# Summary

Much like that of the US, Canada's petroleum industry began in the populated eastern regions near the Great Lakes. In 1857, a small still was built in Ontario to treat oil seeping from springs that had been known since 1830. The first commercial field was developed nearby in 1861 when flowing wells were completed at depths between 350 and 400 ft. By 1865, Canada had produced 110,000 barrels (bbls) of oil per year, compared to 2.5 million bbls in the US.

However, it was Western Canada that held the most significant hydrocarbons. The Athabaska oil sands (or tar sands) were first reported in 1778, but did not begin first commercial production until 1967. Canada's first oil boom began in 1914 with a discovery at Turner Valley in the Alberta Foothills. Next came Norman Wells in 1920, which was 55 miles from Fort Norman on the Mackenzie River, near the Arctic Circle in the Northwest Territories. The discovery of Leduc oil field near Edmonton, Alberta, in 1947 propelled Canada into the position of being a major supplier of North American energy. By the end of 1970, cumulative oil production from Canada had reached 5.1 billion bbls.

The bulk of the mineral rights in the western provinces are held by the "Crown," i.e., owned and administered by the provincial governments. Exceptions include the Hudson's Bay Company, Canadian Pacific Railroad and some other private railroads, which received land grants.

Gas was first discovered in Western Canada by Canadian Pacific Railroad in a well drilled for water. Later discoveries near Medicine Hat, Alberta, dating back to 1890, were used locally for domestic and industrial purposes. Development remained limited until 1951 when distant markets were made accessible.

Currently, the two primary oil producing areas are the Western Canadian Sedimentary Basin (WCSB--which includes the oil sands) and offshore eastern Canada. With WCSB conventional oil production declining, development is being focused on the oil sands and the offshore.

Figure 1 presents forecast crude production in Canada as an extension of history beginning in 1945. By type, the history and forecast of total production are as follows:

**Thousand Barrels Per Day (mmbd)**

| | Crude Oil | | | | | | |
|---|---|---|---|---|---|---|---|
| | Conventional | | | | | | |
| | On-shore | Off-shore | Syn-thetic | Bitu-men | Total | Con-densate | Gas Liquids |
| 1973 | 1,742 | - | 51 | - | 1,793 | 4 | 320 |
| 1978 | 1,241 | - | 64 | 8 | 1,313 | 3 | 281 |
| 1986 | 1,194 | - | 185 | 93 | 1,472 | 2 | 401 |
| 1994 | 1,328 | 23 | 262 | 135 | 1,748 | 5 | 578 |
| 1995 | 1,359 | 21 | 282 | 148 | 1,810 | 6 | 602 |
| 1996 | 1,383 | 18 | 280 | 163 | 1,844 | 7 | 632 |
| 1997 | 1,401 | 13 | 290 | 238 | 1,942 | 7 | 652 |
| 1998 | 1,346 | 82 | 308 | 282 | 2,018 | 8 | 666 |
| 1999 | 1,240 | 106 | 323 | 244 | 1,913 | 9 | 652 |
| 2000 | 1,247 | 144 | 320 | 288 | 1,999 | 16 | 696 |
| 2001 | 1,229 | 149 | 349 | 309 | 2,036 | 20 | 667 |
| 2002 | 1,160 | 286 | 438 | 304 | 2,188 | 21 | 692 |
| 2003 | 1,122 | 337 | 509 | 349 | 2,317 | 20 | 663 |
| 2004 | 1,091 | 314 | 599 | 386 | 2,390 | 19 | 664 |
| 2005 | 1,054 | 305 | 545 | 441 | 2,345 | 26 | 657 |
| 2006 | 1,054 | 290 | 656 | 468 | 2,468 | 27 | 681 |
| | | | Forecast | | | | |
| 2007 | 1,003 | 301 | 674 | 515 | 2,493 | 26 | 664 |
| 2008 | 964 | 314 | 732 | 628 | 2,638 | 26 | 651 |
| 2009 | 915 | 323 | 819 | 619 | 2,676 | 25 | 638 |
| 2010 | 893 | 334 | 1,000 | 660 | 2,887 | 25 | 650 |
| 2011 | 838 | 329 | 1,186 | 641 | 2,994 | 24 | 607 |
| 2012 | 809 | 322 | 1,577 | 410 | 3,118 | 24 | 618 |
| 2013 | 786 | 307 | 1,800 | 468 | 3,361 | 24 | 610 |
| 2014 | 751 | 301 | 2,101 | 422 | 3,575 | 24 | 600 |
| 2015 | 784 | 274 | 2,174 | 473 | 3,705 | 23 | 597 |

Conventional oil production peaked in 1973 at 1.74 million bpd. Better economic conditions and increased drilling during the 1980s and 1990s stabilized production at around 1.4 million bpd, but output began another, and we forecast, irreversible decline in 2005.

The salvation for Canada is its massive oil sands resources. Production from the first oil sands surface mine began in 1967 and, after many fits and starts, has grown to 1.12 million bpd in 2005. The opening of new surface mines, plus numerous in situ thermal recovery projects are forecast to raise oil sands production to 1.66 million bpd in 2010 and to 2.65 million bpd in 2015, bringing total Canadian crude output to 3.705 million bpd.

As shown in Figure 2, natural gas production is forecast to peak in 2007 at 18.37 MMcfd, then decline to 17.34 MMcfd in 2010 and 16.38 MMcfd by 2015. Non-associated gas output from Alberta, the largest producing province, peaked in 2001 at 12.77 MMcfd. This decline occurred despite record drilling rates between 2000 and 2006, which underscores the mature nature of the province.

The beginning of East Coast offshore production in 1998, plus rising deliverability from British Columbia and Saskatchewan, allowed the peak in total Canadian production to be delayed until 2007.

While coal bed methane, process gas from bitumen upgrading and associated gas from bitumen in situ recovery projects all are projected to rise, the volumes will not be enough to counter the declining rates from Alberta, especially with the new, higher royalty rates the province has adopted beginning in 2009.

Forecast production and ultimate recovery of crude and condensate compare with history as follows:

**Million Barrels**

| | Off-shore | On-shore | Synthetic & Bitumen |
|---|---|---|---|
| Ultimate Recovery 12-31-1978 | 7,231 | - | 3,375 |
| Reserve Additions | | | |
| 1979-1994 | 7,627 | 868 | 1,345 |
| 1995-2004 | 4,027 | 556 | 6,693 |
| 2005-2015 | 2,715 | 550 | 12,271 |
| Ultimate Recovery 12-31-2015 | 21,600 | 1,974 | 23,684 |
| Cumulative Production 12-31-1978 | 3,536 | - | 214 |
| 1979-1994 Production | 7,278 | 14 | 1,487 |
| 1995-2004 Production | 4,591 | 538 | 2,340 |
| 2005-2015 Production | | | |
| 2005 | 385 | 112 | 360 |
| Estimated 2006 | 385 | 106 | 410 |
| Forecast 2007-2015 | 2,791 | 1,025 | 6,173 |
| Subtotal | 3,561 | 1,243 | 6,943 |
| Cumulative Production 12-31-2015 | 18,966 | 1,795 | 10,984 |
| Proved Reserves | 2,634 | 179 | 12,700 |
| Ultimate Recovery 12-31-2005 | 21,600 | 1,974 | 23,684 |
| of which: | | | |
| Crude Oil | 21,168 | 1,934 | 23,684 |
| Condensate | 432 | 40 | - |

Oil sands development over the last decade has more than doubled Canada's ultimate recovery. However, the oil sands reserve additions shown in this table only include projects on stream now or those that will start production before 2015. They do not include highly potential, but undeveloped reserves.

Canada boasts immense potential for oil sands resources. Currently, three surface mines (Suncor, Syncrude, and Shell/Chevron's Muskeg River) and 13 in situ thermal projects are producing 674 Mbpd of synthetic crude and 515 Mbpd of bitumen. By 2015, expansions of existing projects, plus the addition of six mines, 10 in situ projects and several third-party upgraders are forecast to boost production to 2,174 Mbpd of synthetic crude and 473 Mbpd of bitumen. Currently, all of the oil sands projects are in Alberta, but exploration is spilling over into Saskatchewan.

At the end of 2006, Canada's bitumen reserves were estimated by the National Energy Board (NEB) to total 173.6 billion barrels (31.8 billion mineable and 141.8 billion in situ). However, reserves under active development were 10.2 billion barrels (7.6 billion mineable and 2.6 billion in situ), according to the NEB.

Presently, there are no functioning markets for bitumen pricing, thus most observers try to tie them to existing markets, such as for West Texas Intermediate (WTI). However, in practice, bitumen buyers and sellers come to terms for a volume of bitumen with specific properties to be delivered over a specified period. These terms have been confidential between the parties. Compounding this opaqueness, all bitumen from different sources are different, depending upon fines (sands, clays) content, sulfur content, etc. Different buyers have configured their upgraders to process different types of bitumen. For these reasons, it is difficult to forecast bitumen prices, especially as to how they will affect a specific project.

A study of a few oil sands operations has shown that bitumen sales prices in the neighborhood of $20 per barrel have produced good profits (after tax return of 15 percent) in past years. With recent skyrocketing costs, however, that same price would cause a project to become barely break-even. A return similar to those of the past would now require a bitumen price of about $31. With the bitumen-to-WTI differential averaging about 55 percent, this is equivalent to a WTI price of $56 per barrel.