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GEOLOGICAL SURVEY OF CANADA
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EXECUTIVE SUMMARY

The Geological Survey of Canada has produced two previous qualitative assessments of the hydrocarbon potential of Hudson Bay Basin (Hanna, 2018, 2019) in support of the Marine Conservation Target program. This report revises the previous qualitative assessments based on an improved calibration of the one of the key input parameters, and provides a quantitative assessment of the volume of hydrocarbons present.

The Hudson Basin is a large intracratonic sedimentary basin that underlies Hudson Bay and adjacent onshore areas of Ontario, Manitoba, and Nunavut (Fig. 1). Preserved Ordovician to Devonian aged limestone and evaporite strata are up to about 2.5 km thick. Source rock is the petroleum system element that has the lowest chance of success; the potential source rock is thin, may be discontinuous, and the thin sedimentary cover may not have been sufficient to achieve the temperatures required to generate and expel oil from a source rock over much of the basin. The highest potential is in the center of the basin, where the hydrocarbon potential is considered 'Medium'. Hydrocarbon potential decreases towards the edges of the basin due to fewer plays being present, and thinner strata reduce the chance of oil generation and expulsion.

Quantitative hydrocarbon assessment considers seven plays. Input parameters for field size and field density (per unit area) are based on analog Michigan, Williston, and Illinois intracratonic sedimentary basins that are about the same age and that had similar depositional settings to Hudson Basin. Basin-wide play and local prospect chances of success were assigned based on local geological conditions in Hudson Bay. Each of the seven plays were analyzed in Rose and Associates PlayRA software, which performs a Monte Carlo simulation using the local chance of success matrix and field size and prospect numbers estimated from analog basins. Hudson sedimentary basin has a mean estimate of 67.3 million recoverable barrels of oil equivalent and a 10% chance of having 202.2 or more million barrels of recoverable oil equivalent. The mean chance for the largest expected pool is about 15 million recoverable barrels of oil equivalent (MMBOE), and there is only a 10% chance of there being a field larger than 23.2 MMBOE recoverable. The small expected field sizes are based on the large analog data set from Michigan, Williston and Illinois basins, and are due to the geological conditions that create the traps. The Southampton Island area of interest includes 93 087 km^2 of nearshore waters around Southampton Island and Chesterfield Inlet in the Kivalliq Region of Nunavut. Of the total resource estimated for Hudson Bay, 14 million barrels are apportioned to the Southampton Island Area of Interest.

INTRODUCTION

This report presents new qualitative and quantitative assessments of the hydrocarbon potential of Hudson Bay. A comprehensive overview of the geology and petroleum system elements of Hudson Basin have recently been published by Lavoie et al. (2022). This report revises the qualitative maps in Hanna et al. (2018; 2019) using their original polygons for each play, but with an improved calibration of the 'Global Scale Factor' used in the qualitative map methodology. The new Global Scale Factors for each play are on average lower than those used in Hanna et al. (2018; 2019), reducing the potential of the area.

The qualitative hydrocarbon potential maps are used to define play areas for the seven plays considered in the quantitative assessment of the hydrocarbon potential of the basin. Data in Hudson Bay is limited to five offshore drillholes, and limited outcrop and drilling around the margin of the basin, a seismic grid of relatively low quality, and gravity and magnetic maps. Input parameters on field sizes and number of prospects for the quantitative assessment are based on analog intracratonic basins in southern Canada and the United States. The Michigan, Williston, and Illinois basins have similar geological histories to Hudson Bay, and there is abundant data from oil and gas exploration and production in these areas. The differences between the analog basins and the local geological conditions in Hudson Basin are accounted for using basin-wide play and local prospect chance-of-success matrices. Monte Carlo simulations of each play were performed in Rose and Associates PlayRA software to estimate the overall recoverable hydrocarbon resource in Hudson Basin. A portion of the resource volumes calculated for Hudson Basin are assigned into the Southampton area of interest on the basis of how much of each play is in the Southampton Area of Interest compared to the basin as a whole, and the prospectivity of the portion of each play in the AOI.

PREVIOUS RESOURCE ESTIMATES

There are seven previous quantitative assessments of the recoverable hydrocarbon potential of Hudson Basin (Table 1, Fig. 2). ***Note that barrels of oil equivalent (BOE) are the sum of oil and gas volumes, where 5800 cubic feet of gas is taken to be equivalent of one barrel of oil. MMBOE are millions of barrels of oil equivalent. Mbbls is millions of barrels of oil; Tcf is trillion cubic feet of natural gas. All values are recoverable.*** Sproule (1968) and the Canadian Petroleum Association (1969, as reported in ISPG, 1972) estimated 3000 million and 5800 million barrels of recoverable oil equivalent. In 1971, Johnson estimated 18 200 million barrels recoverable oil equivalent. Johnson's estimate was based on overly optimistic estimates of the total sediment thickness in the basin, and on the speculation that the eastern side of the basin was fault controlled rather than a gradual thinning. Following the acquisition of magnetic, refraction, and reflection seismic data, and drilling of the Polar Bear C-11 and Narwhal O-54 wells in 1974, Tillement (1975) concluded that, "the chances of discovering major, economic accumlations of hydrocarbon in the Hudson Bay are so slim that additional expensive exploration is not justified".

Procter et al. (1984) estimated a P50 of 816 million barrels and 3.2 trillion cubic feet of gas (Tcf) of recoverable oil and gas (1346 million barrels of oil equivalent, abbreviated as MMBOE). Procter et al. (1984) low (P90) estimate was 122 MMBOE (63 million barrels of oil and 0.35 Tcf of gas), and high (P10) estimate was 5870 MMBOE (3517 million barrels of oil and 14.1 Tcf of gas). Procter noted that the geological understanding of Hudson Bay was, "…inadequate to predict the hydrocarbon potential with confidence…". Drummond (2009) used the resource distribution presented by Procter et al. (1984) and ran a Monte Carlo simulation using his own risking parameters. Drummond only estimated resources north of 60˚N, assessing 85.4 million barrels of risked recoverable oil and 0.341 Tcf of gas (his Tables 15 and 16), or 142 MMBOE recoverable.

Hudson Bay			Ultimate Recoverable oil (Mbbls)	Ultimate Recoverable gas (Tcf)	NGL (Mbbls)	Recoverable BOE (Mbbls)
Sproule et al. 1968			1000	12		3,000
Canadian Petroleum Association 1969			2900	17.4		5,800
Johnson 1971	Hudson and James Bay, Evans Strait		9000	55		18,167
ISPG 1972	all plays	P50	1500	8.7		2,950
GSC 1973			1500	7.3		2,717
Procter et al. 1984	all plays	P50	816.4	3.177		1,346
Dewing et al. 2023	all plays	P50				63
Drummond 2009	N of 60 only		85.4	0.3412		142
Procter et al. 1984	all plays	P90	62.8	0.353		122
Procter et al. 1984	all plays	P10	3516.8	14.12		5,870

Table 1. Hydrocarbon resource assessments for Hudson Basin. Note that Drummond (2009) only assessed the area of Hudson Bay north of 60˚N. Dewing et al. (2023) is this paper. NGL are natural gas liquids.

PETROLEUM RESOURCE ESTIMATION

The qualitative hydrocarbon resource maps are produced using the methodology of Lister et al. (2018). The basis of the method is to map the four petroleum systems elements (source, reservoir, trap, seal) and assign a chance of success for each element over the map area. The probabilities of the four petroleum systems elements are multiplied to give a Combined Chance of Success (CCOS) over the area (Fig. 3). Because plays are inherently different sizes (for instance Devonian reef traps tend to be much larger than Ordovician reef traps due to the evolution of reef building organisms over time), the CCOS can not be added without an adjustment. The Global Scale Factor is applied to each CCOS to get a Technical Combined Chance of Success (TCCOS) for each play. The final hydrocarbon potential for an area is found by adding all the TCCOS for each play together (Stacked Technical Combined Chance of Success - STCCOS). Figure 4 gives an illustration of the method.

Global Scale Factor calibration

The Global Scale Factor was initially defined by Lister et al (2018) as 1.0 where a play has a P50 chance of producing one 500 MMBOE recoverable field, and three 300 MMBOE fields. The lower end of the scale was described as being "proportionally normalized with a lower percentage", but the scale was not defined. Herein we propose a scale for the lower end of the Global Scale Factor based on the cumulative size of the four largest expected fields in a play (at P50). The scale is logarithmic. A GSF of 0.1 is for plays where the largest field is less than 3 MMBOE recoverable and the sum of the four largest fields is less than 9 MMBOE recoverable; GSF of 0.2 has a largest field size of 3-6 MMBOE etc. (Table 2 and Fig. 5).

Global Scale Factor	Largest Field greater than (recoverable MMBOE)	Second to fourth largest fields average (recoverable MMBOE)	Minimum Total recoverable MMBOE in 4 largest fields
1.0	500	300	1400
0.9	325	175	850
0.8	200	100	500
0.7	100	50	250
0.6	50	30	140
0.5	25	15	70
0.4	12	8	36
0.3	6	4	18
0.2	3	2	9

Table 2. Global Scale Factor bins. For example, GSF of 0.2 is assigned where the largest field is 3-6 recoverable MMBOE, plus there are three additional fields averaging 2 MMBOE. See Figure 5 as well.

Qualitative Resource Potential Map

Hanna et al. (2018; 2019) produced qualitative hydrocarbon resource assessment maps for Hudson Basin. The mapping of petroleum systems elements for each play is kept the same in this report, but the GSF is revised based on a more complete analysis of the field sizes in analog basins. The change in GSF from Hanna et al. (2018) to this report is shown in Table 3. The impact of using lower GSF in five of the seven plays is to reduce the qualitative hydrocarbon prospectivity of the basin (Fig. 6).

Age (Ma)	Play	Global Scale factor (0-1)	GSF Hanna et al. 2018
359	Devonian structural Small fault offsets	0.30	0.50
411	Silurian / Devonian unconformity	0.30	0.30
416	Silurian reef	0.40	0.50
416	Paleozoic Hydrothermal Dolomite	0.50	0.50
419	Silurian structural Small fault offsets	0.30	0.50
450	Ordovician reef	0.40	0.50
450	Ordovician structural Small fault offsets	0.30	0.50

Table 3. Comparison of the Global Scale Factor used in this report compared to those used in Hanna et al. (2018).

QUANTITATIVE HYDROCARBON ASSESSMENT

A quantitative assessment for Hudson Bay was done using the methodology outlined in Lister et al. (2022, Appendix D) and Rose (2001). The method assesses the hydrocarbon volumes in separate petroleum plays. This study examines the same 7 plays (which are petroleum systems that have a common source-reservoir-trap-seal combination) used to generate the qualitative map and are discussed in detail below.

Petroleum systems data are limited in Hudson Basin. There are only seven wells, and outcrop is scattered in the onshore areas. There is a seismic grid over the centre of the basin, but the data quality is poor compared to modern seismic surveys. There are no hydrocarbon discoveries or production data to guide estimates of field sizes. To make up for the lack of local data, analogous basins are used to estimate field density (how many fields per unit area), and field size distributions. The Michigan, Williston, and Illinois basins are excellent analogs to Hudson Bay because they are also intracratonic basins of similar age and depositional environment, however they are much thicker, with 4 km or greater maximum sediment thickness (Lavoie et al., 2022; Appendix One). These basins are onshore so they have been extensively drilled which gives a complete distribution of field sizes and number of fields in an area.

If Hudson Basin were oil bearing, then it would be expected to have similar field density and field size distributions to these analog basins. Publicly available data from the analog basins are used to count how many fields are in a given area, and production data are used to estimate field size distributions. Because fields have been producing for a long time in the analog basins, the total production is taken to be the recoverable volume of a field. Gas is converted to oil equivalent at the ratio of 5700 cubic feet of natural gas = 1 barrel of oil. Field density and field size are then given probability distributions based on the data from the analog basins. Probability distributions are lognormal, with P90 meaning that 90% of the data are larger than that value, P50 is the median value and 10% of the data are larger than the P10 value.

Hudson Bay is similar, but not identical to the analog basins. Hudson Bay, with 1.3-2.5 km of strata in the centre is not as thick as the analogs which have 4-5 km of strata in their centres, making it less likely that the source rocks reached sufficient temperatures to generate and expel oil, and potential source rock intervals are much thinner in Hudson Bay than those in the analog basins. To account for the differences between Hudson Bay and the analog basins, play and prospect chance of success are estimated for Hudson Bay. Studies from Hudson Bay (summarized in Lavoie et al. 2022) and the analog basins inform the chance of success values. The play chance of success is the chance that the petroleum system elements for that play are present and effective somewhere in the basin (i.e., what are the chances that the play works at all?). The play chance is the product of the probabilities of source, timing reservoir, trap, and seal. The prospect chance of success is the chance that the petroleum system elements work at a single prospect, given that the play works regionally. For instance, not every prospect will have an effective seal, so there is a chance that a single prospect will fail, even if hydrocarbon had once flowed into the reservoir. The field density is converted to number of expected prospects by dividing the field density by the prospect chance and multiplying by the play area (Fig. 7).

The choice of play area from the analog basin(s) should match the geology of the target basin. The analog areas chosen for this study extend from the centre of the basin to the last hydrocarbon field in the play rather than the limit of strata involved in the play. For instance, the analog area in Ontario for Ordovician structural fields does not include Ordovician strata in central Ontario where no hydrocarbon fields have been found. For the purposes of this study, the play areas (in km^2) for each play in the quantitative study are the sum of the areas where the CCOS is 5 or greater on the qualitative play CCOS map. This excludes areas, typically on the margins of Hudson Basin, where there is a small chance of finding hydrocarbons, but where fields are likely to be very small. The fringe areas with CCOS 0.1-4.999 have a very low chance of discoveries but huge areas. There were run separately with using lower COS for source and seal, and smaller field size distributions.

These chances of success, along with the prospect distribution and field size distribution, are input parameters into the PlayRA Monte Carlo simulation software package (Rose and Associates, v4-1-37; see also Lister et al. 2022, Appendix D). The PlayRA simulation runs 25 000 individual ‘realizations’ that sample the chances of success and input parameters to calculate an expected hydrocarbon volume. PlayRA randomly choses input parameters from the probability distributions with the frequency reflected in that 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. The 25 000 results are then combined to make a probability distribution of the expected resource volume (Fig. 7). The method provides a range of expected hydrocarbon volumes, with a probability that a given size is present.

The first step in a realization is to use the Play Chance of success to test whether the play succeeds regionally for that particular realization. If yes, the number of prospects ‘N’ is chosen from the prospect probability distribution that is based on the analog dataset. Then those N prospects are ‘tested’ using the Prospect Chance of success. Some of the tested prospects succeed and some don’t. The sum of the hydrocarbon volumes for all those that succeed are recorded as the output for that realization (Fig. 7).

In Hudson Bay, the petroleum system element at the play level with the lowest chance of success is source rock. This is because the source rock is thin; on Southampton Island Zhang (2011) measure 84 cm at Cape Donovan; Sixteen Mile Brook has two very thin shale beds (Nelson and

Johnson 1976); Gore Point 'very thin bed' (Macauley, 1986), and Boas River exposure '1 m at most' (Macauley, 1986). There is no direct evidence of source rock in the five wells in the middle of Hudson Bay. Well history reports do not record black shale intervals in these wells, and the onshore wells in Manitoba are missing organic rich units (Wong, 2011). Nelson and Johnson (1976) reported oil shale fragments in 99/350 locations they visited to prospect for oil shale. Organic-rich shale is clustered in discrete areas separated by areas without shale. The lack of demonstrated continuity of the potential source rock interval reduce the COS.

This report follows the analysis of thermal maturity in Hanna et al. (2018; Appendix C), which predicts a thick eroded section of Devonian. Hanna et al. (2018, their Fig. C-2) modelled 1.5 to 2.5 km of eroded Devonian or post-Devonian strata, in addition to 0.6 to 1 km of Cretaceous deposition. The deepest basement intersection is in Beluga O-23 at about 2200 m, with seafloor at about 200 m. With the inferred 1400 m of "post-Devonian" and 900 m of inferred Cretaceous (in Hanna et al., 2018), the maximum depth of burial is 4.3 km. Narwhal O-58 has 1100 m of preserved section, with 2900 m of inferred "post-Devonian" and 500 m of inferred Cretaceous for at maximum burial depth of 4.5 km. These burial depths, along with a high end member heat flow of (58 mW/m^2) puts the center of Hudson Bay into the oil window (Hanna et al. 2018, Fig. C-5A).

Setting the basin scale conditional probabilities for source rock presence at 0.5, maturity at 0.9, and expulsion-migration at 0.8 gives a COS of 0.35 in the center of the basin. Presence is given 0.5 COS even though no organic rich shale was found in the five wells. This accounts for the possibility of a geographic dependency where source rocks were only deposited in lows, but drilling only occurs on highs. This COS is applied over the area predicted by Hanna et al. (2018) to be within the oil window.

The lowest chance of success at the local Prospect level is closure and seal. The lower chance of success for these parameters is due to lack of data to either support or refute the closures and seal being effective. In the method of Lister et al. (2018), parameters with low data density or confidence trend towards 0.5, whereas samples that have high data density and confidence trend towards zero (if they refute the presence of the petroleum system element) or one (if they support the presence of the petroleum system element).

Hydrocarbon Plays in Hudson Basin.

Seven plays are evaluated as part of the quantitative assessment. The plays are described in Hanna et al. (2018), Lavoie et al. (2022) and summarized in Table 4 and Figure 8.

Age (Ma)	Play	Source	Reservoir	Trap	Seal
359	Devonian structural	Carbonates, Clastics	Small offset faults	Upper Ordovician black shales	Tight Carbonates, Shales
411	Silurian / Devonian unconformity	Carbonates, Clastics	Stratigraphic	Upper Ordovician black shales	Tight Carbonates, Shales
416	Silurian / Devonian reef	Carbonate reefs	Stratigraphic	Upper Ordovician black shales	Tight Carbonates, Shales
416	Paleozoic Hydrothermal Dolomite	Carbonates	Stratigraphic	Upper Ordovician black shales	Tight Carbonates, Shales
419	Silurian structural	Carbonates, Clastics	Small offset faults	Upper Ordovician black shales	Tight Carbonates, Shales
450	Ordovician reef	Red Head Rapids Fm.	Stratigraphic	Upper Ordovician black shales	Tight Carbonates, Shales
450	Ordovician structural	Carbonates, Clastics	Small offset faults	Upper Ordovician black shales	Tight Carbonates, Shales

Table 4. Conceptual plays evaluated in Hudson Bay quantitative assessment. See Hanna et al. (2018) for more detailed description.

Ordovician structural small fault offsets

Play concept. Source: Upper Ordovician organic-rich shale in the Red Head Rapids Formation or hypothetical algal-rich bed (kukersites) in the Bad Cache Rapids Formation. Reservoir: carbonate and clastic strata of the Bad Cache Rapids or Churchill River formations. Trap: Small offset faults, basement highs and drape anticlines. Seal: impermeable carbonates in Ordovician strata.

Analogs. Cambrian sandstone fields in Ontario (Colquhoun et al, 2019; Ontario Oil, Gas and Salt Library, 2013); Deadwood, Winnipeg, Red River and Interlake fields of the Williston Basin (Nesheim, 2012; Saskatchewan data from PetroNinja, 2022), and Devonian Granite Wash of Alberta (Hein, 1999).

Play Area. 49 341 km^2 (orange areas in Fig. 9)

Field density (fields larger than 1 MMBOE/ 1000km^2). The probability distribution for the field density is estimated by using 0.03 (the highest value for this play type in the Williston Basin) as P90; the highest value for this play type (0.16; Silurian sandstone fields of Ontario, Granite Wash Alberta) as P10. P50 of 0.07 fields/1000km2 is calculated from P90 and P10. P50 of 0.07 is close to the measured value from the Cambrian of Ontario (0.08). The expected number of prospects is (field density x area)/prospect chance, or for P90 (0.03*49.341)/0.26 = 5.7. The number of prospects is set as 6-31 (P90-P10).

Field size distribution. Field size distribution is determined from the combined 326 field sizes from the Cambrian of Ontario, and Deadwood, Winnipeg, Red River and Interlake formations of the Williston

Basin of Saskatchewan, and the lower Ordovician of North Dakota. Of these 326 fields, 12 are >= 1 MMBOE recoverable. The largest known field is 8.57 MMBOE.

Play chance of success. Source is the lowest COS at 0.35. The thickest occurrence of organic rich shale is about 1 m, which is much thinner than in the analog basins; for instance, equivalent source rocks in the Ontario part of the Michigan Basin are locally 9 m thick (Chen et al. 2019). The thermal maturity seems marginal for oil generation and expulsion over much of the basin. The hydrocarbon generation model presented in Hanna et al. (2018, appendix C) requires high heat flow, extra Devonian burial, and type II-S kerogen to achieve oil generation and expulsion, and the shape of the area modelled in Hanna et al. (2018) governs the play areas to a large extent. Timing and migration is 0.6, based on the long time since possible oil generation in the Devonian for biodegradation to have occurred. Trap and seal are not documented, so are given 0.75 based on lower data confidence.

Prospect chance of success. Source and migration are 0.9 on the assumption that if they work regionally, then they will work at the local scale. Reservoir, trap and seal are not documented, although sandstones are present at the base of the Paleozoic section at many locations. These parameters are given 0.65 to 0.75 based on lack of data confidence.

Estimated volumes. PlayRA simulation with 25 000 realizations returns a mean of 1.1 MMBOE and an 8.8% chance of success cases which have Mean 12 MMBOE (recoverable).

Largest field size. The largest field size in any of the 25 000 realizations is 11.2 MMBOE (P0.01). There is a 10% chance that a field is larger than 8.1 MMBOE, and P50 is 4.2 MMBOE (recoverable).

Fringe area: The fringe area (COS 0.01-0.0499 on the qualitative maps) are given lower COS for source and seal due to the reduced chance of mature source rock and thinner sealing units. A mean of 0.155 MMBOE recoverable with P10 largest pool is 6.7 MMBOE.

Ordovician reef

Play concept. Source: Upper Ordovician organic-rich shale in the Red Head Rapids Formation or hypothetical kukersites in the Bad Cache Rapids Formation. Reservoir: bioherm and mud mounds in the Red Head Rapids Formation; Seal impermeable carbonates, shales

Analogs. Analogs are the Boda Limestone in the Baltic Sea, offshore Sweden, which confirms the existence of widespread Upper Ordovician bioherms. There are no discoveries of oil or gas in the Boda Limestone, except next to an impact crater where transient heating matured source rocks. The Upper Ordovician Red River Formation has 14 discoveries in the Canadian portion of the Williston Basin in Saskatchewan.

Play Area.109 858 km^2 (Fig. 10).

Field density (fields larger than 1 MMBOE/ 1000km^2). The field density distribution is estimated to be between P90 of 0.235 (field density within the area of mature Ordovician source rocks in the Williston Basin) and P10 of 1.4, which is the number of reefs on seismic images of the Boda Limestone times the prospect chance of 0.23 (Levendal et al., 2019). P50 is calculated from these values as 0.57. The number of prospects is set as 113-671.

Field size distribution. Field size distribution is estimated from the field sizes of Silurian reefs with greater than 1 recoverable MMBOE in the Michigan Basin. P90 is 1.07 and P10 is 4.24 MMBOE.

Play chance of success. Source and migration are same as Ordovician structural small fault offsets. Reservoir and trap are given 0.9 based on description of Ordovician reefs in Lavoie et al. (2022) and Castagner et al. (2016). Seal is less certain and is assigned 0.85 for a Play Chance of 0.16.

Prospect chance of success. Source and migration are 0.9 on the assumption that if they work regionally, then they will work at the local scale. Reservoir is 0.65 based on abundance of cement shown in Castagner et al. (2016), and trap (0.7) and seal (0.8) are lower due to lack of information.

Estimated volumes. PlayRA simulation with 25 000 realizations returns an all case mean of 29 MMBOE recoverable and an 15.6% chance of success cases which have Mean 184 MMBOE (recoverable).

Largest field size. The largest field size in any of the 25 000 realizations is 7.4 MMBOE (P0.01). There is a 10% chance that a field is larger than 7.2 MMBOE, and P50 is 6.4 MMBOE.
Fringe area: The fringe area (COS 0.01-0.0499 on the qualitative maps) are given lower COS for source and seal due to the reduced chance of mature source rock and thinner sealing units. A mean of 0.73 MMBOE recoverable with P10 largest pool is 5.6 MMBOE.

Silurian small fault offsets
Play concept. Source Upper Ordovician organic-rich shale; Reservoir carbonate strata; Trap Small offset faults, small folds; Seal impermeable carbonates, shale, salt.
Analogs. Same as Ordovician small fault offsets.
Play Area. 26 860 km^2 (Fig. 11).
Field density (fields larger than 1 MMBOE/ 1000km^2). Same as Ordovician small fault offsets. The number of prospects is set as 3-17.
Field size distribution. Same as Ordovician small fault offsets.
Play chance of success. Same as Ordovician small fault offsets.
Prospect chance of success. Same as Ordovician small fault offsets.
Estimated volumes. PlayRA simulation with 25 000 realizations returns an all case mean of 1 MMBOE recoverable and an 7.8% chance of success cases which have Mean 7 MMBOE (recoverable).
Largest field size. The largest field size in any of the 25 000 realizations is 11.2 MMBOE (P0.01). There is a 10% chance that a field is larger than 7.0 MMBOE, and P50 is 3.5 MMBOE (recoverable).
Fringe area: A mean of 0.66 MMBOE recoverable with P10 largest pool is 6.9 MMBOE is assigned within the fringe area (COS 0.01-0.0499 on the qualitative maps).

Paleozoic Hydrothermal Dolomite
Play concept. Source: Upper Ordovician organic-rich shale; Reservoir: Carbonate units dolomitized by high temperature fluids; Trap: dolomite body along or near faults; Seal impermeable carbonate, shale units
Analogs. High temperature dolomite bodies associated with faults in the Michigan Basin of Ontario (Ontario Oil, Gas and Salt Library, 2013) and Michigan (Grammar, 2007; Harrison, 2017), and Ohio-New York-Kentucky (Patchen et al., 2006).
Play Area. 61 566 km^2 (Fig. 12)
Field density (fields larger than 1 MMBOE/ 1000km^2). The low end of the distribution is P99=0.014, which is the density of hydrothermal dolomite in the study of Trenton-Black River groups of New York, Ohio and Kentucky (Patchen et al., 2006). The high end of the distribution is P10=0.25 from Ontario. P50 is calculated as 0.09. Michigan State is 0.12. The number of prospects is set as 5-40.
Field size distribution. The field size distribution is based on recovered hydrocarbons from 186 fields in the Michigan Basin (Grammer et al., 2007; Ontario Oil, Gas and Salt Library, 2013). The largest field is 26.55 recoverable MMBOE, and 12 of the 186 fields are larger than 1 MMBOE.
Play chance of success. Source has the lowest chance of success (see discussion under Ordovician small fault offsets). Timing is 0.6 based on the old age of generation. Reservoir is 0.85 based on descriptions in Lavoie et al. (2022), but reduced from the highest COS bin due to lack of measured porosity or permeability. Closure (0.75) and seal (0.8) are likely, but not documented.
Prospect chance of success. The lowest COS is for seal due to dolomite bodies typically being associated with faults. The seal in analog basins is the thick Utica-Collingwood shale, but no equivalent thick shale is present in Hudson Basin.

Estimated volumes. PlayRA simulation with 25 000 realizations returns an all case mean of 6 MMBOE recoverable and an 10.7% chance of success cases which have Mean 57 MMBOE (recoverable).
Largest field size. The largest field size in any of the 25 000 realizations is 26.5 MMBOE (P0.01). There is a 10% chance that a field is larger than 21.0 MMBOE, and P50 is 13.4 MMBOE (recoverable).
Fringe area: A mean of 2.7 MMBOE recoverable with P10 largest pool is 17.1 MMBOE is assigned within the fringe area (COS 0.01-0.0499 on the qualitative maps).

Silurian reef
Play concept. Source: Upper Ordovician organic-rich shale; Reservoir: reefs in the Attawapiskat Formation; Trap: bioherms and carbonate grainstone adjacent to bioherms; Seal impermeable carbonates, salt of the Ekwan River and Kenogami River formations.
Analogs. Analogs are Silurian reefs in Michigan Basin of Ontario and Michigan. These areas have been extensively drilled for oil and gas exploration, with over 1200 discoveries in Michigan.
Play Area. 76 648 km^2 (Fig. 13)
Field density (fields larger than 1 MMBOE/ 1000km^2). P90 of 0.45 is chosen based on the density of fields in the entire Michigan basin and midwestern United States. The field density on the NW side of the Michigan basin (1.58) is taken as P01. The values of P50 (0.70) and P10 (1.10) are calculated. Seismic data from Hudson Bay do not indicate that reefs at the same density as in the NW Michigan Basin, so that area is taken as the extreme end of the distribution.
Field size distribution. Using 1 MMBOE cut-off from the Silurian reef data of Ontario, we estimate P90 is 1.07 MMBOE recoverable; P50 is 2.1 MMBOE and P10 is 4.24 MMBOE recoverable (Fig. 13)
Play chance of success. Source is 0.35 as discussed above. Timing/migration are reduced to 0.55 (slightly lower than the older plays) due to extra distance of migration and risk of migration pathways between the potential source rocks and the widespread Silurian reefs. Reservoir, closure and seal (salt) are documented in outcrop.
Prospect chance of success. Source is 0.9, as discussed above, migration is 0.7, reflecting the difficulty in establishing migration pathways to access all bioherms. Reservoir, closure and seal range from 0.65-0.75 based on lack of measured parameters.
Estimated volumes. The mean of all cases is 20 recoverable MMBOE, and P10 is 108 MMBOE. The success case has a 14.7% chance of success with mean 137 MMBOE (recoverable).
Largest field size. The largest field size in any of the 25 000 realizations is 7.4 MMBOE (P0.01). There is a 10% chance that a field is larger than 7.2 MMBOE, and P50 is 6.3 MMBOE (recoverable). The two biggest fields of this play type in Ontario are 6.0 and 4.1 MMBOE.
Fringe area: A mean of 2.2 MMBOE recoverable with P10 largest pool is 6.5 MMBOE is assigned within the fringe area (COS 0.01-0.0499 on the qualitative maps).

Silurian / Devonian unconformity
Play concept. Source: Upper Ordovician organic-rich shale; Reservoir carbonate and clastic strata in the Kwataboahegan and Stooping River formations; Trap stratigraphic pinchout and small structures at the unconformity; Seal impermeable carbonate, shale units in the Kwataboahegan, Stooping River , and Moose River formations.
Analogs. Sandstone traps in the Silurian of Ontario (Colquhoun et al., 2019; Ontario Oil, Gas & Salt library, 2013). The reservoir in Ontario is the Grimbsy sandstone, for which there is no direct analog in Hudson Bay. There are no similar play in the Williston Basin. Unconformity related traps in the Mississippian of Kansas are used for field size and field density, although the Mississippian fields are

very large and the size is adjusted to more reasonably match the area yield of intracratonic basins – see below (Ball et al., 1991; https://www.kgs.ku.edu/Magellan/Field/index.html)
Play Area. 63 512 km^2 (Fig. 14).
Field density (fields larger than 1 MMBOE/ 1000km^2). Unconformity traps in Kansas with a field density of 0.64 fields/1000 km^2 are taken as P10. P50 is chosen as 0.23 (slightly higher than the measured Ontario field density of 0.16). P90 is calculated as 0.08. This leads to 21-165 prospects within this play area in Hudson Bay.
Field size distribution. Rose (2001) points out that field size distributions in analog datasets can be reduced or 'discounted' if the actual field sizes are unreasonably large. In this case we discount the measured Mississippian unconformity fields by 19% to achieve an area yield of 4.7 MMBOE/1000 km2, which is the P10 of area yields in all our analog datasets (Michigan, Williston, Illinois basins; P90 is 0.07). This makes the largest field size in the 'discounted' field size distribution 29.2 MMBOE, which we consider P01. P10 is measured from the discounted Kansas dataset at 10.66 MMBOE. Calculated from these are P50 3.09 and P90 0.896 MMBOE (recoverable). The largest fields of this play type in Ontario are four fields of about 9 MMBOE each, implying that the largest field has yet to be found.
Play chance of success. Source is assessed a COS of 0.3 given its long distance from the potential source rocks in Upper Ordovician strata, and need to fill other traps along the route. Timing/Migration is 0.55. Reservoir, closure and seal are 0.75, 0.85, and 0.9 respectively. Reservoir and seal are not measured parameters. Sealing lithologies are present above the unconformity.
Prospect chance of success. Source and Timing/Migration are 0.9, given that if they work regionally, they likely work locally. Faults are known to truncate against the unconformity, so migration pathways are possible. Reservoir, closure and seal are all hypothetical, with no know discoveries and no documented occurrences, reducing their COS based on the lack of data certainty.
Estimated volumes. The mean of all cases is 8 recoverable MMBOE. The success case has a 9.3% chance of success with mean 87 MMBOE recoverable.
Largest field size. The largest field size in any of the 25 000 realizations is 29.2 MMBOE (P0.01). There is a 10% chance that a field is larger than 24.5 MMBOE, and P50 is 14.6 MMBOE (recoverable).
Fringe area: A mean of 1.9 MMBOE recoverable with P10 largest pool is 22.9 MMBOE is assigned within the fringe area (COS 0.01-0.0499 on the qualitative maps).

Devonian small fault offsets
Play concept. Source: Upper Ordovician organic-rich shale; Reservoir: carbonate and clastic strata of the Kwataboahegan, Moose River or Williams Islands formations; Trap: small offset faults, drape or drag folds; Seal: impermeable carbonate and shale of the Murray Harbour, Williams Island or Long Rapids formations, sealing fault.
Analogs. Same as Ordovician small fault offsets.
Play Area. 77 338 km^2, (Fig. 15).
Field density (fields larger than 1 MMBOE/ 1000km^2). Same as Ordovician small fault offsets
Field size distribution. Same as Ordovician small fault offsets
Play chance of success. Similar to Ordovician and Silurian small fault offset plays
Prospect chance of success. Same as Ordovician small fault offsets
Estimated volumes. The mean of all cases is 2 recoverable MMBOE, with P10 of 0. The success case has a 8.4% chance of success with mean 18 MMBOE (recoverable)
Largest field size. The largest field size in any of the 25 000 realizations is 11.3 MMBOE (P0.01). There is a 10% chance that a field is larger than 8.6 MMBOE, and P50 is 4.9 MMBOE (recoverable).
Fringe area: A mean of 0.155 MMBOE recoverable with P10 largest pool is 4.8 MMBOE is assigned within the fringe area (COS 0.01-0.0499 on the qualitative maps).

Summary and Aggregation of all plays

Combining the 7 play results requires a statistical aggregation method. Only the means of statistical distributions can be summed because each play has a different shape to the resource probability distribution. Aggregation requires that each distribution be resampled to produce a final result. The 7 plays in this study are aggregated using ‘Multi-Zone Master’ (v4-2-104b) from Rose & Associates. This software can be used to aggregate any lognormal distributions using each play’s 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 to the overall resource estimate).

The software uses a Monte Carlo process 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 30,000 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’ (i.e., we only need <u>one</u> of A or B or C) to get a success in the aggregate. This is why the regional aggregated Play Chance is higher than the individual Play Chances.

	Combined Play and Fringe	All case P90	All case P50	All case Mean	All case P10	Success P90	Success P50	Success Mean	Success P10	Play chance	largest pool 10th percentile
359	Devonian structural	0	0	1.7	1.05	2.6	10.8	16.1	34.8	10.2	8.6
411	Silurian / Devonian unconformity	0	0	9.8	18.1	19.4	61.7	89.7	189.3	10.9	23.2
416	Silurian reef	0	0	22.3	112.3	39.4	121.1	124.7	204.5	17.9	7.2
416	Paleozoic Hydrothermal Dolomite	0	0	8.8	21.7	13.9	46.9	69.7	151.5	12.7	21.0
419	Silurian structural	0	0	1.2	0	2.4	7.8	12.6	28.5	9.7	7.0
450	Ordovician reef	0	0	29.2	115.4	11.7	124.4	156.6	321.6	18.6	7.2
450	Ordovician structural	0	0	1.5	1.58	3.33	10.3	14.7	30.5	10.1	8.1
	Combined reef-unconformity-HTD	0	0	65.4	216.9	31.5	138.3	205.8	431.7	31.8	
	Combined structure	0	0	4.4	14.5	3.5	14.3	21.9	48.7	20.3	
	All plays	0	0	67.3	202.2	11.0	87.6	164.1	379.9	41.0	

Table 5. Summary of the aggregated results for all plays in Hudson Basin. All values millions of barrels of recoverable oil equivalent. Values are from statistical distributions for each play and do not add arithmetically. Success cases are matched with the play chance. The P10 for largest individual pool size in the main Play area is given in the second last column. Note the small expected size of pools in Hudson Bay due to the geological context of the traps.

APPORTIONING INTO SMALLER AREAS

Method

Play areas are defined using a qualitative assessment of the four petroleum systems elements. In an area like Hudson Bay where information on maturity and migration are scarce, play areas are necessarily large. Quantitative assessments are then done within each play area without consideration as to where the resource is located within that area. For practical applications, like marine protected areas, some of the overall resource needs to be apportioned from the large play polygon into that smaller part of the play polygon that lies within the MPA. There is no established protocol for apportioning resources to smaller areas. In this report, we have used the CCOS polygons* from qualitative map for each play to assign resources from the quantitative assessment in those polygons. In the absence of an established protocol, we propose four methods and present the results from two. *(*CCOS is the combined chance of success of source, reservoir, trap and seal for a single play)*

The Random Assortment method of randomly assigning resources across an assessed area (i.e., if 10% of the play area is within the MPA, then it gets 10% of the resource) does not match the observed pattern of hydrocarbon discoveries, where most of the resource tends to be concentrated into small areas of higher potential. The Weighted Random Fraction method assigns resource by the area of each CCOS bin (0-5, 5-10, 10-15 etc.) multiplied by the average CCOS within that bin. Resources are assigned based on the weighted (area*average_CCOS) value.

The Dominance Model assigns a dominance of the resource yield into the highest CCOS bin, with 50% or more of the resource yield assigned to the highest CCOS bin, and then proportionally less to each CCOS bin below (Table 5). (This is conceptually like the Dominance pre-emption model of niche apportionment in biological studies of relative species abundance; e.g. Tokeshi 1990) Table 5 shows that for qualitative maps with 3 CCOS bins, we assign no resource to the 0-5% CCOS bin, 30% of the resource to the 5-10% CCOS bin and 70% of the resource to the 10-15% CCOS bin. These correspond to area yield proportions 0:1:2.3. These are then multiplied by the area of each COS bin to get an area weighted average yield (i.e., area yield * area = yield). The matrix for the Dominance Model has a monotonic increase in both directions for consistency, but there is no calibration using area yields from the analog basins due to the lack of accessible data. Figure 16 gives an example of the method.

Dominance Model

CCOS bin					
0-5	0	0	0	0	0
5-10	30	15	8	5	4
10-15	70	30	15	8	5
15-20		55	22	12	7
20-30			55	25	12
30-40				50	22
40-100					50

CCOS bin					
0-5	0	0	0	0	0
5-10	1	1	1	1	1
10-15	2.3	2.0	1.9	1.6	1.3
15-20		3.7	2.8	2.4	1.8
20-30			6.9	5.0	3.0
30-40				10.0	5.5
40-100					12.5

Table 6. Ratios used in the two dominance models. Dominance Model assigns no resource to the 0-5 CCOS bin due to the small size of both fields and total resource expected around the margin of Hudson Basin. The upper part is the percentage of the area yield given to each CCOS bin, the lower part is the ratio of area yields in each CCOS bin

The Ascending Field Size Model assigns the field sizes in ascending order to each COS bin. For instance, if the 0-5 COS bin has 30% of the area, it receives a volume equivalent to the smallest 30% of field sizes. Because the largest 5 fields tend to be so much larger than all the other fields (in the Silurian reef analogs from Ontario, the 5 largest fields contain 50% of the resource), the effect of this method is to assign almost all the resource to the highest COS bin. This seems to heavily discount the uncertainty inherent in COS estimates of the four petroleum system elements.

Example: Southampton AOI

The apportioning from the total resource for Hudson Basin into the Southampton Area of Interest was done using the Dominance and Weighted Random Fraction models (Table 6). Both methods give 14 MMBOE recoverable within the proposed marine protected area.

Hudson Basin				
Play name	*CCOS Range*	*Sq km total*	*Dominance model Mean MMBOE*	*Weighted Random Fraction model Mean MMBOE*
Devonian faults				
Play 359 Fault	0	729,653		
Play 359 Fault	0.0100 - 0.0499	159,312	0.16	0.37
Play 359 Fault	0.0500 - 0.0999	164,033	0.96	1.06
Play 359 Fault	0.1000 - 0.1499	77,338	1.04	0.73
Play 359 Fault	0.1500 - 0.1999	-		
S/D unconformity				
Play 411 Unc	0	410,640		
Play 411 Unc	0.0100 - 0.0499	454,216	1.85	2.48
Play 411 Unc	0.0500 - 0.0999	169,541	2.69	2.79
Play 411 Unc	0.1000 - 0.1499	63,512	2.31	1.61
Play 411 Unc	0.1500 - 0.1999	-		
Silurian reef				
Play 416 Reef	0	724,768		
Play 416 Reef	0.0100 - 0.0499	141,862	2.21	3.46
Play 416 Reef	0.0500 - 0.0999	187,063	10.98	8.96
Play 416 Reef	0.1000 - 0.1499	76,443	8.97	9.71
Play 416 Reef	0.1500 - 0.1999	205	0.04	0.03
Paleozoic hydrothermal				
Play 416 HTD	0	267,255		
Play 416 HTD	0.0100 - 0.0499	587,348	2.72	3.68
Play 416 HTD	0.0500 - 0.0999	192,640	3.66	3.39
Play 416 HTD	0.1000 - 0.1499	61,381	2.33	1.63
Play 416 HTD	0.1500 - 0.1999	186	0.01	0.01
Silurian fault				
Play 419 Fault	0	282,523		
Play 419 Fault	0.0100 - 0.0499	570,013	0.66	0.72
Play 419 Fault	0.0500 - 0.0999	184,496	0.82	0.81
Play 419 Fault	0.1000 - 0.1499	19,630	0.18	0.13
Play 419 Fault	0.1500 - 0.1999	-		
Ordovician reef				
Play 450 Reef	0	267,371		
Play 450 Reef	0.0100 - 0.0499	579,367	0.73	11.44
Play 450 Reef	0.0500 - 0.0999	173,661	12.80	9.14
Play 450 Reef	0.1000 - 0.1499	109,858	16.20	9.15
Play 450 Reef	0.1500 - 0.1999	-		
Ordovician faults				
Play 450 Fault	0	274,976		
Play 450 Fault	0.0100 - 0.0499	510,436	0.40	0.69
Play 450 Fault	0.0500 - 0.0999	86,390	0.47	0.38
Play 450 Fault	0.1000 - 0.1499	49,341	0.53	0.33
Play 450 Fault	0.1500 - 0.1999	-		

Southampton AOI				
Play name	*CCOS Range*	*Sq km total*	*Dominance model Mean MMBOE*	*Weighted Random Fraction model Mean MMBOE*
Devonian faults				
Play 359 Fault	0	330,173		
Play 359 Fault	0.0100 - 0.0499	11,834	0.01	0.03
Play 359 Fault	0.0500 - 0.0999	19,887	0.12	0.13
Play 359 Fault	0.1000 - 0.1499	13,772	0.19	0.13
Play 359 Fault	0.1500 - 0.1999	-		
S/D unconformity				
Play 411 Unc	0	215,240		
Play 411 Unc	0.0100 - 0.0499	102,843	0.42	0.56
Play 411 Unc	0.0500 - 0.0999	34,665	0.55	0.57
Play 411 Unc	0.1000 - 0.1499	34,666	1.26	0.88
Play 411 Unc	0.1500 - 0.1999	-		
Silurian reef				
Play 416 Reef	0	337,253		
Play 416 Reef	0.0100 - 0.0499	7,989	0.12	0.20
Play 416 Reef	0.0500 - 0.0999	38,026	2.23	1.82
Play 416 Reef	0.1000 - 0.1499	-		-
Play 416 Reef	0.1500 - 0.1999	-		-
Paleozoic hydrothermal				
Play 416 HTD	0	170,915		
Play 416 HTD	0.0100 - 0.0499	157,447	0.73	0.99
Play 416 HTD	0.0500 - 0.0999	16,887	0.32	0.30
Play 416 HTD	0.1000 - 0.1499	33,572	1.27	0.89
Play 416 HTD	0.1500 - 0.1999	-		
Silurian fault				
Play 419 Fault	0	172,670		
Play 419 Fault	0.0100 - 0.0499	161,613	0.19	0.20
Play 419 Fault	0.0500 - 0.0999	31,353	0.14	0.14
Play 419 Fault	0.1000 - 0.1499	1,010	0.01	0.01
Play 419 Fault	0.1500 - 0.1999	-		
Ordovician reef				
Play 450 Reef	0	170,915		
Play 450 Reef	0.0100 - 0.0499	161,327	0.20	3.19
Play 450 Reef	0.0500 - 0.0999	16,904	1.25	0.89
Play 450 Reef	0.1000 - 0.1499	33,572	4.95	2.80
Play 450 Reef	0.1500 - 0.1999	-		
Ordovician faults				
Play 450 Fault	0	172,239		
Play 450 Fault	0.0100 - 0.0499	161,440	0.13	0.22
Play 450 Fault	0.0500 - 0.0999	31,615	0.17	0.14
Play 450 Fault	0.1000 - 0.1499	2,069	0.02	0.01
Play 450 Fault	0.1500 - 0.1999	-		
		Total	***14.28***	***14.08***

CONCLUSIONS

The Hudson Basin is estimated to contain 67.3 million recoverable barrels of oil equivalent. The current assessment is considerably smaller than previous estimates of hydrocarbon potential. The reduction in estimated resource is due to the addition of two dry wells in 1985 (post-Procter's 1984 assessment) that lack any organic rich shale, thereby reducing the source COS; and the assessment done for this report likely uses a smaller play area than those used by earlier assessments. The play areas used in this report are based on the qualitative map, but are primarily controlled by the area of potentially mature source rock as outlined in Hanna et al. (2018; their appendix C).

The largest expected discoveries are in the Hydrothermal Dolomite and Silurian-Devonian Unconformity plays. In the Hydrothermal Dolomite Play, the largest pool size distribution is: *P01* 25.6; *P10* 21.0; *P50* 13.4 MMBOE recoverable. For the Silurian-Devonian unconformity play, the largest pool size distribution is: *P01* 28.8; *P10* 23.2; *P50* 15.0 MMBOE recoverable. The small expected field sizes are based on the large analog data set from Michigan, Williston, and Illinois basins and are due to the geological conditions that create the traps.

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RECOMMENDATIONS

Further work in Hudson Bay could improve the resource assessment. The cheapest and easiest information would come from samples from active seeps collected at the sea surface. These samples could be collected by community member from small vessels. Information from seeps would help support or refute the presence of an active petroleum system. Indirect information on active seeps can be obtained from aircraft and satellite detectors over time (these techniques can give the location of potential seeps, but do not sample directly), and from multibeam sonar on ships. Note that while direct hydrocarbon samples may help de-risk the presence of source rocks, and increase the assessed overall volume of hydrocarbon in the basin, it will not affect the analysis of largest field size.

Improving the overall understanding of petroleum systems in the most prospective areas in the center of the basin would rely on expensive seismic and deep drilling programs.

ACKNOWLEDGEMENTS

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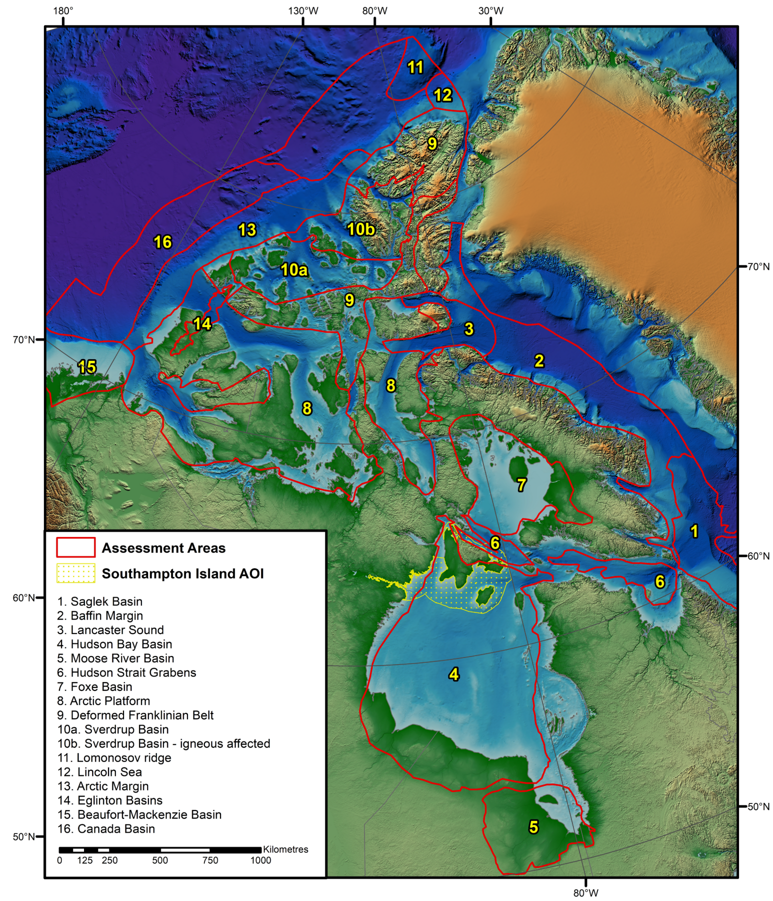


Figure 1. Location of Phanerozoic sedimentary basins in northern Canada. Hudson Bay sedimentary basin is marked with “4”, and underlies most of modern Hudson Bay. The Southampton Island area of interest for resource apportioning is shown as the stippled yellow polygon at the north end of Hudson Bay.

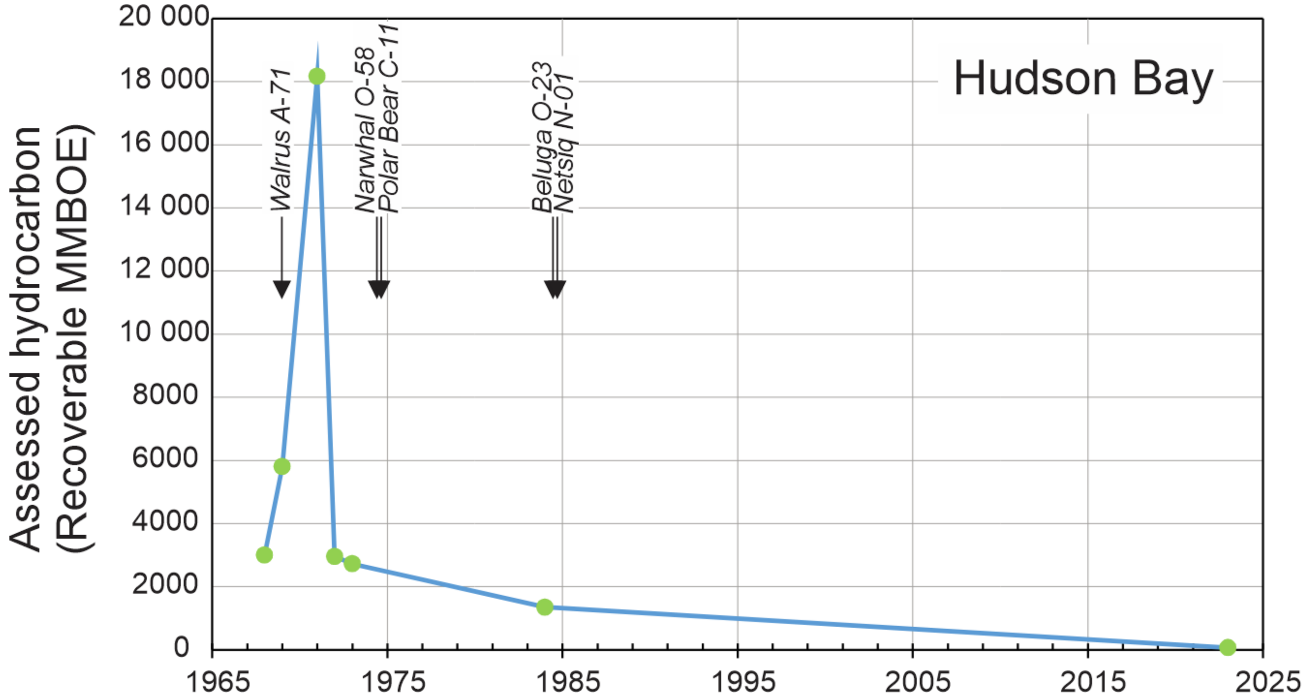


Figure. 2. Assessed hydrocarbon volumes for Hudson Basin (recoverable million barrels of oil equivalent) vs. time. The drilling dates of the 5 offshore wells are shown.

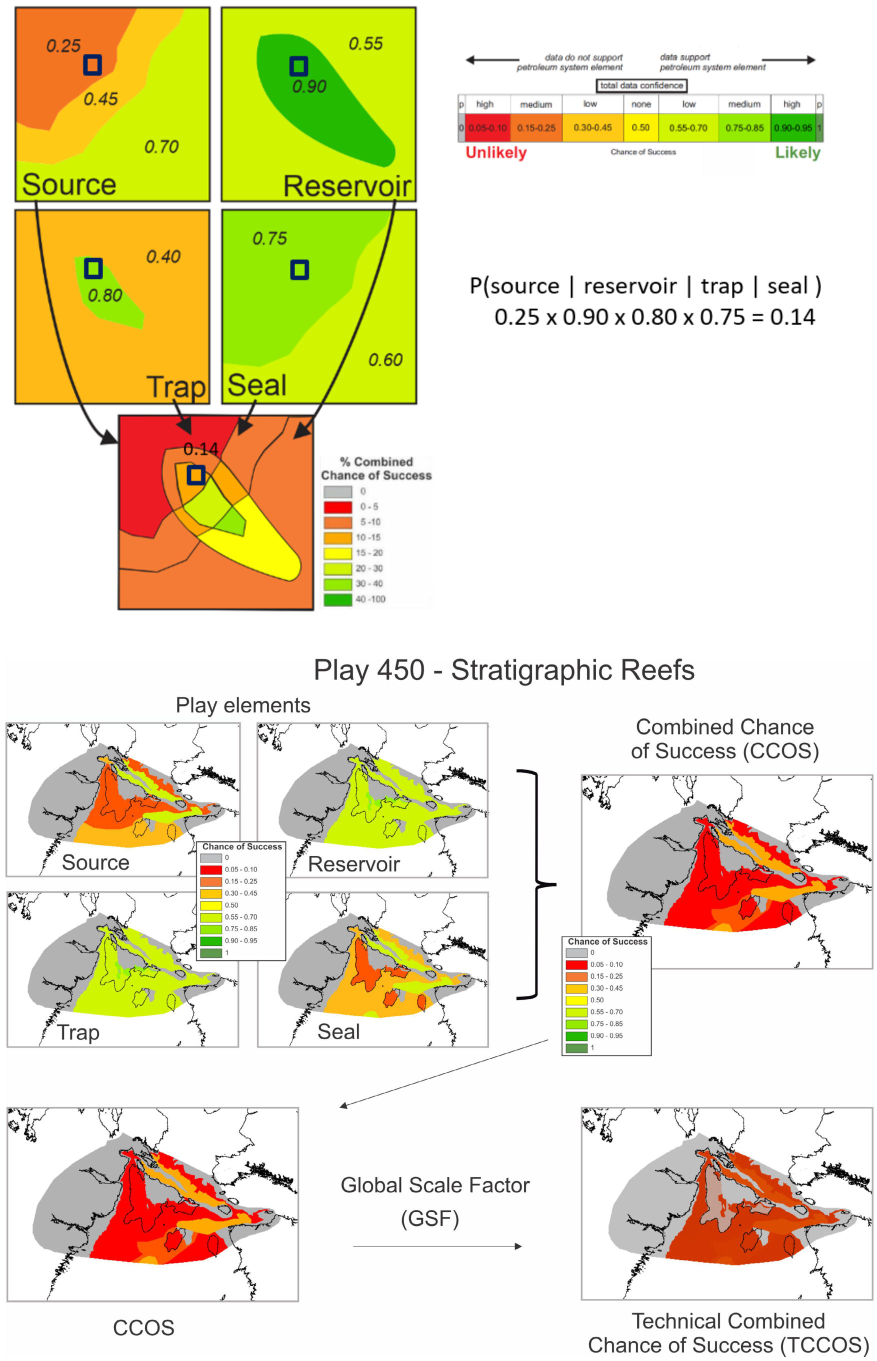


Figure 3. Top. Qualitative map method to produce a combined chance of success for a single play. The probabilities of each petroleum systems element are multiplied to give a final Combined Chance of Success for this play. Bottom. Example from northern Hudson Basin for the Ordovician reef play (values from Hanna, 2018).

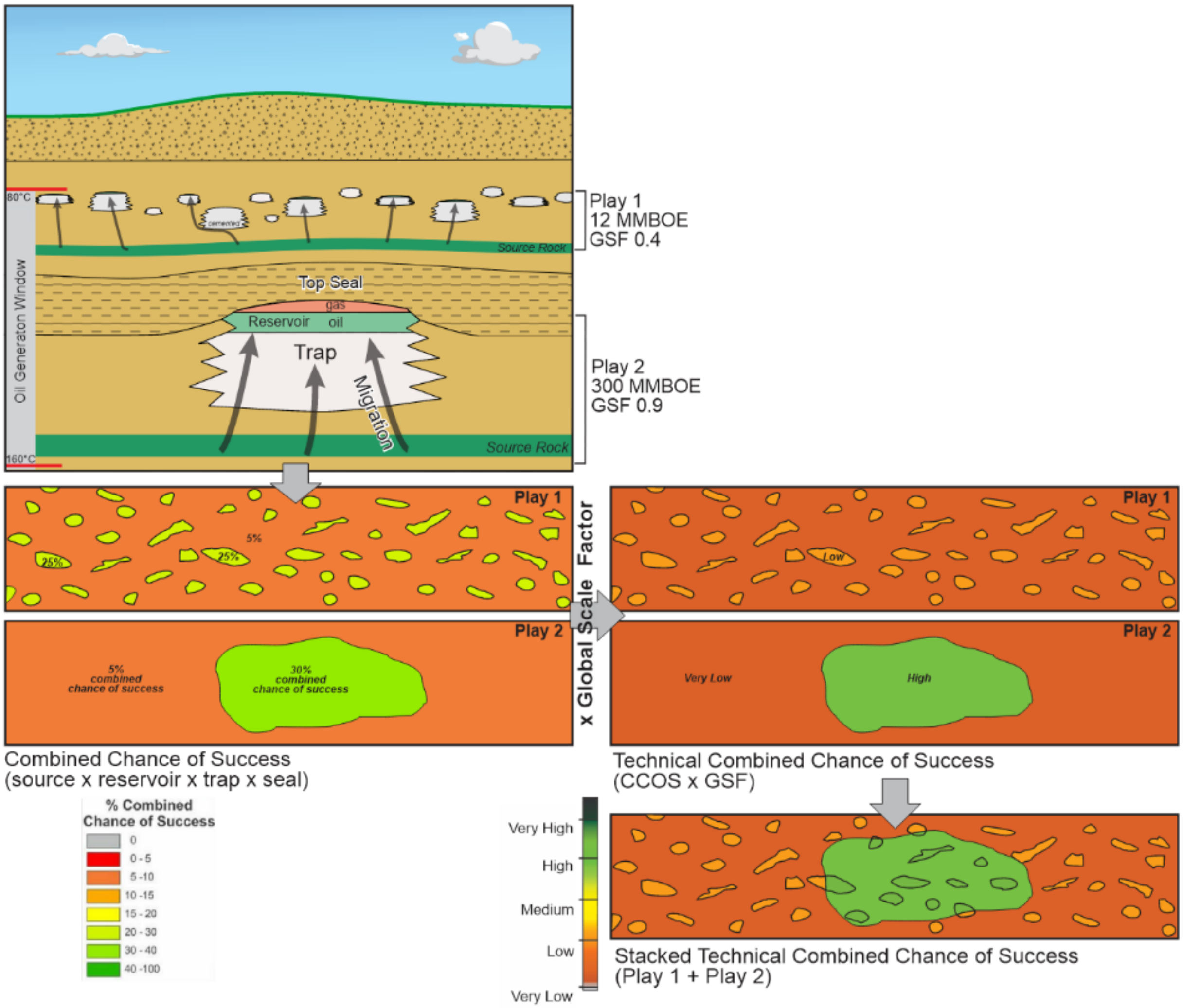


Figure 4. Combining plays in qualitative mapping. Play 1 is inherently smaller so has a lower Global Scale Factor (GSF) than Play 2. The combined chance of success for each play is multiplied by that play's GSF to produce a technical combined chance of success. Plays are then added to get a final stacked technical combined chance of success that shows the hydrocarbon potential of the area.

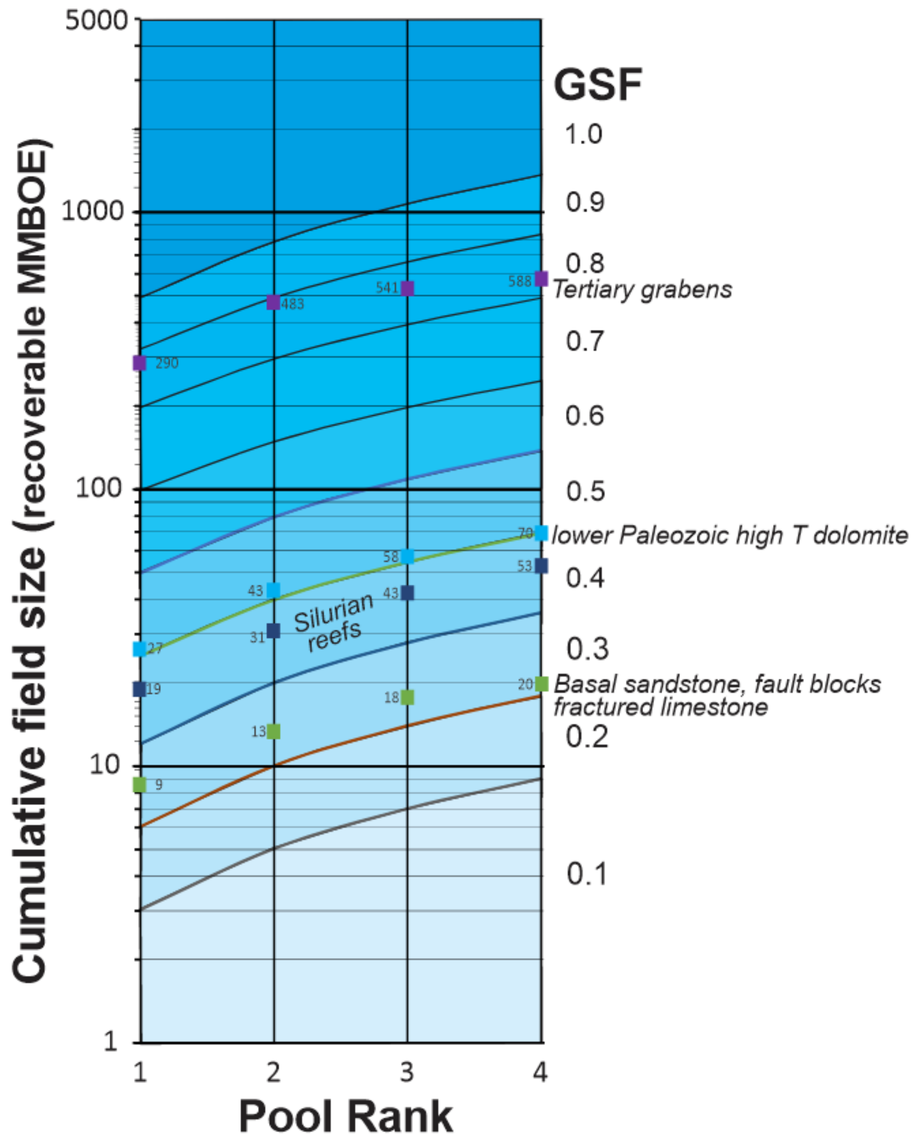


Figure 5. Calibration of the Global Scale Factor. Four examples of plays are shown. The Basal Sandstone play has a largest field size of 9 MMBOE (recoverable), then the cumulative values when the next three fields are added are shown (13, 18, 20 MMBOE) This falls within a GSF of 0.3. Silurian reefs from Michigan have a GSF of 0.4 based on the largest field size of 19 MMBOE, and the next three largest fields being 12, 12, 10 MMBOE for a cumulative value of 53 MMBOE. Ordovician dolomite in Michigan has a GSF of 0.5 based on the trajectory of the 4 largest fields. Tertiary grabens from the Bohai Basin of China have a GSF of 0.8.

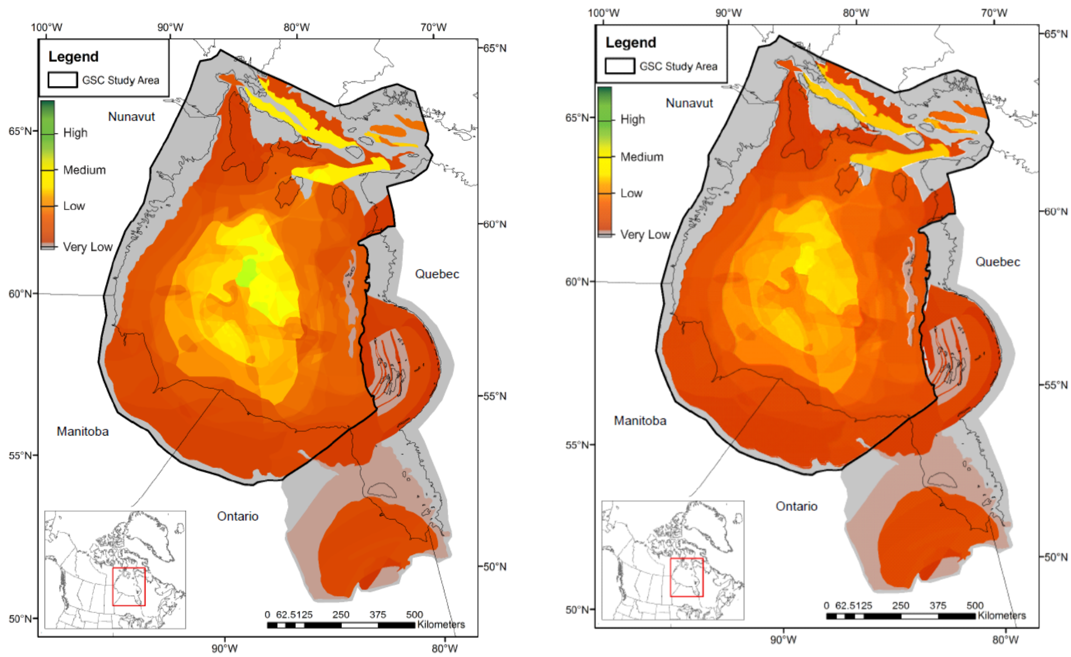


Figure 6. Comparison of the Qualitative hydrocarbon potential map of Hanna (2018; 2019) on the left, and the revised qualitative map using the new Global Scale Factors (right). The prospectivity of Hudson Basin is not considered to exceed 'Medium'.

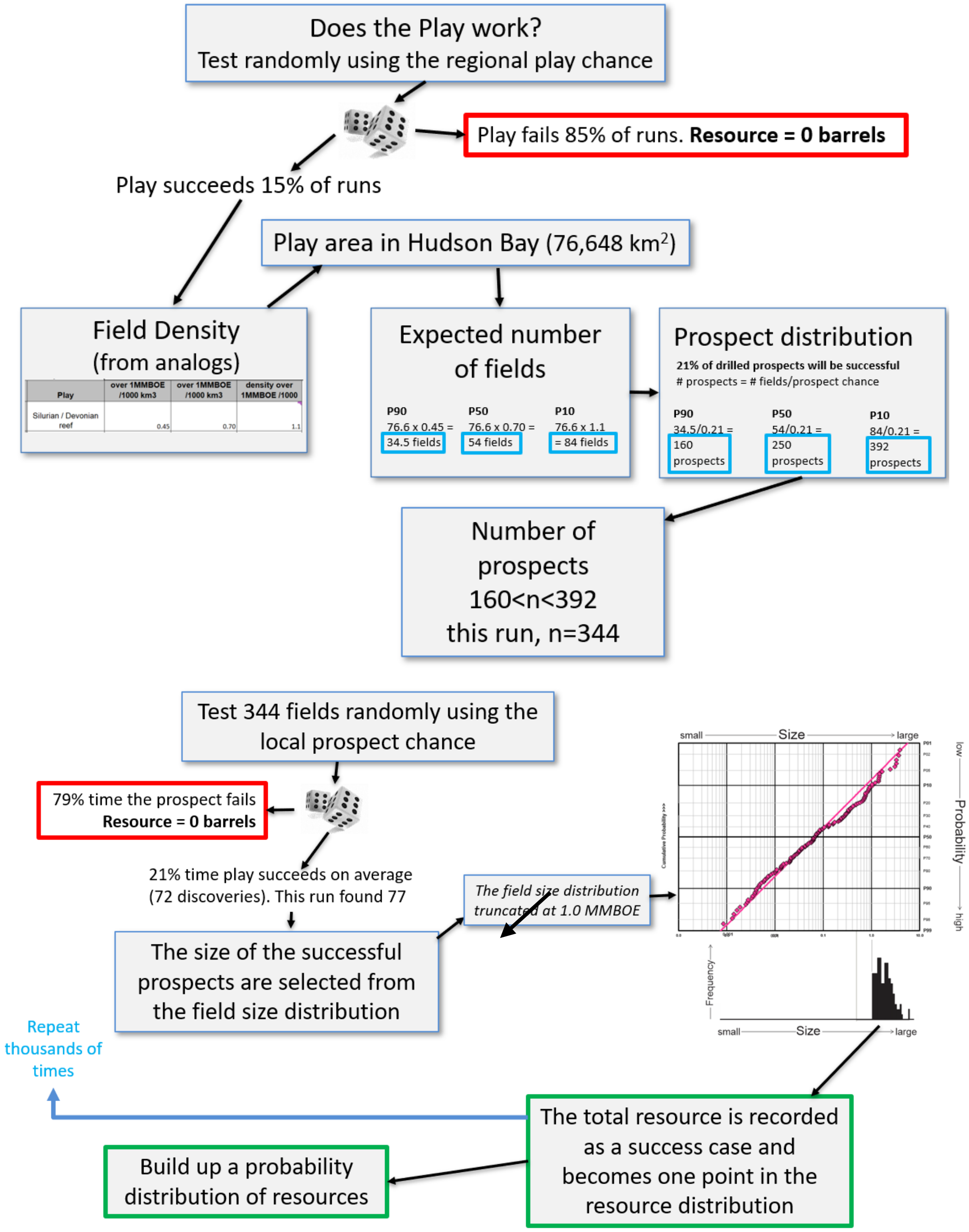


Figure 7. An example of a single realization of the Silurian Reef play in PlayRA software. The upper part uses the regional Play chance of success (0.15 for Silurian reefs) to generate the number of prospects. The lower part tests each prospect using the Prospect chance of success (0.21) and assign them a field size.

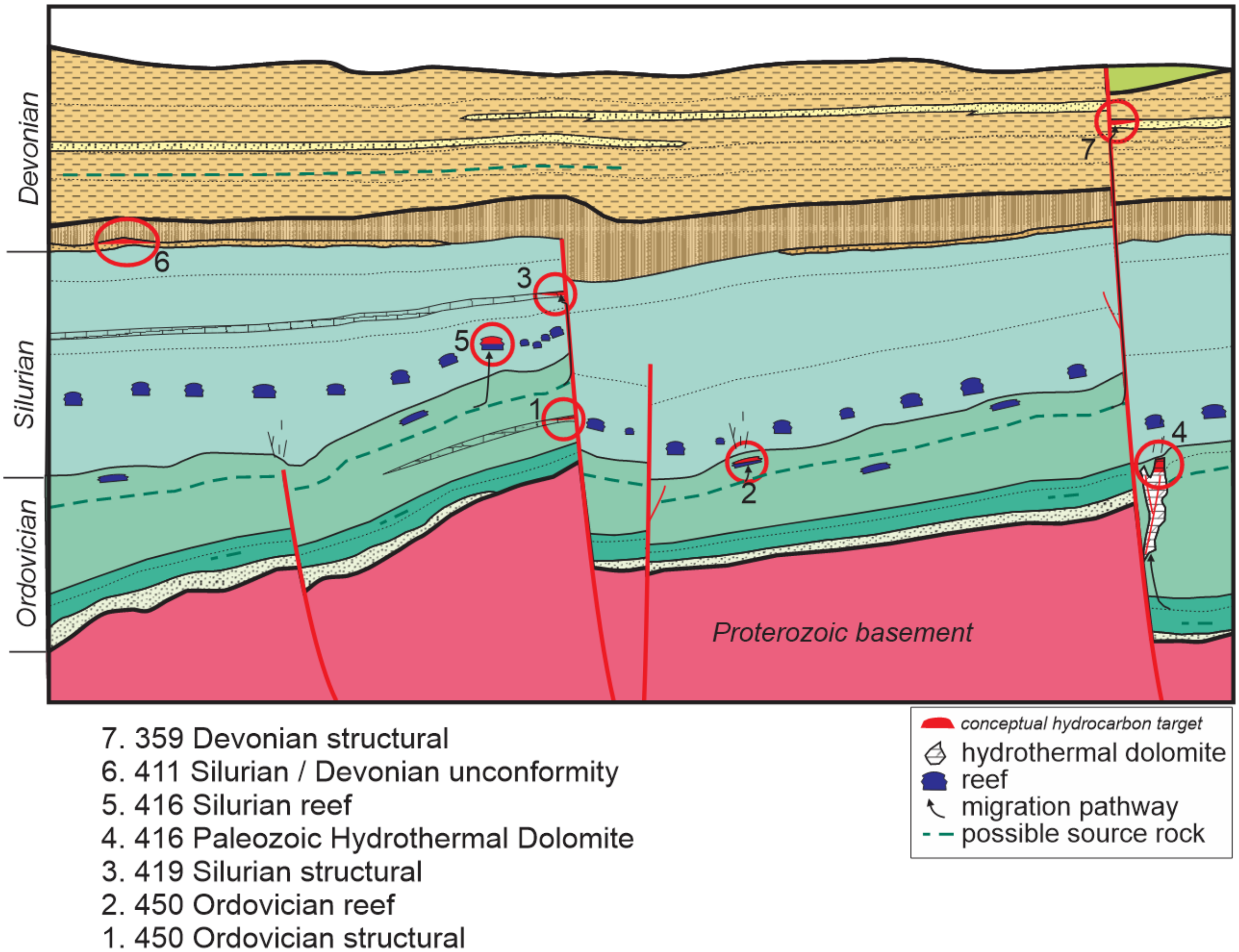
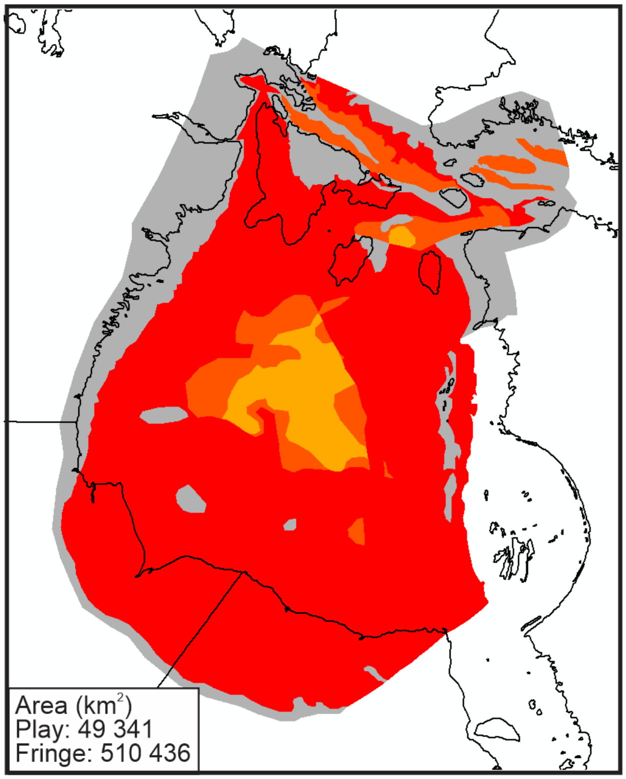


Figure 8. Schematic cross section through the central part of Hudson Basin showing the seven conceptual hydrocarbon plays evaluated in this report. Based on Hanna et al. (2018) and Lavoie et al. (2022).



Ordovician Structural play

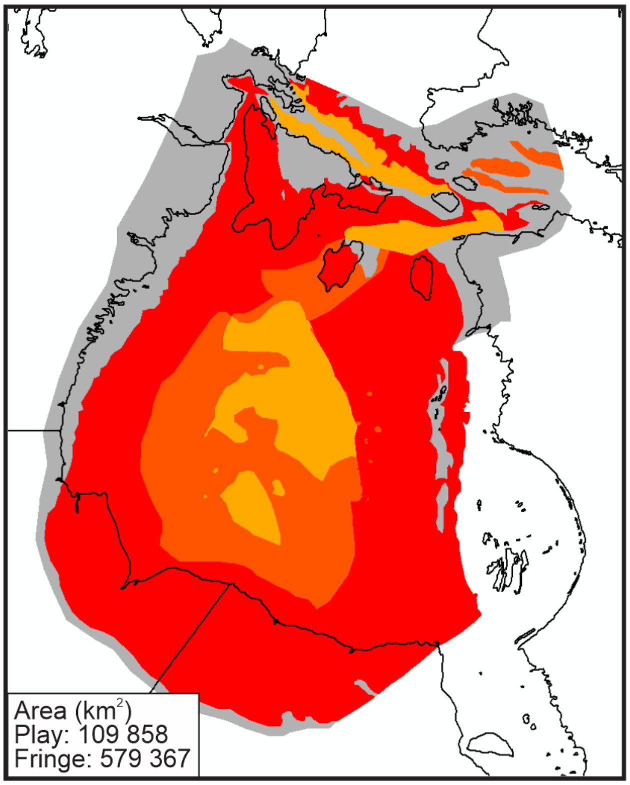
	Play area		Fringe area	
Petroleum System Element	Play Chance	Prospect Chance	Play Chance	Prospect Chance
Source	0.35	0.9	0.12	0.9
Timing/Migration	0.6	0.9	0.6	0.9
Reservoir	0.8	0.65	0.8	0.65
Trap (closure)	0.75	0.75	0.75	0.75
Seal	0.75	0.65	0.5	0.65
Play Chance	*0.09*		*0.02*	
Prospect Chance		*0.26*		*0.26*
Average Prospect Chance (Pg)		0.02		0.01

	Estimated Field Size Distribution (recoverable MMBOE)		**Number of prospects**	
	Play area	**Fringe area**	**Play area**	**Fringe area**
P99	0.445	0.002	3.1	29.8
P90	0.92	0.012	6.0	60.0
P50	2.24	0.119	13.6	141.8
Mean	2.77	0.432	16.3	172.3
P10	5.46	1.19	31.0	335.0
P01	11.28	7.75	60.5	675.3

	All Cases				Success Cases					
	P90	P50	Mean	P10	P90	P50	Mean	P10	Play chance	largest pool P10
Play area	0	0	1.1	0	3	10	12.5	26	8.8	8.1
Fringe area	0	0	0.155	0	5	15	18	35	2.2	6.7

Estimated recoverable hydrocarbon volumes (MMBOE)

Figure 9. Inputs for Ordovician structure small fault offset play. Left: Play COS map from the qualitative assessment. Play area is within the orange polygons, fringe within the red area. Top right: chance of success matrix for play and prospect levels. Bottom centre: Field size and prospect distribution. The bottom panel shows the predicted recoverable hydrocarbon volumes for all cases (green) and the success cases (blue).



Ordovician Reef play

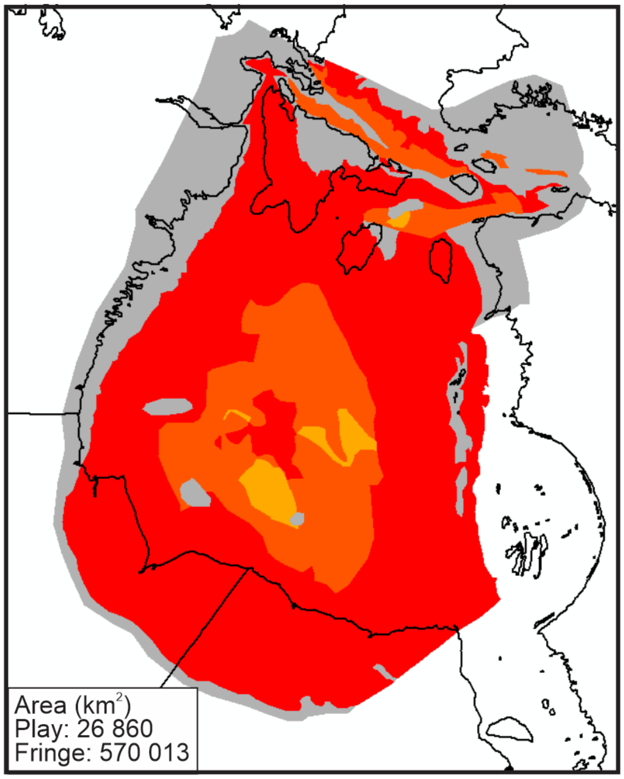
	Play area		Fringe area	
Petroleum System Element	Play Chance	Prospect Chance	Play Chance	Prospect Chance
Source	0.35	0.9	0.12	0.8
Timing/Migration	0.65	0.7	0.65	0.7
Reservoir	0.9	0.65	0.9	0.65
Trap (closure)	0.9	0.7	0.9	0.7
Seal	0.85	0.8	0.8	0.35
Play Chance	*0.16*		*0.05*	
Prospect Chance		*0.23*		*0.09*
Average Prospect Chance (Pg)		0.04		0.005

	Distribution (recoverable MMBOE)		Number of prospects	
	Play area	Fringe area	Play area	Fringe area
P99	0.61	0.002	54.7	65.7
P90	1.07	0.01	113.0	136.0
P50	2.13	0.102	275.4	332.1
Mean	2.42	0.38	339.3	409.6
P10	4.24	1.04	671.0	811.0
P01	7.43	6.87	1387.0	1679.3

	All Cases				Success Cases					
	P90	P50	Mean	P10	P90	P50	Mean	P10	Play chance	largest pool P10
Play area	0	0	29	118	61	151	184	347	15.6	7.2
Fringe area	0	0	0.73	0	3	11	13	27	5.4	5.6

Estimated recoverable hydrocarbon volumes (MMBOE)

Figure 10. Inputs for Ordovician reef play. Left: Play COS map from the qualitative assessment. Play area is within the orange polygons, fringe within the red area. Top right: chance of success matrix for play and prospect levels. Bottom centre: Field size and prospect distribution. The bottom panel shows the predicted recoverable hydrocarbon volumes for all cases (green) and the success cases (blue).



Silurian Structural play

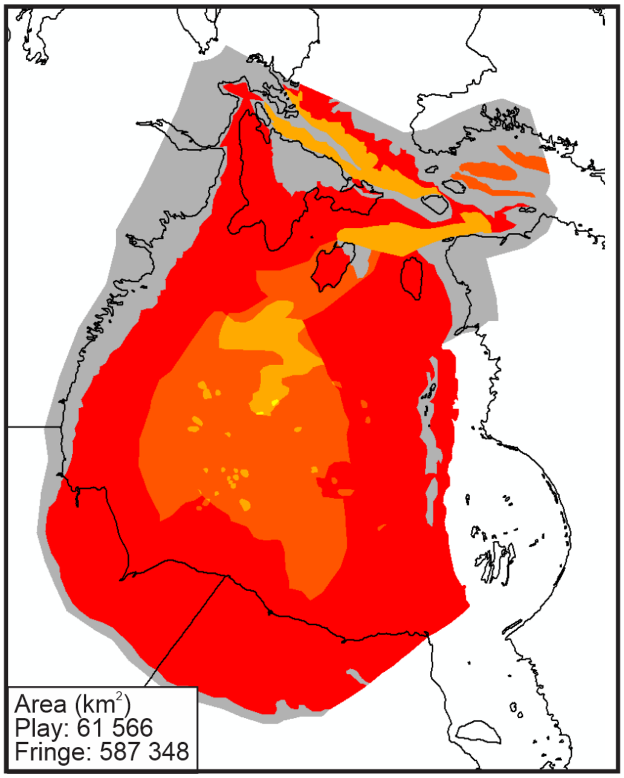
Petroleum System Element	Play area: Play Chance	Play area: Prospect Chance	Fringe area: Play Chance	Fringe area: Prospect Chance
Source	0.35	0.9	0.12	0.8
Timing/Migration	0.6	0.9	0.6	0.9
Reservoir	0.8	0.65	0.8	0.65
Trap (closure)	0.75	0.75	0.75	0.75
Seal	0.75	0.65	0.75	0.4
Play Chance	*0.09*		*0.03*	
Prospect Chance		*0.26*		*0.14*
Average Prospect Chance (P_g)		0.02		0.005

	Estimated Field Size Distribution (recoverable MMBOE): Play area	Estimated Field Size Distribution (recoverable MMBOE): Fringe area	Number of prospects: Play area	Number of prospects: Fringe area
P99	0.445	0.002	1.5	61.7
P90	0.92	0.012	3.0	122.0
P50	2.24	0.119	7.1	281.6
Mean	2.77	0.432	8.7	338.6
P10	5.46	1.19	17.0	650.0
P01	11.28	7.75	34.5	1285.5

	All Cases: P90	All Cases: P50	All Cases: Mean	All Cases: P10	Success Cases: P90	Success Cases: P50	Success Cases: Mean	Success Cases: P10	Success Cases: Play chance	largest pool P10
Play area	0	0	0.57	0	2	6	7	15	7.8	7.0
Fringe area	0	0	0.66	0	6	18	21	42	3.1	6.9

Estimated recoverable hydrocarbon volumes (MMBOE)

Figure 11. Inputs for Silurian small fault offset structural play. Left: Play COS map from the qualitative assessment. Play area is within the orange polygons, fringe within the red area. Top right: chance of success matrix for play and prospect levels. Bottom centre: Field size and prospect distribution. The bottom panel shows the predicted recoverable hydrocarbon volumes for all cases (green) and the success cases (blue).



Paleozoic Hydrothermal dolomite play

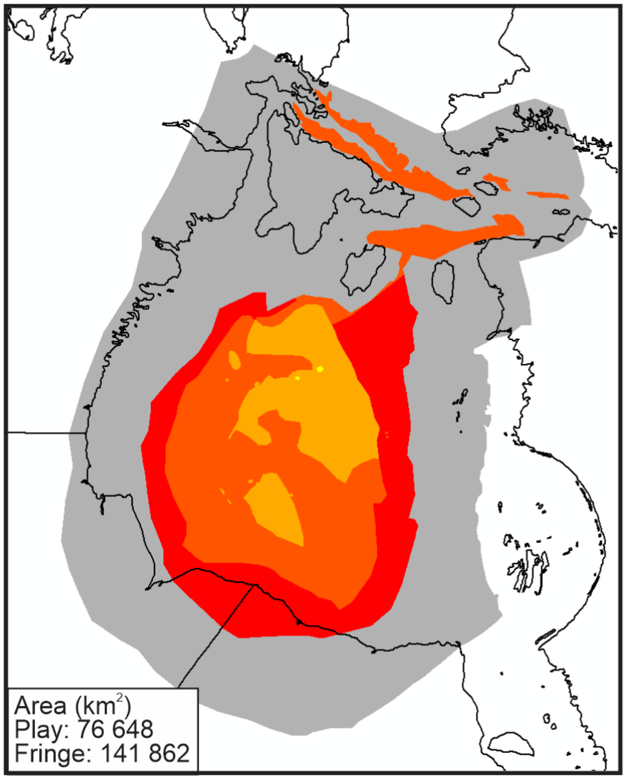
	Play area		Fringe area	
Petroleum System Element	Play Chance	Prospect Chance	Play Chance	Prospect Chance
Source	0.35	0.9	0.12	0.8
Timing/Migration	0.6	0.9	0.6	0.9
Reservoir	0.85	0.85	0.85	0.85
Trap (closure)	0.75	0.85	0.75	0.85
Seal	0.8	0.65	0.75	0.5
Play Chance	*0.11*		*0.03*	
Prospect Chance		*0.38*		*0.26*
Average Prospect Chance (P_g)		0.04		0.009

	Estimated Field Size Distribution (recoverable MMBOE)		**Number of prospects**	
	Play area	**Fringe area**	**Play area**	**Fringe area**
P99	1.76	0.007	2.1	32.9
P90	3.24	0.042	5.0	75.0
P50	6.84	0.367	14.1	205.9
Mean	7.94	1.164	18.8	268.9
P10	14.44	3.21	40.0	565.0
P01	26.55	18.8	93.4	1286.9

	All Cases				Success Cases					
	P90	P50	Mean	P10	P90	P50	Mean	P10	Play chance	largest pool P10
Play area	0	0	6.1	9	12	43	57	123	10.7	21.0
Fringe area	0	0	2.7	0	22	64	82	169	3.3	17.1

Estimated recoverable hydrocarbon volumes (MMBOE)

Figure 12. Inputs for Ordovician-Silurian high temperature dolomite. Left: Play COS map from the qualitative assessment. Play area is within the orange polygons, fringe within the red area. Top right: chance of success matrix for play and prospect levels. Bottom centre: Field size and prospect distribution. The bottom panel shows the predicted recoverable hydrocarbon volumes for all cases (green) and the success cases (blue).



Silurian Reef play

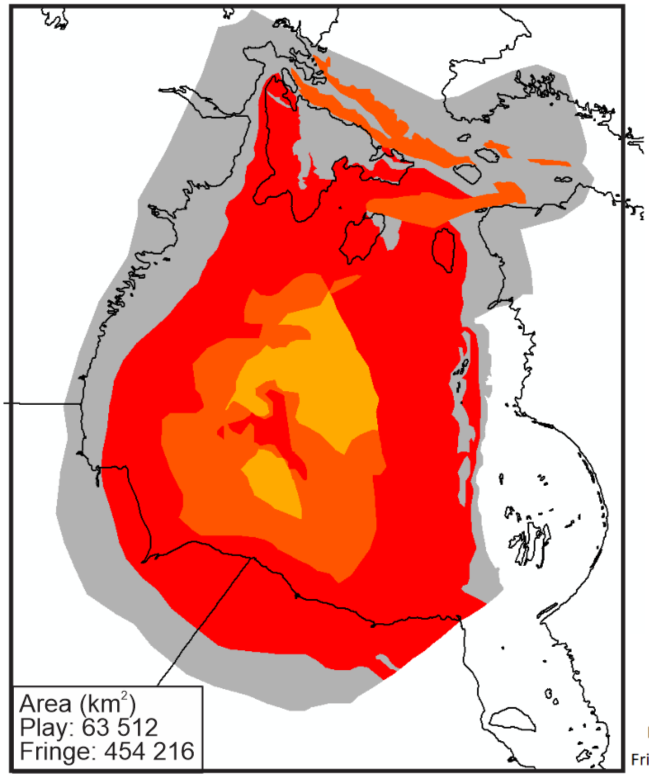
	Play area		Fringe area	
Petroleum System Element	Play Chance	Prospect Chance	Play Chance	Prospect Chance
Source	0.35	0.9	0.16	0.8
Timing/Migration	0.55	0.7	0.55	0.7
Reservoir	0.95	0.65	0.95	0.65
Trap (closure)	0.9	0.7	0.9	0.7
Seal	0.9	0.75	0.75	0.5
Play Chance	*0.15*		*0.06*	
Prospect Chance		*0.21*		*0.13*
Average Prospect Chance (Pg)		0.03		0.007

	Estimated Field Size Distribution (recoverable MMBOE)		**Number of prospects**	
	Play area	**Fringe area**	**Play area**	**Fringe area**
P99	0.61	0.002	111.0	348.0
P90	1.07	0.01	160.0	501.0
P50	2.13	0.102	250.4	783.4
Mean	2.42	0.376	264.2	826.2
P10	4.24	1.04	392.0	1225.0
P01	7.4	6.87	564.8	1763.7

	All Cases				Success Cases					
	P90	P50	Mean	P10	P90	P50	Mean	P10	Play chance	largest pool P10
Play area	0	0	20.1	108	80	128	137	204	14.7	7.2
Fringe area	0	0	2.2	0	22	37	40	61	5.6	6.5

Estimated recoverable hydrocarbon volumes (MMBOE)

Figure 13. Inputs for Silurian reef play Left: Play COS map from the qualitative assessment. Play area is within the orange polygons, fringe within the red area. Top right: chance of success matrix for play and prospect levels. Bottom centre: Field size and prospect distribution. The bottom panel shows the predicted recoverable hydrocarbon volumes for all cases (green) and the success cases (blue).



Silurian--Devonian unconformity play

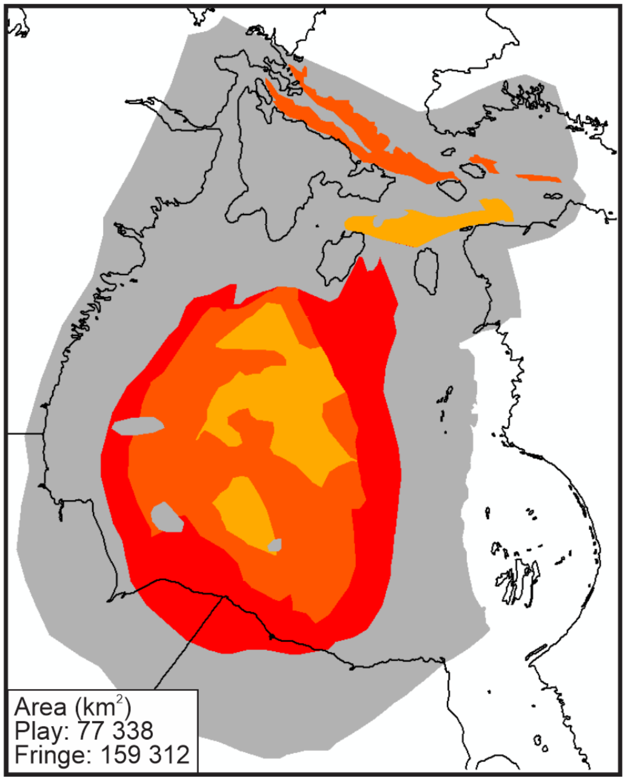
	Play area		Fringe area	
Petroleum System Element	Play Chance	Prospect Chance	Play Chance	Prospect Chance
Source	0.3	0.9	0.12	0.7
Timing/Migration	0.55	0.9	0.5	0.9
Reservoir	0.75	0.65	0.75	0.65
Trap (closure)	0.85	0.55	0.85	0.55
Seal	0.9	0.85	0.7	0.5
Play Chance	*0.09*		*0.03*	
Prospect Chance		*0.25*		*0.11*
Average Prospect Chance (Pg)		0.02		0.003

	Estimated Field Size Distribution (recoverable MMBOE)		**Number of prospects**	
	Play area	**Fringe area**	**Play area**	**Fringe area**
P99	0.327	0.368	9.1	348.0
P90	0.896	0.97	21.0	501.0
P50	3.09	3.18	58.9	783.4
Mean	4.6	4.6	77.7	826.2
P10	10.66	10.4	165.0	1225.0
P01	29.2	27.5	382.3	1763.7

	All Cases				Success Cases					
	P90	P50	Mean	P10	P90	P50	Mean	P10	Play chance	largest pool P10
Play area	0	0	8.1	0	20	67	87	178	9.3	24.5
Fringe area	0	0	1.9	0	14	51	69	148	2.7	22.9

Estimated recoverable hydrocarbon volumes (MMBOE)

Figure 14. Inputs for Silurian-Devonian unconformity play. Left: Play COS map from the qualitative assessment. Play area is within the orange polygons, fringe within the red area. Top right: chance of success matrix for play and prospect levels. Bottom centre: Field size and prospect distribution. The bottom panel shows the predicted recoverable hydrocarbon volumes for all cases (green) and the success cases (blue).



Devonian Structural play

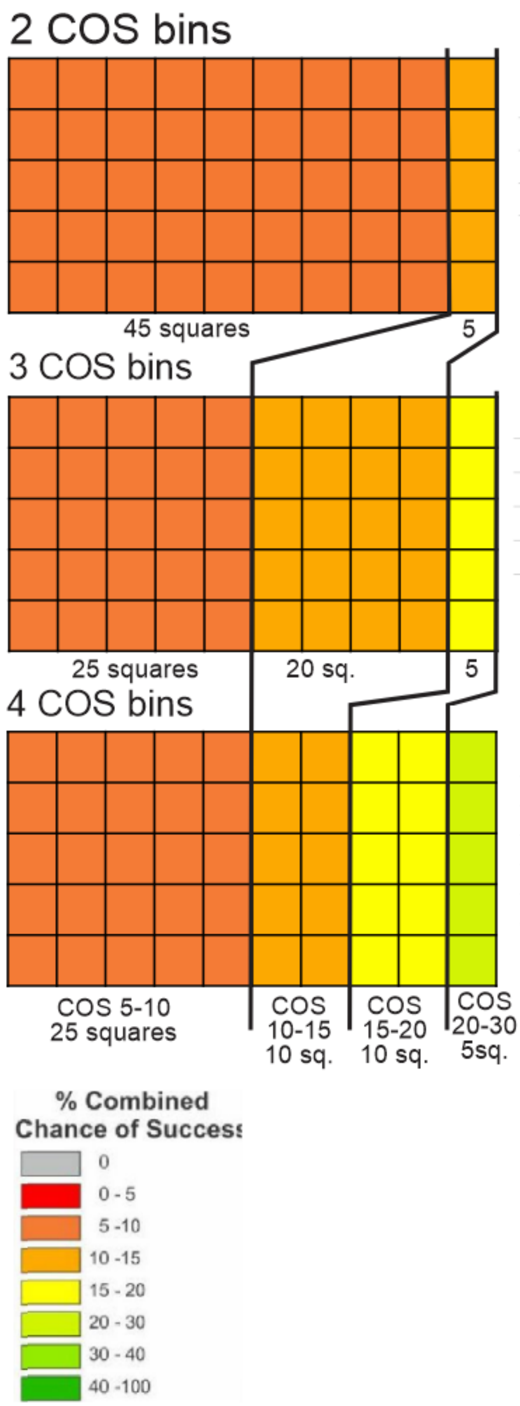
	Play area		Fringe area	
Petroleum System Element	Play Chance	Prospect Chance	Play Chance	Prospect Chance
Source	0.3	0.9	0.16	0.7
Timing/Migration	0.55	0.9	0.5	0.9
Reservoir	0.85	0.65	0.85	0.65
Trap (closure)	0.75	0.756	0.75	0.75
Seal	0.8	0.65	0.6	0.5
Play Chance	*0.08*		*0.03*	
Prospect Chance		*0.26*		*0.15*
Average Prospect Chance (P_g)		0.02		0.005

	Estimated Field Size Distribution (recoverable MMBOE)		**Number of prospects**	
	Play area	**Fringe area**	**Play area**	**Fringe area**
P99	0.445	0.002	4.5	15.6
P90	0.92	0.012	9.0	31.0
P50	2.24	0.119	20.8	71.7
Mean	2.77	0.432	25.0	86.4
P10	5.46	1.19	48.0	166.0
P01	11.28	7.75	95.0	329.0

	All Cases				Success Cases					
	P90	P50	Mean	P10	P90	P50	Mean	P10	Play chance	largest pool P10
Play area	0	0	1.5	0	4	15	18	37	8.4	8.6
Fringe area	0	0	0.155	0	1	4	5	12	3	4.8

Estimated recoverable hydrocarbon volumes (MMBOE)

Figure 15. Inputs for Devonian Structural play. Left: Play COS map from the qualitative assessment. Play area is within the orange polygons, fringe within the red area. Top right: chance of success matrix for play and prospect levels. Bottom centre: Field size and prospect distribution. The bottom panel shows the predicted recoverable hydrocarbon volumes for all cases (green) and the success cases (blue).



Ratio assigned to each COS bin

0-5	0
5-10	1.0
10-15	2.3

Bin	Area	Area * ratio	Percentage of resource
5-10	45	45*1=45	79%
10-15	5	5*2.3=11.7	21%

10% of the area gets 21% of the resource

0-5	0
5-10	1.0
10-15	2.0
15-20	3.7

Bin	Area	Area * ratio	Percentage of resource
5-10	25	25*1=25	30%
10-15	20	20*2=40	48%
15-20	5	5*3.7=18.5	22%

10% of the area gets 22% of the resource

0-5	0
5-10	1.0
10-15	1.9
15-20	3.0
20-30	6.9

Bin	Area	Area * ratio	Percentage of resource
5-10	25	25*1=25	23%
10-15	10	10*1.9=19	18%
15-20	10	10*2.8=28	26%
20-30	5	5*6.9=34.5	32%

10% of the area gets 32% of the resource

Figure 16. Example of how resources are apportioned using the Dominance Matrix in Table 5. For a map with 2 COS bins, the area yield of the highest bin is taken as 2.3 times the lower bin. The resource in the lowest COS bin (0.01-0.0499) is calculated in a separate PlayRA run using a smaller field size and lower COS.

APPENDIX ONE

Analog areas used in this report showing play area, area yield (how many MMBOE recoverable oil per 1000 km^2), total number of fields, how many of those fields are larger than 1 MMBOE recoverable, field density (how many fields per 1000 km^2), field density for fields larger than 1 MMBOE recoverable, largest field size in the analog (recoverable MMBOE). 5800 cubic feet of gas is converted to 1 barrel of oil equivalent.

Analog Area	**Play area (km^2)**	**Area Yield (MMBOE /1000km^2)**	**Total fields**	**Fields> 1 MMBOE**	**Fields /1000km^2**	**Fields > 1MMBOE /1000km^2**	**Largest field size (MMBOE)**	**Reference**
Cambrian Michigan Basin Ontario	49 000	0.23	19	4	0.39	0.08	4.79	Ontario Oil Gas and Salt Library, 2013
Lower Ordovician Williston Basin North Dakota	164 000	0.029	8	5	0.05	0.03	8.57	Nesheim 2012
Cambrian Deadwood Williston Basin Saskatchewan	245 000	0.012	16	2	0.07	0.01	1.35	PetroNinja 2022
Devonian Granite Wash Alberta	120 000	0.012	233	0	1.94	0.00		PetroNinja 2022
Devonian Granite Wash Alberta	133 200		190	21	1.42	0.16		Hein, 1999; O'Connell, 1994
Illinois Basin Basal sand	110 000	0	0	0	0	0.00	0.00	Hickman, 2013
Ordovician high temperature dolomite, Michigan Basin Ontario	40 400	0.62	65	10	1.61	0.25	6.70	Ontario Oil Gas and Salt Library, 2013
Ordovician high temperature dolomite, Michigan Basin Michigan	103 800	0.37	43	12	0.41	0.12	26.55	Grammer, 2007
Ordovician high temperature dolomite Ohio-New York-Kentucky	442 000	0.07	82	6	0.19	0.01	7.49	Patchen et al. 2006
Ordovician Ellenburger Texas	169 157	8.87		93		0.55	177.72	Dutton et al. 2003
Ordovician Red River Williston Basin Saskatchewan	14 500		14	9		0.02	0.07	PetroNinja 2022
Silurian reefs Michigan Basin Ontario	40 357	1.47	167	18	4.14	0.45	6.01	Ontario Oil Gas and Salt Library, 2013

Silurian reefs Michigan Basin Michigan	113 238	3.65	1187	224	10.5	1.98	19	Charpentier 1987
Silurian reefs Midwest US	385 700			268		0.63		Prezbindowski 2018
Silurian sandstone Michigan Basin Ontario	31 140	0.855	22	5	0.71	0.16	9.9	Ontario Oil Gas and Salt Library, 2013
Mississippian unconformity Kansas	47 232	5.82	47	32	1	0.68	36.1	Ball et al., 1991

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