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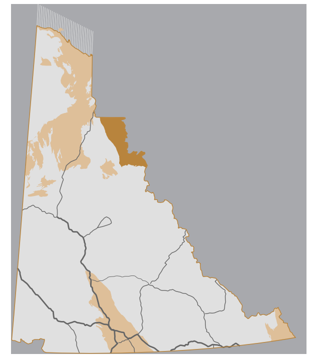
Petroleum Resource Assessment, Peel Plateau and Plain, Yukon Territory, Canada



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Published under the authority of the Minister of Energy, Mines and Resources, Yukon Government

http://www.emr.gov.yk.ca

Printed in Whitehorse, Yukon, 2005.

This report may be obtained from:

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In referring to this publication, please use the following citation:

Osadetz, KG., MacLean, B.C., Morrow, D.W., Dixon, J. and Hannigan, P.K., 2005. Petroleum Resource Assessment, Peel Plateau and Plain, Yukon Territory, Canada. Yukon Geological Survey Open File 2005-3, Geological Survey of Canada Open File 4841, 76 p.

Production by K-L Services, Whitehorse, Yukon.

Cover photo. *Outcropping lower Paleozoic succession, predominantly carbonate rocks, illustrative of the the Ordovician-Silurian Mount Kindle Formation to Devonian Hume Formation succession that occurs in the subsurface of the Peel Plain, at section MTA-82-6 (Morrow, 1999; see his Figure 6, section location #19 and his Figure 41, for details; GSC Calgary photo 4298-13).*

ABSTRACT

The Peel Plateau and Plain in the Yukon is a potentially prospective petroleum province that lies north of the Mackenzie Mountains and east of the Richardson Mountains up to the inter-territorial boundary. The area contains a Lower Cambrian to Upper Cretaceous stratigraphic succession up to approximately 4.5 km thick. Nineteen exploratory wells have been drilled within the region without economic reserves or production, but with some petroleum shows. A probablilistic petroleum resource assessment suggests that there is a significant potential for natural gas throughout the region with a summed mean play potential of approximately 83.428 x 10^9 m^3 initial raw gas in place (~3 Tcf) in approximately 88 pools. The largest expected pool of 3.36 x 10^9 m^3 gas is expected to occur in Mesozoic clastic rocks of the Peel Plain. In general, petroleum potential is inferred to decrease both westward, and with increasing depth and stratigraphic age. The small size of gas pools will be an impediment to their development because of their location. No crude oil potential can be estimated due to an inferred lack of oil-prone sources in strata of suitable maturity. Where previous work speculated that the history of petroleum systems in the Peel Plateau and Plain was distinctive from that of surrounding regions that are suitably characterized, this work finds no justification for such a distinctive petroleum system history. The resulting undiscovered potential is, therefore, considered to be consistent with the results of the exploration history.

EXECUTIVE SUMMARY

The Peel Plateau and Plain in the Yukon (Fig. 1) is a potentially prospective petroleum province that lies north of the Mackenzie Mountains and east of the Richardson Mountains up to the inter-territorial boundary (Table 1). The region contains a Lower Cambrian to Upper Cretaceous stratigraphic succession, up to approximately 4.5 km thick, that overlies a poorly described Proterozoic succession that is currently ascribed as "economic basement". Nineteen exploratory wells have been drilled within the region. None of these wells have established economic reserves or production, but there have been several shows. One surface natural gas seep occurs in the NWT in the contiguous Mackenzie-Peel Shelf geological province. Assessment of this region suggests that there is a significant potential for natural gas throughout the region with a summed mean play potential of approximately 83.428 x 10^9 m^3 initial raw gas in place[1] (~3 Tcf) in approximately 88 pools. The largest expected pool of 3.36 x 10^9 m^3 gas is expected to occur in Mesozoic clastic rocks of the Peel Plain. Likely the small size of gas pools will be an impediment to their development because of their location. In general, petroleum potential is inferred to decrease both westward, and with increasing depth and stratigraphic age. The result of this study, while differing in detail from previous work (Bird, 2000, 1999) for gas, is generally similar in aggregate potential. This study differs significantly from previous studies with respect to crude oil potential. No crude oil potential can be estimated due to an inferred lack of oil-prone sources in strata of suitable maturity. This difference occurs primarily because of a lack of hard data that could be obtained from the available wells if there were time and resources to perform suitable analysis (Rock-Eval/TOC pyrolysis). Where previous work speculated that the history of petroleum systems in the Peel Plateau and Plain was distinctive from that of surrounding regions that are suitably characterized, this work finds no justification for such a distinctive petroleum system history.

The geological outcrop structure is obscured by the monotonous topography and poor outcrop of the Peel Plain physiographic region. Seismic surveys are incomplete and cover only a small portion of the region, with wide spacing. To some degree this means that the lack of exploratory drilling success is not diagnostic of the potential. None of these wells have been characterized geochemically, so that the potential and maturity of petroleum sources must be inferred from regional data, and functioning of the petroleum systems is not known.

The unfavourable results of exploratory drilling in this part of the Yukon are part of a larger unsuccessful effort in the adjacent NWT. Most notable has been the lack of success in the Paleozoic carbonate successions of the Mackenzie-Peel Platforms. The lack of additional exploration during the last quarter century, while largely due to economic considerations, must also consider lack of previous success and the unfavourable geological characteristics, including the following. These successions are dominated by carbonate ramp deposition that results in large stratiform porosity zones following a predominantly vertical succession of facies. While internal stratigraphic traps exist, most carbonate ramp settings rely on a structural component of entrapment.

Two features invoked by a previous assessment, an abrupt margin carbonate depositional model and a hydrothermal dolomitization event were examined and evaluated. There is a small probability for an abrupt carbonate margin play that could be provided by isolated carbonate build-ups growing off the drowned Hume platform, like the Horn Plateau reefs of the NWT. Such reefs, generally limestone, lack porosity because burial compaction by a thick and largely eroded

[1]Note: All gas volumes reported in this assessment is initial raw and in-place.

Table 1. Executive summary of the petroleum potenial of the Peel Plateau and Plain.

Basin age	Proterozoic to Cretaceous with economic basement in the Lower Cambrian
Basin area in Yukon	10 300 km^2
Depth to target zones	Mesozoic: surface to 1000 m Carboniferous: surface to 2500 m Devonian shale: surface to 3500 m Paleozoic carbonate: 1500 m to 4000 m
Maximum Phanerozoic thickness	~4500 m stratigraphic thickness, thickened by Cordilleran thrusting and folding
Hydrocarbon traces	1. Shell Peel River YT B-06 (gas to surface, too small to measure, gas-cut mud) 2. MCD GCO Northrup Taylor Lake YT K-15 (gassy fresh water) 3. Pacific et al. Peel YT F-37 (gassy muddy salt water) 4. Gulf Mobil Caribou YT N-25 (gas-cut mud) 5. Shell Peel River YT M-69 (gas to surface, too small to measure) 6. Swan Lake Surface Gas Seepage (106 N4/1) estimated 700 cf/d (Norris, 1997, p. 383)
First discovery	No discoveries
Potential resources	**Oil:** No potential can be estimated due to an inferred lack of oil-prone sources in strata of suitable maturity. **Gas:** Sum of mean play potentials 83.428 x 10^9 m^3 gas (~3 Tcf) in approximately 88 pools. Largest expected pool of 3.36 x 10^9 m^3 gas is expected to occur in Mesozoic clastic rocks of the Peel Plain. In general, petroleum potential is inferred to decrease both westward and with increasing depth and stratigraphic age.
Basin type	Coupled Cordilleran (Aptian-Eocene) thick-skinned Foreland Thrust and Fold Belt and Foreland basin overlying a Paleozoic succession of Franklinian (Middle Devonian-Carboniferous) flysch/molasse, Taghanic (Upper Silurian to Middle Devonian) Carbonate Platform and Basin deposited on an Early Paleozoic (Lower Cambrian to Lower Silurian) intra-cratonic rift basin.
Depositional setting	Shallow- to deep-water Paleozoic carbonate platform, rift basin and orogenic foreland, and Mesozoic orogenic foreland and clastic shelf.
Potential reservoirs	Basal sandstone and sand bodies within the shale- and siltstone-dominated Mesozoic succession; dolostone and limestone carbonate ramps within the Paleozoic, with possible internal biostromal buildups. There is a slight chance for an abrupt margin carbonate build-up growing off the drowned surface of the Hume Platform, like Horn Plateau reefs.
Regional structure	Thick-skinned and associated thin-skinned Laramide north- and east-verging thrust and fold belt. In the west, the fold and thrust belt is an inversion of extensional fault structures of an early Paleozoic intracratonic rift basin (Richardson Anticlinorium and Trevor Fault). Between the Trevor Fault and the eastern limit of the deformation, just west of the Peel River, the fold and thrust belt incorporates the Paleozoic succession as well as cannibalizing its own Foreland Basin succession. The early Paleozoic intracratonic rift is probably linked to formation of the PaleoPacific margin, but the duration of subsidence indicates that other tectonic mechanisms, not yet elucidated, explain the Upper Ordovician to Carboniferous successions. Large epeirogenic uplift and erosion events of uncertain origin and only roughly known age are responsible for the formation of major erosional surfaces at the present outcrop and top of the Paleozoic succession.
Seals	External: Road River Gp., Canol Formation Imperial Formation; Internal: Paleozoic carbonate ramps, Imperial/Tuttle flysch-foreland succession, Martin House/Arctic Red foreland succession
Petroleum systems	No data available in study region for either source rock potential or thermal maturity. Results from surrounding area suggest a number of potential source rocks in the Paleozoic basinal facies, all of which reached late stages of petroleum generation during burial by the Late Paleozoic succession. Potential sources in the Mesozoic succession, while within the oil window, are inferred dominated by gas-prone organic facies. Organic-rich mid to outer shelf mudrocks, possible oil sources, occur within the Upper Cretaceous succession just north of the study region, in the NWT, but they are situated unfavourably to allow for oil migration into the study area.
Depth to oil/gas window	Based on regional patterns of thermal maturity, the start of the oil window is inferred for surface outcrops of Mesozoic strata in the undeformed Plains, increasing to the outcrop of the over-mature gas zone inferred for the Paleozoic strata in the region west of the Trevor Fault. Still, the region lacks any specific data from outcrops and wells within the study area.
Wells in study area	19 dry and abandoned

later Paleozoic succession. However, there is no reasonable expectation that the region was affected by hydrothermal dolomitization events during the Paleozoic, as the limit of the Manetoe Facies is about 63°N, on the Mackenzie-Peel Shelf. Deep burial in limestone-dominated Paleozoic successions reduces porosity by compaction destroying reservoir potential. The same deep late Paleozoic burial appears, regionally, to have matured potential Paleozoic source rocks and destroyed any Paleozoic oil potential prior to the latest Cordilleran deformation.

The Mesozoic succession is shale- and siltstone-dominated, except for the basal Martin House Formation Sandstone. While the timing for petroleum generation from these strata is favourably related to the timing of the Cordilleran deformation of a foreland succession wherein depositional processes provide many opportunities for internal stratigraphic traps, the sedimentary facies and inferred sources are inferred to be gas-prone. Therefore it is not reasonable to attribute a crude oil potential to any plays within this region without the provision of new, currently missing, organic geochemical data. Such data could be obtained from the existing wells if they were suitably analysed. Both thermogenic and biogenic natural gas generation may have occurred within the Mesozoic succession during the Cordilleran orogeny. The basal Mesozoic sandstone might also have been charged by gas re-migrated from Paleozoic strata by the effects of the Cordilleran deformation.

The combination of depositional and tectonic history indicate that the petroleum potential will be gas-prone, largest in the highest stratigraphic levels and, by analogy to other thrust and fold-belt to Foreland Basin settings, greatest in the undeformed portion of the Foreland Basin. These geological framework considerations influence the definition of plays and assessment regions. Despite the negative characteristics and features of the geological setting and history, the inferred natural gas potential is significant, with gas of ~3 Tcf in approximately 88 pools.

The Peel Plateau and Plain assessment region is divided into three structural and stratigraphic belts that do not coincide with the physiographic boundaries. 1) From the outcrop of the Richardson and Mackenzie mountains, east to the Trevor Fault, is the first assessment region. This region lies primarily in the Peel Plain, but it is underlain by east-verging Cordilleran thrust and fold structures that are similar to those that underlie the Peel Plateau. This assessment region is referred to as the Peel Plateau – West of Trevor Fault. 2) Most of the Peel Plateau and contiguous portions of the Peel Plain lying east of the Trevor Fault but west of the Peel River are also part of the east- and north-verging Cordilleran Thrust and Fold Belt. This assessment area, from the surface trace of the Trevor Fault to the eastern limit of Cordilleran thrusting, is referred to as the Peel Plateau, regardless of the physiography. The carbonate to shale transition of a persistent Paleozoic paleotopographic feature, the Richardson Trough, occurs in the region between the Trevor Fault and the eastern limit of the Cordilleran deformation. 3) East and north of the region affected by Cordilleran diastrophism are the undeformed successions of the Mackenzie-Peel Paleozoic carbonate shelf, also known as the Mackenzie-Peel Platform, which, to the inter-territorial boundary constitutes the third assessment region of this study.

PETROLEUM PLAYS

Peel Plateau – West of Trevor Fault

The total petroleum potential of the Peel Plateau – West of Trevor Fault is small to negligible, as would be expected from its geological history and characteristics. In this region dominated by Paleozoic outcrops, the Cambrian to Devonian succession is composed of Road River and Imperial Formation and equivalents. Dominantly shales, no potential is inferred for the sub-Imperial succession. There is some potential for gas occurrence in the sandy intercalations within the post-Hume equivalent succession, although many of these units are near the surface and the preservation of this potential is a high risk. A single pool of 105 million m^3 initial in-place resource is assessed for the upper Paleozoic (Imperial-Tuttle-Ford Lake succession). This region is the least attractive for petroleum potential in the assessment area.

Peel Plateau – East of Trevor Fault to the Eastern Limit of Cordilleran Deformation

This region contains the temporally and geographically persistent Platform-to-Basin facies transition that marks the eastern margin of the Richardson Trough. This facies transition is unfavourably oriented with respect to the Cordilleran structure to provide a strong trapping mechanism. There is no strong evidence to support a distinctive diagenetic history or events that would help to preserve reservoir quality by way of hydrothermal dolomitization. Therefore, the plays in Paleozoic carbonates of this region will be in Cordilleran structural culminations where vestigial limestone porosity and minor dolostones will constitute potential reservoirs. The potential is for dry, over-mature gas generated by combinations of Foreland and tectonic burial, or for Paleozoic gas re-migrated into Cordilleran structures. The western margin of the Mackenzie-Peel Shelf constitutes a single play within Cordilleran structures. It is expected that the Peel Plateau Cambrian-to-Devonian carbonate margin will consist of about seven gas pools with a mean potential of approximately 4.460×10^9 m^3 gas. The largest expected pool is 1.337×10^9 m^3 gas. Paleozoic clastic rocks have a greater potential for a favourable stratigraphic component of entrapment. They have an improved potential for the preservation of petroleum generated in the Paleozoic. It is expected that the Upper Paleozoic Clastic Play will consist of about two gas pools with a mean potential of approximately 7.799×10^9 m^3 gas. The largest expected pool is 5.517×10^9 m^3 gas. This is the single largest projected pool in this assessment region. This play resembles deep-water sandstone plays on current oceanic margins.

Mesozoic sandstones in the Martin House and Arctic Red formations constitute the third play in the Peel Plateau Cordilleran Thrust and Fold Belt. Although less likely to have large and thick extent, the timing of hydrocarbon generation relative to structure is favourable for Mesozoic-hosted petroleum systems, compared to Paleozoic ones. The Peel Plateau Mesozoic Clastic Play will consist of about 12 gas pools with a mean potential of approximately 13.157×10^9 m^3 gas. The largest expected pool is 2.861×10^9 m^3 gas.

The total potential of the Peel Plateau assessment region, between the Trevor Fault and the eastern limit of Cordilleran deformation, is about 25.4×10^9 m^3 (~0.9 Tcf) gas. This potential is significant, but moderate compared to that of the Peel Plain to the east.

Peel Plain East of the Cordilleran Deformation

The remaining, and most prospective assessment region is the Peel Plain, east of the Cordilleran Deformation Front to the inter-territorial boundary. Five plays occur here. The Cambrian-to-Devonian Carbonate platform, all of which is dominated by carbonate ramp deposition, constitutes the largest volume of rock in any single play. Factors adversely affecting this play include: the style of porosity development and the lack of lateral seals in carbonate ramps, the preservation of reservoir porosity in the absence of pervasive dolomitization, and the timing of hydrocarbon generation relative to structure formation. Throughout the northern Interior Platform there has been a general lack of success drilling to the Hume Formation and the Ronning Group. It is expected that the Peel Plain Carbonate Platform Play will consist of a single pool of probably smaller than 0.218×10^9 m^3 gas.

Manetoe dolostones do not extend north of 63 degrees in the Mackenzie-Peel Shelf. This means that there is no potential in the previous defined Devonian Fractured Arnica Dolomite (Bird, 2000, 1999). Most of the Devonian is in a carbonate ramp setting in the Peel Plain. The one significant opportunity for an abrupt carbonate margin facies model accompanies the persistence of carbonate deposition following the drowning of the Hume Platform. This is similar in configuration to the Horn Plateau Play of the southern NWT. While, this play is not known to exist, neither can it be entirely discounted. It is expected that the Peel Plain Post-Hume Reef play will consist of one single gas pool with a mean potential of approximately 0.888 x 10^9 m^3 gas, should it occur.

Clastic plays in the Upper Paleozoic and Mesozoic section are the equivalent of plays in the same succession of the thrust and fold belt, but within the Interior Platform setting. The Upper Paleozoic Clastic Play of the Peel Plain is expected to have about 9 gas pools with a mean potential of approximately 7.26 x 10^9 m^3 gas. The largest expected pool is 1.352 x 10^9 m^3 gas. The smaller size reflects the small available untested structures of the Plains, and also the more distal setting of this play area relative to the apparent source of these clastic rocks. The Mesozoic Clastic play is expected to consist of about 55 gas pools with a mean potential of approximately 49.487 x 10^9 m^3 gas. The largest expected pool is 3.356 x 10^9 m^3 gas. In total, the Peel Plain region east of the limit of Cordilleran Deformation constitutes the most attractive exploration region within the Peel Plateau and Plain. In total this region could produce 57.907 x 10^9 m^3 gas, or about 70% of the potential in-place resource.

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INTRODUCTION

LOCATION AND PHYSIOGRAPHY

The Peel Plateau assessment region lies in the northeast corner of the Yukon Territory in the region between latitudes 65°N, 67.5°N; longitudes 132°W and 136°W (Figs. 1 and 2). The prospective petroleum basin occurs in the northern three quarters of that quadrangle, north of the Mackenzie Mountains and east of the Richardson Mountains. The study area comprises a prospective region of approximately 10 300 km^2, underlain by a Phanerozoic succession more than 4 km thick. The "Peel Plateau" assessment region includes portions of the Anderson Plain, the Peel Plain, Peel Plateau and the Richardson and Mackenzie Mountains physiographic provinces (Fig. 2). For the purpose of this study, the region is subsequently referred to generally as the Peel Plateau, Peel Plateau and Plain, or the Peel region. The assessment region is geologically and physiographically contiguous with portions of the Anderson and Peel plains and Mackenzie Mountains of the Northwest Territories. Petroleum exploration has occurred in both the Yukon and the Northwest Territories. This assessment captures the experience and data from the NWT portion of the Peel region in the analysis and discussion below. The dashed line on Figure 2 indicates the geographic boundaries of subsequent maps that illustrate the discussion below.

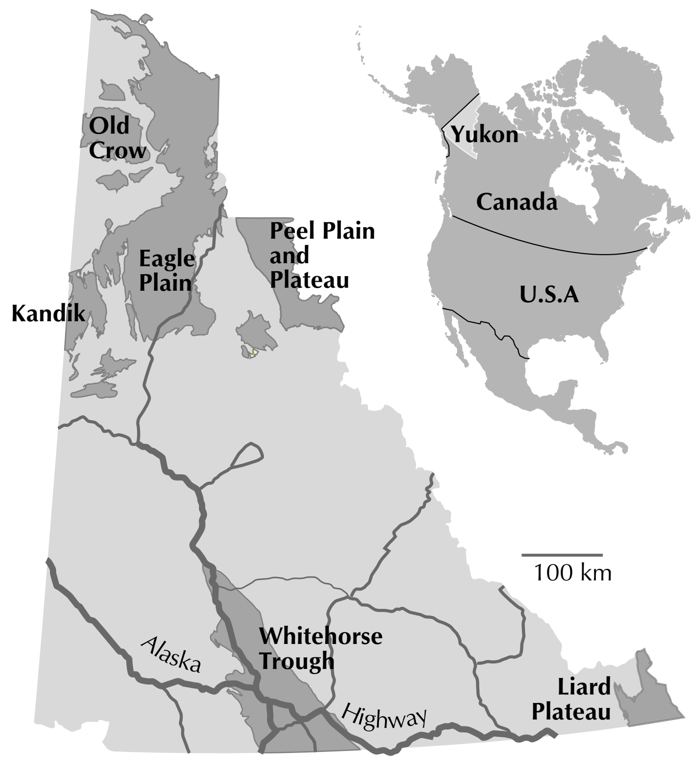


Figure 1. Location map showing the distribution of Yukon's oil and gas regions in relation to Peel Plateau and Plain. Modified from http://www.emr.gov.yk.ca/Publications/OilandGasPublications/yukon_stratigraphic_chart2003.pdf

TECTONO-STRATIGRAPHIC DOMAINS

The physiographic regions of the Peel Plateau assessment region do not follow closely, or provide clear indications of the underlying geological structure. Three structural and stratigraphic belts that do not coincide closely with physiographic subdivisions underlie the region. Within each of these three tectono-stratigraphic domains there are generally similar stratigraphic successions and structural elements with similar tectonic and depositional histories. These similarities unify the petroleum systems and prospects within each of these domains while distinguishing the domains from one another. We employ these internal similarities and external distinctions as the basis for identifying the different petroleum assessment regions defined below.

Peel Plateau West of the Trevor Fault: Within the Richardson Mountains east to the Trevor Fault is a region that is underlain predominantly by Upper Paleozoic and older successions (Figs. 3 and 4). Phanerozoic stratigraphic successions in this region were deposited within the Richardson Trough (Fig. 5), a north-northwest to south-southeast Paleozoic extensional basin that separates the Mackenzie and Peel shelves from elements of the Yukon Stable Block, such as the Porcupine Platform and the Ogilvie Arch. Tectonic controls on the Paleozoic paleogeography result from extensional tectonics that accompanied the formation of the Paleo-Pacific passive margin of the North American craton. Structural inversion of the Richardson Trough during the Laramide orogeny transformed the Richardson Trough into the Richardson Anticlinorium, of which the tectono-stratigraphic domain lying between the older Paleozoic outcrops in the core of Richardson Mountain and the Trevor Fault constitutes its eastern flank. The distinctive tectonic history and stratigraphic successions of this region distinguish it from more easterly portions of the Cordilleran Foreland Thrust and Fold Belt.

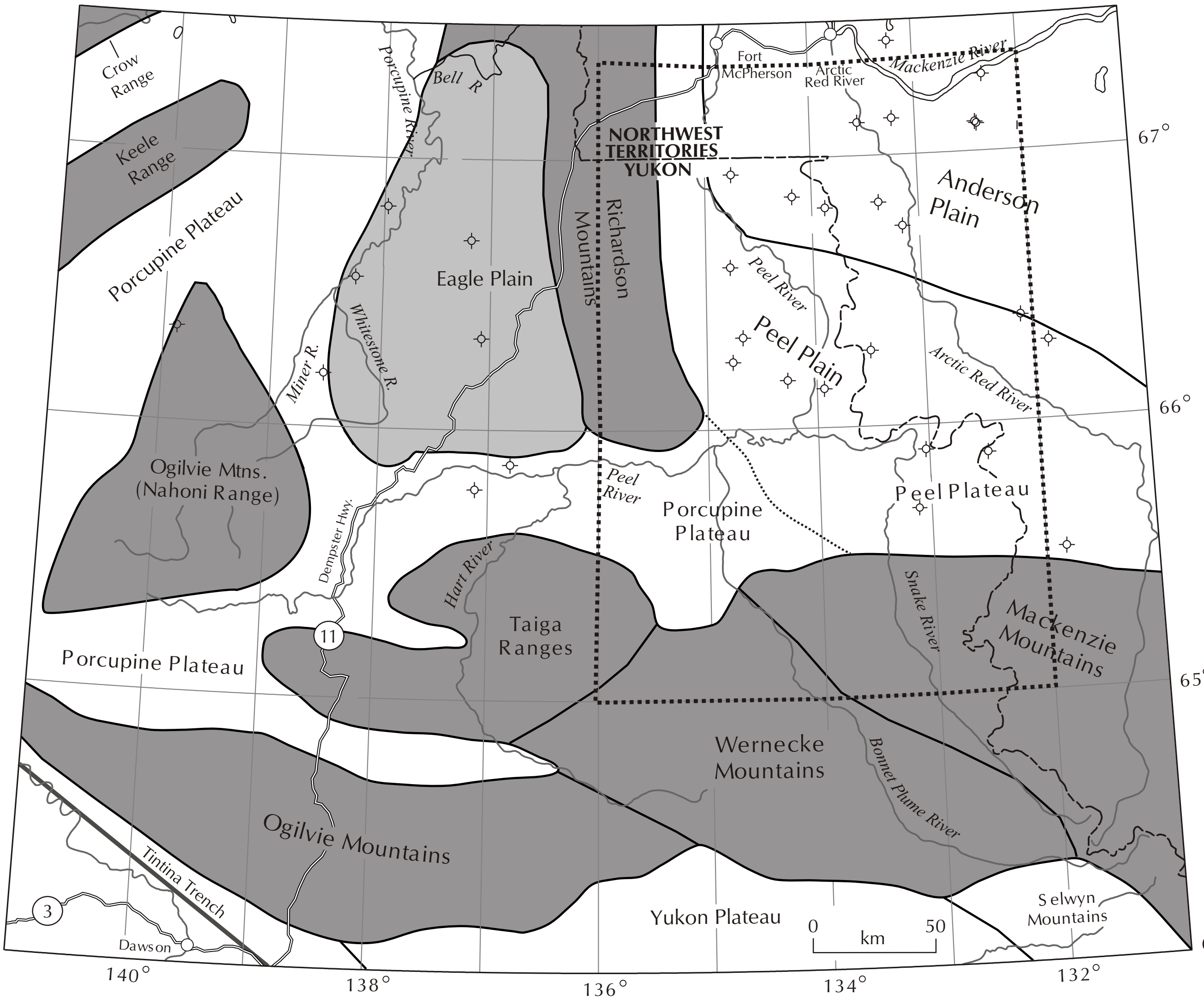
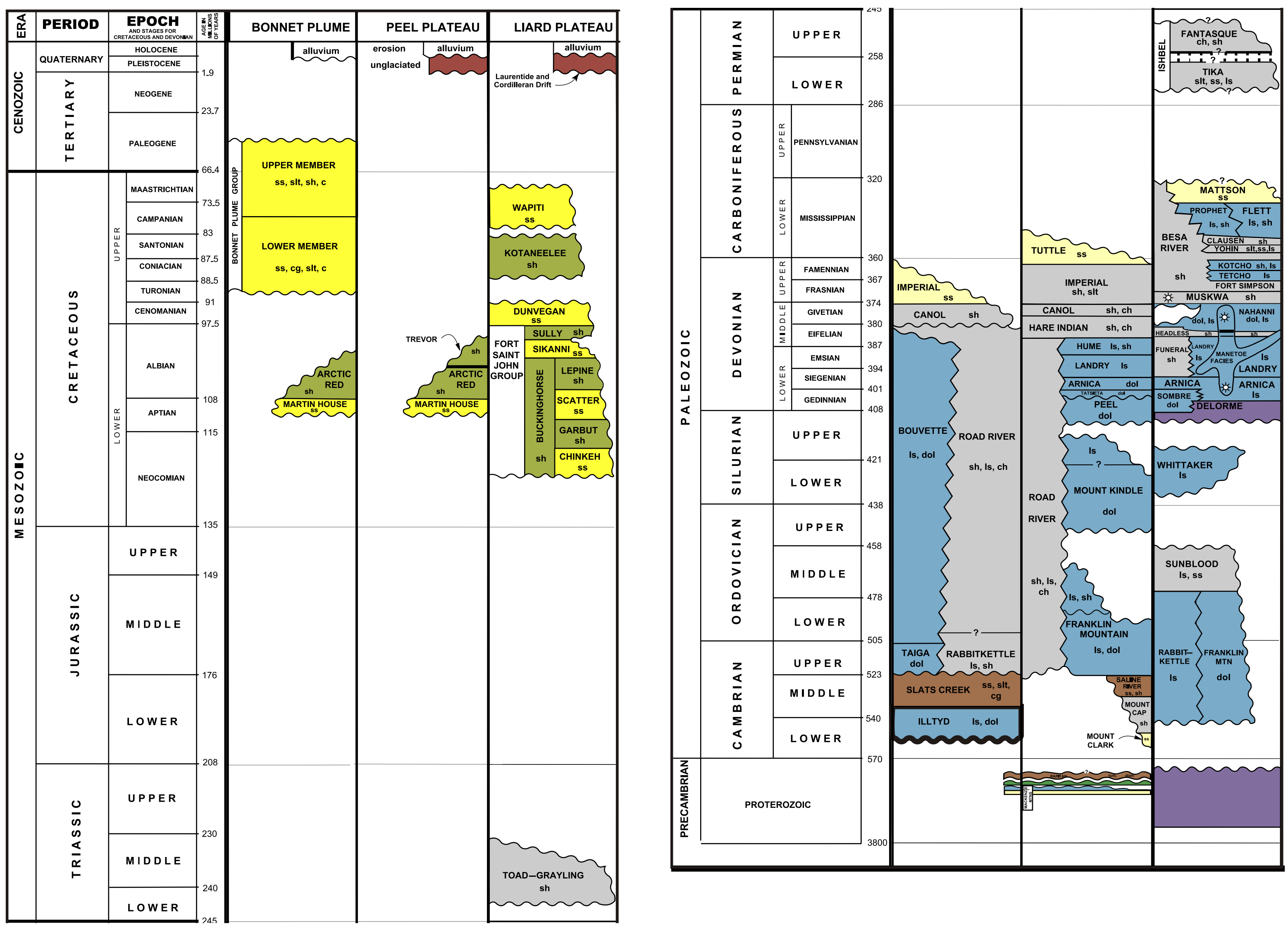


Figure 2. *Major physiographic subdivisions within the Peel Plateau and Plain assessment region including, portions of Anderson Plain, Peel Plateau, Peel Plain, Richardson Mountains and Mackenzie Mountains (from Morrow, 1999). The dashed line indicates the geographic boundaries of subsequent maps.*

Peel Plateau: East of the Trevor Thrust Fault bedrock outcrops are composed generally of Cretaceous Cordilleran Foreland Basin clastic successions that underlie the Peel and Anderson plains (Fig. 4). These rocks are in turn predominantly underlain by Paleozoic platformal successions of the Peel and Mackenzie shelves. Within that region occur both the eastern marginal zone of the Cordilleran Foreland Thrust and Fold Belt, lying predominantly west of the Peel River and south of the sharp elbow in the Cranswick River, and the Interior Platform structural province that extends south contiguously to the American border. The abrupt transition between the Mackenzie-Peel Shelf and the Richardson Trough occurs within the structures of the Foreland Belt eastern marginal domain, where both Paleozoic and Mesozoic succession are involved in east- and north-verging portions of the Cordilleran Foreland Thrust and Fold Belt. Structures within this region are somewhat similar to those in the Liard Plateau, on the southern side of the Mackenzie Mountains structural and physiographic salient. The abrupt margin basin-to-platform facies transition in Paleozoic successions is unfavourably oriented with respect to regional dip for petroleum entrapment prior to the formation of Laramide structural closure. The region also does not contain favourable diagenetic features, like the Manetoe Dolomite in the Liard Plateau, which might enhance the opportunity for petroleum accumulation. This tectono-stratigraphic domain is distinguished by the above-



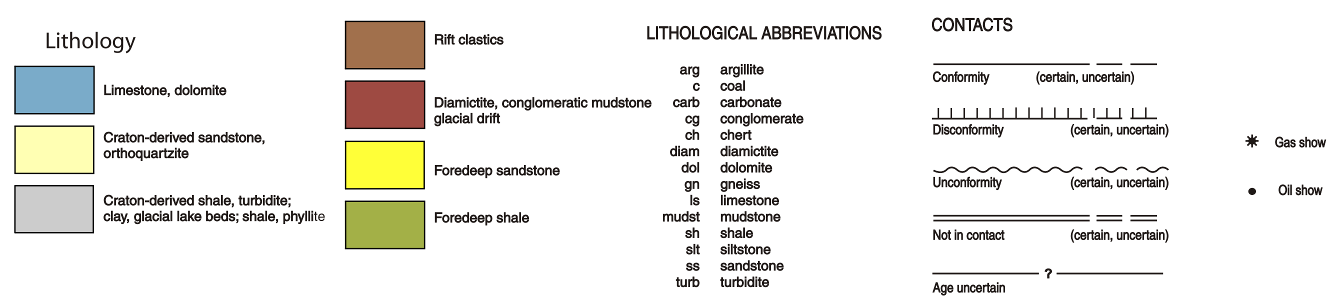


Figure 3. *Time-stratigraphic column of the Peel Plateau showing age relationships of the Phanerozoic succession. Modified from http://www.emr.gov.yk.ca/Publications/OilandGasPublications/yukon_stratigraphic_chart2003.pdf*

mentioned variations in geological history and it constitutes a distinctive assessment region.

Peel Plain: East of major structures of the Cordilleran Foreland Belt, the Phanerozoic succession deposited on the Peel and Mackenzie shelves is part of the Interior Platform structural province. The Peel Shelf is separated from the Mackenzie Shelf by an episodically active gentle epeirogenic feature, the Mackenzie-Peel Arch that lays between the Peel and Arctic Red rivers and which generally separates Yukon portions of the Interior Platform from the Interior Platform in the Northwest Territories (Fig. 5). The stratigraphic successions on both sides of the Mackenzie-Peel Arch are broadly similar and well correlated. The "undeformed" Paleozoic and Mesozoic successions of the Mackenzie-Peel shelves, lying east and north of the region affected by Cordilleran diastrophism, constitute this assessment region.

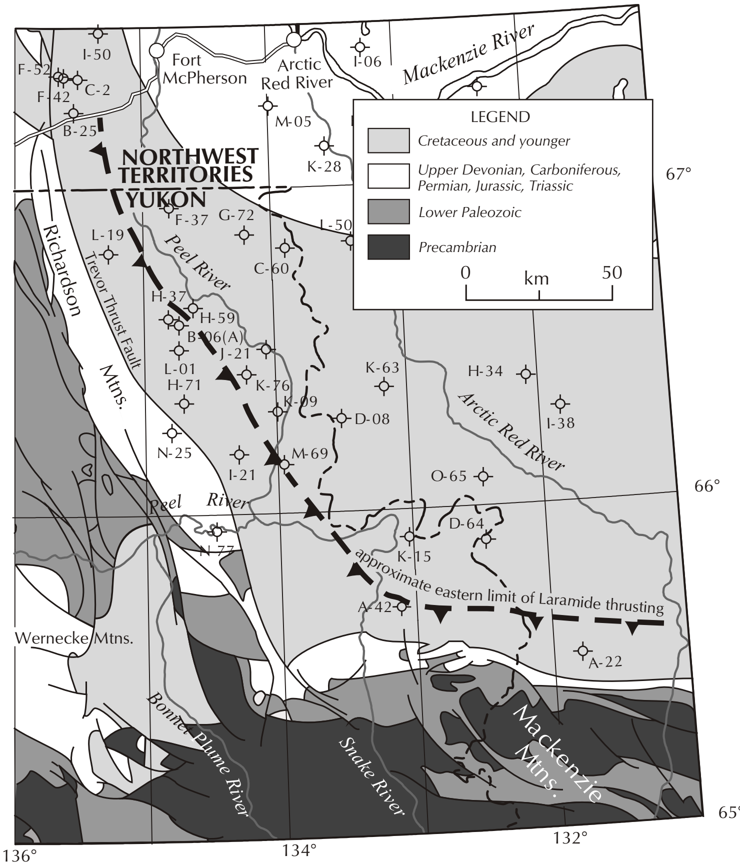


Figure 4. Simplified geological map of the assessment area in the Yukon and adjacent regions of the Northwest Territories. The location of exploratory petroleum wells and the eastern limit of the Cordilleran deformation are also shown (after Morrow, 1999).

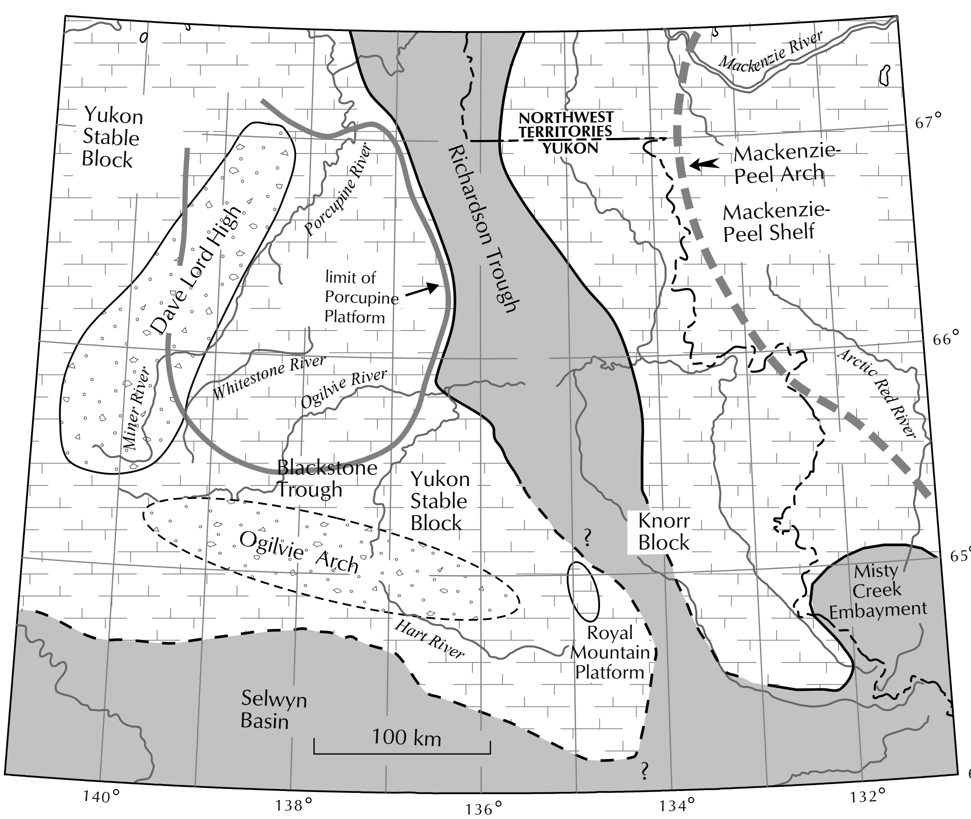


Figure 5. Major early Paleozoic paleogeographic elements that repeatedly influenced Phanerozoic sedimentation and tectonic fabric in the region. Areas of predominantly shallow-water carbonate deposition are filled by a modified brick pattern, while the shaded regions are predominately regions of basinal shale deposition, including the Richardson Trough (after Morrow, 1999).

STRATIGRAPHY

An easterly tapering wedge of Phanerozoic sedimentary rock, more than 4 km thick, that unconformably overlies Proterozoic successions of varying ages and tectonic affinities, underlies the Peel assessment region (Dixon, 1999; Morrow, 1999; Norris, 1997; Kunst, 1973). The Phanerozoic succession is composed of two major, unconformity-bounded, sequences (Fig. 3 and 4). The younger Cretaceous succession, comprising predominantly terrigenous clastic rocks, is up to 1 km thick north of the Mackenzie Mountains and thins to an erosional edge in the vicinity of the Mackenzie River (Dixon, 1999, 1997, 1992). These rocks were deposited in the Foreland Basin of the Cordilleran orogen. The Cretaceous succession unconformably overlies a wedge of westerly thickening Paleozoic sedimentary rocks deposited in a cratonic continental margin and platform setting.

The generally conformable Paleozoic sequence is composed of two major successions. The Lower Cambrian to Devonian succession, predominantly carbonates and shales generally 1800 to 2000 m thick, comprises the abrupt margin succession of the Richardson Trough and Peel-Mackenzie Platform (Morrow, 1999). During the Middle Devonian, the abrupt carbonate platform — basinal clastic facies transition retreated into northern Alberta and British Columbia, drowning and starving the Peel-Mackenzie Platform. During the Late Devonian and Early Carboniferous, the Peel Region was the site of rapid deposition of a southerly prograding, upwardly coarsening basin and offlapping, slope and shelf-shoreface sediments up to approximately 1500 m thick that were probably contiguous with correlative successions in the Eagle Plain (Richards, 1997; Norris, 1984; Pugh, 1983). Permian to lowermost Cretaceous strata are not present in the Peel region, although Lower Cretaceous strata, which were probably overlain by Upper Cretaceous and Tertiary successions of the Cordilleran Foreland Basin, are preserved. Upper Cretaceous and Tertiary successions preserved elsewhere are not present in the study area. Since the end of the Cordilleran orogeny, the region had been a site of non-deposition and erosion.

CAMBRIAN TO LOWER SILURIAN (RONNING GROUP AND OLDER AND EQUIVALENT STRATA)

The Cambrian to Lower Silurian succession comprises strata of the Ronning Group and older strata on the Mackenzie-Peel Shelf and equivalent strata of the Road River Group in the Richardson Trough. The Ronning Group succession is unconformably underlain by generally thin, and variably eroded Cambrian successions of Saline River to Mount Clark formations (formations), predominantly clastic rocks, up to approximately 230 m thick in the Ontaratue H-34 well. However, across much of the Peel Shelf, in the footwall, or lower plate of the large basement-controlled normal faults that bound the eastern side of the Richardson Trough, the Ronning Group sits either on very thin undifferentiated lowermost Paleozoic strata, or directly on Proterozoic successions, similar to outcrop relationships in the Snake River Map Area. Within the Richardson Trough, generally west of the Knorr Fault, but possibly also west of the Trevor Fault, the Ronning Group and Road River Group overlie the Lower and Middle Cambrian Illtyd and Slats Creek formations.

Morrow (1999) interprets the silty limestone and massive dolostones of the Lower Cambrian Illtyd Formation to have been deposited accompanying the initial extension on the Knorr Fault and other, similar, structures that may include the Trevor Fault that formed the Richardson Trough. The conformably overlying Middle Cambrian Slats Creek Formation, predominantly sandstones, were probably derived from the erosion of Proterozoic strata, like Katherine Group, in the footwall of extensional faults bounding the half-grabens on the eastern margin of the Richardson Trough. The Caribou N-25 well penetrates approximately 168 m of Slats Creek Formation (Morrow, 1999), and similar successions to those that outcrop in the Wind River Map area may be present in the area east of the Trevor Fault.

The overlying upper Middle Cambrian to Lower Silurian Ronning Group, mainly ramp and abrupt margin carbonates deposited on the Peel Shelf, passes eastward into the Road River Group, mainly fine carbonate and clastic rocks, in the Richardson Trough. The Ronning Group, up to approximately 1100 m thick, is composed of an internally disconformable succession of Franklin Mountain, Loucheux, and Mount Kindle formations. The Upper Cambrian to Lower Ordovician Franklin Mountain Formation, predominantly dolostones, is composed of three informal members, a basal Cyclic member composed of silty, sandy and shaly dolostones, up to approximately 100 m thick, overlain by the thinly laminated and rhythmically bedded dolostones of the Rhythmic member, which is overlain by the predominantly light brown cherty dolostones of the Cherty or Upper Dolostone member (Fig. 6).

The unconformably overlying Mount Kindle Formation, predominantly dolostones, is up to approximately 443 m thick. It is also composed of lithologically distinctive members, which from the base include a Basal member, predominantly dolostones, overlain by argillaceous dolostones that become less argillaceous up section and which comprise the Middle Resistant member that is, in turn overlain by the Upper member, predominantly dolostones.

Ronning Group ramp and abrupt margin carbonate rocks of the Franklin Mountain and Mount Kindle Formation change facies into fine basinal clastic and carbonate rocks of the Road River Group and its constituent formations in the Richardson Trough. The Franklin Mountain passes westward into the Rabbitkettle Formation, predominantly laminated basinal lime mudstones and argillaceous lime mudstones, of the Road River Group. That facies change occurs somewhere west of the Caribou N-25 well and the outcrops of Rabbitkettle Formation in the Richardson Mountains (Fig. 4). When Mount Kindle Formation deposition began, the basin-platform margin had back-stepped into the region east of the Trevor Fault (Fig. 7), such that the Loucheux Formation, 577 m thick and predominantly calcareous shales, of the Road River Group overlies Franklin Mountain Formation in the Caribou N-25 well (Fig. 8). The correlative basinal deposits of the Road River Group and Formation are up to 1235 m thick in the Caribou N-25 well, but there are more than 2676 m

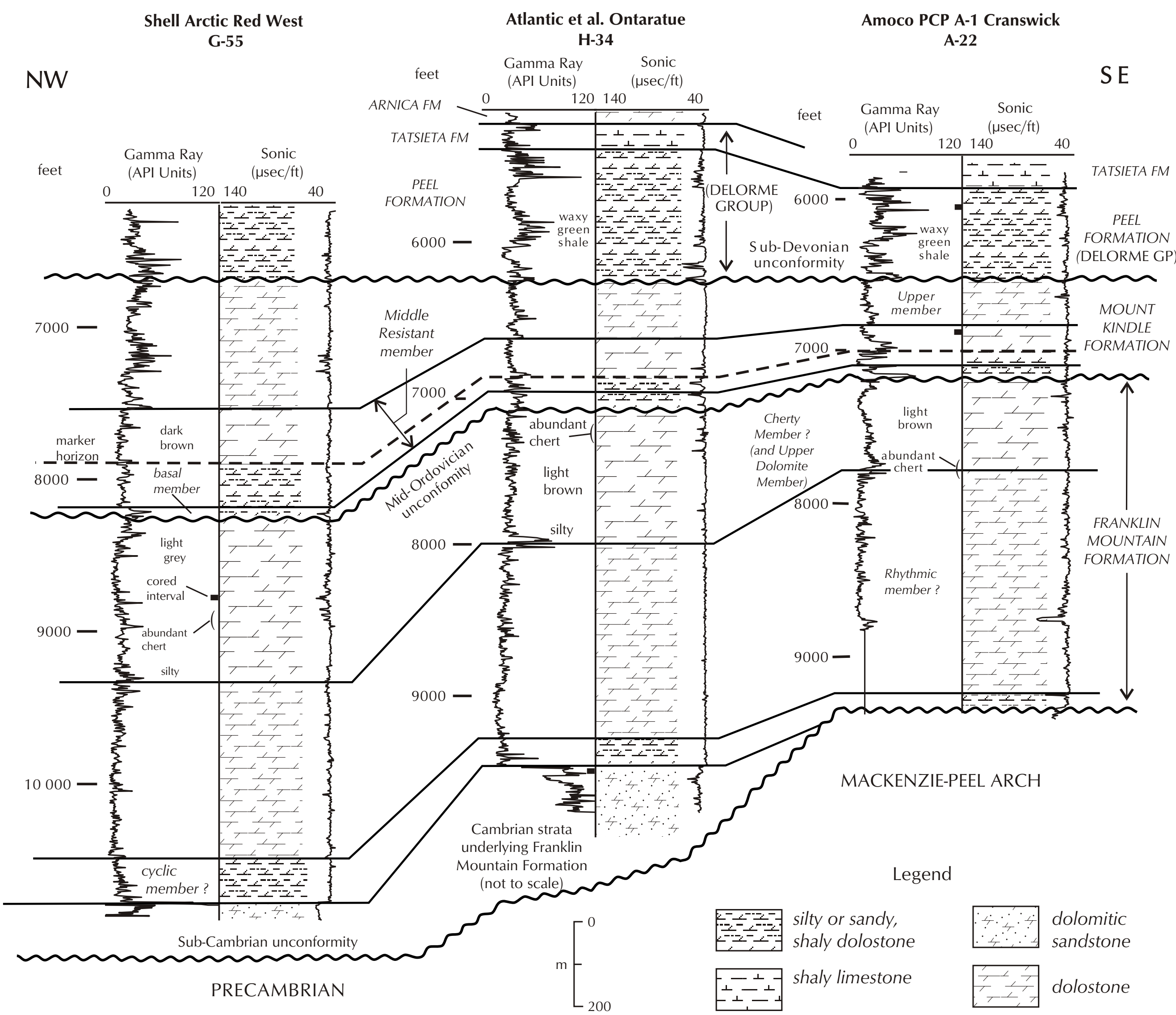


Figure 6. A northwest to southeast stratigraphic cross-section of lower Paleozoic strata across the Mackenzie-Peel Shelf, illustrating the inferred lateral continuity of the stratigraphy of the carbonate platform successions, including the stratigraphic subdivisions of the Franklin Mountain and Mount Kindle formations (from Morrow, 1999). Well locations as indicated in Figures 4 and 15 (p. 20).

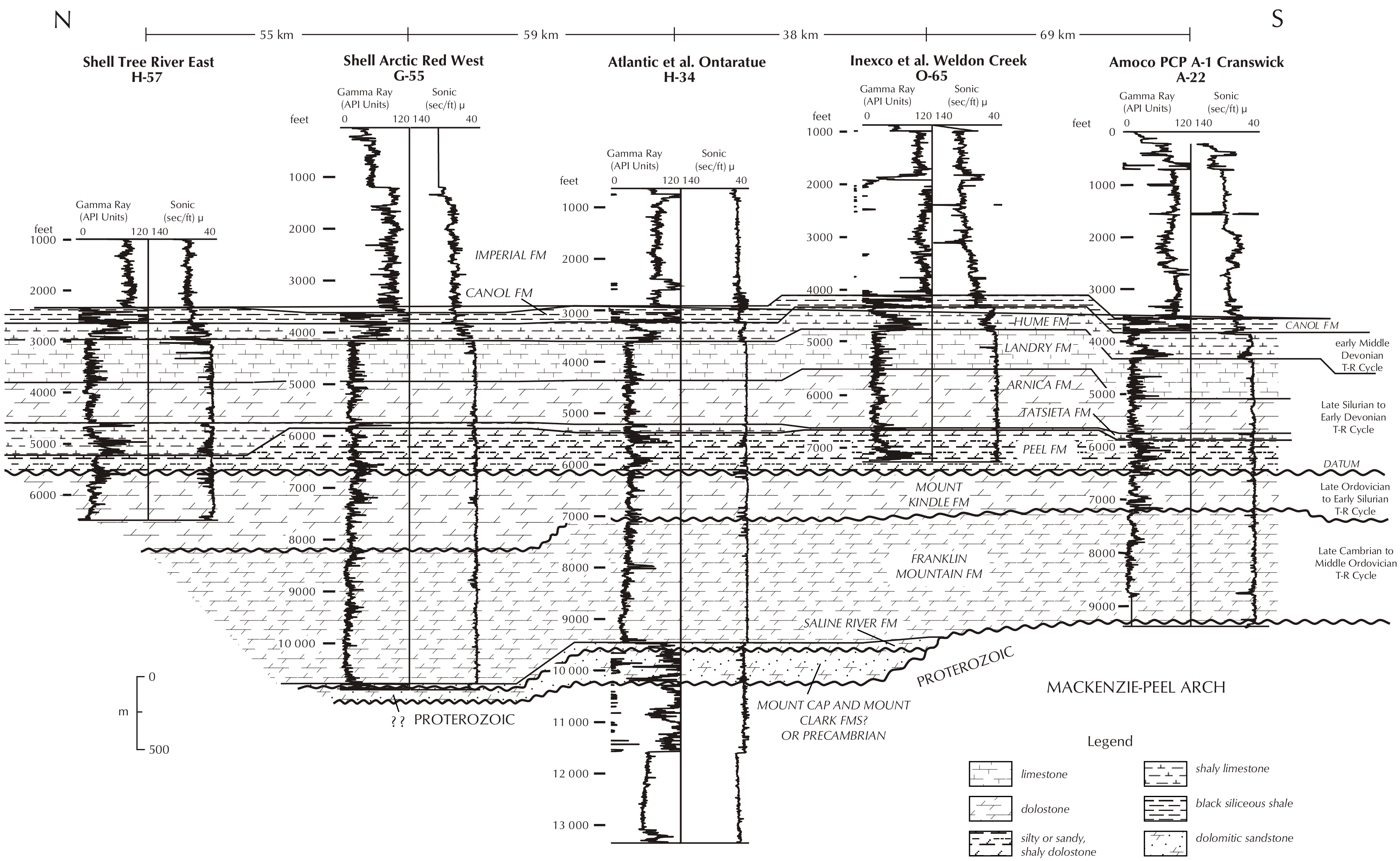


Figure 7. *An north–south cross-section of lower Paleozoic strata across Richardson Trough (from Morrow, 1999). Well locations as indicated in Figures 4 and 15 (p. 20).*

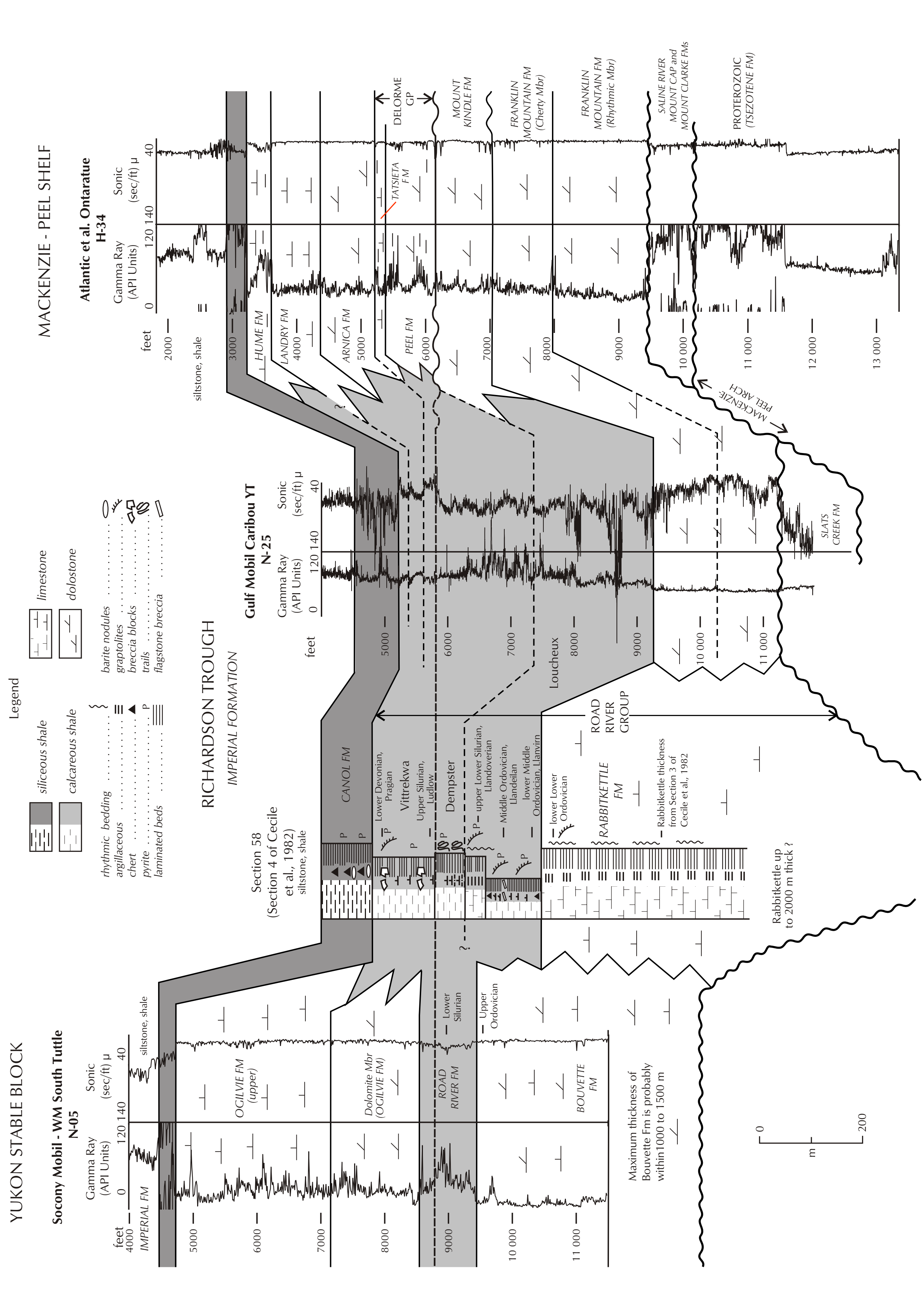


Figure 8. *A north–south stratigraphic cross-section of lower Paleozoic strata across the Mackenzie–Peel Shelf (from Morrow, 1999) that illustrates facies relationships at the margins of the Richardson Trough. Well locations as indicated in Figures 4 and 15 (page 20). FM = formation, Mbr = member*

thick in outcrops on the eastern flank of the Richardson Mountain (Fig. 8). The basin-platform transition remained geographically stable from the onset of Mount Kindle deposition until the Hume Formation platform was drowned by the Canol transgression, indicating a persistent and abrupt carbonate margin from Late Ordovician until Middle Devonian time.

UPPER SILURIAN TO LOWER MIDDLE DEVONIAN

Following a widespread fall in base level in Late Silurian time, the Peel Platform was again transgressed and sedimentation resumed with the deposition of the Delorme Group, predominantly silty and sandy dolostones of the Peel Formation and overlying green shale interbedded with shaley limestones of the Tatsieta Formation (Fig. 8). The Delorme Group is generally between 200 and 300 m thick, but it is up to about 380 m thick in the Peel F-37. The Delorme Group is conformably overlain by the Arnica Formation dolostones which are up to 400 m thick. Arnica dolostones are conformably overlain by Landry Formation predominantly brown pelleted limestone interbedded with the shaly limestones that is generally between 200 and 250 m thick, but up to more than 500 m thick in some wells (Table 1, p. iii). The Hume Formation, predominantly grey argillaceous limestones and calcareous shales cap the succession, generally between 100 and 150 m thick (Table 1). Most is underlain by carbonate-ramp and patch-reef depositional settings, but at the platform-basin transition to the Richardson Trough, an abrupt carbonate margin like the Keg River Barrier existed throughout this interval. Details of this succession are discussed by Morrow (1997). Porous zones occur at several horizons in this succession, but most notably in the Arnica dolostones, as at in the Tree River F-57 well.

UPPER MIDDLE DEVONIAN TO CARBONIFEROUS

In Late Middle Devonian time, a major base-level rise resulted in a major back-step of the abrupt carbonate margin into northern Alberta and British Columbia where the abrupt carbonate margin was re-established as the Keg River barrier reef. The Hume platform on the Peel and Mackenzie shelf was drowned by this event, except where platformal facies persisted as atoll and pinnacle reefs, referred to as Horn Plateau Reefs. Such reefs are have not been identified in the study region, but they may exist, where they could constitute a petroleum play, if reservoir exists.

The preceding assessment (NEB, 2000b) referred to the presence of the Hare Indian Formation, predominantly fine calcareous clastic rocks, within the study area. However, that formation, a distinctive lobe of shale overlying more eastern and southern parts of the Hume Platform, on which Kee Scarp reefs like the one at Norman Wells are rooted, does not occur in the study region. On the Peel Shelf the Hume platform is "drowned" by a major base-level rise and back-step of the carbonate margin. Hume Carbonates and Road River shales are overlain by the Canol Formation shales, generally about 50 m thick, and containing a discontinuously developed bituminous basal limestone facies known as the Bluefish Member, an excellent potential petroleum source rock. It was within this formation that the IOE Tree River H-38 well encountered a significant show of gas.

Subsequently the Peel-Mackenzie Platform and Richardson Trough were the sites of thick deposits from a down-lapping and prograding shelf and slope clastic assemblage, the Imperial Formation. The Imperial Formation was part of a major progradational clastic wedge derived from the north and west, possibly from the Franklinian orogen. The Imperial Formation represents shelf and slope deposits of this succession that are commonly characterized by prominently down-lapping oblique reflections on seismic sections. The Imperial Formation is up to 2000 m thick just north of the east-west segment of the inter-territorial boundary, but it is generally between 1500 and 750 m thick within the assessment region (Norris, 1997; Pugh, 1983). The Imperial Formation becomes sandier westward and northward. The slope and shelf sandstones of this succession are inferred to represent significant opportunities for the structural entrapment of petroleum, following modern analogues on the Gulf Coast and Atlantic margin of the Atlantic Ocean, which are currently among the most active and rewarding petroleum plays.

Shoreface, deltaic and fluvial coarse clastic rocks that conformably and gradationally overlie the Imperial Formation comprise the Tuttle Formation. The Tuttle Formation is part of the prograding clastic wedge depositional system that begins with deposition of the Imperial Formation. Tuttle Formation is between 250 to 1250 m thick within the study region, although has been deeply eroded and is absent both over the Richardson Mountains and east of the Arctic Red River. The subcrop of these sandstones may provide a significant stratigraphic component of entrapment below Cretaceous rocks, where a seal exists. However, it is more likely that the erosional upper surface of Tuttle sandstones presents a preservation risk, or a conduit for petroleum migration into the basal sandstones of the Martin House Formation, that overlies them.

Tuttle Formation sandstones are argillaceous, poorly sorted, and commonly exhibit low porosities and permeabilities. The coarsest sedimentary rocks occur in the Peel F-37 and L-19 wells and grain sizes decrease southward (Pugh, 1983). Reservoir quality follows grain size generally, and it improves southward where the overall argillaceous component of Tuttle Formation sandstones decreases and the discrete shales are interbedded with sandstones. The Tuttle Formation contains thick shale intervals indicative of internal sequence and parasequence boundaries, and the general transition to the Ford Lake shales in the south. Channel sandstone bodies have been observed in fluvial parts of the formation and coarsening-upwards sequences are common in shoreface settings, particularly toward the southwest.

Major clastic depositional wedges are commonly major petroleum systems, and the Tuttle-Imperial sequence is a reasonable depositional analogue to the Heiberg sandstones and Blaa Mountain Shales of the Sverdrup Basin in the Canadian Arctic Archipelago (Chen et al., 2000). Discoveries within the Sverdrup basin include 19 major petroleum fields, comprising 8 oil and 25 gas pools equivalent to 10% and 23%, respectively, of the remaining national reserves of conventional crude oil and natural gas as of January, 1999 (CAPP, 1999). Although it is unlikely that the Peel region will be so prolific (see discussion below), the depositional setting of the Tuttle-Imperial clastic wedge, and its similarity to other productive petroleum systems provides one of the major encouragements within this assessment. Most important to this analogy are recent observations of petroleum preservation in another deeply buried and extensively eroded clastic wedge. Significant indications for petroleum preservation and potential have been recently recognized in the Jurassic and Cretaceous Bowser Lake Group in British Columbia (Hayes et al., 2004; Osadetz et al., 2003). There, despite great burial and high levels of thermal maturity and diagenesis, recent studies have found both “live” oil stains and shows of natural gas, including by-passed pay in a well. These analogues and developments, as well as the focus and success of major exploration efforts in similar prograding clastic wedges provide one of the most important reasons for attributing petroleum potential to the Peel Plateau. Correlative strata in the Eagle Plains basin, west of the Richardson Mountains, host significant petroleum occurrences.

LOWER CRETACEOUS

Unconformably overlying the deeply and differentially eroded Paleozoic succession is a Lower Cretaceous succession composed Aptian and Albian Martin House Formation, predominantly sandstone, Albian Arctic Formation, predominantly shales and siltstones, and the Albian to Turonian Trevor Formation, predominantly sandstones (Dixon, 1999). The succession is up to between approximately 250 m and 1000 m thick in Yukon portions of the Peel Plateau, with the thickest preserved thickness occurring north of the Mackenzie Mountains.

The basal sandstone, Martin House Formation, is between 50 and 125 m thick in the study region, and it is commonly overlain by a succession of finer clastic rocks in the Arctic Red Formation. The Martin House Formation has a basal sandstone member overlain by thinly interbedded siltstone, sandstone, and shale, providing a distinctive response on wireline logs. In the basal member, thick to very thick beds of fine- to medium-grained sandstone grade laterally and locally into thin beds of pebbly sandstone. The overlying member is composed of thin beds of very fine- to fine-grained sandstone. Martin House strata contains a basal transgressive sandstone which was deposited in a shallow-water, marine shelf setting as indicated by hummocky cross-stratification and marine fossils.

The Arctic Red Formation, predominantly marine shale, concretionary or silty shale, and lesser sandstone and siltstone, is approximately 350 m thick at its type section near the confluence of the Peel and Arctic Red rivers. It reaches 1500 m thick in the Arctic Red F-47 well on the Peel Plateau. The section is capped by the Trevor sandstones, which are not sealed from the surface. The seismic section and well log illustrates the Cretaceous succession in the vicinity of the F-47 well. Mountjoy and Chamney (1969) subdivided the Arctic Red into a number of informal local members, but these do not appear to follow subsurface seismic and well log markers that provide informal marker units. The formation may be analogous to the younger Colorado Group in the southern Interior Platform.

The conformably and gradationally overlying Upper Albian to Upper Cretaceous Trevor Formation, predominantly fine- to coarse-grained, locally conglomeratic sandstone interbedded with shale (Mountjoy and Chamney, 1969), extends eastward along the front of the Mackenzie Mountains to Hume River (Yorath and Cook, 1981). In the Arctic Red F-47 the Trevor Formation is composed of coarsening-upward hemicycles. The top of the Trevor Formation is everywhere eroded. In the type area the formation is 360 m thick and this increases eastward to 602 m in the Arctic Red F-47 well (Fig. 9). There is probably a significant disconformity with the formation (Dixon, 1999).

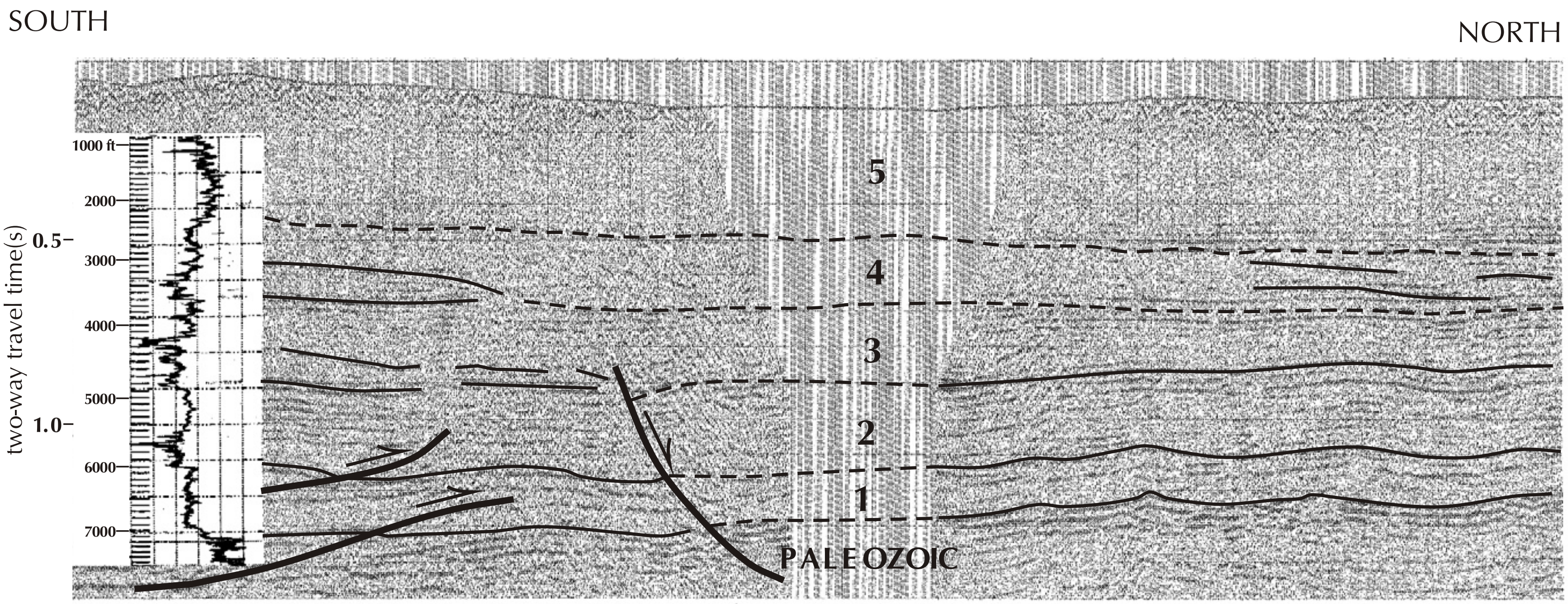


Figure 9. *A Peel Plateau reflection seismic profile that intersects the Arctic Red F-47 well. The section exhibits five seismo-stratigraphic units that are recognized in the Upper Aptian to Albian succession and can be correlated to sonic log markers in the F-47 well. Units 1 to 4 correspond to the Arctic Red Formation and unit 5 to the Trevor Formation (from Dixon, 1999). Well locations as indicated in Figures 4 and 15 (page 20).*

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 will have to appear elsewhere. Previously, the structures of the Peel region were interpreted to result from complicated interactions of structural events and elements strongly linked to the formation of the Amerasian Ocean Basin (Beaufort Sea) (Norris, 1984; 1997).

At regional map scale, the major structural elements include the Richardson Anticlinorium (Fig. 10), a gently north-plunging structure that interacts at its north end with faults interpreted to emanate in the Mackenzie Delta and on the margin of the Amerasian Basin. The eastern flank of the Richardson Anticlinorium is marked by the Trevor Fault, east of which is the broad expanse of the Peel physiographic plain, where no diastrophic structures were mapped at outcrop. Norris (1984, 1997) interpreted the Trevor Fault to have a normal Laramide offset. The Bonnet Plume Basin, with a thick Cretaceous and possibly younger stratigraphic succession, marks the south end of the Richardson Anticlinorium. At this junction, the structural trends turn sharply east in an oroclinal fashion to link with the north-verging structures of the Mackenzie Mountains. Several large, east-trending open folds with hinges more than 40 km long were mapped in Cretaceous strata north of the Mackenzie Mountains, but south of the sharp right-angled eastward bend in the Cranswick River. Norris interpreted the structures to be of variable ages and styles, inferring that the north-verging compressional structures were Early Cretaceous structures of the “Columbian” phase of the Cordilleran Orogen and that the north-south structures, which he erroneously inferred to be extensional, were formed subsequently during the “Laramide” phase of the Cordilleran deformation.

It is suspected that industrial explorers have long known the inadequacies of the structural geometry and kinematics discussed above. Among the first non-industrial geoscientists to notice the true nature of the structure were G. Morrell and M. Fortier of Indian and Northern Affairs Canada, although the analysis has not been published. The scientists, and, to be sure, others recognized that both the north and east trending structures are compressional, and that most of the region west of the Peel River and south of the “elbow” in the Cranswick River are underlain by a

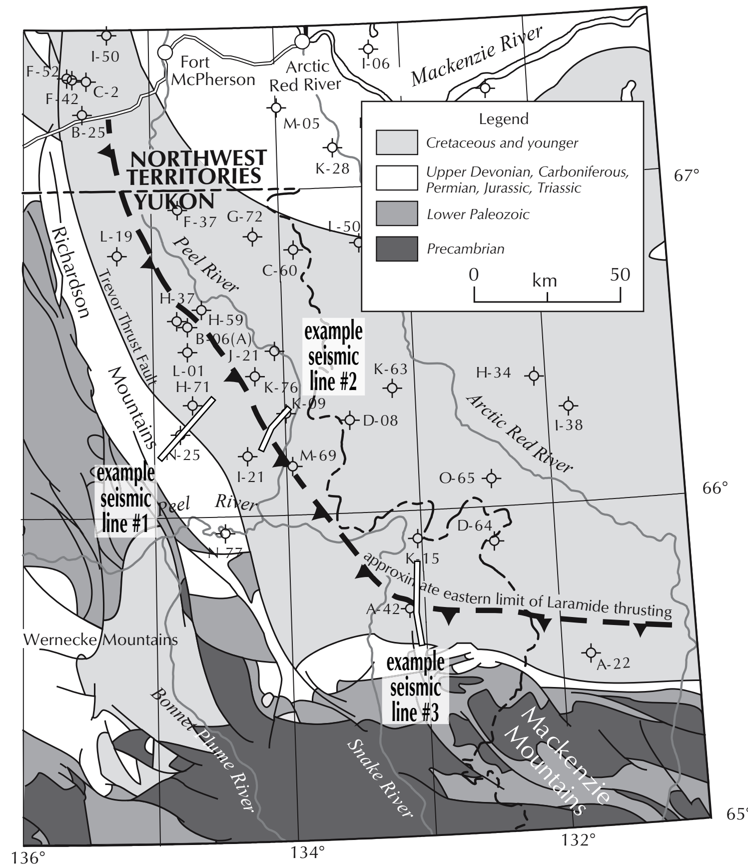


Figure 10. The major structural elements of the Peel Plateau and Plain including the Richardson Anticlinorium. The Anticlinorium is marked by the Trevor Fault, on its eastern side and by the Bonnet Plume Basin in the south. The Figure also illustrates the reflection seismic lines illustrated in Figures 11, 12 and 13. Well locations as indicated in Figures 4 and 15.

north- and east-verging “thick-skinned” thrust and fold belt, the basal detachment of which occurs within the thick Proterozoic succession. The nature of the large reorientation of the thrust and fold belt about the hinge overlain by the Bonnet Plume Basin is not well understood, but it is most probable that the entire north- and east-verging orogen is composed of contemporaneous structures that shorten the Proterozoic and Phanerozoic succession under the controls of Proterozoic and Paleozoic structures that have been reactivated and “inverted” during Cordilleran compressive diastrophism.

The age of the deformation is not well known, but the involvement of the entire Cretaceous succession and the preservation of proximal rudaceous clastic rocks in the Monster Formation suggests that the deformation is temporally and mechanically linked to the Cordilleran orogen south of the Mackenzie Mountains salient. How these structures are linked or affected by the structures of the Mackenzie Delta and the passive margin on the Amerasian Basin has been discussed by Lane (2000), but much detail remains to be described and analysed.

The continuity of the structural style in the Peel Plateau with that of the Cordilleran Orogen to the south suggests that petroleum potential in both the allocthonous tectonic wedge of the Foreland Thrust and Fold Belt and the undeformed Interior Platform could result in an emulation of the effective petroleum systems of the eastern marginal zone, or Foreland Belt of the Cordillera and its adjacent Foreland Basin in the Interior Platform structural province. This would account for the changes in petroleum system thermal history and the variations in structural style due to the changes in mechanical stratigraphy.

For the purposes of this discussion we display and discuss three interpreted reflection seismic profiles (Fig. 10; data and interpretation courtesy of B. MacLean, GSC Calgary). The three structure sections are:

Line 1: A northeasterly trending seismic time section, the 1972 Gulf Canada Line C-11. The line is migrated and displayed with a vertical exaggeration of approximately 2:1. The well is in the vicinity of the Caribou N-25 well. A synthetic seismic trace has been constructed from the wire-line logs of the N-25 well, and that synthetic trace is displayed on the interpreted seismic section for the purpose of assisting the structural and stratigraphic interpretation (Fig. 11).

Line 2: A northeasterly trending section through the 1969 Esso Resources Line 4. The line is migrated and displayed with a vertical exaggeration of approximately 2:1. The well is in the vicinity of the Peel River K-09 well. A synthetic seismic trace has been constructed from the wire-line logs of the K-09 well, and that synthetic trace is displayed on the interpreted seismic section for the purpose of assistin g the structural and stratigraphic interpretation (Fig. 12).

Line 3: A northerly trending seismic section 1970 Amoco Canada Line CKR-10. The line is migrated and displayed with a vertical exaggeration of approximately 2:1. The well is in the vicinity of the Cranswick A-22 well. A synthetic seismic trace has been constructed from the wire-line logs of the A-22 well, and that synthetic trace is displayed on the interpreted seismic section for the purpose of assisting the structural and stratigraphic interpretation (Fig. 13).

The 1972 Gulf Canada Line C-11 (Fig. 11) passes through the Caribou M-25 well and crosses the Trevor Fault approximately 5 km northeast of the well. In this line the Trevor Fault is a westerly, or hinterland, verging antithetic thrust. This fold is inferred to have developed above a larger east-verging fault that results in the open fold in the Phanerozoic succession. This fold is the most obvious structure of the line, on the crest of which the N-25 well has been located. This suggests that the main structure is a very thick-skinned, perhaps even basement-cored, east-verging thrust sheet, which is responsible for the generally deeper level of exposure and erosion that occurs west of the Trevor Thrust. This structure may be a reactivation, or inversion of an early Paleozoic basement structure that controlled Paleozoic paleogeography on the eastern flank of the Richardson Trough, which now lies on the eastern flank of the Richardson Mountains. It is clear that the highest structural culmination in the immediate hanging wall (east side) of the Trevor Fault has not been tested.

The 1969 Esso Resources Line 4 (Fig. 12) passes through the Peel River K-09 well and it crosses the front of the main Cordilleran deformation, approximately 25 km southwest of the K-09 well. Here the Cordilleran structure is dominated by visible and interpreted, northeast-verging synthetic and southwest-verging, antithetic thrusts. The obvious and interpreted structures appear to be developed on a larger and deeper detachment that counts for the broader open, although disrupted, structural culmination that is the largest and most characteristic feature of the southwestern half of the section. While part of the rise in Paleozoic reflectors near the foreland-verging thrust in the centre of the section may be due to velocity effects near the leading edge of the deformation, it appears that part of that structure is also real, perhaps due to a small tectonic wedge, or triangle zone, perhaps in the form of an antiformal stack of thinner thrust sheets that have been inserted into the otherwise largely undeformed Foreland Basin succession that dominates the eastern half of the section. Note rising of reflections toward the eastern limit of the section, where the K-09 well appears to be located on at the leading edge of a series of sharply imbricated reflections in the Upper Paleozoic succession. The imbricate reflections are interpreted to be clinobeds developed on the Late Paleozoic slope during deposition of the Imperial/Tuttle progradation. The presence of these features indicates stratigraphic opportunities for entrapment in the Upper Paleozoic succession that constitutes a major play in this assessment. Note that the K-09 well, which had one of the few encouraging tests, appears to be located on a small foreland-verging thrust that is rising steeply out of an inferred detachment lying just above the Hume Formation platform carbonate. This structure might be similar, or analogous, to structures like those developed in the Monarch Fault of southern Alberta, where small thrusts and thrust sheet antiforms are developed deep in the foreland, without obvious connection to the main limit of the deformation, which appears clearly in the centre of the section.

The 1970 Amoco Canada Line CKR-10 (Fig. 13) passes through the Cranswick A-22 well where it is involved in north-verging Cordilleran thrust sheets that are linked to the Mackenzie Mountains. The nearby Yukon Territory well, Cranswick A-42, tests one of several potential structural prospects in an area that is sparsely penetrated. Two major concerns in this region are, the preservation of porosity under closure, and the timing of deformation relative to hydrocarbon generation and thermal maturation of sources. Note the thick-skinned style of the deformation that involves the Proterozoic succession. Most thrusts appear to terminate within detachment, or strain zones within the thick Cretaceous succession. The section shows how the style of the deformation changes in the stratigraphic succession. The deformation of the Proterozoic and Paleozoic successions, which is dominated by thrusting, is commonly manifest as a train of open upright folds within the Mesozoic succession, producing structures like those mapped by Norris.

These three seismic lines show that the overall structure in the Cordillera is compressional and that the style and timing of the deformation of the easterly and northerly verging structures is the same, resulting in a single unified structural model through the region. Many of the structures, especially the broad open folds like those tested by the Caribou N-25, are probably developed over deep detachments in the Precambrian successions or even the basement, which might include inversion of the Richardson Trough. Not all prospects have been tested nor is the structural style sufficiently well described or analysed to clearly show that the drilling to date has diagnostically tested the Cordilleran structures, or the combined structural and stratigraphic

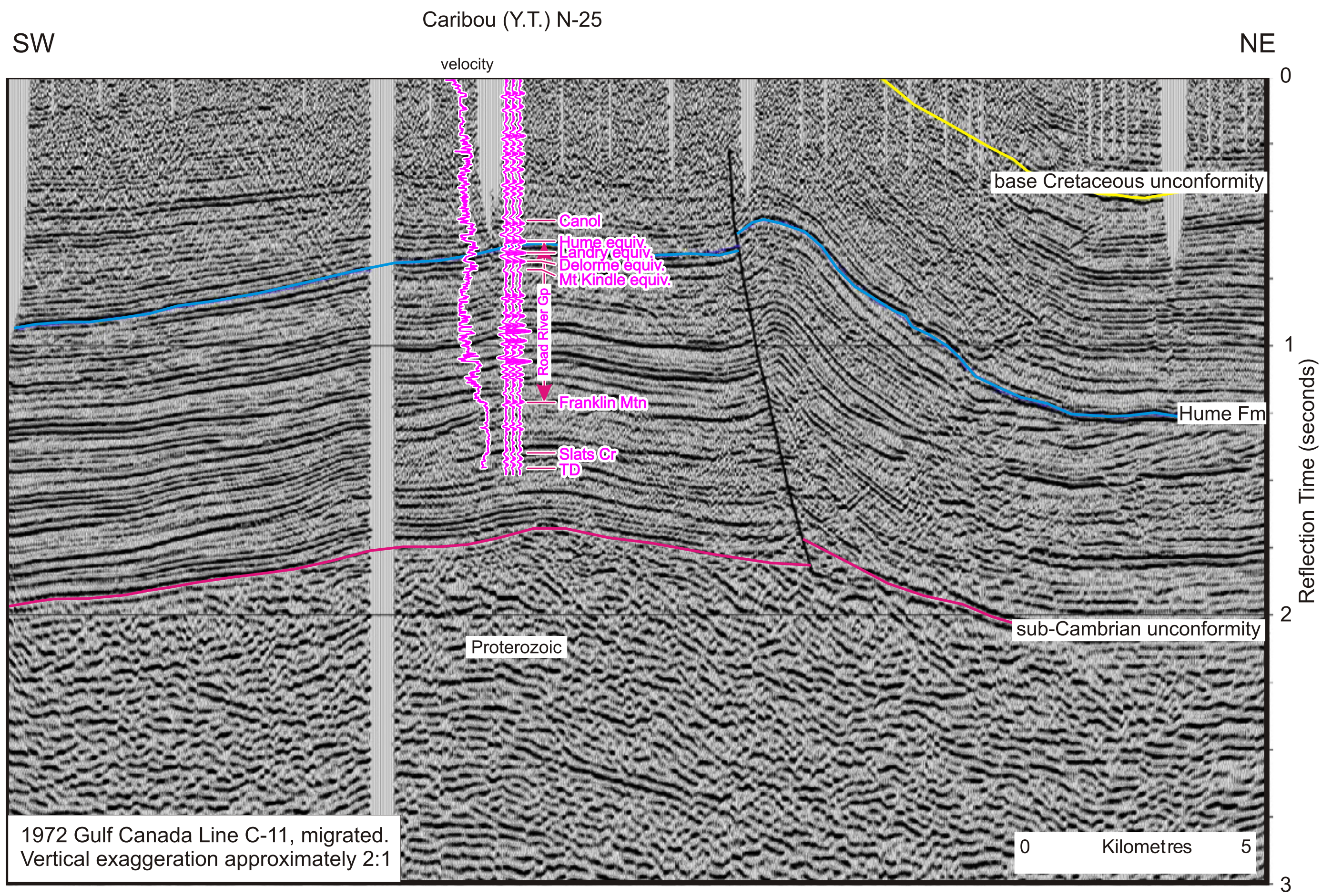


Figure 11. *The 1972 Gulf Canada Line C-11 northeasterly trending seismic time section. The line is migrated and displayed with a vertical exaggeration of approximately 2:1. A synthetic seismic trace that has been constructed from the wire-line logs of the nearby Caribou N-25 well is displayed on the interpreted seismic section to assist the structural and stratigraphic interpretation. Well locations as indicated in Figures 4 and 15.*

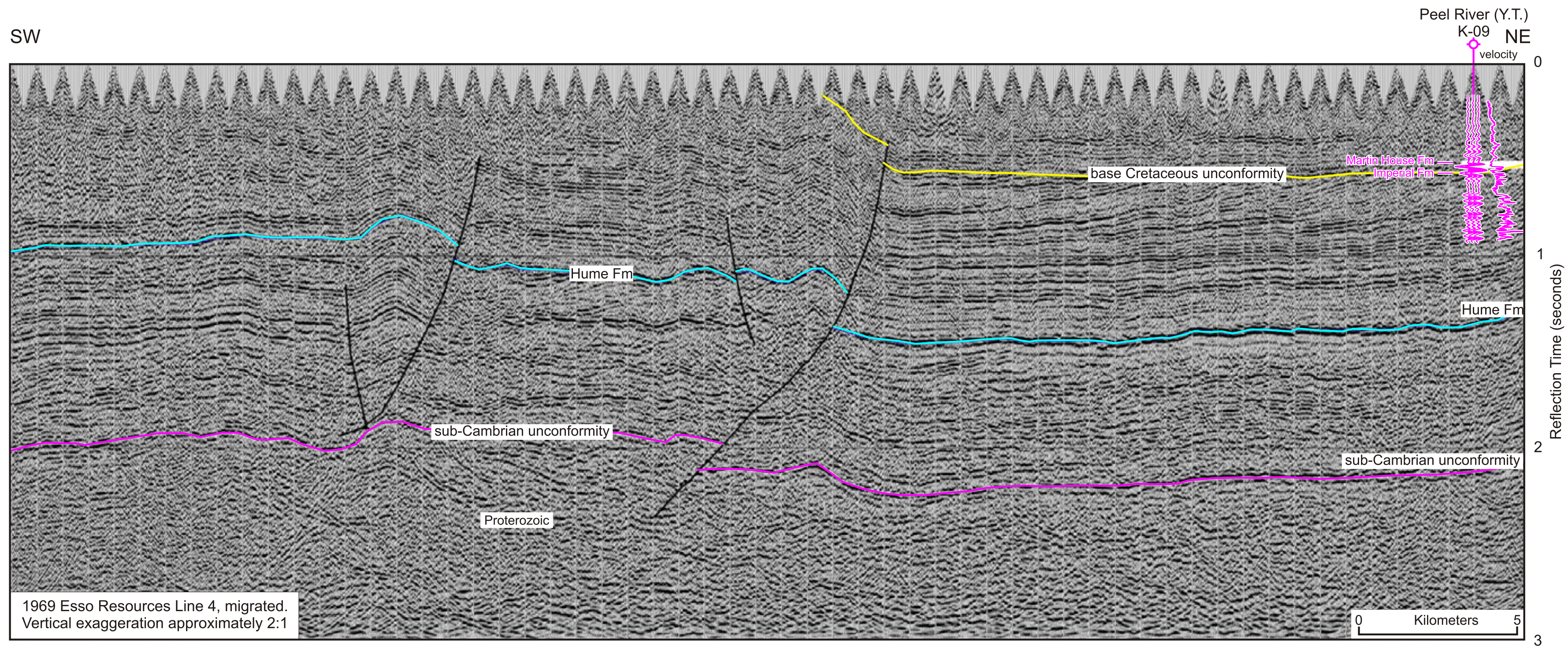


Figure 12. *A northeasterly trending section through the 1969 Esso Resources Line 4. The line is migrated and displayed with a vertical exaggeration of approximately 2:1. A synthetic seismic trace has been constructed from the nearby wire-line logs of the Peel River K-09 well, and that synthetic trace is displayed on the interpreted seismic section to assist the structural and stratigraphic interpretation. Well locations as indicated in Figures 4 and 15.*

complexities of the Foreland Fold and Thrust Belt beyond the most obvious limits of the Cordilleran deformation. Clearly there are problems with both reservoir and seal in the Paleozoic succession. Several wells test only mud, indicating a lack of porosity, or freshwater, showing a failure of the seal and communication with the surface. However, the region is sufficiently complicated both structurally and stratigraphically that numerous exploratory opportunities remain, with some being illustrated on these three example seismic lines. Clearly the structure and tectonics should be comprehensively re-evaluated in light of the large seismic and well data set that is available.

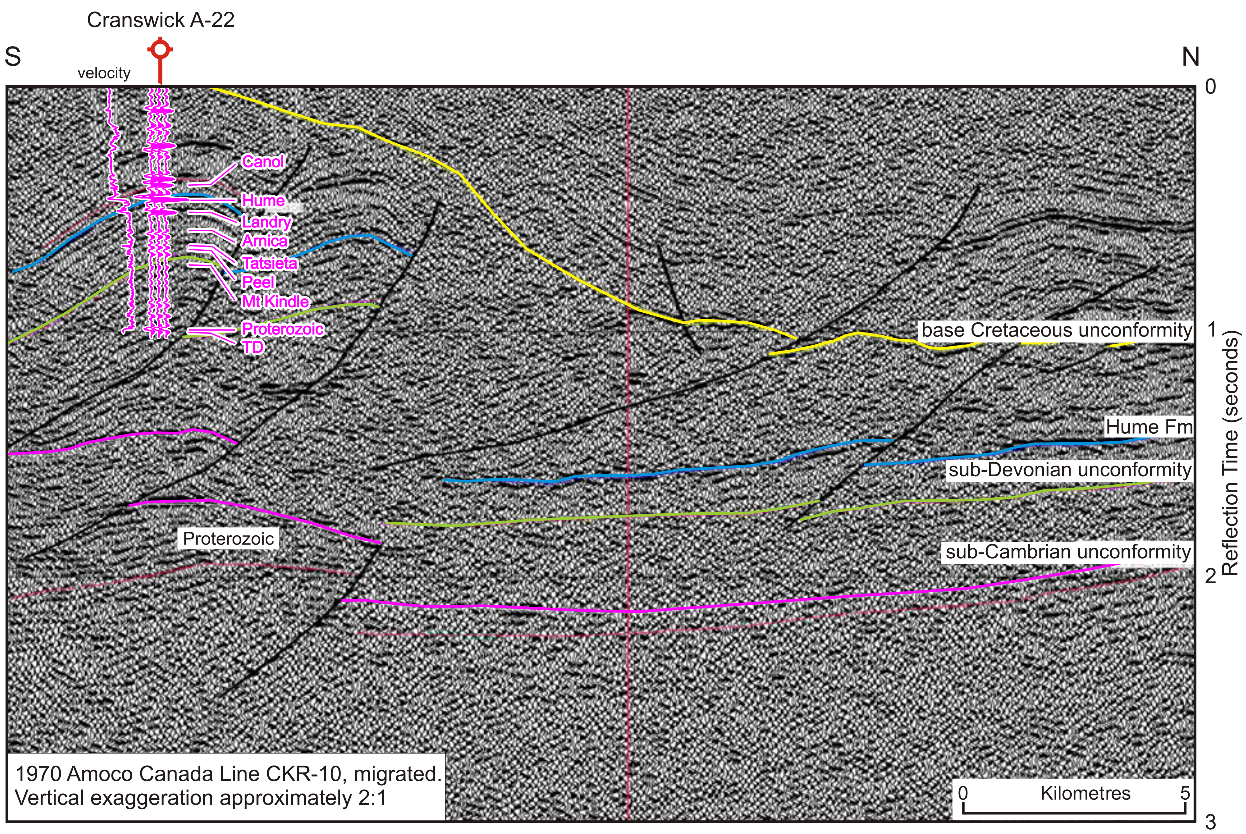


Figure 13. *The northerly trending seismic section 1970 Amoco Canada Line CKR-10. The line is migrated and displayed with a vertical exaggeration of approximately 2:1. A synthetic seismic trace has been constructed from the wire-line logs of the nearby Cranswick A-22 well, and that synthetic trace is displayed on the interpreted seismic section to assist the structural and stratigraphic interpretation. Well locations as indicated in Figures 4 and 15.*

PETROLEUM SYSTEMS

There are four indications for effective petroleum systems in the Peel Plateau including, potential petroleum source rocks, surface seepages, bitumen stains and residues, and tests of natural gas from wells. The most important of these are the tests from wells. At least eight wells have had minor, but encouraging shows of natural gas that prove there are active petroleum systems in the region. The encouraging tests include:

Atlantic et al. **Ontaratue H-34**, where drill stem test 2, run between 1351.7 m and 1360.3 m, recovered 54.9 m gas-cut mud and 167.7 m of gas-cut salt water from the Devonian Arnica Formation carbonate.

Shell **Peel River YT B-06**, where drill stem test 2, between 312.4 to 430.4 m across the base of the Cretaceous succession and the top of the Tuttle Formation, recovered gas to surface in 30 seconds that was too small a volume to measure.

Shell **Peel River YT B-06A**, where the single drill stem test, between 798.3 to 866.9 m in the Tuttle Formation, flowed water to surface in 55 minutes and recovered 789.4 m gas-cut salt water.

IOE **Tree River H-38**, where during drilling at about 721 m in the Canol Formation, the well flowed sweet gas at an estimated rate of 17.7 x 10^6 m^3 (NEB, 1995, p. 24).

MCD GCO Northup **Taylor Lake YT K-15**, where drill stem test 1, between 729.4 to 737.0 m, recovered 30.5 m of watery mud and 121.9 m of muddy gassy fresh water and drill stem test 3, between 792.2 to 1852.0 m, recovered 137.2 m of water and mud and 362.7 m of gassy salt water.

Pacific et al. **Peel YT F-37**, where test 1, of a porous zone in the top of the Mount Kindle Formation, between 3319.3 to 3368.0 m recovered 137.2 m of mud, 1388.1 m of gassy salt water and 109.7 m of gassy muddy salt water.

Gulf Mobil **Caribou YT N-25**, where drill stem test 3, between 1773.9 to 1787.7 m in the Road River Group, recovered 27.4 m of gas-cut mud.

Shell **Peel River YT M-69**, where test 4, in the lower Tuttle Formation between 1742.8 to 1799.8 m, flowed gas to surface at rates too small to measure and recovered 94.5 m of mud.

Norris (1997) reported a surface seepage of natural gas in northern Swan Lake (106 N4/1) west of the Arctic Red River, near the location of the Swan Lake K-28 well.

Two bitumen dykes were discovered by Stelck (1944) on Peel River between the Bonnet Plume and Snake rivers (106E15/1 and 106E15/2) and a 3rd "spectacular" sill-like mass of solid bitumen is reported within the Imperial Formation. This is in a borrow pit on the Dempster Highway 7 km north of Rengleng River, north of the town of Arctic Red River (Norris, 1997, his Figure 15.1, his Table 15.1), well beyond the limits of this study, but within similar successions. Pugh (1983) and Kunst (1973) report other, minor shows of bitumen within the study area and in its environs. Together these tests and occurrences suggest active petroleum systems that should be effective if suitable reservoirs formed and have preserved traps with appropriate timing.

The wells have not been extensively studied for their petroleum potential, except in proprietary reports. Bird (NEB, 2000a and b) provides a summary of one such study by Exploration Geosciences. That study examined 325 rock samples using pyrolytic techniques and it found average total organic carbon exceeding 1% in six formations, including, the Arctic Red, the Tuttle, Imperial, Canol, Hare Indian and Hume. The Paleozoic formations all contained rich zones that each exceed about 4% TOC in each of the five formations, while the maximum TOC of the Lower Cretaceous Arctic Red Formation was 1.61% TOC. The thermal maturities and organic matter type of these samples were not reported.

Like the Liard Plateau, the inferred problem in petroleum systems is not the potential of the petroleum system, but the timing of generation and migration relative to the formation of structures. In the Liard Plateau, detailed studies suggest that the potential petroleum sources follows stratigraphic position and that all Paleozoic potential sources are currently in the wet gas to over-mature zone, with some oil potential in the Mesozoic succession (Potter et al., 1993). Liard Plateau maturation models suggest a Late Devonian heating event and the generation of liquid hydrocarbons during the Late Paleozoic to Early Mesozoic interval (Potter et al., 1993). Devonian Manetoe facies reservoirs commonly contain pore-coating bitumen that is attributed to this early hydrocarbon generation interval. Thus, the gas in Manetoe reservoirs has been attributed to catagenesis of oil in overlying Besa River Shale, when the reservoir entered the gas window approximately 280 million years ago (Morrow, 1991; Potter et al., 1993). While all of these events are well documented by authoritative study, it conflicts generally with the inferred history of petroleum systems elsewhere in the Cordilleran Foreland Belt. In general, Foreland Belt Laramide structural accumulations of petroleum are inferred to have been generated syntectonically in response to tectonic burial by the stacking and thickening inherent in overthrusting and folding, commonly from source rocks in the footwall succession. Certainly wherever liquids are found within the southern Foreland Belt their molecular and isotopic compositions show them to be derived from footwall sources (Geological Survey of Canada, unpublished data), while the alteration of isotopic compositions in drier gas fractions, by processes like thermochemical sulphate reduction, prevent a complete and diagnostic analysis of the source of all gases. Within the Cordilleran Foreland, the syntectonic generation of reservoir charge clearly operates from Wyoming to 60°N. Therefore the early gas generation model proposed for Liard Basin is a stark, but unresolved anomaly in the Foreland Belt. Fortunately, the large discovered reserve in the Liard Plateau indicates that an effective petroleum system exists, regardless of our understanding of its function and history.

Although the Peel Plateau lacks the Manetoe Dolomite event, it has an otherwise similar stratigraphic history to the Liard Plateau. Like the Liard Plateau there are indications from wells and outcrops of an effective petroleum system. It would appear that some of the structures, like those tested by the wells with positive shows for petroleum, are not overly hampered by timing considerations. It would appear that reservoir quality and seal are also important considerations, which are captured by the exploratory risks of the plays assessed in the following sections.

EXPLORATION HISTORY

REFLECTION SEISMIC SURVEYS

The distribution of reflection seismic surveys with in the study area is shown in Figures 14 and 15. Within NTS map sheets 106E, F, G, K, L and M, there are 2283 km of reflection seismic surveys, covering the entire prospective region, in all three play areas. The data, acquired largely prior to 1977, has been used to locate wells used to test petroleum prospects in the Peel region. Three seismic lines were discussed in the previous sections in the illustration of the structural style; the focus of this discussion is on the history of drilling, to which the seismic surveys contributed prospects and locations.

EXPLORATORY DRILLING

Petroleum exploration has resulted in the drilling of 39 wells in the region of the Peel Plateau and Plain between 1964 and 1977 (Table 2; Figure 16). None of these wells have resulted in a significant discovery during 30 years of generally unsuccessful exploration, although there have been some encouraging shows. These wells and the data derived from them are key data for this study. The wells occur west of 132°W and south of 67.5°N in the region east of the Richardson Mountains and north of the Mackenzie Mountains. A total of 19 of these wells were drilled in the Yukon Territory. An additional 24 wells, not all in the Peel region, were drilled in the Northwest Territories to test the petroleum plays assessed in this work. All these wells were used in the formulation of play parameters and exploratory risks. The four additional important wells lie just east and north of these geographic study limits, bounded by the Point Separation #1 A-05 well on the north, and the Cranswick A-22 well on the east. These wells were also used in the formulation of play parameters and risks and they are discussed below, in the context of the exploration history. A further nine wells were examined and are mentioned within the exploratory history sequence discussed below. Five of these wells lie north of the Separation Point #1 A-05 well and four lie east of the Cranswick A-22 well, all in the Northwest Territories.

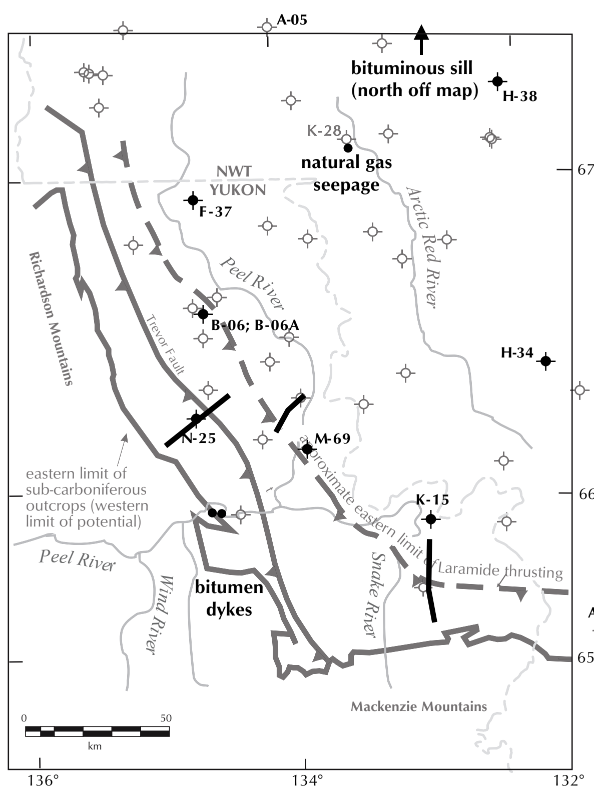


Figure 14. *Geographic references and locations of encouraging shows of petroleum system function and accumulations as discussed in the text. The figure also illustrates the reflection seismic lines illustrated in Figures 11, 12 and 13. Well locations as indicated in Figures 4 and 15.*

Exploration for petroleum in the Peel Plateau and Plain region, relevant to this study, began in 1960. During that decade a total of 21 new field wildcat and 4 structure test holes were drilled in the study region, without significant result. The first well drilled was the RO Corp et al. **Point Separation #1 A-05** well in the Northwest Territories. This new field wildcat well was located just beyond the northern limits of this study at 67.57°N, 134.00°W. The well spudded on July 31, 1960 from a Kelly Bushing elevation of 18.90 m and it was drilled to 2445.4 m in the Mount Kindle Formation. The well was determined to be dry and abandoned as of October 16, 1960. Exploratory drilling moved south into the assessment region with the spudding of Atlantic et al. **Ontaratue H-34** on December 20, 1963. This Northwest Territories new field wildcat well (66.39°N, 132.10°W) was spudded at a Kelly Bushing elevation of 141.70 m. It penetrated Proterozoic rocks at 3109.7 m and was drilled to a total depth of 4075.2 m, bottoming in map unit H-1. The well cored five intervals between 1370.1 m and 3459.8 m and tested two zones. The 2nd drill stem test, run between 1351.7 m and 1360.3 m recovered 54.9 m gas-cut mud and 167.7 m of gas-cut salt water from the Arnica Formation carbonate. The show was non-commercial and the well was declared dry and abandoned (dry and abandoned) in April 1, 1964. The third well drilled was Imperial Oil Enterprises (IOE) **Clare F-79**. This new field

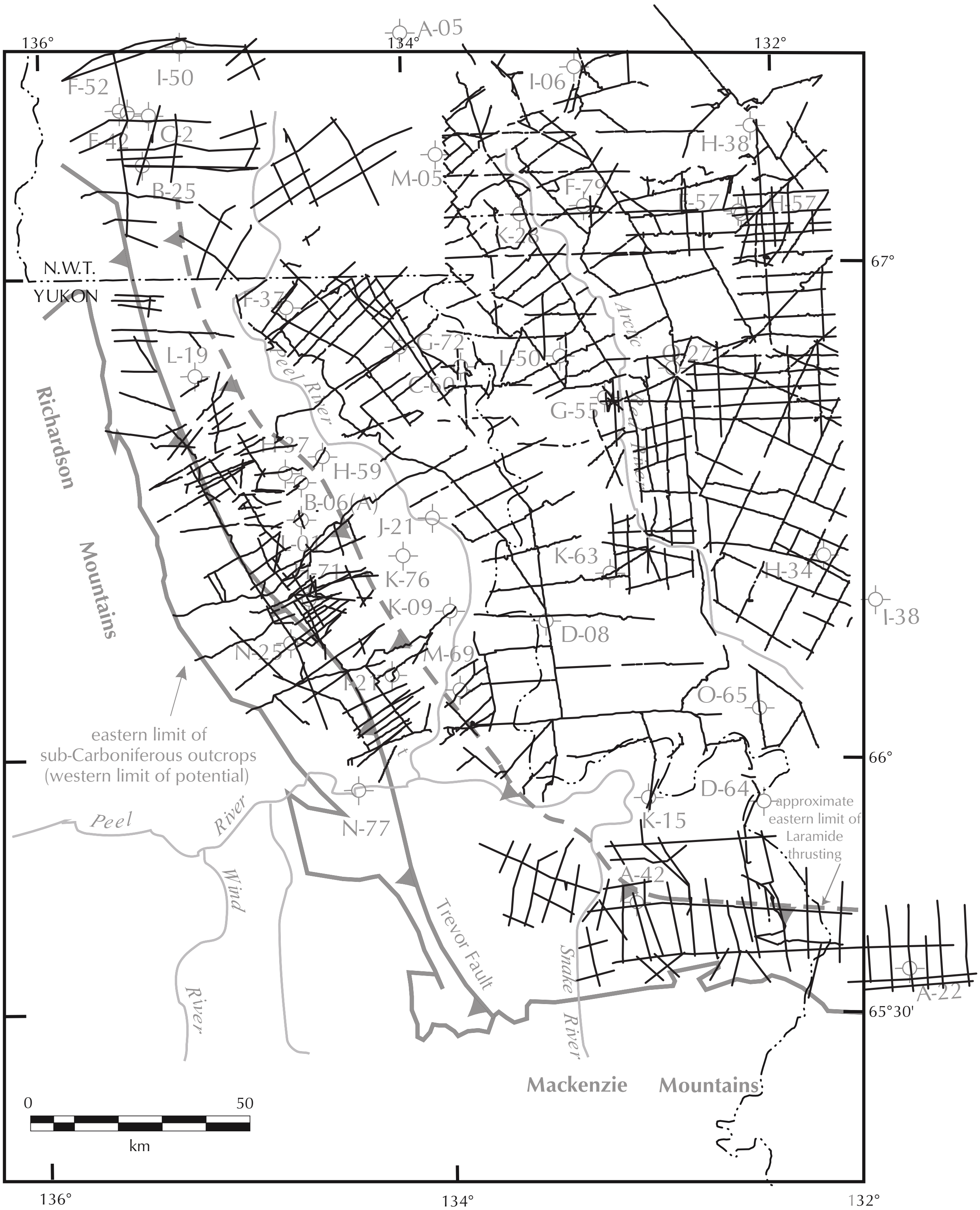


Figure 15. Distribution of petroleum exploration wells with respect to reflection seismic surveys in Peel Plateau and Plain, of all vintages.

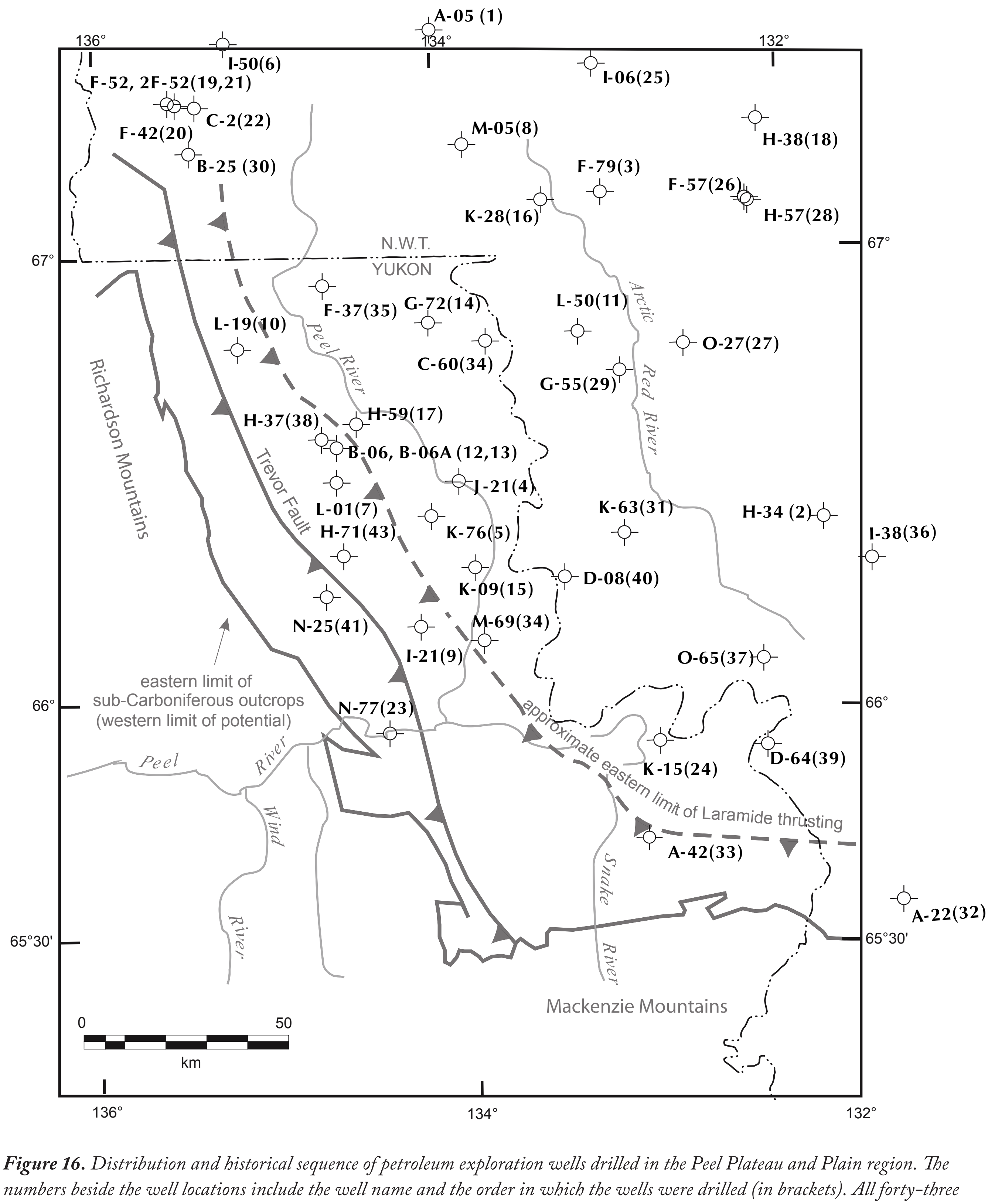


Figure 16. Distribution and historical sequence of petroleum exploration wells drilled in the Peel Plateau and Plain region. The numbers beside the well locations include the well name and the order in which the wells were drilled (in brackets). All forty-three exploratory petroleum wells were dry and abandoned.

Table 2. *Schedule of petroleum exploration wells in the Peel Plateau and Plain region. The table illustrates the location, Kelly Bushing elevation (KBE) and spud date of 43 wells discussed in the text.*

	Well Name		Latitude	Longitude	KBE	SPUD
1	Ro Corp et al. Point Separation #1 A-05	NWT	67.57	-134.00	18.90	07/31/1960
2	Atlantic et al. Ontaratue H-34	NWT	66.39	-132.10	141.70	12/20/1963
3	IOE Clare F-79	NWT	67.14	-133.24	108.80	6/20/1965
4	Shell Peel River YT J-21	YT	66.51	-134.07	45.70	07/31/1965
5	Shell Peel River YT K-76	YT	66.43	-134.24	76.50	10/07/1965
6	IOE Stony I-50	NWT	67.50	-135.38	321.90	12/10/1965
7	Shell Peel River YT L-01	YT	66.51	-134.77	394.70	12/12/1965
8	IOE Nevejo M-05	NWT	67.25	-134.03	74.40	02/01/1966
9	Shell Peel River YT I-21	YT	66.18	-134.31	381.30	02/20/1966
10	Shell Peel River YT L-19	YT	66.81	-135.31	95.10	04/11/1966
11	IOE Martin House L-50	NWT	66.83	-133.40	88.10	04/17/1966
12	Shell Peel River YT B-06	YT	66.59	-134.76	65.20	12/14/1966
13	Shell Peel River YT B-06a	YT	66.59	-134.76	66.40	01/03/1967
14	IOE Satah River YT G-72	YT	66.86	-134.23	89.60	01/13/1967
15	Shell Peel River YT K-09	YT	66.31	-134.02	349.60	02/06/1967
16	IOE Swan Lake K-28	NWT	67.13	-133.58	89.60	3/2/1967
17	Shell Peel River YT H-59	YT	66.64	-134.66	33.50	03/13/1967
18	IOE Tree River H-38	NWT	67.29	-132.35	79.60	4/23/1967
19	IOE Stoney F-52	NWT	67.36	-135.67	304.80	07/27/1967
20	IOE Stoney F-42	YT	67.36	-135.64	327.70	08/02/1967
21	IOE Stoney 2F-52	YT	67.36	-135.68	304.80	08/13/1967
22	IOE Stoney C-02	YT	67.35	-135.52	275.80	08/23/1967
23	Toltec Peel River YT N-77	YT	65.95	-134.49	148.40	10/07/1968
24	MCD GCO Northup Taylor Lake YT K-15	YT	65.91	-133.05	468.80	02/05/1969
25	INC NCO Mobil Attoe Lake I-06	NWT	67.43	-133.25	86.30	12/16/1969
north	Banff Aquit Arco Rat Pass K-35	NWT	67.91	-135.37	24.70	10/21/1970
north	Banff Aquit Arco Treeless Creek I-51	NWT	67.85	-135.41	28.30	12/18/1970
26	IOE Tree River F-57	NWT	67.11	-132.43	98.00	12/12/1970
27	Shell Arctic Red River O-27	NWT	66.78	-132.83	136.60	12/26/1970
28	Shell Tree River East H-57	NWT	67.11	-132.41	108.20	3/17/1971
29	Shell Arctic Red West G-55	NWT	66.74	-133.17	44.50	03/31/1971
30	Union Amoco McPherson B-25	NWT	67.23	-135.57	492.30	01/08/1972
31	Shell Sainville River K-63	NWT	66.38	-133.20	138.70	01/12/1972
32	Amoco PCP A-1 Cranswick A-22	NWT	65.52	-131.82	768.40	01/25/1972
33	Amoco PCP B-1 Cranswick YT A-42	YT	65.69	-133.13	620.00	04/14/1972
34	Skelly-Getty Mobil Arctic Red C-60	YT	66.82	-133.92	92.00	01/15/1972
north	Skelly-Getty Amoco Ft. McPherson C-78	NWT	67.62	-134.24	19.80	04/09/1972
35	Pacific et al. Peel YT F-37	YT	66.94	-134.87	54.60	02/13/1972
north	Dome Union IOE Stony G-06	NWT	67.59	-135.26	56.70	12/13/1972
north	Bluemount et al. Gulf S Delta J-80	NWT	67.66	-134.73	15.20	12/21/1972
east	Candel et al. Texaco Arctic Red F-47	NWT	65.61	-130.90	790.70	12/23/1972
east	Candel Mobil et al. North Ramparts A-59	NWT	65.47	-130.66	580.30	01/22/1973
36	Decal Trans Ocean Exco Ontaratue I-38	NWT	66.29	-131.85	144.50	11/6/1972
37	Inexco et al. Weldon Creek O-65	NWT	66.08	-132.45	222.80	03/05/1973
east	Candel Mobil et al. South Ramparts I-77	NWT	65.44	-130.97	595.60	03/14/1973
38	Shell Trail River YT H-37	YT	66.60	-134.85	393.20	11/27/1973
39	Dome Texaco Imperial South Peel D-64	NWT	65.88	-132.46	558.10	04/04/1973
40	Arco Shell Sainville River D-08	NWT	66.29	-133.53	203.00	01/09/1974
41	Gulf Mobil Caribou YT N-25	YT	66.25	-134.83	495.30	05/01/1974
42	Shell Peel River YT M-69	YT	66.15	-133.97	291.70	10/06/1974
43	Mobil Gulf Peel YT H-71	YT	66.34	-134.73	513.00	02/03/1977
east	Chevron Ramparts River F-46	NWT	65.76	-130.15	215.60	02/24/1991

wildcat well was drilled on the east side of the Arctic Red River in the Northwest Territories at 67.14°N, 133.24°W. It was spudded on June 20, 1965 and was dry and abandoned.

The 4th well drilled in the study region, Shell **Peel River YT J-21**, was the first well drilled in the Yukon Territory portion of the play area. The J-21 well was located at 66.51°N, 134.07°W, east of the limit of the Cordilleran folding and thrusting. Spudded on July 31, 1965 from a Kelly Bushing elevation of 45.70 m, the well was drilled to a total depth of 1219.2 in the Tuttle Formation, which it entered at 354.8 m depth. The well cored two intervals between 614.8 to 617.8 m, and between 894.3 to 1202.1 m in both Mesozoic and Paleozoic strata. A single test was run between 829.1 to 851.0 m, which recovered 89.9 m of mud cut salt water. The well was declared dry and abandoned, September 1, 1965. The 5th well drilled in the play was Shell **Peel River YT K-76**. It was also drilled in the Yukon Territory (66.43°N, 134.24°W, Kelly Bushing elevation 76.50 m). This well was drilled southeast of the J-21 well, on the west side of the Peel River, but still east of the Cordilleran deformation. The well was spudded on October 7, 1965. It entered Paleozoic Tuttle Formation clastic rocks at 451 m and was drilled to a total depth of 1386.8 m. No conventional cores were cut and it tested a single interval in the Tuttle Formation between 1143.0 to 1189.0 m from which 18.3 m mud and 33.5 m water were recovered. The well was dry and abandoned, November 25, 1965. The next exploratory well was IOE **Stony I-50**, which was drilled almost due west of the Separation Point #1 well in the Northwest Territories at 67.50°N, 135.38°W, from December 10, 1965. The well cored three intervals and had two tests, which recovered only mud and mud-cut water. Drilled to a total depth of 3343.0 m in the Devonian Landry Formation the well was dry and abandoned, May 8, 1966. The next well drilled, the 7th in the assessment region, was the Shell **Peel River YT L-01**. This Yukon Territory new field wildcat well (66.51°N, 134.77°W) was the first well drilled in the Laramide Fold and Thrust Belt. The well was spudded on December 12, 1965 and drilled to a total depth of 1834.9 m in the Devonian Imperial Formation. The well entered the Tuttle Formation at 682.7 m depth and the Imperial Formation at 1785 m depth. The well tested two zones. The first test between 1338.7 and 1394.2 m recovered 914.4 m of mud cut water while the 2nd test, run between 917.4 and 971.7 m recovered only 39.5 m of drilling mud. The well was dry and abandoned, February 7, 1966.

The 8th well drilled was IOE **Nevejo M-05**, a new field wildcat (67.25°N, 134.03°W) located west of the Arctic Red River and begun on February 1, 1966. It was drilled to a total depth of 2378.7 m in the Peel Formation. It was dry and abandoned, March 28, 1966. The Shell **Peel River YT I-21** new field wildcat (66.18°N, 134.31°W) was spudded February 20, 1966 from a Kelly Bushing elevation of 381.30 m. This well drilled below the Imperial Formation, penetrating the Hume Formation at 1451.8 m and entering the Gossage Formation at 1571.5 m, which it drilled to a well total depth of 2072.6 m. This well had three drill stem tests. The first test, run between 668.7 to 710.5 m recovered 9.1 m of mud. The 2nd test, from 767 m to 888.8 m recovered 418.5 m of fresh water. The 3rd test recovered 6.1 m of mud from between 1384.4 to 1486.8 m depth. The well was dry and abandoned, March 30, 1966.

The Shell **Peel River YT L-19** new field wildcat was the next drilled. L-19 is located in the Yukon Territory, in the Cordilleran Fold and Thrust Belt west of the Peel River, but east of the Trevor Fault (66.81°N, 135.31°W). This well spudded April 11, 1966 in the Tuttle Formation. It was drilled to a total depth of 1981.2 m in the Imperial Formation, which it penetrated at 1045 m depth. A single test was run in the lowermost Tuttle succession between 994.9 to 1012.9 m that recovered 243.8 m of fresh water. The well was dry and abandoned, June 12, 1966. The 11th well, IOE **Martin House L-50**, tests an Interior Platform structure in the Northwest Territories. Spudded on April 17, 1966, this new field wildcat well was drilled to a total depth of 2407.9 m in the Mount Kindle Formation. It was dry and abandoned, June 11, 1966.

Shell **Peel River YT B-06** was the 12th, new field wildcat well drilled. It is inferred that this well (66°35'09.4"N, 134°45'37.5"W) and its succeeding test B-06A (66°35'09.5"N, 134°45'40.0"W) were located to test the leading edge of the Cordilleran Thrust and Fold Belt west of Peel River. The B-06 well was spudded December 14, 1966. It was drilled to a total depth of 1066.8 m, bottoming in the Tuttle Formation. Two tests were run in the Mesozoic succession just above the Tuttle Formation, which occurs at 332.2 m depth. The 1st test run between 315.5 and 430.4 m recovered 24.4 m mud, but a 2nd test run over the same interval, between 312.4 to 430.4 m, recovered gas to surface in 30 seconds that was too small a volume to measure. The well was dry and abandoned, December 31, 1966, but it represents the first recovery of gas from the Cordilleran structures of the area and the second positive indication for petroleum since the test run at Ontaratue H-34 in 1963. This favourable result led to the drilling of Shell **Peel River YT B-06A** from essentially the same location. B-06A was begun on January 3, 1967. The well was spudded in Cretaceous shales and siltstones at surface and it penetrated the Tuttle Formation at 333.4 m depth and it continued in that deformed succession until total depth at 1066.8 m. A single drill stem test was run in the interval 798.3 to 866.9 m. It flowed water to surface in 55 minutes and recovered 789.4 m gas-cut salt water. The well was abandoned on January 25, 1967. Still these two wells indicated the presence of the structural gas play in the Cordillera, a concept that remains valid and inadequately tested.

Exploration effort was subsequently moved to the Interior Platform. The 14th well drilled in the study area was IOE **Satah River YT G-72**, which was drilled west of the L-50 well, on the NWT side of the inter-territorial boundary. This well (66°51'28.0"N, 134°13'57.0"W) was spudded January 13, 1967 in Cretaceous siltstones and shales and drilled to a total depth of 2286.0 m in the Devonian Arnica/Landry carbonates. No tests were run and the well was abandoned March 9, 1967. The next well, Shell **Peel River YT K-09** (66°18'35.7"N, 134°01'02.2"W) was located in the western reaches of the Interior Platform, west of the Peel River. Spudded in Cretaceous glauconitic shales on February 6, 1967 the well was drilled to a total depth of 1554.5 m in the Tuttle Formation, which it penetrated at 851 m depth. Two tests recovering mud, salt water and muddy salt water were run in the deepest formation penetrated. The well was dry and abandoned, March 7, 1967.

The next well was drilled near the site of surface seepages of natural gas where Cretaceous rocks outcrop in the Interior Platform. The IOE **Swan Lake K-28** (66°38'17.9"N, 134°39'33.1"W) was drilled to a total depth of 1838.2 m in the Devonian Arnica Formation carbonate, which it penetrated at 1801.4 m, and was subsequently abandoned. The next test drilled was also an Interior Platform well, but one located in the extreme western limit, almost in the Cordillera. The Shell **Peel River YT H-59** new field wildcat (66.64°N, 134.66°W) lies west of Peel River. It was begun March 13, 1967 in Cretaceous shales and sandstones and it penetrated the Tuttle Sandstone at 295.7 m to a total depth of 763.2 m. A single test was run in the Tuttle Formation between 591.3 to 652.3 m, but recovered only 91.4 m of muddy water. The well was dry and abandoned, April 1, 1967.

The 18th well, also in the Interior Platform, was IOE **Tree River H-38** (67°17'21"N, 132°21'00"W). It was drilled more than 50 km east of the Arctic Red River and spudded in Imperial Formation shales. Drilling began on the well on April 23, 1967, and went to a total depth of 1279.2 m in the Arnica Formation. This well provides the most significant gas show in the region. During a loss of drilling control at about 721 m, in the Canol Formation, the well had a flow of sweet gas at an estimated rate of 17.7 thousand m^3/day (0.5 million cubic feet/day) (Morrell et al., 1995, p. 24; note that the original reference incorrectly converts the gas flow rates from Imperial to metric units). The gas show suggests an effective hydrocarbon system in stratigraphically isolated porosity. This is the basis for much of the optimism for gas in the inferred combined structural-stratigraphic traps in both Mesozoic and Upper Paleozoic plays, as discussed below. The well also had several zones of lost circulation and logs suggest porosity in several Paleozoic intervals. Unfortunately there were no tests and the well was abandoned April 23, 1967.

Next, Imperial moved into the Cordillera where it drilled four structure tests along structural strike from the L-19 well. These four wells, IOE **Stoney F-52, Stoney F-42, Stoney 2F-52** and **Stoney C-02** were drilled sequentially between July 27, 1967 and August 29, 1967. All four were drilled to a structural marker in the Lower Cretaceous succession to total depths of 162.0 m, 310.9 m, 305.7 m and 176.8 m, sequentially and respectively. These wells suggest possible problems in seismic interpretation and prospect identification, which would also be reflected by the Shell Peel River B-06 and B-06A wells.

With the drilling of the 23rd well in this region, Toltec **Peel River YT N-77** (65°56'46.0"N, 134°29'12.0"W), exploration returned to the Yukon Territory; it moved west of the Trevor Fault, to that part of the Cordillera lying immediately east of the Richardson Mountains. The later GSC bedrock geology map mistakenly shows the Trevor Fault as having a normal offset, where seismic shows clearly is a thrust in a more internal zone of the Cordilleran Foreland Belt. West of the Trevor Thrust Fault, older stratigraphic units commonly crop out, due to the large amount of shortening on the fault, accompanying the change in mechanical stratigraphy at the western edge of the Paleozoic carbonate Platform. This is essentially equivalent to the “Front Range-Foothills” transition in this part of the Cordillera. The well was spudded October 7, 1968 in Imperial Shales and it was drilled to a total depth of 1123.5 m in what are probably Landry Formation carbonates, which it penetrates below the Prongs Creek-Landry contact at 483.4 m depth. The well was not tested and it was dry and abandoned, July 23, 1970.

The 24th well drilled in the assessment region was MCD GCO Northup **Taylor Lake YT K-15**. It is located in an Interior Platform setting near the inter-territorial boundary east of the bite in the Snake River (65°54'39.0"N, 133°03'00.0"W). This well was spudded February 5, 1969 in the Arctic Red Formation clastic rocks. It intersected the Martin House Formation at 632.2 m and passed into the Tuttle Formation at 641.8 m. The well penetrates a complete carbonate platform succession below the Paleozoic shales of the Imperial (1051.8 m), Canol (1314.8 m), and Bluefish (1352.8 m) formations. The platform succession is over 1000 m thick, consisting of Hume (1357.8 m), Landry (1523.8 m), Arnica (1904.8 m), Tatsieta (2057.8 m), Peel (2097.8 m) and Mt Kindle (2316.8 m) formations. The well reached 2378.7 m in Mount Kindle Formation.

Five intervals were tested as follows.

Mount Kindle Formation		
1	729.4 to 737.0 m	recovered 30.5 m of watery mud and 121.9 m of muddy gassy fresh water
2	860.8 to 915.3 m	recovered 100.6 m of mud and 378.0 m of fresh water
3	792.2 to 1852.0 m	recovered 137.2 m of water and mud and 362.7 m of gassy salt water
4	2252.5 to 2378.7 m	recovered 277.4 m of salt-water-cut mud
5	1719.1 to 1738.6 m	recovered 387.1 m of salt water

The well was abandoned March 29, 1969.

The INC NCO Mobil **Attoe Lake I-06** well was drilled near the northern limit of the study region, in the Interior Platform. Located between H-38 and A-05 (67.43°N, 133.25°W), this well was begun on December 16, 1969 and drilled to a total depth of 2257 m in the Mount Kindle Formation before it was abandoned. This was the last well begun in the 1960s and it represented the last of a decade of tests in which 25 wells were drilled in all 3 major structural settings of the assessment region, with only minor shows of gas and no significant discoveries.

New wells drilled in the next decade include two wells drilled north of the study region. One of these wells is the Banff Aquitanearco **Rat Pass K-35** well that was begun October 21, 1970. It was drilled to a total depth of 1830.0 m in the Cherty Unit of the Franklin Mountain Formation before being abandoned December 13, 1970. The 2nd well is Banff Aquitane Arco **Treeless Creek I-51**, which was begun December 18, 1970 and drilled to a total depth of 1831.8 m, also in the Mount Kindle Formation, before it too was abandoned January 29, 1971. Exploration resumed within the Interior Platform of the assessment region with test number 26, IOE **Tree River F-57** (67.11°N, 132.43°W). Well F-57 was begun December 12, 1970, and drilled to 1979.3 m in Silurian and Ordovician strata before being abandoned. The next well drilled was Shell **Arctic Red River O-27**, located east of the Arctic Red River (66.78°N, 132.83°W). An Interior Platform test, this well was begun December 26, 1970 and drilled to 2154.0 m depth in the Mount Kindle Formation It was abandoned January 23, 1971. Shell pursued the Tree River prospect drilled by the IOE F-57 well with the Shell **Tree River East H-57** well (67.11°N, 132.41°W), which was begun March 17, 1971 and which was drilled to 1981.2 m, in Lower Paleozoic strata like the F-57, well before it too was abandoned. The 29th well drilled in the assessment region was Shell **Arctic Red West G-55**, which is located on the west side of the Arctic Red River (66.74°N, 133.17°W). The well was begun March 31, 1971 and drilled to the Cambrian Mount Clark Formation, at the base of the Phanerozoic succession. The well was drilled to a total depth of 3322.3 m before being abandoned on May 22, 1971.

January 8, 1972 saw the spudding of the Union Amoco **McPherson B-25** well, the 30th well in the study region. This new field wildcat well was located in the Northwest Territories (67°14'00.78"N, 135°34'22.37) within the Cordilleran Foreland Thrust and Fold Belt along structural strike from the Shell **Peel River L-19**. This well was spudded in the Tuttle Formation and drilled to a total depth of 4136.1 m in the Franklin Mountain Formation, which it penetrated at 3992.9 m depth. The well tested four intervals, 4015.7 to 3986.8 m, 4023.4 to 3996.5 m, 4136.1 to 2656.5 m, 4136.1 to 2656 m, all of which were mis-run results, and the well was abandoned March 12, 1973. The Shell **Sainville River K-63** (66.38°N, 133.20°W) is an Interior Platform test that was spudded January 12, 1972 and drilled to only 790.0 m in the Imperial Formation before being abandoned January 23, 1972.

The 32nd well drilled was Amoco PCP **Cranswick A-22**. This well was drilled in the Cordilleran Thrust and Fold Belt in front of the Mackenzie Mountains, just east of the study area, in the Northwest Territories (65.52°N, 131.82°W). The well was begun January 25, 1972 and it drilled to a total depth of 2869 m, bottoming in the Proterozoic succession where it is involved in the deformation, prior to being abandoned March 28, 1972. This well was spudded just before the Amoco PCP **Cranswick YT A-42** (65°41'12.6"N, 133°07'52.1"), which penetrates a similar Foreland Belt structural setting in the Yukon. The A-42 well was spudded April 14, 1972 and drilled to a total depth of 4267.2 m in the Cherty Member of the Mount Kindle Formation. The well tested six intervals, 2171.7 to 2210.4 m, 2510.9 to 2533.8 m., 2650.2 to 2712.7 m., 3331.8 to 3366.5 m., 3431.1 to 3474.7 m., 3435.4 to 3474.7 m., all of which were mis-run results. The well was abandoned March 20, 1973.

The next well drilled was Skelly-Getty Mobil **Arctic Red C-60** (66°49'00.0"N, 133°55'19.0"W). This Yukon Territory new field wildcat well was located in the Interior Platform structural province near the inter-territorial boundary. This well was spudded January 15, 1972 and drilled to a total depth of 2599.9 m in the Ronning

Group. The well tested seven intervals, most of the tests having mis-run results, except for test number six, which was run in the Devonian Arnica Formation, between 2242.7 to 2251.9 m depth. That test recovered 82.3 m of mud and 992.4 m of salt water. The well was abandoned March 26, 1972. The next well was drilled to the north of the study area. The Skelly-Getty Amoco **Ft. McPherson C-78** (67.62°N, 134.24°W) was begun April 9, 1972 and drilled to a total depth of 3068.1 m in the Franklin Mountain Formation prior to being abandoned on July 17, 1972, without significant result.

A following Interior Platform test drilled just south of the inter-territorial boundary was the Pacific et al. **Peel YT F-37** (66°56'26.0"N, 134°51'54.0"W) new field wildcat well that was drilled to a total depth of 3368.0 m in the Mount Kindle Formation between February 13, 1972 and April 20, 1972, when it was abandoned. This well tested six zones. The first test, of a porous zone in the top of the Mount Kindle Formation, between 3319.3 and 3368.0 m recovered 137.2 m of mud, 1388.1 m of gassy salt water and 109.7 m of gassy muddy salt water. Tests 2 through 5 recovered only mud or were mis-run results. The 6th test of the Tuttle Formation between 457.2 and 496.8 m recovered only 272.8 m of muddy water. The next four Interior Platform tests were drilled north and east of the study region. The first was the Dome Union IOE **Stony G-06** (67.59°N, 135.26°W) which was begun December 13, 1972 and which drilled to a total depth of 2529.8 m in the Franklin Mountain Formation before being abandoned on February 17, 1973. The 2nd was the Bluemount et al. Gulf **S Delta J-80** (67.66°N, 134.73°W) which was begun eight days later and which drilled to a total depth of 2895.6 m in the Cherty Member of the Franklin Mountain Formation before abandonment on February 23, 1973. December 23, 1972 saw the beginning of the Candel et al. **Texaco Arctic Red F-47** (65.61°N, 130.90°W), which drilled to a total depth of 2371.3 m in the Imperial Formation before it too was abandoned, March 7, 1973. The next result of the 1972 to 1973 winter drilling season was the Candel Mobil et al. **N Ramparts A-59** (65.47°N, 130.66°W) which spudded January 22, 1973 and which was abandoned June 11, 1973 at 3205.0 m in the Franklin Mountain Formation. A similar fate awaited the Decal Trans Ocean Exco **Ontaratue I-38** (66.29°N, 131.85°W), and the Inexco et al. **Weldon Creek O-65** (66.08°N, 132.45°W), which were begun November 6, 1972 and March 5, 1973, respectively, as the 36th and 37th wells drilled in the study area. The O-65 well reached a total depth of 2214.4 m in the Peel Formation before abandonment on April 12, 1973. Another well drilled to the Cherty Unit of the Franklin Mountain Formation was the 1621.8 m deep Candel Mobil et al. **S Ramparts I-77** well located east of the study area (65.44°N, 130.97°W). This well too was abandoned with significant result, on April 14, 1973.

On November 27, 1973 exploratory efforts were refocused on the Cordillera, east of the Trevor Fault. The specific test, Shell **Trail River YT H-37** was the 38th well drilled in the study area. It was located near the B-06 and B-06A wells, and it was probably an attempt to capitalize on one of the few structures to provide a promising drill stem test result. The well was drilled to a total depth of 3721.6 m in the Peel Formation of the Ronning Group, which it penetrated at 3510.2 m. Three unsuccessful or mis-run drill stem tests were attempted before the well was abandoned March 26, 1974.

The H-37 well was followed by another unsuccessful Interior Platform test, the Dome Texaco Imperial **South Peel D-64** (65°53'04"N, 132°27'50"W), which was drilled to 1985.5 m total depth in the Landry Formation. It tested four zones between 1921.5 m and 1689.7 m between April 4, 1973 and March 15, 1974. Three of the four tests were run over the same interval, 1689.7 to 1741.9 m, in the Hume Formation, without obtaining a successful test. This suggests a favourable indication for hydrocarbons that could not be realized or properly evaluated due to technical problems. Subsequently the Arco Shell **Sainville River D-08** well (66°17'07"N, 133°31'39"W) was drilled very near the inter-territorial boundary between January 9, 1974 and its abandonment March 6, 1974. The well was drilled to a total depth of 2651.8 m in the Peel Formation, which it penetrated at 2506.1 m depth. The well tested six zones but recovered only mud.

The 41st well drilled in the assessment region marked a return to the Cordilleran structural play, as tested by the next three wells. The first of these three is the Gulf Mobil **Caribou YT N-25** (66°14'46.0"N, 134°50'04.0"W). This well was the 2nd test drilled west of the Trevor Thrust Fault, and with the N-77 well (see above) they comprise the only two tests of this very large, apparently prospective region. The N-25 well was spudded in Tuttle Formation sandstones on May 1, 1974 and it drilled to a total depth of 3600.3 m in Proterozoic strata, which it penetrated at 3433.3 m. Five drill stem tests were made as follows.

Tuttle Formation		
1	3014.5 to 3154.7 m	mis-run result
2	3014.5 to 3139.4 m	recovered 30.5 m of water-cut mud and 121.9 m mud
3	1773.9 to 1787.7 m	recovered 27.4 m of gas-cut mud
4	1432.6 to 1467.6 m	recovered only small volumes of drilling mud
5	1380.7 to 1414.3 m	recovered only small volumes of drilling mud

The well was abandoned August 10, 1974. The next well was drilled near the leading edge of the Cordilleran deformation east of the Peel River. The Shell **Peel River YT M-69** (66°08'56.0"N, 133°58'04.0"W) was begun October 6, 1974. Five drill stem tests were carried out. The first two tests between 3130.9 to 3152.5 m and 3115.7 to 3146.8 were both mis-runs and the 3rd test between 3103.8 to 3272.6 m recovered only 106.1 m of mud. A 4th test of the lower Tuttle Formation between 1742.8 to 1799.8 m flowed gas to surface at rates too small to measure and recovered 94.5 m of mud. A 5th test higher in the Tuttle Formation between 1677.9 to 1724.6 m recovered only drilling mud. The well was abandoned on December 4, 1974 after having drilled to 3272.5 m total depth in the Peel Formation. The 3rd Cordilleran test is the Mobil Gulf **Peel YT H-71** (66°20'28.6"N, 134°43'34.6"W). This well was drilled almost due south of the L-01 well and much closer to the surface trace of the Trevor Fault, although it still lies east of, or below, that structure. The H-71 well was begun on February 3, 1977 and drilled to a total depth of 3392.1 m in the Cherty Unit of the Franklin Mountain Formation. The well had two unsuccessful overlapping tests across the lower Peel Formation and the upper Mount Kindle Formation, apparently to test the first porous zone in the latter formation. The well was abandoned June 12, 1977.

SUMMARY

Thus, after 43 unsuccessful tests, and very few modest favourable gas shows, in all three structural settings in both territories, the exploratory efforts in the Peel region were suspended. Most recently the Interior Platform play was revived with the drilling of the Chevron **Ramparts River F-46** (65.76°N, 130.15°W) to the east of the study area. That well was begun February 24, 1991 and it was drilled to a total depth of 1510.0 m in the Devonian Nahanni Formation before its final abandonment July 22, 1998.

Hence a lower prospectivity should be assigned to the Peel Region, in light of what can only be described as a disappointing exploratory history. The assessment in the following pages considers the disappointing and unsuccessful results in the Peel region to date, and it uses methods and risks appropriate to the local setting. Due to the similarity in approach and analysis, the results of the Peel assessment, presented here, should be directly comparable to other regions in 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 Peel Plateau and Plain region 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 Peel Plateau and Plain region, 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 18 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 18, the most likely number of pools is 140. The application of the nonparametric discovery process model to this example data set yields almost the same result.

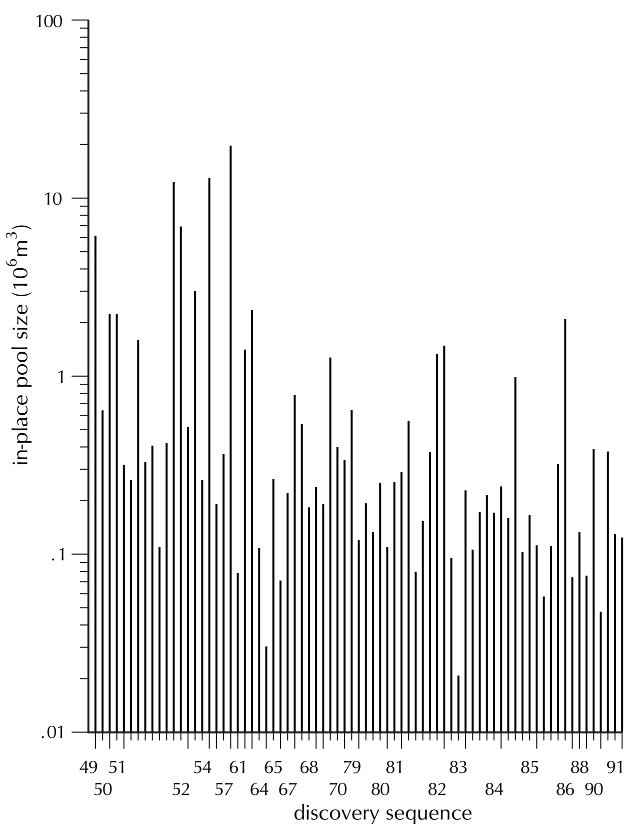


Figure 17. An example petroleum accumulation discovery sequence taken from the Carboniferous Jumping Pound Rundle Play of the southern Alberta Foothills. The logarithm of pool sizes is plotted sequentially as a function of discovery date, producing the time series or discovery sequence, which forms the 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.

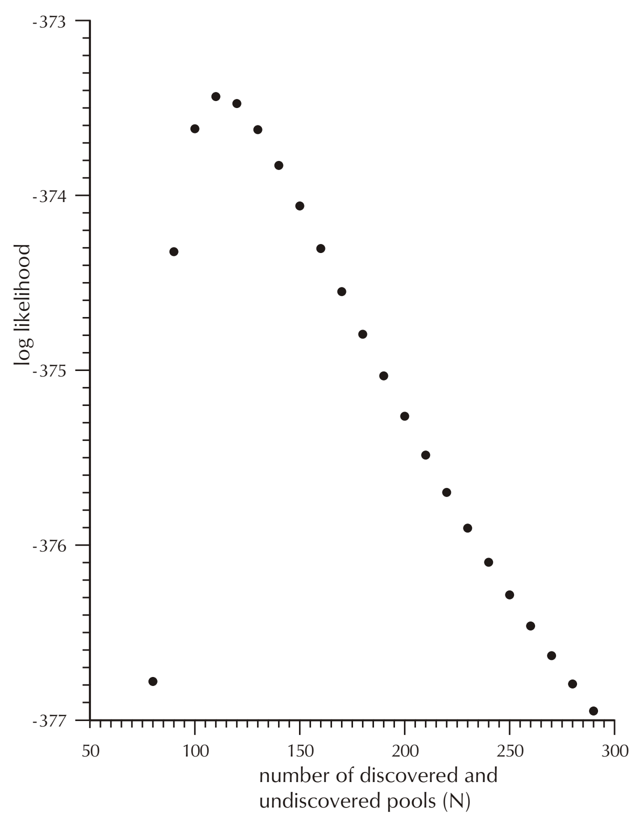


Figure 18. This figure illustrates the result of the lognormal discovery process model. The vertical axis represents the log likelihood value and the horizontal axis indicates the total number of discovered and undiscovered pools in a play, N. The higher the log likelihood value, the more plausible the value of N. In this example the most likely number of pools is 140.

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 accumulation-size distributions, as used in this study is discussed below.

Estimating pool, or prospect, size probability distribution

After estimating the N, or number of accumulations, value, 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 number of inferred accumulations are determined as the product of that distribution and the prospect level risks.

Estimating play-potential distribution

A play-resource distribution (Fig. 19) can be estimated from the N value and the pool-size distribution (Lee and Wang, 1983a). Furthermore, a play-potential distribution (Fig. 20) 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 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

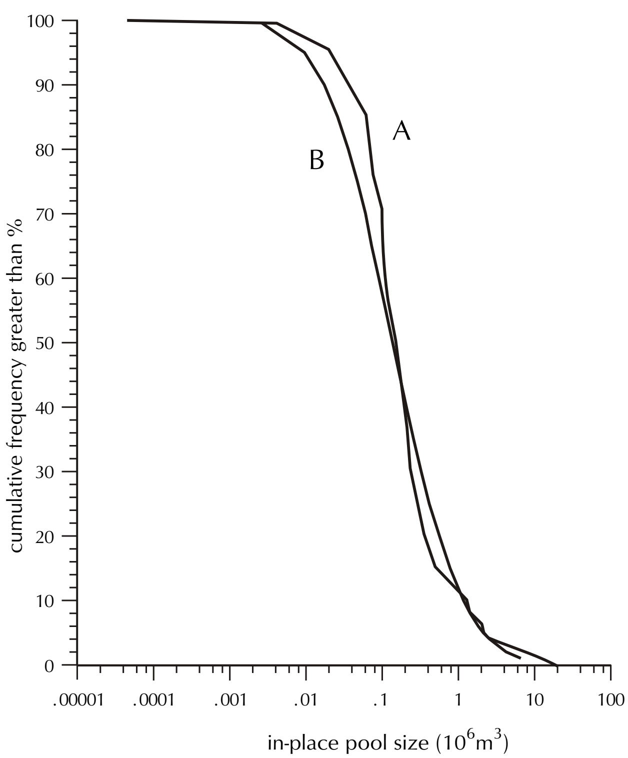


Figure 19. A play total resource distribution can be estimated from the N value and the pool-size distribution (either lognormal distribution A or nonparametric distribution B) (Lee and Wang, 1983a).

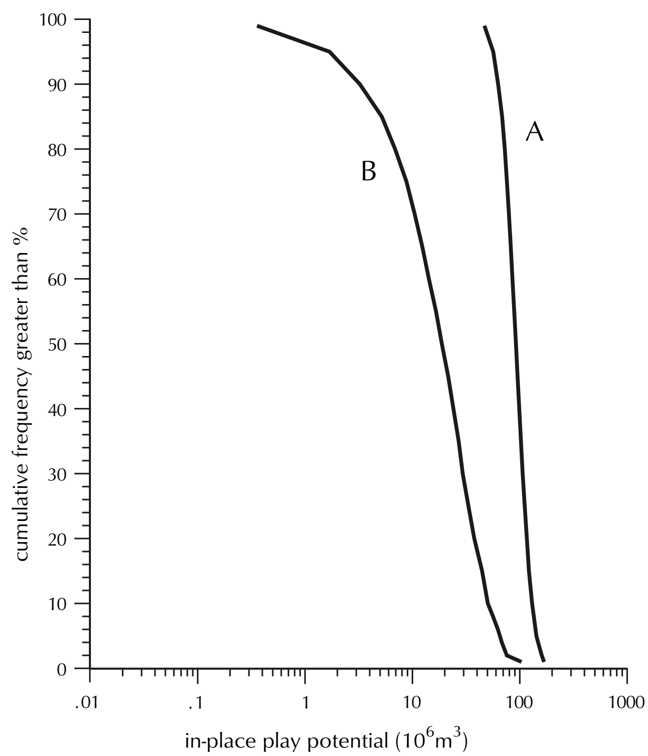


Figure 20. Undiscovered play-potential distribution for both the lognormal distribution A and nonparametric distribution B models displayed in Figure 19. The undiscovered potential is conditioned against the discovered volume, which has been discounted from these distributions.

probability distributions. 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 its 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.

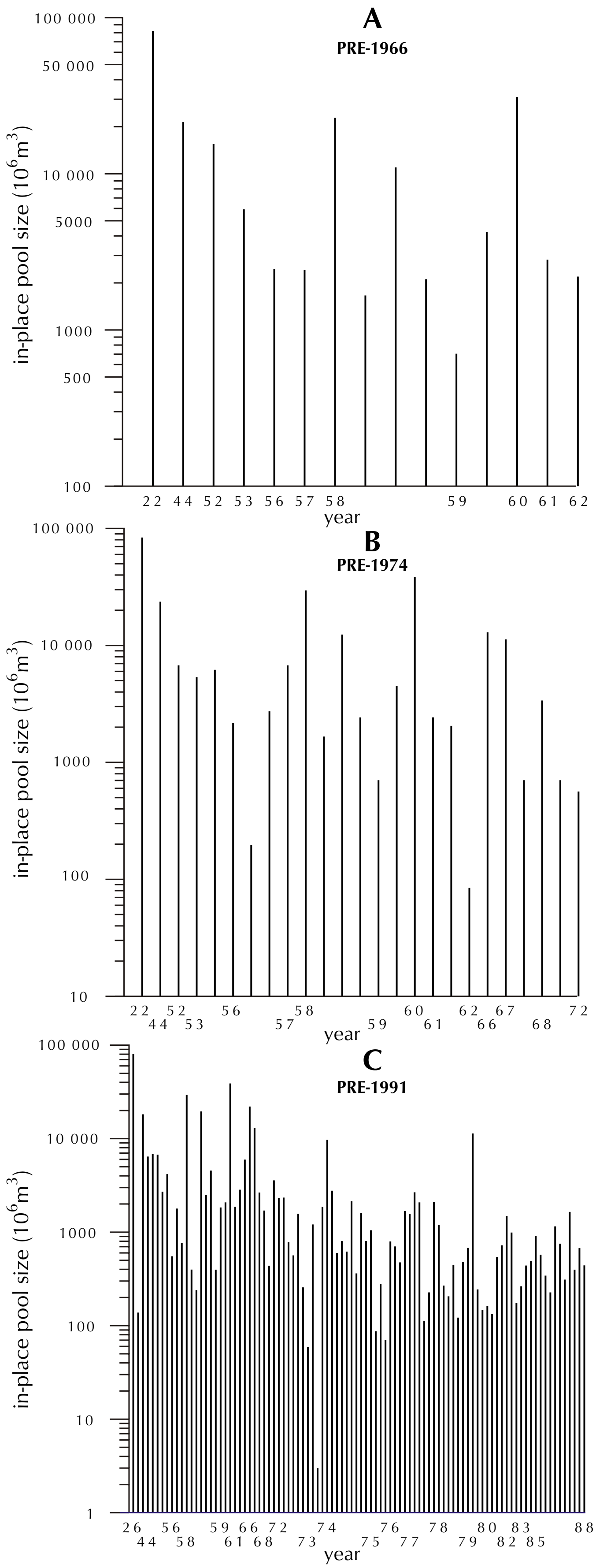
Figure 21 illustrates an example of a well-behaved Foreland Belt play, the Jumping Pound Rundle Play, as it was analysed in the 1992 Geological Survey of Canada Foreland Thrust and Fold Belt assessment (Lee, 1998). This play, in which the first discovery was made more than 80 years ago, should behave like the Peel Plateau Paleozoic Carbonate Margin (C5570111) play, 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. 21, left). The three resulting petroleum resource estimates for the three discovery sequence subsets are shown on the top-right diagram of Figure 21. 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. 21, bottom right).

Only 15 accumulations were discovered in this play between the first Rundle Group discovery and 1962. Still, early in the exploration history of the Jumping Pound Rundle Play it was possible to make a prediction of total potential that was comparable to the total potential that was estimated after another three decades of exploration had elapsed and 94 discoveries had been made (Fig. 21, top right). The Jumping Pound Rundle Play was very comparable early in its exploration history to the Liard Plateau Play, which itself serves as a type of model for the conceptual Peel Plateau Paleozoic Carbonate Margin (C5570111) Play, analysed in this report. 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. 21, 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. 21, bottom left).

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. 21, 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 the Peel Plateau Paleozoic Carbonate Margin (C5570111) Play 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.

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 method used herein. 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



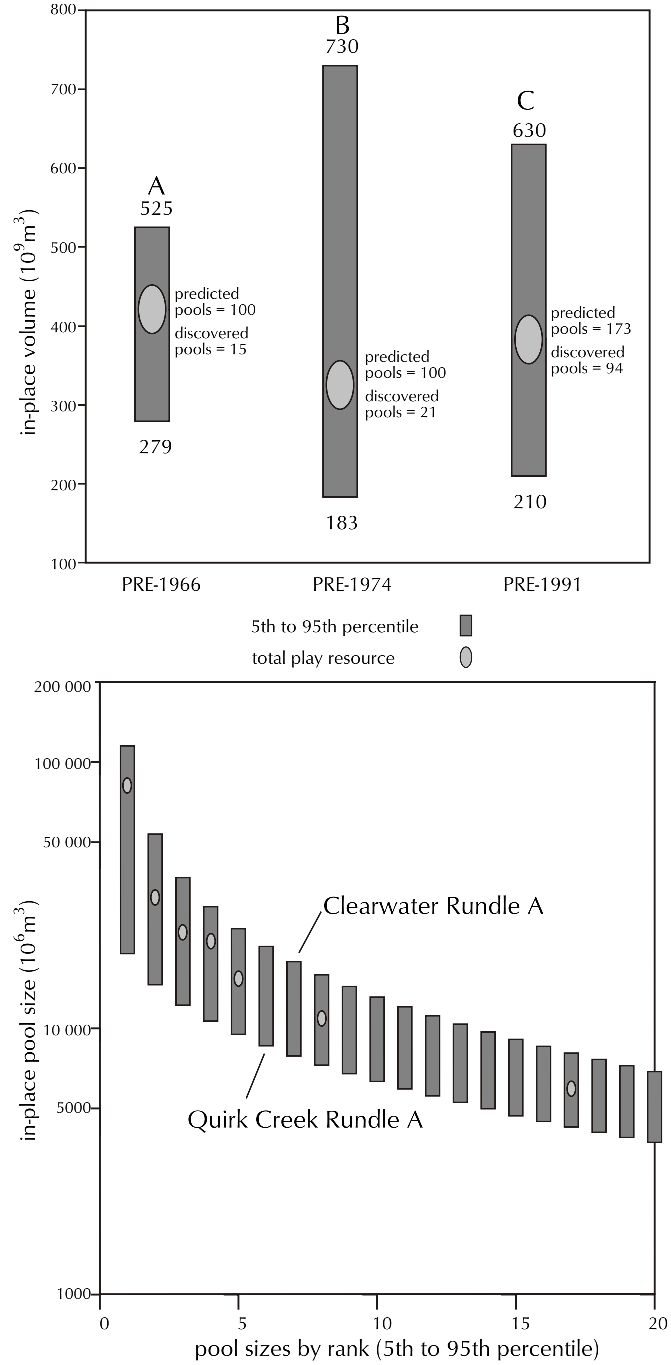


Figure 21. *An example of discovery history analysis and its historical vindication, by using subsets of the data to make predictions of the total resource. It includes that portion of the discovery history not used as input data for a well-behaved Foreland Belt play, the Jumping Pound Rundle Play (following Lee, 1998).*

and physical 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. 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 unbiased reservoir parameters; and
- Computation of the oil and gas potential distributions and construction of individual accumulation size by rank plots.

The accumulation (prospect) size distribution can be expressed using the reservoir volume engineering equation:

$$V = A*T*C*PHI*Shc*FVF$$

*represents a multiplication

V = the prospect hydrocarbon volume/or possible reserve

A = prospect area

T = thickness of the reservoir

C = percentage of the closed prospect volume that contains hydrocarons, or trap fill

PHI = porosity of the reservoir

Shc = the saturation of petroleum in the pore space

FVF = the formation volume factor that describes the expansion of natural gas, or the shrinkage of oil, due to loss of solution gas, that occurs when the petroleum is brought to the surface.

PETROLEUM RESOURCE ASSESSMENT

ASSESSMENT REGIONS

The Peel Plateau and Plain assessment is subdivided into three structural and stratigraphic belts that do not coincide with the physiographic boundaries of the Peel Plateau and Plain (Fig. 22):

- Peel Plateau West of Trevor Fault,
- Peel Plateau, and
- Peel Plain.

The first assessment region, **Peel Plateau West of Trevor Fault,** extends eastward from the outcrops of sub-Carboniferous successions in the Richardson and Mackenzie mountains east to the Trevor Fault. This region lies primarily in the Peel Plain, but it is underlain by east-verging Cordilleran thrust and fold structures that are similar to those that underlie the Peel Plateau. A broad outcrop of Carboniferous strata characterizes this region, and it is underlain by a thick succession of basin facies in Cambrian and Carboniferous successions. It lies generally west of the thick Paleozoic carbonate platform succession. This region contains a single play in Upper Paleozoic clastic rocks, predominantly combined structural and stratigraphic traps in the Imperial formation clastic rocks and overlying Ford Lake and Tuttle successions. The region is also underlain by very deeply buried Cambrian clastic rocks, which outcrop farther west. These rocks may have some petroleum potential, but they were not assessed in this study.

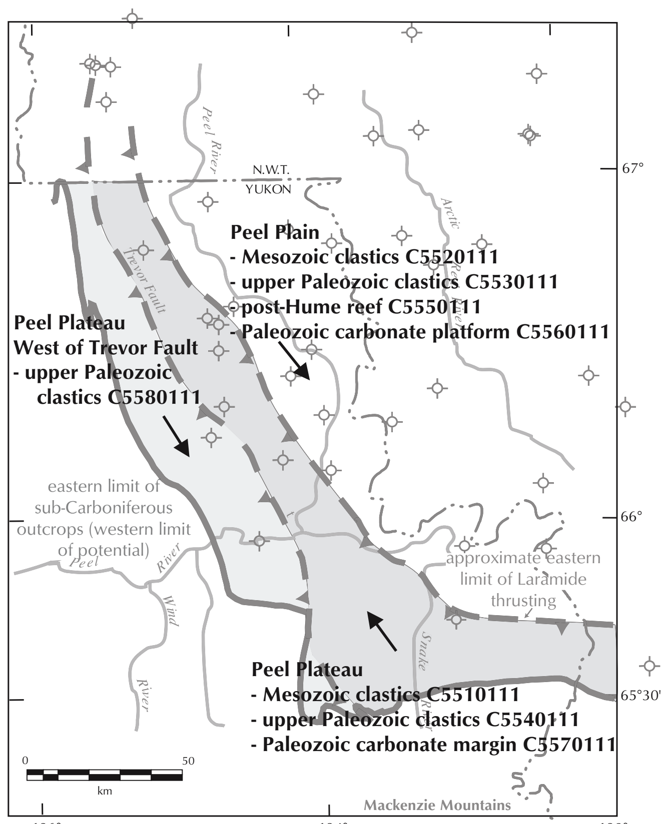


Figure 22. Play area map illustrating the geographic extent, name and unique assessment identifier numbers of each of the petroleum plays assessed in this report.

Most of the Peel Plateau and contiguous portions of the Peel Plain lying east of the Trevor Fault but west of the Peel River are also part of the east- and north-verging Cordilleran Thrust and Fold Belt (Fig. 22, shaded). This assessment area, from the surface trace of the Trevor Fault to the eastern limit of Cordilleran thrusting is referred to as the **Peel Plateau**, regardless of the physiography of the region. The carbonate to shale transition of a persistent Paleozoic paleogeographic feature, the Richardson Trough, occurs within this assessment region. This region is dominated by structures of the Laramide orogeny, in which occur three major potential reservoirs, each of which is a play assessed in this report. The three stacked reservoir intervals include: 1) porous zones in the Cambrian to Devonian carbonate platform succession, 2) clastic rocks in the basinal succession of the same age, but where it is expected that significant reservoirs will occur only in Imperial Formation clastics and overlying Ford Lake and Tuttle successions, and 3) potential coarse clastic reservoirs in the Mesozoic Foreland Basin succession where it is involved in the Cordilleran deformation.

East and north of the region affected by Cordilleran diastrophism are regions underlain by the undeformed successions of the Mackenzie-Peel Paleozoic carbonate shelf, also known as the Mackenzie-Peel Platform, that are overlain by a succession like that which has been deformed in the Cordillera (Fig. 22). This region, to the inter-territorial boundary, constitutes the third assessment region of this study, called the **Peel Plain** assessment region. Similar major reservoir intervals constitute plays in the Cambrian to Devonian carbonate platform succession, the Upper Paleozoic clastic succession of Imperial, Ford Lake and Tuttle formations, and potential coarse clastic reservoirs in the Mesozoic Foreland Basin succession where it has not become involved in the Cordilleran deformation. It is also possible that abrupt-margin carbonate reefs, similar to Horn Plateau reefs, grew rooted on the Hume Platform after the Devonian carbonate platform margin back-stepped to the region of the Keg River Barrier (to the south near the territorial boundary). This is treated as a speculative play, although there are no clear indications that such reefs occur.

Within each of the assessment regions there is a characteristic, and broadly similar, assemblage of stratigraphic successions and structural styles that are inferred to control petroleum system, migration, and trap reservoir/seal that provides the basis for defining petroleum plays to be assessed. The assessment follows a pool-based, rather than a field-based approach. This is done for several reasons. The reservoirs within each of the three major successions analysed are distinctive, while the similarity of structural style in each of the three regions is internally similar. Therefore the combinations of reservoir parameters are quite distinctively characteristic of each play, and strongly distinguished from other successions in the same assessment region/structural province.

To combine these successions in a field-based approach would have not been appropriate, and it would have resulted in two other major problems. First it would have prevented the direct comparison between different successions, which could impact the depth focus of exploratory drilling. If large reserves are predicted it is useful to know at what stratigraphic level they occur, so that needless drilling to less prospective successions can be avoided. This is very much the result here. Second, as there are no discoveries, it is important to be able to compare the predictions of the assessed plays to potential play analogues. Since the analogues are characterized and assessed on a pool-based structure, it would have been impossible to make this important comparison and validation if a field-based approach had been used. Below, each of these eight plays is defined, characterized and assessed, from oldest to youngest, from the undeformed Foreland Basin into progressively more westerly portions of the Cordillera.

PEEL PLATEAU WEST OF TREVOR FAULT

C5580111 – Upper Paleozoic Clastics - conceptual

Structural or stratigraphic traps in the arenaceous to rudaceous clastic rocks of the Imperial, Ford Lake and Tuttle formations, lying west of, or in the hanging wall of, the Trevor Fault, constitute a significant conceptual play for natural gas in the Richardson Mountains region. This play is designated Peel Plateau West of the Trevor Fault Upper Paleozoic Clastics - C5580111 (Fig. 22). Play parameters (Table 3) are difficult to infer because of the lack of data. However, the play parameters, and play and prospect-level risks can be inferred from the Upper Paleozoic Clastic Play (C5540111, Figure 22; Tables 4 and 27) in the adjacent deformed region to the east. This play is a slope-basin sandstone play.

Prospect-volume characteristics

As for the other two upper Paleozoic clastic plays in the Peel Plateau and Plain section, all of the prospect volume characteristics of this play are based, as far as possible, on locally derived play and prospect parameters, much from the adjoining analogous plays (Table 3). All prospects are inferred to exceed 0.4 km^2 in area. The lower value is inferred to represent the approximate limits of a structure that can be resolved within this frontier region, while considering that this play will have strong stratigraphic components of entrapment, such that a reservoir is not likely to cover the entire structure. It is consistent with lower limits of prospect size used in previous assessments (Bird, 2000, 1999; Hannigan, 2001) and it is about the area of a standard oil spacing unit (0.64 km^2) in established producing areas, which also provides an approximate lower limit on pool area definition. The size of more than half of the prospects is based on constraints from the geological map, observations of seismic data in the adjacent Peel Plateau Assessment Area (Play C5570111), and the estimates derived are from the data sources of previous assessments (Bird, 2000, 1999; Hannigan, 2001). The upper limits on prospect area — 50 km^2 at 1% probability and 90 km^2 at 0 probability — are derived in a similar way and are likewise comparable with previous work (Table 3).

Within this play, average net pay is again controlled by the thickness of individual sandstone reservoir intervals. It is inferred that sandstone layers will vary between 5 and 40 m thickness, based largely on bedding characteristics of the target formations in field photographs and measured stratigraphic sections. The setting is inferred to be more distal than that of the Upper Paleozoic clastic play in Peel Plateau to the east of the Trevor Fault, and for this reason, the average sandstone thickness in this play area is thinner than to the east. The diagenetic history of reservoir sandstones is not well known, but the range of prospect average porosities is consistent with facies and burial depths for both this depositional environment and tectonic setting. Formation Volume Factor parameters express expected values considering the geological and tectonic setting of this play, including its great potential depth.

Derived prospect size

The characteristics of the derived prospect size distribution are given in Table 4 as a cumulative probability distibution. The expected prospect size is 794 million m^3 with a standard deviation of 762 million m^3.

Number of prospects

The number of prospects is estimated to be between 20 and 200, with a greater than 50% probability that the number of prospects exceeds 100 (Table 3). This is a difficult play parameter to infer. Two things complicate the estimate. There is little objective data on which to base the estimate, while the strength of the analogy to current slope-basin plays has some associated uncertainties. As inferred for the other plays in this succession, there is a strong likelihood that all pools will have a component of stratigraphic entrapment. The inference made here considers the size of the first order inversion structure lying above the Trevor Thrust, which defines the limits of the play, while relying strongly on reference to other inversion settings to estimate the number of prospects. However, when the complications due to a stratigraphic component of entrapment are considered, it is likely that we have significantly underestimated the total number of prospects. It is strongly believed that this play, if it is demonstrated to exist, has been significantly underestimated in number of potential accumulations. The included estimates point to the existence of the play. Results could be revised if discoveries were made.

Play- and prospect-level exploration risks

Inferred play- and prospect-level risks (Table 3) are onerous, but not prohibitive. Seismic data show clearly that the Trevor Fault is a large thrust fault rather than a normal fault, as mapped. The uncertainties in the tectonic history and structural interpretation — as there is no structural data other than the map, which is wrong — serve only to increase the risks on this play. The problems of structural interpretation encumber the analysis of the play as it is suspected that this play may persist to great depth. It is also possible that there are both seal and formation volume factor risks, as it could be that many potential reservoirs are near the surface and the preservation of potential is at high risk. Mitigating factors provided by the play analogue and the observations in the Bowser Basin are as discussed elsewhere in this report.

Resource potential

To the west of the Trevor Fault, the outcrop is dominated by Paleozoic outcrops of the Cambrian to Devonian succession, composed of Road River and Imperial formations and their equivalents. The succession below the Imperial Formation is dominantly shales and no potential is inferred, at this time, for the sub-Imperial succession.

The potential prospect size is governed by local structural and stratigraphic characteristics and largely subjective play- and prospect-level risks. Exploratory risks are onerous because of the many uncertainties, which range from the incorrectly mapped nature of the play bounding Trevor Fault, to the appropriateness of the play analogues and the lack of data on reservoir and prospect characteristics directly derivable from the play region.

The play potential calculation suggests that between zero and five pools could occur, but that a single pool is expected (Table 5). The play potential is between 0 and 5873 million m^3 of initial raw gas in place (Fig. 23). The expected value of the undiscovered pool size is 105 million m^3 of initial raw gas in place (Fig. 24; Table 6). Note that the expected play potential lies between 99% and 95% on the predicted pool size and the expected predicted pool size is 822 million m^3, but that the standard deviation of the expected pool size is 780 million m^3. Where the analysis predicts only a single pool, we employ the description of the expected play potential to describe both the mean play potential and the undiscovered pool size.

The total petroleum potential of the Peel Plateau West of Trevor Fault as portrayed here is small to negligible, as would be expected from its geological history and characteristics. The analytical results rate this as the least attractive in the assessment. Therefore, the assessment of this play should seen more as an indicator that potential may exist and that the play should be reassessed if there is a discovery in similar strata to east, under the Peel Plateau and Plain.

Cambrian-Devonian Play (speculative)

A dominantly fine clastic Cambrian to Devonian succession, equivalent to the base of the Canol Formation, occurs West of Trevor Fault, primarily in its hanging wall (Figs. 6 (p. 6) and 22). This succession, which is not well known between the Knorr and Trevor Faults, carries unknown and unestimated petroleum potential. In this region there is insufficient data to allow inference of play parameters, play-level risks and prospect-level risks. The most prospective reservoir horizons in this part of the succession are expected to occur in the sub-Road River Formation succession. The potential reservoir formations are best developed west of the paleo-Knorr Fault (Morrow, 1999, his Figure 12), but they may extend between the Knorr and Trevor Faults, especially to the north, where this succession occurs below the very thick Road River to Imperial succession and its equivalents. The most prospective horizons are inferred to occur in the Middle Cambrian and older Iltyd and Slats Creek formations, both of which had a mature provenance in Precambrian footwall rocks (regions lying east) of the Trevor Fault during its initial extension. The protracted extension and subsequent inversion, combined with deep burial, all increase the risk for the preservation of both petroleum and reservoirs. These risks are currently not quantified, however, recent discoveries of natural gas at depths greater than 5 km, in a number of regions of the continental United States suggest that this play should be considered to have a real, but currently unknown potential for natural gases.

C5580111 - Upper Paleozoic Clastics Play

Table 3. *Input parameters.*

Probability distributions of reservoir parameters					
Geological variable	**Unit of measurement**	**Value at an upper percentile probability**			
		1.00	**0.50**	**0.01**	**0.00**
Area of closure	km^2	0.4	5	50	90
Net pay	m	5	25	35	40
Porosity	decimal fraction	0.09	0.12	0.15	0.17
Gas saturation	decimal fraction	0.50	0.70	0.85	0.90
Gas compressibility factor	decimal fraction	0.84	0.85	0.86	0.90
Reservoir temperature	°C	37	50	80	110
Reservoir pressure	kPa	10 000	15 000	20 000	25 000

Marginal probabilities of geological risk factors	Marginal probability	Play level	Prospect level
Presence of closure	0.7		X
Presence of reservoir facies	0.3	X	
Adequate seal	0.5	X	
Appropriate timing	0.05		X
Adequate source	0.6		X

Probability distribution for number of prospects			
Probability in upper percentiles	0.99	0.5	0.00
Number of prospects	20	100	200

Table 4. *Calculated prospect size using the lognormal approximation (millions of metres initial in place)*

Logarithmic Mean = 6.3516	Expected (Mean) Value = 794.32	
Sigma Squared= .65187	Standard Deviation = 761.52	
Upper Percentiles of the Prospect Size Distribution (Percentile = Value)		
99.99% = 28.471	60.00% = 467.32	15.00% = 1323.9
99.00% = 87.645	55.00% = 518.06	10.00% = 1613.7
95.00% = 151.95	50.00% = 573.38	8.00% = 1782.9
90.00% = 203.74	45.00% = 634.61	6.00% = 2011.9
85.00% = 248.33	40.00% = 703.52	5.00% = 2163.7
80.00% = 290.63	35.00% = 782.62	4.00% = 2356.7
75.00% = 332.61	30.00% = 875.63	2.00% = 3010.1
70.00% = 375.46	25.00% = 988.44	1.00% = 3751.1
65.00% = 420.08	20.00% = 1131.2	.01% = 11547.

Table 5. *Number of pools distribution.*

Minimum number of pools	0				
Maximum number of pools	5				
Expected number of pools	0.13242				
Standard Deviation	0.36963				
Summary statistics for 4000 simulations					
Play resource: (million cubic metres)					
Minimum	= 0.0				
Maximum	= 5873.068				
Expectation	= 104.8084				
Standard Deviation	= 404.9322				
Play potential greater than (million cubic metres)					
100.00	0.0	5.00	735.90	.01	5691.4
10.00	257.53	4.00	854.67	.00	5854.9
8.00	446.59	2.00	1365.0		
6.00	620.84	1.00	2031.6		

Table 6. *Pool-size rank, followed by a description of the individual pool-size distribution. The probability (P) that the total number of pools in the play (N) is greater than or equal to the assumed number of pools in the model play (r) is equal to "value" is employed to show that there is only a small probability that the number of pools in the play could be larger than the number of model pools being used to illustrate pool size ranges.*

1	Expected (Mean) Value = 822.52	Standard Deviation = 780.58	P(N≥r) = .12219
	99% = 89.839	75% = 345.86	10% = 1668.1
	95% = 156.68	50% = 597.43	5% = 2229.1
	90% = 210.81	25% = 1027.1	1% = 3842.3

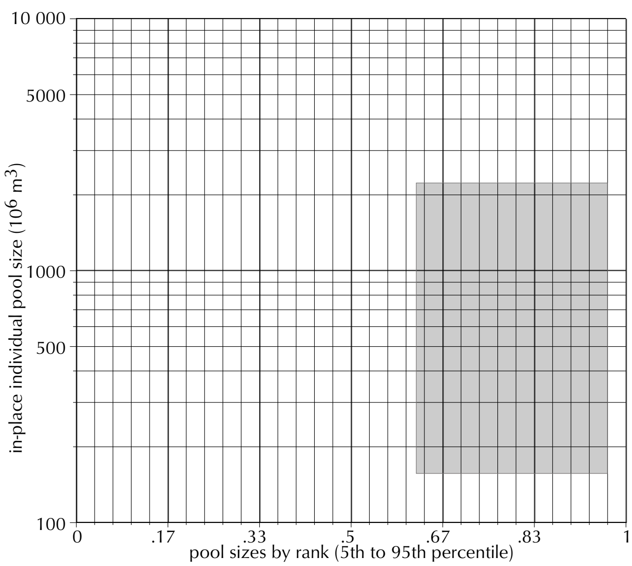


Figure 23. *Play potential plot.*

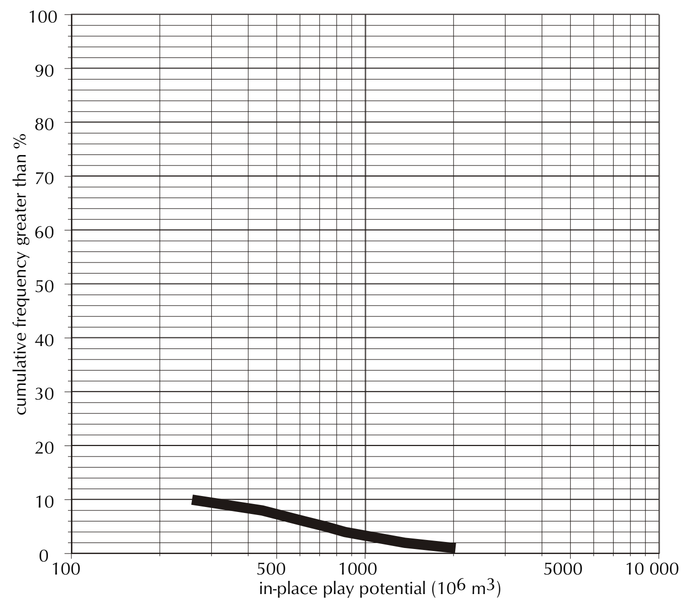


Figure 24. *Accumulation-size-by-rank plot. Details of individual pool-size distributions are given in Table 6.*

PEEL PLAIN

C5560111 – Paleozoic Carbonate Platform Play

Structural or stratigraphic traps in the platform carbonates of the Hume Formation and older Paleozoic carbonate successions lying east of the limits of Laramide thrusting and folding in the Peel Plain constitute a possible, but notably unsuccessful, conceptual play for natural gas. This play is designated Peel Plain Paleozoic Carbonate Platform - C5560111 (Fig. 22). Play parameters (Table 7) are inferred from a combination of map, well and seismic data; however, some play parameters and all prospect-level risks must be inferred subjectively because of the lack of discoveries, and the reasonable, but still reconnaissance scale of the geoscience data set.

This play occurs within a relatively shallow-water carbonate platform succession of Cambrian to Devonian age. The play characteristics are broadly similar to that of the thick, extensive carbonate platform successions that are major producing horizons in the central, or mid-continent, and Rocky Mountains regions of North America. However, there are distinctive differences because of the change in structural setting. Four features of the mid-continent and Rocky Mountains plays result in the very large reserves that are associated with that setting:

- reservoir, predominantly dolostone;
- source, including the Ordovician kukersitic/kerogenite beds;
- large basement-controlled structure, such as the Cedar Creek Anticline; and
- favourable timing of hydrocarbon generation and structural formation.

The failure to establish production in similar successions in north of 60° latitude is a major disappointment, which is expected to repeat in the Peel Plain.

Prospect-volume characteristics

All prospects are inferred to exceed 0.4 km^2 in area, with more than half of the prospects inferred to exceed 5.0 km^2 (Table 7). The analysis of this parameter follows a rationale similar to that discussed above. The size of more than half of the prospects is based on constraints from the geological map (see above discussion). The estimates are derived generally from similar data sources used by previous assessment studies (Bird, 2000, 1999; Hannigan, 2001). The upper limits on prospect area are 20 km^2 at 1% probability, and 45 km^2 at 0 probability, approximately half of that expected in the analogous play in the same succession in the Cordillera. These estimates are derived from similar data to, and are likewise comparable with previous work.

Within this play, average net pay is controlled by the thickness of ramp-type stratiform porous intervals that are developed within each of the carbonate formations. It is inferred that porous layers will vary between 2 and 40 m thickness, based on data inferred from wells. The possibility of thicker porous intervals cannot be precluded, and thinner intervals are not likely to be tested or completed. The diagenetic history of reservoirs is not well known, but it is known that Manetoe dolostones do not extend into the assessment region. Therefore the development of porous intervals will be predominantly stratiform, typical of ramp depositional settings. The range of prospect average porosities, 2 to 20%, is consistent with facies and burial depths for both this depositional environment and tectonic setting. Formation Volume Factor parameters including gas composition (compressibility) and reservoir factors (temperature and pressure) capture expected values that consider the geological and tectonic setting of this play (Table 7).

Derived prospect size

The expected prospect size is 211.7 million m^3 with a standard deviation of 191.5 million m^3 (Table 8).

Number of prospects

The number of prospects is estimated to be between 30 and 300, with a greater than 50% probability that the number of prospects exceeds 150 (Table 7). There is little objective data on which to base the estimate, as the wells represent but a small sample of the play volume. In addition, the relationships between stacking of porous layers within individual prospects, and the distribution of potential relative to structures within the Peel Plain do not follow a predictable model, as in the Cordillera. There is a strong likelihood that all accumulations will have a component of stratigraphic or diagenetic entrapment, which is inherent from the depositional environment of these sediments and their Interior Platform setting. The long distance between seismic lines makes it impossible to map individual prospects between points of control. It is, however, unlikely that the total number of prospects is underestimated.

Play- and prospect-level exploration risks

The total risk (Table 7) placed on this play is justifiably very high. There have been several hundred wells drilled to test, at least in part, the Paleozoic carbonate platform of the Northern Interior platform, with little success. None of the previously listed factors that affect the productivity of plays is most favourably developed in this assessment region. The Manetoe dolostones that are so important to the formation of dolostones reservoirs in the Devonian succession of the Liard Basin are not known to occur north of 63°N, a fact not correctly portrayed in one of the earlier studies of the Peel region (Bird, 2001). Although there are many dolostones intervals within this succession, the total volume of favourable reservoir is small compared to the thickness and extent of the Paleozoic platform carbonates. The presence of rich source rocks like those of the Ordovician succession is inferred, but not known. Although there are large structures controlled by basement features, such as Keele Arch, they have not been shown to be productive, despite considerable analysis and drilling (Morrell, 1995; Williams, 1987; Feinstein et al., 1996, 1991, 1988). The major risks include timing and closure. Carbonate ramp depositional environments commonly develop stratiform porous zones that require structure to provide the trap. Since large structural traps exist elsewhere in this succession, although not in the assessment region, it is inferred that the problem is most likely timing. The prospect-level risks strongly reflect these concerns as justifiably high risks that are the product of many unsuccessful wells drilled to test the potential of this succession elsewhere. The assigned play- and prospect-level risks are strongly subjective, but are also the consensus of exploration experience (Table 7).

Resource potential

The Cambrian to Devonian carbonate platform in the Peel Plain, all the units of which are dominated by carbonate ramp deposition, constitutes the largest volume of rock of any single play. Factors that adversely affect this play include the style of porosity development and the lack of lateral seals, the preservation of limestone reservoir porosity in the absence of pervasive dolomitization, and the timing of hydrocarbon generation relative to structure formation. Throughout the northern Interior Platform there has been a most notable lack of success drilling to the Hume Formation and the Ronning Group. The analysis suggests that between 0 and 11 pools could occur, but only a single pool of about 218 million m^3 initial raw gas in place is expected (Table 9). The play potential is between 0 and 2.780 x 10^9 m^3 of initial raw gas in place, with an expected value of 272 million m^3 of initial raw gas in place (Fig. 25).

The description of the expected pools in this play (Table 10; Figure 26) is predicted by the pool-size-by-rank analysis to be 278.72 million m^3 of gas. Instead, because only a single accumulation is expected, we employ the expected play potential, 272 million m^3, rather than the mean of the pool-size-by-rank prediction to describe the largest pool. The value employed occurs at about 40% probability in the predicted largest pool-size distribution above. The total petroleum potential of this play is not considered attractive, because of the small undiscovered pool size and the high exploratory risk. This play is an immense rock volume, but to date it has defied considerable efforts to establish production with the drilling of several hundreds of wells that, at least in part, attempted to test this succession.

C5550111 – Horn Plateau Reef Play

Stratigraphic traps in Horn Plateau reefs that are rooted on the Devonian Hume Formation platform, lying east of the limits of thrusting and folding in the undeformed Peel Plain, constitute a speculative, and elsewhere notably unsuccessful, conceptual play for natural gas. This play is designated Peel Plain Horn Plateau Reef - C5550111 (Fig. 22). Play parameters are inferred by analogy to Horn Plateau reefs elsewhere (Table 11); however, some play parameters and prospect-level risks must be inferred subjectively. The subjective assessment of play potential occurs because of the lack of discoveries, and the reliance on parameters derived largely outside of the assessment area, where Horn Plateau reefs have been identified and drilled.

Horn Plateau reefs represent large stromatoporoid atolls or pinnacles that represent the restricted development of abrupt-margin shallow-water carbonate facies that persisted after the general drowning of the Hume Formation ramp-platform in Devonian time. This occurred as the platform margin migrated south to the Keg River and Slave Point margins in northern Alberta and the southern Northwest Territories. In contrast to the Norman Wells Kee Scarp reef, numerous Horn Plateau reefs have been drilled, without success. This play is not a Kee Scarp Formation (Norman wells) analogue, as it is expected that reefs in the Peel Plain would be rooted directly on the Hume Platform. The play definition assumes not only the presence of Horn Plateau reefs in the area, something that is possible, but unsubstantiated, but also that such reefs might have porosity to provide a reservoir. The failure to establish production in these reefs has been a major disappointment elsewhere, especially in the adjacent NWT.

Prospect-volume characteristics

Prospect volume characteristics of this play are based, as far as possible, on analogously derived play and prospect parameters (Table 11). If discoveries are made and the analogy is strengthened, then it is reasonable to review the assessment of this play and the possibility of using analogous pool- and prospect-size parameters from model Devonian reef pools elsewhere in the Interior Platform.

All prospects are inferred to exceed 1 km^2 in area, with more than half of the prospects exceeding 5.0 km^2. The lower value represents the approximate limits of a reef that could be resolved within this region. It is consistent with lower limits of prospect size for reefs elsewhere in the basin. It is similar to the area of a standard oil spacing unit (0.64 km^2) in established producing areas, which also provides an approximate lower limit on petroleum pool area definition. The upper limits on prospect area are 8 km^2 at 1% probability and 10 km^2 at 0 probability, otherwise it is expected that these reefs would have been detected on seismic in this area. Within this play, average net pay is controlled by the thickness of the reef and the percentage of fill. The reefs can be very thick, up to 250 m, but it is rare for large atoll reefs to be filled to spill point, even in the most effective petroleum systems, like the Frasnian reefs of central Alberta. Other prospect parameters are extracted from the main development of Horn Plateau reefs north of the Keg River/Slave Point platform margins.

Derived prospect size
The expected prospect size is 755.76 million m^3 with a standard deviation of 927.39 million m^3 (Table 12). If the play could be proved to exist it could include very large prospects.

Number of prospects
The number of prospects is estimated to be between 1 and 40, with a greater than 50% probability that the number of prospects exceeds 10 (Table 11). This play parameter is difficult to infer. There is no objective data on which to base the estimate, as these reefs have not been identified in the assessment area and the play is based entirely on analogy to non-productive reefs outside of the assessment area. The play potential here is strongly controlled by the degradation of reservoir potential that is inferred to result from the lack of favourable diagenesis or timing of important geological processes, which is the nature of exploratory risk in Horn Plateau reefs elsewhere (Table 11).

Play- and prospect-level exploration risks
The total risk placed on this play is justifiably very high (Table 11). The diagenetic history of Horn Plateau reef reservoirs is not known, as reefs have not been drilled locally, but it is expected to be marginal to unfavourable, based on experience elsewhere. As mentioned in the Paleozoic Carbonate Platform Play, Manetoe dolostones do not occur north of 63°N (Morrow, 1999 and Morrow et al., 1990). Compaction quickly reduces limestone porosity, so that without anomalous diagenesis it is unlikely that reservoir quality survives burial. However, the presence of a Horn Plateau reef in this part of the Hume Platform would itself be an anomaly, so the play is strictly, but not prohibitively, risked. The risk reflects this concern, with a combination of favourable exploratory risks significantly tempered by only a 10% chance that reservoir will occur, since this risks both the occurrence of the reef facies and its diagenesis. The assigned play- and prospect-level risks are, therefore, strongly subjective, but consistent with exploration experience.

Resource potential
Most of the Devonian succession is in a carbonate ramp setting in the Peel Plain. The one significant opportunity for an abrupt carbonate margin facies model accompanies the persistence of carbonate deposition following the drowning of the Hume Platform. This is identical in configuration to the Horn Plateau Play of the southern NWT. While this play is not known to exist, neither can it be entirely discounted. The play potential calculation suggests that between 0 and 37 pools could occur, but only a single pool is expected (Table 13). The play potential is between 0 and 32.38 x 10^9 m^3 of initial raw gas in place, but with an expected value of 888 million m^3 of initial raw gas in place (Fig. 27). Note that because only a single accumulation is expected, we employ the expected play potential, 888 million m^3, rather than the mean of the pool size by rank prediction, 2.381 x 10^9 m^3, to describe the size of the largest pool (Table 14, Figure 28). The value employed occurs at about 80% probability in the predicted largest pool-size distribution above. The petroleum potential of the Peel Plain Horn Plateau Reef - C5550111 is a speculative “long shot”. The analytical results rate this as an unattractive play to pursue because of the smaller undiscovered pool size and the very high exploratory risk. While the reef itself is volumetrically attractive, much effort to find a reservoir and reserve in similar reefs elsewhere has met with persistent failure.

C5530111 – Upper Paleozoic Clastics

Structural or stratigraphic traps in the arenaceous to rudaceous clastics of the post-Canol Paleozoic succession of the Imperial, Ford Lake and Tuttle formations, lying east of the limits of thrusting and folding in the undeformed Peel Plain constitute a significant conceptual play for natural gas in the Peel Plain region. This play is designated Peel Plain Upper Paleozoic Clastics - C5530111 (Fig. 22). Play parameters are described in the preceding pages from the reconnaissance scale geoscience data set (Table 15). This play is a shoreface, slope-basin sandstone play that includes depositional settings that may be similar to what are among the most attractive plays in the current exploration portfolio of major oil companies, in the Gulf of Mexico and on the passive margin of the South Atlantic Ocean. The play is also the stratigraphic analogue of the two Upper Paleozoic Clastic plays in the Cordilleran part of this assessment.

Prospect-volume characteristics

The characteristics of this play are broadly similar to that of the two other Upper Paleozoic Clastic plays in this assessment (C-5580111 and C-5540111; Figure 22, Tables 3 and 27). However, there are distinctive differences because of the change in the structural setting. The possibilities for structural stacking and the component of closure due to Laramide diastrophism are much reduced. The net impact on this play is complicated, but in general it results in smaller prospects, with a greater component of stratigraphic entrapment and with what are probably degraded reservoir characteristics. The affect of change in tectonic history and setting on reservoir characteristics may at first appear counter intuitive, however, the lack of Laramide thrusting and folding reduces the possible contributions of fracturing to reservoir storage and transmissibility. Due to the probable deep late Paleozoic burial of this part of the succession, in comparison to Cretaceous burial, and the time for diagenetic processes to work at the reduction of reservoir quality, it is inferred that better reservoir quality will be found in the Cordillera than in the Interior Platform for this succession. The situation is analogous to the Liard Plateau and Plain to the south, where diastrophic fracturing in some units is an important contribution to reservoir quality.

All of the prospect volume characteristics of this play are based, as far as possible, on locally derived play and prospect parameters. An alternative would have been to use the pool parameters of the current slope-basin sandstone plays of the Atlantic and Gulf Coast passive margins as an analogue for this play. However, the strength of the analogue is unproven and it is likely that prospects will be evaluated on the basis of their local characteristics. It is inferred that this decision strongly depreciated the play potential, the number of expected pools and the size of the largest undiscovered pool. However, it is responsible considering the uncertainties in the play analogy. If discoveries are made and the analogy is strengthened then it is reasonable to review the assessment of this play and the possibility of using analogous pool and prospect-size parameters from the passive margin setting, especially where stratigraphic components of entrapment are demonstrated.

Minimum prospect sizes are based on rationale given in the discussion of other plays (Table 15). The size of more than half of the prospects is based on constraints from the geological map, and observations of seismic data within the Cordilleran Thrust and Fold Belt of the Peel Plateau (see elsewhere in this report). The upper limits on prospect area are 10 km^2 at 1% probability and 20 km^2 at 0 probability, approximately half of which are expected in the play in the same succession in the Cordillera. These estimates are derived from similar data and are likewise comparable with previous work.

Within this play, average net pay is controlled by the thickness of individual sandstone reservoir intervals, each of which will be a prospect. In the undeformed region, we can expect that stratigraphic prospects will be pursued individually, but that the number of sand bodies in a single prospect will be stacked only by stratigraphic processes. In comparison, there is both stratigraphic and structural stacking of reservoirs in the Cordillera, but it is unlikely that stratigraphic plays will be pursued there. Therefore, this play will have a significantly higher number of prospects in the Plains because of the greater number of prospects related to stratigraphic entrapments. The same is true for clastic plays in the Plains of the Alberta Basin, as compared to same stratigraphic intervals in the southern Cordillera. Therefore, in comparison to the Cordillera it is expected this play will have a significantly higher number of prospects, because of the greater component of stratigraphic entrapment and the absence of the diastrophic deformation. It is inferred that sandstone layers will vary between 2 and 20 m thickness, based largely on bedding characteristics inferred from wells. The sandstone thickness in this part of the play are inferred to be on average thinner than those west of the Trevor Fault, due to the more distal nature of the depositional setting. Thinner sandstone intervals are observed, but they are not likely to provide exploratory targets at this stage of exploration. The possibility of thicker sandstones cannot be entirely precluded, but they could not be adequately documented.

The diagenetic history of reservoir sandstones is poorly known. The prospect average porosities are reduced compared to the most prospective parts of the Cordillera because of the uninterrupted period for, and general tendency of diagenesis, to reduce reservoir quality with time. It is also likely that a tectonic component of diastrophic porosity enhancement, especially fracturing, will be lower here than in the Cordillera. The range of prospect average porosities, 5 to 15%, is consistent with facies and burial depths for both this depositional environment and tectonic setting. Formation Volume Factor parameters are consistent with the geological and tectonic setting of this play.

Derived prospect size

The derived expected prospect-size distribution for this play is 772 million m^3 with a standard deviation of 395 million m^3 (Table 16).

Number of prospects

The number of prospects is estimated to be between 60 and 500, with a greater than 50% probability that the number of prospects exceeds 250 (Table 15). This play parameter is difficult to infer. Two things complicate this estimate. There is little objective data on which to base the estimate, as the wells represent but a small sample of the play volume and the relationships between stacking of sandstone layers within individual structural prospects and the distribution of these sandstones relative to structures within the Peel Plain does not follow a predictable model, as in the Cordillera. Furthermore, the strength of the analogy to current slope-basin plays currently being exploited on the Atlantic and Gulf of Mexico passive margins has greater uncertainties and applicability in what should have been generally shallow-water setting over the Hume Platform, than would be expected over the Richardson Trough. There is a strong likelihood that all pools will have a strong component of stratigraphic entrapment, which is inherent from the depositional environment of these clastic sediments and the lack of diastrophic structure. It is less likely that we have underestimated the total number of prospects here compared to the two plays in the same succession in the Cordillera. The play potential here is strongly controlled by the degradation of reservoir potential that is inferred to result from the lack of tectonic porosity enhancement and the reduction in focused migration that is more typical of the strongly deformed rocks in the Cordillera. Results should be revised to reflect an improved data set and reduced play-level risks if discoveries are made in this play.

Play- and prospect-level exploration risks

The total risk placed on this play is high, but not as high as in either of the two plays in the Cordillera equivalents of this succession (Table 15). Neither are there any play-level risks, i.e., it is considered certain that some of these accumulations exist, based on shows in wells such as the three Shell Peel River wells (see petroleum systems and exploration history sections). The complexity, duration and uncertainties in the diagenetic and tectonic history serve to depreciate the potential of this play by increasing the number of potential points of failure and the duration over which reservoir and seal could be degraded. Seismic data shows clearly that a component of structural closure that was important in defining prospects in the Cordillera is not present east and north of the deformation front. This has implications for the timing of reservoir diagenesis, hydrocarbon migration and up-dip seal. Whether there was a significant charge of petroleum migrated out of the Cordillera during the Laramide orogeny is uncertain, but this could serve to increase the potential for charge at later times, while the strong components of stratigraphic entrapment provide better opportunities for seals, even if the quality of the reservoir is adversely affected by the lack of tectonic fracturing. Several processes remain poorly understood in this lightly explored region, however, the variations of possibilities are hopefully captured in the prospect-level risks used in this analysis.

This play analogue of deep-water slope and basin sandstones like those being exploited currently in the Gulf of Mexico, and on both the South American and African portions of the Atlantic passive margin, may be different here due to the setting and its impact on depositional processes. There are obvious differences in tectonic setting between Peel Plain and the Atlantic passive margin, but the general similarities of the depositional setting are preserved in the Upper Paleozoic succession. The cratonic and terrestrial setting of this play makes it more attractive than the same play in thousands of metres of water depth. However, the access to small prospects is adversely offset by the age of the reservoirs and their longer exposure to processes of reservoir degradation that would generally be interpreted to increase exploratory risks and decrease the size and number of accumulations.

The slope-basin sandstones of the Ritchie-Alger Assemblage in the Bowser Basin have had, like this play, a complicated diagenetic and tectonic history. Recent work by British Columbia Energy and Mines staff have shown that one of only two wells (Amoco Ritchie A -3-J/104-A-6) drilled in the Bowser Basin contains by-passed petroleum pay, probably gas (Hayes et al., 2004). This discovery has profound implications for the analogous deep-water clastic play in the Peel Plateau. It demonstrates that conditions for the preservation of both reservoir and petroleum can occur in the cratonic analogues of the passive margin deep-water plays, despite their complicated diagenetic and tectonic history. Local details of the diagenetic history for the Peel Plain Upper Paleozoic Clastics - C5530111 are not known, but they could be the subjects of future study. Once a discovery was made in this succession in this region, it would be necessary to carry out an intensive study to more adequately determine the levels of exploratory risks. The high risks imposed here are considered valid due to the uncertainties, or risks, associated with the appropriateness of the analogies discussed above. All of these factors included, the play is still considered to have potential largely because even more complicated settings appear to have not only preserved reservoir, but to have demonstrable evidence for hydrocarbon accumulation.

Resource potential

Paleozoic clastic rocks, although comprising a thinner succession dominated by non-reservoir facies than in the Cordillera, have a greater potential for a favourable stratigraphic component of entrapment. Therefore they have an improved potential for the preservation of the petroleum generated in the Paleozoic, as some petroleum system analyses suggest, with an uncertain gathering potential for petroleum generated during the Cordilleran deformation that could have also migrated north and east into the Foreland in front of the deformation.

The play potential suggests that between 0 and 36 pools could occur, but that 9 pools are expected (Table 17). The play potential is between 0 and 27.6 x 10^9 m^3 of initial raw gas in place, with an expected value of 7.260 x 10^9 m^3 of initial raw gas in place (Fig. 29). The largest expected pool is 1.352 x 10^9 m^3 initial raw gas in place (Table 18, Figure 30). The smaller size here reflects both the small available structures of the Plains, but also the more distal setting of this play area relative to the apparent source of these clastics. The total petroleum potential of the Peel Plain Upper Paleozoic Clastics - C5530111 is significant. Compared to the other two plays in this succession, as they occur in the Cordillera, much less of the expected play potential is predicted to occur within the largest pool, which has a median size of 1.352 x 10^9 m^3. This may be an undesirable result, since the wider distribution of potential among a larger number of pools might result in a situation where no pool is economically viable, in comparison to the large undiscovered potential attributed to the single undiscovered pool within the Cordillera.

The characteristics of the undiscovered resource are consistent with geological history and play characteristics, although they may be conservative considering play analogues, should those analogies hold in the Peel Plain. The combinations of geological characteristics for this play are favourable, but the exploratory risks are high. The lack of structure and the possibility of early hydrocarbon generation could significantly depreciate the potential of this play. Therefore the possibility that numerous accumulations will be found is unlikely, and it is also unlikely that any of the accumulations will be very large. The analytical results rate this as a less attractive play to pursue compared to the same succession in the Cordillera, largely because of the smaller undiscovered pool sizes. The lack of structure that is inferred to both enhance porosity and focus petroleum migration in the Cordillera, contrasts with the longer duration for reservoir degradation by diagenesis that reduces the potential of this play in the Peel Plain. Therefore, the assessment of this play should be seen as an indicator of a realizable potential, even if the undiscovered pool sizes are smaller than in the Cordillera. The possibility of stacked pay zones from several plays in different succession could help make this play economic on a field level.

C5520111 – Mesozoic Clastics

Structural or stratigraphic traps in the arenaceous to rudaceous clastic rocks of the Mesozoic succession of the Martin House, Arctic Red and Trevor formations, lying east of the limits of thrusting and folding in the undeformed Peel Plain, constitute a significant conceptual play for natural gas in the Peel Plain region. This play is designated Peel Plain Mesozoic Clastics - C5520111 (Fig. 22). Play parameters are inferred from a combination of map, well and seismic data; however, some play parameters and prospect-level risks must be inferred subjectively because of the lack of discoveries, and the inferred possibility of stratigaphic traps (Table 19). This play is a fluvial-shoreface and shallow shelf sandstone play that includes depositional settings similar to what are among the most active natural gas plays in Saskatchewan, Alberta and northeastern British Columbia.

Prospect–volume characteristics

The characteristics of this play are broadly similar to that of the other Mesozoic Clastic plays in this assessment (C-5510111, Figure 22, Table 31), accounting for the change in the structural setting. The possibilities for structural stacking and the component of closure due to Laramide diastrophism are not present in this play. The net impact of tectonic setting on this play is complicated, but in general it results in smaller prospects, with a greater component of stratigraphic entrapment. However, it probably enhances reservoir characteristics in the Mesozoic succession, as illustrated by the marked difference between the Mesozoic reserves in the Cordillera south of the Nahanni River and that in the facing Interior Platform of the south. Much more gas occurs in the Interior Platform, due to lower burial depths and tectonic compaction, which preserves reservoir quality, and because of the presence of a unique biogenic source for natural gases, as at Medicine Hat. Therefore it is inferred that better reservoir quality will be found in the Interior Platform than in the Cordillera for Mesozoic succession, although the effects of fracturing could have a beneficial effect in the Cordillera.

All of the prospect volume characteristics of this play are based, as far as possible, on locally derived play and prospect parameters (Table 19). An alternative would have been to use the pool parameters from the southern Foreland Basin. However, the strength of the analogue is unproven and it is likely that prospects will be evaluated on the basis of their local characteristics. If discoveries are made and the analogy to the southern Foreland Basin is strengthened, then it is reasonable to review the assessment of this play and the possibility of using analogous pool- and prospect-size parameters from existing discovered pool analogues.

The lower prospect size (Table 19) was inferred following rationales similar to that of previously discussed plays. The size of more than half of the prospects is based on inference and constraints from the geological map and observations of seismic data (see above). The upper values are approximately half that which are expected in the play on the same succession in the southern Cordillera. The generally consistent pool area throughout this analysis results from the stratigraphic layering in structures that affect the complete succession.

Within this play, average net pay is again controlled by the thickness of individual sandstone reservoir intervals, which might occur stacked in an individual structural prospect. Therefore, it is expected this play will have a significantly higher number of prospects in the Peel Plain than in the Cordillera, because of the greater component of stratigraphic entrapment and the absence of the diastrophic deformation. It is inferred that sandstone layers will vary between 2 and 20 m thickness, based largely on bedding characteristics inferred from wells. This thickness is also characteristic of gas plays in the Mesozoic succession to the south, where there are abundant discoveries. The diagenetic history of reservoir sandstones is not well known. The prospect average porosities of 5 to 20% are consistent with facies and burial depths for both this depositional environment and tectonic setting, as is the formation volume factor.

Derived prospect size

The derived prospect-size distribution for this play results from input play parameters, and is an expected prospect size of 920 million m^3 with a standard deviation of 728 million m^3 (Table 20).

Number of prospects

The number of prospects is estimated to be between 50 and 400, with a greater than 50% probability that the number of prospects exceeds 200 (Table 19). These estimates are conservative compared to southern productive portions of the Foreland Basin where even higher prospect densities occur. It is less likely that we may have underestimated the total number of prospects here compared to other plays in this assessment. However, results could be revised to reflect an improved data set and stronger comparisons to southern producing regions if discoveries are made in this play.

Play- and prospect-level exploration risks

The total risk placed on this play is moderate, but higher than that for the same succession in the Cordillera (Table 19). There are also no play-level risks, i.e., it is considered certain that some of these accumulations exist, both because of the seepage through these rocks at Swan Lake in the Northwest Territories, and due to the analogy with the southern Foreland Basin succession. Seismic data show clearly that a component of diastrophic structural closure that was important in defining prospects in the Cordillera is not present east and north of the deformation front. This has implications for the degree of compaction and the degradation of reservoir quality accompanying burial diagenesis. Whether a significant charge of petroleum migrated out of the Cordillera and into the Peel Plain, or across the sub-Mesozoic unconformity in the Peel Plain itself, is uncertain, but this could serve to increase the potential in this succession. Several of these processes remain uncertain in this lightly explored area, however, the variations of possibilities are hopefully captured in the prospect-level risks used in this analysis.

The play analogue/comparison to producing portions of the southern Foreland Basin in the Interior Platform is considered well founded and appropriate. The lower risks imposed here are considered valid due to observations in other parts of the Foreland Basin. The play is among the most attractive, and it has more than half of the total potential, of the entire assessment region.

Resource potential

Gas occurs ubiquitously in the Mesozoic Foreland succession of the Cordillera, as indicated by the discovery of more than 2 trillion m^3 of initial reserves in thousands of Mannville Group pools in Alberta, Saskatchewan and Northeastern British Columbia. There is no reason to believe that the Mesozoic Foreland Basin succession in the Peel Plain would not also have a significant potential gas resource. Like the more southern producing region, the accumulations will be expected to be predominantly stratigraphic, but like the south, it is expected that non-diastrophic structure, including compaction drape, will provide both the method for identifying these prospects as well as a component of the entrapment.

The play potential is between 0 and 139 x 10^9 m^3 of initial raw gas in place, with an expected value of 49.487 x 10^9 m^3 of initial raw gas in place (Fig. 31). The play potential calculation suggests that between 0 and 138 pools could occur, but that 55 pools are expected (Table 21). The accumulations can be inferred to be primarily of smaller size due to the small available structures and the complexity of the internal stratification that controls the stratigraphic components of entrapment (Fig. 32). The largest expected pool is 3.633 x 10^9 m^3 initial raw gas in place (Table 22).

The total petroleum potential of the Peel Plain Mesozoic Clastics - C5520111 is significant. Compared to the other plays in this assessment, a small amount of the expected play potential is predicted to occur within the largest pool, but this is compensated for by the large play potential. The median size of the largest undiscovered pool is estimated to be 3.356 x 10^9 m^3, or three times that in the largest pool expected in the next prospective play in the Peel Plains, the Upper Paleozoic Clastics - C5530111. In fact, the first 15 pools in this play have median potentials that would suggest they are larger or of comparable size to the deeper plays in this region. Clearly the undiscovered potential in the Peel Plain is inferred to occur primarily within the Mesozoic succession.

The characteristics of the undiscovered resource are consistent with geological history and play characteristics. The situation is similar to that of southern Alberta, where important accumulations occur within the Foothills, as at Waterton, but where the potential in the Plains occurs largely in the Mesozoic succession of the Foreland Basin, as at Medicine Hat, with very little petroleum potential or reserves proved in the underlying Paleozoic succession of the Interior Platform. This similarity, although unanticipated, provides an important confirmation of the assessment process, which has been successfully applied in the producing regions of the Cordillera and the Foreland Basin.

The size of the largest projected pools is also consistent with the size of the largest discovered pools in southern Alberta. If the Martin House Formation is seen as comparable to the Lower Manville Formation in stratigraphic position, as the lowest coarse clastic unit in the Foreland succession, we see that the largest pool in that succession in southern Alberta is the Long Coulee, Sunburst G pool, with a discovered initial in-place reserve of 2.666 x 10^9 m^3.

Therefore, we conclude that the combinations of geological characteristics for this play are favourable, and that the exploratory risks are moderate, with an opportunity similar to that of southern Alberta. The results rate this as among the most attractive plays, even in comparison to the same succession in the Cordillera, largely because of the smaller total resource and undiscovered pool sizes west of the deformation limit. It is, however, unlikely that any of the accumulations will be very large, considering current models. The possibility that numerous accumulations will be found is good and this might facilitate the production of groups of geographically associated pools. The possibility of stacked zones from plays in different parts of the succession could also make this play economic at the field level. The appropriateness of the play analogue to southern Alberta is strong, both in setting and in pool-size characteristics. Therefore, the assessment of this play should be seen as an indicator of a realizable potential. The lack of underlying potential in the Paleozoic succession makes it essential that the focus of exploration be on the Cretaceous succession itself, east of the deformed belt.

C5560111 – Paleozoic Carbonate Platform Play

Table 7. Input parameters.

Probability distributions of reservoir parameters					
Geological variable	Unit of measurement	Value at an upper percentile probability			
		1.00	0.50	0.01	0.00
Area of closure	km^2	0.4	5	20	45
Net pay	m	2	10	35	40
Porosity	decimal fraction	0.02	0.06	0.12	0.20
Gas saturation	decimal fraction	0.70	0.77	0.80	0.81
Gas compressibility factor	decimal fraction	0.94	0.96	0.98	0.98
Reservoir temperature	°C	70	110	120	125
Reservoir pressure	kPa	20 000	25 000	30 000	33 000

Marginal probabilities of geological risk factors	Marginal probability	Play level	Prospect level
Presence of closure	0.2		X
Presence of reservoir facies	0.8		X
Adequate seal	0.5		X
Appropriate timing	0.2		X
Adequate source	0.5		X

Probability distribution for number of prospects			
Probability in upper percentiles	0.99	0.5	0.00
Number of prospects	30	150	300

Table 8. Calculated prospect size using the lognormal approximation (millions of metres initial in place).

Logarithmic Mean = 5.0562	Expected (Mean) Value= 211.69	
Sigma Squared = 0.59778	Standard Deviation= 191.47	
99.99% = 8.8539	60.00% = 129.07	15.00% = 349.88
99.00% = 25.987	55.00% = 142.46	10.00% = 422.88
95.00% = 44.014	50.00% = 157.00	8.00% = 465.26
90.00% = 58.288	45.00% = 173.02	6.00% = 522.35
85.00% = 70.451	40.00% = 190.97	5.00% = 560.03
80.00% = 81.903	35.00% = 211.49	4.00% = 607.78
75.00% = 93.201	30.00% = 235.50	2.00% = 768.26
70.00% = 104.67	25.00% = 264.47	1.00% = 948.51
65.00% = 116.55	20.00% = 300.95	.01% = 2784.0

Table 9. Number of pools distribution.

Minimum number of pools	0
Maximum number of pools	11
Expected number of pools	1.25916
Standard Deviation=	1.28291
Play resource: (millions of cubic metres)	
Minimum	= 0.0
Maximum	= 2779.982
Expectation	= 271.6128
Standard Deviation	= 351.8854

Play potential greater than (millions of cubic metres)					
100.00	0.0	35.00	280.80	6.00	912.42
65.00	39.658	30.00	338.07	5.00	995.62
60.00	78.761	25.00	408.19	4.00	1095.4
55.00	116.01	20.00	486.22	2.00	1328.8
50.00	153.46	15.00	578.89	1.00	1564.5
45.00	192.73	10.00	725.79	0.01	2727.9
40.00	232.88	8.00	808.45	0.00	2774.8

Table 10. *Pool-size rank, followed by a description of the individual pool-size distribution.*

1	Expected (Mean) Value = 278.72	Standard Deviation = 229.56	P(N≥r) = .65924
	99% = 32.580	75% = 130.47	10% = 541.62
	95% = 58.240	50% = 218.45	5% = 698.81
	90% = 79.281	25% = 354.23	1% = 1134.9

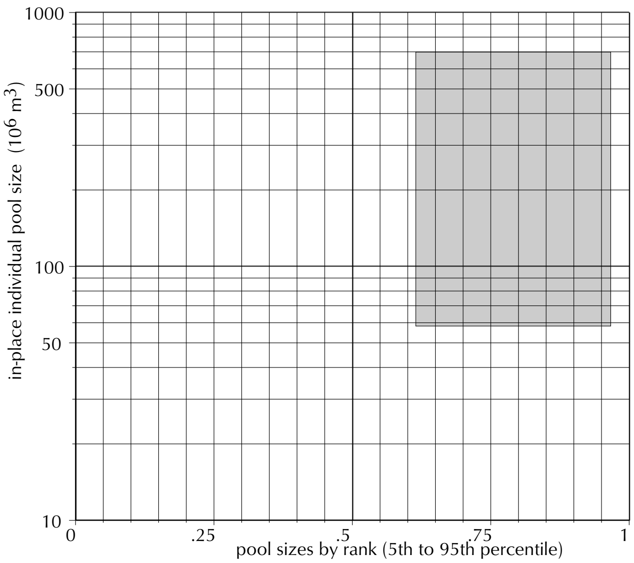


Figure 25. *Play potential plot.*

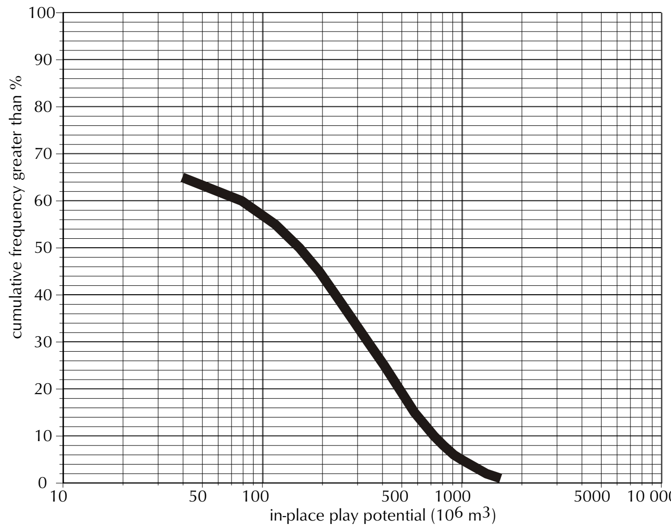


Figure 26. *Accumulation-size-by-rank plot. Details of individual pool-size distributions are given in Table 10.*

C5550111- Horn Plateau Reef Play

Table 11. *Input parameters.*

Probability distributions of reservoir parameters					
Geological variable	**Unit of measurement**	**Value at an upper percentile probability**			
		1.00	**0.50**	**0.01**	**0.00**
Area of closure	km²	1	5	8	10
Net pay	m	1	10	50	250
Porosity	decimal fraction	0.03	0.05	0.10	0.20
Gas saturation	decimal fraction	0.70	0.77	0.81	0.85
Gas compressibility factor	decimal fraction	0.94	0.96	0.98	0.98
Reservoir temperature	°C	70	110	120	125
Reservoir pressure	kPa	20 000	25 000	30 000	33 000

Marginal probabilities of geological risk factors	Marginal probability	Play level	Prospect level
Presence of closure	0.9		X
Presence of reservoir facies	0.1	X	
Adequate seal	0.9		X
Appropriate timing	1.0		X
Adequate source	0.9		X

Probability distribution for number of prospects			
Probability in upper percentiles	0.99	0.5	0.00
Number of prospects	1	10	40

Table 12. *Calculated prospect size using the lognormal approximation (millions of metres initial in place)*

Logarithmic Mean = 6.1684	Expected (Mean) Value = 755.76	
Sigma Squared = .91860	Standard Deviation = 927.39	
99.99% = 13.517	60.00% = 374.50	15.00% = 1289.2
99.00% = 51.355	55.00% = 423.26	10.00% = 1630.6
95.00% = 98.685	50.00% = 477.43	8.00% = 1835.5
90.00% = 139.79	45.00% = 538.54	6.00% = 2118.7
85.00% = 176.81	40.00% = 608.65	5.00% = 2309.8
80.00% = 213.10	35.00% = 690.71	4.00% = 2556.4
75.00% = 250.13	30.00% = 789.20	2.00% = 3418.0
70.00% = 288.82	25.00% = 911.30	1.00% = 4438.5
65.00% = 330.01	20.00% = 1069.6	0.01% = 16863.

Table 13. *Number of pools distribution.*

Minimum number of pools	0				
Maximum number of pools	37				
Expected number of pools	1.14453				
Standard Deviation=	4.40238				
Play resource:(billions of cubic metres)					
Minimum	= 0.0				
Maximum	= 32.37705				
Expectation	= .8881077				
Standard Deviation	= 3.504533				
Play potential greater than (billions of cubic metres)					
100.00	0.0	5.00	6.7448	1.00	19.307
8.00	2.2546	4.00	9.2399	.01	31.480
6.00	4.9818	2.00	16.084	.00	32.287

Table 14. *Pool-size rank, followed by a description of the individual pool-size distribution.*

1	Expected (Mean) Value = 2381.5	Standard Deviation - 1956.3	P(N≥r) = .99180E-01
	99% = 192.56	75% = 1135.4	10% = 4543.1
	95% = 439.67	50% = 1922.7	5% = 5836.3
	90% = 644.53	25% = 3033.6	1% = 9591.6

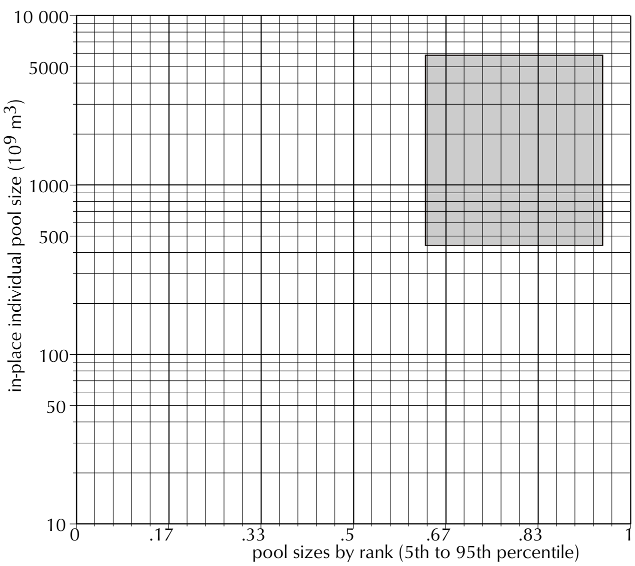


Figure 27. *Play potential plot.*

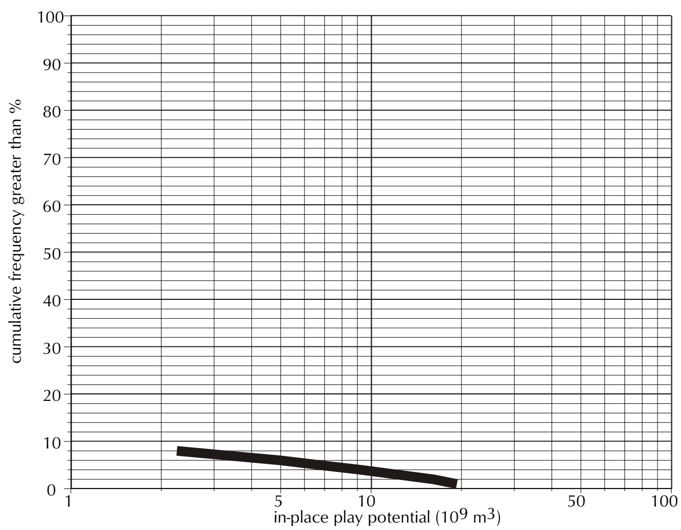


Figure 28. *Accumulation-size-by-rank plot. Details of individual pool-size distributions are given in Table 14.*

C5530111- Upper Paleozoic Clastics Play

Table 15. *Input parameters.*

Probability distributions of reservoir parameters					
Geological variable	**Unit of measurement**	**Value at an upper percentile probability**			
		1.00	**0.50**	**0.01**	**0.00**
Area of closure	km^2	0.4	5	15	20
Net pay	m	2	10	35	40
Porosity	decimal fraction	0.05	0.06	0.08	0.15
Gas saturation	decimal fraction	0.70	0.77	0.80	0.91
Gas compressibility factor	decimal fraction	0.94	0.96	0.98	0.98
Reservoir temperature	°C	50	70	70	110
Reservoir pressure	kPa	20 000	21 000	22 000	23 000

Marginal probabilities of geological risk factors	Marginal probability	Play level	Prospect level
Presence of closure	0.5		X
Presence of reservoir facies	0.7		X
Adequate seal	0.4		X
Appropriate timing	0.5		X
Adequate source	0.5		X

Probability distribution for number of prospects			
Probability in upper percentiles	0.99	0.5	0.00
Number of prospects	60	250	500

Table 16. *Calculated prospect size using the lognormal approximation (millions of metres initial in place)*

Logarithmic Mean = 6.5331	Expected (Mean) Value = 772.34	
Sigma Squared = 0.23273	Standard Deviation = 395.36	
99.99% = 114.31	60.00% = 608.41	15.00% = 1133.5
99.00% = 223.81	55.00% = 647.06	10.00% = 1275.8
95.00% = 310.92	50.00% = 687.50	8.00% = 1354.1
90.00% = 370.48	45.00% = 730.47	6.00% = 1455.5
85.00% = 416.99	40.00% = 776.88	5.00% = 1520.2
80.00% = 458.08	35.00% = 827.95	4.00% = 1599.8
75.00% = 496.54	30.00% = 885.40	2.00% = 1851.7
70.00% = 533.83	25.00% = 951.89	1.00% = 2111.9
65.00% = 570.88	20.00% = 1031.8	.01% = 4134.8

Table 17. *Number of pools distribution.*

Minimum number of pools	0
Maximum number of pools	36
Expected number of pools	9.25908
Standard Deviation=	5.39641
Play resource: (billions of cubic metres)	
Minimum	= .0 000000E+00
Maximum	= 27.59620
Expectation	= 7.260026
Standard Deviation	= 4.380226

Play potential greater than (billions of cubic metres)

100.00	0.0	55.00	6.1362	8.00	13.924
99.00	33379	50.00	6.7263	6.00	14.700
95.00	1.1521	45.00	7.3981	5.00	15.162
90.00	1.9489	40.00	8.0641	4.00	15.627
85.00	2.5999	35.00	8.7398	2.00	17.323
80.00	3.1681	30.00	9.5145	1.00	18.724
75.00	3.7273	25.00	10.306	.01	26.776
70.00	4.2834	20.00	11.024	.00	27.514
65.00	4.8640	15.00	11.920		
60.00	5.5146	10.00	13.208		

Table 18. *Pool-size rank, followed by a description of the individual pool-size distribution.*

1	Expected (Mean) Value = 1417.5	Standard Deviation = 514.16	P(N≥r) = .99044
	99% = 475.23	75% = 1074.3	10% = 2061.9
	95% = 709.27	50% = 1351.5	5% = 2343.0
	90% = 843.51	25% = 1682.3	1% = 3020.9
2	Expected (Mean) Value = 1068.9	Standard Deviation = 339.51	P(N≥r) = .96095
	99% = 355.00	75% = 839.72	10% = 1499.6
	95% = 533.68	50% = 1054.5	5% = 1649.1
	90% = 645.45	25% = 1277.1	1% = 1975.5
3	Expected (Mean) Value = 908.56	Standard Deviation = 280.84	P(N≥r) = .91119
	99% = 304.31	75% = 716.47	10% = 1265.3
	95% = 449.31	50% = 905.88	5% = 1376.7
	90% = 544.52	25% = 1091.4	1% = 1608.0
4	Expected (Mean) Value = 809.00	Standard Deviation = 246.57	P(N≥r) = .84812
	99% = 276.94	75% = 638.21	10% = 1123.0
	95% = 401.54	50% = 809.78	5% = 1215.6
	90% = 484.50	25% = 974.19	1% = 1402.3
5	Expected (Mean) Value = 738.29	Standard Deviation = 222.15	P(N≥r) = .77902
	99% = 259.29	75% = 583.00	10% = 1022.0
	95% = 370.41	50% = 739.91	5% = 1103.1
	90% = 444.34	25% = 889.38	1% = 1263.4
6	Expected (Mean) Value = 683.75	Standard Deviation = 203.18	P(N≥r) = .70848
	99% = 246.35	75% = 540.85	10% = 944.08
	95% = 347.65	50% = 685.25	5% = 1017.3
	90% = 414.64	25% = 823.05	1% = 1159.8
7	Expected (Mean) Value = 639.32	Standard Deviation = 187.74	P(N≥r) = .63880
	99% = 235.97	75% = 506.73	10% = 880.64
	95% = 329.58	50% = 640.31	5% = 947.92
	90% = 390.99	25% = 768.53	1% = 1077.7
8	Expected (Mean) Value = 601.73	Standard Deviation = 174.78	P(N≥r) = .57109
	99% = 227.15	75% = 477.93	10% = 827.12
	95% = 314.40	50% = 602.07	5% = 889.80
	90% = 371.15	25% = 722.18	1% = 1009.8
9	Expected (Mean) Value = 569.07	Standard Deviation = 163.68	P(N≥r) = .50587
	99% = 219.34	75% = 452.86	10% = 780.83
	95% = 301.12	50% = 568.71	5% = 839.79
	90% = 353.86	25% = 681.83	1% = 952.01

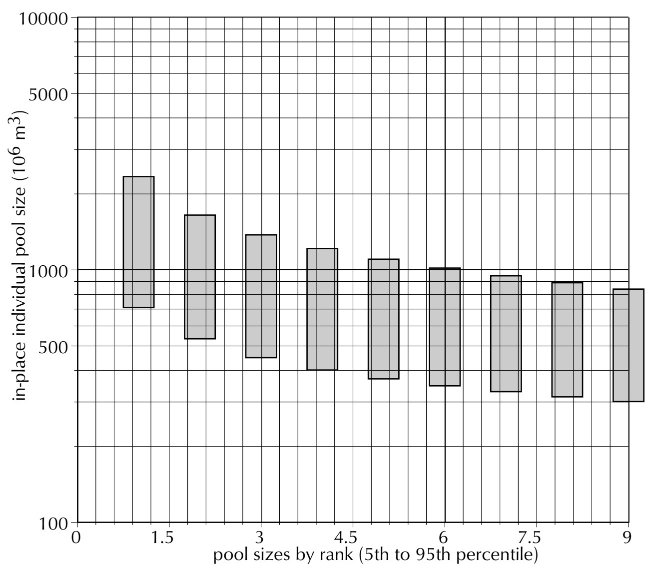


Figure 29. *Play potential plot.*

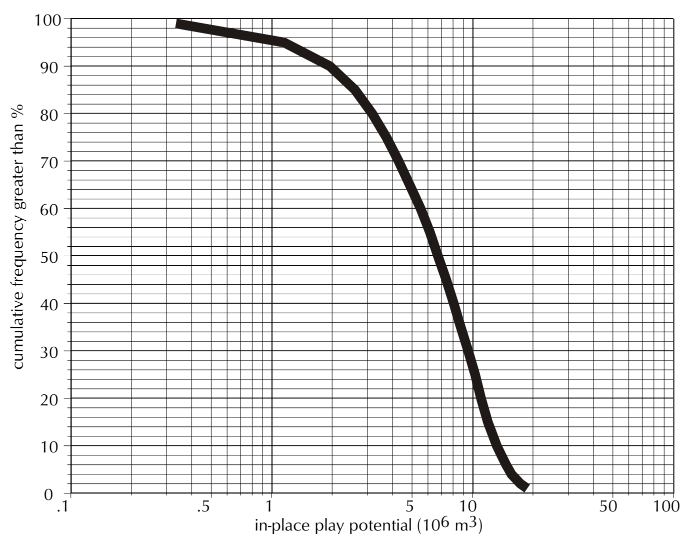


Figure 30. *Accumulation-size-by-rank plot. Details of individual pool-size distributions are given in Table 18.*

C5520111 – Mesozoic Clastics Play

Table 19. *Input parameters.*

Probability distributions of reservoir parameters					
Geological variable	**Unit of measurement**	**Value at an upper percentile probability**			
		1.00	**0.50**	**0.01**	**0.00**
Area of closure	km²	0.4	5	10	12
Net pay	m	2	10	25	40
Porosity	decimal fraction	0.05	0.08	0.15	0.20
Gas saturation	decimal fraction	0.65	0.75	0.80	0.85
Gas compressibility factor	decimal fraction	0.90	0.92	0.94	0.98
Reservoir temperature	°C	25	30	35	40
Reservoir pressure	kPa	10 000	18 000	20 000	22 000

Marginal probabilities of geological risk factors	Marginal probability	Play level	Prospect level
Presence of closure	0.5		X
Presence of reservoir facies	0.7		X
Adequate seal	0.4		X
Appropriate timing	0.5		X
Adequate source	0.5		X

Probability distribution for number of prospects			
Probability in upper percentiles	0.99	0.5	0.00
Number of prospects	60	250	500

Table 20. *Calculated prospect size using the lognormal approximation (millions of metres initial in place).*

Logarithmic Mean = 6.5819	Expected (Mean) Value = 920.40	
Sigma Squared = .48592	Standard Deviation = 728.03	
99.99% = 54.022	60.00% = 605.01	15.00% = 1486.7
99.00% = 142.62	55.00% = 661.33	10.00% = 1763.7
95.00% = 229.35	50.00% = 721.87	8.00% = 1922.3
90.00% = 295.45	45.00% = 787.96	6.00% = 2133.8
85.00% = 350.50	40.00% = 861.31	5.00% = 2272.1
80.00% = 401.49	35.00% = 944.31	4.00% = 2446.0
75.00% = 451.10	30.00% = 1040.4	2.00% = 3021.4
70.00% = 500.85	25.00% = 1155.2	1.00% = 3653.7
65.00% = 551.84	20.00% = 1297.9	.01% = 9646.1

Table 21. *Number of pools distribution.*

Minimum number of pools	0
Maximum number of pools	138
Expected number of pools	55.01390
Standard Deviation	= 27.23049
Play resource: (billions of cubic metres)	
Minimum	= 0.0
Maximum	= 139.1178
Expectation	= 49.48738
Standard Deviation	= 25.81436
Play potential greater than (billions of cubic metres)	

100.00	0.0	55.00	42.768	8.00	87.846
99.00	7.1327	50.00	46.447	6.00	91.343
95.00	12.975	45.00	51.235	5.00	93.114
90.00	16.682	40.00	55.609	4.00	95.001
85.00	20.495	35.00	60.557	2.00	99.913
80.00	24.165	30.00	65.401	1.00	107.67
75.00	27.931	25.00	70.118	0.01	138.94
70.00	31.707	20.00	74.641	0.00	139.10
65.00	35.430	15.00	79.168		
60.00	39.197	10.00	84.661		

Table 22. *Pool-size rank, followed by a description of the individual pool-size distribution.*

1	Expected (Mean) Value = 3633.1	Standard Deviation = 1463.5	P(N≥r)=1.00000
	99% = 1437.8	75% = 2665.8	10% = 5404.6
	95% = 1875.4	50% = 3356.3	5% = 6305.9
	90% = 2149.2	25% = 4265.5	1% = 8655.7
2	Expected (Mean) Value = 2683.3	Standard Deviation = 828.45	P(N≥r)=1.00000
	99% = 1143.2	75% = 2112.7	10% = 3738.6
	95% = 1490.6	50% = 2600.0	5% = 4156.2
	90% = 1708.8	25% = 3148.6	1% = 5122.5
3	Expected (Mean) Value = 2271.0	Standard Deviation = 652.01	P(N≥r)=1.00 000
	99% = 961.95	75% = 1818.0	10% = 3105.0
	95% = 1265.9	50% = 2237.7	5% = 3394.6
	90% = 1458.7	25% = 2672.7	1% = 4026.6
4	Expected (Mean) Value = 2014.3	Standard Deviation = 567.75	P(N≥r)= .99999
	99% = 828.12	75% = 1618.1	10% = 2738.1
	95% = 1105.9	50% = 2004.0	5% = 2967.9
	90% = 1283.6	25% = 2382.4	1% = 3451.5
5	Expected (Mean) Value = 1830.1	Standard Deviation = 517.94	P(N≥r)= .99997
	99% = 720.33	75% = 1467.6	10% = 2487.1
	95% = 981.01	50% = 1833.3	5% = 2681.7
	90% = 1148.9	25% = 2177.6	1% = 3080.7
6	Expected (Mean) Value = 1687.4	Standard Deviation = 484.95	P(N≥r)= .99989
	99% = 628.96	75% = 1347.3	10% = 2299.2
	95% = 878.21	50% = 1699.6	5% = 2470.3
	90% = 1039.3	25% = 2020.9	1% = 2814.2
7	Expected (Mean) Value = 1571.3	Standard Deviation = 461.46	P(N≥r)= .99965
	99% = 549.22	75% = 1247.6	10% = 2150.4
	95% = 790.66	50% = 1590.2	5% = 2304.6
	90% = 947.08	25% = 1894.9	1% = 2609.4
8	Expected (Mean) Value = 1474.0	Standard Deviation = 443.77	P(N≥r)= .99910
	99% = 479.02	75% = 1162.7	10% = 2028.0
	95% = 714.63	50% = 1497.8	5% = 2169.3
	90% = 867.69	25% = 1790.1	1% = 2444.8
9	Expected (Mean) Value = 1390.6	Standard Deviation = 429.67	P(N≥r)= .99797
	99% = 418.00	75% = 1089.4	10% = 1924.7
	95% = 648.13	50% = 1418.3	5% = 2055.7
	90% = 798.62	25% = 1700.7	1% = 2308.3
10	Expected (Mean) Value = 1318.3	Standard Deviation = 417.74	P(N≥r)= .99592
	99% = 366.62	75% = 1025.5	10% = 1835.6
	95% = 590.27	50% = 1348.8	5% = 1958.2
	90% = 738.48	25% = 1623.1	1% = 2192.3
11	Expected (Mean) Value = 1255.0	Standard Deviation = 407.00	P(N≥r)= .99261
	99% = 325.11	75% = 969.61	10% = 1757.5
	95% = 540.67	50% = 1287.5	5% = 1873.2
	90% = 686.50	25% = 1554.8	1% = 2092.0
12	Expected (Mean) Value = 1199.5	Standard Deviation = 396.80	P(N≥r)= .98776
	99% = 292.85	75% = 920.83	10% = 1688.4
	95% = 499.08	50% = 1233.1	5% = 1798.1
	90% = 642.14	25% = 1494.2	1% = 2003.9
13	Expected (Mean) Value = 1150.5	Standard Deviation = 386.79	P(N≥r)= .98123
	99% = 268.47	75% = 878.26	10% = 1626.5
	95% = 465.00	50% = 1184.5	5% = 1731.0
	90% = 604.82	25% = 1439.8	1% = 1925.6
14	Expected (Mean) Value = 1107.2	Standard Deviation = 376.82	P(N≥r)= .97307
	99% = 250.33	75% = 841.12	10% = 1570.6
	95% = 437.60	50% = 1141.1	5% = 1670.4
	90% = 573.75	25% = 1390.6	1% = 1855.4
15	Expected (Mean) Value = 1068.5	Standard Deviation = 366.89	P(N≥r)= .96349
	99% = 236.88	75% = 808.55	10% = 1519.7
	95% = 415.76	50% = 1101.9	5% = 1615.4
	90% = 547.96	25% = 1345.8	1% = 1791.8

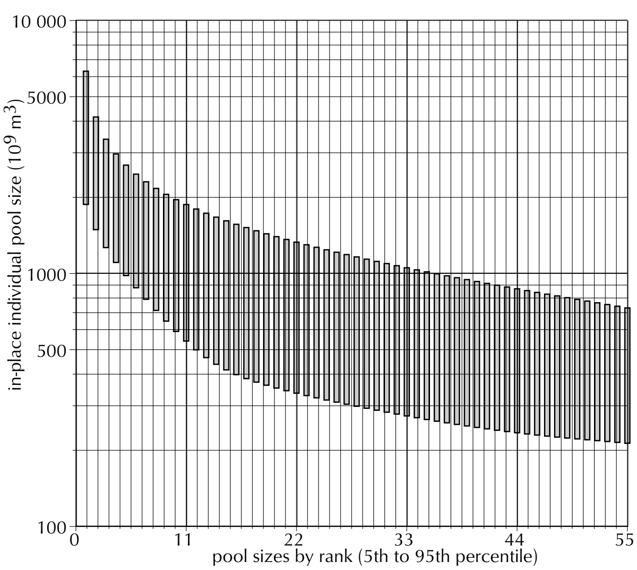


Figure 31. *Play potential plot.*

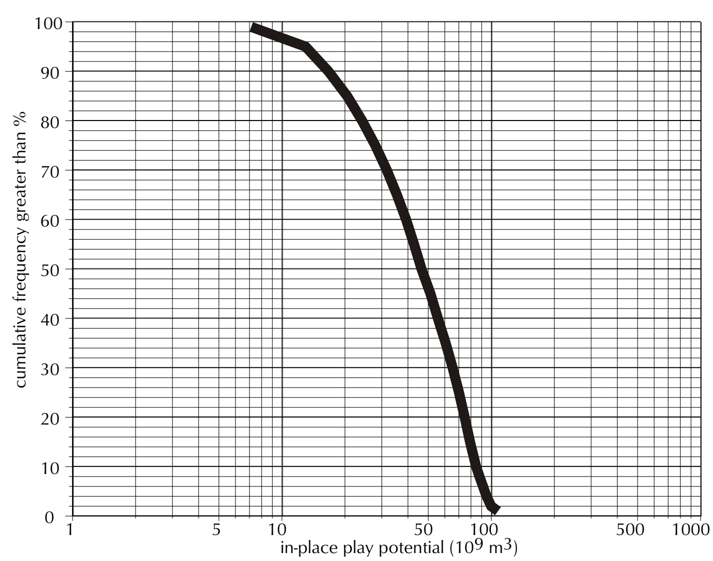


Figure 32. *Accumulation-size-by-rank plot. Details of individual pool-size distributions are given in Table 22.*

PEEL PLATEAU

C5570111 – Paleozoic Carbonate Margin

Structural or stratigraphic traps in the ramp carbonates of the Hume Formation and older Cambrian to Devonian carbonate succession, lying within the Cordillera in the Peel Plateau, constitute a possible, but speculative conceptual play for natural gas in the Peel Plateau region. This play is designated Peel Plateau Paleozoic Carbonate Margin - C5570111 (Fig. 22). Play parameters are inferred from a combination of map, well and seismic data; however, some play parameters and prospect-level risks must be inferred subjectively because of the lack of discoveries, and the reasonable, but still reconnaissance-scale of the geoscience data set (Table 23).

This play includes regions where the Cambrian to Devonian carbonate margin and adjacent platform were deformed within the eastern thrust and fold belt of the Cordillera. The margin east of the surface trace of the Trevor Fault is characterized by thick and laterally extensive Paleozoic platformal carbonates that pass abruptly into the basinal facies of the Road River Group. While this facies change probably affects the mechanical stratigraphy and structural style, the stratigraphic component of entrapment related to the carbonate facies change is considered unimportant to the potential of this play. This is largely because the facies change is unfavourably oriented to provide a major trap with respect to Paleozoic depositional slope and Laramide tectonic dip. Before the formation of Laramide structures, hydrocarbons migrating into the abrupt carbonate margin would have been lost into the persistent carbonate platform, probably during the widely accepted Late Paleozoic phase of petroleum generation. To the east or north of this facies transition and structure, the Hume and older carbonate platform and overlying clastic-dominated formations are involved in the thrusts and folds of the Laramide diastrophic deformation of the Cordillera. The play can be considered to be the rough analogue of the Liard Plateau Overthrust Play, developed on the eastern flank of the northernmost Cordillera.

Prospect-volume characteristics

All prospects are inferred to exceed 0.4 km^2 in area, with more than half of the prospects inferred to exceed 5.0 km^2. The lower value is inferred to represent the approximate limits of definable structures consistent with lower limits of prospect size used in previous assessments (Table 23). The size of more than half of the prospects is based on constraints from the geological map, and observations of seismic data within the Cordilleran Thrust and Fold Belt of the Peel Plateau (Table 23). The estimates are derived from similar data to that used by previous assessment studies (Bird, 2000, 1999; Hannigan, 2001), although the seismic interpretation used here is much different. The upper limits on prospect area are 10 km^2 at 1% probability and 20 km^2 at 0 probability, approximately half that which are expected in the play on the same succession in the Cordillera.

Within this play, average net pay is controlled by the thickness of ramp-type stratiform porous intervals that are developed within each of the carbonate formations. There is no clear evidence for a thick platform margin reef build-up and no certainty that even if it existed, that it would be suitably located in the deformed structure. It is inferred that porous layers will vary between 2 and 40 m thick, based largely on data inferred from wells in the deformed and undeformed platform successions. The diagenetic history of reservoirs is poorly known, but it is known that the Manetoe dolostones do not extend north into the assessment region. Therefore the development of porous intervals will be typically stratiform, as is typical of ramp depositional settings. The range of prospect average porosities, 2 to 20%, is consistent with facies and burial depths for both this depositional environment and tectonic setting. Formation Volume Factor parameters capture reasonably expected values considering the geological and tectonic setting of this play.

Derived prospect size

The characteristics of the derived prospect-size distribution for this play resulting from the analysis of input play parameters and their combination is provided below, in millions of cubic metres, as a function of cumulative probability. The expected prospect size is 676 million m^3 with a standard deviation of 694 million m^3 (Table 24).

Number of prospects

The number of prospects is estimated to be between 10 and 200, with a greater than 50% probability that the number of prospects exceeds 100 (Table 23). There is insufficient data to truly map the prospects in the play. The long distance between seismic lines makes it impossible to map individual structures between points of control. It is likely that we have underestimated the total number of prospects, due to the internal complications of the structure.

Play- and prospect-level exploration risks

The total risk placed on this play is high, especially with respect to timing (Table 23). All of the concerns expressed for the Carbonate Platform Play - C5560111 in the Interior Platform are generally valid here also. Trap is provided by the Laramide structure. The advantage of this play is that the risk of having closure is greatly reduced. After locating seismic anomalies relative to the position of the wells drilled in this area, it is clear that some wells were not optimally located with respect to structure, either due to insufficient seismic data, or access and logistics problems. Many of the drills appear to have been barged or transported on “winter roads” up the rivers in the region, “as close as possible” to the structure. The facies transition is unfavourably oriented with respect to trapping migrating hydrocarbons, but the impact of Laramide diastrophism reduces this risk by providing structural closure, and its own charge of hydrocarbons, from the footwall succession. For these reasons the exploratory risks of the Paleozoic carbonate platform in the Cordillera are less compared to similar plays in the platform.

It may be that concerns about the timing of hydrocarbon generation relative to trap formation could have been reduced compared to the Interior Platform, but they were not. It appears that there is a general syntectonic generation of hydrocarbons in the footwall of thrust faults that accompanies the deformation. Elsewhere, fracturing may have improved reservoir porosity or provided communication between stratiform porous zones. In this fashion the play can be considered an analogue to the Liard Plateau play, without the regional reservoir diagenesis. However, the possibility of syntectonic hydrocarbon generation would have to be documented before that risk could be reduced.

Resource potential

This region contains the temporally and geographically persistent Platform to Basin facies transition that marks the eastern margin of the Richardson Trough. This facies transition is unfavourably oriented with respect to the Cordilleran structure to provide a distinctive trapping mechanism for early-generated hydrocarbons. Neither is there strong evidence to support a distinctive diagenetic history that would help to preserve reservoir quality by way of hydrothermal dolomitization. Therefore, the plays in Paleozoic carbonates of this region will be in Cordilleran structural culminations where fractured stratiform limestone and dolostone porosity will constitute potential reservoirs in a petroleum system that experienced its first peak generation during the late Paleozoic. The remaining potential is for dry, over-mature gas generated by combinations of foreland and tectonic burial, or for gas generated in the Paleozoic to be re-migrated into Cordilleran structures.

The play potential calculation suggests that between 0 and 29 pools could occur, with an expected 7 pools (Table 25). The play potential is between 0 and 22.28 x 10^9 m^3 of initial raw gas in place, with an expected value of 4.46 x 10^9 m^3 of initial raw gas in place (Fig. 33). It is expected that the Peel Plateau Cambrian to Devonian Carbonate Margin play will consist of seven gas pools with a mean potential of approximately 4.460 x 10^9 m^3 initial raw gas in place (Fig. 34). The largest expected pool is 1.604 x 10^9 m^3 initial raw gas in place (Table 26).

The total petroleum potential of the Paleozoic Carbonate Margin - C5570111 is significant. The largest pool predicted for the play is generally comparable to the largest pool predicted for the Mesozoic play in the Cordillera. The number of medium and large pools is, however, small. The play is significantly adversely affected by the large prospect-level risks on both reservoir and timing, as is appropriate considering the general results exploring this succession in both the Cordillera and the plains north of the Nahanni River and the absence of a Manetoe dolostones to improve reservoir quality. However, once a discovery is made it is expected that the very sizeable prospect-level risks on reservoir and timing could collapse, and that the potential of this play would revise upward significantly.

Upper Paleozoic Clastics, C5540111

Structural or stratigraphic traps in the arenaceous to rudaceous clastic rocks of the post-Canol Paleozoic succession of the Imperial, Ford Lake and Tuttle formations, lying east, or in the footwall of the Trevor Fault, but which are involved in Laramide structures west of the limits of thrusting and folding constitute a significant conceptual play for natural gas in the Peel Plateau region. This play is designated Peel Plateau Upper Paleozoic Clastics - C5540111 (Fig. 22). Play parameters (Table 27) are measured and inferred as for other plays above. This play is a shoreface, slope-basin sandstone play that includes depositional settings similar to what are among the most attractive plays in the current exploration portfolio of major oil companies, on passive margins, as mentioned above.

Prospect-volume characteristics

All of the prospect volume characteristics of this play are based, as far as possible, on locally derived play and prospect parameters. The alternative would have been to use the pool parameters of the current slope-basin sandstone plays of the Atlantic and Gulf Coast passive margins as an analogue for this play. However, this was not done for the same reasons discussed above (C5530111, Figure 22; Table 15), recognizing that this strongly depreciated play potential. If discoveries are made and the analogy is strengthened then it is reasonable to review the assessment and the possibility of using analogous pool and prospect-size parameters from the passive margin setting.

The size of more than half of the prospects is based on constraints from the geological map, and observations of seismic data within the Cordilleran Thrust and Fold Belt of the Peel Plateau. The upper limits on prospect area, 20 km^2 at 1% probability and 40 km^2 at 0 probability, are derived from similar data and are likewise comparable with previous work.

Within this play, average net pay is controlled by the thickness of individual sandstone reservoir intervals, many of which may be stacked in an individual structural prospect, but each of which is, by virtue of its stratigraphic components an individual prospect. It is inferred that sandstone layers will vary between 15 and 40 m in thickness, based largely on bedding characteristics of the target formations in field photographs. The sandstone thickness in this part of the play are inferred to be, on average thicker than those west of the Trevor Fault, discussed below, due to the more proximal nature of the depositional setting. Thinner sandstone intervals are observed, but they are not likely to provide exploratory targets at this stage of exploration. The possibility of thicker sandstones cannot be entirely precluded, but they could not be adequately documented to allow for quantitative analysis.

The diagenetic history of reservoir sandstones is not well known, but the range of prospect average porosities, 9 to 20%, is consistent with facies and burial depths for both this depositional environment and tectonic setting. Formation Volume Factor parameters including gas composition capture reasonably expected values considering the geological and tectonic setting of this play.

Derived prospect size

The derived expected prospect-size distribution for this play is 4852 million m^3 with a standard deviation of 3114 million m^3 (Table 28).

Number of prospects

The number of prospects is estimated to be between 40 and 400, with a greater than 50% probability that the number of prospects exceeds 200 (Table 27). Two things complicate this estimate. There is little objective data on which to base the estimate, as the wells represent only a small sample of the play volume; and the relationships between stacking of sandstone layers within individual structural prospects and the distribution of these sandstones relative to structural shape, as a function of mechanical stratigraphy, is unknown. There is a strong likelihood that all pools will have a component of stratigraphic entrapment, which is inherent from the depositional environment of these clastic sedimentary rocks, especially within deeper water slope environments typical of the Imperial Formation.

The long distance between seismic lines makes it impossible to know how structural culminations and thrusts are linked between points of control. However, when the complications due to a stratigraphic component of entrapment are considered, it is likely that we have may have underestimated the total number of prospects. The discussion below shows that the role of number of pools, as a function of exploration risks, is a dominant control on the size of individual accumulations and the potential of the play. Results should be revised to reflect an improved data set and prospect-level risks if discoveries are made in this play.

Play- and prospect-level exploration risks

The total risk placed on individual prospects is high, but not prohibitive (Table 27). There are no play-level risks, indicating the play is inferred to exist, due to shows in wells, which suggest that the petroleum system has operated, and that it is only the number and size of accumulations that must be inferred. Seismic data show clearly that a component of structural closure may exist and that the general structural style is similar to that of other regions in the Cordillera where production is established. The complexity, duration and uncertainties in the diagenetic and tectonic history would typically serve to depreciate the potential of this play, by increasing the number of potential points of failure and the duration over which charge, reservoir and seal could be degraded. However, the standard analysis of the Liard Plateau petroleum system would suggest that hydrocarbon generation was early in that region also. Other analyses might suggest that the actual petroleum system functioning in this part of the play is like that found elsewhere in the Cordillera and that footwall sources might provide the majority of the charge syntectonically. This question cannot be resolved within the scope of this study, but the variations of possibilities are captured in the prospect-level risks used in this analysis.

Should a discovery be made in this succession, more intensive study would be necessary to adequately determine the levels of exploratory risks.

Resource potential

Paleozoic clastic rocks, although comprising a thinner succession than the Paleozoic carbonates and being dominated by non-reservoir facies, have a greater potential for a favourable stratigraphic component of entrapment. Therefore they have an improved potential for the preservation of the petroleum generated in the Paleozoic, without depreciating the potential to trap petroleum generated during the Cordilleran deformation.

The play potential curve and pool-size-by-rank diagram describe the petroleum potential of this play in additional detail, however, the play potential is essentially captured by characteristics of the two predicted pools and the discussion of exploratory risk elsewhere in this report. The play potential is described by the expected, or mean, play potential, the number of expected pools, and the median of the expected pool sizes. The play potential calculation suggests that between 0 and 13 pools could occur, but that two pools are expected (Table 29). The play potential is between 0 and 62.13 x 10^9 m^3 of initial raw gas in place, with an expected value of 7.799 x 10^9 m^3 of initial raw gas in place (Fig. 35). The largest expected pool is 5.517 x 10^9 m^3 initial raw gas in place (Table 30). This is the single largest projected pool in this assessment. It is likely to occur as a slope-basin sandstone body, in an accumulation that resembles deep-water sandstone plays on current oceanic margins. Note that the individual median and mean pool sizes do not sum to the statistically inferred play potential, due to the different statistical calculations used to determine play potential compared to the calculation of undiscovered pool sizes.

The analytical results rate this as an attractive play to pursue for its likely large individual undiscovered pool. The total petroleum potential of the Peel Plateau Upper Paleozoic Clastics - C5540111 is significant. Most of the expected potential is predicted to occur within the largest pool, which has a median size of 5.517 x 10^9 m^3, and which is the largest undiscovered pool predicted for this entire assessment (Fig. 36, Table 30). The characteristics of the undiscovered resource are consistent with geological history and play characteristics, although they may be conservative considering the play analogues.

C5510111 – Mesozoic Clastics

Structural or stratigraphic traps in the arenaceous to rudaceous clastic rocks of the Mesozoic succession of the Martin House, Arctic Red and Trevor formations, lying in the allocthonous Cordillera, west or south of the limits of thrusting and folding in the Peel Plateau, constitute a significant conceptual play for natural gas. This play is designated Peel Plateau Mesozoic Clastics – C5510111 (Fig. 22). Play parameters are inferred as above; however, some play parameters and prospect-level risks must be also inferred subjectively because of the lack of discoveries (Table 31). This play occurs in a fluvial-shoreface and shallow-shelf sandstone play that includes depositional settings similar to active natural gas plays in the southern Cordillera. An equivalent succession in the south have proven reserves, accounting for about 15% of the volume in equivalent successions of the Interior Platform. In the southern Cordillera, pools in the Mesozoic succession were the second identified, and first commercially productive interval; however, it has been more common for pools in the Cretaceous succession to be discovered as additional up-hole plays that are encountered fortuitously during the development of deeper Devonian, Carboniferous and Triassic reservoirs.

Prospect-volume characteristics

The characteristics of this play are broadly similar to that of the other Mesozoic Clastic plays in this assessment (C-5520111, Figure 22, Table 19). However, there are distinctive differences because of the change in structural setting. The possibility for structural stacking, and the closure due to Laramide diastrophism, increases within the Cordillera. The net impact on this play is complicated, but in general it results in larger prospects, although there are higher risks on closure even where there is a strong component of stratigraphic entrapment. Within the Cordillera, deeper burial and greater compaction degrades reservoir characteristics in the Mesozoic succession. Therefore it is inferred that better reservoir quality will be found in the Interior Platform than in the Cordillera for Mesozoic succession, although the effects of fracturing could have a beneficial effect in the Cordillera.

About half of the prospects are using constraints from the geological map, and observations of seismic data (see above). The upper limits on prospect area, 20 km^2 at 1% probability and 105 km^2 at 0 probability, reflect the structural style and the tendency for the higher stratigraphic units to have much more volume under closure than do deeper horizons closer to the thrust faults. The upper values are approximately that of the closures that are expected in the play on the same succession in the Foreland Basin, east of the deformation.

Within this play, average net pay is controlled by the thickness of individual sandstone reservoir intervals, which might occur stacked in an individual prospect, or distributed across portions of Laramide structures. Structural depressions and footwall closures are unlikely to be drilled in a frontier setting, so it is expected this play will have a significantly lower number of prospects in the Cordillera than in the Peel Plain. It is inferred that sandstone layers will vary between 2 and 30 m in thickness, based largely on data from wells. Thinner sandstone intervals are observed, but they are not likely to provide exploratory targets at this stage of exploration. Even if sandstone units were thicker, it is unlikely that net pays would be greater, as is commonly the case in the southern Cordillera.

The diagenetic history of reservoir sandstones is not well known. The prospect average porosities of 2 to 10% are consistent with facies and burial depths for both this depositional environment and its tectonic setting. Note the significantly lower porosity expected in these successions in the Cordillera compared to the Foreland Basin.

Derived prospect size

The expected prospect size is 1050 million m^3 with a standard deviation of 1138 million m^3 (Table 32).

Number of prospects

The number of prospects is estimated to be between 30 and 90, with a more than 50% probability that the number of prospects exceeds 45 (Table 31). The analogy to southern productive portions of the Cordillera supports these prospect densities. There is a strong likelihood that all pools will have a component of stratigraphic entrapment, which is inherent from the depositional environment of these clastic sediments and the analogues in the southern Cordillera. The play potential here is strongly controlled by the size of prospects, which are comparable to known southern Cordillera accumulations.

Play- and prospect-level exploration risks

The total risk placed on this play is low, comparable to that of the same succession in the Foreland Basin (Table 31). There are no play level risks because of the seepage through these rocks in the Foreland Basin portion and due to the analogy with the southern Cordillera. Where the association of differential compaction and bending folds often influences patterns of sedimentation east of the deformation, such a coincidence is commonly lacking between Cretaceous reservoirs and Laramide structures. This has the impact of increasing exploratory risk for the presence of closure as reflected in the play input data sheet. There is an enhanced possibility for charge, especially from syntectonically maturing successions. The play analogue/comparison to producing portions of the southern Cordillera is well founded and appropriate. The lower risks imposed here are considered valid due to the observations in other parts of the Foreland Basin.

Resource potential

Mesozoic sandstones in the Martin House and Arctic Red formations constitute the primary reservoir horizons of the Peel Plateau Cordilleran Thrust and Fold Belt. Although less likely to have great thickness and large extent, as do the Paleozoic plays in the Cordillera, the timing of hydrocarbon generation relative to structure is much more favourable for Mesozoic-hosted petroleum systems compared to those in Paleozoic strata. The play potential calculation suggests that between 0 and 39 pools could occur, but that 12 pools are expected (Table 33). The play potential is between 507 million m^3 and 51.76 x 10^9 m^3 of initial raw gas in place, with an expected value of 13.157 x 10^9 m^3 of initial raw gas in place (Fig. 37). The largest expected pool is 3.393 x 10^9 m^3 initial raw gas in place (Fig. 38, Table 34).

The total petroleum potential of the Peel Plateau Mesozoic Clastics – C5510111 is significant. The play is among the most attractive and it has the second largest total potential in the entire assessment. Compared to the other plays in this assessment, a small amount of the expected play potential is predicted to occur within the largest pool, which is compensated for by the larger play potential. The median size of the largest undiscovered pool is estimated to be 2.861 x 10^9 m^3, or about one half of that in the largest pool expected in the next prospective play in the Peel Plateau, the Upper Paleozoic Clastics - C5540111. In fact, the first four pools in this play have median potentials that would suggest they are larger, or of comparable size to, the sub-Imperial Formation plays of this region. Clearly the undiscovered potential in the Peel Plateau is inferred to occur within the Paleozoic and Mesozoic clastic succession, rather than in the carbonate successions. This is different than the resource distribution in the southern Cordillera.

C5570111 – Paleozoic Carbonate Margin Play

Table 23. *Input parameters.*

Probability distributions of reservoir parameters					
Geological variable	**Unit of measurement**	**Value at an upper percentile probability**			
		1.00	**0.50**	**0.01**	**0.00**
Area of closure	km^2	0.4	5	40	90
Net pay	m	20	30	40	41
Porosity	decimal fraction	0.02	0.06	0.12	0.20
Gas saturation	decimal fraction	0.70	0.77	0.80	0.81
Gas compressibility factor	decimal fraction	0.94	0.96	0.98	0.98
Reservoir temperature	°C	70	110	120	125
Reservoir pressure	kPa	20 000	25 000	30 000	35 000

Marginal probabilities of geological risk factors	Marginal probability	Play level	Prospect level
Presence of closure	0.8		X
Presence of reservoir facies	0.5		X
Adequate seal	0.8		X
Appropriate timing	0. 2		X
Adequate source	1.0		X

Probability distribution for number of prospects			
Probability in upper percentiles	0.99	0.5	0.00
Number of prospects	10	100	200

Table 24. *Calculated prospect size using the lognormal approximation (millions of metres initial in place).*

Logarithmic Mean = 6.1549	Expected (Mean) Value = 675.53	
Sigma Squared = .72128	Standard Deviation = 694.54	
99.99% = 20.013	60.00% = 379.82	15.00% = 1135.8
99.00% = 65.309	55.00% = 423.32	10.00% = 1398.6
95.00% = 116.50	50.00% = 471.00	8.00% = 1553.3
90.00% = 158.61	45.00% = 524.05	6.00% = 1763.9
85.00% = 195.32	40.00% = 584.07	5.00% = 1904.2
80.00% = 230.46	35.00% = 653.35	4.00% = 2083.3
75.00% = 265.61	30.00% = 735.26	2.00% = 2694.8
70.00% = 301.72	25.00% = 835.22	1.00% = 3396.8
65.00% = 339.55	20.00% = 962.60	0 .01% = 11 085.

Table 25. *Number of pools distribution.*

Minimum number of pools	0
Maximum number of pools	29
Expected number of pools	6.56288
Standard Deviation	= 4.32511
Play resource (billions of cubic metres)	
Minimum	= 0.0
Maximum	= 22.28020
Expectation	= 4.459507
Standard Deviation	= 3.445769

Play potential greater than (billions of cubic metres)

100.00	0.0	50.00	3.9029	8.00	9.7657
90.00	.47541	45.00	4.3781	6.00	10.395
85.00	.85890	40.00	4.8487	5.00	10.759
80.00	1.2871	35.00	5.3115	4.00	11.323
75.00	1.7286	30.00	5.8657	2.00	13.041
70.00	2.1535	25.00	6.5147	1.00	14.371
65.00	2.5039	20.00	7.2689	.01	22.206
60.00	2.9304	15.00	8.1095	.00	22.273
55.00	3.4309	10.00	9.1523		

Table 26. *Pool-size rank, followed by a description of the individual pool-size distribution.*

1	Expected (Mean) Value = 1603.8	Standard Deviation = 1176.6	P(N≥r) = .95375
	99% = 166.98	75% = 853.44	10% = 2942.3
	95% = 361.80	50% = 1336.7	5% = 3717.3
	90% = 519.40	25% = 2020.0	1% = 5895.6
2	Expected (Mean) Value = 947.62	Standard Deviation = 557.36	P(N≥r) = .87829
	99% = 116.51	75% = 554.35	10% = 1654.1
	95% = 236.23	50% = 855.09	5% = 1971.9
	90% = 335.89	25% = 1226.2	1% = 2747.6
3	Expected (Mean) Value = 705.67	Standard Deviation = 387.85	P(N≥r) = .79491
	99% = 96.003	75% = 423.50	10% = 1210.8
	95% = 185.66	50% = 650.41	5% = 1416.3
	90% = 259.40	25% = 919.32	1% = 1887.5
4	Expected (Mean) Value = 569.07	Standard Deviation = 302.68	P(N≥r) = .71078
	99% = 83.623	75% = 345.69	10% = 968.26
	95% = 156.20	50% = 528.59	5% = 1122.7
	90% = 214.81	25% = 742.87	1% = 1464.6
5	Expected (Mean) Value = 477.97	Standard Deviation = 249.30	P(N≥r) = .62750
	99% = 74.810	75% = 292.57	10% = 809.31
	95% = 135.97	50% = 445.17	5% = 934.09
	90% = 184.47	25% = 624.00	1% = 1204.4
6	Expected (Mean) Value = 411.65	Standard Deviation = 211.89	P(N≥r) = .54575
	99% = 67.989	75% = 253.42	10% = 694.77
	95% = 120.82	50% = 383.56	5% = 799.97
	90% = 162.00	25% = 536.92	1% = 1024.4
7	Expected (Mean) Value = 360.74	Standard Deviation = 183.88	P(N≥r) = .46627
	99% = 62.448	75% = 223.16	10% = 607.40
	95% = 108.86	50% = 335.91	5% = 698.53
	90% = 144.48	25% = 469.80	1% = 891.01

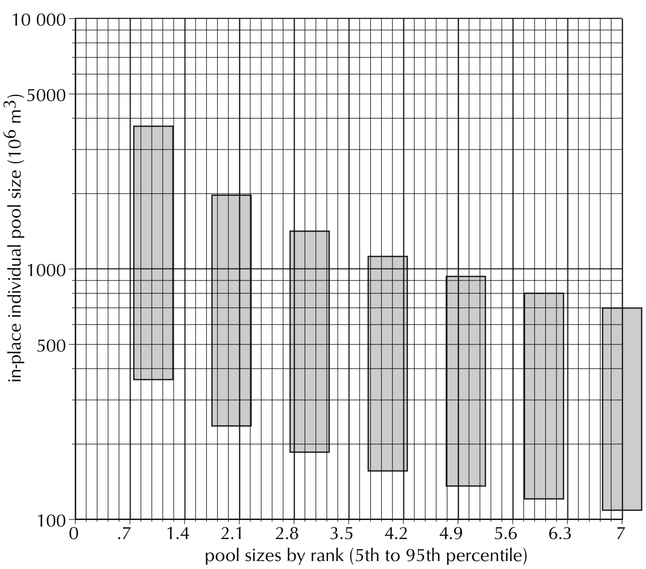


Figure 33. *Play potential plot.*

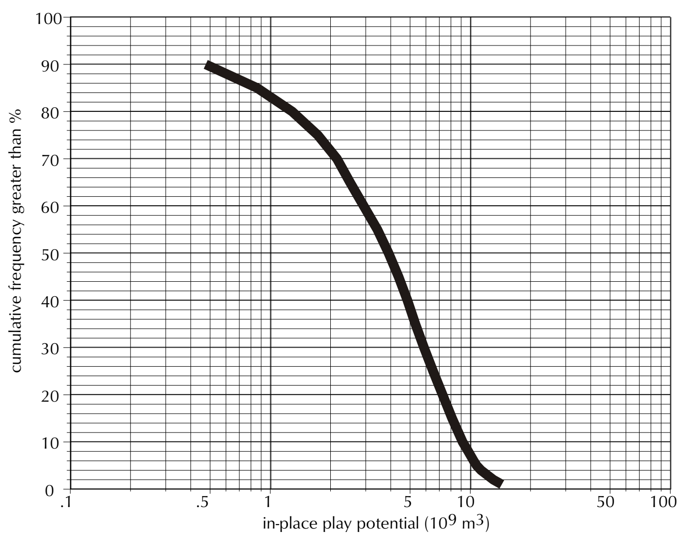


Figure 34. *Accumulation-size-by-rank plot. Details of individual pool-size distributions are given in Table 26.*

C5540111 - Upper Paleozoic Clastics Play

Table 27. *Input parameters.*

Probability distributions of reservoir parameters					
Geological variable	**Unit of measurement**	**Value at an upper percentile probability**			
		1.00	**0.50**	**0.01**	**0.00**
Area of closure	km²	0.4	5	50	90
Net pay	m	15	25	35	40
Porosity	decimal fraction	0.09	0.13	0.18	0.20
Gas saturation	decimal fraction	0.50	0.70	0.85	0.90
Gas compressibility factor	decimal fraction	0.78	0.80	0.82	0.92
Reservoir temperature	°C	37	50	80	110
Reservoir pressure	kPa	20 100	22 100	23 100	25 000

Marginal probabilities of geological risk factors	Marginal probability	Play level	Prospect level
Presence of closure	0.3		X
Presence of reservoir facies	0.5		X
Adequate seal	0.4		X
Appropriate timing	0.25		X
Adequate source	0.5		X

Probability distribution for number of prospects			
Probability in upper percentiles	0.99	0.5	0.00
Number of prospects	40	200	400

Table 28. *Calculated prospect size using the lognormal approximation (millions of metres initial in place).*

Logarithmic Mean = 8.3146	Expected (Mean) Value = 4851.6	
Sigma Squared = .34496	Standard Deviation = 3113.9	
99.99% = 459.57	60.00% = 3518.5	15.00% = 7505.0
99.00% = 1041.3	55.00% = 3792.5	10.00% = 8667.1
95.00% = 1553.9	50.00% = 4083.0	8.00% = 9319.2
90.00% = 1923.5	45.00% = 4395.8	6.00% = 10 176
85.00% = 2221.3	40.00% = 4738.1	5.00% = 10 729
80.00% = 2490.6	35.00% = 5120.0	4.00% = 11 417
75.00% = 2747.5	30.00% = 5555.8	2.00% = 13 641
70.00% = 3000.7	25.00% = 6067.7	1.00% = 16 009
65.00% = 3256.1	20.00% = 6693.6	.01% = 36 275

Table 29. *Number of pools distribution.*

Minimum number of pools	0
Maximum number of pools	13
Expected number of pools	1.57271
Standard Deviation	= 1.47677
Play resource: (billions of cubic metres)	
Minimum	= 0.0
Maximum	= 62.13422
Expectation	= 7.799449
Standard Deviation	= 8.224876

Play potential greater than (billions of cubic metres)

100.00	0.0	35.00	8.9801	5.00	23.842
70.00	2.0023	30.00	10.389	4.00	25.707
65.00	2.8683	25.00	12.046	2.00	30.410
60.00	3.8776	20.00	13.813	1.00	34.442
55.00	4.7777	15.00	16.001	.01	61.286
50.00	5.6841	10.00	19.156	.00	62.049
45.00	6.6630	8.00	20.694		
40.00	7.7021	6.00	22.545		

Table 30. *Pool-size rank, followed by a description of the individual pool-size distribution.*

1	Expected (Mean) Value = 6278.5	Standard Deviation = 3661.6	P(N≥r) = .72551
	99% = 1288.2	75% = 3750.0	10% = 10 832
	95% = 2021.9	50% = 5517.1	5% = 13 097
	90% = 2565.4	25% = 7900.5	1% = 18 823

2	Expected (Mean) Value = 4157.9	Standard Deviation = 2005.1	P(N≥r) = .43770
	99% = 1053.9	75% = 2708.0	10% = 6785.4
	95% = 1571.0	50% = 3820.8	5% = 7890.2
	90% = 1935.9	25% = 5223.8	1% = 10 411

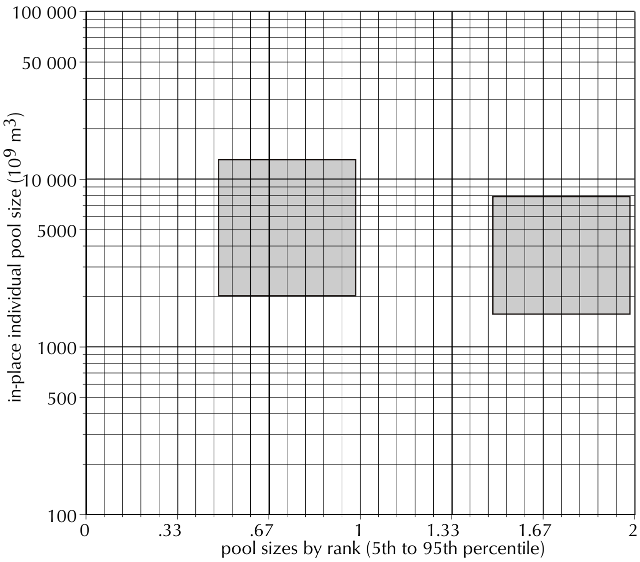


Figure 35. *Play potential plot.*

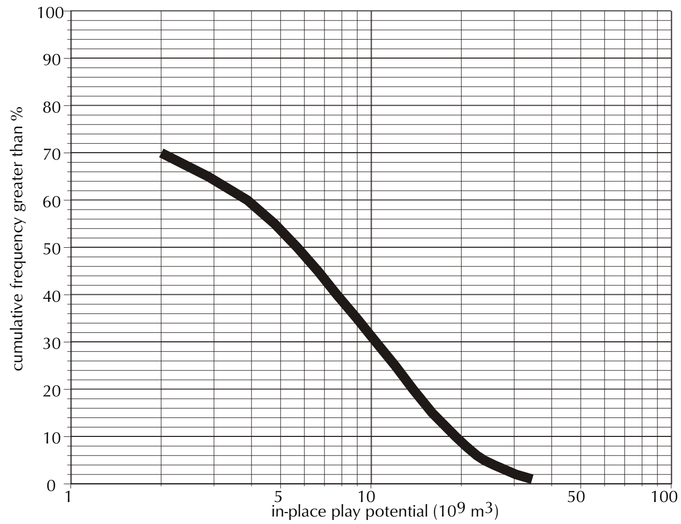


Figure 36. *Accumulation-size-by-rank plot. Details of individual pool-size distributions are given in Table 30.*

C5510111 – Mesozoic Clastics Play

Table 31. Input parameters.

Probability distributions of reservoir parameters					
Geological variable	**Unit of measurement**	**Value at an upper percentile probability**			
		1.00	**0.50**	**0.01**	**0.00**
Area of closure	km^2	0.1	5	50	105
Net pay	m	2	10	20	30
Porosity	decimal fraction	0.03	0.06	0.09	0.10
Gas saturation	decimal fraction	0.70	0.77	0.80	0.91
Gas compressibility factor	decimal fraction	0.76	0.78	0.8	0.8
Reservoir temperature	°C	50	80	90	120
Reservoir pressure	kPa	20 000	21 000	22 000	23 000

Marginal probabilities of geological risk factors	Marginal probability	Play level	Prospect level
Presence of closure	0.75		X
Presence of reservoir facies	0.5		X
Adequate seal	.70		X
Appropriate timing	1.0		
Adequate source	0.9		X

Probability distribution for number of prospects			
Probability in upper percentiles	0.99	0.5	0.00
Number of prospects	30	45	90

Table 32. Calculated prospect size using the lognormal approximation (millions of metres initial in place).

Logarithmic Mean = 6.5685	Expected (Mean) Value = 1050.2	
Sigma Squared = .77653	Standard Deviation = 1137.9	
99.99% = 26.878	60.00% = 569.79	15.00% = 1775.5
99.00% = 91.700	55.00% = 637.64	10.00% = 2203.6
95.00% = 167.18	50.00% = 712.31	8.00% = 2456.9
90.00% = 230.26	45.00% = 795.72	6.00% = 2803.4
85.00% = 285.77	40.00% = 890.49	5.00% = 3035.0
80.00% = 339.30	35.00% = 1000.3	4.00% = 3331.7
75.00% = 393.13	30.00% = 1130.7	2.00% = 4351.6
70.00% = 448.72	25.00% = 1290.6	1.00% = 5533.1
65.00% = 507.23	20.00% = 1495.4	.01% = 18 878

Table 33. Number of pools distribution.

Minimum number of pools	0
Maximum number of pools	39
Expected number of pools	12.50235
Standard Deviation	= 5.24344
Play resource: (billions of cubic metres)	
Minimum	= .5068488
Maximum	= 51.76637
Expectation	= 13.15733
Standard Deviation	= 6.809610

Play potential greater than (billions of cubic metres)					
100.00	.50685	55.00	11.217	8.00	23.468
99.00	2.3877	50.00	12.018	6.00	25.013
95.00	4.0868	45.00	12.800	5.00	25.718
90.00	5.3688	40.00	13.758	4.00	26.910
85.00	6.3688	35.00	14.807	2.00	29.845
80.00	7.3402	30.00	15.919	1.00	33.223
75.00	8.1008	25.00	17.114	0.01	49.720
70.00	8.8384	20.00	18.570	0.00	51.562
65.00	9.7182	15.00	20.202		
60.00	10.462	10.00	22.316		

Table 34. *Pool-size rank, followed by a description of the individual pool-size distribution.*

1	Expected (Mean) Value = 3392.7	Standard Deviation = 2181.7	P(N≥r) = .99996
	99% = 823.97	75% = 2020.7	10% = 5842.2
	95% = 1216.0	50% = 2860.7	5% = 7311.9
	90% = 1476.2	25% = 4111.6	1% = 11 478
2	Expected (Mean) Value = 2033.4	Standard Deviation = 987.53	P(N≥r) = .99960
	99% = 528.32	75% = 1351.8	10% = 3276.8
	95% = 813.65	50% = 1852.8	5% = 3858.7
	90% = 994.03	25% = 2503.6	1% = 5292.6
3	Expected (Mean) Value = 1502.0	Standard Deviation = 687.66	P(N≥r) = .99772
	99% = 352.60	75% = 1015.7	10% = 2392.4
	95% = 586.18	50% = 1399.6	5% = 2763.9
	90% = 731.96	25% = 1870.3	1% = 3622.2
4	Expected (Mean) Value = 1191.0	Standard Deviation = 548.43	P(N≥r) = .99144
	99% = 240.95	75% = 797.28	10% = 1910.1
	95% = 432.68	50% = 1119.8	5% = 2189.7
	90% = 556.38	25% = 1503.1	1% = 2810.3
5	Expected (Mean) Value = 980.99	Standard Deviation = 465.06	P(N≥r) = .97596
	99% = 174.64	75% = 641.87	10% = 1596.5
	95% = 326.80	50% = 924.89	5% = 1824.4
	90% = 432.05	25% = 1256.0	1% = 2316.0
6	Expected (Mean) Value = 830.42	Standard Deviation = 406.95	P(N≥r) = .94581
	99% = 136.47	75% = 528.57	10% = 1373.7
	95% = 256.33	50% = 782.16	5% = 1567.9
	90% = 344.84	25% = 1077.3	1% = 1978.0
7	Expected (Mean) Value = 719.69	Standard Deviation = 362.41	P(N≥r) = .89742
	99% = 113.86	75% = 446.62	10% = 1207.1
	95% = 210.90	50% = 676.05	5% = 1377.2
	90% = 285.40	25% = 943.44	1% = 1730.4
8	Expected (Mean) Value = 637.17	Standard Deviation = 326.25	P(N≥r) = .83122
	99% = 99.855	75% = 388.38	10% = 1078.4
	95% = 181.77	50% = 597.18	5% = 1229.7
	90% = 245.71	25% = 841.04	1% = 1540.4
9	Expected (Mean) Value = 574.79	Standard Deviation = 295.84	P(N≥r) = .75195
	99% = 90.866	75% = 347.56	10% = 976.03
	95% = 162.90	50% = 538.45	5% = 1112.2
	90% = 219.36	25% = 761.15	1% = 1389.3
10	Expected (Mean) Value = 526.42	Standard Deviation = 269.57	P(N≥r) = .66682
	99% = 84.947	75% = 318.83	10% = 892.28
	95% = 150.47	50% = 493.88	5% = 1015.6
	90% = 201.73	25% = 697.02	1% = 1265.4
11	Expected (Mean) Value = 487.32	Standard Deviation = 246.45	P(N≥r) = .58289
	99% = 80.926	75% = 297.83	10% = 821.49
	95% = 142.01	50% = 458.41	5% = 933.87
	90% = 189.54	25% = 643.50	1% = 1160.9
12	Expected (Mean) Value = 453.96	Standard Deviation = 225.88	P(N≥r) = .50504
	99% = 77.985	75% = 281.04	10% = 759.79
	95% = 135.78	50% = 428.13	5% = 862.81
	90% = 180.38	25% = 596.87	1% = 1070.7

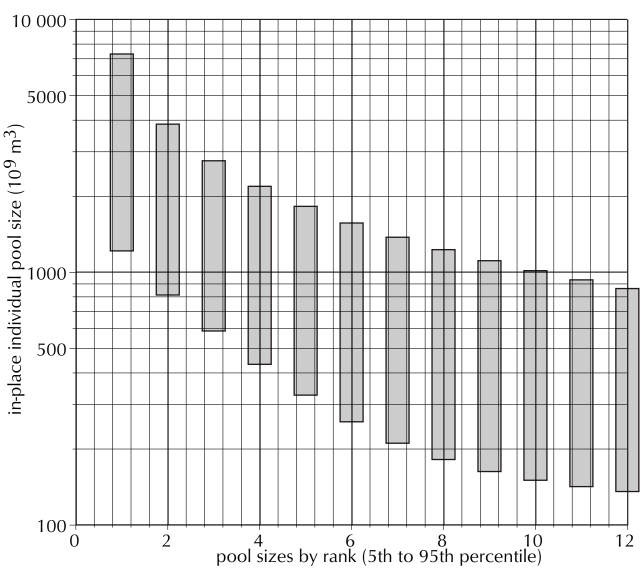


Figure 37. *Play potential plot.*

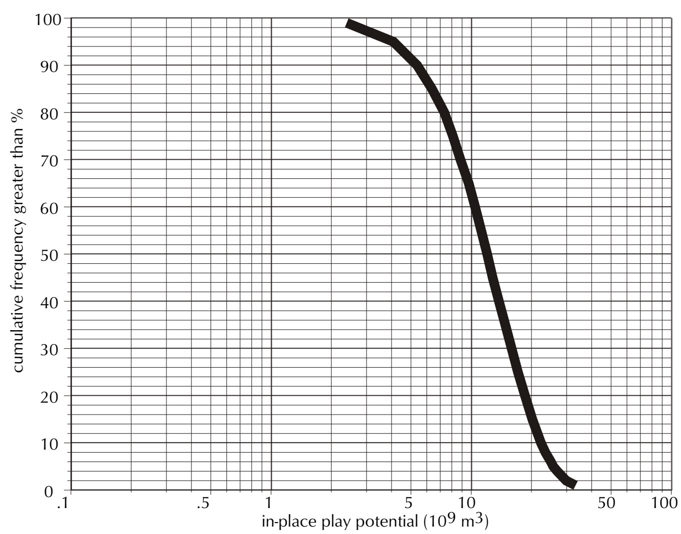


Figure 38. *Accumulation-size-by-rank plot. Details of individual pool-size distributions are given in Table 34.*

DISCUSSION

The Peel Plateau and Plain in the Yukon is a prospective petroleum region bounded to the south by the Mackenzie Mountains and to the west by the Richardson Mountains (Fig. 4). It is comprised of a Lower Cambrian to Upper Cretaceous stratigraphic succession up to approximately 4.5 km thick overlying a poorly described, unprospective Proterozoic succession. There are several shows including a surface seep of natural gas that occurs in the NWT in the contiguous Mackenzie-Peel Shelf geological province (Fig. 14, p. 19; Norris, 1997). Nineteen exploratory wells have been drilled within the assessment region, none of which have established economic reserves or production (Fig. 15, p. 20). The Mackenzie-Peel Shelf/Platform has had, with the exception of Norman Wells, a similarly disappointing exploratory history (Fig. 16, p. 21).

This study determined that significant undiscovered petroleum potential remains in the Peel Plateau and Plain despite the failure of previous exploration efforts. It appears, for example, that several wells were not drilled in optimal locations, particularly within the Cordilleran portion, due to difficulties defining (geophysical) and testing (logistical) the prospects. Although the details are neither described nor clear, regional studies of thermal maturation indicate that there might be two stages of petroleum system function. The first, in late Paleozoic time, generated petroleum prior to the creation of effective stratigraphic traps. The second, during the Laramide orogeny, generated petroleum predominantly in the Mesozoic succession and may have subsequently provided some footwall charge in overthrust structures, but probably without effectively charging Paleozoic successions east of the Cordillera. This situation is analogous to southernmost Alberta, where petroleum occurs in both Paleozoic and Mesozoic reservoirs in the Cordillera, but where only the Mesozoic succession is highly prospective in the undeformed portions of the Foreland Basin.

This report differs from previous petroleum assessments for the Peel Plateau and Plain in that it is based on:

- indications that Cordilleran portions of the Peel Plateau and Plain have not been diagnostically tested by wells;
- improved play analogues and comparisons; and
- improved appraisals of exploratory risks.

NATURAL GAS POTENTIAL

The depositional and tectonic histories of the Peel Plateau and Plain suggest it is gas-prone, due to generally higher thermal maturity levels, especially in the Paleozoic successions. Assessment of the Yukon portion suggests that there is a significant potential for natural gas (Fig. 39), with a summed mean play potential of approximately 2.950 trillion cubic feet (Tcf) or 83.428 x 10^9 m^3 initial raw gas-in-place in 88 pools (Fig. 40, Table 35; note that the arithmetic sum of the individual play potentials and the probabilistic total play potential are slightly different in size). In comparison, the proven initial gas-in-place for the Mackenzie-Delta and Beaufort Sea is about 12 Tcf.

The study indicates that uncertainties in reservoir quality, trap preservation and timing significantly depreciate the potential of the Paleozoic carbonate reservoir plays within both the Cordillera and the Foreland Basin (Fig. 39). The

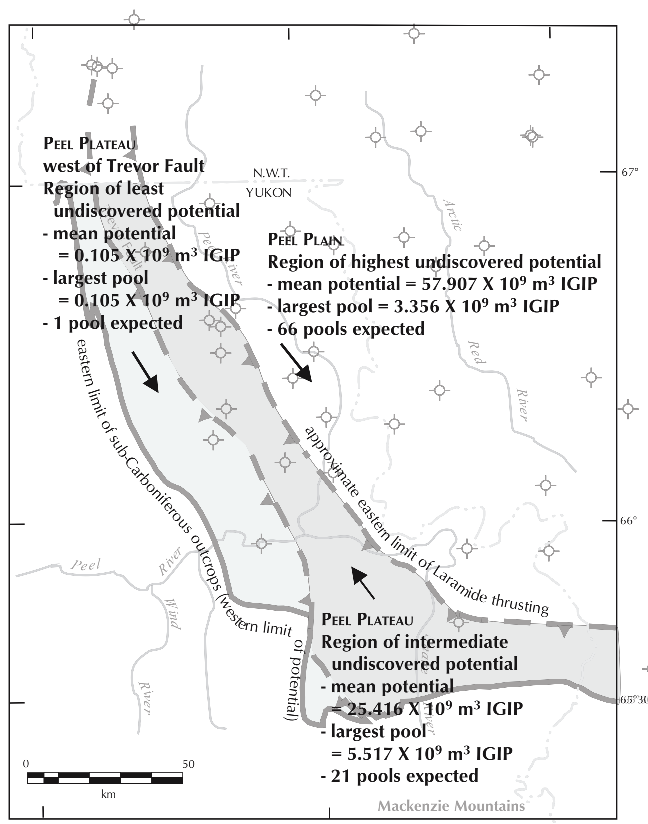


Figure 39. Summary of Peel Plateau and Plain petroleum resource assessment indicating key inferred characteristics of the undiscovered petroleum potential resulting from this analysis. IGIP = initial gas in place.

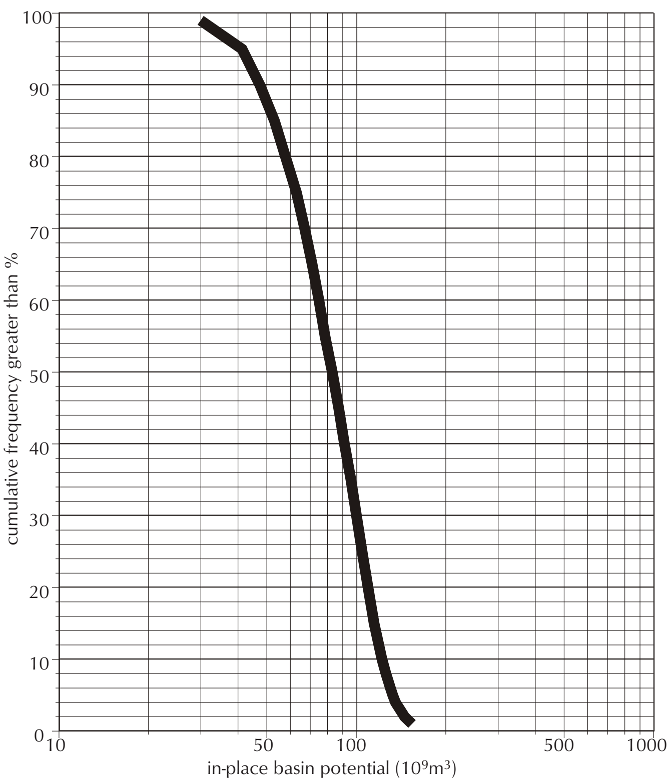


Figure 40. *Summary petroleum potential for all of the plays combined in the Peel Plateau and Plain petroleum resource assessment.*

plays, historically the main targets of exploration, have an aggregate potential of only 198 billion cubic feet (Bcf) (5.620 x 10^9 m^3) in 9 pools, or about 6% of the expected potential in the whole Peel region and have greatest potential in plays where the Paleozoic carbonate platform succession is deformed in the Cordillera. The Paleozoic carbonate play in the Cordillera is expected to contain 158 Bcf (4.460 x 10^9 m^3) in 7 pools, the largest of which is predicted to have a median pool size of 47.2 Bcf (1.337 x 10^9 m^3).

Better opportunities are inferred to occur in the Paleozoic and Mesozoic clastic successions. The Paleozoic clastic plays are expected to contain 536 Bcf (15.164 x 10^9 m^3), or about 18% of the potential in 12 pools. The largest pool in this play, in the Peel Plateau, is predicted to have a median pool size of 195 Bcf (5.517 x 10^9 m^3) and is the largest pool in the regional assessment.

The Upper Paleozoic Clastic plays are analogous to deep-water sand plays actively explored along the Atlantic and Gulf Coast passive margins. Such slope sandstone 'valley-fills' are among the most attractive petroleum plays globally, as indicated by the discovery, relatively recently, of the Thunderhorse Field in the Gulf of Mexico, which is the second largest American oil field after Prudoe Bay. Despite a complicated geological history, these plays retain their petroleum potential typically due to a component of stratigraphic entrapment in the submarine incised valley fill. Recent studies in the Bowser Basin of British Columbia show that deep-water sandstones can retain both reservoir potential and entrapped hydrocarbons, despite complex tectonic and thermal histories (Hayes et al., 2004).

Most of the potential gas for the Peel Plateau and Plain is predicted to occur within the Mesozoic clastic plays. One of these plays lies within the Foreland Belt region and has a potential of 1750 Bcf (49.487 x 10^9 m^3) in 55 pools, with a largest median pool size of 119 Bcf (3.356 x 10^9 m^3). A smaller Mesozoic gas play occurs in the Cordillera with 465 Bcf (13.157 x 10^9 m^3) expected in 12 pools, the largest of which has a median predicted pool size of 101 Bcf (2.861 x 10^9 m^3). Together, these plays contain an expected resource of 2.210 Tcf (62.64 x 10^9 m^3), or 75% of the total undiscovered resource for the Peel Plateau and Plain. The combined potential for the largest pools is 220 Bcf (6.217 x 10^9 m^3), which is 7.4% of the total potential and greater than the expected gas in all the Paleozoic carbonate plays combined.

DISTRIBUTION OF GAS PLAYS AND POTENTIAL

The distribution of undiscovered natural gas potential is expected to occur within three subregions of the Peel Plateau and Plain (Fig. 40, Table 35).

Peel Plateau – West of Trevor Fault

The total petroleum potential of this subregion is small to negligible, as would be expected from its geological history and characteristics, and it is the least prospective. Some gas is predicted to occur in sandy intercalations of the upper Paleozoic Imperial-Tuttle-Ford Lake succession within this region, although many of these units are near surface and the preservation probability of the trap is low. A single pool of 3.71 Bcf (105 million m^3) is predicted for this play (Fig. 39).

Peel Plateau

This subregion contains the temporally and geographically persistent platform-to-basin facies transition that marks the eastern margin of the Richardson Trough. The orientation of this facies transition is unfavourable with respect to the Cordilleran structure and is not expected to provide

Table 35. *Summary petroleum resource endowment of the Peel Plateau and Plain in the Yukon, indicating the assessed Play Name, expected number of accumulations, their median and mean play potentials and the median size of the largest undiscovered accumulation in each play. Note the Peel Plain Arnica/Manetoe Dolostone Play was previously assessed, but it is no longer inferred to exist (see the discussion in the text). Note also that the arithmetic sum of the mean play potentials differs slightly from the statistical total potential derived by a probabilistic summation of the contributing play potentials, as quoted in the text.*

Hydrocarbon potential in the Peel Plateau and Plain of the Yukon				
Natural gas plays (in-place volumes)				
Play name	**Expected no. of accumulations (mean)**	**Median play potential (in-place) (million m³)**	**Mean play potential (in-place) (million m³)**	**Median of largest field size (in-place) (million m³)**
Peel Plain Mesozoic Clastics - C5520111	55	46 447.0	49 487.0	3356.0
Peel Plain Upper Paleozoic Clastics - C5530111	9	6726.0	7260.0	1352.0
Peel Plain Post-Hume Reef (Horne Plateau) - C5550111	1	-	888.0	888.0
Peel Plain Arnica/Manetoe Dolostone -	0	0.0	0.0	0.0
Peel Plain Paleozoic Carbonate Platform - C5560111	1	153.0	272.0	218.0
Peel Plateau Mesozoic Clastics - C5510111	12	12 018.0	13 157.0	2861.0
Peel Plateau Upper Paleozoic Clastics - C5540111	2	5684.0	7799.0	5517.0
Peel Plateau Cambrian-Devonian Carbonate Margin - C5570111	7	3903.0	4460.0	1337.0
Peel Plateau U. Paleozoic Clastics West of Trevor Fault - C5580111	1	-	105.0	105.0
Peel Pleateau Cambrian-Devonian West of Trevor Fault	0	0.0	0.0	0.0
Arithmatic total all gas plays*	**88**	**74 931.0**	**83 428.0**	**15 634.0**
Totals (Bcf)		**2645.1**	**2945.0**	**551.9**

* The totals are not statistically derived.

a distinctive trapping mechanism. There is also a lack of strong diagenetic evidence for the preservation of reservoir quality by hydrothermal dolomitization. Therefore, the Paleozoic carbonate plays in the Peel Plateau are anticipated to occur in Cordilleran structural culminations where vestigial limestone porosity and minor dolostones constitute the potential reservoirs and by peak gas generation during the late Paleozoic. Additional potential exists for dry, over-mature gas generated by foreland and tectonic burial, or the remigration of Paleozoic gas into Cordilleran structures. The western margin of the Mackenzie-Peel Shelf comprises a single play within Cordilleran structures.

In this region (Fig. 39), the total undiscovered potential is 898 Bcf (25.416 x 10^9 m^3) in 21 pools. It is expected that Cambrian to Devonian carbonate succession will have a natural gas resource of about seven gas pools with a mean potential of approximately 158 Bcf (4.460 x 10^9 m^3). The largest expected pool is 47.2 Bcf (1.337 x 10^9 m^3). Paleozoic clastics, although comprising a thinner succession dominated by non-reservoir facies, have a greater potential for a favourable stratigraphic component of entrapment. Therefore they have an improved potential for the preservation of gas generated in the Paleozoic. It is expected that the upper Paleozoic clastic play in this subregion will consist of about two gas pools with a mean potential of approximately 275 Bcf (7.799 x 10^9 m^3). The largest expected pool is 158 Bcf (5.517 x 10^9 m^3), the single largest projected pool in the entire Peel Plateau and Plain, and is likely to occur as a turbiditic sandstone body. This play resembles deep-water sandstone plays on current oceanic margins, similar to Shell's current successful exploration on the margin of the African continent.

Mesozoic sandstones in the Martin House and Arctic Red formations constitute the third play in the Cordilleran Thrust and Fold Belt of the Peel Plateau. Although less likely to have large and thick extent, the timing of hydrocarbon generation relative to the structure is much more favourable for Mesozoic-hosted petroleum systems than Paleozoic ones. It is expected that the Peel Plateau Mesozoic Clastic Play consists of about 12 gas pools with a mean potential of approximately 465 Bcf (13.157 x 10^9 m^3). The largest expected pool is 101 Bcf (2.861 x 10^9 m^3). It is significant to compare the thrust and fold belt in the Peel region with that of the Southern Cordillera where only about 15% of the conventional petroleum potential occurs in the thrust and fold belt, as compared to the undeformed Plains (not accounting for the tar sands and heavy oils). In the Peel region, about 30% of the estimated potential is attributed to the thrust and fold belt. This, however, does not represent a real difference as only a portion of the Peel Plain petroleum potential occurs within the Yukon.

Peel Plain

The remaining, and most prospective assessment region is the Peel Plain, which, for this assessment, extends east of the Cordilleran Deformation Front to the inter-territorial boundary. Five plays were defined here (Fig. 39). In total, this area constitutes the most attractive exploration region within the Peel Plateau and Plain, with 2.040 Tcf (57.907 x 10^9 m^3), or about 70% of the potential in-place resource, expected to occur in 66 pools.

The Cambrian to Devonian carbonate platform play contains the largest volume of rock of all plays in this assessment. The style of porosity development and the lack of lateral seals in carbonate ramps, the preservation of limestone reservoir porosity in the absence of pervasive dolomitization, and the timing of hydrocarbon generation relative to structure formation all significantly affect the probability of this play. Throughout the northern Interior Platform, there has been a most notable lack of success drilling to the Hume Formation and the Ronning Group. It is expected that the Peel Plain Carbonate Platform Play will consist of a single pool of about 7.7 Bcf (0.218 x 10^9 m^3).

Manetoe dolostones do not extend north of 63°N in the Mackenzie-Peel Shelf. This means that there is no potential for the previous defined Devonian Fractured Arnica Dolomite (Bird, 2000, 1999). Most of the Devonian deposition in the Peel Plain occurs in a carbonate ramp setting. Persistent carbonate deposition following the drowning of the Hume Platform provides a significant opportunity for an abrupt-carbonate-margin facies play. This play is identical in configuration to the Horn Plateau Play of the southern NWT. While this play is not known to exist, neither can it be entirely discounted. A major risk for this play is the lack of reservoir, something that should also depreciate the play potential in the Peel Plain. It is expected that the Peel Plain Post-Hume Reef play will consist of about single gas pool with a mean potential of approximately 31.4 Bcf (0.888 x 10^9 m^3).

Clastic plays in the Upper Paleozoic and Mesozoic section are the equivalent of plays in the same succession of the thrust and fold belt, but within the Interior Platform setting. The Upper Paleozoic clastic play of the Peel Plain is expected to consist of about nine gas pools with a mean potential of 256 Bcf (7.26 x 10^9 m^3). The largest expected pool is 47.7 Bcf (1.352 x 10^9 m^3). The smaller pool sizes reflects both the size of the available structures of the Plains, but also a more distal setting relative to the apparent source of these clastic rocks. The Mesozoic clastic play of the Peel Plain is expected to consist of about 55 gas pools with a mean potential of approximately 1.750 Tcf (49.487 x 10^9 m^3). The largest expected pool is 119 Bcf (3.356 x 10^9 m^3).

CONCLUSIONS

Assessment of this region suggests that there is a significant potential for natural gas throughout the region with a summed mean play potential of approximately 83.428 x 10^9 m^3 initial raw gas in place (~3 Tcf) in approximately 88 pools (Fig. 40, Table 35). The largest expected pool of 3.36 x 10^9 m^3 gas is expected to occur in Mesozoic clastic rocks of the Peel Plain. In general, the small size of gas pools will be an impediment to their development because of their location. In general, petroleum potential is inferred to decrease both westward, and with increasing depth and stratigraphic age. The results of this assessment are inferred consistent with the results of 19 exploratory wells, none of which have established economic reserves or production, despite the presence of several petroleum shows. The result of this study, while differing in detail from previous work (Bird, 1999, 2000) for gas, is generally similar in aggregate potential.

This study differs significantly from previous studies with respect to crude oil potential. No crude oil potential can be estimated due to an inferred lack of oil-prone sources in strata of suitable maturity. This difference occurs primarily because of a lack of hard data that could be obtained from the available wells, if there were time and resources to perform suitable analysis (Rock-Eval/TOC pyrolysis). Where previous work speculated that the history of petroleum systems in the Peel Plateau and Plain was distinctive from that of surrounding regions that are suitably characterized, this work finds no justification for such a distinctive petroleum system history.

The results of this assessment refocus exploratory efforts away from the traditional Paleozoic targets and onto the upper Paleozoic and Mesozoic clastic successions and out of the Cordillera into the undeformed Foreland Basin succession in the Interior Platform. Individual pool sizes are not large and pool numbers are not numerous, but several potentially attractive exploratory targets can be identified. By avoiding drilling to the historically unproductive and less prospective Paleozoic carbonate succession, exploration costs can be reduced. The stacking of pools, particularly in the Cordillera, or the discovery of geographically associated accumulations, particularly in the Peel Plain, might reduce development costs.

ACKNOWLEDGEMENTS

This report was supported by the Oil and Gas Resources Branch of the Yukon Department of Economic Development, Whitehorse, Yukon. The work benefited from the support and comments of both Ms. Riona Freeman and Ms. Tammy Allen of the Oil and Gas Resources Branch. Release of this work was facilitated by Diane Emond, Peter Long, Wynne Krangle, Lee Pigage, Don Dempster and Grant Abbott whose help was much appreciated. We thank certain Calgary petroleum companies for their review and comments on this assessment.

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