Natural Resources Canada / Ressources naturelles Canada

GEOLOGICAL SURVEY OF CANADA
OPEN FILE 8897

High Arctic basins petroleum potential, northern Canada

C.J. Lister, E.A. Atkinson, K.E. Dewing, H.M. King,
L.E. Kung, and T. Hadlari

2022

Canada

ISSN 2816-7155
ISBN 978-0-660-44155-9
Catalogue No. M183-2/8897E-PDF

GEOLOGICAL SURVEY OF CANADA
OPEN FILE 8897

High Arctic basins petroleum potential, northern Canada

C.J. Lister, E.A. Atkinson, K.E. Dewing, H.M. King, L.E. Kung, and T. Hadlari

2022

Permanent link: https://doi.org/10.4095/330203

This publication is available for free download through GEOSCAN (https://geoscan.nrcan.gc.ca/).

Recommended citation

Lister, C.J., Atkinson, E.A., Dewing, K.E., King, H.M., Kung, L.E., and Hadlari, T., 2022. High Arctic basins petroleum potential, northern Canada; Geological Survey of Canada, Open File 8897, 88 p. https://doi.org/10.4095/330203

Publications in this series have not been edited; they are released as submitted by the author.

This report is dedicated to the memory of Edward (Ted) Little,
a friend, mentor, and manager whose ideas pushed us to innovate and excel.
His smile, laugh, and support will be dearly missed.

CONTENTS

EXECUTIVE SUMMARY

Qualitative and quantitative assessments of the hydrocarbon resource potential are presented for the High Arctic sedimentary basins (HAB) study area that underlies a portion of the Arctic Ocean north and west of Ellesmere Island. The review was requested by the Department of Fisheries and Oceans Canada and the Parks Canada Agency to help inform discussions about creating marine protected areas.

The HAB study area includes parts of six distinct geological provinces, each with its own geological history and resource potential: NE Sverdrup Basin, Deformed Lower Paleozoic basins, Lincoln Sea Basin, Lomonosov Ridge, Alpha Ridge, and NW Canada Arctic Margin (Fig. 1).

The geologic setting of the study area was evaluated using published reports and geophysical surveys, as well as regional geological expertise at the Geological Survey of Canada (GSC). Quantitative petroleum resource estimates in this report were developed using the adjacent Sverdrup Basin, and rift basins around the world as analogs. Estimates were developed for each geologic province/assessment area, and reflect the varying chance of success in each area and the limited data. Results were compared to previously published estimates of petroleum resource potential in and around the study area.

The petroleum potential map (Fig. 2) is a qualitative estimate of the likely distribution of petroleum potential in the study area. The highest potential is in the thick, relatively undeformed sedimentary sequences of the Lincoln Sea Basin and the NW Canada Arctic Margin. The Deformed Lower Paleozoic, Alpha Ridge, and Lomonosov Ridge assessment areas have very low potential due to thin sedimentary cover or complex deformation.

The individual quantitative estimates for each geological province were aggregated into a total resource potential estimate for the entire Proposed Protected Area (PPA). There is a 95% chance that some petroleum exists somewhere in the PPA, and the risked recoverable[1] petroleum resource potential in the PPA is estimated to **range from 279 million barrels oil equivalent[2] (MMBOE) (44.4x10^6 m^3) at the low end (P90), to 5362 MMBOE (852.5x10^6 m^3) at the high end (P10), with a mean of 2462 MMBOE (391.4x10^6 m^3)**. The large range in the petroleum resource estimate reflects the limited data and information about geological elements necessary to generate and trap petroleum.

A qualitative map showing the potential distribution of methane hydrate saturations shows that the highest relative methane hydrate saturations are most likely present on the continental shelf and slope of the study area (Fig. 3). Quantitative estimates for methane hydrate accumulations are not given in this report due to a lack of data.

There are no existing offshore oil and gas licenses, upcoming calls for bids, or proposed project activities in the study area. No offshore wells have been drilled in the study area and there is very limited seismic data. The operating conditions for oil and gas exploration in the study area are among the most extreme on the planet due to severe ice conditions, limited operating season, and geographic remoteness.

---

[1] *Risked means the distribution described incorporates the Chance of Success and all possible results from the Monte Carlo modelling, including failure (zero resource) cases. Recoverable refers to the portion of the total resource that can be extracted with current technology – further details of in-place resources are provided in the appendices.*

[2] *Barrels of oil equivalent (BOE) is a convenient way to express the total amount of energy without distinguishing between oil and natural gas. In this study, the amount of BOEs includes both oil and natural gas, with 5700 cubic feet of natural gas converted to one barrel of oil equivalent.*

INTRODUCTION

In 2016, the Government of Canada committed to exploring with Inuit and northern partners, the establishment of a protected area within the 'last ice area' in the Canadian High Arctic region. This area is projected to retain multi-year ice in the future and potentially provide important refuge for ice-dependent and culturally significant species in the Arctic.

In October 2018, the Parks Canada Agency (PCA), Department of Fisheries and Oceans Canada (DFO), and the Qikiqtani Inuit Association (QIA) reached an agreement in principle that committed the parties to, among other things, work collaboratively with the Government of Nunavut (GN) to advance consideration of permanent protections in the High Arctic Basins (HAB) located in the 'last ice area', including the consideration of potential interim protection measures under the *Oceans Act*.

Assessment of the non-renewable resource endowment contributes to the decision-making process around conservation. This report provides a qualitative resource potential map showing the most likely locations of petroleum resources, as well as quantitative estimates of the petroleum resource potential for each geologic province and the Proposed Protected Area. Details of the input parameters and resource assessment analyses are provided in the appendices.

GEOLOGIC SETTING

The offshore area in the inter-island channels between the northernmost Canadian Arctic Islands and extending northward and northwestward into the Arctic Ocean, is underlain by six separate geological provinces. The boundaries between assessment areas are based primarily on the interpretation of gravity and magnetic potential field geophysical maps in Anudu et al. (2016), Oakey and Stephenson (2008), and from geologic mapping onshore. The level of geological information is very low, so assessment areas are treated as fairly geologically homogenous because they cannot be mapped in detail. In some areas, the geology could be analysed in a bit more detail using the 'play' concept. A play is a family of prospects and/or discovered fields that share a common geologic history, and similar 'petroleum system elements': source rocks, hydrocarbon generation and migration, reservoir development, and trap and seal configuration. A play forms a natural geological population limited to a specific area. See Appendix A for details of how assessment boundaries were chosen.

Area 1. NE Sverdrup Basin – HALIP Influenced

The Sverdrup Basin is an intracontinental basin that underlies the northern Canadian Arctic Islands. There is an extensive seismic grid in the western part of the basin (Fig. 4), and about 125 drill holes and 19 gas or oil discoveries (Fig. 5). Nansen Sound, which is part of the Proposed Protected Area, extends into the Sverdrup Basin.

The Sverdrup Basin is made up of Carboniferous to Cretaceous carbonate, evaporite, and clastic strata up to 13 km thick. Carboniferous evaporite strata accumulated in the centre of the Sverdrup Basin during the early stages of rifting. As the Sverdrup Basin deepened, shallow-water carbonate deposits formed around the margin with correlative deep-water shale and chert in the basin center (Embry and Beauchamp 2008). The depositional realm changed in Early Triassic time with clastic strata becoming dominant. Thick Lower Triassic deltaic and basinal strata accumulated (Embry and Beauchamp 2008). Middle Triassic transgression deposited shale units of the Schei Point Group above the deltaic complex. The Schei Point Group contains potential oil-prone hydrocarbon source rocks (Obermajer et al., 2007). In Late Triassic and Early Jurassic time a deltaic system prograded from the northeast (Heiberg Group; Embry 1982). This deltaic complex forms the main reservoirs in the Sverdrup Basin. The basin accumulated mainly mud and silt from late Early Jurassic to the beginning of the Late Jurassic (Embry 1993). These shale units form the seal for the discovered hydrocarbon accumulations.

The modern Arctic Ocean rift margin formed by the rotation of Alaska-Chukotka away from Canada in Jurassic-Cretaceous time. Sediment supply increased during the Cretaceous starting with fluvial sandstones deposited during the Early Cretaceous, and followed by a rapid subsidence in the early Aptian and rapid accumulation of mud. Salt-cored diapirs rooted in Carboniferous evaporites grew at this time in the northeastern parts of the Sverdrup Basin (Jackson and Harrison 2006; Dewing et al., 2016).

Volcanic units related to the Cretaceous High Arctic Large Igneous Province (HALIP) are present in the NE Sverdrup Basin from Ellef Ringnes Island to north Ellesmere. Initial HALIP magmatism began as a minor stage of basaltic volcanism prior to 130 Ma, followed by widespread 129-125 Ma basaltic flows, and 100-90 Ma continental flood basalts of the Strand Fiord Formation (Ricketts et al., 1985; Williamson et al., 2016; Dockman et al., 2018; Dostal and MacRae, 2018) which continued as thin lava flows in the 92-90 Ma Hassel Formation (Ellef Ringnes; Evenchick et al., 2015), as well as ~80 Ma alkaline volcanics of the Audhild Bay Magmatic Suite (Ellesmere Island; Naber et al., 2020). This portion of HALIP consists of volcano-sedimentary successions and flood basalts exposed on Axel Heiberg and Ellesmere islands (Embry and Osadetz, 1988; Anudu et al., 2016), and associated dykes and sills that are widespread across the Canadian Arctic (Saumur et al., 2016).

Clastic strata were deposited over much of the Sverdrup Basin from the latest Cretaceous to mid-Eocene in response to the formation of significant relief associated with the collision of Greenland with Ellesmere Island (Harrison et al., 1999). Deformation related to the Eurekan Orogeny peaked in late Eocene time with thrust faulting and folding in the north-eastern part of the basin, and long wavelength folds and salt diapirism in the central part of the basin (Harrison et al., 1999; de Paor et al., 1989). Regional erosion across the Sverdrup Basin, either during or after the Eurekan Orogeny, is estimated between 1.0 and 1.5 km based on level of thermal maturity (Dewing and Obermajer 2011; Spiegel et al., 2011).

Hydrocarbon discoveries within the Sverdrup Basin are in structural traps in Triassic-Jurassic reservoirs, sourced from Middle Triassic organic-rich rocks. Hydrocarbon generation peaked in the Cretaceous to Paleogene. The largest discoveries lie between Sabine Peninsula and Ellef Ringnes Island in the central Sverdrup Basin. The centre of the Sverdrup Basin has passed through the oil and gas generation window and source rocks there are overmature; however, outside of the basin centre these rocks are primarily within the hydrocarbon generation window. Embry and Beauchamp (2008) and Dewing et al. (2016) predict a Late Cretaceous to Eocene timing for maximum burial so traps must be no younger than Eocene. After reaching the generation window, it is possible for hydrocarbons to have a lag time between generation and migration, even being held in secondary pools before eventual migration into their final position.

The potential of stratigraphic traps and deeper petroleum systems has not been tested. Galloway et al., (2016) published a comprehensive evaluation of potential upper Paleozoic source rocks in the Sverdrup Basin. Oil staining and gas kicks are found in numerous locations within the upper Paleozoic succession in the Sverdrup (see details in Appendix B; Galloway et al., 2016). Potential source rocks include Middle Mississippian oil-prone lacustrine and marginal marine strata, and mixed oil and gas prone organic matter in Permian formations.

There has been little investigation of the upper Paleozoic formations of the Sverdrup Basin for their potential as hydrocarbon reservoirs. Hu and Dewing (2011) found that some porosity is retained up to 5 km depth; Galloway et al. (2018) determined that oldest Permian units retained their porosity to ~2 km burial depth (current depth) while younger Permian units had prospective porosities to depths greater than

4 km (Galloway et al., 2018, their Fig. 11). Potential reservoir units include platform sandstones and platform carbonates with either fracture or dissolution porosity.

Potential trapping mechanisms within upper Paleozoic strata of the Sverdrup Basin are sub-salt sandstones or carbonates, the flanks of salt structures, shelf margin transitions, and the Permian-Triassic unconformity. The Lower Carboniferous Otto Fiord and Lower Permian Mt. Bayley evaporite formations were deposited above potential reservoir units. Salt flank plays have been identified within the Sverdrup Basin (Embry, 2011) but the petroleum systems are located on structures with Triassic to Jurassic aged reservoirs. Galloway et al. (2018) acknowledge this but suggest that there may be older, untested salt movement creating hydrocarbon traps within Paleozoic sediments.

Seals within the upper Paleozoic petroleum systems would include overlying salt formations, salt flank formations (where the reservoir abuts the evaporitic seal), and lithologic seals (tight carbonate or shale). Galloway et al. (2018) propose that the basinal van Hauen Formation shale could be a source rock, which then oversteps potential reservoir units of the Assistance Bay and Sabine Bay Formation sandstones. This type of seal (shale overstepping reservoir unit) is possible throughout the Paleozoic section. The Permian-Triassic unconformity seal requires the lowest Triassic basinal shale unit (Blind Fiord Formation) to act as a seal, creating some potential for an angular unconformity play.

Embry et al. (1983) divided the Paleozoic hydrocarbon systems in the Sverdrup Basin based on potential reservoir units, defining 11 plays. Galloway et al. (2018) used source rocks to divide their petroleum plays and defined eight plays.

Only one discovery was made in the NE Sverdrup Basin where igneous intrusions are common. On Fosheim Peninsula, just south of Nansen Sound, Romulus C-42 exploration well encountered oil in the Jurassic Awingak Formation and in the Triassic Murray Harbour and Bjorne formations as well as gas in the Jurassic Heiberg Formation. All the petroleum system elements (source, timing, reservoir, trap, and seal) present at Romulus well could be present in Nansen Sound. Hydrocarbon potential decreases northward towards the Arctic Ocean due to erosion into deeper stratigraphic units and an increase in igneous intrusions.

This area represents 138 500 km^2 (11% of the area is within the Proposed Protected Area, Fig. 1) and the chance of significant petroleum in the region is estimated at just over 50%). Mean recoverable petroleum resources are estimated at **1876 MMBOE** (298.2×10^6 m^3), with a range from low (P90) of zero to high (P10) of 5261 MMBOE (836.4×10^6 m^3).

Area 2. Deformed Lower Paleozoic Strata

Lower Paleozoic strata underlie most of the Canadian Arctic Islands, either at surface or below younger strata. In the northern Arctic Islands lower Paleozoic rocks are exposed on northernmost Axel Heiberg Island and over northern and eastern Ellesmere Island. Strata were deposited between Ediacaran and Devonian time on a continental margin (the Franklinian margin) that was initially passive, then convergent, and then part of a compressive deformation event in the Late Devonian (the Ellesmerian Orogeny). Many of the faults that formed in the Late Devonian were re-activated during the Eurekan Orogeny around 50 million years ago. Lower Paleozoic strata on northern Ellesmere were part of an offshore belt of basins and island arcs, and possibly contain structural blocks that are exotic to North America.

On eastern and central Ellesmere Island petroleum systems elements were present (source, reservoir, trap, seal). Widespread Upper Ordovician-Lower Silurian source rocks (that generated oil at Bent Horn), numerous potential reservoirs, and both evaporite and shale seals were present. Hydrocarbons were likely generated in the Late Devonian due to burial by the foreland basin that developed in front of the advancing compressive deformation (Dewing and Obermajer, 2011). Peak hydrocarbon generation likely occurred prior to structural trap formation. Subsequent Late Devonian deformation, extension, and burial by younger strata of the Sverdrup Basin, as well as uplift, deformation, and erosion related to the Eurekan Orogeny likely destroyed any hydrocarbon pools that may have formed in the Late Devonian due to leakage or biodegradation. Consequently, the hydrocarbon potential of lower Paleozoic strata in the High Arctic Basin study area is considered low.

The offshore shelf north of Ellesmere Island is underlain by less than 1 km of sedimentary strata that overlie metasedimentary lower Paleozoic rocks (Oakey and Stephenson, 2008). Low temperature thermochronology studies on northern Ellesmere (Schneider et al., 2019) show major structures cooled rapidly to <200°C around 53 million years ago and that 5-10 km of erosional unroofing took place around this time. Sedimentary strata on the Ellesmere Shelf are younger than this event, hence Eocene and younger, in agreement with locally mapped fault blocks containing Eureka Sound Formation on northern Ellesmere Island (Trettin, 1994). Given the young age and thin sedimentary succession, the hydrocarbon potential of this area is considered very low. No source rocks are known from the Eocene or younger, and the thin succession makes it unlikely that source rocks would be thermally mature. Traps, seals, and reservoir rocks may be present based on Eureka Sound Formation outcrops on Ellesmere Island (Ricketts, 1994).

This area represents 159 800 km^2 (22% of the area is within the Proposed Protected Area, Fig. 1) and the chance of petroleum in the region is estimated at only about 4% in the south part of the area, and 1% in the rest of the area. Petroleum resources were not quantitatively estimated due to the low chance of success.

Area 3. Lincoln Sea Basin

The northeastern Ellesmere-Greenland shelf is underlain by a 3-8 km thick sedimentary basin imaged on the LORITA refraction line (Fig. 2; Jackson et al., 2010). There are no other data defining this sedimentary basin besides potential field gravity and magnetic data. Seismic refraction data indicate high velocity strata below the basin, so based on analogy with the Canadian Arctic Islands these are inferred to be metasedimentary rocks of the lower Paleozoic Franklinian Margin. A moderate velocity interval is inferred to correlate with the Upper Paleozoic to Mesozoic Sverdrup Basin of Arctic Canada (around 8 km thick) and a low velocity upper layer is correlated with the Late Cretaceous to Cenozoic Arctic Margin succession (2-3 km). The Lincoln Sea Basin appears to be oval or elongate parallel to the coast of north Greenland based on gravity and magnetic maps (Oakey and Stephenson, 2008; Jackson et al., 2010).

The tectonic model of Hadlari and Issler (2019) predicts that the Lincoln Sea region subsided when the Sverdrup Rim was uplifted (see discussion of tectonics under NW Arctic Margin) due to the relative motion of North America away from Greenland-Lomonosov-Laurasia. The Lincoln Sea Basin may have avoided Eurekan deformation and uplift that removed 1 to 1.5 km of strata from the Sverdrup Basin. Magnetic maps show no evidence of high frequency anomalies that might indicate extensive HALIP intrusion into the Lincoln Sea Basin (Jackson et al., 2010).

Petroleum systems elements that are speculated to result in hydrocarbon accumulations based on analogy with the Sverdrup Basin and Barents Sea include Triassic to Cenozoic oil- and gas-prone source rocks as well as reservoirs in fluvial to shelf sandstones of Jurassic age and in fluvial to shelf sandstones of Cretaceous to Cenozoic age. Traps are most likely to be stratigraphic, possibly with salt-cored structures in the Lincoln Sea. Hydrocarbon generation likely peaked in the Cretaceous to Paleogene. One-D burial history models by Sørensen et al. (2011) indicate the top of the oil window is in Jurassic-Lower Cretaceous strata at depths of 3-4 km (Fig. 6A, Fig. 7); however, Jackson et al. (2010) show greater sediment thickness than Sørensen et al. used in their models, and Hadlari and Issler (2019) predict a slightly younger timing of maximum burial. Uncertainty also exists over the number of traps, which Sørensen et al. predicts will be 50% higher than the Sverdrup Basin, and the oil:gas ratio. A key uncertainty is the presence and behavior of Carboniferous salt. Although there is no evidence of evaporite formations in the Lincoln Sea, they are presumed present because the Lincoln Sea is thought to have similar geologic history to the contemporaneous basins to the east and west (Sverdrup Basin and eastern Barents Sea), both of which contain evaporitic formations. If salt was deposited in the Lincoln Sea Basin, it is unknown if it formed a widespread sheet like in the Sverdrup Basin or localized accumulations in half grabens like in the Barents Sea. Localized salt would result in fewer prospects in broad salt-cored anticlines as opposed to a sheet that would produce a higher number of prospects in tighter folds, diapirs, and salt flanges.

The Lincoln Sea (in Canadian Waters) represents 18 900 km^2 (all within the Proposed Protected Area, Fig. 1) and the chance of petroleum resources in the region is estimated at 58%. Mean petroleum resources are estimated at **546 MMBOE** (86.8×10^6 m^3), with a range from low (P90) of zero to high (P10) of 1601 MMBOE (254.5×10^6 m^3).

Area 4. Lomonosov Ridge

The Lomonosov Ridge is a relatively shallow water ribbon microcontinent that forms a submarine mountain belt between northern Canada and Siberia (Moore et al., 2019). Geological data from the region is limited to short cores and grab samples from the ocean floor, as well as a few reflection seismic and refraction seismic profiles (Moore et al., 2011, 2019). The assessment area boundaries are largely based on bathymetric, magnetic, and gravity data (Fig. 6B, Fig. 8). The main stratigraphic packages are interpreted from reflection data.

The Lomonosov Ridge was originally located on the northern margin of Russia where it was part of the broad Barents Sea shelf during Triassic times. By the Early Jurassic, opening of the Arctic Ocean created a passive margin succession at least 2-3 km thick along the (now) west side of the Lomonosov Ridge. Passive margin sedimentation continued through the Cretaceous and is continuous with strata in the Makarov Basin. By the Late Cretaceous, the Lomonosov Ridge began to separate from the northern margin of the Eurasian continent. Uplift related to the rift shoulder caused tilting and erosion of the passive margin succession. In the late Paleocene, the Lomonosov Ridge was fully separated from Eurasia and sedimentation resumed once the Lomonosov Ridge subsided below sea level at about 55 Ma. Cenozoic strata are about 1 km thick. Modelling of low temperature thermochronology data indicates that about 4 km of pre-rift strata were removed at the rift shoulder, and that strata deposited subsequent to the Late Cretaceous have never reached over 60ºC (Oakey et al., 2018). The extent of uplift along the Lomonosov Ridge is uncertain. The United States Geological Survey (USGS) analysis of the Lomonosov Ridge hydrocarbon potential did not include this uplift in their modelling. In addition, the impact of the High Arctic Large Igneous Province on these strata is uncertain.

Petroleum system elements could be present in the Triassic pre-rift and Jurassic-Cretaceous passive margin succession. Source rocks are known from the Triassic succession on the Barents Sea, and reservoirs are likely to be present in Triassic-Jurassic and Cretaceous strata. Maximum generation likely occurred just prior to uplift and rifting associated with the separation of Lomonosov Ridge from Eurasia. Any hydrocarbons generated at this time would have had to survive the uplift and erosion related to the rift shoulder. Cenozoic strata were not buried deeply enough to generate hydrocarbons.

The petroleum resource potential of this area is low because of the suspected uplift of the Triassic to Cretaceous section, and the thin Cenozoic sedimentary succession makes it unlikely that these are thermally mature. This area represents 32 700 km^2 (all within the Proposed Protected Area, Fig. 1) and the chance of petroleum resources in the region is estimated at 14%. Mean petroleum resources are estimated at **103 MMBOE** ($16.4x10^6 m^3$), with a range from low (P90) of zero to high (P10) of 107 MMBOE ($17.0x10^6 m^3$).

Area 5. Alpha Ridge-High Arctic Large Igneous Province (HALIP)

The Alpha Ridge – HALIP area covers both the topographic Alpha Ridge and deep water areas with complex magnetic signature interpreted as HALIP igneous intrusions (Anudu et al., 2016; Chian et al., 2016). Alpha Ridge – HALIP is an Early Cretaceous aged volcanic province that lies north of Axel Heiberg Island. The volcanic units overlap with HALIP volcanics exposed on northern Axel Heiberg and Ellesmere islands. Some geological models include attenuated continental crust within the Alpha Ridge closer to Canada. Igneous rocks are overlain by thin sediments of Late Cretaceous to Recent age that are generally less than 1 km thick (Jokat, 2003; Anudu et al., 2016; Evangelatos et al., 2017). Anudu et al. (2016) proposed that areas of subdued magnetic signature are thicker sediments (up to 2.7 km) in grabens formed by extensional faulting that post-dated magmatic activity. These grabens were not mapped in this assessment due to uncertainty over their origin and a lack of clear gravity signal.

Alpha Ridge has low petroleum potential due to the thin sedimentary cover that overlies volcanic basement. This area covers 196 400 km^2 (86% of the area is within the Proposed Protected Area, Fig. 1) and the chance of petroleum in the region is estimated at only about 4%. Petroleum resources were not quantitatively estimated due to the low chance of success.

Area 6. NW Canada Arctic Margin

The NW Canada Arctic Margin includes the marine shelf and slope areas north of Ellef Ringnes, Axel Heiberg, and parts of Ellesmere Islands. It extends offshore from the point where Mesozoic-Cenozoic strata begin to increase rapidly in thickness, extending northwest to the toe of the continental slope. To the northwest, the assessment area extends to where regional magnetic data indicate significant HALIP intrusions exist (Anudu et al., 2011), and to the southwest to where potential field data change from low amplitudes to having more variation and higher amplitude anomalies.

There is very little geological or geophysical data available for this region. There is a small seismic grid and one refraction line to the northwest, one drill hole on Meighan Island, regional potential field data including a gravity model profile, and field mapping on the adjacent Arctic Islands (Fig. 4, 5). There are no hydrocarbon discoveries or known seeps.

The rifted margin formed by the rotation of Alaska-Chukotka away from Canada in Jurassic-Cretaceous time, which resulted in the formation of the Amerasia oceanic basin. Late Paleozoic-Mesozoic strata correlative with units in the Sverdrup Basin are likely present as pre-rift strata (Fig. 9, Sobczak et al., 1986; Galloway et al., 2020). Based on analogy with offshore Banks Island where seismic images are available and the geological history is similar, Jurassic to Lower Cretaceous clastic strata occupy synrift half grabens. The oldest strata (Fig. 10) in the continuous clastic wedge making up the main rifted margin succession are likely Early Cretaceous and sedimentation was likely continuous until widespread glaciation began in the Arctic around 4 million years ago.

In the Late Cretaceous, following the rifting that formed the Arctic Ocean, Eurasia to Greenland and northern Canada formed a single tectonic plate because the Eurasia Basin, the North Atlantic, and Baffin Bay had not yet opened (Gaina et al., 2017; Hadlari and Issler, 2019). The initial motion of North America away from Greenland-Eurasia took place as i) extension and rifting between Baffin Island and Greenland, ii) extension between Ellesmere Island and the future Lomonosov Ridge, and iii) strike-slip fault motion around Nares Strait. The Arctic Ocean was already present by the Late Cretaceous so the motion of northern Canada away from Eurasia implies extension along the passive margin between the

Amerasia Basin and the western Canadian Arctic Islands, manifested as uplift on northern Axel Heiberg Island (Hadlari and Issler, 2019) and deposition of thick fluvial, deltaic and marine units of Late Cretaceous to Holocene age on the Arctic Margin. Mesozoic-Cenozoic sedimentary strata on the Arctic Margin are estimated to be 2 to 8 km thick (Fig. 4, Sobczak et al., 1986; Oakey and Stephenson, 2008; Funck et al., 2011).

Volcanic units related to the Cretaceous High Arctic Large Igneous Province (HALIP) are present from Ellef Ringnes Island to northern Greenland and into parts of the Arctic Ocean (Embry and Osadetz, 1988; Anudu et al., 2016). HALIP magmatism ranges in age from 130 Ma to 80 Ma (Evenchick et al., 2015; Dockman et al., 2018). HALIP may have affected the oldest strata in the northern part of the rifted margin in the assessment area, but the southeastern portion appears to have been unaffected; areas of significant intrusion, based on magnetic data, are not included in this assessment area.

The Canadian Arctic Islands were affected by the Eurekan Orogeny in the Cenozoic. The rotation of Greenland away from Baffin Island and subsequent northern drift of Greenland and collision with Ellesmere Island (Piepjohn et al., 2016) led to extensive thrust faults and folds, uplift and erosion, and strike-slip deformation. Eurekan folds and reverse faults are visible on seismic on Meighan Island (Brent and Embry, 1995), but the extent of Eurekan deformation along the northern part of the rifted margin is poorly known. Timing of the Eurekan Orogeny was governed by rifting in Baffin Bay. Major rifting related to the opening of Labrador Sea and Baffin Bay occurred in the Late Cretaceous to early Cenozoic (early Campanian; Dam et al., 2000; and Maastrichtian-Danian, Harrison et al., 2011). The first phase of sea floor spreading in Baffin Bay took place between 61-55 Ma (Oakey and Chalmers, 2012), followed by slow spreading in Baffin Bay during the second phase between 55-45 Ma. Sea floor spreading in Baffin Bay ceased by ~35 Ma.

Potential source rocks include Permian-Triassic units in the pre-rift succession, Jurassic-Lower Cretaceous organic rich units in the synrift succession, and Upper Cretaceous to Paleocene organic rich rocks in the thick clastic wedge. Upper Cretaceous (Cenomanian-Turonian) source rocks were deposited in a marine environment and hence more likely to be oil prone, whereas younger source rocks are likely dominated by terrestrial input and are likely gas prone. Triassic source rocks intersected in exploration wells on northern Ellef Ringnes Island are near the top of the oil window (~0.75% vitrinite reflectance). These could have had renewed gas generation if buried deeply enough (~5 km, Fig. 11).

Upper Cretaceous (Cenomanian-Turonian) source rocks are important source rocks for major discoveries around the world, including offshore Guyana, Senegal, and Morocco. Upper Cretaceous organic rich strata of the Kanguk Formation are widespread in the Sverdrup Basin. Given that the Arctic Margin had already formed by the Late Cretaceous, strata of the Kanguk Formation are considered likely present in the assessment area. This is supported by evidence of Kanguk Formation in the Meighen Island well (Crocker I-53) on the south side of the assessment area, and in dredge samples from the deep water basin on the north side of the assessment area (Clark et al., 1986). If buried deeply enough they could be thermally mature (Chen et al., 2011) and may have generated significant hydrocarbon volumes at burial depths below 3 km (Appendix C).

Reservoirs could be present in Jurassic-Cretaceous synrift grabens and Cretaceous to Cenozoic fluvial to shelf sandstones, turbidites, and fan deposits. Hydrocarbon generation took place in the Cenozoic, synchronous with or post-dating trap formation.

The NW Canada Arctic Margin area represents 82 300 km^2 (62% of the area is within the Proposed Protected Area, Fig. 1) and the chance of petroleum resources in the region is estimated at 74%. Mean petroleum resources are estimated at **2563 MMBOE** (407.5×10^6 m^3), with a range from low (P90) of zero to high (P10) of 6448 MMBOE (1025.1×10^6 m^3).

PREVIOUS RESOURCE ESTIMATES

NW Canada Arctic Margin

Four reports assessed the Arctic Margin between Amundsen Gulf and Ellesmere Island. The P50 values range between **3562** and **7950** MMBOE recoverable hydrocarbon (Table 1). The four reports that assess the Arctic Margin use different boundaries. The southern boundary is in Amundsen Gulf, and the northern boundary varies between central Banks Island (Chen et al., 2011) and Ellesmere Island (Chen et al., 2013; Houseknecht et al., 2012). The eastern boundary varies between the offshore hinge separating thin Cenozoic strata from rapidly thickening Cenozoic strata (Houseknecht et al., 2012) to the coast of the islands (Chen et al., 2013). The differing choices of boundary may account for much of the difference in assessed values. These assessments were made before researchers had access to the ION seismic dataset from offshore Banks Island and were based in large part on analogs with offshore Alaska and successions in the Beaufort Sea (Houseknecht and Conners, 2016). The GSC has recently been granted access to the ION seismic grid for the Banks margin which gives more insight into the validity of the old assessments. In particular, the old assessments likely overemphasized the importance of young (Cenozoic) potential source rock units and underemphasized older (Jurassic or Cretaceous) source rock units. The net effect of this on the quality of the assessments is unknown.

Sverdrup Basin

Seven reports assessed the Sverdrup Basin. The range of assessments that quantified both oil and gas is between **2284** and **13 326** MMBOE recoverable hydrocarbon (Table 2, Fig. 10). The main exploration target in the Sverdrup Basin was Mesozoic sandstones in salt-cored anticlines. Assessments by Chen et al. (2000; 2011; 2013) only consider these Mesozoic structural plays. Procter et al. (1984), USGS (2008) and Drummond (2009) consider both Mesozoic and Upper Paleozoic plays.

Lincoln Sea Basin & Lomonosov Ridge and Makarov Basin

There are four reports on the hydrocarbon potential of the Lincoln Sea Basin (Sørensen et al., 2011), Lomonosov Ridge and Makarov Basin (USGS 2008; Moore et al., 2011; 2019) (Table 3). Note that the 2008 USGS Circum-Arctic resource assessment has a larger assessment area boundary than the two reports by Moore et al. (2011; 2019) and includes the Siberian Passive Margin and Podvodnikov Basin. The values in Moore et al. (2019) are thought to more accurately represent the hydrocarbon resource potential as there are inconsistencies in the values reported by Moore et al. (2011). The Lomonosov Ridge was considered to have less than 10% chance of a 50 MMBOE field and was not assessed further by the USGS. The Makarov Basin (outside Canadian waters) was estimated to have **304** MMBOE.

The Lincoln Sea Basin mean assessment (total basin, only partly in Canadian waters) is **2185** MMBOE (including **6.3** Tcf of gas). Sørensen et al. (2011) makes a number of assumptions about the distribution of salt, igneous rocks, stratigraphy and lack of erosion that remain untested, so there is considerable uncertainty about this value.

Table 1. Assessed mean recoverable resources for the Canadian Arctic Margin

Report	Assessment Area	Ultimate Recoverable oil (MMBO)	Ultimate Recoverable gas (Tcf)	Recoverable Natural Gas Liquids (MMBO)	Recoverable barrels of oil equivalent (MMBOE)
3a. Houseknecht 2012	Tuk Peninsula to Ellesmere Island	2370.7	15.1	55.3	4943

1g. Chen 2013	South end of Banks to Pearya	2600	23.7	1400	7950
4a. Chen 2011	Tuk Peninsula to Banks Island	5200	15.6		7800
1f. Drummond 2009 Table 8	Arctic Coastal Plain - unrisked	1102.4	14.76		3562

Table 2. Assessed mean recoverable resources for the Sverdrup Basin

Report	Assessment Area	Reported Type	Ultimate Recoverable oil (MMBO)	Ultimate Recoverable gas (Tcf)	Recoverable Natural Gas Liquids (MMBO)	Recoverable barrels of oil equivalent (MMBOE)
5e. Chen 2011 geo-anchored	Sverdrup Heiberg structural	Median	1270.1	33.5		5589
5e Chen 2011 volumetric	Sverdrup Heiberg structural	Median	1318.4	34.0		6980
1f. Drummond 2009	ALL	Mean Unrisked	1831.3	51.67		10 443
1f. Drummond 2009	Sverdrup Basin Mesozoic	Mean Unrisked	1433.8	43.10		8617
1f. Drummond 2009	Sverdrup Basin Perm-Carb	Mean Unrisked	397.5	8.57		1826
1g. Chen 2013	Sverdrup Heiberg structural	Mean	1600	29.5		6517
1c.iii CGPC 2005	All reservoir zones - Mesozoic - Sverdrup Basin	Mean	N/A	23.15		*3858 (gas only)
1d. USGS 2008	Sverdrup Basin		1343.11	25.07		5521
5b. Chen 2000	Mesozoic structure all reservoirs	Mean	1849.76	17.66		4793
1a Procter	ALL	P50	3161	76.25		15 869
1a Procter	Mesozoic plays	P50	844	36.3		6894
1a Procter	Upper Paleozoic plays	P50	2317	39.95		8975

Table 3. Assessed mean recoverable resources for the High Arctic sedimentary basins

Report	Assessment Area	Reported Type	Ultimate Recoverable oil (MMBO)	Ultimate Recoverable gas (Tcf)	Recoverable Natural Gas Liquids (MMBO)	Recoverable barrels of oil equivalent (MMBOE)
6c. Moore 2019	Lomonosov Ridge	N/A	N/A	N/A	N/A	
6c. Moore 2019	Makarov Basin	Mean	123	0.93	25	304
6b. Moore 2011	Lomonosov Ridge	N/A	N/A	N/A	N/A	
6b. Moore 2011	Makarov Basin	Mean	123	0.74	N/A	
1d. USGS 2008	Lomonosov Ridge & Makarov Basin	Mean	1106.78	7.16	191.55	2491
6a. Sørensen 2011, Table 44.3	Lincoln Sea (includes Greenland waters) - risked	Mean	900	6.3		

PETROLEUM RESOURCE ESTIMATION

Qualitative Resource Potential Map

The GSC has developed a methodology to create qualitative petroleum potential maps by analyzing each of the plays that could reasonably exist in the study area (Lister et al., 2018). A petroleum exploration 'play' is a family of prospects and fields that share a common history of hydrocarbon source, generation, migration, reservoir development, trap configuration, and seal. The extent of four petroleum system elements for each play was mapped and the chance of success (COS) estimated:

- source (includes source rock presence and quality; generation; migration; timing relative to trap formation)
- reservoir (presence and quality)
- trap (presence, extent, geometry)
- seal (includes preservation)

When determining the COS for each petroleum systems element, data quality/calibre, data density, and confirmation of physical data was considered. COS maps reflect both the amount of available information and confidence in that information (Lister et al., 2018). The petroleum systems elements are then combined into a COS map for the play over the whole study area. Finally, the plays are weighted by an estimated global scale factor to rank their volumetric significance and global competitiveness for offshore exploration, and summed, to create a regional petroleum potential map (Fig. 2).

In order to establish the plays present, the study began with an extensive literature review. The HAB region is sparsely explored, but geological data from wells adjacent to the study area and outcrop were examined, along with refraction and reflection seismic data, and interpretations of gravity and magnetic potential field from previous studies were compiled.

Quantitative Petroleum Resource Methodology

Quantitative petroleum resource estimates were run using PlayRA software (v4-1-37), developed by Rose & Associates for use in the petroleum industry. Assessments here are based on an analog method that provides estimates of basin-scale oil/gas yields based on comparison to similar oil and gas producing sedimentary basins, in the adjacent western Sverdrup Basin, and elsewhere in the world.

The first step in quantitative analysis is to choose assessment areas. Each assessment area has a distinct geological history that produced distinct petroleum system elements, and is hence considered to have a distinct resource potential. Assessment areas are chosen on the basis of surface geological maps and geophysical data (see Appendix A). In regions of the world with more information, areas can be sub-divided with greater precision and detail into overlapping petroleum plays, but in the High Arctic whole basins are assessed together, with limited sub-plays.

Then for each assessment area or sub-play, a 'chance of success' (COS) estimate is made for five petroleum system elements (source and maturation; migration and timing; reservoir; trap; seal and preservation). Note that 'source and maturation' and 'migration and timing' are treated as distinct petroleum systems elements in the quantitative assessment. This is because 'migration and timing' were not thought to have a significantly different geographic distribution than the 'presence of mature source rocks', but were used in the quantitative report where it was needed to add some additional precision, especially regarding igneous intrusions, cross basinal migration, or long vertical migrations. The 'Play Chance' is estimated at the play/basin scale, and a second, conditional 'Prospect Chance' is chosen at the local scale. For example, source may be uncertain at the play/basin scale, but because when source rocks are present they are widespread, it is seldom a local problem. Conversely, reservoirs facies may not have been deposited or may have been cemented everywhere, providing play scale uncertainty, and in addition certain local reservoirs may have been cemented or be of poor facies when other areas succeeded, adding additional local uncertainty. Due to the lack of data in all of the High Artic Basins there is a great deal of uncertainty that petroleum systems exist at all, and thus the Play Chance for every assessment area is considerably less than 100%.

Finally, lognormal 'field size' distributions and 'number of prospects or expected fields' distributions are estimated from analogs. The western Sverdrup Basin was used as a strong analog where appropriate, and public information from rift basins elsewhere in the world was also used. Field sizes are analyzed using the 'barrels of oil equivalent' concept (see footnote in Executive Summary).

Petroleum phase (oil vs. gas) is only considered in economics. The western Sverdrup Basin is gas prone, with an oil to gas ratio of approximately 30:70. This ratio was applied to the NE Sverdrup assessment area based on analogy. No data are available on phase for other assessment areas, so a ratio of 50:50 is assumed.

These parameters are then run in a Monte Carlo simulation with 25 000 iterations, using Rose & Associates software (for further details see Appendix D). The software produces a probabilistic estimate of resource size, as a risked distribution. The risked distributions show zero resources at the small end of the distribution, at probabilities higher than the Play Chance. Results cover the entire assessment area being analyzed. These resource estimation ranges were apportioned on an areal percentage basis to the Proposed Protected Area, and statistically aggregated into an average distribution for the whole PPA.

Quantitative Petroleum Resource Estimates

The input parameters for each assessment area are in Appendix E, and detail of the output is provided in Appendix F. The risked distributions of recoverable hydrocarbons are summarized in Table 4. Table 5 provides the Play Chance and the success distributions – that is, the distribution of recoverable hydrocarbons that are estimated to be present *if* the play actually exists. It is very important to note the Play Chance associated with each success distribution, as in some areas the chance is quite low. These success distributions do provide another way to conceptualize the estimates, and are used to run economics and aggregate the results for the entire region.

Table 4. High Arctic Basins estimated total recoverable resources (Risked)

Assessment Area	**% Area in Proposed Protected Area**		**P90**	**P50 median**	**mean**	**P10**
HAB1_NESverdrup_HALIPinfluenced	**11%**	**MMBOE**	**0**	**773**	**1876**	**5261**
		10^6 m^3	0.0	122.9	298.2	836.4
HAB2_Deformed_LPaleozoic_Strata	**22%**		Play COS justifies zero resources			
HAB3_LincolnSea_CanadianWaters	**100%**	**MMBOE**	**0**	**224**	**546**	**1601**
		10^6 m^3	0.0	35.6	86.8	254.5
HAB4_LomonosovRidge	**100%**	**MMBOE**	**0**	**0**	**103**	**107**
		10^6 m^3	0.0	0.0	16.4	17.0
HAB5_AlphaRidge-HALIP	**86%**		Play COS justifies zero resources			
HAB6_NWCanadaArcticMargin	**62%**	**MMBOE**	**0**	**1256**	**2563**	**6448**
		10^6 m^3	0.0	199.7	407.5	1025.2
Totals in Proposed Protected Area		**MMBOE**	**279**	**1605**	**2462**	**5362**
		10^6 m^3	44.4	255.2	391.4	852.5

Table 5. High Arctic Basins estimated total recoverable resources (Success Cases)

Assessment Area	Play Chance		P90	P50 median	mean	P10
HAB1_NESverdrup_HALIPinfluenced	**50.7%**	**MMBOE**	**1322**	**3041**	**3696**	**6916**
		10^6 m^3	210.2	483.5	587.6	1099.6
HAB2_Deformed_LPaleozoic_Strata	4.2% and 0.9% in subareas					
HAB3_LincolnSea_CanadianWaters	**57.8%**	**MMBOE**	**176**	**738**	**945**	**2010**
		10^6 m^3	28.0	117.3	150.2	319.6
HAB4_LomonosovRidge	**13.5%**	**MMBOE**	**42**	**445**	**826**	**2212**
		10^6 m^3	6.7	70.7	131.6	351.7
HAB5_AlphaRidge-HALIP	4.2%					
HAB6_NWCanadaArcticMargin	**73.5%**	**MMBOE**	**519**	**2084**	**3487**	**7754**
		10^6 m^3	82.5	331.3	554.5	1232.7

The Monte Carlo simulations of each assessment area also estimate the size of the largest fields in each area. The chance of having large enough individual fields is significant for estimating the economic viability of a play or basin. Based on exploration history on the east coast of Canada (in easier development conditions), a cut-off of 300 MMBOE recoverable was used as a generous estimate of the minimum size of economically viable field. Table 6 outlines these probabilities for each assessment area:

- Probability of at least one large field –the overall probability that the largest field in the assessment area will be equal to or greater than 300 MMBOE recoverable, incorporates the Play Chance.
- Probability of at least one large field within the Proposed Protected Area – the overall probability X the proportion of the assessment area within the PPA.

Table 6. High Arctic Basins probability of large fields

Assessment Area	Play Chance	Probability of Large Field(s) in each assessment area	Proportion of assessment area within the Proposed Protected Area	Probability of Large Field(s) within the Proposed Protected Area in each assessment area
HAB1_NESverdrup_HALIPinfluenced	**50.7%**	**47.1%**	**11%**	**5.2%**
HAB2_Deformed_LPaleozoic_Strata	**4.2% and 0.9% in subareas**			
HAB3_LincolnSea_CanadianWaters	**57.8%**	**32.3%**	**100%**	**32.3%**
HAB4_LomonosovRidge	**13.5%**	**6.5%**	**100%**	**6.5%**
HAB5_AlphaRidge-HALIP	**4.2%**			
HAB6_NWCanadaArcticMargin	**73.5%**	**62.7%**	**62%**	**38.9%**

GAS HYDRATES

Gas hydrates are crystalline solids that trap light hydrocarbons between water molecules in an ice-like structure. They are believed to represent a large, mostly untapped, global methane resource (e.g. Kvenvolden, 1993; Johnson, 2011; Beaudoin et al., 2014). Factors that affect gas hydrate formation include pressure, temperature, and how much gas and water are available in the reservoir. Gas hydrates can form different structures depending on the gases they hold and for this report we consider 100% methane (Type I) hydrates.

There are several global and Arctic-wide estimates on the extent of methane gas hydrate stability zone (e.g. Piñero and Wallmann, 2013; Giustianini et al., 2013; Bogoyavlensky et al., 2018). However, no local qualitative or quantitative assessments are available which cover the study area. The most proximal quantitative gas hydrate study is Majorowicz et al. (2002) which gave an assessment of gas hydrate volumes in the onshore sub-permafrost Sverdrup Basin and inter-island waterways, but these are outside of the study area for this report. Smith (2001) showed a hydrate stability zone in some of the inter-island waterways in the study area, but did not include the continental shelf, slope, or deeper water.

A qualitative assessment of the methane hydrate saturation potential for the study area was produced in-house using available published and analog data and following a similar methodology to the GSC conventional qualitative petroleum resource assessment described above and in Lister et al. (2018). Using a conventional petroleum systems approach in gas hydrate resource assessment is not a new concept (e.g. Collett, 1995; Johnson, 2011; Max and Johnson, 2014; Beaudoin et al., 2014). For the GSC methane hydrate assessment in this report, three petroleum system elements were considered: (1) source, (2) reservoir, and (3) trap/seal. Source, or gas availability, is a major limiting factor in the formation of gas hydrates. Sources for a gas hydrate petroleum system can be thermogenic, biogenic, abiogenic, or a combination thereof. Source chance of success was assigned based on the thermogenic (conventional) assessment generated for this report, with consideration for biogenic gas potential where applicable. Abiogenic sources were not considered as they only form under rare conditions that are not encountered in the study area. The reservoir for a gas hydrate petroleum system includes filling available pore-space or fractures within formations, as well as forming their own reservoirs by sediment-displacement within formations and free-standing accumulations at the seafloor (mounds). In general, more permeable formations have higher saturations of gas hydrates and are also easier to produce (Beaudoin et al., 2014). The trap/seal for a gas hydrate petroleum system is geochemical and hydrates are stable wherever stability conditions exist. The methane hydrate stability curve developed by Lewin & Associates (1983; described in Majorowicz et al., 2002) predicts gas hydrates are stable at the seafloor at water depths greater than approximately 250 m in the study area (assuming a bottom water temperature of 0˚C).

Each petroleum system element (source, reservoir, trap/seal) was assessed for chance of success and mapped throughout the study area with consideration for data quality/calibre, data density, and overall data confidence. The petroleum system element maps were combined to reflect the distribution of relative gas hydrate saturation (Fig. 3). This qualitative method for gas hydrate saturation assessment will be described in more detail in a future open file.

Figure 3 shows the highest gas hydrate saturations likely occur along the continental shelf and slope in the study area.

Calculating in-place gas hydrate volumes would require more data on several parameters including thickness of the gas hydrate stability zone, how much of this zone might be occupied by hydrates (gas hydrate occurrence zones), and the porosity and gas hydrate saturation within the reservoir. Thickness of the hydrate stability zone is controlled by factors such as salinity, bottom water temperature, geothermal gradient, and gas type. Several short (~100m) drill holes distributed throughout the study area would provide better geothermal gradient measurements. However, there is currently no underwater drill in Canada capable of this length and equipment would need to be obtained from Europe. At least one mid-length (~600m) IODP-style drill hole would be required to evaluate rock properties like porosity and thermal conductivity. Core data from at least one well that sampled the gas hydrate layer(s) would inform not only the gas type and origin, but also the thickness of the gas hydrate occurrence zone and the hydrate saturation. Reflection seismic and multibeam bathymetry would be useful for detecting bottom-simulating reflectors, gas chimneys, seafloor mounds, pockmarks, etc., that could indicate the presence and spatial extent of gas hydrates. Collecting any data in this area would be very expensive and technically challenging, as described in Exploration Challenges below.

EXPLORATION CHALLENGES

Petroleum resource management on Canada's federal lands north of 60-degrees is governed under two federal statutes: the *Canada Petroleum Resources Act* (CPRA) and the *Canada Oil and Gas Operations Act* (COGOA). The High Arctic Basins study area falls within the Crown-Indigenous Relations and Northern Affairs (CIRNA) and the National Energy Board (NEB) offshore oil and gas administrative area.

Exploration History and Potential

Due to its geographic remoteness and sea ice cover, no offshore wells have been drilled in the area within the High Arctic Basin study area. Eleven exploration boreholes were drilled onshore in areas adjacent to the Proposed Protected Area (4 on Ellef Ringnes; 1 on Meighan Island; 1 on Axel Heiberg; 5 on Ellesmere Island). The last well drilled in the area was in 1974.

The High Arctic Basin study area slightly overlaps with areas that have been included in Calls for Bids for the Arctic Islands, including the last Call for Bids in this area in 2012-2013; however, industry has never nominated nor presented a bid on any parcel in the High Arctic since at least 2000. As per the 2016 moratorium on offshore oil and gas activity, there are no upcoming Calls for Bids or proposed project activities in Canada's Arctic, including the study area.

Condition Challenges

The geologic, climatic and environmental challenges are numerous in this area of the world. Multi-year Arctic sea ice covers all of the offshore Arctic Islands area, with September and October having the lowest sea ice coverages historically. Offshore exploration and development would be difficult to conduct as compared to onshore historical production in the Sverdrup Basin. Ice conditions in the Arctic Ocean are far more challenging than in the Sverdrup Basin, where multiyear ice is less common, icebergs are absent, the speed of ice movement much slower, and distance to land is much less. Seismic acquisition in the HAB area would require specialized sub-ice streamers, and two icebreakers, or would need to be shot through the ice. Rough ice reduces image quality due to echoes that come off ridges on the base of the ice. The shifting multiyear ice in the Arctic Ocean contains numerous ice ridges, making it more difficult to both plant receivers and set off sources. This challenge might be mitigated some by new acquisition technology that uses wireless receivers placed by drones, but it remains that this is one of the most severe environments to collect data on the planet. Cost of seismic acquisition would be enormous. The costs of the UNCLOS program give some point of comparison. Canada committed $109.2M between 2004-2013 to support scientific work (www.international.gc.ca/gac-amc/publications/evaluation/2019/evaluation-ecs-pce.aspx?lang=eng), including 13,000 line kilometres of seismic, to delineate the outer limits of its continental shelf.

Drill ships would be difficult to stabilize in the moving ice, increasing the risk of disruptions to drilling, or requiring a second ice vessel for support. The distance from infrastructure is also much greater; northern Ellesmere is about 1000 km from the logistical hub in Resolute Bay compared to 450 km from Resolute Bay to Ellef Ringnes Island. Even short holes needed to characterize gas hydrates would be enormously difficult to collect. Drilling in an ice-free area with the international ocean drilling project ship JOIDES would cost about $15M CDN, based on estimates from their 2020 budget (www.nsf.gov/about/budget/fy2020/pdf/40i_fy2020.pdf). Methane hydrates are stable in the study area at water depths greater than approximately 250 m (Fig. 3). If present, gas hydrates are a naturally-occurring drilling hazard if they disassociate rapidly due to pressure release or temperature change during drilling.

CONCLUSION

Qualitative petroleum potential mapping indicates that the areas of highest conventional petroleum potential in the study area are the Lincoln Sea Basin and the NW Canada Arctic Margin, whereas the Deformed Lower Paleozoic strata, Alpha Ridge, and Lomonosov Ridge have very low potential (Fig. 2).

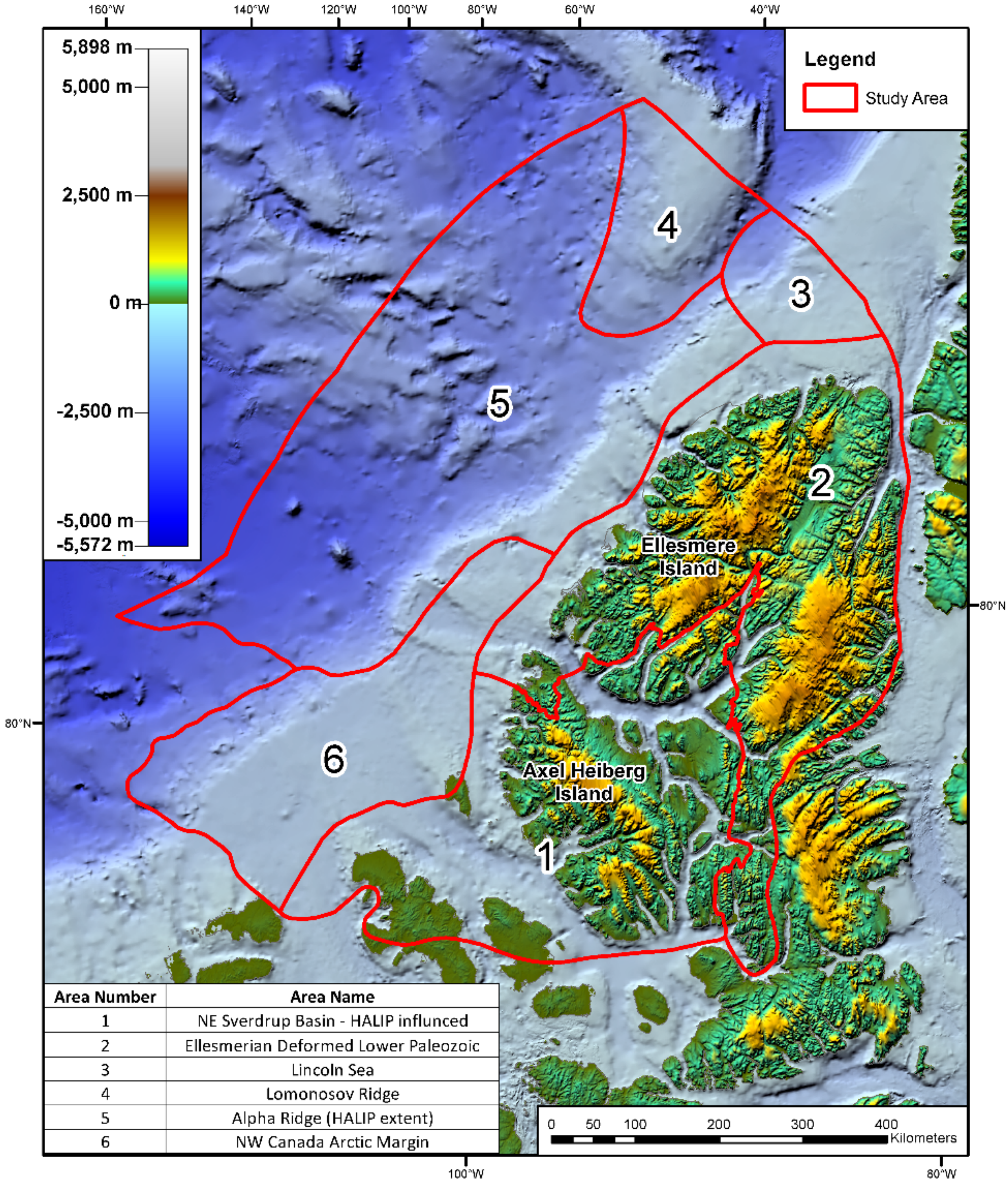
Quantitative petroleum resource modelling estimates a 95% chance that some petroleum exists somewhere in the Proposed Protected Area, and the risked recoverable petroleum resource potential in the PPA is estimated to range from 279 million barrels oil equivalent (MMBOE) (44.4×10^6 m^3) at the low end (P90), to 5362 MMBOE (852.5×10^6 m^3) at the high end (P10), with a mean of 2462 MMBOE (391.4×10^6 m^3). This is equivalent to about 493 MMBOE (78.4×10^6 m^3) to 9103 MMBOE (1447.3×10^6 m^3) in-place, with a mean of 4222 MMBOE (671.2×10^6 m^3) in-place, fully risked. 'Risked' means that the estimated range of petroleum resources fully incorporates, in each of the areas assessed, the significant chance that the petroleum systems may not exist at all (Play Chance of Success is much less than 100%). More information on 'Success Cases' is provided in Appendix F. The large range in the petroleum resource estimate reflects the limited data and information about geological elements necessary to generate and trap petroleum.

There is potential for gas hydrate resources in the study area (Fig. 3), however more work needs to be done to produce a quantitative volumetric assessment.

Acknowledgements

Thanks to Sonya Dehler, Josh Murphy, and Jeffrey Schmidtke for discussions around policy, exploration and production issues. A preliminary, unpublished assessment of the HAB area, by Marian Hanna, Jim Dietrich, Keith Dewing, Zhuoheng Chen, Thomas Hadlari and Jessica MacIntosh was used as a starting point for this report.

Quantitative assessments were conducted using PlayRA, Toolbox and Multi-zone Master software, developed by Rose & Associates for use in the petroleum industry. They are thanked for allowing the GSC to modify the code to customize outputs and graphs for our regional petroleum assessment needs.



Area Number	Area Name
1	NE Sverdrup Basin - HALIP influnced
2	Ellesmerian Deformed Lower Paleozoic
3	Lincoln Sea
4	Lomonosov Ridge
5	Alpha Ridge (HALIP extent)
6	NW Canada Arctic Margin

Figure 1. Study area and assessment areas of the Canadian High Arctic.

Elevation colour bar shown at top left, in metres above or below sea level.

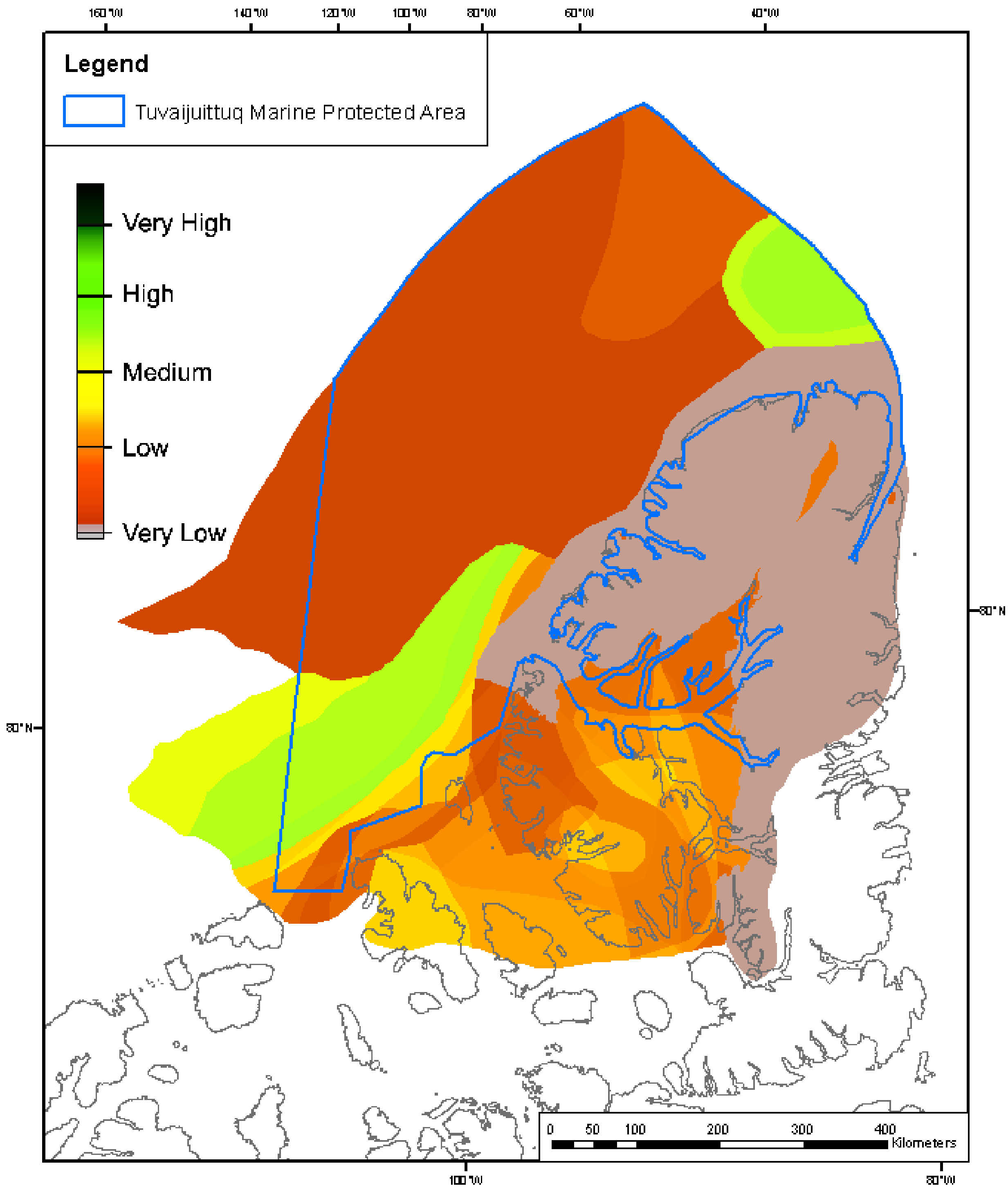


Figure 2. Qualitative Assessment of Conventional Hydrocarbon Resources.

The colour bar shows the qualitative assessment of hydrocarbon prospectivity. It is derived from the stacked chance of success of the various petroleum systems elements for each of the plays described in appendices A and E. The scale is relative but factors in both the chance of finding hydrocarbons and the size of potential discoveries.

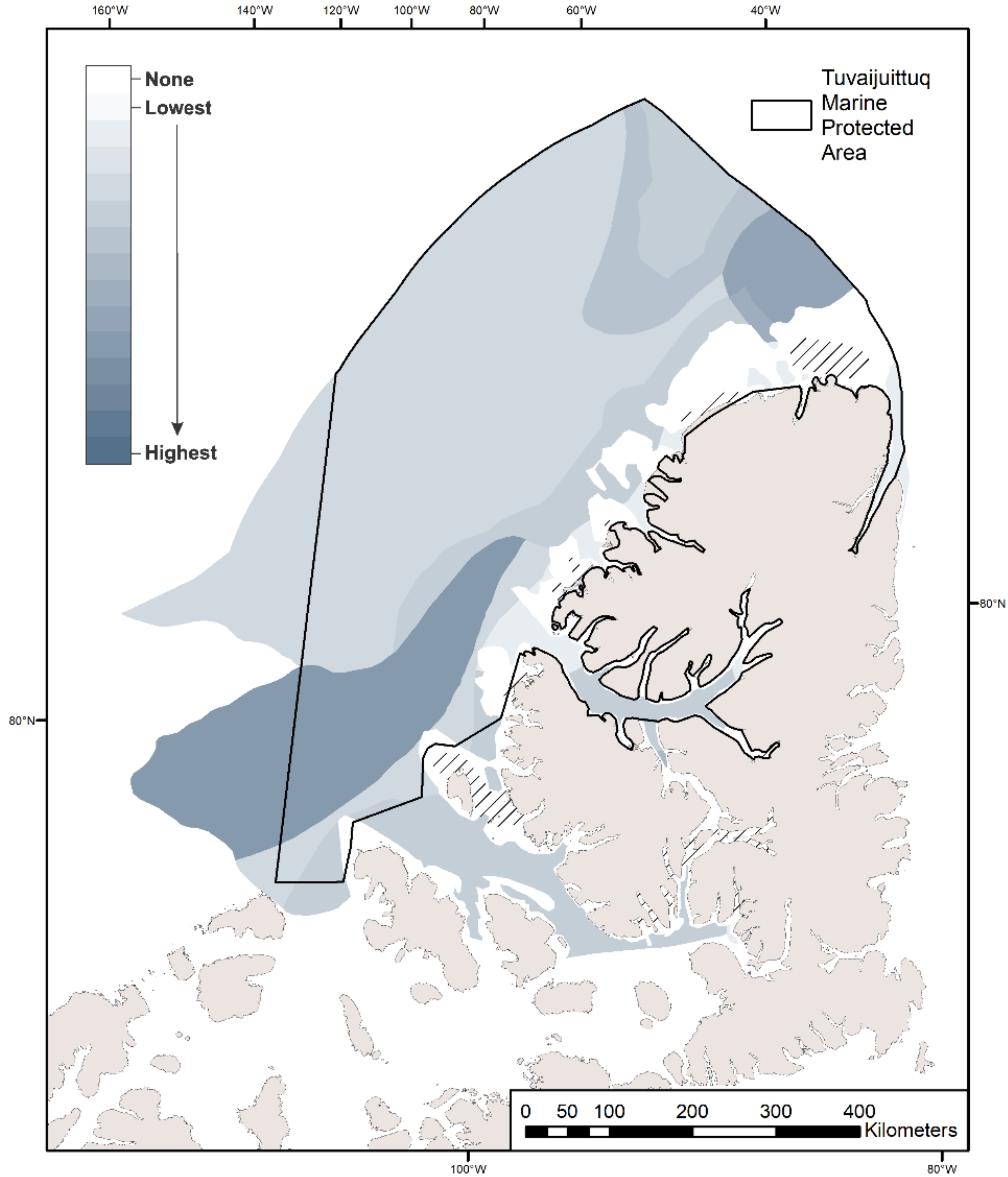


Figure 3. Qualitative Methane Hydrate Saturation Potential in Offshore Sediments

Lower to higher potential for methane hydrate saturation shown by lighter to darker blue, respectively. Hatched area shows where submarine permafrost, and associated hydrates, may be present (submarine permafrost locations from Bogoyavlensky et al., 2018, their Fig. 7). Areas with higher saturation are thought to have an effective thermogenic source and reservoir in the hydrate stability field, but the chance for thick hydrates with possible exploration interest is unknown.

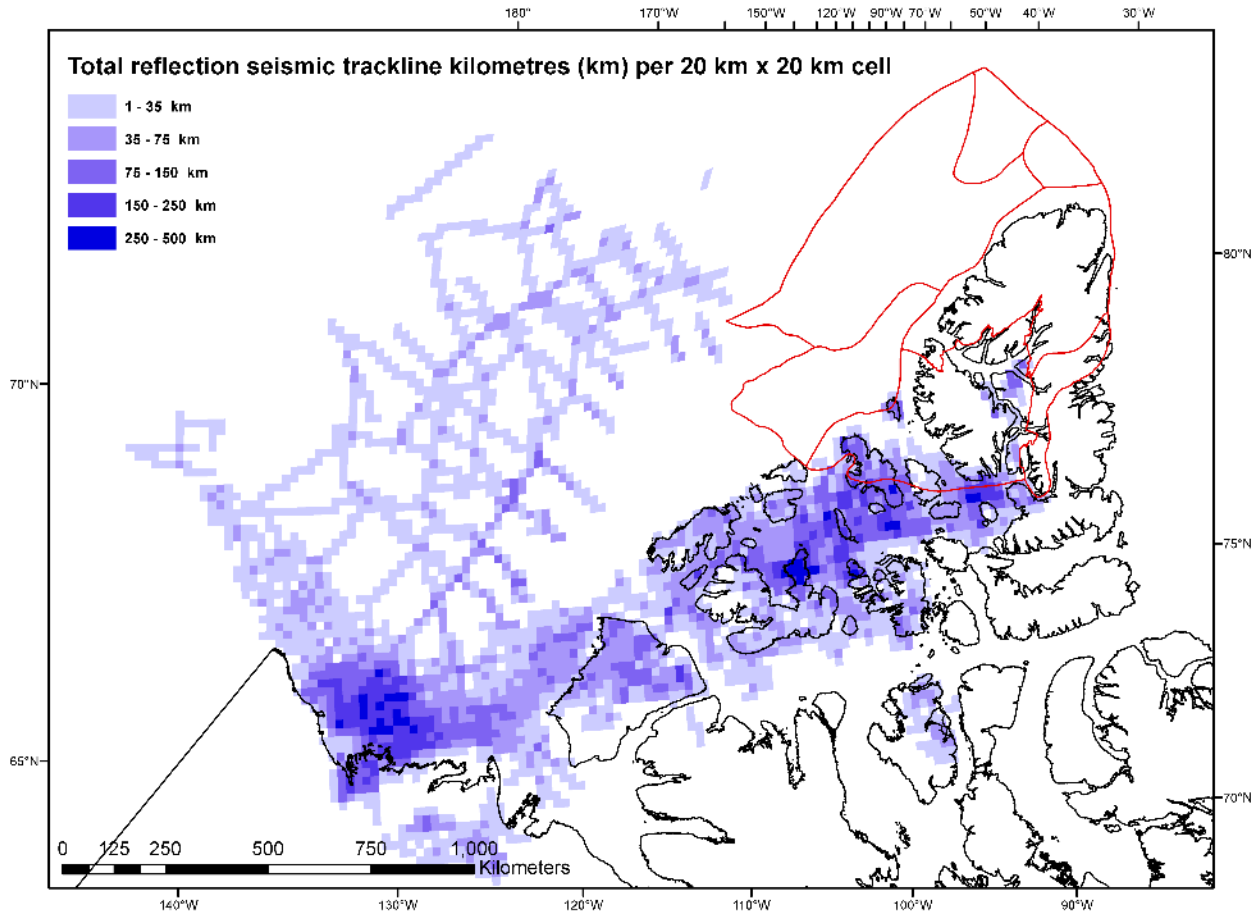


Figure 4. Reflection Seismic in the Canadian Arctic

Length of seismic lines within a 20 x 20 km grid. There is very little seismic reflection data in the offshore areas of the study area. Seismic on the Baffin Margin not included.

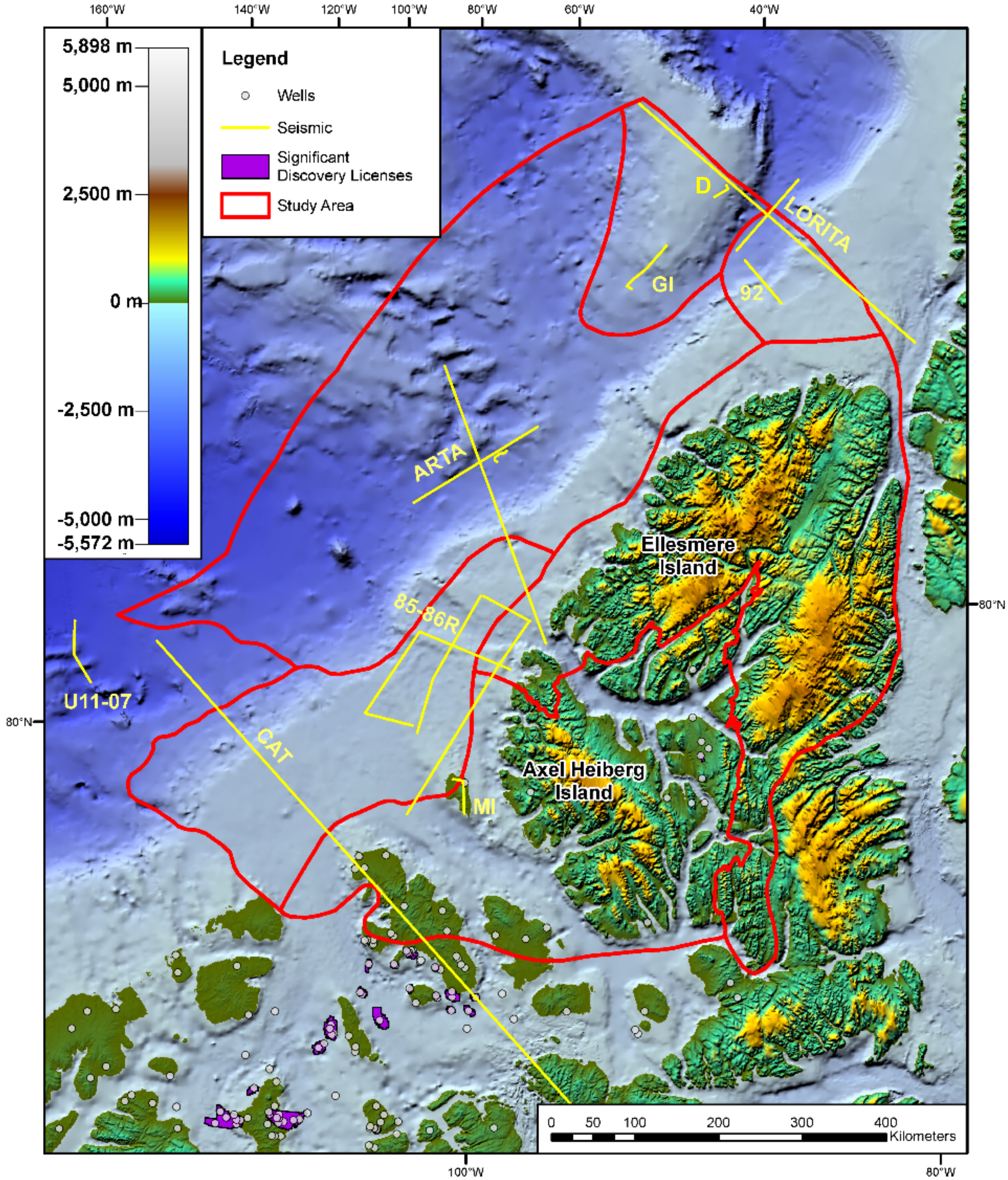


Figure 5. High Arctic Basin study area, with seismic data

Illustrated are locations of seismic refraction lines (LORITA, ARTA, 1992 shelf margin (92), 1985-86 shelf (85-86R)), seismic reflection lines (GreenICE (GI), LORITA Line D, 2011 UNCLOS (U11-07), Meighen Island (MI)), and Central Arctic gravity transect (CAT). White circles are exploration boreholes. Purple shaded areas are significant discovery licenses. Elevation colour bar shown at top left, in metres above or below sea level.

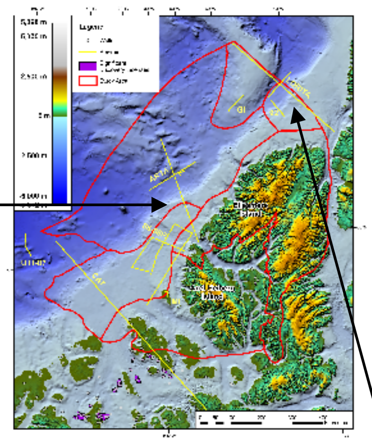
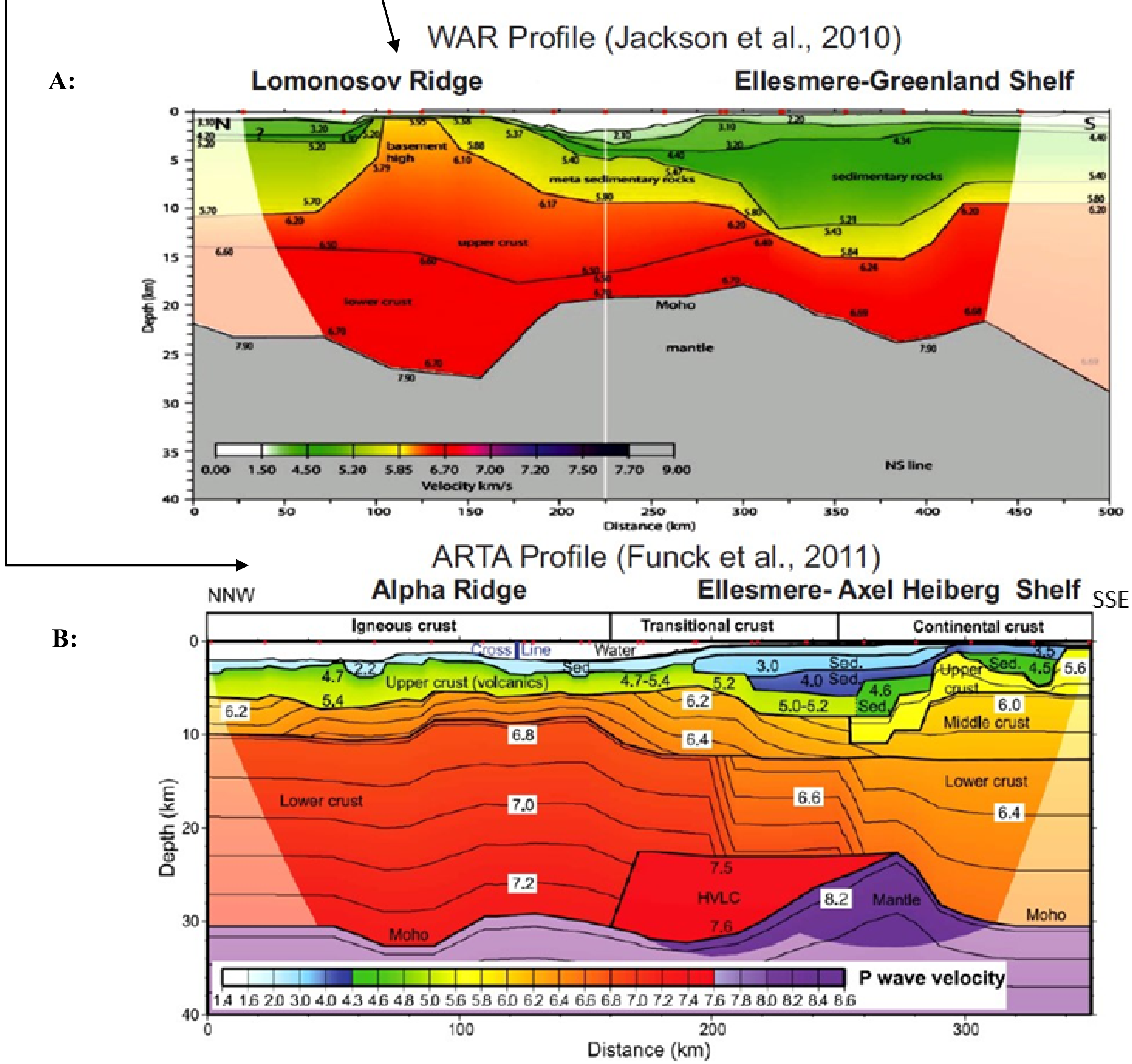


Figure 6. Refraction Profile Interpretations

A: LORITA Wide angle reflection/refraction profiles (WAR) from Jackson et al. (2010, their Fig. 7).

B: ARTA main profile from Funck et al. (2011, their Fig. 7a).

Line locations are in Figure 5.



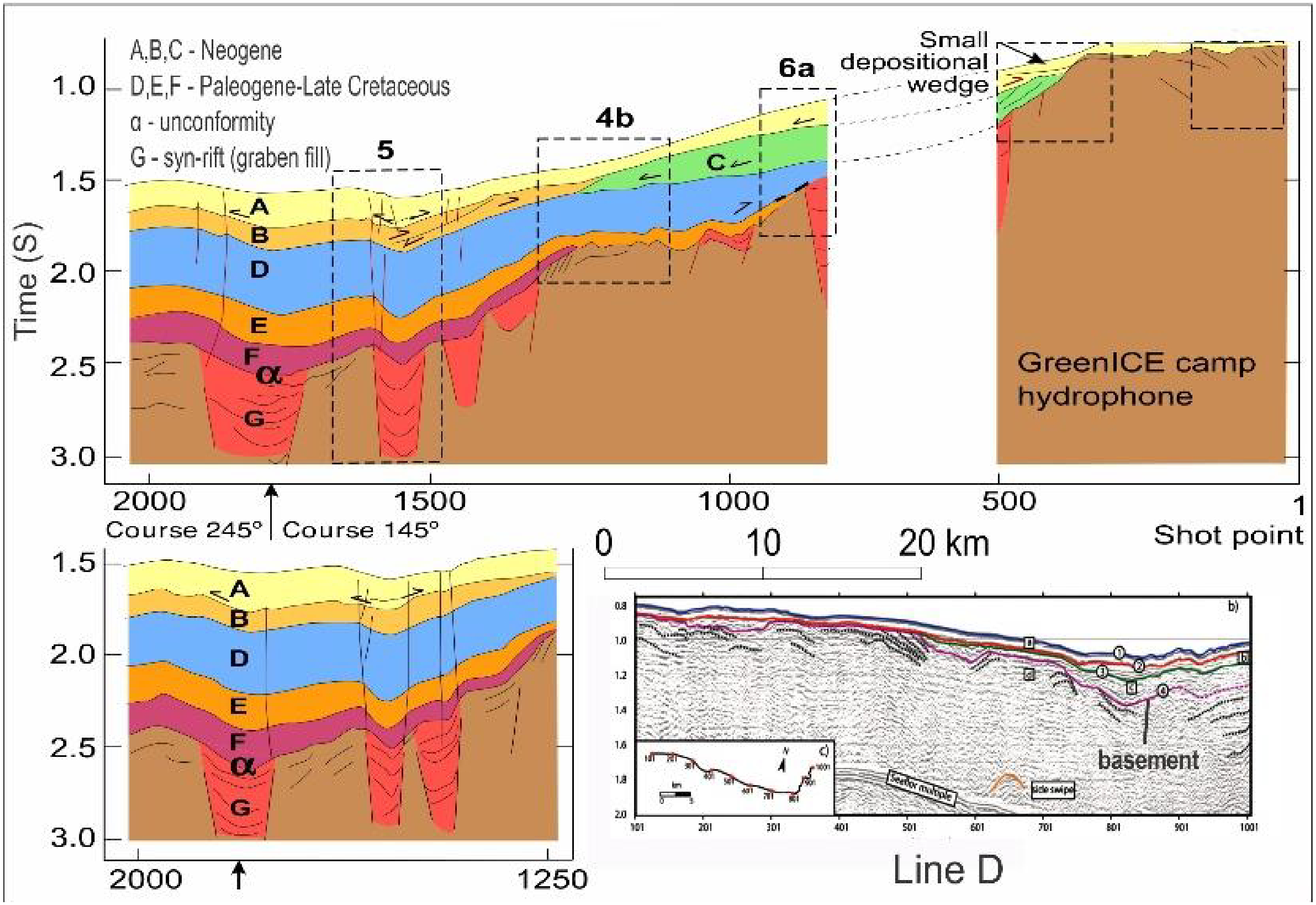


Figure 7. GreenICE and LORITA Line D Seismic Reflection Profiles, Lomonosov Ridge

GreenICE (Kristoffersen and Mikkelsen, 2006) main and cross lines show Late Mesozoic-Cenozoic sedimentary strata (up to 1 km thick) unconformably overlie synrift strata (500+ m thick). The LORITA program Line D (Jackson et al., 2010) shows the top of Lomonosov Ridge has only thin sediments preserved. Volcanic rocks form the basement in this area. Location of lines shown as GI and D on Figure 5.

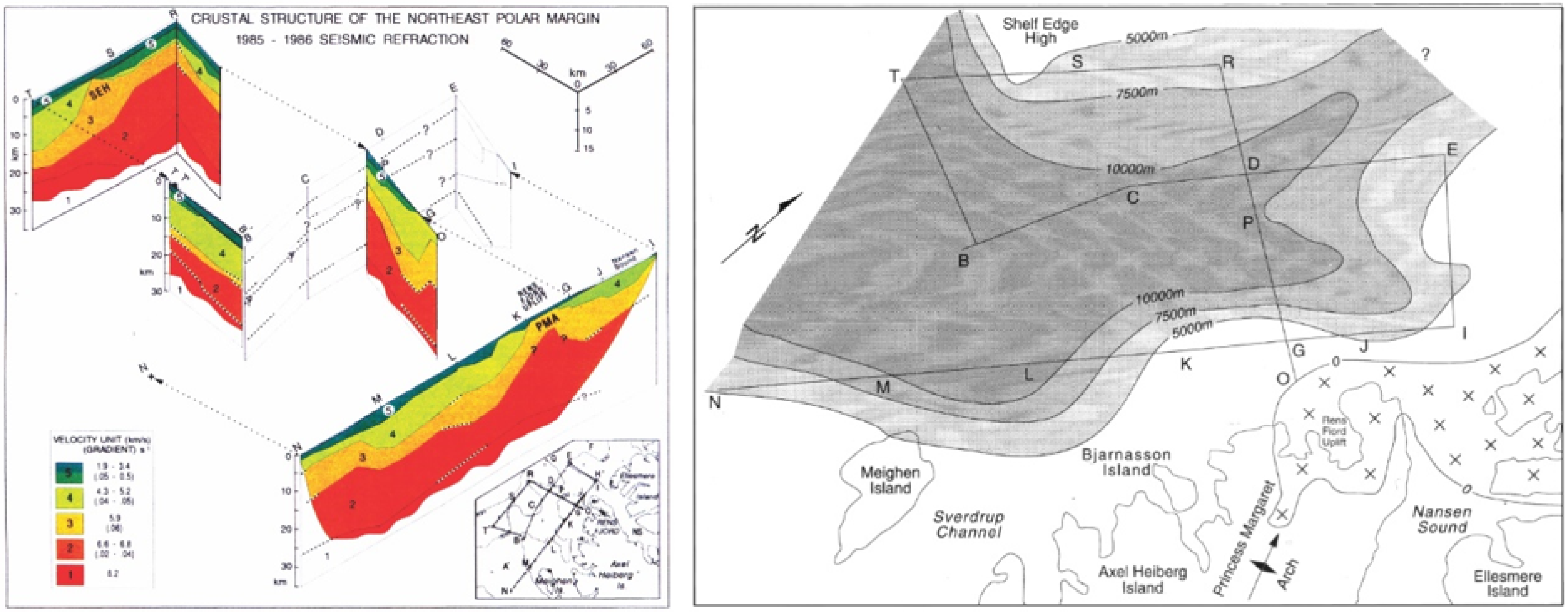


Figure 8. Velocity Models and Thickness of Sedimentary Strata from 1985-86 Polar Margin Seismic Reflection Lines

Locations in Figure 5, labelled 85-86R (Forsyth et al., 1998; their Fig. 4 and Fig. 6). Sedimentary strata are more than 10 km thick beneath the continental shelf northwest of Axel Heiberg Island. An outer shelf basement high is identified in northern data segments.

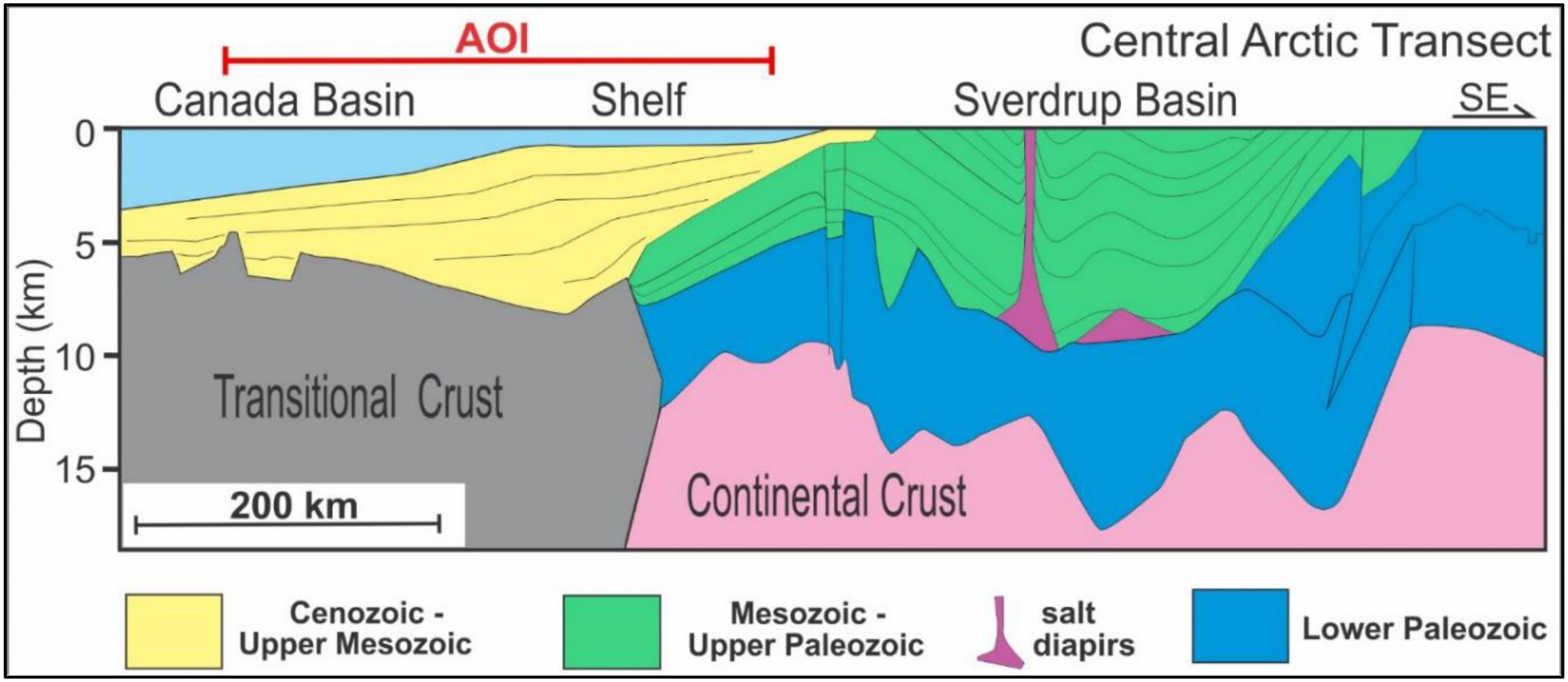


Figure 9. Central Arctic Crustal Transect (CAT)

Transect derived from gravity model and CAT refraction line (modified from Sobczak et al., 1986). Model indicates up to 8 km of Cenozoic-Upper Mesozoic sedimentary strata beneath the continental shelf northwest of Ellef Ringnes Island. Location of CAT line shown in Figure 5.

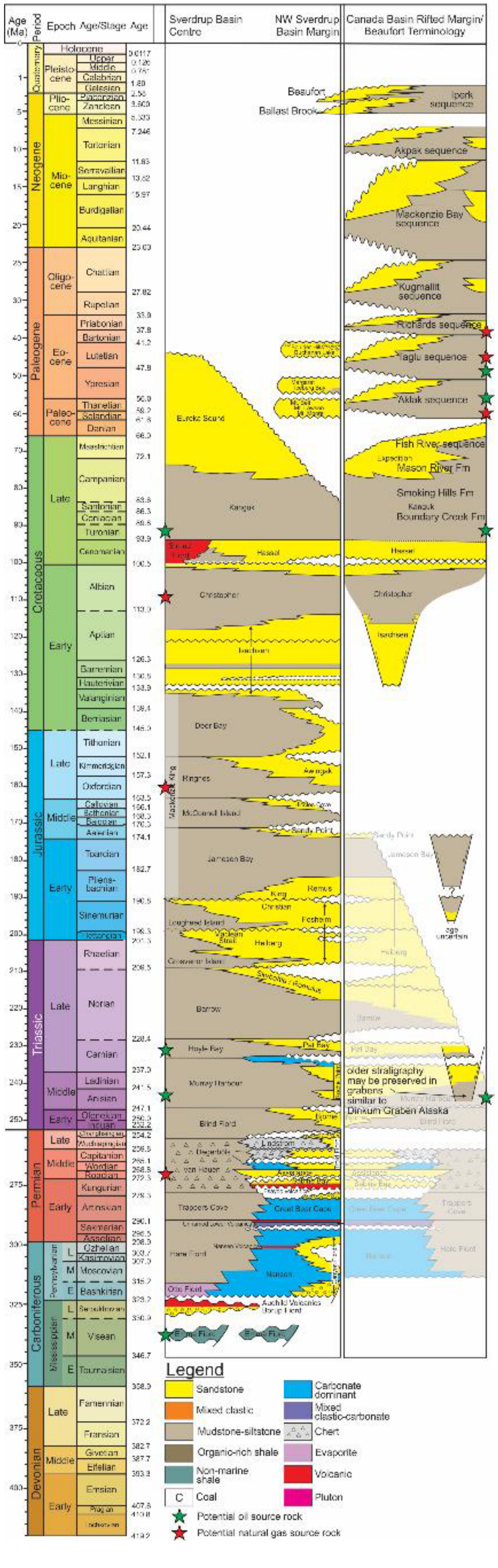
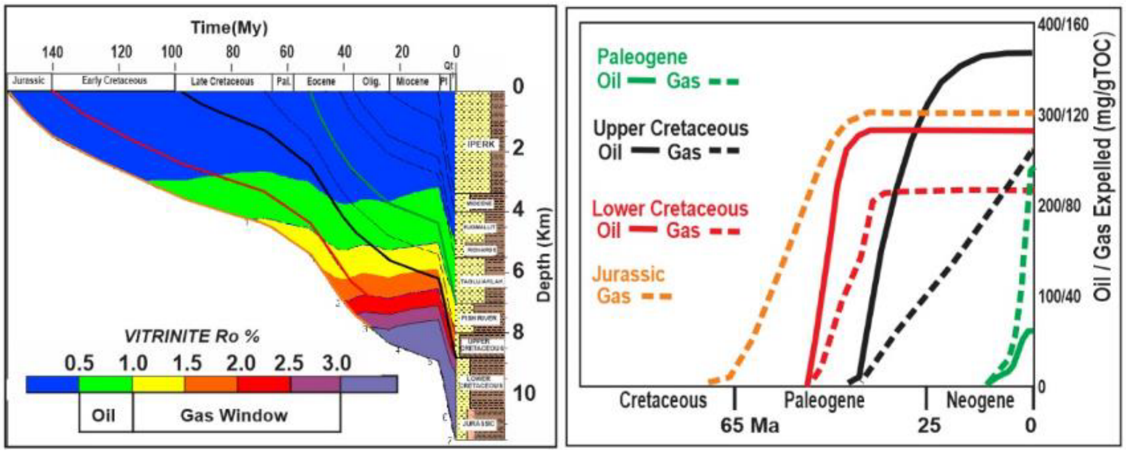


Figure 10. Late Paleozoic-Cenozoic Lithostratigraphic Chart for Sverdrup, Beaufort-Mackenzie, Banks Island, and Canada Basins

Sverdrup Basin (Hadlari et al., 2016, Embry and Beauchamp, 2008); Beaufort-Mackenzie Basin, Banks Island, and Canada Basin (adapted from Miall, 1979; Dixon and Dietrich, 1990; Fyles et al., 1994; Dietrich et al., 2018).

A:



B:

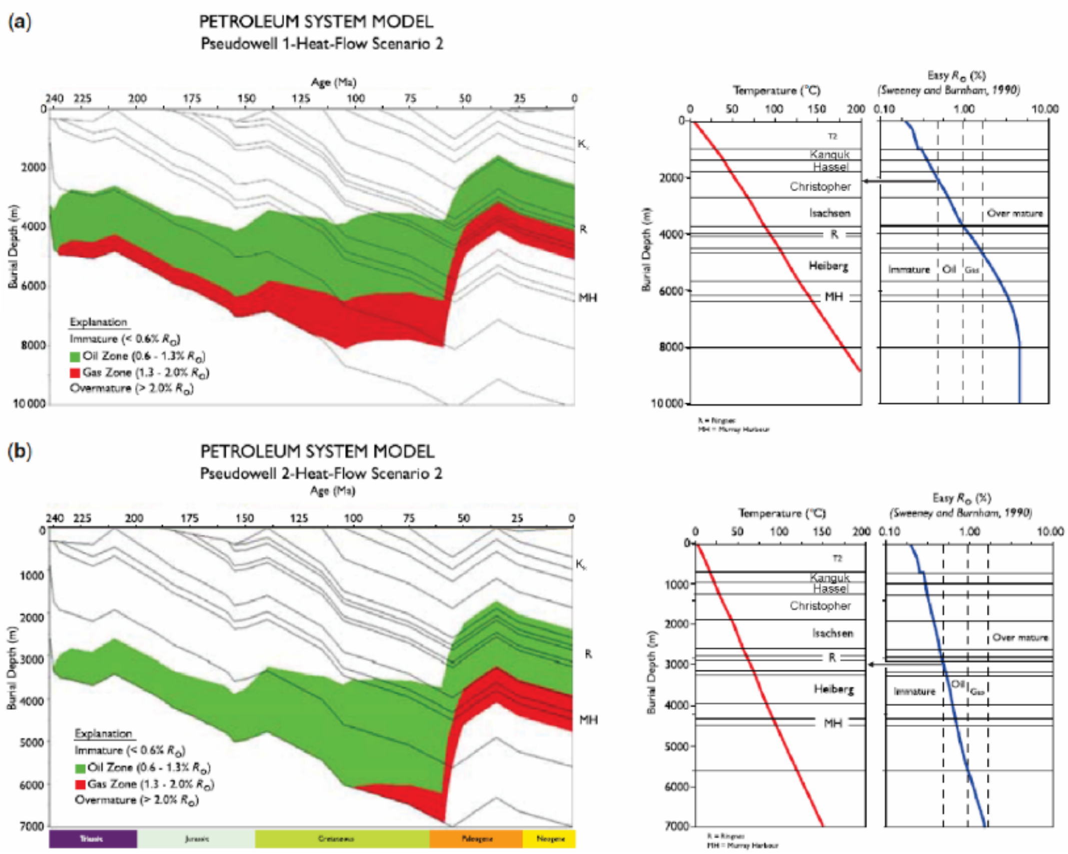


Figure 11. Subsidence, maturation and hydrocarbon generation models

A: Subsidence, maturation and hydrocarbon generation model for the Beaufort Mackenzie Basin rift margin, which may be representative of parts of the study area with thick sedimentary successions (8+ km). The model indicates significant oil generation potential from Upper Cretaceous source rocks. (Chen et al., 2011).

B: Subsidence, maturation and hydrocarbon generation model for the Sverdrup Basin into the NW Canada Arctic Margin (Sørensen et al., 2011, their Fig. 44.10). These models may be representative of the southwest and the extreme northeast end of this report's study area and include estimated heat flows in Late Paleozoic with uniform low heat through the Mesozoic and a pulse of high heat flow in the Early Cenozoic. Two thermal regimes are modelled in Sørensen et al. (2011, their Fig. 44.9 and 44.10). The authors of this report are more inclined to the second model as seen in the lower figure, (Sørensen et al., 2011, their Fig. 44.10). The top of the oil window is between the Christopher and Jameson Bay formations in these interpretations.

REFERENCES

Anudu, G.K., Stephenson, R.A., Macdonald, D.I.M, and Oakey, G.N., 2016. Geological features of the northeastern Canadian Arctic margin revealed from analysis of potential field data; Tectonophysics v. 691 p. 48-64. doi:10.1016/j.tecto.2016.03.025

Atkinson, E.A., Fustic, M., Hanna, M.C., and Lister, C.J., 2017. Qualitative assessment of petroleum potential in Lancaster Sound region, Nunavut; Geological Survey of Canada, Open File 8297, 18 p. doi: 10.4095/305321

Beaudoin, Y.C., Dallimore, S.R., and Boswell, R. (eds.), 2014. Frozen Heat; A UNEP Global Outlook on methane hydrates, v. 2. United Nations Environment Programme, GRID-Arendal, 96 p.

Brent, T.A., and Embry, A.F., 1995. Stratigraphy and structure of Meighen Island, Canadian Arctic Archipelago; *In* Proceeding of the Oil and Gas Forum 96, (eds.) J.S. Bell, T.D. Bird, T.L. Hiller, and P.L. Greener; Geological Survey of Canada, Open File 3058, p. 163-168

Bogoyavlensky, V., Kishankov, A., Yanchevskaya, A., and Bogoyavlensky, I., 2018. Forecast of gas hydrate distribution zones in the Arctic Ocean and adjacent offshore areas; Geosciences, v.8, p. 453-469.

Chen, Z., Dietrich, J., Hannigan, P., Osadetz, K., Dewing, K., Brent, T., and Issler, D., 2013. Assessment of yet-to-find petroleum resources of the Canadian Arctic; American Association of Petroleum Geologists Conference.

Chen, Z., Dietrich, J., and Liu, Y., 2011. Petroleum resource potential of the rifted margin of the Beaufort-Mackenzie Basin, Arctic Canada; Polar Petroleum Potential Conference & Exhibition, AAPG Article #90130.

Chen, Z., Osadetz, K.G., Embry, A.F., Gao, H., and Hannigan, P.K., 2000. Petroleum potential in western Sverdrup Basin, Canadian Arctic Archipelago; Bulletin of Canadian Petroleum Geology, v. 48, p. 323-338.

Chian, D., Jackson, H.R., Hutchinson, D.R., Shimeld, J.W., Oakey, G.N., Lebedeva-Ivanova, N., Li, Q., Saltus, R.W., and Mosher, D.C., 2016. Distribution of crustal types in Canada Basin, Arctic Ocean; Tectonophysics v. 691 p. 8-30, doi:10.1016/j.tecto.2016.01.038

Clark, D.L., Byers, C.W., and Pratt, L.M., 1986. Cretaceous black mud from the central Arctic Ocean; Paleoceanography, v. 1, p. 265-271.

Collett, T.S., 1995. Gas hydrate resources of the United States; *In*: Gauthier, D.I., Dolton, G.I., Takahashi, K.I., Varnes, K.I. (Eds.). National assessment of United States oil and gas resources on CD-ROM. U.S. Geological Survey Data Series, vol. 30.

Dam, G., Nøhr-Hansen, H., Pedersen, G.K., and Sønderholm, M., 2000. Sedimentary and structural evidence of a new early Campanian rift phase in the Nuussuaq Basin, West Greenland; Cretaceous Research, v. 21, p. 127-154. doi:10.1006/cres.2000.0202

Davies, G.R., and Nassichuk, W.W., 1988. An Early Carboniferous (Visean) lacustrine oil shale in Canadian Arctic Archipelago; American Association of Petroleum Geology Bulletin, v. 72, p. 8-20. doi:10.1306/703c81b9-1707-11d7-8645000102c1865d

de Paor, D.G., Bradley, D.C., Eisenstadt, G., and Phillips S.M., 1989. The Arctic Eurekan orogeny: a most unusual fold-and-thrust belt; Geological Society of America Bulletin, v. 101, p. 952-967.

Dewing, K., Obermajer, M., and Goodarzi, F., 2007. Geological and Geochemical Data from the Canadian Arctic Islands. Part III: Organic matter reflectance data; Geological Survey of Canada Open File 5476

Dewing, K., and Obermajer M., 2009. Lower Paleozoic Thermal maturity and hydrocarbon potential of the Canadian Arctic Archipelago; Bulletin of Canadian Petroleum Geology, v. 57, p. 141–166., doi:10.2113/gscpgbull.57.2.141.

Dewing, K., and Obermajer, M., 2011. Chapter 38 Thermal maturity of the Sverdrup Basin, Arctic Canada and its bearing on hydrocarbon potential; *In:* Spencer, A.M., Embry, A.F., Gautier, D.L., Stoupakova, A.V. & Sørensen, K. (eds.) Arctic Petroleum Geology. Geological Society, London, Memoirs, Volume 35, p. 567–580., doi:10.1144/m35.38.

Dewing, K., Springer, A., Guest, B., and Hadlari, T., 2016. Geological evolution and hydrocarbon potential of the salt-cored Hoodoo Dome, Sverdrup Basin, Arctic Canada; Marine and Petroleum Geology, v. 71, p. 134-148. doi:10.1016/j.marpetgeo.2015.11.024

Dewing, K., Hadlari, T., Pearson, D.G., and Matthews, W., 2019. Early Ordovician to Early Devonian tectonic development of the northern margin of Laurentia, Canadian Arctic Islands; Geological Society of America Bulletin, v.131, p. 1075-1094. doi:10.1130/b35017.1

Dietrich, J.R., Chen, Z., Hannigan, P.K, Hu, K., Yu, X., 2018. Oil and gas resource potential in the deep-water Canada Basin, Arctic Ocean; Geological Survey of Canada, Open File 8355, ed. rev., https://doi.org/10.4095/311219

Dixon, J., and Dietrich, J.R., 1990. Canadian Beaufort Sea and adjacent land areas; The Arctic Ocean Region, p. 239-256. doi:10.1130/dnag-gna-l.239

Dockman, D., Pearson, D., Heaman, L., Gibson, S., and Sarkar, C, 2018. Timing and origin of magmatism in the Sverdrup Basin, Northern Canada—Implications for lithospheric evolution in the High Arctic Large Igneous Province (HALIP); Tectonophysics, v. 742-74*3*, p. 50-65. doi:10.1016/j.tecto.2018.05.010

Dostal, J., and Macrae, A., 2018. Cretaceous basalts of the High Arctic large igneous province at Axel Heiberg Island (Canada): Volcanic stratigraphy, geodynamic setting, and origin; Geological Journal*,* v. 53, p. 2918-2934. doi:10.1002/gj.3132

Drummond, K.J., 2009. Northern Canada distribution of ultimate oil and gas resources; Drummond Consulting: Calgary; 60 p.

Embry, A.F., 1982. The Upper Triassic-Lower Jurassic Heiberg deltaic complex of the Sverdrup Basin; Canadian Society of Petroleum Geology, Memoir 8, p. 189-217.

Embry, A.F., 1991. Mesozoic History of the Arctic Islands; *In* Geology of the Innuitian Orogen and Arctic Platform of Canada and Greenland*,* p. 369-433. doi:10.1130/dnag-gna-e.369

Embry, A.F., 1993. Crockerland — the northwest source area for the Sverdrup Basin, Canadian Arctic Islands; Norwegian Petroleum Society Special Publications, p. 205-216. doi:10.1016/b978-0-444-88943-0.50018-6

Embry, A.F., 2011. Chapter 36 Petroleum prospectivity of the Triassic–Jurassic succession of Sverdrup Basin, Canadian Arctic Archipelago; *In:* Spencer, A.M., Embry, A.F., Gautier, D.L., Stoupakova, A.V. & Sørensen, K. (eds.) Arctic Petroleum Geology. Geological Society, London, Memoirs, Volume 35, p. 545-558. doi:10.1144/m35.36

Embry, A.F., and Beauchamp, B., 2008. Chapter 13 Sverdrup Basin; Sedimentary Basins of the World v. 5, p. 451-471.

Embry, A.F., and Osadetz, K.G., 1988. Stratigraphy and tectonic significance of Cretaceous volcanism in the Queen Elizabeth Islands, Canadian Arctic Archipelago; Canadian Journal of Earth Sciences, v. 25(8), p. 1209-1219. doi:10.1139/e88-118

Embry, A.F., Osadetz, K.G., Smith, D.R., Taylor, G.S., and Procter, R.M., 1983. Petroleum resources of the Arctic Islands region. Canada. Internal Report, Geological Survey of Canada.

Evangelatos, J., Funck, T., and Mosher, D., 2017. The sedimentary and crustal velocity structure of Makarov Basin and adjacent Alpha Ridge; Tectonophysics, v. 696–697, p. 99–114.

Evenchick, C.A., Davis, W.J., Bédard, J.H., Hayward, N., and Friedman, R.M., 2015. Evidence for protracted High Arctic large igneous province magmatism in the central Sverdrup Basin from stratigraphy, geochronology, and paleodepths of saucer-shaped sills; Geological Society of America Bulletin, v. 127, p. 1366-1390. doi:10.1130/b31190.1

Firth, J.V., and Clark, D.L., 1998. An early Maastrichtian organic-walled phytoplankton cyst assemblage from an organic-rich black mud in Core Fl-533, Alpha Ridge: evidence for upwelling conditions in the Cretaceous Arctic Ocean; Marine Micropaleontology, v. 34, p. 1-27.

Forsyth, D.A., Asudeh, I., White, D., Jackson, R., Stephenson, R.A., Embry, A.F., and Argyle, M., 1998. Sedimentary basins and basement highs beneath the polar shelf north of Axel Heiberg and Meighen Islands; Bulletin of Canadian Petroleum Geology, v. 46, p. 12-29

Funck, T., Jackson, H.R., and Shimeld, J., 2011. The crustal structure of the Alpha Ridge at the transition to the Canadian Polar margin - results from a seismic refraction experiment. Journal of Geophysical Research v. 116, issue B12, B12101, p. 1-26, https://doi.org/10.1029/2011jb008411

Fyles, J., Hills, L., Matthews, J., Barendregt, R., Baker, J., Irving, E., and Jetté, H., 1994. Ballast Brook and Beaufort Formations (late Tertiary) on Northern Banks Island, Arctic Canada; Quaternary International, v. 22-23, p. 141-171. doi:10.1016/1040-6182(94)90010-8

Gaina, C., Nasuti, A., Kimbell, G.S., and Blischke, A., 2017. Break-up and seafloor spreading domains in the NE Atlantic; Geological Society, London, Special Publications, v. 447, p. 393-417. doi:10.1144/sp447.12

Galloway, B.J., 2016. Geological and geochemical data from the Canadian Arctic Islands. Part XIV: Compilation of rock-eval/TOC and mineralogical data from Upper Paleozoic strata of the Sverdrup Basin; Geological Survey of Canada, Open File 8154. doi:10.4095/299486

Galloway, B.J., Dewing, K., and Beauchamp, B., 2018. Upper Paleozoic hydrocarbon systems in the Sverdrup Basin, Canadian Arctic Islands; Marine and Petroleum Geology, v. 92, p. 809-821. doi:10.1016/j.marpetgeo.2017.12.013

Galloway, B.J., Dewing, K., Beauchamp, B., and Matthews, W., 2020. Upper Paleozoic stratigraphy and detrital zircon geochronology along the northwest margin of the Sverdrup Basin, Arctic Canada: Insight into the paleogeographic and tectonic evolution of Crockerland; Canadian Journal of Earth Sciences. https://doi.org/10.1139/cjes-2019-0226

Gentzis, T., and Goodarzi, F., 1991. Thermal maturity and hydrocarbon potential of the sedimentary succession from the Hecla field in Sverdrup Basin, Arctic Canada; International Journal of Coal Geology, v. 19, p. 483-517. doi:10.1016/0166-5162(91)90031-d

Gentzis, T., and Goodarzi, F., 1993. Maturity studies and source-rock potential in the southern Sverdrup Basin, Arctic Canada; International Journal of Coal Geology, v. 24, p. 141-177. doi:10.1016/0166-5162(93)90008-x

Gentzis, T., Goodarzi, F., and Embry, A.F., 1996. Thermal maturation, potential source rocks and hydrocarbon generation in Mesozoic rocks, Lougheed Island area, Central Canadian Arctic archipelago; Marine and Petroleum Geology, v. 13, p. 879-905. doi:10.1016/s0264-8172(96)00028-1

Giustiniani, M., Tinivella, U., Jakobsson, M., and Rebesco, M., 2013. Arctic Ocean Gas Hydrate Stability in a Changing Climate; Journal of Geological Research, v. 2013, 10 p.

Goodarzi, F., Nassichuk, W., Snowdon, L., and Davies, G., 1987. Organic petrology and RockEval analysis of the Lower Carboniferous Emma Fiord Formation in Sverdrup Basin, Canadian Arctic Archipelago; Marine and Petroleum Geology, v. 4, p. 132-145. doi:10.1016/0264-8172(87)90030-4

Hadlari, T., and Issler, D.R., 2019. Late Cretaceous uplift of northern Axel Heiberg Island, Nunavut, revealed by apatite fission track data, and a schematic model related to Baffin Bay extension; Geological Survey of Canada, Open File 8494. https://doi.org/10.4095/313399

Hadlari, T., Midwinter, D., Galloway, J.M., Dewing, K., and Durbano, A.M., 2016. Mesozoic rift to post-rift tectonostratigraphy of the Sverdrup Basin, Canadian Arctic; Marine and Petroleum Geology, v. 76, p. 148-158.

Harrison, J.C., Mayr, U., McNeil, D.H., Sweet, A.R., Eberle, J.J., McIntyre, D.J., Harington, C.R., Chalmers, J.A., Dam, G., and Nøhr-Hansen H.,1999. Correlation of Cenozoic sequences of the Canadian Arctic region and Greenland: implications for the tectonic history of northern North America; Bulletin of Canadian Petroleum Geology, v. 47, p. 223–254. doi: https://doi.org/10.35767/gscpgbull.47.3.223

Harrison, J.C., Brent, T.A., and Oakey, G.N., 2011. Chapter 40. Baffin Fan and its inverted rift system of Arctic eastern Canada: Stratigraphy, tectonics and petroleum resource potential; *In:* Spencer, A.M., Embry, A.F., Gautier, D.L., Stoupakova, A.V. & Sørensen, K. (eds.) Arctic Petroleum Geology. Geological Society, London, Memoirs, Volume 35, p. 595-626. doi:10.1144/m35.40

Houseknecht, D.W., Bird, K.J., and Garrity, C.P., 2012. Assessment of Undiscovered Petroleum Resources of the Amerasia Basin Petroleum Province; Circum-Arctic Resource Appraisal Project, United States Geological Survey Scientific Investigations Report 2012-5146, 36 p.

Houseknecht, D.W., and Connors, C.D., 2016. Pre-Mississippian tectonic affinity across the Canada Basin–Arctic margins of Alaska and Canada; Geology, v. 44, p. 507-510. doi:10.1130/G37862.1

Hu, K., and Dewing, K., 2011. Geological and geochemical data from the Canadian Arctic Islands. Part X: Core petrophysical data from petroleum exploration boreholes; Geological Survey of Canada, Open File 6669. doi:10.4095/287314

Hu, K., Dewing, K., Embry, A., and Liu, Y., 2014. Hydrocarbon Reservoir Evaluation in Triassic-Jurassic Strata in the Western Sverdrup Basin, Canadian Arctic Islands; AAPG Search and Discovery Article #10588.

Hülse, P., Herrle, J., Schneider, S., Kelly, S., and Gize, A., 2015. The Kanguk Formation: A Late Cretaceous Source Rock in the Sverdrup Basin, Canadian Arctic Islands; AAPG Annual Convention and Exhibition, Denver CO.

Hutchinson, D.R., Jackson, H.R., Houseknecht, D.W., Li, Q., Shimeld, J.W., Mosher, D.C., Chian, D., Saltus, R.W., and Oakey, G.N., 2017. Significance of Northeast-trending features in Canada Basin, Arctic Ocean; Geochemistry, Geophysics, Geosystems, v. 18, p. 4156-4178. doi:10.1002/2017gc007099

Jackson, M.P.A., and Harrison, J.C., 2006. An allochthonous salt canopy on Axel Heiberg Island, Sverdrup Basin, Arctic Canada; Geology, v. 34, p. 1045-1048. doi:10.1130/g22798a.1

Jackson, H.R., Dahl-Jensen, T., and the LORITA working group, 2010. Sedimentary and crustal structure from the Ellesmere Island and Greenland continental shelves onto Lomonosov Ridge, Arctic Ocean; Geophysical Journal International, v 182, p. 11-35.

Johnson, A.H., 2011. Global resource potential of gas hydrate – a new calculation; *In*: Proceedings of the 7th International Conference on Gas Hydrates (ICGH 2011), July 17-21, Edinburgh, Scotland, UK

Jokat, W., 2003. Seismic investigations along the western sector of Alpha Ridge, Central Arctic Ocean; Geophysical Journal International, v. 152, p. 185–201.

Kristoffersen, Y., and Mikkelsen, N., 2006. On sediment deposition and nature of the plate boundary at the junction between the submarine Lomonosov Ridge, Arctic Ocean and the continental margin of Arctic Canada/North Greenland; Marine Geology, v. 225, p. 265-278.

Kumar, N., Helwig, J., and Dinkelman, M.G., 2009. Preliminary evaluation of a potential major petroleum province from BeaufortSPAN^{TM} 2-D seismic data: Canadian Arctic passive margin, Banks Island segment; CSEG Recorder, May 2009, p.28-35.

Kvenvolden, K.A., 1993. A primer on gas hydrates; *In*: The Future of Energy Gases. USGS Professional Paper 1570, p. 279-291.

Lewin and Associates, Inc., 1983. Handbook of gas hydrate properties and occurrence; U.S. Geological Survey Report DE-AC21-82-MC19239, 234 p.

Lister, C.J., King, H.M., Atkinson, E.A., Kung, L.E., and Nairn, R., 2018. A probability-based method to generate qualitative petroleum potential maps: Adapted for and illustrated using ArcGIS; Geological Survey of Canada, Open File 8404, 2018, 50 p. doi:10.4095/311225

Majorowicz, J.A., Hannigan, P.K., Osadetz, K.G., 2002, Study of the natural gas hydrate “trap zone” and the methane hydrate potential in the Sverdrup basin, Canada; Natural Resources Research, v. 11, p. 79-96.

Mayr, U., Packard, J.J., Goodbody, Q.H., Okulitch, A.V., Rice, R.J., Goodarzi, F., and Stewart, K.R., 1994. The Phanerozoic geology of southern Ellesmere and North Kent Islands, Canadian Arctic archipelago. Canada; Geological Survey of Canada Bulletin 470, 310 p.

Max, M.D., and Johnson, A.H., 2014. Hydrate petroleum system approach to natural gas hydrate exploration; Petroleum Geosciences, v. 20, p. 187-199.

Miall, A.D., 1979. Mesozoic and Tertiary geology of Banks Island, Arctic Canada; Geological Survey of Canada, Memoir 387, 235 p. doi:10.1017/s0016756800032726

McWhae, J.R.H., 1979. Canadian Arctic Islands geological field operation – Lancaster Sound segment; Industry report, National Energy Board, Report no. 246-1-12-100.

Miles, W., Oneschuk, D., 2016. Magnetic anomaly map, Canada; Geological Survey of Canada, Open File 7799.

Moore, T.E., Grantz, A., Pitman, J.K., and Brown, P.J., 2011. Chapter 49, A first look at the petroleum geology of the Lomonosov Ridge microcontinent, Arctic Ocean; *In:* Spencer, A.M., Embry, A.F., Gautier, D.L., Stoupakova, A.V. & Sørensen, K. (eds.) Arctic Petroleum Geology. Geological Society, London, Memoirs, Volume 35, p. 751–769. doi: 10.1144/M35.49

Moore, T.E., and Pitman, J.K., 2019. Geology and assessment of undiscovered oil and gas resources of the Eurasia Basin Province; Chapter DD of Moore, T.E., and Gautier, D.L., eds., The 2008 Circum-Arctic Resource Appraisal: U.S. Geological Survey Professional Paper 1824, 35 p., https://doi.org/10.3133/pp1824DD.

Naber, T.V., Grasby, S.E., Cuthbertson, J.P., Rayner, N., & Tegner, C., 2020. Tracing the extension of the Alpha Ridge onto Ellesmere Island, Canada: New constraints on the age and geochemistry of High Arctic Large Igneous Province magmatism; Bulletin of the Geological Society of America.

National Energy Board (NEB), 2014. Assessment of Discovered Conventional Petroleum Resources in the Northwest Territories and Beaufort Sea; Energy Briefing Note, NE23-180/2014E-PDF, 11 p.

Oakey, G.N., and Chalmers, J.A., 2012. A new model for the Paleogene motion of Greenland relative to North America: Plate reconstructions of the Davis Strait and Nares Strait regions between Canada and Greenland; Journal of Geophysical Research: Solid Earth, v. 117(B10), 10401. doi:10.1029/2011jb008942

Oakey, G.N., and Stephenson, R., 2008. Crustal structure of the Innuitian region of the Arctic Canada and Greenland from gravity modelling: implication for the Palaeogene Eurekan orogeny; Geophysical Journal International v. 173, p. 1039–1063. doi: 10.1111/j.1365-246X.2008.03784.x

Oakey, G.N., Davis, W., McDannell, K., Currie, L., Percival, J., Shimeld, J., Salisbury, M., Kellett, D., Travaglini, P., Wilton, D., Schmitt, D., Kofman, R., and King, B., 2018. Analytical results of Canada’s 2016 dredge sampling of Lomonosov Ridge. International Conference on Arctic Margins VIII, Stockholm, Sweden, June 11-14

Obermajer, M., Stewart, K.R., and Dewing, K., 2007. Geological and Geochemical Data from the Canadian Arctic Islands. Part II: RockEval/TOC data; Geological Survey of Canada, Ottawa, Open File 5459.

Peel, F.R., and Brooks, J.R.V., 2016. A practical guide to the use of success versus failure statistics in the estimation of prospect risk. AAPG Bulletin, v. 100(2), p. 137–150. doi: https://doi.org/10.1306/08101515059

Piepjohn, K., von Gosen, W., and Tessensohn, F., 2016. The Eurekan deformation in the Arctic: an outline; Journal of the Geological Society, v. 173(6), p. 1007-1024. doi:10.1144/jgs2016-081

Piñero, E., and Wallmann, K., 2013. Estimation of the global inventory of methane hydrates in marine sediments using transfer functions; Biogeosciences, v. 10, p. 959-975.

Procter, R.M., Taylor, G.C., and Wade, J.A., 1984. Oil and natural gas resources of Canada. Geological Survey of Canada, Paper 83-31, 59 p.

Powell, T., 1978. An assessment of the hydrocarbon source potential of the Canadian Arctic islands; Geological Survey of Canada, Paper 78-12, 82 p.

Randell, R.N., 1994. Geology of the Polaris Zn-Pb Mississippi Valley-Type deposit, Canadian Arctic Archipelago; Ph.D. thesis, University of Toronto, Toronto, Canada.

Rayer, F.G., 1981. Exploration prospects and future petroleum potential of the Canadian Arctic Islands; Journal of Petroleum Geology, v. 3, p. 367-412.

Reid, S., Dewing, K., Sharp, R., 2013. Polaris as a guide to northern exploration: Ore textures, paragenesis and the origin of the carbonate-hosted Polaris Zn-Pb Mine, Nunavut, Canada; Ore Geology Reviews, v. 51, p. 27-42

Ricketts, B., Osadetz, K.G., and Embry, A.F., 1985. Volcanic style in the Strand Fiord Formation (Upper Cretaceous), Axel Heiberg Island, Canadian Arctic Archipelago; Polar Research, v. 3, p. 107-122. doi:10.3402/polar.v3i1.6942

Ricketts, B.D., 1994. Basin analysis, Eureka Sound Group, Axel Heiberg and Ellesmere islands, Canadian Arctic Archipelago; Geological Survey of Canada, Memoir 439, 126 p.

Rose, P.R., 2001. Risk analysis and management of petroleum exploration ventures; AAPG Methods in Exploration Series, no. 12, 123 p.

Saltus, R.W., Miller, E.L., Gaina, C., and Brown, P.J., 2011. Chapter 4 Regional magnetic domains of the Circum-Arctic: A framework for geodynamic interpretation; *In:* Spencer, A.M., Embry, A.F., Gautier, D.L., Stoupakova, A.V. & Sørensen, K. (eds.) Arctic Petroleum Geology. Geological Society, London, Memoirs, Volume 35, p. 49-60. doi:10.1144/m35.4

Saumur, B., Dewing, K., and Williamson, M.-C., 2016. Architecture of the Canadian portion of the High Arctic Large Igneous Province and implications for magmatic Ni–Cu potential; Canadian Journal of Earth Sciences, v. 53(5), p. 528-542. doi:10.1139/cjes-2015-0220

Schneider, D.A., Faehnrich, K., Majka, J., and Manecki, M., 2019. $^{40}Ar/^{39}Ar$ geochronologic evidence of Eurekan deformation within the West Spitsbergen Fold and Thrust Belt; *In:* Circum-Arctic Structural Events: Tectonic Evolution of the Arctic Margins and Trans-Arctic Links with Adjacent Orogens, K. Piepjohn, J.V. Strauss, L. Reinhardt, and W.C. McClelland (eds.). Geological Society of America Special Paper 541. doi:10.1130/2018.2541(08)

Schreiber A., 1975. Kalkul und Risiko der Kohlenwasserstoff—Exploration im Gebiet der Arktischen Inseln Kanadas (Calculation and Risk in Hydrocarbon Exploration in Canada's Arctic Islands); Sond. Compend., 74/75, Erganz. Zeit. Erdol Kohle (1975), p. 3-12

Skibo, D.N., Harrison, C., Gentzis, T., and Goodarzi, F., 1991. Organic maturity/time-temperature models of the Ellesmerian (Paleozoic) Orogeny, Melville Island, Northwest Territories; Geological Survey of Canada, Paper 91-1E, p. 165–175.

Smith, S.L., 2001. A synthesis of geological hazards in Canada; Geological Survey of Canada, Bulletin 548*,* 265-280. doi:10.4095/212221

Sobczak, L.W., Mayr, U., and Sweeney, J.F., 1986. Crustal section across the polar continent–ocean transition in Canada; Canadian Journal of Earth Sciences, v. 23, p. 608-621. doi:10.1139/e86-063

Sørensen, K., Gautier, D., Pitman, J., Jackson, H.R., and Dahl-Jensen, T., 2011. Chapter 44 Geology and petroleum potential of the Lincoln Sea Basin, offshore North Greenland; *In*: Spencer, A.M., Embry, A.F., Gautier, D.L., Stoupakova, A.V. & Sørensen, K. (eds.) Arctic Petroleum Geology. Geological Society, London, Memoirs, 35, 673–684. DOI: 10.1144/M35.44

Spiegel, C., Lisker, F., Dörr, N., and Piepjohn, K., 2011. Cenozoic denudation history of northern Ellesmere Island: Eurekan tectonics or Eocene glaciation? Geophysical Research Abstracts, EGU General Assembly, 13.

Stasiuk, L.D., and Fowler, M.G., 1994. Paleozoic hydrocarbon source rocks, Truro Island, Arctic Canada: Organic petrology, organic geochemistry and thermal maturity; Bulletin of Canadian Petroleum Geology v. 42, p. 419–431

Synnott, D.P., Dewing, K., Ardakani, O.H., and Obermajer, M., 2018. Correlation of zooclast reflectance with Rock-Eval Tmax values within Upper Ordovician Cape Phillips Formation, a potential petroleum source rock from the Canadian Arctic Islands; Fuel, v. 227, p. 165-176. doi:10.1016/j.fuel.2018.04.096

Trettin, H.P., 1994. Pre-Carboniferous geology of the northern part of the Arctic islands, Hazen Fold Belt and adjacent parts of central Ellesmere Fold Belt, Ellesmere Island; Geological Survey of Canada, Bulletin 430, 260 p.. doi:10.4095/194326

United States Geological Survey (USGS), 2008. Circum-Arctic Resource Appraisal. USGS Fact sheet 2008-3049, 4 p.

Waylett, D., and Embry, A. 1992. Hydrocarbon loss from oil and gas fields of the Sverdrup Basin, Canadian Arctic Islands. In: T.O.Vorren, E. Begsager, Ø.A. Dahl-Stamnes, E. Holter, B. Johansen, E. Lie, and T.B. Lund (eds.), Arctic Geology and Petroleum Potential. Norwegian Petroleum Society, Special Publication v. 2, p. 195-204.

Wikipedia, 2022. Monte Carlo method; last modified April 19, 2022. https://en.wikipedia.org/wiki/Monte_Carlo_method

Williamson, M.-C., Saumur, B.-M., and Evenchick, C.A., 2016. HALIP volcanic-intrusive complexes, Axel Heiberg Island, Nunavut; *In:* Report of Activities for High Arctic Large Igneous Province (HALIP) – GEM 2 Western Arctic Region Project: Bedrock Mapping and Mineral Exploration. Edited by M.-C. Williamson. Geological Survey of Canada, Open File Report 7950, p. 14–26.

APPENDIX A. ASSESSMENT AREA DEFINITIONS.

The first step in conducting a quantitative resource assessment in frontier areas is to create assessment areas. Assessment areas are areas that have similar geology because they have undergone a common geological history. For instance, the NW Canada Rifted Margin assessment area formed during the rifting of the Arctic Ocean, hence it has a history unlike other areas in the study. Because an assessment area has a unique geological history, it has a distinct combination of petroleum system elements (source, timing, reservoir, trap and seal) that result in a distinct hydrocarbon potential.

This appendix outlines the reasoning used in selecting the boundaries of assessment areas for this study. Due to limited information, whole basins are assessed as units, with very limited subdivision into sub-plays within the basins.

Area 1. NE Sverdrup Basin - HALIP Influenced

This assessment area is defined as the HALIP (High Arctic Large Igneous Province) influenced part of the Sverdrup Basin. The magnetic interpretations of Anudu et al. (2016) – their domains D and E – are used as the main definition of this region. Their interpretation was extended to the southwest around linear anomalies using the regional magnetic map in GSC Open File 7799 (Miles and Oneschuk, 2016).

The outline was compared to the thermal maturity map in Galloway et al. (2018) and intrusions in wells. The southern boundary was straightened to include high maturity area and some intruded wells.

Along the eastern margin of the Sverdrup Basin (east of Anudu et al., 2016 study area), the higher thermal maturity, thicker preserved sedimentary rock, and regional magnetic anomalies were similar to where the Triassic or younger strata are at surface (not counting where very young strata is directly on pre-Sverdrup strata). Thus, much of the eastern/northeastern boundary was defined as a smoothed version of the Triassic-Permian contact.

Areas of metamorphosed lower Paleozoic rocks in northern Alex Heiberg Island, which correspond well to one of Anudu et al.'s (2016) D2 sub-areas, were excluded from this area, and added to the Lower Paleozoic area below.

Area 2. Deformed Lower Paleozoic Strata (Ellesmere shelf and Ellesmere Island)

This assessment area has limited younger sedimentary rocks preserved and low petroleum potential due to high thermal maturity and multiple deformation events. Most of the rocks exposed in this area are Lower Paleozoic in age, and significantly deformed. Much of the area is onshore on Ellesmere Island.

The southwestern boundary matches the Triassic-Permian boundary of NE Sverdrup Basin above. The southeastern boundary extends to the deformation front of the Eurekan deformed belt. A portion of the eastern boundary is the international boundary with Denmark (Greenland).

The assessment area is extended northeast into the offshore, based on the sediment thickness map of Oakey and Stephenson (2008). Their map uses gravity data to suggest where the edge of significant younger (less dense) sedimentary rocks begins – the assessment area boundary generally follows their 'zero edge'. Evidence from the LORITA refraction profile (Jackson et al., 2010) was also considered. Where Oakey and Stephenson (2008) do not completely agree with the LORITA refraction profile, evidence from each was averaged.

The northwestern boundary is based on the extent of HALIP (see Alpha Ridge – HALIP below), and the edge of significant shelf sedimentation, based on the magnetic interpretations of Anudu et al. (2016) and the ARTA refraction profile (Funck et al., 2011).

The Pearya composite terrane is included in this area reflecting the lower Paleozoic age and low petroleum potential. Similarly, the area includes Lower Paleozoic rocks on northern Axel Heiberg which also exhibit intense deformation and low hydrocarbon potential.

Area 3. Lincoln Sea Basin

An assessment area for the total Lincoln Sea Basin geologic province was created. The boundary used by Sørensen et al. (2011) was considered and edited as follows.

The southern boundary adjoins Area 2 above, and the boundary was moved further offshore to the zero edge of Oakey and Stephenson (2008), and edited to account for the LORTIA refraction profile (Jackson et al., 2010), as discussed above. The northern boundary was also taken from the LORITA refraction profile and was extended along the flank of Lomonosov Ridge with bathymetry.

The eastern boundary of the whole basin was interpreted generously on regional magnetic data, similarly to Sørensen et al. (2011). The western boundary is also interpreted on regional magnetic data, up to the edge of the HALIP magnetic signature (after Saltus et al., 2011; Sørensen et al., 2011).

Quantitative analysis was initially run for this total basin area, and mean resources compared favourably with the results of Sørensen et al. (2011). For quantitative analysis for the Proposed Protected Area, the total basin was trimmed to the Canadian international border with Denmark (Greenland). The Canadian portion of the Lincoln Sea is a good sample of the whole basin, and does not represent just a margin of it or a sweet spot in it. Thus, the same logic of analogies to use and prospect densities apply for the entire basin and the Canadian portion.

Area 4. Lomonosov Ridge

An assessment area was created on the geographic Lomonosov Ridge encompassing the limited Canadian portions of both the Lomonosov Ridge Assessment Unit and Makarov Basin Margin Assessment Unit of Moore and Pitman (2019). The boundary uses those published units and is also consistent with the bathymetry - the bathymetric cut-off is about 1500 m.

Limited seismic data suggests the sediment thickness is low (Jackson et al, 2010; Kristoffersen and Mikkelsen, 2006) and petroleum potential is limited, so the area is considered here in one assessment area. The best petroleum potential is on the flank of the ridge.

Adjacent to the western and southern boundaries are magnetic anomalies from the intrusions of HALIP (Saltus et al., 2011, Anudu et al, 2016). The eastern boundary is the international border Denmark (Greenland), and the northern boundary is the Canadian 200 mile limit.

Area 5. Alpha Ridge - HALIP

The High Arctic Large Igneous Province (HALIP) underlies the geographic Alpha Ridge and the adjacent deeper water basins. The extent of HALIP has been interpreted by many authors from regional magnetic data. Anudu et al. (2016) interpreted a magnetic anomaly and domain character for HALIP , designated Domain A. Their Domain A was extended with regional magnetic maps.

The assessment area is consistent with Saltus et al. (2011) who also interpret a regionally extensive igneous province extending south against the Canada Basin slope and Canadian Arctic Margin and north into the loosely labelled geographic ‘Makarov Basin’ area. The ‘Makarov Basin’ is a geographical term for deep water between the geographic Lomonosov Ridge and Alpha Ridge, and should not be confused with the geological Makarov Basin, which is outside Canadian waters and the High Arctic Basins study area, and has better potential. Saltus et al. (2011) do not see potential in this HALIP area and do not analyze quantitative petroleum here.

The assessment area also includes part of the geographic ‘Stefannson Basin’, to the west of the Alpha Ridge. Chian et al. (2016) and Hutchinson et al. (2017) also interpret the southern and southwestern end of HALIP in agreement with Anudu et al. (2016) and the assessment area boundary. The northwestern boundary of the assessment area is the Canadian 200 mile limit.

Area 6. NW Canada Arctic Margin

Anudu et al. (2016) interpret a portion of the regional magnetic data – Domain B – to indicate the presence of a rift margin basin with much less intrusion. Their Domain B was used as the main basis to define an assessment area for this rift margin basin. The north and northeastern boundary of the assessment area is Anudu et al.’s boundary with their Domain A – interpreted as the High Arctic Igneous Province (our assessment area 5). A minor edit of their boundary was made for the ARTA refraction profile interpretation (Funck et al., 2011) of the basin shape.

This rift margin includes marine shelf and slope areas, and extends from where Mesozoic-Cenozoic strata begin to increase rapidly in thickness, to the northwest to the toe of the continental slope. Southwest of the Anudu et al. study area, the toe of slope was extended using the 2000 m bathymetric contour, to include the thicker slope sediments.

A similar margin extends southwest off of Prince Patrick and Banks Islands, and seismic data offshore Banks Island can be used by analogy to gain insight into this part of the margin. The southwestern margin of the current assessment area is defined at about Borden Island where the magnetic signature of the rifted margin starts to show more complex, short wavelength features.

The southeast boundary of the assessment area is defined where Anudu et al. (2016) interpret more intrusion and thinner sediments – the border of their Domain E. Their interpretation was extended southwest on regional magnetic data up to distinctive linear magnetic anomalies, similar to their Domains D and E. This boundary abuts assessment area 1 – NE Sverdrup Basin.

APPENDIX B. PETROLEUM SYSTEMS FOR THE LINCOLN SEA, SVERDRUP BASIN, AND LOWER PALEOZOIC

The Lincoln Sea is located to the north and east of Ellesmere Island. The area is so remote that few geological expeditions have explored this region. Due to the lack of localized data, characterization of the Lincoln Sea Basin and its associated petroleum systems must use analog studies of adjacent basins with geologically similar histories.

The Upper Paleozoic to Eocene history of the Lincoln Sea Basin is thought to be similar to the history of the Sverdrup Basin (to the southwest in a modern orientation), and potentially the Barents Sea (east of Svalbard) because the basins were likely contiguous at the time of deposition. Based on two seismic refraction lines and gravity modelling, Jackson et al., (2010) suggest the floor of the Lincoln Sea Basin is extended continental crust, overlain by metamorphosed Lower Paleozoic sediment, and then preserved Upper Paleozoic, Mesozoic, and Cenozoic sediments. The lowermost geology of the Lincoln Sea Basin (extended continental crust and metamorphosed Lower Paleozoic sediments) are not prospective for hydrocarbon accumulation. To understand the potential hydrocarbon systems within the Lincoln Sea we must look to similarly aged sedimentary deposits in the adjacent Sverdrup Basin, which have been extensively sampled and analysed.

Lower Paleozoic Plays underneath the Lincoln Sea and Sverdrup basins

Cambrian to Devonian strata of the Franklinian Basin underlie the Lincoln Sea Basin (Jackson et al., 2010). These strata are metamorphosed and have little to no petroleum potential. However, during burial, organic rich units would have passed through the hydrocarbon generation window. Dewing and Obermajer (2009) studied the thermal maturity of Lower Paleozoic sediments in the Canadian Arctic Archipelago; they report a thin band of mature to overmature Hazen shale on northeastern Ellesmere Island. To preserve any lower Paleozoic hydrocarbon generated in the Lincoln Sea or NE Sverdrup basins, it must have migrated upwards into younger sediments. This is considered unlikely due to intense deformation during the Late Devonian Ellesmerian Orogeny.

Upper Paleozoic Plays

Galloway et al., (2018) assessed the hydrocarbon potential of Upper Paleozoic sediments in the Sverdrup Basin and their work will be extrapolated into the Lincoln Sea. Upper Paleozoic (Carboniferous to Permian) sediments in the Lincoln Sea Basin are believed to be stratigraphically similar to Upper Paleozoic sediments in the Sverdrup Basin (Jackson et al., 2010).

Source Rocks

Oil staining and gas kicks are found throughout the Upper Paleozoic rocks in the Sverdrup (Galloway et al., 2016), indicating the potential for widespread source rocks. Galloway et al. (2018) published a comprehensive evaluation of potential Upper Paleozoic source rocks in the Sverdrup Basin; the paper (and its included references) forms the basis for interpreting potential source rock interpretation in the Lincoln Sea. The Viséan (Middle Mississippian) Emma Fiord formation is an organic rich formation deposited in lacustrine, marginal marine, and fluvial lithologies (Goodarzi et al., 1987; Davis and Nassichuk, 1988). The primary organic material is a mixture of Types I and II, with minor Type III organics found within the formation (Goodarzi et al., 1987). Average TOC within the Emma Fiord is 21.8 wt. %, with an initial HI of ~553 mg HC/g (Galloway et al., 2018). The Emma Fiord Formation is organic rich, but is restricted to areas of early rifting.

Three formations within the early rift assemblages of the Sverdrup Basin may also be present within the Lincoln Sea. 1. Antoinette Formation (Moscovian to Asselian) contains Type III source rock with lower S_2 and low HI values, an HI value of 119 mg HC/g TOC was determined from the slope of the S_2 vs TOC plot (Galloway et al., 2018). 2. Early Permian Trapper Cove Formation (1.36 avg. wt. % TOC, 2.16 mg HC/g) contains a mixture of Type II/III organic material in the western Sverdrup (Galloway et al., 2018); oil staining and gas kicks have been reported in the Satellite F-68 and Graham C-52 wells (Galloway et al., 2016). 3. Sabine Bay Formation is a high potential source rock with a 4.8 wt. % TOC and an average S_2 value of 3.47 HC/g (Galloway et al., 2018). Organic rich facies in this Roadian formation are coaly shales, which implies a Type III gas prone source rock (Galloway et al., 2018).

Units deposited during early passive subsidence contains three potential source rock formations (Galloway et al., 2018). 1. Shales within the van Hauen Formation average 1.34 wt. % TOC, and an average HI of 56 mg HC/g. The van Hauen Formation is sampled along the basin margins, and Galloway et al. (2018) speculate that within the basin centre this formation may transition to a more marine, oil and gas prone source rock. 2. The Trold Fiord Formation averages 15.2 wt. % TOC with an average HI of 156 mg HC/g, this formation has excellent potential as a source rock (Galloway et al., 2018). The kerogen is a mix of Type I and Type IV on Prince Patrick Island (SW Sverdrup Basin), elsewhere in the Trold Fiord formation organics are more gas-prone Type III (Galloway et a., 2018). 3. Assistance Formation, a sandstone dominated unit containing coal beds. These coals average 4.46 wt. % TOC and are a Type III gas prone source (Galloway et al., 2018).

The centre of the Sverdrup Basin has passed through the oil and gas generation window and source rocks there are overmature (Galloway et al., 2018, their Fig. 10); however, outside of the basin centre these rocks are primarily within the hydrocarbon generation window. Embry and Beauchamp (2008) and Dewing et al. (2016) predict a Late Cretaceous timing for maximum burial, although Dewing and Obermajer (2011) suggest maximum burial may have been in the Late Eocene in the North Sabine H-49 well, and also proposed that the onset of hydrocarbon generation in Upper Paleozoic sediments was during Triassic burial by the Bjorne and Blind Fiord formations. If hydrocarbon generation occurred in the Triassic, then trapping mechanism must be Triassic or older. If generation occurred during the Cretaceous to Eocene, then for the best chance of creating hydrocarbon accumulation, traps must be no younger than Eocene (Galloway et al., 2018). After reaching the generation window, it is possible for hydrocarbons to have a lag time between generation and migration, even being held in secondary pools before eventual migration into their final position. Using the Sverdrup Basin as an analog, the Upper Paleozoic sediments in the Lincoln Sea should have potential as both oil and gas generating source rocks. If the timing of oil and gas generation from these Paleozoic sources is Cretaceous to Eocene, there is even greater potential for a working Paleozoic source petroleum system.

Reservoirs

There has been little investigation of the Upper Paleozoic formations of the Sverdrup Basin concerning their potential as hydrocarbon reservoirs. Hu and Dewing (2011) compiled petrophysical data from 80 wells in the Canadian Arctic Islands and only 2% of these data were from Paleozoic rocks. Hu and Dewing (2011) found that some porosity is retained up to 5 km depth; Galloway et al., (2018) determined that oldest Permian units retained their porosity to ~2 km burial depth (current depth) while younger Permian units had prospective porosities to depths greater than 4 km (Galloway et al., 2018, their Fig. 11). Potential reservoir units include platform sandstones of Bjorne, Lindstrom, Trold Fiord/Degerböls, Assistance, Sabine Bay, and Canyon Fiord formations, as well as platform carbonates of the Great Bear Cape and Nansen formations with either fracture or dissolution porosity (Galloway et al., 2018). Two basinal plays are identified in the sediments of the Black Stripe and Borup Fiord formations.

Traps

Trapping mechanisms within the Upper Paleozoic sediments of the Sverdrup Basin are sub-salt sandstones or carbonates, the flanks of salt structures, shelf margin transitions, and the Permian-Triassic unconformity. The Lower Carboniferous Otto Fiord Formation sits unconformably on top of the Borup Formation conglomerate. The Lower Permian Mt. Bayley Formation is a more spatially confined evaporite but is deposited above the Nansen (carbonate) and Canyon Fiord (sandstone) formations. Salt flank plays have been discovered within the Sverdrup Basin (Embry, 2011) but the petroleum systems are located on structures with Triassic to Jurassic aged reservoirs. Galloway et al. (2018) acknowledge this but suggest that there may be older, untested salt movement creating hydrocarbon traps within Paleozoic sediments.

Although there is no evidence of evaporite formations in the Lincoln Sea, they are presumed present (Sørensen et al., 2011). This is because the Lincoln Sea is thought to have similar geologic history to the Sverdrup Basin and potentially the eastern Barents Sea, both of which contain evaporitic formations.

Seals

Seals within the Upper Paleozoic petroleum systems would include overlying salt formations, salt flank formations (where the reservoir abuts the evaporitic seal), and lithologic seals (tight carbonate or shale). Galloway et al. (2018) propose that the basinal van Hauen Formation shale could be a source rock, which then oversteps potential reservoir units of the Assistance Bay and Sabine Bay formation sandstones. This type of seal (shale overstepping reservoir unit) is possible throughout the Paleozoic section. The Permian-Triassic unconformity seal requires lithologic contacts not currently recorded in the Sverdrup Basin. There is evidence of an angular unconformity between the Permian and Triassic sediments; however, on Prince Patrick Island the Trold Formation sandstones are in direct contact with the Triassic Bjorne Formation sandstones, making a sealing angular contact unlikely (Galloway et al., 2018). It is possible that in other parts of the Sverdrup Basin the lowest most Triassic unit would act as a seal, creating some potential for an angular unconformity play.

Embry et al. (1983) divided the Paleozoic hydrocarbon systems in the Sverdrup Basin based on potential reservoir units, defining 11 plays. Galloway et al. (2018) used source rocks to divide their petroleum plays and defined eight plays. In a similar sense, potential sealing units within the Sverdrup Basin are well described. This level of division is reasonable within the Sverdrup but in the data poor Lincoln Sea it is not possible to define plays so specifically. This study attempts to define and delineate a Late Carboniferous to Permian play sourced by Upper Permian shales into Permian carbonates and sandstones. These reservoirs are predominantly in stratigraphic traps although structural traps related to the poorly-known Melvillian Disturbance (mid- to late Permian aged transpression?) may exist.

Mesozoic Plays

Much like the Paleozoic, the Mesozoic stratigraphy of the Lincoln Sea is presumed to be similar to that of the Sverdrup Basin, in which 17 oil and/or gas fields have been discovered within Mesozoic sediments (Rayer, 1981; Embry, 2011). Chen et al. (2000) reported a total original in-place reserve of 294 x 10^6 m^3 (1850 MMBO) oil and 500 x 10^9 m^3 (17.7 Tcf) natural gas, which would account for 10% of Canadian oil reserves and 23% of natural gas reserves at the time of publication. If the Lincoln Sea does have geologic conditions similar to the Sverdrup Basin one would expect hydrocarbon generation and accumulations.

Based on reservoir characteristics and source rock potential, Embry (2011) identified 22 petroleum plays within the Triassic to Jurassic sediments of the Sverdrup Basin, but such a fine resolution is not possible in the Lincoln Sea due to the limited data.

Source Rocks

Source rock study in the Sverdrup Basin initiated in 1975 by Schreiber and has continued through to the present day including regional studies by Powell (1978), Gentzis and Goodarzi (1991, 2007), Gentzis et al. (1996), and Dewing and Obermajer (2011).

Mesozoic potential source rocks in the Sverdrup Basin included the Triassic Murray Harbour and Hoyle Bay formations of the Schei Point Group (which are considered the source of the discovered oil and gas), the Lower Jurassic Jameson Bay Formation, the Late Jurassic Ringnes Formation, the Late Jurassic-Early Cretaceous Deer Bay Formation, and the Upper Cretaceous Kanguk Formation (Hülse et al., 2015). Migration of gas from older, Permian strata is possible (Dewing et al., 2016).

The Triassic Murray Harbour and Eden Bay members of the Schei Point Formation are black, bituminous shales, deposited in a marine setting in the central and western Sverdrup Basin (Embry, 1991). Triassic sediments have a vitrinite reflectance ranging from 0.50 to 0.80% at the Drake Field (Gentzis and Goodarzi, 2007), and 0.50 to 0.65% at the Hecla Field (Gentzis and Goodarzi, 1991), both values are within the early oil generation window.

The Lower Jurassic (Pleinsbachian to Toarcian) Jameson Bay Formation is a gas-prone potential source rock that is immature to marginally mature at Drake Point (Gentzis and Goodari, 2007), and has a VR_o from 0.43 to 0.64% at the Hecla Field (Gentzis and Goodari, 1991). Contrary to the Triassic sediments, the Jameson Bay Formation contains terrestrial organic matter, and in the eastern Sverdrup Basin is part of a fluvial-deltaic to nearshore marine depositional setting (Embry, 1991).

The Late Jurassic Ringnes Formation, interbedded shales and siltstones, is thought to have been deposited in a low oxygen marine shelf environment due to the black, bituminous shales, and large dolomitic concretions found within the formation (Embry, 1991). Despite the high TOC, the hydrogen index is low and may indicate the organic matter was biodegraded prior to burial. The presence of coals in the overlying Awingak sandstones (Embry, 1991) are a potential gas prone source.

Embry (1991) mapped up to 500 m of Kanguk Formation on Axel Heiberg Island. Although immature in the Sverdrup Basin, the Upper Cretaceous (Cenomanian to Campanian) Kanguk shale is a widespread (Banks to Devon to Axel Heiberg Islands) shale. Two black shale units near the base of the Kanguk Formation on Ellesmere Island have values of 6.2 and 5.2 wt. % TOC respectively (Hülse et al., 2015). These organic rich units were deposited during ocean anoxic events OAE2 and OAE3. If this widespread, organic-rich shale were deposited in the Lincoln Sea, it has excellent potential as an oil-prone source rock, providing it is buried deep enough to enter the oil generation window.

Reservoirs

Mesozoic sediments in the Sverdrup Basin are proven hydrocarbon reservoirs at Drake, Hecla, and other discoveries. Reservoir units are primarily Jurassic sandstone of the Heiberg Formation which Embry (2011, Fig. B.1, his Fig. 36.8) divided in to 1st, 2nd, and 3rd order sequences. Embry (2011) was able to subdivide to such an extent due to the >100 wells and field samples collected throughout the Sverdrup Basin. In the Lincoln Sea, where no lithological data has been collected it is neither prudent, nor advisable to attempt such a precise resolution for potential reservoir units. Hu et al. (2014) analysed reservoir characteristics using core and petrophysical data of four Mesozoic reservoir intervals using the three 1st order sequences identified by Embry (2011), with a subdivision within the Middle Triassic.

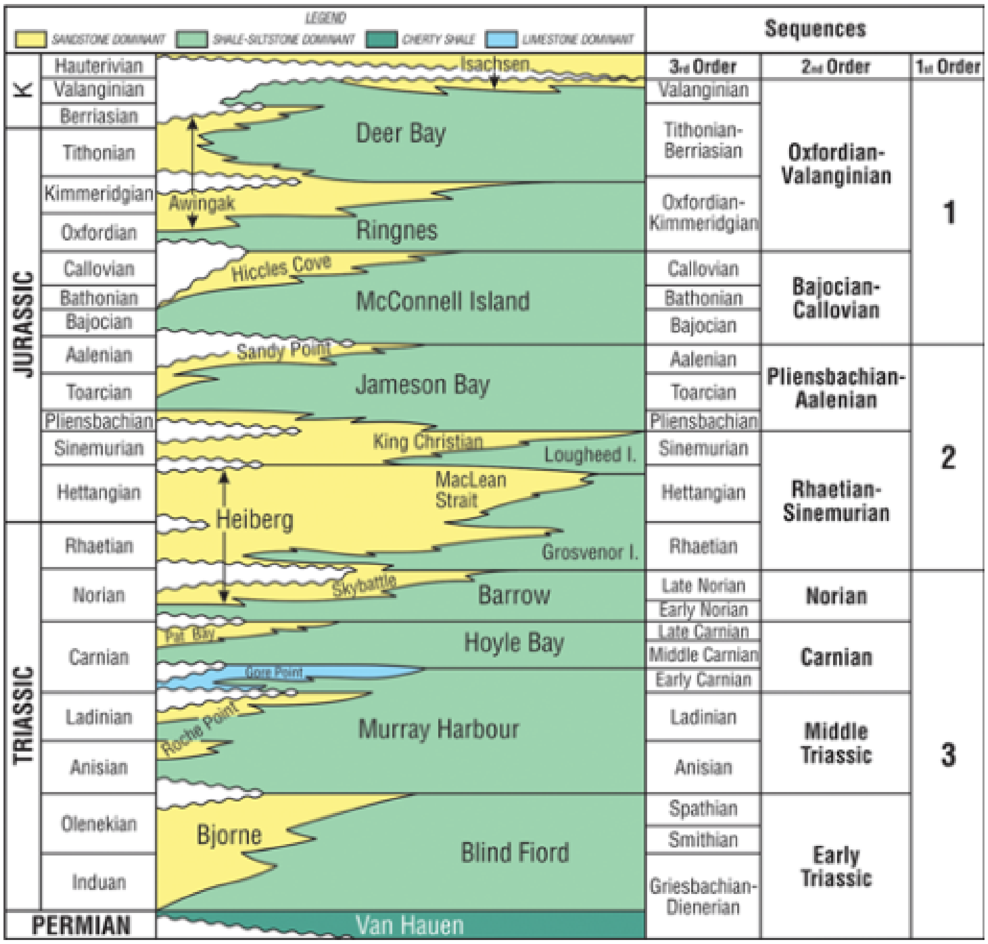


Figure B.1. Triassic-Jurassic Stratigraphy, Sverdrup Basin

Triassic-Jurassic stratigraphy, Sverdrup Basin, with boundaries of first-, second, and third-order sequences indicated (Embry, 2011).

These four reservoir intervals are the Lower Triassic Bjorne Formation, the Middle Triassic Schei Point Group, the Triassic to Jurassic Heiberg Group, and Mid-Upper Jurassic sands, including the Sandy Point, Hiccles Cove, and Awingak formations. Hu et al.'s (2014) analysis shows reservoir potential within all four intervals (Fig. B.2), with the Heidberg Group and Bjorne Formation sands centred by 15-25% porosity intervals. Sands of the Mid-Upper Jurassic units had porosities centred on 10-20%, and Schei Point Group porosities were evenly distributed from 5-25%. Based on the work of Hu et al. (2014) it is clear that reservoir potential exists within the entire Triassic and Jurassic section. Based on a similar geologic setting, sediments present in the Eastern Arctic and Labrador are indicators that the Hassel Formation (up to 28% porosity on surface outcrop near Lancaster Sound, McWhae 1979) and Eureka Sound Formation (encountered across the Canadian Arctic) are also prospective Cretaceous and Paleogene reservoir units.

Traps

All of the discovered hydrocarbon fields within the Sverdrup are in Paleogene anticlinal structures, with evidence of early salt movement (Embry, 2011; Dewing et al., 2016). A number of prospects are under-filled, this is probably due to leaky seals, or growth of the anticline after it was charged. Numerous

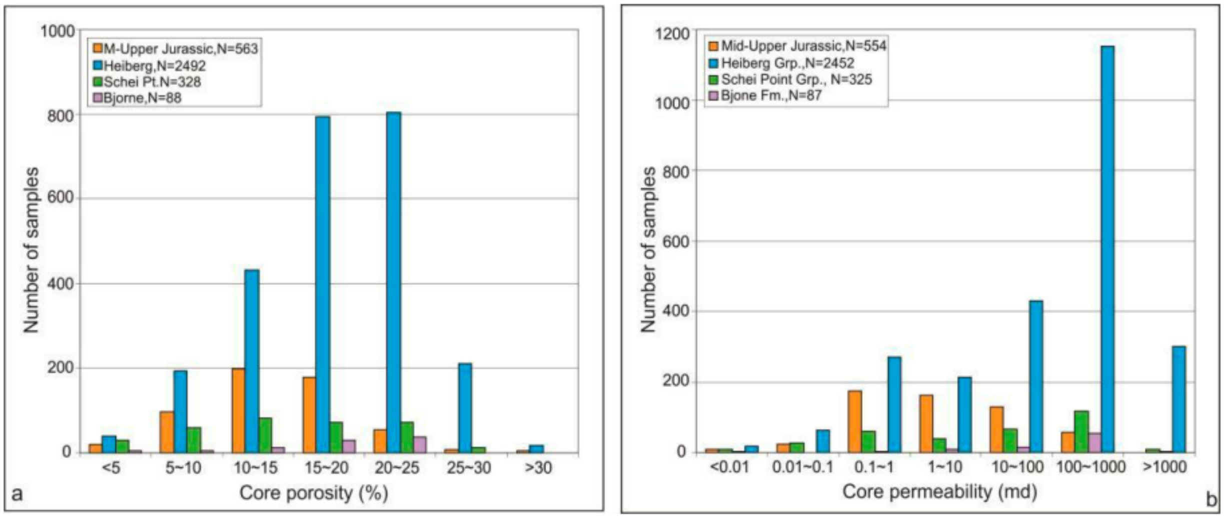


Figure B.2. Core Porosity and Permeability

Histogram plots show distributions of core porosity (a) and permeability (b) for all analyzed core samples for different reservoir intervals in the western Sverdrup Basin (Hu and Dewing, 2011).

smaller structures have been mapped seismically in the basin, but have not been tested. The Drake field is located above the edge of a Paleozoic half-graben (Dewing et al., 2016). These two fields are the largest known conventional gas fields in Canada and offer a potential analog for petroleum exploration in the Lincoln Sea. Dewing et al. (2016) suggest that the Drake anticline began developing during the Late Cretaceous, based on seismic and well profiles showing thinning within these Mesozoic units. This anticline may be formed by reactivation of Paleozoic faults.

Embry (2011) identified second- and third-order sequences, which are favourable for the development of stratigraphic traps. The third-order sequences range from Early-Middle Triassic, Late Triassic to Mid-Jurassic, and Upper Jurassic to Early Cretaceous (Embry, 2011). These sequences should also be present in the Lincoln Sea, and potentially younger Mid to Late Cretaceous sediments.

Seals

The seal for the Heiberg petroleum system is the lower Jurassic Jameson Bay Formation. The seal is locally breached (Balaena well, Waylett and Embry, 1992) and Panarctic Oils considered the underfill in traps near Ellef Ringnes Island to be due to limited capacity of the Jameson Bay to retain pressure (the gas pressure was very similar in all discoveries around Ellef Ringnes). Dewing et al. (2106) considered the underfill to be due to tightening of the anticlines after peak generation.

Key risks for hydrocarbon exploration are seal integrity, and destruction of source and reservoir by igneous intrusions.

Lower Paleozoic Petroleum Systems

Potential Source Rocks

Prior to the widespread greening of the continents by vascular plants in the Devonian, hydrocarbon source units would have been dominated by algae and marine phytoplankton. Source rocks would have accumulated as a result of some combination of high productivity, ocean anoxia, and high preservation, either due to widespread oceanic conditions or local algal blooms. Neoproterozoic strata contain organic-rich shale in the uppermost part of the Kennedy Channel Formation (~550 Ma?), but these are only exposed in areas of extremely thermal high maturity on NE Ellesmere Island and their organic content has not been quantified. Member C of the Hazen Formation (Miaolingian) appears organic rich, but like the Kennedy Channel Formation, is only exposed in areas of extremely high thermal maturity and the organic matter has not been quantified.

Cambro-Silurian shelf and platform successions have low total organic carbon (TOC), although Type I kerogen has been observed at single locations in middle Cambrian strata on southern Ellesmere Island (Mayr et al., 1994); in late Cambrian strata in the Cornwallis Central Dome K-40 well (Dewing et al., 2007); and within the Upper Ordovician Thumb Mountain Formation on western Cornwallis Island (Randell, 1994; Reid et al., 2013). A typical example of this type of source rock is a 1-3 m thick organic-rich bed in the Thumb Mountain Formation at Polaris Mine that varies between 2 and 10 wt. % TOC, with HI of 590 to 825 mg HC/g TOC (Obermajer et al., 2007; Reid et al., 2013).

Latest Ordovician to Silurian Cape Phillips Formation is the most likely potential source rock for large hydrocarbon deposits in the lower Paleozoic because it is very organic rich, thick, and widespread. This unit has thick intervals with high TOC (TOC av. = 2.0%, max. = 13.6%, and 78% of samples have TOC greater than 1%). Thermally unaltered samples have hydrogen indices up to 600 and a dominance of Type II kerogen (Obermajer et al., 2007; Synnott et al., 2018). The lower part of the Cape Phillips Formation was deposited a time when the shelf margin was depressed due to tectonic loading to the north and was onlapped by euxinic water related to a widespread ocean anoxic event (Dewing et al., 2019).

Upper Silurian to Lower Devonian flysch derived from the Boothia Uplift has organic-rich intervals, but total organic carbon content is less than 1% in two-thirds of the samples. Samples with TOC>1% have an average HI of 225 mg HC/g TOC. Stasiuk and Fowler (1994) described samples from Lower Devonian carbonate Disappointment Bay and Blue Fiord formations that have 1 to 3% TOC and HI between 500 to 600 mg HC/ g TOC, but the small number of samples and the restricted area from which samples have been analysed leaves the source potential of this succession poorly evaluated. Similar values might be expected from flysch derived from the Ingelfield Uplift on Ellesmere Island.

Thermal Maturity

Thermal maturity of lower Paleozoic strata in the Canadian Arctic was set by maximum burial by the Devonian Clastic Wedge during the Famennian, prior to folding associated with the Ellesmerian Orogeny (Skibo et al., 1991; Gentzis and Goodarzi, 1993; Dewing and Obermajer, 2009). Potential source rocks of the Cape Phillips Formation in the southeastern Canadian Arctic Islands as far west as the Boothia Uplift have low thermal maturity (<0.7% VR_o equivalent; Dewing and Obermajer 2009). Lower Paleozoic strata have very high thermal maturity from northern Ellesmere Island in the east to Prince Patrick Island and Banks Island in the west.

Reservoirs, Seals, and Traps

Potential clastic reservoirs tend to be well-cemented (Hu and Dewing, 2011). Potential carbonate reservoirs in the Cambrian to Devonian shelf and shelf margin successions have primary pores filled with calcite cements, so effective porosity would need to be either intercrystalline secondary dolomite or fractures in limestone. Porosity in 349 core plugs from lower Paleozoic carbonates average 2.0% and range up to 13.8%. Average permeability is 155 mD.

Regional seals are Ordovician evaporite units of Baumann Fiord and Bay Fiord formations, and latest Ordovician to Silurian shale of the Cape Phillips Formation. Local seals could be present in each succession, but an extremely effective seal (like an evaporite) would be required to retain integrity during the long time since hydrocarbon generation in the Late Devonian.

Potential hydrocarbon traps in the Lower Cambrian through Silurian successions and in the Upper Silurian to Lower Devonian succession along the margins of the Inglefield Uplift may include north-south-oriented, salt-cored folds formed during Late Silurian to Early Devonian time, hence folds would have been present prior to maximum hydrocarbon generation in the Late Devonian (Atkinson et al., 2017; Dewing and Obermajer, 2009). Ellesmerian folds formed in Late Devonian time. The youngest Upper Devonian sandstone unit is preserved regionally in synclines, indicating that maximum burial (hence oil generation) pre-dated the formation of anticlinal traps.

Key risks for hydrocarbon exploration are: 1) over much of the islands hydrocarbon generation occurred during deposition of the Devonian Clastic Wedge, before structural traps developed; 2) high chance of petroleum destruction and/or leakage during the long time since hydrocarbon generation (370 Ma).

APPENDIX C. PETROLEUM SYSTEMS FOR RIFT MARGINS

Rift Margin Analogs

The NW Canada Arctic Margin formed during opening of the Arctic Ocean in the Early Cretaceous. The age of synrift strata are likely Early Jurassic to Early Cretaceous based on analogy with Banks Island rift basin and tectonic models of the Arctic Ocean. Based on this, the oldest sediments on the rift margin are likely younger than 120 Ma. The sedimentary clastic wedge would include Late Cretaceous strata that regionally include an organic-rich potential source rock (Kanguk Formation). This has been found in Crocker I-53 well on Meighan Island on the south side of the assessment area and dredged from the floor of the Arctic Ocean on the north side of the assessment area. Overlying the Kanguk Formation are assumed to be Cretaceous to Cenozoic sandstone and shale successions, similar in age to those found in the Beaufort Mackenzie Basin (NEB, 2014). Turbidites and submarine fans are assumed to be present in the deep water and extend towards the Canada Basin.

Total sediment thickness is from Oakey and Stephenson (2008), although this thickness estimate is based on modelled gravity data and may include older (pre-rift) strata. Similar sediment thickness is seen offshore Banks Island (Kumar et al., 2009). The zone of synrift grabens is about 30 km wide and located where sediment thickness starts to increase rapidly to the offshore based on analogy with the shelf offshore Banks Island, and with the rifted Labrador margin.

Field size distribution is estimated from discoveries on the rifted Norwegian margin, offshore north of Norway and Guyana-Suriname Basin. Two discoveries in these areas are over 2000 million recoverable barrels of oil equivalent. The size of these fields informs the likely distribution of the larger fields possible along the NW Canada Arctic Margin. Smaller fields are not drilled in the offshore, so an onshore basin in Brazil (Sergipe-Alagoas Basin) with similar geological characteristics was used to constrain the small end of the distribution. These areas were also used to constrain the upper and lower ends of the prospect density probability distribution.

Lomonosov Ridge Petroleum Systems

Petroleum assessment of the Lomonosov Ridge follows that of the USGS analysis published by Moore et al. (2019), who presented a comprehensive summary of the geology and petroleum systems of the Lomonosov Ridge along its length. Given that the 'west' side of Lomonosov Ridge was a rift margin originally attached to northern Europe, the same field size distribution and prospect density probability distribution as was used on the NW Canada Arctic Margin was applied.

Alpha Ridge Petroleum Systems

Basement are rocks of HALIP affinity that either constitute the crust or have intruded older continental rocks and destroyed any hydrocarbon potential. Potential source rocks are organic rich Upper Cretaceous strata recovered from dredge samples (Clark et al., 1986; Firth and Clark 1998), similar in age and organic matter content to the Kanguk Formation in the Sverdrup Basin. The thickness of sediments is estimated at 500-1200 m (Jokat, 2003) and less than 1 km (Evangelatos et al., 2017). This sediment thickness is insufficient to reach the oil generation window.

APPENDIX D. METHODOLOGY FOR QUANTITATIVE ANALYSIS

Quantitative assessments in this report were done using commercial software PlayRA (v4-1-37), developed by Rose & Associates for use in the petroleum industry. While the detailed code remains proprietary, the method is described by Rose (2001). PlayRA builds on the concept of a petroleum ‘play’. A play is a family of prospects and/or discovered fields that share a common geologic history, and similar ‘petroleum system elements’ (PSE): source, timing of maturation and migration, reservoir development, and trap and seal. A play forms a natural geological population limited to a specific area. Because the play’s prospects and/or fields share geologic history, they can be described as a group, with common ‘chance of success’ (COS), range of field sizes, and number of prospects/fields likely to exist. To build these play descriptions, which become PlayRA inputs, the following steps are taken:

Define Play Areas and Analogs

Quantitative petroleum resource assessment starts with identifying areas that have common petroleum system elements and similar geological history, and defining these as assessment areas. Assessment areas must be defined carefully such that the areas (or sub-areas within them) can be described as a ‘play’, based on consistent geologic history. Consistent play history allows comparison to appropriate analogs with similar history.

Appropriate analogs can be researched from public sources. Good analogs are those with clear geologic setting information, quantitative information on field sizes as Estimated Ultimate Recovery – EUR (not just production to date), number of fields, and the geographic extent of the existing fields and related geologic potential. These analogs become key comparisons for geologic parameters in the study area, and sources of numerical inputs. They are especially important in frontier areas, where the analogs may be the only data source to estimate an appropriate field size distribution.

The areal extent of each assessment area is an important input, as other inputs developed from analogous basins are applied to the assessment areas in proportion to the area covered. For example, the number of fields from an analog is expressed as N fields / 1000 km^2, and then used to calculate the expected number of fields or prospects in the new assessment area based on its area (see below).

Chance of Success

The next step in quantitative assessment is to consider available geological and geophysical data to develop the ‘chance of success’ (COS) for each assessment area. COS estimates are affected by the amount of data available and the resulting confidence in whether there is an increased chance (positive information), or decreased chance (negative information), about a given petroleum system element (Fig. D.1).

A COS estimate is made for five petroleum system elements:

- source rock presence and maturation
- timing of maturation and migration paths
- reservoir
- trap
- seal and preservation

Note that this study separates ‘migration and timing’ from ‘source and maturation’ for the quantitative assessment to give more precision, especially in areas of complex geological timing relationships. These elements are sometimes combined where they are considered related or sufficient data is lacking.

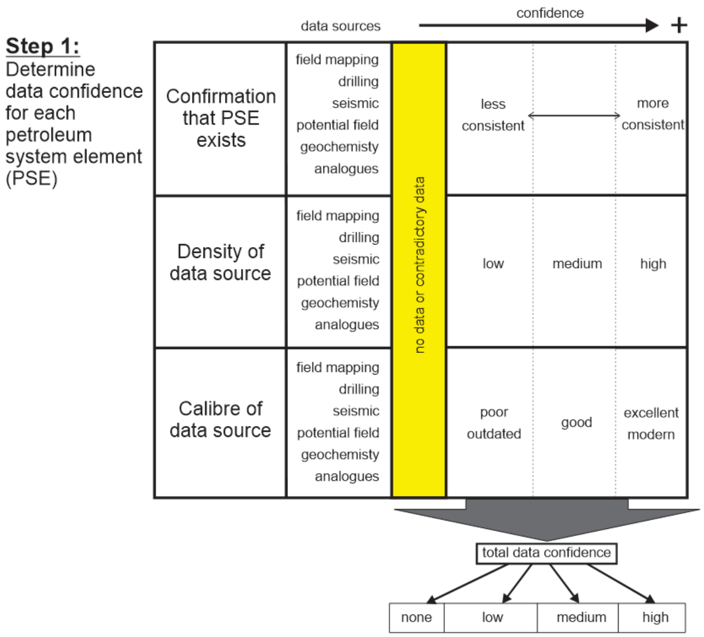


Figure D.1. Chance of Success and Data Confidence

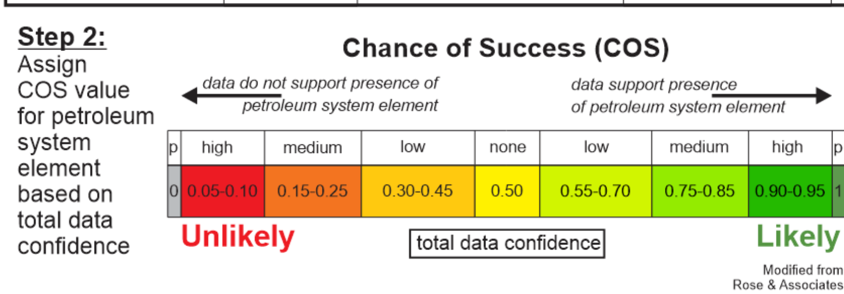
Step 1 – Data confidence is established using the density and calibre (quality) of data sources, plus whether the data clearly and consistently support/confirm that a petroleum systems element exists (or consistently support/confirm that it doesn't exist).

The lower table shows the types of data used and what factors are considered in evaluating density and calibre.

Step 2 – COS is chosen based on data confidence and whether evidence is positive or negative.

Criteria used in evaluating confidence levels for petroleum system elements

Petroleum System Element Input parameters	Data theme	Analyses	Density	Calibre
Source Quality: thickness kerogen type,TOC/HI Maturity: VRo, Tmax, models	field mapping	field sample analysis	scale of mapping	vintage, scale, chronostrat
	drilling	core sample analysis	drill spacing, depth	logs run, cores
	seismic	direct hydrocarbon indicators	seismic spacing	seismic quality, depth, well ties
	potential field	sediment thickness (maturity)	potential field line spacing	density
	geochemisty	known petroleum systems, oil source correlation, VRo	geochemisty sample spacing	vintage, types
	analogues	age	number of analogues	variability of analogues
Migration and Timing Migration: models, geochemistry Timing: geological relations	field mapping	field sample analysis	scale of mapping	vintage, scale, chronostrat
	drilling	core sample analysis	drill spacing, depth	logs run, cores, dst samples
	seismic	seismic grids	seismic spacing	seismic quality, depth, well ties
	potential field			
	geochemisty	oil source correlation	geochemisty sample spacing	vintage, types
	modelling	3D migration models	seismic spacing	seismic quality
Reservoir lithology porosity, permeability depth saturation phase	field mapping	samples, environment of deposition	number of samples	types of analyses
	drilling	core, DST, log analysis	core spacing, samples	types of analyses
	seismic	seismic mapping	seismic spacing	seismic quality, well ties
	potential field	sediment thickness, fault location	potential field line spacing	
	geochemisty			
	analogues	analogue size distributions	number of analogues	variability of analogues
Trap Size Type: structure, statigraphic Lateral seals **Caution double dipping with reservoir only in strat-traps*	field mapping	mapped geometries	scale	vintage
	drilling	discovered fields, reserve estimates	drill spacing	DSTs
	seismic	seismic mapping	seismic spacing	seismic quality, depth
	potential field	potential field anomalies (faults, reefs)	potential field line spacing	data corrections, 1st derivative
	geochemisty			
	analogues	tectonic/stratigraphic setting	number of analogues	variability of analogues
Seal thickness lithology depth extent intact/breached preservation	field mapping	known fields, env. of deposition	scale	vintage
	drilling	samples, overpressure analysis	drill spacing	logs run, core size
	seismic	flat spots,fluid escape structures	seismic spacing	seismic quality, well ties
	potential field	sediment thickness		
	geochemisty			
	analogues	depositional setting	number of analogues	variability of analogues



The COS is first considered regionally, and estimated for each element at the play/basin scale. The question is asked "Does this petroleum system element work anywhere in the play area?". The five play COS are multiplied to produce an overall 'Play Chance'. The Play Chance is the chance that there is an effective petroleum system in this play at all. With the state of knowledge in frontier areas, it is often not at all certain whether a play exists, and the Play Chance will be well less than 100%

Then the COS is also considered locally. The question is asked "What is the additional risk that an individual prospect could fail, even when the element works somewhere in the play?". The local COS of the five petroleum system elements are multiplied together to produce a 'Prospect Chance' – the chance a given prospect succeeds, given that the play has already succeeded. Note that Prospect Chance is conditional, and does not doubly count the risk.

Different aspects of petroleum system elements are typically more regional issues or more local issues (Fig. D.2). For example, hydrocarbon source may be a risk at the play/basin scale, but because source rocks are typically widespread when they are deposited, it is seldom a local problem. In contrast, reservoir COS may be partly regional (chance of widespread sand deposition, for example) and partly local (were sands cemented in the prospect location?), and trap effectiveness COS typically varies with each prospect.

Figure D.2. Which PSEs are typically regional or local issues?

Chart showing which petroleum system elements are generally considered regional versus local issues.

Petroleum System Element	Parameter	Play/Regional issue	Local/Prospect issue
Source	thickness	X	
	kerogen type	X	
	total organic carbon	X	
	thermal maturity	X	X
Migration and Timing	expulsion	X	
	migration path		X
	migration timing	X	X
Reservoir	lithology	X	
	porosity		X
	permeability		X
	depth		X
	saturation		X
	phase	X	
Trap	size		X
	type	X	
	trapping effectiveness		X
Seal	thickness	X	
	lithology	X	
	depth		X
	extent	X	
	intact/breached		X
	preservation	X	X

The overall COS for a given prospect is called the probability of geologic success, P_g, and is the multiplication of Play Chance and Prospect Chance. Play Chance and Prospect Chance are used in the Monte Carlo simulation to determine if each realization succeeds. COS estimates are used for both qualitative and quantitative resource estimates, and details of the rationale for each COS estimate are recorded in the GIS archive for this study. This terminology matches that used in Rose & Associates PlayRA software and Rose, 2001, but may differ slightly from other users (e.g., Peel and Brooks, 2016).

Field Size Distribution

The Monte Carlo software requires a range of possible field sizes in the play being analyzed. There are two ways to obtain this field size range. One is to use geological data to create a 'generic prospect'. The possible range of prospect parameters are estimated: trap area, net pay, porosity, hydrocarbon saturation, and fluid properties. The formula to calculate the volume of a prospect is:

$$\text{Field Size} = \frac{\text{Productive Area x Reservoir Thickness x Porosity x Hydrocarbon Saturation}}{\text{Formation Volume Factor}}$$

A Monte Carlo simulation (see below) is run to calculate this formula over and over, selecting each input from ranges of possible values, and calculating a range of field sizes. This method is most commonly used when analyzing detailed plays where a good amount of data is available.

The second way to obtain a field size range is to use field size data from geologically analogous basins. This method is more suitable in frontier basins with very limited data, and is used here. Data from analogous basins are plotted with an associated Rose & Associates program – 'Toolbox v5-1-159'. It is typical for the distribution of sizes of fields in a mature basin to be approximately lognormal (Rose, 2001), and thus lognormal curves are fit to the data, to allow the range sizes of observed fields to be described with simple lognormal parameters.

The Field Size Distribution is input into PlayRA using the P90 and P10 of the fitted lognormal curves. Normally recoverable field sizes are input (Estimated Ultimate Recovery data from fields in analogous basins are by definition 'recoverable'), and thus output resources are 'recoverable'. But in-place resources for plays can be calculated, by using a distribution of in-place field size estimates as input.

Number of Prospects / Expected Number of Fields

The final parameter required is an estimate of the number of prospects available to be tested, or the number of fields (or pools) expected to be found. Prospects are untested concepts that may contain petroleum. Fields are actually tested petroleum accumulations. Pools are sub-units of fields in distinct reservoirs that are in pressure communication. A field can contain one or more pools (pressure units), and the terms field and pool are often used interchangeably at the play scale.

The number of prospects relates to the number of expected fields with the Prospect Chance:

$$\text{\# Prospects X Prospect Chance} = \text{\# Expected Fields}$$

This number of prospects or fields is expressed as a range of reasonable values (a lognormal distribution), not a single number. As with field size distributions, there are two main sources for these estimates.

In areas with sufficient data, geologic units may be mapped, and prospects outlined. The number of known prospects can be used at the high confidence end of the distribution – typically P90, up to P99, depending on the quality of the data and mapping. This number of prospects can also incorporate the exploration history (number of prospects already tested) thus far. Mapping of opportunities with less confidence (leads), or other estimates that extrapolate mapping or exploration history into less understood areas of the play/basin can also be used as a point on the distribution. This process is used in HAB for plays using the Sverdrup Basin as analog.

The number of prospects/fields distribution (or points on this distribution) can also be built from the same analogous basins as the field size distributions. The number of fields in analogous basins can be expressed as N fields / 1000 km^2. This 'field density' can then used to calculate the expected number of fields or prospects in the assessment area, based on its area. Field densities from various analogs can be used to develop a reasonable range of expected fields – this approach is used for Rift Margin analog plays in HAB. Alternatively, expected field numbers from analogous basins can be combined with mapped prospects, and used to constrain the mean to lower confidence end of the distribution.

PlayRA accepts input of either ‘number of prospects’ or ‘expected number of fields’ and will calculate one from the other as described above. Distributions are typically input as a lognormal distribution described with P90 and P10, but normal, triangular and uniform distributions can be used.

Monte Carlo Simulation Concept

PlayRA uses the classic Monte Carlo simulation / method (Wikipedia, 2022), where the amount of resources are calculated over and over again, with the inputs for the calculation chosen randomly from input distributions. Each individual calculation is called a ‘realization’ and the whole Monte Carlo calculation process is called a ‘simulation’. This statistical approach was named for the casino in Monaco, as it involves “rolling the dice” to choose inputs randomly for each realization. The PlayRA simulation typically calculates 25 000 realizations (used for HAB), though this can be varied by the user, to speed test runs, for example. More realizations produce a more accurate and consistent output distribution. The PlayRA Monte Carlo simulation is illustrated in Figure D.3:

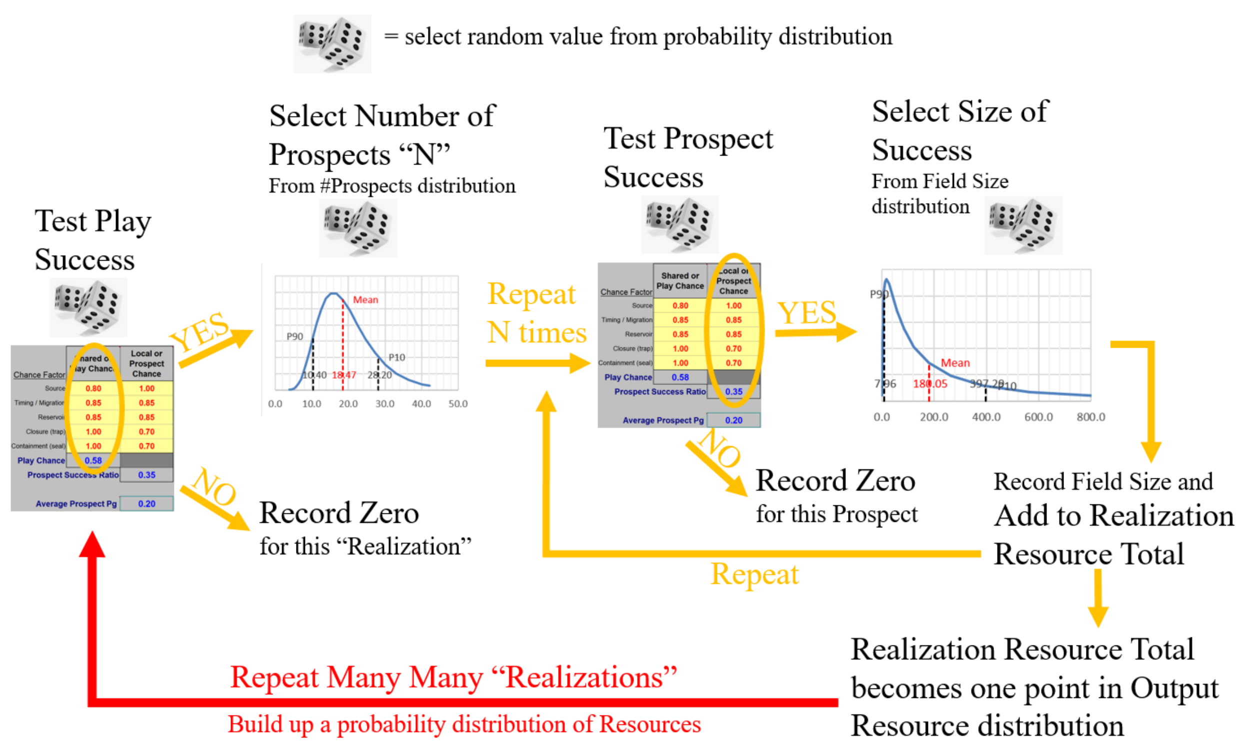


Figure D.3. Monte Carlo calculation process in Rose & Associates PlayRA software

Cartoon outlines the calculation process, where the range of possible resources are calculated by repeated calculation of a possible resource outcome that randomly samples from the input distributions – the chance of success for the Play, the number of prospects in the Play, the chance of success of each prospect, and the range of size of the fields.

The PlayRA simulation calculation first tests whether the play succeeds for that particular realization (using the Play Chance). If yes, the number of prospects ‘N’ is ‘chosen’ from that input distribution. Then those N prospects are ‘tested’ (using the Prospect Chance) – some succeed and some don’t. For those that succeed, a size of the successful field is 'chosen' from the field size distribution. That resource volume is added to the Realization total. When the N prospects have been tested, the total resources summed are recorded as one point on the output resource distribution.

All 'choices' of values are made randomly from the input distributions, with a frequency that reflects their position in each distribution – for example, the mode (the most common value in a distribution) will be chosen much more often than extreme values from that same distribution. When many many realizations are complete, the distribution of possible resources becomes apparent, with moderate values being calculated more often than occasional extreme results.

PlayRA also records the sizes of each of the successful fields within each realization. These field sizes are then sorted, and a ranked list of the field sizes for each realization is tracked. This allows statistical analysis of the individual field sizes. The largest field found, second largest field, third largest, etc., can be described with a mean size and size distribution.

Resource Estimate Outputs

The key output is the Risked Resource distribution, which includes 'All Cases' calculated, including failures. It is plotted as a cumulative frequency distribution (Fig. D.4), which illustrates the probability of

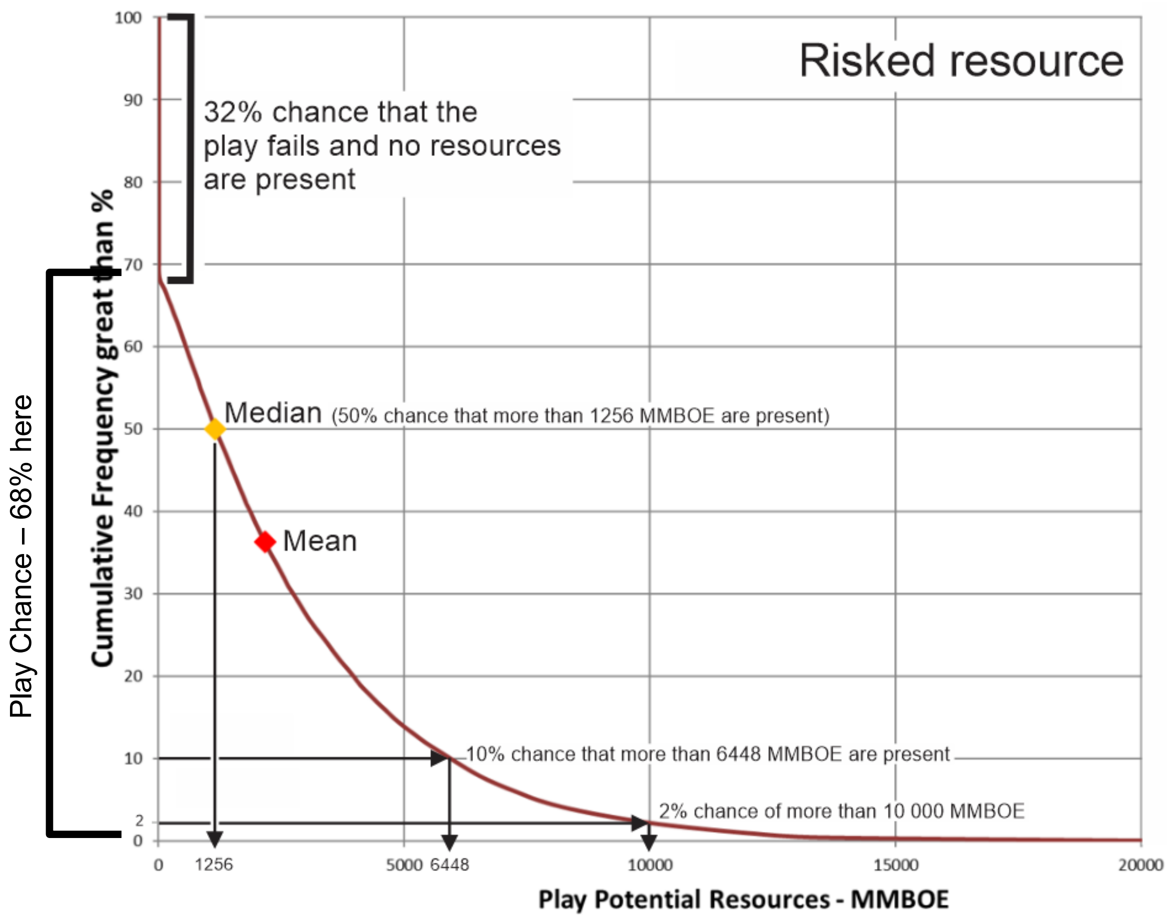


Figure D.4. Output of risked resource for a single play

Example of an output for risked potential resources for a single play, showing the probabilistic distribution of resource size calculated in the Monte Carlo simulation. The risked resource includes the chance of finding no resource. In this example, the Play Chance is 68%, and there is a 32% chance that no resource is present at all (100% - 68%).

finding a resource of a certain size or more, and also illustrates the risk (with a probability characterized by the Play Chance) that no oil and gas resource exists in the assessment area. Note that PlayRA graphs automatically produce both imperial (MMBOE) and metric (E^6 m^3) versions.

The output of the Monte Carlo simulation also gives the 'Success Case' resource distribution. This is the distribution of resources that are calculated to exist for the whole play, given the play succeeds; that is, it is the distribution of resources when the zero valued failure cases are dropped from the sample set. It is used in conjunction with the Play Chance, which is the chance that play succeeds and the Success Case applies, and it is a lognormal distribution. The Success Case does not include the chance of finding no resource, and it is used in performing economic analysis because it gives a probability of finding a field of a certain size, given the play is working. The Success Case of each play is also required for aggregating multiple plays (see below).

In addition, PlayRA outputs the distribution of the number of fields found, based on the Monte Carlo simulation, for both All Cases and Success Cases. A cumulative frequency graph of the number of fields/pools in the play is produced, similar to the All Cases risked resource cumulative frequency graph. The expected number of fields can also be calculated from the number of prospects and COS values (but the formula calculation does not match exactly, because PlayRA is using the Monte Carlo simulation result). In considering All Cases, by definition, a large number of prospects that failed are included in the grouping. So for a prospect to become a successful field in All Cases, the play and the prospect itself will both have to work. Thus the formula for Expected Number of Fields = Number of Prospects X Play Chance X Prospect Chance. In the Success Case, as the name implies, only the cases where the play is successful are considered. So, quite logically, in the case that the play is declared successful, the Expected Number of Fields, becomes = Number of Prospects X 100% X Prospect Chance.

As described above, PlayRA also tracks the individual fields it finds in each realization, and thus produces a ranked list of fields – largest field, second largest field, third largest field, etc. Each ranked field size is described by a distribution around a mean size. These ranked field sizes are plotted on two types of graphs. Firstly, individual field size is plotted versus pool/field rank, with the mean pool size plotted as a line and the P90 to P10 range plotted as a shaded area behind. And secondly, the resource size of the first through fifth largest pools are plotted on a cumulative frequency graph. The number of fields and their sizes are important for economic analysis of the play.

In addition, economic cut-offs can be used in PlayRA. This allows the resource summation to discard small fields that have no chance of being economic from each realization. All Case and Success Case distributions are then calculated based only on fields that are larger than the cut-off, which are the accumulations that would contribute in a practical situation. Finally, the PlayRA simulation can calculate the chance of finding a field greater than a certain size. Typically an economic field size in offshore environments, such as 300 MMBOE, is input, and the output chance of exceeding this size helps provide another way to elucidate the chance that the play will be economic at a practical, field scale level.

As mentioned, resource distributions are typically calculated based on recoverable resources, and the Estimated Ultimate Recovery data from fields in analogous basins are by definition 'recoverable' figures. However, in-place resources for plays can also be calculated by using estimates of the range of in-place resources in fields, either from a generic prospect calculation or from analogs (see field size distributions above). The same Play Chance applies to in-place calculations, and the same number of fields are predicted. Note also, means output from PlayRA are the means of the truncated P1-P99 distribution.

Rose & Associates is thanked for allowing the GSC to modify the code to customize outputs and graphs for our regional petroleum assessment needs.

Aggregation of Plays and Assessment Areas

Assessment areas often have more than one geologic play, and a number of assessment areas may be used to study a whole region, as in this study. Thus, a method of statistically combining play results is needed. It is important to note that only the means of statistical distributions can be summed; proper statistical 'aggregation' methods must be used to fully combine plays and/or assessment areas.

The various plays and assessment areas in this study are aggregated for the whole region using 'Multi-Zone Master' (v4-2-104b) from Rose & Associates. This software was written to aggregate the contributions from various stacked plays within a well or field, but can be used to aggregate any lognormal distributions. There is functionality to specify full or partial dependence between the various plays, but for HAB we have assumed that the different play areas are independent. The input for each play or area is the Success Case resource distribution (described with its P90 and P10 values), and the Play Chance (which is the chance that this resource distribution is successful and will contribute).

The software uses a Monte Carlo process (Wikipedia, 2022, typically 30,000 realizations) to sum up the plays. For each realization, it tests whether each play is successful, and if so, picks a resource size for that play from that play's Success Case resource distribution, to add to the realization resource total. After many many realizations, the full distribution of aggregated resource totals is determined.

The percentage of realizations in the Monte Carlo simulation where one or more plays are successful is used to calculate the overall aggregated Play Chance that there will be non-zero resources somewhere in the region. This is equivalent to the statistical concept of the chance of 'A or B or C or …', i.e., we only need one of A or B or C or… to get a success in the aggregate. This is why the regional aggregated Play Chance is higher than the individual Play Chances.

The statistical formula for the probability of A or B (i.e. that either or both A or B succeed) = Probability of A + Probability of B – Probability of A and B. (Probability of A and B is subtracted so that it isn't counted twice, once with A and once with B.) This formula shows that the Probability of A or B is clearly greater than either the Probability of A or the Probability of B – this is another way to consider why the Play Chance of an aggregation is greater than the Play Chance of the individual plays aggregated.

A corollary of this increased aggregated Play Chance is that, for the final aggregated All Cases resource distribution, there will be non-zero values at higher percentiles on the cumulative frequency chart, than for the input risked resource distributions. For example, it is possible to input several plays that all have Play Chance less than 50%, and thus zero P50 value, and aggregate to a regional Play Chance of greater than 50%, and thus have a P50 greater than zero for the final aggregate.

Aerial Apportionment

PlayRA does not analyse where, within a play or assessment area, the resources are likely to exist. Our qualitative petroleum potential map illustrates the more likely locations of resources, and thus makes a good compliment to quantitative analysis.

To calculate the resources within the Proposed Protected Area, the percentage of each assessment area that falls within the PPA was calculated. Then the resources of each play area are 'apportioned' by multiplying the distribution by this percentage to obtain the resources for that assessment area within the PPA. If one aerially apportions the All Cases mean resources from each assessment area and sums them, one can directly obtain the overall All Cases mean resource for the PPA. To calculate the full distribution of resources within the overall PPA, the Success Cases for each assessment area are aerially apportioned and then aggregated with the appropriate Play Chances (see above).

APPENDIX E. INPUT PARAMETERS FOR QUANTITATIVE ANALYSIS

Areal Extent of Assessment Areas

Appendix A outlines the rationale for our assessment areas in the High Arctic Basins. The various analogs used to develop input distributions are discussed above, in Appendices B and C. The areal extent of each assessment area is an important input (Table 7), as other inputs are developed from analogous basins and are applied in our assessment areas in proportion to the area covered:

Table 7. Areal extent of assessment areas

Assessment Area	Area (km^2)	% of Area in Proposed Protected Area
HAB1_NESverdrup_HALIPinfluenced	138 492	11 %
HAB2_Deformed_LPaleozoic_Strata	159 813	22 %
HAB3_LincolnSea_TotalBasin	44 490	41 %
HAB3_LincolnSea_CanadianWaters	18 402	100 %
HAB4_LomonosovRidge	32 712	100 %
HAB5_AlphaRidge-HALIP	196 438	86 %
HAB6_NWCanadaArcticMargin	82 318	62 %

Chance of Success

COS for each assessment area is detailed in Table 8. Due to the lack of data, there is a great deal of uncertainty that petroleum systems even exist in all of the High Artic Basins, and thus the Play Chance for every assessment area (highlighted in **red bold** below) is well less than 100%.

The risked resource estimates that are calculated using the COS values will estimate that no resources are present at a probability greater than the Play Chance. For instance, if the Play Chance is 0.41, then 59% of the time the play will fail and the assessed resource will be zero.

Table 8. Chance of success (COS) in assessment areas

Assessment Area / Sub-play		Source / Maturation	Migration / Timing	Reservoir	Trap	Seal / Preservation	Play Chance / Prospect Chance	Prospect Pg
HAB1_NESverdrup _ HALIPinfluenced: Mesozoic play	Play COS	1.0	0.8	0.85	1.0	0.6	**0.408**	
	Local COS	0.5	0.8	0.7	0.8	0.8	**0.179**	**0.073**
HAB1_NESverdrup _ HALIPinfluenced: U Paleozoic play (stacked plays)	Play COS	1.0	0.4	0.6	1.0	0.7	**0.168**	
	Local COS	0.5	0.8	0.8	0.7	0.7	**0.157**	**0.026**
HAB2_Deformed_ LPaleozoic_Strata: Ordovician sub-area (southern area)	Play COS	0.4	0.3	0.7	1.0	0.5	**0.042**	
	Local COS	1.0	1.0	0.5	0.7	0.8	**0.28**	**0.012**

HAB2_Deformed_ LPaleozoic_Strata: elsewhere (larger northern area)	Play COS	0.15	0.3	0.4	1.0	0.5	**0.009**	
	Local COS	1.0	1.0	0.5	0.7	0.5	**0.175**	**0.002**
HAB3_LincolnSea_ CanadianWaters (and Total Basin)	Play COS	0.8	0.85	0.85	1.0	1.0	**0.578**	
	Local COS	1.0	0.85	0.85	0.7	0.7	**0.354**	**0.205**
HAB4_Lomonosov Ridge	Play COS	0.75	0.3	0.6	1.0	1.0	**0.135**	
	Local COS	1.0	1.0	0.6	0.7	0.7	**0.294**	**0.040**
HAB5_AlphaRidge- HALIP	Play COS	0.15	0.7	0.4	1.0	1.0	**0.042**	
	Local COS	1.0	1.0	0.3	0.3	0.7	**0.063**	**0.003**
HAB6_NWCanada ArcticMargin: Cretaceous-Recent play	Play COS	0.8	0.85	1.0	1.0	1.0	**0.68**	
	Local COS	1.0	0.85	0.8	0.7	0.7	**0.333**	**0.227**
HAB6_NWCanada ArcticMargin: pre-rift play (stacked plays)	Play COS	0.45	0.85	0.45	1.0	1.0	**0.172**	
	Local COS	1.0	0.85	0.8	0.7	0.7	**0.333**	**0.057**

Field Size Distribution

This study uses geologically analogous basins to estimate the range of possible field sizes in each assessment area. The closest explored basin with good field size data is the western Sverdrup Basin. It was explored during the 1960s to 1980s, and has 17 discoveries directly in the basin and 2 more small fields on its periphery (included as representative of the smallest field sizes). The western Sverdrup is a rift sag basin. As discussed above (Appendix B), it is a good analogy for Area 1: NE Sverdrup Basin, which is an extension of the same basin, and Area 3: Lincoln Sea Basin, which is on trend between the Sverdrup Basin and the Barents Sea (another similar basin off Norway), and the pre-rift sub-play in Area 6, which has similar stratigraphy.

The Geological Survey of Canada has unpublished records of the discovery sizes from Panarctic Oils and the Canadian Oil and Gas Lands Administration (COGLA). These figures are summarized in Table 9. Base-case and upside estimates are listed for every field, as well as in-place and recoverable figures. The rationale for the upside varies. In some fields the base-case uses the observed 'gas-down-to' (which is a conservative estimate of field size), and the upside uses the gas-water contact calculated from pressures. In other fields, a more generous recovery factor is used for upside. Chen et al. (2000) published the base-case in-place figures for the Sverdrup Basin. This study uses recoverable figures for the main resource estimates, and in the case of the Sverdrup Basin analogy, we are using the recoverable upside estimates, as more representative of the total useable resource. In-place resource estimates were also calculated, for comparison to previous studies, using the Sverdrup upside in-place figures.

Table 9. Petroleum field sizes in the western Sverdrup Basin region

Field name	Base-case In-Place (MMBOE)	Base-case In-Place (10^6 m^3)	Base-case Recoverable (MMBOE)	Base-case Recoverable (10^6 m^3)	Upside In-Place (MMBOE)	Upside In-Place (10^6 m^3)	**Upside Recoverable (MMBOE)**	Upside Recoverable (10^6 m^3)
Drake	764.7	121.6	611.7	97.3	959.6	152.6	**767.7**	122.1
Cisco	722.9	114.9	227.7	36.2	721.9	114.8	**227.5**	36.2
Hecla	619.1	98.4	529.4	84.2	619.3	98.5	**529.5**	84.2
Balaena	592.4	94.2	29.6	4.7	593.3	94.3	**89.0**	14.1
Cape Allison	483.4	76.9	215.3	34.2	484.1	77.0	**215.6**	34.3
Whitefish	422.3	67.1	349.2	55.5	756.9	120.3	**626.0**	99.5
Kristoffer	345.7	55.0	242.0	38.5	345.6	54.9	**241.9**	38.5
Skate	257.5	40.9	125.5	20.0	256.1	40.7	**124.8**	19.8
Jackson Bay	245.7	39.1	172.0	27.3	283.2	45.0	**198.2**	31.5
King Christian	152.4	24.2	121.9	19.4	152.9	24.3	**122.3**	19.4
Maclean	98.7	15.7	78.9	12.6	98.7	15.7	**78.9**	12.6
Thor	86.3	13.7	69.0	11.0	86.2	13.7	**68.9**	11.0
Char	67.8	10.8	37.2	5.9	72.2	11.5	**39.4**	6.3
Cape MacMillan	37.7	6.0	22.3	3.5	70.4	11.2	**48.0**	7.6
Wallis	21.7	3.4	17.3	2.8	21.7	3.5	**17.4**	2.8
Sculpin	16.7	2.6	13.3	2.1	16.7	2.6	**13.3**	2.1
Roche Point	11.4	1.8	9.1	1.5	11.6	1.8	**9.3**	1.5
Bent Horn	3.3	0.5	1.0	0.2	6.7	1.1	**2.0**	0.3
Romulus	3.3	0.5	1.0	0.2	3.3	0.5	**1.0**	0.2

As described above (Appendix D), Rose & Associates Toolbox software was used to fit a lognormal curve to this field size data, and the data is input to the PlayRA software using P90 and P10 of this lognormal distribution. These distributions are outlined in Table 10.

Area 4: Lomonosov Ridge and Area 6: NW Canada Margin, Cretaceous to Recent sub-play are in a rift margin geologic setting, which hosts many significant fields worldwide. In order to create a reasonable field size distribution for this setting, public data from analogous rift basins were assembled and a lognormal distribution fit to the reported (recoverable) field sizes:

- 24 fields from the Norwegian Sea (https://www.norskpetroleum.no/en/facts/field/#),
- 11 fields from the Guyana-Suriname Basin (https://seekingalpha.com/article/4240592-guyana-suriname-basin-emerging-petroleum-province)
- 30 fields from the Sergipe-Alagoas Basin (https://www.researchgate.net/publication/313975123_IBP1422_16_ASSESSMENT_OF_YET-TO-FIND_OIL_IN_SEAL_BASIN_BRAZIL)

Minimum field size considered viable is 1 MMBOE. The field size distribution for rift margins, applicable for recoverable resource estimates in Area 4 and Area 6 Cretaceous to Recent, is outlined in Table 10. In-place resource estimates were not publically available for these analogs, so an in-place field distribution was estimated from the recoverable field sizes. We assume that oil and gas are equally likely, and oil recovery factor is typically 30% and gas recovery factor is typically 80%, for an average recovery factor of 55%. In-place figures were back-calculated using this 55% recovery factor.

Table 10. Field size distributions for HAB resource assessments

Field Size Distribution	P90 (MMBOE)	Mean (MMBOE)	P10 (MMBOE)	Used for
Western Sverdrup Upside Recoverable	7.96	182.75	397.29	Areas 1 and 3, Area 6 pre-rift
Western Sverdrup Upside In-place	15.23	296.99	653.92	Comparison to Total Lincoln Sea Basin and other studies
Rift Margin Analogs Recoverable	4.89	275.25	532.69	Area 4 and Area 6 Cretaceous to Recent
Rift Margin Analogs In-place	8.89	495	968.53	Comparison to other studies

Number of Prospects/Number of Expected Fields

The final parameter required is an estimate of the number of prospects available to be tested, or the number of fields expected to be found. For plays analogous to the Sverdrup Basin, these estimates are built from exploration history, mapping and estimates of future potential in the Sverdrup Basin. For Rift Margin plays, the same analogous basins as the field size distributions are used to estimate field density.

For the western Sverdrup Basin an extensive seismic database is available, and Chen et al. (2000) report an estimate of 150 prospects in this 150 000 km^2 basin. This estimate of 150 is used as the mean number of prospects. 114 wells were drilled in the basin, including 14 stratigraphic tests, 42 delineation wells, and 2 not testing the play, leaving 56 different prospects tested yielding 17 discoveries. This figure of 56 prospects is taken as the P99 number of prospects. A lognormal distribution was estimated from these data (using Toolbox v5), and then scaled by areal proportion for the two assessment areas analogous to the western Sverdrup. These distributions are outlined in Table 11.

Table 11. Number of prospects distributions for Sverdrup and analogous basins

Basin / Assessment Area	Area (km^2)	P99	P90	Mean	P10
Western Sverdrup	150 000	56	84.2	150	229.3
Area 1. NE Sverdrup	138 500 (90%)		75.8	135	206.4
Area 3. Lincoln Sea Canadian Waters	18 400 (12.3%)		10.4	18.5	28.2
Area 3. Lincoln Sea Total Basin	44 490 (30%)		25.3	45	68.8

Estimates of numbers or density of prospects in rift margins are not publicly available. The number of fields in analogous rift margin basins and the area of those basins allow the calculation of field density (# of fields / 1000 km^2) in each basin. The maturity of exploration in the analogous basins was considered, and the observed field densities used accordingly: the P90 field density for rift basins is taken from the number of fields in the Norwegian Sea to date, and the P10 field density for rift basins is taken from the well-explored Sergipe-Alagoas Basin in Brazil. Area 6: NW Canada Margin averages very analogous rift margin potential with other lesser areas downslope or closer to HALIP, so the field density numbers were multiplied by 80% to account for these lesser parts. Area 4: Lomonosov Ridge was studied by Moore and Pitman (2019), who suggested a limited density of accumulations in the region, due to less opportunity for continent derived sedimentation. They estimated a field density of 50% of other margins they studied, and thus we also multiplied our field density by 50%. Field densities and resulting 'number of expected fields' are shown in Table 12.

Table 12. Field density and number of expected fields distributions for rift margins and analogous assessment areas

	Field Density / 1000 km2			Number of Expected Fields		
Basin / Assessment Area	**P90**	**Mean**	**P10**	**P90**	**Mean**	**P10**
Rift Margin Analogous Basins	0.08	0.258	0.5			
Area 6. NW Canada Margin	0.064	0.207	0.4	5.7	17.0	32.9
Area 4. Lomonosov Ridge	0.04	0.129	0.25	1.3	4.2	8.2

APPENDIX F. DETAIL OF RESOURCE ASSESSMENT OUTPUTS FROM QUANTITATIVE ANALYSIS

This appendix provides detailed outputs of the Monte Carlo resource assessments for each assessment area, as well as the statistically aggregated resource assessment for the Proposed Protected Area. As explained in Appendix D, these assessments were created with PlayRA, Toolbox, and Multi-Zone Master software developed by Rose & Associates.

Outputs tabulated here include statistical distributions of the potential recoverable resources for All Cases ('risked'), and for Success Cases (means are truncated, P1-P99). In addition, the number of fields and the size of those fields in ranked order are estimated. These are important for economic analysis of the play. The chance of a large field >= 300 MMBOE is also calculated. Graphs from the model depict: i) potential risked recoverable resources, ii) the number of fields, and iii) (for the Success Cases) field sizes by rank and cumulative frequency. A second series of Monte Carlo models calculate the distribution of potential in-place resources; these are reported in the tables. The same Play Chance applies to in-place calculations, and the same number of fields are predicted.

In assessment areas with stacked plays, Rose & Associates 'Multi-zone Master' was used to statistically combine them, with the assumption that plays are independent of each other. Then, the Success Cases for each assessment area were apportioned by area to the Proposed Protected Area, and these apportioned Success Cases and the Play Chance for each area were input into 'Multi-zone Master', to calculate an aggregated resource estimate for the whole PPA. Both recoverable and in-place resources are estimated.

Our field size distributions assumed a minimum field size to be 1 MMBOE recoverable. The minimum cut-off used does have some affect the resources calculated. For comparison we ran a second set of calculations of recoverable resources, using the minimum economic field size feature in 'PlayRA' set to 50 MMBOE (the minimum field size typically used in USGS analyses of Arctic Basins), and a third set of calculations, with the minimum economic field size set to 300 MMBOE (the minimum stand-alone field size of economic significance on Canada's east coast). The mean resource size using the >50 MMBOE cut-off was about 94% of the mean of the risked resource. The mean resource size using the >300 MMBOE cut-off compared to the mean of the risked resource was more variable. In some areas, no fields larger than 300 MMBOE were predicted, in cases where fields of >300 MMBOE are predicted, the mean recoverable resource using a 300 MMBOE cut-off is about 69% of the risked resource.

Resource assessments were not run for two assessment areas, because of the very low chance of success for the whole basin / play in those areas. Area 2: Deformed Lower Paleozoic Strata is judged to have a Play Chance of 4.2% in a limited part of the area to the south, and 0.9% elsewhere. Area 5: Alpha Ridge – HALIP is also judged to have a Play Chance of 4.2%.

Area 1. NE Sverdrup Basin - HALIP Influenced

This first assessment area contains two stacked plays. Reservoirs and sources of Mesozoic age are the most productive in the Western Sverdrup Basin, and form the more significant play in the NE Sverdrup. An older upper Paleozoic aged petroleum system is thought to exist beneath the Mesozoic play in the Western Sverdrup, and may also exist stacked beneath the NE Sverdrup Basin. These two plays are statistically aggregated into a resource assessment for the whole assessment area – mean recoverable resources are 1876 MMBOE (298.2 x 10^6 m^3) (Table 13). The resources in this area are spread over a large area (138 492 km^2); mean resources per area are 13.5 MMBOE / 1000 km^2.

Some exploration occurred within this assessment area from the 1960s to the 1980s – some limited 2D seismic data was acquired and 24 wells were drilled within the area. There is one very small discovery in this assessment area – Romulus, but it barely meets a threshold of 1 MMBOE, and was not taken as proof that petroleum resources are wide spread or significant in volume in the assessment area (i.e. it was not taken as proof that the petroleum systems are regionally present). This assessment area is the only area with significant resources where there is an opportunity for fields to be near shore (possibly in shallow water) or on shore, and not challenged by very significant ice issues (1 to 2 year ice is typical in the inter-island channels, and communities can be reached by ship). These more benign operating conditions affect the feasibility and economics of any future exploration and drilling. Remoteness and high operating costs in the High Arctic will still challenge economics.

Table 13. Resource assessment output: Area 1. NE Sverdrup Basin – HALIP Influenced

		Mesozoic Play			upper Paleozoic Play			Aggregated Resources	
		MMBOE	10^6 m^3	# of fields	MMBOE	10^6 m^3	# of fields	MMBOE	10^6 m^3
Recoverable - All Cases (risked)	P90	0	0	0	0	0	0	0	0
	P50 median	0	0	0	0	0	0	773	122.9
	mean	1387	220.5	9.6	498	79.2	3.5	1876	298.2
	P10	4507.8	716.7	30	2274	361.6	17	5261	836.4
Recoverable – Success Cases	Play Chance	40.8%			16.8%			50.75%	
	P of large field	37.7%			15.1%			47.1%	
	P90	1328	211.1	13	1105	175.7	11	1322	210.2
	P50 median	3119	495.9	22	2683	426.6	19	3041	483.5
	mean	3458	549.8	23.9	2999	476.8	20.9	3696	587.6
	P10	6075	965.8	38	5293	841.5	33	6916	1099.6
In-place – All Cases (risked)	P90	0	0		0	0		0	0
	P50 median	0	0		0	0		1379	219.2
	mean	2327	370.0		855	135.9		3113	494.9
	P10	7516	1194.9		4002	636.3		8743	1390.0
In-place – Success Cases	P90	2280	362.5		1953	310.5		2285	363.3
	P50 median	5316	845.2		4591	729.9		5127	815.1
	mean	5806	923.1		5049	802.7		6135	975.4
	P10	10081	1602.8		8695	1382.4		11413	1814.5
Recoverable – 50 MMBOE min field, risked	Play Chance	40.1%			16.6%			50.0%	
	P90	0	0	0	0	0	0	0	0
	P50 median	0	0	0	0	0	0	382	60.8
	mean	1291	205.3	5.1	463	73.6	1.8	1713	272.3
	P10	4243	674.6	16	2086	331.6	9	4869	774.1
Recoverable –300 MMBOE min. Field, risked	Play Chance	37.1%			14.9%			46.5%	
	P90	0	0	0	0	0	0	0	0
	P50 median	0	0	0	0	0	0	0	0
	mean	799	127.0	1.2	285	45.3	0.4	1043	165.9
	P10	2813	447.2	4	1084	172.3	2	3111	494.6

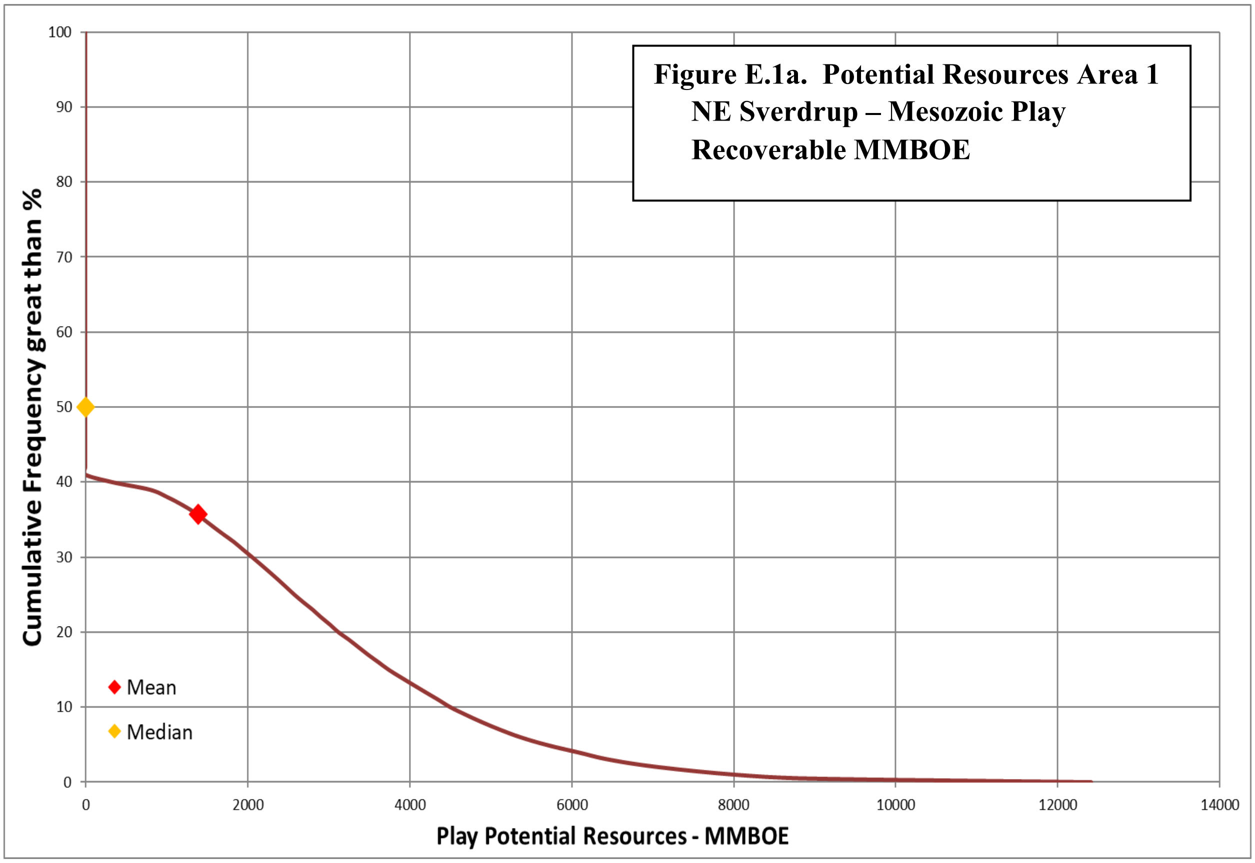


Figure E.1a. Potential Resources Area 1 NE Sverdrup – Mesozoic Play Recoverable MMBOE

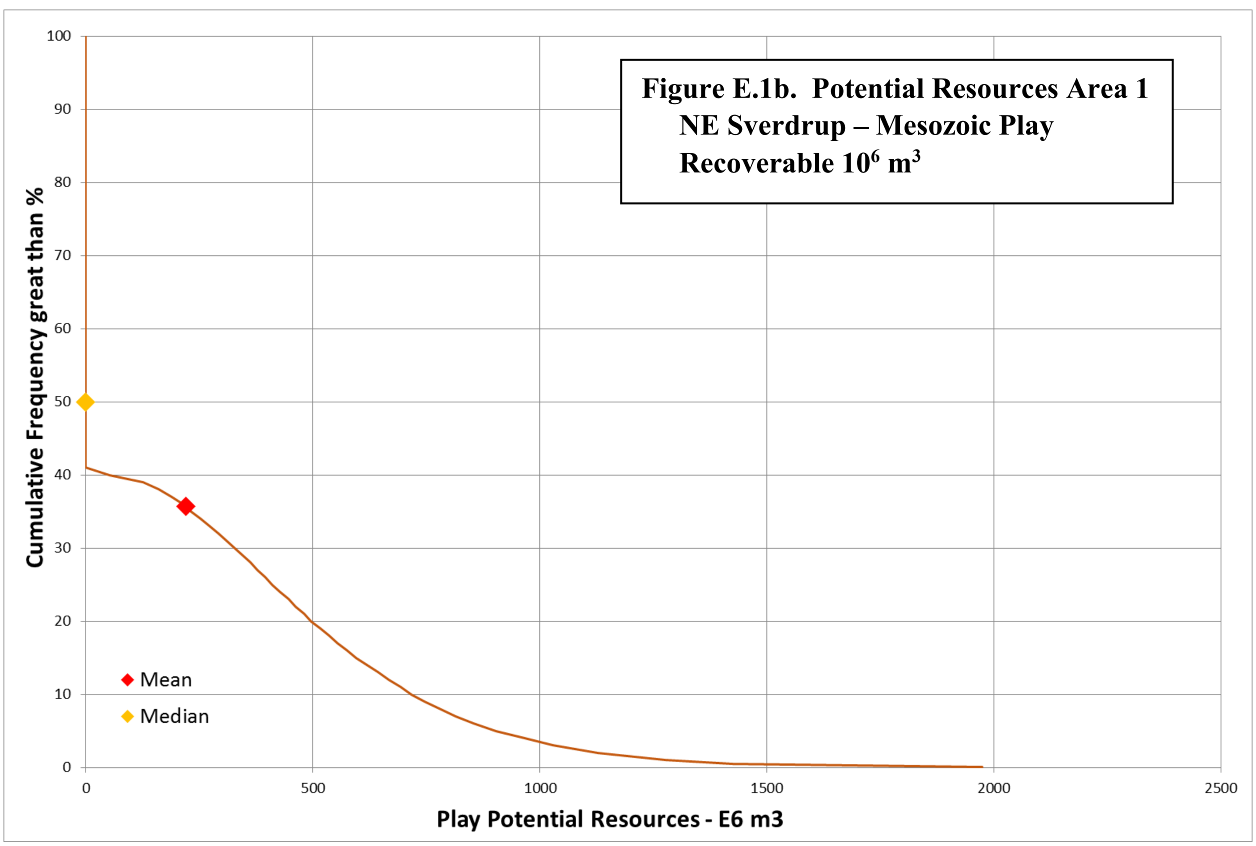


Figure E.1b. Potential Resources Area 1 NE Sverdrup – Mesozoic Play Recoverable 10^6 m^3

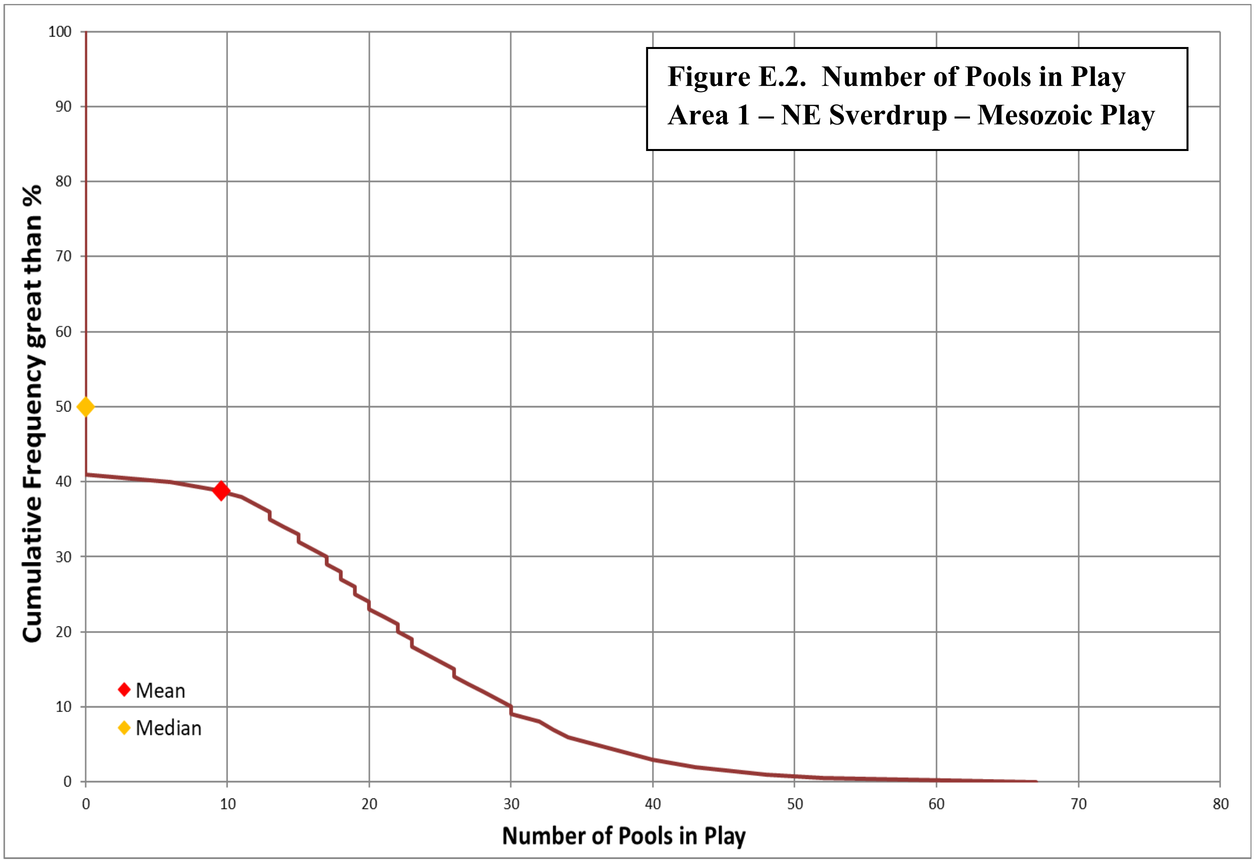


Figure E.2. Number of Pools in Play
Area 1 – NE Sverdrup – Mesozoic Play

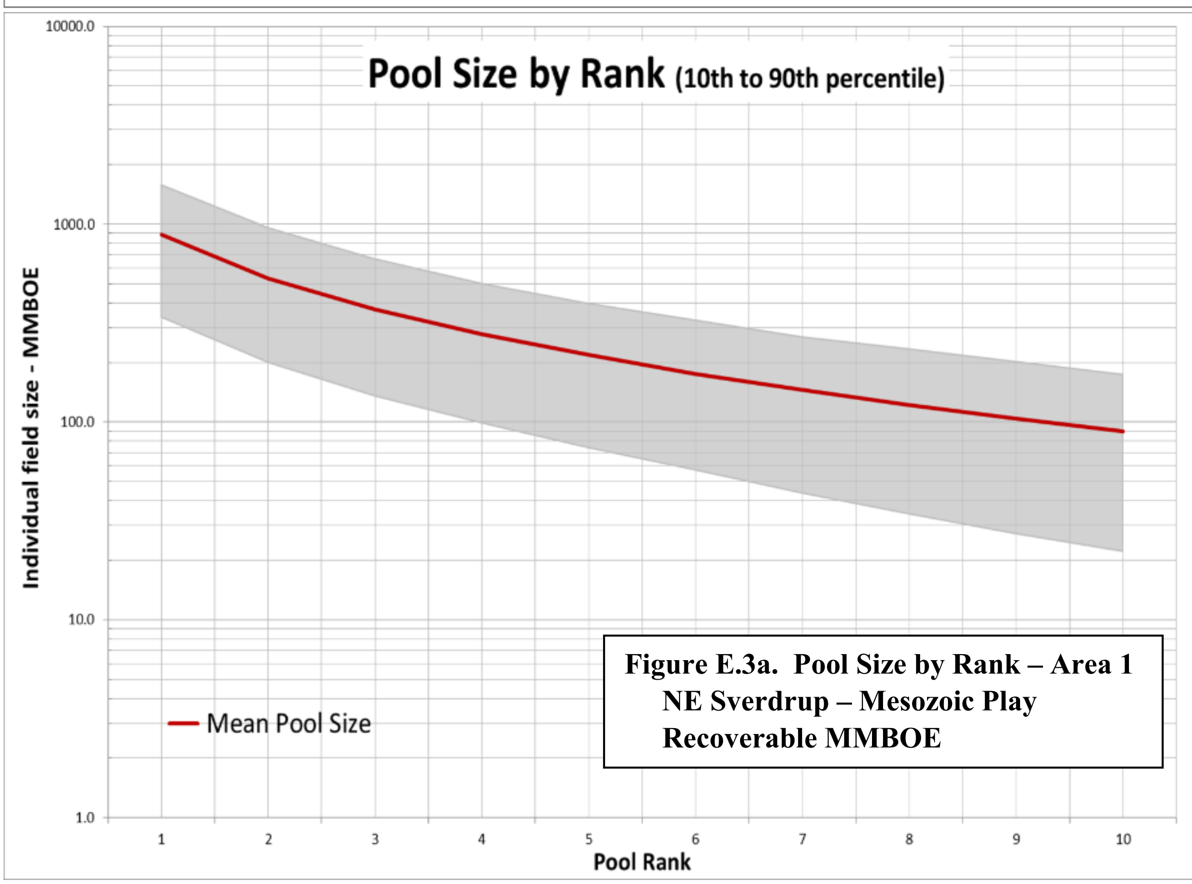


Figure E.3a. Pool Size by Rank – Area 1
NE Sverdrup – Mesozoic Play
Recoverable MMBOE

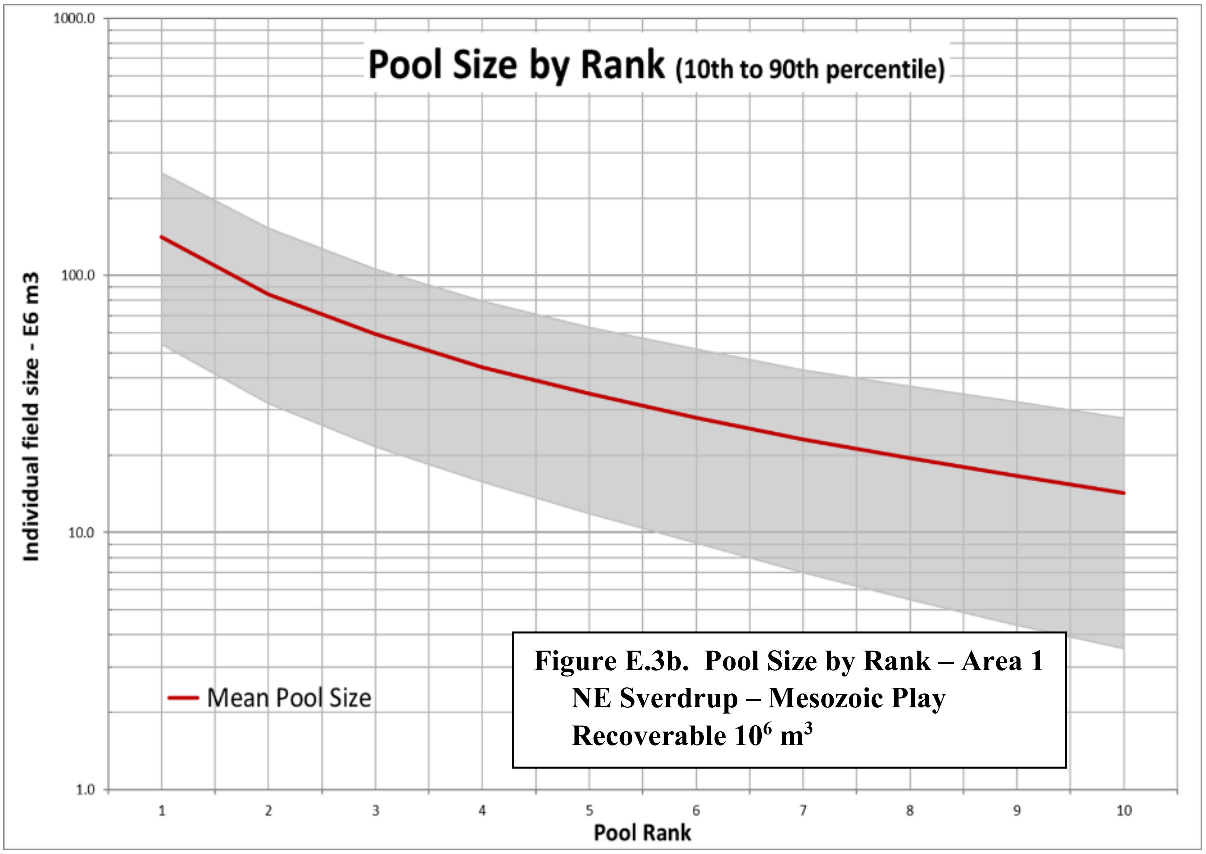


Figure E.3b. Pool Size by Rank – Area 1 NE Sverdrup – Mesozoic Play Recoverable 10^6 m^3

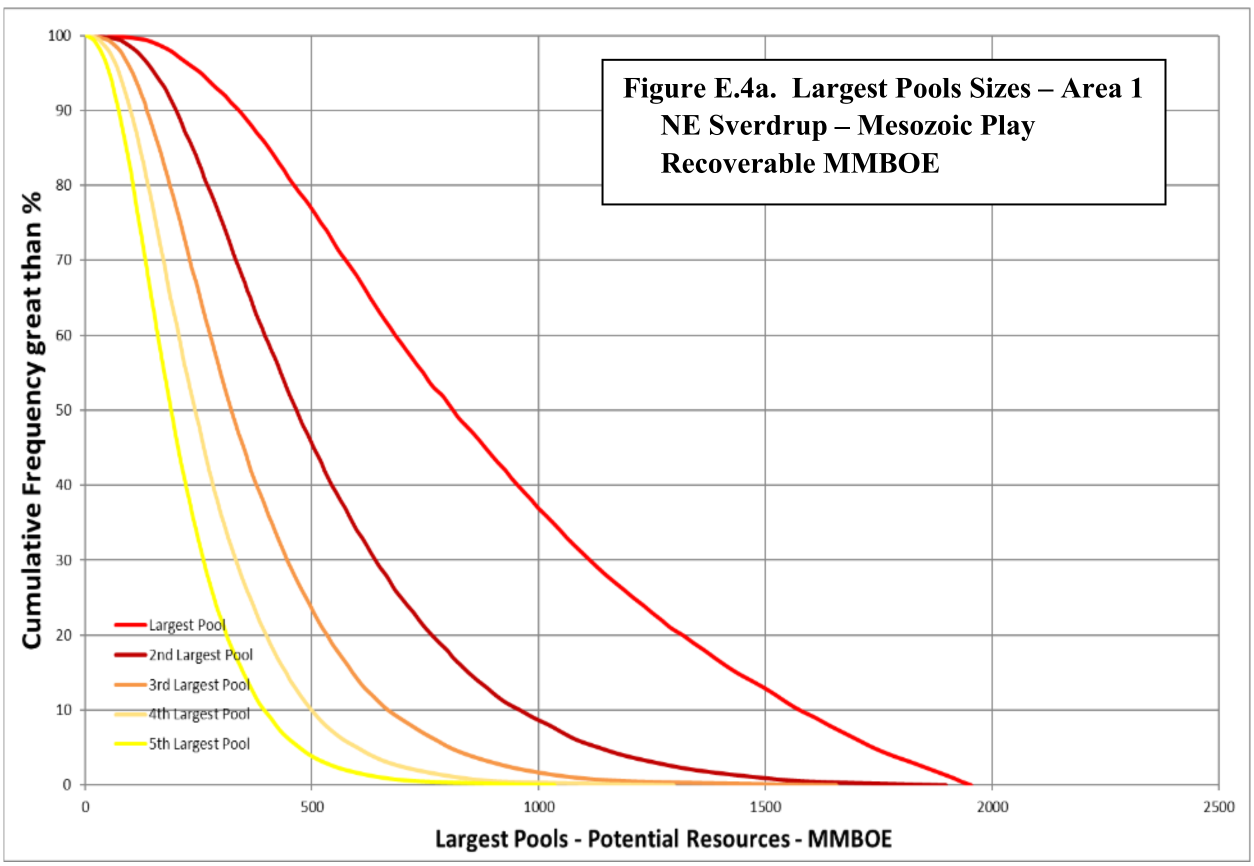


Figure E.4a. Largest Pools Sizes – Area 1 NE Sverdrup – Mesozoic Play Recoverable MMBOE

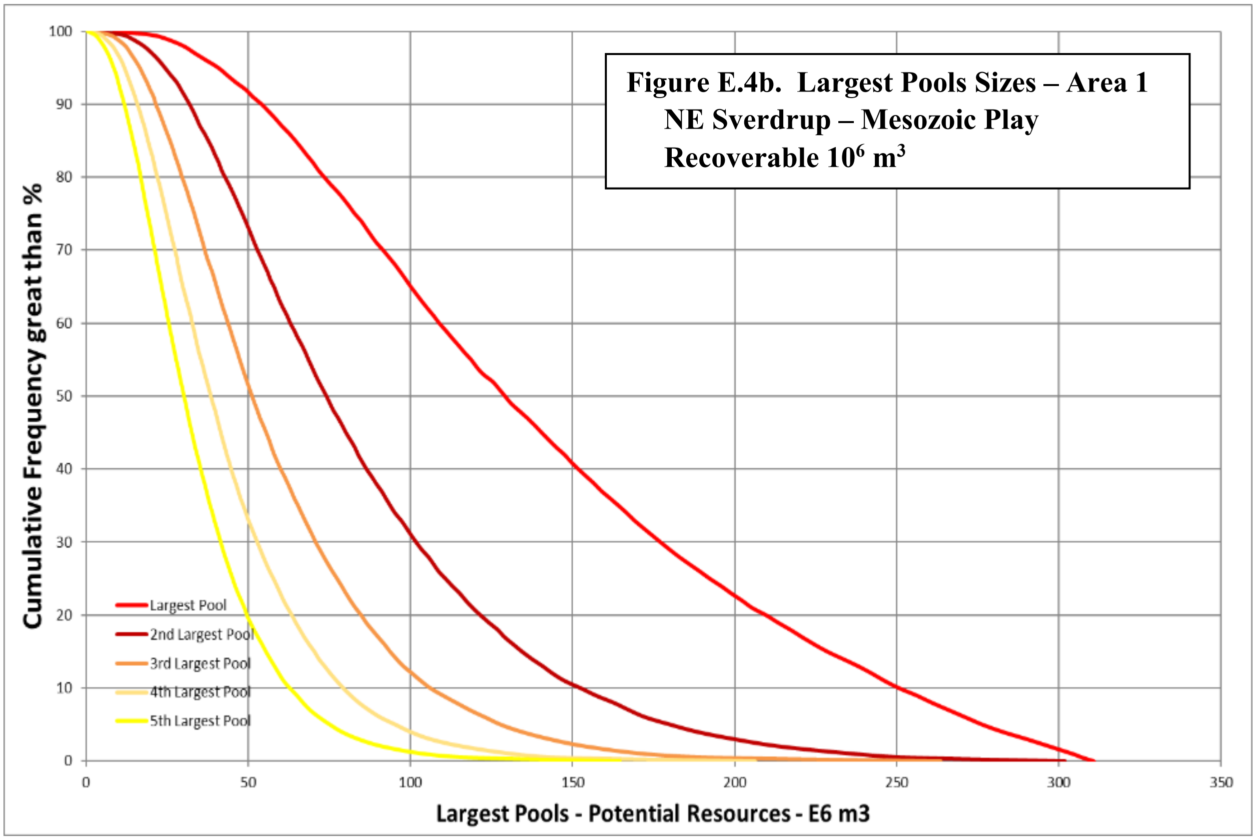


Figure E.4b. Largest Pools Sizes – Area 1
NE Sverdrup – Mesozoic Play
Recoverable 10^6 m^3
Cumulative Frequency great than %
Largest Pool
2nd Largest Pool
3rd Largest Pool
4th Largest Pool
5th Largest Pool
Largest Pools - Potential Resources - E6 m3
0
50
100
150
200
250
300
350
10
20
30
40
50
60
70
80
90
100

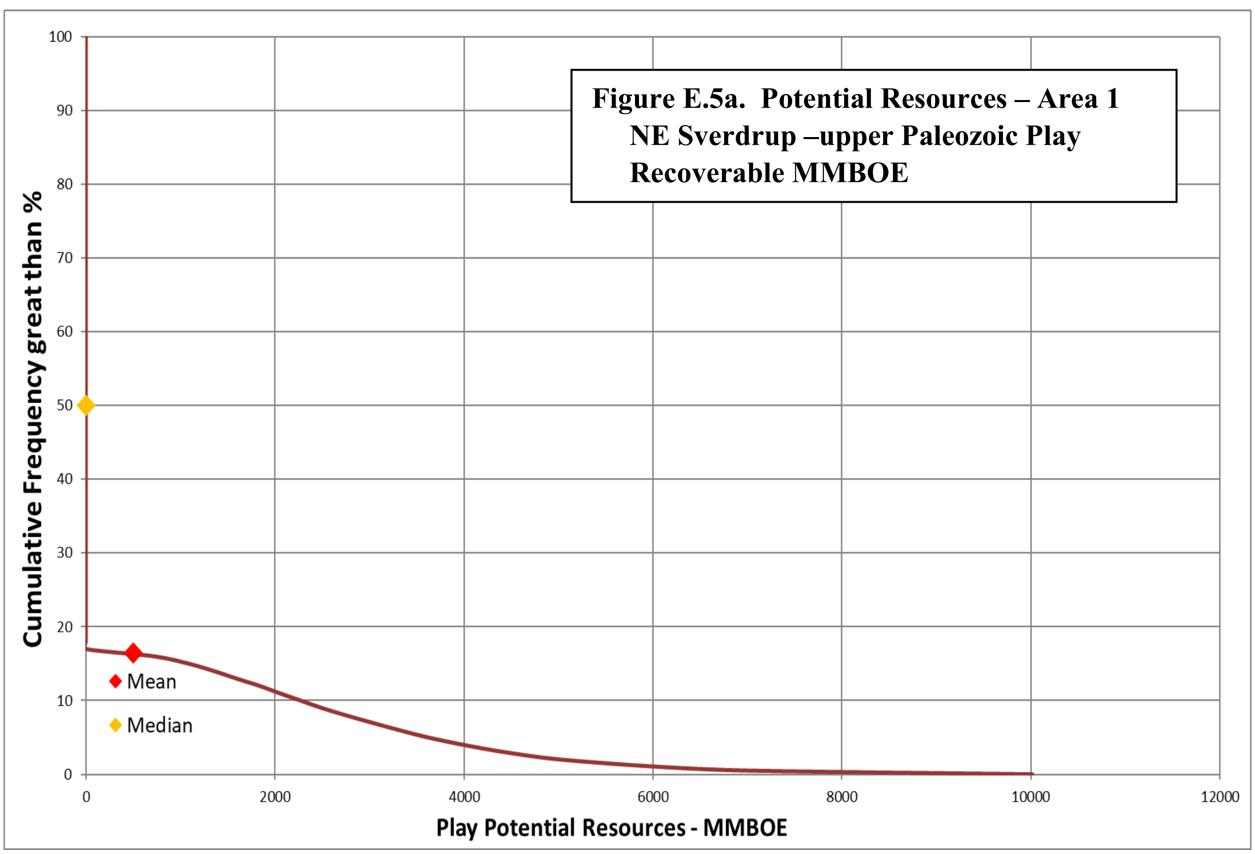


Figure E.5a. Potential Resources – Area 1
NE Sverdrup –upper Paleozoic Play
Recoverable MMBOE
Cumulative Frequency great than %
Mean
Median
Play Potential Resources - MMBOE
0
2000
4000
6000
8000
10000
12000
10
20
30
40
50
60
70
80
90
100

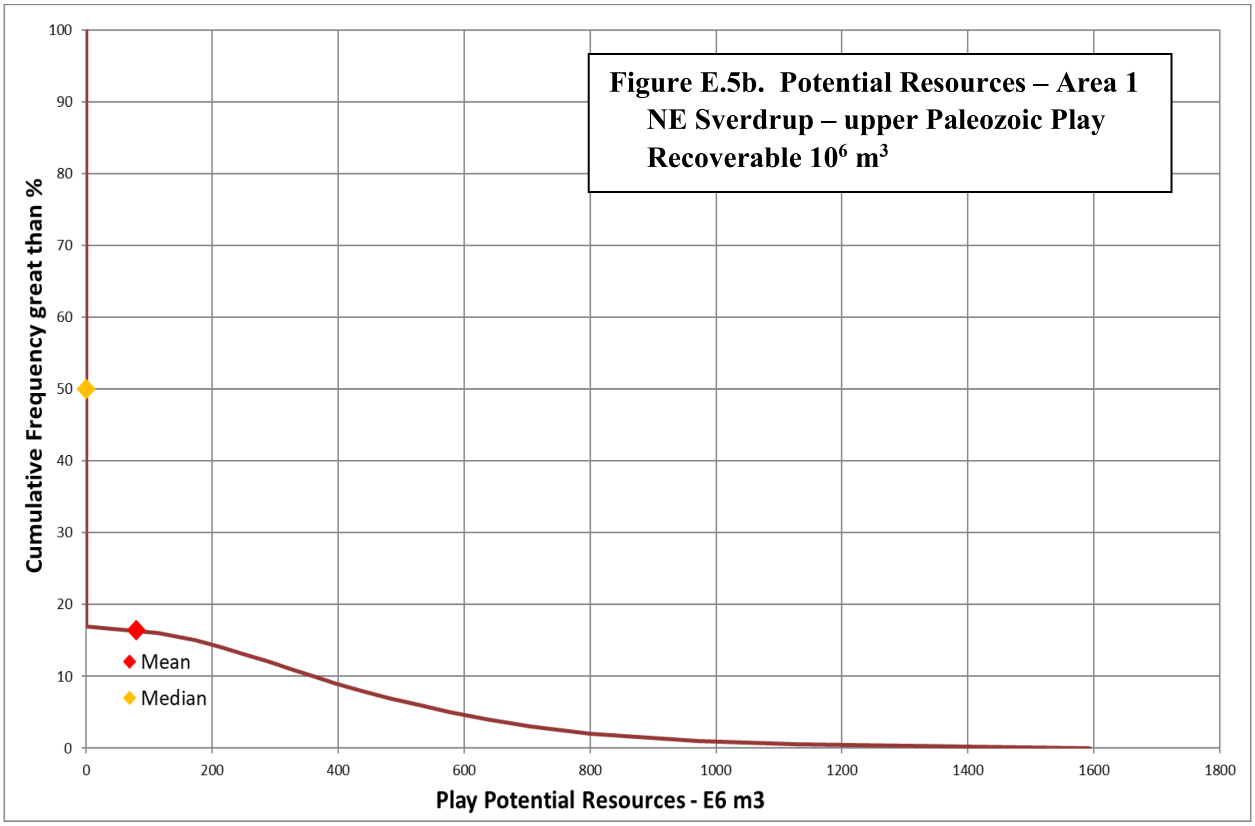


Figure E.5b. Potential Resources – Area 1
NE Sverdrup – upper Paleozoic Play
Recoverable 10⁶ m³
Cumulative Frequency great than %
Play Potential Resources - E6 m3
Mean
Median
0
10
20
30
40
50
60
70
80
90
100
0
200
400
600
800
1000
1200
1400
1600
1800

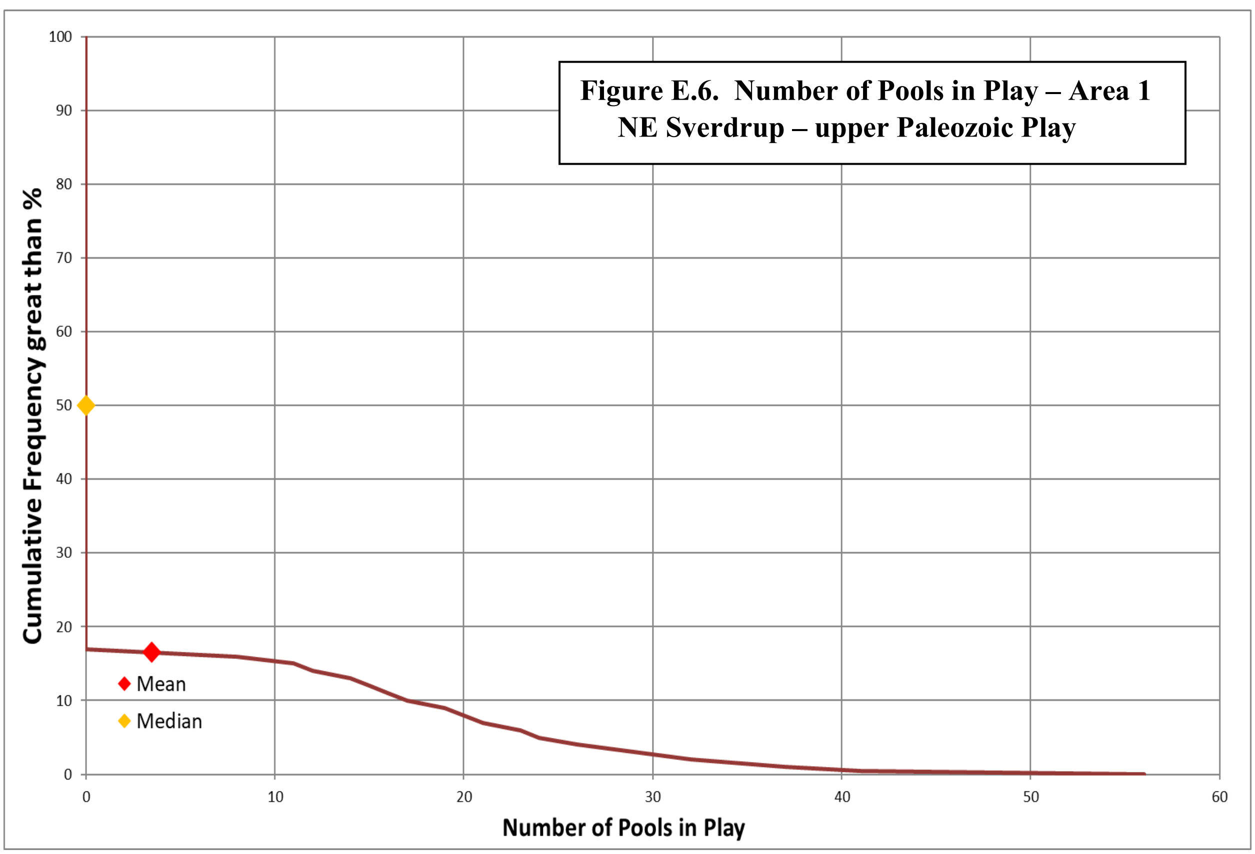


Figure E.6. Number of Pools in Play – Area 1
NE Sverdrup – upper Paleozoic Play
Cumulative Frequency great than %
Number of Pools in Play
Mean
Median
0
10
20
30
40
50
60
70
80
90
100
0
10
20
30
40
50
60

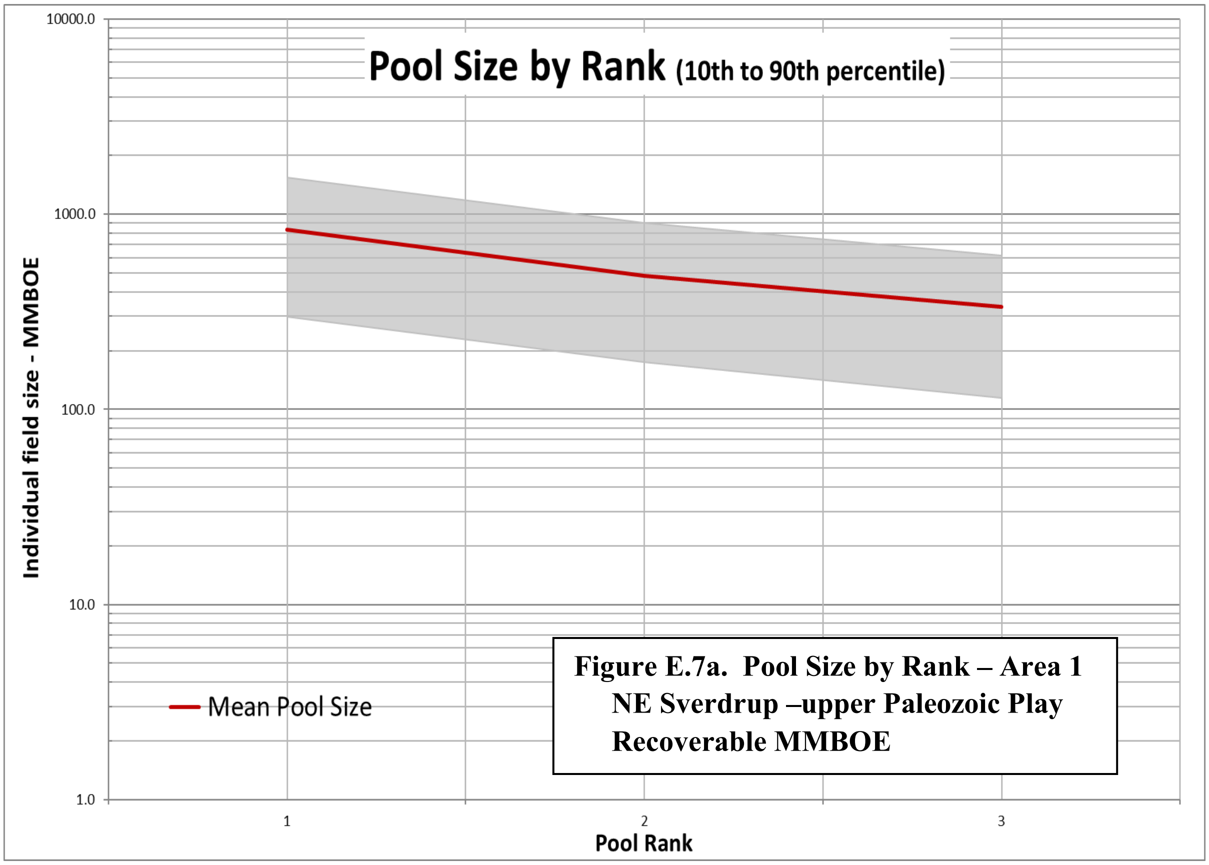


Figure E.7a. Pool Size by Rank – Area 1 NE Sverdrup –upper Paleozoic Play Recoverable MMBOE

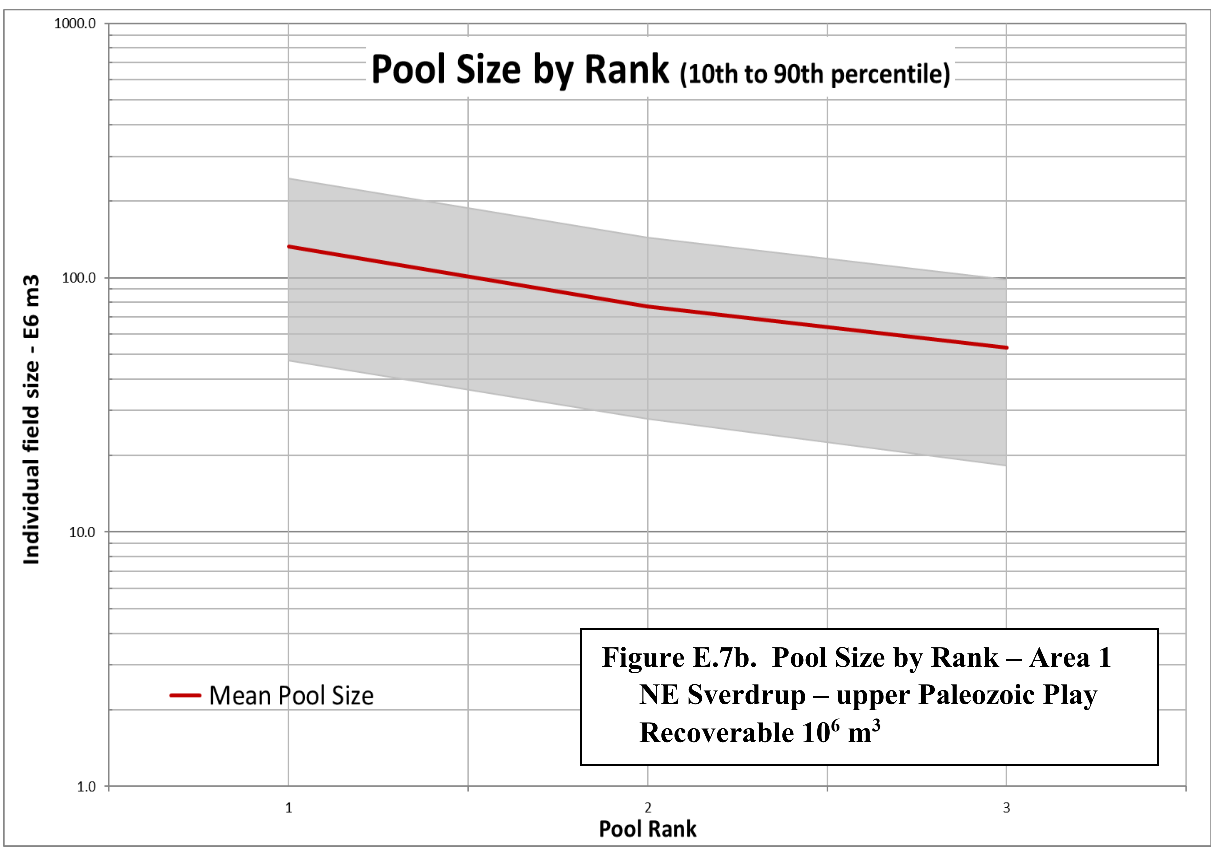


Figure E.7b. Pool Size by Rank – Area 1 NE Sverdrup – upper Paleozoic Play Recoverable 10^6 m^3

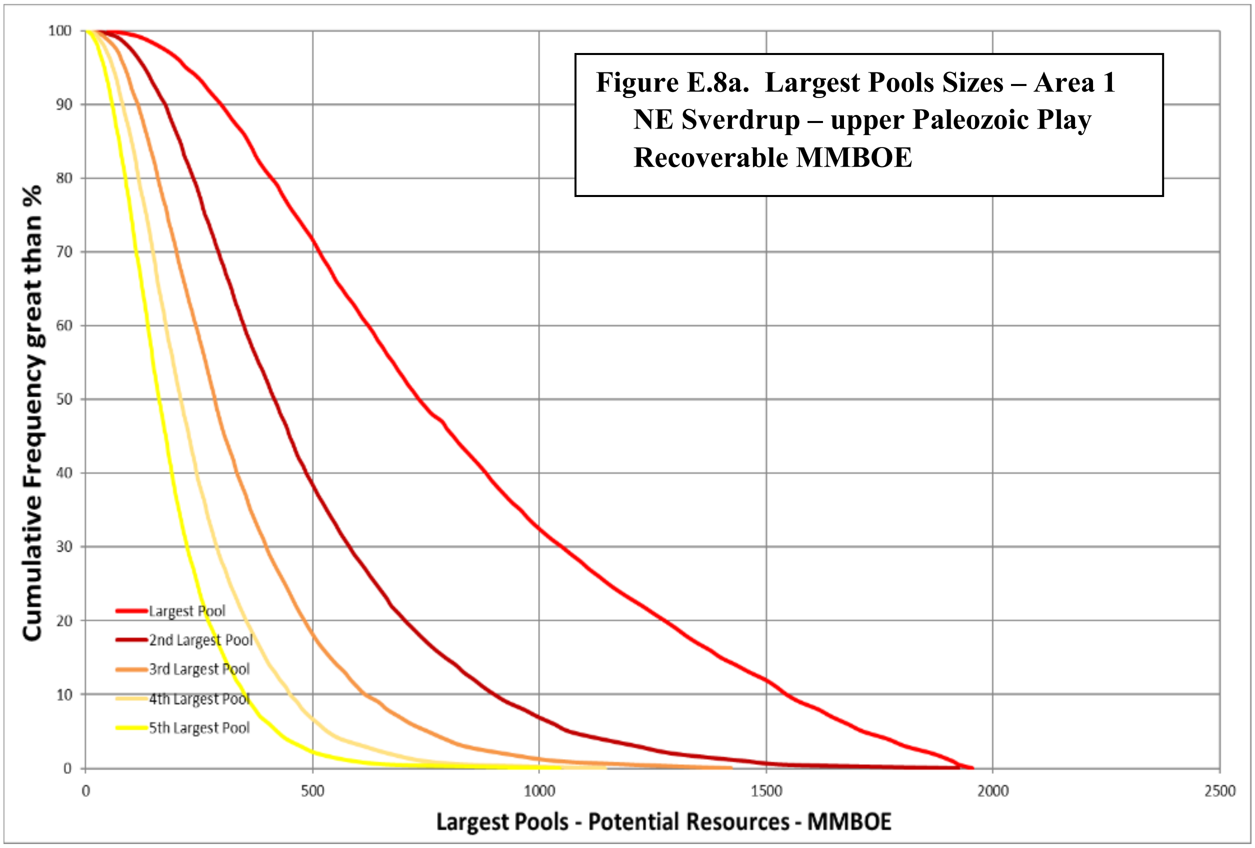


Figure E.8a. Largest Pools Sizes – Area 1
NE Sverdrup – upper Paleozoic Play
Recoverable MMBOE
Cumulative Frequency great than %
Largest Pools - Potential Resources - MMBOE
Largest Pool
2nd Largest Pool
3rd Largest Pool
4th Largest Pool
5th Largest Pool

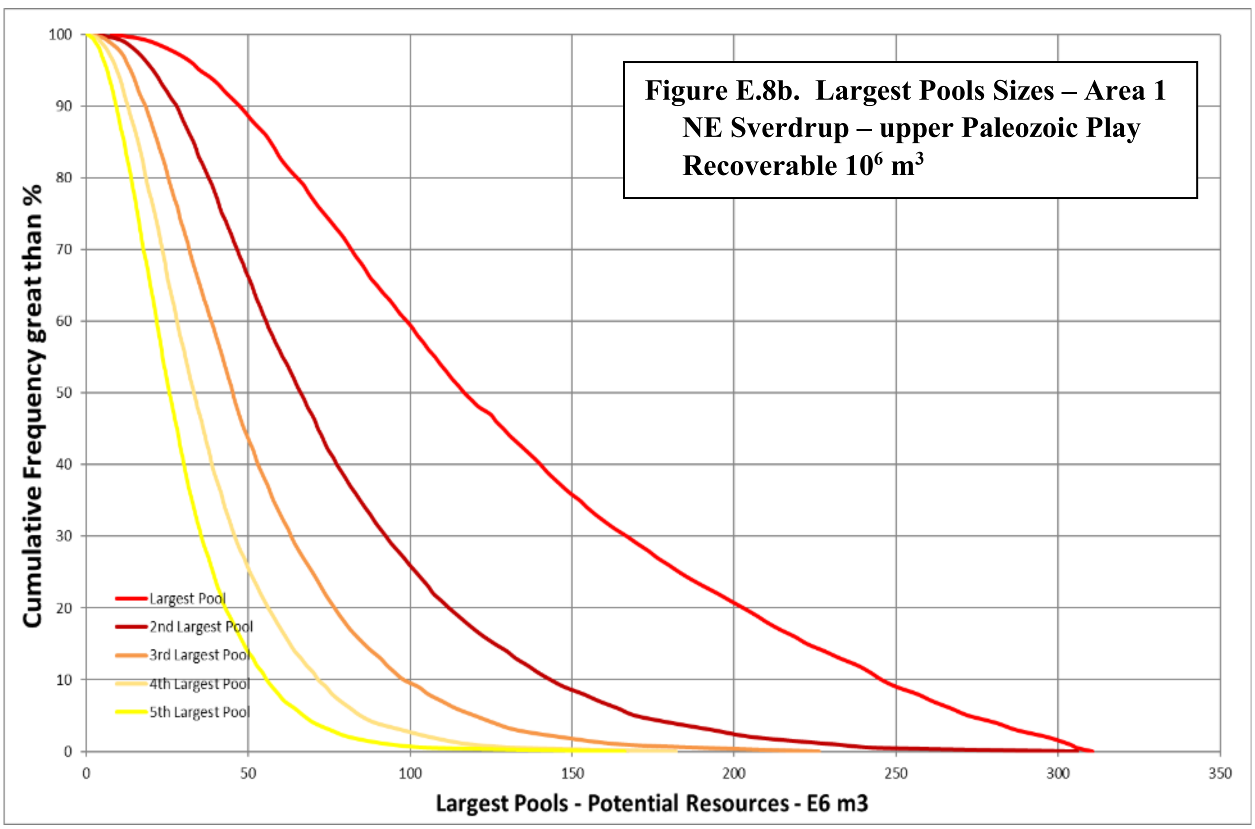


Figure E.8b. Largest Pools Sizes – Area 1
NE Sverdrup – upper Paleozoic Play
Recoverable 10⁶ m³
Cumulative Frequency great than %
Largest Pools - Potential Resources - E6 m3
Largest Pool
2nd Largest Pool
3rd Largest Pool
4th Largest Pool
5th Largest Pool

Area 3. Lincoln Sea Basin

The Lincoln Sea Basin was analyzed extensively by Sørensen et al. (2011); they asserted that the Sverdrup Basin is a good analog for the Lincoln Sea Basin and reported mean in-place resources of 2185 MMBOE. To compare our analysis to theirs, an assessment area for the total Lincoln Sea Basin geologic province was created. The in-place upside field size distribution (Tables 9 and 10) and an aerially proportionate number of prospects from the western Sverdrup Basin (Table 11), along with COS estimates specifically for the Lincoln Sea Basin (Table 8), were used to calculate mean in-place resources of 2169 MMBOE. Mean recoverable resources in the total Lincoln Sea Basin were calculated as 1307 MMBOE, using the western Sverdrup recoverable upside field size distribution (Tables 9 and 10). These figures compare favourably to the previous analysis.

To calculate resources specifically in Canadian Waters, the same COS and same western Sverdrup field size distributions and number of prospects were used – numbers were just scaled down to the smaller Canadian area (18 930 km^2). This makes sense because international boundary transects the basin, making the Canadian portion a full sample of the whole basin. It is neither only marginal parts of the basin, nor just ‘sweet spots’ within it, so the same parameters scaled to area are thought to be sensible. Insufficient information exists to divide the area into sub-plays. Mean recoverable resources are 546 MMBOE (86.8 x 10^6 m^3), which equates to mean resources per area of 28.8 MMBOE / 1000 km^2 – one of the areas of highest conventional petroleum potential in the Canadian High Arctic (Table 14).

This assessment area is very far from shore and about 2/3 of the area has moderate water depths (200 to 600 m), with the rest in deeper waters. Ice conditions include significant multi-year shifting ice pack.

Table 14. Resource assessment output: Area 3. Lincoln Sea – Canadian Waters

		MMBOE	10^6 m^3	# of fields
Recoverable - All Cases (risked)	P90	0	0	0
	P50 median	224	35.6	3
	mean	546	86.8	3.8
	P10	1601	254.5	9
Recoverable – Success Cases	Play Chance	57.8%		
	P of large field	32.3%		
	P90	176	28.0	3
	P50 median	738	117.3	6
	mean	945	150.2	6.5
	P10	2010	319.6	11
In-place – All Cases (risked)	P90	0	0	
	P50 median	403	64.1	
	mean	904	143.7	
	P10	2640	419.7	
In-place – Success Cases	P90	320	50.9	
	P50 median	1233	196.0	
	mean	1560	248.0	
	P10	3271	520.0	

Recoverable – 50 MMBOE min field, risked	**Play Chance**	**55.3%**		
	P90	**0**	0	**0**
	P50 median	**166**	26.4	**1**
	mean	**508**	80.8	**2.0**
	P10	**1527**	242.8	**5**
Recoverable –300 MMBOE min. Field, risked	**Play Chance**	**32.2%**		
	P90	**0**	0	**0**
	P50 median	**0**	0	**0**
	mean	**314**	49.9	**0.5**
	P10	**1132**	180.0	**2**

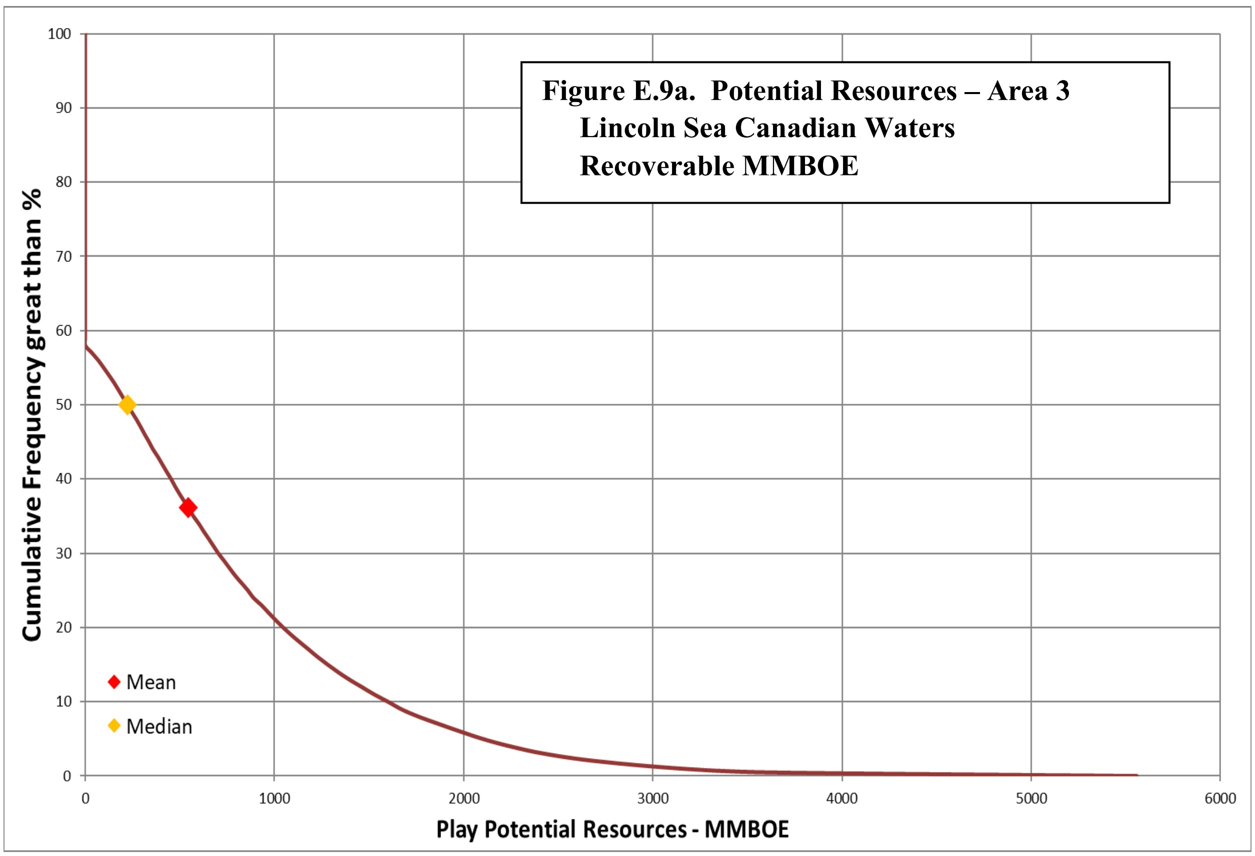


Figure E.9a. Potential Resources – Area 3 Lincoln Sea Canadian Waters Recoverable MMBOE

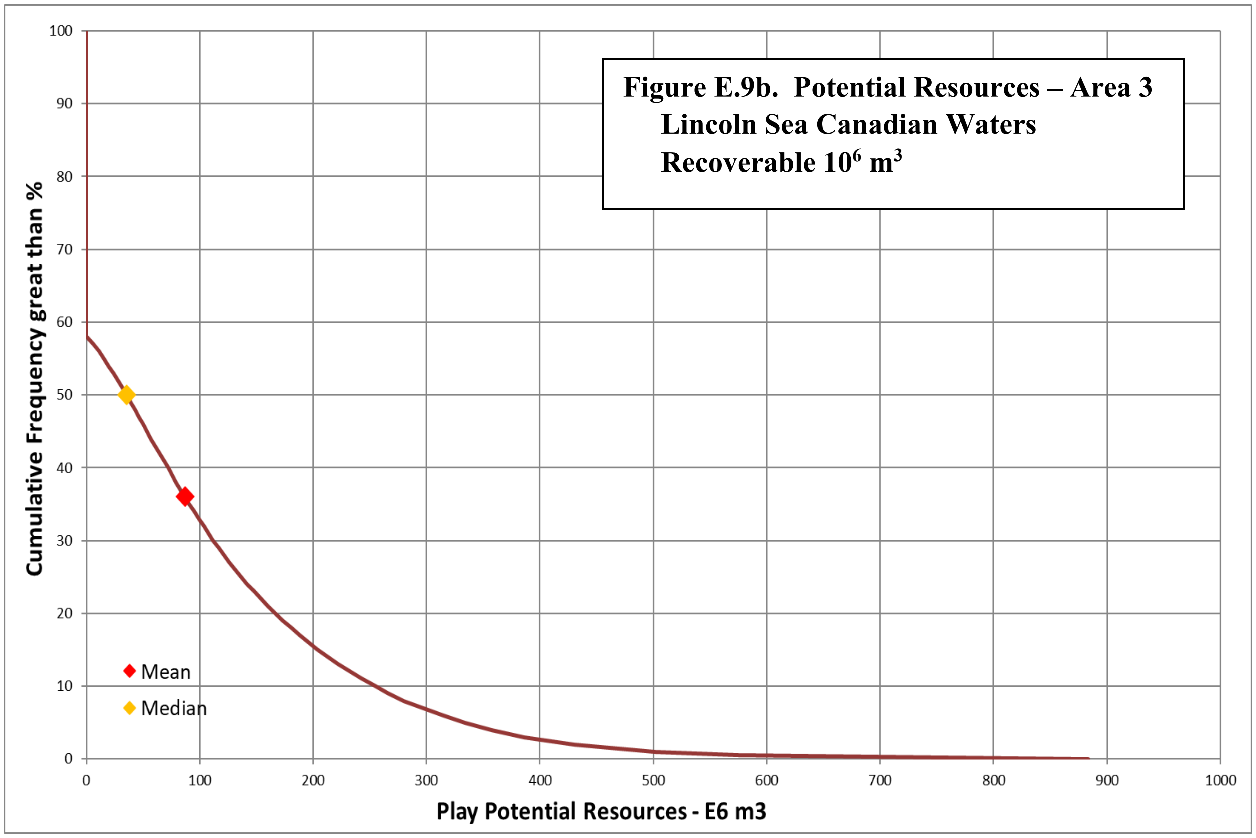


Figure E.9b. Potential Resources – Area 3
Lincoln Sea Canadian Waters
Recoverable 10^6 m^3
Cumulative Frequency great than %
Play Potential Resources - E6 m3
Mean
Median
0
10
20
30
40
50
60
70
80
90
100
0
100
200
300
400
500
600
700
800
900
1000

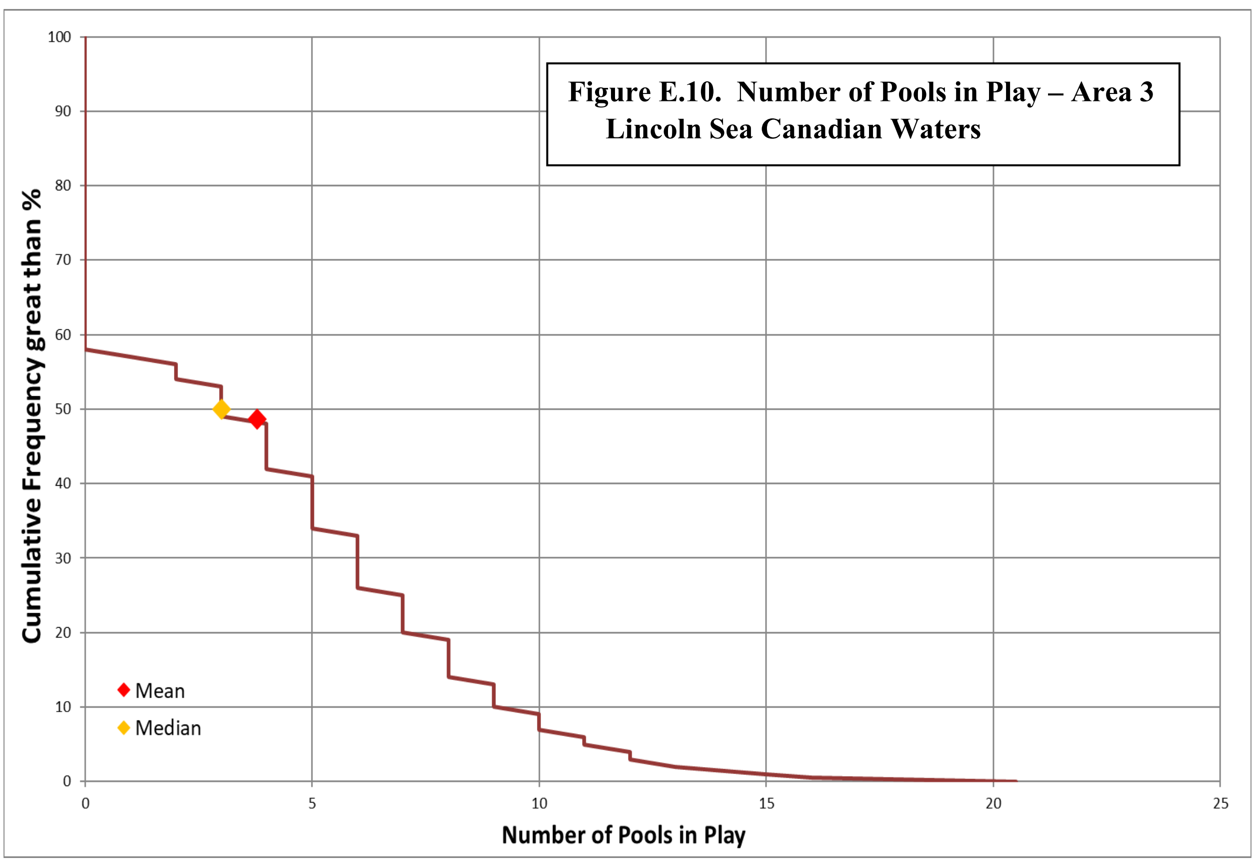


Figure E.10. Number of Pools in Play – Area 3
Lincoln Sea Canadian Waters
Cumulative Frequency great than %
Number of Pools in Play
Mean
Median
0
10
20
30
40
50
60
70
80
90
100
0
5
10
15
20
25

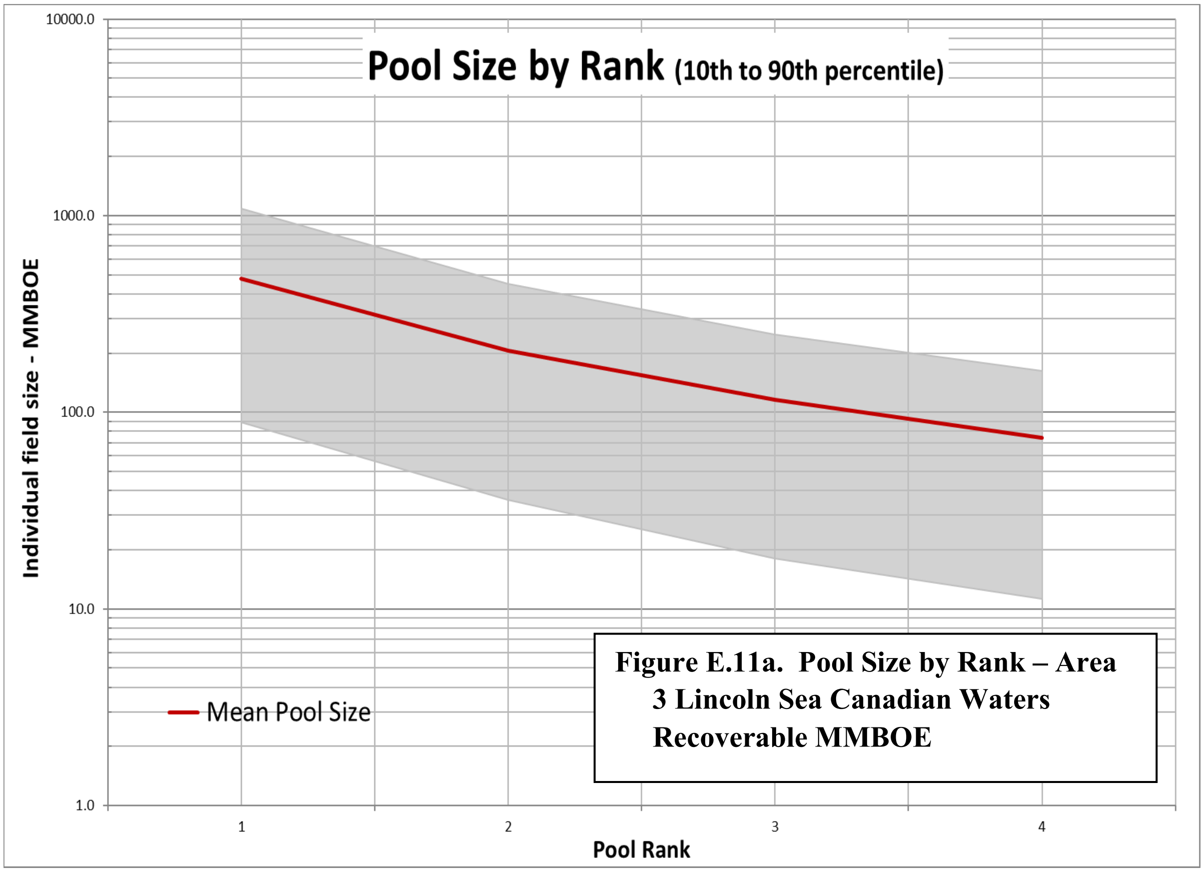


Figure E.11a. Pool Size by Rank – Area 3 Lincoln Sea Canadian Waters Recoverable MMBOE

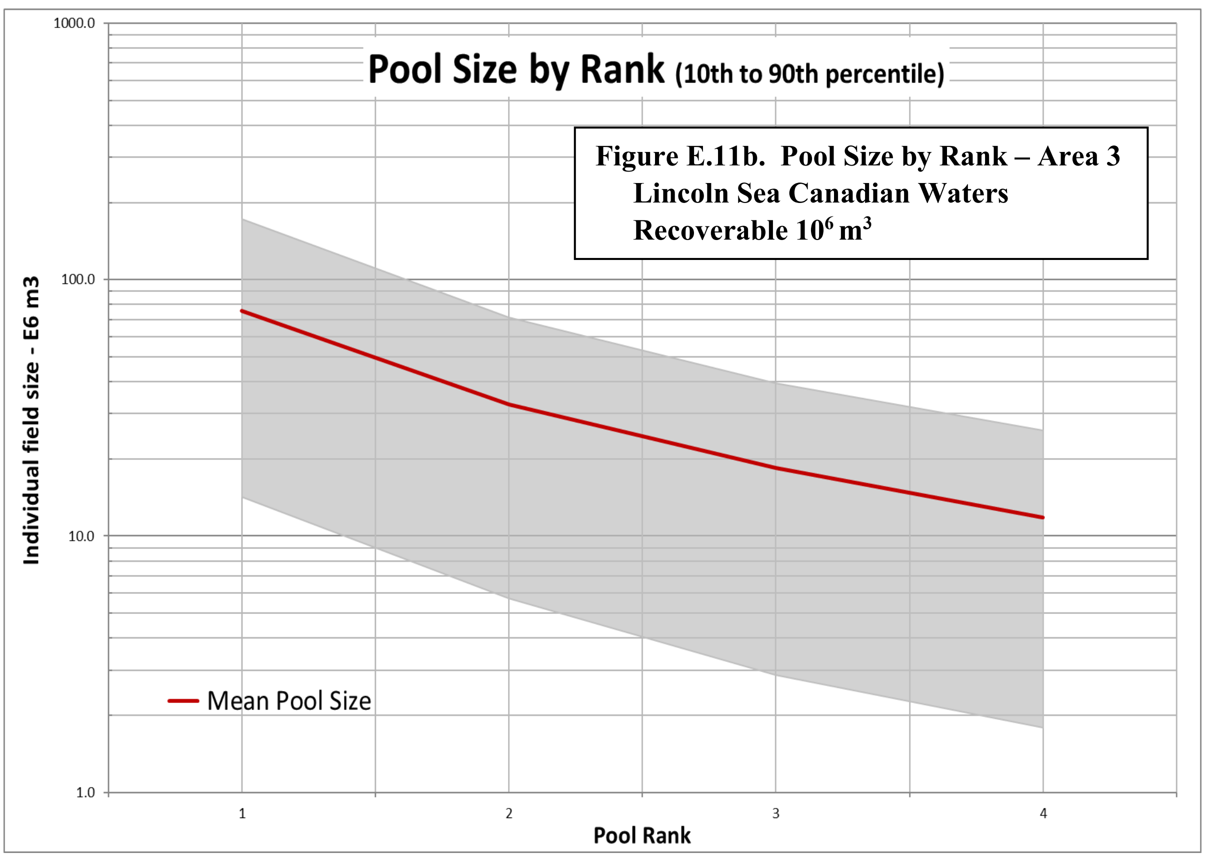


Figure E.11b. Pool Size by Rank – Area 3 Lincoln Sea Canadian Waters Recoverable 10^6 m^3

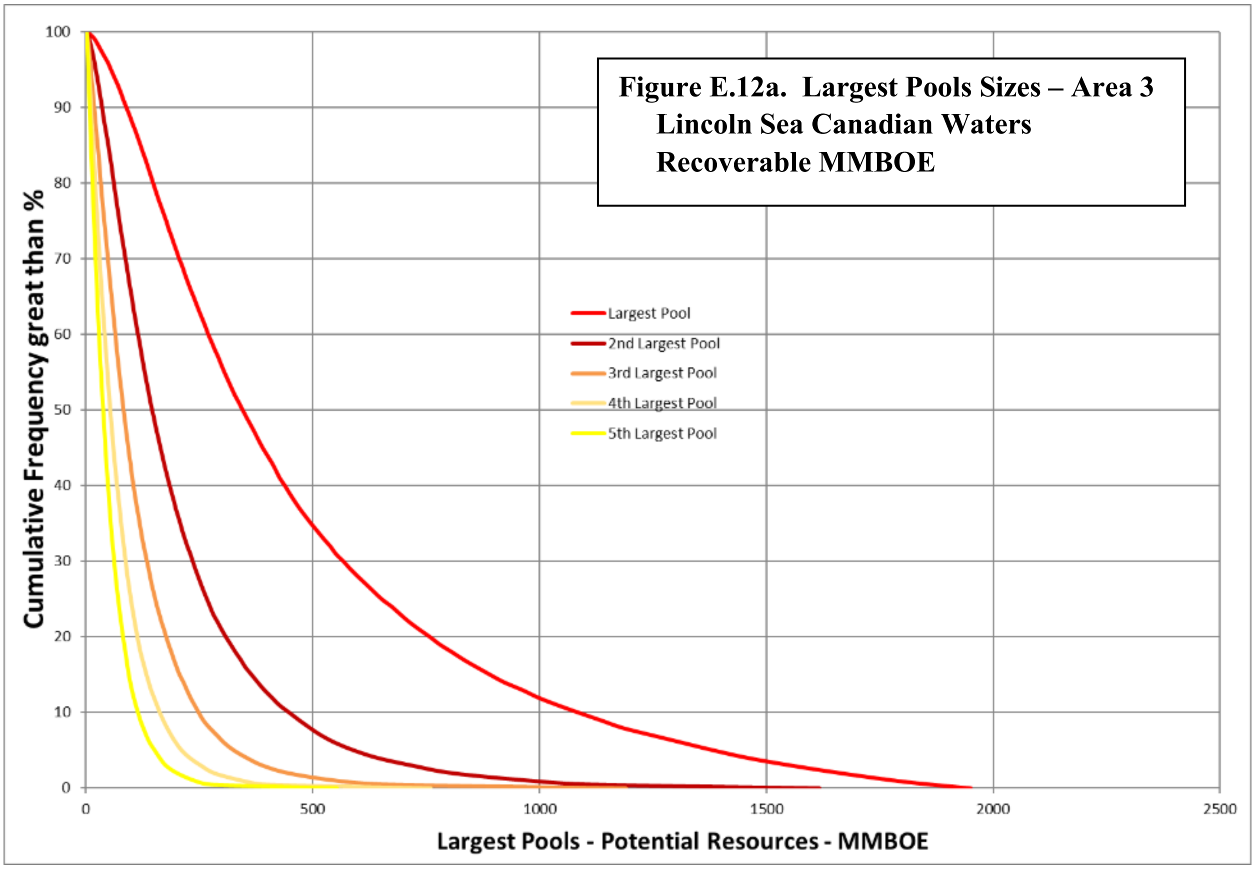


Figure E.12a. Largest Pools Sizes – Area 3
Lincoln Sea Canadian Waters
Recoverable MMBOE
Largest Pool
2nd Largest Pool
3rd Largest Pool
4th Largest Pool
5th Largest Pool
Cumulative Frequency great than %
Largest Pools - Potential Resources - MMBOE
0
10
20
30
40
50
60
70
80
90
100
0
500
1000
1500
2000
2500

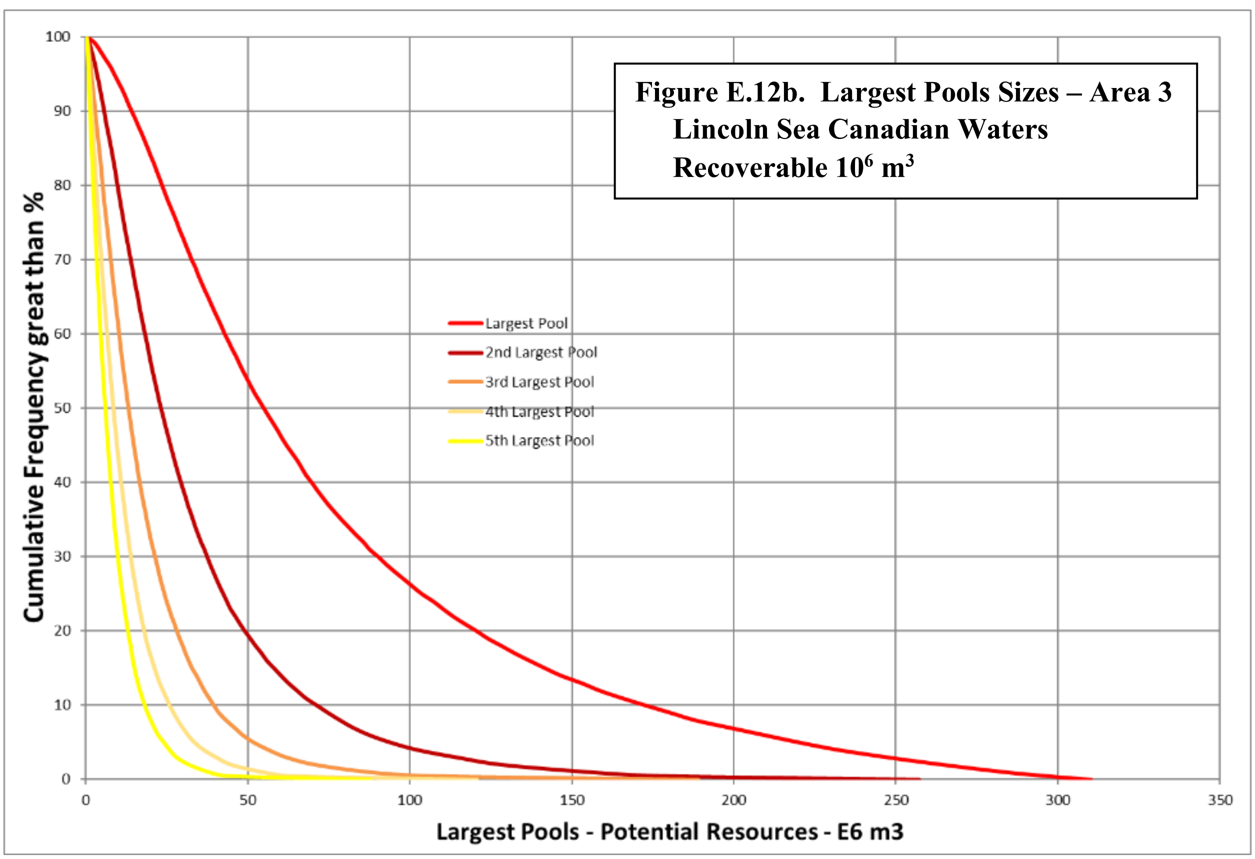


Figure E.12b. Largest Pools Sizes – Area 3
Lincoln Sea Canadian Waters
Recoverable 10⁶ m³
Largest Pool
2nd Largest Pool
3rd Largest Pool
4th Largest Pool
5th Largest Pool
Cumulative Frequency great than %
Largest Pools - Potential Resources - E6 m3
0
10
20
30
40
50
60
70
80
90
100
0
50
100
150
200
250
300
350

Area 4. Lomonosov Ridge

An assessment area was assigned to the geographic Lomonosov Ridge. The USGS (Moore et al., 2011; Moore and Pitman, 2019) have previously assessed this region and found a low chance of significant petroleum resources. Their assessment units extend a long distance out of Canadian waters and are not directly comparable, though their analysis of the geology and prospect / field density was helpful to our analysis. Moore and Pitman (2019) divided the area into sub-plays on the crest and flank of the ridge, but we have lumped these areas together due to limited information.

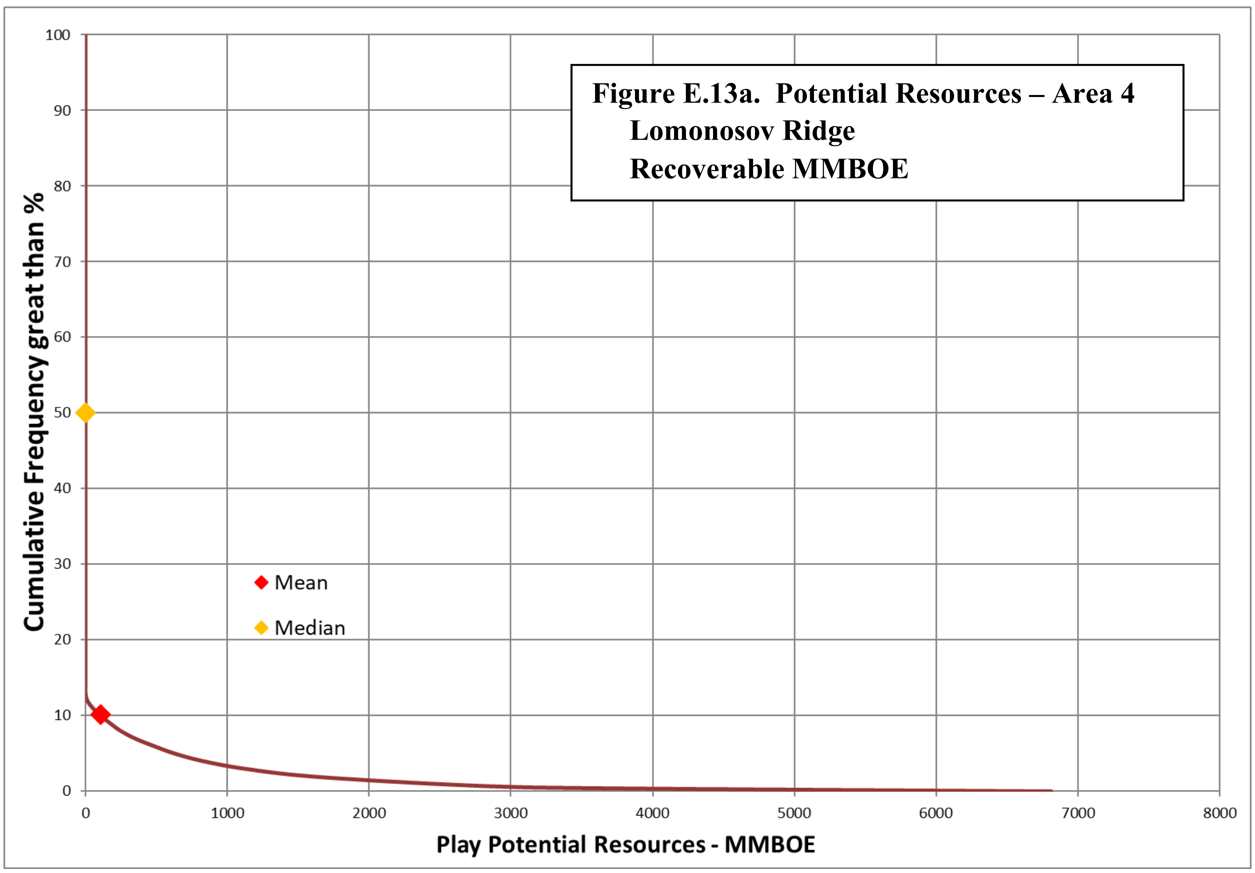
This study also interpreted a low chance of success, and thus a very modest quantity of resources is estimated. Mean recoverable resources are 103 MMBOE (16.4 x 10^6 m^3) (Table 15), which equates to mean resources per area of 3.0 MMBOE / 1000 km^2, over the assessment area of 32 712 km^2. The limited size of this geologic assessment area within Canadian waters, combined with an interpreted lower density of prospects / fields lead to a mean number of fields (over all Monte Carlo realizations) of less than 1, so no plots of size by rank were produced. The mean size of the largest field is 530 MMBOE, but it is a rare event.

This assessment area is very far from shore and about 1/3 of the area has moderate water depths (200 to 600 m) on the ridge crest, with the rest in deeper waters descending to 1500 m. Ice conditions include significant multi-year shifting ice pack.

Table 15. Resource assessment output: Area 4. Lomonosov Ridge

		MMBOE	10^6 m^3	# of fields
Recoverable - All Cases (risked)	P90	0	0	0
	P50 median	0	0	0
	mean	103	16.4	0.5
	P10	107	17.0	2
Recoverable – Success Cases	Play Chance	13.5%		
	P of large field	6.5%		
	P90	42	6.7	1
	P50 median	445	70.7	3
	mean	826	131.3	4.4
	P10	2212	351.7	8
In-place – All Cases (risked)	P90	0	0	
	P50 median	0	0	
	mean	196	31.2	
	P10	217	34.5	
In-place – Success Cases	P90	76	12.1	
	P50 median	772	122.7	
	mean	1527	242.8	
	P10	4319	686.7	

Recoverable – 50 MMBOE min field, risked	**Play Chance**	**10.7%**		
	P90	**0**	0	**0**
	P50 median	**0**	0	**0**
	mean	**98**	15.6	**0.3**
	P10	**78**	17.0	**1**
Recoverable –300 MMBOE min. Field, risked	**Play Chance**	**6.0%**		
	P90	**0**	0	**0**
	P50 median	**0**	0	**0**
	mean	**74**	11.8	**0.1**
	P10	**0**	0	**0**



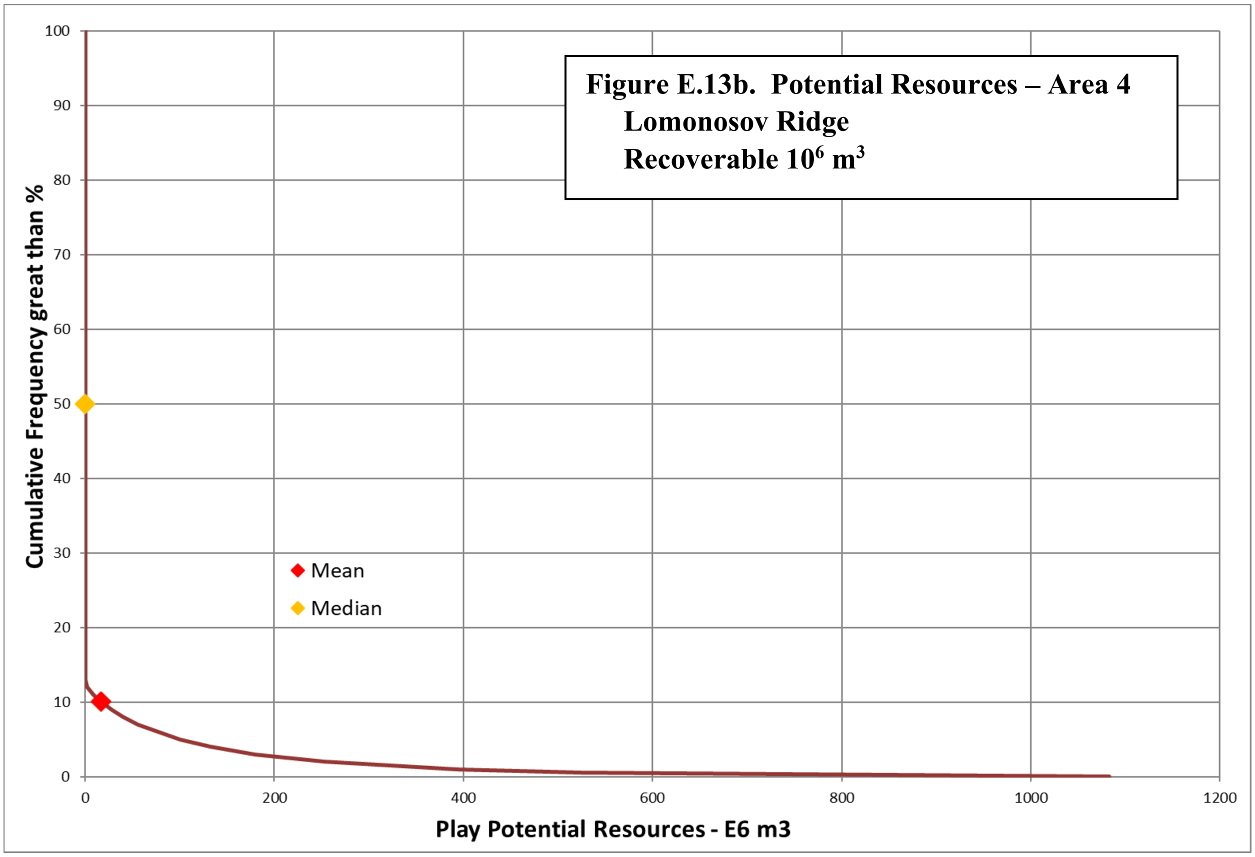


Figure E.13b. Potential Resources – Area 4
Lomonosov Ridge
Recoverable 10^6 m^3
Cumulative Frequency great than %
Play Potential Resources - E6 m3
Mean
Median
0
10
20
30
40
50
60
70
80
90
100
200
400
600
800
1000
1200

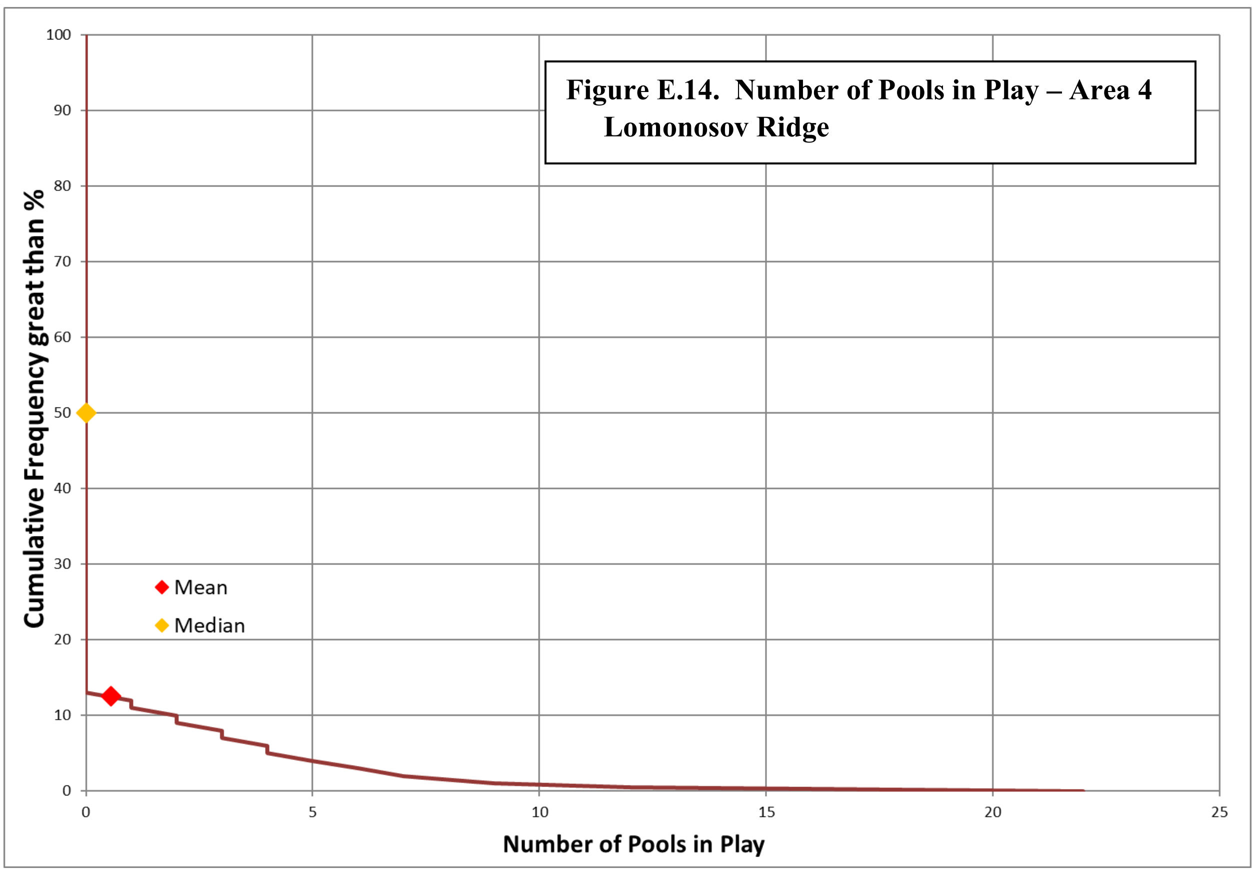


Figure E.14. Number of Pools in Play – Area 4
Lomonosov Ridge
Cumulative Frequency great than %
Number of Pools in Play
Mean
Median
0
5
10
15
20
25
30
40
50
60
70
80
90
100

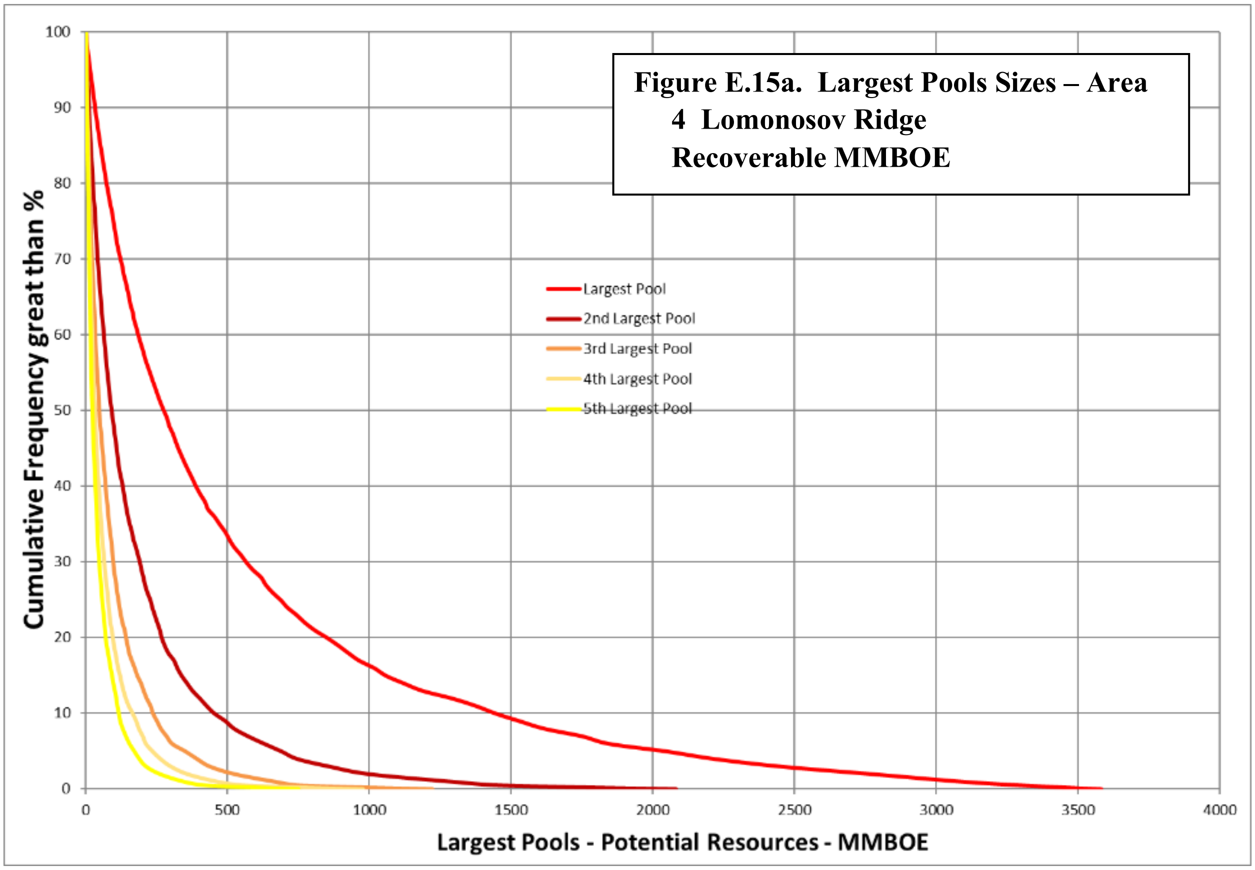


Figure E.15a. Largest Pools Sizes – Area 4 Lomonosov Ridge Recoverable MMBOE
Cumulative Frequency great than %
Largest Pool
2nd Largest Pool
3rd Largest Pool
4th Largest Pool
5th Largest Pool
Largest Pools - Potential Resources - MMBOE

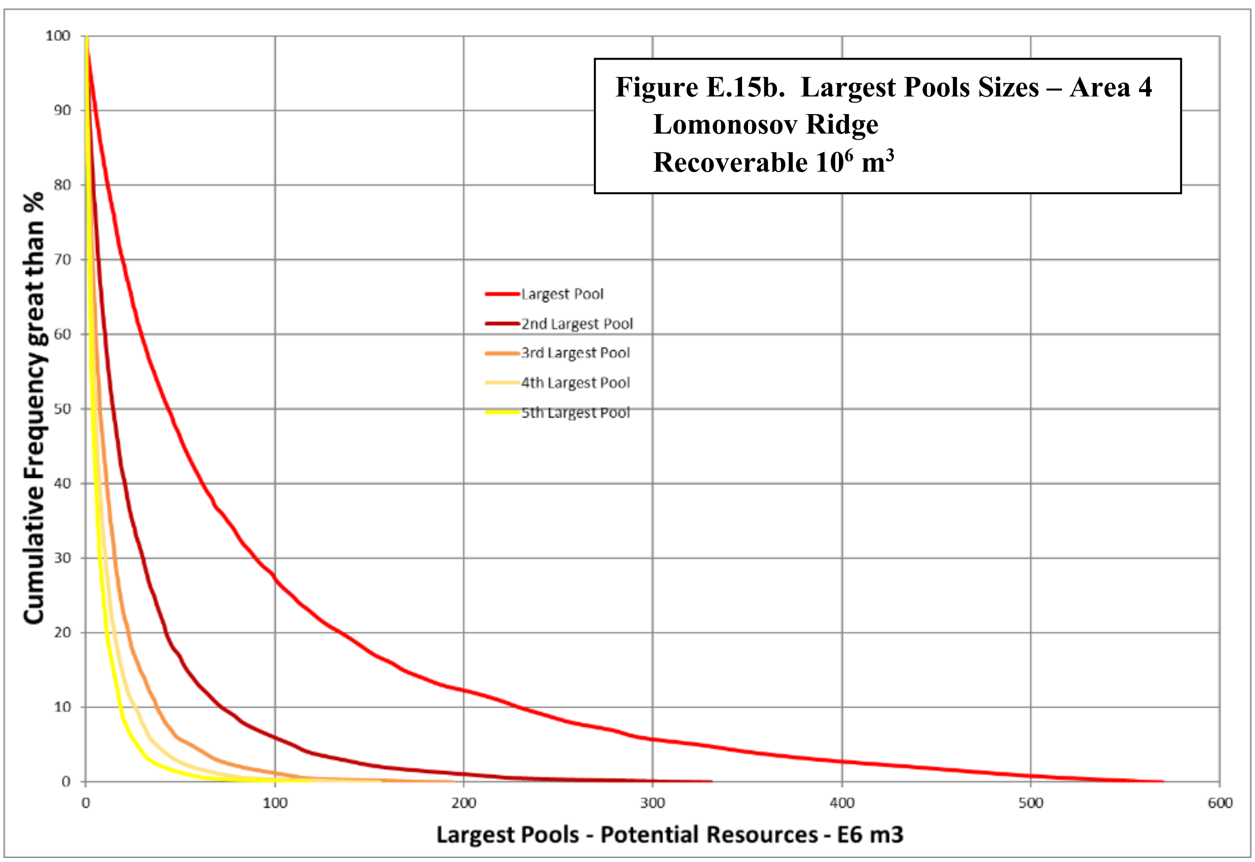


Figure E.15b. Largest Pools Sizes – Area 4 Lomonosov Ridge Recoverable 10^6 m^3
Cumulative Frequency great than %
Largest Pool
2nd Largest Pool
3rd Largest Pool
4th Largest Pool
5th Largest Pool
Largest Pools - Potential Resources - E6 m3

Area 6. NW Canada Arctic Margin

Anudu et al. (2016) interpret a portion of the regional magnetic data off Ellef Ringnes, Axel Heiberg, and southern Ellesmere Islands to indicate the presence of a rift margin basin with much less intrusion. Such rift margins host many significant conventional petroleum fields around the globe, and this area has the highest conventional petroleum potential in the Canadian High Arctic and the highest chance of success. Mean recoverable resources are 2563 MMBOE (407.5 x 10^6 m^3) (Table 16), which equates to mean resources per area of 31.1 MMBOE / 1000 km^2, over the area of 82 318 km^2.

This assessment area contains two stacked plays. Reservoirs and sources of post-rift Cretaceous to Recent age are the most prospective. An older pre-rift petroleum system exists beneath the post-rift succession, which is potentially an extension of Sverdrup Basin stratigraphy beneath the younger deposits. These two plays are statistically aggregated into a resource assessment for the whole assessment area.

This assessment area is mostly far from shore and remote, and about 70% of the assessment area is on the continental shelf in moderate water depths (300 to 600 m, except one small shallow area near Crocker Island), with the rest in deeper waters descending to 2000 m. Ice conditions dominated by multi-year shifting ice pack.

Table 16. Resource assessment output: Area 6. NW Canada Arctic Margin

		Cretaceous to Recent Play			Pre-rift Play			Aggregated Resources	
		MMBOE	10^6 m^3	# of fields	MMBOE	10^6 m^3	# of fields	MMBOE	10^6 m^3
Recoverable - All Cases (risked)	P90	0	0	0	0	0	0	0	0
	P50 median	1154	183.5	8	0	0	0	1256	199.8
	mean	2162	343.7	11.3	413	65.7	2.9	2563	407.5
	P10	5962	947.8	28	1514	240.6	11	6448	1025.1
Recoverable – Success Cases	Play Chance	68.0%			17.2%			73.5%	
	P of large field	56.9%			13.4%			62.7%	
	P90	469	74.6	5	447	71.1	5	519	82.5
	P50 median	2348	373.3	13	1824	290.0	13	2084	331.3
	mean	3167	503.5	16.5	2394	380.6	16.6	3487	554.5
	P10	6947	1104.5	33	5112	812.7	33	7754	1232.7
In-place – All Cases (risked)	P90	0	0		0	0		0	0
	P50 median	2112	335.8		0	0		2275	361.7
	mean	3960	629.6		713	113.4		4439	705.7
	P10	10870	1728.2		2688	427.4		11395	1811.7
In-place – Success Cases	P90	858	136.4		771	122.6		949	150.9
	P50 median	4307	684.8		3042	483.6		3778	600.7
	mean	5776	918.3		3961	629.7		6039	960.1
	P10	12607	2007.4		8336	1325.3		13268	2109.4

Recoverable – 50 MMBOE min field, risked	Play Chance	67.3%			17.1%			72.9%	
	P90	0	0	0	0	0	0	0	0
	P50 median	1059	168	4	0	0	0	1154	183.5
	mean	2059	327	5.7	384	61.0	1.5	2439	387.8
	P10	5710	908	14	1382	220.0	6	6153	978.2
Recoverable –300 MMBOE min. Field, risked	Play Chance	57.1%			13.4%			62.9%	
	P90	0	0	0	0	0	0	0	0
	P50 median	570	90.6	1	0	0	0	804	127.9
	mean	1553	246.9	1.8	237	37.7	0.4	1777	282.5
	P10	4586	729.1	5	741	117.8	1	13742	2184.7

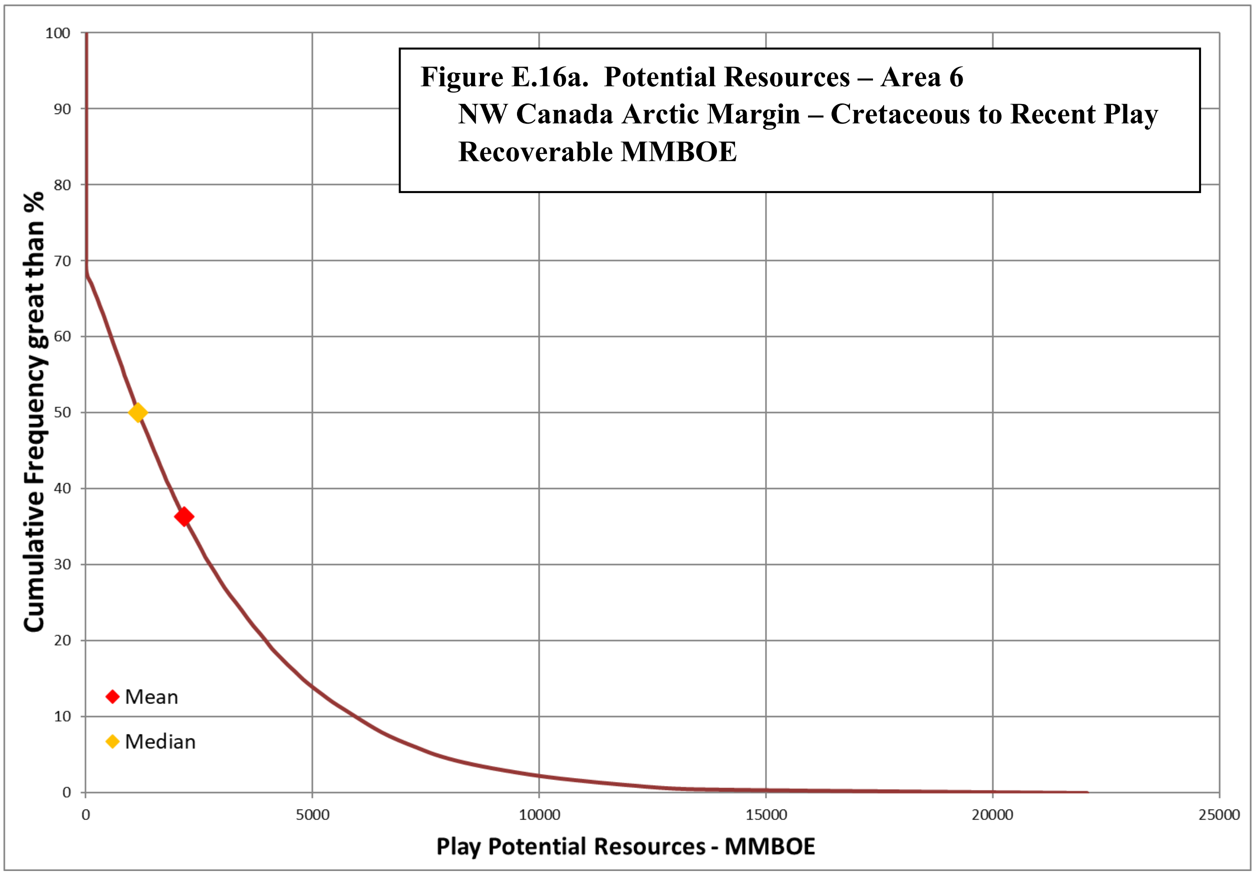


Figure E.16a. Potential Resources – Area 6
NW Canada Arctic Margin – Cretaceous to Recent Play
Recoverable MMBOE

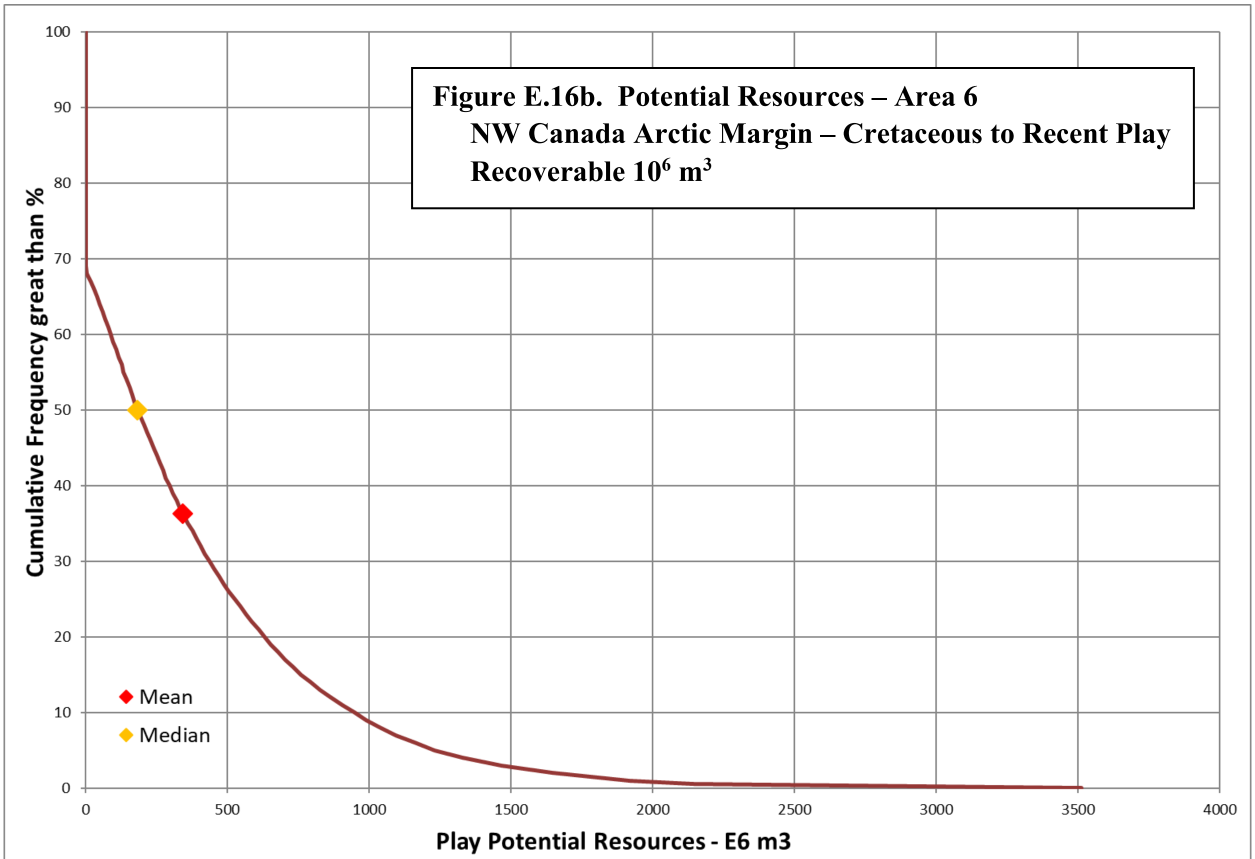


Figure E.16b. Potential Resources – Area 6
NW Canada Arctic Margin – Cretaceous to Recent Play
Recoverable 10^6 m^3
Cumulative Frequency great than %
Play Potential Resources - E6 m3
Mean
Median
0
500
1000
1500
2000
2500
3000
3500
4000
0
10
20
30
40
50
60
70
80
90
100

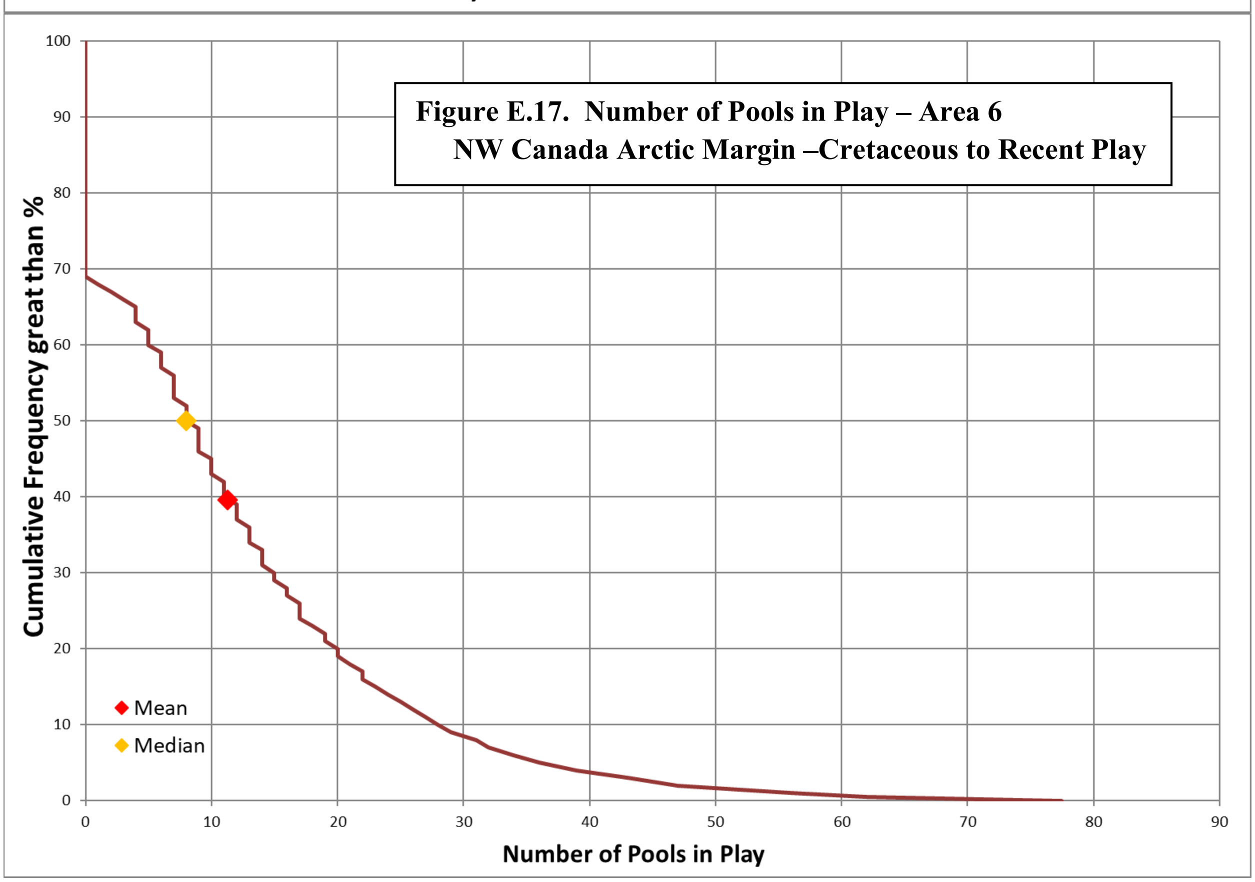


Figure E.17. Number of Pools in Play – Area 6
NW Canada Arctic Margin –Cretaceous to Recent Play
Cumulative Frequency great than %
Number of Pools in Play
Mean
Median
0
10
20
30
40
50
60
70
80
90
100

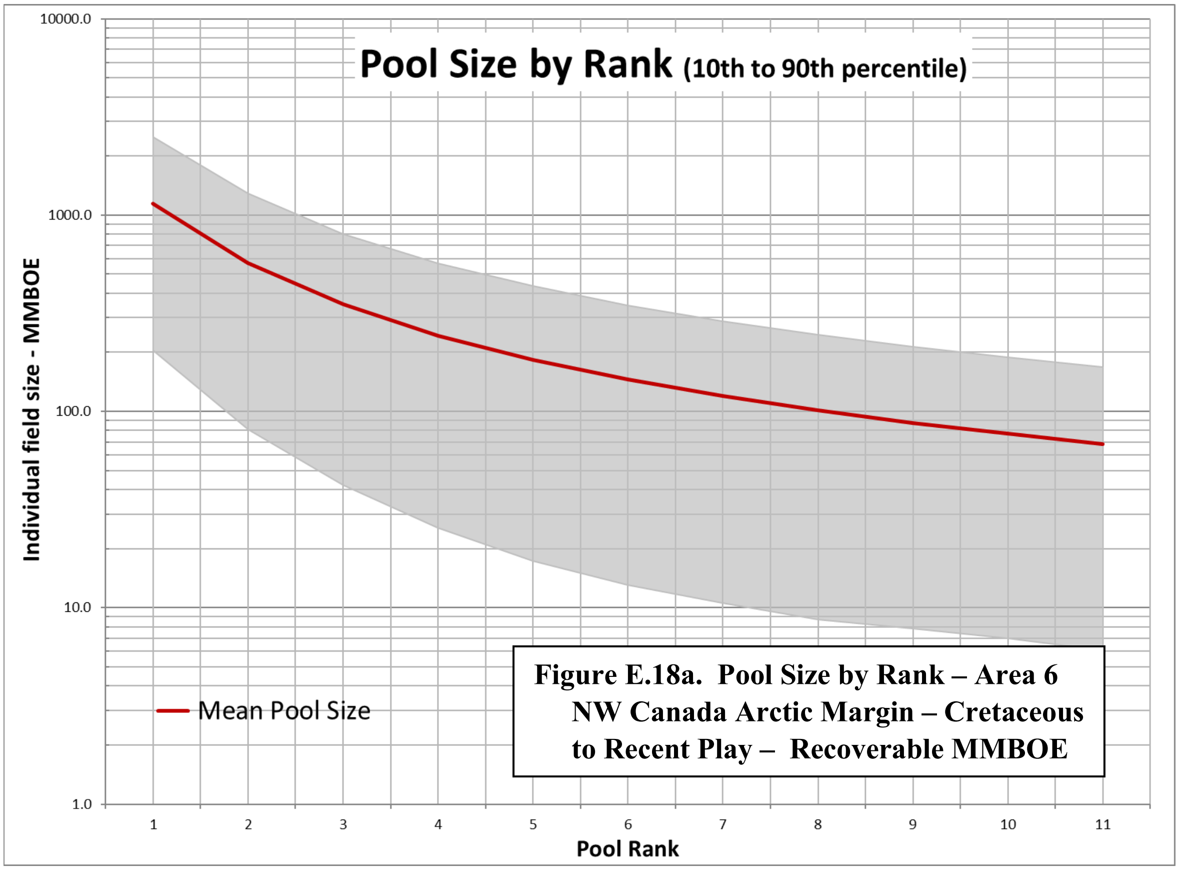


Figure E.18a. Pool Size by Rank – Area 6 NW Canada Arctic Margin – Cretaceous to Recent Play – Recoverable MMBOE

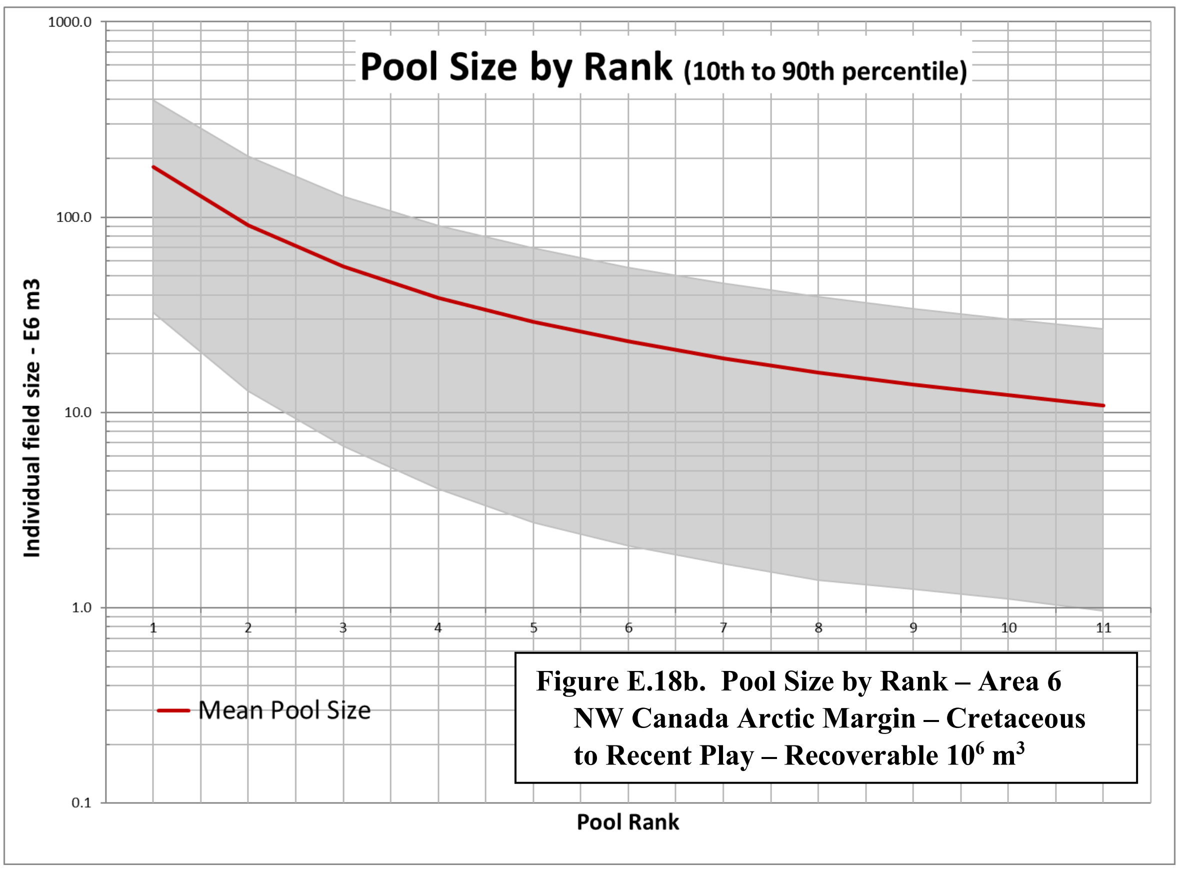


Figure E.18b. Pool Size by Rank – Area 6 NW Canada Arctic Margin – Cretaceous to Recent Play – Recoverable 10^6 m^3

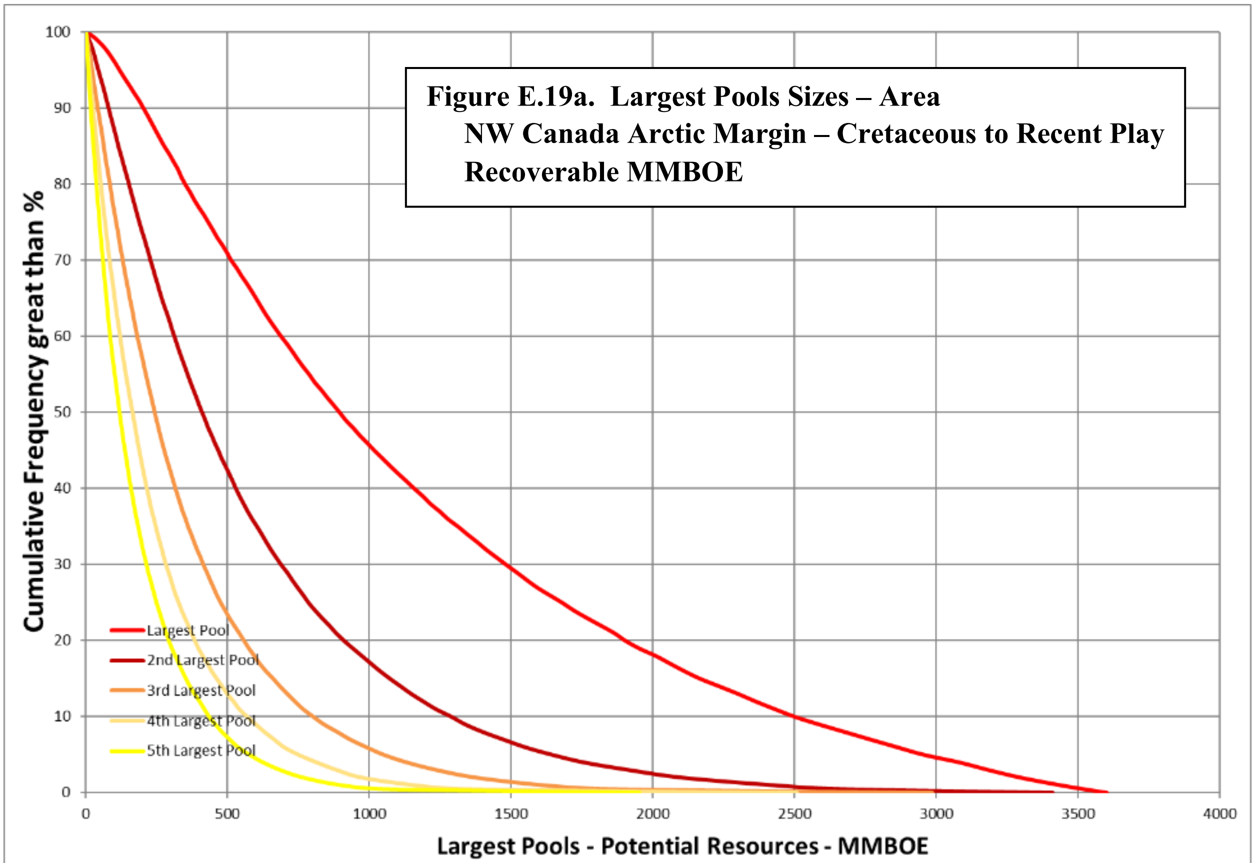


Figure E.19a. Largest Pools Sizes – Area
NW Canada Arctic Margin – Cretaceous to Recent Play
Recoverable MMBOE
Cumulative Frequency great than %
Largest Pools - Potential Resources - MMBOE
Largest Pool
2nd Largest Pool
3rd Largest Pool
4th Largest Pool
5th Largest Pool
0
10
20
30
40
50
60
70
80
90
100
0
500
1000
1500
2000
2500
3000
3500
4000

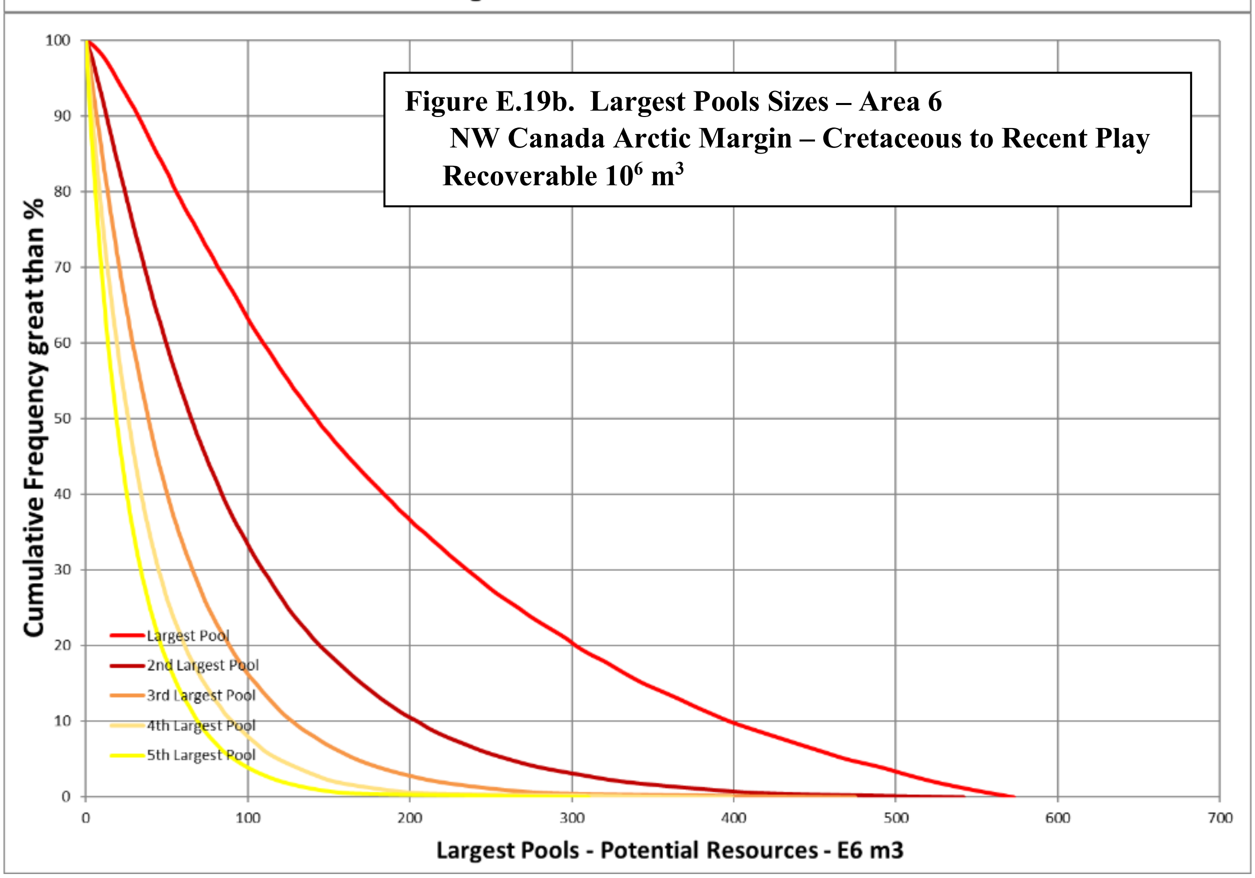


Figure E.19b. Largest Pools Sizes – Area 6
NW Canada Arctic Margin – Cretaceous to Recent Play
Recoverable 10^6 m^3
Cumulative Frequency great than %
Largest Pools - Potential Resources - E6 m3
Largest Pool
2nd Largest Pool
3rd Largest Pool
4th Largest Pool
5th Largest Pool
0
10
20
30
40
50
60
70
80
90
100
0
100
200
300
400
500
600
700

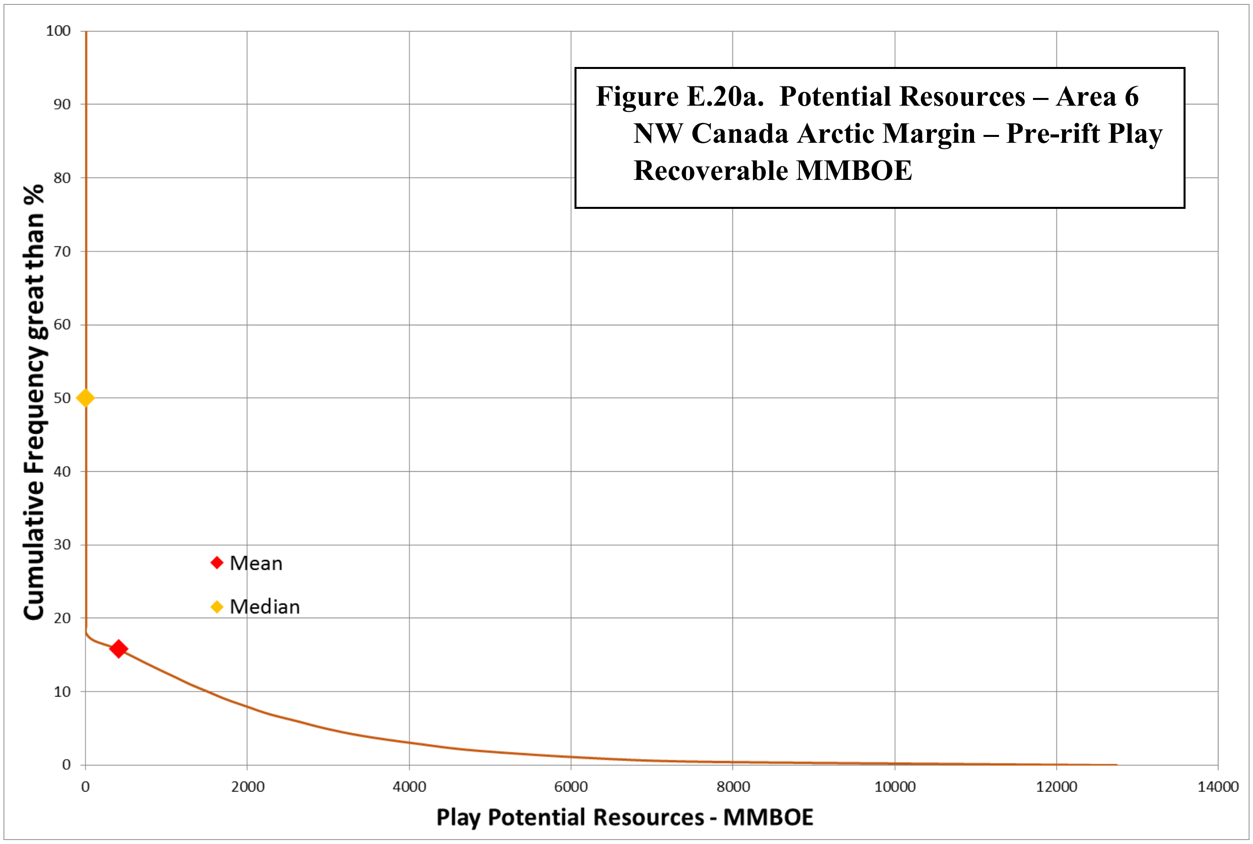


Figure E.20a. Potential Resources – Area 6
NW Canada Arctic Margin – Pre-rift Play
Recoverable MMBOE
Cumulative Frequency great than %
Play Potential Resources - MMBOE
Mean
Median
0
10
20
30
40
50
60
70
80
90
100
0
2000
4000
6000
8000
10000
12000
14000

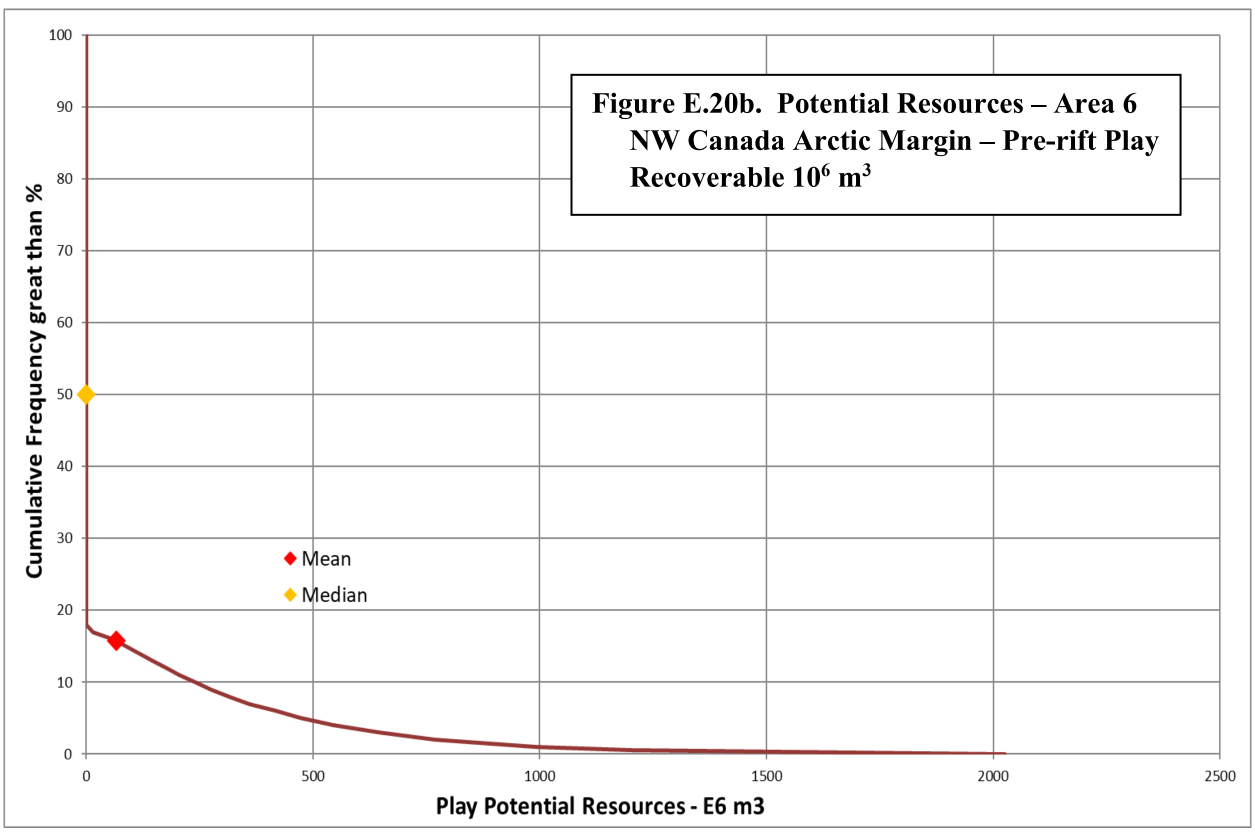


Figure E.20b. Potential Resources – Area 6
NW Canada Arctic Margin – Pre-rift Play
Recoverable 10^6 m^3
Cumulative Frequency great than %
Play Potential Resources - E6 m3
Mean
Median
0
10
20
30
40
50
60
70
80
90
100
0
500
1000
1500
2000
2500

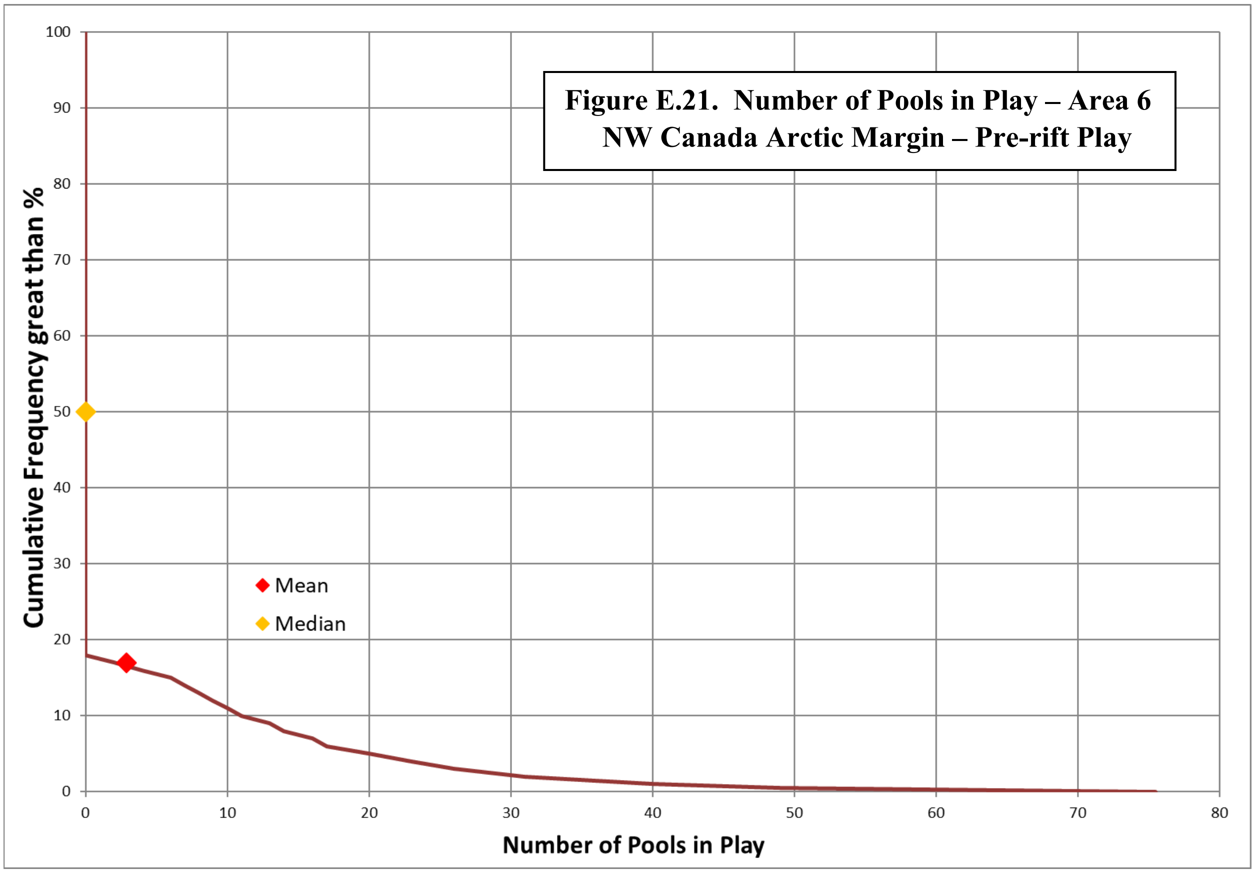
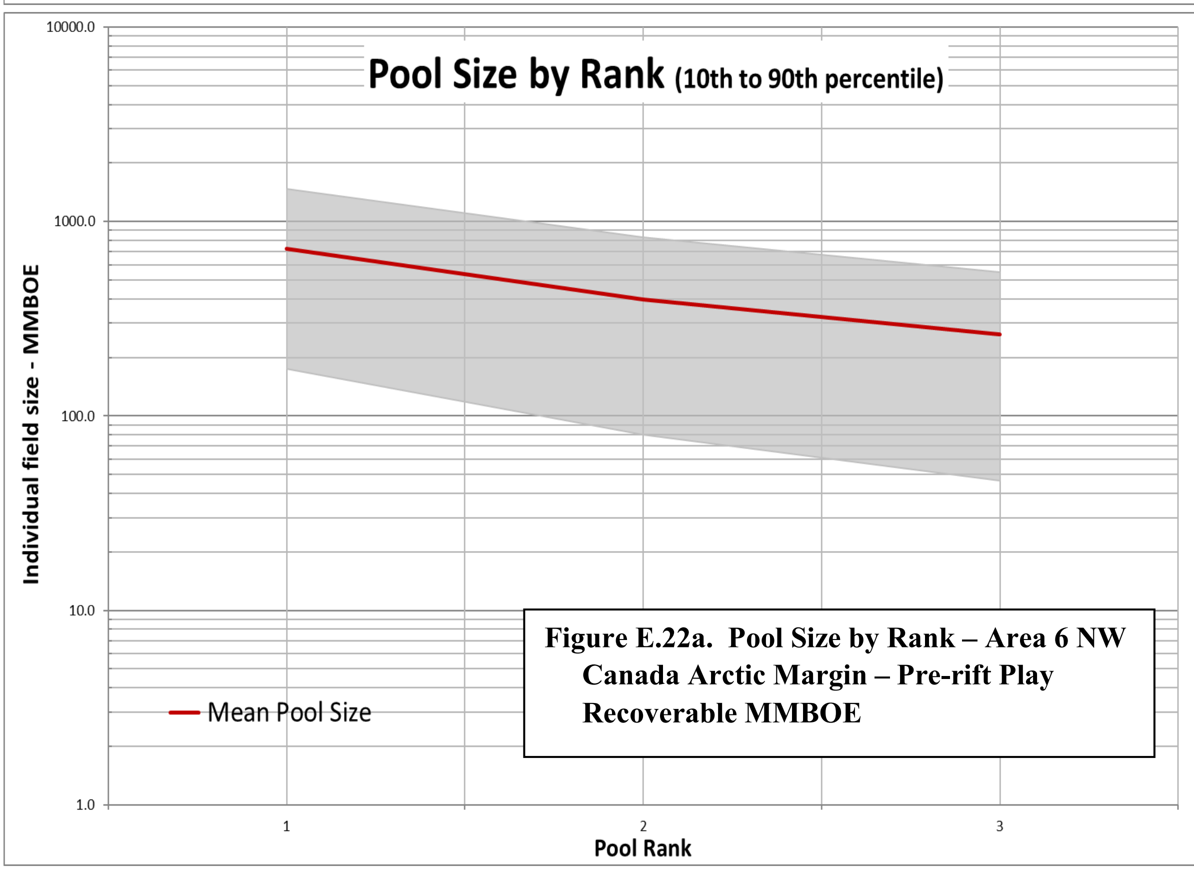


Figure E.21. Number of Pools in Play – Area 6
NW Canada Arctic Margin – Pre-rift Play
Cumulative Frequency great than %
Number of Pools in Play
Mean
Median
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80



Pool Size by Rank (10th to 90th percentile)
Figure E.22a. Pool Size by Rank – Area 6 NW
Canada Arctic Margin – Pre-rift Play
Recoverable MMBOE
Individual field size - MMBOE
Pool Rank
Mean Pool Size
10000.0
1000.0
100.0
10.0
1.0
1
2
3

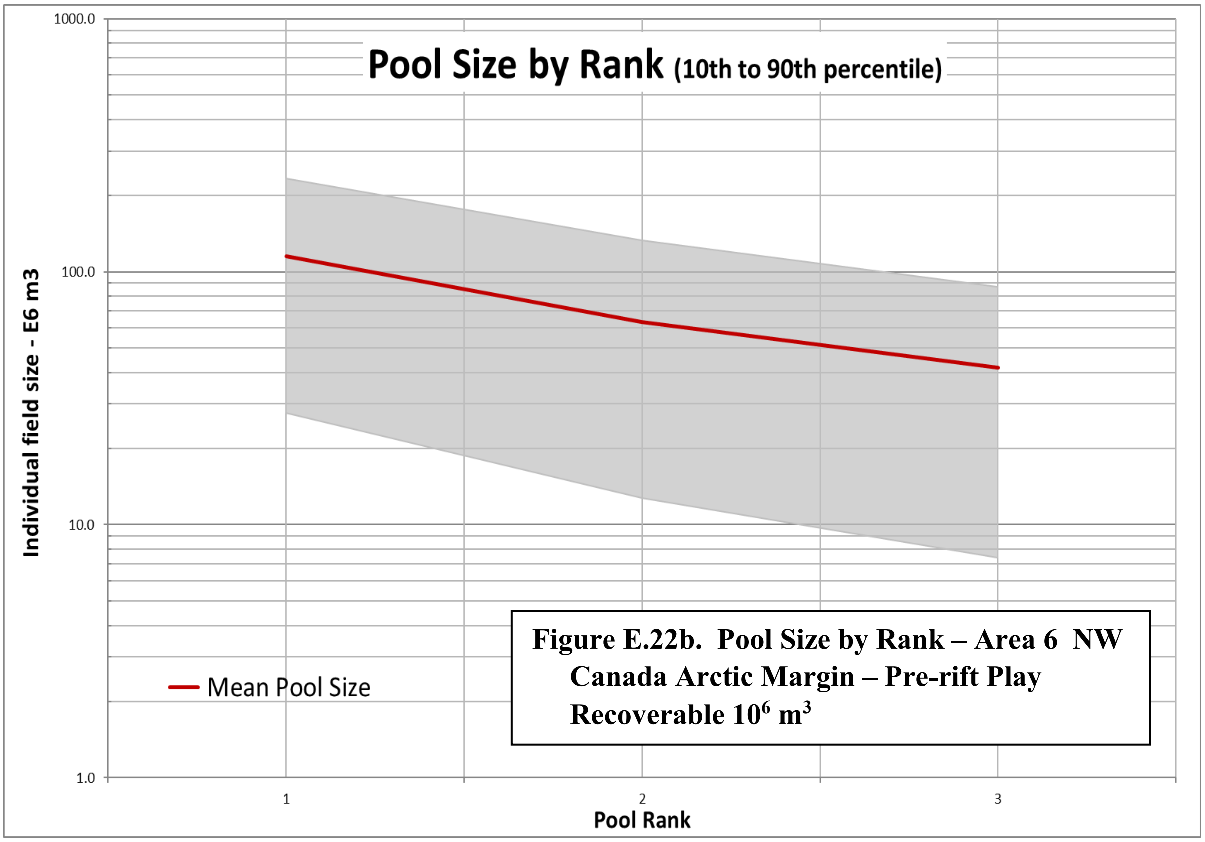


Figure E.22b. Pool Size by Rank – Area 6 NW Canada Arctic Margin – Pre-rift Play Recoverable 10^6 m^3

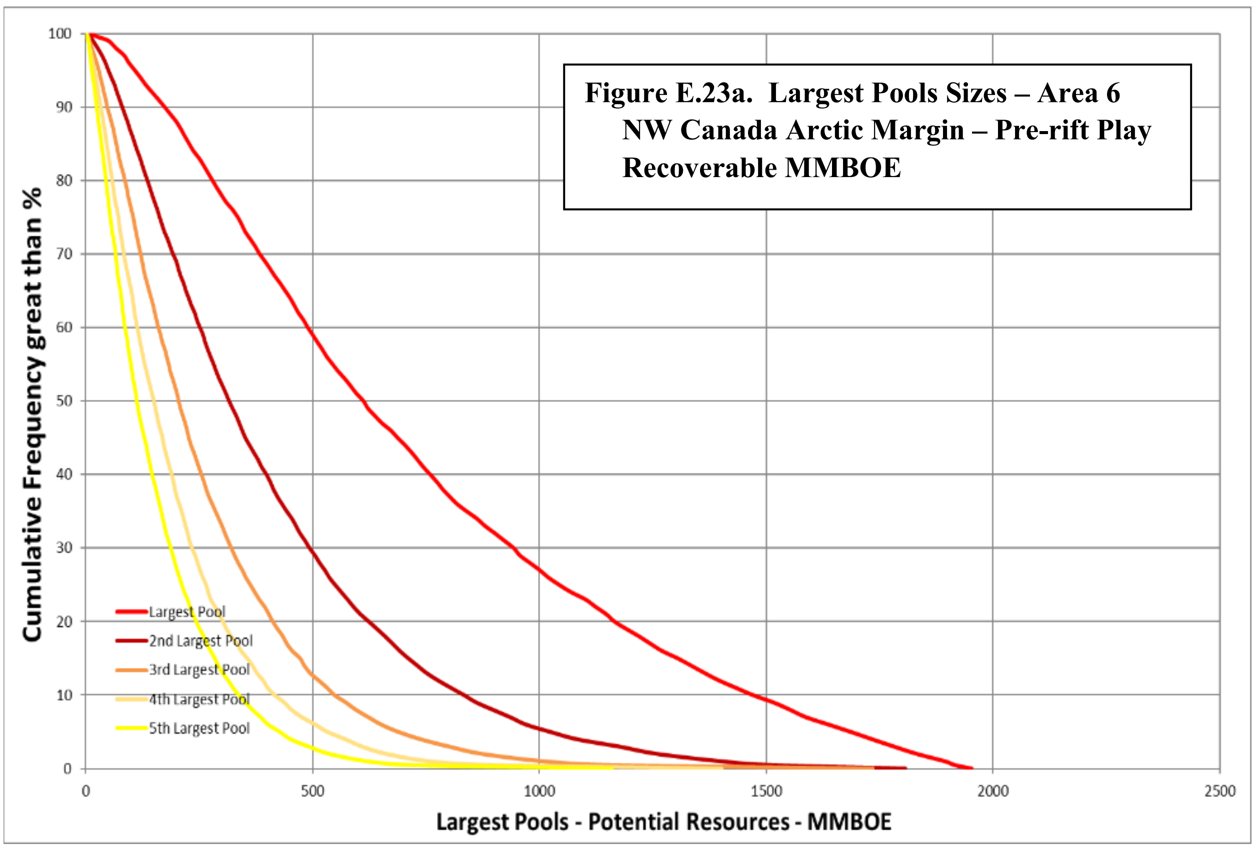
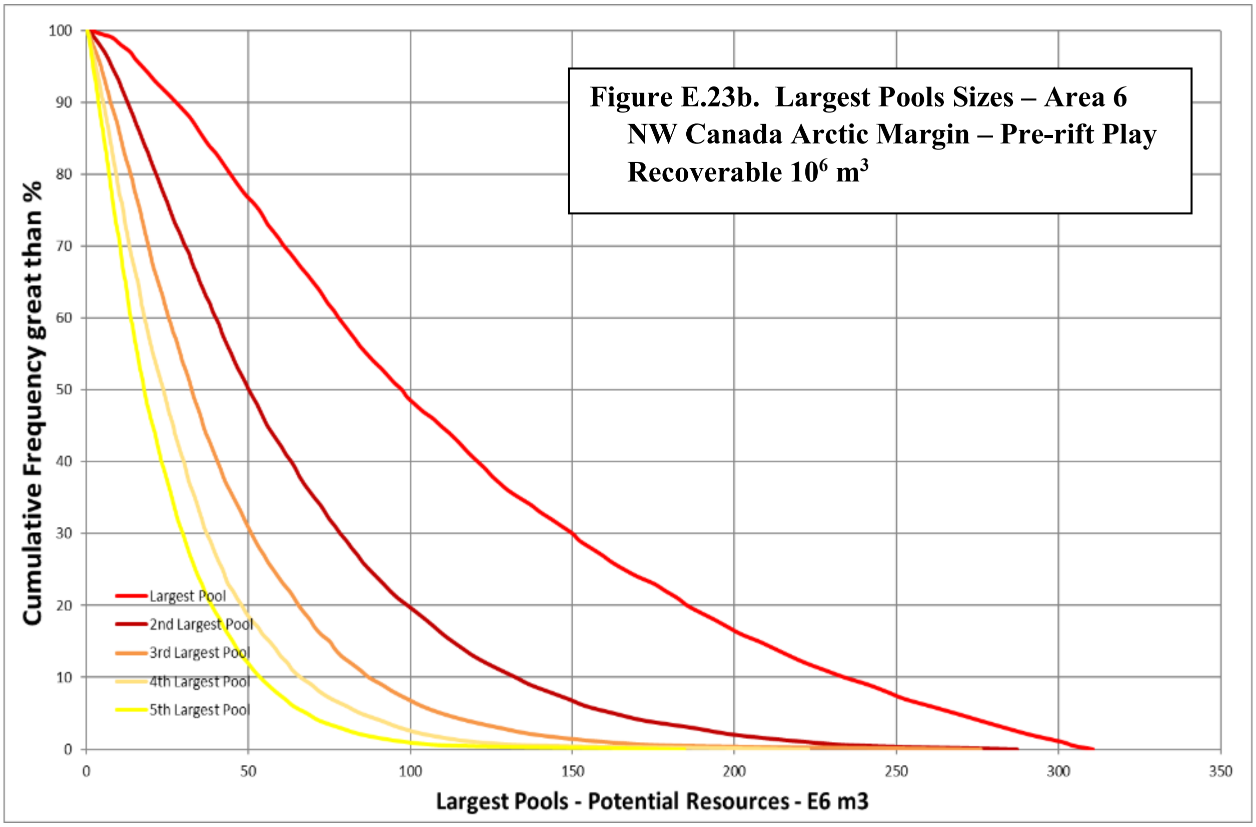


Figure E.23a. Largest Pools Sizes – Area 6 NW Canada Arctic Margin – Pre-rift Play Recoverable MMBOE



Aggregated Resource Assessment for the Proposed Protected Area

Table 17 summarizes the aggregated recoverable resources assessment for the entire Proposed Protected Area. To create this aggregated distribution, the Success Cases of each of the four assessment areas with significant resources were first aerially apportioned to the PPA area: 11% of Area 1 and 62% of Area 6 are in the PPA, and thus the aggregated success distributions were multiplied by 11% and 62% respectively. The other areas with significant resources are entirely in the PPA. Then the apportioned Success Cases and the Play Chance for each of those assessment areas were input into Rose & Associates 'Multi-Zone Master', which statistically aggregates (combines) them. The overall Chance of Success for the aggregated resources is calculated from the percentage of realizations in Multi-Zone Master where at least one assessment area was successful.

All assessment areas have a Play Chance (chance that the petroleum system is actually present and functioning) considerably below 100%, and the combination of the assessment areas results in a significantly higher chance of success somewhere in the PPA. This is because 'success' for the whole PPA requires success in just one of the four assessment areas (it is the probability of one or more of the assessments areas being successful). The chance of petroleum resources somewhere in the PPA is 95.2%.

If one aerially apportions the All Cases mean resources from each assessment area and sums them, one can directly obtain the overall All Cases mean resource of 2462 MMBOE (with minor difference due to calculation method). However, the Success Case means must be weighted by their respective chance factors, before they are summed to the final All Cases mean resource. Thus the final All Cases mean resource is not much greater than the Success Case mean resource of some assessment areas.

This statistical aggregation does not track where estimated resources will occur within the PPA; however, the ‘Qualitative Assessment of Conventional Petroleum Resources Map’ (Fig. 2) illustrates where the modelled resources are most likely to occur, and thus is a good compliment to the quantitative assessment.

As discussed, our field size distributions assumed a minimum field size to be 1 MMBOE recoverable, and the minimum cut-off does affect the resources calculated. The second set of calculations of recoverable resources, using the minimum economic field size feature in ‘PlayRA’ set to 50 MMBOE (typical USGS cut-off), and the third set of calculations, with the minimum economic field size set to 300 MMBOE (based on economic fields on Canada’s east coast), were both statistically aggregated for the PPA, in the same manner. Figure E.24 graphs the total recoverable resources for the region on a cumulative percent plot, for ALL Cases (purple line) and SUCCESS Cases (blue line).

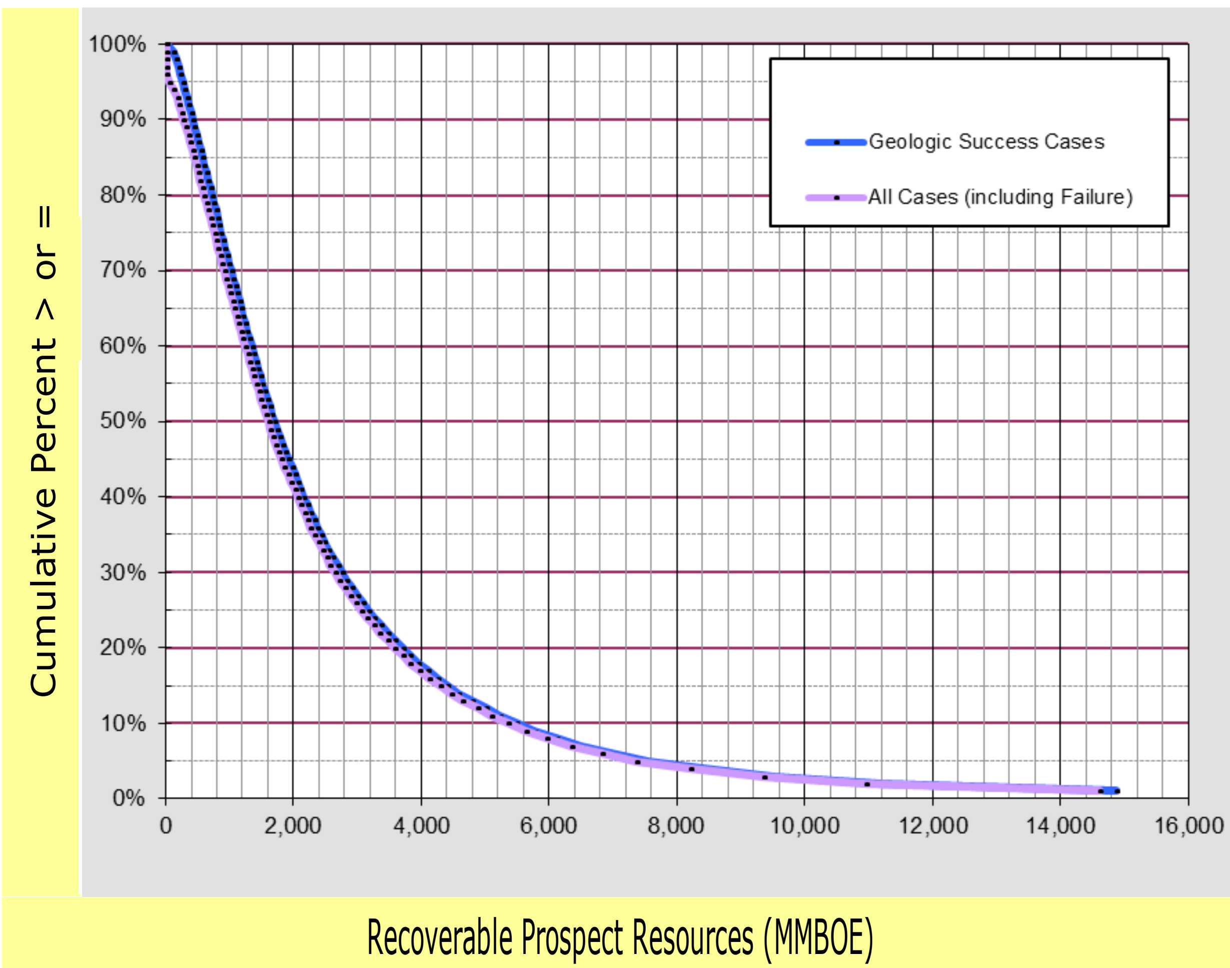


Figure E.24. Cumulative percent plot of total recoverable resources (MMBOE) in the Proposed Protected Area.

Table 17. Aggregated recoverable resources for Proposed Protected Area

	Recoverable – All Cases (risked)		Recoverable - Success Cases		Recoverable – All Cases, 50 MMBOE min. field		Recoverable – All Cases, 300 MMBOE min. field	
	MMBOE	10^6 m^3	MMBOE	10^6 m^3	MMBOE	10^6 m^3	MMBOE	10^6 m^3
Chance of Success	95.2%		95.2%		94.6%		87.3%	
P90	279	44.4	423	67.3	238	37.8	0	0
P50 median	1605	255.2	1699	270.2	1494	237.5	1043	165.8
mean	2462	391.4	2585	411.0	2334	371.1	1609	255.8
P10	5362	852.5	5488	872.6	5093	809.7	3718	591.1

Figure E.25 illustrates the contributions of the different assessment areas to the overall total recoverable resources 'for sample outcomes selected from Geologic Success Cases' (Zone A = HAB1, Zone B = HAB3, Zone C = HAB4, Zone D = HAB6). The large amount of blue on the graph illustrates that Area 6 is the largest contributor to total resources in the Proposed Protected Area.

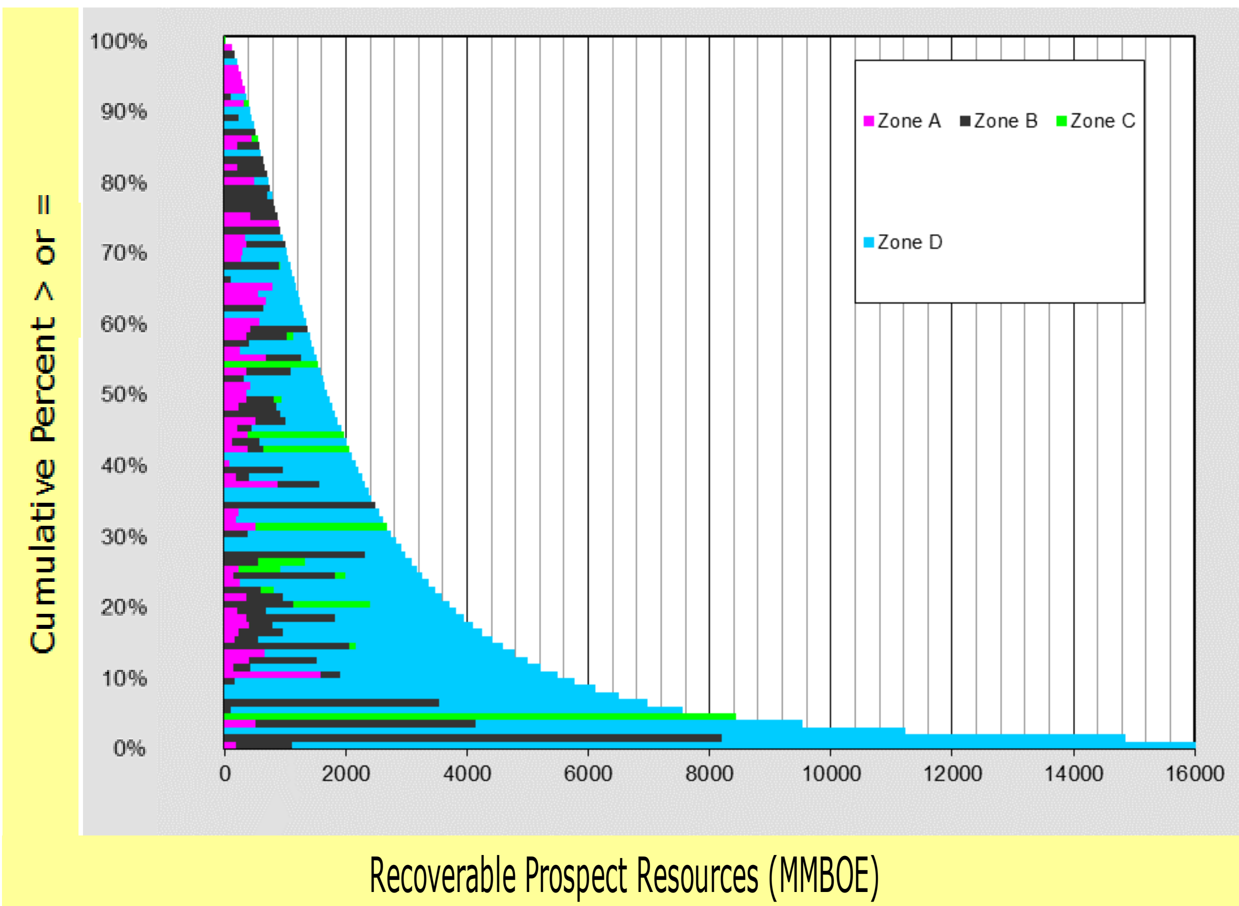


Figure E.25. Assessment area contributions for sample outcomes from geologic success

To total recoverable resources (MMBOE) in the Proposed Protected Area. Zone A = HAB1, Zone B = HAB3, Zone C = HAB4, Zone D = HAB6. Illustrates that Area 6 makes the largest contribution to the total recoverable resources.

Table 18 summaries the aggregated in-place resource assessment for the entire Proposed Protected Area. The aggregated distribution was created in a similar manner to the recoverable distribution, and fully incorporates the Play Chance for each assessment area (i.e. it is 'risked'). This statistical aggregation does not track the location of resources, but the 'Qualitative Assessment of Conventional Petroleum Resources Map' (Fig. 2) illustrates where the modelled resources are most likely to occur

Table 18. Aggregated in-place resources for Proposed Protected Area

	In-Place – All Cases (risked)		**In-Place - Success Cases**	
	MMBOE	10^6 m^3	**MMBOE**	10^6 m^3
Chance of Success	**95.2%**		**95.2%**	
P90	**493**	78.4	**747**	118.8
P50 median	**2793**	444.1	**2948**	468.7
mean	**4222**	671.2	**4433**	704.8
P10	**9103**	1447.3	**9352**	1486.8

The fully un-risked sum of all Success Case mean (average) in-place resources in the HAB region comes to 23 679 MMBOE (3764.7x10^6 m^3) – these in-place Success Case figures for each assessment area are highlighted in blue in the tables above. This figure is provided only for comparison to other studies, which sometimes quote fully unrisked estimates, and is not a realistic expectation in the physical world.