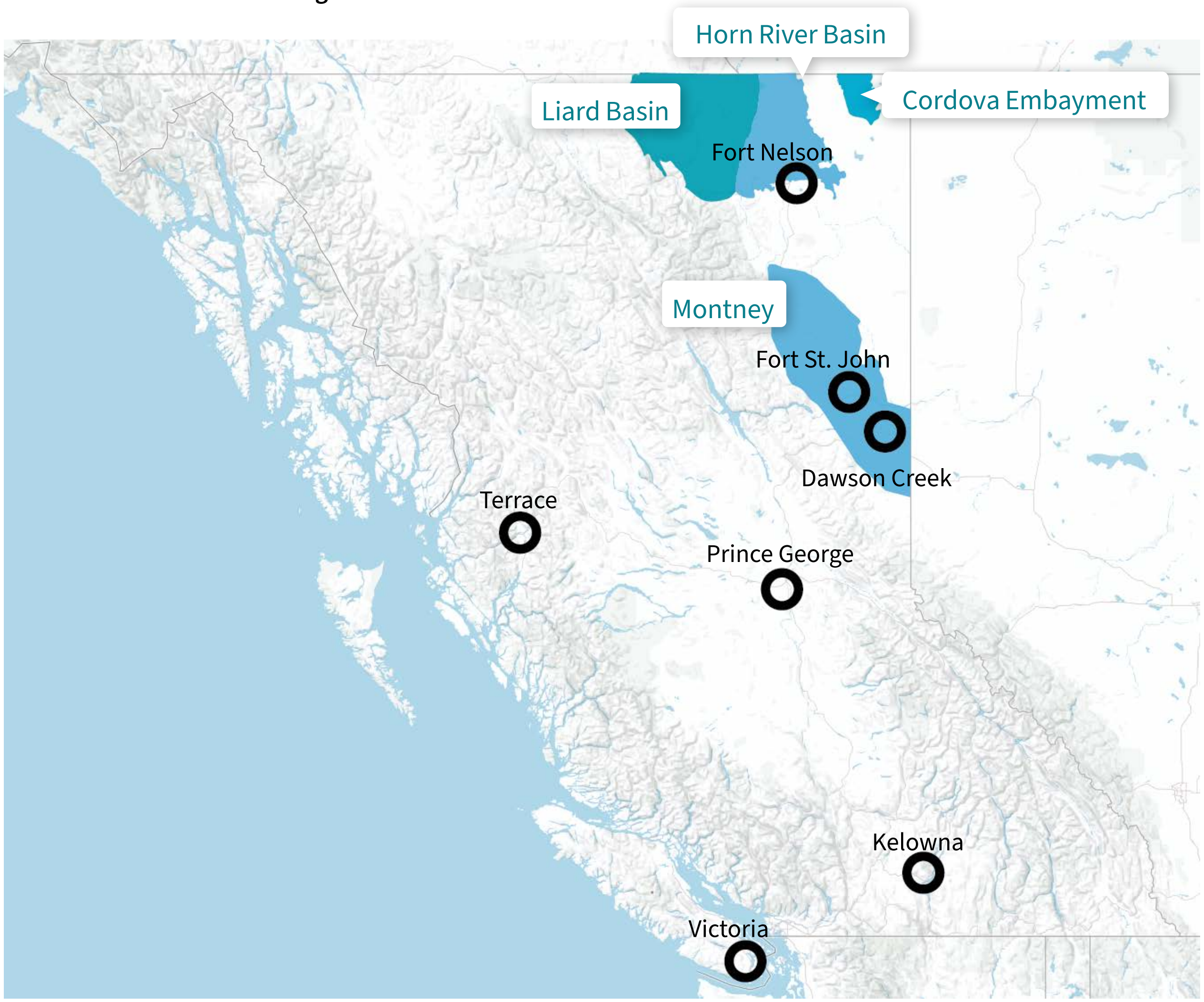
We regulate energy resources through the Energy Resource Activities Act (ERAA) and other associated laws related to heritage conservation, roads, land and water use, forestry, and other natural resources. We work closely with land owners, rights holders, local government, industry, academia and other regulators to gather skills, knowledge and multiple perspectives to evolve our regulatory model.

We respect Indigenous values and seek learning opportunities as we co-develop new processes that we put into practice in all facets of our business and decision-making. We are focused on advancing reconciliation and building trust and apply this in our work with First Nations and Indigenous communities as partners in building B.C.'s energy resource future.

We currently have 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 25 years' dedicated service, we're committed to ensuring safe and responsible energy resource management for British Columbia.

BCER Office Locations Throughout B.C.



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 BCER'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, 2022. The estimates have been prepared by the British Columbia Energy Regulator (BCER) 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.

Revisions

January 2024: Revisions have been made to 2022 production volumes and the reserves of natural gas byproducts since the original August 2023 publication of this report. A detailed table of revisions is available on page 72.

Available on the BCER 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

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

The terms ‘resources’ and ‘reserves’ are not interchangeable.

This section highlights the significant differences in the criteria associated with their classification.

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:

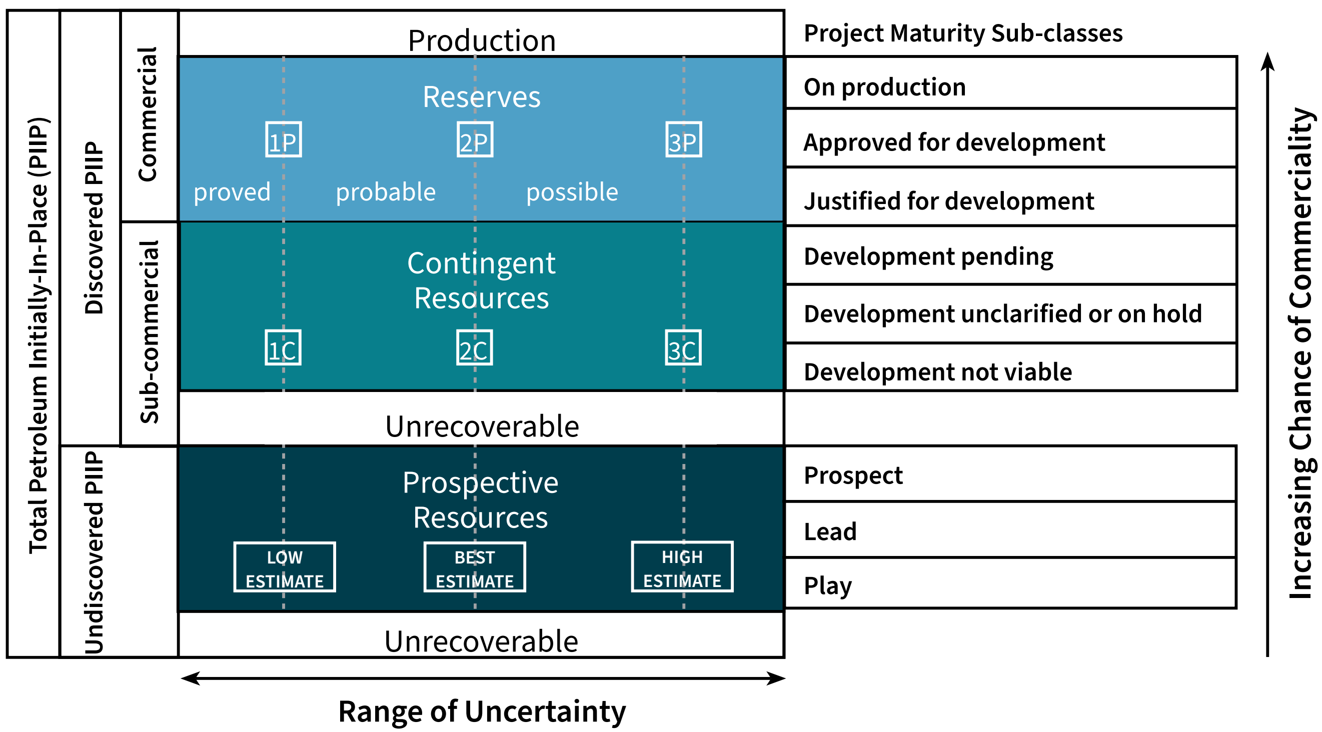
- Penetrated by a wellbore.
- Confirmation the well will produce (either a production test, or on production).
- Meets regulatory requirements (production or development not prohibited by government policy or legislation).
- Marketable to sell (viable transportation to sales point available either through 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 subdivided into three uncertainty categories providing a low estimate, best estimate, or high estimate. Contingent resources are subdivided 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 (1,965 Tcf); however, currently recoverable initial raw gas reserves of 2,773.3 e^9m^3 (98.0 Tcf) are approximately five per cent of the resource estimate. This reserves percentage is expected to increase with continued development of the play.

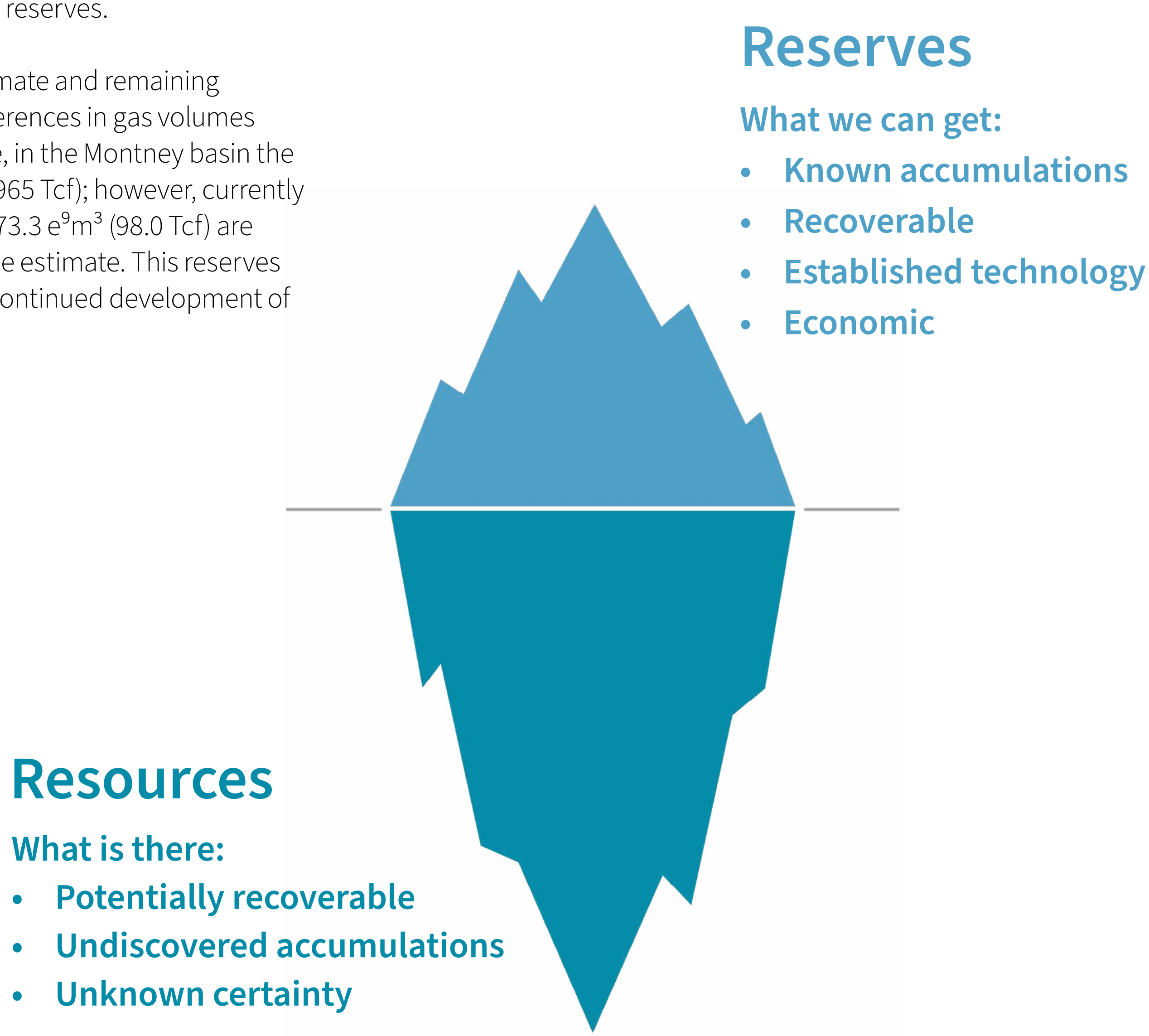


Table 1: Unconventional Gas Resource, Reserves and Cumulative Production

	RESOURCE				2022 RESERVES						
Basin/Play	Basin Total GIP Resource		Ultimate Resource Marketable		Initial Raw Gas Reserves		Remaining Reserves (Raw)		Cumulative Production (Raw)[6]		% Reserve per Resource
Unit	E^9M^3	Tcf	E^9M^3	Tcf	E^9M^3	Tcf	E^9M^3	Tcf	E^9M^3	Tcf	
Montney [1]	55,610	1,965	7,669	271	2,773.30	98.00	2,305.84	81.48	467.46	16.52	4.99%
Liard Basin[2]	23,998	848	4,726	167	2.31	0.08	0.21	0.01	2.10	0.07	0.01%
Horn River Basin[3]	12,678	448	2,207	78	78.99	2.79	40.71	1.44	38.28	1.35	0.62%
Cordova[4]	1,902	67	249	9	3.06	0.11	0.94	0.03	2.12	0.07	0.16%
Deep Basin Cadomin, Nikanassin[5]	255	9	207	7	25.58	0.90	5.95	0.21	19.63	0.69	10.04%
Total	94,443	3,337	15,058	532	2,883.24	101.88	2,353.65	83.17	529.59	18.71	3.05%

[1] NEB/OGC/AER/MNGD Energy Briefing Note - The Ultimate Potential for Unconventional Petroleum from the Montney Formation of BC and Alberta (Nov. 2013)

[2] NEB/OGC/ NWT/Yukon Energy Briefing Note – The Unconventional Gas Resources of Mississippian-Devonian Shales in the

[3] NEB/MEM Oil and Gas Reports 2011-1, Ultimate Potential for Unconventional Natural Gas in Northeastern BC's Horn River Basin (May 2011)

[4] MNGD/OGC Cordova Embayment Resource Assessment (June 2015)

[5] MEMPR/NEB Report 2006-A, NEBC's Ultimate Potential for Conventional Natural Gas

[6] Cumulative production to December 31, 2022

Table 2: B.C. Remaining Reserves as of Dec. 31, 2022

	2022		2021		Percent Change
Gas (raw)	2,475.2 10^9m^3	87.8 Tcf	2,093.0 10^9m^3	74.0 Tcf	18.26%
Oil	12.2 10^6m^3	76.6 MMSTB	13.4 10^6m^3	83.0 MMSTB	-9.34%
Pentanes+	140.1 10^6m^3	881.8 MMSTB	117.5 10^6m^3	739.4 MMSTB	19.31%
LPG	181.8 10^6m^3	1,145.3 MMSTB	149.1 10^6m^3	939.4 MMSTB	21.93%
Sulphur	6.1 10^6 tonnes	6.0 MMLT	4.7 10^6 tonnes	4.6 MMLT	29.52%

Executive Summary

In 2022, there were 9,988 producing wells — 9,196 gas wells and 792 oil wells. The remaining 456 active wells are a mixture of observation (78), water source (19), water injection (254), gas injection (3), deep disposal (92), and storage (10).

In 2022, there were 288 new well applications approved and 374 wells drilled —primarily in the Montney basin, the continued focus of activity. The number of wells drilled decreased by 20 per cent versus 467 wells drilled in 2021.

As shown in Table 2, estimated remaining gas reserves increased 18.3 per cent due to added Montney development wells. Remaining oil reserves decreased 9.3 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.

Sulphur reserves increased 29.5 per cent, driven by increased reserves in the Bullmoose, Heritage, and Northern Montney fields.

As shown in Figure 2, of the 374 wells rig released in 2022, all but one well were drilled in the Montney.

Starting in 2023, the provincial government and several First Nations came to agreements which included limits on location and amount of new land disturbance for industry activities that impact treaty rights. The impact of these limits has not been considered in this report but may be considered in future reports.

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 hydraulic fracturing, deep disposal and deep saline water sourcing can be found at the end of this report. Additionally, a new section on drilling and decommissioning is included on page 50.

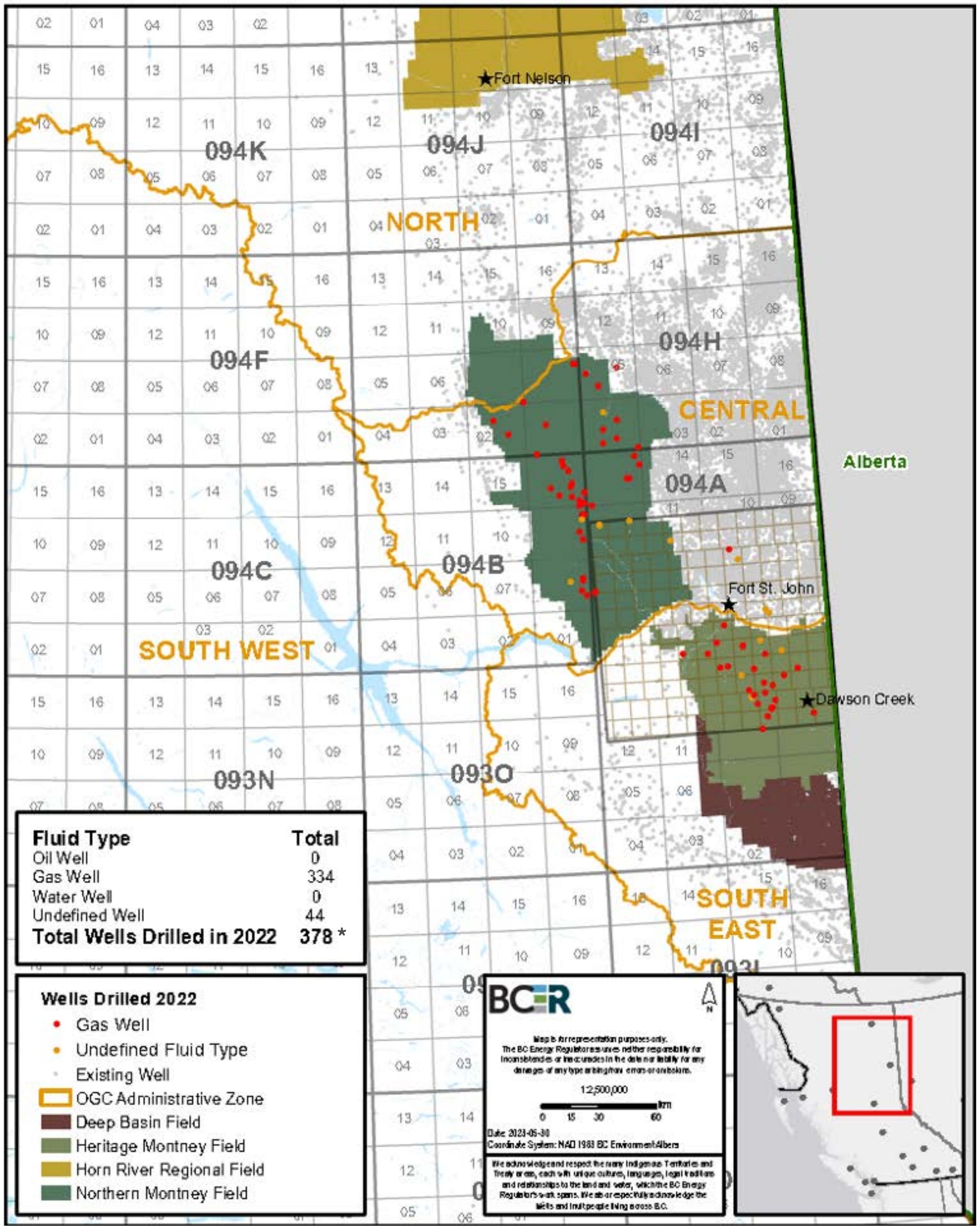


Figure 2: 2022 Wells Drilled by Fluid Type

* Well count of 378 includes 374 new drills and four re-entries.

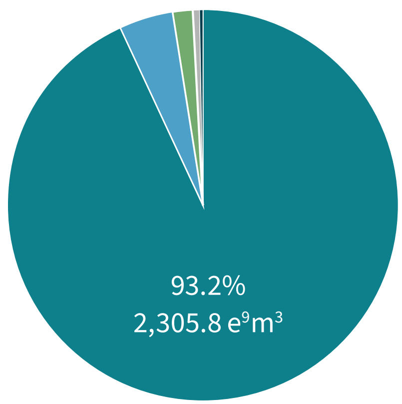
Discussions: Gas Reserves and Production

As of December 2022, unconventional gas zones accounted for 95.7 per cent of all remaining gas reserves and 92.7 per cent of annual gas production in the province.

As of Dec. 31, 2022, B.C.'s remaining raw gas reserves were 2,475.2 e^9m^3, an 18.3 per cent increase from the 2021 remaining reserves.

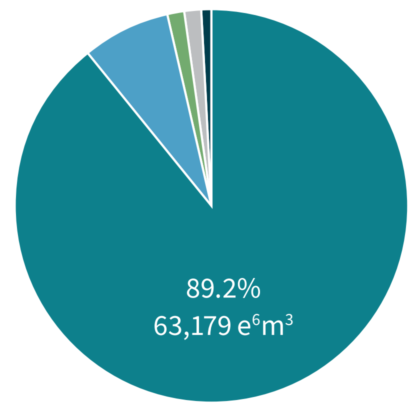
Figure 3 illustrates the distribution of remaining conventional and unconventional gas reserves, with 93.2 per cent of the remaining recoverable reserves held in the Montney basin. The distribution of remaining reserves is echoed by Figure 4 and 5, which show gas production split by source (as of December 2022). The majority of production in B.C. originates from the Montney.

Figure 3: 2022 Annual Remaining Gas Reserves by Source



Montney	93.2%	2,305.8 e^9m^3 (81,429 Bcf)
Conventional	4.3%	106.4 e^9m^3 (3,757 Bcf)
Horn River + Liard + Cordova	1.7%	41.9 e^9m^3 (1,478 Bcf)
Jean Marie	0.6%	15.0 e^9m^3 (530 Bcf)
Deep Basin Cadomin	0.2%	6.0 e^9m^3 (210 Bcf)

Figure 4: 2022 Annual Raw Gas Production by Source



Montney	89.2%	63,179 e^6m^3 (2,232.5 Bcf)
Conventional	7.3%	5,170 e^6m^3 (182.7 Bcf)
Horn River	1.5%	1,082 e^6m^3 (38.2 Bcf)
Jean Marie	1.4%	965 e^6m^3 (34.1 Bcf)
Deep Basin Cadomin	0.6%	406 e^6m^3 (14.4 Bcf)
Liard	0.0%	0 e^6m^3 (0.0 Bcf)

Figure 5: Raw Gas Production by Source 2013 to 2022

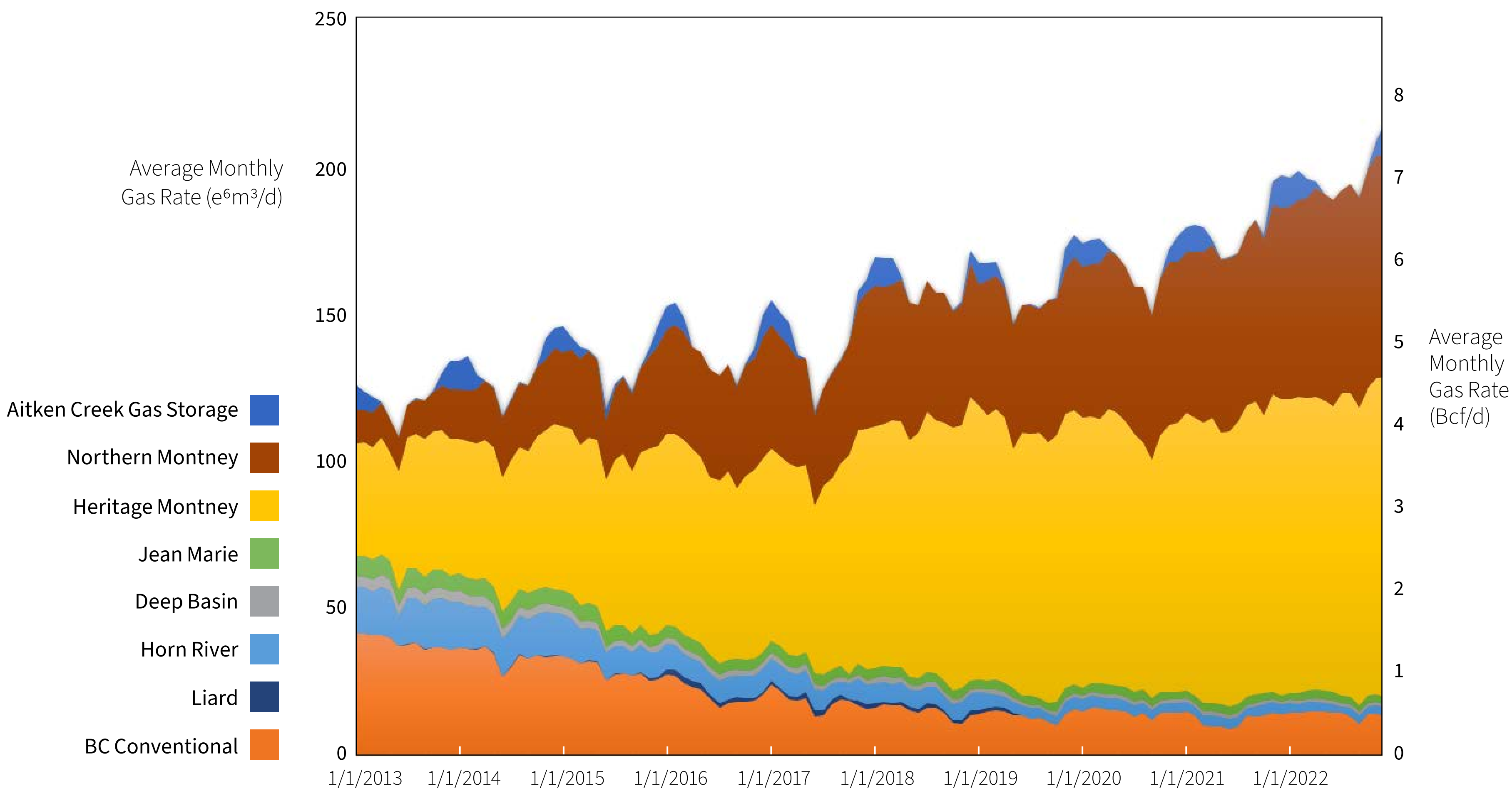
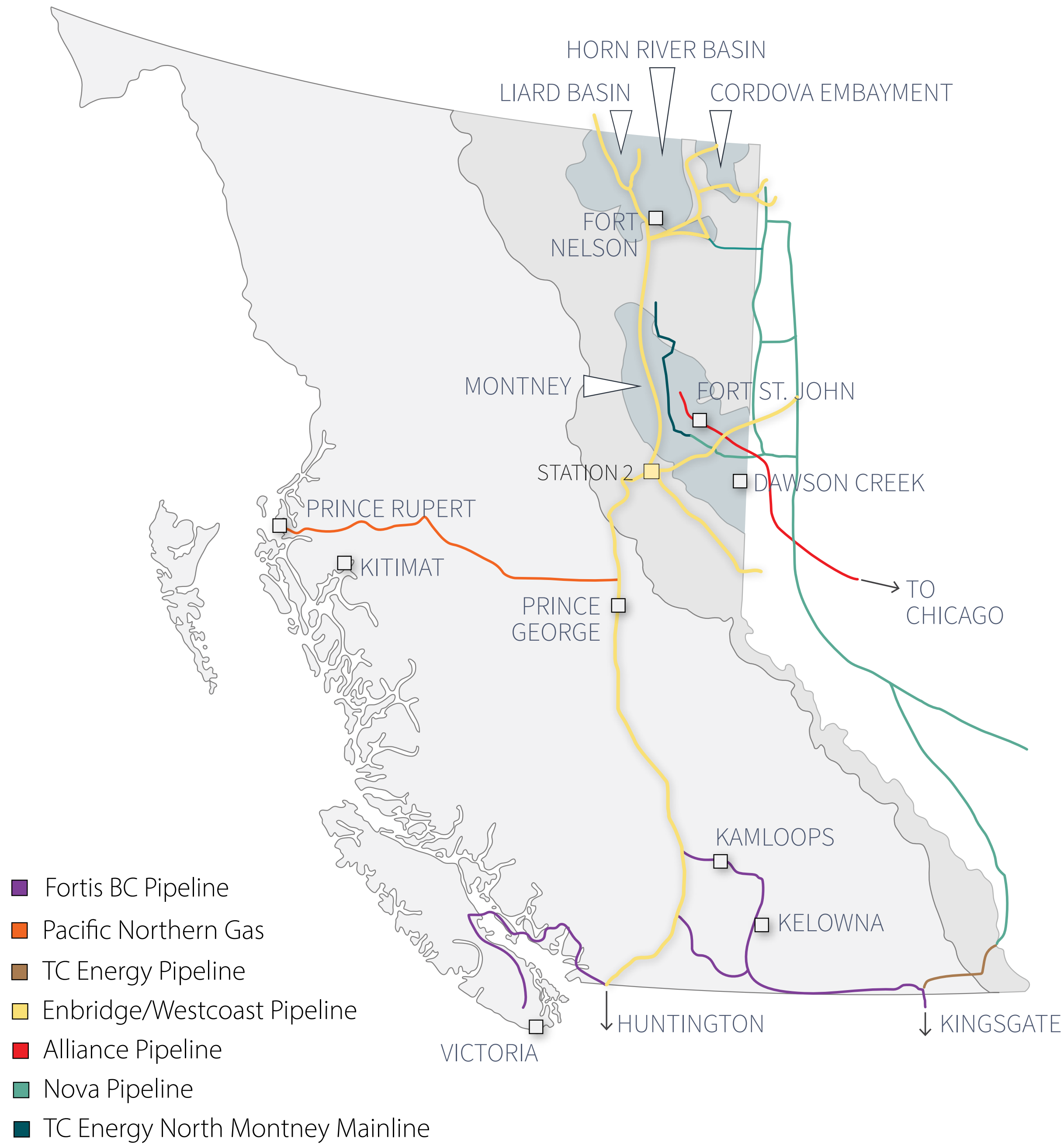


Figure 6: British Columbia's Gas Pipelines Systems



In the last five years, gas production in B.C. has increased 40.2 per cent, resulting in increased loads within existing pipeline delivery points for the Montney. Gas within these regions is transported by pipelines to Station 2 (shipped on Enbridge/Westcoast Pipeline, formerly Spectra), AECO (shipped on TC Energy Pipeline) and Chicago (shipped on Alliance Pipeline). See Figure 6.

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

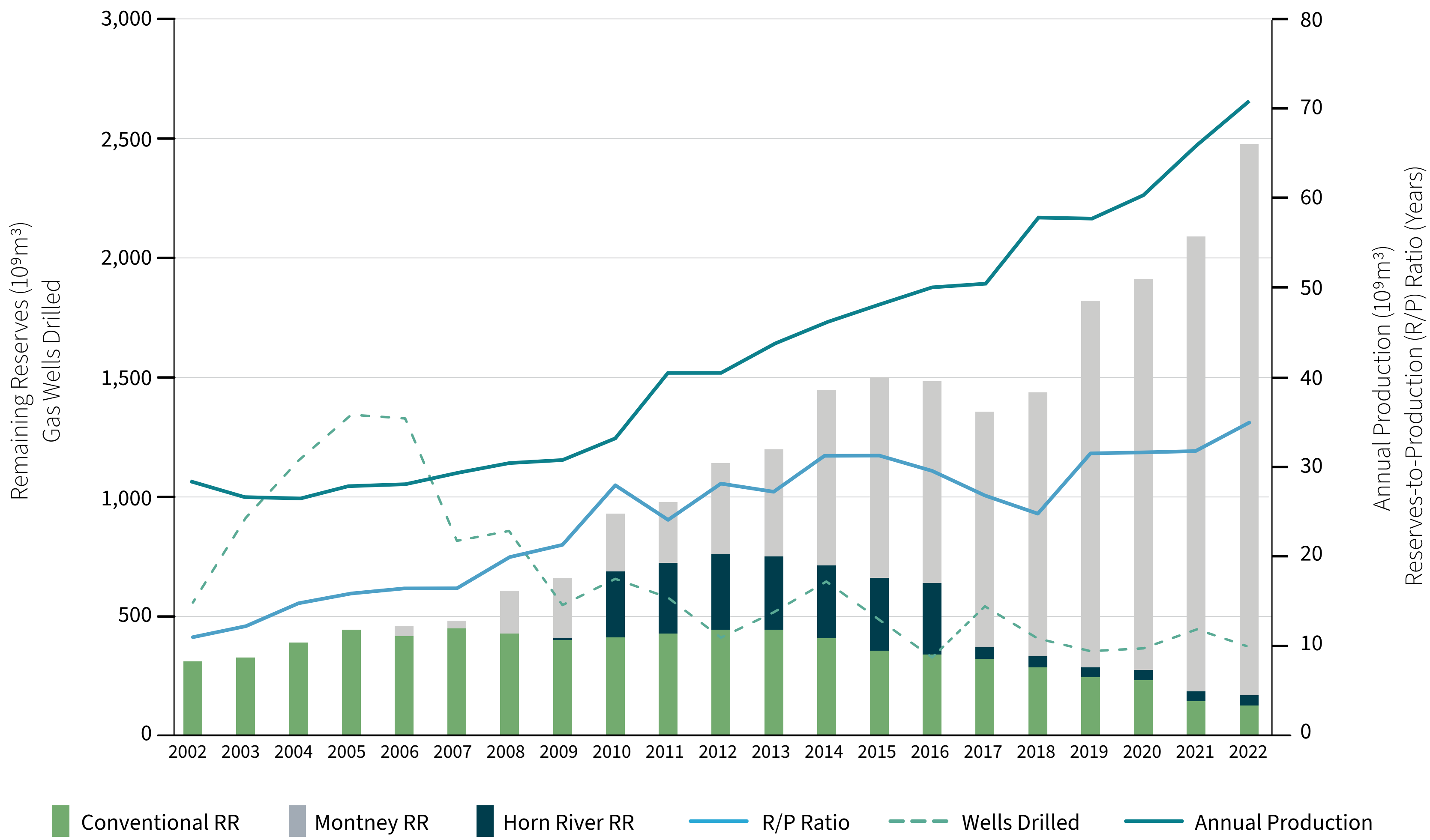
Northeast B.C. gas production has access to multiple markets.

The Coastal GasLink project now underway will further diversify delivery.

Figure 7 represents the BCER's raw gas reserves bookings from 2002 to 2022, 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.

Figure 7: Historical Development in B.C. 2002 to 2022



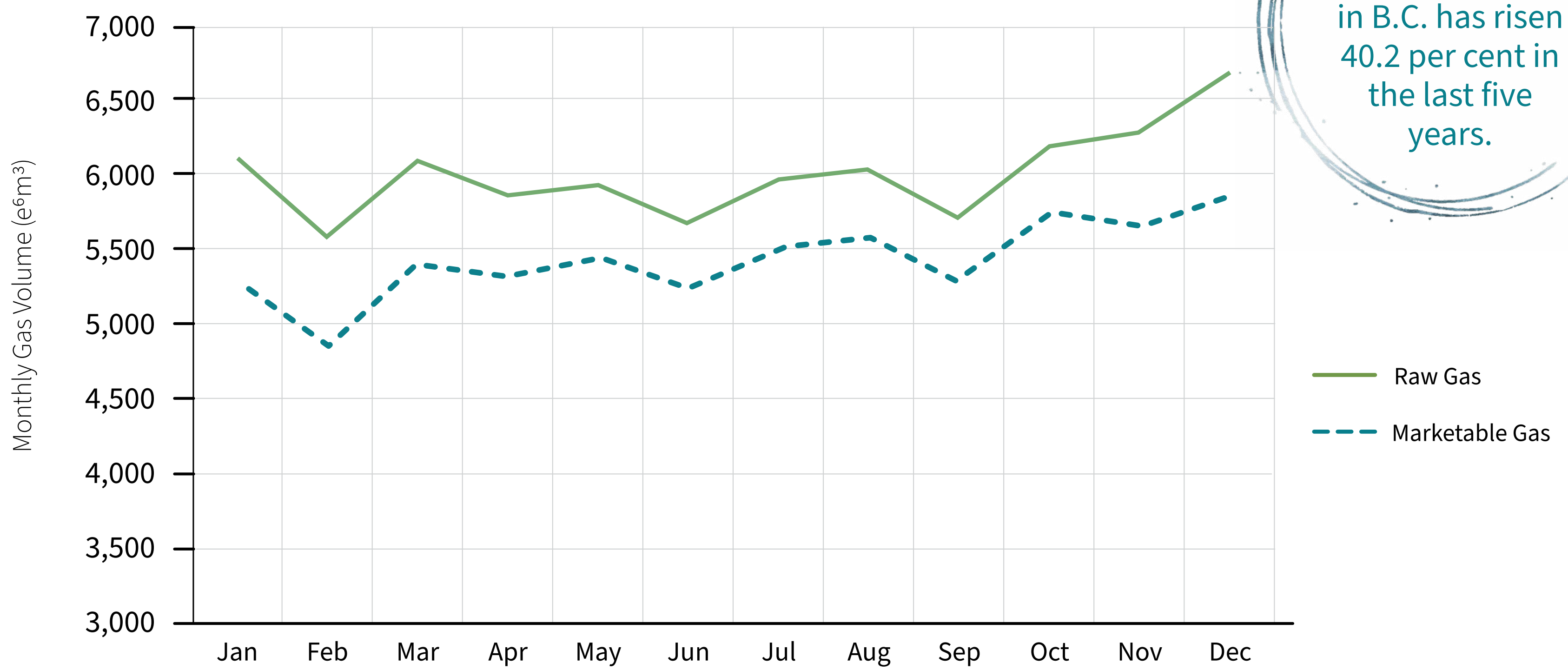
Between 2003 and 2006, activity reached record levels (1,300 gas wells drilled in 2006), with predominant targets being shallow Cretaceous (Notikewin, Bluesky and Gething) and Triassic (Baldonnel and Halfway), in the Deep Basin (the Cadomin and Nikanassin) and the Jean Marie in the northeast.

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 2022, production in the Liard Basin remained suspended, and the Horn River basin, having ceased development years prior, saw declining production.

The province's monthly raw and marketable gas volumes for 2022 can be seen in Figure 8. Average annual raw gas production in 2022 was 197.5 e^6m^3 per day (6.97 Bcf/d).

Annual production in B.C. has risen 40.2 per cent in the last five years.

Figure 8: 2022 Raw Gas and Marketable Gas



Figures 9 and 10 show gas production by initial production (IP) year (excluding Aitken Creek gas storage). These figures demonstrate a large portion of production at any given time comes from newly on-production wells, and if the addition of wells were to stop, there would be a sharp decline in gas production. This is due to the steep decline in the production profile of unconventional gas wells.

Figure 10: 2022 Gas Production by Well IP Date

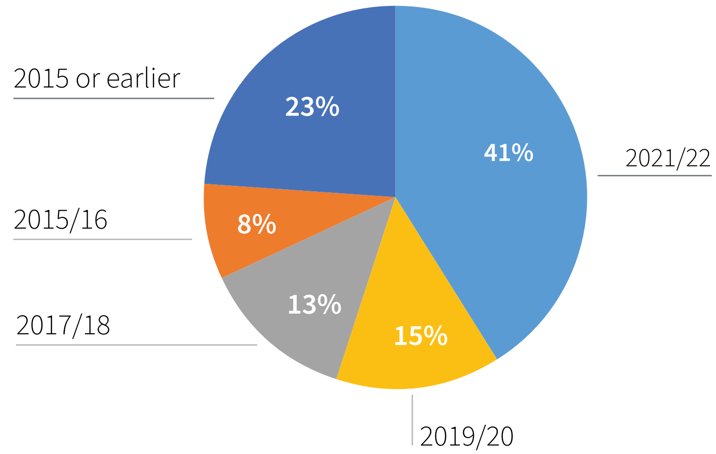
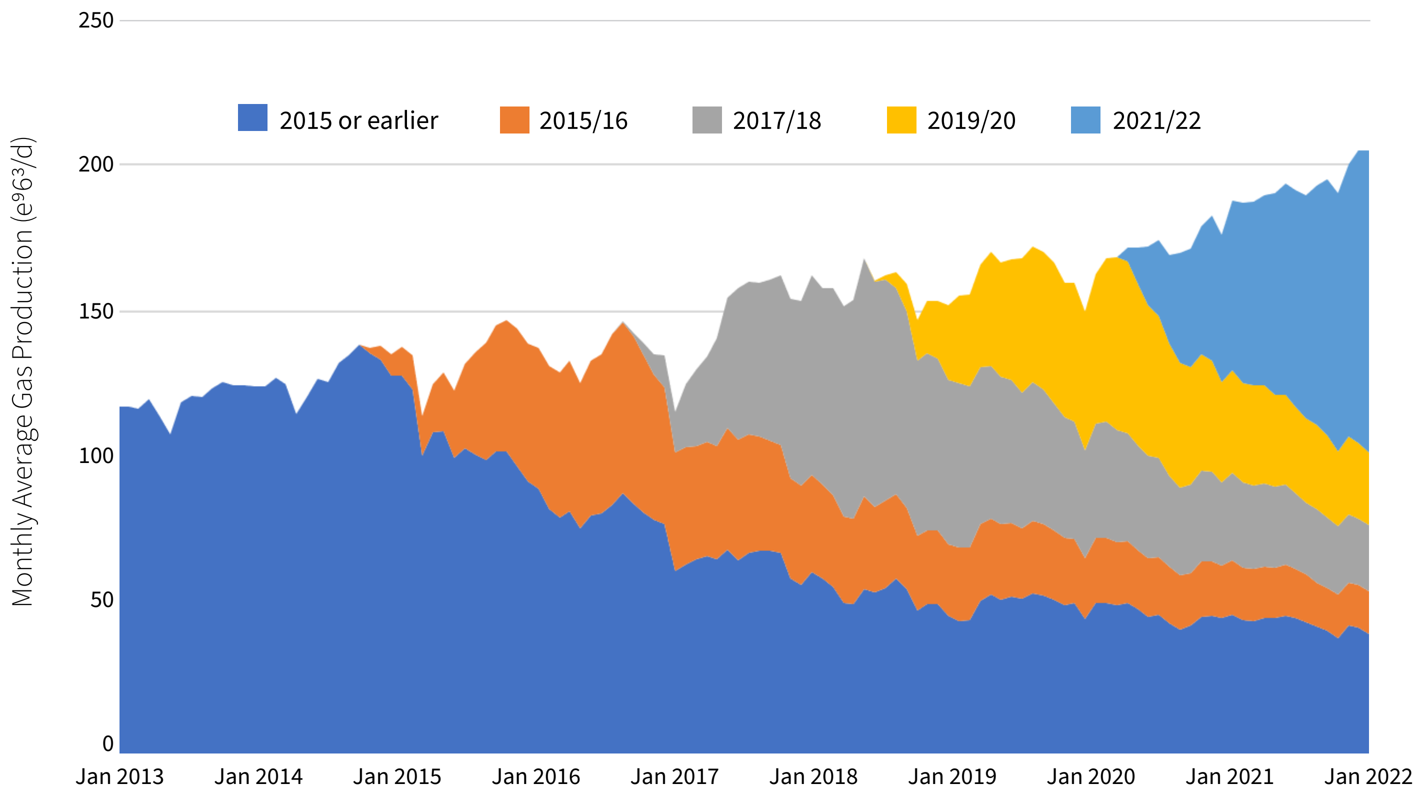
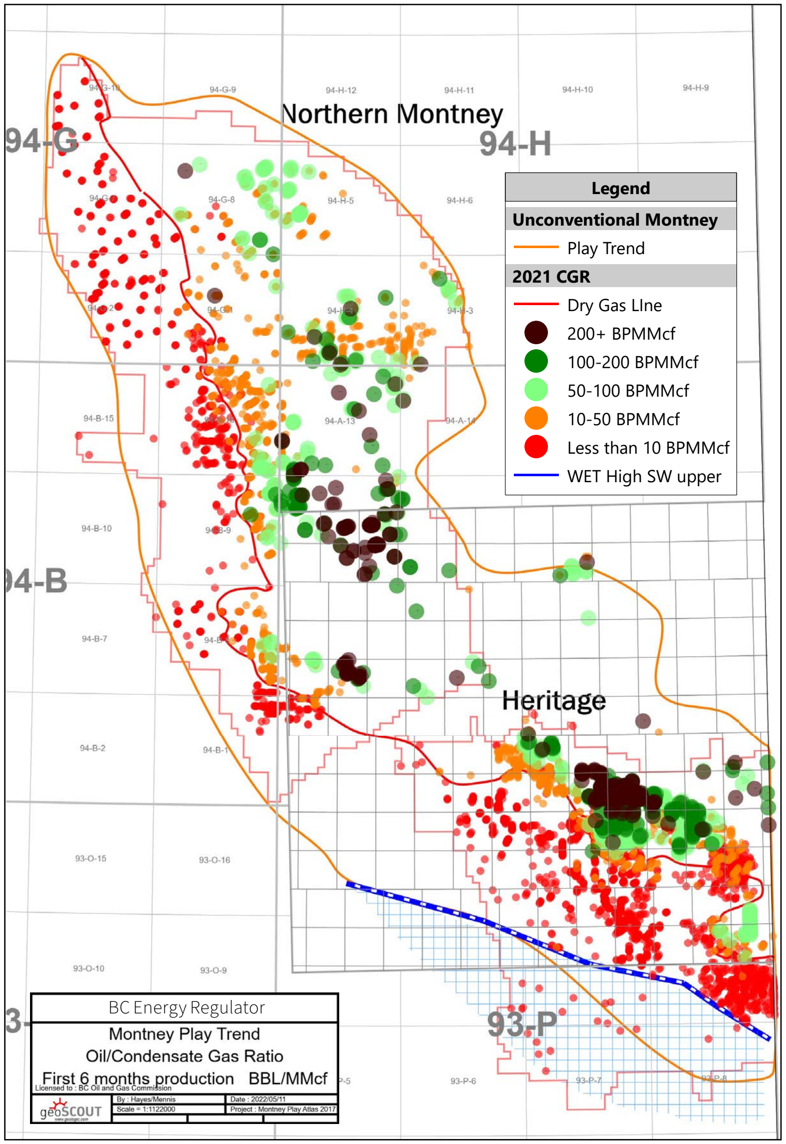


Figure 9: Gas Production by Well IP Date 2013 - 2022



Montney Unconventional Gas Play

Figure 11: Montney Dry/Wet/Oil Distribution



The Montney contains 93.2 per cent (81.4 Tcf) of B.C.'s remaining raw gas reserves and contributed 89.2 per cent (6.11 Bcf/d; annual average rate) of the province's 2022 production.

Significant development of the Montney began in 2005 and 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 liquefied petroleum gas (LPG) and condensate increased significantly. This increase is also a reflection of BCER policy in assigning well primary product, with few new wells with high liquid hydrocarbon content qualifying as oil wells. Of the 9,988 producing wells in the province in 2022, 5,277 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 11 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.

The 2022 average daily gas production rate was 70.8 e^6m^3 per day (2.5 Bcf/d) in the Northern Montney field and 102.3 e^6m^3 per day (3.6 Bcf/d) in the Heritage field.

As of Dec. 31, 2022 the remaining gas reserves for the Montney formation was 2,305.8 e^9m^3 (81.5 Tcf) (raw). The initial reserves of 2,773.3 e^9m^3 represents a five per cent recovery of the estimated total basin gas-in-place of the Montney resource. Both reserves and recovery factor will increase with additional drilling and production. A detailed record of remaining reserve estimates for each Montney pool/sub-zone can be found in Table 3 below.

Table 3: Montney Remaining Reserves as of Dec. 31, 2022

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	7.30	2.09	6.30	13.11	32,537.8		1285	3173	Statistical
	Dry Lower	7.02	2.44	6.00	13.27	10,537.9		593	908	Statistical
	Liquid Upper	3.93	1.06	3.34	7.48	9,200.3		927	1413	Statistical
	Liquid Lower	2.73	1.14	2.52	4.62	3,266.9		239	956	Intermediate
	Area Average/Total	**5.87**	**1.50**	**4.79**	**11.45**	**55,543**	**44,858**	**3,044**	**6,450**	
Northern Montney - Montney A	NW - Upper	5.63	1.60	5.28	10.11	6,650.2		237	948	Intermediate
	NW - Lower	3.80	1.01	3.49	7.54	4,425.5		234	936	Intermediate
	SW - Upper	5.36	1.24	4.88	10.31	7,243.6		272	1088	Intermediate
	SW - Lower	4.75	1.30	3.95	9.48	3,710.8		156	624	Intermediate
	NE - Upper	6.04	1.90	5.56	10.61	9,410.4		584	972	Statistical
	NE - Lower	4.05	1.07	3.55	7.62	5,583.9		459	920	Statistical
	SE - Upper	3.41	0.52	2.40	6.92	1,623.2		159	318	Early
	SE - Lower	3.21	0.73	2.46	6.54	3,116.5		194	776	Intermediate
	Area Average/Total	**4.70**	**1.05**	**4.08**	**9.25**	**41,764.1**	**36,301**	**2,295**	**6,582**	

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

As seen in Table 4, horizontal Montney gas wells make up the vast majority of Montney gas reserves and well count compared to vertical Montney gas wells and solution gas from Montney oil wells.

Table 4: Montney Gas Reserves and Well Count by Horizontal, Vertical, and Solution Gas as of Dec. 31, 2022

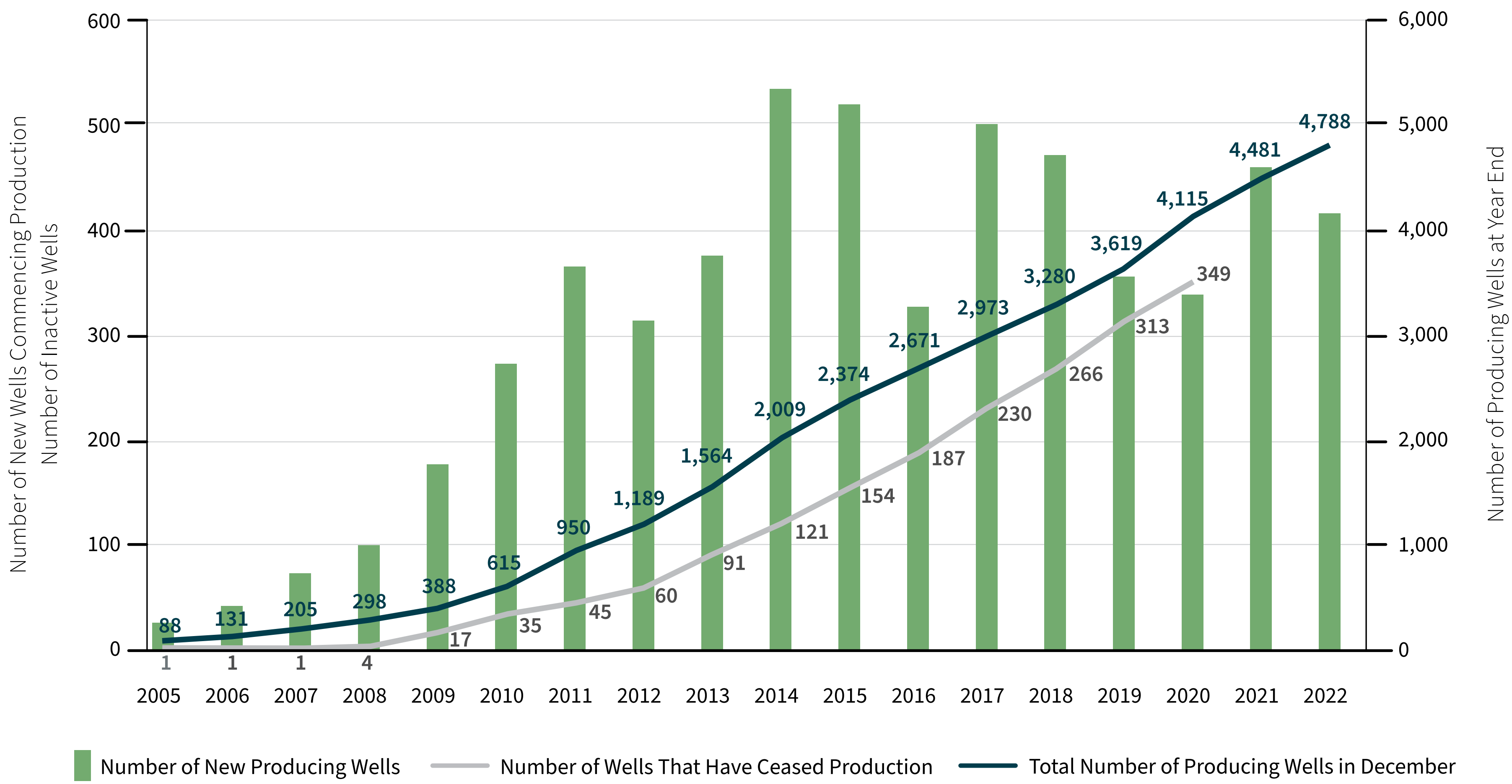
Field/Pool		Initial Reserves (Raw) Bcf	Remaining Reserves (Raw) Bcf	Exisiting Wells	PUDs
Heritage - Montney A	Horizontal wells	55,542.9	44,885.2	3,044	6,450
	Vertical wells	180.6		222	0
	Solution gas	474.7	290.5	153	306
	Heritage total	**56,198.2**	**45,175.7**	**3,419.0**	**6,756.0**
Northern Montney - Montney A	Horizontal wells	41,764.1	36,301.1	2,295	6,582
	Vertical wells	25.0		37	0
	Solution gas	3.1	0.1	7	14
	Northern Montney Total	**41,792.2**	**36,301.2**	**2,339.0**	**6,596.0**
Total Montney Play		**97,990.40**	**81,476.90**	**5,758.0**	**13,352.0**

Figure 12 on page 22 compares the number of new Montney wells drilled to the number of Montney producing wells from 2005 to 2022. The number of wells producing from the Montney increased year-over-year, from 88 in 2005 to 4,788 by the end of 2022. 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 12 is a cumulative count of wells which had produced for six months or more but have since ceased production for more than 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 example 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 23 e^6m^3 (0.8 Bcf), 26 e^6m^3 (0.9 Bcf)in the Heritage and 17 e^6m^3 (0.6 Bcf) in the Northern Montney).

A general upward trend in average new well Estimated Ultimate Recovery (EUR) over the course of play development is shown in Figure 13. 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 2021/22 upswing in EUR is the increase in well length, as shown in Figure 39.

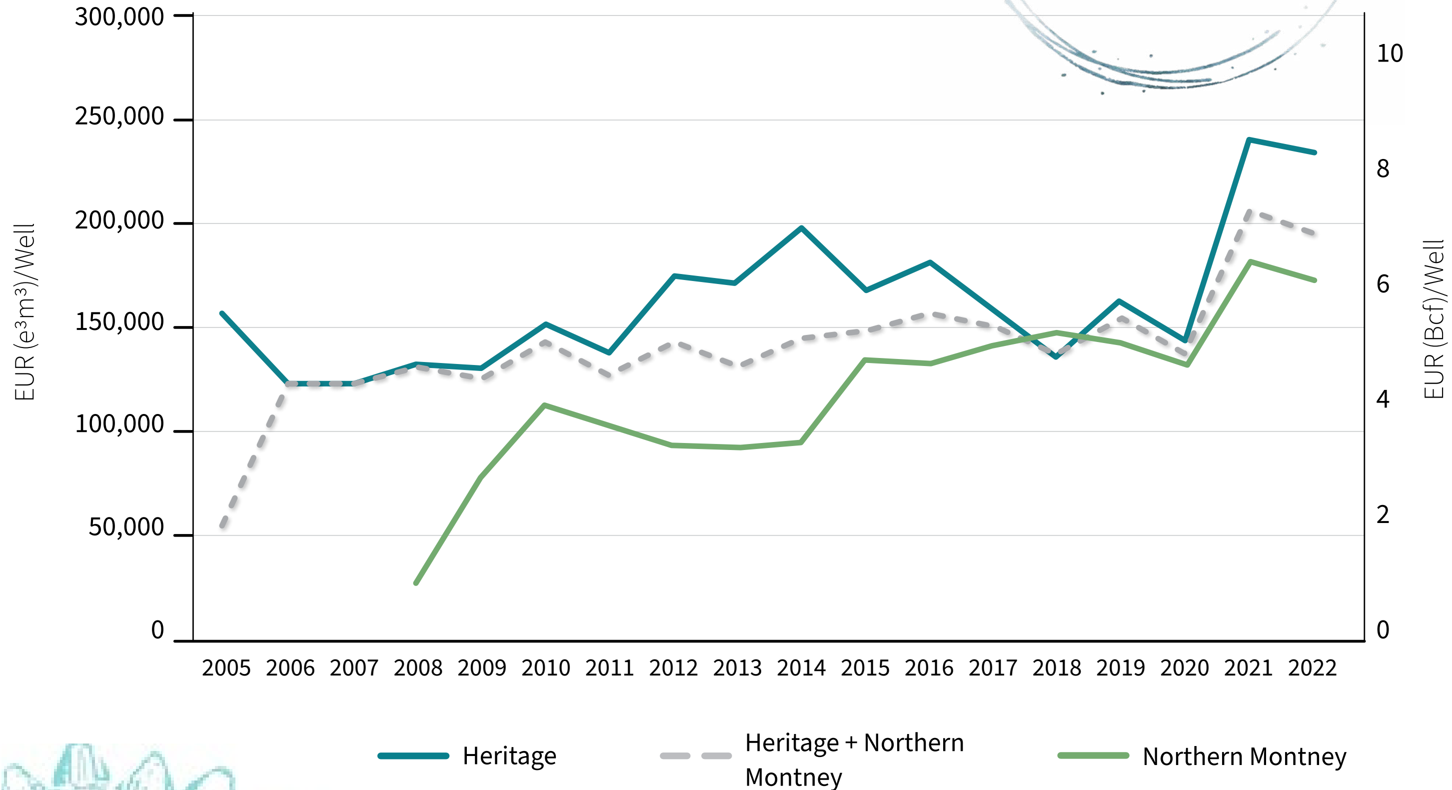
Figure 12: Number of New Wells, Wells that Ceased Production and Producing Wells in Montney Play 2005 to 2022



Note: “Ceased Production” count ceases in 2020 as two years of history are required to be counted as inactive.

Figure 13: Well EUR Average by IP Year – Heritage and Northern Montney

There is a general upward trend in average new well EUR over the course of play development.



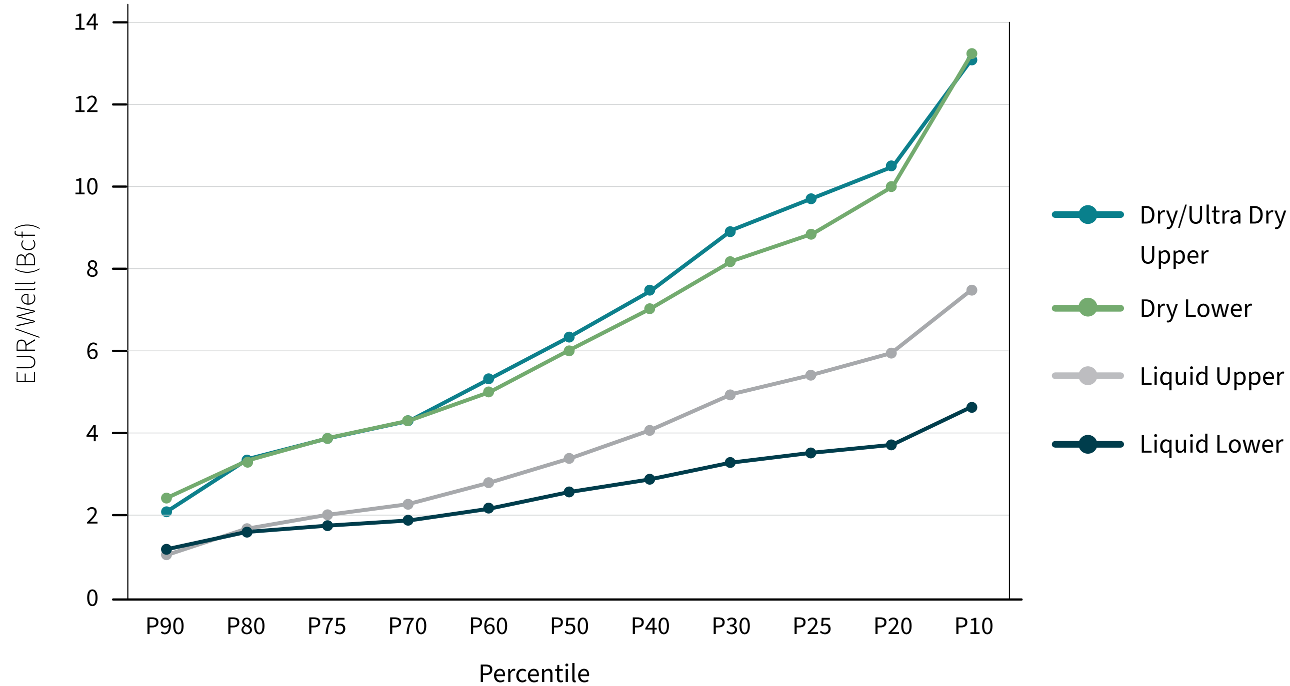
As shown in Figure 14 and 15, the Montney's various subareas and zones differ in their gas EUR volumes.

The Heritage field has been divided into four subgroups, based on liquid content and targeted Montney layer, with P50 EURs ranging from 2.5 to 6.3 Bcf per well. The Northern Montney has been divided into eight subgroups, by geographic area and targeted Montney layer, with P50 EURs ranging from 2.4 to 5.6 Bcf per well.

These variations occur due to a number of factors, including formation (zone) characteristics and completion techniques, to stage of development.

For maps of subarea locations, see Appendix B.

Figure 14: Heritage Montney EUR Distribution by Subareas/Zones



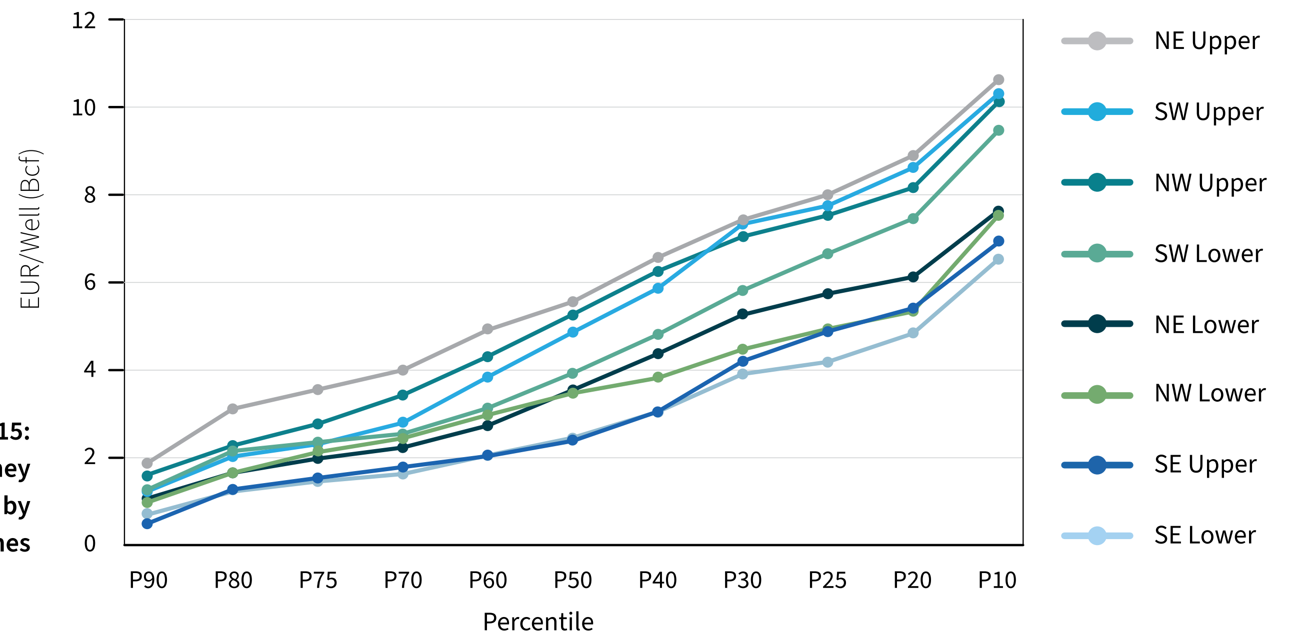
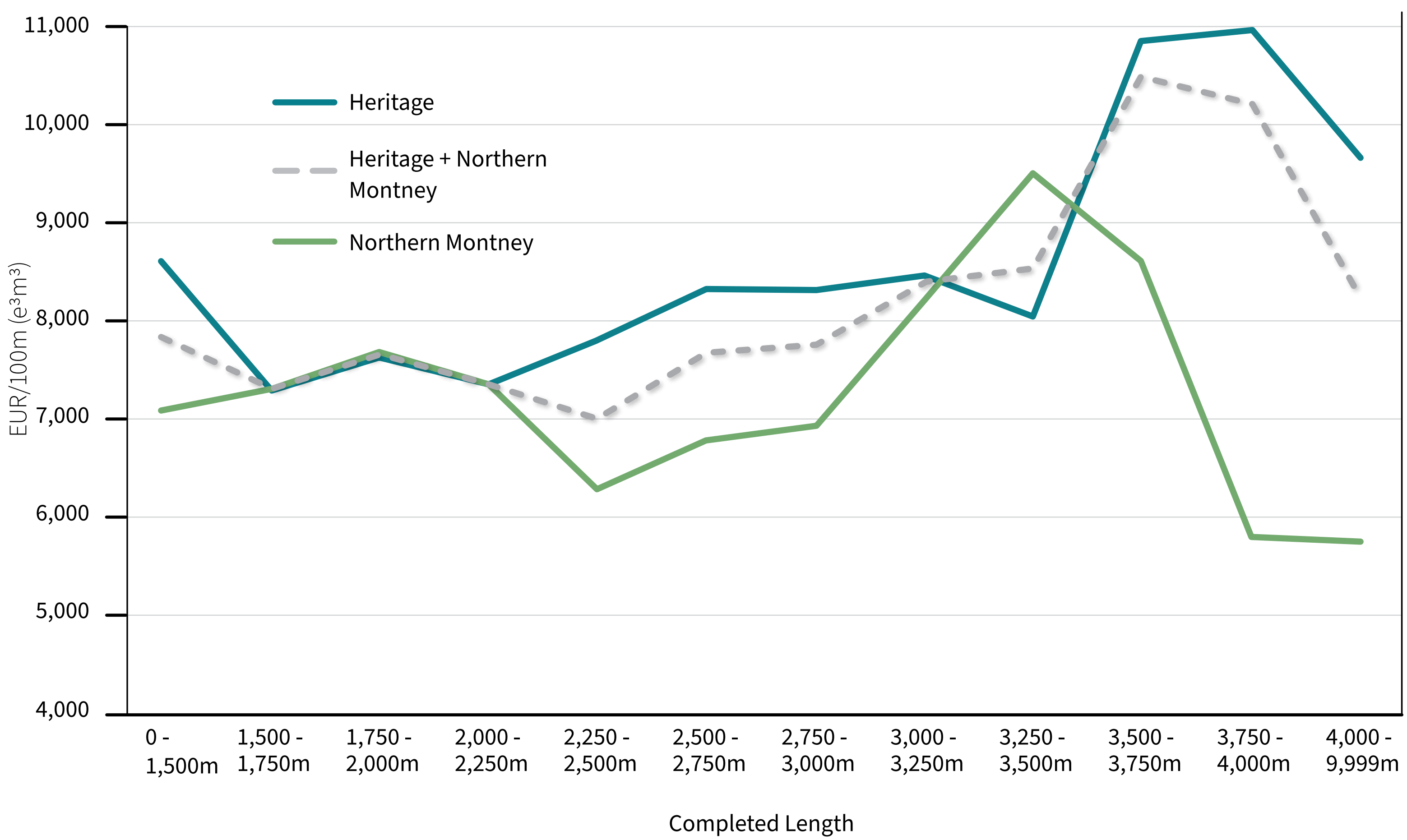


Figure 15: Northern Montney EUR Distribution by Subareas/Zones

Figure 16 shows EUR per 100m for Heritage and Northern Montney wells. In theory, it's expected that wells would experience diminishing EUR per unit length with increasing length, however, this trend is not clearly seen. It is likely due to other confounding factors, such as, location, vintage and completion method.

Figure 16: Montney EUR Per Completed 100m



As seen in Figure 17, 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 drilled outside of focus areas for reserves delineation and land continuation obligations.

Production of gas, LPG and condensate increased in 2022. 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 17: Top 10 Gas Producers in Montney Play 2022

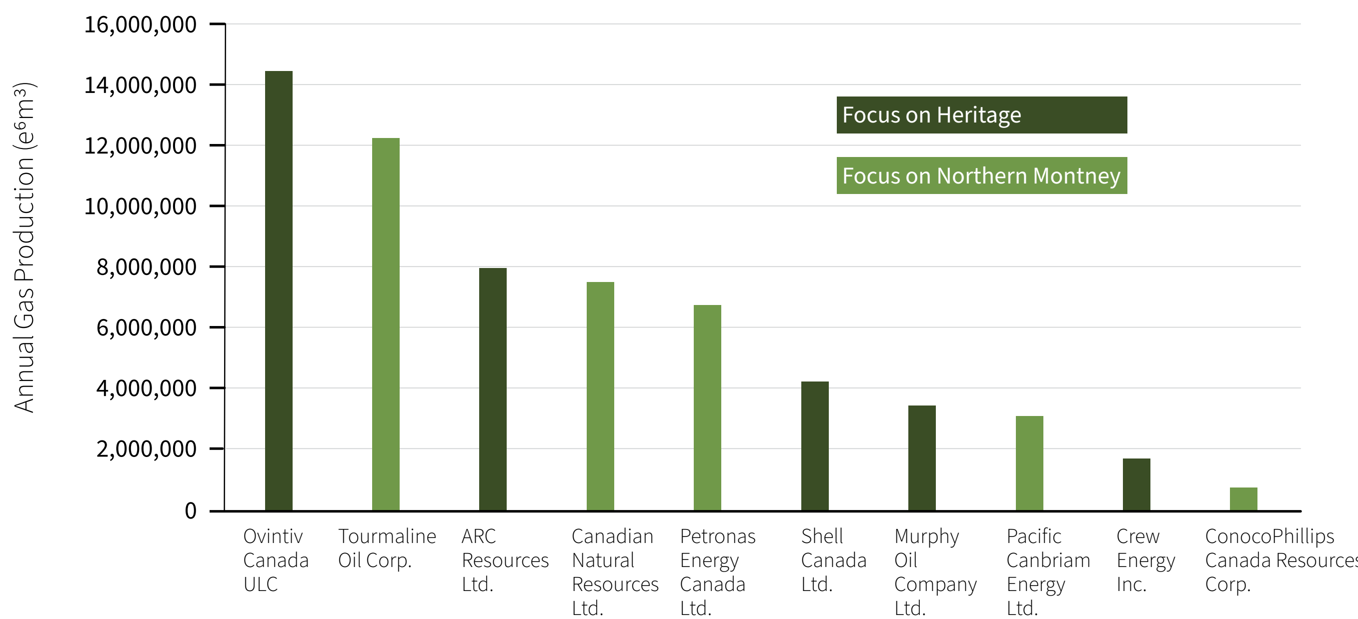
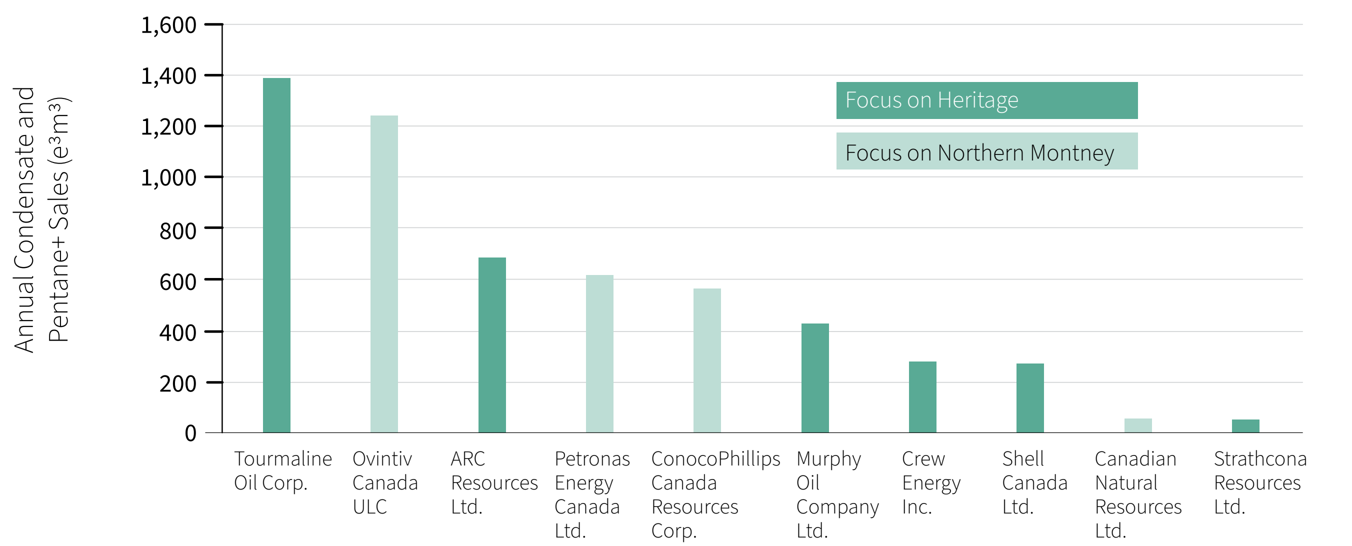


Figure 18: Top 10 Condensate and Pentanes+ Producers in Montney Play 2022



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 19: British Columbia's Oil and Gas Resource Basins

Liard Basin

Exploration in the Liard Basin started in 2008. Initial raw gas reserves are 2,315 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

In 2022, the average daily production rate from the Horn River Basin was 2.96 e^6m^3/d (104.5 mmcf/d), down 11 per cent from 2021. Operators have continued to shut-in wells that are no longer economic to produce and no new wells have been drilled or completed since 2015. Continued production without new drilling resulted in a significant decrease in reserves from the previous year. Due to lack of drilling activities since March 2015, a detailed evaluation, shown in the 2018 Reserves Report, resulted in a reduction in recovery factor for initial raw gas reserves. During the 2022 calendar year, there were 110 wells producing from the Horn River Basin shales, down from a peak of 223 wells in 2014 and 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. During the calendar year of 2022, there were 16 wells producing from the Cordova Basin shale play, with a total production rate of 270.1 e^3m^3/d (9.5 mmcf/d). Further background information on the Horn River and Cordova fields is available in the 2014 Reserves Report.

Image: Liard Basin

Summary

Figure 20 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 21 illustrates "type wells" 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 because of significant capital and operating expenses due to the depth and remote location.

Figure 20: Pressure vs. Temperature Plot

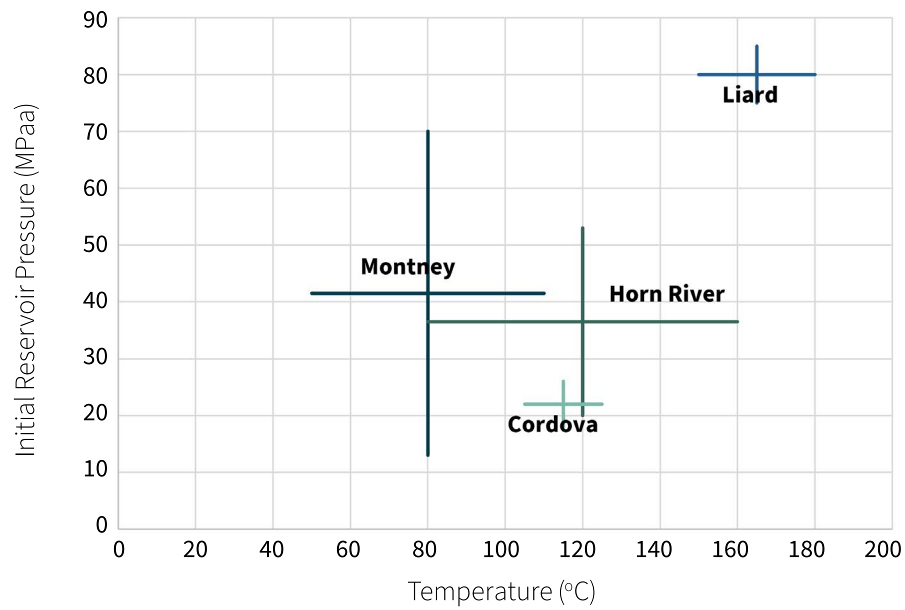
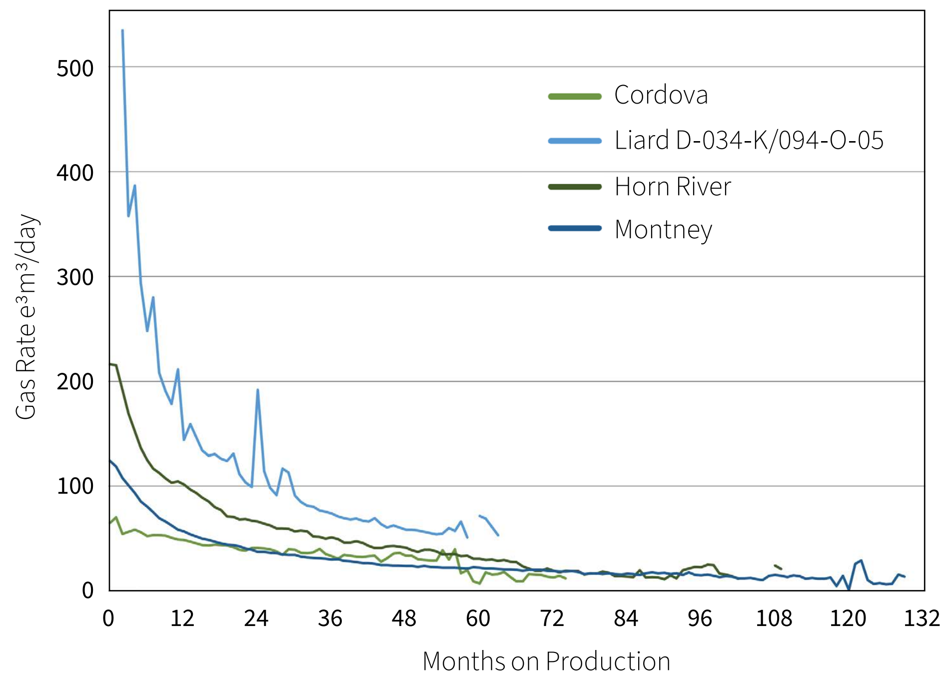


Figure 21: Comparison of Montney, Horn River, Liard and Cordova Production Type Wells



Discussions: Oil Reserves

Annual oil production decreased 2.2 per cent from 680.0 to 661.7 10^3m^3 (4.16 MMSTB) in 2022.

Remaining oil reserves decreased 8.2 per cent from 2021 to 2022, resulting in total remaining reserves of 12.2 10^6m^3 (76.7 MMSTB). This reserves decrease is mainly due to production without replacement with newly drilled oil wells. In 2022, no 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 2022 reserves-to-production (R/P) ratio is 18.4 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, a subset of the massive Montney unconventional gas play.

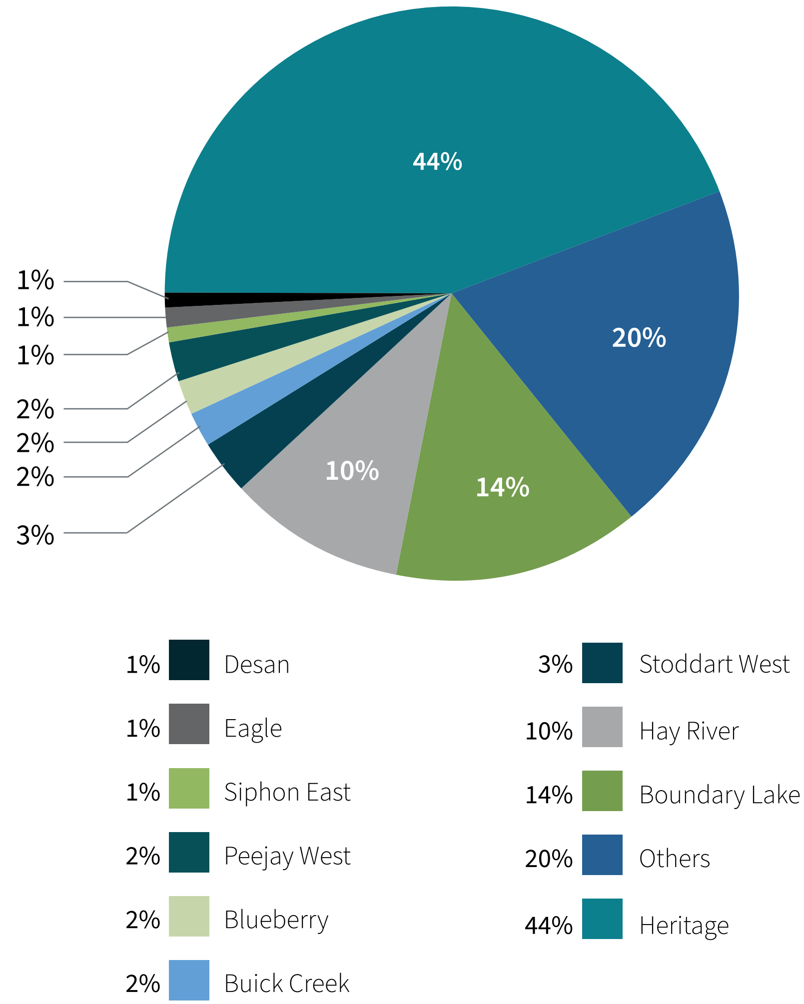
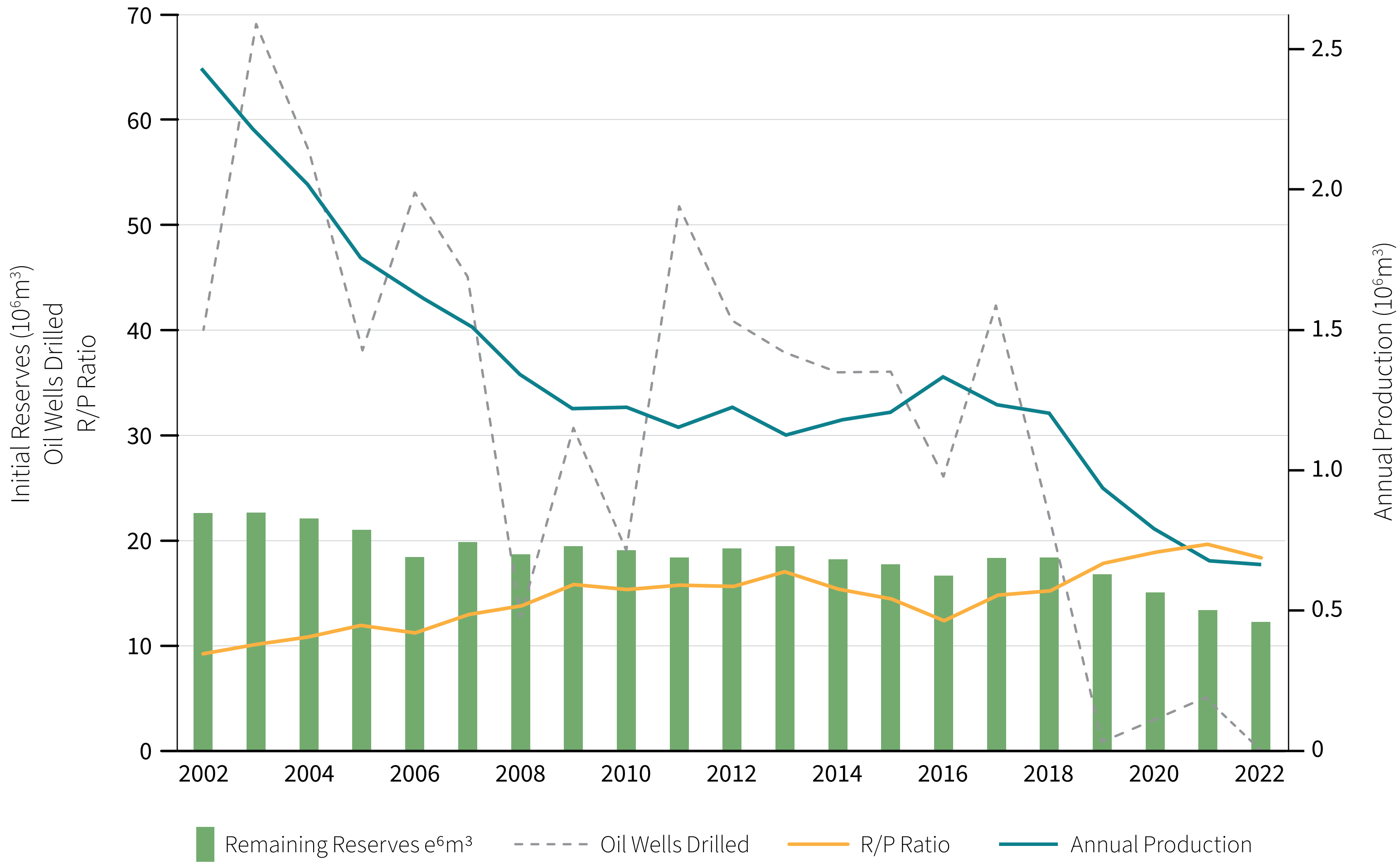


Figure 22: Remaining Oil Reserves by Field

Figure 23: Historical Oil Development 2002 to 2022



There is 28.7 per cent of the remaining oil reserves in B.C. located in pools with secondary recovery pressure maintenance waterflood projects. These oil pools are listed in Table A-4: Oil Pools Under Waterflood, on page 60.

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, on page 61.

Figure 24: B.C. Oil Production 2012-2022

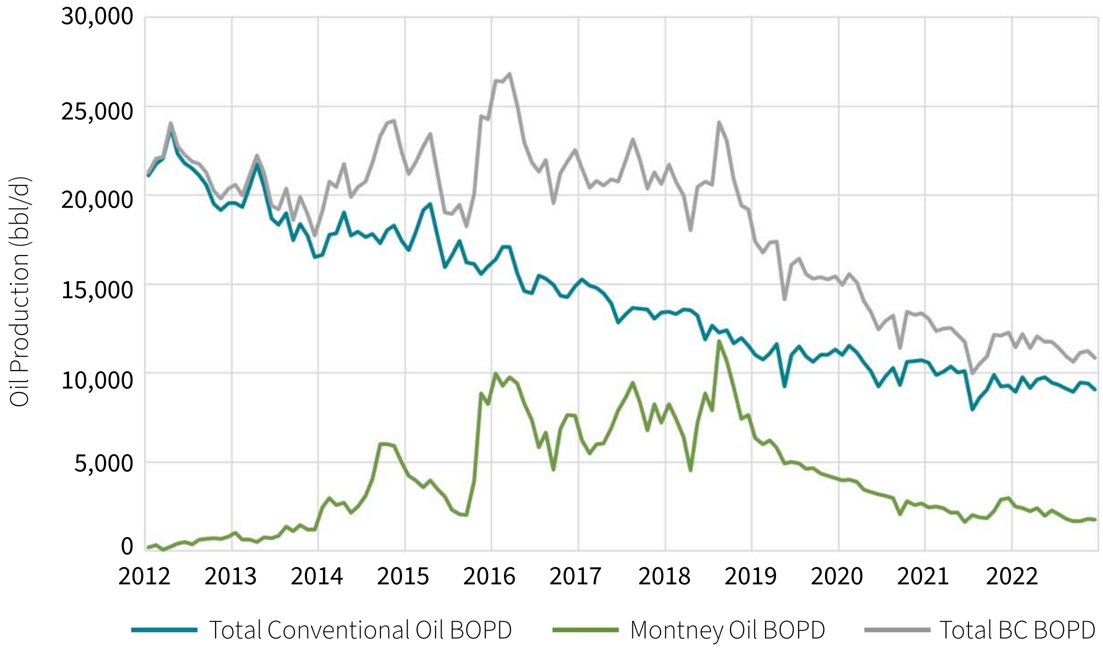
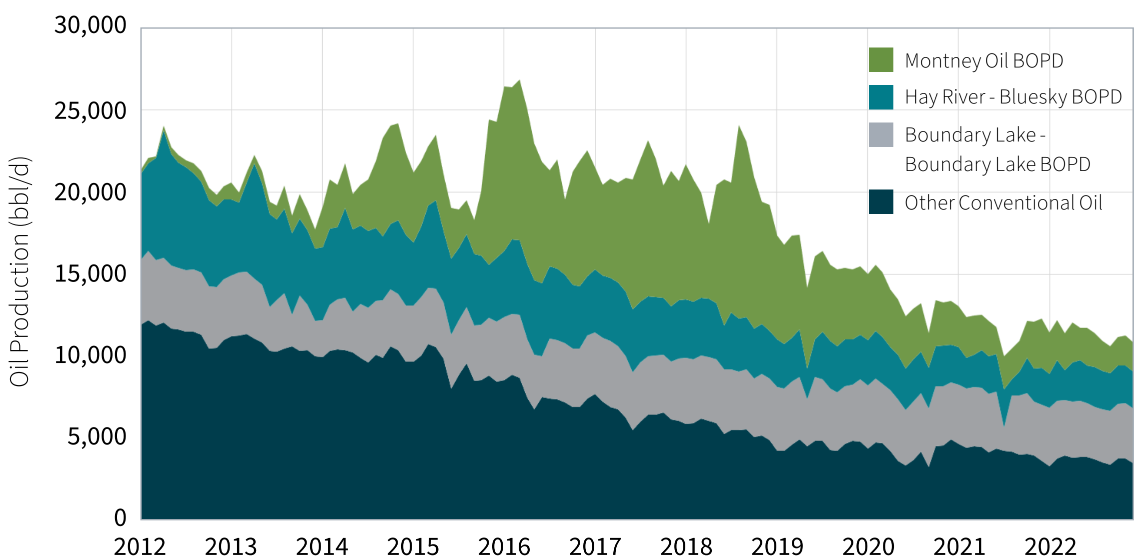


Figure 25: B.C. Oil Production Sources by 2012-2022



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 BCER 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 24.

Leucrotta's 4-well Montney Phase 1 Mica 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 24 and 25.

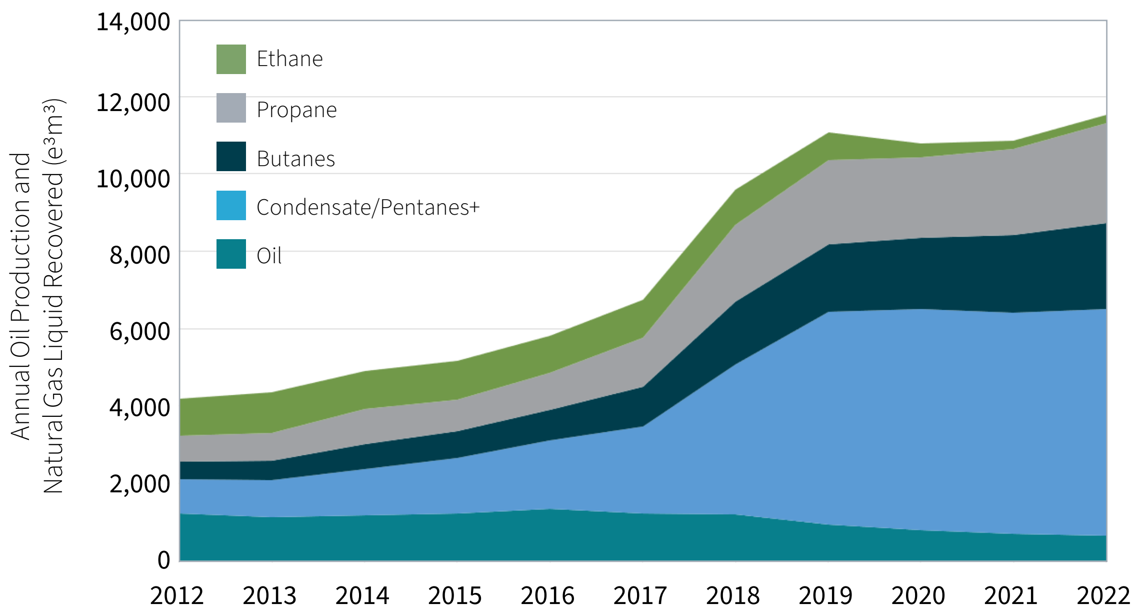
Discussions: Condensate, Pentanes+ and LPGs

Production of condensate/pentanes+ and Liquefied Petroleum Gas increased in 2022.

Overall, liquid by-products production in 2022 increased versus 2021, which had 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 since 2019 and were only 203.0 e^3m^3 in 2022. This reduction in ethane sales suggests ethane remains in plant outlet gas streams, to be extracted in other jurisdictions closer to end markets, or is reaching the burner tip.

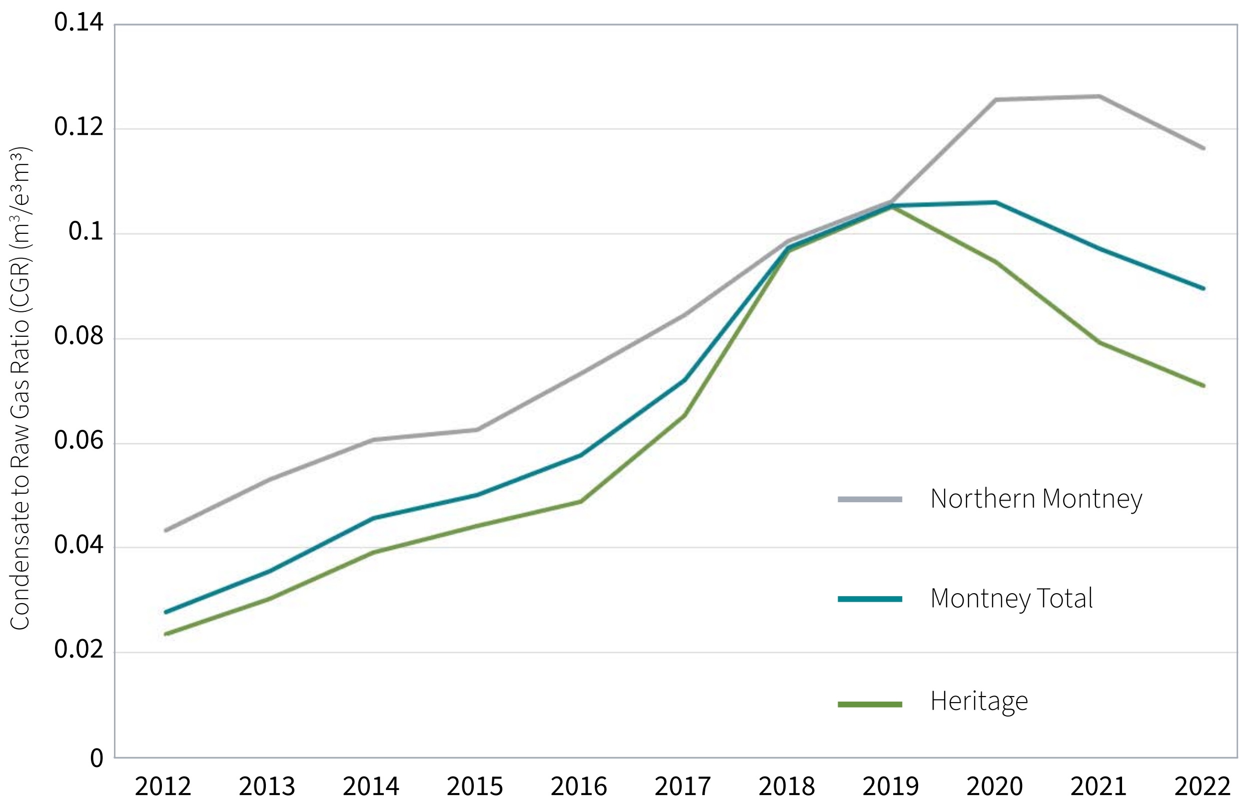
Figure 26: Annual Oil, Condensate and LPG Production 2012-2022



Butane and propane sales have been on an upward trend since 2008, which continued in 2022 with an 12 per cent and 15 per cent increase respectively over 2021. The general increase in butane and propane sales volume in recent years is a result of the capability of some companies 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 largely leveled off since 2019. In 2022, condensate/pentanes+ production increased by two per cent to 5,852.1 e^3m^3, whereas LPG production increased by 13 per cent to 5,001.1 e^3m^3 versus 2021 (Figure 26).

Figure 27: Condensate/Pentanes+ and Raw gas Ratio (CGR)(m^3/e^3m^3) 2012 to 2022



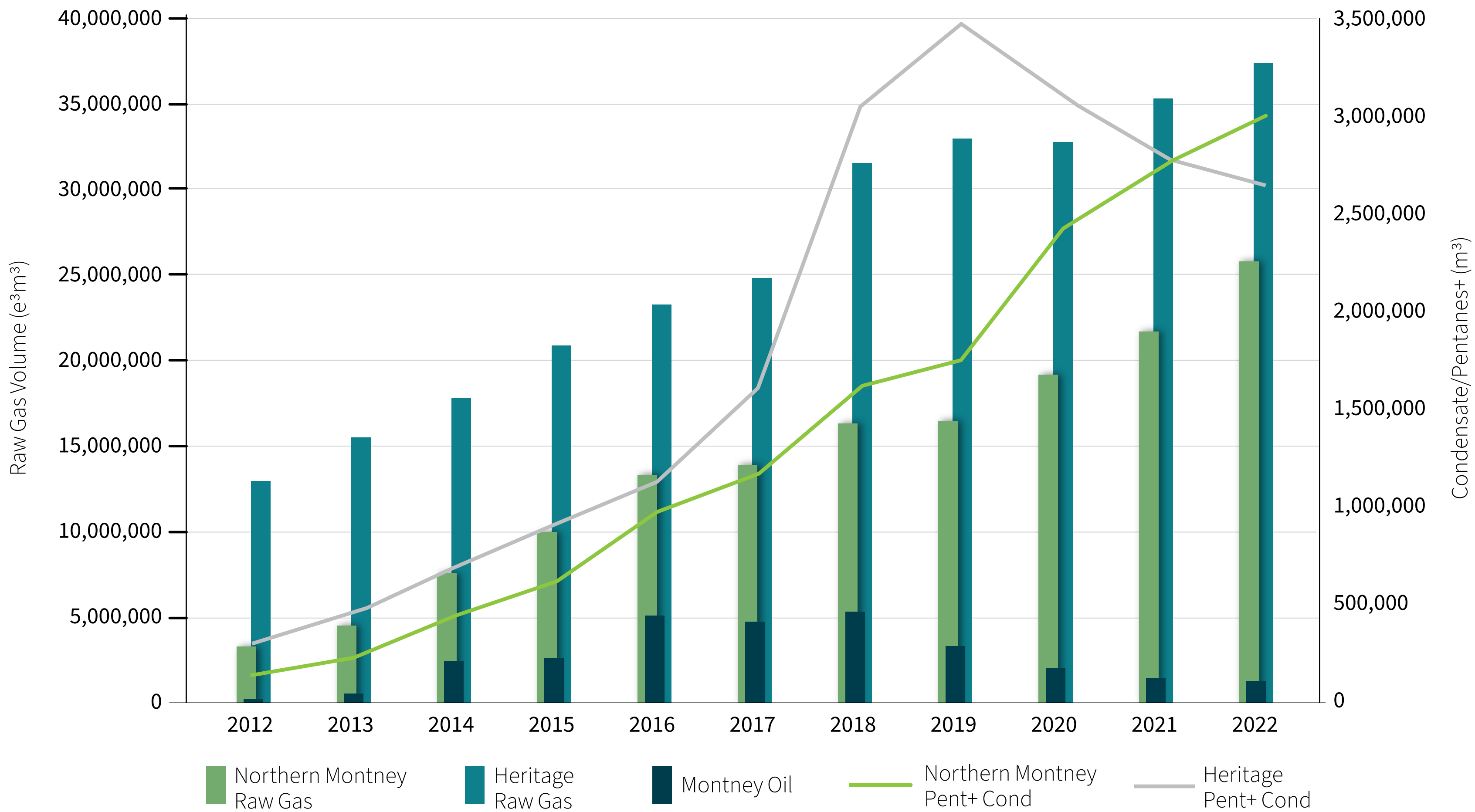
The general increase in liquids production is in part due to a shift towards development of liquids-rich Montney areas in recent years. This is also due to a change in policy for determining the primary product of Montney formation wells, which has allowed for a primary product review of oil wells producing 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 2022 is 140.1 e^6m^3, an increase of 19.3 per cent from last year. LPG remaining reserves increased by 21.9 per cent versus last year to 181.8 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 BCER identifies an oil leg and several "oily" areas, as illustrated earlier in Figure 11 on page 19. Annual natural gas, liquid and oil production from 2012 to 2022 is shown in Figure 28.

Figure 27 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 2022, CGR in the Heritage region decreased by 10.3 percent, due to a shift to dry gas to meet market gas demand, while CGR in the Northern Montney region decreased by eight per cent.

Figure 28: Annual Montney Oil, Raw Gas and Condensate/Pentanes+ Production 2012 to 2022

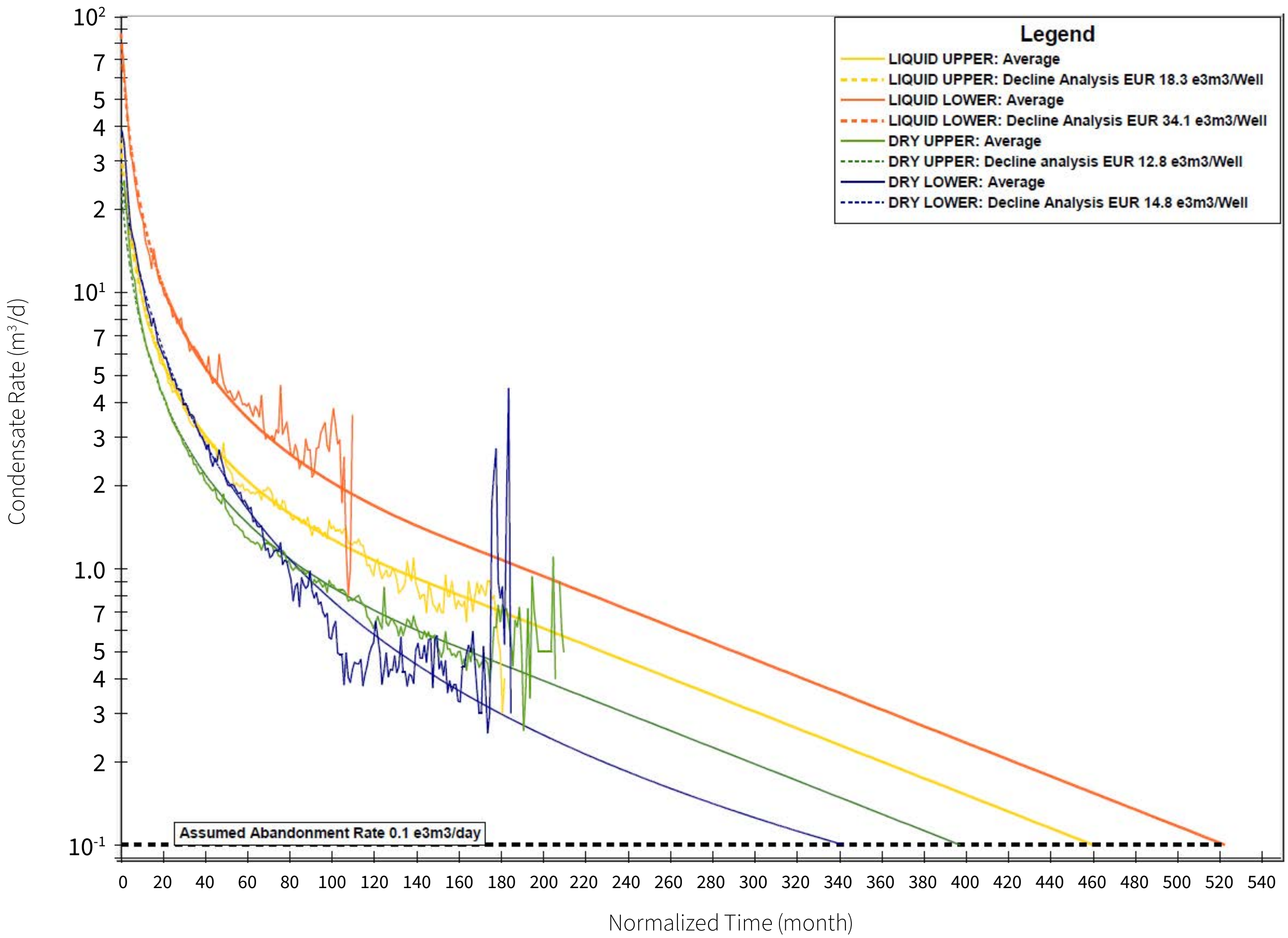


The majority of the NGL volumes are captured as an increase in marketable gas heating value, with liquids being recovered at the pipeline delivery point. To be more resilient towards changing market conditions, operators have invested in upgrading existing facilities or building additional deep-cut facilities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

Significant capital investment in gas processing, pipelines and gas and associated liquids export facilities, has continued in recent years. 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, Alberta. This northeast expansion has a capacity of 75,000 bbls/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.

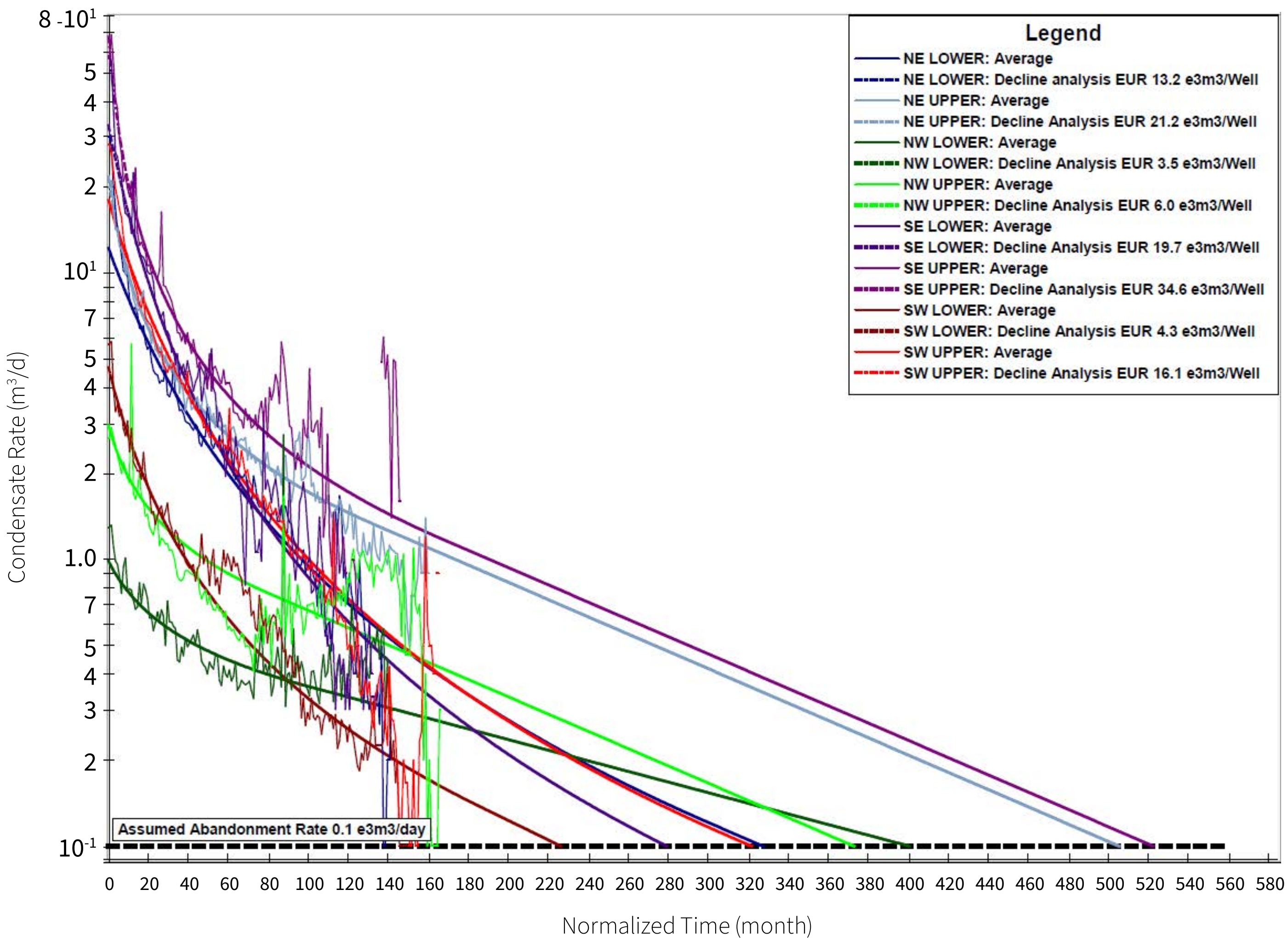
Figure 29: Heritage Condensate Type Wells by Subareas and Layers



In 2022, there was a 5.1 per cent decrease in condensate/pentanes+ production in the Heritage region versus 2021 (Figure 28), whereas the Northern Montney region saw a 9.3 per cent increase. This is a result of the decreased CGR in the Heritage, and increased gas production and CGR in the Northern Montney.

Figures 29 and 30 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 type wells in Figure 29 and 30 is 12.8 to 14.8 e³m³ (80.5 to 93.1 mbbl) per well in dry and ultra dry areas and 18.3 to 34.1 e³m³ (115.1 to 214.5 mbbl) 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 3.5 to 34.6 e³m³ (22 to 217.6 mbbl) per well.

Figure 30: Northern Montney Condensate Type Wells by Subareas and Layers



Discussions: Sulphur

Sulphur sales increased in 2022.

As of Dec. 31, 2022, recoverable sulphur remaining reserves was 6.1 10^6 tonnes (6.0 MMLT). Sulphur reserves saw a thirty per cent increase in 2022. Figure 31 shows the breakdown of remaining sulphur reserves in the major sour fields as of Dec. 31, 2022.

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 32, decreased significantly between 2015 and 2018. Sales have fluctuated in recent years, with 2019 and 2021 being low, at approximately 245,000 tonnes, while 2020 and 2022 had significantly higher sales at approximately 400,000 tonnes.

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

Figure 31: 2022 Major Sour Fields by Remaining Sulphur Reserves

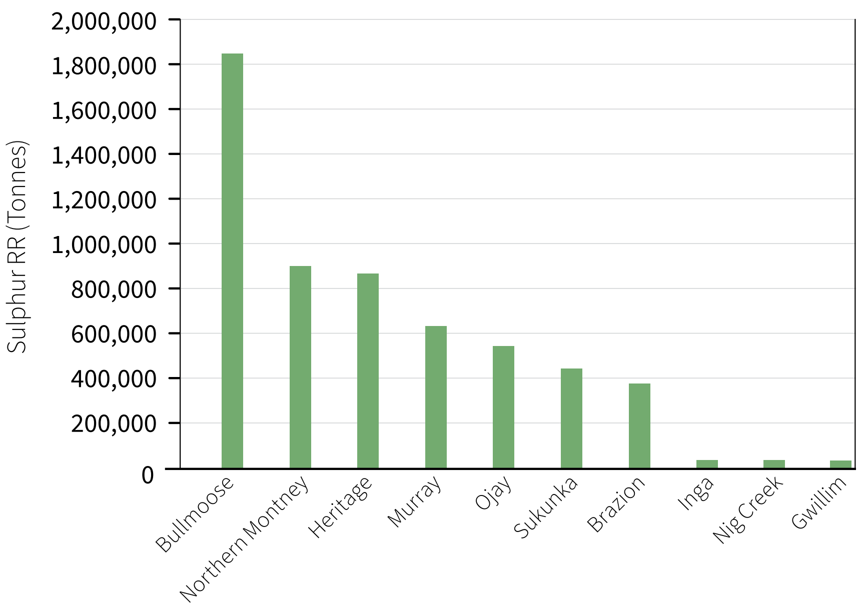
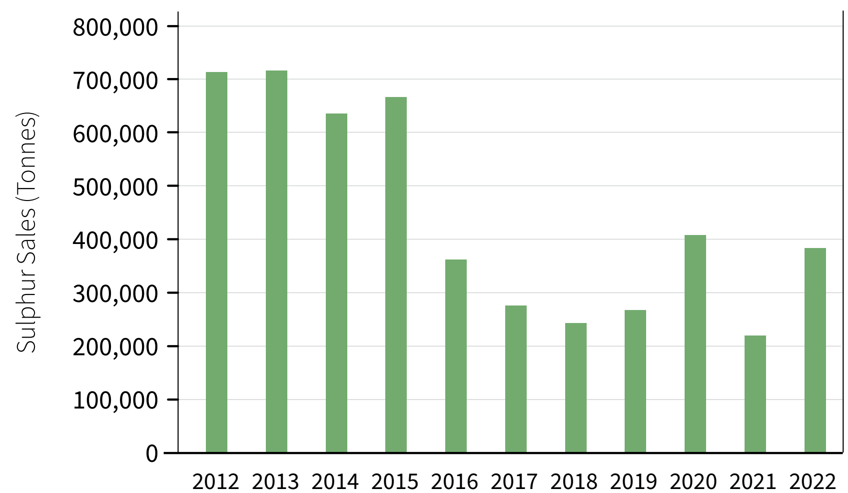


Figure 32: Annual Sulphur Sales 2012-2022

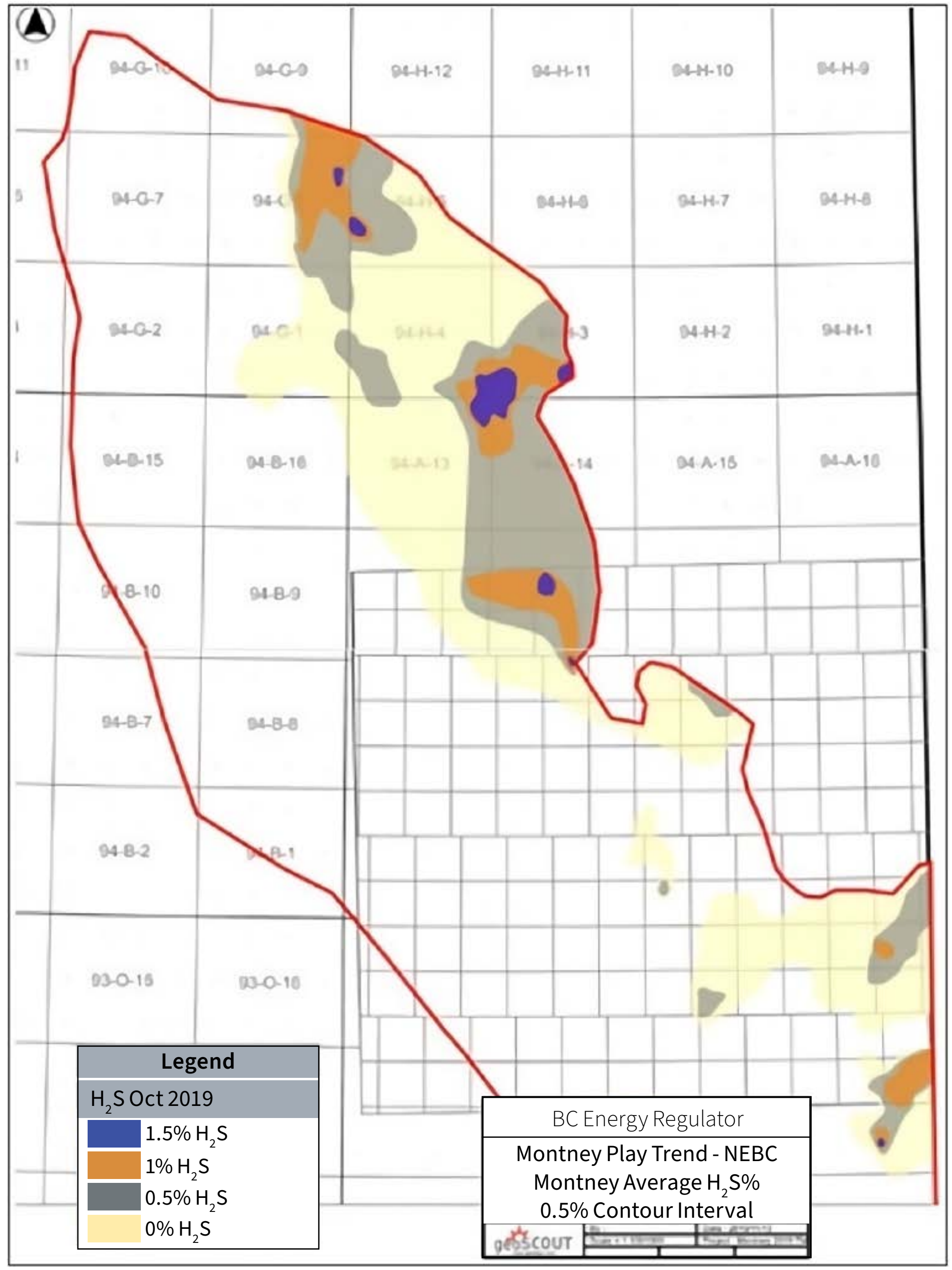


content, the immense volumes of natural gas recovered from the Northern Montney play results in an appreciable amount of sulphur. Sulphur production occurs at the McMahon gas plant. Additionally, there are some cases where the percentage of H_2S can be significant in Montney gas (Figure 33).

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

Figure 33: Average H_2S in the Montney Field



Discussions: Deep Disposal

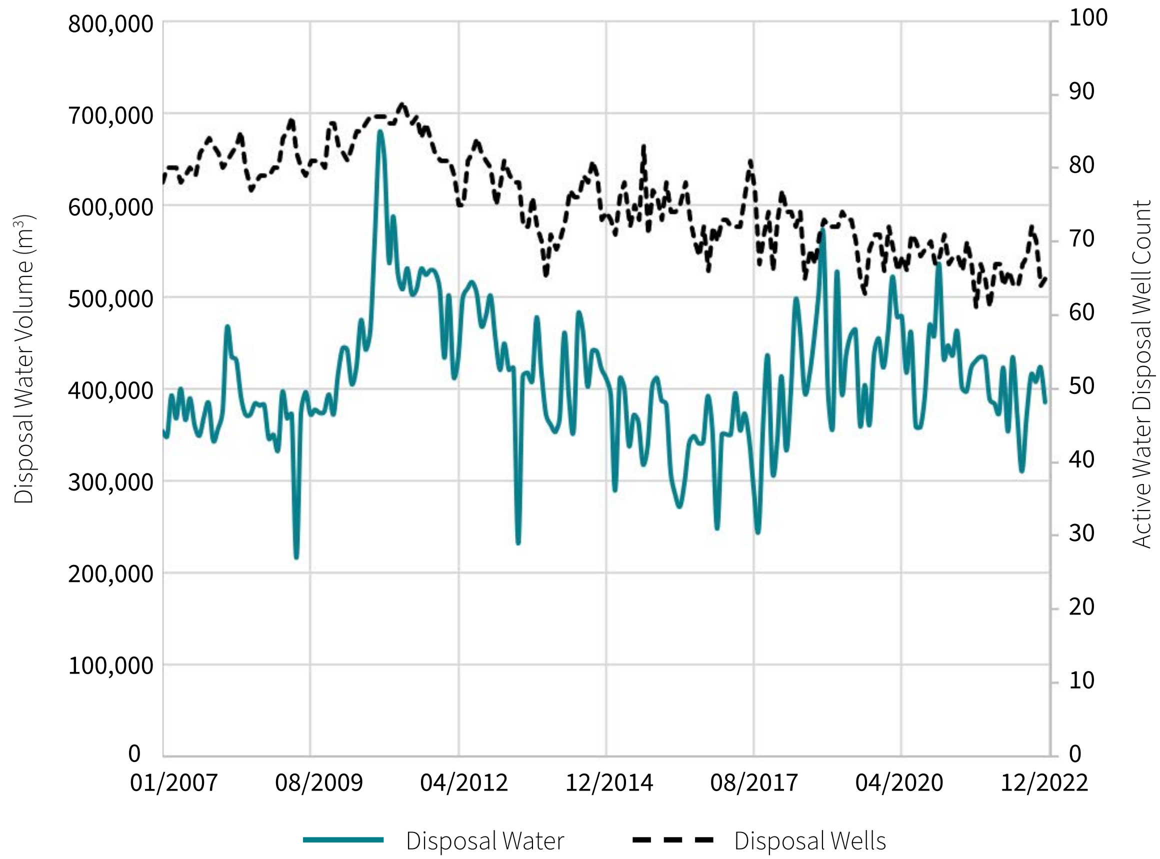
Disposal wells inject undesired fluid by-products of oil and gas production into deep subsurface geological formations for long term storage. Disposal fluids fall into three categories: produced water (including flowback water from hydraulic fracturing), non-hazardous waste (NHW), and acid gas (CO_2 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 saline water to the surface, 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

Figure 34: Monthly Water Disposal Well Count and Volume 2007-2022



disposal wells. As a result, produced water disposal activity is now highly correlated with new well stimulations.

Oilfield NHW, 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 34 shows the monthly active water disposal well count and volume from 2007 to 2022. Total water disposal volume has mostly remained in the range of 400 ± 100 e^3m^3/month over this 15-year period, as disposal of fracture flow-back water has been replacing conventional formation produced water. The large spike in water disposal occurring in 2010 is attributed largely to increased development (and thus increased wastewater from hydraulic fracturing) in the Horn River basin. Development of this area ceased in 2015.

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 environmentally friendly alternative to flaring and the atmospheric release of SO_2 and CO_2. Figure 35 shows annual estimates for CO_2 production in raw gas for the province over the past decade. Both total CO_2 volume and CO_2 as a percentage of total raw gas steeply decline from 2013 to 2019, whereafter they have been relatively constant. This decrease

Figure 35: $C0_2$ Production from Raw Gas 2013-2022

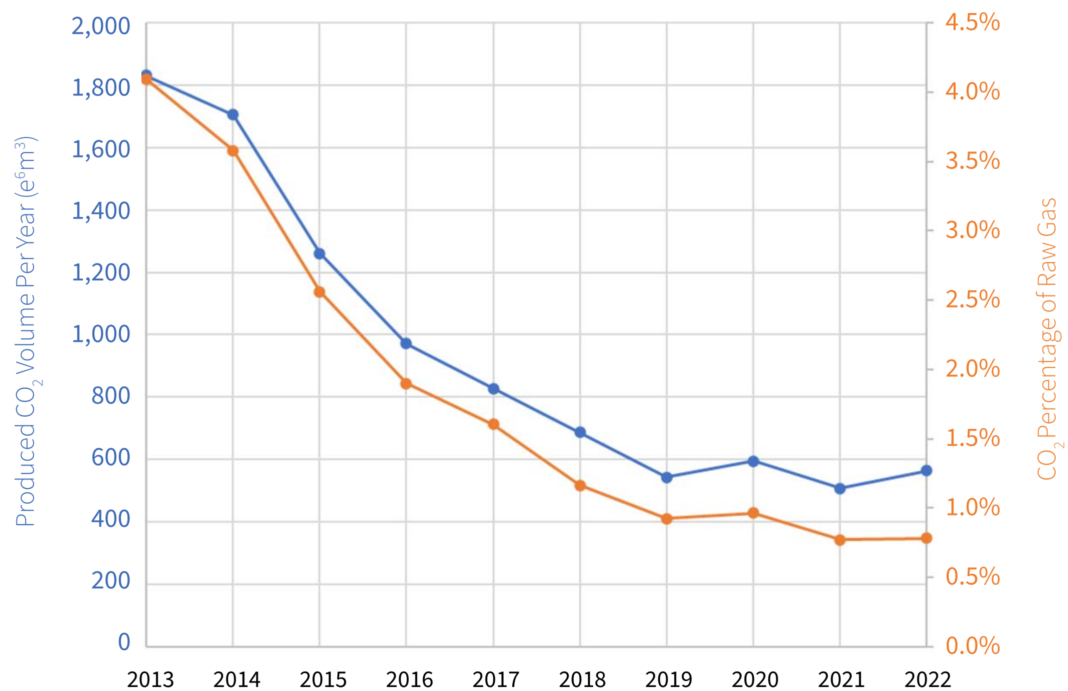
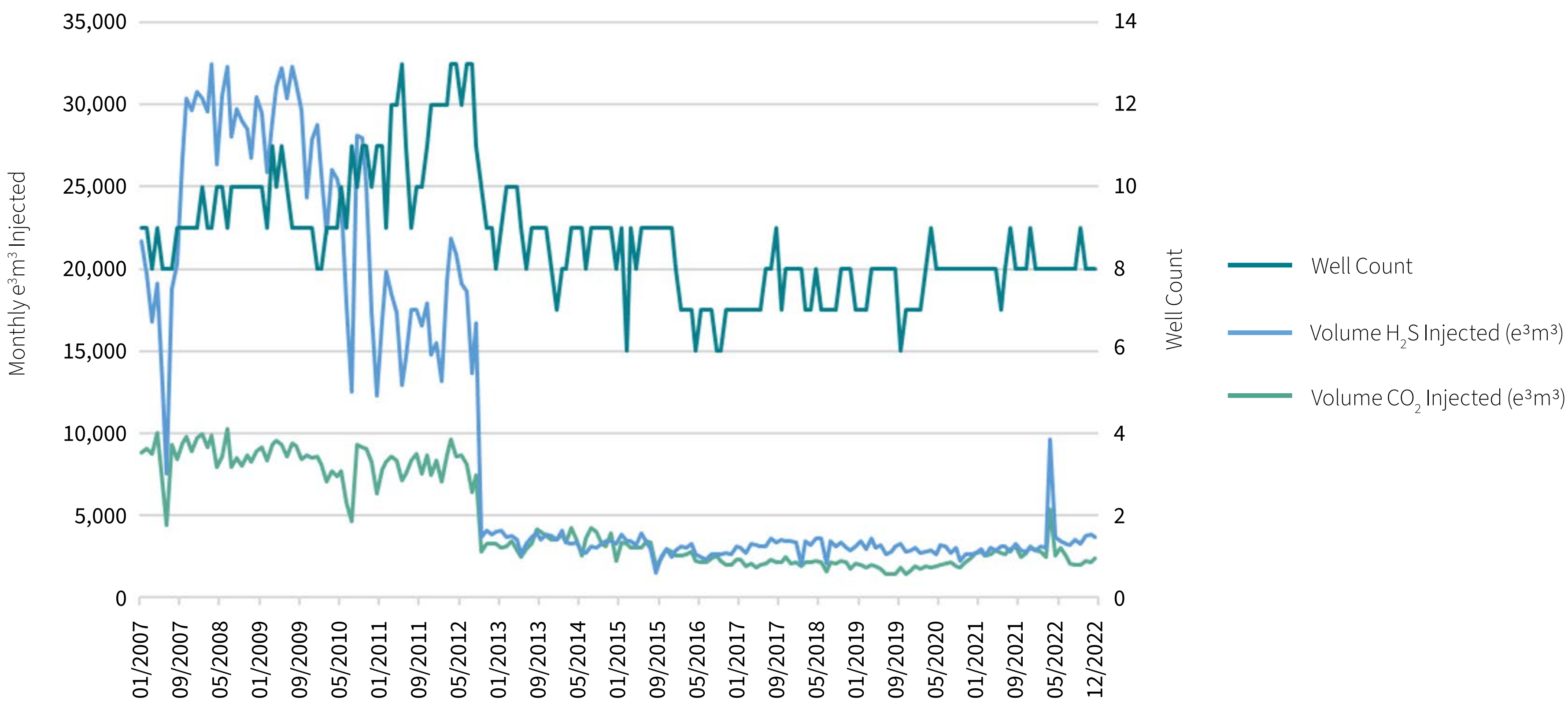


Figure 36: Monthly Acid Gas Disposal Well Count and Volume 2007-2022



was largely driven by decreased production from the Horn River and lower estimated CO_2 composition from the Heritage Montney. Note that CO_2 composition is estimated from pool-wide sample gas analyses and is not based on true measured volumes.

Figure 36 shows the active monthly acid gas disposal well count and CO_2 and H_2S volumes from 2007 to 2022. Total acid gas disposal volume averaged around 25-40 e^6m^3/month from 2007 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.

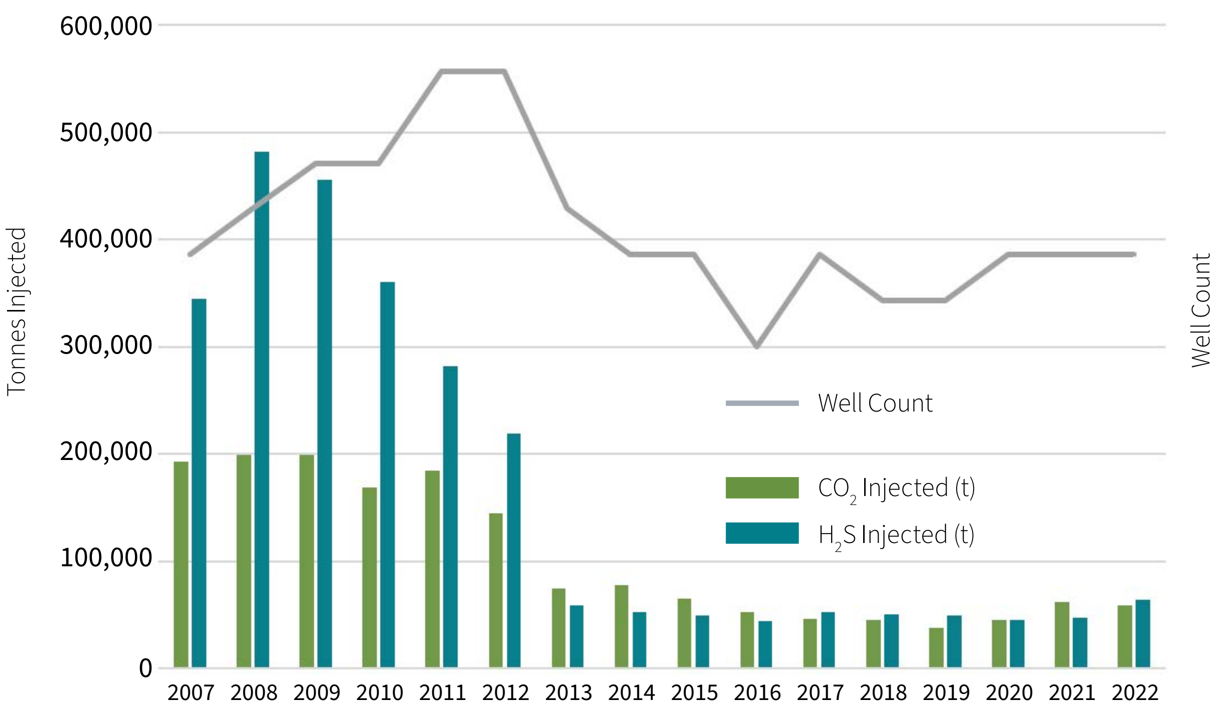
The current trend in acid gas disposal is the installation of smaller rate acid gas disposal wells for plants processing Montney gas, which varies from sweet to around 1.5 per cent H_2S content.

Disposal Summary

It should be noted that a total of 2.687 megatonnes of CO_2 have been sequestered as of December 2022, since acid gas disposal began in 1996. Additionally, during this time period, acid gas disposal has diverted the atmospheric release of 8.822 megatonnes of SO_2, if the H_2S had instead been flared.

In summary, 2022 disposal represented a continuation of existing trends for both water and acid gas disposal. Total water disposal for 2022 averaged 387 e^3m^3/month (2,434 mbbl/month) which was within the historical range, though approximately 10 per cent below reported disposal from 2018–2021. In recent years, the location of new disposal demand has been in the Montney fairway, and the only disposal well approved in 2022 is located in that fairway. All of the operating acid gas disposal wells were located in the Montney fairway.

Figure 37: Annual Acid Gas Disposal Well Count and Tonnage 2007-2022



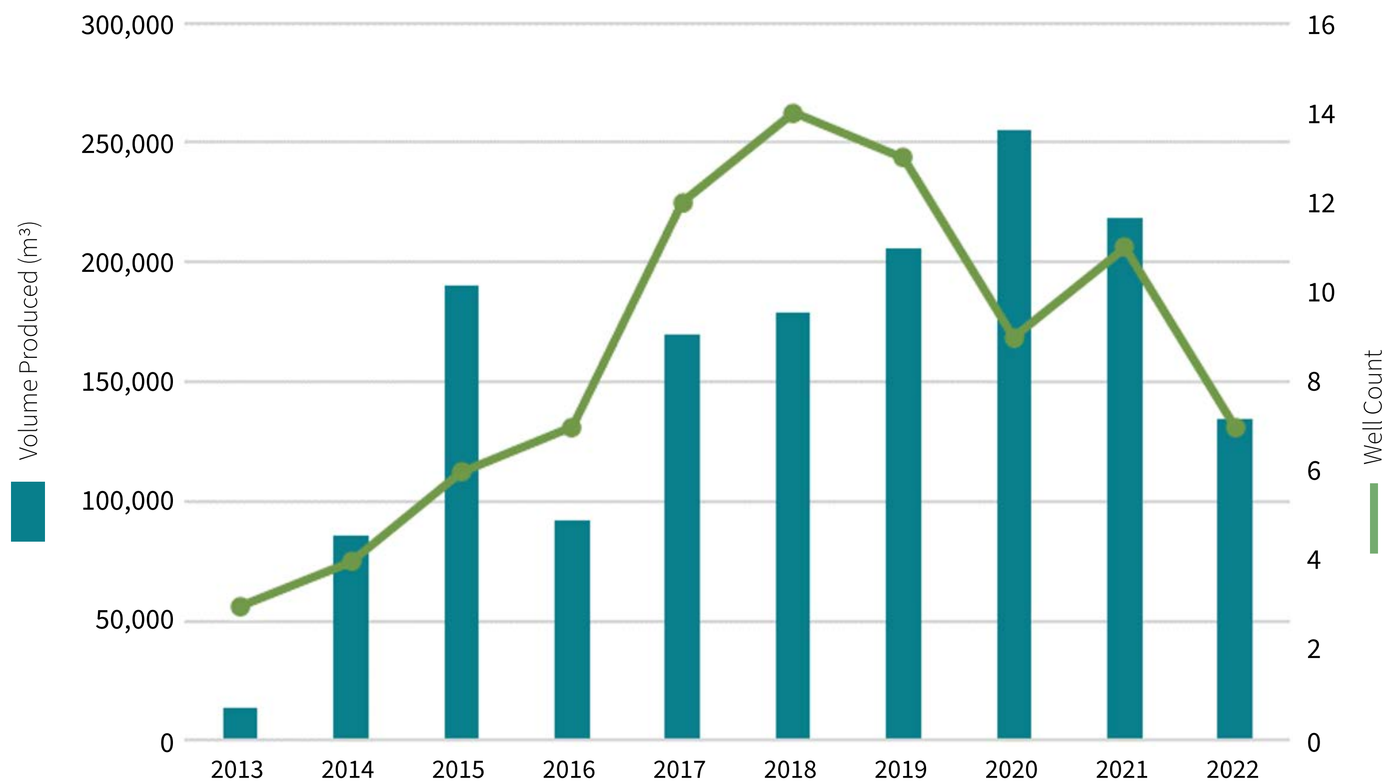
Additional information regarding disposal wells can be found on the BCER's website. Chapter 3 of the Water Service Wells Summary Information Document and Acid Gas Disposal Wells Summary Document provide comprehensive guides on the regulation of disposal wells in B.C. Individual disposal well approvals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

The BCER regulates disposal wells with conditions for operating, 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 Sourcing

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 license, however, these wells are subject to normal BCER regulation for well life cycle 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 38 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 BCER does not maintain an inventory for deep saline water reservoir 'reserves', however, understanding of the location and potential reservoir size, is informed partially from the extensive data obtained from disposal wells.

Figure 38:
Annual Deep Saline Water Data 2013-2022



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 98 per cent of wells drilled in 2022, 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.

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

The Montney formation covers a vast area, as illustrated in Figure 19 on page 27. Through that fairway, reservoir quality varies significantly, with factors such as hydrocarbon content, reservoir pore pressure, rock stress and potential for induced seismicity, being a few of the variables which influence fracture stimulation design. Wells from a common pad are completed in different Montney layer sub-units, each with these variations. The following graphs include data for Montney wells representing averaging of values and trends, unless specified as data for specific sub-layer or region.

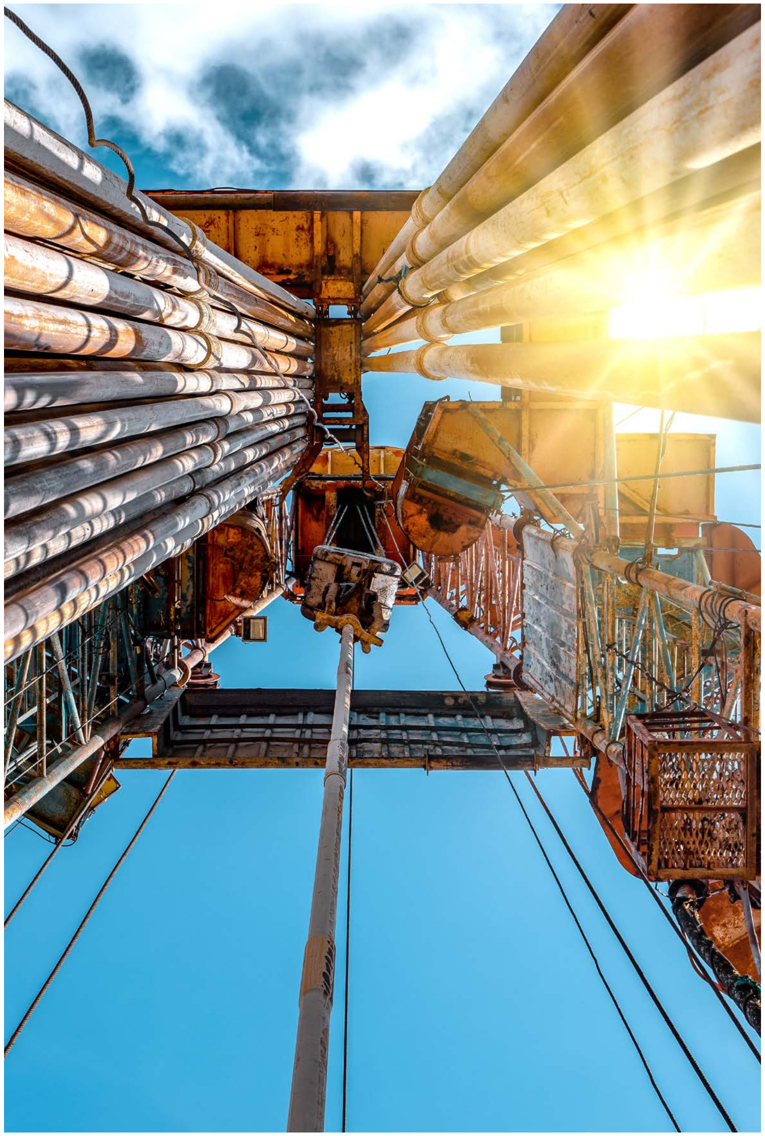
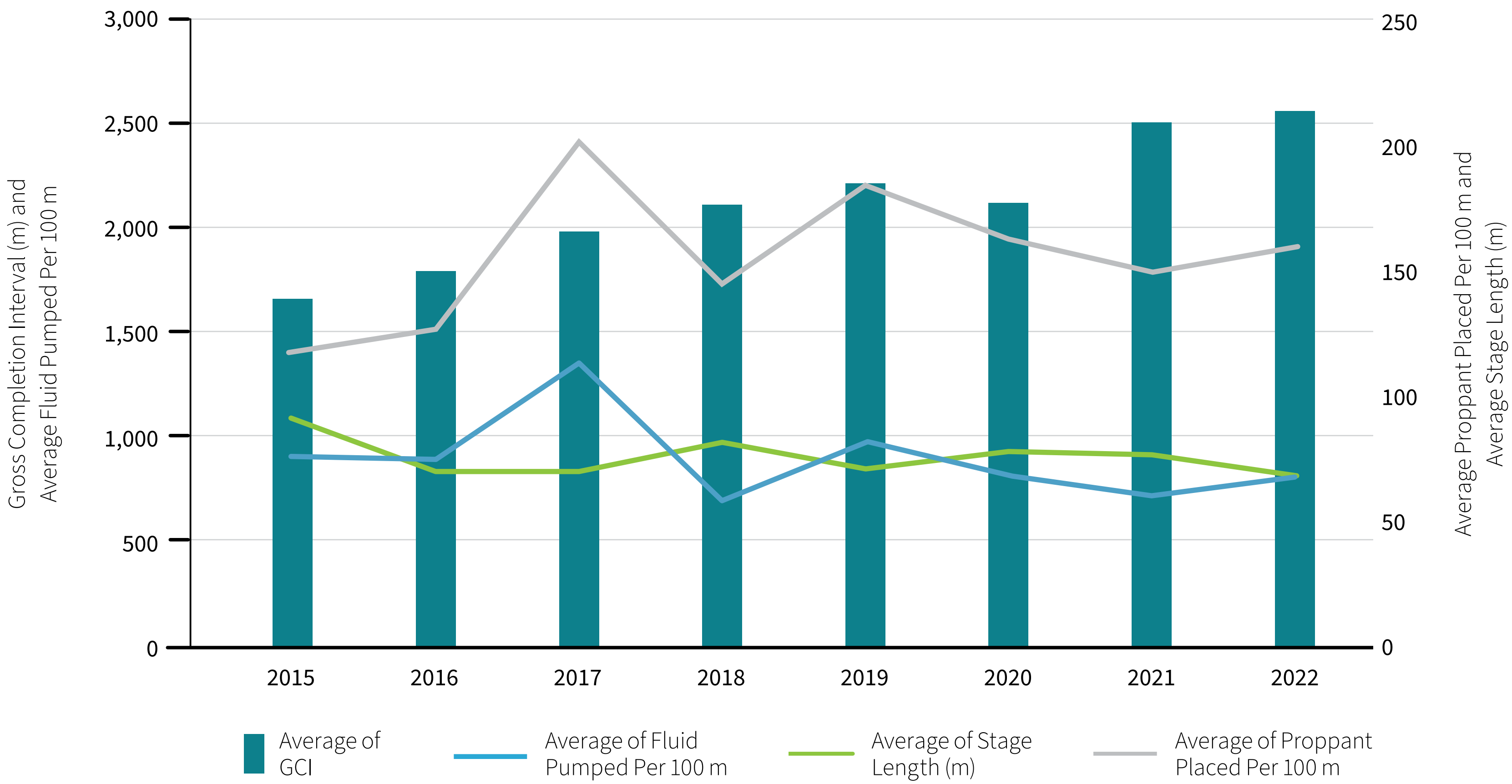


Figure 39 shows the horizontal well lengths, or gross completion interval (GCI) as a bar graph, which has been increasing since 2015 with a jump of several hundred metres, on average, in 2021 and a further modest increase in 2022. The proppant placed per 100 m decreased following 2019 but showed a slight increase in 2022. Advances in fracking optimization may allow for less proppant to accomplish similar production and lower costs. 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 BCER reports.

Figure 39: Montney Hydraulic Fracture Summary Data 2015-2022



In closer detail, Figure 40 represents the pumped fluid to proppant ratios by Montney stratigraphic layer. As all three trends are downward, the implication is less fluid to proppant is being injected, meaning the injected slurry is denser.

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, recovery of wet gas relies on fracture density. The distance between horizontal wells is balanced, with the ability to effectively open or stimulate the rock between wells, while limiting "frac hit" contacts.

Table 5: Average Montney Gross Completed Interval (GCI) by Well Vintage

Completion Year	Average Gross Completed Interval (m)
2015	1,654
2016	1,793
2017	1,978
2018	2,104
2019	2,211
2020	2,116
2021	2,499
2022	2,554

Figure 40: Annual Pumped Fluid to Proppant Ratio 2015-2022

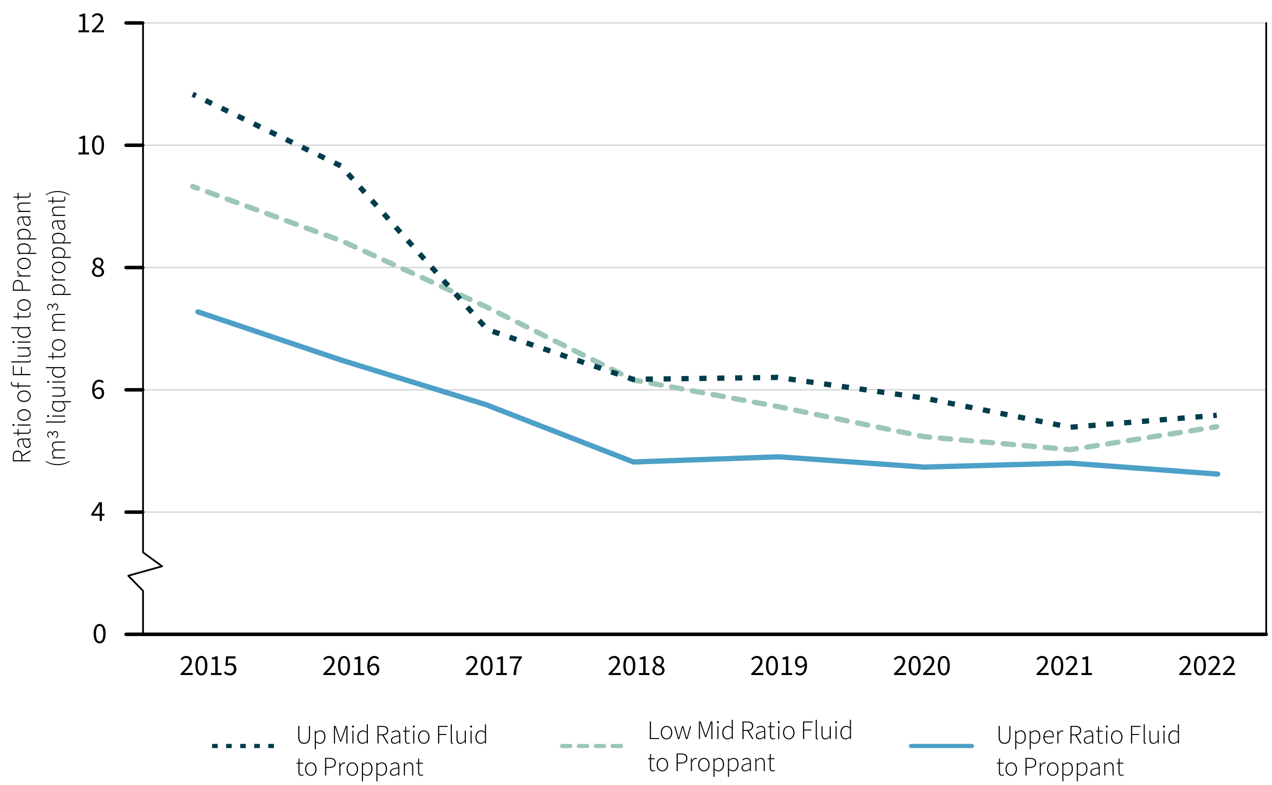


Figure 41 depicts the average lengths of horizontal GCI for each of the two main fracture methods – Open Hole (OHB) and Cemented (Plug and Perf or Sliding Sleeve). From this plot, it becomes clear that in the beginning of 2017, there was a reversal of preference, with cemented completions outnumbering open hole completions, however the closing gap in 2020 and 2021 shows a closer to equal populations. Again, this may reflect which operators are most active during the past two years, since each operator tends to complete their wells in a consistent manner.

Again, it is obvious that the GCIs have steadily risen through the years, including into 2022. This indicates less surface disturbance with more resource reach.

Interesting to note, is the longer GCI achieved with cemented completions This difference widened further in 2022, with cemented wells on average, 3,000 m long and open hole wells averaging 2,000 m. There can be many reasons for this, including, operator, area, technology or land available.

Figure 41: Montney Well Completions

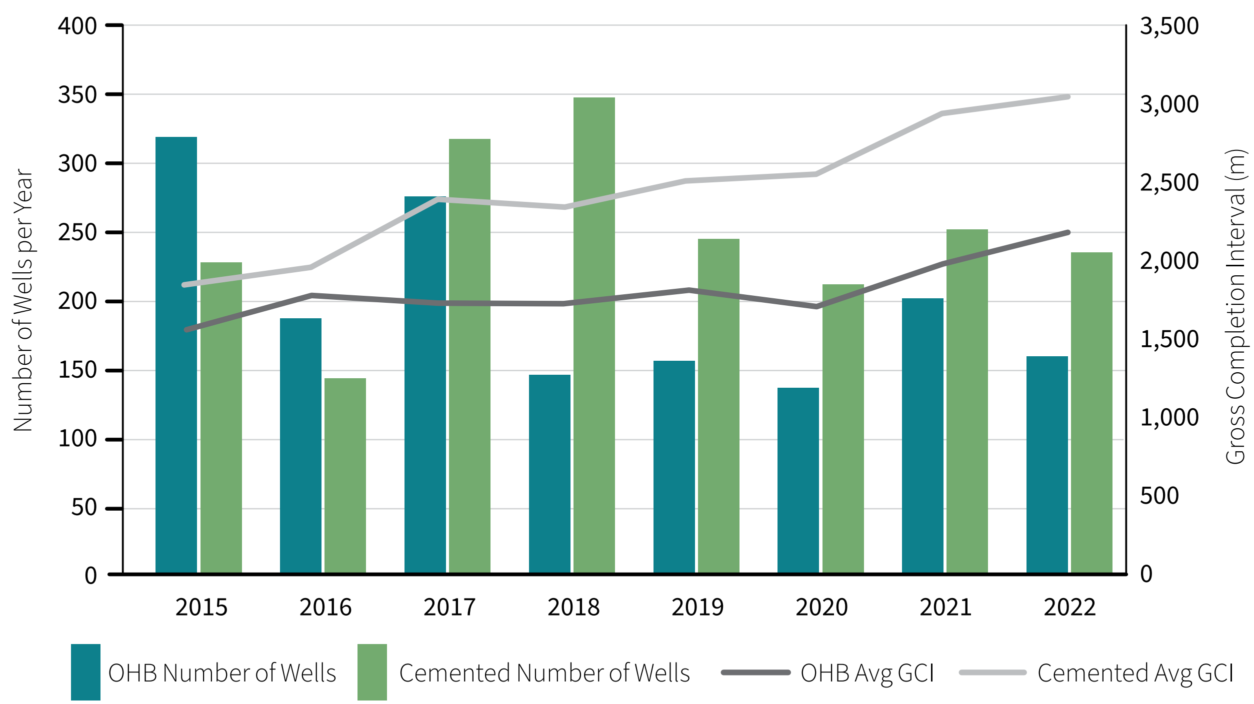
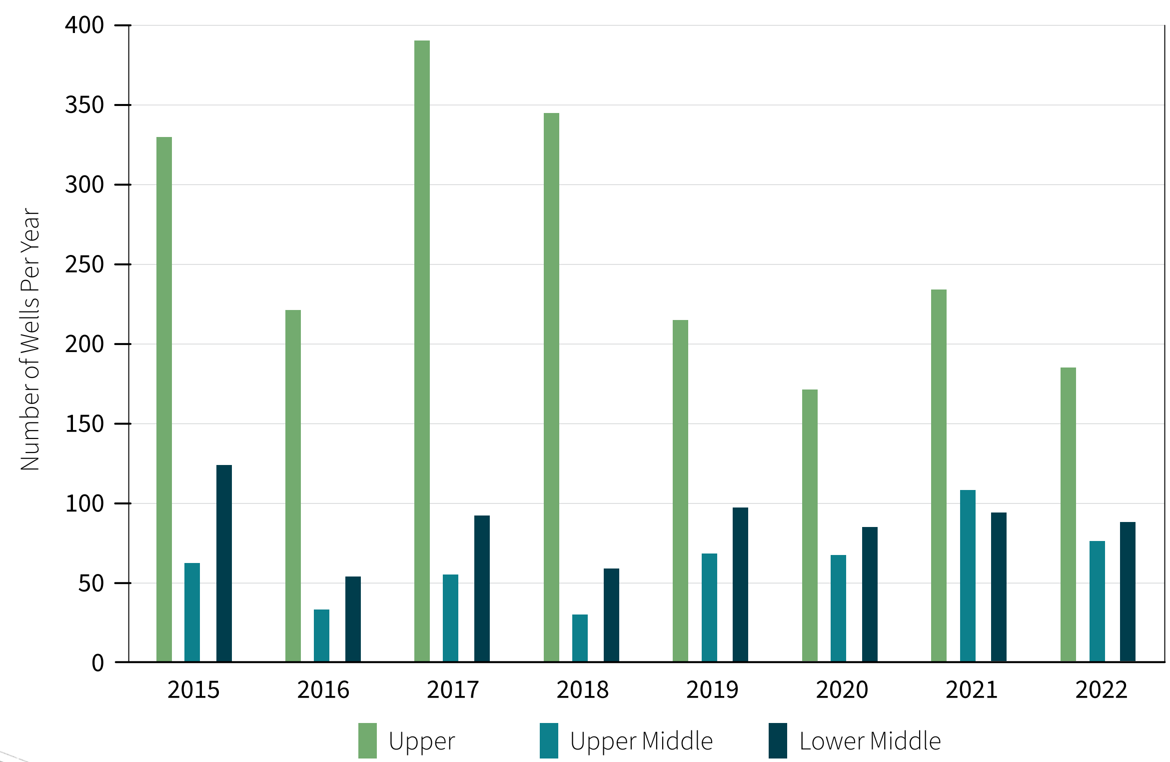
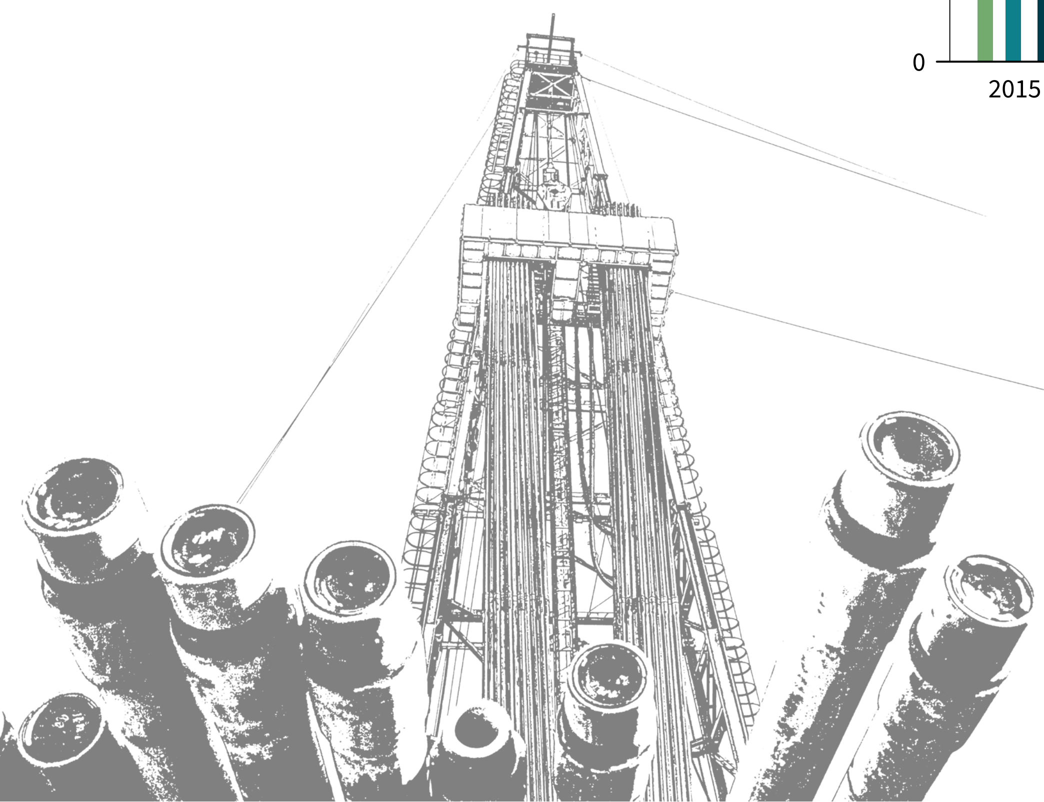


Figure 42 shows the Montney layer targets each year. From this plot, it becomes clear that the Upper Montney (U) is the most targeted layer with over 2,000 wells completed since 2015. Next is the Lower Middle (LM) layer, with about 700 wells and the Upper Middle (UM) has the fewest wells, at approximately 500 wells. The year 2022 concluded with fewer wells completed than 2021, with uppers still dominating. 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.

Figure 42: Number of Wells Per Year Per Montney Layer



Note: The lower Montney has been excluded due to very low well count



Additional information on hydraulic fracturing is available at Hydraulic Fracturing | BC Energy Regulator (bc-er.ca).

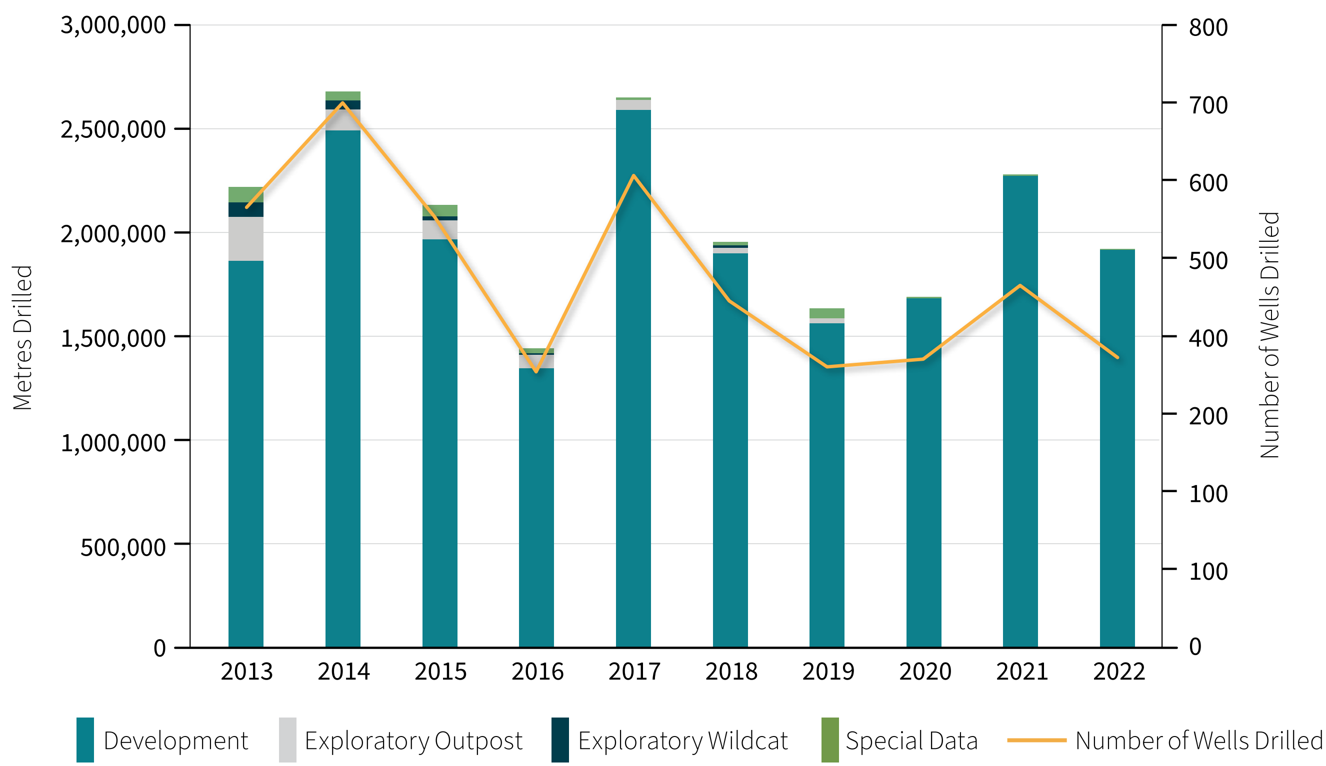
The detailed hydraulic fracturing database, the source for graphs in this section, is available in the BCER's Data Centre (Hydraulic Fracture Summary Data). Additionally, information regarding frac fluids can be found in the BCER's FracFocus report.

Discussion: Drilling and Decommissioning

Figure 43 shows the metres drilled by well classification and the number of wells drilled per year. The amount of non-development wells drilled per year has been steadily decreasing, with only one or two wells drilled in 2020, 2021, and 2022. Few exploratory or special data wells are needed, as operators target the Montney near existing wells. The number of wells drilled has also been on a decline, as operators continue to increase the length of their wells, access the same amount of reservoir with less wells.

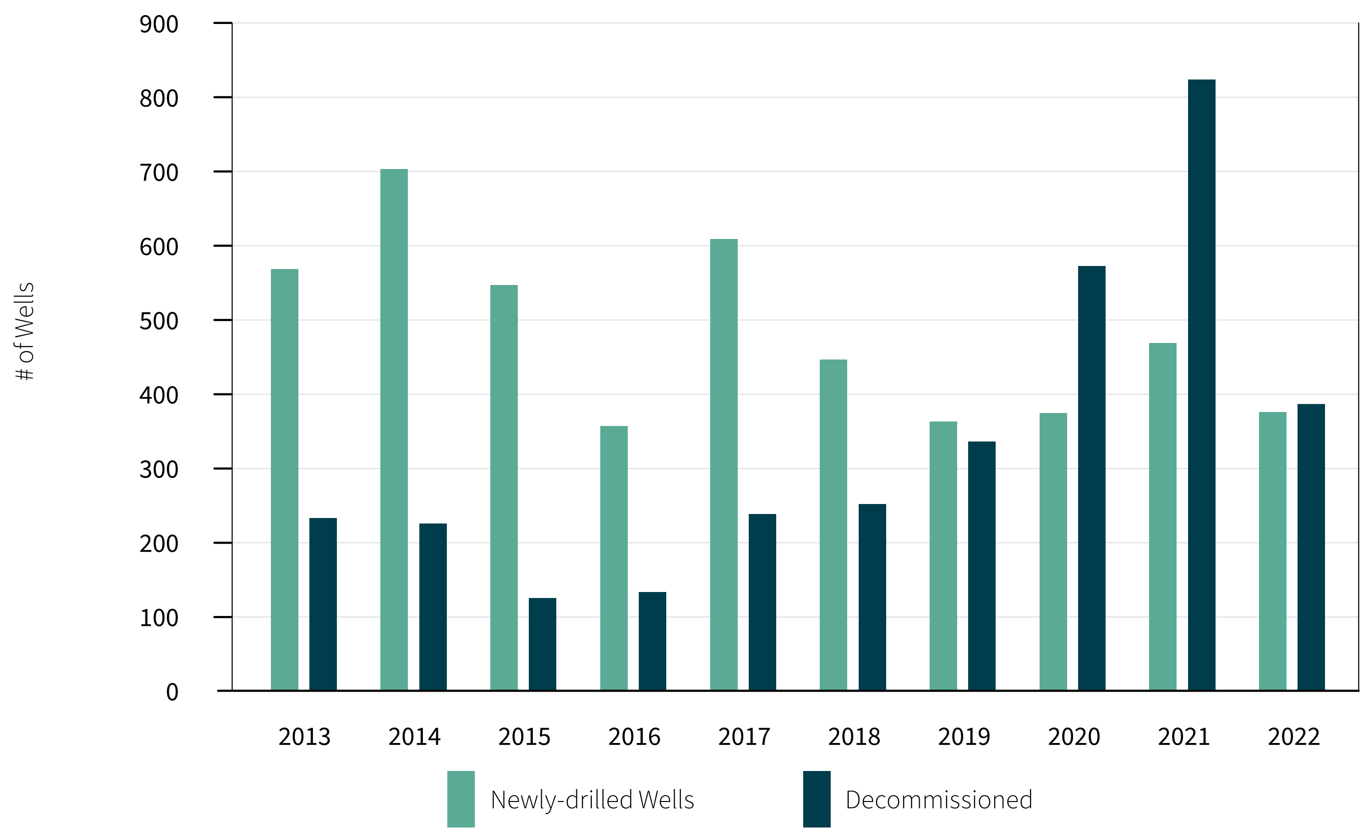
Figure 44 shows the number of wells drilled and decommissioned by year. In 2020, for the first time in the province's history, more wells were

Figure 43: Length Drilled by Well Classification Per Year



decommissioned than were drilled. A trend that continued in 2021 and 2022. Note that, due to a delay in processing decommissioning reports, the number of decommissioned wells in recent years may be amended upwards, as reports are entered into the database. The BCER is improving systems to address this increase in data. The large increase in the number of wells decommissioned in recent years is mostly due to the introduction of the Dormancy and Shutdown Regulation, which requires operators to decommission inactive wells and restore inactive sites within a strict timeline.

Figure 44: Number of Wells Drilled and Decommissioned by Year



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 Gas (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 BCER.

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 BCER as a zone.

Appendix A

Table A-1: Established Hydrocarbon Reserves (SI Units) at Dec. 31, 2022

	Oil ($10^3 m^3$)	Raw Gas ($10^6 m^3$)
Initial Reserves, Current Estimate	138,142	3,900,387
Discovery 2022	0	0
Revisions 2022	-518	452,988
Production 2022	662	70,802
Cumulative Production Dec. 31, 2022	125,975	1,425,323
Remaining Reserves Estimate Dec. 31, 2022	12,167	2,475,065

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
2022	3,900,387	0	452,988		70,802	1,425,323	2,475,065

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	-1,006		676	125,403	13,257
2022	138,142	0	-518		662	125,975	12,167

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	G	05	1438.4	29.6%	425.8	425.8	0.0
BEATTON RIVER	HALFWAY	A	02	3430.1	47.1%	1616.2	1616.2	0.0
BEATTON RIVER WEST	BLUESKY	A	02	2956.3	37.2%	1098.3	1098.3	0.0
BEAVERTAIL	HALFWAY	B	06	499.0	18.0%	89.8	87.7	2.1
BEAVERTAIL	HALFWAY	H	05	874.1	20.0%	174.8	173.1	1.7
BIRCH	BALDONNEL	C	03	2058.1	49.0%	1008.5	970.3	38.1
BLUEBERRY	DEBOLT	E	03	1211.5	30.0%	363.4	354.2	9.2
BOUNDARY LAKE	BOUNDARY LAKE	A	04	5769.2	60.0%	3461.5	3211.2	250.3
BOUNDARY LAKE	BOUNDARY LAKE	A	05	1587.4	65.0%	1031.8	996.1	35.7
BOUNDARY LAKE	BOUNDARY LAKE	A	02	43666.1	48.0%	20959.7	20203.0	756.7
BOUNDARY LAKE	BOUNDARY LAKE	A	03	30218.0	44.0%	13295.9	12978.7	317.2
BOUNDARY LAKE NOR	HALFWAY	I	04	1085.8	40.0%	434.3	388.4	45.9
BOUNDARY LAKE NOR	HALFWAY	D	03	588.3	20.0%	117.7	109.8	7.9
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	958.6	119.0
EAGLE	BELLOY-KISKATINAW		02	6928.9	40.0%	2771.5	2610.8	160.7
EAGLE WEST	BELLOY	A	03	20337.5	31.0%	6304.6	6271.8	32.8
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	6204.7	1193.8
INGA	INGA	A	04	8356.0	39.9%	3334.0	3331.1	3.0
INGA	INGA	A	06	7521.3	31.1%	2335.4	2335.0	0.3
INGA	INGA	A	08	1716.5	32.5%	557.7	557.7	0.0
INGA	INGA	A	07	1400.6	44.8%	627.5	627.5	0.0
LAPP	HALFWAY	D	02	395.3	42.0%	165.8	165.8	0.0
LAPP	HALFWAY	C	02	1036.8	43.6%	451.7	451.7	0.0
MICA	MICA	A	04	1128.7	40.0%	451.5	360.0	91.4
MICA	DOIG	B	04	509.7	30.0%	152.9	130.1	22.8
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	1029.8	6.8
MUSKRAT	BOUNDARY LAKE	A	03	1142.8	40.0%	457.1	396.2	60.9
MUSKRAT	LOWER HALFWAY	A	03	464.4	23.0%	107.0	107.0	0.0
OAK	CECIL	C	03	907.7	55.0%	499.3	451.2	48.1
OAK	CECIL	B	02	424.3	23.5%	99.8	99.8	0.0
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		04	10137.3	44.3%	4490.8	4474.5	16.3
PEEJAY	HALFWAY		03	8937.6	43.0%	3843.2	3835.6	7.6
PEEJAY	HALFWAY		02	5802.7	38.4%	2227.1	2227.1	0.0
PEEJAY WEST	HALFWAY	A	03	1904.0	23.0%	437.9	430.8	7.1
PEEJAY WEST	HALFWAY	C	02	510.9	40.0%	204.4	170.3	34.1
RED CREEK	DOIG	C	03	609.3	30.0%	182.8	152.6	30.1
RIGEL	CECIL	H	03	1820.9	50.0%	910.4	888.8	21.6
RIGEL	DUNLEVY	A	02	195.5	9.7%	19.0	19.0	0.0
RIGEL	CECIL	I	02	1962.0	40.0%	784.8	776.9	7.9
RIGEL	CECIL	G	02	952.7	45.0%	428.7	419.0	9.7
RIGEL	CECIL	B	02	1502.6	40.0%	601.1	596.8	4.3
RIGEL	HALFWAY	C	03	752.3	38.8%	292.0	292.0	0.0
RIGEL	HALFWAY	C	02	738.7	26.6%	196.6	196.6	0.0
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	35.3%	75.4	75.4	0.0
STODDART WEST	BELLOY	C	05	5784.4	25.0%	1446.1	1393.1	53.0
STODDART WEST	BEAR FLAT	D	03	451.9	34.5%	156.0	156.0	0.0

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

Table A-4 (continued from previous page): 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)
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	263.1	17.3
WEASEL	HALFWAY		02	3720.0	65.0%	2418.0	2383.3	34.7
WEASEL	HALFWAY		03	1729.5	58.2%	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				271,260.2		103,944.2	100,452.4	3,491.8
% of Total British Columbia Oil Reserves						75.2%	79.7%	28.7%
			total			138142.2509	125975.0297	12167.2212

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	339.8	34.4
CECIL LAKE	CECIL	D	03	1091.3	38.0%	414.7	374.5	40.2
RIGEL	HALFWAY	H	03	702.8	12.9%	90.7	90.7	0.0
STODDART WEST	BELLOY	C	03	1525.5	25.3%	385.9	385.0	0.9
TOTAL				4702.9		1428.6	1353.1	75.5
% OF TOTAL BRITISH	COLUMBIA RESERVES					1.0%	1.1%	0.6%

Appendix B

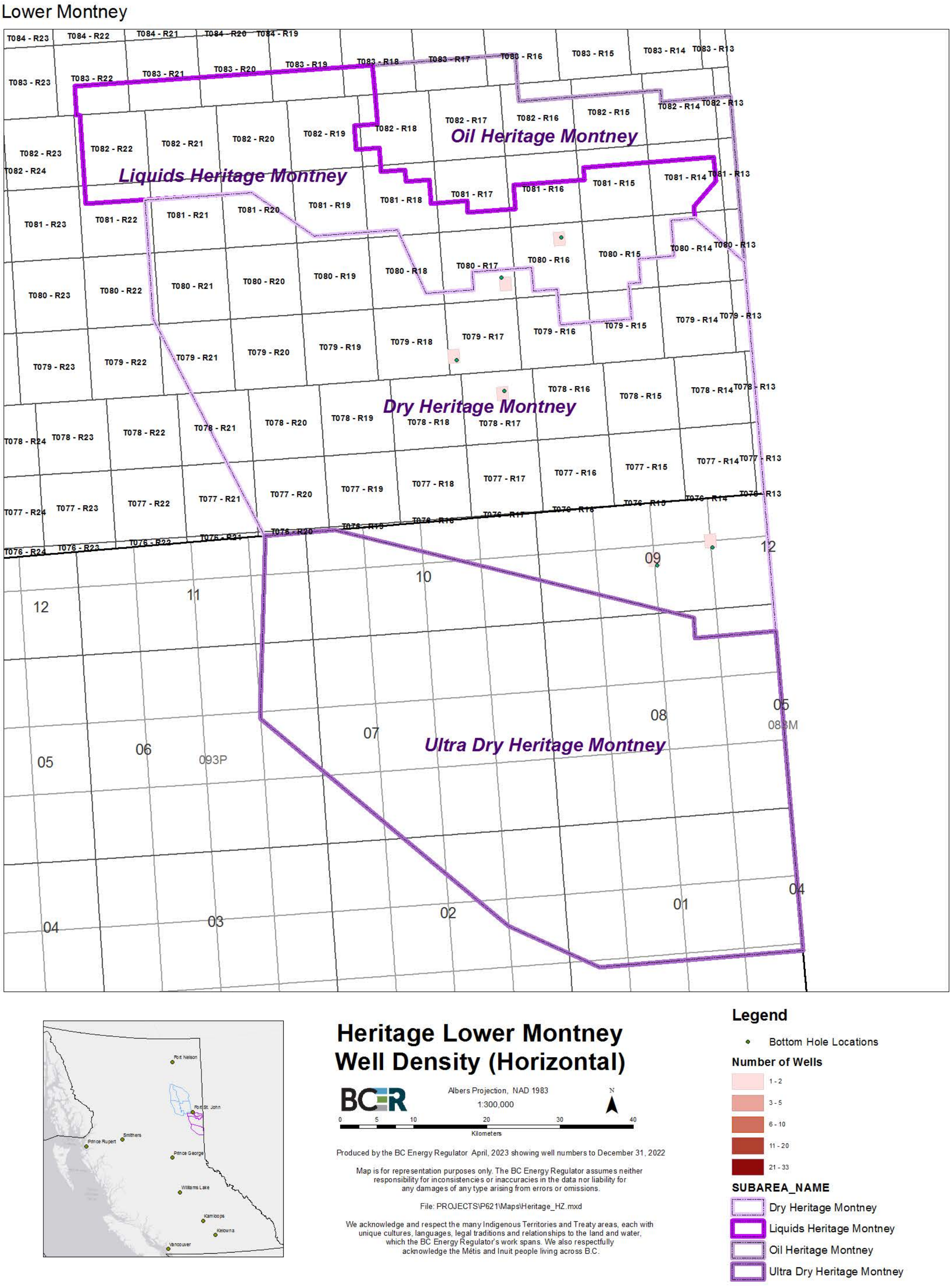
Well density is an indicator of the current phase of Montney development and the number of wells per gas spacing unit is used to determine the number of PUD locations for the estimation of recoverable reserves. For regulatory purposes, the BCER has split the Montney Regional field into the Heritage Montney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

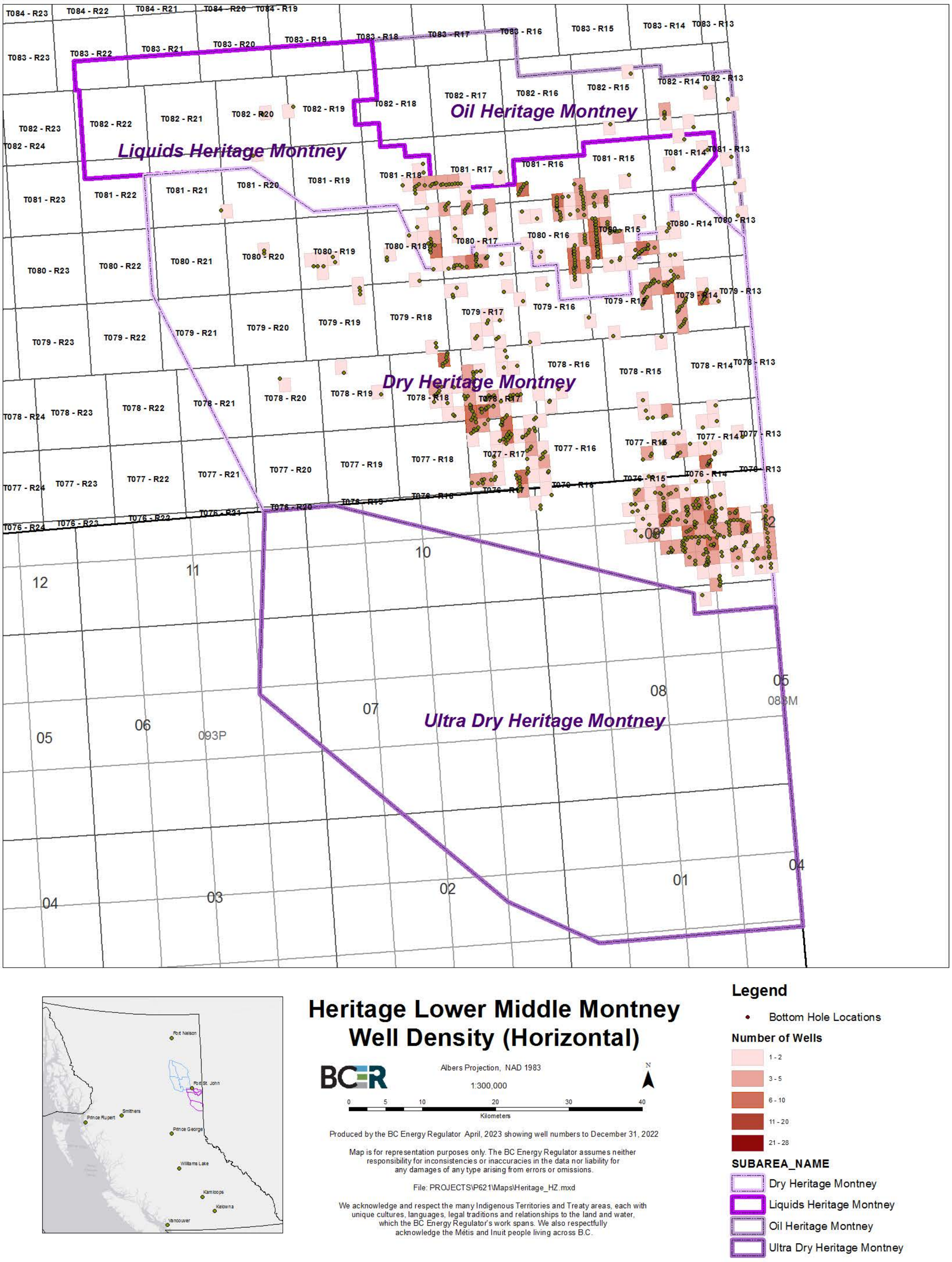
Note the majority of the wells in the Doig Phosphate pool have been merged into the Montney A pool resulting in changes to Montney A well density.

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

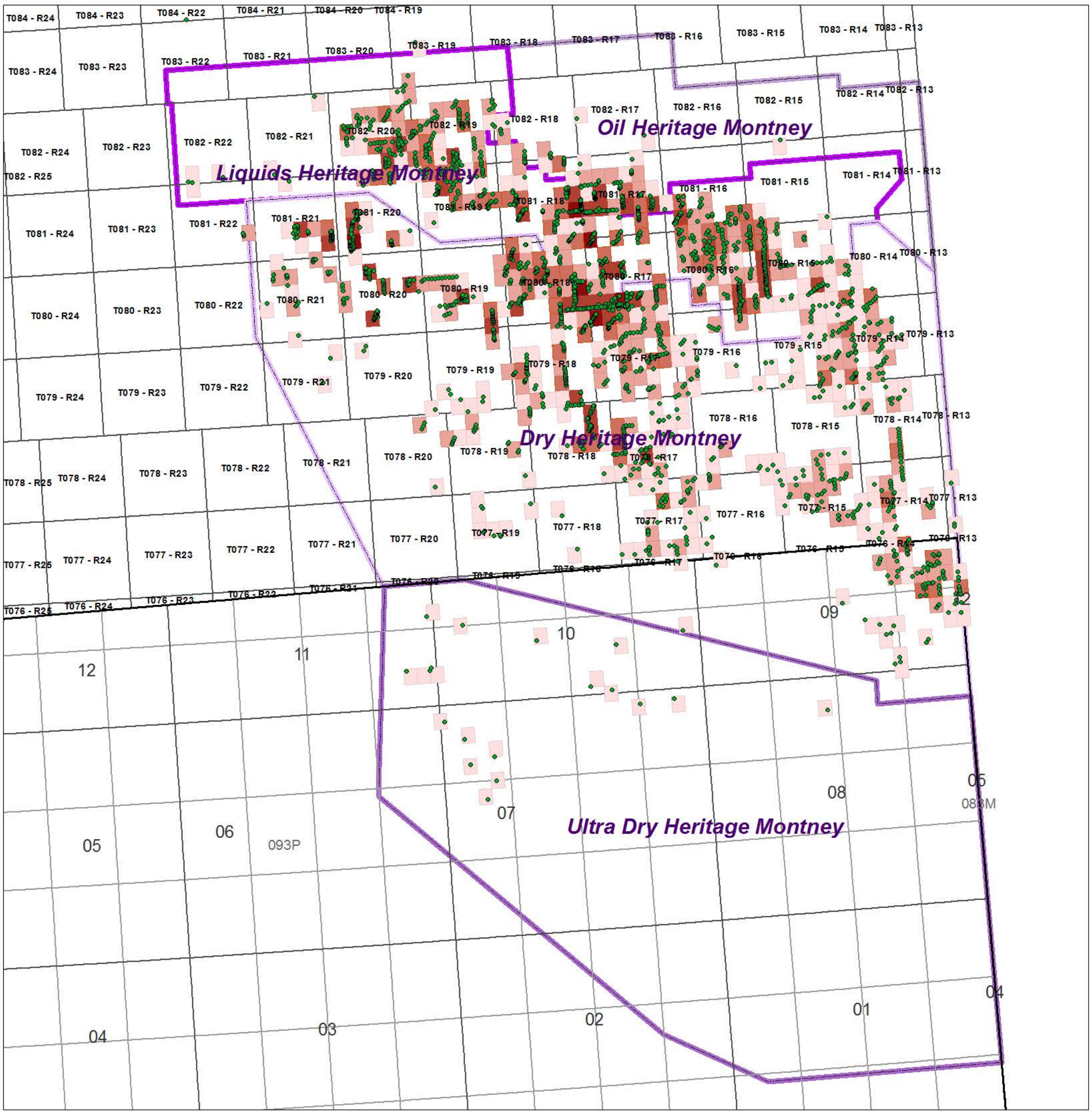
Lower Montney

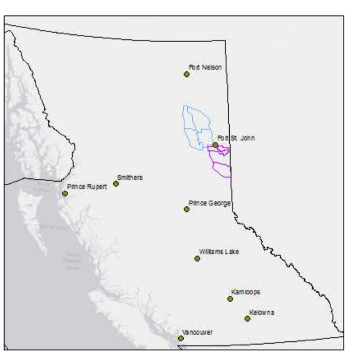


Lower Middle Montney



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 BC Energy Regulator April, 2023 showing well numbers to December 31, 2022

Map is for representation purposes only. The BC Energy Regulator 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

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 Energy Regulator's work spans. We also respectfully acknowledge the Métis and Inuit people living across B.C.

Legend

- Bottom Hole Locations

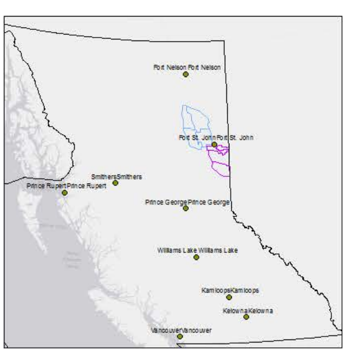
Number of Wells

- 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



Heritage Upper Middle Montney Well Density (Horizontal)

Albers Projection, NAD 1983

1:300,000

Kilometers

Produced by the BC Energy Regulator April, 2023 showing well numbers to December 31, 2022

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File: PROJECTS\P621\Maps\Heritage_HZ.mxd

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Legend

- Bottom Hole Locations

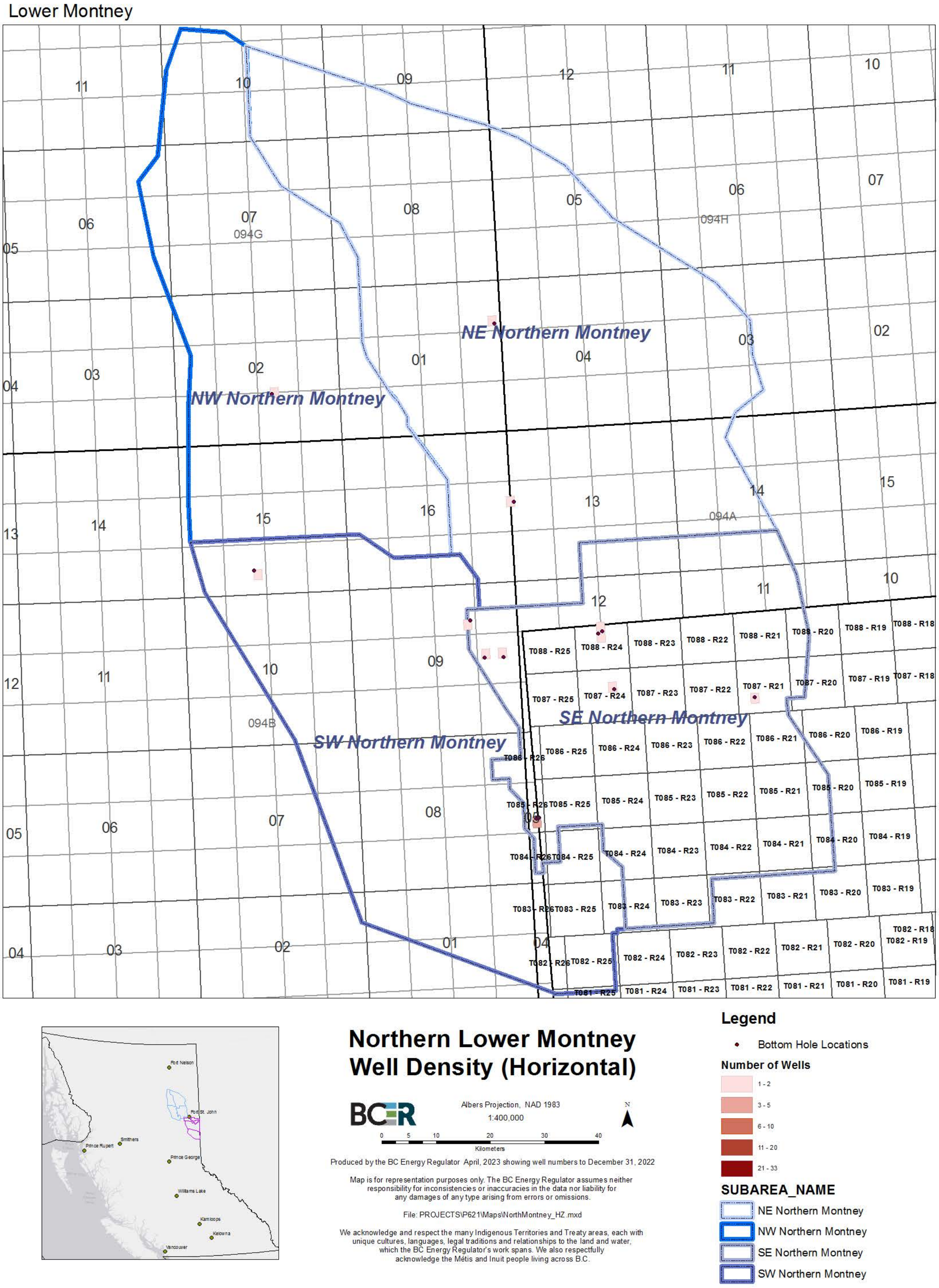
Number of Wells

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

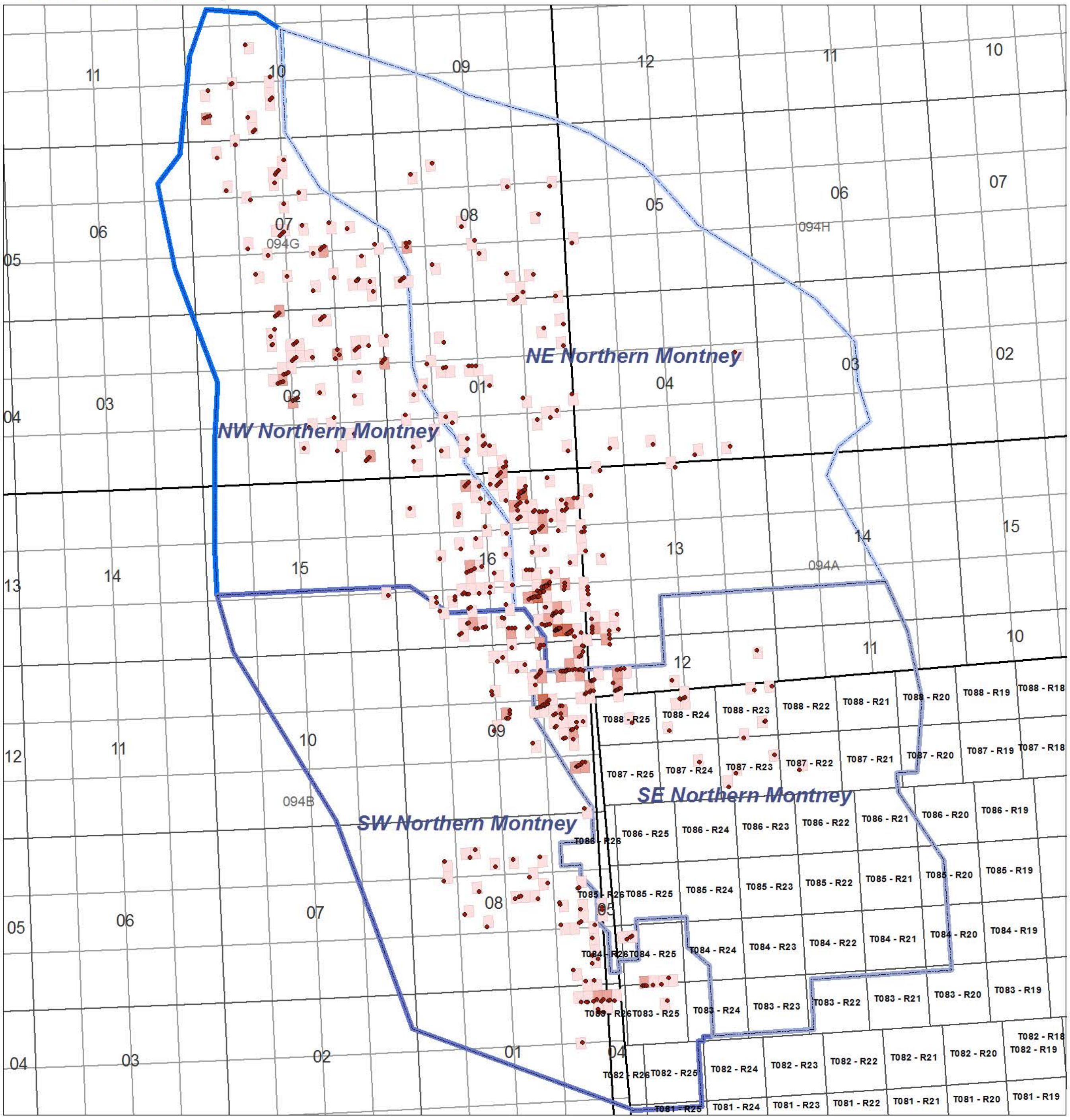
SUBAREA_NAME

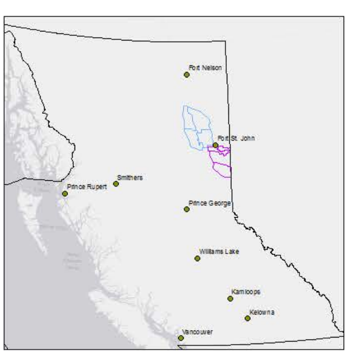
- Dry Heritage Montney
- Liquids Heritage Montney
- Oil Heritage Montney
- Ultra Dry Heritage Montney

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



Lower Middle Montney





Northern Lower Middle Montney Well Density (Horizontal)

BCER

Albers Projection, NAD 1983

1:400,000

0 5 10 20 30 40 Kilometers

Produced by the BC Energy Regulator April, 2023 showing well numbers to December 31, 2022

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File: PROJECTS\P621\Maps\NorthMontney_HZ.mxd

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Legend

- Bottom Hole Locations

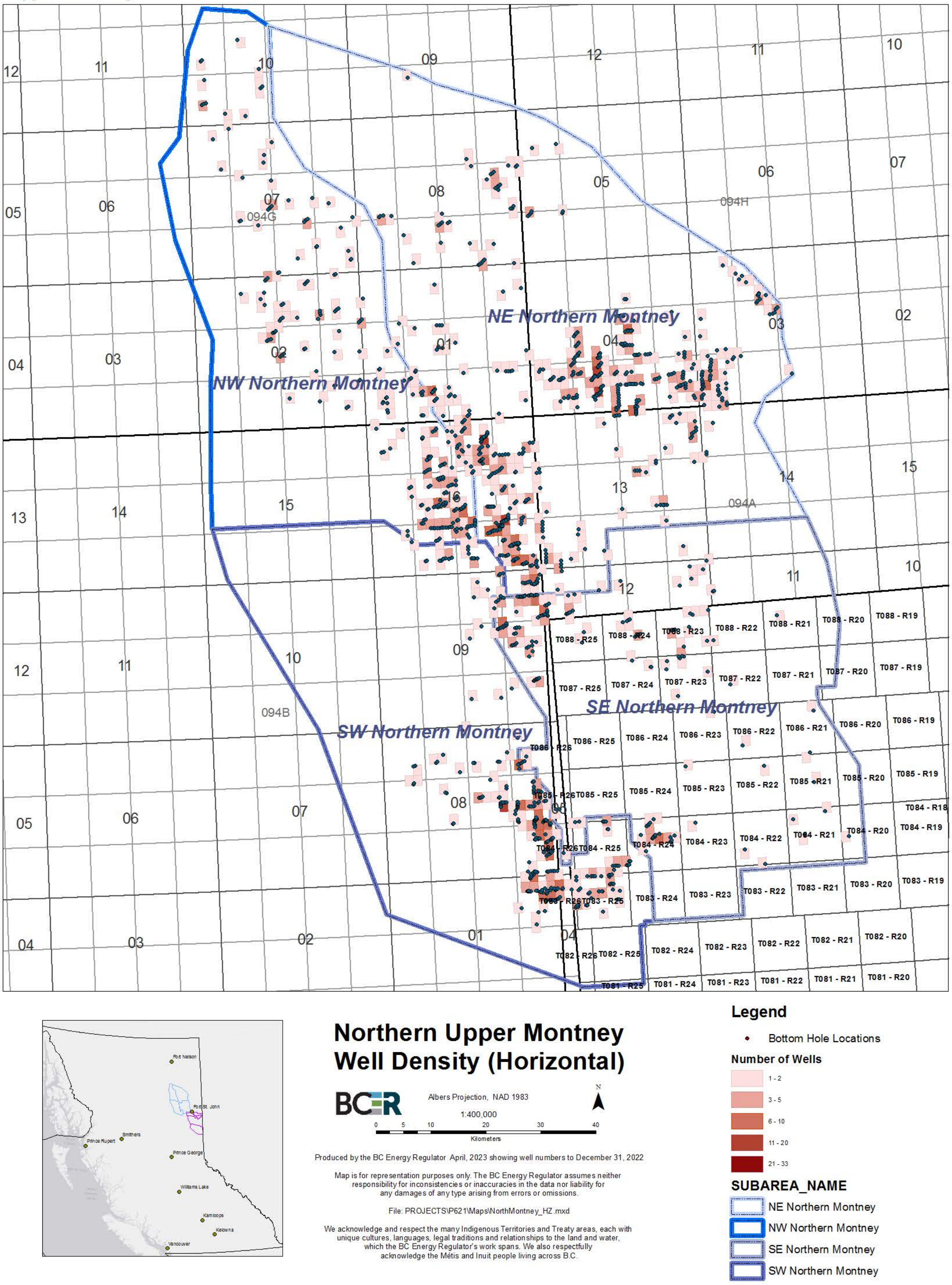
Number of Wells

- 1 - 2
- 3 - 5
- 6 - 10
- 11 - 20
- 21 - 33

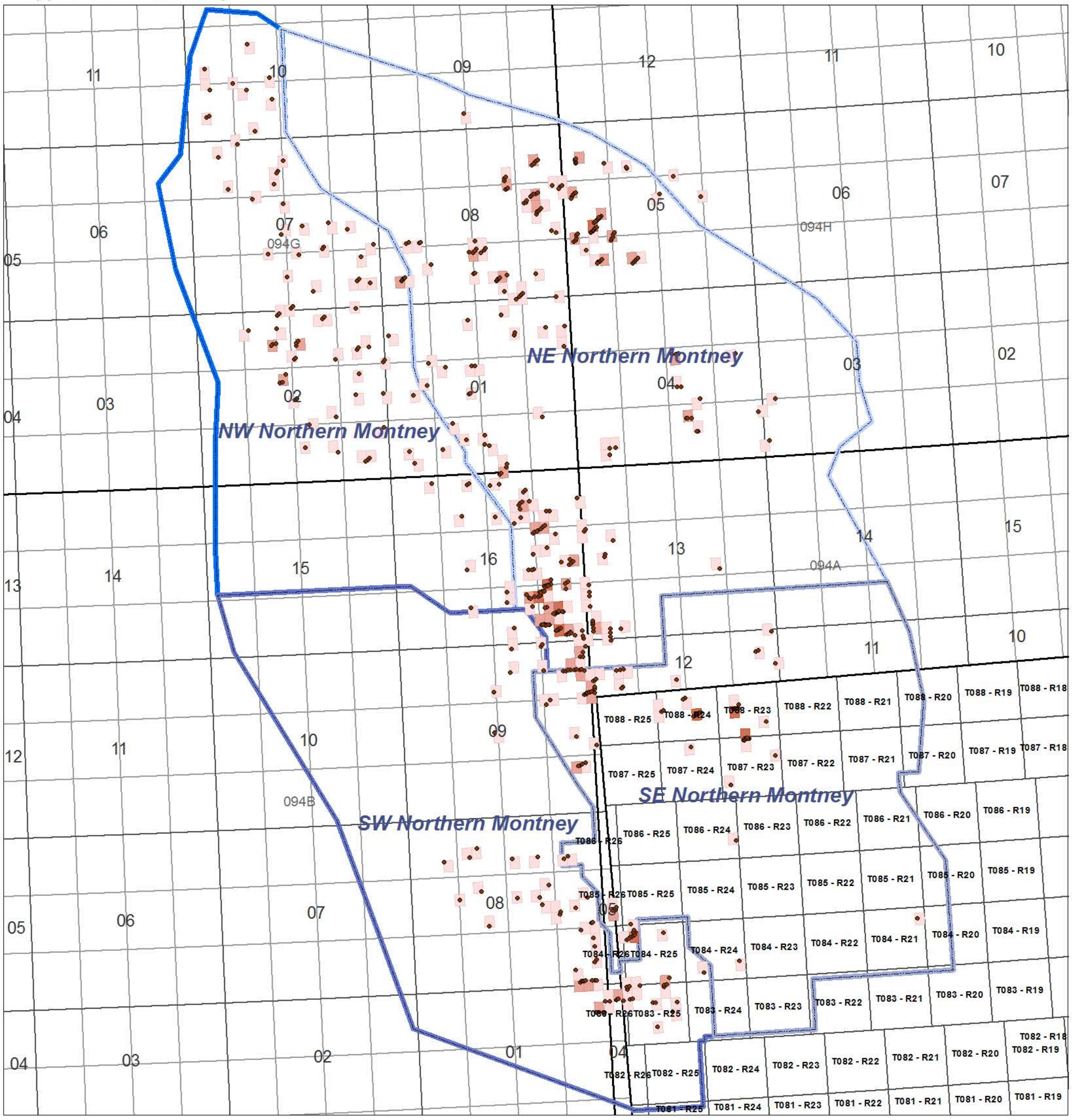
SUBAREA_NAME

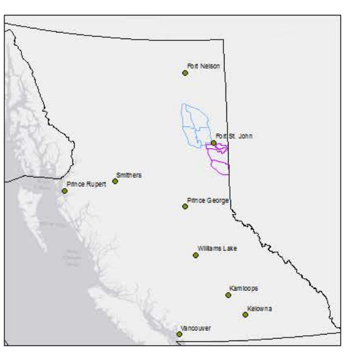
- NE Northern Montney
- NW Northern Montney
- SE Northern Montney
- SW Northern Montney

Upper Montney



Upper Middle Montney





Northern Upper Middle Montney Well Density (Horizontal)

BCER

Albers Projection, NAD 1983

1:400,000

0 5 10 20 30 40

Kilometers

Produced by the BC Energy Regulator April, 2023 showing well numbers to December 31, 2022

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File: PROJECTS\P621\Maps\NorthMontney_HZ.mxd

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Legend

Bottom Hole Locations

Number of Wells

- 1 - 2
- 3 - 5
- 6 - 10
- 11 - 20
- 21 - 33

SUBAREA_NAME

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

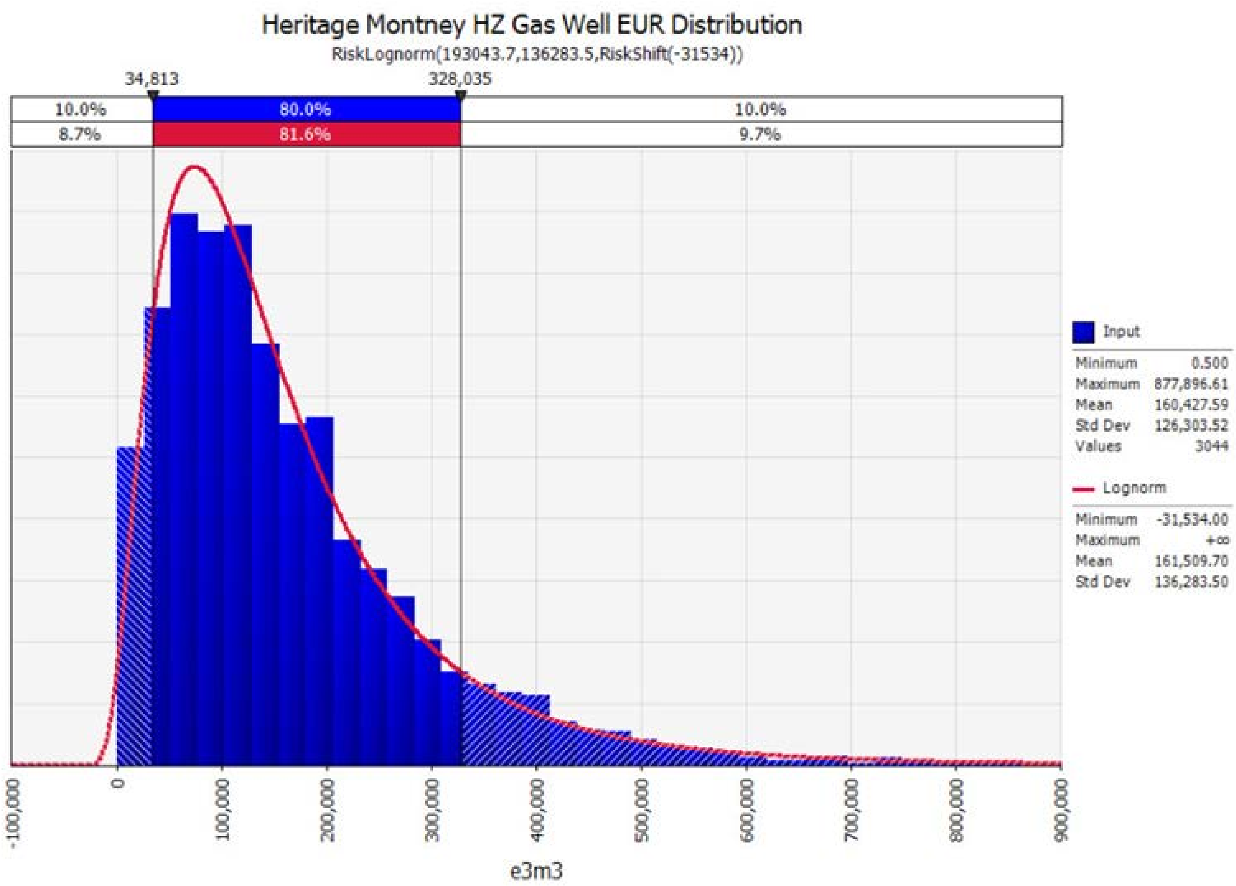
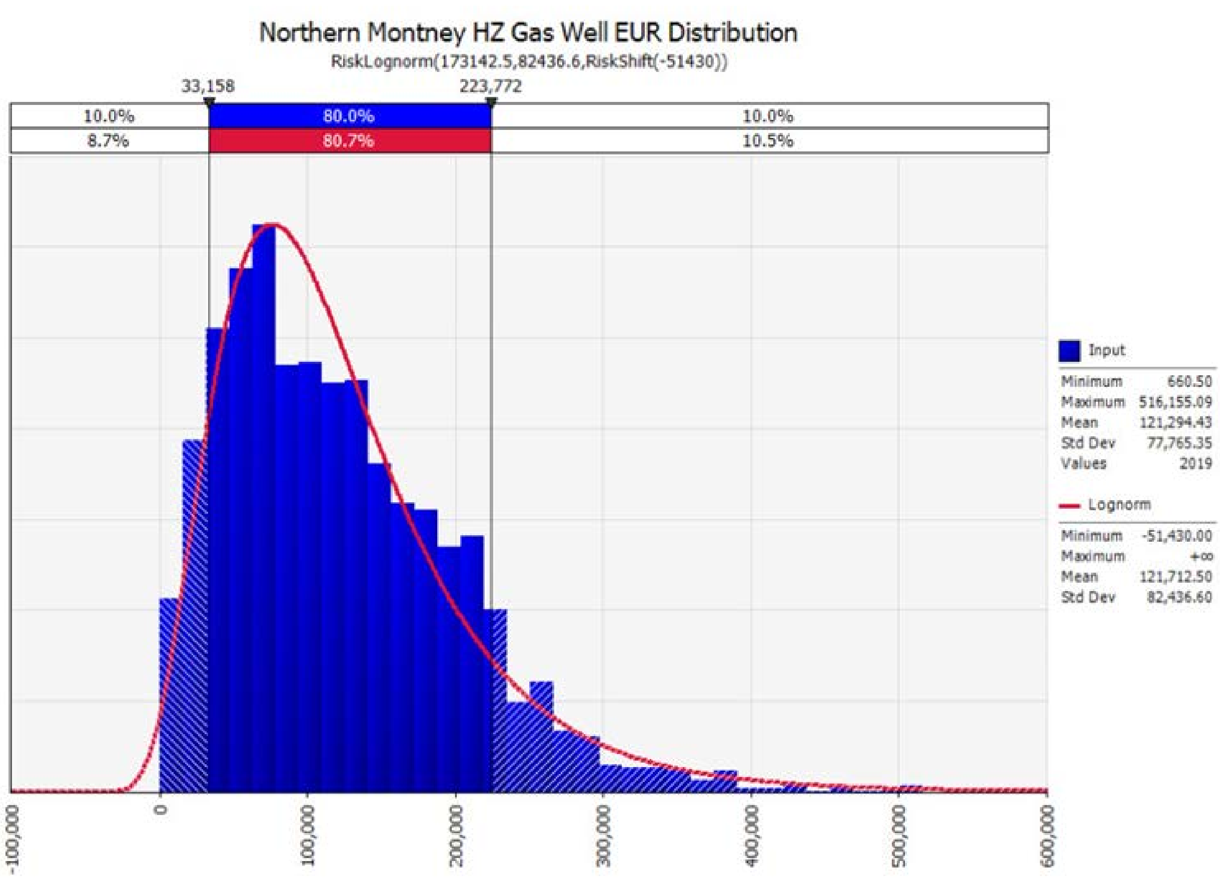
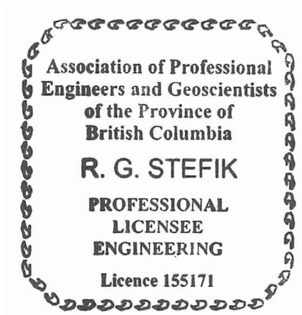


Figure B-2: Heritage Montney HZ Gas Well EUR Distribution



Professional Authentication

Authenticating Engineer	Responsible Registrant
	PERMIT NUMBER: 1000398 BC ENERGY REGULATOR ________________________ Date: _____2024-01-31___
Company: BC Energy Regulator	Company: BC Energy Regulator
Title: Supervisor, Reservoir Engineering	Title: Vice President, Well and Energy Resource Stewardship
Name: Ron Stefik, P.L. Eng.	Name: Richard Slocomb, M.A.Sc., P. Eng.

Revised January 2024. See page 72 for details.

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Table of Revisions

Revision 1

January 2024: Due to an error in the Reserves Management calculation process, the reserves of natural gas by-products were misreported in the original August 2023 publication of this report. Also, some minor amendments to 2022 production have also been included. Revisions are tabulated below.

Item	Pages	Erroneous Value	Revised Value
2022 pentanes+ remaining reserves	10, 34	124.5 10^6m^3	140.1 10^6m^3
Increase in pentanes+ remaining reserves 2022 vs 2021	10, 34	5.9%	19.3%
2022 LPG remaining reserves	10, 34	162.6 10^6m^3	181.8 10^6m^3
Increase in LPG remaining reserves 2022 vs 2021	10, 34	9.0%	21.9%
LPG production in 2022	33	5,002.4 e^3m^3	5,001.1 e^3m^3
Increase in butane sales 2022 vs 2021	33	11%	12%
Condensate/pentanes+ production in 2022	33	5,853.5 e^3m^3	5,852.1 e^3m^3
Condensate/pentanes+ production increase 2022 vs 2021	37	9.2%	9.3%
2022 sulphur remaining reserves	10, 38	5.1 10^6m^3	6.1 10^6m^3
Increase in sulphur remaining reserves 2022 vs 2021	10, 11, 38	8%	29.5%
Figure 31	38	Sulphur remaining reserves for multiple fields.	

Note: the same values reported in other units are not included in this table but have also been revised.

This report was originally published in August 2023 and is updated annually.

For specific questions or enquiries regarding this document, please contact:

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