Executive Summary

By

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One Page Brief

2 Key Study Areas (30% of Area of Interest)

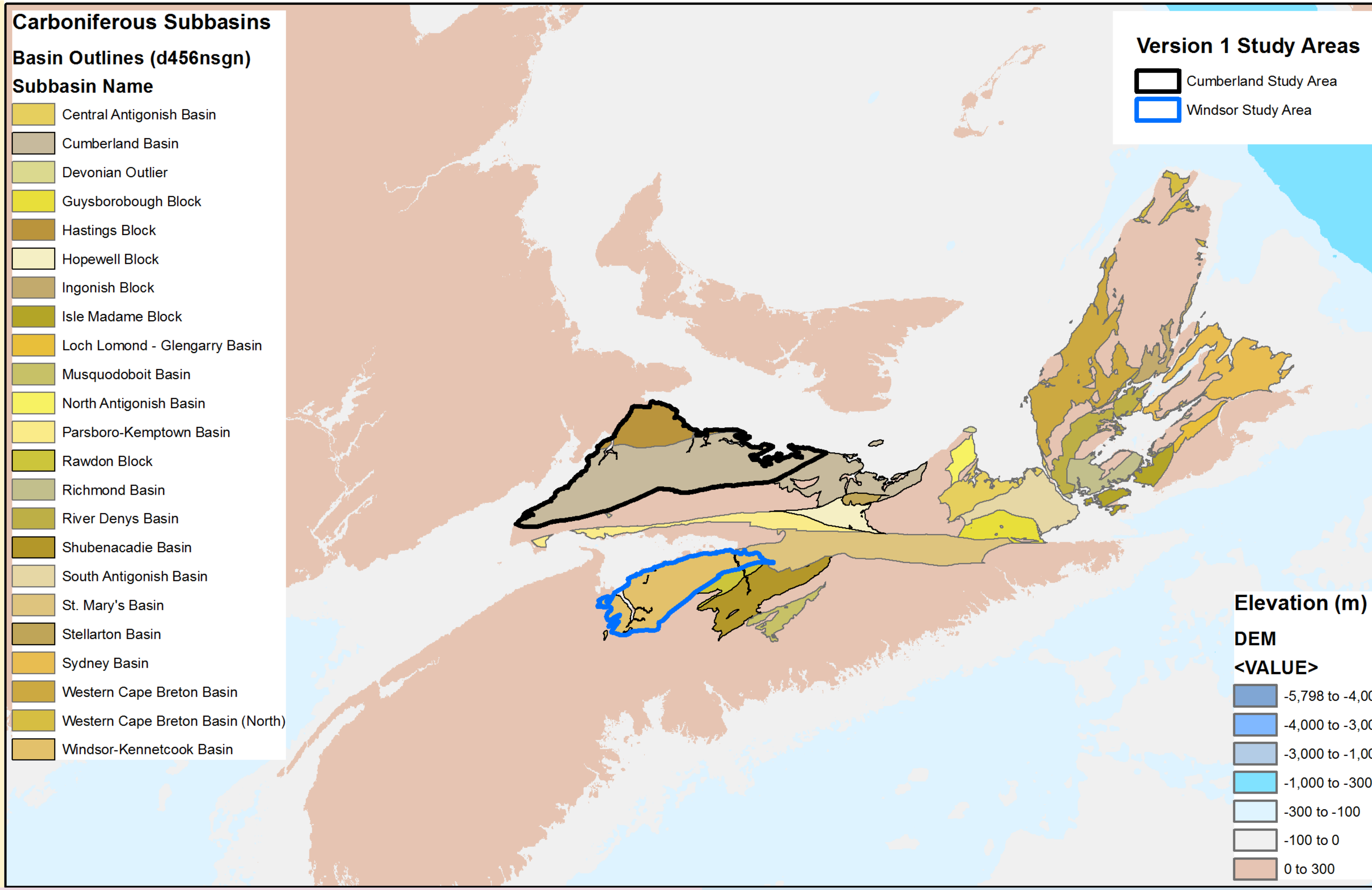
- Cumberland Subbasin
- Windsor Subbasin

3 Key Play Types

- Conventional
- Coal Bed Methane (CBM)
- Shale Gas

In-Place Gas Potential (36 tcf)

- Conventional (1.5 tcf)
- Coal Bed Methane (3 tcf)
- Shale Gas (32 tcf)



Recoverable Gas Potential (7 tcf or ~3 Sables or ~80 years supply**)

- Conventional (0.7 tcf) = $2.2 to 5.5 billion USD *
- Coal Bed Methane (1.4 tcf) = $4.4 to 13.2 billion USD*
- Shale Gas (4.5 tcf) = $13.6 to 40.9 billion USD*

* at $3 to $9 USD per million British Thermal Units (MMBTU)

** at ~189 MCF/day (2010 Nova Scotia and New Brunswick average demand)

Royalty Potential (in money of the day)

- ~5% for CBM, ~10% for other plays
- ~$2 to ~$5 billion USD total
- ~$200 to ~$700 million USD Coal Bed Methane

Onshore Atlas Highlights

- First Regional Sub-basin Correlation Chart
- First Open Subsurface Models of Study Areas
- First Provincial Compilation of Petroleum System Data since ca. 1985
- First Attempt to Quantify Onshore Potential at Sub-basin scale

1.1 Introduction

1.1.1 Goals of the Atlas

This document is the Executive Summary of Nova Scotia's Onshore Petroleum Atlas project. The purpose of the Atlas project is to quantify the hydrocarbon resource potential of onshore Nova Scotia using the available subsurface geological data and established methods of conventional and unconventional resource estimation (Figure 1-1; Hayes et al., 2017). Other results relating to syntheses of regional geology and petroleum systems data have been developed and are released as a series of Open File Reports. A guiding principle in the preparation and release of the Atlas project results is to provide the geological data, model interpretations, and assessment methods with sufficient completeness so that reported calculations and conclusions can be reproduced by external stakeholders. Geoscientists and technical professionals with a working interest in the hydrocarbon potential of onshore Nova Scotia or its underlying geology are expected to make use of the Atlas and its related materials to evaluate and critique exploration opportunities and resource predictions.

External stakeholders with an expected interest in the Atlas include: (1) the people and government of Nova Scotia (i.e., the owners of identified resources), (2) exploration and production companies from the oil and gas industry, and (3) the local and global petroleum geoscience communities. This Executive Summary highlights the main outputs of the Onshore Atlas project. Three key questions are addressed. First, what is Nova Scotia's onshore hydrocarbon resource potential. Second, how is this resource distributed between conventional, coal bed, and shale gas (or tight sand) reservoirs. Third, what challenges are involved in successfully finding or producing this resource in economic quantities.

Key Questions

1. What is Nova Scotia's onshore resource potential?
2. How is this resource distributed between conventional, coal bed, and shale gas (or tight sand) reservoirs?
3. What challenges are involved in successfully finding or producing this resource in economic quantities?

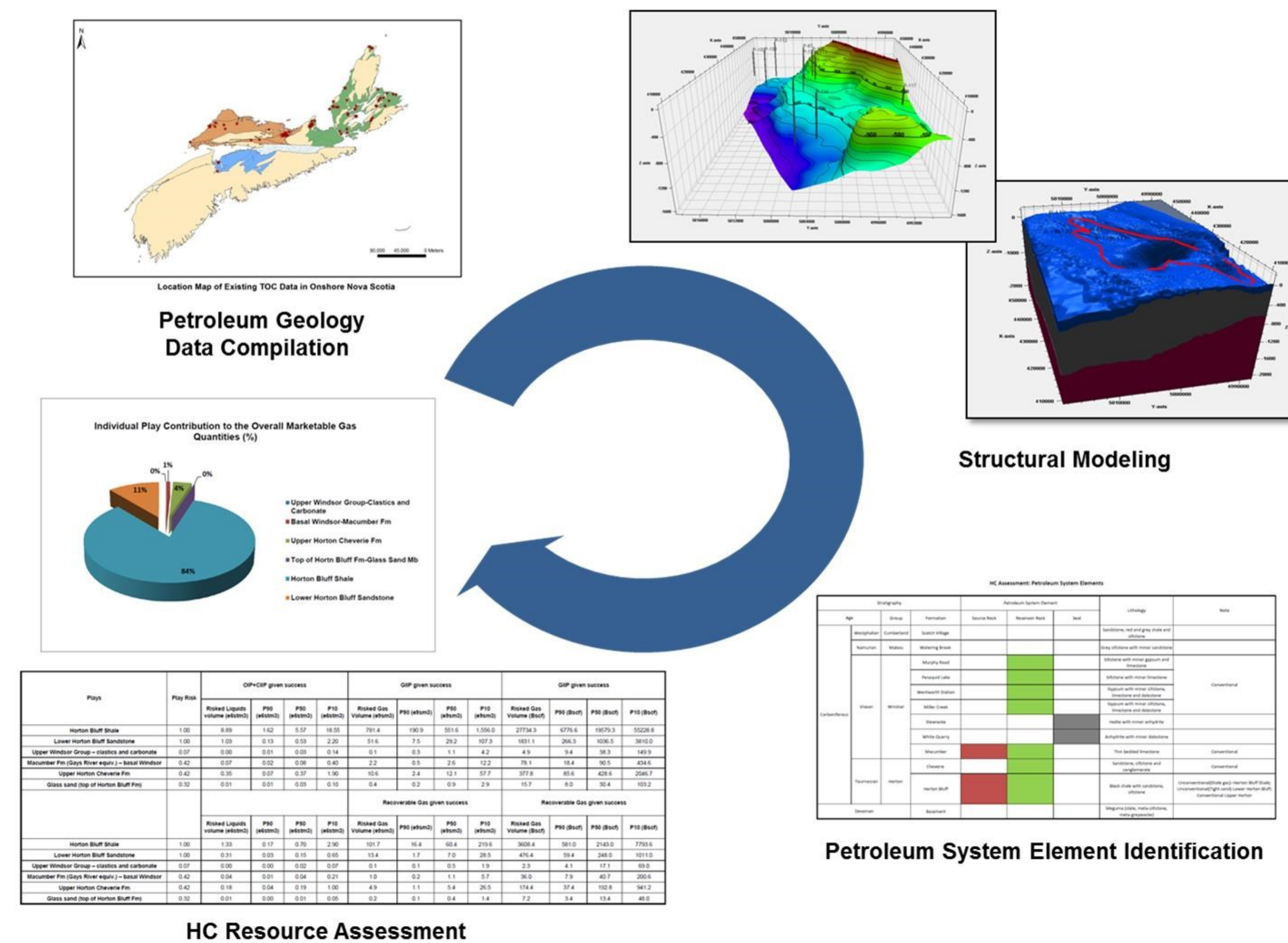


Figure 1-1: Nova Scotia's Onshore Petroleum Atlas project workflow. New hydrocarbon resource numbers were produced following successive steps that included: (1) collection and compilation of the basic data, (2) modeling of the subsurface geometry and structures of targeted petroleum-bearing basins in onshore Nova Scotia, (3) the identification and characterization of the critical elements of the regional petroleum systems, and (4) resource volume estimates calculated using statistical, Monte Carlo protocols and equations for the quantification of conventional and unconventional reservoir targets (Hayes et al., 2017). The Atlas project comprises a series of Open File Reports describing intermediate and final results for interested stakeholders. Figure courtesy of Helen Cen, 2017.

1.1.2 Scope of the Atlas

- New oil and gas volume predictions were created for ~30% of the area of interest in onshore Nova Scotia (Hayes et al., 2017). Approximately 5300 km2 of area from two study areas, a Cumberland Study Area and a Windsor Study Area (Figure 1-2), were analyzed in the 2013-2017 Onshore Petroleum Atlas project. The entire area of interest is potentially as large as ca. 17800 km2 (Figure 1-2). Areas not addressed in the 2013-2017 Onshore Petroleum Atlas project may be evaluated in the future depending on research priorities identified in subsequent initiatives.
- The two study areas were selected on the basis of good oil and gas potential as inferred previously in a qualitative assessment of onshore Nova Scotia (NSDNR, 2010) (Figure 1-3). These areas also had the greatest quantities of modern seismic and petroleum well data. Such data are necessary for building subsurface geology models and to constrain the critical elements of the governing petroleum systems and their hydrocarbon resource potential (Hayes et al., 2017).
- The 2013-2017 Onshore Petroleum Atlas project appears to be the first attempt to put quantitative numbers on the oil and gas potential of onshore Nova Scotia across all hypothesized late Paleozoic reservoir types at the sub-basin scale. Previous assessments of oil and gas potential in late Paleozoic reservoirs of Atlantic Canada have been made at the scale of Atlantic Canada as a whole (e.g., Dietrich et al., 2013; EIA, 2013) or at the scale of specific property holdings or play types (e.g., Hughes, 2003; Lam et al., 2008).

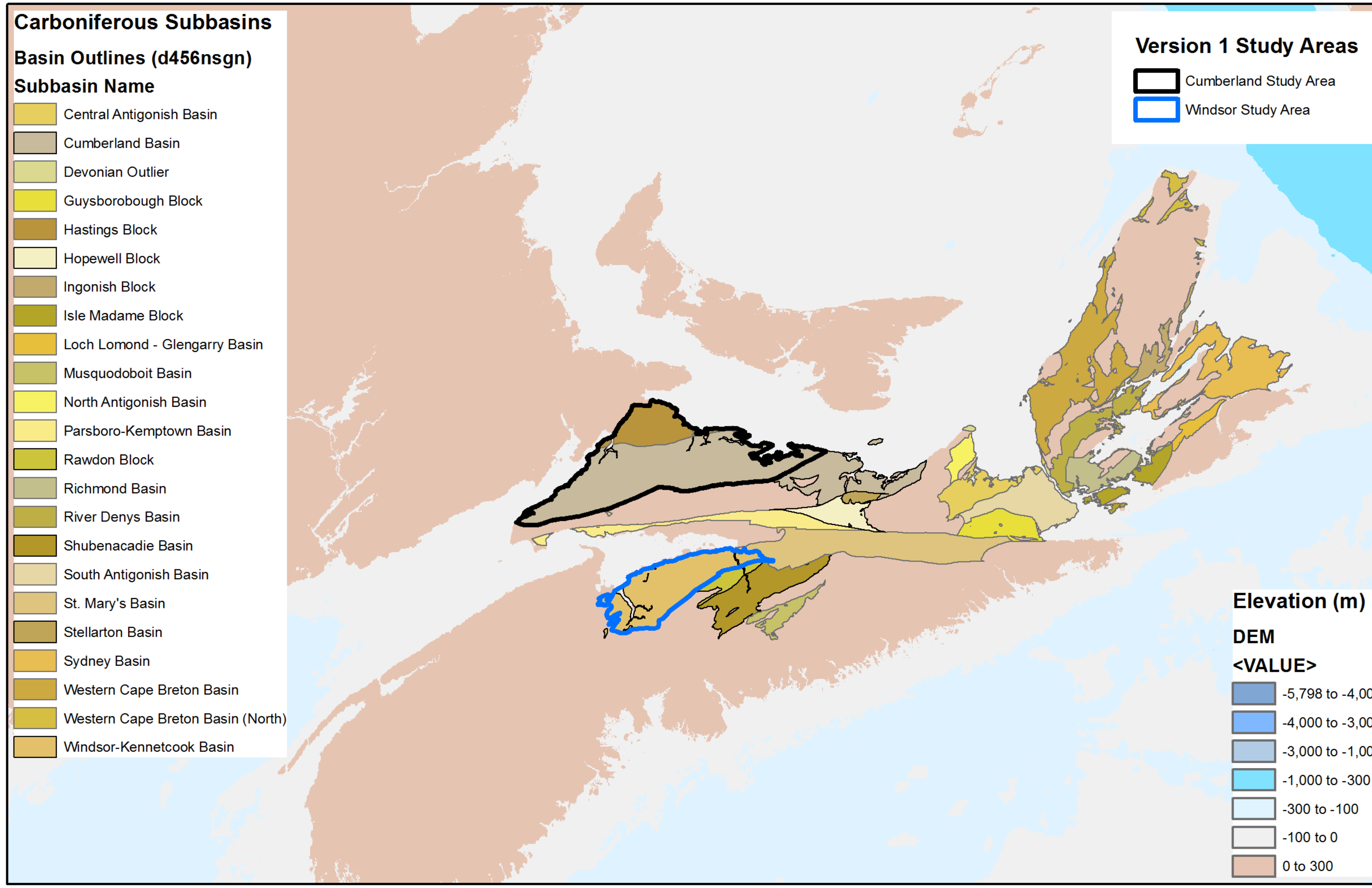
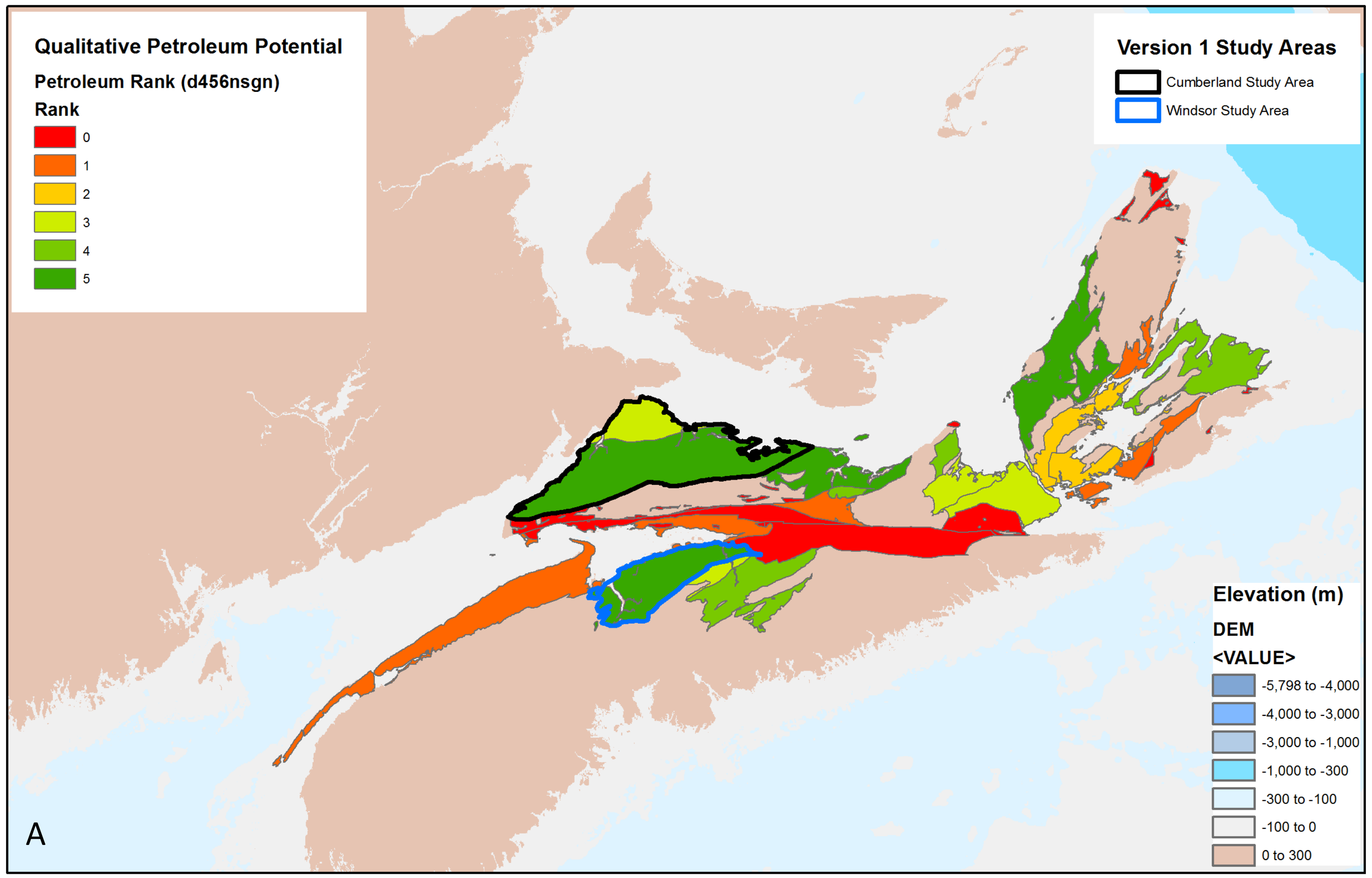


Figure 1-2: A classification of sub-basins in onshore Nova Scotia with inferred oil and gas potential (NSDNR, 2010). Targeted study areas from this atlas are indicated: (1) Cumberland Study Area (black outline) incorporates the Hopewell Block and northern Cumberland Basin of the NSDNR classification, and (2) Windsor Study Area (blue outline) incorporates the Windsor-Kennetcook Basin of the NSDNR classification. Note that, in general across the literature, sub-basin names are used with flexible senses of meaning and do not always have the equivalent geographic meaning in detail.



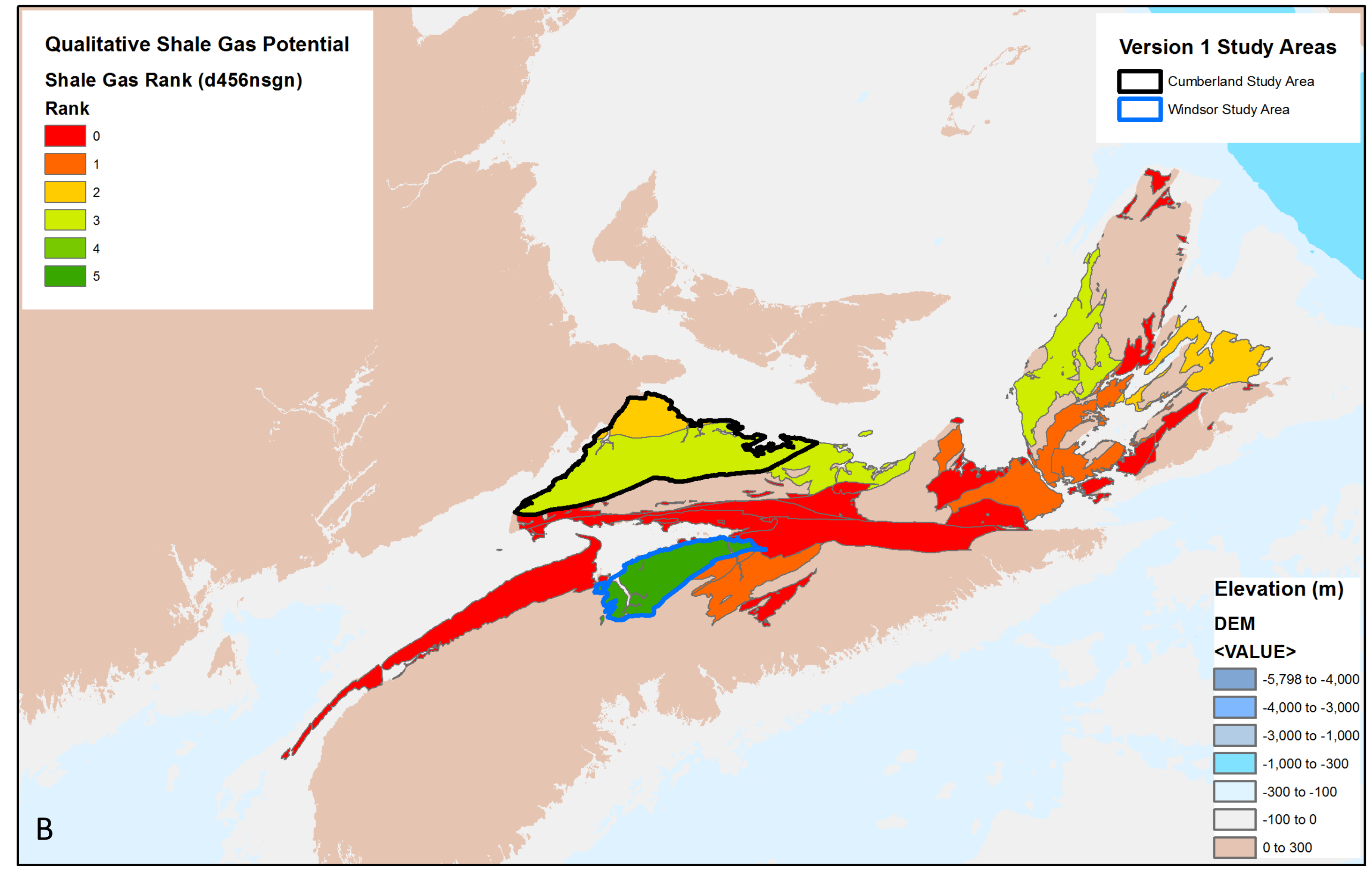


Figure 1-3: Traffic light maps (green = high potential; red = low potential) showing a qualitative classification of sub-basins in onshore Nova Scotia ranked according to (A) general petroleum potential across all reservoir types (NSDNR, 2010), and (B) shale gas potential (NSDNR, 2010). Targeted study areas for Nova Scotia's 2013-2017 Onshore Petroleum Atlas are indicated and correspond to two of the highest rated areas for both types of potential.

Cumberland and Windsor Basin study areas

were prioritized for version 1 of the onshore atlas

Study areas were prioritized on the basis of:

(1) High inferred oil and gas potential (Fig. 1-2 & 1-3),

(2) Greatest availability of necessary geological data.

1.1.3 Limitations and Uncertainties

Nova Scotia's 2013-2017 Onshore Petroleum Atlas has been managed and produced under the direction of a small number of Department of Energy staff with the help of a handful of external consultants. It is important to acknowledge that the preparation of Nova Scotia's Onshore Petroleum Atlas Project was necessarily resource and expertise limited. It is not a Play Fairway Analysis, but does include much of what can be found in a PFA. The complete assessment workflow comprises data synthesis, quality control, integration and interpretation of 3D and 4D geology, and integration of all of the above with a resource assessment calculation. This workflow can be considered to span many geology and data specializations. Department of Energy staff have had to make decisions in how much of the previous literature to review and incorporate, how much detail should be applied to each workflow step, and when to spend funds to take advantage of external expertise or to complete parts of the workflow in-house. Although efforts have been taken to ensure the validity and accuracy of all work steps, it can be expected in a complex process that both known and unknown errors and omissions may have arisen. Two strategies were adopted to accommodate these challenges while still allowing the workflow to be completed and results to be produced. First, individual data issues (for example, mis-tied seismic lines, competing subsurface horizon picks, etc.) were considered to be acceptable for present purposes if the expected effects on the final results were believed to be modest (e.g., <5%). Second, considerable effort has been made to make available all data, interpretations, and assessment algorithms for open review and external critique. Interested stakeholders should have the option to independently verify and reproduce the calculations and interpretations developed in the context of the 2013-2017 Onshore Atlas Project.

The open approach to data and models exposes additional limitations and uncertainties. First, even in the selected study areas there is a limited amount of petroleum geology data available to constrain resource estimates; this may be because onshore Nova Scotia has only been explored historically to a modest degree. This can mean that a lot of weight is placed on the few data that are available when such data is critical to constraining a particular variable or calculation. Revisions to the results presented herein will be possible as more of the basic data required are collected and incorporated. The area of interest also formed in the years preceding the late Paleozoic assembly of the supercontinent Pangaea. This means the geological evolution preserved in the onshore petroleum basins is relatively complex compared to other petroleum -bearing basins globally. As a consequence of resource constraints, data limitations, and geological complexity, the resource assessment method implemented in the Atlas is a statistical one. The statistical approach taken was recommended and implemented by Petrel Robertson Consulting, Limited (Hayes et al., 2017). This assessment algorithm has been identified and refined over a number of years and has been applied in other jurisdictions of Canada and abroad where oil and gas exploration can be considered immature. The strength of the selected approach is the development of reasonable estimates of potential resource volumes without employing sophistication that may not be justified by the present database.

Two staff members, Dr. Fraser Keppie and Helen Cen, from the Nova Scotia Department of Energy were assigned to manage the Nova Scotia's Onshore Petroleum Atlas project. Supporting funds were spent on the following activities in approximately the following proportions:

(1) Data compilation, processing, and quality control (40%)

(2) Acquisition of new data (20%)

(3) Purchase of software licenses (5%)

(4) Synthesis of regional stratigraphy and tectonic framework (5%)

(5) Subsurface modeling of Windsor and Cumberland study areas (10%)

(6) Resource assessment calculations (20%)

1.1.4 Acknowledgements

Collaborators have offered input for the Onshore Atlas project. Notable contributions are acknowledged as follows.

Evan Bianco and colleagues of Agile Geoscience are acknowledged for their work in the compilation and quality control of petroleum well, seismic, and striplog data from Nova Scotia's onshore petroleum basins. Assembled petroleum geology databases are included in this Atlas. Agile Geoscience also contributed computer codes aiding the quality control and visualization of these databases.

Dr. Peter Giles and the Geological Survey of Canada are thanked for his contributions providing advise and geological expertise on the assessment of the petroleum basins of onshore Nova Scotia. He is also a co-author on the newly constructed regional stratigraphic correlation chart for the Maritimes Basin (Waldron et al., 2017).

Brad Hayes and colleagues of Petrel Robertson Consulting Limited are acknowledged for their work leading to the completion of the resource assessment calculations reported and summarized in this Atlas. Their assessment report is included as an Open File Report released with this Atlas.

Kris Kendall and the Canada-Nova Scotia Offshore Petroleum Board are thanked for their contributions to advising, guiding, and aiding the interpretation of subsurface data with particular emphasis on the Sydney Basin.

Dr. Eugene MacDonald is acknowledged for his work in the compilation and quality control of biostratigraphic and petroleum geochemistry data from Nova Scotia's onshore petroleum basins. Assembled petroleum geology databases are included as Open File Reports with this Atlas.

Gil Machado and colleagues of Chrono Surveys are acknowledged for their work performing new petroleum geochemistry and biostratigragphic analysis on onshore petroleum wells. Their report is included as an Open File Report with this Atlas.

Dr. John Waldron of the University of Alberta and co-authors are acknowledged for their work on building a new stratigraphic correlation chart for the Maritimes Basin in Atlantic Canada. This chart is included as an Open File Report with this Atlas. Dr. John Waldron is also acknowledged for his support as a lead advisor in the construction of the Cumberland Basin subsurface geology model; the model is included as an Open File Report as well.

Janice Weston and colleagues of RPS Energy are acknowledged for their work performing new biostratigraphic analysis on selected onshore petroleum wells. Their report is included in this Atlas.

Department of Natural Resources, Nova Scotia

Drs. John Calder, Robert Ryan, Trevor MacHattie, and colleagues and Nova Scotia's Department of Natural Resources are thanked for their many contributions to advising, guiding, and aiding the interpretation of subsurface data. Dr. Trevor MacHattie provided the bedrock mapping context and samples analyzed by Chrono Surveys for new petroleum geochemistry and biostratigraphic data from northern Nova Scotia.

Department of Energy, Nova Scotia

Former and current staff from the Petroleum Resources Division of Nova Scotia's Department of Energy are acknowledged for their varied and continual assistance throughout this project including, but not limited to, Paul Harvey, Jack MacDonald, Scott Weldon, Kim Doane, Brenda Hatch, Brenda Kenty, Sarah Thurbide, Adam MacDonald, Michael Bird, Bill O'Halloran, and Sandy MacMullin.

Compilers

Dr. Fraser Keppie and Helen Cen of the Petroleum Resources Division of Nova Scotia's Department of Energy are acknowledged for their roles in the compilation of Nova Scotia's 2013-2017 Onshore Petroleum Atlas.

1.1.5 Disclaimer

1.2 Results

1.2.1 General Play Concepts

Hydrocarbon play concepts in onshore Nova Scotia can be defined specifically in terms of the hydrocarbon source, hydrocarbon migration, hydrocarbon reservoir, and hydrocarbon trapping systematics on a case by case and sub-basin by sub-basin basis. This approach is taken, for example, in the specific assessment project completed by Petrel Robertson for this Atlas project (Hayes et al., 2017); specific volume estimates are tied to specific rock formations from each sub-basin. While this approach is self-explanatory in detail, it is difficult to scale to a regional or general synthesis because formation names are not necessarily the same between the different sub-basins of onshore Nova Scotia (e.g., Waldron et al., 2017). An alternative approach used in the regional analyses of conventional petroleum potential is to label reservoirs according to their general age. (e.g., Dietrich et al., 2011; Figure 1-4).

In the present study, the age-based approach is used and extended for both Conventional and Unconventional play concepts. This approach is taken to facilitate the comparison and summing of results from the two Atlas study areas as well as for the purposes of comparing new results with results published in previous studies. Specifically, the following general play concepts are conceived:

(C1) Tournaisian-aged clastics

(C2) Base Windsor Group (reefal) carbonate

(C3) Upper Mississippian clastics

(C4) Pennsylvanian clastics

(U1) Tournaisian-aged shales

(U2) Tournsaisian-aged tight sands

(U3) Pennsylvanian-aged coal beds

In the above scheme, play concepts C1-C4 are conceived as conventional reservoirs in which the preservation of oil and gas volumes at depth is entirely dependent on suitable trap geometries existing. Play concepts U1-U3 are conceived as unconventional (or continuous) reservoirs in which stimulation of reservoirs with low primary porosity may be anticipated as necessary for achieving economic production. Also herein, the Tournaisian-aged shales and tight sands are considered together as the “shale gas” potential. This use of the term shale gas (or shale oil) includes any gas (or oil) preserved in a tight clastic reservoir and potentially requiring reservoir stimulation to produce.

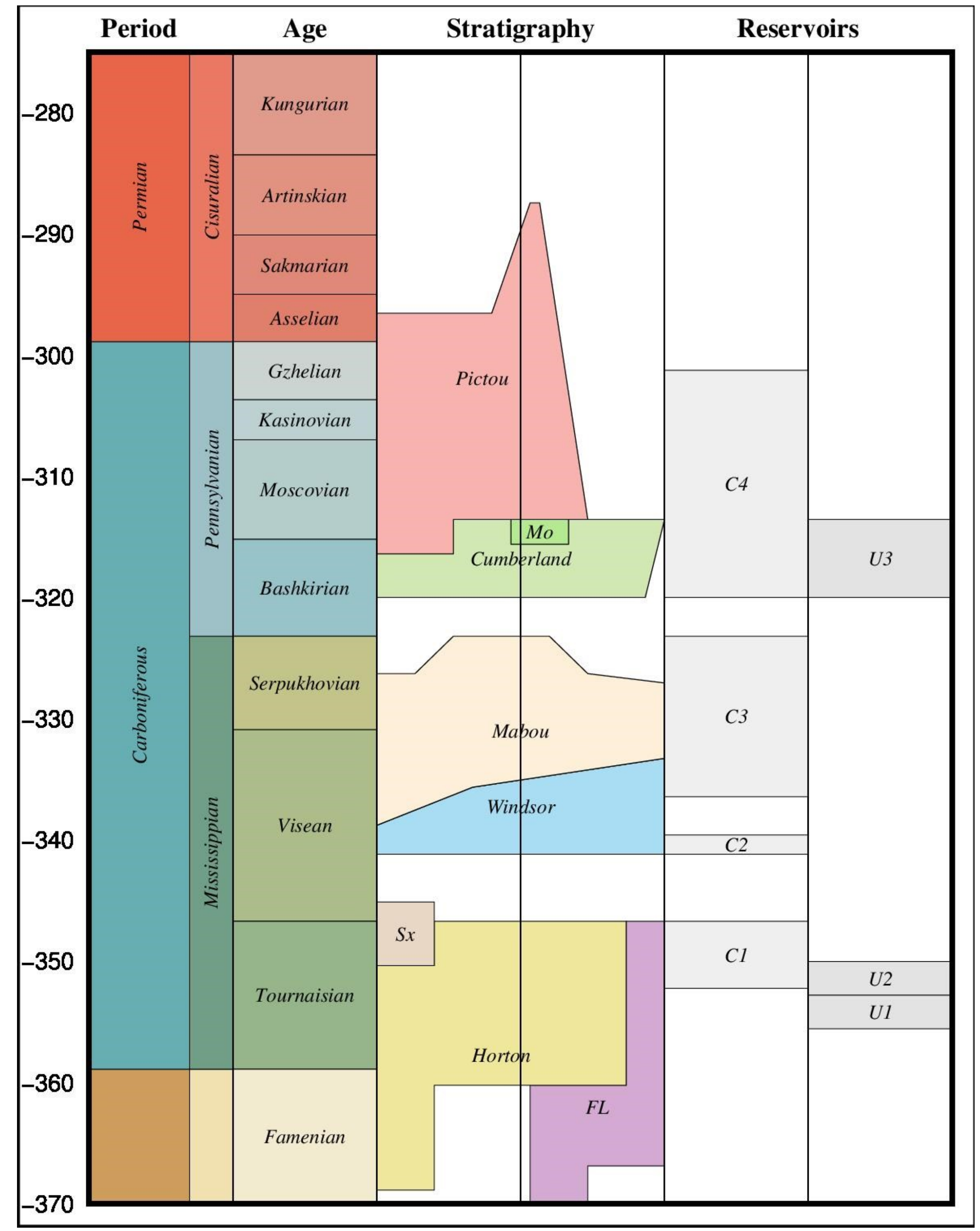


Figure 1-4: Regional stratigraphy and petroleum resource plays hypothesized for onshore Nova Scotia. Stratigraphy corresponds to a rift-to-sag basin sequence comprising, from top to bottom, the Fountain Lake (FL), Horton and Sussex Groups overlain by the Windsor and Mabou Groups overlain, in turn, by the Cumberland, Morien (Mo), and Pictou Groups. Stratigraphic synthesis derived from Waldron et al. (2017). Conventional play types C1-C4 and unconventional play types U1-U3 defined in text.

1.2.2 Gas In Place and Recoverable Gas In Place Potential

Table 1-1 summarizes the Gas In Place (GIP) and Recoverable Gas In Place (RGIP) potential resources predicted for the Windsor and Cumberland study areas. The resource is distributed between four conventional plays (C1-C4), two “shale gas” plays (U1 and U2) and one coal bed methane play (U3) (Figure 1-6). Gas In Place potential across all play types in the Windsor and Cumberland Basins is estimated to be approximately 36 tcf (Hayes et al., 2017). Recoverable gas volumes are inferred to be ~6.5 tcf in total with 4.4 tcf considered as shale gas, 1.4 tcf considered as coal bed methane, and 0.7 tcf considered as conventional gas. These are partial results that would be increased if the remaining 70% of sub-basins in the area of interest of onshore Nova Scotia were to be assessed as well. Figure 1-5 shows the relative proportions of the estimated recoverable gas volumes.

Reservoir	Proportion of Total Area of Interest	Shale Gas (In Place Potential)	Shale Gas (Recoverable Potential)	Coal Methane (In Place Potential)	Coal Methane (Recoverable Potential)	Conventional (In Place Potential)	Conventional (Recoverable Potential)
Pennsylvanian Clastics (C4)	0.3 (5300 km2)					0.381 (CB)	0.172 (CB)
Upper Mississippian Clastics (C3)	0.3 (5300 km2)					0.366 (CB) 0.005 (WB)	0.165 (CB) 0.002 (WB)
Visean Reefal Carbonate (C2)	0.3 (5300 km2)					0.196 (CB) 0.078 (WB)	0.090 (CB) 0.036 (WB)
Lower Mississippian Clastics (C1)	0.3 (5300 km2)					0.100 (CB) 0.394 (WB)	0.046 (CB) 0.181 (WB)
Pennsylvanian Coal beds (U3)	0.3 (5300 km2)			2.705 (CB)	1.411 (CB)		
Lower Mississippian Tight Sands (U2)	0.3 (5300 km2)	1.831 (WB)	0.476 (WB)				
Lower Mississippian Shales (U1)	0.3 (5300 km2)	2.311 (CB) 27.734 (WB)	0.301 (CB) 3.608 (WB)				
Total	0.3 (5300 km2)	31.876	4.385	2.705	1.411	1.520	0.692
Other*	1.0* (17800 km2)	17-69		1.7		2.8	

Table 1-1: Current Assessed Natural Gas Potential in trillions cubic feet (tcf) (from Hayes et al., 2017). CB = Cumberland Basin; WB = Windsor Basin. *Other assessment results inferred from previous studies discussed and cited below.

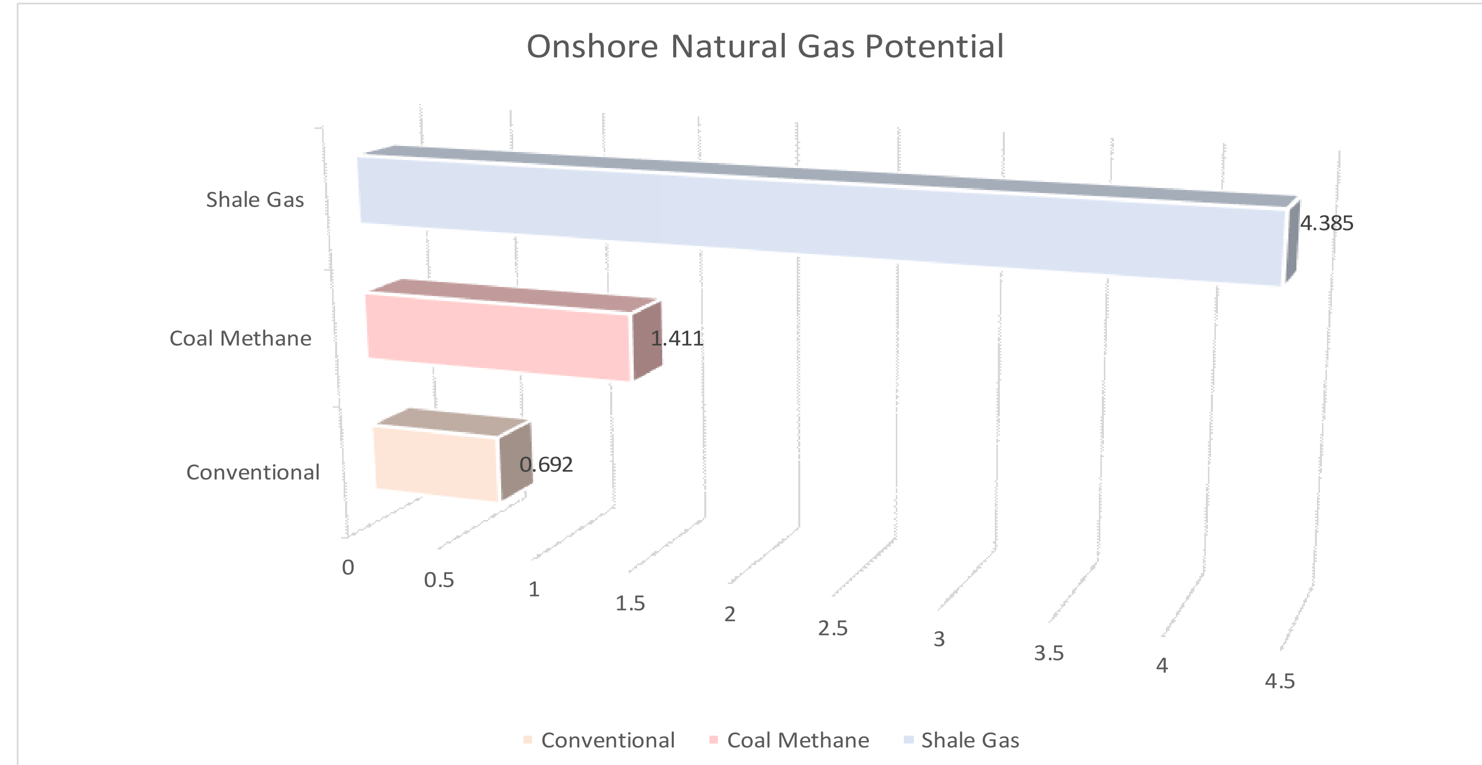


Figure 1-5: Predicted risked recoverable gas potential (in tcf) for the evaluated Windsor and Cumberland Basin Study Areas (results from Hayes et al., 2017). Shale gas (blue), coal bed methane (red), and conventional gas (orange) comprise the total potential.

1.2.3 Value of Recoverable Gas Potential

Table 1-2 shows one approach to converting the estimated gas volumes in onshore Nova Scotia into US dollar amounts. In North America, gas prices are most often quoted in $U.S. dollars. Therefore, the ap0proach used in the Atlas was to express dollar amounts in $U.S. dollars (of the day). Broadly, this exercise permits three main conclusions to be drawn from the reported estimates:

(1) 30% of the area of interest may host recoverable natural gas valued from $20 to $60 billion USD using a $3-$9 USD/MMBTU price range;

(2) Coal bed methane is a sizeable component of the petroleum potential of onshore Nova Scotia; 30% of the Area of Interest hosts ~3 tcf gas-in-place with ~1.5 tcf recoverable gas-in-place. This corresponds to a $4-$13 billion USD resource using the same price assumptions as in (1). Note that these new assessment results apply only to the Windsor and Cumberland Basin study areas (Fig. 1-1); They do not yet include results from Stellarton and Sydney basins among other prospective areas.

(3) Shale gas resources (from Tournaisian-aged shales, tight sands, etc.) host the majority of Nova Scotia's onshore potential. Such resources may need reservoir stimulation methods to be produced economically; current legislation disallows high-volume hydraulic fracturing in shales in exploring for or producing hydrocarbon resources in onshore Nova Scotia (Michael Bird, pers. comm.).

Some additional comments about the hydrocarbon resource potential of onshore Nova Scotia are as follows. First, Atlas research confirms that conventional reservoir targets probably also have low porosity values relative to conventional reservoirs elsewhere (Hayes et al., 2017). If so, reservoir stimulation methods such as hydraulic fracturing may be useful for producing from these targets as well. The Petrel Robertson assessment suggests that oil volumes in the Cumberland and Windsor study areas is minimal (Hayes et al., 2017).

Reservoir(s)	**Total (tcf)**	**Value (billions $)** **Price at $3 USD/mmBTU**	**Value (billions $)** **Price at $9 USD/mmBTU**
Conventional (C1-C4)	0.692	2.2	6.5
Coal Methane (U3)	1.411	4.4	13.2
Shale Gas (U1-U2)	4.385	13.6	40.9
Total	**6.488**	**20.2**	**60.6**

Table 1-2: Current assessed recoverable natural gas potential for assessed Windsor and Cumberland basins of onshore Nova Scotia (from Hayes et al., 2017) in terms of billions USD at $3.00 USD/MMBTU and $9.00 USD/MMBTU.

Onshore Nova Scotia

may host natural gas resources worth

$20 to $60 billion USD*.

Coal Bed Methane

Coal bed methane potential may be worth $4 to $13 billion USD*

Current regulations in onshore Nova Scotia support present and near-future exploration in coal bed reservoirs.

Shale Gas and Conventional

Shale gas potential may be worth $13 to $40 billion USD*.

Current onshore legislation in Nova Scotia disallows high-volume hydraulic fracturing in shales.

* Results are for 30% of the total area of interest only. The 30% of the area of interest is the ~5,300 sq. km underlying the Windsor and Cumberland study areas used in the Onshore Petroleum Atlas project (Fig. 1-1). The $20 to $60 billion USD valuation of the resource is based on a 6.5 tcf volume of recoverable gas in place, a $3.00 to $9.00 USD/MMBTU unit price range for natural gas (EIA, 2017A), and a conversion factor of 1.037 to convert from 1 million cubic feet (MCF) of gas to 1 million British thermal units (MMBTU) (EIA, 2017B).

1.3 Exploration history

1.3.1 Petroleum Drilling and Seismic data acquisition

Figure 1-6 plots the meters of petroleum well drilled and kilometers of seismic data acquired per year in onshore Nova Scotia for the last 170 years along with some other petroleum industry data provided for context. This plot indicates that exploration activity has taken place in onshore Nova Scotia since ca. 1870. Total amounts of drilling and seismic data acquisition are modest by global standards, but are consistent with onshore Nova Scotia's status as a frontier hydrocarbon basin with recognized potential. Exploration has been greatest in recent decades. Since 1970, Nova Scotia has had fifty-four petroleum exploration wells drilled in the onshore. Thirty-four of these post-1970 wells exceeded a depth of 1000 meters and eighteen of these have a modern suite of down hole log data to facilitate the interpretation of rock and fluid properties at depth. Of the eighteen wells with a modern log suite, eight were drilled in coal measures targeting coal bed gas plays and ten have been drilled to evaluate the other oil and gas target reservoirs noted above (Scott Weldon, pers. comm.).

Two periods of relatively greater exploration activity can be identified in Figure 1-6. These periods are labeled "Interest I" and "Interest II" in the rightmost column of Figure 1-6. These periods correspond to periods of elevated oil (blue curve, column 3) and/or gas (red curve, column 4) prices in the North American and global markets. The "Interest I" period occurred between ca. 1973 and 1983 and is headlined by the efforts of Anschutz and Chevron corporations to acquire the first regional seismic surveys for onshore Nova Scotia. Energy price increases during this decade may have been related to the emergence of the Organization of the Petroleum Exporting Countries (OPEC) in the global oil and gas market as a key group of producers. Both higher prices and global competition may have brought industry attention to consider previously frontier areas like onshore Nova Scotia.

The "Interest II" period occurred between ca. 1999 and 2009 and represents the efforts of multiple small to intermediate companies to find economic hydrocarbons in onshore Nova Scotia principally in the regions covered by the two study areas targeted in this Atlas project. This second period of interest may have been facilitated by the build out of the Maritimes & Northeast pipeline to support Nova Scotia's offshore Sable project after ca. 1999. The Maritimes & Northeast pipeline connects Atlantic Canada to North America's existing gas pipeline network through the northeast United States (Figure 1-7). Shale gas production in the eastern United States appears to have come onstream in sufficient quantities by ca. 2009 to help supply-side constraints in the general market (cyan curve, column 5); lower North American gas prices since then are correlated with this new production (Figure 1-6). The Maritimes & Northeast Pipeline has facilitated the import of natural gas into Nova Scotia from other North American producers in recent years to help meet local demand (black curve, column 6).

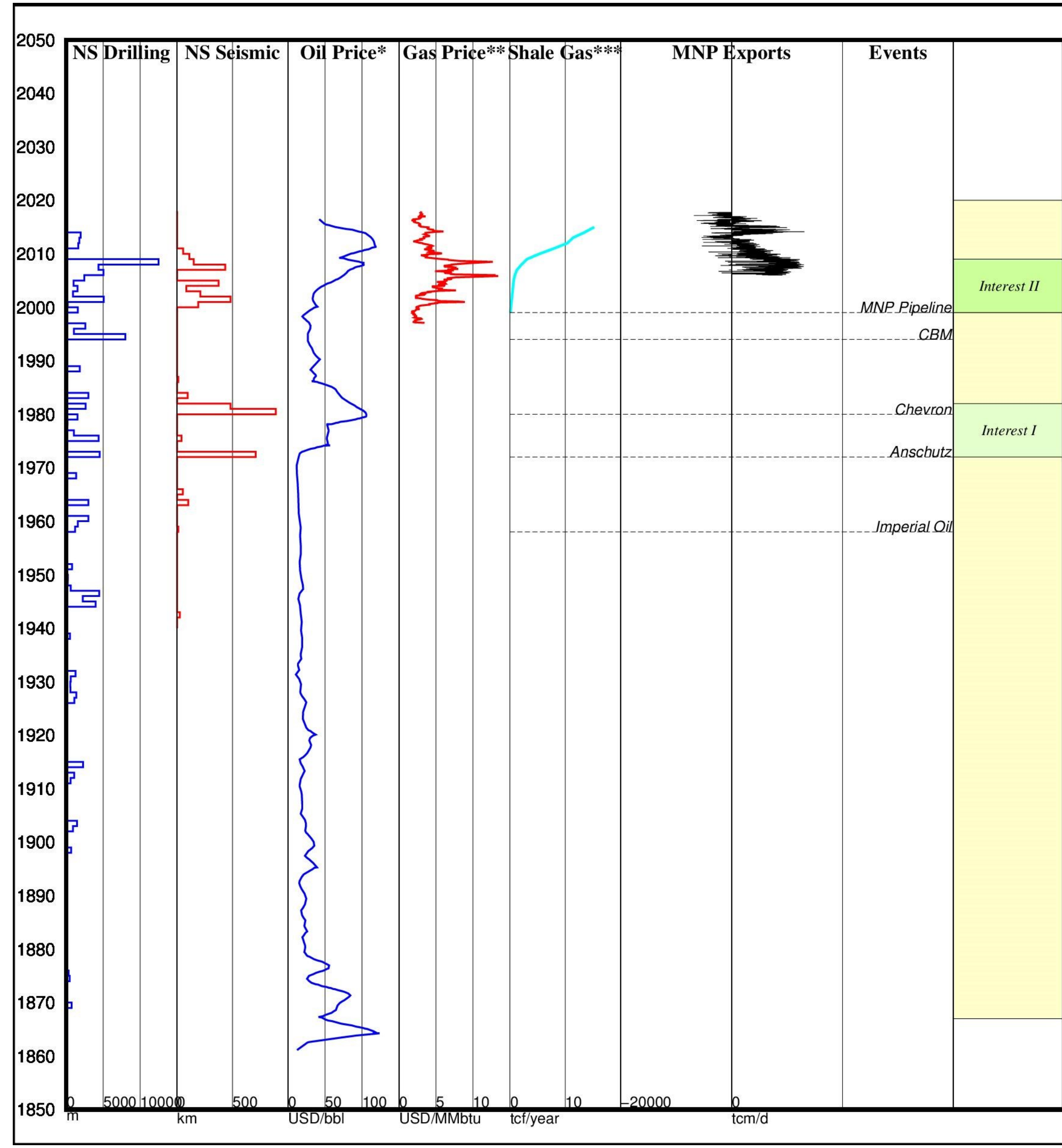


Figure 1-6: Exploration activity data for onshore Nova Scotia plotted in context. Metres of petroleum drilling in onshore Nova Scotia (NSDoE; Column 1), kilometres of seismic acquired in onshore Nova Scotia (NSDoE; Column 2), global oil price data in blue (EIA; column 3), Henry Hub gas prices in red (EIA; column 4), United States shale gas production data in cyan (EIA; column 5), gas throughput on the Maritimes & Northeast pipeline in black (thousands of cubic meters per day), NRCAN; column 6; positive flow is exported gas), and identified periods of elevated hydrocarbon exploration activity in onshore Nova Scotia (column 7).

1.3.2 Maritimes & Northeast Pipeline

The "Maritimes & Northeast pipeline is a 1,101-kilometre mainline transmission pipeline built to transport natural gas from developments offshore Nova Scotia to markets in Atlantic Canada and the northeastern United States" (MNPP, 2017). MNP has an annual average capacity of 0.56 billion cubic feet of gas per day (bcf/d) (MNPP, 2017).

Figure 1-7 plots the approximate path of the Maritimes & Northeast pipeline (MNP) and its points of connection or proximity to various other sites and networks of interest. Gas production in Atlantic Canada targeted for MNP distribution has come in recent years from the McCully Field ("McCully") in onshore New Brunswick, as well as from the Sable Offshore Energy Project ("Sable" or SOEP) and Deep Panuke Gas Development Project ("Panuke") in offshore Nova Scotia.

Production from the McCully Field has been from Horton Group reservoirs in onshore New Brunswick that are analogous to the U1 (shale gas) or U2 (tight sand) plays considered herein for onshore Nova Scotia. Production from the two projects in offshore Nova Scotia are from reservoirs deposited subsequent to the Mesozoic breakup of the supercontinent Pangaea. The producing offshore plays are from younger petroleum systems than those preserved in onshore Nova Scotia.

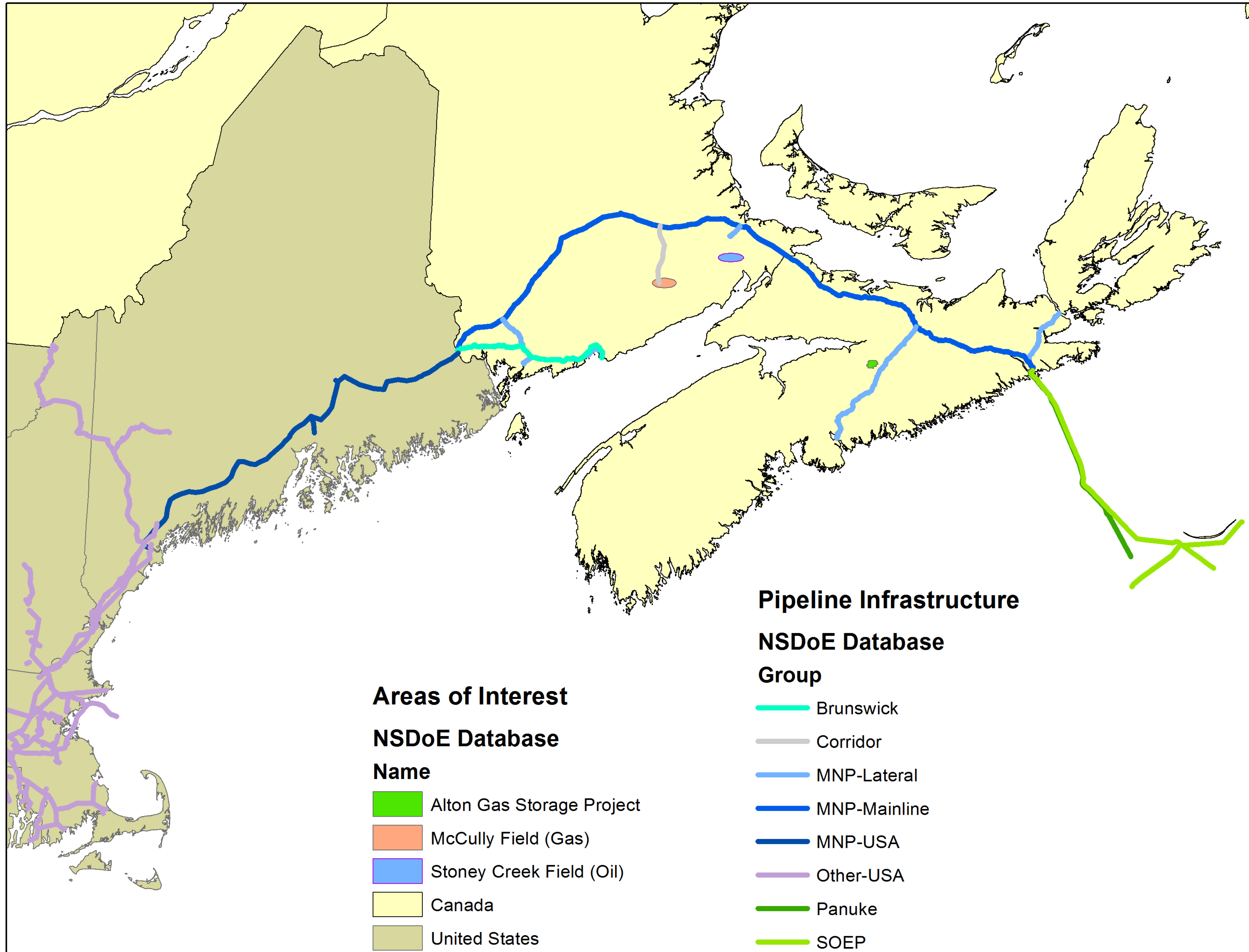


Figure 1-7: Location map for the Maritimes & Northeast Pipeline (MNP) with related points of interest (Keppie, 2017).

1.4 Geological Context

1.4.1 The Maritimes Basin of Atlantic Canada

The area(s) of onshore Nova Scotia that have oil and gas potential are inferred to be those areas that are underlain by sedimentary rocks of the late Paleozoic Maritimes Basin (Fig. 1-8). Maritimes Basin rocks were deposited from the latest Devonian, throughout the Carboniferous and into the earliest Permian periods in a succession of stratigraphic groups. Broadly, deposition occurred first in the form of continental rift and clastic rocks accumulated as growth strata during active basin extension (Fountain Lake, Horton and Sussex Group rocks). This was followed by a period of likely passive subsidence and fill that included a period of evaporite and limestone deposition of various thickness with marine affinities (Windsor Group rocks) that gave way to continental clastic deposition again in the upper sections (i.e., Mabou, Cumberland, Morien, and Pictou Group rocks).

The Maritimes Basin as a whole underlies a significant part of eastern Canada stretching from eastern Quebec to northern Newfoundland and includes onshore and offshore portions of all of the Maritime provinces (i.e., New Brunswick, Prince Edward Island, and Nova Scotia). The area of interest with inferred oil and gas potential in onshore Nova Scotia corresponds to those parts of the Martimes Basin that underlie central, northern, and eastern Nova Scotia at present day. These parts occur today as a set of sub-basins as indicated previously in Fig. 1-2.

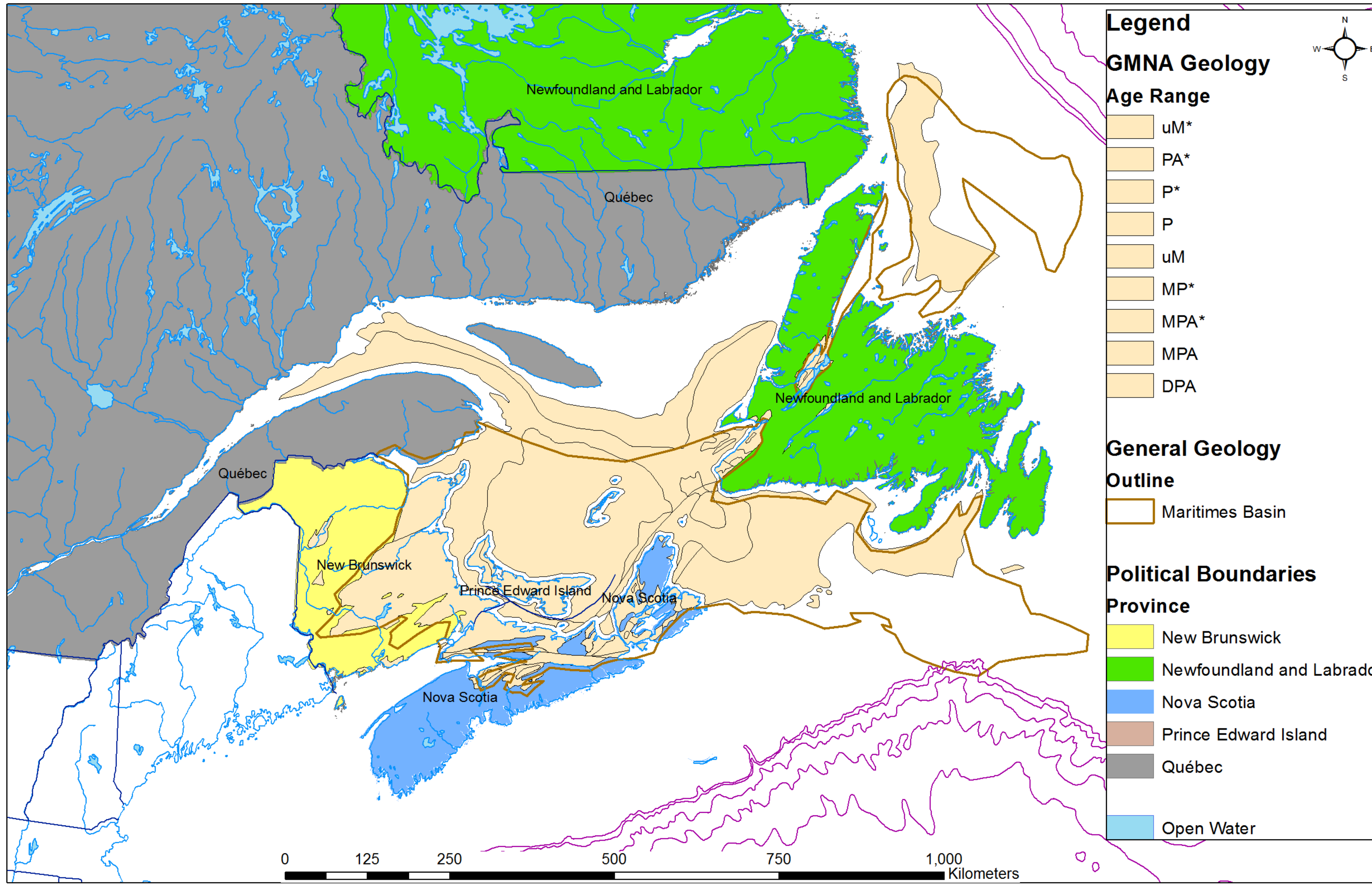


Figure 1-8: Map of Atlantic Canada showing approximate extents of the Maritimes Basin. Extents from the Geological Map of North America Database (Garrity and Soller, 200() indicated based on age of geological units (i.e., late Devonian to early Permian; uM*, uM (upper Mississippian), PA* (Pennsylvanian), P*, P (Permain), MP* (Mississippian-Permian); MPA*,MPA (Mississippian-Pennsylvanian), DPA (Devonian-Pennsylvanian). Extents from the Geological Survey of Canada (after Dietrich et al., 2011) digitized from a georeferenced figure (digitization and geo-referencing were manual exercises that will have introduced errors in the location and shape of the basin boundaries. The Garrity-Soller extents correspond to the limits of inferred surface exposure, whereas the Dietrich et al. extents include subsurface basin limits as well.

1.4.2 Carboniferous Basins of eastern North America and western Europe

The Maritimes Basin can be correlated with a set of similarly-aged basins of predominantly late Devonian to early Permian age, with most of the sediment accumulation taking place in the Carboniferous period. This system of Carboniferous basins extend in one or more linear belts extending from Mississippi to Poland when reconstructed to late Carboniferous time (Fig. 1-9).

Comparisons of petroleum systems along this belt of basins are different in detail. Nonetheless, in a regional sense, these basins show many similarities including the preservation of organic-rich shales (i.e., potential source rocks and shale gas deposits), evaporite sequences (i.e., possible seal rocks), sandstones and carbonate beds (i.e., possilbe reservoir rocks), and coal measures (coal bed methane targets).

In this global perspective, it is conspicuous that the oil and gas industry got started in the late 1800's with the drilling of the Drake well in the Devono-Carboniferous sediments of the eastern United States (Fig. 1-6). And, the shale gas revolution in recent decades has received out-sized contributions from tight reservoirs in these basins as well. And, the oil and gas industry in western Europe, especially the southern North Sea, has benefited from contributions from Carboniferous petroleum systems. Atlantic Canada stands out as an underexplored but prospective region in this context.

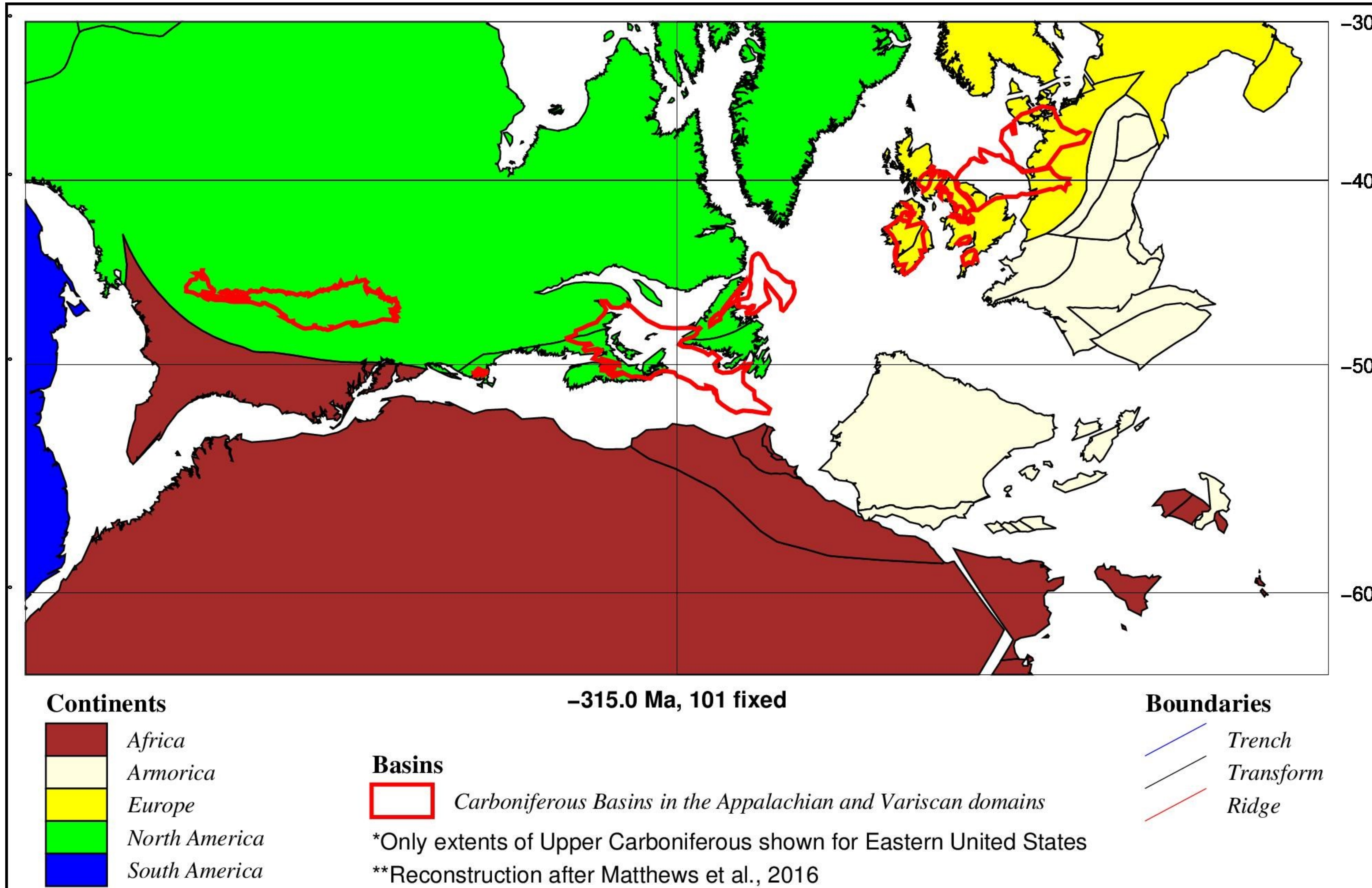


Figure 1-9: Map of Atlantic Canada in a global paleogeographic context 315 million years ago in a stationary North American reference frames. Polygons in red depict outlines for Carboniferous basins deposited in the eastern United States, Atlantic Canada, and western Europe (including the U.K. and the southern North Sea). Hydrocarbon discoveries in the eastern United States and western Europe have played important roles for regional energy supplies and global energy prices over the past one and a half century. The Atlantic Canadian region stands out as an area likely to host comparable petroleum systems as found in eastern United States and western Europe, but Atlantic Canada is substantially less explored.

1.4.3 Proven analogues in Atlantic Canada

Oil and gas discoveries are proven in the Maritimes Basin regionally (Dietrich et al., 2011). Figure 1-10 reproduces a figure constructed by Dietrich et al. (2011) to illustrate the location of known producing oil and gas wells or significant discovery wells from New Brunswick to Newfoundland.

Many of these discoveries, such as the Stoney Creek oilfield or McCully gas field in the Moncton sub-basin, may have been discovered initially by coincidence rather than intention (Dietrich et al., 2011). This may reflect, in part, the lack of systematic knowledge about the petroleum geology systematics across the region. It is conspicuous that discoveries to date have been made to the Magdalen Basin side of major regional faults (Figure 1-19). If this trend is meaningful, it may mean that western Cape Breton and Cumberland sub-basins have the greatest potential in onshore Nova Scotia (Figure 1-2). However, due to the relative lack of exploration in onshore Nova Scotia and the offshore Sydney Basin, it would be premature to view this trend as particularly meaningful. Rather, it seems reasonable to infer that oil and gas discoveries of economic volume could be made in onshore Nova Scotia on the basis of a comparison with these proven local analogues (Dietrich et al., 2011). Although regional variation does exist, many of the key petroleum system parameters are comparable across New Brunswick, Nova Scotia, and Newfoundland.

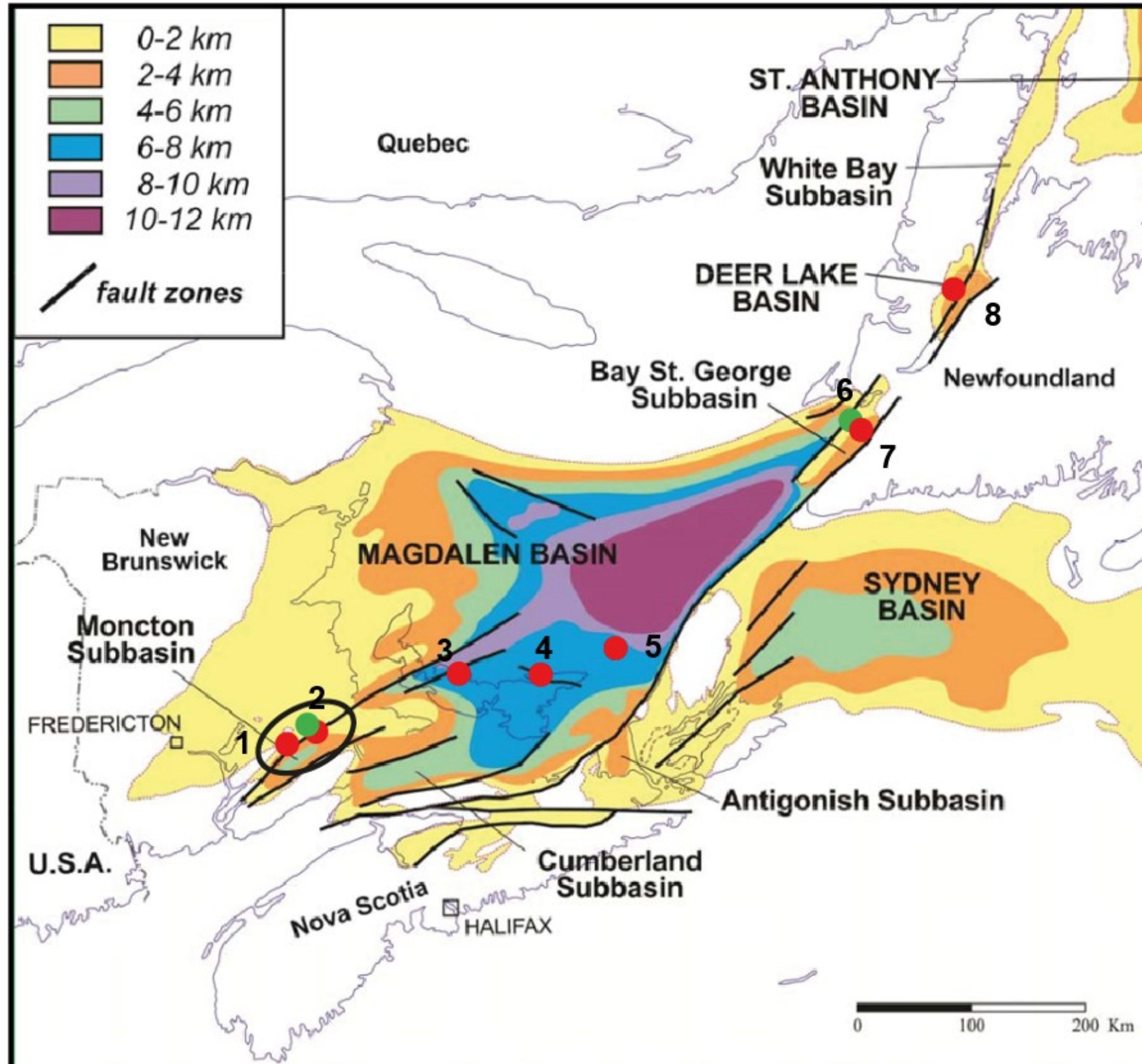


Figure 1-10: Map of Atlantic Canada with locations of significant discoveries or economic production of oil (green) and gas (red) indicated. The Moncton sub-basin, in particular, is an area where production of oil and gas resources from late Paleozoic stratigraphy is proven. These discoveries provide a local analogue for the potential identified in onshore Nova Scotia Figure from Deitrich et al., 2011.

1.5 Summary of Results by Study Area

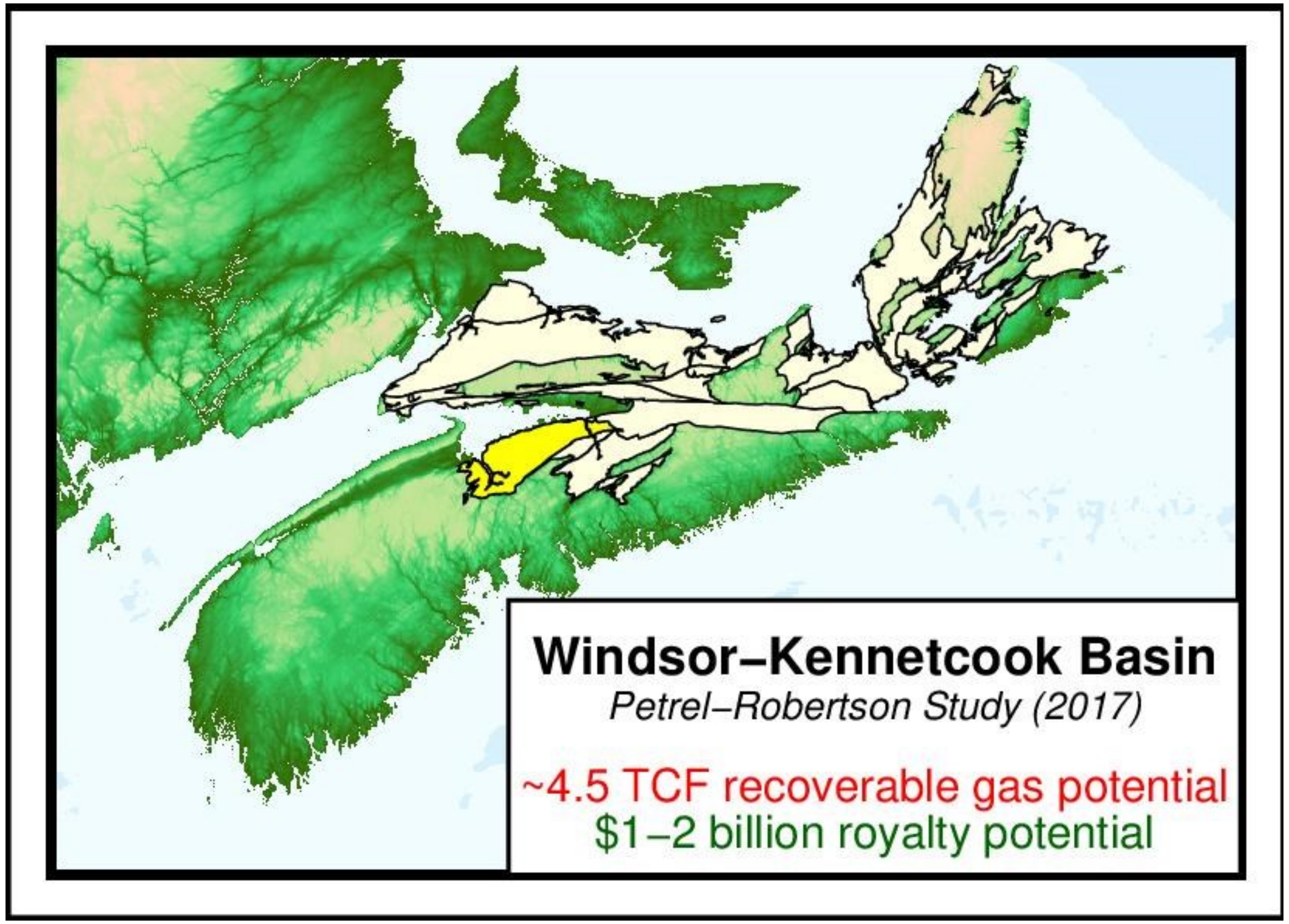


Figure 1-11: Map of Atlantic Canada with Windsor Basin study area highlighted in bright yellow (Hayes et al., 2017).

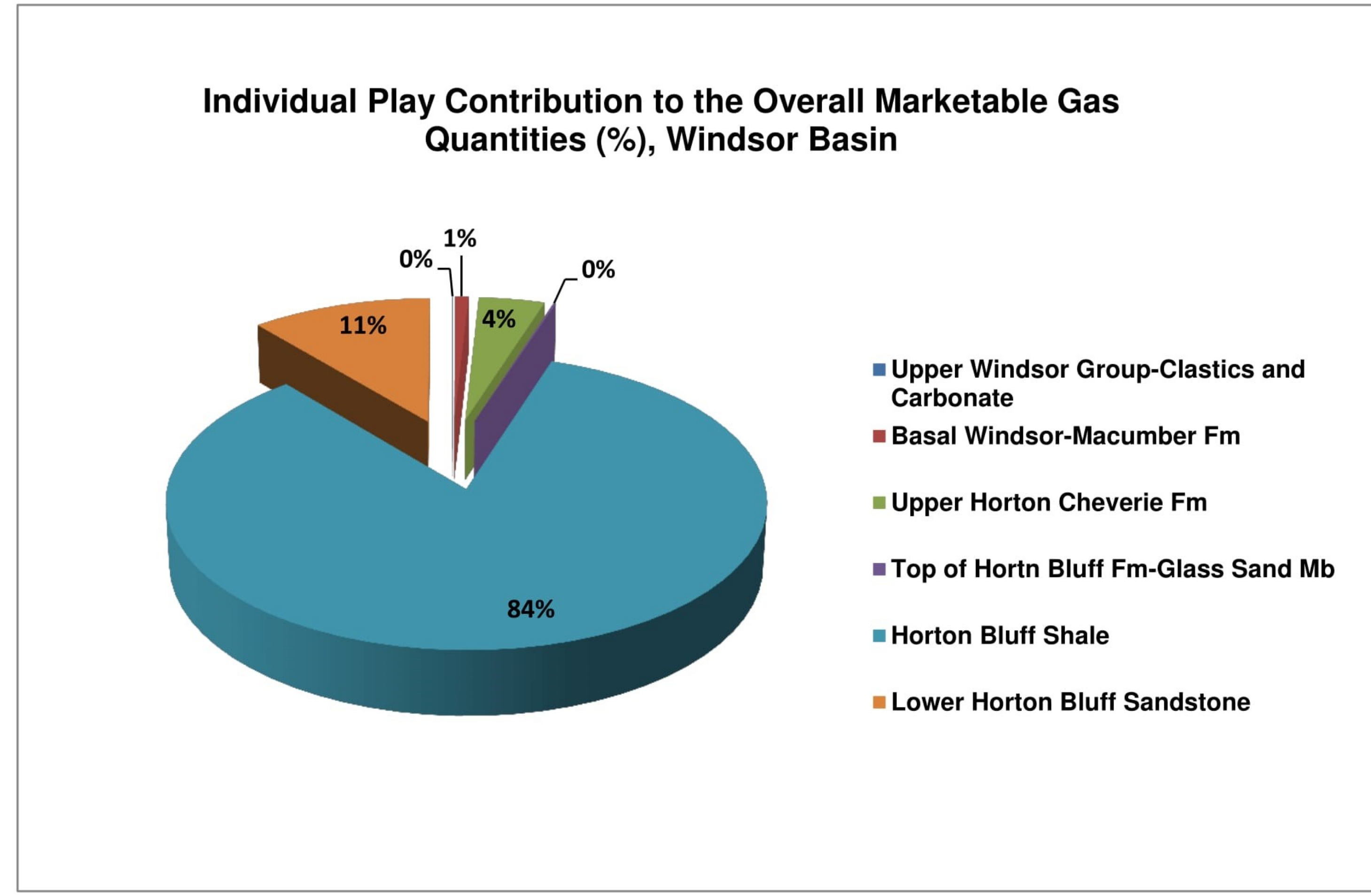


Figure 1-12: Proportions of natural gas resource attributed to six different general play types in the Windsor Basin study area (Hayes et al., 2017). Figure courtesy of Helen Cen, 2017.

1.5.1 Windsor Basin Study Area

Six general reservoir targets were investigated for their oil and gas potential in the Windsor Basin Study area (Fig. 1-11, Fig. 1-12, and Table 1-3; Hayes et al., 2017). These included: (1) Upper Windsor Group clastics and carbonates, (2) a basal Windsor Group carbonate, (3) sandstones of the Upper Horton Group (Cheverie formation), (4) sandstone of the middle Horton Group (Glass Sand member of the Horton Bluff formation), (5) shale of the lower Horton Group (Horton Bluff formation), and (6) tight sandstone of the lower Horton Group (Horton Bluff formation). Table 1-3 shows that only modest volumes of petroleum liquids were predicted across these plays. Table 1-3 also shows that the majority of the predicted gas volumes correspond to the shale and tight sand plays of the lower Horton Group. An approximately ~4.5 TCF recoverable gas resource is predicted in the Petrel Robertson analysis (Hayes et al., 2017). This volume of gas would be worth approximately $10 to $20 billion USD dollars for gas prices in the range of $2.5 to $4.5 USD/MMBTU. This volume of gas, if produced, would correspond roughly to a $1 to $2 billion USD dollars royalty stream for the government of Nova Scotia at the current 10% royalty framework if the identified resource were to be fully produced and neglecting royalty holidays and other adjustments.

Resource Volume Output, Windsor Basin Plays

Plays	Play Risk	OIP+CIIP given success				GIIP given success				GIIP given success			
		Risked Liquids volume (e6stm3)	P90 (e6stm3)	P50 (e6stm3)	P10 (e6stm3)	Risked Gas Volume (e9sm3)	P90 (e9sm3)	P50 (e9sm3)	P10 (e9sm3)	Risked Gas Volume (Bscf)	P90 (Bscf)	P50 (Bscf)	P10 (Bscf)
Horton Bluff Shale	1.00	8.89	1.62	5.57	18.55	781.4	190.9	551.6	1,556.0	27734.3	6776.6	19579.3	55228.8
Lower Horton Bluff Sandstone	1.00	1.03	0.13	0.53	2.20	51.6	7.5	29.2	107.3	1831.1	266.3	1036.5	3810.0
Upper Windsor Group – clastics and carbonate	0.07	0.00	0.01	0.03	0.14	0.1	0.3	1.1	4.2	4.9	9.4	38.3	149.9
Macumber Fm (Gays River equiv.) – basal Windsor	0.42	0.07	0.02	0.08	0.40	2.2	0.5	2.6	12.2	78.1	18.4	90.5	434.6
Upper Horton Cheverie Fm	0.42	0.35	0.07	0.37	1.90	10.6	2.4	12.1	57.7	377.8	85.6	428.6	2046.7
Glass sand (top of Horton Bluff Fm)	0.32	0.01	0.01	0.03	0.10	0.4	0.2	0.9	2.9	15.7	8.0	30.4	103.2
						Recoverable Gas given success				Recoverable Gas given success			
		Risked Liquids volume (e6stm3)	P90 (e6stm3)	P50 (e6stm3)	P10 (e6stm3)	Risked Gas Volume (e9sm3)	P90 (e9sm3)	P50 (e9sm3)	P10 (e9sm3)	Risked Gas Volume (Bscf)	P90 (Bscf)	P50 (Bscf)	P10 (Bscf)
Horton Bluff Shale	1.00	1.33	0.17	0.70	2.90	101.7	16.4	60.4	219.6	3608.4	581.0	2143.0	7793.6
Lower Horton Bluff Sandstone	1.00	0.31	0.03	0.15	0.65	13.4	1.7	7.0	28.5	476.4	59.4	248.0	1011.0
Upper Windsor Group – clastics and carbonate	0.07	0.00	0.00	0.02	0.07	0.1	0.1	0.5	1.9	2.3	4.1	17.1	69.0
Macumber Fm (Gays River equiv.) – basal Windsor	0.42	0.04	0.01	0.04	0.21	1.0	0.2	1.1	5.7	36.0	7.9	40.7	200.6
Upper Horton Cheverie Fm	0.42	0.18	0.04	0.19	1.00	4.9	1.1	5.4	26.5	174.4	37.4	192.8	941.2
Glass sand (top of Horton Bluff Fm)	0.32	0.01	0.00	0.01	0.05	0.2	0.1	0.4	1.4	7.2	3.4	13.4	48.0

Table 1-3: Recoverable oil and gas .from six general play types from the Windsor Basin study area (from Hayes et al., 2017).

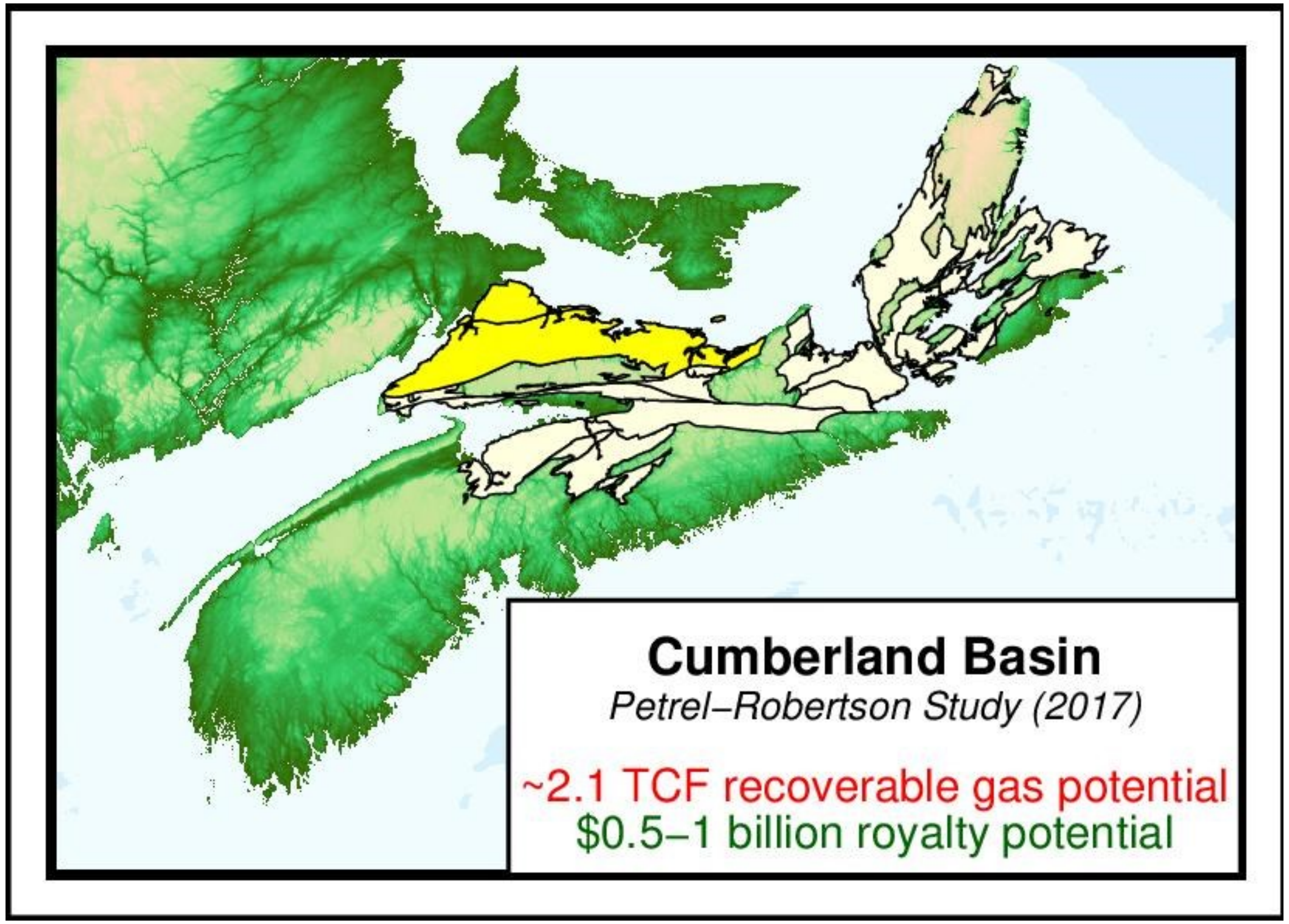


Figure 1-13: Map of Atlantic Canada with Cumberland Basin study area highlighted in bright yellow (Hayes et al., 2017)

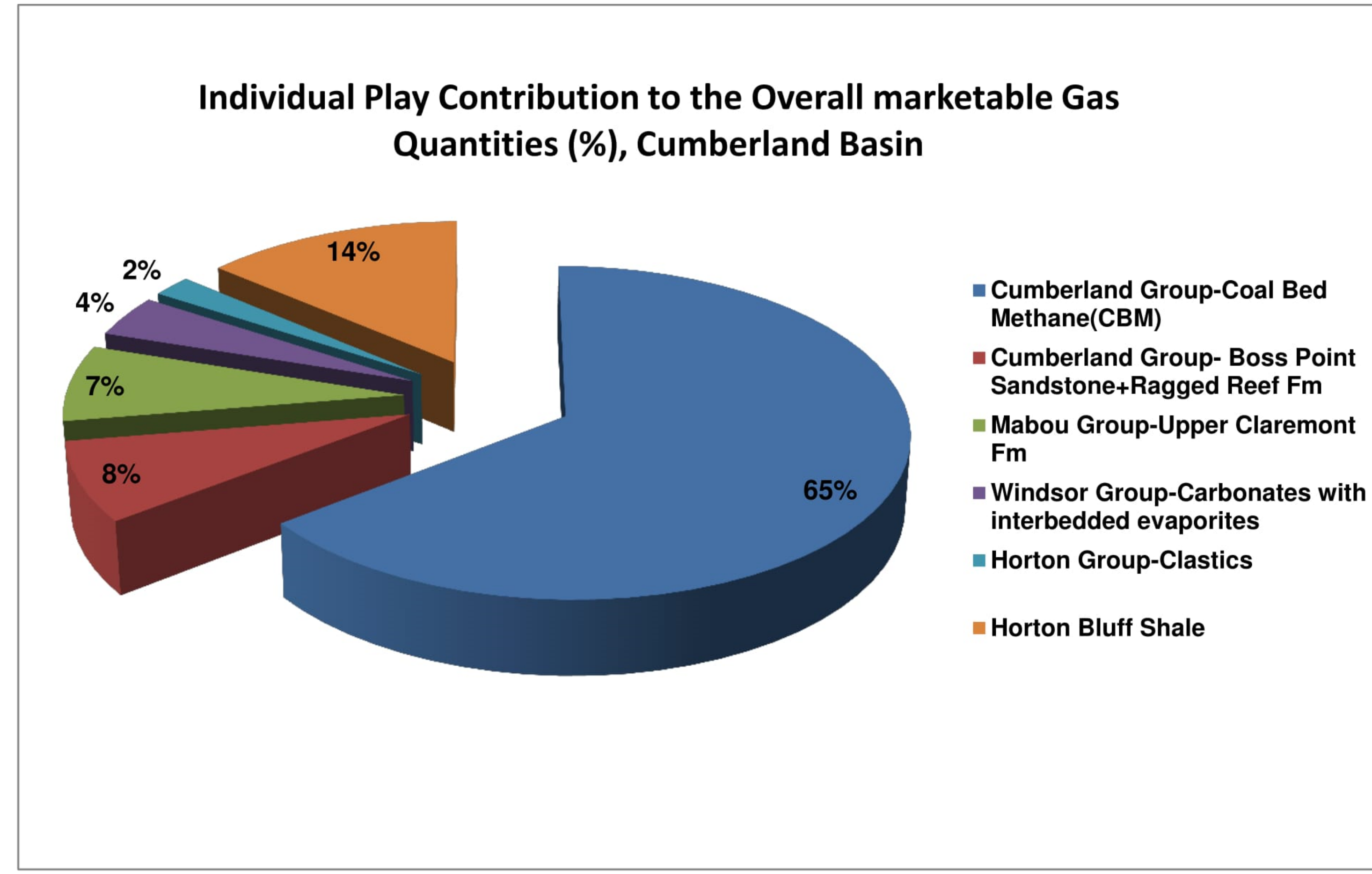


Figure 1-14: Proportion of natural gas resource attributed to six different general play types in the Cumberland Basin study area (Hayes et al., 2017). Figure courtesy of Helen Cen, 2017.

1.5.2 Cumberland Basin Study Area

Six general reservoir targets were investigated for their oil and gas potential in the Cumberland Basin Study area (Fig. 1-13, Fig. 1-14, and Table 1-4; Hayes et al., 2017). These included: (1) Cumberland Group Coal Beds, (2) Cumberland Group sandstones (Boss Point and Ragged Reef formation), (3) Mabou Group sandstone (Upper Claremont Formation), (4) Windsor Group carbonates and interbedded evaporites, (5) Horton Group sandstones (or clastics), and (6) Horton Group shale (Horton Bluff formation). Table 1-4 shows that only modest volumes of petroleum liquids were predicted across these plays. Table 1-4 also shows that the majority of the predicted gas volumes correspond to the Cumberland Group coal bed methane play. An approximately ~2.1 TCF recoverable gas resource is predicted in the Petrel Robertson analysis (Hayes et al., 2017). This volume of gas would be worth approximately $5 to $10 billion USD dollars for gas prices in the range of $2.5 to $4.5 USD/MMBTU. This volume of gas, if produced, would correspond roughly to a $0.5 to $1 billion USD dollars royalty stream for the government of Nova Scotia in the current royalty framework if the identified resource were to be fully produced and neglecting royalty holidays and other adjustments. Note a possibility for shale gas potential much greater than reported here may exist for the Cumberland Basin. Shale gas potential was reduced in the present assessment due to uncertainties about the deeper stratigraphy in the Cumberland Basin. Previous drilling programs have not penetrated the necessary depths to test for the presence of shales.

Resource Volume Output-Cumberland Basin Plays

	Play Risk	OIP+CIIP given success				GIIP given success				GIIP given success			
		Risked Liquids volume(e6stm3)	P90(e6stm3)	P50(e6stm3)	P10(e6stm3)	Risked Gas Volume(e6stm3)	P90(e6stm3)	P50 (e6stm3)	P10(e6stm3)	Risked Gas Volume(Bscf)	P90(Bscf)	P50(Bscf)	P10(Bscf)
Horton Bluff Shale	0.50	0.69	0.08	0.50	3.14	65.1	9.2	52.7	306.0	2311.1	326.8	1871.8	10862.3
Cumberland Coal Bed Methane (CBM)	1.00	0.39	0.03	0.15	0.84	76.2	8.7	39.1	169.9	2705.3	308.8	1386.8	6031.9
Cumberland Group Boss Point sandstone, Ragged Reef fm	0.29	0.35	0.14	0.59	2.46	10.7	4.7	19.2	74.0	381.3	168.0	682.1	2624.8
Mabou Group Upper Claremont Fm	0.37	0.34	0.06	0.34	1.90	10.3	2.0	11.1	58.7	366.2	72.3	394.6	2085.2
Windsor Group – carbonates with interbedded evaporites	0.38	0.18	0.02	0.14	1.12	5.5	0.5	4.3	34.6	196.5	19.3	154.0	1228.8
Horton Fm clastics	0.36	0.09	0.03	0.12	0.55	2.8	1.0	4.0	16.8	99.9	34.1	141.2	595.2
	Play Risk					Recoverable Gas given success				Recoverable Gas given success			
		Risked Liquids volume(e6stm3)	P90(e6stm3)	P50(e6stm3)	P10(e6stm3)	Risked Gas Volume(e6stm3)	P90(e6stm3)	P50 (e6stm3)	P10(e6stm3)	Risked Gas Volume(Bscf)	P90(Bscf)	P50(Bscf)	P10(Bscf)
Horton Bluff Shale	0.50	0.10	0.01	0.06	0.46	8.5	0.9	5.7	39.0	300.7	31.1	203.8	1385.4
Cumberland Coal Bed Methane (CBM)	1.00	0.23	0.02	0.09	0.51	39.8	4.4	20.1	88.9	1411.3	157.5	714.0	3155.4
Cumberland Group Boss Point sandstone, Ragged Reef fm	0.29	0.19	0.07	0.31	1.31	4.9	2.0	8.4	33.4	172.2	71.5	299.2	1184.7
Mabou Group Upper Claremont Fm	0.37	0.18	0.03	0.18	1.02	4.7	0.9	4.9	26.6	165.4	30.7	172.7	943.1
Windsor Group – carbonates with interbedded evaporites	0.38	0.10	0.01	0.07	0.58	2.5	0.2	1.9	15.8	90.5	8.4	68.7	560.3
Horton Fm clastics	0.36	0.05	0.01	0.06	0.29	1.3	0.4	1.8	7.7	46.0	14.8	62.8	272.6

Table 1-4: Recoverable oil and gas estimates from six general play types from the Cumberland Basin study area (from Hayes et al., 2017)

1.5.3 Comparison with Previous Assessments

Previous studies have also assessed the petroleum potential of onshore Nova Scotia, either by inclusion in a regional study of Atlantic Canada as a whole (e.g., Dietrich et al., 2011; EIA, 2013) or in terms of local property holdings of companies or past mining areas (e.g., Hughes, 2003; Lam et al., 2008). It is desirable to compare the new results reported here (Hayes et al., 2017) with the results of the earlier assessment studies. Unfortunately, between even this small handful of studies, there is not a common scheme for how different play concepts and study areas were defined and evaluated and so direct comparison is non-trivial.

Nevertheless, the attempt was made in this atlas to obtain an order of magnitude comparison between the different studies. Two strategies were employed to achieve this goal. First, a scheme of four conventional (C1-C4) and three unconventional (U1-U3) play types was conceived as outlined in Figure 1-15, and then the results of all of the studies were fit to this general classification. This involved combining play results or separating play results as reported in the different studies. Second, for studies in which the evaluated area was greater than the province of Nova Scotia (i.e., Dietrich et al., 2011; EIA, 2013) a simple area fraction was computed for the area of onshore Nova Scotia to the area of the whole Maritimes Basin. Results from the more regional studies were multiplied by this area-based fraction to obtain a value representing an assessment for onshore Nova Scotia only. This back-of-the-envelope type of calculation is not justified on the basis of geological variation across Atlantic Canada. However, it was believed to be a useful exercise in the present context to achieve a rudimentary comparison of results between the different studies. Where the study areas of previous assessments were smaller than the sub-basin scale (i.e., Hughes, 2003; Lam et al., 2008) the total estimated values were compared directly to the new results. This crude comparison is also not justified because the new results from Hayes et al. (2017) results only represent 30% of the total area of interest and the previous studies represent even smaller areas. Nonetheless, the direct comparison was forced to generate an order of magnitude comparison of the new results with previous works. The outcome of this crude comparison is shown in Figure. 1-15; what is indicated is that where multiple studies exist assessing the same play type, the different studies have similar results to the closest order of magnitude.

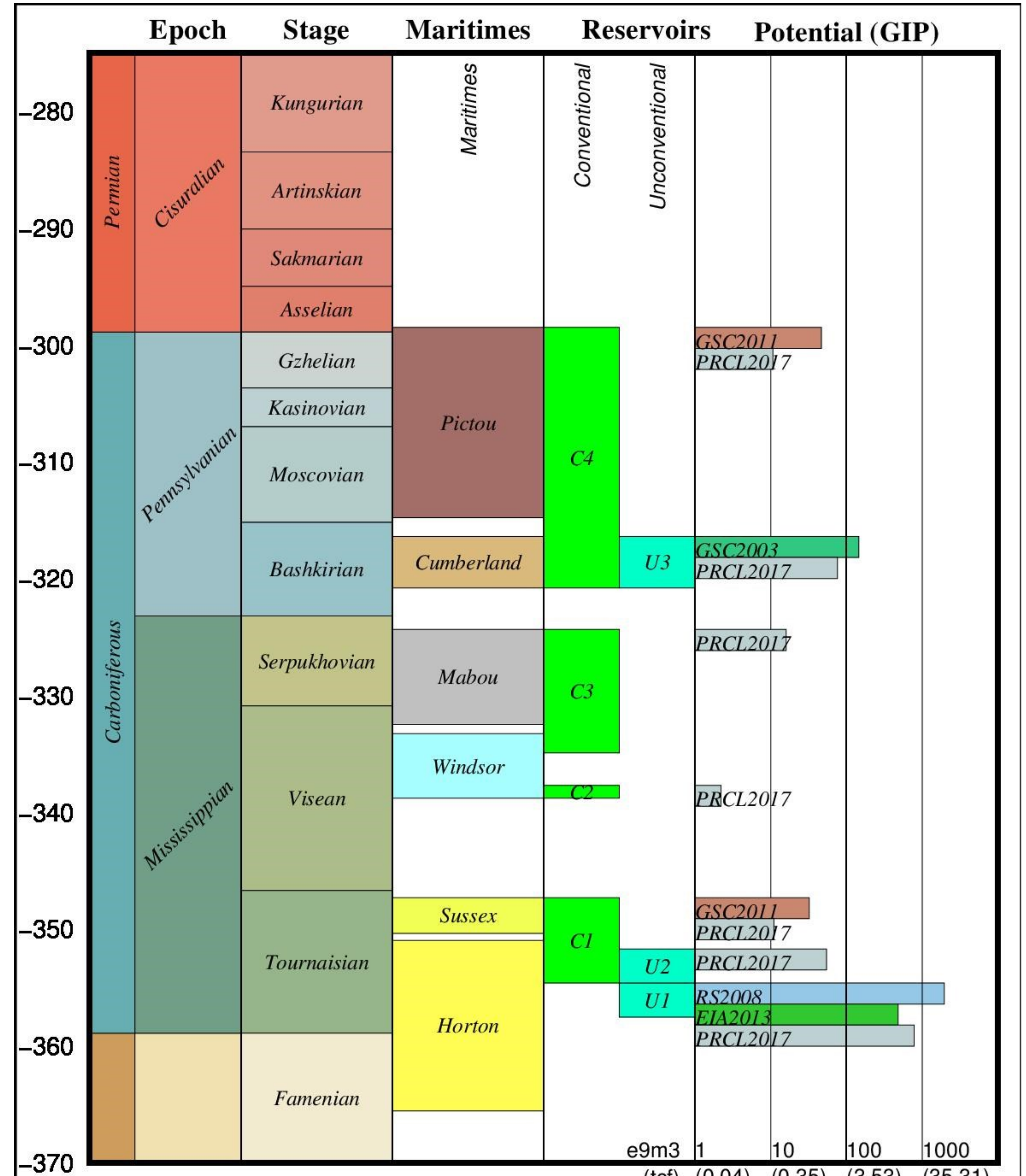


Figure 1-15: Correlation chart showing the general regional stratigraphy of the Maritimes Basin (after Waldron et al., 2017) in terms of absolute age in millions of years before present and relative age according to global geological periods. Along with general lithostratigraphy, four general conventional play type concepts : C1—Tournaisian clastics, C2—base Windsor Group carbonate, C3— Upper Mississippian clastic/carbonate, C4—Pennsylvanian clastic are indicated, and three general unconventional play type concepts: U1—Tournaisian shale gas, U2—Tournaisian tight sand, and U3-Pennsylvanian coal bed methane are indicated as well. The results from five assessment studies are compared in the right-most column with respect to these play concepts. Compared studies include GSC2003 (Hughes, 2003), RS2008 (Lam et al., 2008), GSC2011 (Dietrich et al., 2011), EIA2013 (EIA, 2013), and PRCL2017 (Hayes et al., 2017). Results for a given play concept are listed in sequence starting at the youngest age of the corresponding play type concept. For example, GSC2011 and PRCL2017 both provide estimates for play type C4 and are shown together at the top of the rightmost column in the figure.

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