CONTENTS

Timing and petroleum sources for the Lower Cretaceous Mannville Group oil sands of northern Alberta based on 4-D modeling

Debra K. Higley, Michael D. Lewan, Laura N. R. Roberts, and Mitchell Henry

ABSTRACT

The Lower Cretaceous Mannville Group oil sands of northern Alberta have an estimated 270.3 billion m^3 (BCM) (1700 billion bbl) of in-place heavy oil and tar. Our study area includes oil sand accumulations and downdip areas that partially extend into the deformation zone in western Alberta. The oil sands are composed of highly biodegraded oil and tar, collectively referred to as bitumen, whose source remains controversial. This is addressed in our study with a four-dimensional (4-D) petroleum system model. The modeled primary trap for generated and migrated oil is subtle structures. A probable seal for the oil sands was a gradual updip removal of the lighter hydrocarbon fractions as migrated oil was progressively biodegraded. This is hypothetical because the modeling software did not include seals resulting from the biodegradation of oil.

Although the 4-D model shows that source rocks ranging from the Devonian–Mississippian Exshaw Formation to the Lower Cretaceous Mannville Group coals and Ostracode-zone-contributed oil to Mannville Group reservoirs, source rocks in the Jurassic Fernie Group (Gordondale Member and Poker Chip A shale) were the initial and major contributors. Kinetics associated with the type IIS kerogen in Fernie Group source rocks resulted in the early generation and expulsion of oil, as early as 85 Ma and prior to the generation from the type II kerogen of deeper and older source rocks. The modeled 50% peak transformation to oil was reached about 75 Ma for the

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Gordondale Member and Poker Chip A shale near the west margin of the study area, and prior to onset about 65 Ma from other source rocks. This early petroleum generation from the Fernie Group source rocks resulted in large volumes of generated oil, and prior to the Laramide uplift and onset of erosion (~58 Ma), which curtailed oil generation from all source rocks. Oil generation from all source rocks ended by 40 Ma. Although the modeled study area did not include possible western contributions of generated oil to the oil sands, the amount generated by the Jurassic source rocks within the study area was 475 BCM (2990 billion bbl).

INTRODUCTION

The Western Canada sedimentary basin (WCSB) is a foreland basin located in Alberta, southeastern British Columbia, and Saskatchewan. The oil sands of northern Alberta cover more than 140,000 km^2 (54,054 mi^2) and contain about 270.3 billion m^3 (BCM) (1701 billion bbl) of in-place bitumen (Alberta Energy and Utilities Board, 2007). These resources are primarily in the Athabasca, Cold Lake, and Peace River accumulations (Figure 1). Tar is viscous petroleum, informally termed bitumen, which resulted from biodegradation of oil that migrated into the unconsolidated sands. Conventional original oil in place (OOIP) and oil reserves for the Lower Cretaceous Mannville Group in Alberta are 3.079 BCM (19.37 billion bbl) and 0.526 BCM (3.3 billion bbl), respectively (Alberta Energy and Utilities Board, 2007). Oil sands account for 98.5% of the in-place crude oil in the province (Hitchon, 1984), with reserves estimated at 258.9 BCM (1630 billion bbl) (Selby and Creaser, 2005) to 269.4 BCM (1690 billion bbl) (Riediger, 1994).

Considerable controversy exists as to the source(s) of these immense bitumen accumulations, as indicated by the following (the Gordondale Member is in parentheses because the member status of this area was subsequent to the publications): (1) Creaney and Allan (1990, 1992) evaluated petroleum source rocks for Mannville reservoirs based on geologic and geochemical characteristics and listed the relative order of contributions (highest first) as (a) Nordegg (Gordondale) Member of the Jurassic Fernie Group, (b) Devonian–Mississippian Exshaw Formation and possibly the (c) Devonian Duvernay Formation of the Woodbend Group, and (d) Triassic Doig Formation. (2) Riediger (1994) concluded that the Nordegg (Gordondale) Member did not contribute sufficient petroleum to fill all the oil sand accumulations, just merely enough for a Mannville

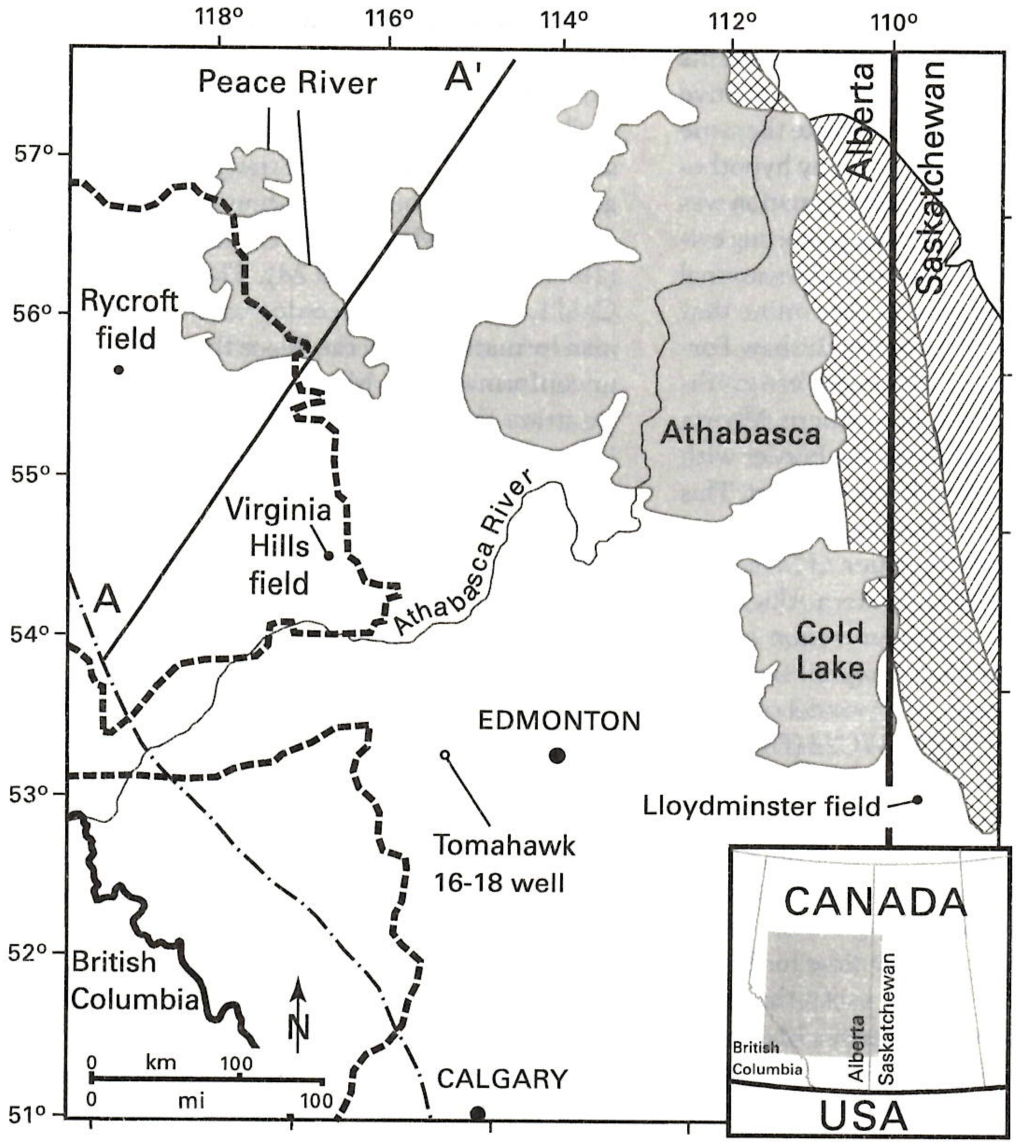


Figure 1. Study area in the Western Canada sedimentary basin is shaded gray on the inset map. Bold dashed lines enclose areas containing Gordondale (north) and Poker Chip A (south) petroleum source rocks of the Jurassic Fernie Group. The generalized locations of oil sands (shaded) are from Wallace-Dudley (1981a, b) and Oil Pools of Western Canada (1981). The Tomahawk 16-18 (16-18-52-5W5) well location is for Figure 3. AA′ is the line of cross section for Figure 5. The dash-dotted line is the eastern limit of the Mesozoic deformation that was used as a closed fault in the modeling. The diagonal line and cross-hatch fill are, respectively, the complete and partial erosion of the Prairie Evaporite Formation of the Devonian Elk Point Group (Meijer Drees (1994).

Group interval within the Peace River oil sands. This conclusion is based mostly on hypothesized very short migration distances of Nordegg (Gordondale) oil. (3) Riediger et al. (2001) used biomarkers to conclude that the main source rock was the Exshaw Formation, although there may be minor contributions from other source rocks. (4) Du Rouchet (1985) indicated that Triassic black shales, such as those in the Doig Formation, were the main source of the oil sand accumulations based on their geochemical homogeneity, and that petroleum was also contributed from the Devonian Wabamun Formation and Cretaceous Colorado Shale. (5) Thode et al. (1958) and Vigrass (1968) determined that Devonian (Woodbend Group) strata are not a probable source because these low-sulfur source rocks could not produce the high sulfur content of the oil sands.

The estimated timing of oil generation and migration into the oil sands is also controversial. Selby and Creaser (2005) used the decay rate of ^{187}Re to ^{187}Os to date the emplacement of oil into the Mannville Group oil sands at 112 ± 5.3 Ma. Selby and Creaser (2005) concluded that (1) dating results do not support oil generation and migration into the Lower Cretaceous Mannville oil sand deposits during the Late Cretaceous and (2) the distinctive isotopic signatures of the samples indicate the same or similar sources for the oil sands. They hypothesized that the Mississippian Exshaw Formation was the initial source but did not include supporting evidence. Riediger et al. (2001) used one-dimensional (1-D) burial history modeling to determine that peak petroleum generation from the Exshaw Formation occurred in northern Alberta before southern Alberta. Peak generation in northern Alberta was between 110 and 80 Ma near the border with British Columbia but much earlier to the west. This indicates that significant petroleum generation and migration occurred during deposition of Mannville Group strata (119–105 Ma) in eastern Alberta.

Source(s) and timing of oil generation results for the Cretaceous Mannville Group oil sands are based on a four-dimensional (4-D) model of about 498,000 km^2 (192,279 mi^2) of the WCSB (Figure 1).

The primary focus of this article is on source rock contributions to the oil sands from the Gordondale Member and Poker Chip A shale of the Poker Chip Shale Member, Jurassic Fernie Group; although oil and gas generation, migration, and accumulation were modeled through time for Devonian through Cretaceous source rocks that may have contributed to Lower Cretaceous Mannville Group reservoirs. Creaney et al. (1994) indicated that the Jurassic Poker Chip Shale contains petroleum source rocks. Oil-prone source rocks in the Fernie Group are in the Gordondale Member (Riediger et al., 1990a) and the overlying Poker Chip A shale (Riediger, 2002). Locations of these modeled lithofacies are shown in Figure 1. The Nordegg Member is the stratigraphically equivalent section south of the Gordondale Member (Asgar-Deen et al., 2004). The Nordegg Member was not defined in the model as a source rock. The 4-D model layer that contains the Nordegg and Gordondale members is named Nordegg/Gordondale (Figure 2). The Gordondale Member is the only area of the Nordegg/Gordondale layer from which oil has been generated and expelled. Likewise, only the Poker Chip A area (Figure 1) in the Poker Chip Shale Member layer is a petroleum source rock.

GEOLOGICAL BACKGROUND

The Lower Cretaceous Mannville Group (Figure 2) is a heterogeneous mix of mainly fluvial to marine sandstone and shale beds. Stratigraphic and other geologic framework information for the group, and assigned to the Mannville layers, is from Hayes et al. (1994, figures 19.22, 19.24). The Athabasca and Cold Lake oil sands unconformably overlie Devonian formations, and the Peace River oil sands are unconformable on Mississippian through Jurassic strata (Vigrass, 1968). The Athabasca, Cold Lake, and Peace River oil sands of northern Alberta (Figure 1) are mainly bitumen-saturated unlithified sands of the Mannville Group. Athabasca and Cold Lake oil sands are primarily within the Clearwater and underlying McMurray formations and equivalent strata, which overlie the sub-Mannville unconformity (Figure 2). Hodgson (1954a, p. 1) stated that the McMurray Formation "consists of unconsolidated sands with interbeddings of clays and shales." The porosity of these oil sands is primarily saturated with as much as 85% by 7° API black oil and 15% water. Porosity in the cleanest sands generally ranges between 30 and 35% (Ranger and Gingras, 2006).

Initial trapping mechanisms were mainly stratigraphic pinch-outs of sandstones against shales or within valley-fill sequences that overlie the sub-Mannville unconformity (Figure 2), which is the case for the Peace River deposit. Other trapping mechanisms include subtle structures like those in the Athabasca deposit (Vigrass, 1968) or combinations of stratigraphic pinch-outs with subtle structures. Vigrass (1968) indicated that a significant part of the Athabasca oil deposit is associated with structures resulting from the dissolution of Devonian Elk Point Group evaporites (Figure 2) that preceded Mannville deposition.

METHODS AND INPUT

Modeling Approach

The purpose of the petroleum system modeling is to recreate the oil generation, expulsion, migration,

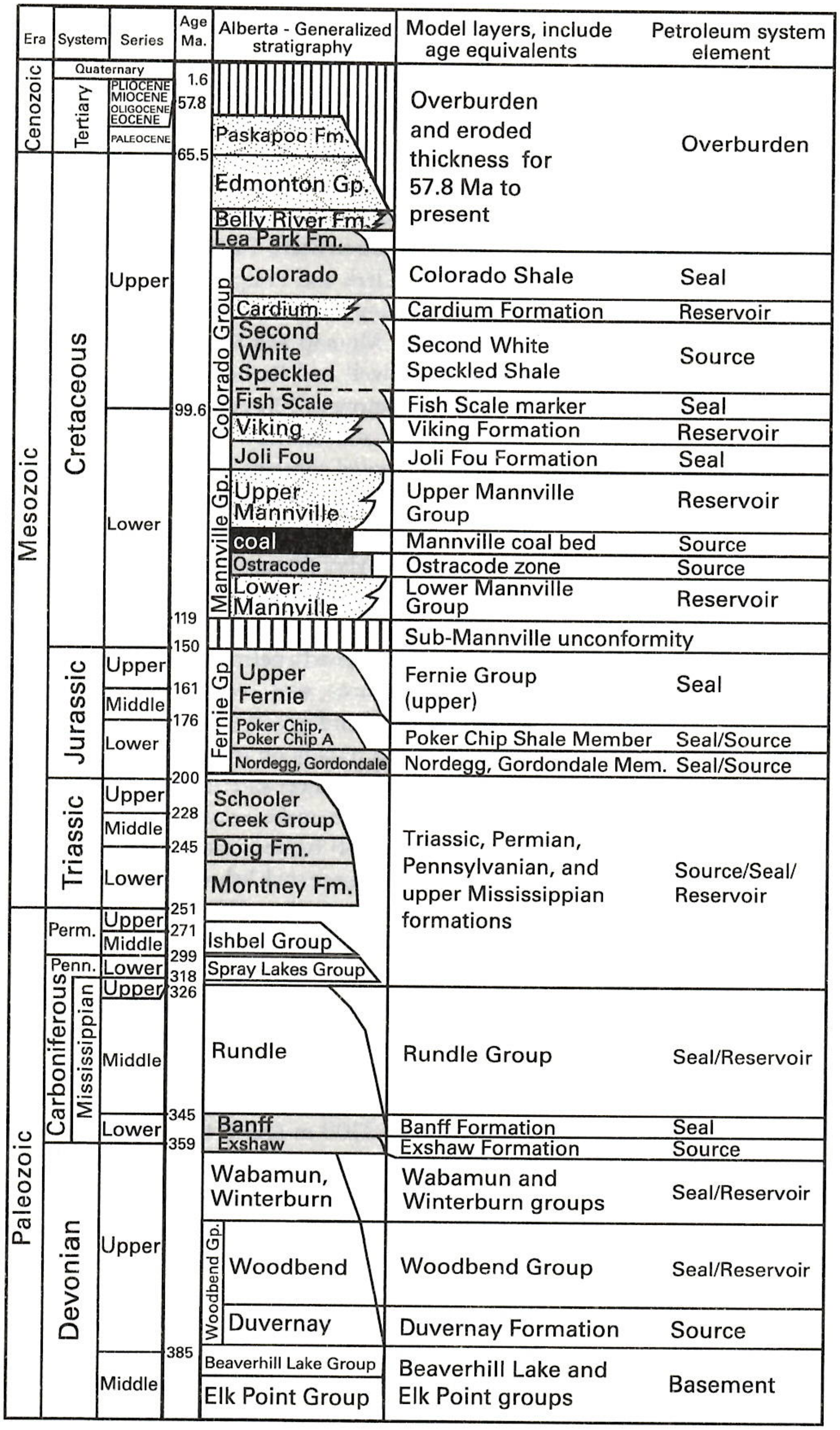


Figure 2. Generalized stratigraphic section of Alberta. Vertical stripes are erosional unconformities used in this study. Lithologies include primarily shale or marl (gray), sandstone (stipple), carbonates (white), and coal (black). Mossop and Shetsen (1994) were the primary source for lithofacies distribution across and composition for each model layer.

and accumulation history for all modeled petroleum source rocks in the study area. The model shows spatial and temporal changes in levels of thermal maturation and extent of oil generation based on hydrous pyrolysis (HP) kinetic parameters for the major source rocks. The model infrastructure incorporates data and influences through time of (1) basal heat flow, (2) water depth, (3) surface temperature, (4) time and extent of deposition and erosion, (5) vertical and lateral lithologic characteristics within each layer, (6) profiles of lithofacies decompaction through time, and (7) geochemical characteristics for each source organofacies, such as total organic carbon (TOC) content and hydrogen index (HI). All of this information (Higley et al., 2006) was integrated using the Integrated Exploration Systems (IES) software. Relative strengths and weaknesses of petroleum system modeling are discussed by Higley et al. (2006).

Two erosional event layers that were important for petroleum generation and migration into the Mannville Group reservoirs are included in our model. The sub-Mannville unconformity represents the time interval from about 150 to 119 Ma. We assigned only a minimal loss of strata by erosion (200 m, 656 ft) because regional vitrinite reflectance (R_o) profiles indicated that erosion was either not a significant factor or that it occurred prior to onset of petroleum generation from underlying source rocks. The uppermost layer in the model represents the thickness and distribution of strata that have been eroded from the late Paleocene (58 Ma) to the present based on 1-D burial history reconstructions across the WCSB (Higley et al., 2005a; Roberts et al., 2005). Intervals within the 4-D model are generally not as detailed as the original 1-D models. For that reason, 1-D extractions from the 4-D model were again calibrated to R_o and temperature data, and this information was used to further calibrate heat flow and thickness of Tertiary erosion across the study area.

Much of the kitchen area for Alberta is in the deformed zone and under the Canadian Rockies (west of the dash-dotted line of Figure 1). This area is underexplored, so associated layer thicknesses and lithologies are generalized. Modeled layers do not extend into northwestern Alberta, which reflects the western boundary of our original well database. Data sources for model layers include Mossop and Shetsen (1994), Riley Electric Log Database (1996), and IHS Energy (2004a, b). Dynamic Graphics® Earthvision® (Dynamic Graphics® and Earthvision® are registered trademarks of Dynamic Graphics, Inc.) and PetroMod® software (IES, 2006) were used to construct the 4-D petroleum system model. Sources of lithology, age, and heat flow assignments include Exploration Staff, Chevron Standard Limited (1979), Clark and Philp (1989), Obradovich (1991), Creaney and Allan (1992), Bloch et al. (1993, 1999), Mossop and Shetsen (1994), Glass (1997), Blackwell and Richards (2004), and the Table of Formations of Alberta (unpublished work, 2008, AGAT Laboratories).

The 4-D model contains 22 isopach layers representing formation intervals from the Middle Devonian (380 Ma) to the present and two erosional-event isopach layers (Figure 2), all of which were stacked vertically relative to the elevation at the top of the Mannville Group. Each lithofacies within each layer was assigned a petroleum system element of reservoir, source, seal, overburden, or underburden. Vertical and lateral facies assignments for layers are based mostly on mapped and tabulated lithofacies from Mossop and Shetsen (1994); in a general sense, our model is an area of the Geologic Atlas of the WCSB turned into a 4-D petroleum system model. Source rock lithofacies were further assigned properties such as HIs, TOC, and kinetic parameters. Thicknesses of erosion and basal heat flow values through time were based mainly on results of 33 1-D burial history models across the WCSB (Higley et al., 2005a; Roberts et al., 2005). The thickness of Tertiary erosion along and west of the deformed belt in our study area ranged from about 1600 to 2300 m (5249 ft to 7576 ft). The eroded thickness decreases to the northeast, about 600 m (1970 ft) in the northeastern corner of the study area, and thins to 0 m northeast of the study area, proximal to the Precambrian shield. Our maximum rate of erosion proximal to the deformed belt is about 0.039 mm/yr and about 0.017 mm/yr in western Saskatchewan. Our rates are comparable to the Bekele et al. (2002) computed maximum uplift and erosion rates of 0.048 mm/yr in west-central Alberta and 0.022 mm/yr in western Saskatchewan, which were based on Nurkowski's (1984) erosional estimates and compaction parameters from Sclater and Christie (1980).

Source Rocks

The major petroleum source rocks considered in this study are based mostly on the work of Creaney and Allan (1992), Creaney et al. (1994), and Riediger et al. (1997). Modeled source rocks are the (1) Duvernay Formation of the Devonian Woodbend Group, (2) Devonian–Mississippian Exshaw Formation, (3) Triassic Doig Formation (Phosphate zone and Whistler members), Jurassic Fernie Group ([4] Gordondale Member and [5] Poker Chip A shale), and Cretaceous Mannville Group ([6] coals and [7] Ostracode zone) (Figure 2). The Second White Speckled Shale was modeled but is not included as a source rock in this article because it did not contribute petroleum to the Mannville Group or deeper accumulations, mostly because of the seal capacity of the marine shales of the Fish Scale and Joli Fou Formation that overlie the Mannville Group (Figure 2). The Joli Fou is the major regional seal for the Mannville and older strata (Creaney and Allan, 1990). Middle Devonian source rocks (e.g., Keg River and Muskeg formations) were also not considered because their petroleum systems (Fowler et al., 2001) lie outside the study area.

Source rock thicknesses are for the assigned lithofacies within the model layer and are not subdivided vertically. These intervals are typically greater than those of the source rocks. To correct this potential exaggeration of source rock potential in the model, weighted mean TOC and HI were calculated for the thicker modeled intervals of each source rock.

Coals and the Ostracode Zone of the Cretaceous Mannville Group

According to Moshier and Waples (1985), the Mannville Group ranges in thickness westward from 150 to 300 m (492 to 984 ft) in eastern Alberta to more than 600 m (1968 ft) near the west margin of the WCSB. Coals and the Ostracode zone were modeled as two separate layers within the group (Figure 2). A coal layer within the Mannville Group is the only gas-prone source rock considered in this study, which emphasizes oil. Only generated oil is reported for this and other source rocks. The coal layer varied in thickness to as much as 10 m (32 ft) and averaged 4.9 m (16 ft). The greatest thickness was in the northwest corner of the study area. The modeled TOC and HI were 60 wt.% and 200 mg HC/g TOC, respectively.

Riediger et al. (1997) characterized the ostracode zone as composed of TOC-lean beds containing type III kerogen, with interbeds of TOC-rich beds containing type I and II kerogen. They used TOC and Rock-Eval analyses from a core in a 20-m-thick (66-ft-thick) Ostracode zone section in well 6-33-35-25W4 as an example of these intercalated beds (Riediger et al., 1997). Rock-Eval pyrolysis T_{max} values less than 435°C are indicative of thermally immature source rocks. Modeled thickness-weighted mean TOC and HI values for thermally immature (T_{max} <435°C) (Peters, 1986) cores of the ostracode zone are 2.79 wt.% and 317 mg HC/g TOC, respectively. These weighted means are for a total of 63.8 m (209.4 ft) of sampled core from a wide geographical area of thermally immature strata in Alberta.

Gordondale and Poker Chip Shale Members of the Fernie Group

Oil-prone source rocks in the Fernie Group are in the Gordondale Member (Riediger et al., 1990a) and the Poker Chip A shale of the Poker Chip Shale Member (Riediger, 2002) (Figure 2). Respective source rock areas and lithofacies assignments are modified from Poulton et al. (1994, figures 18.19, facies 1, and 18.20, facies 2). The Gordondale Member is generally north of the Athabasca River (Figure 1), whereas the stratigraphically equivalent Nordegg Member lies to the south (Asgar-Deen et al., 2004). Nordegg lithofacies were designated as seal rocks. The Nordegg/Gordondale layer grid includes the Nordegg and Gordondale lithofacies and ranges in thickness up to 67.7 m (220 ft), with a median thickness of 26.0 m (85 ft), based on 1258 well control points using the Mossop and Shetsen (1994) data set. Gordondale source rock facies are as much as 35 m (115 ft) thick (Riediger, 1994), and cross sections by Riediger et al. (1990a) show a mean thickness of 24.0 ± 4.2 m (78.7 ± 13.7 ft). Most of the variation appears to be in the limestone unit that typically is in the middle of the Gordondale. The northwestern extent of the Gordondale Member is truncated by the boundaries of our study area. This excluded area also contains some of the thickest section of the Nordegg Member (Poulton et al., 1994). Subsidence of the underlying Dawson Creek graben complex, located west of the Peace River oil sands (Figure 1), and other structures that were active during deposition may have resulted in the increased thickness (O'Connell, 1994) and lateral facies variations of the Fernie Group (Poulton et al., 1990).

Gordondale data from six wells (well 11-19-85-3W6 [Table 1], 16-27-88-7W6, 16-5-81-24W5, 2-14-82-2W6, 10-17-84-22W5, and 6-8-87-3W6) had an average T_{max} <435°C and similar mean TOC and HI of 15.9 wt.% and 740 mg HC/g TOC, respectively (Riediger, 1990). We used these values in the model for the Gordondale source rock properties. The mean TOC and HI values published by Riediger (1994) for the thermally immature Gordondale (T_{max} <435°C) are 16 wt.% and 759 mg HC/g TOC, respectively. Reported respective TOC and HI values of thermally immature samples of the Gordondale were as much as (1) 23.5 wt.% and 600 mg HC/g TOC (Riediger et al., 1989); (2) 28 wt.% and 800 mg HC/g TOC, based on our evaluation of 200 Gordondale samples that were reported by Riediger et al. (1990a); and (3) 27 wt.% and 600 mg HC/g TOC (Creaney and Allan, 1990).

The Poker Chip A shale of the Jurassic Poker Chip Shale Member (Figure 1) consists of marine calcareous shale and thin limestone of south- and west-central Alberta that are potential source rocks (Riediger, 2002). Outcrops in the foothills of southern Alberta contain TOC as high as 4.9 wt.% (Stronach, 1984). Riediger (2002) attributed this maximum value to overmaturity and suggested that immature equivalents could have had TOC values greater than 10 wt.% and estimated TOC and HI as much as 18.5 wt.% and 740 mg HC/g TOC, respectively. Except where removed by erosion, the Poker Chip Shale Member overlies the Nordegg and Gordondale members. Riediger (1994) stated that the Poker Chip Shale is not an effective seal, and that upward migration of petroleum from the Gordondale occurs where the Poker Chip Shale was removed by erosion. The Upper Jurassic (Kimmeridgian) Fernie Group shales located east of our study area contain TOC as much as 4.4 wt.% (Rosenthal, 1989). The median thickness of the Poker Chip Shale Member layer is 15.8 m (51.8 ft), with an average thickness of 26.0 m (85 ft), based on isopach data from 405 wells (Mossop and Shetsen, 1994). The Poker Chip A source rock interval in the model (Figure 1) is from Poulton et al. (1994) and is characterized as a silty, slightly dolomitic, and calcareous shale. Mean TOC and HI of 7.36 wt.% and 553 mg HC/g TOC were used for the Poker Chip A petroleum source facies in the model. These conservative estimates were based on a 50% loss from the mean TOC of 3.68% for overmature Poker Chip A shale at the Bighorn Fall site (Riediger, 2002) (Table 1) and the HI for well 10-20-39-3W5.

Phosphate Zone, Triassic Doig Formation

The Triassic Doig Formation (Figure 2) consists of an upper siltstone unit with low TOC (<2 wt.%) and a lower shale unit with high radioactivity and high TOC (2–11 wt.%) (Riediger et al., 1990b). The lower shale is referred to as the Phosphate zone and is considered to be the source rock for oil in some Triassic reservoirs (Riediger et al., 1990b). Doig source rocks are only present near the western margin of the study area. Lithofacies areas and characteristics are based on Edwards et al. (1994). The Doig is 78 m (256 ft) thick and the basal phosphate zone is 39 m (129 ft) thick in the type section (Texaco N.F.A. 7 Buick Creek, 6-26-87-21 W6) (Riediger et al., 1990b). Mean TOC and HI values were 2.9 wt.% and 446 mg HC/g TOC, respectively, based on analyses of four cores from the Phosphate zone (wells 6-4-72-3W6, 10-5-84-11W6, A-59-G/94-A-16 [Riediger, 1990b], and D-48-H/9-H-1 [Table 1]).

The Whistler Member of the Sulfur Mountain Formation, located west of the deformation belt, is the equivalent to the Phosphate zone (Figure 1). This member also has high TOC, but measured

Table 1. Location, Rock Analyses, Kerogen Analyses, and Hydrous Pyrolysis Kinetic Parameters for the Composite Samples of the Major Source Rocks*

Formation/Group	Mannville Group	Fernie Group	Doig Formation	Exshaw Shale	Duvernay Formation
Member/Zone	Ostracode	Gordondale	Phosphate	Lower black shale	Undifferentiated
UWI**	5-18-37-7W4	11-19-85-3W6	D-48-H/9-H-1	12-1-9-20W4	10-27-57-21W4
Depth (m)	991.6–0991.8	1057.5–164.5	1052.8–1055.9	1474.5–1478.1	1140.5–1158.2
Number of samples	2	10	7	6	15
Rock Analyses					
Leco TOC (wt.%)	3.4	18.1	3.1	8.2	6.9
Rock-Eval analysis					
S_1 (mg/g rock)	0.67	4.00	1.30	4.25	1.61
S_2 (mg/g rock)	22.89	120.14	15.15	52.21	38.69
S_3 (mg/g rock)	0.83	1.45	0.61	0.46	1.71
T_{max} (°C)	434	419	436	419	413
HI (mg S_2/g TOC)	669	664	490	633	564
OI (mg S_3/g TOC)	24	8	20	6	25
PI ($S_1/[S_1 + S_2]$)	0.03	0.03	0.08	0.08	0.04
Kerogen Analyses					
Kerogen type	Type I/II	Type IIS	Type II	Type II	Type II
Elemental analysis					
C (wt.%)	76.07	74.73	79.12	78.90	76.66
H (wt.%)	8.95	8.11	7.95	7.78	7.41
N (wt.%)	0.92	1.34	2.05	2.68	3.54
O (wt.%)	8.17	4.50	5.68	5.98	10.04
S_{org} (wt.%)	5.90	11.32	5.20	4.66	2.35
Atomic ratios					
H/C	1.41	1.30	1.21	1.18	1.16
O/C	0.081	0.045	0.054	0.057	0.098
S_{org}/C	0.029	0.057	0.025	0.022	0.012
Hydrous Pyrolysis Kinetic Parameters					
E_a (kcal/mol)†	50.4	37.5	52.3	53.7	58.3
Log A_o (1/m.y.)††	26.1	21.9	26.7	27.2	28.7
Model parameters					
TOC (wt.%)	2.8	15.8	2.9	9.6	5.8
HI (mg S_2/g TOC)	317	740	446	502	509
E_a (kcal/mol)†	50.4	37.6	52.5	53.6	58.5
Log A_o (1/m.y.)††	26.1	21.9	26.8	27.1	28.7

*Model parameters incorporate these values with published data listed in the text. A_o = frequency factor; C = carbon; E_a = activation energy; H = hydrogen; HI = hydrocarbon index; N = nitrogen; O = oxygen; OI = oxygen index; PI = petroleum index; S_{org} = organic sulfur within types I, II, and IIS kerogen; T_{max} = temperature maximum measurement based on Rock-Eval pyrolysis S_2 peak; TOC = total organic carbon.

**UWI = unique well identifier: legal subdivision location, section, township, range, geographic meridian.

†Calculated from $E_a = -461.2345[S_{org}/C] + 63.804$ with $r^2 = 0.994$ from Lewan (1998) and Lewan and Ruble (2002).

††Calculated from $\log A_o = 0.32639\, E_a + 9.6308$ with $r^2 = 0.999$ from Lewan (1998) and Lewan and Ruble (2002).

HI is typically lower because of high levels of thermal maturity in the deformation belt (Riediger, 1997). Outcrops of the Whistler Member at West Burnt River (lat. 55.212°N, long. 122.212°W) and Casket Mountain (lat. 53.817°N, long. 119.975°W) are only marginally mature with T_{max} from 439 to 444°C (Riediger, 1997). Mean TOC and HI for samples from these localities are 6.1 wt.% and 302 mg HC/g TOC, respectively. Averaging these values with those of the Phosphate zone gives overall means of 4.5 wt.% TOC and 374 mg HC/g TOC, which were used in the model (Table 1). The underlying Montney Formation (Figure 2) and its western equivalent typically have TOC less than 2 wt.% (Riediger, 1997) and were not considered as source rocks in the model.

Exshaw Formation

The Devonian–Mississippian Exshaw Formation (Figure 2) consists of a nonsource upper siltstone member and a lower black shale member that is an oil-prone source rock (Caplan and Bustin, 1996; Smith and Bustin, 2000). The entire extent of Exshaw in the model was assigned as a source rock with a composition of 75% shale and 25% limestone. Modeled thickness values were based on about 11,000 wells (IHS Energy, 2004a). The lower black shale member is typically less than 5 m (16 ft) thick, and the modeled average thickness was 4.2 m (13.8 ft). This is in general agreement with Caplan and Bustin's (1996) average thickness of 3.75 m (12.3 ft) for the lower black shale member used to represent this unit (well 12-01-009-20W4). Their calculated mean TOC and HI for thermally immature samples were 8.4 ± 3.41 wt.% and 638 ± 80.39 mg HC/g TOC, respectively. Fowler et al. (2001) provided geochemical data on thermally immature (T_{max} <435°C) cores at various locations. The TOC values (Fowler et al., 2001) are variable for the Exshaw in the southern region with a mean of 3.91 ± 4.30 wt.%. Seventeen of the 42 samples had TOC less than 1.0 wt.%, which were most likely from the siltstone. Therefore, only the thermally immature core samples reported for northern, north-central, and south-central regions were used to calculate mean respective TOC and HI values of 9.64 wt.% and 503 mg HC/g TOC.

Duvernay Formation of the Devonian Woodbend Group

Core samples of the Duvernay Formation (Figure 2) in well 10-27-57-21W4 (Table 1) are considered representative of the thermally immature organic-rich laminites that constitute source rock in this unit (Chow et al., 1995). Using the core description of Chow et al. (1995) and TOC and Rock-Eval data from Fowler et al. (2001), an estimate of the amount of source rock was made using a 2.0-wt.% TOC lower limit to define source rocks. On that basis, a composite source rock thickness of 45.5 m (149 ft) was calculated. The average modeled thickness of the Duvernay layer is 43.6 m (143 ft) based on data from about 1500 wells (Mossop and Shetsen, 1994). Modeled lithofacies areas and lithologic assignments for Devonian layers are modified from Switzer et al. (1994). The mean TOC and HI are 5.29 wt.% and 536 mg HC/g TOC, respectively, for this source rock in the core from well 10-27-57-21W4 (Table 1). These values were weight averaged on the basis of the number of samples analyzed with thermally immature (T_{max} <435°C) Duvernay samples from eight other wells (Fowler et al., 2003) (wells 16-26-59-21W4, 6-14-34-20W4, 7-29-38-19W4, 16-18-52-5W5, 12-9-49-19W4, 12-28-57-21W4, 15-14-48-23W4, and 10-16-61-26W4). Values were weighted on the basis of the number of samples analyzed to give modeled mean TOC and HI of 5.81 wt.% and 509 mg HC/g TOC, respectively.

Petroleum Generation Kinetics

Kinetic parameters derived from the hydrous pyrolysis (HP) relation with the organic sulfur (S_{org}) content of immature kerogen were used to determine the extent and timing of oil generation from the major source rocks. These kinetic parameters were used because previous studies show that they provide more geologically reasonable determinations of the timing of oil generation than do Rock-Eval-derived kinetic parameters (Ruble et al., 2001, 2003), especially in the case of source rocks with high-sulfur kerogen (Lewan, 2002; Lewan and Ruble, 2002; Lewan et al., 2006). Although HP kinetic parameters can provide more reasonable determinations of the timing of oil generation, the technique is time consuming and requires several kilograms of sample. Fortunately, several relations among the experimentally derived kinetic parameters and organic sulfur content of kerogen provide a means of indirectly deriving them. This can be done by inferring the organic sulfur content of kerogen from the sulfur content of their generated crude oils (e.g., see Orr, 2001; Pitman et al., 2004) or by measuring the organic sulfur content of immature kerogen isolated from a source rock (e.g., Lillis et al., 1999). The latter was used in this study on a collection of samples composited from cores of source rocks considered representative of the immature source rocks (Table 1). Selection criteria for the composite samples required that they be thermally immature with a T_{max} less than 435°C and contain at least 2.5-wt.% TOC. Initially, 117 core samples were taken from 14 wells of which 46 samples from 5 cores were used to make representative composite samples from which HP kinetic parameters were derived.

The HP kinetic parameters used in this study were derived from previously established relations between the organic sulfur content of immature type II and type IIS kerogens and kinetic parameters determined by HP (Lewan and Ruble, 2002; Lewan et al., 2006). The parameters are based on oil that was generated and expelled from source rocks that were heated isothermally in closed reactors with water temperatures ranging from 300 to 365°C and times ranging from 12 to 500 hr. This oil, which is similar physically and chemically to natural crude oil (Lewan, 1993), is quantitatively collected from the water surface in the reactor at the end of the experiments and used to determine the activation energy (E_a) and frequency factor (A_o) as described by Lewan and Ruble (2002).

The relations used to derive the HP kinetic parameters for the composite source rocks are from Lewan and Ruble (2002) and are given in the footnotes of Table 1. First, the activation energy is calculated from the relation between the S_{org}/C ratio of immature type II and type IIS kerogens and their HP activation energy. The activation energy is then used to establish the HP frequency factor (A_o) based on the compensation relationship established between activation energies and frequency factors. The S_{org}/C ratios of the kerogens isolated from the composite samples and the calculated activation energies and frequency factors are given in Table 1.

The Gordondale Member of the Fernie Group (Figure 2) is the only major source rock with an S_{org}/C ratio high enough to be classified as a type IIS kerogen, according to Orr and Sinninghe-Damsté (1990) (>0.04). This is in agreement with the high sulfur content of this source rock as reported by Creaney and Allan (1990). The thermally immature core of the Poker Chip A shale was not available for a composite sample, so the HP kinetic parameters of a type IIS kerogen used for the Gordondale Member were also used for the Poker Chip A shale. Its lithologies of organic-rich, black calcareous shale and thin limestone (Riediger, 2002) make this a reasonable assumption until additional data are available.

Mannville Group petroleum accumulations include oil generated from Mannville coals and associated carbonaceous shales. The kinetics used in the 4-D model for petroleum generation from Mannville Group coals are those reported by Pepper and Corvi (1995a), who stated that coals within their D/F facies also generate some oil, which is in agreement with Goodarzi et al.'s (1994) observation that some Mannville coals are liptinite rich with high HI values. Pepper and Corvi (1995b) suggested a gas-to-oil ratio of 1:3 (25 wt.% gas and 75 wt.% oil) from the D/E organofacies and described the oil generation with a Gaussian activation-energy distribution of 54.54 ± 1.89 kcal/mol (E_{mean} and σ_E, respectively) and a frequency factor (A_o) of 1.568×10^{28} m.y.$^{-1}$ (Pepper and Corvi, 1995b), which are used in the model. Our model incorporates gas generation from the cracking of oil with the kinetic parameters determined by Tsuzuki et al. (1999). These kinetic parameters were used because the experiments from which they were derived were conducted in the presence of water, which is ubiquitous in the subsurface and has a stabilizing effect on oil cracking (Hesp and Rigby, 1973). A comparative study of published kinetic parameters for oil cracking to gas (Henry and Lewan, 1999) shows that the kinetics of Tsuzuki et al. (1999) predict slightly higher thermal stabilities for oil. As also shown by Tsuzuki et al. (1999), the saturate fraction of oil is most susceptible to cracking to gas with an overall C_1-C_5 gas conversion yield of 35.6 wt.%. For this conversion, the model used the kinetic parameters for the saturate C_{15+} fraction (E_a = 76.0 kcal/mol and A_o = 3.419 × 10^{33} m.y.$^{-1}$) to represent the overall cracking of oil to gas.

Burial History

The primary depositional and erosional trends in the study area are shown by a 1-D extraction from the 4-D model of the Tomahawk 16-18 (16-18-52-5W5) well (Figure 3). This well, located outside the area containing Gordondale and Poker Chip A source rocks (Figure 1), exhibits fairly good correlation of depth to temperature and R_o data for the 1-D model, as do Roberts et al. (2005) 1-D models constructed from wells of northern Alberta. The burial history model illustrates decompaction through subtle increases in layer thickness backward through time. Sweeney and Burnham's (1990) kinetics for R_o were used to calibrate the thermal history of the burial history profile. Included in Figure 3 are 1580 m (5184 ft) of erosion from about 58 Ma to the present and a constant heat flow of 46.1 mW/m^2 through time, whereas the Roberts et al. (2005) burial history for the Tomahawk 16-18 well included 1250 m (4101 ft) of erosion and 47 mW/m^2 heat flow for the same period. These minor differences are mostly caused by lithologic variation between the 4-D layer model and the 1-D well model. Using Sweeney and Burnham's (1990) kinetics, the Nordegg Member reached 0.4% R_o about 78 Ma at a depth of 1580 m (5184 ft), and the current 0.58% R_o was achieved about 58 Ma. Jurassic and older source rocks would be thermally mature for oil generation at this location.

RESULTS

Petroleum Generation

The onset of oil generation from source rocks is defined in this study by a transformation ratio (TR) of 0.1% as determined by the kinetic parameters for each source rock interval. This low value is used because HP kinetics are based on the generation of an expelled oil, where expulsion is a direct consequence of generation as proposed for natural oil generation by Momper (1978). Volumes of generated oil through time are shown in Figure 4 for each of the Devonian through Lower Cretaceous source rock units modeled. Oil generation in the model is tied primarily to increases in burial depth associated with Laramide tectonics.

The primary result shown in Figure 4 is the greater volumes of oil generated from the Fernie Group source rocks (Gordondale and Poker Chip A shales) as compared to other source rocks. Calculations within the study area indicate that Fernie source rocks generated almost two times the combined volume of oil from all other Devonian through Lower Cretaceous source rocks, including the Duvernay. Minor volumes of oil were generated in the Gordondale Member starting about 97 Ma and about 88 Ma in the Poker Chip A shale. The slightly later onset of generation from the Poker Chip A source rock is caused by its slightly shallower depth than the Gordondale Member. The onset of oil generation from the Gordondale Member corresponds to depths of about 1300–1600 m (~4265–5249 ft), temperatures of about 60°C, and R_o of about 0.4%. This is in general agreement with the observation by Creaney and Allan (1990) that the type IIS kerogen of the Nordegg (Gordondale) Member is thermally mature for oil generation at 0.40–0.45% R_o.

The model indicates that, unlike the other source rocks containing type II kerogen, oil generation and expulsion from the Fernie Group source rocks with type IIS kerogen started as early as 85 Ma. The onset of peak generation, as indicated by the 50% transformation for oil generation, was reached about 75 Ma for the Gordondale and Poker Chip A in the western study area, prior to onset about 65 Ma for other source rocks. An increased volume of oil generated through time (Figure 4) is associated with increased thermal maturation. Completion of burial and onset of erosion at about 58 Ma essentially ended further maturation of source rocks. Subsequent generation is associated with a gradual decrease in subsurface temperatures, as reflected in the leveling off of cumulative volumes of generated oil. Oil generation ended for all source rocks by about 40 Ma (Figure 4). Proximity of the Poker Chip A source rock to the deformed belt and associated deeper

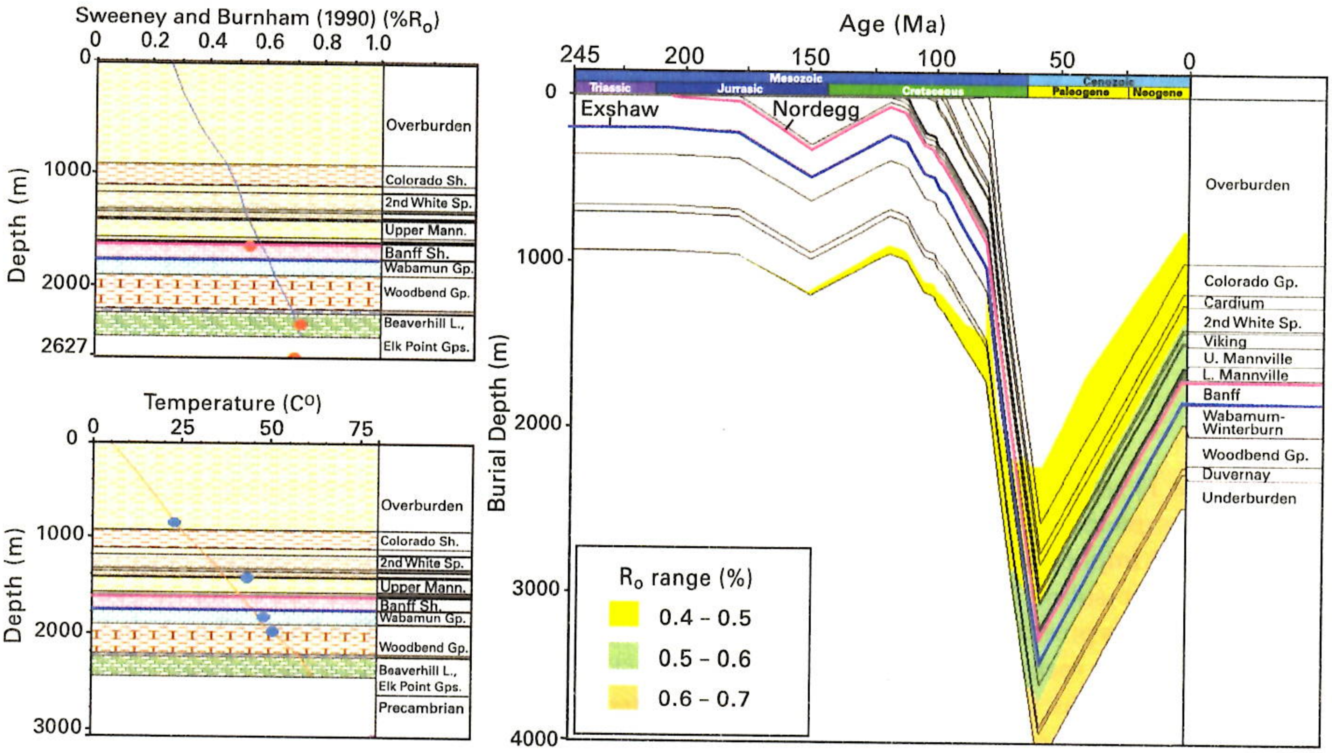


Figure 3. Maturation and temperature history from Triassic to present day based on a 1-D extraction of the Tomahawk 16-18 (16-18-52-5W5) well from the 4-D model (Figure 1). Vitrinite reflectance (R_o) is calculated using Sweeney and Burnham's (1990) Easy% R_o kinetic algorithm. Measured R_o (Stasiuk and Fowler, 2002; Stasiuk et al., 2002) and temperature data are associated with this well. The orange dot indicates temperature at the Precambrian surface (Bachu and Burwash, 1994) and the blue dots are drill-stem test and corrected borehole temperatures (IHS Energy, 2004a). Temperature and R_o data were used to externally calibrate the model.

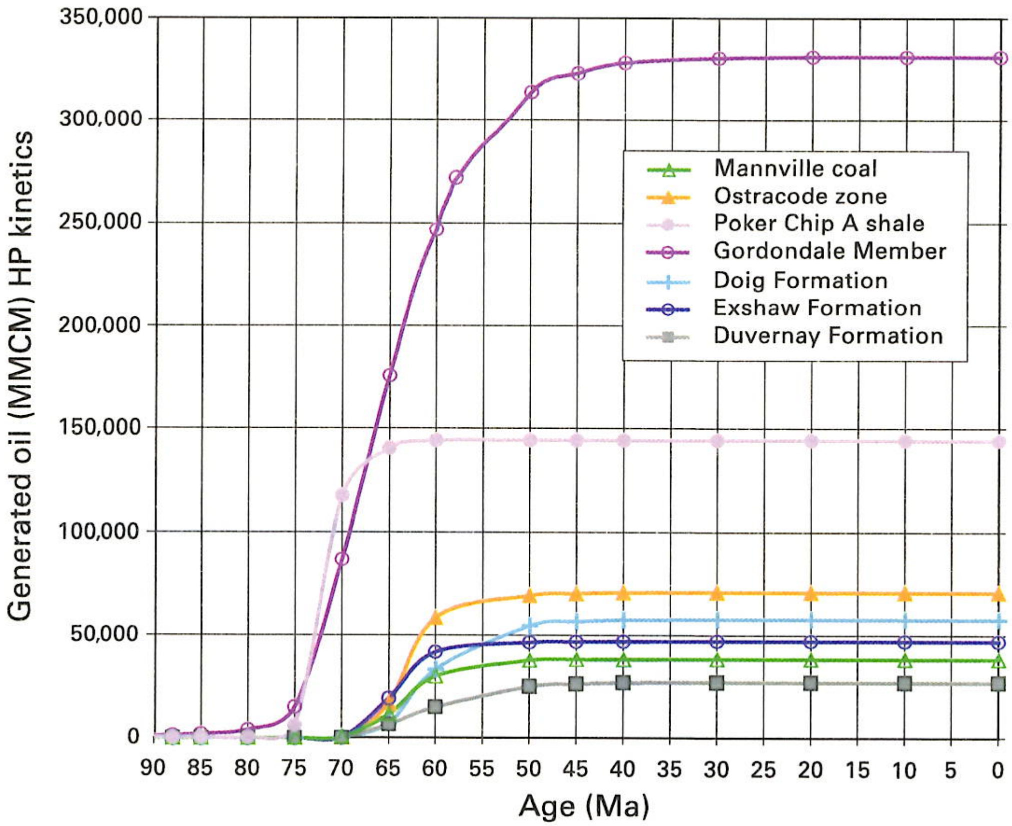


Figure 4. Cumulative volumes through time of oil by primary generation from Devonian through Lower Cretaceous source rocks in the study area are based on hydrous pyrolysis kinetics. Generation was completed for all source rocks by 40 Ma. All volumes are in million cubic meters (MMCM) at model reservoir pressure and temperature conditions. Liquid and vapor densities change through time, but the respective final densities are 765.9 and 0.9221 kg/m^3.

burial (Figure 1) resulted in associated oil generation being completed about 60 Ma. These results have important implications. Early generation of oil from the high-sulfur Gordondale and Poker Chip A source rocks provided a greater area of thermally mature source rocks and associated increase in volume contributions. Oil generation from these type IIS kerogen source rocks preceded generation and migration from the other source rocks with low-sulfur type II kerogen. This effect is critical with respect to the timing of trap formation and reservoir potential. Because increased burial depth is generally associated with the decrease in porosity and permeability of reservoir and carrier strata, the early and shallow generation and migration could have enhanced migration along and accumulation in more porous and permeable intervals. This is particularly the case with the unlithified strata of the oil sands.

The two-dimensional (2-D) cross section (Figure 5) extracted from the 4-D model (Figure 1) shows the TRs of Devonian through Lower Cretaceous petroleum source rocks at 60 Ma, near the time of maximum burial and thermal maturation. Transformation ratios of the Gordondale range from mature (1%) to overmature (99%) for oil generation along this section. The Poker Chip A shale is located south of this line of section (Figure 1). The extent of oil generation as measured by the TR is greater for the Fernie Group source rocks than for other source rocks in the study area. Petroleum migration into the Mannville was enhanced by truncation of source rocks against the sub-Mannville unconformity, as shown in Figure 5. Proximity of the Jurassic source rocks to potential Mannville Group reservoirs resulted in shorter vertical and lateral migration distances than for Triassic and older source rocks.

Petroleum Migration

Secondary Migration

The 4-D model used a combination of flow path and Darcy flow migration that is referred to as

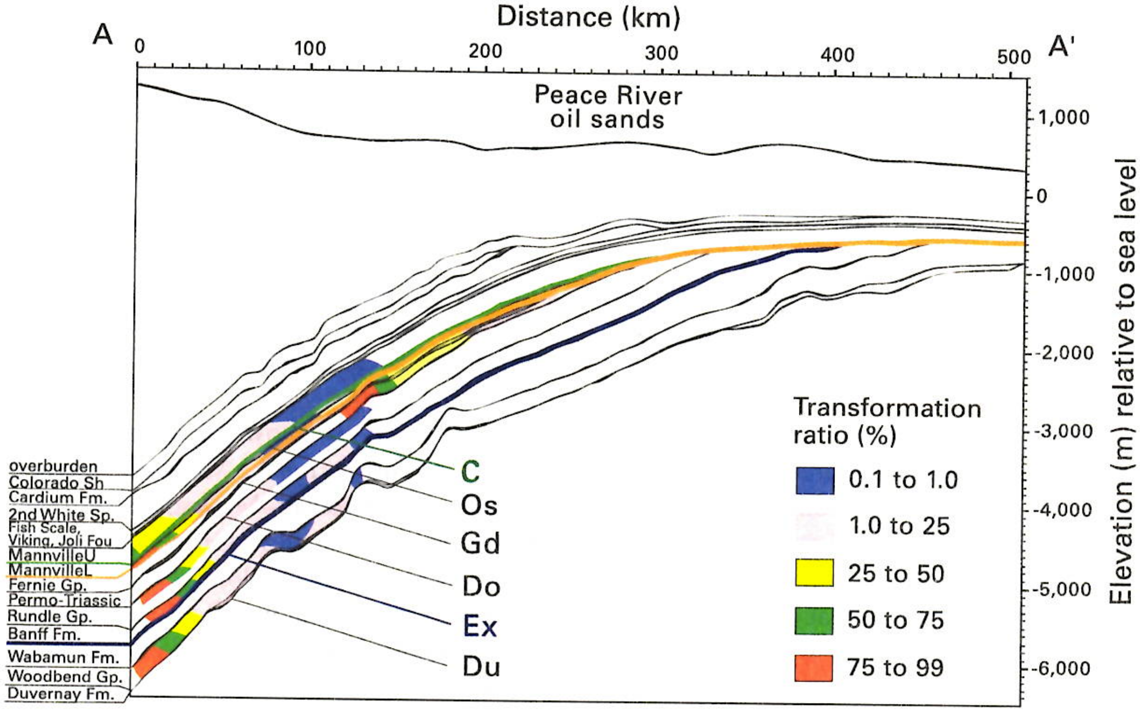


Figure 5. Southwest–northeast cross section AA′ (Figure 1) is a 2-D extraction from the 4-D model from 60 Ma. It is approximately parallel to petroleum migration pathways. Transformation ratios (TRs) of source rock layers are shown. The TRs are extrapolated above and below source layers to better view the ratios. Ratios are based on hydrous pyrolysis kinetics of the Duvernay (Du), Exshaw (Ex), Gordondale (Gd), and Ostracode zone (Os) petroleum source rocks. Mannville coal (C) kinetics is from Pepper and Corvi (1995a, b). Mannville coal (green) and base of the lower Mannville (orange) layers are delineated. The Exshaw layer is highlighted in dark blue. Minimally mature is 0.1% TR and peak generation occurs at about 50% TR. Areas west of 99% TR are overmature for oil generation.

hybrid-Darcy in PetroMod® documentation. This three-dimensional (3-D) flow incorporates pressure, volume, and temperature (PVT) and other changes through time to model flow through lithologic layers. Flow-path migration is mostly buoyancy driven by hydrostatic pressure changes, whereas the Darcy component is a multiphase process that uses gas diffusion and PVT to model the migration of liquid and vapor components of petroleum and water. Petroleum migration flow paths are mostly vertical. When fluids and gases enter a reservoir or other permeable layer, the flow is shifted to the top of the layer and follows the topography under a sealing layer. These paths are more readily viewed than the more diffuse oil and gas Darcy flow within the reservoir layer. For example, generated and expelled oil in layers below the sub-Mannville angular unconformity migrates vertically and laterally until reaching a permeable interval, such as sandstone within a Mannville Group layer. The petroleum then migrates primarily vertically until it reaches a sealing layer, such as the overlying Joli Fou Formation (Figure 2), with subsequent migration mainly updip along the Mannville topographic surface. Oil that is trapped as residual oil in carrier beds or accumulations in reservoirs is not available for further migration without a change in PVT conditions.

Structural relief on the top of the carrier layers is the primary control on migration pathways for oil that (1) is not trapped in the carrier layer; (2) does not breach bounding seal lithologies, should pressure increase exceed seal capacity; or (3) escapes along open faults. Proximity of reservoir strata to vertical and lateral seals and to thermally mature source rock is also critical to migration and accumulation. Models do not fully represent the heterogeneity at well to basin scales. Grid spacing for our 4-D model is 9 km (5 mi) laterally, primarily because of computer processing and display limitations. Intervals with their associated lithologic properties are homogenized at this 9-km (5-mi) scale. Models for stratigraphic traps and those constrained by PVT history require more detailed lithologic assignments and closer grid spacing. Diagenetic and unconventional (continuous) trapping mechanisms or biogenic processes, such as oil biodegradation and microbial methanogenesis, are also not modeled.

The model in northeastern Alberta has early development of subtle structures that enhanced trapping of oil. The generated oil in our model is trapped in the Mannville Group and other accumulations or migrates northeast toward the Precambrian shield. Much of the oil that is not trapped or migrated out of the study area is retained in pore spaces of the source, reservoir, carrier, and other strata. The volume of oil lost to secondary cracking to gas is very minor because most oil migrated out of the deeper high thermal maturity parts of the basin needed to initiate oil cracking. Modeled percentages of expelled oil that is lost to migration vary through time and for each source rock. Gordondale migration losses from 70 to 40 Ma range from about 2.6 to 3.6%, whereas Poker Chip A migration losses are 13.4 to 24.0%. The probable reason for this disparity is the Gordondale early generation and expulsion, with an associated greater volume of oil that filled carrier and reservoir pore spaces, although the Poker Chip A expulsion began several million years later. Also, the Gordondale may have subcropped against more porous and permeable carrier and reservoir lithologies. Migration losses for the Exshaw from 60 to 40 Ma ranged from 34.3 to 35.0%. A probable factor in Exshaw values is that Devonian and Lower Cretaceous accumulations were partly filled by oil from Gordondale, Poker Chip A, and Mannville source rocks. Figure 6 shows the variable contributions through time to Mannville Group petroleum accumulations that resulted from filling and replacement within existing accumulations and remigration caused by post-Laramide tilting of layers. Oil accumulations in the Mannville Group initiated at 97 Ma, but cumulative volumes were about 1 million m^3 or less until 70 Ma. Generated oil from the Fernie source rocks (Gordondale and Poker Chip A) accumulated in the Mannville Group starting at 70 Ma, followed by oil from Mannville Group coals and the Ostracode zone (Figure 6). The oil accumulation history shows that the Doig and Exshaw were only minor contributors. Because much of the Exshaw oil migrated out of the study area instead of being trapped, actual contributions to Mannville and other accumulations from the Exshaw were probably greater.

Figure 7A–D show migration pathways and oil accumulations for the Mannville layers from all contributing Devonian–Mississippian through Lower Cretaceous source rocks. Oil-generation (TR) contours refer only to the Nordegg/Gordondale layer. Although TRs are shown for the entire layer, only the Gordondale is assigned source and kinetic parameters and it is the only area of the layer (Figure 1) from which oil has been generated. Likewise, only the Poker Chip A area (Figure 1) in the Poker Chip Shale Member layer is a petroleum source. Poker Chip A source rocks that overlie the Nordegg/Gordondale layer (Figures 1, 2) are slightly less mature than the TRs displayed in Figure 7A–D because of their shallower depth. Lateral migration of oil from the tops of the upper and lower Mannville layers (Figure 2) is displayed as green lines. Short-distance lateral migration is visible as an isolated star or point sources with short branching lines. Those located over immature parts of the study area, such as south of 53.5° on Figure 7A, result from the modeling program and gridding artifacts. Migration pathways do not represent volumes of oil but instead the occurrence and trajectory of oil flow on surfaces and to oil accumulations. Migration within the Mannville layers is not visible.

High-angle reverse faults along the eastern boundary of the Canadian Rocky Mountains were incorporated into the model at the onset of the Laramide orogeny (65 Ma) to present. These series of vertical faults were laterally connected at layer boundaries. The fault boundary (Figure 1) is the limit of Mesozoic deformation as shown by Mossop and Shetsen (1994). The purpose of the closed faults was to limit petroleum migration from the west after the onset of Laramide deformation in the

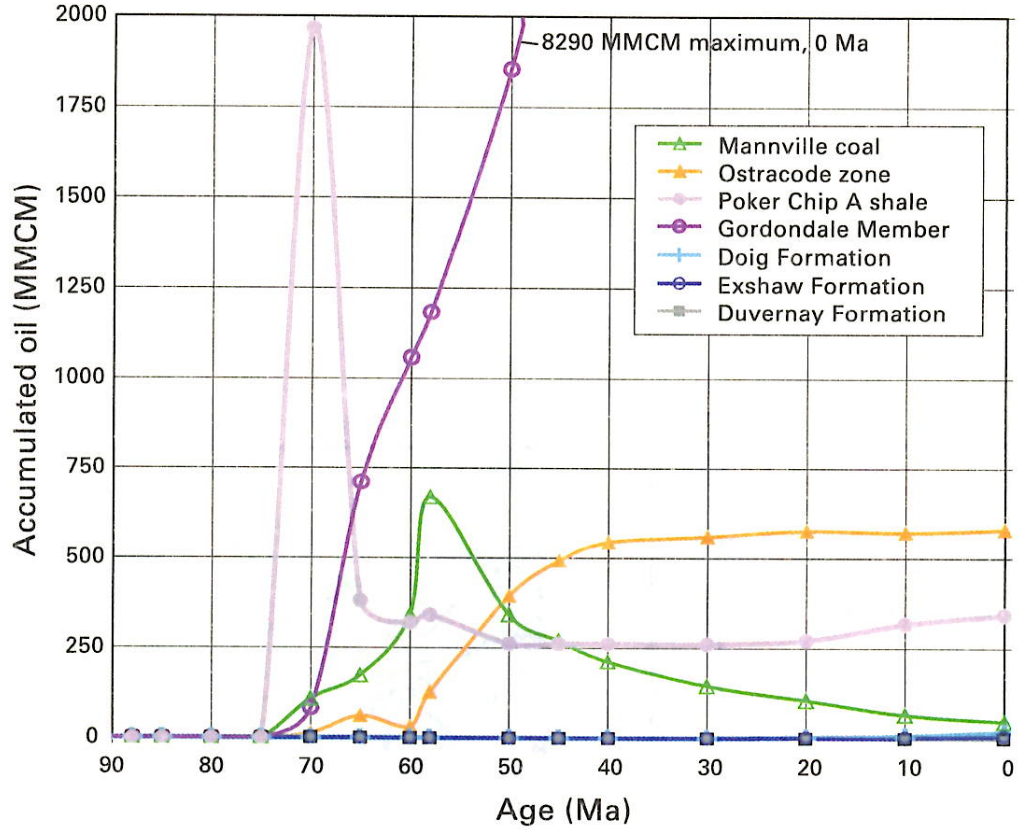


Figure 6. Contributions through time of source rocks to oil accumulations in the Lower Cretaceous Mannville Group based on hydrous pyrolysis kinetics. Most petroleum migrated out of the study area or was residual oil in carrier beds, instead of being trapped, so this is only intended to show generalized timing and volumes. Contributions are also influenced by factors such as pressure-volume-temperature history, proximity to potential reservoirs, and whether the traps are already filled. Mannville coal petroleum is isolated almost completely to the upper Mannville layer. Volumes are in millions of cubic meters (MMCM).

Late Cretaceous. Timing and volume of generated oil are included with the tabulated totals in the model.

Parts of the Gordondale and other source rocks are located west of the study area and north from about latitude 54° (Figure 7A–D). These source intervals are expected to continue to deeper depths, with associated higher levels of thermal maturity, than those in the study area. Exclusion of these sources results primarily in a decreased volume of generated and migrated petroleum. This is evident at 70 Ma (Figure 7B) by the decreased density of flow paths located west and southwest of the Peace River oil sands. Oil-flow directions from latitude about 52° north are mainly from southwest to northeast, and south of this are west–east. At 70 Ma (Figure 7B), the Gordondale Member subcrops proximal to the Peace River oil sands and is generating oil. Peak generation for the Exshaw Formation (TR = 50%, purple line, Figure 7C, D) is west of the Gordondale area, which is thermally mature for oil. Migration flow paths that originate west of the fully mature Gordondale are from the Exshaw Formation, Doig Formation, and Mannville Group source rocks. The present-day extent of oil generation of the source rocks ranges from 0.1% TR near the northeastern boundary to 99% TR parallel and proximal to the eastern boundary of the source rock (Figures 1, 7D).

The general northeast trend and convergence of flow paths (Figure 7B–D) compare with Hitchon (1984), who indicated that the oil sand deposits of northeastern Alberta are along a series of converging flow paths that drain most of the Alberta part of the WCSB. Petroleum migration pathways north of about latitude 54° are primarily from the Gordondale (Figure 1), with lesser contributions from other Devonian–Mississippian through Lower Cretaceous sources. Athabasca oil sands have lesser petroleum contributions from the Poker Chip A and other source rocks, but oil and flow paths are concentrated south of about latitude 53° because of the primarily eastern flow direction. Oil migration pathways west of the 99% TR for the Fernie

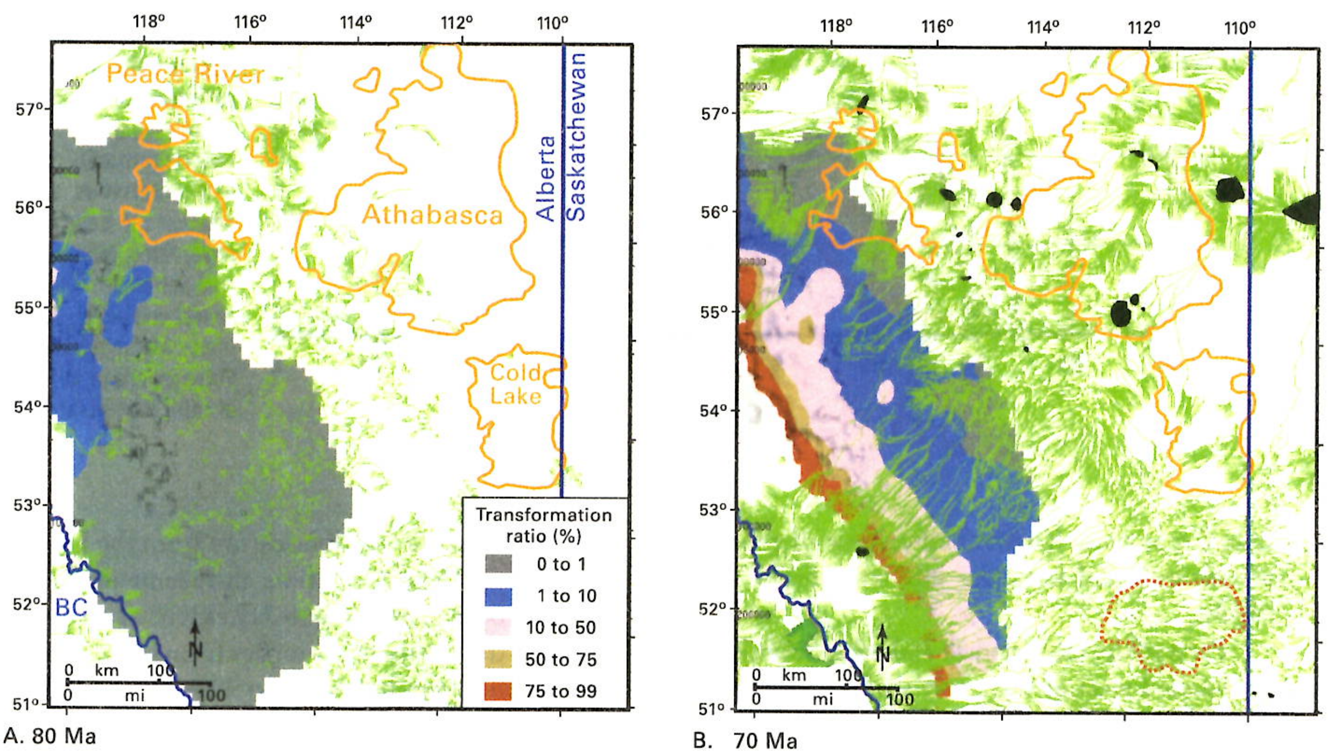
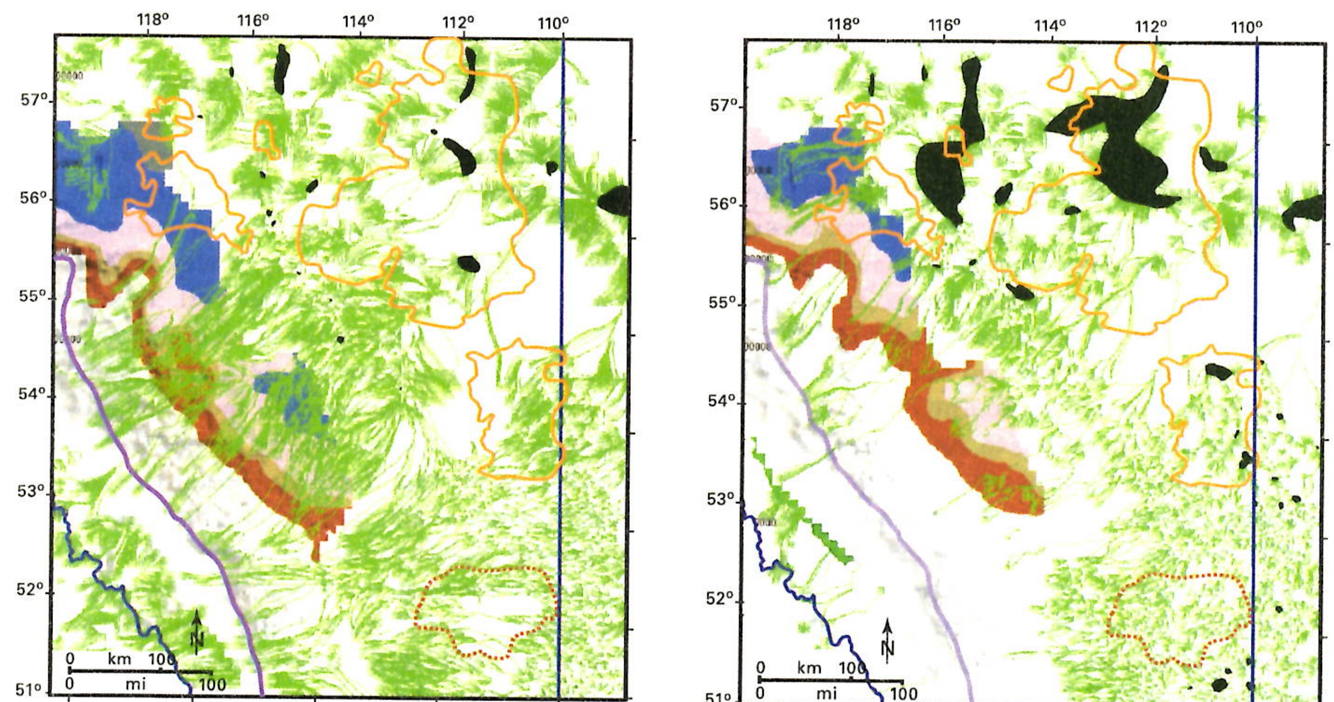


Figure 7. Eastward increase through time of thermal maturity levels based on hydrous pyrolysis transformation ratios (TRs) on the entire Nordegg/Gordondale layer (Figures 1, 2). Areas west of the 99% TR (B–D) are overmature for oil generation from the Gordondale and overlying Poker Chip A shale but not from deeper source rocks (Figure 5) that may contribute to oil migration pathways. Petroleum accumulations (dark green) and migration flow paths (light green) are shown for the Mannville Group layers. Heavy purple lines at 60 and 0 Ma are the onset of peak generation for the Exshaw Formation based on 50% TR for Exshaw kinetic parameters. Oil sand deposit outlines are orange. Provost field is outlined by a dashed red line (B–D). Province boundaries are dark blue lines.



C. 60 Ma

D. 0 Ma

Figure 7. Continued.

Group source rocks represent contributions from shallower and deeper source rocks that are less mature than the Gordondale and Poker Chip A strata. Concentration of petroleum along pathways and at focal points results in the irregular distribution of economic deposits. Mobilization of water from source rock maturation is included in the model. Modeled hydrodynamic flow did increase the migration efficiency of the expelled oil; however, it resulted in flushing of oil accumulations, which made the determination of contributing source rocks more difficult. For this reason, hydrodynamic flow was not included in the final model. Hydrodynamic flow from the west or from the Precambrian shield is an important process for petroleum migration and/or biodegradation. Garven (1989) indicated that a primary agent in the origin of the oil sand accumulations was gravity-driven groundwater flow during the Tertiary as a result of uplift of the foreland basin. He calculated upward discharge rates of 1–10 m/yr (3–32 ft/yr) across the Mannville Group reservoir sands at their eastern margin. Trapping is also influenced by timing of oil generation and migration relative to faulting and folding, and PVT changes associated with tectonism.

Oil migration pathways to the northeast correspond generally to those of groundwater flow postulated by Garven (1989) and Bethke and Marshak (1990). Our modeling supports previous research that indicates migration distances of as much as 200–500 km (124–311 mi) for petroleum across Alberta (Moshier and Waples, 1985; Riediger et al., 1999; Adams et al., 2000; Bekele et al., 2002). Migration distances for oil vary in the model but are as much as 600 km (373 mi) based on the location of producing wells and oil sands relative to areas where contributing source rocks are thermally mature, and on the directions of migration flow paths.

Tertiary Migration

Tilting as a result of differential deposition or erosion can initiate remigration of oil and gas. Such migration was active in the study area following the onset of erosion at 58 Ma. Because the thickness of eroded sediment in the WCSB was greatest near the deformed belt, the angle of dip decreased toward the belt. This altered the trap area of structural accumulations and resulted in the remigration of accumulated oil and gas. These remigration flow paths are included with secondary generation flow paths and cannot be separated using the software. They are most visible through changes in volume and area of accumulations through time. This is especially visible on the images from about 40 Ma to the present. During this period, almost no petroleum generation occurred, but the sizes and shapes of the accumulations change slightly. Flow path directions, however, did not change as a result of this minor tilting, retaining a primary northeast trend.

Petroleum Accumulation

Most generated petroleum was not trapped in the Mannville Group in our model but is instead residual oil in reservoir and carrier bed pores or migrated to the east and northeast, outside of the study area. Although adding hydrologic flow to the model increased the migration efficiency, it was too efficient and resulted in no accumulated oil. This inefficient trapping was mostly the result of the model's coarse grid size relative to subtle stratigraphic traps, and the lack of software to model oil biodegradation. These factors resulted in modeled oil accumulations for the Mannville Group that are generally smaller in area and volume than are actually present. Subtle structures in the model are based on elevations at the top of the Mannville Group (Mossop and Shetsen, 1994; Riley Electric Log Database, 1996; IHS Energy, 2004a, b; Higley et al., 2005b). Irregular surfaces of underlying layers resulted from the stacking of isopach grids relative to this structure grid, combined with compaction through time and other factors explained in the Methods and Input section. These structures on Mannville layers resulted in early accumulations of oil that would have been available for biodegradation. Formation of biodegradation seals was not an option with the modeling software. This function would have mimicked the gradual loss in volume of oil caused by biodegradation and associated decrease in pressure. Our attempts were unsuccessful in creating a seal along the updip edge of the Athabasca oil sands using an impermeable boundary because the pressure associated with influx of the total volume of oil allowed the Joli Fou seal to be breached.

A subtle dome across the Athabasca oil sands is about 150 mi (241 km) long by 60 mi (97 km) wide and may have resulted from dissolution of evaporites of the Prairie Evaporite Formation of the Devonian Elk Point Group (Figure 2) and incised drainages following deposition of the lower Mannville Group (Vigrass, 1968). Vigrass (1968) indicated that this structural doming was present before deposition of the Lower Cretaceous sandstones. Localized thickening of basal Cretaceous sandstones suggests structural subsidence during deposition of the lower Mannville. This indicates that dissolution of salts from the Prairie Evaporite Formation of the Elk Point Group (Figures 1, 2) preceded deposition of the Mannville reservoir sandstones. Continued dissolution during migration of oil is unknown but would contribute insufficient amounts of sulfur to supply the volume in the oil sands.

Allan and Creaney (1991) identified three oil families in the WCSB, which is consistent with our model results. These families are typically in the Lower–middle Cretaceous (Viking, Cardium, and Belly River) reservoirs; Mississippian, Jurassic, and Lower Cretaceous reservoirs (including Mannville); and Upper Devonian reservoirs. Modeled oil and gas from the Duvernay are a Devonian closed system in which accumulations were primarily in carbonates of the Woodbend Group. The Upper Cretaceous Second White Speckled Shale did not contribute to Mannville Group accumulations but to primarily sourced Cretaceous Cardium and Viking reservoirs. Based on our modeling results, the Exshaw through Mannville Group source rocks used in this study contributed petroleum to the Lower Cretaceous Mannville Group accumulations.

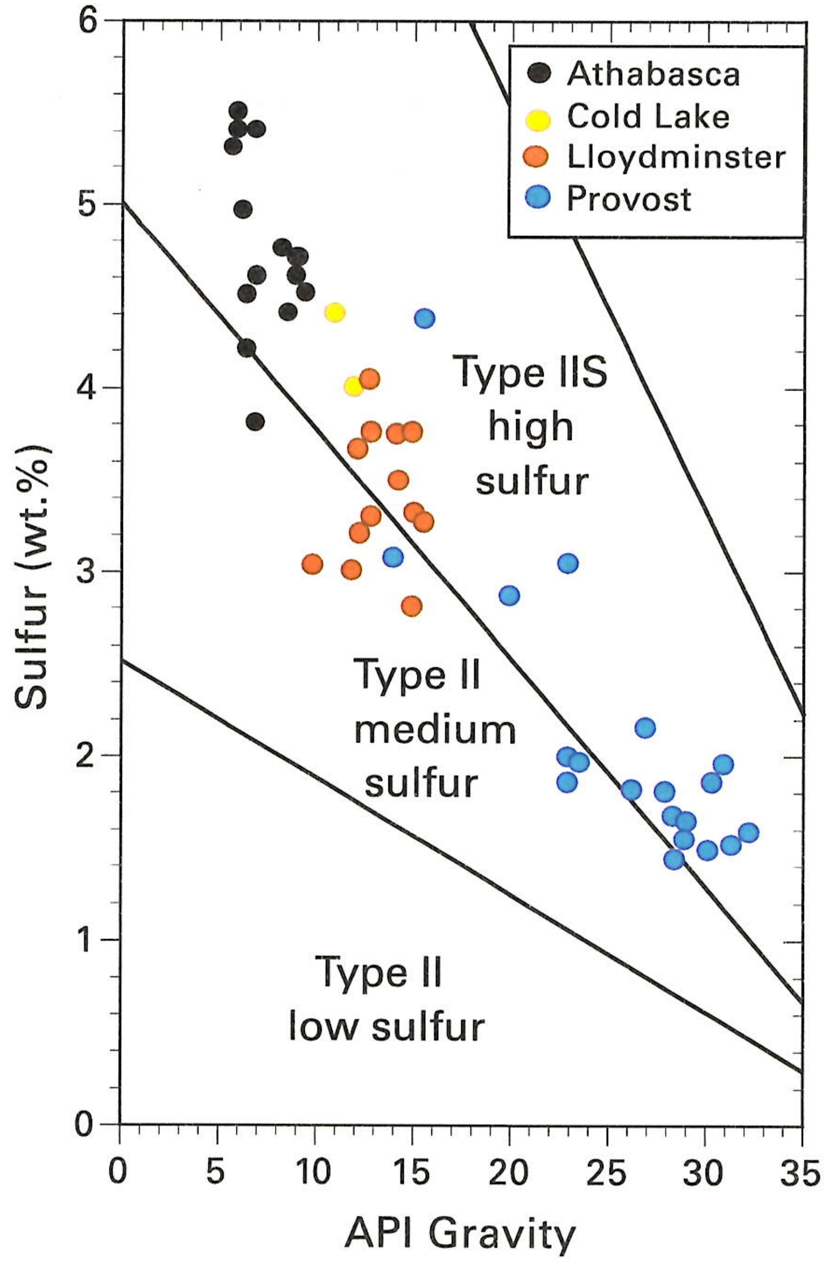
DISCUSSION

The large volume of oil sand accumulations was probably enhanced by an updip heavy-oil seal formed by biodegradation that enhanced existing structural and stratigraphic traps. Incursion of meteoric water from the east limb of the WCSB may have accelerated biodegradation and subsequent conversion of petroleum to heavy oil (API gravities less than 25°) (Creaney and Allan, 1990). Riediger (1994) indicated that 25–50% of the OOIP was lost because of biodegradation. Moshier and Waples (1985) stated that bitumen of the oil sands represents 80% of OOIP and that 20% was destroyed or lost by microbes and water washing.

Creaney and Allan (1990) indicated that the Nordegg (Gordondale) is an important sulfur-rich source rock (Figure 8), as well as a seal for older subcrops, and that it is overmature in the deformed belt for petroleum generation. The WCSB has an estimated 5101 BCM (180 tcf) of gas from overmature oil-prone source rock and from Mannville coals and carbonaceous shales (Creaney and Allan, 1990).

Moshier and Waples (1985) stated that at least 6200 billion bbl of oil equivalent (985 BCM) must have been generated to have emplaced their estimated 1300 billion bbl (206 BCM) of in-place bitumen in the Alberta oil sands. Selby and Creaser (2005) indicated the oil sands contain about 258.9 BCM (1630 billion bbl) of petroleum. Riediger (1994) estimated the volume of petroleum in the Alberta oil sands at 269.4 BCM (1690 billion bbl). Her calculated volume of 19.5 BCM (123 billion bbl) of oil generated from the Gordondale was based on a limited 82.7-BCM area of mature rocks that are proximal to the Mannville Group subcrop, a rock density of 2.39 g/cm^3, 16% TOC, and 759 HI. She estimated the amount of expelled oil to range from 5.9 to 17.6 BCM (37 to 110 billion bbl) and indicated that this was sufficient to have filled the Lower Cretaceous Bluesky-Gething interval of the Peace River oil sands but is not sufficient for all Lower Cretaceous oil sands in Aberta. Excluded from Riediger (1994, p. 70) Gordondale calculations were "regions of low maturity and thin (less than 10 m) source rock development." Riediger (1994, p. 70) indicated that associated "oils generated from such low maturity sources are of low API with a low percentage of hydrocarbons in the oil and, therefore, are difficult to expel and unlikely to migrate far." In contrast, (1) our model indicates that almost the entire Gordondale in the study area is thermally mature for oil or gas generation and

Figure 8. Plot of sulfur content versus API gravity of heavy oils and tars in Lower Cretaceous reservoirs of the Athabasca oil sands (Hodgson, 1954b; Carrigy, 1975; Camp, 1976; Rubinstein and Strausz, 1979), Cold Lake oil sands (Winestock, 1974; Flock and Lee, 1977), Lloydminster heavy-oil field (Hodgson and Baker, 1959), and Provost oil field (Riediger et al., 1999). Lines separating high, medium, and low sulfur kerogen fields are from Orr (2001).



expulsion, (2) our area is about 1431 BCM or 17.3 times the Riediger area, and (3) Gordondale unit C sampled by Ross and Bustin (2006) located just west of the study area contains an average 12% TOC and S_{org}/C ratio of 0.04 to 0.12, within the range of type IIS kerogen.

Model results indicate that the Gordondale and Poker Chip A source rocks generated sufficient oil (475 BCM, 2980 billion bbl) to fill the oil sand accumulations in northern Alberta. However, this number is based on the original mean Rock-Eval HI used in the model, which has been shown in other studies to overstate oil-charge values (Lewan et al., 2002; Peters et al., 2006). No attempt to correct these modeled values was made in this study because the potentially large volumes of additional oil from mature source rock west and northwest of the model area were not taken into account. The current implication of the model area is that the Fernie Group source rocks generated about twice as much oil as the other source rocks combined. Because of the limited trapping mechanisms for petroleum in the model, most of the expelled oil migrated east and northeast of the deep basin instead of being trapped and available for secondary generation of gas. Also, many of the oil accumulations are within the area that is thermally immature for gas generation in northern Alberta and in the model.

Brooks et al. (1988) reported that the distinctive organic chemistries of the heavy oils and bitumens of the oil sands indicate the same or similar sources, except for the heavy oils from the Provost field (Figure 7B–D), which contain unusual polycyclic alkane and aromatic compounds known only from the Ostracode zone source rock (Riediger et al., 1999). The Provost oil and gas field produces primarily from the Mannville Group and Viking Formation. The Provost field was not filled using our model; however, numerous small accumulations in this area (Figure 7C–D) record the Ostracode zone and Mannville coal layers as the primary sources of oil and the Poker Chip A as a secondary source. Riediger et al. (1997, 1999) determined that the primary source rock for Provost field was the Ostracode zone based on comparison of source rock extract biomarkers to oil samples from the field. Based on our model, Mannville Group accumulations located in the southeastern quarter of the study area, such as the Cold Lake oil sands and Provost field, originated primarily from the Ostracode zone and coals of the Mannville Group and Poker Chip A shale of the Poker Chip Shale Member. Absence of Gordondale oil contributions to Provost and Cold Lake is mostly caused by the northeastward migration of generated petroleum, north of these accumulations. Migration from the Poker Chip A shale fans out to the east and northeast. Exshaw and Doig contributions are primarily in scattered accumulations in the northern half of the study area, including the oil sands. Based on model results, the Gordondale is the initial and primary source for the Peace River and Athabasca oil sand accumulations with additional but lesser and later sources from the Exshaw, Doig, Poker Chip A, and Mannville Group coal and the Ostracode zone. Gordondale and Poker Chip A also contributed oil to other formations, including Devonian carbonates located near the sub-Mannville unconformity and within the Athabasca oil sands.

The use of biomarkers to determine the source of bitumen in the Alberta oil sands has resulted in opposing interpretations. Fowler et al. (1989) concluded that the Nordegg (Gordondale) was not the main source, whereas Creaney and Allan (1992) concluded that the Nordegg (Gordondale) was a main source. Genetic correlations based solely on biomarkers can be equivocal, particularly for oils from mixed sources (Wilhelms and Larter, 2004) as well as for oils that have undergone various levels of biodegradation (Peters et al., 2005). Wilhelms and Larter (2004) contended that bulk parameters, such as light hydrocarbons, can be better correlation parameters than biomarkers because their concentrations in oils do not span several orders of magnitude. Biodegradation of the oil in the Alberta oil sands excludes the use of light hydrocarbons as a correlation tool, but other bulk properties like sulfur content and its relation to the API gravity of oils offer a good alternative. Although different degrees of thermal maturity and biodegradation can change the sulfur content and API gravity of oil and tar, the changes are proportional and readily distinguished on a plot of sulfur content versus API gravity. Orr (2001) used these observations to define sulfur-API gravity relations to differentiate oil generated from type IIS or type II kerogen. These relations are shown in Figure 8 with data from oils and tars in reservoirs of the Mannville Group. Most of these oils and tars are indicative of a type IIS kerogen. As shown in Table 1, the only source in the study area that contains type IIS kerogen is the Fernie Group. The other source rocks contain only type II kerogen with low organic sulfur ($S_{org}/C < 0.03$), which would only generate low-sulfur oils. These oils could have contributed to the accumulations, as suggested by variations within the type IIS field and the occurrence of some oils and tars within the medium-sulfur kerogen field. Some mixing is likely, as our model suggests, but these bulk properties indicate that the high-sulfur kerogen in the Fernie Group source rocks was a major contributor to the Lower Cretaceous Mannville Group reservoirs and especially to the oil sands. This is also supported by high sulfur contents (2.0 to 3.6 wt.%) of 30.2 to 28.7° API oils in the Virginia Hills and Rycroft fields, which are indicative of a type IIS kerogen source and considered by Creaney and Allan (1992) to be sourced from the Nordegg (Gordondale).

For investigators who dismiss the Fernie Group as a source of the oil sands, explaining why some of the richest source rocks in the WCSB have limited oil accumulations is difficult. The main argument for this discrepancy has been that migration of high-sulfur oils generated by the Fernie Group source rocks was greatly curtailed by their low API gravities (Riediger, 1994). However, this intuitive explanation is not observed in other sedimentary basins where oils generated from source rocks with high-sulfur kerogen (type IIS) have been expelled and migrated. Concerns about long-distance migration of high-sulfur oil are negated by the hundreds of kilometers of lateral migration of high-sulfur oils generated from type IIS kerogen in Phosphoria source rocks (Sheldon, 1967; Claypool et al., 1978). In addition, high-sulfur oils produced in Iraq were generated from type IIS kerogen in Jurassic source rocks (Sargelu and Naokelekan formations) of the Mesopotamian Basin (Pitman et al., 2004). Despite the early generation of these 15–35° API oils (Lewan and Ruble, 2002), they were expelled from their source rocks and migrated vertically and laterally into reservoirs to form some of the largest oil accumulations in the Middle East.

CONCLUSIONS

Thermal maturation from all source rocks and associated petroleum generation in Alberta began near the present-day Rocky Mountains and progressed eastward. Generated and migrated petroleum was trapped or migrated to the east and northeast as much as 600 km (373 mi). Modeled migration pathways and accumulations show that the oil sand deposits were located at migration focal points and that subtle structures in the area of the Athabasca oil sands contributed to early trapping. Petroleum migration in the study area was enhanced in the Lower Cretaceous Mannville Group by truncation of Jurassic and older source rocks against this basal angular unconformity. The major source of oil in the oil sands is from Jurassic Fernie Group source rocks, for which vertical and lateral oil migration was shorter than for older source rocks. The Ostracode zone of the Mannville Group is a primary contributor to the Provost accumulation.

Our modeling shows that type IIS kerogen in Fernie Group source rocks is the initial and major source of petroleum of the northern Alberta oil sands. This is consistent with the sulfur-API gravity relations of Mannville Group oils and tars that are indicative of a type IIS source. Of the major source rocks, only the Fernie Group contains source rocks with type IIS kerogen. The high sulfur content of this kerogen type results in early oil generation at low thermal maturities. As a result, the amount of source rock that matured prior to the onset of uplift and erosion (~58 Ma) was significantly greater for the Fernie Group than for the other source rocks. Modeled amounts of oil generated from the Fernie Group source rocks with their type IIS were more than sufficient to source the northern Alberta oil sands and were about twice the combined volume of oil generated from the other source rocks. Concerns about long-distance migration of oil generated from type IIS kerogen are dismissed based on analogs, such as high-sulfur oils from type IIS kerogen in the Phosphoria source rocks that migrated hundreds of kilometers to source accumulations throughout most of Wyoming, and high-sulfur oil from type IIS kerogen in the Jurassic source rocks of Iraq that migrated into large accumulations.

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