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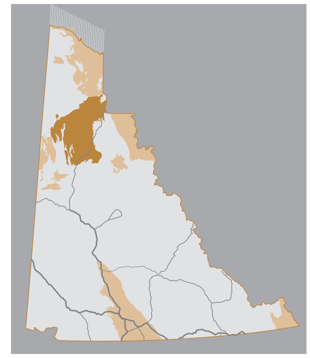
Petroleum Resource Assessment, Eagle Plain Basin and Environs, Yukon Territory, Canada



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Cover photo. *The transitional contact between Parkin Formation and Fishing Branch Formation, immediately east of the Fishing Branch River, Eagle Plain Basin, Yukon Territory (ISPG Photo 2619-19; courtesy of J. Dixon, GSC Calgary). The base of the first prominent sandstone defines the base of the Fishing Branch Formation.*

ABSTRACT

Abstract

The Eagle Plain Basin and its environs is a potentially prospective petroleum province in the Yukon. Extensive initial exploration in this area, focused on discovering crude oil, identified 83.7 Bcf of natural gas and 11.05 MMbbls of crude oil, with 33 wells, many of which had shows of petroleum in other zones, throughout the succession and across the geographic extent of the basin. A probabilistic petroleum assessment of 15 petroleum plays suggests that an expected 5.971 Tcf of natural gas and 425.95 MMbbls of crude oil remain to be discovered, as part of a total resource endowment in 146 accumulations of crude oil and natural gas containing between 2.379 Tcf to 12.0 Tcf of natural gas, and 132 MMbbls to 926 MMbbls of crude oil. This study differs significantly from previous estimates of undiscovered potential, which were less optimistic. The total expected petroleum endowment of the Cambrian to Middle Devonian carbonate succession is 1327.86 Bcf of natural gas, which remains an important secondary deeper exploration target. The main target is the Permo-Carboniferous succession, with three main potential reservoirs, at the base (Tuttle Formation), in the middle (Hart River Formation) and at the top (Jungle Creek Formation) of the succession. The Tuttle Formation is expected to have resources of 323.02 Bcf of natural gas and 68.95 MMbbls of crude oil. Another 1823.32 Bcf and 155.09 MMbbls are inferred for the Hart River Formation, while the Jungle Creek Formation is expected to contain 2231.8 Bcf and 104.89 MMbbls. The expected potential in the Mesozoic succession is 349.34 Bcf and 107.81 MMbbls, an important up-hole interval. While the entire section is prospective, plays that target structural and stratigraphic prospects in the upper part of the Paleozoic succession are the best targets, as these form major traps at and near the top of the succession that contain thermally mature sources, below major regional seals, which are commonly involved in Laramide structures. Predicted undiscovered pool sizes point toward success accompanying the continued exploration of plays in the Permian and Carboniferous successions, with a new focus on Jungle Creek Formation sandstones. These results are consistent with the exploration history, the stratigraphic architecture and the analysis of petroleum systems. Intriguing plays exist associated with the stratigraphic opportunities for entrapment in Paleozoic carbonates against the Richardson Trough, but these appear to be higher risk/reward targets than the continued exploration of the uppermost Paleozoic succession. Additional conceptual play concepts, including those in the Devonian Imperial and Jurassic Porcupine River formations, which have indications of petroleum occurrence, were not quantitatively assessed.

CONTENTS

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Table 1. *Executive summary table of the petroleum potential of the Eagle Plain Basin and environs.*

Basin age	Proterozoic to Upper Cretaceous with economic basement in the Cambrian
Basin area	20 608 km; entirely within the Yukon.
Depth to target zones	Mesozoic: surface to 2000 m Carboniferous: surface to 1700 m Devonian to Cambrian carbonates: surface to 4500 m
Maximum Phanerozoic thickness	~5800 m stratigraphic thickness, thickened by Cordilleran thrusting and folding
First discovery	Chance L-08 (M-08) which found gas and oil in both Mesozoic and Paleozoic formations
Potential resources	**Oil:** Potential is demonstrated by indications from tests of crude oil from the succession lying above the Devonian Ogilvie Formation throughout the geographic extent of the basin. Potential sources are inferred to occur related more to straigraphic analysis than to the results of laboratory studies, however, the presence of oil discoveries and shows in well tests indicates that effective oil sources exist. The Mesozoic succession is largely immature for crude oil generation, but shows in wells indicate the migration of oil from stratigraphically lower petroleum sources. The results of petroleum systems studies are more pessimistic than the results of drilling, a difference that remains unresolved. **Gas:** Potential is demonstrated by indications from tests of gas from the entire succession throughout the geographic extent of the basin. The Mesozoic succession is largely immature for thermogenic natural gas generation, but biogenically generated gases are potentially important. **Potential:** A total mean potential of 6055.34 Bcf and 436.74 MMbbls of oil are expected to occur in a total of 146 accumulations (114 gas and 32 oil), of which only three accumulations with total initial in-place reserves of 83.7 Bcf and 11.05 MMbbls are recognized. In general, petroleum potential is inferred to be significant throughout the entire succession across the breadth of the basin.
Basin type	Coupled Cordilleran (Cretaceous) thick-skinned Foreland Thrust and Fold Belt, and Foreland basin overlying a Paleozoic succession of Franklinian (Middle Devonian-Carboniferous) flysch/molasse, Taghanic (Cambrian to Middle Devonian) carbonate platform and lesser basin deposits lying west of the Richardson Trough
Depositional setting	Shallow- to deep-water Paleozoic carbonate platform, marginal to a rift basin and orogenic foreland, and Mesozoic orogenic foreland and clastic shelf
Potential reservoirs	Basal sandstone and sand bodies with the shale- and siltstone-dominated Mesozoic succession, dolostone and limestone carbonate ramps within the Paleozoic, with possible abrupt carbonate margin that is favourably oriented with respect to regional dip and facies changes
Regional structure	Complicated thick-skinned and associated thin-skinned Laramide north- and east-verging thrust and fold belt involved in a complicated structural history
Seals	Multiple, both vertical and lateral related to both facies changes and stratification
Petroleum systems	Established and proven to be effective by existing reserves of both crude oil and natural gas
Depth to oil/gas window	Variable, but the Middle Devonian and older succession tends to be gas prone to possibly overmature. Current studies of thermal maturity variations show both stratigraphic and geographic variations that are described within, but need additional study.
Exploration wells in study area	33 wells drilled; 2 gas wells, 2 gas and oil wells, 1 oil well and 28 dry and abandoned (D&A).

INTRODUCTION

This reports discusses the assessment of 15 immature and conceptual petroleum plays with crude oil and natural gas potential in the Eagle Plain Basin and its environs, in the Yukon Territory (Table 1).

LOCATION AND PHYSIOGRAPHY

The Eagle Plain Basin assessment region, roughly coincident with the Eagle Lowland (Norris 1997) lies in the north central Yukon in the region between latitudes 65°N and 67.5°N, longitudes 136°W and 140°W (Figs. 1 and 2). It covers approximately 20 600 km^2, the central 13 600 km^2 of which are a broad region of generally Cretaceous bedrock (Fig. 3) that is between 400 and 800 elevation, covered by Quaternary deposits. The region underlain by Cretaceous bedrock has a north-south extent of approximately 170 km, and 80 km east-west, forming a rectangular region of subdued topography and younger bedrock than the surrounding regions. The prospective petroleum basin occupies a larger area that includes regions underlain by Paleozoic bedrock west of the Richardson Mountains, largely north of the Peel River and south of the Keele Range (Fig. 3). It is bounded on the east, south and west by distinctive escarpments that follow the geological structure. The Eagle River, after which the region takes its name, flows northward following the eastern escarpment. The Porcupine River flows diagonally, to the northeast across the Eagle Plain, and at its confluence with the Bell River it forms the Bell Basin, which is underlain by similar bedrock successions. The dashed line on Figure 1 indicates the geographic boundaries of subsequent maps that illustrate the discussion below.

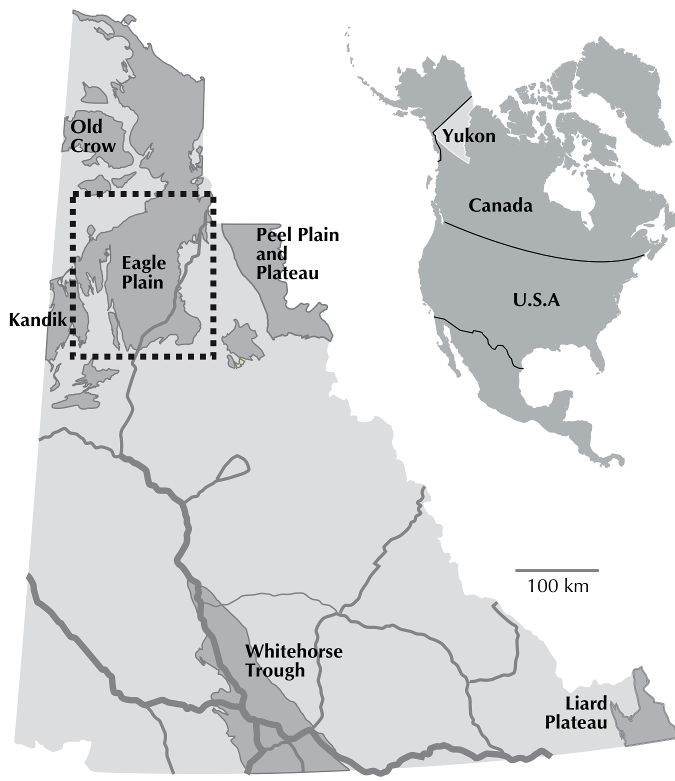


Figure 1. *Location map showing the distribution of Yukon's oil and gas regions in relation to Eagle Plain Basin and environs. The area within the indicated box is the area of this assessment region.*

TECTONO-STRATIGRAPHIC DOMAINS

The assessment area includes most of the Eagle Fold Belt and parts of the Taiga-Nahoni Fold Belt and the Richardson Anticlinorium (Fig. 3; Norris 1997, his Figure 3.15).

The Eagle Fold Belt is a broad region of low relief, of predominantly Cretaceous bedrock outcrops, that coincides with the Eagle Lowland (Eagle Plain and Bell Basin). In this region structures are typically characterized by north-trending folds and thrust faults that parallel the Whitestone Syncline, west of which lies the northern part of the Taiga-Nahoni Fold Belt, a region of largely pre-Mesozoic outcrops deformed in Laramide thrust and fold structures. The southwestern corner of the Eagle Fold Belt, in the vicinity of the headwaters of the Ogilvie River, is the margin of the Ogilvie deflection. There the structural trend of the Taiga-Nahoni Fold Belt, which forms the western- and southern-most parts of the assessment regions, turns continuously, but abruptly to the east, wrapping around the region of Cretaceous bedrock outcrop that underlies the Eagle Lowland to the north and east of the Taiga-Nahoni Fold Belt (Fig. 3). The Ogilvie and Peel rivers generally mark the southern limit of the Eagle Fold Belt, which merges gradually with the structures of the Taiga-Nahoni Fold Belt, east of the Ogilvie deflection. The easternmost parts of the Eagle Plain Basin forms the complicated western limb of Richardson Anticlinorium. The Eagle Fold Belt, the Taiga-Nahoni Fold Belt, and the Richardson Anticlinorium are all linked Laramide structures influenced by the structural fabric of the underlying basement, faults which controlled the deposition of Paleozoic successions on the Porcupine Platform and its margins. To the north lies the Aklavik

Arch Complex, structures related to the formation of the Canada Basin that were subsequently involved in the Laramide compression, the southern limit of which coincides with the southeasterly verging Sharp Mountain Thrust Fault (see Figs. 3 and 10).

Generally elements of the surface bedrock structure follow major, fault-bounded early Paleozoic or older tectono-stratigraphic domains (Fig. 4). The Eagle Plain Basin is part of the Yukon Stable Block, an Early Paleozoic cratonic fragment that was rifted from the margin of the ancestral North American craton in early Paleozoic time, probably following Precambrian structural trends and elements. The Richardson Trough and Selwyn Basin separated the Yukon Stable Block from North American craton. The southeastern part of the Yukon Stable Block was a persistent Paleozoic shallower water carbonate platform called the Porcupine Platform, the margins of which now occur deformed in Laramide structures in the Taiga-Nahoni Fold Belt. To the east, the platform passed into the Richardson Trough, the transition to which is buried beneath the Mesozoic and upper Paleozoic successions in the eastern Eagle Plain Basin. The Richardson Anticlinorium, which borders the eastern side of the assessment region, follows the Richardson Trough roughly, although it is now a structurally inverted and east-verging thrust sheet (Hall, 1996), bordered on its east by the Trevor thrust fault (east of map area, Osadetz et al., 2005a). Another important structure is the buried, antiformal, probably thrust-faulted structure that lies immediately west of the Whitestone Syncline (see Fig. 10), and which is probably a reactivated or modified structure in Precambrian successions and possibly the basement. This

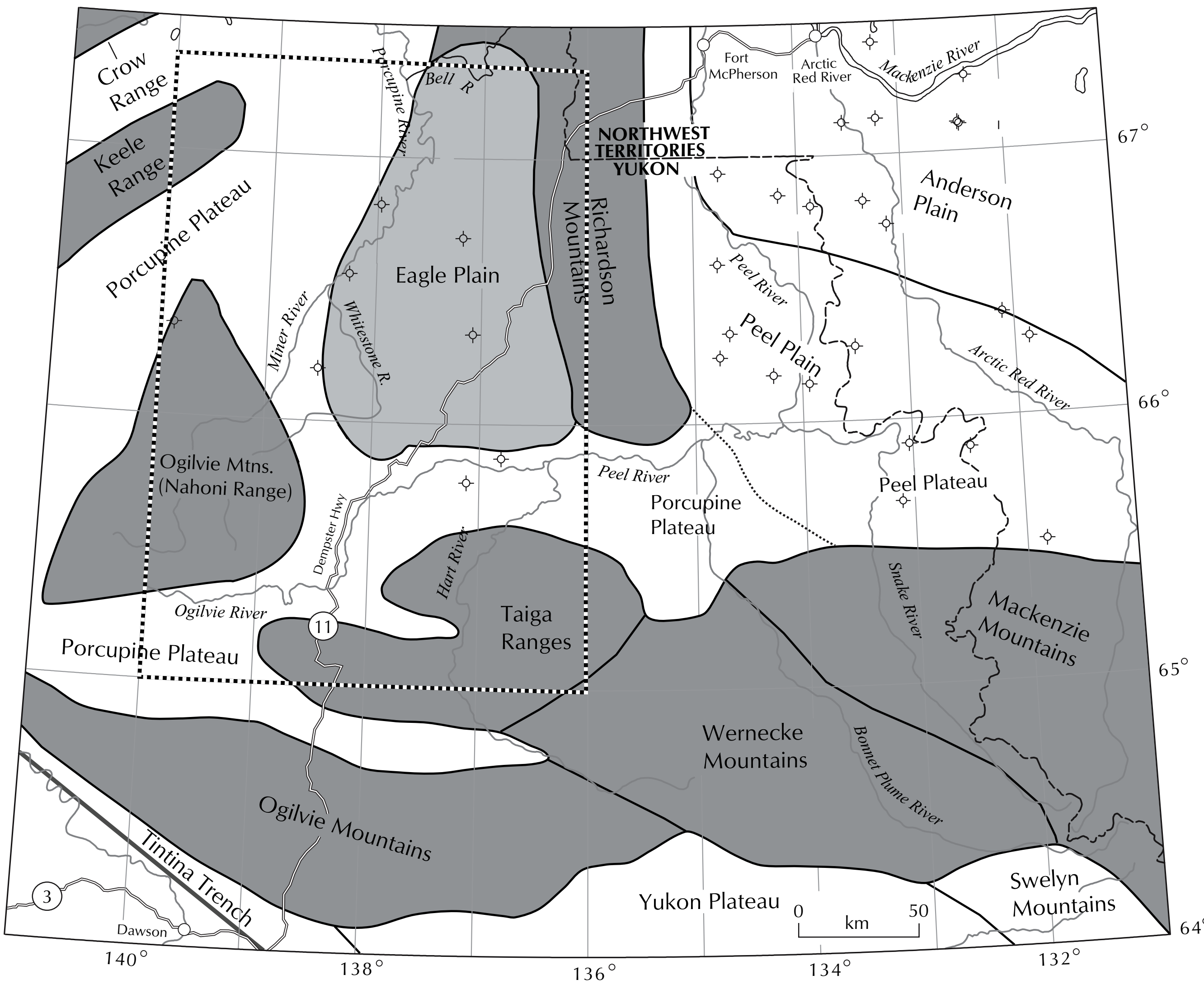
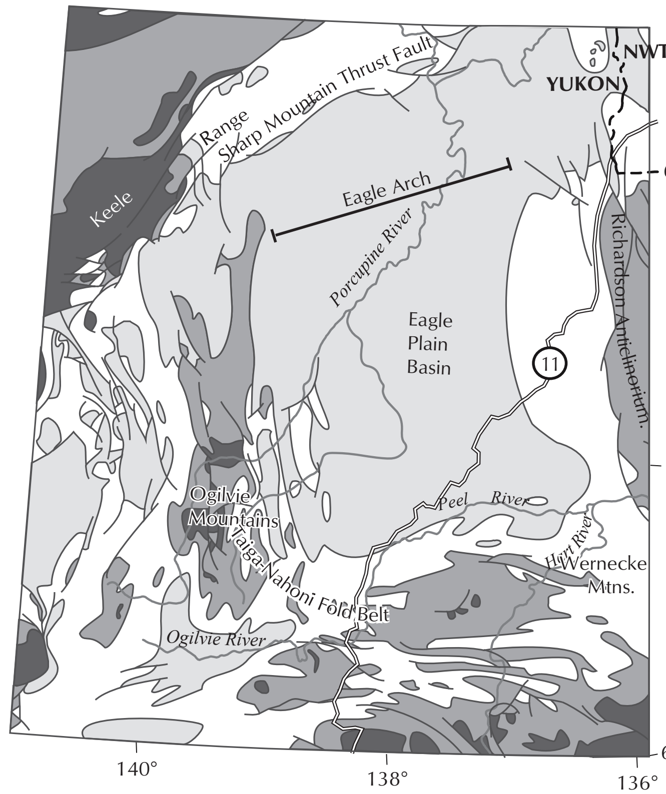


Figure 2. Major physiographic subdivisions within the Eagle Plain Basin and environs assessment region including, portions of Anderson Plain, Peel Plateau, Peel Plain, Richardson Mountains and Mackenzie Mountains (from Morrow, 1999). Dashed outline shows area of Figure 3.

buried structure (see below) is probably related, in part, to the southern portions of the Dave Lord High.

Within the Eagle Basin, a major northeast- to southwest-trending feature, the Eagle Arch (Ancestral Aklavik Arch of Richards et al. in Norris 1997) is marked by the erosional edges of Paleozoic successions. Figure 4 illustrates Morrow's (1999) interpretation that links the Eagle Arch and the Dave Lord High, where the Dave Lord High is the persistent carbonate platform, or positive region, that is coeval to Upper Ordovician to Lower Devonian basinal clastic deposition on the southeastern Bouvette carbonate platform. The Eagle Arch was active during the Late Carboniferous and Early Permian when the Carboniferous succession was generally eroded to the north of its hinge (Richards et al. in Norris, 1997). The Eagle Arch appears not to have directly influenced the trends in the Eagle Fold Belt during Laramide deformation.



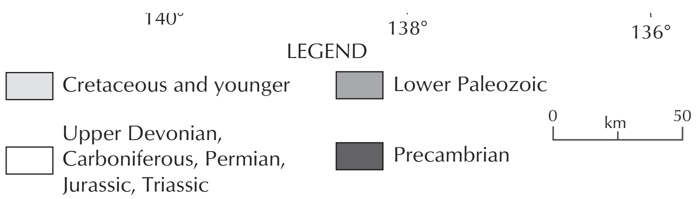
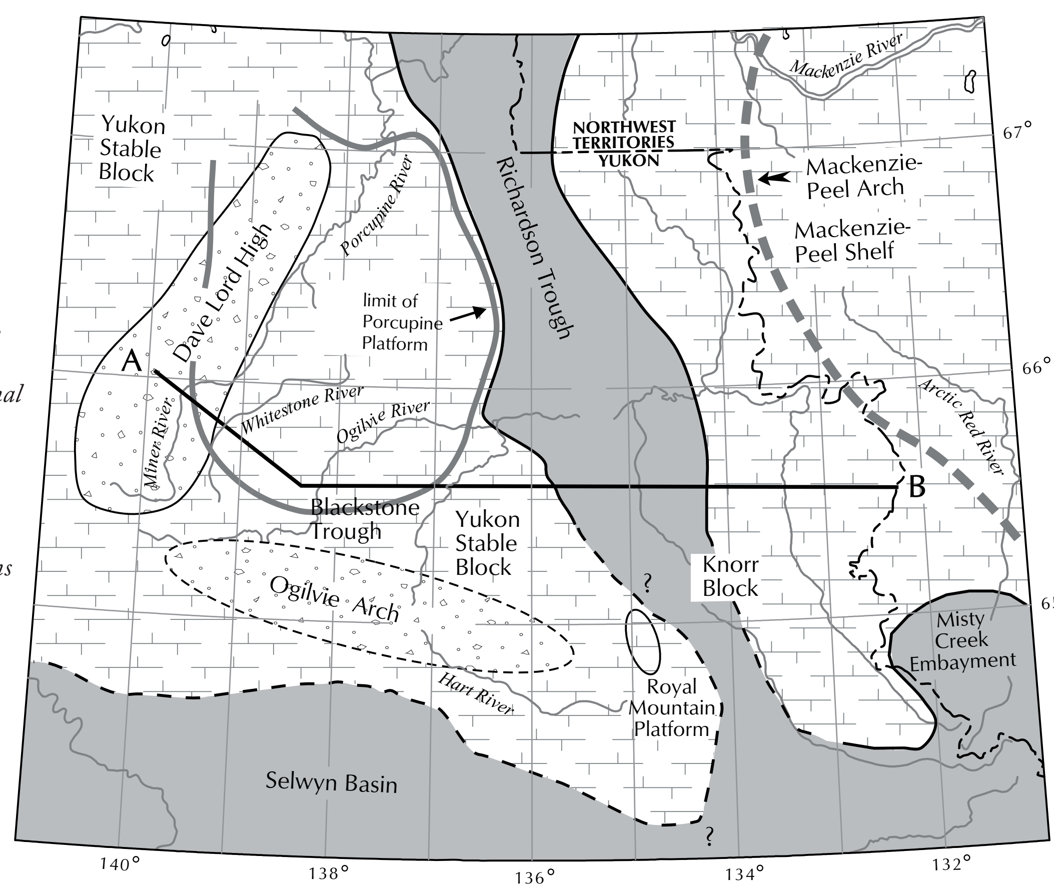


Figure 3. Simplified geological map of the Eagle Plain Basin assessment area, and environs, in the Yukon (after Morrow, 1999).

Figure 4. Major early Paleozoic paleogeographic elements that repeatedly influenced Phanerozoic sedimentation and tectonic fabric in the region. Areas of predominantly shallow water carbonate deposition are filled with a modified brick pattern, while the shaded regions are predominately regions of basinal shale deposition, including the Richardson Trough (after Morrow, 1999). The stratigraphic relationships in Devonian and older successions along section line A–B are illustrated in Figure 5.



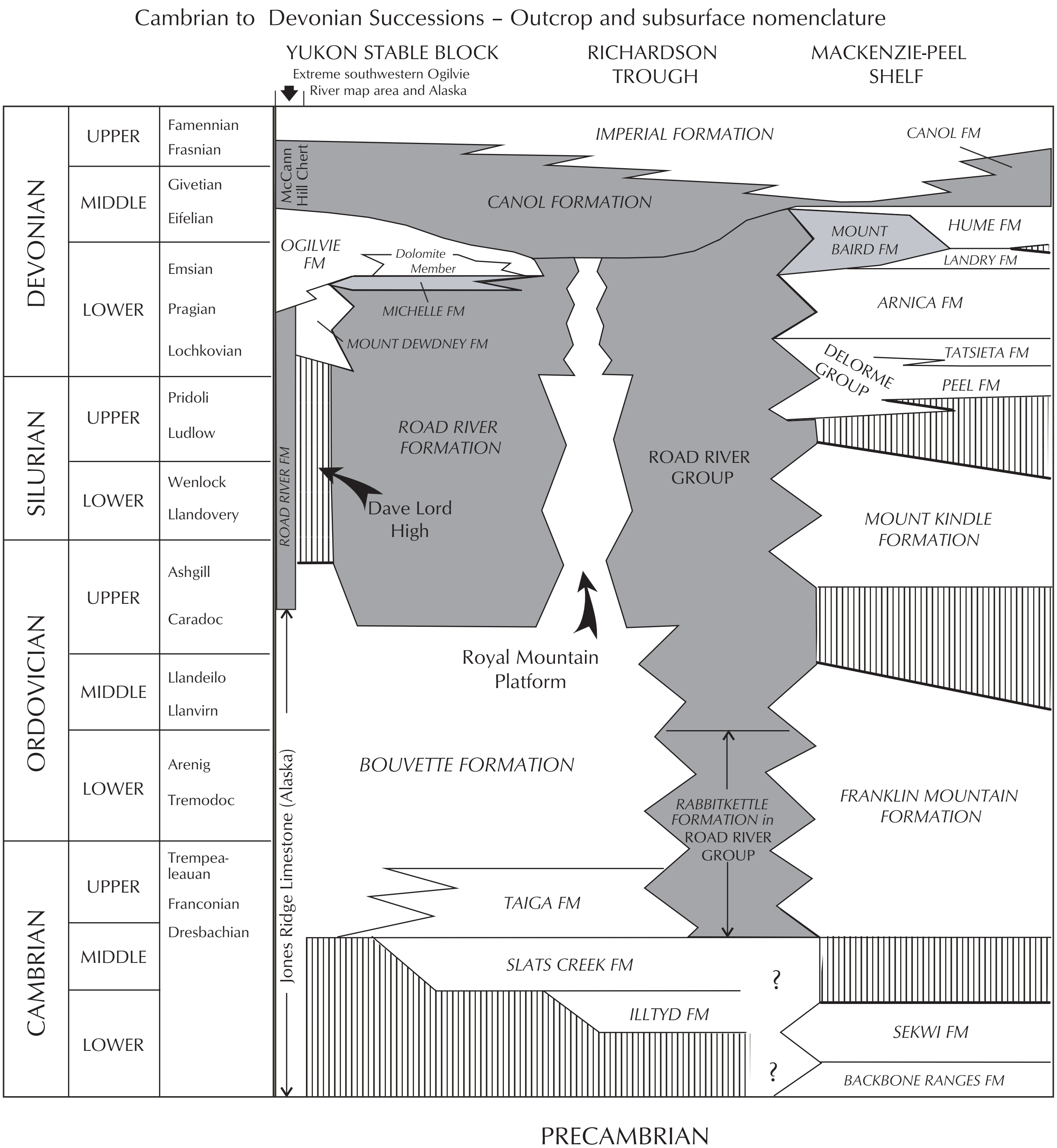


Figure 5. *An east-west diagrammatic illustration of stratigraphic relationships (correlation chart, after Morrow, 1999) of lower Paleozoic strata across the study region from the Dave Lord High into the Mackenzie Peel Shelf (section line A-B in Figure 4) illustrating the stratigraphic relationships on both sides of the Richardson Trough. Note the major change in stratigraphic nomenclature that occurs across Richardson Trough. The Eagle Plain Basin is underlain by lower Paleozoic successions of the Yukon Stable Block. The figure, and this report, shows and uses the current Yukon Stable Block stratigraphic nomenclature (Morrow, 1999). The Bouvette Formation strata (i.e., Norris's, map unit CDb (1985a) is termed the Royal Mountain Platform, where it extends into the base of the Canol Formation, and it is projected into the line of section from mountain outcrops to the south of the Eagle Plain (Morrow, 1999). FM = Formation.*

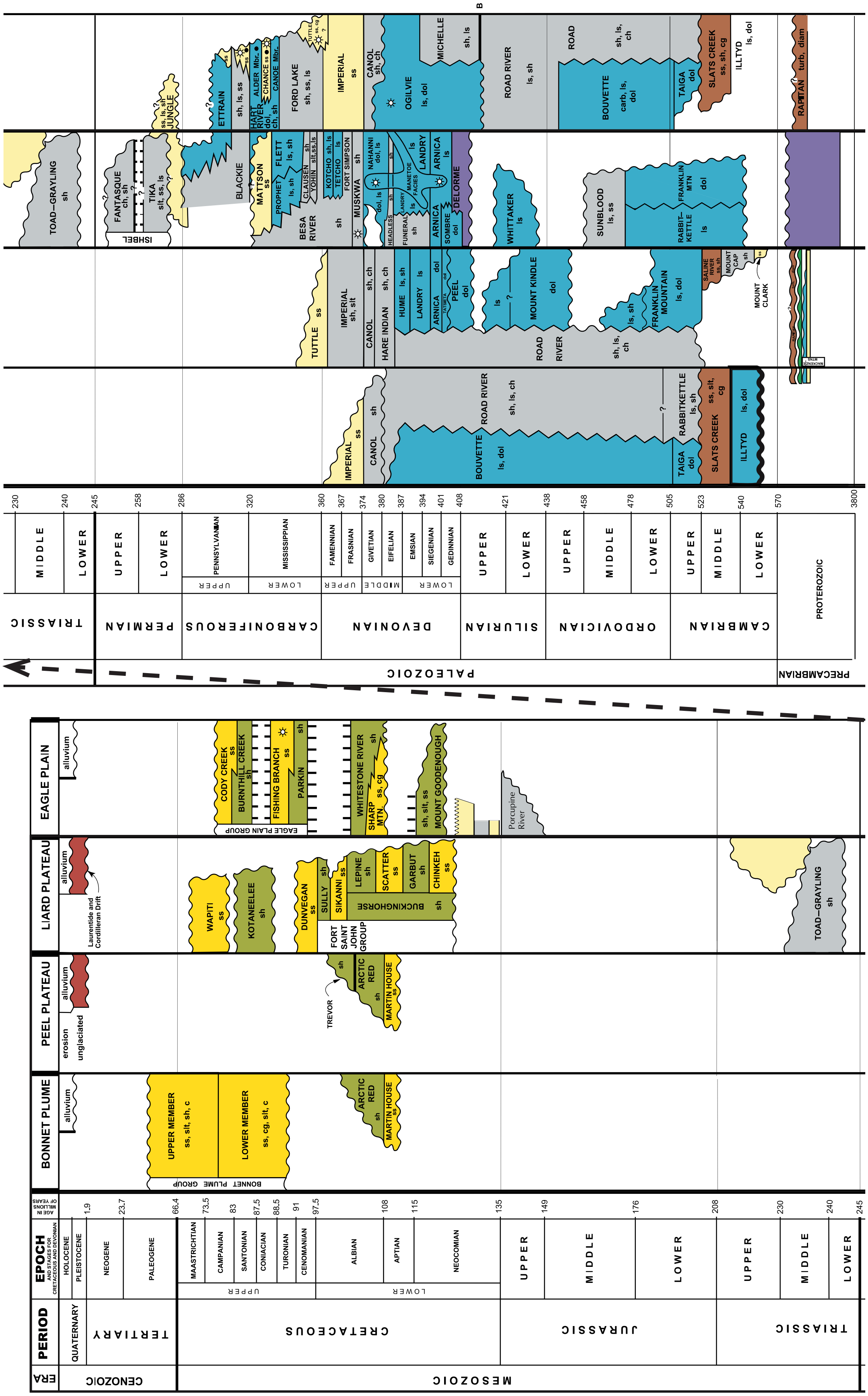


Figure 6. *Time-stratigraphic column of the Eagle Plain Basin (far right) showing age relationships of the Phanerozoic succession, and compared to the stratigraphic successions of the nearby areas. Modified from http://www.emr.gov.yk.ca/Publications/OilandGasPublications/yukon_stratigraphic_chart2003.pdf.*

STRATIGRAPHY

An easterly tapering wedge of Phanerozoic sedimentary rock, up to approximately 6 km thick, that unconformably overlies Proterozoic successions of varying ages and tectonic affinities, underlies the Eagle Plain Basin. The Phanerozoic succession is composed of two major unconformity-bounded sequences, which themselves contain significant, but lesser unconformities (Fig. 6). The stratigraphy of the region is well described in several recent reports (Martin, 1973; Hamblin, 1990; Dixon, 1992; 1999; Norris 1997 and contributions therein; Morrow, 1999; NEB, 2000). Note especially that cores of potential reservoir intervals are available for much of the succession. Many of these cores are described by Dixon (1992; 1999), Hamblin (1990) and Morrow (1999).

Morrow (1999) provides a detailed analysis of the lower Paleozoic successions that includes tables of formation tops for all the wells penetrating below the top of the Devonian Canol Formation. Hamblin (1990, his Figure 10) provides a chart indicating the formations penetrated by 22 wells in the southern Eagle Plain Basin, south of the Carboniferous subcrop edge, but he did not provide a table of formations. Dixon (1992) provides a table of formations for all of the wells penetrating the Cretaceous succession that includes a description of the strata underlying the Mesozoic succession. The appropriate, individually authored, stratigraphic chapters in Norris (1997) describe the intervening Jurassic, Permian and Carboniferous strata, although none of these successions have tables of formations for the wells in the region. Stratigraphic top assignments in the wells for this study, either use the formation tops of Morrow (1999), Dixon (1992) or they use the Department of Indian and Northern Affairs tops, which were mostly assigned by Morrow, Dixon, or the contributors to the 1997 Norris publication. It is from these sources that the stratigraphic assignments of deepest formation penetrated and drill stem test intervals are derived in the discussion of exploration history and petroleum systems that follows.

Cambrian strata are not penetrated by any wells in the study region, but outcrops on the margin of the basin suggest that the Cambrian to Middle Devonian carbonate succession and its coeval strata overlie a basal Cambrian clastic succession, or its equivalents (Figs. 5 and 6). The Middle Cambrian to Upper Ordovician was an interval of pervasive carbonate platform deposition across most of the study area, resulting in the deposition of the Bouvette Formation, up to 1500 m thick, which was a persistent carbonate platform that passed eastward into the Road River clastic sediments of the Richardson Trough (Fig. 7 and 8). During the Upper Ordovician that portion of the Bouvette Platform lying south and east of the Porcupine River was transgressed by the Road River Formation, and a fine clastic succession of Road River and Michelle formations, commonly up to 500 m thick were deposited on top of the southeastern half of the Bouvette Platform, south of the Dave Lord High.

During the Early Devonian, a carbonate platform, Mount Dewdney Formation, up to ~200 m thick was re-established on the Dave Lord High. During the Middle Devonian this carbonate platform expanded to form the Ogilvie Formation, up to ~1100 m thick, across most of the Eagle Plains, except for the Bell Basin region in the northeast. Potential reservoirs are indicated in a number of zones in the Bouvette and Mount Dewdney-Ogilvie succession by the recovery of formation fluids on drill stem tests (Morrow, 1999).

The Canol and Imperial basinal clastic sediments, approaching 2000 m thick, drowned and transgressed the Ogilvie Platform during the Middle and Upper Devonian, as the harbinger of southward- and westward-prograding Ellesmerian clastic wedge that becomes more proximal and coarser both up section and toward the southeast (Fig. 9; Norris 1997). A lack of shows and tests of the Imperial Formation should be reconsidered, since the same formation has indications for reservoir potential on the eastern side of the Richardson Anticlinorium (Osadetz et al., 2005a).

The Imperial Formation passes upward, conformably into the coarse clastic sediments of the Tuttle sandstones, exceeding 1400 m thick, which prograded across the eastern half of the Eagle Basin by Tournaisian time (early Carboniferous; Richards, 1997; Hamblin, 1990; Graham, 1973; Martin, 1973; 1972; 1971). A major transgression during the Late Tournaisian and Visean is recorded in the deposition of the Ford Lake Formation shale, up to 975 m thick, which transgresses the Tuttle Formation Sandstone, and which passes conformably upward into the Hart River Formation that includes both the Canoe River, up to 480 m thick, and Alder limestone members, which lie below and above the Chance Sandstone Member, up to 310 m thick, respectively (Hamblin, 1990). The succeeding mid-Carboniferous transgression of the fine-grained Blackie Formation lime mud rocks, up to 294 m thick, is overlain by the Ettrain Formation limestones, up to 732 m thick. During the Late Carboniferous to Early Permian the Eagle Arch, a rejuvenation, in part, of the Dave Lord High, resulted in the erosion of the Carboniferous and uppermost Devonian such that Imperial Formation subcrops below younger strata. The unconformity is overlain by a Permian sandstone and shale succession commonly inferred to as Jungle Creek Formation (Dixon, 1992; Nassichuk, 1971; Bamber et al., 1989), although Richards et al. (in Norris 1997), suggests that this sandstone and shale succession, which is up to 719 m thick, might be better distinguished as an unnamed stratigraphic unit. Reserves, shows and tests indicate good potential reservoirs in all of the proximal lithologies of the Carboniferous succession.

Jurassic strata are present in F-48 and P-34 wells (Dixon, 1992, his Figure 27 and Appendix 1; Jeletzky, 1974) and they may also occur in the J-70 well (ibid., Appendix 1). Otherwise they are inferred eroded from the Eagle Basin, prior to Cretaceous deposition. While there were some minor shows in Jurassic strata it remained an unassessed, but conceptual play interval in this analysis.

A basal transgressive Lower Cretaceous sandstone, Mount Goodenough Formation, up to 341 m thick in the Whitefish J-70 well, is identified in the northern Eagle Plain (Fig. 6; Dixon, 1992, his Figures 5 and 10), although an outlier occurs in the southern Eagle Plain. The Cretaceous succession thickens northwesterly, from less than 500 m thick in the southeasternmost Eagle Plain to over 2000 m in the western reaches of the preserved Cretaceous succession. Farther west, a deeper erosional level results from the Laramide structure. The Cretaceous succession is composed of Albian Whitestone River (up to 1500 m thick), Cenomanian-Turonian Fishing Branch (up to 300 m thick), and Santonian-Campanian Cody Creek (originally much more than 800 m thick) formations, all of which are sandstone-dominated strata that are interbedded with the shalier Upper Cretaceous Parkin (up to 500 m thick, and containing a sandstone member up to 200 m thick) and Burnthill Creek (up to 400 m thick) formations. The Cretaceous strata are arranged in trangressive-regressive cycles that record the episodic progradation of coarse clastic wedges from the Cordillera into the Laramide Foreland Basin on the Eagle Plain (Dixon, 1992). At least four major sandstone-dominated units in the Whitestone River, Parkin, Fishing Branch and Cody Creek formations are potential petroleum reservoirs.

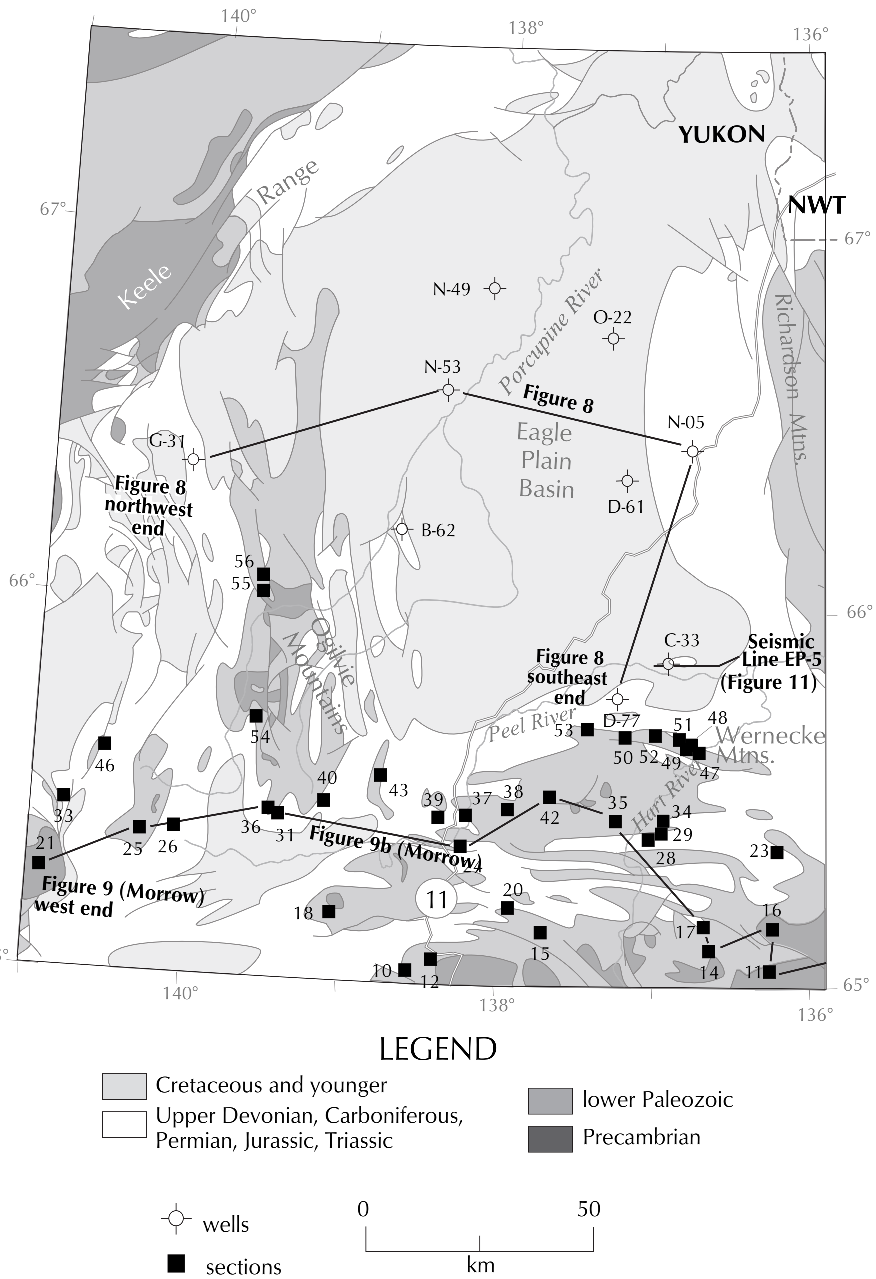


Figure 7. Bedrock geological map showing the location of wells used in the subsurface stratigraphic correlation section for the lower Paleozoic succession in the Eagle Plain as illustrated in Figure 8 (following and from Morrow, 1999). Also shown is the location of surface sections described by Morrow (1999), which provide data that constrains the play parameters in the lower Paleozoic succession.

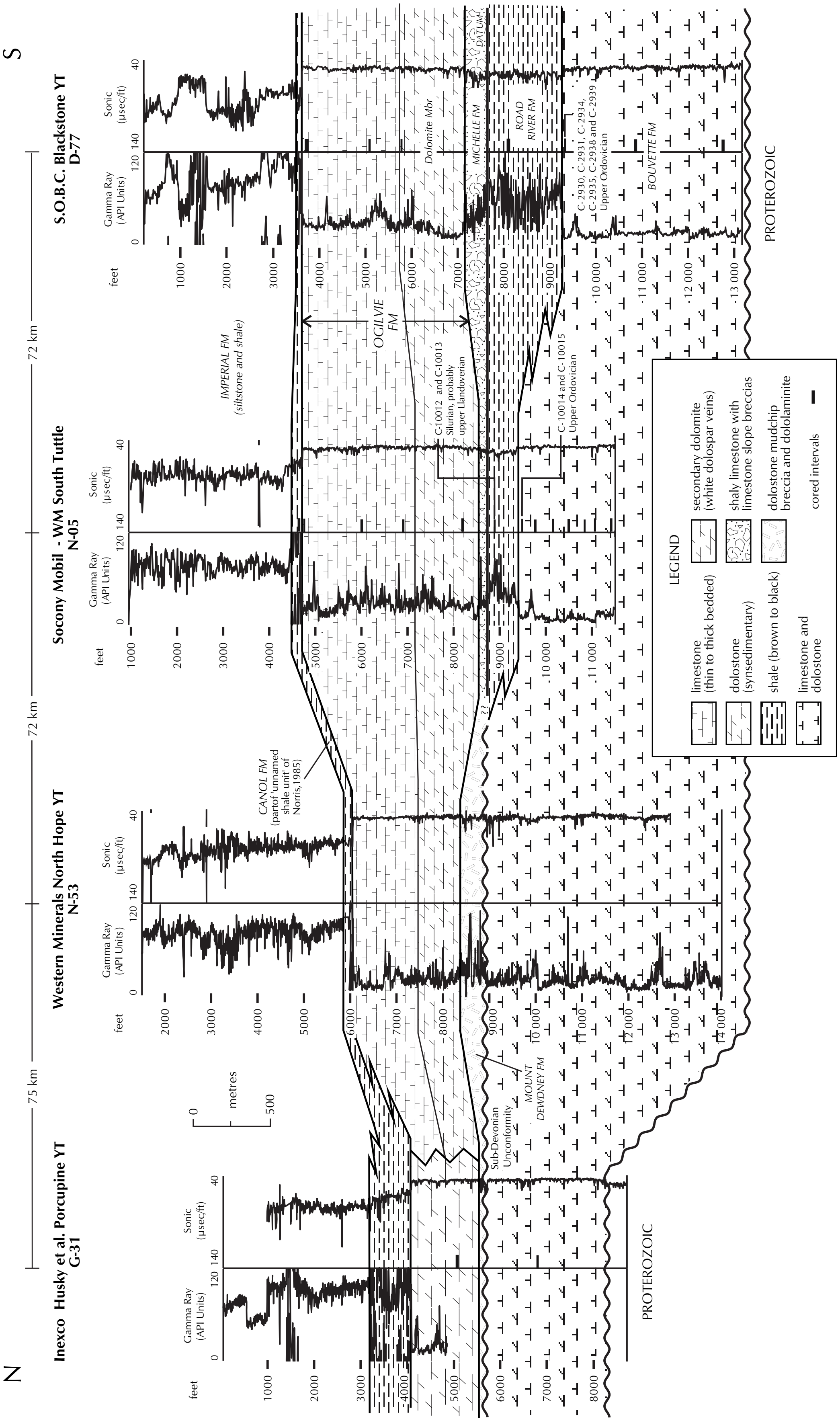


***Figure 8.** A subsurface stratigraphic cross-section of lower Paleozoic strata beneath Eagle Plain (Fig. 7). The Ogilvie Formation in the Porcupine G-31 well at the west end of the cross-section has undergone late-stage dolomitization and contains abundant, white, sparry, fracture-filling, "saddle" dolomite. FM = Formation, Mbr = Member*

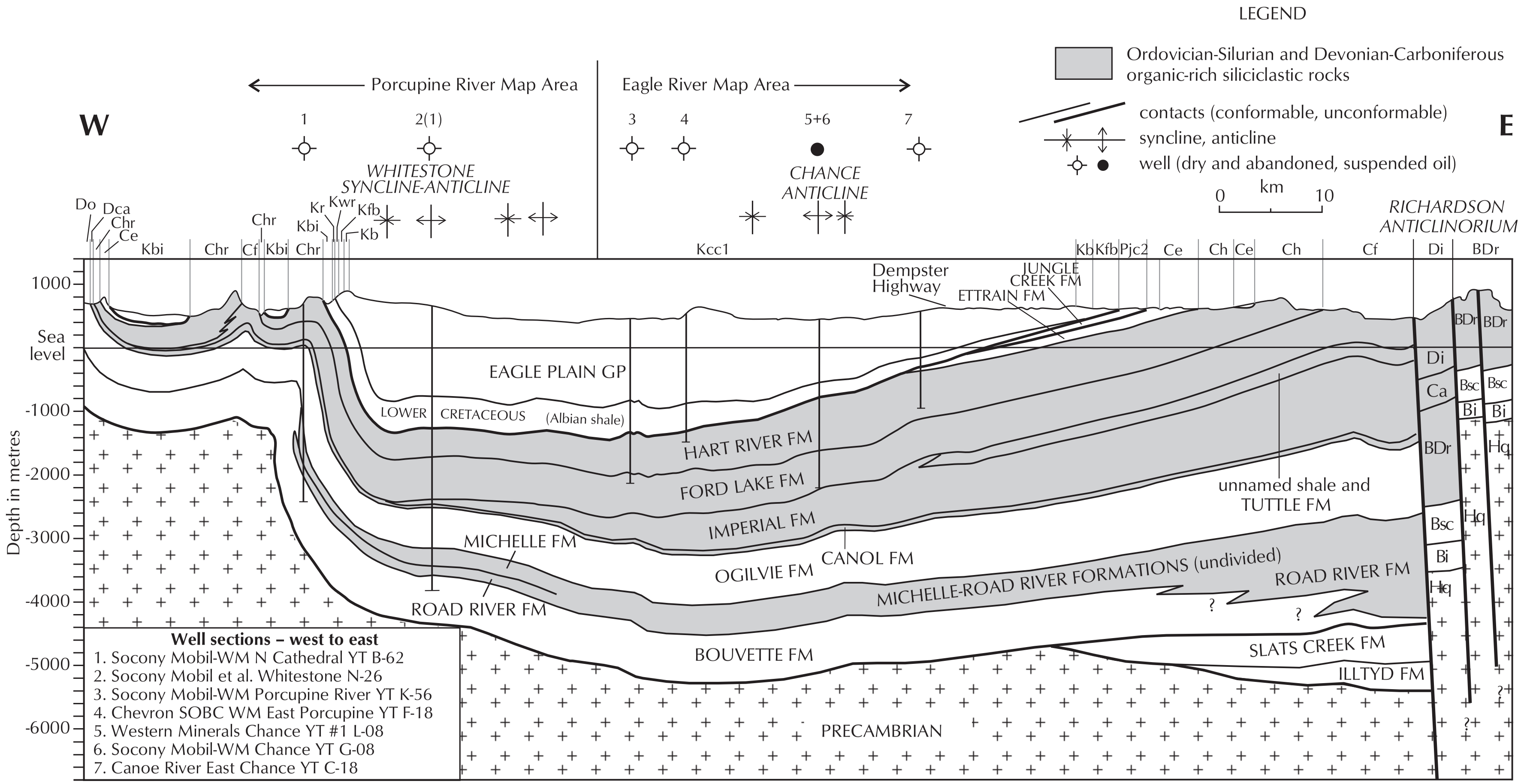


Figure 9. *An east–west structural cross-section across Eagle Plain along 66°07'30" latitude westward from Eagle River map area (116I/) into Porcupine River map area (116I/ and 116K, E1/2) (from Morrow, 1999). Thick lines on subsurface stratigraphic contacts represent unconformities. Siliciclastic units, potential intervals for major source rock development, are shaded. See Norris (1981a, b) for explanation of map symbols (e.g., the 'Do' map unit represents the Ogilvie Formation). Note the distribution of the Carboniferous and Permian succession that is progressively truncated northward beneath the unconformity at the base of the Mesozoic succession. The subcrop of the Hart River Formation provides a major stratigraphic trapping opportunity that is associated with the Chance oil field. Note also, both the favourable orientation of lower Paleozoic carbonate platforms relative to facies changes and structures on the western flank of the Richardson Anticlinorium/Trough, and the major Precambrian-cored anticlinorium, which is probably thrust faulted at depth, which lies immediately west of the Whitestone Syncline and which is a major structural element of the Eagle Plain Basin.*

STRUCTURAL GEOLOGY

The structural geology of the assessment region requires a comprehensive study and revision that is beyond the scope of this report. Elements of a revised structural model have been incorporated into the characterization of petroleum play definitions and prospect parameters, but their detailed discussion is the subject of current study, the details of which were not available to the authors of this report, and which will appear elsewhere (Lane, 1996a; 1996b; 1996c; 1998b; oral communication). There are several generations of structures, some of which were reactivated or modified during subsequent periods of deformation. The manifest bedrock structures are Laramide contractional structures that involved the reactivation or modification of early structural elements (Figs. 9 and 10).

Early Paleozoic rifting formed the Yukon Stable Block and controlled Cambrian to Middle Devonian depositional patterns (Fig. 4 and 5). Few individual structures related to this episode are identifiable, although the major features are preserved in the depositional pattern of the Early Paleozoic carbonate platform (Morrow, 1999), forming the Richardson Trough, the Yukon Stable Block and the Selwyn Basin, as well as the associated structures of this event. These structures had a profound influence on the subsequent history of reactivation and modification during succeeding compressional deformations. The southerly progradation of the Middle and Upper Devonian Imperial Formation clastic wedge is the harbinger of the poorly described, but fundamentally important, Franklinian-Ellesmerian deformation. This is a compressive deformation which controlled the depositional patterns of the Carboniferous and Permian strata, and during which time the most important erosional truncation occurred on the Eagle Arch (Fig. 12). Lane (1996b; 1996c; oral comm.) has identified and is analysing structures of this deformational episode, although they are currently not well described.

The major change in depositional patterns during Jurassic to Aptian time, as compared to the Carboniferous, is probably indicative of far-field influences related to the formation of the Canada Basin, which was forming at this time. At that time, the Aklavik Arch and the ancestral faults to the Sharp Mountain thrust were active. Structures of this interval are also poorly described. Dixon's sub-Albian geology map (Dixon, 1992, his Figure 17) illustrates the complicated subcrop pattern of older successions below the Cretaceous succession.

During the Albian, sediments derived from the Cordilleran orogen prograded northward into the developing Canada Basin (Dixon, 1992), which was linked to the formation of the Keele-Kandik and Blow troughs during the Early Albian (Young, 1973; 1975), during the northward progradation of the Whitestone River Formation, which Dixon (1992) interpreted to be derived from the erosion of the Cordillera. During the interval Cenomanian to Campanian the Cretaceous succession indicates Foreland Basin cycles of trangressive and regressive sedimentation that Lane (1998) used to show that the contractional Laramide structures in the Eagle Fold Belt post-date the deposition of the youngest preserved Campanian strata (Figs. 10, 13, 14 and 15). This shows that all of the Eagle Fold Belt, the Taiga-Nahoni Fold Belt, and the Richardson Anticlinorium are linked Laramide structures influenced by the structural fabric of the underlying basement, the faults in which controlled Paleozoic successions on the Porcupine Platform and its margins (Figs. 9 and 10). The Laramide structures developed after the deposition of the youngest preserved strata in the Cretaceous succession (Lane, 1996a; 1996b; 1996c; 1998b). The bedrock structures of this deformation are very well described where Cretaceous strata are preserved (Fig. 10, from Dixon, 1992 after Norris 1984). However, there are regions where Cretaceous strata are not preserved and the recognition of structures of earlier events will be difficult to identify and separate from the Laramide deformational geometry. In addition, there are clearly multiple important structural detachments in the Laramide deformation (Fig. 15). The relationship between the deformation in the Proterozoic, Paleozoic and Cretaceous is complicated by the presence of these major detachment surfaces (Figs. 14 and 15).

Hall (1996) reported on a 250-km-long east-west geological and geophysical transect constructed at about 66° 40'N, from near the Yukon-Alaska border, across the Eagle Plains and Richardson Anticlinorium, into the Interior Platform. His study considered reprocessed reflection seismic, gravity data and stratigraphic information from the petroleum exploration wells. He described the Richardson Anticlinorium, which is cored by lower Paleozoic and Proterozoic strata as a post-Carboniferous pop-up structure bounded on the east and west by thrust faults, with shortening of about 33 km, which is probably Laramide in age, like the Trevor Thrust (see Osadetz et al., 2005), consistent with the timing inferred by Lane (1998). Hall (1996) inferred the 'pop-up' structure to be developed above a regional detachment that he extended beneath the Eagle Plains to the west, and that the 'pop-up' was localized by a pre-existant crustal-scale ramp, probably related to the formation of the Richardson Trough during early Paleozoic crustal extension.

Most of the wells drilled to date have been located on or in association with structures that have a mapped bedrock expression (Fig. 10). The complicated and incompletely described structural analysis was a major factor that led to the manner in which petroleum plays were defined and analysed, since it was not possible to identify and subdivide specific structures into groups that would allow the definition of specific plays based on structural history.

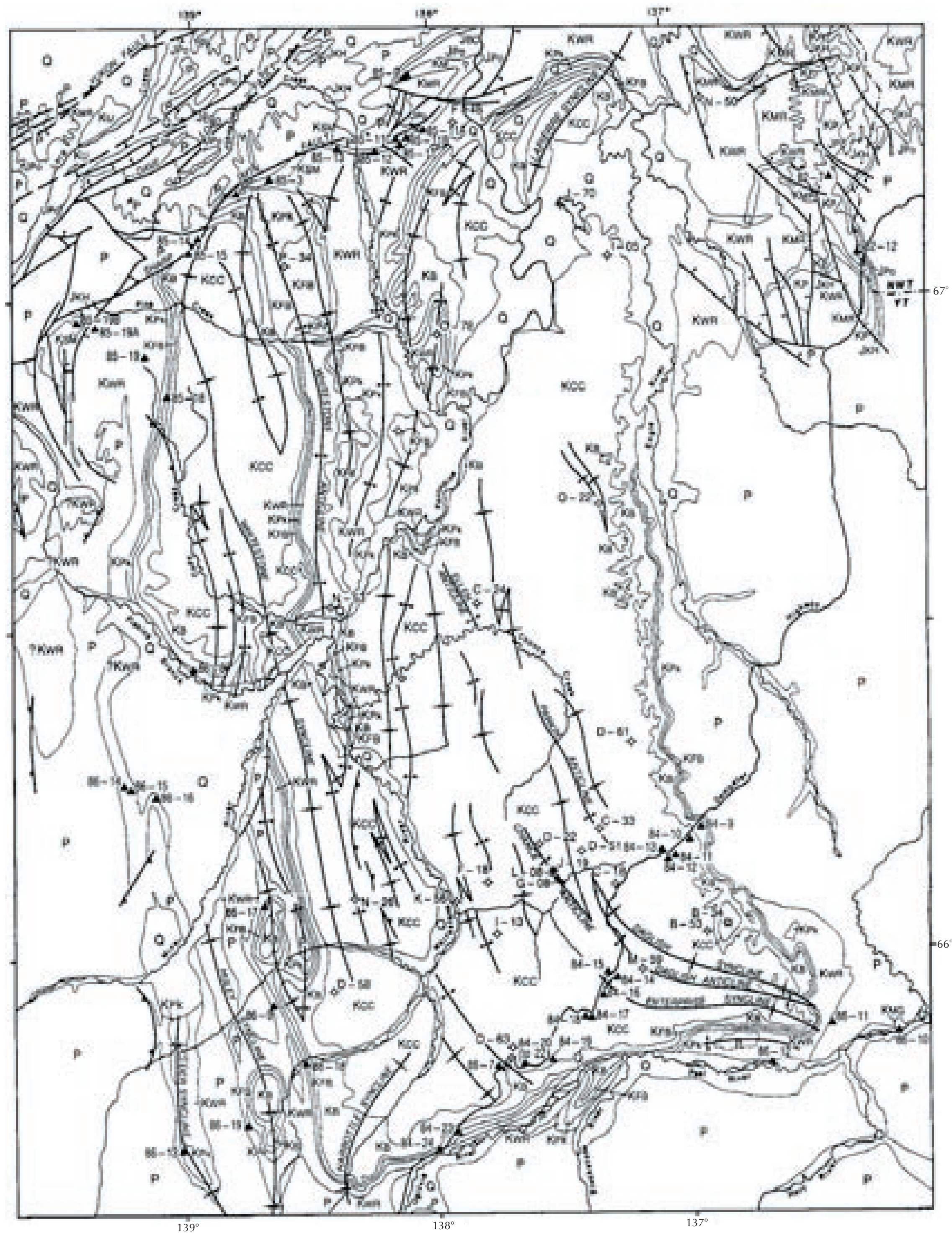


Figure 10. *The bedrock structural elements of the Eagle Plain Basin and environs including the Richardson Anticlinorium as outlined primarily by Cretaceous stratigraphic markers (from Dixon, 1992) in a simplification of Norris's mapping (1985a). Note the relationship of structures on this map with the structure section in the southern Basin (Fig. 9).*

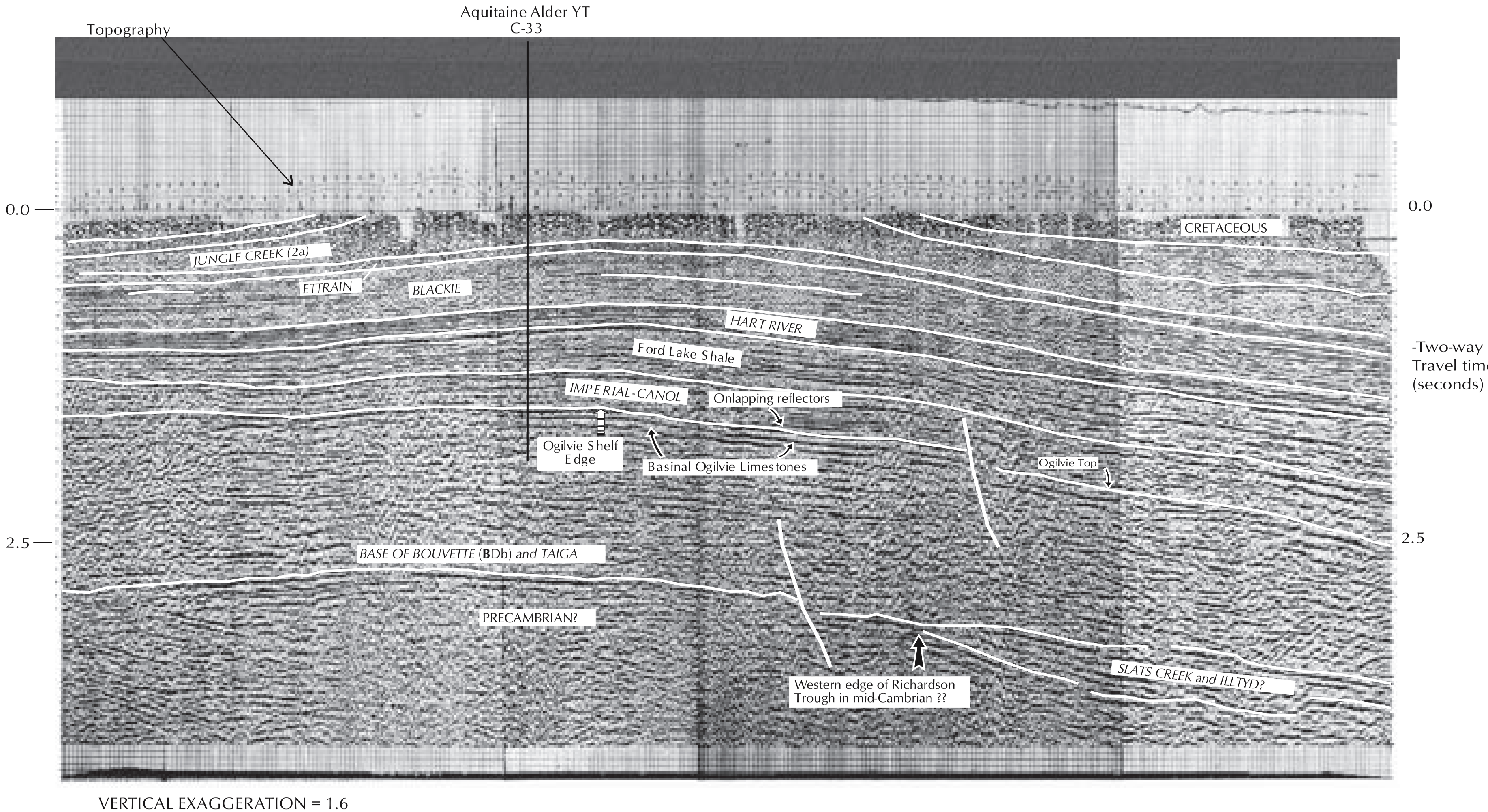


Figure 11. *A west (left) to east (right) reflection seismic line in the southeastern Eagle Plain Basin (EP-5 from Aquitaine of Canada Ltd, from Morrow, 1999, his Figure 13). The seismic line trends west-east through the Aquitaine Alder C-33 well (Fig. 7, Table 2). The seismic section is parallel to the outcrop line of sections in the mountain studied by Morrow (1999), which is also shown in Figure 7. The line illustrates the eastward shelf–to–basin transition within the Ogilvie Formation, and which could provide a major stratigraphic trapping opportunity.*

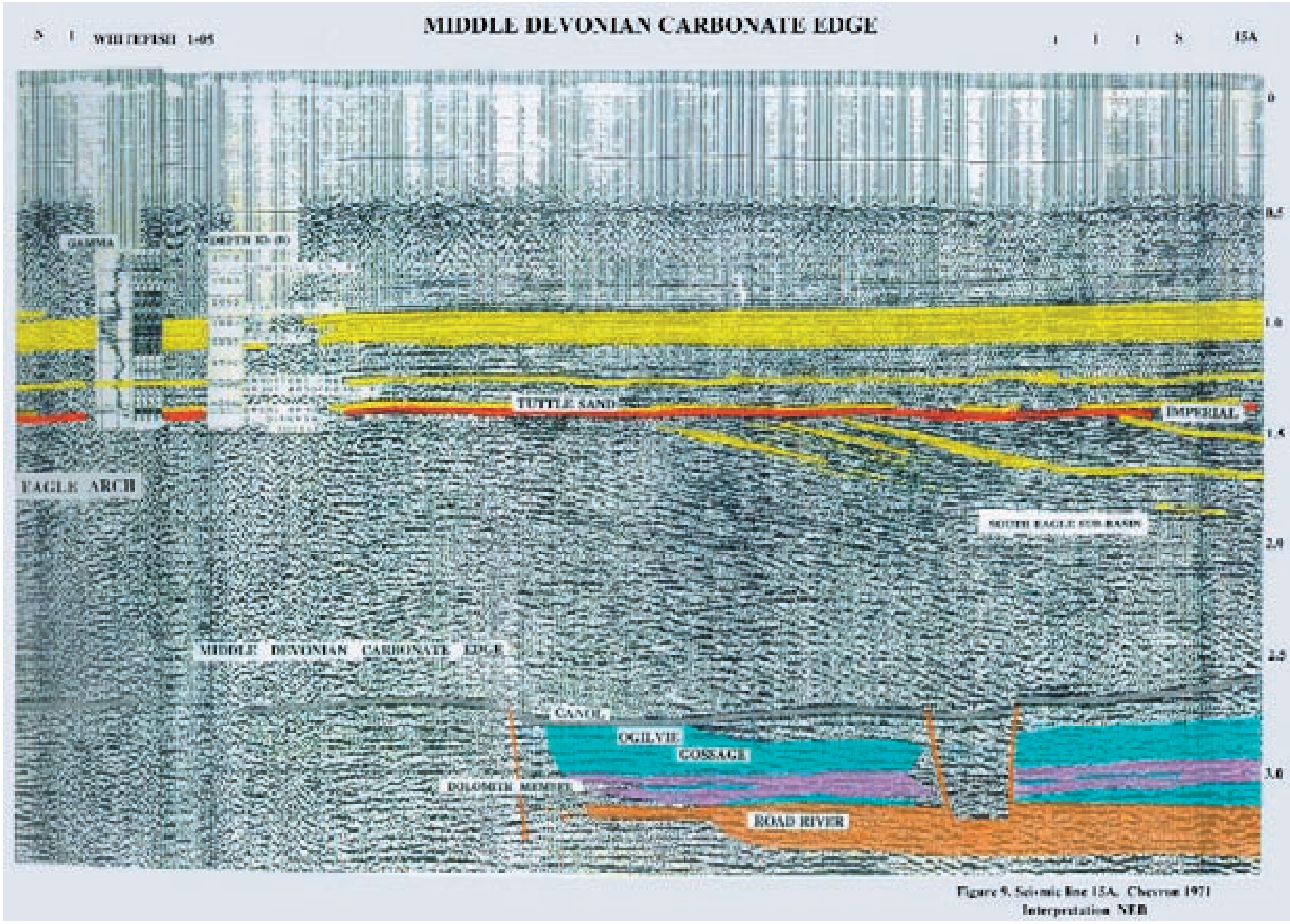


Figure 12. A north (left) to south (right) reflection seismic line in the northeastern Eagle Plain Basin in the vicinity of the Eagle Arch (Ancestral Aklavik Arch of Richards et al., 1997), where Latest Carboniferous to Early Permian erosion resulted in the angular unconformity between underlying Carboniferous and Devonian formations and overlying strata. Note the truncation of the Imperial Formation (line 15A from Chevron Canada Ltd. interpreted in NEB, 2000, their Figure 9). The seismic line trends west–east through the Whitefish I-05 well (Fig. 10, Table 2). The seismic section also illustrates the eastward shelf–to–basin transition from the Ogilvie Formation to the Road River Formation (note that some of the NEB interpreted stratigraphic markers such as "Gossage" are inconsistent with the stratigraphic nomenclature of Morrow (1999), which is used in this report, and which could provide a major stratigraphic trapping opportunity).

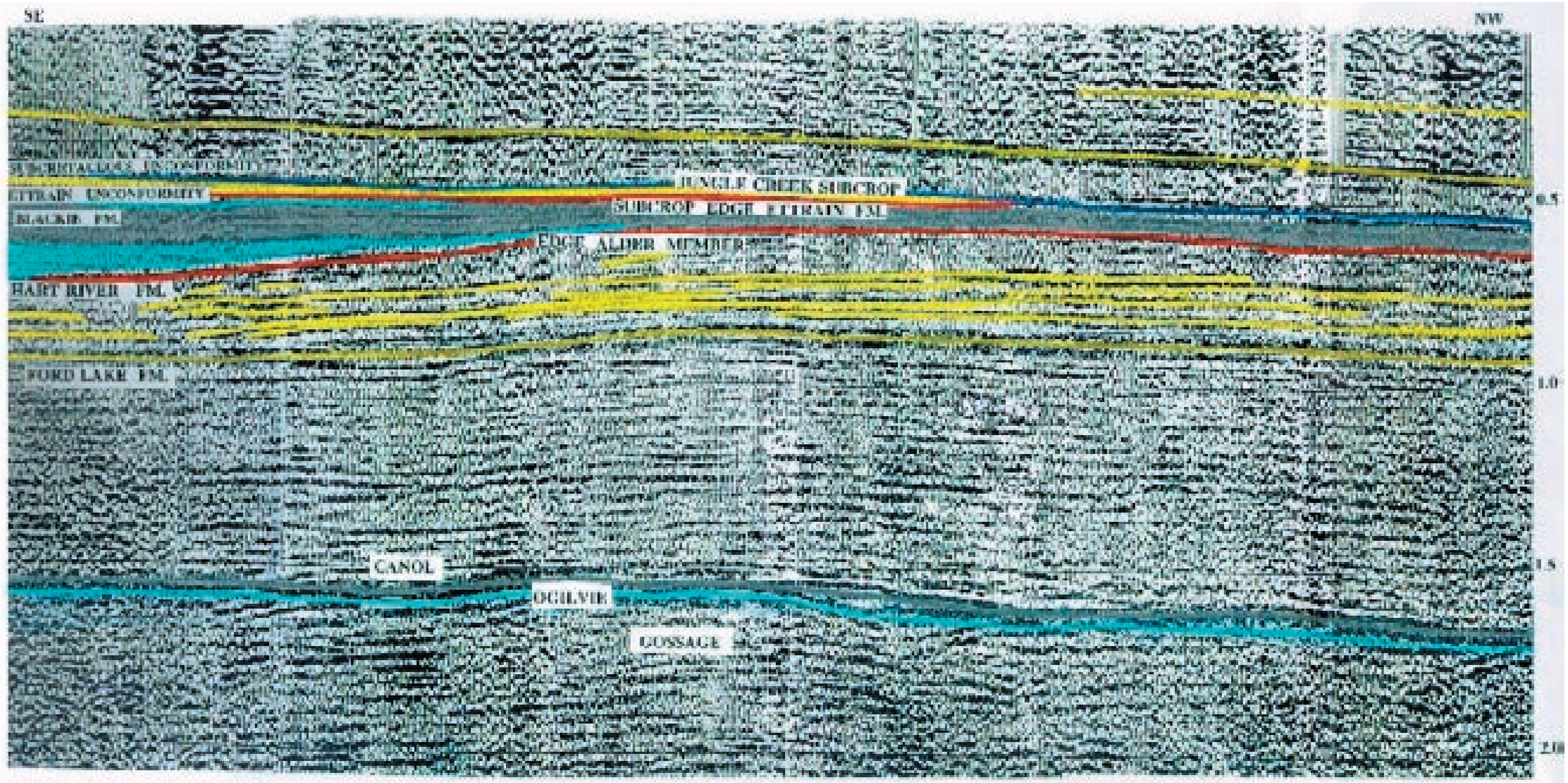


__Figure 13.__ A southeast (left) to northwest (right) reflection seismic line in the central Eagle Plain Basin, located between the Chance and Blackie petroleum accumulations (line 4XA from 1971 Chevron Canada Ltd. data interpreted in NEB, 2000, their Figure 8). The line illustrates the erosional truncation of Permian and Carboniferous strata that subcrop below the Mesozoic succession, providing a stratigraphic opportunity for petroleum entrapment.

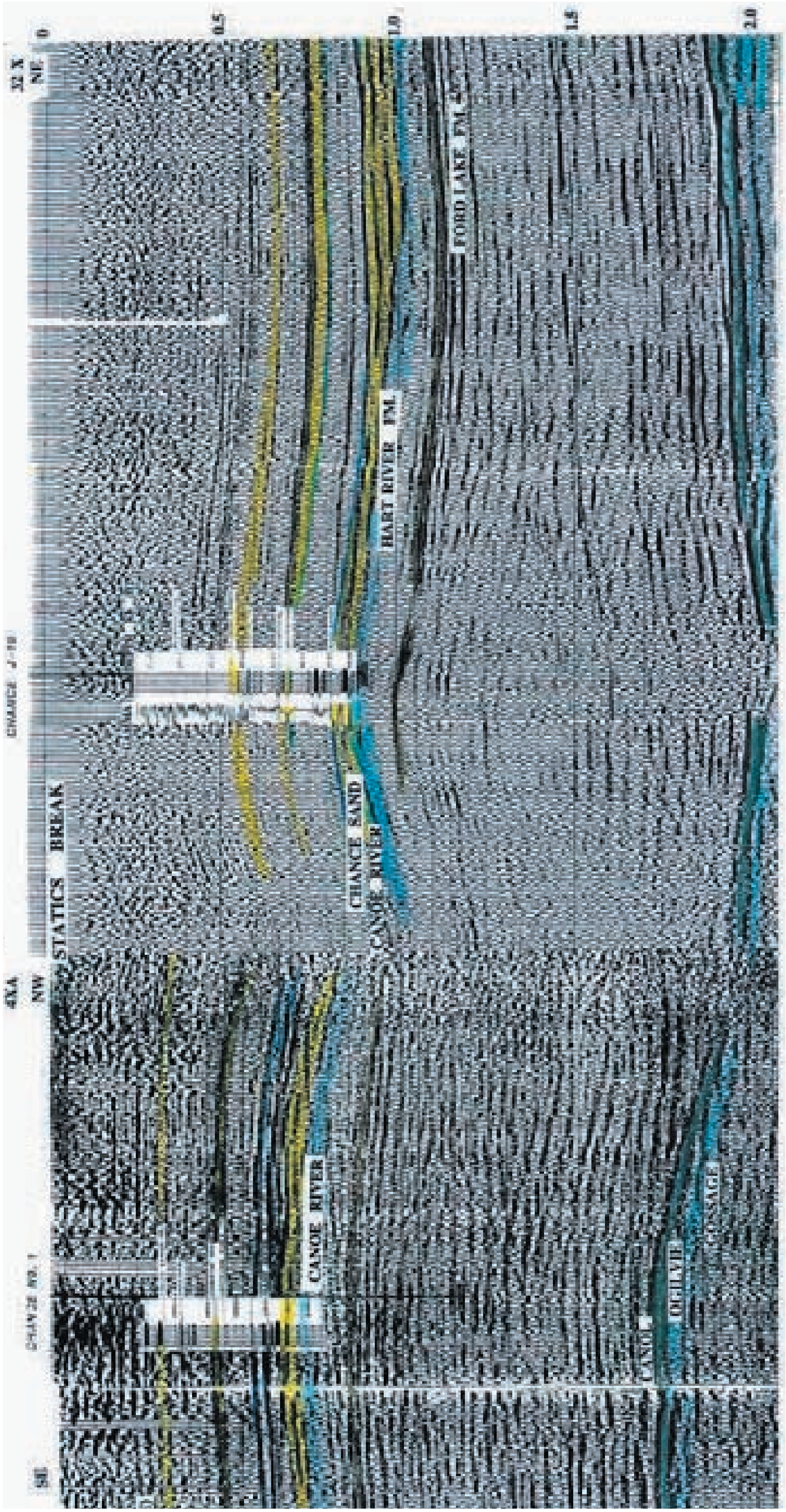


***Figure 14.** A southeast (left) to northwest (right) reflection seismic line in the central Eagle Plain Basin, that is in the vicinity of the Chance L-08 and Chance J-19 wells, approximately along the hinge of the Chance Anticline, illustrating the structural trap in Hart River Formation Chance Sandstone member, south of its subcrop edge (line 4XA from 1971 Chevron Canada Ltd. data interpreted in NEB, 2000, their Figure 8).*

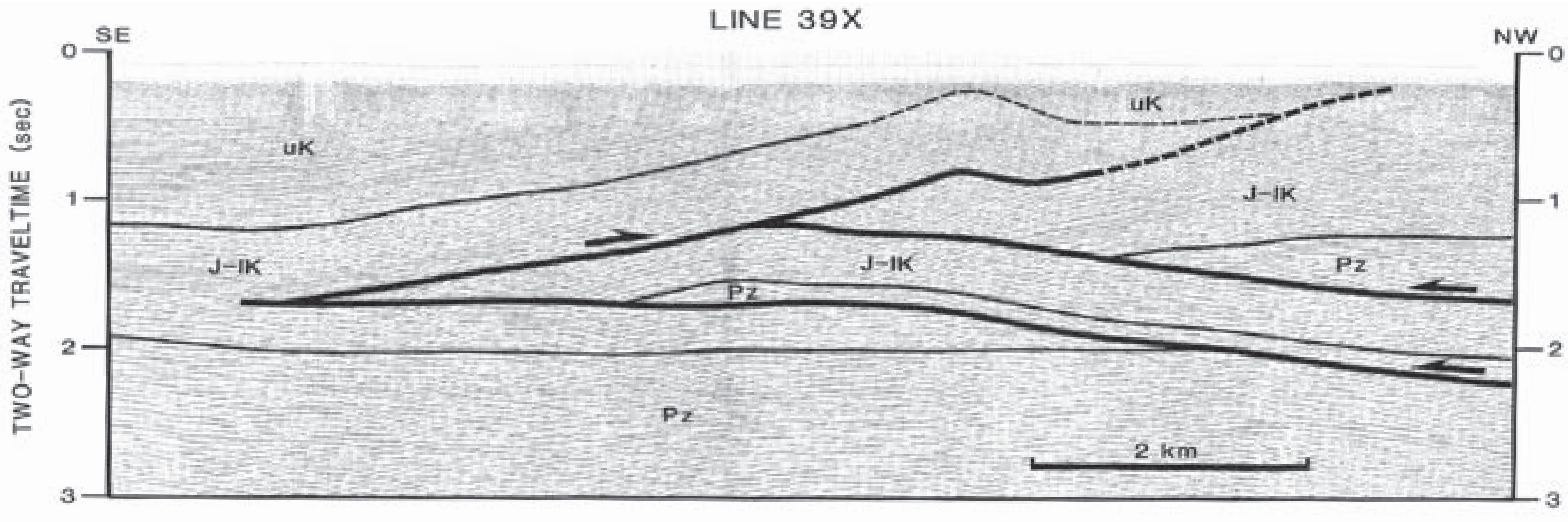


Figure 15. *A southeast (left) to northwest (right) reflection seismic line in the northeastern Eagle Plains Basin, north of the Eagle Arch in the Bell Sub-basin (from Lane, 1996a, see his Figure 5 for the surface location of the survey), where the Mesozoic section is deformed by Laramide thrusting and folding to form a hinterland verging structure in its hanging wall, referred to as the 'triangle zone' (line 39X from 1971 Chevron Canada Ltd. data interpreted by Lane 1996a; an alternative interpretation is presented in NEB (2000, their Figure 10)). The figure illustrates the structure in the triangle zone adjacent to the Dave Lord Mountains. The line lies near both the I-05 and N-50 wells (NEB, 2000, Fig. 10). The thrusts and folds occur in the Mesozoic succession but also occur in the Paleozoic succession.*

PETROLEUM SYSTEMS

INDICATIONS OF PETROLEUM OCCURRENCE AND EFFECTIVE PETROLEUM SYSTEM FUNCTION

There are many indications for effective petroleum systems in the Eagle Plain Basin including potential petroleum source rocks, surface seepages, bitumen stains and flows, and shows in drill stem tests of natural gas and crude oil from wells (Tables 2 and 3; Figure 16; NEB, 2000; Morrell, 1995; Hamblin, 1993). The most important of these are the tests from wells, particularly the discovered petroleum fields.

Table 2. *Schedule of wells in the Eagle Plain Basin and environs. The table illustrates the short well name, total depth (TD) drilled, the formation encountered at total depth, the current status of the well, Kelly Bushing elevation (KB) and the location of the 33 wells discussed in the text.* D&A *= dry and abandoned,* OBS *= temperature observation well*

Well name	TD(m)	Formation@TD	Current status	KB(m)	Latitude	Longitude
Eagle Plain N-49	2922.7	Bouvette Formation	D&A	447.8	66.815	-138.141667
Chance L-08	2635. 9	Ford Lake Shale	gas & oil suspended	539.2	66.128333	-137.528333
Bell River N-50	2439.6	Imperial Formation	D&A	317.6	67.329167	-136.891389
Blackstone D-77	4028.5	Bouvette Formation	D&A	645	65.769658	-137.24855
Chance G-08	1579.8	Chance Sandstone Member	oil suspended	524.3	66.121694	-137.513889
Porcupine River K-56	2286	Ford Lake Shale	D& A	498	66.092617	-137.925597
Blackie M-59	1931.8	Ford Lake Shale	gas suspended	562.1	65.981922	-137.186353
Molar P-34	2649.6	Imperial Formation	D&A	803.5	67.066389	-138.6
Whitestone N-26	2464.3	Ford Lake Shale	D&A	696.5	66.099722	-138.333333
Ellen C-24	2174.4	Tuttle Formation	D&A	414.5	66.552464	-137.835597
South Tuttle N-05	3513.4	Bouvette Formation	D&A	504.7	66.414222	-136.772972
Birch B-34	1649.9	Ford Lake Shale	gas suspended	667.5	66.050872	-136.854864
West Parkin D-51	1508.8	Chance Sandstone Member	D&A	475.5	66.169028	-137.434583
North Cathedral B-62	2138.5	Bouvette Formation	temp OBS	540.1	66.187083	-138.698056
Chance J-19	1446.3	Chance Sandstone Member	gas suspended	518.8	66.142	-137.541117
East Chance C-18	1540.8	Chance Sandstone Member	D&A	535.2	66.11915	-137.299283
North Hope N-53	4280.3	Bouvette Formation	D&A	350.5	66.548333	-138.425
Shaeffer Creek O-22	3161.7	Ogilvie Formation	D&A	352	66.698333	-137.327778
East Porcupine I-13	2439.3	Chance Sandstone Member	D&A	507.5	66.043056	-137.782778
West Parkin C-33	1256.7	Hart River Formation	D&A	520	66.201111	-137.365556
East Pine Creek O-78	947.678	Imperial Formation	D&A	389.2	66.964722	-137.9827
North Parkin D-61	3352.8	Ogilvie Formation	D&A	489.2	66.336667	-137.216944
Birch E-53	684.3	Blackie Formation	D&A	621.5	66.039167	-136.934722
South Chance D-63	2020.8	Carboniferous	D&A	707.4	65.869167	-137.714167
Whitefish I-05	1498.4	Tuttle Formation	D&A	348.1	67.076944	-137.256944
East Porcupine F-18	2050.7	Hart River Formation	D&A	523	66.123611	-137.804444
Ridge F-48	1868.7	Imperial Formation	D&A	321.3	67.289722	-137.893056
Whitefish J-70	2127.5	Porcupine River Formation	D&A	330.7	67.158889	-137.445556
Whitestone N-58	2131.5	Ettrain Formation	D&A	889.4	65.963889	-138.425
North Porcupine F-72	2251.9	Bouvette Formation	D&A	349.3	67.5231	-137.985
Alder C-33	3714	Carboniferous	D&A	530	65.867108	-136.919444
West Parkin D-54	1811	Ogilvie Formation	abandoned	506.8	66.21875	-137.433589
North Chance D-22	1830	Carboniferous	D&A	536	66.185028	-137.592475

Table 3. *Inferred reserves (i.e. proven resources), by well and stratigraphic zone, of natural gas and crude oil in the Eagle Plain Basin and environs, from NEB (2000).*

Well	Zone	Oil Recovery from test, m (feet)	Estimated Reserve, 10^6 m^3 (MMbbls)
Chance D-22	Fishing Branch	oil cut mud	0
Birch B-34	Jungle Creek	oil cut mud	0
Chance L-08	Chance Sandstone Member #1	610 m (2000)	oil 700 (4.44)
Chance L-08	Chance Sandstone Member #2	4 Bbls oil	20 (0.12)
Chance L-08	Chance Sandstone Member #3	4 Bbls oil	0
Chance L-08	Canoe River Member #2	290 m (1000) oil	7.3 (0.05)
Chance G-08	Chance Sandstone Member #1A	360 m (1180) oil	770 (4.87)
Chance J-19	Chance Sandstone Member #3	500 m (1640) oil	260 (1.64)
Chance J-19	Canoe River Member	oil cut mud	0
East Chance C-18	Canoe River Member	37 m (120) cond.	0
West Parkin D-51	Canoe River Member	91 m (300) oil	0
Total oil			**1.757 (11.05)**
Well	**Zone**	**Gas Recovery from test, m^3/d (mcf/d)**	**Estimated Reserve, 10^6 m^3 (Bcf)**
Chance G-08	Fishing Branch	93 447 (3300)	150 (5.0)
Chance G-08	Chance Sandstone Member #1A	gas too small to measure	0
Chance L-08	Fishing Branch	22 994 (812)	incl.
Chance L-08	Chance Sandstone Member #1	283 174 (10,000)	770 (27.2)
Chance L-08	Chance Sandstone Member #2	14 159 (500)	212 (7.5)
Chance L-08	Chance Sandstone Member #3	14 159 (500)	212 (7.5)
Chance L-08	Canoe River Member #2	283 000 (10,000)	2.8 (0.1)
Chance L-08	Tuttle	226 539 (8000)	57 (2.0)
West Parkin C-33	Fishing Branch	7929 (280)	0
West Parkin C-33	Canoe River Member	gas too small to measure	0
West Parkin D-51	Fishing Branch	gas too small to measure	0
West Parkin D-51	Canoe River Member	gas too small to measure	0
North Parkin D-61	Fishing Branch	gas cut water	0
Whitefish J-70	Fishing Branch	gas cut water	0
West Parkin D-54	Fishing Branch	1004 (36)	0
West Parkin D-54	Canoe River Member	gas cut water	0
Chance D-22	Fishing Branch	gas cut mud	0
Blackie M-59	Jungle Creek	79 288 (2800)	660 (23.3)
Blackie M-59	Canoe River Member	4021 (142)	0
South Chance D-63	Jungle Creek	gas cut mud	0
Birch E-53	Jungle Creek	gas cut water	0
Porcupine I-13	Jungle Creek	368 (13)	0
Porcupine I-13	Canoe River Member	1444 (51)	0
Birch B-34	Jungle Creek	gas too small to measure	0
Birch B-34	Chance Sandstone Member	150 000 (5500)	179 (6.3)
Birch B-34	Tuttle	200 000 (7300)	81 (3.0)
East Chance C-18	Chance Sandstone Member	56 502 (1600)	0
East Chance C-18	Canoe River Member	14 640 (512)	0
Chance J-19	Canoe River Member #1	62 690 (2214)	52 (1.8)
Porcupine K-56	Canoe River Member	gas too small to measure	0
Whitestone N-26	Tuttle	13 026 (460)	0
Ellen C-24	Tuttle	gas cut mud	0
Whitefish I-05	Tuttle	gassy water	0
Ridge F-48	Tuttle	1246 (44)	0
South Tuttle N-05	Ogilvie	gas too small to measure	0
South Tuttle N-05	Lower Ogilvie	28 540 (1000)	0
Schaffer O-22	Lower Ogilvie	gas cut mud	0
Eagle Plain N-49	Ogilvie	gassy mud	0
North Hope N-53	Bouvette	gas cut mud	0
Total natural gas			**2376 (83.7)**

Thirty drill stem and production tests, in 10 wells:

Chance L-08;	East Chance C-18;
Chance G-08;	Shaeffer Creek O-22;
Blackie #1 M-59;	Porcupine F-18;
Birch B-34;	Ridge F-48; and
Chance J-19;	West Parkin D-54.

These are not all from unique zones, and have flowed gas to surface. One test, from Chance G-08, flowed oil to surface. Shows of petroleum occur throughout the penetrated Cretaceous to Lower Paleozoic succession.

Petroleum fields were discovered by the Chance (L-08 discovery well; Figure 17); Blackie (M-59 discovery well) and Birch (B-34 discovery well) wells. The Yukon Department of Economic Development and the National Energy Board (2000) describe these three accumulations as "proven" resources, and they are herein termed "reserves," consistent with the terminology used in this report. The initial total oil reserve (Table 2) is estimated to be 1.757 x 10^6 m^3 (11.05 million barrels) of crude oil and the initial total gas reserve is estimated to be 2.376 x 10^9 m^3 (83.7 Bcf) of natural gas (NEB, 2000). The National Energy Board attributes "discovered resources" of oil only at the Chance Field, in Hart River Formation, Chance Sandstone and Canoe River members in the Chance L-08 (M-08), G-08, and J-19 wells (NEB 2000; Table 2). Reserves of natural gas are attributed to the Chance, Blackie and Birch fields. At the Chance Field 1.924 x 10^9 m^3 of gas occurs in Upper Cretaceous Fishing Branch Formation, and Carboniferous Hart River and Tuttle formations. In the Blackie Field, 660 x 10^6 m^3 of gas, occurs in the Permian Jungle Creek Formation, and in the Birch Field,

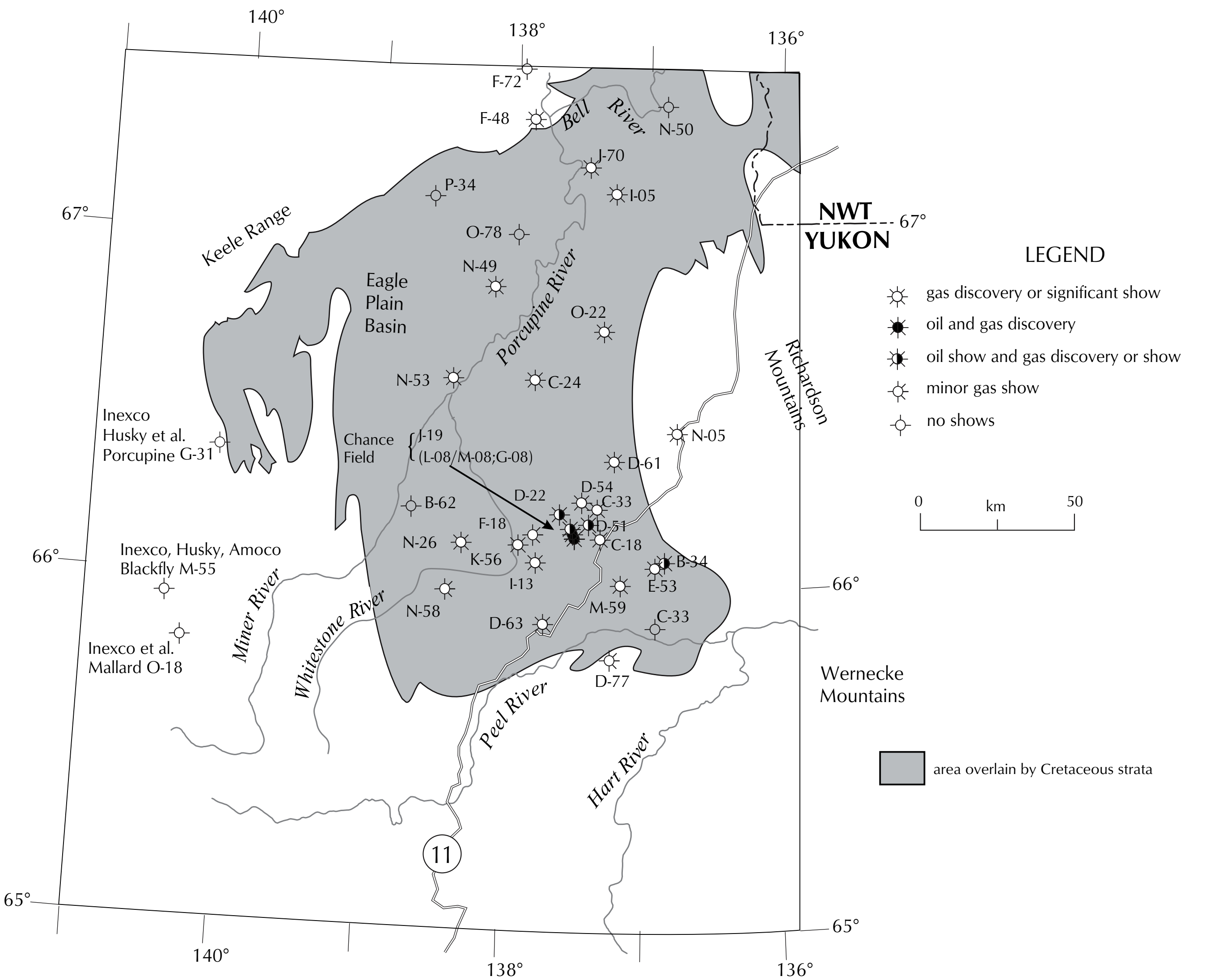


Figure 16. Geographic locations of encouraging shows of petroleum system function and accumulations as discussed in Table 3 and the text. Note that minor gas shows are shows recorded on test that were not included in Table 3 by the NEB (2000).

260 x 10^6 m^3 of gas, occurs in both the Chance Sandstone Member of Hart River Formation and in Carboniferous Tuttle Formation.

The NEB (2000) does not attribute a "discovered resource" to five other wells, testing other structures and prospects, all of which flowed gas to surface, and which are inferred to have potential "discovered resources". These include: West Parkin D-54, East Chance C-18, Shaeffer Creek O-22, East Porcupine F-18 and Ridge F-48. While the results of these tests are summarized below, it was beyond the scope of this study to undertake detailed calculations that would determine the sizes of the accumulations attributed either to these five wells, or the wells that showed indications for crude oil occurrence.

The results of the five "non-discoveries" are as follows. The 3rd test in West Parkin D-54 flowed gas to surface at a rate of 1000 m^3/d from Lower Cretaceous sandstones between 742 and 747 m depth. The D-54 well is near the West Parkin C-33 well that also had encouraging shows from the same structural culmination. The East Chance C-18 well flowed gas to surface at a rate of 45.3 K m^3/d (K m^3/d = thousands of cubic m per day) from Carboniferous strata lying between 925.1 and 934.8 m depth including the Hart River Formation. In the same well, two other tests of Chance Sandstone Member between 1524 to 1540.8 and 1496.6 to 1517.9 m both flowed gas to surface at rates of 161.4 K m^3/d, while recovering 36.6 m of condensate-cut sulphurous salt water 10.2 K m^3/d, respectively. The Shaeffer Creek O-22 well flowed gas to surface at a rate of 311.5 m^3/d and recovered 313.9 m of gas-cut water cushion and 45.7 m of gas-cut mud from a test of the Devonian Ogilvie Formation above the Dolomite Member (2744.4 to 2763.9 m). The East Porcupine F-18 well flowed gas to surface at 1911.4 m^3/d from the Fishing Branch Formation (1174.1 to 1198.5 m), from which this and another test (1210.1 to 1241.8 m) in the same formation, both had shows. The Ridge F-48 well flowed gas to surface

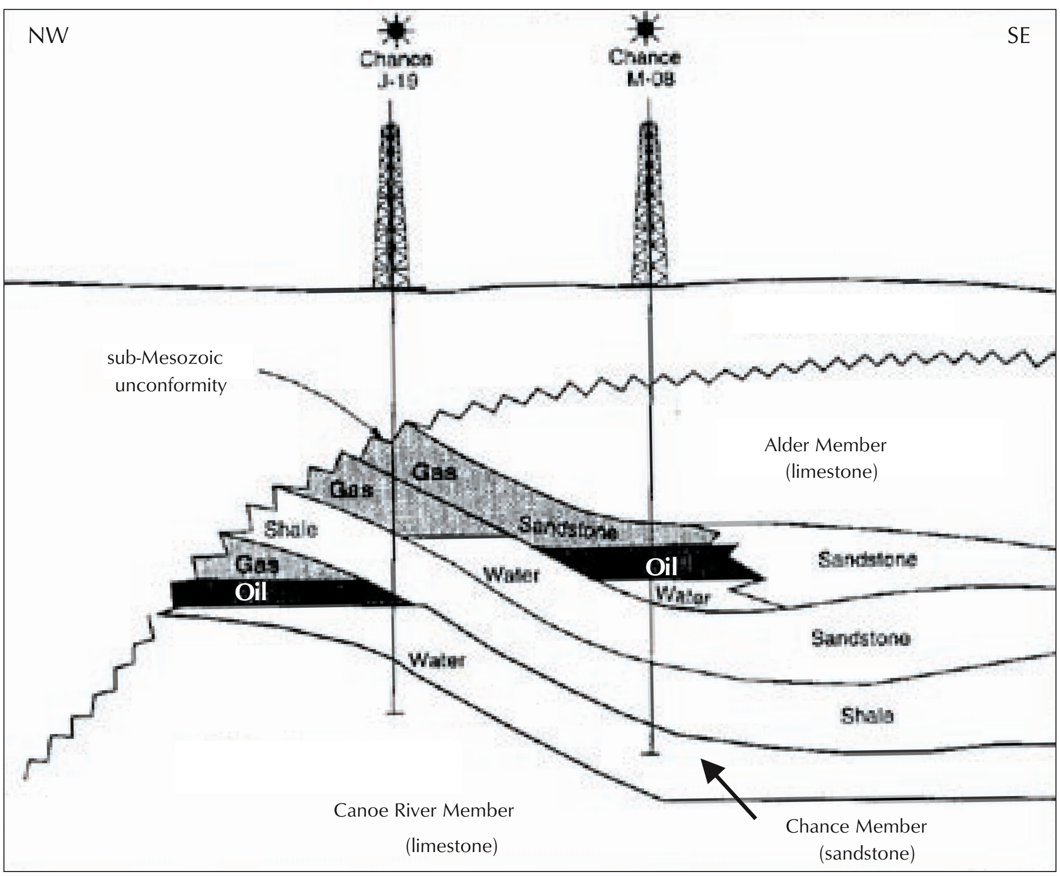


Figure 17. *Schematic northwest to southeast structure section running along the hinge of the Chance Anticline, illustrating the stratigraphic relationships in the Chance petroleum accumulation, relative to individual sub-units of the Chance Sandstone Member and the Canoe River (below) and Alder Limestone Members of the Carboniferous Hart River Formation below the sub-Mesozoic unconformity. The inset location map shows the location of the discovered petroleum accumulations.*

at a rate of 962.8 m^3/d from Jurassic Porcupine Creek Formation (1289.3 to 1327.4 m) and had a show in the recovered fluid of that test and another (1204 to 1289.3 m).

Tests in 25 different wells (Table 2) have recovered gas-cut drilling or testing fluids, specifically:

Eagle Plain #1 N-49;	Shaeffer Creek O-22;
Chance L-08;	Porcupine I-13;
Chance G-08;	West Parkin C-33;
Blackstone D-77;	North Parkin D-61;
Blackie #1 M-59;	Birch E-53;
Whitestone N-26;	South Chance D-63;
Ellen C-24;	Whitefish I-05;
South Tuttle N-05;	Porcupine F-18;
West Parkin D-51;	Ridge F-48;
Birch B-34;	Whitefish J-70;
Chance J-19;	Whitestone N-58; and
East Chance C-18;	West Parkin D-54.
North Hope N-53;	

Indications of crude oil have been recovered from drill stem tests in eight wells:

Chance L-08	Birch B-34
Chance G-08	Chance J-19
Ellen C-24	East Chance C-18
West Parkin D-51	Porcupine I-13

Petroleum occurs throughout the Phanerozoic succession. The zones from which accumulations have been indicated by drill stem tests in wells include the following successions. Shows in the Bouvette Formation occur in the Blackstone D-77 and North Hope N-53 wells. Both indicated that prospectivity extends to the base of the Phanerozoic carbonate succession. Three shows have been obtained from Devonian strata, with those in the Shaeffer Creek O-22 and Eagle Plain #1 N-49 wells occurring above the Dolomite Member, and those in the South Tuttle N-05 occurring within the Dolomite Member in the lower Ogilvie Formation.

The largest number of petroleum indications and accumulations occur in Carboniferous strata, including the Tuttle Formation in the Ellen C-24 well. In the Hart River Formation, especially within the Chance Sandstone Member, shows commonly occur near its eroded edge, where it subcrops below the Mesozoic succession. Wells with petroleum indications on tests from the Hart River Formation include Chance L-08, Chance G-08, East Chance C-18, Chance J-19, Whitestone N-26, Blackie #1 M-59, West Parkin D-51, Birch B-34 and West Parkin C-33. The Ettrain Formation exhibited a hydrocarbon show in the Porcupine I-13 well. Permian Jungle Creek Formation had shows in South Chance D-63, Birch B-34, Blackie #1 M-59, Birch E-53 and Whitestone N-58. Jurassic Porcupine River Formation had shows in the Whitefish J-70 and Ridge F-48 wells.

Lower Cretaceous sandstones, including the Whitestone River and Mt. Goodenough formations, had shows in the Chance L-08, North Parkin D-61, West Parkin D-54 and Whitefish I-05 wells. The Upper Cretaceous Eagle Plain Group had petroleum shows in tests from the Fishing Branch Formation: in the Whitefish I-05, Porcupine I-13 and Porcupine F-18 wells, and from the Burnthill Creek to Fishing Branch interval in the Chance G-08 well. Additional shows occurred in Upper Cretaceous Cody Creek and underlying Burnthill Creek formations in the Porcupine I-13 well. Details of these tests, the well intervals evaluated and the test recoveries are discussed below.

Norris and Hughes reported two surface seepages of crude oil (1997). The seepages occur approximately 35 km northeast of the Chance Oil Field (Norris and Hughes, 1997, p. 383, their Figure 15.1 and Table 15.1). The well nearest to these seepages is the Chevron, Standard Oil of British Columbia Western Minerals North Parkin D-61 (Fig. 20), which is located where there is no obvious map-scale bedrock structural culmination. The first seepage occurs in an oil-saturated outcrop of Upper Devonian shale located on an unnamed north-flowing tributary of the Eagle River (116I16/1) that is approximately 6 km northeast of an oil-saturated ridge of sandstone in the base of the Eagle Plain Group (116I16/2). Stelck (1944) described bitumen occurrences in the Richardson Anticlinorium, in strata equivalent to, and of similar lithology to, some portions of the Paleozoic successions that underlie the eastern Eagle Plain basin.

Together these tests and occurrences, throughout the succession, suggest active petroleum systems that should be effective if suitable reservoirs and preserved traps formed with appropriate timing. The results of the drilling show that there are no play-level risks throughout the Phanerozoic succession, rather it is just uncertain as to how large and how numerous are the economically recoverable accumulations of petroleum in the Eagle Plain Basin.

PETROLEUM SOURCE ROCK OCCURRENCE, RICHNESS AND ORGANIC MATTER TYPE

Rock-Eval/TOC analysis and organic petrography have been used to evaluate the petroleum source rock potential and depositional setting of the Phanerozoic succession in Eagle Plain Basin. There are abundant potential petroleum source rocks, the occurrence of which is consistent with the observed indications for petroleum occurrence. Snowdon (1988) and Link (1988) report on the Rock-Eval/TOC analysis of 10 Eagle Plain wells (Fig. 18). The 10 wells studied for their source rock potential and thermal maturity are from south to north: Blackstone D-77, Whitestone N-58, Birch B-34 Chance L-08, East Porcupine F-18, South Tuttle N-05, Ellen C-24 Molar P-34, Whitefish J-70 and Ridge F-48.

Rock-Eval/TOC is a technique that evaluates oil and gas shows, oil and gas generation potential, thermal maturity and identifies organic matter type. Espitalie et al. (1985), Peters (1986), and Tissot and Welte (1978, p. 443-447) discuss this technique. The Rock-Eval/TOC analysis gives five parameters: S1, S2, S3, TOC and Tmax. The S1 parameter measures free or adsorbed hydrocarbons volatilized at moderate temperatures (300˚C). S2 measures the hydrocarbons liberated during a ramped heating (300-550˚C at 25˚C/min.). The S3 parameter measures organic CO_2 generated from the kerogen during rapid heating (300-390˚C at 25˚C/min.). Milligrams product per gram rock sample, the equivalent to kilograms per tonne, is the measure of all these parameters. The measure of Total Organic Carbon (TOC) is weight percent. Tmax, the temperature corresponding to the S2 peak maximum temperature is measured in ˚C. Rock-Eval/TOC is a useful screen for recognizing sources and stained lithologies.

Rock-Eval results correlate to other techniques (Espitalie et al., 1985; Tissot and Welte, 1978). Source rock potential is sensitive to lithology, also TOC and S2 values (Table 1). It is common practice to rate carbonate rocks with lower TOC comparably with richer clastic rocks. Leaner carbonate rocks tend to have extractable HC yields comparable to richer clastic source rocks (Tissot and Welte, 1978, p. 430; Gehman, 1962). The organic matter associated with carbonate rocks is commonly more hydrogen-rich and thermally labile than that commonly associated with fine-grained clastic rocks. As a result, more TOC in carbonate rocks may be transformed into bitumen with equivalent thermal stress compared with average clastic source rocks.

Those making reference to the Eagle Plain Rock-Eval/TOC results should note that parameters have significance only above threshold TOC, S1 and S2 values. If TOC is less than about 0.3% then all parameters have questionable significance and the experiment suggests no potential. Oxygen Index (OI), S3/TOC, has questionable significance if TOC is less than about 0.5%. OI values greater than 150 mg/g TOC can result from either low TOC determination or from a mineral matrix CO_2 contribution during pyrolysis. Both Tmax and Production Index (PI = S1/(S1+S2)) have questionable significance if S1 and S2 values are less than about 0.2. Results can be affected by mineral matrix-effects. These either retain generated petroleum compounds, generally lowering the S1 or S2 peaks, while increasing Tmax; or by liberating inorganic CO_2 and increasing S3 and OI. Mineral matrix-effects are important if TOC, S1 and S2 are low, an effect not significant in this study as most sources have TOC values >5%. As well, the stratigraphic unit tops used by Snowdon (1988) should be confirmed against more authoritative sources (e.g., Morrow, 1999; Dixon 1992).

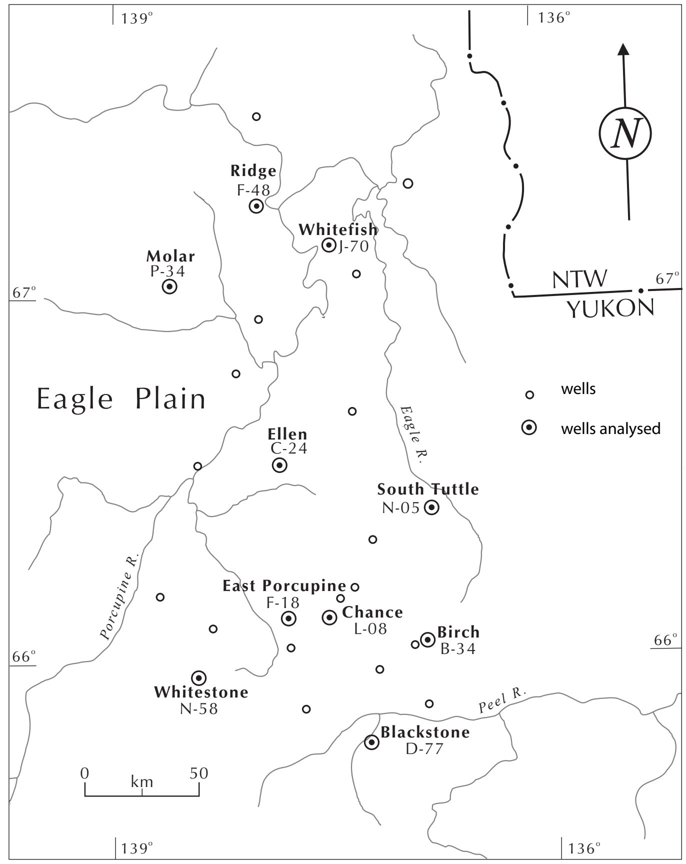


Figure 18. *Geographic location of wells analysed for RockEval/TOC source rock potential and thermal maturity (after Snowdon, 1988).*

From the Rock-Eval/TOC analyses of these 10 wells the overall average total organic carbon (TOC) values of stratigraphic units are generally low to moderate (0.1 to 2.0%) but organic-rich intervals occur throughout the studied succession. The quality of organic matter varies significantly as a result of variability in the level of organic maturity, the type of organic matter and, in some cases, migration. For some strata, the variation in source rock quality closely reflects the depositional environment. Average quality of organic matter of stratigraphic units is generally low to moderate (0.01 to 1.5 mg HC/g TOC) and, along with low to moderate hydrogen indices (HI <300 mg HC/g TOC), suggests a general, poor to moderate petroleum source potential.

Source rock studies of Eagle Plain Basin that combined similar studies of regional results from equivalent stratigraphic units and facies suggest that there are at least seven stratigraphic intervals that may contain significant source rock facies, even if not all of these have been recognized by the analysis of cuttings samples from the Eagle Plain wells. The potential and prospective petroleum source rock intervals are identified or inferred to occur in Road River Formation, Ogilvie Formation or basinal equivalent strata, Canol Formation, Imperial Formation, Ford Lake Shale, Blackie Formation and Whitestone River Formation.

The kerogen is dominantly Type III except for minor amounts of Type I or II in Lower Paleozoic strata, and locally a mixture of Type II and III in Middle Devonian, Carboniferous, Jurassic and Lower Cretaceous strata. Relatively few examples of potential oil-prone source rocks (Type I or Type II kerogen) occur in the area. The Paleozoic succession is considered the most prospective for the oil-prone source rocks, based primarily on the stratigraphic distribution of oils shows, stratigraphic analysis and comparison to regional results for strata of similar ages.

No source interval is known in the Cambrian and Ordovician Bouvette Formation, but potential sources are clearly developed in the Road River Formation, which may reach up to 2% TOC, is predominantly gas prone, and which is generally in the gas generation window. In addition, Upper Cambrian and Ordovician carbonate platforms are globally renowned for the presence of a specific bituminous, oil-prone source facies (see the description of Ordovician source rocks in Osadetz and Snowdon, 1995). Such an oil-prone source has not been identified in the Bouvette Formation, but the potential for its occurrence should be considered reasonable, especially considering the large area and few penetrations of this part of the Phanerozoic succession in Eagle Plain Basin.

Devonian bituminous mudstones are not a major lithological constituent of the Ogilvie Formation, or its basinal equivalents. Some regional indications from Prongs Creek mud rocks, similar facies to those which may occur as intercalations in the Ogilvie Formation, indicate thin sources of up to 9.5% TOC. These are typically gas-prone and might be present in parts of the Devonian succession underlying the Eagle Plains. The observed shows on tests from the Ogilvie Formation suggest this is the case. The Devonian Imperial Formation is typically organically lean, < 1 wt. % TOC. The lean content may be compensated for by the large volume of organic matter and the full thermal maturity of these potential sources. Thin richer intervals, perhaps accumulated during periods of transgression or sediment starvation, such as the Canol Formation lithologies, which are typically good potential oil sources regionally, may exist as a facies in the Imperial Formation, but they have yet to be identified in the Eagle Plain.

Devonian and Carboniferous Ford Lake shales can contain up to 4% TOC by weight. Ford Lake shales are typically thermally mature for petroleum generation from both oil-prone and gas-prone kerogens. The Carboniferous Blackie shale underlies the Ettrain Formation, in which a number of petroleum shows have been encountered. Type II, oil-prone, and Type III, gas-prone, organic matter, which is up to 5% TOC by weight, is commonly marginally to fully mature in the Blackie shales.

Carbonaceous samples from deltaic sediments of the Porcupine River Formation have some gas potential. Gas-prone (Type III kerogen) source rocks are present in the Blackie Formation, and in low-energy shelf deposits of the Mount Goodenough and Whitestone River formations. Carbonaceous samples from deltaic sediments of the Porcupine River Formation and nearshore to inner shelf deposits of the Eagle Plain Group also have some gas potential, but thermal maturities are typically low in the Upper Cretaceous succession, although this interval may be a potential source for biogenic gases like those found in the Upper Cretaceous strata of southern Alberta.

PATTERNS, GRADIENTS AND HISTORY OF SOURCE ROCK THERMAL MATURITY

The levels of organic maturation and thermal history of Phanerozoic sedimentary sequences in northern Yukon and northwestern District of Mackenzie was investigated by Link, Bustin, Snowdon and Utting (Link and Bustin, 1989; Link et al., 1989; Utting, 1989; Link, 1988; Snowdon, 1988). They measured vitrinite reflectance

(% Ro; mean random reflectance in oil), spore colouration index and conodont alteration index (CAI). Vitrinite does not occur in Lower Paleozoic rocks where CAI provides an alternative indicator of thermal maturity. They found that Phanerozoic strata in the northern Yukon and northwestern District of Mackenzie vary from immature to overmature with respect to the oil window, and that maturation increases geographically toward regions of increasing structural complexity. Regionally, lower thermal maturities were typical of strata in the Eagle Plain and Peel Plateau compared to equivalent stratigraphic levels in the Richardson and Ogilvie mountains.

Throughout the region CAI values in Upper Cambrian to Lower Devonian strata are between 3.5 and 5; whereas, vitrinite reflectance in Middle Devonian to Upper Cretaceous strata is between 0.2 and 3.75% Ro. Eagle Plain Upper Cretaceous strata have the lowest reflectance values and these vary between 0.38 and 0.53% Ro at the base of the Upper Cretaceous succession in Eagle Plain. In the subsurface of the central Eagle Plain, much of the Carboniferous to Upper Cretaceous succession is thermally immature (<0.61‰ Ro). Anomalously high organic maturity is found in the Lower Cretaceous succession of the Campbell Uplift, where organic maturity indications of 0.92 to 1.60% Ro were attributed to high paleo-heat flow associated with uplifted basement rocks.

There is a wide range of maturation gradients in Eagle Plain, from 0.10 to 0.32 log % Ro/km, which primarily reflects the effect and timing of maximum depths of burial beneath Upper Mesozoic and potentially younger successions. These successions are now partly or totally eroded, as a function of local geological history. Central Eagle Plain organic maturity gradients between 0.10 to 0.32 log % Ro/km, indicate paleogeothermal gradients of about 10 to 20°C/km. The lower geothermal gradient history inferred for the Eagle Plain Basin is attributed to a combination of both low paleoheat flow and rapid Late Cretaceous sedimentation and uplift. This is much lower than the inferred geothermal gradients of 20 to 45°C/km in the adjacent Richardson and Ogilvie mountains. The average geothermal gradients inferred for the Eagle Plain Basin is also lower than that inferred for the southern Mackenzie Delta and Peel Plateau, where average paleogeothermal gradients were like those observed in the Richardson and Ogilvie mountains.

Higher maturity levels in the mountainous areas adjacent the Eagle Plain were inferred to reflect both higher maturation gradients and a deeper sedimentary burial. Extrapolated maturation gradients suggested that between 0.7 to 4.7 km of the Phanerozoic succession was variably eroded from the Eagle Plain Basin, and its environs, during the Late Cretaceous and subsequent time, with the greatest thickness being removed from the most structurally complicated regions. Estimates of the amount of Upper Cretaceous and possibly younger section eroded from the central to northern Eagle Plain Basin varies from between 0.7 to 3.5 km thick. The amount of post-Carboniferous succession removed in eastern Eagle Plain is approximately 2.6 to 2.8 km, while up to 4.7 km of a similar succession was eroded from the western Eagle Plain. In northwestern Eagle Plain, about 3.5 km of post mid-Cretaceous section has been eroded, while the least erosion is inferred to have occurred in the central Eagle Plain Basin, where only 0.7 km is inferred to have been removed. The pattern of erosion assists in the reconstruction of thermal history and Late Mesozoic depositional patterns.

Thermal history analysis or inferred paleogeothermal gradients and eroded thickness provide models which indicate the time when peak petroleum generation occurred as a function of petroleum composition, considering source rock Organic Matter Type. In general, the pattern of thermal maturity, especially in the Paleozoic succession, reflects the amount of stratigraphic burial, and this indicates that most of the thermal maturation in the deeper succession occurred prior to the most recent deformation during the Laramide orogeny. Such analyses suggest that Devonian potential petroleum source rocks reached peak oil generation maturities during Late Carboniferous to Permian time in Eagle Plain, at a time significantly later than that inferred for the Peel Plateau (Late Devonian to Early Carboniferous time). Eagle Plain Devonian successions entered the gas generation window variably during the interval Carboniferous to Early Tertiary. This model indicates that the oil occurrence in the Chance field has a complicated history. This thermal history difference alone is the primary cause for the significant difference in the numbers of shows of petroleum in the lower Paleozoic carbonate succession between these two regions.

Carboniferous and Permian potential source rocks entered the oil window in the Late Carboniferous to Early Tertiary in most of Eagle Plain. As a result of Upper Cretaceous burial, most of the Carboniferous potential source rocks in the western Eagle Plain entered the gas generation window during the Late Cretaceous. In northwestern, eastern and southeastern Eagle Plain, potential Carboniferous source rocks remain within the oil window. In central Eagle Plain, Carboniferous and Permian strata remain thermally immature, due to the combination of shallow burial and low paleogeothermal gradients (10 to 20°C/km) which result in the lowest maturation gradients in the northern Yukon (0.10 to 0.18 log % Ro/km).

Potential Lower Cretaceous source rocks in the northwestern Eagle Plain entered the oil window during the interval Late Cretaceous to Early Tertiary. In contrast, in most of the Eagle Plain Basin, Cretaceous potential source rocks were not buried sufficiently to reach the oil window. Therefore, indications for petroleum in drill stem tests in the Cretaceous succession are currently inferred migrated from deeper sources, or, in the case of natural gas, they may have been generated by biogenic processes, although, no carbon isotope data is available from the natural gases to confirm a biogenic origin.

EXPLORATION HISTORY

REFLECTION SEISMIC SURVEYS

The distribution of reflection seismic surveys within the study area is shown in Figure 19. Within the study region there are 9952 line-km of reflection seismic surveys, covering most of the prospective region at a regional scale. The data, acquired largely prior to 1975, has been used to locate the 33 wells used to test petroleum prospects in the Eagle Plain and environs (Table 2). Several seismic lines were discussed in the illustration of the structural style of the previous section, but the focus of this discussion is on the history of drilling to which the seismic surveys contributed prospects and locations.

EXPLORATORY DRILLING

Initial exploratory surface investigations were made in the mid 1950s. Since then, petroleum exploration has resulted in a total of 33 exploratory and outpost wells in the Eagle Plain Basin and its environs, between April 17, 1957, when the first well was spudded, and March 01, 1985, when the last well was begun (Table 2; Figure 20).

Several of these wells resulted in significant discoveries of petroleum, during almost three decades of generally economically unsuccessful, but not unencouraging, exploration. These wells and the data derived from them are key for this study. The wells relevant to this assessment occur between approximately 136° and 139° W and between approximately between 65.5° and 67.5° N in the region east of the Eagle Plains, entirely within the Yukon. All these wells, especially the results of their drill stem and production tests, were used in the formulation of play parameters and exploratory risks that constrained the assessment of the undiscovered petroleum potential. Three additional wells lie just west of these geographic study limits, including the Inexco, Husky et al., Porcupine G-31, Inexco, Husky and Amoco Blackfly M-55; the Inexco et al. and Mallard O-18 wells (Fig. 20) were also considered. These wells were also used in the formulation of play parameters and risks but they are not discussed below. Only eight of the wells have been drilled into strata below the Devonian Canol Formation clastic succession, a potential regional seal. Unless otherwise indicated, all tests discussed below are conventional drill stem tests.

The first well drilled in the Eagle Plain Basin (Fig. 20) was the **Eagle Plain #1 N-49** (Unique Well Identifier = 300N496650138000). This new field wildcat exploration well is located east of the Porcupine River at 66.815° N, 138.141667° W. It is located on southeast flank of the Eagle Arch (Moorehouse, 1966; Young, 1973; 1975), on the western limb of a north-trending synformal structure in NTS map sheet 116J/16. The well was spudded on April 17, 1957, at a Kelly Bushing elevation of 447.8 m, in Cretaceous Parkin Formation, and drilled to a total depth of 2922.7 m in the Cambrian-Ordovician Bouvette Formation, which it penetrated at a depth of 1989 m. The Eagle Plain N-49 drilling rig was released in July, 1958 and the current well status is dry and abandoned.

A total of 21 tests were run in the Eagle Plain #1 N-49 well. Tests 1, 13 and 15, respectively run over the intervals 1091.2 to 1194.2 m (Canol and Ogilvie formations); 2327.5 to 2345.7 m (Bouvette Formation); and interval 2295.4 to 2353.4 m (Bouvette Formation) were mis-run. The 2nd drill stem test (1071.4 to 1194.2 m) in the Canol and Ogilvie formations recovered 61 m of drilling mud. Six technically successful tests evaluate the Ogilvie Formation above the Dolomite Member, as follows.

Ogilvie Formation, N-49		
3	1431 to 1438.7 m	recovered 146.3 m of gas-cut mud, 1176.5 m of salt water
4	1447.8 to 1458.5 m	recovered 48.8 m of drilling mud, 1290.8 m of salt water
5	1356.4 to 1429.5 m	recovered 199.9 m of water-cut mud, 569.4 m of drilling mud-cut salt water
6	1466.1 to 1508.8 m	recovered 48.8 m of drilling mud, 1211.9 m of gas-cut salt water
18	1245.1 to 1348.1 m	recovered nothing
19	1245.1 to 1348.1 m	recovered 57.9 m of drilling mud

A single test was run in the Mount Dewdney Formation between 1903.8 to 1976.6 m, which recovered 515.4 m of salt water-cut mud.

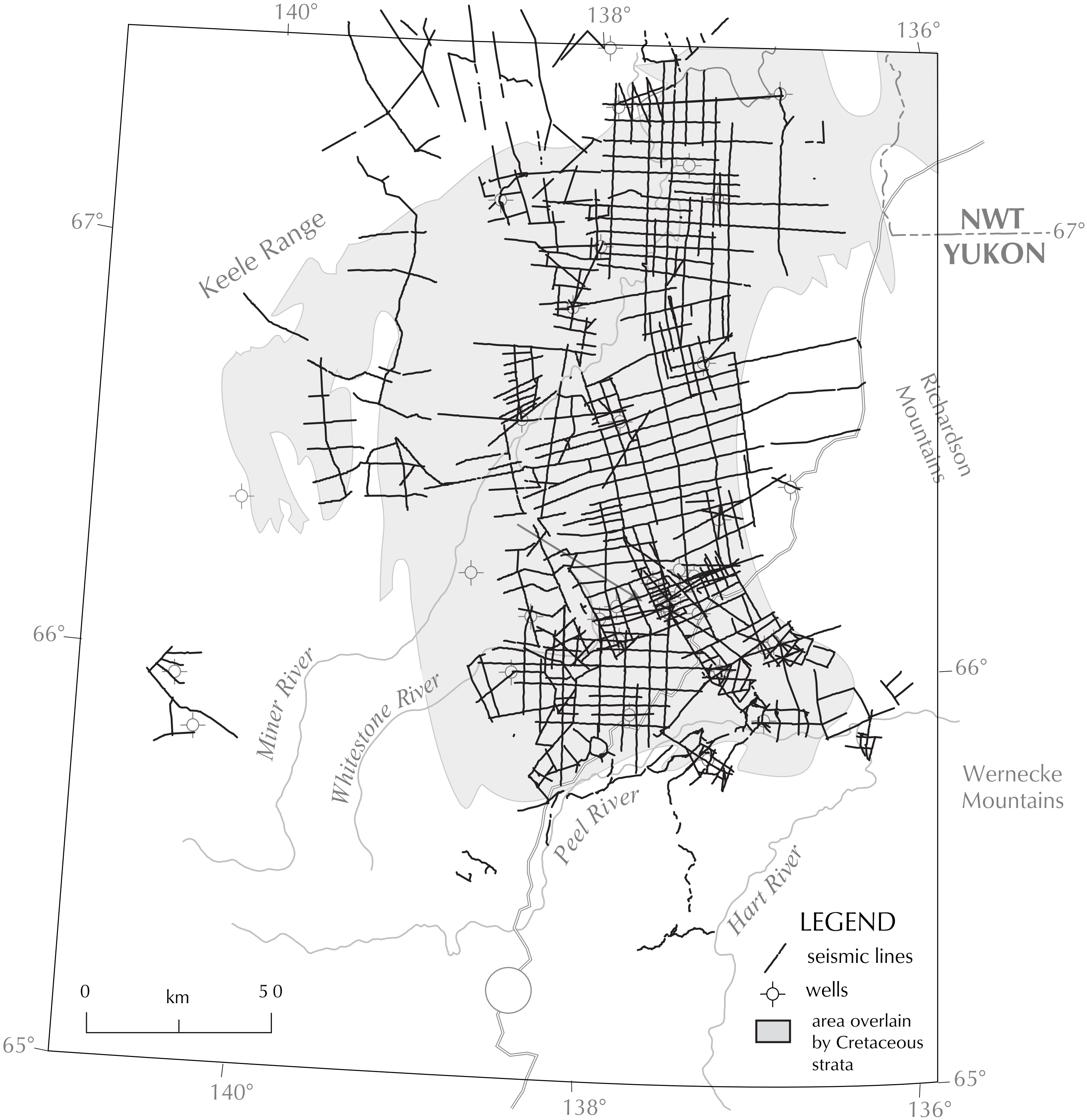


Figure 19. *Distribution of petroleum exploration wells with respect to reflection seismic surveys in Eagle Plain Basin and environs, of all vintages.*

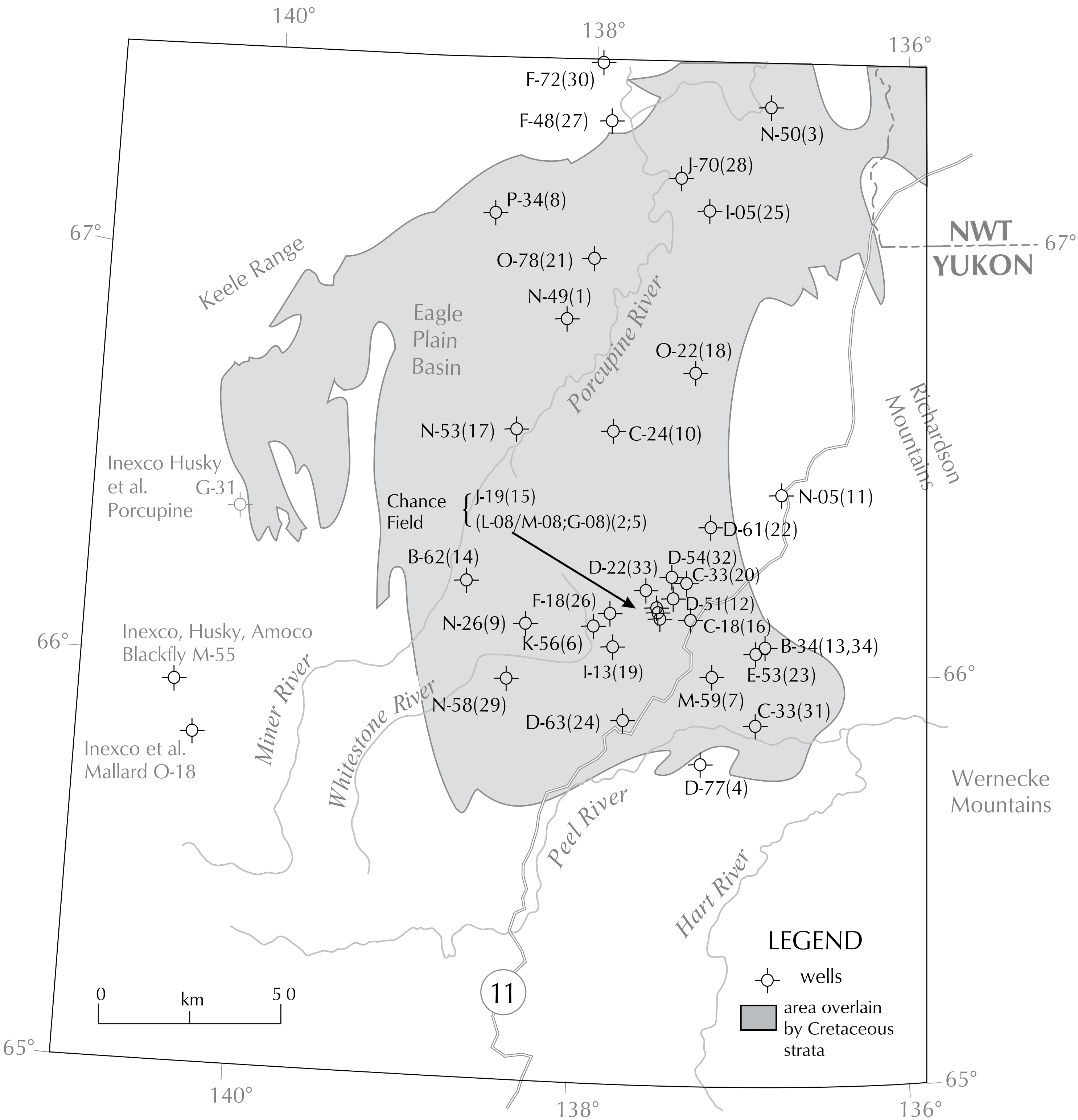


Figure 20. *Distribution and historical sequence of petroleum exploration wells drilled in the Eagle Plain Basin and environs region. The numbers beside the well locations include the well name and the order in which the wells were drilled (in brackets).*

Ten technically successful tests were run in the Bouvette Formation, as follows.

Bouvette Formation, N-49		
7	2104.3 to 2145.8 m	recovered 270.4 m of drilling mud-cut salt water
8	2069.6 to 2104.3 m	recovered 202.4 m of salt water
10	2145.8 to 2214.1 m	recovered 1695 m of salt water
11	2214.1 to 2296.1 m	recovered 304.2 m of drilling mud-cut salt water
12	2331.7 to 2343.3 m	recovered 42.7 m of fresh water-cut mud
14	2327.5 to 2345.7 m	recovered 42.7 m of drilling mud
16	2294.2 to 2353.4 m	recovered 47.2 m of drilling mud
17	2541.4 to 2560.9 m	recovered 242.6 m of salt water and 204.8 m of water-cut cushion
20	2711.8 to 2774.3 m	recovered 537.7 m of salt water and cushion
21	2774.3 to 2847.7 m	recovered 68.6 m of drilling mud

The 2nd well drilled in the Eagle Plain Basin was the Western Minerals **Chance #1 L-08** (Fig. 20; UWI = 300L086610137300). This new field wildcat exploration well was the discovery well of the Chance oil field. The discovery well is located northwest of the Dempster Highway (#11), at 66.128333° N; 137.528333° W. The well tests the Chance Anticline, a map-scale bedrock culmination, in NTS map sheet 116I/4, in the vicinity of where the Carboniferous subcrop might be expected, based on regional map patterns. The well was spudded on May 30, 1959, in the Cretaceous Cody Creek Formation, at a Kelly Bushing elevation of 539.2 m. The well was drilled to a total depth of 2635.9 m in Ford Lake Shale. The same well is also referred to as Western Minerals Chance M-08.

Forty-six tests were run in the Chance #1 L-08 well, many of which tested the Chance Sandstone Member, as follows.

Cody Creek Formation, L-08		
1	413.6 to 423.7 m	recovered 270.4 m of drilling mud-cut salt water
Lower Cretaceous Burnthill Creek Formation		
4	607.2 to 620.3 m	recovered 3 m of drilling mud
Burnthill Creek Formation to Carboniferous		
5	697.7 to 709 m	flowed gas to surface at a rate of 23 K m^3/d and recovered 30.5 m of drilling mud from Lower Cretaceous
Carboniferous		
6	707.7 to 713.8 m	recovered 33.5 m of drilling mud
7	719.3 and 735.8 m	flowed gas to surface at a rate of 18. K m^3/d and recovered 29 m of drilling mud
8	734.6 to 740.7 m	recovered 59.4 m of drilling mud
Albian Whitestone River Formation to Hart River Formation		
10	1226.8 to 1240.5 m	recovered 59.4 m of drilling mud
Hart River Formation		
11	1240.5 to 1267.4 m	recovered 30.5 m of drilling mud
Upper Hart River Formation and Chance Sandstone Member		
12	1289.3 to 1303.9 m	recovered 59.4 m of drilling mud
13	1289.3 to 1314.6 m	flowed gas to surface at a rate of 172.7 K m^3/d and recovered 36.6 m of condensate and 24.4 m of gas-cut mud

A total of 26 successful drill stem tests were performed to test intervals in the Chance Sandstone Member interval in the Chance L-08 well, with the following results.

Chance Sandstone Member, L-08		
14	1314.9 to 1327.1 m	flowed gas to surface at a rate of 283.2 K m^3/d. and recovered 9.1 m of condensate
16	1326.8 to 1337.2 m	flowed gas to surface at a rate of 1699 m^3/d and recovered 609.6 m of oil
17	1337.2 to 1345.7 m	drilling mud, measured as 30.5 m in the drill string
18	1345.4 to 1401.2 m	recovered 51.8 m of drilling mud and salt water-cut oil, as well as 786.4 m of drilling mud-cut sulphurous salt water
19	1487.4 to 1540.5 m	recovered 1280.2 m of sulphurous salt water
20	1540.5 to 1581.9 m	flowed gas to surface at a rate of 283.2 K m^3/d and recovered 289.6 m of oil
21	1565.1 to 1586.5 m	recovered 150.9 m of gas-cut mud
22	1399 to 1487.4 m	flowed gas to surface at a rate of 14.2 K m^3/d and recovered 457.2 m of sulphurous salt water
23	1325.9 to 1335 m	recovered 0.6 m^3 oil and 0.5 m^3 mud-cut oil
24	1581.9 to 1586.5 m	recovered 5.5 m of drilling mud
25	1563.6 to 1581.9 m	recovered 4.6 m of gas-cut mud
26	1540.5 to 1563.6 m	recovered 256 m of oil, 128 m of oil-cut mud and 378 m of water
27	1548.4 to 1563.6 m	recovered 150 m oil, 91.4 m of oil-cut mud and 662.9 m of water
28	1540.5 to 1548.4 m	recovered 3 m of gas-cut mud
29	1555.7 to 1563.6 m	recovered 9.1 m of drilling mud
30	1549.6 to 1553 m	recovered 45.7 m of oil, 45.7 m of oil-cut mud, 646.2 m of water
31	1586.5 to 1621.5 m	recovered 64 m of drilling mud and 243.8 m of oil-cut mud
33	1586.5 to 1621.5 m	recovered 426.7 m of oil-cut mud, 85.3 m of oil-cut salt water and 463.3 m of salt water
34 35 38 39 40	over intervals 1667 to 1685.8 m; 1667 to 1687.4 m; 1726.4 to 1738.6 m; 1849.5 to 1860.2 m; 1927.9 to 1953.8 m; and 1990 to 2011.7 m	recovered drilling mud, in the amounts of 45.7, 137.2, 4.6, 6.1, 6.1, and 33.5 m, respectively
37	1754.1 to 1776.4 m	recovered 310.9 m of drilling mud and 1383.8 m of sulphurous salt water
41	2036.1 to 2051.3 m	no recovery
46	2184.5 to 2190 m	flowed gas to surface at 226.5 K m^3/d

The 2nd, 3rd, 15th and 32nd tests ran over the intervals of 612.3 to 620.3 m and 615.4 to 620.3 m (both Upper Cretaceous Burnthill Creek Formation tests), as well as, 1334.1 to 1327.1, and 1586.5 to 1621.5 m (both Chance Sandstone Member tests). Additional mis-run tests occurred over the intervals 2183.9 to 2224.4; 2164.1 to 2224.4; 2135.7 to 2224.4; and 2138.2 to 2224.4 m, during the 42nd to 45th tests. The Chance L-08 drilling rig was released on the 25th of May, 1960. The current status of the well is suspended.

The encouraging oil shows of the L-08 (M-08) well were exploited by the Socony Mobil-Western Minerals **Chance G-08** (Fig. 20; UWI = 300G086610137300). The G-08 well was drilled as an outpost well to the Chance L-08 well, a short distance to the southeast on the crest of the Chance Anticline, at 66.121694° N, 137.513889° W in the same NTS map sheet as L-08. The G-08 well was spudded on December 04, 1962, as the 5th well to be drilled in the Eagle Plain Basin, at a Kelly Bushing elevation of 524.3 m, in the Cody Creek Formation. It was drilled to a total depth of 1579.8 m in the Chance Sandstone Member.

Twenty tests were run in the Chance G-08 well. The 1st (673.6 to 688.8 m) was a test of the strata from Burnthill Creek Formation into the Fishing Branch Formation. It flowed gas to surface at a rate of 94.7 K m^3/d, and it recovered 0.6 m of drilling mud. The 2nd test, in the Fishing Branch Formation (691.9 to 710.2 m) recovered 54.9 m of drilling mud. The 3rd test, in the Hart River formation above the Chance Sandstone over the interval 1194.8 to 1207 m, recovered 51.8 m of gas-cut mud. The 5th test, of the Hart River Formation including the Chance Sandstone Member, recovered 48.8 m of gas-cut sulphurous salty mud. The 4th, 8th and 13th tests in the Chance G-08 were mis-run over the Chance Sandstone Member between 1295.4 to 1299.1 m; 1340.2 to 1343.3 m; and 1417.3 to 1434.4 m; although, the 13th test flowed gas to surface at a rate of 24.3 K m^3/d and it recovered 137.2 m of gas-cut mud.

A total of 13 technically successful additional tests were performed on the Chance Sandstone Member in the G-08 well.

Chance Sandstone Member, G-08		
6	1333.5 to 1340.2 m	recovered 359.7 m of oil
7	1302.4 to 1333.5 m	recovered 12.2 m of gas- and oil-cut mud
9	1340.2 to 1346.3 m	recovered 42.7 m of oil
10	1345.1 to 1379.2 m	recovered 125 m of oil, 30.5 m of drilling mud-cut oil
11	1379.2 to 1384.4 m	recovered nothing
12	1385.9 to 1392.9 m	recovered 82.3 m of gas-cut mud, 27.4 m of drilling mud-cut oil
14	1435 to 1462.1 m	recovered 1423.4 m of oil-cut sulphurous salt water
15	1462.1 to 1506.9 m	recovered 225.6 m of gas-cut sulphurous salty mud
16	1495.3 to 1530.7 m	recovered 192 m of gas- and water-cut mud
17	1530.7 to 1538.3 m	recovered 61 m of gas-cut mud; 457.2 m of drilling mud- and gas-cut salt water
18	1418.8 to 1426.2 m	flowed gas to surface at a rate of 1415.8 m^3/d
19	1363.7 to 1389 m	flowed gas to surface at a rate of 849.5 m^3/d and recovered 0.6 m^3 oil
20	1339 to 1358.2 m	flowed oil to surface at a rate of 5663.4 m^3/d and recovered 27.2 m^3 oil

The Chance G-08 drilling rig was released on March 31, 1965. The well is currently a suspended oil well.

The 3rd new field wildcat exploration well drilled in the Eagle Plain Basin was the Amerada et al. **Crown Bell River YT N-50** (Fig. 20; UWI = 300N506720136450), located at 67.329167° N, 136.891389° W. It was drilled in the northern Eagle Plain Basin, east of the Bell River. It tests a bedrock antiformal culmination, in NTS map sheet 116P/17, the southwest side of which is bounded by a southwest-verging thrust fault. The well was spudded on February 29, 1960, in Neocomian strata, at a Kelly Bushing elevation of 317.6 m and drilled to a total depth of 2439.6 m in the Imperial Formation. No tests were run or reported in the Bell River N-50 well. The drilling rig was released September, 1960 and the current well status of N-50 is dry and abandoned.

The 4th new field wildcat exploration well is the Standard Oil of British Columbia **Blackstone D-77**, (Fig. 20; UWI = 300D776550137000), located at 65.769658° N, 137.24855° W. This well spudded March 10, 1962, at Kelly Bushing elevation of 645 m in a region of pre-Cretaceous bedrock south of the Peel River, east of the Blackstone River, on a mapped east-trending antiformal culmination in the area just north of the Ogilvie Mountains. The structure is outlined by outcrops of Permian Jungle Creek Formation, in NTS map sheet 116H/14. The well was drilled to a total depth of 4028.5 m in the Cambrian-Ordovician Bouvette Formation, which it penetrated at 2827.3 m depth. A total of 11 tests were run.

Ogilvie Formation, above the Dolomite Member, D-77		
1	1494.7 to 1616.4 m	recovered 57.9 m of drilling mud
2	1737.4 to 1774.5 m	recovered 121.9 m of drilling mud-cut salt water and 792.5 m of sulphurous salt water
3	2011.7 to 2061.7 m	recovered 164.6 m of water-cut mud and 1185.7 m of water
Road River Formation		
4	2499.4 to 2514.9 m	recovered 12.2 m of drilling mud
5	2650.8 to 2660 m	recovered 173.7 m of water cushion
Bouvette Formation		
6	2889.5 to 3021.5 m	recovered 762 m of water cushion and 1688.6 m of drilling mud- and gas-cut water
Road River Formation and Bouvette Formation		
7	2807.2 to 2852.9 m	recovered 684.3 m of water cushion and 9.1 m of drilling mud
8	3811.2 to 3859.4 m	mis-run
9	3974 to 4028.5 m	mis-run
10	3974 to 4028.5 m	mis-run
11	3974.6 to 4028.5 m	mis-run

The Blackstone D-77 drilling rig was released in January, 1963. The well status is currently dry and abandoned.

The 6th well drilled in the study region was the Socony Mobil-Western Minerals **Porcupine River K-56** (Fig. 20; UWI = 300K566610137450). This 5th new field wildcat exploration well is located in the western limb of a mapped bedrock synform, such that the well is inferred to test a blind thrust fault culmination at depth in NTS map sheet 116I/4. The well is located just east of the Whitestone River at 66.092617° N, 137.925597° W. It was spudded on March 26, 1963, from a Kelly Bushing elevation of 498 m in Upper Cretaceous Cody Creek Formation and drilled to a total depth of 2286 m in the Carboniferous Ford Lake Shale. Five tests were run in the Porcupine River K-56 well. The 1st (286.2 to 291.7 m) was a test of the Cody Creek Formation, but recovered only drilling mud (1.2 m). The 2nd (621.8 to 651.1 m) was a test of the stratigraphic interval from Upper Cretaceous Cody Creek Formation into the Lower Cretaceous succession. It too recovered only drilling mud (4.6 m). The 3rd test in Porcupine River K-56, over the interval 735.5 to 754.7 m and which was designed to evaluate an interval within the Lower Cretaceous succession was mis-run. Test 4 in the Fishing Branch Formation (1036.6 to 1051.3 m) recovered 4.6 m of drilling mud.

The 5th and final drill stem test in the Porcupine River K-56 well was run between 1966 and 1973 m to test Hart River Formation, with a flow of gas to surface, too small to measure (NEB, 2000). The Porcupine River K-56 drilling rig was released July, 1963 and the current status is dry and abandoned.

The next new field wildcat exploration well, the 7th well drilled in the region, was the Socony Mobil-Western Minerals **Blackie #1 M-59** (Fig. 20; UWI = 300M596600137000). This well, the discovery well of the Blackie gas accumulation, in NTS map sheet 116H/14, is located at 65.981922° N, 137.186353° W. The well is located on culmination of the Daglish Anticline, a map-scale bedrock structure, in the vicinity of where the trend of the hinge changes from southeasterly to more easterly trending. The well was spudded on December 11, 1963, from a Kelly Bushing elevation of 562.1 m in the Upper Cretaceous Cody Creek Formation. The well was drilled to 1931.8 m and reached total depth in the Carboniferous Ford Lake Shale. Nine tests were run in the Blackie #1 M-59 well.

Jungle Creek Formation, M-59		
1	640.7 to 649.8 m	flowed gas to surface at a rate of 79.3 K m^3/d and recovered 45.7 m of drilling mud
2	649.8 to 656.5 m	flowed gas to surface at a rate of 42.5 K m^3/d and recovered 36.6 m of drilling mud
3	656.5 to 669 m	flowed gas to surface at a rate of 2491.9 m^3/d and recovered 30.5 m of drilling mud
4	716.3 to 724.8 m	recovered 27.4 m of drilling mud, 54.9 m of mud-cut water and 451.1 m of fresh water
5	749.8 to 759 m	recovered 3 m drilling mud
6	749.8 to 759 m	recovered 12.2 m drilling mud
7	749.2 to 759 m	recovered 42.7 m of water-cut mud and 269.7 m of mud-cut water
Chance Sandstone Member		
8	1770.9 to 1783.1 m	recovered 12.2 m of drilling mud
Chance Sandstone Member into the Ford Lake Shale		
9	1895.2 to 1931.8 m	recovered 563.9 m of gas-cut mud G625

The Blackie M-59 drilling rig was released in March, 1964. The current well status is a suspended gas well.

The 8th well drilled was the Socony Mobil-Western Minerals **Molar P-34** (Fig. 20; UWI = 300P346710138300). This new field wildcat exploration well is located toward the northwestern limit of Cretaceous outcrop, in NTS map sheet 116O/2. The well, located at 67.066389° N, 138.6° W, is on the mapped hinge of a major structure, the Whitestone Anticline, which trends north-south from the southwesterly verging Sharp Mountain Thrust Fault, at the northern limit of the Eagle Plains, to the confluence of Cody Creek and the Porcupine River, where the North Hope N-53 well is located, over a distance of approximately 80 km. The well was spudded on March 29, 1964, in Upper Cretaceous Fishing Branch Formation at a Kelly Bushing elevation of 803.5 m and drilled to a total depth of 2649.6 m in the Imperial Formation. A single drill stem test was run over an interval (2420.4 to 2434.4 m) to test the Jurassic Porcupine River Formation, but only 137.2 m of drilling mud and 304.8 m of water cushion were recovered. The Molar P-34 drilling rig was released in August, 1964. The well status is currently dry and abandoned.

The 9th well drilled in the Eagle Plain and its environs was the Socony Mobil et al. **Whitestone N-26** (Fig. 20; UWI = 300N266610138150). It was located at approximately the latitude of the Chance field, west of the Whitestone River, in NTS map sheet 116J/1. This new field wildcat exploration well was spudded at the following location, 66.099722° N, 138.333333° W on the hinge of, and presumably to test, the 1st mapped anticlinal structure that lies east of the Whitestone Syncline, one of the largest and most continuous structures of the Eagle Plains. This well can be inferred to test a structural prospect south of, but equivalent to, those tested on the Whitestone Mountain Anticline by Molar P-34 and North Hope N-53 wells. The well commenced on April 7, 1964 from a Kelly Bushing elevation of 696.5 m in Upper Cretaceous Cody Creek formation and was drilled to a total depth of 2464.3 m in the Carboniferous Ford Lake Shale. Like the Molar P-34 well, the Whitestone N-26 drilling rig was released in August, 1964. Seven tests were run in the Whitestone N-26 well: the 1st, 3rd, 4th, 5th and 6th tests were mis-runs. These five tests were designed to test the Hart River Formation (1935.8 to 1939.4 m) and Chance Sandstone Member (2406.4 to 2464.3; 2406.4 to 2464.3; 2406.4 to 2464.3 and 2406.4 to 2464.3 m, respectively). The 2nd drill stem test was run over the interval (1937 to 1941.9 m) that evaluates the Hart River Formation. The 2nd test recovered 68.6 m of gas-cut mud. Test 7, a drill stem test (2406.4 to 2464.3 m) was also designed to evaluate the Chance Sandstone Member, but it only recovered 41.1 m of drilling mud. The current status of N-26 is dry and abandoned.

The Socony Mobil-Western Minerals **Ellen C-24** (Fig. 20; UWI = 300C246640137450) was the 10th well drilled in the region. This new field wildcat exploration well was located near, but not directly on, a mapped structure, the Ellen Anticline, in NTS map sheet 116I/12, north of Chance Creek. The well spudded at 66.552464° N, 137.835597° W in Upper Cretaceous Cody Creek Formation on December 25, 1964, from a Kelly Bushing elevation of 414.5 m and was drilled to a total depth of 2174.4 m in the Tuttle Formation. Nine tests were run in the Ellen C-24 well. The first three tests run in the C-24 well, #1, #1A, and #2, were mis-runs. These included tests over the intervals: 460.6 to 482.8 m (Cody Creek Formation), 722.1 to 746.5 m (Fishing Branch Formation) and 723.6 to 732.7 m (Fishing Branch Formation). Test 2 recovered 277.4 m of drilling mud. Test 3 (1377.4 to 1423.7 m) evaluated the Tuttle Formation and recovered 123.4 m of oil-cut mud. Five subsequent tests of the Tuttle Formation produced no significant flows or recoveries. The 4th (1508.2 to 1530.4 m) recovered 161.5 m of gas-cut mud, and tests 5 (1649 to 1667 m) and 6 (1649 to 1676.7 m) were mis-runs. Test number 5 recovered 64 m of drilling mud. Test 7 (1649 to 1676.7 m) recovered 70.1 m of drilling mud and test 8 (1886.7 to 1912.9 m) recovered 4.6 m of gas-cut mud. The Ellen C-24 drilling rig was released in April, 1965, and the well has a dry and abandoned status.

The 11th well in the region, drilled beyond the strict limits of the Eagle Plain Basin, was the Socony Mobil-Western Minerals **South Tuttle N-05** (Fig. 20; UWI = 300N056630136450). It is located at 66.414222° N, 136.772972° W, just west of the Dempster Highway, in NTS map sheet 116I/7. This new field wildcat exploration was drilled to test the hinge of a broad, complicated structural culmination, cored at outcrop by Upper Devonian shale, that forms part of the western flank of the Richardson Anticlinorium, west of the Deception Fault. The well was spudded on February 18, 1965, from a Kelly Bushing elevation of 504.7 m in Norris's map unit "Dus" – which he distinguished between the Imperial and Tuttle formations. It was drilled to a total depth of 3513.4 m in the Bouvette Formation, which it first penetrated at a depth of 2868.8 m. Nine tests were run in the South Tuttle N-05 well. An interval from 1478.3 to 1542.9 m in the Ogilvie Formation recovered 18.3 m of drilling mud and 743.7 m of gas-cut salt water. The 3rd test, but 2nd successful attempt, from an interval in the Ogilvie Formation from 2042.2 to 2116.5 m recovered 175.3 m of drilling mud. The 5th test was run over an interval 2530.1 to 2542.3 m also in the Dolomite Member of the Ogilvie Formation. It recovered 152.4 m of gas-cut mud. The 8th test in the Bouvette Formation (informal Cherty Unit) between 3483.6 and 3513.4 m recovered 54.9 m of drilling mud and 1043 m of water-cut cushion. Tests 2, 4, 6, 7 and 9 were mis-run. The 2nd test (2046.7 to 2062.3 m) evaluated the Ogilvie Formation, and recovered 426.7 m of drilling mud. The 4th test, in the interval from 2530.1 to 2542.3 m also tested the Ogilvie Formation, in the Dolomite Member, and it recovered 1654.5 m of gas-cut mud. Test 6, within the Bouvette Formation (informal Cherty Unit) (3499.7 to 3513.4 m), recovered 517.6 m of drilling mud and 770.2 m of water-cut cushion. Tests 7 and 9 also tested the Bouvette Formation. Test 7 from 3493 to 3513.4 m recovered 290.5 m of drilling mud and 1043 m of water-cut cushion. Test 9 recovered 995.8 m of water cushion, 30.5 m of drilling mud and 137.2 m of sulphurous salt water from the depths of 3379.6 to 3393 m. The South Tuttle N-05 drilling rig was released July, 1965. The current well status is dry and abandoned.

The next well, the 12th, was drilled east of the Chance oil prospect. The well, a new field wildcat, is located at 66.169028° N, 137.434583° W. The location is just north of the northern surface expression of the Daglish Anticline and Daglish Syncline, in the western limb of the Parkin Anticline. The well presumably tests the eastern extension of the Chance sandstone member subcrop play in NTS map sheet 116I/3. This well, Socony Mobil-Western Minerals **West Parkin D-51** (Fig. 20; UWI = 300D516620137150) was spudded on February 24, 1965, in Upper Cretaceous Cody Creek Formation from a Kelly Bushing elevation of 475.5 m. It was drilled to the Chance Sandstone Member at a total depth of 1508.8 m. The first of five tests run in the West Parkin D-51 well, over an interval 1336.5 to 1358.2 m, tests the Chance Sandstone Member. This test recovered 109.7 m of oil-cut mud and 762.9 m of sulphurous brackish water. The 2nd test, of the same stratigraphic unit between 1323.4 and 1333.8 m), recovered 121.9 m of oil-cut mud; 258.5 m of gas-cut sulphurous water. Tests 3 and 4 in the West Parkin D-51 were mis-run. Test 3, between 1124.7 and 1136.9 m in the stratigraphic interval from Whitestone River Formation into the Hart River Formation recovered 198.1 m of drilling mud; while, test 4, between 1109.5 to 1135.7 m, testing the same interval, recovered 272.8 m of drilling mud. The 5th test in the D-51 well, between 685.8 and 718.1 m evaluates the Fishing Branch Formation. It recovered 336.5 m of drilling mud-cut fresh water. The West Parkin D-51 drilling rig was released in April, 1965 with a status of dry and abandoned.

The 13th well drilled in the Eagle Plain Basin and its environs discovered the Birch natural gas accumulation. This new field wildcat exploration well Socony Mobil-Western Minerals **Birch B-34** (Fig. 20; UWI = 300B346610136450) is located at 66.050872° N, 136.854864° W. It occurs east of the Blackie gas discovery, nearer the outcrop edge of Cretaceous strata in NTS map sheet 116I/2, but not clearly associated with mapped bedrock structure. The well was spudded on April 8, 1965, in Upper Cretaceous Cody Creek Shale from a Kelly Bushing elevation of 667.5 m and drilled to a total depth of 1649.9 m in the Carboniferous Ford Lake Shale. Nine tests were run in the Birch B-34 well. The first four tests, 289.6 to 293.8; 293.8 to 354.5; 354.5 to 405.1; 487.7 to 509.9 m, were all run within the Jungle Creek Formation. The 1st test recovered 6.1 m of water-cut mud. The 2nd recovered 36.6 m of water-cut mud. The 3rd recovered 67.1 m of drilling mud and the 4th recovered 4.6 m of oil-cut mud. The 5th drill stem test (701 to 707.1 m) evaluated the Blackie Formation and recovered 54.9 m of water-cut mud; 213.4 m of drilling mud-cut salt water and 198.1 m of salt water. Test 6 (1350.3 to 1371.9 m) tests the Chance Sandstone Member. It flowed gas to surface at a rate of 156.5 K m^3/d and recovered 91.4 m of gas-cut sulphurous water. The 7th and 8th tests in the Birch B-34 were mis-run. Test 7, run an interval 453.5 to 464.8 m to evaluate the Jungle Creek Formation, recovered 213.4 m of drilling mud. Test 8, run over effectively the same interval (458.7 to 463.3 m) recovered 82.3 m of drilling mud and 128 m of fresh water. The 9th test (1583.4 to 1649.9 m) also evaluates the stratigraphic interval from the Chance Sandstone Member to the Ford Lake Shale. It flowed gas to surface at a rate of 207.8 K m^3/d and recovered 100.6 m of gas-cut mud. The Birch B-34 drilling rig was released in June, 1965. It is a gas discovery well. The well was re-entered, in July 20, 1988, and abandoned.

The 14th well drilled was the Socony Mobil-Western Minerals **North Cathedral B-62** (Fig. 20; UWI = 300B626620138300). This new field wildcat exploration well is located to test a local culmination on the very large mapped antiformal structure that effectively delineates the thicker preserved Cretaceous succession of the Eagle Plain Basin from the thinner preserved succession and outliers that occur west of this Precambrian-cored anticlinal structure. The western limb of the Whitestone Syncline is the eastern limb of this anticlinorium, a local culmination of which was tested by the B-62 well, in NTS map sheet 116J/2. The B-62 well is located at 66.187083° N, 138.698056° W. The well was spudded on April 16, 1965, in Carboniferous Hart River Formation, from a Kelly Bushing elevation of 540.1 m and drilled to a total depth of 2138.5 m in the Cambrian-Ordovician Bouvette Formation, which it penetrated at a depth of 1886 m. The North Cathedral B-62 drilling rig was released June, 1965, without a significant discovery. A single test was run in the well, over the interval 1323.4 to 1333.8 m that evaluates the Dolomite Member of the Ogilvie Formation, without significant results or recovery. Currently the well is used as a temperature observation well, for geophysical purposes.

The Canoe River **Chance J-19** outpost well was the 15th drilled in the Eagle Plain Basin and its environs (Fig. 20; UWI = 300J196610137300). The J-19 well is located at 66.142° N, 137.541117° W also on the hinge of the Chance Anticline, in NTS map sheet 116I/4, where the L-08 and G-08 wells had been drilled previously. The well was spudded in Upper Cretaceous Cody Creek Formation on December 14, 1967 at a Kelly Bushing elevation of 518.8 m and drilled to a total depth of 1446.3 m in the Chance Sandstone Member. Nine tests were run in the Chance J-19 well as follows.

Fishing Branch Formation, J-19		
1	726.6 to 744 m	recovered 163.1 m of water-cut mud
Hart River Formation		
2	1239.3 to 1260.7 m	flowed gas to surface at a rate of 184.1 m^3/d and recovered 42.7 m of condensate
3	1264.9 to 1279.2 m	flowed gas to surface at a rate of 116.1 m^3/d and recovered 15.2 m of drilling mud-cut condensate
Upper Hart River Formation and the Chance Sandstone Member		
4	1278.9 to 1329.8 m	flowed gas to surface at a rate of 2157.7 m^3/d and recovered 42.7 m of gas-cut sulphurous salty mud
Chance Sandstone Member		
5	1330.1 to 1356.1 m	flowed gas to surface at a rate of 142.7 K m^3/d
6	1356.1 to 1372.8 m	recovered 499.9 m of gas-cut oil and 109.7 m of brackish water, the salinity of which was 1925 ppm
7	1409.7 to 1446.3 m	mis-run, recovering 115.8 m of drilling mud
8	1377.7 to 1392.9 m	flowed gas to surface at a rate of 62.7 K m^3/d and recovered 91.4 m of gas- and oil-cut mud
9	1396 to 1447.8 m	flowed gas to surface at a rate of 538 m^3/d and recovered 141.7 m of gas-cut mud, 54.9 m of drilling mud- and gas-cut water and 160 m of salt water

The rig used to drill the Chance J-19 well was released in February, 1968. The well has current status as a suspended oil and gas well.

The 16th well drilled in the study area was the Canoe River **East Chance C-18** (Fig. 20; UWI = 300C186610137150). This outpost well, is located at 66.11915° N, 137.299283° W just west of the Dempster Highway in NTS map sheet 116I/3. The well is not located on the Chance Anticline as was J-19, but rather it was drilled in the eastern limb of the Daglish Syncline southwest of the end of the surface hinge of the Parkin Anticline. Well C-18 was spudded in Cody Creek formation on February 29, 1968, from a Kelly Bushing elevation of 535.2 m. It was drilled to a total depth of 1540.8 m in the Chance Sandstone Member, presumably to test the subcrop play on that reservoir. The first of three drill stem test run in the East Chance C-18 well was run over an interval 925.1 to 934.8 m to evaluate the Carboniferous strata including the Hart River Formation.

The test flowed gas to surface at a rate of 45.3 K m^3/d. A 2nd drill stem test (1524 to 1540.8 m) tests the Chance Sandstone Member. It flowed gas to surface at a rate of 161.4 K m^3/d and recovered 36.6 m of condensate-cut sulphurous salt water and 61 m of water with a salinity of 28 600 ppm. The final test, also in the Chance Sandstone Member between 1496.6 and 1517.9 m, flowed gas to surface at a rate of 10.2 K m^3/d and recovered 128 m of water-cut mud. The East Chance C-18 drilling rig was released in April, 1968. The current well status is dry and abandoned.

The Western Minerals **North Hope N-53** new field wildcat well was the 17th drilled in the study area (Fig. 20; UWI = 300N536640138150). It is located just north of the confluence of Cody Creek and Porcupine River at 66.548333° N, 138.425° W. The N-53 well also tests the Whitestone Anticline, near its southern surface limit in NTS map sheet 116J/9. The equivalent structural position had been tested previously by the Molar P-34 well, which was drilled near the northern surface limit of this major anticlinal structure, and by the Whitestone N-26 well, which was also located to test the first major anticlinal culmination east of the Whitestone Syncline, although farther to the south. The N-53 well was spudded on April 18, 1970, from a Kelly Bushing elevation of 350.5 m in Albian Whitestone River Formation and drilled to a total depth of 4280.3 m in the Cambrian-Ordovician Bouvette Formation, which it penetrated at 2731.3 m depth. Six tests were run in the North Hope N-53 well. The first three tests in the N-53 were mis-run.

Ogilvie Formation, Dolomite Member, N-53		
1	2453.6 to 2475 m	mis-run
2	2505.5 to 2529.8 m	recovered 243.8 m of water cushion and 61 m of drilling mud
Bouvette Formation		
3	3305.6 and 3343.7 m	recovered 30.5 m of mud-cut water, 926.6 m of water cushion and 137.2 m of gas-cut mud
4	3305.6 to 3343.7 m	recovered 83.8 m of mud-cut water, 1063.8 m of gas-cut cushion, 780.3 m of gas-cut mud and 527.3 m of sulphurous water-cut mud
5	2952 to 3026.7 m	mis-run
Imperial Formation		
6	1161.9 to 1165.6 m	recovered 0.6 m of drilling mud

The North Hope N-53 drilling rig was released in August, 1970. The status of N-53 is currently dry and abandoned.

The 18th well drilled in the Eagle Plain Basin and its environs was the Standard Oil of British Columbia Western Minerals **Shaeffer Creek O-22** (Fig. 20; UWI = 300O226650137150). This new field wildcat exploration well is located on the eastern side of the Basin at 66.698333° N, 137.327778° W. The well tests the hinge of a mapped north-trending anticline in NTS map sheet 116I/11. It was spudded in Upper Cretaceous Cody Creek Formation on January 12, 1971, from a Kelly Bushing elevation of 352 m, and drilled to a total depth of 3161.7 m in the Dolomite Member of the Ogilvie Formation, which it penetrated at 3075.4 m depth. Six tests were run in the Shaeffer Creek O-22 well. The 1st test (2744.4 to 2763.9 m) evaluated Devonian Ogilvie Formation above the Dolomite Member. It flowed gas to surface at a rate of 311.5 m^3/d and recovered 313.9 m of gas-cut cushion and 45.7 m of gas-cut mud. The 2nd test in O-22 (2534.1 to 2565.5 m) was mis-run during an attempt to evaluate the Canol and Ogilvie formations. It recovered 19.8 m of drilling mud. Test 3 (2534.1 to 2566.4 m) was an attempt to repeat test 2 in the Canol and Ogilvie formations. It recovered 36.6 m of drilling mud. The 4th test was a mis-run production drill stem test over the interval 150.9 to 212.4 m in the Upper Cretaceous Eagle Plain Group. Test 5, a production drill stem test run between 136.9 to 338 m, was an attempt to repeat test 4, although it too was mis-run, recovering only 99.1 m of drilling mud. A 3rd attempt over the interval 152.1 to 338 m during test 6 only resulted in the recovery of 85.6 m of drilling mud from the Upper Cretaceous Eagle Plain Group. The Shaeffer Creek O-22 drilling rig was released in May, 1971. The well status is currently dry and abandoned.

The Standard Oil of British Columbia Western Minerals **East Porcupine I-13** (Fig. 20; UWI = 300I136610137450) was the 19th well drilled in the Eagle Plain Basin and its environs. This new field wildcat exploration well is located on the eastern flank of a mapped anticlinal hinge in NTS map sheet 116I/4, at 66.043056° N, 137.782778° W. The well was spudded on February 10, 1971, from a Kelly Bushing elevation of 507.5 m in Upper Cretaceous Cody Creek Formation and drilled to a total depth of 2439.3 m in the Carboniferous Chance Sandstone Member. Nine tests were run in the Porcupine I-13 well.

Burnthill Creek Formation and Fishing Branch Formation, I-13		
1	1103.4 to 1115 m	recovered 141.7 m of water-cut mud
Fishing Branch Formation		
2	1109.2 to 1162.2 m	recovered 330.7 m of oil- and water-cut mud
3	1106.1 to 1162.2 m	mis-run, recovered 178.3 m of drilling mud
Ettrain Formation		
4	1821.8 to 1845 m	mis-run, recovered 393.2 m of drilling mud
Chance Sandstone Member		
5	2377.4 to 2439.6 m	recovered 56.7 m of drilling mud
Upper Cretaceous strata in the Cody Creek and underlying Burnthill Creek formations		
6	755.3 to 781.8 m	recovered 170.1 m of gas-cut mud
Ettrain Formation		
7	1823.3 to 1847.1 m	recovered 57.9 m of gas-cut mud and 707.1 m of salt water, the salinity of which was 39 300 ppm
Upper Cretaceous Cody Creek and underlying Burnthill Creek formations		
8	758 to 781.8 m	recovered 38.1 m of drilling mud
Cody Creek Formation		
9	757.7 to 776.6 m	recovered 36.6 m of drilling mud and 9.1 m of mud-cut water.

The East Porcupine I-13 drilling rig was released in April, 1971. The current well status is dry and abandoned.

The 20th well drilled in the region was the Chevron, Standard Oil of British Columbia Western Minerals **West Parkin C-33** (Fig. 20; UWI = 300C336620137150). Located in NTS map sheet 116I/3, this new field wildcat exploration well tests the hinge of the Parkin Anticline at 66.201111° N, 137.365556° W. The well was spudded in the Upper Cretaceous Cody Creek Formation on November 29, 1971, from a Kelly Bushing elevation of 520 m and drilled to a total depth of 1256.7 m in the HART River Formation. Six tests were run in the West Parkin C-33 well. The two tests were run over intervals 669.3 to 691 and 691.3 to 696.8 m and evaluated the Upper Cretaceous Parkin Formation. The 1st test recovered 42.7 m of drilling mud. The 2nd drill stem test recovered 6.1 m of drilling mud. Test 3 (874.8 to 895.2 m) evaluated from the Chance Sandstone Member into lower Hart River Formation strata. This test recovered 18.3 m of drilling mud and 835.2 m of gas-cut sulphurous water. The 4th and 5th tests in C-33, run within the Hart River Formation over intervals of 969.3 to 979.6 and 1005.8 to 1066.5 m, recovered, respectively, 15.2 m and 27.4 m of drilling mud. The salinity of the recovered waters was, respectively, 2000 ppm and 700 ppm. Test 6 (481.6 to 498 m) evaluated the strata from Burnthill Creek Formation into the Fishing Branch Formation. This test recovered 6.1 m of drilling mud and 227.1 m of water. The West Parkin C-33 drilling rig was released in January, 1972. The well is dry and abandoned.

The 21st well drilled in the Eagle Plain Basin and its environs was the Chevron, Standard Oil of British Columbia Western Minerals **East Pine Creek O-78** (Fig. 20; UWI = 300O786700137450). It is a new field wildcat exploration well to test a deeply eroded, high amplitude, north-trending anticlinal culmination over the crest of the northeast-trending Eagle Arch (Moorehouse, 1966; Young, 1973; 1975) in NTS map sheet 116I/13. The well, located at 66.964722° N, 137.982778° W, was spudded on December 25, 1971, from a Kelly Bushing elevation of 389.2 m in Albian Whitestone River Formation. It was drilled to a total depth of 947.6 m in Imperial Formation. A single test was run in the East Pine Creek O-78 well. The test (768.4 to 792.5 m) evaluated a succession of Whitestone River to Imperial strata with a recovery of 9.1 m of drilling mud and 76.2 m of mud-cut water. The well status is dry and abandoned and the rig was released January, 1972.

The 22nd well drilled in the region was the Chevron, Standard Oil of British Columbia Western Minerals **North Parkin D-61** (Fig. 20; UWI = 300D616630137000). This new field wildcat exploration well tested the eastern flank of the Eagle Plain Basin in NTS map sheet 116I/6. It is located at 66.336667° N, 137.216944° W where there is no obvious bedrock structural culmination; however, the well is located approximately in the vicinity of two reported petroleum seepages that occur approximately 55 km northeast of the Chance Oil Field (Norris and Hughes 1997, p. 383, their Figure 15.1 and Table 15.1). The well was spudded in Upper Cretaceous Cody Creek Formation on January 04, 1972, from a Kelly Bushing elevation of 489.2 m and it was drilled into the Dolomite Member of the Ogilvie Formation, which it first penetrated at 3033.4 m and remained in until total depth at 3352.8 m. Two tests were run in the North Parkin D-61 well. The 1st (2325.6 to 2404.9 m) was a test of the Ogilvie Formation and it recovered 100.6 m of drilling mud. Test 2 (459 to 464.5 m) evaluated the Whitestone River Formation. The test of the Whitestone River Formation recovered 107.6 m of drilling mud and 138.1 m of gas-cut fresh water. The D-61 is a dry and abandoned well and was released in May, 1972.

Chevron, Standard Oil of British Columbia Western **Minerals Birch E-53** was the 23rd well drilled in the Eagle Plain Basin and its environs (Fig. 20; UWI = 300E536610136450). Located at 66.039167° N, 136.934722° W, this new field wildcat exploration well is located immediately southwest of the Birch B-34 well that discovered the Birch Gas Field, in NTS map sheet 116I/2. The well was spudded on January 20, 1972, in Upper Cretaceous Cody Creek Formation from a Kelly Bushing elevation of 621.5 m, and drilled to a total depth of 684.3 m in the Blackie Formation. The first of two drill stem tests (403.9 to 419.4 m) examined the Jungle Creek Formation. It recovered 100.6 m of water, with a salinity of 2000 ppm. The 2nd drill stem test (496.5 to 516.6 m), also in the Jungle Creek Formation, recovered 51.8 m of drilling mud and 215.8 m of drilling mud- and gas-cut water, with a salinity of 150 ppm. The Birch E-53 drilling rig was released in February, 1972. The current well status is dry and abandoned.

The Chevron, Standard Oil of British Columbia Imperial **South Chance D-63** new field wildcat was the 24th well drilled in the Eagle Plain Basin and its environs (Fig. 20; UWI = 300D636600137300). This well is located almost due south of the Porcupine I-13 well, just north of the Dempster Highway, in NTS map sheet 116H/13. The well was spudded at 65.869167° N, 137.714167° W, slightly northeast of a mapped bedrock anticline, on February 21, 1972. It is located on the Upper Cretaceous Cody Creek Formation and drilled from a Kelly Bushing elevation of 707.4 m. It was drilled to a total depth of 2020.8 m in the Upper Carboniferous strata. Two tests were run in the D-63 well. The 1st test (1639.2 to 1793.7 m) evaluated the Jungle Creek Formation and upper Carboniferous strata and it recovered 221.3 m of gas-cut mud and 85.3 m of water-cut mud. The 2nd drill stem straddle test was run over the Jungle Creek Formation (1674 to 1712.1 m). This Jungle Creek Formation test recovered 27.4 m of drilling mud, 82.3 m of gas and 364.2 m of gas-cut mud. The salinities of the recovered waters were 1200 and 2000 ppm. The South Chance D-63 drilling rig was released in May, 1972, with a status of dry and abandoned.

The 25th well drilled in the Eagle Plain Basin and its environs was the Chevron, Standard Oil of British Columbia Western Minerals **Whitefish I-05** (Fig. 20; UWI = 300I056710137150). This new field wildcat exploration well is located at 67.076944° N, 137.256944° W, in the vicinity of the Eagle Arch, in NTS map sheet 116P/3, although it is not located on a mapped bedrock structure. The well was spudded on February 23, 1972, in Upper Cretaceous Cody Creek Formation from a Kelly Bushing elevation of 348.1 m. It was drilled to a total depth of 1498.4 m in the Tuttle Formation. Four tests were run in the Whitefish I-05 well. The first three tests in the I-05 were mis-run. All three tests attempted to evaluate the Mount Goodenough Formation, over the intervals of 1415.8 to 1450.2, 1421.9 to 1450.2 and 1426.5 to 1450.2 m. Tests 1 and 3 recovered 455.7 m of drilling mud, and 1353.3 m of drilling mud- and gas-cut fresh water, respectively. Test 4 (668.1 to 671.2 m) evaluated the Fishing Branch Formation and recovered 502.9 m of drilling mud- and gas-cut fresh water. The Whitefish I-05 drilling rig was released in April, 1973. The current well status is dry and abandoned.

The Chevron, Standard Oil of British Columbia Western Minerals **East Porcupine F-18** well was the 26th drilled in the study area (Fig. 20; UWI = 300F186610137450). This new field wildcat exploration well is located at 66.123611° N, 137.804444° West, in NTS map sheet 116I/4. It lies north of both the East Porcupine I-13 and Porcupine River K-56 wells and it is located near the hinge of a mapped anticline in Upper Cretaceous Cody Creek Formation, which appears to be a separate culmination equivalent to the structure tested by the East Porcupine I-13 well. The well was spudded in Upper Cretaceous strata on March 6, 1972, from a Kelly Bushing elevation of 523 m. It was drilled to a total depth of 2050.7 m in the Chance Sandstone Member of the Hart River Formation. Four tests were run in the Porcupine F-18 well. The 1st drill stem test (1885.8 to 1911.7 m) over the Hart River Formation recovered 30.5 m of drilling mud. The salinity of the recovered water was 400 ppm. Test 3, a straddle test (1210.1 to 1241.8 m) within the Fishing Branch Formation, recovered 254.2 m of drilling mud and 9.1 m of gas-cut mud. The 2nd and 4th tests in the Porcupine F-18 well were mis-runs. Test 2 (1174.1 to 1198.5 m) in the Fishing Branch Formation flowed gas to surface at a rate of 1911.4 m^3/d and recovered 182.9 m of gas-cut mud. Test 4 (283.5 to 315.8 m) in Cody Creek Formation, was without significant result or recovery. The East Porcupine F-18 drilling rig was released May, 1972 with the well status as dry and abandoned.

The 27th well drilled in the study area is located on the edge of the Eagle Plain Basin. This well, the Chevron, Standard Oil of British Columbia, **Gulf Ridge F-48**, new field wildcat (Fig. 20; UWI = 300F486720137450) is located at 67.289722° N, 137.893056° W, near the eroded limit of Cretaceous strata in NTS map sheet 116P/5. The well tests a structure in the footwall of a mapped normal fault that lies northeast of the end of the surface trace of the Sharp Mountain Thrust, which borders the northwestern side of the Eagle Plain Basin. The well was spudded in Albian Whitestone River Formation on January 3, 1973, from a Kelly Bushing elevation of 321.3 m. It was drilled to a total depth, in the Imperial Formation, of 1868.7 m. Three tests evaluating Jurassic Porcupine River Formation were run in the Ridge F-48 well.

Jurassic Porcupine River Formation, F-48		
1	1404.8 to 1432.3 m	recovered 164.6 m of water-cut mud and 1130.5 m of water
2	1204 to 1289.3 m	flowed gas to surface at a rate of 962.8 m^3/d and recovered 286.5 m of gas-cut mud
3	1289.3 to 1327.4 m	recovered 170.7 m of drilling mud, 54.9 m of gas-cut mud and 82.3 m of mud-cut water

The Ridge F-48 drilling rig was released in March, 1973. The well is dry and abandoned.

The Chevron, Standard Oil of British Columbia Western Minerals **Whitefish J-70** was the 28th well drilled in the Eagle Plain Basin and its environs (Fig. 20; UWI = 300J706710137150). This new field wildcat exploration well is located at 67.158889° N, 137.445556° W. It is located in a region of low relief and extensive Quaternary cover, southeast of the Lapierre Syncline, but in a region of NTS map sheet 116P/3, with no mapped bedrock prospect. The well was spudded, probably in Upper Cretaceous Cody Creek Formation bedrock on January 17, 1973, at a Kelly Bushing elevation of 330.7 m. It was drilled to a total depth of 2127.5 m in the Jurassic Porcupine River Formation. Three tests were run in the Whitefish J-70 well. The 1st test, over the interval 2054.4 to 2076.3 m, was a test of the Mount Goodenough Formation and recovered 76.2 m of drilling mud and 150.3 m of mud-cut water. The 2nd test, run an interval 2098.5 to 2127.5 m in the Jurassic Porcupine River Formation, was mis-run, without significant result or recovery. The 3rd test, between 2098.5 to 2127.5 m, also designed to evaluate the Jurassic Porcupine River Formation, recovered 137.2 m of drilling mud and 1764.8 m of gas-cut brackish water. The current well status is dry and abandoned. The J-70 rig was released in April, 1973.

The Murphy Mesa PB **Whitestone N-58** was the 29th well drilled in the study region (Fig. 20; UWI = 300N586600138150), located at 65.963889° N, 138.425° W. This new field wildcat exploration well was located in the west limb of Whitestone Syncline, between it and the Precambrian-cored anticlinorium that marks the west side of the Eagle Plain Basin, in NTS map sheet 116G/16, and which was tested by the North Cathedral B-62 well. The N-58 well was spudded in Upper Cretaceous Cody Creek Formation on February 10, 1973, from a Kelly Bushing elevation of 889.4 m, and drilled to a total depth of 2131.5 m in the Ettrain Formation. Four tests were run in the Whitestone N-58 well. The 1st test, over an interval 1807.5 to 1829.4 m, evaluated the Jungle Creek Formation, and recovered 128 m of drilling mud and gas-cut water. The salinity of the recovered water was 2500 ppm. The last three tests in the Whitestone N-58 well, all attempts to evaluate the Fishing Branch Formation, over the intervals of 719.3 to 749.8, 717.8 to 749.8 and 719.6 to 748 m were all mis-run. The Whitestone N-58 drilling rig was released in April, 1973. The current well status is dry and abandoned.

The Westcoast et al. **North Porcupine F-72** well, was the 30th well drilled in the region (Fig. 20; UWI = 300F726740137450). This new field wildcat exploration well is located north of the Porcupine River, and beyond the proper limits of the Eagle Plain at 67.5231° N, 137.9850° W. However, the well is spudded in Permian strata northeast of the footwall of a normal fault on the northern rim of the Eagle Plain that preserves Cretaceous strata in its hanging wall. The Kelly Bushing elevation of the F-72 well is 349.3 m and the well was drilled to a total depth of 2251.9 m in what was reported as Ordovician Bouvette Formation, but which is presumably Cambrian-Ordovician Bouvette Formation (Morrow, 1999; Norford in Norris et al., 1997 refers to this as an “unnamed carbonate unit” although the well lies north of the Morrow’s study area). No tests were reported. The North Porcupine F-72 drilling rig was released April, 1974. The current well status is dry and abandoned.

The 31st well drilled in the Eagle Plain Basin and its environs was the **Aquitaine Alder C-33** (Fig. 20; UWI = 300C336600136450). This new field wildcat exploration well is located at 65.867108° N, 136.919444° W. The well tested an east-trending anticline, located immediately north of the Peel River, in NTS map sheet 116H/15, from which the Cretaceous succession has been eroded. Morrow (1999) illustrated an interpreted seismic section through this well (his Figures 11 and 13). The structure is similar to that tested previously by the Blackstone D-77 well. The C-33 well was spudded on March 8, 1978, in Permian Jungle Creek Formation from a Kelly Bushing elevation of 530 m. It was drilled to a total depth of 3714 m in the Dolomite Member of the Ogilvie Formation, which it penetrated at 3300 m. No tests were reported. The Alder C-33 well was finally abandoned and dry March 4, 1979.

The Exco et al. **West Parkin D-54** new field wildcat well was the 32nd well drilled in the study region (Fig. 20; UWI = 300D546620137150). This exploration well was drilled northwest of the West Parkin C-33 well, also on the Parkin Anticline in NTS map sheet 116I/3. The D-54 well is located at 66.21875° N, 137.433589° W and it was spudded in Upper Cretaceous Cody Creek Formation on December 20, 1984. It was drilled from a Kelly Bushing elevation of 506.8 m to a total depth of 1811 m in Devonian strata. Five tests were run in the West Parkin D-54 well. The 1st test, run over the interval 1062 to 1064 m, evaluated the Lower Cretaceous and recovered 305 m of gas-cut sulphurous water. The 3rd test in the D-54 well between 742 and 747 m more successfully evaluated the Lower Cretaceous. This test flowed gas to surface at a rate of 1000 m^3/d. The 2nd (700 to 750 m), 4th (1042 to 1047 m) and 5th (1039 to 1049 m), drill stem tests, all attempts to evaluate Lower Cretaceous strata, were mis-run, without significant result or recovery. The Exco et al. West Parkin D-54 drilling rig was released in February, 1985. The current well status is abandoned, although it was previously classified as a shut-in gas well.

The 33rd well drilled in the Eagle Plain Basin and its environs was the Exco et al. **North Chance D-22** (Fig. 20; UWI = 300D226620137300). This new field wildcat exploration well is located at 66.185028° N, 137.592475° W. It is drilled on the Chance Anticline northwest of the Chance L-08 well. The well was spudded on March 1, 1985, from a Kelly Bushing elevation of 536 m, in Upper Cretaceous Cody Creek Formation, and drilled to a total depth of 1830 m in Carboniferous Imperial Formation. Four tests were run in the North Chance D-22 well. The 1st test was run between 1433 and 1436 m. The 2nd was run between 1538 to 1554 m, and the 3rd between 1538 to 1554 m, all with the intention of evaluating Carboniferous strata, but all without significant result or reported recovery. Test 4 in the D-22 well was a drill stem test run over an interval 786 to 789 m to evaluate the Fishing Branch Formation, although this test also had neither a significant result, nor recovery. The North Chance D-22 well was released on April 8, 1985. Its current status is dry and abandoned.

SUMMARY

A high prospectivity should be assigned to the Eagle Plain Basin, in light of existing discoveries, numerous shows in wells from drill stem tests and a few surface seepages (Norris and Hughes, 1997) of petroleum. All point toward effective petroleum systems throughout the entire Phanerozoic succession, across the entire geographic breadth of the basin. Therefore it is reasonable to assume that petroleum is present in all potential reservoirs, and that there are no play-level risks at any level. Rather, it is just a question of where specific accumulations that meet economic criteria for production may be identified. The preliminary results indicate that the early exploratory history in the Eagle Plain was intermediately successful, qualitatively, being better than the early exploration in the Peel Plateau, and the Atlantic Margin of Canada, but not as successful as the early exploration of either the Beaufort Mackenzie Basin (Osadetz et al., 2005b) or the Sverdrup Basin (Chen et al., 2000). Most wells drilled to date concentrate on testing Laramide age bedrock surface structures, following an anticlinal accumulation model, as clearly identified in the exploration history discussion above. This is comparable to the post-Turner Valley but pre-Waterton exploration phase in the Foothills of the Rocky Mountains. That exploratory phase was also generally unsuccessful. Although specific attempts to exploit the subcrop play in the Carboniferous, have not been successful – probably due to timing considerations, there has been little effort to exploit other stratigraphic plays, both internal to the Mesozoic succession, and at the up-dip limit of the Bouvette to Ogilvie carbonate platforms, which are favourably oriented, with respect to dip and seal, against the fine clastic successions of the Richardson Trough. Nor have internal stratigraphic plays in the Imperial Formation been sufficiently evaluated.

The following assessment considers the promising results in the Eagle Plain Basin to date, and uses methods and risks appropriate to the local setting. Due to the similarity in approach and analysis, the results of the Eagle Plain Basin, presented here, should be directly comparable to other regions, including the Western Canadian Sedimentary Basin.

ASSESSMENT METHOD

INTRODUCTION

The following discussion illustrates the analytical resource assessment method used in this assessment compared with a similarly analysed example of a mature petroleum play in the Western Canada Sedimentary Basin. Historical differences between the immature and conceptual petroleum plays of this assessment and the mature petroleum plays of the Alberta Foothills result in different input data, but the analytical assessment method, based on the size distribution of petroleum accumulations and the inferred number of accumulations is identical. The comparison of immature and conceptual plays provides an understanding of the robustness of the assessment technique, the uncertainties associated with it, and expected historical evolution of plays as they progress from concepts to a set of discovered accumulations. The Eagle Plain Basin has been explored by talented and capable scientists, with numerous encouraging indications, but without significant economic results. Therefore, it is important to explain the resource assessment method used in this report (the results of which are more optimistic than both the historical exploration results and previous assessment calculations — especially for gas). The results of this assessment are then seen as consistent with the results of the exploration history, considering the level of exploratory work.

TERMINOLOGY

The terms resource, reserve and potential, as defined previously (Podruski et al., 1988; Bird, 1994), are used in this study. *Resource* is defined as all hydrocarbon accumulations that are known or inferred to exist. *Reserves* are that portion of the resource that has been discovered, whether or not they are economically producible. The term *potential* describes that portion of the resource that is inferred to exist but is not yet discovered. The terms *potential* and *undiscovered resources* are synonymous and are used interchangeably.

A *prospect* is defined as a geographic region, where the combination of geological characteristics and history indicate the possibility of an underlying petroleum pool or field. A *pool* is defined as a petroleum accumulation, typically within a rock reservoir composed of a single stratigraphic interval that is hydrodynamically separate from other petroleum accumulations. A *field* consists of a number of discrete pools, at varying stratigraphic levels, which exist within a specific geographic region and generally have some common geological characteristics. A *play* consists of a set of pools or prospects that share a common history of hydrocarbon generation, migration, reservoir development and trap configuration.

METHODS OF PETROLEUM RESOURCE ASSESSMENT

Petroleum is an important, even strategic, commodity in modern societies. The understanding of where, when and under which economic conditions certain petroleum resources become a part of the petroleum supply is essential to economic management and planning. The principal origin of petroleum from kerogen and coal, its transformation by thermal and biological processes to petroleum, and its principal modes of occurrence in sedimentary basins are well understood.

The mathematical delineation of "pools" and "reserves," as a continuous function of technology and price, requires a detailed description of the spatial variation of reservoir characteristics and an understanding of the relationship between reservoir characteristics and reservoir performance. The determination of that proportion of undiscovered petroleum resources that could be economically realizable remains a function of the technological, engineering and economic criteria for the development.

Discrete conventional petroleum accumulations commonly result from the migration and entrapment of petroleum in the complicated porosity and permeability system of a sedimentary basin. Discrete accumulations are best located by exploring for anticlinal and stratigraphic traps. The location and size of undiscovered petroleum accumulations, however, are not easily identified.

A petroleum resource assessment describes the total petroleum potential of specific regions and includes both discovered and undiscovered resources. There are three general types of assessment methods: petroleum systems analysis, prospect analysis and probabilistic methods that include both the volumetric analysis of conceptual and immature plays, and the discovery history analysis of mature plays.

Petroleum system analysis attempts to determine the resources inherent in, derivable from, and attributable to a particular petroleum source rock as a result of the processes affecting the source rock and its resultant petroleum. Petroleum systems analysis requires a detailed description of the petroleum source, including its geological history, and a description of the migration and entrapment of the resulting petroleum. Although all aspects of petroleum source rock accumulation, petroleum generation, migration and entrapment can be calculated, the dependence of such calculations on the specific and detailed features of the real environment renders such calculations either impracticable or impossible.

In the study region, the empirical drilling results and the significant indications of petroleum from drill stem tests are more tangible indicators of potential petroleum resources than is a petroleum system analysis. Favourable indications in such tests occur throughout the Phanerozoic succession and across the geographic breadth of the Eagle Plain basin, indicating that the entire succession has potential. This includes the thermally immature strata in the Cretaceous succession, where gas may have been generated by biogenic processes, as in the case of the Medicine Hat Field of southern Alberta, where very large marketable reserves occur as the result of biogenic petroleum generation and stratigraphic entrapment.

Discrete conventional petroleum resources (e.g., pools) can be assessed using a probabilistic analysis formulated on the play level. There are two such methods, each dependent on the exploration history of the plays and basins being assessed. Undiscovered resources are assessed using both a discovery process analysis (when and where sufficient numbers of discoveries exist) or an accumulation volume analysis (which can be employed even where there are not yet discoveries). Where sufficient numbers of discoveries exist, the discovery process analysis infers the accumulation-size distribution and number of pools from the discovery sequence of accumulation sizes identified. The prospect volume analysis infers the accumulation- size distribution from the characteristics of geological and physical features of the play combined with the inferred distribution of the number of potential accumulations. Once the accumulation-size distribution and number of pools within the play are inferred, resource estimates can be calculated, subject to play-level risks. This approach, regardless of the nature of the input data set and the maturity of the play history, is based on the inference of a play-based accumulation-size distribution and the inferred number of accumulations distribution characteristic of the play.

Potential resource estimates using these two resource assessment methods can be further conditioned against the set of discovered and known pools to additionally condition the size of the undiscovered resource, subject to perceived size of the discovered accumulations. Such calculations provide a practical and useful method for the inference of the inferred undiscovered accumulation sizes that are the target of future exploratory effort. The method is useful because it predicts the economically most critical play characteristic, the size-range of the undiscovered accumulations. The method is amenable to historical vindication (as illustrated in the following discussion), while the similarity of the analysis make the predictions of plays directly comparable whether they are analysed using either the discovery-process or prospect-volume input data.

PETRIMES

This study uses a statistical method developed by the Geological Survey of Canada (Lee and Wang, 1983a, 1983b, Lee and Tzeng, 1993, 1995). We employed a play-oriented petroleum assessment method using the PETRIMES (Petroleum Resource Information Management and Evaluation System) computer program (Lee and Tzeng, 1993). Since the early 1980s, the PETRIMES program has been applied to petroleum plays and mineral deposits from various settings worldwide. Some assessments have been verified by either subsequent exploration activities, or by the historical analysis of established plays (Lee and Tzeng, 1995).

The following sections describe the basic statistical principles employed by PETRIMES. PETRIMES allows both discovery process and volumetric methods of assessment. Where few or no accumulations are discovered, the prospect-size distribution must be estimated using a reservoir volume approach and the Multivariate Discovery Process model (Lee, 1999). This is the approach followed in this report. A resource assessment calculation using PETRIMES is illustrated by a historical analysis of a mature play with many discoveries. This example provides insight into the method and technique.

Discovery process module and input data

Petroleum pool sizes can be plotted as a function of discovery sequence to produce a discovery sequence diagram (Fig. 21). Discovery process models infer the characteristics of the accumulation-size and number-of-accumulations distribution by analysing the historical record of discovered pools and their sizes alone. This assumes that the discovery history sequence is a biased sample of the set of accumulations in the play. The pool-size distribution is then combined with the inferred number of accumulations to infer the total petroleum potential. In the example, (Fig. 21) note the general decline of pool size over time, which indicates that the exploration process produces a biased sample, since the prospects, which are commonly the locations of the largest accumulations, are the preferential targets for exploratory effort.

The effects of the biased sample can be accounted for, assuming that the probability of discovery is proportional to accumulation size, while the associated exploration efficiency provides additional information useful for the estimation of undiscovered resources.

On one hand, the sample bias causes a statistical problem, because statistical procedures commonly assume random sampling. On the other hand, the biased sample contains other information useful for the estimation of undiscovered resources. PETRIMES employs a new statistical model that considers samples biased by purposeful selection of larger prospects to estimate pool populations, assuming that the probability of discovering a pool is proportional to either its size or some other pool parameter, and that a pool can be discovered only once. The mathematical analysis of the discovery sequence that infers the conditional accumulation-size probability distribution and the number of accumulations is the discovery process model (Lee and Wang, 1985, 1986, 1990; Lee, 1993). PETRIMES contains two discovery process models. One employs a lognormal pool-size distribution assumption and the other employs a nonparametric approach. Figure 22 is a result of the discovery process model. The vertical axis represents the log-likelihood value and the horizontal axis indicates the total number of discovered and undiscovered pools in a play, N. The more favourable the log-likelihood value, the more plausible the value of N. In Figure 22, the most

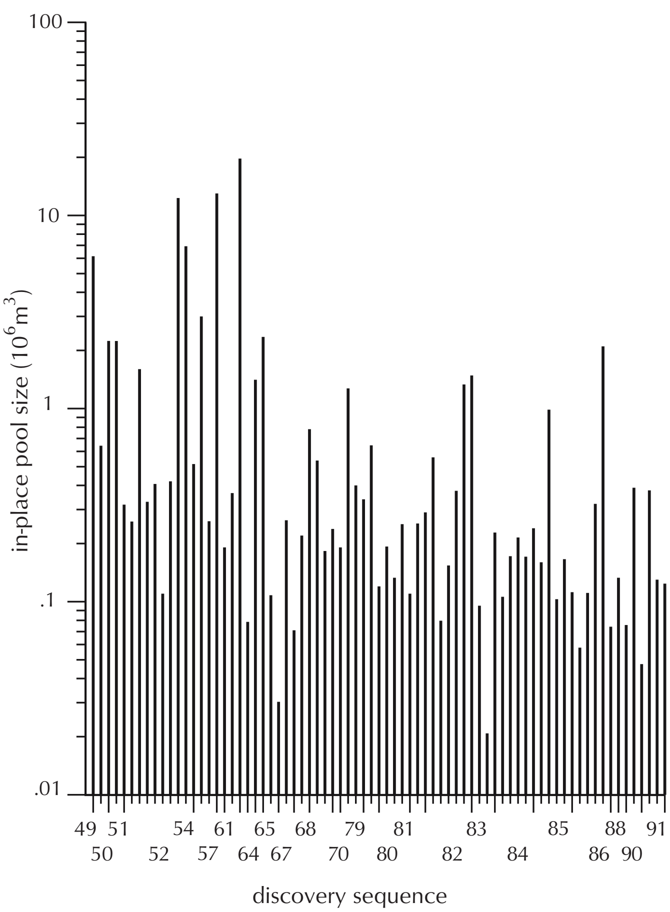


Figure 21. *An example petroleum accumulation discovery sequence taken from the Carboniferous Jumping Pound Rundle Play of the southern Alberta Foothills. The logarithm of pool sizes is plotted sequentially as a function of discovery date, producing the time series or discovery sequence, which forms the basis for a sequential sampling assessment of petroleum potential as discussed in the text. The vertical axis represents the pool size, plotted on a logarithmic scale, and the horizontal axis shows the discovery date.*

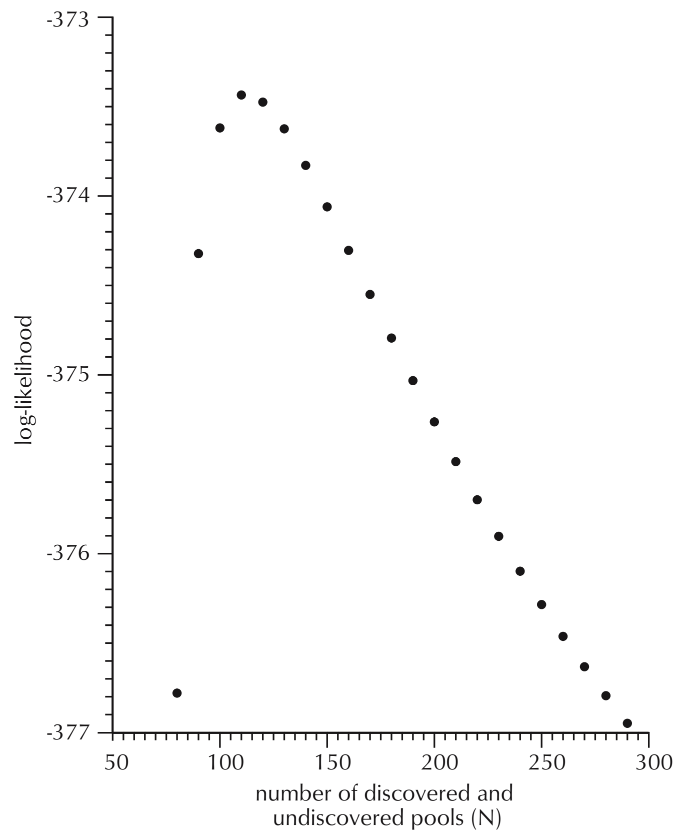


Figure 22. *This figure illustrates the result of the lognormal discovery process model. The vertical axis represents the log-likelihood value and the horizontal axis indicates N, the total number of discovered and undiscovered pools in a play. The higher the log-likelihood value, the more plausible the value of N. In this example, the most likely number of pools is 140.*

likely number of pools is 140. The application of the nonparametric discovery process model to this example data set yields almost the same result.

Where no discoveries have been made, there are no pool-size inputs. However, combinations of geological parameters can be combined to formulate a prospect-size distribution that serves the same function as the pool-size distribution. Such a risked prospect volume method is used in this study. The formulation of an accumulation-size distribution, as used in this study, is discussed below.

Estimating pool, or prospect, size probability distribution

After estimating the N value, or number of accumulations, the corresponding pool-size distribution was used. The statistics of the inferred pool-size distribution were used to generate the pool-size distribution of a play. Discovery process models contain an unknown variable, the exploration efficiency coefficient, which is estimated from the discovery sequence. The discovery process is proportional to the magnitude of the pool size, as well as other factors (e.g., commercial objectives, land availability, pool depth, and exploration techniques). Where there are no discoveries, the pool-size distribution is replaced by the prospect size distribution and the numbers of inferred accumulations are determined as the product of that distribution and the prospect-level risks.

Estimating play potential distribution

A field size probability distribution (Fig. 23) can be estimated from the N value and the pool-size distribution (Lee and Wang, 1983a). Furthermore, a play potential distribution (Fig. 24) can be derived from the play resource distribution, given that the sum of all discoveries of the play is used as a condition. The potential values of the 95th and 5th upper percentiles and the expected values are used in this report as a 0.9 probability prediction interval for undiscovered potential.

Uncertainties and the historical vindication of assessment methods

All estimates contain uncertainties, which can be evaluated and expressed as probabilities. Uncertainties can be expressed in terms of a probability distribution and

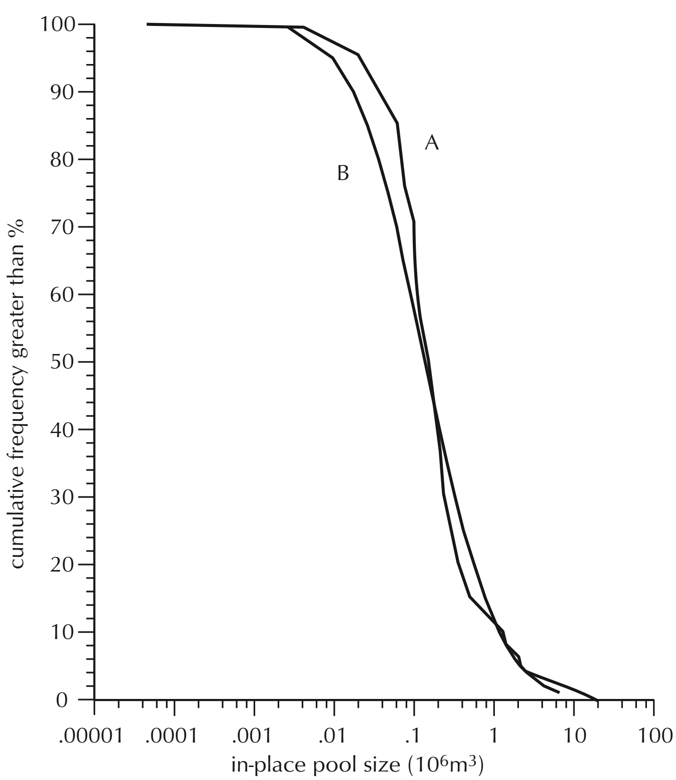


Figure 23. A play total resource distribution can be estimated from the N value and the pool-size distribution (either lognormal distribution A, or nonparametric distribution B) (Lee and Wang, 1983a).

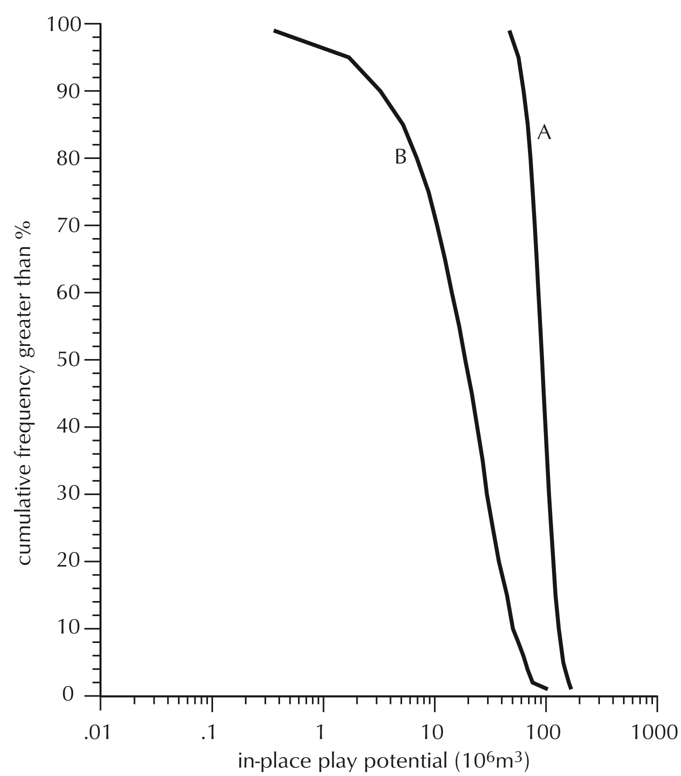


Figure 24. Undiscovered play potential distribution for both the lognormal distribution A, and nonparametric distribution B models displayed in Figure 23. The undiscovered potential is conditioned against the discovered volume, which has been discounted from these distributions.

evaluated by comparison with historical discoveries. The following estimates, e.g., play potential, individual pool size for undiscovered pools, and potential are all expressed as probability distribution. All these distributions are derived by formal statistical procedures. The same is not true for certain types of previous assessments, both regionally and locally (i.e., Bird, 2002).

An important feature of sequential sampling, or discovery process resource assessments, is their amenity to historical analysis and vindication, derived from the analysis of the total data set by a prediction made from a historical subset of the data. If the truncated data set successfully predicts all of the discovered accumulations not used in the input data set, then the residual unidentified resource can be confidently considered to represent the currently undiscovered potential. Such a vindication is, where possible to calculate, an essential criterion for accepting a resource assessment. History and historical analysis shows that geoscientists habitually underestimate the number of accumulations, often significantly. We present, as an example, the historical vindication of another thrust and fold belt anticlinal play to illustrate the manner in which the number of accumulations changes, and how this affects the estimated resource potential as a function of play history.

Figure 25 illustrates an example of a well-behaved Foreland Belt play, the Jumping Pound Rundle Play, as it was analysed in the 1992 Geological Survey of Canada Foreland Thrust and Fold Belt assessment (Lee, 1998). This play, in which the first discovery was made more than 80 years ago, should behave like the structural plays in the Eagle Plain Basin, once discoveries are made. This approach allows us to examine the limitations of PETRIMES when it is applied to a play that has gone through the immature to established exploration stages. The illustrated play lies immediately west of Calgary. The Jumping Pound Rundle Play has been analysed at three different stages of its exploration history: 1966, 1974 and 1991 (Fig. 25, left side). The three resulting petroleum resource estimates for the three discovery sequence subsets is shown in the top right diagram of Figure 25, and a prediction of the range of discovered (ovals) and undiscovered (boxes) accumulation sizes from the pre-1966 data set, conditioned against the discoveries at that time, is also illustrated (Fig. 25, bottom right).

Only 15 accumulations were discovered in this play between the first Rundle Group discovery and 1962. Still, from that data set, it was possible make a prediction of the total potential that was comparable to the total potential estimate in 1991 (Fig. 25, top right), when 94 discoveries had been made after another three decades of exploration had elapsed in a region of easy access and logistics. The effect of small sample size on the resource distribution estimation is minimal, as can be observed from the similarity in the resource distributions for all time windows. The sum of the discovered and expected potential values is almost the same for all time windows. If the sums are compared to the 1991 value, the maximum difference is 16% for the 1966 time window and 3% for the 1974 time window. More important is the observation that the pre-1966 dataset successfully predicts the Quirk Creek Rundle A and Clearwater Rundle A pools (Fig. 25, bottom right), the 6th and 7th largest accumulations in the play. The two largest pools predicted by the 1966 time window data set are the Quirk Creek Rundle A pool and the Clearwater Rundle A pool. The former was discovered in 1967 and the latter pool was discovered in 1980. Since then, no pools larger than these two pools have been discovered. However, several pools with sizes smaller than the Clearwater Rundle have been discovered (Fig. 25).

The impact on resource assessments due to a small number of discoveries is evident in estimating the total number of pools, N. The numbers of discovered accumulations and the number of predicted accumulations in each of the three calculations are 15 and 100; 21 and 100; 94 and 173, respectively (Fig. 25, top right). Through time, the total number of predicted accumulations has increased through the addition of a number of accumulations of smaller size, without major impact on the total resource potential, while the prediction of the largest individual accumulations has remained unchanged. Whether the Jumping Pound Rundle Play is a good analogue for Eagle Plain Basin plays can be debated, but what cannot be debated is the efficacy of the discovery process method in predicting both play potential and number of accumulations from a small number of discoveries, early in the exploratory history of the play. It is also clear there is a tendency for assessments early in an exploration history to be conservative.

Reservoir volume methods

A second, independent assessment can be obtained using a risked prospect volumetric approach and the Multivariate Discovery Process model in PETRIMES (Lee, 1999). If there are few or no discoveries, it is necessary to assess undiscovered potential volumetrically, using such a model. This is the approach used in this assessment for both crude oil and natural gas. Where discovery process methods use discovered accumulation parameters as a biased sample of the accumulation (pool) size distribution, volumetric methods infer the accumulation (prospect) size distribution using combinations of observations, analogy and inference. Observed parameters include reservoir material and physical

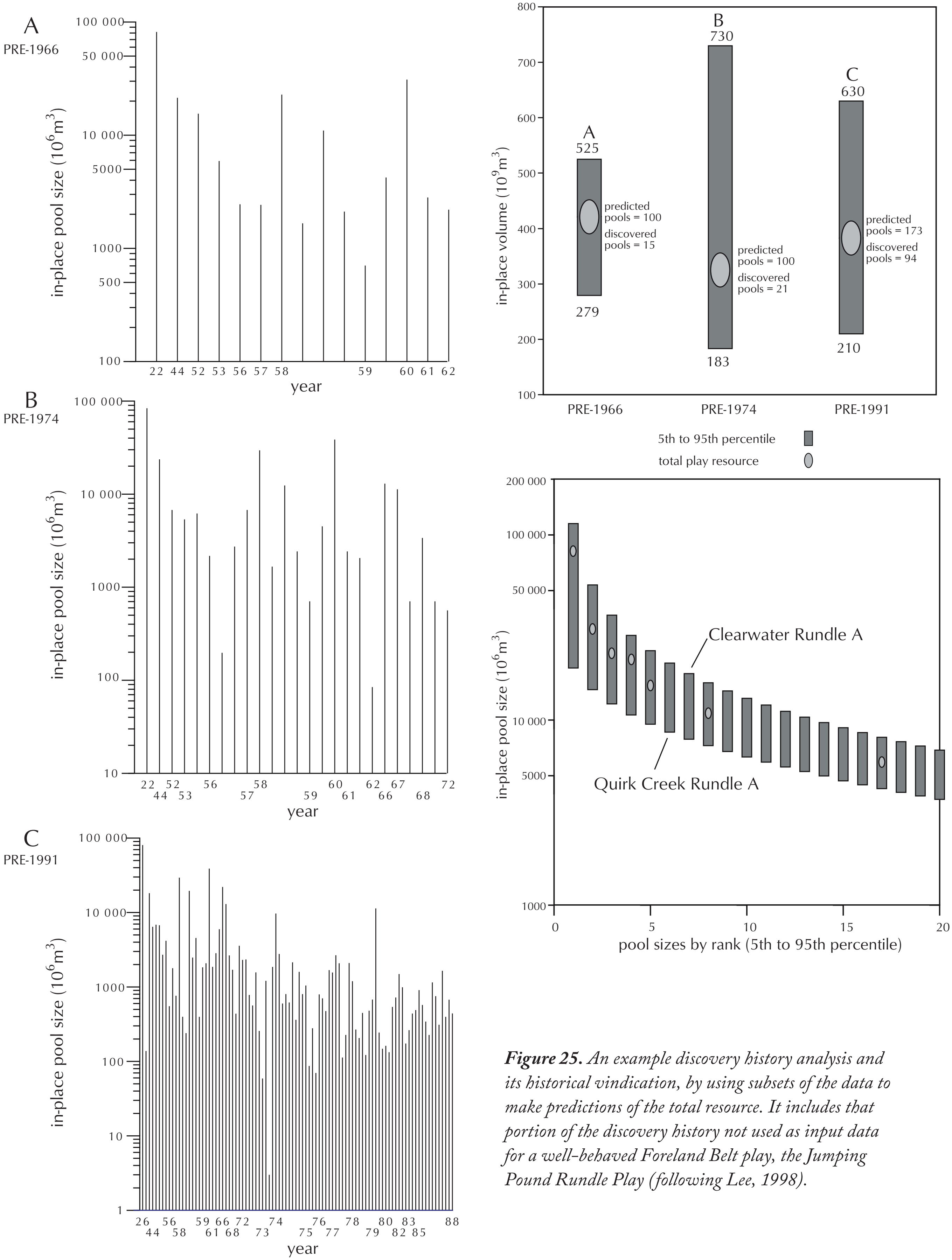


Figure 25. *An example discovery history analysis and its historical vindication, by using subsets of the data to make predictions of the total resource. It includes that portion of the discovery history not used as input data for a well-behaved Foreland Belt play, the Jumping Pound Rundle Play (following Lee, 1998).*

characteristics that incorporate well and seismic data, corrected for sampling biases, expressed as probability distributions, however, there are practical problems associated with the availability and comprehensiveness of required data. Typically, the geoscience data is incomplete and observations must be augmented by extrapolations or supplemented by analogies and inferences. Geographically comprehensive seismic and well data sets are not generally available, or as was the case for the Eagle Plain Basin, were not available for complete incorporation into this assessment. Aspects of prospect volumes, reservoir parameters and trap-fill proportion must be estimated either from geographically limited data sets or appropriate analogues.

The volumetric method requires an independent estimation of the number of accumulations. This number is commonly formulated as the product of the total number of prospects, many of which must be inferred because of the geometry of the seismic grid, and the prospect-level risks, which are commonly estimated subjectively in the absence of discoveries.

The volumetric method used in this study consists of a three-step procedure:

- Estimation of the distributions of reservoir volumetric parameters and possible number of prospects and exploratory risks, as constrained by available geological and well data;
- Estimation of oil and gas accumulation-size distributions from the combination, using the suitable reservoir-volume equation of unbiased reservoir parameters; and
- Computation of both the oil and gas potential distributions and individual accumulation size distributions, contingent on, or conditioned against a specific number of accumulations in pool size by rank plots.

PETROLEUM RESOURCE ASSESSMENT

GENERAL FEATURES AND RATIONALE OF THE PETROLEUM ASSESSMENT

Different combinations of geological history, combined with a variety of different exploratory results and characteristics were used to define the plays used in this assessment. Both the play definitions and input parameters were reviewed and modified subsequent to the comments of active industrial explorers. Plays were defined based on:

- stratigraphic interval, which encapsulates geological history and reservoir environment (pressure and temperature) considerations;
- reservoir style and history;
- petroleum system relative to thermal history and migration potential;
- petroleum composition (as the assessments for natural gas and crude oils need to performed separately; and
- trapping mechanism.

As a result, it was realized that there were four primary stratigraphic intervals of differing geological and reservoir characteristics and history that were prospective for both structurally and stratigraphically entrapped accumulations of both crude oil (plays referred to in this report with a suffix "a") and natural gas. Three parts of the Paleozoic succession were assessed for their petroleum potential, but some intervals, as noted below, were not assessed, either due to problems in parameter specification, or due to a lack of encouragement from the results of drilling that made it impossible to assess play and prospect risks. The Mesozoic succession was treated as a single stratigraphic interval, which was otherwise subdivided into plays. The tendency to aggregate stratigraphic intervals increases the amount of data pertinent to each play, especially when there are few wells, as is the case here. However, it is widely agreed that such aggregation results in more conservative estimate of potential, than if more plays were considered using finer stratigraphic subdivisions.

The lowest stratigraphic segregation was the *Lower Paleozoic (Cambrian to Middle Devonian) succession of the Porcupine Carbonate Platform*, which was judged to have both structural and straigraphic opportunities for the entrapment of natural gas, but which was not attributed to be a significant potential for crude oil, based on the analysis of potential petroleum source rocks and the results of exploratory wells and tests. No significant potential was assigned to the fine-clastic-dominated Cambrian to Carboniferous succession that includes formations, such as the Imperial Formation, which have had shows and significant undiscovered potential assigned elsewhere. This omission was based largely on the negative results from existing exploration wells, but it could be revised, if clear indications of potential were identified by either new drilling or a reconsideration of the existing data.

The 2nd interval identified as prospective is the *Carboniferous succession of the Eagle Plain Basin*, which has established reserves (discovered resources) of both natural gas and crude oil as well as numerous encouraging drill stem test results. Both structural and stratigraphic opportunities for petroleum potential were identified in the Carboniferous succession, but the characteristics of the lowest potential reservoir, the Tuttle Formation, was distinguished from other intervals in higher Carboniferous strata, due to differences in lithology and depositional patterns. In the Permian succession, both structural and stratigraphic opportunities were identified for natural gas potential, but only the structural play could be confidently defined with respect to potential crude oil potential. This is largely because of uncertainties in both petroleum system function and prospect definition, since the available data was not judged sufficiently constrained with respect to potential prospect size and trap-fill.

Although it combines several prospective reservoir horizons, the *Mesozoic succession* was considered as a single major stratigraphic unit. The shale-dominated intervals are not attributed any potential, and the potential in the Mesozoic sandstones is only a conventional potential, for both structurally and stratigraphically entrapped natural gas and crude oil. Petroleum system considerations figured prominently in the assessment of Mesozoic units, since most Mesozoic succession is thermally immature for the thermocatalytic generation of petroleum. However, biogenic petroleum generation is a well established mechanism for producing natural gas in Alberta and Saskatchewan Mesozoic-hosted accumulations. Still, all of the crude oil and some of the natural gas in Mesozoic reservoirs in the Eagle Plains, both in accumulations and shows, has migrated from deeper petroleum systems, and the resulting complications in petroleum systems to this setting are best treated by considering a single Mesozoic interval in the assessment. Contrary to the previous assessment (NEB, 2000), there are Jurassic strata within the Eagle Plain Basin

(Dixon, 1994; Norris 1997). There are even indications of petroleum in the Jurassic succession, however, the Jurassic succession is not assessed separately from the Cretaceous succession in this report, although most of the Mesozoic rock volume, and hence most of the Meosozic petroleum potential, is inferred to occur in the Cretaceous portion of the Mesozoic clastic succession.

As a result 15 plays, 9 natural gas and 6 oil, were defined as characteristic of 9 different stratigraphic levels. These 15 plays are:

- Play 1a, Stratigraphically Trapped Crude Oil Play in Cretaceous Sandstone
- Play 1, Stratigraphically Trapped Natural Gas Play in Cretaceous Sandstone
- Play 2a, Structurally Trapped Crude Oil Play in Cretaceous Sandstone
- Play 2, Structurally Trapped Natural Gas Play in Cretaceous Sandstone
- Play 3, Stratigraphically Trapped Natural Gas Play in Jungle Creek Formation Sandstones
- Play 4a, Structurally Trapped Crude Oil Play in Jungle Creek Formation Sandstones
- Play 4, Structurally Trapped Natural Gas Play in Jungle Creek Formation Sandstones
- Play 5a, Stratigraphically Trapped Crude Oil Play in Hart Creek Formation Sandstones and Carbonates
- Play 5, Stratigraphically Trapped Natural Gas Play in Hart Creek Formation Sandstones and Carbonates
- Play 6a, Structurally Trapped Crude Oil Play in Hart Creek Formation Sandstones and Carbonates

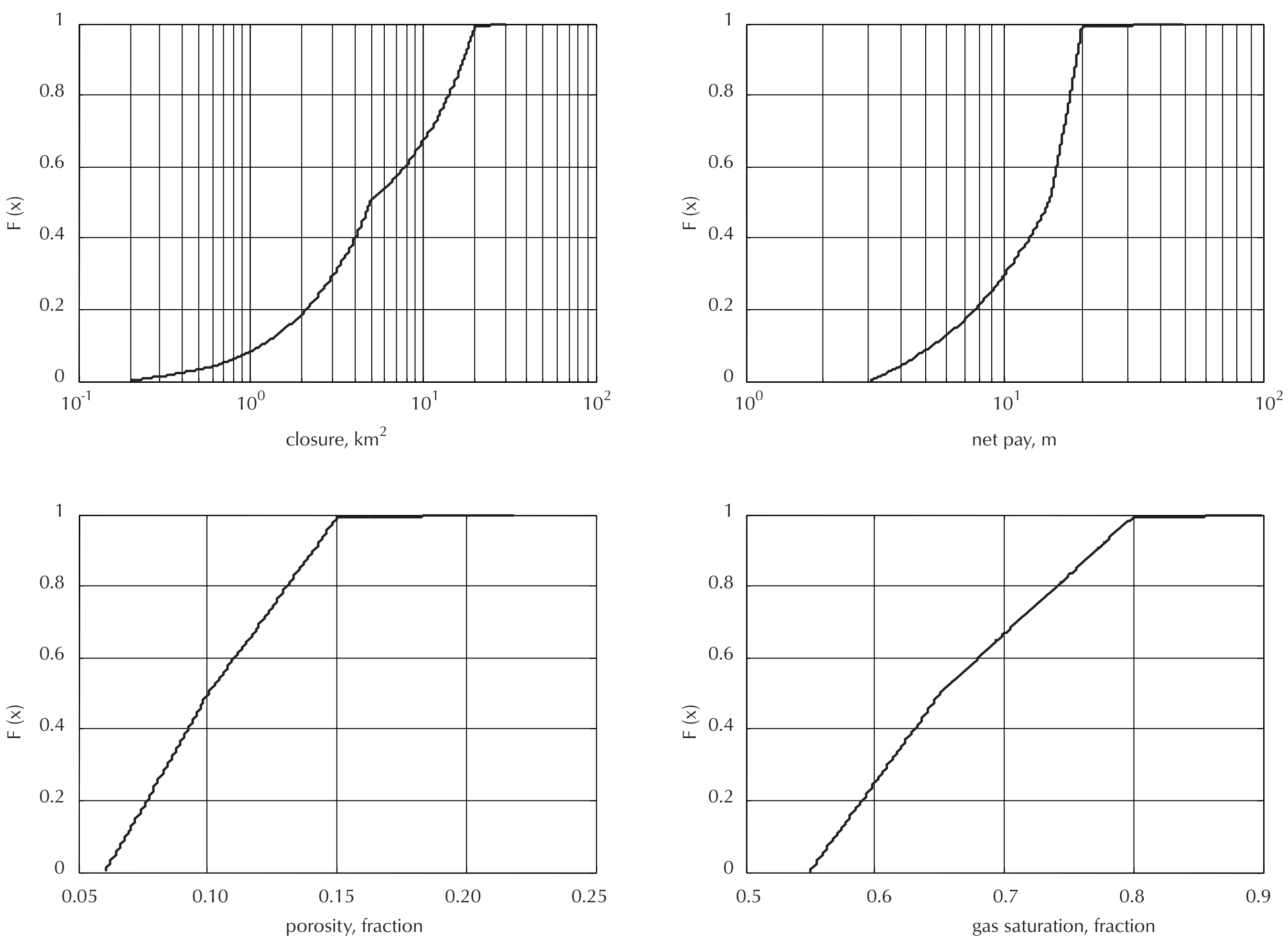


Figure 26. *Example play parameter input distributions for select accumulation size equation input variables, specifically the accumulation area of closure, net pay, reservoir porosity and hydrocarbon saturation, for Play 1, in the Cretaceous sandstones. Complete sets of input play parameters are presented in Tables 4, 8, 12, 16, 20, 24, 28, 32, 36, 40, 44, 48, 52, 56, and 60, which are reported at the 100th, 50th, 1st and 0 percentiles of the input play parameter distributions. F(x) = cumulative frequency*

- Play 6, Structurally Trapped Natural Gas Play in Hart Creek Formation Sandstones and Carbonates
- Play 7a, Stratigraphically Trapped Crude Oil Play in Lower Carboniferous Tuttle Formation Sandstone
- Play 7, Stratigraphically Trapped Natural Gas Play in Lower Carboniferous Tuttle Formation Sandstone
- Play 8, Stratigraphically Trapped Natural Gas Play in Lower Paleozoic (Cambrian to Middle Devonian) Carbonates
- Play 9, Structurally Trapped Natural Gas Play in Lower Paleozoic (Cambrian to Middle Devonian) Carbonates

The petroleum assessment of these 15 plays is presented and discussed below. (Note: Presented in order of oldest to youngest, Play 9 to Play 1.) Input play parameters were derived from measured and mapped analysis of geological data, as well as the use of analogues and inference, based on the experience of the assessors (Fig. 26). Note that the assessment of individual plays and aggregate potential presented in the following pages is the total petroleum endowment, both discovered and undiscovered. Since the description of the "identified resource" or reserve (NEB, 2000) is not pool-based it was not possible to precisely distinguish the undiscovered potential, other than to subtract the "identified resource numbers", which are relatively small compared to the inferred total petroleum endowment, from the aggregate potentials (see below).

NATURAL GAS PLAYS IN THE LOWER PALEOZOIC (CAMBRIAN TO MIDDLE DEVONIAN) SUCCESSION OF THE PORCUPINE CARBONATE PLATFORM

Play 9, Structurally Trapped Natural Gas Play in Lower Paleozoic (Cambrian to Middle Devonian) Carbonates

A significant immature play for natural gas in the Eagle Plain Basin, referred to as Play 9, occurs in structural traps in the Lower Paleozoic succession of porous carbonate strata. The base of this succession is the Middle Cambrian to Upper Ordovician Bouvette Formation; it may contain porous intervals in the Upper Cambrian to Lower Devonian basinal Road River and Michelle formations; and it ends in the platformal carbonates of the Lower and Middle Devonian Mount Dewdney and Ogilvie formations. The extent of this play is roughly similar to the extent of the Porcupine Platform, a region of shallow water carbonate platform deposition throughout early Paleozoic time that lay west of the Richardson Trough. Play parameters are difficult to infer because of the few wells penetrating this succession. However, the inference of play parameters is assisted by reference to outcrops of correlative strata in the mountainous regions flanking the Eagle Plain Basin. This play is a structural play in both the carbonate platform interior, which has stratabound porous intervals, and at its margin, which probably includes both ramp and abrupt margin regressive cycles, where the reservoir intervals are favourably located in structural culminations.

The Lower Paleozoic carbonate successions are involved in Laramide structures, both along the margins of the basin, where they have can be mapped at surface, some of which have been tested as in the D-77, C-33 and N-05 wells, but also in structures buried beneath the younger Mesozoic succession, from which they are structurally detached. Most important is the opportunity for the entrapment of petroleum in stratigraphically persistent zones of porosity in the large, over 150-km-long, buried antclinorium culmination in the Paleozoic carbonates. This culmination lies on the western margin of the basin, immediately east of the Whitestone River Syncline which is inadequately tested by both the B-62 and N-58 wells. Tests, both showing petroleum and recovering water from these successions, indicate the presence of apparently stratabound porous intervals in both the Bouvette and Ogilvie formations, which may be analogous to the stratigraphically persistent porous intervals in coeval carbonate platforms that lie east of the Richardson Trough.

The distribution of input play parameters for Play 9, Structurally Trapped Natural Gas Play in Lower Paleozoic (Cambrian to Middle Devonian) Carbonates, is given in Table 4. The volume of prospects was determined by discounting the product of the area of prospects and net pay, and the prospect gross volume, with a trap-fill fraction based primarily on analogue. The prospect area distribution was inferred to be not smaller than 2 km^2. No prospects exceeding an area of 100 km^2 could be identified or inferred for this play. Average net pay was determined to possibly range between 5 and 150 m, while it is unlikely (1% probability) that average net pay will exceed 60 m thickness. The fractional pool average porosity is inferred to be between 0.03 and 0.18, and fractional hydrocarbon saturations are expected to vary between 0.65 and 0.90, which are reasonable values consistent with observations in the Eagle Plain and general occurrences in similar plays elsewhere. The median value of trap-fill, the percentage of the available prospect that is inferred to be filled with hydrocarbon pay, is 0.20%, with a lower limit (an inferred 100% probability) of 0.05 and an upper practical limit (1% probability) of 0.50. Formation volume factor for gas was computed using reservoir pressure and temperature distributions based on the depth range of potential prospects, together with a distribution of gas compressibility factors, as shown in input parameter in Table 4. The number of prospects in this play was estimated to be not less than 20, and not expected to exceed 70 (Table 4).

Prospect-level risk factors for Play 9 are listed in Table 5. Due to the generally higher levels of thermal maturity and deeper burial of these strata, no oil potential is assigned to this play. The presence of shows of natural gas from the Bouvette Formation, in anticlinal structures tested by the Blackstone D-77 and North Hope N-53 wells, indicated that there is no play-level risks for structures at the base of the Phanerozoic carbonate succession. Three shows from Devonian strata, in the Shaeffer Creek O-22 and Eagle Plain #1 N-49, in the stratigraphically constrained porous zone that occurs above the Dolomite Member as well as porous zones within the Dolomite Member, which tested gas in the South Tuttle N-05 well indicate a high likelihood for porous reservoir and gas charge in structures involving the lower Paleozoic carbonate successions. The N-05 well tested approximately 28 540 m^3/d of gas, suggesting that the first pool in this play may have been discovered, even if it is uneconomical and unrecognized.

The product of individual prospect-level risk factors (Table 5) is the combined prospect-level risk, which for this play is 0.151.

The natural gas pool, or accumulation, size probability distribution for Play 9 is given in Table 6. The expected, or mean, natural gas pool size is predicted to be 74.33 Bcf. The number of expected prospects is 40 (Table 6). The play potential distribution for natural gas in Play 9 is listed in Table 6. The median and mean natural gas potentials calculated for this play are 294.57 and 448.41 Bcf, respectively, which are inferred to occur in six accumulations. The probability distributions describing the calculated individual model accumulations are given in Table 7. The median and mean sizes of the largest predicted natural gas pools in Play 9 are 5.07 and 7.78 billion cubic m, respectively, of initial raw natural gas in-place, at standard conditions. Details of the predicted pool sizes for all six pools are listed in the graph in Figure 27.

Play 9, Structurally Trapped Natural Gas Play in Lower Paleozoic (Cambrian to Middle Devonian) Carbonates

Table 4. *Distributions of input play accumulation parameters.*

Parameter	100%	50%	1%	0%
Closure, km²	2.00	6.00	80.00	100.00
Net pay, m	5.00	15.00	60.00	150.00
Porosity, fraction	0.03	0.06	0.12	0.18
Hydrocarbon saturation, fraction	0.65	0.70	0.85	0.90
Trap-fill, fraction	0.05	0.20	0.50	0.95
Gas compressibility, fraction	0.88	0.90	0.91	0.92
Reservoir pressure, Kpa	25 000.00	31 027.00	51 788.00	51 799.00
Reservoir temperature, °C	65.00	110.00	120.00	121.00

Parameter	100%	50%		0%
Number of prospects	20	35		70

Table 5. *Prospect-level risk factors.*

Presence of source rock	1.000
Presence of closure	0.500
Presence of reservoir facies	0.600
Presence of adequate seal	0.900
Adequate timing	0.700
Migration pathway risk	0.800
Prospect-level risk	0.151

Table 6. *Field size and play potential probability distributions, as well as the number of prospects and pools – Assessment results.*
Units: billion cubic feet of initial raw natural gas in place.

Field size probability distribution						
5%	25%	50%	75%	95%	Mean	Number of prospects
332.54	69.29	20.03	6.15	1.48	74.33	40
Play potential probability distribution						
5%	25%	50%	75%	95%	Mean	Number of pools
1373.92	564.42	294.57	152.65	59.01	448.41	6

Table 7. *Predicted accumulation sizes (x 10^9 m^3).*

Size rank	5%	25%	50%	75%	95%	Mean
1	24.19	9.88	5.07	2.59	0.92	7.78
2	8.19	3.39	1.81	0.93	0.39	2.72
3	3.61	1.51	0.81	0.44	0.19	1.22
4	1.73	0.73	0.39	0.21	0.10	0.59
5	0.83	0.33	0.19	0.10	0.05	0.28
6	0.35	0.14	0.07	0.04	0.02	0.11

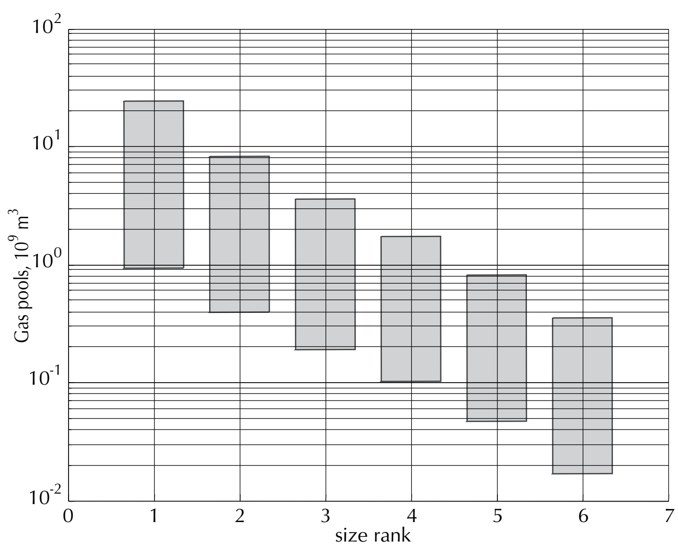


Figure 27. *Predicted accumulation size by rank diagram. The predicted pool sizes are obtained using order statistics and conditioning the accumulation-size distribution against the number of expected pools, as listed in Table 5. This and subsequent figures of the same type show the 90% confidence interval for predicted accumulation sizes, as derived from a rank dependent accumulation size distribution, for each of the predicted potential accumulations in the play, as a function of the rank, or size order (i.e., rank 1 = the largest accumulation) of the model accumulations.*

Play 8, Stratigraphically Trapped Natural Gas Play in Lower Paleozoic (Cambrian to Middle Devonian) Carbonates

A significant conceptual stratigraphic natural gas play in the Eagle Plain Basin, referred to as Play 8, occurs in stratigraphic traps in the Lower Paleozoic succession of porous carbonate strata. The base of this succession is the Middle Cambrian to Upper Ordovician Bouvette Formation. It may contain porous intervals in the Upper Cambrian to Lower Devonian basinal Road River and Michelle formations. It ends in the platformal carbonates of the Lower and Middle Devonian Mount Dewdney and Ogilvie formations. The extent of this play is roughly similar in extent to the structural play, which was itself similar to that of the Porcupine Platform.

Two main types of opportunities exist for stratigraphic entrapment in this succession. Most important is the opportunity for the entrapment of petroleum where the margin of the porous zones, possibly including some abrupt carbonate margins on the carbonate platform, change facies up-dip into the basinal non-porous strata that fill the Richardson Trough. The 2nd type of trap involves stratigraphic traps formed in the carbonate ramp transgressive-regressive cycles that segregate generally persistent stratigraphic zones of porosity. An analogue for this play is the Upper Devonian Birdbear Formation Star Valley oil pool in Saskatchewan. Tests, both showing petroleum and recovering water from these successions, indicate the presence of apparently stratabound porous intervals in both the Bouvette and Ogilvie formations, which may be analogous to the stratigraphically persistent porous intervals in coeval carbonate platforms that lie east of the Richardson Trough. Play parameters are difficult to infer because of the few wells penetrating this succession. However, the inference of play parameters is assisted by reference to outcrops of correlative strata in the mountains regions flanking the Eagle Plain basin. This play is a carbonate platform interior and margin play. However, Canadian explorers have not shown the same level of success in exploiting platform interior stratigraphic traps that geologists exploring in the United States have demonstrated. Lack of local success does not, however, negate the potential of the play.

The distribution of input play parameters for Play 8, Stratigraphically Trapped Natural Gas Play in Lower Paleozoic (Cambrian to Middle Devonian) Carbonates, is given in Table 8. The volume of prospects was determined by discounting the product of the area of prospects and net pay, and the prospect gross volume, with a trap-fill fraction based primarily on analogue. The prospect area distribution was inferred to be not smaller than 5 km^2. No prospects exceeding an area of 90 km^2 could be identified or inferred for this play. Average net pay was determined to possibly range between 5 and 45 m, while it is unlikely (1% probability) that average net pay will exceed 40 m thickness. The fractional pool average porosity is inferred to be between 0.03 and 0.18, and fractional hydrocarbon saturations are expected to vary between 0.65 and 0.90, which are reasonable values consistent with observations in the Eagle Plain and general occurrences in similar plays elsewhere. The median value of trap-fill is 30%, with a lower limit (an inferred 100% probability) of 0.10 and an upper practical limit (1% probability) of 0.70. Formation volume factor for gas was computed using reservoir pressure and temperature distributions based on the depth range of potential prospects, together with a distribution of gas compressibility factors, as described in input parameter Table 8. The number of prospects in this play was estimated to be not less than 20, and not expected to exceed 300 (Table 8).

Prospect-level risk factors for Play 8 are listed in Table 9. Due to the generally higher levels of thermal maturity and deeper burial, no oil potential is assigned to this play. Shows of natural gas in the Bouvette Formation in the Blackstone D-77 and North Hope N-53, and in the Devonian carbonates in the Shaeffer Creek O-22, Eagle Plain #1 N-49 and South Tuttle N-05 wells, indicate that gas and reservoir occur at several levels in the Paleozoic carbonate succession. The most interesting of these is the show in the N-05 well that indicates a potential for gas charge at the up-dip margin of the carbonate platforms against the Richardson Trough. Therefore no play level risk is associated with this play. The product of individual prospect-level risk factors (Table 9) is the combined prospect-level risk, which for this play is 0.126.

The natural gas pool, or accumulation, size probability distribution for Play 8 is given in Table 10. The expected, or mean, natural gas pool size is predicted to be 43.94 Bcf. The number of expected prospects is 155 (Table 10). The play potential distribution for natural gas in Play 8 is listed in Table 10. The median and mean natural gas potentials calculated for this play are 800.63 and 879.45 Bcf, respectively, which are inferred to occur in 20 accumulations. The probability distributions describing the calculated individual model accumulations are given in Table 11. The median and mean sizes of the largest predicted natural gas pools in Play 8 are 5.45 and 6.25 billion cubic m, respectively, of initial raw natural gas in-place, at standard conditions. Details of the predicted pool sizes for all 20 pools are listed in the graph in Figure 28.

Play 8, Stratigraphically Trapped Natural Gas Play in Lower Paleozoic (Cambrian to Middle Devonian) Carbonates

Table 8. *Distributions of input play accumulation parameters.*

Parameter	100%	50%	1%	0%
Closure, km²	5.00	10.00	40.00	90.00
Net pay, m	5.00	15.00	40.00	45.00
Porosity, fraction	0.03	0.06	0.12	0.18
Hydrocarbon saturation, fraction	0.65	0.70	0.85	0.90
Trap-fill, fraction	0.10	0.30	0.70	0.95
Gas compressibility, fraction	0.88	0.90	0.91	0.92
Reservoir pressure, Kpa	20 000.00	25 000.00	27 000.00	30 000.00
Reservoir temperature, °C	57.00	70.00	110.00	120.00

Parameter	100%	50%		0%
Number of prospects	20	150		300

Table 9. *Prospect-level risk factors.*

Presence of source rock	1.000
Presence of closure	0.700
Presence of reservoir facies	0.500
Presence of adequate seal	0.800
Adequate timing	0.600
Migration pathway risk	0.750
Prospect-level risk	0.126

Table 10. *Field size and play potential probability distributions, as well as the number of prospects and pools – Assessment results.*
Units: billion cubic feet of initial raw natural gas in place.

Field size probability distribution						
5%	25%	50%	75%	95%	Mean	Number of prospects
157.31	51.75	22.67	10.38	3.65	43.94	155
Play potential probability distribution						
5%	25%	50%	75%	95%	Mean	Number of pools
1599.75	1060.84	800.63	607.30	415.26	879.45	20

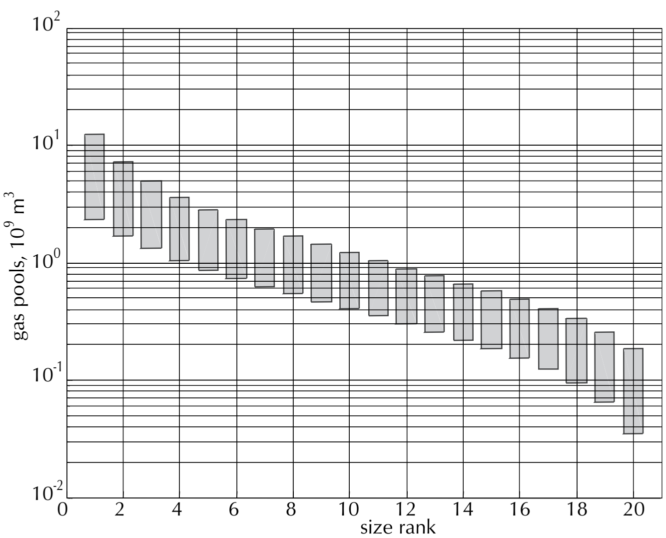


Figure 28. *Predicted accumulation size by rank. The predicted pool sizes are obtained using order statistics and conditioning the accumulation-size distribution against the number of expected pools, as shown in Table 9.*

Table 11. *Predicted accumulation sizes (x 10^9 m^3).*

Size rank	5%	25%	50%	75%	95%	Mean
1	12.57	7.75	5.45	3.77	2.32	6.25
2	7.17	4.54	3.27	2.45	1.67	3.71
3	4.91	3.16	2.43	1.88	1.31	2.67
4	3.63	2.46	1.93	1.51	1.04	2.08
5	2.82	2.00	1.58	1.24	0.87	1.68
6	2.33	1.67	1.31	1.03	0.73	1.40
7	1.95	1.40	1.11	0.87	0.62	1.18
8	1.67	1.19	0.94	0.74	0.54	1.00
9	1.43	1.01	0.81	0.63	0.47	0.85
10	1.22	0.87	0.68	0.55	0.41	0.74
11	1.05	0.75	0.60	0.48	0.35	0.63
12	0.89	0.64	0.52	0.42	0.30	0.55
13	0.77	0.56	0.45	0.36	0.26	0.47
14	0.66	0.48	0.38	0.31	0.22	0.40
15	0.57	0.41	0.33	0.26	0.19	0.34
16	0.48	0.35	0.27	0.22	0.16	0.29
17	0.40	0.28	0.22	0.18	0.12	0.24
18	0.33	0.23	0.18	0.14	0.10	0.19
19	0.26	0.18	0.13	0.10	0.07	0.14
20	0.19	0.12	0.09	0.06	0.03	0.10

NATURAL GAS AND CRUDE OIL PLAYS IN THE CARBONIFEROUS SUCCESSION OF THE EAGLE PLAIN BASIN

Play 7, Stratigraphically Trapped Natural Gas Play in Lower Carboniferous Tuttle Formation Sandstones

Stratigraphic traps in the Carboniferous Tuttle Formation Sandstones, referred to as Play 7, constitute a significant immature play for natural gas in the Eagle Plain Basin. The Tuttle Formation contains booked reserves of 81 x 10^6 m^3 of initial in-place natural gas in the Birch B-34 well and 57 x 10^6 m^3 of initial in-place natural gas in the Chance L-08 (M-08) well (NEB, 2000). Indications for accumulation to date have occurred largely where stratigraphic changes coincide with Laramide structural culminations, but the play includes purely stratigraphic prospects in its definition and description of play parameters.

Play 7 includes stratigraphic plays at the subcrop edge of the Tuttle Formation, which generally occurs just west of the Porcupine River, internal stratigraphic plays related to interformational stratification and facies changes, as well as up-dip facies change from Tuttle sandstones into the coeval Ford Lake shales, as is the case in the B-34 well (NEB, 2000). Play parameters are considered relatively well constrained because of the moderate number of wells, and the presence of identified accumulations of natural gas.

The distribution of input play parameters for Play 7 is given in Table 12. The volume of prospects was determined by discounting the product of the area of prospects and net pay, and the prospect gross volume, with a trap-fill fraction based primarily on analogue. The prospect area distribution was inferred to be not smaller than 5 km^2. No prospects exceeding an area of 80 km^2 could be identified or inferred for this play. Average net pay was determined to possibly range between 0.50 and 15 m, while it is unlikely (1% probability) that average net pay will exceed 10 m thickness. The fractional pool average porosity is inferred to be between 0.05 and 0.14, and fractional hydrocarbon saturations are expected to vary between 0.55 and 0.90, which are reasonable values consistent with observations in the Eagle Plain and general occurrences in similar plays elsewhere. The median value of trap-fill is 40%, with a lower limit (an inferred 100% probability) of 0.05 and an upper practical limit (1% probability) of 0.70. Formation volume factor for gas was computed using reservoir pressure and temperature distributions based on the depth range of potential prospects, together with a distribution of gas compressibility factors, as described in input parameter Table 12. The number of prospects in this play was estimated to be not less than 50, and not expected to exceed 200 (Table 12).

Prospect-level risk factors for Play 7 are listed in Table 13. There are no play-level risks, as the play has established reserves and it has tested gas from wells. Successful tests of natural gas from the Tuttle Formation included the Chance L-08 well, which the NEB (2000) attributes 2.0 Bcf of initial in-place reserves, and shows in the Birch B-34; Whitestone N-26, Ellen C-24, Whitefish I-05 and Ridge F-48 wells (Table 2). Prospect-level risks are reasonably estimated, as the stratigraphic, structural and petroleum system history of the Tuttle Formation are generally similar to that of the main plays in Hart River Formation reservoirs. The product of individual prospect-level risk factors (Table 13) is the combined prospect-level risk, which for this play is 0.161.

The natural gas pool, or accumulation, size probability distribution for Play 7 is given in Table 14. The expected, or mean, natural gas pool size is predicted to be 17.92 Bcf. The number of expected prospects is 113 (Table 14). The play potential distribution for natural gas in Play 7 is listed in Table 14. The median and mean natural gas potentials calculated for this play are 304.36 and 323.02 Bcf, respectively, which are inferred to occur in 18 accumulations. The probability distributions describing the calculated individual model accumulations are given in Table 15. The median and mean sizes of the largest predicted natural gas pools in Play 7 are 1.83 and 1.99 billion cubic m, respectively, of initial raw natural gas in-place, at standard conditions. Details of the predicted pool sizes for all 18 pools are listed in the graph in Figure 29.

Play 7, Stratigraphically Trapped Natural Gas Play in Lower Carboniferous Tuttle Formation Sandstones

Table 12. *Distributions of input play accumulation parameters.*

Parameter	100%	50%	1%	0%
Closure, km²	5.00	25.00	40.00	80.00
Net pay, m	0.50	5.00	10.00	15.00
Porosity, fraction	0.05	0.08	0.12	0.14
Hydrocarbon saturation, fraction	0.55	0.65	0.85	0.90
Trap-fill, fraction	0.05	0.40	0.70	0.90
Gas compressibility, fraction	0.80	0.82	0.84	0.85
Reservoir pressure, Kpa	7000.00	17 000.00	22 000.00	24 000.00
Reservoir temperature, °C	15.00	30.00	35.00	40.00

Parameter	100%	50%		0%
Number of prospects	50	100		200

Table 13. *Prospect-level risk factors.*

Presence of source rock	1.000
Presence of closure	0.600
Presence of reservoir facies	0.600
Presence of adequate seal	0.800
Adequate timing	0.800
Migration pathway risk	0.700
Prospect-level risk	0.161

Table 14. *Field size and play potential probability distributions, as well as the number of prospects and pools – Assessment results.*
Units: billion cubic feet of initial raw natural gas in place.

Field size probability distribution						
5%	25%	50%	75%	95%	Mean	Number of prospects
58.44	23.91	10.86	4.62	1.21	17.92	113
Play potential probability distribution						
5%	25%	50%	75%	95%	Mean	Number of pools
548.52	387.95	304.36	237.30	163.35	323.02	18

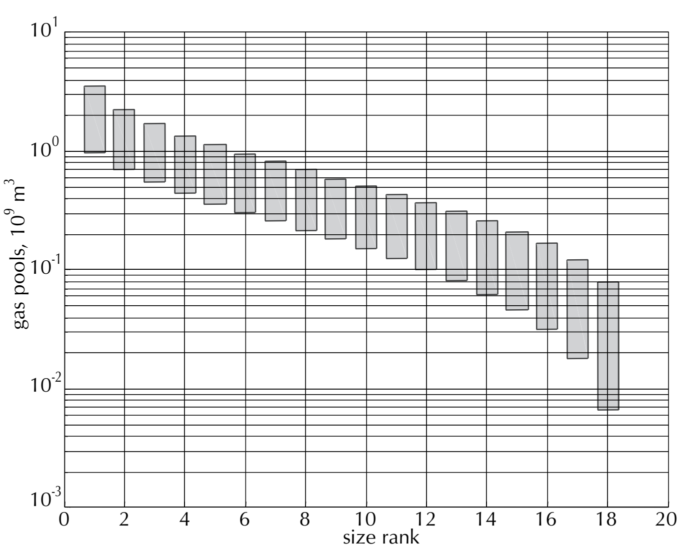


Figure 29. *Predicted accumulation size by rank. The predicted pool sizes are obtained using order statistics and conditioning the accumulation-size distribution against the number of expected pools, as shown in Table 13.*

Table 15. *Predicted accumulation sizes (x 10^9 m^3).*

Size rank	5%	25%	50%	75%	95%	Mean
1	3.58	2.39	1.83	1.41	0.96	1.99
2	2.24	1.62	1.28	1.01	0.71	1.35
3	1.70	1.23	1.00	0.79	0.55	1.04
4	1.36	1.01	0.81	0.64	0.44	0.84
5	1.14	0.84	0.67	0.53	0.36	0.70
6	0.96	0.70	0.55	0.44	0.31	0.58
7	0.82	0.58	0.47	0.37	0.26	0.49
8	0.70	0.50	0.40	0.31	0.22	0.42
9	0.59	0.43	0.33	0.26	0.18	0.35
10	0.51	0.36	0.28	0.22	0.15	0.30
11	0.43	0.31	0.24	0.19	0.13	0.25
12	0.37	0.26	0.20	0.15	0.10	0.21
13	0.31	0.21	0.17	0.12	0.08	0.18
14	0.26	0.18	0.13	0.10	0.06	0.14
15	0.21	0.14	0.10	0.07	0.05	0.11
16	0.17	0.11	0.08	0.05	0.03	0.09
17	0.12	0.08	0.05	0.04	0.02	0.06
18	0.08	0.04	0.03	0.02	0.01	0.03

Play 7a, Stratigraphically Trapped Crude Oil Play in Lower Carboniferous Tuttle Formation Sandstones

Stratigraphic traps in the Carboniferous Tuttle Formation sandstones, referred to as Play 7a, constitute a significant conceptual play for crude oil in the Eagle Plain Basin. The Tuttle Formation contains natural gas, as described above (NEB, 2000). Oil occurs in overlying Carboniferous Hart River Formation (Chance Sandstone and Canoe Lake members) and Permian Jungle Creek Formation. Therefore, consistent with the observed levels of thermal maturity, as discussed above, the Tuttle Formation stratigraphic play is also assigned an oil potential. The play definition is identical to that of Play 7, except for the composition of the petroleum, since PETRIMES requires that crude oil and natural gas potentials be assessed separately. This play includes stratigraphic plays at the subcrop edge of the Tuttle Formation, which generally occurs just west of the Porcupine River; internal stratigraphic plays related to interformational stratification and facies changes; as well as up-dip facies change from Tuttle sandstones into the coeval Ford Lake shales, as is the case in the B-34 well (NEB, 2000). Play parameters are considered relatively well constrained because of the moderate number of wells, and the presence of identified accumulations of natural gas.

The distribution of input play parameters for Play 7a is given in Table 16. The volume of prospects was determined by discounting the product of the area of prospects and net pay, and the prospect gross volume, with a trap-fill fraction based primarily on analogue. The prospect area distribution was inferred to be not smaller than 5 km^2. No prospects exceeding an area of 80 km^2 could be identified or inferred for this play. Average net pay was determined to possibly range between 0.500 and 15.0 m, while it is unlikely (1% probability) that average net pay will exceed 10 m thickness. The fractional pool average porosity is inferred to be between 0.050 and 0.190, and fractional hydrocarbon saturations are expected to vary between 0.550 and 0.900, which are reasonable values consistent with observations in the Eagle Plain and general occurrences in similar plays elsewhere. The median value of trap-fill is 10%, with a lower limit (an inferred 100% probability) of 0.05 and an upper practical limit (1% probability) of 0.15. Shrinkage, the formation volume factor for crude oil, was computed using reservoir pressure and temperature distributions based on the depth range of potential prospects, together with a distribution of solution gas factors, as described in input parameter shown in Table 16. The number of prospects in this play was estimated to be not less than 25, and not expected to exceed 55 (Table 16).

Prospect-level risk factors for Play 7a are listed in Table 17. Although there are no oil reserves established in the Tuttle Formation sandstones, it is reasonable to assume that there are no play-level risks, as the play has established natural reserves and it has tested gas from wells. Successful tests from the Tuttle Formation included the following wells: Chance L-08, Birch B-34, Whitestone N-26, Ellen C-24, Whitefish I-05 and Ridge F-48 (see above and Table 2). An oil potential in this play is consistent with both shows in adjacent formations and the thermal history of petroleum systems as discussed above. Prospect-level risks are reasonably estimated, as the stratigraphic, structural and petroleum system history of the Tuttle Formation are generally similar to that of the main plays in Hart River Formation Reservoirs. The product of individual prospect-level risk factors (Table 17) is the combined prospect-level risk, which for this play is 0.121.

The crude oil pool, or accumulation, size probability distribution for Play 7a is given in Table 18. The expected, or mean, crude oil pool size is predicted to be 13.77 MMbbls. The number of expected prospects is 38 (Table 18). The play potential distribution for crude oil in Play 7a is listed in Table 18. The median and mean, crude oil potentials calculated for this play are 62.31 and 68.95 MMbbls, respectively, which are inferred to occur in 5 accumulations. The probability distributions describing the calculated individual model accumulations are given in Table 19. The median and mean sizes of the largest predicted crude oil accumulations in Play 7a are 4.42 and 4.78 million cubic m, respectively. Details of the predicted pool sizes for all five pools are listed in the graph in Figure 30.

Play 7a, Stratigraphically Trapped Crude Oil Play in Lower Carboniferous Tuttle Formation Sandstones

Table 16. *Distributions of input play accumulation parameters.*

Parameter	100%	50%	1%	0%
Closure, km²	5.000	25.000	40.000	80.000
Net pay, m	0.500	5.000	10.000	15.000
Porosity, fraction	0.050	0.100	0.160	0.190
Hydrocarbon saturation, fraction	0.550	0.650	0.850	0.900
Trap-fill, fraction	0.05	0.10	0.12	0.15
Formation Volume Factor	1.120	1.120	1.120	1.120
Reservoir pressure, Kpa	7000.000	17 000.000	22 000.000	24 000.000
Reservoir temperature, °C	15.000	30.000	35.000	40.000

Parameter	100%	50%		0%
Number of prospects	25	35		55

Table 17. *Prospect-level risk factors.*

Presence of source rock	1.000
Presence of closure	0.600
Presence of reservoir facies	0.600
Presence of adequate seal	0.700
Adequate timing	0.800
Migration pathway risk	0.600
Prospect-level risk	0.121

Table 18. *Field size and play potential probability distributions, as well as the number of prospects and pools – Assessment results.*
Units: initial crude oil in place, 10^6 bbls.

Field size probability distribution						
5%	25%	50%	75%	95%	Mean	Number of prospects
39.00	19.05	10.01	4.71	1.43	13.77	38
Play potential probability distribution						
5%	25%	50%	75%	95%	Mean	Number of pools
137.29	88.01	62.31	42.66	23.90	68.95	5

Table 19. *Predicted accumulation sizes (x 10^9 m^3).*

Size rank	5%	25%	50%	75%	95%	Mean
1	9.09	6.02	4.42	3.11	1.81	4.78
2	5.38	3.56	2.54	1.78	1.01	2.80
3	3.59	2.29	1.59	1.06	0.59	1.77
4	2.38	1.40	0.92	0.58	0.30	1.07
5	1.40	0.72	0.43	0.24	0.10	0.54

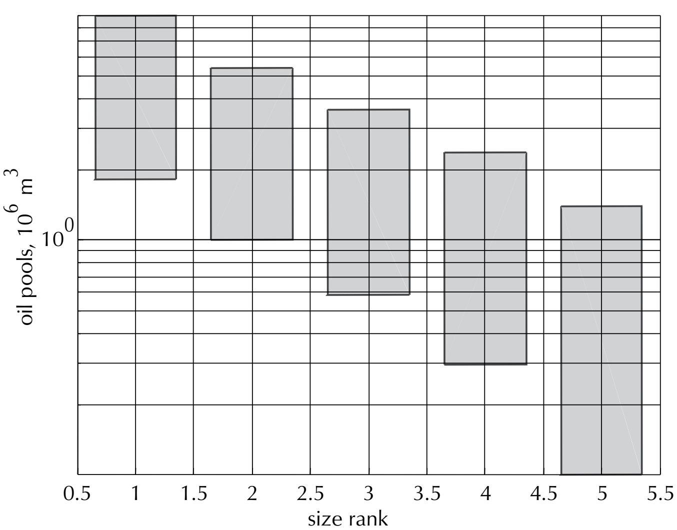


Figure 30. *Predicted accumulation size by rank. The predicted pool sizes are obtained using order statistics and conditioning the accumulation-size distribution against the number of expected pools, as shown in Table 17.*

Play 6, Structurally Trapped Natural Gas Play in Hart Creek Formation Sandstones and Carbonates

The structurally trapped natural gas play in Hart Creek Formation sandstones and carbonates, referred to as Play 6, occurs above the Tuttle Formation sandstone, and includes the Chance Sandstone Member of the Hart River Formation. This constitutes a significant immature play for petroleum in the Eagle Plain Basin. Carboniferous strata are the primary reservoir of both crude oil and natural gas in the Eagle Plain Basin (Table 2; Norris 1997; NEB, 2000). Therefore, consistent with the observed levels of thermal maturity, as discussed above, the post-Tuttle Carboniferous reservoirs in structural traps have a significant natural gas potential. The play definition is identical to that of Play 6a, except for the composition of the petroleum, since PETRIMES requires that crude oil and natural gas potentials be assessed separately.

This play includes all structural prospects where potential and established Carboniferous reservoir strata lying above the Tuttle Formation are involved in Laramide structures, south of their subcrop margin. Carboniferous strata are involved in Laramide structures south of the broad band of the Carboniferous subcrop, south of the Eagle Arch, on both sides of the Arctic Circle in an east-west band across the study region, where Mesozoic strata are preserved. In addition, possible Hart Creek Formation sandstones and carbonates may be present in Laramide structures south of the basal Permian subcrop edge, which runs west to east just north of the Chance J-19 well. In this particular play there may be a stratigraphic component of entrapment, but it occurs coincident with culminations in Laramide structures, which provide an anticlinal mechanism for entrapment of the accumulation. Carboniferous strata also occur in the hanging wall of the Sharp Mountain thrust, where they are also involved in Laramide structures, and there is some potential for Hart Creek Formation sandstones and carbonates north of the Jurassic subcrop on the north side of the Eagle Arch. A particular opportunity for entrapment may be associated with the footwall “cut-off” of Carboniferous strata at the Sharp Mountain thrust fault. Play parameters are considered relatively well constrained because of the moderate number of wells, and the presence of identified accumulations of natural gas.

The distributions of input play parameters for Play 6, Structurally Trapped Natural Gas Play in Hart Creek Formation sandstones and carbonates, are given in Table 20. The volume of prospects was determined by discounting the product of the area of prospects and net pay, and the prospect gross volume, with a trap-fill fraction based primarily on analogue. The prospect area distribution was inferred to be not smaller than 0.40 km^2. No prospects exceeding an area of 40 km^2 could be identified or inferred for this play. Average net pay was determined to possibly range between 5 and 23 m, while it is unlikely (1% probability) that average net pay will exceed 20 m thickness. The fractional pool average porosity is inferred to be between 0.15 and 0.22, and fractional hydrocarbon saturations are expected to vary between 0.72 and 0.90, which are reasonable values consistent with observations in the Eagle Plain and general occurrences in similar plays elsewhere. The median value of trap-fill is 40%, with a lower limit (an inferred 100% probability) of 0.10 and an upper practical limit (1% probability) of 0.80. Formation volume factor for gas was computed using reservoir pressure and temperature distributions based on the depth range of potential prospects, together with a distribution of gas compressibility factors, as described in input parameter Table 20. The number of prospects in this play was estimated to be not less than 10, and not expected to exceed 40 (Table 20).

This is the main productive stratigraphic interval in the basin (Table 2) and there are no play-level risks. Prospect-level risk factors for Play 6 are listed in Table 21. The product of individual prospect-level risk factors (Table 21) is the combined prospect-level risk, which for this play is 0.246.

The natural gas pool, or accumulation, size probability distribution for Play 6 is given in Table 22. The expected, or mean, natural gas pool size is predicted to be 19.67 Bcf. The number of expected prospects is 23 (Table 22). The play potential distribution for natural gas in Play 6 is listed in Table 22. The median and mean natural gas potentials calculated for this play are 102.57 and 118.09 Bcf, respectively, which are inferred to occur in 6 accumulations. The probability distributions describing the calculated individual model accumulations are given in Table 23. The median and mean sizes of the largest predicted natural gas pools in Play 23 are 1.26 and 1.45 billion cubic m, respectively, of initial raw natural gas in-place, at standard conditions. Details of the predicted pool sizes for all 6 pools are listed in the graph in Figure 31.

Play 6, Structurally Trapped Natural Gas Play in Hart Creek Formation Sandstones and Carbonates

Table 20. *Distributions of input play accumulation parameters.*

Parameter	100%	50%	1%	0%
Closure, km²	0.40	5.00	15.00	40.00
Net pay, m	5.00	10.00	20.00	23.00
Porosity, fraction	0.15	0.17	0.20	0.22
Hydrocarbon saturation, fraction	0.72	0.75	0.85	0.90
Trap-fill, fraction	0.10	0.40	0.60	0.80
Gas compressibility, fraction	0.78	0.80	0.85	0.95
Reservoir pressure, Kpa	5000.00	14 000.00	18 000.00	20 000.00
Reservoir temperature, °C	32.00	32.00	32.00	32.00
Parameter	**100%**	**50%**		**0%**
Number of prospects	10	20		40

Table 21. *Prospect-level risk factors.*

Presence of source rock	1.000
Presence of closure	0.800
Presence of reservoir facies	0.600
Presence of adequate seal	0.800
Adequate timing	0.800
Migration pathway risk	0.800
Prospect-level risk	0.246

Table 22. *Field size and play potential probability distributions, as well as the number of prospects and pools – Assessment results.*
Units: billion cubic feet of initial raw natural gas in place.

Field size probability distribution						
5%	25%	50%	75%	95%	Mean	Number of prospects
63.55	25.87	12.36	5.25	1.50	19.67	23
Play potential probability distribution						
5%	25%	50%	75%	95%	Mean	Number of pools
248.07	149.85	102.57	68.23	37.61	118.09	6

Table 23. *Predicted accumulation sizes (x 10^9 m^3).*

Size rank	5%	25%	50%	75%	95%	Mean
1	2.98	1.84	1.26	0.85	0.47	1.45
2	1.63	1.00	0.70	0.47	0.27	0.79
3	1.03	0.63	0.44	0.30	0.16	0.50
4	0.68	0.41	0.27	0.18	0.10	0.32
5	0.44	0.24	0.16	0.10	0.05	0.19
6	0.25	0.12	0.07	0.04	0.02	0.09

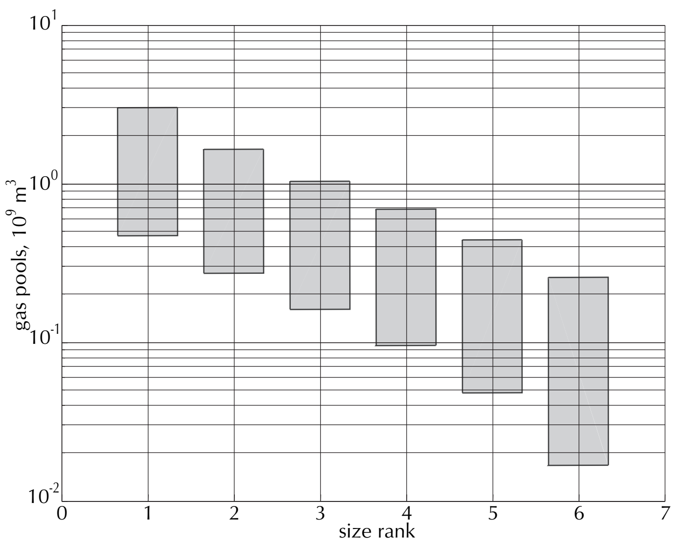


Figure 31. *Predicted accumulation size by rank. The predicted pool sizes are obtained using order statistics and conditioning the accumulation-size distribution against the number of expected pools, as shown in Table 21.*

Play 6a, Structurally Trapped Crude Oil Play in Hart Creek Formation Sandstones and Carbonates

The structurally trapped crude oil play in Hart Creek Formation sandstones and carbonates, referred to as Play 6a, lies above the Tuttle Formation Sandstone, and includes the Chance Sandstone Member of the Hart River Formation. This constitutes a significant immature play in the Eagle Plain Basin. Post-Tuttle Carboniferous strata are the primary reservoir of both crude oil and natural gas in the Eagle Plain Basin (Table 2; Norris 1997; NEB, 2000). The play definition is identical to that of Play 6, except for the composition of the petroleum, since PETRIMES requires that crude oil and natural gas potentials be assessed separately. There are significant sedimentological similarities between this Carboniferous play in the Yukon and the mixed clastic-carbonate Jurassic reservoirs that are the main producing horizons in southwestern Saskatchewan. The complicated depositional system results in complex compartmentalization that leads to multiple prospects, which decreases individual prospect size, but which increases the number of prospects in the structural component of this play.

The distribution of input play parameters for Play 6a is given in Table 24. The volume of prospects was determined by discounting the product of the area of prospects and net pay, and the prospect gross volume, with a trap-fill fraction based primarily on analogue. The prospect area distribution was inferred to be not smaller than 0.400 km^2. No prospects exceeding an area of 40 km^2 could be identified or inferred for this play. Average net pay was determined to possibly range between 5 and 23.0 m, while it is unlikely (1% probability) that average net pay will exceed 20.00 m thickness. The fractional pool average porosity is inferred to be between 0.150 and 0.220, and fractional hydrocarbon saturations are expected to vary between 0.720 and 0.900, which are reasonable values consistent with observations in the Eagle Plain and general occurrences in similar plays elsewhere. The median value of trap-fill is 10%, with a lower limit (an inferred 100% probability) of 0.05 and an upper practical limit (1% probability) of 0.20. Shrinkage, the formation volume factor for crude oil, was computed using reservoir pressure and temperature distributions based on the depth range of potential prospects, together with a distribution of solution gas factors, as described in input parameter Table 24. The number of prospects in this play was estimated to be not less than 40, and not expected to exceed 90 (Table 24).

Due to the established reserves in post-Tuttle Formation Carboniferous reservoirs, there are no play-level risks, although the play is considered to be immature. The product of individual prospect-level risk factors (Table 25) is the combined prospect-level risk, which for this play is 0.086.

The crude oil pool, or accumulation, size probability distribution for Play 6a is given in Table 26. The expected, or mean, crude oil pool size is predicted to be 15.33 MMbbls. The number of expected prospects is 57 (Table 26). The play potential distribution for crude oil in Play 6a is listed in Table 26. The median and mean, crude oil potentials calculated for this play are 68.80 and 76.71 MMbbls, respectively, which are inferred to occur in five accumulations. The probability distributions describing the calculated individual model accumulations are given in Table 27. The median and mean sizes of the largest predicted crude oil accumulations in Play 6a are 4.92 and 5.40 million cubic m, respectively. Details of the predicted pool sizes for all five pools are listed in the graph in Figure 32.

Play 6a, Structurally Trapped Crude Oil Play in Hart Creek Formation Sandstones and Carbonates

Table 24. Distributions of input play accumulation parameters.

Parameter	100%	50%	1%	0%
Closure, km²	0.400	5.000	15.000	40.000
Net pay, m	5.000	10.000	20.000	23.000
Porosity, fraction	0.150	0.170	0.200	0.220
Hydrocarbon saturation, fraction	0.720	0.750	0.850	0.900
Trap-fill, fraction	0.05	0.10	0.12	0.20
Formation Volume Factor	1.120	1.120	1.120	1.120
Reservoir pressure, Kpa	5000.000	14 000.000	18 000.000	20 000.000
Reservoir temperature, °C	32.000	32.000	32.000	32.000

Parameter	100%	50%		0%
Number of prospects	40	50		90

Table 25. Prospect-level risk factors.

Presence of source rock	1.000
Presence of closure	0.600
Presence of reservoir facies	0.500
Presence of adequate seal	0.800
Adequate timing	0.600
Migration pathway risk	0.600
Prospect-level risk	0.086

Table 26. Field size and play potential probability distributions, as well as the number of prospects and pools – Assessment results. Units: initial crude oil in place, 10^6 bbls.

Field size probability distribution						
5%	25%	50%	75%	95%	Mean	Number of prospects
44.33	20.97	10.89	5.07	1.60	15.33	57
Play potential probability distribution						
5%	25%	50%	75%	95%	Mean	Number of pools
153.78	98.03	68.80	46.75	26.26	76.71	5

Table 27. Predicted accumulation sizes (x 10^9 m^3).

Size rank	5%	25%	50%	75%	95%	Mean
1	10.35	6.87	4.92	3.42	1.98	5.40
2	6.05	3.91	2.81	1.95	1.11	3.09
3	3.95	2.50	1.73	1.16	0.64	1.94
4	2.59	1.52	1.00	0.63	0.32	1.17
5	1.52	0.78	0.47	0.27	0.13	0.60

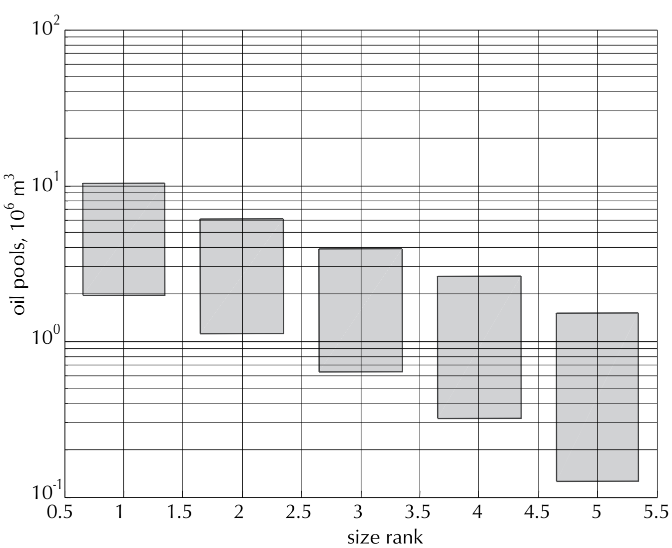


Figure 32. Predicted accumulation size by rank. The predicted pool sizes are obtained using order statistics and conditioning the accumulation-size distribution against the number of expected pools, as shown in Table 25.

Play 5, Stratigraphically Trapped Natural Gas Play in Hart Creek Formation Sandstones and Carbonates

This stratigraphically trapped play in Hart Creek Formation sandstones and carbonates, referred to as Play 5, constitutes a significant immature play for natural gas within the Eagle Plain Basin. This play and Play 5a, its matching crude oil play, occur where post-Tuttle Formation Carboniferous strata have vertical and lateral lithostratigraphic variations either within or between the Carboniferous succession, and their superjacent strata are not coincident with Laramide structural culminations. The above-mentioned strata includes the Chance Sandstone, and Canoe River and Alder carbonate members of the Hart River Formation, which are the primary reservoir of both crude oil and natural gas in the Eagle Plain Basin (Table 2; Norris 1997; NEB, 2000). For similar reasons to that discussed above related to the structural play in the post-Tuttle Formation Carboniferous play, these stratigraphic traps have a significant natural gas potential. The play definition has similarities to Play 6, except for the nature of the trap, which enhances the possible trapping mechanism, although it makes prospecting more difficult and risky.

This play includes all stratigraphic prospects where potential and established Carboniferous reservoir strata lying above the Tuttle Formation occur, south of their subcrop margin. The subcrop edge of Hart Creek Formation sandstones and carbonates occurs in a ~40- to ~100-km-wide band, south of the Eagle Arch, that straddles the Arctic Circle in an east-west direction across the study region, where Mesozoic strata are preserved. In addition, possible Hart Creek Formation sandstones and carbonates may be present to the south in both the Carboniferous and the Permian subcrop edges, the latter of which runs west to east just north of the Chance J-19 well. This play does not include any assessment of stratigraphic traps in Carboniferous strata north of the Eagle Arch, as does the structural play, although this removes only a minor part of the succession from consideration. Play parameters are considered relatively well constrained because of the moderate number of wells, and the presence of identified accumulations of natural gas.

The distributions of input play parameters for Play 5 are given in Table 28. The volume of prospects was determined by discounting the product of the area of prospects and net pay, and the prospect gross volume, with a trap-fill fraction based primarily on analogue. The prospect area distribution was inferred to be not smaller than 5 km^2. No prospects exceeding an area of 80 km^2 could be identified or inferred for this play. Average net pay was determined to possibly range between 2 and 60 m, while it is unlikely (1% probability) that average net pay will exceed 40 m thickness. The fractional pool average porosity is inferred to be between 0.05 and 0.22, and fractional hydrocarbon saturations are expected to vary between 0.72 and 0.90, which are reasonable values consistent with observations in the Eagle Plain and general occurrences in similar plays elsewhere. The median value of trap-fill is 60%, with a lower limit (an inferred 100% probability) of 0.20 and an upper practical limit (1% probability) of 0.75. Formation volume factor for gas was computed using reservoir pressure and temperature distributions based on the depth range of potential prospects, together with a distribution of gas compressibility factors, as shown in input parameters in Table 28. The number of prospects in this play was estimated to be not less than 35, and not expected to exceed 55 (Table 28). Prospect-level risk factors for Play 5 are listed in Table 29. The product of individual prospect-level risk factors (Table 29) is the combined prospect-level risk, which for this play is 0.245.

The natural gas pool, or accumulation, size probability distribution for Play 5 is given in Table 30. The expected, or mean, natural gas pool size is predicted to be 154.89 Bcf. The number of expected prospects is 45 (Table 30). The play potential distribution for natural gas in Play 5 is listed in Table 30. The median and mean natural gas potentials calculated for this play are 1581.96 and 1705.23 Bcf, respectively, which are inferred to occur in 11 accumulations. The probability distributions describing the calculated individual model accumulations are given in Table 31. The median and mean sizes of the largest predicted natural gas pools in Play 5 are 12.82 and 13.79 billion cubic m, respectively, of initial raw natural gas in-place, at standard conditions. Details of the predicted pool sizes for all 11 pools are listed in the graph in Figure 33.

Play 5, Stratigraphically Trapped Natural Gas Play in Hart Creek Formation Sandstones and Carbonates

Table 28. *Distributions of input play accumulation parameters.*

Parameter	100%	50%	1%	0%
Closure, km²	5.00	25.00	40.00	80.00
Net pay, m	2.00	20.00	40.00	60.00
Porosity, fraction	0.05	0.15	0.20	0.22
Hydrocarbon saturation, fraction	0.72	0.75	0.85	0.90
Trap-fill, fraction	0.20	0.60	0.75	1.00
Gas compressibility, fraction	0.79	0.80	0.85	0.95
Reservoir pressure, Kpa	5000.00	14 000.00	18 000.00	20 000.00
Reservoir temperature, °C	10.00	25.00	30.00	35.00

Parameter	100%	50%		0%
Number of prospects	35	45		55

Table 29. *Prospect-level risk factors.*

Presence of source rock	1.000
Presence of closure	0.800
Presence of reservoir facies	0.500
Presence of adequate seal	0.900
Adequate timing	0.850
Migration pathway risk	0.800
Prospect-level risk	0.245

Table 30. *Field size and play potential probability distributions, as well as the number of prospects and pools – Assessment results. Units: billion cubic feet of initial raw natural gas in place.*

Field size probability distribution						
5%	25%	50%	75%	95%	Mean	Number of prospects
488.64	208.32	101.39	44.29	12.82	154.89	45
Play potential probability distribution						
5%	25%	50%	75%	95%	Mean	Number of pools
3066.72	2099.08	1581.96	1177.72	757.02	1705.23	11

Table 31. *Predicted accumulation sizes (x 10^9 m^3).*

Size rank	5%	25%	50%	75%	95%	Mean
1	24.88	17.00	12.82	9.42	6.12	13.79
2	15.76	10.96	8.31	6.42	4.12	8.97
3	11.40	8.00	6.22	4.71	3.10	6.59
4	8.74	6.15	4.72	3.56	2.34	5.03
5	6.95	4.85	3.65	2.74	1.78	3.93
6	5.53	3.78	2.86	2.14	1.35	3.07
7	4.45	2.97	2.21	1.59	1.03	2.39
8	3.42	2.27	1.63	1.18	0.74	1.81
9	2.62	1.65	1.18	0.84	0.49	1.33
10	1.89	1.14	0.79	0.53	0.28	0.90
11	1.20	0.66	0.41	0.23	0.10	0.50

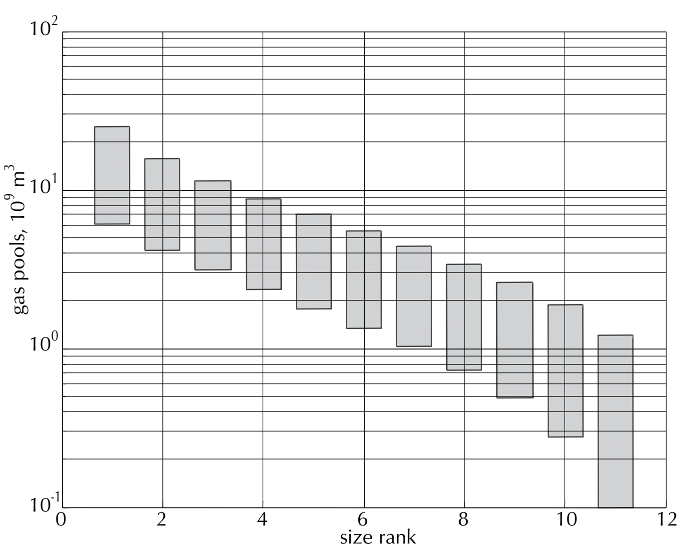


Figure 33. *Predicted accumulation size by rank. The predicted pool sizes are obtained using order statistics and conditioning the accumulation-size distribution against the number of expected pools, as shown in Table 29.*

Play 5a, Stratigraphically Trapped Crude Oil Play in Hart Creek Formation Sandstones and Carbonates

The stratigraphically trapped crude oil play in Hart Creek Formation sandstones and carbonates, referred to as Play 5a, constitutes a significant immature play for petroleum within the Eagle Plain Basin. This play and Play 5, its matching natural gas play, occur where post-Tuttle Formation Carboniferous strata, which make up the primary reservoir of both crude oil and natural gas in the Eagle Plain Basin (Table 2; Norris 1997; NEB, 2000), are trapped by vertical and lateral lithostratigraphic variations either within the Carboniferous succession, or between the Carboniferous succession and its superjacent strata, where these relationships are not coincident with Laramide structural culminations. Therefore, as discussed above, the post-Tuttle Carboniferous reservoirs in stratigraphic traps have a significant crude oil potential. The play definition has similarities to Play 5, except for the composition of the petroleum, since PETRIMES requires that crude oil and natural gas potentials be assessed separately.

The distributions of input play parameters for Play 5a are given in Table 32. The volume of prospects was determined by discounting the product of the area of prospects and net pay, and the prospect gross volume, with a trap-fill fraction based primarily on analogue. The prospect area distribution was inferred to be not smaller than 0.600 km^2. No prospects exceeding an area of 35 km^2 could be identified or inferred for this play. Average net pay was determined to possibly range between 3 and 50 m, while it is unlikely (1% probability) that average net pay will exceed 35 m thickness. The fractional pool average porosity is inferred to be between 0.050 and 0.200, and fractional hydrocarbon saturations are expected to vary between 0.500 and 0.850, which are reasonable values, consistent with observations in the Eagle Plain and general occurrences in similar plays elsewhere. The median value of trap-fill is 10%, with a lower limit (an inferred 100% probability) of 0.05 and an upper practical limit (1% probability) of 0.20. Shrinkage, the formation volume factor for crude oil, was computed using reservoir pressure and temperature distributions based on the depth range of potential prospects, together with a distribution of solution gas factors, as described in input parameter Table 32. The number of prospects in this play was estimated to be not less than 25, and not expected to exceed 55 (Table 32). Prospect-level risk factors for Play 5a are listed in Table 33. The product of individual prospect-level risk factors (Table 33) is the combined prospect-level risk, which for this play is 0.121.

The crude oil pool, or accumulation, size probability distribution for Play 5a is given in Table 34. The expected, or mean, crude oil pool size is predicted to be 15.65 MMbbls. The number of expected prospects is 38 (Table 34). The play potential distribution for crude oil in Play 5a is listed in Table 34. The median and mean, crude oil potentials calculated for this play are 68.28 and 78.38 MMbbls, respectively, which are inferred to occur in five accumulations. The probability distributions describing the calculated individual model accumulations are given in Table 35. The median and mean sizes of the largest predicted crude oil accumulations in Play 5a are 5.14 and 5.82 million cubic m, respectively. Details of the predicted pool sizes for all five pools are listed in the graph in Figure 34.

Play 5a, Stratigraphically Trapped Crude Oil Play in Hart Creek Formation Sandstones and Carbonates

Table 32. *Distributions of input play accumulation parameters.*

Parameter	100%	50%	1%	0%
Closure, km²	0.600	10.000	20.000	35.000
Net pay, m	3.000	15.000	35.000	50.000
Porosity, fraction	0.050	0.080	0.120	0.200
Hydrocarbon saturation, fraction	0.500	0.600	0.800	0.850
Trap-fill, fraction	0.05	0.10	0.15	0.20
Formation Volume Factor	1.120	1.120	1.120	1.120
Reservoir pressure, Kpa	30 082.000	30 082.000	30 082.000	30 082.000
Reservoir temperature, °C	32.000	32.000	32.000	32.000
Parameter	**100%**	**50%**		**0%**
Number of prospects	25	35		55

Table 33. *Prospect-level risk factors.*

Presence of source rock	1.000
Presence of closure	0.600
Presence of reservoir facies	0.600
Presence of adequate seal	0.700
Adequate timing	0.800
Migration pathway risk	0.600
Prospect-level risk	0.121

Table 34. *Field size and play potential probability distributions, as well as the number of prospects and pools – Assessment results. Units: initial crude oil in place, 10^6 bbls.*

Field size probability distribution						
5%	25%	50%	75%	95%	Mean	Number of prospects
49.61	20.85	10.39	4.58	1.28	15.65	38
Play potential probability distribution						
5%	25%	50%	75%	95%	Mean	Number of pools
167.15	101.40	68.28	44.92	24.01	78.38	5

Table 35. *Predicted accumulation sizes (x 10^9 m^3).*

Size rank	5%	25%	50%	75%	95%	Mean
1	12.05	7.51	5.14	3.42	1.91	5.82
2	6.48	4.02	2.76	1.88	1.01	3.14
3	4.07	2.45	1.65	1.07	0.56	1.88
4	2.54	1.44	0.92	0.55	0.26	1.10
5	1.44	0.70	0.39	0.22	0.08	0.53

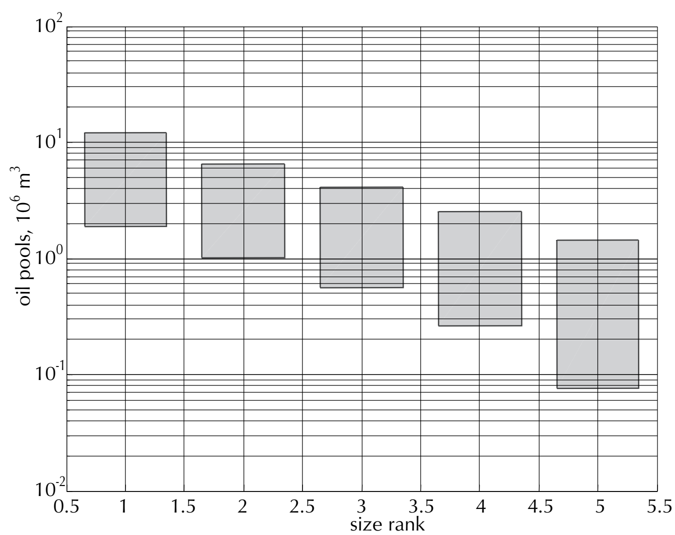


Figure 34. *Predicted accumulation size by rank. The predicted pool sizes are obtained using order statistics and conditioning the accumulation-size distribution against the number of expected pools, as shown in Table 33.*

NATURAL GAS AND CRUDE OIL PLAYS IN THE PERMIAN SUCCESSION OF THE EAGLE PLAIN BASIN

Play 4, Structurally Trapped Natural Gas Play in Jungle Creek Formation Sandstones

The structurally trapped natural gas play in Permian strata of the Jungle Creek Formation, referred to as Play 4 (Fig. 6), constitutes a significant conceptual play for natural gas in the Eagle Plain Basin. Only minor shows of natural gas and crude oil have been recovered from the Permian Jungle Creek Formation (Table 2), but this indicates that petroleum is present in this succession and the play should exist if there is a suitable reservoir trapped structurally in a Laramide anticlinal culmination. Therefore, consistent with these indications, the Jungle Creek Formation sandstones in Laramide structural traps have a significant natural gas potential.

This play includes all structural prospects where potential and established Permian reservoir strata were involved in Laramide structures, south of their basal subcrop margin, where Mesozoic strata are preserved. The basal Permian subcrop edge runs west to east just north of the Chance J-19 well, and the trapping mechanism should be enhanced in the vicinity of the Dempster Highway between 137° and 138° W longitude, where the uppermost preserved Permian succession is composed of an unnamed shale, which should act as an excellent top seal in Laramide structures. There may be a stratigraphic component of entrapment in this play, but this play occurs specifically where traps are caused by and coincident with culminations in Laramide structures. Play parameters are considered relatively well constrained because of the moderate number of wells, and the presence of identified shows of natural gas.

The distributions of input play parameters for Play 4 are given in Table 36. The volume of prospects was determined by discounting the product of the area of prospects and net pay, and the prospect gross volume, with a trap-fill fraction based primarily on analogue. The prospect area distribution was inferred to be not smaller than 0.20 km^2. No prospects exceeding an area of 30 km^2 could be identified or inferred for this play. Average net pay was determined to possibly range between 5 and 80 m, while it is unlikely (1% probability) that average net pay will exceed 50 m thickness. The fractional pool average porosity is inferred to be between 0.05 and 0.23, and fractional hydrocarbon saturations are expected to vary between 0.50 and 0.90, which are reasonable values consistent with observations in the Eagle Plain and general occurrences in similar plays elsewhere. The median value of trap-fill is 40%, with a lower limit (an inferred 100% probability) of 0.10 and an upper practical limit (1% probability) of 0.80. Formation volume factor for gas was computed using reservoir pressure and temperature distributions based on the depth range of potential prospects, together with a distribution of gas compressibility factors, as described in input parameter Table 36. The number of prospects in this play was estimated to be not less than 20, and not expected to exceed 45 (Table 36). The product of individual prospect-level risk factors (Table 37) is the combined prospect-level risk, which for this play is 0.150.

The natural gas pool, or accumulation, size probability distribution for Play 4 is given in Table 38. The expected, or mean, natural gas pool size is predicted to be 14.38 Bcf. The number of expected prospects is 31 (Table 38). The play potential distribution for natural gas in Play 4 is listed in Table 38. The median and mean natural gas potentials calculated for this play are 57.86 and 72.10 Bcf, respectively, which are inferred to occur in five accumulations. The probability distributions describing the calculated individual model accumulations are given in Table 39. The median and mean sizes of the largest predicted natural gas pools in Play 4 are 0.90 and 1.09 billion cubic m, respectively, of initial raw natural gas in-place, at standard conditions. Details of the predicted pool sizes for all four pools are listed in the graph in Figure 35.

Play 4, Structurally Trapped Natural Gas Play in Jungle Creek Formation Sandstones

Table 36. Distributions of input play accumulation parameters.

Parameter	100%	50%	1%	0%
Closure, km²	0.20	5.00	20.00	30.00
Net pay, m	5.00	35.00	50.00	80.00
Porosity, fraction	0.05	0.12	0.16	0.23
Hydrocarbon saturation, fraction	0.50	0.55	0.65	0.90
Trap-fill, fraction	0.10	0.40	0.60	0.80
Gas compressibility, fraction	0.79	0.80	0.85	0.95
Reservoir pressure, Kpa	3000.00	5500.00	10 000.00	12 000.00
Reservoir temperature, °C	28.00	32.00	36.00	39.00

Parameter	100%	50%		0%
Number of prospects	20	30		45

Table 37. Prospect-level risk factors.

Presence of source rock	1.000
Presence of closure	0.600
Presence of reservoir facies	0.600
Presence of adequate seal	0.700
Adequate timing	0.800
Migration pathway risk	0.600
Prospect-level risk	0.121

Table 38. Field size and play potential probability distributions, as well as the number of prospects and pools – Assessment results. Units: initial crude oil in place, 10^6 bbls.

Field size probability distribution						
5%	25%	50%	75%	95%	Mean	Number of prospects
53.91	18.19	7.18	2.77	0.60	14.38	31
Play potential probability distribution						
5%	25%	50%	75%	95%	Mean	Number of pools
176.99	95.43	57.86	34.29	15.68	72.10	5

Table 39. Predicted accumulation sizes (x 10^9 m^3).

Size rank	5%	25%	50%	75%	95%	Mean
1	2.61	1.45	0.90	0.54	0.24	1.09
2	1.20	0.67	0.40	0.24	0.12	0.50
3	0.68	0.34	0.20	0.12	0.06	0.26
4	0.35	0.17	0.10	0.06	0.02	0.13
5	0.17	0.07	0.04	0.02	0.01	0.06

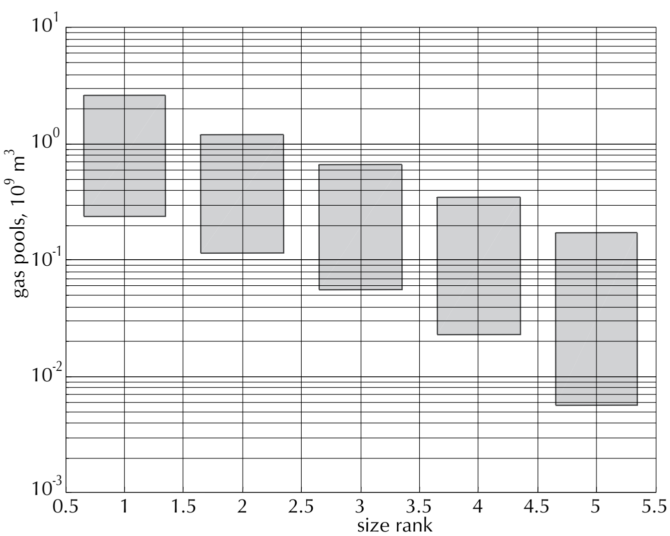


Figure 35. Predicted accumulation size by rank. The predicted pool sizes are obtained using order statistics and conditioning the accumulation-size distribution against the number of expected pools, as shown in Table 37.

Play 4a, Structurally Trapped Crude Oil Play in Jungle Creek Formation Sandstones

The structurally trapped crude oil play in Permian strata, Jungle Creek Formation, referred to as Play 4a (Fig. 6), constitutes a significant conceptual play for crude oil in the Eagle Plain Basin. Only minor shows of natural gas and crude oil have been recovered from the Permian Jungle Creek Formation (Table 2), but this indicates that petroleum is present in this succession and the play should exist if there is a suitable reservoir trapped structurally in a Laramide anticlinal culmination. The play definition is similar to that of Play 4, except for the composition of the petroleum, since PETRIMES requires that crude oil and natural gas potentials be assessed separately. It includes all structural prospects where potential and established Permian reservoir strata were involved in Laramide structures, south of their basal subcrop margin, where Mesozoic strata are preserved, as described above. Play parameters are considered relatively well constrained because of the moderate number of wells, and the presence of a single show of crude oil (Table 2).

The distribution of input play parameters for Play 4a is given in Table 40. The volume of prospects was determined by discounting the product of the area of prospects and net pay, and the prospect gross volume, with a trap-fill fraction based primarily on analogue. The prospect area distribution was inferred to be not smaller than 0.200 km^2. No prospects exceeding an area of 30 km^2 could be identified or inferred for this play. Average net pay was determined to possibly range between 5 and 80 m, while it is unlikely (1% probability) that average net pay will exceed 50 m thickness. The fractional pool average porosity is inferred to be between 0.050 and 0.230, and fractional hydrocarbon saturations are expected to vary between 0.500 and 0.900, which are reasonable values consistent with observations in the Eagle Plain and general occurrences in similar plays elsewhere. The median value of trap-fill is 10%, with a lower limit (an inferred 100% probability) of 0.05 and an upper practical limit (1% probability) of 0.20. Shrinkage, the formation volume factor for crude oil, was computed using reservoir pressure and temperature distributions based on the depth range of potential prospects, together with a distribution of solution gas factors, as described in the input parameters in Table 40. The number of prospects in this play was estimated to be not less than 20, and not expected to exceed 45 (Table 40).

Prospect-level risk factors for Play 4a are listed in Table 41. The product of individual prospect-level risk factors (Table 41) is the combined prospect-level risk, which for this play is 0.141.

The crude oil pool, or accumulation, size probability distribution for Play 4a is given in Table 42. The expected, or mean, crude oil pool size is predicted to be 26.23 MMbbls. The number of expected prospects is 31 (Table 42). The play potential distribution for crude oil in Play 4a is listed in Table 42. The median and mean, crude oil potentials calculated for this play are 86.93 and 104.89 MMbbls, respectively, which are inferred to occur in four accumulations. The probability distributions describing the calculated individual model accumulations are given in Table 43. The median and mean sizes of the largest predicted crude oil accumulations in Play 4A are 8.17 and 9.35 million cubic m, respectively. Details of the predicted pool sizes for all four pools are listed in the graph in Figure 36.

Play 4a, Structurally Trapped Crude Oil Play in Jungle Creek Formation Sandstones

Table 40. *Distributions of input play accumulation parameters.*

Parameter	100%	50%	1%	0%
Closure, km²	0.200	5.000	20.000	30.000
Net pay, m	5.000	35.000	50.000	80.000
Porosity, fraction	0.050	0.120	0.160	0.230
Hydrocarbon saturation, fraction	0.500	0.550	0.650	0.900
Trap-fill, fraction	0.05	0.10	0.15	0.20
Formation Volume Factor	1.120	1.120	1.120	1.120
Reservoir pressure, Kpa	0.000	5500.000	10 000.000	12 000.000
Reservoir temperature, °C	28.000	32.000	36.000	39.000

Parameter	100%	50%		0%
Number of prospects	20	30		45

Table 41. *Prospect-level risk factors.*

Presence of source rock	1.000
Presence of closure	0.600
Presence of reservoir facies	0.600
Presence of adequate seal	0.700
Adequate timing	0.800
Migration pathway risk	0.700
Prospect-level risk	0.141

Table 42. *Field size and play potential probability distributions, as well as the number of prospects and pools – Assessment results. Units: initial crude oil in place, 10^6 bbls.*

Field size probability distribution						
5%	25%	50%	75%	95%	Mean	Number of prospects
89.24	35.71	14.97	5.80	1.32	26.23	31
Play potential probability distribution						
5%	25%	50%	75%	95%	Mean	Number of pools
248.51	139.59	86.93	50.00	22.19	104.89	4

Table 43. *Predicted accumulation sizes (x 10^9 m^3).*

Size rank	5%	25%	50%	75%	95%	Mean
1	20.64	12.51	8.17	4.76	2.20	9.35
2	10.62	5.82	3.47	2.05	0.90	4.36
3	5.69	2.75	1.62	0.87	0.35	2.11
4	2.57	1.12	0.56	0.27	0.09	0.85

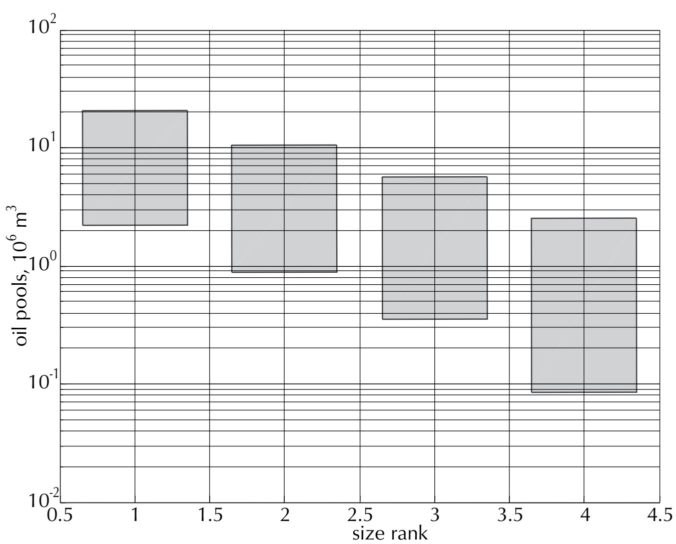


Figure 36. *Predicted accumulation size by rank. The predicted pool sizes are obtained using order statistics and conditioning the accumulation-size distribution against the number of expected pools, as shown in Table 41.*

Play 3, Stratigraphically Trapped Natural Gas Play in Jungle Creek Formation Sandstones

The stratigraphically trapped natural gas play in Permian strata, Jungle Creek Formation, referred to as Play 3 (Fig. 6), constitutes a significant conceptual play in the Eagle Plain Basin. Only minor shows of natural gas and crude oil have been recovered from the Permian Jungle Creek Formation (Table 2), but this indicates that petroleum is present in this succession and the play should exist if there is suitable reservoir trapped structurally in a Laramide anticlinal culmination. Therefore, consistent with these indications, stratigraphic plays in the Jungle Creek Formation sandstones have significant natural gas potential. The play definition is analogous to that of Play 5. A very significant potential is envisaged for this play for several reasons. First, the Permian subcrop is large and lightly, probably not purposefully explored. 2nd, the Permian stratigraphic play exists deep in the keel of the Eagle Plain Basin, and so formation volume factors might be significantly higher for this play than for the Carboniferous play, due to the original facies control on the geographic distribution of the reservoir. The play consists of all stratigraphic plays where Jungle Creek Formation sandstones occur, both internally, and where stratigraphic traps are provided by superjacent strata.

The distributions of input play parameters for Play 3 are given in Table 44. The volume of prospects was determined by discounting the product of the area of prospects and net pay, and the prospect gross volume, with a trap-fill fraction based primarily on analogue. The prospect area distribution was inferred to be not smaller than 1.50 km^2. No prospects exceeding an area of 160 km^2 could be identified or inferred for this play. Average net pay was determined to possibly range between 2 and 100 m, while it is unlikely (1% probability) that average net pay will exceed 45 m thickness. The fractional pool average porosity is inferred to be between 0.07 and 0.20, and fractional hydrocarbon saturations are expected to vary between 0.65 and 0.90, which are reasonable values consistent with observations in the Eagle Plain and general occurrences in similar plays elsewhere. The median value of trap-fill is 0.65%, with a lower limit (an inferred 100% probability) of 0.25 and an upper practical limit (1% probability) of 1. Formation volume factor for gas was computed using reservoir pressure and temperature distributions based on the depth range of potential prospects, together with a distribution of gas compressibility factors, as shown in the input parameters in Table 44. The number of prospects in this play was estimated to be not less than 20, and not expected to exceed 100 (Table 44). Prospect-level risk factors for Play 3 are listed in Table 45. The product of individual prospect-level risk factors (Table 45) is the combined prospect-level risk, which for this play is 0.287.

The natural gas pool, or accumulation, size probability distribution for Play 3 is given in Table 46. The expected, or mean, natural gas pool size is predicted to be 134.40 Bcf. The number of expected prospects is 55 (Table 46). The play potential distribution for natural gas in Play 3 is listed in Table 46. The median and mean natural gas potentials calculated for this play are 1925.35 and 2159.70 Bcf, respectively, which are inferred to occur in 16 accumulations. Note the very large play potential pool inferred for this play. It is notable that this is comparable in size to the Tuttle Sandstone Play 5, with which it shares many similarities, however, the extent of Permian prospects extends to much deeper depths below the Mesozoic succession, than does the Tuttle Formation, since the former Lower Carboniferous reservoir is not present in the deepest parts of the basin. Therefore the predictions of this play are considered consistent with the assessment of other plays in this basin. The probability distributions describing the calculated individual model accumulations are given in Table 47. The median and mean sizes of the largest predicted natural gas pools in Play 3 are 17.36 and 19.47 billion cubic m, respectively, of initial raw natural gas in-place, at standard conditions. These are among the most attractive gas pools suggested for the basin, and it is reasonable to assume that they will be located in the deeper parts of the basin, probably west of 138° and south of 66.3 °. Details of the predicted pool sizes for all 16 pools are listed in the graph in Figure 37.

Play 3, Stratigraphically Trapped Natural Gas Play in Jungle Creek Formation Sandstones

Table 44. Distributions of input play accumulation parameters.

Parameter	100%	50%	1%	0%
Closure, km²	1.50	14.00	100.00	160.00
Net pay, m	2.00	15.00	45.00	100.00
Porosity, fraction	0.07	0.13	0.16	0.20
Hydrocarbon saturation, fraction	0.65	0.70	0.85	0.90
Trap-fill, fraction	0.25	0.65	0.80	1.00
Gas compressibility, fraction	0.80	0.90	0.95	0.95
Reservoir pressure, Kpa	5000.00	10 000.00	15 000.00	20 000.00
Reservoir temperature, °C	10.00	25.00	35.00	40.00

Parameter	100%	50%		0%
Number of prospects	20	50		100

Table 45. Prospect-level risk factors.

Presence of source rock	1.000
Presence of closure	0.800
Presence of reservoir facies	0.800
Presence of adequate seal	0.700
Adequate timing	0.800
Migration pathway risk	0.800
Prospect-level risk	0.287

Table 46. Field size and play potential probability distributions, as well as the number of prospects and pools – Assessment results. Units: billion cubic feet of initial raw natural gas in place.

Field size probability distribution						
5%	25%	50%	75%	95%	Mean	Number of prospects
554.01	154.94	50.71	16.94	4.06	134.40	55
Play potential probability distribution						
5%	25%	50%	75%	95%	Mean	Number of pools
4366.55	2701.08	1925.35	1332.93	768.75	2159.70	16

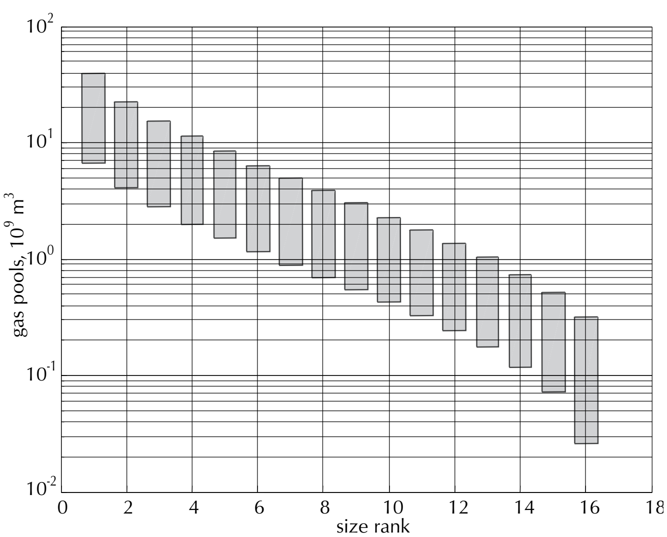


Figure 37. Predicted accumulation size by rank. The predicted pool sizes are obtained using order statistics and conditioning the accumulation-size distribution against the number of expected pools, as shown in Table 45.

Table 47. Predicted accumulation sizes (x 10^9 m^3).

Size rank	5%	25%	50%	75%	95%	Mean
1	39.76	24.03	17.36	11.99	6.63	19.47
2	22.30	14.34	10.40	7.09	4.14	11.40
3	15.41	9.91	6.90	4.86	2.78	7.76
4	11.39	7.02	5.01	3.47	2.01	5.60
5	8.44	5.21	3.72	2.57	1.52	4.16
6	6.38	3.97	2.79	1.93	1.17	3.16
7	5.01	3.06	2.12	1.48	0.89	2.43
8	3.90	2.35	1.63	1.15	0.70	1.87
9	3.02	1.81	1.27	0.89	0.54	1.45
10	2.28	1.39	0.98	0.69	0.43	1.12
11	1.78	1.09	0.75	0.52	0.33	0.87
12	1.37	0.81	0.57	0.40	0.24	0.66
13	1.03	0.60	0.42	0.30	0.17	0.49
14	0.74	0.44	0.31	0.20	0.12	0.35
15	0.52	0.30	0.19	0.13	0.07	0.23
16	0.32	0.16	0.10	0.06	0.03	0.13

NATURAL GAS AND CRUDE OIL PLAYS IN THE CRETACEOUS SUCCESSION OF THE EAGLE PLAIN BASIN

Play 2, Structurally Trapped Natural Gas Play in Cretaceous Sandstones

The Structurally Trapped Natural Gas Play in Mesozoic strata, referred to as Play 2 (Fig. 6), constitutes a significant immature play for natural gas in the Eagle Plain Basin. This play includes all structural prospects where potential and established Mesozoic, generally Cretaceous, reservoir strata are involved in Laramide structures, across the length and breadth of the basin. There may be a stratigraphic component of entrapment in this play, but this play occurs specifically where traps are caused by and coincident with culminations in Laramide structures. Play parameters are considered relatively well constrained because of the moderate number of wells, and the presence of identified shows of natural gas. Only minor reserves and shows of natural gas have been intersected in this succession (Table 2), but this indicates that petroleum functions and the play exists if there is suitable reservoir trapped structurally in a Laramide anticlinal culmination. The number of tests and shows in this part of the succession may be significantly under-reported. As most petroleum exploration to date was focused on oil and shallow natural gas, probably neither were adequately tested or evaluated, as was the case in the early exploration history of the Western Canada sedimentary basin. Therefore, consistent with these indications, Laramide structural traps have a significant natural gas potential. Cretaceous petroleum source rocks are commonly immature, but natural gas can have biogenic sources, as is the case for most of the natural gas in the shallow Cretaceous succession in Alberta and Saskatchewan. Therefore, source is not considered to be a significant problem, however, the shallower depth of these reservoirs significantly reduces the formation volume factor for this play. This results in a smaller gas potential than a play of similar reservoir characteristics would in the older part of the succession.

The distributions of input play parameters for Play 2 are given in Table 48. The volume of prospects was determined by discounting the product of the area of prospects and net pay, and the prospect gross volume, with a trap-fill fraction based primarily on analogue. The prospect area distribution was inferred to be not smaller than 0.20 km^2. No prospects exceeding an area of 30 km^2 could be identified or inferred for this play. Average net pay was determined to possibly range between 5 and 50 m, while it is unlikely (1% probability) that average net pay will exceed 20 m thickness. The fractional pool average porosity is inferred to be between 0.05 and 0.25, and fractional hydrocarbon saturations are expected to vary between 0.55 and 0.90, which are reasonable values consistent with observations in the Eagle Plain and general occurrences in similar plays elsewhere. The median value of trap-fill is 50%, with a lower limit (an inferred 100% probability) of 10 and an upper practical limit (1% probability) of 1. Formation volume factor for gas was computed using reservoir pressure and temperature distributions based on the depth range of potential prospects, together with a distribution of gas compressibility factors, as described in the input parameters in Table 48.

The number of prospects in this play was estimated to be not less than 40, and not expected to exceed 90 (Table 48). Prospect-level risk factors for Play 2 are listed in Table 49. The product of individual prospect-level risk factors (Table 49) is the combined prospect-level risk, which for this play is 0.270.

The natural gas pool, or accumulation, size probability distribution for Play 2 is given in Table 50. The expected, or mean, natural gas pool size is predicted to be 14.39 Bcf. The number of expected prospects is 57 (Table 50). The play potential distribution for natural gas in Play 2 is listed in Table 50. The median and mean natural gas potentials calculated for this play are 216.52 and 230.89 Bcf, respectively, which are inferred to occur in 16 accumulations. The probability distributions describing the calculated individual model accumulations are given in Table 51. The median and mean sizes of the largest predicted natural gas pools in Play 2 are 1.43 and 1.56 billion cubic m, respectively, of initial raw natural gas in-place, at standard conditions. Details of the predicted pool sizes for all 16 pools are listed in the graph in Figure 38.

Play 2, Structurally Trapped Natural Gas Play in Cretaceous Sandstones

Table 48. Distributions of input play accumulation parameters.

Parameter	100%	50%	1%	0%
Closure, km²	.20	5.00	16.00	30.00
Net pay, m	5.00	15.00	20.00	50.00
Porosity, fraction	0.05	0.10	0.15	0.25
Hydrocarbon saturation, fraction	0.55	0.65	0.80	0.90
Trap-fill, fraction	0.10	0.50	0.70	1.00
Gas compressibility, fraction	0.80	0.90	0.95	0.95
Formation Volume Factor	1.12	1.13	1.14	1.15
Reservoir pressure, Kpa	11 000.00	14 000.00	16 000.00	18 000.00
Reservoir temperature, °C	37.00	45.00	50.00	53.00

Parameter	100%	50%		0%
Number of prospects	40	50		90

Table 49. Prospect-level risk factors.

Presence of source rock	1.000
Presence of closure	0.900
Presence of reservoir facies	0.500
Presence of adequate seal	1.000
Adequate timing	1.000
Migration pathway risk	0.600
Prospect-level risk	0.270

Table 50. Field size and play potential probability distributions, as well as the number of prospects and pools – Assessment results. Units: billion cubic feet of initial raw natural gas in place.

Field size probability distribution						
5%	25%	50%	75%	95%	Mean	Number of prospects
47.28	19.01	8.58	3.59	0.84	14.39	57
Play potential probability distribution						
5%	25%	50%	75%	95%	Mean	Number of pools
402.88	279.01	216.52	165.20	110.44	230.89	16

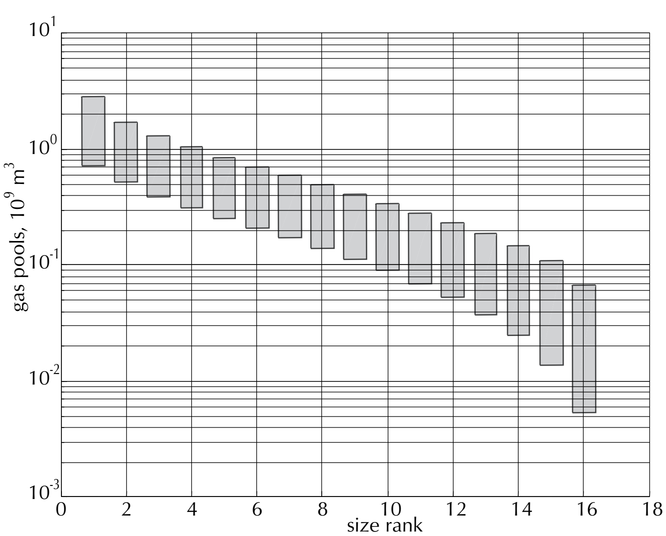


Figure 38. Predicted accumulation size by rank. The predicted pool sizes are obtained using order statistics and conditioning the accumulation-size distribution against the number of expected pools, as shown in Table 49.

Table 51. Predicted accumulation sizes (x 10^9 m^3).

Size rank	5%	25%	50%	75%	95%	Mean
1	2.86	1.86	1.43	1.09	0.72	1.56
2	1.73	1.25	0.99	0.76	0.52	1.04
3	1.31	0.96	0.75	0.58	0.39	0.79
4	1.04	0.76	0.60	0.46	0.31	0.63
5	0.86	0.62	0.48	0.37	0.25	0.51
6	0.71	0.50	0.39	0.30	0.21	0.42
7	0.60	0.42	0.33	0.25	0.17	0.35
8	0.50	0.35	0.27	0.21	0.14	0.29
9	0.41	0.29	0.22	0.17	0.11	0.24
10	0.34	0.24	0.18	0.14	0.09	0.20
11	0.29	0.20	0.15	0.11	0.07	0.16
12	0.24	0.16	0.12	0.09	0.05	0.13
13	0.19	0.12	0.09	0.06	0.04	0.10
14	0.15	0.09	0.07	0.04	0.02	0.07
15	0.11	0.06	0.04	0.03	0.01	0.05
16	0.07	0.03	0.02	0.01	0.01	0.03

Play 2a, Structurally Trapped Crude Oil Play in Cretaceous Sandstones

The structurally trapped crude oil play in Mesozoic strata, referred to as Play 2a (Fig. 6), constitutes a significant immature play for natural gas in the Eagle Plain Basin. This play includes all structural prospects where potential and established Mesozoic, generally Cretaceous reservoir strata, are involved in Laramide structures, across the length and breadth of the basin. Only minor reserves and shows of natural gas have been intersected in this succession (Table 2), but this indicates that petroleum functions and the play exists if there is suitable reservoir trapped structurally in a Laramide anticlinal culmination. Play parameters are considered relatively well constrained because of the moderate number of wells, and the presence of identified shows of natural gas. The play definition is similar to that of Play 2, except for the composition of the petroleum, since PETRIMES requires that crude oil and natural gas potentials be assessed separately. The Cretaceous succession does not have well identified oil-prone source rocks and most of the Cretaceous succession is immature for the thermal generation of petroleum. Yet, there have been shows of crude oil in these strata, presumably migrated from deeper petroleum systems. This complicated migration pathway reduces the potential of this play significantly, despite its very large prospective area. Therefore, consistent with these indications, Laramide structural traps have a significant natural gas potential.

The distributions of input play parameters for Play 2a are given in Table 52. The volume of prospects was determined by discounting the product of the area of prospects and net pay, and the prospect gross volume, with a trap-fill fraction based primarily on analogue. The prospect area distribution was inferred to be not smaller than 0.200 km^2. No prospects exceeding an area of 30 km^2 could be identified or inferred for this play. Average net pay was determined to possibly range between 5 and 50 m, while it is unlikely (1% probability) that average net pay will exceed 20 m thickness. The fractional pool average porosity is inferred to be between 0.050 and 0.250, and fractional hydrocarbon saturations are expected to vary between 0.550 and 0.900, which are reasonable values consistent with observations in the Eagle Plain and general occurrences in similar plays elsewhere. The median value of trap-fill is 10%, with a lower limit (an inferred 100% probability) of 0.05 and an upper practical limit (1% probability) of 0.30. Shrinkage, the formation volume factor for crude oil, was computed using reservoir pressure and temperature distributions based on the depth range of potential prospects, together with a distribution of solution gas factors, as described in the input parameters in Table 52.

The number of prospects in this play was estimated to be not less than 40, and not expected to exceed 90 (Table 52). Prospect-level risk factors for Play 2a are listed in Table 53. The product of individual prospect-level risk factors (Table 53) is the combined prospect-level risk, which for this play is 0.101.

The crude oil pool, or accumulation, size probability distribution for Play 2a is given in Table 54. The play potential distribution for crude oil in Play 2a is listed in Table 54. The median and mean crude oil potentials calculated for this play are 59.71 and 67.34 MMbbls, respectively, which are inferred to occur in six accumulations. The probability distributions describing the calculated individual model accumulations are given in Table 55. The median and mean sizes of the largest predicted crude oil accumulations in Play 2a are 4.04 and 4.49 million cubic m, respectively. Details of the predicted pool sizes for all six pools are listed in the graph in Figure 39.

Play 2a, Structurally Trapped Crude Oil Play in Cretaceous Sandstones

Table 52. *Distributions of input play accumulation parameters.*

Parameter	100%	50%	1%	0%
Closure, km²	0.200	5.000	16.000	30.000
Net pay, m	5.000	15.000	20.000	50.000
Porosity, fraction	0.050	0.100	0.150	0.250
Hydrocarbon saturation, fraction	0.550	0.650	0.800	0.900
Trap-fill, fraction	0.05	0.10	0.15	0.30
Formation Volume Factor	1.120	1.130	1.140	1.150
Reservoir pressure, Kpa	11 000.000	14 000.000	16 000.000	18 000.000
Reservoir temperature, °C	37.000	45.000	50.000	53.000

Parameter	100%	50%		0%
Number of prospects	40	50		90

Table 53. *Prospect-level risk factors.*

Presence of source rock	1.000
Presence of closure	0.600
Presence of reservoir facies	0.500
Presence of adequate seal	0.800
Adequate timing	0.700
Migration pathway risk	0.600
Prospect-level risk	0.101

Table 54. *Field size and play potential probability distributions, as well as the number of prospects and pools – Assessment results. Units: initial crude oil in place, 10^6 bbls.*

Field size probability distribution						
5%	25%	50%	75%	95%	Mean	Number of prospects
35.07	15.13	7.30	3.21	0.83	11.22	57
Play potential probability distribution						
5%	25%	50%	75%	95%	Mean	Number of pools
138.19	86.23	59.71	40.39	22.46	67.34	6

Table 55. *Predicted accumulation sizes (x 10^9 m^3).*

Size rank	5%	25%	50%	75%	95%	Mean
1	8.84	5.73	4.04	2.78	1.57	4.49
2	5.15	3.28	2.31	1.58	0.93	2.57
3	3.40	2.09	1.45	1.00	0.54	1.64
4	2.25	1.36	0.93	0.61	0.33	1.06
5	1.48	0.83	0.53	0.34	0.16	0.64
6	0.86	0.42	0.24	0.12	0.05	0.32

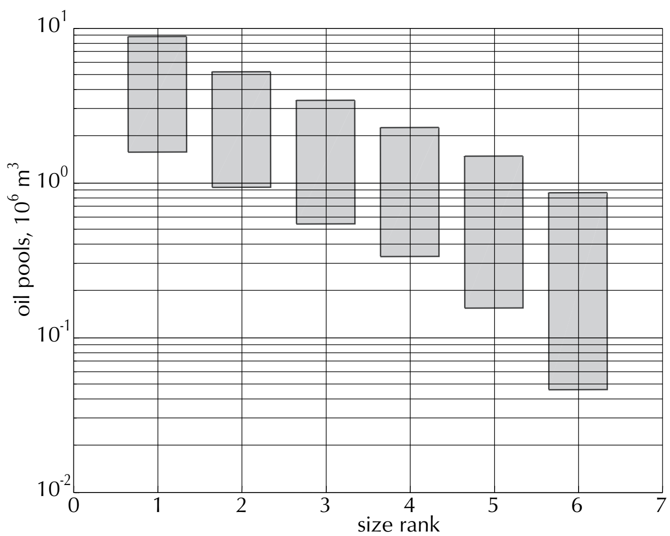


Figure 39. *Predicted accumulation size by rank diagram for Play 2a, Structurally Trapped Crude Oil Play in Cretaceous Sandstones. The predicted pool sizes are obtained using order statistics and conditioning the accumulation-size distribution against the number of expected pools, as shown in Table 53.*

Play 1, Stratigraphically Trapped Natural Gas Play in Cretaceous Sandstones

The stratigraphically trapped natural gas plays in Cretaceous strata (Fig. 6) constitute an immature conceptual play in the Eagle Plain Basin. Only minor reserves and shows have been identified in this stratigraphic interval (Table 2). However, this play constitutes a great rock volume, and the exploration history of similar successions in Alberta and Saskatchewan, has established and continues to establish very large reserves, of commonly biogenically sourced natural gas. The concerns of reservoir pressure and formation volume factor that affected the structural play in these strata remains, but it is compensated for by the large play volume. This play, also referred to as Play 1, has formation parameters that are well established by drilling. Depending on the efficiency and extent of the potential biogenic mechanism for petroleum generation, it is possible that this play has been assessed very conservatively.

The distribution of input play parameters for Play 1, Stratigraphically Trapped Natural Gas Play in Cretaceous Sandstones, is given in Table 56. The volume of prospects was determined by discounting the product of the area of prospects and net pay, and the prospect gross volume, with a trap-fill fraction based primarily on analogue. The prospect area distribution was inferred to be not smaller than 0.20 and 30 km^2. No prospects exceeding an area of 30 km^2 could be identified or inferred for this play. Average net pay was determined to possibly range between 3 and 50 m, while it is unlikely (1% probability) that average net pay will exceed 20 m thickness. The fractional pool average porosity is inferred to be between 0.06 and 0.22, and fractional hydrocarbon saturations are expected to vary between 0.55 and 0.90, which are reasonable values consistent with observations in the Eagle Plain and general occurrences in similar plays elsewhere. The median value of trap-fill is 50%, with a lower limit (an inferred 100% probability) of 0.10 and an upper practical limit (1% probability) of 1. Formation volume factor for gas was computed using reservoir pressure and temperature distributions based on the depth range of potential prospects, together with a distribution of gas compressibility factors, as shown in the input parameters in Table 56.

The number of prospects in this play was estimated to be not less than 40, and not expected to exceed 90 (Table 56). Prospect-level risk factors for Play 1 are listed in Table 57. The product of individual prospect-level risk factors (Table 57) is the combined prospect-level risk, which for this play is 0.270.

The natural gas pool, or accumulation, size probability distribution for Play 1 is given in Table 58. The expected, or mean, natural gas pool size is predicted to be 7.38 Bcf. The number of expected prospects is 58 (Table 58). The play potential distribution for natural gas in Play 1 is listed in Table 58. The median and mean natural gas potentials calculated for this play are 108.59 and 118.45 Bcf, respectively, which are inferred to occur in 16 accumulations. The probability distributions describing the calculated individual model accumulations are given in Table 59. The median and mean sizes of the largest predicted natural gas pools in Play 1 are 0.79 and 0.87 billion cubic m, respectively, of initial raw natural gas in-place, at standard conditions. Details of the predicted pool sizes for all 16 pools are listed in the graph in Figure 40. Only the sizes of the first 15 pools are described.

Play 1, Stratigraphically Trapped Natural Gas Play in Cretaceous Sandstones

Table 56. Distributions of input play accumulation parameters.

Parameter	100%	50%	1%	0%
Closure, km²	0.20	5.00	20.00	30.00
Net pay, m	3.00	15.00	20.00	50.00
Porosity, fraction	0.06	0.10	0.15	0.22
Hydrocarbon saturation, fraction	0.55	0.65	0.80	0.90
Trap-fill, fraction	0.10	0.50	0.70	1.00
Gas compressibility, fraction	0.80	0.90	0.95	0.95
Reservoir pressure, Kpa	3000.00	6000.00	10 000.00	15 000.00
Reservoir temperature, °C	37.00	40.00	45.00	50.00

Parameter	100%	50%		0%
Number of prospects	40	50		90

Table 57. Prospect-level risk factors.

Presence of source rock	1.000
Presence of closure	0.900
Presence of reservoir facies	0.500
Presence of adequate seal	1.000
Adequate timing	1.000
Migration pathway risk	0.600
Prospect-level risk	0.270

Table 58. Field size and play potential probability distributions, as well as the number of prospects and pools – Assessment results.
Units: billion cubic feet of initial raw natural gas in place.

Field size probability distribution						
5%	25%	50%	75%	95%	Mean	Number of prospects
26.48	9.53	3.87	1.45	0.32	7.38	58
Play potential probability distribution						
5%	25%	50%	75%	95%	Mean	Number of pools
216.87	145.19	108.59	80.69	51.69	118.45	16

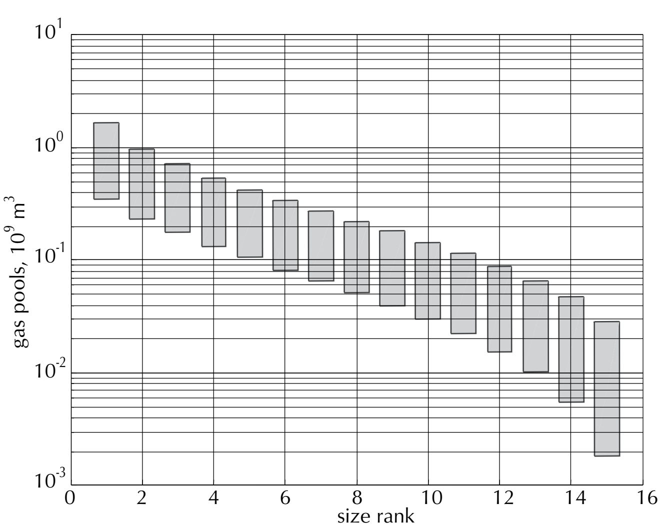


Figure 40. Predicted accumulation size by rank diagram for Play 1, Stratigraphically Trapped Natural Gas Play in Cretaceous Sandstones. The predicted pool sizes are obtained using order statistics and conditioning the accumulation-size distribution against the number of expected pools, as shown in Table 57.

Table 59. Predicted accumulation sizes (x 10^9 m^3).

Size rank	5%	25%	50%	75%	95%	Mean
1	1.66	1.06	0.79	0.57	0.35	0.87
2	0.98	0.68	0.50	0.38	0.24	0.55
3	0.72	0.48	0.37	0.27	0.18	0.39
4	0.54	0.37	0.28	0.21	0.13	0.30
5	0.43	0.29	0.22	0.16	0.11	0.24
6	0.34	0.23	0.18	0.13	0.08	0.19
7	0.27	0.19	0.14	0.10	0.07	0.15
8	0.22	0.15	0.11	0.08	0.05	0.12
9	0.18	0.12	0.09	0.06	0.04	0.10
10	0.14	0.09	0.07	0.05	0.03	0.08
11	0.11	0.07	0.05	0.04	0.02	0.06
12	0.09	0.06	0.04	0.03	0.02	0.04
13	0.07	0.04	0.03	0.02	0.01	0.03
14	0.05	0.03	0.02	0.01	0.01	0.02
15	0.03	0.01	0.01	0.00	0.00	0.01

Play 1a, Stratigraphically Trapped Crude Oil Play in Cretaceous Sandstones

The stratigraphically trapped oil play in Cretaceous strata, referred to as Play 1a (Fig. 6), constitutes an immature conceptual play in the Eagle Plain Basin. Only minor reserves and shows have been identified in this stratigraphic interval (Table 2). However, this play also encompasses a great rock volume. The play potential is adversely affected by concerns regarding petroleum system function, as crude oil is not biosynthesized, as is methane. Therefore the relative potential of this play, which resembles Play 1 and occurs in the same strata as Plays 2 and 2a, results in a significantly lower potential than would have been attributed if a more functional petroleum system could have been established. To what degree the focus, during early exploration, on deeper targets and very large reserves may have under-reported shows or under-evaluated the oil potential of the Cretaceous succession is not known.

The distributions of input play parameters for Play 1a are given in Table 60. The volume of prospects was determined by discounting the product of the area of prospects and net pay, and the prospect gross volume, with a trap-fill fraction based primarily on analogue. The prospect area distribution was inferred to be not smaller than 0.200 km^2. No prospects exceeding an area of 30 km^2 could be identified or inferred for this play. Average net pay was determined to possibly range between 3 and 50 m, while it is unlikely (1% probability) that average net pay will exceed 10 m thickness. The fractional pool average porosity is inferred to be between 0.060 and 0.220, and fractional hydrocarbon saturations are expected to vary between 0.550 and 0.900, which are reasonable values consistent with observations in the Eagle Plain and general occurrences in similar plays elsewhere. The median value of trap-fill is 8%, with a lower limit (an inferred 100% probability) of 0.50 and an upper practical limit (1% probability) of 0.30. Shrinkage, the formation volume factor for crude oil, was computed using reservoir pressure and temperature distributions based on the depth range of potential prospects, together with a distribution of solution gas factors, as described in input parameter Table 60. The number of prospects in this play was estimated to be not less than 40, and not expected to exceed 90 (Table 60). The product of individual prospect-level risk factors (Table 61) is the combined prospect-level risk, which for this play is 0.115.

The crude oil pool, or accumulation, size probability distribution for Play 1a is given in Table 61. The expected, or mean, crude oil pool size is predicted to be 5.78 MMbbls. The number of expected prospects is 57 (Table 61). The play potential distribution for crude oil in Play 1a is listed in Table 61. The median and mean crude oil potentials calculated for this play are 35.63 and 40.47 MMbbls, respectively, which are inferred to occur in seven accumulations. The probability distributions describing the calculated individual model accumulations are given in Table 63. The median and mean sizes of the largest predicted crude oil accumulations in Play 1a are 2.25 and 2.60 million cubic m, respectively. Details of the predicted pool sizes for all seven pools are listed in the graph in Figure 41.

Play 1a, Stratigraphically Trapped Crude Oil Play in Cretaceous Sandstones

Table 60. *Distributions of input play accumulation parameters.*

Parameter	100%	50%	1%	0%
Closure, km²	0.200	5.000	20.000	30.000
Net pay, m	3.000	6.000	10.000	50.000
Porosity, fraction	0.060	0.120	0.200	0.220
Hydrocarbon saturation, fraction	0.550	0.650	0.800	0.900
Trap-fill, fraction	0.05	0.08	0.10	0.30
Formation Volume Factor	1.120	1.130	1.140	1.150
Reservoir pressure, Kpa	3000.000	6000.000	10 000.000	15 000.000
Reservoir temperature, °C	37.000	40.000	45.000	50.000

Parameter	100%	50%		0%
Number of prospects	40	50		90

Table 61. *Prospect-level risk factors.*

Presence of source rock	1.000
Presence of closure	0.600
Presence of reservoir facies	0.500
Presence of adequate seal	0.800
Adequate timing	0.800
Migration pathway risk	0.600
Prospect-level risk	0.115

Table 62. *Field size and play potential probability distributions, as well as the number of prospects and pools – Assessment results.*
Units: initial crude oil in place, 10^6 bbls.

Field size probability distribution						
5%	25%	50%	75%	95%	Mean	Number of prospects
18.60	7.74	3.53	1.49	0.39	5.78	57
Play potential probability distribution						
5%	25%	50%	75%	95%	Mean	Number of pools
80.79	51.38	35.63	24.52	13.66	40.47	7

Table 63. *Predicted accumulation sizes (x 10^9 m^3).*

Size rank	5%	25%	50%	75%	95%	Mean
1	5.26	3.23	2.25	1.57	0.90	2.60
2	2.85	1.85	1.32	0.94	0.53	1.46
3	1.89	1.22	0.87	0.58	0.34	0.96
4	1.32	0.83	0.56	0.37	0.21	0.64
5	0.94	0.53	0.36	0.23	0.13	0.42
6	0.59	0.33	0.21	0.13	0.06	0.25
7	0.34	0.17	0.09	0.05	0.02	0.13

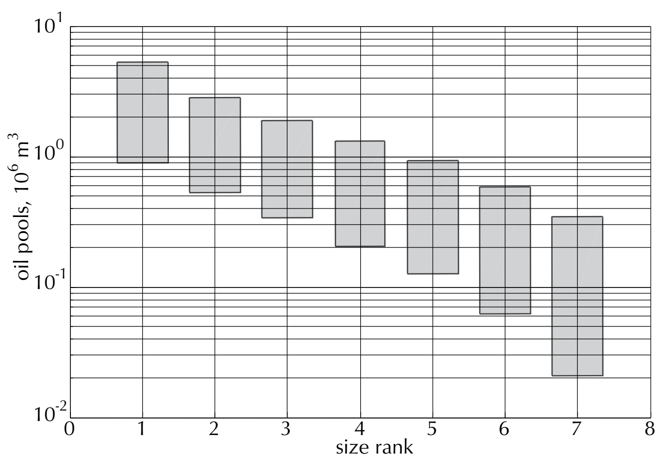


Figure 41. *Predicted accumulation size by rank. The predicted pool sizes are obtained using order statistics and conditioning the accumulation-size distribution against the number of expected pools, as shown in Table 61.*

TOTAL PETROLEUM POTENTIAL OF THE EAGLE PLAIN BASIN

The results of the assessment are summarized for specific plays in Table 64. The aggregate petroleum potential for the nine natural gas and six crude oil plays can be statistically aggregated to give a total basin potential. The result of this aggregate potential determination is presented in Figure 42. It is inferred that a total of 146 accumulations of crude oil and natural gas will have a 90% probability of containing between 2.379 Tcf to 12.0 Tcf of natural gas and 132 MMbbls to 926 MMbbls of crude oil. The mean, or expected, natural gas endowment is inferred to be 6.055 Tcf, occurring in 114 accumulations, and that the mean crude oil endowment is inferred to be 437 MMbbls in 32 accumulations, the sizes of which are described in the tables of this report (Figs. 27 to 41). The discovered volumes, termed variously "identified resources" or "reserves" of natural gas and crude oil are reported to be 83.7 Bcf and 11.05 MMbbls, respectively (NEB, 2000). This suggests that an expected 5.971 Tcf of natural gas and 425.95 MMbbls of crude oil remain to be discovered in the Eagle Plain Basin, although no more detailed distinction between the discovered reserve and the undiscovered potential can be specified, since the reserve (NEB) is not pool-based.

The assessment of potential that accompanied the description of the reserve suggested undiscovered potentials of 1000 Bcf and 28.2 MMbbls natural gas and oil, respectively; with total potentials of 1.100 Tcf and 39.2 MMbbls (NEB, 2000). The region was also assessed by the Canadian Gas Potential Committee (CGPC, 2001). The CGPC suggested that the initial in-place discovered natural gas volume was 104 Bcf and that the undiscovered natural gas potential was 718 Bcf, from the total of which they inferred that 532 Bcf would be marketable. The CGPC does not estimate crude oil potential. Clearly there is a significant difference among these estimates of total potential. Some of the reasons for the differences are objective. The NEB (2000) employed an assessment method that differs from the common approach of the CGPC (2001) and this report (see methodology discussion above). This assessment considered and evaluated more plays than did the CGPC study, however, this alone does not account for the significant differences in the potential between this study and the others. Much of the difference in the assessed values results from differences in input parameters, most specifically the number of expected prospects and the prospect-level risks. Comparisons indicated that the CGPC routinely produces more conservative estimates than the assessors employed to prepare this report. Since the differences arise from subjective interpretations, extrapolations and selection of

Table 64. *Summary total petroleum resource endowment of the Eagle Plain Basin and environs in the Yukon. Plays have either natural gas or crude oil potential. The critical values of the play potential distributions are described, as are the mean values of the total potential and the number of pools expected. Natural gas potential is indicated billions of cubic feet and crude oil is indicated in millions of barrels. All values are in initial volume in place.*

Play number	5%	25%	50%	75%	95%	Mean gas (Bcf)	Mean oil (MMbbls)	# of pools	Prospect risk
Play 1	216.87	145.19	108.59	80.69	51.69	118.45		16	0.27
Play 1a	80.79	51.38	35.63	24.52	13.66		40.47	7	0.115
Play 2	402.88	279.01	216.52	165.2	110.44	230.89		16	0.27
Play 2a	138.19	86.23	59.71	40.39	22.46		67.34	6	0.101
Play 3	4366.55	2701.08	1925.35	1332.93	768.75	2159.7		16	0.287
Play 4	176.99	95.43	57.86	34.29	15.68	72.10		5	0.15
Play 4a	248.51	139.59	86.93	50.00	22.19		104.89	4	0.141
Play 5	3066.72	2099.08	1581.96	1177.72	757.02	1705.23		11	0.245
Play 5a	167.15	101.4	68.28	44.92	24.01		78.38	5	0.121
Play 6	248.07	149.85	102.57	68.23	37.61	118.09		6	0.246
Play 6a	153.78	98.03	68.8	46.75	26.26		76.71	5	0.086
Play 7	548.52	387.95	304.36	237.30	163.35	323.02		18	0.161
Play 7a	137.29	88.01	62.31	42.66	23.90		68.95	5	0.121
Play 8	1599.75	1060.84	800.63	607.30	415.26	879.45		20	0.126
Play 9	1373.92	564.42	294.57	152.65	59.01	448.41		6	0.151
Total potential						**6055.34**	**436.74**	**146**	

Table 65. Total petroleum potential, both discovered and undiscovered, for the Eagle Plain Basin as cumulative probability distribution functions percentiles for both natural gas and crude oil, showing the number of expected accumulations of both natural gas and crude oil.

Basin Resource Potential							
	5%	20%	50%	75%	95%	Mean	N
Gas	12 000	7483	5392	3856	2379	6055	114
Oil	926	565	382	249	132	437	32

Gas potential: Bcf; oil potential: 10^6 bbls

analogues, it is impossible to vindicate one interpretation over the other. However, historical analysis of basin assessments and even the historical vindication of individual plays, as presented above in the methodology section, indicates that there is a tendency to be conservative in the estimate of undiscovered potential, that is not borne out historically. Most notably, even the optimistic assessors of Western Canadian Sedimentary Basin crude oil and natural gas potential have found that the assessments of ultimate potential inferred between 10 and 20 years ago are now seen to be smaller that the established reserve, while the basin is still an active and successful target of continued exploration. Whether the estimates produced herein will also be shown to be conservative cannot be known now, but the trends of history, in basins with much more data and activity, suggest that assessments performed early in the exploratory history of a basin are a very conservative relative to the ultimate potential proved by decades of active exploration and thousands of wells. Certainly the numerous indications of petroleum in wells in the Eagle Plain Basin suggest that it should be considered a highly prospective region, which would tend to prefer the current assessment over the previous efforts.

DISCUSSION

The current study recognized four primary stratigraphic intervals that were prospective for the accumulation of structurally and stratigraphically entrapped crude oil and natural gas. The Lower Paleozoic (Cambrian to Middle Devonian) succession of the Porcupine Carbonate Platform was judged to have both structural and stratigraphic opportunities for the entrapment of natural gas, but it was attributed no crude oil potential due to its high thermal maturity and deep burial. Large structures in this succession have been only rarely penetrated, but there have been encouraging shows. An especially favourable opportunity occurs on the eastern side of the basin, where there is a favourable potential trap against the eastern up-dip margins of carbonate platform depositions cycles. In this succession it was inferred that there would be six structurally controlled pools with an expected natural gas resource of 448.41 Bcf and another 20 stratigraphically entrapped pools with an expected resource of 879.45 Bcf (Table 64, Figure 42).

No significant potential was assigned to the fine-clastic-dominated Cambrian to Carboniferous succession, especially within the Richard Trough, or its margins, which includes formations such as the Imperial Formation, which have had shows and significant undiscovered potential assigned elsewhere, such as in the Peel Plain and Plateau (Osadetz et al., 2005a). This omission was based largely on the negative results from existing exploration wells, but it could be revised, if subsequent considerations or additional data indicate that petroleum potential exists in these successions and regions.

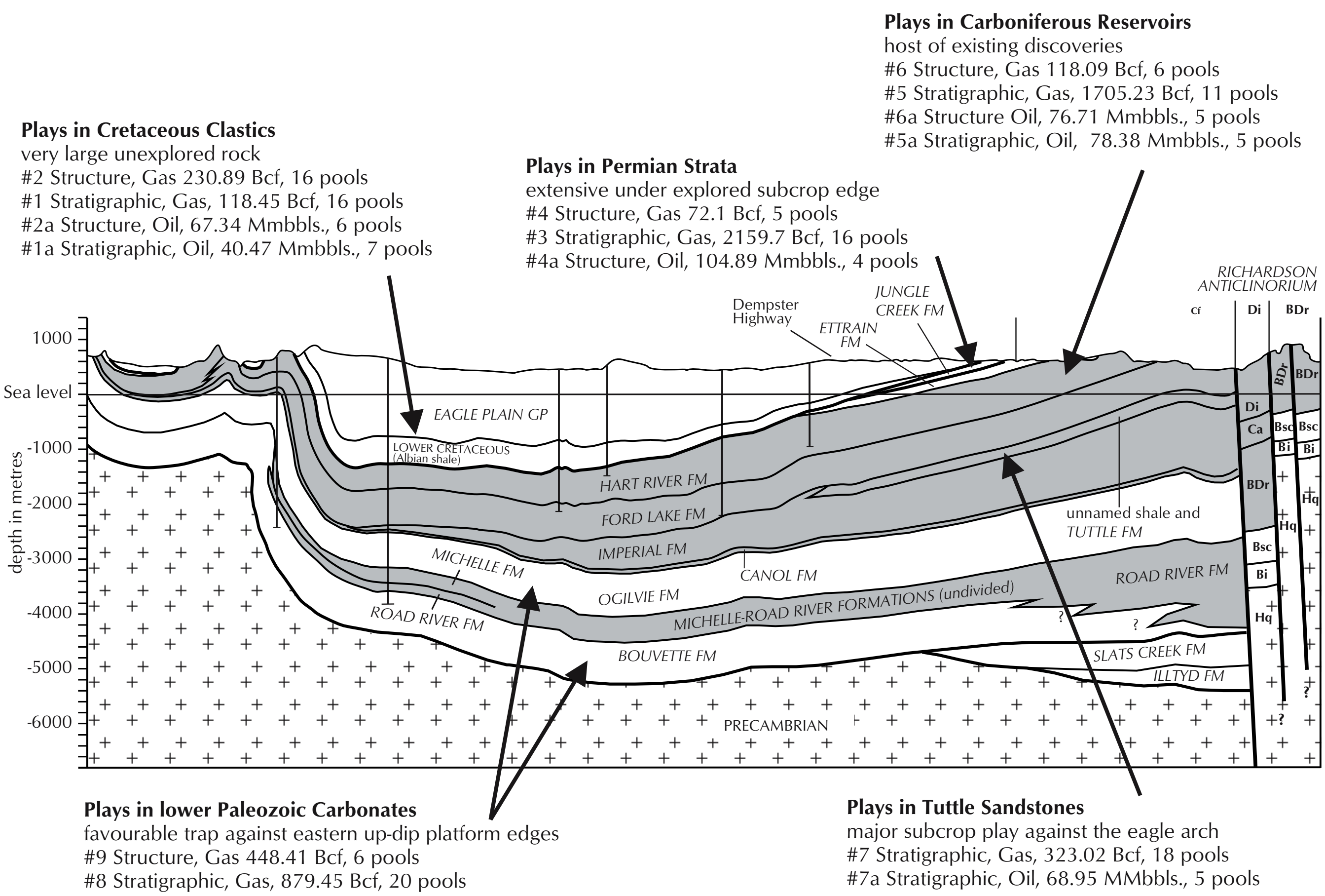


***Figure 42**. Summary diagram illustrating the results of this assessment for both natural gas and crude oil, showing the number of expected accumulations of both natural gas and crude oil for all the individual plays analysed and discussed in the text. The stratigraphic intervals for each of the plays are indicated. Note that no assessment was performed for either the Jurassic successions, which have had shows of gas in wells, or for the Devonian Imperial Formation, which is considered to be prospective on the eastern side of the Richardson Mountains. There was insufficient information to appropriately specify the play parameters in either of these two plays.*

The Carboniferous succession is the one of the primary targets of exploration. It has established reserves (discovered resources) of natural gas and crude oil as well as numerous encouraging drill stem test results. Both structural and stratigraphic opportunities for petroleum potential were identified in the Carboniferous succession, within which three different intervals were assessed separately because of their specific reservoir characteristics and exploratory risks. A total of 23 accumulations were inferred for the Tuttle sandstones. The expected natural gas and crude oil potential for stratigraphic traps in the Tuttle Formation is 323.02 Bcf in 18 pools and 68.95 MMbbls in 5 pools, respectively. The main established reserves occur in sandstone and limestone members of the Hart River Formation, which has both structural and stratigraphic potential to entrap both natural gas and oil. The expected natural gas resource inferred entrapped resource in the structural and stratigraphic plays in the Carboniferous succession overlying the Tuttle Formation is expected to be 118.09 Bcf, in 6 pools and 1705.23 Bcf in 11 pools, respectively. The expected crude oil resource in the same structural and stratigraphic plays was inferred to be 76.71 MMbbls and 78.38 MMbbls, respectively, in a total of 10 pools, of which half are structural and half are stratigraphically entrapped.

The highest Paleozoic reservoir that subcrops below the Mesozoic succession is composed of Permian sandstones. They represent another, less explored primary target for exploration. This play is inferred prospective for structural accumulations of crude oil and both structural and stratigraphically entrapped natural gas. The mean natural gas potential is 72.1 Bcf, in 5 structurally entrapped accumulations and 2159.7 Bcf, in 16 stratigraphically entrapped accumulations, most of which are inferred to be at or near the extensive but under-explored subcrop edge of the Permian succession. The mean crude oil potential is inferred to be 104.89 MMbbls, probably occurring in four pools, most of which will likely occur in the southern part of the basin, particularly where the top of the Permian succession is composed of an unnamed shale, which could be an effective seal.

The Mesozoic succession was considered as a single stratigraphic unit, with potential in its sandstone members for both crude oil and natural gas, although both petroleum systems and formation factor considerations depreciate the undiscovered resource potential and potential size of individual undiscovered accumulations. The expected natural gas potential in the Mesozoic is inferred to be 230.89 Bcf, in 16 structurally entrapped pools and 118.45 Bcf, in a similar number of stratigraphically entrapped pools. The expected crude oil potential, all of which must be migrated from deeper sources that are more thermally mature and oil-prone, is 67.34 MMbbls, in six structural traps and 40.47 MMbbls, in seven stratigraphic traps.

The petroleum assessment of 15 petroleum plays in the Eagle Plain Basin suggests that an expected 5.971 Tcf of natural gas and 425.95 MMbbls of crude oil remain to be discovered in the Eagle Plain Basin. This undiscovered mean potential is expected to be part of a total resource endowment of 146 accumulations of crude oil and natural gas containing between 2.379 Tcf and 12.0 Tcf of natural gas and 132 MMbbls to 926 MMbbls of crude oil (Fig. 42), of which 83.7 Bcf and 11.05 MMbbls, has been discovered (NEB, 2000). In comparison to previous assessments, this potential is significantly larger and more comprehensively specified than in previous studies.

Individual undiscovered pool sizes were predicted for each play (Figs. 27 to 41), conditional on the expected number of accumulations. The largest undiscovered gas pools were identified as occurring in Plays 5 and 3 (Tables 47 and 31), which are the stratigraphic plays in the Permian and Carboniferous successions, respectively. The largest expected undiscovered crude oil pool sizes were identified in the Permian structural play (Play 4a, Table 43). Otherwise the largest oil targets, i.e., undiscovered model pools in other plays, excepting the Cretaceous stratigraphic play, were generally comparable in size. The results of the pool size predictions are consistent with the general results of the exploratory history, the stratigraphic architecture and the petroleum systems analysis. The exploratory history indicates that the best sources and accumulations occur in Paleozoic succession, among which the stratigraphically and structurally highest prospects should be the most prospective. The Permian Jungle Creek Formation and Carboniferous Hart River and Tuttle sandstones are the stratigraphically highest and 2nd highest potential reservoirs below the sub-Mesozoic unconformity, and they are the most favourably positioned to accumulate petroleum subsequent to the Mesozoic burial beneath the foreland succession, much of which is now removed by erosion. This follows, in general, the experience of previous exploration and the stratigraphic segregation of potential.

CONCLUSIONS

In the Eagle Plain basin, extensive initial exploration focused on discovering crude oil identified 83.7 Bcf of natural gas and 11.05 MMbbls of crude oil, most of which occurs in the Permo-Carboniferous reservoirs of the Tuttle, Hart River and Jungle Creek formations. This was identified by the drilling of 33 wells (Table 2), many of which had shows of petroleum in multiple zones (Table 3). This petroleum assessment of 15 petroleum plays suggests that an expected 5.971 Tcf of natural gas and 425.95 MMbbls of crude oil remain to be discovered in the Eagle Plain Basin, as part of a total resource endowment of 146 accumulations of crude oil and natural gas containing between 2.379 Tcf to 12.0 Tcf of natural gas and 132 MMbbls to 926 MMbbls of crude oil (Fig. 42; Table 64). This study differs significantly from previous estimates of undiscovered potential, which produced much more conservative estimates of undiscovered potential. The reasons for this difference are at least partly subjective, but the current assessment is inferred to attempt to reduce the conservative bias that is characteristic of early petroleum potential estimates in basins that do not produce immediate commercial success. Additional conceptual plays occur in the Devonian basinal clastic and Jurassic successions, which have had encouraging shows, both locally and regionally. These additional conceptual plays were not assessed quantitatively.

In terms of total petroleum endowment, the Lower Paleozoic (Cambrian to Middle Devonian) succession of the Porcupine Carbonate Platform is expected to have 1327.86 Bcf natural gas, and this interval presents an important, but deeper secondary exploration target (Table 64, Figure 43). The Carboniferous succession, the main target to date, is inferred, as a result of this assessment to remain the primary stratigraphic interval of interest. It is inferred to have an expected 323.02 Bcf of natural gas and 68.95 MMbbls of crude oil in the Tuttle Formation, another 1823.32 Bcf of natural gas and 155.09 MMbbls of crude oil in the Hart River Formation, while the Jungle Creek Formation sandstones are expected to contain 2231.8 Bcf of natural gas, mainly in stratigraphic prospects and 104.89 MMbbls of crude oil in structural traps. The expected total potential in the Mesozoic is inferred to be 349.34 Bcf of natural gas and 107.81 MMbbls of crude oil. Predicted undiscovered pool sizes point toward a continued exploration of stratigraphic plays in the Permian and Carboniferous successions and a focus on the Jungle Creek Formation sandstones in structures for the largest undiscovered oil accumulation. While the entire section is prospective throughout the basin, the results of this assessment refocus exploratory efforts and re-enforce the general exploratory efforts of the past, that were dominated by emphasis on the structural and stratigraphic prospects in the upper part of the Paleozoic succession, where excellent reservoirs occur (Dixon, 1999; Hamblin, 1990). Intriguing conceptual plays exist associated with the entrapment in Paleozoic carbonates reservoirs against the Richardson Trough (Morrow, 1999), but these appear to be higher risk/reward efforts than the continued exploration of the uppermost potential reservoirs in the Paleozoic succession. Both conclusions are consistent with the exploration history and the analysis of petroleum systems. Important parts of the succession, particularly the Devonian Imperial Formation, could not be confidently assessed at this time. It, with other intervals such as the Jurassic, is a family of conceptual plays that has indications for additional undiscovered petroleum potential.

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