CHAPTER 1

INTRODUCTION TO THE PLAY FAIRWAY ANALYSIS PROJECT
INTRODUCTION TO THE PLAY FAIRWAY ANALYSIS PROJECT

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011

Introduction
A review of the exploration history of offshore Nova Scotia in 2007/2008 identified the need for a re-evaluation of the remaining hydrocarbon prospectiveivity (see MacMullen et al. 2010). The 2007/2008 review was conducted for the Department of Energy of Nova Scotia, who subsequently allocated a fund to DERTI (Offshore Energy and Technology Research association) to conduct a research project with the objective of assessing the oil and gas potential of offshore Nova Scotia. This Play Fairway Analysis programme was created to address this issue.

The Play Fairway Program was designed to address three key issues:

- Plate tectonic reconstruction: Understanding the relationship between rifting and salt deposition was critical in developing models for potential syn-rift and early post rifting depositional environments and the development of source rocks.
- Forensic geochemistry: although much geochemical data existed, through the many hydrocarbon shows and discoveries, the source rock story was not well understood. The program included a systematic evaluation of geochemical source rock and hydrocarbon type data.
- Sequence stratigraphic framework: there was a lack of a robust public domain sequence stratigraphic framework for the margin. The program included a re-evaluation of the biostratigraphy of several key wells which were integrated with seismic interpretation and tectonic models, to build a comprehensive sequence framework.

The Play Fairway Analysis (PFA) program was designed to study these issues and thereby develop a robust analysis of the remaining hydrocarbon potential. The programme was specifically designed around a well established industry approach (play based exploration) and integrated contributions from the academic and geoscience community in Halifax, as well as various contractors. This PFA evolved into a number of linked and actively integrated individual projects. These included:

- Seismic Database Preparation / Synthetics
- Re-processing of seismic lines of around 7,400km data
- Plate Tectonic analysis
- Biostratigraphy and sequence stratigraphy
- Geochemistry
- Petroleum Systems Modeling
- Seismic Rock Physics Review
- Salt Structural Interpretation
- Reservoir Quality
- Integrated Play Fairway Evaluation (the core project)

The objective of these studies was to identify and assess the key exploration plays. The play based exploration approach is extensively used in the oil industry and relies on developing a thorough understanding of the evolution of key sedimentary sequences through time. The PFA integrated the results of these individual projects to develop an industry standard Play Fairway Analysis and atlas. This program included the creation of Gross Depositional Environment (GDE) and Common Risk Segment (CRS) maps on each key sequence, leading to the development of a final Yet-to-Find (YTF) analysis by play segment (as described in the various Chapters below).

Play Fairway Analysis - Overview

Figure 1 below illustrates the structure of the Play Fairway Program and the relationship between the key elements of the PFA with the various special projects and external contractors. The core Play Fairway Program was delivered by BEICIP/PRINLAB in Paris, while the individual supporting sub-projects were worked on by a mix of academic and commercial organisations.

Core Program

Database Build
The database to build the PFA includes the following:

- A data set consisting of approximately 70,000km of 2D data and 30,000km of 3D data. The data was cross equalized and phase matched. Synthetics for around 30 wells were included.
- The sequence stratigraphic framework was provided through the biostratigraphic analysis of around 20 key wells. An iterative process was used to integrate the biostratigraphy into the stratigraphic model and seismic interpretation elements of the PFA.
- These, plus the wells with synthetics, were linked with a broad grid of reprocessed 7,400km 2D data.

Create the Stratigraphic Model
Using the data set provided, the project embarked on a rigorous process to define a standard stratigraphic model for the margin. Exploration efforts have been hampered by the inability to integrate various operators and contractors work into a single framework. The work to build the stratigraphic framework covered the following:

- Definition of the sequence stratigraphic framework (based on input from the biostratigraphy special project, see below, and the seismic data).
- Interpreted key lines (7,400km 2D) with the key mega-sequences and sequences.
- Mega-sequences were linked to key tectonic events on the margin.
- chronostratigraphic diagram with biostratigraphic information were collated.
- Stratigraphic columns were constructed for the 20 key wells (plus other wells as appropriate), containing lithostratigraphy, chronostratigraphy, sequence stratigraphy, systems tracts, and depositional environments.
- Broad GDEs identified on key megasequences and description of the overall basin architecture and evolution.
- Architectural cross sections combining wells and seismic data.
- Definition of the key plays on the margin in terms of source, reservoir, and seal.
- Definition of the sequences to be mapped.

Seismic Interpretation
Selected surveys and lines from the seismic database have been interpreted and a structured set of products are being created. The key products from the seismic interpretation project are:

- Calibration of plates showing the well synthetics linked to the seismic data.
- Cross sections at both the regional and local scale.
- Seismic cross sections on a regional scale with increased local detail as appropriate.
- Structural maps – time velocity and depth on each sequence boundary.
- Isopach maps in both interval time and thickness.
- Seismic facies maps for key sequences, accompanied by their geological interpretation.
- Amplitude and other attribute (as appropriate) extraction maps within key sequences accompanied by their geological interpretation.
- Structural lineaments identified on gravity and magnetic data and tied to seismic data where possible.
- Integration of the salt modeling project (see below) in understanding the structural evolution of the salt basins.

Gross Depositional Environment (GDE) Mapping
This included:

- GDE analysis for each key sequence, which allowed the identification of source, reservoir and seal for major plays.
- A number of the academic and commercial projects were integrated into the GDE work. These included the Reservoir Quality work being done at St. Mary's and the Plate Tectonic project.
- Seismic inversion results (as appropriate) and their link to lithology and depositional.
- 3D forward modeling (DIONSIS) to predict reservoir distribution through time both regionally and in the salt domain.
- Reservoir effectiveness cross plots.
- Property trend maps/volumes: porosity, lithology prediction by sequence.
- Seal effectiveness maps.
- Source rock maps extracted from relevant GDEs with their supporting seismic and structural interpretation.

PL. 1

Introduction to Play Fairway Program
INTRODUCTION TO THE PLAY FAIRWAY ANALYSIS PROJECT

Petroleum Systems Modelling

Petroleum Systems Modelling is the critical component of the whole project in which the seismic interpretation, GDE mapping is integrated into a 3D fluid prediction model for the basin. The project used the Tems Suite to undertake the modeling. The analysis produced:

- Hydrocarbon occurrences maps
- Geochemical analysis results displayed in map form.
- 3D block model of the margin. The 3D model was based on the surfaces and maps produced from the seismic interpretation and GDE modeling.
- Calibration of the 3D model was based on the following:
  - Matching maturity related parameters (T, Tpeak, Rv, etc.; API; GOR).
  - Matching of Pressure (mdwights, or P' tests).
  - Comparison of published resources in place in the Sable area (derive the resources from the reserve assessments - see above).
  - Comparison of HC type (API; GOR; composition).

Thermal modeling was used a fully coupled 2D/3D sediment-crustal model, including:
Migrating and trapping efficiency model.
Migration maps by sequence and through geologic time.
The information has been summarised into petroleum systems charts for each region of the margin (see Chapter 8).

Common Risk Segment (CRS) Mapping

Many companies have found it useful to combine the depositional history maps and source rock charge story into a layered map that highlights the most prospective area of the basins. The "CRS Mapping" (Chapter 8-2). This approach offers a powerful way of integrating the risk maps for each play element. The methodology also provides a rigorous check list for a petroleum systems analysis of a basin. This technique was used in this project with the creation of the following:
- Risk model definition.
- Risk maps for each play to include charge, reservoir, seal and others as appropriate.
- A risk map for each play that synthesises the risks of each play element (CCRS – Composite Common Risk Segment maps).

The Special Projects

Plate Tectonic Modeling

The purpose of the Plate Tectonic Reconstruction Project was to provide an integrated 3D model of the crustal structure and evolution of the Nova Scotia continental margin, in space and time, from rifting to spreading. This model underpins an understanding of early rift and post-rift depositional environments and provides a predictive model for salt deposition and the distribution of Triassic and Early Jurassic source and reservoir rocks.

The project included a number of elements such as acquisition of new refraction data offshore Nova Scotia, reprocessing of refraction data offshore Morocco, reprocessing of long offset multi-channel seismic offshore Nova Scotia, merging and integrated reprocessing of potential fields data, and integrated interpretation of all these data. The integrated interpretation of these data enabled a revised plate reconstruction to be produced, together with a model for the along-strike variation of rifting styles, for the Nova Scotia margin.

The tectonic analysis leads to an interpretation that allows for the possibility of an Early Jurassic source rock system offshore Nova Scotia and provides a model for the distribution of such a source rock system. This, in turn, greatly enhances the potential for hydrocarbon prospectivity (see Chapter 2).

Biostratigraphy

Prior to this study, there was no public domain sequence stratigraphic framework for the Nova Scotia margin. Therefore, the program of work included a re-evaluation of the biostratigraphy of several key wells, which were integrated with seismic interpretation, and tectonic models, to build a comprehensive sequence framework (see Chapter 3).

Geochemistry

Although much geochemical data existed on the margin through the many hydrocarbon discoveries and discoveries, the source rock story was not well understood. The project undertook a systematic evaluation of geochemical source rocks and hydrocarbon typing data. The forensic geochemistry project, with a broad geographic coverage included:

- Rock evaluation – including source rock molecular biomarker analyses.
- Vitritne reflectance (VRI).
- Quality control of existing VR database.
- Oil gas chromatography-Mass spectrometry.
- Fluid inclusion analysis of clastics, carbonates, and salt.

The work is described in Chapter 4.

Seismic Reprocessing

The vintage of the various seismic datasets offshore Nova Scotia are such that there was a considerable potential to improve their quality using modern technology. Two particular datasets were targeted because of their consistent high quality:

- Regional Framework Data: 3,400km 2D seismic data from the ION/STT NOVASPAN survey, which provides a consistent regional seismic framework across the Nova Scotia margin able to provide a comprehensive view of the geologic evolution and basin architecture.
- The lines: 4,000km 2D seismic data from the TGS-NOPEC 1998/99 survey, chosen to intersect the 20 key wells, selected by the biostratigraphy project as the basic for a geological framework for the Project.

This selection of data was reprocessed (by ION/STT and TGS-NPEC for the relevant surveys). Reprocessing was from field tapes and included pre-stack and post stack processes (including two passed of de-multiple and Reverse Time Migration pre – stack). The reprocessing was closely guided by the project seismic interpreters to ensure robust selection of parameters, especially velocity models for depth migration.

The result was a major improvement in data quality of these lines, which was critical for establishing ties to the key 20 wells. Some examples are shown in Chapter 5.

Salt Structural Interpretation

Understanding the interaction of sedimentation with salt kinematics was critical to the study. This interaction exerts a strong control on sediment dispersal and creates significant changes in the characteristics of petroleum systems across the margin. Section 8-1 describes this analysis and the implications on the distribution of plays.

Reservoir Quality

This project was conducted at St. Mary’s University and Geological Survey of Canada, in Halifax. The objective of this work was:

- To develop an understanding of the variation of diagenesis and effects on reservoir quality in the Lower Cretaceous using a sequence stratigraphic based approach.
- To build models for predicting heterogeneity in Cretaceous turbidite reservoirs, and
- To review the variation of potential reservoir facies in the Jurassic carbonate bank and identify possible play models using seismic and well data.

The work produced key insights on controls on reservoir quality and also on provenance of Cretaceous reservoirs. It is reported in an Appendix to this Atlas.

Project Process

The PFA process and special projects described above were designed to replicate the quality of analysis that is typically undertaken by the major oil companies. It has proved challenging to recreate this approach in the contractor community. This has included integrating the many years of research that has taken place in the academic institutions in Halifax into the overall "commercial" geotechnical analysis project.

The key novel insights in this approach were gained from integrating this disparate network of experts and contributors. The program included monthly integration meetings in which the project participants met to discuss technical progress. This process replicates the "over assist" program’s that are used in many oil companies.

Bibliography

The Scotian Basin is a passive volcanic, conjugate margin. It represents over 200 million years of continuous sedimentation recording the region’s dynamic geologic history from the initial opening of the Atlantic Ocean to the recent post-glacial deposition. The basin is located on the northeastern flank of the Appalachian Orogen and covers an area of approximately 280,000 km² and may contain up to 15 kilometers of sediments deposited in its deepest areas south and east of Sable Island. The continental-size drainage system of the paleo-Saint Lawrence River provided a continuous supply of sediments that accumulated in a number of complex interconnected sub-basins. Early syntax, carbonate margin, fluvial-decadal-lacustrine and deep water depositional systems are all represented in the basin stratigraphic succession (Figure 1).

**PRE-RIFT**

The Scotian Basin is located offshore Nova Scotia where it extends for 1200 km from the Yarmouth Arch/United States border in the southeast to the Avalon Uplift on the Grand Banks of Newfoundland in the northeast (Plate 7-1b) with an average breadth of 250 km. Half of the basin lies on the present-day continental shelf in water depths less than 100 m, while the other half of the continental shelf in water depths from 200 to 4000 m. The Scotian Basin formed on a passive continental margin that developed after North America rifted and separated from the African continent during the break-up of Pangaea (Fig. 7-1).

From the southeast to the northeast they are named the Shelburne Sub-basin, LaHave Platform, Sable and Abenaki Sub-basins, Bangor Platform, Huron and Laurentian Sub-basins and Orphane Platform (Plate 7-1b). The boundaries of these platforms and basins may have been defined by regularly-spaced oceanic fracture zones that extended landward onto continental crust (Waisel et al., 1995). A northeast trending basement hinge zone is also present along the margin, defining the landward limit of maximum syntectonic extension and an abrupt seaward increase in basement depth due to thermal subsidence. Together, these basement elements asserted a strong control on sediment distribution in the region for more than 250 million years.

**SYN-RIFT**

Red beds and evaporites were the dominant deposits during the late pre-rift phase, whereas typical clastic progradational sequences with periods of carbonate deposition dominated the shift phase.

At the beginning of the late-middle Triassic Period, about 225 million years ago (Ma), the Scotian basin was reworked and a new orogenic phase was initiated, characterized by orogenic activity, compression and the development of the Appalachian Mountains. The eastern part of the basin was turned into a passive continental margin, while the western part of the basin was rifted and separated from the African continent during the break-up of Pangaea (Fig. 7-1). The result was a series of thick, red, clastic sediments accumulated. By late Early Jurassic, transgressive shallow water to tidally influenced dolomites and clastics were laid down in localized areas on the shelf in the eastern part of the basin. The end of the Cretaceous period in the Scotian Basin saw a rise in sea level and the development of coastal areas near the harvest of the shelf sediments. By the end of the Cretaceous, the Scotian Basin was located in the northeast of the Grand Banks of Newfoundland in the northeast (Plate 7-1b).

**EARLY POST-RIFT**

EARLY POST-RIFT Marine transgression above the BU-J200Ma, eventually covered the basin with a narrow, shallow and restricted sea within which thin sequences of carbonate and clastic sediments accumulated. By late Early Jurassic, transgressive shallow water to tidally influenced dolomites and clastics were laid down in localized areas on the shelf. Modern carbonate shelf and slope sedimentation ceased along much of the Scotian margin following a late Early Cretaceous major marine transgression (Aptian MFS) when the shelf was blanketed by shallow water carbonates and other shelf sediments were reworked and re-deposited. The end of the Cretaceous period in the Scotian Basin saw a rise in sea level and the development of coastal areas near the harvest of the shelf sediments. By the end of the Cretaceous, the Scotian Basin was located in the northeast of the Grand Banks of Newfoundland in the northeast (Plate 7-1b).

**LATE POST-RIFT**

By the Late Jurassic, Oxfordian-Tithonian, conjugate margin, regional uplift resulted in the establishment of the mixed energy (current and tidal) Sable Delta complex in the Scotian Basin and the development of the Sable Delta platform, while along the northern margin and adjacent to it, during the early Tertiary and Cenozoic, the Middle Atlantic and the Sable Delta complex and other shelf basins were established. At the beginning of the early Tertiary, the Sable Delta prograded rapidly southwest into the Laurentian, Huron and Sable Sub-basins and over the Banquereau Platform, while in the Shelburne Sub-basin the polyhalite Shelburne Delta changed into Barremian time and disappeared as the result of its sediment supply. The end of the Cretaceous period in the Scotian Basin saw a rise in sea level and the development of coastal areas near the harvest of the shelf sediments. By the end of the Cretaceous, the Scotian Basin was located in the northeast of the Grand Banks of Newfoundland in the northeast (Plate 7-1b).
INTRODUCTION - REGIONAL GEOLOGY

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Geological Map of the Province of Nova Scotia
J.D. Keppie, 2000, Ref.: Map ME 2000-1
See separate legend to Plate 3-1

Datum plane = Mean Sea Level
Contour interval: 200 m

Legend
• Salt diapirs, MacLean, B.C., 1991
• Basement Faults
• Volcanics
• Oceanic Crust

20 reference wells
2010 reprocessed GXT-Novaspain 2D seismic lines
2010 reprocessed TGS 2D seismic lines

Projection system: Universal Transverse Mercator - Zone 20N
Datum: NAD 27
Ellipsoid: Clarke 1866

Major Tectonic Elements of the Scotian Basin
PL. 1-1b
CHAPTER 1-2

PRODUCCION HISTORY

OFFSHORE PROJECTS

Petroleum production offshore Nova Scotia has included three projects:

✓ The Cohasset-Panuke project produced oil from 1992-1999 and is now decommissioned. Project operators were Pan Canadian (now EnCana), and Lasmo.

✓ The Sable Offshore Energy Project, operated by Exxon Mobil and partners has been producing gas since 1999.

✓ The Deep Panuke Offshore Gas Development Project, operated by EnCana Corporation and partners, which is currently under development and expecting first gas in 2011.

PRODUCTION HISTORY
PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011

Field Production

- North Triumph 1 / 2 / 3
- Venture 1 / 2 / 3 / 4 / 5 / 6 / 7
- Panuke 1 / 2 / 3 / 5 / 6
- Thebaud 1 / 2 / 3 / 5 / 6

Web address for last updates: http://www.cnsopb.ns.ca/production.php
Regional Hydrocarbon Distribution from Wells – General Map

Production field symbols:
- Gas and Condensate
- Oil
- Oil and Gas
- Water, no show
- Tight: No Flow
- Oil < 44 API
- Gas show
- Oil show
- Oil and Gas show
- HC trace
- No show

Projection system: Universal Transverse Mercator – Zone 20N
Datum: NAD 27
Ellipsoid: Clarke 1866
Bathymetry interval: 50 m shelf – 500 m slope

The wells reported on this map represent the 148 Exploratory and Delineation wells (complete collection) from CNSOPB well directory, updated Oct. 2010

Production fields:
- Gas and Condensate
- Oil
- Oil and Gas

Major exploration discoveries:
- Gas and Condensate
- Oil
- Gas and Condensate

Test (DST & WLT):
- Hydrocarbon show (no test)
- Gas show
- Oil show
- Oil and Gas show
- HC trace
- No show

Geological Map of the Province of Nova Scotia, J.D. Keppie, 2000, Ref.: Map ME 2000-1
See separate legend: PL. 3-1-1
CHAPTER 1-3

EXPLORATION HISTORY AND WELL FAILURE ANALYSIS

Section 1-3 presents Exploration History and Well Failure Analysis—reviewed by CNSOPB.

• Plate 1-3:14: Conclusion “… Therefore most of the plays defined by this PFA outside Sable sub-basin are untested. The exception is the Lower Missisauga discovery at Annapolis, which although not drilled in an optimal location, does prove that this petroleum system does work.”
Introduction

Exploration began offshore Nova Scotia in 1967 when Mobil spudded their first well on Sable Island. Since then 127 exploration wells have been drilled for a total of 205 including development wells (see map in previous Plate PL. 1-3-1). The bulk of these wells were drilled in the Sable Island region, to follow up and exploit the gas success. The exploration history and failure analysis has been studied in depth by the CNSOPB. These reports provide a detailed analysis of the results of each exploration well and form the basis for this study.

The PFA study has developed a revised sequence stratigraphic framework for the basin and defined a set of new reservoir play fairways. The PFA team have therefore reevaluated the excellent CNSOPB work in terms of the revised play definitions emerging from this study. We have looked at the wells in terms of plays, determined the main failure mode and made an assessment if each well was a valid play test.

Some key themes emerge through the failure analysis that determine the main exploration risk for each play. This has then focused the PFA work on understanding the key risk element. It is interesting to note that when we started the PFA work our mind set was that the key failure mode was lack of source rock. The PFA study has developed robust source rock models for both the Sable delta region and the deepwater which have substantially de-risked the charge play element. This well failure analysis shows that reservoir presence, and seal are the main failure modes. As a result, increasing emphasis has been placed on understanding these components in the study.

Approach

Time constraints have not allowed us to re-pick the horizons in each well with the new sequence stratigraphy. We have crudely undertaken the failure analysis in the following broad plays using the existing lithostratigraphic nomenclature:

- Upper Jurassic Mic Mac
- Mid to Upper Jurassic Carbonate
- Lower Cretaceous Mississauga
- Lower Cretaceous Logan Canyon

Each is discussed in the following sections.

The table below (on the plates) presents a list of the wells with, primary target, secondary target and failure model. We then determine success rate for each play and calibrate the CRS maps with the drilling results.

Background

The basin creaming curve (Figure 2) is critical in explaining the exploration history. Overall success rate is around 1:5. But this rate is heavily influenced by the lack of exploration success since 1986. Deep Panuke is the only discovery in 1999 from some 30 exploration wells. Pre 1986 the success rate is 1:3. On deeper analysis, it emerges that the finding rate in the core Sable sub basin on Mississauga tests is better than 1:3.

The well cross section through the significant discoveries in the Sable Sub basin (Figure 3) shows that the discoveries and gas production comes from a number of different stratigraphic levels. This diagram suggests that gas is found when over top there is a resistant horizon. A resistant horizone, but indicates no systematic variation in successful plays in the sub basin. The closures are defined by the presence of a sealing surface (generally an MFS) in dip closure. Fault closures do work in the shalier sections. Some operators have proposed that fault seal is effective based on a N/G threshold. We have not been able to substantiate this. We prefer a model for seals based on sub regional MFS surfaces with sufficient shale thickness.

Considering the presence of fields along with the fault maps shows that the gas discovery density conforms with the fault density (Figure 44, 45 and 46). The main controls on the successful structures are role over features into growth faults. We observe that the fault density is also closest in the area of 3D seismic data. We therefore postulate that the lack of mapped growth faults is a function of the lack of data rather than lack of faulting.

This success rate was achieved without 3D data. It is interesting to note that the acquisition of 3D data 2000 – 2006 had no impact on exploration success. This is in clear contrast to other regions of the world. It is not entirely clear why this is. One can speculate that perhaps explore were using the wrong models for the plays.

The diagrammatic geo cross-section (Figure 2) through the Sable sub basin shows the key features of the hydrocarbon system. The producing fields are found in Upper Jurassic through to Lower Cretaceous deltaic reservoirs. The structures are growth fault role over features with the model for main source rocks being within the delta itself.

1 The Upper Jurassic Abenaki Formation: A seismic and geologic perspective 2005
3 Post 2000 Exploration Drilling/Results (Unpublished)
Jurassic Play Tests: Clastics

Figure 4 shows the play tests and success rates for the Jurassic carbonates and clastics. We first consider the clastic system. Figure 4 shows play tests and Figure 5 the GDE maps derived from the PFA study and the Jurassic fault systems. We have superimposed the location of the main delta fairway onto the fault map and also marked on the Mid Jurassic shelf slope break (Figure 6). The main PFA study shows that source rocks are not a problem for this play.

Through the Mid to Upper Jurassic carbonates were established to the South West of the margin in a well defined rimmed platform environment. The main source of clastic input was to the North and North East associated with the uplift of Newfoundland. Throughout this period there was an inter-fingering between the clastics and carbonates controlled by clastic supply (in times of low clastics input, carbonate deposition migrated to the North East). The presence of carbonates in the clastics kills reservoir quality. The Southwest boundary for reservoir quality controlled by carbonate cementation is difficult to establish, and perhaps predict. A number of wells (e.g. Mariner – Figure 7) were drilled in this area and failed for lack of reservoir quality.

The Upper Jurassic delta system underlies the core of the Lower Cretaceous delta systems. Therefore a large portion of the Jurassic play is has seal problems. The Upper Jurassic top sequence boundary is defined by the Tithonian MFS. This acts as a regional seal. Therefore the sweet spot for the play is defined by the juxtaposition of reservoir quality sands and sufficient thickness of seal at the Tithonian MFS.

This play model explains the failure modes for the Upper Jurassic clastic tests. Lack of reservoir quality to the South West and seal in the core part of the reservoir fairway. Much of the exploration on this play in the North East was undertaken in the 1970’s on 2D data. Lack of structure and definition of closure was also a contributing factor to well failures.

Jurassic Play Tests: Carbonates

Figure 5: Dionisos simulation map @149.5 Ma (Mic-Mac)

Figure 6: Late Jurassic sand play tests

Figure 7: Mariner – Mic-Mac tests - 2004
We illustrate the well failures with two relatively recent wells, Mariner (Figure 7 in Plate 1) and Queensland (Figure 8). Both failed for lack of reservoir.

Queensland was targeted on a presumed clastic channel system in a stratigraphic trap against the carbonate bank. The well discovered carbonate debris flows. The GDE maps derived from this study suggest it unlikely that clastics would be present in this location. We consider this to be a poor exploration well.

Jurassic Play Tests: Carbonates

This analysis draws extensively on the CNSOPB analysis which is summarized here.

The well locations (Figure 9) and results show that lack of reservoir is the main failure mode; the only success being Deep Panuke. We illustrate the Deep Panuke discovery well and appraisal programme below. The discovery well (PP-3C – Figure 10) discovered gas in carbonate reservoir on a presumed amplitude anomaly.

The appraisal (Figures 10 and 11) and step out exploration program (Figures 14 to 16) showed how tightly constrained the reservoir distribution is and that amplitudes are misleading. Appraisal well PP-1A was dry. The well was deviated a short distance and discovered a thick gas column. Following the success of Deep Panuke, a number of wells were drilled on amplitudes – which failed.
Well failure modes for wells placed on the carbonate bank are less clear cut. Wells, Bonnet and Albatross (Figure 13 and Figure 29) both encountered vuggy porosity but wet. The shows are inconclusive. The seismic sections show that in both well locations the carbonate bank is intersected by a major unconformity. This suggests that seal may be the failure mode. Both wells are located in ideal locations for charge from a postulated Lower Jurassic source rock. A lack of charge cannot be conclusively ruled out.

A number of early wells, drilled in the 1970s on basement involved dip closed features, could have targeted the carbonate section. The wells did not penetrate any reservoir. However given their distance from the potential source kitchen, the failure mode is charge.

Lower Cretaceous – Mississauga Play Tests

Figure 17a shows the locations of the Mississauga play tests and Figure 17b shows the locations of the Mississauga play tests – Wells and Fields. Note that in this commentary we’ve consolidated the three Mississauga sequences into one. A large proportion of the Scotian exploration wells targeted this reservoir and the success rate is good. Dip closed features in an area where the regional seal can be mapped are successful.

Figure 18 shows the GDE for the Middle Mississauga. This shows that reservoir presence over most of the Sable sub basin is not a risk. Reservoir quality is not a problem either. The main control on well success/failure is trap and trap integrity.
Lower Cretaceous Missisauga Play Tests and Deep Water Tests

Deep Water Tests

There have been 9 deep water tests (Figure 21). The location and sections for these are shown in Figures 22 and 23 (next Plate). Most of the wells were drilled on clearly defined dip closed features. All had reservoir problems. The main failure mode is lack of reservoir. All the wells found thin stringers of sand all of which were gas charged.

The locations of the wells and the reason they were drilled is clear from the seismic sections. The following points of note can be made about specific wells:

- A number of the early wells (Schubenacadie - Figure 27) were drilled on Tertiary fan systems, and then deepened to test the Cretaceous section. There was no reservoir at Tertiary, or Cretaceous.
- Shelburn (Figure 28 and 29) is a "teazer" well. The well targeted the shallow section and then deepened to test a large dip closed anticlinal feature. However the well stopped short of testing the closure. Oolites were discovered at TD. No shows were encountered. The age of the anticlinal feature is unknown.
- The Tantallon well (Figure 30 and 31) tested a huge dip closed feature but did not find reservoir. However it appears that the well was located on a palaeo high and sands may have bypassed it. The feature is down dip of the very sandy Mississauga delta package and seaward of the well there is evidence of turbidites. A valid test of the feature would search for the channel systems. Tantallon was not located based on 3D data.
- Weymouth (Figure 34 and 35) was drilled on a sub salt structure. This is a high risk well. Given 7 failures due to lack of reservoir prior to Weymouth, the presence of reservoir under the salt canopy would also appear to be unlikely. And so it proved.

Main Failure Mode
- Seal and Fault Seal
- Lack of closure
- Lack of reservoir in the delta front

Within the core Sable producing area it appears that trap integrity is the key risk element (Figure 20) even in areas covered by 3D. However we assert that dip closed features in areas where there is seal presence have a good chance of success. Outside the Sable Sub basin, to the North East the main failure mode is a combination of lack of structure and seal (in the proximal parts of the delta). Many of these wells were drilled in the 1970's on 2D data. We have difficulty in seeing any closure at the well locations.

In the North East of Sable we do not think there is a valid play test at Mississauga, or Mic Mac level.

Figures 19 show sections through locations of four of the most recent Mississauga tests. The failure mode is fault seal and lack of closure. Wells Emma (Figure 19a) and Adamant (Figure 19b) were drilled down dip of dip closure into section that relied on fault closure to be effective. The locations were chosen to prove up "volume". However the fault closure failed. Southampton (Figure 19c) was drilled on a location that subsequent mapping has shown to be on a feature that does not close. Onondaga (Figure 19d) was a complex well drilled on a salt feature that was cut with faults. We interpret this to be a fault closure failure also.
EXPLORATION HISTORY AND WELL FAILURE ANALYSIS

PL. 1-3-7

Deep Water Tests: Evangeline, Shubenacadie and Shelburne

The locations of the wells and the reason they were drilled is clear from the seismic sections. The following points of note can be made about specific wells:

- A number of the early wells (Shubenacadie – Figure 23) were drilled on Tertiary fan systems, and then deepened to test the Cretaceous section. There was no reservoir at Tertiary, or Cretaceous.
- Shelburne (Figure 24 and 25) is a "teaser" well. The well targeted the shallow section and then deepened to test a large dip closed anticlinal feature. However the well stopped short of testing the closure. Oolites were discovered at TD. No shows were encountered. The age of the anticlinal feature is unknown.

Figure 22: Evangeline – 1984 - Husky

Figure 23: Shubenacadie – 1985 - Shell

Figure 24: Shelburne – 1985 - PEX

Figure 25: Shelburne and Albatross
The locations of the wells and the reason they were drilled is clear from the seismic sections. The following points of note can be made about specific wells:

- The Tantallon well (Figure 26 and 27) tested a huge dip closed feature but did not find reservoir. However, it appears that the well was located on a palaeo high and sands may have bypassed it. The feature is down dip of the very sandy Mississauga delta package and seaward of the well there is evidence of turbidites. A valid test of the feature would search for the channel systems. Tantallon was not located based on 3D data.

Regional 2D seismic dip line through Tantallon M-41. Data courtesy of TGS-NOPEC from Kidston et al. (2007), "Nova Scotia Deepwater Post-Drill Analysis 1982-2004"

Deep Water Tests: Tantallon and Newburn

Newburn 2002 Chevron
- 977m water
- TD 5983m early Hauterivian
- Pebble conglomerate
- Few thin gas sands (2-3m).

Figure 28: Newburn – 2002 - Chevron

Regional 2D seismic dip line through Tantallon M-41. Data courtesy of TGS-NOPEC

Tantallon 1986 Shell
- 1540m water
- TD 5602m Late Valanginian
- Poor quality sand.

Figure 26: Tantallon – 1986 - Shell

Figure 27: Tantallon

from Kidston et al. (2002), "Hydrocarbon Potential of the Deep-Water Scotian Slope"
The locations of the wells and the reason they were drilled is clear from the seismic sections. The following points of note can be made about specific wells:

- **Weymouth** (Figure 34 and 35) was drilled on a sub salt structure. This is a high risk well. Given 7 failures due to lack of reservoir prior to Weymouth, the presence of reservoir under the salt canopy would also appear to be unlikely. And so it proved.

Deep Water Tests: Balvenie and Weymouth

**Balvenie 2003 - Imperial**
- 1803m water
- Only 515m tested.
- TD 4750m Early Aptian (C30)
- Gas charged siltstone.

**Weymouth 2004 - EnCana**
- 1690m water
- TD 6500m Lower Miss.
- 1507m salt.
- Kick 260m below salt
- Flooded 5m OP silt
- No sand.

The locations of the wells and the reason they were drilled is clear from the seismic sections. The following points of note can be made about specific wells:
EXPLORATION HISTORY AND WELL FAILURE ANALYSIS

Deep Water Tests: Annapolis and Crimson

Annapolis and Crimson (Figures 32, 33 and 34)
Annapolis is an important well. This was drilled by Marathon on a dip closed feature. After many drilling problems the well penetrated a 16m gas column. This was abandoned without being tested. This is the first well that discovered gas in the deep water. The presence of gas hints at a second source rock independent of the delta systems.

Marathon drilled the follow up well Crimson down dip on a separate feature. Crimson found no reservoir.

There is a good quality 3D survey over the wells. The PFA team undertook some simple attribute extractions from the 3D cube. These are illustrated (Figures 35a to 35f). They suggest that the wells were located away from the main sand fairway. Going back to the dip and strike lines (Figures 36 and 37) through the Annapolis well one can see clear evidence of high amplitude features that are part of a section that thins up to the Annapolis well location. We suggest that neither well is drilled in an optimal location for reservoir

The Annapolis discovery is critical to the prospectivity of the deep offshore for two reasons
1) The well demonstrates the presence of a working hydrocarbon system
2) The attribute work shows evidence for channel systems in deep water and shows that the channels can be mapped using high quality seismic

Both are profound observations in de-risking the deep offshore.
EXPLORATION HISTORY AND WELL FAILURE ANALYSIS

Crimson and Annapolis – Seismic Attributes

Hauterivian MFS, -80 to -40ms, RMS Amp

Annapolis G-24 (gas discovery)
Crimson F-81 (wet)

Hauterivian MFS, -40 to 0ms, RMS Amp

Annapolis G-24 (gas discovery)
Crimson F-81 (wet)

Hauterivian MFS, 0 to +40ms, RMS Amp

Annapolis G-24 (gas discovery)
Crimson F-81 (wet)

Hauterivian MFS, +40 to +80ms, RMS Amp

Annapolis G-24 (gas discovery)
Crimson F-81 (wet)

B24_01, 0 to +100ms, Max Instantaneous frequency

Annapolis G-24 (gas discovery)
Crimson F-81 (wet)

B24_01, +20 to +80ms, Max Instantaneous frequency

Annapolis G-24 (gas discovery)
Crimson F-81 (wet)
Lower Cretaceous - Logan Canyon Tests

The locations of the Logan Canyon tests are shown on Figure 38. It proved difficult to separate out the Logan tests from the Mississauga tests as wells were chosen to drill structural closures and drilled the complete section. The main failure mode for the Logan Canyon is seal. Most well failures were drilled in a proximal location.

Figure 39 shows the GDE map and Figures 40 to 43 show the fault map and the palaeoshore line. Both are helpful in illustrating the main reservoir fairways, but not the sealing potential. The sealing surface for the Logan formation is the Cenomanian MFS and this defines the 'working' dip closed structures.
EXPLORATION HISTORY AND WELL FAILURE ANALYSIS

Logan Canyon Play Tests – Seal & Faults

Main failure mode
Seal and structure

Figure 40: Logan Canyon - Faulting

Figure 41: Three (3) stages of faulting

Figure 42: Faulting and salt structures

Figure 43: Faulting, salt structures and distribution of fields
Figure 44 summarizes the main findings of this well failure analysis for the four plays studied. This shows that outside the Sable Sub basin there have been no valid play tests. Therefore the plays defined by this PFA are untested.

Conclusion