### EAGLE PLAIN BASIN

<table>
<thead>
<tr>
<th>Age</th>
<th>Paleozoic to Cretaceous, with Quaternary cover</th>
</tr>
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<tbody>
<tr>
<td>Depth to Target Zones</td>
<td>650-2800 m</td>
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<tr>
<td>Maximum Basin Thickness</td>
<td>5800 m</td>
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<tr>
<td>Hydrocarbon Shows</td>
<td>Middle Devonian to Lower Cretaceous strata; in several wells</td>
</tr>
<tr>
<td>First Discovery</td>
<td>1960 (Western Minerals Chance L-08; gas and oil)</td>
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<tr>
<td>Discovered Resources</td>
<td>Gas: 1760-3620 x E6 m³ (90% range); 2524 x E6 m³ (at 50%) Oil: 1.34-2.85 x E6 m³ (90%, range); 1.86 x E6 m³ (at 50%)</td>
</tr>
<tr>
<td>Production</td>
<td>No production to date</td>
</tr>
<tr>
<td>Basin Type</td>
<td>Shallow marine shelf (Paleozoic to early Mesozoic); intermontane compressional (Cretaceous to Recent)</td>
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<tr>
<td>Depositional Setting</td>
<td>Shallow-water carbonate and clastic shelf</td>
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<tr>
<td>Reservoirs</td>
<td>Carbonate reefal mounds and facies fronts; fractured carbonates; unconformity traps and discontinuous marine clastic lenses</td>
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<tr>
<td>Regional Structure</td>
<td>Long wavelength folds at surface; detachments with thrust folds within deeper strata; contraction and minor relaxation faulting</td>
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<tr>
<td>Seals</td>
<td>Marine shales and tight carbonates</td>
</tr>
<tr>
<td>Source Rocks</td>
<td>Shales and organic-rich carbonates</td>
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<td>Depth to Oil/Gas Window</td>
<td>2300 m</td>
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<tr>
<td>Total Number of Wells</td>
<td>36 (31 dry; 1 oil; 2 gas; 2 gas and oil); 2 wells post-1980</td>
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<tr>
<td>Seismic Coverage</td>
<td>9952 km; 790 km post-1980</td>
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<td>Pipelines</td>
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<tr>
<td>Area</td>
<td>24,060 km²</td>
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<td>Area under Licence</td>
<td>8900 ha (0.4% of basin, in 3 Significant Discovery Licences)</td>
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The Eagle Plain Basin is an under-explored basin with proven oil and gas potential. Clastic reservoir rocks of Mississippian to Permian and Early Cretaceous age host the discovered pools in combined structural and unconformity traps in the southern Eagle Plain close to the Dempster highway. High potential exists for additional discoveries of oil and gas pools of small to moderate size. There is additional potential for discoveries in northern Eagle Plain along the transition between Paleozoic platform carbonates and basinal shales.

**Geological Setting** (Fig. 27)

The Eagle Plain Basin is an intermontane compressional basin straddling the Arctic Circle in the Yukon Territory, 2500 km north of Calgary and 80 km east of the Yukon-Alaska border. The basin formed during the Laramide orogeny when Palaeozoic and Cretaceous shallow-water shelf sediments (clastics and carbonates) were folded and faulted. The preserved extent of the Mesozoic sediments outlines the present day limits of the basin, which is surrounded by outcrop belts in the Richardson Mountains to the east and north, the Ogilvie Mountains to the south and west and the Dave Lord Range of the Ogilvie Mountains to the north.
Figure 27. Major structures, well locations and sub-basins, Eagle Plain Basin.

The basin is bisected by the Eagle Arch, a northeast-southwest aligned subsurface ridge that separates the shallower northern portion of the basin - the Bell subbasin - from the southern part of Eagle Plain Basin, which contains a thicker and more complete stratigraphic section.

Exploration History (Figs. 28, 29)

Petroleum exploration started in the late 1950s with the drilling of the Peel Plateau Eagle Plain Y.T. No. 1 N-49 well in the north-central part of the basin. The N-49 well was drilled on a surface anticline to 2923 m, terminating in Cambrian-Ordovician shales and carbonates without encountering hydrocarbons. The second prospect tested a surface anticline in the southern part of the basin, and resulted in the first discovery in the basin at Western Minerals Chance Y.T. No. 1 L-08 in 1960. The L-08 well was drilled to 2636 m, terminating in Mississippian carbonates and encountered hydrocarbons in six separate zones. Since the first discovery, additional exploratory and delineation wells have been drilled. Two additional significant hydrocarbon discoveries have been made at the Blackie (1964) and Birch (1965) fields. Hydrocarbons have been discovered in a total of nine separate zones with potential in two deeper horizons indicated by shows.

Seismic lines totalling 9952 km have been shot in the basin, about half this total since 1970. By far the largest regional program was shot by Chevron in 1971. There is a concentration of seismic coverage in the vicinity of the three discovered fields.

Half the wells in the basin were drilled after 1970 with the most recent drilling in 1985 (Exco West Parkin D-54 and Exco North Chance D-22). The drilling density is 1 well per 745 km² but is concentrated in the southern portion of the basin. However, wells have been drilled in all quarters of the basin and provide useful stratigraphic control.

Stratigraphy (Fig. 30)

Within the Eagle Plain Basin, strata of Precambrian to Cretaceous age are preserved along with a thin cover of
Quaternary deposits. Triassic and Tertiary strata are absent. Carbonates dominate the Ordovician to the Middle Devonian, with mixed carbonate/clastic lithologies typical of the Upper Devonian and Carboniferous. The Permian strata of the basin are predominantly clasticas is the Mesozoic section. Mesozoic deposition was characterised by lateral facies transitions. Three main unconformities are present in the section. The schematic cross-section shows the stratigraphic relationships and trap styles within the basin.

Two important stratigraphic controls on hydrocarbon prospectivity are: a) the sub-Cretaceous unconformity, which defines the limits of plays represented by subcropping Carboniferous to Permian strata in southern Eagle Plain; b) the Lower to Middle Devonian carbonate to shale facies transitions in the Bell subbasin.

**Potential Reservoirs (Fig. 31)**

Hydrocarbons have been tested from five horizons within upper Paleozoic and Lower Cretaceous strata:

1) Western Minerals et al. Chance No. 1 L-08, tested gas at good flow rates (225 x 10³ m³/d) from a 3.6 m brecciated, cherty, pebbly sandstone with 16% porosity - the Tuttle Sandstone.

2) Gas and oil were recovered from the Canoe River Member (lower limestone) of the Hart River Formation in Chance field. The Canoe River Member consists of thinly bedded, micritic, crinoidal limestone with chert, dolomite and shale interbeds. Five hundred metres of clean carbonate are present with porosity up to 13%. Within the Chance field two pools have been found (one oil and one gas pool at Chance L-08, and one gas pool at Chance G-19). The unit has tested gas at rates up to 283 x 10³ m³/d and has recovered 290 m of oil.

3) Gas and oil also have been recovered from the Chance Sandstone Member of the Hart River Formation in the vicinity of Chance field. The Chance Sandstone Member consists of fine to medium grained, moderately to well sorted, salt and pepper sandstone with porosity ranging from 5 to 22% (average 14%) and permeability varying from 100 to 500 mD. Gross thickness of sandstone
at Chance amounts to 130 m. Within the Chance field six Chance Sandstone pools have been found (one oil and three gas pools defined in Chance G-19, L-08 and G-08, and one oil pool at Chance G-08). An additional gas pool in the Chance Sandstone was discovered at Birch B-34. The unit tested gas at rates up to 230 x 10³ m³/d with 610 m pipe recovery of oil and condensate.

4) Gas has also been recovered from the Lower Permian Jungle Creek Formation in the Blackie field. The unit is a medium to coarse grained, poorly sorted, conglomeratic sandstone, 3 to 30 m thick. Porosity ranges from 5 to 20% (average 15%) and permeability from 100 to 200 mD. Up to 166 m of clean sandstone are present. The unit tested gas at rates up to 99 x 10³ m³/d at Blackie. Possible oil potential is indicated by an oil cut mud DST recovery from the Jungle Creek in Birch B-34, to the north and east of the Blackie field.

All the upper Paleozoic reservoirs thin to the south and, with the exception of the Tuttle Sandstone and the Hart River Formation, are not developed in the outcrop belts surrounding the basin. All units rise to subcrop the basal Cretaceous unconformity north of Chance field.

5) Gas has also been recovered from the Lower Cretaceous Fishing Branch Formation (Eagle Plain Group; “Blackie K1 Sandstone”) in the Chance L-08 well. The unit is a salt and pepper, fine grained, moderately well sorted, cherty marine sandstone. Porosity ranges from 15 to 25% (average 22%). The unit has up to 50 m of clean sandstone and thins to the northwest. The unit tested gas at rates up to 23 x 10⁶ m³/d.

In addition, two DSTs recovered minor amounts of gas from the Alder Member (upper limestone) of the Hart River Formation near the subcrop limit of this unit along the Chance anticline. The unit is a micritic crinoidal limestone up to 200 m thick with poor to fair porosity. One DST had a minor gas show from the Ettrain Formation. The unit is a light brown skeletal and cherty limestone and sandy packstone with up to 226 m of clean carbonate, but with poor to fair porosity.

Gas shows were also noted in the Middle Devonian Ogilvie Formation (Peel Plateau N-49 and South Tuttle N-05) and in the Lower Devonian Gossage Formation (South Tuttle N-05). Both these thick carbonate unit are potential reservoir rocks.

**Structure, Traps and Seal**

Parallel, northward-striking anticlines and synclines are the principal surface structures. Thrust faults parallel to the surface structures are present in the subsurface. These faults may or may not have surface expression with the limited thrust-ramping concentrated at the basal Cretaceous unconformity. Trapping configurations are multiplied by permutations of several potential reservoirs subcropping beneath unconformities along the plunge of the anticlines. In addition, several possibilities for stratigraphic traps are present.

Five types of hydrocarbon traps have been identified within the basin: 1) Laramide folds (Jungle Creek in Blackie M-59 and Fishing Branch sandstone in Chance L-08); 2) combined structural-stratigraphic-unconformity traps beneath Lower Cretaceous shale (Chance sandstones in Chance L-08); 3) reverse dip stratigraphic facies changes (gas show in South Chance D-63); 4) pinch-out of discontinuous sandstone lenses (basal Chance sandstones), and 5) carbonate to shale facies transitions (Canoe River limestones in Chance M-08 and possible Ogilvie/Gossage traps as demonstrated by the gas shows in South Tuttle N-05).
Intraformational shale forms local seals for the Carboniferous and Cretaceous reservoirs while facies changes from carbonate to shale form lateral seals for lower Palaeozoic reservoirs. The Lower Cretaceous Whitestone River Formation is a regional top seal for reservoirs truncated by the sub-Cretaceous unconformity. The Canol and Prongs Creek shales form regional top seals for the Ogilvie and Gossage carbonates.

Source Rocks

Five source rocks have been identified: 1) the lower Palaeozoic Prongs Creek Formation (no maturity information); 2) the lower Palaeozoic Canol Formation (Type II and III, TOC up to 9%; currently overmature for oil); 3) the upper Palaeozoic Ford Lake Formation (Type II and III, TOC up to 4%; currently mature for oil and the most likely source of the Chance oil); 4) the upper Carboniferous shales and organic-rich carbonates of the Blackie Formation (Type II and III, TOC up to 5%; marginally mature for oil), and 5) the Albian shales of the Whitestone River Formation (Type II and III, marginally mature). Minor source rock potential may exist in shales of the Imperial (Type III, TOC less than 1% and Jungle Creek formations (no maturity data).

Gas discovered to date has been 75 to 85% methane with minor amounts of CO₂, N₂ and liquids. Oil discovered to date has been a low sulphur, 29° to 37° API crude.

Potential

Potential is high for further discoveries in upper Palaeozoic stratigraphic and sub-unconformity traps along the crest of folds in southern Eagle Plain. In this region several subsurface thrust-folds remain to be
delineated and further possibilities exist down the plunge of already drilled structures. Also, but with greater risk, there are structurally reversed basinward facies changes within the Hart River and Jungle Creek formations between the Blackie area and the outcrop belts in the Ogilvie Mountains.

Potential exists in the carbonate to shale facies transition zone in lower Paleozoic carbonate sequences in the northeastern part of the basin. Porosity development and preservation is the principal risk in this play and the carbonate fronts themselves require better delineation. The highest potential for both oil and gas is in the southern portion of the basin on either side of the Dempster highway.

**Key Reading and References**


The Whitehorse Basin contains variably preserved Mesozoic strata in a highly structured intermontane setting. Reefs and associated carbonates, and deltaic sandstones have potential for porosity development in the subsurface; shales and fine grained volcaniclastic rocks have sealing potential, and several potential source rocks have been identified. Surface anticlines are possible drilling targets, although the high density of faulting complicates structural definition in the subsurface. Maturity levels are high within the axial part of the basin, but drop to within the gas window towards the flanks of the basin. Oil potential is minor.

**Geological Setting** (Fig. 32)

The Whitehorse Basin lies within the Intermontane Belt of the North American Cordillera. The basin fill consists of Mesozoic volcanic and sedimentary rocks of an allochthonous terrane - Stikinia - which attached to the margin of ancient North America during the mid-Jurassic. The basin is sandwiched between igneous rocks of the older Omineca to the east and the younger Coastal Plutonic Belt to the west.

Sediments of the basin were deposited in a back-arc setting with the volcanic island arc to the southwest. Thick sequences of Triassic volcanic and volcaniclastic rocks were deposited close to the emergent arc, yet areas of the basin were sufficiently remote from clastic input or favourably situated in the oceanic circulation to favour the growth of reefs. In the early Jurassic, the emplacement and un-roofing of granitic plutons accompanied accelerated subsidence in the basin and the deposition of thick sequences of fan-conglomerates and volcaniclastics.

Uplift and compression at the beginning of the Cretaceous ended sediment accumulation in the basin. Paleomagnetic evidence suggests subsequent northward movement of the Stikine terrane relative to the North American continent in the Late Cretaceous and early Tertiary (although estimates of the amount of northward displacement are poorly constrained by the data). Shear stress generated during displacement of the basin caused extensive jointing and faulting, and much of the western and southwestern basin suffered intrusion by plutonic rocks over this period.
Figure 32. Simplified geological map of the Whitehorse Basin.

Exploration History

Hydrocarbon exploration in the basin has been limited to field geology: most of the stratigraphic section is well exposed within the limits of the basin and surface studies provide a good notion of units to be expected in the subsurface. No seismic lines have been shot nor wells drilled in the basin.

Several coal deposits are known from the basin, principally in the Upper Jurassic and Lower Cretaceous Tantalus Formation. Coals are generally of limited extent as a result of restricted deposition. Rank is variable: one deposit (at Braeburn) is an anthracite. Coals are generally bituminous, of moderate to high volatility. Some deposits may have potential for coal bed methane development, although direct utilization of the coal itself has been the preferred option for local energy sources to date.

Stratigraphy (Fig. 33)

As much as 5 km of sedimentary strata may have been deposited in the basin, but the degree of preservation of this original fill is highly variable. The basin is floored by metasediments of the Yukon Group (Precambrian and younger). These are overlain by upper Paleozoic (Permian and ?Pennsylvanian) volcanic rocks and limestones of the Taku Group. The Mesozoic stratigraphy of the basin comprises three main divisions - the Lewes River Group (Upper Triassic) the younger Laberge group (Jurassic), and the Upper Jurassic to Lower Cretaceous Tantalus Formation. No type sections have been defined for these units and their boundaries are ill defined. The Lewes and Laberge groups do not appear to be separated by any major discontinuity.

1) Lewes River Group. The Povoas Formation at the base of the group comprises basalts and volcanic breccia, metamorphosed to schist in the Carmacks area. The volcanic rocks are overlain by the Aksala Formation, divided into three members. In the Laberge area, the Casca Member consists of calcareous greywacke and sandstone, interbedded bioclastic limestone and argillaceous limestone, and minor conglomerate and agglomerate. The Hancock Member is a carbonate unit comprising thick limestones and minor argillaceous limestones. Reef growth occurred where substrate and turbidity permitted. Reefs may be stacked or merge laterally to cause major variations in thickness. The northeastern side of the reefs is typically steep and faced by greywacke and limestone boulders from the reef margin. The southwestern margin of the reefs grade into bioclastic sands deposited in
shallow-water lagoons, and farther west, closer to
the shores of the island arc, into, quartzose
sandstones. The Mandanna Member consists of red
greywacke and pebble conglomerate. The unit may
represent shallowing in the basin and exposure of
reef tops.

The Lewes River Group outcrops along the trend of
the Povoas Anticline east of Lake Laberge and in a
broad band crossing the central basin at the latitude
of Whitehorse. It is presumably present in the
subsurface beneath the outcrop of younger Laberge
strata. Over 2000 m of strata are present.

2) The Laberge Group represents a major progradation
of clastic material from the developing island arc,
which inhibited further reef development in the
basin. Deep-water silty shales with minor
conglomerate, and more proximal arkosic sand-
stones of the Richthofen Formation are overlain by
thick conglomerates of the Conglomerate
Formation, tuffs of the Nordenskold Formation, and
coarse grained arkosic sandstones of the Tanglefoot
Formation. The Laberge Group outcrops
to the north and west of Lake Laberge and
southwest of Whitehorse. Over 2000 m of
strata are present.

3) The Tantalus Formation overlies the Laberge Group
above an angular unconformity. Its chert-rich
conglomerates and sandstones are distinctly
different from the granite-derived clasts of the
underlying strata. Tantalus sediments were
deposited on a broad coastal plain, possibly within
an enclosed basin removed from marine influence.
Rocks are conglomeratic sandstones, deltaic
sandstones and coals, which may have been
derived from both eastern and western margins of
the basin. The Tantalus is preserved as small
outliers in the northern part of the basin, with the
most extensive outcrop in the Carmacks area.
About 750 m of strata are present.

Potential Reservoirs

1) Sandstones and conglomeratic sandstones of the
Laberge Group. The proximal facies of the
Richthofen, the Conglomerate and Tanglefoot
formations have potential for subsurface porosity as
a result of feldspar dissolution.

2) Reef carbonates and associated clastic facies of the
Lewes River Group. The well exposed reef complex
at Lime Peak (east of Lake Laberge) is 250 m thick
and has been mapped laterally for 3 km. The reefs,
inter-reef limestone conglomerates and carbonate
sandstones, have the potential to develop porosity
in the subsurface. Laterally equivalent carbonate
and relatively mature quartz-feldspathic
sandstones are additional potential reservoirs and
may be more extensive in the subsurface than the
reefs themselves.

Porosity and permeability may be enhanced through
fracturing in all of these units.

Structure, Traps and Seal

The principal trend of fold axes and faults is
northwesterly, parallel to the basin-bounding faults and
at right angles to the direction of principal compression.
However, post-compressional shear has imposed high
densities of subsidiary faults at diverse orientations on
most of the original structures.

Surface mapping has delineated a series of faulted
anticlines within the basin. Mesozoic cover is deeply
truncated across the more prominent anticlines and
there is high risk of reservoir breaching, particularly in
the Laberge Group. The deeper structure of the basin
can only be inferred: however, it is likely that structural
traps with no surface expression exist in the subsurface.

Reservoir properties may be enhanced by fracturing
but the integrity of potential seals is likely to have been
lessened. The Richthofen shales may form an effective
seal above the Lewes River Group. Seals are likely to be
scarce in the proximal sandstone facies that charac-
terizes the Laberge Group in the southwestern part of
the basin. Fine grained volcaniclastic rocks are potential
seals and recur throughout the Mesozoic succession. In
general there is a high risk of seal failure in this highly
structured and repeatedly stressed basin.

Source Rocks

A number of oil seeps have been reported from the
region. Limited sampling suggests that these were spills
of refined products and not geological oil. Surface gas
seeps have also been inferred from the reports of
“fireballs” ignited by the hot exhausts of passing traffic.
A biogenic origin for the gas seems the most probable
explanation for this phenomenon.

Templeman-Kluit (1978) noted that the back-reef
facies of the Lewes River Group are locally bituminous
and may be potential sources of hydrocarbon
accumulations in the associated reefs and shoal clastic
facies, given a suitable cap rock. Limited geochemical
sampling and analysis of shales within the major stratigraphic units of the basin have shown the Aksala Formation of the Lewes River Group to be lean in organic carbon and a fair source of gas at best. The Jurassic/Cretaceous Tantalus Formation has Total Organic Carbon content (TOC) values in excess of 1% in the northeastern and southwestern parts of the Whitehorse basin. Both oil and gas potential is possible. The Jurassic Richthofen Formation has TOC over 1% in the western part of the basin but with gas potential only. All potential source rocks appear to be over-mature along the central axis of the basin (reflecting deepest burial?) but within the gas generation window towards the flanks of the basin. The Tantalus Formation at surface falls within the oil window on the basis of limited vitrinite reflectance measurements.

Potential

The basin has low to moderate potential for conventional gas accumulations, and exploration in this highly structured area with discontinuous and unproven reservoirs must be considered high risk. Surface anticlines are obvious targets for a first phase of drilling where potential reservoir units have not been breached. Oil potential appears to be minor in the absence of regionally extensive oil-prone source rocks and the high levels of maturity. Coal seams offer some possibility for exploitation of coal-bed methane.

Key Reading and References


**KANDIK BASIN**

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<th>Parameter</th>
<th>Description</th>
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<tbody>
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<td>Age</td>
<td>Palaeozoic to Cretaceous; Quaternary cover</td>
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<td>Depth to Target Zones</td>
<td>2500-4500 m</td>
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<tr>
<td>Maximum Basin Thickness</td>
<td>Up to 5500 m of Mesozoic rocks</td>
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<td>Hydrocarbon Shows</td>
<td>Surface: dead oil in Triassic shales and Paleozoic limestones; Subsurface: oil staining and minor gas shows, bitumen</td>
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<td>First Discovery</td>
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<td>Depositional Setting</td>
<td>Shallow-water carbonate and clastic shelf</td>
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<td>Potential Reservoirs</td>
<td>Carbonate reef mounds and facies fronts; fractured carbonates; sandstone lenses</td>
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<td>Regional Structure</td>
<td>Long wavelength open folds; minor expansion faults; thrusting in southern portion of basin</td>
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<td>Marine shales and tight carbonates</td>
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<td>Source Rocks</td>
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<td>Depth to Oil/Gas Windows</td>
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<td>Total Number of Wells</td>
<td>1 in US; none in Canada (3 wells in outcrop belt east of basin)</td>
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<td>Seismic Coverage</td>
<td>Approximately 200 km along basin margins in Canada (all pre-1980)</td>
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<td>Area</td>
<td>9209 km² (83% in Alaska)</td>
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<td>Area under Licence</td>
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The Kandik Basin is in the early stages of exploration. There is potential for small to moderate sized oil and gas pools in Lower Cretaceous to Upper Devonian and upper Proterozoic sandstones in combined structural-unconformity and thrust-related traps. Triassic, Permian, Carboniferous and Paleozoic carbonates have the potential for stratigraphic traps.

**Geological Setting**  (Fig. 34)

The Kandik Basin is a Paleozoic-Mesozoic basin preserved within the Cordillera. It straddles the Yukon/Alaska border, 907 km southeast of Prudhoe Bay and 2600 km northwest of Calgary. The extent of Mesozoic sediments delimits the basin, which is surrounded by outcrop belts of unmetamorphosed Precambrian and Palaeozoic rocks. The basin underwent east-west compression in the Late Cretaceous and Tertiary, resulting in uplift and the development of thrust-folds.

**Exploration History**

Petroleum exploration in the Canadian portion of the basin began in 1970 with the drilling of the INC Husky Amoco Blackfly YT M-55 well near the eastern margin of the basin. The M-55 well was spudded on Blackfly Dome in Permian Jungle Creek sandstone. The well drilled to a total depth of 2070 m, ending in Devonian to Carboniferous Ford Lake shales. Inexco Husky et al. Porcupine YT G-31 (1972) penetrated 2658 m to upper Proterozoic Tinder Group sediments. The most recent well drilled in Canada (also in 1972) was Inexco et al.
Mallard Y.T. O-18, which was drilled on a thrust-faulted anticline with Carboniferous Hart River strata exposed at surface. The well penetrated 3200 m of fault-repeated Hart River strata. None of these wells encountered hydrocarbons.

In addition, one well has been drilled in the Alaska portion of the basin. In 1976, Louisiana Land and Exploration No. 1 drilled 3367 m to the Permian Jungle Creek Formation. It did not encounter commercial hydrocarbons, but dead oil and oil staining was noted in the cuttings and several gas “kicks” were encountered while drilling. In 1977, two additional wells (Louisiana Land and Exploration No. 2 and 3) were drilled in the shallower Yukon Flats Basin to the north of the Kandik Basin. Both failed to encounter hydrocarbons.

**Stratigraphy (Figs. 35, 36)**

The Kandik Basin contains over 11 km of Paleozoic to Recent strata confined by Precambrian to Permian outcrop around the basin margin.

The upper Proterozoic Tindir Group is composed of deep-water diamictites, clastics, dolomites and siliceous limestones. These strata are unconformably overlain by a series of carbonate/shale cycles in the Paleozoic. The first cycle is represented by dolomitic limestones of the Jones Ridge Formation (Cambrian-Ordovician), which unconformably overlie the Tindir Group, and by the Road River shales (Ordovician-Silurian). The second cycle is represented by Devonian platform dolomites and limestones of the Ogilvie Formation and by cherty shales of the McCann Hill Formation (in Alaska) and the Canol shale (in Canada).

During the Late Devonian, sedimentation on the Paleozoic shelf became dominated by clastics with
deposition of the Nation River Formation in the west and thick Ford Lake shales in the east. Carbonate sedimentation resumed during the Mississippian in the eastern basin with the deposition of the Hart River Formation, contemporaneously with bituminous calcareous shales and shaly limestones of the Calico Bluff Formation. Another cycle is represented by shaly clastics of the Lower to Upper Carboniferous Blackie Formation and cherty limestones and dolomites of the Upper Carboniferous Ettrain Formation, which conformably overlie Hart River and Calico Bluff strata.

The Ettrain/Blackie package is overlain by calcareous sandstones of the Permian Jungle Creek Formation, and by Upper Permian argillaceous, cherty limestones of the Tahkandit Formation. The Tahkandit strata grade westward into coarse limey clastics of the Step Formation.

A major unconformity separates the Tahkandit/Step strata from the overlying upper Triassic Shublik limestone and its western equivalent - the organic-rich "oil" shales of the Glenn Formation. Thick shales of the Jurassic Kingak Formation unconformably overlie Triassic strata. These, in turn, are overlain by Cretaceous strata composed of recurrent clastic wedges separated by unconformities. The Cretaceous strata include sandstones and shaly siltstones of the Martin Creek, Kamik, Mount Goodenough and Kathul formations, and conglomeratic sandstones of the Monster Formation. Unconformably overlying the Cretaceous are Quaternary to Recent alluvial sediments.

**Potential Reservoirs**

Potential for reservoir development exists in the following horizons:

1) Tahkandit Formation limestones. In the Alaska portion of the basin, these strata show local porous zones containing a dark brown oil stain.

2) Jungle Creek (Calico Bluff) calcareous sandstones. In the Alaska portion of the basin these strata have yielded a pale reddish brown oil cut.

3) Ettrain Formation. Within the Kandik Basin the Ettrain limestones are almost twice as thick as those in the Eagle Plain Basin.

4) Hart River Formation limestones and calcareous sandstones.
5) Ogilvie Formation. Reefal carbonates have good porosity and permeability in outcrop along the Porcupine River in Alaska. Fractures and vugs within the formation have yielded a pale greenish brown oil cut.

6) Jones Ridge Formation. Limestones and argillites show good porosity and permeability in outcrop and have yielded a dark brown oil cut.

7) Limestones and sandstones of the uppermost Tindir Group with sufficient fracture porosity could contain hydrocarbons.

Discoveries of hydrocarbons have been made in the Jungle Creek and Hart River formations in the Eagle Plain Basin. Minor gas shows have also been noted from the Ettrain and Ogilvie formations.

**Structure, Traps and Seal**

The Kandik Basin was pervasively folded and faulted during the Late Cretaceous to Tertiary. Fold axes trend northeastward and relate to wrench movement along the Tintina Fault zone at the southern margin of the basin. Proterozoic and Paleozoic rocks form broad open folds with little fracturing along the hinge lines while Mesozoic and Cenozoic rocks form tight isoclinal folds with fractured hinge lines and steep, commonly overturned limbs.

At least two orthogonal sets of Cretaceous or younger high-angle faults are present within the basin. Low-angle thrust faults have been mapped in the Canadian portion of the basin making over-thrust traps a possibility in this area.

Shales of the Mount Goodenough, McGuire, Kingak, and Ford Lake formations are potential seals for Carboniferous and Cretaceous units. Facies transitions from carbonate to shale (Ogilvie/McCann and Ettrain/Blackie) and from sandstone to shale (Nation River/Ford Lake) are potential lateral seals for lower Paleozoic units. The Canol and upper Road River shales, although relatively thin, could act as top seals for Middle Devonian and older reservoirs. The Lower Cretaceous Kingak Formation could form a regional top seal for reservoirs truncated by the sub-Jurassic unconformity.

**Source Rocks**

Geochemistry indicates that Middle Devonian to Lower Cretaceous source rocks are mature to overmature for oil. Three source rocks have been identified within the Kandik Basin. These are type II and III kerogen-rich shales of the Canol Formation with TOCs up to 7%; type I and II kerogen-rich shales of the upper Road River Formation with TOCs up to 5% and the Mount Goodenough Formation type II and III kerogen-rich shales with TOCs up to 2%.

In addition to the above, four other possible source rocks are suggested by high visual estimates of organic content. These are: the limestones of the Tindir Group; the limestones of the lower and upper Jones Ridge; the cherty shales of the McCann Hill Formation, and the organic-rich “oil shales” of the lower Glenn Formation.

Two additional potential source rocks are suggested by analogy with the Eagle Plain Basin. Both the Ford Lake and Blackie formations contain type II and III kerogen but may be overmature for oil in the Kandik Basin.

**Potential**

The geology of the Kandik Basin is comparable with the neighbouring Eagle Plain Basin in which several oil and gas discoveries have been made. Similar stratigraphy and trap styles suggest moderate to high potential for discoveries in upper Paleozoic to Mesozoic rocks, particularly in stratigraphic and sub-unconformity traps along the crest of folds and associated with faults. In the Canadian portion of the Kandik Basin, over-thrust traps are an additional possibility. Additional plays, but more risky, are structural/stratigraphic traps associated with facies changes. Lower Paleozoic potential may exist in the carbonate to shale transition zones in the Cambrian through Devonian carbonate sequences.

The high exploration risk for plays in the basin relates to reservoir facies development, porosity preservation, source rock maturity, and timing of migration to coincide with Cretaceous tectonics.
Key Reading and References


Figure 37. The ancestral (diagonal plus vertical patterns) and preserved (vertical pattern) Bonnet Plume Basin (after Norris and Hopkins, 1977).

Figure 38. Schematic cross-section, Bonnet Plume Basin (after Norris and Hopkins, 1977).
### BONNET PLUME BASIN

(Figs. 37, 38)

<table>
<thead>
<tr>
<th>Age</th>
<th>Late Early Cretaceous to Early Tertiary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum Basin Thickness</td>
<td>Up to 700 m(?)</td>
</tr>
<tr>
<td>First Discovery</td>
<td>None</td>
</tr>
<tr>
<td>Basin Type</td>
<td>Intermontane</td>
</tr>
<tr>
<td>Depositional Setting</td>
<td>Alluvial, continental</td>
</tr>
<tr>
<td>Potential Reservoirs</td>
<td>Cretaceous sandstones and conglomerates</td>
</tr>
<tr>
<td>Regional Structure</td>
<td>Block faulting: overthrust at south</td>
</tr>
<tr>
<td>Seals</td>
<td>Intraformational shales, overthrust sheets</td>
</tr>
<tr>
<td>Source Rocks</td>
<td>Subcropping Upper Devonian to Mississippian shales</td>
</tr>
<tr>
<td>Depth to Oil Window</td>
<td>Not known</td>
</tr>
<tr>
<td>Total Number of Wells</td>
<td>None (nearest well is Toltec Peel River YT N-77, drilled in 1970, 20 km to northwest of basin)</td>
</tr>
<tr>
<td>Seismic Coverage</td>
<td>None</td>
</tr>
<tr>
<td>Area</td>
<td>40,000 km²</td>
</tr>
<tr>
<td>Area under Licence</td>
<td>None</td>
</tr>
</tbody>
</table>

Thin Quaternary deposits mask the Albian to ?Paleocene Bonnet Plume Formation, comprising conglomerates and sandstones succeeded by sandstones, shales and lignites. Across most of the basin, the Cretaceous overlies block faulted and deeply truncated Proterozoic rocks. To the southwest, Cretaceous rocks thicken and may overlie possible source rocks of the Paleozoic Road River, Canol and ?Ford Lake formations. The southern margin of the basin is overthrust by Proterozoic and Cambrian rocks creating a high-risk subthrust play in the Wernecke Mountains. With shallow targets, poor seals and only local preservation of possible source rock, overall oil and gas potential must be rated as low.

**Key Reading and Reference**

Figure 39. Geological features of Old Crow Basin and adjacent areas.
# OLD CROW BASIN

(Figs. 39, 40)

<table>
<thead>
<tr>
<th>Age</th>
<th>Tertiary overlying Paleozoic/?Mesozoic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth to Target Zones</td>
<td>1-3 km</td>
</tr>
<tr>
<td>Maximum Basin Thickness</td>
<td>2 km (Tertiary); 4 km ?Mesozoic + Paleozoic</td>
</tr>
<tr>
<td>First Discovery</td>
<td>None</td>
</tr>
<tr>
<td>Basin Type</td>
<td>Tectonically deformed cratonic margin; intermontane basin</td>
</tr>
<tr>
<td>Depositional Setting</td>
<td>Alluvial (Tertiary). Distal marine shelf/basin (Mesozoic). Marine carbonate shelf basin (Paleozoic)</td>
</tr>
<tr>
<td>Potential Reservoirs</td>
<td>Upper Paleozoic carbonates, Mesozoic and Tertiary sandstones</td>
</tr>
<tr>
<td>Regional Structure</td>
<td>Faulted anticlines</td>
</tr>
<tr>
<td>Seals</td>
<td>?Mesozoic marine shales</td>
</tr>
<tr>
<td>Source Rocks</td>
<td>?Carboniferous and Mesozoic shales</td>
</tr>
<tr>
<td>Depth to Oil Window</td>
<td>Tertiary immature; Mesozoic and older rocks overmature for oil</td>
</tr>
<tr>
<td>Total Number of Wells</td>
<td>None</td>
</tr>
<tr>
<td>Seismic Coverage</td>
<td>Approximately 200 km of reconnaissance seismic shot between 1969 and 1972</td>
</tr>
<tr>
<td>Area</td>
<td>75,000 km²</td>
</tr>
<tr>
<td>Area under Licence</td>
<td>None</td>
</tr>
</tbody>
</table>

(Flat terrain of muskeg and lakes. Lightly forested. The sole population centre is at Old Crow (airstrip) with no road access from the Dempster highway.)

A shallow Tertiary basin overlying folded Paleozoic and Mesozoic rocks of the northern Cordilleran foldbelt. The basin is undrilled and potential in the shallow Tertiary section is low (lack of structure, poor seals, immature source rocks). The Mesozoic section is variably preserved in the axes of synclines: sedimentary facies are anticipated to be distal with poor reservoir potential. Paleozoic carbonates have potential for development of fracture enhanced diagenetic porosity, but may be breached across the major anticlines. Paleozoic clastics - if present - are distal equivalents of deltaic sandstones of the Alaska North Slope. Source rock maturation from surrounding outcrop belts suggest that the basin should be gas prone.
Key Reading and Reference


Figure 40. Inferred stratigraphy of Old Crow Basin.