HYDROCARBON AND BY-PRODUCT RESERVES IN BRITISH COLUMBIA

2011

who what why when where

BC Oil & Gas COMMISSION

We are the BC Oil and Gas Commission.

About the

BC Oil and Gas Commission

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

The Commission's core roles include reviewing and assessing applications for industry activity, consulting with First Nations, ensuring industry complies with provincial legislation and cooperating with partner agencies. The public interest is protected through the objectives of ensuring public safety, protecting the environment, conserving petroleum resources and ensuring equitable participation in production.

The Commission works with communities, industry and First Nations to minimize the surface area and effects of oil and gas development. The Commission plays a role as a steward of the environment and the goal is to deepen the understanding of interplay between surface and subsurface resource development.

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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 be the leading oil and gas regulator in Canada.

Values

Respectful	Efficient
Accountable	Responsive
Effective	Transparent

Table of Contents

Summary

This report presents estimates of British Columbia's oil, natural gas and associated by-product reserves as of Dec. 31, 2011. The estimates have been prepared by the BC Oil and Gas Commission (Commission) utilizing the most currently available geologic and reservoir interpretations. The reserve estimates represent established reserves and are based on accepted geological and engineering practices.

British Columbia's Remaining Established Reserves as of Dec. 31, 2011, together with a comparison of the Dec. 31, 2010 reserves, are summarized below.

Remaining Established Reserves

		2010	2011
OIL		18.7 10^6 m^3 (117.7 MMSTB)	18.2 10^6 m^3 (114.5 MMSTB)
GAS	Total, raw	932.0 10^9 m^3 (33.1 TCF)	974.9 10^9 m^3 (34.6 TCF)
	Unconnected Gas Raw	22.3 10^9 m^3 (0.792 TCF)	22.4 10^9 m^3 (0.795 TCF)
BY-PRODUCTS	LPG	28.9 10^6 m^3 (168.0 MMSTB)	30.5 10^6 m^3 (192.2 MMSTB)
	Pentanes+	11.1 10^6 m^3 (69.9 MMSTB)	11.3 10^6 m^3 (71.1 MMSTB)
	Sulphur	14.4 10^6 tonnes (14.2 MMLT)	13.7 10^6 tonnes (13.5 MMLT)

DISCUSSION

A. Oil Reserves

The province's oil production for the 2011 calendar year was 1,154 10^3 m^3, which is a slight decrease of 2010's volume of 1,270 10^3 m^3*.

There were 52 oil wells (Figure 3) drilled during 2011, predominantly in the Hay River Bluesky A oil pool. This development activity was the major contributor to supporting remaining oil reserves.

The largest positive revision resulted from a performance review of the Lower Halfway A pool within the Fireweed area. This revision accounted for 364.8 10^3 m^3 or 77 per cent of the total revisions that took place during 2011. Overall changes to oil reserves yielded an increase of 475 10^3 m^3.

Drilling activity resulted in four new oil pools being discovered: Flatrock-Halfway O, Cache Creek-Doig CC, Helmet-Tetcho C and Monias-Charlie Lake B. These new pools increased the Initial Reserves by 99 10^3 m^3.

The overall increase to the Initial Oil Reserve elevated the remaining reserves to production ratio (R/P ratio) from 14.7 years in 2010 to 15.5 years in 2011 (Figures 1 and 2).

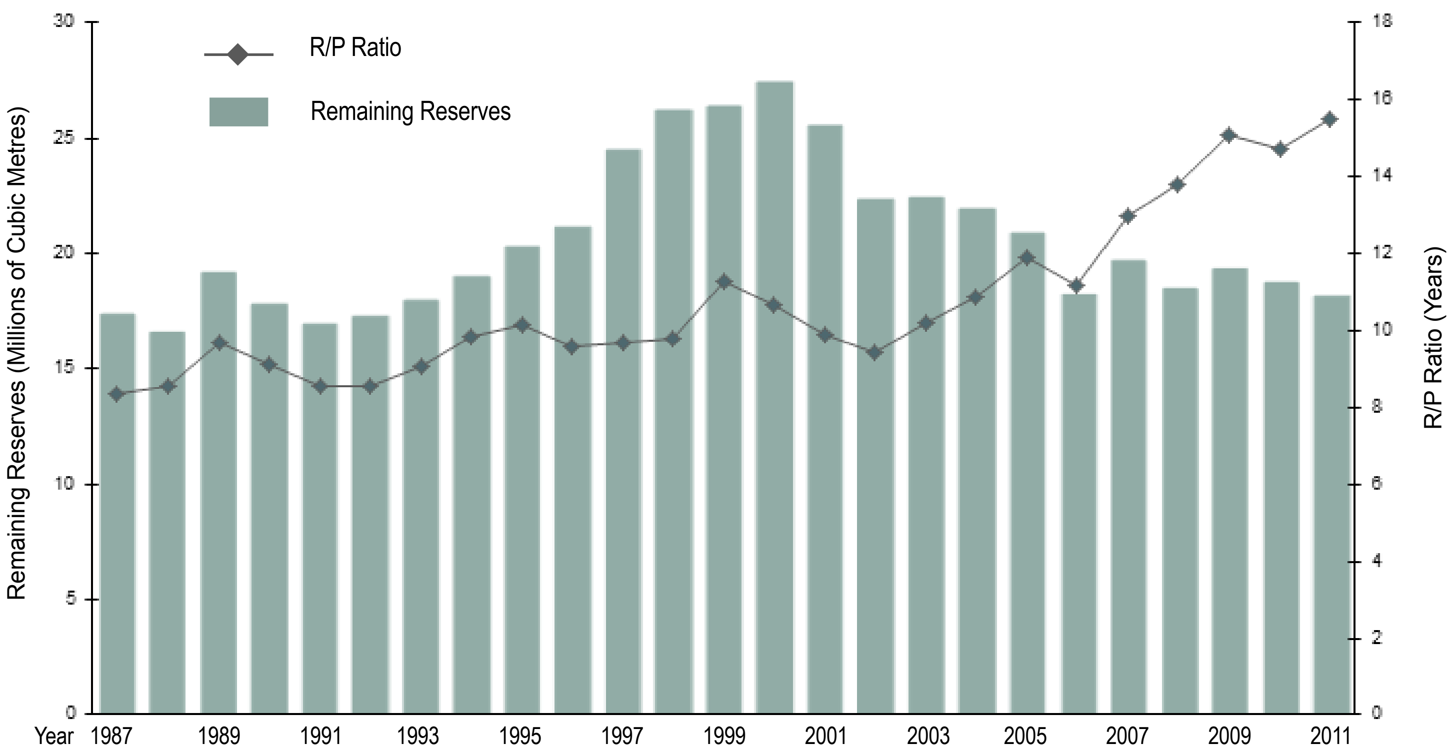
This increase in oil well drilling, however, did not increase the reserves added per well. There was a decrease going from 47 10^3 m^3 in 2010 to 11 10^3 m^3 in 2011 (Figure 3).

British Columbia's oil reserves continue to be dominated by secondary recovery schemes. Waterflood pools account for 47 per cent of remaining oil reserves (Table VII) with Hay River and Boundary Lake still being the dominant contributors.

Gas injection is currently occurring in four pools (Table VIII) and contributes about one per cent to the provincial remaining reserves.

*Note: 2010 oil production figures have been adjusted to actual figures from the Ministry of Finance.

Figure 1: Historical Remaining Oil Reserves Versus R/P Ratio



DISCUSSION

Figure 2: Historical Remaining Oil Reserves Versus Annual Production

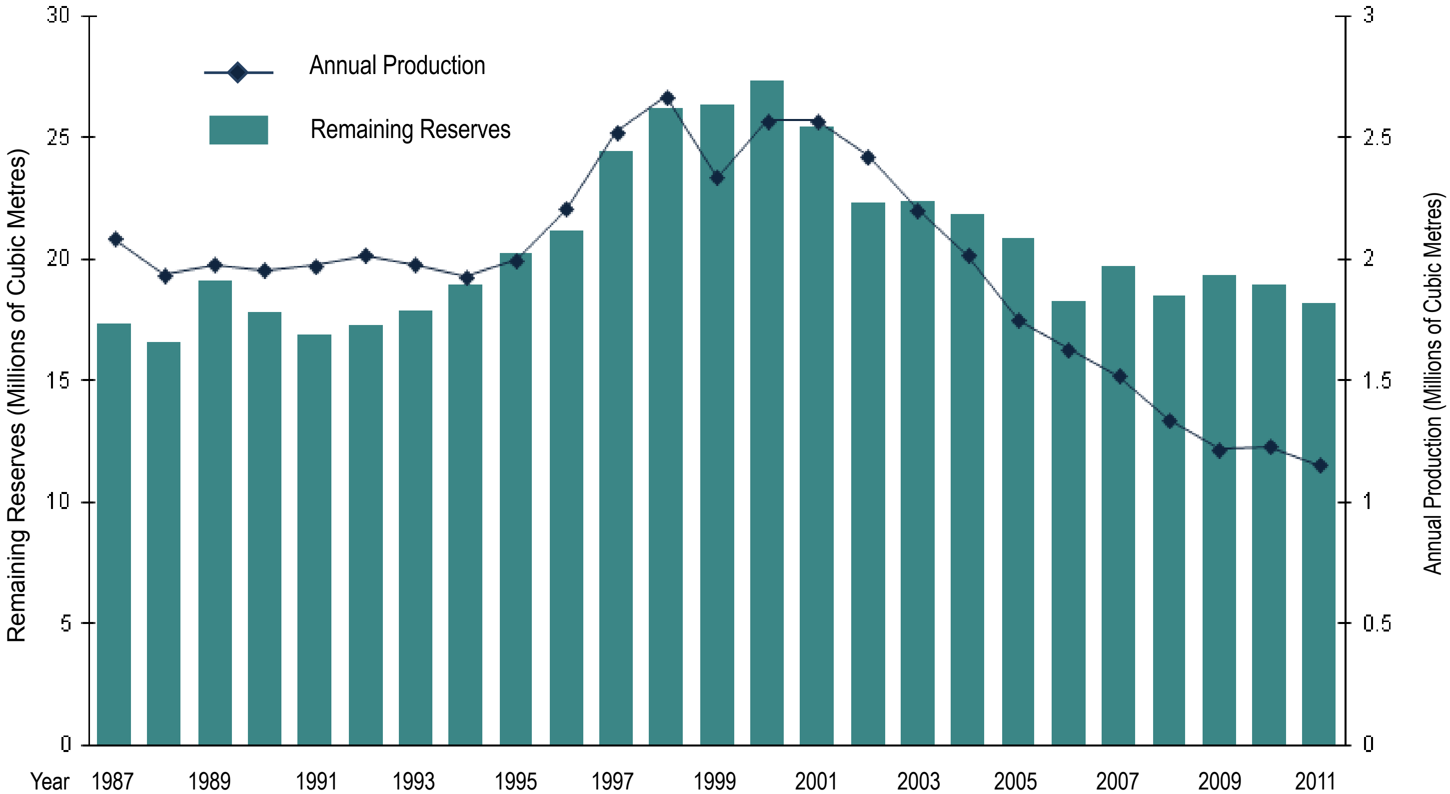
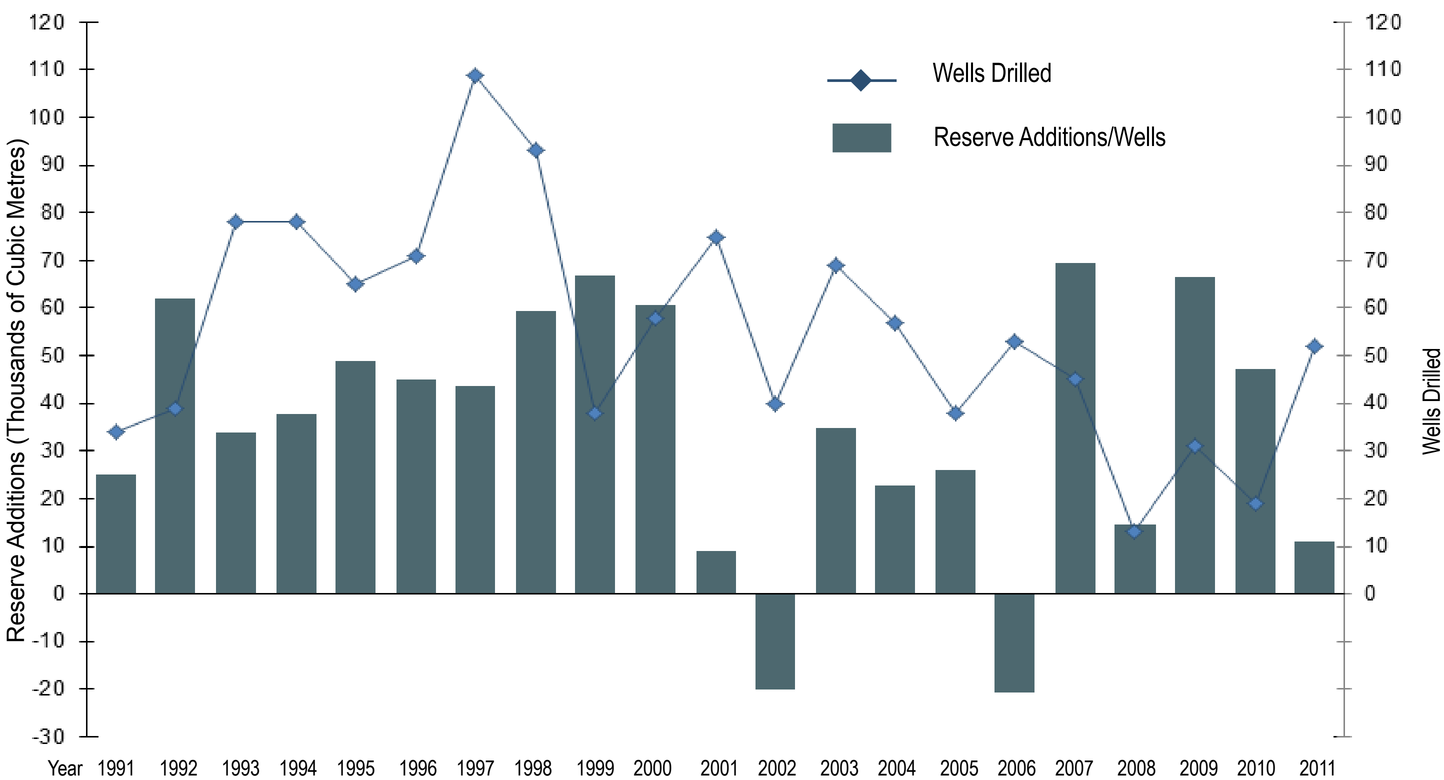


Figure 3: Oil Reserves - Reserve Additions Per Well Drilled



DISCUSSION

B. Gas Reserves

The province's established Remaining Reserves of Raw Gas were 975 10^9 m^3 as at Dec. 31, 2011, an increase of five per cent over the 2010 year-end reserves. Once again this represents the highest level of established Remaining Raw Gas reserves, which is due in part to shale gas exploration in north-east B.C.

Raw natural gas production for the year was 40.5 10^9 m^3. This was a 22 per cent increase over the preceding year's published production. The raw gas production for the year 2011 as reported by the Mineral, Oil and Gas Revenue Branch of the Ministry of Finance was 41.6 10^9 m^3, an 18 per cent increase over last year's reported production. The discrepancy in reported raw gas production between agencies is due to the fact the Commission only reports raw natural gas production for wells associated with gas pools that have been assigned established reserves.

The development of B.C.'s unconventional gas deposits continue to contribute the bulk of the reserves additions for 2011. For this reporting period, a review of the mapping within the Horn River Basin shale gas play has resulted in an increase in initial raw gas reserves of 44.5 10^9 m^3.

Horn River	2010	2011
Producing wells	98	159
Cumulative Gas Prod (BCF)	74	237
Gas Trend Daily rate (MMCF/D)	392	382

As of December 2011, there were a total of 159 producing shale gas wells in the Horn River Basin, with many still held in confidential status under the terms of Innovative Technology approvals. Production from the Horn River group of formations accounted for just over 9.7 per cent of 2011 total production in the province.

Montney	2010	2011
Producing wells	603	981
Cumulative Gas Prod (BCF)	577	1,005
Gas Trend Daily rate (MMCF/D)	918	1,234

The Montney tight gas trend continued to be the most active natural gas play in British Columbia with 372 wells targeting the Montney formation. These accounted for 62 per cent of all wells drilled in 2011 and extended the play to the northwest into the Altares and Town fields (Figure 7). This northwest trend enabled the creation of another Regional Field called the Northern Montney, which is comprised of the following: Doig Phosphate Montney pools from the fields of Altares, Chowade, Cypress, Kobes, Graham along with the Montney pools from Beg, Blueberry, Bernadet, Kobes, Town, Townsend, and single well pools formerly noted as Other Areas.

Montney production accounted for a little over 31 per cent of the total production within the province for 2011. Review and new mapping, primarily of the Northern Montney Regional Field, Doig Phosphate-Montney "A" and Montney "A" pools, added an additional 15.9 10^9 m^3 to the Initial Gas Reserves.

DISCUSSION

Northern Montney Reserves

Determination of recoverable reserves for the Northern Montney Regional Field combined the statistical analysis methodology of Society of Petroleum Evaluation Engineers (SPEE) Monograph 3, "Guidelines for the Practical Evaluation of Undeveloped Reserves in Resource Plays" and decline curve analysis. The cumulative probability distribution of Estimated Ultimate Recovery (EUR) of wells in a pool was used to assign reserve volumes to developed and undeveloped gas spacing areas. P50 values were assigned to the current producing wells and P90 values were assigned to wells in undeveloped gas spacing areas (Figures 4 and 5).

Steps for Reserve Determination:

1. Wells within the Northern Regional Montney Field, Doig Phosphate - Montney "A" pool and the Montney "A" pool were divided into sub-groups of vertical and horizontal wells.

2. Production data for all wells was utilized to create type curves and identify wells with analogous characteristics.

3. Production profiles of wells of the same vintage identified variations from group representative wells.

4. A power slope was applied to a plot of production versus time on log-log scale. The negative reciprocal of that slope is representative of the exponent used in decline analysis.
   a. The decline exponent (either "b" or "N") is segmented into transient and pseudo steady state dominated flow regimes. The time for transient flow is still unknown in most tight plays, specifically the Montney because of its relatively short production periods and extremely low permeability. As a result a period time of six years was used for the transient flow period based on industry consultations and analogy research.

5. EUR was determined for all the wells: an N value of 2.3 was used for the Doig Phosphate Montney "A" pool and an N value of 2.4 used for the Montney "A" pool. After six years an N value of 0.5 was applied to the curve and extended to an economic limit of 100mcf/d ($2.8e^3m^3/d$).
   a. Due to variations in horizontal length, fracture stimulation and production practices, the value for decline percentage was left variable, but with restraints. The forecasted line was fit to the actual production data providing a more accurate description of early time data.

6. A lognormal distribution was assigned to each set of EUR data to develop cumulative probability curves, histograms and probability distributions (Figure 6).
   a. The P90 and P50 were noted for the four data sets.

7. Referencing the PUD guidelines described in SPEE Monograph 3 a simple equation was derived to calculate reserves.
   a. Reserves = (Producing wells x P50 EUR) + (Producing wells x 2 x P90 EUR)
   b. This was applied to vertical and horizontal well groups and then summed.

Figure 4: Approximate Producing Well Count at Various Stages of Resource Play Development

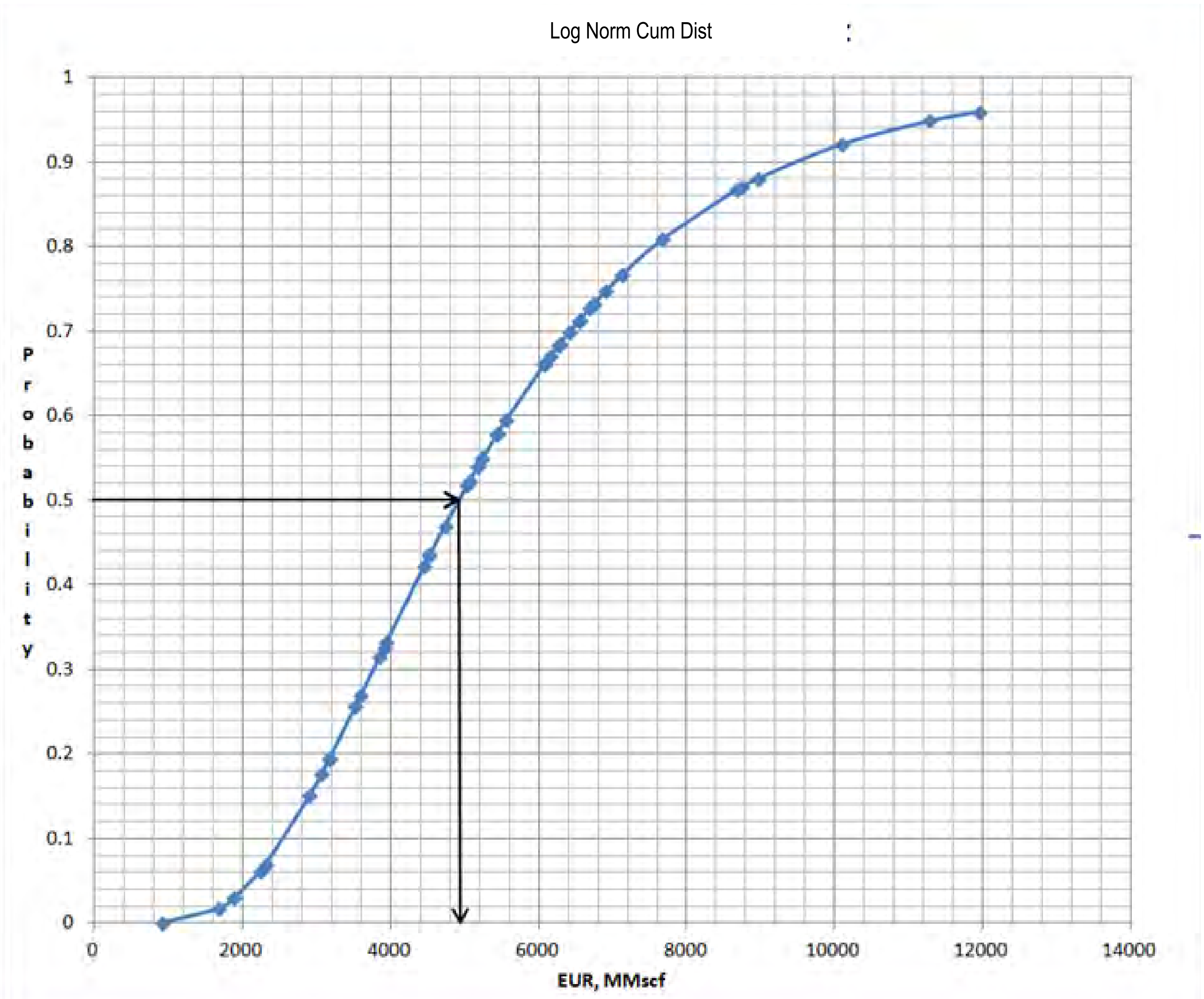
	Phase of Resource Play Development			
	Early	Intermediate	Statistical	Mature
Ratio of Analogous Producing Wells To Recommended Minimum Sample Size	**< 1**	**1 to 4**	**> 3**	**Very Large**
P10/P90 <4, Approximate Well Count	**< 50**	**100**	**150**	**> 500**
P10/P90 4 to 10, Approximate Well Count	**< 50 - 200**	**100 - 400**	**150 - 600**	**> 1,000**
P10/P90 10 to 30, Approximate Well Count	**< 200 - 700**	**200 - 1,400**	**600 - 2,100**	**> 4,500**

Figure 5: Recommended Maximum Number of PUD Offsets at Various Stages of Resource Play Development

	Phase of Resource Play Development			
	Early	Intermediate	Statistical	Mature
Recommended Maximum Number of PUD Offsets Per Producing Well (Vertical Wells)	**4**	**8**	**Statistical**	**Statistical**
Recommended Maximum Number of PUD Offsets Per Producing Well (Horizontal Wells)	**2 - 4**	**4 - 8**	**Statistical**	**Statistical**

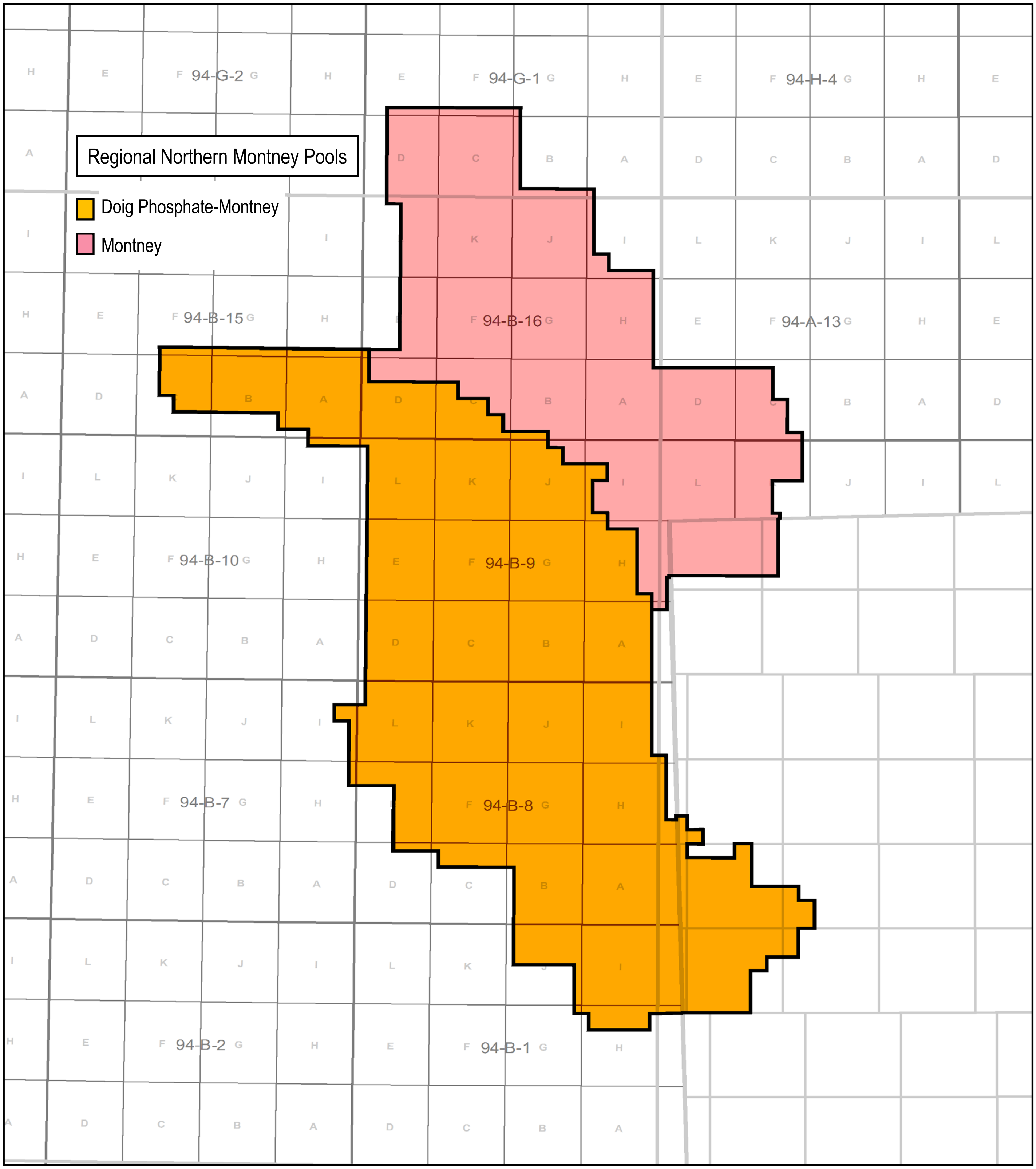
DISCUSSION

Figure 6: Example Cumulative Distribution 1



DISCUSSION

Figure 7: Regional Northern Montney Pools



DISCUSSION

Conventional Reserves

Conventional production and reserve additions have been in decline over the past decade. In 2011, 116 wells were drilled for conventional targets with initial raw gas reserve additions totaling 4.3 10^9 m^3, a significant decrease from 2010's figures. A notable revision to conventional gas reserves during 2011 was the Engineering pools Ojay Cretaceous A, B and C, which amalgamated a number of smaller commingling pools. This revision increased Initial Reserves by 8.5 10^9 m^3. The discussion below outlines "Engineering pools" and their use in the valuation of hydrocarbon reserves.

Engineering Pools

Engineering Pools are created to accommodate both reserves and production volume allocation when production volumes cannot be allocated to individual pools due to commingling production, in some cases under Area Commingling approval Orders. An Engineering Pool, specific to an individual field, may be comprised of differing geological formations or stacked pools within the same formation. Creation of an engineering pool does not replace the geologically evaluated pools used for well classification.

Fourteen engineering pools are currently identified: Boundary Lake/Halfway, Boundary Lake/Basal Kiskatinaw, Desa/ Pekisko, Eagle/ Belloy-Kiskatinaw, Hay River/Bluesky, Kobes/Charlie Lake A, B, C, & D, Monias/Halfway, Muskrat/Halfway, Peejay/Halfway, Weasel/ Halfway, Zaremba/Charlie Lake.

Ojay Engineering Pools

Three Engineering Pools have been created within the Ojay field due to commingling Cretaceous pools. The Ojay field is located within the "Outer Foothills" Area Commingling Production approval.

Cretaceous A

Cadotte pools	B, C, D, E, F, G
Notikewin pools	A, B, C, D, E
Falher pools	A-A, C-B, C-C, C-D, C-E, C-F
Gething pools	B, C, D, G
Cadomin pools	A, C, E, F, G
Nikinassin pools	A, C, D, E, F

Cretaceous B

Cadotte pools	I, J, K, L, M, N
Notikewin pools	F, G
Falher pools	A-C, C-H, D-A, G-A
Bluesky pools	B, C, D
Gething pools	L, M, N
Cadomin pools	J, K, L, M, P, Q, R, S, T, Y
Nikinassin pools	J, K, L, M, P, Q, S, T, U, W

Cretaceous C

Cadotte pools	A, O, Q
Falher pools	A, A-B, C-A, C-G, D-B, F-A, F-B, F-C, F-D
Bluesky pools	A, E
Gething pools	A, E, H, I, O, P, Q, R, S, T, U
Cadomin pools	B, D, I, N, O, U, V, W, X
Nikinassin pools	B, G, I, N, R, O, X, Y, Z

DISCUSSION

Hiding Creek - Cretaceous A Gas Pool

This engineering pool was created in April 2012 to accommodate commingling production from overlapping Cretaceous formations/pools. The Hiding Creek field is located within the “Outer Foothills” Area Commingling Production approval.

Hiding Creek – Cretaceous A pool includes the following 44 geological pools in Hiding Creek field:

Paddy:	A
Cadotte:	A, E, G, I, L, Nothing (WA14740)
Notikewin:	B, D, E, F, G, H, J, K, Nothing (WA14740)
Falher A:	A, B
Falher C:	D, F, H, I, J, K, L
Falher G:	A
Bluesky:	A, B, C, D, E, F, Nothing (WA 26182)
Gething:	A, B, D, E, F, G
Cadomin:	B, E, J, K, L
Nikanassin:	D, E, H, K

DISCUSSION

Figure 8: Historical Remaining Gas Reserves Versus R/P Ratio

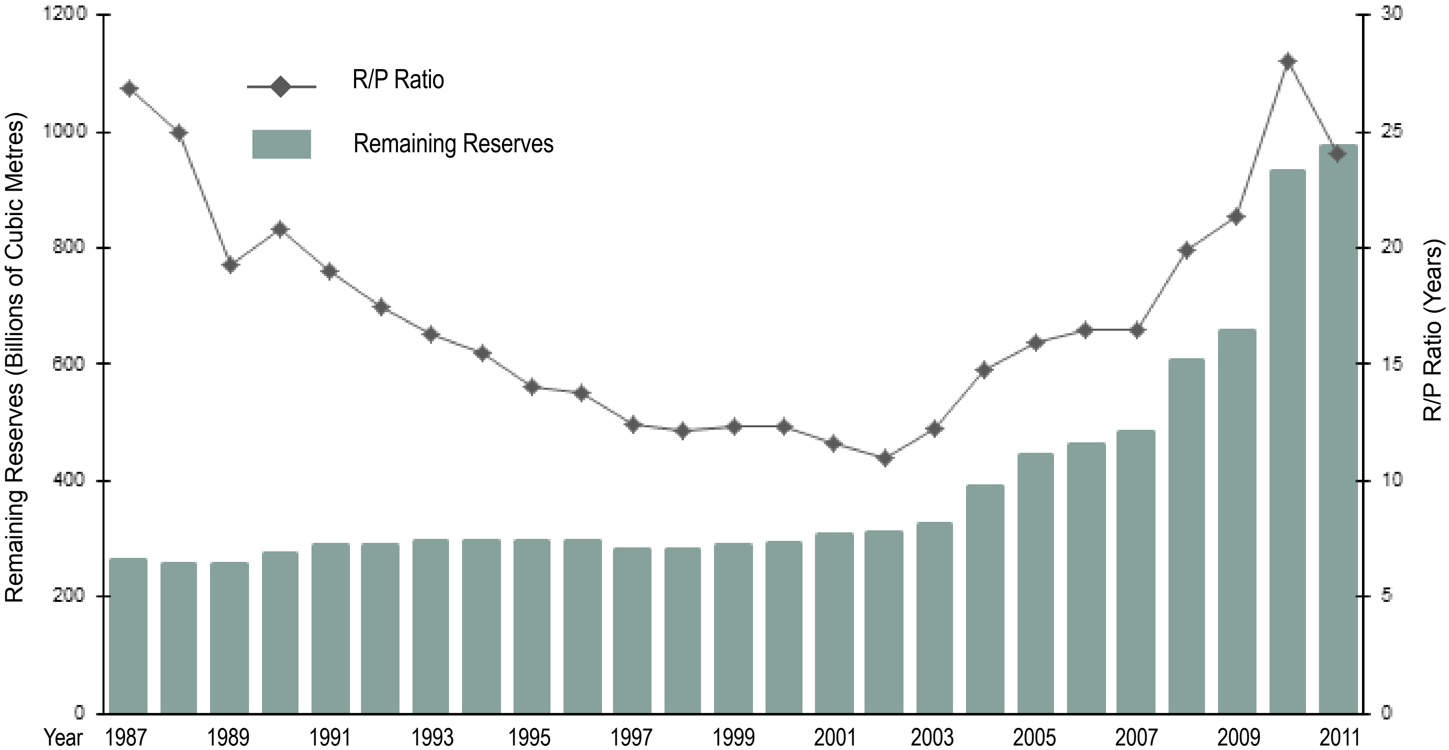


Figure 9: Historical Remaining Gas Reserves Versus Annual Production

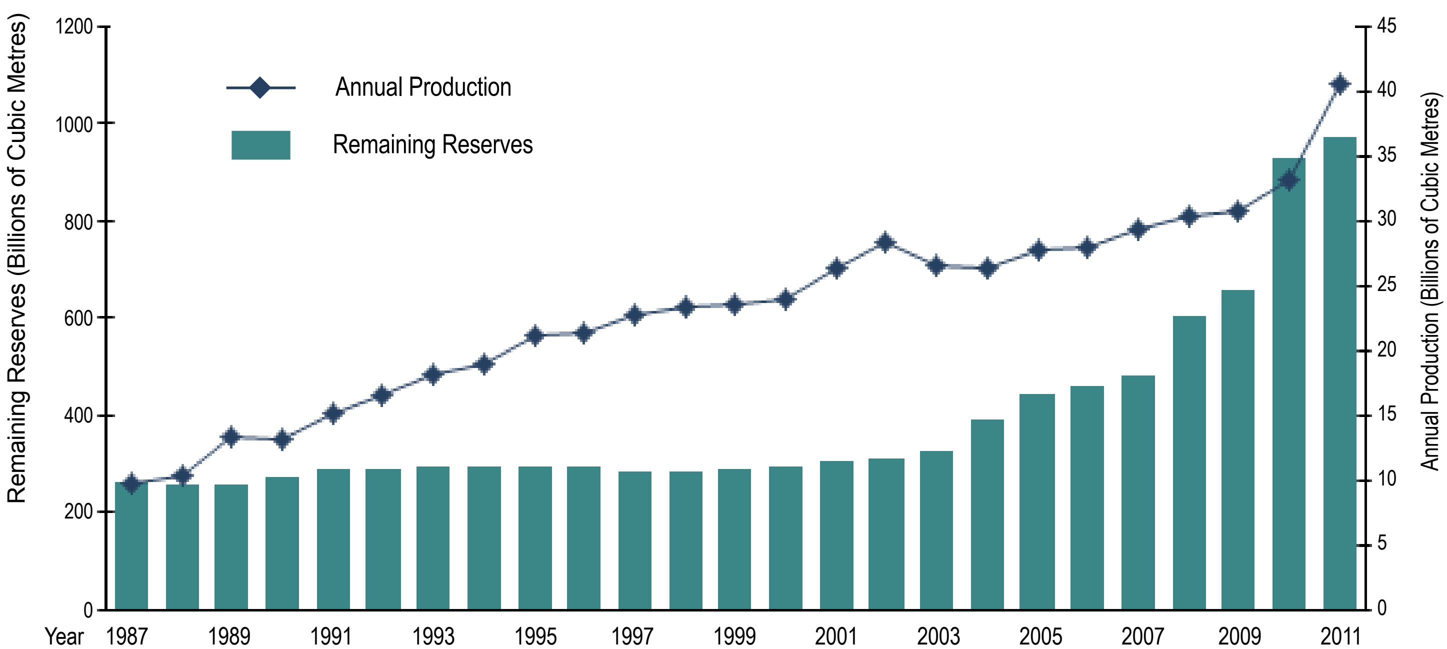


Figure 10: Gas Reserves - Reserve Additions Per Well Drilled

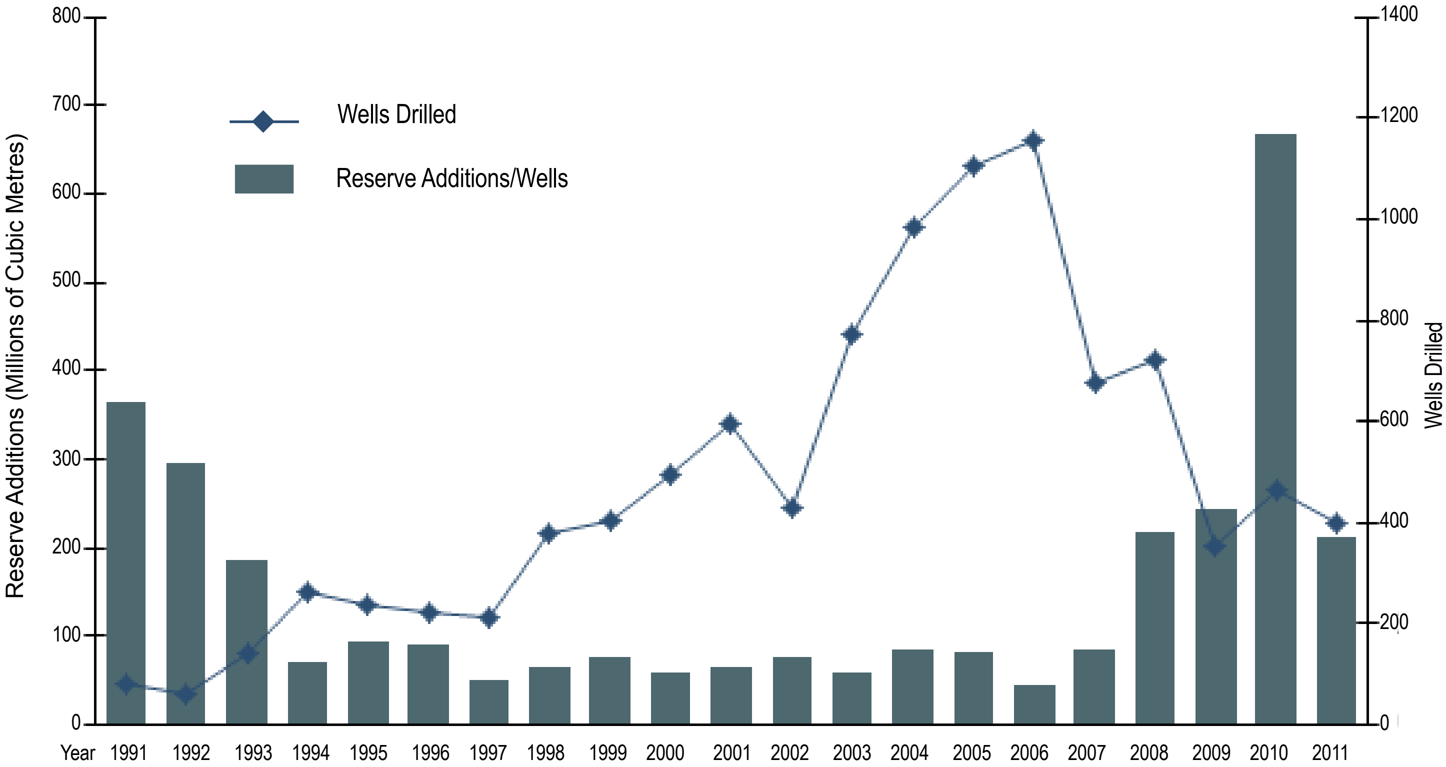
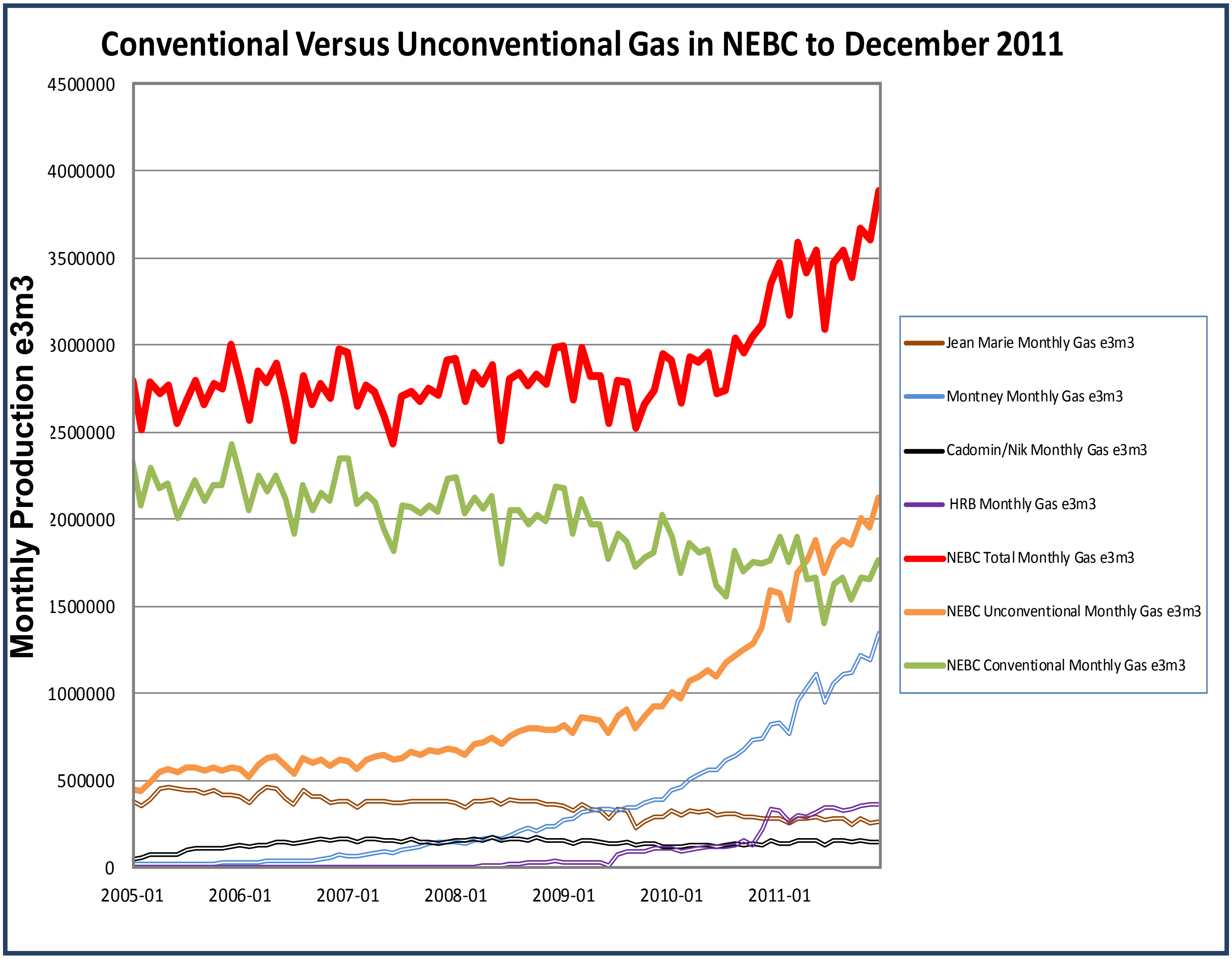


Figure 11: Conventional Versus Unconventional Gas Production in NEBC



DISCUSSION

Figure 12: Conventional Versus Unconventional 2011 Remaining Recoverable Raw Gas Reserves TCF

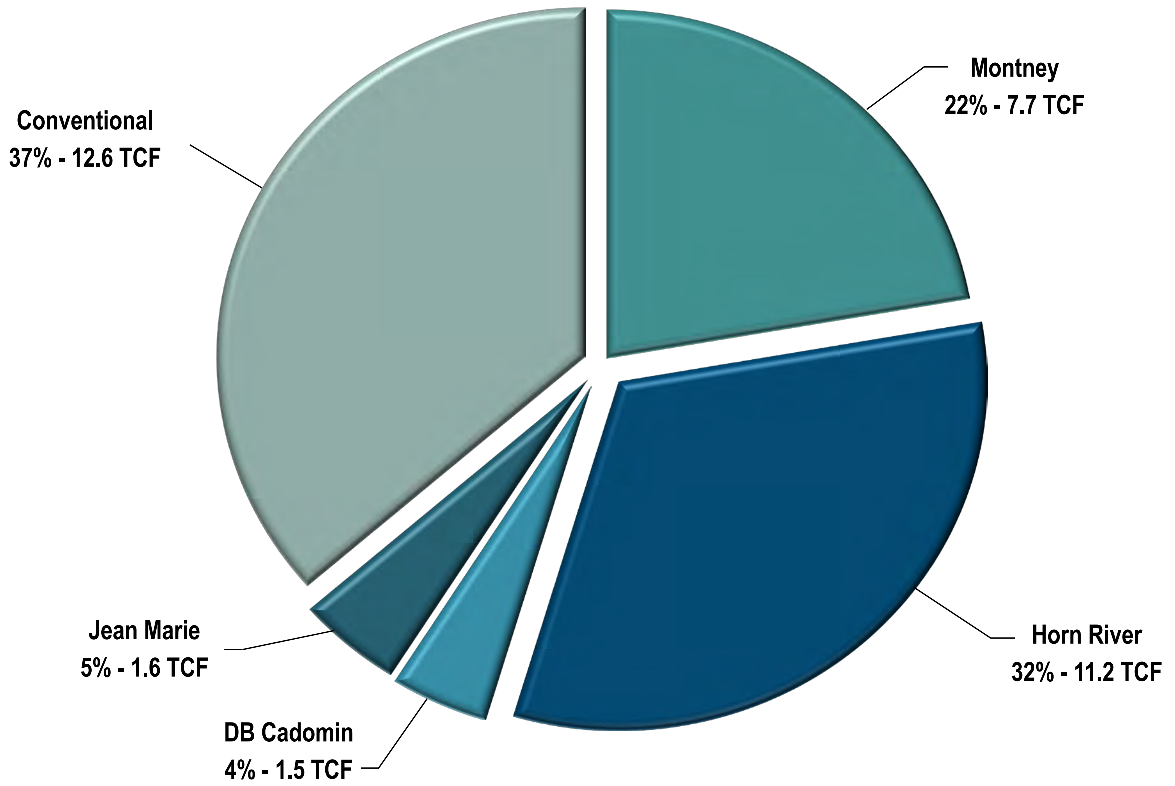
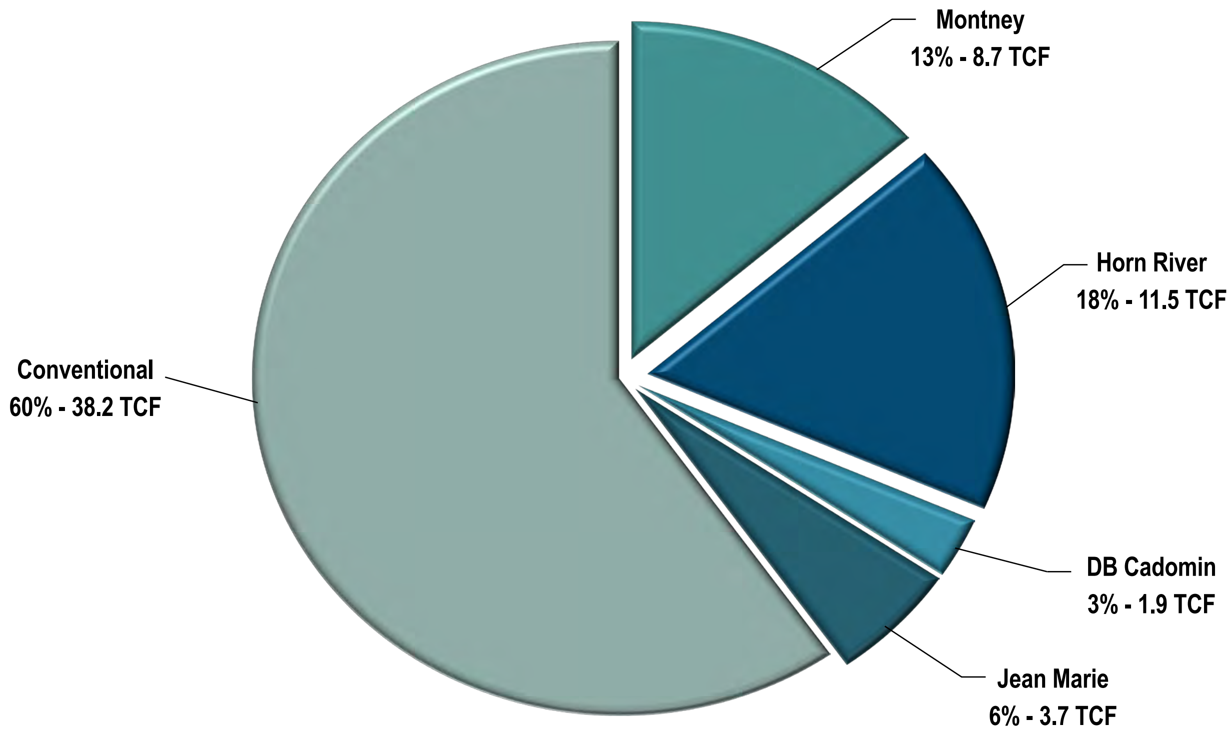


Figure 13: Conventional Versus Unconventional 2011 Initial Recoverable Raw Gas Reserves



DISCUSSION

Figure 14: Horn River Basin

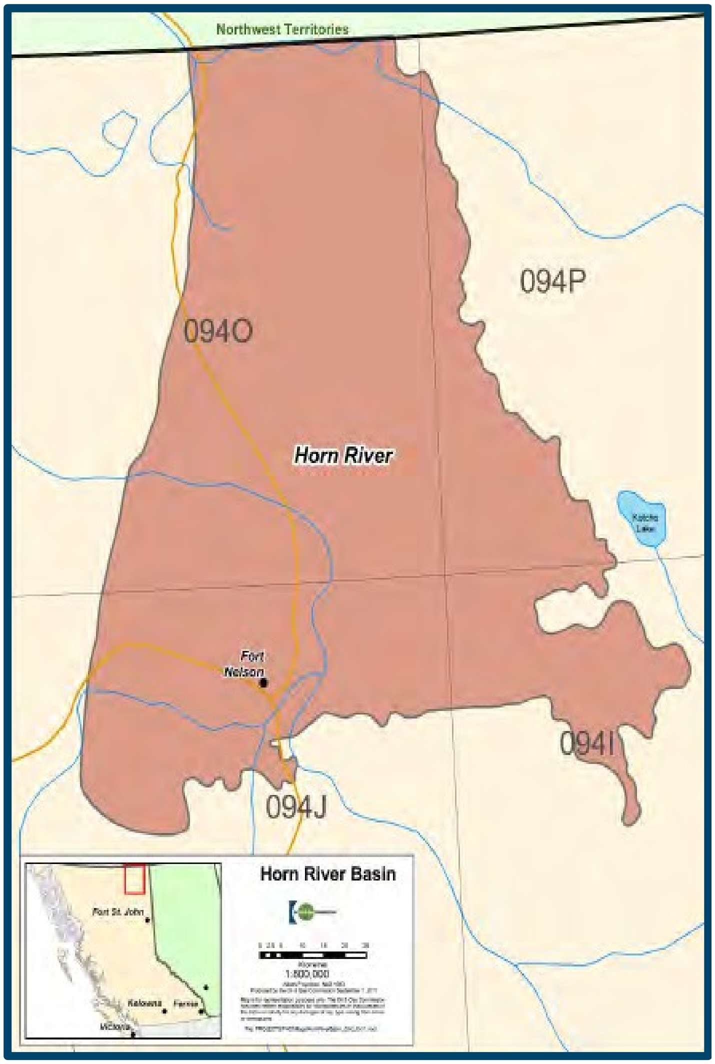


Figure 15: Montney

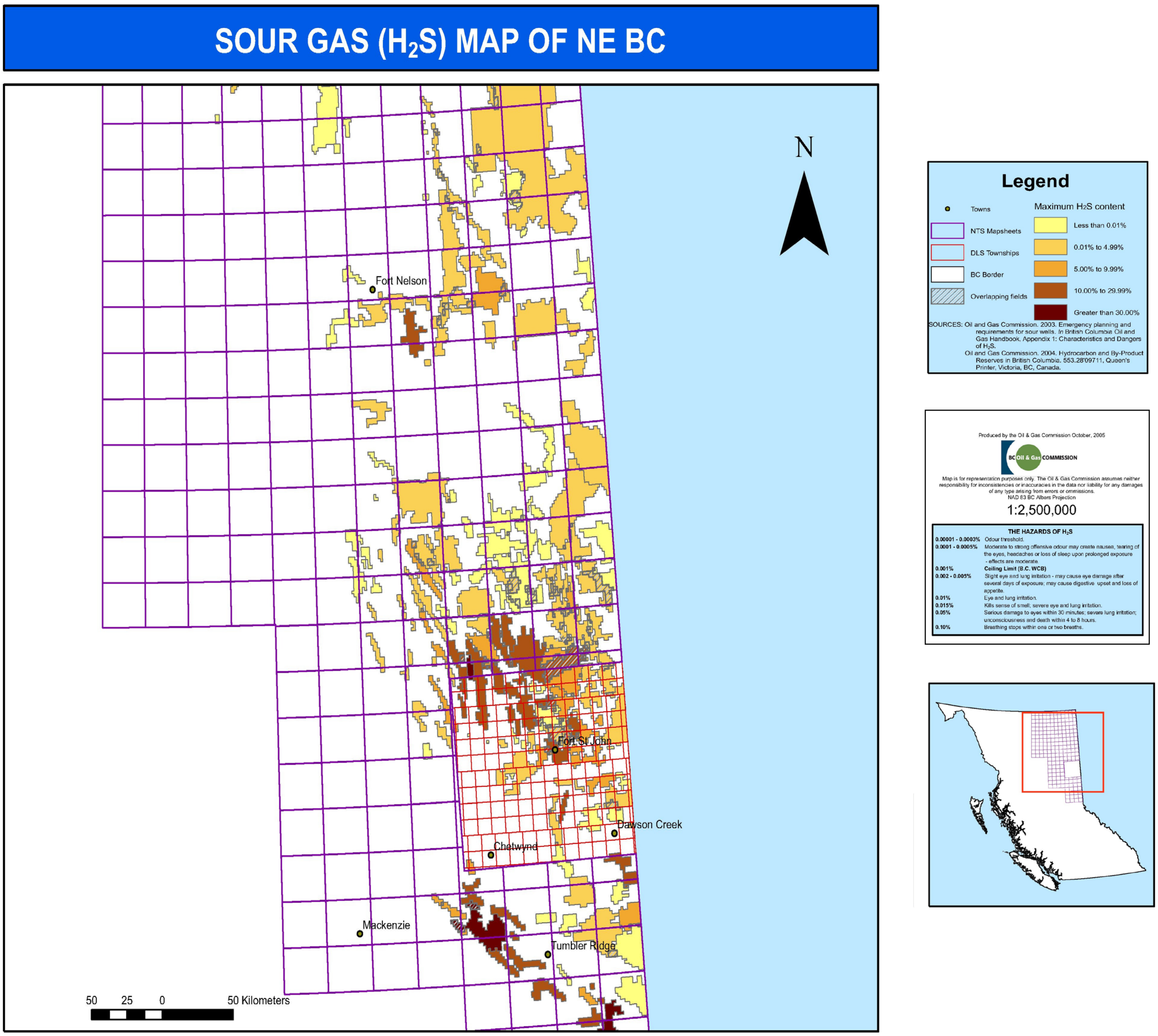
DISCUSSION

C. By-Product Reserves

Established remaining reserves of liquefied petroleum gases (LPG) increased for the fifth year to 30.5 10^6 m^3, as compared to 28.9 10^6 m^3 at year-end 2010. Established remaining reserves of pentanes plus (C5+) increased for the third year to 11.3 10^6 m^3 from 11.1 10^6 m^3. Established remaining reserves of sulphur decreased slightly to 13.7 10^6t from 14.4 10^6t in 2009. Figure 16 shows the distribution of sour gas (H_2S percentage) throughout northeast British Columbia.

For gas pools on production, the by-products reserves are estimated on the basis of the yield from raw gas reserves achieved at the plant to which the gas is delivered. For pools yet to be connected to a plant, the yields are estimated based on gas composition and capacity of the plant to which the pool is expected to be connected.

Figure 16: Sour Gas Map of NE BC

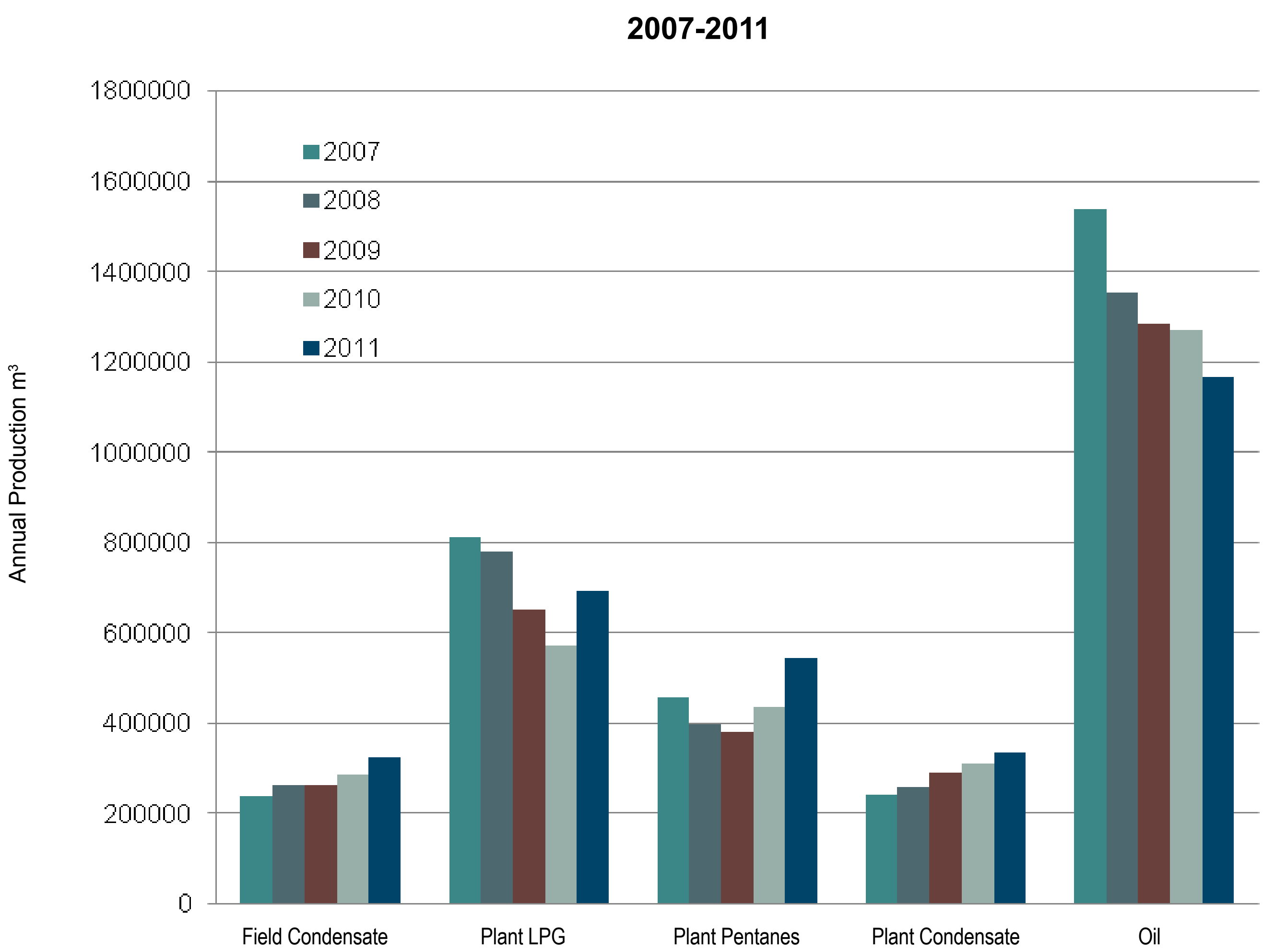


DISCUSSION

NGL and Condensate Outlook 2011

Annual oil production in B.C. peaked in 1998 at about 2.7 10^6 m^3 and has been in steady decline since 2001. Over the past five years annual oil production fell from 1.52 10^6 m^3 in 2007 to 1.15 10^6 m^3 in 2011. In contrast to the decline in produced oil, B.C.'s annual production of condensate and natural gas liquids has displayed robust growth over the past five years. This increase is largely due to the development of the liquids rich unconventional Montney play (Figure 17).

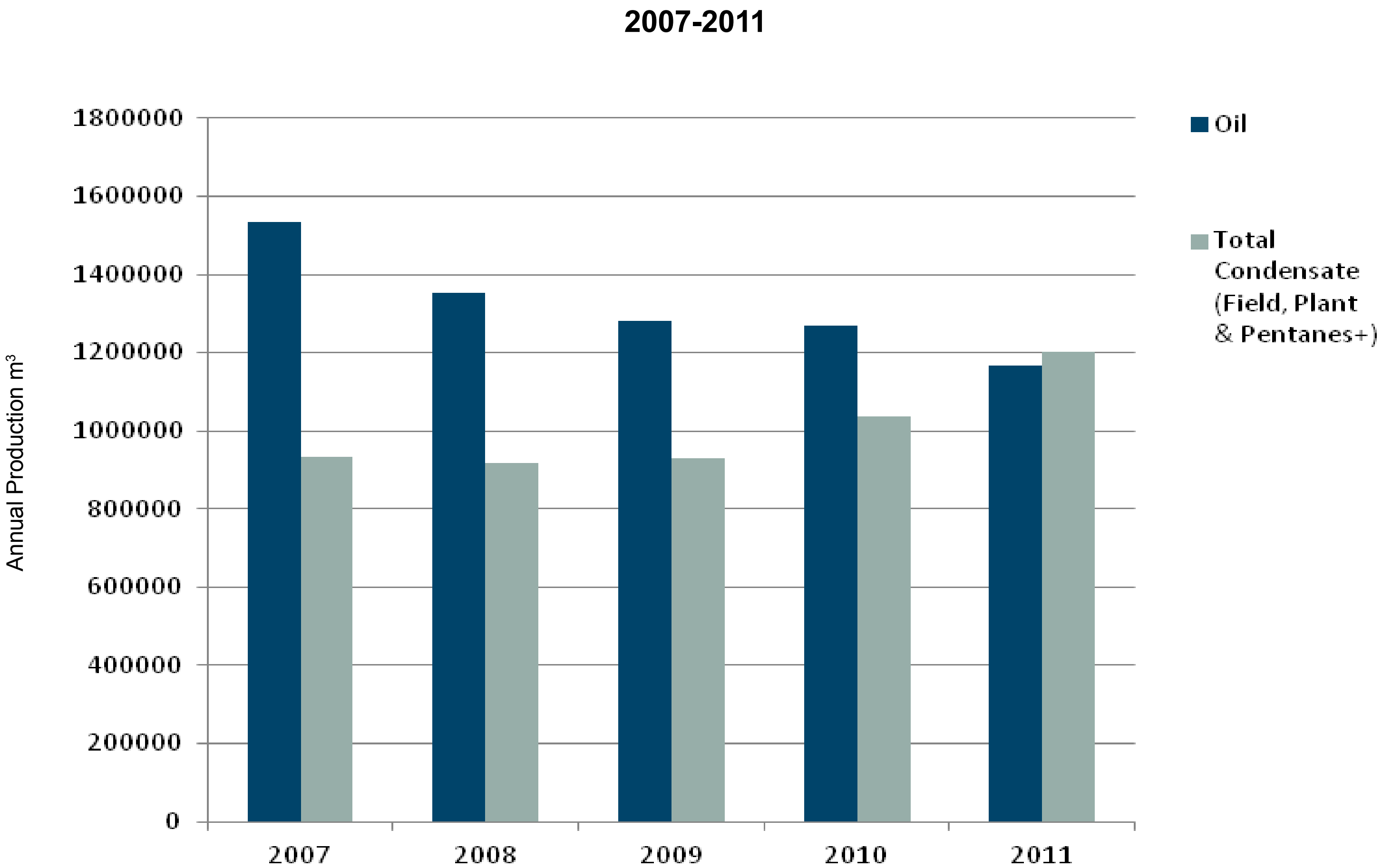
Figure 17: Annual Condensate, NGL and Oil Production



Focused development of the Montney wet gas trend began about 2009-2010, as natural gas commodity prices fell and it was recognized that significant associated natural gas liquids and condensate production enhanced economic returns. Over the 2007-2011 period, total condensate (combined field, plant and pentanes + volumes) increased 28 per cent from 0.9 10^6 m^3 to 1.2 10^6 m^3 (Figure 18). This increase in tandem with the decline in oil production, led 2011 annual condensate production volumes to surpass annual oil volumes. The future outlook is for these respective trends to continue and for NGL and condensate production to increase in importance to the province.

DISCUSSION

Figure 18: Annual Oil Versus Total Condensate Production



DISCUSSION

D. Additional Information

The Hydrocarbon and By-Product Reserves in British Columbia statistical information will continue to be offered to industry at www.bcogc.ca under Web Applications/Data Downloads. In an effort to reduce paper waste, hardcopies are not available.

For additional information on the content of this report, contact:

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ESTABLISHED HYDROCARBON RESERVES

December 31, 2011 (SI Units)
Table I

	Oil[1] (10^3m^3)	Raw Gas[1] (10^6m^3)
Initial Reserves, Current Estimate	132,414	1,809,591
Drilling 2011	+99	+7,909
Revisions 2011	+475	+76,934
Production 2011	-1,154	-40,519
Cumulative Production Dec. 31, 2011	-114,253	-834,715
Remaining Reserves Estimate Dec. 31, 2011	18,161	974,876

[1] Crude Oil and Raw Gas figures are taken from current and previous Hydrocarbon Reserves Reports. Any discrepancies in balancing are attributed to system rounding and production history reconciliation.

NOTE: Gas volumes measured at 101.325 kPa and 15^oC.

Actual plant and refinery recoveries of propane, butanes, pentanes+ and sulphur for 2011 were 468 10^3m^3, 375 10^3m^3, 485 10^3m^3 and 831 10^3 t, respectively.

December 31, 2011 (Imperial Units)
Table II

	Oil[1] (MSTB)	Raw Gas[1] (BSF)
Initial Reserves, Current Estimate	833,268	64,229
Drilling 2011	+620	+281
Revisions 2011	+2,992	+2,731
Production 2011	-7,262	-1,438
Cumulative Production Dec. 31, 2011	-718,983	-29,627
Remaining Reserves Estimate Dec. 31, 2011	114,285	34,602

[1] Crude Oil and Raw Gas figures are taken from current and previous Hydrocarbon Reserves Reports. Any discrepancies in balancing are attributed to system rounding and production history reconciliation.

NOTE: Gas volumes measured at 14.65 psi and 60^oF.

Actual plant and refinery recoveries of propane, butanes, pentanes+ and sulphur for 2011 were 2950 MSTB, 2360 MSTB, 3052 MSTB and 818 MLT, respectively.

1. OIL RESERVES

Historical Record of Established Reserves[1] (10^3 m^3)
Table III(a)

Year	Initial Reserve Current Estimate	Yearly Drilling	Yearly Revisions	Yearly Other	Production in Year	Cumulative Production at Year-End	Remaining Reserves at Year-End
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		2,015	104,104	21,873
2005	126,941	247	636		1,750	106,086	20,857
2006	125,845	222	(1,322)	188	1,631	107,603	18,244
2007	128,971	266	2,859	110	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

1 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.

2. RAW GAS RESERVES

Historical Record of Established Reserves[1] (10^6 m^3)
Table III(b)

Year	Initial Reserve Current Estimate	Yearly Drilling	Yearly Revisions	Yearly Other	Production in Year	Cumulative Production at Year-End	Remaining Reserves at Year-End
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		26,430	584,033	389,738
2005	1,065,288	8,974	63,268		27,854	620,696	444,592
2006	1,114,562	15,356	33,912	12,897	28,056	652,137	462,425
2007	1,172,136	21,468	36,109	19,104	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

[1] 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.

ESTABLISHED OIL RESERVE CHANGES

Established Oil Reserve Changes (10^3 m^3)
Table IV

Field	Pool	Amount of I.R. Change (10^3 m^3)	Reason for Change
REVISION 2011			
Fireweed	Lower Halfway A	+ 365	Performance review
Oak	Cecil C	+ 182	
Rigel	Cecil G	- 62	
	* Others	+ 89	
	SUBTOTAL REVISIONS	+ 475	
DRILLING 2011			
Flatrock	Halfway O	+ 42	New Drilling
Monias	Charlie Lake B	+ 3	
	*Others	+ 54	
	SUBTOTAL DRILLING	+ 99	
TOTAL		+ 574	

*Others – includes all additional changes both positive and negative.

ESTABLISHED RAW GAS RESERVE CHANGES

Established Raw Gas Reserve Changes (10^6 m^3)
Table V

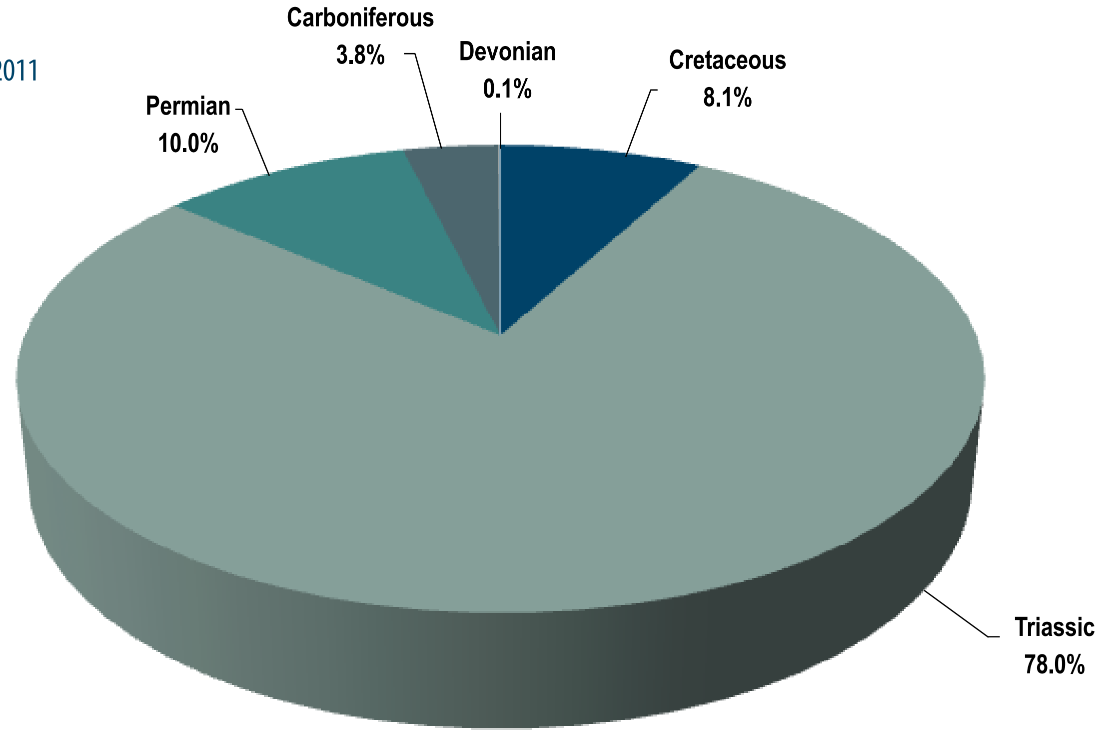
Field	Pool	Amount of I.R. Change (10^6 m^3)		Reason for Change
REVISION 2011				
Northern Montney	Doig Phosphate-Montney A	+	10,372	Re-mapping
Ojay	Cretaceous C	+	6,803	Engineering Pool
Northern Montney	Montney A	+	5,569	Re-mapping
Hiding Creek	Cretaceous A	-	5,321	Engineering Pool
Milo	Pine Point D	-	943	Pool Depleted
	*Others	+	60,454	
	SUBTOTAL REVISIONS	**+**	**76,934**	
DRILLING 2010				
Grizzly North	Nikanassin D	+	961	Mapping
Noel	Nikanassin J	+	866	Mapping
Horn River	Evie E	+	704	Mapping
Horn River	Muskwa-Otter Park D	+	692	Mapping
Noel	Nikanassin I	+	566	Mapping
Grizzly North	Baldonnel B	+	375	Mapping
	*Others	+	3,745	Mapping
	****SUBTOTAL DRILLING**	**+**	**7,909**	
TOTAL		**+**	**309,633**	

*Others – includes all additional changes both positive and negative.

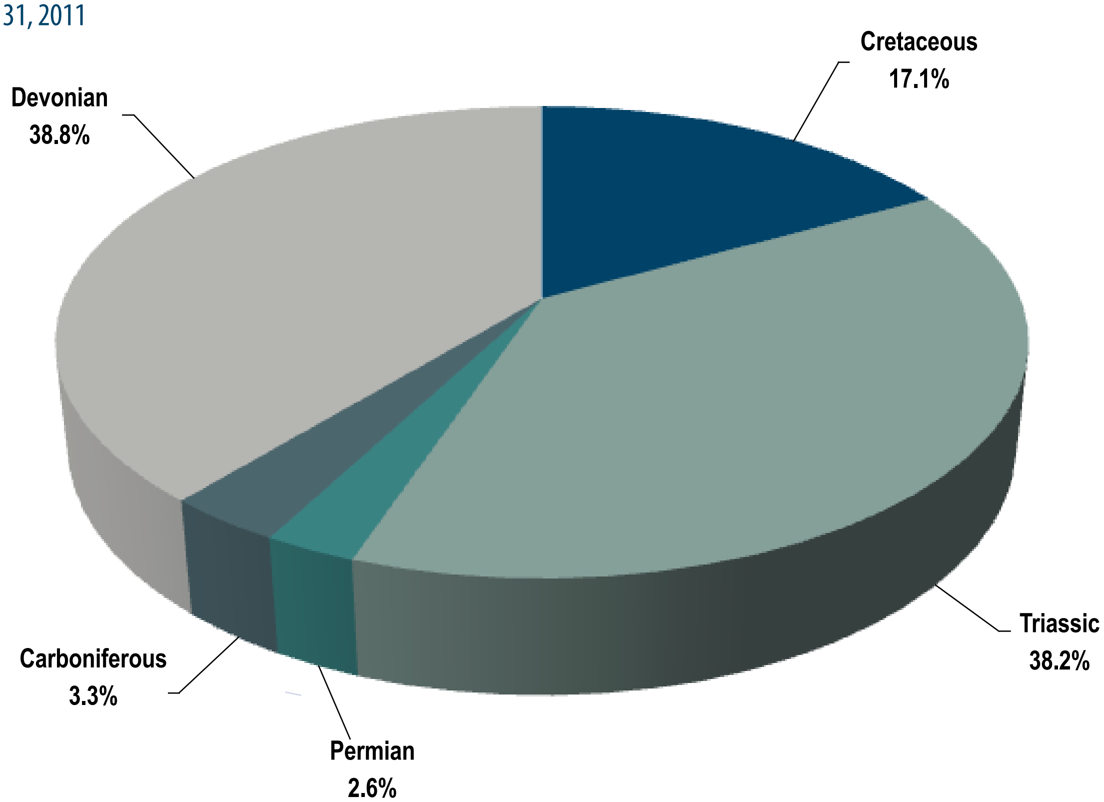
RESERVES BY GEOLOGICAL PERIOD

Figure 19: Initial Oil and Raw Gas Reserves by Geological Period

Initial Oil Reserves
as of December 31, 2011



Initial Raw Gas Reserves by Geological Period
as of December 31, 2011



RESERVES BY GEOLOGICAL PERIOD

Initial Recoverable Oil Reserves by Geological Period (10^6 m^3)
Table VI(a)

GEOLOGICAL PERIOD	OIL RESERVES	PERCENTAGE %
Cretaceous	10.7	8.1
Triassic	103.2	77.9
Permian	13.3	10.0
Carboniferous	5.0	3.8
Devonian	0.2	0.2
Total	**132.4**	

Initial Recoverable Raw Gas Reserves by Geological Period (10^9 m^3)
Table VI(b)

GEOLOGICAL PERIOD	GAS RESERVES	PERCENTAGE %
Cretaceous	309.6	17.1
Triassic	692.1	38.3
Permian	46.6	2.6
Carboniferous	59.4	3.3
Devonian	701.8	38.8
Total	**1,809.6**	

OIL POOLS UNDER WATER FLOOD

Oil Pools Under Waterflood (10^3 m^3)
Table VII

FIELD	POOL	Initial Reserve	Remaining Reserve
Beatton River	Halfway A	1,617	1
Beatton River	Halfway G	470	47
Beatton River West	Bluesky A	1,117	34
Beavertail	Halfway B	91	5
Beavertail	Halfway H	182	20
Birch	Baldonnel C	215	64
Boundary Lake	Boundary Lake A	38,099	2,802
Bubbles North	Coplin A	58	21
Crush	Halfway A	510	7
Crush	Halfway B	56	6
Currant	Halfway D	24	16
Desan	Pekisko	784	137
Eagle	Belloy-Kiskatinaw	2,772	274
Eagle West	Belloy A	6,569	381
Elm	Gething B	133	7
Hay River	Bluesky A	6,207	2,365
Inga	Inga A	7,266	417
Lapp	Halfway C	457	26
Lapp	Halfway D	166	14
Milligan Creek	Halfway A	7,440	60
Muskrat	Boundary Lake A	401	104
Muskrat	Lower Halfway A	116	10
Oak	Cecil B	127	29
Oak	Cecil C	545	231
Oak	Cecil E	631	40
Oak	Cecil I	267	43
Owl	Cecil A	353	39
Peejay	Halfway	10,578	154
Peejay West	Halfway A	525	92
Red Creek	Doig C	218	71

OIL POOLS UNDER WATER FLOOD

Oil Pools Under Waterflood(10^3 m^3) (continued)
Table VII

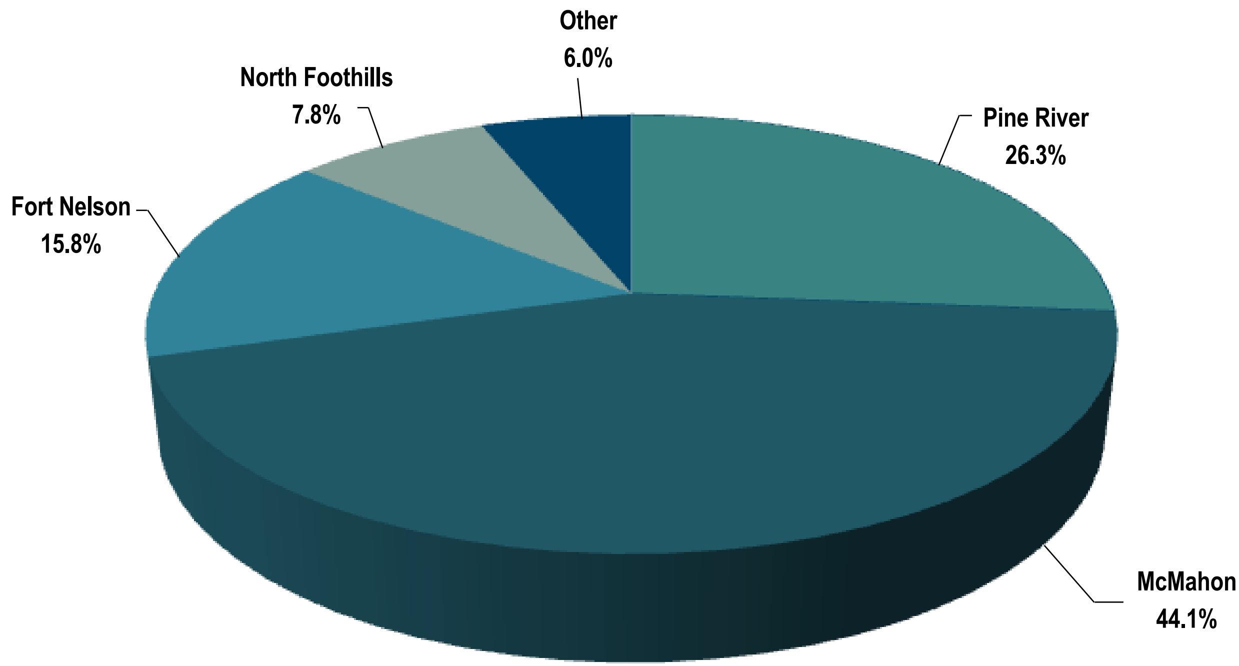
FIELD	POOL	Initial Reserve	Remaining Reserve
Rigel	Cecil B	637	72
Rigel	Cecil G	429	16
Rigel	Cecil H	910	47
Rigel	Cecil I	858	115
Rigel	Halfway C	495	7
Rigel	Halfway Z	21	14
Squirrel	North Pine C	413	4
Stoddart	North Pine C	156	96
Stoddart West	Bear Flat D	155	4
Stoddart West	Belloy C	1,446	124
Stoddart West	North Pine D	38	17
Sunset Prairie	Cecil A	353	24
Sunset Prairie	Cecil C	147	27
Sunset Prairie	Cecil D	152	147
Two Rivers	Siphon A	274	61
Weasel	Halfway	3,439	133
Wildmint	Halfway A	1,554	16
Total		**99,471**	**8,441**
% of Total British Columbia Reserves		75.1	46.5

Oil Pools Under Gas Injection (10^3 m^3)
Table VIII

FIELD	POOL	Initial Reserve	Remaining Reserve
Brassey	Artex A	15	1
Brassey	Artex G	150	1
Bulrush	Halfway A	369	58
Cecil Lake	Cecil D	357	40
Rigel	Halfway H	105	14
Stoddart West	Belloy C	425	50
Total		**1,421**	**164**
% of Total British Columbia Reserves		1.1	0.9

UNCONNECTED GAS RESERVES BY PLANT AREA

Figure 20: Unconnected Gas Reserves by Plant Area (10^9 m^3)
Remaining Reserves (Raw)



Unconnected Gas Reserves by Plant Area (10^9 m^3)
Table IX

Plant Name	Initial Remaining Raw Gas (10^9 m^3)
[1] Pine River (c-85-d/93-P-12)	5.9
McMahon (5-31-82-17)	9.9
Fort Nelson (b-84-G/94-J-10)	3.5
[2] North Foothills	1.7
Other	1.4
Total	**22.4**

* Totals may not add up due to rounding.

[1] Includes BRC Elmworth (4-8-70-11-W6) and Burlington Noel (b-59-D/093-P-8).

[2] Includes WGSI Buckinghorse (a-81-H/094-G-6), Anadarko Cypress (b-99-C/094-B-16) and WEI Sikanni (b-41-I/094-G-3).

PROJECT/UNIT CROSS REFERENCE LISTING

Table X

Project Type	Description
CONC	Concurrent Production
EOR	Enhanced Oil Recovery
GEPG	Good Engineering Practice - Gas
GEPO	Good Engineering Practice - Oil
PMGI	Pressure Maintenance - Gas Injection
PMWF	Pressure Maintenance - Water Flood
UNIT	Unitization

For a complete project/unit cross-reference listing, please visit our website: www.bcogc.ca
Access Web Applications/Data Downloads

Definitions: SI Units

British Columbia's reserves of oil, natural gas liquids and sulphur are presented in the International System of Units (SI). The provincial totals and a few other major totals are shown in both SI units and the Imperial equivalents in the various tables. 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])

RESERVES TERMINOLOGY

Original Gas and Original Oil in Place
The volume of oil, or raw natural gas calculated or interpreted to exist in a reservoir before any volume has been produced.

Established Reserves
Reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing, or production, plus that judgment portion of contiguous recoverable reserves that are interpreted from geological, geophysical, or similar information, with reasonable certainty to exist.

Initial Reserves
Established reserves prior to the deduction of any production.

Remaining Reserves
Initial established reserves less cumulative production.

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

DEFINITIONS

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
In addition to its normal scientific meaning, a mixture mainly of butanes which ordinarily may contain some propane or pentanes plus.

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 that may be contaminated with sulphur compounds that is recovered or is recoverable at a well 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 or estimated.

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.

DEFINITIONS

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.

Liquid Petroleum Gases (LPG)
A hydrocarbon mixture comprised primarily of propane and butanes. Some ethanes may be present.

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

DEFINITIONS

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 ordinarily may contain some butanes and which 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.

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

Propane
In addition to its normal scientific meaning, a mixture mainly of propane, which ordinarily may contain some ethane or butanes.

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.

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

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.

Underbalanced Drilling
A technique in which the hydrostatic pressure in the circulating downhole fluid system is maintained at some pressure less than the pressure of the target formation.

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