PS Current and Future Perspectives on Recovery Growth from the Western Canada Sedimentary Basin*

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Oil Resource Base

The Western Canada Sedimentary Basin (WCSB, *senso lato* including contiguous mainland Northwest Territories successions) hosts large proven and potential conventional and non-conventional oil resources. The ultimate recoverable reserve continues to grow. The basin is inferred to host an original in place conventional oil resource of ~26.6 x 10^9 m^3 (168 x 10^9 bbls; Lee 1998; National Energy Board (NEB, 2001) (Figure 1), of which ~16.4 x $10^9 m^3$ (103 x 10^9 bbls) has been discovered (CAPP, 2005). These resources have been variably altered, most significantly by biodegradation, and heavy oil is 7.9 x 10^9 m^3 (50 x 10^9 bbls) of the original oil in place.

Oil Resource Base (Bitumen)

Alberta original in place bitumen accumulations are confidently estimated to be ~269 x 10^9 m^3 (1.7 x 10^{12} bbls; Marsh, 2006; AEUB, 2006; Procter et al., 1984, p. 48). Alberta original in-place bitumen reserves are estimated ~28.4 x 10^9 m^3, (179 x 10^9 bbls; Marsh, 2006; AEUB, 2006), although this may increase. The official estimate of bitumen reserves includes industrially recognized reserves that comprise at least 2.6 x 10^9 m^3 (16 x 10^9 bbls; CAPP, 2005) initial in-place *in-situ* bitumen, with no primary recovery, and surface mineable bitumen accumulations of ~1.44 x $10^9 m^3$ (9 x 10^9 bbls; CAPP, 2005).

Oil Resource Base (Other Resources)

Tertiary recovery of conventional oils is a minor effort, in part because of history, availability, and the cost of miscible fluids, but new efforts (Figures 2 and 3) are providing a previously ignored potential conventional oil resource, which competes for attention with the non-conventional resources.

Tertiary recovery efforts also compete with other potential non-conventional resources. Currently there are neither significant shale-oil nor oil-shale developments, although potential exists for both. Major bituminous shales occur across the WCSB, with the most significant occurring in Devonian Duverney, Devonian and Carboniferous Bakken/Exshaw, Jurassic Fernie, Upper Cretaceous Boyne and Favel (white speckled shales equivalent to Greenhorn and Niobrara) formations (Creaney et al., 1994). These formations produce small conventional volumes, but the shale-oil resource is neither well described nor exploited. Some bituminous formations are mineable oil shales, the upper Cretaceous being most important. There is no oil-shale resource estimate; yet outcrops are commonly 20-40 m thick, extending over hundreds of kilometres. Yields up to 100 litres oil/tonne were obtained from the Pasquia Hills, Manitoba (Macauley, 1984). Immense coal resources (Smith, 1989) host natural gas from coal that has begun to augment the gas supply. A reliable natural gas supply is important for several recovery technologies, particularly for bitumen, but in the future these coals may also be a source for synthetic oil.

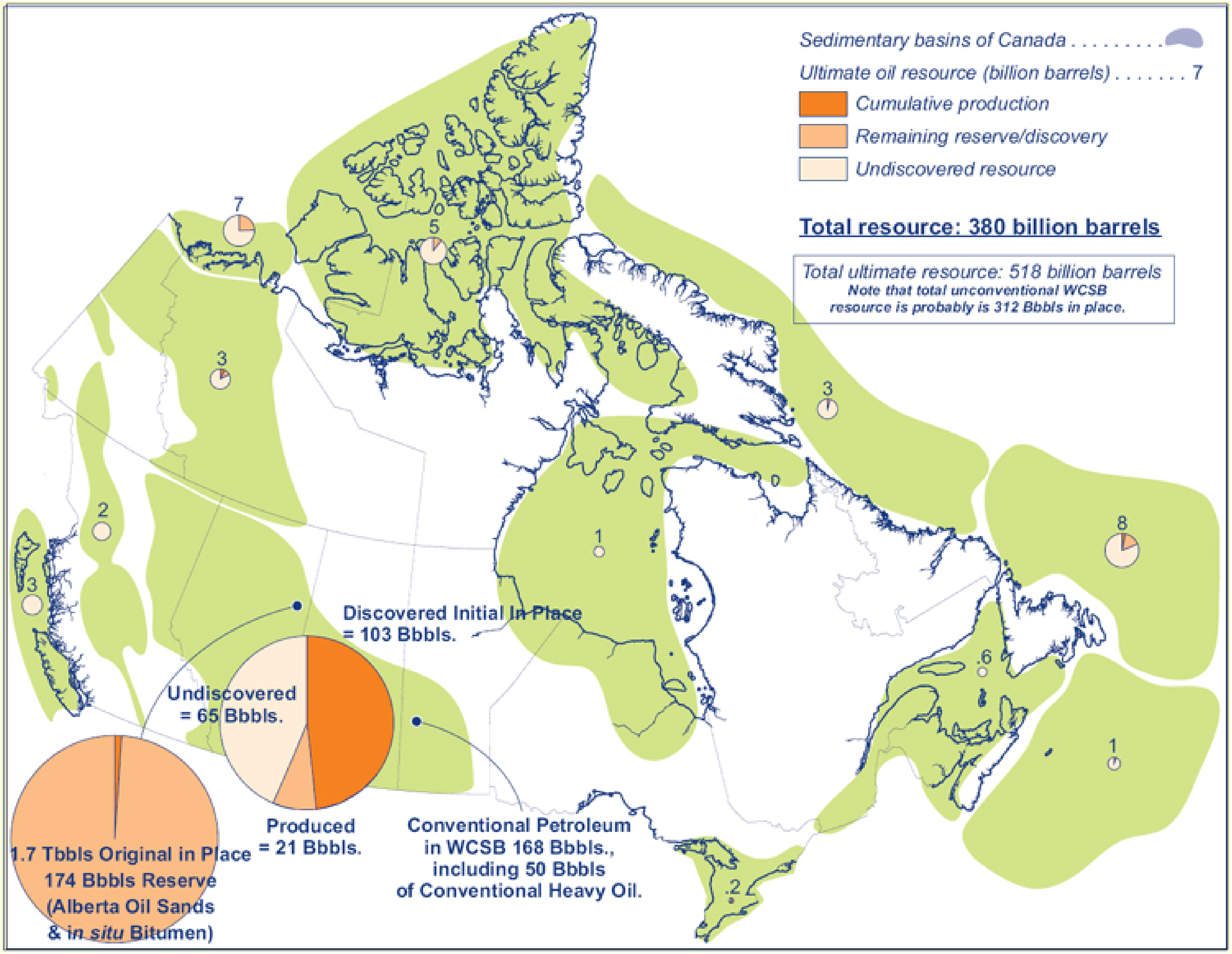

Figure 1. Geographic distribution of Canadian crude oil (area of circle proportional to initial in-place resource), bitumen and tar sands resources (area of circle proportional to current official reserve estimate). The majority of the resource occurs in the Western Canada Sedimentary Basin, south of 60° N. This presentation addresses enhanced recovery potential only in that region.

Figure 2. Photo of Weyburn field facilities.

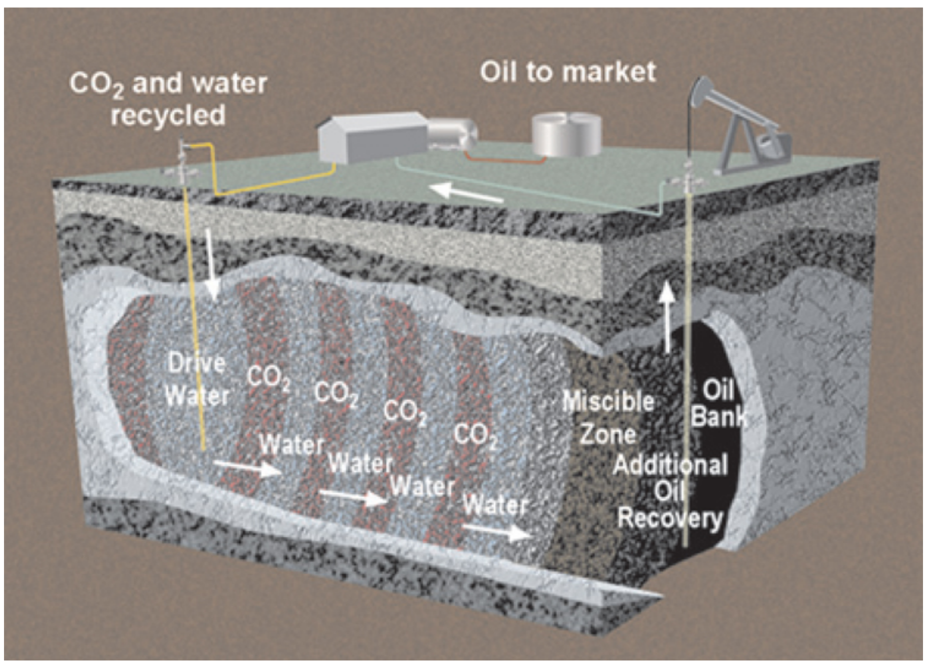

Figure 3. Illustration of successive CO_2 and water slugs injected at Weyburn.

Current Primary and Secondary Recovery:

Most production employs primary natural depletion, or secondary recovery, most commonly pressure maintenance. Primary recovery factors vary. The average WCSB primary RF is ~14%. The average is lower for heavy oils, where primary recovery can be 5% or lower. Typically, primary recoveries are ~16% for Paleozoic carbonates and even higher, exceeding 19%, for non-biodegraded Mesozoic reservoirs. Secondary recovery commonly adds an incremental 4%-10% recovery. Secondary recovery can be spectacularly effective, as in the Northwest Territories, where production comes primarily from Devonian carbonates and most of that from the Norman Wells reef. There secondary recovery increased the recovery from the 16% typical of Paleozoic carbonates to 46%, adding an incremental 15.2 x $10^6 m^3$ (96 x 10^6 bbls). Elsewhere secondary recovery results are more modest. Most of the incremental 957.8 x $10^6 m^3$ (6,034 x 10^6 bbls) from secondary recovery is from Alberta, where secondary recovery identified an incremental 652.0 x $10^6 m^3$ (4,108 x 10^6 bbls). In Saskatchewan 4% or 233.9 x $10^6 m^3$ (1,473 x 10^6 bbls) has been added mostly from Carboniferous subcrop pools. The use of secondary schemes in Manitoba has been negligible and only 1% or 1.3 x $10^6 m^3$ (8 x 10^6 bbls) is attributable to secondary recovery.

Future Recovery:

The WCSB is a potential target for established and new recovery and stimulation technologies, including, miscible floods, simulated horizontal wells, and SAGD/JIVE. A recent oil supply model (NEB, 2006) suggests WCSB oil supply will increase from 2005 volumes of 365 x 10^3m^3/day (2.3 x 10^6 bbls/day) to 613 x 10^3m^3/day (3.9 x 10^6 bbls/day) by 2015, due to increased bitumen production alone. The model suggests that conventional oil production will decline in spite of improved recovery (NEB, 1999; 2003). Still, the model suggests that future improvements in conventional light and heavy recovery will contribute 722 x 10^6m^3 to 794 x 10^6m^3 (4.55 x 10^9 bbls to 5.00 x 10^9 bbls; NEB 1999; 2003; CAPP, 2005). *This represents an incremental 16%-19% increase in recovery and a volume comparable to the remaining established reserve.* It implies that average recovery factor increases from 21%, currently, to 27.5%. The NEB (2001) increased conventional heavy oil 30% over previous resource estimates (Lee, 1998), and both heavy-oil and oil-sand resource bases may increase as technology develops. Shale oil and oil shale are not yet part of supply, and their input could add significantly to recovery growth. While encouraging, it will require much study and many more projects to know if the inferred recovery improvements can be commercial.

Current Tertiary Recovery:

Aside from a few projects, often technology demonstrations, tertiary recovery has not been applied widely (Figure 4). Overall, to the end of 2004, tertiary recovery produced only an incremental 209.0 x 10^6m^3 (1,317 x 10^6 bbls) accounting for less than one percent increase in recovery. Some regions, notably Manitoba, British Columbia, and the Northwest Territories have effectively no contribution from tertiary programs. This is not indicative of the tertiary programs, but rather it indicates the lack of their application. Tertiary programs have been historically restricted to Alberta, where projects added an incremental 176.9 x 10^6m^3 (1,071 x 10^6 bbls), resulting in a 2% increase in reserves. Alberta tertiary recovery projects do not include in-situ oil sands projects, such as cyclic steam stimulation project at Cold Lake, or Steam Assisted Gravity Drainage (SAGD) projects, which produced 203.5 x 10^6m^3 (1,282 x 10^6 bbls) bitumen by the end of 2004 (CAPP, 2005), all of which is attributed to tertiary recovery. The recoverable reserve of in-situ oil sands 534.8 x 10^6m^3 (3,369 x 10^6 bbls), is a small fraction of the initial in-place bitumen (ibid.).

Weyburn and Midale Projects

In Saskatchewan, the small incremental volume, 32.0 x 10^6m^3 (202 x 10^6 bbls) from tertiary programs conceals the importance of the Weyburn CO_2 sequestration and tertiary recovery project (Figures 2,3, 5). The project, in a Carboniferous carbonate pool, will produce an incremental 20.6 x 10^6m^3 (130 x 10^6 bbls), using miscible or near-miscible CO_2 displacement from a pool that produced 53.2 x 10^6m^3 oil (335 x 10^6 bbls) since 1955. Important recovery improvements accompanied the in-fill drilling program that preceded the CO_2 flood. The project extends field life by ~25 years, and recovery factor improves ~28%, from the CO_2 flood alone. It will permanently sequester ~20 million tonnes CO_2. Plans are underway to apply a similar scheme of enhanced recovery to the nearby and geologically similar Midale Field.

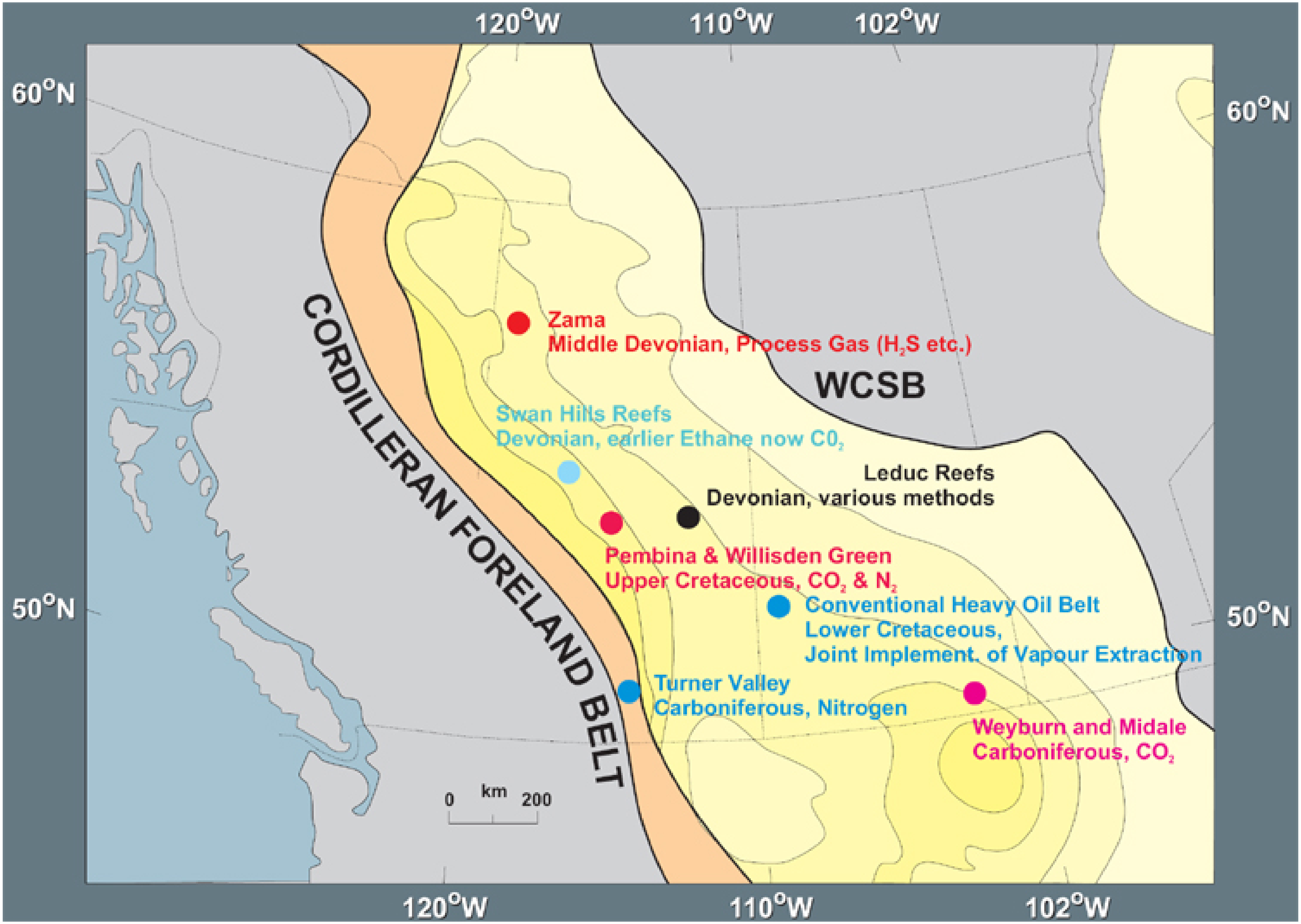

Figure 4. Map of the Western Canada Sedimentary Basin, indicating the thickness of the succession and the location of select planned, current, and historical programs of Tertiary recovery (generalized).

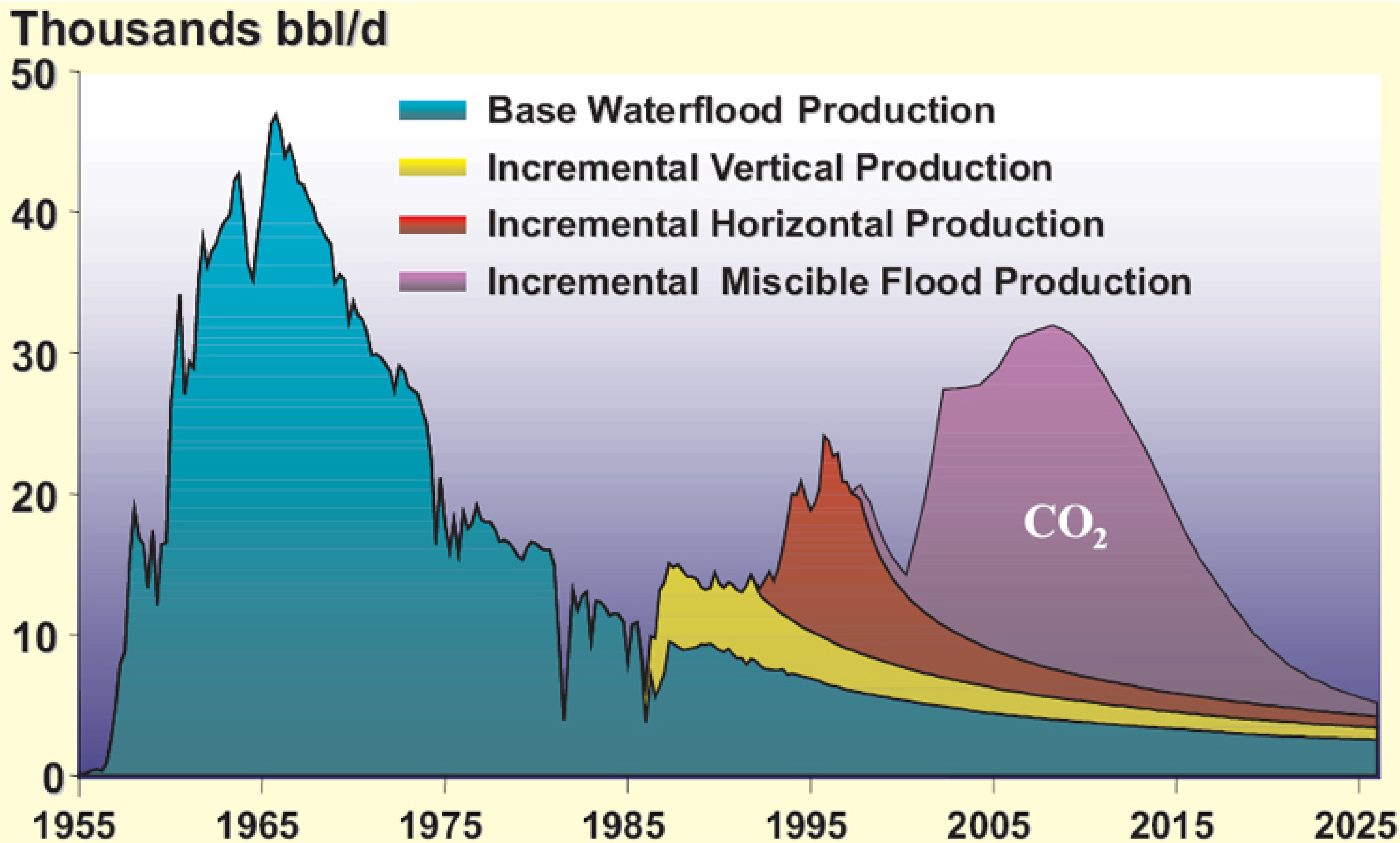

Figure 5. Production history and projections for the Weyburn field, distinguishing incremental improvements associated with various project phases.

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