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Petroleum resource potential of the Laurentian Channel area of interest, Atlantic Margin of Canada

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PETROLEUM RESOURCE POTENTIAL OF THE LAURENTIAN CHANNEL AREA OF INTEREST, ATLANTIC MARGIN OF CANADA

P.K. Hannigan and J.R. Dietrich

Geological Survey of Canada – Calgary, 3303-33rd Street, NW, Calgary Alberta T2L 2A7

SUMMARY

The conventional and unconventional oil and gas resource potential in the Laurentian Channel area of interest on the Atlantic margin of Canada is described in this report. The area of interest (AOI) encompasses approximately 16,000 square kilometres of the Laurentian Channel located offshore of Nova Scotia and Newfoundland (Fig. 1). Parts of two major sedimentary basins (Sydney Basin and Scotian (Orpheus Graben); Fig. 2) occur within the AOI, both of which have conventional oil and gas potential.

Quantitative assessments of petroleum potential for the Laurentian Channel AOI include high-confidence estimates of 40.8 x 10^6 m^3 (257 MMbbls) of oil and 113.1 x 10^9 m^3 (4.0 Tcf) of gas, and speculative estimates of 302.2 x 10^6 m^3 (1901 MMbbls) of oil and 432.7 x 10^9 m^3 (15.3 Tcf) of gas (mean values of in-place volumes). The petroleum resource estimates are based on a modified areal apportionment of resource potential of previously defined conventional petroleum plays. The high-confidence and speculative estimates reflect two resource distribution scenarios; the high-confidence estimates assume the largest oil or gas fields occur outside the AOI, and the speculative estimates assume the largest fields are located within the AOI. In the speculative resource scenario, the AOI may contain fields with in-place volumes of 76.2 x 10^6 m^3 (479 MMbbls) of oil and 88.2 x 10^9 m^3 (3.1 Tcf) of gas.

The Laurentian Channel AOI encloses areas of varying prospectivity for conventional petroleum resource. Areas of high to moderate petroleum potential occur in the northern portion of the AOI, where Lower and Upper Carboniferous petroleum plays are present in the Sydney Basin. An area of high potential for petroleum occurs in the southern portion of the AOI, where numerous stacked petroleum plays occur in the thick Mesozoic-Cenozoic succession of the Orpheus Graben. Small areas of low potential for petroleum are mapped in the northwestern and central AOI, where thin sections of Carboniferous and Mesozoic strata are found on the margins of Sydney Basin and Burin Platform.

Unconventional coal-bed methane and gas hydrate resources may occur within the Laurentian Channel AOI. Coal-bed methane potential within the AOI is estimated at 45.5 x 10^9 m^3 (1.6 Tcf). Estimates for gas hydrate potential in the AOI vary from 7.1 x 10^{11} m^3 to 2.9 x 10^{12} m^3 (25 to 102 Tcf). Although gas hydrate volumes may be substantial, technical and economic factors limit the potential for development of gas hydrate resources, much more so than for conventional oil or gas resources.

INTRODUCTION

An area of interest in the Laurentian Channel region of the Atlantic margin of Canada has been identified by the Department of Fisheries and Oceans for consideration as a Marine Protected Area. The area of interest (AOI) encompasses approximately 16,000 square kilometres of the Laurentian Channel, south of Newfoundland and northeast of Nova Scotia (Fig. 1). The Laurentian Channel is a deep-water gully that intersects the Atlantic continental shelf, with St. Pierre Bank to the northeast and Scotian Shelf to the southwest. Water depths in the Channel (within the AOI) are 250 to 500 m. The southeastern boundary of the AOI abuts the southward offshore extension of the French territory of St. Pierre and Miquelon (Fig. 1). Most of the AOI is within the jurisdiction of Newfoundland and Labrador, with a small portion of the west-central AOI in Nova Scotia waters.

This report evaluates the conventional and unconventional petroleum resource potential of the Laurentian Channel AOI. Energy resource assessments are one of many socio-economic and technical assessments that must be undertaken and considered as part of the evaluation process for the establishment of marine protected areas. Establishment of a marine protected area may have an impact on access to offshore petroleum resources, and an assessment of the resource potential within the area is required for informed decision-making.

Two basins with potential for conventional oil or gas resources occur in the Laurentian Channel AOI; Sydney Basin, which is part of the Upper Paleozoic Maritimes Basin, and Orpheus Graben, part of the Mesozoic-Cenozoic Scotian Basin (Fig. 2, 3). Reviews of the geological setting, petroleum systems, and exploration history in the Maritimes Basin (including Sydney Basin) and Scotian Basin (including Orpheus Graben) have been discussed by Wade et al. (1989), MacLean and Wade (1992), Lavoie et al. (2009), and Dietrich et al. (2011). The geological summaries presented in this report are derived from these publications.

Large volumes of unconventional gas resource may occur in the Laurentian Channel AOI as coal-bed

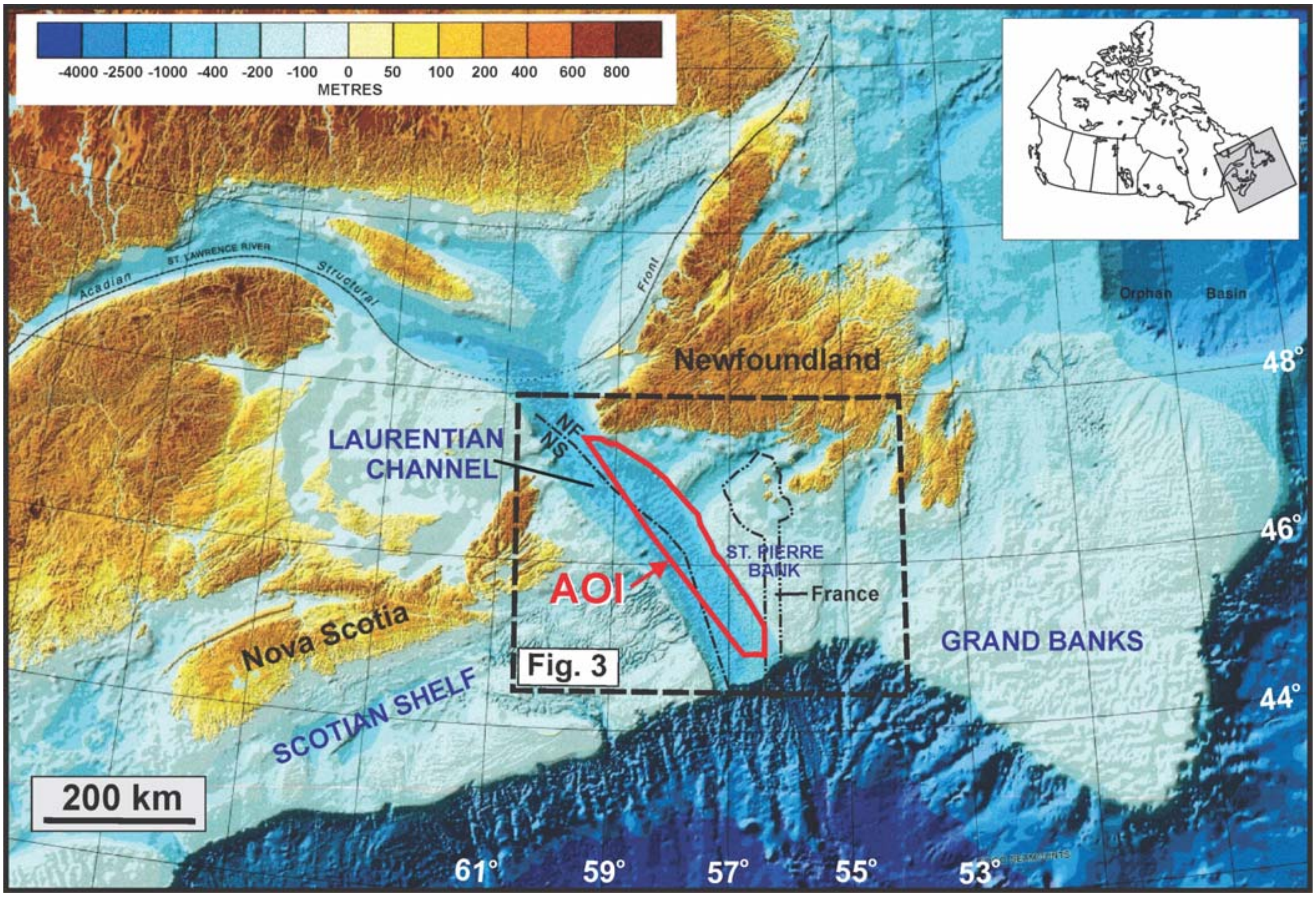

Figure 1. Topographic and bathymetric map of the Atlantic region of Canada (adapted from Oakey (1999)), with the location of the Laurentian Channel area of interest (AOI), petroleum-assessment study area (see Fig. 3), Newfoundland-Nova Scotia offshore boundary, and St. Pierre and Miquelon Economic Exclusion Zone (France).

methane and gas hydrates. The Sydney Basin, which extends across the northwestern AOI, contains abundant coal seams with coal-bed methane potential. Conditions are favourable for the stability of gas hydrates over large parts of the offshore Atlantic margin, including the AOI.

SYDNEY BASIN

Regional Geological Setting

The Sydney Basin is part of the Upper Paleozoic Maritimes Basin, which extends across the southern Gulf of St. Lawrence, Cabot Strait, southwestern Grand Banks, and northeastern Newfoundland continental shelves, and adjacent onshore areas in all five eastern Canadian provinces (Fig. 2). The southeastern part of the Sydney Basin underlies Mesozoic-Cenozoic strata of the Burin Platform (Fig. 3). Other major sedimentary depocentres within the Maritimes Basin include the Magdalen, Deer Lake, and St. Anthony basins, and the Moncton, Cumberland, and Bay St. George subbasins (Fig. 2). The Maritimes Basin developed in equatorial latitudes in an oblique collisional zone between Laurussia and Gondwana cratons, during the final stages of the assembly of the Pangaea supercontinent (Calder, 1998). The basin overlies a collage of Appalachian accreted tectonic zones of varying age and composition (Fig. 2; Williams, 1984). Regional strike-slip faults were active during many phases of basin evolution, leading to the development of pull-apart subbasins and subsequent basin inversions and deformation. Widespread deposition of evaporites and ensuing salt mobilization produced salt diapir zones in many parts of the basin, including two areas in Sydney Basin (Fig. 3).

Stratigraphy

The Upper Paleozoic sedimentary succession in Sydney Basin is up to 5000 m thick and comprises four major unconformity-bounded stratigraphic packages (Fig. 4); a Middle Devonian succession of alluvial and lacustrine clastic rocks (McAdams Lake Formation), an Upper Devonian/Lower Carboniferous alluvial and lacustrine clastic succession (Horton/Anguille Group), a Lower Carboniferous succession of marine carbonate and evaporite, and non-marine clastic rocks (Windsor/Codroy and Mabou/Barachois groups,

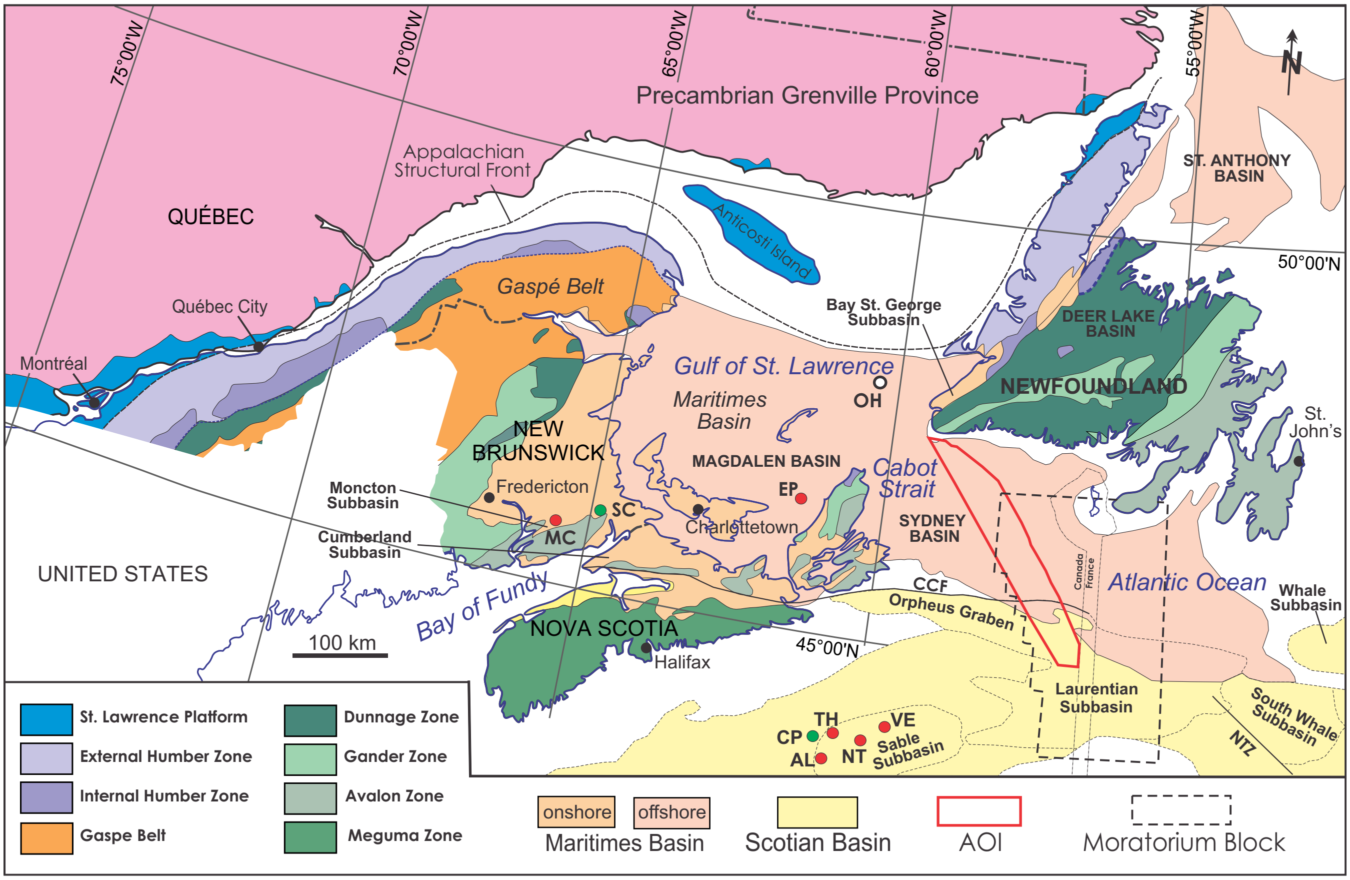

Figure 2. Regional tectonostratigraphic setting of eastern Canada with the location of the Upper Paleozoic Maritimes Basin (including Magdalen, Sydney, and St Anthony basins), Mesozoic-Cenozoic Scotian Basin (including Sable, Laurentian, South Whale subbasins, and Orpheus Graben), Cobequid-Chedabucto Fault (CCF), and the Newfoundland Transform Zone (NTZ). Producing oil/gas fields, significant discoveries, and prospects in the Maritimes and Scotian basins include Alma (AL), Cohasset-Panuke (CP). East Point (EP), McCully (MC), NorthTriumph (NT), Old Harry (OH), Stoney Creek (SC), Thebaud (TH), and Venture (VE). The Laurentian Channel area of interest (AOI) encompasses parts of the Sydney Basin and Orpheus Graben. The St Pierre Moratorium Block, in effect from 1967 to 1992, was established to exclude petroleum exploration in the region of a Canada-France territorial dispute. Maclean and Wade (1992) assessed the petroleum potential in the southern part of the moratorium block (see Fig. 3).

respectively), and an Upper Carboniferous succession of alluvial, fluvial, and estuarine clastic sedimentary rocks (Pictou/Morien Group). Carbonate bioherms occur in the basal Windsor/ Codroy Group (Gays River Formation). Coal-bearing sections (coal measures) are abundant in the Bradelle and Green Gables formations in the Pictou/Morien Group.

The early phases of sedimentation in the Sydney Basin are marked by deposition in extensional half-grabens (Pascucci et al., 2000; Kendell, 2005), including coarse siliciclastic rocks, organic-rich shale and coal in the McAdams Lake Formation, and alluvial fan and braided stream conglomerate, sandstone, siltstone, and shale in the Horton/Anguille Group (Fig. 4). These terrestrial synrift strata are up to 3000 m thick, with significant lateral thickness and facies variations in individual fault subbasins. These strata are complicated by lateral thickness and facies variations, typical of terrestrial depocentres adjacent to basin-bounding fault systems.

Marine sedimentation in Maritimes Basin began with the deposition of the Windsor/Codroy Group (Fig. 4). Windsor/Codroy strata include marine fossiliferous carbonate and evaporite, along with non-marine clastic rocks, deposited as a series of high-frequency transgressive-regressive cycles (Giles, 2009). Carbonate buildups or bioherms of the Gays River Formation occur locally in basal Windsor Group. Evaporitic deposits, including thick salt sections, occur in the lower Windsor/Codroy Group. Windsor strata are up to 1000 m thick in the Sydney Basin, with significant local depositional and structural variations due to syndepositional salt diapirism and salt withdrawal.

The Windsor/Codroy Group is gradationally overlain by the Mabou/Barachois Group (Fig. 4). Mabou/Barachois strata consist of a lower unit of shale, sandstone, minor limestone, and evaporite beds, and an

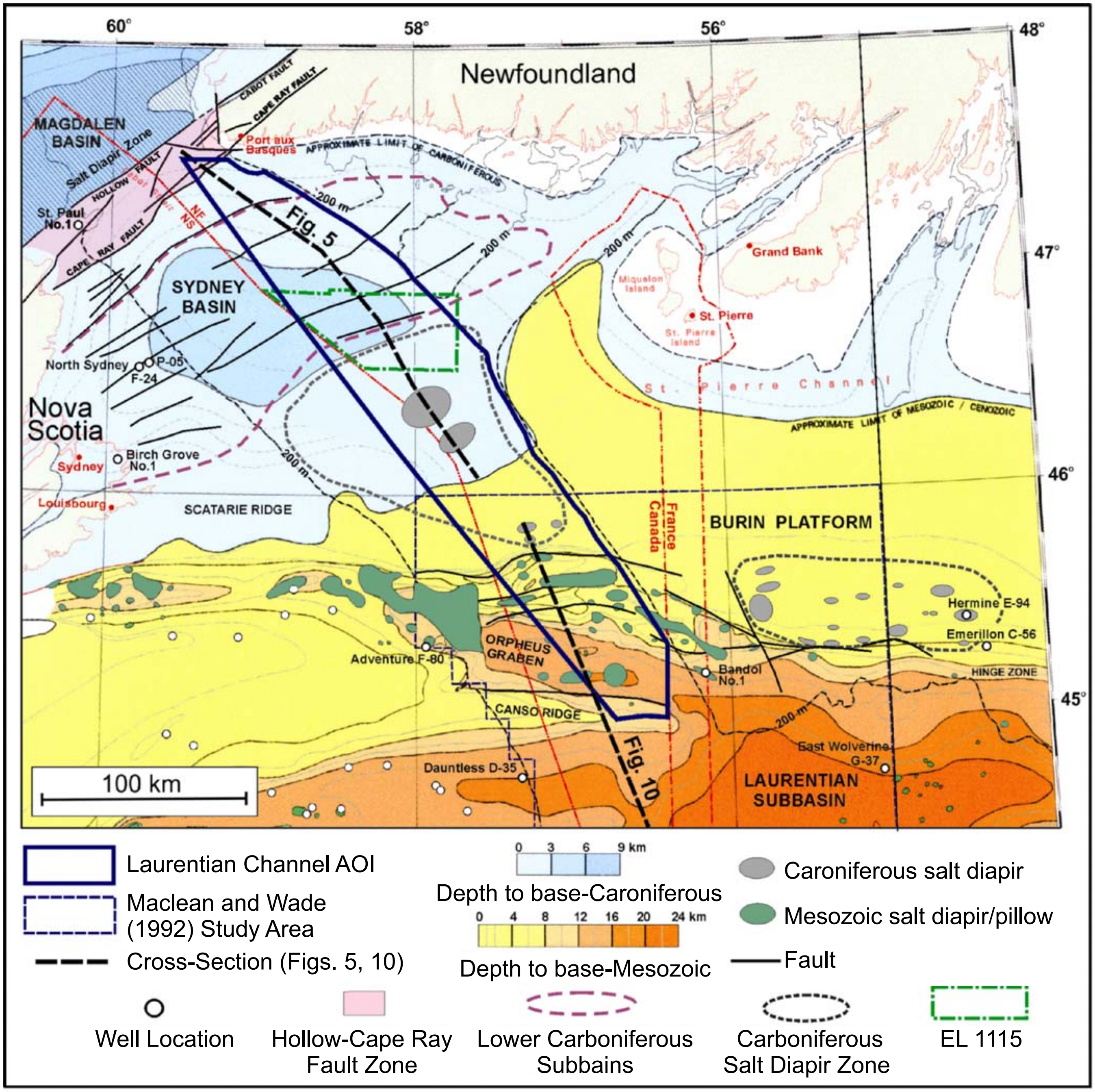

Figure 3. Geological map of the Laurentian Channel region offshore Nova Scotia and Newfoundland, with the location of the Laurentian Channel area of interest (ADI), petroleum assessment study area of Maclean and Wade (1992), regional cross-sections (see Figs. 5, 10), well locations (with select well names), and Canada-Newfoundland Offshore Petroleum Board Exploration License EL 1115 (Husky Oil limited). Base map modified from Wade (2000) and Canada-Nova Scotia Offshore Petroleum Board (2006). Depicted geological elements include depth-to-basement contours of the Carboniferous Sydney Basin and Mesozoic-Cenozoic Burin Platform, Orpheus Graben, and Laurentian Subbasin, Carboniferous and Mesozoic salt structures and diapir zones, major faults, offshore subsurface extent of Lower Carboniferous fault subbasins, and Hollow-Cape Ray fault deformation zone (compiled from MacLean and Wade (1992), Langdon and Hall (1994), Pascucci et al. (2000), Enachescu (2006), and this study).

upper unit containing sandstone and fine-grained redbeds. Dark, organic-rich shale and coal seams occur locally in the section.

Unconformably overlying Lower Carboniferous strata is the Upper Carboniferous Pictou/Morien Group (Fig. 4). Pictou/Morien strata include a thick basal section of coarse-grained fluviatile sandstone and coal measures (Bradelle Formation). Bradelle strata are gradationally overlain by the Green Gables Formation that consists of grey and red shales with locally well devel-

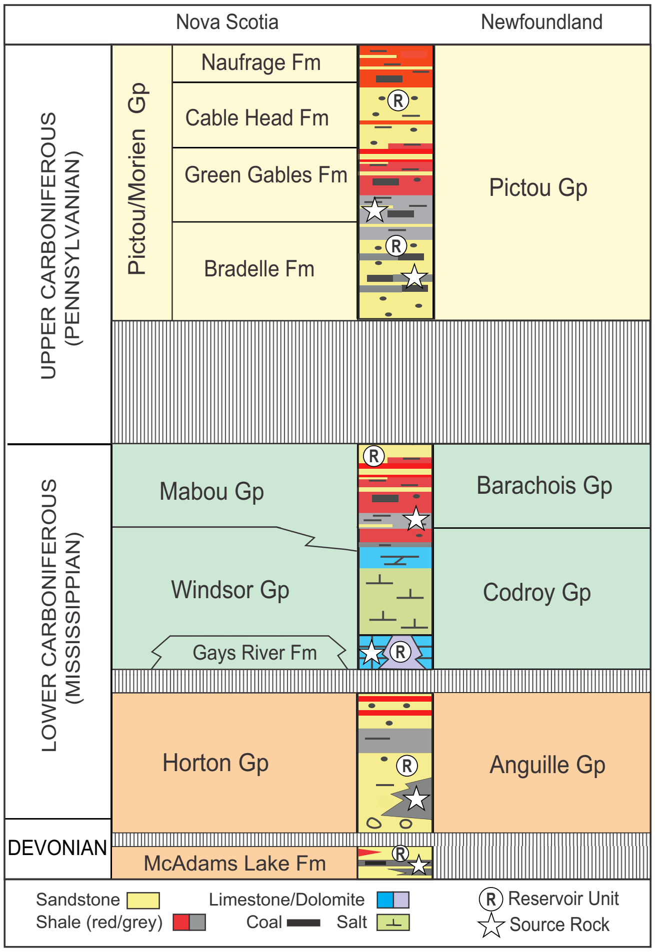

Figure 4. Stratigraphic column for the Upper Paleozoic Sydney Basin, with indicated petroleum reservoir and source-rock intervals (modified from Dietrich et al. (2011)).

oped fluvial sandstone. Coal seams are abundant in the lower part of the formation. A succession dominated by thick coarse-grained sandstone (Cable Head Formation) overlies Green Gables strata. The Cable Head Formation is abruptly overlain by fine-grained variably calcareous redbeds of the Naufrage Formation. The Pictou/Morien Group is up to 2000 m thick in the Sydney Basin.

Structural Features

Middle Devonian–Early Carboniferous basin evolution included development of fault-bounded pull-apart basins with complex internal depositional and structural patterns (Bell and Howie, 1990). Middle and Late Carboniferous tectonism led to transpressional faulting and subbasin inversions. A major phase of basin development involved mobilization of Windsor/Codroy Group evaporites, resulting in salt-withdrawal mini-basins and salt diapir zones.

Major structural elements in Sydney Basin include faults and fault subbasins, inversion anticlines, and salt diapirs (Figs. 3, 5). Salt diapir zones occur in the central and eastern parts of the basin (Fig. 3). The western margin of the offshore Sydney Basin is a complex deformation zone (Hollow-Cape Ray Fault Zone; Figs. 3, 5) containing basement ridges and faulted grabens.

Petroleum Exploration History

Hydrocarbon, in the form of coal, has a long history of exploitation in the Sydney Basin; production has taken place over the last 280 years. Although coal extraction has nearly ended, methane adsorbed within unmined

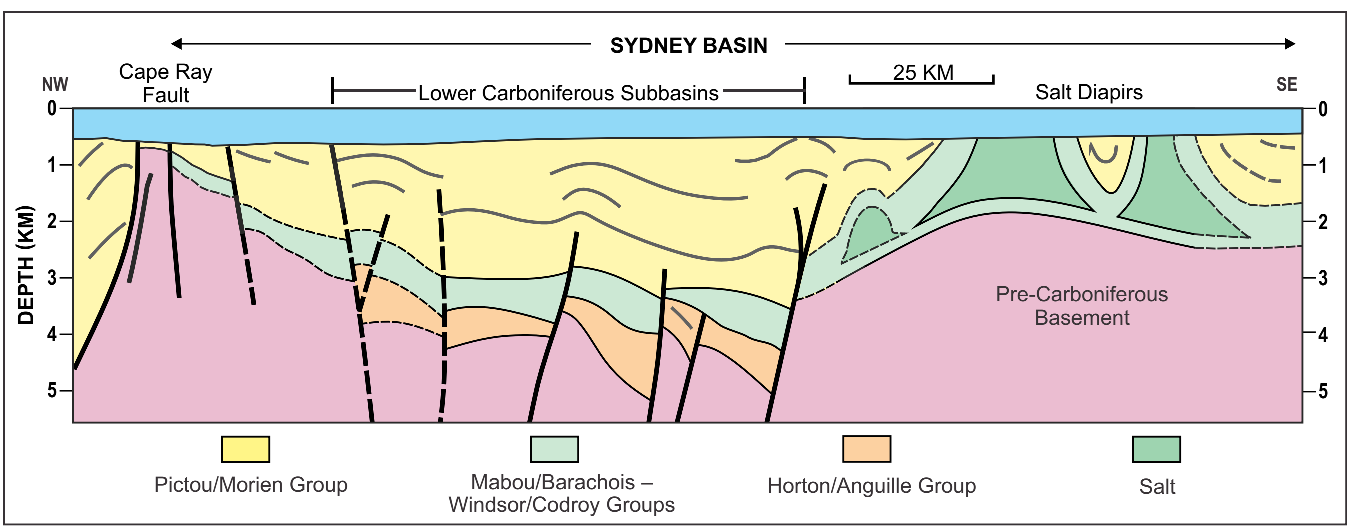

Figure 5. Geological cross-section of the Upper Paleozoic Sydney Basin in the northern part of the Laurentian Channel area of interest (section location in Fig. 3; includes interpretations from Langdon and Hall (1994), Kendell el al. (2005), Enachescu (2006), and this study). Depicted features include Lower Carboniferous (Horton/Anguille Group) fault subbasins, Lower Carboniferous (Windsor/Codroy Group) salt diapirs, and Upper Carboniferous (Pictou/Morien Group) faults and inversion folds (dashed-line segments are projected or inferred). The Cape Ray Fault and associated basement high is part of the Hollow-Cape Ray fault zone that separates the Sydney and Magdalen basins (Fig. 3).

coal seams remains and represents a significant energy resource. Conventional petroleum exploration in the Maritimes Basin began in the 1800s when shallow exploratory wells were drilled onshore Nova Scotia and New Brunswick to test oil seeps in outcropping Carboniferous rocks (McMahon et al., 1986; St. Peter, 1987; Fowler et al., 1993). The earliest conventional petroleum drilling activity centred around the Dover area in New Brunswick (first well drilled in 1859) and the Lake Ainslie area on Cape Breton Island (first well in 1869). This early exploration also led to the discovery of albertite in southern New Brunswick, a solid form of bitumen occurring in the Lower Carboniferous Horton Group (Fig. 4). These oil shales, mined in the 1850s, were exploited using retorting techniques to produce kerosene oil. Macauley et al. (1984) estimated in situ oil potential in the Albert Formation oil shales as 42.9 x 10^6 m^3 (270 MMbbls).

Onshore exploration activity has continued sporadically over the past 150 years. Several hundred wells have been drilled, most to relatively shallow depths of less than 1000 m. The Stoney Creek oil and gas field was discovered in southern New Brunswick in 1909 (Fig. 2). The field was in production for 82 years, with total production of 127 x 10^3 m^3 (800,000 barrels) of oil and 810 x 10^6 m^3 (28.6 Bcf) of natural gas from sandstones in the Lower Carboniferous Horton Group (Howie, 1968; Keighley and St. Peter, 2006). Redevelopment of the Stoney Creek field in recent years has led to new production of small volumes of oil. The Stoney Creek field contains an estimated in-place oil volume of 3.2 x 10^6 m^3 (20 MMbbls; Keighley and St. Peter, 2006). The McCully gas field, discovered in 2000 in the Moncton Subbasin in New Brunswick (Fig. 2), is the most significant discovery in the basin to date. The gas reservoir in the McCully field occurs in sandstone of the Lower Carboniferous Horton Group. Production in the field began in 2007, with daily average production rates of 0.7 x 10^6 m^3 (26.1 MMcf) from 29 wells (Corridor Resources, 2010a). The proven plus probable reserve estimate for the drilled portion of the McCully field (as of December, 2010) is 3.4 x 10^9 m^3 (121.4 Bcf) (Corridor Resources, 2010b). The wells are producing with very modest decline rates, indicating stable production performance. The estimated ultimate in-place gas resource of the field is 28.3 x 10^9 m^3 (1 Tcf; Durling and Martel, 2004). Other undeveloped oil and gas fields in the Moncton Subbasin include the Downey and West Stoney gas discoveries and the South Branch oil discovery. Undeveloped gas discoveries in other parts of the onshore Maritimes Basin include the Green Gables and Naufrage wells in Prince Edward Island and the Western Adventure wells in the Deer Lake Basin in Newfoundland (Fig. 2). A significant oil show was encountered in Carboniferous sandstone in wells drilled (in the 1990s) in the Bay St. George Subbasin in Newfoundland (Fig. 2).

Offshore exploration in the Maritimes Basin began with the drilling of the Hillsborough No. 1 well in 1943, in the southern Magdalen Basin. During the 1970s and early 1980s, numerous marine seismic reflection surveys were undertaken and fourteen offshore wells were drilled. One significant offshore gas discovery was made in the East Point E-49 well, drilled in 1970 (Fig. 2). A drill-stem test in the E-49 well flowed gas at a rate of 0.156 x10^6 m^3 (5.5 MMcf) per day. The gas reservoir occurs in sandstone in the Upper Carboniferous Cable Head Formation above a salt diapir. Development of the East Point field was deemed uneconomic after a step-out well was unsuccessful. The field contains an estimated in-place gas resource of 2180 x 10^6 m^3 (77 Bcf). There have been numerous large prospects and leads identified in the offshore Maritimes Basin. One of the largest undrilled prospects in the basin is the 360 km^2 Old Harry structure in northeastern Magdalen Basin (Fig. 2). The Old Harry structure is a salt-withdrawal anticline with reported multi-billion barrel (or multi-Tcf) resource potential (Corridor Resources, 2011).

Petroleum exploration in Sydney Basin, undertaken in the 1960s to 1980s, included numerous seismic surveys that culminated in the drilling of the onshore Birch Grove No.1 well and the offshore North Sydney P-05 and F-24, St. Paul P-91, and Hermine E-94 wells (Fig. 3). The Birch Grove well, drilled in 1968, penetrated 1344 m of Carboniferous strata. This well encountered no hydrocarbon accumulations or shows. The North Sydney wells were drilled to depths of 1661 m (well P-05) in 1974 and 1770 m (well F-24) in 1976, testing Upper Mississippian–Pennsylvanian strata in an anticlinal structure. Oil and gas shows were encountered in both wells. Although thick sandstone was intersected in these wells, reservoir quality was low (Enachescu, 2008). The St. Paul P-91 well (1983) was drilled in the complexly faulted transition zone between Sydney and Magdalen basins (Hollow-Cape Ray fault zone, Fig. 3). This well, drilled to a depth of 2885 m, encountered gas shows in Pennsylvanian strata. The Hermine well, drilled in eastern Sydney Basin in 1971 on the Burin Platform (Fig. 3), penetrated 1630 m of Carboniferous strata in a salt-cored anticline beneath 1600 m of Tertiary–Cretaceous strata. The well encountered gas shows in coal-bearing Upper Carboniferous strata. No petroleum exploration wells have been drilled in the Sydney Basin within the Laurentian Channel AOI. However, an active exploration license is held by Husky Oil Limited in the AOI (Fig. 3). This license was awarded by the Canada-Newfoundland Offshore Petroleum Board to the company in 2009. The company acquired 3000 line kilometres of seismic data in this license area in 2010.

Petroleum Geology

The Sydney Basin contains key system elements for petroleum generation and entrapment, including widespread reservoir rocks, abundant thermally mature source rocks, thick shale and salt sequences for seals, and abundant and diverse types of trap.

Reservoir Rocks

Sandstone reservoirs in the Sydney Basin are present in the McAdams Lake Formation, Horton/Anguille Group, Mabou/Barachois Group, and Bradelle and Cable Head formations in the Pictou/Morien Group (Fig. 4). Sandstone depositional environments include lacustrine shoreface, deltaic-fluvial channel fills, alluvial fans, and multi-storied fluviatile channels. The sandstone is of variable porosity and permeability and is often overlain by or laterally terminates abruptly into fine-grained facies. The porosity and permeability of sandstone in the Sydney Basin decreases with depth, with average porosity and permeability values (as measured in the offshore North Sydney F-24 well) of less than 10% and 1 mD, respectively, below depths of about 800 m (Hu and Dietrich, 2010). However, some sandstone units have above average porosity over a range of depth intervals, including porosity values above 10% to depths of up to 1500 m. The enhanced porosity of sandstone is likely secondary in origin and related to dissolution of calcite cements that formed early. The best quality sandstone reservoirs encountered in the Sydney F-24 well have log-calculated porosity and permeability of 20% and 100 mD, respectively (Hu and Dietrich, 2010).

Marine carbonate rocks in Windsor/Codroy Group strata also constitute potential reservoirs. Fossiliferous bioherms have been documented at several stratigraphic levels within the Windsor/Codroy Group, including the locally dolomitized and porous Gays River Formation at the base of the succession (Fig. 4; Giles et al., 1979; Boehner et al., 1988). Typical dimensions of mapped Gays River biohermal bank complexes have strike lengths of 10 km, widths of up to 2000 m, and thicknesses near 50 m (Boehner et al., 1988).

Source Rocks

Potential petroleum source rocks in the Sydney Basin include oil-prone lacustrine and alluvial shale in the McAdams Lake Formation, oil-prone lacustrine and gas-prone fluvio-deltaic shale in the Horton/Anguille Group, oil- and gas-prone marine carbonate and shale in the Windsor/Codroy Group, gas-prone fluvio-deltaic shale and coal in the Mabou/Barachois Group, and oil-prone lacustrine, oil- and gas-prone fluvio-deltaic shale and gas-prone coal measures in the Pictou/Morien Group (Fig. 4) (Macauley and Ball, 1984; Gibling and Kalkreuth, 1991; Mukhopadhyay, 1991; Mossman, 1992; Pascucci et al., 2000; Mukhopadhyay et al., 2002, 2004). Total organic carbon (TOC) content in Horton Group black shale is commonly greater than 2% and up to 20% in some organic-rich units. Although not directly identified in the offshore Sydney basin, seismic data indicate the possibility of lacustrine source rocks in Lower Carboniferous half-grabens (Pascucci et al., 2000). Windsor/Codroy Group carbonate and calcareous shale contain Type II and III kerogens with up to 5% TOC (Mossman, 1992). Although quite laterally extensive, Windsor marine limestone units are relatively thin and are separated by tight evaporitic strata, possibly limiting petroleum source capacity and charge. Coal measures are thick and widespread in the Upper Carboniferous Pictou/Morien Group. These coal measures contain Type II and III organic matter, with TOC values of up to 40%. Type III kerogens are dominant, indicating these coal measures have the potential to be a major natural gas source. In terms of thickness and areal distribution, the coal measures are likely the most abundant source rocks in the Sydney Basin. Natural gas generation from coal measures in the Maritimes Basin is documented by abundant gas shows in wells drilled through coal measure sections (Grant and Moir, 1992). Biomarker analyses of an oil-stained sandstone in Pictou/Morien Group in the North Sydney F-24 well indicates both marine and terrestrial source rock signatures, with a dominant derivation from terrestrial source rocks (Mukhopadhyay, 2004).

Source Rock Maturation and Hydrocarbon Generation and Migration

There are significant variations in thermal maturation conditions in Upper Paleozoic source rocks in the Maritimes Basin. The highest maturation levels on surface occur in onshore basin-margin areas of the Magdalen and Sydney basins, where strata are in the gas generation window or are over-mature. Strata are within the oil window (at surface) in most parts of the offshore Magdalen and Sydney basins. Depth-maturation trends indicate that present-day oil and gas generation windows in Carboniferous strata occur at depths from near-surface to about 5000 m (Grant and Moir, 1992; Rehill, 1996). In offshore wells in Magdalen Basin, the base of the oil generation window occurs at depths from 1500 to 2500 m (Lavoie et al., 2009). Carboniferous strata encountered in the offshore North Sydney F-24 and P-05 wells have maturation levels within the oil generation window to drilled depths of 1700 m (Mukhodpadhyay, 2004). The St. Paul P-91

Table 1. In-place oil and gas potential in the Maritimes Basin and Laurentian Subbasin.

Play name	Expected no. of fields (mean)	Range of play potential (million m^3)	Median play potential (million m^3)	Mean play potential (million m^3)	Mean of largest field size (million m^3)
Maritime Basin					
Lower Carboniferous sandstone oil	32	47.8-188.4	124	121	16.5
Lower Carboniferous sandstone gas	73	171630-672430	452070	439161	62034
Visean Windsor reefs (oil & gas)					
Upper Carboniferous sandstone oil	16	50.5-195.5	111.2	118.4	26.6
Upper Carboniferous sandstone gas	56	342760-1042000	656730	676808	88208
Total	48 (oil); 129 (gas)	143-345 (oil); 712220-1564900 (gas)	239 (oil); 1116500 (gas)	242 (oil); 1124724 (gas)	
Laurentian Subbasin					
Lower Jurassic Eurydice Formation shallow structural gas	2	0.0-30188	7277	12519	10001
Lower Jurassic Eurydice Formation deep structural gas	2	0.0-16609	3110	6795	6183
Middle Jurassic Mohican Formation shallow structural oil	1	0.0-76.3	12.4	28.3	29.9
Middle Jurassic Mohican Formation shallow structural gas	5	6905-83120	30460	39847	21826
Middle Jurassic Mohican Formation deep structural gas	2	0.0-25480	5855	10243	8517
Upper Jurassic Mic Mac Formation shallow structural oil	5	14.6-232-3	79.1	109.8	67.9
Upper Jurassic Mic Mac Formation shallow structural gas	20	53223-298923	148563	165421	49972
Upper Jurassic Mic Mac Formation deep structural gas	3	389-48077	12060	19999	14371
Lower Cretaceous Missisauga Formation structural oil	3	6.6-107.3	36.4	50	30.4
Lower Cretaceous Missisauga Formation structural gas	8	14326-99832	41835	51783	23986
Upper Cretaceous Logan Canyon/Wyandot structural oil	4	7.6-263.8	69.5	113.5	46.2
Upper Cretaceous Logan Canyon/Wyandot structural gas		1983-66732	17766	28680	19108
Stratigraphic oil				31.7	
Stratigraphic gas				34769	
Total	13 (oil); 46 (gas)	116.5-558.5 (oil); 188850-516500 (gas)	262.5 (oil); 319400 (gas)	349.2 (oil); 376719 (gas)	
Grand Total	61 (oil); 175 (gas)			591.2 (oil); 1501443 (gas)	

and Hermine E-94 wells, at the western and eastern margins of offshore Sydney Basin, respectively (Fig. 3), encountered above average thermal maturation levels, with most of the penetrated Carboniferous sections within the gas generation window. In the Hermine well, a pronounced increase in thermal maturation levels occurs across a Cretaceous–Carboniferous unconformity, indicating peak maturation of Carboniferous strata occurred prior to Mesozoic erosion and sedimentation (Avery, 1987).

Subsidence and petroleum generation modelling in the Maritimes Basin indicates that peak hydrocarbon generation occurred early in the basin's history, during late Carboniferous to Permian time (Ryan and Zentilli, 1993; Rehill, 1996). Most known oil and gas accumulations in the basin occur in reservoirs that are located in close proximity to source rocks, indicating that hydrocarbon migration occurred over relatively short distances. The thermal maturation models also indicate post-Early Permian uplift and erosion of 1000 to 4000 m across the Maritimes Basin.

Seals

Effective seals for Carboniferous petroleum accumulations are numerous and widespread in Sydney Basin. Excellent and effective seal for reservoirs in the McAdams Lake Formation, Horton/Anguille Group and lower Windsor/Codroy Group are the thick halite deposits in the middle Windsor/Codroy Group. Potential seals include thick shale intervals in the Mabou and Pictou/Morien groups. Reservoir sandstone is commonly interbedded with or laterally grade into shale, which can provide effective local seals for petroleum accumulations. Impermeable shale provides trap seals for all of the discovered oil and gas fields in the Maritimes Basin, including Stoney Creek, McCully, and East Point.

Traps

A variety of potential structural and stratigraphic petroleum traps occur in Carboniferous strata within the Sydney Basin. The complex structural history of the basin, including multiple phases of deformation and basin inversion, provide abundant opportunities for trap development. Common trap types include fault-blocks, roll-over anticlines, transpressional anticlines, and salt-diapir structures (Fig. 5; Enachescu, 2008). Potential salt-diapir traps are prominent in central and eastern Sydney Basin (Fig. 3). Stratigraphic traps may include Windsor Group carbonate reefs, onlap of sandstone onto basement highs or subbasin margins, and unconformity truncations.

Petroleum Plays and Oil and Gas Potential

A modern oil and gas assessment of the Paleozoic Maritimes Basin, including the Sydney Basin, was recently completed (Lavoie et al., 2009). This petro-

Figure 6. Lower Carboniferous (Horton/Anguille Group) sandstone play in the Maritimes Basin (modified from Lavoie et al., 2009), with location of the Laurentian Channel area of interest.

leum assessment involved analysis of three regional-scale petroleum plays. Based on considerations of source rock types, maturation levels, and hydrocarbon shows, all of the Maritimes Basin plays are considered to have both oil and gas potential. The oil and gas assessments were derived separately for each play, and all prospects were considered potential sites for individual oil or gas fields or combinations of oil and gas fields.

Lower Carboniferous Sandstone Play

The Lower Carboniferous sandstone oil and gas play includes all prospects in the Mississippian Horton and Anguille groups (Fig. 4) in fault subbasins in the onshore-offshore Magdalen, Sydney, Deer Lake, and St. Anthony basins (Fig. 6). In Sydney Basin, the play also locally includes Middle Devonian sandstone in the McAdams Lake Formation. The Stoney Creek and McCully oil and gas fields occur in this play. In offshore western Sydney Basin, including part of the Laurentian Channel AOI, Lower Carboniferous subbasins have been seismically mapped but not tested by exploration wells (Figs. 3, 6). Lower Carboniferous subbasins have not been identified in eastern Sydney Basin. Structural traps in the Lower Carboniferous sandstone play include compressional folds and fault blocks (Fig. 5). Stratigraphic traps include updip sandstone pinchouts and unconformities.

The Lower Carboniferous sandstone play has an estimated in-place oil potential of 47.8 x 10^6 to 188.4 x 10^6 m^3 (P90-P10), with median and mean estimates of 124 x 10^6 m^3 and 121 x 10^6 m^3, respectively (Table 1). The mean value of the number of predicted fields is 32. The mean estimate of the largest undiscovered field is 16.5 x 10^6 m^3 (Table 1). The Stoney Creek oil discovery is reported to contain 2.8 x 10^6 m^3 (Contact Exploration, 2008), which matches the 17^{th} largest pre-

Figure 7. Lower Carboniferous (Windsor/Codroy Group) carbonate play in the Maritimes Basin, with location of the Laurentian Channel area of interest (modified from Lavoie et. al. (2009)).

dicted field. The Lower Carboniferous sandstone play has an estimated in-place gas potential of 171.6 x 10^9 to 672.4 x 10^9 m^3, with median and mean estimates of 452.1 x 10^9 m^3 and 439.2 x 10^9 m^3, respectively (Table 1). The mean estimate of the number of gas fields in the play is 73, with the largest undiscovered gas field containing 62.0 x 10^9 m^3 of in-place gas (mean volume). The McCully gas field is reported as having an in-place median volume of 28.3 x 10^9 m^3 (1 Tcf) (Keighley, 2008). This volume matches most closely with the third largest predicted pool size.

Lower Carboniferous Carbonate Play

The Lower Carboniferous carbonate play is a stratigraphic play that includes all marine carbonate rocks in the Mississippian Windsor and Codroy groups (Fig. 4). The most prospective reservoirs in the play are the biohermal, usually dolomitized reefs in the Gays River Formation at the base of the succession. In some areas, Gays River bioherms are overlain by evaporite, which may provide an effective seal for petroleum accumulations. Very few petroleum exploration wells have tested these reef occurrences. Paleogeographic models and well and seismic data indicate the reef play occurs in a fairway around the Magdalen and western Sydney Basin (Fig. 7).

No quantitative analyses of the Lower Carboniferous carbonate play are available because the required data to constrain reservoir parameters and prospect numbers is lacking.

Upper Carboniferous Sandstone Play

The Upper Carboniferous sandstone play includes all clastic reservoirs in the Upper Mississippian to Pennsylvanian Mabou, Barachois, Pictou, and Morien

Figure 8. Upper Carboniferous sandstone play in the Maritimes Basin (modified from Lavoie et al., 2009), with location of the Laurentian Channel area of interest.

groups (Fig. 4). The play extends across most of the Maritimes Basin (Fig. 8). Primary reservoirs are fluvial sandstone units, which are thickest and most widespread in the Bradelle and Cable Head formations. The offshore East Point E-49 gas discovery occurs in this play, within the Cable Head Formation. Source rocks include interbedded coal measures and underlying Windsor carbonate or Horton Group shale. Seal is provided by interbedded or overlying shale units.

Primary trap-types are associated with salt structures, including salt-withdrawal anticlines, salt pillows and diapirs, and overhang and subsalt prospects (Fig. 5). Salt-diapir zones occur in the eastern Magdalen Basin, and central and eastern Sydney Basin (Fig. 3). Other structural trap-types include inversion folds and fault blocks (Fig. 5). Potential stratigraphic traps include channel sandstone pinchouts and unconformity truncations.

The Upper Carboniferous sandstone play has an estimated in-place oil potential of 50.5 x 10^6 m^3 to 195.5 x 10^6 m^3 (P90-P10), with median and mean estimates of 111.2 x 10^6 m^3 and 118.4 x 10^6 m^3 of in-place oil, respectively (Table 1). The mean estimate of the number of oil fields in the play is 16, with the largest undiscovered oil field predicted to contain 26.6 x 10^6 m^3 (mean estimate, in-place oil). The Upper Carboniferous gas play predicts a mean value of 56 fields having a play potential ranging from 342.8 x 10^9 to 1042 x 10^9 m^3, with a median in-place potential of 656.7 x 10^9 m^3 (Table 1). The mean volume of the play potential is 676.8 x 10^9 m^3. The largest gas field is estimated to contain 88.2 x 10^9 m^3 (mean in-place volume) (Table 1). The East Point E-49 field is reported to con-

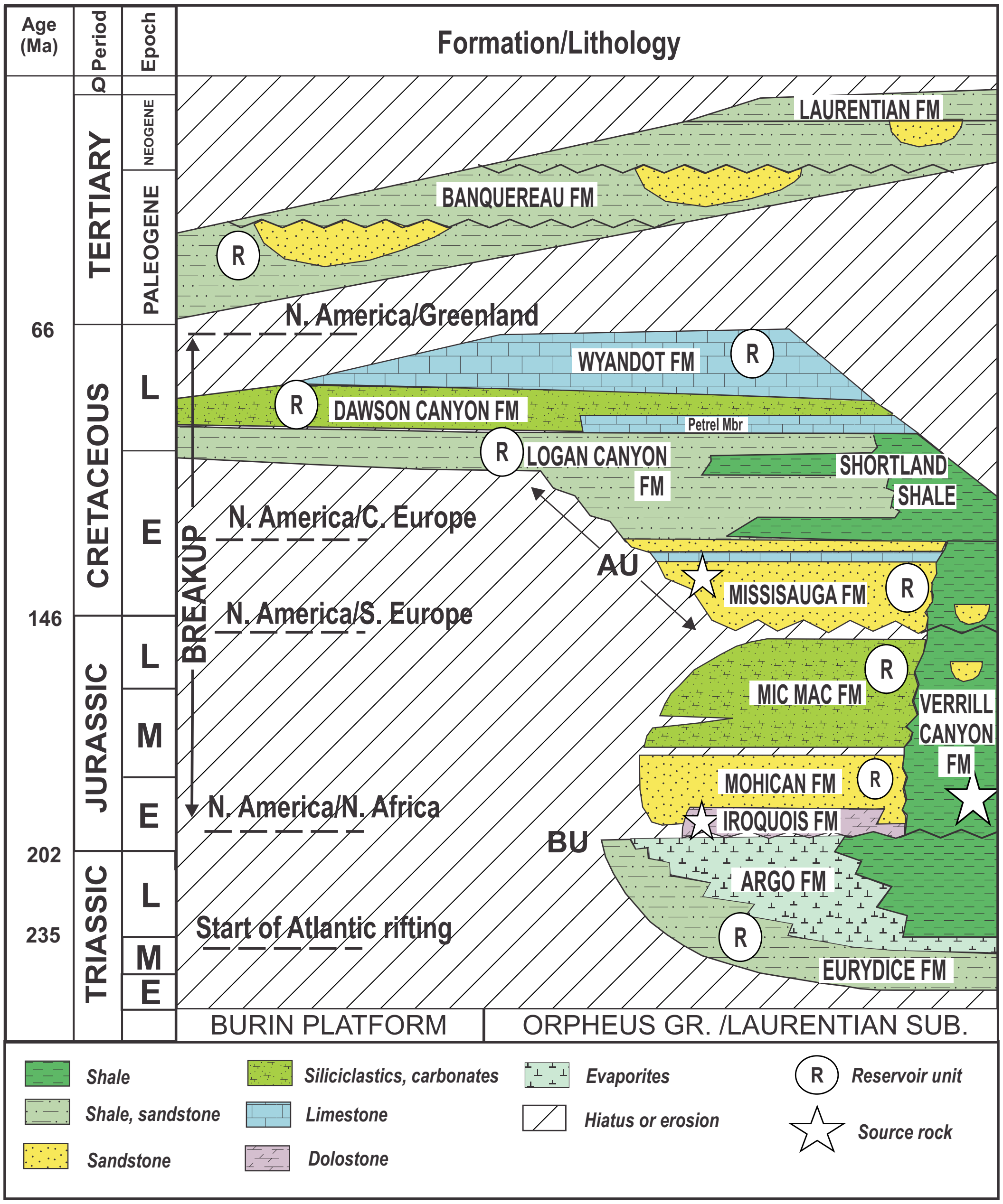

Figure 9. Stratigraphic column for the Mesozoic-Cenozoic Burin Platform, Orpheus Graben, and Laurentian Subbasin (modified from Maclean and Wade (1992)), with indicated petroleum reservoir and source-rock intervals. Abbreviations: AU-Avalon Unconformity; BU-Breakup Unconformity; Q-Quaternary. Timescale after Walker and Geissman (2009).

tain an in-place gas volume of 2.2 x 10^9 m^3. This relatively small field size does not satisfactorily match with any of our 56 predicted field sizes. The authors believe that this reported East Point gas volume relates to one sand horizon (an individual gas pool) in the East Point structure. Net pay estimates for this play were derived by measuring all potential sandy reservoir horizons in the thick Upper Carboniferous succession according to predefined net-pay cutoffs including porosity, permeability, water saturation and thickness criteria (Hu and Dietrich, 2008). The greater net-pay values derived from the petrophysical well-log analyses in Upper Carboniferous strata in the basin (including the succession in the East Point well) may have produced this apparent poor match of known and predicted field sizes in the play.

Total Petroleum Potential

Mean estimates of the total petroleum potential for the Maritimes Basin assessment region (from all plays quantitatively analyzed) are 242 x 10^6 m^3 (1521 MMbbl) of in-place oil and 1124.7 x 10^9 m^3 (39.7 Tcf) of in-place gas (Table 1). High-confidence (90% probability) and speculative (10% probability) estimates of total oil potential are 143 x 10^6 and 345 x 10^6 m^3 (899

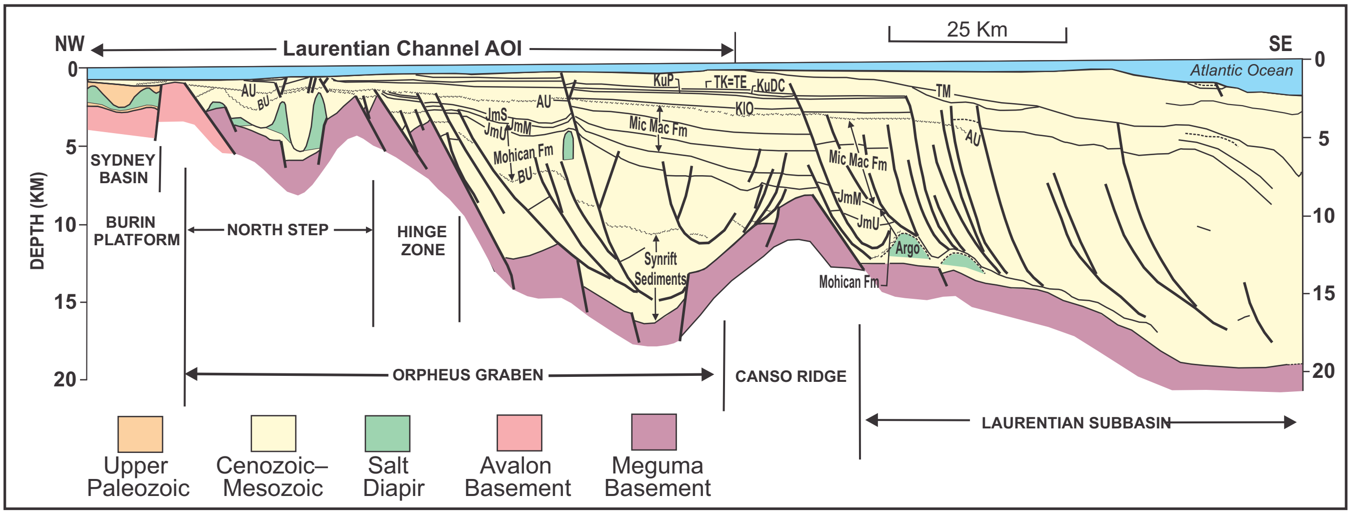

Figure 10. Geological cross-section of the southern Sydney Basin, Burin Platform, Orpheus Graben, Canso Ridge, and Laurentian Subbasin (section location in Fig. 3; adapted from Maclean and Wade (1992) and Fagan (2010)). Abbreviations: AU-Avalon Unconformity; BUBreakup Unconformity; JmM-Middle Jurassic Mohican Formation; JmS-Middle Jurassic Scatarie Member; JmU-Middle Jurassic Unconformity; KIO-Lower Cretaceous 'O' Marker; KuDC-Upper Cretaceous Dawson Canyon Formation; KuP-Upper Cretaceous Petrel Member; TE-Eocene Unconformity; TK-Cretaceous-Tertiary boundary; TM-Miocene Unconformity. The southern part of the Laurentian Channel area of interest (AOI; Fig. 3) encompasses parts of the Sydney Basin, Burin Platform, Orpheus Graben, and northern Canso Ridge.

and 2170 MMbbl), respectively. High-confidence and speculative estimates of gas potential are 712.2 x 10^9 and 1564.9 x 10^9 m^3 (25.2 and 55.3 Tcf), respectively (Table 1).

Comparing Lower and Upper Carboniferous sandstone play results, the greater gas potential occurs in the Upper Carboniferous play (about 30% greater) but oil potential is slightly less (Table 1). Even though seal is expected to considerably enhance hydrocarbon preservation in the subsalt Lower Carboniferous play, the significantly greater gas potential in the Upper Carboniferous play reflects its greater play size with larger numbers and sizes of prospects. This prospect number and size difference overrides the differences in seal risk for the two plays – the Lower Carboniferous play having lower seal risk due to enhanced seal potential associated with subsalt prospects (Fig. 5). The slightly lower oil potential in the Upper Carboniferous play is attributed to the higher risk associated with potential source rock charging the Upper Carboniferous potential reservoirs with liquid hydrocarbons. The largest individual oil and gas fields are predicted to occur in the Upper Carboniferous play (Table 1). The oil and gas resources in the Upper Carboniferous play are concentrated in fewer large fields compared to the Lower Carboniferous play. The higher risk associated with seal, source, and timing assigned to the Upper Carboniferous play reduced the number of predicted fields, even though there are more prospects in the play. Field-size rankings for all plays suggest that about 35 to 60% of the region's total petroleum resource is expected to occur in the five largest oil and gas fields. This resource distribution indicates a moderately to highly concentrated hydrocarbon habitat, typical of rifted passive margin basins (Klemme, 1984).

SCOTIAN BASIN (ORPHEUS GRABEN)

Regional Geological Setting

The Orpheus Graben is part of the Mesozoic-Cenozoic Scotian Basin (Fig. 2). The Scotian Basin, which is offshore of Nova Scotia and southern Newfoundland, includes the Sable, South Whale, Whale, and Laurentian subbasins (Fig. 2). Development of the Scotian Basin began during Late Triassic rifting of the super-continent Pangaea. Oblique and perpendicular rift arms or branches also formed, such as Orpheus Graben. Rifting continued until Middle Jurassic in the Scotian Basin (Young et al., 2005).The Laurentian Subbasin developed as part of the Scotian Basin depositional regime during Late Triassic to Middle Jurassic. However, during Middle Jurassic to Aptian, the hybrid Laurentian Subbasin developed on a transform margin (Newfoundland Transfer Zone; Fig. 2), where extension, transtension, and subsidence took place (Enachescu and Fagan, 2009). The basin is located at a major transform margin (southwest Grand Banks Transform; Pe-Piper and Piper, 2004) where continental crust beneath the Grand Banks basins abuts underlying oceanic-transform crust in Laurentian Subbasin. The subbasin continued to subside, tilt, and receive massive sediment influx from the paleo-St. Lawrence River during Late Cretaceous to Tertiary. After movements along the transform margin, north Atlantic rifting and seafloor spreading resumed along a north-south axis during Aptian, followed by rifting between

Labrador and Greenland. The Orpheus Graben developed as a faulted subbasin (within the larger Laurentian Subbasin) in response to Jurassic–Cretaceous strike-slip and extensional displacements on the Cobequid-Chedabucto fault zone (Fig. 2). The Canso Ridge forms the southern margin of the Orpheus Graben (Fig. 3).

Stratigraphy

The Orpheus Graben and Laurentian Subbasin contain up to 20,000 m of Mesozoic-Cenozoic sedimentary strata (Figs. 9, 10). Synrift (non-marine, lacustrine, and shallow marine) and post-rift (carbonate margin, fluvial-deltaic, and deep water) depositional systems are all represented in the stratigraphic succession. The oldest synrift strata comprise red sandstone, siltstone and shale of the Eurydice Formation (Fig. 9). In the Orpheus Graben, the Eurydice succession is up to 3000 m thick (MacLean and Wade, 1992). The Eurydice Formation is overlain by evaporite of the Upper Triassic-Lower Jurassic Argo Formation, consisting of thick salt beds separated by zones of red shale (Wade and MacLean, 1990). Interfingering relationships between the partly coeval Eurydice and Argo formations occur on the basin margins. The Argo Formation attains thicknesses in excess of 5000 m in the Orpheus Graben, with widespread salt deposits in the western part of the graben. Salt flowage occurred during post-Argo sediment loading and periodic reactivation of the Cobequid-Chedabucto fault system (Wade and MacLean, 1990). Salt pillows and diapirs are most common in areas of thick sediment in withdrawal synclines. Authochthonous salt is up to1800 m thick (Jansa and Wade, 1975), with salt sections up to 10 km thick in diapirs.

The Breakup Unconformity (BU; Figs. 9, 10), which occurs at the top of the synrift sequence, developed during uplift at the onset of seafloor spreading and plate separation (Fagan, 2010). Diapiric Argo salt has pierced this unconformity in several places in the Orpheus Graben (MacLean and Wade, 1992). Overlying the BU is the post-rift Lower Jurassic dolomite-rich Iroquois Formation and a partly coeval, basinward-prograding succession of sandstone and shale (Mohican Formation; Fig. 9). The Lower to Middle Jurassic Mohican Formation is up to 5500 m thick in the study area. The formation thins dramatically in the hinge zone (Fig. 10). There are some indications of reservoir and source rock potential in the Iroquois and Mohican formations in Scotian and Grand Banks basins (Sinclair, 1988; Wade and MacLean, 1990). The Mohican Formation completed the process of filling rift-related grabens.

A second thick post-rift clastic sequence, the Middle to Upper Jurassic Mic Mac Formation, overlies the Mohican Formation (Figs. 9, 10). The formation ranges in thickness from 6000 m in the Laurentian Subbasin to an erosional edge at the hinge zone. The Mic Mac Formation consists of varying proportions of siliciclastic and limestone beds.

A second breakup phase during the Late Jurassic to Early Cretaceous (when North America separated from Europe) produced the Avalon Unconformity (AU; Figs. 9, 10), with its associated erosion of older sediments. The unconformity separates faulted and folded rocks below from the relatively undeformed flat-lying Cretaceous strata above (Fig. 10). Directly overlying the AU is the Lower Cretaceous Missisauga Formation, a 250 to 1500 m thick succession of alluvial and delta plain sandstone and shale (Fig. 9). The succession also contains a thin transgressive limestone zone (O marker, Fig. 10; Jansa and Wade, 1975).

The distal or basinal facies equivalent of the Lower Jurassic–Lower Cretaceous Iroquois, Mohican, Mic Mac, and Missisauga formations is the Verrill Canyon Formation (Fig. 9). It consists of shale with thin beds of limestone, siltstone, and sandstone. Well data indicate the Verrill Canyon Formation is 94 to 920 m thick. Verrill Canyon dark shale is considered to be a major potential source rock (Barss et al., 1980; Powell, 1982; Mukhopadhyay 1989, 1990).

The Missisauga Formation marks the termination of the thick post-rift clastic regressive sequence on the southeastern Canadian Atlantic margin. Slow transgression ensued, leading to the deposition of extensive alternating units of shale and fining-upward sandstone and shale of the Aptian to Early Cenomanian Logan Canyon Formation (Fig. 9). Depositional environments vary from a broad coastal plain to a shallow shelf (Wade and MacLean, 1990). Well control indicates the Logan Canyon is 175 to 775 m thick. The distal/turbidite equivalent of the Logan Canyon Formation is the Shortland Shale unit. In the Orpheus Graben, basalt flows and volcaniclastic rocks are interbedded with shale units in the lower Logan Canyon Formation. These thin volcanic flows probably originated at tensional fractures along the southern flank of the Orpheus Graben (Wade and MacLean, 1990). The flows were later disturbed and deformed by salt tectonics and faulting.

During the Late Cretaceous, continued subsidence and sea-level rise led to deposition of transgressive marine shale, chalk, and minor amounts of limestone of the Dawson Canyon Formation (Fig. 9). Thicknesses vary from 330 to 520 m in the study area. Overlying Dawson Canyon strata are approximately 100 to 400 m of Wyandot chalk, chalky mudstone, marl, and minor limestone. Late Cretaceous subsidence in the Laurentian Subbasin and Orpheus Graben led to deposition of a relatively thick Wyandot section, compared to other parts of the Scotian Basin (MacLean and Wade, 1992).

Unconformably overlying the Wyandot Formation and older strata is the Paleocene to Pliocene Banquereau Formation, consisting of mudstone, sandstone, and conglomerate (Fig. 9). Tertiary strata were deposited in a series of downlapping or prograding sequences, with a cumulative thickness of up to 4000 m. Glaciomarine sand, silt and clay of the Pleistocene Laurentian Formation overlie the Tertiary succession. Pleistocene sediments are thin in inner shelf areas, but attain thicknesses of up to 1500 m on the outer shelf and slope (Wade and MacLean, 1990).

Structural Features

The early basin evolution of Orpheus Graben and Laurentian Subbasin involves rifting with widespread development of extensional features such as half-grabens (Fig. 10). Mobilization of evaporite deposits (Argo salt) created halotectonic structures (pillows, diapirs, swells, and withdrawal structures) that deformed the sedimentary succession. Transtensional movements during Late Jurassic to Cretaceous, along the Cobequid-Chedabucto fault zone and the Newfoundland Transform Fault, resulted in the development of compressional folds, locally contemporaneous with and altered by salt tectonics. Parallel Late Cretaceous-Tertiary sediments were deformed by gravity slides and intruded by salt diapirs.

The Orpheus Graben in the AOI region contains two subbasins separated by a faulted basement ridge (Fig. 10). The North Step is a relatively shallow subbasin containing basement fault blocks, salt diapirs, and pillows. The main Orpheus Graben depocentre, south of the hinge zone, contains abundant listric faults, rollover anticlines, and salt diapirs (Figs. 3, 10). The Canso Ridge, a faulted basement high, separates the Orpheus Graben and Laurentian Subbasin. The Burin Platform, north of Orpheus Graben and Laurentian Subbasin, consists of a relatively thin section of undeformed Mesozoic-Cenozoic strata overlying the Carboniferous Sydney Basin (Figs. 3, 10).

Petroleum Exploration History

Petroleum exploration in the Scotian Basin began in the early 1960s with the acquisition of several hundred thousand line kilometres of reflection seismic data. This seismic work led to the drilling of the first well in the Scotian Basin (Sable Island C-67) in 1967. This well encountered gas shows in a thick section of Cenozoic–Mesozoic sedimentary clastic rocks.

The first significant gas discovery in Scotian Basin was made in 1969 in the Sable Subbasin at Onondaga E-84 (Fig. 2; Wade et al., 1989). This undeveloped average-size gas accumulation (6.8 x 10^9 m^3 (241 Bcf): Canada-Nova Scotia Offshore Petroleum Board (CNSOPB), 2000) occurs in Early Cretaceous sandstone draped over a Jurassic Argo salt diapir. The first significant oil discovery was made in 1971 within the Sable Island E-48 well of the West Sable field (Fig. 2; Wade et al., 1989). This undeveloped field is also draped over an Argo salt diapir with oil, gas, and condensate-charged sands scattered among 1000 m of gross pay in Early to Late Cretaceous sands. Best current estimate of in-place oil and gas in this field is 18.3 x 10^6 m^3 (115 MMbbls) and 8.9 x 10^9 m^3 (315 Bcf), respectively (CNSOPB, 2000). In 1972, a major gas and condensate discovery was made in the Thebaud P-84 well (Fig. 2). The Thebaud gas field was put into production in 1999 (Sable Energy Offshore Project - SOEP). The gas reservoirs occur in Cretaceous sandstone units within a fault-bounded rollover anticline. The field contains an in-place mean gas resource of 33.1 x 10^9 m^3 (1.17 Tcf; CNSOPB, 2000). Other commercial gas discoveries in the Scotian Basin include the Venture, North Triumph, and Alma fields (Fig. 2), all currently in production as part of the SOEP development system. Average daily production from SOEP is 400 to 500 Bcf and 20,000 barrels of condensate (Enachescu and Fagan, 2009). Other oil discoveries in the Scotian Basin include the Cohasset and Panuke fields, which were put into production in 1992 (Fig. 2). The oil reservoirs in these fields occur in Lower Cretaceous sandstone beds in anticlinal structures. Production from the Cohasset-Panuke fields ended in 1999. The last major discovery in the Scotian Basin was made in 1998, in a well drilled below the depleted Panuke oil field. The Deep Panuke gas reservoir occurs in fractured and dolomitized Jurassic platform-margin carbonate (Hogg and Enachescu, 2001; Wierzbicki et al., 2004) and contains an estimated 39.6 x 10^9 m^3 (1.4 Tcf) of in-place gas. Delays in development of Deep Panuke occurred because of insufficient initial reserve volumes and low commodity prices. The field is currently under development, with initial production expected in 2011.

Petroleum exploration in the Orpheus Graben and Laurentian Subbasin was limited and sporadic, due to the establishment of the St. Pierre Moratorium Block in 1967 (Fig. 2). Petroleum exploration activity was prohibited in the moratorium block during the 25 year period of an offshore territorial dispute between Canada and France (Fig. 2). In 1992, an International Court of Arbitration awarded France exclusive jurisdiction over a zone of 24 nautical miles around the islands of St. Pierre and Miquelon as well as a 10.5 nautical mile corridor extending 200 nautical miles due south from the islands (Figs. 1, 2). The remainder of the St. Pierre Moratorium Block was awarded to Canada.

Industry seismic surveys were undertaken in the Laurentian Subbasin region in the early 1970s, outside the area of the moratorium block. Eight exploration wells were drilled during the 1970s exploration phase, including Dauntless D-35 in the western Laurentian Subbasin, Emerillon C-56 in the northern Laurentian Subbasin, Hermine E-94 in the Burin Platform, and Adventure F-80 in the Orpheus Graben (Fig. 3). All of the early exploration wells encountered good reservoir sections, but no oil or gas accumulations. Additional industry seismic surveys were undertaken in the region in the early 1980s. In 1984 and 1985, the Geological Survey of Canada acquired 3100 line-kilometres of reflection seismic data in the southern part of the St. Pierre Moratorium Block, to provide data for a geological and petroleum resource assessment (MacLean and Wade, 1992). In the late 1990s and early 2000s, three deep wells were unsuccessfully drilled on the Scotian Slope looking for turbidite reservoirs. In Laurentian Subbasin, a well was drilled by Exxon-Mobil in 2001 on a continental shelf location in French territory (Bandol No. 1; Fig. 3). Although the Bandol well remains confidential, media and operator reports indicated the well encountered thick reservoir sections, but no oil or gas accumulations (Fagan and Enachescu, 2007; Enachescu and Fagan, 2009). The period of confidentiality for Bandol ends in 2011, although no further information is known at the time of writing. In 2002, a territorial dispute in the region between Newfoundland and Labrador and Nova Scotia was resolved, with most of Laurentian Subbasin falling under Newfoundland and Labrador jurisdiction. In 2004 and 2005, large seismic data sets were acquired in the area by Conoco-Phillips and partners. In 2009, the East Wolverine G-37 well was drilled in the deep-water part of the east-central Laurentian Subbasin (Fig. 3). The well was dry and abandoned.

Orpheus Graben, the northwestern arm of Laurentian Subbasin, was tested by five wildcat petroleum exploration wells in the early 1970s (Fig. 3). The wells intersected Tertiary and Mesozoic sediments unconformably overlying the Lower Paleozoic Meguma Terrane basement but no significant hydrocarbon shows were encountered.

No petroleum exploration wells have been drilled in the Orpheus Graben or Burin Platform within the Laurentian Channel AOI. Petroleum exploration permits were granted to industry companies (including Mobil, Gulf Canada, and Texaco) in the early 1960s and 1970s, in the Laurentian Subbasin-Orpheus Graben region. These exploration permits were converted to eight exploration licenses in 2004, after boundary disputes were resolved. Seven of these exploration licenses were awarded to Conoco-Phillips and partners and the other to Imperial Oil. Two of these licenses encompassed areas that are now part of the Laurentian Channel AOI. However, these exploration licences have expired in recent years and there are currently no active licences in the southern AOI. Conoco-Phillips acquired about 3300 line-kilometres of 2-D seismic data in 2004. In 2005, the company acquired two areas of 3-D seismic data on the continental slope and rise.

Petroleum Geology

All key petroleum system elements for petroleum generation and entrapment occur in the Orpheus Graben and Laurentian Subbasin, including abundant reservoir rocks, thermally mature source rocks, thick shale and salt sequences for seals, and abundant and diverse trap types.

Reservoir Rocks

Good quality sandstone reservoirs occur throughout the Jurassic to Cretaceous succession, with particularly thick alluvial and deltaic sandstone present in the Mic Mac and Missisauga formations (Fig. 9). Mesozoic deep-water turbidite and submarine fan sandstones also occur in the region. Tertiary sediments, especially in deep water, may also have significant reservoir potential. Dolomitized carbonate reservoirs, developed at the platform margin in the Jurassic Iroquois Formation, may occur in the Laurentian Subbasin. A carbonate reservoir analogue in the central Scotian Basin is the Deep Panuke gas field. In the Deep Panuke area, fault-controlled dolomitization in Jurassic platform-margin carbonate created reservoirs with porosity from 3 to 40% and permeability from 1 millidarcy to several darcies.

Source Rocks

The proven source rock for most of the gas, condensate, and oil discovered in the Scotian Basin is the Middle Jurassic–Lower Cretaceous Verrill Canyon Formation (Fig. 9). Shale in the Verrill Canyon Formation contains 2 to 4% TOC, with mainly gas-prone Type III kerogens. Some intervals contain marine Type II kerogen. Prodelta shale in the Missisauga Formation contains oil-prone Type II organic matter (Mukhopadhyay, 1989, 1990). Evaporitic dolostone in the Iroquois Formation is a potential oil source rock (Sinclair, 1988). In northern parts of the Laurentian Subbasin and Orpheus Graben, underlying Carboniferous coal measures may be sources for natural gas accumulations in Jurassic-Cretaceous reservoirs.

Source Rock Maturation and Hydrocarbon Generation and Migration

Petroleum generation in the Jurassic Verrill Canyon Formation began in the Early Cretaceous and continued until Tertiary. The top of the petroleum generation zone occurs at a depth of about 4000 m in shelf areas, with increasing depths on the deep-water slope and rise

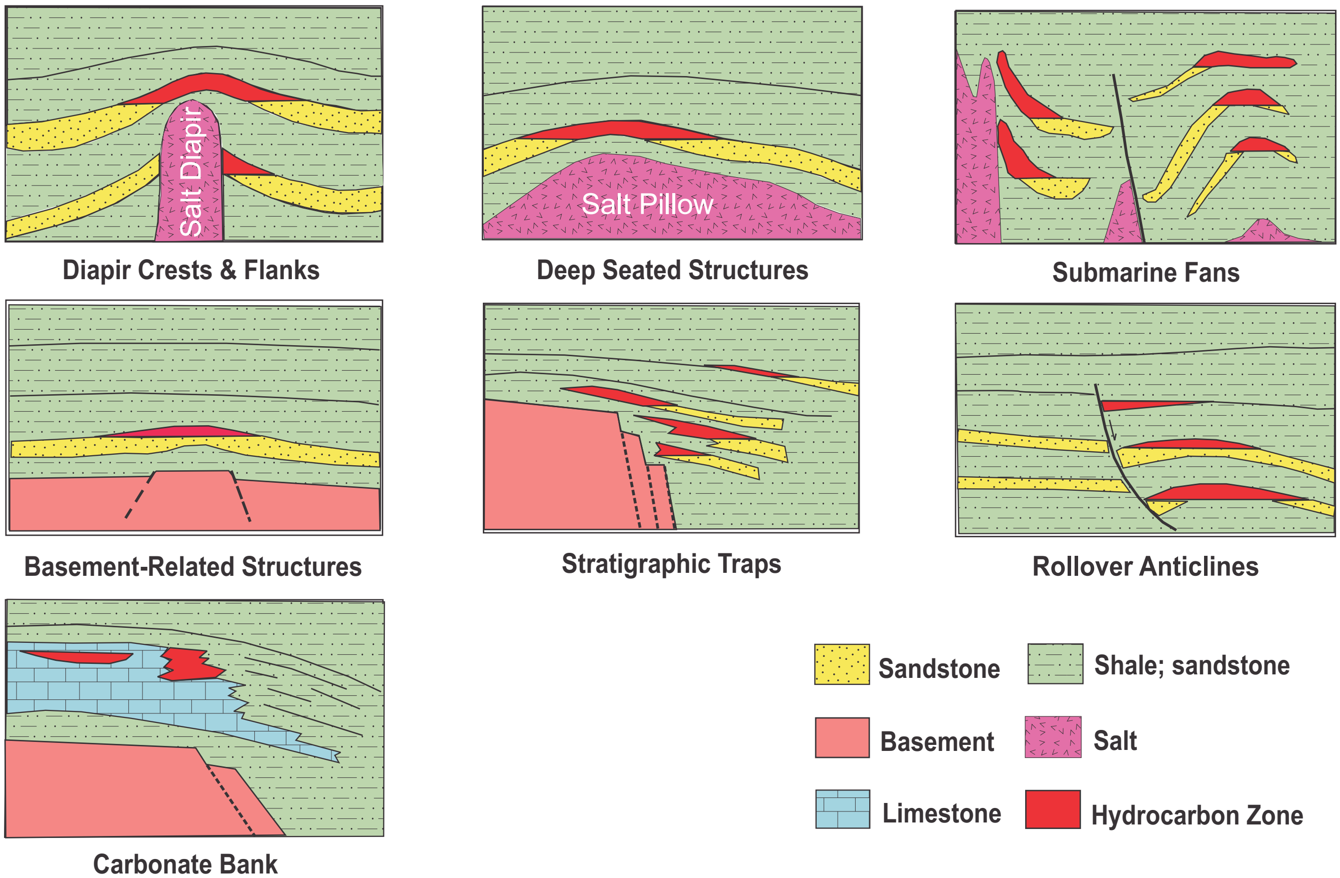

Figure 11. Trap types in the Laurentian Subbasin and Orpheus Graben (modified from Wade et al. (1989)).

(MacLean and Wade, 1992). Peak petroleum expulsion occurred at burial depths between 4000 and 6000 m (Nantais, 1983). The generated hydrocarbons have migrated mostly vertically, predominantly along the numerous extensional faults. The Verrill Canyon Formation in the central Laurentian Subbasin is within the marginally mature to mature zone for petroleum generation (Powell, 1982). In contrast, Verrill Canyon strata in the Orpheus Graben may have reached higher levels of thermal maturation, with source rocks in the mature to over-mature windows. The kerogen types and maturation levels indicate the Orpheus Graben will have both oil and gas potential, albeit with natural gas the most likely or abundant hydrocarbon type. Gas chimneys have been identified on seismic sections in the study area (MacLean and Wade, 1992; Fagan, 2010) showing that the gas appears to be rising from Jurassic sediments to the surface.

Seals

Abundant sections of shale, tight sandstone, and carbonate provide top and lateral seals for reservoirs in the Laurentian Subbasin and Orpheus Graben (Enachescu and Fagan, 2009). An excellent regional top seal are mudstone and clay intervals in the Upper Cretaceous Dawson Canyon Formation (Fig. 9). Argo salt diapirs and canopies may provide excellent seals for adjacent or underlying clastic units.

Traps

A variety of potential structural and stratigraphic petroleum traps occur in Mesozoic and Cenozoic strata within the Orpheus Graben and Laurentian Subbasin (Fig. 11). The polyphase structural history of the basins, where various subsidence phases are interspersed with periods of deformation or basin inversion and salt tectonics, provides abundant opportunity for trap development and filling by petroleum. Structural traps include rollover anticlines, tilted fault blocks, and drape over basement highs. Salt-related traps include drape over salt diapirs and swells, onlap against salt-structure flanks, and subsalt traps associated with salt overhangs or canopies. Fault-related traps may occur in strata within or above salt-withdrawal minibasins. Stratigraphic traps include updip pinchouts of fluvial channel and submarine fan sandstone units, and dolomitized shelf-margin carbonate banks (Fig. 11).

Petroleum Plays and Oil and Gas Potential

MacLean and Wade (1992) presented a comprehensive petroleum assessment of the Orpheus Graben and Laurentian Subbasin in the St. Pierre Moratorium

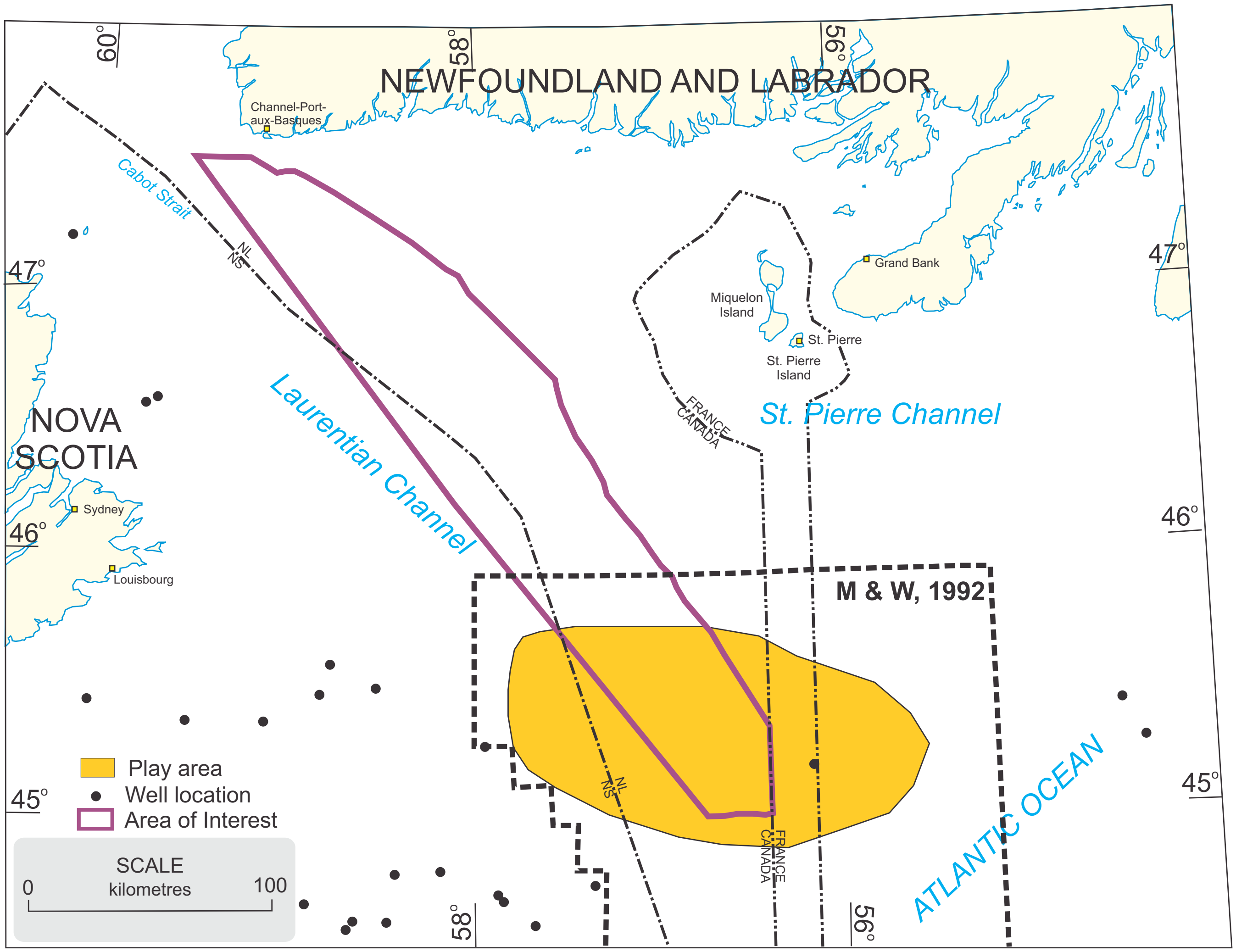

Figure 12. Map showing the location of the Lower Jurassic Eurydice Formation structural gas play in the Laurentian Subbasin and Orpheus Graben. Location of the Laurentian Channel area of interest and the assessment study area of Maclean and Wade (1992) are also shown.

Block (Figs. 2, 3). Their study involved analyses of nine regional-scale petroleum plays including a Carboniferous play whose strata have now been included in a more recent Maritimes Basin assessment (Lavoie et al., 2009). The plays assessed by MacLean and Wade (1992) were defined on the basis of potential reservoir units and their accompanying structural and stratigraphic traps, at depths above 7000 m. The petroleum resource volumes derived in their study represent conservative estimates, as many deep prospects in Lower Jurassic strata on the outer shelf and slope, such as turbidites, submarine fans, and channels, were not included in the assessment. Based on considerations of source rock types, maturation, and hydrocarbon shows, most of the assessed plays were considered to have both oil and gas potential. Oil and gas assessments were derived separately for each play, and all prospects were considered potential sites for individual oil or gas fields or combinations of oil and gas pools. A Lower Jurassic play was considered to have only gas potential, due to the gas-prone (Type III) source rocks in the play.

Lower Jurassic Eurydice Formation Structural Plays

The Lower Jurassic Eurydice play has 51 structural prospects identified in the northwestern Laurentian Subbasin and Orpheus Graben (Fig. 12). Depths of these structures vary from 1000 to 7000 m. Two plays were defined in the same area, one for deep prospects (5000-7000 m) and one for shallower prospects (1000-5000 m). Most of the prospects are related to salt structures, although rollover anticlines, tilted blocks, and deep basement structures are also present (see Figure 23 of MacLean and Wade (1992)). Effective reservoir porosity in Eurydice sandstone reservoirs is 15% in shallow prospects and up to 8% in deep prospects. Due to the predominance of gas-prone and/or over-mature source rocks, the play was assessed for natural gas potential only.

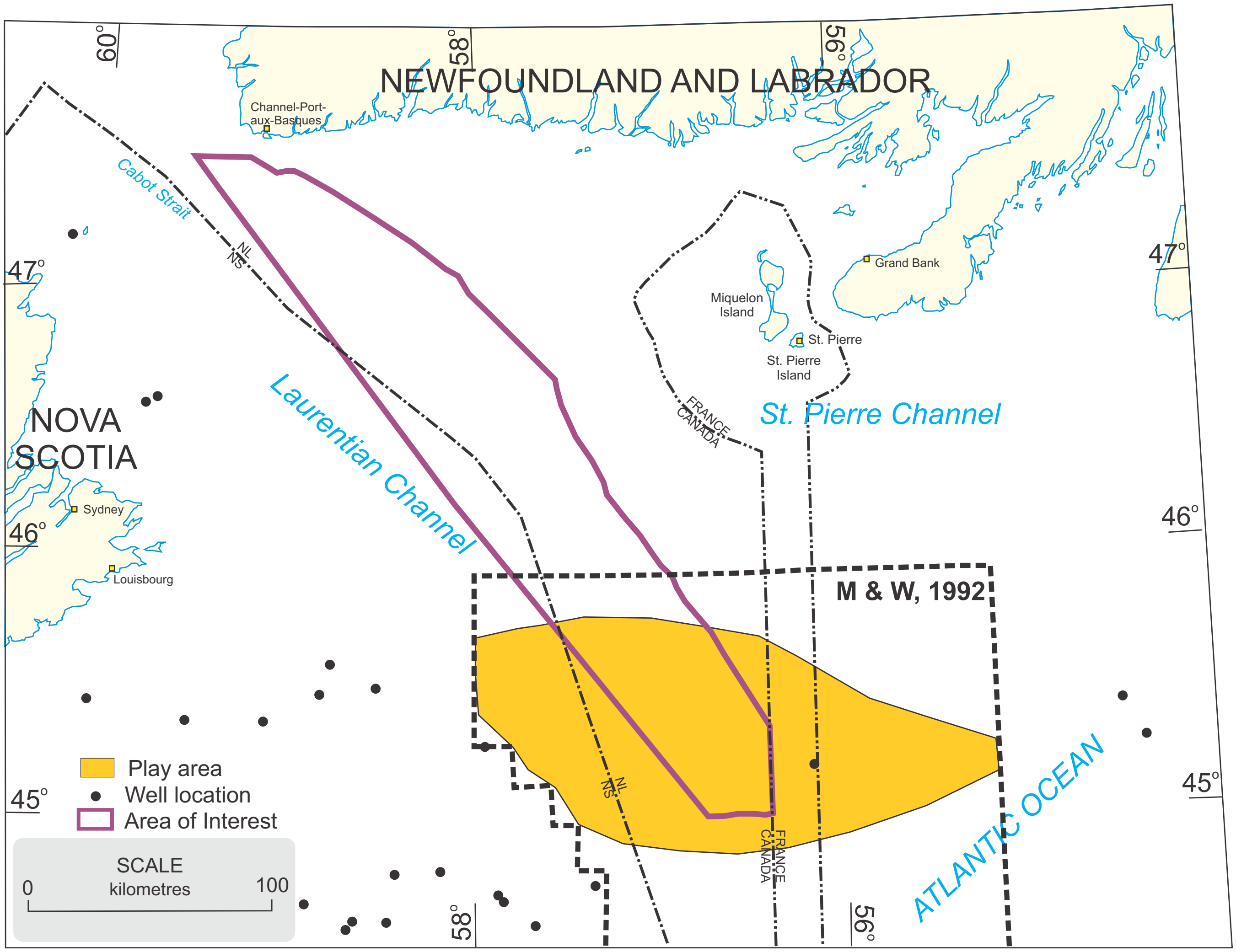

Figure 13. Map showing the location of the Middle Jurassic Mohican Formation structural oil and gas play in the Laurentian Subbasin and Orpheus Graben. Location of the Laurentian Channel area of interest and the assessment study area of Maclean and Wade (1992) are also shown.

The Lower Jurassic shallow structural play has a median estimate for in-place gas potential of 7.2 x 10^9 m^3 (mean estimate is 12.5 x 10^9 m^3; Table 1). MacLean and Wade (1992) reported recoverable volumes and this together with a recovery factor of 65% for gas was adopted in this report to obtain in-place volumes (Canada Nova Scotia Offshore Petroleum Board, 2000). Two fields are predicted in the play (mean estimate) with the largest field containing an estimated 10 x 10^9 m^3 in-place gas (Table 1). The Lower Jurassic deep structural play has a median estimate of in-place gas of 3.1 x 10^9 m^3 (mean estimate is 6.5 x 10^9 m^3; Table 1) distributed between 2 fields, with the largest field predicted to contain 6.2 x 10^9 m^3 of in-place gas (mean estimate, Table 1).

Middle Jurassic Mohican Formation Structural Plays

The Middle Jurassic Mohican plays include shallow oil and gas as well as deep gas prospects, most of which are in the Orpheus Graben and at the hinge zone (Figs. 3, 13). The 59 mapped structural prospects in the play include salt structures, rollover anticlines, and tilted fault blocks. Similar to the Lower Jurassic plays, shallow structures occur at 1000 to 5000 m depth, and deep structures from 5000 to 7000 m. Potential reservoirs are continental to shallow-marine sandstone in the Mohican Formation, with sandstone porosity up to 20% in shallow structures, and average porosity of 10 to 12% over the entire depth range. Source rocks are dominated by Type III kerogen, but marine Type II kerogen is possible. Oil and gas accumulations are expected at shallow depths, while deeper prospects likely contain gas only.

The Middle Jurassic Mohican shallow oil play has a median estimate for in-place oil of 12.4 x 10^6 m^3 (mean estimate is 28.3 x 10^6 m^3; using a recovery factor of 30%; CNSOPB, 2010; Table 1). The mean value of the number of predicted oil fields is 1, with the largest oil field expected to contain 29.9 x 10^6 m^3

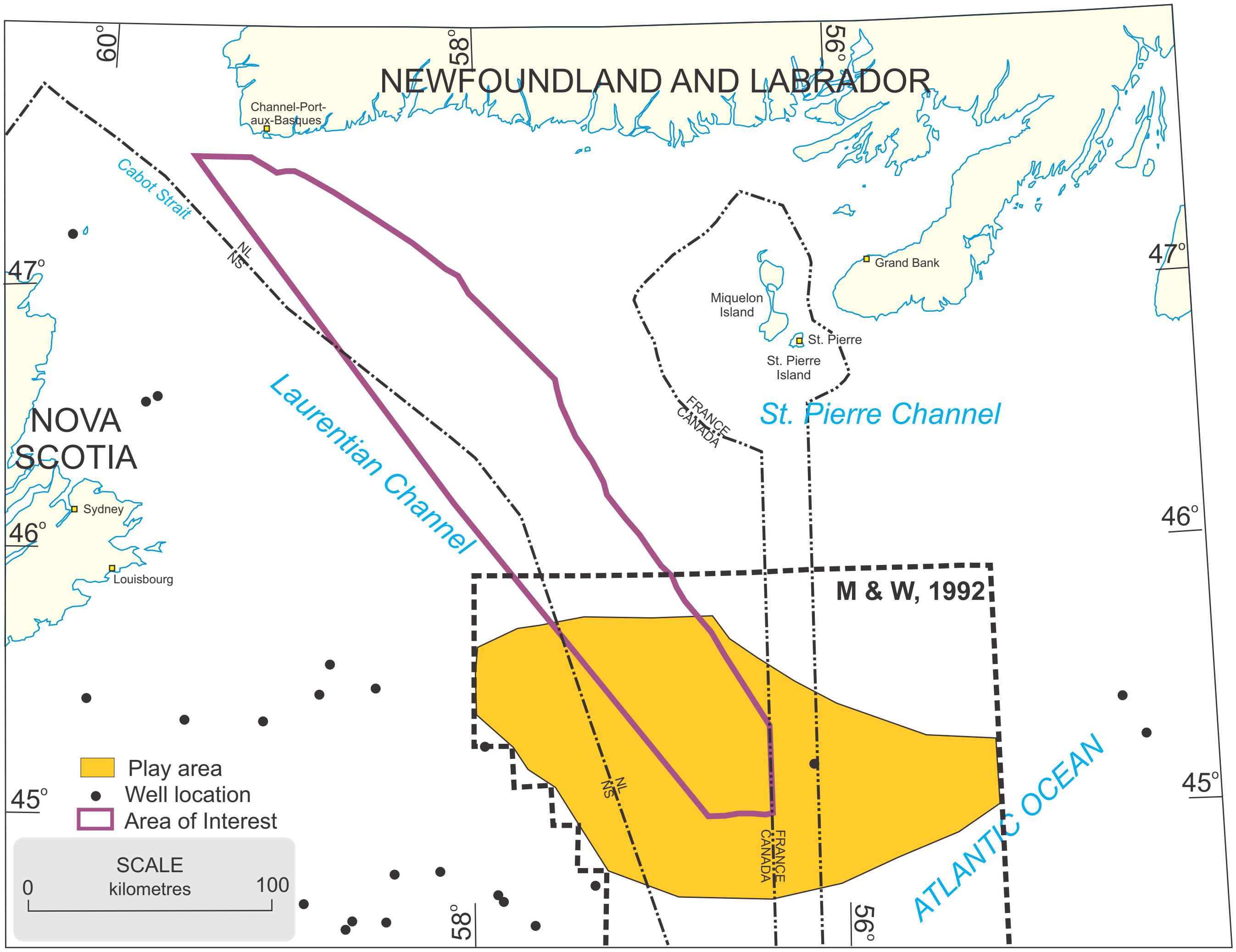

Figure 14. Map showing the location of the Upper Jurassic Mic Mac Formation structural oil and gas play in the Laurentian Subbasin and Orpheus Graben. Locations of the Laurentian Channel area of interest and the assessment study area of Maclean and Wade (1992) are also shown.

(mean value; Table 1). Potential for the Middle Jurassic shallow gas play ranges from 6.9 x 10^9 m^3 to 83.1 x 10^9 m^3 in-place (P90-P10) with median and mean volumes of 30.5 x 10^9 m^3 and 39.8 x 10^9 m^3, respectively (Table 1). The estimate assumes a total field population of 5 (mean value), with the largest undiscovered field having an initial in-place volume of 21.8 x 10^9 m^3 of natural gas (mean value) (Table 1). The deep gas play's median potential is 5.9 x 10^9 m^3 and its mean volume is 10.2 x 10^9 m^3 (Table 1). The expected number of deep gas fields in Middle Jurassic reservoirs is 2. The largest gas field is predicted to contain a mean volume of 8.5 x 10^9 m^3 (Table 1).

Upper Jurassic Mic Mac Formation Structural Plays

Seventy-five prospects have been mapped in Mic Mac strata in the Orpheus Graben and northern Laurentian Subbasin (Figs. 2, 14). Rollover anticlines, tilted fault blocks, and salt diapirs are common structures. Again, shallow structures are differentiated from deep structures in the play assessments. Potential sandstone reservoirs in the Mic Mac Formation are 5 to 100 m thick, with effective porosity values up to 20% to depths of 3000 m, and less than 10% below 5000 m. Mature Type II and III kerogens, capable of producing both gas and oil, are expected in the play area. Oil accumulations are expected only at shallow depths, with gas accumulations possible at all depths.

The Mic Mac shallow oil potential is predicted to range between 14.6 x 10^6 m^3 and 232.3 x 10^6 m^3(Table 1) distributed among 5 fields. Median and mean play volumes are 79.1 x 10^6 m^3 and 109.8 x 10^6 m^3, respectively. The largest undiscovered oil field in this play is predicted to hold an in-place mean volume of 61.9 x 10^6 m^3 (Table 1). Mic Mac shallow gas has 20 fields (mean value) containing in-place natural gas volumes varying between 53.2 x 10^9 m^3 and 298.9 x 10^9 m^3 (P90-P10) (Table 1). The play's median and mean gas values are 148.6 x 10^9 m^3 and 165.4 x 10^9 m^3, respec-

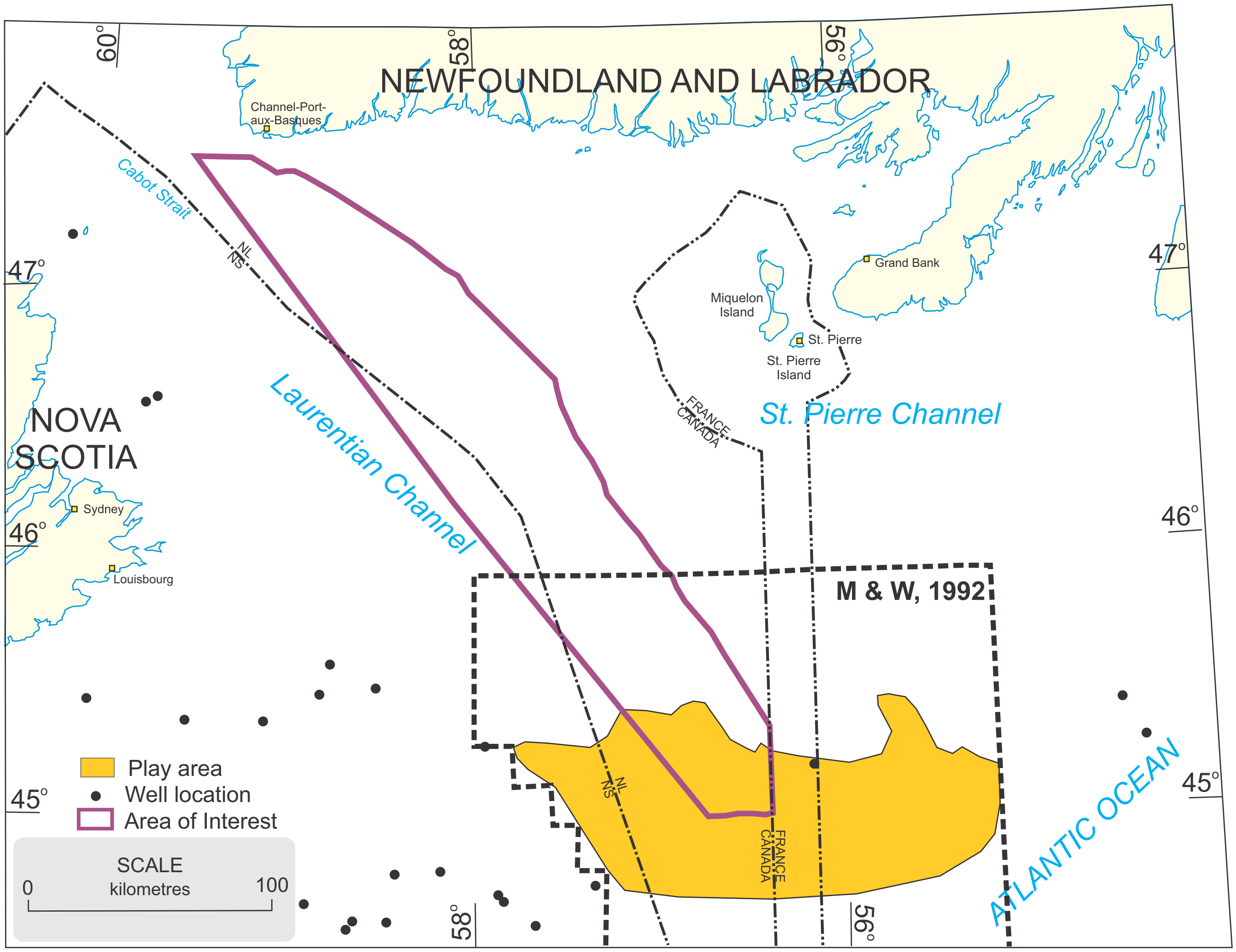

Figure 15. Map showing the location of the Lower Cretaceous Missisauga Formation structural oil and gas play in the Laurentian Subbasin and Orpheus Graben. Location of the Laurentian Channel area of interest and the assessment study area of Maclean and Wade (1992) are also shown.

tively. The mean volume of the largest gas field is 50.0 x 10^9 m^3 in-place (Table 1).

Median and mean potential of in-place gas in the Upper Jurassic deep gas play are predicted to be 12.1 x 10^9 m^3 and 20.0 x 10^9 m^3, respectively (Table 1). Gas volumes range from 0.4 x 10^9 m^3 to 48.1 x 10^9 m^3 distributed among 3 fields. The largest field is expected to have an in-place mean volume of 14.4 x 10^9 m^3 (Table 1).

Lower Cretaceous Missisauga Formation Structural Play

The Lower Cretaceous oil and gas play includes all structural prospects in sandstone reservoirs in the Missisauga Formation, at depths from 900 to 7000 m. The play occurs in the Orpheus Graben and northern Laurentian Subbasin (Figs. 2, 15). Forty prospects were identified within the play area (MacLean and Wade, 1992), with rollover anticlines on growth faults constituting the main structure type. There are also some tilted fault blocks and salt-related structures. Thick porous sandstone is the main prospective reservoir, although some limestone beds occur in outer shelf areas. Mature Jurassic strata provide source rocks for both oil and gas accumulations.

This play has an estimated in-place oil potential range of 6.6 x 10^6 m^3 to 107.3 x 10^6 m^3 (P90-P10) (Table 1) distributed among 3 fields. Median and mean play potential volumes are 36.4 x 10^6 m^3 and 50.0 x 10^6 m^3, respectively. The largest undiscovered field is expected to contain 30.4 x 10^6 m^3 (mean value) (Table 1).

Potential for the Missisauga structural gas play ranges from 14.3 x 10^9 m^3 to 99.8 x 10^9 m^3 (Table 1) with a mean volume of 51.8 x 10^9 m^3. The estimate assumes a total field population of 8, with the largest field having an initial in-place volume of 24.0 x 10^9 m^3 (Table 1).

Upper Cretaceous Logan Canyon to Wyandot Formation Structural Play

The Upper Cretaceous Logan Canyon to Wyandot Formation play includes all prospects within siliciclas-

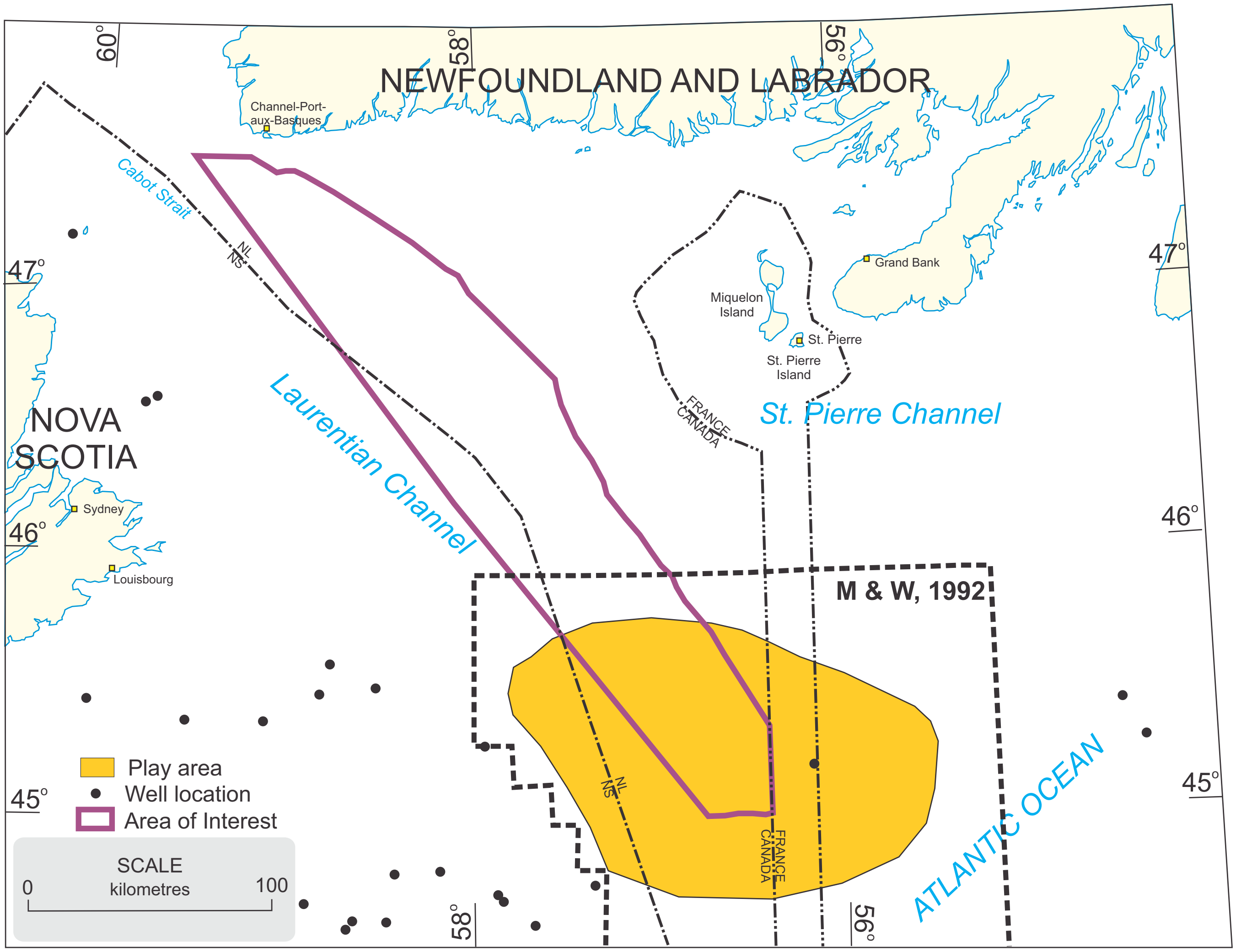

Figure 16. Map showing the location of the Upper Cretaceous Logan Canyon to Wyandot formations structural oil and gas play in the Laurentian Subbasin and Orpheus Graben. Also shown are the location of the Laurentian Channel area of interest and assessment study area of Maclean and Wade (1992).

tic strata of the Logan Canyon and Dawson Canyon formations and chalk in the overlying Wyandot Formation (Fig. 9). The formations are widespread across the northern Laurentian Subbasin and Orpheus Graben (Figs. 2, 16), with 41 structural prospects mapped in the play area, at depths between 500 and 5000 m (MacLean and Wade, 1992). Salt-related structures dominate in the north while rollover anticlinal traps are abundant in the south. Thin-bedded sandstone with excellent porosity (20-22%) is expected to occur in the Logan Canyon Formation. Dawson Canyon Formation sandstone is more argillaceous and has lower (fair to good) porosity. Chalk in the Wyandot Formation may also have fair to good porosity. Although mature source rocks do not occur in these formations, potential traps may be charged by upward-migrating Jurassic-sourced hydrocarbons. Possible gas seeps above Upper Cretaceous strata have been identified in seismic sections (MacLean and Wade, 1992).

Estimates of the potential for the Upper Cretaceous Logan Canyon to Wyandot oil play range from 7.6 x 10^6 m^3 to 263.8 x 10^6 m^3 (P90-P10) (Table 1) with a mean in-place volume of 113.5 x 10^6 m^3 distributed among 4 fields. The largest undiscovered oil field is predicted to encompass a volume of 76.2 x 10^6 m^3. The gas play predicts 4 fields having a play potential ranging from 2.0 x 10^9 m^3 to 66.7 x 10^9 m^3 (Table 1) with a mean in-place potential of 28.7 x 10^9 m^3. The largest gas field is estimated to contain 19.1 x 10^9 m^3.

Total Potential in Structural Plays

Median estimates of the total petroleum potential in structural plays in the Laurentian Subbasin - Orpheus Graben in the moratorium block are 262.5 x 10^6 m^3 (1651 MMbbl) of in-place oil and 319.4 x 10^9 m^3 (11.3 Tcf) of in-place gas (Table 1). High-confidence (90 % probability) and speculative (10 % probability) estimates for total in-place oil potential are 116.5 x 10^6 m^3

(733 MMbbl) and 558.5 x 10^6 m^3 (3513 MMbbl), respectively (Table 1). High-confidence and speculative estimates for total in-place gas potential are 188.9 x 10^9 m^3 (6.7 Tcf) and 516.5 x 10^9 m^3 (18.2 Tcf), respectively.

Stratigraphic Play

There are numerous stratigraphic trap possibilities for oil or gas accumulations in the Orpheus Graben and Laurentian Subbasin. A major potential stratigraphic trap is related to truncation of dipping Jurassic strata below the Avalon Unconformity (Figs. 10, 11). Other unconformities within the succession also provide the potential for truncation traps. Stratigraphic pinchouts of porous sandstone reservoirs, including channel, shoreface, and offshore bar strata, are expected in these basins. Dolomitized carbonate reservoirs, grading laterally to tight carbonate or shale, may occur in the area (Fig. 11).

Specific stratigraphic prospects were not mapped in the Orpheus Graben and Laurentian Subbasin. An estimate of oil and gas potential in stratigraphic traps can be derived by assigning a percentage of the total resource in structural plays to stratigraphic traps. This is based on empirical observations (from other basins) that 5 to 15 % of the total petroleum resource in a structured basin is contained in stratigraphic traps (Wade et al., 1989). Assigning 10% of the total structural-play resource to stratigraphic traps provides mean estimates of 31.7 x 10^6 m^3 oil and 34.8 x 10^9 m^3 gas for the Orpheus Graben - Laurentian Subbasin stratigraphic play (Table 1). When stratigraphic play potential is included with structural play potential, the total mean estimates for the Orpheus Graben/Laurentian Subbasin assessment area are 349.2 x 10^6 m^3 (2196 MMbbl) of oil and 376.7 x 10^9 m^3 (13.3 Tcf) of gas.

Resource Distribution

The greatest oil potential is expected in the Upper Cretaceous structural play and gas potential in shallow structures of the Upper Jurassic Mic Mac play (Table 1). The largest undiscovered oil and gas field sizes are predicted to occur in the same two plays. The largest oil field size in the Upper Cretaceous play can be attributed to a very large structure on the outer shelf where the combination of a deep salt pillow and the stacking of fault toes leads to a very large drainage area (the St. Pierre Prospect No. 4 of MacLean and Wade (1992) illustrated in their Figure 30). This structure can hold a considerable amount of petroleum. A direct analogue of this structure can be made to the Chebucto gas discovery in Scotian Basin where a rollover anticlinal structure has been accentuated by uplift from underlying salt pillowing or imbrication of fault toes. The large gas potential in the Mic Mac play can be best ascribed to the high number of expected fields in the play, many of which have large closure areas.

CONVENTIONAL PETROLEUM RESOURCE POTENTIAL IN THE LAURENTIAN CHANNEL AREA OF INTEREST

Quantitative Assessment of Conventional Petroleum Potential

The quantitative assessment of petroleum potential in the Laurentian Channel AOI utilizes the previously derived regional play-potential numbers for the Maritimes Basin (Lavoie et al., 2009) and the Laurentian Subbasin - Orpheus Graben in the St Pierre Moratorium Block (MacLean and Wade, 1992). Properly defined petroleum exploration plays are based solely on geology and it is inappropriate to define and statistically analyse plays based on arbitrary geographic limits such as borders or park boundaries. It is necessary, therefore, to perform statistical analyses on exploration plays over the full extent of their geologically defined limits and subsequently impose proper areal and volumetric proportions for play areas located within a study area (in this case the AOI). Probabilistic statistical analysis does not provide information on locations of individual hydrocarbon accumulations in a play. An assumption is made in this analysis that oil or gas resources in each exploration play are evenly distributed throughout the total play area. The percentage of the play area within the AOI is used to derive an apportionment of resource potential from the total play resource. The assumption of an evenly distributed resource over a play area is not necessarily accurate, in that certain areas of an exploration play may have greater or lesser potential, depending on local geological factors (as noted in the following discussion of the qualitative evaluation of petroleum prospectivity). Nonetheless, the assumption of an even resource distribution provides an initial statistical framework for assessing resource potential in portions of regional exploration plays.

In most petroleum plays, a substantial volume of the total play potential is concentrated in the largest field. In the Maritimes Basin, the largest fields constitute 13 to 22% of the total play potential. In the assessed part of the Orpheus Graben - Laurentian Subbasin, the largest fields contain 30 to 95% of the total play potential. Accordingly, the apportionment of resources within the AOI is further modified by adopting two scenarios; the first one being that the largest field in each play is assumed to occur outside the AOI, and the second scenario that the largest field in each play occurs within the boundaries of the AOI. Since the AOI encompasses a relatively small part of the total area of assessed geological plays, the first scenario (largest

Table 2. Oil and gas potential in proposed Laurentian Channel area of interest.

Play name	Mean play potential (million m^3)	Mean of largest field size (million m^3)	Play potential in Area of Interest - *high-confidence estimate* (million m^3)	Play potential in Area of Interest - *speculative estimate* (million m^3)
Maritime Basin				
Lower Carboniferous sandstone oil	121	16.5	9	25.5
Lower Carboniferous sandstone gas	439161	62034	32565	94599
Upper Carboniferous sandstone oil	118.4	26.6	5.2	31.8
Upper Carboniferous sandstone gas	676808	88208	33403	121611
Laurentian Subbasin				
Lower Jurassic Eurydice Formation shallow structural gas	12519	10001	827	10828
Lower Jurassic Eurydice Formation deep structural gas	6795	6183	103	6286
Middle Jurassic Mohican Formation shallow structural oil	28.3	29.9	0	29.9
Middle Jurassic Mohican Formation shallow structural gas	39847	21826	5282	27108
Middle Jurassic Mohican Formation deep structural gas	10243	8517	506	9023
Upper Jurassic Mic Mac Formation shallow structural oil	109.8	61.9	11.7	73.6
Upper Jurassic Mic Mac Formation shallow structural gas	165421	49972	28297	78269
Upper Jurassic Mic Mac Formation deep structural gas	19999	14371	1379	15750
Lower Cretaceous Missisauga Formation structural oil	50	30.4	2.8	33.2
Lower Cretaceous Missisauga Formation structural gas	51783	23986	3936	27922
Upper Cretaceous Logan Canyon/Wyandot structural oil	113.5	49.2	9.7	85.9
Upper Cretaceous Logan Canyon/Wyandot structural gas	28680	19108	2498	21606
Stratigraphic oil	31.7		2.4	22.3
Stratigraphic gas	34769		4283	19679
Total	349.2 (oil); 376719 (gas)		40.8 (oil); 113079 (gas)	302.2 (oil); 432681 (gas)

high confidence estimate: largest undiscovered field in each play is assumed to occur outside the area of interest

speculative estimate: largest undiscovered field in each play is assumed to occur within the area of interest

field in each play outside the AOI) is the more likely situation and provides a high-confidence resource estimate. The second scenario (largest fields inside the AOI) has a low probability of occurrence and provides a speculative resource estimate.

Paleozoic Oil and Gas Resource Potential in the Area of Interest

The Upper Paleozoic Maritimes Basin covers a total area of approximately 250,000 km^2 (Fig. 2). The Lower Carboniferous play in the basin extends over an area of about 50,000 km^2, including large parts of the Magdalen and western Sydney basins (Fig. 6). The area of interest occupies about 8.6% of the full areal extent of the play. Based on this areal proportion, the high-confidence estimate of the in-place oil potential of the Lower Carboniferous play in the AOI is 9.0 x 10^6 m^3 (Table 2). The speculative estimate of the oil potential is 25.5 x 10^6 m^3 (Table 2). The high-confidence and speculative estimates of in-place gas potential in the AOI are 32.6 x 10^9 m^3 and 94.6 x 10^9 m^3, respectively (Table 2).

The Upper Carboniferous play in the Maritimes Basin extends over an area of about 245,000 km^2, including most parts of the Magdalen and Sydney basins (Fig. 8).The play also occupies a much larger portion of the AOI. Compared to the total play area, however, the AOI encompasses only 5.6% of the area. High-confidence predictions for Upper Carboniferous oil and gas potential in the AOI are 5.2 x 10^6 m^3 and 33.4 x 10^9 m^3, respectively (Table 2). Speculative mean estimates of oil and gas volumes within the AOI are 31.8 x 10^6 m^3 and 121.6 x 10^9 m^3, respectively (Table 2).

Mesozoic Oil and Gas Resource Potential in the Area of Interest

The Lower Jurassic Eurydice Formation and equivalents natural gas play encompasses an area of about 11,200 km^2. The AOI covers approximately 33% of the total play area (Fig. 12). The natural gas potential was assessed by means of two plays, one at shallow depths ranging from 1000 to 5000 m and the other at depths of 5000 to 7000 m. High confidence is attributed to the estimate of 827 x 10^6 m^3 for shallow gas accumulations (Table 2). Maximum upside or the speculative prediction for shallow gas is 10.8 x 10^9 m^3. High-confidence and speculative estimates for deep gas potential within the AOI are 103 x 10^6 m^3 and 6.3 x 10^9 m^3, respectively (Table 2).

The Middle Jurassic Mohican Formation shallow oil together with shallow and deep gas plays encompass an area of 13,560 km^2. The Laurentian Channel AOI encompasses about 29% of the play area (Fig. 13). The Mohican Formation oil play contains only one predicted field (Table 1). Since only 29% of the play area occurs within the AOI, it is probable that this single field is located outside the AOI. Therefore, the high-confidence estimate (field outside the AOI) is 0.0 and the speculative estimate (field inside the AOI) is 29.9 x 10^6 m^3, representing the mean size of the single field (Table 2). The Mohican Formation shallow gas play within the AOI has a high-confidence prediction of 5.3 x 10^9 m^3 (Table 2). The speculative mean volume for shallow gas is 27.1 x 10^9 m^3. The Mohican Formation deep gas play in the AOI has high-confidence and speculative estimates of 506 x 10^6 m^3 and 9.0 x 10^9 m^3, respectively (Table 2).

The Upper Jurassic Mic Mac Formation oil and shallow and deep gas plays encompass an area of about 15,900 km^2 of which the AOI occupies about 24.5% of the play area (Fig. 14). The high-confidence estimate of the mean in-place oil potential of the Upper Jurassic play in the AOI is 11.7 x 10^6 m^3 (Table 2). The speculative estimate of the oil potential is 73.6 x 10^6 m^3 (Table 2). The high-confidence prediction for shallow gas in the Mic Mac Formation is 28.3 x 10^9 m^3 (Table 2). If the largest field is assumed to occur within the AOI, the shallow gas potential in the AOI is 78.3 x 10^9 m^3 (mean speculative estimate; Table 2). The deep Mic Mac Formation gas play in the AOI has mean gas potential estimates of 1.4 x 10^9 m^3 and 15.8 x 10^9 m^3 (high-confidence and speculative estimates, respectively; Table 2).

The Lower Cretaceous Missisauga Formation oil and gas play encompasses an area of about 10,450 km^2 with the AOI encompassing about 14% of the total play area (Fig. 15). The high-confidence and speculative estimates of oil potential in the AOI are 2.8 x 10^6 m^3 and 33.2 x 10^6 m^3, respectively (Table 2). Departing from the Jurassic plays, Cretaceous gas potential was assessed as one play, regardless of depth. Most prospects occur at depths ranging up to 5 km. The high-confidence and speculative estimates of Lower Cretaceous gas potential in the AOI are 3.9 x 10^9 m^3 and 27.9 x 10^9 m^3, respectively (Table 2).

The Upper Cretaceous Logan Canyon to Wyandot oil and gas play encompasses an area of about 14,100 km^2, with the AOI encompassing about 26% of the play area (Fig. 16). The high-confidence estimate of the mean in-place oil potential of the Upper Cretaceous play in the AOI is 9.7 x 10^6 m^3 (Table 2). The speculative estimate of the oil potential is 85.9 x 10^6 m^3 (Table 2). The high-confidence estimate for gas in the Logan Canyon, Dawson Canyon, and Wyandot formations is 2.5 x 10^9 m^3 (Table 2). If the largest field is assumed to occur within the AOI, the gas potential in the AOI is 21.6 x 10^9 m^3 (mean speculative estimate; Table 2).

Specific prospects in stratigraphic traps cannot be mapped using regional seismic data; therefore, largest field-size estimates are unknown. If one, however, applies the same 10% rating of stratigraphic compared to structural oil and gas potential, high-confidence and speculative estimates for stratigraphic traps for all assessed horizons are derived. The high-confidence mean estimates for oil and gas resources in the stratigraphic play are 2.4 x 10^6 m^3 and 4.3 x 10^9 m^3, respectively (Table 2). The speculative estimates for stratigraphic oil and gas in the AOI are 22.3 x 10^6 m^3 and 19.7 x 10^9 m^3, respectively (Table 2).

Total Conventional Petroleum Potential in the Laurentian Channel Area of Interest

High-confidence estimates of total conventional petroleum potential for the area of interest are 40.8 x 10^6 m^3 (256 MMbbls) oil and 113.1 x 10^9 m^3 (3.9 TCF) gas (mean in-place volumes, Table 2). Speculative estimates of total oil and gas potential in the area of interest are 302.2 x 10^6 m^3 (1900 MMbbls) and 432.7 x 10^9 m^3 (15.3 TCF), respectively (Table 2). The estimates reflect two resource-distribution scenarios – the largest oil and gas fields of every play occur outside the AOI (high-confidence estimate) or the largest fields of all plays occur within the AOI (speculative estimate). The speculative estimate is considered highly improbable since it is considered unlikely that the largest predicted field from every play that was defined as occurring partly in the AOI would occupy a similar geographic position within the AOI. It also may be appropriate to point out that the so-called high-confidence estimate may, in fact, be somewhat conservative in that it is feasible that the predicted largest fields in one or two Mesozoic plays may occur within the AOI because of the relatively high proportion of the AOI compared to the total play area (14 to 33%). MacLean and Wade (1992) identified four large prospects in their study area that provide examples of greater potential for large petroleum accumulations. Their analysis revealed two of the four prospects as occurring wholly or partly within the AOI.

Qualitative Assessment of Petroleum Prospectivity

The Laurentian Channel AOI encompasses parts of the western Sydney Basin and eastern Orpheus Graben (Figs. 2, 3). Geographic variations in petroleum prospectivity in the AOI were identified and mapped, based on qualitative evaluations of the geological setting and petroleum plays in the study area (Fig. 17). The qualitative ranking of petroleum prospectivity uses the general terms of high, moderate, and low potential.

High Potential

Areas of high potential for petroleum in the AOI include northwestern Sydney Basin and most of Orpheus Graben (Figs. 2, 17). The high potential areas

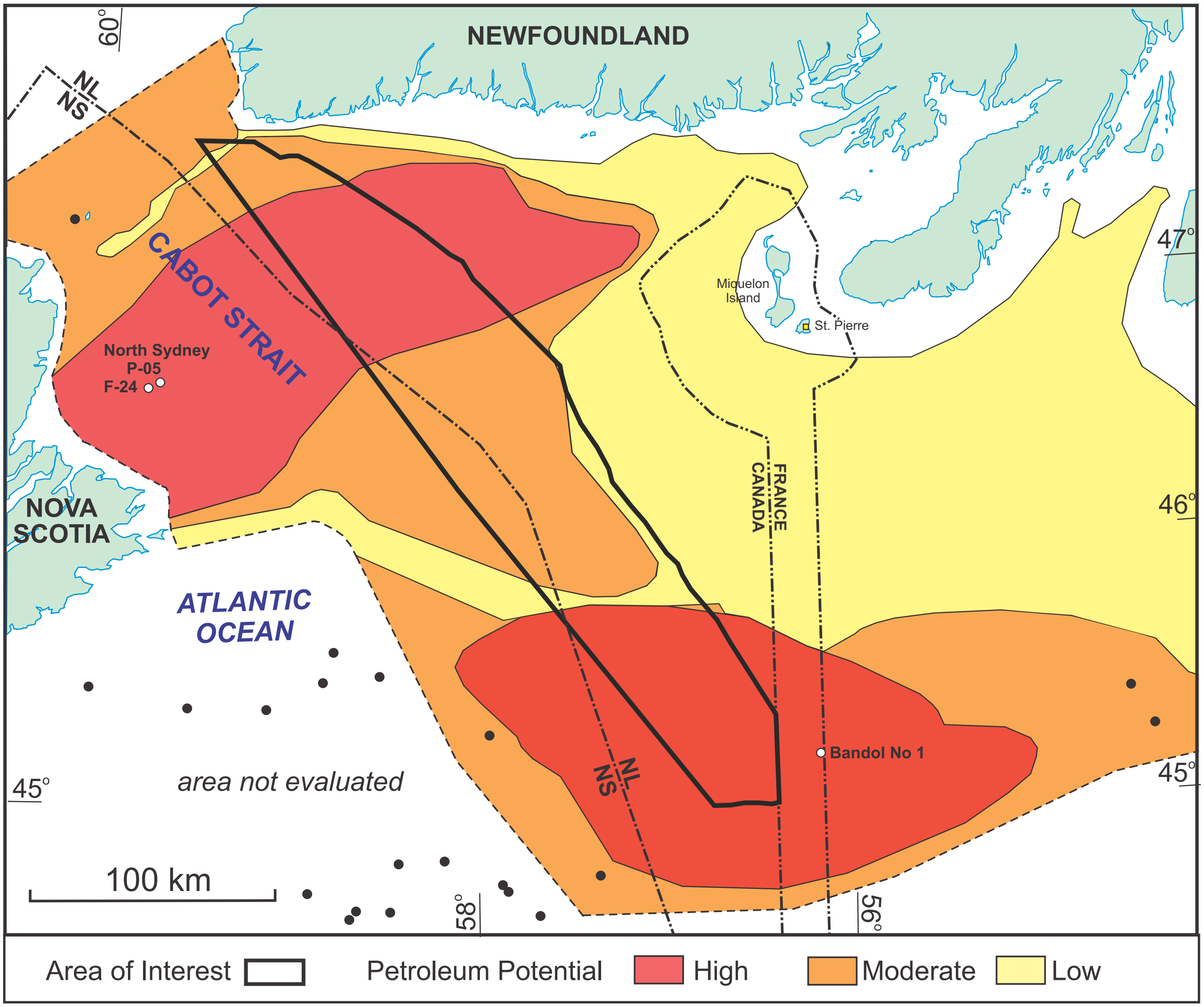

Figure 17. Qualitative ranking of conventional petroleum potential in the Laurentian Channel region offshore Nova Scotia and Newfoundland, with location of the Laurentian Channel area of interest and offshore wells (with well names referred to in text).

encompass approximately 7500 km^2 or about 47 % of the AOI. The high potential area of Sydney Basin contains both Lower and Upper Carboniferous sandstone plays. This part of Sydney Basin contains large fault-block and inversion anticline structures (Figs. 3, 5), with possible seismic hydrocarbon indicators in some structures (Enachescu, 2006). Two wells (North Sydney P-05 and F-24) were drilled in this high potential area. Both wells encountered fair to good quality reservoirs and oil and gas shows in Upper Carboniferous strata. The Lower Carboniferous play has not been tested in this high potential area. The Orpheus Graben high potential area contains three to six stacked Mesozoic petroleum plays. Structural prospects within the AOI include tilted fault blocks, rollover anticlines, and salt structures. Seismic hydrocarbon indicators are present in some areas (MacLean and Wade, 1992; Fagan, 2010). One well was drilled in this high potential area (Bandol No. 1), in French territory east of the southeastern limit of the AOI. The Bandol well was reported to have encountered thick reservoir sections, but no oil or gas accumulations. Nearby petroleum exploration wells, including Hermine E-94, Emerillon C-56, Dauntless D-35 and Adventure F-80 (Fig. 3), were dry and abandoned, but each well encountered good quality reservoirs and oil or gas shows.

Moderate Potential

Areas of moderate petroleum potential in the AOI include large parts of Sydney Basin and a small fringe area at the northern margin of Opheus Graben (Figs. 2, 17). The moderate potential areas encompass approximately 6800 km^2 or about 43% of the AOI. The moderate potential areas in Sydney Basin contain the Upper Carboniferous sandstone play, but not the Lower

Carboniferous play (Figs. 3, 6, 8). The moderate potential area in the central part of the AOI contains large salt-diapir structures, some of which may be prospective exploration targets (Fig. 5). The small area of moderate potential in the northern Orpheus Graben contains two to three stacked Mesozoic petroleum plays.

Low Potential

Small areas in the central and northwestern portion of the AOI have interpreted low petroleum potential (Fig. 17). The low potential areas encompass approximately 1600 km^2 or about 10% of the AOI. These low potential areas occur in Sydney Basin and Burin Platform (Fig. 3), where Carboniferous and Mesozoic strata are relatively thin and structural prospects are unknown.

UNCONVENTIONAL PETROLEUM RESOURCE POTENTIAL IN THE LAURENTIAN CHANNEL AREA OF INTEREST

Of the known unconventional types of oil and gas resources in eastern Canada (bitumen, heavy oil, oil shale, shale gas, coalbed methane, tight gas, gas hydrates), there is potential for coal-bed methane and gas hydrates within the Laurentian Channel AOI. Assessments of coal-bed methane (CBM) potential in the Maritimes Basin were undertaken by Grant and Moir (1992) and Hacquebard (2002). These studies indicated the Magdalen Basin and western Sydney Basin may have significant CBM resource potential. Majorowicz and Osadetz (2001, 2003) predicted a substantial volume of gas hydrate may be present in the Atlantic continental margin due to the presence of an extensive hydrate stability zone. There has been no coal-bed methane or gas hydrate production in the region to date. One coal deposit in the Cumberland Subbasin in Nova Scotia (Fig. 2) is currently in development for CBM production.

Coal-bed Methane

Coal-bed methane consists of biogenic or thermogenic gas generated from and contained within coal seams. Gas is retained in coal seams in several ways, including adsorbed gas within nanometre-sized pores, trapped gas within matrix porosity, free gas in cleats and fractures, or solution gas in groundwater within coal fractures (Bustin and Clarkson, 1998).

Most coal zones in the Upper Carboniferous Pictou/Morien Group in the Maritimes Basin, including Sydney Basin, have CBM potential (Grant and Moir, 1992; Hacquebard, 2002; Lavoie et al., 2009). The CBM play occurs principally in northern and eastern Nova Scotia, eastern New Brunswick, Prince Edward Island, and southwestern Newfoundland as well as closely adjacent offshore areas in the Gulf of St. Lawrence and Cabot Strait. Individual coal seams are up to 18 m thick, and the coal rank is commonly high volatile bituminous A (Hacquebard and Donaldson, 1969). The Sydney Mines coal measures in the Sydney basin in northern Cape Breton Island have laterally extensive coal seams up to 4 m thick (Masson and Rust, 1990). These same coal seams extend many kilometres offshore into Cabot Strait (Hacquebard, 2002).

Hacquebard (1986) described the Gulf of St. Lawrence Carboniferous Basin (including Sydney Basin) as the largest coalfield of eastern Canada. Seismic mapping and offshore well data provide constraints on the extent of coal measures in the Magdalen and Sydney basins (Fig. 18), which corresponds to a CBM potential play map (Grant and Moir, 1992; Hacquebard, 2002). Hacquebard (2002) estimated offshore in-place coal-bed methane resources of 1950 x 10^9 m^3 (69 Tcf) in Magdalen Basin of the Gulf of St. Lawrence, and 263 x 10^9 m^3 (9.3 Tcf) in offshore Sydney Basin. The CBM play in the Sydney Basin extends across part of the northern AOI (Fig. 18). Using areal apportionment, about 45.5 x 10^9 m^3 (1.6 Tcf) of CBM may occur within the AOI.

Gas Hydrates

Gas hydrate, a solid form of natural gas and water, occurs in offshore sedimentary successions under conditions of high hydrostatic pressure due to the overlying seawater column, low sea-bottom temperatures, and moderate to low thermal gradients. Such conditions are common where water depths exceed about 300 m. The thickness and depth of the base of the gas-hydrate stability zone increases with increasing water depths and decreasing geothermal gradients. Relatively low geothermal gradients, perhaps in the neighbourhood of 32ºC/km (Majorowicz and Osadetz, 2001), are expected in the Atlantic margin.

Conditions are favourable for the stability of gas hydrates over large areas of the continental shelf and slope in Atlantic Canada, in water depths between 300 and 2000 m (Majorowicz and Osadetz, 2001). The inferred area of hydrate stability for the Atlantic margin is approximately 402,000 km^2, with an average estimated thickness of hydrates (from wells) of 79 m. Low-to-moderate thermal gradients, low sea-bottom temperatures, and thick water columns contribute to this vast region of potential hydrate stability. The expected hydrate-stability area and average hydrate thickness are combined to provide preliminary estimates of hydrate volume in the study region. The hydrate resource estimate further incorporates an assumption that only part of the potential volume has suitable geological conditions for hydrate formation. Gas-hydrate volume depends on porosity of the reservoirs (34-46% assumed for the Atlantic margin) of

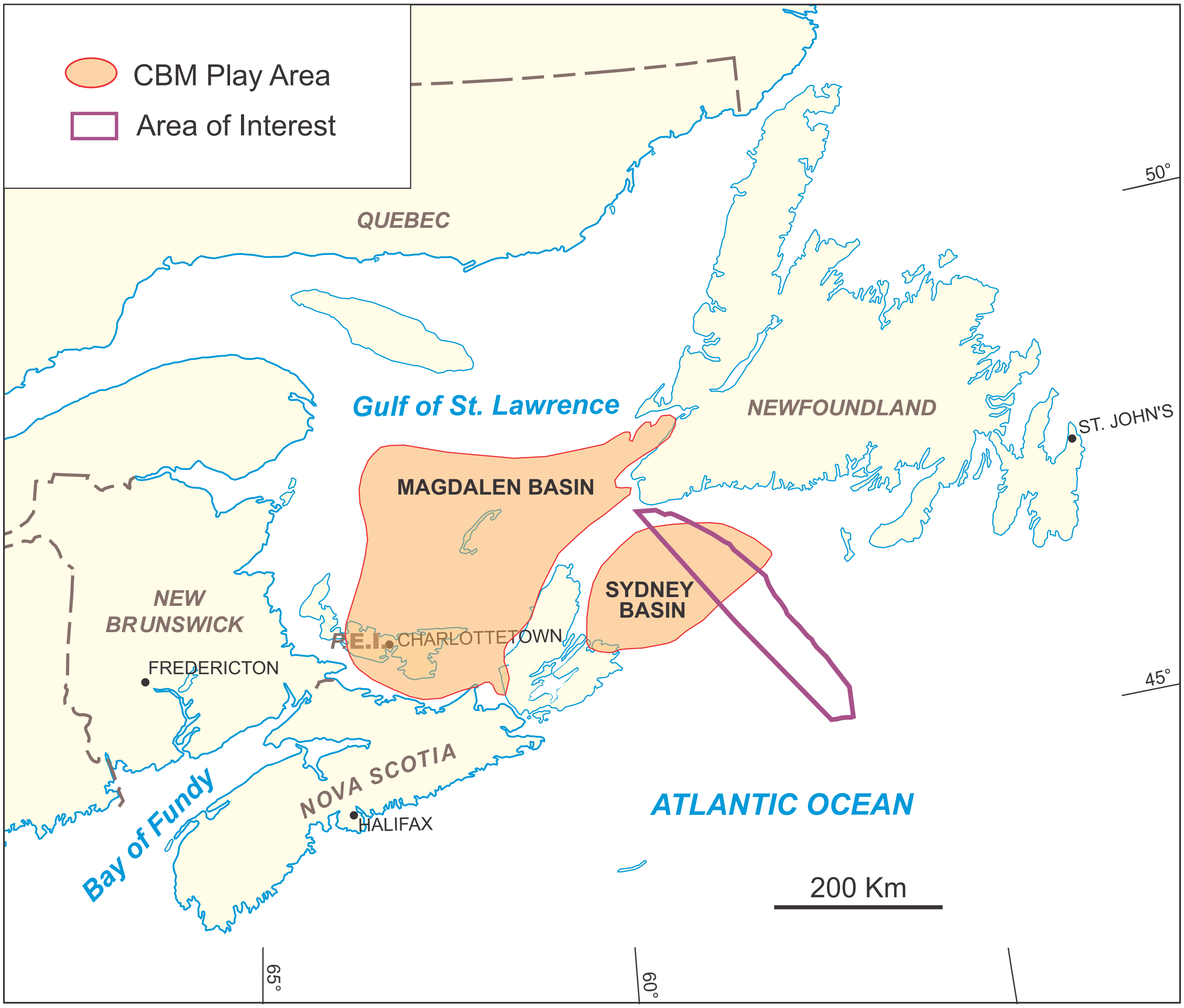

Figure 18. Potential coal-bed methane (CBM) play in the central Magdalen and Sydney basins (modified from Grant and Moir (1992) and Hacquebard (2002)) with location of the Laurentian Channel area of interest .

which only part is occupied by hydrate (hydrate saturation is assumed to be 2-6%). The porosity range was derived from subsidence models established in the Labrador and West Greenland continental margins (Issler and Beaumont, 1987) and hydrate saturation estimates are from results of offshore drilling on the Atlantic margin (Collett, 1998). Assumptions of pure methane hydrate and hydrostatic pore pressures results in a conservative estimate of potential hydrate volumes.

For gas-saturated hydrates (90% gas-filled) at conditions of standard temperature and pressure, one volume of gas hydrate contains 164 equivalent volumes of free gas. Assuming that 1 m^3 of hydrate can release approximately 164 m^3 of gas, the minimum and maximum volumes of gas in inferred gas hydrates in the Canadian Atlantic margin are 1.9 x 10^{13} m^3 and 7.8 x 10^{13} m^3 (Majorowicz and Osadetz, 2001). The Laurentian Channel AOI occurs almost entirely within the hydrate stability zone (Fig. 19; Majorowicz and Osadetz, 2003). Using a simple areal apportionment of Atlantic-margin hydrate resource estimates, the volume of gas-hydrate resource that may occur in the AOI is 7.1 x 10^{11} m^3 to 2.9 x 10^{12} m^3 (25 to 102 Tcf).

Unconventional Gas Resource and Petroleum Prospectivity in the Area of Interest

The very large amount of methane inferred to reside in coal seams and gas hydrates on the Atlantic margin is potentially a significant energy resource. However, as great as the inferred resource is, there are significant technical and economic challenges associated with offshore development of these resources. Production would be most viable in areas where the unconven-

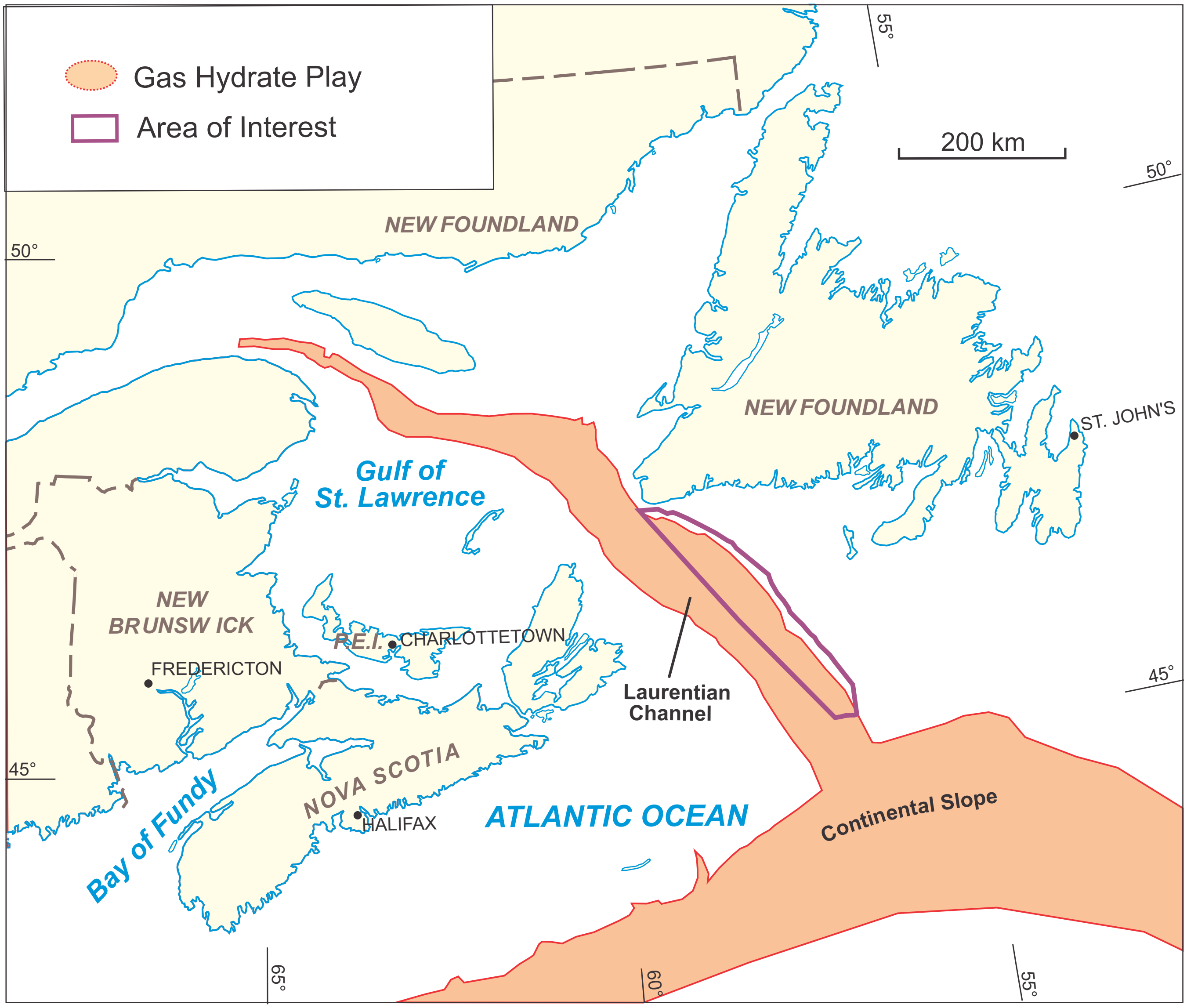

Figure 19. Potential gas-hydrate play in the Laurentian Channel and Atlantic margin continental slope, with the location of the Laurentian Channel area of interest. The map depicts the areal extent of a sub-sea hydrate stability zone, up to 200 m thick in the Laurentian Channel and up to 600 m thick in the Atlantic continental-slope region (adapted from Majorowicz and Osadetz (2003)).

tional resource can be directly linked to conventional petroleum production. The prospectivity map of Figure 17 does not include and illustrate these unconventional resources because of these challenges and limitations with respect to offshore production.

CONCLUSIONS

The Laurentian Channel AOI contains regions of varying conventional petroleum potential. Most of the AOI has high to moderate potential, with the high potential regions occurring in Sydney Basin and Orpheus Graben. Two Carboniferous petroleum plays occur in the Sydney Basin high potential area and nine Mesozoic plays occur in the Orpheus Graben high potential area. Minor areas of low petroleum potential occur in the AOI, along the margins of Sydney Basin and in Burin Platform. There are no areas within the AOI that are considered non-prospective for petroleum resources.

Mean estimates for total conventional oil and gas potential for all offshore and/or onshore Atlantic margin plays that extend into the area of interest are 591.2 x 10^6 m^3 (3.7 Bbbls) of in-place oil and 1501 x 10^9 m^3 (53.0 Tcf) of in-place gas (Table 1). Using a modified areal apportionment of oil and gas resource in the Maritimes Basin and Laurentian Subbasin - Orpheus Graben, the conventional petroleum potential in the Laurentian Channel AOI is estimated to be 40.8 x 10^6 m^3 (257 MMbbl) of in-place oil and 113.1 x 10^9 m^3 (4.0 Tcf) of in-place gas (high-confidence estimates, mean values). A speculative or upside estimate of total petroleum potential in the AOI is 302.2 x 10^6 m^3 (1901 MMbbl) of oil and 432.7 x 10^9 m^3 (15.3 Tcf) gas (Table 2). These estimates represent two resource distribution scenarios; the largest oil/gas fields occurring outside the AOI (high-confidence estimates) or within the AOI (speculative estimates). In the speculative resource scenario, the AOI could contain fields with in-place volumes of 76.2 x 10^6 m^3 (479 MMbbls) of oil and 88.2 x 10^9 m^3 (3.1 Tcf) of gas.

Substantial volumes of unconventional coal-bed methane and gas hydrates are inferred to occur within the Laurentian Channel AOI. The offshore Sydney Basin contains thick and widespread Upper Carboniferous coal measures. Using a simple areal apportionment, the CBM potential in the AOI is estimated at 45.5 x 10^9 m^3 (1.6 Tcf) of in-place gas. A widespread gas hydrate stability zone occurs in Atlantic-margin continental shelf and slope strata at water depths of between 300 and 2000 m. Based on an areal apportionment of total estimated Atlantic margin gas-hydrate resource, the in-place gas-hydrate potential in the AOI is estimated to be 7.1 x 10^{11} m^3 to 2.9 x 10^{12} m^3 (25 to 102 Tcf). Although possibly a large resource exits, current technical and economic factors limit the potential for development of offshore gas hydrates and coal-bed methane in the AOI, much more so than for conventional oil or gas resources.

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