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PETROLEUM RESOURCE POTENTIAL OF THE HECATE STRAIT / QUEEN CHARLOTTE SOUND GLASS REEF AREAS OF INTEREST, PACIFIC MARGIN OF CANADA

P.K. Hannigan and J.R. Dietrich

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SUMMARY

The conventional and unconventional oil and gas resource potential of the Hecate Strait/Queen Charlotte Sound sponge reef areas of interest on the Pacific margin of Canada are described in this report. The sponge reef areas of interest encompass an area of approximately 1600 square kilometres in relatively shallow water on the Pacific continental shelf in Hecate Strait and Queen Charlotte Sound. Parts of two major sedimentary basins (Cretaceous Hecate Basin and Tertiary Queen Charlotte Basin) are found within the areas of interest, both of which have oil and gas potential. Conditions are favourable for the stability of specific types of natural gas hydrates in the sponge reef areas of interest and adjacent areas of the Pacific continental margin.

Qualitative evaluations of petroleum prospectivity indicate that the sponge reef areas of interest have varying petroleum potential. The northern sponge reef area of interest (AOI-1) is located in a region that is considered to have mainly high petroleum potential. The central sponge reef area of interest (AOI-2) occurs within a region that has a mainly low petroleum potential with a small part of AOI-2 covering in a region that is considered non-prospective for petroleum resources. The southern sponge reef area of interest (AOI-3) is located in a region of high petroleum potential.

Based on a modified areal apportionment of resource potential of previously defined conventional petroleum plays, high-confidence quantitative estimates of petroleum potential for the sponge reef areas of interest are as follows: northern area of interest (AOI-1) – 8 x 10^6 m^3 (50 MMbbls) of oil and 6.8 x 10^9 m^3 (240 BCF) of gas (mean values of in-place volumes); central area of interest (AOI-2) – 4 x 10^6 m^3 (25 MMbbls) of oil and 0.7 x 10^9 m^3 (24 BCF) of gas; southern area of interest (AOI-3) – 2.5 x 10^6 m^3 (18 MMbbls) oil and 1.0 x 10^9 m^3 (35 BCF) of gas. Speculative estimates of petroleum potential in the areas of interest are the following: AOI-1 – 884 x 10^6 m^3 (5560 MMbbls) of oil and 329 x 10^9 m^3 (11.6 TCF) of gas; AOI-2 – 166 x 10^6 m^3 (1044 MMbbls) of oil and 38 x 10^9 m^3 (1.3 TCF) of gas; AOI-3 – 435 x 10^6 m^3 (2736 MMbbls) of oil and 154 x 10^9 m^3 (5.4 TCF) of gas (mean in-place volumes). The high-confidence and speculative estimates reflect two resource-distribution scenarios; the high-confidence scenario assumes the largest oil or gas fields for the defined plays occur outside the proposed AOI, and the speculative scenario assumes the largest fields for the defined plays are located within the proposed AOI. Since these areas of interest encompass a relatively small part of the total area of assessed geological plays, the high-confidence scenarios (largest fields outside the AOI) are the most likely situation. The speculative scenarios (largest fields inside the AOI) have a low probability of occurrence. The central AOI (AOI-2) occurs in a geological setting that is much less favourable for petroleum resource than is expected in AOI-1 or AOI-3. The speculative resource estimate for AOI-2 is considered the most unlikely scenario (lowest probability of occurrence) of the three areas of interest.

Gas hydrate, a solid form of natural gas and water, is inferred to occur widely in the Pacific continental margin region. Three modes of gas hydrate occurrences may develop in this region. Type 1 and Type 3 hydrates may occur in the areas of interest; however, only the pervasive Type 2 gas hydrate accumulations (below 300 m water depth) can be assessed for resource potential. All identified sponge reefs are found in relatively shallow water depths and Type 2 methane hydrates are not stable under these conditions. Thus, gas hydrate potential is not quantifiable in the areas of interest.

INTRODUCTION

An area of interest (AOI) for a potential marine protected area (MPA) has been identified by the Department of Fisheries and Oceans for sponge reef developments on the Pacific margin of Canada. The AOI encompasses three regions of concentrated glass sponge reef occurrences in Hecate Strait and Queen Charlotte Sound (Figs. 1, 2). These regions, designated AOI-1, AOI-2, and AOI-3 in this report (Fig. 2), cover approximately 1600 square kilometres. The areas are currently closed to bottom trawling fishing, preventing damage to these globally unique, reef ecosystems. A government-mandated process of evaluating an AOI (prior to designation as an MPA) includes assessments of energy and mineral resource potential. This report evaluates the conventional and unconventional petroleum resource potential of the Hecate Strait/Queen Charlotte Sound sponge reefs AOI. Establishment of an MPA may have impacts on access to offshore petroleum resources. The petroleum assessment presented here provides an energy resource framework for an informed decision-making process.

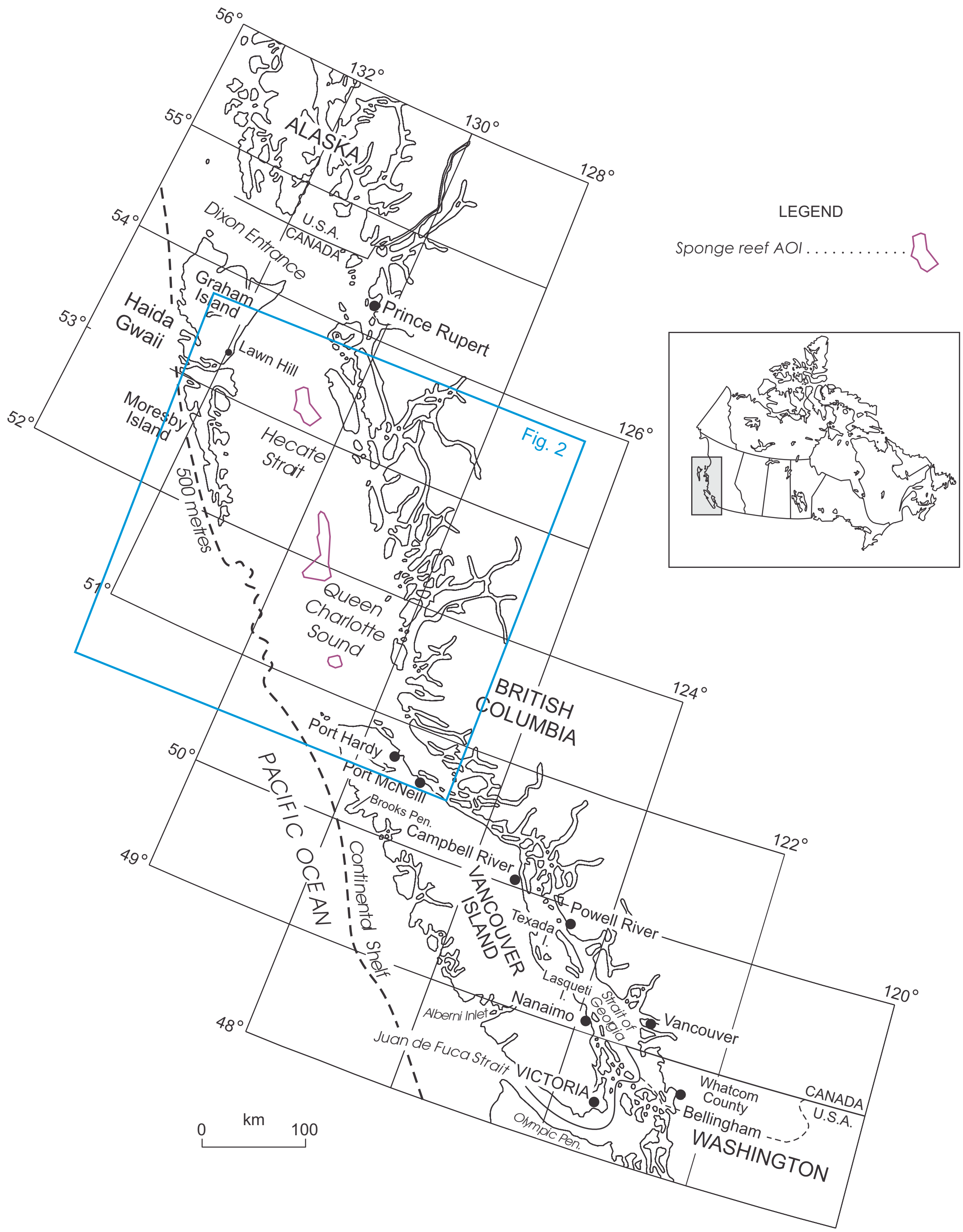

Figure 1. Geographic setting of the west coast region of Canada. The location of the three areas of interest that contain concentrated sponge reef development are outlined in purple. The location of Figure 2 is also shown.

Two sedimentary basins with potential for conventional oil and gas resource (Tertiary Queen Charlotte Basin and Cretaceous Hecate Basin) underlie large parts of Hecate Strait and Queen Charlotte Sound (Fig. 3). The sponge reef areas of interest occur partly or wholly in both basins.

Immense volumes of unconventional gas resource may occur in the form of gas hydrates in the offshore Pacific margin. Methane gas hydrates are ice-like crystalline structures that form in marine sedimentary basins under conditions of high pressure, low sea-bottom temperature, and low to moderate geothermal gra-

Figure 2. Location map of sponge reefs and areas of interest Abbreviations: AOI-1 – northern area of interest 1; AOI-2 – central area of interest 2; AOI-3 – southern area of interest 3.

dients. In the offshore Pacific continental shelf, including the Hecate Strait/Queen Charlotte Sound sponge reefs AOI, conditions are favourable for the stability of certain types of gas hydrate.

Petroleum Exploration History

The major phase of offshore petroleum exploration in the west coast region of Canada was undertaken by Shell Canada Ltd. from 1965 to 1969. Eight offshore wells were drilled in Hecate Strait and Queen Charlotte Sound during this period (Fig. 3; Table 1). No oil or gas fields were discovered but several wells encountered oil or gas shows. None of these wells are located in the sponge reefs areas of interest. In 1972, the Canadian federal government imposed an indefinite moratorium on petroleum exploration in the Pacific offshore. There has been no offshore drilling since the moratorium was established.

Previous Petroleum Assessments

Quantitative assessments of conventional petroleum potential of Canada's Pacific margin basins were pre-

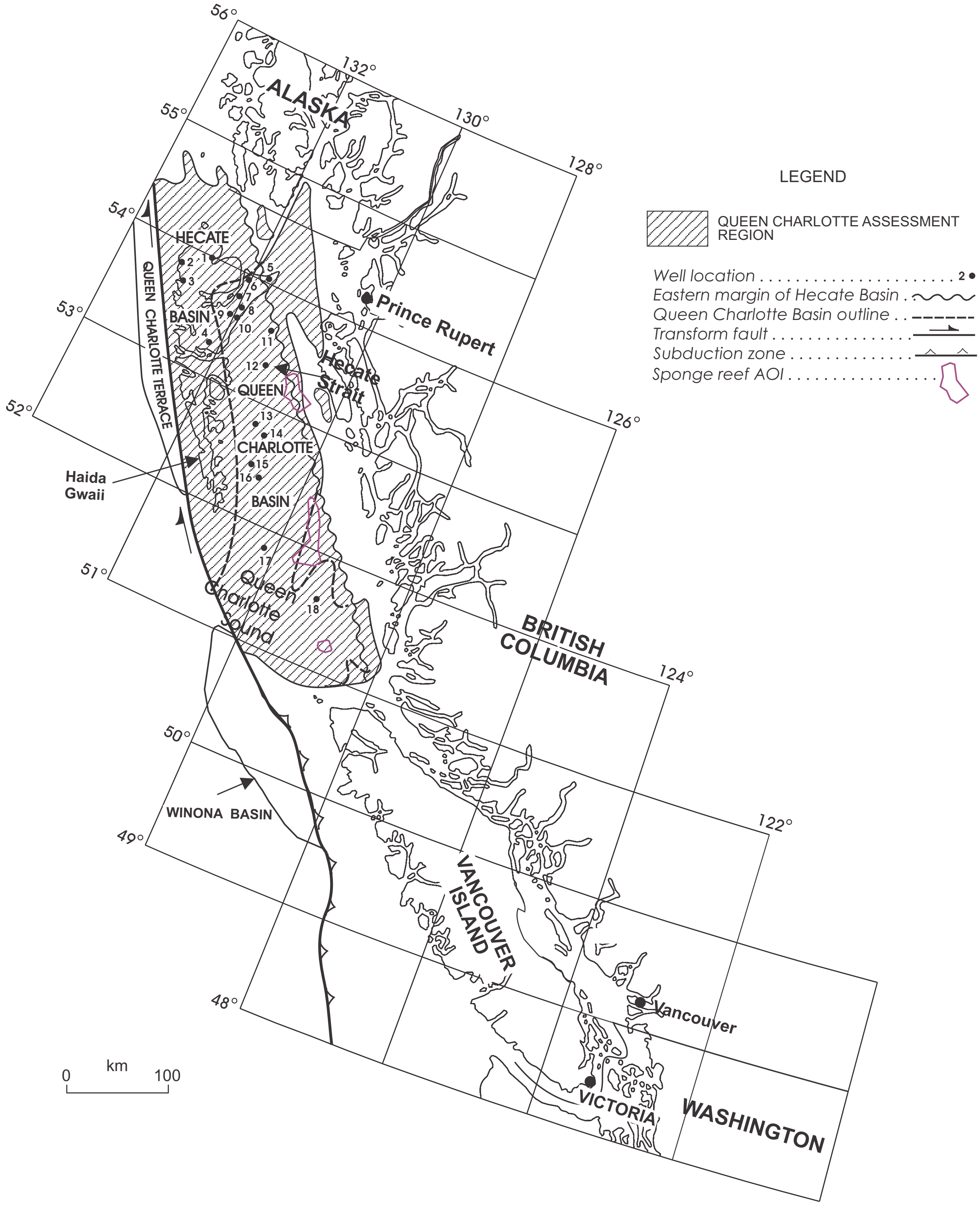

Figure 3. Regional setting, basin outlines, and areas of interest on the Pacific margin of Canada. The assessment region is the patterned area. The location of the eastern edge of the Hecate Basin is modified from Haggart (1993). The well names are listed in Table 1.

sented by Dietrich (1995) and Hannigan et al. (2001). The Hannigan et al. (2001) study provides a comprehensive review of petroleum potential of all west coast basins, including detailed descriptions of exploration history, petroleum geology, and exploration plays in each basin, and the probabilistic statistical techniques used in estimating basin and play hydrocarbon petroleum endowments. These studies indicate that the Canadian west coast basins have significant petroleum resource potential, with the Queen Charlotte Basin

Table 1. Well reference numbers in the Queen Charlotte and Hecate basins (Fig. 3).

Well number	Well details
1	Bow Valley et al. Naden Harbour b-A27-J
2	British Columbia Coal Co. Tian Bay
3	Union Port Louis c-28-L
4	Queen Charlotte No. 1
5	Richfield-Mic Mac-Homestead Tow Hill d‑93‑C
6	Richfield-Mic Mac-Homestead Masset c-10-I
7	Richfield-Mic Mac-Homestead Nadu River b-69-A
8	Richfield-Mic Mac-Homestead Cape Ball d-41-L
9	Richfield-Mic Mac-Homestead Gold Creek c-56-H
10	Richfield-Mic Mac-Homestead Tlell c-56-D
11	Shell Anglo South Coho I-74
12	Shell Anglo Tyee N-39
13	Shell Anglo Sockeye B-10
14	Shell Anglo Sockeye E-66
15	Shell Anglo Murrelet L-15
16	Shell Anglo Auklet G-41
17	Shell Anglo Harlequin D-86
18	Shell Anglo Osprey D-36

having the largest estimated oil and gas resource endowment.

Majorowicz and Osadetz (2001) evaluated the gas hydrate potential throughout Canada and indicated a substantial volume of gas hydrate may be present along the Pacific margin of Canada due to the presence of extensive hydrate stability zones.

PETROLEUM POTENTIAL OF HECATE AND QUEEN CHARLOTTE BASINS

Geological Setting

The Queen Charlotte and Hecate basins occur within the Insular Belt of the North American plate. The Insular Belt includes several tectonic terranes, the largest of which are the Wrangellia and Alexander terranes. The Wrangellia Terrane encompasses most of Vancouver Island, Haida Gwaii (formerly Queen Charlotte Islands), and most of the offshore region of Hecate Strait and Queen Charlotte Sound. The continental-oceanic plate boundary along the west coast of Canada is marked by the Cascadia subduction zone west of Vancouver Island and the Queen Charlotte dextral transform fault north of Vancouver Island and west of the Haida Gwaii (Fig. 3). The plate boundary is located at or near the present-day shelf edge (approximated by the 500 m isobath). The geological history of the region is directly linked to the evolution of the Pacific continental margin and its associated convergent and transcurrent plate interactions (Lewis et al., 1991; Rohr and Dietrich, 1992).

The Hecate Basin is a plate-margin-parallel, Cretaceous forearc basin that developed in response to accretion, convergence, and orthogonal subduction of the Pacific Plate beneath the continental margin of western North America. Basin-fill sediments were derived from uplifted areas in the Coast Mountains to the east. The Hecate Basin underlies large parts of Haida Gwaii (Queen Charlotte Islands) and offshore shelf areas of Hecate Strait and Queen Charlotte Sound (Haggart, 1991, 1993). The Queen Charlotte Basin is a Late Tertiary strike-slip basin that developed in response to transtensional and transpressional Pacific-North America plate interactions (Lewis et al., 1991; Rohr and Dietrich, 1992; Rohr and Currie, 1997). The Queen Charlotte Basin is underlain by lower Tertiary and Mesozoic volcanic, plutonic, and sedimentary rocks, locally including sedimentary strata of the Hecate Basin. Upper Tertiary basin-fill sediments were derived from variable source areas and directions. In detail, the Queen Charlotte Basin consists of a series of separate or partly coalesced strike-slip subbasins, which developed across a 150 km wide, plate margin-parallel shear zone (Rohr and Dietrich, 1992; Dietrich, 1995). The subbasins are commonly half grabens bound by normal or oblique-slip faults. They contain Miocene synrift clastic sediments and local volcanic flows, with considerable local variability in lithology and thickness. Overlying the synrift succession are post-rift Pliocene clastic sediments. The post-rift sediments are relatively undeformed in southern Queen Charlotte Basin. These sediments drape the deeper structures and are more laterally continuous. Late Pliocene–Pleistocene compression and uplift resulted in deformation and inversion of synrift and post-rift sediments in northern Queen Charlotte Basin. Erosional truncation of folds at the seafloor indicate geologically recent uplift (Rohr and Dietrich, 1992).

Stratigraphy and Structure

Basement for petroleum exploration in the Hecate and Queen Charlotte basins is the Upper Triassic Karmutsen Formation (Fig. 4). This widespread succession consists of up to 4000 m of pillow basalt and volcanic flows (Haggart, 2003). On Haida Gwaii, the Karmutsen basalt is conformably overlain by more than 1000 metres of widely distributed Upper Triassic and Lower Jurassic limestone, sandstone, and shale of the Kunga and Maude groups (Fig. 4). The Kunga Group consists of 200 m of massive carbonate overlain by thinly bedded fossiliferous limestone (Cameron and Tipper, 1985; Desrochers and Orchard, 1991). In the uppermost Kunga, the limestone is overlain by argillite and lesser interbedded sandstone and tuff of the Early Jurassic. This unit is up to 400 metres thick. The Lower and Middle Jurassic Maude Group consist of 400 metres of organic-rich shale, shaly limestone, coquinoid sandstone, and minor tuff and tuffaceous siltstone. These rocks were deposited in a stable-shelf to slope setting. Principal structures in lower Mesozoic

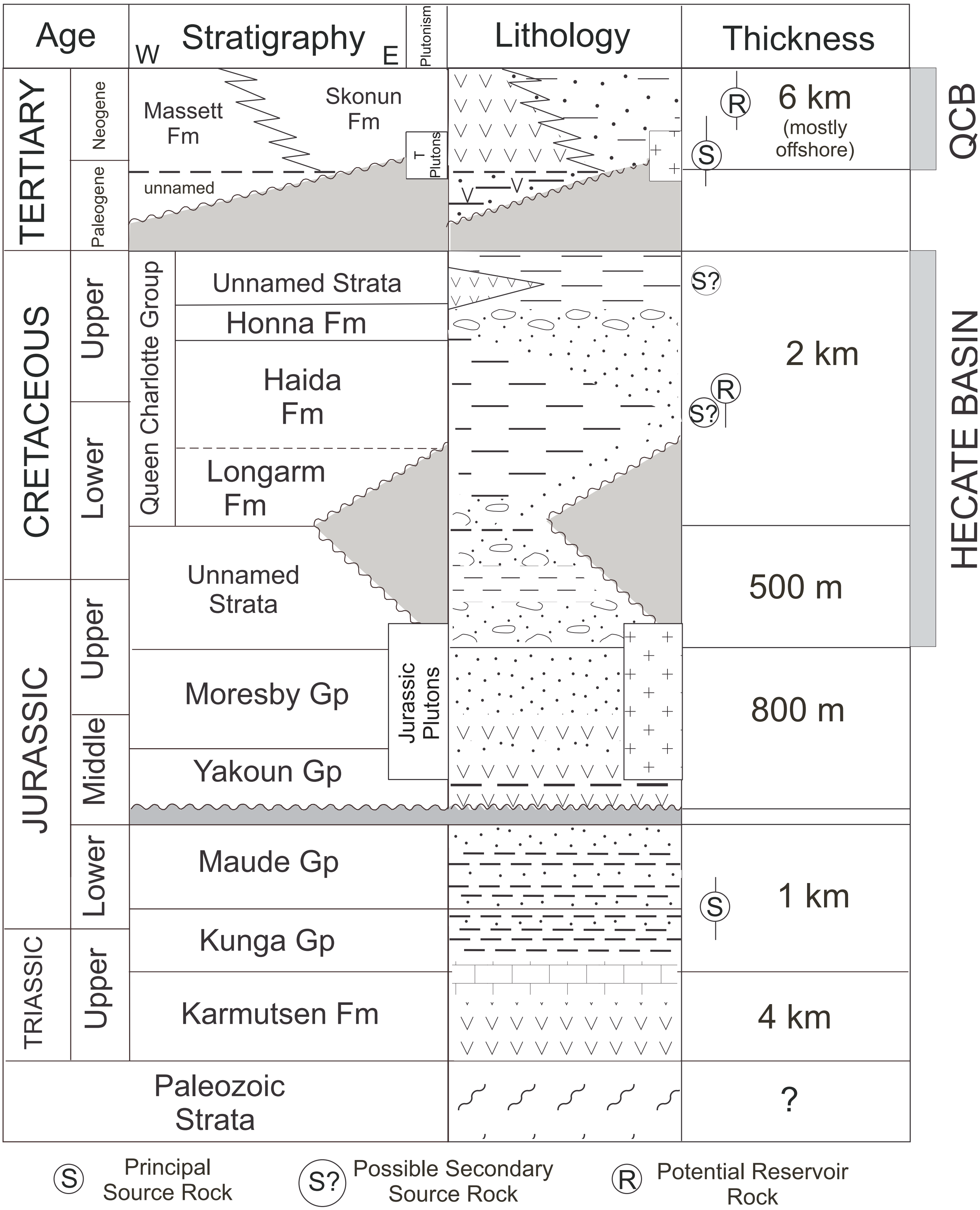

Figure 4. Generalized stratigraphic column for Queen Charlotte assessment region (from Haggart, 2003). Major sedimentary reservoirs include the Queen Charlotte Group (Hecate Basin) and Skonun Formation. Abbreviations: Fm-formation; Gp-Group; QCB-Queen Charlotte Basin; T-Tertiary.

rocks are Middle Jurassic northwest-trending folds and thrust faults (Lewis et al., 1991; Thompson et al., 1991). Karmutsen, Kunga, and Maude rocks accumulated in intra-oceanic and island arc settings, as part of the Wrangellia Terrane.

The Wrangellian (Lower Mesozoic) succession is unconformably overlain by approximately 800 m of volcanic and volcaniclastic rocks of the Middle Jurassic Yakoun and Moresby groups (Fig. 4). The Yakoun Group consists of 480 metres of volcanic breccia, lapilli tuff, and agglomerate with minor lenticular sandstone and siltstone (Cameron and Tipper, 1985). These rocks represent the onset of widespread volcanism, possibly associated with plate subduction. The overlying siliciclastic sediments of the Moresby Group consist of siltstone, shale, and sandstone, with minor pebble conglomerate. Middle Jurassic and older rocks are locally intruded by late Middle to Late Jurassic plutons of intermediate to felsic composition. These plutonic bodies are aligned in northwesterly and northerly trends (Sutherland Brown, 1968).

Unconformably overlying Moresby-Yakoun rocks are up to 500 metres of unnamed Upper Jurassic-Cretaceous sandstone, shale, and conglomerate strata overlain in turn by 2000 m of sandstone, shale, conglomerate, and minor volcanic rocks of the Cretaceous Queen Charlotte Group (Fig. 4; Sutherland Brown, 1968; Haggart, 1991). In contrast to the underlying Mesozoic sedimentary succession, this Cretaceous sedimentary package is widespread across the region. These rocks are primarily shallow-water sediments deposited in linear facies belts in a fore-arc basin setting (Hecate Basin; Haggart, 2003). Continuous sedimentation likely occurred during much of the Cretaceous in the western part of Hecate Strait and Queen Charlotte Sound. Some sandstone and conglomerate units in the Queen Charlotte Group have good reservoir characteristics and are potential petroleum reservoirs (Fogarassy and Barnes, 1991). The coarse-grained deposits are overlain by several hundred metres of siltstone and carbonaceous shale. Structures in Jurassic and Cretaceous strata include early Tertiary northwest-trending contractional folds (Lewis et al., 1991).

The Mesozoic succession is locally intruded by Late Eocene to Oligocene plutons and overlain by unnamed Eocene-Oligocene sedimentary and volcanic rocks that attain a maximum thickness of a few hundred metres.

Uppermost Paleogene and Neogene volcanic and sedimentary rocks of the Masset and Skonun formations unconformably overlie older Paleogene rocks in the Queen Charlotte assessment region (Fig. 4). Neogene volcanic rocks of the Masset Formation are up to 2000 metres thick. Volcanic rocks are widespread and are both overlain and locally interbedded with Neogene clastic sedimentary rocks of the Skonun Formation. The Skonun Formation comprises most of Queen Charlotte basin-fill. It consists of up to 6000 metres of interbedded sandstone, shale, conglomerate, and coal (Fig. 4). These rocks were deposited in both marine and nonmarine settings. Structural features within the Queen Charlotte Basin developed in association with Miocene transtensional and Plio-Pleistocene transpressional tectonics (Rohr and Dietrich, 1992). Miocene structures include north-, northwest-, and east-west-aligned normal and oblique-slip faults. Pliocene structures include reverse faults (commonly developed as inversions of Miocene normal faults), contractional folds, and combination fault-fold flower structures. Pleistocene structural features in the Queen Charlotte Basin include local folds and tilted/truncated Neogene strata.

Petroleum Geology

Reservoirs

The Upper Jurassic-Cretaceous Queen Charlotte Group and other strata (Fig. 4) include thick sections of sandstone and conglomerate, portions of which have reservoir potential. The best reservoir qualities occur in shallow marine sandstone and granule conglomerate within the basal part of the Haida and Longarm formations. This time-transgressive unit, referred to as basal transgressive lithofacies by Haggart (1991), contains texturally mature, arkosic sandstone (compositional data in Sutherland Brown, 1968; Fogarassy and Barnes, 1991). The basal transgressive strata were deposited along northwest-southeast-aligned paleoshorelines in the Haida Gwaii area and probably the western parts of Dixon Entrance, Hecate Strait, and Queen Charlotte Sound (Haggart, 1991; Lyatsky and Haggart, 1993). These strata persist laterally for many tens of kilometres on Haida Gwaii. The average porosity in the unit is 5 to 10%, with values locally exceeding 15% (Fogarassy and Barnes, 1991). The observed porosity is a combination of preserved intergranular porosity and appreciable secondary porosity due to calcite dissolution. Permeability is considered fair to good due to well rounded framework grains and the lack of clay cements. The basal transgressive unit is 30 to 190 m thick in onshore areas, with increasing thickness and porosity in a southeast direction (see Fig. 5 for location of interpreted paleoshorelines, marked as moderate to high prospective area). Cretaceous nonmarine strata occur in the subsurface along the west side of Hecate Strait. Three offshore wells (Tyee and Sockeye B-10 and E-66, Fig. 3 and Table 1) penetrated probable Upper Cretaceous coal-bearing nonmarine strata (Haggart, 1991). Sandstone is common in the nonmarine Cretaceous sections penetrated in offshore wells, but in all cases well logs indicate low porosity and per-

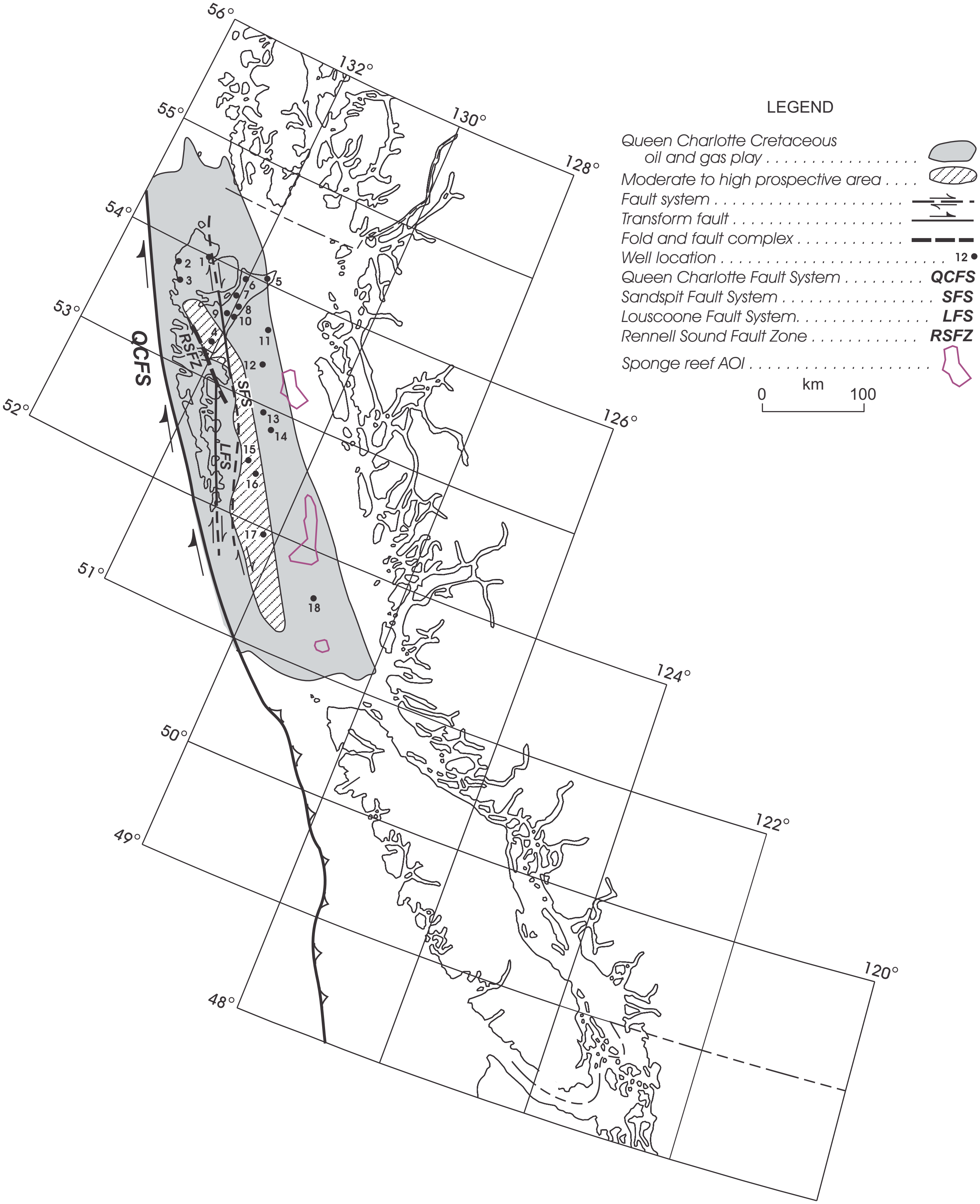

Figure 5. Queen Charlotte Cretaceous oil and gas play area. The area of higher prospectivity occurs in the central part of the play area.

meability. Cretaceous sandstone may have improved reservoir potential in other parts of Hecate Basin due to local development of secondary porosity (Fogarassy and Barnes, 1991).

The Neogene Skonun Formation (Fig. 4) contains large volumes of sandstone and conglomerate deposited in a wide range of nonmarine and marine depositional environments, including delta-front, tidal-shelf, alluvial fan, fan delta, and marine slope settings (Higgs, 1991; Dietrich et al., 1993). Most or all Neogene subbasins contain a mix of nonmarine and marine strata, with northern subbasins beneath Hecate Strait containing greater percentages of nonmarine deposits. The wide geographic distribution, large volume, and commonly good reservoir characteristics of Skonun sandstone/conglomerate strata make them the principal petroleum exploration targets in the region. Skonun sandstone and conglomerate beds are up to tens of metres thick and comprise 25 to 75% of the total Neogene sedimentary section. Skonun reservoir strata attain cumulative thicknesses of up to several thousand metres in the deepest subbasins. Skonun sandstone beds are predominantly arkose and lithic arkose, and generally have the highest mineralogical maturity of all arenaceous rocks in the region (Shouldice, 1971). At depths less than 2000 m, Skonun sandstone beds have very good reservoir qualities, characterized by high porosity (25-35%) and fair to very good permeability (10-500 md) (Dietrich, 1995). At depths from 2000 to 3000 m, Skonun sandstone beds have high porosity (20-30%) and fair permeability (10-100 md). Skonun reservoir potential is limited below depths of about 3000 m, due to low permeability. Tidal-shelf and storm-dominated-shelf sandstone strata are commonly the most permeable Skonun reservoirs, due to advanced textural and compositional maturity (Higgs, 1991). Shelf sandstone occurs throughout the Queen Charlotte Basin and is most abundant in southern basin areas. In some areas, Neogene sections contain volcaniclastic sandstone and conglomerate characterized by poor reservoir qualities, even at shallow depths. Low porosity and permeability in volcaniclastic strata are due to advanced cementation associated with diagenesis of volcanic rock fragments (Galloway, 1974). Volcanic and volcaniclastic rocks usually occur in the oldest synrift sections adjacent to basin-bounding faults. From a regional perspective, volcaniclastic strata comprise a relatively small portion of the basin's total sediment volume.

Seals

Effective seals include Neogene volcanic rocks of the Masset Formation and mudstone and siltstone beds in the Skonun Formation. Basal Cretaceous sandstone units are commonly overlain by thick Upper Cretaceous shale sections. The Queen Charlotte Basin contains thick successions, generally between 1000 and 3000 m depth, of interbedded Neogene reservoir and seal rocks, providing potential for entrapment of oil or gas at many stratigraphic intervals. Impermeable strata are least common in shallow Neogene sections (above 1000 m depth) in the northern half of the basin. Fault-related seals for Tertiary or Cretaceous reservoirs may be associated with impermeable fault zones or cross-fault juxtaposition of permeable and impermeable strata.

Traps

A variety of potential structural and stratigraphic petroleum traps occur in Cretaceous and Tertiary strata in the Queen Charlotte assessment region. Traps involving Cretaceous strata include Late Cretaceous folds and extensional fault blocks. Combined structural-stratigraphic traps may be associated with Cretaceous subcrop patterns at the sub-Neogene unconformity. Neogene reservoir strata occur in Miocene- to Pleistocene-age structural and stratigraphic traps. Miocene structures include tilted fault blocks, fault-related rollover and drag closures, and low-relief drape anticlines. Stratigraphic traps may occur in Miocene strata that onlap onto or subcrop below local unconformities, within cone-shaped alluvial fan or fan delta deposits banked against fault scarps, or sandstone beds that pinch-out within half-grabens. Pliocene structural traps, restricted to the northern half of the basin (Hecate Strait and Dixon Entrance), include abundant large-amplitude folds, commonly cut by steep-dipping reverse faults. Most of the Late Pliocene folds are structurally detached from underlying Mesozoic rocks. Structural decoupling results in lateral separation of closures in Neogene and Cretaceous strata. Stratigraphic traps may also be locally present in shallow parts of the Queen Charlotte Basin where tilted Neogene strata are unconformably overlain by Quaternary mudstone.

Seismic mapping and outcrop information (and related extrapolations into limited data areas) indicate there may be hundreds of untested structural traps within the Hecate and Queen Charlotte basins. The largest structural closures involve Neogene strata within Pliocene folds, some of which exceed 50 km^2 in area.

Source Rocks

Good to excellent hydrocarbon source rocks have been identified in Upper Triassic-Lower Jurassic Kunga Group and Maude Group strata (Fig. 4; Macauley, 1983; Vellutini and Bustin, 1991a). These marine organic-rich mudstone and limestone beds are up to 600 m thick and of wide lateral distribution, and are a significant potential petroleum source rock (Bustin and

Mastalerz, 1995). Upper Kunga Group limestone and thin-bedded argillite, and lower Maude Group shale contain oil-prone Type I and oil- and gas-prone Type II organic matter, with total organic content (TOC) averaging 1 to 4% in sections up to several hundred metres thick. Organic-rich shale with 5 to 10% TOC occurs in beds up to 10 m thick. Measured hydrocarbon yields from organic-rich beds from the central Haida Gwaii area range up to between 50 and 100 mg HC/g rock, indicating excellent oil source potential (Macauley, 1983). The subsurface distribution of Kunga-Maude strata is largely unknown but is expected to be highly irregular, due to varying effects of episodic Middle Jurassic to Tertiary erosion. Kunga-Maude strata are most likely preserved in greatest abundance in the southwestern half of the region, beneath Graham Island and western parts of Dixon Entrance, Hecate Strait, and Queen Charlotte Sound (Thompson et al., 1991; Lyatsky and Haggart, 1993).

Sedimentary strata within the Upper Jurassic-Cretaceous succession contain Type III (gas-prone) organic matter, with generally poor hydrocarbon source potential (TOC less than 1%; Vellutini and Bustin, 1991a). In offshore areas, carbonaceous beds and coal seams in nonmarine Upper Cretaceous strata may have some gas potential (Fig. 4).

The Neogene Skonun Formation and unnamed upper Paleogene strata (Fig. 4) contain coal beds and carbonaceous mudstone with good to excellent gas source potential (Bustin et al., 1990; Vellutini and Bustin, 1991a; Bustin, 1997). Although lower in overall source-rock quality than Kunga-Maude rocks, Tertiary source rocks occur in much greater volume and wider distribution. Organic content in Skonun strata in offshore wells averages 0.5 to 8% TOC, with high TOC values (up to 60%) occurring in coal and carbonaceous mudstone beds. Systematic variations in TOC content with depth occur in many of the offshore Queen Charlotte Basin wells, with organic-rich intervals most abundant in upper parts of the synrift succession (Bustin, 1997). The northern half of the Queen Charlotte Basin contains the most organic-rich synrift strata. Low hydrogen indices (HI) and kerogen types indicate most organic matter in the Skonun Formation is gas-prone terrestrial Type III. Skonun mudstone locally contains moderate amounts of Type II organic matter, with fair to good oil source potential (Vellutini and Bustin, 1991a; Bustin, 1997). Some coal beds in the Skonun Formation also contain resinite (fossil tree sap), a potential source of oil and condensate (Snowdon et al., 1988).

Source Rock Maturation

Present thermal maturation conditions of Mesozoic and Tertiary strata are known from pyrolysis T_{max} data (Bustin et al., 1990), vitrinite reflectance measurements (Vellutini and Bustin, 1991b; Bustin, 1997), and conodont-alteration indices (Orchard and Forster, 1991) from outcrop and well samples. Kunga-Maude source rocks are overmature in southwestern Haida Gwaii (due to proximity to Jurassic and Tertiary plutons and dyke swarms), and marginally mature to mature in central and northern Haida Gwaii (Vellutini and Bustin, 1991b). Maturation levels of Kunga-Maude strata in offshore areas are unknown, but are expected to vary from mature to overmature. Thermal-maturation models indicate that Kunga-Maude strata, if present in the Hecate Strait area, may be within the oil-generation window at depths from about 2000 to 4000 m (Dietrich, 1995; Schuemann et al., 2011).

Neogene strata within the Queen Charlotte Basin are immature to mature, with an estimated 30 to 40% of the total basin fill occurring at maturation levels within oil- or gas-generation windows. The depth to the top of the hydrocarbon generation window (0.5 % R_O) in Neogene strata in offshore wells varies from 1500 to 2500 m (Dietrich 1995; Bustin 1997). In the Sockeye B-10 well, the deepest well in the basin, the base of the oil- and gas-generation windows occurs at depths of about 4000 and 5000 m, respectively. Regional tectonic- and thermal-modelling studies indicate high heat-flow areas and above-average thermal maturation conditions are likely associated with deep Tertiary subbasins in southern parts of the Queen Charlotte Basin (Dehler et al., 1997). The Cape Scott subbasin (located near the southern Sponge Reef AOI) may have the highest thermal-maturation conditions of the entire Queen Charlotte Basin.

Timing of Hydrocarbon Generation

Maturation of source rock within the Queen Charlotte Basin region was controlled to varying degrees by heat flow associated with Jurassic and Tertiary magmatism, and late Tertiary rifting and subsidence. Temporal and spatial variations in heat flow resulted in substantial variability in timing of source-rock maturation and hydrocarbon generation across the region. In Haida Gwaii, Kunga-Maude strata entered the oil-generation window at various times from Late Jurassic to Late Miocene (Vellutini and Bustin, 1991b). This pattern reflects greater distances from plutonic and volcanic centres. Paleogene sedimentary strata entered the oil window during Pliocene time in western Graham Island area (wells 1, 2 and 3, Fig. 3). With the exception of the deepest part of the Tow Hill well (well 5 of Fig. 3, Table 1), Neogene strata penetrated by onshore wells along eastern Graham Island (wells 4, 6-10, Fig. 3) have yet to enter the oil window.

Similar variations in maturation history and timing of hydrocarbon generation occurred in the offshore.

Subsidence and hydrocarbon generation models of the Sockeye B-10 well (located in a deep Tertiary subbasin) indicate hydrocarbon generation occurred from Middle Jurassic to early Miocene in Kunga-Maude strata, and from early Miocene to Holocene in lower Skonun strata (Dietrich, 1995). In contrast, similar models of the nearby Sockeye E-66 well (located at the margin of a subbasin, with thinner Tertiary strata) indicate petroleum generation occurred from early Miocene to Holocene in Kunga-Maude strata, with no petroleum generation in Skonun strata. These models indicate the potential for a highly variable and complex hydrocarbon charge history, even within local areas of the Queen Charlotte Basin.

Petroleum-generation models of all eight offshore wells, incorporating more detailed and accurate maturation data, indicate the onset of oil generation in Lower Miocene strata occurred between 16 and 27 Ma, with highly variable times of peak hydrocarbon generation (Bustin, 1997). In southern Queen Charlotte Basin, peak hydrocarbon generation varied from 5 Ma in the Harlequin well to 18 Ma in the Osprey well. Middle Miocene strata entered the oil window between 7 and 20 Ma and currently lie within the oil window. Upper Miocene and younger strata in the offshore wells have not entered the oil window.

Two-dimensional petroleum system models of the Queen Charlotte Basin indicate Kunga-Maude strata (if present in offshore areas) would have generated significant volumes of petroleum, with peak generation during Miocene development of the Queen Charlotte Basin (Schuemann and Whiticar, 2007; Schuemann et al., 2011). Some of the generated petroleum is predicted to have migrated into Cretaceous or Neogene reservoirs. These models indicate Miocene Skonun strata would have generated some petroleum, at depths below 3000 m.

Petroleum Shows

The potential for significant petroleum accumulations in the Hecate and Queen Charlotte basins is demonstrated by the common occurrence of oil and gas shows. More than 50 sites of oil, tar, or natural gas seeps have been identified on Haida Gwaii (Hamilton and Cameron, 1989). Most of the surface seeps occur in Cretaceous and Tertiary volcanic and sedimentary rocks, many of which are in the Masset Formation. Geological and geochemical studies indicate the seeps are migrated conventional oils, sourced from both Jurassic (Kunga-Maude) and Tertiary sedimentary strata (Fowler et al., 1987; Hamilton and Cameron, 1989). One of the more aerially extensive surface oil seeps occurs in Masset volcanic rocks and fractured Cretaceous shales at Lawn Hill on the southeast coast of Graham Island (Fig. 1). The geology and geochemistry of the Lawn Hill seeps indicate the oil was probably sourced from underlying or subjacent Jurassic rocks, with migration into the host rocks in late Neogene (Snowdon et al., 1988; Hamilton and Cameron, 1989). The Lawn Hill area is part of a high-standing block within westernmost Queen Charlotte Basin. Cretaceous or Neogene reservoir strata in surrounding or basinward areas may be highly prospective for conventional accumulations of similar oils.

Subsurface hydrocarbon shows were encountered in several petroleum and mineral exploration wells, including gas flows from the Tian Bay well (Hamilton and Cameron, 1989), oil staining in Tertiary volcanic rocks in the Port Louis and Naden wells, oil staining in Cretaceous sandstone in the Queen Charlotte well, and oil staining in Neogene sandstone in the Tow Hill and Sockeye B-10 wells. The Sockeye B-10 well encountered the best subsurface hydrocarbon shows, including a 40 m thick oil-stained Miocene sandstone, and multiple gas shows from Miocene and Cretaceous coal-bearing zones below 3000 m depth. Geochemical analysis of a saturate fraction from the Sockeye oil show indicated the presence of a biomarker compound diagnostic of Jurassic Kunga Group source rocks (Fowler et al., 2003). The recognition of a probable Jurassic Kunga source for the Sockeye oil show is an important finding that links the region's principal source and reservoir rocks

Subsurface gas occurrences in Neogene and Quaternary strata have been inferred from anomalies in seismic reflection profiles in many offshore locations (Barrie, 1988; Dietrich, 1995; Halliday et al., 2008; Duchesne et al., 2011; this study). Seafloor indications of gas seepage (pockmarks and carbonate mounds) have been mapped in many areas in Hecate Strait and Queen Charlotte Sound (Halliday, 2008; Halliday et al., 2008).

Petroleum Plays and Oil and Gas Resource Potential in Hecate and Queen Charlotte Basins

Cretaceous Oil and Gas Play (Hecate Basin)

The Cretaceous oil and gas play involves all structures and prospects within Cretaceous strata in Hecate Basin beneath and adjacent to Queen Charlotte Basin. The Cretaceous play area encompasses most of the Haida Gwaii and adjacent shelf areas, extending as far east as the Hecate Basin margin (Figs. 3, 5). Potential hydrocarbon traps involve Cretaceous sandstone, principally within the basal units of the Queen Charlotte Group, in fault blocks, or anticlinal structures. Onshore areas have been mapped where Cretaceous reservoir strata directly overlie Kunga-Maude source rocks (Thompson et al., 1991), an optimum stratigraphic relationship that may occur in some fault blocks in the subsurface. The

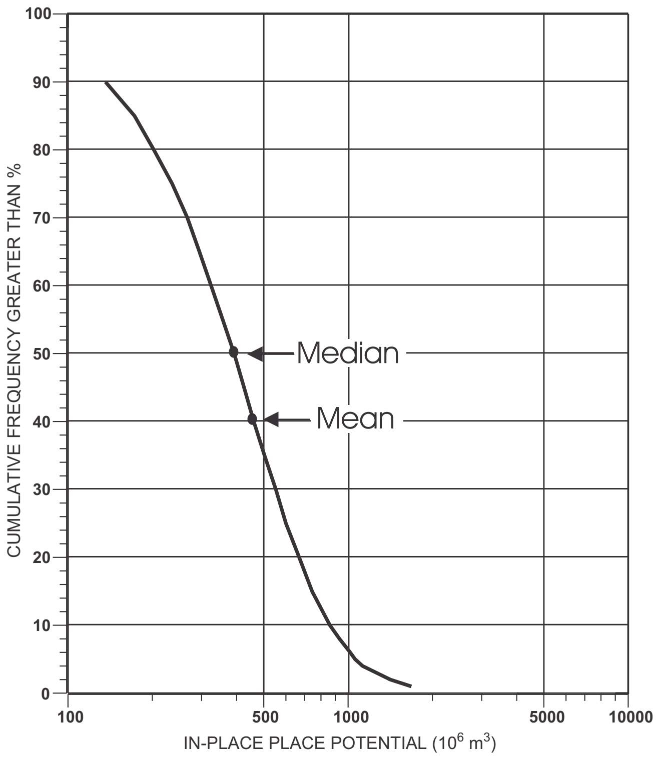

Figure 6. Estimate of in-place oil potential of the Cretaceous play in Hecate Basin. Median value of probabilistic assessment is 392 million m^3 of in-place oil distributed in 62 fields. The mean estimate is 460 million m^3.

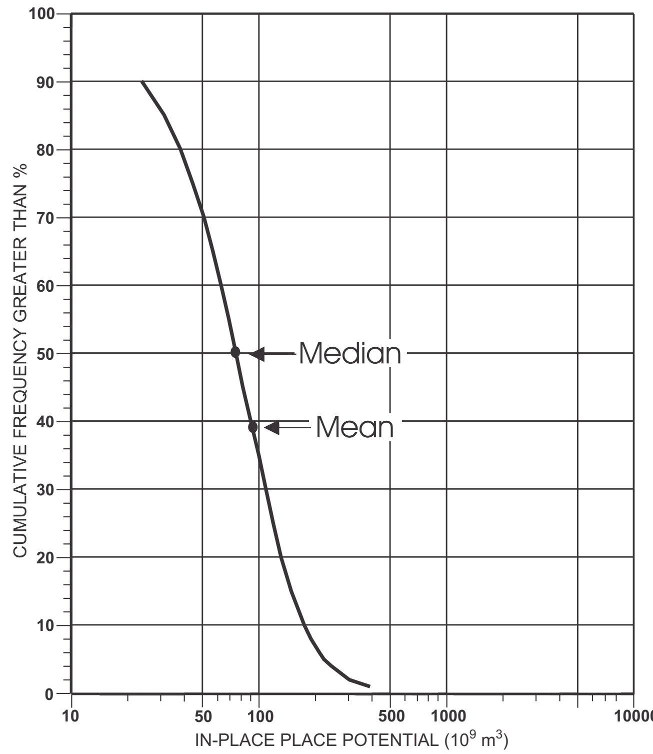

Figure 7. Estimate of in-place gas potential of the Cretaceous play in Hecate Basin. Median value of probabilistic assessment is 75 billion m^3 of in-place gas distributed in 50 fields. The mean volume is 93 billion m^3.

most prospective part of the play area occurs in a southeast-trending fairway from central Graham Island to southwestern Queen Charlotte Sound (Lyatsky and Haggart, 1993); an area where the main reservoir facies was deposited (Fig. 5). The play includes areas where potential reservoir strata underlie thick Tertiary volcanic rocks. This play is characterized by relatively small structures and single reservoir zones.

The Cretaceous play has an estimated in-place oil potential of 460 x 10^6 m^3 (mean value, Fig, 6). The volumes are predicted to range from 136 x 10^6 m^3 to 861 x 10^6 m^3 of in-place oil (90% and 10% probability). The mean value of the number of predicted fields is 62. The largest undiscovered field is expected to contain 162 x 10^6 m^3 of oil (mean value). The Cretaceous gas play has an in-place potential predicted to range from 24 x 10^9 m^3 to 175 x 10^9 m^3, with 93 x 10^9 m^3 representing the mean volume (Fig. 7). The estimate assumes a total field population of 50 (mean value), with the largest undiscovered field having an initial in-place volume of 38 x 10^9 m^3 of natural gas (see Table 2 for listing of plays, mean and median play potential, and mean of the largest field size).

Table 2. Oil and gas potential in the Queen Charlotte region (in-place).

Play name	Expected no. of fields (mean)	Median play potential (million m^3)	Mean play potential (million m^3)	Mean of largest field size (million m^3)
Queen Charlotte Region				
Cretaceous oil	62	392	460	162
Cretaceous gas	50	75,435	92,672	37,679
Miocene oil	28	574	656	270
Miocene gas	40	285,710	316,209	115,010
Pliocene oil	13	398	652	444
Pliocene gas	30	321,750	389,710	169,670
Total	103 (oil); 120 (gas)	1559.8 (oil); 733,760 (gas)	1,800 (oil); 819,681 (gas)	

Miocene Oil and Gas Play (Queen Charlotte Basin)

The Miocene oil and gas play extends across all of Queen Charlotte Basin (an area of about 52,000 km^2) and involves extensional structural and stratigraphic traps that developed during the transtensional phase of basin development (Fig. 8). Potential reservoirs include Miocene sandstone and conglomerate. Structural traps include tilted fault blocks, fault-related rollover and drag features, and drape anticlines. Stratigraphic traps are associated with intra-Tertiary unconformities (onlap or subcrop), and updip pinchouts within half-grabens and against fault scarps. The Miocene play incorporates areas or structures where reservoir strata are in direct stratigraphic or structural contact with Mesozoic rocks, providing favourable conditions for local hydrocarbon charging from Kunga-Maude source rocks. Structures or prospects within deep sub-basins

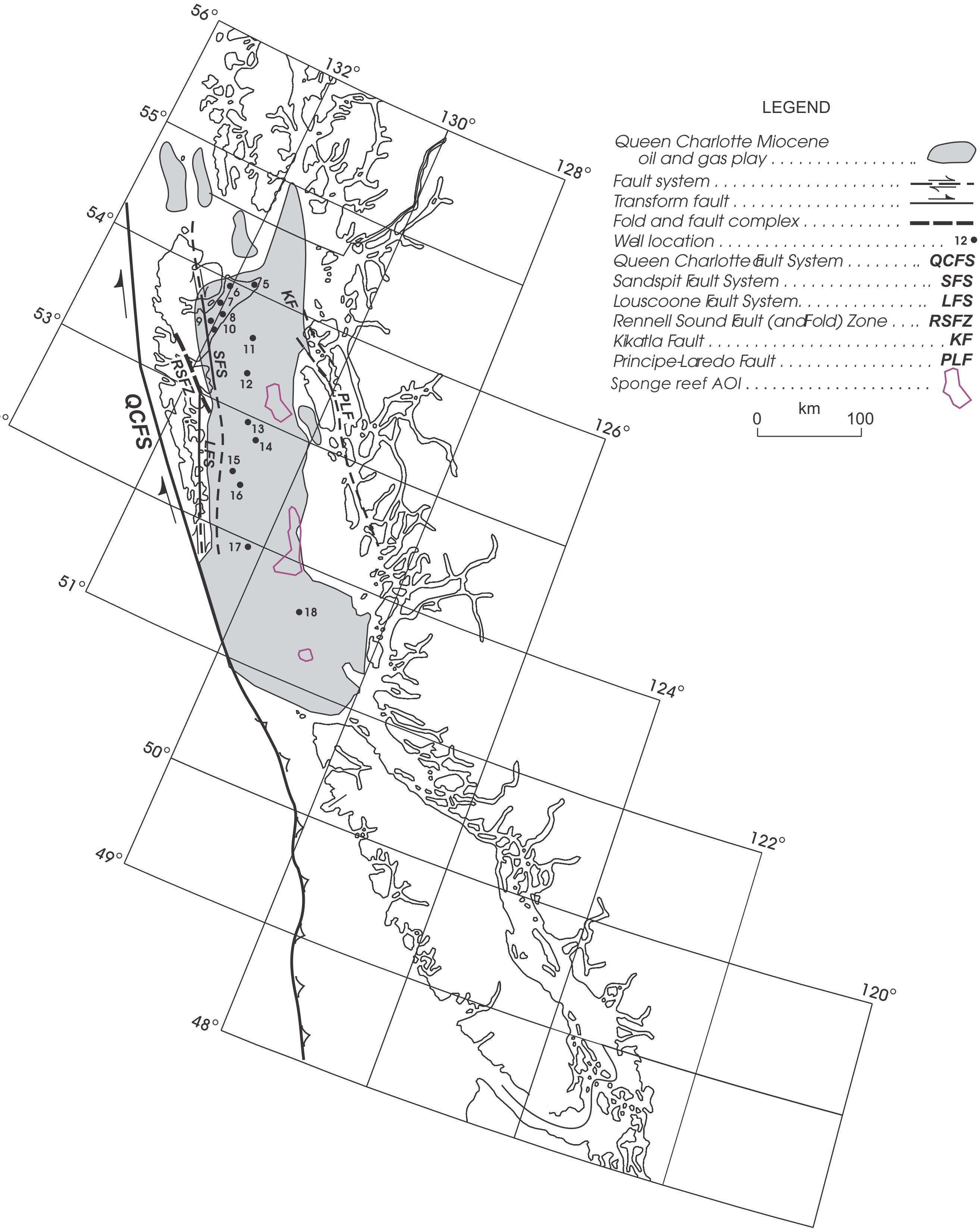

Figure 8. Queen Charlotte Miocene oil and gas play area.

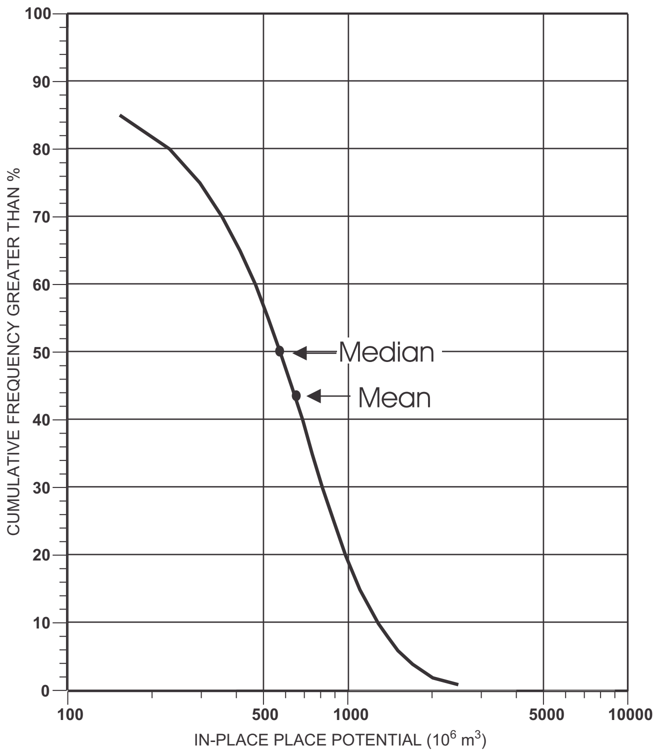

Figure 9. Estimate of in-place oil potential of the Miocene play in Queen Charlotte Basin. Median value of probabilistic assessment is 574 million m^3 of in-place oil distributed in 28 fields. The mean volume is 656 million m^3.

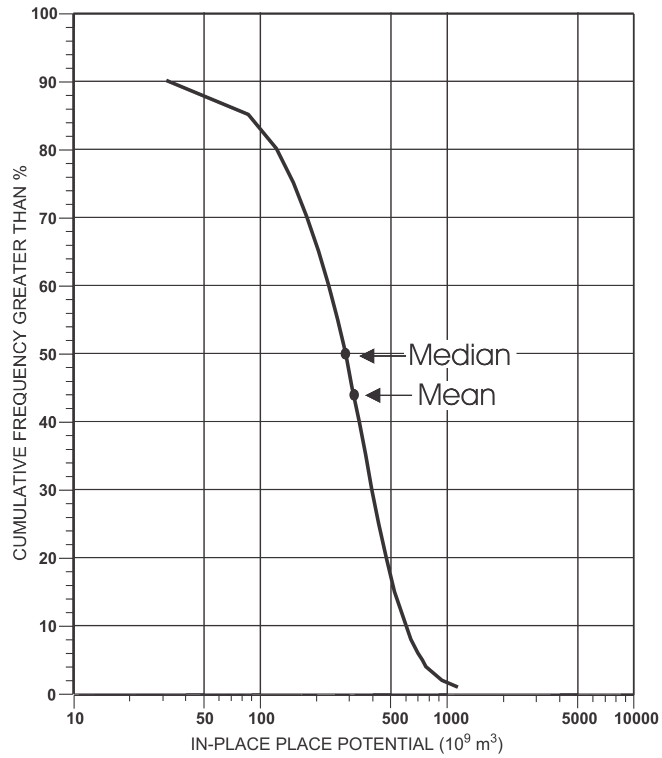

Figure 10. Estimate of in-place gas potential of the Miocene play in Queen Charlotte Basin. Median value of probabilistic assessment is 286 billion m^3 of in-place gas distributed in 40 fields. The mean in-place gas volume is 316 billion m^3.

may occur in favourable positions for hydrocarbon charging from Tertiary source rocks.

The Miocene oil play has an estimated in-place oil potential of 656 x 10^6 m^3, distributed in 28 fields (mean values) (Fig. 9, Table 2). The largest undiscovered oil field is predicted to contain 270 x 10^6 m^3 (mean value). The Miocene gas play predicts 40 fields may be present (mean value) containing a mean in-place potential of 316 x 10^9 m^3 (Fig. 10, Table 2). Estimates of in-place gas potential for the play vary from 31 x 10^9 m^3 to 603 x 10^9 m^3. The largest estimated gas field is 115 x 10^9 m^3 (mean in-place volume).

Pliocene Oil and Gas Play (Queen Charlotte Basin)

The Pliocene oil and gas play includes all structural traps in Neogene reservoirs formed during contractional deformation associated with late Pliocene transpression. The play area is restricted to the northern half of the Queen Charlotte Basin (Fig. 11). Similar to the Miocene play, Skonun Formation sandstone and conglomerate constitute the principal reservoir in the play. The Pliocene play is differentiated from the Miocene play on the basis of structural style and timing of trap development. Pliocene structures include large-amplitude folds and faulted anticlines (flower structures) (Rohr and Dietrich, 1992). Many of the Pliocene antiforms are structurally detached from underlying Mesozoic rocks. In comparison to Miocene prospects, the Pliocene prospects are generally larger in area and involve thicker (multi-zone) reservoir sections. Like the Miocene play, the Pliocene play includes many prospects where reservoir strata are in direct structural juxtaposition with Mesozoic rocks, locally including Kunga-Maude source units.

The Pliocene play has an estimated oil potential of 652 x 10^6 m^3, distributed in 13 fields (in-place volumes, mean values) (Fig. 12, Table 2). The largest undiscovered field has a predicted volume of 444 x 10^6 m^3 of oil (mean volume). The predicted mean gas resource within the Pliocene is 390 x 10^9 m^3 (Fig. 13, Table 2), in 30 fields. A mean value of 170 x 10^9 m^3 of gas is predicted for the largest field.

Total Petroleum Potential in Hecate and Queen Charlotte Basins

Mean estimates of total petroleum potential for the three defined plays in the Hecate and Queen Charlotte basins are 1.8 x 10^9 m^3 (11.3 Bbbl) of in-place oil and 820 x 10^9 m^3 (28.9 TCF) of in-place gas (Table 2). Total oil potential varies from 657 x 10^6 m^3 to 3088 x 10^6 m^3 (6.3 and 19.4 x 109 bbl) and the gas potential ranges from 338 x 10^9 m^3 to 1351 x 10^9 m^3 (12 TCF and 48 TCF) (P90-P10) (Figs. 14, 15). The greatest oil potential (volume) occurs in the Miocene play and greatest gas potential in the Pliocene play (Table 2).

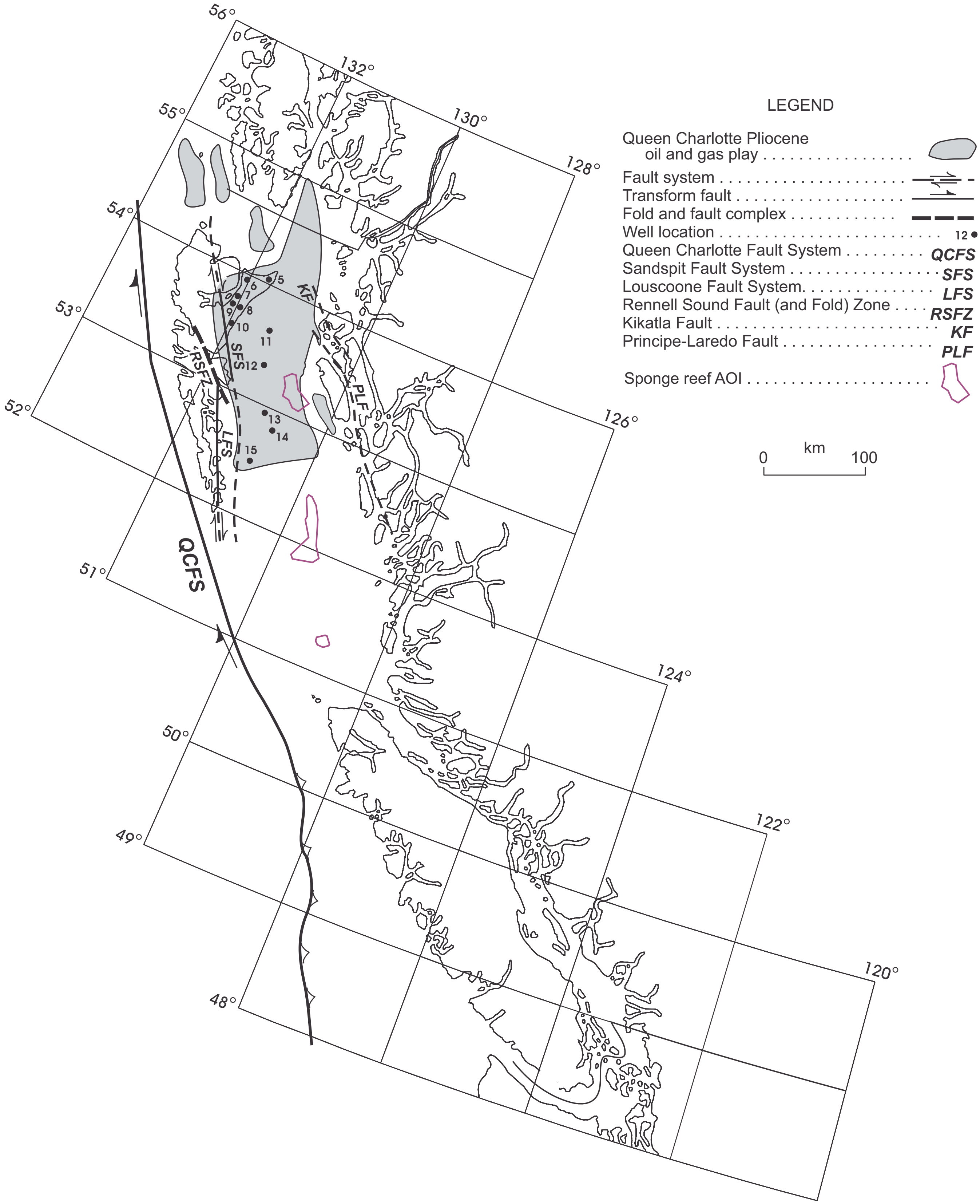

Figure 11. Queen Charlotte Pliocene oil and gas play area showing the major structural elements.

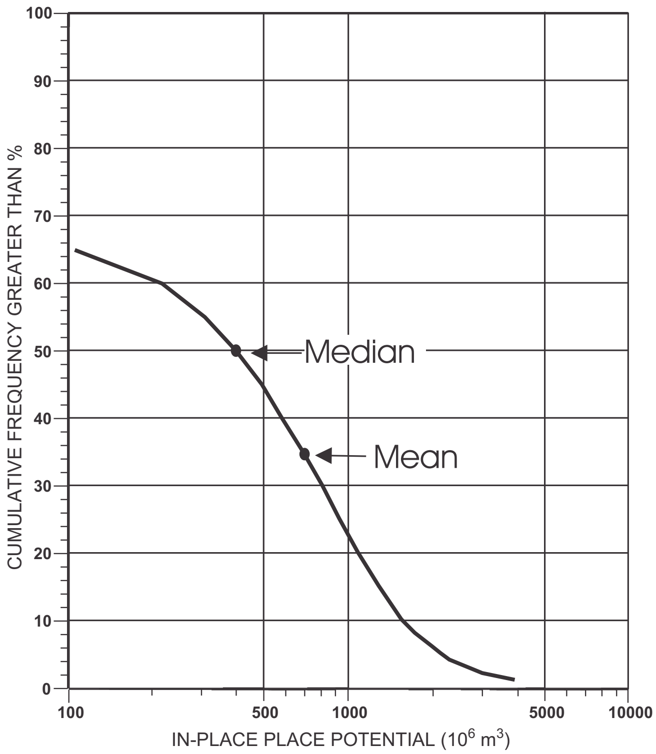

Figure 12. Estimate of in-place oil potential of the Pliocene play in Queen Charlotte Basin. Median value of probabilistic assessment is 398 million m^3 of in-place oil distributed in 13 fields. The mean volume is 652 million m^3.

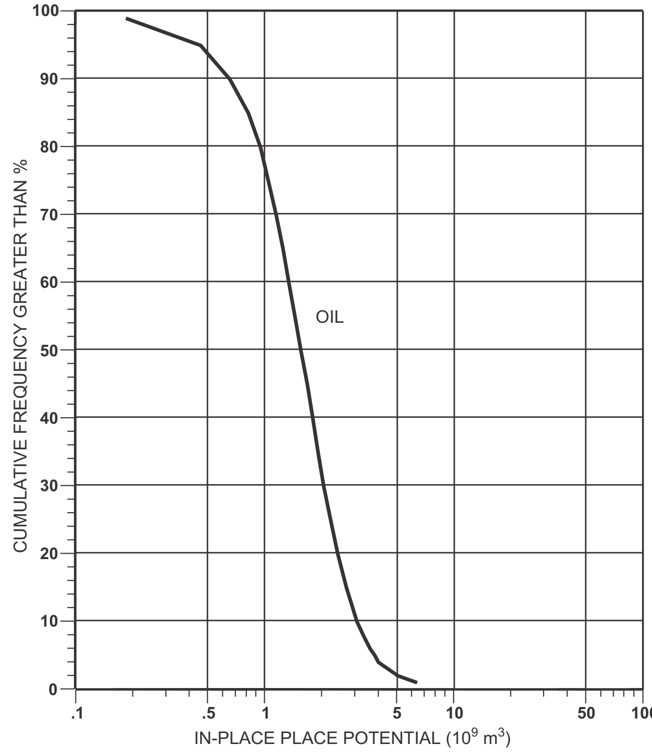

Figure 14. Estimate of total oil potential for the Queen Charlotte Basin region. Mean value of probabilistic assessment is 1.8 billion m^3 of in-place oil.

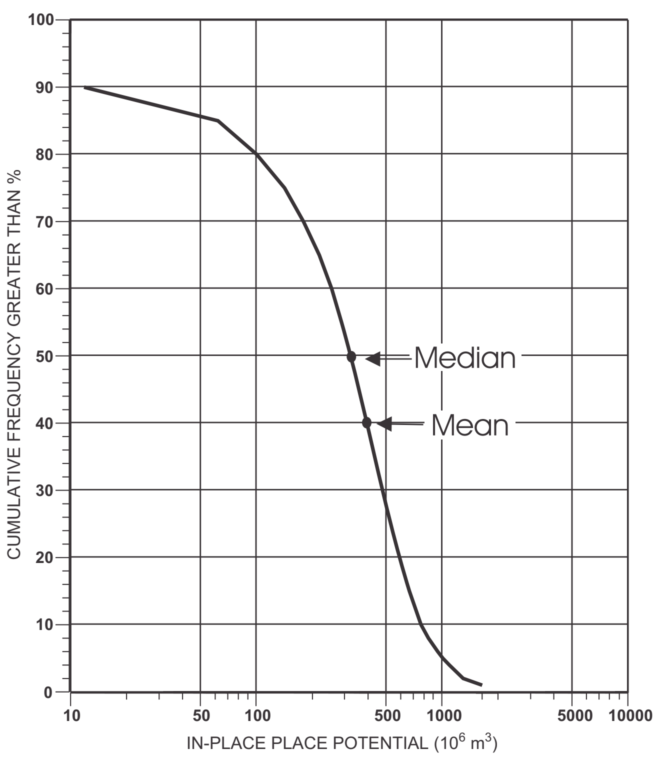

Figure 13. Estimate of in-place gas potential of the Pliocene play in Queen Charlotte Basin. Median value of probabilistic assessment is 322 billion m^3 of in-place gas distributed in 30 fields. The mean in-place gas volume is 390 billion m^3.

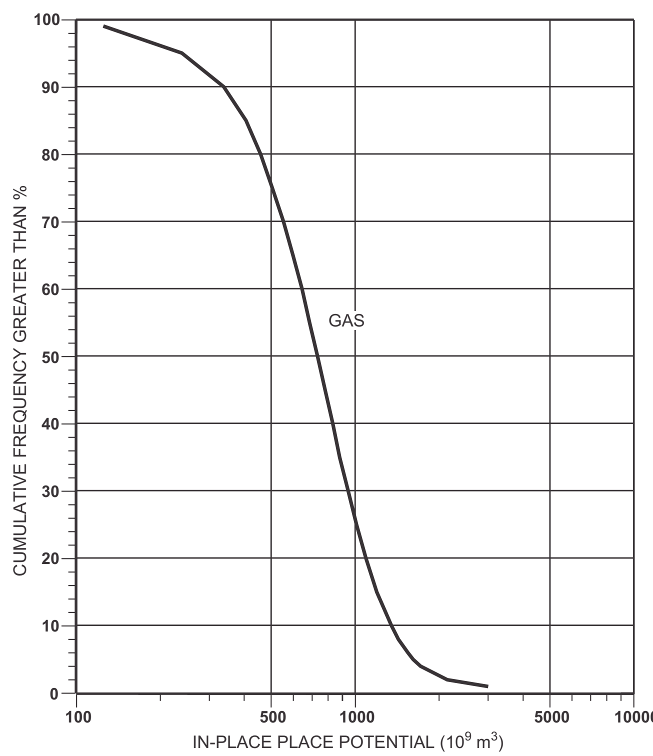

Figure 15. Estimate of total gas potential for the Queen Charlotte Basin region. Mean value of probabilistic assessment is 820 billion m^3 of in-place gas.

The largest individual oil and gas fields are predicted to occur in the Pliocene play. Field-size rankings for all plays suggest that about 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 concentrated hydrocarbon habitat, typical of large convergent and transform plate margin basins (Klemme, 1984).

PETROLEUM POTENTIAL OF THE HECATE STRAIT/ QUEEN CHARLOTTE SOUND SPONGE REEF AREAS OF INTEREST

Geological Setting

The Hecate Strait/Queen Charlotte Sound sponge reef areas of interest are located in central and southern Queen Charlotte Basin and along the eastern margin of Hecate Basin (Fig. 3) on the Pacific continental shelf of Canada. A regional Tertiary isopach map and three seismic reflection profiles illustrate the major geological features within and near the three sponge reef areas of interest (AOI-1, 2, and 3, Figs. 16 to 18).

The northern seismic profile (Profile 1) crosses Hecate Strait (between Haida Gwaii and Banks Island) and the southern part of AOI-1 (Fig. 16). Geological features imaged in Profile 1 include Mesozoic half-grabens and rift blocks with associated normal faults, a prominent late Miocene unconformity, and Pliocene reverse faults, inversion folds, and rollover anticlines (Figs. 17, 18). A significant oil show was encountered in Miocene sandstone in the Sockeye B-10 well (Fig. 17). Petroleum prospects in AOI-1 include an inversion fold and rollover anticline, fault blocks, and a potential stratigraphic pinchout or erosional truncation (Fig. 18). Direct seismic hydrocarbon indicators, including reflection amplitude and frequency anomalies, and flat spots and sags, occur in or near AOI-1, indicating hydro-carbon migration and accumulation in this part of the Queen Charlotte Basin (Figs. 18, 19). Seafloor gas-escape features (pockmarks and carbonate mounds) are observed in this area, indicating local gas migration to the surface (Fig. 18; Halliday, 2008; Duchesne et al., 2011).

The central seismic profile (Profile 2) crosses northern Queen Charlotte Sound and AOI-2 (Fig. 16). Geological features imaged in Profile 2 include Mesozoic half grabens, a late Miocene unconformity, and a local Pliocene inversion fold near the Harlequin D-86 well (Fig. 17). Profile 2 shows the significant eastward thinning of Neogene strata (Skonun Formation) towards the margin of the Queen Charlotte Basin. Remnants of deeply buried Cretaceous strata are inferred to occur beneath the Tertiary Masset Formation. In AOI-2, a thin Neogene sedimentary section overlies Tertiary Masset volcanic rocks (in fault subbasins) and Mesozoic plutonic-metamorphic basement rocks (Fig. 18). There are no obvious petroleum prospects in AOI-2.

The southern seismic profile (Profile 3) extends northwest-southeast across southern Queen Charlotte Sound and AOI-3 (Fig. 16). Geological features in Profile 3 include Mesozoic half grabens and rift blocks with associated normal faults, a late Miocene unconformity, and local Pliocene inversion folds (Figs. 17, 18). The southeastern end of Profile 3 crosses the Cape Scott Subbasin, previously identified as an area of high petroleum potential (Hannigan et al., 2005). Petroleum prospects in AOI-3 include fault blocks, inversion folds, and stratigraphic traps (Fig. 18). Direct seismic hydrocarbon indicators, including phase-reversed reflection amplitude and frequency anomalies, occur in AOI-3 (Figs. 18, 19). Seafloor gas-escape features, including pockmarks and carbonate mounds, have been mapped in and near AOI-3 (Fig. 18; Halliday et al., 2008). The seafloor features and hydrocarbon indicators indicate hydrocarbon migration and accumulation in this part of the Queen Charlotte Basin.

Qualitative Assessment of Conventional Petroleum Potential in the Sponge Reef Areas of Interest

A regional petroleum-potential map for offshore Hecate Strait and Queen Charlotte Sound (Fig. 20) indicates the three sponge reef areas of interest (AOI-1, -2 -3) occur in areas of varying petroleum prospectivity. The map depicts a qualitative ranking of conventional petroleum potential, using general terms of high, moderate, and low potential, as well as non-prospective. The qualitative evaluation of petroleum potential was based on analyses of published seismic reflection profiles, regional isopach maps, potential field data, and basin thermal and maturation analyses.

High Petroleum Potential

The areas of high petroleum potential encompass a large proportion of the Tertiary Queen Charlotte Basin, specifically in central and western Hecate Strait, and western and southern Queen Charlotte Sound (Fig. 20) The regions of high potential contain numerous positive factors for petroleum accumulations, including thick Neogene sedimentary sections, abundant sandstone with good to excellent reservoir qualities, Miocene shale and coal beds with good petroleum source potential, possible Mesozoic (Kunga-Maude) shale beds with excellent source potential, and abundant and diverse structural and stratigraphic trap types. The high-potential regions also contain direct hydrocarbon indicators, including reflection anomalies in seismic profiles sections, and seafloor gas-escape fea-

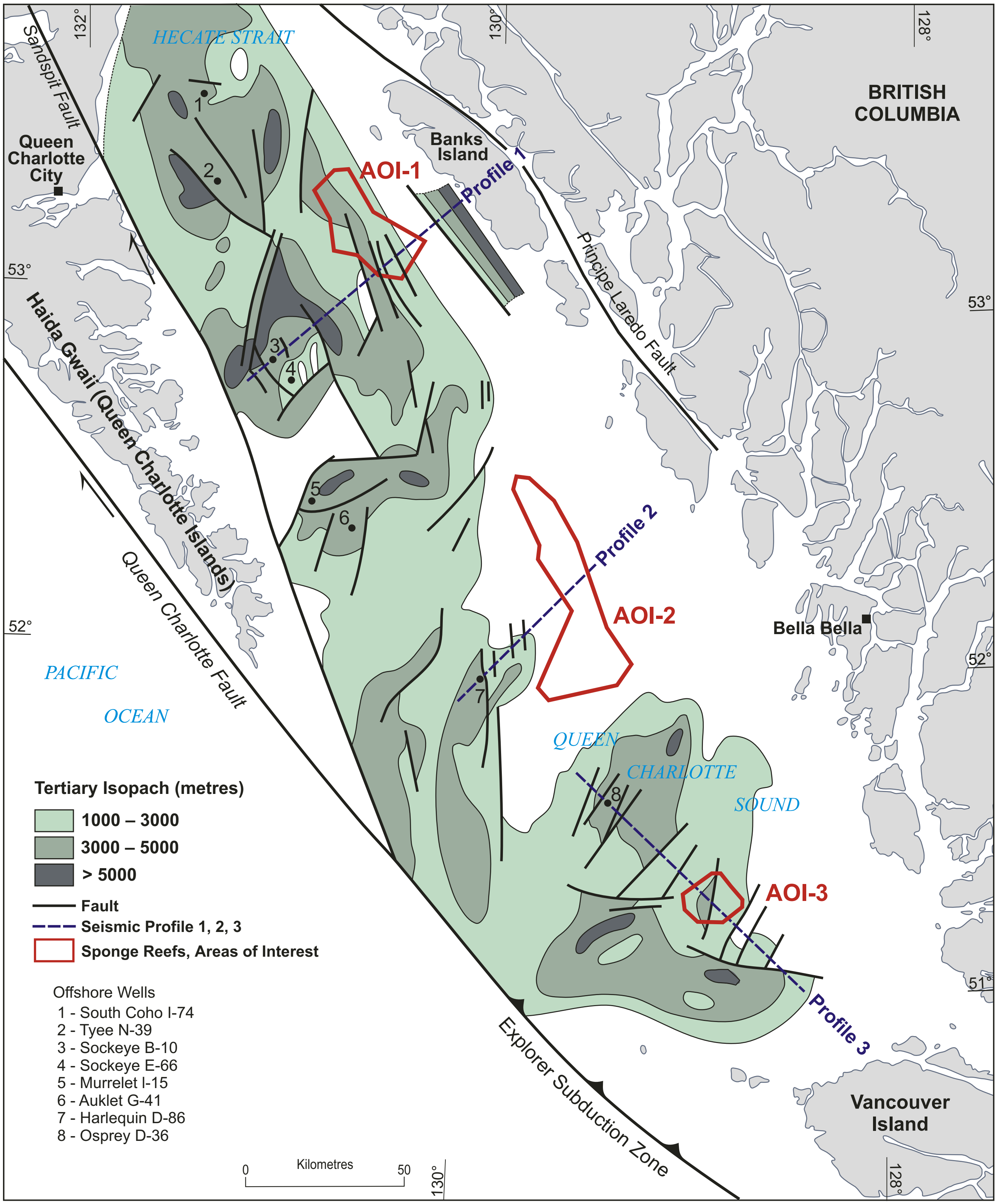

Figure 16. Regional isopach map of Tertiary strata in the offshore Queen Charlotte Basin (modified from Rohr and Dietrich, 1992), with locations of seismic reflection profiles 1, 2, 3 (illustrated in Fig. 17), offshore wells, and the three Sponge Reefs areas of interest; Area of Interest 1 (AOI-1) in eastern Hecate Strait, Area of Interest 2 (AOI-2) in southern Hecate Strait -northern Queen Charlotte Sound, and Area of Interest 3 (AOI-3) in southern Queen Charlotte Sound.

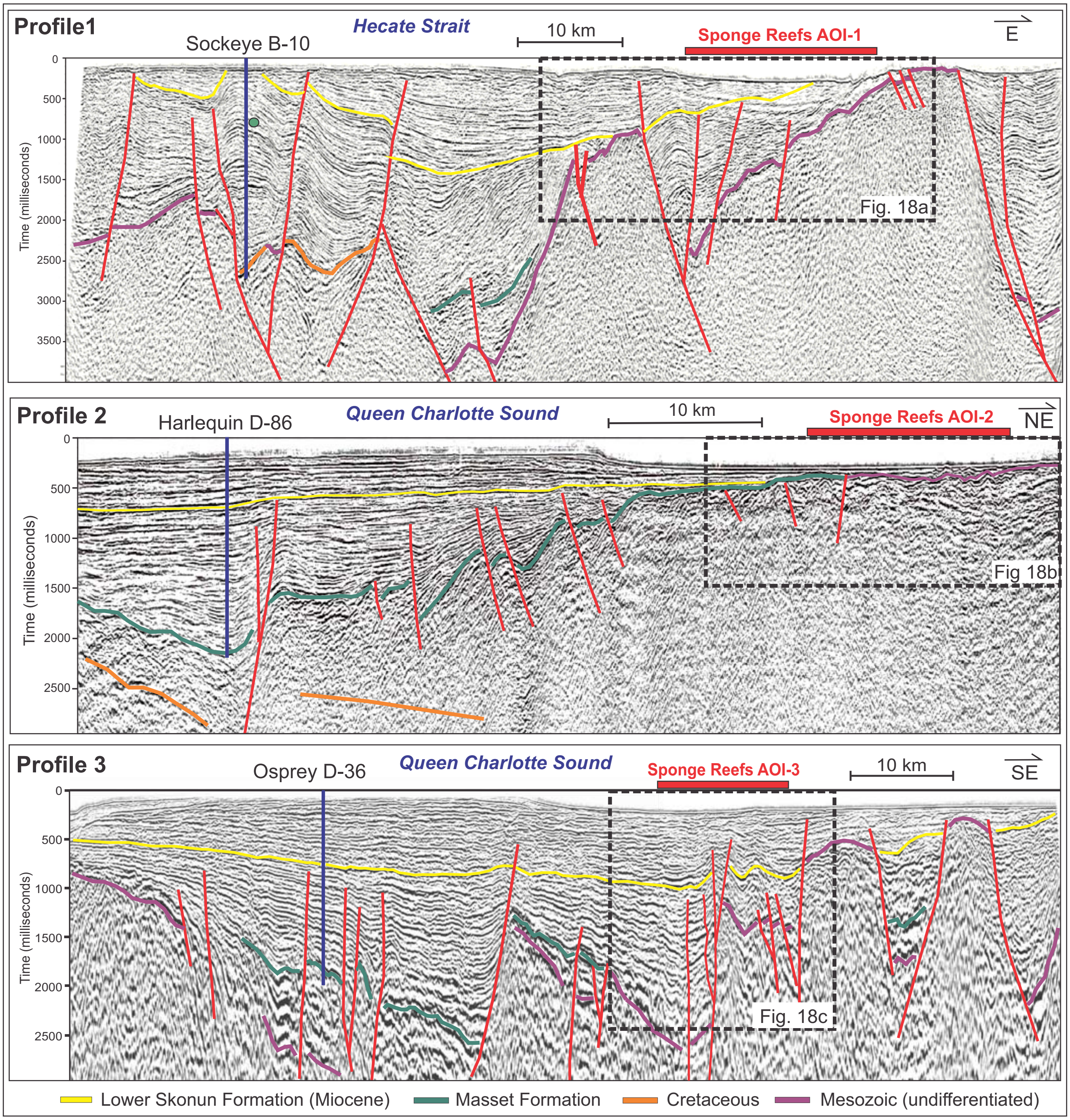

Figure 17. Marine seismic reflection profiles across the Glass Sponge Reefs areas of interest (AOIs) in Hecate Strait (Profile 1, AOI-1 -top panel), northern Queen Charlotte Sound (Profile 2, AOI-2 -middle panel), and southern Queen Charlotte Sound (Profile 3, AOI-3 -bottom panel; profile locations in Fig. 16). Seismic data were acquired in 1988 (Rohr and Dietrich 1990); interpretations presented here modified from Rohr and Dietrich (1992). The Tertiary Queen Charlotte Basin includes sedimentary strata in the Neogene Skonun Formation and volcanic rocks (locally interbedded with sedimentary strata) in the Masset Formation. The basin contains numerous extensional and strikeslip faults (solid red lines in seismic profiles). The Skonun Formation, penetrated by the Sockeye, Harlequin and Osprey wells, contains numerous sandstone intervals with good reservoir characteristics (Dietrich, 1995; Hannigan et al., 2001). Oil shows were encountered in Skonun sandstones in the Sockeye B-1 0 well (Profile 1, green circle). The Queen Charlotte Basin is underlain by Cretaceous sedimentary strata (Hecate Basin) or older Mesozoic sedimentary and igneous rocks. Cretaceous strata in Profile 2 are inferred from seismic refraction data (Clowes and Gens-Lenartowicz, 1985). Segments of Profiles 1,2 and 3 (dashed-line boxes; Fig. 18 a,b,c) illustrate details of subsurface features and possible petroleum prospects in Sponge Reef AOIs 1,2 and 3.

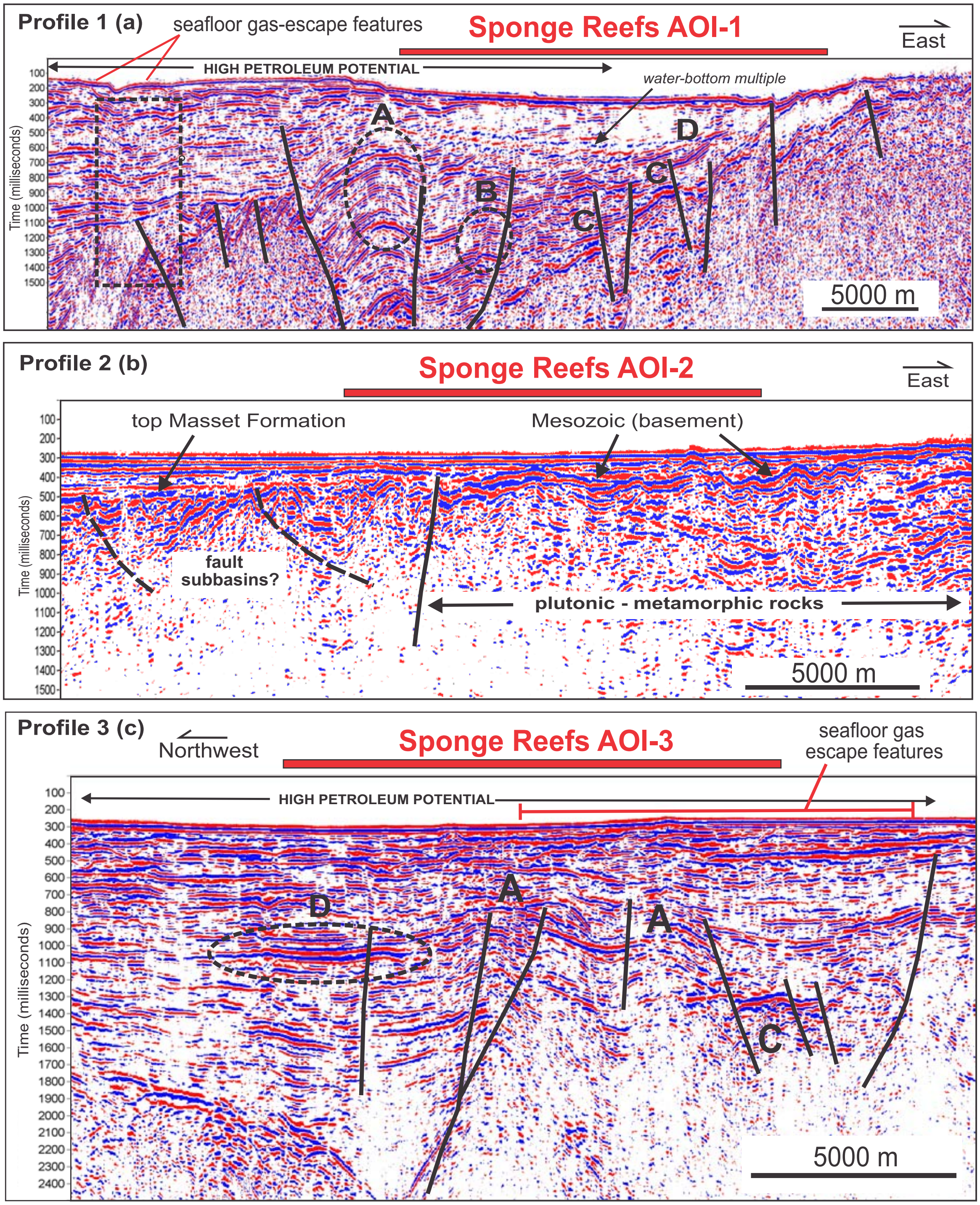

Figure 18. Detail segments of Seismic Profiles 1, 2, and 3 (a,b,c in Fig. 17) across the Sponge Reef areas of interest: AOI-1 in eastern Hecate Strait, AOI-2 in northern Queen Charlotte Sound, and AOI-3 in southern Queen Charlotte Sound. Areas of interpreted high petroleum potential indicated for Profiles 1 and 3 (see Fig. 20). Petroleum prospects in AOI-1 and -3 include faulted inversion anticlines (A), rollover anticlines (B), fault blocks (C), and stratigraphic pinchouts/truncations (D). Anticline prospects in Profile 1 (and B) contain intervals of reflection bright spots and flat spots (dashed ovals) interpreted as direct hydrocarbon indicators (detailed seismic-attribute plots of anomaly A are illustrated in Fig. 19). In the western part of Profile 1 (dashed box), seismic reflection sags and amplitude, and frequency anomalies indicate gas migration and accumulation in Miocene-Pliocene strata (Duchesne et al., 2011). Seafloor gas-escape features (pockmarks and carbonate mounds) occur above this area of seismic hydrocarbon indicators. A Miocene stratigraphic prospect (D) in Profile 3 is associated with a phase-reversed reflection amplitude anomaly (dashed oval) interpreted as a direct hydrocarbon indicator (see attributes in Fig. 19). Seafloor gas-escape features (pockmarks and carbonate mounds) have been mapped in the area of AOI-3 (Halliday, 2008). Profile 2 (AOI-2) encompasses areas of shallow basement (Mesozoic plutonic-metamorphic rocks) and Masset Formation volcanic rocks in possible fault subbasins, overlain by a thin cover of flat-lying Plio-Pleistocene strata. No obvious petroleum prospects occur in Sponge Reefs AOI-2.

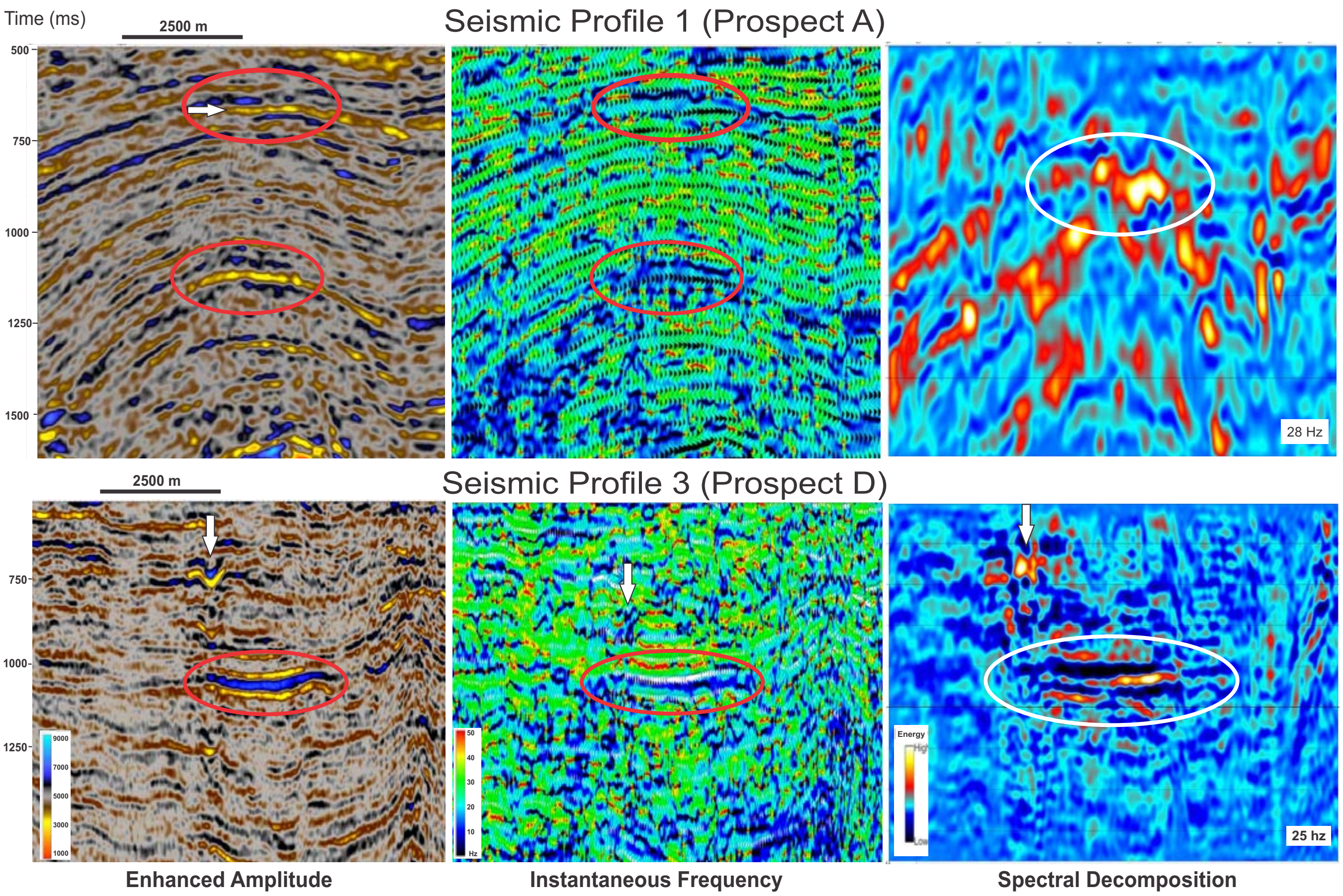

Figure 19. Seismic reflection attributes (enhanced amplitude, instantaneous frequency, and spectral decomposition) of segments of Seismic Profile 1 (top panels) and Seismic Profile 3 (bottom panels), illustrating coincident high amplitude and low frequency anomalies (red circled zones -left and centre panels) in petroleum prospect A, located at the edge of AOI-1 (Fig. 18a), and prospect D in AOI-3 (Fig. 18c). The amplitude-frequency anomalies occur at the structural crest of an inversion anticline (Profile 1) and in a faulted Miocene subbasin (Profile 3). The upper anomaly in Profile 1 and anomaly in Profile 3 display significant low-frequency energy anomalies (white circles in right panels; the top spectral plot has an expanded time scale, from 0.5 to 1.0 seconds). The upper anomaly zone in Profile 1 also displays a local reflection flat spot (white arrow -top left panel). In Profile 3, vertical amplitude and frequency anomalies (indicated by white arrows) occur above the edge of the horizontal amplitude-frequency anomaly. In both profiles, the noted reflection anomalies are considered direct indicators of hydrocarbon accumulations -the upper anomaly in Profile 1 has the most definitive hydrocarbon-indicator signature. The indicated hydrocarbon accumulations occur in the Neogene Skonun Formation. Seismic attribute plots provided by M. Duchesne (methodology of attribute analysis presented by Duchesne et al., 2011).

tures. Most of AOI-1 and all of AOI-3 occur in areas of high petroleum potential (Figs. 18, 20).

Moderate and Low Petroleum Potential

The high-potential areas are surrounded by regions of moderate and low petroleum potential. The low-potential areas are regions where potential reservoir rocks are limited in thickness or quality, potential source rocks are limited in thickness or have less optimum maturation conditions, trap configurations are uncertain, and direct hydrocarbon indicators are absent. The moderate-potential areas are transitional areas between the high- and low-potential areas, and contain some but not all of the positive factors for petroleum accumulations. A small part of AOI-1 occurs in an area of moderate potential (Fig. 20). Most of AOI-2 occurs in area of low potential. The low-potential portion of AOI-2 encompasses an area of Masset Formation volcanic rocks (in fault subbasins), overlain by a thin interval of flat-lying Plio-Pleistocene strata (Fig. 18). Although reservoir rocks may be present in the shallow Plio-Pleistocene section, no obvious petroleum prospects occur in this low-potential area of AOI-2.

Non-Prospective

Areas outside of the Queen Charlotte and Hecate sedimentary basins are considered non-prospective for petroleum resources. A small portion of AOI-2 in eastern Queen Charlotte Sound occurs in a non-prospective area (Fig. 20). This area is underlain by (interpreted) Mesozoic crystalline basement rocks (Fig. 18).

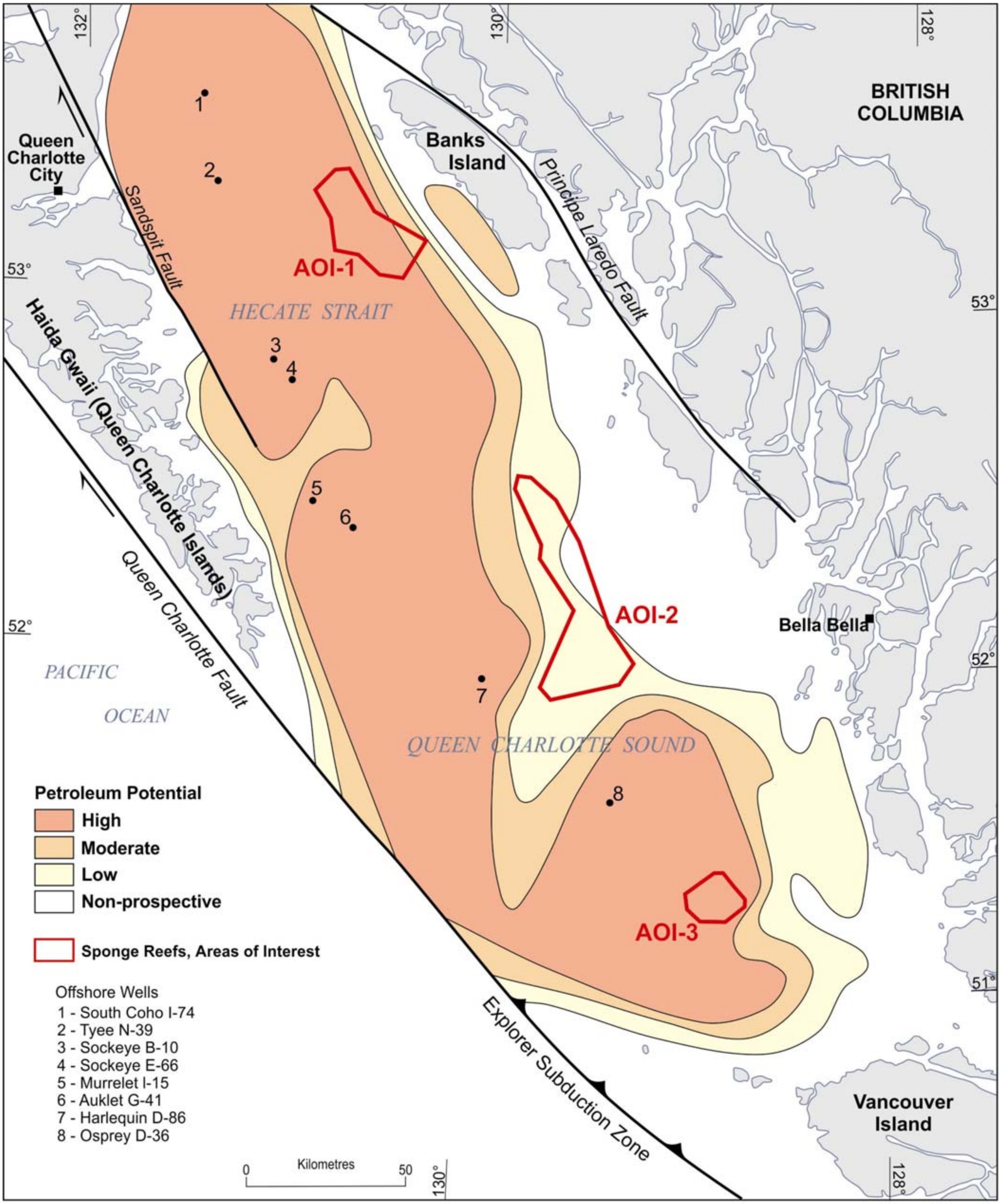

Figure 20. Qualitative ranking of petroleum potential in Hecate Strait and Queen Charlotte Sound. Sponge Reefs AOI-1 (in eastern Hecate Strait) occurs in an area of mainly high petroleum potential. A small part of AOI-1 occurs in an area of moderate potential. Sponge Reefs AOI-2 (in southern Hecate Strait and northern Queen Sound) occurs in an area of mainly low petroleum potential. A small part of AOI-2 occurs in an area that is considered non-prospective for petroleum resources. Sponge Reefs AOI-3 (in southern Queen Sound) occurs in an area of high petroleum potential.

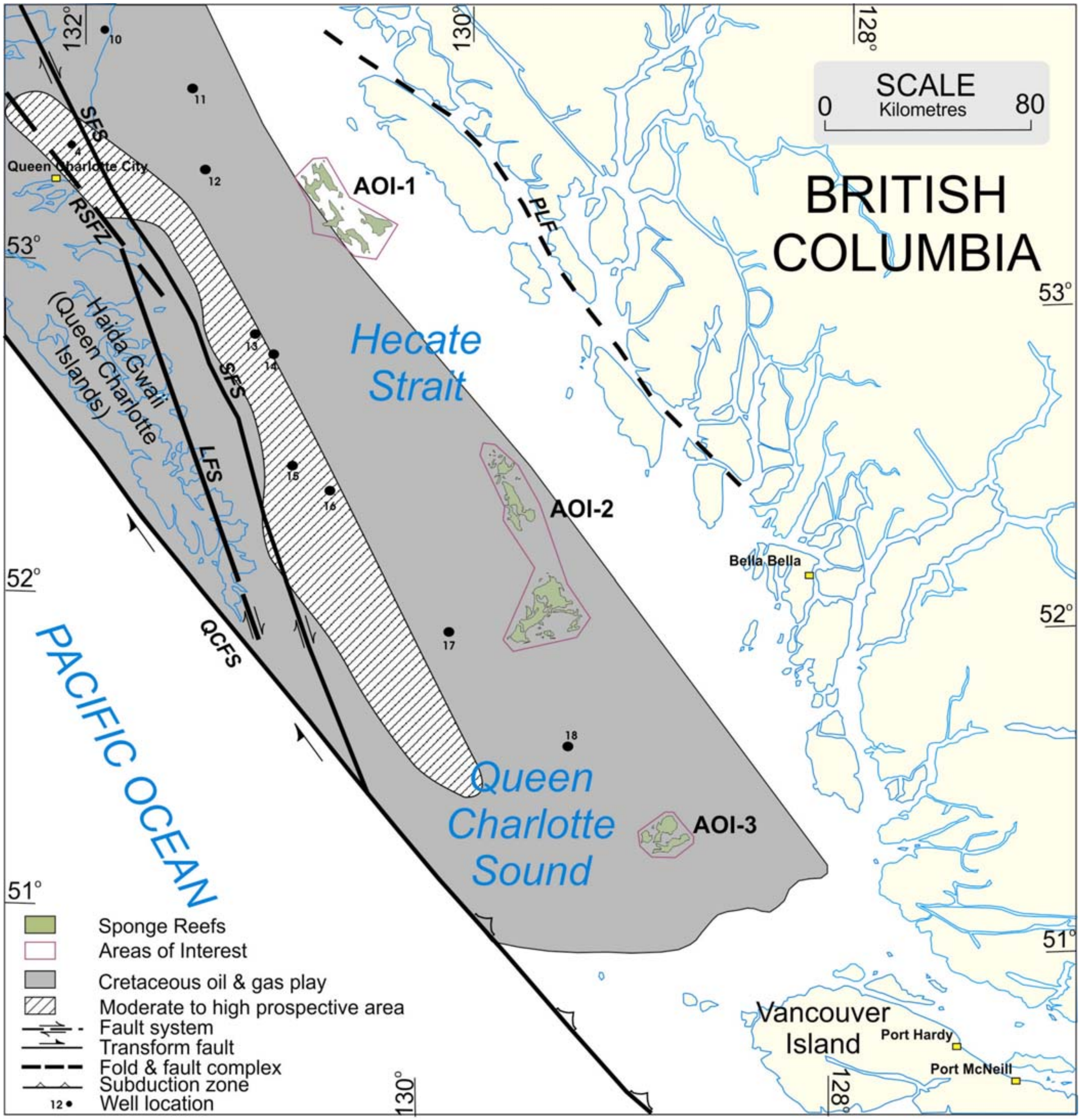

Figure 21. Areal extent of Queen Charlotte Cretaceous oil and gas play in the proposed areas of interest. Abbreviations: LFS-Lousconne Fault System, PLF-Principe-Laredo Fault, QCFS-Queen Charlotte Fault System, RSFZ-Rennell Sound Fault Zone, SFS-Sandspit Fault System.

Quantitative Assessment of Conventional Petroleum Potential in the Sponge Reef Areas of Interest

Methodology

The quantitative assessment of petroleum potential in the sponge reef areas of interest utilizes the previously derived regional play-potential numbers for the Hecate and Queen Charlotte basins. The estimates of petroleum potential within the three areas of interest are based on the assumption that oil or gas resources in each regional exploration play are evenly distributed throughout the total play area. The percentage of the play area within each AOI is used to derive an apportionment of resource potential from the total play resource. This assumption of an evenly distributed resource over a play area is not necessarily accurate, in that certain areas of an exploration play may have

Table 3. Oil and gas potential in proposed area of interest 1 (in place).

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)
Area of Interest 1				
Cretaceous oil	460	162	0.3	162
Cretaceous gas	92,672	37,679	56	37,825
Miocene oil	656	270	4	274
Miocene gas	316,209	115,010	2,133	117,143
Pliocene oil	652	444	4	448
Pliocene gas	389,710	169,670	4,621	174,291
Total	1800 (oil); 819,681 (gas)		8 (oil); 6810 (gas)	884 (oil); 329,259 (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

Table 4. Oil and gas potential in proposed area of interest 2 (in place).

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)
Area of Interest 2				
Cretaceous oil	460	162	4	166
Cretaceous gas	92,672	37,679	704	38,383
Miocene oil				
Miocene gas				
Total	460 (oil); 92,672 (gas)		4 (oil); 704 (gas)	166 (oil); 38,383 (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

Table 5. Oil and gas potential in proposed area of interest 3 (in place).

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)
Area of Interest 3				
Cretaceous oil	460	162	1	163
Cretaceous gas	92,672	37,679	198	37,877
Miocene oil	656	270	1.5	271.5
Miocene gas	316,209	115,010	805	115,815
Total	1,116 (oil); 408,881 (gas)		2.5 (oil); 1,003 (gas)	435 (oil); 153,692 (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

greater or lesser potential, based on geological factors (as noted in the discussion above of qualitative potential). Nonetheless, the assumption of an even resource distribution provides a framework for a statistical technique for evaluating areas of frontier exploration plays. For the assessment of the sponge reefs in the AOI, qualitative comments are included to indicate expected variations in play-resource distribution patterns (e.g. assessment of AOI-2).

In most petroleum plays, a substantial volume of the total play potential is concentrated in the largest field (ranging from 10 to 30%). This statistical observation from established plays is used to further constrain the assessment of local areas in regional frontier plays (in this case AOI-1, -2 and -3) by incorporating two resource-distribution scenarios: the first scenario assumes the largest field in each play occurs outside the proposed AOI; the second scenario assumes the largest field in each play occurs within the boundaries of the proposed AOI. Since the proposed AOI encompasses a relatively small part of the total area of assessed geological plays, the first scenario (largest field outside the proposed AOI) is the more likely proposition, resulting in a high-confidence resource estimate. The second scenario (largest field inside the proposed AOI) gives a speculative or low-probability resource estimate. Scenario 2 represents a maximum upside value for resource potential in that it assumes the largest expected field for every play occurs in the AOI. The probability of this occurrence (largest fields for multiple plays occurring in one local area) is considered low.

Cretaceous Resource Distribution

The Cretaceous Hecate Basin covers an area of about 57,400 square kilometres (Figs. 3, 5). The Cretaceous oil and gas play is defined as occupying the full extent of this basin. The central and southern areas of interest (AOI-2 and AOI-3) are entirely within the Cretaceous oil and gas play. Most of the northern AOI (AOI-1) is located northeast of the Cretaceous play area, with only the westernmost part of the AOI within the play area (Fig. 21). The areas of interest occupy about 1.7 % of the total areal extent of the Cretaceous play area (Figs. 5, 21). Individually, AOI-1 covers 0.1% of the play

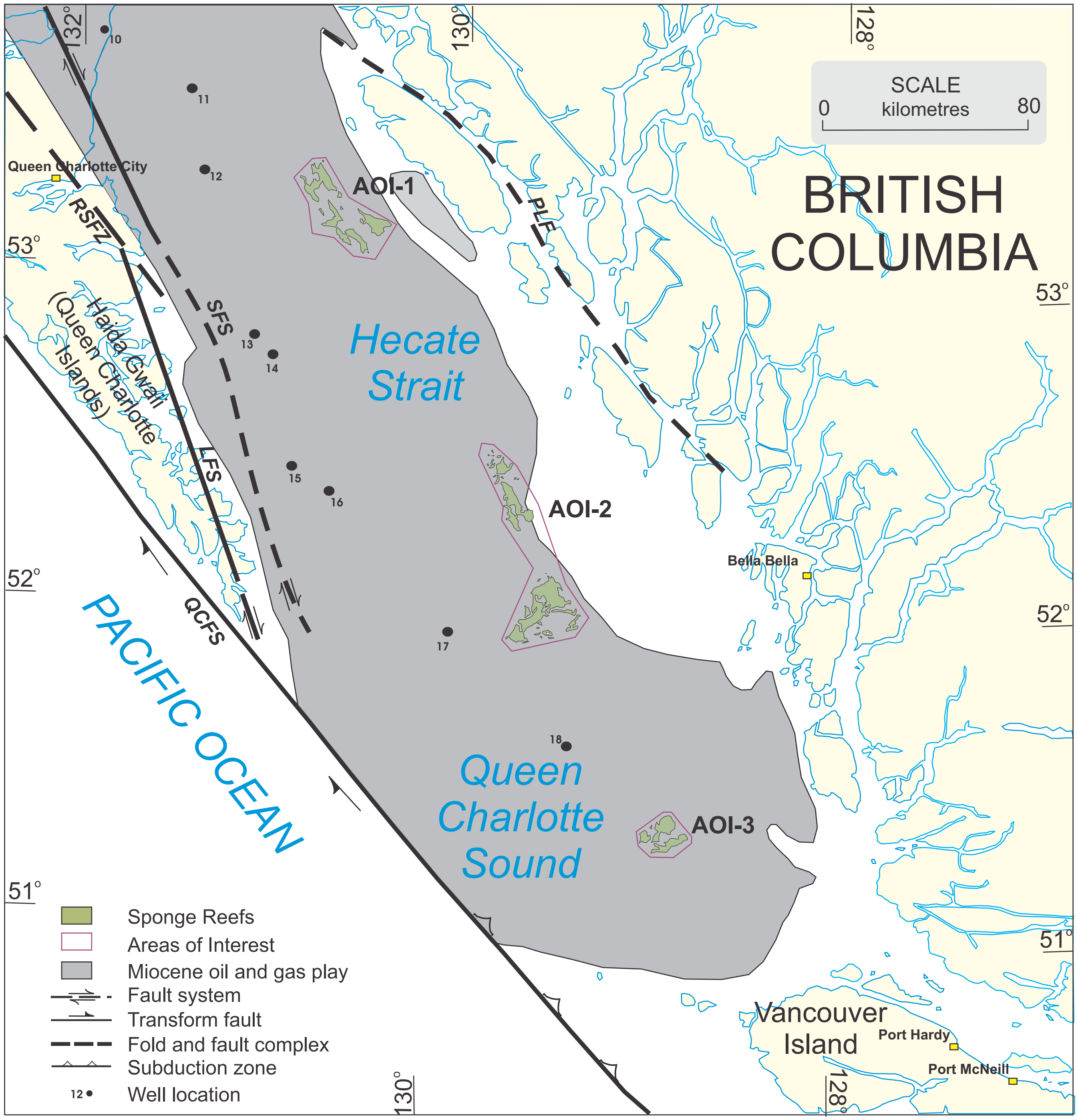

Figure 22. Areal extent of Queen Charlotte Miocene oil and gas play in the proposed areas of interest. Abbreviations: LFS-Lousconne Fault System, PLF-Principe-Laredo Fault, QCFS-Queen Charlotte Fault System, RSFZ-Rennell Sound Fault Zone, SFS-Sandspit Fault System.

area, AOI-2 occupies 1.3% of the play area, and AOI-3 encircles about 0.4% of the play area.

The high-confidence estimate of the mean in-place oil potential of the Cretaceous play in AOI-1 is 0.3 x 10^6 m^3 (Table 3). The speculative estimate of the mean in-place oil potential is 162 x 10^6 m^3 (Table 3). The high-confidence and speculative estimates of mean in-place gas potential in AOI-1 are 56 x 10^6 m^3 and 37.8 x 10^9 m^3, respectively (Table 3).

High-confidence estimates for oil and gas potential in the Cretaceous play in AOI-2 are 4 x 10^6 m^3 and 704 x 10^6 m^3, respectively (Table 4). Speculative mean estimates of Cretaceous play oil and gas volumes within AOI-2 are 166 x 10^6 m^3 and 38.4 x 10^9 m^3, respectively (Table 4).

High-confidence estimates for oil and gas potential in the Cretaceous play in AOI-3 are 1 x 10^6 m^3 and 198 x 10^6 m^3, respectively (Table 5). Speculative estimates

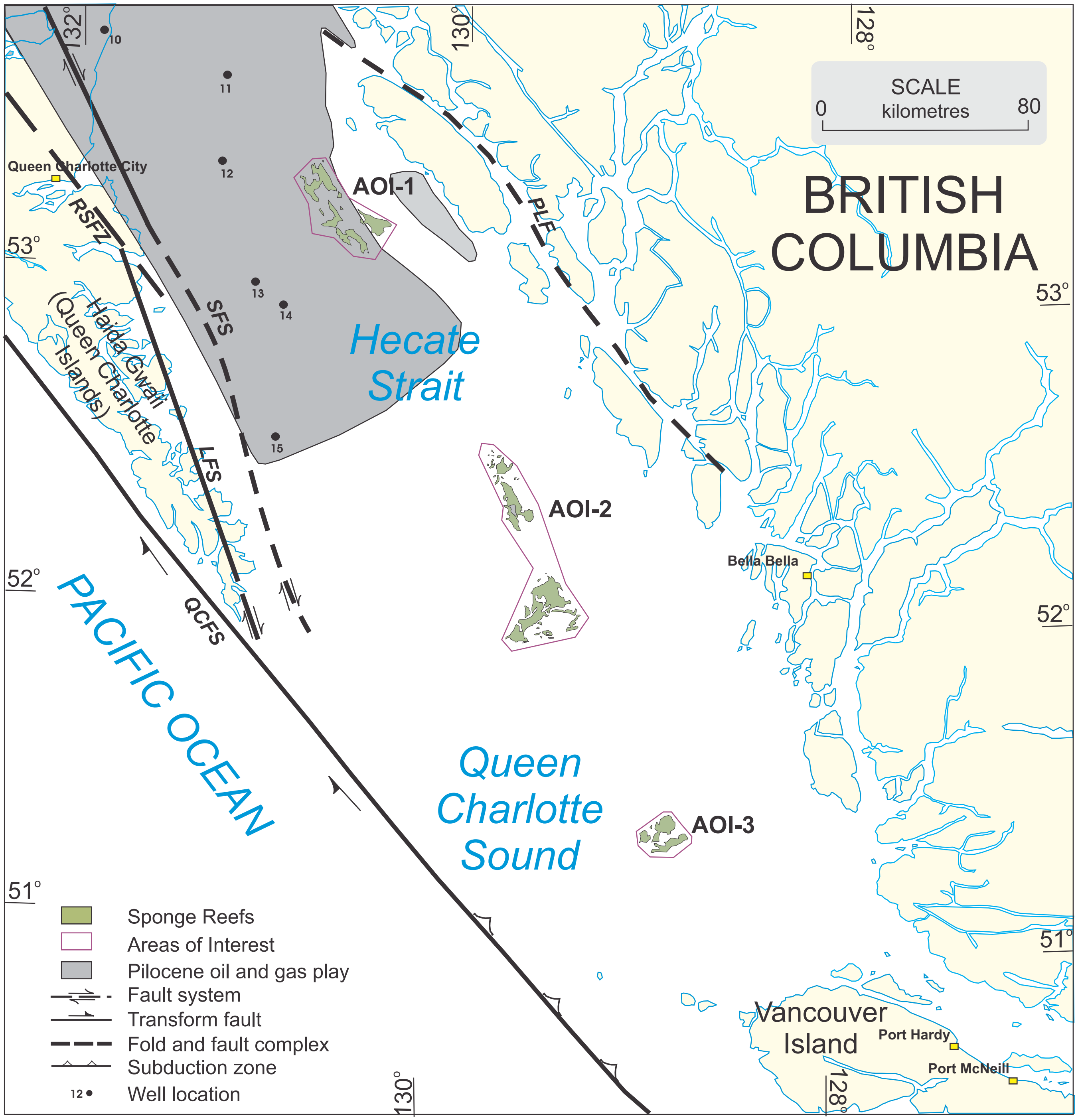

Figure 23. Areal extent of Queen Charlotte Pliocene oil and gas play in the proposed areas of interest. LFS-Lousconne Fault System, PLF-Principe-Laredo Fault, QCFS-Queen Charlotte Fault System, RSF-Rennell Sound Fault Zone, SFS-Sandspit Fault System.

for the Cretaceous play in AOI-3 include mean volumes of 163 x 10^6 m^3 and 37.9 x 10^9 m^3 of in-place oil and gas, respectively (Table 5).

Miocene Resource Distribution

The Neogene Queen Charlotte Basin covers an area of about 52,200 square kilometres (Fig. 3). The Miocene exploration play covers the full extent of this basin. Approximately 2.7% of the total Miocene play area is located in the areas of interest (Figs. 8, 22). AOI-1 occupies about 1.1% of the play area; AOI-2 covers about 1.6% of the play area, and AOI-3 about 0.4 % of the play area.

The high-confidence estimate of the mean in-place oil potential of the Miocene play in AOI-1 is 4.0 x 10^6 m^3 (Table 3). The speculative estimate of the mean in-

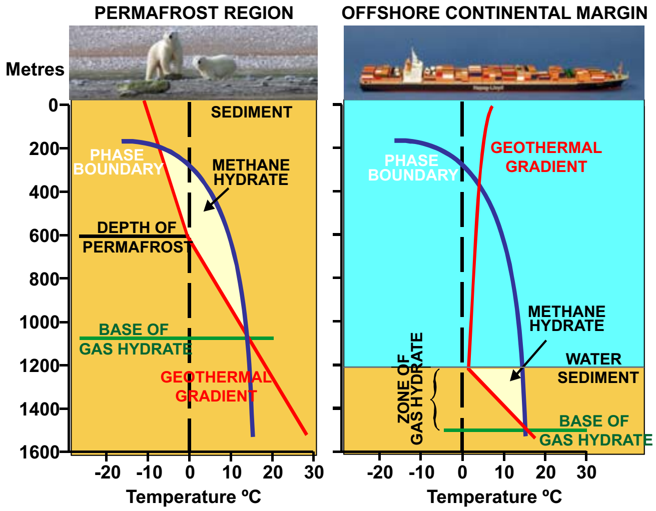

Figure 24. Temperature and pressure (depth) regimes for gas hydrate stability zones in permafrost (left) and marine (right) settings.

place oil potential is 274 x 10^6 m^3 (Table 3). The high-confidence and speculative estimates of mean in-place Miocene gas potential in AOI-1 are 2.1 x 10^9 m^3 and 117.1 x 10^9 m^3, respectively (Table 3). The Miocene play may occur in parts of AOI-2, but the Tertiary succession in this area is thin and unstructured, with little or no potential for petroleum accumulations. Therefore, no Miocene petroleum potential is attributed to AOI-2 (Table 4). The high-confidence estimate of the mean in-place potential of the Miocene oil play in AOI-3 is 1.5 x 10^6 m^3 and the speculative estimate is 271.5 x 10^6 m^3 (Table 5). The high-confidence and speculative in-place estimates of natural gas in the Miocene play in AOI-3 are 805 x 10^6 m^3 and 115.8 x 10^9 m^3, respectively.

Pliocene Resource Distribution

The Pliocene play occurs in the northern half of the Queen Charlotte Basin (Fig. 11). Only the northern AOI (AOI-1) occurs in the Pliocene play and it occupies about 2.1% of the total play area (Fig. 23).

The high-confidence and speculative estimates of the mean in-place oil potential of the Pliocene play in AOI-1 is 4.0 x 10^6 m^3 and 448 x 10^6 m^3, respectively (Table 3). High-confidence and speculative estimates of the mean in-place gas potential of the Pliocene play in AOI-1 are 4.6 x 10^9 m^3 and 174.3 x 10^9 m^3, respectively (Table 3).

Total Conventional Petroleum Potential in the Sponge Reef Areas of Interest

The total petroleum potential for the northern area of interest (AOI-1) includes resource contributions from the Cretaceous, Miocene, and Pliocene plays. High-confidence estimates of total conventional petroleum potential for AOI-1 are 8 x 10^6 m^3 (50 MMbbls) oil and 6.8 x 10^9 m^3 (240 BCF) gas (mean in-place volumes, Table 3). The speculative estimates of total oil and gas potential in AOI-1 are 884 x 10^6 m^3 (5560 MMbbls) and 329.3 x 10^9 m^3 (11.6 TCF), respectively (Table 3).

The central AOI (AOI-2) resource potential is attributed to the Cretaceous play only, with high-confidence estimates of oil and gas potential of 4 x 10^6 m^3 (25 MMbbls) oil and 0.7 x 10^9 m^3 (24 BCF) gas (mean in-place volumes, Table 4). The speculative estimates of total oil and gas potential in AOI-2 are 166 x 10^6 m^3 (1029 MMbbls) oil and 38.4 x 10^9 m^3 (1.35 TCF) gas. The central AOI (AOI-2) occurs in a geological setting that is much less favourable for petroleum resources, compared to AOI-1 or -3 (Fig. 20). The speculative resource scenario for AOI-2 is considered the most unlikely (lowest probability of occurrence) of the three areas of interest.

The total petroleum potential for the southern area of interest (AOI-3) includes resource contributions from the Cretaceous and Miocene plays. High-confidence estimates of total conventional petroleum potential for AOI-3 are 2.5 x 10^6 m^3 (16 MMbbls) oil and 1.0 x 10^9 m^3 (35 BCF) gas. The speculative estimates of total oil and gas potential in AOI-3 are 435 x 10^6 m^3 (2735 MMbbls) and 153.7 x 10^9 m^3 (5.4 TCF), respectively (Table 5).

Assessment of Unconventional Petroleum Resources – Gas Hydrates

Gas hydrate, a solid form of natural gas and water, is inferred to occur widely in Canadian continental margins. Gas hydrates occur in offshore sedimentary reservoirs in regions of high hydrostatic pressure due to the overlying seawater column, low sea-bottom temperatures, and moderate to low thermal gradients (Fig. 24). Such conditions are common where water depths exceed about 300 m. Gas hydrate characteristics indicate three end-member accumulation types: Type 1 – higher saturation, discrete, sediment/rock pore space accumulations commonly co-located with conventional petroleum accumulations; Type 2 – lower saturation, possibly continuous, sediment/rock pore space accumulations commonly inferred to be sourced by biogenic petroleum; and, Type 3 – discrete, massive seafloor/near seafloor accumulations. Gas hydrate occurrences are much more frequent in active margins, such as the Pacific margin, where fluid expulsion and upward fluid migration is a significant factor (Hyndman and Davis, 1992).

In the Pacific margin of Canada, both Type 2 and Type 3 gas hydrate accumulations are known to occur, and it is reasonable to assume that Type 1 accumulations will be found in association with seepages from conventional petroleum accumulations, perhaps underlying some of the Type 3 accumulations. The most

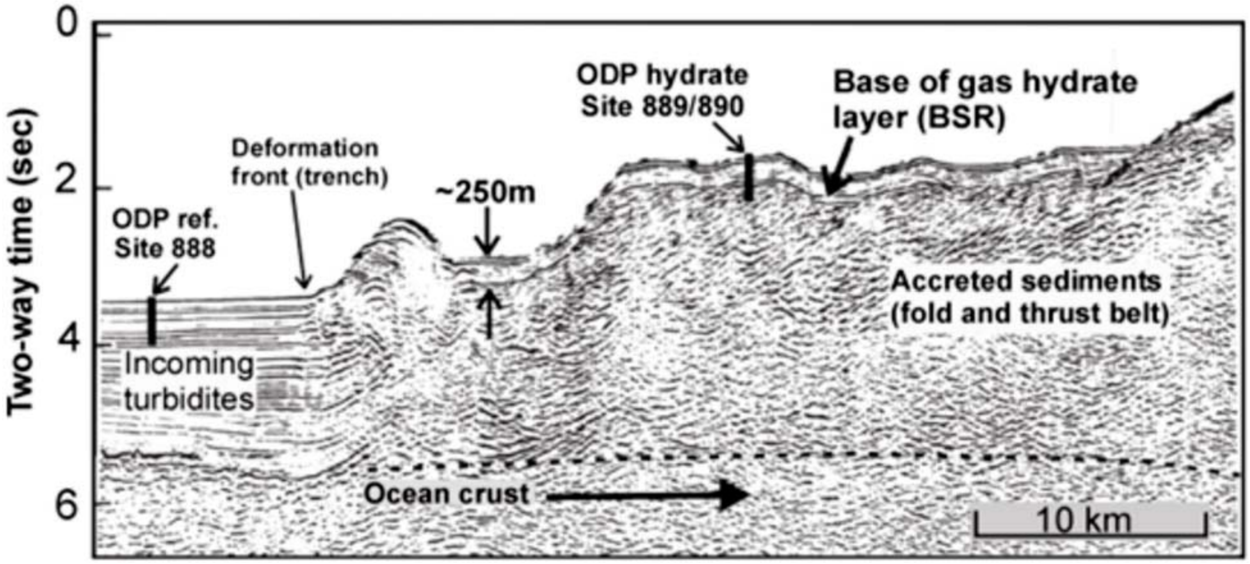

Figure 25. Seismic indication (bottom simulating reflector; BSR) for Type 2 gas hydrate occurrence on the Pacific margin.

common indicator of Type 2 gas hydrate on the Pacific margin is a seismic reflection called the bottom-simulating reflector (BSR; Fig. 25). The BSR displays the acoustic contrasts between gas hydrates and underlying gas-bearing sediments. Type 3 gas hydrates off the Pacific coast of Canada have been detected in Ocean Drilling Program boreholes, robotic submersible observations, and accidental dredging from fishing vessels (Fig. 26). Favourable conditions for the stability of gas hydrates occur over a 30 km wide zone on the continental margin, in water depths between 300 m and 2000 m (Fig. 27), encompassing a total area of approximately 30,000 km^2. The average estimated thickness of hydrates (from seismic data) is approximately 110 m (Hyndman, 1997). The hydrate-stability area and average hydrate thickness provide data for preliminary estimates of gas hydrate volume in the Pacific margin region. The minimum and maximum volumes of methane stored in inferred gas hydrates are 0.32 x 1013 m3 and 2.4 x 1013 m3, respectively (Majorowicz and Osadetz, 2001).

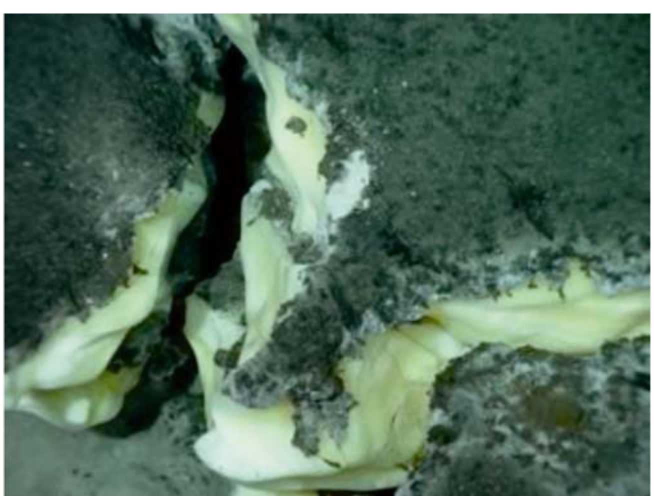

Figure 26. Photograph of gas hydrate exposed on the seafloor (Type 3 gas hydrate occurrence) on the Pacific margin (University of Victoria, 2002).

The Hecate Strait/Queen Charlotte Sound sponge reefs occur in water depths too shallow for Type 2 hydrate stability (Fig. 27) and no Type 2 gas hydrate is expected to occur in the areas of interest. Type 1 and Type 3 gas hydrate occurrences may be found in the sponge reef areas of interest; however, there is insufficient data to estimate the volume.

CONCLUSIONS

Qualitative evaluation of geological and geophysical data indicate the Hecate Strait/Queen Charlotte Sound sponge reefs occur in areas of varying petroleum potential. Most of the northern and southern areas of interest (AOI-1 and all of AOI-3) occur in areas of high petroleum potential. The high-potential areas contain thick sections of Neogene sedimentary strata and abundant fault-related structures. Direct hydrocarbon indicators are observed in these areas. The central area of interest (AOI-2) encompasses an area of low potential and an area that is non-prospective for petroleum resources. Petroleum prospects are not recognized in AOI-2.

Using a modified areal apportionment of previously estimated oil and gas resources in the Hecate and Queen Charlotte basins, high-confidence and speculative estimates of total petroleum potential for the sponge reef areas of interest are determined. The northern AOI in eastern Hecate Strait (AOI-1) is estimated to have the greatest potential, with contributions from all three defined petroleum plays (high-confidence estimates: 8 x 10^6 m^3 (50 MMbbl) oil and 6.8 x 10^9 m^3

Figure 27. Regional map of area of potential methane hydrate stability on the Pacific margin of Canada,

(240 BCF) gas (in-place volumes, mean values); speculative estimates: 884 x 10^6 m^3 (5560 MMbbl) oil and 329.3 x 10^9 m^3 (11.6 TCF) gas). The southern AOI in Queen Charlotte Sound (AOI-3) is also considered to have high potential, albeit lower than AOI-1, with resource contributions from two of three defined plays (high-confidence estimates: 2.5 x 10^6 m^3 (16 MMbbl) oil and 1.0 x 10^9 m^3 (35 BCF) gas; speculative estimates: 435 x 10^6 m^3 (2735 MMbbl) oil and 153.7 x 10^9 m^3 (5.4 TCF) gas). The central AOI in southern Hecate Strait-northern Queen Charlotte (AOI-2) is estimated to have the lowest petroleum potential of the three areas of interest, with a resource contribution from only one defined play (high-confidence estimates: 4 x 10^6 m^3 (25 MMbbl) oil and 704 x 10^6 m^3 (24 BCF) gas (in-place volumes, mean values; speculative estimates: 166 x 10^6 m^3 (1029 MMbbl) of oil and 38.4 x 10^9 m^3 (1.35 TCF) gas). The estimates represent two resource-distribution scenarios – the largest oil/gas field(s) occurs outside the proposed AOI (high-confidence esti-

mate) or the largest field(s) occurs within the proposed AOI (speculative estimate). The speculative estimates for the central AOI (AOI-2) are considered the least likely (lowest probability of occurrence) of the three areas of interest.

Significant volumes of Type 1 and Type 3 unconventional gas hydrates may be present in the sponge reef areas of interest; however, there is insufficient information to estimate possible gas hydrate resource volumes. There is no potential for Type-2 gas hydrate in the areas of interest, due to the relatively shallow water depths of the sponge reef occurrences. Technical and economic factors may limit the potential for commercial development of gas hydrates in this region, more so than for conventional petroleum accumulations.

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