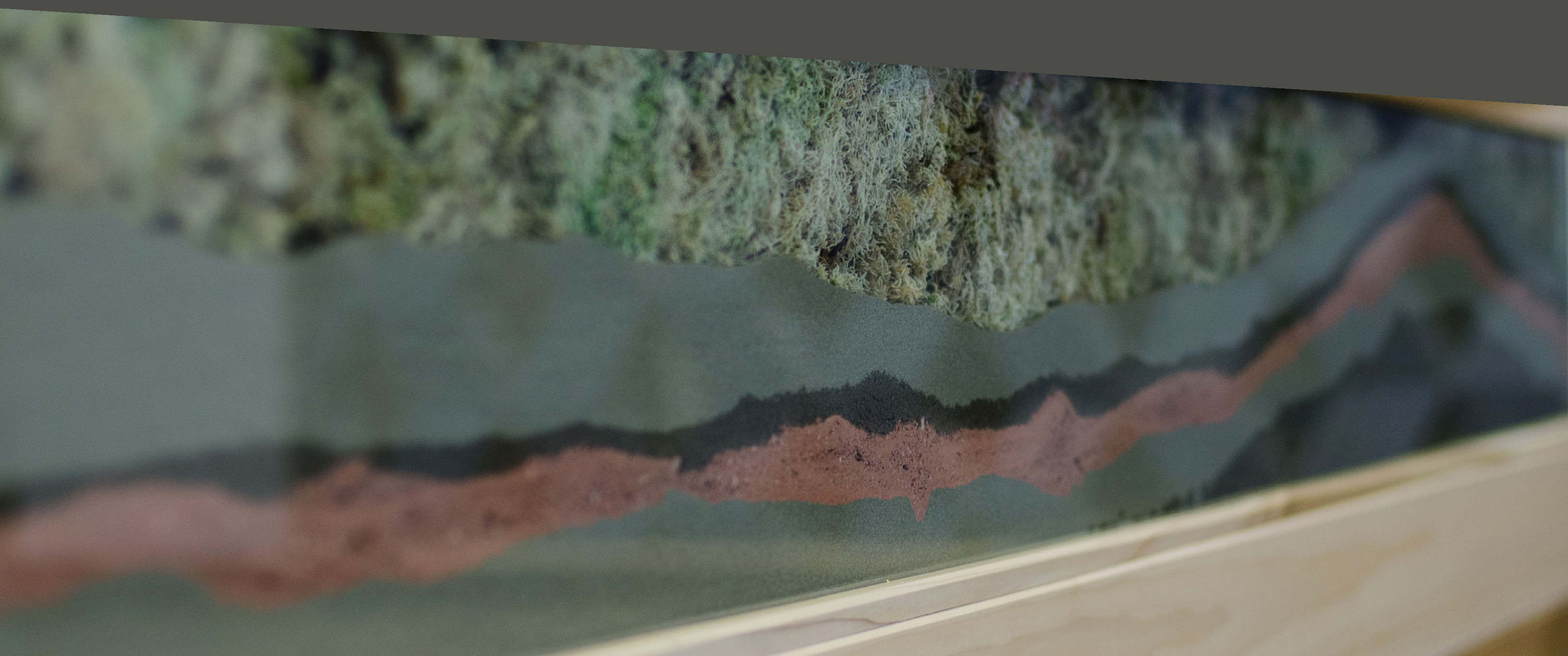
British Columbia's Oil and Gas Reserves and Production Report

2015 | BC Oil and Gas Commission



About the

BC Oil and Gas Commission

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

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

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

Mission

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

We achieve this by:

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

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

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

We serve with a passion for excellence.

Vision

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

Values

Respectful

Accountable

Effective

Efficient

Responsive

Transparent

Purpose of Report

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 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, 2015. The estimates have been prepared by the BC Oil and Gas Commission (Commission) using 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.

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.

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Available on the Commission website:

- Detailed Gas Reserves By Field and Pool
- Detailed Oil Reserves by Field and Pool
- Detailed Condensate and By-Product Reserves by Field and Pool

Cover Photo: Fort St John reception

Difference Between Resources and Reserves

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

Resources

Resources are the total quantity of oil and gas estimated to be contained in subsurface accumulations. The term resource is applied to a formation in a large geographic region or a specific geologic basin. Resource estimates include proven reserves, produced quantities and unproven resources. The Commission cautions those using resources (prospective or contingent) as an indicator of future production.

Reserves

Reserves are quantities of petroleum 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 by production or production test).
- Meet regulatory requirements (production or development cannot be prohibited by governmental regulations).
- Marketable to sell (transportation either through pipelines, rail or trucking).
- Developed within a reasonable time frame (up to five years for probable reserves).
- Economic to recover.

Dawson Creek Resource Centre

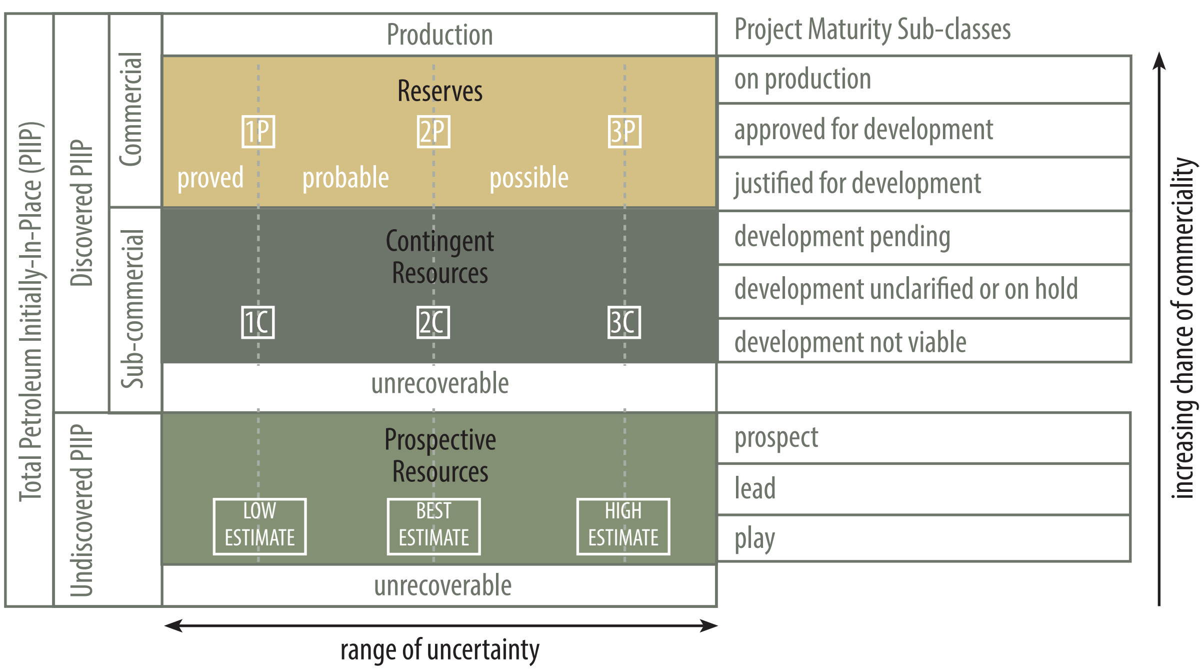
Difference Between Resources and Reserves

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

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

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

Figure 1: Resources Classification Framework and Sub-classes Based on Project Maturity
Sourced from: Petroleum Resources Management System (Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council and Society of Petroleum Evaluation Engineers. (not to scale)



Comparing Resource Estimates and Remaining Reserves

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

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 1,965 Tcf; however, currently recoverable (29.8 Tcf + 4.3 Tcf) is substantially less than is present.

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 at right. It shows the vast quantity of hydrocarbons available (resources) versus the known and established reserves.

Table 1: Unconventional Gas Resource, Reserves and Cumulative Production

	Resource		Reserve			
Basin/Play	Basin Total GIP Resource (Tcf)	Ultimate Potential (Marketable, Tcf)	Initial Raw Gas Reserves (Raw, Tcf)	Remaining Reserves (Raw, Tcf)	Cumulative Production (Raw, Tcf)[6]	% Reserve per Resource
Montney[1]	1,965	271	34.08	29.77	4.31	1.73%
Liard Basin[2]	848	167	0.10	0.09	0.01	0.01%
Horn River Basin[3]	448	78	11.72	10.82	0.90	2.62%
Cordova[4]	67	9	0.11	0.07	0.04	0.16%
Deep Basin Cadomin, Nikanassin[5]	9	7	1.04	0.43	0.61	11.56%
Total	3,337	532	47.05	41.18	5.87	1.41%

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

Executive Summary

The remaining reserves at the end of 2015 recognize the Montney as the major play for drilling activity, production, reserves and resources. As shown on Table 2, reserve estimates for gas, pentanes+ and petroleum liquid gas (LPG) increased while oil and sulphur decreased.

The increase is due to continued gas drilling in the Montney. The decrease is due to a lack of new oil discoveries, production depletions, and the shut-in of wells in areas where it was not economically viable to continue production. The reserve revisions are shown in Appendix A Table A-1.

Table 2: Remaining Reserves as of Dec. 31, 2015

	2015		2014		Percent Change
Type					
Gas (raw)	1,504.7 $10^9 m^3$	53.2 Tcf	1,443.9 $10^9 m^3$	51.0 Tcf	4.2%
Oil	17.6 $10^6 m^3$	110.4 MMSTB	18.1 $10^6 m^3$	113.6 MMSTB	-2.8%
Pentanes$^+$	30.9 $10^6 m^3$	194.3 MMSTB	29.7 $10^6 m^3$	186.8 MMSTB	3.0%
LPG	93.9 $10^6 m^3$	590.6 MMSTB	77.8 $10^6 m^3$	489.6 MMSTB	20.7%
Sulphur	14.4 10^6 tonnes	14.2 MMLT	14.8 10^6 tonnes	14.6 MMLT	-2.7%

As shown in Figure 2, well drilling activity was concentrated in northeast B.C. with the majority of wells in the Montney. Of the 531 wells drilled in 2015, 94.2 per cent were drilled in the Montney. The remaining 5.8 per cent of wells drilled in 2015 include Hay River (oil), Liard Basin (gas) and others.

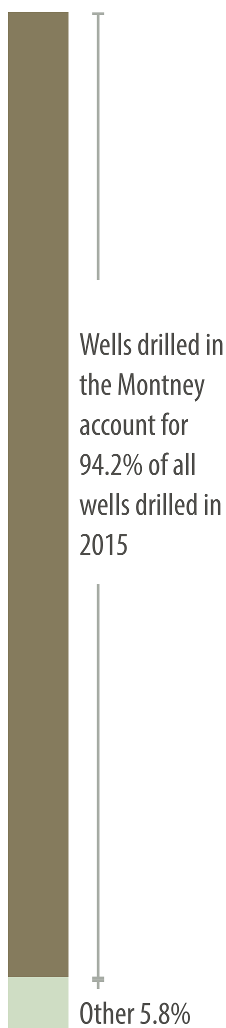
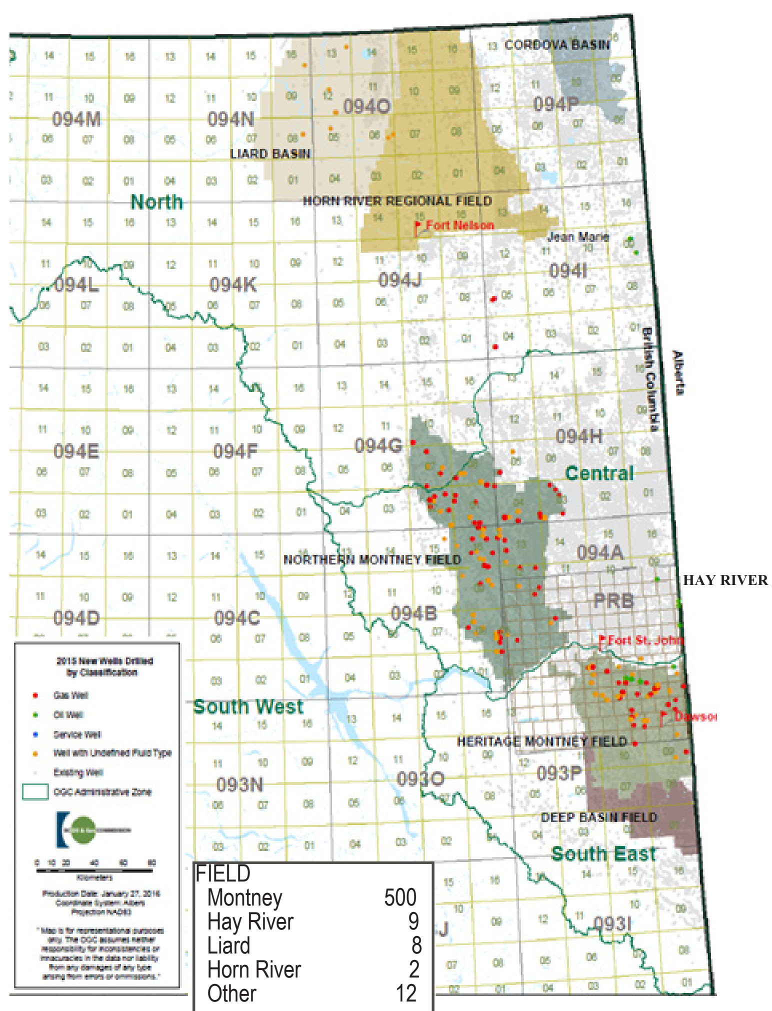


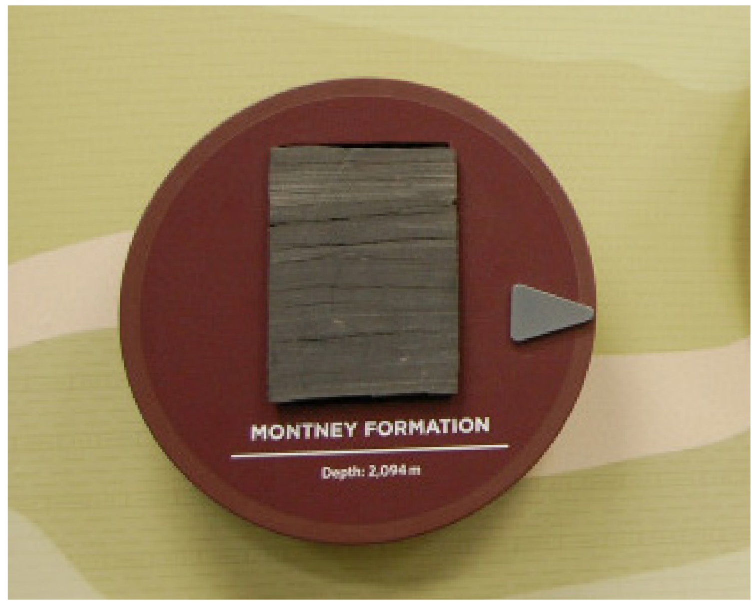
Figure 2: 2015 Wells Drilled



Discussions: Gas Reserves and Production

As of December 2015, gas reserves increased and unconventional gas zones accounted for 84% of all gas production in the province.

As of Dec. 31, 2015, the province's remaining raw gas reserves were 1,504.7 10^9 m^3, a 4.2 per cent increase over 2014 remaining reserves. The upward trend in reserve revisions continues due to the successful development of unconventional gas outpacing production reserve depletion.



Dawson Creek Resource Centre

Figure 3 illustrates the distribution of remaining conventional and unconventional gas reserves, with 56 per cent of the remaining recoverable reserves held in the Montney basin.

Figure 3: Remaining Gas Reserves

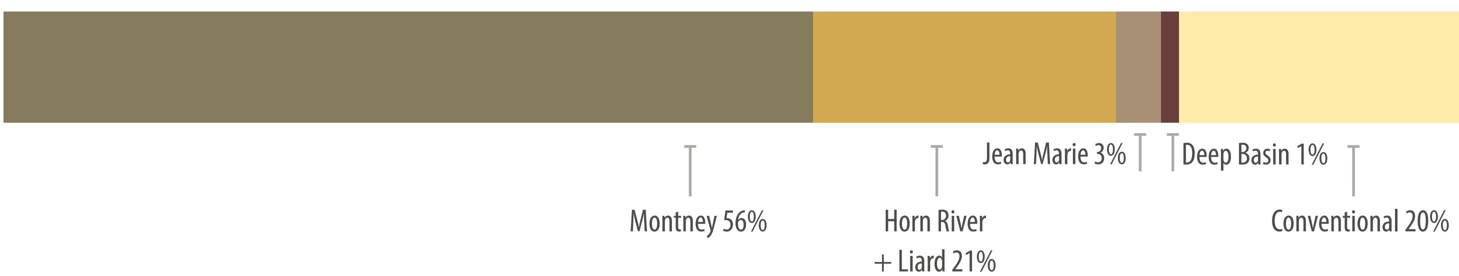


Figure 4: Gas Production Split by Source

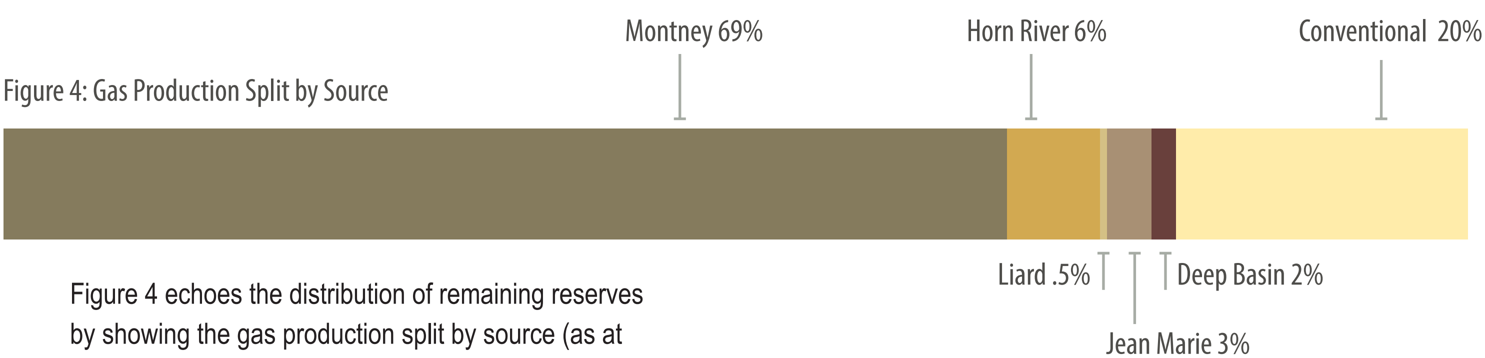


Figure 4 echoes the distribution of remaining reserves by showing the gas production split by source (as at December 2015) and the larger percentage in the Montney.

As shown in Figure 5, unconventional gas production continues to surpass conventional production.

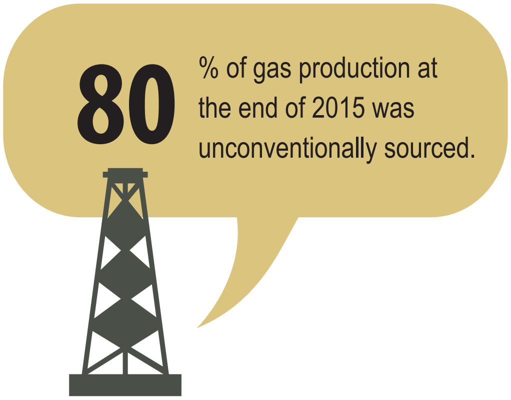
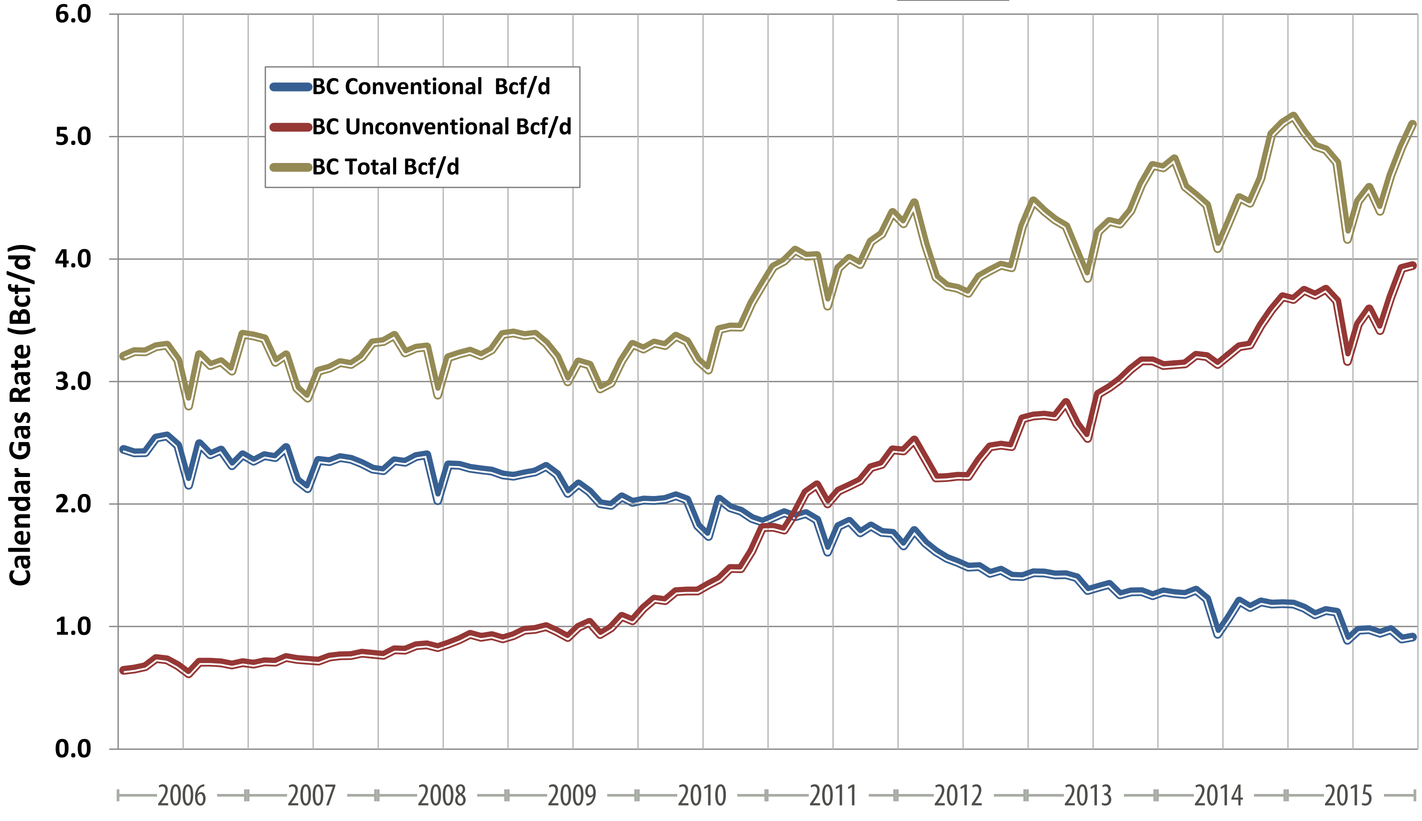


Figure 5: Unconventional Raw Gas Production

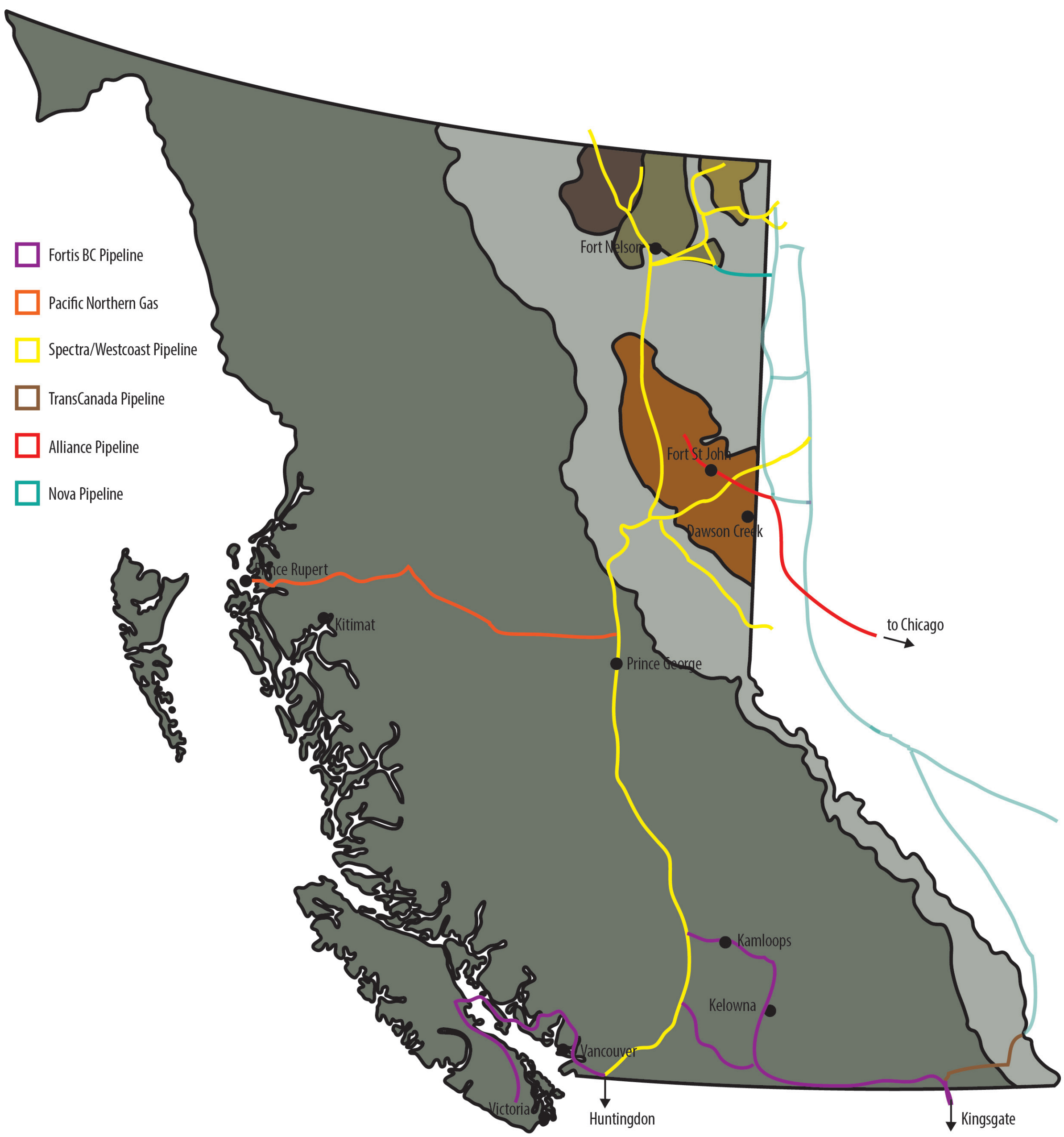


Discussions: Gas Reserves and Production

Gas production has increased by 45 per cent since 2010 resulting in increased loads within the existing pipeline delivery points for the Montney, Horn River and Liard gas. Gas within these regions is transported by pipeline as shown in Figure 6 to Station 2 (shipped on Spectra), AECO (shipped on Trans Canada Pipeline) and Chicago (shipped on Alliance).

The major gas pipeline system in northeast B.C. is operated by Spectra, with Station 2 being the main receiving point for most gas in Northern B.C. Additional gas pipeline systems are proposed by producers to access the LNG market on the west coast of British Columbia but gas pipeline transportation remains a challenge for the province.

Figure 6: British Columbia's Gas Pipeline System



Discussions: Gas Reserves and Production

Figure 7 presents the Commission's raw gas reserves bookings from 1995 to 2015, highlighting unconventional Montney and Horn River reserves versus all other reserves grouped together.

Remaining reserves were consistent a decade prior to 2003 and then increased dramatically due to the number of gas wells drilled. Between 2003 and 2006, activity reached record levels (1,300 gas wells drilled in 2006), with predominant targets such as shallow Cretaceous (Notikewin, Bluesky and Gething) and Triassic (Baldonnel and Halfway), in the Deep Basin the Cadomin and Nikanassin, and the Jean Marie in the north east.

In 2005, the onset of Montney horizontal drilling with large hydraulic stimulation created a new supply of gas. This was followed by Horn River development in 2010. Further development of the Horn River basin has now ceased, awaiting economic gas demand.

Average gas production for the province in December 2015 was 146.3 e^6m^3 per day (5.17 BCF/d).

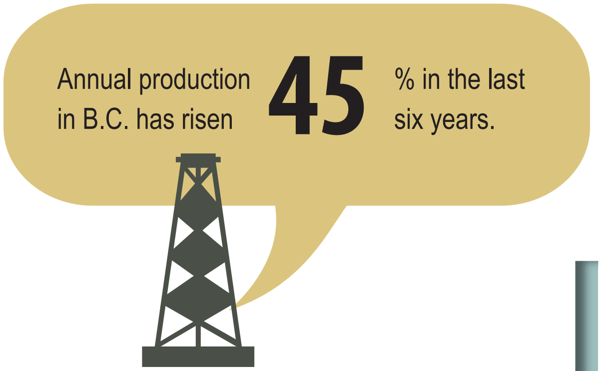
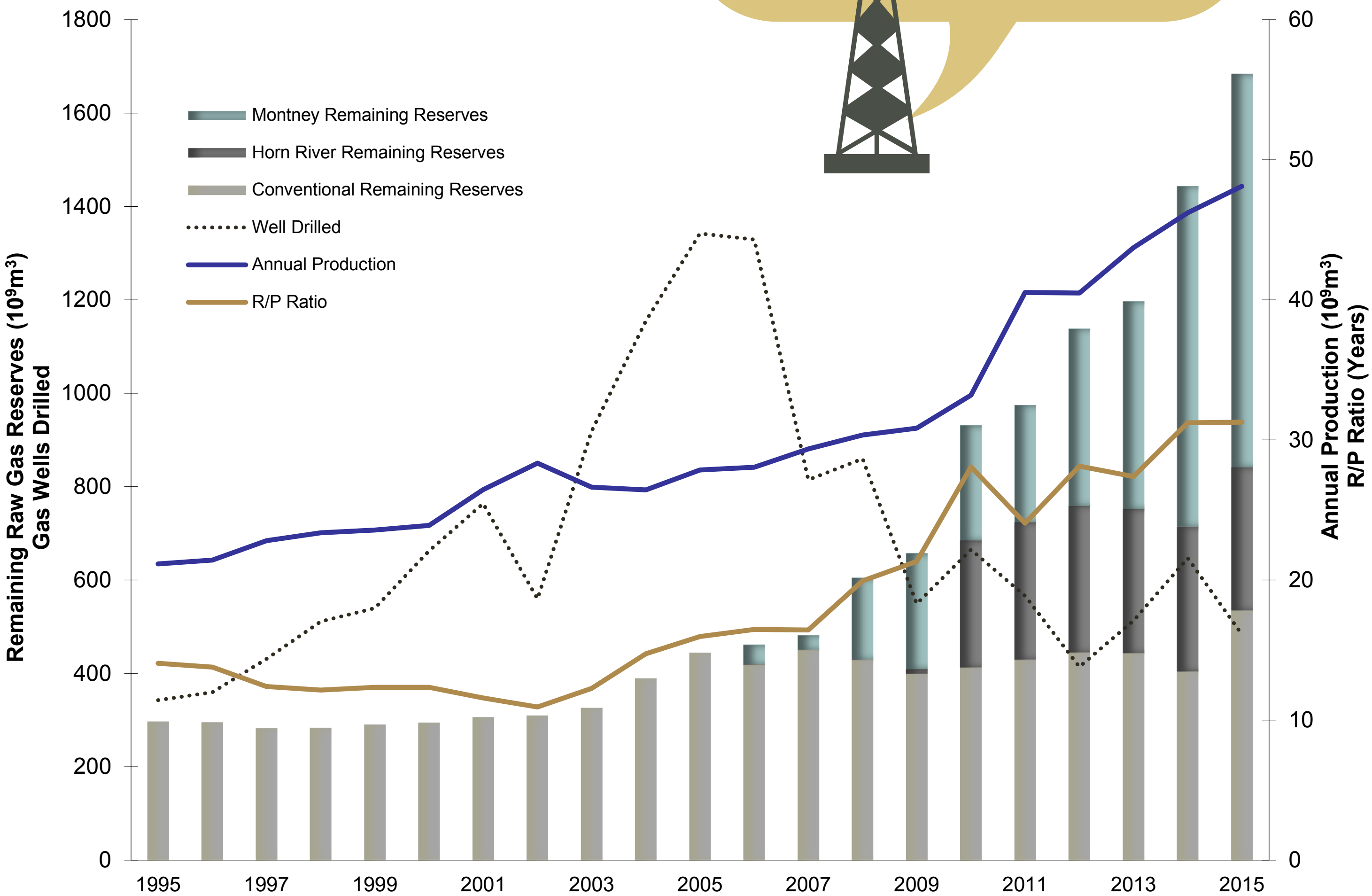


Figure 7: Historical Development in B.C.



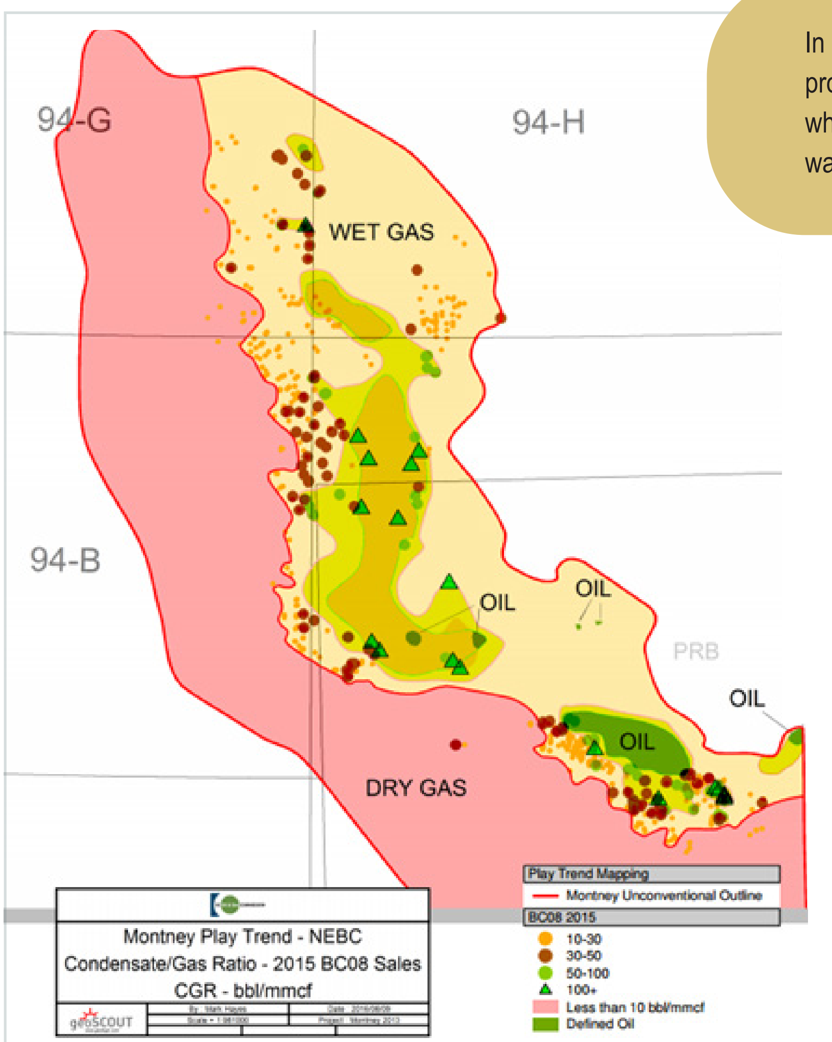
Montney
Unconventional Gas Play

The Montney contains 56% (29.8 Tcf) of the province's recoverable raw gas reserves and contributed 64.4 % (3.4 Bcf/d) of the province's 2015 production.

Significant development of the Montney began in 2005 and the area has become the largest contributor to natural gas production volumes in the province. In 2015, drilling was focused on the liquid rich gas portions of the play trend and as a result, production of natural gas liquids and condensate increased. In 2015 the number of production wells increased to 2,374 wells.

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

Figure 8: Montney 2015 Dry/Wet/Oil Distribution



In December 2015 the Northern Montney production was 33.9 e^6m^3 per day (1.2 Bcf/d) while the Montney Heritage field production was 62.1 e^6m^3 per day (2.2 Bcf/d).

Montney
Unconventional Gas Play

As of Dec. 31, 2015, the remaining gas reserves for the Montney are 29.8 Tcf (raw), which represents a 1.7 per cent recovery of the total basin GIP of the Montney resource estimate.

A complete record of the reserve estimates for each Montney pool can be found in Table 3 below. The methodology is discussed in detail in Appendix II.

Table 3: Montney Remaining Reserves as of Dec. 31, 2015

Field	Pool	Horizontal Well EUR (Bcf) per well				Initial Reserves (Raw) Bcf	Remaining Reserves (Raw) Bcf	Existing Horizontal Wells	PUDs
		Pmean	P90	P50	P10				
Heritage	Montney A	4.6	1.6	4.1	8.3	18,096	15,002	1,567	2,564
Northern Montney	Montney A	3.7	1.2	3.2	6.6	9,438	8,944	515	2,060
	Doig Phosphate-Montney A	3.7	1.2	3.2	6.6	4,779	4,361	291	1,164
	Montney B	3.1	0.6	2.8	6.1	1,555	1,463	164	328

The Ministry of Natural Gas Development (MNGD) commissioned McDaniel & Associates Consultants to prepare type curves in the Montney area and to determine the expected Estimated Ultimate Recovery (EUR) for each field. Within each area it was then determined the normalized average EUR as mmcf/well/100m HZ. These results, as shown in Table 4, indicate that the southeastern part of the Montney field is the most prolific with Dawson Creek, Sundown, Swan, Sunrise Dry and Parkland having the greatest reserves per 100 metres.

Table 4: Montney Subareas Normalized Average EUR as of Dec. 31, 2015

Area Name*	Normalized Average EUR (mmcf/well/100m HZ)
Dawson Creek	448
Sundown	388
Swan	377
Sunrise Dry	369
Parkland	337
Altares	326
Nig Creek	299
Septimus	276
Sunset	270
Caribou	239
Graham	215
Sunrise Wet	209
Jedney	200
Monias	184
Groundbirch	178
Tumbler	117
Inga	30

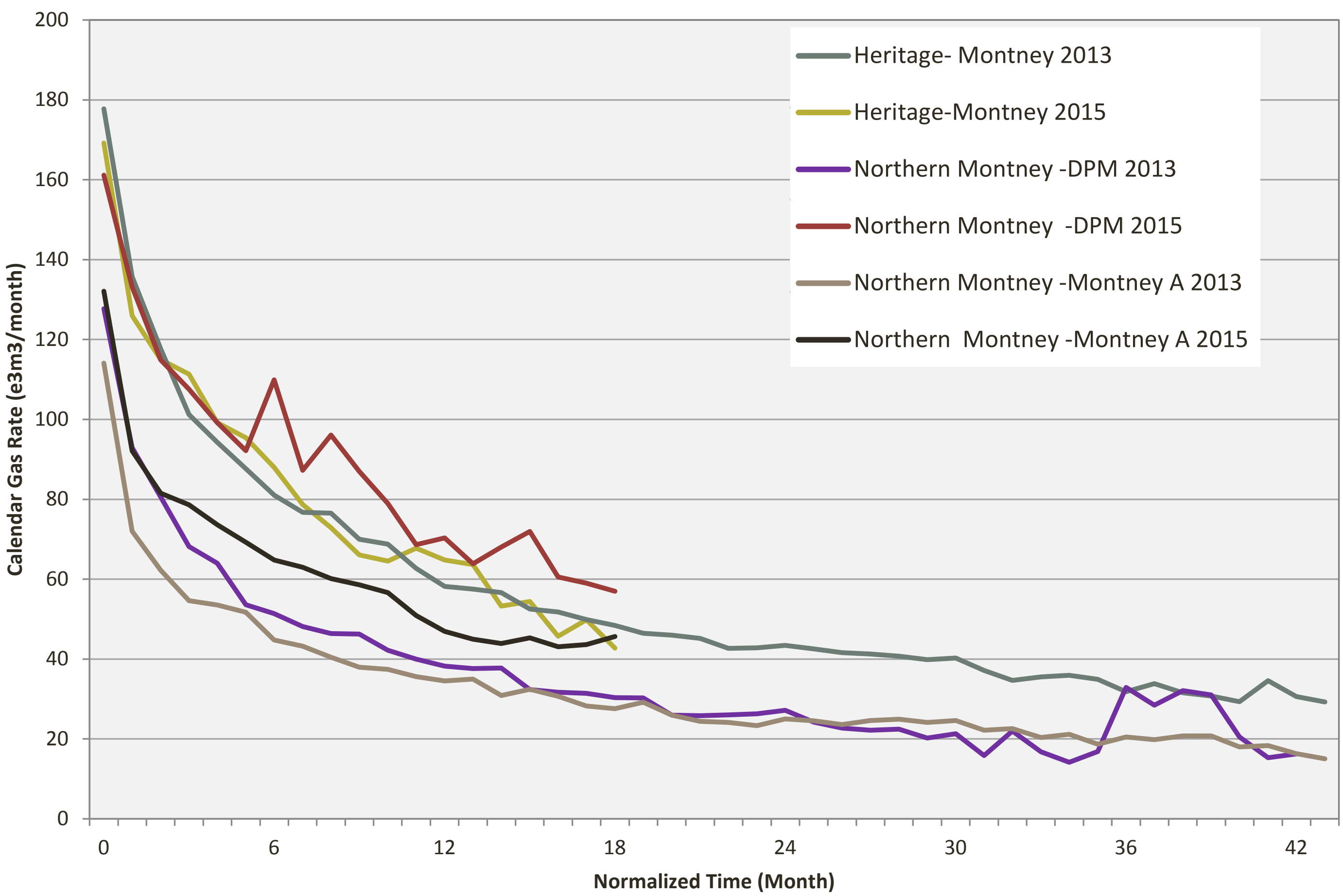
*Subdivided into appropriate conventional field areas for evaluation purpose

Montney
Unconventional Gas Play

In Figure 9 the type curves were created by grouping wells based on year on production. As evident from these data, the 2015 type well is superior to previous years 2013 and 2014, most likely as a result of continuous improvement of completion techniques together with selective development of targets.

The plot also shows that the Heritage Montney formation has been the better area of the play with the highest production rates followed by wells developing the Doig Phosphate-Montney A zone.

Figure 9: Comparison of Montney Production Type Wells by Year



Other Unconventional Gas Plays
Liard, Horn River and Cordova

Other play areas continue to demonstrate the province's natural gas potential.

British Columbia has been a leader of exploration and development of unconventional natural gas resources since the mid 1990's with horizontal drilling in the Devonian carbonates of the Jean Marie. Beginning in 2006, continued unconventional tight gas resources followed with shale gas development in the Devonian Muskwa, Otter Park and Evie shales in the Horn River Basin and the Triassic aged siltstones of the Montney formation. More recent drilling in the Liard basin continues to demonstrate the province's natural gas resource potential. See Table 1 on page 6 for detailed reserve data for each gas play.

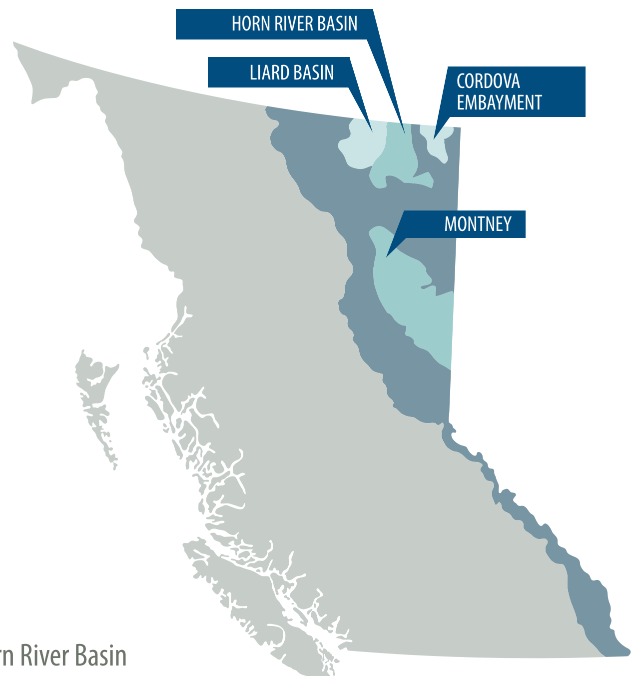
Liard Basin

Exploration in the Liard Basin started in 2008. The EUR as of December 2015 was 2,933 10^6m^3 (0.1 Tcf) based on production from four existing non-confidential wells (two vertical wells and two horizontal wells).

The Exshaw-Patry shales within the B.C. portion of the Liard basin are significantly deeper than the productive shales of the adjacent Horn River Basin and range from 3.5 to 5 km depth. Net pay ranges from 30 m near the Liard basin's eastern edge to over 250 m in the basin interior. The reservoir pressure is double the normal pressure gradient. The brittle nature of the siliceous shales allows them to be effectively stimulated by hydraulic fracturing which, combined with the elevated reservoir pressure, yields high initial gas production rates.

The pay zone depth and difficult drilling conditions have resulted in high costs which has limited activity in the current low gas price environment.

The forecasts for the Liard are EUR of 8 Bcf/well to the vertical wells and 19 Bcf/well to the horizontal wells. With six stimulations over a 900 m horizontal section, (1,500T sand; 23,000 m^3 water), the Commission forecasts more than three Bcf/frac for the horizontal Liard well, compared with one Bcf/frac for the Horn River and 0.5 Bcf/frac for the Montney.



Horn River Basin

In the Horn River Basin, production rates were 262,838 e^3m^3/month (0.3 Bcf/d) with 185 producing wells. During the year 38 wells were shut-in as they were no longer economic to produce, which resulted in no increase in reserves from the previous year. Only 2 wells were drilled in 2015 as activity slowed in the area.

Cordova Basin

Exploration and development activity in the Cordova Basin declined in 2015. While three new horizontal wells targeting Muskwa-Otter Park were drilled in the Cordova Embayment in 2015, they have not yet been completed.

Further background information on the Horn River and Cordova fields is available in the 2014 Reserves Report.

Other Unconventional Gas Plays
Liard, Horn River and Cordova

Figure 10 shows the Pressure versus Temperature plot for the Montney, Horn River, Cordova and Liard areas. The temperatures of these fields fall within expected ranges except for Liard, which is significantly higher than that of the Horn River, Cordova or Montney fields. The wide range in values reflects the large geographic area and depths of deposits.

Figure 11 shows the 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”.

Figure 10:
Pressure vs. Temperature Plot

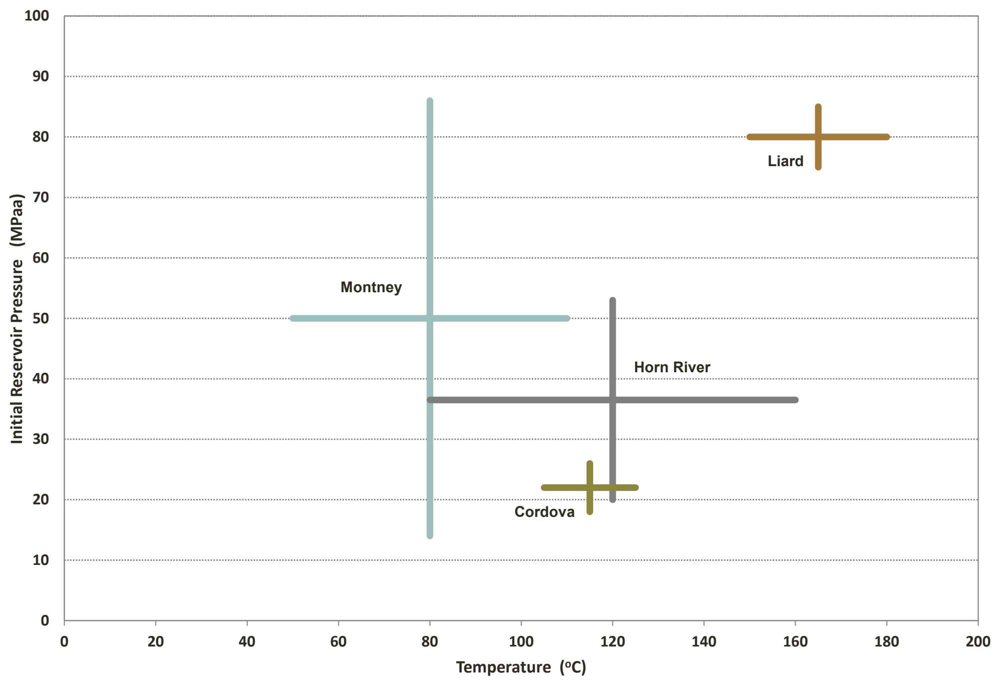
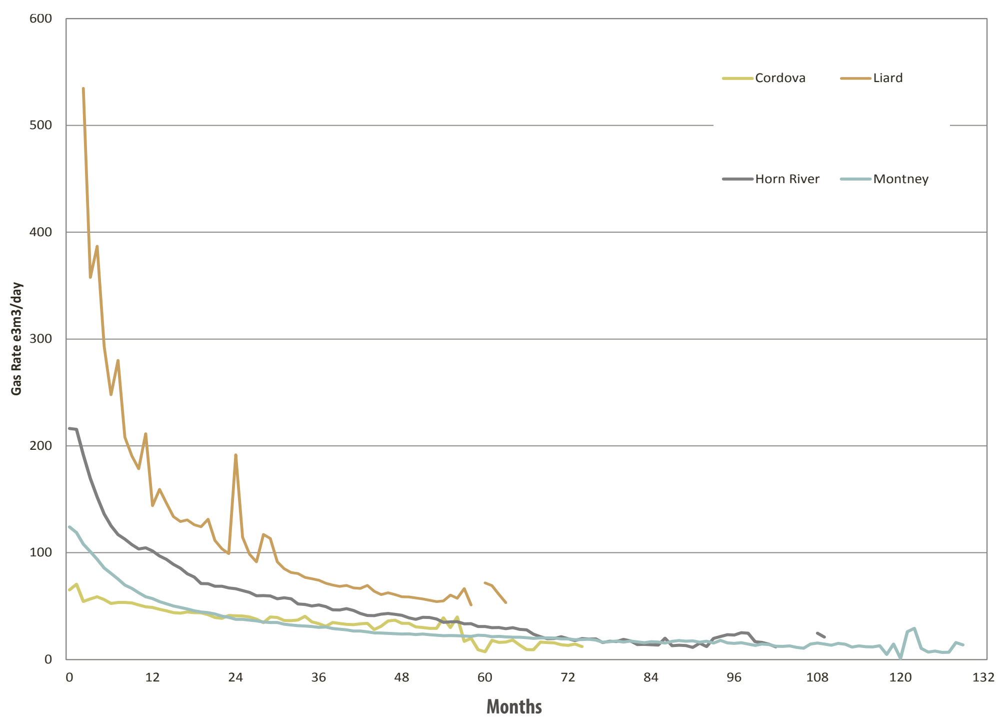
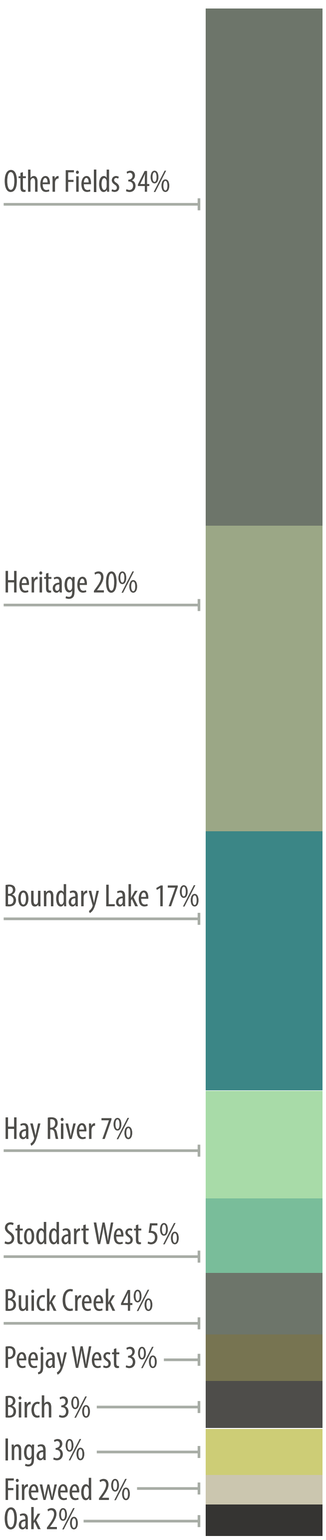


Figure 11:
Comparison of Montney, Horn River, Liard & Cordova Production Type Wells



Remaining oil reserves are 17.3 10^6m^3 and annual oil production was 1.2 10^6m^3 in 2015.

Remaining Oil Reserves by Field



Oil reserves decreased 2.8 per cent in 2015 for total remaining reserves of 17.6 10^6m^3 (110.7 MMSTB). Remaining reserves dropped due to natural decline and the lack of new discoveries. Annual oil production in 2015 was 1.2 10^6m^3 (7.5 MMSTB).

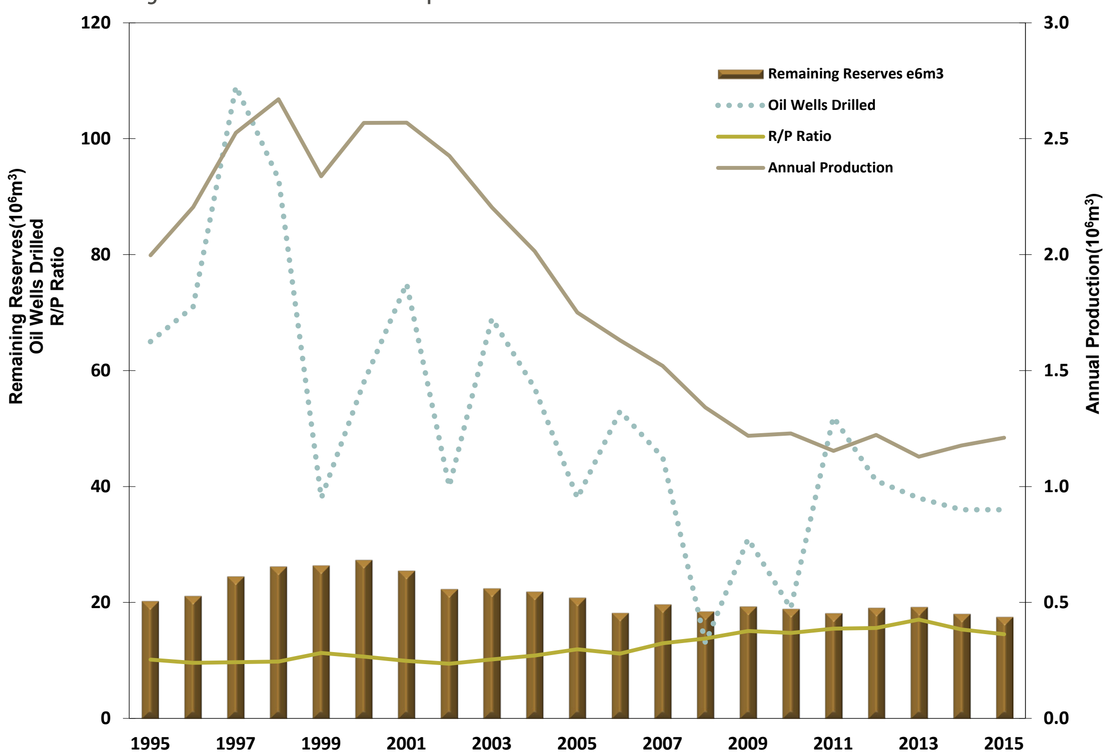
Historical oil reserves, drilling, production and reserves to annual production ratio (R/P) are plotted in Figure 12 below. Oil production peak of 2.7 10^6m^3 (17.0 MMSTB) in 1998 declined until 2010; when it began to stabilize with continued horizontal drilling and waterflood pressure maintenance.

The R/P ratio has been steady since 2009, with approximately 15 years of reserve life booked, until 2015 when the reserves to production ratio dropped to 14 years. Comparing to 2014, the distribution of remaining oil reserves has a noticeable change, the Montney Oil continues growing, in 2015 it surpassed Boundary Lake, and became the largest oil pool in B.C.

Thirty nine per cent of the remaining oil reserves in B.C. come from pools with secondary recovery pressure maintenance schemes, predominantly waterfloods (37.9 per cent). Oil pools are listed in Table A-4: Oil Pools Under Waterflood.

Gas injection recovery schemes account for one per cent of remaining oil reserves and occurs in seven oil

Figure 12: Historical Oil Development



pools (see Table A-5: Oil Pools Under Gas Injection).

Montney A Oil

The regional Triassic Montney in northeast B.C. consists of dry gas on the west side of the field and oil in the east. Significant oil reserves are present in the central Tower Lake area of the Montney play trend.

Conventional oil production continued to decline from 2006; however, significant growth from unconventional sources commenced in late 2013 as shown in Figure 14 and 15.

Figure 14:
BC Oil Production

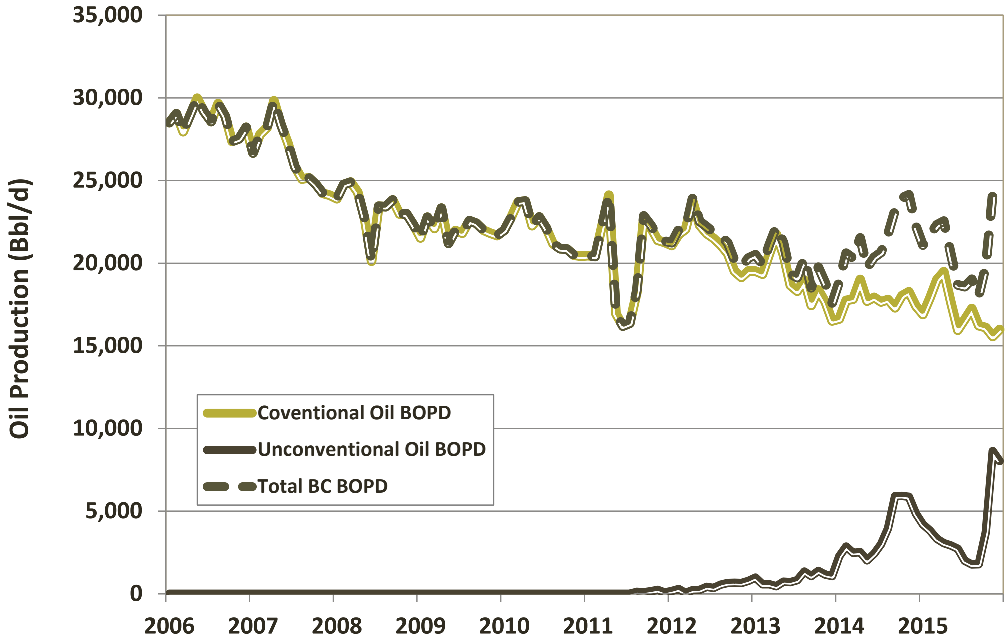
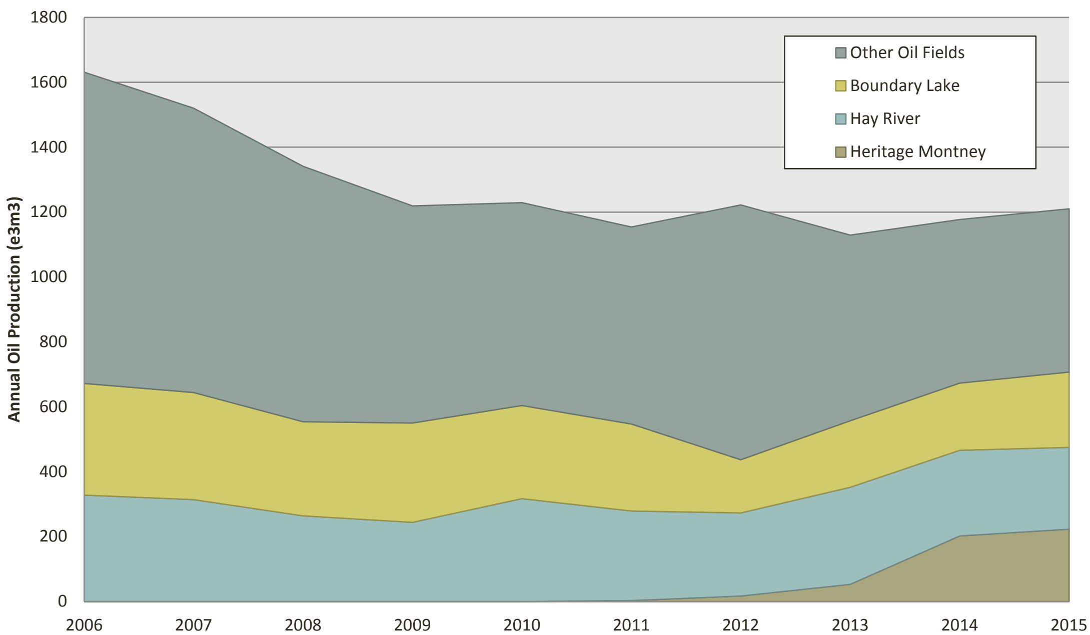


Figure 15:
BC Oil Production by Source



Production of condensate/pentane+ and LPG increased in 2015.

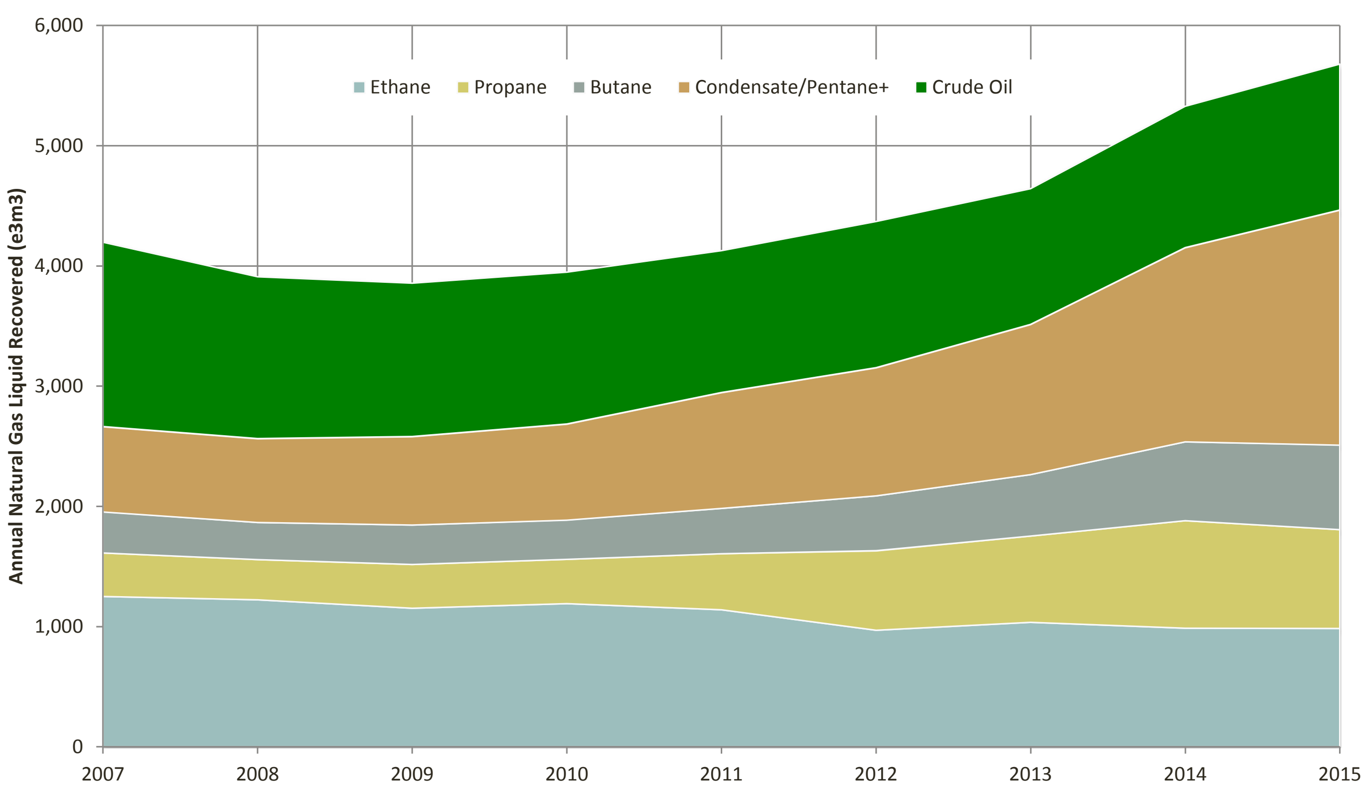
Condensate/pentane+, and butane production continue to increase in B.C., while ethane and propane is decreasing slightly. This trend is contributed by the development of gas/liquids rich portions of the Montney play. Across all of B.C. the condensate/pentanes+ increased 21 per cent from last year.

While condensate production increased in 2015, it is not as significant as in previous years. A reduction in the number of annual new wells and restrictions in the infrastructure for gas transportation has impacted reserves and production growth.

Drilling concentrated in those liquid rich areas in the eastern side of the Montney field with ratios reaching as high as 50–100 bbl/mmcf. The Commission has identified an oil leg and several new "oily" areas, as illustrated earlier in Figure 8.

Liquid petroleum gas (LPG) remaining reserves increased 20.7 per cent in 2015 (93.9 e^6m^3 in 2015 from 77.8 e^6m^3 in 2014). Pentane+ remaining reserves increased 3.0 per cent. Annual natural gas liquid and oil production from 2007 to 2015 is shown in Figure 16.

Figure 16: 2007-2015 Annual Oil, Condensate and NGL Production



Discussions: Sulphur

Sulphur production continues to decrease year over year.

As of Dec. 31, 2015, the remaining recoverable sulphur reserves were 14.4 10^6 tonnes. Sulphur reserves continue to decrease year over year due to a natural decline in production from the Bullmoose, Sukunka and Ojay fields, where the majority of the sulphur production occurs in B.C. Figure 17 shows the breakdown at Dec. 31 2015.

Operators continue to shut in wells in these areas where acid gas levels are high as continued production is no longer economic. Sulpher sales for the past five years are shown decreasing in Figure 18.

Figure 17: Major Sour Field by Remaining Sulphur Reserve

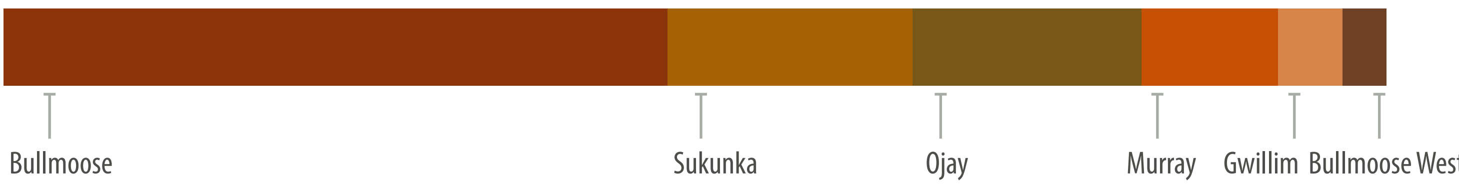
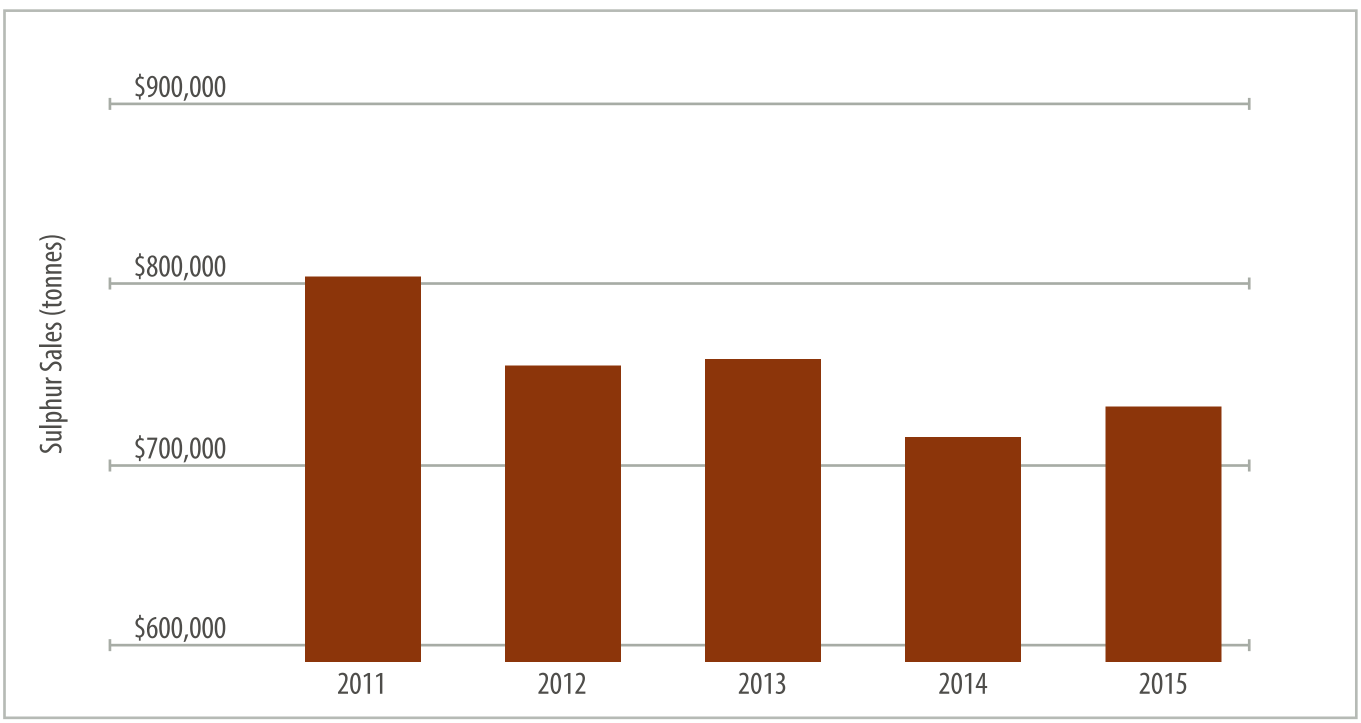


Figure 18: Annual Sulphur Sales



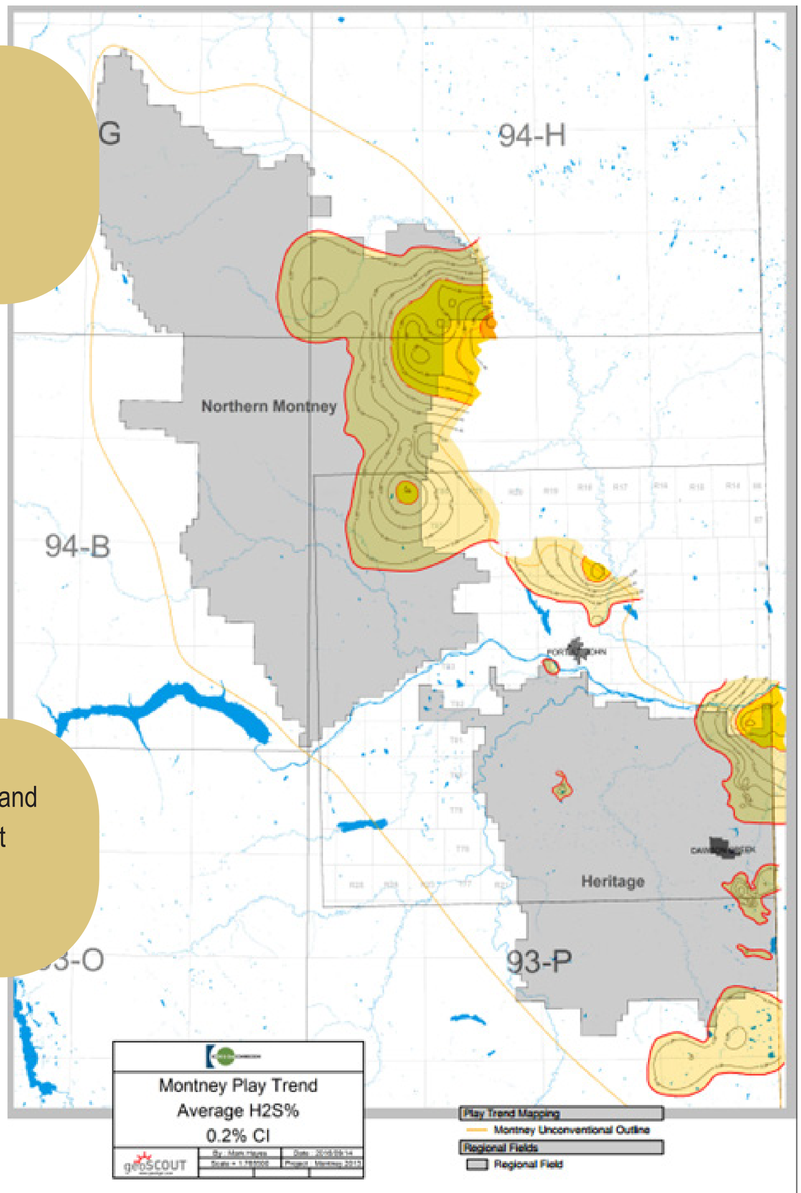
Discussions: Sulphur

Most of the natural gas recovered from the unconventional Montney Play Trend in B.C. has very little to no H_2S component. There are exceptions however, where the percentage of H_2S can reach significant levels (Figure 19).

In the Doe-Dawson area of the regional Heritage Field average concentrations are 0.1 per cent but H_2S 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 1 per cent, with some recorded values as high as 2.2 per cent. The volume of sour natural gas continues to decline from 2011 to 2015.

Figure 19: Average H_2S in the Montney Field

The most active areas in the Montney and Horn River contain little to no H_2S and are expected to have a minimal effect on future sulphur reserves.



Areas such as Sukunka (> than 20 % H_2S) and Bullmoose (> than 30 % H_2S) are significant producers of sour gas.

Definitions

SI Units

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

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

Definitions

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

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

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

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

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

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

Density
The mass or amount of matter per unit volume.

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

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

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

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

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

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

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

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

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

Definitions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Definitions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SPEE Monograph 3
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.

Definitions

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

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

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

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

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

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

Appendix A

2015 Hydrocarbon Reserves

Table A-1: Established Hydrocarbon Reserves at Dec. 31, 2015

	Oil ($10^3 m^3$)	Raw Gas ($10^6 m^3$)
Initial Reserves, Current Estimate	136,691	2,517,904
Discovery 2015	0	0
Revisions 2015	1,034	109,231
Production 2015	1,210	48,106
Cumulative Production Dec. 31, 2015	119,138	1,013,247
Remaining Reserves Estimate Dec. 31, 2015	17,553	1,504,657

Appendix A

Table A-2: Historical Record of Raw Gas Reserves

Year	Estimated Ultimate Recovery 10^6m^3	Yearly Discovery 10^6m^3	Yearly Revisions 10^6m^3	Yearly Other 10^6m^3	Annual Production 10^6m^3	Cumulative Production at Year-End 10^6m^3	Remaining Reserves at Year-End 10^6m^3
1977	376,960	18,119	-14,107		11,039	143,958	233,002
1978	399,535	21,190	1,386		9,943	153,900	245,635
1979	424,805	26,142	-872		11,394	165,294	259,511
1980	462,596	28,909	8,882		8,968	174,262	288,334
1981	478,689	13,842	2,251		8,293	182,555	296,134
1982	488,316	7,765	1,862		7,995	190,550	297,766
1983	490,733	2,550	-133		7,845	198,395	292,338
1984	496,703	1,798	4,172		8,264	206,659	290,044
1985	505,233	2,707	5,823		8,799	215,458	289,775
1986	501,468	4,822	-8,463		8,506	223,964	277,628
1987	497,466	1,986	-5,940		9,810	233,794	263,777
1988	500,738	6,083	-1,661		10,275	244,249	256,483
1989	513,662	12,193	-2		13,276	257,862	255,782
1990	547,058	27,683	5,888		13,226	271,344	275,685
1991	574,575	24,708	3,812		15,162	285,965	288,582
1992	591,356	6,377	10,404		16,510	302,916	288,408
1993	617,379	22,901	3,122		18,202	321,090	296,246
1994	635,774	22,004	-3,301		19,069	339,861	295,885
1995	657,931	21,065	1,051		21,157	361,106	296,825
1996	677,769	16,083	3,852		21,435	382,332	295,437
1997	688,202	12,835	-2,394		22,811	405,157	283,045
1998	712,677	9,957	14,502		23,375	428,822	283,855
1999	743,816	13,279	17,824		23,566	453,000	290,816
2000	772,221	13,832	14,571		23,894	477,381	294,800
2001	811,146	7,199	31,690		26,463	504,620	306,526
2002	843,612	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	109,231		48,106	1,013,247	1,504,657

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.

Appendix A

Table A-3: Historical Record of Oil Reserves

Tab	Estimated Ultimate Recovery 10^3m^3	Yearly Discovery 10^3m^3	Yearly Revisions 10^3m^3	Yearly Other 10^3m^3	Annual Production 10^3m^3	Cumulative Production at Year-End 10^3m^3	Remaining Reserves at Year-End 10^3m^3
1977	72,841	4,159	-84		2,201	46,318	26,523
1978	77,826	2,650	2,376		2,004	48,280	29,546
1979	78,882	427	629		2,140	50,397	28,485
1980	80,043	234	927		2,002	52,399	27,644
1981	79,968	143	-218		2,060	54,459	25,509
1982	80,760	126	666		2,095	56,554	24,206
1983	82,149	661	727		2,079	58,634	23,515
1984	79,551	781	-3,378		2,113	60,747	18,805
1985	82,887	1,767	1,569		1,944	62,691	20,196
1986	83,501	456	144		2,010	64,701	18,786
1987	84,201	631	68		2,084	66,793	17,361
1988	85,839	1,238	-50		1,937	68,759	16,623
1989	89,899	2,306	-2,402		1,978	70,737	19,129
1990	90,650	569	181		1,954	72,714	17,823
1991	91,606	233	630		1,974	74,689	16,911
1992	94,030	823	1,596		2,017	76,750	17,273
1993	96,663	803	1,830		1,976	78,726	17,925
1994	99,619	1,477	1,482		1,929	80,664	18,956
1995	102,823	2,887	290		1,997	82,658	20,167
1996	106,009	1,306	1,878		2,205	84,856	21,153
1997	110,765	3,199	1,561		2,525	87,401	23,364
1998	116,294	815	4,717		2,670	90,105	26,189
1999	118,840	345	2,201		2,338	92,453	26,388
2000	122,363	504	3,018		2,568	95,031	27,357
2001	123,048	106	582		2,569	97,591	25,478
2002	122,245	427	-1,233		2,426	99,977	22,313
2003	124,660	424	1,990		2,203	102,234	22,426
2004	125,953	154	947	188	2,015	104,104	21,873
2005	126,941	247	636	110	1,750	106,086	20,857
2006	125,845	222	-1,322		1,631	107,603	18,244
2007	128,971	266	2,859		1,520	109,283	19,692
2008	129,117	162	25		1,341	110,632	18,485
2009	131,172	289	1,766		1,282	111,924	19,252
2010	131,840	643	28		1,270	113,197	18,653
2011	132,414	99	475		1,154	114,253	18,161
2012	134,600	537	1,614		1,222	115,492	19,108
2013	135,883	0	1,278		1,129	116,633	19,250
2014	135,657	0	-226		1,177	117,598	18,059
2015	136,691	0	1,034		1,210	119,138	17,553

Appendix A

Table A-4: Oil Pools Under Waterflood

FIELD	POOL	POOL SEQUENCE	PROJECT CODE	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cum Oil (10^3m^3)	RR (10^3m^3)
BEATTON RIVER	HALFWAY	A	02	3,429.9	47	1,616.5	1,616.2	0.3
BEATTON RIVER	HALFWAY	G	05	1,438.4	30	431.5	425.8	5.8
BEATTON RIVER WEST	BLUESKY	A	02	2,956.1	38	1,123.3	1,098.3	25.1
BEAVERTAIL	HALFWAY	H	05	909.3	20	181.9	167.8	14.1
BEAVERTAIL	HALFWAY	B	06	503.0	18	90.5	86.2	4.3
BIRCH	BALDONNEL	C	03	2,581.2	50	1,290.6	785.5	505.1
BLUEBERRY	DEBOLT	E	03	1,211.5	30	363.4	354.2	9.2
BOUNDARY LAKE	BOUNDARY LAKE	A	03	31,026.6	45	14,055.1	12,640.4	1,414.6
BOUNDARY LAKE	BOUNDARY LAKE	A	05	1,548.3	65	1,006.4	969.3	37.1
BOUNDARY LAKE	BOUNDARY LAKE	A	04	5,355.8	60	3,213.5	3,061.9	151.6
BOUNDARY LAKE	BOUNDARY LAKE	A	02	43,666.1	45	19,824.4	19,357.5	466.9
BOUNDARY LAKE NORTH	HALFWAY	I	04	1,084.9	40	434.0	268.2	165.8
BOUNDARY LAKE NORTH	HALFWAY	D	03	743.2	20	148.6	86.1	62.5
BUBBLES NORTH	COPLIN	A	02	143.8	40	57.5	41.4	16.1
BULRUSH	HALFWAY	C	02	96.3	5	4.3	4.2	0.2
CRUSH	HALFWAY	A	02	1,449.3	35	510.1	503.2	6.9
CRUSH	HALFWAY	B	02	148.6	38	55.7	49.9	5.8
CURRANT	HALFWAY	D	02	121.9	20	24.4	8.0	16.3
CURRANT	HALFWAY	A	02	792.7	53	419.3	419.0	0.4
DESAN	PEKISKO		03	5,388.1	18	969.9	793.7	176.2
EAGLE	BELLOY-KISKATINAW		02	6,928.9	40	2,771.5	2,516.0	255.6
EAGLE WEST	BELLOY	A	03	20,337.5	31	6,304.6	6,233.9	70.7
ELM	GETHING	B	04	1,772.6	7	131.2	129.2	2.0
HALFWAY	DEBOLT	A	03	950.0	10	95.0	94.7	0.3
HAY RIVER	BLUESKY	A	05	31,032.8	20	6,206.6	4,996.6	1,210.0
INGA	INGA	A	08	1,716.5	34	583.6	557.7	25.9
INGA	INGA	A	06	7,521.3	34	2,564.8	2,335.0	229.8
INGA	INGA	A	07	1,400.6	50	700.3	626.7	73.6
INGA	INGA	A	04	8,236.6	41	3,368.8	3,322.1	46.7
LAPP	HALFWAY	D	02	381.8	45	171.8	163.0	8.8
LAPP	HALFWAY	C	02	1,075.5	45	484	448.7	35.3
MILLIGAN CREEK	HALFWAY	A	03	1,972.5	54	1,065.2	1,016.7	48.4
MILLIGAN CREEK	HALFWAY	A	02	12,119.2	53	6,423.2	6,376.3	46.9
MUSKRAT	LOWER HALFWAY	A	03	464.5	24	109.2	107.0	2.2
MUSKRAT	BOUNDARY LAKE	A	03	1,002.5	40	401	342.0	59.0
OAK	CECIL	B	02	424.5	24	101.9	99.5	2.4
OAK	CECIL	I	03	1,334.6	20	266.9	234.5	32.4

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

FIELD	POOL	POOL SEQUENCE	PROJECT CODE	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cum Oil (10^3m^3)	RR (10^3m^3)
OAK	CECIL	E	03	1,313.9	48	630.7	601.0	29.7
OAK	CECIL	C	03	907.7	60	544.6	406.3	138.4
OWL	CECIL	A	03	784.7	45	353.1	319.9	33.2
PEEJAY	HALFWAY		06	2,835.6	35	992.5	978.3	14.2
PEEJAY	HALFWAY		03	8,937.6	43	3,843.2	3,788.1	55.1
PEEJAY	HALFWAY		04	7,897.0	45	3,553.6	3,479.8	73.9
PEEJAY	HALFWAY		02	5,802.6	39	2,234.0	2,226.7	7.3
PEEJAY WEST	HALFWAY	C	02	510.9	40	204.4	132.0	72.4
PEEJAY WEST	HALFWAY	A	03	1,560.6	50	780.3	483.6	296.7
RED CREEK	DOIG	C	03	4,358.9	5	217.9	148.6	69.3
RIGEL	CECIL	I	02	1,962.0	40	784.8	767.6	17.2
RIGEL	CECIL	G	02	952.7	45	428.7	419.0	9.7
RIGEL	HALFWAY	Z	02	104.4	20	20.9	6.9	14.0
RIGEL	HALFWAY	C	03	752.3	39	293.4	292.0	1.4
RIGEL	CECIL	B	02	1,225.4	52	637.2	588.8	48.4
RIGEL	DUNLEVY	A	02	195.5	10	19.0	19.0	0.0
RIGEL	HALFWAY	C	02	738.9	28	203.2	196.6	6.6
RIGEL	CECIL	H	03	1,820.9	50	910.4	881.8	28.6
SQUIRREL	NORTH PINE	C	03	1,376.5	30	412.9	408.9	4.1
STODDART	NORTH PINE	G	04	214.0	40	85.6	75.0	10.6
STODDART WEST	BEAR FLAT	D	03	451.9	35	158.2	154.5	3.6
STODDART WEST	BELLOY	C	05	5,784.4	25	1,446.1	1,349.8	96.3
SUNSET PRAIRIE	CECIL	C	02	420.2	35	147.1	120.2	26.9
SUNSET PRAIRIE	CECIL	A	02	882.3	40	352.9	328.9	24.0
SUNSET PRAIRIE	CECIL	D	02	380.3	40	152.1	5.2	146.9
TWO RIVERS	SIPHON	A	03	1,370.0	20	274.0	259.3	14.7
WEASEL	HALFWAY		02	3,734.4	65	2,427.4	2,358.6	68.8
WEASEL	HALFWAY		03	1,729.4	59	1,011.7	1,005.7	6.0
WILDMINT	HALFWAY	A	02	2,867.9	54	15,48.6	1,541.2	7.4
WOODRUSH	HALFWAY	E	02	579.4	20	115.9	107.6	8.3
TOTAL						102,354.9		6,568.0
% of Total British Columbia Oil Reserves						75.0		37.9

Appendix A

Table A-5: Oil Pools Under Gas Injection

FIELD	POOL	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cum Oil (10^3m^3)	RR (10^3m^3)
Bulrush	Halfway A	820	45	369	323	46
Cecil Lake	Cecil D	893	40	357	344	13
Mica	Mica A	1,129	30	339	258	80
Rigel	Halfway H	703	15	105	91	15
Stoddart West	Belloy C	1,701	25	425	381	44
Total				1,595		198
% of Total British Columbia Reserves				1.2		1.1

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

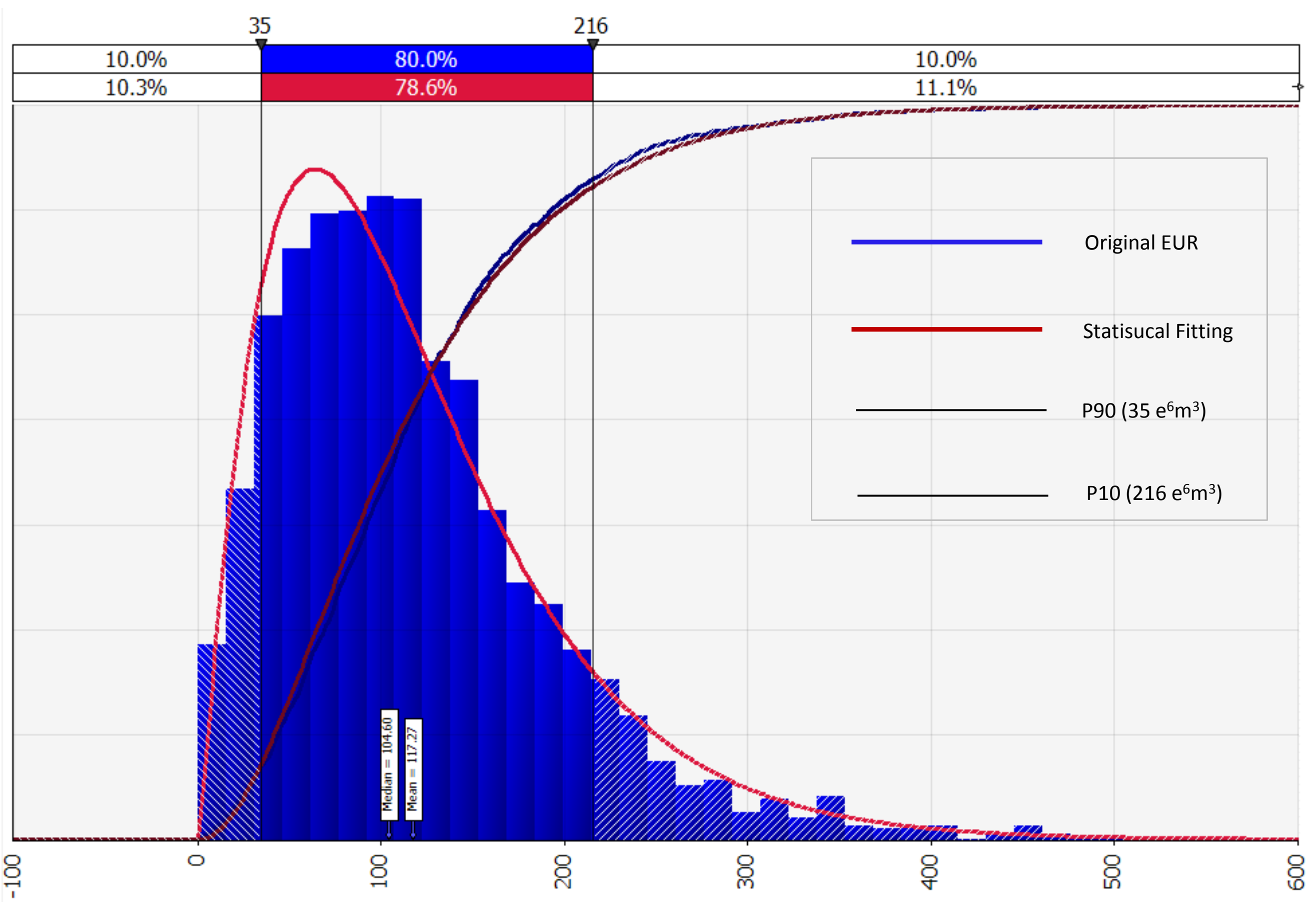
Using these guidelines, the Heritage Regional field remained in the mature phase of development while the Northern Montney Regional field has shifted its development phase from “Early” to an “Intermediate” stage. As a result of this shift in the phase of resource play development, the Commission focused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

Within the Northern Montney Regional field, there are three PDAs (Pool Designation Areas):

1. Doig Phosphate–Montney in the south east.
2. Montney B in the north.
3. Montney A.

Within each field a modified Arps decline analysis was employed using two segments.

- The first segment matched the transient flow, using decline exponent b of 1.5 to 2.0 for three to six years. The initial decline rate was adjusted manually to best fit the production curve. In liquid rich areas, boundary dominated flow appears earlier.
- In the second segment, matching of the boundary dominant flow used a b of 0.3 to 0.5 and a decline rate of approximately 10 to 15 per cent per year.
- The assumed abandonment rate was 100 Mcf/d.



Appendix B

Unconventional Reserves Evaluation Method

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

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

- A decline forecast was obtained for every Montney gas well.
- A simulation was run on the aggregated EURs to get outcome of P90, P50, P10 and Mean.
- The aggregated P90 EUR was applied to each PUD as an expected result. The sum of (aggregated P90 EUR times the number of PUDs) + (P50 EUR times the number of existing wells) resulted in the Pool EUR for the Montney North field.
- The methodology for determining the Regional Heritage EUR can be found in the 2012 Hydrocarbon and By-Product Reserves in British Columbia report (Appendix B -- Unconventional Reserves Evaluation Method).

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

For the early-to-intermediate phase of development in the Northern Montney A, four PUDs were assigned for every existing well. Monte Carlo simulations were performed to obtain aggregated P90 EUR. These values were used to assign reserves to PUDs.

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

In the Northern Montney B field, which is in the early phase of development, two PUDs were assigned for every existing well. Existing wells were assigned the P50 EUR in both the Heritage and Northern Montney.

More information

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