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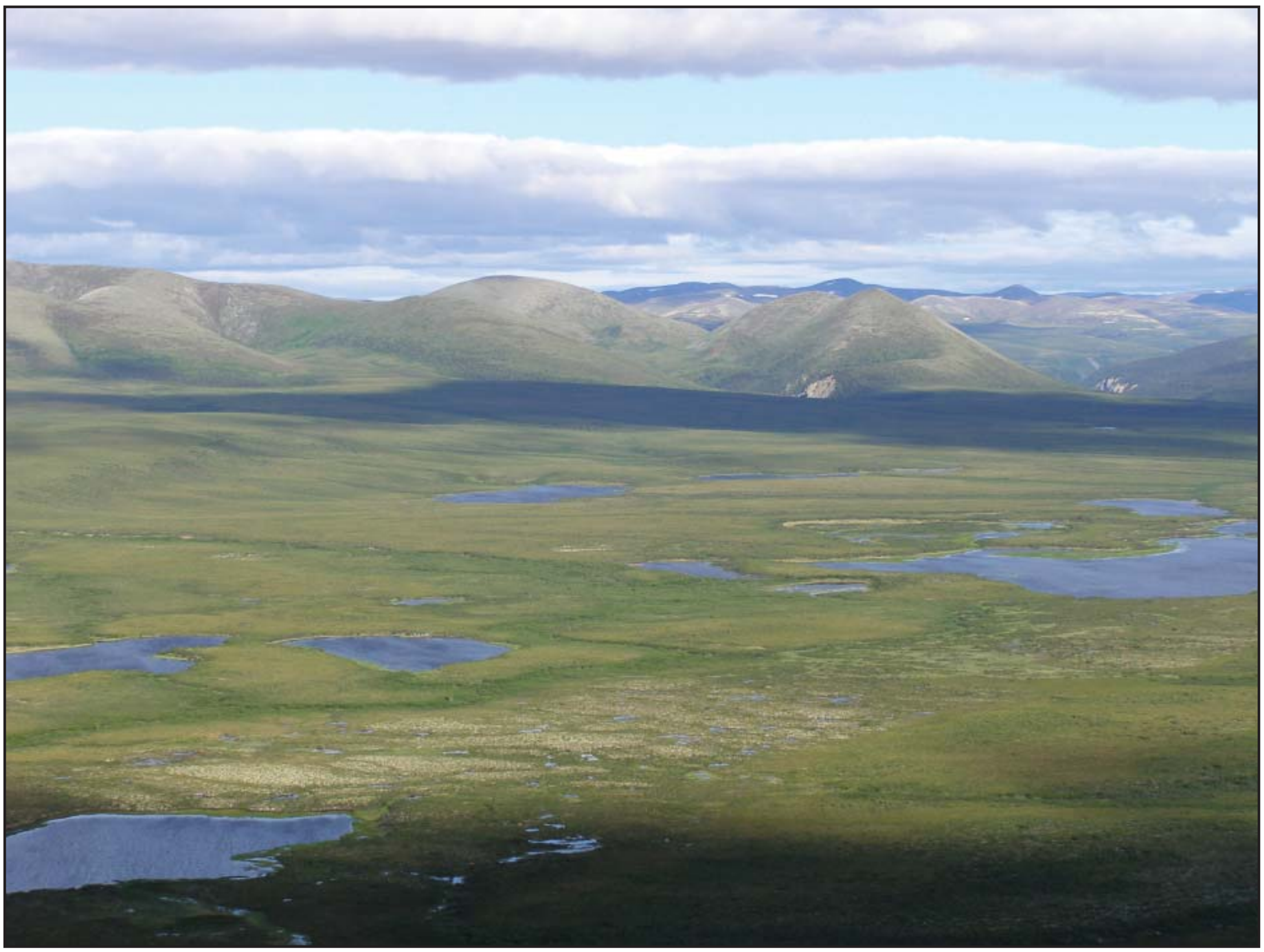
Conventional reservoir petrophysical property assessment for 17 wells, Peel Plateau and Plain, Yukon Territory (65º 00’ to 67º 00’ N; 132º 00’ to 136º 00’ W)

Tiffani A. Fraser



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Cover photo. View of the Yukon Peel Plateau looking west towards the Richardson Mountains.

FOREWORD

In 2008, the Yukon Geological Survey contracted Petrel Robertson Consulting Limited, of Calgary, Alberta, to undertake a conventional reservoir petrophysical assessment of wireline geophysical logs from 17 oil and gas exploration wells in the Peel Plateau and Plain exploration region of the northeastern Yukon Territory. The study was initiated to enhance the research of the hydrocarbon potential of the Peel region that had begun in 2005 with the *Regional Geoscience Studies and Petroleum Potential, Peel Plateau and Plain, Northwest Territories and Yukon* project, a four-year collaborative research effort among the Northwest Territories Geoscience Office, the Yukon Geological Survey (YGS), the Geological Survey of Canada (GSC), and university and industry affiliates. The aim of this reservoir petrophysical assessment is to highlight specific geological formations which have the potential of hosting economic quantities of conventional hydrocarbons in the Yukon Peel region. The data presented from this report will be used to update a resource assessment of the entire Mackenzie Corridor (including the Peel region), as part of the GSC's Geo-Mapping for Energy and Minerals (GEM) 2008-2013 initiative.

ACKNOWLEDGEMENTS

Reviews of this manuscript by Peter Hannigan of GSC Calgary, and Lee Pigage and Tammy Allen of YGS, are greatly appreciated. Bailey Staffen of YGS, assisted with maps and figures. Editing, layout and final publication was made possible by Karen MacFarlane and Leyla Weston of YGS. Technical explanations of reservoir petrophysical assessment methodology were offered by Yevgen Mykula and David Kisilevsky of Petrel Robertson Consulting Limited.

EXECUTIVE SUMMARY

In 2008, the Yukon Geological Survey contracted Petrel Robertson Consulting Limited, of Calgary, Alberta, to undertake a conventional reservoir petrophysical assessment of wireline geophysical logs from 17 oil and gas exploration wells in the Peel Plateau and Plain region of northeastern Yukon. This report summarizes the assessment and highlights particular geological formations in the Yukon Peel region that have the potential of hosting economic quantities of natural gas and/or oil.

Fourteen formations ranging in age from Proterozoic to Upper Cretaceous were assessed in this study. The study was limited by the lack of well data in the region (only 17 wells covering an area of over 10 000 km^2), a variability in drillhole depth (dominance of well penetration in upper Paleozoic and younger formations) and discontinuous geophysical logging of the boreholes. Despite these limitations, the formations are ranked in terms of conventional hydrocarbon prospectivity based upon average net reservoir and average net pay thicknesses, published field reports, DST information, proximity to surface, and unconventional resource potential.

Upper Paleozoic and Mesozoic clastic formations (excluding the shale-dominant Middle to Upper Devonian Canol Formation and Middle Devonian Bluefish Member of the Hare Indian Formation) have better potential for hosting conventional hydrocarbons than carbonate units. Of the clastic reservoirs, the Upper Devonian to Lower Mississippian Tuttle Formation shows the most potential, followed by Cretaceous strata (Arctic Red and Martin House formations) and the Upper Devonian Imperial Formation. Proterozoic strata are not considered prospective.

Between the limestone units, the Lower to Middle Devonian Landry Formation is more prospective than the Middle Devonian Hume Formation. Among the dolostone units, the upper Silurian to Lower Devonian Peel and Lower to Middle Devonian Arnica formations show the most potential, followed by Upper Ordovician to lower Silurian Mount Kindle and upper Cambrian to Lower Ordovician Franklin Mountain strata. The Lower Devonian Tatsieta Formation is not considered prospective.

The Canol Formation and Bluefish Member are not considered to contain conventional reservoir rock; however, they are organic-rich and often bituminous which makes them prospective for unconventional hydrocarbons. Further research into their shale gas potential is recommended. Shale in Cretaceous formations, and in the Imperial and Tuttle formations should also be examined for their unconventional shale gas potential.

Table of Contents

LIST OF FIGURES

List of Tables

INTRODUCTION

In the 1960s and 1970s, 19 exploratory petroleum wells were drilled in the Yukon Peel Plateau and Plain oil and gas exploration region. Of these wells, 18 were logged for a variety of geophysical parameters. This study presents a petrophysical property analysis of 17 of these well logs for the purpose of identifying the presence of conventional reservoir rocks and hydrocarbons. The study aims to bring attention to particular geological formations that have the potential of hosting economic quantities of conventional natural gas and/or oil.

STUDY AREA

The Yukon Peel region is situated in northeast Yukon Territory (Fig. 1) between latitudes 65º and 67º N, and longitudes 132º and 136º W. It consists of Peel Plateau to the west and Peel Plain to the east. The region is bordered by Richardson Mountains to the west, Mackenzie Mountains to the south, Beaufort Sea/Mackenzie Delta to the north, and Anderson Plain and Colville Hills to the east. The region covers an area spanning approximately 10 300 km^2 (Osadetz *et al*., 2005).

The terms 'Peel Plateau' and 'Peel Plain' have been used to describe physiographic regions (Bostock, 1948, 1970), sedimentary basins (Mossop *et al*., 2004), and exploration areas/regions (Morrow *et al*., 2006; Oil and Gas Resources, 2010), all with slightly different boundaries. This study employs the 'Peel Plateau and Plain oil and gas exploration region' adopted by the Oil and Gas Resources Branch, Department of Energy, Mines and Resources, Government of Yukon (Oil and Gas Resources, 2010; Fig. 1); herein referred to as the 'Yukon Peel region'. The boundaries of this region encompass all areas expected to have hydrocarbon potential, and include the wells analysed in this assessment. The western and southern limits of the region are marked by the base of Devonian siliciclastic outcrop on the flanks of the Richardson and Mackenzie mountains respectively (Fig. 2). The northern and eastern boundaries coincide with the Yukon – Northwest Territories (NWT) interterritorial boundary. When the terms Peel Plain or Peel Plateau are used in this report, they refer to the sedimentary basins of Mossop *et al*., 2004, depicted in Figure 2, unless otherwise specified.

PHYSIOGRAPHIC AND GEOLOGICAL SETTINGS

The Peel Plateau and Plain physiographic regions form the northwestern part of the Interior Platform, which is one of five geological provinces that characterizes the northern mainland of Canada (Dixon *et al*., 2007). Peel Plain (Bostock, 1948, 1970) occurs mainly in NWT, with a small part in northeastern Yukon Territory, and consists of lowlands with elevations ranging from 150 m to 450 m (Stott and Klassen, 1993). Peel Plateau (Douglas *et al*., 1963) occurs in northeastern Yukon and northwestern NWT and is an erosional remnant of Cretaceous sandstone terraces up to 975 m in elevation (Aitken *et al*., 1982; Stott and Klassen, 1993). The Mackenzie Mountains to the south of Peel Plateau and Plain rise to elevations of more than 1600 m, while the Richardson Mountains to the west of Peel Plateau have a maximum elevation of 1350 m (Morrow, 1999). Figure 2 displays the location of the Peel Plateau and Plain and adjacent sedimentary basins in the northeast Yukon and northwest NWT, and the simplified bedrock geology of the region.

The Yukon Peel region consists of three tectonic elements referred to as Northern Interior Platform, Richardson Anticlinorium, and Mackenzie Foldbelt (Norris, 1997b). In a general sense, the Northern Interior Platform is characterized by flat-lying to very gently west-dipping Phanerozoic strata,

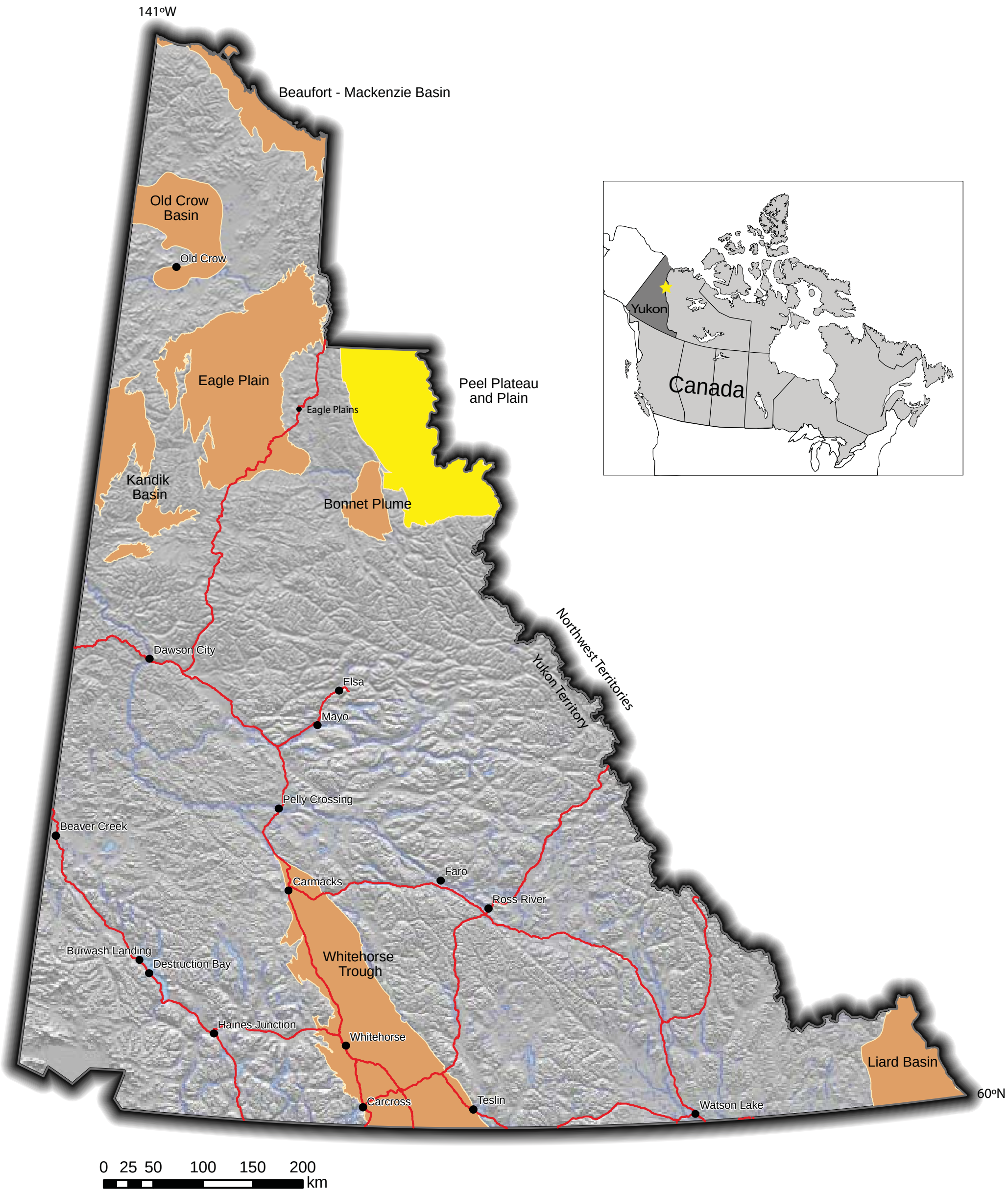


Figure 1. *Location map of Yukon Territory displaying Yukon's oil and gas exploration regions in brown (Oil and Gas Resources, 2010). The Peel Plateau and Plain exploration region is located in the northeastern part of the territory and is identified in yellow. Inset map displays the location of Yukon Territory within Canada, with the Peel region identified by a yellow star.*

overlying a thick (up to 14 km) succession of deformed Proterozoic strata. However, west of the Cordillera deformation front (Fig. 2), the sedimentary strata of the Northern Interior Platform are deformed with north and east-trending compressional structures occurring in the region between the Richardson and Mackenzie mountains (Fig. 2; see also figures 4 and 11-13 from Osadetz *et al*., 2005). In the Peel region, east of the limit of this deformed belt, the underlying geology is mainly flat-lying and undeformed and contains minor local structural uplifts (Osadetz *et al*., 2005; Lemieux *et al.*, 2009).

West of Peel Plateau, are the Richardson Mountains, forming the Richardson Anticlinorium tectonic element (Norris, 1997b). The Richardson Anticlinorium tectonic element is a broad north to northwest-trending structure forming a linear range of mountains which are cut by north-trending, curviplanar, near-vertical faults assigned to the Richardson Fault Array (Norris, 1997b). Its eastern limit with Peel Plateau is the Trevor fault. The anticlinorium marks the position of the early and middle Paleozoic Richardson trough (Norris, 1985). Inversion of the trough into the anticlinorium occurred during the latter stages of the Cordilleran orogeny (Norris, 1997b).

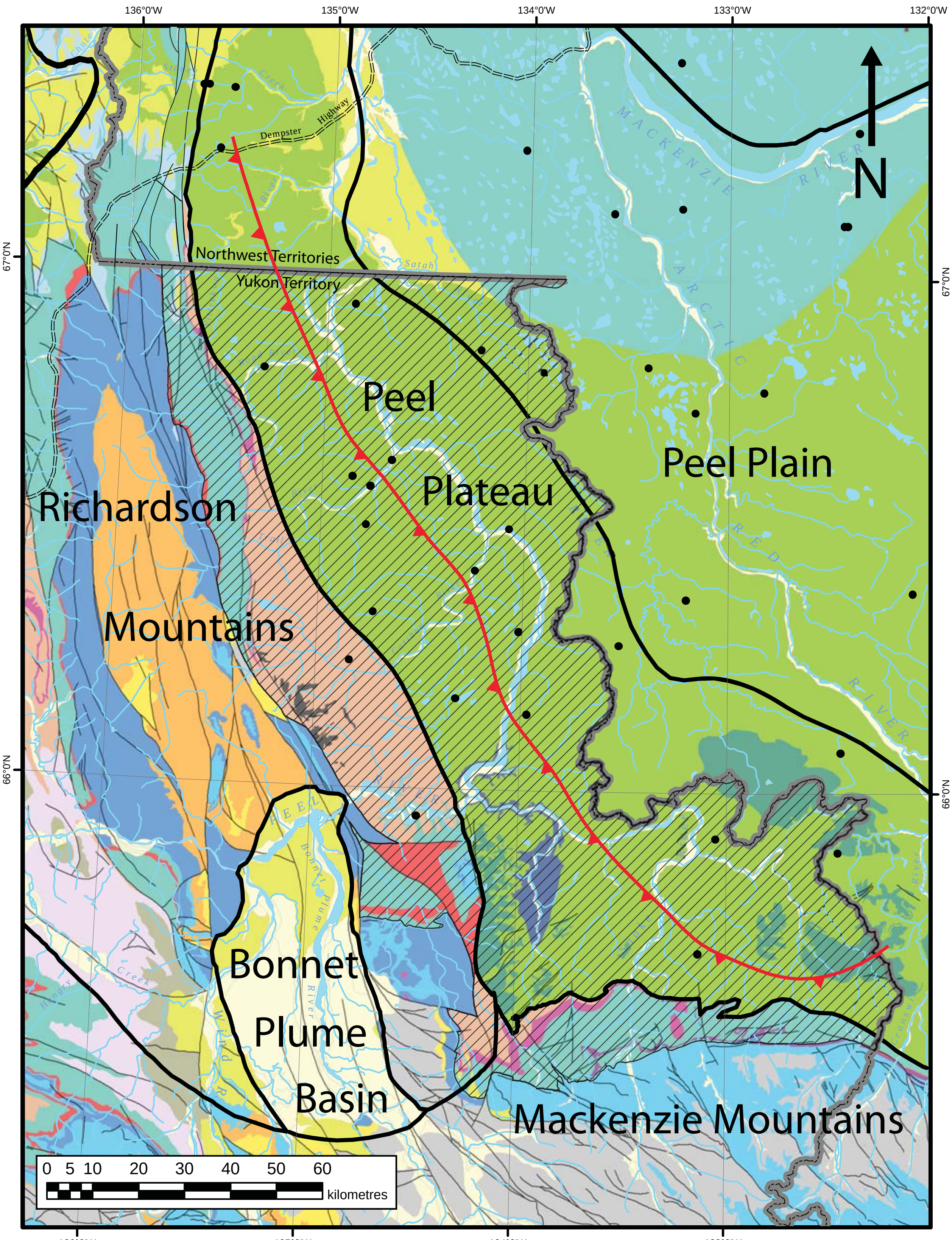
South of Peel Plateau and Plain are the Mackenzie Mountains, forming the western segment of the Mackenzie Foldbelt tectonic element (Norris, 1997b). The Mackenzie Foldbelt tectonic element forms the northern segment of the foreland fold and thrust belt of the Canadian Cordillera, and is dominated by parallel and concentric fold bundles with associated strike-slip or oblique-slip displacement. The orientation of these structures south of Peel Plateau is west-northwest, outlining an arcuate trend called the Mackenzie deflection (Norris, 1997b).

Phanerozoic stratigraphic columns (Fig. 3) illustrate the stratigraphy of Peel Plateau and Peel Plain. The succession forms an easterly tapering wedge of sedimentary rock, which is locally more than 4 km thick, and unconformably overlies Proterozoic rocks of the Mackenzie Mountains Supergroup (Norris, 1997a; Dixon, 1999; Morrow, 1999). The wedge can be divided into a Paleozoic succession overlain unconformably by a Cretaceous succession. Paleozoic strata, generally 1800-2000 m thick, can be further divided into two tectono-stratigraphic successions. The lower Paleozoic passive margin succession includes Cambrian to Devonian carbonates of the Mackenzie-Peel shelf (or Mackenzie platform) in the east, and shale deposited on the margin of the Richardson trough in the west (Morrow, 1999). In the Yukon Peel region, the carbonate platform consists of the Franklin Mountain, Mount Kindle, Peel, Tatsieta, Arnica, Landry and Hume formations. Shale and carbonates in the Richardson trough are assigned to the Road River Group. Figure 4 illustrates the location of the Richardson trough, Mackenzie-Peel shelf and other major paleogeographic elements of the region in early Paleozoic time. The younger Paleozoic foredeep succession includes Upper Devonian and Lower Carboniferous siliciclastic sediments (Imperial, Tuttle and Ford Lake Shale formations) derived from a northerly Ellesmerian orogenic source (Pugh, 1983; Richards *et al*., 1997).

Lower Cretaceous siliciclastic rocks unconformably overlie the Paleozoic succession, and include the Martin House, Arctic Red and Trevor formations. These rocks, up to one kilometre thick in the Yukon Peel Plateau, were deposited in the foreland basin adjacent to the Cordilleran orogen (Dixon, 1999). Lower to Upper Cretaceous (Albian to Turonian) sandstone and shale of the Trevor Formation are exposed at surface along the front ranges of the Mackenzie Mountains, marking the youngest strata exposed in outcrop in the zone below surficial debris (Norris, 1982a,b).

PETROLEUM EXPLORATION HISTORY

Petroleum exploration in the Yukon Peel region occurred during the 1960s and 1970s. Nineteen exploratory wells were drilled between the years 1965 and 1977. No hydrocarbons were produced from any of these wells, and their current status is ‘dry and abandoned’. Seismic data were also acquired during the 1960s and 1970s, although the number of kilometres and location of data acquired is difficult to determine as much of these data are not publicly available. Many companies conducted field studies in the Peel region during this era, with some reports available through the National Energy Board (NEB), in Calgary, Alberta.



136°0'W
135°0'W
134°0'W
133°0'W
132°0'W
67°0'N
66°0'N
N
Dempster Highway
Northwest Territories
Yukon Territory
Peel
Plateau
Peel Plain
Richardson
Mountains
Bonnet
Plume
Basin
Mackenzie Mountains
0 5 10 20 30 40 50 60
kilometres

Map Legend

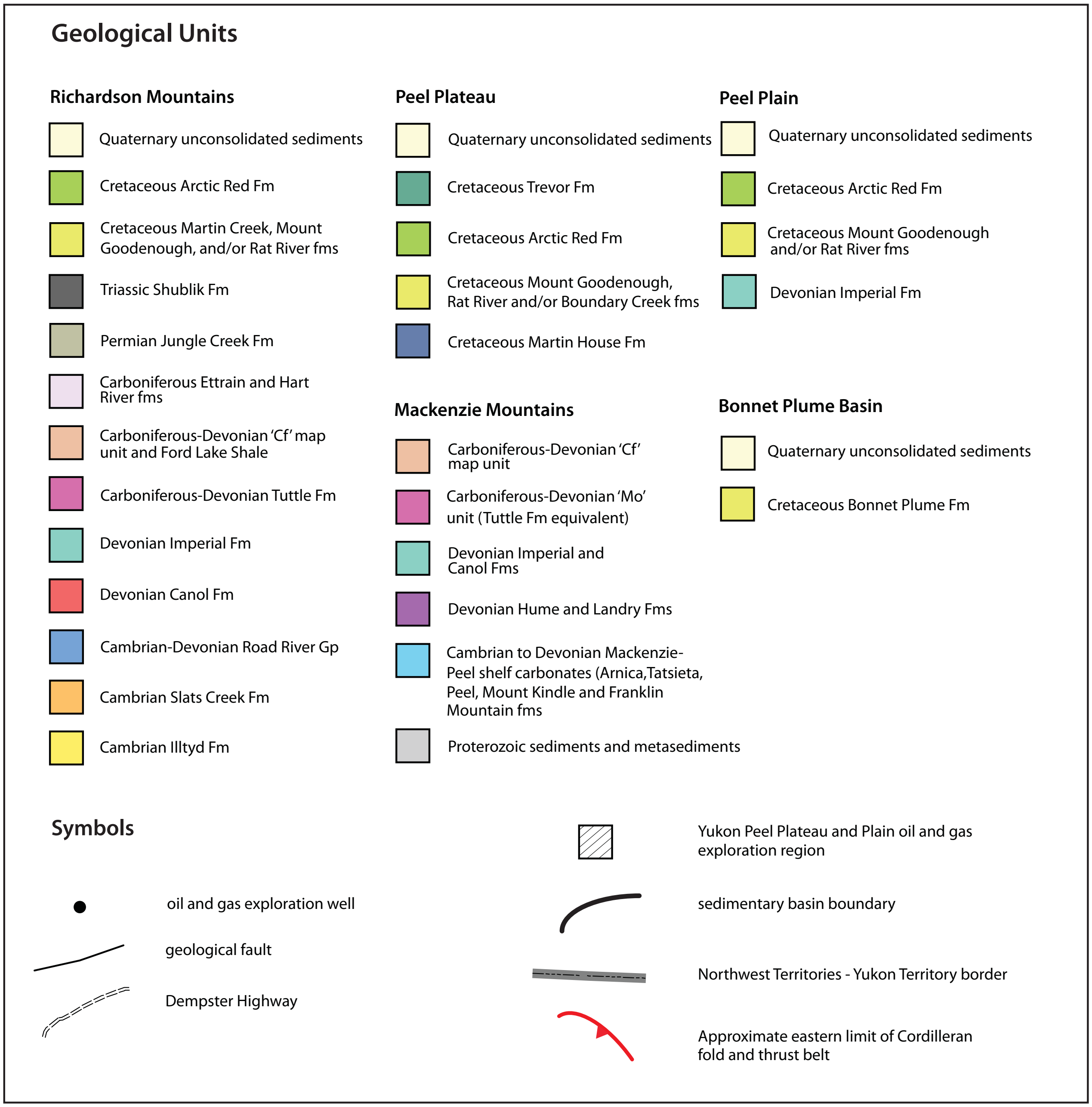


Figure 2. *Simplified geological map displaying locations of Peel Plain, Peel Plateau, Richardson Mountains, Bonnet Plume and Mackenzie Mountains sedimentary basins; Yukon Peel Plateau and Plain exploration region; and limit of Cordilleran fold and thrust belt. Geology after Gordey and Makepeace (2001); and Norris (1981a and 1981b). Sedimentary basins after Mossop et al. (2004). Yukon Peel Plateau and Plain exploration region from Oil and Gas Resources (2010). Limit of Cordilleran fold and thrust belt after Osadetz et al. (2005).*

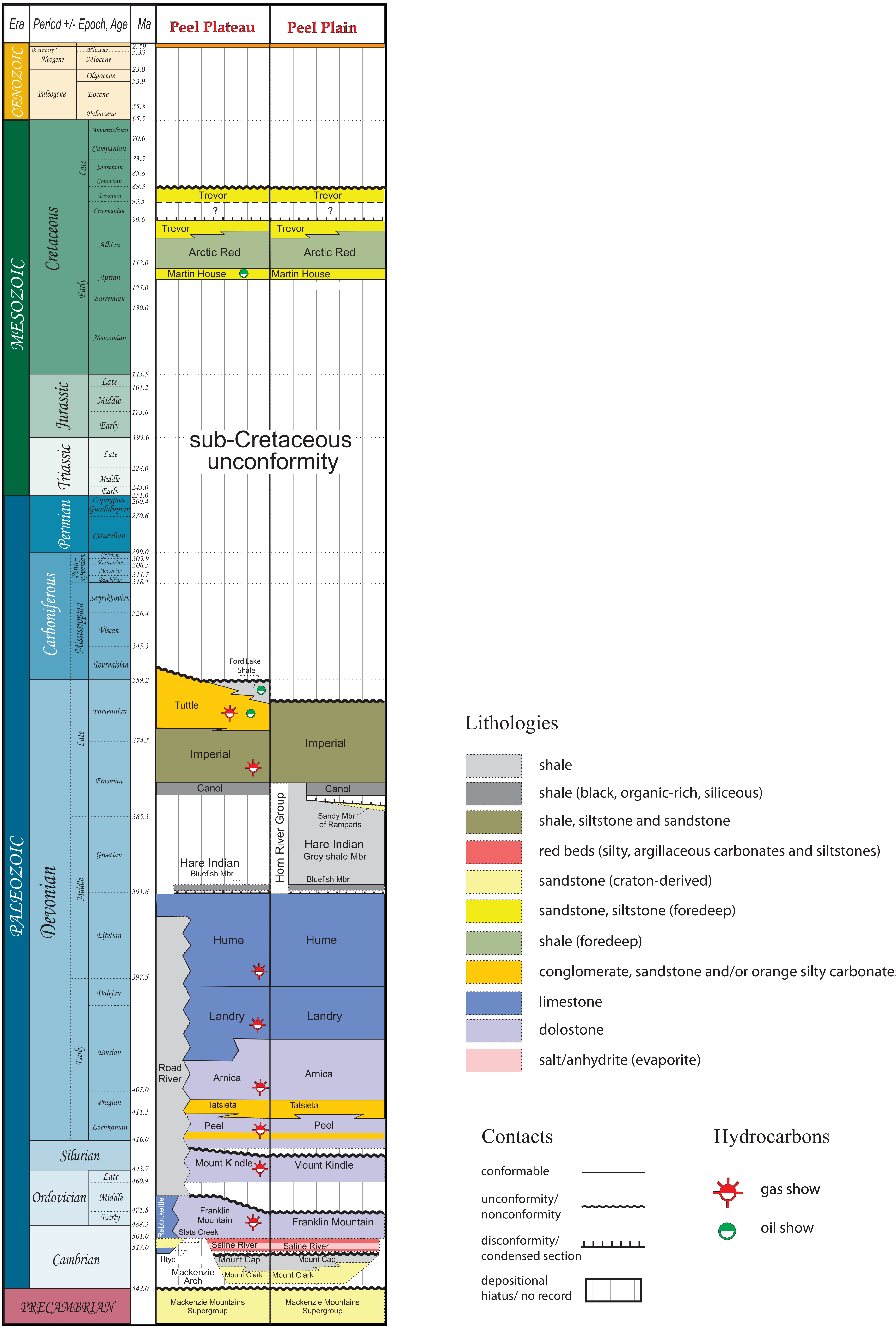


Figure 3. *Stratigraphic correlation chart for Peel Plateau and Peel Plain, modified from Morrow et al. (2006) and Pigage (2009). Time scale ages after Gradstein et al. (2004). Gas and oil show data derived from Yukon well history reports and field data in the Peel Plateau and Plain.*

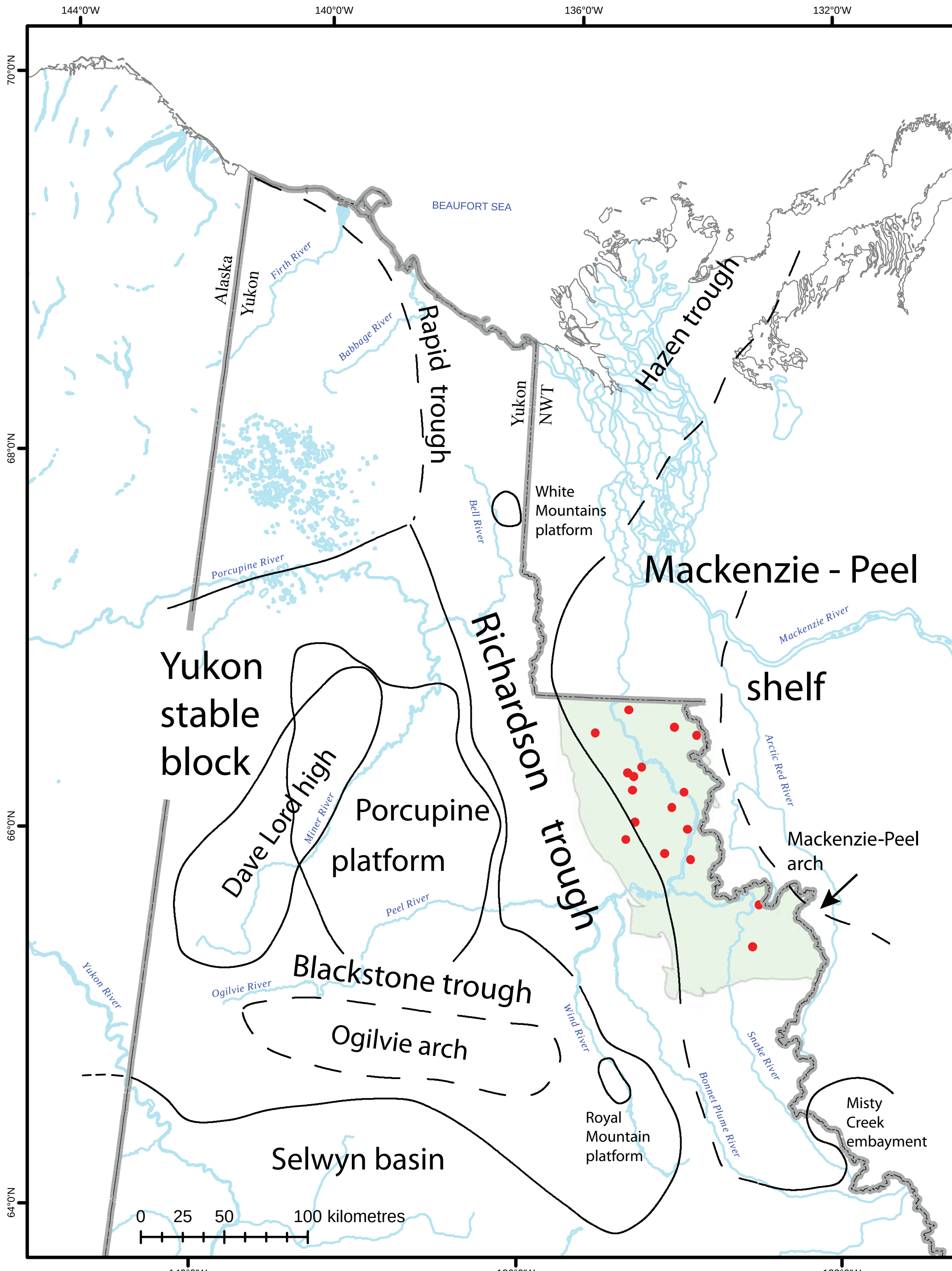


Figure 4. *Map of northern Yukon displaying major paleogeographic elements that influenced sedimentation in early Paleozoic time (after Pugh, 1983; Norris, 1985; and Morrow, 1999). Note locations of the Mackenzie-Peel shelf and Richardson trough, both influential to the Yukon Peel region in early Paleozoic time. Location of Yukon Peel region is highlighted in green. Location of seventeen oil and gas wells used in this assessment is denoted with red dots.*

Government research during this time included the large-scale GSC mapping project called *Operation Porcupine*, which provided 1:250 000-scale coverage of the northern Yukon Territory and the northwest corner of NWT, specifically north of latitude 65º N and west of longitude 132º W. *Operation Porcupine* commenced in 1961 (with follow-up investigations extending into the early 1980s), culminating in a report published in 1997 (Norris, 1997a). More recent research in the Peel area occurred from 2005-2009 as part of the *Regional Geoscience Studies and Petroleum Potential, Peel Plateau and Plain, Northwest Territories and Yukon* project, a four-year collaborative research effort among the Northwest Territories Geoscience Office (NTGO), the Yukon Geological Survey (YGS), the Geological Survey of Canada (GSC), and university and industry affiliates (Pyle and Jones, 2009). Current geological research in the Yukon Peel region is associated with the *Geo-Mapping for Energy and Minerals (GEM) 2008-2013* project initiated by the GSC in 2008.

PETROPHYSICAL ASSESSMENT METHODOLOGY

Petrel Robertson Consulting Limited (PRCL), of Calgary, Alberta, was contracted to perform the reservoir petrophysical analysis of 17 wells in the Yukon Peel region. PRCL uses the HDS 2000 software by Hydrocarbon Data Systems Inc. (HDS)[1] to undertake these well analyses. The analysis of the Peel wells was performed by petrophysicist Yevgen Mykula, and was overseen by PRCL vice-president, David Kisilevsky, P. Geol.

The main objectives of the assessment were to: a) identify and tabulate conventional reservoir intervals within each formation/member[2]; and b) identify and tabulate the presence of hydrocarbons (or pay zones) within these reservoir intervals. Other data resulting from this analysis include: average effective porosity, average permeability, average volume of shale and average water saturation over reservoir and pay zones; dominant lithology over pay zones; and a flag for holes with questionable log responses due to drill hole irregularities (bad hole flag).

PRCL was provided digital well log files (Log ASCII Standard or *.LAS) from the YGS collection. Formation well tops used for this analysis were taken from Fraser and Hogue (2007).

Data Quality and Availability

Table 1 lists the seventeen wells used for this study by unique well identifier (UWI), and includes the well long and short names, geographical coordinates, kelly bushing elevation (KB), total measured well depth in metres (TMD) and formation at the base of each well (Fm@TD). This report will refer to a particular well in question with the short name rather than the longer UWI. Figure 5 displays the distribution of these wells throughout the Yukon Peel region. Although 19 wells have been drilled in the study area, two of these, N-77 and B-06, were not used in this analysis. Well N-77 was not logged for geophysical properties. Well B-06 was a shallow hole that was redrilled as 2B-06 (sometimes referred to as B-06A) presumably due to drilling difficulties. Well data from 2B-06 were used in this study.

As is common with older wells, the type and coverage of geophysical properties logged varies greatly from well to well. As an example, well A-42 has twelve different log curves, with only a portion

1 More information about the HDS 2000 software and HDS can be found on the internet at www.hds-log.com/index.htm.

2 As identified in Fraser and Hogue (2007).

Table 1. *List of Yukon Peel region wells used in this study, including unique well identifier (UWI), well long name, well short name, geographical coordinates (North American Datum 83), kelly bushing elevation (KB), total measured depth (TMD), and formation at bottom of each well (FM@TD). TMD and KBE are measured in metres (m).*

UWI	Well long name	Well short name	Latitude (NAD 83)	Longitude (NAD 83)	KB (m)	TMD (m)	FM@TD
300A426550133000	Cranswick Y.T. A-42	A-42	65.68	-133.14	620.05	4267.2	Franklin Mountain
300K156600133000	Taylor Lake Y.T. K-15	K-15	65.91	-133.05	468.78	2378.7	Mount Kindle
300M696610133450	Peel River Y.T. M-69	M-69	66.14	-133.96	291.69	3272.6	Peel
300K096620134000	Peel R Y.T. K-09	K-09	66.30	-134.01	349.54	1554.5	Tuttle
300I216620134150	Peel R Y.T. I-21	I-21	66.17	-134.30	381.3	2072.6	Landry
300N256620134450	Caribou Y.T. N-25	N-25	66.24	-134.82	495.3	3600.3	?Proterozoic
300K766630134000	Peel R. Y.T. K-76	K-76	66.42	-134.23	76.5	1386.8	Tuttle
300H716630134300	Peel Y.T. H-71	H-71	66.34	-134.72	512.97	3419.6	Franklin Mountain
300J216640134000	Peel River Y.T. J-21	J-21	66.50	-134.07	45.72	1219.2	Tuttle
300H596640134300	Peel R. Y.T. H-59	H-59	66.63	-134.66	33.37	763.2	Tuttle
300L016640134450	Peel R Y.T. L-01	L-01	66.51	-134.77	394.71	1834.9	Imperial
302B066640134450	Peel River Y.T. 2B-06	2B-06	66.58	-134.76	66.29	1066.8	Tuttle
300H376640134450	Trail River Y.T. H-37	H-37	66.60	-134.84	393.19	3721.6	Peel
300C606650133450	Arctic Red Y.T. C-60	C-60	66.81	-133.92	92.04	2599.9	Peel
300L196650135150	Peel R Y.T. L-19	L-19	66.80	-135.31	95.15	1981.2	Imperial
300G726700134000	Satah River Y.T. G-72	G-72	66.85	-134.23	89.61	2286	Landry
300F376700134450	Peel Y.T. F-37	F-37	66.93	-134.86	54.4	3368	Mount Kindle

covering the Cretaceous, Carboniferous and Upper Devonian sections. H-59, on the other hand, has five different log curves which cover the entire length of the well. Due to these data gaps, not all formations or petrophysical properties could be analysed in this study.

As stated, YGS provided the *.LAS files for this study. Every effort was made to acquire complete *.LAS files for each borehole location; however, the possibility remains that additional data exist that we were unaware of when analyses were completed for this study.

Definition of Reservoir and Pay

The focus of the reservoir petrophysical assessment was to identify and tabulate conventional reservoir and pay intervals within each formation/member included in this study. The following paragraphs define how the terms reservoir and pay are employed in this analysis.

Reservoir

Generally speaking, any rock that contains interconnected pores may become a reservoir rock (Levorson, 2001). A reservoir rock must be porous enough to contain a 'tank' of petroleum in the trap, and the pores must be sufficiently interconnected to allow the petroleum to flow through the rock towards the wellbore (Allen and Allen, 2005). As a result, the primary considerations in determining the presence of reservoir rock, are the determination of porosity and permeability. For this study, reservoir intervals were identified by using cut-off values for effective porosity[3] and permeability, and differed depending on whether the rock type was siliciclastic, limestone or dolostone. Table 2 lists the different reservoir cut-off values used in this study for the various rock types encountered.

3 Effective porosity is a measure of a rock's total porosity minus the porosity found in shale. The definition for effective porosity is found in Appendix A and is explained further in the *Calculations* section of this report.

__Table 2.__ Reservoir zone cut-off values used in this analysis, including effective porosity (%) and permeability (mD).

Rock type	Effective porosity (%)	Permeability (mD)
siliciclastic	≥ 8	≥ 2
limestone	≥ 6	≥ 1
dolostone	≥ 4	≥ 1

For siliciclastic rocks, a reservoir is defined as an interval with ≥8.0% effective porosity, and ≥2 millidarcies (mD) permeability. For limestone, a reservoir is defined as an interval with ≥6% effective porosity and ≥1 mD permeability. A reservoir in dolostone is defined as an interval with ≥4% effective porosity and ≥1 mD permeability.

This analysis calculated both gross reservoir and net reservoir. Gross reservoir is an interval of rock, defined by the petrophysicist, which exhibits zones of reservoir, interspersed with zones of non-reservoir strata. It is used as a first approximation to identify zones of interest. Net reservoir refers to the sum of those gross reservoir intervals that have actual reservoir properties. Net reservoir therefore, is a subset of gross reservoir.

Pay

Net reservoir intervals with hydrocarbons are referred to in this study as pay. Gross pay intervals are identified as all reservoir intervals with a water saturation value (Sw) ≤55% (*i.e.*, an inferred hydrocarbon saturation of ≥45%). Net pay is identified as the sum of those gross pay intervals with a consecutive thickness of ≥1 m for siliciclastic rocks, and ≥3 m for carbonate rocks. Net pay therefore, is a subset of gross pay. Pay zone cut-off values are listed in Table 3.

__Table 3.__ Pay zone cut-off values used in this analysis including effective porosity (%), permeability (mD), water saturation (Sw; decimal) and interval thickness (m).

Rock type	Effective porosity (%)	Permeability (mD)	Sw (decimal)	Thickness (m)
siliciclastic	≥ 8	≥ 2	≤ 0.55	≥ 1
limestone	≥ 6	≥ 1	≤ 0.55	≥ 3
dolostone	≥ 4	≥ 1	≤ 0.55	≥ 3

Calculations

To perform the reservoir petrophysical property assessment, several calculations were employed that required the identification of a number of variables including lithology, effective porosity, permeability, water saturation and resistivity, shale volume and hydrocarbon saturation. The following paragraphs describe how these parameters were calculated or determined. Appendix A contains detailed descriptions of all calculations used in this analysis.

To determine whether a rock is siliciclastic or carbonate, and thus which reservoir and pay filters to apply, a lithology for each formation had to be defined. Lithology is best determined using the Photoelectric Factor (PEF) geophysical log, however, none of the wells in this study have a PEF log associated with them. In the absence of a PEF log, lithology was determined by using a combination of log curves (*e.g.*, gamma ray, density, neutron porosity and resistivity) accompanied by lithology descriptions in existing publications (*e.g.*, Norris, 1997a).

Porosity values were determined by density, sonic and neutron logs, or a combination thereof. Where available, log-derived porosity values were calibrated with data acquired from core analyses to verify the validity of the log analysis procedure. All porosity values reported in this study were converted to effective porosity (PhiE), which are porosity values corrected for the presence of shale.

Permeability values for this analysis were determined by using the Wyllie and Rose (1950) formula and the 'Coates' equation (Crain, 2010, modified from Coates and Dumanoir, 1974). The Wyllie and Rose formula was used for clastic rocks as it had the best match to core data. The 'Coates' equation for permeability was used for carbonate rocks.

Water saturation (Sw) values were determined by the Archie equation (Schlumberger, 1989) for carbonate formations. For clastic formations, a modified version of the Simandoux equation (Simandoux, 1963), known informally as the 'Silty Simandoux' equation[4], was used. Both of these equations rely on determinations of water resistivity (Rw) and formation resistivity (Rt). Rw is a value that must be established for each zone of interest. Table 4 displays the Rw values at 25°C that were established for each formation, including the source of the data. Rt is determined from resistivity logs.

Table 4. *Water resistivity (Rw) values in ohm-metres (ohm-m) at 25°C used in this analysis. 'PRCL' refers to Petrel Robertson Consulting Limited.*

Formation/Member	Rw (ohm-m) @ 25 °C	Source
Arctic Red	1.025	Pickett cross-plot (Pickett, 1972)
Martin House, Tuttle, Imperial, Canol, Bluefish	0.200	Pickett cross-plot (Pickett, 1972)
Hume, Landry	0.310	Previous PRCL projects in NWT
Arnica, Tatsieta, Peel	0.150	Previous PRCL projects in NWT
Mount Kindle, Franklin Mountain, Proterozoic	0.856	Average derived from several sources (PRCL files and well history reports)

Volume of shale (Vsh) is determined by using the gamma ray (GR) log and the Larionov Older Rock equation (Larionov, 1969). This equation requires the determination of GR minimum and maximum values (*i.e.*, 0% and 100% shale) which were determined by the petrophysicist visually for each well.

As the quality of the wellbore can affect the quality of the log data, a 'bad hole' flag (FBH) was provided for most wells to identify zones of poor data caused by borehole caving. A bad hole flag exists when the density correction log exceeds 100 kg/m^3, or the caliper (borehole diameter measurement) is 1.25 times larger than the bit size. Zones in the well exhibiting bad hole criteria are marked with a value of '1'. If the zones do not meet the bad hole criteria, they are marked as '0'.

Assumptions

Selecting cut-off values for porosity, permeability, Sw and interval thickness in order to determine reservoir and pay zones is subjective, and may be influenced by a number of factors including rock

4 The 'Silty Simandoux' equation modifies the original Simandoux equation by correcting for excess conductivity caused by the presence of shale. The Silty Simandoux equation used in the HDS 2000 software is the same equation used by Schlumberger in the early 1970s and internally referred to then as the 'V Shale Squared' equation (L. Wells, pers comm e-mail, Jan 18, 2010).

type, size of hydrocarbon pool, depth of pool from surface, drilling and completion technology and distance of well to infrastructure. Cut-off values for porosity, permeability, Sw, and interval thickness chosen for this study are the same values that are being used for the Mackenzie Corridor resource assessment, an assessment currently being undertaken by the GSC. These values are listed in Tables 2 and 3. Scientists at the GSC provided cut-off values, and concluded that it would not be economic to pursue any reservoir having consecutive net pay thicknesses ≤1 m in siliciclastic rocks, and ≤3 m in carbonates rocks (P. Hannigan, pers comm email, Nov. 19, 2009).

Unlike porosity or formation resistivity, deciding on appropriate calculations for permeability and water saturation can be challenging, as these values cannot be read directly from well logs and thus must be calculated using a variety of variables. The petrophysicist at PRCL was encouraged to be consistent with the equations being used by the GSC for the wider Mackenzie Corridor study, but did deviate where data, such as core analyses, warranted the use of other equations.

The choice of well formation tops is also a subjective exercise. As stated, well formation tops for this study were taken from Fraser and Hogue (2007). These well tops were picked based on the character of geophysical well log response, and may not coincide with formation tops based on biostratigraphic and/or lithostratigraphic controls.

In this study, Road River 'basinal facies' strata in wells N-25 and H-71 have been correlated with their time-equivalent carbonate 'platform facies' strata located further to the east. N-25 and H-71 are the westernmost wells in the Peel region, occurring to the west of the Devonian Mackenzie-Peel shelf, on the eastern margin of the former Richardson trough (Fig. 5). In this region, Devonian shelf carbonates (Hume, Arnica, Landry, Tatsieta and Peel formations) transition westward into basinal shales (Road River Group; Fig. 3). Formation tops for these wells are listed in Fraser and Hogue (2007) as Road River strata with an equivalent carbonate formation in brackets (*e.g.*, Road River (Peel Eq)), and were picked based on traceable markers that extend from the shelf to the basin. In this transition zone, carbonates and shales are both present, and it was decided for this study to assign these strata as carbonates to avoid bypassing potential reservoir intervals.

EXPLANATION OF DATA PRESENTATION

Data accompanying this report are found in two additional folders: 1) data unique to each well; and 2) summary data for 17 wells, the contents of which are described below.

Data Unique to Each Well

The folder '*Data Unique to Each Well*' is subdivided into 17 subfolders named by borehole unique well identifier (UWI), *e.g.* 300A4265450133001. Each subfolder contains a series of files and subfolders including: *LAS coverage.pdf*, *Log Plots* and *Log Analysis Tables*. The contents of these subfolders are the raw data (with minor changes) provided to YGS from PRCL.

LAS coverage.pdf

The file *LAS coverage.pdf* graphically depicts the *.LAS wireline data available for the borehole, and the depths (in metres) over which the data were available for this study. Overlain onto this graph are the formation tops taken from Fraser and Hogue (2007). Log curve abbreviations in this graph are explained in Appendix B.

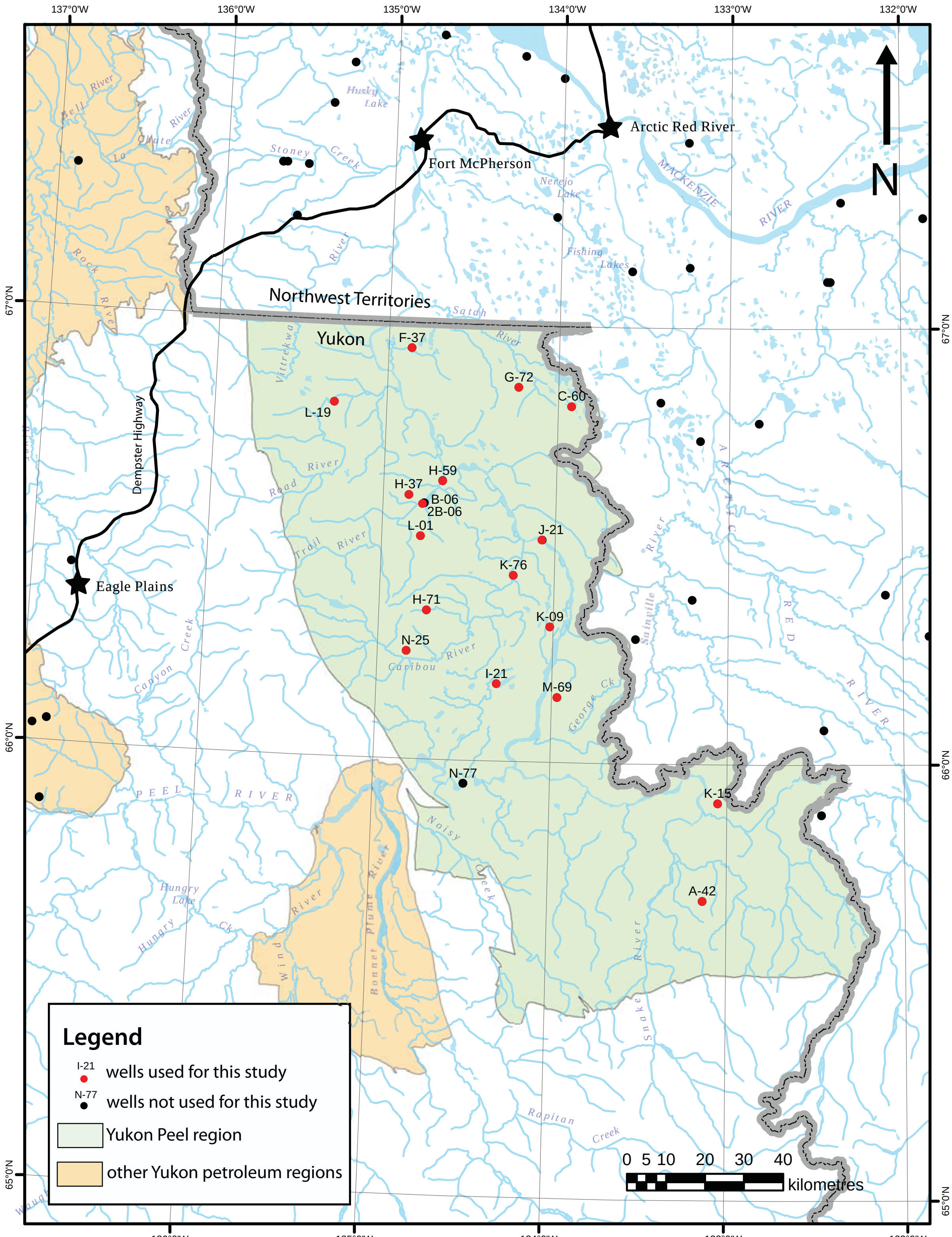


__Figure 5.__ Distribution of oil and gas exploration wells in the Yukon Peel region. Wells examined for the purpose of this study are displayed with red dots and are labelled with their short name. Other wells in the vicinity, but not used in this study, are displayed with black dots.

Log Plots

The '*Log Plots'* subfolder contains *.pdf files named "Log Plot xx-xx m.pdf" which are visual displays of the available wireline log data along with results of the reservoir petrophysical assessment plotted over a specific depth interval of the borehole. The data are presented in a series of seven tracks, including their units and value ranges and/or lithology displayed at the top of each track. The acronyms of each log and calculated curve are given in Appendix B. Track one displays the logs for borehole size (BS), caliper (CALI), gamma ray (GR), and spontaneous potential (SP). It may also show the bulk density correction curve (DRHO).

Track two is the measured depth log and shows reservoir zones (labeled 'gross') and pay zones (labeled 'pay'), highlighted by yellow and red flags respectively. Track two also displays the bad hole flag (FBH) as blue flags on the left side of the track.

Track three displays a variety of resistivity logs (ILD01; ILM; LL8; SFL; SN; LLD; SN16; and LLS).

Track four displays the sonic logs (DT), neutron logs (NPHI and PHInls), density logs (RHOB and DPHI), the calculated effective porosity curve (PhiE), and the core porosity curve (PhiCor). It may also show the density correction curve (DC). A red solid bar on the right side of this track identifies cored intervals.

Track five displays calculated water saturation (Sw) and shale volume (Vsh) curves.

The sixth track is the visual lithology track displaying calculated relative abundance of shale (Vsh), sandstone (Sand), limestone (Lime), dolostone (Dolo), and the effective porosity (PhiE) and bulk water volume (Bvw) curves.

Track seven displays the calculated permeability curve (K*). Ki is the permeability curve calculated from the Wyllie and Rose equation, and Kc (or Kc-2) is the permeability curve calculated from the 'Coates' equation. Ka is a curve merging Ki and Kc where the data spanned both clastic and carbonate formations. Kmax is permeability calculated from core analyses.

Log Analysis Tables

The '*Log Analysis Tables'* subfolder contains Excel spreadsheets named "Log Analysis Table xx-xx m.xls". These files contain tables of data displaying borehole depths below kelly bushing with respective calculated values for bad hole flag (FBH), effective porosity (PhiE), permeability (Ki, Kc or Ka), volume of shale (Vsh), and water saturation (Sw). In some wells, one or more of these values may be absent due to insufficient log coverage. The interval/step between borehole depths is determined by the interval/step that was in the original *.LAS file.

Summary Data for 17 Wells

Folder '*Summary Data for 17 Wells*' contains the comprehensive results of the reservoir petrophysical assessment in a series of spreadsheets labeled Appendix C, Tables A – O. Appendix C, Table A, *Summary of conventional reservoir petrophysical property assessment from 17 Peel region wells, Yukon Territory* is a compilation of all results of the analysis in a single spreadsheet, organized by well and formation, including formation thickness, all reservoir and pay data, and cut-off values employed. Appendix C, Tables B–O provide the same information on a formation/member basis.

RESULTS OF CONVENTIONAL RESERVOIR PETROPHYSICAL PROPERTY ANALYSIS

This section describes the results of the conventional reservoir petrophysical property analysis on a formation basis, from youngest to oldest. The comprehensive results of the study are given in Appendix C, Table A. Results on a formation basis are given in Appendix C, Tables B-O.

Arctic Red Formation

Description and Thickness

The youngest formation (not including Quaternary strata) penetrated by wells in the Yukon Peel region is the Lower Cretaceous (Albian) Arctic Red Formation[5]. This formation is dominated by marine shale and lesser siltstone, and has been divided into a silty shale and a concretionary shale facies (Mountjoy and Chamney, 1969). The silty shale facies is divided into three members: two silty shale members, separated by a middle siltstone member. The concretionary shale facies has a lower fossiliferous member and an upper silty member. The Arctic Red Formation gradationally overlies the Martin House Formation (Mountjoy and Chamney, 1969). In the Peel region wells, the Arctic Red Formation is the uppermost Mesozoic formation observed.

Twelve wells in this study penetrate the Arctic Red Formation; however, three of them do not have logs for the Arctic Red interval. As a result, nine wells were used to analyse Arctic Red reservoir properties. Of these nine, eight have discontinuous logs over the Arctic Red interval. The formation is thickest in well A-42 at 1097.9 m, and thinnest in well F-37 at 55.2 m (Fraser and Hogue, 2007).

Reservoir and Pay Summary

The results of the reservoir petrophysical assessment for the Arctic Red Formation are reported in Appendix C, Table B. Cut-off values used to calculate reservoir and pay for the Arctic Red Formation are those which apply to siliciclastic rocks (Tables 2 and 3). One exception is well C-60 which has insufficient well log data to determine permeability and water saturation for the Arctic Red Formation. To determine reservoir for C-60, only the porosity cut-off was employed.

Eight of nine wells with well log data over the Arctic Red Formation have calculated reservoir intervals (Fig. 6a). The average porosity over the net reservoir zone ranges from 13% in K-09 to 23% in A-42 (Fig. 6b). Average permeability over net reservoir zone ranges from 4 mD in K-09 to 152 mD in A-42 (Fig. 6b). The average net reservoir thickness for the Arctic Red Formation, calculated for 9 wells, including data from well C-60 which uses only porosity data, is 13.5 m. Without C-60 the average net reservoir thickness is 13.2 m.

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5 The youngest formation shown in Figure 3, the stratigraphic correlation chart for Peel Plateau and Peel Plain, is the Albian to Turonian Trevor Formation (Mountjoy and Chamney, 1969). In Yukon, this formation occurs at surface in Peel Plateau, in the Trevor Range, a north-south ridge south of the confluence of the Snake and Peel rivers, and near the Yukon – NWT border north of the Mackenzie Mountain front (Norris, 1982a). The Trevor Formation is not penetrated by any wells in Yukon, and is therefore not discussed in this study. The Trevor Formation, however, is penetrated in the Peel Plain in NWT in the Arctic Red F-47 well (UWI 300F476540130450). For a discussion of the Trevor Formation in the Peel region in NWT, see Hadlari *et al*. 2009a.

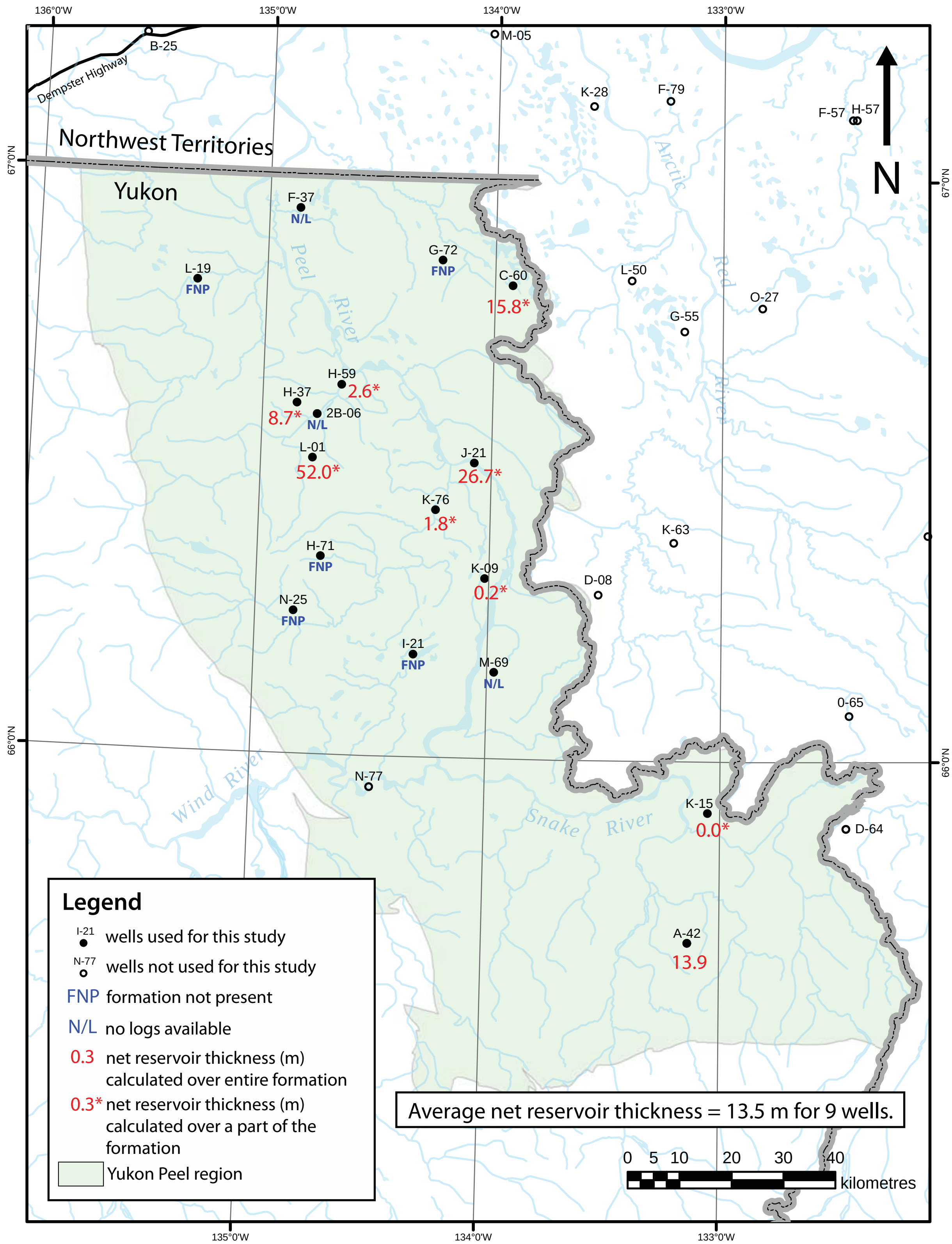

Figure 6a. *Net reservoir thickness (m) in the Arctic Red Formation.*

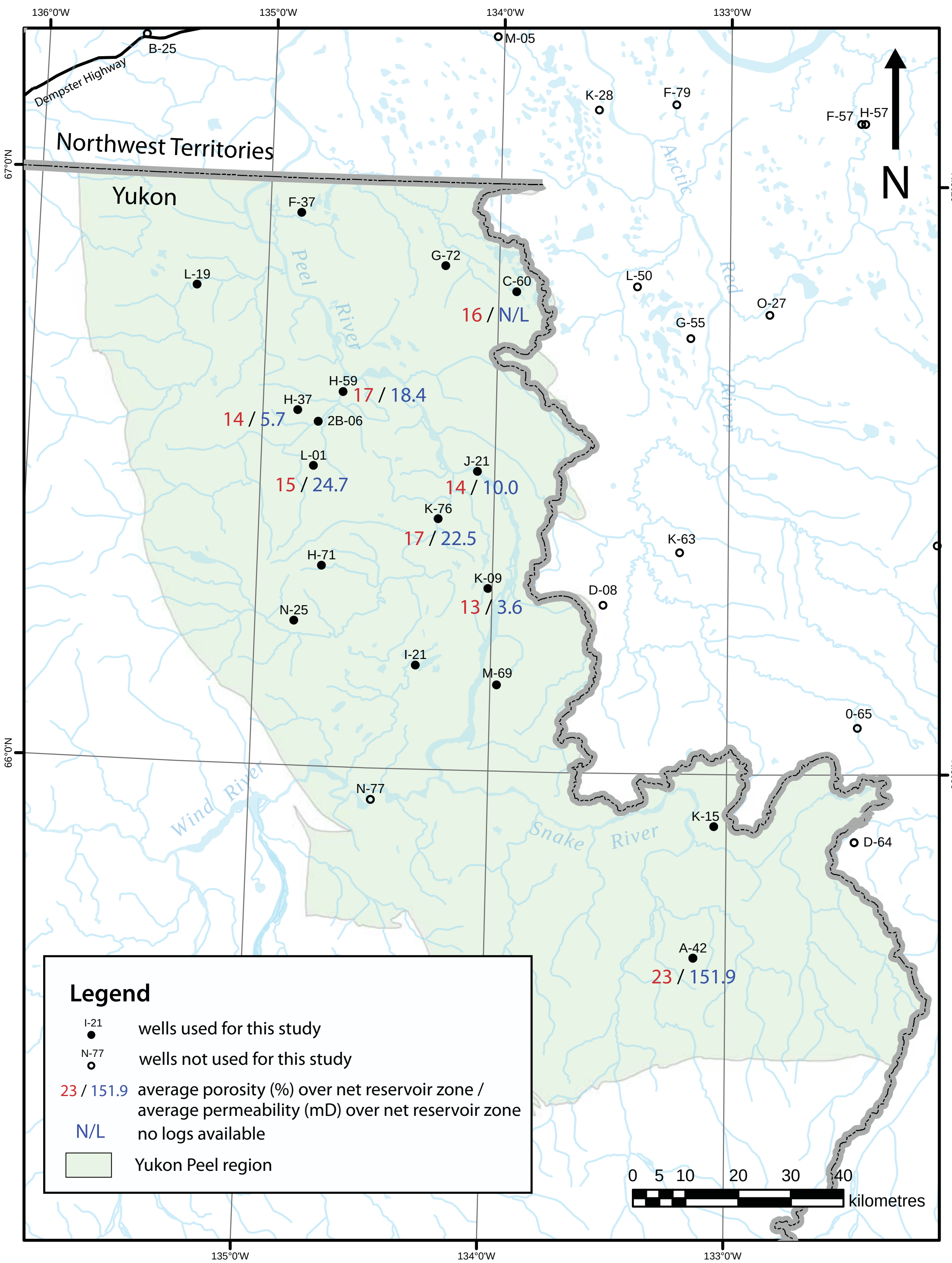

Figure 6b. *Average porosity (%) and permeability (mD) over net reservoir zone in the Arctic Red Formation. Data represent only wells having net reservoir values for the Arctic Red Formation (see Figure 6a).*

Of the eight wells with reservoir in the Arctic Red Formation, two have associated pay intervals (L-01 and H-37) and one has insufficient logs for this analysis (C-60). L-01 has a net pay thickness of 3.0 m, with average porosity and permeability over this interval of 24% and 258 mD respectively (Figs. 6c,d). H-37 has a net pay thickness of 2.4 m, with an average porosity and permeability of 15% and 10 mD respectively (Figs. 6c,d). The average net pay thickness calculated among 8 wells is 0.7 m.

Martin House Formation

Description and Thickness

The Lower Cretaceous (upper Aptian and lower Albian) Martin House Formation is overlain gradationally by the Arctic Red Formation and rests unconformably on Paleozoic strata (Mountjoy and Chamney, 1969). Mountjoy and Chamney (1969) describe the Martin House Formation as a distinctive unit containing glauconite, shale and siltstone. They divide the Martin House Formation into a Basal Siltstone member, comprising siltstone and silty shale, and a Glauconite member, comprised of glauconitic sandstone, siltstone and silty shale. Hadlari *et al*. (2009a) informally subdivided the Martin House Formation into a lower non-marine member (Tukweye member), a basal marine sandstone, and an upper Martin House Formation sandstone interval based on field and drill core investigations in the NWT, east of the Yukon Peel region.

In this study, 14 wells penetrate the Martin House Formation[6]; however, five of them do not have logs for the Martin House interval. As a result, only nine wells were used to analyse the Martin House interval. The formation is thickest in well M-69 at 476.8 m and thinnest in the F-37 well at 46.9 m (Fraser and Hogue, 2007).

Reservoir and Pay Summary

The results of the reservoir petrophysical assessment for the Martin House Formation are reported in Appendix C, Table C. Cut-off values used to calculate reservoir and pay for the Martin House Formation are those which apply to siliciclastic rocks (Tables 2 and 3). One exception is for well C-60 which has insufficient well log data to determine permeability and water saturation for the Martin House interval. To determine reservoir for C-60, only the porosity cut-off was employed.

Eight of nine wells with well log data over the Martin House Formation have reservoir properties (Fig. 7a). Well C-60 has a net reservoir thickness of 70 m, which is likely inflated as it is based solely on porosity cut-offs. The range in net reservoir thickness, not including C-60, is 2.4 m in K-15 to 7.5 m in L-01 (Fig. 7a). The average porosity over net reservoir intervals ranges from 14% in K-15, M-69, L-01 and C-60 to 21% in K-09 (Fig. 7b). The average permeability over net reservoir intervals ranges from 7 mD in K-15, M-69, and L-01, to 83 mD in K-76 (Fig. 7b). The average net reservoir thickness for the Martin House Formation, calculated among 9 wells, including well C-60 which uses only porosity data, is 10.8 m. Without well C-60 the average net reservoir thickness is 3.4 m. The latter is probably a more realistic estimate.

6 Well H-71 has a formation top for 'Cretaceous' and this has been attributed to the Martin House Formation as it includes the lowermost 24.4 m of strata overlying Paleozoic strata.

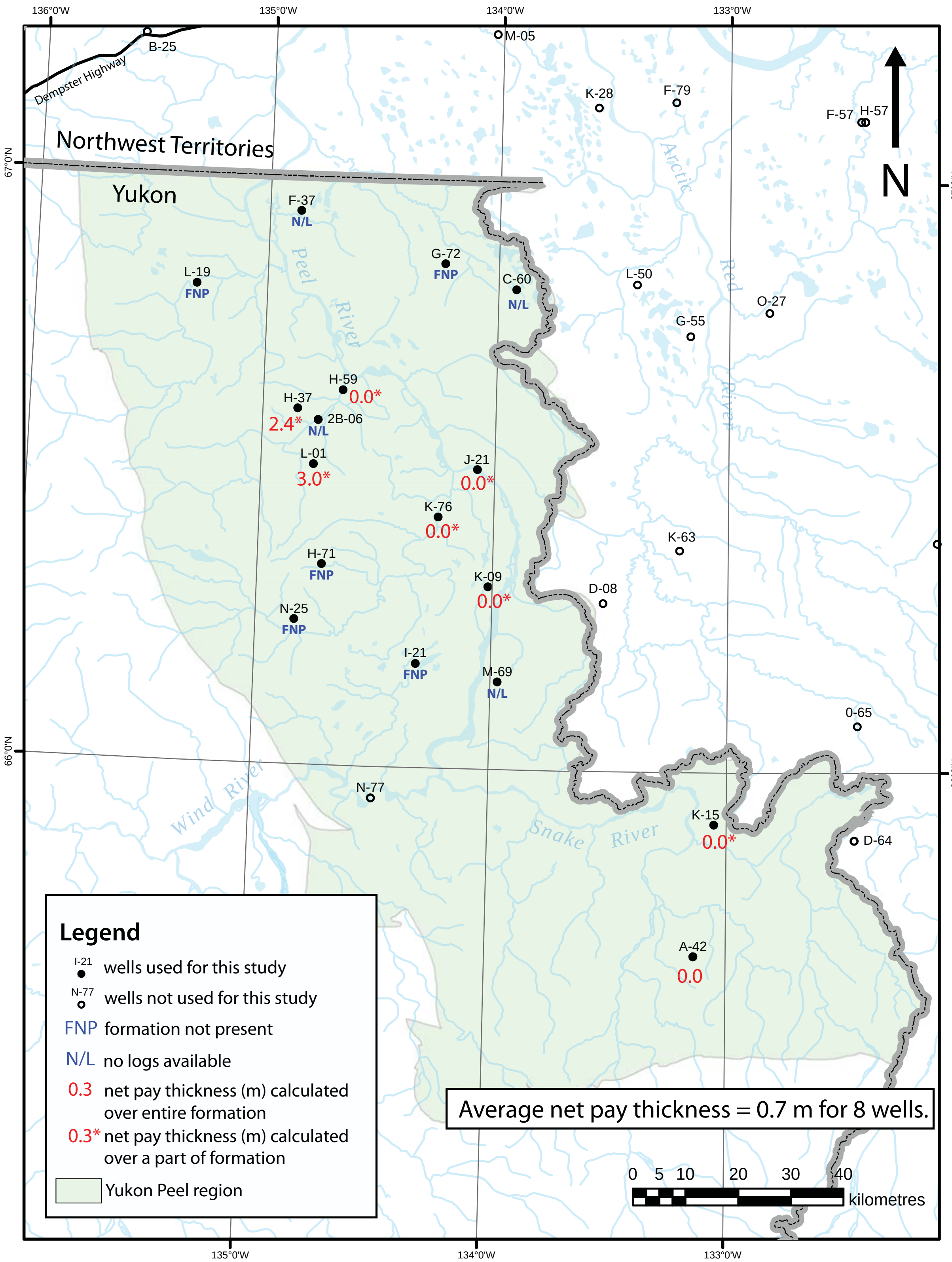

Figure 6c. Net pay thickness (m) in the Arctic Red Formation.

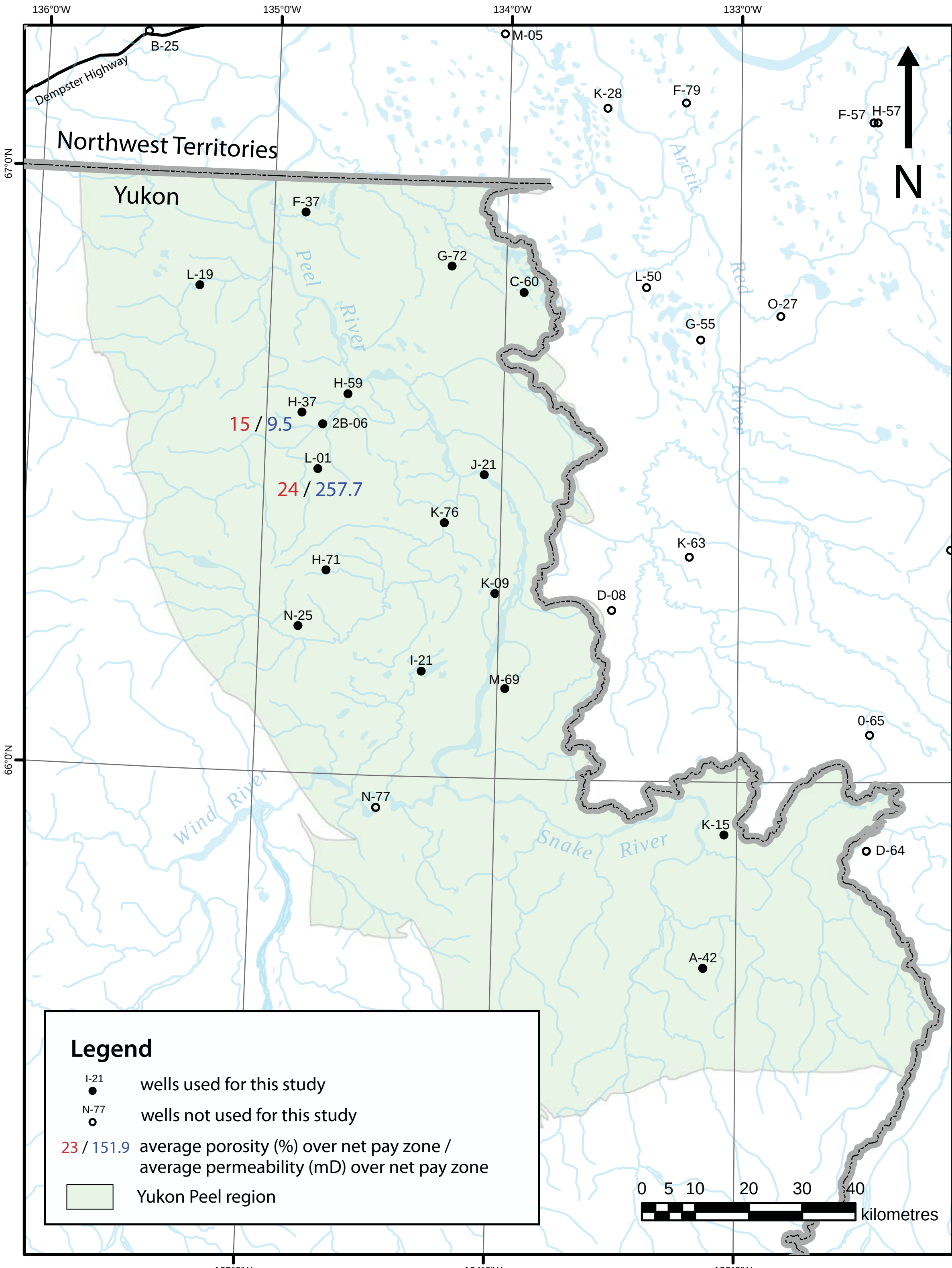

Figure 6d. *Average porosity (%) and permeability (mD) over net pay zone in the Arctic Red Formation. Data represent only wells having net pay values for the Arctic Red Formation (see Figure 6c).*

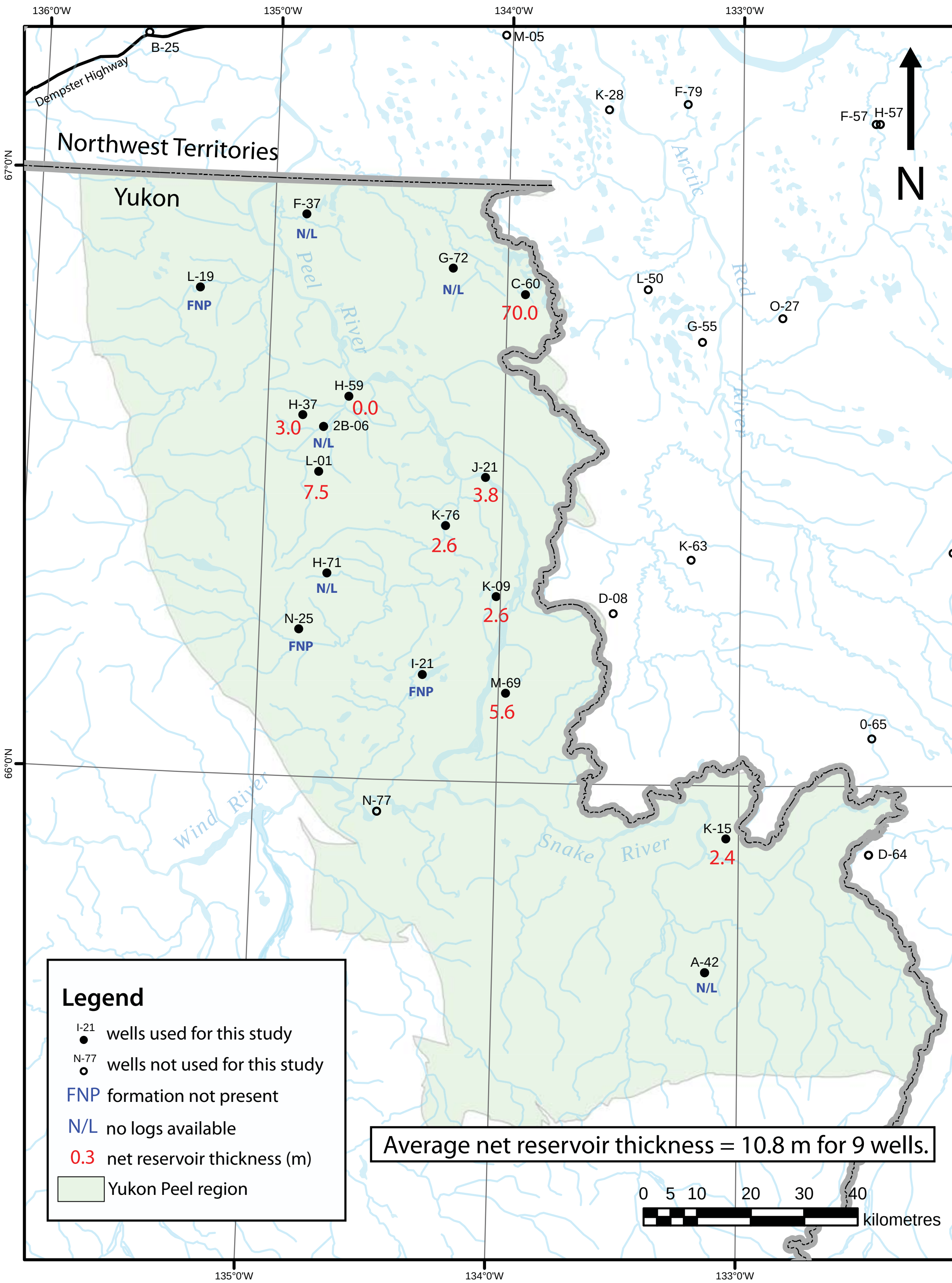

Figure 7a. *Net reservoir thickness (m) in the Martin House Formation.*

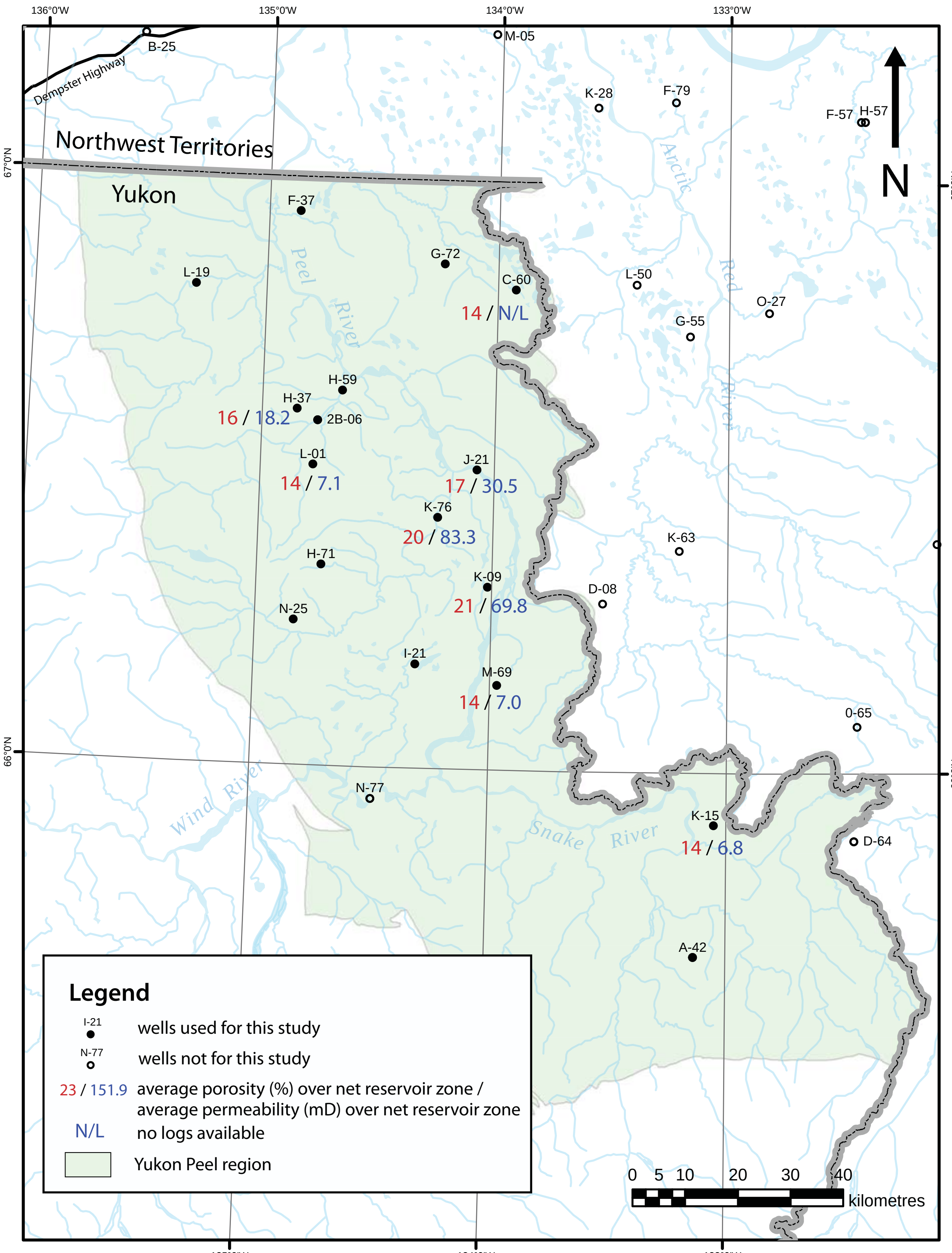

__Figure 7b.__ Average porosity (%) and permeability (mD) over net reservoir zone in the Martin House Formation. Data represent only wells having net reservoir values for the Martin House Formation (see Figure 7a).

Four wells, K-15, K-09, J-21, and H-37, have pay intervals within the Martin House Formation. Pay could not be calculated for the Martin House Formation in well C-60 due to a lack of well data. The thickness of pay ranges from 1.9 m in K-15 to 2.4 m in H-37 and K-09 (Fig. 7c). There is a range in average porosity over these intervals from 14% in K-15 to 21% in K-09 (Fig. 7d). Average permeability ranges from 7 mD in K-15 to 74 mD in K-09 (Fig. 7d). The average net pay thickness calculated among 8 wells is 1.1 m.

Tuttle Formation

Description and Thickness

The Upper Devonian to Lower Mississippian Tuttle Formation was recognized by Pugh (1983) as a thick sequence of sandstones, conglomerates and shales overlying the Imperial Formation in the lower Peel River area. In the eastern Richardson Mountains, immediately east of Peel Plateau, the Tuttle Formation is described as alternating packages of coarse-grained clastic rocks including medium to very coarse grained sandstone and conglomerate, with finer grained intervals of siltstone and shale (Fraser and Allen, 2007). At an exposure on Trail River, east Richardson Mountains (NTS 106L), the Tuttle Formation is interpreted as having been deposited by turbidity currents (Hills and Braman, 1978; Allen *et al*., 2009). In the Peel region, Tuttle strata (which may include sediments of the Upper Devonian Ford Lake Shale Formation) have been truncated by the sub-Cretaceous unconformity, and have a conformable, diachronous and intertonguing contact with the underlying Imperial Formation (Pugh, 1983). The Tuttle Formation has been assigned most recently to an age ranging from Frasnian to early Tournaisian based on palynological evidence (Allen *et al*., 2009).

The type section selected by Pugh (1983) for the Tuttle Formation is found in the F-37 borehole between 107 and 981 m measured depth below KB. Pugh (1983) describes the Tuttle type section as containing vari-coloured chert conglomerate, very poorly sorted quartz and chert sandstone, siltstone and shale. More recent palynological dating of well cuttings from the F-37 well suggest the Tuttle Formation pick may be deeper than previously defined by Pugh, and reported in Fraser and Hogue (2007), by as much as 63.7 m (Allen and Fraser, 2009).

All 17 wells in this study penetrate the Tuttle Formation to some degree, however, three of these wells have no logs for the Tuttle interval. As a result, the Tuttle interval was analysed using 14 wells. Of these 14, four wells have logs only over a portion of the formation, and another five did not penetrate the entire Tuttle Formation. The Tuttle is thickest in well H-37 at 1198.0 m and thinnest in well C-60 at 35.9 m (Fraser and Hogue, 2007).

Reservoir and Pay Summary

The results of the reservoir petrophysical assessment for the Tuttle Formation are reported in Appendix C, Table D. Cut-off values used to calculate reservoir and pay for the Tuttle Formation are those which apply to siliciclastic rocks (Tables 2 and 3). One exception is for well C-60 which has insufficient well log data to determine permeability and water saturation for the Tuttle interval. To determine Tuttle Formation reservoir for C-60, only the porosity cut-off was employed.

All 14 wells used to analyse the Tuttle Formation have reservoir intervals. The Tuttle Formation has the highest average net reservoir thickness of all formations analysed in this study, with a value of

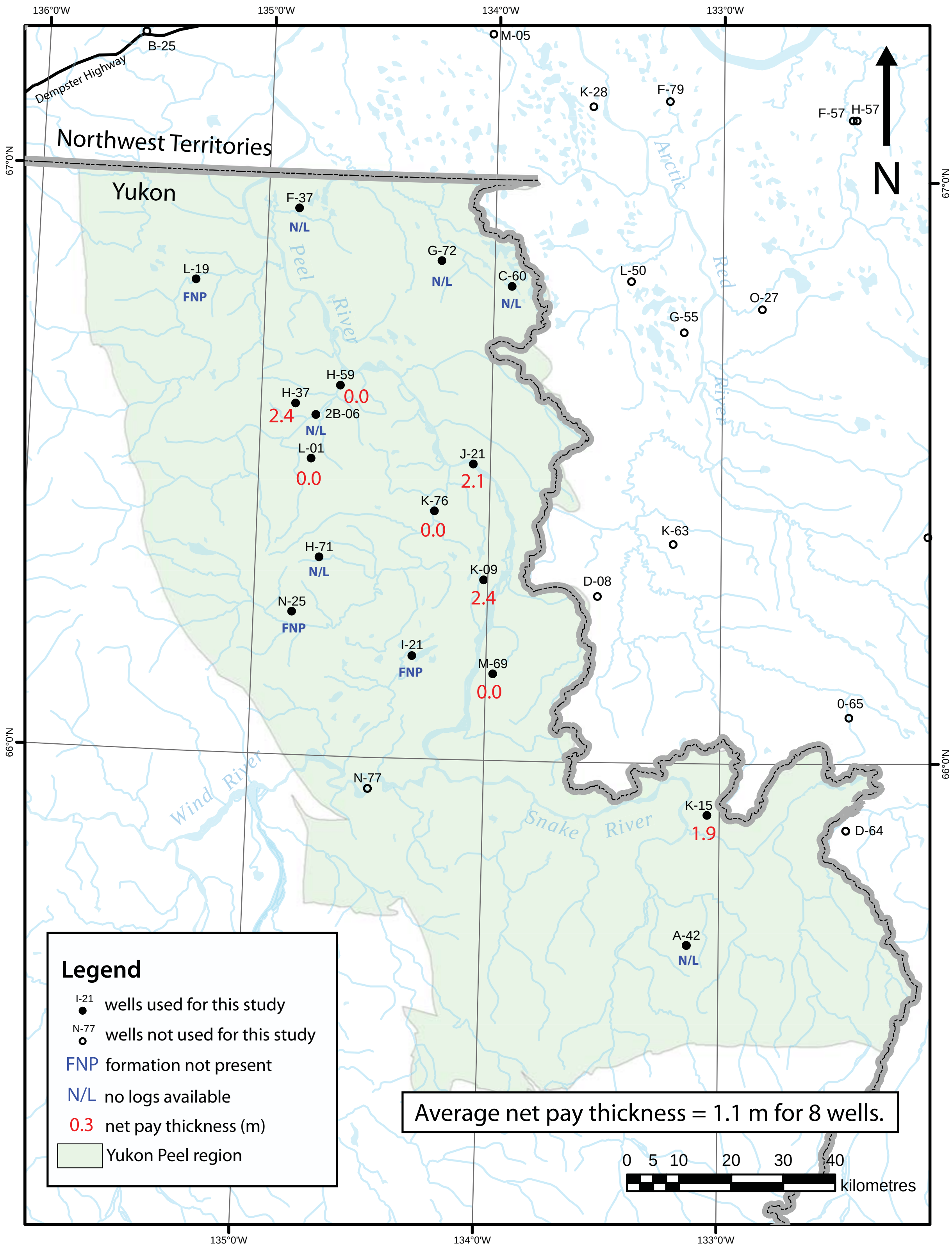

Figure 7c. *Net pay thickness (m) in the Martin House Formation.*

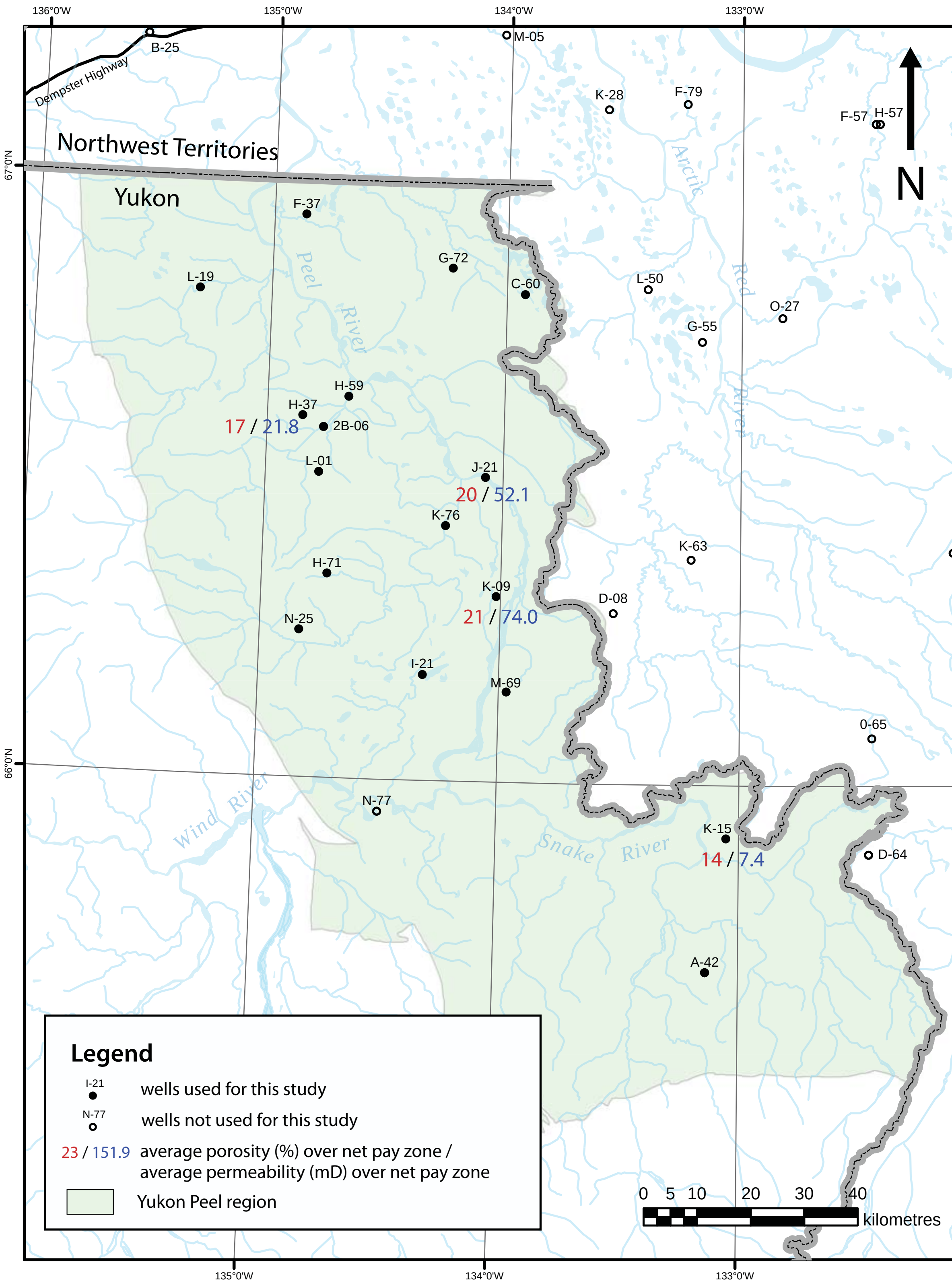

Figure 7d. *Average porosity (%) and permeability (mD) over net pay zone in the Martin House Formation. Data represent only wells having net pay values for the Martin House Formation (see Figure 7c).*

53.8 m among 14 wells (Fig. 8a). When the net reservoir thickness from well C-60 is removed, the average net reservoir thickness increases to 56.8 m among 13 wells. Net reservoir thickness ranges from 4.3 m in M-69 to 221.6 m in well F-37 (Fig. 8a). Average porosity over these intervals ranges from 13% in C-60 to 19% in H-71 and 2B-06 (Fig. 8b). Average permeability over these net reservoir intervals ranges from 6 mD in M-69 to 58 mD in H-71 (Fig. 8b).

Thirteen wells have associated pay intervals in the Tuttle Formation (Fig. 8c). Pay could not be calculated in well C-60 due to the lack of well log data. The Tuttle Formation has the highest average net pay thickness of all formations analysed in this study, with a value of 20.1 m among 13 wells. Net pay thickness ranges from a minimum of 1.0 m in K-09 to a maximum of 71.2 m in well H-37. The highest average porosity and permeability over the net pay interval is in well H-71, with values of 20% and 105 mD respectively (Fig. 8d). The lowest average porosity and permeability is 14% and 6 mD respectively, in well K-09 (Fig. 8d).

Imperial Formation

Description and Thickness

The Upper Devonian Imperial Formation is a thick package of siliciclastic strata representing shelf, slope and basin deposits of a major progradational clastic wedge derived from a northern and western orogenic source (Pugh, 1983; Norris, 1985; Braman and Hills, 1992). In the Richardson Mountains, immediately west of the Yukon Peel region, the Imperial Formation consists of two lithologically different units: a lower mudstone unit and an upper interbedded shale/mudstone and sandstone unit (Allen and Fraser, 2008). The Imperial Formation in this region is dated as Frasnian to Famennian, based on palynology (Utting, 2008, 2009). According to Hadlari *et al*. (2009b), the Imperial Formation in Peel Plateau and Plain, at the front of the Mackenzie Mountains, was deposited by a fan-slope complex that prograded southwest from an eastern basin margin. In the Yukon Peel region, the Imperial Formation in the subsurface is overlain conformably and non-gradationally by the Tuttle Formation, and underlain conformably and non-gradationally by the Canol Formation (Pugh, 1983).

Twelve wells in this study penetrate the Imperial Formation, all of which were used to analyse the Imperial interval to some degree. Two of these wells have logs that cover only a portion of the formation. Another two of these wells did not penetrate the entire formation. The Imperial is thickest in well G-72, with 1520.7 m of strata. By contrast, the Imperial is thinnest in well L-01 at 49.1 m; however, this wellbore did not penetrate the entire Imperial Formation (Fraser and Hogue, 2007).

Reservoir and Pay Summary

The results of the reservoir petrophysical assessment for the Imperial Formation are reported in Appendix C, Table E. Cut-off values used to calculate reservoir and pay for the Imperial Formation are those which apply to siliciclastic rocks (Tables 2 and 3).

Of the 12 wells analysed, ten have reservoir intervals in the Imperial section (Fig. 9a). Net reservoir thickness ranges from 0.2 m in M-69 to 86 m in G-72. The average net reservoir among 12 wells is 16.4 m. Average porosity over the net reservoir intervals ranges from 13% in M-69 and H-37 to 19% in L-19 (Fig. 9b). Average permeability over net reservoir intervals ranges from 3 mD in M-69 and H-37 to 41 mD in L-19 (Fig. 9b).

There is one pay interval in the Imperial Formation in well F-37 (Fig. 9c). The net pay thickness is 4.7

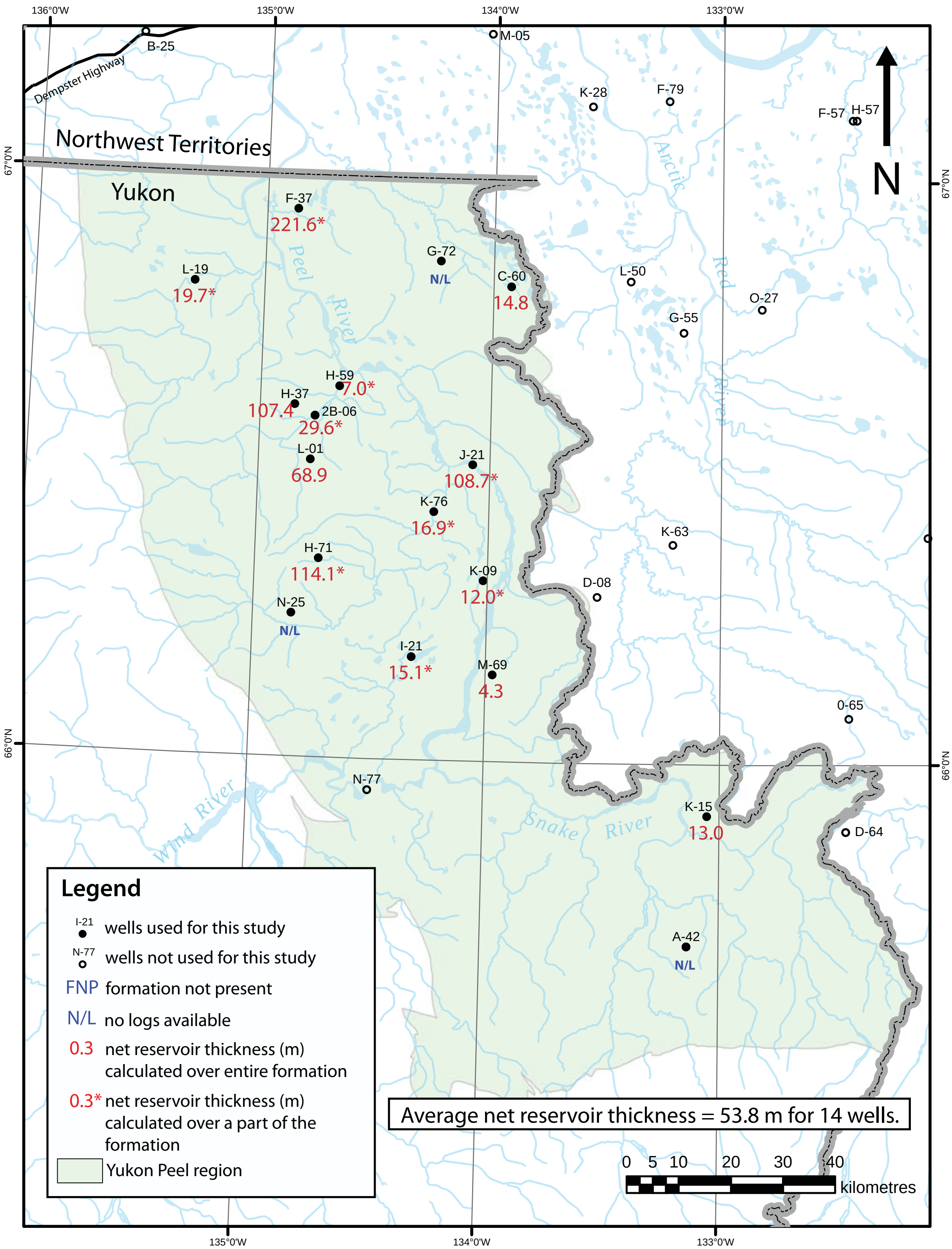

Figure 8a. *Net reservoir thickness (m) in the Tuttle Formation.*

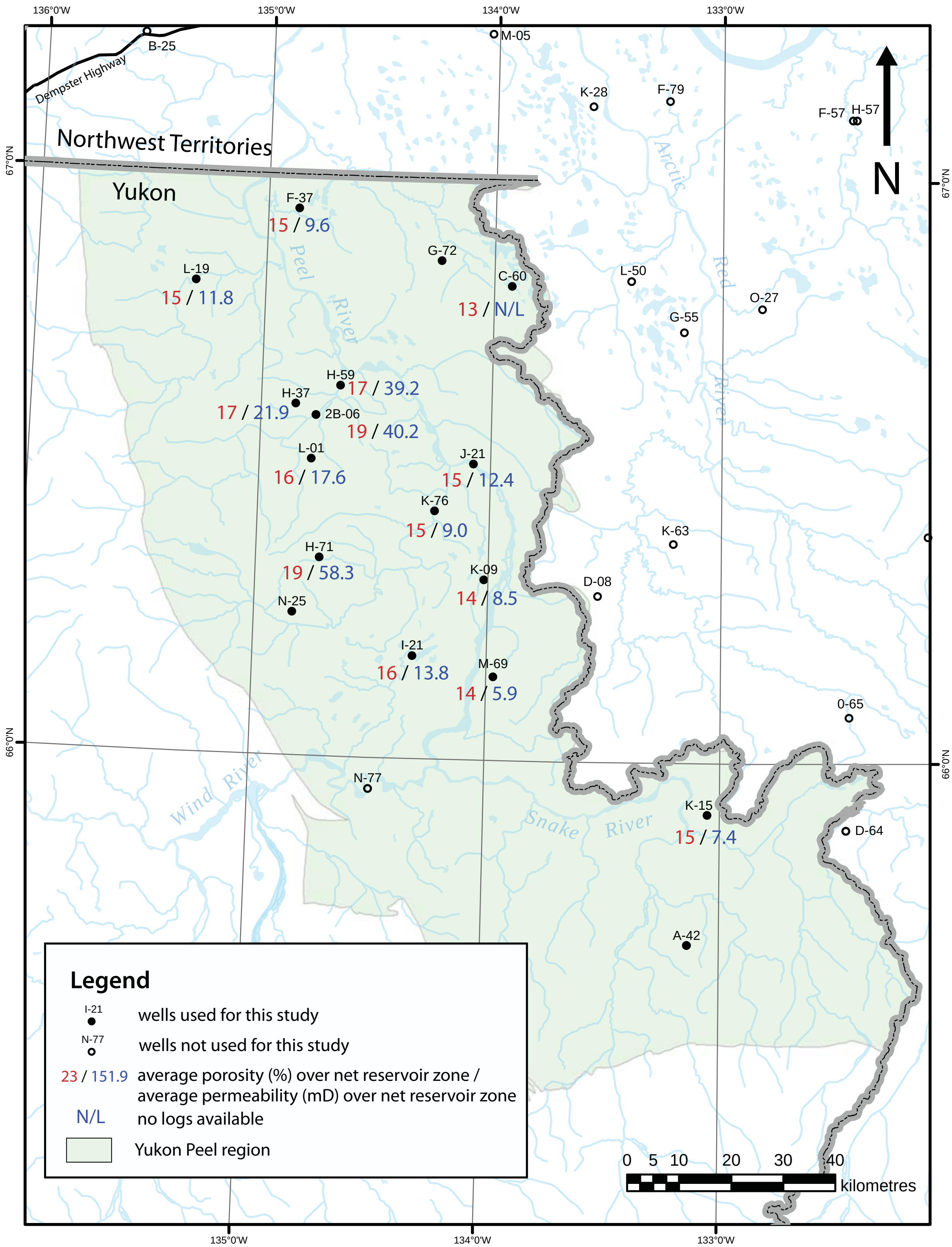

Figure 8b. *Average porosity (%) and permeability (mD) over net reservoir zone in the Tuttle Formation. Data represent only wells having net reservoir values for the Tuttle Formation (see Figure 8a).*

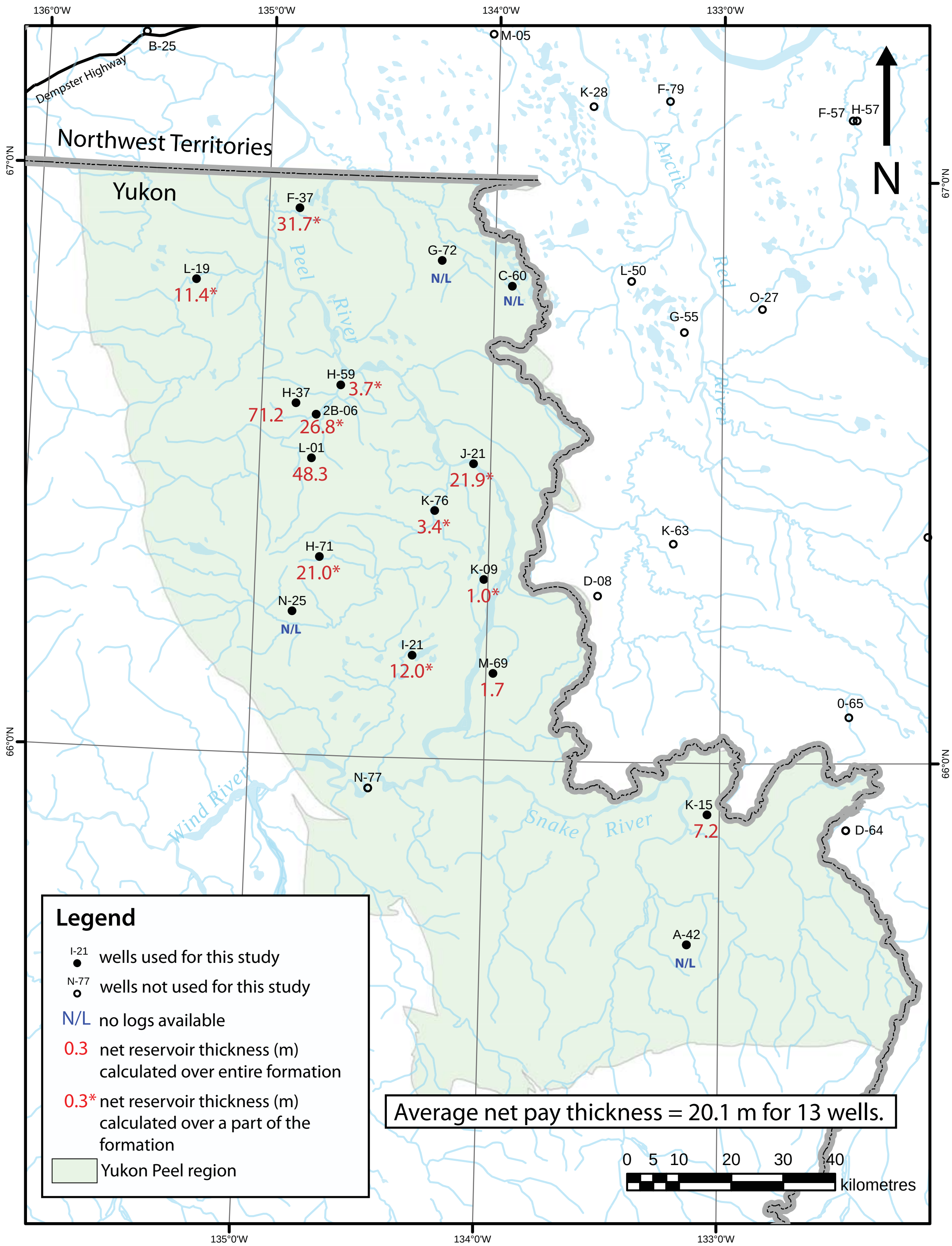

Figure 8c. *Net pay thickness (m) in the Tuttle Formation.*

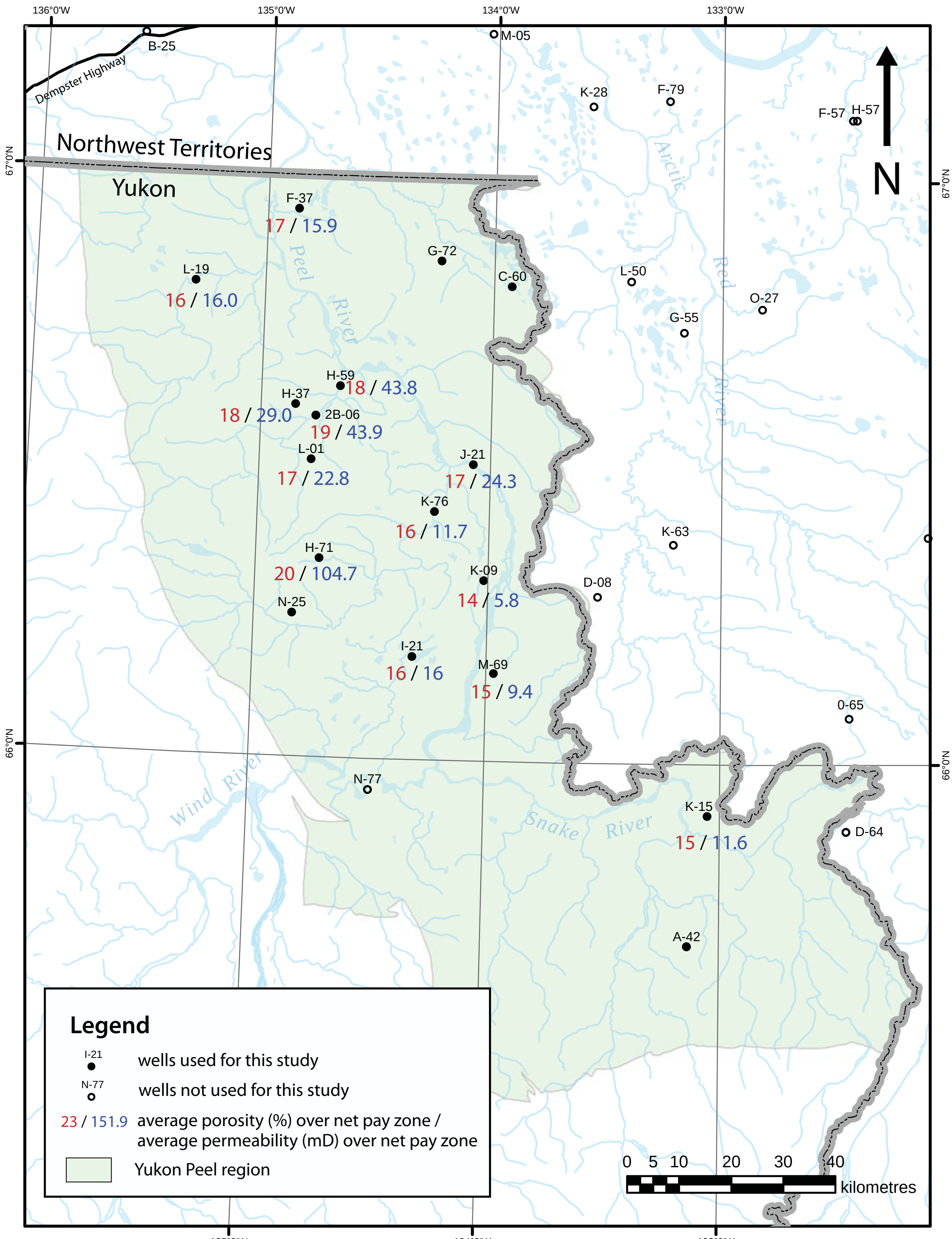

Figure 8d. *Average porosity (%) and permeability (mD) over net pay zone in the Tuttle Formation. Data represent only wells having net pay values for the Tuttle Formation (see Figure 8c).*

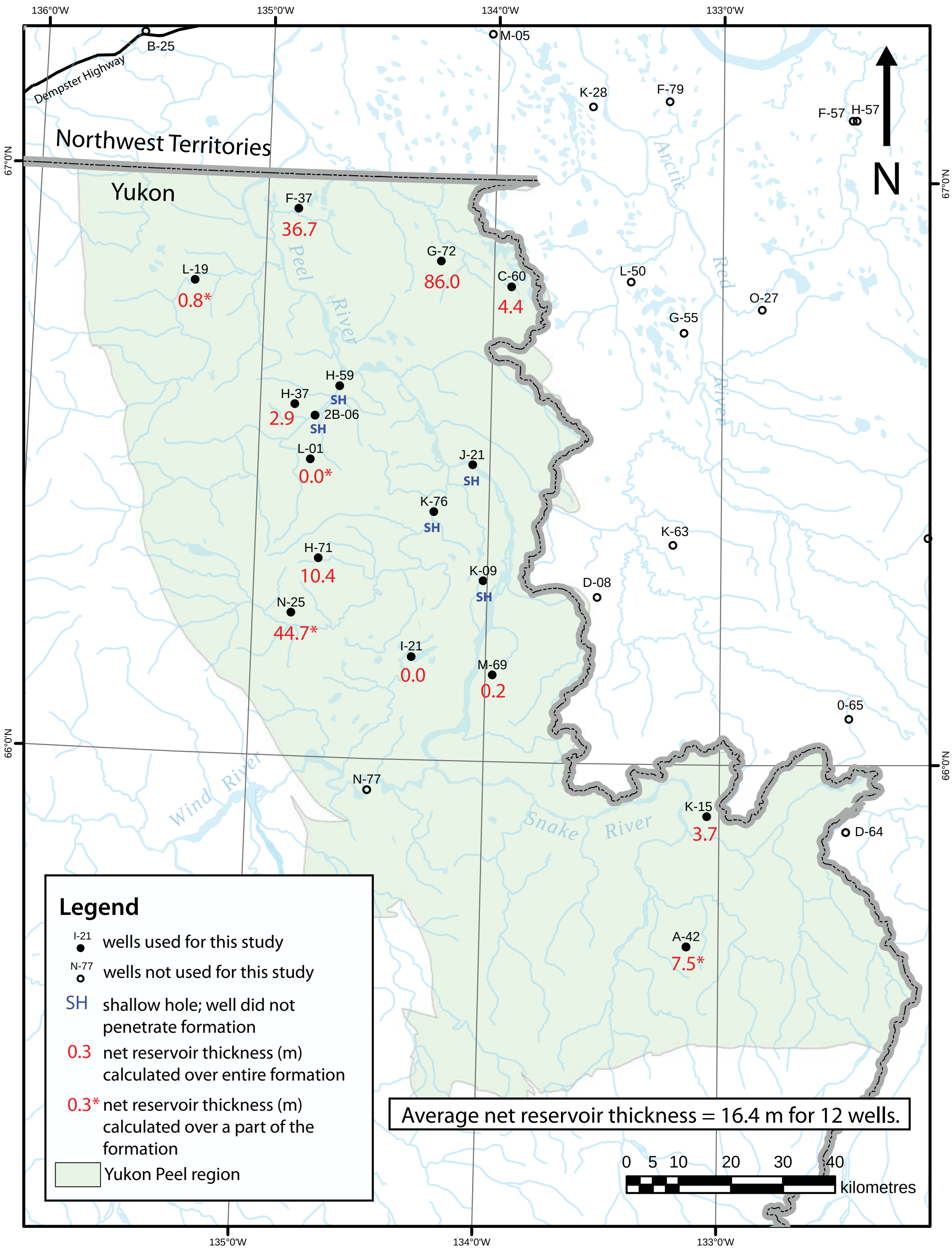

Figure 9a. *Net reservoir thickness (m) in the Imperial Formation.*

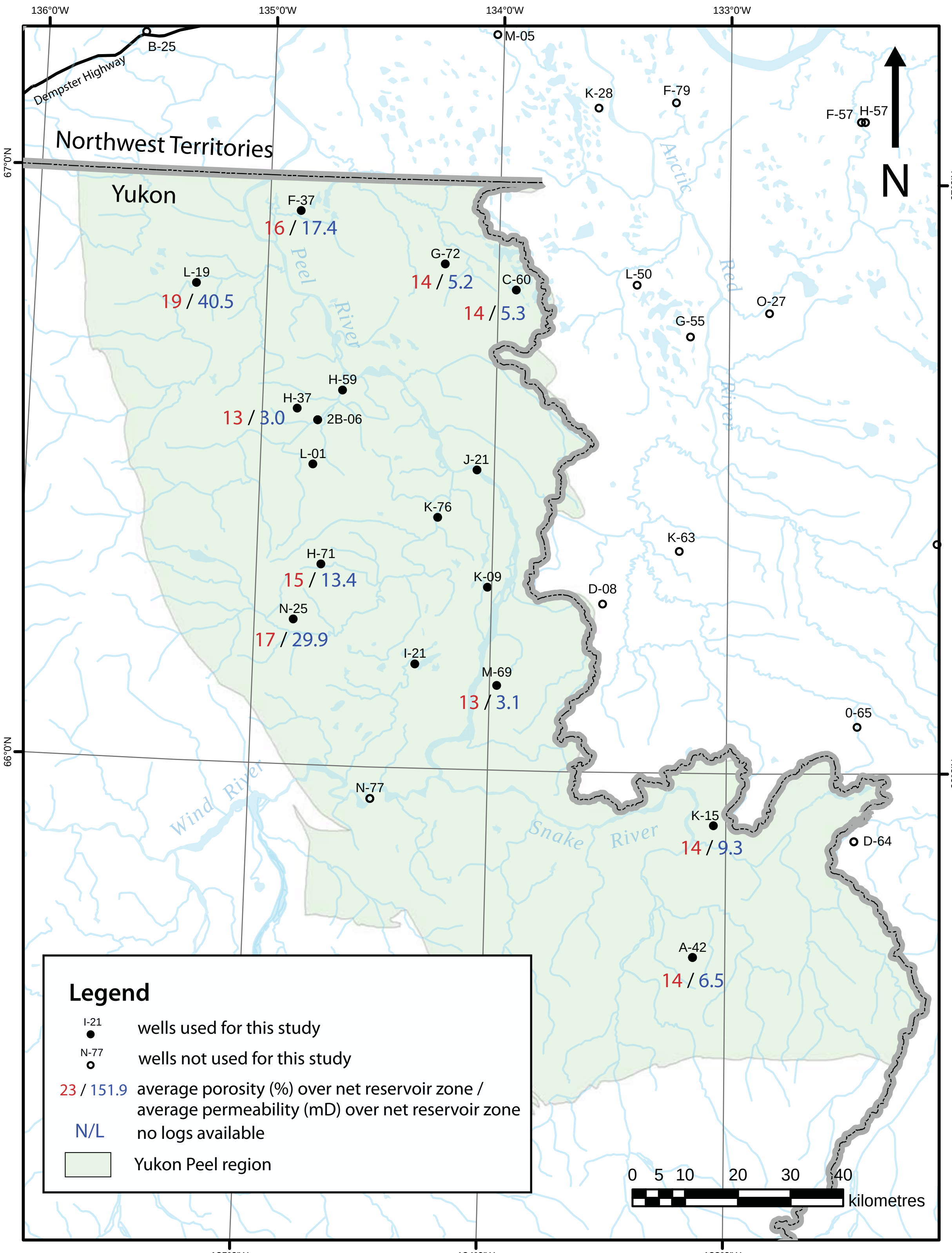

Figure 9b. *Average porosity (%) and permeability (mD) over net reservoir zone in the Imperial Formation. Data represent only wells having net reservoir values for the Imperial Formation (see Figure 9a).*

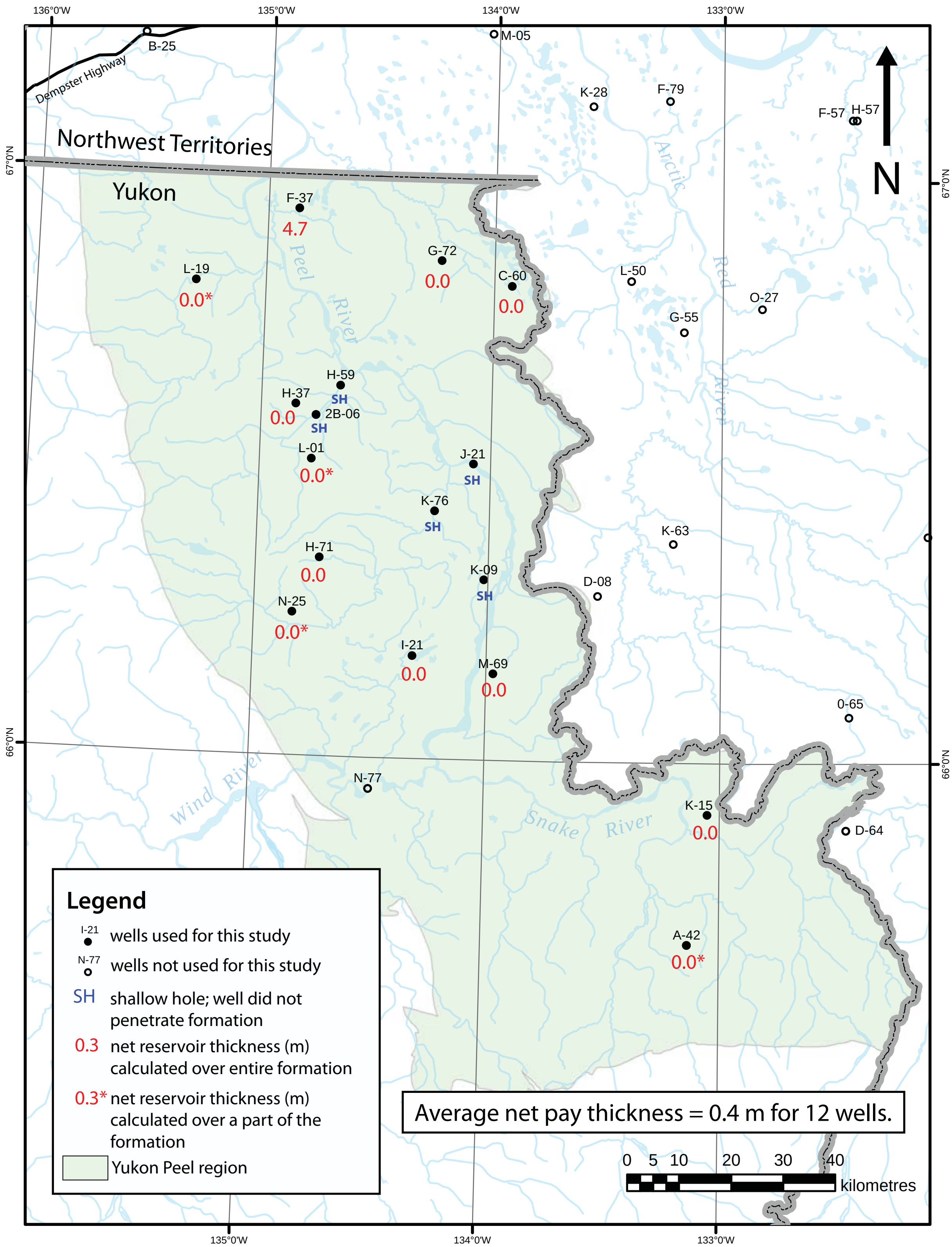

Figure 9c. *Net pay thickness (m) in the Imperial Formation.*

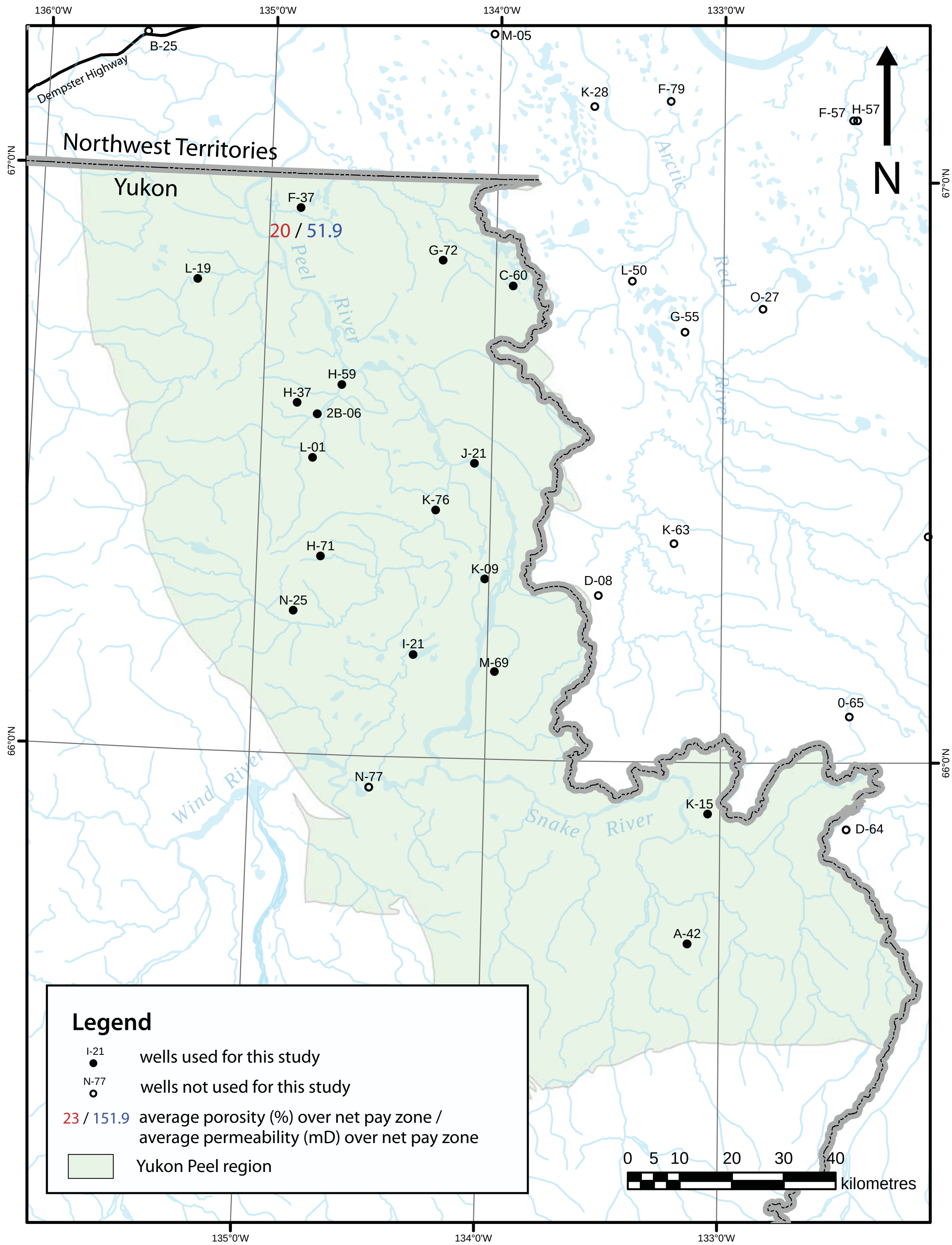

Figure 9d. *Average porosity (%) and permeability (mD) over net pay zone in the Imperial Formation. Data represent only wells having net pay values for the Imperial Formation (see Figure 9c).*

m, and has an average porosity of 20% and an average permeability of 52 mD (Fig. 9d). The average net pay thickness calculated among 12 wells is 0.4 m.

Canol Formation

Description and Thickness

The Devonian Canol Formation is a grey to black, siliceous, thin-bedded, fissile and predominantly non-calcareous shale and chert (Bassett, 1961). It may contain ironstone nodules and can have bright yellow sulphide and white mineral coatings. Palynomorphs from the east Richardson Mountains indicate a late Givetian or an early Frasnian age for the formation (Norris, 1985). The Canol Formation can be distinguished from the overlying Imperial Formation in gamma logs by its high, ragged response (Gal *et al*., 2009a). In the Richardson Mountains, immediately west of Peel Plateau, the Canol Formation is overlain conformably by the Imperial Formation (Allen and Fraser, 2008), which is consistent with Pugh's (1983) interpretation of the contact in the Peel region subsurface. The nature of the Canol Formation's lower contact, however, is a contentious issue surrounding the question of a possible unconformity at the boundary between the Middle and Upper Devonian (Pugh, 1983). Morrow (1999) suggests that the Canol Formation in Richardson trough, immediately west of Peel Plateau, represents a condensed section and that no unconformity at the base of the Canol is apparent.

Ten wells in this study penetrate the entire Canol Formation. In the study region, the Canol Formation ranges in thickness from 70.1 m in H-71, to 5.5 m in H-37 (Fraser and Hogue, 2007).

Reservoir and Pay Summary

The results of the reservoir petrophysical assessment for the Canol Formation are reported in Appendix C, Table F. Cut-off values used to calculate reservoir and pay for the Canol Formation are those which apply to siliciclastic rocks (Tables 2 and 3).

Of the 10 wells analysed, the only well with reservoir properties in the Canol Formation is A-42, with 0.9 m of net reservoir located between 2111.7 and 2112.6 m below KB (Fig. 10a). The average porosity over this interval is 14% and the average permeability is 5 mD (Fig. 10b). No pay is associated with this interval.

Bluefish Member of the Hare Indian Formation

Description and Thickness

The Middle Devonian (Givetian) Hare Indian Formation (Bassett, 1961) consists of greenish-grey, calcareous shale and interbedded limestone or siltstone, with a basal dark grey or brown, bituminous, spore-bearing shale. Pugh (1983) subdivided the Hare Indian Formation into a lower Bluefish Member and an informal, upper 'Grey shale member'. In the Yukon Peel region, the upper 'Grey shale member' is absent, and the 'Bluefish Member' exists only east of 135º to 136º W longitude (see Pugh 1983, Fig. 14).The Bluefish Member is characterized by black to dark grey, bituminous, fissile shale with thin interbeds of light brown-grey to dark and blue-grey limestone (Pugh, 1983; Gal *et al*., 2009a).

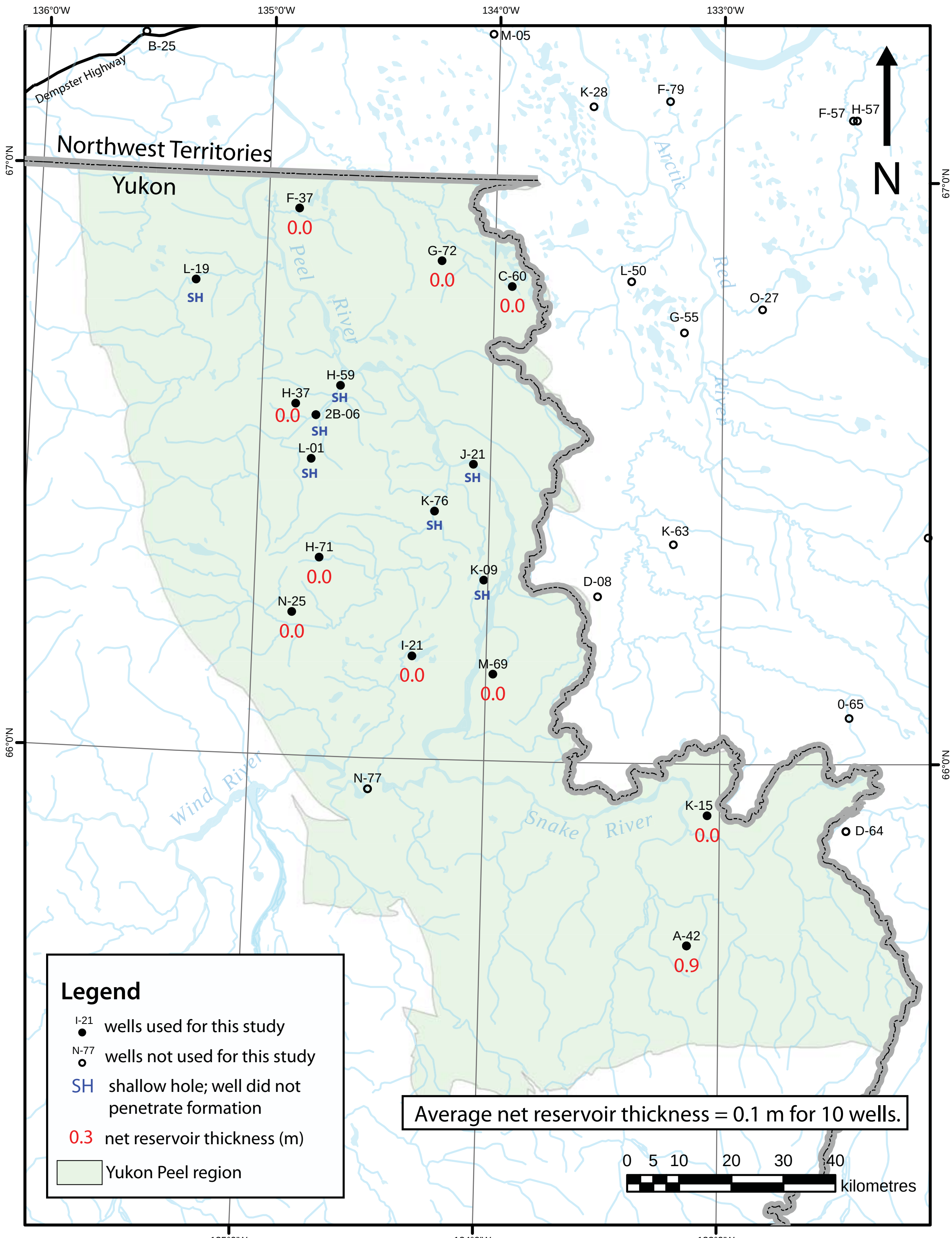

Figure 10a. *Net reservoir thickness (m) in the Canol Formation.*

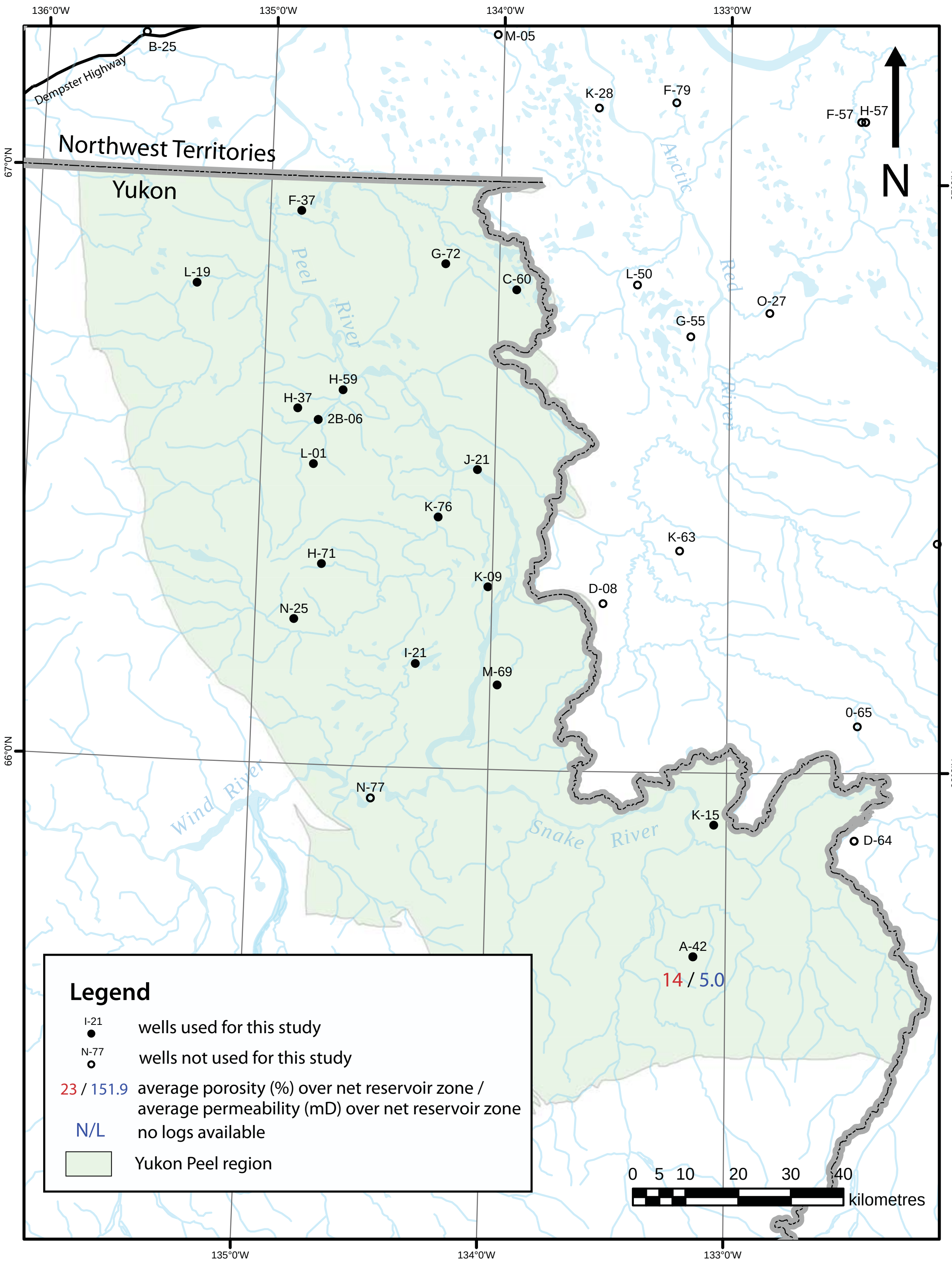

Figure 10b. *Average porosity (%) and permeability (mD) over net reservoir zone in the Canol Formation. Data represent only wells having net reservoir values for the Canol Formation (see Figure 10a).*

Pugh (1983) describes the lower contact of the Bluefish Member with the Hume Formation as conformable (with the possibility of localized erosion on the Hume surface), whereas Gal *et al*. (2009a) describe it as sharp and erosional. As mentioned in the description and thickness section of Canol Formation, the lower contact of the Canol Formation with underlying strata is contentious. In the subsurface, the basal bed or beds of the Bluefish Member are highly calcareous shale or limestone (Pugh, 1983). The gamma ray log response of the Bluefish Member is marked by high values of shale. In contrast, the underlying Hume Formation has a low response indicative of cleaner limestone. The Bluefish Member's upper contact with the Canol Formation is more difficult to decipher on well logs as both contain radioactive shales.

The Bluefish Member is a thin unit found in five Peel region wells. It ranges in thickness from 14.0 m in M-69 to 2.1 m in F-37 (Fraser and Hogue, 2007).

Reservoir and Pay Summary

The results of the reservoir petrophysical assessment for the Bluefish Member are reported in Appendix C, Table G. Cut-off values used to calculate reservoir and pay for the Bluefish Member are those which apply to siliciclastic rocks (Tables 2 and 3).

Of the five wells analysed, the only reservoir identified in the Bluefish Member is in well I-21 (Fig. 11a), where a 0.6 m section between 1449.0 and 1449.6 m below KB has an average porosity of 14% and an average permeability of 7 mD (Fig. 11b). No pay is associated with this interval.

Hume Formation

Description and Thickness

The Middle Devonian (Eifelian to Givetian) Hume Formation is the youngest unit of the carbonate succession on the cratonic Mackenzie-Peel shelf. It is a unit of fossiliferous and argillaceous limestone with interbeds of calcareous shale. It can be divided into a lower recessive limestone and calcareous shale unit and an upper resistant fossiliferous limestone (Bassett, 1961).

Based on field evidence in the northern Mackenzie Mountains, Gal *et al*. (2009a) suggest the Hume Formation is unconformable with the overlying Bluefish Member, and has a sharp, conformable lower contact, generally marked by black shale beds. Bassett (1961) describes the upper contact with the Hare Indian shale to be sharp with no evidence of erosion, whereas the lower contact with the Landry Formation is described as possibly disconformable. Tassonyi (1969) describes the Landry-Hume contact zone in the subsurface to be conformable and generally marked by the presence of dark shales that are semi-bituminous and exhibit an increase in radioactivity.

In the Yukon Peel region, the entire Hume Formation is penetrated in eight wells. In addition, wells N-25 and H-71 contain Road River Group – Hume Formation equivalent strata, which for the purpose of this study were analysed as carbonates. In the study region, the thickness of the Hume Formation ranges from 389.2 m in well A-42 to 87.8 m in H-37 (Fraser and Hogue, 2007).

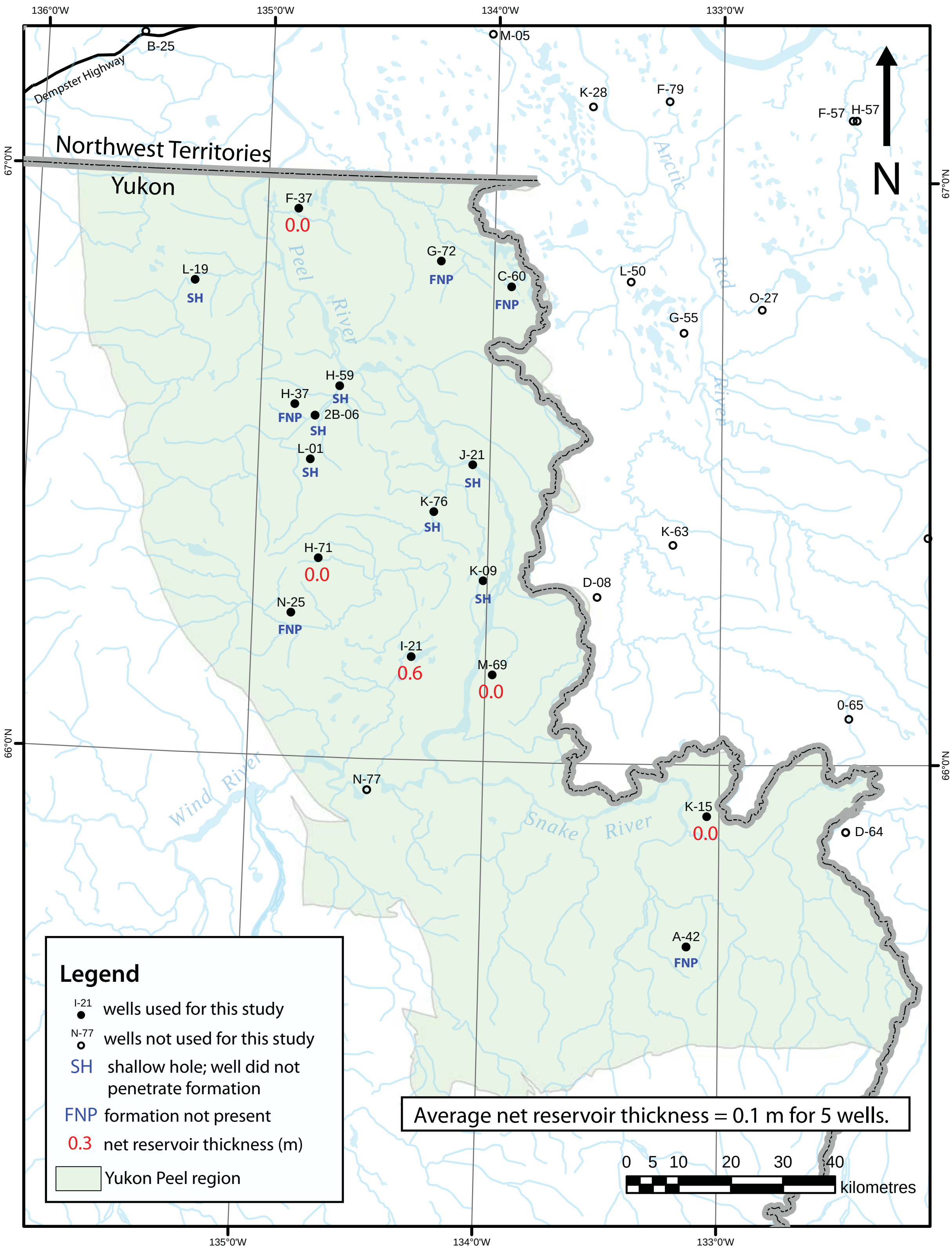

Figure 11a. *Net reservoir thickness (m) in the Bluefish Member of Hare Indian Formation.*

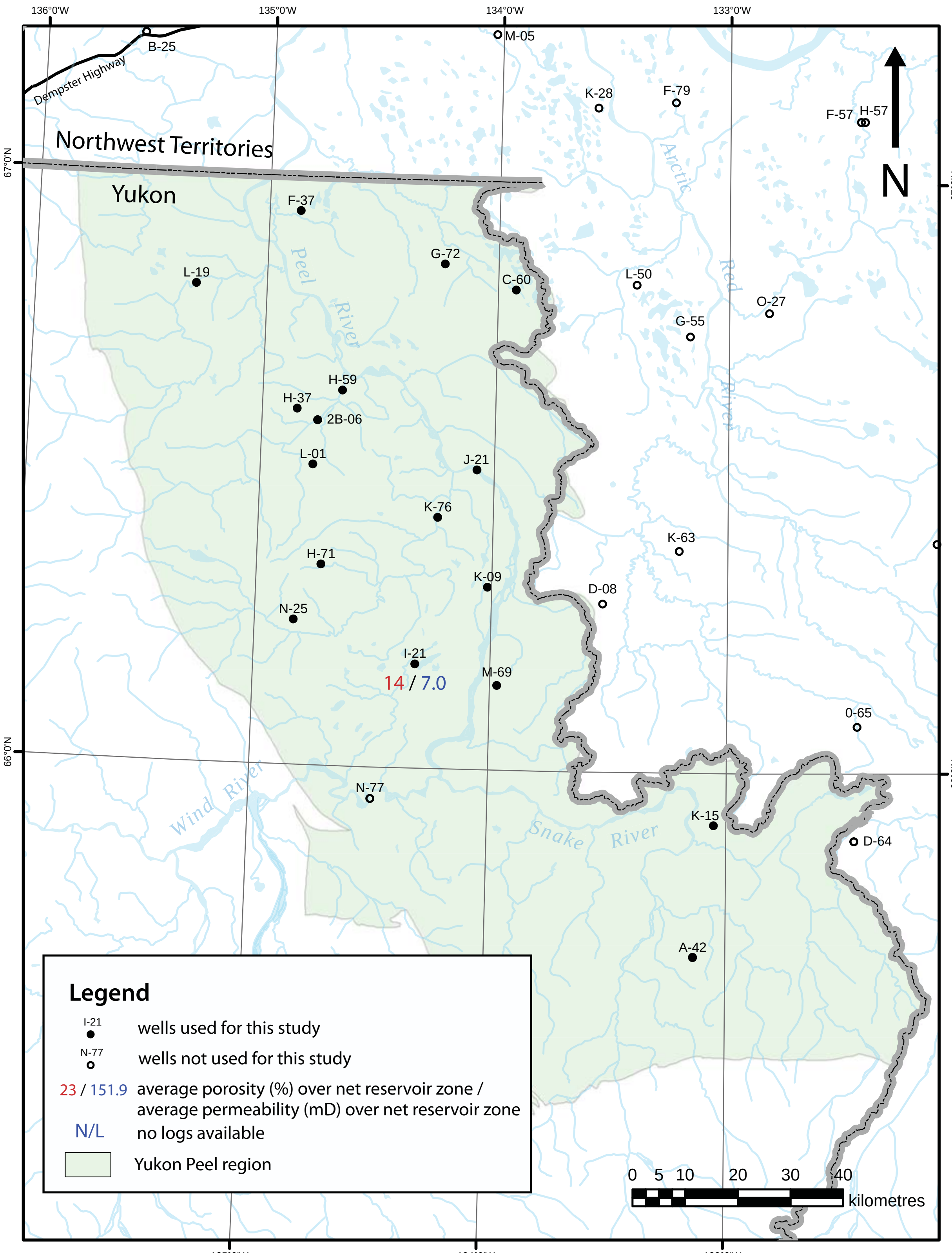

Figure 11b. *Average porosity (%) and permeability (mD) over net reservoir zone in the Bluefish Member of the Hare Indian Formation. Data represent only wells having net reservoir values for the Bluefish Member (see Figure 11a).*

Reservoir and Pay Summary

The results of the reservoir petrophysical assessment for the Hume Formation are reported in Appendix C, Table H. Cut-off values used to calculate reservoir and pay for the Hume Formation are those which apply to limestone (Tables 2 and 3).

Six of ten wells contain reservoir intervals in the Hume Formation (Fig. 12a). The net reservoir interval is thinnest in G-72 at 1.7 m and thickest in F-37 at 18.6 m. The average net reservoir thickness among 10 wells is 6.6 m. Average porosity over the net reservoir interval ranges from 7% in F-37 to 13% in K-15 and I-21; and average permeability over the same interval ranges from 1 mD in G-72 to 21 mD in K-15 (Fig. 12b). K-15 is the only well with pay in the Hume Formation (Fig. 12c). A thickness of 5.9 m of net pay is found at a depth between 1359.7 and 1365.7 m below KB. The average porosity and permeability over this net pay interval is 14% and 16 mD respectively (Fig. 12d). The average net pay thickness among 10 wells is 0.6 m.

Landry Formation

Description and Thickness

The Lower to Middle Devonian Landry Formation is described as a unit of marine, thick to massive-bedded, grey-weathering, crypto-grained limestone, which is locally mottled with medium to dark grey dolomite (Douglas and Norris, 1961; Pugh, 1983). In the northern Mackenzie Mountains, immediately south of Peel Plateau and Plain, the Landry Formation is a relatively unfossiliferous lime mudstone situated above the Arnica Formation and below the Hume Formation (Gal *et al*., 2009a). Towards the western portion of the study area, the formation becomes progressively shaley as it moves into the basinal Road River Group within the Richardson trough. The basal contact of the Landry Formation with the Arnica Formation is conformable and in many cases gradational (Douglas and Norris, 1961; Pugh, 1983; Gal *et al*., 2009a). The upper contact with the Hume Formation is described as possibly disconformable (Bassett, 1961).

In this study, the Landry Formation is present in eight wells. In addition, wells N-25 and H-71 contain Road River Group – Landry Formation equivalent strata, which for the purpose of this study were analysed as carbonates. Two of these wells did not penetrate the entire Landry interval. The Landry Formation has a maximum thickness of 692.5 m in H-37, although the Road River Group - Landry Formation equivalent strata in well N-25 are thicker at 860.2 m. The LandryFormation is thinnest in G-72 at 307.5 m; however, this well does not penetrate the entire formation (Fraser and Hogue, 2007).

Reservoir and Pay Summary

The results of the reservoir petrophysical assessment for the Landry Formation are reported in Appendix C, Table I. Cut-off values used to calculate reservoir and pay for the Landry Formation are those which apply to limestone (Tables 2 and 3).

Reservoir intervals in the Landry Formation and equivalent strata occur in seven wells (Fig. 13a). N-25 has the thickest net reservoir value with 97.7 m, whereas M-69 has the thinnest with only 2.0 m. The average net reservoir thickness among 10 wells is 20.7 m. Average porosity over the net interval zones ranges from 7% in M-69 to 15% in N-25 (Fig. 13b). Average permeability over the net interval zones ranges from 2 mD in H-71 to 647 mD in A-42 (Fig. 13b).

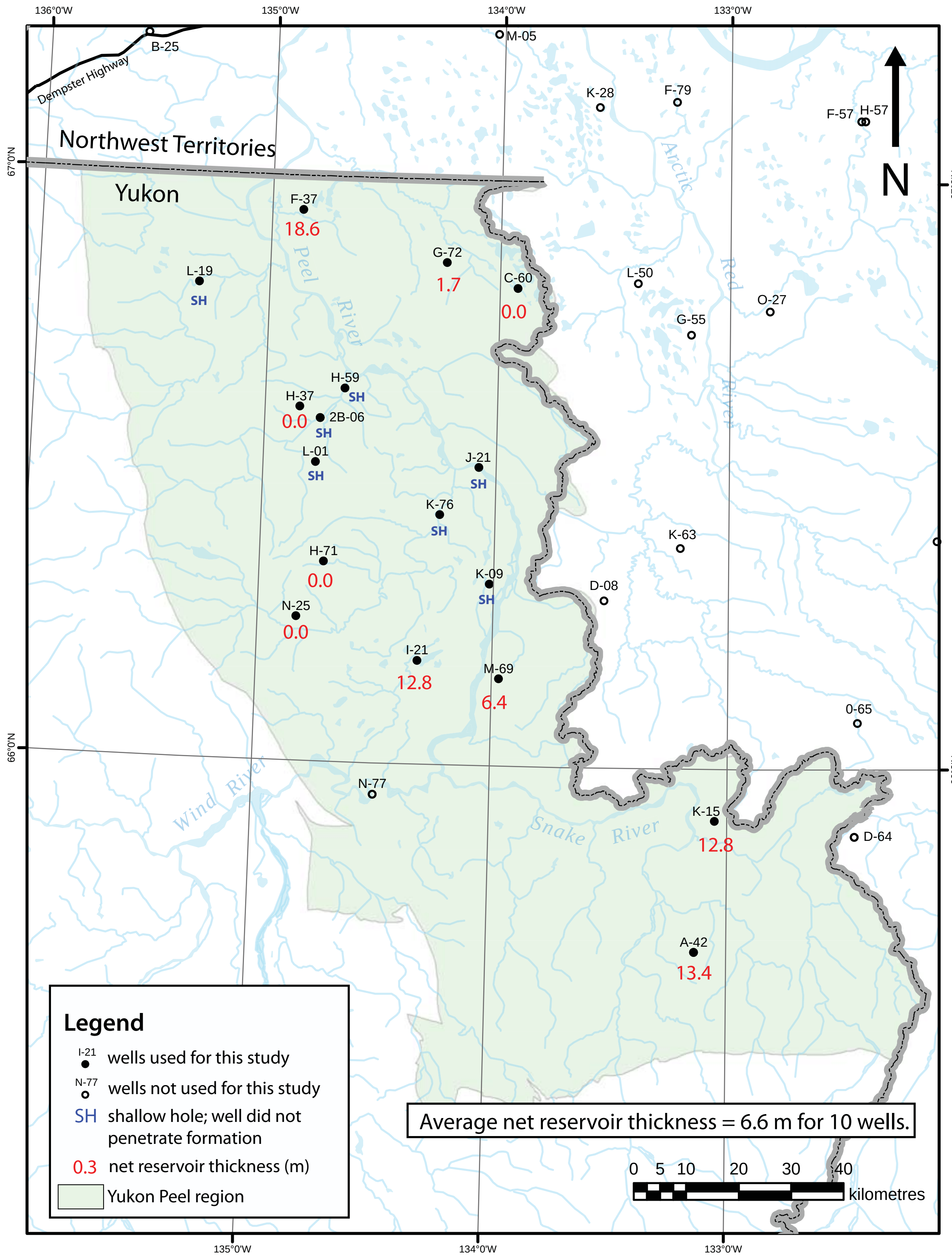

Figure 12a. *Net reservoir thickness (m) in the Hume Formation and equivalent strata. Note that wells H-71 and N-25 contain Road River (Hume-equivalent) strata.*

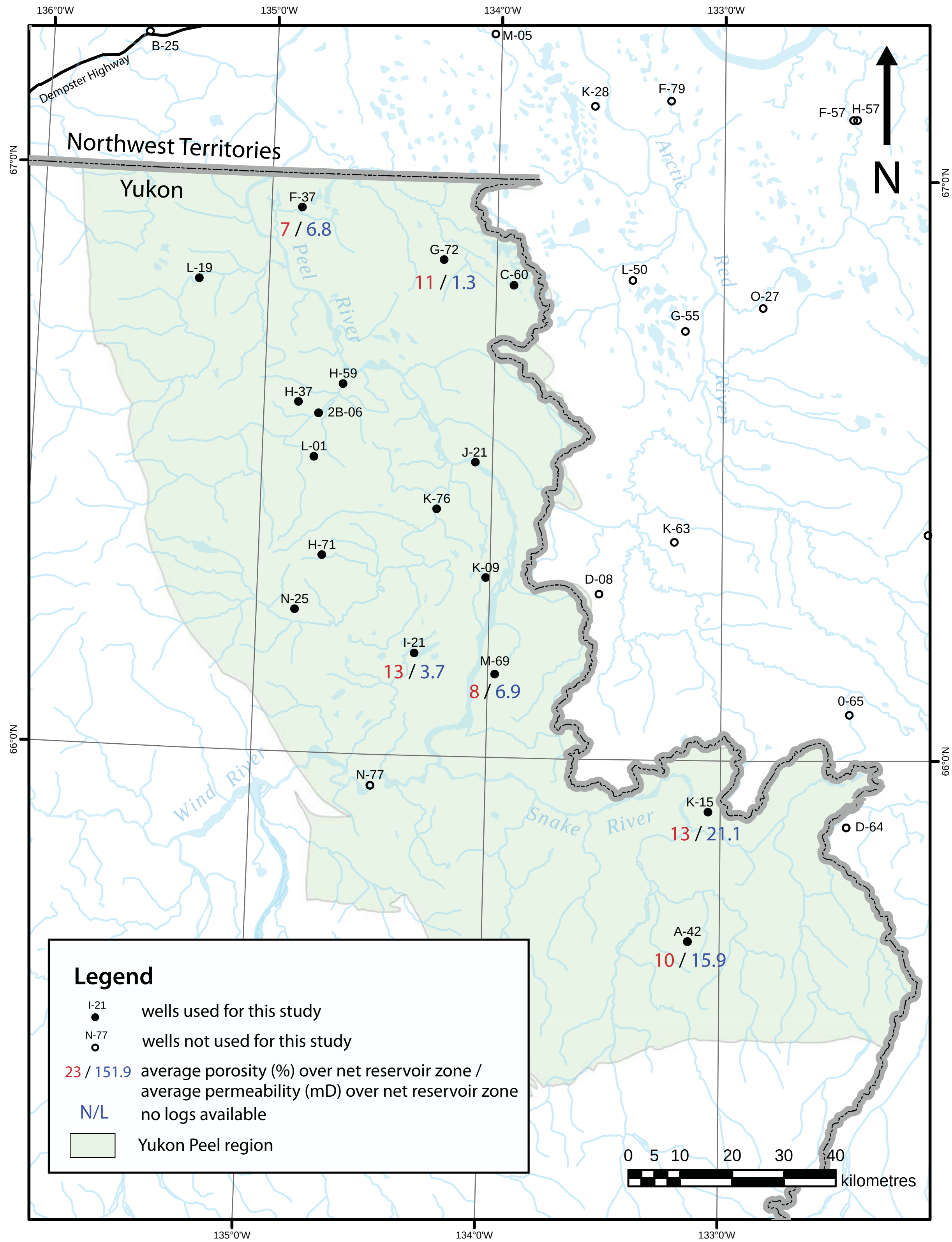

Figure 12b. *Average porosity (%) and permeability (mD) over net reservoir zone in the Hume Formation and equivalent strata. Data represent only wells with net reservoir values for the Hume Formation and equivalent strata (see Figure 12a).*

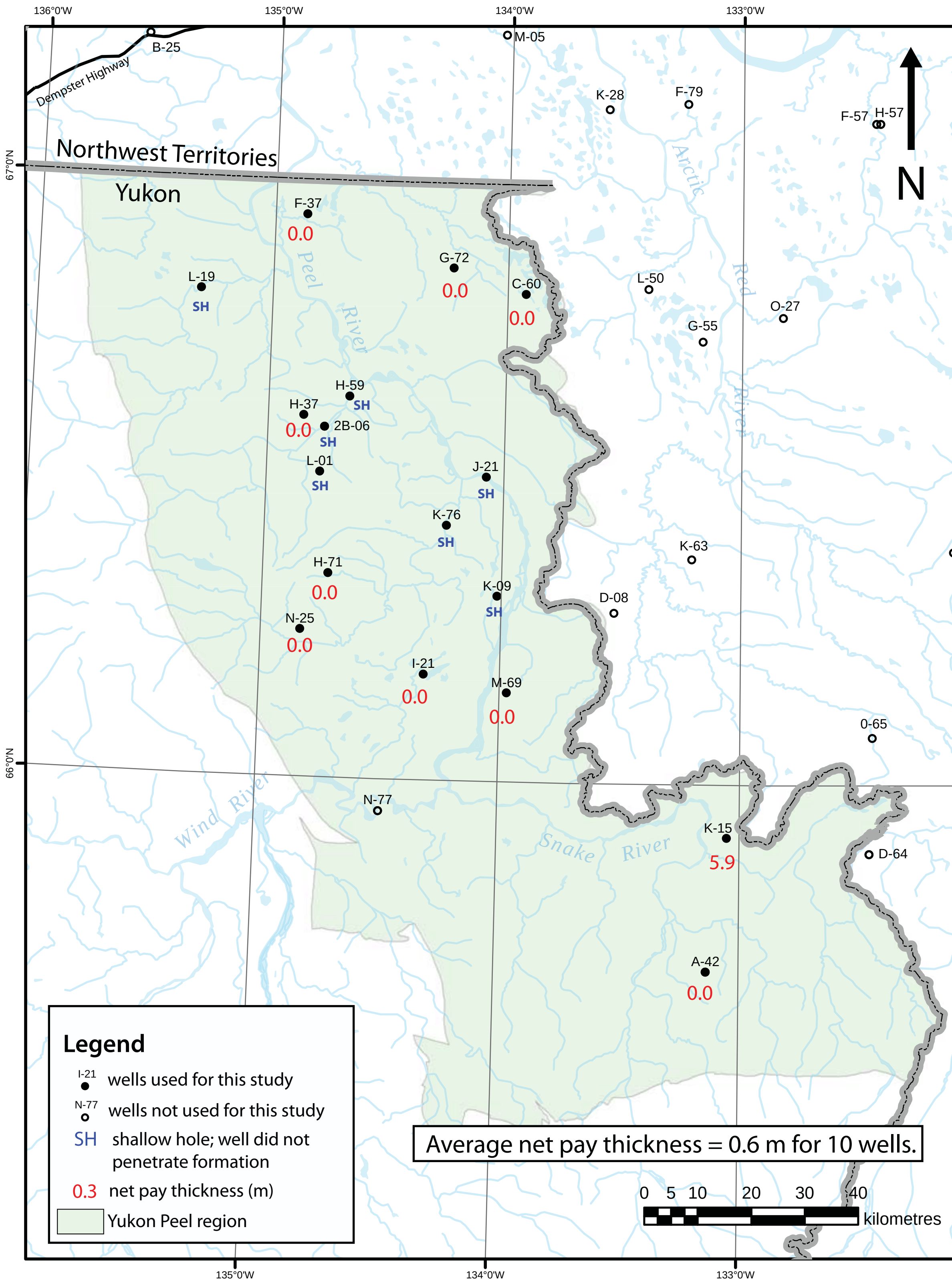

Figure 12c. *Net pay thickness (m) in the Hume Formation and equivalent strata. Note that wells H-71 and N-25 contain Road River (Hume-equivalent) strata.*

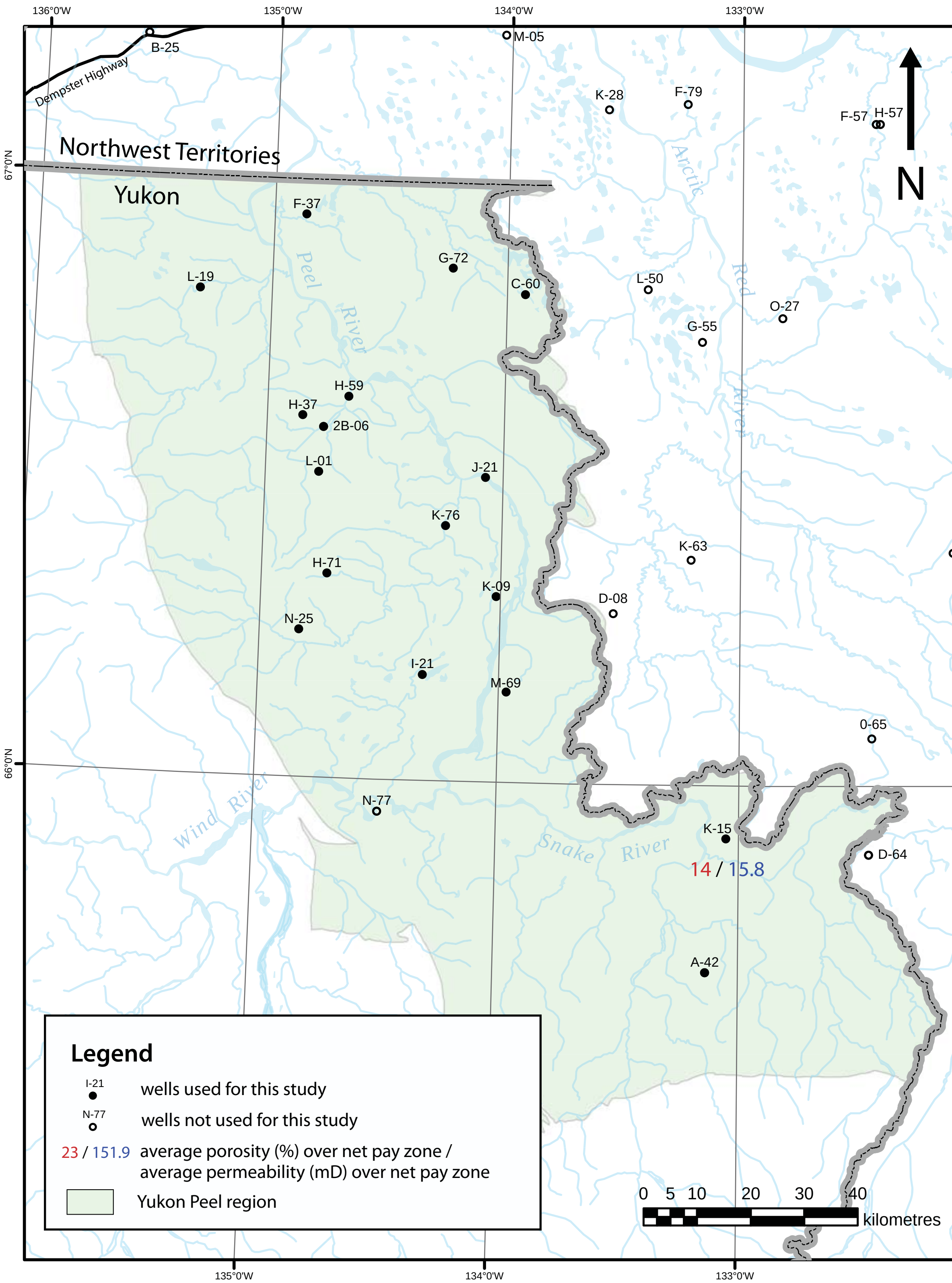

Figure 12d. *Average porosity (%) and permeability (mD) over net pay zone in the Hume Formation and equivalent strata. Data represent only wells with net pay values for the Hume Formation and equivalent strata (see Figure 12c).*

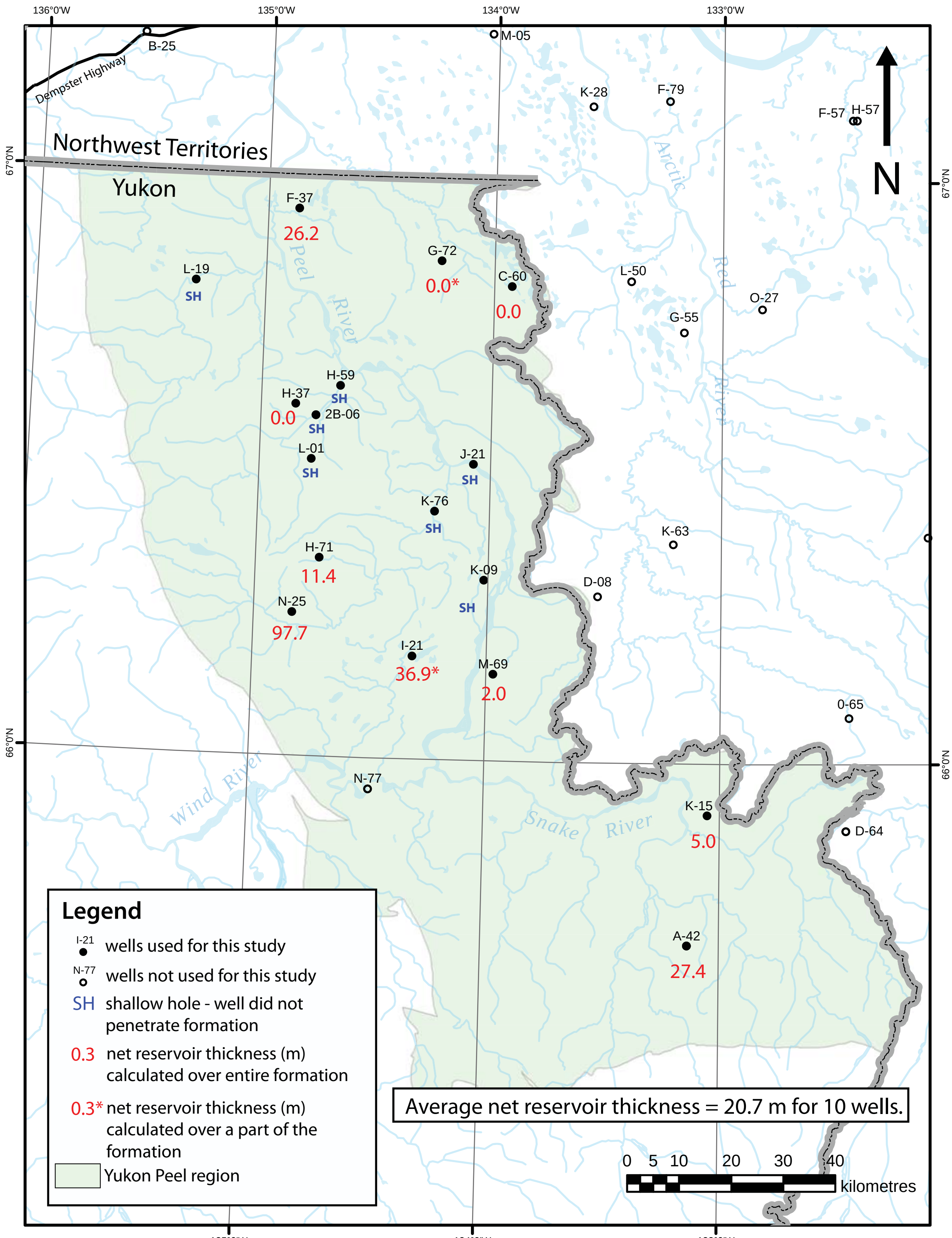

Figure 13a. *Net reservoir thickness (m) in the Landry Formation and equivalent strata. Note that wells H-71 and N-25 contain Road River (Landry-equivalent) strata.*

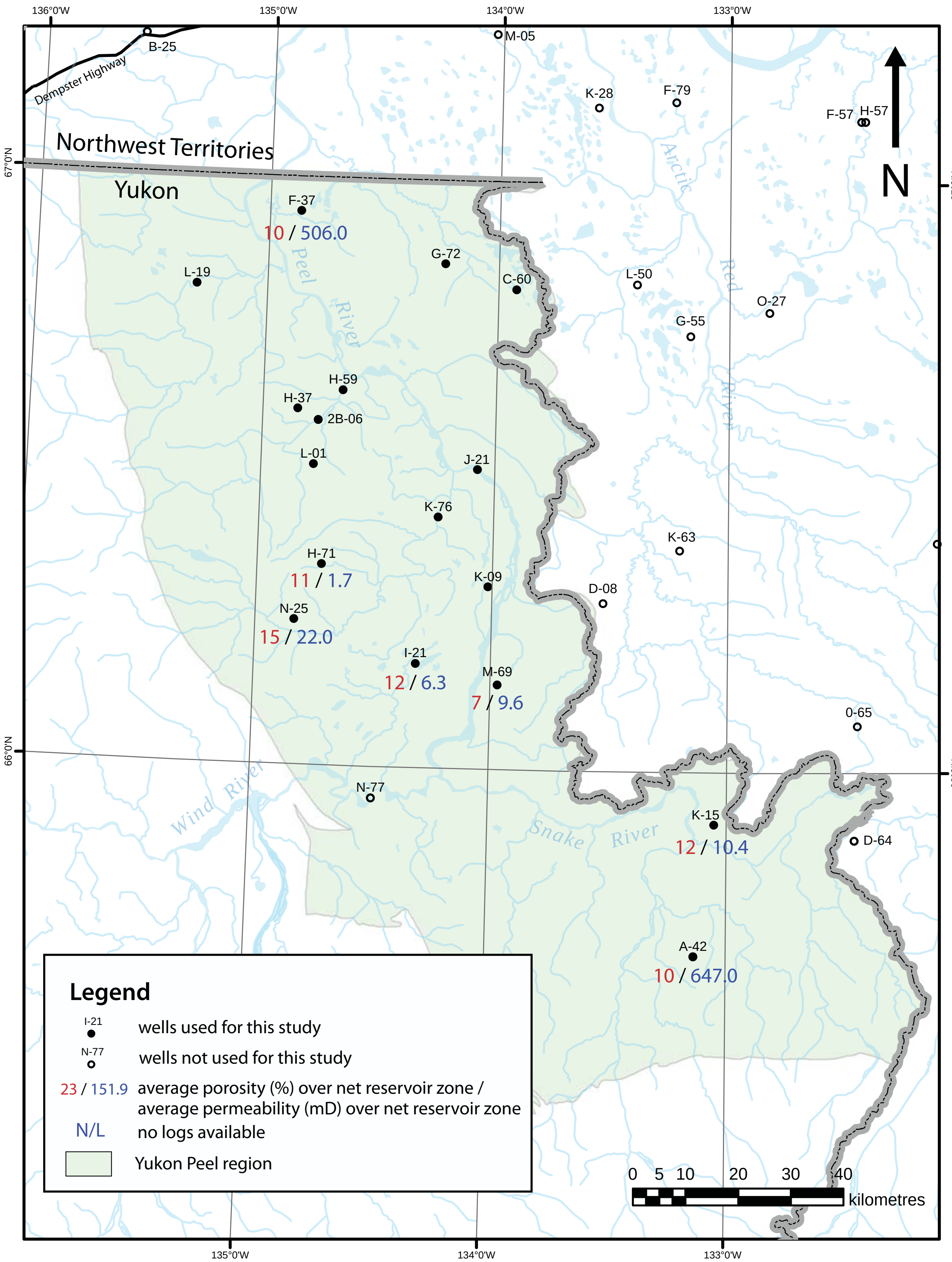

Figure 13b. Average porosity (%) and permeability (mD) over net reservoir zone in the Landry Formation and equivalent strata. Data represent only wells with net reservoir values for the Landry Formation and equivalent strata (see Figure 13a).

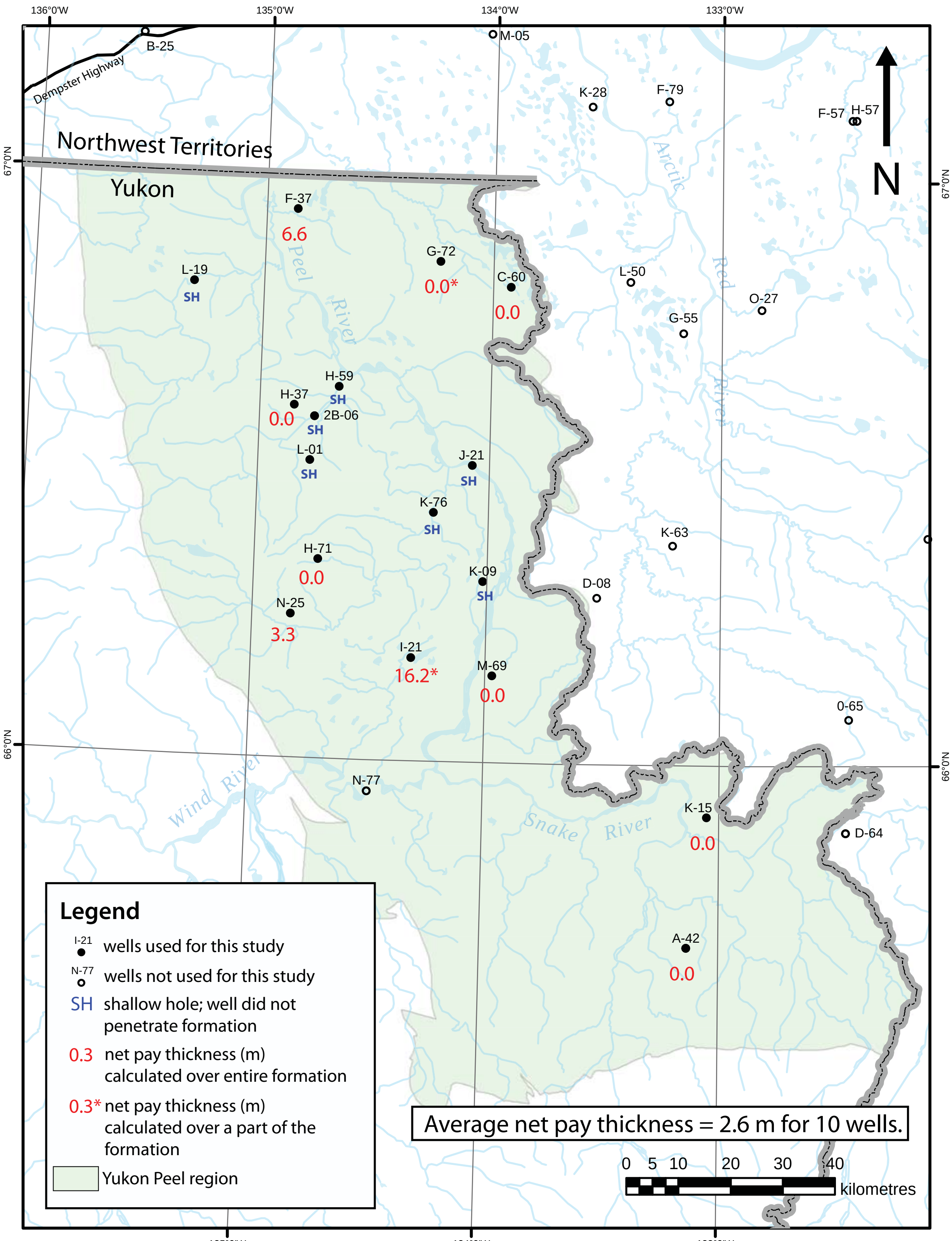

Figure 13c. *Net pay thickness (m) in the Landry Formation and equivalent strata. Note that wells H-71 and N-25 contain Road River (Landry-equivalent) strata.*

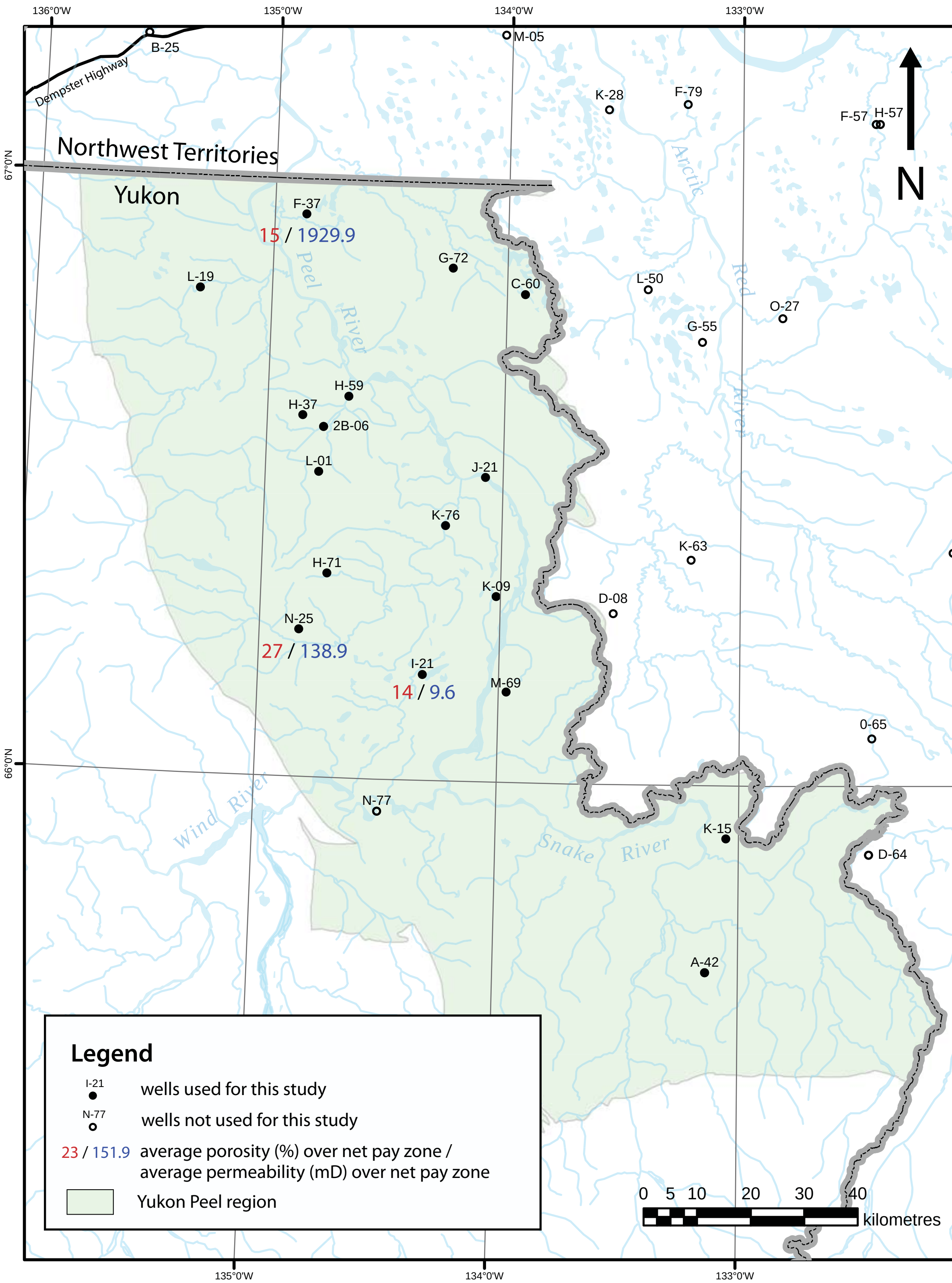

Figure 13d. *Average porosity (%) and permeability (mD) over net pay zone in the Landry Formation and equivalent strata. Data represent only wells with net pay values for the Landry Formation and equivalent strata (see Figure 13c).*

An average of 2.6 m of net pay thickness is calculated among 10 wells. Net pay is found in the Landry Formation and equivalent strata in wells N-25, I-21 and F-37 (Fig. 13c). Net pay thickness in these wells is 3.3 m, 16.2 m, and 6.6 m, respectively. The net pay zone in N-25 has an average porosity of 27% and an average permeability of 139 mD (Fig. 13d). In I-21, the average porosity and permeability over the net pay zone is 14% and 10 mD respectively. In F-37, the average porosity over the net pay zone is 15%, and the permeability is 1930 mD.

Arnica Formation

Description and Thickness

The Lower to Middle Devonian Arnica Formation is a succession of dark grey and brownish-grey, fine to medium-crystalline, thickly bedded dolostone (Douglas and Norris, 1961; Pugh, 1983). The lower part of the Arnica Formation is observed to be distinctively banded with white dolomite laminates and dolomitized packstones. The upper portion is more fossiliferous and may be porous and vuggy and contain chert nodules. In outcrop in the northern Mackenzie Mountains, the Arnica Formation is distinctly banded (Gal *et al*., 2009a). Like the Landry, the Arnica Formation becomes increasingly shaley as it transitions westward into the Richardson trough. The lower contact of the Arnica Formation with the Tatsieta Formation is observed to be sharp and conformable in the northern Mackenzie Mountains (Gal *et al*., 2009a; Gal and Pyle, 2009). Pugh (1983) considers the Tatsieta-Arnica/Landry contact to represent a depositional hiatus from shallow and locally restricted marine environment (Tatsieta) to open-water marine (Arnica/Landry). The upper contact of the Arnica Formation with the Landry Formation is conformable (Douglas and Norris, 1961) and has been observed in the northern Mackenzie Mountains to be generally sharp and conformable, and, in places, gradational (Gal *et al*., 2009a)

In this study, the Arnica is present in five wells. The Arnica ranges in thickness from 152.7 m in K-15 to 40.9 m in A-42 (Fraser and Hogue, 2007).

Reservoir and Pay Summary

The results of the reservoir petrophysical assessment for the Arnica Formation are reported in Appendix C, Table J. Cut-off values used to calculate reservoir and pay for the Arnica Formation are those which apply to dolostone (Tables 2 and 3).

There are reservoir intervals in all five wells which penetrate the Arnica Formation. Among these five wells, the average net reservoir thickness is 3.3 m. Net reservoir thickness ranges from 6.9 m in K-15 to 1.1 m in A-42 (Fig. 14a). Average porosity over these intervals ranges from 13% in C-60 to 5% in M-69 (Fig. 14b). Permeability over these intervals ranges from 8 mD in A-42 to 2 mD in F-37 (Fig. 14b).

The average net pay thickness among the five wells which penetrate the Arnica Formation is 0.6 m.

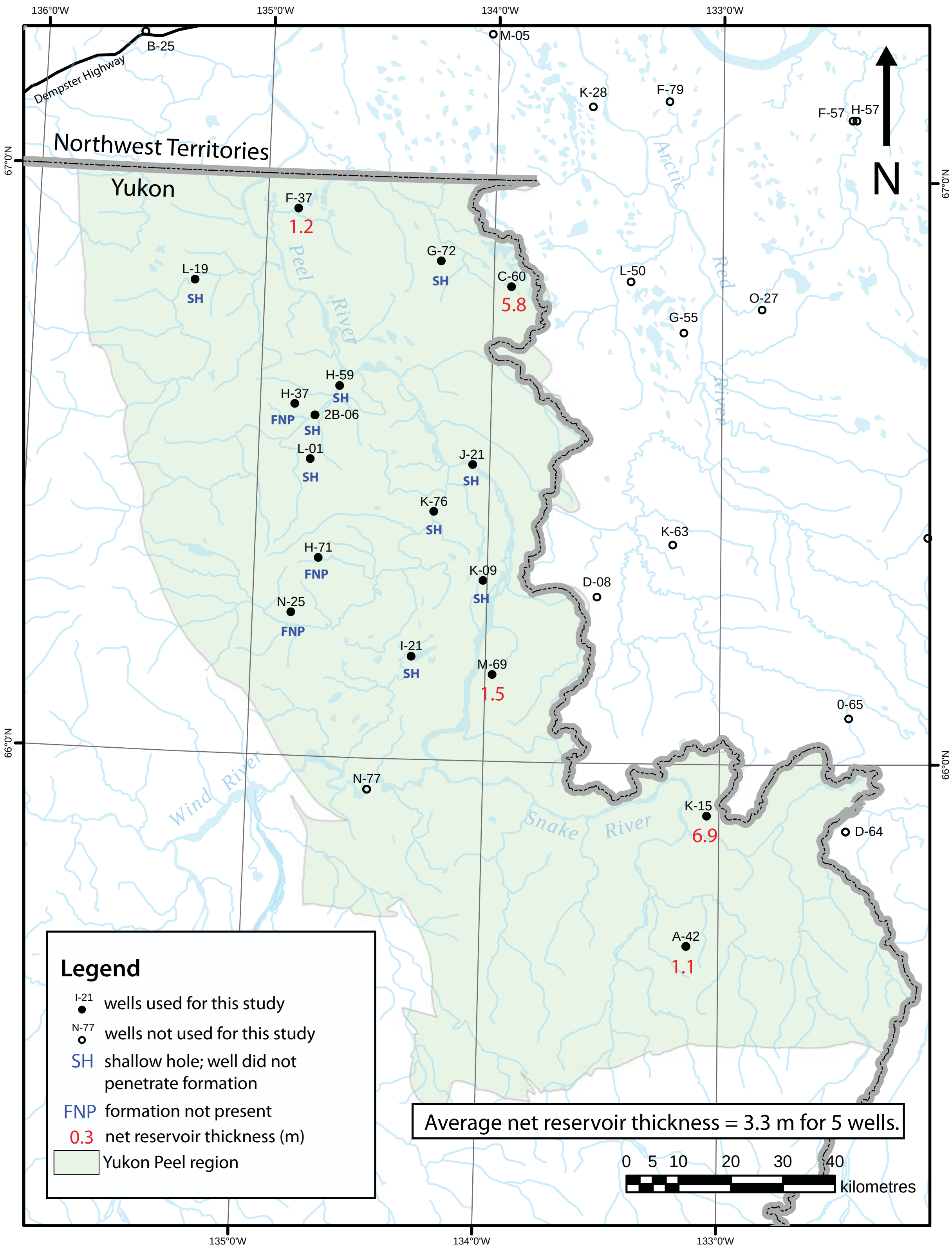

Figure 14a. *Net reservoir thickness (m) in the Arnica Formation.*

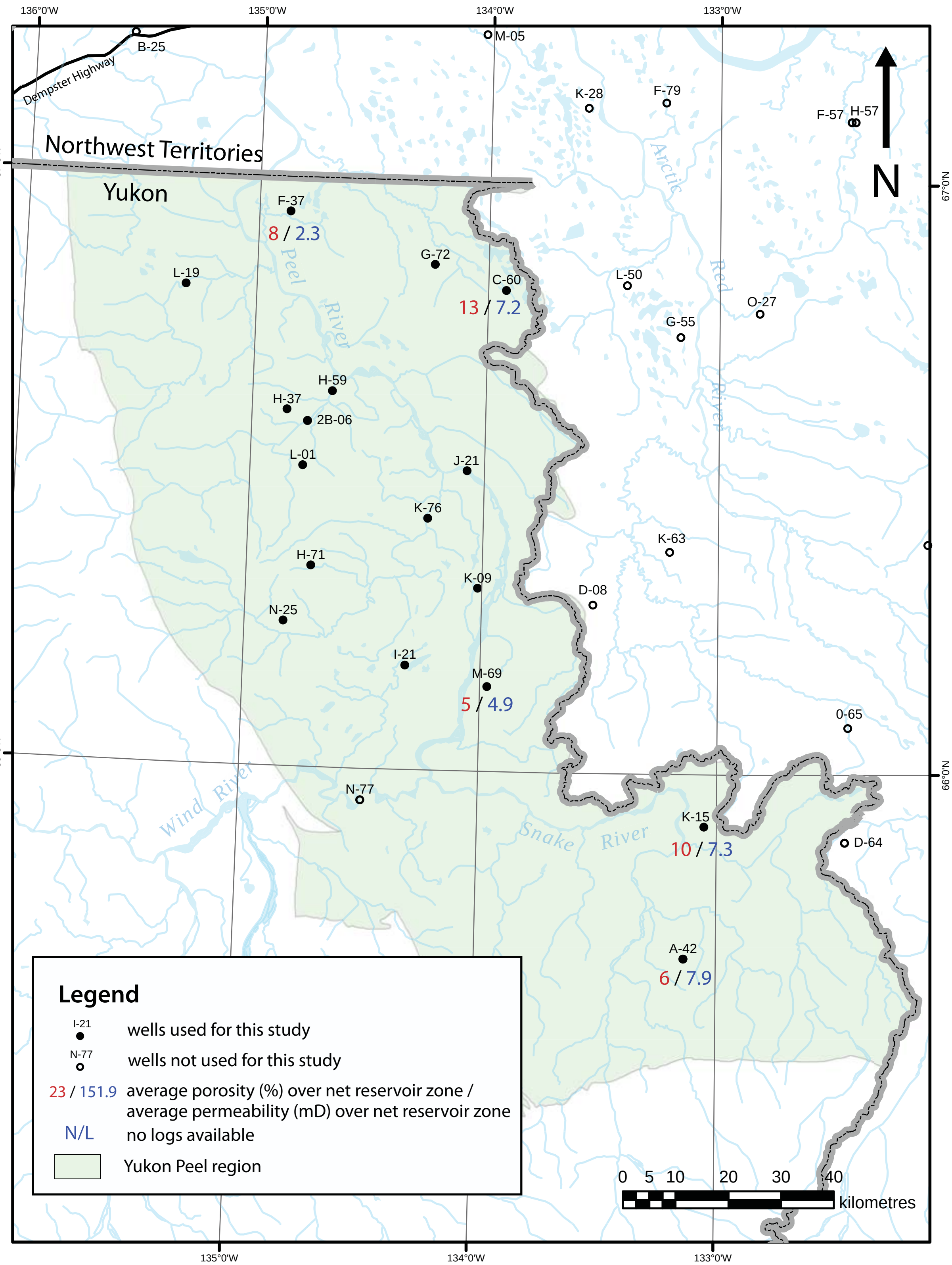

Figure 14b. *Average porosity (%) and permeability (mD) over net reservoir zone in the Arnica Formation. Data represent only wells with net reservoir values for the Arnica Formation (see Figure 14a).*

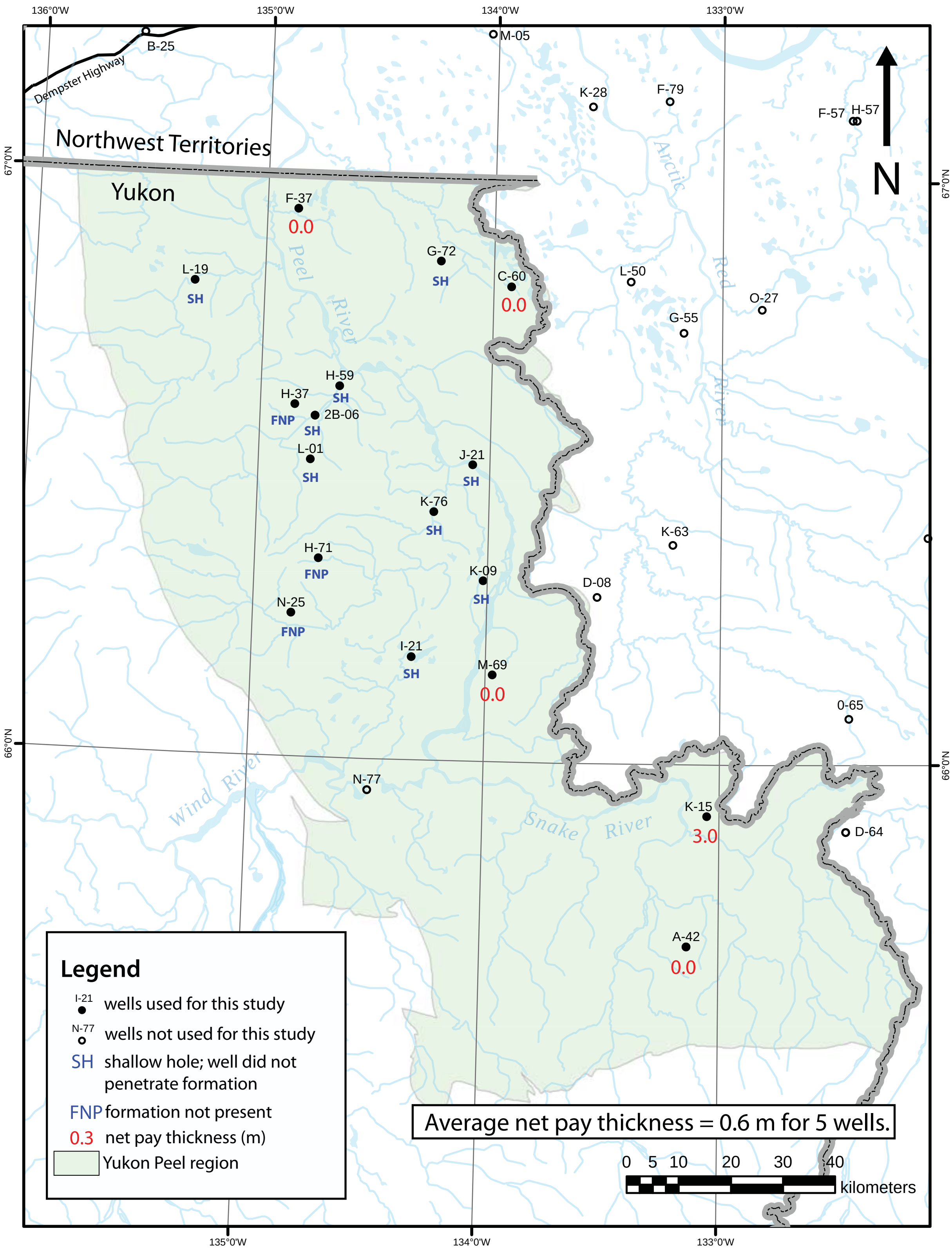

Figure 14c. *Net pay thickness (m) in the Arnica Formation.*

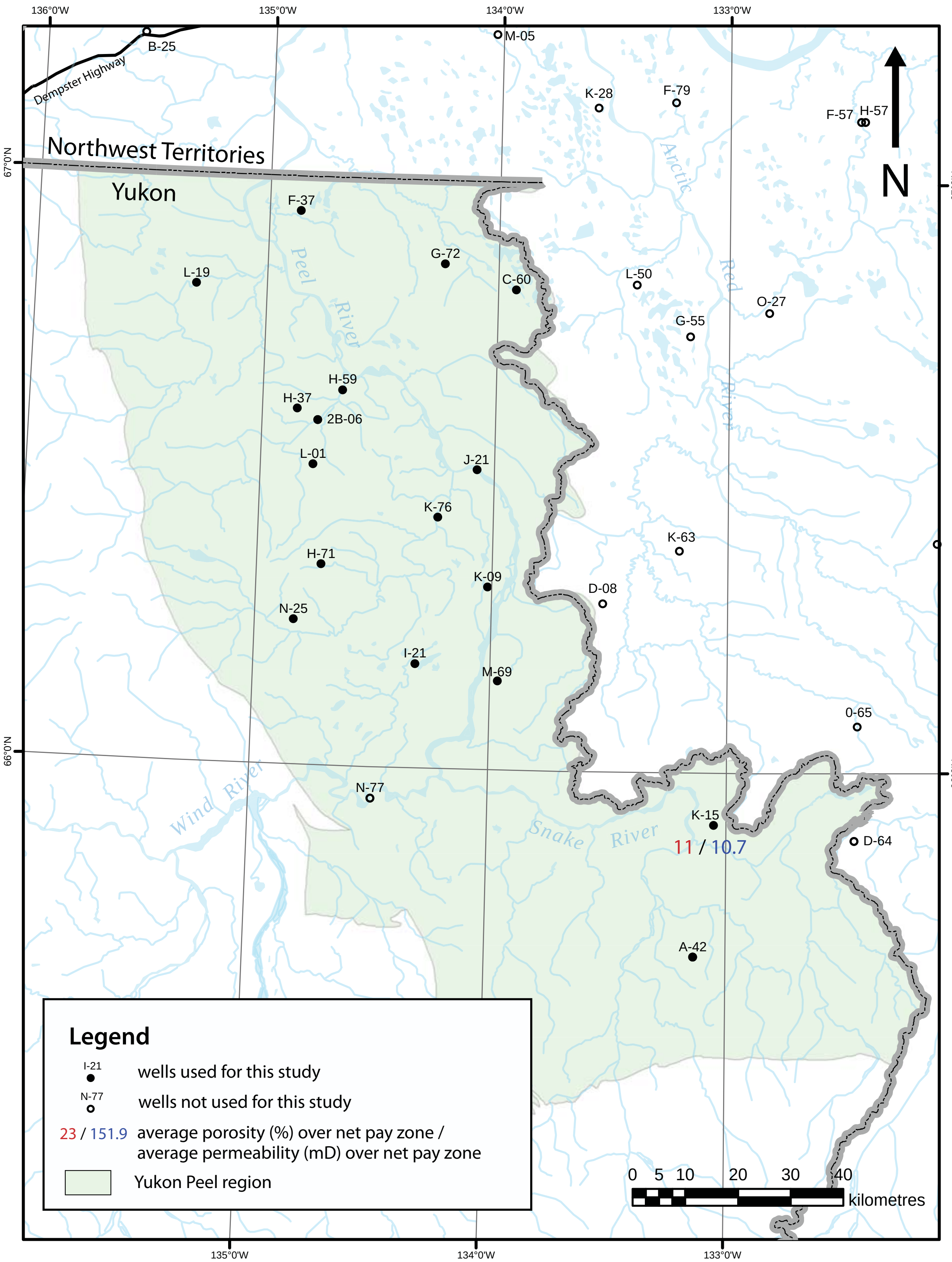

Figure 14d. *Average porosity (%) and permeability (mD) over net pay zone in the Arnica Formation. Data represent only wells with net pay values for the Arnica Formation (see Figure 14c).*

The only well with pay strata is K-15 which has a cumulative net pay interval of 3.0 m, in the interval between 1915.2 and 1918.3 m below KB (Fig. 14c). The average porosity over this zone is 11%, and the average permeability is 11 mD (Fig. 14d).

Tatsieta Formation

Description and Thickness

The Lower Devonian Tatsieta Formation is dominantly limestone and green shale with minor calcareous dolomite (Pugh, 1983). The limestone is aphanitic, mainly buff coloured and is sometimes white and chalky. In the subsurface, the formation is generally identified by its ragged and spiky gamma log signature due to shale interbeds (Gal and Pyle, 2009). Pugh (1983) defines the lower contact of the Tatsieta Formation with the Peel Formation to be the 'sub-Devonian erosional unconformity', and suggests the upper contact with the Landry/Arnica succession represents a depositional hiatus. Morrow (1999) suggests the base of the Tatsieta Formation is conformable, and locally diachronous, and outcrops in the northern Mackenzie Mountains exhibit both sharp and gradational contacts at this stratigraphic position. Morrow (1999) further suggests the stratigraphic position of the 'sub-Devonian unconformity' is not at the base of the Tatsieta Formation, but rather at the base of the Peel Formation. In northern Mackenzie Mountains, the lower contact of the Tatsieta unit with the Peel Formation has been observed to be generally gradational, but may be sharp, and the upper contact with the Arnica Formation sharp and conformable (Gal and Pyle, 2009; Gal *et al*., 2009a). Pugh (1983) considers the Tatsieta-Arnica/Landry contact to represent a depositional hiatus from shallow and locally restricted marine environment (Tatsieta) to open-water marine (Arnica/Landry).

In this study, the Tatsieta Formation is fully penetrated in six wells. In addition, wells N-25 and H-71 contain Road River Group – Tatsieta Formation equivalent strata, which for the purpose of this study were analysed as carbonates. The formation is thickest in well A-42 at 82.9 m, and is thinnest in H-37 at 25.6 m, although it is thinner in H-71 as the Road River Group - Tatsieta Formation equivalent at 17.3 m (Fraser and Hogue, 2007).

Reservoir and Pay Summary

The results of the reservoir petrophysical assessment for the Tatsieta Formation are reported in Appendix C, Table K. Cut-off values used to calculate reservoir and pay for the Tatsieta Formation are those which apply to dolostone (Tables 2 and 3). The Tatsieta unit contains many interbedded lithologies and it could be argued that a limestone filter may have provided more accuracy when applied to some wells. A dolostone filter was used because the Tatsieta unit is a relatively thin formation located between thicker dolostone formations, and as a result, the Tatsieta limestone unit was lumped in with the dolostones. The dolostone filter is actually less restrictive than the limestone filter (porosity ≥4% as opposed to ≥6%) so the values of net reservoir for the Tatsieta Formation could be slightly inflated, but this is not expected to impact the result of the study.

There are reservoir intervals in four of eight wells which penetrate Tatsieta (or equivalent) strata (Fig. 15a). Net reservoir thickness ranges from 1.5 m in F-37 to 5.5 m in A-42. Average net reservoir thickness among eight wells is 1.9 m. The range in average porosity over these net reservoir intervals is 5% in M-69 to 12% in C-60 (Fig. 15b). The range in average permeability over these net reservoir zones is 2 mD in F-37 to 94 mD in A-42 (Fig. 15b). There are no pay zones observed in the Tatsieta Formation or equivalent strata.

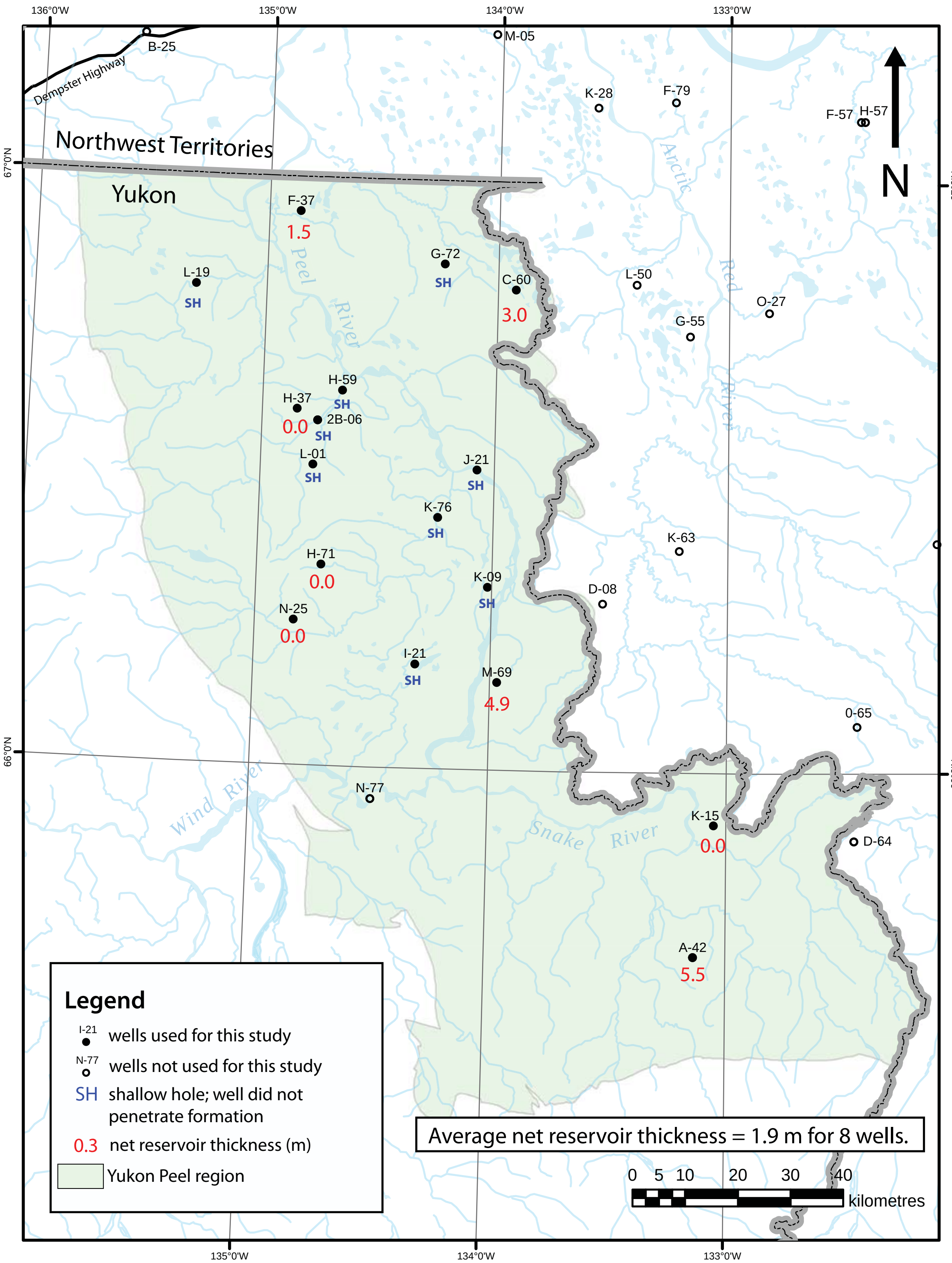

Figure 15a. *Net reservoir thickness (m) in the Tatsieta Formation and equivalent strata. Note that wells H-71 and N-25 contain Road River (Tatsieta-equivalent) strata.*

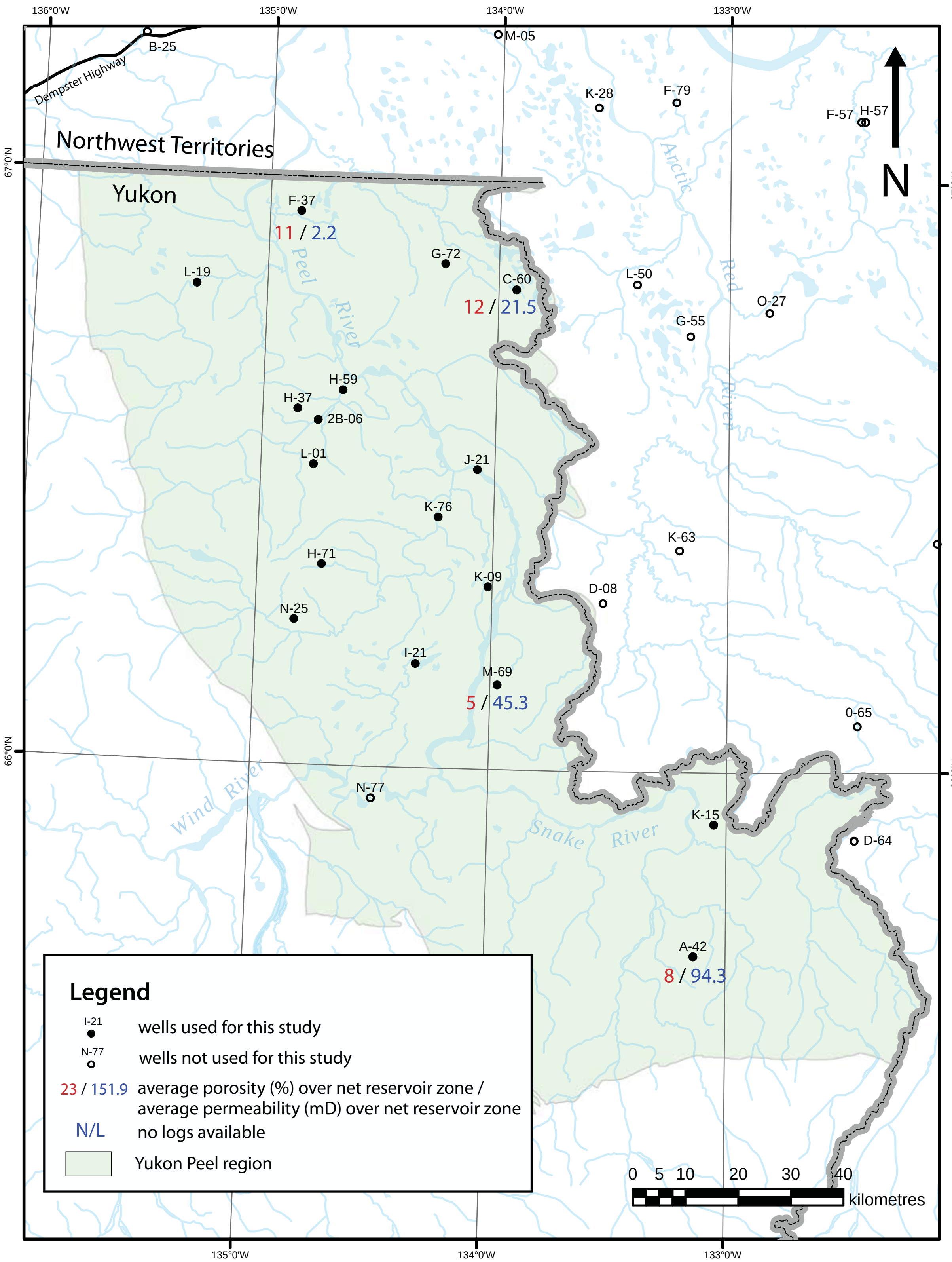

Figure 15b. *Average porosity (%) and permeability (mD) over net reservoir zone in the Tatsieta Formation and equivalent strata. Data represent only wells with net reservoir values for the Tatsieta Formation and equivalent strata (see Figure 15a).*

Peel Formation

Description and Thickness

The upper Silurian to Lower Devonian Peel Formation is a micro to finely crystalline dolomite that is buff and grey (Pugh, 1983). Some of the dolomite is calcareous and the lower part of the formation is argillaceous or silty and includes interbedded very dark grey shale (interpreted as interfingering Road River Group shales). Based on field observations in the northern Mackenzie Mountains, Gal and Pyle (2009) describe the Peel Formation as dominantly silty, finely crystalline dolostone.

Pugh (1983) identified the lower contact of the Peel Formation with the Mount Kindle Formation as generally conformable, and in some parts, disconformable. In contrast, Morrow (1999) described a prominent sub-Peel Formation unconformity, referred to as the 'sub-Devonian unconformity' in the northern Mackenzie Mountains, where the top of the Mount Kindle Formation is irregular and karstified. Gal and Pyle (2009) describe the Peel – Mount Kindle contact as generally sharp, but poorly exposed in outcrop sections in the northern Mackenzie Mountains. The upper contact of the Peel Formation with the Tatsieta Formation has been described as erosional (Pugh, 1983), conformable and diachronous (Morrow, 1999), and gradational and possibly sharp (Gal and Pyle, 2009).

In this study, the Peel Formation is present in six wells. In addition, wells N-25 and H-71 contain Road River Group – Peel Formation equivalent strata, which for the purpose of this study were analysed as carbonates. Three of these wells do not penetrate the entire formation. The Peel Formation ranges in thickness from 270.0 m in C-60 to 147.2 m in M-69, although it is thinner in H-71 at 132.3 m as Road River Group – Peel Formation equivalent (Fraser and Hogue, 2007). The Peel Formation is not fully penetrated in wells C-60 and M-69, so these thickness values may be under-represented.

Reservoir and Pay Summary

The results of the reservoir petrophysical assessment for the Peel Formation are reported in Appendix C, Table L. Cut-off values used to calculate reservoir and pay for the Peel Formation are those which apply to dolostone (Tables 2 and 3).

There are reservoir intervals in seven of eight wells that penetrate the Peel Formation or equivalent strata (Fig. 16a). Net reservoir thickness ranges from 0.3 m in M-69 to 50.6 m in A-42. Average net reservoir thickness among eight wells is 8.7 m. A-42 has the greatest average porosity and permeability values over the net reservoir zone, at 10% and 733 mD respectively. The lowest porosity over the net reservoir intervals is 5% in M-69 and H-37, and the lowest permeability is 2 mD in wells C-60 and K-15 (Fig. 16b).

There is one pay interval in the Peel Formation, in well A-42 in the interval between 3331.5 and 3348.5 m below KB (Fig. 16c). The net pay thickness is 17.2 m which has an average porosity and permeability of 13% and 2046 mD respectively (Fig. 16d). Calculated among eight wells, the average net pay thickness is 2.2 m.

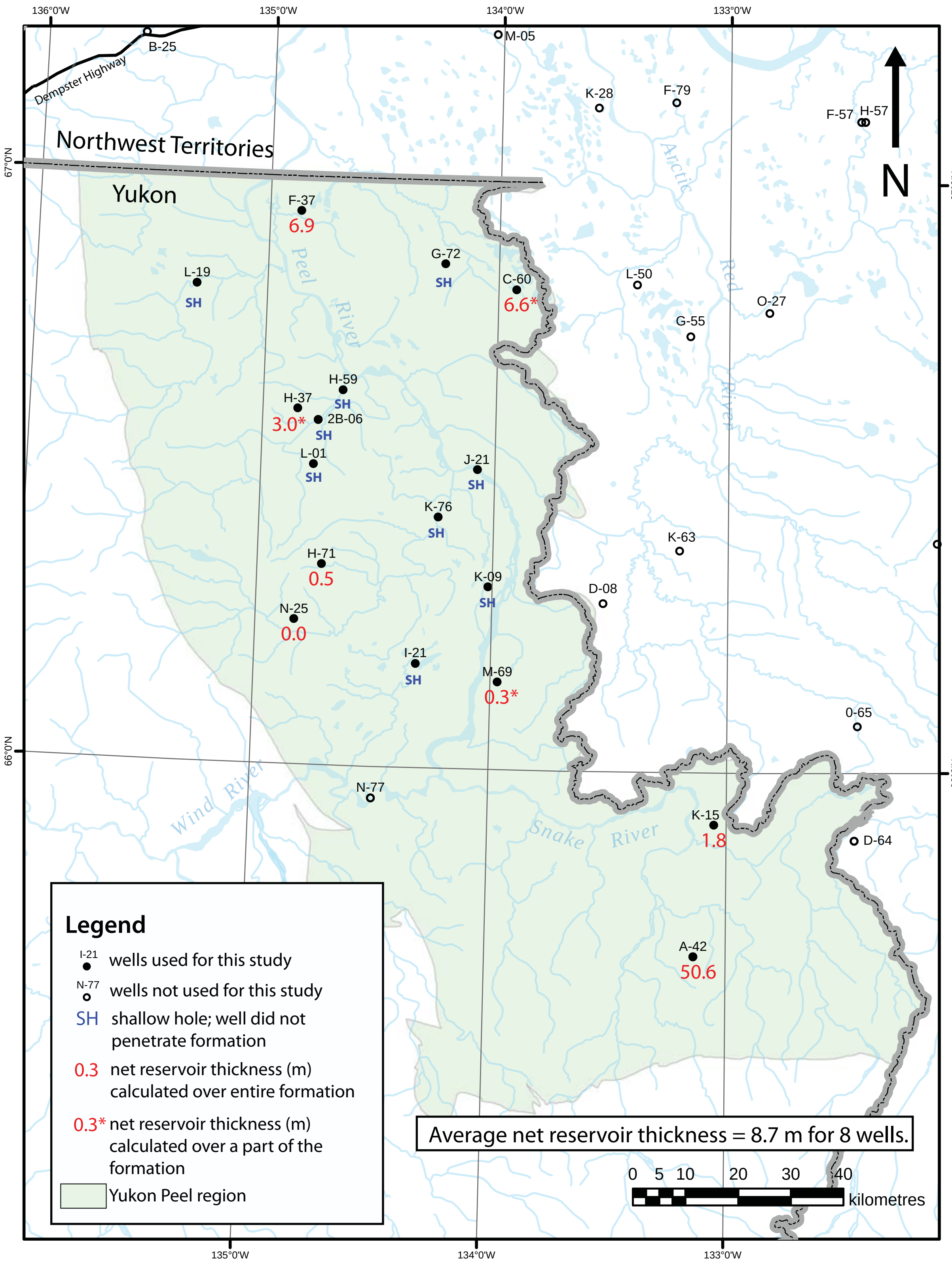

Figure 16a. *Net reservoir thickness (m) in the Peel Formation and equivalent strata. Note that wells H-71 and N-25 contain Road River (Peel-equivalent) strata.*

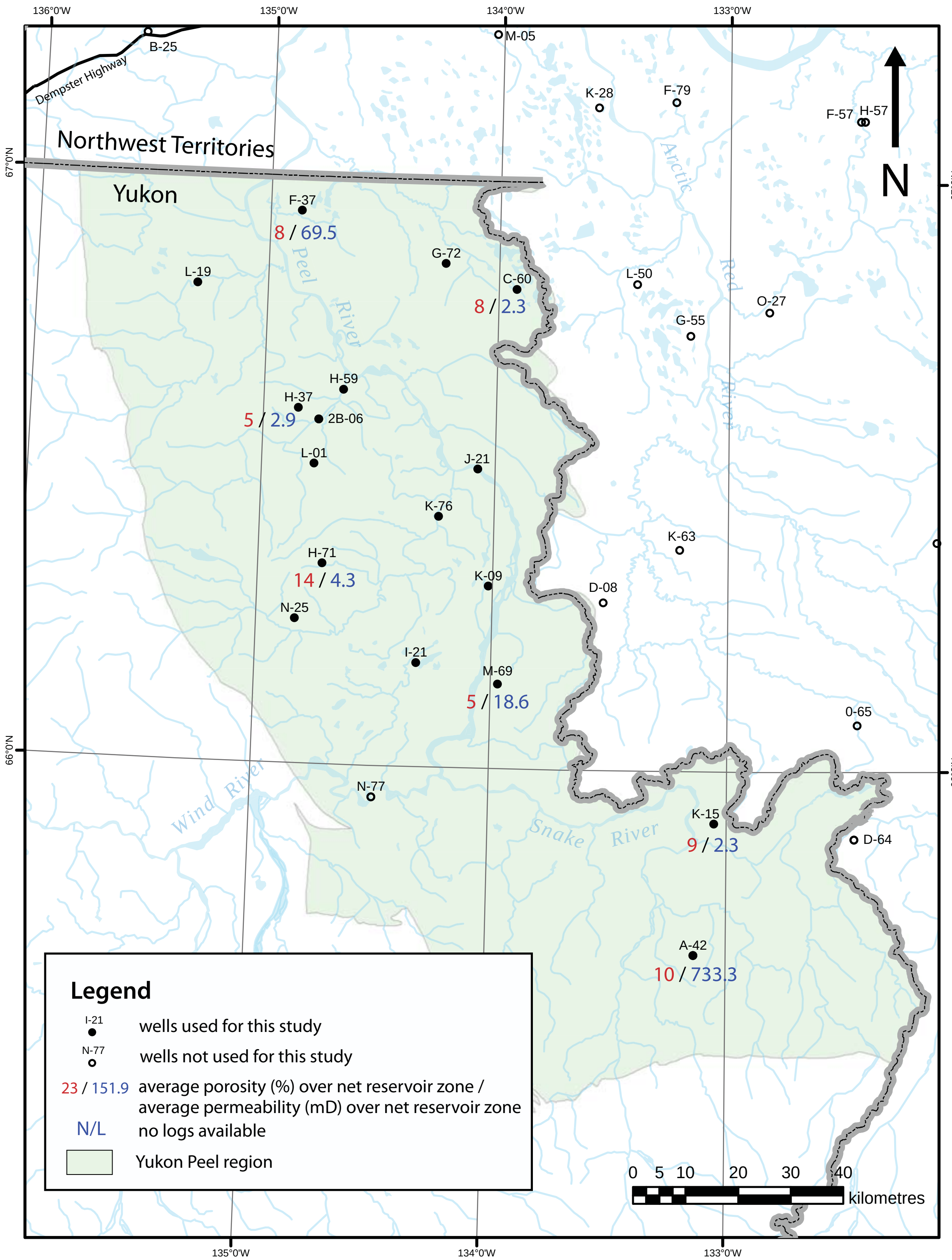

Figure 16b. Average porosity (%) and permeability (mD) over net reservoir zone in the Peel Formation and equivalent strata. Data represent only wells with net reservoir values for the Peel Formation and equivalent strata (see Figure 16a).

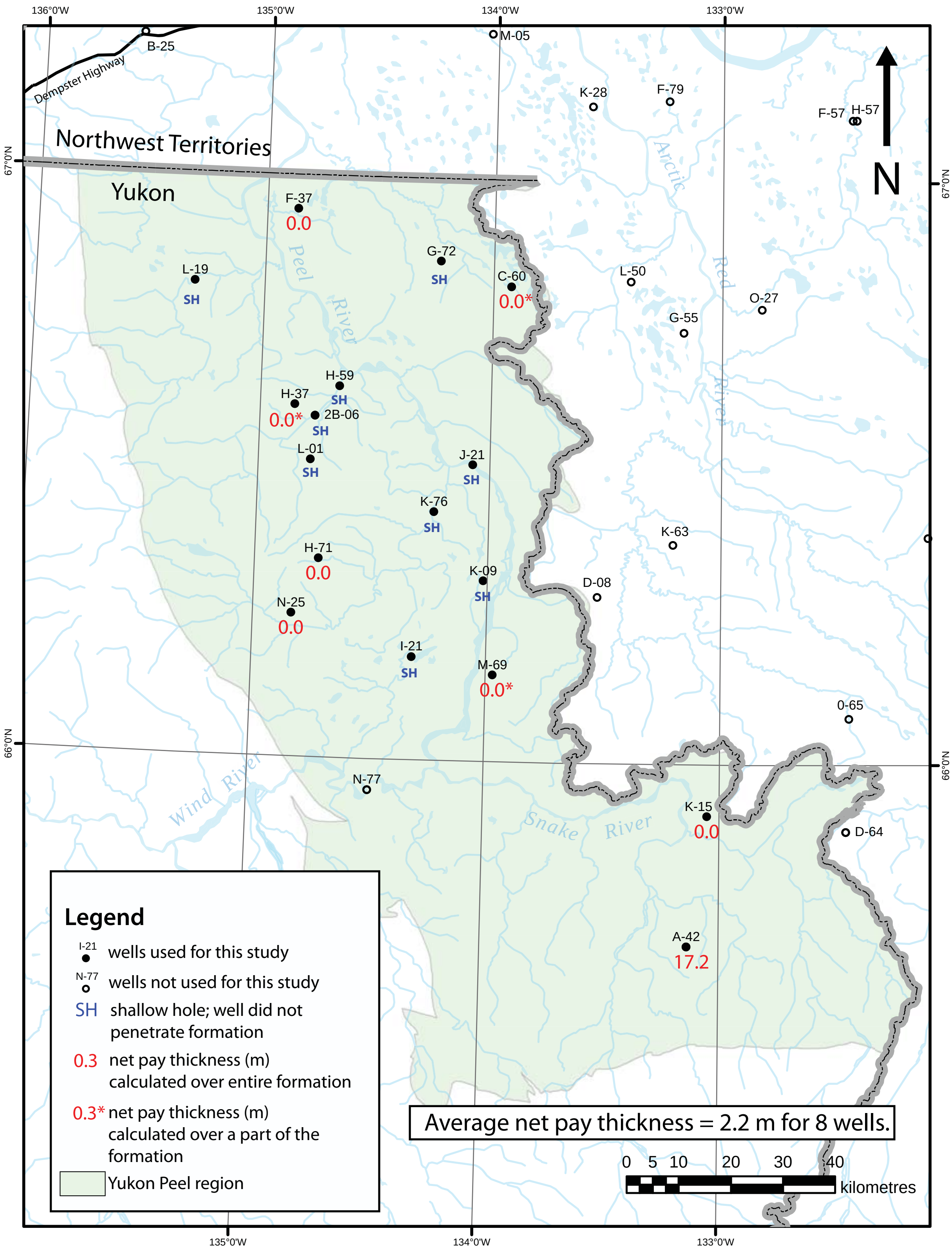

Figure 16c. *Net pay thickness (m) in the Peel Formation and equivalent strata. Note that wells H-71 and N-25 contain Road River (Peel-equivalent) strata.*

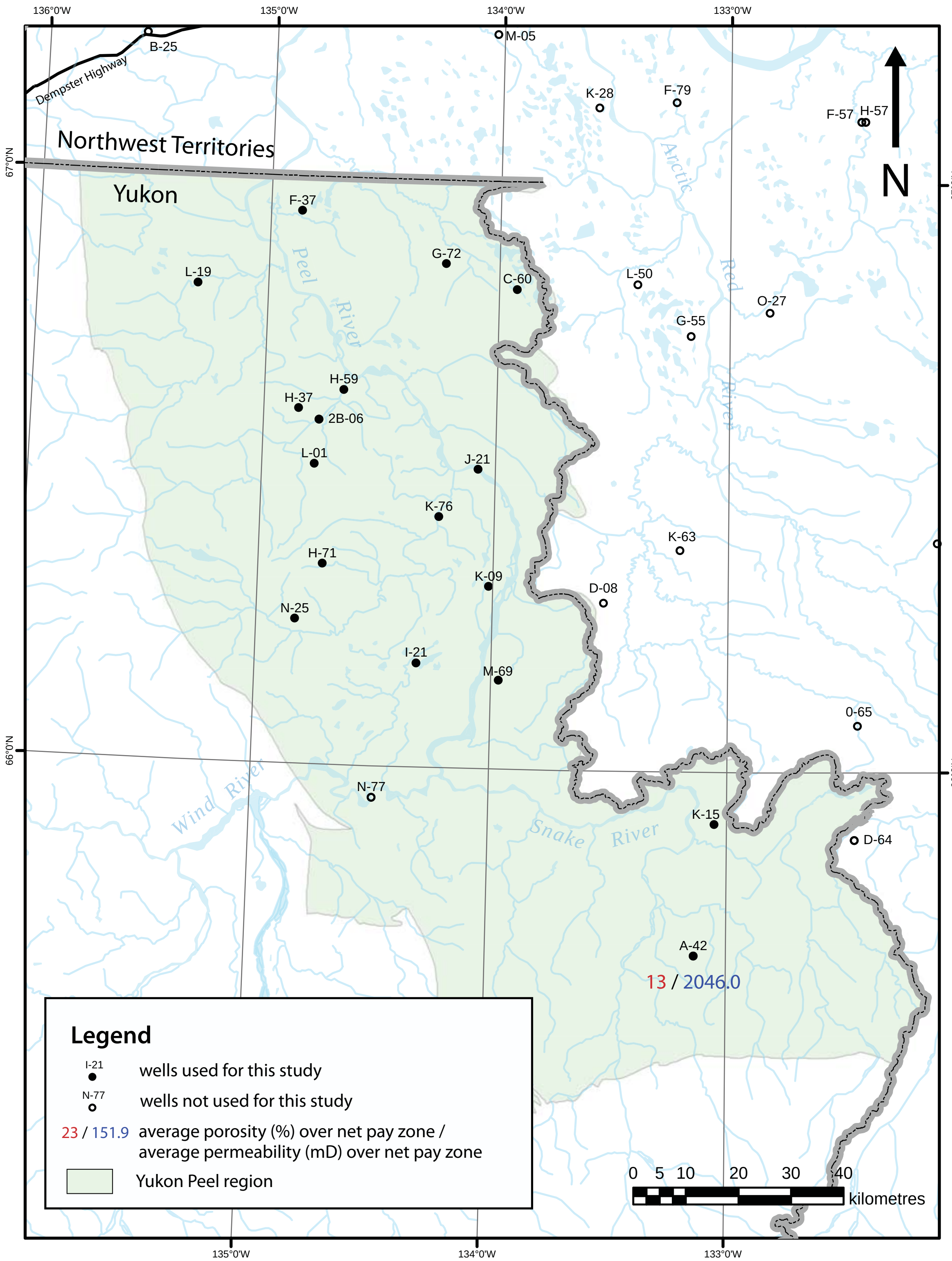

Figure 16d. *Average porosity (%) and permeability (mD) over net pay zone in the Peel Formation and equivalent strata. Data represent only wells with net pay values for the Peel Formation and equivalent strata (see Figure 16c).*

Mount Kindle Formation

Description and Thickness

The Upper Ordovician to lower Silurian Mount Kindle Formation was originally defined by Williams (1922) at Mount Kindle, near Wrigley, NWT. Norford and Macqueen (1975) redefined the type section and divided the Mount Kindle Formation into three informal members including a basal, recessive argillaceous dolomite with abundant fossil debris; a middle, resistant member of thin to thick-bedded brownish-grey dolomite with fossils in the lower part; and an upper, less thickly bedded dolomite member with less fossil debris than the middle member. Pugh (1983) describes Mount Kindle strata in the Peel subsurface as a lithologically uniform, brown and buff, finely crystalline dolostone that may be siliceous with locally occurring light-coloured chert. Pyle and Gal (2009) observe the Mount Kindle succession in the Peel region as a finely crystalline dolostone, which has an overall banded weathering appearance and an abundance of silicified fossil material. In addition, bedded and nodular chert is common in outcrop and the formation is more resistant in nature than the underlying Franklin Mountain Formation. Mount Kindle carbonates are correlative with Road River Group basinal deposits of the Richardson trough.

The contact separating Mount Kindle and Franklin Mountain strata is a regional unconformity (Norford and Macqueen, 1975). The upper contact of the formation is unconformable with the overlying Peel Formation, representing the regional sub-Devonian unconformity of Morrow (1999). In the immediate vicinity of the Road River shale belt, Pugh (1983) suggests the lower and upper contacts of the Mount Kindle Formation may be conformable, based on continuous deposition of Road River shale during the early Paleozoic.

In this study, five wells penetrate the Mount Kindle Formation, with only three of these covering the entire formation. The Mount Kindle is thickest in well A-42 at 231.9 m and thinnest in F-37 at 40.8 m; however, in F-37 it represents only a part of the formation (Fraser and Hogue, 2007).

Reservoir and Pay Summary

The results of the reservoir petrophysical assessment for the Mount Kindle Formation are reported in Appendix C, Table M. Cut-off values used to calculate reservoir and pay for the Mount Kindle Formation are those which apply to dolostone (Tables 2 and 3).

Four of five wells which penetrate the Mount Kindle Formation have associated reservoir intervals (Fig. 17a). Net pay thicknesses are 20.0 m, 18.1 m, 2.4 m, and 0.2 m in wells A-42, N-25, F-37 and H-71, respectively. The average net reservoir calculated among five wells is 8.1 m. Average porosity over net reservoir intervals ranges from 10% in N-25 to 13% in F-37 (Fig. 17b). Average permeability over these intervals ranges from 430 mD in A-42 to 1 mD in H-71 (Fig. 17b). There are no pay zones associated with these reservoir intervals.

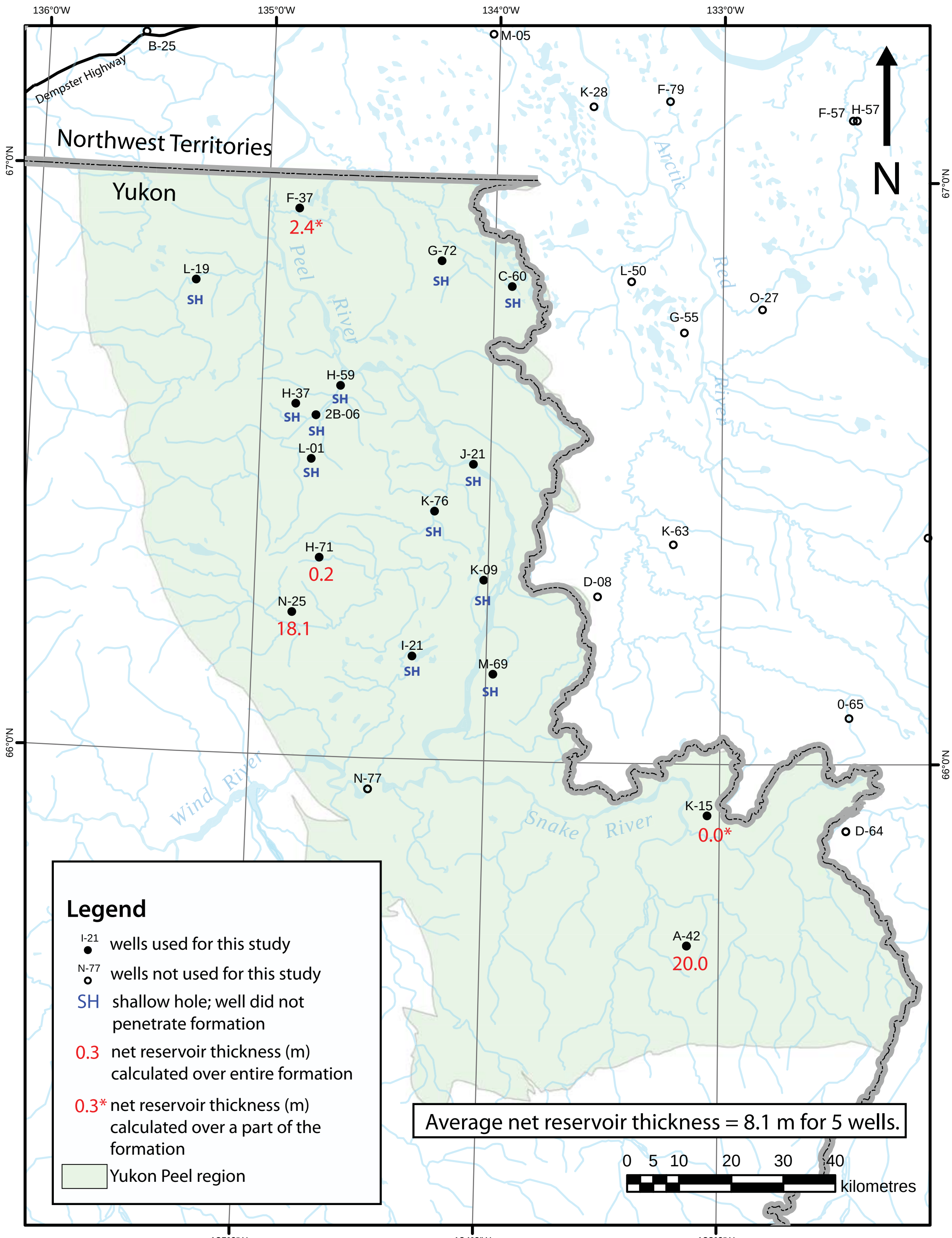

***Figure 17a**. Net reservoir thickness (m) in the Mount Kindle Formation.*

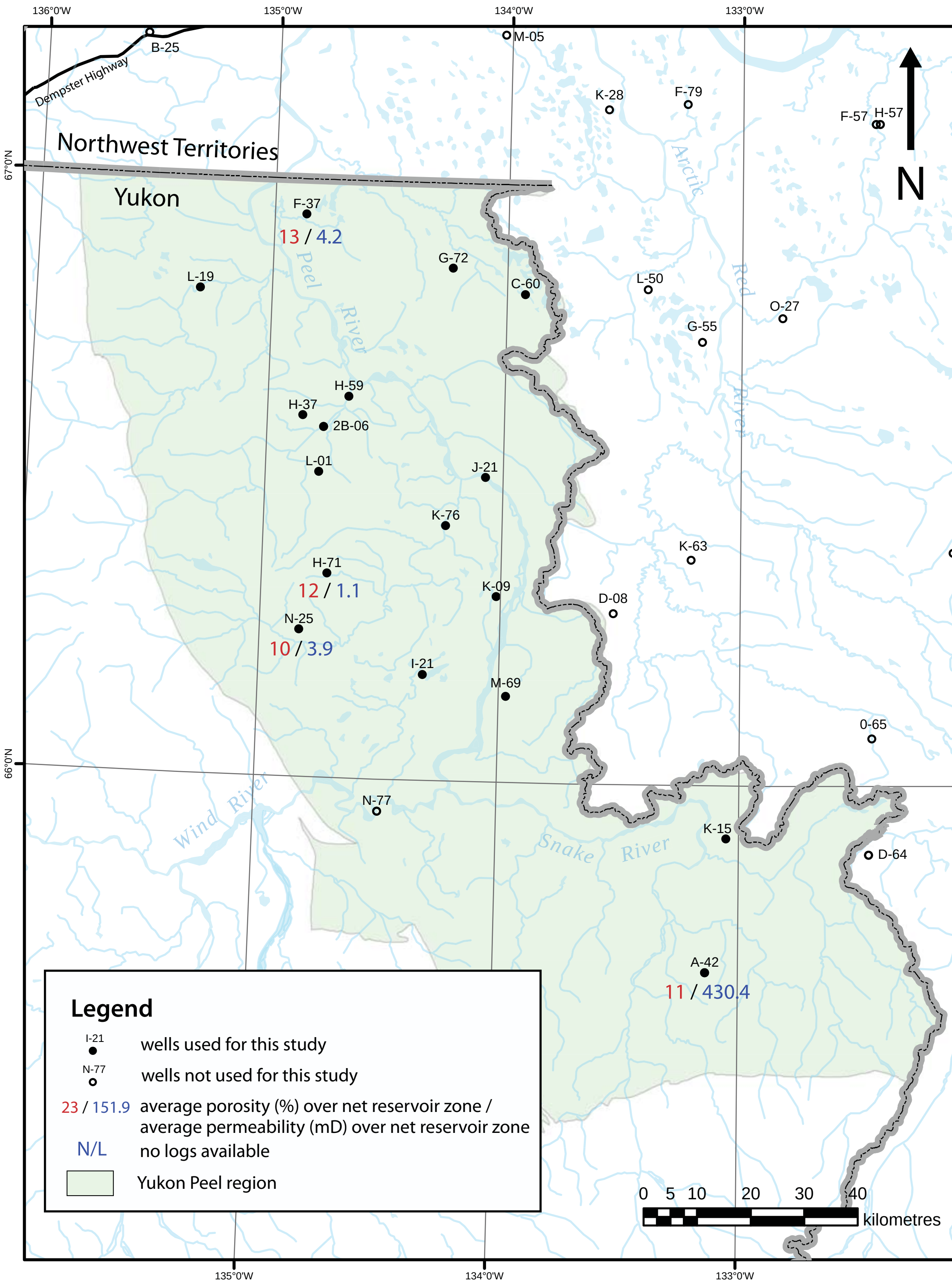

Figure 17b. *Average porosity (%) and permeability (mD) over net reservoir zone in the Mount Kindle Formation. Data represent only wells with net reservoir values for the Mount Kindle Formation (see Figure 17a).*

Franklin Mountain Formation

Description and Thickness

The upper Cambrian to Lower Ordovician Franklin Mountain Formation was originally described by Williams (1922, 1923) at the same location as the type section for the Mount Kindle Formation, near Wrigley, NWT. Norford and Macqueen (1975) redefined the type section and divided the Franklin Mountain Formation into three dolomitic units including a basal cyclic unit defined by finely crystalline dolostone with argillaceous dolostone; a middle rhythmic unit defined by finely crystalline and sometimes oolitic dolostone and alternating silty dolostone; and an upper dolostone unit with abundant chert. In the Peel subsurface, Pugh (1983) includes an upper porous dolomite unit (originally identified by MacKenzie, 1974) in his definition of the Franklin Mountain Formation. From field observations in the northern Mackenzie Mountains, Pyle and Gal (2009) identify four units in the Franklin Mountain succession including a basal clastic unit of red-weathering quartz sandstone and red (and lesser green) shale; a lower cyclic unit containing mainly grey to yellow-weathering, finely crystalline, dolomudstone including algal laminae and stromatolites; a middle unit containing alternations of brown grey-weathering, burrow mottled dolostone and grey-weathering laminated dolostone; and an upper cherty unit which includes grey-weathering dolostone with white and black chert nodules and bedded chert. Like the Mount Kindle Formation, these carbonates are correlative with Road River basinal shales of the Richardson trough.

The upper contact of the Franklin Mountain Formation with the Mount Kindle Formation is a regional unconformity (Norford and Macqueen, 1975). In well N-25, the base of the Franklin Mountain Formation has been interpreted as an unconformity with either the Middle Cambrian Slats Creek Formation (Morrow, 1999), or possibly Proterozoic orthoquartzites of the Katherine Group (Pugh, 1983).

Wells A-42, H-71 and N-25 penetrate the Franklin Mountain Formation; however, only N-25 spans the entire interval. The thickness of the formation in N-25 is 649.9 m, but it is thicker in A-42 at 685.2 m, even though the entire formation was not drilled. A thickness of 415.5 m of the Franklin Mountain Formation was drilled in well H-71 (Fraser and Hogue, 2007).

Reservoir and Pay Summary

The results of the reservoir petrophysical assessment for the Franklin Mountain Formation are reported in Appendix C, Table N. Cut-off values used to calculate reservoir and pay for the Franklin Mountain Formation are those which apply to dolostone (Tables 2 and 3).

Of the three wells analysed, reservoir intervals in the Franklin Mountain Formation were identified in wells A-42 and H-71, with net thicknesses of 27.1 m and 1.7 m respectively (Fig. 18a). The average porosity over these net reservoir zones is 11% in A-42, and 14% in H-71 (Fig. 18b). Average permeability over these same zones is 176 and 322 mD respectively (Fig. 18b). The average net reservoir thickness among three wells is 9.6 m. No pay is associated with these reservoir intervals.

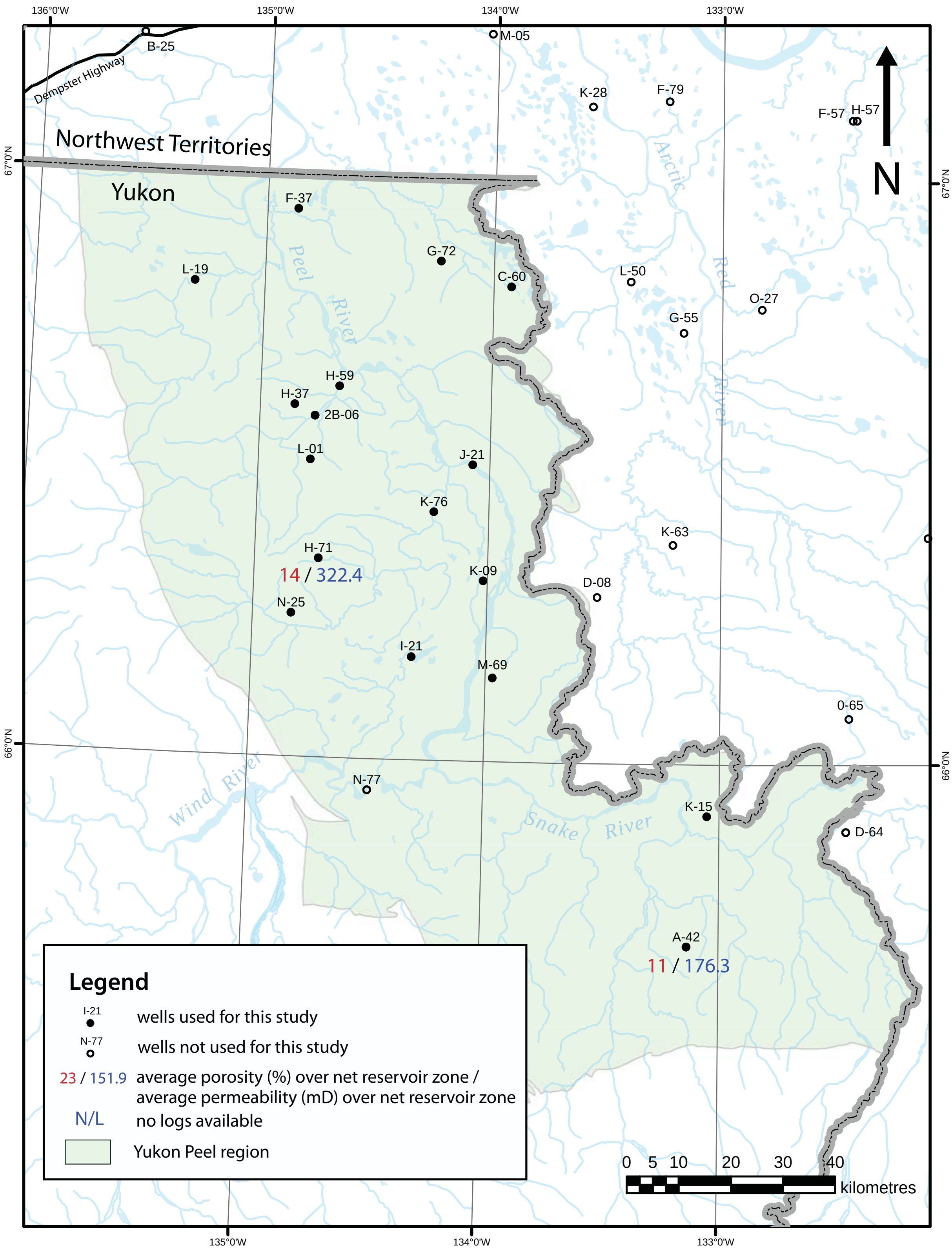

Figure 18a. *Net reservoir thickness (m) in the Franklin Mountain Formation.*

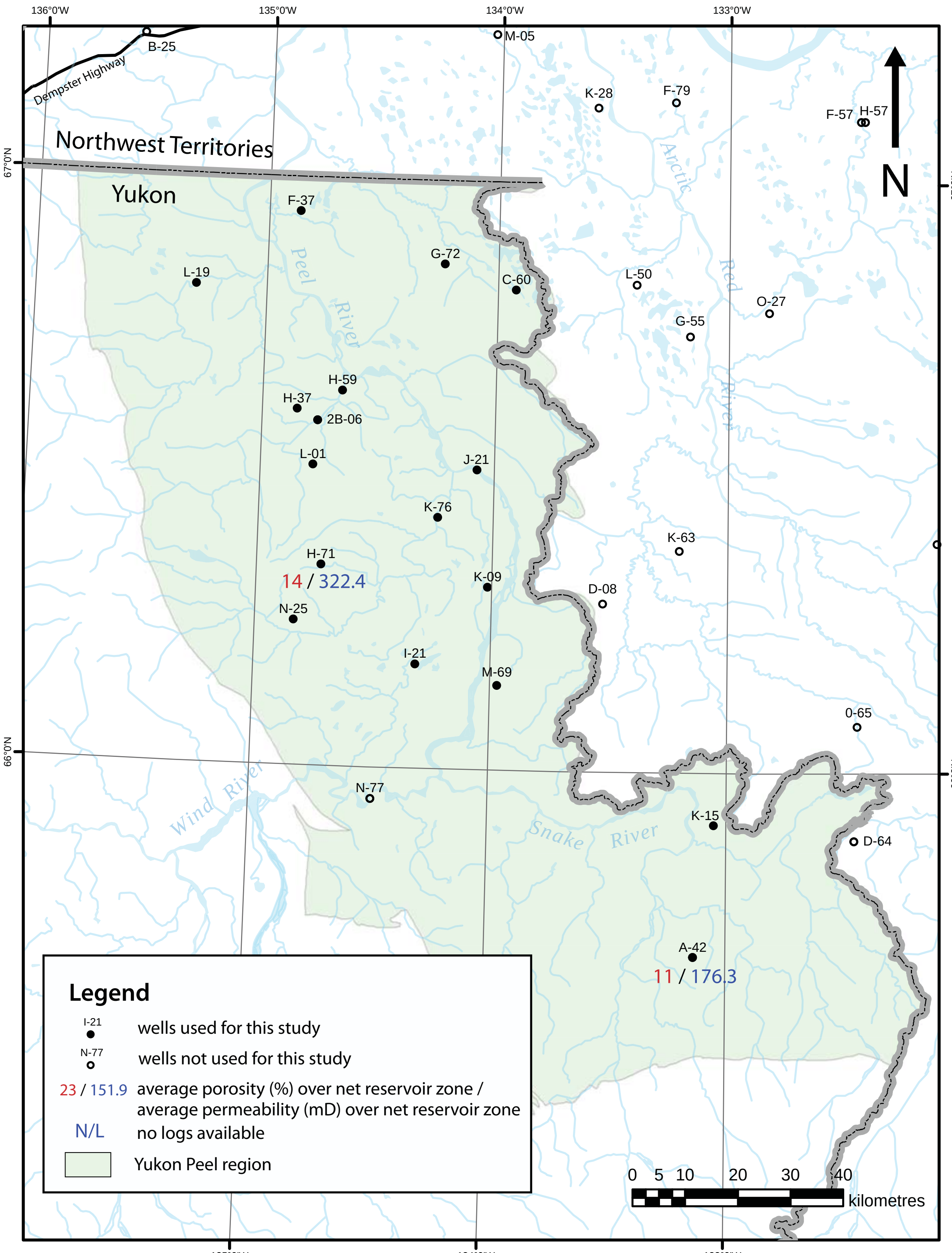

__Figure 18b.__ Average porosity (%) and permeability (mD) over net reservoir zone in the Franklin Mountain Formation. Data represent only wells with net reservoir values for the Franklin Mountain Formation (see Figure 18a).

Proterozoic

Description and Thickness

Only one well in the study area, N-25, penetrates strata below the Franklin Mountain Formation. This unit, beginning at a depth of 3433.3 m below KB, was determined as the top of the Proterozoic succession in Fraser and Hogue (2007), which is consistent with Pugh (1983). Pugh (1983) suggests the orthoquartzite beds encountered in the lowest part of well N-25 may be assigned to the Helikian Katherine Group, based on a "reasonable projection" from a cross-section from Aitken *et al*. (1973). This cross-section displays borehole A-22 (UWI 300A226540131450, located in the NWT) penetrating the crestal region of the Mackenzie arch, where the Franklin Mountain Formation uncomformably overlies orthoquartzite of the Katherine Group.

In the same well, Morrow (1999) assigned the same unit to the Cambrian Slats Creek Formation with a formation top at 3432.4 m below KB. The Slats Creek Formation is mainly composed of sandstone, possibly derived from the erosion of Proterozoic strata, like the Katherine Group (Osadetz *et al*., 2005).

Reservoir and Pay Summary

The results of the reservoir petrophysical assessment for the Proterozoic strata are reported in Appendix C, Table O. Whether the unit at the base of N-25 is Proterozoic or Cambrian, it contains no reservoir intervals, and no measurable intervals of porosity or permeability (Fig. 19). In addition, this section of the well has a high percentage of flagged bad hole intervals.

DISCUSSION

Clastic strata are closer to the surface in the Peel region, and thus have higher drill penetration than the deeper carbonates. As a result, there is significantly more data from clastic strata than from carbonate strata. All 17 wells used in this study penetrate the clastic section to some degree, with eight of these spanning the entire Cretaceous to Middle Devonian clastic section. In contrast, only ten wells penetrate lower Paleozoic carbonate strata, with only one well penetrating the entire carbonate interval.

Because of the variability in drill hole depth and the discontinuous nature of log data available for this study, it is difficult to accurately and statistically compare reservoir characteristics between formations. This discussion will present the study highlights, bearing these limitations in mind.

This discussion will use the descriptive terms for porosity and permeability terms from Levorsen (2001), given in Table 5.

Clastic Reservoirs

The results of this study demonstrate that upper Paleozoic and Mesozoic clastic formations (excluding the Canol Formation and Bluefish Member) have better potential for hosting economic quantities of conventional hydrocarbons than the carbonate units. Of the clastic reservoirs, the Tuttle shows the most promise as a hydrocarbon-bearing formation, followed by the Cretaceous strata and then the Imperial Formation. In this study, both the Canol Formation and Bluefish Member are not identified as reservoir units in the conventional sense.

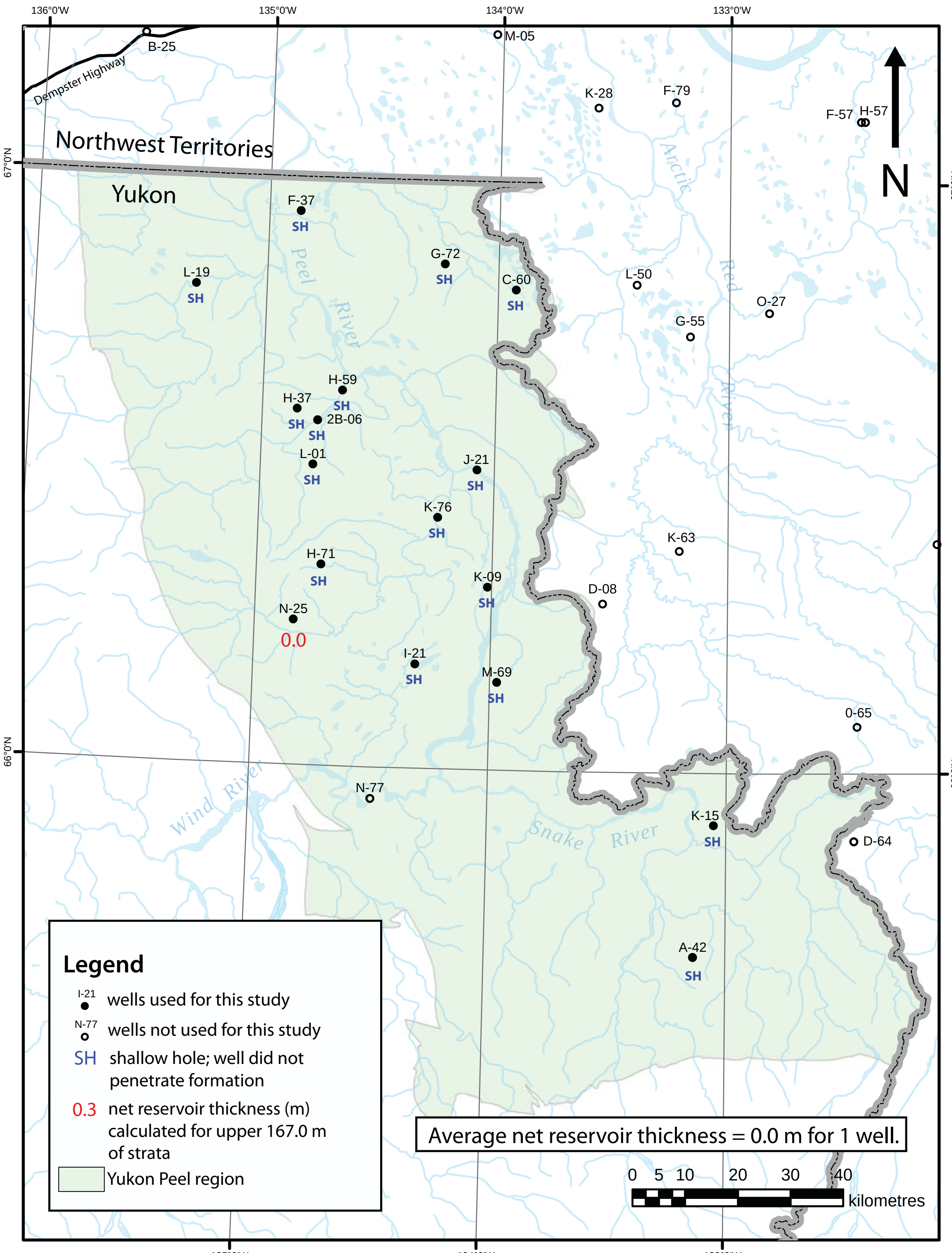

Figure 19. *Net reservoir thickness (m) in Proterozoic strata.*

Table 5. Descriptive porosity and permeability terms used in this assessment (after Levorsen, 2001).

Descriptive porosity term	Porosity range (%)	Descriptive permeability term	Permeability range (mD)
negligible	0-5	poor	0-1
poor	5-10	fair	1-10
fair	10-15	good	10-100
good	15-20	very good	100-1000+
very good	20-25+		

Tuttle Formation

This study indicates that the best prospects for finding hydrocarbons in the Peel subsurface are in the Tuttle Formation. The Tuttle ranks number one in terms of overall average net reservoir[7] and average net pay, where thickness values are 53.8 m and 20.1 m respectively (Figs. 20 and 21 respectively). The Tuttle Formation has significantly thick packages of porous and permeable strata, found in all wells with log data throughout the Peel region, exceeding 100 m in wells H-37, J-21, and H-71, and as much as 221.6 m in well F-37 (Fig. 8a). Over the reservoir zones, average porosity and permeability ranges from fair to very good. Average net pay in Tuttle Formation equates to 37.4% of the average net reservoir thickness. Average porosity over net pay zones ranges from fair to good and average permeability ranges from fair to good. Pay zones are greater than 20 m thick in wells H-37, 2B-06, J-21, F-37, L-01 and H-71 (Fig. 8c). Of note is the Tuttle interval in well H-37, where the net pay thickness is 71.2 m with 18% average porosity and 29 mD average permeability.

Table 6 lists the drill stem test (DST) data for seven wells that tested positive for gas in Tuttle strata (wells B-06 and D-08 were not included in this petrophysical study, but are in the Peel region; D-08 is located immediately to the east of the Yukon Peel region in the NWT). Although having only minor gas shows, the wells do confirm the presence of an active petroleum system in Tuttle strata in Peel Plateau and Plain.

In addition to DST gas shows, oil-stained Tuttle Formation sandstone samples were collected in the field in 2006 and 2007 on the Trail River in eastern Richardson Mountains, immediately west of the Peel Plateau (Allen and Fraser, 2008). Analysis of biomarkers from these samples suggests that the oil stains are very characteristic of oil from a Paleozoic marine source. The DST results in Table 6, combined with the oil shows reported by Allen and Fraser (2008), suggest that both oil and gas accumulations are possible in the Tuttle Formation.

Previous resource assessments of the Yukon Peel region comment on the reservoir potential of the Tuttle Formation. A National Energy Board (2000) assessment indicates that in the undisturbed Yukon Peel Plateau assessment region[8] (east of the limit of the Cordilleran fold and thrust belt on Figure 2), the Tuttle Formation has a mean undiscovered initial gas in-place estimate of 5.0 x 10^9 m^3 (177 Bcf). This estimate accounts for ~6.9% of the total mean undiscovered initial gas in-place for the entire Yukon Peel region, estimated at 71.6 x 10^9 m^3 (2.5 Tcf). Small volumes of oil may also be

7 Average net reservoir data from well C-60 were used in this ranking, even though the average net reservoir in this well was calculated using porosity values alone, as opposed to porosity and permeability. When data from C-60 are not included, the ranking of the Tuttle remains at number one.

8 The National Energy Board (2000) report defines the Yukon Peel Plateau assessment region by the NWT-Yukon interterritorial boundary in the north and east, the Trevor fault in the west, and the Mackenzie Mountains in the south.

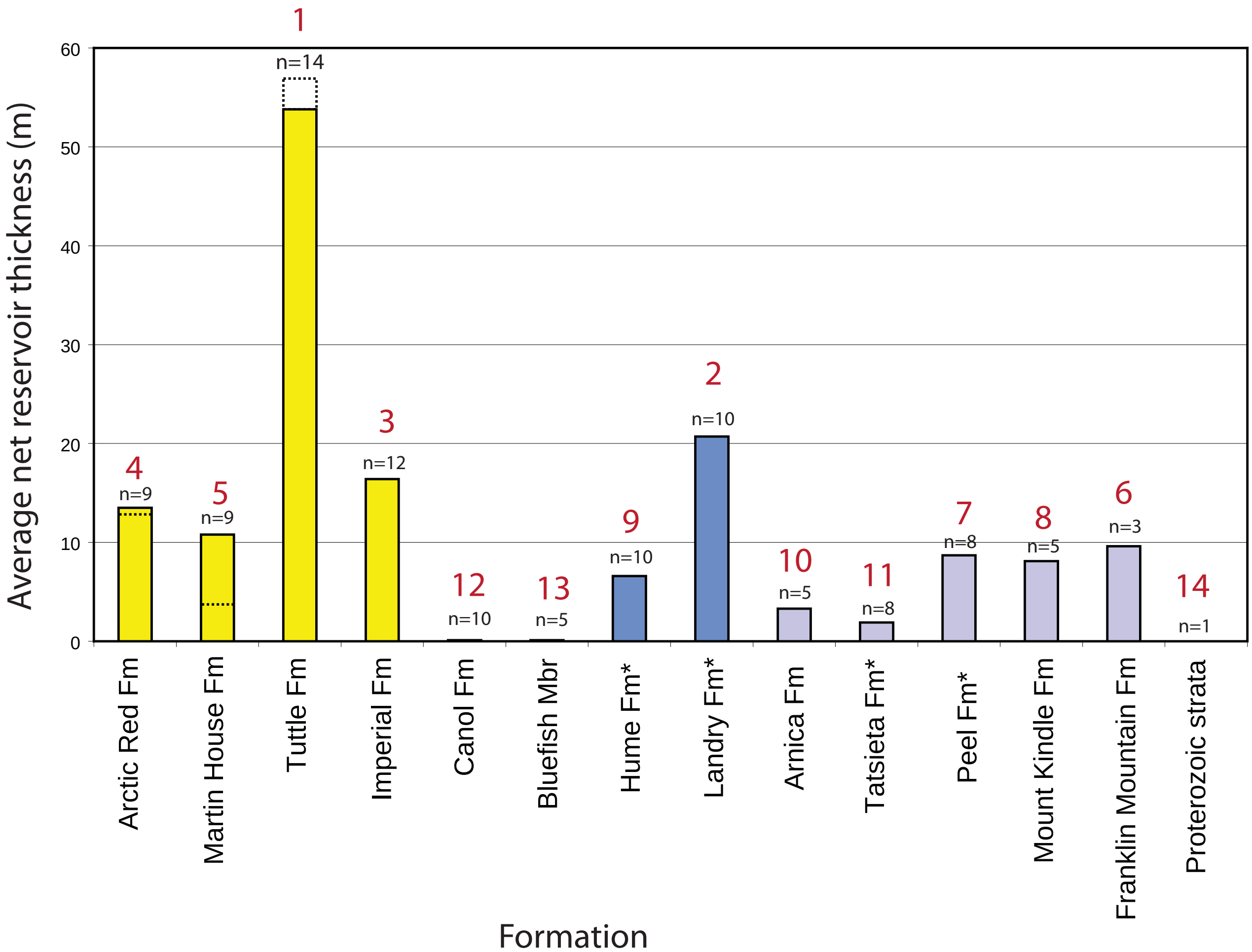

Figure 20. *Average net reservoir thickness and rank by formation/member identified in this study. The red number at the top of each column is the formation rank. Younger strata are displayed to the left of the table. The black 'n' value represents the number of wells used to evaluate each formation. Yellow, blue and purple bars represent siliciclastic, limestone and dolostone strata, respectively. Asterisks (*) refer to formations which incorporated Road River- equivalent strata into the analysis. Note the dashed lines in the Arctic Red, Martin House and Tuttle Formation bars; these represent the average net reservoir thickness when values from well C-60 are removed. Logs from C-60 did not provide enough data to determine permeability in these formations and net reservoir values were calculated by porosity cut-offs alone. Rank numbers incorporate C-60 net reservoir values.*

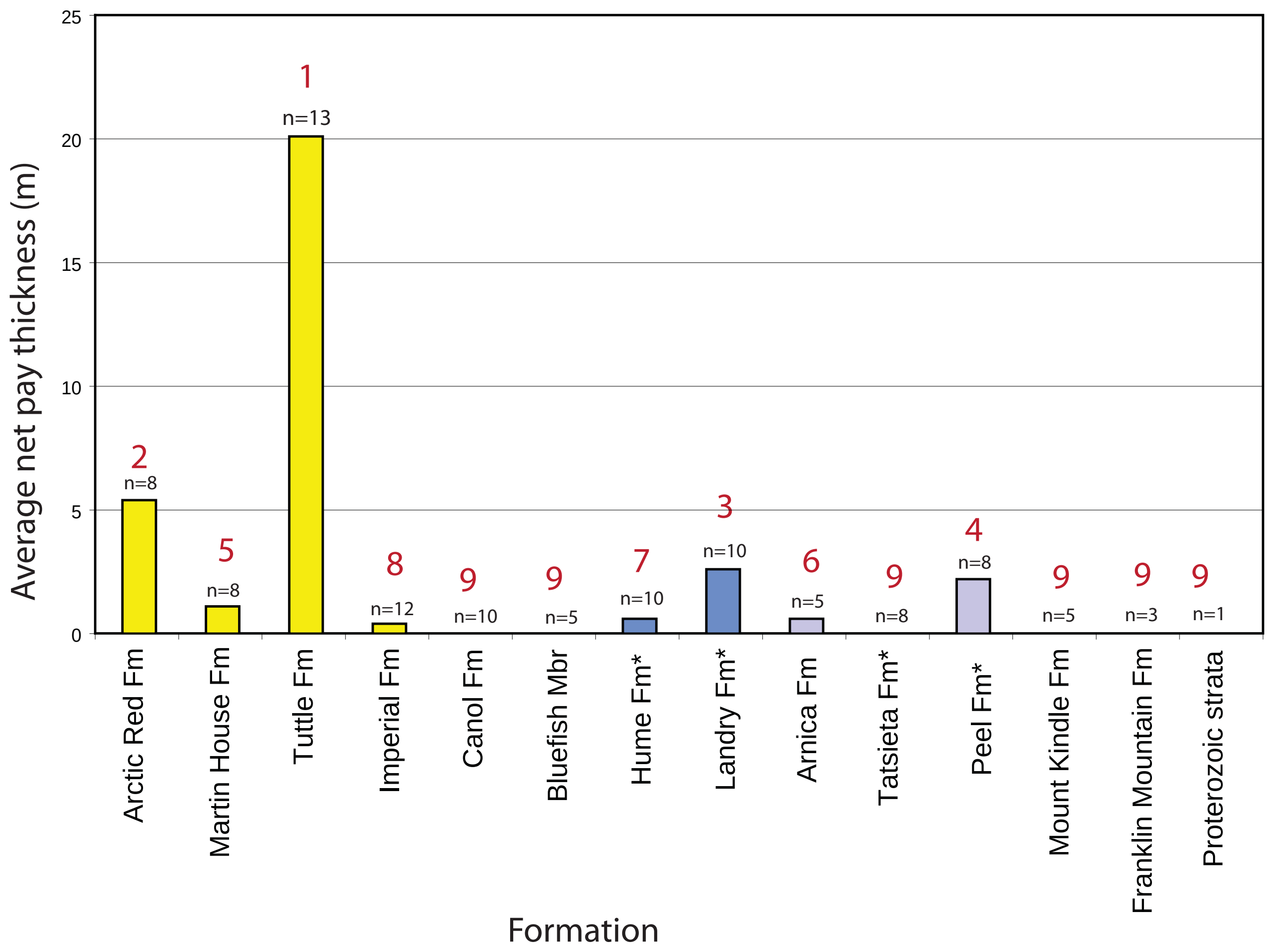

Figure 21. *Average net pay thickness and rank by formation/member identified in this study. The red number at the top of each column is the formation rank. Younger strata are displayed to the left of the table. The black 'n' value represents the number of wells used to evaluate each formation. Yellow, blue and purple bars represent siliciclastic, limestone and dolostone strata, respectively. Asterisks (*) refer to formations which incorporated Road River-equivalent strata into the analysis.*

discovered, having an estimate for mean undiscovered oil in-place of 0.031 x 10^6 m^3 (0.2 MMbbl)[9]. This estimate accounts for ~0.2% of the mean total undiscovered oil in-place for the entire Yukon Peel Plateau study area, estimated at 16.4 x 10^6 m^3 (103 MMbbl). The assessment also reports that the greatest risk to the Tuttle play is the likelihood of freshwater flushing of the reservoir due to proximity to outcrop at surface. Another risk is overlying Cretaceous sandstone which could act as a thief zone above the Tuttle subcrop trend. In addition, bitumen plugging was also reported to be common within the formation.

Table 6. *Drill stem tests (DST) with gas shows in the Tuttle Formation, Peel Plateau and Plain, Yukon and Northwest Territories. Data are sourced from Indian and Northern Affairs, 1966a, 1966b, 1967, 1969, 1974a, 1975. All wells were analysed in this reservoir petrophysical assessment except for B-06 and D-08. B-06 was redrilled as 2B-06, which is included in this assessment. D-08 is located immediately east of the Yukon Peel region in the Northwest Territories.*

UWI	Well short name	Drill stem test (DST) depth	Recoveries
300B06664013445	B-06	DST #2 312.4-430.4 m (1025-1412 ft)	18.3 m (60 ft) mud; 18.3 m (60 ft) mud-cut water; gas to surface in 30 seconds, amount too small to measure across base of Cretaceous and top of Tuttle
302B066640134450	2B-06	DST #1 798.3-866.9 m (2619-2844 ft)	789.4 m (2590 ft) gasified slightly salty water; gas to surface in 45 minutes; water to surface in 55 minutes
300K156600133000	K-15	DST #1 729.4-737.0 m (2393-2418 ft)	30.5 m (100 ft) water-cut mud; 121.9 m (400 ft) mud-cut gassy fresh water
300K156600133000	K-15	DST #2 860.8-915.3 m (2824-3003 ft)	100.6 m (330 ft) watery mud and 378.0 m (1240 ft) muddy gassy water; 0.9 m (3 ft) flare at surface
300M696610133450	M-69	DST #4 1742.8-1799.8 m (5718-5905 ft)	94 m (310 ft) salt-cut, gas-cut drilling fluid; gas to surface, amount too small to measure
300I216620134150	I-21	DST #2 767.5-888.8 m (2518-2916 ft)	418.5 m (1373 ft) fresh water, slightly gasified
300L016640134450	L-01	DST #2 1338.7-1394.2 m (4392-4574 ft)	91.4 m (300 ft) water-cut mud; 182.9 m (600 ft) mud-cut water; 640 m (2100 ft) slightly gasified water
300D08662013330	D-08	DST #5 898.6-907.7 m (2948-2978 ft)	gas to surface in 25 minutes, amount too small to measure

A more recent petroleum resource assessment of the Yukon Peel Plateau and Plain[10] by Osadetz *et al.* (2005), does not offer an estimate specifically for the Tuttle Formation, but does suggest that upper Paleozoic clastic strata, including the Imperial, Tuttle and Ford Lake Shale formations, are expected to contain a mean in-place play potential of about 15.2 x 10^9 m^3 (536 Bcf) of natural gas, accounting for 18% of the total mean in-place gas resource for the Peel Plateau and Plain, estimated to be ~83.4 x 10^9 m^3 (2.9 Tcf). No estimate is given for crude oil potential due to the lack of absolute data at the time of the assessment. The study compares the upper Paleozoic clastic plays to deep-water sand plays actively being explored along the Atlantic and Gulf Coast passive margins, stating that these slope sandstone 'valley-fills' are among the most attractive petroleum plays globally.

9 There is also potential for gas and possibly oil in the Tuttle Formation in the deformed Yukon Peel region (west of the limit of the Cordilleran fold and thrust belt and east of the Carboniferous outcrop); however, the National Energy Board (2000) assessment provides only one estimate for both Mesozoic and Paleozoic clastic rocks combined. If the estimates are divided equally between the Mesozoic strata and Tuttle Formation, the Tuttle Formation mean undiscovered initial gas in-place estimate would account for ~16.0%, and the mean undiscovered oil in-place estimate would account for ~14.5% of the totals for the entire Yukon Peel region.

10 The Osadetz *et al.* (2005) report defines the Yukon Peel Plateau and Plain assessment region by the NWT-Yukon interterritorial boundary in the north and east, and the limit of sub-Carboniferous outcrops in the west and south.

There is also possible unconventional hydrocarbon potential in the Tuttle Formation or related strata. The 'Cf' map unit of Norris,1981 (Ford Lake Shale equivalent of Norris, 1985) has been identified on 1:250 000-scale maps of the Peel region (Norris, 1981c, 1982a), and is believed to be time equivalent and/or younger than the Tuttle Formation (Allen and Fraser, 2008). 'Cf' map unit and Ford Lake Shale have not been identified in Peel region well logs, but are likely included as part of the Tuttle interval. They have been identified in the field as diverse packages of predominant shale with lesser siltstone and sandstone (Allen and Fraser, 2008). Oil-stained siltstone from the 'Cf' map unit (Ford Lake Shale) was collected in the field in 2007 and held a flame when it was lit with a propane torch (Allen *et al*., 2008a). Compositional traces from these rocks suggest an upper Paleozoic marine source (Allen *et al*., 2010). Rocks of the Tuttle Formation or equivalent strata should be considered as a potential unconventional source of hydrocarbons, such as shale gas and oil shale, and further analysis is recommended.

Cretaceous strata

Cretaceous strata qualify as the next best prospects for siliciclastic-hosted hydrocarbon potential after the Tuttle Formation. In terms of average net reservoir thickness, the Arctic Red Formation ranks 4th and the Martin House Formation 5th of 14 formations analysed[11]; the Tuttle and Imperial formations are the only clastic formations ranking higher (Fig. 20). The Arctic Red and Martin House formations rank 2nd and 5th respectively in terms of average net pay, the Tuttle Formation is the only clastic unit ranking higher (Fig. 21).

This reservoir petrophysical property study indicates that Cretaceous strata have notable porous and permeable sandstone intervals, particularly in the Arctic Red Formation in wells L-01 and J-21 (Figs. 6a,b). The Martin House Formation has notable porous strata in well C-60; however, permeability data are unavailable due to insufficient well log data. For the Martin House and Arctic Red formations, the average porosity and permeability over these reservoir intervals range from fair to very good. Unfortunately, these thicker, porous and permeable intervals are mainly water-filled, and do not qualify as pay zones. Only 5.2% of average net reservoir in the Arctic Red Formation qualifies as pay (including net reservoir data from well C-60). By contrast, this value is double for the Martin House Formation, at 10.2% (including net reservoir data from well C-60). This is notable as the Martin House Formation is distinctly thinner than the Arctic Red Formation (*e.g.*, in well A-42 the Arctic Red interval is 1098 m thick and the Martin House interval 66 m thick; and in well H-37 the Arctic Red interval is 559 m and the Martin House interval 80 m thick). Average porosity over pay intervals in the Arctic Red Formation is good to very good, while permeability is fair to very good. Average porosity over pay intervals in the Martin House Formation is fair to good, and permeability is fair to very good.

No DST data exist for Cretaceous strata in the Peel region as these were not original drilling targets. However, it must be noted that DST #2 in well B-06 had gas to surface in 30 seconds, and 35.6 m (120 ft) of mud and water across the base of the Cretaceous strata and the top of the Tuttle Formation, suggesting reservoir prospects associated with the sub-Cretaceous unconformity (Indian and Northern Affairs, 1967).

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11 Both Arctic Red Formation and Martin House Formation average net reservoir data from well C-60 have been included in this ranking, even though the average net reservoir in this well was calculated using porosity values alone, as opposed to both porosity and permeability. When data from C-60 are not included, the ranking of the Arctic Red Formation remains at 4, while the Martin House Formation moves to tenth place of 14 formations analysed. This is not an issue for average net pay as there was not enough data to calculate net pay for either formation in C-60.

A recent petroleum resource assessment of the Yukon Peel Plateau and Plain (Osadetz *et al*., 2005, p.69) states that "…[m]ost of the potential gas for the Peel Plateau and Plain is predicted to occur within the Mesozoic clastic plays". When combined, the Mesozoic clastic plays are expected to contain a mean in-place play potential of 62.6 x 10^9 m^3 (2.2 Tcf) natural gas, or 75% of the total mean undiscovered in-place natural gas resource for the Yukon Peel Plateau and Plain, estimated to be ~83.4 x 10^9 m^3 (2.9 Tcf). This study draws on similarities between the Mesozoic clastic plays in the Peel Plateau and Plain to the producing Mesozoic strata of the southern Cordillera and Foreland succession (*i.e.*, Alberta, Saskatchewan and northeast British Columbia). No estimate is given for crude oil potential due to the lack of absolute data available at the time of the assessment.

In contrast to the Osadetz *et al*. (2005) report, an earlier assessment by the National Energy Board (2000) provides a smaller in-place gas estimate for both the Yukon Peel Plateau assessment region as a whole, as well as the proportion attributed to Cretaceous strata. In addition, it provides an estimate for undiscovered oil in-place. The assessment suggests the mean undiscovered initial gas in-place for the Yukon Peel Plateau is 71.6 x 10^9 m^3 (2.5 Tcf), and <21%[12] is attributed to Cretaceous strata. The mean estimate for undiscovered in-place oil for the Peel Plateau assessment region is 16.4 x 10^6 m^3 (103 MMBbls), and <38%[13] is attributed to Cretaceous strata. This assessment suggests that Cretaceous clastic strata are a higher risk exploration play (when compared to Paleozoic clastic strata) due to their generally thin character, proximity to the surface, and low thermal maturity. Martin House Formation sandstones are considered to have the most reservoir potential.

The results of this reservoir petrophysical assessment do not identify significant hydrocarbon-bearing zones in Cretaceous strata that are in accord to the Osadetz *et al*. (2005) estimate of Mesozoic natural gas reserves in the region. It did, however, identify the presence of hydrocarbons in two wells in the Arctic Red Formation and in three wells in the Martin House Formation, suggesting active petroleum systems do exist in the Cretaceous strata. Oil-stained sandstone samples collected from the Martin House Formation on a tributary of the Snake River, at the western margin of Peel Plateau provide further evidence for a petroleum system in Cretaceous strata (Allen *et al*., 2008a). Oil compositional traces from these Martin House Formation sandstones are consistent with a Lower Cretaceous(?) or younger marine source. The results of this study, combined with the oil samples collected in the field, suggest that both oil and natural gas should be considered when exploring Cretaceous strata in the Yukon Peel region.

It is unknown if Cretaceous strata have been tested or even considered for unconventional potential such as shale gas or oil shales. Further study is required, particularly in the fine-grained intervals of the Arctic Red Formation.

Imperial Formation

The Imperial Formation is the least prospective of the clastic units (not including the Canol Formation and Bluefish Member which are not considered reservoir rock in the conventional sense). The Imperial

12 This number is based on a mean undiscovered initial gas in-place estimate that includes both Cretaceous and Paleozoic clastic strata in the region west of the limit of the Cordilleran fold and thrust belt. If the estimate is divided equally between Cretaceous and Paleozoic strata, the proportion of the mean undiscovered initial gas in-place for the Yukon Peel region attributed to Cretaceous strata would be ~12%.

13 This number is based on a mean undiscovered oil in-place estimate for both Cretaceous and Paleozoic clastic strata in the region west of the limit of the Cordilleran fold and thrust belt. If the estimate is divided equally between Cretaceous and Paleozoic strata, the proportion of the mean undiscovered in-place oil for the Yukon Peel region attributed to Cretaceous strata would be ~23%.

Formation ranks 3rd of all formations analysed in terms of average net reservoir (Fig. 20); however, it ranks 8th of eight formations with measurable data in terms of net pay (Fig. 21). Because of this low ranking, the Imperial Formation is classified in this study as less prospective than the Cretaceous formations. Wells with the greatest net reservoir thicknesses are F-37, G-72 and N-25, which have cumulative thicknesses of 36.7, 86.0 and 44.7 m, respectively (Fig. 9a). However, considering that the Imperial Formation total thickness in these wells is in excess of 1100 m, and over 1500 m in G-72, the amount of reservoir to non-reservoir rock is quite minimal. Average porosity and permeability over net reservoir intervals range from fair to good. Calculated net pay in the Imperial Formation was unremarkable with only one well, F-37, having a 4.7 m-thick interval with good porosity and permeability (Fig. 9c). Average net pay constitutes 2.4% of average net reservoir thickness for all 12 wells analysed.

Only two drill stem tests occur within Imperial strata in Yukon Peel region wells. DST #3 from well I-21 tested the bottom 23 m of the Imperial Formation, the Canol Formation, the Bluefish Member, and the top 35 m of the Hume Formation, and recovered only mud (Indian and Northern Affairs, 1966a). DST #1 in well H-37 recovered 64 m (210 ft) of mud from the Imperial Formation; however, a gas analysis report associated with the well history report (Indian and Northern Affairs, 1974b) documented the recovery of gas-cut mud in the Imperial Formation at a depth of 2613.7 m (8575 ft) below KB. A surface occurrence of bitumen in the Imperial Formation has been identified in an abandoned pit west of the Dempster Highway and north of Rengleng River (68° 48.234’ N; 133° 45.806’ W) in NWT (Pyle *et al*., 2007) confirming the presence of a petroleum system in the Imperial Formation.

Gal *et al*. (2009b) consider the Imperial Formation to have low to moderate potential in the Peel region. From surface samples in the northern Mackenzie Mountains, Zantvoort (2007) considers the best reservoir potential to be in the eastern part of the Peel region, in NWT. Surface samples from the east Richardson Mountains, immediately west of Peel Plateau, indicate that Imperial Formation sandstones have negligible porosity and permeability values with pore spaces fully or partially plugged by a combination of fused quartz grain boundaries with overgrowths, infill with silt and clay grains, and calcite cement (Allen and Fraser, 2008). These reports, along with the results of this petrophysical study, suggest that the Imperial sandstones do not show significant promise for hosting economic quantities of conventional hydrocarbons in the Yukon Peel region.

It is unknown if Imperial shales have been tested or considered as unconventional reservoirs. Further study is suggested in this area.

Canol Formation and Bluefish Member of Hare Indian Formation

The Canol Formation and Bluefish Member are not considered to contain reservoir rock of a conventional nature. The poor ranking of these units (Figs. 20 and 21) in this evaluation confirms this statement. Both the Canol Formation and the Bluefish Member are shale-rich and have been described as bituminous (Pugh, 1983). They have been identified as good source rocks (Gal *et al*., 2009b), particularly the Canol Formation in the Yukon Peel region where total organic carbon values in Peel subsurface wells can be as high as 5.73 wt.% (Allen *et al*., 2008b).

This study has identified 0.9 m of porous and permeable rock in the Canol Formation in well A-42 (Fig. 10a); however, there are no associated hydrocarbons. Upon inspection of the logs over this interval, it is likely that an incorrect top was picked for the Canol Formation, and that the porous rock identified is actually an interval of sandstone in the lower part of the Imperial Formation. The gamma ray curve for the Canol Formation is characterized by high values and a ragged-looking response. A pick of 2116 m below KB (rather than 2108 m) may be a better choice for the top of the Canol Formation, as it defines the top of a distinctly ragged section extending to the top of the Hume Formation at a depth of 2159.8 m below KB. If 2116 m is picked as the top of the Canol Formation, than the 0.9 m porous interval would occur in the Imperial Formation.

The study has also identified 0.6 m of reservoir rock in the Bluefish Member in well I-21 (Fig. 11a); no hydrocarbons were associated with this interval. There is a spike (low value) in the gamma ray curve at the depth of 1449 m below KB at the top of the reservoir interval. This is approximately 2.5 m above the top of the Hume Formation. It is possible that this potential reservoir interval correlates to a limestone interbed within the fissile shales of the Bluefish Member.

As the Canol Formation and Bluefish Member are organic-rich shales, and are widely distributed throughout the northeastern Yukon and northwestern NWT, they should be considered targets for unconventional shale gas reservoirs. Further study is suggested in this area.

Carbonate Reservoirs

The results of this reservoir petrophysical property analysis suggest generally that the potential carbonate reservoirs are less promising as hydrocarbon-bearing formations than the upper Paleozoic and Mesozoic clastics. Between the limestone units, the Landry Formation exhibits more promise than Hume strata as a hydrocarbon-bearing unit. Among the dolostone units, the Peel and Arnica formations show the most promise, followed by the Mount Kindle and Franklin Mountain strata.

Previous resource assessments have varied in their estimates for natural gas and oil potential from carbonate strata in the Yukon Peel region. An assessment conducted in 2000 by the National Energy Board attributes 72% of the mean undiscovered initial natural gas in-place in the region to Paleozoic carbonate formations including fractured reservoirs in the Arnica, Landry and Hume formations, and isolated reefs that could exist on the Devonian platform. Fifty-nine percent of the mean undiscovered oil in-place is attributed to Devonian isolated reefs and reservoirs in fractured or secondary Arnica dolomite[14]. Osadetz *et al.* (2005) place a higher risk on carbonate plays, attributing only 6% of the expected mean in-place natural gas potential in the Peel region to Paleozoic (Cambrian to Devonian) carbonate reservoir plays. Factors influencing this lower estimate include style of porosity development (primary versus secondary), lack of pervasive dolomitization (*i.e.,* absence of Manetoe dolomite), the absence of evidence for thick platform margin reef build-up, and the timing of hydrocarbon generation relative to structures (*e.g.*, late Paleozoic hydrocarbon generation with trapping structures created much later, during the Laramide (Late Cretaceous – Early Tertiary) orogeny). The 2005 assessment does not provide an estimate for oil, due to the absence of absolute data available at time of resource assessment.

Limestone strata

The Landry Formation and equivalent strata is the most prospective carbonate formation ranking 2nd of fourteen formations analysed in terms of average net reservoir, and 3rd in terms of average net pay (Figs. 20 and 21 respectively). A total of 206.6 m of net reservoir was found in a total of seven wells spread throughout the Yukon Peel region, having poor to fair average porosities, and fair to very

14 Formations older than the Arnica Formation are not considered in this assessment.

good average permeabilities. Of note are the extremely high permeabilities of 506 mD and 647 mD in wells F-37 and A-42 respectively (Fig. 13b). In the Landry Formation, average net pay accounts for 12.6% of average net reservoir thickness. Average porosity over the net pay intervals ranges from fair to very good, and average permeability ranges from good to very good. Of note is the average permeability over 6.6 m of Landry pay strata in F-37 at 1930 mD (Figs. 13c,d).

Three wells had gas shows in DST results in the Landry Formation and equivalent strata in the Peel region (Table 7). In well K-15, at a depth of 1792.2-1852.0 m (5880-6076 ft), DST #3 recovered 137.2 m (450 ft) of watery mud and 362.7 m (1190 ft) of muddy gassy salt water (Indian and Northern Affairs, 1969). In well N-25, at a depth of 1773.9 – 1787.7 m (5820 – 5865 ft) in Road River Group - Landry Formation equivalent strata, DST #3 recovered 27.4 m (90 ft) of gas-cut drilling mud (Indian and Northern Affairs, 1974c). DST #3, in well A-42 at a depth of 2650.2 – 2712.7 m (8695 – 8900 ft) reports gas to surface in 30 minutes, the amount too small to measure (Indian and Northern Affairs, 1972c). Another gas show in the Landry Formation is in the well history report for H-71, which reports gas kicks at 2023.3 m (6638 ft) and 2091.5 m (6862 ft) in Road River Group – Landry Formation equivalent strata (Indian and Northern Affairs, 1977).

Table 7. *Drill stem tests (DST) and drilling activity reports with gas shows in the Landry Formation and Road River Formation - Landry equivalent strata, Peel Plateau and Plain, Yukon and Northwest Territories. Data are sourced from Indian and Northern Affairs, 1969, 1972c, 1974c, 1977.*

UWI	Well short name	Formation	Drill stem test (DST) depth or depth of activity	Recoveries
300K156600133000	K-15	Landry	DST #3 1792.2-1852.0 m (5880-6076 ft)	137.2 m (450 ft) watery mud; 362.7 m (1190 ft) muddy gassy salt water
300N256620134450	N-25	Road River - Landry eq.	DST #3 1773.9-1787.7 m (5820-5865 ft)	27.4 m (90 ft) gas-cut mud in Road River Group
300A426550133001	A-42	Landry	DST #3 2650.0-2712.7 m (8695-8900 ft)	gas to surface in 30 minutes, amount too small to measure
300H716630134300	H-71	Road River - Landry eq.	2023.3 m (6638 ft) and 2091.5 m (6862 ft)	gas kick while drilling

Based on field evidence, Gal *et al*. (2009a) conclude that the Landry Formation appears to have poor reservoir potential (when compared to the Arnica Formation) as the lithology is almost always a tight limy mudstone. This petrophysical study does not confirm this conclusion, as the Landry Formation outranks the Arnica in terms of average net reservoir and average net pay thicknesses (Figs. 20 and 21 respectively). Gal *et al*. (2009a) also infer that the oil and gas shows obtained from DST data in NWT suggest that recoveries may be due to fracture porosity and permeability and/or brecciation of the unit at a facies change. The exceptional permeabilities in Landry Formation and equivalent strata identified in this analysis (*i.e.*, F-37 and A-42), and the gas shows recovered in the DSTs could also be a result of fractures in the formation, and it is important to keep this in mind while prospecting in the Landry Formation and other tight limestones.

The Hume Formation (and equivalent strata) ranks 9th of 14 formations analysed in terms of average net reservoir thickness, and 7th in terms of average net pay thickness (Figs. 20 and 21 respectively). In the Hume interval (and equivalent strata), average net pay thickness accounts for 9.1% of average net reservoir thickness. Average porosity values over net reservoir intervals are poor to fair, and average permeabilities are fair to good. Well K-15 is the only well with net pay identified. In this well, 5.9 m of net pay has fair porosity and good permeability (Fig. 12d). DST results from the Hume Formation in wells I-21 and N-25 (Road River – Hume Formation equivalent strata) recovered only mud (Indian and Northern Affairs, 1966a and 1974c). In well A-42, at a depth of 2510.9-2533.8 m (8238-8313 ft) in the Hume Formation, DST #2 recovered gas to surface in 30 seconds with amounts too small to measure (Indian and Northern Affairs, 1972c).

The Hume Formation is considered to be a poor reservoir unit (Williams, 1986; Gal *et al*., 2009a) which is supported by this petrophysical analysis. Osadetz *et al*. (2005), however, did examine a conceptual play based on stromatoporoid atolls or pinnacles that would be rooted directly on the Hume platform (Horn Plateau Reef Play, Peel Plain). Only 1% of the estimated gas potential of the Yukon Peel region was attributed to this play. They further comment that these reefs have been drilled in NWT without success.

Dolostone strata

The results of this study suggest that the Peel and Arnica formations show the most promise of the dolostone hydrocarbon-bearing units, whereby the Peel Formation outranks the Arnica Formation. No pay zones were identified in the Tatsieta, Mount Kindle or Franklin Mountain formations; however, two DST results from Mount Kindle strata and one from Franklin Mountain strata reported minor gas shows.

The Peel Formation (and equivalent strata) ranks 7th out of 14 formations analysed in terms of average net reservoir thickness, and 4th in terms of average net pay thickness (Figs. 20 and 21 respectively). The average net reservoir thickness is 8.7 m calculated for eight wells with well log data. Among these eight wells, average net pay thickness accounts for 25.3% of average net reservoir thickness. The majority of this potential reservoir is found in well A-42 where the net reservoir thickness is 50.6 m (Fig. 16a). Average porosity over reservoir intervals ranges from poor to fair, and average permeability ranges from fair to very good. Most notable is the average permeability of 733.3 mD over 50.6 m of net reservoir in A-42 (Figs. 16a,b). Net pay is found only in well A-42, where average porosity over this 17.2 m interval is fair and average permeability exceptional at 2046.0 mD (Figs. 16c,d). This high permeability suggests, like the Landry Formation, porosity could be associated with fracture zones within the formation.

The Peel Formation was tested 11 times among six wells in the Yukon Peel region. Of note is DST #1 in well F-37, at a depth of 3319.3-3368.0 m (10890-11050 ft) below KB over the basal 8 m of the Peel Formation and upper 41 m of the Mount Kindle Formation, which recovered 137.2 m (450 ft) mud, 1388.1 m (4554 ft) slightly gassy salt water, 109.7 m (360 ft) slightly gassy muddy salt water, 9.1 m (30 ft) gassy mud (in the top of the Mount Kindle) and 914.4 m (3000 ft) fresh water (Indian and Northern Affairs, 1972b). In well H-71, in the interval between 2724.9 – 2892.6 m (8940 – 9490 ft) below KB, DST #2 reported gas to surface in 32 minutes at a rate of 1841 m^3/day (65 mcf /day), and had recoveries of 109.7 m (360 ft) water cushion, 1033.3 (3390 ft) gassy mud, and 710.2 m (2330 ft) gassified salt water, over the basal 58 m of the Peel Formation and the upper 109.5 m of the Mount Kindle Formation (Indian and Northern Affairs, 1977). DSTs from the Peel interval in wells A-42, K-15 and C-60 recovered only mud and/or muddy water (Indian and Northern Affairs, 1972c, 1969, 1972a). From outcrop studies, Gal and Pyle (2009) identify the Peel Formation as having limited reservoir potential throughout the Peel region, stating that it generally lacks porosity, with minor exceptions in sucrosic, fine and medium-crystalline dolostones. This study demonstrates that the Peel Formation in well A-42 has some reservoir and pay potential, and that there may be gas associated with the formation as shown by the DST results in H-71 and F-37.

The Arnica Formation ranks 10th out of 14 formations analysed in terms of average net reservoir thickness, and 6th in terms of average net pay thickness (Figs. 20 and 21 respectively). The average net reservoir thickness of the Arnica Formation among five wells spanning both northeast and northwest

Yukon Peel region is 3.3 m. The average porosity over these zones is poor to fair and the average permeability fair. Net pay is found in only one well, K-15 (Fig. 14c). Average porosity over this net pay interval is fair, and the average permeability is borderline fair to good. Averaged over 5 wells, net pay thickness accounts for 18.2% of the net reservoir thickness in this formation.

Regarding lower Paleozoic dolomites in the Peel region, Pugh (1983) identifies porous sucrosic dolomites of the Arnica Formation as having the greatest potential for oil and gas. He reports that Arnica Formation dolomites in NWT are often oil-stained, or have an oily odour. In addition, several wells in the Arctic Red River area have recovered gas-cut mud or water from the Arnica Formation. Further, well H-47[15] tested gas to surface at a rate of less than 2832 m^3/day (100 Mcf/d)). Gal *et al*. (2009a) define an Arnica-Landry Platform play and identify potential reservoirs in the Arnica Formation as porous dolostone with porosities of 3-10%, and permeabilities of 1-2 mD over gross intervals of tens of metres. They also compile DST results from wells in the NWT's Peel region which have reported gas and oil shows in the Arnica Formation. DSTs in Arnica strata in the Yukon Peel region in wells C-60 and F-37 recovered only mud and water (Indian and Northern Affairs, 1972a and 1972b). Only five of 17 wells in this study penetrate the Arnica Formation. As a result, there is insufficient information to support Pugh's optimistic view of the Arnica Formation as a hydrocarbon-bearing unit in Yukon; however, DST results from NWT and the Gal *et al*. (2009a) study necessitate further examination into the prospectivity of this formation.

Although the Franklin Mountain and Mount Kindle formations rank 6th and 8th of 14 formations analysed respectively, in terms of average net reservoir thickness (Fig. 20), no pay zones were found in either of these formations. Little well data exist for these formations as only five wells have logs over the Mount Kindle interval and three over the Franklin Mountain interval. This paucity of well data likely contributes to an under-ranking of these units in the basin.

Only 40.7 m of net reservoir thickness was identified in the Mount Kindle Formation, whereby the majority was divided between wells N-25 and A-42. Average porosity over these intervals is fair. Average permeability is mainly fair, with an exception in A-42 where the value is very good at 430.4 mD (Fig. 17b).

Several tests in the Mount Kindle Formation have recovered water and minor gas shows, suggesting reasonable porosity and permeability. Of note is DST #1 in well F-37, at a depth of 3319.3-3368.0 m (10890-11050 ft) below KB, over the basal 8 m of the Peel Formation and upper 41 m of the Mount Kindle Formation, which recovered 137.2 m (450 ft) mud, 1388.1 m (4554 ft) slightly gassy salt water, 109.7 m (360 ft) slightly gassy muddy salt water, 9.1 m (30 ft) gassy mud (in the top of the Mount Kindle Formation) and 914.4 m (3000 ft) fresh water (Indian and Northern Affairs, 1972b). In well H-71, in the interval between 2724.9 and 2892.6 m (8940 and 9490 ft) below KB, DST #2 recovered 109.7 m (360 ft) water cushion, 1033.3 (3390 ft) gassy mud, and 710.2 m (2330 ft) gasified salt water, over the basal 58 m of the Peel Formation and the upper 109.5 m of the Mount Kindle Formation (Indian and Northern Affairs, 1977). This test indicated high permeability over the zone tested, and reported gas to surface in 32 minutes and a 1.5 m (5 ft) lazy surging flame at surface. The gas amount was too small to measure, but flow was estimated at 1841 m^3/day (65 mcf/d). Despite the low ranking of the Mount Kindle Formation in this study, the DST recoveries suggest there is potential for gas accumulations in this formation. Further exploration is required to adequately assess Mount Kindle Formation potential.

15 The UWI for this well is 300H47655012900.

A total of 28.8 m of net reservoir was identified in the Franklin Mountain Formation. The majority of net reservoir was found in well A-42 (94%) and a minor component in H-71 (6%). Average porosity in these intervals is fair, and average permeability is very good. Gas shows in wells include DST #1 from well N-25 at a depth of 3014.5-3154.7 m (9890-10350 ft) which recovered 335.3 m (1100 ft) slightly gassy mud and 1585.0 m (5200 ft) water (Indian and Northern Affairs, 1974c). DST #2 from the same well, and approximately over the same interval, recovered 30.5 m (100 ft) water-cut mud and 121.9 m (400 ft) gas-cut mud.

Pugh (1983) comments that intercrystalline porosity is a regional feature of the platform carbonates, notably in the Franklin Mountain, Mount Kindle and Arnica dolomites. Based primarily on field observations, Pyle and Gal (2009) describe the Mount Kindle and Franklin Mountain formations as mainly composed of finely crystalline dolomudstone, which is poorly porous to tight, recognizing, however, that fracture porosity may occur locally. They identify a conceptual hydrocarbon play (Lower Paleozoic Platform Play) of potential pools and prospects hosted in vuggy, fractured, and otherwise porous dolostones of the Mount Kindle and Franklin Mountain formations. The play is described as conceptual because there have been no discoveries, and only a few minor shows, despite several tests of these formations (Gal *et al*., 2009b). In addition, they suggest this play carries a high exploration risk in the Peel area.

Despite the low ranking of the Mount Kindle and Franklin Mountain formations in this study (likely based on the lack of well data), the DST results offer some encouragement in that these formations could contain porous and permeable intervals that are charged with hydrocarbons (*i.e.*, gas).

The Tatsieta Formation is the poorest-ranking carbonate in this study (Figs. 20 and 21). Only 14.9 m of net reservoir was identified in the study, spread over four wells, two in the northern part of Yukon Peel region, and two in the south. No net pay was identified within these reservoir zones. Average porosity over reservoir intervals is poor to fair. Average permeability over the same intervals is slightly better and has values in the fair to good range. Of note is the average permeability of 94.3 mD over 5.5 m of net reservoir in well A-42 (Figs. 15a,b). Other than this single high permeable interval, the Tatsieta Formation has no other indication of being a hydrocarbon exploration target. In addition, Gal and Pyle (2009) identify the Tatsieta Formation as having limited potential as a reservoir rock based on their analysis of outcrop and well data.

CONCLUSIONS

The aim of this conventional reservoir petrophysical property assessment is to bring attention to particular geological formations in the Yukon Peel region that have the potential of hosting economic quantities of natural gas and/or oil. While the study was limited by the well log data available (only 17 wells covering an area of over 10 000 km^2), and the dominance of well penetration in upper Paleozoic and younger formations, it does highlight certain prospective formations, and identifies areas requiring further exploration.

Included in this report is a subjective overall formation ranking, using a combination of average net reservoir and average net pay thicknesses derived from this study, along with DST information, formation/member depths, and unconventional resource potential. Table 8 provides the formation ranking, and also includes information about the amount of data available for each formation/member (*i.e.*, number of wells with log data). Also tabulated by formation/member are average net reservoir

Table 8. Overall rank of formation/member in terms of conventional hydrocarbon prospectivity as determined in this study. The table includes information about data availability for each formation (well penetration and log coverage) and tabulates average net reservoir and average net pay on a formation/member basis, and descriptions of average porosity and permeability over net reservoir and net pay intervals. Comments about hydrocarbon prospectivity for each formation/member are mentioned in the final column. The rank of each formation was determined subjectively by a combination of cumulative net reservoir and pay thickness values, DST data, depth to formation, and possibility for unconventional potential. Asterisks (*) indicate values which include Road River equivalent strata in two wells. Crosses (+) indicate values which include Road River equivalent strata in one well.

Overall rank for conventional hydrocarbon prospectivity	Formation or member	Number of wells which penetrate formation	Number of wells with full or partial log coverage	Number of wells with net reservoir	Cumulative net reservoir thickness (m)	Average net reservoir thickness (m)	Average porosity over net reservoir intervals	Average permeability over net reservoir intervals	Number of wells with net pay	Cumulative net pay thickness (m)	Average net pay thickness (m)	Average porosity over net pay intervals	Average permeability over net pay intervals	Percentage of average net reservoir that qualifies as net pay	Comments about formation/member prospectivity
1	Tuttle	17	14	14	753.1	53.8	fair to very good	fair to very good	13	261.3	20.1	fair to good	fair to good	37.4	prospective for gas and oil; oil-stained sandstone observed in field samples; DST with minor gas shows; noteworthy hydrocarbon charge of reservoir rock (37%); proximal to outcrop and may be susceptible to freshwater flushing; report of bitumen plugging; lack of seal at top of formation; shales of Tuttle and equivalent Ford Lake Shale formations may be prospective for unconventional hydrocarbons
2	Landry	10*	10*	7*	206.6*	20.7*	poor to fair	fair to very good	3^{+}	26.1^{+}	2.6^{+}	fair to very good	good to very good	12.6	prospective for gas; extremely high permeabilities in two wells; minor gas shows in drilling/DST reports; fractures appear to play a major role in reservoir development
3	Arctic Red	12	9	8	121.7	13.5	fair to very good	fair to very good	2	5.4	0.7	good to very good	fair to very good	5.2	notable porous and permeable strata identified; shallow formation, therefore less costly to explore, but may also be subject to freshwater flushing; shale-rich formation that could be studied for unconventional hydrocarbon potential
4	Martin House	14	9	8	97.5	10.8	fair to very good	fair to very good	4	8.8	1.1	fair to very good	fair to good	10.2	prospective for oil and gas; oil-stained sandstone observed in field samples; gas associated with the sub-Cretaceous unconformity in one DST report; thin unit
5	Imperial	12	12	10	197.3	16.4	fair to good	fair to good	1	4.7	0.4	good	good	2.4	substantial reservoir intervals in formation, however only a small portion are hydrocarbon-charged; minor gas reported in one DST report and bitumen observed in outcrop in NWT north of the Peel region; appears more prospective to west in NWT; thick, shale-rich formation that could be studied for unconventional hydrocarbon potential
6	Peel	8*	8*	7^{+}	69.7	8.7^{+}	poor to fair	fair to very good	1	17.2	2.2	fair	very good	25.3	prospective for gas; minor gas shows in DST reports; noteworthy average hydrocarbon charge of reservoir rock (25%); outcrop studies suggest it generally lacks porosity
7	Arnica	5	5	5	16.5	3.3	poor to fair	fair	1	3	0.6	fair	fair to good	18.2	notable gas recoveries from DST results in NWT suggesting further examination of formation
8	Hume	10*	10*	6	65.7	6.6	poor to fair	fair to good	1	5.9	0.6	fair	good	9.1	poor conventional reservoir unit; possible conceptual play in reef build-ups along the Devonian Mackenzie-Peel Platform margin although these plays have been unsuccessful in NWT
9	Mount Kindle	5	5	4	40.7	8.1	fair	fair to very good	0	0	0.0	n/a	n/a	0.0	little well information; minor gas shows in DST reports; deep formation, therefore costly to explore
10	Franklin Mountain	3	3	2	28.8	9.6	fair	very good	0	0	0.0	n/a	n/a	0.0	little well information; minor gas shows in DST reports; deep formation, therefore costly to explore
11	Canol	10	10	1	0.9	0.1	fair	fair	0	0	0.0	n/a	n/a	0.0	prospective for unconventional hydrocarbons, further research strongly recommended
12	Bluefish	5	5	1	0.6	0.1	fair	fair	0	0	0.0	n/a	n/a	0.0	prospective for unconventional hydrocarbons, further research strongly recommended
13	Tatsieta	8*	8*	4	14.9	1.9	poor to fair	fair to good	0	0	0.0	n/a	n/a	0.0	not prospective
14	Proterozoic	1	1	0	0.0	0.0	n/a	n/a	0	0	0.0	n/a	n/a	0.0	not prospective

thicknesses, average porosity and permeability over average net reservoir intervals, average net pay thicknesses, average porosity and permeability over average net pay intervals, and percentage of average net reservoir that qualifies as average net pay. Brief comments about the formation/member prospectivity are given in the final column of the table.

This study concludes that the best prospects for finding hydrocarbons in the Peel subsurface are in the Upper Devonian to Lower Mississippian Tuttle Formation. The data derived from this study, combined with oil shows identified in the field and trace gas encountered in well DST reports, suggest a viable petroleum system is expected to occur in the Tuttle Formation in the Yukon Peel region, and further exploration in this unit is highly encouraged.

The Lower to Middle Devonian Landry Formation ranks as the second best prospective hydrocarbon-bearing formation in this study. Although field reports suggest the Landry Formation is dominantly a tight lime mudstone, exceptional permeabilities suggest that fractures in the formation could act as viable reservoirs and conduits for hydrocarbon migration. Trace amounts of gas in DST data, and gas kicks encountered during drilling of these strata, suggest that petroleum is present in the formation. If indeed fractures are the cause for gas accumulations in the Landry Formation, then determining the origin of the fractures and their distribution would be a useful exercise.

The Lower Cretaceous Arctic Red and Martin House formations rank 3rd and 4th respectively in this study in terms of prospectivity for hosting hydrocarbons. Hydrocarbons were identified in both formations in this study, and both formations have significant porous and permeable strata. In addition, oil-stained Martin House sandstones have been confirmed in the field. These formations are relatively shallow, therefore exploration within these units is likely relatively economic to pursue. Identification of gas associated with the sub-Cretaceous unconformity from DST data is notable, and this geologic feature (*e.g.*, Cretaceous shale unconformably overlying Carboniferous sandstone) should be considered as an exploration target. The shale-rich Arctic Red Formation should be assessed for its unconventional hydrocarbon potential.

The Upper Devonian Imperial Formation ranks 5th in this study in terms of prospectivity for hosting conventional hydrocarbons and is the least prospective of clastic units (not including Canol Formation and Bluefish Member shales). Field investigations of Imperial sandstone in the east Richardson Mountains do not favour the Imperial Formation as an exploration target; however, it has been suggested that the Imperial Formation is more prospective in the eastern Peel region, in NWT. This study has indicated that there are porous and permeable Imperial sandstone intervals in the subsurface of the Yukon Peel region. In addition, the Imperial Formation contains thick shale beds, and directly overlies the bituminous Canol Formation, suggesting the proximity of a hydrocarbon source. Despite the lack of net pay reported in the Imperial Formation in this study, the reservoir-quality sandstone and the proximal potential source rocks contribute to its 5th-place ranking.

This study ranks the upper Silurian to Lower Devonian Peel Formation as 6th overall based on thickness of average net reservoir and average net pay. This formation has been documented to have limited reservoir potential throughout the Peel region; however, this study concludes that the Peel Formation has some reservoir and pay potential, and contains some intervals with exceptional permeability. In addition, DST data report minor gas shows in two wells.

Based on average net reservoir and pay thicknesses alone, the Arnica and Hume formations were difficult to rank. In conclusion, the Lower to Middle Devonian Arnica Formation was ranked 7th and the Middle Devonian Hume Formation 8th place overall. The Arnica Formation was ranked higher based on previous encouraging reports from Arnica strata in NWT including: notable gas shows in DSTs and the occurrence of oil-stained Arnica dolostone field samples reported by Pugh (1983); and fair porosity/permeability values occurring over gross intervals of tens of metres reported by Gal *et al*. (2009a). All of these factors suggest that further examination into the prospectivity of the Arnica Formation is warranted.

In contrast to the Arnica Formation, the Hume Formation has been previously classified as a poor reservoir unit. This petrophysical analysis supports this classification. Exploration along the carbonate margin between the Richardson trough and the Mackenzie platform is suggested, where reef build-ups hosting hydrocarbons are a possibility. It should be noted, however, that reef plays have been explored in NWT without success (Osadetz *et al*., 2005).

While this study ranks the Upper Ordovician to lower Silurian Mount Kindle and upper Cambrian to Lower Ordovician Franklin Mountain formations as 9th and 10th respectively for hydrocarbon prospectivity, these formations have sparse well data on which to make a solid conclusion. They are also the deepest carbonate reservoirs meaning exploration of these units is relatively costly. Of note, these formations do contain trace amounts of gas identified in DST reports. These formations are worthy of further study and their prospectivity at this time is inconclusive.

In terms of reservoirs of a conventional sense, the Upper Devonian Canol Formation and the Middle Devonian Bluefish Member are ranked 11th and 12th respectively in this study. These formations are composed primarily of shale, and do not exceed porosity and permeability cut-offs defined in this study. The organic and bituminous nature of these shales, however, suggests that their prospectivity for unconventional hydrocarbons may be high and should be considered for further investigation.

The Lower Devonian Tatsieta Formation and Proterozoic strata are not considered exploration targets in the Yukon Peel region, and have been given a ranking of 13 and 14 respectively, in this study.

Although this petrophysical assessment has focused upon conventional reservoirs in the Yukon Peel region, the possibility for unconventional reservoirs is high, particularly for gas in the organic-rich shales of the Devonian Canol Formation and the Bluefish Member of the Hare Indian Formation. Also to consider are possible hydrocarbon accumulations in the shales of the Tuttle Formation and associated Ford Lake Shale, Arctic Red, Martin House, and Imperial formations. An unconventional hydrocarbon study of the Yukon Peel region is strongly recommended.

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Appendix A: Equations used in the reservoir petrophysical assessment.

1. Porosity equations

1.a Effective porosity:

$$\text{Phi E} = \Phi = \Phi t - (Vsh^* \ \Phi sh)$$

2. Permeability equations

2.a Wyllie and Rose (Wyllie and Rose, 1950):

$$K = (250 * \Phi^3 / S_{wirr})^2$$

2.b Coates method for permeability (Crain, 2010; modified from Coates and Dumanoir, 1974):

$$K = 5000 * \Phi^4 * ((\Phi_t - \Phi * S_{wirr}) / (\Phi * S_{wirr}))^2$$

3. Water saturation equations

3.a Archie equation (Schlumberger, 1989):

$$S_W = [(a*R_w / (\Phi_t{}^m * R_t)]^{1/n}$$

where a = 1; m = 2; and n = 2

3.b Silty Simandoux equation (unpublished; modified after Simandoux,1963; originally used by Schlumberger in the early 1970s and internally referred to as the 'V Shale Squared' equation (L. Wells, pers comm email, January 18, 2010))

$$1 / Rt = (Vsh^2 / Rsh) * Sw + (1 / (F * Rw * (1 - Vsh^2)) * Sw^n$$

where $F = a / \Phi_t{}^m$

where a = 0.62; m = 2.15; and n = 2.0

4. Shale volume calculations

4.a Larionov equation for older rocks (Larionov, 1969):

$$Vsh = 0.33(2^{(2*IGR)}-1)$$

where $IGR = (GR_{log} – GR_{min}) / (GR_{max} – GR_{min})$

5. Hydrocarbon saturation

5.a Hydrocarbon saturation = 1 – Sw

Where:

Phi E – effective porosity (fractional)
Φ – effective porosity (fractional)
Φt – total rock porosity (fractional)
Vsh – shale volume (fractional)
Φsh – shale porosity (fractional)
K – permeability (mD)
Swirr – water saturation of a zone at irreducible water saturation (fractional)
F – formation factor (unitless)
Sw – water saturation (fractional)
Rw – water resistivity (ohm-m)
Rt – formation resistivity (ohm-m)
a – tortuosity exponent (fractional)
m – cementation exponent (fractional)
n – saturation exponent (fractional)
IGR – shale volume calculated by assuming the relationship between gamma ray value and shale volume is linear (fractional)
GR - gamma-ray log reading (API units)

APPENDIX B

Log abbreviations

Wireline log abbreviations:

BS	bit size
CALI	caliper
DC	density correction
DPHI	density porosity
DRHO	bulk density correction
DT	sonic
GR	gamma ray
ILD	deep induction
ILM	medium induction
LLS	laterolog shallow
LL8	laterolog 8
LLD	laterolog deep
MINV	microlog inverse
MNOR	microlog normal
NPHI	neutron porosity
PHInls	neutron porosity, limestone matrix
RHOB	bulk density
SFL	spherically focused resistivity
SN	short normal
SN16	short normal 16"
SP	spontaneous potential

Log plot abbreviations:

Depth	borehole depth below Kelly Bushing
PhiE	effective porosity
PhiCor	porosity from core analysis
Sw	water saturation
Vsh	shale volume
Sand	sandstone
Lime	limestone
Dolo	dolostone
BvW	bulk water volume
Ki	permeability from Wyllie-Rose method
Kc or Kc_2	permeability from Coates method
Ka	permeability from Wyllie and Coates method
Kmax	permeability from core analysis