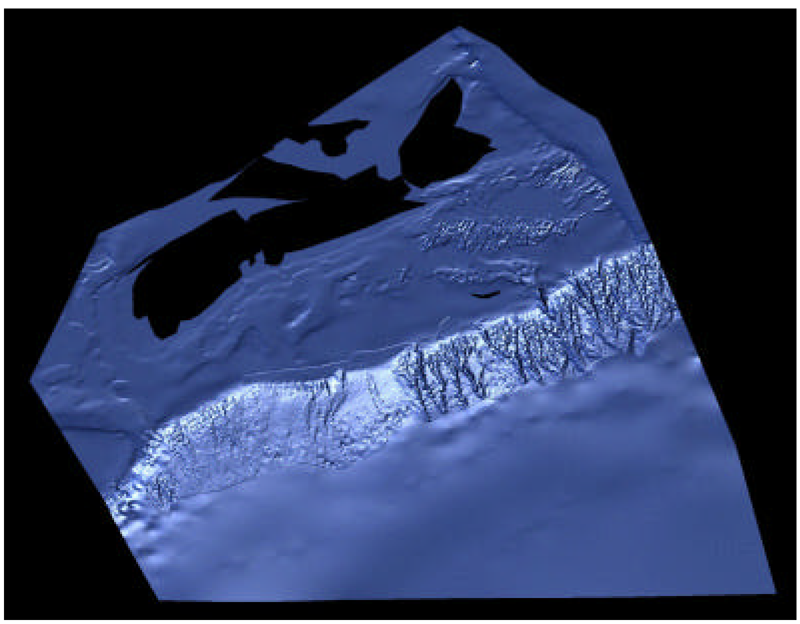
Canada-Nova Scotia
Offshore Petroleum Board

HYDROCARBON POTENTIAL OF THE DEEP-WATER SCOTIAN SLOPE



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OCTOBER, 2002 – Version 1.0

HALIFAX, NOVA SCOTIA, CANADA

DISCLAIMER

While every effort was made to ensure the timeliness and accuracy of the information, data, material and interpretations (the "Information") contained in this report – "Hydrocarbon Potential of the Deep-Water Scotian Slope" - the Canada-Nova Scotia Offshore Petroleum Board assumes no liability or responsibility whatsoever for the completeness, accuracy or usefulness of any of the Information. The Information in the document is provided solely for general public information purposes and is provided strictly "as is."

The precise locations of the five Geochemistry sites selected from specific seismic lines representative of the different play types along the slope margin are not given in this report. This information was specifically omitted to eliminate any possibility of "high-grading" a particular area and compromising regulatory integrity and independence of the Canada-Nova Scotia Offshore Petroleum Board. Furthermore, the exact locations of the seismic lines published in this report, with permission, are also not provided in order to protect the proprietary rights of the owners of this data and respecting Section 122 of the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act.

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ABSTRACT

The Canada-Nova Scotia Offshore Petroleum Board has recently completed a geological basin evaluation and numerical assessment of the hydrocarbon potential for the deep-water slope region, offshore Nova Scotia. The Scotian Slope lies in water depths of 200 to 4000 metres and extends 850 kilometers from the United States international border in the southwest, to the Newfoundland provincial border in the northeast. Within this region, no previous resource assessments have been published.

This basin evaluation is based on the interpretation of 30,000 kilometers of regional 2-D seismic data, with stratigraphic correlations to shelf wells, industry seismic lines, deep crustal regional seismic data, and Deep Sea Drilling Project well-bores. The major challenge was mapping the top and base of the ubiquitous, mobile Argo Salt. Twelve hydrocarbon play types were identified throughout the region. All are salt-related to varying degrees. Supra-salt minibasins and salt flank plays for Cretaceous and Tertiary age reservoirs are widespread, as well as sub-salt plays. Some of these plays are well defined, others less so. Geochemical models were created and included three known source rocks and three potential source rocks. All are interpreted to have undergone maturation and expelled significant quantities of oil and gas. The stochastic numerical analysis employed probability distributions for all input parameters. Local data were used wherever possible, plus other data from global analogue basins.

The assessment results are presented as probability distributions for oil, gas, solution gas, and natural gas liquids for each of the 12 plays, and, a statistically summed total. Both in-place and recoverable hydrocarbon resource values were generated. Because the petroleum system(s) have yet to be proved in the deepwater slope, this analysis also included geological risk factors. The undiscovered gas potential for the deepwater Scotian Slope is forecast at 15 to 41 trillion cubic feet, depending on the assumed geological risk factors. Similarly, the undiscovered oil potential is 2 to 5 billion barrels. This oil potential is very significant, and conforms to the high oil-to-gas discovery ratios encountered in other deepwater areas of the circum-Atlantic region.

RÉSUMÉ

L'Office Canada - Nouvelle-Écosse des hydrocarbures extracôtiers vient de terminer l'évaluation du bassin géologique et l'analyse numérique du potentiel en hydrocarbures du talus continental au large de la Nouvelle-Écosse. Cette région s'étend par des fonds de 200 à 4000 mètres; elle débute à 850 kilomètres de la frontière américaine, au sud-ouest, et se termine à la frontière terre-neuvienne, au nord-est. Aucune évaluation des ressources de cette région n'avait été publiée auparavant.

L'évaluation de ce bassin se fonde sur l'interprétation de données sismiques régionales bidimensionnelles, incluant des corrélations stratigraphiques aux puits forés dans la plate-forme continentale, aux profils sismiques produits par l'industrie, aux données sismiques régionales de la croûte profonde et aux trous de sondage effectués par le Deep Sea Drilling Project. Le principal défi à surmonter a été de cartographier le sommet et la base de la vaste formation salifère Argo d'origine allochtone. On a décelé la présence de douze types de zones d'hydrocarbures. Elles sont toutes à des degrés variables liées au sel. Les mini-bassins dans le sommet de formations salifères et dans leurs flancs sont répandus dans les réservoirs crétacés et tertiaires. Il en est de même des zones d'hydrocarbures au-dessous des formations salifères. Certaines zones d'hydrocarbures sont bien définies, d'autres moins. On a créé des modèles géochimiques dans lesquels on a inclus trois roches mères connues et trois roches mères potentielles. Les données d'interprétation indiquent qu'elles ont toutes subi une période de maturation et qu'elles ont expulsé d'importantes quantités de pétrole et de gaz. Pour les analyses stochastiques numériques, on a utilisé, quand c'était possible, des données locales que l'on a combiné à d'autres données provenant de bassins analogues dans le monde.

Les résultats de l'évaluation sont présentés comme des distributions de probabilité pour le pétrole, le gaz, le gaz dissous et les liquides de gaz naturel pour chacune des douze zones d'hydrocarbures et comme une somme totale statistique. On a généré des valeurs en ressources pour les hydrocarbures en place et récupérables. Étant donné que l'on n'a pas encore prouvé la présence de système(s) pétroliers dans le talus profond, l'analyse comporte des facteurs de risques géologiques. Les prévisions du potentiel en gaz non découvert dans le talus continental profond au large de la Nouvelle-Écosse indiquent entre 15 et 41 trillions de pieds cubes, selon les facteurs de risques géologiques utilisés. Le potentiel de pétrole non découvert varie entre 2 et 5 milliards de barils. Le potentiel de pétrole est très important et est conforme aux rapports élevés de découverte pétrole-gaz obtenues pour les autres zones très profondes de la région circum-atlantique.

EXECUTIVE SUMMARY

In September 2001, the Canada-Nova Scotia Offshore Petroleum Board (the Board) determined that an evaluation of the hydrocarbon potential was required for the deep-water Scotian Slope region under its jurisdiction. Industry's pro-activity in permit acquisition, exploration seismic acquisition and drilling, the development and production of Sable gas and application for development of the Deep Panuke gas discovery indicated the need for the Board to have a comprehensive assessment of the offshore potential.

Industry's recent interest in the deep-water off Nova Scotia has been driven by their tremendous successes in other deep-water basins in the Gulf of Mexico, offshore Brazil and West Central Africa. Indeed, these Atlantic-facing look-alike basins have attributes very similar to the Nova Scotia region and were used as analogues for the deepwater slope assessment.

Historically, the Geological Survey of Canada (GSC) carried out resource assessments of Canada's frontier regions and the oft-quoted number of 18 trillion cubic feet (discovered + potential) for the Scotian Shelf is sourced from their 1983 report. In 2001, the Canadian Gas Potential Committee (CGPC) assessed the Shelf region and arrived at a similar value but subdivided the region into assessment areas equivalent to the geological sub-basins such as the Sable Subbasin, Orpheus Graben, Jurassic Abenaki Carbonate Bank Edge, etc. However, there remained no publicly-available assessment of the deep-water slope region.

The Scotian Slope is approximately 65% the size of the Shelf region. It is 850 km long, stretching from the United States border in the southwest to the Newfoundland provincial border in the northeast, and with an average width of slightly less than 100 km from the shelf edge in 200 m of water out to 4,000 m of water, encompassing an area of 80,000 km^2.

Hydrocarbon resource assessment consists of two major components; geological basin evaluation and numerical analyses. The basin evaluation included significant original work in geology, geophysics and geochemistry by the Board staff. Stratigraphic correlations from the Shelf to the deep-water Slope were generated and required integration with the work of the Deep Sea Drilling Project (DSDP) and correlative charts with the analogue global basins. An extensive digital dataset of a regional 2-D speculative seismic survey of 30,000 km was obtained from TGS-NOPEC. Interpretations of the ubiquitous allochthonous salt features and regional sedimentary mega-sequences were carried out. Mapping of key horizons including the top and base of the salt was instrumental in the basin study phase. Geochemical modeling of petroleum source rock potential was carried out by Dr. P.K. Mukhopadhyay (Halifax) and indicated the potential for oil and gas in significant quantities along the Slope. The various anticipated trapping styles, based on seismic interpretation, resulted in a total of 12 individual plays to be assessed.

The numerical analyses were undertaken in-house using probability distributions for all input parameters with Excel™ spreadsheets and the @Risk™ software. Volumetric parameters, recovery factors, oil/gas ratios, etc. were estimated using local data wherever possible plus available worldwide analogue data. Mr. K.J. Drummond (Calgary) provided the Excel™ templates and acted as an objective observer during the "number-crunching" phase of the study.

During the study period, discussions and liaison were ongoing with staff from the provincial Nova Scotia Department of Energy, GSC, NEB and CNOPB. Board staff also participated in an assessment workshop in Calgary including leading assessors from primarily Canada and the United States, and several international deep-water geoscience symposia.

This assessment is therefore a forecast of what the offshore potential could be given the simultaneous occurrence of numerous geological assumptions. The results of the evaluation are presented as probability distributions for oil, gas, solution gas and natural gas liquids for each of the 12 defined plays. These were statistically summed and total values defining both in-place and recoverable resources were generated. The analyses also included values for geological risk factors at both the play and prospect level. It is thus very important to acknowledge that calculated upside potentials for these various plays also have a downside possibility and so any conclusions or expectations drawn from these should be cautiously employed.

The assessment results are summarized in the following table for oil and gas only. The values for minimum (90% probability of occurrence), mean, and maximum (10% probability) are shown for the unrisked and risked recoverable values. The risked category is used because the petroleum system(s) have not yet been proven. Given certain degrees of success over time, the individual plays can be unrisked or "de-risked" and the values increased.

Therefore, the Board's assessment of the undiscovered gas potential for the deep-water slope offshore Nova Scotia reveals the potential for between 15 and 41 trillion cubic feet (Tcf) of gas depending on the assumed geological risk factors. The oil potential of 2 to 5 billion barrels (BB) is very significant and in keeping with the high oil to gas discovery ratios seen in other global deep-water areas. The lateral ranges for the unrisked and risked categories indicate the broad spectrum of possible outcomes. Additionally, the associated gas and natural gas liquids (not shown here) are also significant.

CATEGORY	**Min – Mean - Max GAS (Tcf)**	**Min – Mean - Max OIL (BB)**
Unrisked Recoverable	**31 – 41 – 53**	**3 – 5 – 6**
Risked Recoverable	**5 – 15 – 28**	**0 – 2 – 3**

No basin assessment can stand alone and relative comparisons are needed with other similar basins in Canada and worldwide. If the estimated ultimate recovery (EUR) per unit area for the Scotian Slope is calculated, it appears to be in line with other Canadian frontier regions such as the Beaufort-MacKenzie Basin, the Labrador Shelf and the Sverdrup Basin in the Arctic Islands. If some or all of the 12 plays defined in the assessment are eventually proven, the slope region will have a much higher global ranking and approach that of offshore Brazil in hydrocarbon richness per unit area, but with a smaller total area.

The impact of these numbers, on a risked basis, is to basically double the gas potential of offshore Nova Scotia while adding significant oil potential. In other words, adding the traditional 18 Tcf from the shelf to a risked value of 15 Tcf for the slope gives a total potential of 33 Tcf. Similarly, adding the traditional 1 BB of oil (and liquids) to the 2 BB for the slope offers a total potential of 3 BB of oil.

CHAPTER 1

INTRODUCTION

Nova Scotia's offshore oil and gas sector has undergone a major resurgence since the late 1990's for a number of reasons. Gas production from the Sable Offshore Energy's Tier One fields (Venture, Thebaud, and North Triumph) started in late 1999 and quickly ramped up to 500 Bcf/d. Tier Two fields (Glenelg, Alma, and South Venture) are currently undergoing development drilling. In early 2002 PanCanadian (EnCana) announced their new discovery at Deep Panuke and submitted a development plan to the regulatory body. Four rigs were working offshore as of July 31, 2002: one Venture Field development well, one shelf wildcat (Marquis L-35) and two in the deep-water (Annapolis G-24 and Newburn H-23). As a result of recent land sales, industry has committed to spend more than C$1.5 billion dollars in new exploration ventures primarily in the deep-water slope that extends along the breadth of offshore Nova Scotia. Such interest and committed activities is no doubt a reflection of industry's phenomenal success in other deep-water margins such as offshore West Central Africa, offshore Brazil and the Gulf of Mexico (GOM).

1.1 Practices and Definitions

The Scotian Shelf (water depth to 200 m) and Slope (200 m to 4000 m) lying within the Board's jurisdiction is the subject of this report. Wherever the term "Scotian Basin" is used as opposed to the "Shelf" or "Slope" it shall refer to the total geological basin as defined by the Geological Survey of Canada (Wade and MacLean, 1990).

In this report, both Metric and Imperial units for volumetric measurements are used for convenience sake, as most operators still prefer to use "cubic feet" for gas and "barrels" for oil and natural gas liquids. In this report the units for gas are Bcf (billions of cubic feet) and Tcf (trillions of cubic feet) and for oil are MMB (millions of barrels) and BB (billions of barrels). Also commonly used are oil-equivalent barrels (OEB: 1 oil-equivalent barrel = 6000 cubic feet natural gas). The assessment results are reported in both Imperial and Metric units in the final summation.

Both hydrocarbons-in-place and recoverable hydrocarbons categories are reported, recognizing that the total deposited resource is a geologic objective whereas recoverable quantities are more of a technologic or economic objective. In addition the geologically unrisked and risked quantities are also calculated. All of the above utilize probabilistic methods, and probabilities of occurrence range of P90, Mean and P10 values are also presented.

1.2 Acknowledgements

The authors would like to sincerely thank Steven Bigelow, Manager Offshore Resources and Rights for initiating the project and for his ongoing support. Other Board Resources Group staff members; Carl Makrides, Christine Bonnell-Eisnor, and Andrew McBoyle, are thanked for their input, suggestions and reviews. Troy MacDonald was most valuable in providing software and hardware support. Mary Jean Verrall, Nancy Williams and Keri O'Kroneg of the Board's Archive and Laboratory performed yeoman service in tracking down files and reports following our many requests.

The authors and the Board wish to extend their sincere thanks to Ken J. Drummond for his expertise and guidance during the numerical assessment phase of this study as an objective observer. We also thank Ken for the use of his Excel™ templates. Sandy MacMullin, Paul Harvey and Jack MacDonald of the Nova Scotia Department of Energy are sincerely thanked for information and discussions related to the project. We are pleased to acknowledge John Wade, John Shimeld, Don McAlpine, Sonya Dehler, Phil Moir and David Piper of the Geological Survey of Canada – Atlantic for their support, data, and their stimulating discussions. Jim Davidson (National Energy Board of Canada - NEB) and Duncan Smith (Natural Resources Canada – NRCan) are acknowledged for providing a "peer" review of the preliminary results. We appreciate Kirk Osadetz (Geological Survey of Canada - ISPG) for providing us a very detailed and comprehensive review and demonstration of the GSC's "PETRIMES" resource assessment software. Neil DeSilva and his staff at the Canada-Newfoundland Offshore Petroleum Board are especially thanked for providing the authors with a comprehensive review of their Jeanne d'Arc Basin assessment and their hospitality during our visit. Dr. Mahmoud Zizi of the Office National de Recherches et d'Exploitations Pétrolières for the Kingdom of Morocco (ONAREP) is kindly thanked for providing geoscience data and information from the Moroccan margin that assisted in our study of its "Nouveau Maroc" conjugate margin.

At the request of the Board, TGS-NOPEC of Houston, Texas, provided the necessary digital dataset of their 1998-1999 seismic surveys over the Scotian Slope. Kim Abdallah and Richard Horschroft are expressly thanked for their support and permission to publish line excerpts in this report illustrating the various play types. Without this singular regional survey, this assessment study could not have been undertaken.

CHAPTER 2

OVERVIEW OF SCOTIAN BASIN AND DEEP-WATER SLOPE

2.1 Regional Geology

The Scotian Basin exists along the entire length of offshore Nova Scotia and southeastern Newfoundland (Figure 1). It extends 1200 kilometers from the Yarmouth Arch and the United States border in the southwest to the Avalon Uplift on the Grand Banks of Newfoundland in the northeast. With an average breadth of 250 km, the total area of the basin is approximately 300,000 km^2. Half of the basin lies on the present-day continental shelf in water depths less than 200 m with the other half on the continental slope in water depths from 200 to 4000 m.

The Scotian Basin lies within the jurisdiction of Canada except for a narrow 20 km zone extending southwards from the French islands of St. Pierre and Miquelon. Within Canada, the Basin falls within both Nova Scotia and Newfoundland provincial jurisdictions, with the provincial boundary between the provinces recently established in March 2002. These jurisdictions are administered by two respective joint federal/provincial agencies: the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) and the Canada- Newfoundland Offshore Petroleum Board (CNOPB).

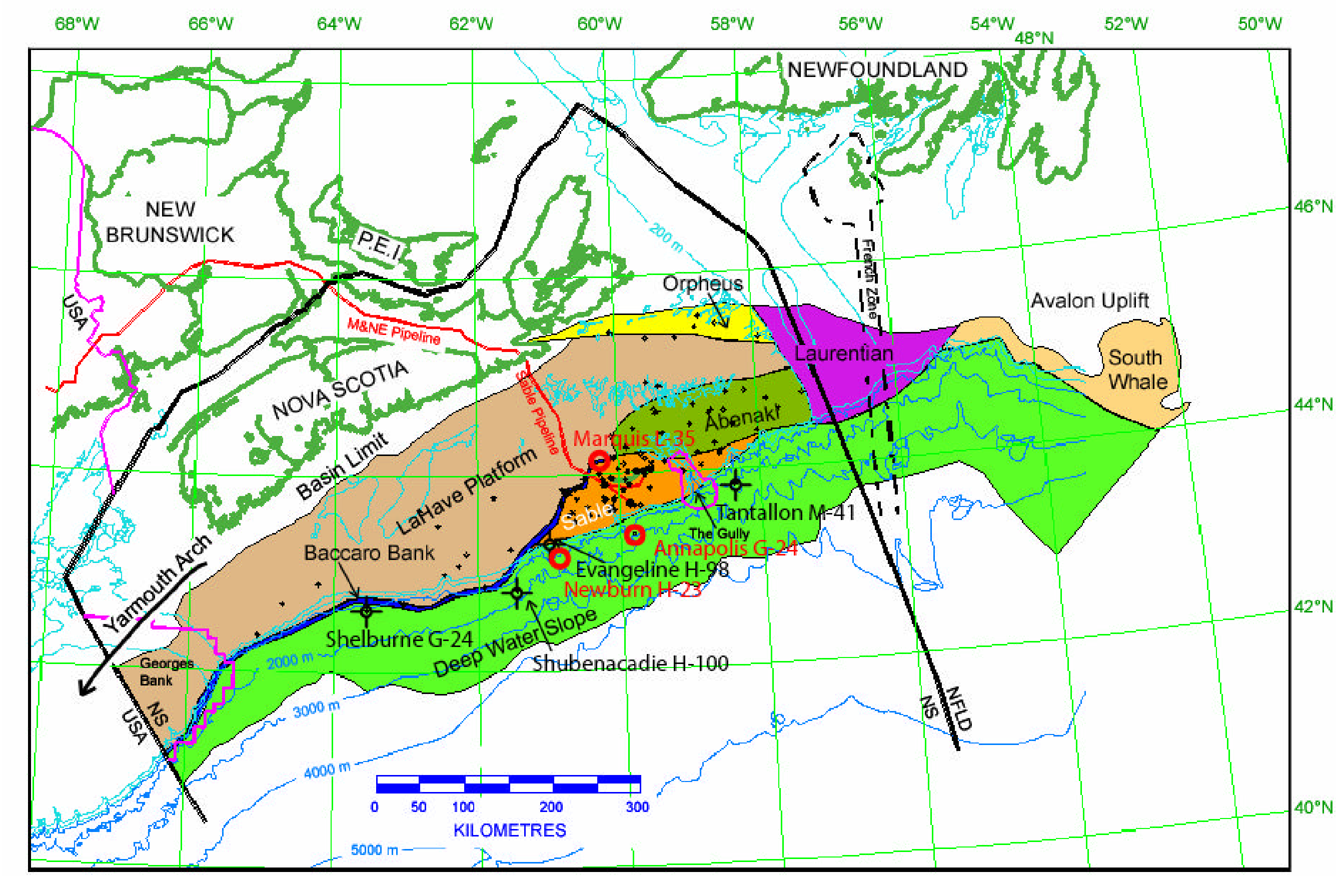


FIGURE 1

Location basemap of the Scotian Basin, offshore Nova Scotia, showing its various subbasins, well distribution and locations of significant wells.

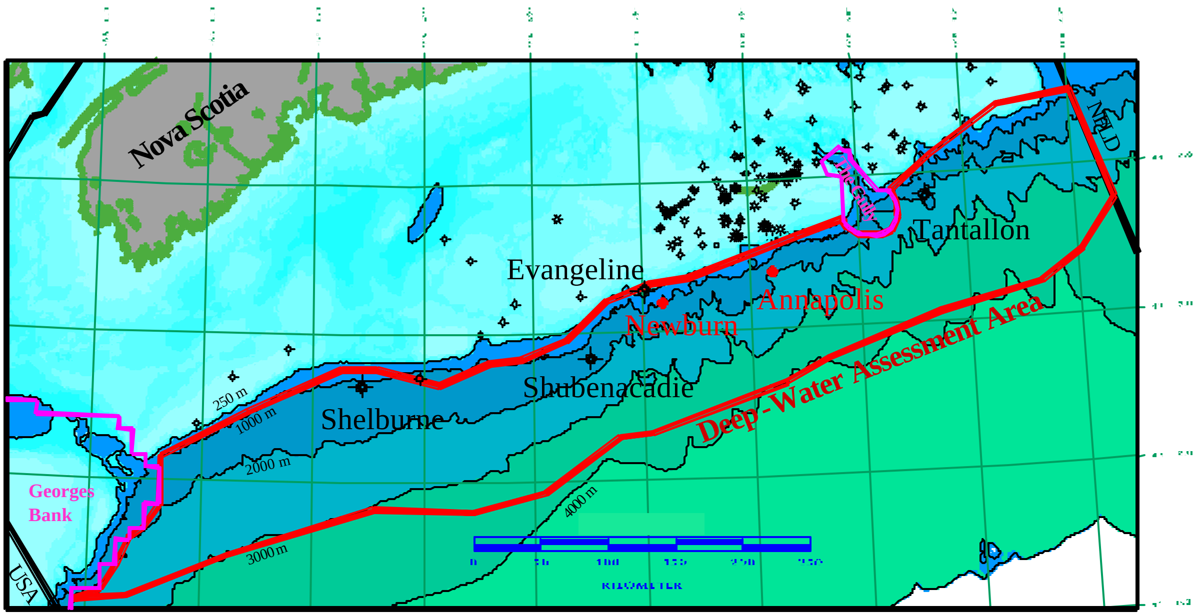


FIGURE 2

Detailed basemap of area studied for the CNSOPB deep-water resource assessment. Illustrated wells are those that have tested deep-water plays. The most recent wells (2002) are shown in red.

The portion of the Scotian Basin lying within Nova Scotia's jurisdiction measures 850 km x 240 km or approximately 200,000 km^2. Roughly 40% (80,000km^2) is in waters greater than 200 m depth beyond the shelf break (Figure 2).

For clarification purposes, George's Bank is a physiographic feature that straddles the Canadian/United States border. The George's Bank Basin lies wholly on the American side and is separated from the Scotian Basin by the Yarmouth Arch and experienced a different geological history and basin evolution. On the Canadian side of the Yarmouth Arch the subsurface rocks are in the Shelburne Sub-Basin, a subset component of the Scotian Basin. An exploration moratorium on the George's Bank area is in place until January 1, 2012.

North of the Yarmouth Arch within Canadian waters of the greater Gulf of Maine, is an area dominated by a faulted basement complex of Paleozoic and older metamorphic and igneous rocks (Figure 1). A number of small Triassic-Jurassic syn-rift basins are located there that are extensions of the much larger Fundy Basin (Wade, et al., 1996). These basins are outside the Mesozoic/Cenozoic passive margin Scotian Basin and are not addressed in this assessment.

The terms "Scotian Basin" and "Scotian Shelf" are sometimes used interchangeably but have a distinctly different connotation. The Scotian Shelf is a physiographic feature that has been defined in earlier studies as that part of the continental shelf between the centerlines of the Northeast Channel (east of George's Bank) and the Laurentian Channel. Only a part of the overall Scotian Basin, a geological feature, underlies this region. The Scotian Slope, defining the transition from the continental shelf to the deep ocean abyssal plain, extends from the 200 m isobath to depths exceeding 4000 m. Together, the Scotian Shelf and Scotian Slope define the Board's area of responsibility for hydrocarbon exploration and production.

2.2 Geological History

This section of the report discusses the geology and geologic history of the Scotian Basin and surrounding region in a level of detail necessary to understand the foundation upon which the assessment is based and from which variables and parameters were determined and used in the evaluation. It is not an exhaustive geological study, and the interested reader can access the excellent publications by the GSC (e.g. Wade and MacLean, 1990; Scotian Basin Atlas, 1991) and others although published material on the older sediments underlying the Scotian Slope is lacking.

The Scotian Basin is a passive continental margin that developed after North America rifted and began to separate from the African continent in the Late Triassic to Early Jurassic. (Figure 3) The rift phase was characterized by red bed and evaporite deposition while the drift phase was characterized by typical clastic progradational sequences with periods of carbonate deposition. A prominent carbonate bank developed in the western part of the basin during the Late Jurassic and its eastern extent was limited by a major deltaic depocentre located in the Sable Island area during the Late Jurassic and Early Cretaceous. Major transgressive sequences continued throughout the Late Cretaceous and Tertiary as relative sea level rose. (Wade and MacLean, 1990; Welsink et al, 1989; Balkwill and Legall, 1989) These were punctuated by major sea level drops and regressive low-stand sequences were deposited as turbidite deposits further seaward.

Break-up and rifting of the Pangean supercontinent commenced in the Middle Triassic Period about 225 million years ago (Mya). At that time, the Nova Scotia region occupied a near equatorial position situated adjacent to Morocco to the east, with most of its older Paleozoic rocks having direct Moroccan affinities. A series of narrow, interconnected, below-sea level basins were created, in which were deposited fluvial and lacustrine red bed sediments as well as volcanic rocks (Fundy-type sequences). As sedimentation continued throughout the Late Triassic, the interconnected basins filled and coalesced, eventually to form a single long, narrow, intracratonic rift basin by the Early Jurassic. (Figures 3, 4)

By the latest Triassic-earliest Jurassic, continental drift processes had slowly moved the North American and African plates northward, with the Nova Scotia-Moroccan region now in the more arid sub-equatorial climate zone (ca. 10-20° paleo-latitude). Renewed Late Triassic rifting further to the north and east in the Grand Banks / Iberia area breached topographic barriers and permitted the first incursions of marine waters from the eastern Tethys paleo-ocean to flood into these interconnected syn-rift basins. Restricted, shallow marine conditions were established with some carbonate sedimentation (Eurydice Formation). Due to the hot and dry climate and below sea level elevation, these waters were repeatedly evaporated, resulting in the precipitation of extensive salt and anhydrite deposits of perhaps one to two kilometers in thickness in this central rift system (Argo Formation). Marine transgressions eventually covered the basin with a shallow sea within which thin sequences of carbonate and clastic sediments accumulated. Coarser grained clastic sediments from fluvial sources were deposited concurrently on the basin margins sourced from adjacent high relief terrains.

Renewed tectonism in the central rift basin during the Early Jurassic (Sinemurian) is manifested by complex faulting and erosion of Late Triassic and Early Jurassic sediments and older rocks. This observed phase of the rifting process is known as the Break-Up Unconformity (BU) and defines the final separation of the North America and Africa continents, creation of true oceanic crust through volcanism, and opening of the proto-Atlantic Ocean.

The basins and platforms that were created on the Nova Scotia and Moroccan margins appear to have been defined by landward extensions of regularly-spaced oceanic fracture zones onto continental crust (Welsink et al., 1990). From the southwest to the northeast, a series of alternating "highs and lows", or platforms and depocentres, occur along the entire Scotian margin, these being the Georges Bank/Shelburne Basin, La Have Platform, Sable and Abenaki Subbasins, Banquereau Bank Platform and the Orpheus Graben/Laurentian Subbasin, (Figure 1). A basement hinge zone in these areas defined the landward limit of maximum tectonic extension and subsidence of the seaward basinal portion of the margin. This basement morphology would thus come to assert a strong control on sediment distribution and deposition in the region for the next 190 million years.

As a result of the final continental separation (Break-Up Unconformity) event, the Scotian Basin margin consisted of a heavily faulted, complex terrane of grabens and basement highs. Shallow water to tidally influenced dolomites were laid down in localized areas on the seaward portion of the margin under slightly restricted marine conditions (Iroquois Formation). This sequence was later followed by a thick succession of coeval fluvial sandstones and shales (Mohican Formation). These clastic sediments eventually prograded out over the margin to fill graben lows and bury basement highs by the early Middle Jurassic. The fine muds from this succession were transported by marine processes further out into relatively deeper water and began to slowly infill the basinal lows and cover new oceanic crust in this depositional setting.

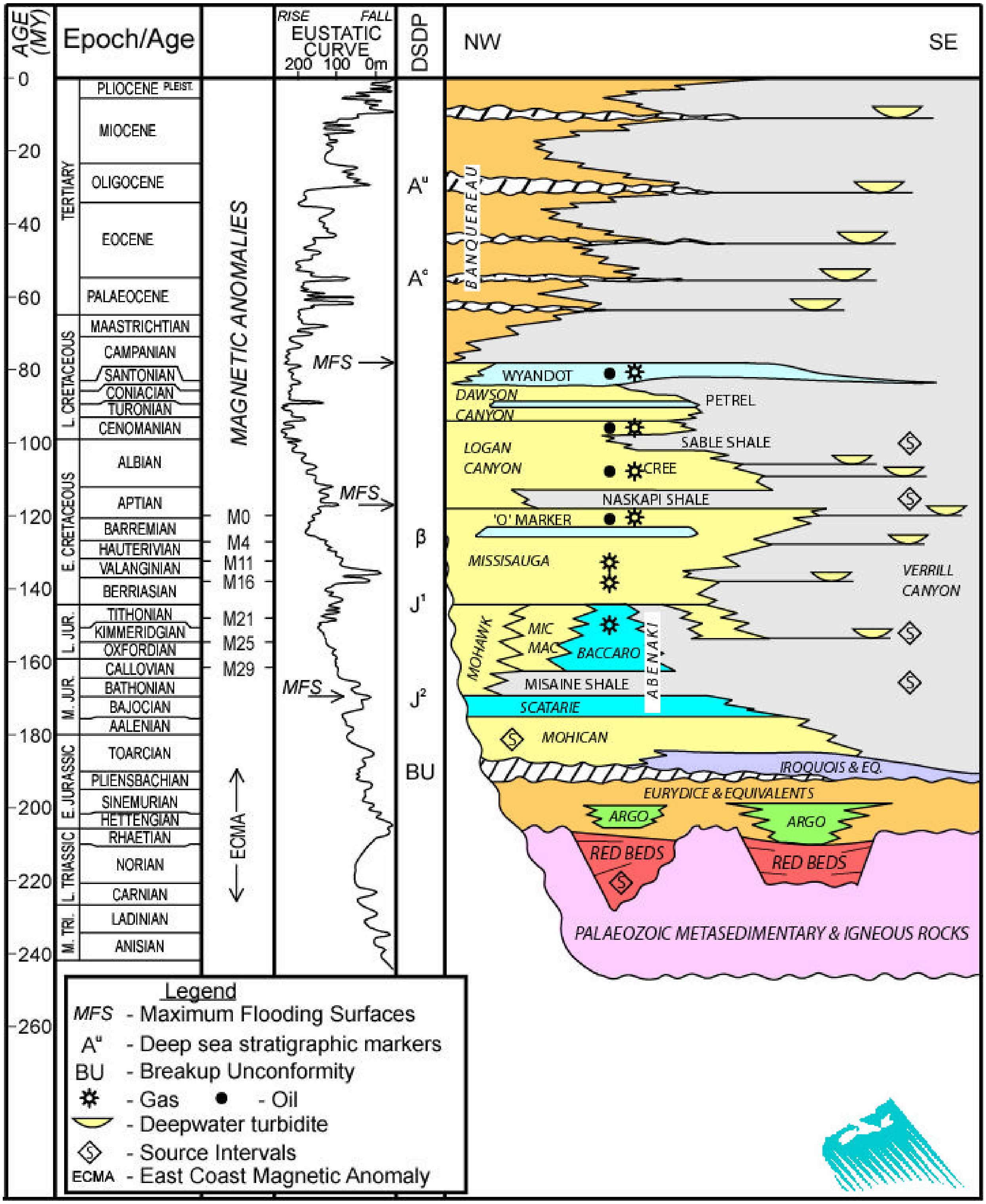


FIGURE 3

Generalized stratigraphic chart for the Scotian Basin, offshore Nova Scotia. The stratigraphic chart has been modified into a time-linear format to facilitate comparison with other basins. Modified after Wade et al. (1993, 1995). Eustatic curve from Haq et al. (1987). Time scale from Palmer & Geissman (1999).

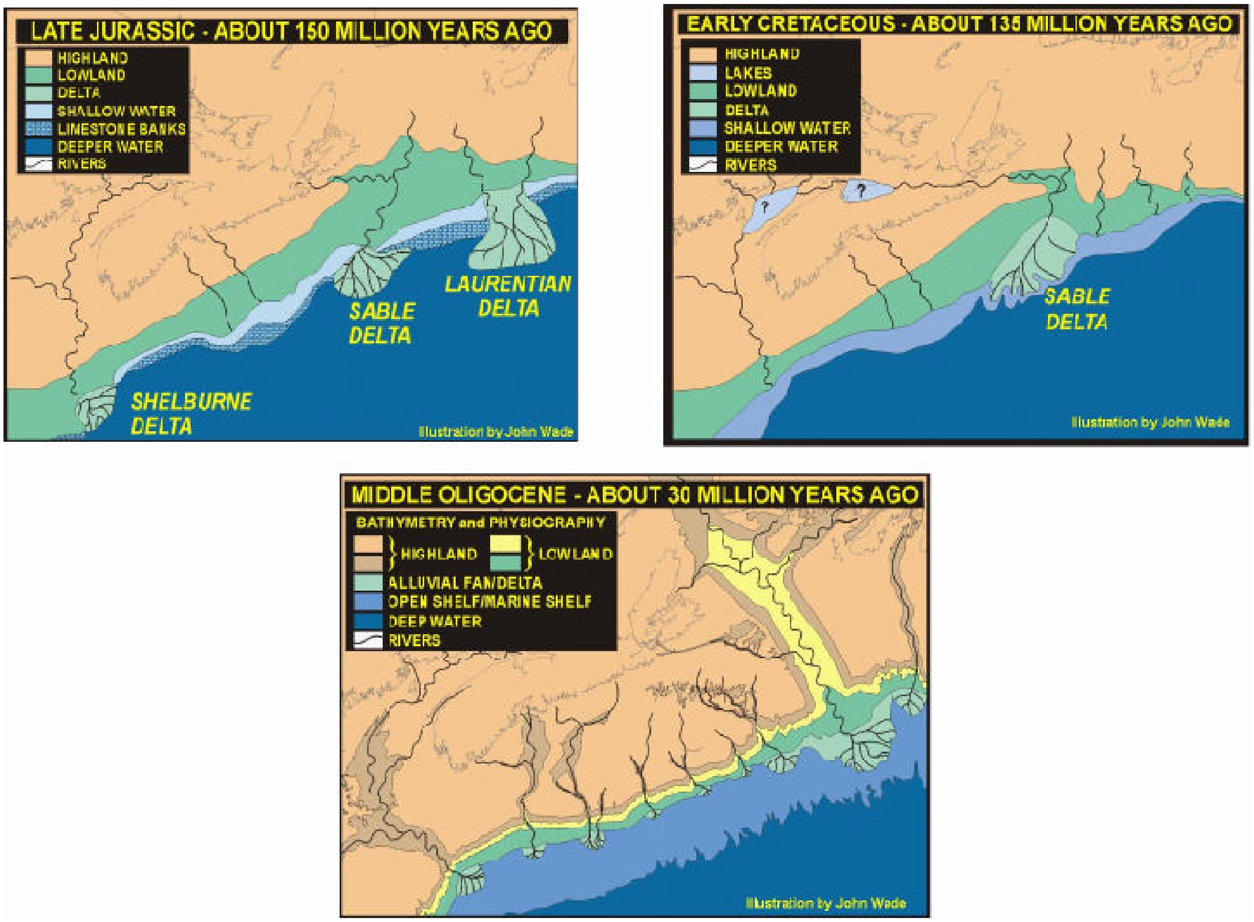


FIGURE 4

Selected Mesozoic and Tertiary paleogeography of the Scotian Basin. The Late Jurassic map approximates deposition of the Mohawk (clastic-coastal plain), Abenaki (carbonate-reef and ramp), MicMac (clastic-deltaic) and Verrill Canyon Formations. The Early Cretaceous map illustrates the near maximum depositional limit of the deltaic Missisauga Formation at about "O-Marker" time. The Middle Oligocene panel depicts Banquereau Formation fluvial coastal plain, shelf-edge delta, and turbidite deposition during a major lowstand event approximating the deep-water A^u seismic marker (Atlantic Geoscience Society, 2001).

The combination of sea-floor spreading, basin subsidence and global sea level rise caused the Atlantic Ocean to become broader and deeper (~1000 metres) by the Middle Jurassic. A carbonate platform succession was established along the hinge zone (Scatarie Member, Abenaki Formation) and prograded out into deeper waters where marls and clastic muds were deposited (~DSDP J2 Reflector). Continuing margin subsidence resulted in a progradation of these waters over the shelf and blanketing the carbonates with marine shales (Misaine Member, Abenaki Formation).

From the late-Middle to the end of the Jurassic, carbonate reef, bank and platform environments were formed and thrived along the basin hinge line on the La Have Platform (Baccaro Member, Abenaki Formation). A shallow mixed carbonate-clastic ramp succession existed on the Banquereau Platform on the northeast margin. Deep-water sedimentation was represented by a thin sequence of shales and limestones (DSDP J1 Reflector). Concurrent with carbonate deposition, regional uplift to the west resulted in an influx of clastic sediments and the establishment of the mixed energy (current and tidal) Sable Delta complex in the Laurentian Subbasin, and slightly later in the Sable Subbasin. In the southwest, a similar progradation of sediments is represented by the Shelburne Delta, (Figures 3, 4). These sediments were primarily sourced from the adjacent thick (14+ km) blanket of latest Devonian to Permian sediments centred in the Gulf of St. Lawrence region that covered the entire Atlantic Provinces region and parts of New England. The MicMac Formation records this first phase of delta progradation into these subbasins, represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales of the Verrill Canyon Formation. Sediment loading of unstable shelf shales south of the basement hinge zone initiated subsidence and development of seaward-dipping growth faults which acted as traps for further sand deposition.

During periods of sea level lowstand, rivers quickly down-cut into the exposed outer shelf. Shelf-edge delta complexes may have been formed at the edge of the continental shelf. Turbidity currents, mass sediment flows and large slumps carried significant volumes of sands and muds into deep-water (500+ metres) and depositing these on the slope and abyssal plain. Sediment loading mobilized deeply buried Jurassic-age salts and via their natural buoyancy the salts intruded vertically into the overlying sediments forming positive relief features on the seafloor. Continuous sedimentation accentuated this process, and in areas such as the Sable and Shelburne Deltas where sedimentation was high, the salt moved both vertically and laterally seaward in an upward-stepping manner forming diapirs, pillows, canopies and related features. This salt motion has been ongoing from about the Middle Jurassic to the present day.

Throughout the Cretaceous Period, the Atlantic Ocean became progressively wider and deeper with significant surface and deep-water circulation patterns. The ancestral St. Lawrence River was well established by the earliest Cretaceous, delivering increasing supplies of clastic sediments into the Scotian Basin that overwhelmed and buried the carbonate reefs and banks on the La Have Platform and later the Banquereau Platform. The Missisauga Formation, a series of thick sand-rich deltaic, strandplain, carbonate shoals and shallow marine shelf successions, dominated sedimentation throughout the Early Cretaceous. The Sable Delta prograded rapidly southwest into the Laurentian and Sable Subbasins and over the Banquereau Platform, while in the Shelburne Subbasin the Shelburne Delta disappeared due to the exhaustion of its river's sediment supply, (Figures 3, 4). Along the La Have Platform, small local rivers draining off of southwest Nova Scotia mainland provided modest amounts of sands and shales to this region and associated deeper water realm.

Within the Sable and Laurentian Subbasins, growth faulting accompanied this time of rapid deposition, moving progressively seaward as the delta advanced. When sea levels dropped, large volumes of sands were again deposited out into deep-waters. Such high deposition rates further loaded salt features that in turn initiated renewed salt motion with turbidite fan and channel sediments filling intra-salt minibasins. Shales of the deep-water Verrill Canyon Formation continued to dominate sedimentation in this environment throughout the Cretaceous.

Deltaic sedimentation ceased along the entire Scotian margin following a late Early Cretaceous major marine transgression that is manifested by thick shales of the overlying Naskapi Member, Logan Canyon Formation. Subdued costal plain and shallow shelf sand and shale sedimentation of the Late Cretaceous Logan Canyon Formation, and later deeper marine shales (and some limestones) of the Dawson Canyon Formation reflected continued high sea level and a lower relief hinterland, together reducing sediment supply to the basins. During periods of sea level fall, mud-rich sediments were still being transported out into the deep-water basin though in reduced quantities (Verrill Canyon Formation).

The end of the Cretaceous period in the Scotian Basin saw a rise in sea level and basin subsidence and deposition of marine marls and chalky mudstones of the Wyandot Formation. These strata were eventually buried by Tertiary age and marine shelf mudstones and later shelf sands and conglomerates of the Banquereau Formation. Throughout the Tertiary on the Scotian margin, several major unconformities related to sea level falls occurred. During Paleocene, Oligocene (Figures 3, 4) and Miocene times, fluvial and deep-water current processes cut into and eroded these mostly unconsolidated sediments and transported sediments out into the deeper water slope and abyssal plain. During the Quaternary Period of the last 2 million years, several hundred metres of glacial and marine sediments were deposited on the outer shelf and upper slope.

CHAPTER 3

GLOBAL ANALOGUES (PASSIVE MARGINS)

The petroleum Industry has been extremely proactive, and successful, exploring in the Atlantic-facing continental shelves (passive margins) in the South Atlantic region as well as the Gulf of Mexico. This pro-activity has been extended into the North Atlantic, offshore Nova Scotia, and more recently, offshore Morocco. Of particular interest in those areas is their focus in the deep-water regime. These areas all share common passive margin histories, salt tectonism, clastic and carbonate regimes and hydrocarbon discoveries.

The continental margin off Nova Scotia has long been known as the definitive Atlantic style passive margin; a pull-apart margin followed by thermal sag and a prograding shelf with a carbonate bank, major river delta and a mobile salt substrate. The three major analogue passive margins believed comparable to the area are all Atlantic-facing, namely the Gulf of Mexico (GOM), offshore Brazil and offshore West Central Africa.

3.1 General Deep-Water Success

Pettingill (1998a and 1998b), and Pettingill and Weimer (2001) provide an excellent overview of industry's success in world-wide deep-water exploration, and is briefly summarized below:

- 57 BBOE has been discovered in deep-water worldwide over the past ten years.
- It is predominantly oil with 37 BB of oil and 120 Tcf of gas.
- Until 1985 the frontier success rate was 10% but has since averaged 30%.
- Three main areas dominate; the Gulf of Mexico, Brazil, West Africa.
- The prime setting is along passive margins down-dip from productive Tertiary delta systems.
- A key appears to be in depocentres confined by a mobile salt substrate.
- Petroleum source rocks are early syn-rift (lacustrine) and/or later passive margin (marine).
- 90% of reserves are found in turbidite reservoirs, primarily Cenozoic age.
- High permeability reservoirs commonly occur in ponded mini-basins surrounded by salt.
- Stacked turbidite sequences result in high net pays.

The worldwide distribution of major deep-water discoveries shows the GOM, offshore Brazil and West Central Africa dominating the scene, especially on the oil side. Pettingill and Weimer (ibid.) noted areas of prospective deep-water basins that include the Scotian Basin and offshore Morocco.

The chronology of discoveries by water depth in these three analogue basins (Figure 5) also illustrates the relative field sizes. The GOM has enjoyed a steady progression into deep-water since 1980 as a function of economics and technology. Brazilian activity started in 1985 when industry was allowed to participate and then made a major leap into deep-water with the discovery of the giant Marlim and Marlim Sul fields. The West African effort only began in 1995 but has been spectacularly successful. By comparison, deep-water exploration off Nova Scotia (and Morocco) is in its infancy.
The wildcat success rates enjoyed by industry in various global deep-water basins, is very impressive (Figure 6). The old 10% rule of thumb for frontier play success has been greatly improved upon with a new global average of 30%. This high success rate is also a function of improved technology, especially seismic imaging, in the pre-drill work-up stage.

The deep-water setting appears to be the critical factor where the mobile salt substrate creates an extensionally confined depocentre. Salt tectonism driven by sediment loading and subsidence creates numerous localized depocentres within which turbidite reservoirs accumulate. This setting provides two-thirds of the global deep-water reserves, with the unconfined setting also important for slope turbidites deposited in an extensional fault regime where salt-related "mini-basins" are absent.

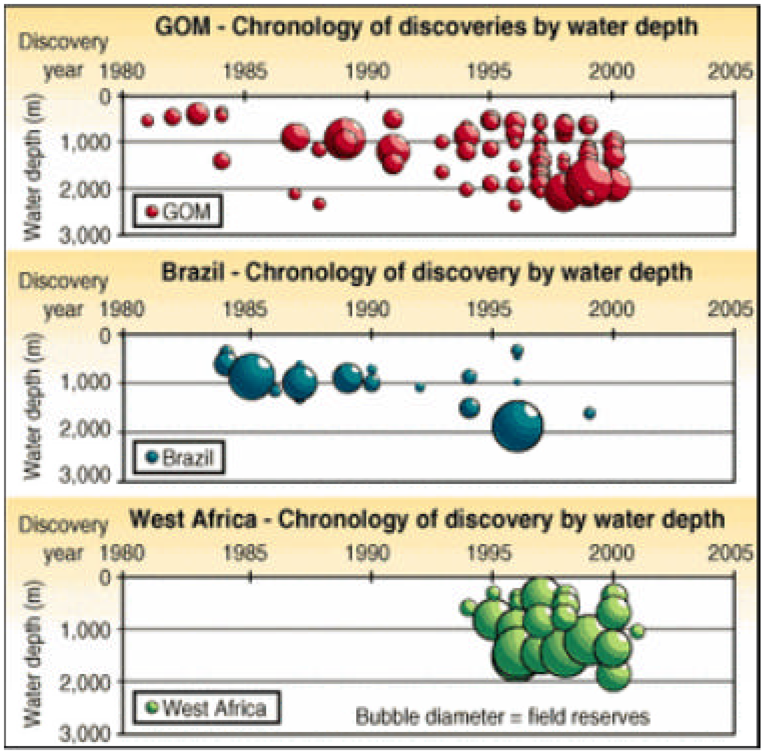


FIGURE 5

Plot of deep-water discoveries by year and water depth for the Gulf of Mexico, Brazil and West Africa. Bubble dimension indicates relative size of the discovery in BBOE (Dyer, 2001).

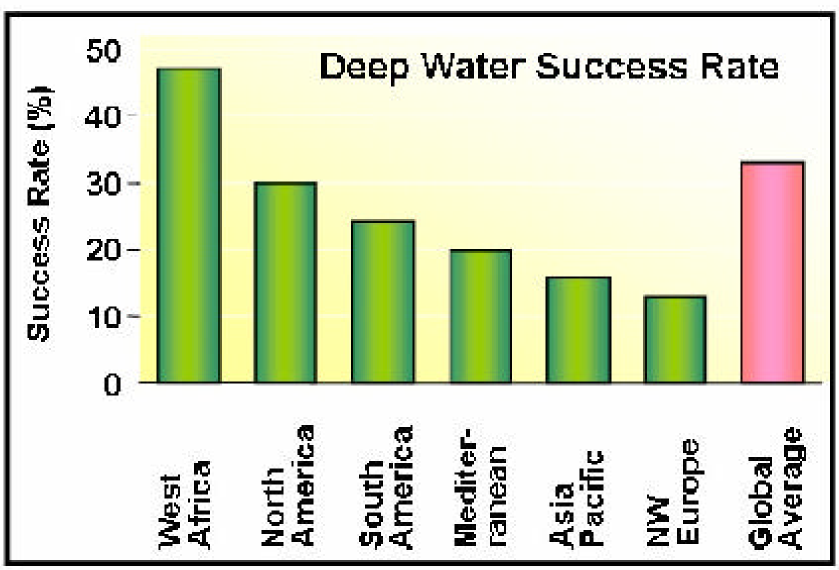


FIGURE 6

Global deep-water success rates (Pettingill & Weimer, 2001).

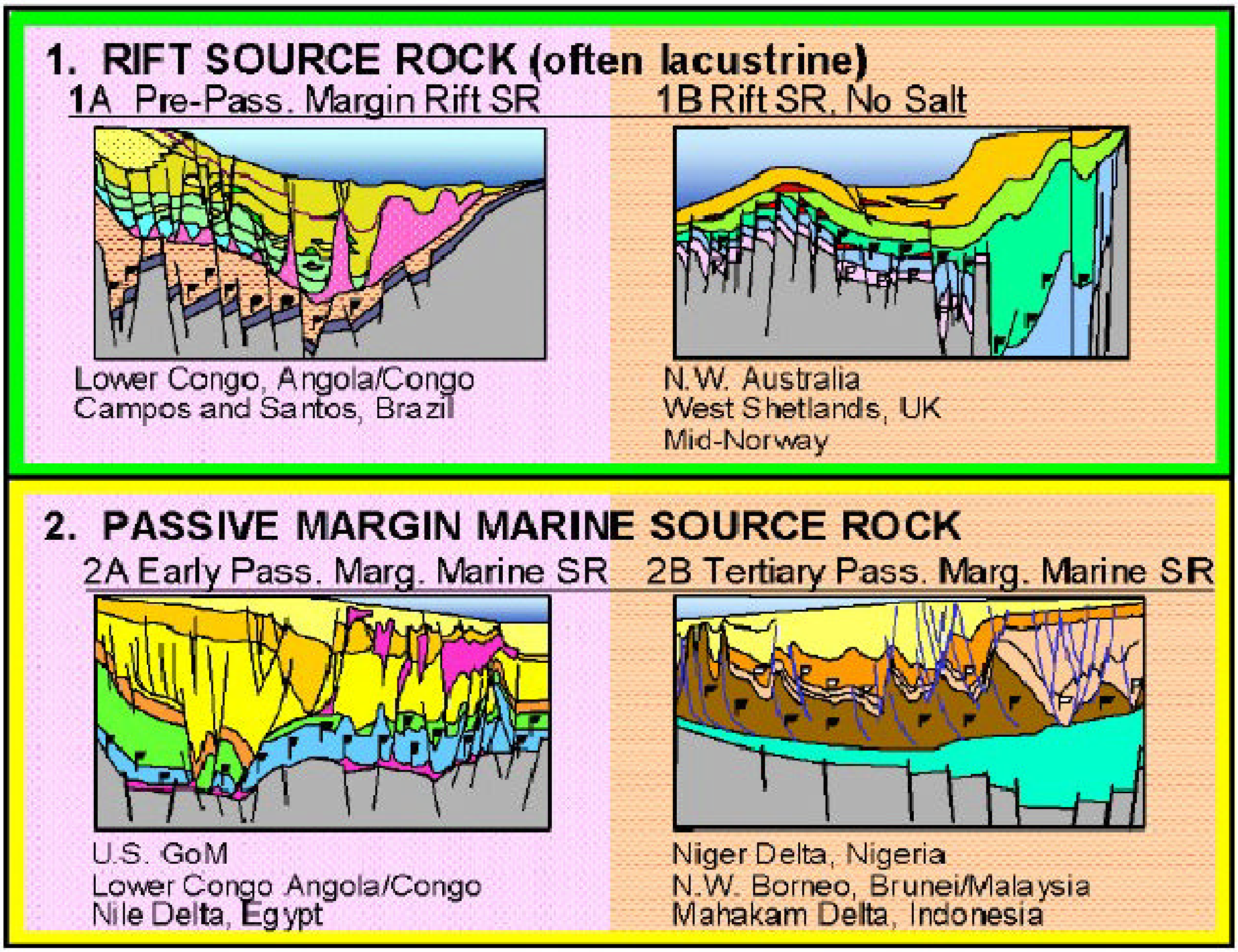


FIGURE 7

Petroleum systems of global deep-water discoveries. Note that the majority of discovered hydrocarbons are sourced from Jurassic and Cretaceous age rocks, with the latter being younger and more oil-prone. Paleocene rocks are also more oil-prone but are equally gas-prone in Neogene sediments (Pettingill & Weimer, 2001).

Figure 7 illustrates the most common types of petroleum systems in deep-water with associated oil and gas resources discovered to date. Most reserves are sourced from Jurassic and Cretaceous syn-rift and marine source rocks. For the Nova Scotia assessment region, the two major source settings are: 1A -the syn-rift lacustrine source facies below the original salt deposition as seen off Brazil and West Central Africa; and 2A - the marine section post salt present in the GOM and West Central Africa.

The profound influence of salt tectonics for the known deep-water turbidite trap types is well illustrated in Figure 8. These configurations are seen in seismic profiles throughout the Scotian Slope and are further discussed in Chapter 5.

3.2 Determination of Basin Analogues

The selection of analogue basins must be technically defensible and Ulmishek (1984) proposed a process to select appropriate analogue basins based on similar tectonic style, stratigraphy, age, etc. Fortunately for our exercise, the selection process was undemanding as the other explored Atlantic-facing passive margins have enjoyed recent deep-water successes.

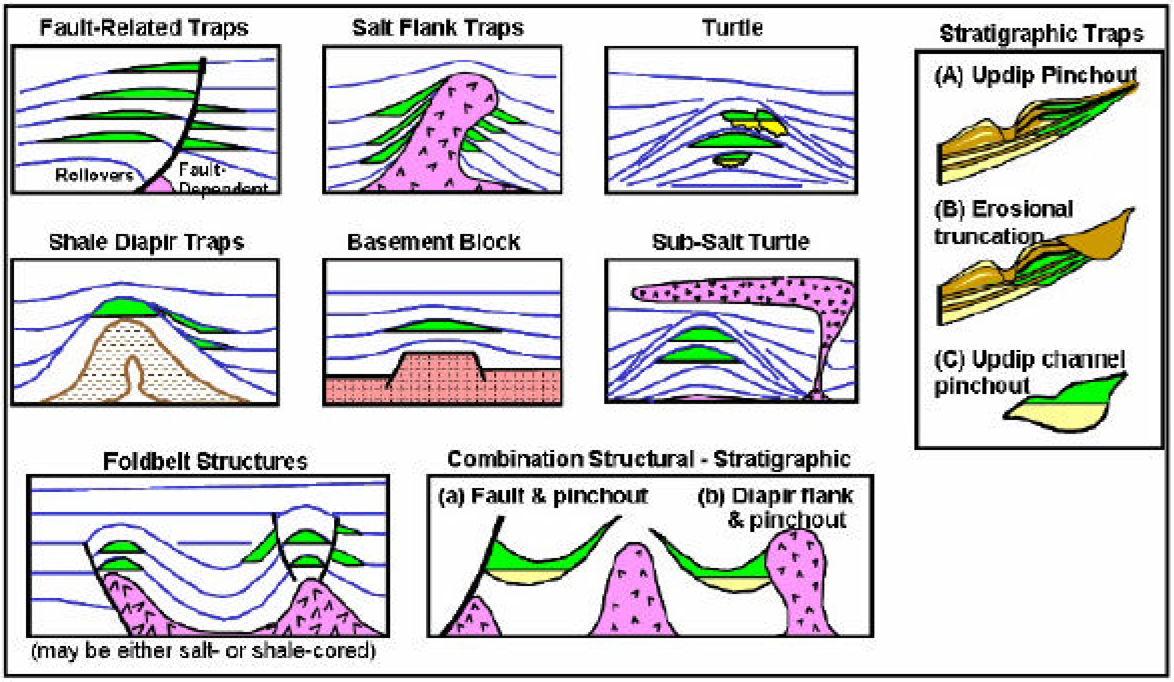


FIGURE 8

Common deep-water turbidite trap types. Note that numerically, most traps are related to structures formed by salt, though many large reserves have been discovered in stratigraphic traps. (Pettingill & Weimer, 2001).

Once a geotectonic similarity is established, Ulmishek and Harrison (ibid.) described four factors to be considered when drawing comparisons:

1. Quality of potential source rocks and their maturation
2. Presence of traps, their abundance and size
3. Presence of reservoir rocks and their quality
4. Presence of regional seals

Another factor considered important is the age of a petroleum system because hydrocarbons appear unevenly distributed within a basin as well as globally.

Figure 9 represents a time-linear composite generalized stratigraphic chart for the North Atlantic and South Atlantic and the GOM, comparing the syn-rift, breakup and drift sequences for all areas. The most striking aspect of this figure is the younging of the Breakup Unconformity (BU) from north to south. The approximate original stratigraphic position of the now-mobile salt is shown in all regions to be older than the BU and it is recognized that the resulting salt tectonic style appears very similar in all regions.

Although the ages of break-up, source, reservoir, maturation, tectonism, etc. are different, it is believed that the geologic processes are similar and generated similar petroleum systems through geologic time. For example, while the early syn-rift source rock intervals (established and/or conceptual) and reservoir sections are proven in Brazil and West Africa, they are not identified in GOM and remain postulated in the North Atlantic. Conversely, marine sources are recognized in all areas. The main productive reservoirs known to date are in the Upper Jurassic/Cretaceous Sable Delta sands on the Scotian Shelf, the Tertiary sands of the GOM and the Upper Cretaceous/Tertiary sands of Brazil and West Africa.

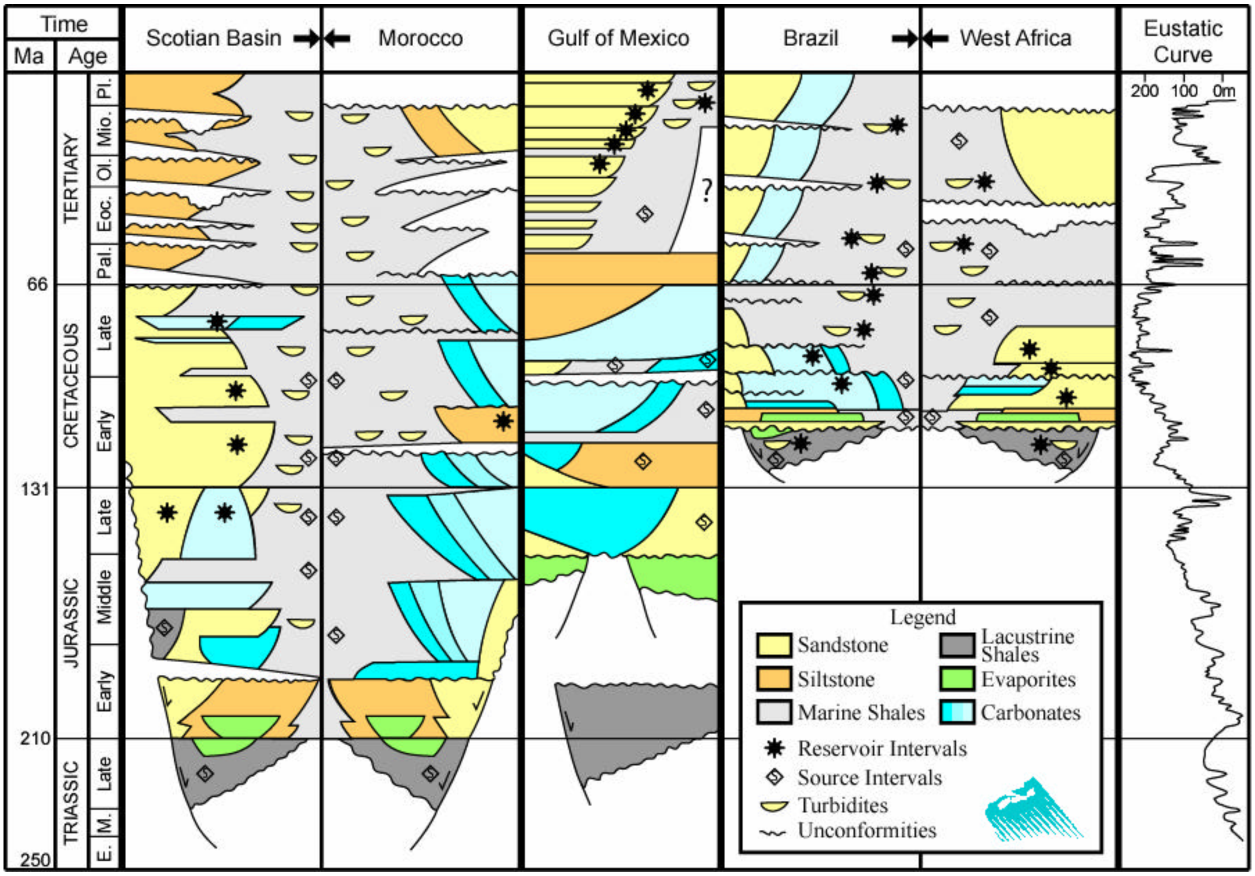


FIGURE 9

Comparative stratigraphic chart of the Scotian Basin and Atlantic margin analogues. Source rocks and reservoir intervals are either confirmed or speculative. (Sources: NOVA SCOTIA: Wade & MacLean (1990), Wade et al. (1995), Ebinger & Tucholke, (1988), Swift (1987); MOROCCO: ONAREP (1999), Morabet et al. (1998), Heyman (1989), Jansa & Wiedmann (1982); GULF OF MEXICO: Colling et al. (2001), Mancini et al. (2001), McBride et al. (1998); Diegel et al. (1995); BRAZIL: Agência Nacional do Petrólo (2002), Guardado et al. (2000), Mohriak et al. (2000), Cainelli & Mohriak (1999), Mohriak et al. (1989); WEST AFRICA: Da Costa et al. (2001), Harris (2000), Liro & Dawson (2000), Schoellkopf & Patterson (2000), Katz & Mello (2000) and Marton et al. (2000).

The offshore Nova Scotia and Moroccan basins have virtually identical successions up to the Late Jurassic, but diverged in the Cretaceous as the Scotian basin was dominated by fluvial-deltaic sedimentation and the establishment of the long-lived Sable Delta sourced by the ancestral St. Lawrence River. No such large-scale system is known from the Moroccan margin where carbonate deposition dominates. The Gulf of Mexico had a complex early history during its initial rifting stage with little sedimentation. The continental-size system of the Mississippi River was established only in the mid-Tertiary following uplift of the Rocky Mountains and draining of the western epi-continental seaway. Indeed, most sediments in the GOM were deposited just in the last 25 million years. The younger basins of West Africa and Brazil, while having been initiated in the Early Cretaceous, have thin sedimentary successions generally due to the limited size of the fluvial systems draining into the basins, with more carbonate deposition on the Brazilian margin. Note that for all margins, major salt deposition occurred prior to the onset of rifting, erosion and resultant formation of a regional break-up unconformity. Later salt tectonism and intrusion into overlying and younger sediments was driven by sediment loading.

The time-linear scale of Figure 9 is somewhat misleading when sediment volume is considered. Figure 10 illustrates a depth-linear plot of basin fill comparison by age. The total 23 km of basin fill for the Scotian Basin compares favourably with the 25 km attributed to the GOM and far exceeds the 6 km in the South Atlantic basins. However, the majority of the reservoir-bearing succession in the GOM (18 km!) was deposited only over the last 25 million years (Miocene to Pleistocene), whereas the older but relatively thinner (11 km) Jurassic/Cretaceous reservoir section (Sable Delta) took over 90 million years to accumulate. The relative thinness of the basins of the South Atlantic margins is at first glance surprising from a stratigraphic and geothermal maturation point of view, but obviously the heat flow and hence the petroleum systems work very well.

3.3 Gulf of Mexico

The Gulf of Mexico (GOM) is by far the most prolific of the basin analogues, and new concepts, seismic data and exploration in deeper waters has led to a revolution in the understanding of the Cenozoic succession in the northern Gulf of Mexico (OCS MMS 2001). The old pre-1980 model of a passive margin with vertical rooted salt stocks and massifs with intervening steep growth faults has been superceded by one with a complex mosaic of diachronous detachment fault systems and variously deformed allochthonous salt sheets and bodies (Webster, 1995; Diegel 1995). Much the same evolution in basin evolution, tectonic and stratigraphic concepts has occurred in the Scotian Basin and as more is learned the Gulf Coast analogue model appears increasingly appropriate.

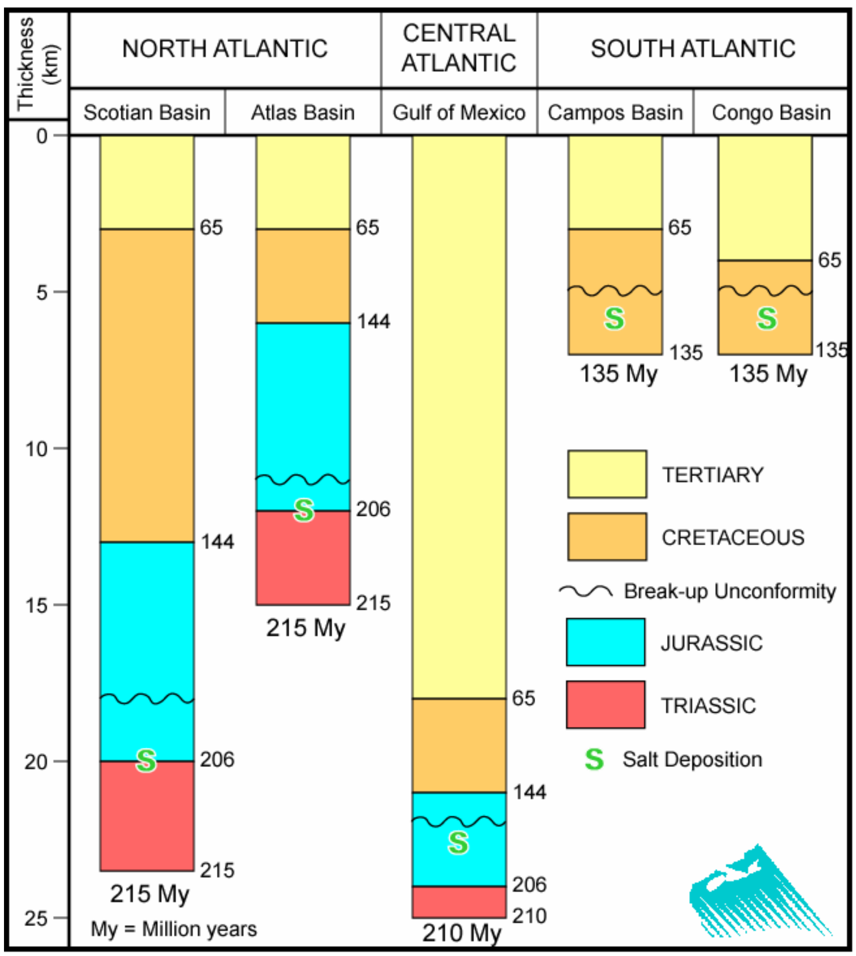


FIGURE 10

Generalized comparison of Atlantic conjugate margin basins' sediment thickness and age. (Sources: See caption for Figure 9.)

There are both similarities and differences between the Scotian Slope and the GOM deep-water regimes. Both regions share the same passive margin history including a salt substrate, thick deltaic sediments and up-dip production. The major difference is the timing of the paleo-Sable Delta off Nova Scotia (Late Jurassic – Early Cretaceous) which ceased to exist by Tertiary time, and the Mississippi Delta which was dominant from the middle Tertiary to the present. The Scotian Basin contains a much thicker Jurassic/Cretaceous section (17 km vs. 6 km) whereas the GOM Tertiary section is about six times thicker than its Scotian counterpart (18 km vs. 3 km). The full effect of this depositional difference as related to the Scotian Basin petroleum systems is yet to be fully determined.

In 1990, Exxon drilled the GOM Mississippi Canyon Block 211 sub-salt discovery Mickey (renamed Mica). The well penetrated a flat-lying salt sheet 1257 metres thick and beneath it encountered oil and gas filled sands with reserves in the 100-200 MMB range. In 1993, Phillips drilled the Mahogany discovery, also a sub-salt play, containing about 125 MMB in turbidite sands that went on-stream in 1997. A new deep-water play had emerged (Lore et al., 2001).

Publications by the American Association of Petroleum Geologists (AAPG) and proceedings of various symposia (e.g. Gulf Coast Society–Society of Economic Paleontologists and Mineralogists - GCS-SEPM; see References) have provided documented the latest knowledge and data on the deep-water petroleum systems of the GOM and the world. The main features of these discoveries is that they are mainly oil, are large (up to 1 BOEB) and the reservoirs are generally Late Tertiary aged turbidite deposits with some reservoirs as young as Pleistocene (less than 2 million years old).

Weimer et al. (1998) studied an area about 10,000 km^2 in the Green Canyon and Ewing Bank areas, northern GOM. A detailed time structure map on the top of the salt and the correlative inter-salt weld provided a base for subsequent seismic facies and geologic facies analyses. Basin-floor turbidite fan depocentres were interpreted for ten seismic sequences and when plotted on the base map resulted in an understanding of how much of the inter-salt area can contain reservoir rocks. In this case approximately 25% of the inter-salt area was interpreted to be under reservoir conditions. Although the data is sparse the fields range in size from 10-400 MMBOE, areas range from 1000-2000 acres (400-800 hectares or 4-8 km^2), net pays from 100-400 feet (30-120 m) thick, porosities ranging from 25-30% and water saturations from 20-40%. Reservoirs are dominantly Miocene to Pleistocene age turbidite channel fills on the flanks of diapiric salt features. A survey of the more recent GOM deep-water discoveries in 1000-2000 metres of water revealed field size ranges of 100-1000 MMBOE, areas of 400-2000 hectares and net pays 30-150 metres thick (Industry press releases, websites, etc.). Such information was invaluable for approximating parameters in the Scotian Slope successions.

The U.S. Minerals Management Service (Lore et al., 2001) stated their GOM resource assessment as of January 1, 1999, from which it is clearly seen as one of the GOM is most prolific basins in the world with a new frontier emerging in the deep-water (Figure 11). Since 1995, the MMS has increased the GOM potential by 29 BB of oil and 97 Tcf of gas. The expected ultimate recovery (EUR) of the Federal offshore part of the GOM now stands at 60 BB and 428 Tcf. Of the 103 deep-water discoveries made to date, the mean field size is 118 MMBOE with the maximum discovery of 1 BBOE at the Thunder Horse field (Pettingill, 2001).

	OIL (BB)	GAS (Tcf)	BOEB
Cumulative Production	**11**	**133**	**35**
Remaining Reserves	**12**	**103**	**30**
Potential (Mean Risked)	**37**	**192**	**71**
Total EUR	**60**	**428**	**136**

FIGURE 11

Estimated Ultimate Recovery (EUR) for the Gulf of Mexico as of January 1, 1999. Data on ‘cumulative production’ and ‘remaining reserves’ is from Crawford et al. (2000); and for ‘potential resources’ from Lori et al. (2001). These numbers are all for Federal waters only.

3.4 Offshore West Central Africa

The USGS World Energy Project (2000) assessed the West Central Coastal region of Central Africa which extends from the southern limit of the Niger Delta south to the Walvis Ridge at the Angola/Namibia border. Their assessment of this margin and the opposite Brazilian margin indicates there is an emerging South Atlantic producing region capable of becoming a major contributor to world petroleum supply over the next 30 years.

As stated in the AAPG Explorer (August 2001, page 20); *"In just eight years, 62 exploratory wells have been drilled in the Lower Congo Basin Tertiary deep-water trend (water depths range from 200 to 1500 metres) and 42 of those wells were geologic successes. Of that total, up to 31 may be commercial accumulations. The 68% success rate is astounding for a rank exploration play. In April, Exxon/Mobil announced its 10th oil discovery in three years in Angolan waters."*

The major difference between the North and South Atlantic margin pull-apart history appears to be timing. The North Atlantic margin separated in Early Jurassic while the South Atlantic margin separated in Early Cretaceous. Hence, while the ages of subsequent evaporite, carbonate and siliciclastic depositional successions may be different, the geological processes are similar (Figures 8, 9, 10). Examples of seismic sections from the offshore West African margin (e.g. Liro et al., 1995; and Tari et al., 2001) exhibit the same variety of shapes and sizes of mobile allochthonous salt bodies as in the Scotian Slope (see Figures 20-22, 27-34).

The USGS (2000) assessed the African West–Central Coastal Basins discoveries at 14.5 BB and 12.2 Tcf. Figure 12 shows the undiscovered potential of the top five plays at 30 bb of oil and 88 Tcf of gas, with the "Central Congo Turbidites" being the most attractive. Of the 30 deep-water discoveries to date, the mean field size is 272 MMBOE and the largest is 1.4 BBOE (Pettingill & Weimer, 2001).

3.5 Offshore Brazil

The 100,000 km^2 Campos Basin is the most prolific of the Brazilian Atlantic margin basins, containing greater than 80% of the reserves and 75% of the production. There are 70 discoveries including 7 giant oil fields in deep-water. The main source rocks are Cretaceous (Barremian - Aptian) calcareous shales of the Lagoa Feia Formation with siliciclastic and carbonate reservoirs of Barremian to Miocene age. Upper Cretaceous to Tertiary turbidites contains most of the oil with peak oil generation occurring in the Late Miocene. Migration was through salt windows and along listric faults (Guardado et al., 2000) (see Figures 8, 9, 10).

Figure 13 is a tabulation of the undiscovered potential for offshore Brazil, including both the Campos and Santos Basins (Schenk et al., 1999), and the discovered volumes (Klett et al., 1997). The undiscovered potential of the Campos basin occurs in three proven petroleum systems as listed, with the Cretaceous/Tertiary Turbidite Play being the most attractive. Of the 19 deep-water discoveries to date, the mean field size is 631 MMBOE and the largest is 3 BBOE (Pettingill & Weimer, 2001). Representative seismic profiles are presented in Cabbold et al. (1995), and Mohriah et al. (1995).

Petroleum System	OIL (BB)	GAS (Tcf)
Undiscovered		
Gabon SubSalt	**0.7**	**3.7**
Gabon SupraSalt	**5.0**	**13.2**
Central Congo Delta	**4.7**	**14.3**
Central Congo Turbidites	**18.5**	**55.3**
Kwanza Composite	**0.8**	**1.6**
Total Undiscovered	**29.7**	**88.1**
Total Discovered	**14.5**	**12.2**
EUR	**44.2**	**100.3**

FIGURE 12

Estimated Ultimate Recovery (EUR) for basins offshore West Central Africa. Data on 'undiscovered resources' from the USGS (2000) and for 'discovered reserves' from Klett et al. (1997).

3.6 Offshore Morocco

The Nova Scotia and Moroccan margins are a conjugate pair, meaning they were juxtaposed in pre-rift times. Figure 9 shows the overall equivalent depositional history except Morocco did not have a major delta system like the long-lived Sable Delta and hence has a thinner equivalent Cretaceous succession (Figure 10). This has implications regarding the presence, abundance and distribution of potential sandstone reservoirs. Tertiary low-stand events and turbidite deposition upon a mobile substrate has resulted in the familiar allochthonous salt and mini-basin architecture as demonstrated by recent seismic surveys of the Agadir, Souss, Essaouira and Doukkala Basins (i.e. Atlas Basin) (ONAREP, 2000a; 2000b, Tari et al., 2001). Exploration in the deep-water offshore Morocco slightly lags that of Nova Scotia. Industry and speculative seismic surveys have been shot, exploration and reconnaissance permits have been issued, but drilling has yet to commence. Seismic profiles from this margin can be found in Tari et al. (2001), and ONAREP (1999, 2000a, 2000b).

Petroleum System	OIL (BB)	GAS (Tcf)
Campos Basin		
Cret/Tert Turbidites	10.9	13.9
Cret. Carbonates	0.9	1.7
Salt Dome, Tertiary Sands	4.5	4.0
Total Campos Undiscovered	16.3	19.6
Total Campos Discovered	10.1	6.2
Total Campos (EUR)	26.4	25.8
Santos Basin		
Shelf	13.7	62.9
Salt-Structured Deep-Water Sands	9.5	17.7
Total Santos (EUR)	23.2	80.6
Total Both Basins (EUR)	49.6	106.4

FIGURE 13

Estimated Ultimate Recovery (EUR) for the Campos and Santos Basins, offshore Brazil. Data on ‘undiscovered resources’ from the USGS (2000) and for ‘discovered reserves’ from Klett et al. (1997).

CHAPTER 4

HISTORICAL ASSESSMENTS AND METHODOLOGIES

The known previous assessments of the Nova Scotia offshore provided much useful information on the methodologies employed and how these, and the resultant resource estimates, evolved through time (Figure 14. See: EMR-Canada (1977), Proctor et al. (1984), Wade et al. (1989), MacLean and Wade (1992), SOEP (1997), CNSOPB (1997), CGPC (1997, 2001)). This included, but was not limited to, major assumptions on the areas assessed, in-place vs. recoverable, and geologic risk factors.

Like any other analytical method, resource assessment techniques have evolved over the years. One of the original methods was *volumetric yield by analogy to known basins*. By comparing source rock area, thickness, organic content, present-day depth, etc., a hydrocarbon yield in *oil-equivalent barrels per unit area* could be calculated. Klemme (1994) used such a method for the Upper Jurassic Petroleum Systems of the world and included the Verrill Canyon Petroleum System of the Scotian Basin.

These deterministic volumetric methods were superceded in the 1970's by statistical analysis using stochastic Monte Carlo sampling techniques and later, in the 1980's, to more advanced techniques such as *discovery process modelling*. The Geological Survey of Canada developed the Petroleum Exploration and Resource Evaluation System (PETRIMES) and has used it extensively (Lee, 1992). The main module is the Discovery Process Model and the basic concept employed in the program is that the discovered pools in a properly defined and proven exploration play make up a sample that can be used to describe the statistical distribution of all the pools in the play, including the undiscovered ones. In most cases, the distribution of the size of pools in a specific play is approximately log-normal.

As techniques evolved for assessing the remaining potential in basins containing proven petroleum systems, it became desirable to extend the assessment capability into basins or plays that lack discoveries or even wells. Hence, conceptual or subjective assessment was added to the PETRIMES repertoire.

For proven plays, field-size distributions and success rates from the basin are used and applied to the undiscovered component. For conceptual plays without any discoveries, an anomaly map of undrilled features can be used along with borrowed field size distributions from analogous plays. If an anomaly map cannot be constructed, either from lack of data or the stratigraphic nature of the play, then another approach must be employed. The remaining approach used in our study was to determine the overall play area from regional mapping and use discount factors to arrive at a net area under trapping conditions. All factors are entered as distributions and the procedure is fully stochastic.

Any assessment methodology has to distinguish between established / proven plays, and conceptual / unproven plays. The best example on the Scotian Shelf is the proven plays within the Sable Sub-Basin. The Verrill Canyon Petroleum System, consisting of known sources, seals and traps, is responsible for the discoveries made to date. However, in the deep-water Scotian Slope, the plays must be conceptualized by analogy to similar basin settings throughout the world, and especially the circum-Atlantic passive margin basins.

4.1 Canadian Federal Agencies: EMR, GSC

The first published report on the resource potential for offshore Eastern Canada was the "Oil and Natural Gas Resources of Canada, 1976" published by Energy, Mines and Resources Canada (1977). Eastern Canada was divided into regions and the "Atlantic Shelf South" covered the entire continental shelf off Nova Scotia and Newfoundland up to latitude 46 degrees north. The hydrocarbon potential (including discoveries) median value (P50) was estimated at 13 Tcf of gas and 1.9 BB of oil and liquids. Using data available to the end of 1975, six small gas and oil fields had been discovered in the Sable Island area totaling about one Tcf and 100 MB respectively. Based solely on the pro-rating of areas, one-third was attributed to the Scotian Shelf, i.e. 4.4 Tcf gas and 633 MMB oil.

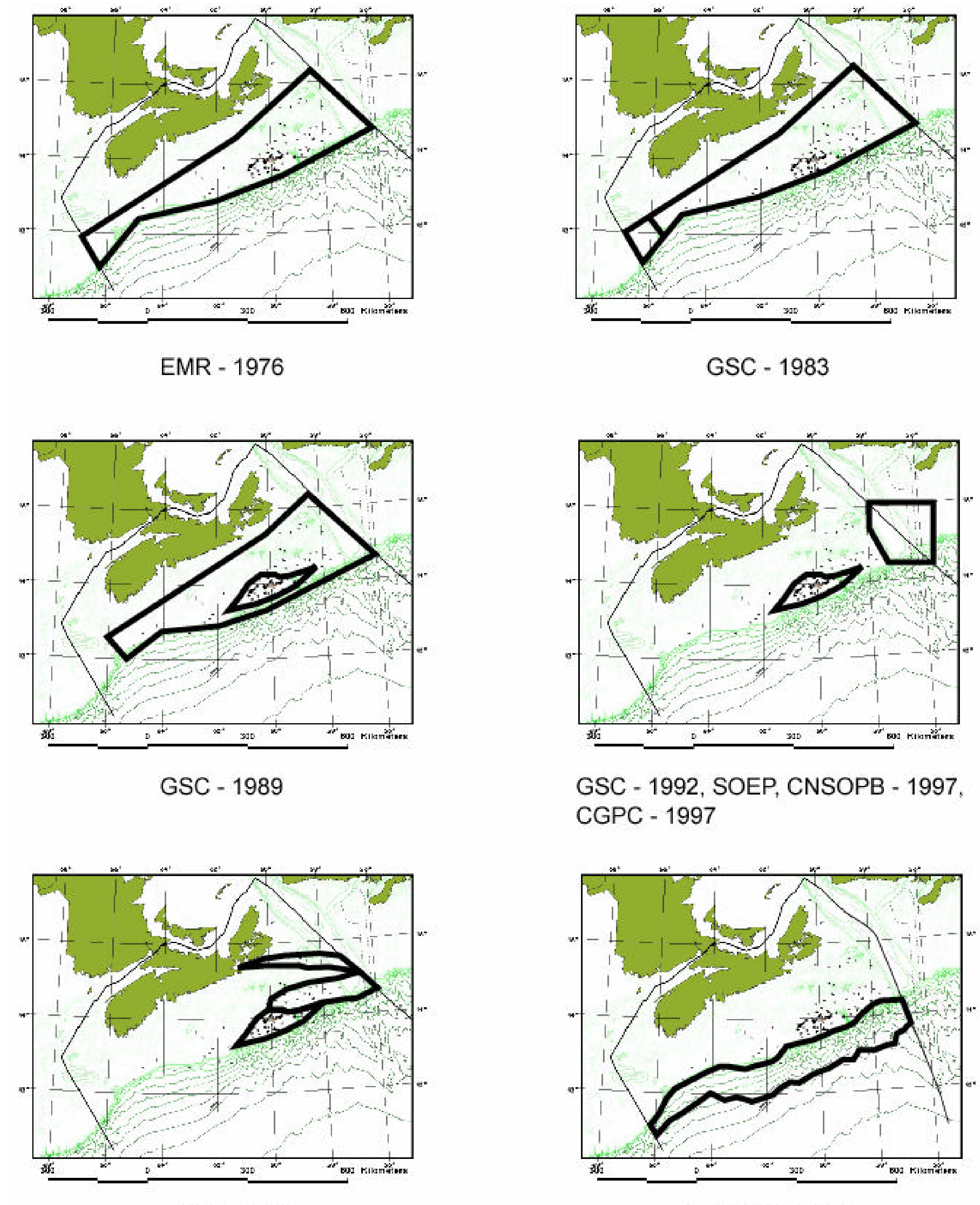


FIGURE 14

Maps of historical petroleum assessments, offshore Nova Scotia, 1976-2002

The GSC's report by Proctor et al. (1984) defined the physiographic Scotian Shelf to the 1500 m isobath. Discovery totals were listed as 3.9 Tcf and 90 MMB. The overall potential (including discoveries) was reported as 18 Tcf and 454 MMB (P50). In addition, the George's Bank was assessed separately at 5.3 Tcf and 1.1 BB. Previously, Nantais (1983) provided a detailed review of the petroleum systems of the Scotian Shelf, though he did not assess and generate potential hydrocarbon reserve and resource numbers.

The GSC 1983 report has been the benchmark assessment for the Scotian Shelf for the last 20 years and the 18 Tcf figure became a widely quoted number and rightly so. However, in light of the 42 wells drilled in the basin since their 1982 data cutoff, and the discovery of 4.1 Tcf gas and 91 MMB of oil, it became obvious that a new regional assessment was required.

In 1989 the GSC expanded the 1983 report by assessing the basin on the basis of play types. It determined that the overall gas number remained at 18 Tcf but with a significant increase of oil and condensate potential of slightly over a billion barrels. The population of anomalies for each play type was based on cumulative anomaly mapping from COGLA of data submitted by Industry over the years that entered the public realm.

The GSC later published a paper on the petroleum geology of the Laurentian Sub-basin (MacLean and Wade, 1992). This sub-basin lies to the northeast of the Sable Subbasin juxtaposed to the Scotian Shelf and according to the distribution of anomalies defined by the authors, about 25% of the potential 8.8 Tcf and 630 MMB were assumed to exist in Nova Scotia waters. However, with the recent inter-provincial boundary decision of March 2002, little of that potential now lies within the CNSOPB's jurisdiction.

4.2 CNSOPB and SOEP

In 1997, several publications addressed the discoveries in the Sable Island area. The Sable Offshore Energy Project (SOEP) consortium submitted their Sable Development Plan application and assigned a recoverable gas amount of 3 Tcf to the six fields; Venture, Thebaud, North Triumph (Tier 1) and Alma, South Venture and Glenelg (Tier 2). In March 1997, the Board published a technical report on all 22 discoveries that had been granted Significant Discovery status. They supported the aforementioned 3 Tcf amount for the six fields, and with new values for the remaining significant discoveries raised the cumulative total to 4.7 Tcf recoverable gas.

4.3 Canadian Gas Potential Committee (CGPC)

Also in 1997, the CGPC published a gas assessment for Canada but numbers for offshore Nova Scotia were limited to the Sable Subbasin. They used the discovery data from the Board (4.7 Tcf recoverable gas) and, for the first time, an *undiscovered potential* was calculated at 8.1 Tcf. The total for the Sable Subbasin was therefore noted as 12.8 Tcf.

The most recent publication is the CGPC's 2001 Report on the Gas Potential of Canada. In Eastern Canada, the Scotian Basin was addressed in its geological entirety that included offshore Nova Scotia and southeastern Newfoundland (Wade and MacLean, 1990). To cope with the lateral variations across the Scotian Basin, it was subdivided into ten geological entities of sub-basins or play areas. This analysis was the first attempt to assess the basin by its various components. A three-fold play category was employed; established or proven, conceptual (i.e. having sufficient drilling data to carry out an assessment) and conceptual (where only qualitative descriptions could be accomplished).

Once again, the only established play area that could be fully assessed was the Sable Subbasin (Figures 1, 14). An anomaly map released by the Nova Scotia Petroleum Directorate (1999: Sourced from original CNSOPB and COGLA compilations) was used to guide the assessment. The defined "Panuke Segment" of the Late Jurassic Abenaki Carbonate Bank Edge, although a proven play (EnCana press releases), could only be assigned a value for the one discovery since technical information was still confidential at that time. Finally, the conceptual plays were assessed with assigned geologic risk factors because the petroleum systems were unproven.

The results were 5.2 Tcf recoverable gas in the Sable Subbasin, plus an undiscovered recoverable potential of 4.8 Tcf for a combined total of 10.0 Tcf. The Panuke segment of the Late Jurassic Abenaki Carbonate Bank Edge was assigned 1.0 Tcf recoverable gas based on the Deep Panuke discovery. The Abenaki Subbasin and Orpheus Graben (Figure 1) were assessed at a mean risked gas-in-place of 7.1 Tcf and 1.3 Tcf respectively. Expressing the above in *risked* *mean recoverable* terms, the total was 16.5 Tcf gas.

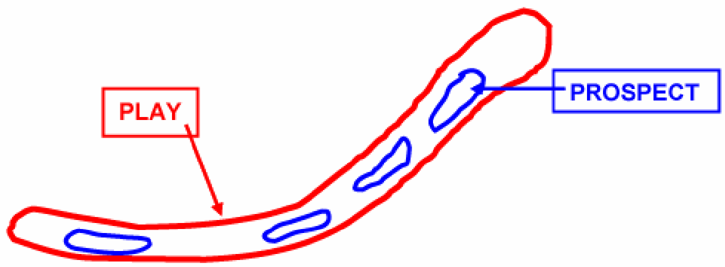
In summary, the historical assessments illustrate the region's robust but rather limited assessment history. However, over the years these assessments have steadily improved knowledge of the region's hydrocarbon endowment, and have laid the foundation upon which higher resource numbers will be forecast as more of the basin and its plays come under quantitative analysis.

4.4 Geologic Risking

Geologic risking is a critical factor in resource assessments because of its subjectivity and the inherent difficulties in quantifying the various geologic components. For conceptual plays, geologic risking must be applied to both the play and prospect. A prospect is a singular feature or structure believed to trap hydrocarbons, whereas a play is the regional area of similar geological conditions that embraces a number of related prospects (Figure 15).

Prospect risk can be thought of as the expected drilling success rate for a specific play type. Play risk can be considered as the chance of the play itself actually existing. In proven plays, there still remains a prospect risk, but the play risk will be zero since it has been proven to exist via previous drilling and discoveries. Thus, an unsuccessful prospect does not end the play's potential, but if the occurrence of any one of the play's geological factors is zero, then all prospects in that play will be dry.

Play and prospect risking is hierarchical and inter-related but addresses different factors (Figure 15). At the lower prospect level, the risk of a prospect to have the *necessary reservoir volume factors* (quantitative) is estimated. At the higher play level, a risk factor is determined for the *adequacy of geological factors* (qualitative) actually occurring (White, 1993). The application of risk for the Nova Scotia deep-water slope is defined in Chapter 7.



Prospect Level: Chance of achieving reservoir volume factors (quantity)

	Example
Area	1.0
Net Pay	0.8
Porosity	0.6
Saturation	0.6
Formation Volume Factor	1.0
Recovery factor	1.0
Total	28%

Play Level: Chance of adequacy of geological factors (quality)

	Example
Source (Maturation, Migration, Preservation)	0.7
Reservoir Quality	0.5
Trap (Timing, Seal)	0.7
Total	25%

FIGURE 15

Play and Prospect Geologic Risk.

CHAPTER 5

DEEP-WATER SLOPE – BASIN EVALUATION

The deep-water Slope area within Nova Scotia's jurisdiction extends 850 km from the American border in the southwest to the Newfoundland border in the northeast. With an overall area of close to 80,000 km^2, the Slope region accounts for approximately 40% of Nova Scotia's offshore portion of the Scotian Basin. The water depths range from 200 to 4000 metres and contain a significant number of submarine canyons.

5.1 Geologic Overview

The present-day deep-water Slope most likely lies above a rifted Middle to Late Triassic succession, in-filled with syn-rift fluvial-lacustrine facies. Initial Early Jurassic (Hettangian) marine flooding of this terrane resulted in the deposition of thick Argo Formation salt deposits. The eastern boundary of this rift basin is defined by the East Coast Magnetic Anomaly (ECMA); a narrow linear highly magnetic trend of interpreted subareal extrusive volcanism of approximate Bajocian age (ca. 175 Mya) which is believed to mark the continental-oceanic crustal boundary (Dehler and Keen, 2001, 2002; Dehler, pers. com., 2002). During the drift phase, the Sable Delta system prograded seaward and built a thick fluvial-deltaic to strandline prism, the Slope was the site of distal fine-grained sediment deposition punctuated by periodic sea level falls. Resultant gravity slides and turbidite flows carried coarse-grained sediments into very deep-water and deposited them over and around the undulating topography created by the mobile salt substrate. The Slope area has been modified by erosion during lowstands of sea level especially in the Tertiary, and even quite recently (Holocene) major canyons like The Gully were carved into the Slope.

5.2 Drilling Results to Date:

There were five deep-water wells drilled prior to 1987 (i.e. beyond the present-day continental shelf) off Nova Scotia (Figures 1, 2). Two of those were drilled on the Middle-Late Jurassic age Abenaki carbonate bank trend; PetroCanada-Texaco et al. Albatross B-13, and Chevron-PetroCanada-Shell Acadia K-62. The other three were drilled for deep-water turbidite targets, these being:

Shell et al. Shubenacadie H-100 (1982)
WD: 1477 m
FTD: 4200 m TVD
Upper slope fan encountered but no reservoir grade clastics found.

PetroCanada et al. Shelburne G-29 (1985)
WD: 1154 m
FTD: 4005 m TVD
Drilled on the crest of a deep-seated feature, probable salt-related. No reservoirs discovered.

Shell et al. Tantallon M-41 (1986)
WD: 1566 m
FTD: 5602 m TVD
Upper slope fan target in roll-over anticline. No reservoirs discovered.

(Sources: Public well files at CNSOPB Archives, and MacLean and Wade, 1993).

Total sub-mud penetrations for G-29 and H-100 were about 3000 m with targets of North Sea type slope turbidite fans. The M-41 well targeted a structured feature and drilled about 4000 m sub-mud including about 2000 m of Cretaceous age Verrill Canyon Fm. shales. Figure 16 shows the depth, age and lithologies penetrated. No hydrocarbon shows were encountered and there was a distinct lack of coarse clastics. Hence these three first wells represented the first tentative scratches of a vast Slope area.

At the time of writing (July 2002), two new exploration wells were underway on the slope. Marathon *et al* Annapolis B-24 was spudded in late December 2001 in 1762 m of water using the drillship *West Navion*. According to press releases gas was encountered in a relatively shallow section and operations were halted when severe mechanical difficulties occurred. The B-24 location was fully abandoned and in April 2002 a new well (G-24) spudded some 500 m away. Concurrently, the Chevron *et al.* Newburn H-23 was spudded in May 2002 in 980 m of water with the drillship *Deep-water Millennium* drillship. As of July 11 the operator was drilling at 5324 m TVD.

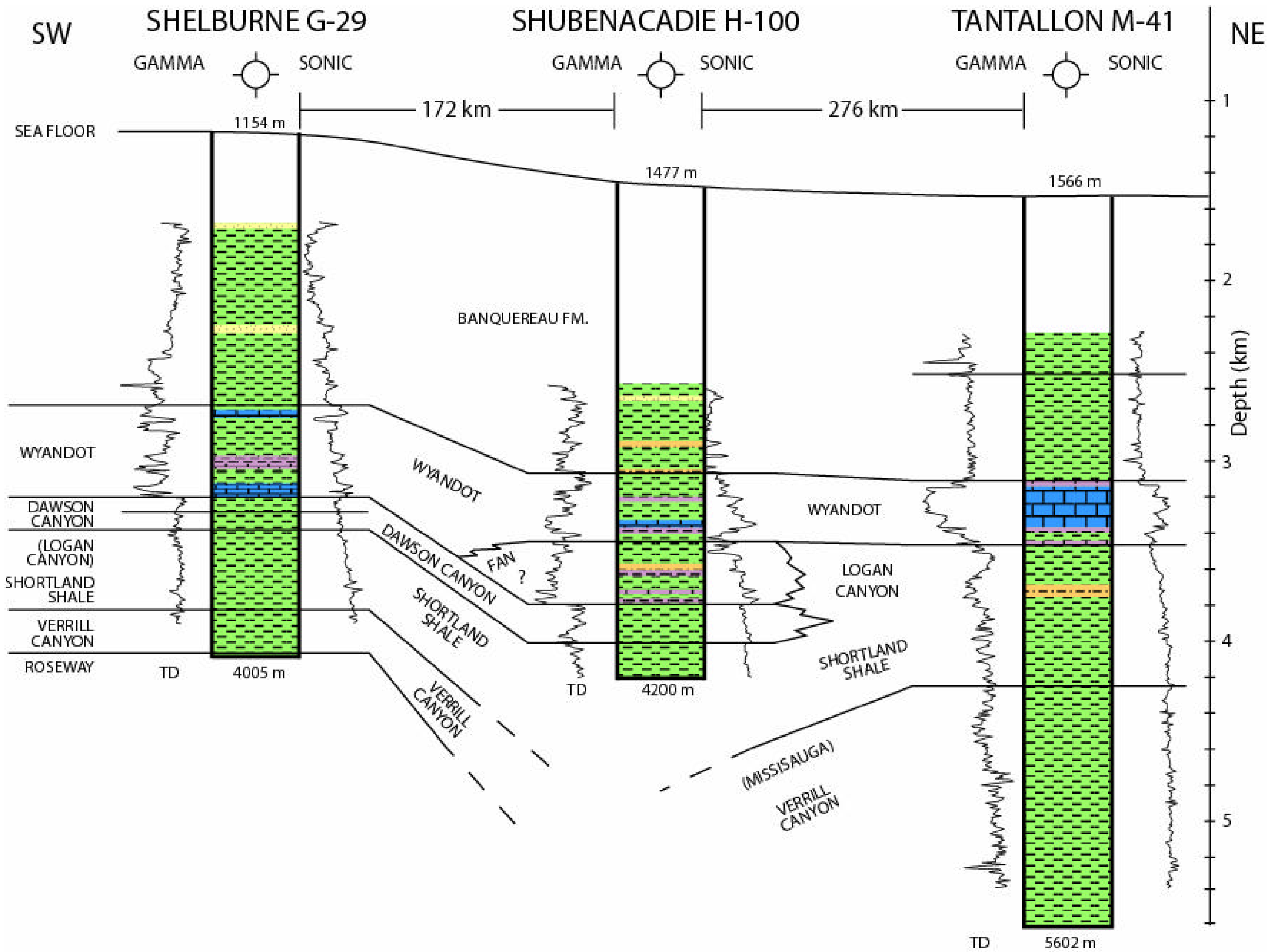


FIGURE 16

Southwest-Northeast strike cross-section of slope deep-water wells drilled prior to 1987 targeting turbidite-related plays. Note that there is an overall lack of coarse (sand) clastics at these locations. See Figure 2 for well locations.

5.3 Database

A major challenge was to correlate stratigraphy from the shelf across the shelf break and into the Slope. From the seaward side, data has been gathered from the DSDP, ODP, Lithoprobe, etc. Therefore, armed with the best correlations from the north and the south, the Slope area can be at least inferred with some sense of reasonableness. Little useful industry reconnaissance seismic data was shot along the slope prior to the late 1990s. It was generally old (early 1970s), very widely-spaced (100-150 km), of limited coverage (~2000 total line km), of variable quality and available as paper copies only.

The seismic dataset used in this study is shown in Figure 17 and consists of the large TGS-NOPEC dataset in blue, with lines from two smaller and older datasets that were acquired for shelf to deep-ocean stratigraphic correlations and scientific deep crustal studies (e.g. GSC, Lithoprobe, Lamont-Doherty).

The TGS-NOPEC survey is a comprehensive dataset of approximately 30,000 km of 80-fold data recorded from 1998-1999 and has equal line spacing (6 km) in both dip and strike directions. It was designed to address the deep-water slope but covers portions of the carbonate bank edge and the present-day shelf. This survey supercedes the venerable "PAREX" survey (SOQUIP, 1983) which focused on the Shelf and upper Slope.

Upon request and within its authority, the CNSOPB requested and received the digital dataset from TGS-NOPEC which was then loaded on a Sun™ workstation with the GeoQuest™ interpretation package. The data quality was very good above the salt and in non-salt areas. Where salt was present, the expected raypath distortion was profound and not fully compensated for by the post-stack time-domain migration. Thus, data quality and the inability to image the sub-salt geology were acknowledged as assessment risk factors.

Selected lines of the 1988 GSC Lithoprobe deep crustal seismic dataset consisted of 700 km of 60-fold data. Digital data was kindly supplied by the GSC, loaded into the workstation, and incorporated in the interpretation. The 1972 GSI dataset (GSI, 1972) consisted of almost 11,000 of 24-fold data and was available only in paper form. Nevertheless, 2000 km this data covered the assessment area and was critical to tie deep-ocean stratigraphy from the DSDP sites.

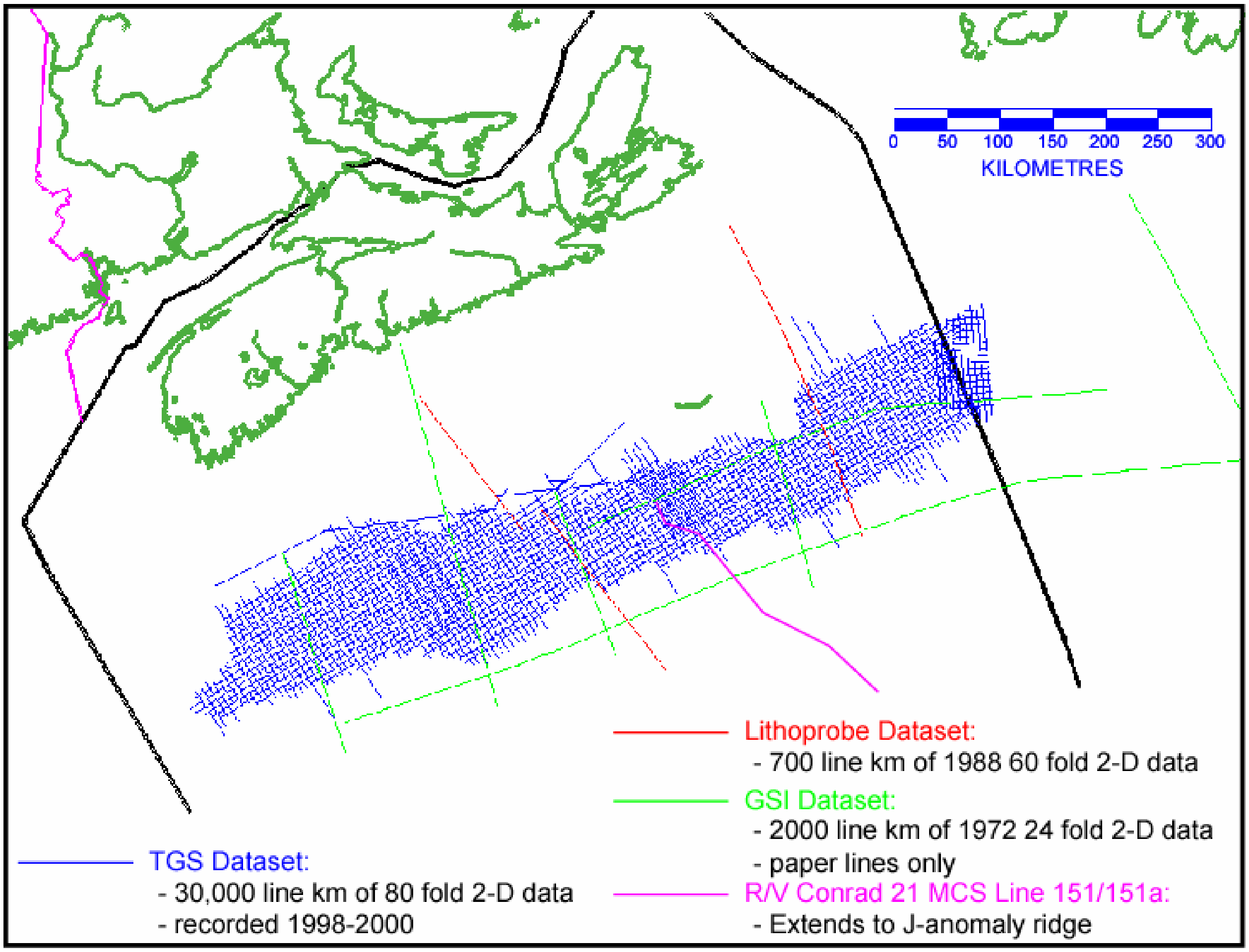


FIGURE 17

Seismic dataset used in the CNSOPB deep-water assessment. The TGS survey (blue) was the cornerstone of this study. The Lithoprobe data (red) and GSI data (green) provided critical seismic ties to the deep ocean stratigraphy including the DSDP sites.

5.4 Stratigraphic Correlations

Well ties on the shelf and regional seismic profiles have permitted workers to assemble the slope stratigraphic framework over the past decades: e.g. Swift (1987), Ebinger and Tucholke, (1988), Wade et al. (1995) and others. Newer (late 1980s), high quality deep crustal seismic data shot and interpreted by the Geological Survey of Canada (GSC) was found to be very useful and integrated into the study, (Keen et al., 1991).

Based on interpretations of the deep-water stratigraphy in the Sohm Basin (deep-water abyssal plain) by previous workers and results from Deep Sea Drilling Project (DSDP) well bores, seismic reflectors and sequences were correlated on paper copies of selected lines from the old 1970's slope seismic data. A series of long, scientific crustal reflection seismic lines along the eastern North American margin provided important stratigraphic links to well-studied deep ocean bore holes with one line (Conrad C21 Line 152/152A) tying into two of the slope lines. These were in turn linked to the newer GSC Lithoprobe seismic profiles.

From these data and interpretations, a stratigraphic column was created for this study that included details on age, reflection characteristics, sequence characteristics and probable lithologies, facies, unconformities for all recognized deep-water seismic reflections (as defined by earlier workers) and augmented with those noted by this study. With this framework, easily discernible seismic megasequences were correlated across the slope region. But where salt features were present, these offered the single greatest obstacle to extending correlations and thus numerous judgments were employed to generate useful regional maps.

5.5 Seismic Interpretation

The GSC had earlier mapped a regional distribution of salt features believed to be mostly diapiric and rooted to the allochthonous 'mother salt' ridge complexes (Wade and MacLean, 1990; and Wade, 2000) Their distribution was based on interpreting individual, widely-spaced dip-oriented seismic lines with little strike control. Nevertheless, their mapping has proved to be very insightful and revealing in the qualitative distribution of a large population of features. The apparent lack of diapiric features east of 58 degrees longitude was thought to be more a function of data control than geology.

Marker DSDP	Marker CNSOPB
--	Seafloor, Present Day
L	Base Pleistocene/Upper Pliocene
A^u	Mid-Tertiary (Oligocene) Unconformity
A*	Near Top Cretaceous, Wyandot Equivalent
ß	Mid-Cretaceous 'O' Marker Equivalent
--	Top Salt
--	Base Salt
J1	Top Jurassic
J2	Mid-Jurassic
BU	Early Jurassic Breakup Unconformity
--	Rifted Triassic
B	Basement

FIGURE 18

A comparison of stratigraphic markers between the Board's seismic interpretation and the commonly held nomenclature from the DSDP as reported in Ebinger and Tucholke (1988) amongst others Several Tertiary markers discussed by the above authors are not included here.

The stratigraphic megasequences employed by the Board and extrapolated both shelfward and seaward are interrupted by the highly deformed salt-structured zone which precisely defines the Slope area under study. The most critical task therefore was to interpret the top and base of the salt features and distinguish between salt and deformed sediments. An iterative loop-tying procedure was used with reference to seismic examples published in the literature from other salt basins in the world. Nonetheless, in many instances the 6 X 6 km seismic grid exceeded the dimensions of the salt features.

The Gulf of Mexico's Louann Salt is Middle Jurassic in age as compared to the Argo Salt in the Scotian Basin which is of Latest Triassic to Early Jurassic / Rhaetian to Hettangian age (references in Williams et al., 1985). The present-day depiction (lower panel) in the basin-ward direction is very similar to the Scotian Slope.

In both the Gulf and offshore Nova Scotia, early interpretations considered the salt to be deeply rooted to its original strata of origin (autochthonous). Through drilling in the Gulf and improved seismic surveys in both areas it has been demonstrated that the majority of the salt is non-rooted (allochthonous) and highly mobile both vertically and laterally giving rise to all sizes and shapes.

With salt diapirs feeding ramp-like canopies into the shallow section, younger strata are now roofed over by impermeable salt. In this structural setting, there thus exists a large potential exploration for sub-salt hydrocarbon plays, and in the in the Gulf of Mexico it is a highly successful play. The Gulf of Mexico sub-salt exploration history is well described by Bascle et al. (2001) and Lori et al. (2001).

Over the past 200 million years, the Argo Salt has responded spectacularly to down-dip gravity sliding caused by sediment loading from the prograding shelf and especially the Sable Delta complex. As the salt moves, its buoyancy requires it to mobilize into isolated bodies and sheets that rise through the overlying strata as diapirs and/or tabular sheets. As sedimentation rates accelerate, these salt bodies respond by moving laterally upward and seaward. All shapes and sizes of salt and related features have been encountered on the Scotian Slope and are recognised as potential traps and plays.

The "Top Salt" seismic reflector consists of the top of salt and the correlative inter-salt welds. Although this surface has a certain amount of confidence of capturing the salt geomorphology, it remains highly interpretative. Definition of the "Base Salt" reflectors is even more speculative but there is sufficient evidence to show the overall allochthonous nature of the salt.

Three regional seismic profiles are presented to illustrate the correlations across the slope (Figures 20, 21,22). The scaling factors are close but for accurate measurement each black tick mark on the horizontal axes represents a seismic cross-line approximately every 6 km. The vertical axes represent depth in time and are in two-way travel time (seconds). On each of the seismic lines, the interpreted salt interval lies between the green and black markers and is shaded in light green.

The seismic profile of Figure 20 is about 120 km long and crosses the slope in a dip direction from the northwest to the southeast. The most obvious aspect of this section is the apparent autochthonous salt withdrawal slumping and the down-slope diapiric accumulation. The diapirs stabilized by mid-Tertiary time. However the lowest yellow reflector is tied into the deep-ocean seismic stratigraphic framework and is the J2 or Mid-Jurassic marker and close to the Early Jurassic breakup unconformity, (Figure 3). This means the Late Triassic Argo salt predates the yellow horizon and had to be mobilized from those depths.

This salt-sediment juxtaposition is not unusual. For example, the GOM Louann Salt has apparently undergone several stages of sediment loading, salt evacuation, and mobilization into piercements followed by coalescence into a canopy. Subsequent remobilizations followed as it progressively seeks density equilibrium with the overlying sedimentary column (Figure 19).

The seismic profile Figure 21 crosses a salt canopy complex extending seaward well beyond the salt limit. This line is tied to the deep ocean stratigraphic framework as previously described. In the undisturbed region, the Top Jurassic J1 (light blue) and Middle Jurassic J2 (lowest yellow) horizons are well documented. The rifted surface (Break-Up Unconformity) is clearly seen (red marker) and even a basement reflector may be present (brown marker). The allochthonous salt is observed to have risen 5-6,000 m from its earliest Jurassic origins upward to the Tertiary level and is about 4000 m higher in the section than the previous example. The sub-salt seismic imaging of the Cretaceous section is very poor and becomes part of the geologic risking exercise. The potential traps in the supra-salt section are a direct result of salt movement.

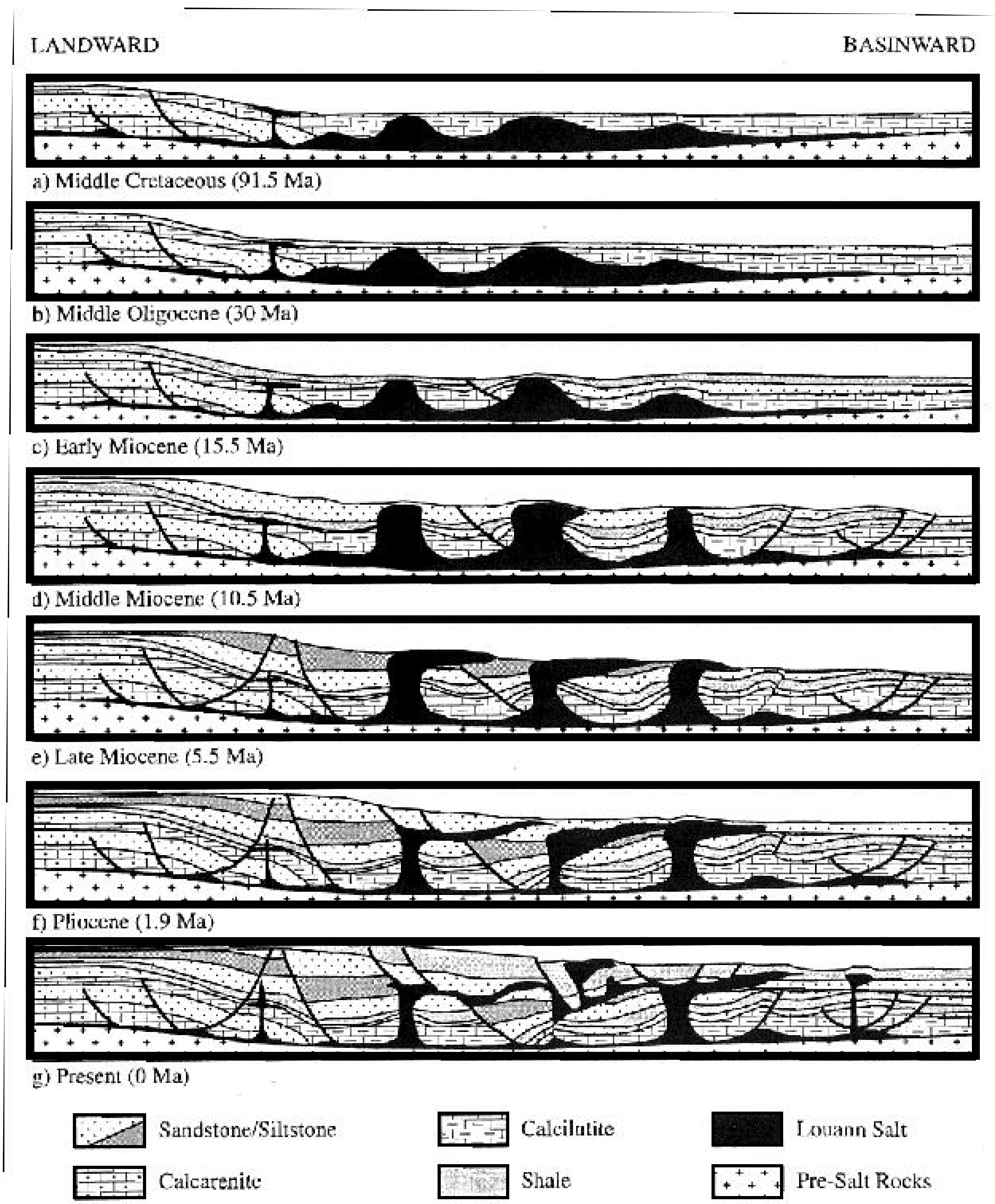


FIGURE 19

A time series of schematic cross-sections shows the mobility of the Louann Salt in the Gulf of Mexico. (from Webster, 1995) The complexities of the present-day section can be seen in seismic profiles along the Scotian Slope.

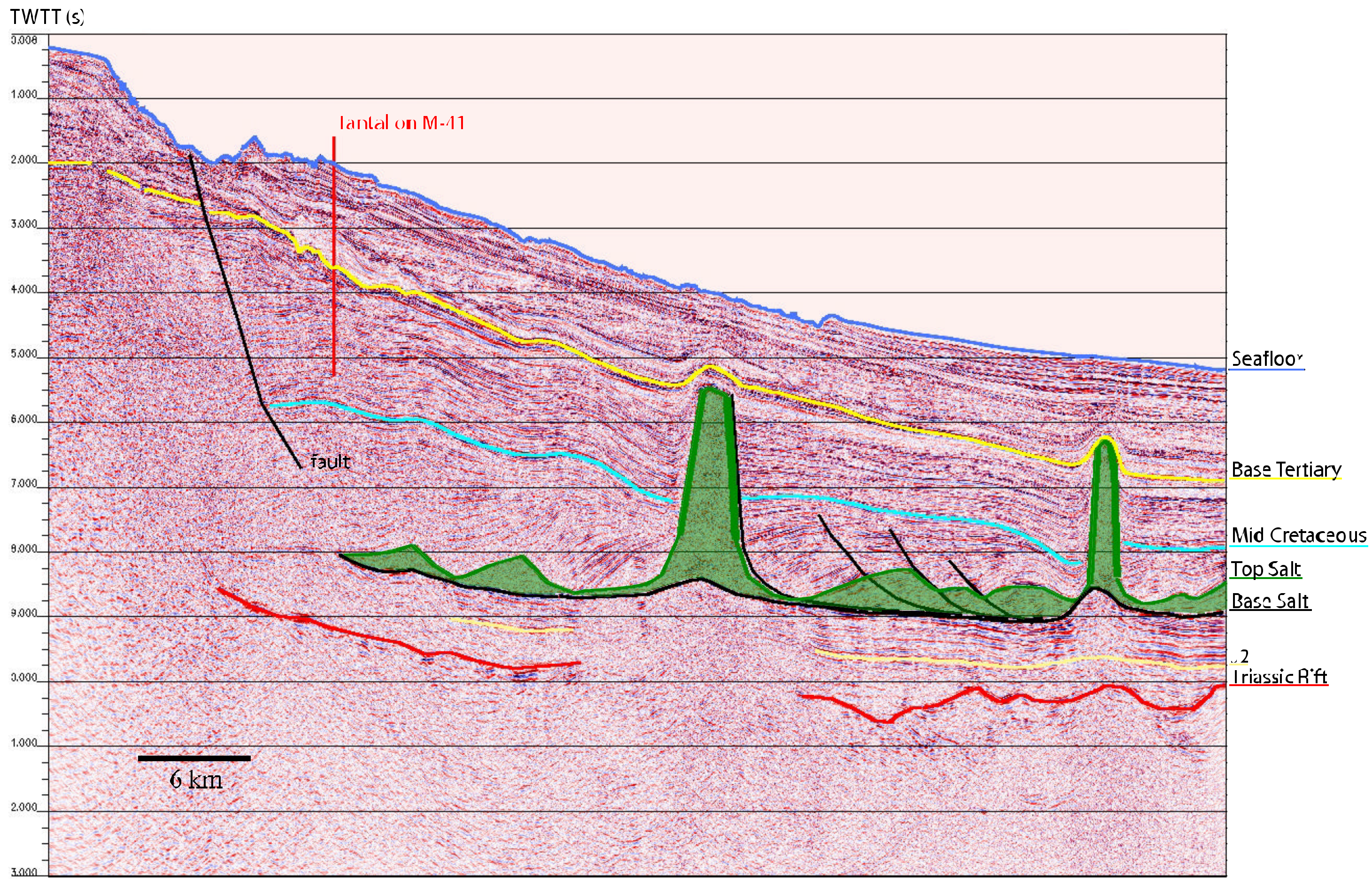


FIGURE 20

A NW-SE regional seismic dip profile from the eastern part of the study area near Geochem Site #1. Salt diapirism is clearly load-driven as evidenced by the rotated fault blocks exhibiting wedge-shaped profiles of interpreted Early Cretaceous age (Missisauga Fm) and the well defined Base Salt weld detachment “roho” reflections approximating the Top Jurassic reflector, J1. These features compare well with similar examples presented in Diegel et al. (1995) and Schuster, (1995). The salt may have been extruded onto the ancient Early Jurassic seafloor in the form of salt “glacier” sheet prior to rapid loading of siliciclastics from the Jurassic-Cretaceous Sable Delta. Note that the flat-lying undisturbed underlying Middle (yellow) to Late Jurassic a strata (MicMac and Abenaki Fm. equivalents) under the inter-salt areas is reasonably well defined compared to the lack of definition beneath the salt diapirs. The Early Jurassic Break-Up Unconformity is defined as the red horizon.

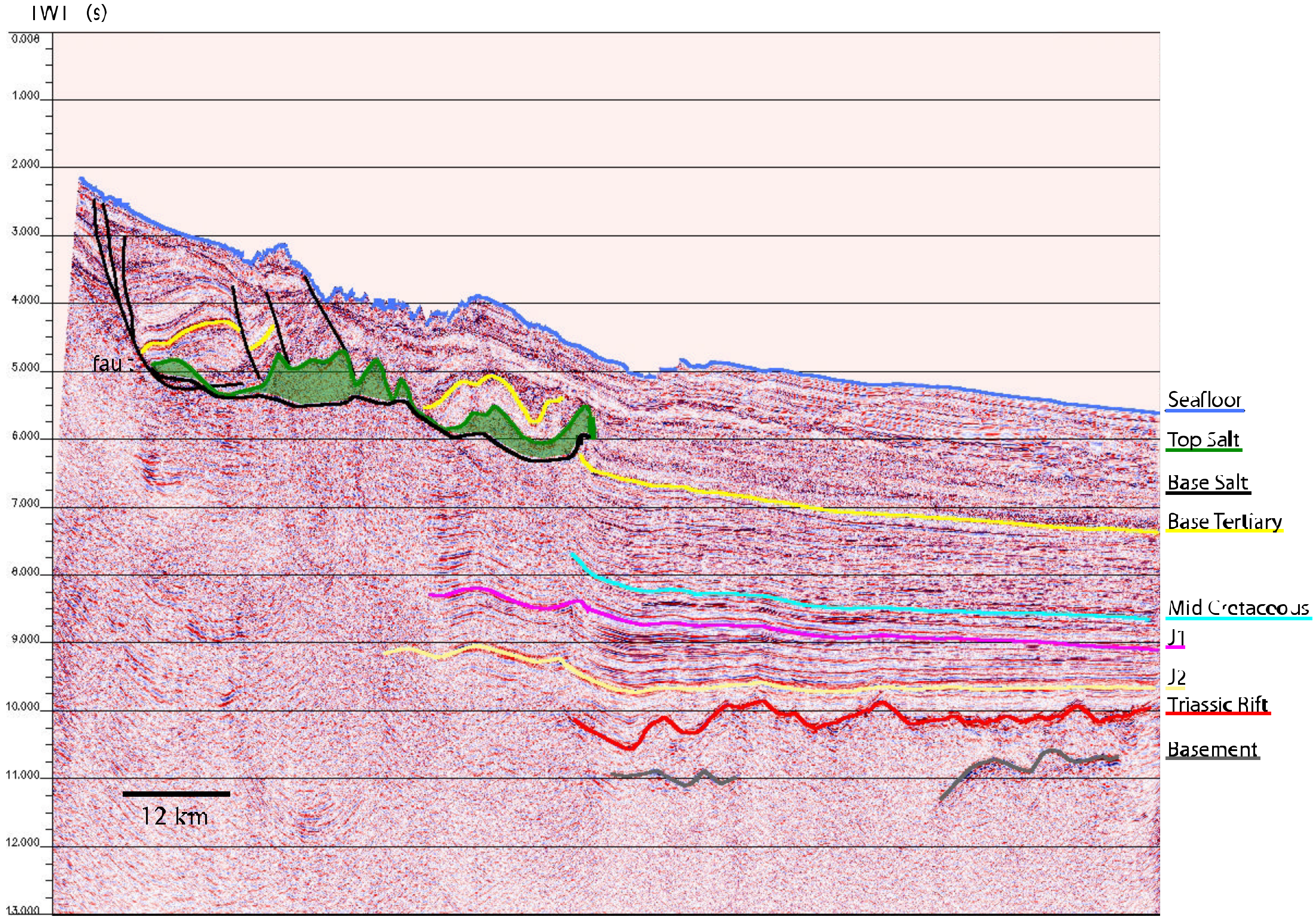


FIGURE 21

A NW-SE regional dip seismic profile from the east-central portion of the Slope. The line traverses the salt canopy (green) intruded into latest Cretaceous sediments and a non-salt section seaward. Note the salt thrust at the leading edge of the canopy complex intruding into Tertiary age sediments. All mapped reflections, from the water bottom to Late Triassic / basement, are well imaged in the non-salt section. The lack of seismic imaging beneath the salt is profound and impedes the landward projection and interpretation of the mapped reflectors.

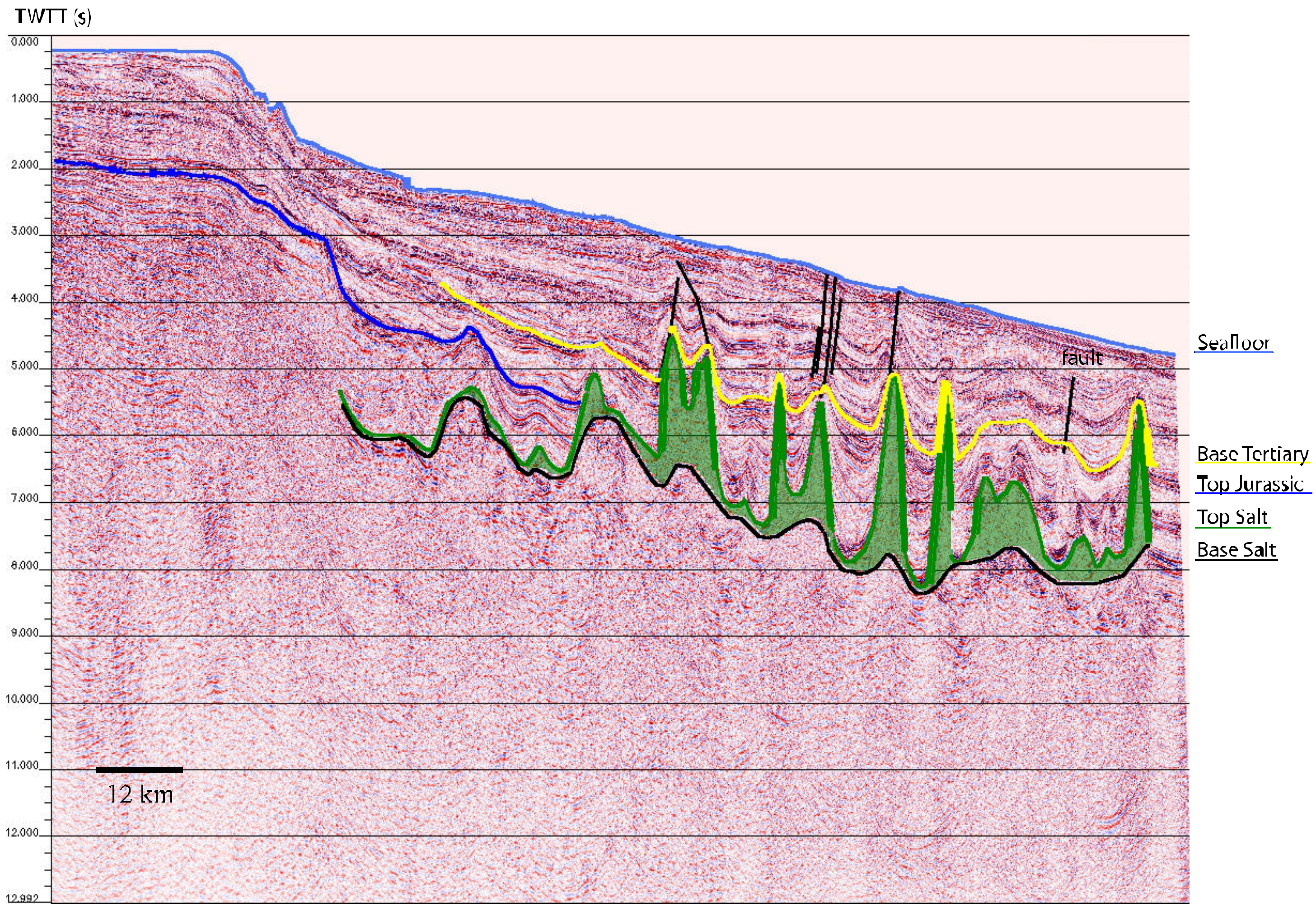


FIGURE 22

A NW-SE regional dip seismic profile across a diapiric zone in the west-central part of the Slope. This example well displays the variety of structural styles and features related to intense salt diapirism. The diapirs have influenced sediments from Middle Jurassic to Late Tertiary in age revealing that they were very long lived (ca. 160 million year time range). Related faults appear to extend up to the present day sea floor. Potential hydrocarbon traps include mini-basin basin-floor turbidite fans, fan pinch-outs against salt flanks, and flank and crest structural closures. Older strata below the regional salt weld are virtually undefined due to the influence of salt.

Figure 22 crosses the entire salt diapir zone terminating just beyond the seaward limit of salt. This limit is firmly established by the remainder of the survey and several deep ocean scientific profiles that were acquired to investigate the continental/oceanic boundary. This line shows the high frequency of salt features with intervening mini-basins of Cretaceous and Tertiary age. The sub-salt imaging is very poor and the geologic section cannot be determined.

In summary, these three profiles reveal the great diversity of structural styles, salt features and stratigraphy along the length of the deep-water Slope. This variability between areas are all reflected in the subsequent numerical assessment.

5.6 Mapping

The most definitive structure map created is the present-day seafloor (Figure 23) which itself is a geologic surface. The 3-D view is from the southeast looking towards Nova Scotia with Sable Island as a reference point. The vertical drop from shelf to abyssal depth is 4 km over a horizontal distance of 100 km, resulting in an actual Slope of 1:25 but vertical exaggeration is applied to accentuate the surface. The right or eastern half of the Slope is cut by a large number of submarine canyons as opposed to the westerly half that is relatively smooth. The Gully, immediately east of Sable Is., formed about 12,000 years ago is the dominant present-day canyon system. Westerly, the Slope relief is muted by Late Tertiary to Recent deposition. The shelf break is an irregular boundary with arcuate and segmented lengths.

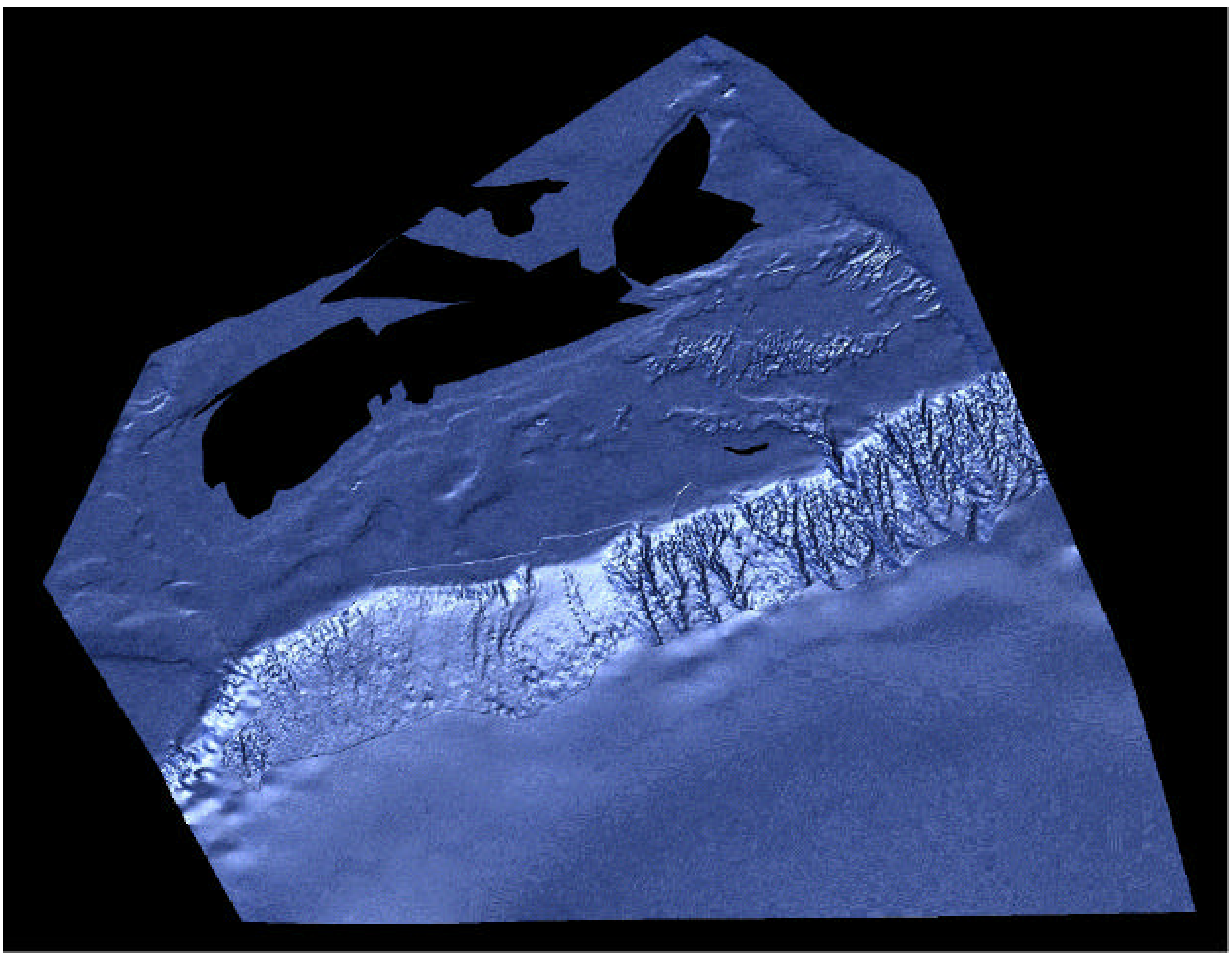


FIGURE 23

Bathymetric map of present-day seafloor with exaggerated vertical scale.

Figure 24 is a 3-D perspective of the top of the salt and/or correlative salt weld in the subsurface beneath the present-day slope. This is a highly exaggerated perspective but shows the complexity of an 850 km long continental slope underlain by a mobile salt substrate. The initial impression is of a very complex surface with changing character along the Slope. The most attractive play types associated with salt generally lie between the salt features as mini-basin floors and flanks. Salt crests and sub-salt plays are also present.

Figure 25 is a combination of three mapped seismic reflection surfaces that together illustrate more aspects of the basin. The basin-bounding Middle to Late Jurassic Abenaki Fm. reef complex (blue) is juxtaposed with the Base Tertiary succession (light yellow to red) and the piercing Argo Fm. salt diapirs (green). Inter-salt areas are filled with mostly Cretaceous-age sediments, many of which also contain Early Tertiary strata. Few of the diapirs reach the present-day seafloor. From the southwest, there appears a landward re-entrant of the salt features followed by a seaward bulge in a long arcuate trend, a smaller area mostly filled in then an area apparently absent of salt and finally ending in another diapiric area. It is long believed that deep crustal faults, related to and/or projected from oceanic transforms, have had a profound influence of the creation of the various subbasins on the shelf and slope, subsequent depositional histories and distribution of petroleum systems (Klitgord and Shouten, 1986; Welsink et al., 1990).

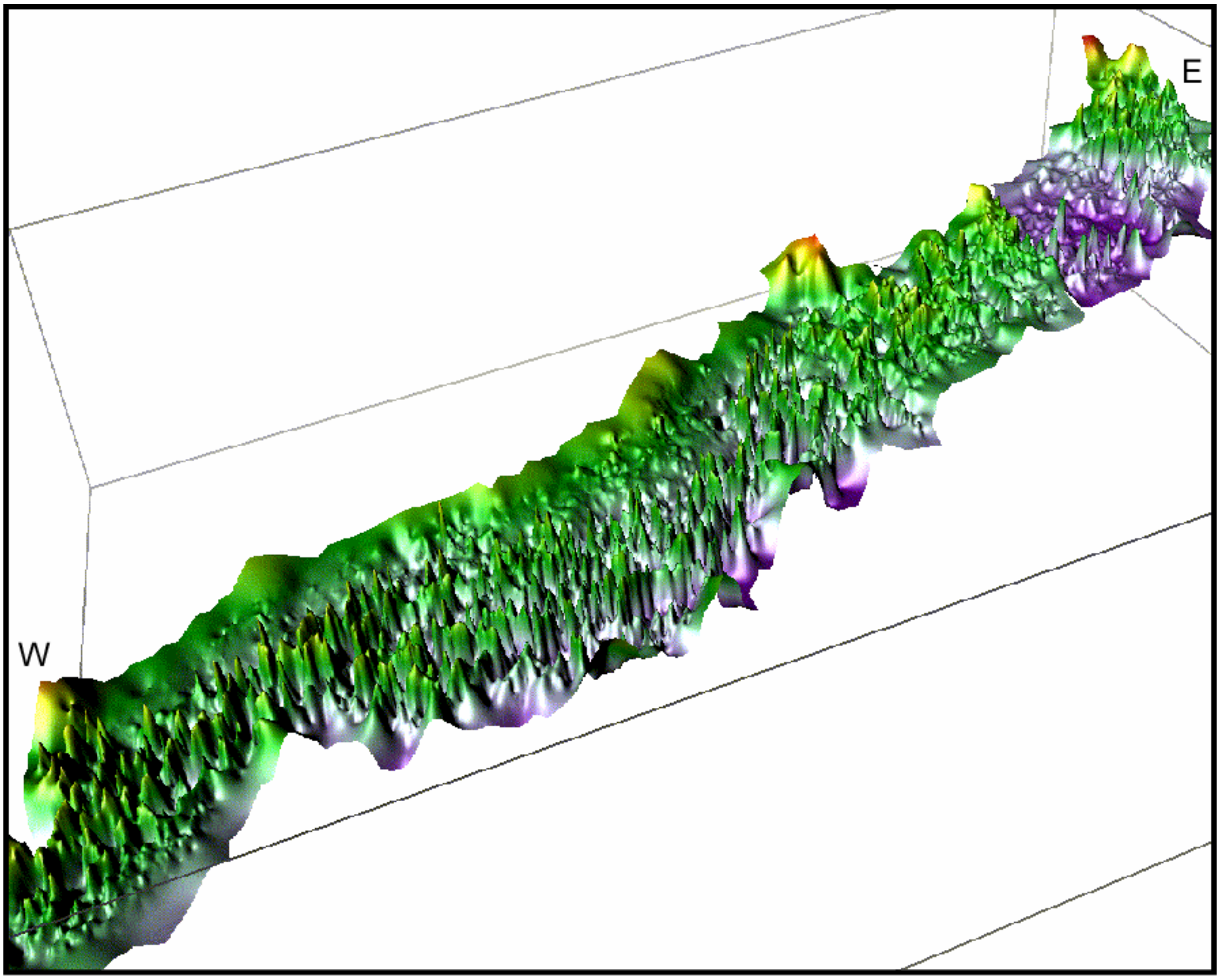


FIGURE 24

3-D perspective of the Top Salt seismic surface viewed from the southwest. The vertical exaggeration makes the salt features look erroneously like spires or pinnacles.

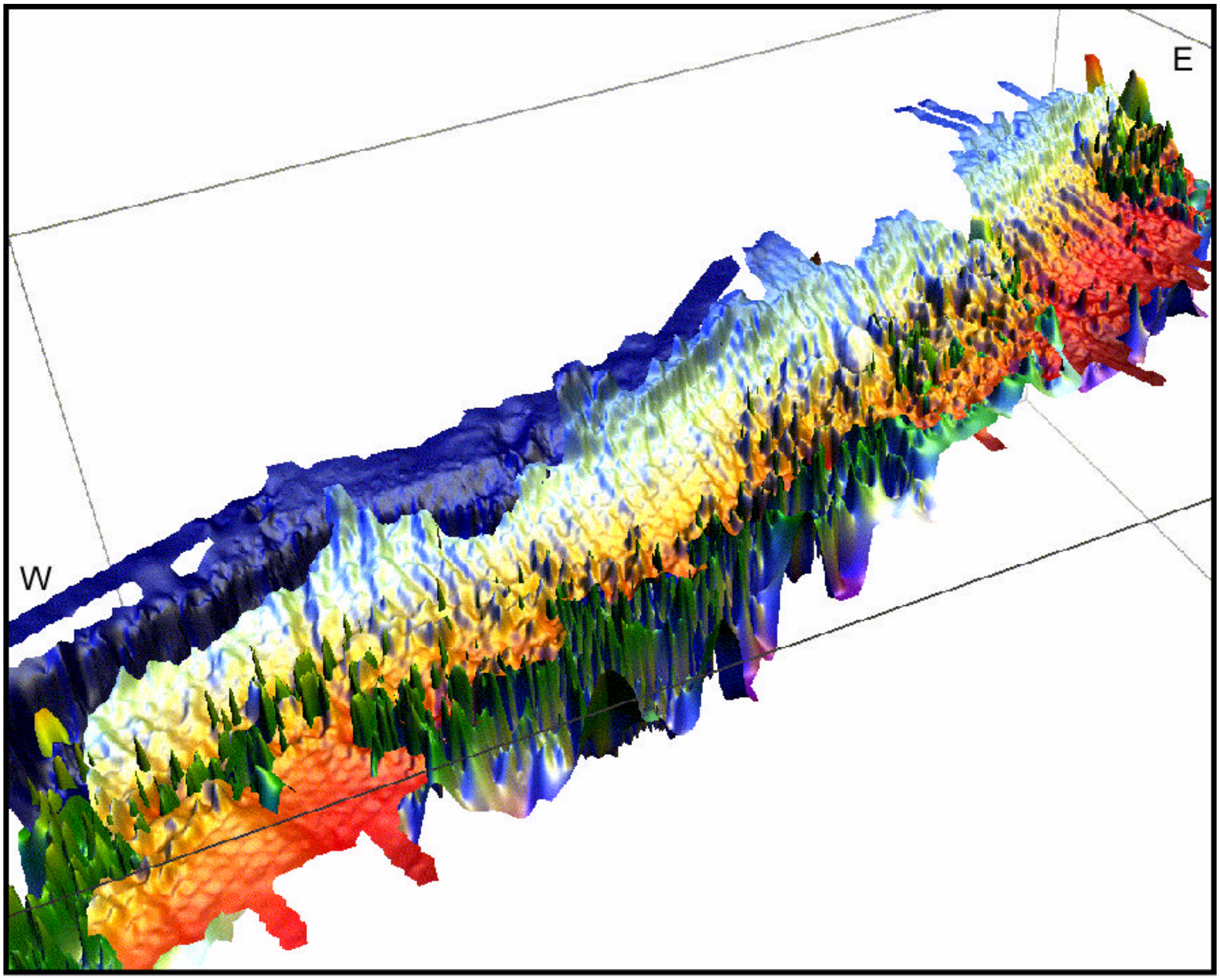


FIGURE 25

3D perspective view from the southwest of the Base Tertiary surface (multihued) draped over the Top Salt (green) and the Jurassic Bank (blue) surfaces.

Figure 26 represents the same surface as Figure 25 but the view has been rotated to the northeast to accentuate the varying nature of the salt features. Of particular note is the northeast area of salt withdrawal or removal.

5.7 Play Types and Seismic Examples

The play types observed in the Scotian Slope are typical of a passive margin modified by later salt tectonics driven by sediment loading over geologic time. Figure 27 is a schematic cross-section illustrating the different play types anticipated to occur along the Scotian Slope. The plays will be supra-salt, inter-salt or sub-salt plus slope fans, large folds, anticlines and syn-rift possibilities. The structural geometry of perhaps half the geologic section can be mapped directly. Due to masking by the salt, sub-salt and syn-rift plays are more conceptual but are expected to occur. Similarly, the presence of source and reservoir, although fully expected to some degree, can only be predicted by analogy to other related basins in the world. Note that all the plays require deep-water turbidite sands for their reservoir except the sub-salt and syn-rift plays. The Slope fan and fold/anticline plays are invariably salt-related to some extent.

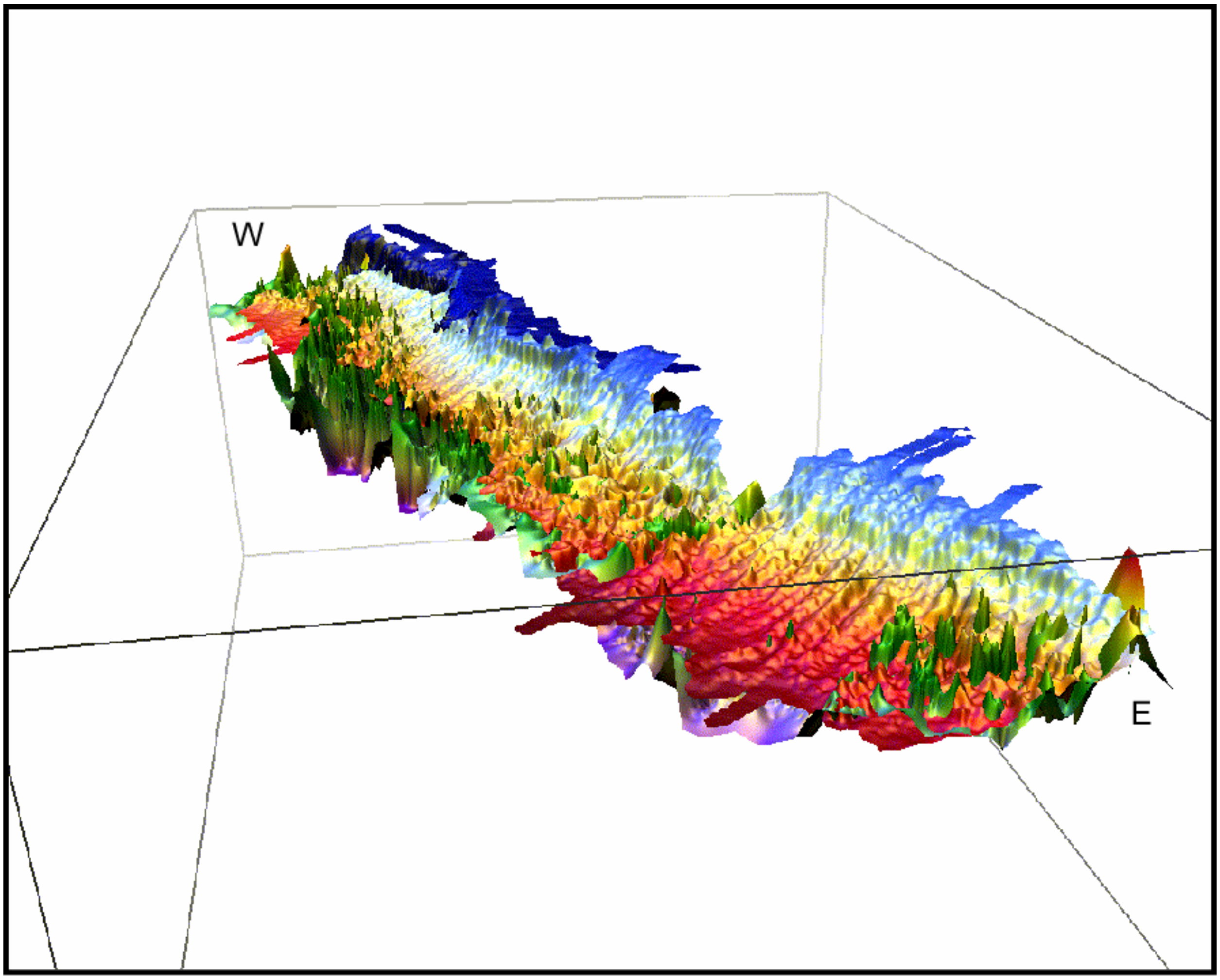


FIGURE 26

3D perspective view from the northeast of the Base Tertiary surface (multihued) draped over the Top Salt (green) and the Jurassic Bank (blue) surfaces. Note that the eastern portion of the Slope exhibits little evidence of salt features, with those few that are present existing as isolated diapirs that rarely penetrate into the Tertiary strata.

Examples of the various play types interpreted to exist on the Scotian Slope are illustrated in the following seismic examples from the TGS-NOPEC dataset. Excellent examples of identical salt features and structures from other global salt basins are presented in the many papers of the AAPG Memoir on salt tectonics edited by Jackson et al. (1995). For the following figures, in addition to the horizontal scale bar (kilometers), the line-crossing tick marks at the top of each figure are about 6 km apart. The vertical axis is presented in two-way travel time at one-second intervals.

The unstructured mini-basin (Figure 28), shown in this example, lies between two salt features (green) about 8 km apart in the western portion of the Slope. The Tertiary fill extends to the yellow marker about 5.5 seconds or 3000 m in thickness. Above and below this marker are numerous high-amplitude reflectors some of which exhibit an irregular surface. The targets are turbidite fans on the floors and flanks of the mini-basin, with excellent comparative seismic profiles of salt structures and various play types from the GOM published by Weimer et al. (1998a), Weimer and Slatt (1999, Figure 8) and Booth et al. (2000, Figure 3).

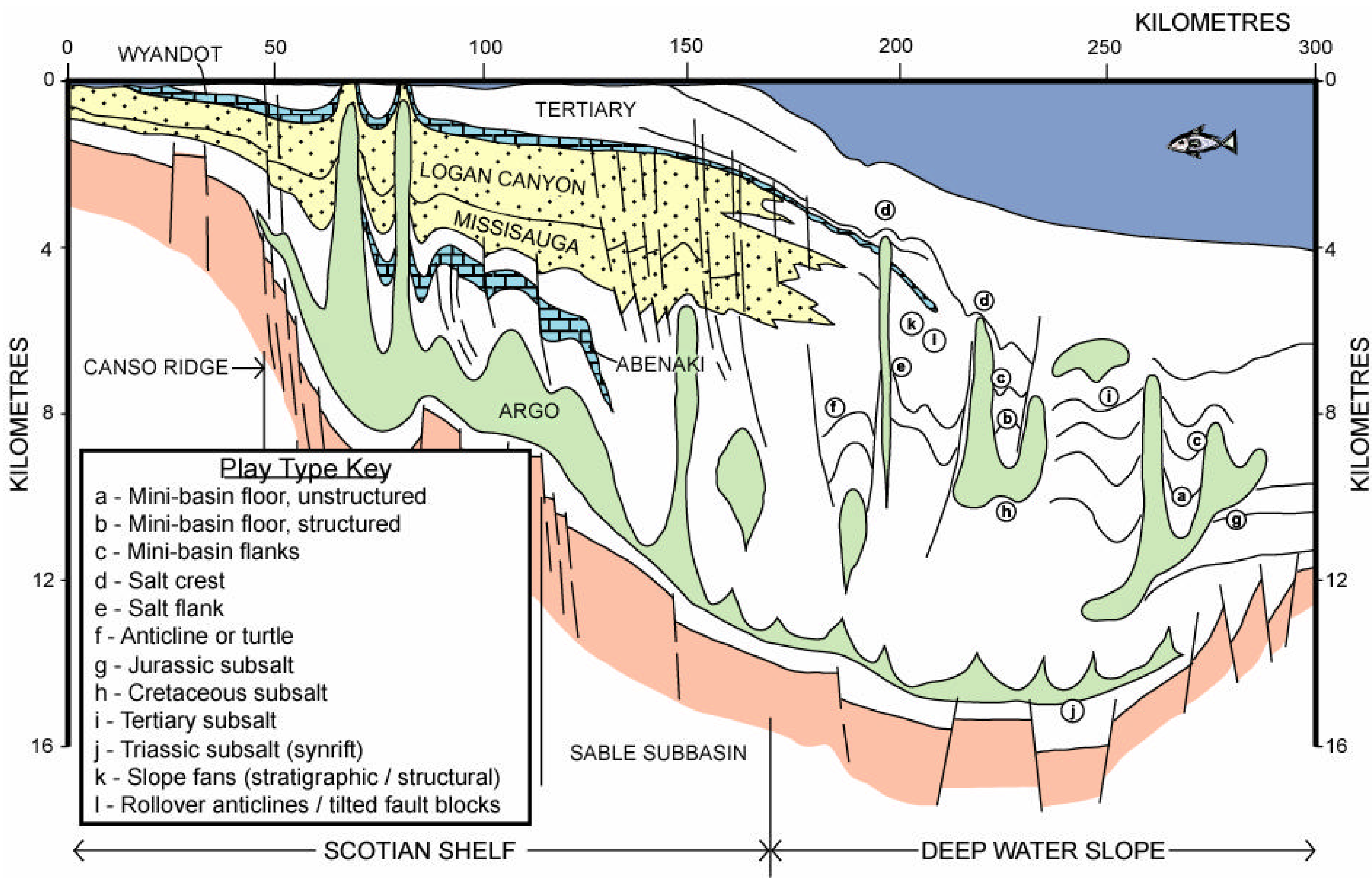


FIGURE 27

Play type schematic for the Scotian Slope illustrating the various trapping configurations expected in a passive margin modified by salt tectonics. Traps can be found in supra-salt, inter-salt and sub-salt situations.

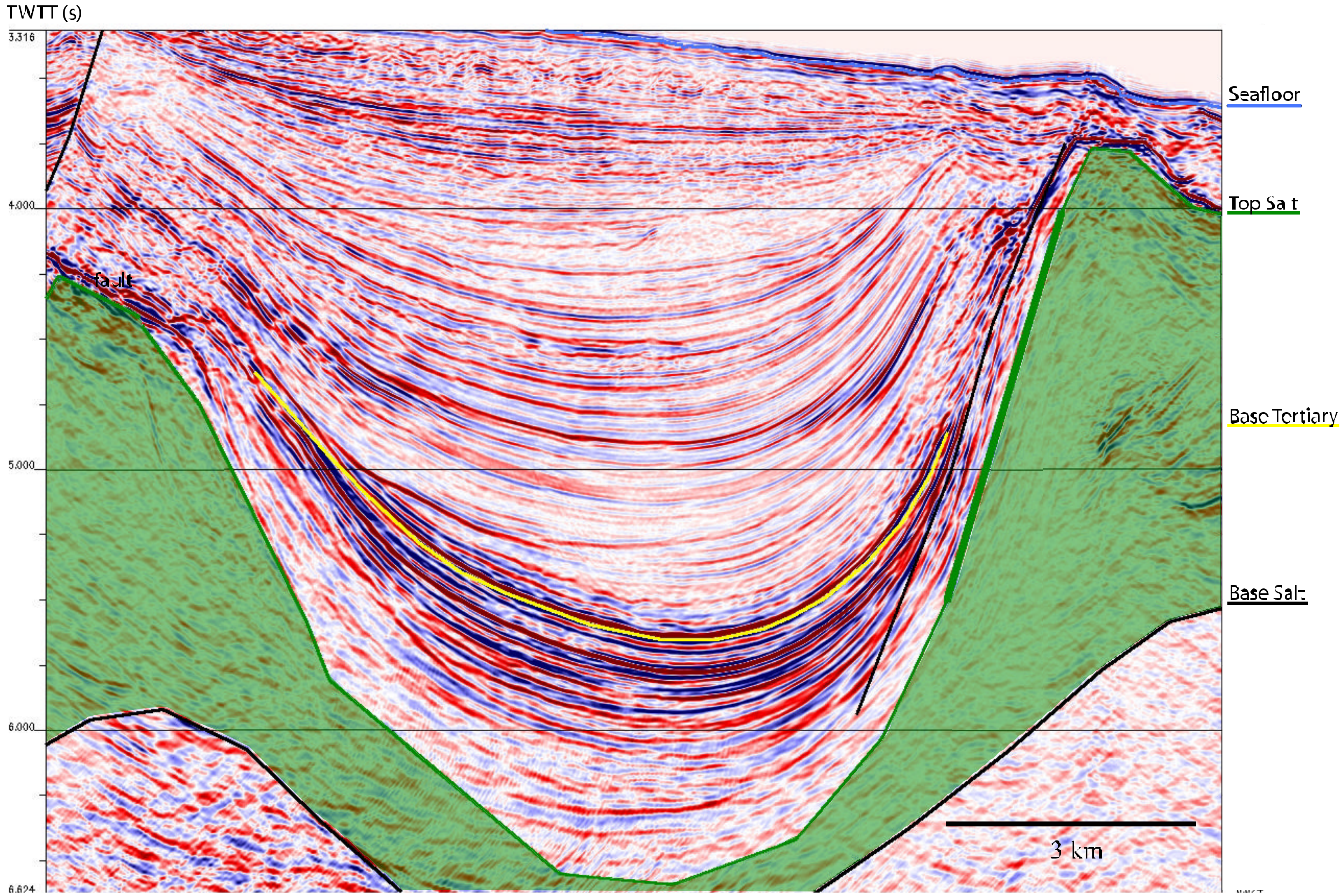


FIGURE 28

Mini-basin floor and flank plays are clearly shown in this seismic example from the western part of the Slope. The zones of varying amplitudes and “corrugated” nature of some reflectors may be of interest.

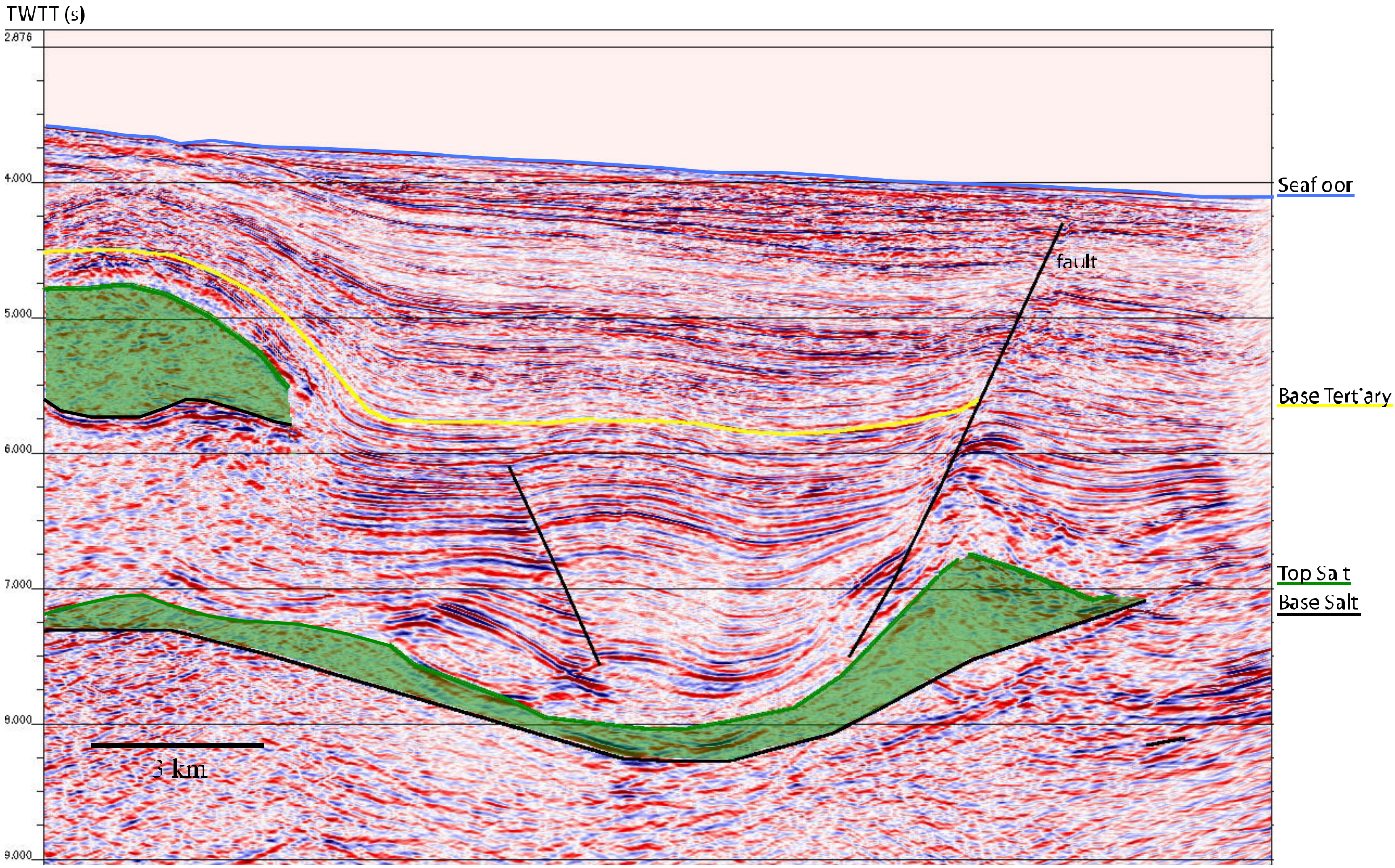


FIGURE 29

Seismic profile from the central region of the Slope showing a mini-basin with deep internal structuring.

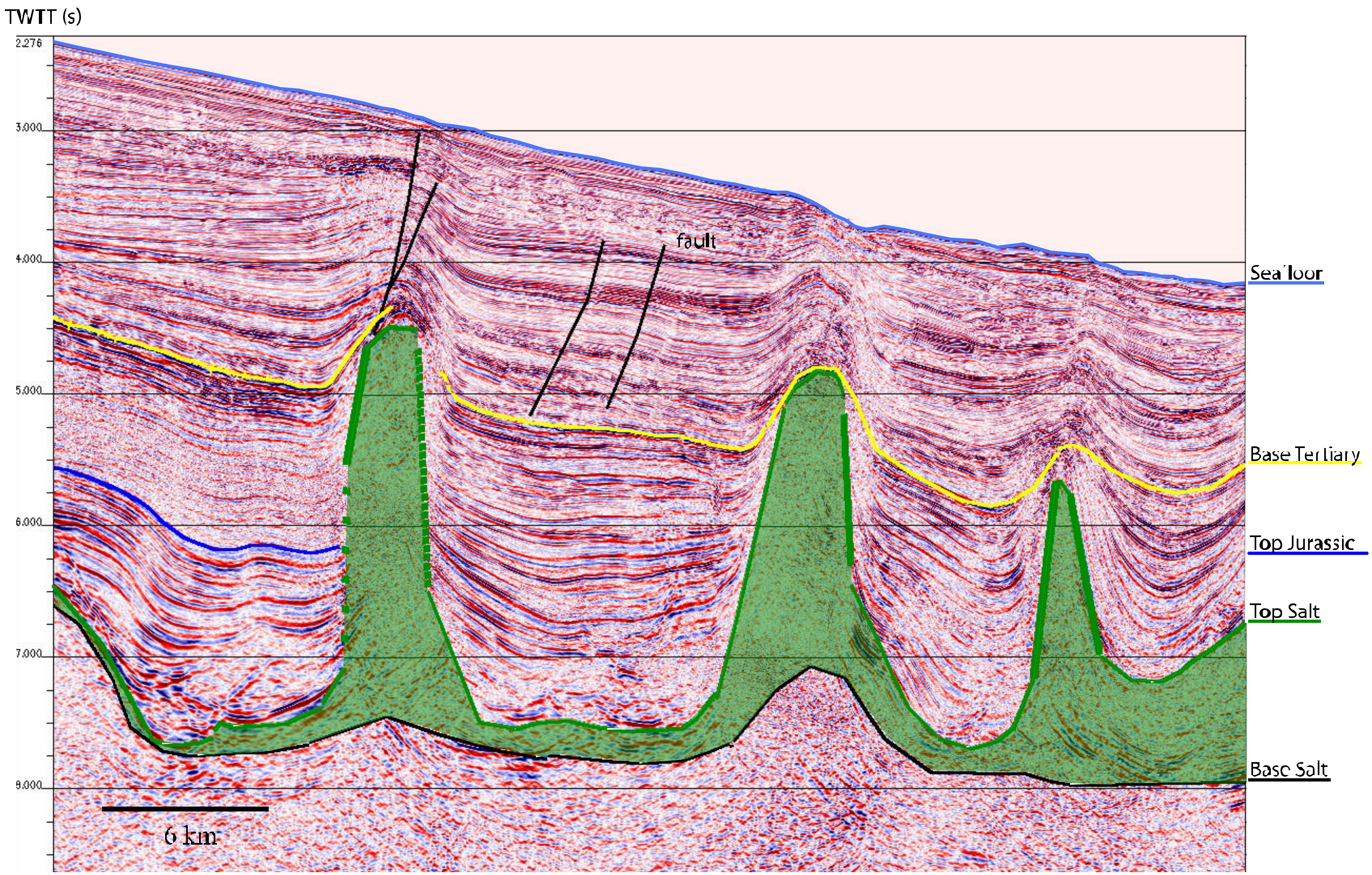


FIGURE 30

Several salt features exhibit inter-salt mini-basins, salt crestal areas but the sub-salt section is poorly imaged. The blue marker on the left side is the Top Jurassic horizon and the yellow is Base Tertiary, with salt shaded in green.

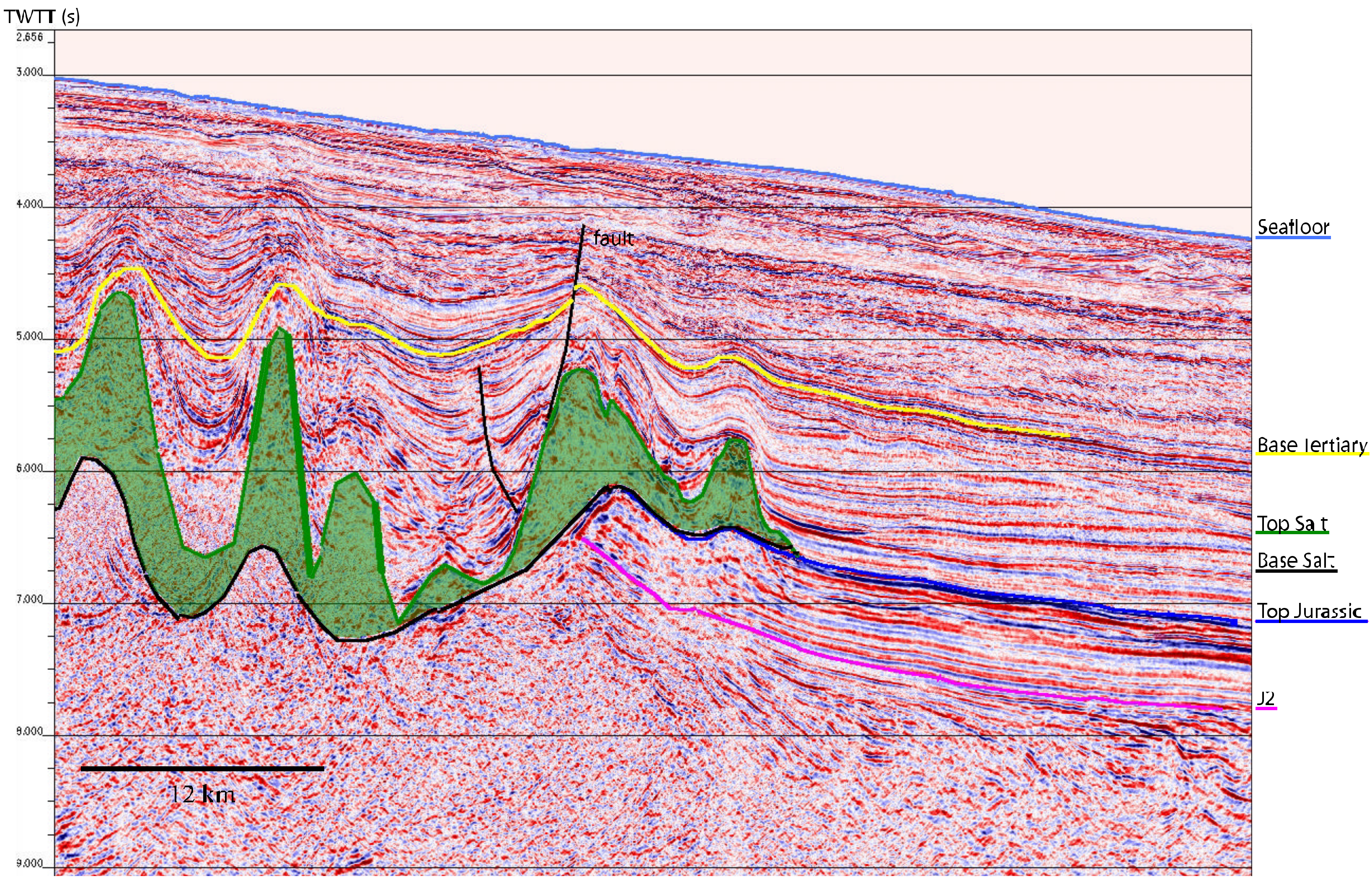


FIGURE 31

The leading-edge sub-salt play from the western portion of the Slope. The salt was probably thrust through the Jurassic strata and onto the then-Late Jurassic age sea floor as a submarine salt glacier. Subsequent sediment loading in the Early Cretaceous resulted in deformation of the salt and formation of deep minibasins behind the thrust. (Salt = green, Base of Tertiary = yellow, Top Jurassic = blue.)

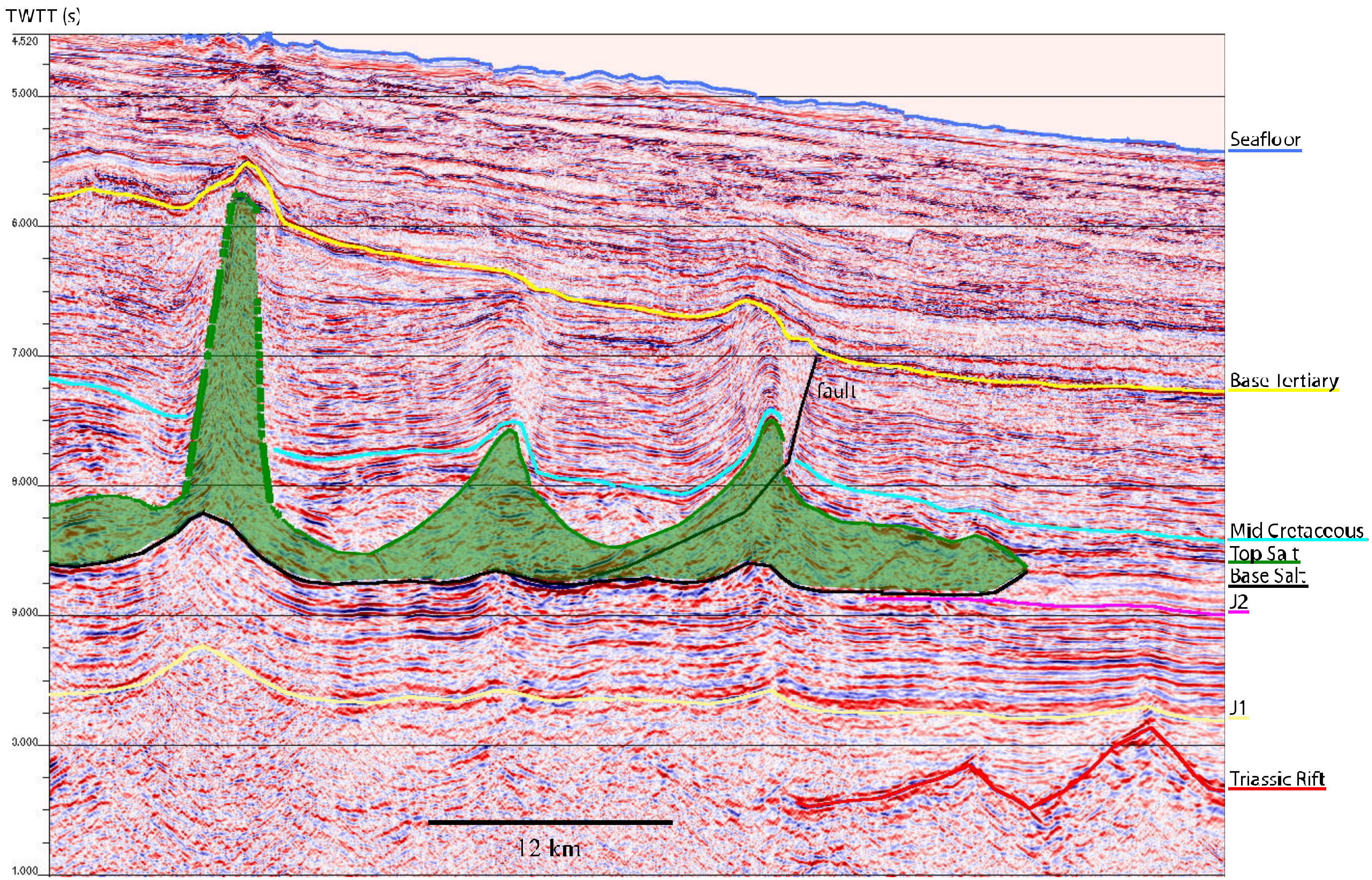


FIGURE 32

The salt leading edge involves several high angle thrust faults with salt-cored folds extending upwards and truncated by the Base Tertiary Unconformity (yellow). Compare with similar GOM examples in Weimer et al., 1999 (his Figures 26 and 27).

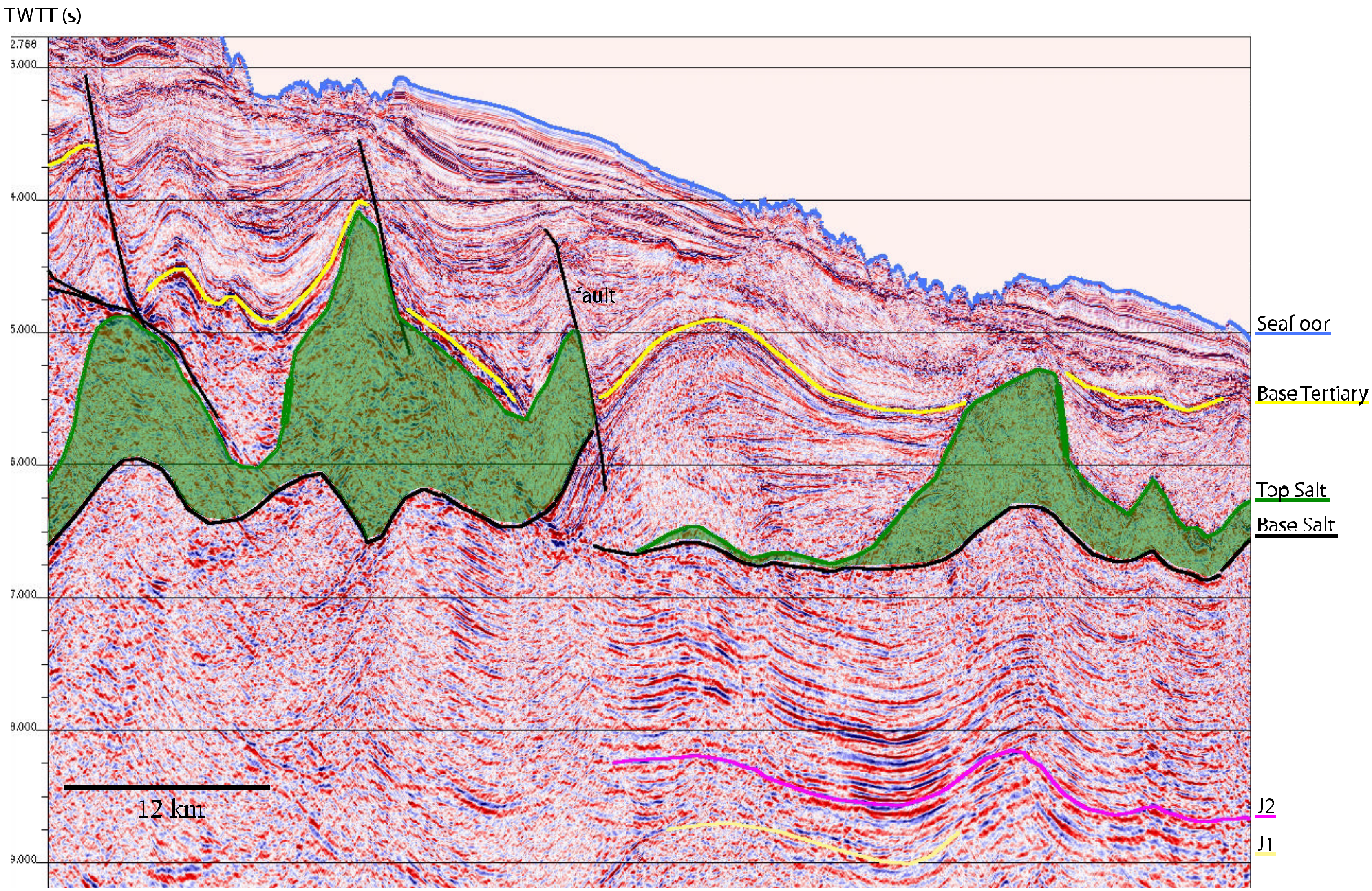


FIGURE 33

The complex of allochthonous salt is green-shaded and involves a large-scale supra-salt fold. Below the salt weld is a low-angle truncated section of probably Cretaceous age with the Top Jurassic in blue.

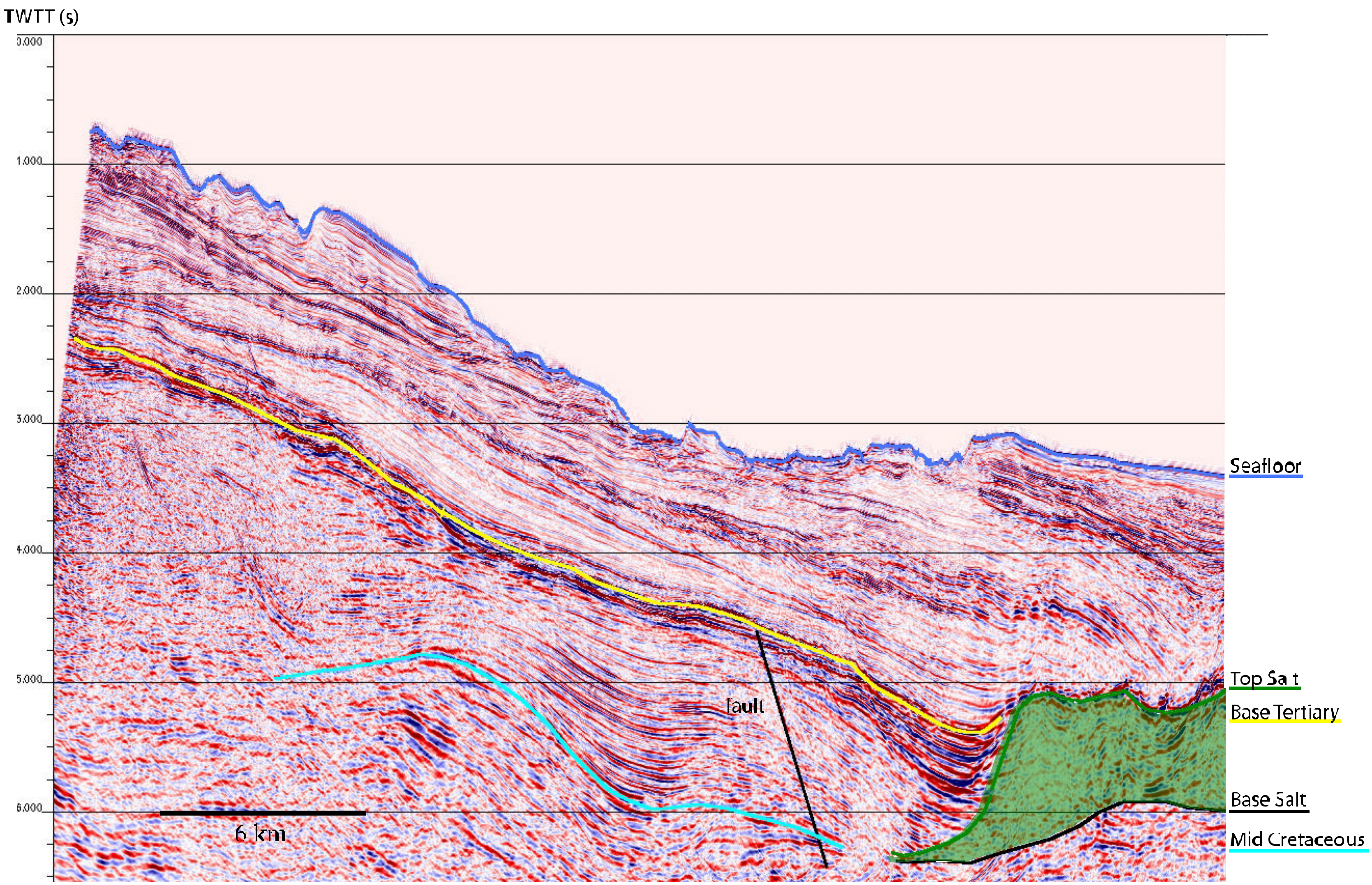


FIGURE 34

This profile is representative of the upper slope with a salt feature (green shaded), the Base Tertiary (yellow) and several form lines within the Cretaceous.

The mini-basin of Figure 29 shows a structured center caused by salt-withdrawal. The mini-basin is about 10 km across and filled with about 6000 m of sediments. The structured section below the yellow marker is interpreted as Cretaceous in age. The bounding fault on the right is observed to reach the sea floor. Four-way closure is not critical in this type because the section will dominantly be fine-grained, and combination structural/stratigraphic traps (pinch-outs) are common throughout the analogue basins (Compare with Figures 11 and 21 of GOM discoveries and producing fields in Weimer et al., 1998a).

Several play types are illustrated in Figure 30; mini-basin floors, flanks and diapir crests from the western Slope area. Note the crestal folds and faults persisting into the Tertiary with a seafloor expression above the middle diapir. Crestal faulting radiating upwards is a risk as it offers pathways for leakage of crestal closures.

The structural complexities found at the leading edge of allochthonous salt are clearly shown in Figure 31. Through down-slope thrusting the salt has intruded into the Lower Cretaceous section above the Top Jurassic (blue marker) and ridden up over the Jurassic strata (blue to lower yellow). If reservoir is present the sub-salt trap is perfectly sealed by the overlying salt. Above the leading edge of the salt are folds that persist for an appreciable height. Compare with Figure 4 of Tari et al. (2001) from the conjugate Moroccan margin with identical age salt and sediment succession.

Figure 32 is another example of the Jurassic sub-salt leading edge play, central Slope region. In addition to the salt overlying flat-lying deep-water Jurassic strata, the overlying thrust folds create another play that extends through the Cretaceous section up to the Base Tertiary (yellow). These plays can be found along the entire seaward edge of the salt basin to varying degrees of attractiveness.

Two plays are depicted in Figure 33 from the central Slope region; a large folded (turtle) feature in a mini-basin and the sub-salt Cretaceous. The Base Tertiary (yellow) to the Top Jurassic (blue) represents about 5000 m of Cretaceous section divided mid-way by a thin salt weld zone (green to black). Compare with a similar seismic profile from the Moroccan margin illustrating the same structural motif and plays (Tari et a., 2001, Figure 4). This is a good example of stacked plays.

The Upper Slope play type (Figure 34) of large structures above and/or adjacent to salt features is shown. There is probably a salt core beneath the structure on the left side of the section but this 2-D seismic does not show it. Seaward lies a salt feature (green shaded) with the Base Tertiary in yellow.

CHAPTER 6

GEOCHEMISTRY

A critical component to the deep-water petroleum assessment was the evaluation of the potential source rocks in this setting, i.e. organic matter type (oil vs. gas), total organic content (richness), maturation history(s) and hydrocarbon yield products. Dr. P. K. Mukhopadhyay (Muki) of Global GeoEnergy Research Ltd. was engaged to evaluate the petroleum systems at five selected locations on the deep-water slope using 1D numerical modelling (Mukhopadhyay, 2002). The following is a summary of this study and the integration with concepts and data from known analogue basins which together were incorporated in our numerical assessment of deep-water petroleum resources.

6.1 Selected Sites and Input Considerations

Since no wells currently exist in the Deep-water Slope that could provide a broad base of geochemical information, five sites, or so-called "dummy wells", were required to be created. The locations for these wells were selected from specific seismic lines and are representative of the different play types along the slope margin and areas as previously defined and discussed. The five sites are approximately evenly-spaced along the Slope and to eliminate any possibility of high-grading a particular area and compromising regulatory integrity, only their general locations are noted, these being:

Site #1 – East Slope
Site #2 – East-Central Slope
Site #3 – Central Slope
Site #4 – West-Central Slope
Site #5 – West Slope

The BasinMod™ software was used for the one-dimensional (1-D) analyses. Each input model consisted of a prediction of ages, depths, lithologies, source and reservoir intervals, hiatus and lacunae across unconformities, etc. The emplacement of allochthonous salt was a major consideration in building the models. Lithologic velocities were extracted from several sources including the Tantallon M-41 well. Ages were consistent with the Geological Society of America 1999 Geologic Time Scale (Palmer et al, 1999). Lithologies, age and distribution of mapped seismic megasequences were estimated from a number of sources including Parsons (1975), Jansa and Wiedmann (1982), Jansa (1986), Arthur and Dean (1986), Tulcholke and McCoy (1986), Tucholke and Mountain (1986), Swift (1987), Ebinger and Tucholke (1988), Wade and MacLean (1990), Wade et al. (1995), Gradstein et al. (1990), Welsink et al. (1990), Keen et al. (1991), MacLean and Wade (1992), various industry-submitted geological and geophysical reports (CNSOPB Archive), projection of shelf well data and interpretations, discussions with previous workers and assessors, and the current assessors' knowledge of the basin.

Six source rock intervals were considered in this study:

1. Logan Canyon Fm.: Cretaceous (Albian – Cenomanian)
2. Verrill Canyon Fm.: Cretaceous (Berriasian – Valanginian)
3. Verrill Canyon Fm.: Jurassic (Kimmeridgian – Oxfordian)
4. Misaine Mbr. / Abenaki Fm.: Jurassic (Callovian)
5. Mohican Fm. (Lacustrine): Jurassic (Toarcian – Bajocian)
6. Early Syn-Rift & Post-Rift Lacustrine: Triassic (Carnian-Norian) & Jurassic (Toarcian–Bajocian)

The first three intervals are well documented from the Sable Subbasin, with the Verrill Canyon Fm. Petroleum System the source for the discoveries in the Subbasin. The Misaine Member. (Abenaki Fm.) source rock is known from the Scotian Shelf region and its equivalent from results of the Deep Sea / Ocean Drilling Projects (DSDP, ODP). The remaining two source intervals are conceptual and based on regional geology (e.g. Wade et al., 1996). The analogue equivalents are very prevalent in the offshore Brazilian and West African margins.

As an illustrative example, the seismic profile for Site #4 (Figure 35) reveals a setting within a mini-basin about 65 km southeast of the Jurassic carbonate bank edge. The intra-salt mini-basin is interpreted to extend from the Base Tertiary seismic marker (purple) down to below the top of the Jurassic (blue). The allochthonous Early Jurassic Argo Salt lies between the green and pink markers. The burial history plot for the Site (Figure 36) illustrates the amount of geological detail required for the numerical analysis. The vertical axis is depth of burial and the horizontal axis is geologic time. The right side column represents the present-day model. The plot shows, at this location, a typical passive-margin subsidence through time with no major uplift. Isotherms are also displayed.

6.2 Output Results and Interpretations

The burial history plot for the preceding figure, Figure 36, is repeated in Figure 37, but with maturation windows superimposed. The mid-mature oil window occurs in the 5000 to 6000 m interval, and the main gas generation window begins at about 6250 m. This indicates that similar mini-basins could generate hydrocarbons from localized sources. This is an important consideration because turbidite flows can carry not only reservoir rocks but also source material into deep-water.

Figure 38 graphs hydrocarbon expulsion over time and indicates, for this scenario, that the main expulsion event for oil, wet gas and gas occurred from 90 – 60 Mya in the Late Cretaceous. The traps, in order to capture hydrocarbons, must be in place prior to expulsion and migration and be effectively sealed. The Late Triassic/Early Jurassic Argo salt is interpreted to have been moving since Late Jurassic time and thus sufficient trapping configurations would be in place.

The cumulative plot of all source intervals indicates relative volumes of expelled products (Figure 39). It shows the two conceptual syn-rift lacustrine source intervals of Jurassic and Triassic age as being prolific hydrocarbon producers if they exist. The Late Cretaceous Logan Canyon interval is immature and hence there is no expulsion. However the two known Early Cretaceous and Late Jurassic Verrill Canyon source intervals can be the source of significant hydrocarbon generation.

The following are the findings and interpretations of the Slope geochemical modelling:

1. Three main source rock intervals have been identified from exploration to date, the Cretaceous Logan Canyon Fm., the Cretaceous Verrill Canyon Fm. and the Jurassic Verrill Canyon Fm.

2. Potential source rocks may occur in older Middle Jurassic (Callovian) Misaine Member (Abenaki Fm.) and syn-rift facies of Late Triassic to Early Jurassic.

3. Transient heat flow measurements from well control show high values during the rifting process then cooling to the present day. The presence of high heat-conductive salt is a major factor but 1-D modeling can only deal with the present-day location and thickness of salt.

4. The Cretaceous and Jurassic age portions of the Verrill Canyon Fm. are the primary slope source rocks and were capable of generating and expelling large quantities of oil and gas.

5. The Cretaceous age Logan Canyon Fm. remains an immature source rock.

6. Expulsion at Sites 1 and 2 on the eastern part of the Slope near the Sable Delta occurred earlier than Sites 3, 4 and 5 in the west, hence earliest traps may have captured hydrocarbons whereas the latter area may have contributed to filling younger traps. This is no doubt due to the tremendous volume of sediments that were rapidly deposited here during the Jurassic and Cretaceous.

7. Similar to sediments encountered in DSDP drill sites, Callovian Type II-III could be a contributor of hydrocarbons on the Scotian Slope.

8. If Early-Middle Jurassic Mohican Fm. and Late Triassic syn-rift Type I lacustrine sources are present at Sites 4 and 5, they could be a major contributor of hydrocarbons.

9. The break-down of anticipated hydrocarbon types along the Slope is interpreted to vary between gas and condensate, oil and wet gas, and oil and gas:

- Sites 1, 2 & 3 – Major deposits of oil and gas in mini-basins (East and Central Slope).
- Sites 1, 4, 5 – Major deposits of oil and wet gas (East and West Slope).
- Site 2 – Major gas and condensate deposits (East-Central Slope).

10. The expected oil fraction may vary between 30-60% across the Slope:

- Site #1 – 60/40 (East Slope)
- Site #2 – 30/70 (East-Central Slope)
- Site #3 – 50/50 (Central Slope)
- Site #4 – 60/40 (West-Central Slope)
- Site #5 – 30/70 (West Slope).

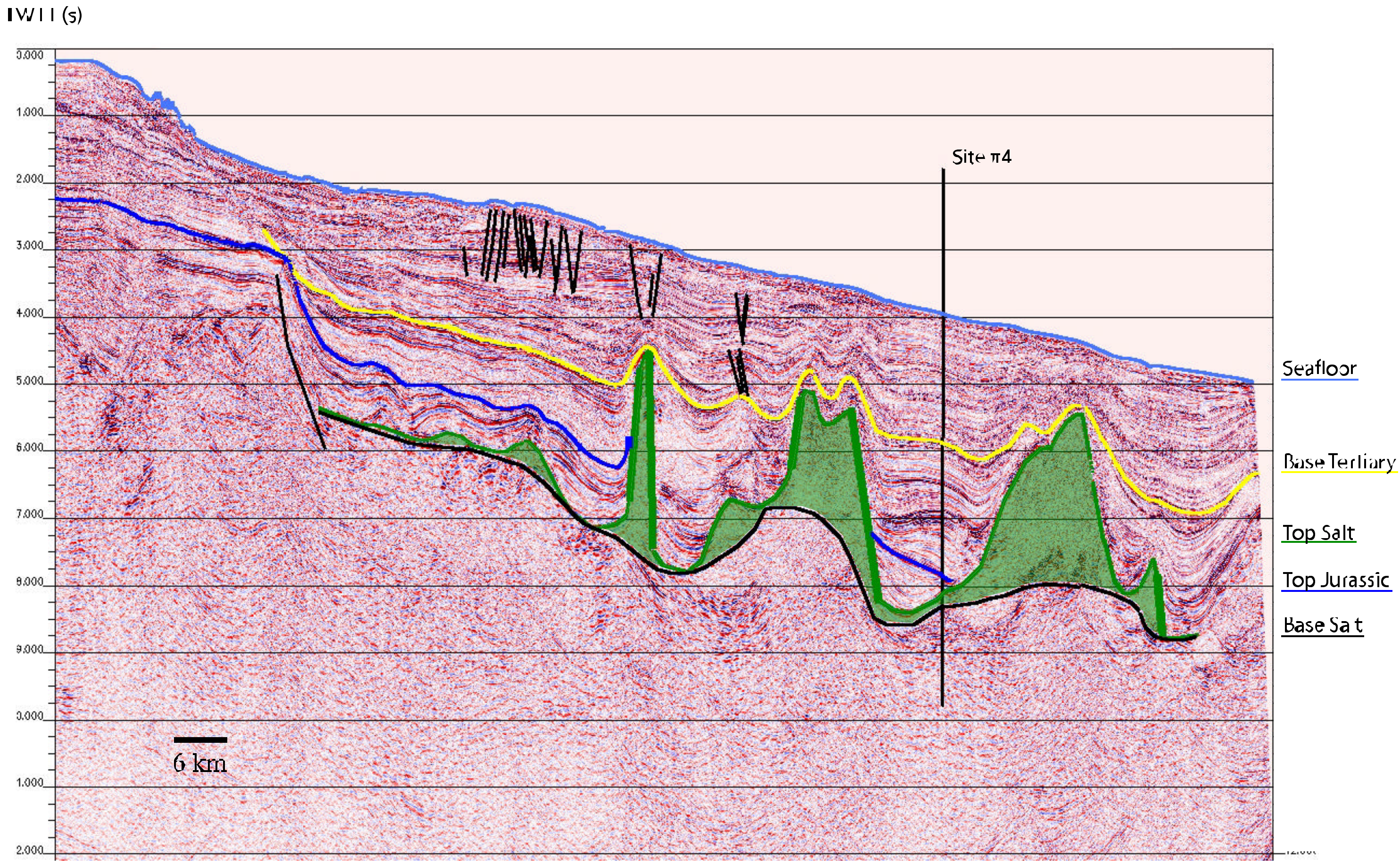


FIGURE 35

Northwest-southeast seismic profile illustrating the location of Geochem Site #4. The “dummy well” extends from the water bottom through a very thick and long-lived Early Tertiary to Late Jurassic intra-salt minibasins, salt weld of the Argo salt, Early Jurassic post-break-up clastics and carbonates and ending in what are interpreted as Late Triassic early syn-rift fluvial-lacustrine successions. The Late Jurassic Abenaki Formation reef margin bounds the salt basin to the west. Salt withdrawal features in the deep Late Jurassic succession are well illustrated in the mini-basins seaward of the reef margin. The profile is indicative of the multiple play types that coevally exist in this region: mini-basin floor fans (Play 1), mini-basin salt flanks, mini-basin salt crests, salt crests, and salt flanks. Refer to Figures 20-22, and 27-34 for these and other play examples.

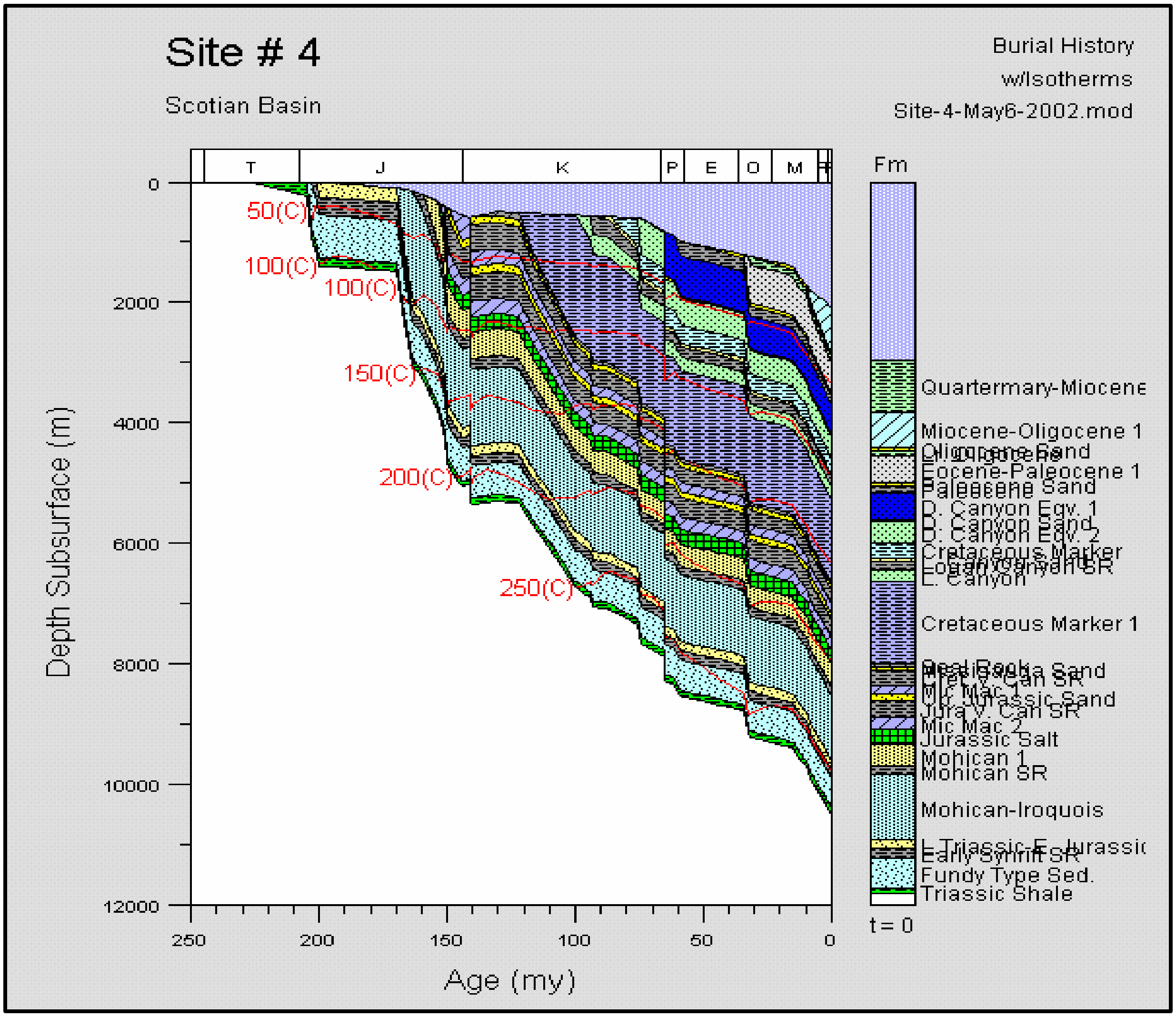


FIGURE 36

Burial History profile for Site #4. Isotherms are in 50°C increments (Mukhopadhyay, 2002).

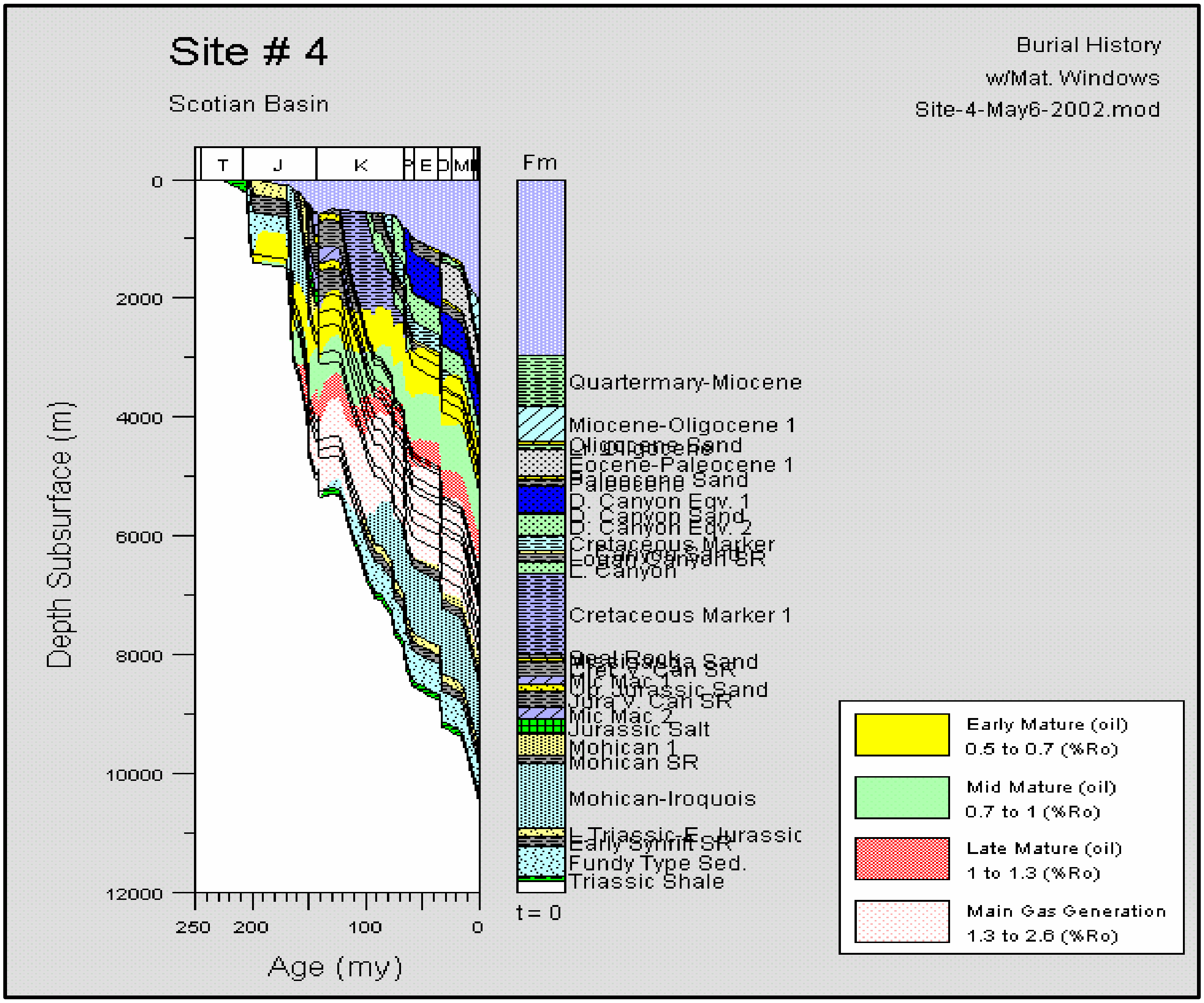


FIGURE 37

Burial History profile for Site #4 with maturation windows for oil (three phases) and natural gas. Note that all four maturation windows fall within the Cretaceous interval, with shallower and deeper successions immature and over-mature respectively (Mukhopadhyay, 2002).

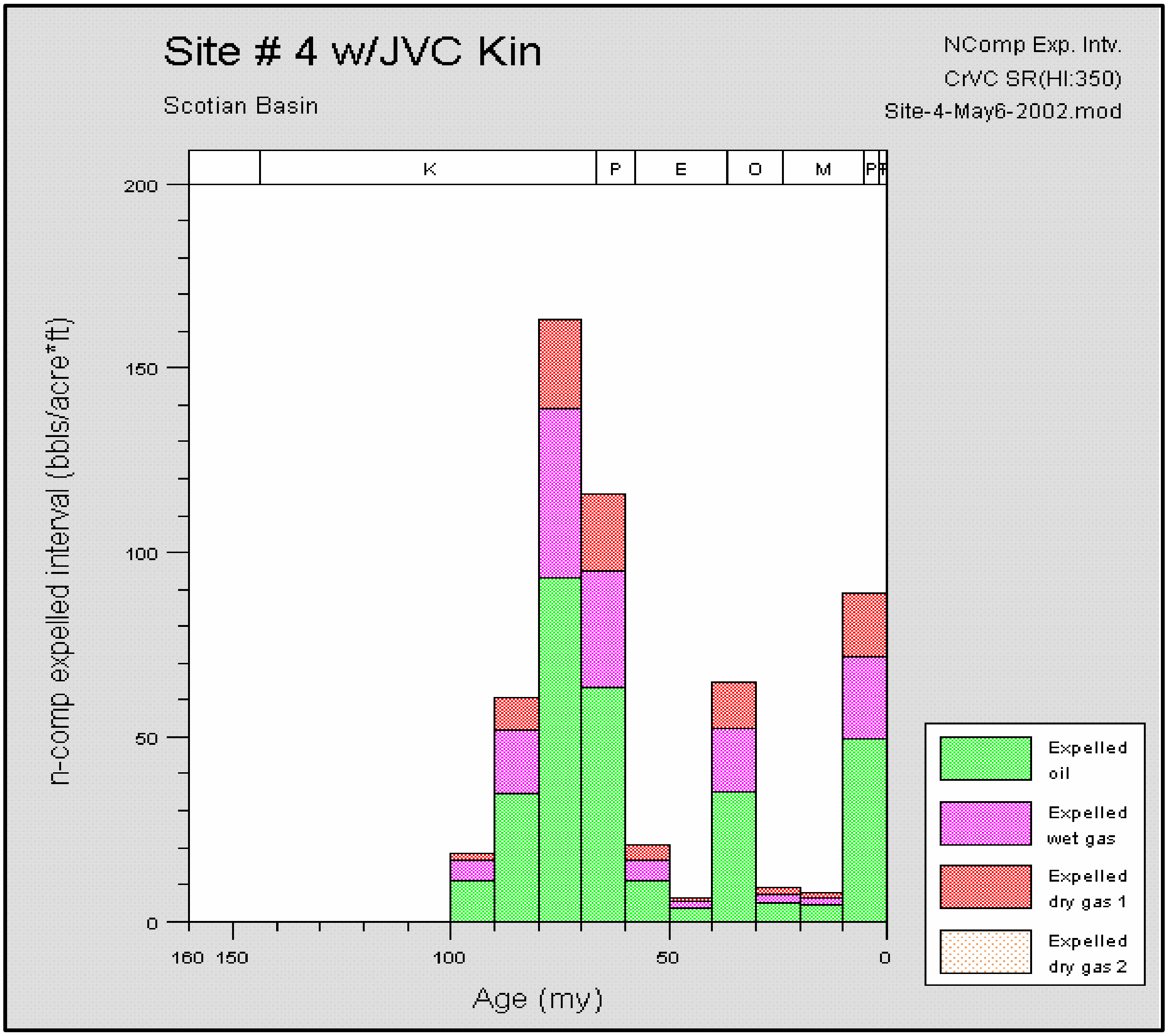


FIGURE 38

Bar histogram illustrating modelled N-Component hydrocarbon expulsion through time for the Cretaceous Verrill Canyon source rock interval at Site 4 (Type II kerogen, 350mg HC/g TOC Hydrogen Index. Type II-III source rock kinetics from the Alma F-67 well). Two pulses of oil and gas expulsion are indicated: Late Cretaceous and Oligocene / Pliocene. This bimodal expulsion appears representative for the Verrill Canyon though the timing is different for each of the five Sites along the Slope (Mukhopadhyay, 2002).

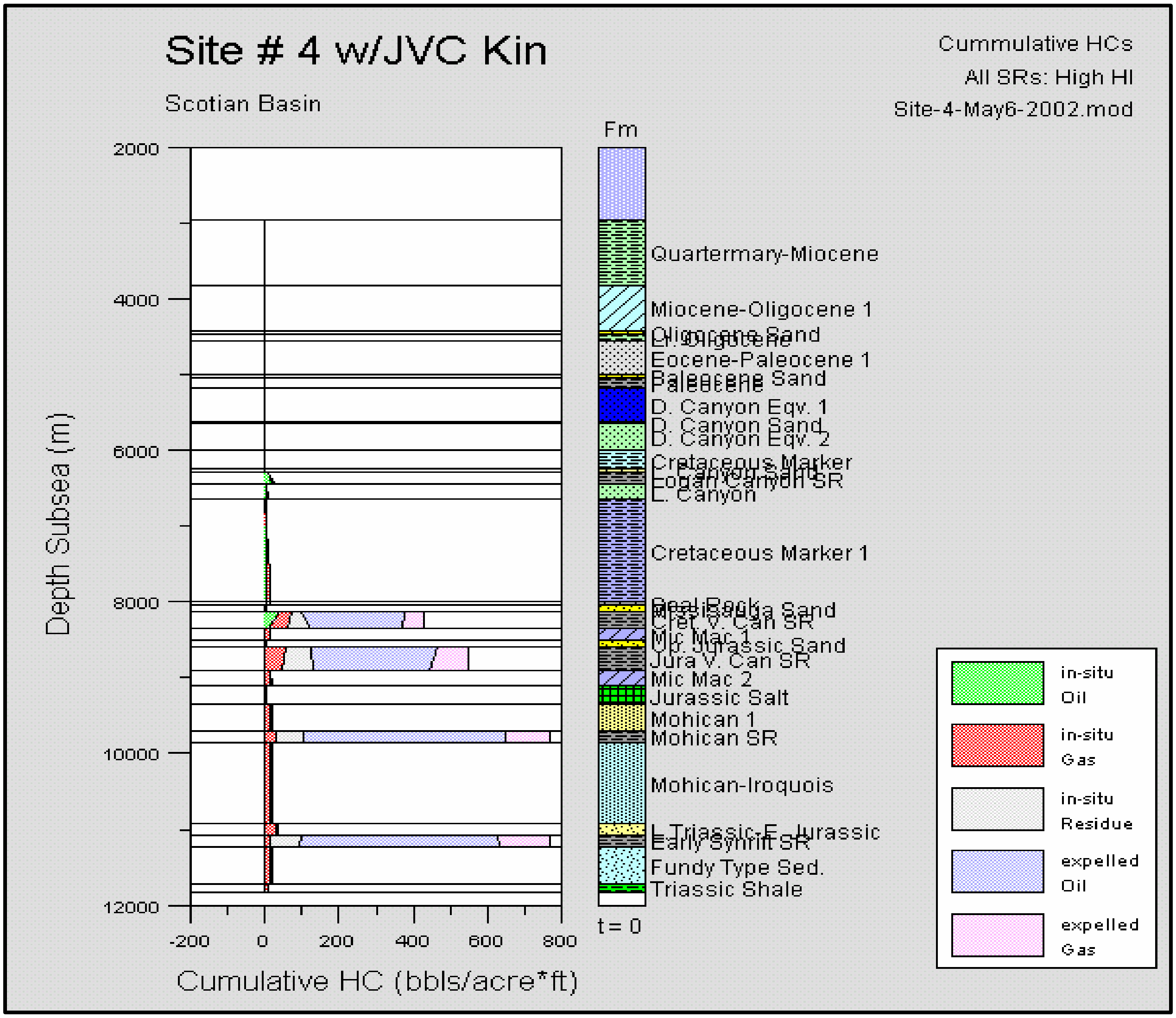


FIGURE 39

Cumulative hydrocarbon generation and expulsion for all selected source rocks using high hydrocarbon index values (Cretaceous Verrill Canyon = 350 HI, Jurassic Verrill Canyon = 450 HI, etc.) (Mukhopadhyay, 2002). Note that the possible lacustrine Type I source rocks of the Middle Jurassic Mohican and Late Triassic could have generated large quantities of hydrocarbons. Similar petroleum systems account for the large oil accumulations in the Brazilian and West African margins.

CHAPTER 7

DEEP-WATER SLOPE – NUMERICAL ANALYSIS

The deep-water Slope seismic interpretation and comparison with global analogues resulted in sufficient information to run 12 separate numerical analyses. The play types (A to L) of Figure 27 were not all analyzed; for example, the Triassic/Jurassic syn-rift play, although believed to exist, lacked sufficient seismic definition to evaluate. Hence, the twelve assessment runs were a combination of particular play types and their interpreted areal extents:

1. Mini-Basin Floors (Structured and Unstructured)
2. Mini-Basin Flanks
3. Salt Crests (Associated with Mini-Basins)
4. Sub-Salt Jurassic
5. Supra-Salt Structures Tertiary
6. Sub-Salt Cretaceous
7. Salt Crests
8. Salt Flanks
9. Deep Structures
10. Other Supra-Salt Structures
11. Upper Slope Fans and Structures (Tertiary and Cretaceous)
12. Upper Slope Fans and Structures (Cretaceous and Jurassic)

7.1 Volumetric Input Data and Geologic Parameters

Detailed information on the input parameters for the 12 assessment runs in this study is presented in the Appendix (Figures 54-78). For Figures 40-46, the plays are ordered according to the seriation of output results in OEB as displayed in Figure 47.

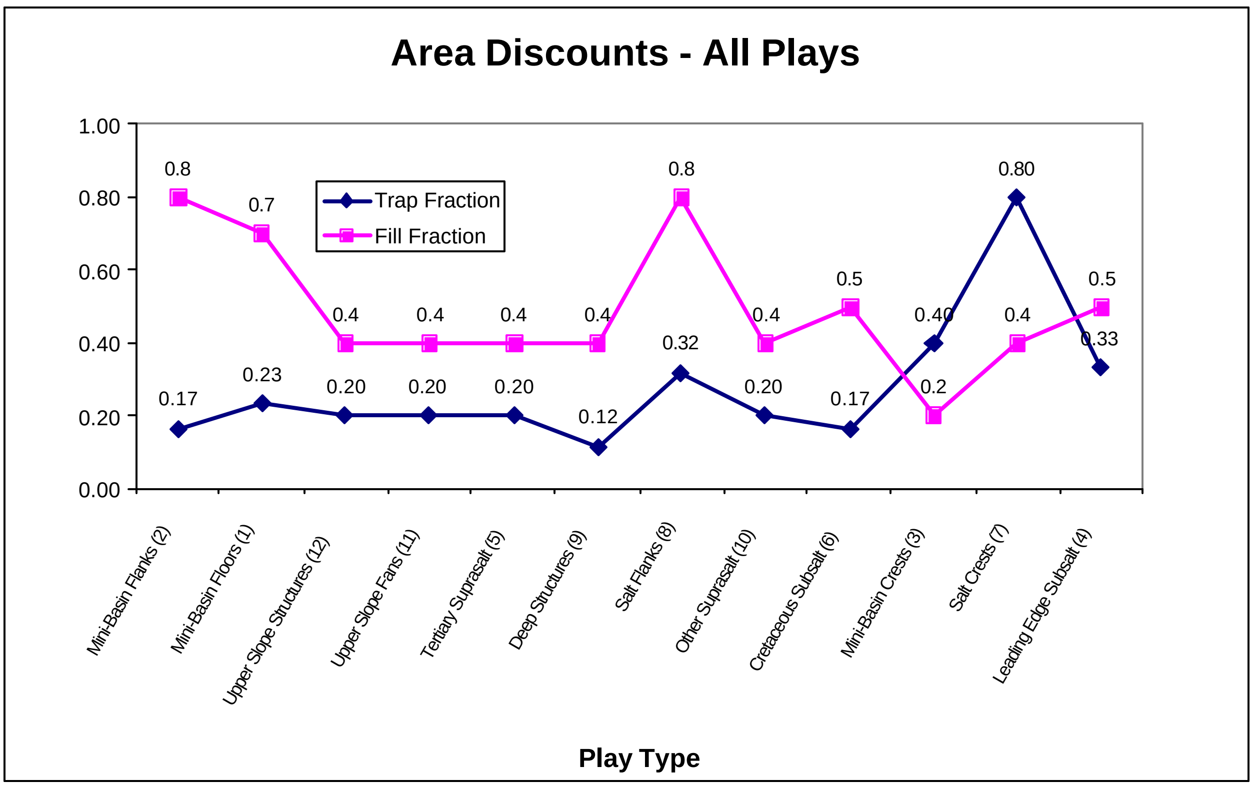


FIGURE 40

Two discount factors were used, one for fraction of play area under trapping conditions and one for percent hydrocarbon fill. These are the mean values with a range for minimum and maximum.

Area (hectares)

Each of the twelve plays had its own area of occurrence and these play areas were digitally measured by inscribing play outlines on the respective time-structure maps. For example, in the main diapir/mini-basin area in the central and western portions of the Slope region, the map was further subdivided into three play areas for mini-basin floors, mini-basin flanks and salt crests. In most cases, the measured areas were used as most likely values with a range for minimums and maximums. The range of uncertainty is further addressed in subsequent discount factors for area under trapping conditions and area of trap fill.

Figure 40 shows the areal discount factors across the slope by play type. The first discount for *percent under trap* was generally a mean value of 20-30 % with a reduced discount for the tightly constrained plays such as salt crests and flanks. This range is supported by the work of Weimer et al. (1998a) in the Gulf of Mexico. The second factor of *percent trap fill* acknowledged the high fill factors of mini-basin floor and flank fans as currently being found in the GOM, (Cossey and Associates, 2002) Otherwise, the general assumed mean fill factor is 40%. These are all mean values with a range for minimum and maximum. (see individual input sheets in the Appendix).

FIGURE 41

This plot illustrates the mean values for net thickness, porosity and water saturation for each play. A range for minimum and maximum was also input.

Net Pay (metres)

This was a difficult parameter to evaluate because benchmark data from the Scotian Slope is lacking, though wells currently being drilled offshore Nova Scotia will eventually provide some information. The GOM provided the best available database for expected *gross and net sand thickness* for mini-basin turbidite floor and flank sands. These appear to have, on average, 100 m of net pay consisting of about six sands per field (K.J. Drummond, pers. comm., 2002). An average pay summary for the GOM Protraction Areas (deeper water) by Cossey and Associates (2002) is 50-60 m. Information gleaned from all industry press releases and papers show a range of 30 – 60 m of net pay with some fields as high as 100 m for salt-associated discoveries.

Figure 41 shows the mean net pays of 20 – 80 m used for the plays with a broad range for minimum and maximum values which can be found in the input sheets for each play in the Appendix. The minimum values reflect the degree of uncertainty while the maximums embrace the potential for thick pays in the mini-basin floors and flanks that are interpreted to exist in front of the Sable Delta Complex. This analysis is at the field level as opposed to a smaller pool level and therefore multiple stacked reservoirs can be achieved.

Porosity (%)

With reference to Bibby and Lake (2000) and in-house expertise, the *porosity* range was generally assumed to be in the 10-20-25 % range for siliciclastic reservoirs of mostly Cretaceous age. Whereas the GOM and other analogue basins report much higher porosities in the 30% range, these are invariably much younger Tertiary sands with some as young as Pleistocene. See Figure 41 and input sheets for each play in the Appendix.

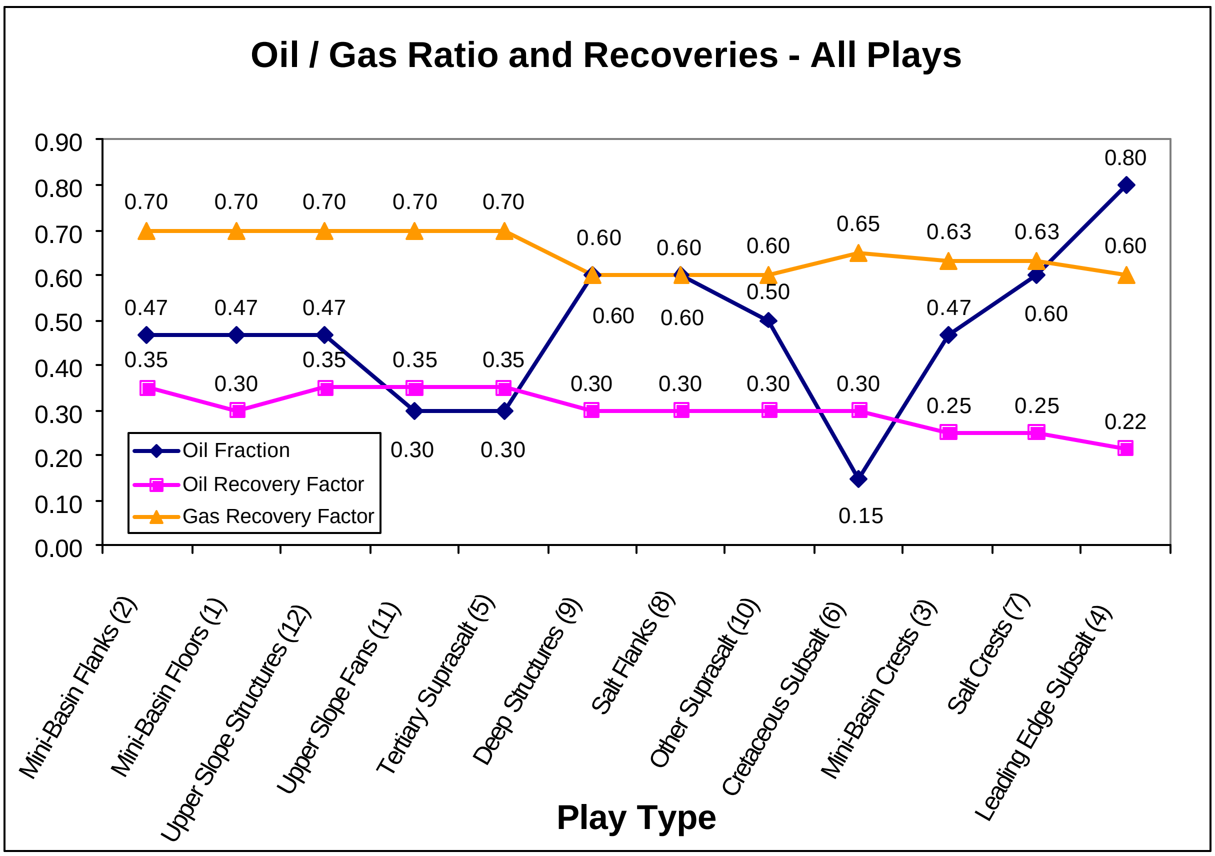


FIGURE 42

The plot illustrates the mean values for oil and gas recovery and for the expected gas/oil ratio expressed as an oil fraction.

Saturation (%)

On average, the range of 60-70-80 % for *hydrocarbon saturations* were used. The expectation of shale- and mud-encased reservoir sands implies high saturation potential. Refer to Figure 41 and input sheets for each play in the Appendix.

Recovery Factors (%)

Oil and gas *recovery factors* were fairly standard with mean values of 60-70% for gas and 20-35% for oil. These are shown in Figure 42 and the input sheets for each play in the Appendix.

Oil/Gas Ratio

The *oil fraction* was obtained from the geochemistry modelling and reflects the change in anticipated organic material type and burial history for the various play areas. The resultant thermal maturation profiles of the assumed organic material will yield different oil/gas percentages. Figure 42 illustrates the mean value for the oil fraction for each play and a range of minimum and maximum is in the input sheets in the Appendix.

Formation Volume Factor (FVF)

This parameter was calculated using estimated depths of reservoir units, measured temperature and pressure gradients from wells, Z factors for gas composition, etc. The resultant *formation volume factors* ranged from 300-350 with a mean of 325. Further details are in Figure 43 and the input sheets for each play in the Appendix.

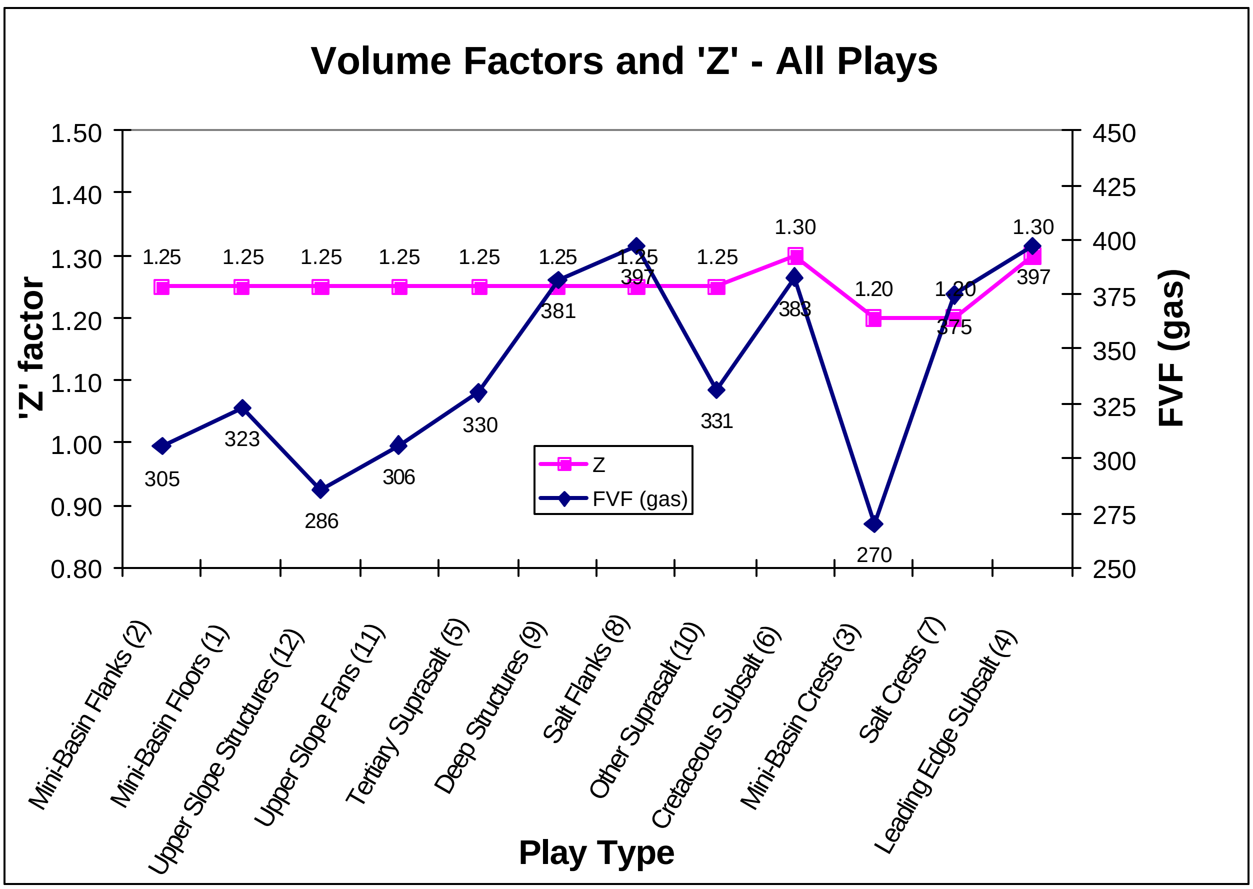


FIGURE 43

Mean values for the gas formation volume factor and the 'Z' factor for each play.

7.2 Geologic Risking

As discussed earlier (Section 4.4), the geologic risking is applied at two levels, prospect (quantitative) and play (qualitative). The *prospect level risk* can be thought of as the anticipated drilling success rate while the *play risk* is expressed as an overall adequacy of the play's existence. In subjective assessment of conceptual plays, this is a critical factor, and three aspects were risked for the overall chance of adequacy for each play:

Adequacy of source (maturation, migration, preservation)
Adequacy of reservoir (presence and type)
Adequacy of trap (timing, seal)

There are several ranking schemes to convert subjective qualitative measures into a numerical scale and the three versions used are shown in Figure 44. Drummond (1998) was based on a 1997 version of MMS as detailed by Lore et al. (1999). The Chevron table is from Otis and Schneidermann (1997). Note the fractions quantify the chance of adequacy. Hence, the risk will be *1 minus the chance of adequacy*, with "1" representing absolute certainty.

The assigned *adequacy values* for each play on the Scotian Slope were determined and are displayed in Figure 45. General considerations in this process were proximity to paleo-deltas and submarine canyons, deep-water marine source, geochemistry of source facies and general rules for trap-fill based on trap style and reservoir type. The overall range of play adequacies, from 16 to 64%, represents the variability across the basin. The input into the play assessment was condensed to a single value.

The values for both prospect and play adequacies (1-risk) are displayed in Figure 46. The prospect chance of success ranges from 10-30% or in drilling success rate terminology, 1:10 to 1:3. The play adequacies range from 16-64 %. Both indices depict an anticipated variability across the Slope with higher chances of success expected, for example, adjacent to paleodelta complexes or major submarine canyon systems, (Figure 46).

<table>
<tr><th>Chance of Adequacy</th><th>Drummond</th><th>MMS</th><th>Chevron (Otis)</th></tr>
<tr><td>0.9 – 1.0</td><td>Excellent</td><td rowspan="2">Probably Exists</td><td rowspan="3">Documented and Favourable</td></tr>
<tr><td>0.8 - 0.9</td><td>Very Good</td></tr>
<tr><td>0.7 - 0.8</td><td></td><td rowspan="2">Possibly Exists</td></tr>
<tr><td>0.6 - 0.7</td><td>Good</td><td rowspan="2">Encouraging</td></tr>
<tr><td>0.5 - 0.6</td><td></td><td rowspan="3">Equally Present Or Absent</td></tr>
<tr><td>0.5</td><td></td><td>Neutral</td></tr>
<tr><td>0.4 - 0.5</td><td>Fair</td><td rowspan="2">Questionable</td></tr>
<tr><td>0.3 - 0.4</td><td></td><td rowspan="2">Possibly Lacking</td></tr>
<tr><td>0.2 - 0.3</td><td>Poor</td><td rowspan="3">Unfavourable</td></tr>
<tr><td>0.1 - 0.2</td><td></td><td rowspan="2">Probably Lacking</td></tr>
<tr><td>0 - 0.1</td><td>Very Poor</td></tr>
</table>

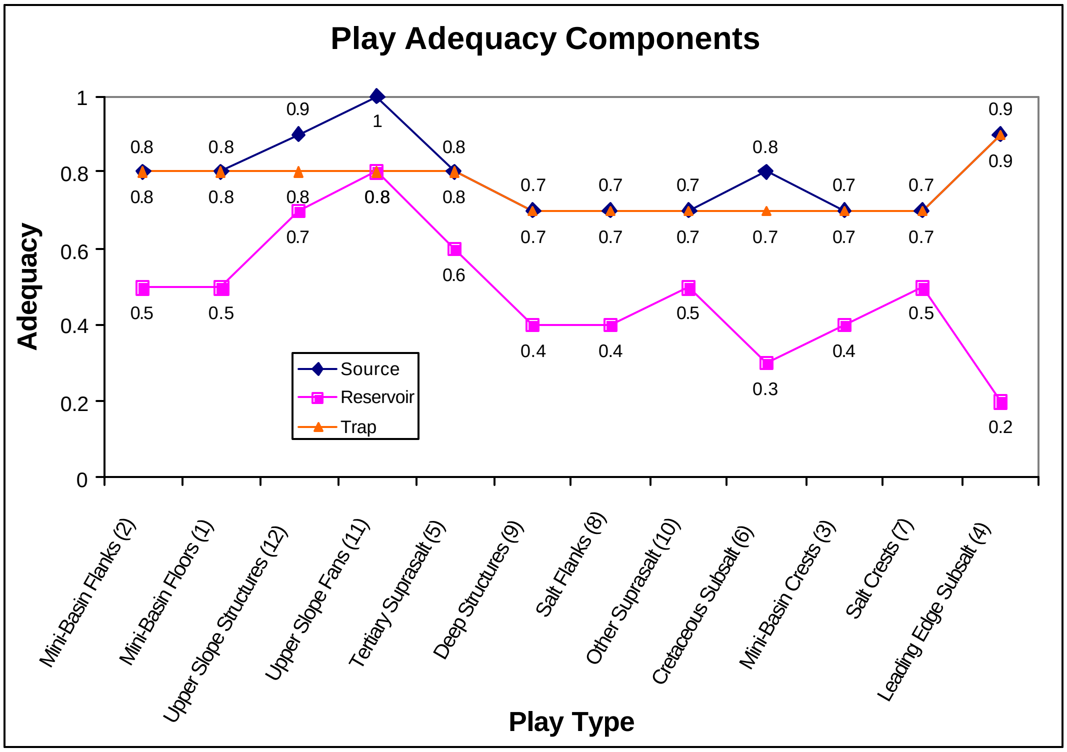
FIGURE 44

A conversion of subjective qualitative descriptions into a numerical scale. These values were determined by consensus of the assessment team.

Play	Source	Reservoir	Trap	Overall
1. Mini-Basin Floors	.80	.50	.80	.32
2. Mini-Basin Flanks	.80	.50	.80	.32
3. Mini-Basin Salt Crests	.70	.50	.70	.25
4. Leading Edge Sub-Salt	.90	.20	.90	.16
5. Canopy Supra-Salt	.80	.60	.80	.38
6. Canopy Sub-Salt	.80	.30	.70	.17
7. Salt Crests	.70	.40	.70	.20
8. Salt Flanks	.70	.40	.70	.20
9. Structures	.70	.40	.70	.20
10. Supra-Salt	.70	.50	.70	.25
11. Upper Slope	1.0	.80	.80	.64
12. Upper Slope	.90	.70	.80	.50

FIGURE 45

The assigned chance of adequacy for the presence of source rocks, reservoir and trap. The overall adequacy for each play was input into the numerical analysis as a single value.



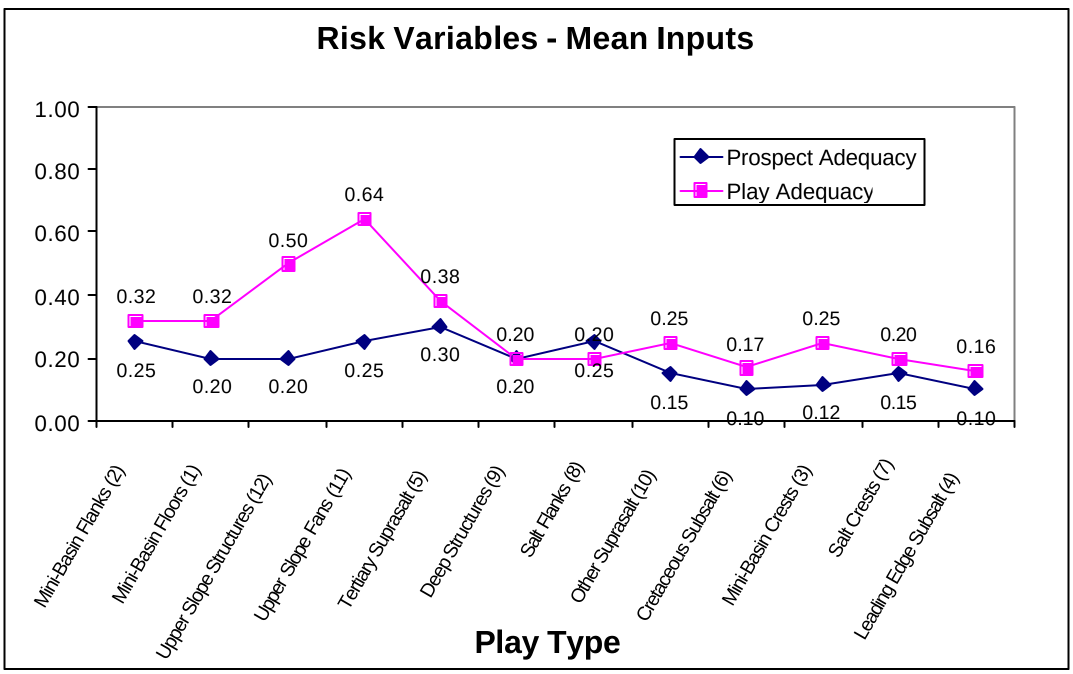


FIGURE 46

Geologic risk factors are displayed at the prospect level and at the play level as a chance of adequacy, in other words, “1 minus risk”.

CHAPTER 8

ASSESSMENT RESULTS

The 12 deep-water plays were run individually using 10,000 iterations of the Monte Carlo simulator in the @Risk™ software. The calculation of all hydrocarbon products were calculated simultaneously, i.e. gas, oil, solution gas and natural gas liquids. The values, or *probabilities of occurrence*, are expressed as minimum (90% probability, or 'P90'), mean, and maximum (10% probability, or 'P10').

8.1 Results By Play (in "Barrel of Oil Equivalents" - BOE)

Figure 47 is a graph of the total unrisked recoverable BOE by play and ranked in descending order. The BOE values also include solution gas and natural gas liquids. The tabular data is also represented in Figure 48.

The plays with the greatest potential appear to be the Mini-Basin Floor and Flank plays, followed by the Upper Slope and the Canopy Supra-salt plays. The major positive factor affecting play assessment is area, and these top plays, by definition, occur over the largest areas. The top six plays account for 86% of the total hydrocarbon assessment values. Another contributing factor is that not all plays are equally imaged by the seismic process, hence the sub-salt plays rank lower in the seriatim. Superior 3D seismic may well alter the perceptions of this study.

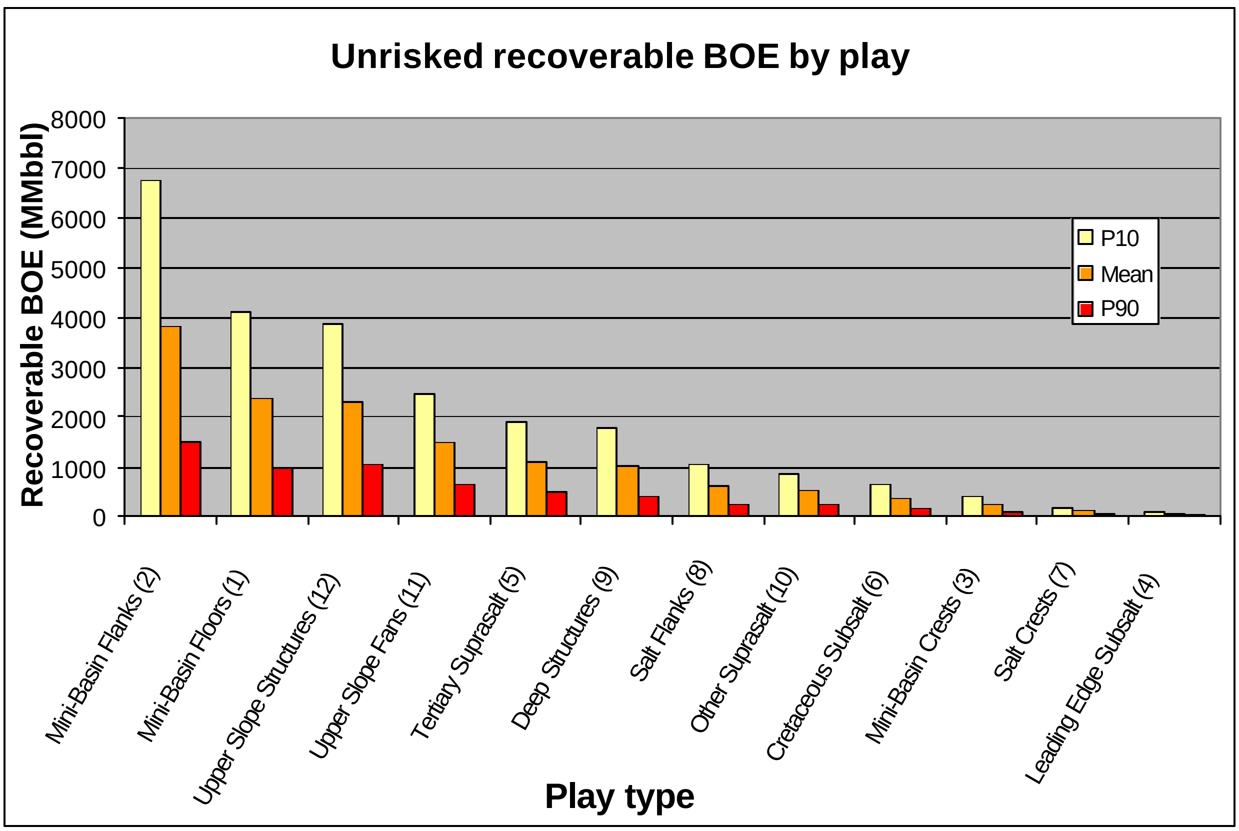


FIGURE 47

A ranking of the twelve plays from largest to smallest of unrisked recoverable BOE. The bars depict the range from P90, Mean and P10.

	Rec. Gas (Bcf)			Rec. Oil (MMB)			Total Rec. in MMOEB		
Play Ranking (Run No.)	**P90**	**Mean**	**P10**	**P90**	**Mean**	**P10**	**P90**	**Mean**	**P10**
Mini-Basin Flanks (2)	3971	10304	18557	531	1434	2605	1520	3810	6746
Mini-Basin Floors (1)	2872	7113	12521	291	762	1375	990	2368	4133
Upper Slope (12)	2712	6149	10463	363	877	1516	1032	2301	3863
Upper Slope (11)	2359	5289	8956	137	330	568	659	1462	2455
Canopy Supra-Salt (5)	1755	4107	6975	98	246	425	485	1120	1893
Structures (9)	986	2449	4332	155	406	730	413	1020	1791
Salt Flanks (8)	608	1490	2590	92	238	419	253	608	1048
Canopy Supra-Salt (10)	664	1432	2358	87	200	338	252	535	872
Canopy Sub-Salt (6)	738	1712	2938	11	28	50	163	375	644
Mini-Basin Salt Crests (3)	283	653	1118	36	90	159	104	236	401
Salt Crests (7)	144	295	472	20	43	71	56	113	181
Leading Edge Sub-Salt (4)	55	109	176	17	31	47	35	64	97
Totals	**30666**	**41102**	**52848**	**3361**	**4685**	**6182**	**10490**	**14012**	**17950**

FIGURE 48

Tabular data to go with the bar graph of Figure 47. Resource values for the 12 play runs are listed in descending order from largest to smallest of unrisked recoverable gas, oil, and BOE.

For each play, figures on the data inputs, and output results for gas, oil, and BOE are included in the Appendix. The following are comments related to the play descriptions and assessment results.

Play 1 – Mini-Basin Floor Turbidite Fans

This play represents a mini-basin depocentre surrounded by autochthonous salt features filled with Cretaceous and Lower Tertiary sediments. They may also include some older Upper Jurassic sediments in certain areas. Some of the mini-basins were structured but most are not, and the floor of the mini-basin may overlie salt, a salt weld or older sediments. There are numerous examples of high and variable amplitudes in these mini-basins suggesting stacked turbidite fans (Figures 28-30). Mapping of the unconformities, especially in the Tertiary succession, suggest that there were sufficient paleo-canyons developed to transport sediments into the deep-water.

The unrisked means for this play are 7.1 Tcf of gas and 762 MMB of oil. The Gulf of Mexico study area described in Section 3.3 is an analogue and provided much-needed constraining factors especially for area considerations. The major play risk was determined to be the presence of reservoir (Figure 45) with less risk for the presence of source rocks and traps, resulting in a play adequacy of 32%.

Play 2 – Mini-Basin Flank Turbidite Fans

This play is intimately related to the floor fan play, but the *percent under trap* and *percent trap fill* factors were treated differently. During the evolution of the adjacent salt feature, the turbidite fans can be deposited either in the topographic lows or carried by momentum to the flanks of the salt-cored highs. Further vertical motion of the salt feature and sediment loading the mini-basin accentuates the vertical relief of the flank sand deposits; some have upturned strata against the salt while others have abrupt terminations. It would appear the dominant GOM trap is the flank trap (Weimer et al., 1998; Cossey, 2002). It is very similar to previous play, but segregation was deemed appropriate because as exploration proceeds one play or the other may be shown to dominate. This play has the largest area hence the largest assessment value.

The unrisked means are 10.3 Tcf of gas and 1434 MMB of oil, and the play adequacy values are the same as the previous play at 32%.

Play 3 – Salt Crests (Associated with Mini-Basins)

This play was tightly constrained for area and consisted of four-way closures over the top of salt features. The crestal closures are relatively shallow in the stratigraphic section and most contain crestal faults with some extending to the sea floor, thus leakage (and seeps) are possible. Net pays are thinner because during rapid salt diapirism the crests become sediment bypass zones. Diagenesis may also negatively affect porosity of any potential reservoirs.

The unrisked means are 0.7 Tcf of gas and 90 MMB of oil. The major play risk was determined to be the presence of reservoir (Figure 45) with less risk for the presence of source rocks and traps, resulting in an overall adequacy of 25%. There have been crestal discoveries of oil in the Sable Subbasin (Shelf) at West Sable and Primrose.

Play 4 – Leading Edge Sub-Salt (Jurassic)

This is a most intriguing play because the spatial geometry is excellent (Figure 31) but the presence of siliciclastic or carbonate reservoir during a period of Late Jurassic sea-level transgression is very risky. A narrow belt exists where the leading edge of the salt is thrust up and over the underlying strata, in this case Late Jurassic sediments. Abyssal-depth marine source rocks probably exist (Dow 1978) and the overlying salt seal is expected.

The unrisked means are 0.1 Tcf of gas and 31 MMB of oil. The greatest play risk is the presence of reservoir (Figure 45) with far less risk for source and trap, such that the overall play adequacy is calculated at 16%.

Play 5 – Supra-Salt Structures (Tertiary and Upper Cretaceous)

This play consists of potentially large folded structures between salt feature incorporating slope fan and channel complexes. Some of these may be classified as "turtle structures" depending on the growth history of the salt and structural inversion of the intervening sediments (Figure 33). These structures appear more prevalent associated with the higher elevation salt canopies, and proximity to paleodeltas should be a positive factor.

The unrisked means for this play are 4.1 Tcf of gas and 246 MMB of oil. The potential for source, reservoir and trap results in a play adequacy of 38% (Figure 45).

Play 6 – Sub-Salt Cretaceous

The sub-salt play consists of Cretaceous age sediments (and possibly some of Jurassic age) and is imaged sufficiently enough to reasonably define and map seismic markers (Figure 33). The traps would be low-relief with some truncation by the salt providing excellent seals. However, where the seal is a salt weld, its sealing integrity may be suspect.

The unrisked means for this play are 1.7 Tcf of gas and 28 MMB of oil. The presence of reservoir is the greatest risk factor such that the overall play adequacy is 17% (Figure 45).

Play 7 – Salt Diapir Crests (Associated with the Salt Withdrawal Area)

The salt withdrawal area has very few salt diapirs and hence a small area that is tightly constrained (Figure 20). The crests appear relatively competent with a low degree of crestal faulting as compared to Play 3. Reservoir will be the greatest risk as crestal areas can be depositionally bypassed or diagenetically-modified.

This play's unrisked means are 0.3 Tcf of gas and 43 MMB of oil. The presence of reservoir, source and seal are all risky resulting in a play adequacy of 20% (Figure 45).

Play 8 – Salt Diapir Flanks

The flanks of the isolated diapirs give rise to a doughnut-shaped feature on mapped horizons, with rim synclines developed (Figure 20). Although small in total size, this play is quite rich on a per-unit basis.

The unrisked means are 1.5 Tcf of gas and 238 MMB of oil, with an overall play adequacy similar to Play 8 at 20% (Figure 45).

Play 9 – Deep Structures

The area of salt withdrawal is a large area, and numerous deep structures of probable Cretaceous age associated with salt pillows and other sediment slumping can be observed (Figure 20). These structures involve down-to-the-basin listric faults, hence roll-over anticlines should be present.

Play 9's unrisked means are 2.4 Tcf of gas and 406 MMB of oil. The major risk is the presence of reservoir, with a lesser risk for source and trap, which together result in a play adequacy of 20% (Figure 45).

Play 10 – Other Supra-Salt Structures

The area covered by Play 10 is the least understood due to data quality. The interpreted supra-salt structures are much like those for Play 5 and are potentially very large. However, here they are less clearly seismically defined. The nature of the controlling salt, whether by canopy or simple diapiric process, is poorly understood.

The unrisked means for Play 10 are 1.4 Tcf of gas and 200 MMB of oil, with the presence of reservoir the greatest risk and a resulting play adequacy of 25% (Figure 45).

Play 11 – Upper Slope Fans and Structures (Tertiary and Cretaceous)

The Upper Slope lies between the Jurassic Abenaki Carbonate Bank to the north, and the advent of the canopy / diapiric region to the south (Figure 34). Turbidite fans on this part of the Slope can either be structured or unstructured. Large-scale features associated with down-to-the-basin listric faults and as yet defined deeper salt structures are observed. This play is poorly imaged and 3-D seismic is required to delineate prospects.

The unrisked means for Play 11 are 5.3 Tcf of gas and 330 MMB of oil. As a result of the announced gas discovery encountered by Marathon it its Annapolis G-24 well, the source risk is mitigated. Reservoir risk is considered minimal given the proximal position to the Sable Paleodelta (Figure 45).

Play 12 – Upper Slope Fans and Structures (Cretaceous and Jurassic)

This is the same play as Play 12 but with a different appreciation of the potential reservoir zones and proximity to paleodeltas (reservoirs). Source and reservoir risk are thus influenced by the relevant position of individual prospects. Three wells have previously been drilled in this play based on the then-current (1980s) understanding of deep-water sedimentary processes and petroleum systems (Figure 16).

Play 12's unrisked means are 6.1 Tcf of gas and 877 MMB of oil. The presence of source and reservoir are considered more risky than Play 11 resulting in an overall play adequacy of 50% (Figure 45).

8.2 Play Totals Summation

The 12 plays were assessed independently and their results combined statistically for the totals. Figures 49 and 50 tabulate these totals for gas, oil, solution gas and natural gas liquids in Imperial and Metric units respectively. Volumes of hydrocarbons were calculated for *in-place* and *recoverable* quantities. The results are expressed *without* geological risk and *with* risk. Each of the four quadrants also show the probability range expressed as P90 (low-side), Mean and P10 (high-side).

With reference to gas only, as an example, there is a risked recoverable mean potential of 15.2 Tcf with a range between 4.6 and 27.7 Tcf. If current and future drilling can prove the existence of the petroleum systems in the deep-water thereby reducing or eliminating the geological play risks the potential can be expressed as a mean potential of 41.1 Tcf with a range between 30.7 and 52.8 Tcf.

If we focus on the mean values and express the potential lying somewhere between the risked and the unrisked values then we can state the mean gas potential is 15.2 to 41.1 Tcf. Similarly the oil component is significant and the potential is 1.7 to 4.7 BB.

Given the potential oil volumes the solution gas is also significant at 2.6 to 7.5 Tcf and the natural gas liquids are 0.5 to 1.2 BB.

	UNRISKED In-Place				UNRISKED Recoverable		
	P90	Mean	P10		P90	Mean	P10
Gas (Tcf)	45.8	60.4	77.2		30.7	41.1	52.8
Oil (BB)	10.7	14.4	18.6		3.4	4.7	6.2
sub-total (BOEB)	18.3	24.5	31.5		8.5	11.6	15.0
Solution Gas (Tcf)	17.2	23.0	29.5		5.4	7.5	9.8
NGL (BB)	1.4	1.8	2.3		0.9	1.2	1.6
sub-total (BOEB)	4.3	5.6	7.2		1.8	2.4	3.2
Total (BOEB)	22.8	30.1	38.3		10.5	14.0	18.0
	RISKED In-Place				RISKED Recoverable		
	P90	Mean	P10		P90	Mean	P10
Gas (Tcf)	7.0	22.1	39.5		4.6	15.2	27.7
Oil (BB)	1.3	5.0	9.4		0.4	1.7	3.2
sub-total (BOEB)	2.5	8.7	16.0		1.2	4.2	7.8
Solution Gas (Tcf)	2.1	7.9	14.7		0.7	2.6	5.0
NGL (BB)	0.2	0.7	1.2		0.1	0.5	0.8
sub-total (BOEB)	0.55	2.02	3.65		0.22	0.9	1.63
Total (BOEB)	3.1	10.7	19.6		1.5	5.1	9.3

FIGURE 49

Assessment Results for the Deep-water Slope offshore Nova Scotia (IMPERIAL Units).

8.3 Richness Comparison with Analogue and Other Basins

It is useful to compare an assessment of conceptual plays with other comparable sedimentary basins. One method is to compare EUR (Estimated Ultimate Recovery) versus basin area. The EUR includes all produced, proven and unproven hydrocarbons of a basin. This ratio yields an overall basin richness expressed in MBOE (Thousands of barrels of oil equivalent) per unit area. The radiating lines in Figure 51 are equal richness lines ranging from 50 to 400 MBOE/km^2. To the extent possible, the EUR's are for oil and gas only, as solution gas and natural gas liquids are not always defined.

The Scotian Slope assessed in this report has an oil equivalent value of 4.2 BB (risked) and an area of 80,000 km^2 for a richness of 53 MBOE/km^2. The Scotian Shelf is plotted separately with 4 BB over an area of 120,000 km^2 or 33 MBOE/km^2. The combined Shelf and Slope values are 8.2 BB over an area of 200,000 km^2 or 41 MBOE/km^2. Thus, the Scotian Basin off Nova Scotia compares approximately the same as other Canadian frontier basins such as the Labrador Shelf, Sverdrup and Beaufort. The Egret Petroleum System off Newfoundland is quite rich at 229 MBOE/km^2 but has a small area of 32,800 km^2 as presently defined.

It is important to remember that the other basins in this comparison have proven petroleum systems, both on the shallow continental shelf and in deeper waters. The Brazilian basins, Campos and Santos, and the west African Congo Delta are significantly richer on a per unit basis. However, if the unrisked Scotian Slope is plotted; i.e. proven petroleum system(s), the richness value would increase from 53 to 144 MBOE/km^2 and become more comparable to the aforesaid basins (Figure 52).

	UNRISKED In-Place				UNRISKED Recoverable		
	P90	Mean	P10		P90	Mean	P10
Gas (E9m3)	1297	1710	2187		868	1164	1497
Oil (E6m3)	1695	2281	2961		534	744	982
sub-total (E6m3)	2992	3991	5148		1402	1908	2479
Solution Gas (E9m3)	487	652	836		154	211	277
NGL (E6m3)	217	288	369		145	196	254
sub-total (E6m3)	704	940	1205		299	407	531
Total (E6m3 OE)	3627	4778	6081		1667	2227	2853
	RISKED In-Place				RISKED Recoverable		
	P90	Mean	P10		P90	Mean	P10
Gas (E9m3)	197	625	1119		131	430	785
Oil (E6m3)	201	792	1502		64	264	510
sub-total (E6m3)	398	1417	2621		195	694	1295
Solution Gas (E9m3)	59	224	417		19	74	141
NGL (E6m3)	33	106	192		22	73	133
sub-total (E6m3)	92	330	609		41	147	274
Total (E6m3 OE)	496	1695	3113		237	811	1473

FIGURE 50

Assessment Results for the Deep-water Slope offshore Nova Scotia (METRIC Units).

Figure 52 is the same graph as above but with a larger scope to include other global basins such as the GOM with its phenomenal richness of close to 400 MBOE/km^2 and the Western Canada Basin with its modest richness of 54 400 MBOE/km^2 but having a much larger area of 1.4 million km^2.

In conclusion, the Scotian Slope covers a relatively small area and has an assessed richness comparable to other Canadian frontier basins with an attractive upside potential.

8.4 Impact on Historical Assessments

The impact of this assessment on the total values for the offshore Scotian Basin are shown in Figure 53 for marketable gas, oil, natural gas liquids and barrel-oil-equivalents. These graphs track the assessments for the areas delineated in Figure 14 and show the overall increase in hydrocarbon resource values as more of the basin area is assessed over time.

The impact of adding the Slope assessment, on a *risked* basis, is to basically double the gas potential of offshore Nova Scotia while adding significant oil potential. In other words, adding the traditional 18 Tcf from the shelf to a *risked* value of 15 Tcf for the slope gives a total potential of 33 Tcf. The graph reads slightly higher at 37 Tcf because it includes 2.6 Tcf of solution gas contained in the oil fraction.

Similarly, adding the traditional 1 BB of oil (and liquids) to the 2 BB for the Slope offers a total potential of 3 BB of oil. On an oil-equivalent basis, the potential has basically doubled from 4 BOEB to 9 BOEB.

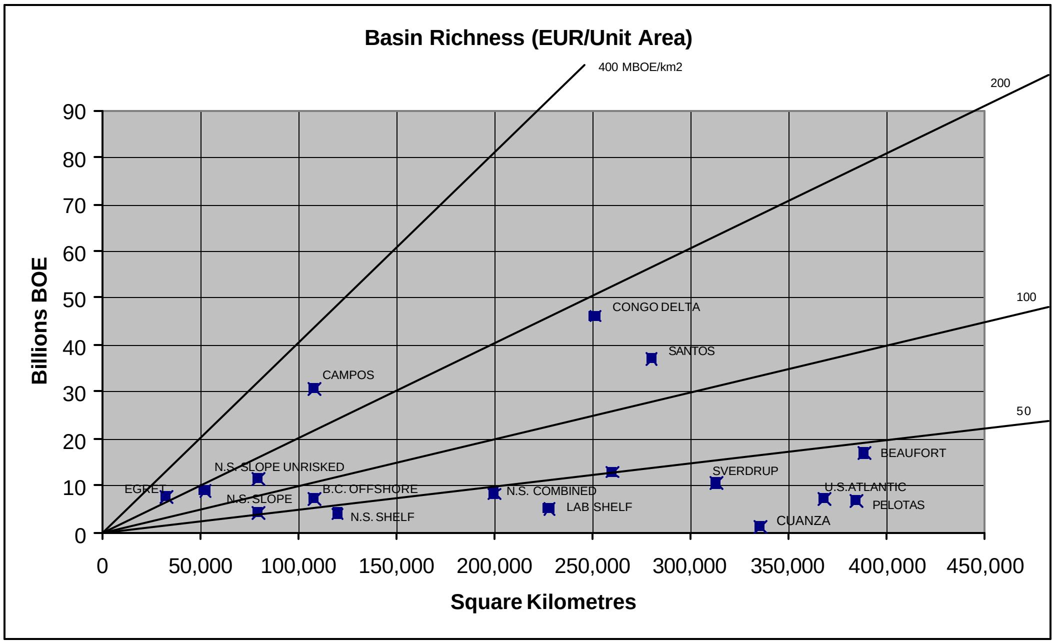


FIGURE 51

This basin richness graph compares EUR (Estimated Ultimate Recovery) versus basin area and is expressed as MBOE/km^2. Information on the Canadian basins are from various GSC and other publications and open files. The GOM and U.S. Atlantic values are from MMS reports and all other global data is from the USGS.

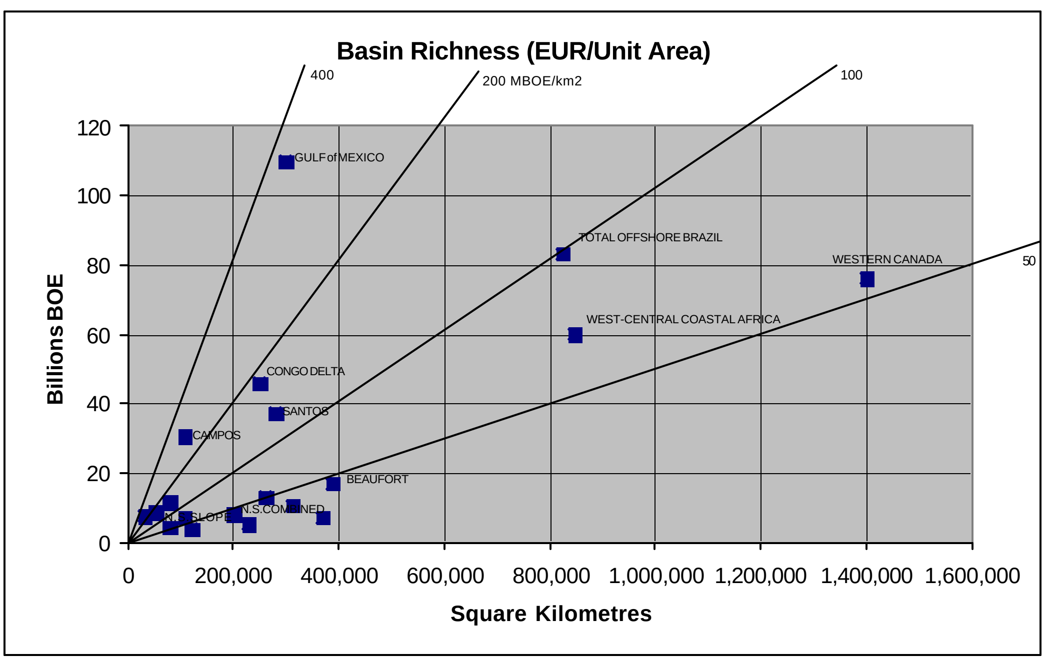
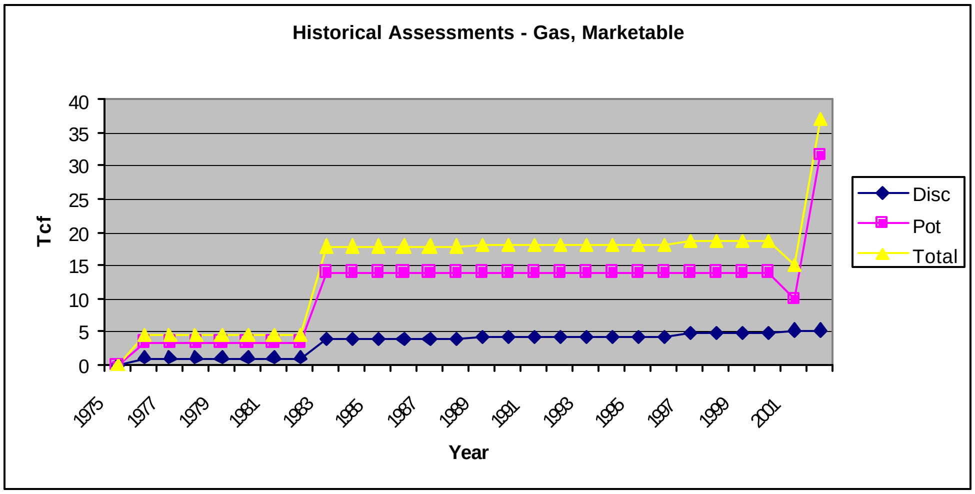
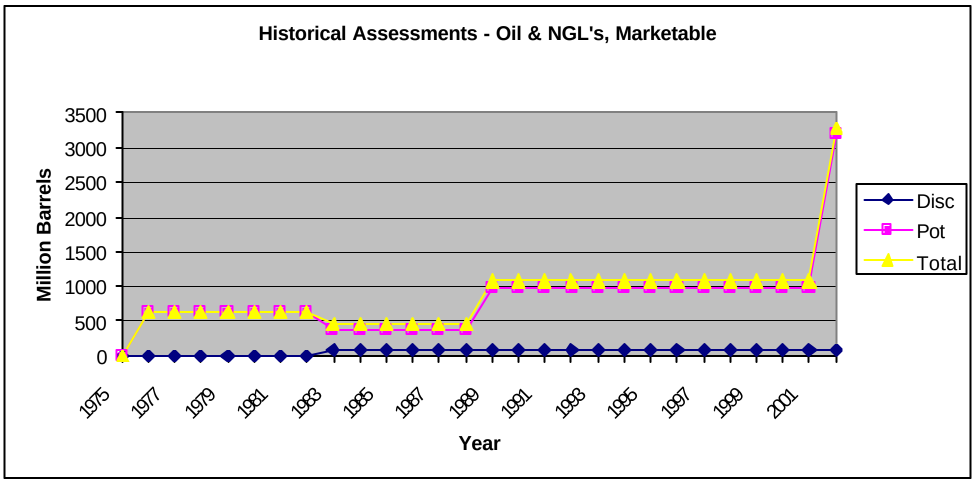


FIGURE 52

Expanded scale graph of basin richness from Figure 51 that includes the Gulf of Mexico, and the total Offshore Brazil and West-Central Coastal African regions (all basins).





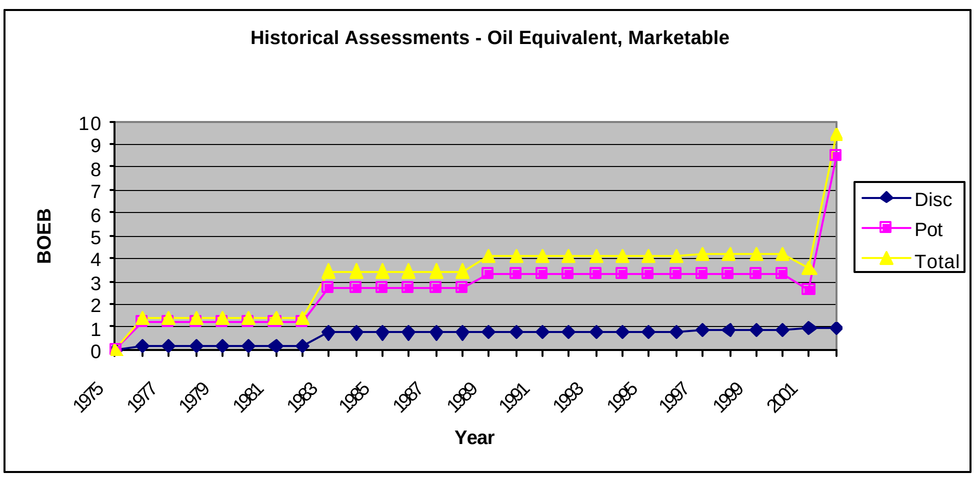


FIGURE 53

Historical assessment graphs for gas, oil and oil equivalent from 1975 to the present: Discoveries (blue), Undiscovered Potential (magenta), and Combined Total (yellow).

CHAPTER 9

CONCLUSIONS

Conclusions can be expressed on the basis of the geological basin evaluation and the results of the numerical analyses. The results of our assessment are encouraging and substantially add to Nova Scotia's offshore hydrocarbon potential. This first step in attempting to assess the deep-water Scotian Slope contains various levels of uncertainty, but as new drilling results come forth it becomes a matter of revision and updating.

9.1 Basin Evaluation

Offshore Nova Scotia and the analogue basins of the Gulf of Mexico, offshore Brazil and West Central Africa are all passive margins with progradation of dominantly siliciclastic sediments over a mobile salt substrate and up-dip hydrocarbon production within a deltaic complex. The conjugate basins offshore Morocco have yet to encounter commercial quantities of hydrocarbons on its shelf.

A major difference is timing of the continental break-up and ages of salt deposition, source rocks and reservoirs. The North Atlantic rifted in Late Triassic to Early Jurassic while the South Atlantic rifted in Early Cretaceous about 100 million years later. The GOM in the Central Atlantic area underwent prolonged rifting from early Jurassic though only accumulated its thick sedimentary succession over the past 40 million years. Nevertheless, although the ages of rifting and breakup are different, the inherent geological processes are the same.

The analogue basins have proven petroleum systems with large discoveries in the billion-barrel range on an oil-equivalent basis, while the Scotian Slope's petroleum system(s) have yet to be proven.

Geochemical analyses and one-dimensional modeling indicate the potential for multiple source rock intervals with favourable maturation and expulsion of hydrocarbons and the expectation for varying oil/gas ratios across the basin.

Interpretation of 30,000 km of 2D seismic data was carried out defining ten geologic markers. The stratigraphic correlations were extended from wells on the Shelf as well as the deep ocean scientific seismic profiles and the Deep Sea Drilling Project wellbores. The single greatest challenge was mapping the top and base of the ubiquitous mobile Jurassic Argo Salt.

Seismic mapping shows a very similar salt tectonic-influenced structural style of play types and trapping configurations. There are supra-salt, inter-salt and sub-salt play types common to the analogue basins. The inter-salt mini-basins are major submarine focal points for turbidite deposition of reservoir-grade coarse clastics and hydrocarbon source organic matter. Folds and anticlinal structures formed through sediment loading and salt withdrawal near the crest of the slope provide excellent large-size traps. Sub-salt plays throughout the geologic section are attractive because the overlying salt provides a perfect seal for trapped hydrocarbons. Folds created along the leading edge of the mobile salt can provide excellent structural traps and seals.

Major submarine canyons are observed on the present-day seafloor and can be mapped in the subsurface, particularly at major times of relative sea level lowstands in the Tertiary and Cretaceous. These submarine canyons are necessary for providing conduits for coarse-grained turbidite fan deposits that provide both reservoir and source material.

All the important ingredients of source, seal and trap are interpreted to be present along the deep-water Slope with the degree of uncertainty being addressed by the geologic risk factors at both the prospect and the play level.

9.2 Numerical Analysis

Numerical analysis were run on twelve individual plays and statistically summed for a total. All input parameters were entered as minimum, most likely and maximum values with Monte Carlo simulation of 10,000 iterations. The results are expressed as *risked* and *unrisked*, *in-place* and *recoverable* values for gas, oil, solution gas and natural gas liquids.

All of the assessment work was completed in-house by Board staff with outside expertise employed as required. The assessment software employed was user-friendly, very transparent and facilitated revisions. The broad range of the assessment results is thus sufficiently robust to have a shelf life until such time as there is significant new information from additional seismic data, wells and the like.

The highest-rated plays are turbidite fans lying on the floors and flanks of inter-salt mini-basins, and upper slope turbidite fans in a structured regime associated with listric down-to-basin faults and salt features. The sub-salt plays are rated lower, but this is partly a function of poorer seismic imaging of the sub-salt strata in the data available to the assessors. The top six plays account for 86% of the total assessment value.

The *undiscovered potential* for the deep-water Slope off Nova Scotia on a *risked mean recoverable basis* is 15 Tcf of gas and 1.7 BB of oil with solution gas of 2.6 Tcf and natural gas liquids of 0.5 BB.

The plays are conceptual because to date the petroleum system(s) are not proven. The overall play adequacies vary from 16% to 64% (average 30%) for the 12 plays identified.

The *undiscovered potential* on an *unrisked mean recoverable basis* (i.e. proven plays by discovery) is 41 Tcf of gas and 4.7 BB of oil with solution gas of 7.5 Tcf and natural gas liquids of 1.2 BB.

The forecast window, in very general terms, therefore is 15 to 41 Tcf of gas and 1.7 to 4.7 BB.

The potential of the Scotian Slope, on a risked basis, doubles the gas potential and triples the oil potential for Nova Scotia's portion of the overall Scotian Basin.

The predicted *hydrocarbon richness per unit area* places the Scotian Slope within the range of other Canadian frontier basins such as the Labrador, Sverdrup and Beaufort Basins and below the richer proven basins in the Gulf of Mexico and offshore Brazil and West Africa.

This assessment is a first step in what is an acknowledged and accepted subjective exercise. As new data and information, especially drilling results, becomes available, revisions and updates can readily be made to the existing study.

GLOSSARY

allochthonous: Formed or produced elsewhere than in its present place; of foreign origin, or introduced.

autochthonous: Formed or produced in the place where it is now found.

BB: Billion barrels (10^9)

Bcf: Billion cubic feet (10^9)

BOE: Barrels of Oil Equivalent

BOEB: Billion of Oil Equivalent Barrels

BBOE: Billion Barrels Oil Equivalent

CGPC: Canadian Gas Potential Committee

COGLA: Canadian Oil and Gas Lands Administration (Canada)

conceptual play: An exploration play that does not yet have discoveries or reserves but which geological analysis indicates may exist.

deterministic calculation: Arithmetic calculation of variables.

discovery: The term applies to the granting by CNSOPB of a Significant Discovery License (SDL) which means oil and/or gas was tested to surface in significant quantities that have potential for future commercial development.

DSDP: Deep Sea Drilling Project

EMR: Energy, Mines and Resources (Canada)

established play: An exploration play that has been demonstrated to exist by the discovery of one or more pools. Commerciality may or may not be a factor in the definition.

fluvial: Of, or pertaining to, a river or rivers.

EUR: Estimated Ultimate Recovery equals, at any point in time, the sum of produced, proven reserves and undiscovered potential.

GIP: Gas-in-place

GOM: Gulf of Mexico

GSC: Geological Survey of Canada

lacustrine: Pertaining to, produced by, or formed in a lake or lakes.

MB: Thousand barrels (10^3)

Mcf: Thousand cubic feet (10^3)

mean: A statistical measure of central tendency; the risk-weighted average value of all possible outcomes / repeated trials.

median: A statistical measure of central tendency; the arithmetic average, or, the 50% probability.

Monte Carlo Simulation: A statistical procedure where variables are expressed as probability distributions and randomly sampled to create an output distribution. Number of random samples commonly between 5,000 and 10,000.

MMB: Million barrels (10^6)

MMcf: Million cubic feet (10^6)

MMS: Minerals Management Service, U.S. Department of the Interior

Mya: million years ago

New Field Wildcat (NFW): The first well on a prospect or geological feature that is testing a new structure or play concept. Such a feature may straddle more than one fault block. As opposed to a delineation well, step-out, development, injector, etc.

NGL: natural gas liquids

ODP: Ocean Drilling Project

OIP: Oil-In-Place

OOIP: Original-Oil-In-Place

play: A geological formation, or structural or stratigraphic trend, which has similar lithologic, reservoir or other characteristics extending over some distance or extent.

potential: Unproven quantities of recoverable hydrocarbons that may exist.

prospect: A singular structure or geologic feature that has the necessary attributes to contain hydrocarbons and hence be a drilling target.

reserves: Quantities of oil, gas and related substances that are proven to exist in known accumulations and are believed recoverable at some point in time. This includes both discovered initial reserves and discovered unrecoverable volumes.

resources: The total quantity of oil, gas and related substances that are estimated at a particular time to be contained in, or that have been produced from, known accumulations, plus, those estimated quantities in accumulations yet to be discovered. This includes both future initial reserves and future unrecoverable volumes.

stochastic calculation: Statistical calculation using Monte Carlo (or other) sampling techniques of input variables to result in a probability output distribution.

Tcf: Trillion cubic feet (10^{12})

turbitite: A sediment or rock deposited from, or inferred to have been deposited from, a turbidity current.

turbidity current: A bottom-flowing current laden with suspended sediment, moving swiftly (under the influence of gravity) down a subaqueous slope and eventually spreading out horizontally on the deep floor of the body of water. Sand and finer sediments can be deposited as fans, channels, sheets etc., their sizes and shapes depending on the topography of the ocean bottom and slope, types of sediments in the flow, size and duration of the turbidite current and so forth. Turbidite currents and related subsea avalanches / slope failures are virtually instantaneous events that can move tremendous volumes of coarse grain sediment great distances far out into the abyssal depths over a period of several minutes to several hours.

USGS: United States Geological Survey

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Canadian Society of Petroleum Geologists, Calgary, Alberta, 572p.

APPENDIX – NUMERICAL INPUT SHEETS AND OUTPUT CHARTS

APPENDIX FIGURES

Probability Input Sheet

Play Type Play 1 - Mini-Basin Floors

Reservoir Parameters	Probability 1	0.5	0	MEAN
Total Play Area (km^2)	6469.2	7188	7906.8	7188
Fraction of Area Under Trap	0.1	0.2	0.4	0.233333
Fraction of Trap Filled	0.6	0.7	0.8	0.7
Discounted Play Area (km^2)	388.2	1006.32	2530.2	1174.0
Net Pay (m)	15	50	100	55
Porosity	0.1	0.2	0.25	0.183333
Hydrocarbon Saturation	0.6	0.7	0.8	0.7
Depth of Reservoir (m)	4000	5000	6000	5000
Z	1.15	1.25	1.35	1.25
Gas Volume Factor	305.9	323.0	331.7	323.0
Fraction of Pore Volume Oil Bearing	0.3	0.5	0.6	0.467
GOR (m3/m3)	232.68	290.85	349.02	290.85
Formation Volume Factor (Oil)	1.748	1.935	2.122	1.935
Prospect Adequacy	0.10	0.20	0.30	0.2
Liquids Yield (BBL/MMCF)	20	30	40	30
Oil Recovery Factor	0.15	0.3	0.45	0.3
Gas Recovery Factor	0.5	0.7	0.9	0.7
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

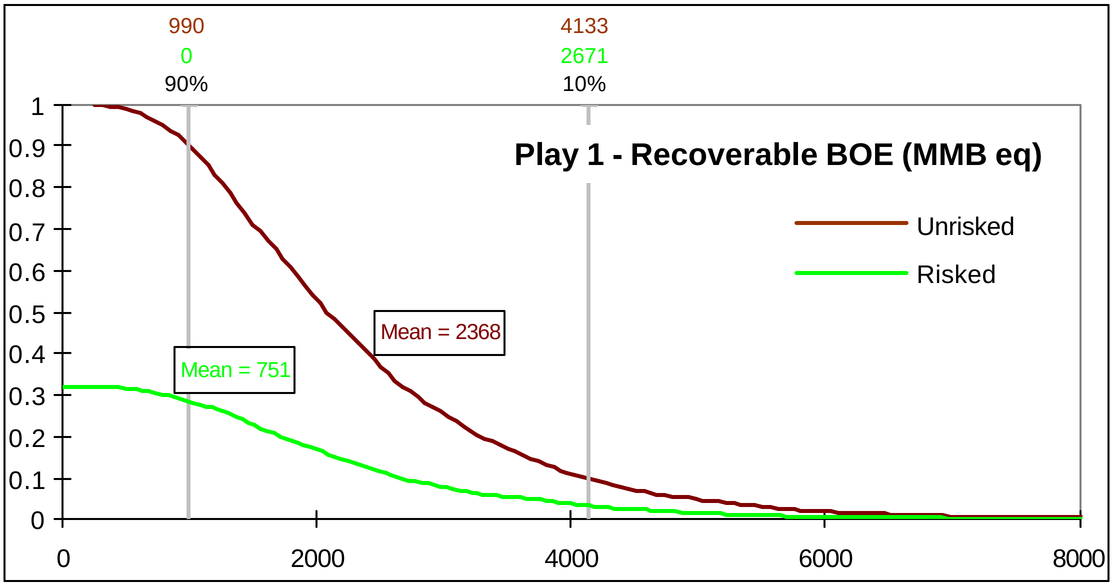
Risk Parameters

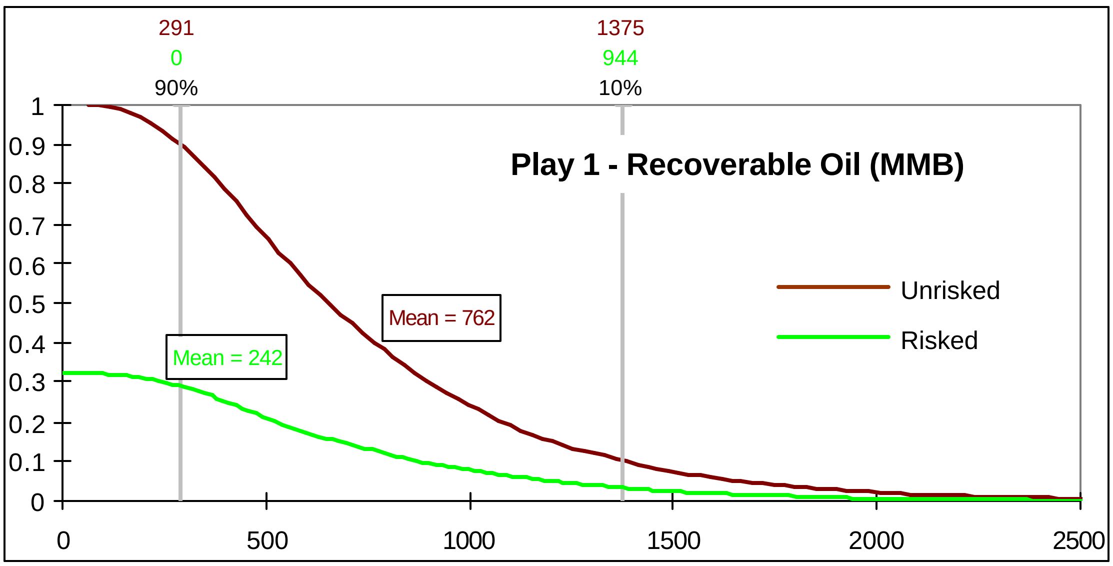
Play Adequacy	32	0

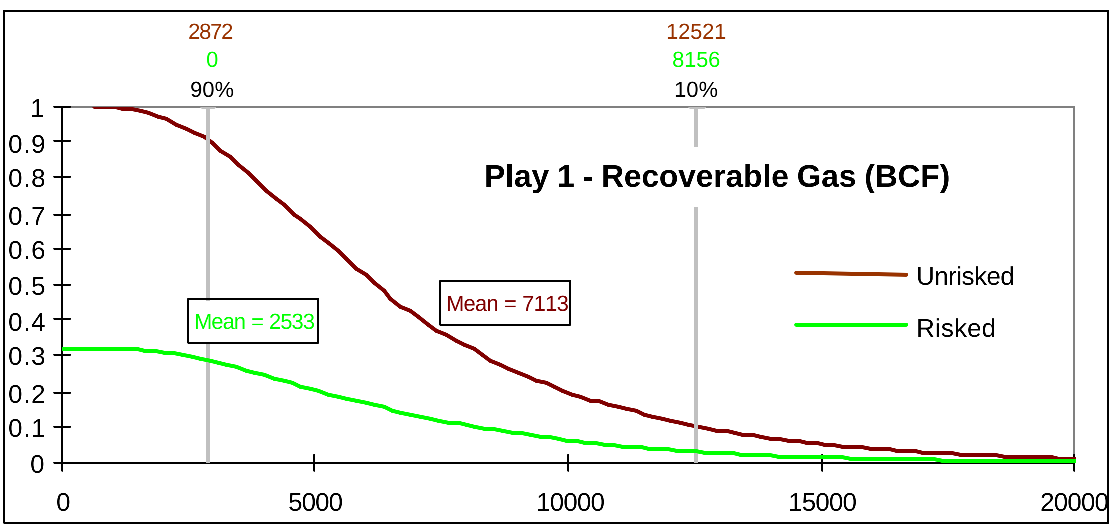
Other Parameters

Pressure gradient (kPa / m)	10.02	Sfc Pressure (kPa)		101.3
Temperature gradient (°C / 100 m)	2.9	Surface Temp (°C)		4
	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	53.3	82.3	111.3	82.3
Reservoir Pressure (kPa)	40181.30	50201.30	60221.30	50201.30

Gas to BOE conversion factor (MCF/BBL) 6


990
0
90%
4133
2671
10%
Play 1 - Recoverable BOE (MMB eq)
Unrisked
Risked
Mean = 2368
Mean = 751
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
2000
4000
6000
8000


291
0
90%
1375
944
10%
Play 1 - Recoverable Oil (MMB)
Unrisked
Risked
Mean = 762
Mean = 242
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
500
1000
1500
2000
2500


2872
0
90%
12521
8156
10%
Play 1 - Recoverable Gas (BCF)
Unrisked
Risked
Mean = 7113
Mean = 2533
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
5000
10000
15000
20000

Probability Input Sheet

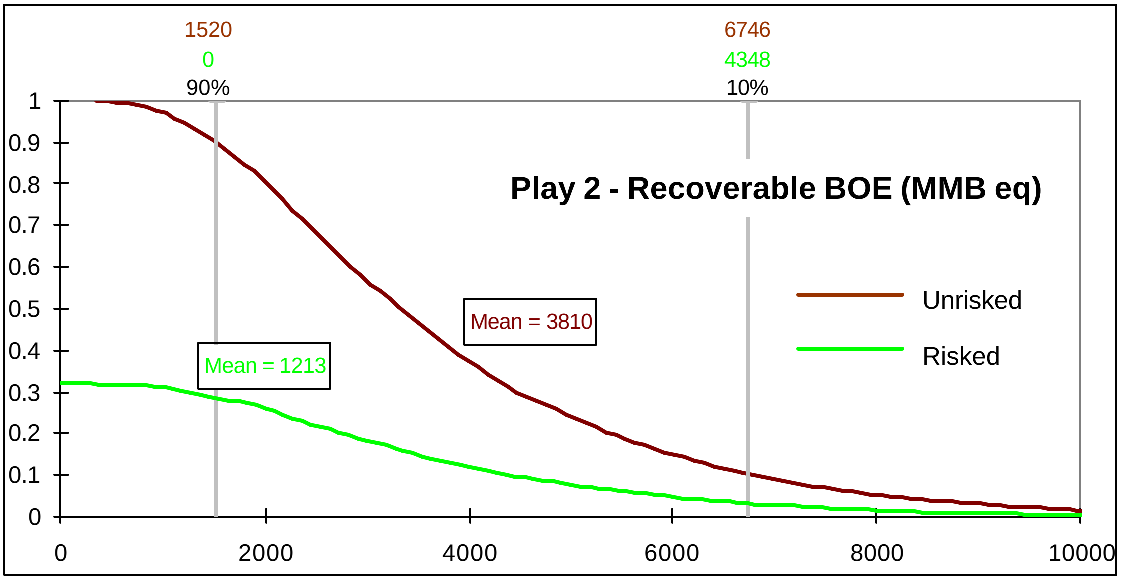
Play Type Play 2 - Mini-Basin Flanks

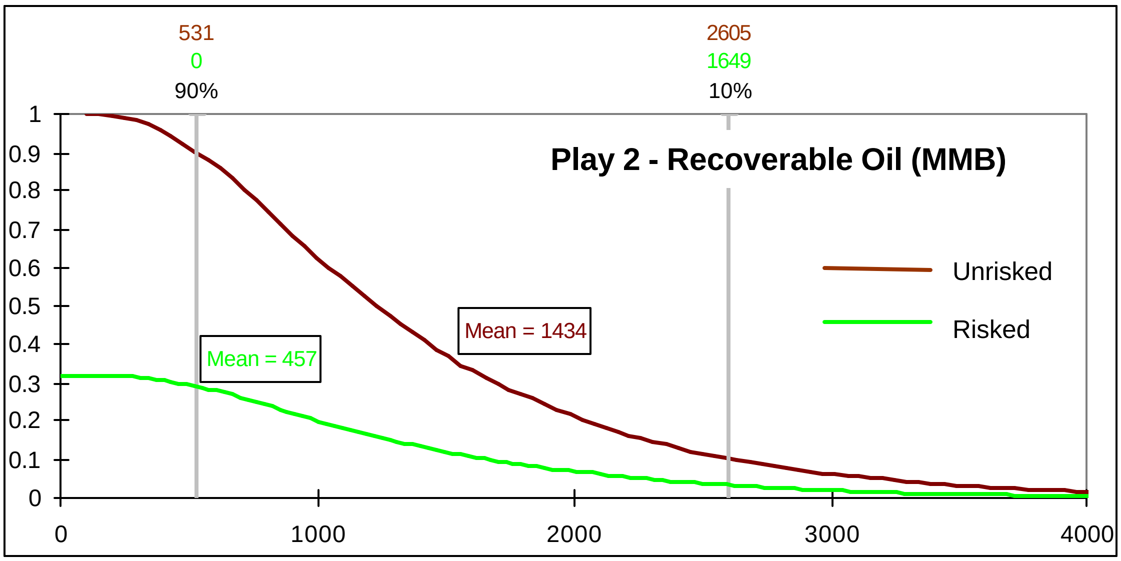
Reservoir Parameters	Probability			
	1	0.5	0	MEAN
Total Play Area (km^2)	8000	10000	14415	10805
Fraction of Area Under Trap	0.05	0.15	0.3	0.166667
Fraction of Trap Filled	0.7	0.8	0.9	0.8
Discounted Play Area (km^2)	280.0	1200	3892.1	1440.7
Net Pay (m)	15	50	100	55
Porosity	0.1	0.2	0.25	0.183333
Hydrocarbon Saturation	0.6	0.7	0.8	0.7
Depth of Reservoir (m)	3500	4500	5500	4500
Z	1.15	1.25	1.35	1.25
Gas Volume Factor	281.3	305.1	318.8	305.1
Fraction of Pore Volume Oil Bearing	0.3	0.5	0.6	0.467
GOR (m3/m3)	203.60	261.77	319.94	261.77
Formation Volume Factor (Oil)	1.655	1.842	2.029	1.842
Prospect Adequacy	0.15	0.25	0.35	0.25
Liquids Yield (BBL/MMCF)	20	30	40	30
Oil Recovery Factor	0.2	0.35	0.5	0.35
Gas Recovery Factor	0.5	0.7	0.9	0.7
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

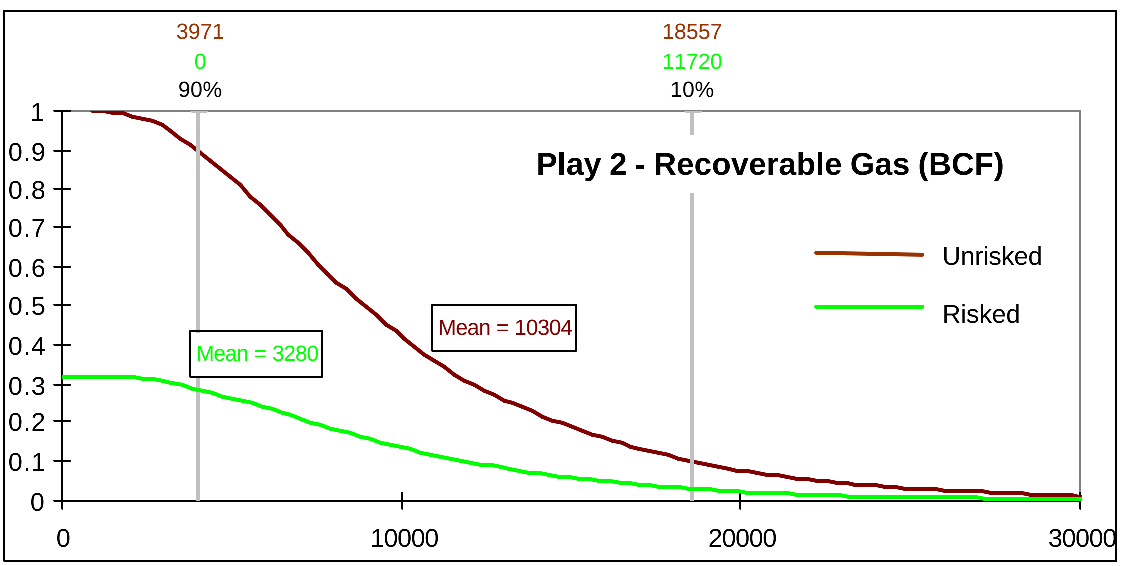
Risk Parameters		
Play Adequacy	32	0

Other Parameters				
Pressure gradient (kPa / m)	10.02	Sfc Pressure (kPa)		101.3
Temperature gradient (°C / 100 m)	2.8	Surface Temp (°C)		4
	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	37.6	65.6	93.6	65.6
Reservoir Pressure (kPa)	35171.30	45191.30	55211.30	45191.30

Gas to BOE conversion factor (MCF/BBL) 6


1520
0
90%
6746
4348
10%
Play 2 - Recoverable BOE (MMB eq)
Unrisked
Risked
Mean = 3810
Mean = 1213
0
2000
4000
6000
8000
10000


531
0
90%
2605
1649
10%
Play 2 - Recoverable Oil (MMB)
Unrisked
Risked
Mean = 1434
Mean = 457
0
1000
2000
3000
4000


3971
0
90%
18557
11720
10%
Play 2 - Recoverable Gas (BCF)
Unrisked
Risked
Mean = 10304
Mean = 3280
0
10000
20000
30000

Probability Input Sheet

Play Type   Play 3 - Salt Crests

Reservoir Parameters

	Probability			
	1	0.5	0	MEAN
Total Play Area (km^2)	6153	6564.5	6976	6564.5
Fraction of Area Under Trap	0.3	0.4	0.5	0.4
Fraction of Trap Filled	0.1	0.2	0.3	0.2
Discounted Play Area (km^2)	184.6	525.16	1046.4	525.2
Net Pay (m)	10	20	35	21.66667
Porosity	0.1	0.25	0.3	0.216667
Hydrocarbon Saturation	0.6	0.7	0.8	0.7
Depth of Reservoir (m)	3000	3500	4000	3500
Z	1.1	1.2	1.3	1.2
Gas Volume Factor	264.1	269.6	272.1	269.6
Fraction of Pore Volume Oil Bearing	0.3	0.5	0.6	0.467
GOR (m3/m3)	174.51	203.60	232.68	203.60
Formation Volume Factor (Oil)	1.561	1.655	1.748	1.655
Prospect Adequacy	0.05	0.10	0.20	0.116667
Liquids Yield (BBL/MMCF)	20	30	40	30
Oil Recovery Factor	0.15	0.2	0.4	0.25
Gas Recovery Factor	0.5	0.6	0.8	0.633333
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

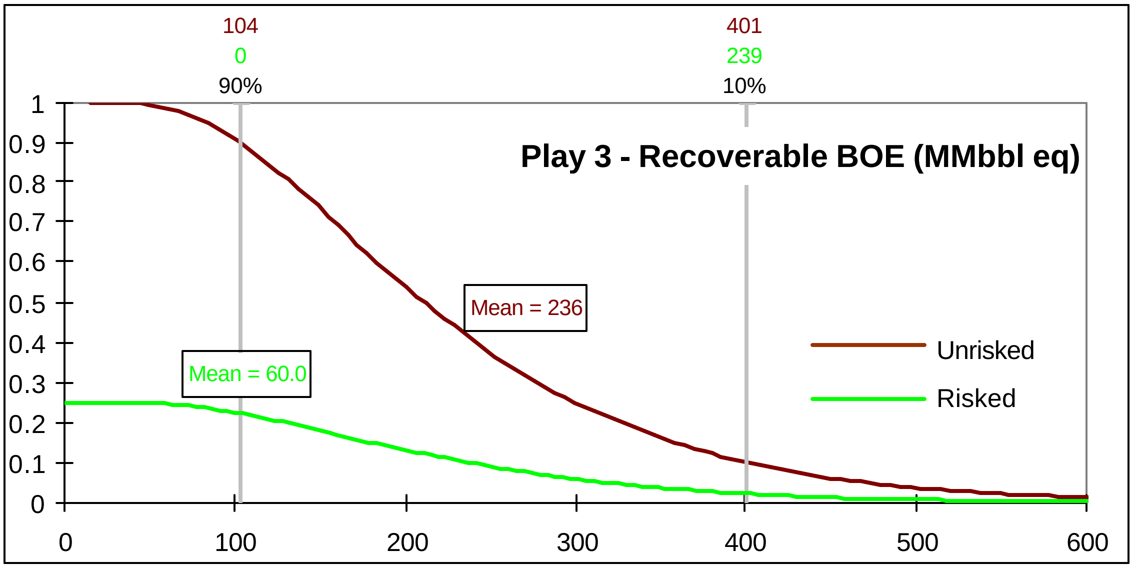
Risk Parameters

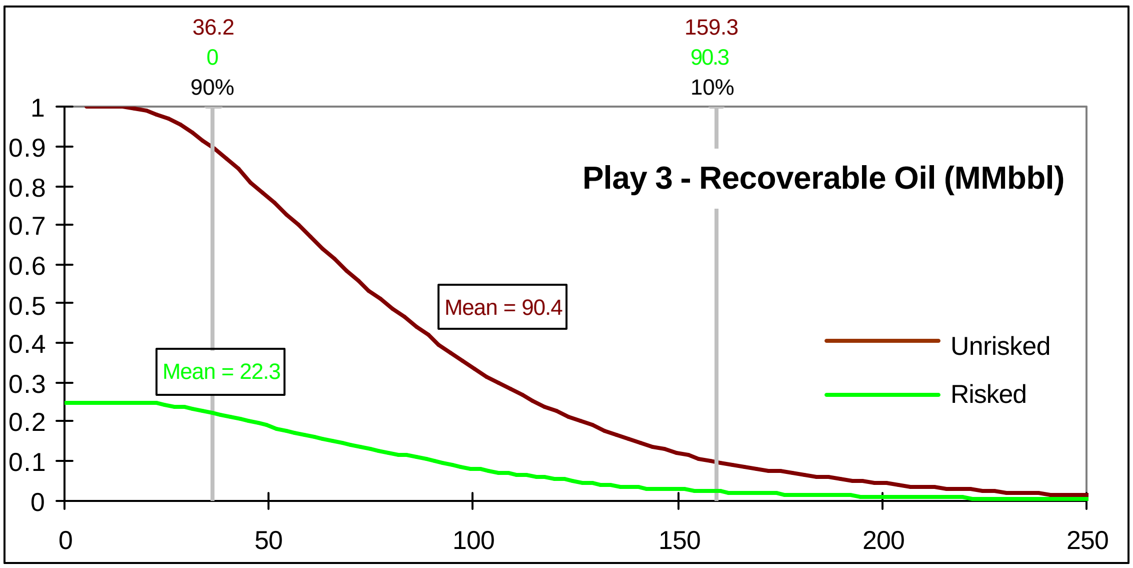
Play Adequacy	25	0

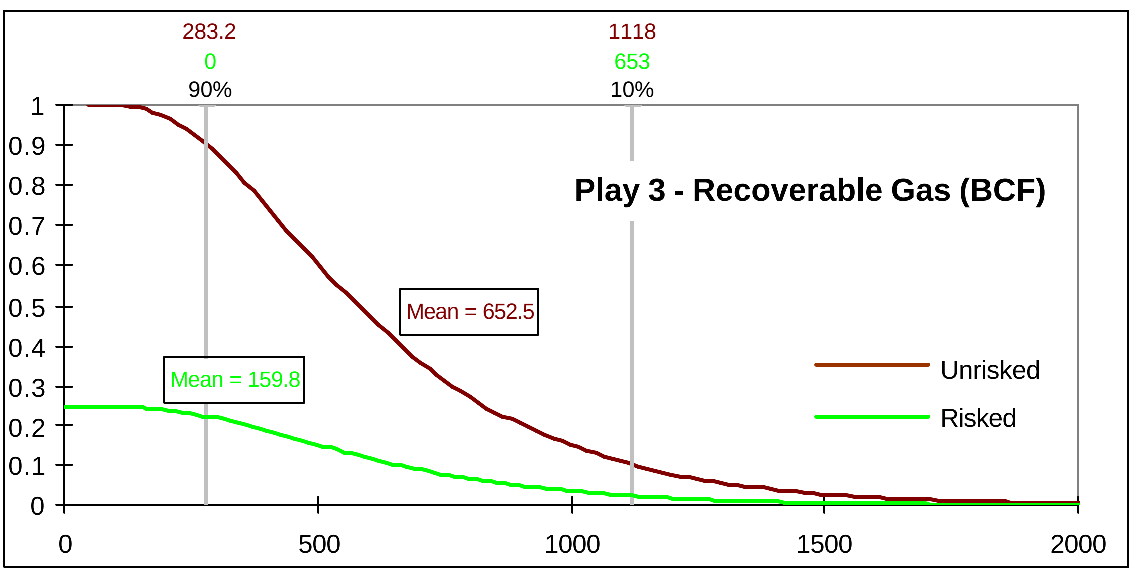
Other Parameters

Pressure gradient (kPa / m)	10.02	Sfc Pressure (kPa)		101.3
Temperature gradient (°C / 100 m)	2.8	Surface Temp (°C)		4
	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	23.6	37.6	51.6	37.6
Reservoir Pressure (kPa)	30161.30	35171.30	40181.30	35171.30

Gas to BOE conversion factor (MCF/BBL)   6


104
0
90%
401
239
10%
Play 3 - Recoverable BOE (MMbbl eq)
Mean = 236
Mean = 60.0
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
100
200
300
400
500
600


36.2
0
90%
159.3
90.3
10%
Play 3 - Recoverable Oil (MMbbl)
Mean = 90.4
Mean = 22.3
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
50
100
150
200
250


283.2
0
90%
1118
653
10%
Play 3 - Recoverable Gas (BCF)
Mean = 652.5
Mean = 159.8
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
500
1000
1500
2000

Probability Input Sheet

Play Type Play 4 - Sub-Salt Jurassic

Reservoir Parameters

	Probability 1	0.5	0	MEAN
Total Play Area (km^2)	2768.4	3076	4614	3486.133
Fraction of Area Under Trap	0.2	0.3	0.5	0.333333
Fraction of Trap Filled	0.4	0.5	0.6	0.5
Discounted Play Area (km^2)	221.5	461.4	1384.2	581.0
Net Pay (m)	10	15	20	15
Porosity	0.1	0.12	0.15	0.123333
Hydrocarbon Saturation	0.5	0.6	0.7	0.6
Depth of Reservoir (m)	6500	7000	7500	7000
Z	1.15	1.3	1.45	1.3
Gas Volume Factor	432.2	396.9	368.0	396.9
Fraction of Pore Volume Oil Bearing	0.7	0.8	0.9	0.800
GOR (m3/m3)	378.11	407.19	436.28	407.19
Formation Volume Factor (Oil)	2.216	2.309	2.403	2.309
Prospect Adequacy	0.05	0.10	0.15	0.1
Liquids Yield (BBL/MMCF)	20	30	40	30
Oil Recovery Factor	0.15	0.2	0.3	0.216667
Gas Recovery Factor	0.4	0.6	0.8	0.6
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

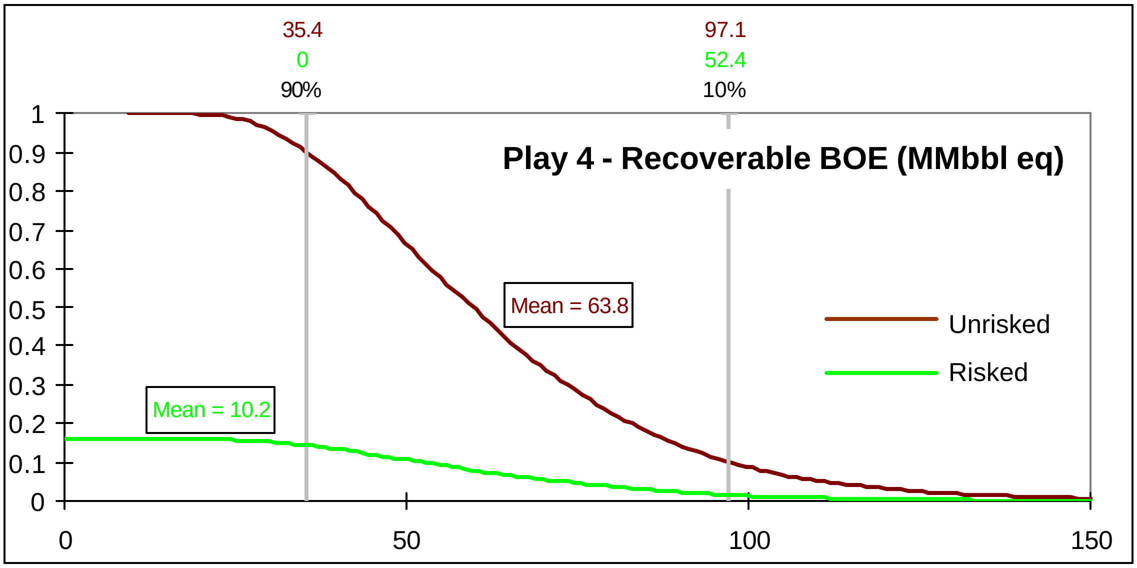
Risk Parameters

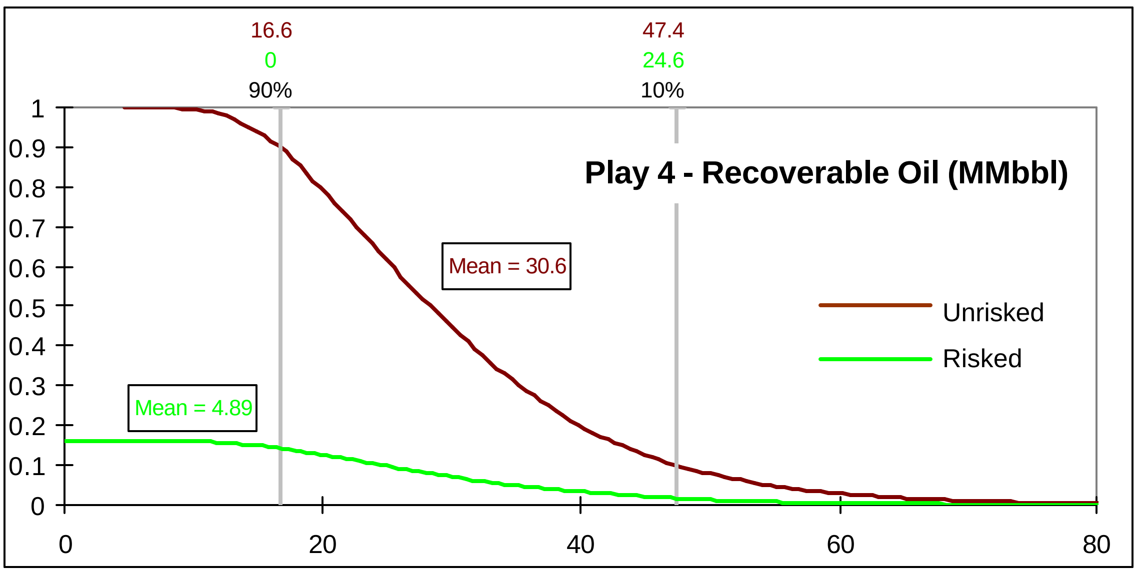
Play Adequacy	16	0

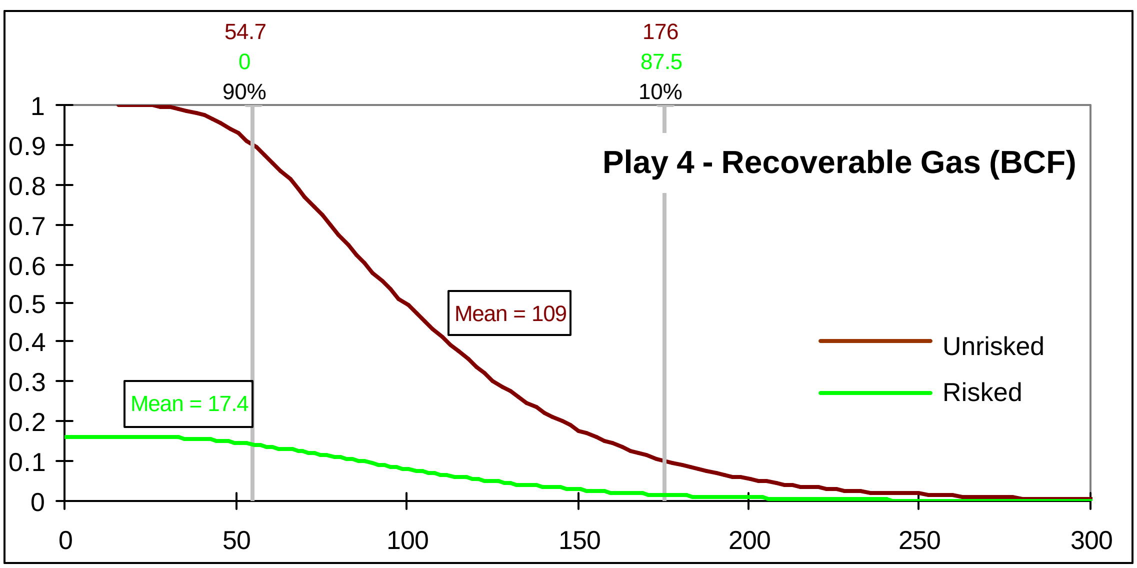
Other Parameters

Pressure gradient (kPa / m)	10.02	Sfc Pressure (kPa)		101.3
Temperature gradient (°C / 100 m)	2.8	Surface Temp (°C)		4
	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	102	116	130	116
Reservoir Pressure (kPa)	65231.30	70241.30	75251.30	70241.30

Gas to BOE conversion factor (MCF/BBL) 6


35.4
0
90%
97.1
52.4
10%
Play 4 - Recoverable BOE (MMbbl eq)
Mean = 63.8
Mean = 10.2
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
50
100
150


16.6
0
90%
47.4
24.6
10%
Play 4 - Recoverable Oil (MMbbl)
Mean = 30.6
Mean = 4.89
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
20
40
60
80


54.7
0
90%
176
87.5
10%
Play 4 - Recoverable Gas (BCF)
Mean = 109
Mean = 17.4
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
50
100
150
200
250
300

Probability Input Sheet

Play Type Play 5 - Suprasalt Structures - Tertiary

Reservoir Parameters	Probability			
	1	0.5	0	MEAN
Total Play Area (km^2)	1198	3844	4205	3082.333
Fraction of Area Under Trap	0.1	0.2	0.3	0.2
Fraction of Trap Filled	0.3	0.4	0.5	0.4
Discounted Play Area (km^2)	35.9	307.52	630.8	246.6
Net Pay (m)	25	75	125	75
Porosity	0.1	0.2	0.25	0.183333
Hydrocarbon Saturation	0.6	0.7	0.8	0.7
Depth of Reservoir (m)	4500	5000	5500	5000
Z	1.15	1.25	1.35	1.25
Gas Volume Factor	337.2	330.7	323.7	330.7
Fraction of Pore Volume Oil Bearing	0.2	0.3	0.4	0.300
GOR (m3/m3)	261.77	290.85	319.94	290.85
Formation Volume Factor (Oil)	1.842	1.935	2.029	1.935
Prospect Adequacy	0.20	0.30	0.40	0.3
Liquids Yield (BBL/MMCF)	20	30	40	30
Oil Recovery Factor	0.2	0.35	0.5	0.35
Gas Recovery Factor	0.5	0.7	0.9	0.7
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

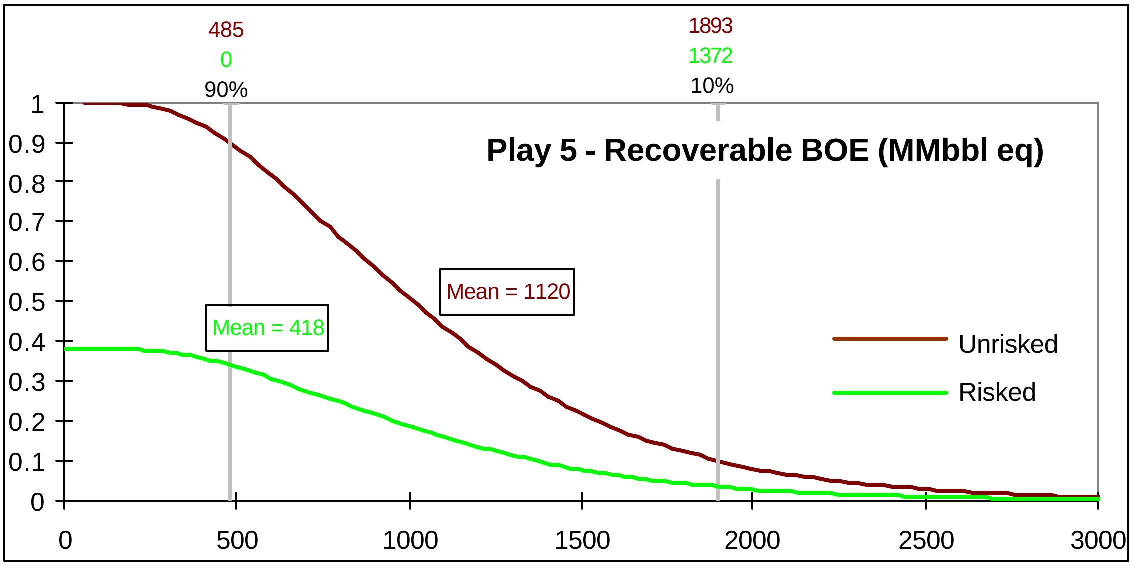
Risk Parameters

Play Adequacy	38	0

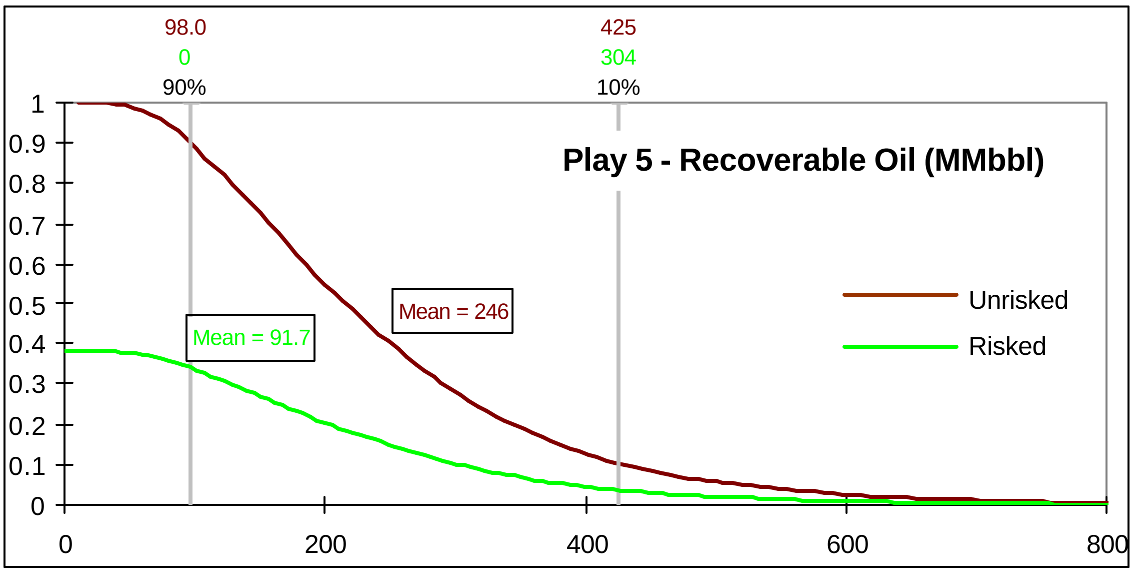
Other Parameters

Pressure gradient (kPa / m)	10.02	Sfc Pressure (kPa)		101.3
Temperature gradient (°C / 100 m)	2.8	Surface Temp (°C)		4
	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	60	74	88	74
Reservoir Pressure (kPa)	45191.30	50201.30	55211.30	50201.30

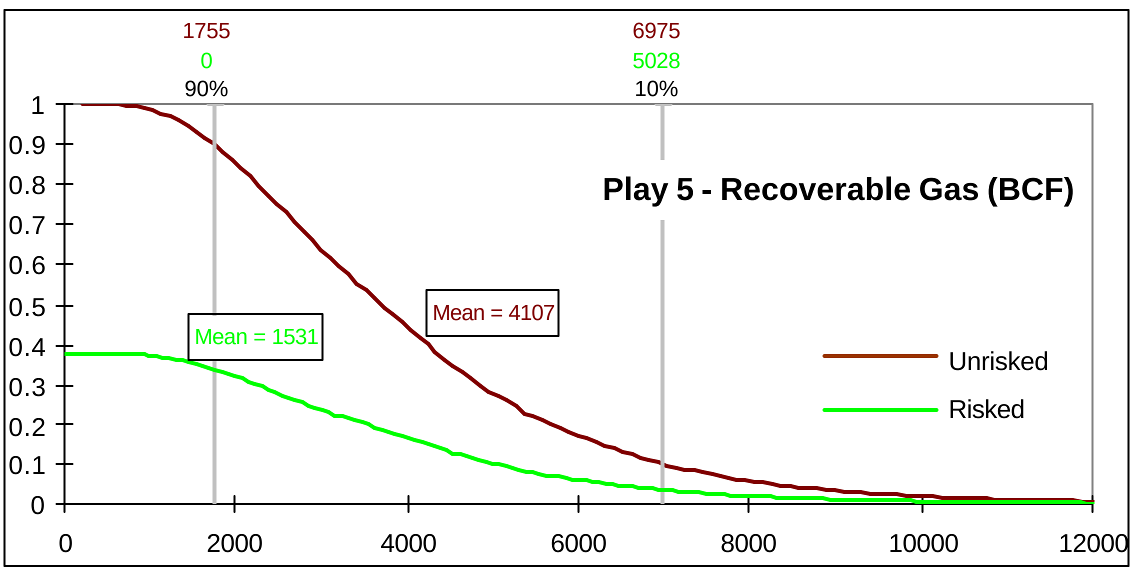
Gas to BOE conversion factor (MCF/BBL) 6



485
0
90%
1893
1372
10%
Play 5 - Recoverable BOE (MMbbl eq)
Mean = 1120
Mean = 418
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
500
1000
1500
2000
2500
3000



98.0
0
90%
425
304
10%
Play 5 - Recoverable Oil (MMbbl)
Mean = 246
Mean = 91.7
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
200
400
600
800



1755
0
90%
6975
5028
10%
Play 5 - Recoverable Gas (BCF)
Mean = 4107
Mean = 1531
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
2000
4000
6000
8000
10000
12000

Probability Input Sheet

Play Type Play 6 - Subsalt Cretaceous

Reservoir Parameters

	Probability 1	0.5	0	MEAN
Total Play Area (km^2)	3844	7797.5	11751	7797.5
Fraction of Area Under Trap	0.05	0.15	0.3	0.166667
Fraction of Trap Filled	0.4	0.5	0.6	0.5
Discounted Play Area (km^2)	76.9	584.8125	2115.2	649.8
Net Pay (m)	20	30	50	33.33333
Porosity	0.1	0.15	0.2	0.15
Hydrocarbon Saturation	0.6	0.7	0.8	0.7
Depth of Reservoir (m)	6000	7000	8000	7000
Z	1.15	1.3	1.45	1.3
Gas Volume Factor	399.0	383.1	367.0	383.1
Fraction of Pore Volume Oil Bearing	0.1	0.15	0.2	0.150
GOR (m3/m3)	349.02	407.19	465.36	407.19
Formation Volume Factor (Oil)	2.122	2.309	2.496	2.309
Prospect Adequacy	0.05	0.10	0.15	0.1
Liquids Yield (BBL/MMCF)	20	30	40	30
Oil Recovery Factor	0.15	0.3	0.45	0.3
Gas Recovery Factor	0.5	0.65	0.8	0.65
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

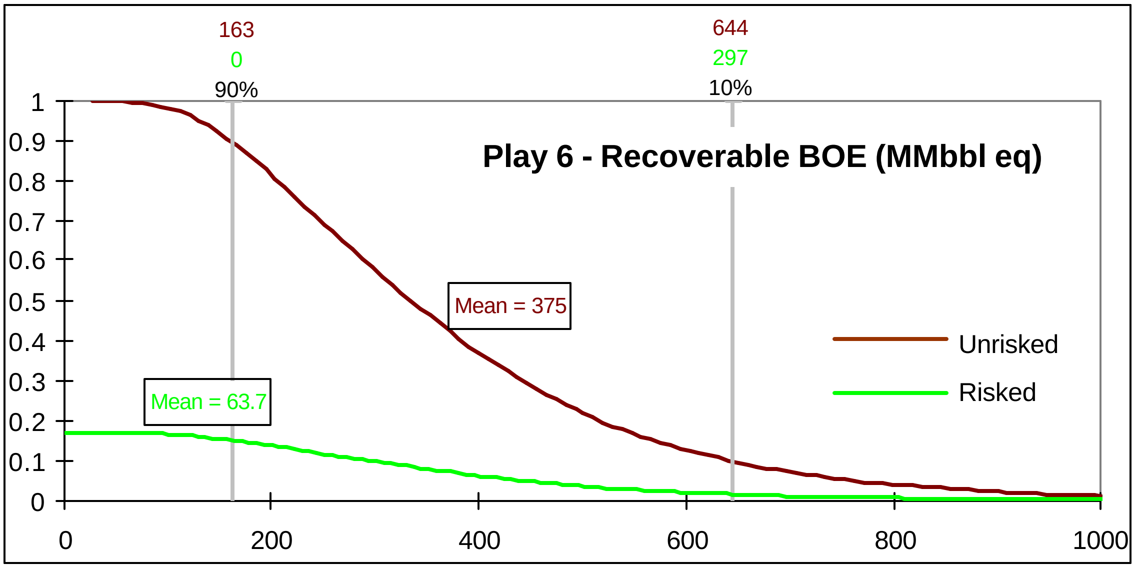
Risk Parameter

Play Adequacy	17	0

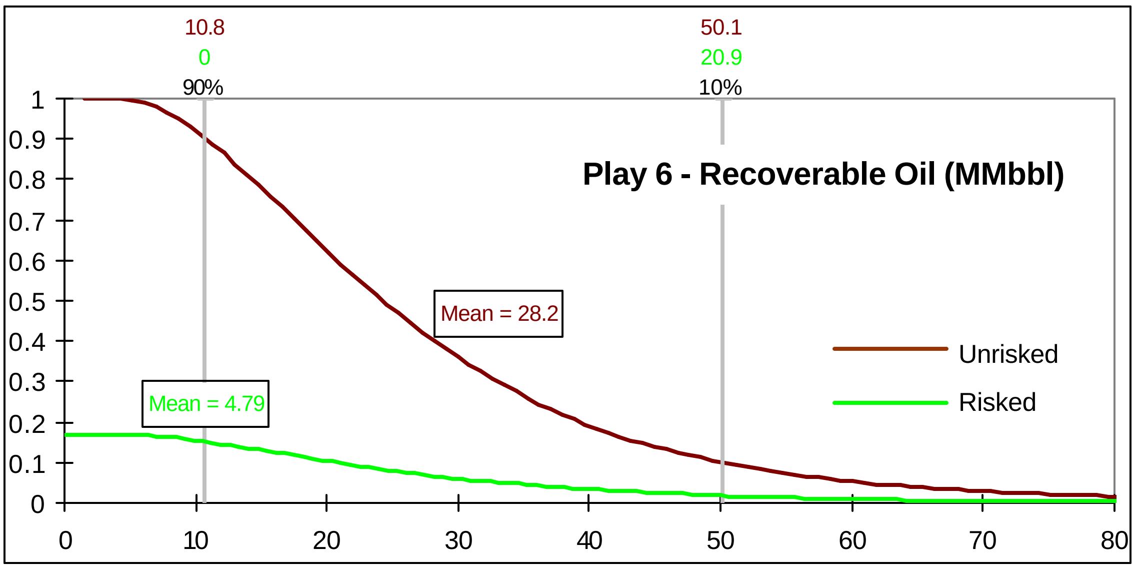
Other Parameters

Pressure gradient (kPa / m)	10.02	Sfc Pressure (kPa)		101.3
Temperature gradient (°C / 100 m)	2.8	Surface Temp (°C)		4
	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	102	130	158	130
Reservoir Pressure (kPa)	60221.30	70241.30	80261.30	70241.30

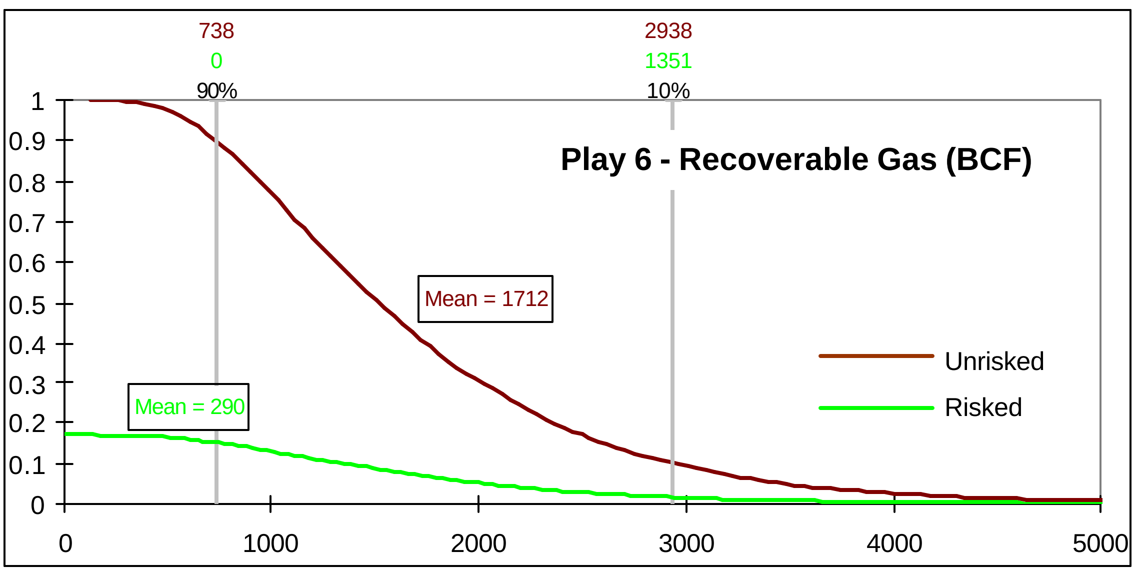
Gas to BOE conversion factor (MCF/BBL) 6



163
0
90%
644
297
10%
Play 6 - Recoverable BOE (MMbbl eq)
Mean = 375
Mean = 63.7
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
200
400
600
800
1000



10.8
0
90%
50.1
20.9
10%
Play 6 - Recoverable Oil (MMbbl)
Mean = 28.2
Mean = 4.79
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
10
20
30
40
50
60
70
80



738
0
90%
2938
1351
10%
Play 6 - Recoverable Gas (BCF)
Mean = 1712
Mean = 290
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
1000
2000
3000
4000
5000

Probability Input Sheet

Play Type — Play 7 - Salt Crests

Reservoir Parameters

	Probability 1	0.5	0	MEAN
Total Play Area (km^2)	526.3	554	581.7	554
Fraction of Area Under Trap	0.7	0.8	0.9	0.8
Fraction of Trap Filled	0.2	0.4	0.6	0.4
Discounted Play Area (km^2)	73.7	177.28	314.1	177.3
Net Pay (m)	10	20	35	21.66667
Porosity	0.1	0.25	0.3	0.216667
Hydrocarbon Saturation	0.6	0.7	0.8	0.7
Depth of Reservoir (m)	4500	5000	5500	5000
Z	1.1	1.2	1.3	1.2
Gas Volume Factor	384.8	374.7	364.4	374.7
Fraction of Pore Volume Oil Bearing	0.5	0.6	0.7	0.600
GOR (m3/m3)	261.77	290.85	319.94	290.85
Formation Volume Factor (Oil)	1.842	1.935	2.029	1.935
Prospect Adequacy	0.10	0.15	0.20	0.15
Liquids Yield (BBL/MMCF)	20	30	40	30
Oil Recovery Factor	0.15	0.2	0.4	0.25
Gas Recovery Factor	0.5	0.6	0.8	0.633333
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

Risk Parameters

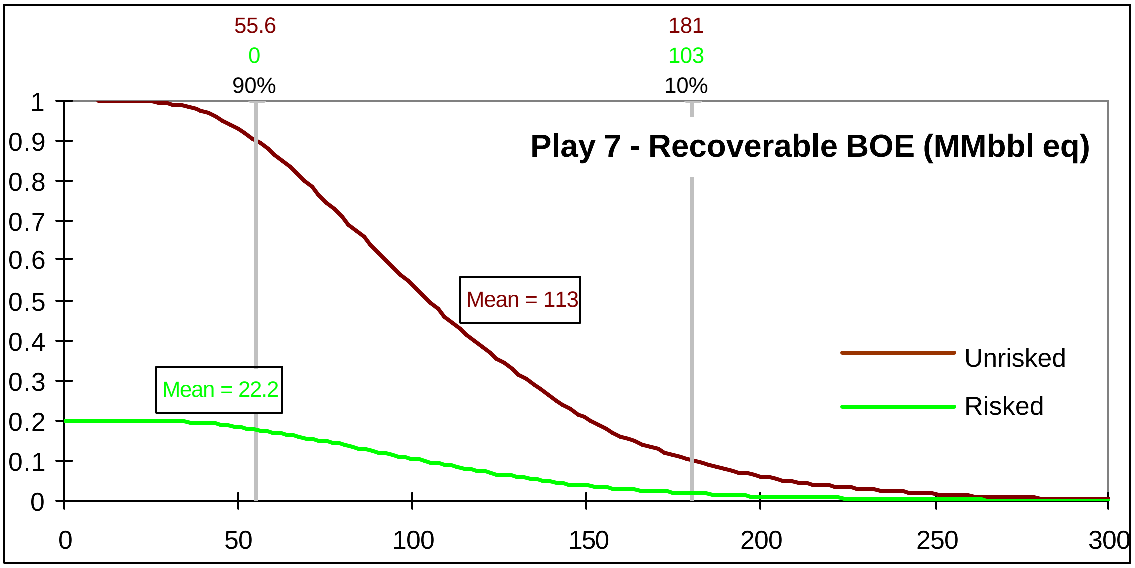
Play Adequacy	20	0

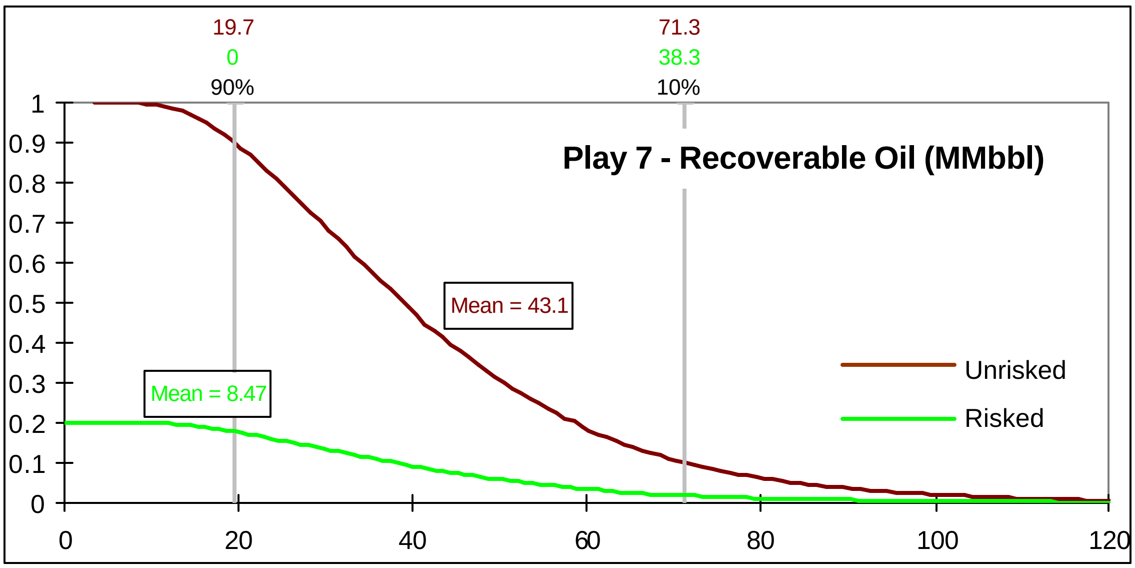
Other Parameters

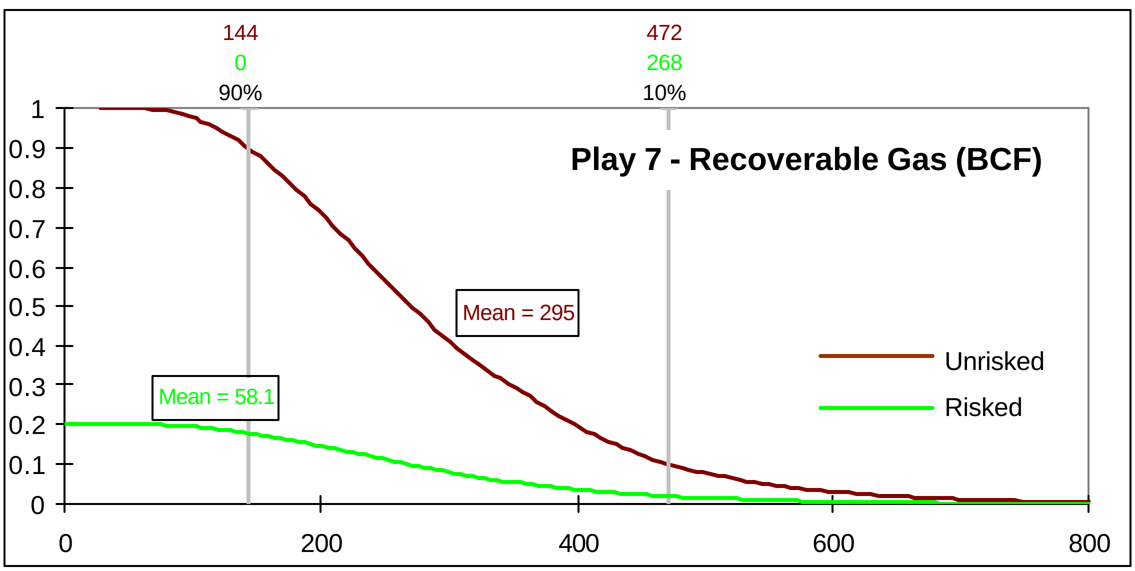
Pressure gradient (kPa / m)	10.02	Sfc Pressure (kPa)	101.3
Temperature gradient (°C / 100 m)	2.8	Surface Temp (°C)	4

	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	32	46	60	46
Reservoir Pressure (kPa)	45191.30	50201.30	55211.30	50201.30

Gas to BOE conversion factor (MCF/BBL) 6


55.6
0
90%
181
103
10%
Play 7 - Recoverable BOE (MMbbl eq)
Mean = 113
Mean = 22.2
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
50
100
150
200
250
300


19.7
0
90%
71.3
38.3
10%
Play 7 - Recoverable Oil (MMbbl)
Mean = 43.1
Mean = 8.47
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
20
40
60
80
100
120


144
0
90%
472
268
10%
Play 7 - Recoverable Gas (BCF)
Mean = 295
Mean = 58.1
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
200
400
600
800

Probability Input Sheet

Play Type — Play 8 - Salt Flanks

Reservoir Parameters

	Probability 1	0.5	0	MEAN
Total Play Area (km^2)	700	750	1500	983.3333
Fraction of Area Under Trap	0.15	0.3	0.5	0.316667
Fraction of Trap Filled	0.7	0.8	0.9	0.8
Discounted Play Area (km^2)	73.5	180	675.0	249.1
Net Pay (m)	15	50	100	55
Porosity	0.1	0.2	0.25	0.183333
Hydrocarbon Saturation	0.6	0.7	0.8	0.7
Depth of Reservoir (m)	5000	6000	7000	6000
Z	1.1	1.25	1.4	1.25
Gas Volume Factor	408.7	396.7	382.3	396.7
Fraction of Pore Volume Oil Bearing	0.5	0.6	0.7	0.600
GOR (m3/m3)	290.85	349.02	407.19	349.02
Formation Volume Factor (Oil)	1.935	2.122	2.309	2.122
Prospect Adequacy	0.15	0.25	0.35	0.25
Liquids Yield (BBL/MMCF)	20	30	40	30
Oil Recovery Factor	0.15	0.3	0.45	0.3
Gas Recovery Factor	0.4	0.6	0.8	0.6
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

Risk Parameters

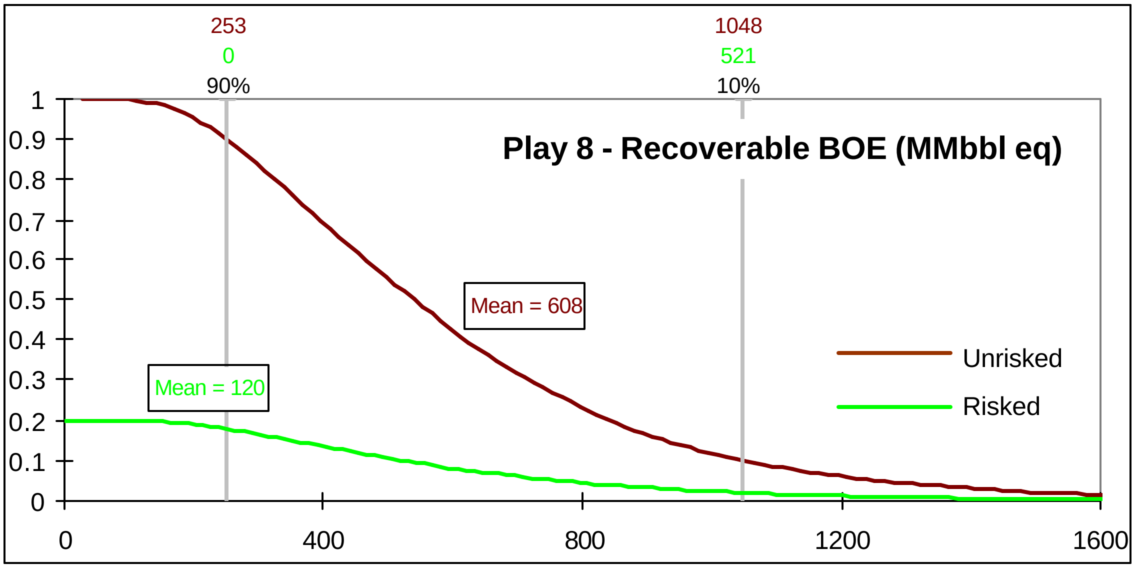
Play Adequacy	20	0

Other Parameters

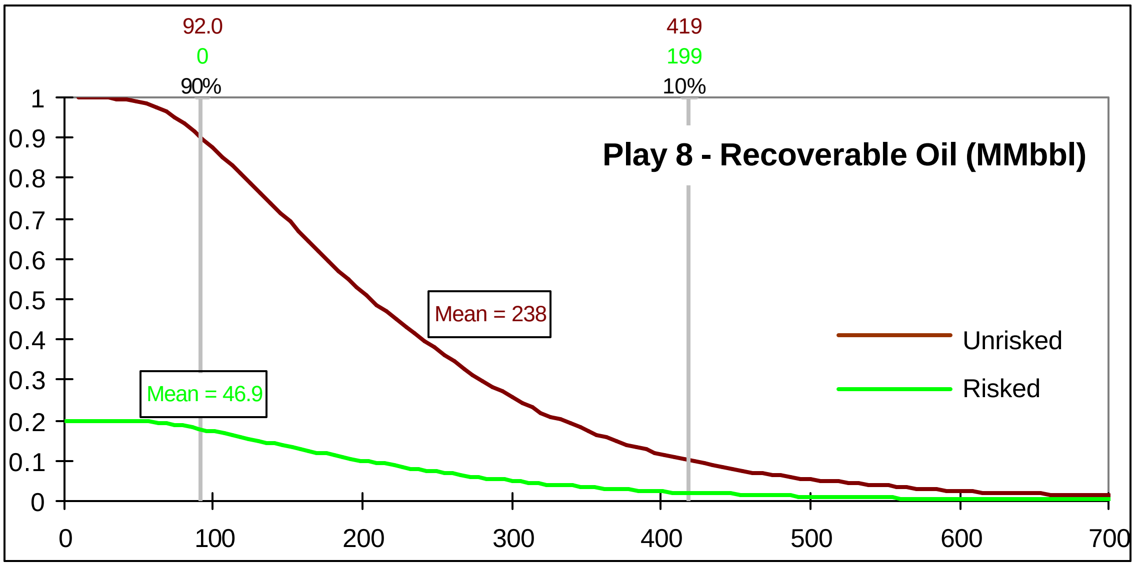
Pressure gradient (kPa / m)	10.02	Sfc Pressure (kPa)	101.3
Temperature gradient (°C / 100 m)	2.8	Surface Temp (°C)	4

	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	46	74	102	74
Reservoir Pressure (kPa)	50201.30	60221.30	70241.30	60221.30

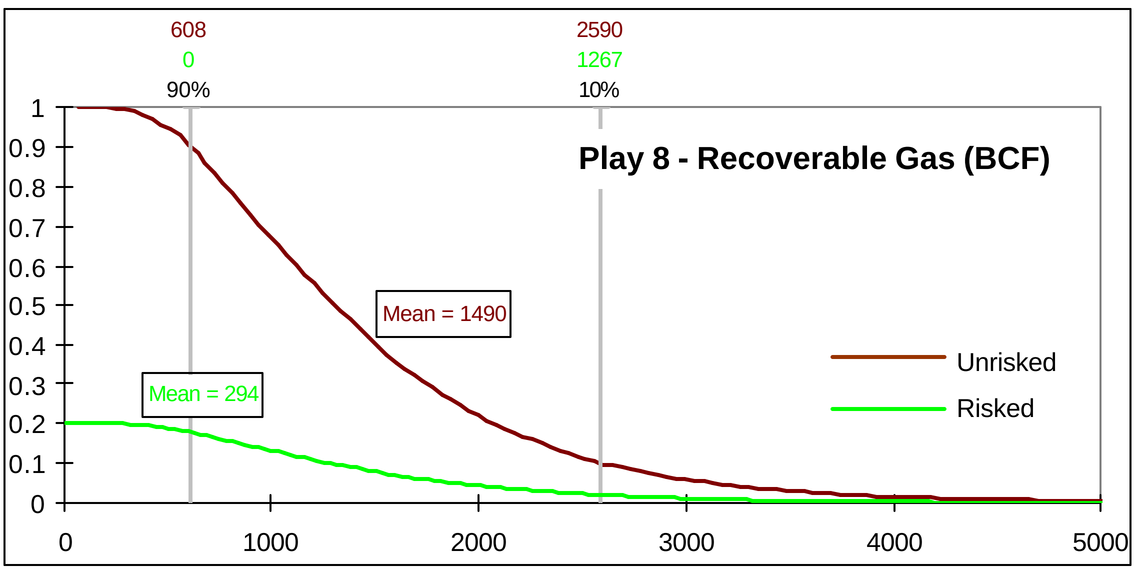
Gas to BOE conversion factor (MCF/BBL) 6



253
0
90%
1048
521
10%
Play 8 - Recoverable BOE (MMbbl eq)
Mean = 608
Mean = 120
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
400
800
1200
1600



92.0
0
90%
419
199
10%
Play 8 - Recoverable Oil (MMbbl)
Mean = 238
Mean = 46.9
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
100
200
300
400
500
600
700



608
0
90%
2590
1267
10%
Play 8 - Recoverable Gas (BCF)
Mean = 1490
Mean = 294
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
1000
2000
3000
4000
5000

Probability Input Sheet

Play Type Play 9 - Deep Structures

Reservoir Parameters	Probability 1	0.5	0	MEAN
Total Play Area (km^2)	10803.4	11404.7	12026	11411.37
Fraction of Area Under Trap	0.05	0.1	0.2	0.116667
Fraction of Trap Filled	0.3	0.4	0.5	0.4
Discounted Play Area (km^2)	162.1	456.188	1202.6	532.5
Net Pay (m)	15	50	100	55
Porosity	0.1	0.2	0.25	0.183333
Hydrocarbon Saturation	0.6	0.7	0.8	0.7
Depth of Reservoir (m)	5000	6000	7000	6000
Z	1.1	1.25	1.4	1.25
Gas Volume Factor	391.6	381.3	368.6	381.3
Fraction of Pore Volume Oil Bearing	0.5	0.6	0.7	0.600
GOR (m3/m3)	290.85	349.02	407.19	349.02
Formation Volume Factor (Oil)	1.935	2.122	2.309	2.122
Prospect Adequacy	0.10	0.20	0.30	0.2
Liquids Yield (BBL/MMCF)	20	30	40	30
Oil Recovery Factor	0.15	0.3	0.45	0.3
Gas Recovery Factor	0.4	0.6	0.8	0.6
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

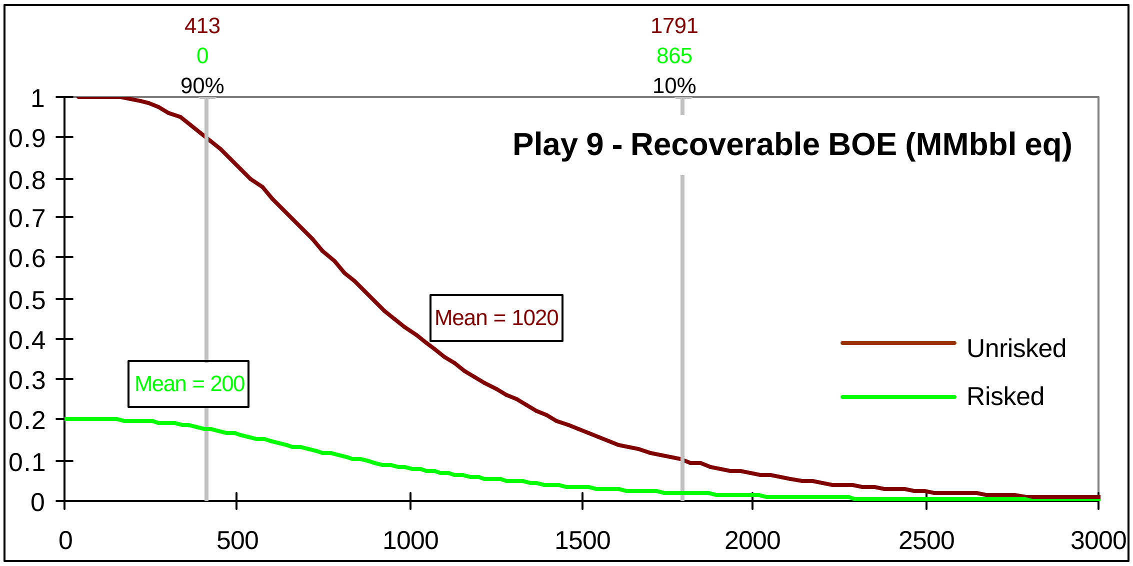
Risk Parameters

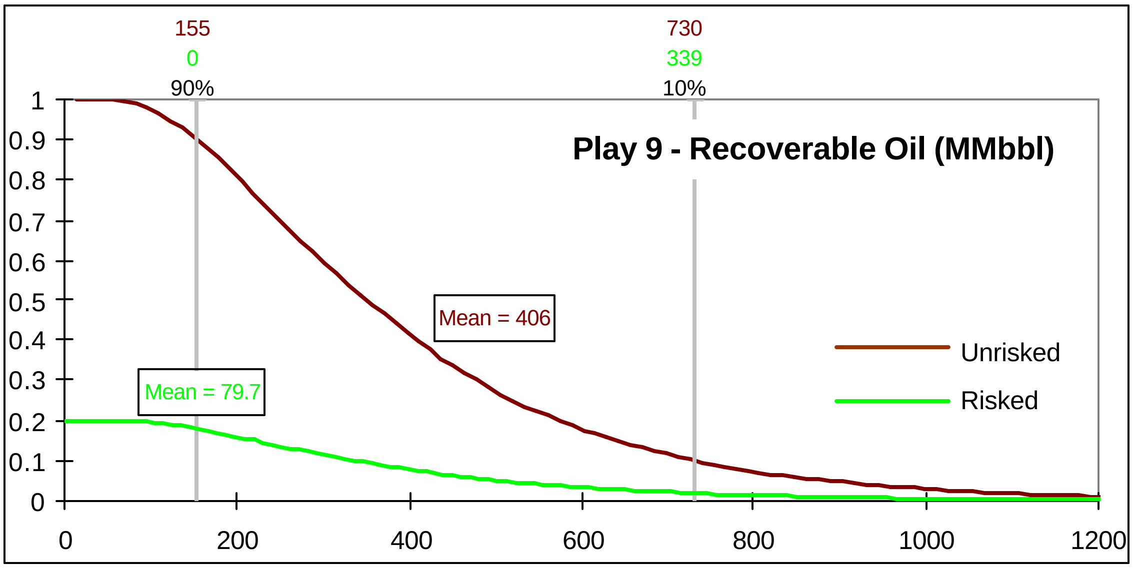
Play Adequacy	20	0

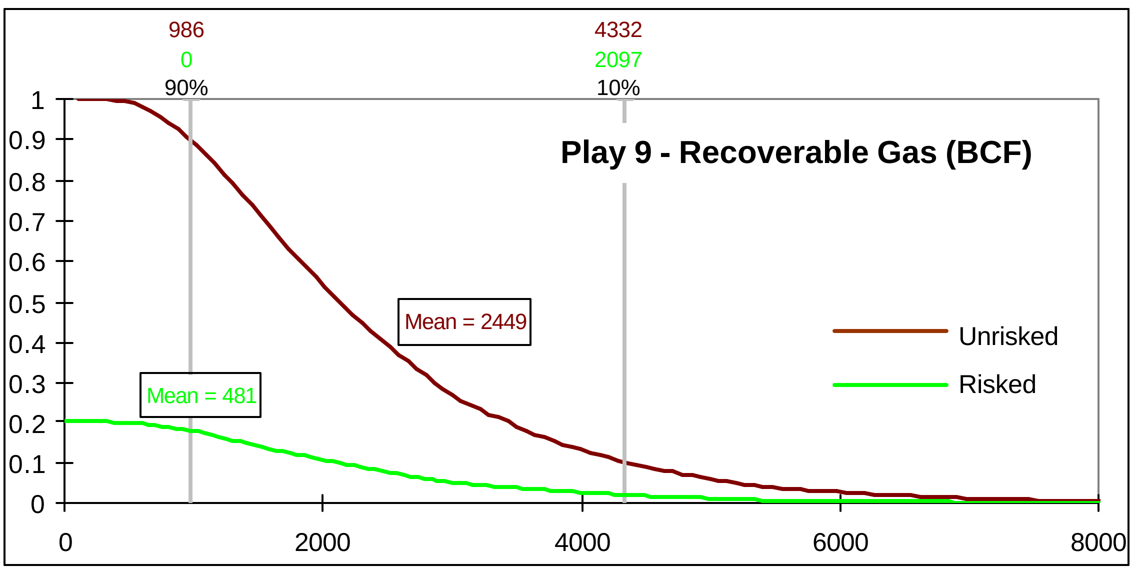
Other Parameters

Pressure gradient (kPa / m)	10.02	Sfc Pressure (kPa)		101.3
Temperature gradient (°C / 100 m)	2.8	Surface Temp (°C)		4
	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	60	88	116	88
Reservoir Pressure (kPa)	50201.30	60221.30	70241.30	60221.30

Gas to BOE conversion factor (MCF/BBL) 6


413
0
90%
1791
865
10%
Play 9 - Recoverable BOE (MMbbl eq)
Mean = 1020
Mean = 200
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
500
1000
1500
2000
2500
3000


155
0
90%
730
339
10%
Play 9 - Recoverable Oil (MMbbl)
Mean = 406
Mean = 79.7
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
200
400
600
800
1000
1200


986
0
90%
4332
2097
10%
Play 9 - Recoverable Gas (BCF)
Mean = 2449
Mean = 481
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
2000
4000
6000
8000

Probability Input Sheet

Play Type Play 10 - Other Supra Salt Structures

Reservoir Parameters

	Probability 1	0.5	0	MEAN
Total Play Area (km^2)	3332.6	3508	3683.4	3508
Fraction of Area Under Trap	0.1	0.2	0.3	0.2
Fraction of Trap Filled	0.3	0.4	0.5	0.4
Discounted Play Area (km^2)	100.0	280.64	552.5	280.6
Net Pay (m)	25	75	125	75
Porosity	0.1	0.2	0.25	0.183333
Hydrocarbon Saturation	0.6	0.7	0.8	0.7
Depth of Reservoir (m)	4500	5000	5500	5000
Z	1.1	1.25	1.4	1.25
Gas Volume Factor	352.5	330.7	312.2	330.7
Fraction of Pore Volume Oil Bearing	0.4	0.5	0.6	0.500
GOR (m3/m3)	261.77	290.85	319.94	290.85
Formation Volume Factor (Oil)	1.842	1.935	2.029	1.935
Prospect Adequacy	0.10	0.15	0.20	0.15
Liquids Yield (BBL/MMCF)	20	30	40	30
Oil Recovery Factor	0.15	0.3	0.45	0.3
Gas Recovery Factor	0.4	0.6	0.8	0.6
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

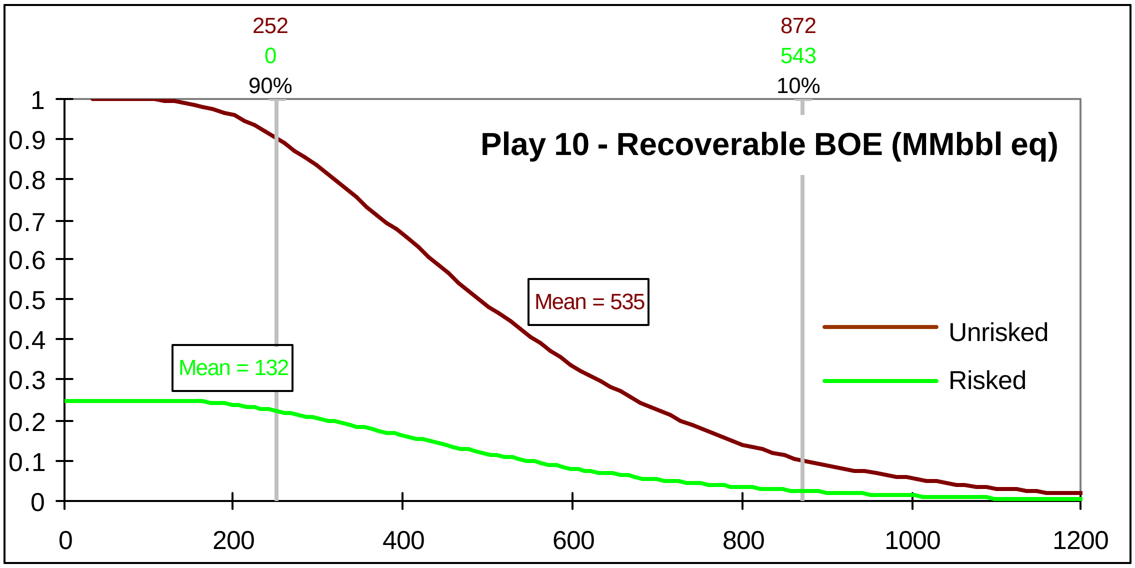
Risk Parameters

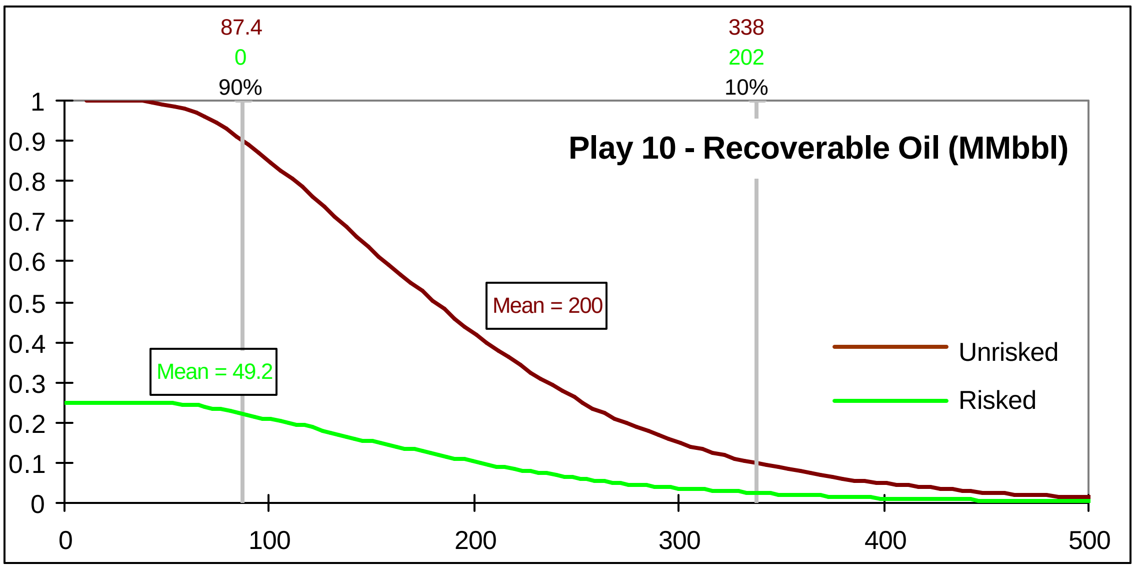
Play Adequacy	25	0

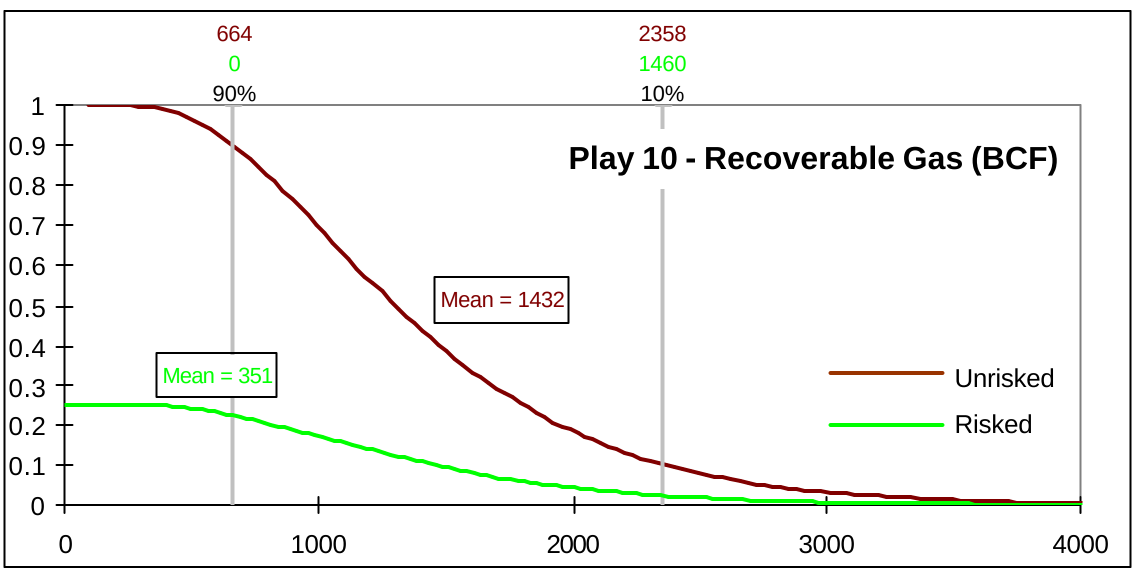
Other Parameters

Pressure gradient (kPa / m)	10.02	Sfc Pressure (kPa)		101.3
Temperature gradient (°C / 100 m)	2.8	Surface Temp (°C)		4
	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	60	74	88	74
Reservoir Pressure (kPa)	45191.30	50201.30	55211.30	50201.30

Gas to BOE conversion factor (MCF/BBL) 6


252
0
90%
872
543
10%
Play 10 - Recoverable BOE (MMbbl eq)
Mean = 535
Mean = 132
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
200
400
600
800
1000
1200


87.4
0
90%
338
202
10%
Play 10 - Recoverable Oil (MMbbl)
Mean = 200
Mean = 49.2
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
100
200
300
400
500


664
0
90%
2358
1460
10%
Play 10 - Recoverable Gas (BCF)
Mean = 1432
Mean = 351
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
1000
2000
3000
4000

Probability Input Sheet

Play Type Play 11 - Upper Slope (Tert/Cret)

Reservoir Parameters

	Probability 1	0.5	0	MEAN
Total Play Area (km^2)	4084.2	4538	4991.8	4538
Fraction of Area Under Trap	0.1	0.2	0.3	0.2
Fraction of Trap Filled	0.3	0.4	0.5	0.4
Discounted Play Area (km^2)	122.5	363.04	748.8	363.0
Net Pay (m)	25	75	150	83.33333
Porosity	0.1	0.2	0.25	0.183333
Hydrocarbon Saturation	0.6	0.7	0.8	0.7
Depth of Reservoir (m)	4500	5000	6000	5166.667
Z	1.1	1.25	1.4	1.25
Gas Volume Factor	325.2	306.0	305.0	312.3
Fraction of Pore Volume Oil Bearing	0.2	0.3	0.4	0.300
GOR (m3/m3)	261.77	290.85	349.02	300.55
Formation Volume Factor (Oil)	1.842	1.935	2.122	1.966
Prospect Adequacy	0.15	0.25	0.35	0.25
Liquids Yield (BBL/MMCF)	20	30	40	30
Oil Recovery Factor	0.2	0.35	0.5	0.35
Gas Recovery Factor	0.5	0.7	0.9	0.7
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

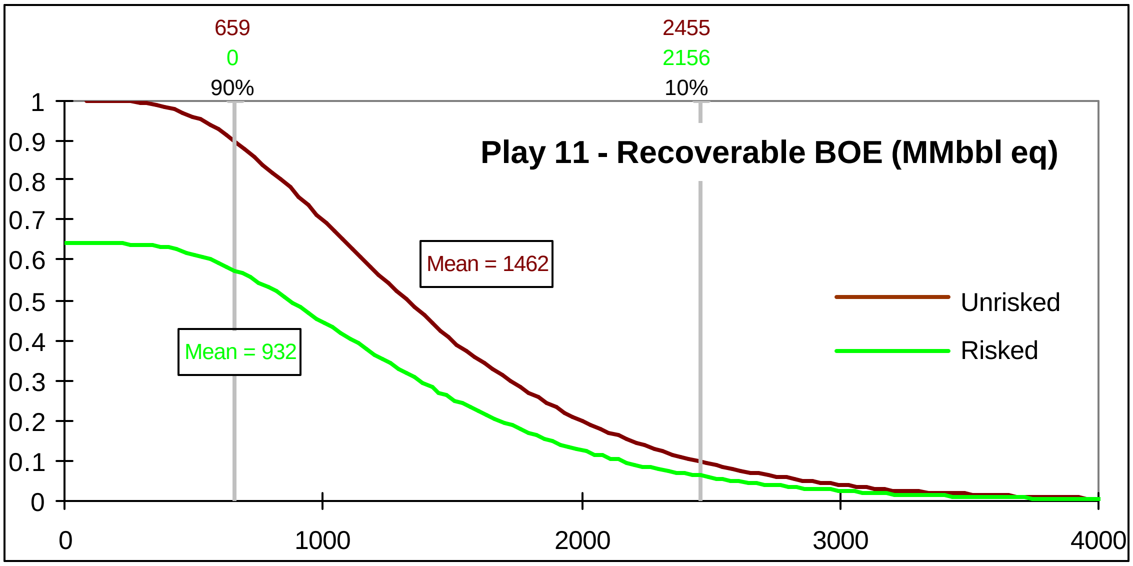
Risk Parameters

Play Adequacy	64	1

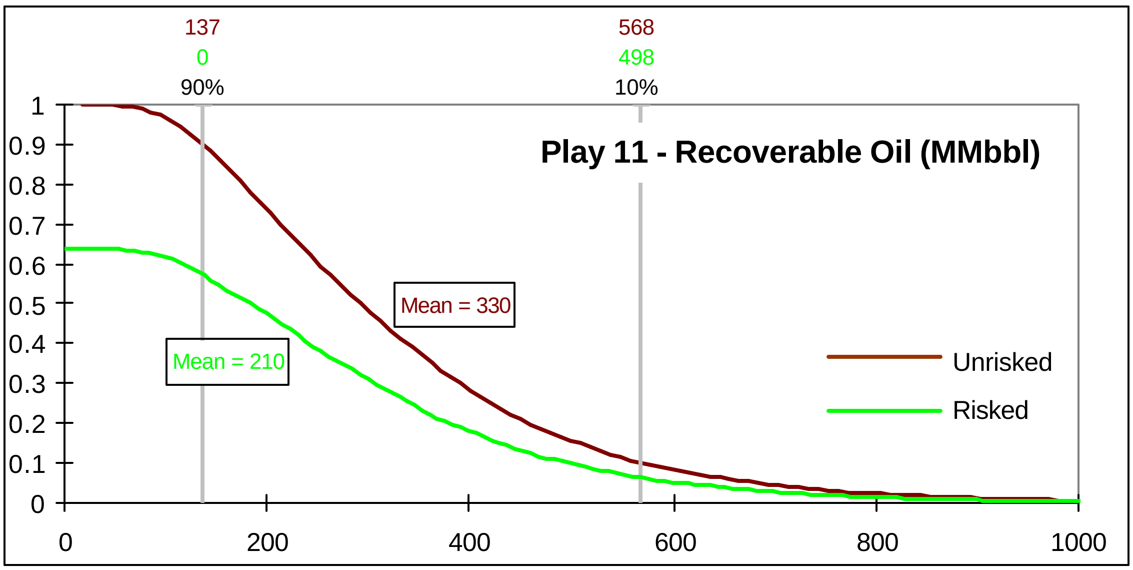
Other Parameters

Pressure gradient (kPa / m)	10.02	Sfc Pressure (kPa)		101.3
Temperature gradient (°C / 100 m)	2.8	Surface Temp (°C)		4
	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	88	102	130	106.6667
Reservoir Pressure (kPa)	45191.30	50201.30	60221.30	51871.30

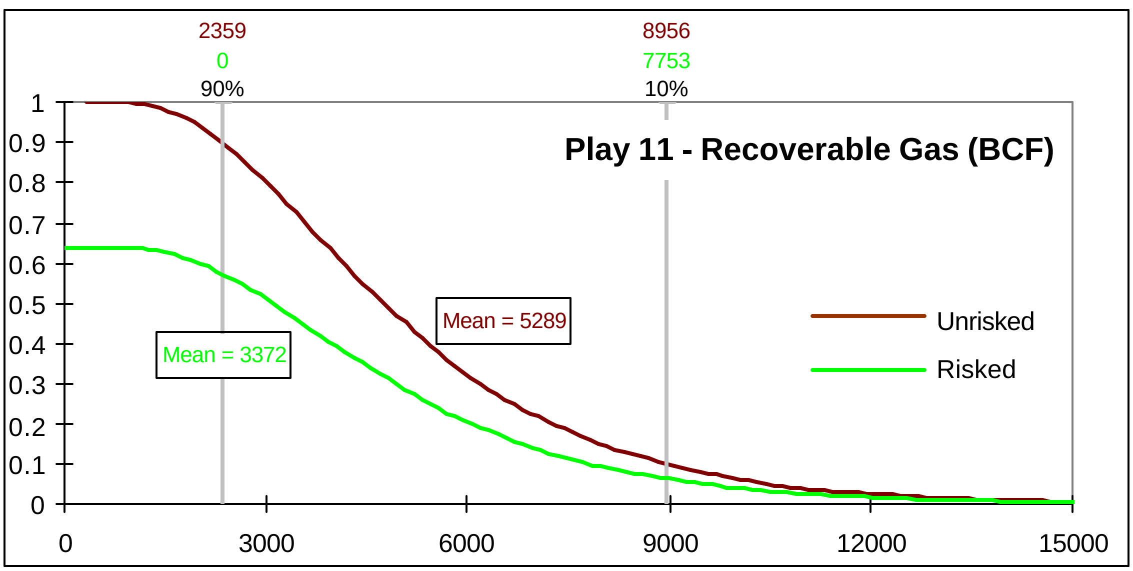
Gas to BOE conversion factor (MCF/BBL) 6



Play 11 - Recoverable BOE (MMbbl eq)
659
0
90%
2455
2156
10%
Mean = 1462
Mean = 932
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
1000
2000
3000
4000



Play 11 - Recoverable Oil (MMbbl)
137
0
90%
568
498
10%
Mean = 330
Mean = 210
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
200
400
600
800
1000



Play 11 - Recoverable Gas (BCF)
2359
0
90%
8956
7753
10%
Mean = 5289
Mean = 3372
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
3000
6000
9000
12000
15000

Probability Input Sheet

Play Type Play 12 - Upper Slope (Cret/Jura)

Reservoir Parameters

	Probability 1	0.5	0	MEAN
Total Play Area (km^2)	12212.4	13576	14939.6	13576
Fraction of Area Under Trap	0.1	0.2	0.3	0.2
Fraction of Trap Filled	0.3	0.4	0.5	0.4
Discounted Play Area (km^2)	366.4	1086.08	2240.9	1086.1
Net Pay (m)	20	50	100	56.66667
Porosity	0.1	0.2	0.25	0.183333
Hydrocarbon Saturation	0.6	0.7	0.8	0.7
Depth of Reservoir (m)	4000	4500	5500	4666.667
Z	1.1	1.25	1.4	1.25
Gas Volume Factor	300.8	286.2	289.7	293.0
Fraction of Pore Volume Oil Bearing	0.3	0.5	0.6	0.467
GOR (m3/m3)	232.68	261.77	319.94	271.46
Formation Volume Factor (Oil)	1.748	1.842	2.029	1.873
Prospect Adequacy	0.10	0.20	0.30	0.2
Liquids Yield (BBL/MMCF)	20	30	40	30
Oil Recovery Factor	0.2	0.35	0.5	0.35
Gas Recovery Factor	0.5	0.7	0.9	0.7
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

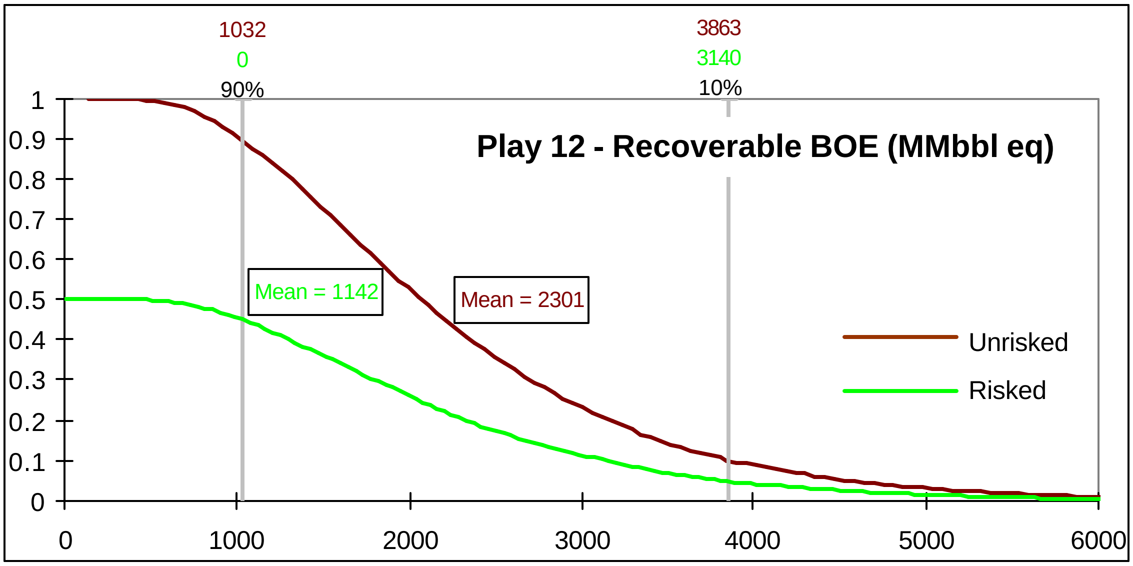
Risk Parameters

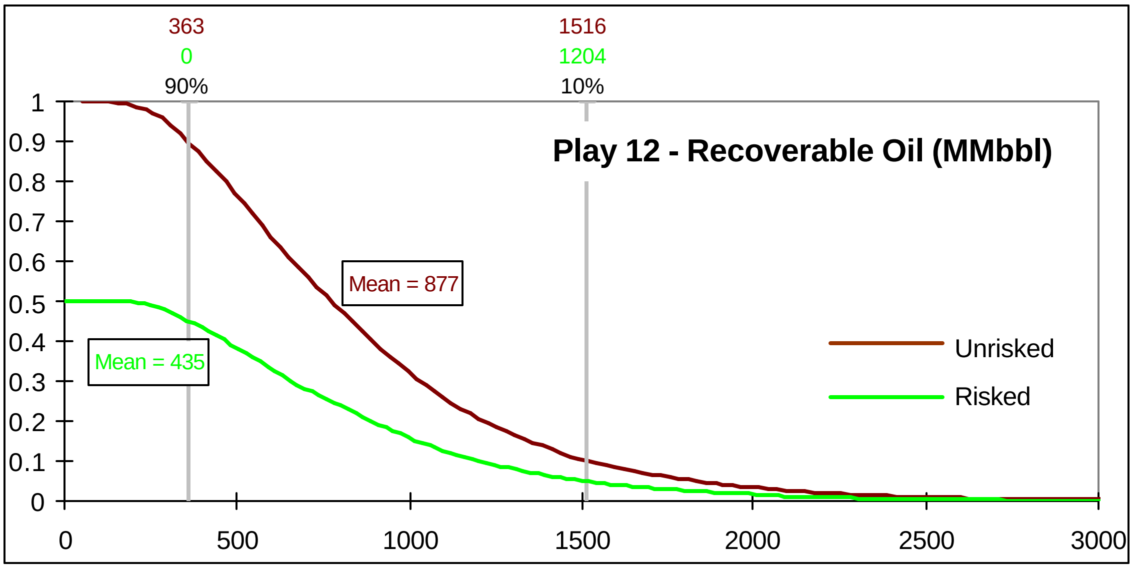
Play Adequacy	50	0

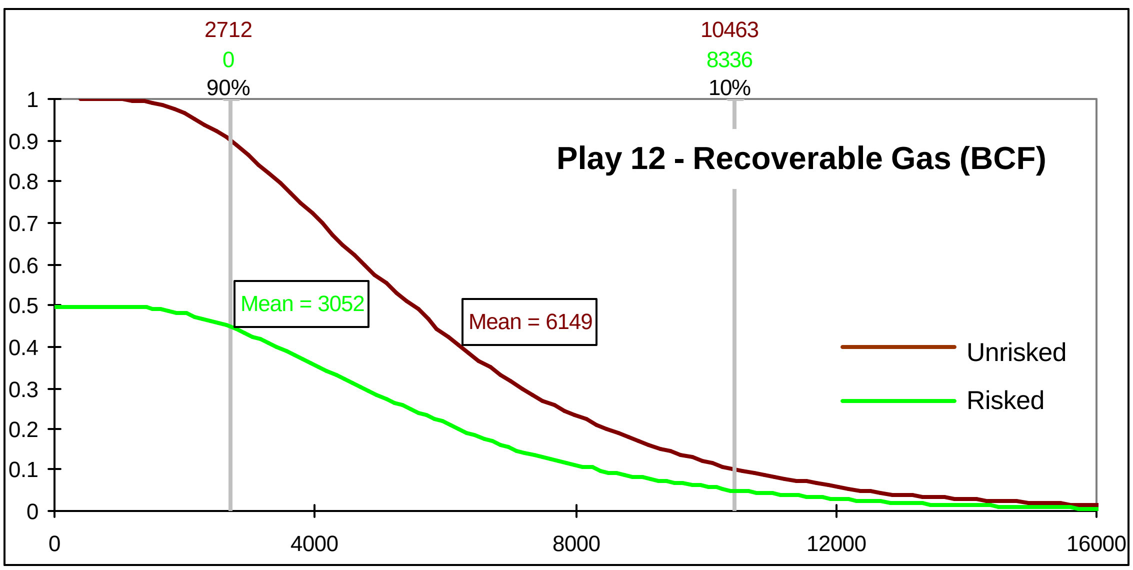
Other Parameters

Pressure gradient (kPa / m)	10.02	Sfc Pressure (kPa)		101.3
Temperature gradient (°C / 100 m)	2.8	Surface Temp (°C)		4
	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	74	88	116	92.66667
Reservoir Pressure (kPa)	40181.30	45191.30	55211.30	46861.30

Gas to BOE conversion factor (MCF/BBL) 6


Play 12 - Recoverable BOE (MMbbl eq)
1032
0
90%
3863
3140
10%
Mean = 1142
Mean = 2301
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
1000
2000
3000
4000
5000
6000


Play 12 - Recoverable Oil (MMbbl)
363
0
90%
1516
1204
10%
Mean = 877
Mean = 435
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
500
1000
1500
2000
2500
3000


Play 12 - Recoverable Gas (BCF)
2712
0
90%
10463
8336
10%
Mean = 3052
Mean = 6149
Unrisked
Risked
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
4000
8000
12000
16000