Evaluation of CO_2 storage potential of Carboniferous sandstones in the Maritime Provinces of Canada†

John S. Carey* and Paul Durling

Natural Resources Canada, Geological Survey of Canada-Atlantic,
Bedford Institute of Oceanography, Dartmouth, Nova Scotia B2Y 4A2, Canada

*Corresponding author: john.carey@nrcan-rncan.gc.ca

Date received: 25 March 2024 ¶ Date accepted 30 July 2024

ABSTRACT

The suitability of Carboniferous sandstones in three regions of the Maritime Provinces of Canada for geologic carbon storage was evaluated: the Horton Bluff Formation in the Windsor Sub-basin, the lower Cumberland Group sandstones in the Cumberland–Sackville Sub-basin, and the Pennsylvanian sandstones of Prince Edward Island. The properties of potential reservoirs and characteristics of vertical seals and barriers to lateral migration were evaluated using previously collected well logs, sample descriptions, core analyses and seismic interpretations. Reservoir quality was found to be the limiting factor in all three regions. Sandstones in the upper Hurd Creek Member of the Horton Bluff Formation locally have porosities up to 15% and permeabilities up to 25 milliDarcies at depths up to 1200 m. Their aggregate thickness may be suitable for GCS, but individual sandstones are thin and likely of limited lateral extent. The lower Cumberland Group contains sand-dominated successions up to 1 km thick with low porosity (5–7%) where known in the subsurface. Sandstone bodies in the Bradelle, Green Gables, and Cable Head formations beneath Prince Edward Island exceed tens of metres in thickness with porosities averaging up to 10–12% and permeabilities up to 10 milliDarcies. Evaporites in the overlying Windsor Group would provide a suitable seal for the Horton Bluff Formation; in other areas the top seal would be provided by mud-prone heterolithic intervals. The evaluated areas may provide opportunities for small onshore storage projects. Further work is warranted to delineate reservoir trends and verify the integrity of potential top seals and traps.

RÉSUMÉ

On a évalué l'utilité des grès carbonifères pour le stockage géologique du carbone (SGC) dans trois régions des provinces maritimes canadiennes : la Formation Horton Bluff dans le sous-bassin de Windsor, les grès de la partie inférieure du Groupe Cumberland dans le sous-bassin de Cumberland–Sackville et les grès pennsylvaniens de l'Île-du-Prince-Édouard. Les propriétés des réservoirs potentiels et les caractéristiques des barrières et des sections d'obturation verticales de la migration latérale ont été évaluées à l'aide de diagraphies précédemment obtenues, de descriptions d'échantillons, d'analyses de carottes et d'interprétations sismiques. On a constaté que la qualité des réservoirs constituait le facteur limitant dans les trois régions. Les grès de la partie supérieure du Membre Hurd Creek de la Formation Horton Bluff ont par endroits des porosités jusqu'à 15 % et des perméabilités jusqu'à 25 millidarcys à des profondeurs pouvant atteindre 1 200 m. Leur épaisseur globale pourrait convenir pour le SGC, mais les grès individuels sont minces et probablement d'une étendue latérale limitée. La partie inférieure du Groupe Cumberland renferme des successions à prédominance de sable de 1 km d'épaisseur à faible porosité (5 à 7 %) dans les sections où elle est connue en subsurface. Des masses dans les formations Bradelle, Green Gables et Cable Head sous l'Île-du-Prince-Édouard ont plus de dizaines de mètres d'épaisseur avec des porosités moyennes de 10 à 12 % et des perméabilités moyennes jusqu'à 10 millidarcys. Les évaporites dans le groupe sus-jacent de Windsor représenteraient un volet d'obturation qui conviendrait pour la Formation Horton Bluff; dans d'autres endroits, la section d'obturation supérieure serait constituée d'intervalles hétérolithiques à prédominance de boue. Les secteurs évalués pourraient offrir des possibilités de petits projets de stockage côtier; d'autres travaux sont nécessaires pour délimiter les orientations des réservoirs et vérifier l'intégrité des sections d'obturation et des pièges supérieurs éventuels.

[Traduit par la redaction]

†From: Atlantic Geoscience Special Series on "Geoscience in support of Net-Zero in Atlantic Canada (and beyond). Atlantic Geoscience, 60, pp. 205-231.

doi: 10.4138/atlgeo.2024.010

2564-2987|24|00205–231 $5.05|0

INTRODUCTION

Geologic Carbon Storage (GCS) is an important component of Canada's plans to reduce greenhouse gas emissions in the coming decades (Environment and Climate Change Canada 2022). Although the active projects in Canada are situated in the Western Canada Sedimentary Basin, a recent study by Carey *et al.* (2023) highlighted the potential for carbon sequestration in Atlantic Canada. They found that the best potential for high-injectivity, large volume GCS projects lay in offshore Mesozoic–Cenozoic basins, drawing similar conclusions to previous workers (Bachu 2003; Bradshaw and Dance 2005; Pothier *et al.* 2010; Keighley and Maher 2015). However, Carey *et al.* (2023) also recognized potential in the upper Paleozoic rocks of onshore areas in the Maritimes Basin (Fig. 1). Drilling costs and infrastructure construction costs are typically much lower onshore than in offshore areas, which could potentially make smaller projects viable onshore. For example, Kaiser (2009) noted that the average offshore well in the USA is four times as costly as the average onshore well, whereas Amado (2013) estimated the cost of drilling offshore to be 6 times greater than onshore in the Gulf of Mexico. Carey *et al.* (2023) examined the chance of success of three key geologic components required for a successful GCS project: reservoir, seal, and trap. Reservoir success was defined as the presence of a porous and permeable unit at a depth of greater than 800 m. The 800 m depth is a commonly rule of thumb used to estimate where temperature and pressure are typically sufficient for supercritical conditions (US Department of Energy 2024; van der Meer *et al.* 2009). A high chance of seal success indicated that an impermeable barrier was expected above the reservoir preventing vertical migration to the surface. A successful trap was inferred if escape to the surface by lateral migration was judged unlikely on the basis of distance from outcrop and major faults. This paper reviews the reservoir, seal and trap characteristics of three of the potential carbon capture, utilization, and storage (CCUS) "plays" in Atlantic Canada identified by Carey *et al.* (2023): the Horton Bluff Formation in the Windsor Sub-basin of Nova Scotia, the lower Cumberland Group sandstones in the Cumberland–Sackville Sub-basin of Nova Scotia and New Brunswick, and the Bradelle and Cable Head formations in Prince Edward Island. This evaluation is based on existing mapping and sample data and highlights what is currently known about the potential of these rocks and what further information would be required to assess their suitability for future CCUS projects.

REGIONAL GEOLOGY

The upper Paleozoic strata of Atlantic Canada lie within an assemblage of structural basins collectively referred to as the Maritimes Basin (Fig. 1; Gibling *et al.* 2019; Van de Poll *et al.* 1995). These rocks were deposited during a complex series of tectonic events occurring after the middle Devonian Acadian Orogeny (Lavoie 2019). Although the timing of subsidence and deformation varies between sub-basins, some general similarities in stratigraphic development allow the usage of the same group-level stratigraphy throughout the region (Waldron *et al.* 2017; Fig. 2). The potential reservoirs of interest lie in different structural regions and at different stratigraphic levels within the Maritimes Basin.

The first potential reservoir lies within the Windsor Sub-basin, a local depocentre located in central Nova Scotia on the southern edge of the Martimes Basin (Fig. 1; Waldron *et al.* 2010). The reservoir lies within the Horton Group (Fig. 2), which is characterized by predominantly terrestrial sediments deposited in half-grabens that developed within crystalline basement rocks (Hamblin and Rust 1989) throughout the region. The Horton Group is the reservoir for the only active onshore hydrocarbon field in Atlantic Canada, the McCully field (Fig. 1) in southeastern New Brunswick (New Brunswick Department of Natural Resources and Energy Development 2023). Up to 2.5 km of Horton Group rocks were deposited in the Windsor Sub-basin (Waldron *et al.* 2010). As in most of the Maritimes Basin, Horton Group deposition was followed by a marine incursion and the deposition of the Windsor Group, which typically contains a lower interval characterized by carbonate and evaporite rocks (Giles 1981). The evaporite rocks make a good seal for underlying reservoir rocks. In the central parts of the sub-basin, Windsor Group sediments are approximately 1 km thick, and overlain by terrestrial rocks of the Cumberland Group (Waldron *et al.* 2010).

The second potential play lies in the Cumberland–Sackville Sub-basin (Fig. 1), which consists of four major synclines separated by uplifted and faulted blocks (Allen *et al.* 2013; Waldron and Rygel 2005). In the Cumberland–Sackville Sub-basin, Carey *et al.* (2023) identified sandstones of the lower Cum-berland Group as potential reservoirs that are overlain in much of the area by units rich in mud-rocks and coals, such as the Joggins Formation (Ryan and Boehner 1994; Fig. 2), that could form a seal. The lower Cumberland Group sandstones comprise the Boss Point Formation and similar, but younger, sandstones. The Boss Point Formation is the lowermost unit in the Cumberland Group in the Cumberland–Sackville Sub-basin (Rygel *et al.* 2015; Waldron *et al.* 2017). It overlies the Claremont Formation, a conglomeratic interval deposited as alluvial fan and braided stream deposits derived from the nearby Cobequid Highlands to the south (Hamblin 2001). Although previously regarded as part of the Cumberland Group (Ryan and Boehner 1994; Ryan *et al.* 1991), recent authors have reassigned the Claremont Formation to the Mabou Group based on palynological identification of an unconformity between it and the Boss Point Formation (Rygel *et al.* 2015). The Boss Point

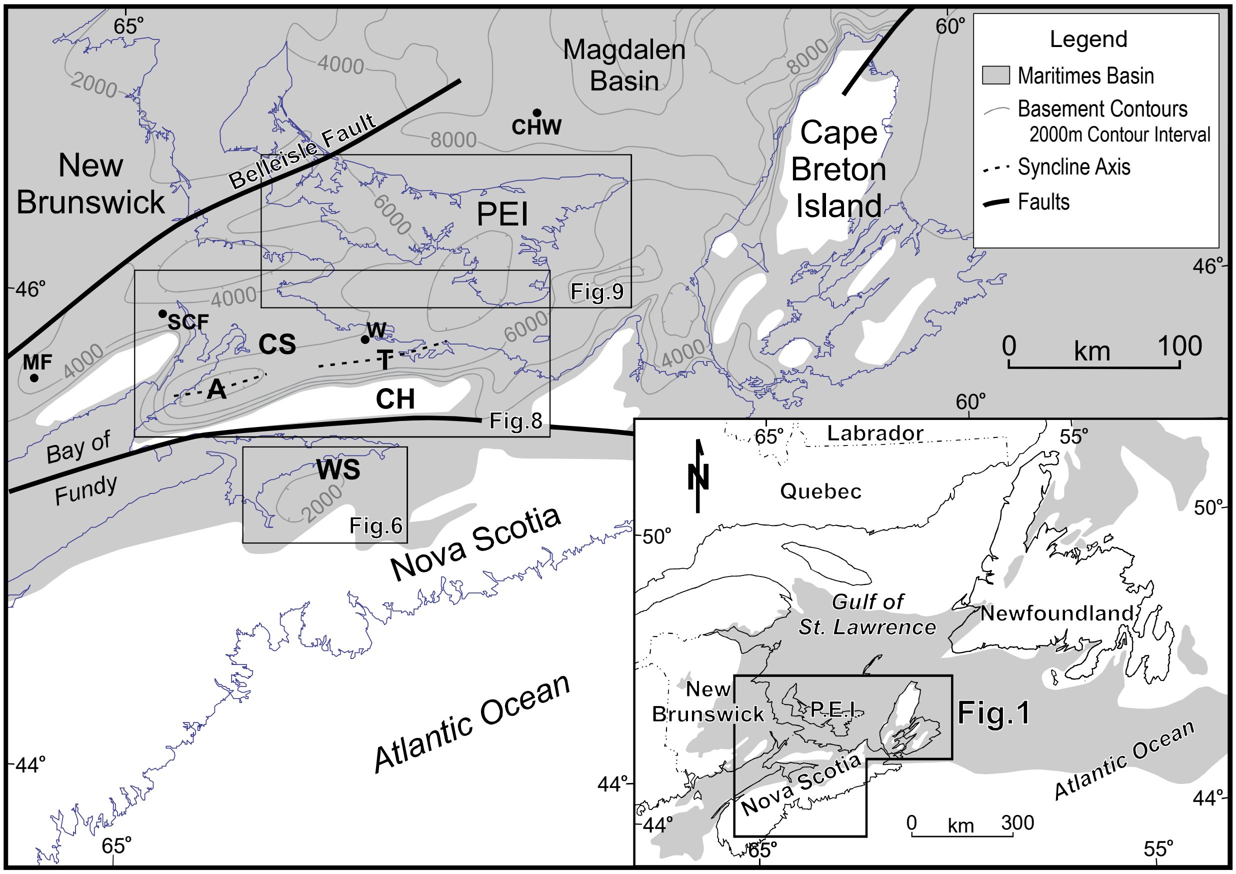

Figure 1. Location map showing area of Maritime Basin outcrop, depth to basement contours and major structural features. A–Athol Syncline; CH–Cobequid Highlands; CHW–Cable Head E-95 well; CS–Cumberland–Sackville Sub-basin; MF–McCully Field; SCF–Stoney Creek Field; T–Tatamagouche Syncline; W–Wallace; WS–Windsor–Kennetcook Sub-basin.

Formation is characterized by the *Raistrickia saetosa* spore zone (Utting et al. 2010). Lithologically similarrocks that are time-equivalent to the younger Joggins Formation are reported in boreholes near Wallace, Nova Scotia (Fig. 1), and formally described as unclassified Cumberland Group (Ryan *et al.* 1991), but often mapped as "Boss Point" (e.g., Keppie 2006). The burial depth of the lower Cumberland Group is highly variable due to the structural complexity of the sub-basin. In the deepest parts of the Athol and Tatamagouche synclines there may be more than 8 km of Boss Point Formation and younger sediments while over the anticlines equivalent strata are typically absent (Ryan 1985).

The third potential play lies on Prince Edward Island, far from the margins of the Maritimes Basin (Fig. 1). Prince Edward Island lies within the Magdalen Basin, a large depo-centre within the Maritimes Basin (Bradley 1982; Durling and Marillier 1993), southwest of the deepest parts of the basin where sediment thicknesses can exceed 15 km (Atkinson *et al.* 2020). Carey *et al.* (2023) viewed the rocks of the Morien and Pictou groups beneath Prince Edward Island as having the greatest potential for GCS. This assessment was based primarily on the presence of sand-rich units at depths (1000–2000 m), where regional work by Bibby and Shimeld (2000) had shown relatively high porosities were common. Broadly speaking strata dip eastward regionally, although there is considerable local relief adjacent to faults in western Prince Edward Island (Fig. 1). These variations reflect compressional deformation during the Mississippian and are related to structures in southeast New Brunswick such as the Belleisle Fault, which extends underneath Prince Edward Island (Durling and Marillier 1993). Cumberland Group and younger rocks in the Magdalen Basin are relatively undeformed; variations in elevation and thickness are controlled by differences in thermal subsidence and compaction of underlying material (Atkinson *et al.* 2020). Although these rocks are widespread in the Maritimes Basin, in much of Nova Scotia and New Brunswick they are likely too shallow for supercritical injection and lack an obvious potential seal (Carey *et al.* 2023). In Prince Edward Island, the burial depth is greater and a widespread mud-rich unit, the Naufrage Formation (Giles and Utting 1999), could provide a seal. The Port

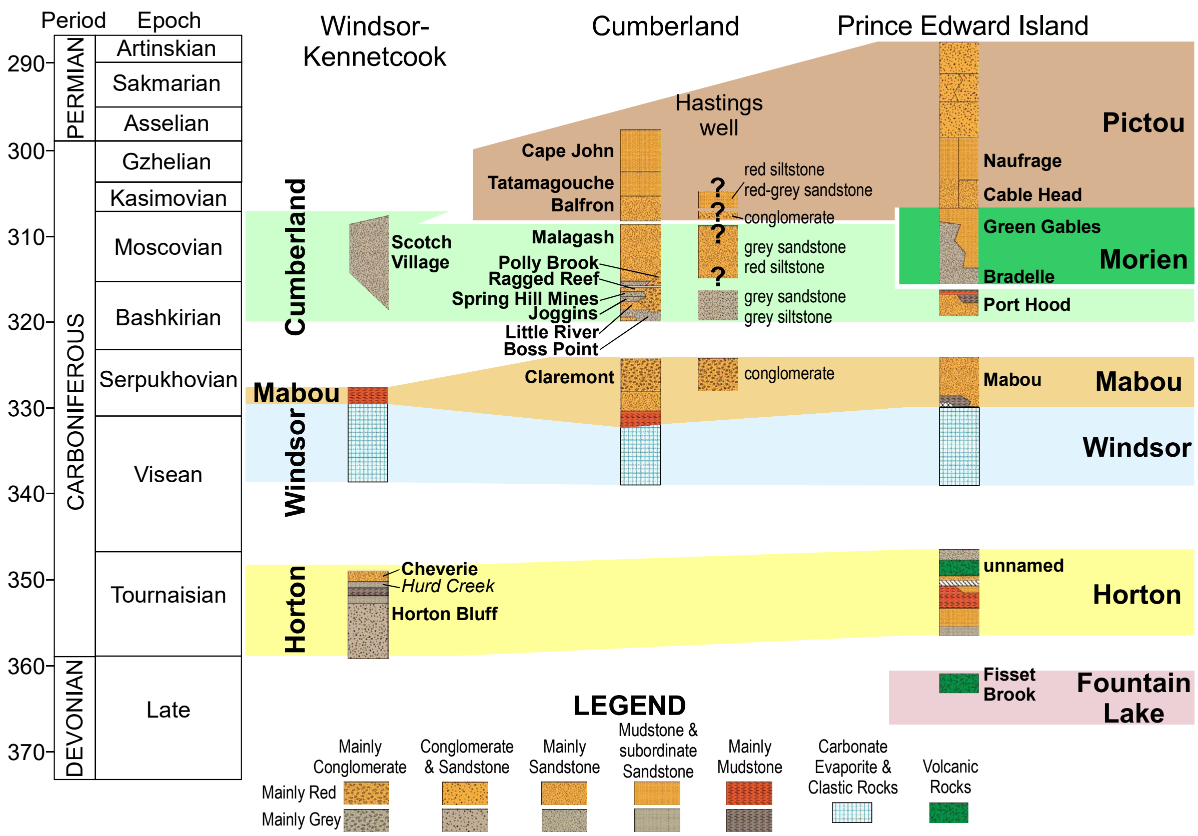

Figure 2. Stratigraphy of the Windsor–Kennetcook Sub-basin, Cumberland–Sackville Sub-Basin and Prince Edward Island (modified from Waldron *et al.* 2017). A column representing the lithologies in the Hastings well is included with a possible correlation. Note that the upper conglomeratic interval is tentatively associated with the unconformity at the base of the Balfron Formation but could be as old as the Ragged Reef Formation.

Hood Formation (a correlative unit to the Boss Point Formation) in the underlying Cumberland Group may be prospective elsewhere in the Maritimes Basin, but is likely too deep to have significant porosity in eastern Prince Edward Island and is thin to absent in western Prince Edward Island (Atkinson *et al.* 2020; Giles and Utting 1999).

DATA SOURCES AND METHODS

Data sources

Geologic data (lithologies, porosities and permeabilities) for the Windsor and Cumberland–Sackville Sub-basins were obtained from published outcrop studies, well history reports, and the logs and core analysis data summarized in the Nova Scotia Onshore Atlas (Nova Scotia Department of Energy 2017a, 2017b; Petrel Robertson Consulting ltd 2017). For Prince Edward Island, data were derived from well logs, core analysis and sample descriptions contained in published sources (Bibby and Shimeld 2000; Chi *et al.* 2001; Giles and Utting 1999; Opdyke *et al.* 2010) and the internal files compiled by the Geological Survey of Canada for the Marine Conservation targets program (e.g., Atkinson et al. 2020).

No new seismic mapping was undertaken for the project. For the Windsor Sub-basin, seismic mapping was based on the interpretation of Bianco (2013) and time-depth maps from Nova Scotia Department of Natural Resources and Renewables (2017). These maps were modified using results of Waldron *et al.* (2010) and surface geologic maps. For the Cumberland–Sackville Sub-basin, mapping was based on time structure contours from Martel (1987), Eggleston (2017), and Durling (2023). A description of contour map compilation and depth conversion are provided in Carey *et al.* (2023). For Prince Edward Island, regional depth surfaces from Atkinson *et al.* (2020) were used.

Petrophysical analysis

A variety of tools measuring rock properties are typically employed when drilling wells for petroleum exploration and development. Logs created during these activities were a key source of information for this study and were used to assist in recognizing stratigraphic markers, identifying lithologies and, through petrophysical analysis, estimating porosity. Although a variety of logs can be used to estimate porosity, three common logs used for porosity estimation were acquired in most wells drilled in the past sixty years in the Maritimes Basin: the density log, the sonic log, and the neutron log. Petrophysical calculations of digital logs were undertaken with Logview++™ software.

Total porosity estimation

Total porosity in this study was estimated using density and sonic logs. Density logs estimate the density of electrons in the surrounding formation using a radioactive source that emits gamma rays and a detector that measures the amount of Compton scattering resulting from collisions with electrons in the formation (Schlumberger 1989). As the scattering intensity correlates closely to the bulk density of the surrounding rock, the total porosity of the rock can then be estimated through the following equation:

$$\phi = \frac{\rho_b - \rho_m}{\rho_g - \rho_f}$$

where ϕ is porosity, ρ_b is bulk density from the log, ρ_g is the density of the rock (if it had no pores), and ρ_f is the density of the fluid in the pores (Schlumberger 1989). Where sufficient core analysis for a formation was available, the average reported grain density was used for ρ_m, otherwise the density of quartz (2650 kg/m^3) was used, as quartz is commonly a major constituent of sandstones. An approximate density for water (1000 kg/m^3) was assumed for the pore fluid density. Sonic logs measure the time it takes sound to pass through the formation from an emitter to a detector and use the difference between the acoustic velocity in solid rock and pore fluid to estimate porosity through the Wyllie time-average equation:

$$\phi = \frac{t_l - t_m}{t_f - t_m}$$

where ϕ is total porosity, t_l is the time from the emitter to the detector divided by the distance from emitter to detector (inverse of acoustic velocity), t_m is the inverse of sonic velocity for the formation if it had no pores, and t_f is the inverse of sonic velocity for the pore fluid. Total porosity was also determined from the sonic log, assuming an acoustic velocity of 5540 km/s (the speed of sound in quartz for the dry formation and 1610 km/s in pore fluids (Schlumberger 1989).

Neutron log porosities were not used in the petrophysical analyses presented here because they were found to significantly overestimate porosity when compared to core analyses. Neutron logs commonly overestimate effective porosity in sandstones with significant clay content due to bound water in the clay minerals (Schlumberger 1989). Substantial clay contents are common in sandstones of the Maritimes Basin (Bibby and Shimeld 2000; Chi *et al.* 2001).

Effective porosity and permeability estimation

Ineffective porosity is pore space in the rock as measured by the logs that is not accessible for fluid migration either because the pore throats are too small or the pores are isolated (not connected to a network). A common technique for reducing the total porosity read by logs to an *effective* porosity value is to assume that ineffective porosity is a result of the clay content in the rock matrix (Schlumberger 1989). The natural radioactivity of the formation as measured by the gamma-ray log is a common tool for estimating the clay content (or shale volume, V_{sh}).For all formations reviewed, shale volume (V_{sh}) was estimated from the gamma-ray log using a linear interpolation between a clean sand line (V_{sh}=0), determined from the radioactivity of clean sandstones (as noted in sample logs) in the formation and a shale line (V_{sh}=1) determined from the radioactivity of shales noted in sample logs. Estimation of shale volume from gamma-ray logs can be inaccurate in areas with sands rich in radioactive minerals such as potassium feldspars (Schlumberger 1989). However, comparison of calculated V_{sh} estimates to sample logs in the intervals of interest showed that the gamma-ray tool was adequate for identifying sands in these formations. Effective porosity (ϕ_e) was then calculated as:

$$\phi_e = \phi\ (1 - V_{sh})$$

where ϕ_e is effective porosity and ϕ is the total porosity. Effective porosities from logs were compared to porosities determined from core analysis, where possible, to verify that the estimated porosities are reasonable. Permeabilities were estimated from the relationship between porosity and permeability derived from core analysis.

RESULTS

The Horton Bluff Formation in Windsor–Kennetcook Sub-basin

Reservoir: the Hurd Creek Member, Horton Bluff Formation

Carey *et al.* (2023) identified sandstones of the Hurd Creek Member as a potential reservoir for GCS in the Windsor Sub-basin. The Hurd Creek Member is the uppermost part of the Horton Bluff Formation and consists of coarsening upward cycles interpreted as lacustrine sandstones (Martel and Gibling 1996). Cameron (2018) concurred with the interpretation of prograding shoreline successions but found ichnological evidence of marine influence. Quartz-rich sands with a characteristically low radioactivity (<45 API) are commonly seen in the uppermost Hurd Creek Member (Cameron 2018). Core analysis porosity and permeability measurements from the Coolbrook well indicate low to moderate permeability. Thirty-seven full-diameter core samples with a total length of 5.4 m were tested, yielding an average porosity of 7.6% and a median permeability of 0.6 mD, with values up to 11.6% porosity and 25.2 mD (Devon Canada 2003). Crossplotting these results yields a best-fit line suggesting permeability values of 1 mD at ~8% porosity and 10 mD at ~12% porosity (Fig. 3). Some variability in permeability is related to grain size rather than porosity. Core 12 in the Coolbrook well (Fig. 4) intersected coarse pebbly sandstone with permeabilities of up to 25 mD, while the highest permeability from core 15 (Fig. 4) was 7 mD in a fine-grained sandstone with slightly higher porosity. Effective porosities estimated from petrophysical analysis for the upper part of the Hurd Creek Member are shown in Fig. 5. The petrophysical analysis was verified by comparison with the core analysis porosities (Devon Canada 2003). The r^2 value was 0.62, and the standard error was 1.7%; on average the petrophysics underestimated the porosity by 0.4%. This underestimate may be related to higher than typical grain densities in the formation increasing the sonic transit speed relative to quartz. Average grain density for the samples from this interval was 2687.5 g/cm^3, possibly due to siderite, which is noted in the sample descriptions (Devon Canada 2003). The Coolbrook well lies in a region identified by Carey *et al.* (2023) as having high prospectivity for suitable reservoir for carbon storage. This assessment was based on the expectation that the Hurd Creek Member would be at an adequate depth for supercritical CO_2 injection, but sufficiently shallow that adequate reservoir quality was relatively likely. Past studies in the Maritimes Basin have noted that porosity and permeability in all the sandstone formations tends to decrease with depth (Bibby and Shimeld 2000; Chi *et al.* 2001).

Four petroleum wells that penetrated the Horton Group have been drilled in this prospective area: the Coolbrook, the Kennetcook #1, Kennetcook #2, and Soquip Noel #1 wells (Nova Scotia Department of Energy 2017b). These four wells were placed on a cross-section to compare the upper part of the Horton Bluff Formation (Fig. 5). The top of the Horton Group (not shown) is clearly defined by the sharp transition from the carbonate rocks of the basal Windsor Group to the fluvial sandstones and red shales of the Cheverie Formation (Martel and Gibling 1996). However, identification of the top of the Horton Bluff Formation from the logs is more difficult. Criteria used to pick the top included qualitative curve matching, the thickness of the overlying Cheverie Formation, the occurrence of readings less than 45 API on the gamma ray log, a change in pattern from predominantly decreasing radioactivity upward (suggesting coarsening upward successions), and a change in sample

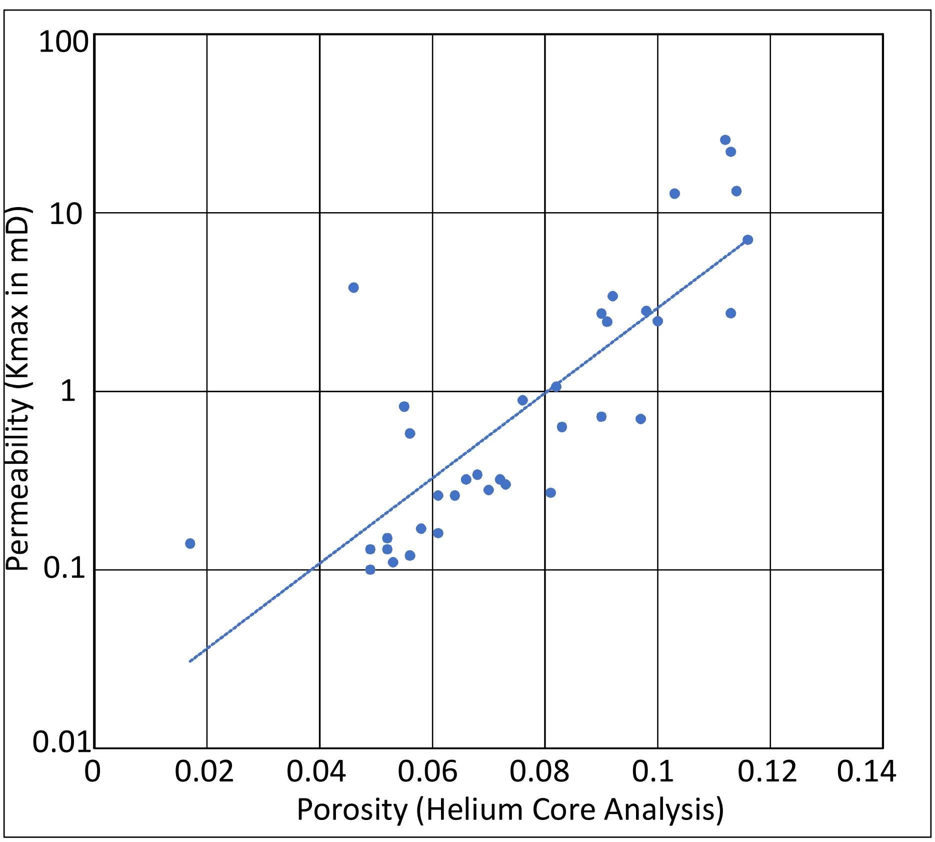

Figure 3. Porosity–permeability crossplot of core analysis data from helium injection for the Devon Coolbrook #1 well between 1035 and 1075 m. A log-linear best-fit line is superimposed on the data. Data reported by Devon Canada (2003).

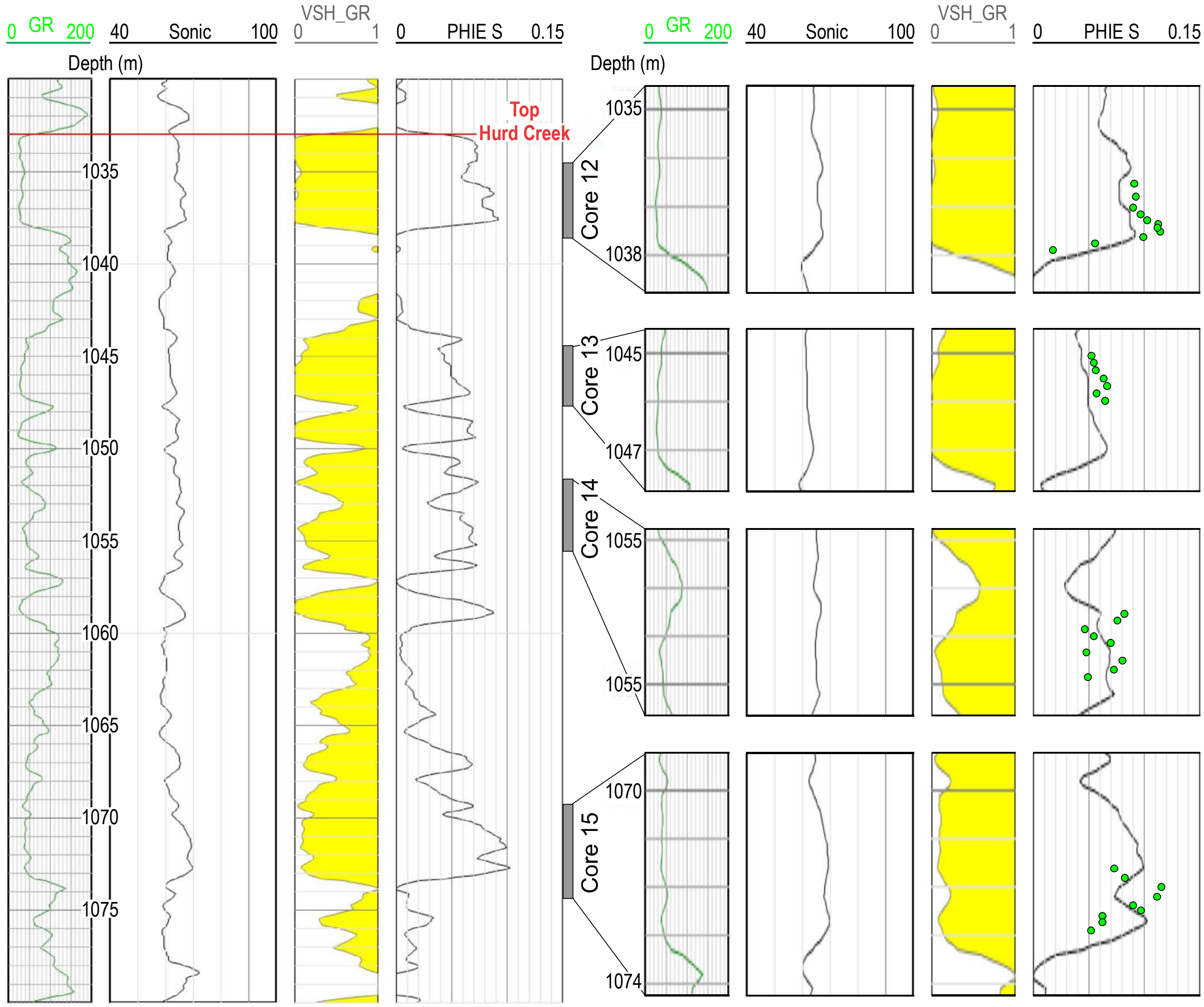

Figure 4. Well logs from the Coolbrook #1well (Devon Canada 2003) for the upper Hurd Creek Member and petrophysical results with expanded sections where cores were available. GR–gamma-ray log measured in API units; sonic log in µs/foot; VSH_GR–shale volume estimated from GR log; PHIE_S–porosity estimated from sonic log. Green points on expanded sections are core analysis porosities. All depths are measured depths from kelly bushing. See Figure 6 for location.

descriptions from predominantly red to predominantly grey mudrocks. The resulting section using the top Horton Bluff Formation as a stratigraphic datum is shown in Figure 5.

This section illustrates the difficulty in correlating strata even over distances of a few kilometres within the Windsor Sub-basin. All four wells show a similar pattern of coarsening upward sandstone intervals generally 3–5 m in thickness, interbedded with light grey siltstone and shale. The radioactivity of sandy beds tends to increase downwards. Some porosity development is seen in all four wells, but correlating individual sand beds between wells is difficult. The best porosity is in the uppermost part of the Kennetcook #2 well, which reaches 15%, but porosities are typically below 10%. Reservoir intervals are thin and, in the absence of clear markers, seem likely to be discontinuous. That said, similar stratigraphic packages in the stratigraphically equivalent McCully and Stoney Creek fields in New Brunswick (Fig. 1) have supported petroleum production.

Top seal

The Hurd Creek Member is directly overlain by the red sandstones, siltstones and shales of the Cheverie Formation (Martel and Gibling 1996). In the absence of a uniform and consistent shale interval, it is not a good seal candidate. In

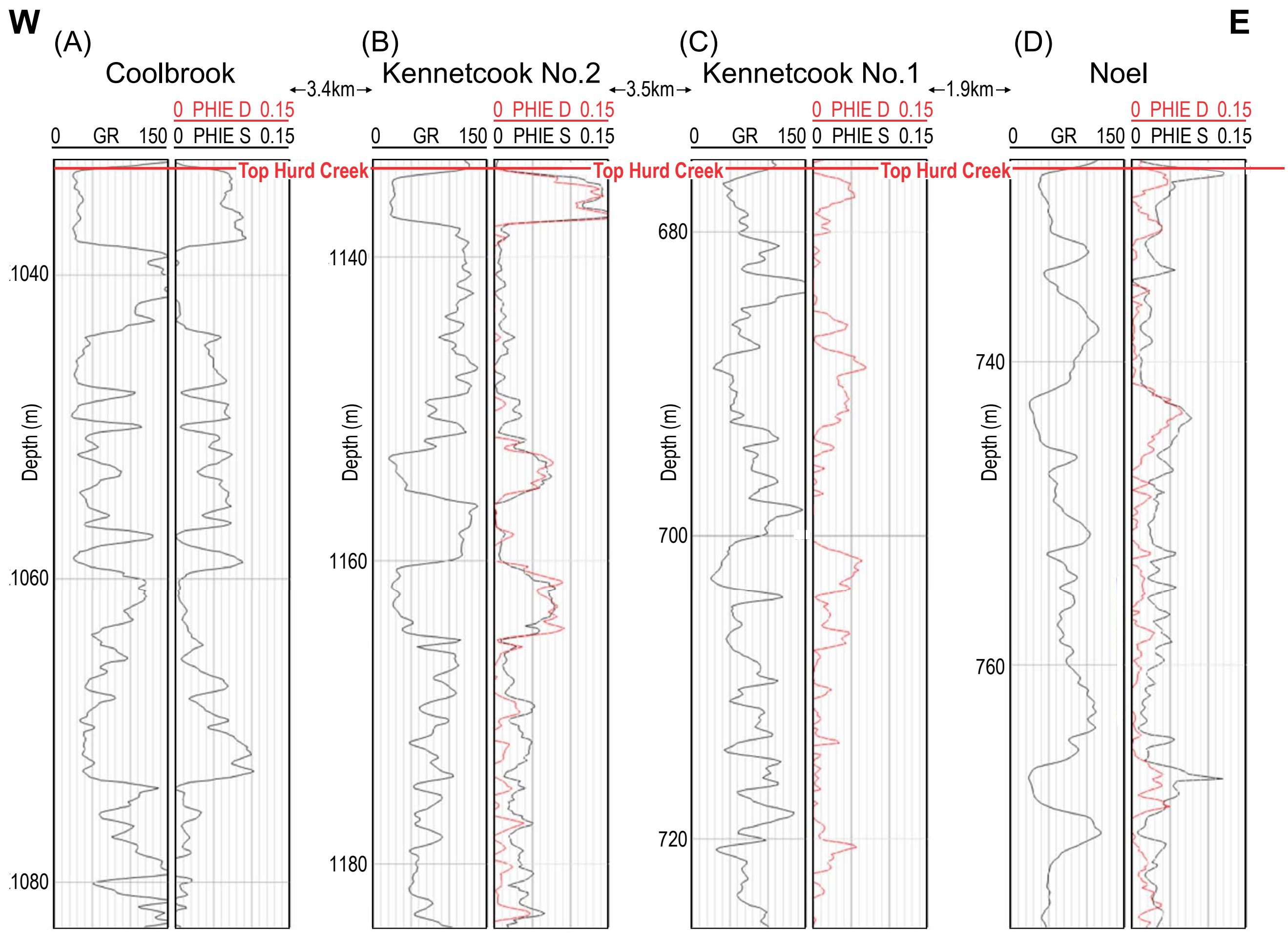

Figure 5. West to east cross-section of upper Hurd Creek Member with gamma-ray log (GR measured in API units) and effective porosity derived from density log (PHIE_D) and sonic log (PHIE_S). Log data from Nova Scotia Department of Energy (2017a). All depths are measured depths from kelly bushing. See Figure 6 for well locations.

fact, log analysis suggests that some of the fluvial sands in the Cheverie Formation have porosities of 10–15% and could be potential reservoirs, though the higher radioactivity suggests higher clay content and lower permeability than the Hurd Creek Member sands at similar porosities. No permeability data for the Cheverie Formation in the subsurface were available (Nova Scotia Department of Energy 2017b) to evaluate its reservoir quality. Outcrop data collected by Felderhof (1975) resulted in highly variable permeabilities without a clear relationship to porosity. The more effective seal preventing upward migration of CO_2 injected into the Hurd Creek Member would be the lower Windsor Group, which is characteristically rich in anhydrite and halite (Giles 1981), and which is recorded in all four wells (Nova Scotia Department of Energy 2017a). Approximately 100 m of anhydrite was reported in the Kennetcook-2 well (E. McDonald Geoconsulting Ltd. 2007) and more than 50 m of anhydrite in the Coolbrook well (Devon Canada 2003). The Windsor Group is approximately 1 km thick and is widespread throughout the Windsor Sub-basin, except where eroded near the basin edges (Waldron *et al.* 2010). Evaporite rocks have very low permeability and fracturing in the Horton Group is unlikely to propagate through these more plastic rocks. Therefore, vertical migration upward to surface is unlikely to pose a problem for CO_2 injection in the Horton Group.

Lateral seal

Horton Group rocks outcrop along the edge of the Windsor Sub-basin within 10 km of the cluster of wells illustrated in the cross-section (Fig. 5). Time structure maps (Bianco 2013) constructed from a sparse, regional seismic grid define a northeast-striking anticline in the southeast part of the Windsor Sub-basin that could prevent lateral migration (Fig. 6). The anticline is approximately 14 km long by 4 km wide with an estimated structural closure of 57 km^2; ver-

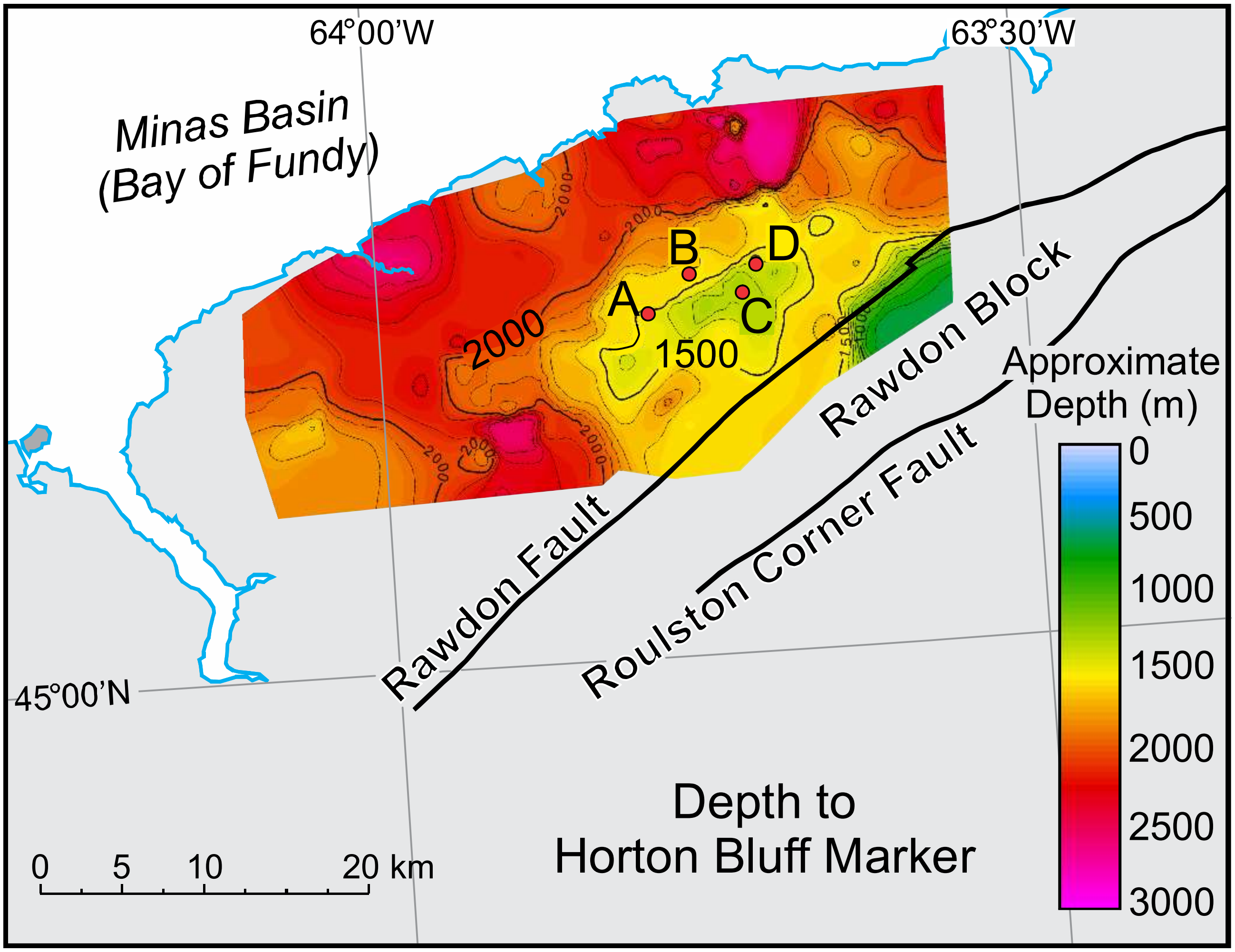

Figure 6. Depth to the Horton Bluff Marker mapped by Bianco (2013) and major structural features of the Windsor–Kennetcook Sub-basin. After Carey *et al.* (2023). Well locations: A–Coolbrook; B–Kennetcook #2; C–Kennetcook #1; D–Noel.

tical closure is estimated to be 200 m at its highest point. Note that the closure on the southeast limb of the anticline is defined by two seismic profiles approximately 15 km apart (Bianco 2013). Further, the surface location of the southerly dipping Rawdon Fault (Fig. 6) occurs adjacent to the southeast limit of structural closure, increasing to risk of potential lateral migration. Additional seismic data is required to better define the closure on the southeast limb of the structure and assess the structural implications of the Rawdon Fault.

Lower Cumberland Group sandstones in the Cumberland and Sackville sub-basins

Reservoir: lower Cumberland Group sandstones

The potential GCS reservoirs in the lower Cumberland Group are typified by the Boss Point Formation (Fig. 2), which is dominated by well-sorted fine to medium-grained grey sandstones (Ryan *et al.* 1991). The sandstones are complex bodies consisting of multiple channel cut-and-fill successions up to 120 m in thickness (Plint and Browne 1994). These thick sandstone units are separated by thinner intervals of mudstone that comprise 20–25% of the section forming repeated cycles termed megacycles by Plint and Browne (1994) which can be traced for more than 12 km in outcrop.

These sandstones have been interpreted as braided stream sands deposited in large valley systems (Rygel *et al.* 2015). Rygel *et al.* (2015) suggested that these river systems had a predominant northeastward flow direction, based in part on the regional work of Gibling *et al.* (1992) for the upper Carboniferous and the Permian. However, considerable variation in flow direction is observed in the Boss Point Formation itself (Browne and Plint 1994). Local anomalous flow directions near salt-cored anticlines in the

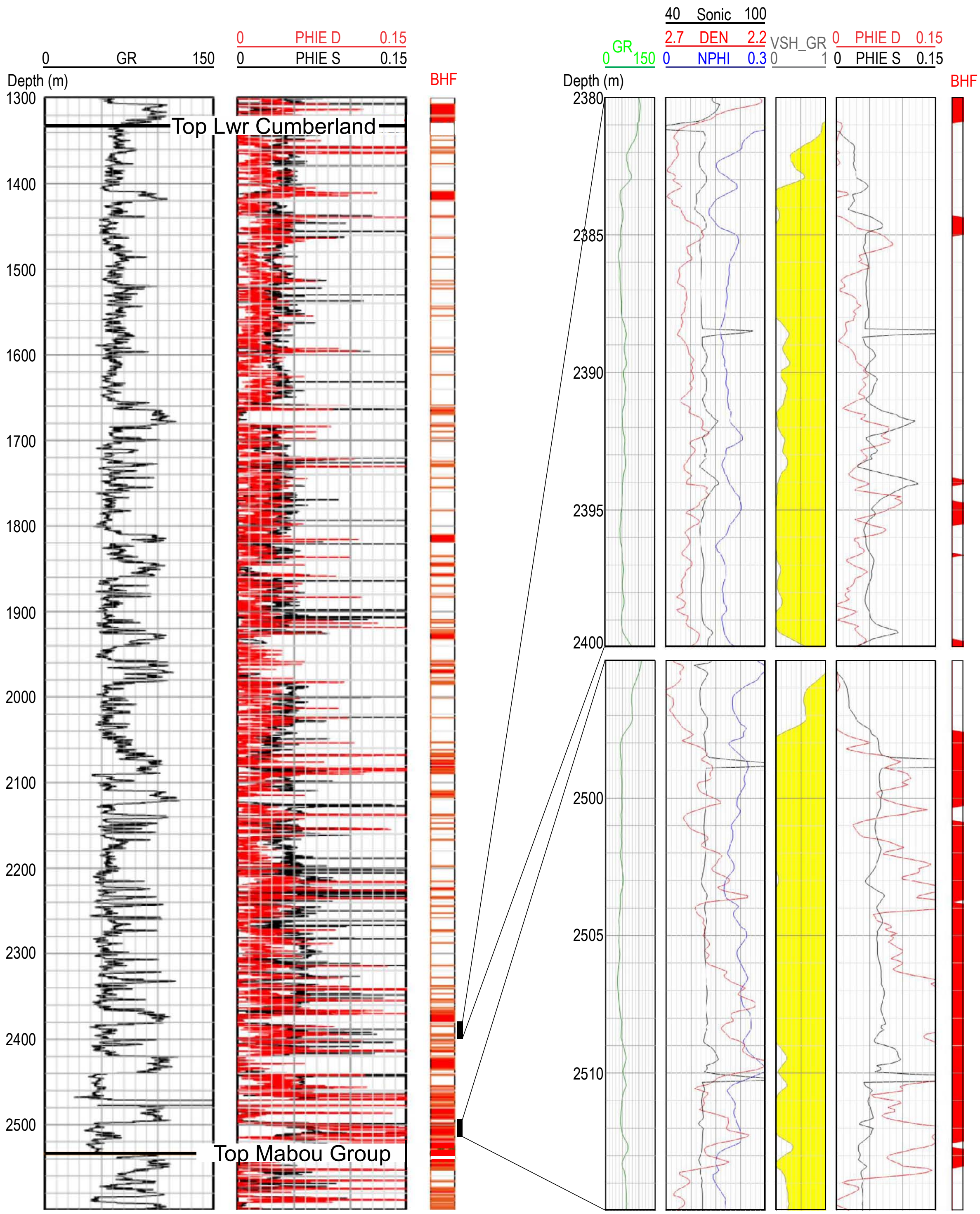

Figure 7. Selected well logs for the lower Cumberland Group interval in the Hastings #1 well. The left side of figure shows gamma-ray log (GR) measured in API units, estimated porosity from density (PHIE_D) and sonic (PHIE_S) logs and a bad hole flag (BHF) column indicating where the density correction reported was greater than 0.1 g/cm^3. The right side shows expansion of two sections with gamma-ray log (GR in API units), sonic log (µs/foot), density log (DEN in g/cm^3), neutron-porosity log (NPHI in %), and the effective porosity calculated from density (PHIE_D) and sonic (PHIE_S). Note erratic behavior of neutron and density logs over bad hole sections. Log data from Nova Scotia Department of Energy (2017a). All depths are measured depths from kelly bushing.

Cumberland–Sackville Sub-basin have been attributed to salt tectonics during deposition (Ryan 1985; Rygel *et al.* 2015), or rotation during transport along strike-slip faults (Browne and Plint 1994).

The distribution of these rocks is well-known from outcrop, but poorly known from subsurface. Most resource exploration companies drilling in the area were either looking for coal-bed methane in the overlying units and did not penetrate the Boss Point Formation, or they were interested in salt or Horton Group plays and drilled the salt anticline areas where the Boss Point Formation is absent. A review of petroleum wells with logs available from Nova Scotia Department of Energy (2017a) revealed only one subsurface section of confirmed lower Cumberland Group sandstones. the Gulf Hastings #1 well from ~1330 to 2650 m records a grey sandstone-dominated section similar to the Boss Point Formation (Rygel *et al.* 2015; Fig. 7). However, a recent review of the palynological data in Souaya (1975) by P.S. Giles (personal communication 2023), indicates that most of this section is younger than the Boss Point Formation, and likely correlative with the overlying Joggins and Springhill Mines formations. Petrophysical analysis of the well proved difficult due to hole problems (Fig. 7); the hole diameter was highly variable, which leads to poor contact between logging tools and the formation. As a result, the density and neutron log measurements are unreliable. due to caving leading to unreliable density and neutron log measurements Figure 7 shows a column (BHF for "bad hole flag") that indicates where log measurements are suspect. Consequently, the sonic log was judged more reliable than the density log because the former tends to read deeper into the borehole side wall (though still quite noisy). the sonic log suggests that the sandstone has generally low porosity (typically ~5%), consistent with borehole cuttings descriptions noting the absence of visible porosity (Gulf 1975). the best interval might be from 2495–2535 m, where porosities of 7–8% (based on sonic log) were common (Fig. 7). Nevertheless, hole conditions in this interval were very poor. there was a thin (<1 m) unconsolidated interval reported, that resulted in the drill stem filling with water at 2638 m (Gulf 1975), indicating thin streaks of porosity may occur. No core analysis was available to validate this petrophysical interpretation.

There is very little information on the reservoir characteristics of lower Cumberland Group sandstones (Fig. 2). Although several of articles have been published on the interval, they have focused on the sedimentary processes (e.g., Plint 1986; Browne and Plint 1994) and their climatic or tectonic implications (e.g., Browne and Kingston 1993; Ielpi *et al.* 2014). Three sidewall cores of sandstones from this interval were collected by the operator, but not analyzed (Gulf 1975). Felderhof (1975) reported two porosity and permeability measurements from Wallace Quarry in an area mapped as the Boss Point Formation. These samples yielded porosities of 15.5 and

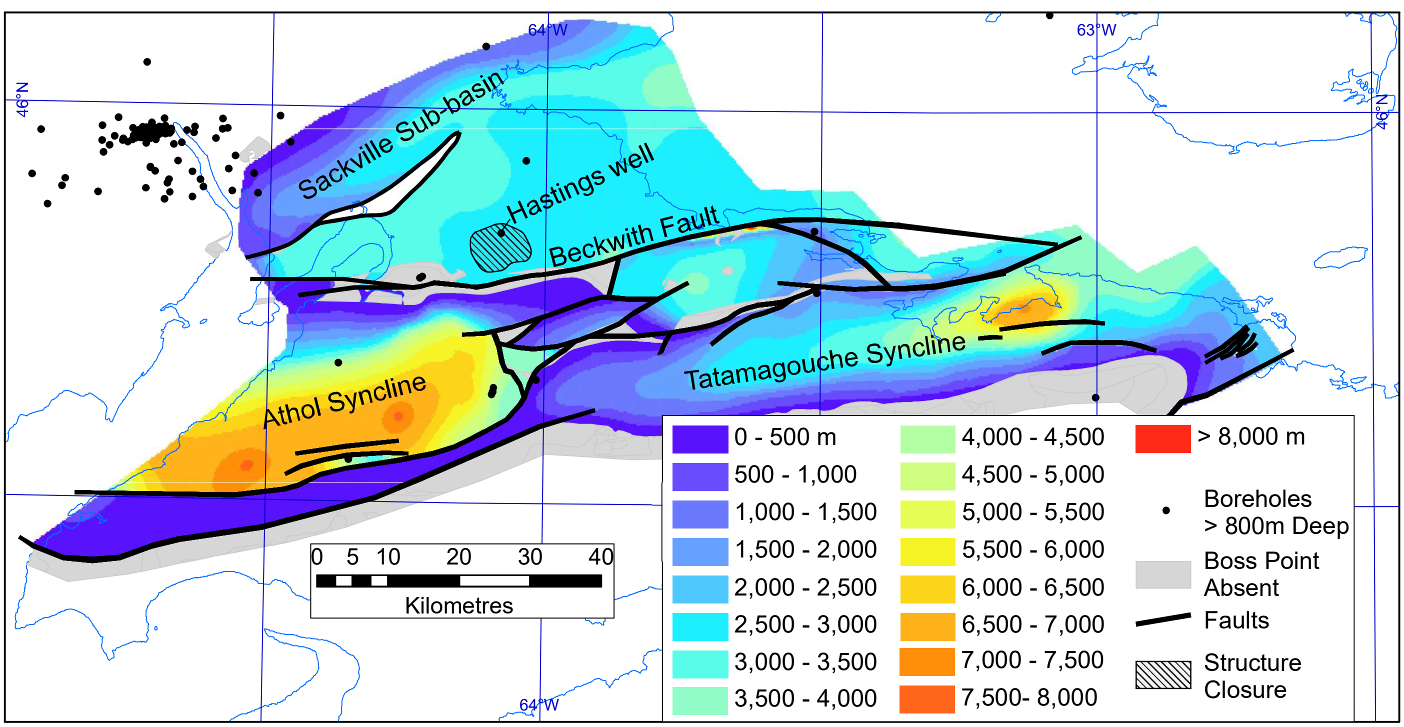

Figure 8. Structure map of the base of the Cumberland Group after Durling (2023), showing key structural features of the Cumberland–Sackville Sub-basin.

17.0% and permeabilities of 2.06 and 4.18 mD. If this is typical of the behavior of these rocks, injectivity would likely be low at the porosities seen in the Hastings well, but the Wallace Quarry samples are described as fine-grained and argillaceous. A medium-grained sandstone with less clay matrix might perform better at lower porosities.

Seal: mudprone Cumberland Group rocks

In the Athol Syncline (Fig. 1), the Boss Point Formation is overlain by the Little River, Joggins, and Springhill Mines formations (Ryan *et al.* 1991). The Little River Formation is described by Calder *et al.* (2005) as a 635 m thick interval at the Joggins exposure consisting primarily of red mudrock with small, channelized sandstone bodies up to 6 m thick. The Joggins Formation is over 900 m thick and of similar lithology but contains significant volumes of coal and limestone beds (Calder *et al.* 2005). The Springhill Mines Formation consists of interbedded sandstone and sideritic mudstone with abundant coal seams up to 4 m thick (Rygel *et al.* 2015). These three heterolithic formations may impede vertical migration of CO_2 effectively. At the Hastings well, the interval from ~600 m to 1350 m is heterolithic with sandstones interbedded with siltstones, carbonaceous shales and minor coal that is also likely to impede upward movement of CO_2. Sandstones are a very minor component of the interval from 1060 to 1260 m (Gulf 1975).

In some parts of the Cumberland–Sackville Sub-basin, particularly around Springhill, the Boss Point Formation is overlain by a polymictic conglomerate containing Boss Point Formation cobbles known as the Polly Brook Formation (Ryan *et al.* 1991; Rygel *et al.* 2015). The Polly Brook Formation thins rapidly away from Springhill. Rygel *et al.* (2015) suggests the interval may have developed from localized erosion and re-deposition around salt-cored anticlines. The Polly Brook Formation is likely to pose a seal risk where present.

Trap

The Hastings well was drilled on a basement cored structural high identified as the Hastings Uplift (Howie 1986; Durling 2023). The lower Cumberland Group rocks are draped over the Hastings Uplift and form a structural closure in the vicinity of the Hastings well (Fig. 8). The area of the closure measures approximately 43 km^2 with maximum vertical height of approximately 250 m. The closure is located roughly 3.5 km north of the Beckwith Fault, a southerly dipping reverse structure (Durling 2023). The proximity of the closure to the Beckwith Fault presents some trap and seal risk. However, the map presented in Figure 8 defines structure based on seismic mapping of a horizon at roughly 1250 m depth in the Hastings well, whereas the closure is defined on a horizon at approximately 2060 m depth. Younger strata (above 1900 m in the Hastings well) are folded upward in a drag-fold associated with the south-over-north movement on the Beckwith Fault (Durling 2023), whereas older (deeper than 1900 m in the well) follow the contours of the underlying basement high. These older strata plunge downward adjacent to the fault and appear little affected by the Beckwith Fault.

Pennsylvanian sandstones in Prince Edward Island

Reservoir: sandstones of the Bradelle, Green Gables and Cable Head formations

Bradelle Formation: The Bradelle Formation is a sand-dominated interval in the lower Morien Group (Fig. 2) characterized by thick grey sandstones with multiple channel incisions interbedded with grey siltstones (Utting *et al.* 1989). In gross character, it resembles the lower Cumberland Group sandstones in the Cumberland–Sackville Sub-basin but is younger and may be less quartzose. Petrographic analysis of eight samples from the Bradelle Formation in the Spring Valley well (using the stratigraphy of Opdyke *et al.* 2010) averaged 42% detrital quartz, 34% lithic grains, and 6% detrital feldspar (Chi *et al.* 2001), the remaining 18% consisted of pore space, cements and matrix. The unit is widespread throughout the Gulf of St. Lawrence and can exceed 500 m in thickness (Giles and Utting 1999; Atkinson *et al.* 2020).

Petrophysical analysis for the Bradelle Formation was validated by comparison with core analysis (Fig. 9). Density porosity was calculated using an average grain density of 2684 g/cm^3 based on all available core analyses for the southern Gulf of St. Lawrence. The mean porosities from core were similar to those determined from effective porosity estimates using both sonic and density logs, suggesting that the petrophysical results are reasonable.

A cross-section through the upper Bradelle Formation in four wells on Prince Edward Island illustrates the properties of the interval (Fig. 10). These wells were selected because they had useful logs for petrophysical analysis throughout the Morien and Pictou groups (Fig. 2) and provide reasonable geographic coverage of the island (Fig. 11). In addition, two wells (Naufrage and Tyrone) had core analysis results that could be used for calibration, whereas the Green Gables wells are close to the Spring Valley well (~20 km away) where detailed petrography results are available (Chi *et al.* 2001). The Spring Valley well was not included in the sections because density and sonic logs were not available.

Sandstone bodies 20–50 m thick are interbedded with grey siltstones. In the western two wells, where the formation is less than 2 km below the surface, porosities are generally greater than 5% and reach 8–10% for intervals up to 30 m in thickness (Fig. 10). The two eastern wells intersected the Bradelle Formation at depths between 2700–3100 m and have much lower porosity, rarely exceeding 5%. These four wells exemplify the typical porosity-depth patterns in the basin where porosity generally decreases

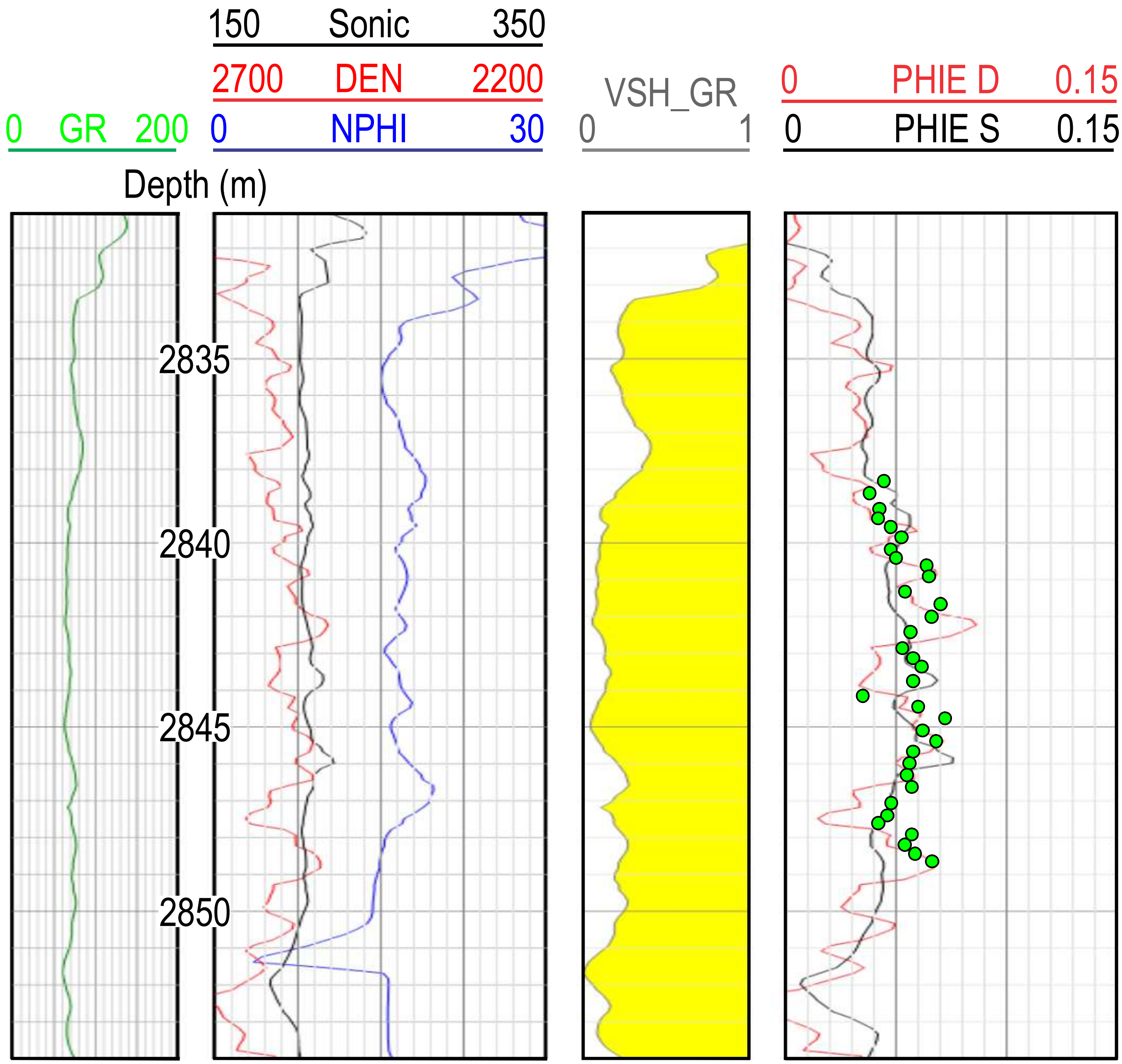

Figure 9. **Logs, petrophysical analysis and core porosities in a cored interval of the Bradelle Formation from the Naufrage well. GR–gamma-ray log (API units), Sonic log (µs/m); DEN–Density log (kg/m³); NPHI–Neutron porosity log (%); Vsh_GR–Shale volume from gamma-ray log); PHIE_D–effective porosity from density log; PHIE_S–effective porosity from sonic log. All depths are measured depths from kelly bushing.**

with depth (Bibby and Shimeld 2000). Porosities estimated petrographically from eight samples in the Spring Valley well (not shown) averaged 13% with sample depths of 1095–1250 m (Chi *et al.* 2001). The higher values could reflect preferential selection for porous sands, differences between porosities derived from core analysis and petrography, or better porosity at that slightly shallower depth.

Green Gables Formation: The Green Gables Formation consists predominantly of red mudrocks with interbedded sandstones, minor coal and carbonaceous shale (Giles and Utting 1999). Although predominantly fine-grained, sandstones within the interval can have good reservoir potential. Porosities of up to 19% and permeabilities up to 90 mD were recorded from a Green Gables Formation

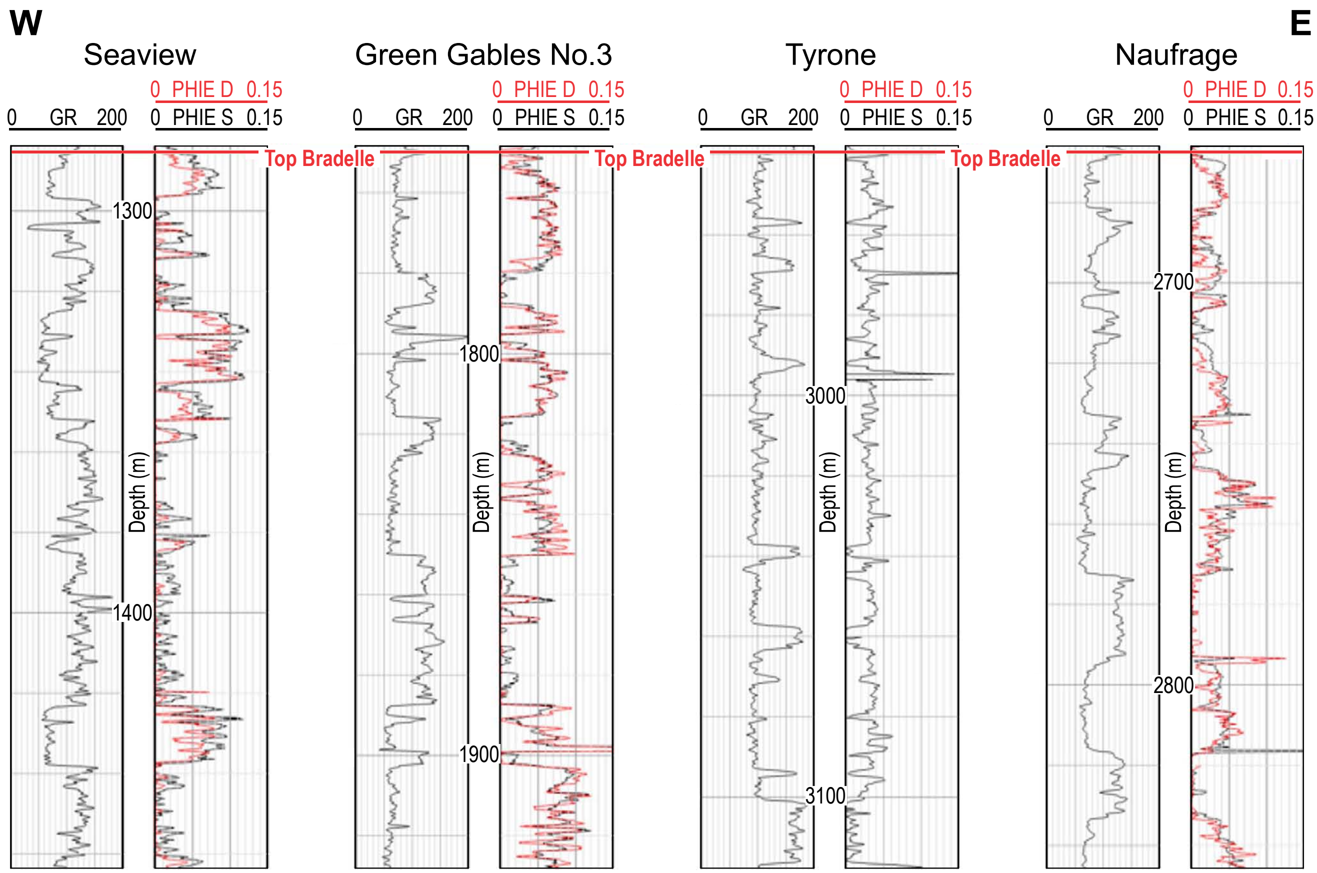

Figure 10. West to east cross-Section of the upper Bradelle Formation in four Prince Edward Island wells. GR–gamma-ray log (API units); PHIE_D–effective porosity from density log; PHIE_S–effective porosity from sonic log. The density log for the Tyrone well was excluded from the analysis due to aberrant values suggestive of a digitizing error. A grain density of 2684 kg/m^3 based on core analyses was used to calculate density porosity. All depths are measured depths from kelly bushing. See Figure 11 for well locations.

core from the Bradelle well (959–966 m depth) in the northwestern Gulf of St. Lawrence (Bibby and Shimeld 2000). The thickness of this widespread unit varies from approximately 300 m in western Prince Edward Island to more than 1200 m in the Tyrone well (Giles and Utting 1999). In the Spring Valley well, sandstones of the Green Gables Formation are similar mineralogically to the underlying Bradelle Formation, with slightly more feldspar and less quartz. Thirteen sandstone samples yielded an average of 37.6%, 10.6%, and 34.4% for the proportion of detrital quartz, feldspar, and lithic grains, respectively (Chi *et al.* 2001). Petrographically determined porosities in this interval averaged 13.2%, similar to those in the Bradelle Formation.

Petrophysical analysis was validated by comparison with core analysis from the Cable Head well (Fig. 12) in the southern Gulf of St. Lawrence (see Fig. 1 for location). The analysis completed was similar to the analysis for the Bradelle Formation, with a mean grain density of 2.692 g/cm^3. This high density for a sandstone may be the result of dolomite cement which is reported in the Cable Head well core samples. Other Green Gables Formation cores report siderite and pyrite, which may also account for the high densities apparently common in the unit (Bibby and Shimeld 2000).

A four-well cross-section from west to east through the upper Green Gables Formation in Prince Edward Island illustrates the characteristics of the unit (Fig. 13). The formation consists predominantly of fine-grained mudrocks, but sandstones up to ~20 m thick occur. In the Seaview well, where the formation is shallowest, two sand bodies in the upper part of the formation have average porosities of 10–12% and a combined thickness of about 25 m. The other three wells show generally lower porosity, but intervals a few metres thick with porosities up to 10% are inferred at nearly 1800 m depth in the Naufrage well (Fig. 12). Sandstones of the Green Gables Formation are thinner and, therefore, likely to be less laterally extensive than those of the Bradelle Formation.

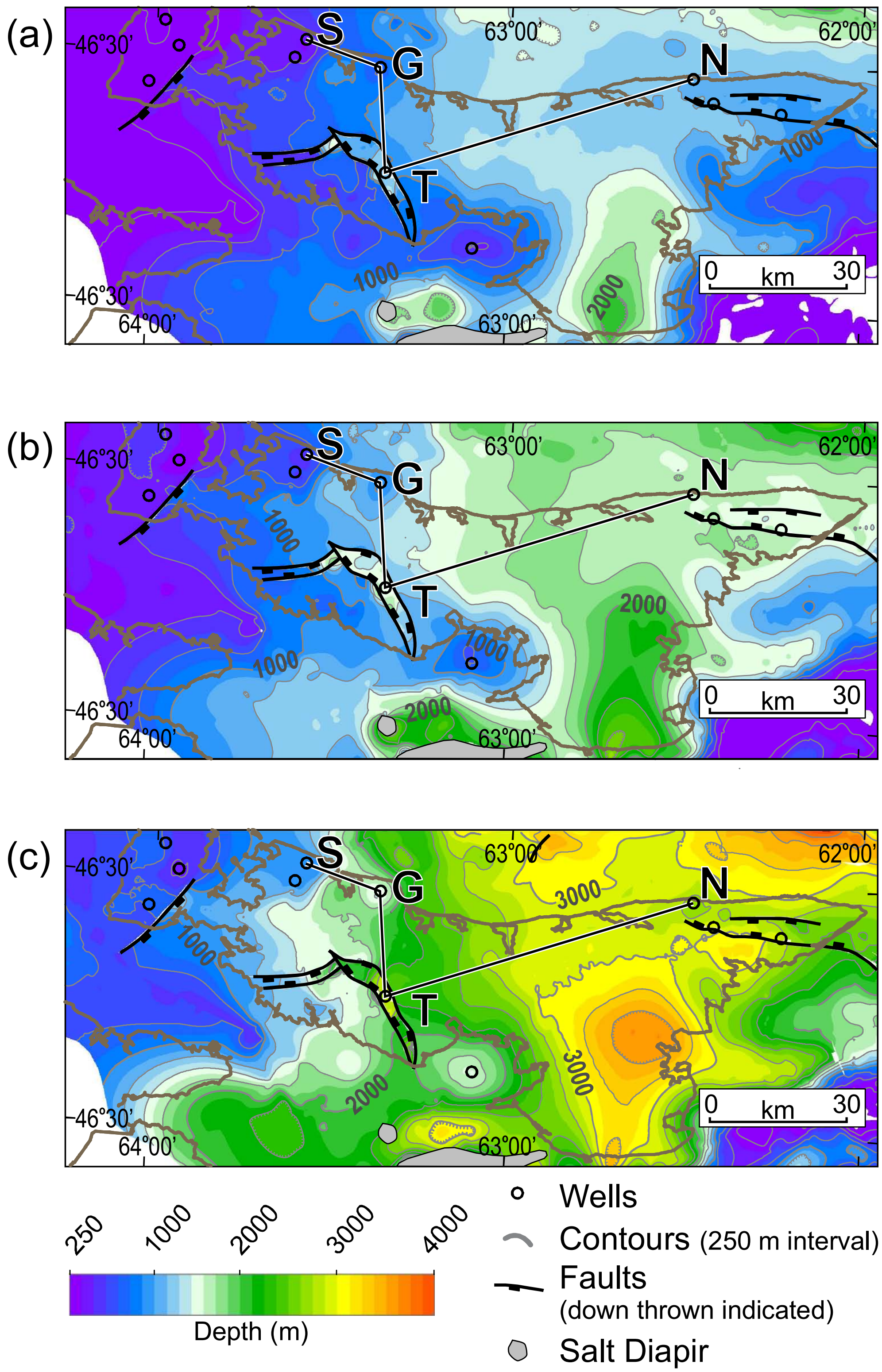

Figure 11. **Structure maps of the top Cable Head (a), Green Gables (b) and Bradelle (c) formations in Prince Edward Island and vicinity. Modified from Atkinson *et al.* (2020). Major structural features, well locations and location of cross-sections (Figs. 10, 13, and 14) indicated. S–Seaview; G–Green Gables #3 and #1; T–Tyrone; N–Naufrage.**

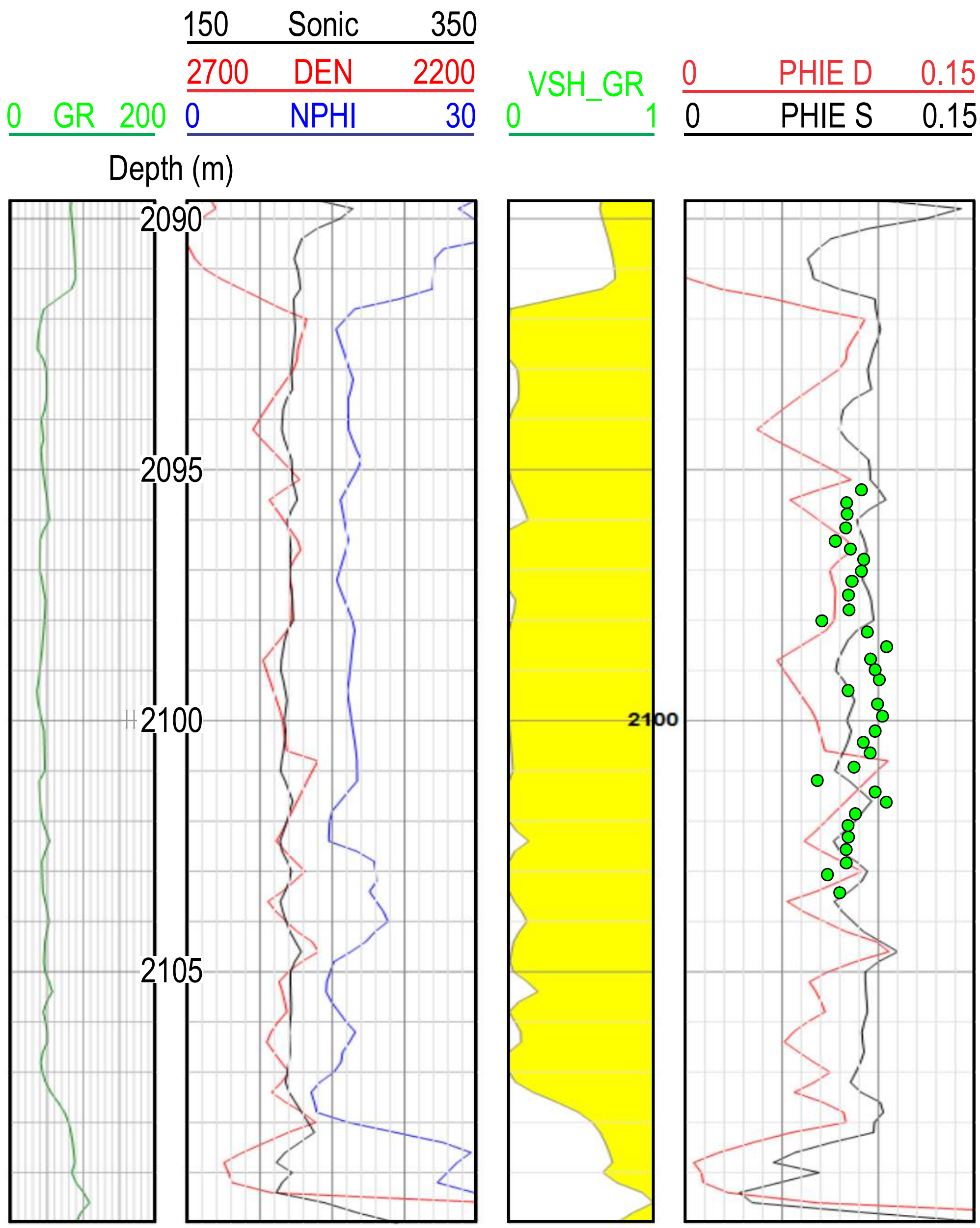

Figure 12. Logs, petrophysical analysis and core porosities in a cored interval of the Green Gables Formation from the Cable Head well (see Figure 1 for location). GR–gamma-ray log (API units); sonic log (µs/m); DEN–density log (kg/m³); NPHI–neutron porosity log (%); Vsh_GR–shale volume from gamma-ray log); PHIE_D–effective porosity from density log; PHIE_S–effective porosity from sonic log. All depths are measured depths from kelly bushing.

Cable Head Formation: The Cable Head Formation is the lowest unit of the Pictou Group in the study area and is predominantly composed of thick red sandstones representing multiple incision events intercalated with red mudrocks (Giles and Utting 1999). The predominantly red colour, and lack of coals and carbonaceous shales differentiates the Pictou Group from the underlying Morien Group. Sandstones of the Cable Head Formation are richer in feldspar than the underlying Morien Group rocks. Twelve sandstone samples yielded an average of 32.4%, 17.5%, and 28.3% for the proportion of detrital quartz, feldspar, and lithic grains, respectively (Chi *et al.* 2001). Average porosities determined from petrography were 13.0%, but that is skewed by three samples with 0% porosity; the other nine ranged from 14% to 20%.

Validating the petrophysics for the Cable Head

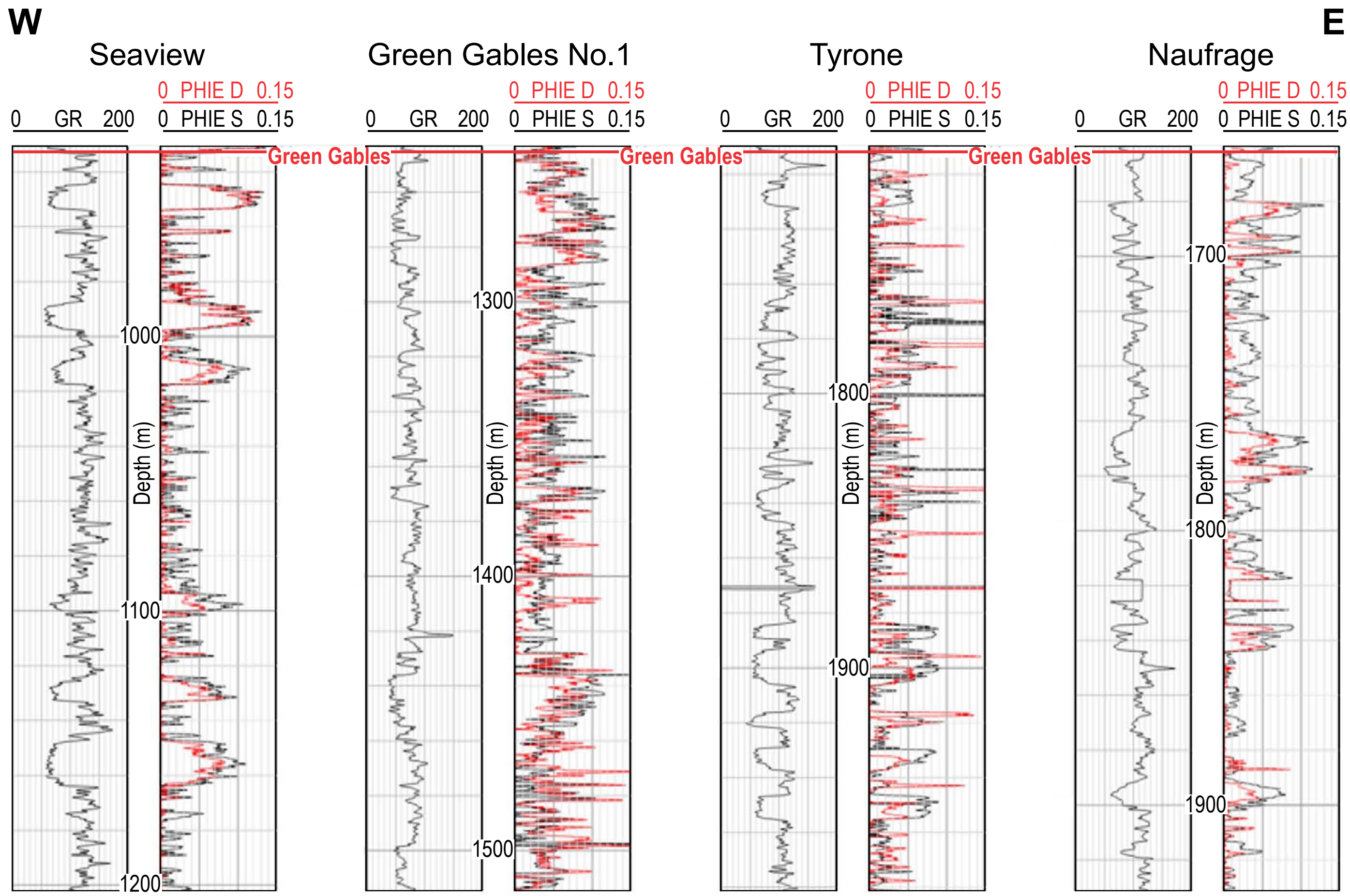

Figure 13. West to east cross-section of the upper Green Gables Formation in Prince Edward Island. GR–gamma-ray log (API units); PHIE_D–effective porosity from density log; PHIE_S–effective porosity from sonic log. Density log for Tyrone excluded from analysis due to aberrant values suggestive of a digitizing error. A grain density of 2692 kg/m^3 based on core analyses was used to calculate density porosity. Note that the Green Gables #3 well used in Figure 11 was replaced by the Green Gables #1 well because the former had only a neutron log for this interval. All depths are measured depths from kelly bushing. See Figure 11 for well locations.

Formation proved challenging. Aside from the Bradelle well in the northern Gulf, which may have substantially better reservoir properties (Bibby and Shimeld 2000), only five core analyses were available, all from the Tyrone well. Furthermore, specific sample depths were not recorded; all that is known is that the samples are from a core depth of 1490–1499.5 m. Samples ranged from 0 to 9.7% porosity, but all samples had permeabilities less than 0.2 mD. The average grain density was 2.662 g/cm^3, less than the underlying Morien Group rocks and close to the standard value for quartz sand. Based on the paucity of information, the density porosity was estimated using a value of 2.65 g/cm^3. The effective porosity of the interval from 1490–1500 m estimated from petrophysics never exceeded 7.5% when derived from sonic or 6.5% when derived from density. These values do not approach the best core porosities for the interval reported, so petrophysical estimates may be low. One possibility is that the shale estimate is excessive due to the higher proportion of feldspar in the sandstone.

Feldspar in the sands may be responsible for the generally higher (and more variable) radioactivity in the sands as shown in the four well cross-section (Fig. 14). Sandstone bodies of 20–40 m thickness are common in the interval. Despite some reduction by the shale volume calculation, the estimated effective porosities are similar to the sands in the underlying Green Gables interval. The shallow section at Seaview has sandstones with porosities typically around 10%, while the two wells in the east where the formation is deeper have lower porosities, consistent with the regional trend reported by Bibby and Shimeld (2000) in which porosity decreases with depth. There is a significant discrepancy between the sonic and density porosities in the Naufrage well, where the sonic estimate often reaches 10–15%, exceeding density porosity estimates by ~5% (Fig. 14). It is possible that the grain or cement density is greater in this well, which would reduce the density porosity more than the sonic; alternatively, there could be more clay cement or matrix present than the gamma-ray calculation predicts, which could lead to an overestimate of the sonic porosity.

Reservoir performance and distribution

Bibby and Shimeld (2000) found that the porosity–permeability relationships for upper Paleozoic sandstones in the region were similar, independent of formation assignment. A crossplot of all available porosity and permeability for rocks in the Morien and Pictou groups shows a broadly exponential trend with a notable gap in the range of 1–10 mD permeability (Fig. 15). The apparent gap in the data is likely a result of the paucity of core analysis information at depths of 1000–2000 m. Of 179 samples in the plot, only thirteen were from these depths which might be expected to have intermediate permeabilities and porosities.

The trend line shown in Figure 15 implies that rocks with porosities of 7%, 10%, and 14% are likely to have permeabilities of roughly 0.1, 1, and 10 mD, respectively. Note that the trend line generally understates the permeability at high (>12%) porosity, where permeability may approach 100 mD for higher porosity core samples. Examination of the logs in Figures 10, 13, and 14 considering the porosity permeability relationship (Fig. 15) suggests that sandstones of the Green Gables and Cable Head formations should commonly exceed 1 mD of permeability (10%

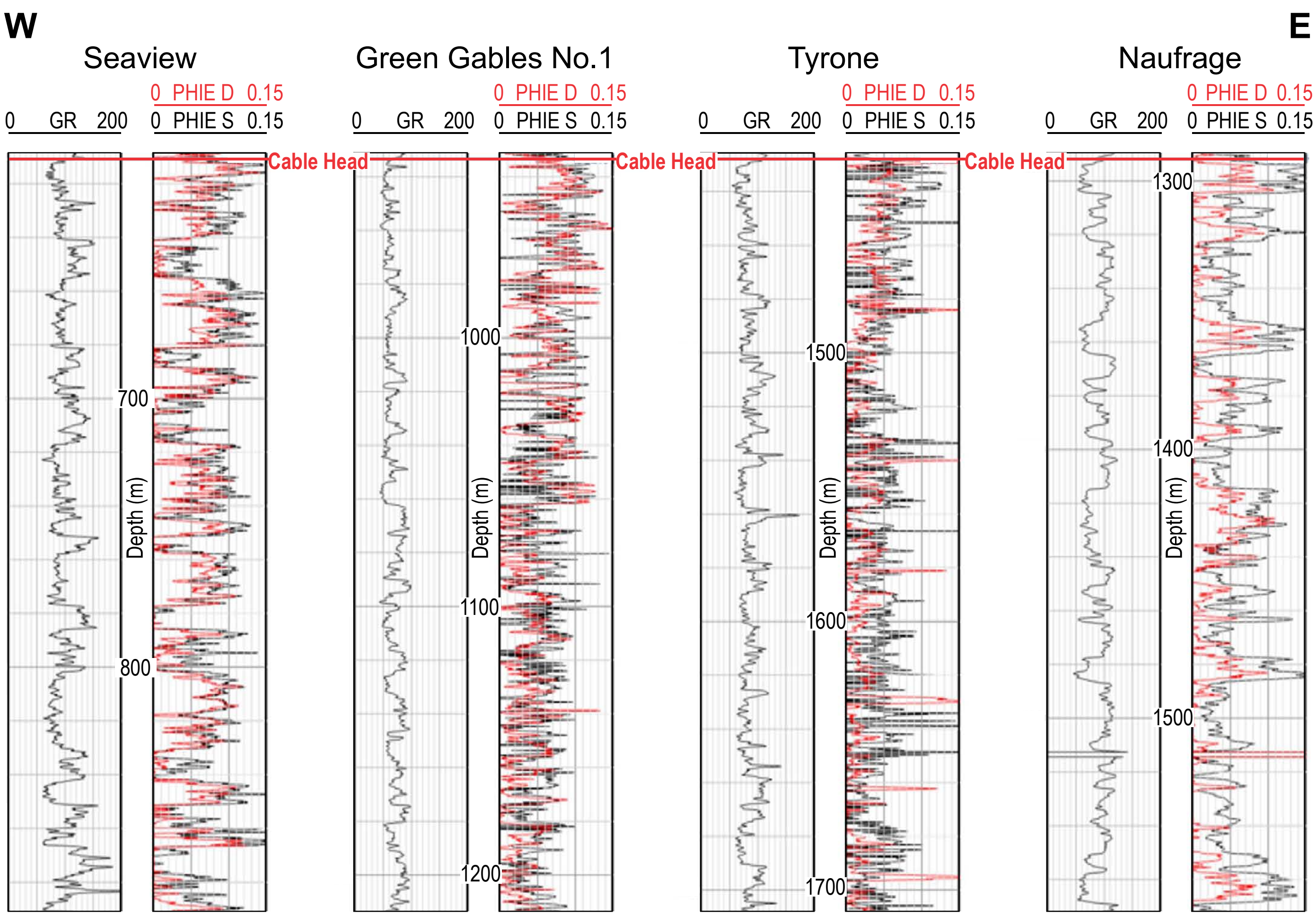

Figure 14. West to east cross-section of the Cable Head Formation in Prince Edward Island. GR–gamma-ray log (API units); PHIE_D–effective porosity from density log; PHIE_S–effective porosity from sonic log. Density log for Tyrone excluded from analysis due to aberrant values suggestive of a digitizing error. Note that the Green Gables #3 well used in Figure 11 was replaced by the Green Gables #1 well because the former had only a neutron log for this interval. All depths are measured depths from kelly bushing. See Figure 11 for well locations.

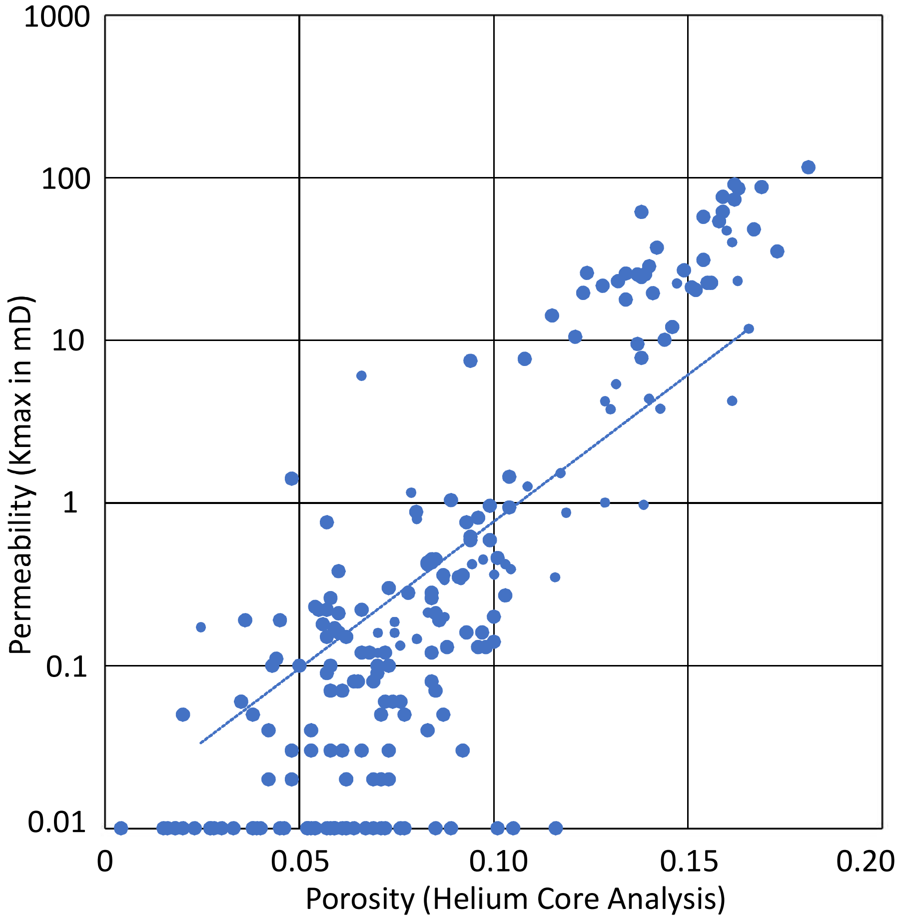

Figure 15. Core analysis porosity/permeability crossplot for all post-Mabou Group sandstones in the southern Gulf of St. Lawrence (Bibby and Shimeld 2000). Note that samples with no measurable permeability were plotted as 0.01 mD to fit on a logarithmic scale. A log-linear best-fit line is superimposed on the data.

porosity) at depths less than ~1200 m, but permeablity is likely less than 1 mD below ~2000 m where porosity is generally less than 10%. Rock reaching 12–14% porosity which would correspond to 10 mD based on the inferred permeability relationship (Fig. 15), appears to be rare in the Bradelle Formation in the four well section (Fig. 9), but that may be because the formation lies below 1300 m depth in all four wells. In view of the inferred relationship between porosity, permeability and depth, the reservoir potential for the Bradelle Formation is likely best in the west-central part of Prince Edawrd Island, in the vicinity of the Green Gables and Spring Valley wells (Fig. 11c). The depth of the formation ranges from 1000 to 2000 m in this area, accompanied by structural highs that provide opportunity for trapped closures. The Green Gables Formation occurs in the favourable depth range from 1000 to 2000 m beneath most of eastern Prince Edward Island (Fig. 11b). Structures identified in the vicinity of the Naufrage well in eastern Prince Edward Island (Atkinson *et al.* 2020) provide interesting GCS targets. Potential storage reservoirs in the Cable Head Formation occur in the eastern part of the island in depths ranging generally from 1000 to 1500 m and up to 2000 m in the southeast (Fig. 11a). Given the depth range and the potential for high porosity and permeability the Cable Head Formation is assessed as the most promising GCS target in Prince Edward Island.

Seal

The Green Gables Formation is a 300 to 1200 m thick, predominantly muddy interval that is regionally continuous. It would likely provide an adequate barrier to upward migration for reservoirs in the Bradelle Formation, or even reservoir sandstones within the lower part of the Green Gables Formation itself. Reservoir sandstones are typically separated by ~100 m thick intervals dominated by shale and siltstone. Although faulting occurs in the Mabou Group and lower parts of the section, the Green Gables Formation is relatively undeformed (Atkinson *et al.* 2020). There could be some structural risk due to fracturing caused by differential subsidence over large offset faults in the underlying section. For the Cable Head Formation and the upper part of the Green Gables Formation, the top seal would be the Naufrage Formation. This formation is dominated by red siltstone and mudstone, with abundant pedogenic calcite (Giles and Utting 1999). The Naufrage Formation is reported in every well on Prince Edward Island (Giles and Utting 1999), and in the central and eastern part of the island is typically about 700 m thick, likely providing a solid seal. Westward of the Green Gables wells, the Naufrage Formation thins and may be absent in westernmost Prince Edward Island (Atkinson et al. 2020).

DISCUSSION

Geologic suitability of the "play areas"

Several researchers in the North Sea have applied threshold geological criteria for establishment of GCS site selection (e.g., Alcalde *et al.* 2021; Chadwick *et al.* 2008; Ramirez *et al.* 2009). For the basic reservoir parameters, a porosity cutoff of 10% has been used by several authors (Alcalde *et al.* 2021; Ramirez *et al.* 2009), along with minimum permeability values ranging from 10 mD (Alcalde *et al.* 2021) to 200 mD (Ramirez *et al.* 2009), and minimum thicknesses ranging from 10 m (Ramirez *et al.* 2009) to 20 m (Chadwick *et al.* 2008). The reservoir properties for all three of the GCS plays investigated in the onshore Maritimes Basin (Table 1) fall short of these suggested minimums for at least one of the basic reservoir parameters, and the more stringent positive indicators of reservoir quality cited by Chadwick *et al.* (2008).

However, it should be noted that these studies were evaluating site suitability for large-scale, offshore GCS sites, and lower standards might be appropriate for smaller scale onshore projects. Two examples of onshore GCS projects in Canada are the Quest Project in Alberta and the Aquistore Project in Saskatchewan. By the end of 2022, Quest had stored 7.7 Mt of CO_2, storing an average of more than 1 Mt/yr between 2016 and 2022 (Shell Canada Energy 2023). The mid-case estimates for the Basal Cambrian Sandstone reservoir in the Quest project are 44 m for average thickness, of which 90% is sandstone, for a net thickness of 40 m (Shell Heavy Oil 2011). The mid-case average porosity was an estimated 14%, which corresponds to ~50 mD, but average porosities were expected to range from 11 to 19% and 20 to 500 mD within the project area. The typical permeabilities of the Quest reservoir are thus below the minimum cited by Ramirez *et al.* (2009). Chadwick et al. (2008) would view the permeability as a cautionary indicator, and neither the thickness nor porosity would be regarded as positive. However, the Quest reservoir comfortably exceeds the minimums suggested by Alcalde et al. (2021).

The Aquistore project is a significantly smaller project than Quest with a total injection volume of 341 000 tonnes of CO_2 between 2015 and November 2020 (Movahedzadeh et al. 2021), less than the annual rate of Quest. White (2018) estimated the average thickness of the reservoir to be 219 m, of which 51% is clean sand for a net thickness of approximately 112 m. Average porosity of the clean sands within the project area, and at the injection well, is approximately 7%, although

Table I. Key indicators of uitability for GCS for each region.

Parameter	Windsor	Cumberland	Prince Edward Island
Reservoir Porosity	8–15%	5–7%?	10–12%
Reservoir Permeability	1–50 mD	no data	1–5 mD*
Reservoir Thickness**	3–5 m	20–120 m	20–50 m
Seal Thickness	50–100 m	~200 m+	300 m+
Seal Composition	Anhydrite	Mudrock-dominated succession with minor sandstone.	Mudrock-dominated succession with minor sandstone
Trap risks	Lateral migration to outcrop - may be limited within antiform	Lateral migration to outcrop or areas where overlying shale facies absent	
Size of secondary tectonic units	730 km^2	1240 km^2	14200 km^2
CO_2 sources	Cement plant in Brookfield, Nova Scotia	Biomass / Pulp and Paper	None currently, potentially biofuels?
Infrastructure	None	Major Gas Pipeline	None
Accessibility	Fair	Good	Poor

*higher permeabilities may exist for thin beds but 1–5 mD is expected to be a typical value for reservoir intervals

**reservoir thicknesses refer to individual sand bodies; multiple reservoir sandstones can occur in the same well it reaches 8–10% in the vicinity of the observation well (White 2018). The porosity–permeability relationship presented by White (2018) shows permeabilities of 1 mD and 10 mD correspond to approximately 8% and 12%, respectively. Alcalde *et al.* (2021), the least restrictive of the offshore site characterization studies, still recommended a minimum permeability of 10 mD, higher than is typical of the Aquistore reservoir. The porosity of the reservoir proved significantly lower than the 10–15% anticipated prior to drilling (White et al. 2016). Despite this comparatively poor reservoir, the Aquistore storage site has proven adequate for its purpose, disposing of excess CO_2 captured by the Sask Power plant that was not needed by enhanced oil recovery projects nearby (Movahedzadeh et al. 2012). It has stored up to 2400 tonnes/day when required.

Given that Aquistore has demonstrated the technical feasibility of CO_2 injections in land-based operations, less restrictive screening criteria than those used for offshore projects appears justified. A study in China that included onshore basins (Wei *et al.* 2013) used less restrictive values for disqualification of a reservoir from consideration (5% porosity, 1 mD permeability and 10 m thickness). They used a ranking scheme subdivided into five categories to assess early development opportunities for GCS potential. Their assessment was based on twenty-five criteria, including porosity, permeability, stratigraphic thickness and other geologic parameters, but also various risk and socio-economic factors. For porosity, Wei *et al.* (2013) used increments of 5% to rank their porosity parameter. For example, although they disqualified saline aquifers with less than 5% porosity, aquifers with porosity between 5–10% were assigned a value of 1, a value of 2 encompassed rocks with porosity between 10–15%, and so on. The assigned rank of each of the 25 parameters were summed to give a total value for relative evaluation of various GCS opportunities.

Applying the Wei *et al.* (2013) five-part evaluation framework to the present study, the Windsor–Kennetcook Sub-basin may be assigned values of 1 to 2 out of five for porosity and permeability but would be disqualified based on thickness of individual sand units. However, the aggregate thickness of Hurd Creek Member sand bodies in some wells (Fig. 5) would exceed the 10 m threshold. Similarly, the Cumberland–Sackville and Prince Edward Island plays achieve the minimum threshold for the Wei *et al.* (2013) evaluation framework (although Cumberland–Sackville lacks permeability data). A summary of the three plays reviewed in the report is presented in Table 1 and detailed discussion of each GCS play is presented below.

Minimum seal thickness of 10–20 m (Chadwick *et al.* 2008; Ramirez *et al.* 2009) have been used for site selection. Uniform stratigraphy in the seal is preferred over greater variation (Chadwick *et al.* 2008). Other geologic concerns include avoidance of sites near faults or salt domes (Chadwick et al. 2008).

Windsor Sub-basin

Core analysis (Fig. 3) and log analyses (Fig. 5) confirm the presence of sandstones with suitable porosity and permeability in the upper Hurd Creek Member in the Windsor Sub-basin. These sands are thin, which would limit both their injectivity and capacity, but could be suitable for a small-scale injection project. Thicker, and likely more laterally extensive sandstones exist elsewhere in the Horton Group, but petrophysical analysis suggests they have much lower porosity.

Thick evaporite deposits in the overlying Windsor Group section should provide a good seal. Although barriers to vertical migration appear solid, lateral migration to outcrop could be an issue in this small basin; the sub-basin is in the smallest allowable category in the scheme of Wei *et al.* (2013) with a size of approximately 730 km^2. Drilling within the antiform interpreted by Bianco (2013) could limit the risk, but new seismic work to verify this structure would be advisable.

The Cumberland–Sackville Sub-basin

The lower Cumberland Group sandstones are thick and have considerable lateral extent. Carey *et al.* (2023) viewed these rocks as prospective because of considerable thickness of sandstones at intermediate (1000–2000 m) depths, at which Carboniferous sandstones often have moderate porosities (Bibby and Shimeld 2000; Chi *et al.* 2001). This trend is based almost entirely on younger Carboniferous sandstones in the region, and the sandstones in the Hastings well show little variation in porosity with depth, however.

Chi *et al.* (2001) found evidence of several diagenetic stages in porous sandstones from the Spring Valley well in PEI including early carbonate cementation that reduced compaction followed by a subsequent period of partial dissolution of early cements and unstable grains. Although the authors are not aware of detailed petrographic descriptions of the Boss Point Formation sandstones, they are commonly described as quartzose sub-lithic sandstones (Ryan *et al.* 1991). It is striking that of eighty-two Carboniferous sandstone thin sections reviewed by Chi *et al.* (1992), only one was classified as sub-lithic. Thus, the mineralogy of these rocks may differ significantly from the younger sandstones in the basin and may not have experienced a similar diagenetic history. The more quartzose rocks of the Grande Anse Formation in New Brunswick (Bahr and Kieghley 2022), which may be time-equivalent to much of the Hastings section (P.S. Giles, personal communication 2023), may provide a suitable analogue. In outcrop, those sandstones averaged only 6% porosity, but proved highly variable with intervals up to 20% porosity.

Rivard *et al.* (2008) found the Boss Point Formation had potential as an aquifer for groundwater based on water well performance, citing it as one of the main aquifer units in the Maritimes Basin. As in other Carboniferous rocks in their study, intergranular porosity was low but natural fracturing provided connectivity to allow flow. It is unclear whether these fracture networks would be sufficiently open to allow flow at depths appropriate for CO_2 injection.

The known reservoir properties of the lower Cumberland Group (Table 1) are not promising, though better reservoir may exist, given that the Hastings well is the only deep borehole with geophysical log data. Some authors have investigated storage potential in rocks with similar reservoir parameters to those seen in the Hastings well, such as the Covery Hill Sandstone in Quebec (Tran Ngoc *et al.* 2014). The permeability in these rocks is akin to tight gas reservoirs which normally require stimulation for flow or injection. Supercritical CO_2 injection has been shown to reduce mechanical strength of rocks (Rinehart *et al.* 2016), increasing permeability in a fashion similar to hydraulic fracturing (Wang *et al.* 2017). However, deliberate fracturing of the reservoir during injection could potentially compromise the seal integrity.

In the Hastings well, the lower Cumberland Group sandstones are overlain by a 200 m thick mud-prone heterolithic interval. No individual continuous shale exceeds ~15 m in thickness, but these shale intervals in tandem with siltstones are likely to form an adequate barrier to upward migration, especially given the low permeability of the thin sandstones present. Structural deformation of the Pennsylvanian section is typically low in the synclines, but there could be fracturing associated with differential compaction over underlying structures or close to salt-cored anticlines. Up-dip migration toward outcrop or areas where mudrocks are thin or absent near salt-cored anticlines could also present a risk. The Hastings Uplift region is approximately 1240 km^2, which would be rated as a small secondary tectonic unit in the Wei *et al.* (2013) scheme.

Prince Edward Island

The Cable Head and Green Gables formations, and possibly the Bradelle Formation meet the minimum standards for reservoir porosity and thickness in Prince Edward Island, indicating that the storage capacity should be sufficient. However, the porosity–permeability relationship (Fig. 15) indicates that a porosity of at least 12–14% would be required for 10 mD permeability. Rock supporting high levels of injectivity are likely limited to streaks within less permeable (1–10 mD?) sandstone bodies. However, these permeabilities are comparable to those in the Aquistore injection well.

The seal rocks are similar to the Cumberland–Sackville Sub-basin, consisting of mud-dominated heterolithic intervals in the Green Gables and Naufrage formations. These units exceed 300 m in all wells examined in this study and can be up to 1000 m thick. Although sandstones (even potential reservoir sandstones) do exist within these successions, they are typically separated from one another by thick intervals of shale and siltstone. Structural deformation of the Pennsylvanian section is typically low, but there could be fracturing associated with differential compaction over underlying structures. A secondary tectonic unit for the Prince Edward Island play is less clear than for the other plays, but there is a relatively undeformed area including central and eastern Prince Edward Island, parts of Northumberland Strait and the southern Gulf of St. Lawrence with an approximate area of 14 300 km^2. Wei *et al.* (2013) would regard this is a medium-sized tectonic unit.

Other factors influencing suitability of the play areas

The present study is focused on the identification of suitable geology for GCS, but there are other considerations that ultimately determine the viability of carbon storage projects (Bachu 2000; Wei *et al.* 2013; Wendt *et al.* 2022). While a review of all the factors that can affect the safety and economic feasibility of a GCS project is beyond the scope of this paper, some of the most important include the distance to sources of CO_2 emissions, accessibility for construction, and presence of infrastructure such as pipelines (Bachu 2003; Wendt *et al.* 2022). The presence of an active petroleum industry was seen as a plus by Bachu (2003) because of the presence of drilling rigs and service companies, but Wendt *et al.* (2022) noted that plugged and abandoned wells could increase leakage risk. Areas near active faults were also viewed as undesirable due to increased risk (Wendt *et al.* 2022).

Table 1 summarizes our evaluation of some of the factors that vary between play area. Some are essentially the same for all three. Risks related to seismic activity appear minimal in all cases. In a recent study on the Moncton Subbasin in southeastern New Brunswick, Lamontagne *et al.* (2015) determined that the frequency of earthquakes of magnitude greater than 4.0 was on average one every 142 years. Regional earthquake frequency mapping suggests that Nova Scotia and Prince Edward Island have even lower earthquake frequency, with the possible exception of western Prince Edward Island (Plourde 2023). The lack of petroleum drilling activity in the study area has both positive and negative effects. There are few abandoned wells that could pose leakage risks, but any drilling equipment would potentially need to be brought in from outside the region.

Atlantic Canada has relatively few large CO_2 emitters, but there are a few industrial sources of note (The International CCS Knowledge Centre 2021). Potential sources of CO_2 in New Brunswick and Nova Scotia include power plants, cement plants, such as one in Brookfield, Nova Scotia, near the Windsor Sub-basin, and the pulp and paper industry. Prince Edward Island has no large point-source emitters currently. Biofuels are expected to play an important role in its future energy plans, however. Biofuels could be combined with GCS for a carbon-negative energy source (The International CCS Knowledge Centre 2021) which could potentially be cost-competitive depending on future carbon-pricing regimes.

Transporting CO_2 from outside the region would require significant infrastructure investment. The Cumberland–Sackville Sub-basin is traversed by the Maritimes & Northeast Pipeline (Nova Scotia Department of Natural Resources and Renewables 2011), which could potentially be repurposed, or new infrastructure could be installed within the existing right-of-way, for CO_2 transportation. The Cumberland–Sackville Sub-basin is also the most accessible of the three areas, as it is traversed by the Trans-Canada Highway and relatively close to southeast New Brunswick which has some petroleum activity. The other areas lack major petroleum industry infrastructure, although the Maritimes & Northeast Pipeline passes within 30 km of the Windsor Sub-basin. The island location of Prince Edward Island would make linkage to the mainland more expensive, although transportation by sea by tanker might be possible. The Northern Lights project in Norway plans to bring in liquefied CO_2 using tankers with compressed liquified CO_2, similar to liquid natural gas (Equinor 2024).

CONCLUSIONS

In all three GCS play areas investigated in this study, lack of a favourable reservoir appears to be the major limiting factor on GCS development. There is considerable uncertainty due to the scarcity of subsurface data in the Maritimes Basin. Outside of the relatively well-known McCully and Stoney Creek fields (Fig. 1), fewer than 100 wells have been drilled in an area of more than 220 000 km^2 (Carey *et al.* 2023). Further drilling and seismic work would be necessary to assess the feasibility of any project in the area. Investigation of the pressure and temperature gradients with depth would also be required to assess the stable phase of CO_2 at reservoir conditions.

The Windsor Sub-basin play appears to have sufficiently porous and permeable reservoir, but its thickness is limited and lateral extent and continuity uncertain. It may be suitable for small-scale injection for a local CO_2 emitter, such as the nearby cement plant in Brookfield. As noted above, further drilling and seismic work is required to confirm closure and sufficient storage capacity.

The Cumberland Sub-basin is the best located of the three areas in terms of infrastructure. However, it does not have a suitable proven reservoir. The thick, laterally extensive, low porosity and permeability lower Cumberland Group sandstones meet the minimum threshold requirements for some evaluation criteria, but not others, in the one well drilled in the subsurface. It is possible that reservoir quality may improve elsewhere in the subsurface as it typically does elsewhere in the Maritimes Basin. Additional subsurface information, a clearer understanding of correlations within the sub-basin and neighboring areas, and evaluation of reservoir properties from outcrop data would be needed to fully assess its potential.

Prince Edward Island has the greatest storage capacity of the three areas, with three potential reservoir plays. But while the thickness and porosity of these rocks appears adequate, the permeability may be marginal depending on GCS design requirements. Further work may identify areas where reservoir quality is better than seen in the small number of well penetrations to date. The island location could also make the economics more challenging because of a lack of pipeline infrastructure.

ACKNOWLEDGMENTS

This work was funded by Natural Resources of Canada through the Office of Energy Research and Development under their Carbon Capture Utilization and Storage program. We would also like to thank our colleague Carla Skinner for a helpful internal review, and several colleagues for insightful discussions of the geology of Atlantic Canada, particularly Peter Giles and Alexandre Plourde. In addition, we would like to thank the reviewers for Atlantic Geoscience for suggesting edits that we believe improved the paper.

REFERENCES

Alcalde, J., Heinemann, N., James, A., Bond, C.E., Ghanbari, S., Eric J. Mackay, E.J., Haszeldine, R.S., Faulkner, D.R., Worden, R.H., and Allen, M.J. 2021. A criteria-driven approach to the CO_2 storage site selection of East Mey for the Acorn project in the North Sea. Marine and Petroleum Geology, 133, 14 pp. https://doi.org/10.1016/j. marpetgeo.2021.105309

Allen, J.P., Fielding, C.R., Rygel, M.C., and Gibling, M.R. 2013. Deconvolving signals of tectonic and climatic controls from continental basins: an example from the late Paleozoic Cumberland Basin, Atlantic Canada. Journal of Sedimentary Research, 83, pp. 847–872. https://doi.org/10.2110/jsr.2013.58

Amado, L. 2013. Reservoir exploration and appraisal. Amsterdam: Elsevier. https://doi.org/10.1016/C2009-0-30581-4

Atkinson, E.A., Durling, P.W., Kublik, K, Lister, C.J., King, H.M., Kung, L.E., Jassim, Y., McCarthy, W.M., and Hayward, H. 2020. Qualitative petroleum resource assessment of the Magdalen Basin in the Gulf of St. Lawrence; Quebec, Prince Edward Island, New Brunswick, Nova Scotia and Newfoundland and Labrador. Geological Survey of Canada Open File 8404, 109 p. https://doi.org/10.4095/321856

Bachu, S. 2000. Sequestration of CO_2 in geological media: criteria for site selection in response to climatic change. Energy Conversion & Management, 41, pp. 953–970. https://doi.org/10.1016/S0196-8904(99)00149-1

Bachu, S. 2003. Screening and ranking of sedimentary basins for sequestration of CO_2 in geological media in response to climate change. Environmental Geology, 44, pp. 277–289. https://doi.org/10.1007/s00254-003-0762-9

Bahr, F. and Keighley, D. 2022. A model for the early diagenesis of humid climate, fluvial strata influenced by adjacent salt deposits: Grand Anse Formation, Cumberland Basin, Canada. Sedimentology, 69, pp. 2715–2739. https://doi.org/10.1111/sed.13015

Bianco, E. 2013. Seismic interpretation of the Windsor–Kennetcook Basin. Geological Survey of Canada Open File 7452, 27 p. https://doi.org/10.4095/292763

Bibby, C. and Shimeld, J. 2000. Compilation of reservoir data for sandstones of the Devonian–Permian Maritimes Basin, eastern Canada. Geological Survey of Canada Open File 3895, 102 p. https://doi.org/10.4095/211514

Bradley, D.C. 1982. Subsidence in late Paleozoic basins in the northern Appalachians. Tectonics, 1, pp. 107–123. https://doi.org/10.1029/TC001i001p00107

Bradshaw, J. and Dance, T. 2005. Mapping geological storage prospectivity of CO_2 for the world's sedimentary basins and regional source to sink matching. *In* Greenhouse gas control technologies 7, Volume 1. *Edited by* E.S. Rubin, D.W. Keith, and C.F. Gilboy. Elsevier, Amsterdam, pp. 583–591. https://doi.org/10.1016/B978-008044704-9/50059-8

Browne, G.H. and Kingston, D.M. 1993. Early diagenetic spherulitic siderites from Pennsylvanian paleosols in the Boss Point Formation, Maritime Canada. Sedimentology, 40, pp. 467–474. https://doi.org/10.1111/j.1365-3091.1993.tb01346.x

Browne, G.H. and Plint, A.G. 1994. Alternating braidplain and lacustrine deposition in a strike-slip setting: the Pennsylvanian Boss Point Formation of the Cumberland Basin, Maritime Canada. Journal of Sedimentary Research, B64, pp. 40–59. https://doi.org/10.1306/D4267F41-2B26-11D7-8648000102C1865D

Calder, J.H., Rygel, M.C., Ryan, R.J., Falcon-Lang, H.J., and Hebert, B.L. 2005. Stratigraphy and sedimentology of early Pennsylvanian red beds at Lower Cove, Nova Scotia, Canada: the Little River Formation with redefinition of the Joggins Formation. Atlantic Geology, 41, pp. 143–167. https://doi.org/10.4138/183

Cameron, R. 2018. A geophysical, petrological and reservoir potential study of the Glass Sand Marker Unit and associated sandstones in the upper Horton Bluff Formation, Windsor Basin, Nova Scotia. Unpublished B.Sc. thesis, Acadia University. Wolfville, Nova Scotia, 64 p.

Carey, J.S., Skinner, C.H., Giles, P.S., Durling, P., Ploude, A.P., Jauer, C., and Desroches, K. 2023. Preliminary assessment of geologic carbon storage potential of Atlantic Canada. Geological Survey of Canada Open File 8996, 90 p. https://doi.org/10.4095/332145

Chadwick, A., Arts, R., Bernstone, C., May, F., Thibeau, S., and Zwigel, P. 2008. Best practice for the storage of CO_2 in saline aquifers—observations and guidelines from the SACS and CO2STORE projects. British Geological Survey, Keyworth, Nottingham, Occasional Publication 14. 267 p.

Chi, G., Giles, P.S., Williamson, M.A., Lavoie, D., and Bertrand, R. 2001. Diagenetic history and porosity evolution of Upper Carboniferous sandstones from the Spring Valley #1 well, Maritimes Basin, Canada—implications for reservoir development. Journal of Geochemical Exploration, 80, pp. 171–191. https://doi.org/10.1016/S0375-6742(03)00190-0

Devon Canada. 2003. Final well report Coolbrook-1. Unpublished report. 10 p.

Durling, P. 2023. Seismic reflection interpretation of the Carboniferous Cumberland Basin, northern Nova Scotia. Geological Survey of Canada Open File 8937, 64 p. https://doi.org/10.4095/331223

Durling, P. and Marillier, F. 1993. Tectonic setting of Middle Devonian to Lower Carboniferous rocks in the Magdalen Basin. Geological Survey of Canada Open File 3320, Poster. https://doi.org/10.4138/2008

E. McDonald Geoconsulting Ltd. 2007. Final geological well report Kennetcook-2. Unpublished report. 27 p.

Eggleston, L.K. 2017. Deformation and kinematic history of the Sackville and Moncton subbasins, southeastern New Brunswick, Maritimes Basin of Atlantic Canada. Unpublished M.Sc. thesis, University of Alberta, Edmonton, Alberta, 101 p.

Environment and Climate Change Canada. 2022. 2030 emissions reduction plan: Canada's next steps to clean air and a strong economy. Ottawa: Environment and Climate Change Canada, Gatineau, Quebec, 240 p.

Equinor 2024. The Northern Lights project. https://www.equinor.com/energy/northern-lights.

Felderhof, H. 1975. Petroleum reservoir study. Department of Natural Resources, Halifax, Nova Scotia, 97 p.

Gibling, M.R., Calder, J.H., Ryan, R., van de Poll, H.W., and Yeo, G.M. 1992. Late Carboniferous and Early Permian drainage patterns in Atlantic Canada. Canadian Journal of Earth Sciences, 29, pp. 338–352. https://doi.org/10.1139/e92-030

Gibling, M.R., Culshaw, N., Pascucci, V., Waldron, J.W.F., and Rygel, M. 2019. The Maritimes Basin of Atlantic Canada: Basin creation and destruction during the Paleozoic assemblage of Pangea. *In* The sedimentary basins of the United States and Canada: second edition. *Edited by* A.D. Miall. Elsevier, Amsterdam, pp. 267–314. https://doi.org/10.1016/B978-0-444-63895-3.00006-1

Giles, P.S. 1981. Major transgressive and regressive cycles in the middle to late Visean rocks of Nova Scotia. Nova Scotia Department of Mines and Energy Paper 81-2. 28 p.

Giles, P.S. and Utting, J. 1999. Maritimes basin stratigraphy Prince Edward Island and adjacent Gulf of St. Lawrence. Geological Survey of Canada Open File 3732. Poster. https://doi.org/10.4095/210469

Gulf Oil Canada Ltd. 1975. Gulf *et al.* Hastings No. 1 well history report. Nova Scotia Department of Natural Resources. Halifax. 56 p.

Hamblin, A.P. 2001. Stratigraphy, sedimentology, tectonics and resource potential of the lower Carboniferous Mabou Group, Nova Scotia. Geological Survey of Canada Bulletin 568.173 pp. https://doi.org/10.4095/212926

Hamblin, A.P. and Rust, B.R. 1989. Tectono-sedimentary analysis of alternate-polarity half-graben basin-fill successions: Late Devonian–Early Carboniferous Horton Group, Cape Breton Island, Nova Scotia. Basin Research, 2, pp. 239–255. https://doi.org/10.1111/j.1365-2117.1989.tb00038.x

Howie, R.D. 1986. Windsor Group salt in the Cumberland Subbasin of Nova Scotia. Geological Survey of Canada Paper 85-11. 12 p. https://doi.org/10.4095/120616

Ielpi, A., Gibling, M.R., Bashforth, A.R., Lally, C., Rygel, M.C., and Al-Silwadi, S. 2014. Role of vegetation in shaping Early Pennsylvanian braided rivers: architecture of the Boss Point Formation, Atlantic Canada. Sedimentology, 61, pp. 1659–1700. https://doi.org/10.1111/sed.12109

Kaiser, M.J. 2009. Modeling the time and cost to drill an offshore well. Energy, 34, pp. 1097–1112. https://doi.org/10.1016/j.energy.2009.02.017

Keighley, D. and Maher, C. 2015. A preliminary assessment of carbon storage suitability in deep underground geological formations of New Brunswick, Canada. Atlantic Geology, 51, pp. 269–286. https://doi.org/10.4138/atlgeol.2015.011

Keppie, J.D. 2006. Digital version of Nova Scotia Department of Natural Resources Map ME 2000-1, Geological Map of the Province of Nova Scotia, scale 1:500 000.

Lamontagne, M., Lavoie, D., Ma, S., Burke, K.B.S., and Bastow, I. 2015. Monitoring the earthquake activity in an area with shale gas potential in southeastern New Brunswick, Canada. Seismological Research Letters, 86, pp. 1068–1077. https://doi.org/10.1785/0220150051

Lavoie, D. 2019. Chapter 3. The Cambrian–Devonian Laurentian platforms and foreland basins in eastern Canada. *In* The sedimentary basins of the United States and Canada: second edition. *Edited by* A. D. Miall. Elsevier, Amsterdam, pp. 267–314. https://doi.org/10.1016/B978-0-444-63895-3.00003-6

Martel, A.T. 1987. Seismic stratigraphy and hydrocarbon potential of the strike-slip Sackville sub-basin, New Brunswick. *In* Sedimentary basins and basin-forming mechanisms. *Edited by* C. Beaumont and A.J. Tankard. Canadian Society of Petroleum Geologists Memoir 12, pp. 319–334.

Martel, A.T. and Gibling, M.R. 1996. Stratigraphy and tectonic history of the Upper Devonian to Lower Carboniferous Horton Bluff Formation, Nova Scotia. Atlantic Geology, 32, pp. 13–38. https://doi.org/10.4138/2076

New Brunswick Department of Natural Resources and Energy Development. 2023. Oil and natural gas. URL <https://www2.gnb.ca/content/gnb/en/departments/erd/energy/content/minerals/content/Oil_Gas.html>, 9 November 2023

Movahedzadeh, Z., Rangriz Shokri, A., Chalaturnyk, R., Nickel, E., and Sacuta, N. 2021. Measurement, monitoring, verification and modelling at the Aquistore CO_2 storage site. First Break, 39, pp. 69–75. https://doi.org/10.3997/1365-2397.fb2021013

Nova Scotia Department of Energy. 2017a. Preliminary petrophysics database, onshore Nova Scotia. Nova Scotia Department of Energy Open File Report 2017-10. URL <https://energy.novascotia.ca/onshore-atlas-version-1-2017/onshore-atlas-open-file-reports>, 8 May 2023.

Nova Scotia Department of Energy. 2017b. Preliminary petroleum well log database, onshore Nova Scotia. Nova Scotia Department of Energy Open File Report 2017-09. URL <https://energy.novascotia.ca/onshore-atlas-version-1-2017/onshore-atlas-open-file-reports>, 8 May 8 2023.

Nova Scotia Department of Natural Resources and Renewables. 2011. Maritimes and Northeast Pipeline Map. URL <https://energy.novascotia.ca/document-library/document/maritimes-and-northeast-pipeline-map>, 27 November 27 2023

Nova Scotia Department of Natural Resources and Renewables. 2017. Onshore atlas–open file reports. URL <https://energy.novascotia.ca/onshore-atlas-version-1-2017/onshore-atlas-open-file-reports>, 9 January 2023

Opdyke, N.D., Giles, P.S., and Utting, J. 2010. Magnetic polarity stratigraphy and palynostratigraphy of the Mississippian–Pennsylvanian boundary interval in eastern North America and the age of the beginning of the Kiaman. Geological Society of America Bulletin, 126, pp. 1068–1083. https://doi.org/10.1130/B30953.1

Petrel Robertson Consulting Ltd. 2017. Assessment of oil and gas potential, Windsor and Cumberland basins, onshore Nova Scotia. Nova Scotia Department of Energy Open File Report 2017-03. URL <https://energy.novascotia.ca/onshore-atlas-version-1-2017/onshore-atlas-open-file-reports>, 9 January 2023

Plint, A.G. 1986. Slump blocks, intraformational conglomerates and associated erosional structures in Pennsylvanian fluvial strata of eastern Canada. Sedimentology, 33, pp. 387–399. https://doi.org/10.1111/j.1365-3091.1986.tb00543.x

Plint, A.G. and Browne, G.H. 1994. Tectonic event stratigraphy in a fluvio-lacustrine, strike-slip setting: the Boss Point Formation (Westphalian A), Cumberland Basin, Maritime Canada. Journal of Sedimentary

Research, B64, pp. 341–364. https://doi.org/10.1306/D4267FC3-2B26-11D7-8648000102C1865D

Plourde, A.P. 2023. Assessing earthquake rates and b-value given spatiotemporal variation in catalog completeness: application to Atlantic Canada. Seismica, 2.2, pp. 1–10. https://doi.org/10.26443/seismica.v2i2.384

Pothier, H.D., Wach, G.D., and Zentilli, M. 2010. Reservoir and seal pairs: carbon sequestration in Atlantic Canada. CSPG/CSEG/CWLS GeoConvention 2010. Abstract, Search and Discovery Article #90172 (2014).

Ramirez, A., Hagedoorn, S., Kramers, L., Wildenborg, T., and Hendriks, C. 2009. Screening CO_2 storage options in The Netherlands. International Journal of Greenhouse Gas Control, 4, pp. 367–380. https://doi.org/10.1016/j.ijggc.2009.10.015

Rinehart, A., Dewers, T.A., Broome, S.T., and Eichhubl, P. 2016. Effects of CO_2 on mechanical variability and constitutive behavior of the Lower Tuscaloosa Formation, Cranfield Injection Site, USA. International Journal of Greenhouse Gas Control, 53, pp. 305–318. https://doi.org/10.1016/j.ijggc.2016.08.013

Rivard, C., Michaud, Y., Lefebre, R., Deblonde, C., and Rivera, A. 2008. Characterization of a regional aquifer system in the Maritimes Basin, eastern Canada. Water Resources Management, 22, pp. 1649–1675. https://doi.org/10.1007/s11269-008-9247-7

Ryan, R.J. 1985. Upper Carboniferous strata of the Tatamagouche Syncline, Cumberland Basin, Nova Scotia. *In* Current Research, part B. Geological Survey of Canada, Paper 85-1B. pp. 481–490. https://doi.org/10.4095/120279

Ryan, R.J. and Boehner, R.C. 1994. Geology of the Cumberland Basin, Cumberland, Colchester and Pictou Counties, Nova Scotia. Halifax. Nova Scotia Department of Natural Resources Mineral Resources Branch Memoir ME 10, 213 p.

Ryan, R.J., Boehner, R.C., and Calder, J.H. 1991. Lithostratigraphic revisions of the Upper Carboniferous to Lower Permian strata in the Cumberland Basin, Nova Scotia and the regional implications for the Maritimes Basin in Atlantic Canada. Bulletin of Canadian Petroleum Geology, 39, pp. 289–314.

Rygel, M. C., Lally, C., Gibling, M. R., Ielpi, A., Calder, J. H., and Bashforth, A. R. 2015. Sedimentology and stratigraphy of the type section of the Pennsylvanian Boss Point Formation, Joggins Fossil Cliffs, Nova Scotia, Canada. Atlantic Geology, 51, pp. 1–43. https://doi.org/10.4138/atlgeol.2015.001

Schlumberger. 1989. Log interpretation principles/ applications. Schlumberger Educational Services, Houston, Texas, 223 p.

Shell Canada Energy 2023. Quest Carbon Capture and Storage Project Annual Summary Report—Alberta Department of Energy: 2022. Alberta Department of Energy, Edmonton, Alberta, 56 p.

Shell Heavy Oil 2011. Quest CCS Project Generation-4 Integrated Reservoir Modeling Report. Government of Alberta Document 07-3-AA-5726-0001, Edmonton, Alberta, 249 p.

Souaya, F.J. 1975. Stratigraphy and biostratigraphy of the Gulf Anschutz Scurry Rainbow Hastings No. 1 Well, Nova Scotia. Unpublished report. 85 p.

The International CCS Knowledge Centre. 2021. Canada's CO_2 landscape—a guided map for sources & sinks. Retrieved on November 29, 2023. URL <https://ccsknowledge.com/pub/Publications/CO2-Sources_&_Sinks_Map_Canada%20(2021-05-12).pdf>, 9 January 2023.

Tran Ngoc, T.D., Lefebvre, R., Konstantinovskaya, E., and Malo, M. 2014. Characterization of deep saline aquifers in the Bécancour area, St. Lawrence Lowlands, Quebec, Canada: implications for CO_2 geological storage. Environmental Earth Science, 72, pp. 119–146. https://doi.org/10.1007/s12665-013-2941-7

US Department of Energy. 2024. Carbon storage FAQs. URL < https://netl.doe.gov/carbon-management/carbon-storage/faqs/carbon-storage-faqs>, 16 July 2024.

Utting, J., Giles, P.S., and Dolby, G. 2010. Palynostratigraphy of Mississippian and Pennsylvanian rocks, Joggins area, Nova Scotia and New Brunswick, Canada. Palynology, 34, pp. 43–89. https://doi.org/10.1080/01916121003620569

Utting, J., Keppie, J.D., and Giles, P.S. 1989. Palynology and stratigraphy of the Lower Carboniferous Horton Group, Nova Scotia. Geological Survey of Canada Bulletin, 396, pp. 117–143. https://doi.org/10.4095/127720

van de Poll, H.W., Gibling, M.R., and Hyde, R.S. 1995. Chapter 5: Upper Paleozoic rocks. *In* Geology of the Appalachian–Caledonian Orogen in Canada and Greenland. *Edited by* H. Williams. The Geology of North America, volume F-1, Geological Survey of Canada, pp. 449–566.

van der Meer, L.G.H., Hofstee, C., and Orlic, B. 2009. The fluid flow consequences of CO_2 migration from 1000 to 600 metres upon passing the critical conditions of CO_2. Energy Procedia, 1, pp. 3213–3220. https://doi.org/10.1016/j.egypro.2009.02.105

Waldron, J.W.F., Giles, P.S., and Thomas, A.K. 2017. Correlation chart for Late Devonian to Permian stratified rocks of the Maritimes Basin, Atlantic Canada. Nova Scotia Department of Energy Open File Report 2017-02.

Waldron, J.W.F., Roselli, C.G., Utting, J., and Johnston, S.K. 2010. Kennetcook thrust system: late Paleozoic transpression near the southern margin of the Maritimes Basin, Nova Scotia. Canadian Journal of Earth Sciences, 47, pp. 137–159. https://doi.org/10.1139/E09-071

Waldron, J.W.F. and Rygel, M.C. 2005. Role of evaporite withdrawal in the preservation of a unique coal-bearing succession: Pennsylvanian Joggins Formation, Nova

Scotia. Geology, 33, pp. 337–340. https://doi.org/10.1130/G21302.1

Wang, L., Yao, B., Xie, H., Kneafsey, T.J., Winterfeld, P.H., Yin, X., and Wu, Y.-S. 2017. Experimental investigation of injection-induced fracturing during supercritical CO_2 sequestration. International Journal of Greenhouse Gas Control, 63, pp. 107–117. https://doi.org/10.1016/j.ijggc.2017.05.006

Wei, N., Li, X., Wang, Y., Dahowski, R.T., Davidson, C.L., and Bromhal, G.S. 2013. A preliminary sub-basin scale evaluation framework of site suitability for onshore aquifer-based CO_2 storage in China. International Journal of greenhouse Gas Control, 12, pp. 231–246. https://doi.org/10.1016/j.ijggc.2012.10.012

Wendt, A., Sheriff, A., Shih, C.Y., Vikara, D. and Grant, T. 2022. A multi-criteria CCUS screening evaluation of the Gulf of Mexico, USA. International Journal of Greenhouse Gas Control, 118. 26 p. https://doi.org/10.1016/j.ijggc.2022.103688

White, D.J. 2018. 3D architecture of the Aquistore reservoir: implications for CO_2 flow and storage capacity. International Journal of Greenhouse Gas Control, 71, pp. 74–85. https://doi.org/10.1016/j.ijggc.2018.02.009

White, D.J., Hawkes, C.D., and Rostron, B.J., 2016. Geological characterization of the Aquistore CO_2 storage site from 3D seismic data. International Journal of Greenhouse Gas Control, 54, pp. 330–344. https://doi.org/10.1016/j.ijggc.2016.10.001

Editorial responsibility: Jordan Eamer