Controls On The Variability Of Fluid Properties Of Heavy Oils And Bitumens In Foreland Basins: A Case History From The Albertan Oil Sands*

By

Jennifer Adams[1], Barry Bennett[1], Haiping Huang[1], Tamer Koksalan[1], Dennis Jiang[1], Mathew Fay[1], Ian Gates[1], and Steve Larter[1]

Search and Discovery Article #40275

Posted March 10, 2008

*Adapted from extended abstract prepared for AAPG Hedberg Conference, "Heavy Oil and Bitumen in Foreland Basins – From Processes to Products," September 30 - October 3, 2007 – Banff, Alberta, Canada

[1]Petroleum Reservoir Group and Alberta Ingenuity Centre of Insitu Energy, University of Calgary, Calgary, Alberta

General Statement

The world oil inventory is dominated by heavy oils and tar sand (HOTS) bitumens in foreland basins, generated almost entirely by the process of biodegradation. This process is a biologically driven, complex reactive diffusion-dominated, in-reservoir oil alteration process that occurs under anaerobic conditions (Aitken et al., 2004). It is driven by oil-water reactions, usually at the base of the oil column, producing methane and CO_2 as by-products and concentrating heavy oil components (Head et al., 2003). In any reservoir with a water leg and without having been pasteurized, large volumes of lighter hydrocarbon components are consumed by microbial metabolism at the oil-water contact (OWC) or transition zone, and this commonly results in significant vertical and lateral gradients in oil composition and thus oil viscosity (Larter et al., 2003, 2006a,b). The controls on progressive oil alteration and associated viscosity increase are related to the oil-charge composition and charge-rate history (Adams et al., 2006), mixing of fresh and biodegraded oils and diffusion of oil components (Koopmans et al., 2002), the extent of the water leg in the reservoir and nutrient supply, and the reservoir temperature history (Larter et al., 2003; 2006a). Temperature ultimately controls the rate of metabolism (decreases with increasing temperature) and survival of micro-organisms in the subsurface with reservoir pasteurization at temperatures of 80°C and greater (Wilhelms et al., 2001).

As a petroleum system evolves and biodegradation progresses, the complex interplay of these mass transport and biological processes leads to large spatial variation in fluid properties commonly seen across basins and at field and reservoir scales. The defining characteristic of heavy and super-heavy oilfields is the significant heterogeneities in fluid properties. For instance, viscosity can increase with depth by up to one hundred times across a 40-m thick reservoir (Figure 1c; Larter et al., 2006). Viscosity variations can often dominate the distribution of the oil phase mobility ratio (oil effective permeability:oil viscosity), which in turn controls production behavior under primary and thermal recovery. Surprisingly, traditional heavy oil and tar sand exploration and production strategies rely significantly on characterization of key reservoir heterogeneities and assessments of fluid saturations, but in most reservoir simulations and operation design, fluid properties are assumed constant! An ability to accurately predict the petroleum biodegradation levels, and thus pre-drill fluid properties, facilitates targeting of the most economic prospects for future development. Also, detailed spatial characterization of oil variability is crucial to developing recovery strategies, well placement, and production schedules to optimize recovery and minimize downstream costs.

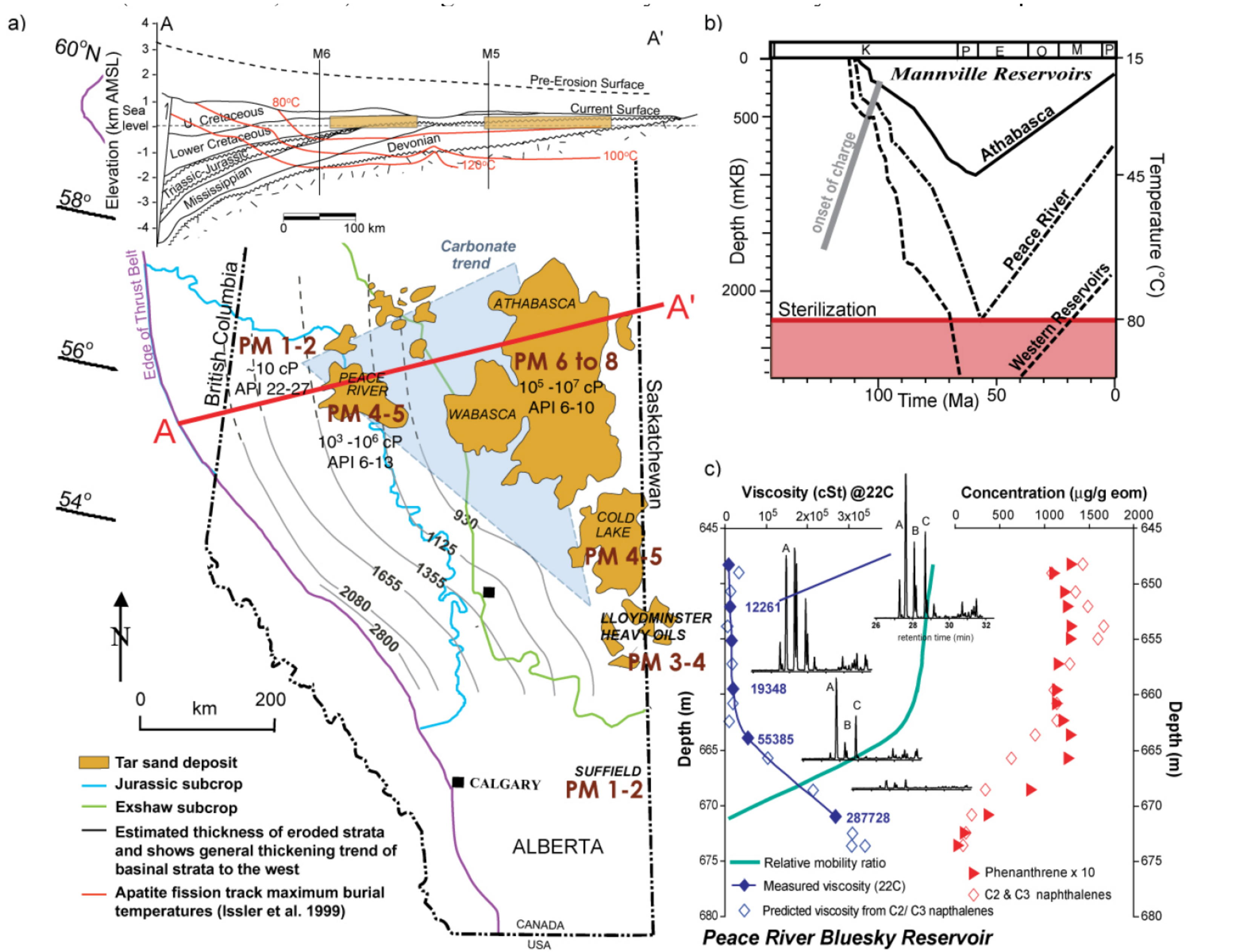

Figure 1. a) Map of Alberta oil sands showing level of biodegradation as PM level (Peters and Moldowan, 1993) and average fluid properties. Cross-section shows maximum burial temperatures as inferred from apatite fission track modeling (Issler et al., 1999). M5 and M6 are the location of the fifth and sixth meridians, respectively. b) Burial history curves, based on 1D thermal basin models, show how increasing temperature is related to limiting biodegradation. c) Viscosity increases and thus mobility (as a function of effective permeability) decreases by orders of magnitude with depth towards the OWC, and the associated variation in aromatic hydrocarbon concentrations is shown with preferential removal of these compounds by micro-organisms at the OWC.

Lower Cretaceous Reservoirs, Alberta Basin

Thermal history of a reservoir is a key control on petroleum biodegradation in the deep subsurface. In the Alberta basin, Lower Cretaceous sandstone reservoirs host over 1.3 trillion barrels of tar sands and heavy oils, which share a common source rock (Figure 1a) but exhibit varying levels of biodegradation (Brooks et al., 1990). In general, oil biodegradation levels increase to the east and north across Alberta, and oil quality decreases from API gravity of 6 in the eastern tar sands to 38 in the Gething Formation pools west of the Peace River tar sands. Burial history modeling predicts heating of these Gething reservoirs to temperatures over 80°C shortly after charging started, thereby effectively pasteurizing them prior to later uplift and reservoir cooling (Figure 1b); this explains the minimal or no biodegradation observed. In contrast, the nearby Peace River tar sands are heavily degraded and remain biologically active today; however, somewhat elevated reservoir temperatures (time average = 50°C; Figure 1b) and complete reservoir filling may have slowed degradation rates (Figure 2b). This thermal history ultimately led to preservation of essentially non-degraded oils in pasteurized Lower Cretaceous reservoirs to the west of the Peace River tar sand area, while heavily degraded oils are found in Peace River and severely degraded oils at Athabasca (Adams et al., 2006). The regional oil viscosity trends broadly also follow this pattern.

Numerical charge-degrade models for tar sand reservoirs along section A-A’ show that continuous long-term charge into these reservoirs and continued degradation until present day best explain the observed oil quality and volumes in the tar sands (Figures 2b-d), rather than instantaneous charge of oil (Figure 2a; Adams et al., 2006). Furthermore, the thermal history of the reservoir, including pasteurization of the westernmost reservoirs (Figure 2c) and decreasing temperature to the east (increasing degradation rates), are required to predict the measured API gravity and oil column heights (Figures 2b-d). Specifically, the Peace River reservoirs effectively need to be filled to slow degradation rates due to limited water legs, and Athabasca requires minor charge past maximum burial (Figures 2b and d).

Variations in biodegradation levels within fields are sometimes related to the transport and dissolution of mineral-buffered essential nutrients to the micro-organisms active at the OWC, which may limit the rate of biodegradation (Rogers et al., 1998; Larter et al., 2006). For example, some of the Gething reservoired oil has low Pristane/nC_{17} and Phytane/nC_{18} ratios, suggesting very slight degradation whereas the other nearby (within 2 to 3 km) Gething oils are slightly to moderately degraded and show loss of n-alkanes. The more degraded oils are underlain by at least a 1-m-thick waterleg or are laterally within 800 m of free water which fueled degradation by providing the necessary nutrients to the micro-organisms, while degradation in the slightly degraded oil columns was curtailed when these reservoirs were filled to the underseal.

There is interplay over geological timescales of oil charge history (oil residence time) and thermal and nutrient controls on degradation rates, along with local-scale mass transport dynamics of oil column mixing, via advective charge, biogenic gas generation, and diffusion of reactive hydrocarbons to the OWC field, reservoir and smaller scale biodegraded oil compositional variations (Figure 1c). Within heavy oil and bitumen-bearing reservoirs, a variety of vertical viscosity gradients are observed, the simplest of which can be defined by two end-member oils; i.e., fresh oil charged near the top of a reservoir (or if charge has stopped a less degraded oil near the top) and a lower quality, more degraded oil near the oil-water contact zone (Figure 1c; Larter et al. 2006b). These fluid property gradients are mimicked by various compositional gradients in specific compounds, depending on the biodegradation level of the oil and susceptibility to degradation of the compounds (Figure 1c). In reservoirs where oil removed by biodegradation has exceeded the rate of fresh oil charge, heavily biodegraded reservoirs commonly have a residual oil zone up to 20 m thick at the base of the oil column characterized by steeper gradients in oil composition and fluid properties than found in the main oil column and abundant evidence of biogeochemical processes. We describe the genesis of curved, parabolic or even exponential viscosity-depth profiles in western Canadian reservoirs where oil charge has terminated, compared to actively charging traps worldwide which exhibit more sub-linear viscosity-depth profiles. Compositional numerical models, including compound specific rates of biodegradation, related to molecular size, aqueous solubility, and partitioning of reactive compounds, predict compositional gradients with increasing degradation with accumulation of non-degradable resins and asphaletenes at the OWC, the generation of biogenic gas, and removal of light-end hydrocarbons faster than C_{11+} hydrocarbons and gas cap development (Figure 2c).

On field scales, significant lateral variations in viscosity of up to an order of magnitude have also been observed from networks of vertical delineation wells over 2 to 5 km distances. Viscosity variations may exhibit areal patterns; for example, lower viscosity “fingers” are often embedded between higher viscosity “islands” though the transitions are typically smooth and wavelike unless faulting is involved (Adams, 2007). Typically, lateral oil viscosity variations occur smoothly by factors of 2 to 10 times on a length scale of 500-1000 m laterally. Interaction of charging and degradation processes are continuous, forming graded transitions between the relatively high and low viscosity regions rather than distinct oil viscosity domains. The combination of intersecting viscous fluid domains and complex sedimentologically controlled permeability domains produces a complex mobility ratio domain in which any optimized oil recovery process must operate. The compositional gradients in highly viscous oils (>1000 cP) strongly impact the mobility of the oil especially in the high-water-saturation, residual oil zones where relative permeability and discontinuous oil limit the effective permeability even in thermal recovery operations at steam temperatures. The dynamics of the biodegradation basal reaction zone which can be several meters thick are described and its impact on the production of HOTS reservoirs and well placement in the lowest parts of a reservoir for thermal gravity drainage processes, such as SAGD or CSS.

References

Adams, J.J., Gates, I.D., and Larter, S., 2007, The impact of oil viscosity heterogeneity on production characteristics of tar sand and heavy oil reservoirs. Part II: Intelligent, geotailored recovery processes in compositionally graded reservoirs: CHOA Slugging It Out Meeting.

Adams, J.J., Fowler, M., Riediger, C. and Larter, S.R., 2006, The Canadian tar sands are limited by deep burial sterilization: Journal Geochemical Exploration, v. 89, no. 1-3, p. 1-4.

Aitken,C.M., Jones, D.M., and Larter, S.R.,2004, Anaerobic hydrocarbon biodegradation in deep subsurface oil reservoirs: Nature, v. 431, p. 291-294.

Bennett, B., and Larter, S.R.,2000, Quantitative separation of aliphatic and aromatic hydrocarbons using silver ion-silica solid-phase extraction: Analytical Chemistry, v. 72, no. 5, p. 1039-1044.

Brooks, P.W., Fowler, M.G., and MacQueen, R.W.,1990, Biomarker geochemistry of Cretaceous oil sands/heavy oils and Paleozoic carbonate trend bitumens, Western Canada Basin: Fourth UNITAR/UNDP Conference on Heavy Crude and Tar Sands, Edmonton, AB, p. 593-606.

Head, I.M., Jones, D.M., and Larter, S.R.,2003, Biological activity in the deep subsurface and the origin of heavy oil. Nature, v. 426, p. 344-352.

Huang H.P., Bowler B.F.J., Oldenburg T.B.P., and Larter S.R.,2004, The effect of biodegradation on polycyclic aromatic hydrocarbons in reservoired oils from the Liaohe basin, NE China: Organic Geochemistry, v. 35, no. 11-12, p. 1619-1634.

Koopmans MP, Larter S.R, Zhang, C.M., et al.,2002, Biodegradation and mixing of crude oils in Eocene Es3 reservoirs of the Liaohe basin, northeastern China: AAPG Bulletin, v. 86, no. 10, p. 1833-1843.

Larter, S., Wilhelms, A., Head, I., Koopmans, M., Aplin, A., Di Primio, R., Zwach, C., Erdmann, M., and Telnaes, N., 2003, The controls on the composition of biodegraded oils in the deep subsurface: (Part 1) Biodegradation rates in petroleum reservoirs. Org. Geochem. 34:601-613.

Larter, S., Adams, J.J., Gates, I.D, Huang, H., and Bennett, B.,2006a, CIPC origin and impact of fluid viscosity variations on production of heavy oils: JCPT in review.

Larter, S., Huang, H., Adams, J., Bennett, B., Jokanola, O., Oldenburg, T., Jones, M., Head, I., Riediger, C., and Fowler, M., 2006b, The controls on the composition of biodegraded oils in the deep subsurface: Part II - Geological controls on subsurface biodegradation fluxes and constraints on reservoir-fluid property prediction: AAPG Bulletin, v. 90, p. 921-938.

Rogers, J.R., Bennett, P.C., and Choi, W.J., 1998, Feldspars as a source of nutrients for microorganisms: American Mineralogist, v. 83, p.1532-1540.

Wilhelms, A., Larter, S., Head, I., et al., 2001, Biodegradation of oil in uplifted basins prevented by deep-burial sterilization: Nature, v. 411 (6841), p. 1034-1037.

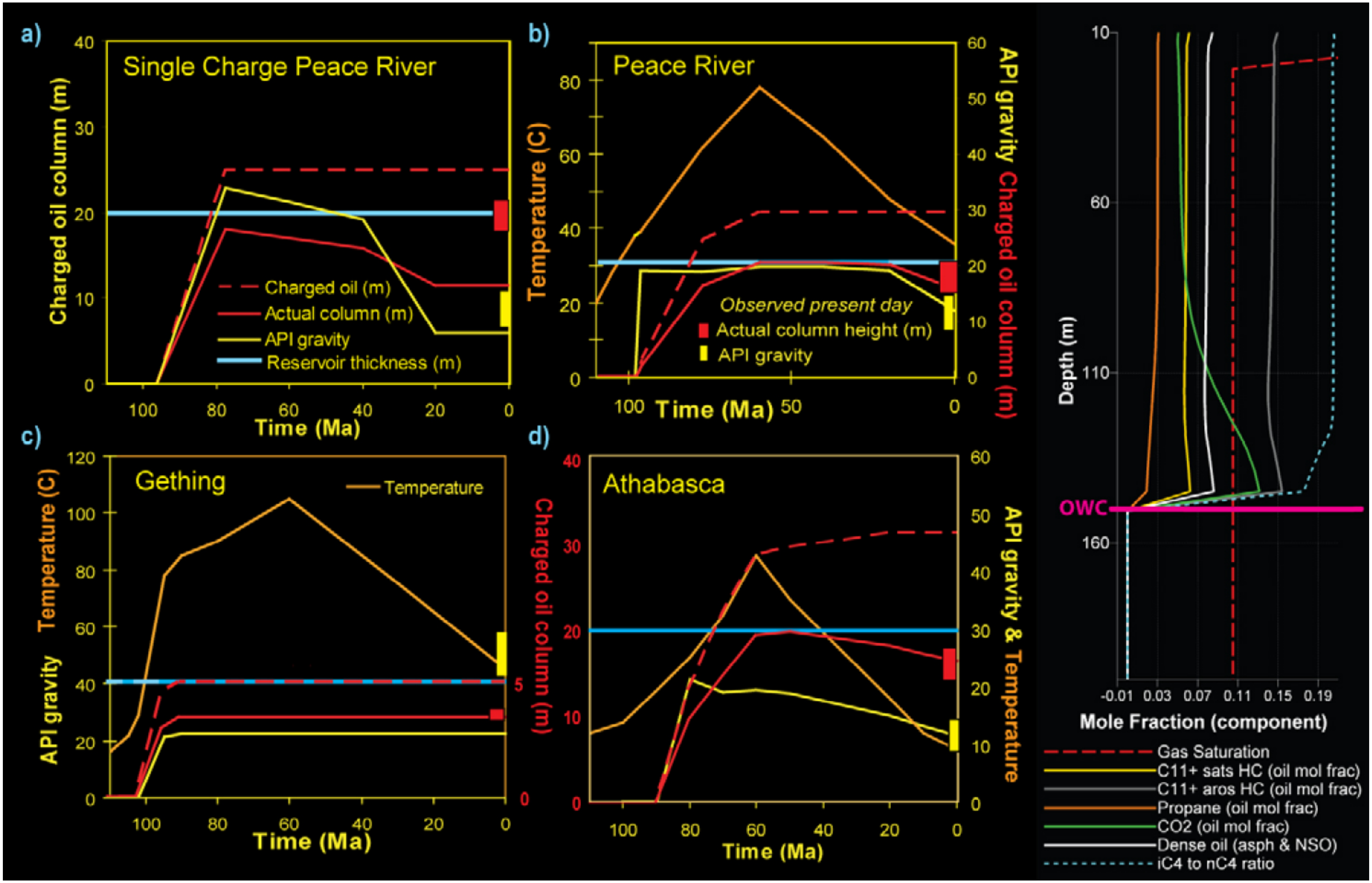

Figure 2. Charge-degrade models (see Larter et al. 2006a for details) for Alberta tar sand reservoirs, showing cumulative charged oil, remaining (actual) oil column in terms of oil column height in the context of oil quality and reservoir temperature: a) assumes a single instantaneous charge of all oil at 95 Ma and degradation to present day for Peace River; b) continuous charge into Peace River until maximum burial (60 Ma) and simultaneous degradation to present day; c) pasteurization of Gething reservoirs curtails degradation shortly after charge starts; and d) Athabasca reservoirs exist at optimal conditions for degradation and require charge after maximum degradation. The concentration-depth profile for oil components after 65 kyr of degradation show slight accumulation of non-degradable dense oil near the OWC and preferential removal of propane and n-butane over i-butane, with lesser alternation of C_{11+} hydrocarbons, generation of CO_2 and formation of gas cap.