CHAPTER 1

INTRODUCTION TO THE PLAY FAIRWAY ANALYSIS PROJECT

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 prospectivity (see MacMullin et. al. 2010). The 2007/2008 review was conducted for the Department of Energy of Nova Scotia, who subsequently allocated a fund to OETR (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 rift depositional environment 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 typing data.
Sequence stratigraphic framework: there was a lack of a robust public domain sequence stratigraphic framework for the margin. Hence the program included a re-evaluation of the biostratigraphy of several key wells which were be 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. Thus the PFA evolved into a number of linked and actively integrated individual projects. These included:

- Seismic Database Preparation / Synthetics
- Reprocessing of seismic lines of around 7,400km data
- Plate Tectonics 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 though 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 BEICIPFRANLAB 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^2 of 3D data. The data was cross equalized and phase matched. Synthetics for around 20 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 biostraigraphy 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 bio stratigraphic 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.

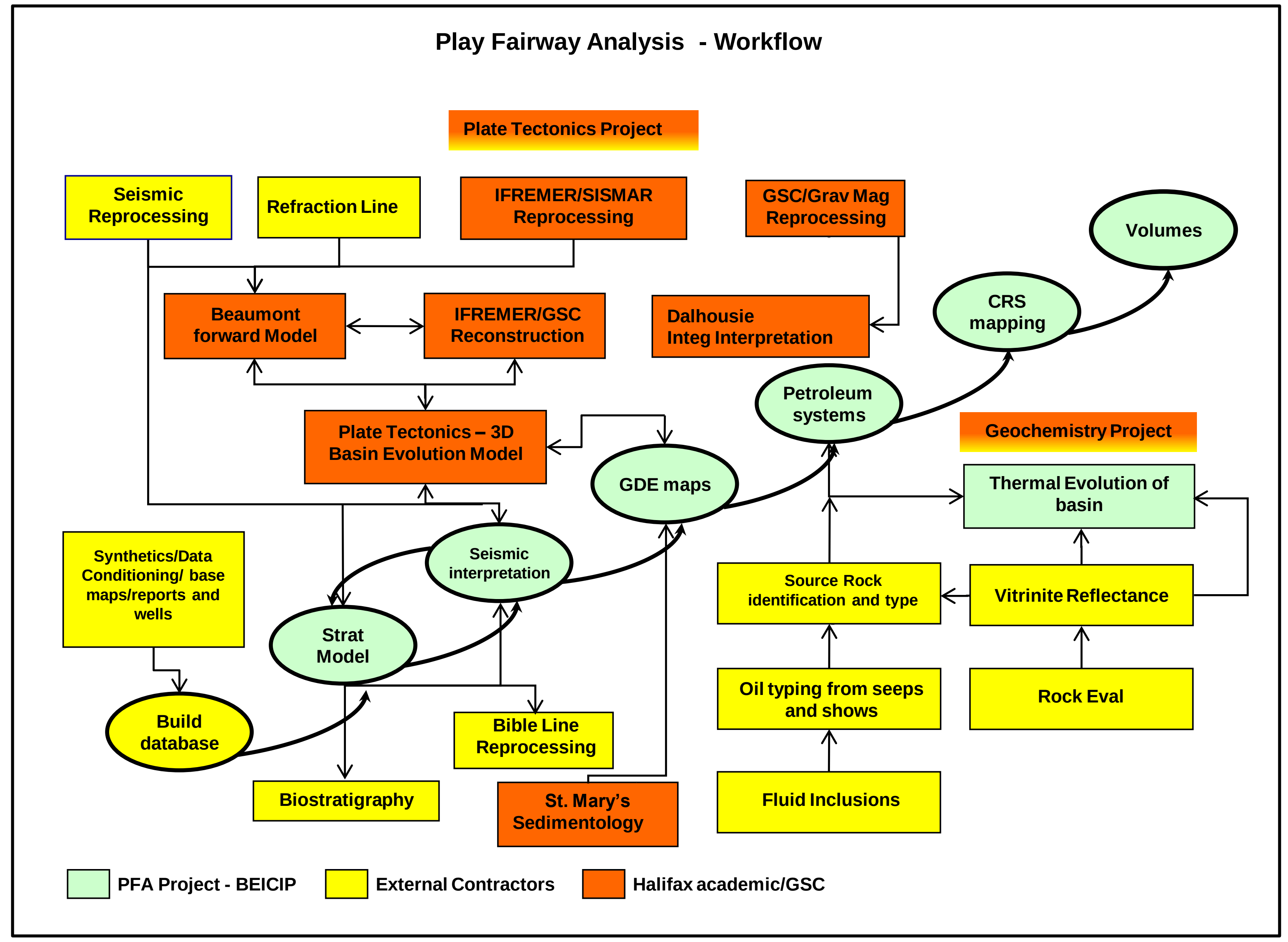

Figure 1: Structure overall PFA program

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 plates showing the well synthetics linked to the seismic data.
- Cross sections at both the regional and local scale.
- ~Ten sequences mapped 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 Tectonics project.
- Seismic inversion results (as appropriate) and their link to lithology and depositional.
- 3D forward modeling (DIONISOS) 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.

Petroleum Systems Modeling

Petroleum Systems Modeling 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 Temis 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, T_{max}, R_0, etc; °API, GOR).
- Matching of Pressure (mudweights, 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 used a fully coupled 2D/3D sediment- crustal model, including:
Migration 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 – ″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:

- Risking 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 shows and discoveries, the source rock story was not well understood. The project undertook a systematic evaluation of geochemical source rock and hydrocarbon typing data. The forensic geochemistry project, with a broad geographic coverage included:

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

The work is described in Chapter 4.

Seismic Reprocessing

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

- Regional Framework Data: 3,400km 2D seismic data from the ION/GXT 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.
- Tie 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 PFA.

This selection of data was reprocessed (by ION/GXT and TGS-NPEC for the relevant surveys). Reprocessing was from field tapes and included modern 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 projects 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 string 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 were:

- 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 wer 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 ″peer assist″ program’s that are used in many oil companies.

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CHAPTER 1-1

INTRODUCTION

REGIONAL GEOLOGY

Regional Geology : An Overview*

The Scotian Basin is a classic passive volcanic, conjugate margin. It represents over 250 million years of continuous sedimentation recording the region's dynamic geological 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 km^2 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-St. Lawrence River provided a continuous supply of sediments that accumulated in a number of complex, interconnected sub-basins. Early synrift, carbonate margin, fluvial-deltaic-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 southwest to the Avalon Uplift on the Grand Banks of Newfoundland in the northeast (*Plate 1-1b*) with an average breadth of 250 km. 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 formed on a passive continental margin that developed after North America rifted and separated from the African continent during the break-up of Pangea (*Figure 1*). It consists of a series of alternating "highs and lows", or platforms and depocentres. From the southwest to the northeast they are named the Shelburne Sub-basin, LaHave Platform, Sable and Abenaki Sub-basins, Banquereau Platform, Huron and Laurentian Sub-basins and Orpheus Graben (*Plate 1-1b*). The boundaries of these platforms and basins may have been defined by regularly-spaced oceanic fracture zones that extended landward onto continental crust (Welsink et al., 1990). A northeast-trending basement hinge zone is also present along the margin, defining the landward limit of maximum tectonic 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 drift phase.
Rifting began in the mddle-early Late Triassic Period, about 225 million years ago (Ma). At that time, the Nova Scotia region occupied a near equatorial position, situated adjacent to Morocco, with most of its older Paleozoic rocks having direct Moroccan affinities (Schenk et al., 1980). A series of narrow, interconnected rift basins were created during the rift phase and were filled with fluvial and lacustrine red bed sediments as well as volcanic rocks (Fundy-type sequences). By the latest Triassic-earliest Jurassic, tectonic motion had moved the North American and African plates slowly northward, with the Nova Scotia-Moroccan region in an arid sub-equatorial climate zone (ca. 10-20°N paleo-latitude). Renewed Late Triassic rifting of continental crust further to the north and east in the Grand Banks / Iberia region 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 mixed clastic and minor carbonate sedimentation (**Eurydice Formation**). Due to the hot and dry climate, the shallow seas were repeatedly evaporated, resulting in the precipitation of extensive salt and minor anhydrite deposits that were as much as two kilometers thick in the central parts of the rift system (**Argo Formation**).
An earliest Jurassic phase of siliciclastic deposition is observed in the west-central part of the Scotian Basin that may exist elsewhere along the margin and the Moroccan conjugate. This eastward-directed pulse of redbed sediments (**Heracles unit**) conformably overlies and deforms (through loading) Argo Formation evaporites in the Mohican Graben. The west-dipping listric faults inboard of the margin hinge-line on the Mohican and Naskapi grabens are interpreted as the antithetic response to extension in the Fundy Basin during the Late Triassic (Wade et al., 1996). These grabens acted as loci for clastic deposition for newly established fluvial drainage systems, with the source of the sediments from the current mainland region of Nova Scotia. While not yet encountered in wells or observed elsewhere along the margin, the age of this succession can be reasonably inferred as late Triassic - early Hettangian since it conformably overlies the Argo Formation and is later truncated by the younger Breakup Unconformity dated early Jurassic J200.
Renewed tectonism in the central rift basin during the Early Jurassic (Hettangian to Mid-Sinemurian) is recorded by the complex faulting and erosion of Late Triassic and Early Jurassic sediments and older rocks. This phase of the rifting process resulted in the formation of a Breakup Unconformity (BU), which coincided with the final separation of the North America and Africa continents, the creation of true oceanic crust through volcanism, and opening of the proto-Atlantic Ocean. As a result of the BU, the heavily faulted, complex terrane of grabens and basement highs along the Scotian margin underwent a significant degree on peneplanation.

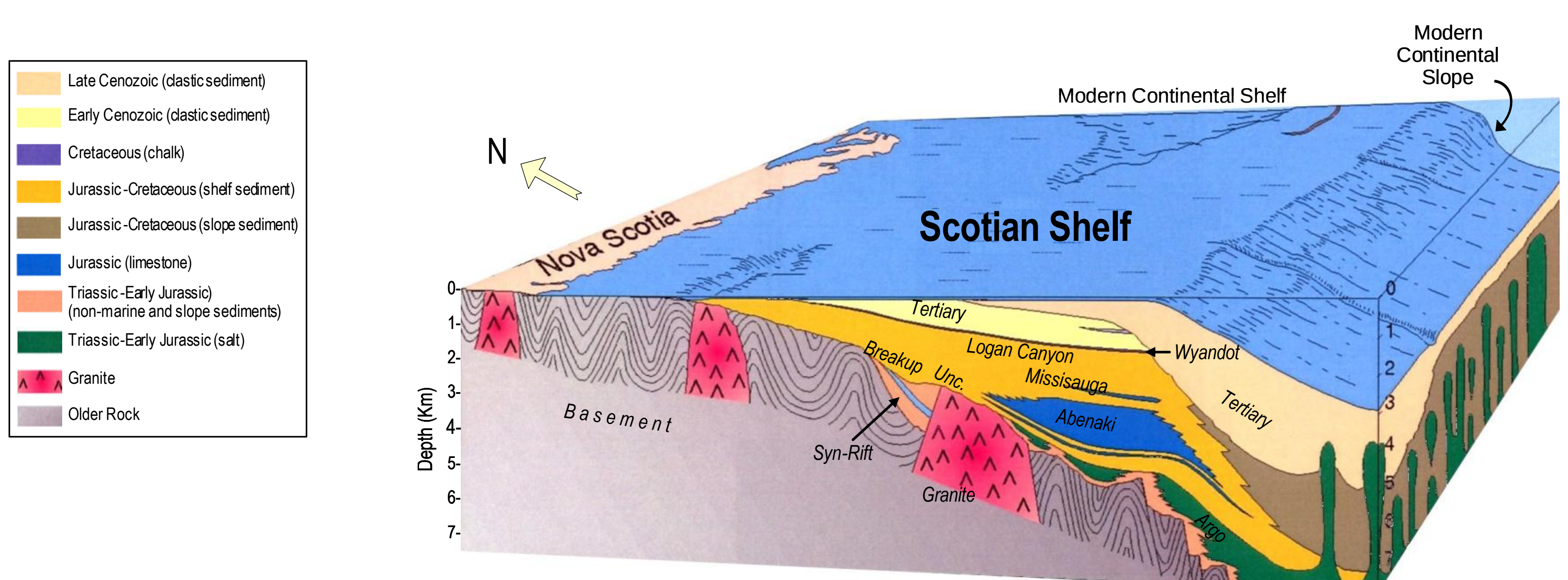

Figure 2: Schematic 3D view of Scotian Basin from the west toward Sable Sub basin showing major stratigraphic and structural relationships (after J; Wade, modified Grant 1986, CNSOPB, 2009).

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 seaward portion of the margin under slightly restricted marine conditions (**Iroquois Formation**). A thick succession of coarser grained clastic sediments and shales from fluvial sources (**Mohican Formation**) was deposited concurrently on the basin margins. The succession was sourced from adjacent high relief terranes and eventually prograded out over the margin to fill graben lows and bury basement highs by the early Middle Jurassic (MacLean and Wade, 1990). The fine muds from this succession were transported by marine processes into deeper water where they slowly infilled basinal lows and blanketed newly formed oceanic crust.
The combination of sea-floor spreading, basin subsidence and global sea level rise caused the Atlantic Ocean to become broader and deeper (~1000 m) by the Middle Jurassic. A prominent carbonate bank developed in the western part of the basin at this time and persisted until the latest Jurassic-earliest Cretaceous. Growth of the carbonate bank was tempered by Upper Jurassic and Lower Cretaceous deltaic depocentres that locally overwhelmed carbonate sedimentation. The carbonate bank succession can be subdivided into a number of members. A carbonate platform and margin succession was established along the basin hinge zone (**Scatarie Member** of the Abenaki Formation) and prograded out into deeper waters where marls and clastic muds were deposited. Continuing margin subsidence coupled with global sea level rise resulted in transgression during which time the carbonates and other shelf sediments were blanketed by deeper marine shales (**Misaine Member** of the Abenaki Formation). From the late-Middle to the end of the Jurassic, carbonate reef, bank and platform environments formed and thrived along the basin hinge line on the LaHave Platform (**Baccaro Member** of the Abenaki Formation). Further north, a shallow mixed carbonate-clastic ramp succession existed on the Banquereau Platform and in deeper water a thin succession of shales and limestones were deposited.

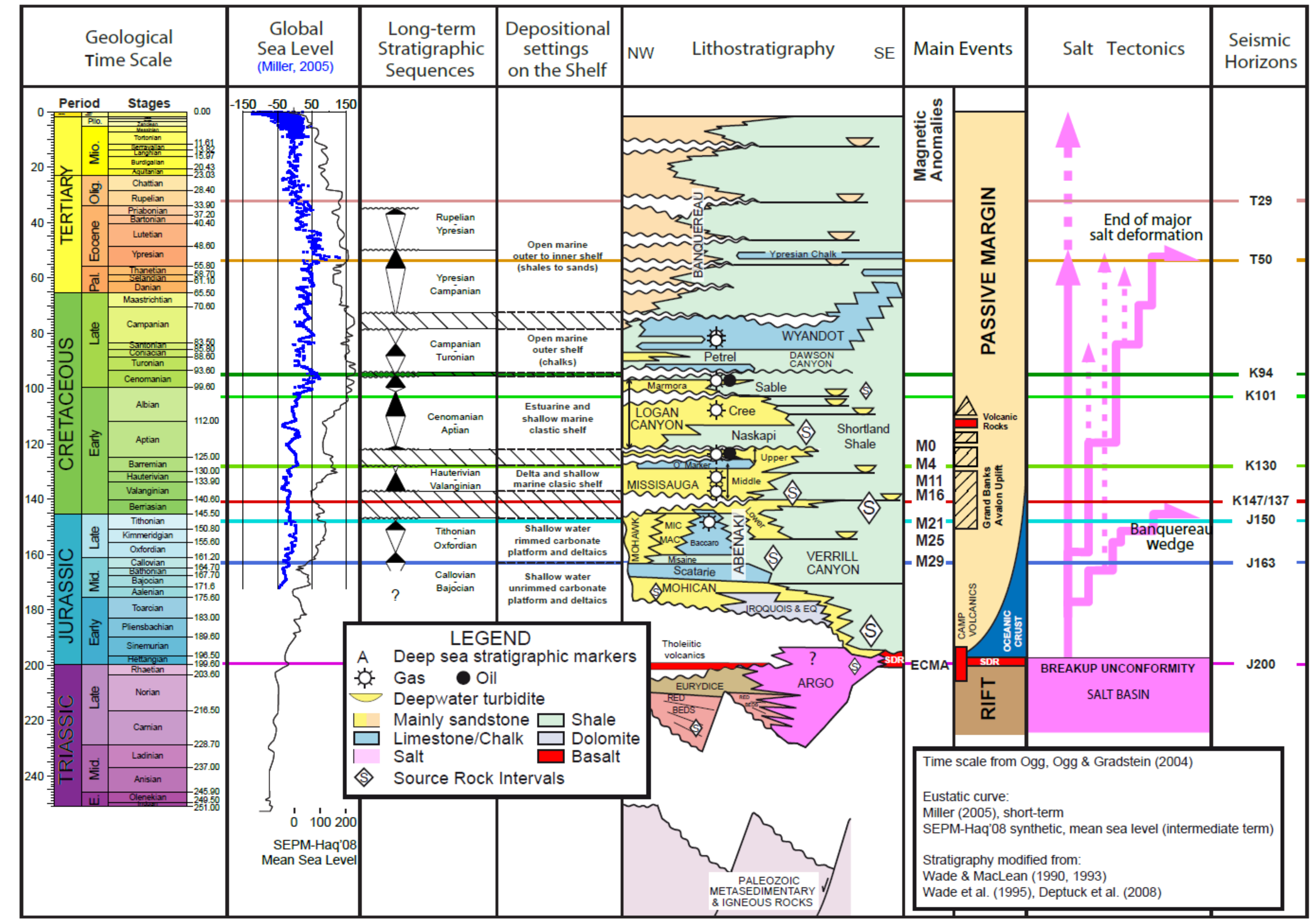

Figure 1: Generalized Stratigraphic Column for the Scotian Basin, Offshore Nova Scotia (CNSOPB, updated PFA project, 2011)

LATE POST RIFT

By the Late Jurassic, Oxfordian-Tithonian, concurrent with carbonate deposition, regional uplift to the east resulted in an influx of clastic sediments and the establishment of the mixed energy (current and tidal) Sable Delta complex in the Huron and Laurentian Sub-basins, and slightly later in the Sable Sub-basin. In the southwest, a similar progradation of sediments may have occurred at an embayment in the vicinity of the U.S.-Canada border, known as the Shelburne Delta. 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 (Pe-Piper & Piper, 2004; Pe-Piper & MacKay, 2006). The **Mic-Mac Formation** records this first phase of delta progradation into these sub-basins, represented by distributary channels and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales of the **Verrill Canyon Formation**. 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 LaHave Platform and later the Banquereau Platform. A series of thick sand-rich deltaic strandplain, carbonate shoals and shallow marine shelf successions (**Missisauga Formation**) dominated sedimentation throughout the Early Cretaceous. 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 postulated Shelburne Delta continued into Barremian time and disappeared due to the exhaustion of its sediment supply. Along the LaHave Platform, small local rivers draining from southwest Nova Scotia mainland provided modest amounts of sands and shales to this region and associated deeper water realm.
Middle Jurassic and Cretaceous sediments loading the slope beyond the shelf edge initiated subsidence and development of seaward-dipping growth faults which acted as traps for sand. Sediment loading also mobilized Jurassic-age salts creating a complex slope morphology (e.g. Kidston et al., 2002; Shimeld, 2004) analogous to other basins with mobile salt substrates (e.g. Gulf of Mexico). Continuous sedimentation accentuated salt mobility, and in areas where sedimentation was high, like the Sable and possibly Shelburne deltas, salt moved both vertically and in the seaward direction forming diapirs, pillows, canopies and related features. During periods of low sea level, extant rivers incised exposed outer shelf sediments, with shelf-edge delta complexes probably forming at the edge of the continental shelf (Cummings & Arnott, 2005; 2006). Such deltas supplied turbidity currents and other mass transport deposits to the slope during the Middle Jurassic through Cretaceous, where potential reservoirs were deposited in canyons and intra-slope mini basins.
Deltaic sedimentation ceased along much of the Scotian margin following a late Early Cretaceous major marine transgression (Aptian MFS) when the shelf was blanketed by thick shales of the **Naskapi Member** of the Logan Canyon Formation. Transgressive shales were periodically interrupted during the influx of coarser clastics in the Albian-Cenomanian (**Cree and Marmora Members** of the Logan Canyon Formation; Wade and MacLean, 1990). Sand was deposited along a broad costal plain and shallow shelf, but these eventually gave way as deeper marine shales (and some limestones) of the **Dawson Canyon Formation**, Turonian-Santonian, were deposited as sediment supply decreased from the lower relief hinterland. 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 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 and Miocene times, fluvial and deep-water current processes cut into and eroded these mostly unconsolidated sediments and transported them out into the deeper water slope and abyssal plain. During the Quaternary Period of the last 2 million years, several hundred meters of glacial and marine sediments were deposited on the outer shelf and upper slope.

* *from CNSOPB, Regional Petroleum Exploration, 2009, modified PFA 2011*

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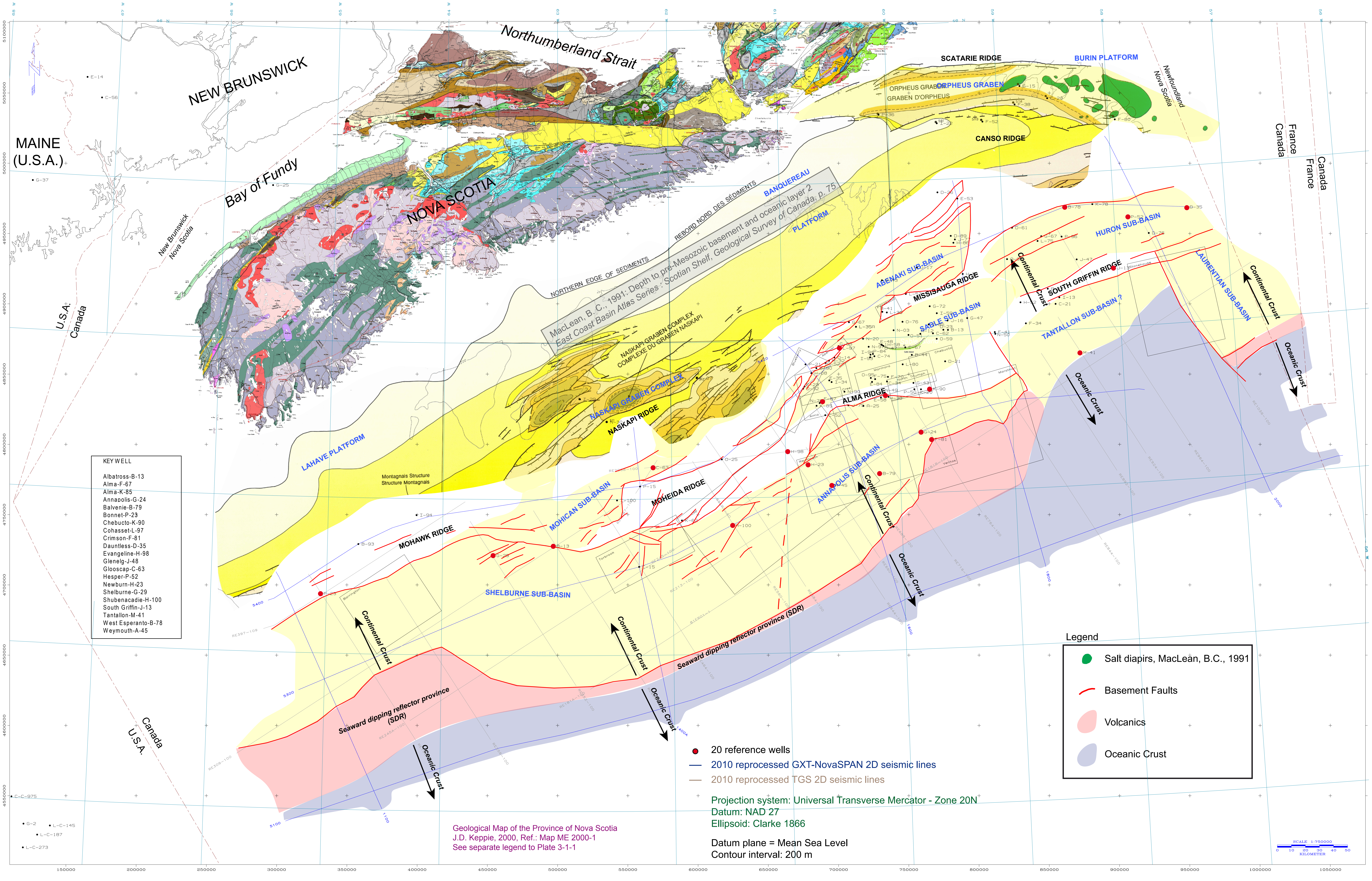


Major Tectonic Elements of the Scotian Basin

CHAPTER 1-2

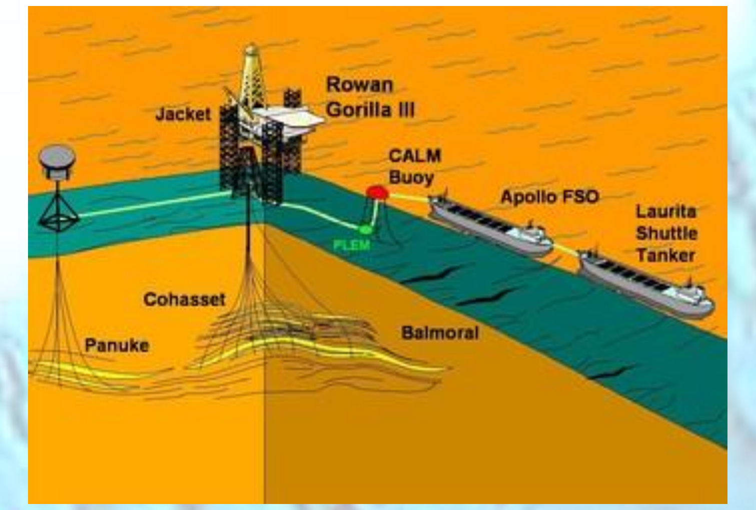
PRODUCION HISTORY

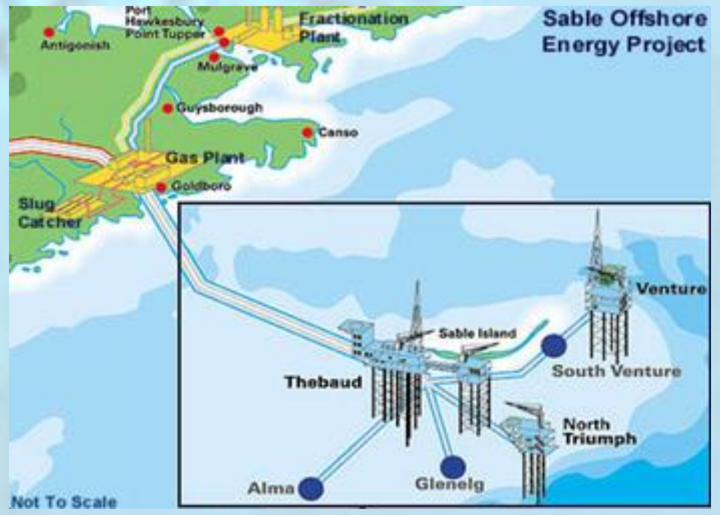
OFFSHORE PROJECTS

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.

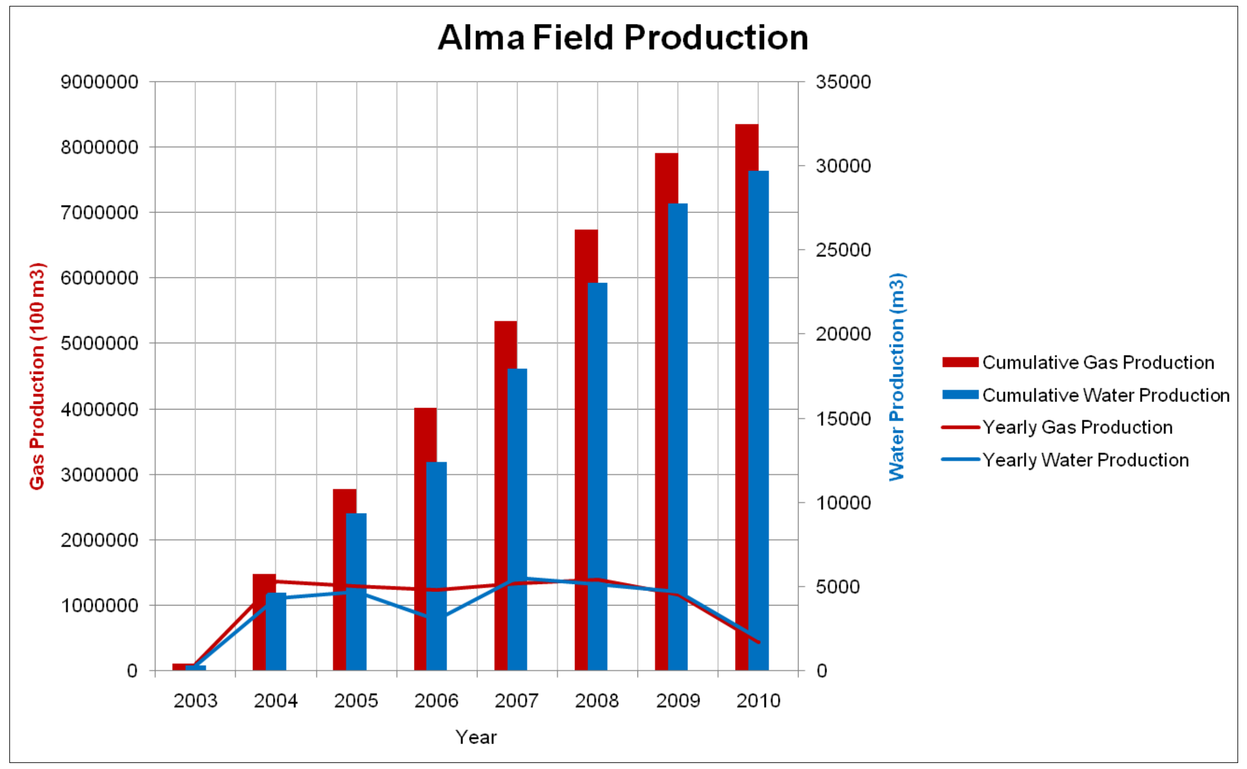
See: http://www.cnsopb.ns.ca/offshore_projects.php for detailed production data.



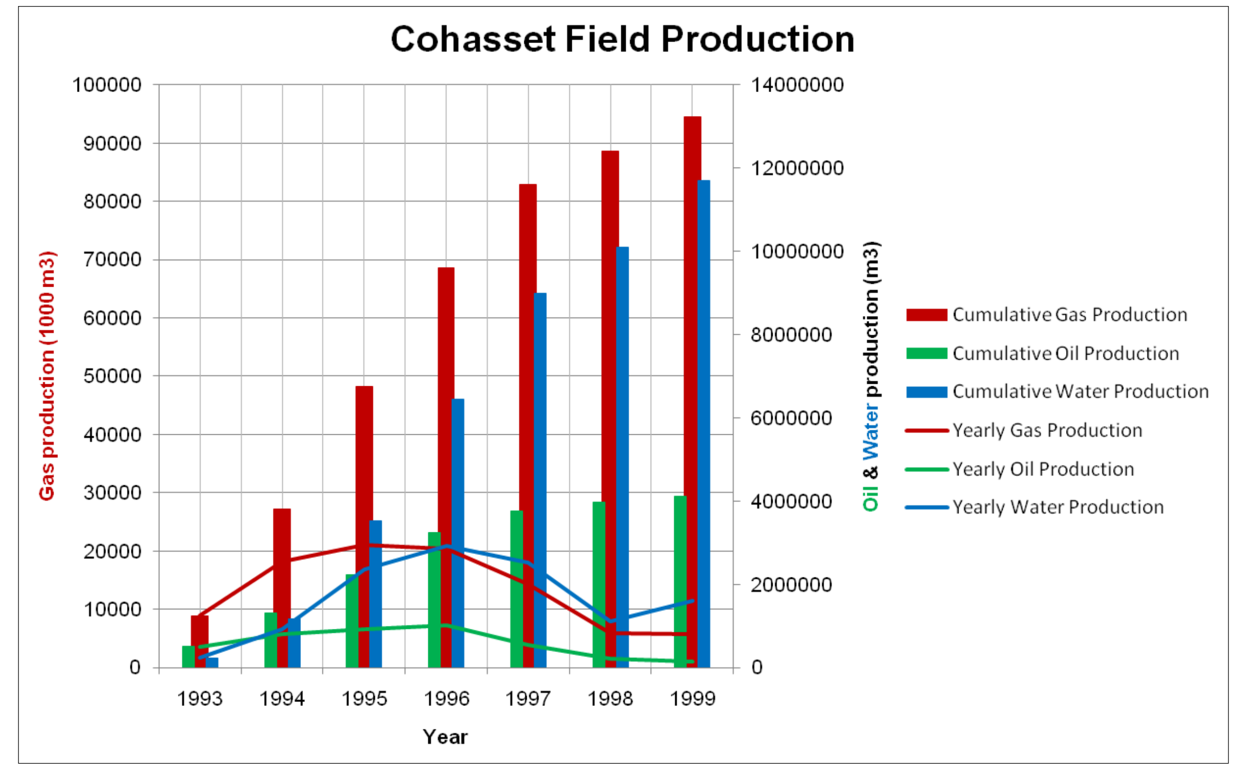


PRODUCTION HISTORY

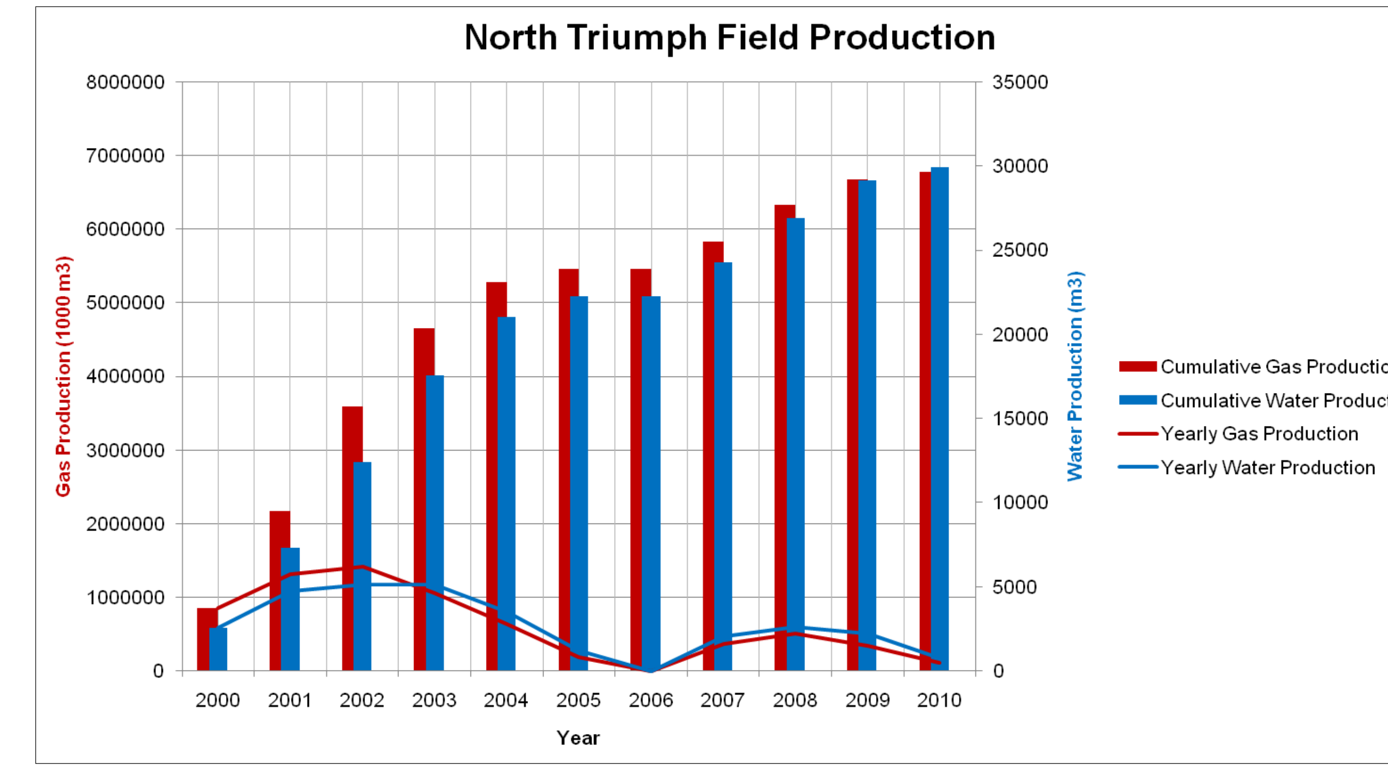
Alma 1 / 2 / 3 / 4A



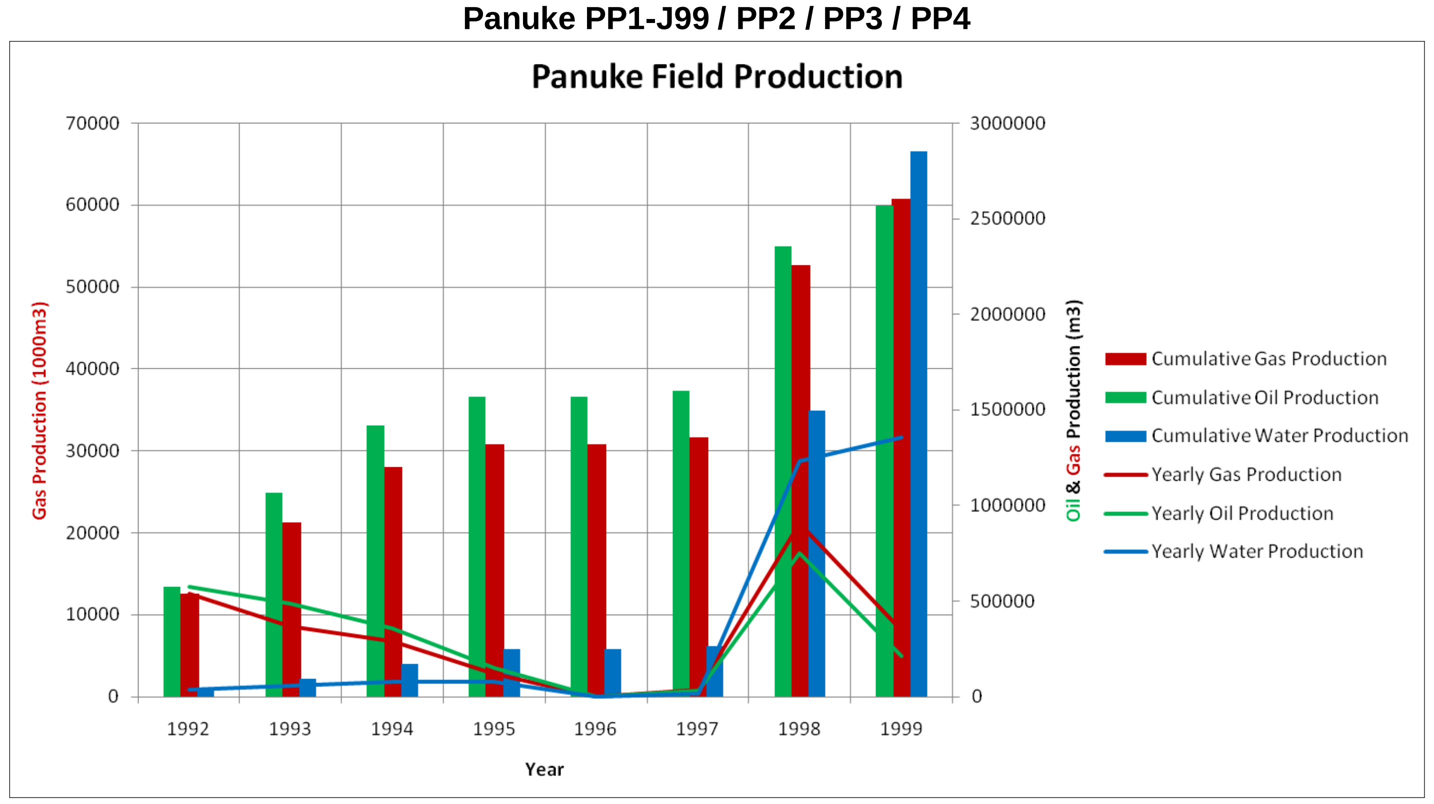
Cohasset CP1-P51 / CP2 / CP3 / CP3A / CP4 / CP5 /CP6 /CP7 / CP8 / CP9 / CP10



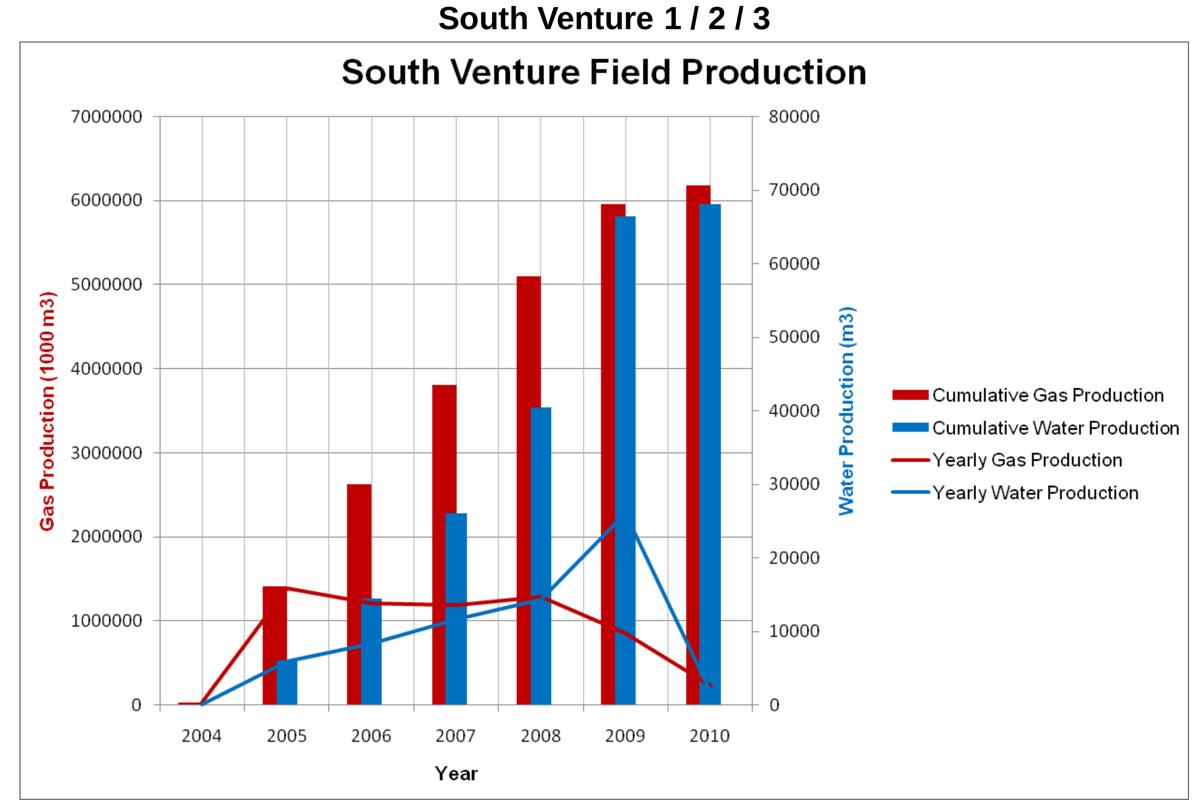
North Triumph 1 / 2 / 3



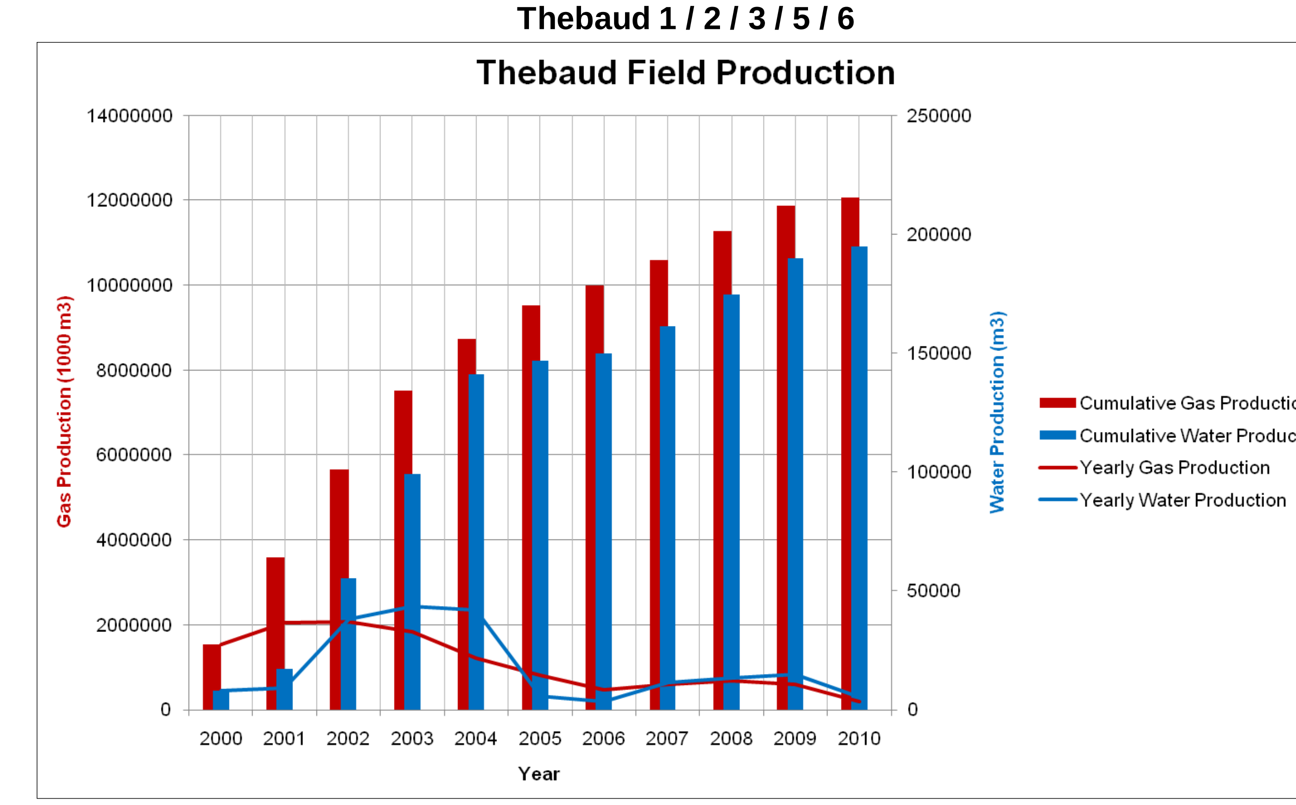
Panuke PP1-J99 / PP2 / PP3 / PP4



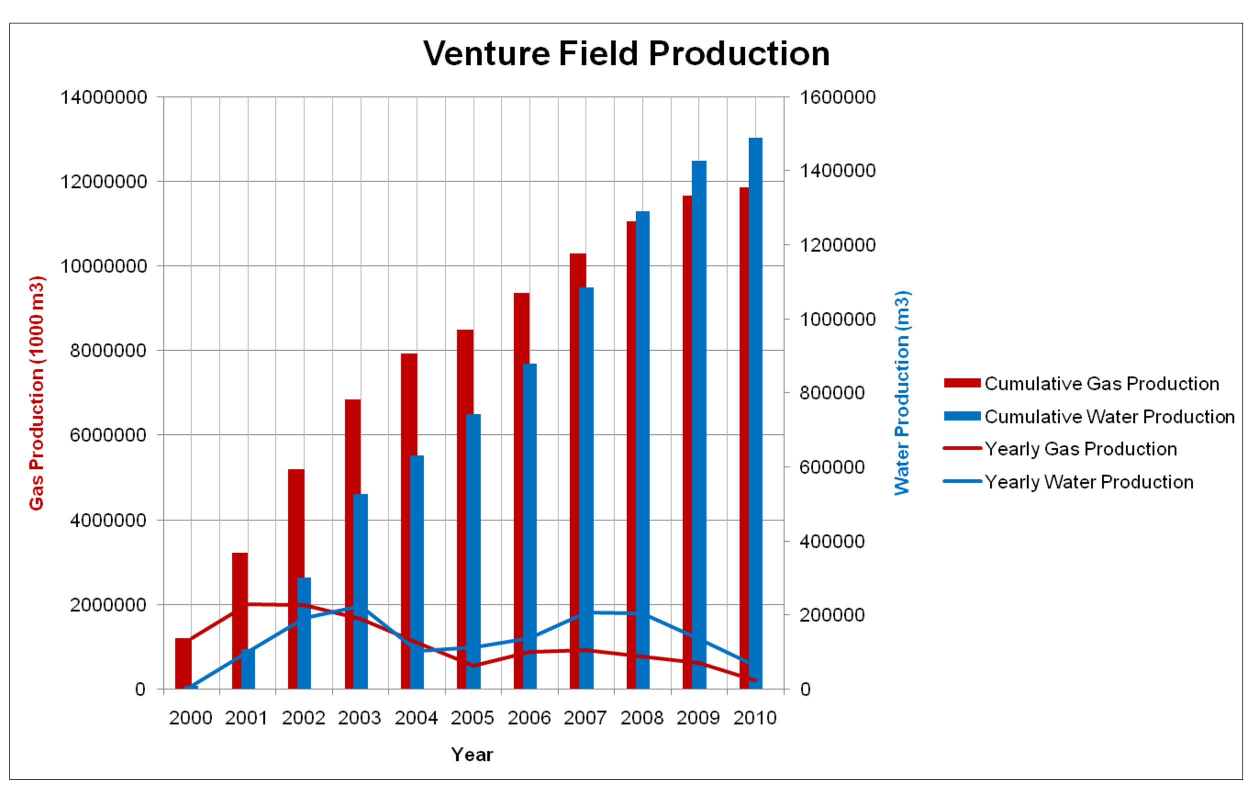
South Venture 1 / 2 / 3



Thebaud 1 / 2 / 3 / 5 / 6

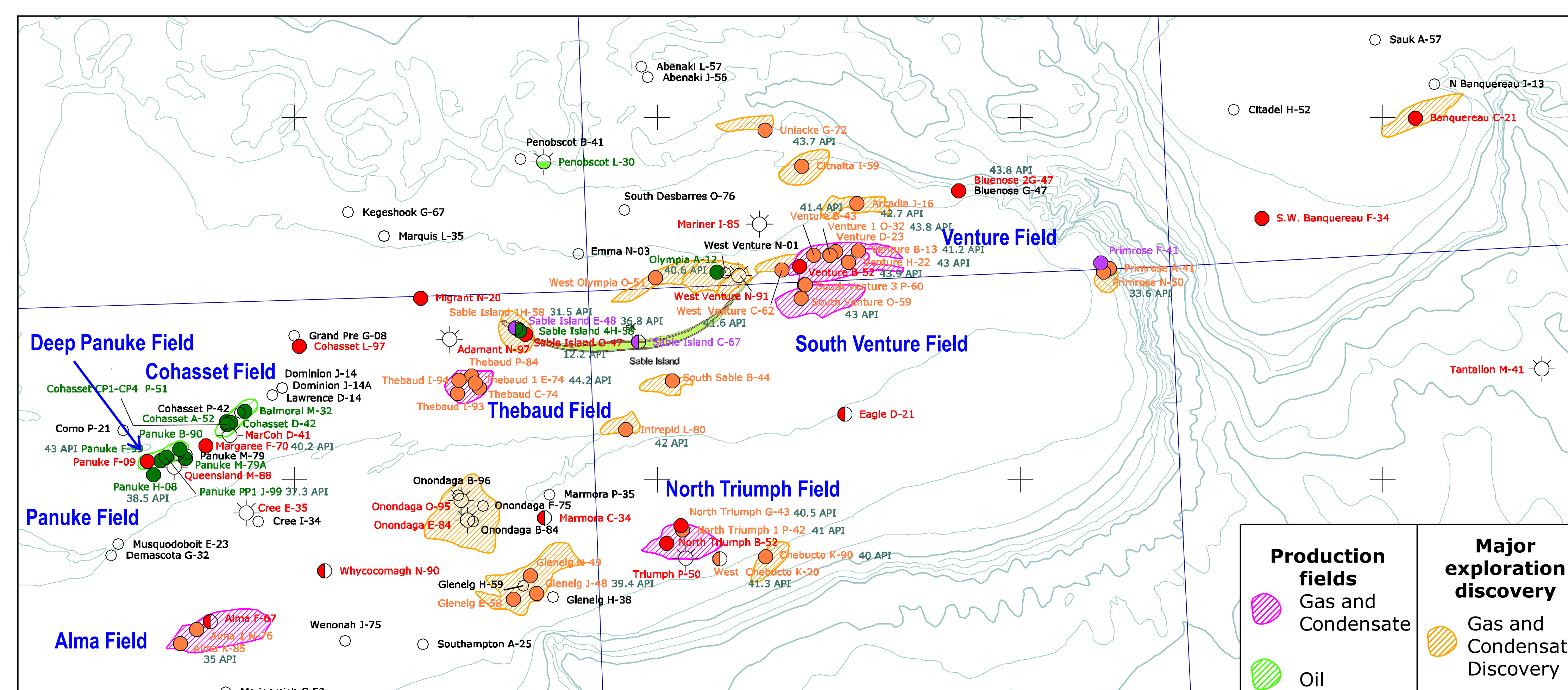


Venture 1 / 2 / 3 / 4 / 5 / 6 / 7

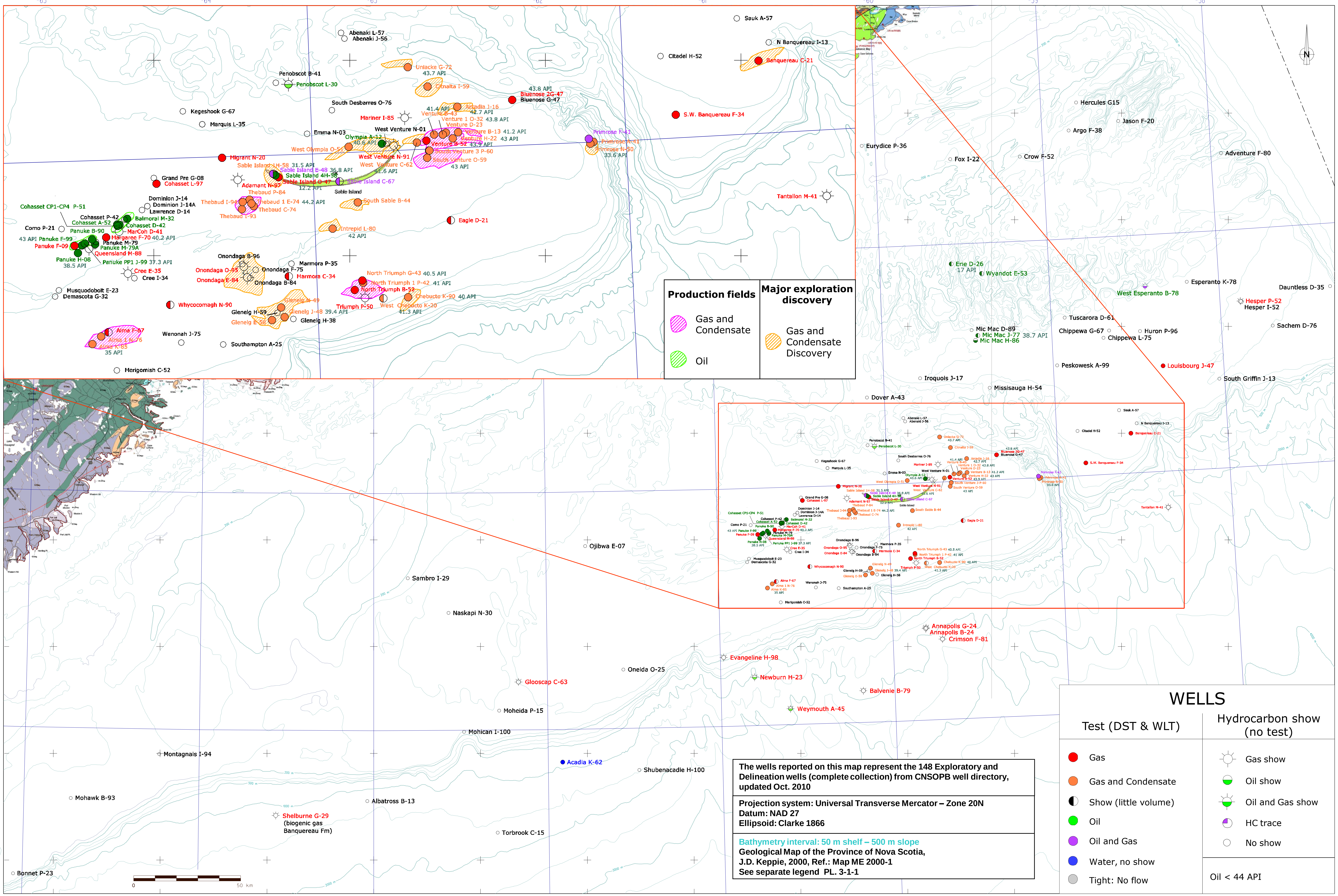


Web address for last updates: http://www.cnsopb.ns.ca/production.php

- Panuke Field
- Deep Panuke Field
- Cohasset Field
- Alma Field
- Thebaud Field
- North Triumph Field
- Venture Field
- South Venture Field



PRODUCTION HISTORY



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

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

Bathymetry interval: 50 m shelf – 500 m slope
Geological Map of the Province of Nova Scotia,
J.D. Keppie, 2000, Ref.: Map ME 2000-1
See separate legend PL. 3-1-1

Regional Hydrocarbon Distribution from Wells – General Map

CHAPTER 1-3

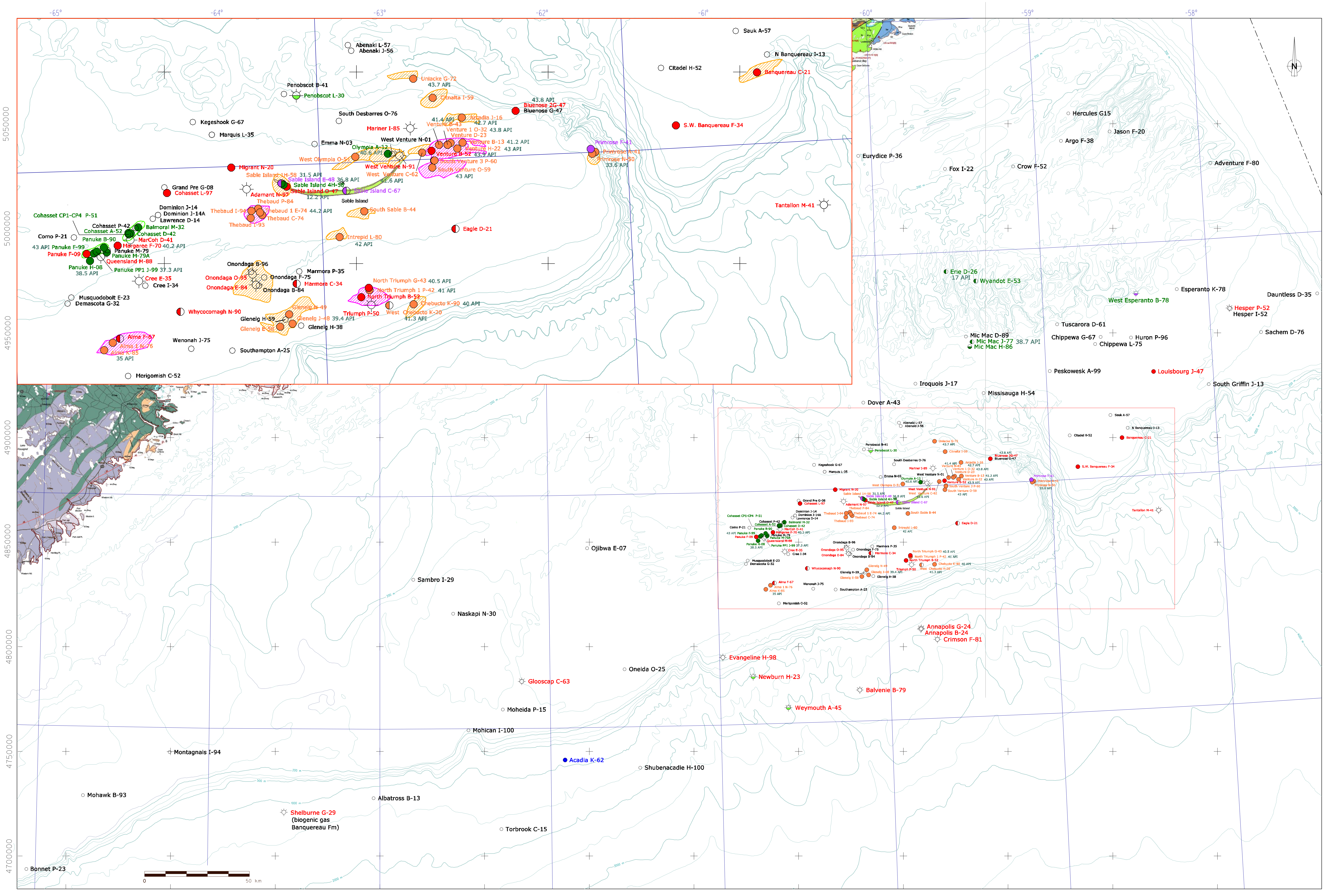
EXPLORATION HISTORY AND WELL FAILURE ANALYSIS

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."

EXPLORATION HISTORY AND WELL FAILURE ANALYSIS

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



PL. 1-3-1

Location Map for all Wells and Fields

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[1,2,3]. 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 revaluated the excellent CNSOPB work in terms of the revised play definitions emerging from the 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 Missisauga
- Lower Cretaceous Logan Canyon

Each is discussed in the following sections.

The table below (on the plate) 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.

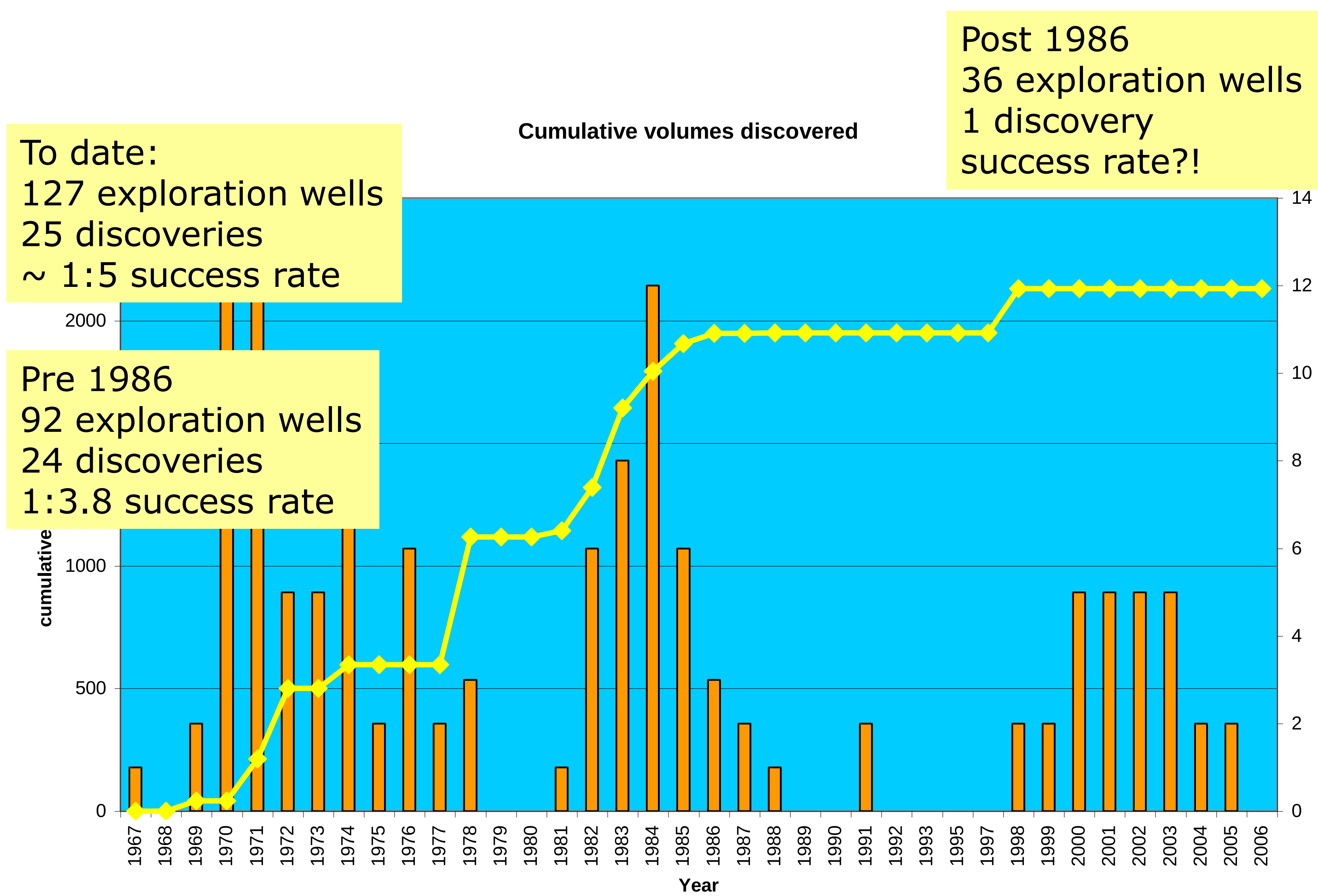


Figure 1: Scotian Basin Creaming Curve

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 delta 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
[2] Nova Scotia Deepwater Post Drill Analysis 1982 - 2007
[3] Post 2000 Exploration Drilling Results (Unpublished)

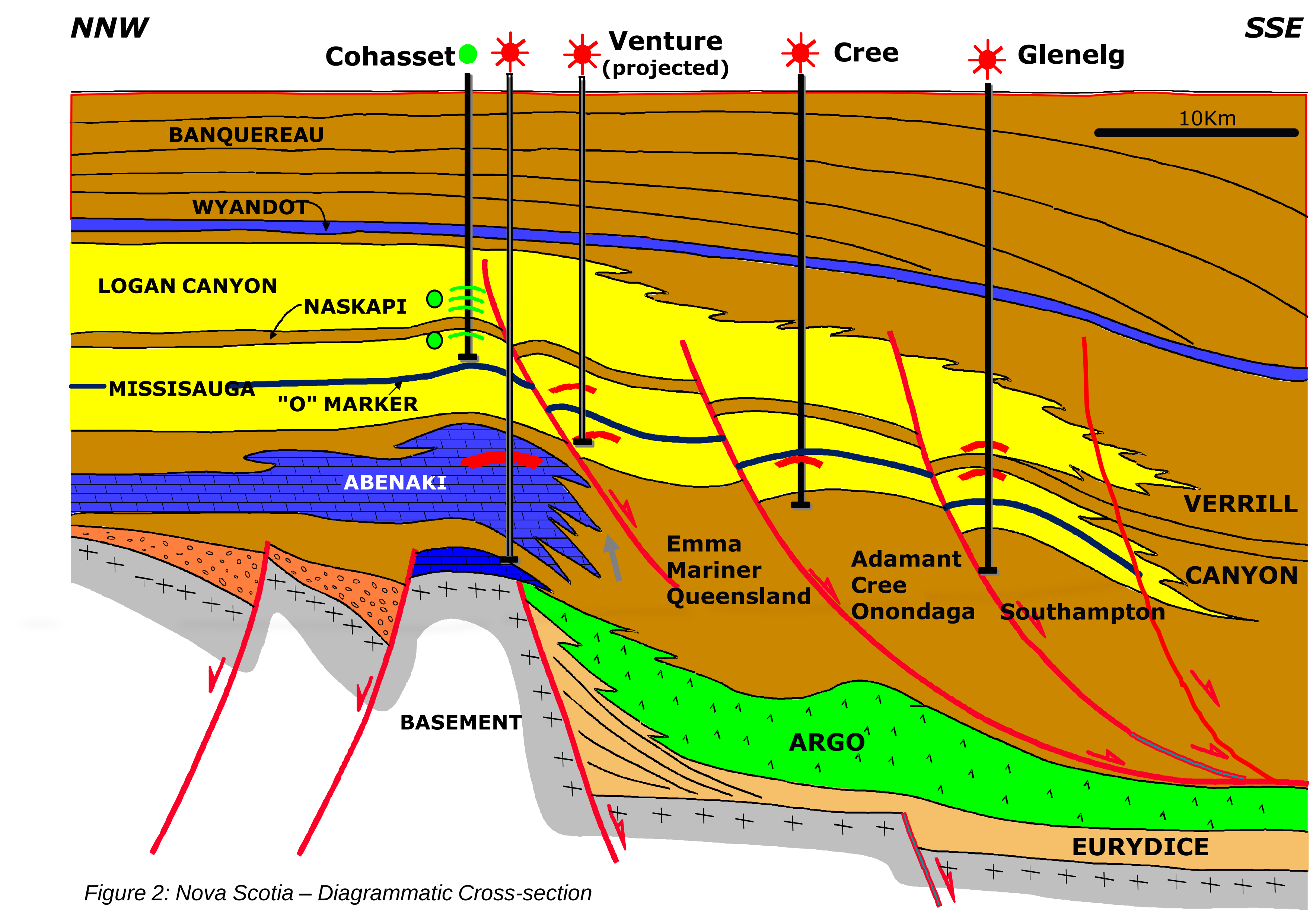


Figure 2: Nova Scotia – Diagrammatic Cross-section

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 explorers were using the wrong models for the plays.

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 ever there is closure at a reservoir horizon. A truism perhaps, 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.

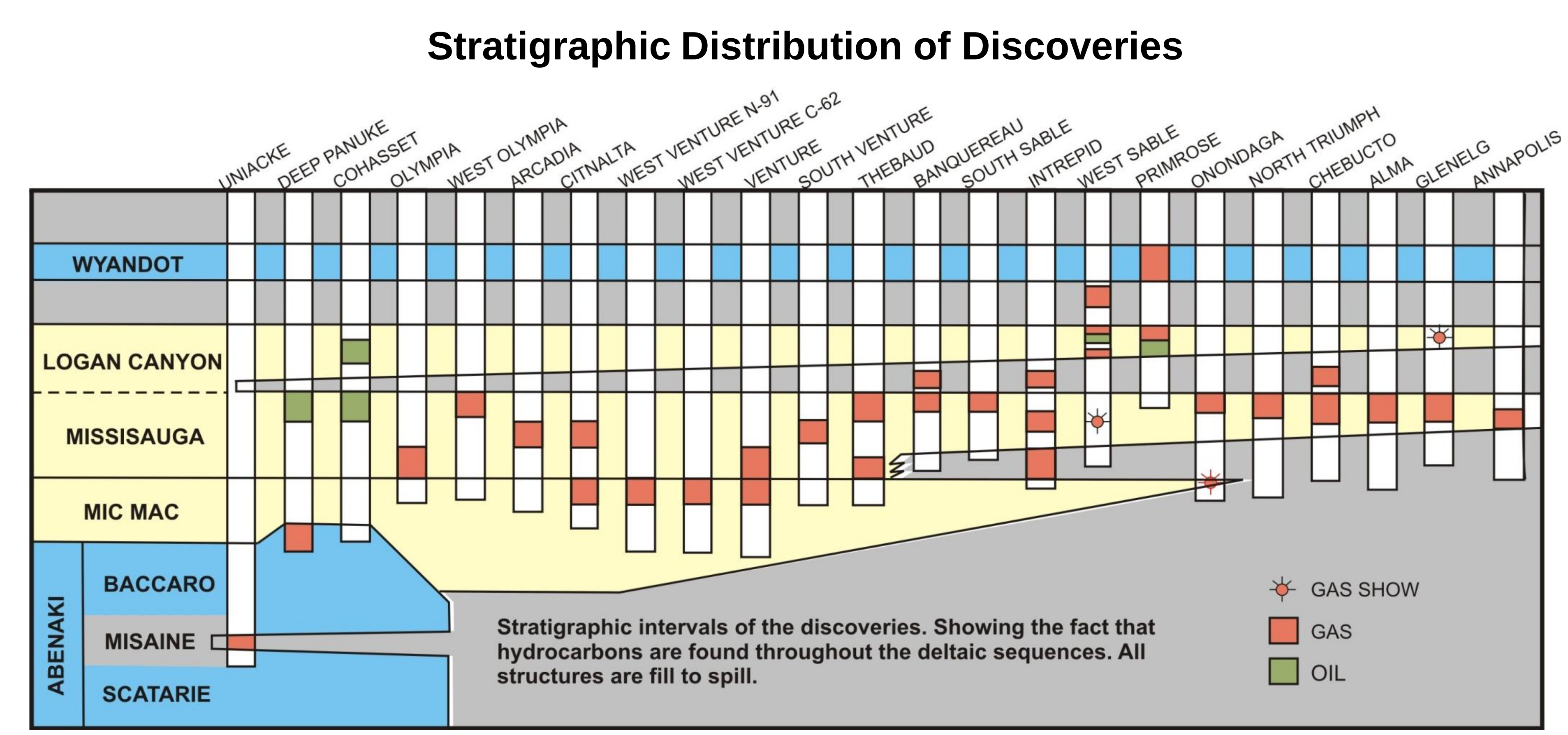


Figure 3: Stratigraphic distribution of discoveries

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.

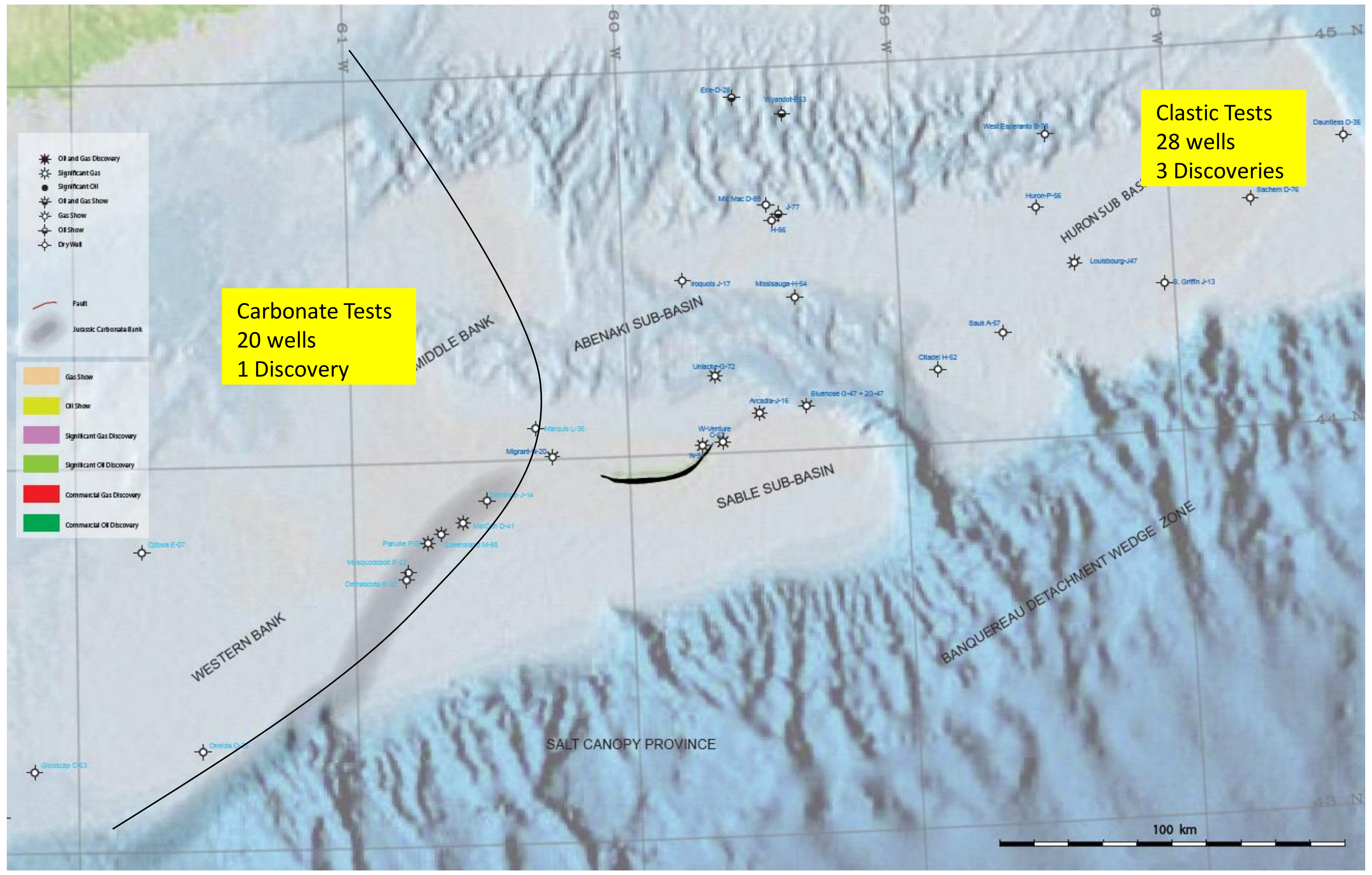


Figure 4: Jurassic play tests – Carbonates and Clastics (Mic Mac)

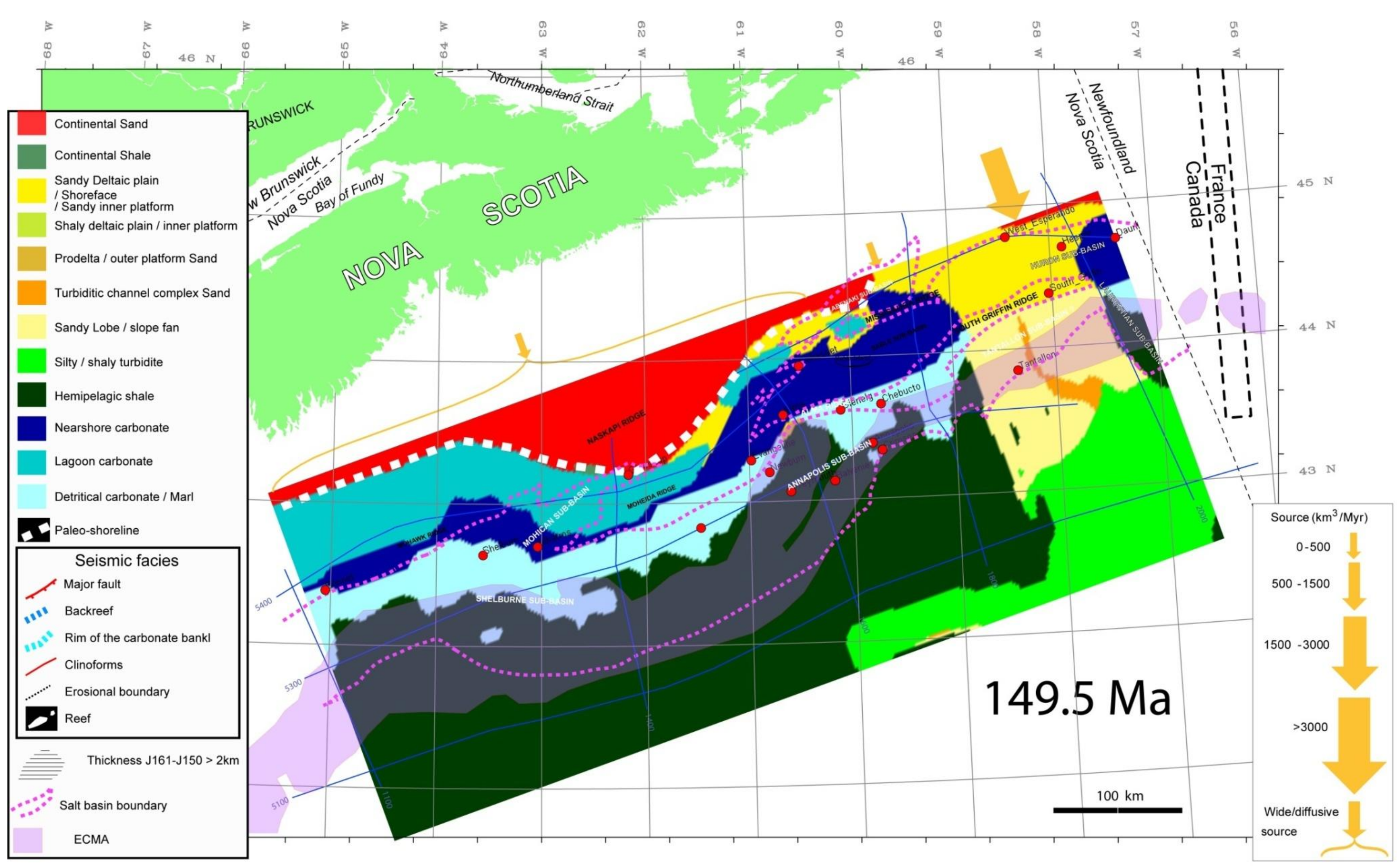


Figure 5: Dionisos simulation map @149.5 Ma (Mic-Mac)

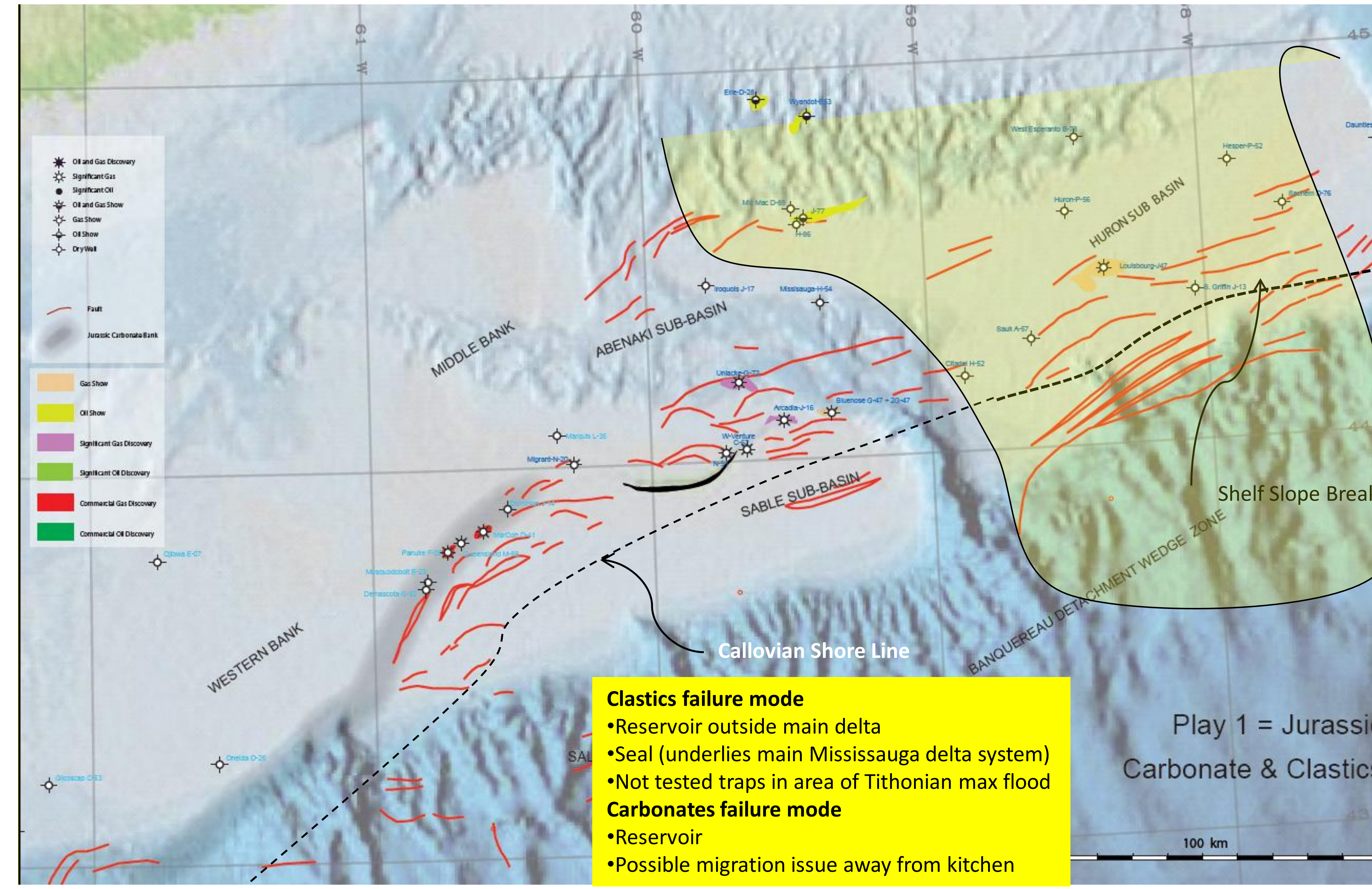


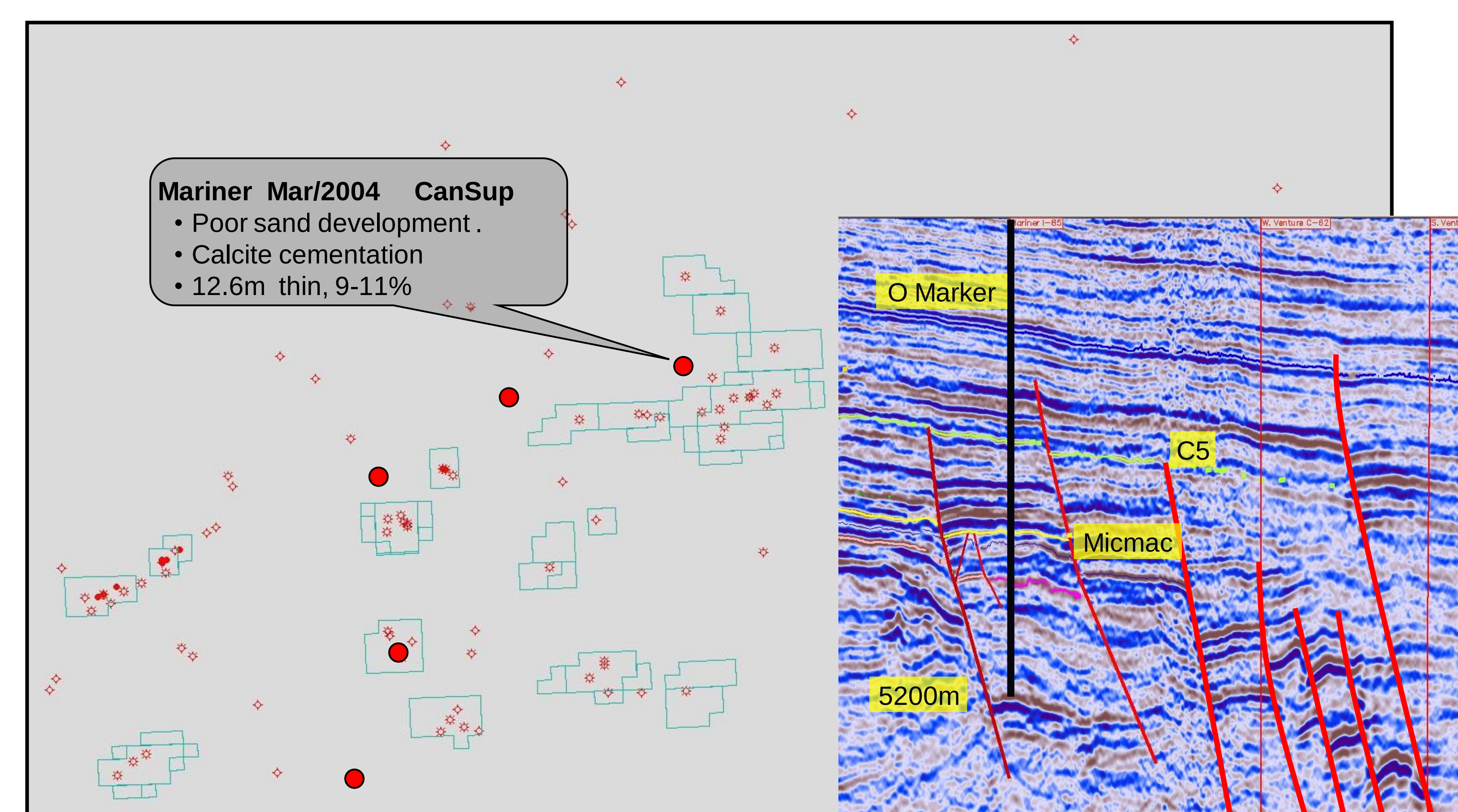
Figure 6: Late Jurassic sand play tests

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 Cretecous 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.

Figure 7: Mariner – Mic Mac tests - 2004



We illustrate the well failures with two relatively recent wells, Mariner (Figure 7 in Plate) 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.

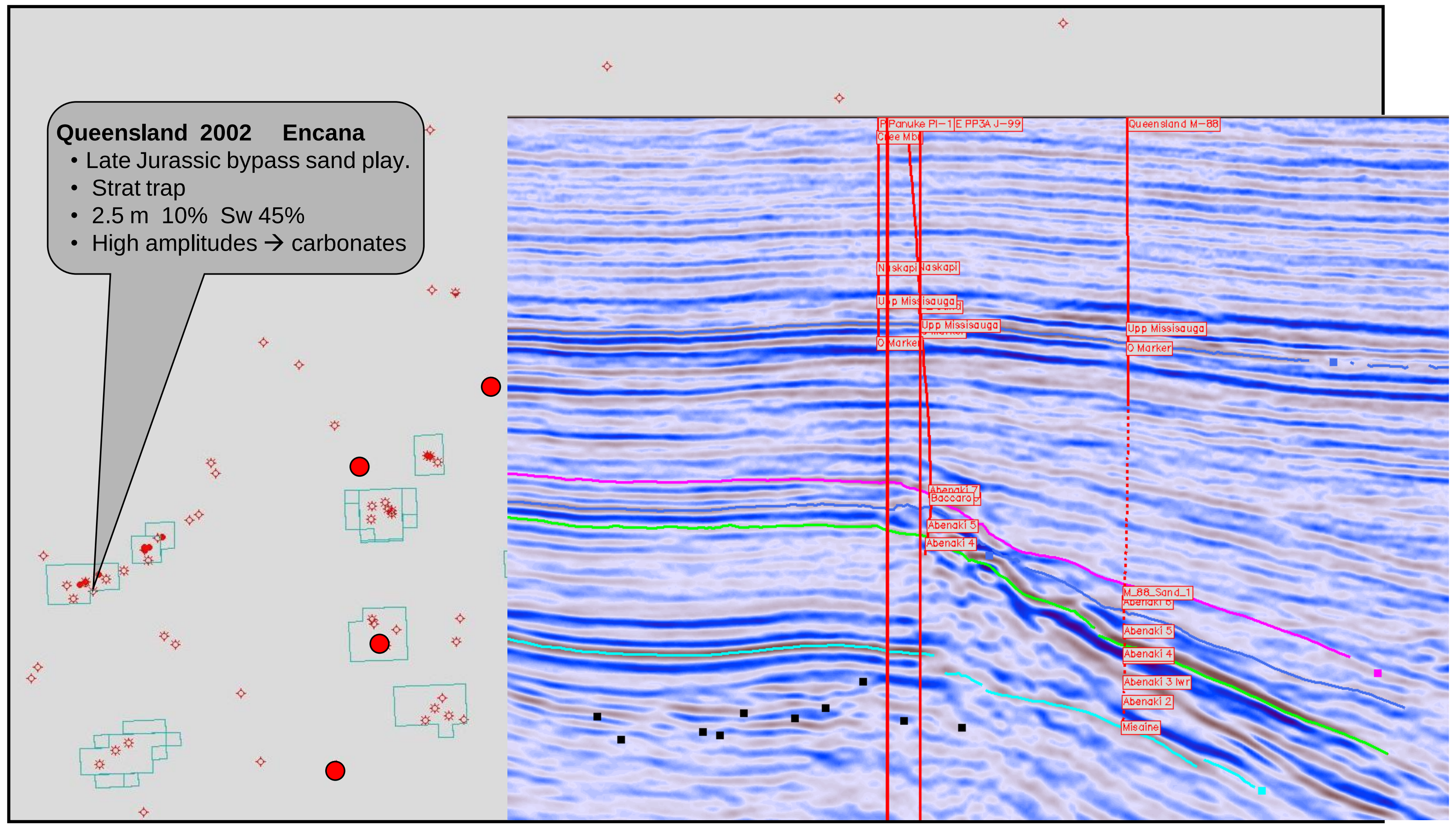


Figure 8: Queensland – reef front - 2003

Jurassic Play Tests: Carbonates

This analysis draws extensively on the CNSOPB analysis[4] 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.

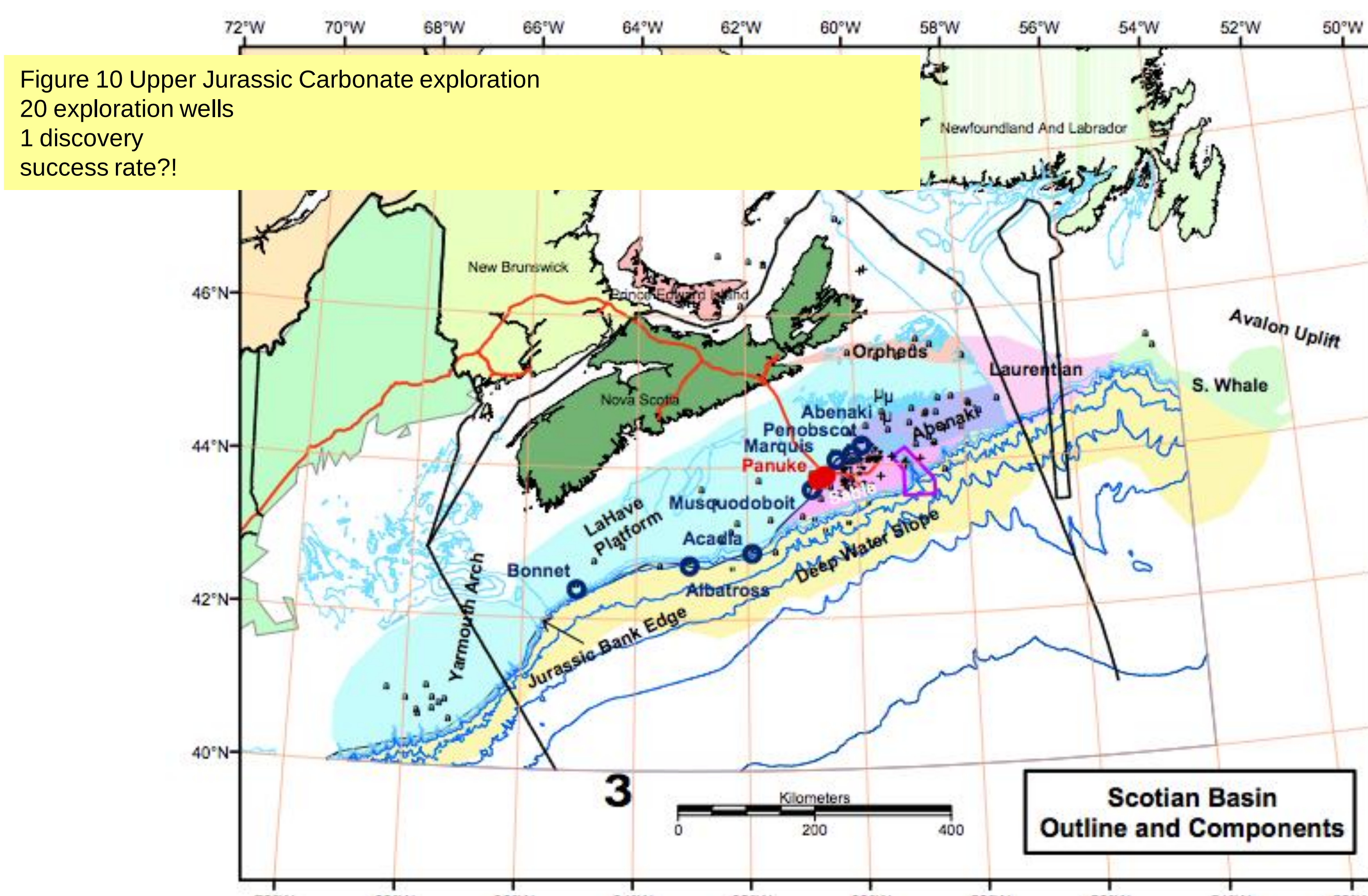


Figure 9: Upper Jurassic Carbonate exploration

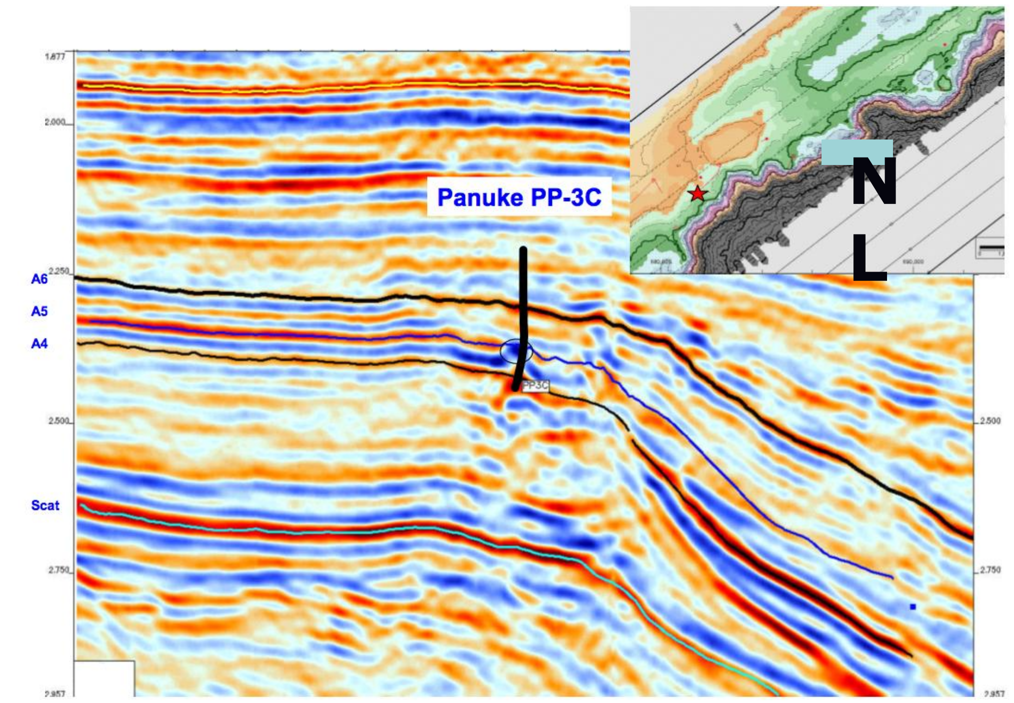


Figure 10: Panuke PP-C3 - 1999

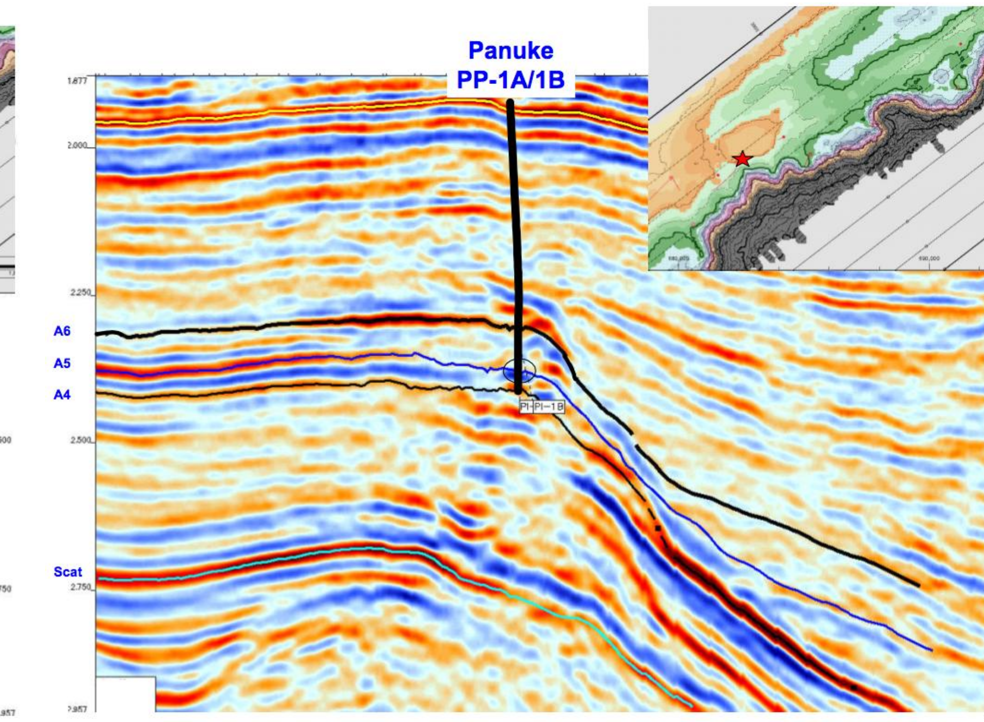


Figure 11: Panuke PP1A/1B

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.

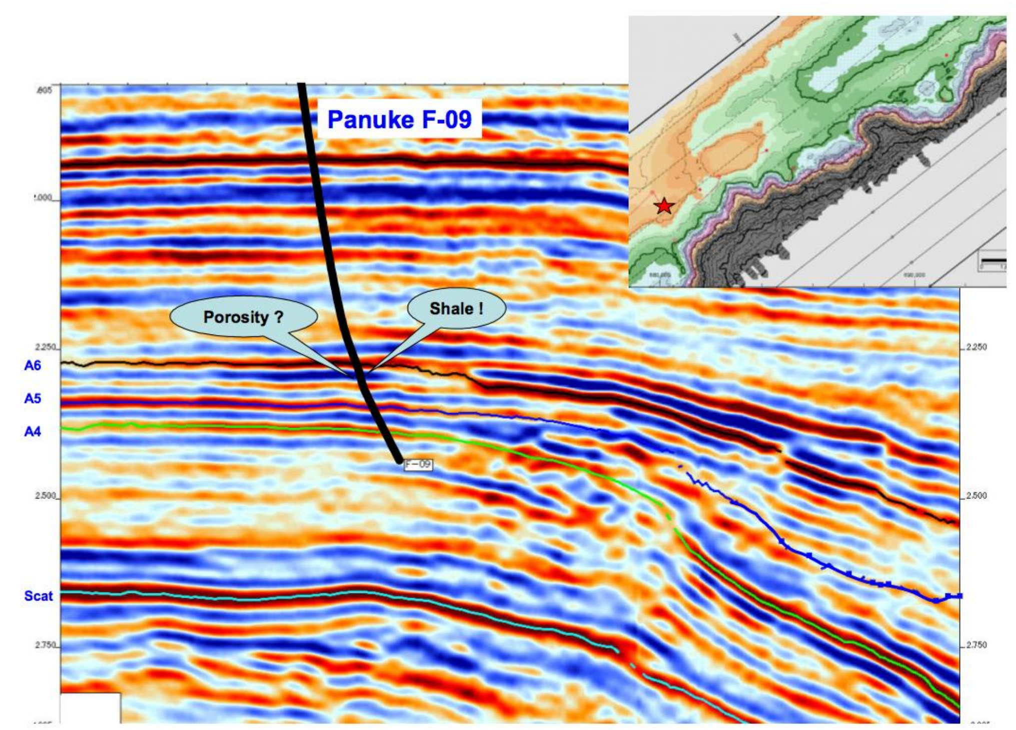


Figure 12: Panuke F-09

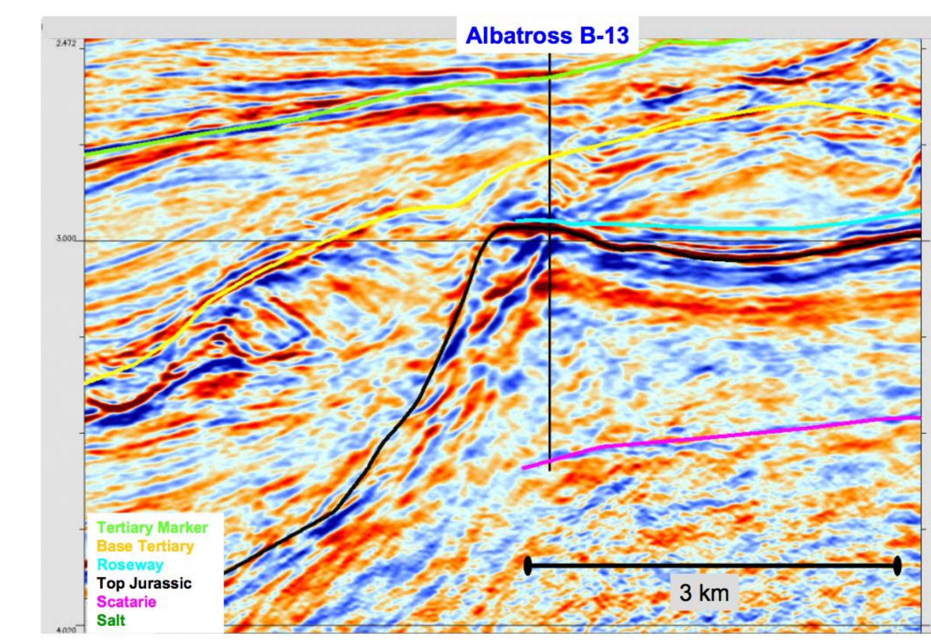


Figure 13: Albatross B-13

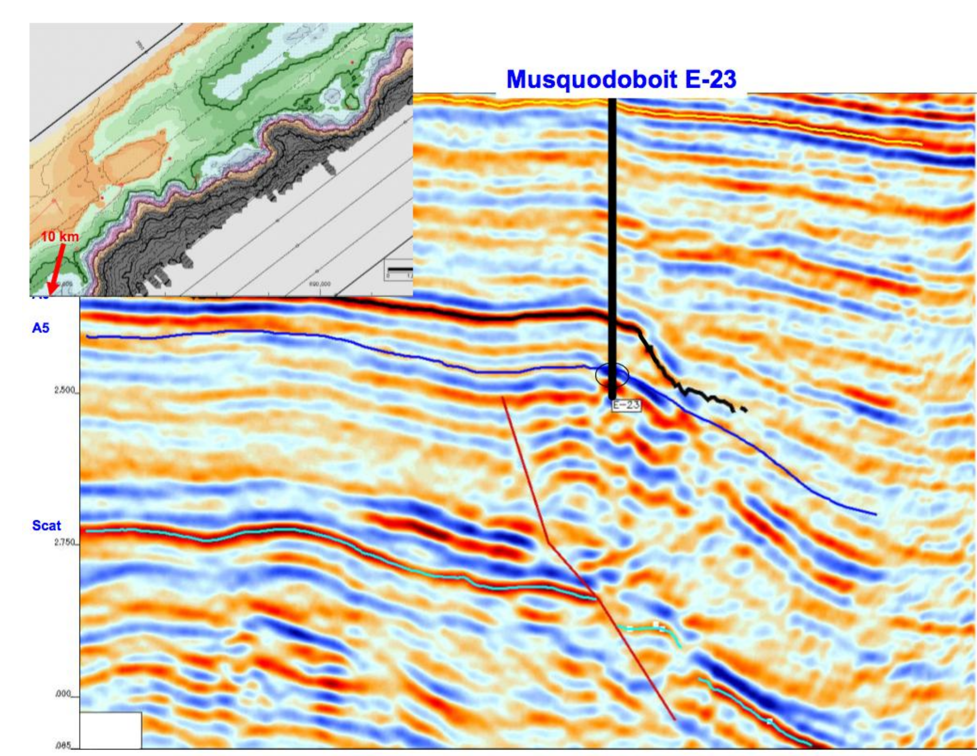


Figure 14: Musquodoboit E-23

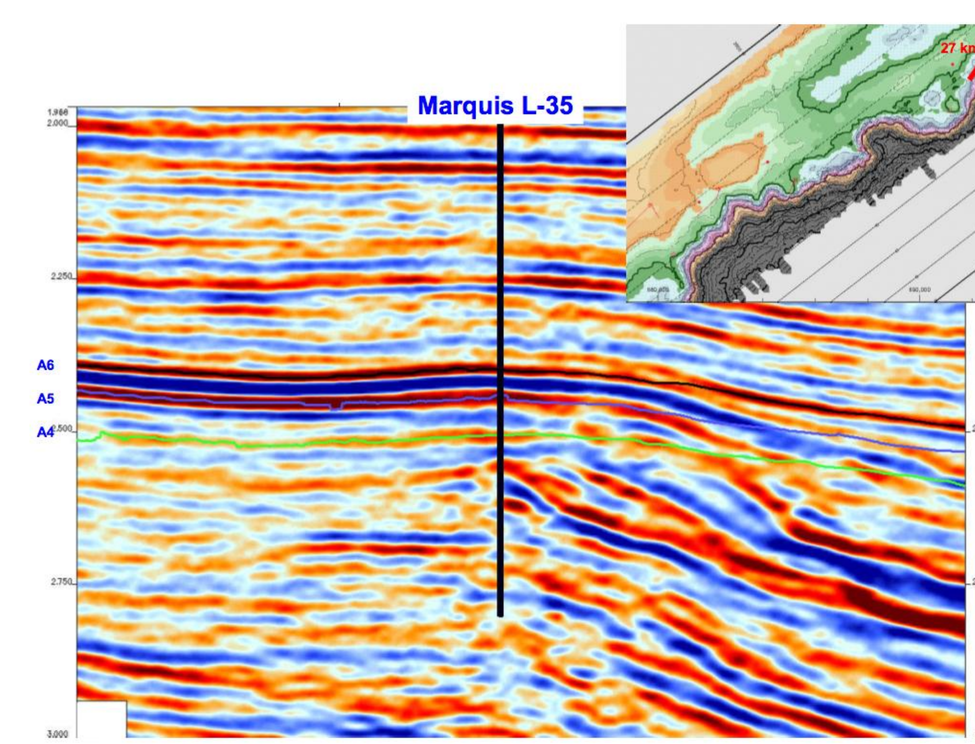


Figure 15: Marquis L-35

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.

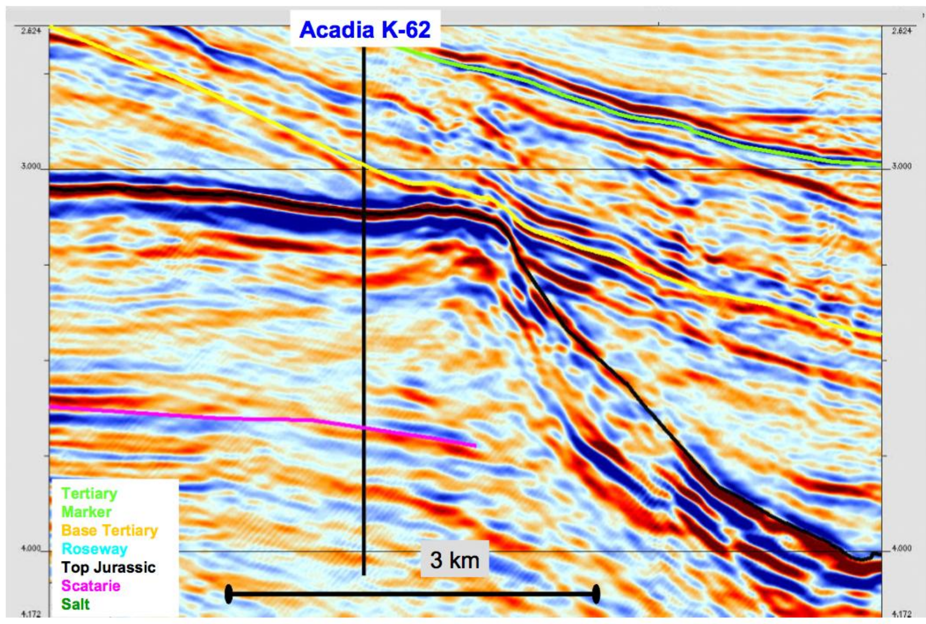


Figure 16: Acadia K-62

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.

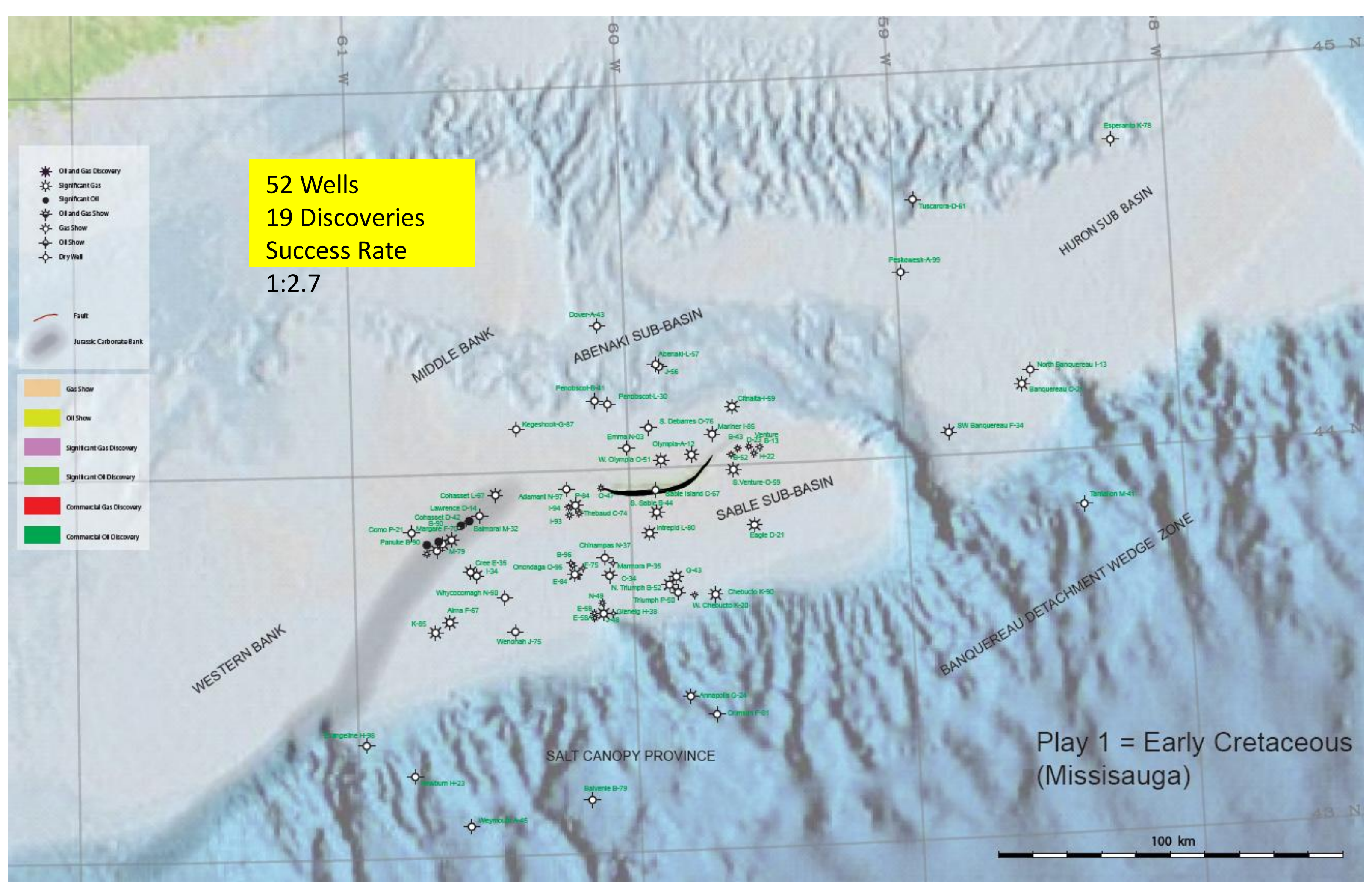


Figure 17a: Lower Cretaceous – Missisauga play tests - Wells

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.

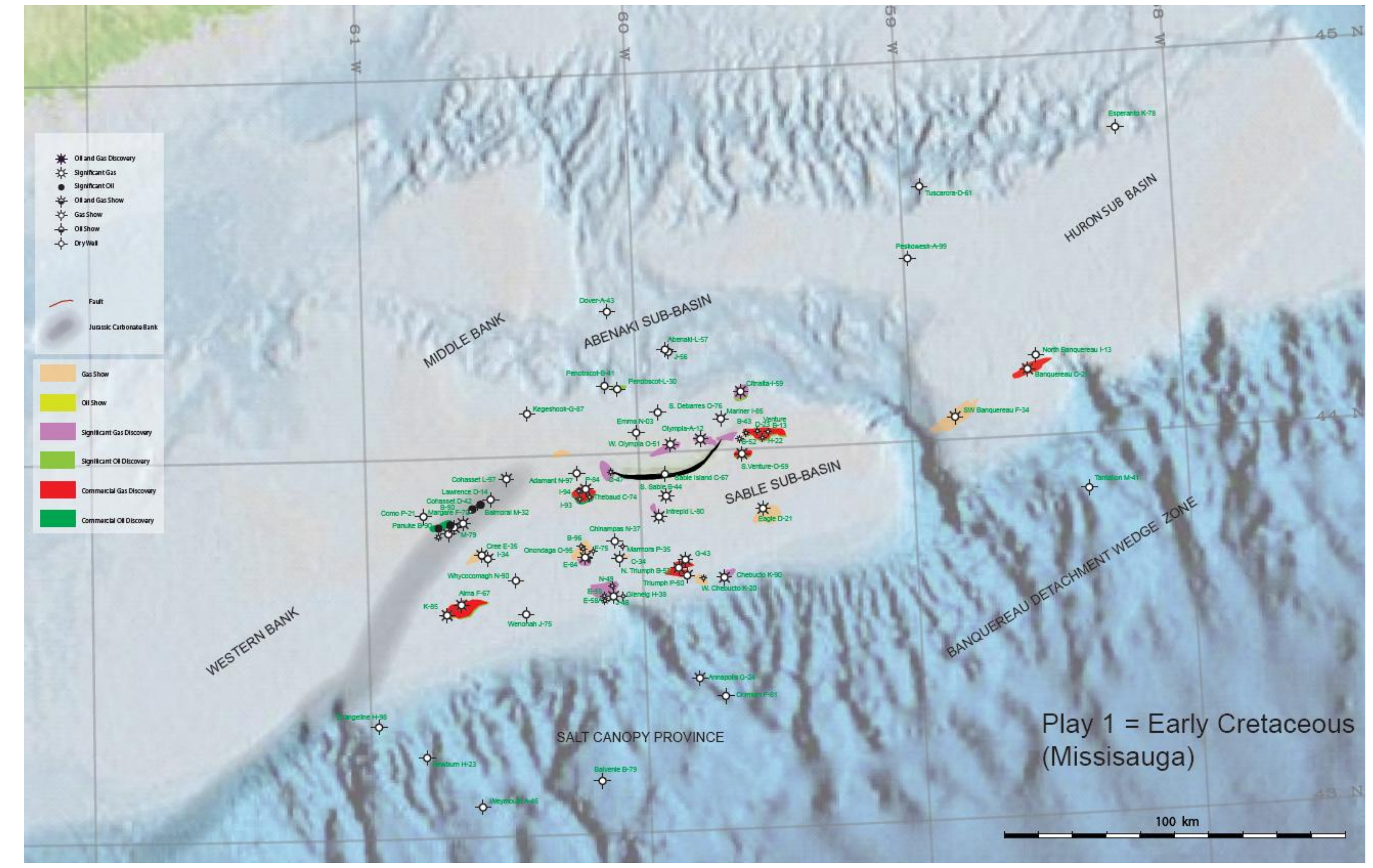


Figure 17b: Lower Cretaceous – Missisauga play tests - Wells

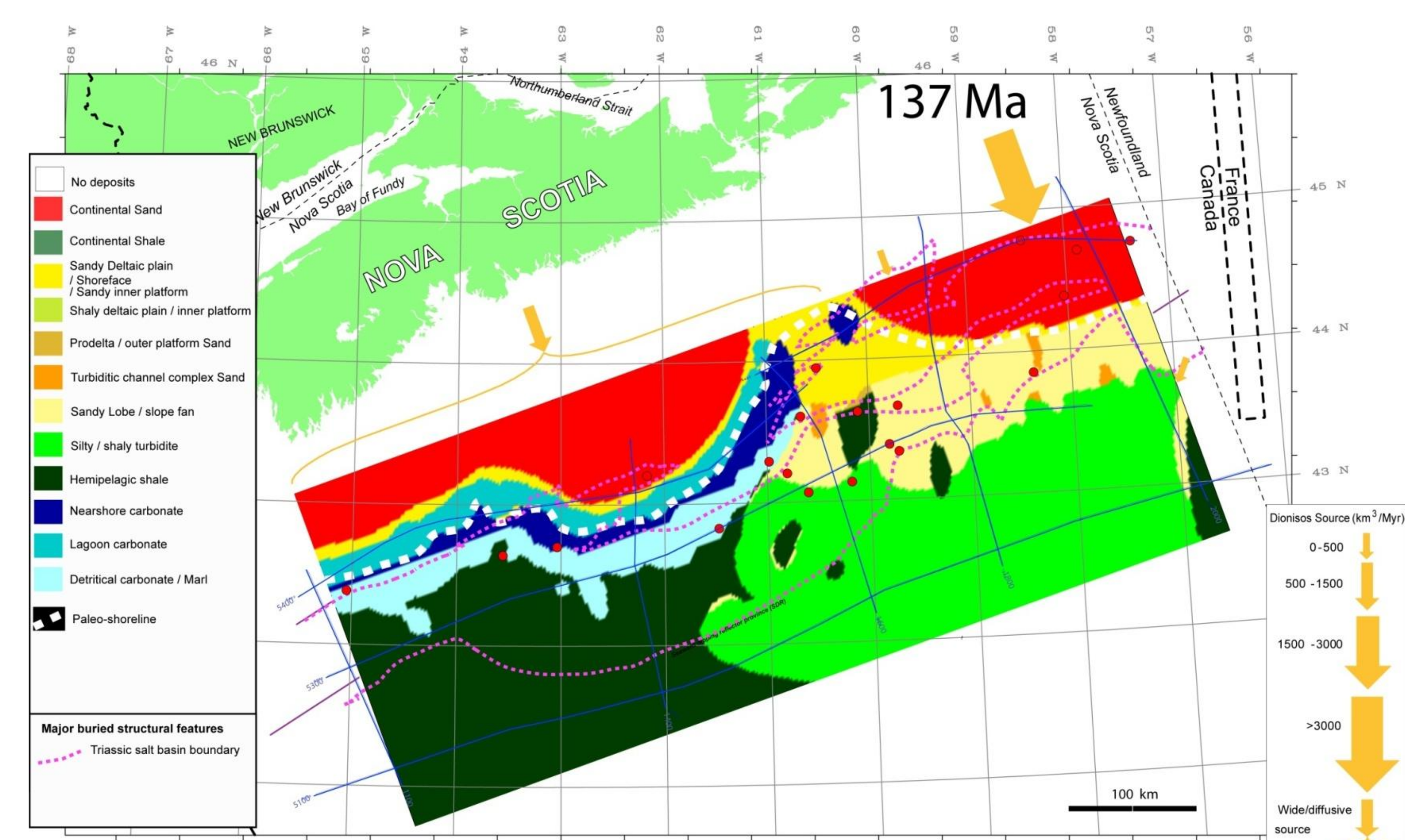


Figure 18: Dionisos simulation @ 137 Ma

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.

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.

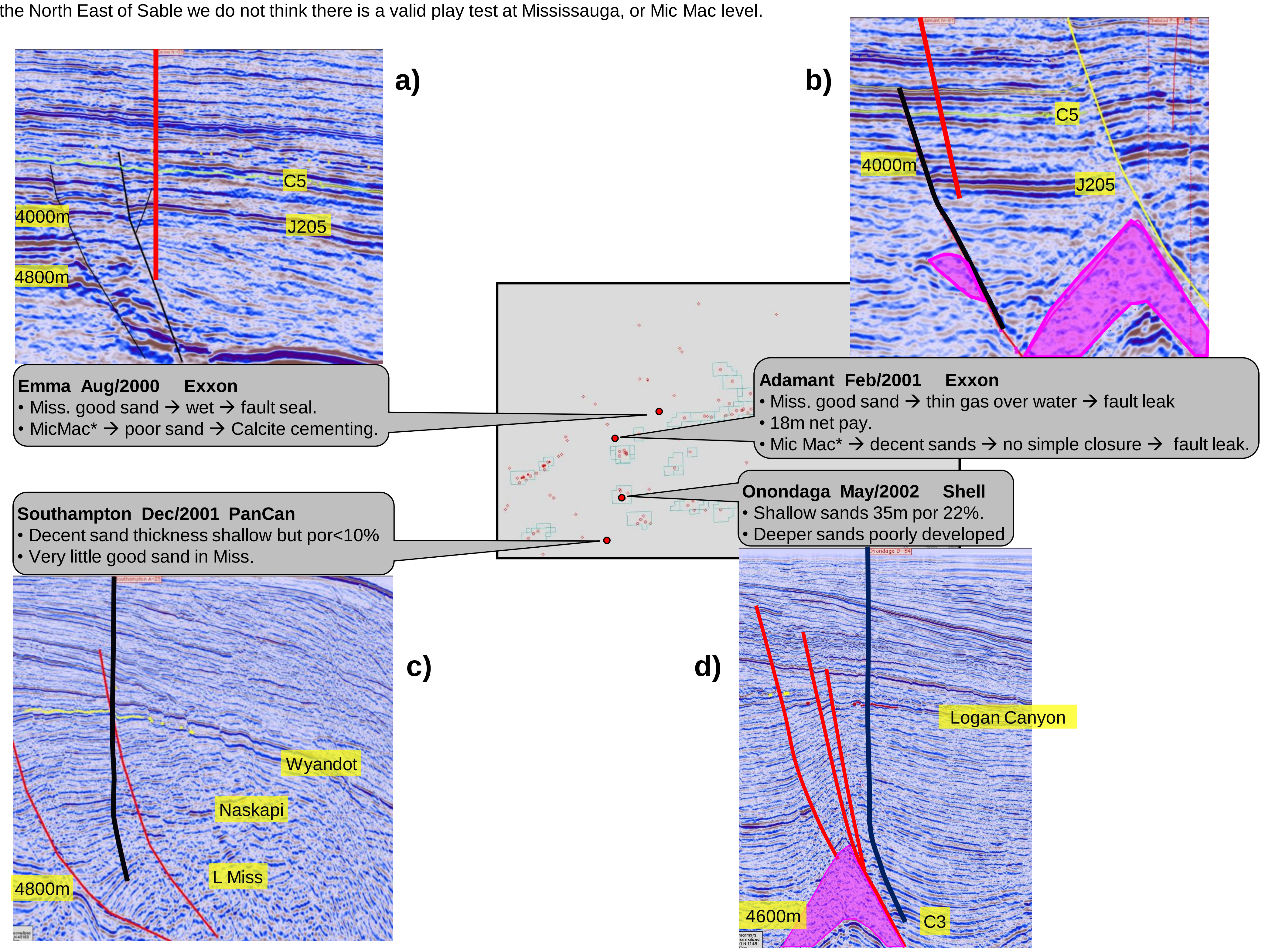


Figure 19: a) Emma – 2000; b) Adamant – 2001; c) Southampton – 2001; d) 0nondaga - 2002

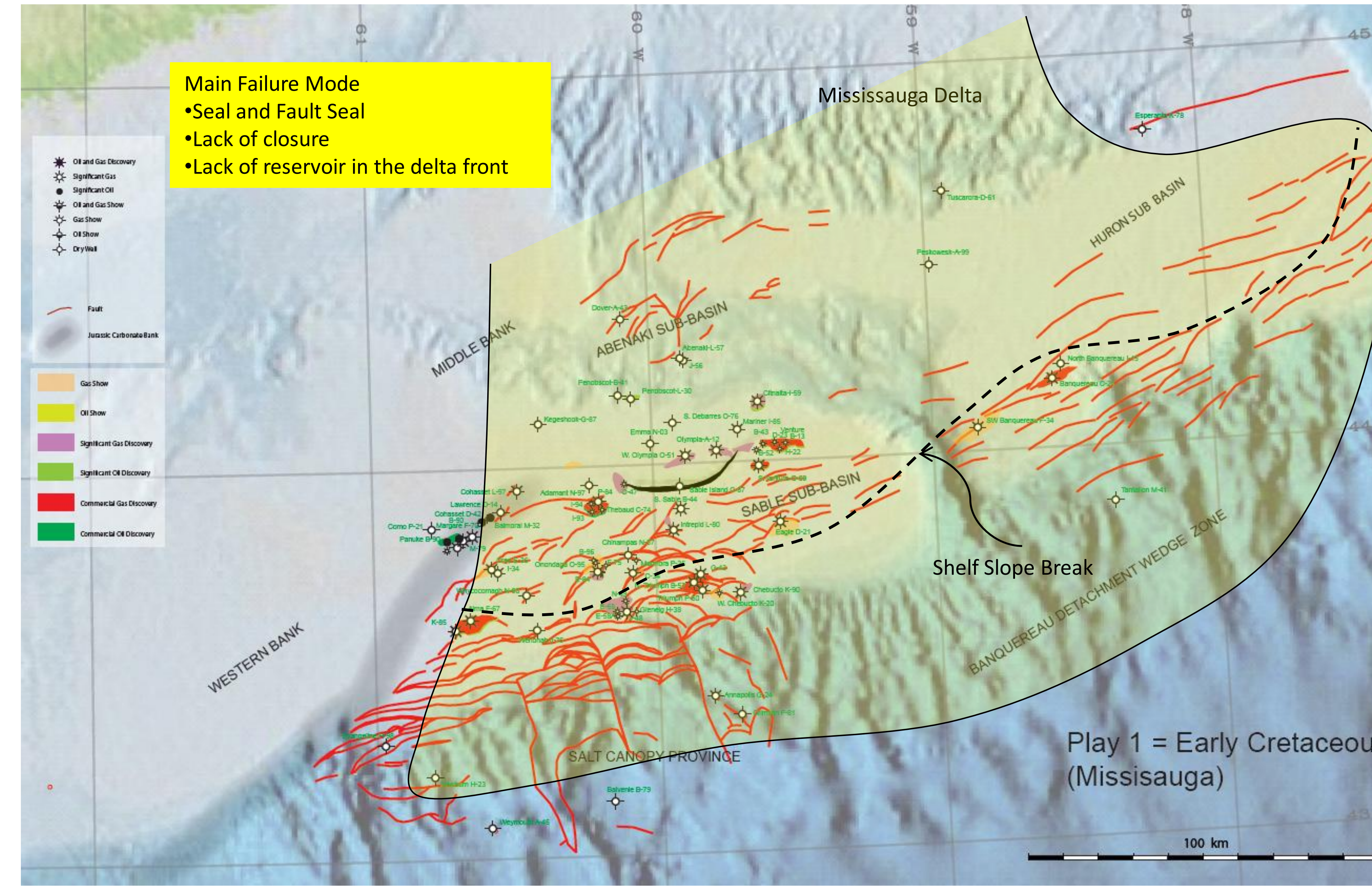


Figure 20: Missisauga play

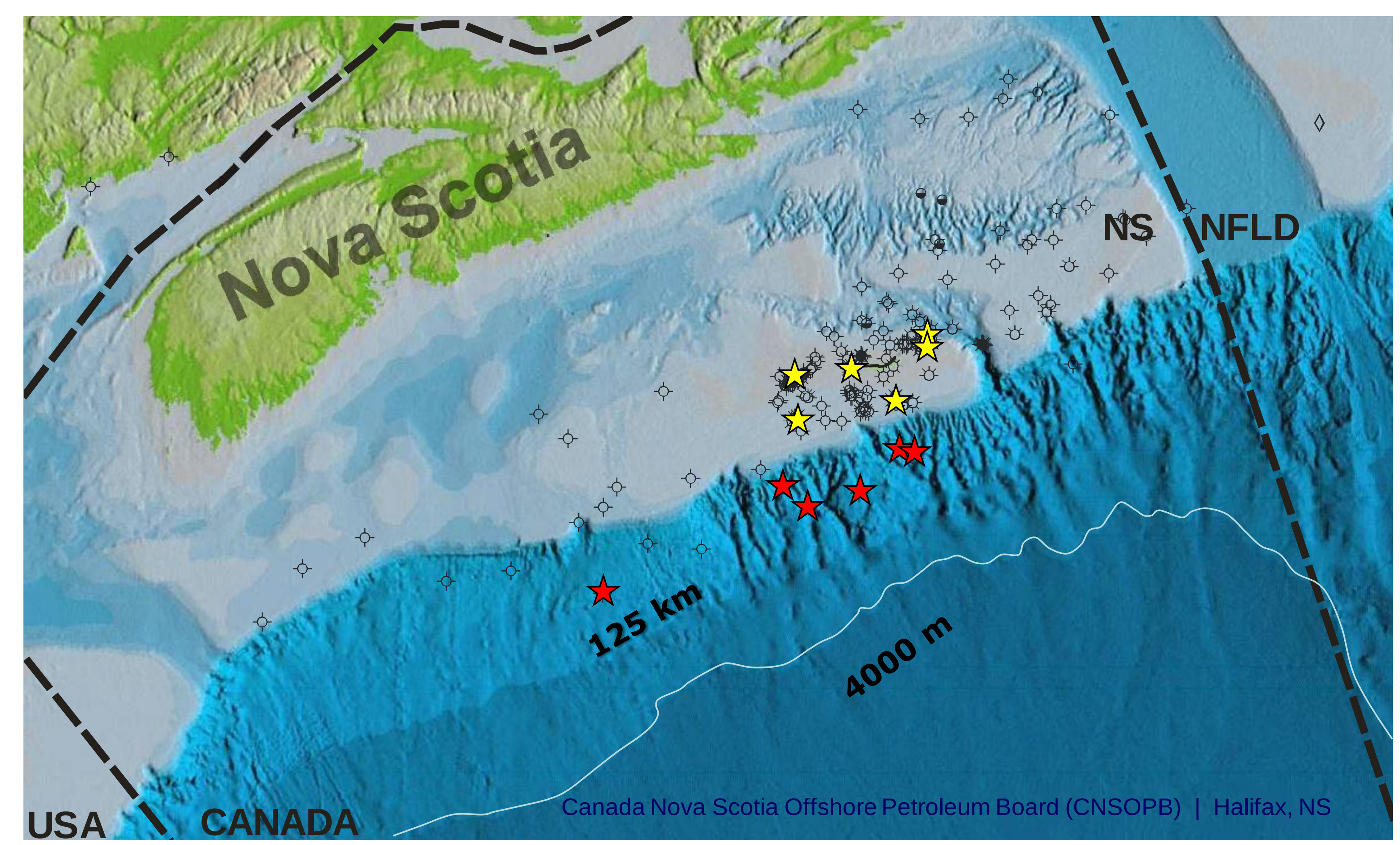


Figure 21: Deep water wells

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 think stringers of sand all of which were gas charged.

The locations of the wells and the reason they were drilled is clear form 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 bi passed 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.

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

- A number of the early wells (Schubenacadie – Figure 23) were drilled on Tertiary fan systems, and then deepened to test the Cretaceous section. There was no reservoir at Tertiary, or Cretaceous
- Shelburn (Figure 24 and 25) 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.

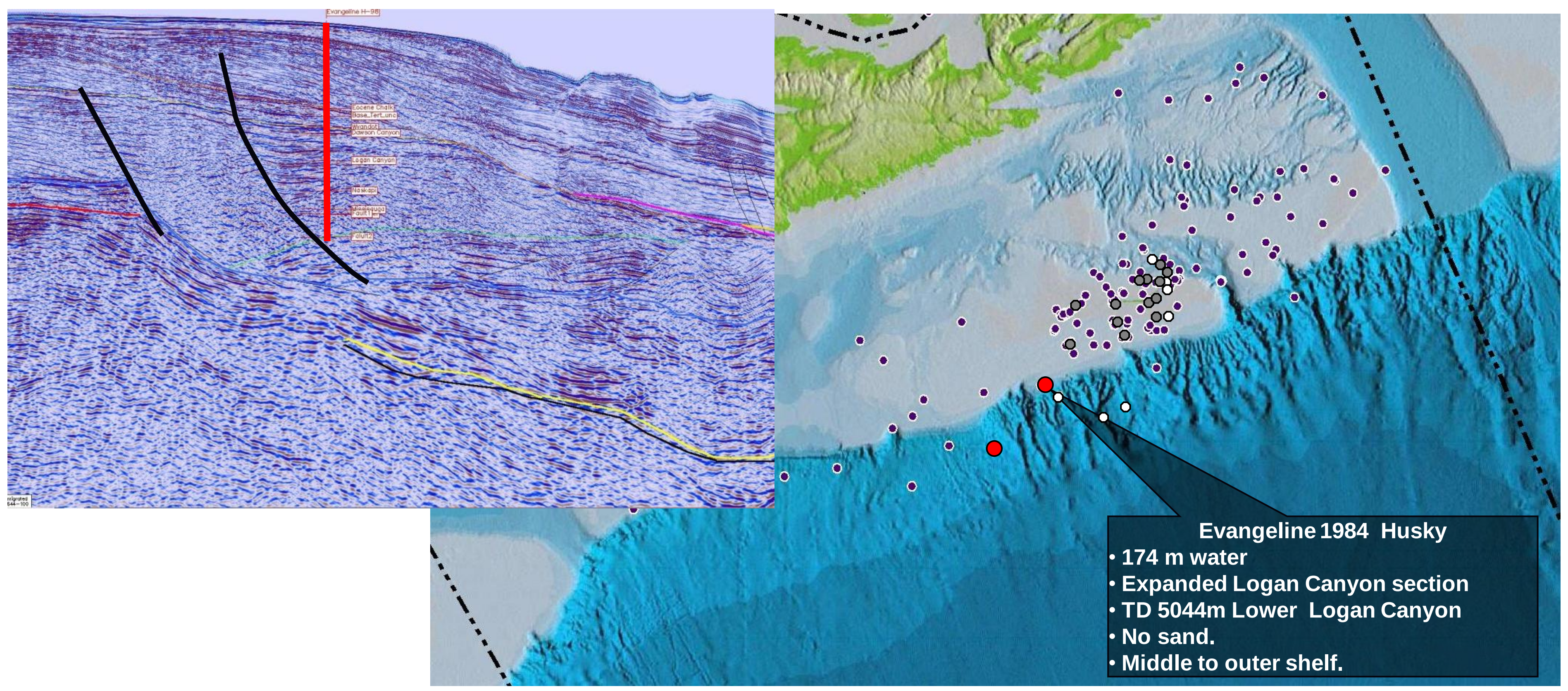


Figure 22: Evangeline – 1984 - Husky

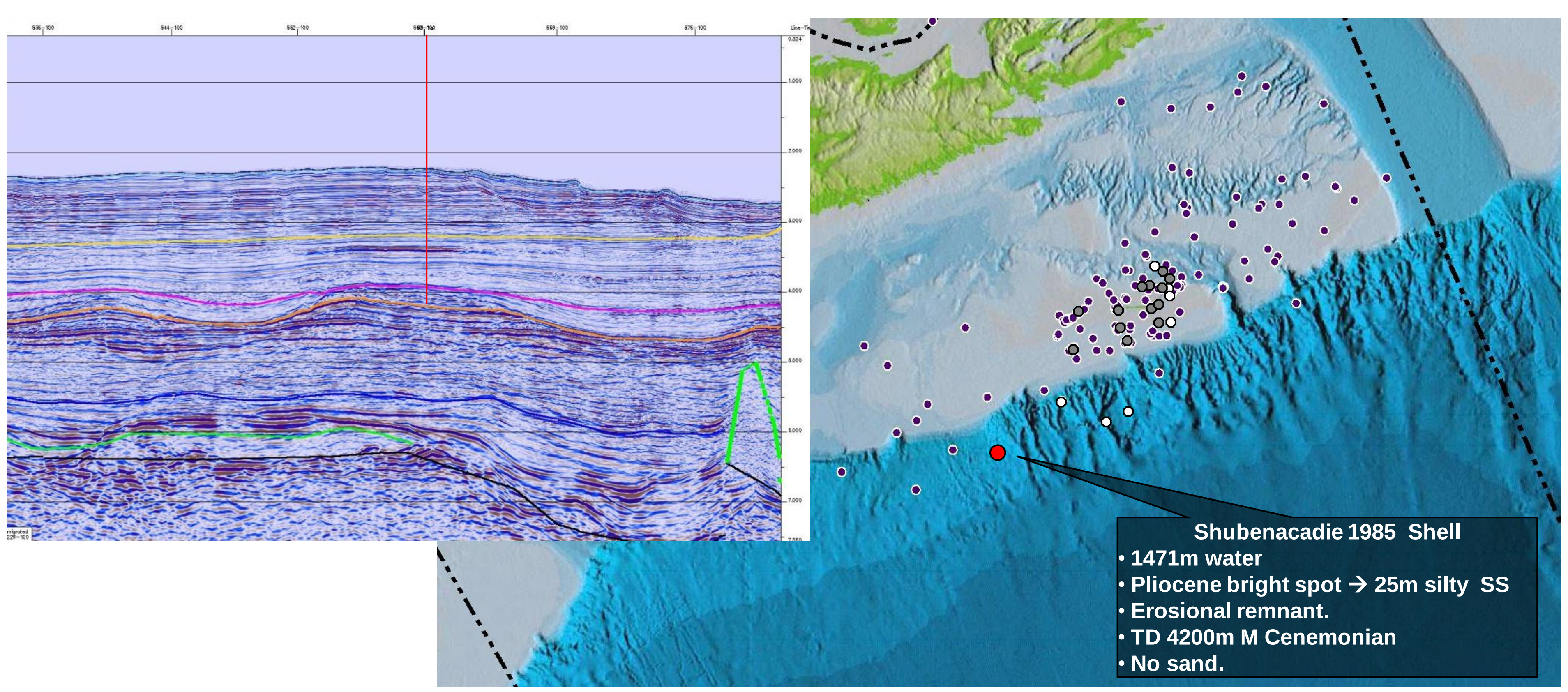


Figure 23: Shubenacadie – 1985 - Shell

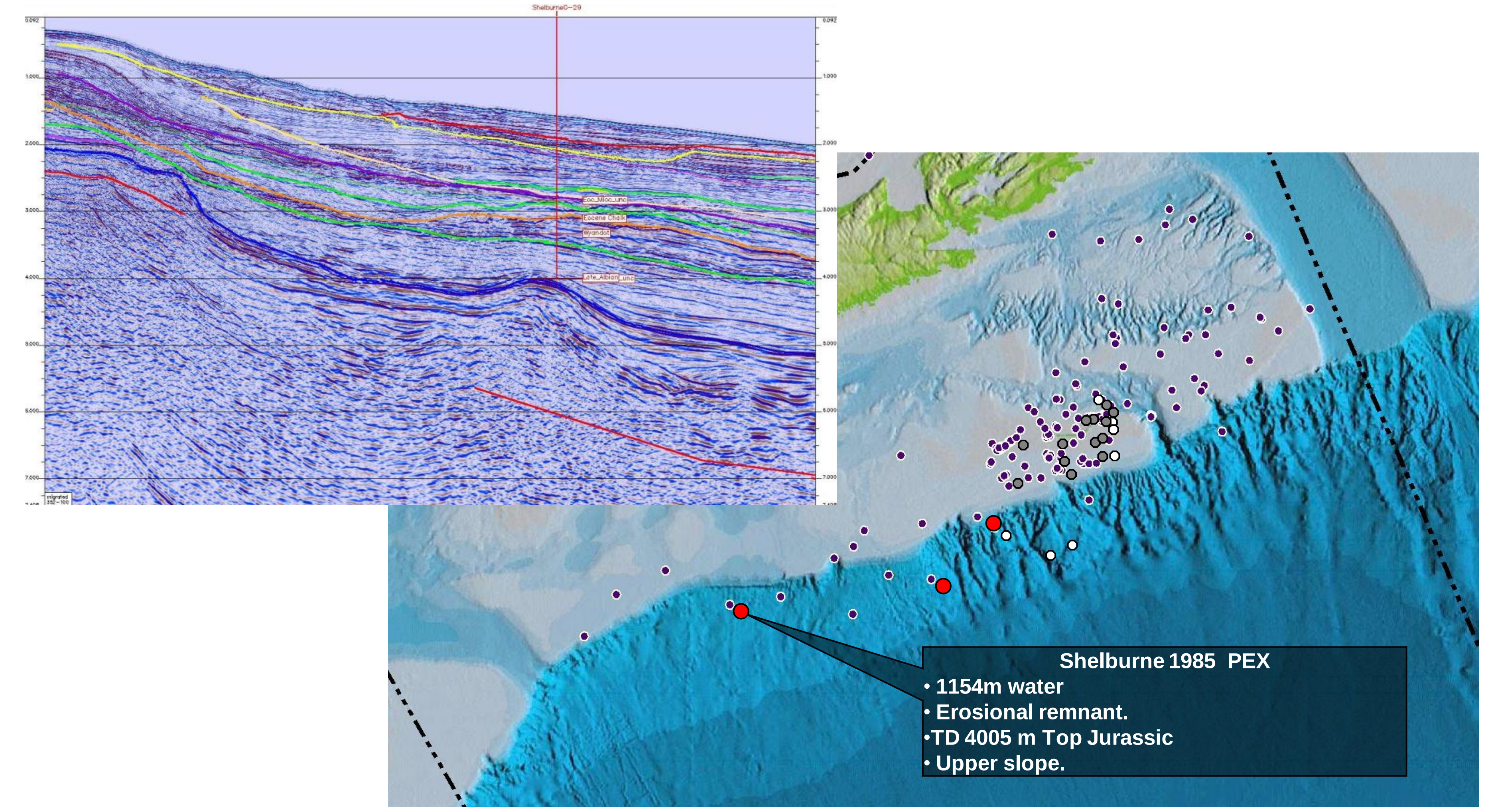


Figure 24: Shelburne – 1985 - PEX

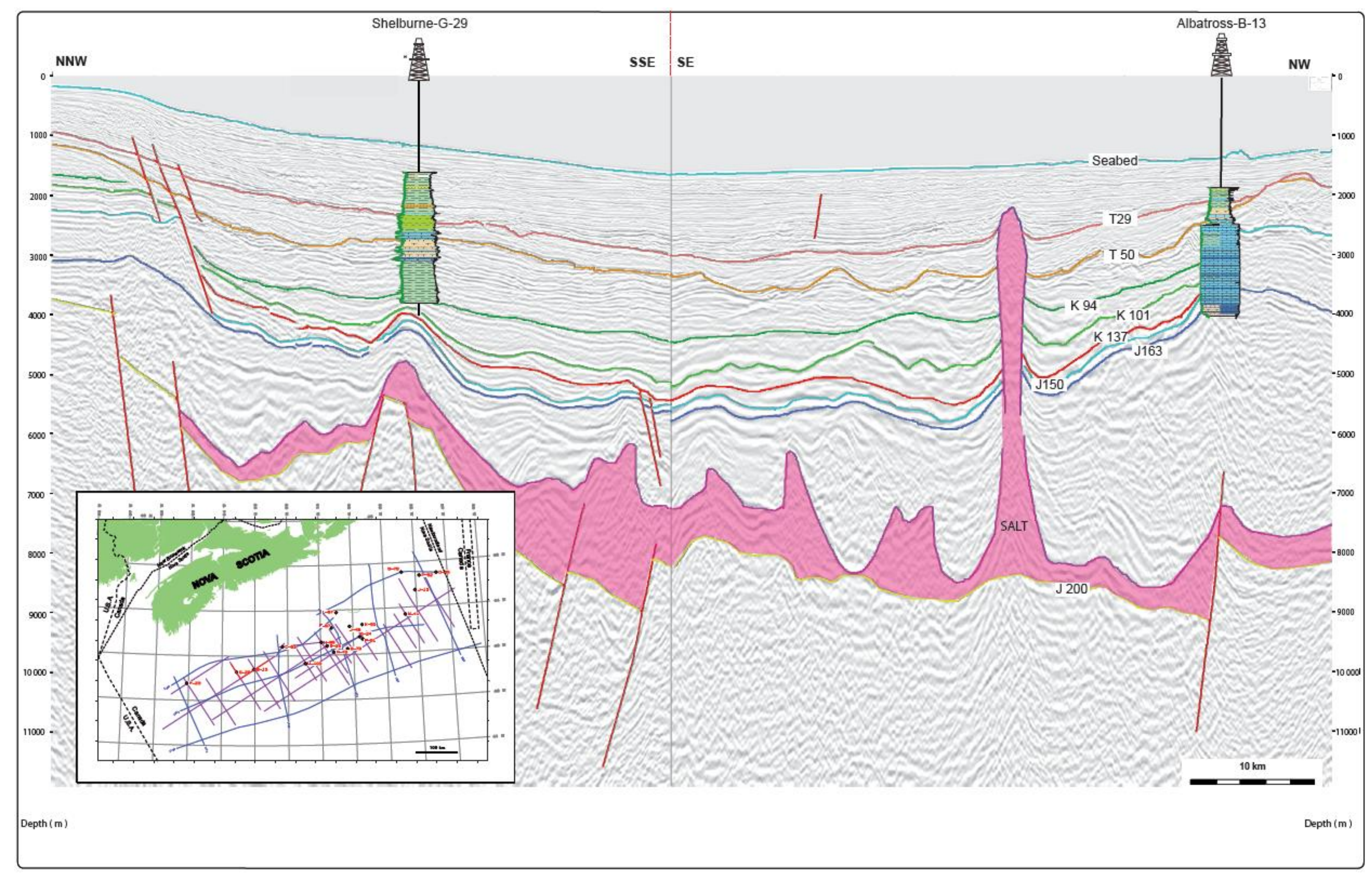
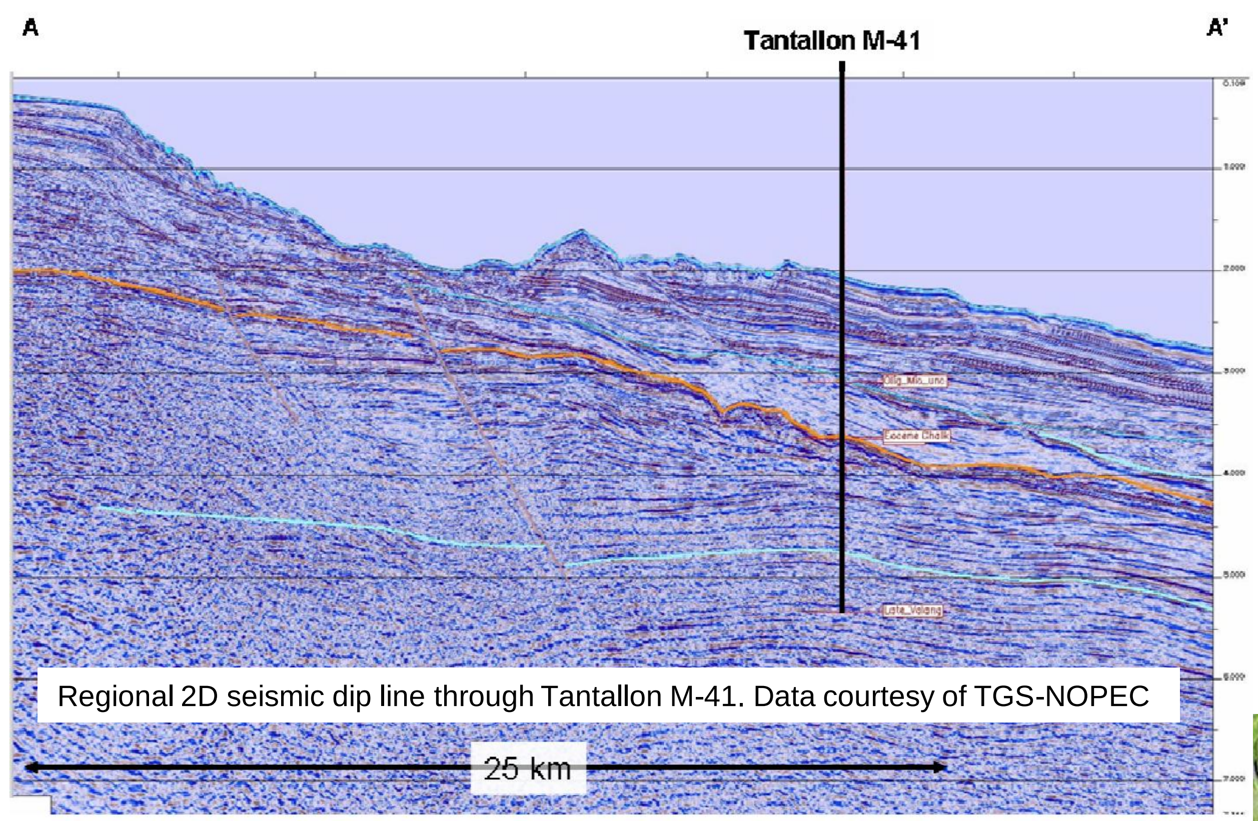


Figure 25: Shelburne and Albatross

Deep Water Tests: Evangeline, Shubenacadie and Shelburne

The locations of the wells and the reason they were drilled is clear form 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 bi passed 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"

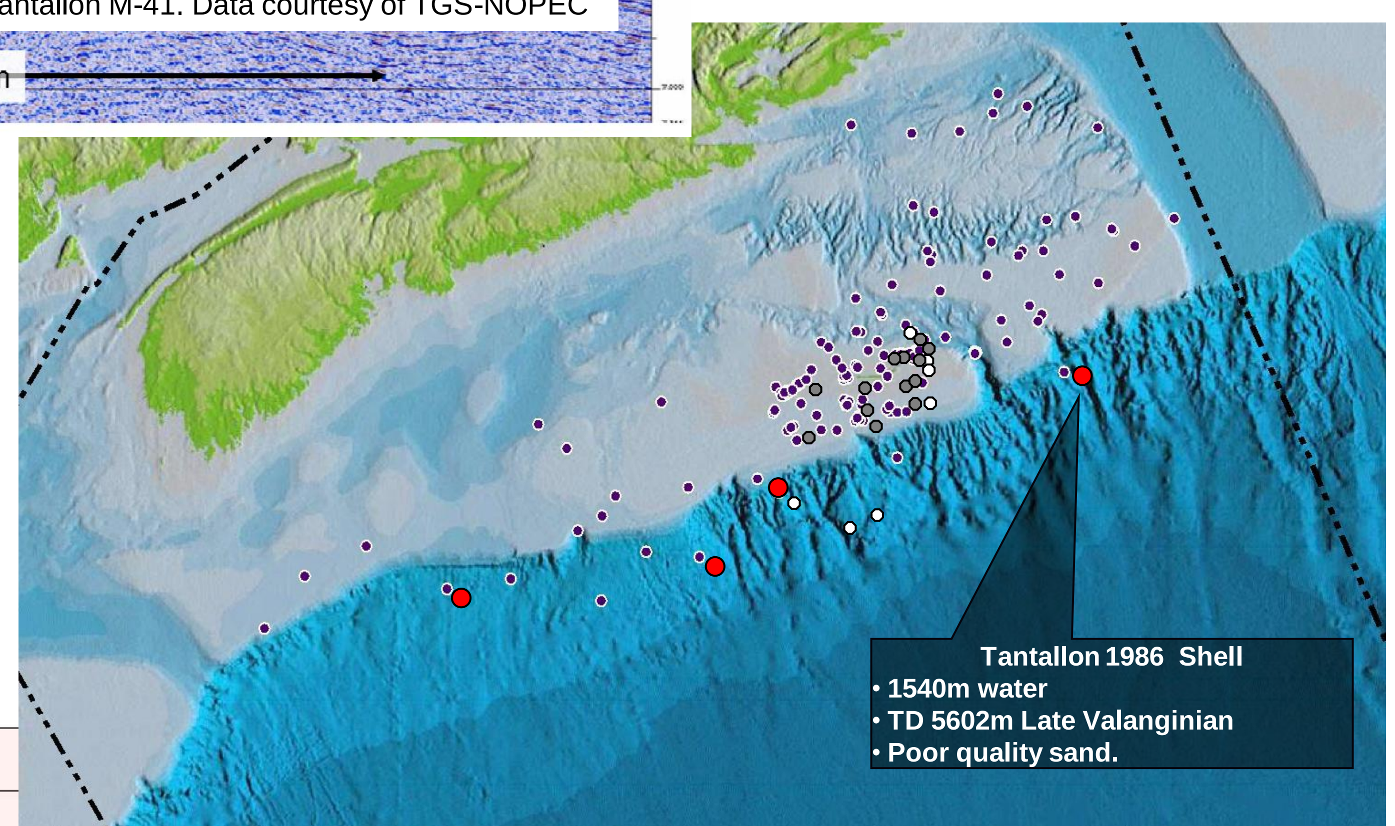
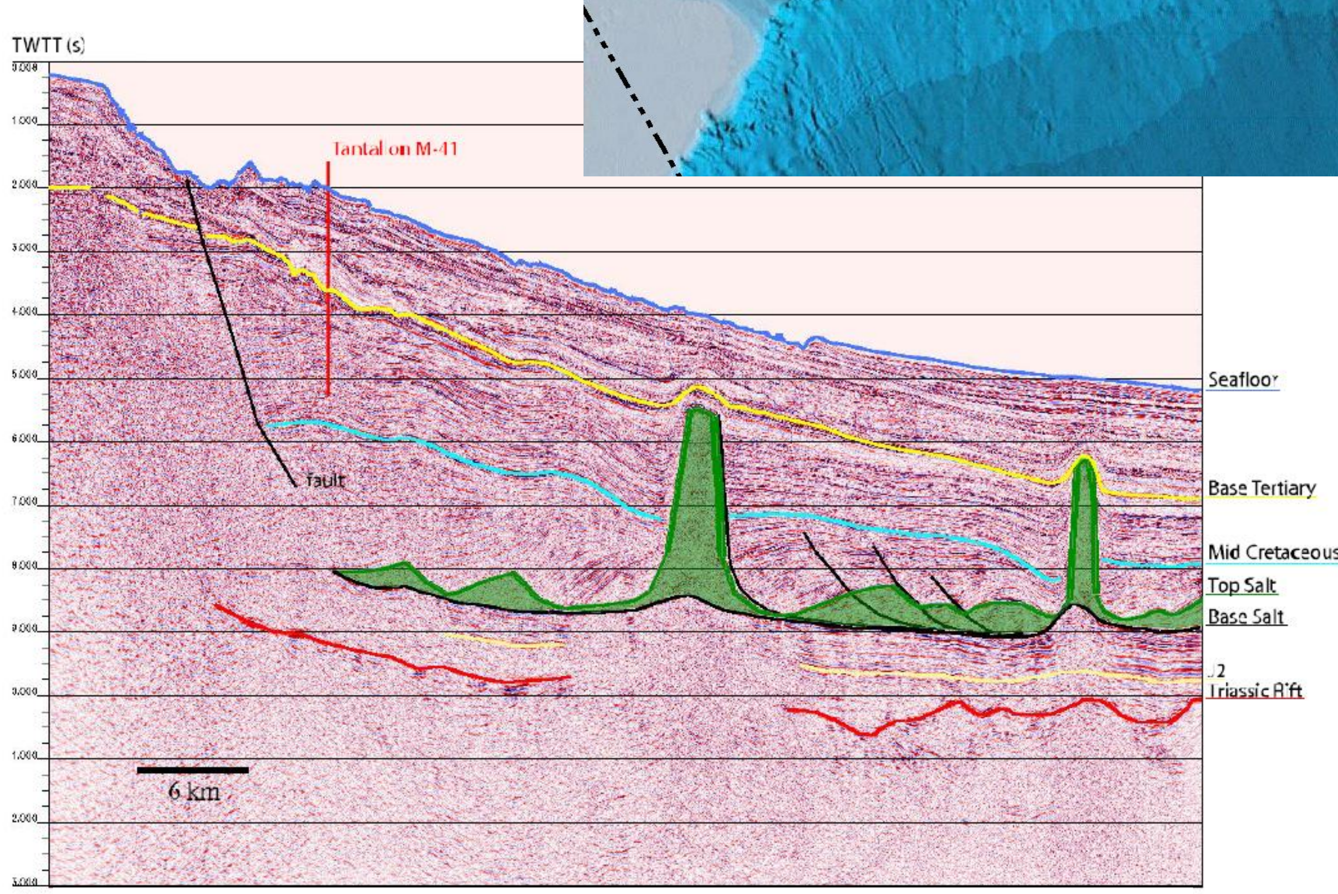


Figure 26: Tantallon – 1986 - Shell



from Kidston et al. (2002), "Hydrocarbon Potential of the Deep-Water Scotian Slope"

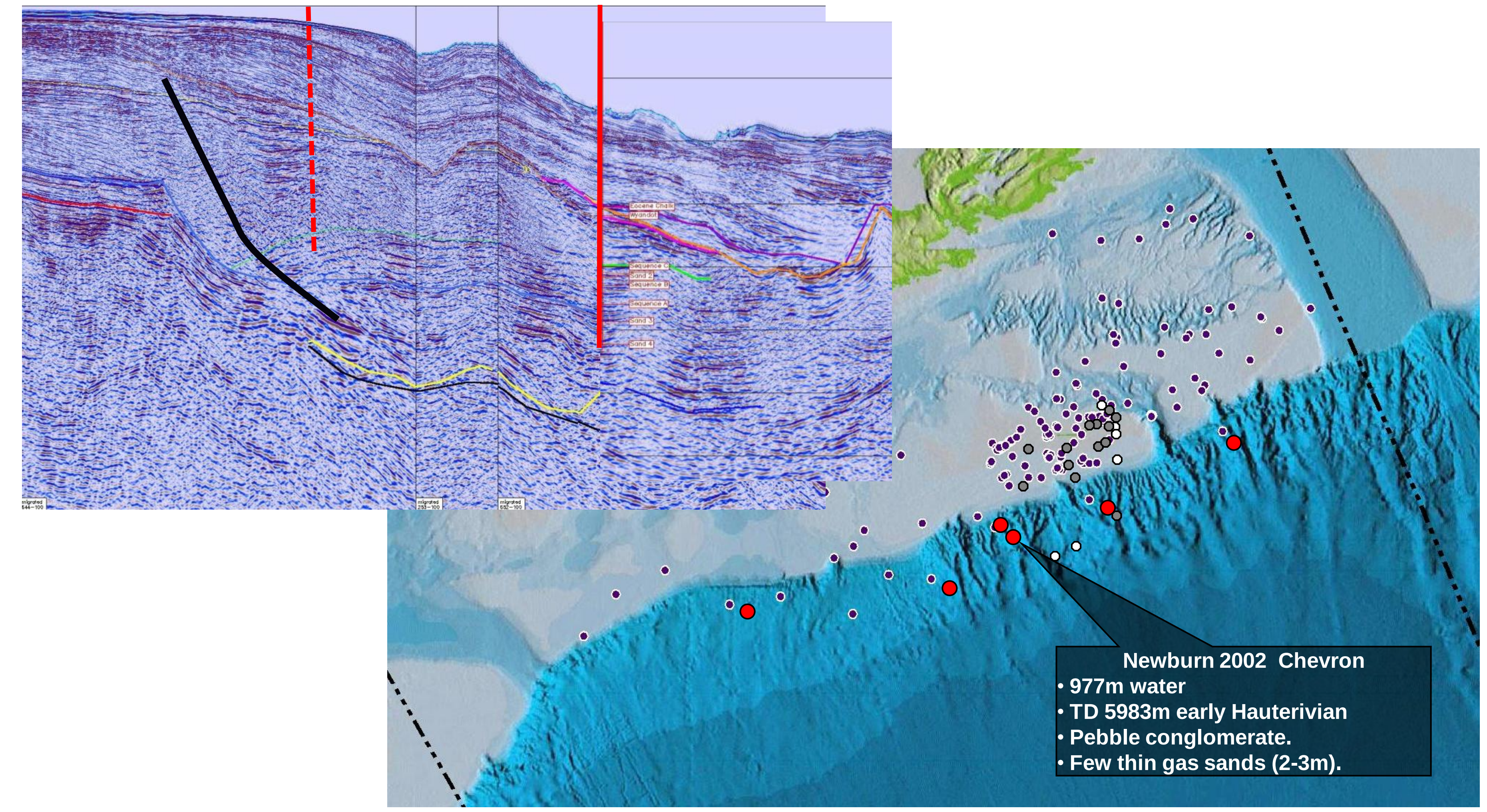


Figure 28: Newburn – 2002 - Chevron

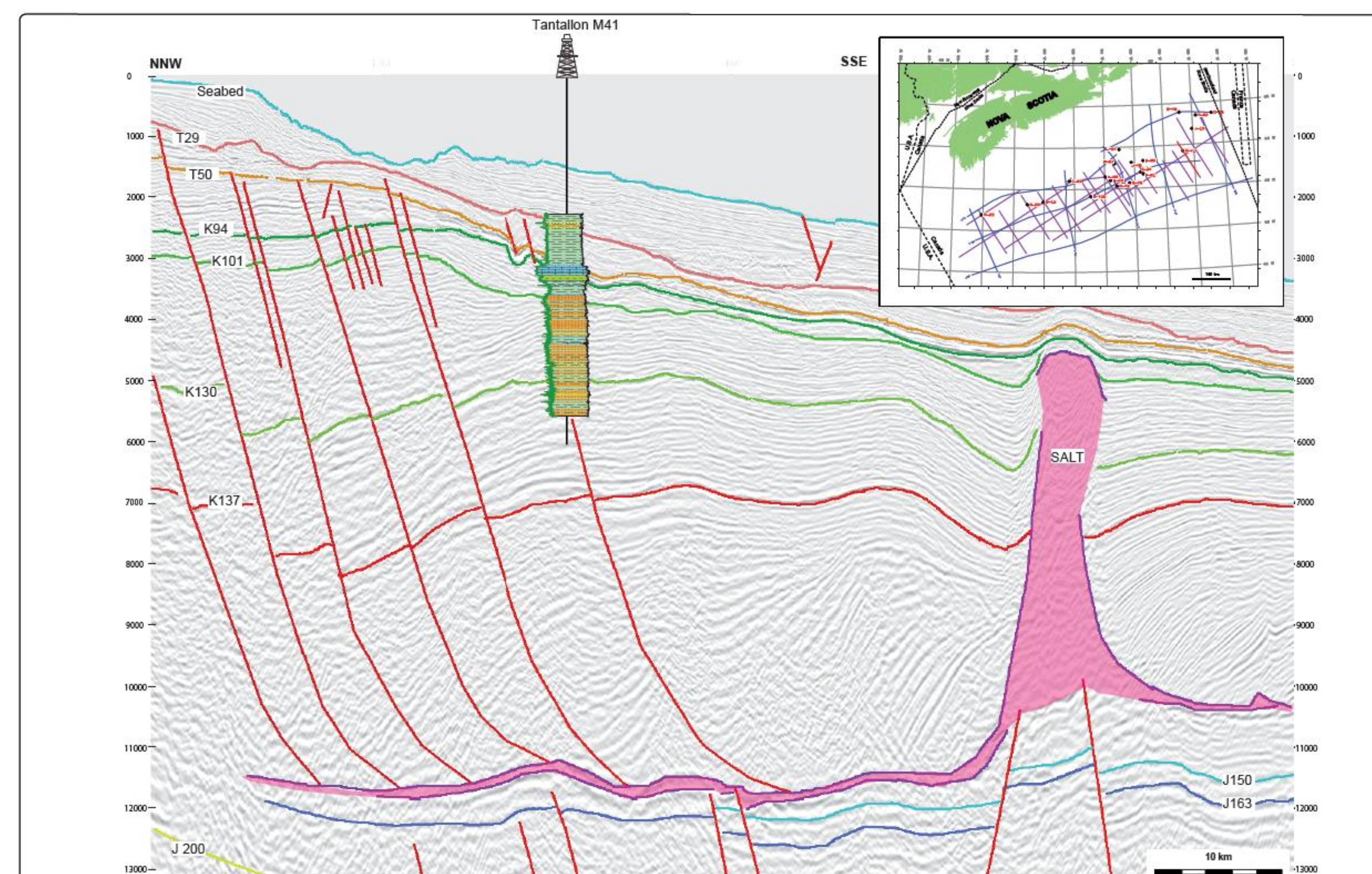


Figure 27: Tantallon

The locations of the wells and the reason they were drilled is clear form 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.

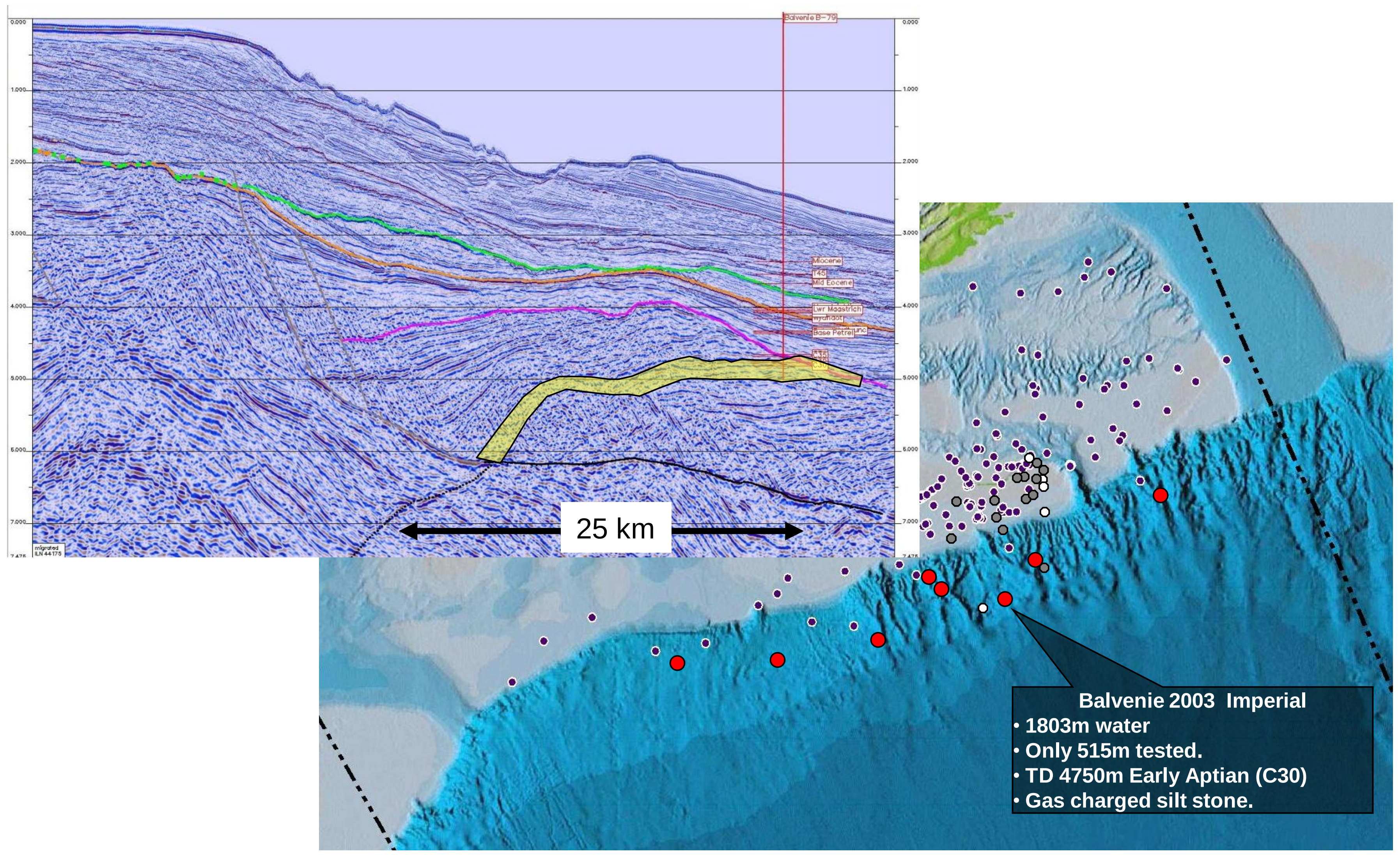


Figure 29: Balvenie – 2003 - Imperial

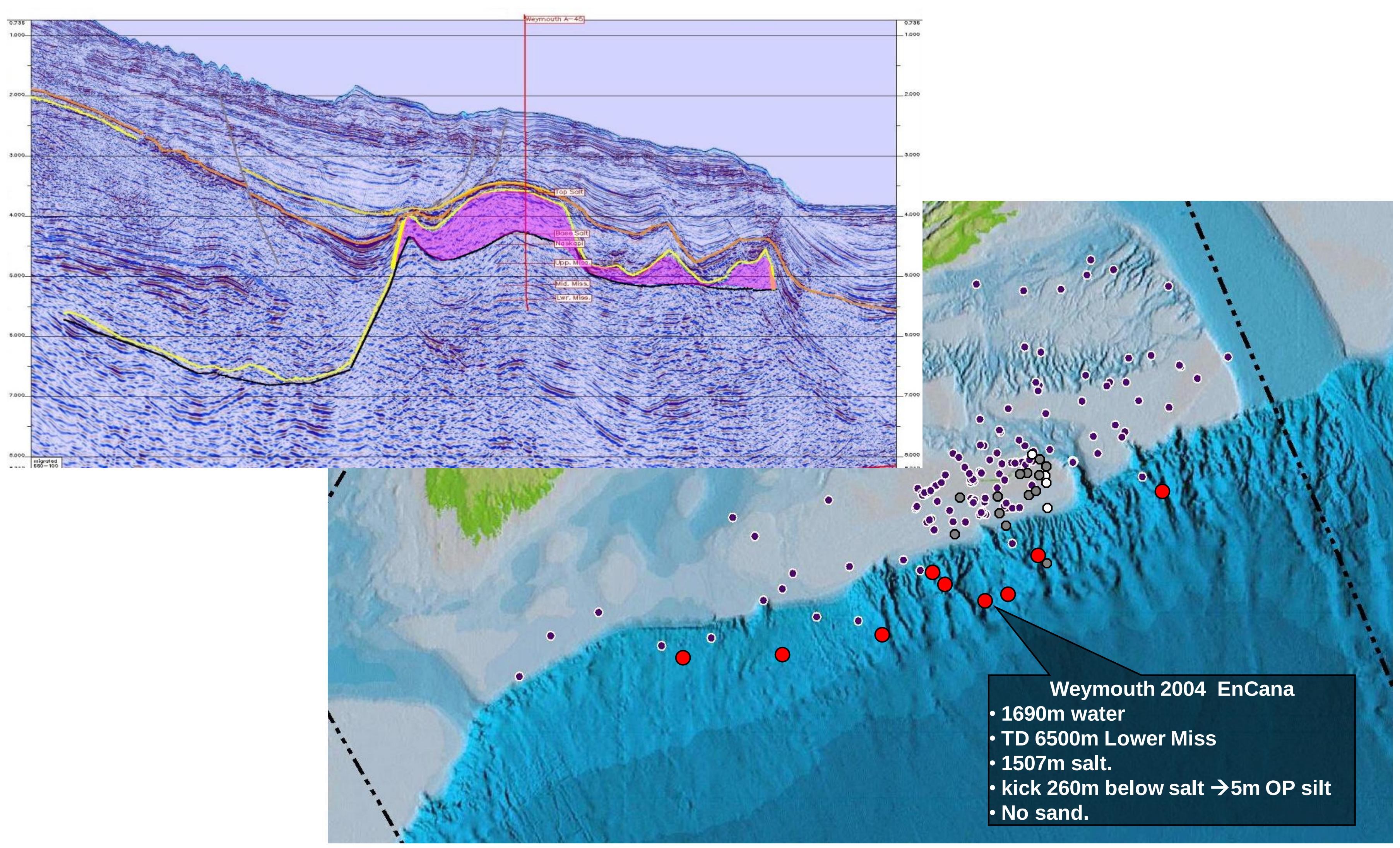


Figure 30: Weymouth – 2004 - EnCana

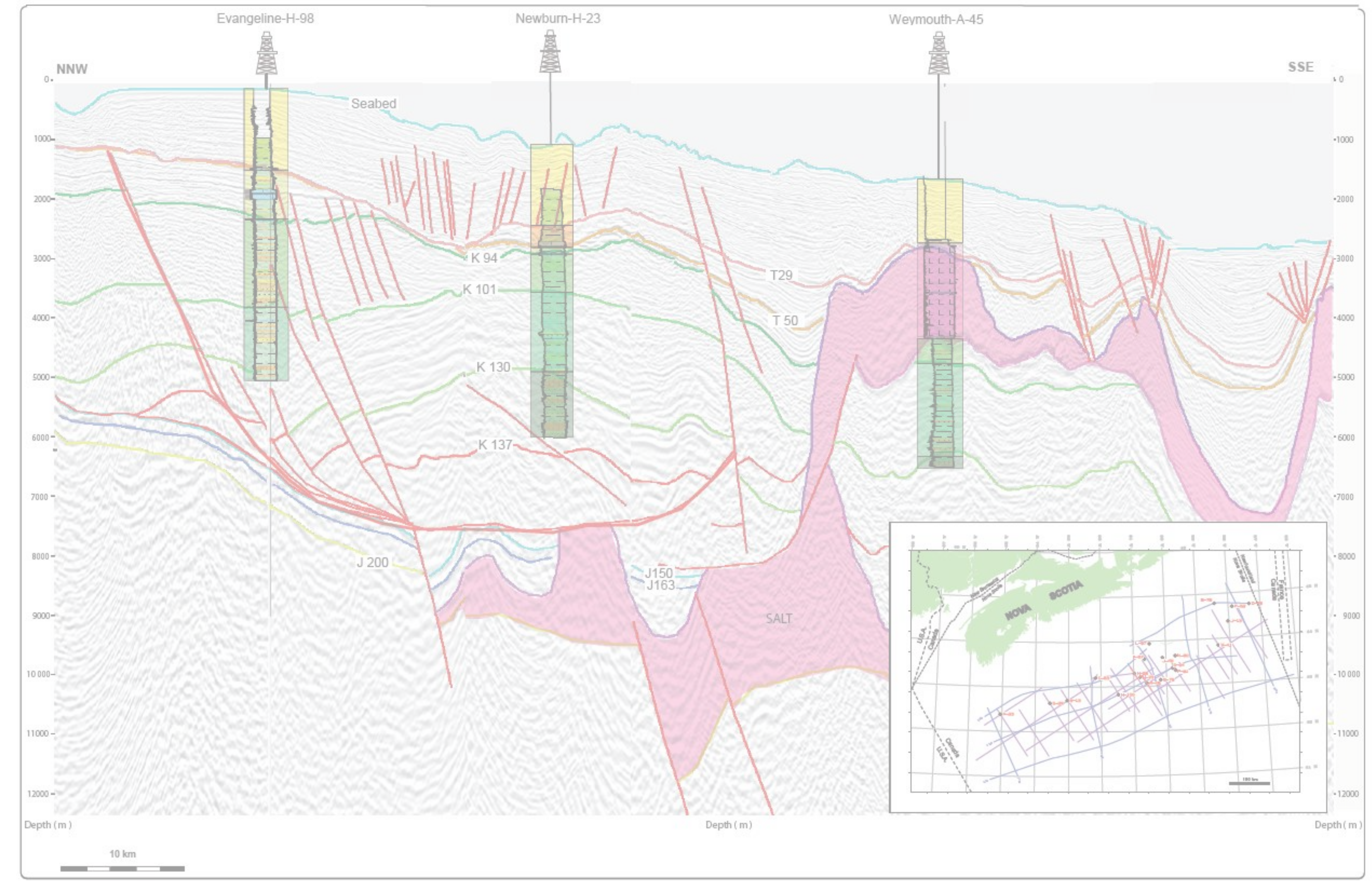


Figure 31: Evangeline, Newburn and Weymouth

Deep Water Tests: Balvenie and Weymouth

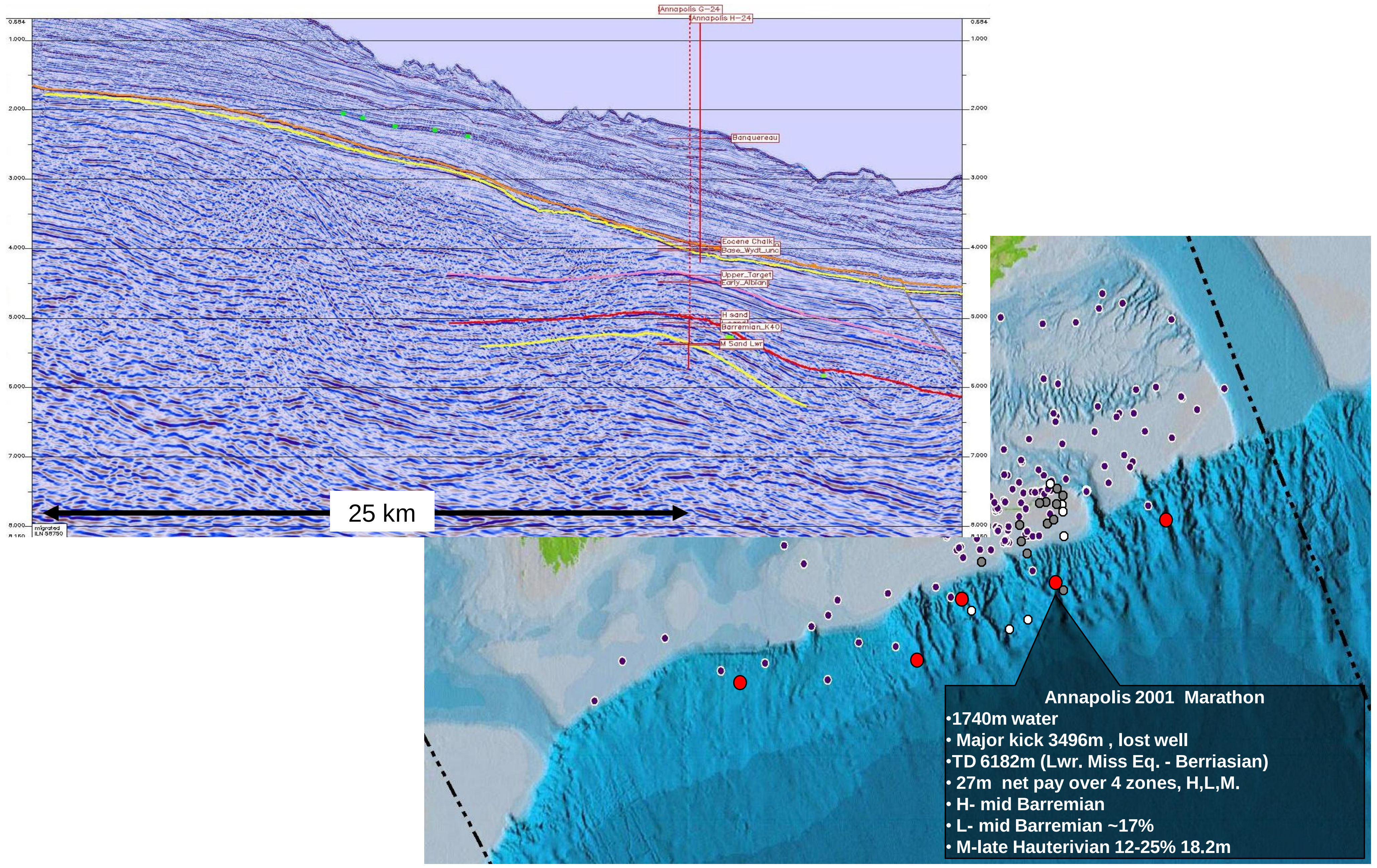


Figure 32: Annapolis – 2001 - Marathon

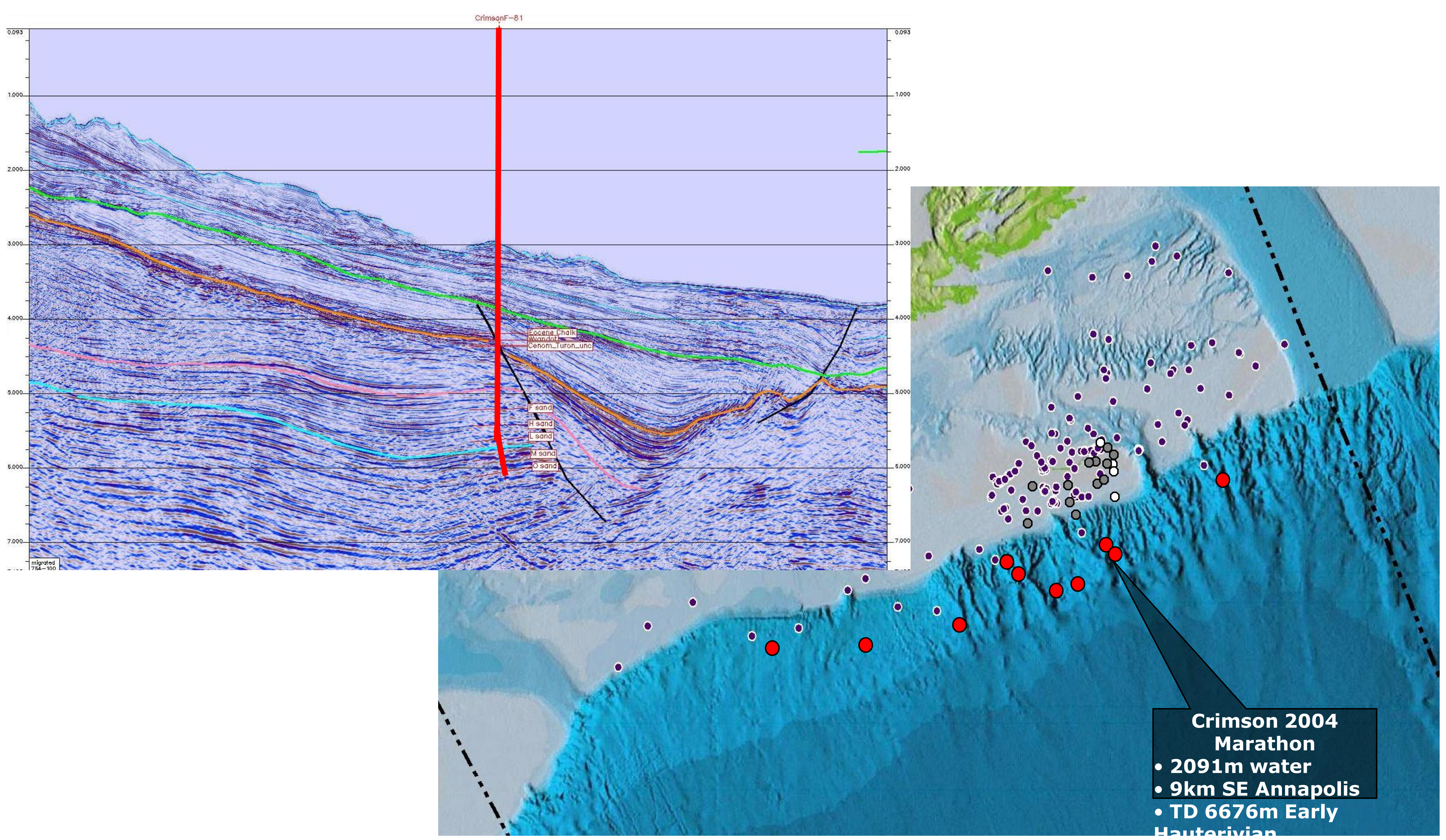


Figure 33: Crimson – 2004 - Marathon

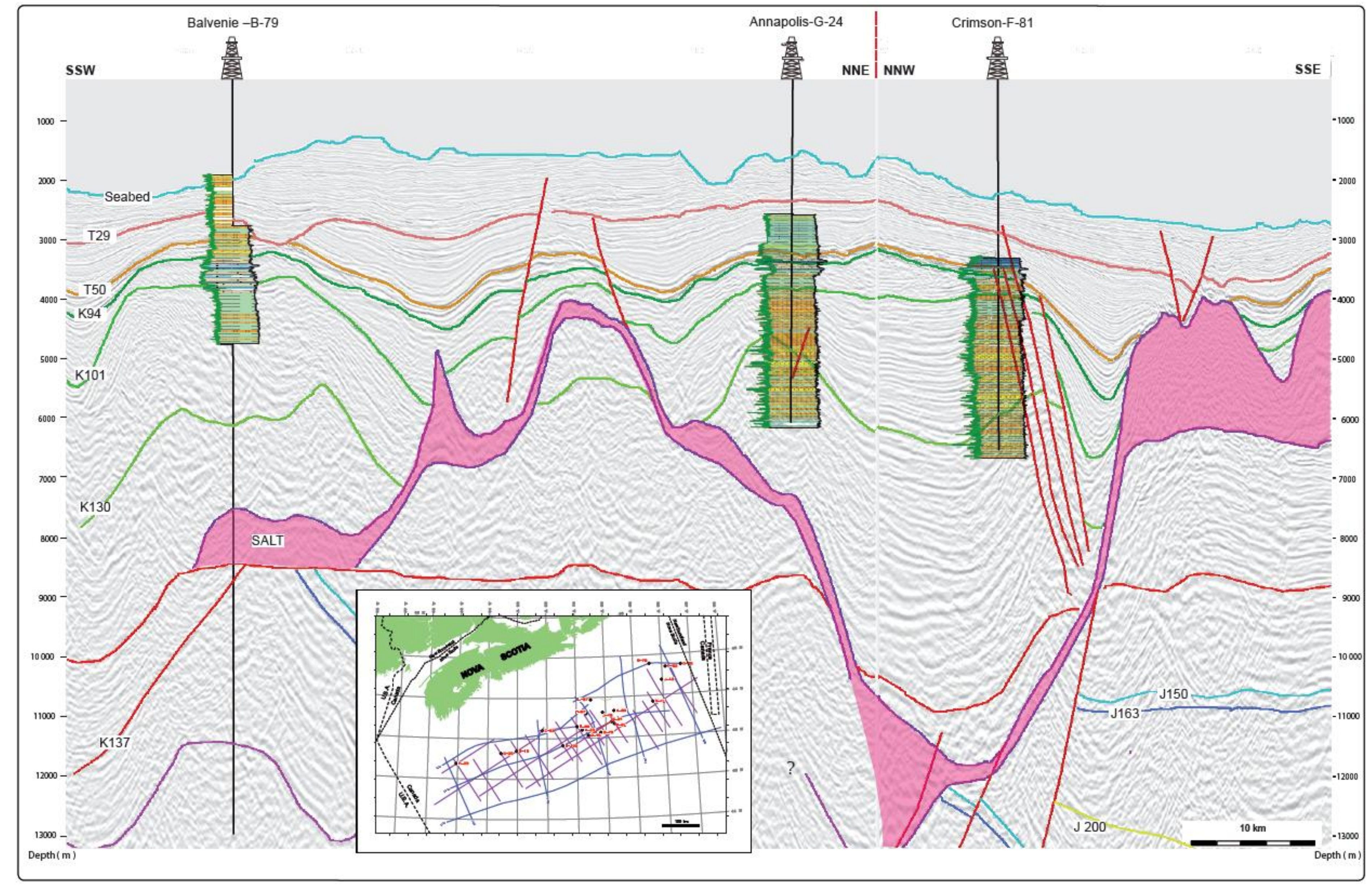


Figure 34: Balvenie, Annapolis and Crimson – Annapolis discovery

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.

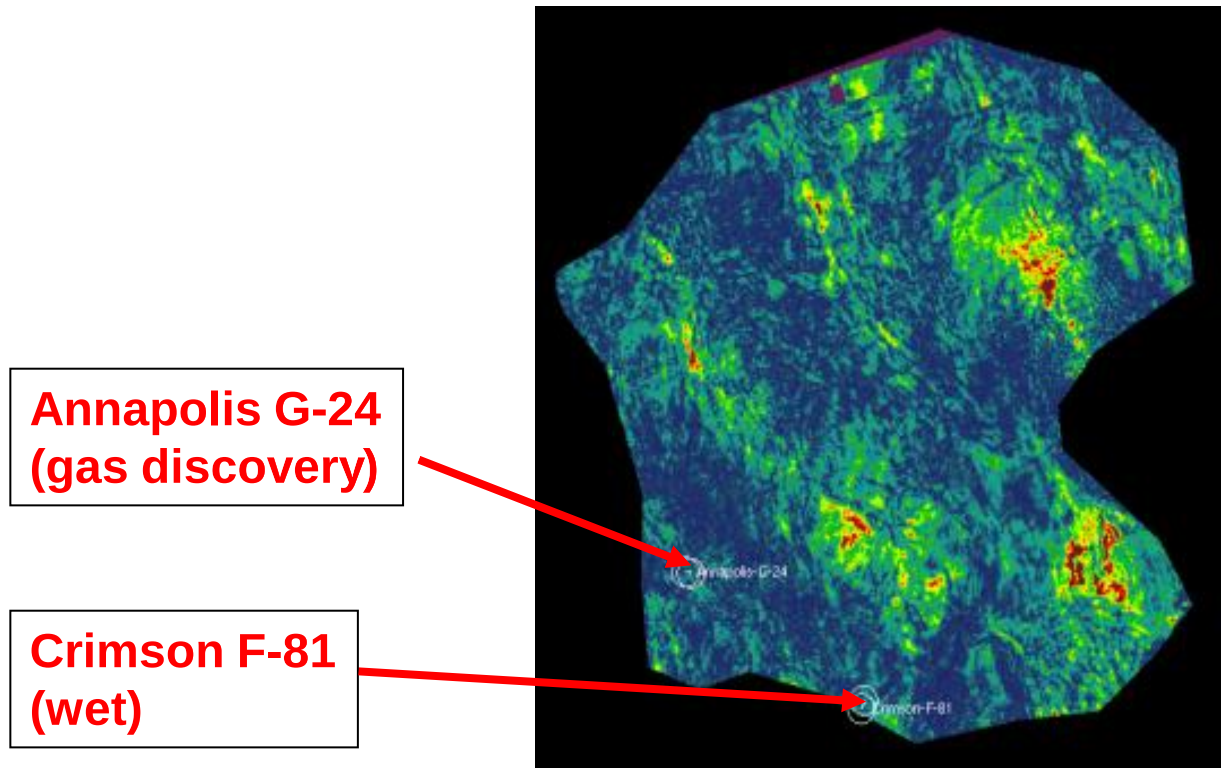
Marathon drilled the follow up well Crimson down dip on a separate feature. Crimson found no reservoir.

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

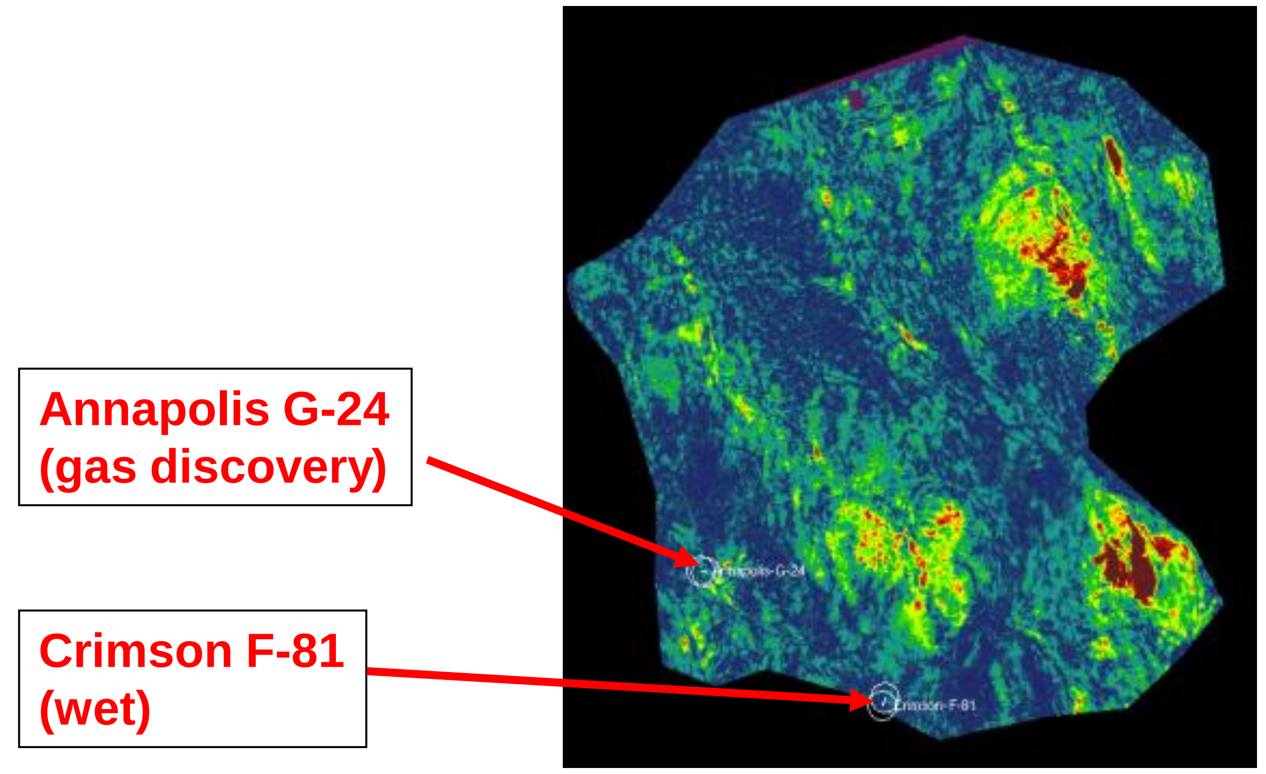
1) The well demonstrates the presence of a working hydrocarbon system
2) The attribute work shows evidence for channel systems in deep water and shows that the channels can be mapped using high quality seismic

Both are profound observations in de-risking the deep offshore.



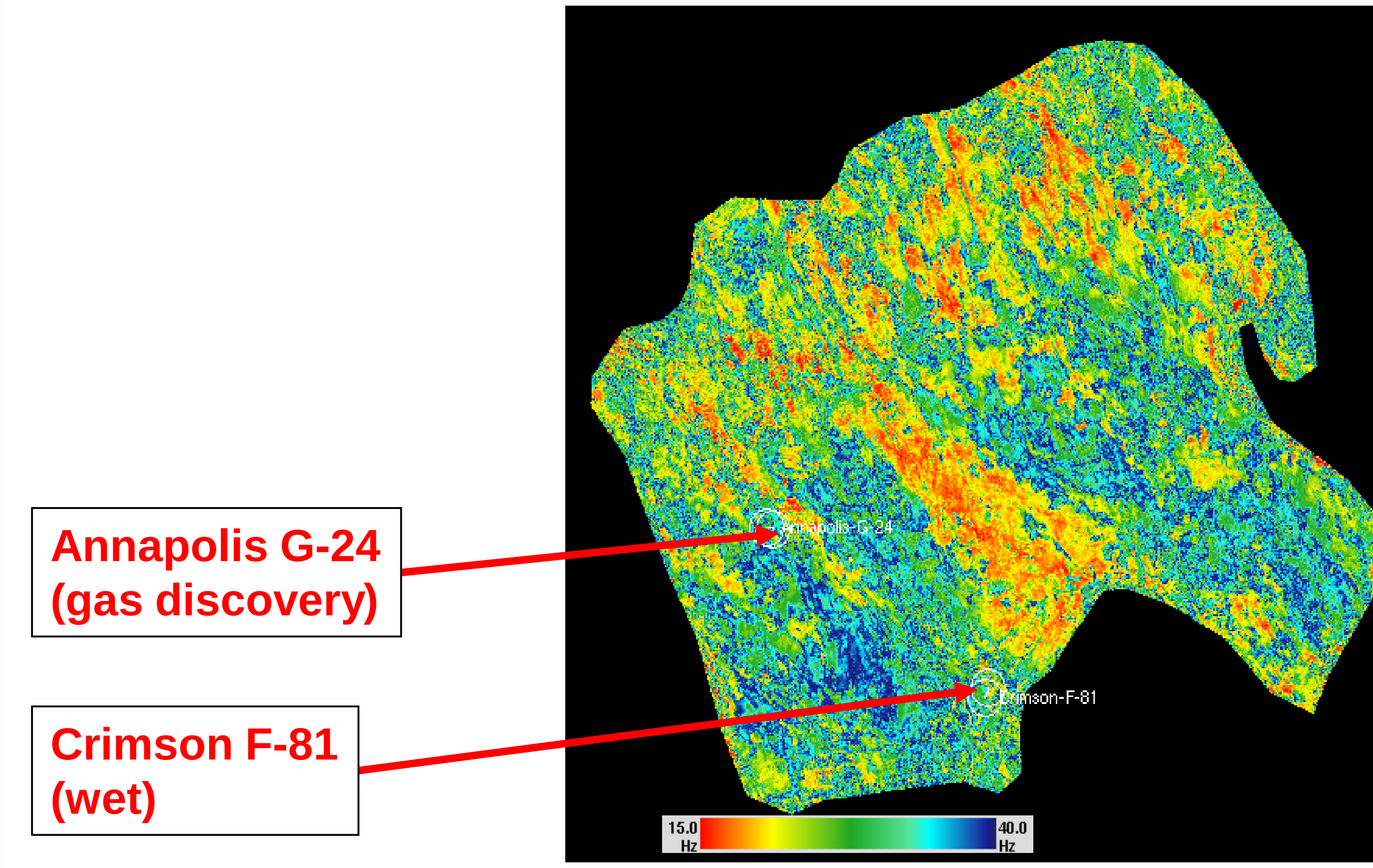
Hauterivian MFS, -80 to -40ms, RMS Amp

Figure 35a: Annapolis attributes map – 2001 - Hauterivian MFS, -80 to -40ms, RMS Amp



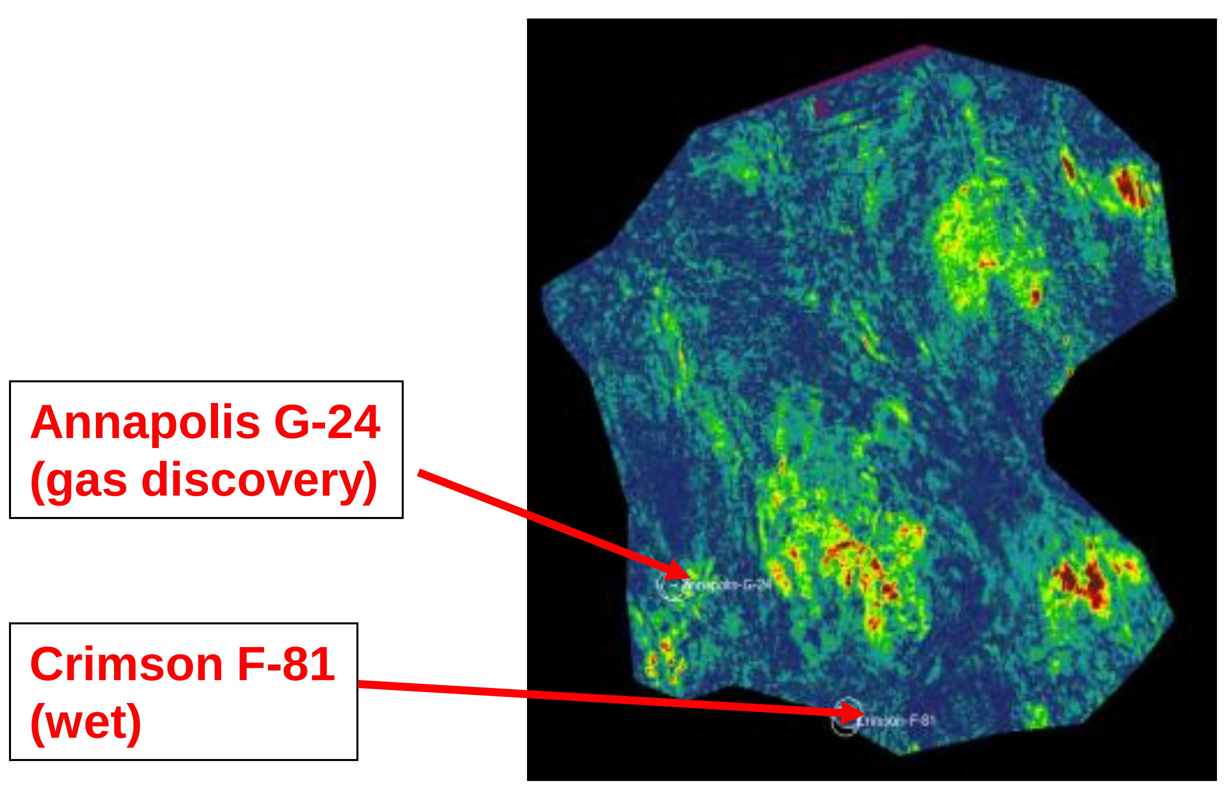
Hauterivian MFS, -40 to 0ms, RMS Amp

Figure 35b: Annapolis attributes map – 2001 - Hauterivian MFS, -40 to 0ms, RMS Amp



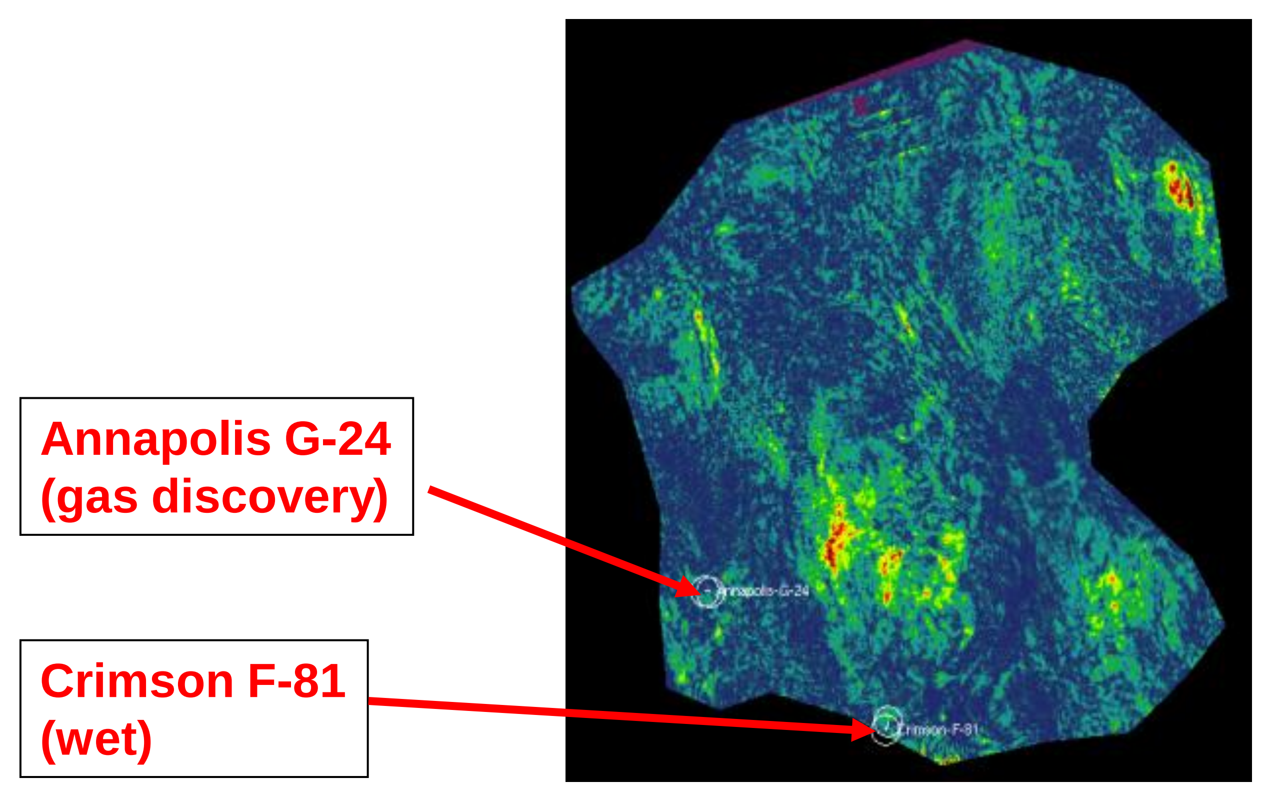
B24_01, 0 to +100ms, Max Instantaneous frequency

Figure 35e: Annapolis attributes map – B24_01, 0 to +100ms, Max Instantaneous frequency



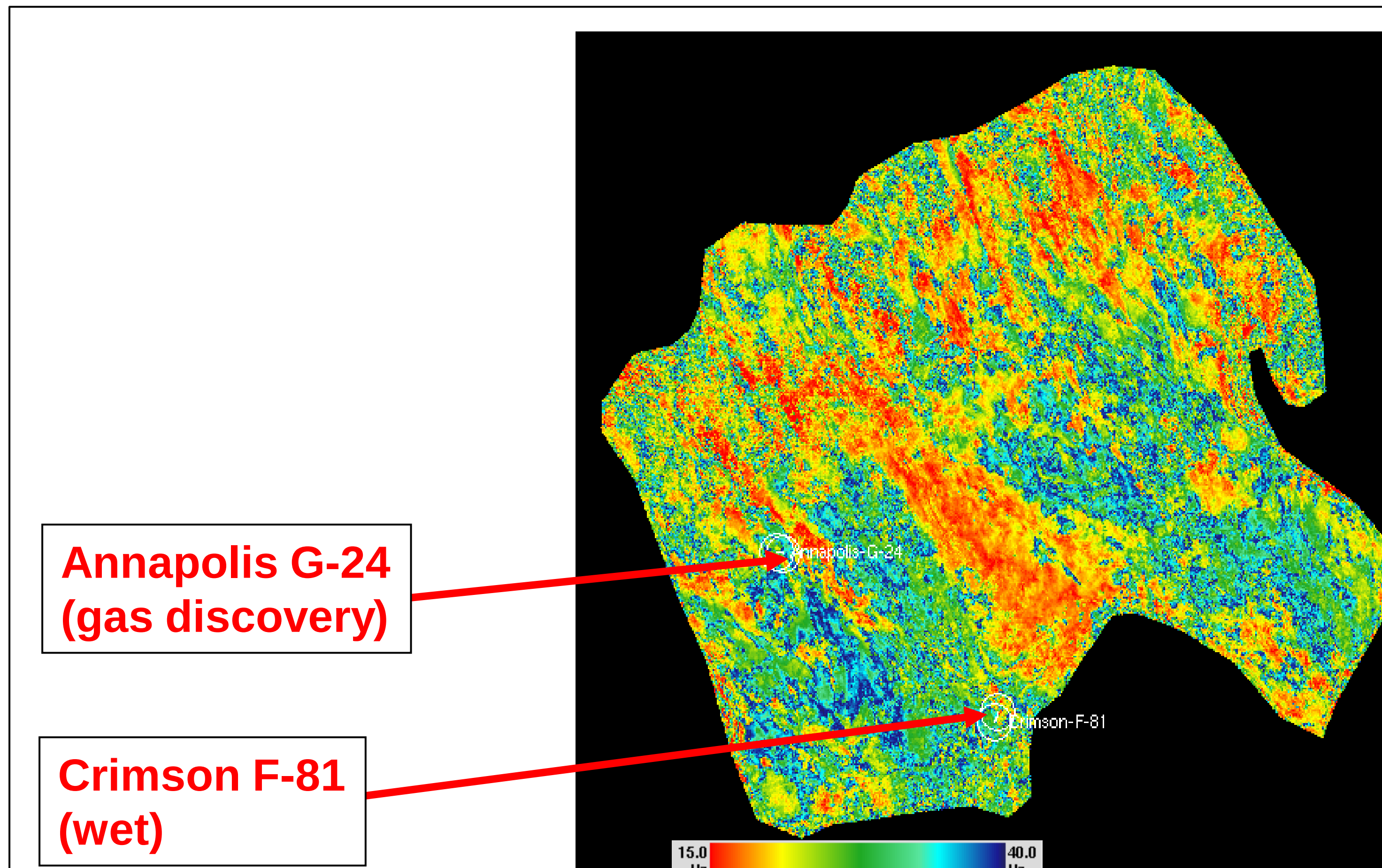
Hauterivian MFS, 0 to +40ms, RMS Amp

Figure 35c: Annapolis attributes map – 2001 - Hauterivian MFS, 0 to +40ms, RMS Amp



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

Figure 35d: Annapolis attributes map – 2001 - Hauterivian MFS, +40 to +80ms, RMS Amp



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

Figure 35f: Annapolis attributes map – B24_01, +20 to +80ms, Max Instantaneous frequency

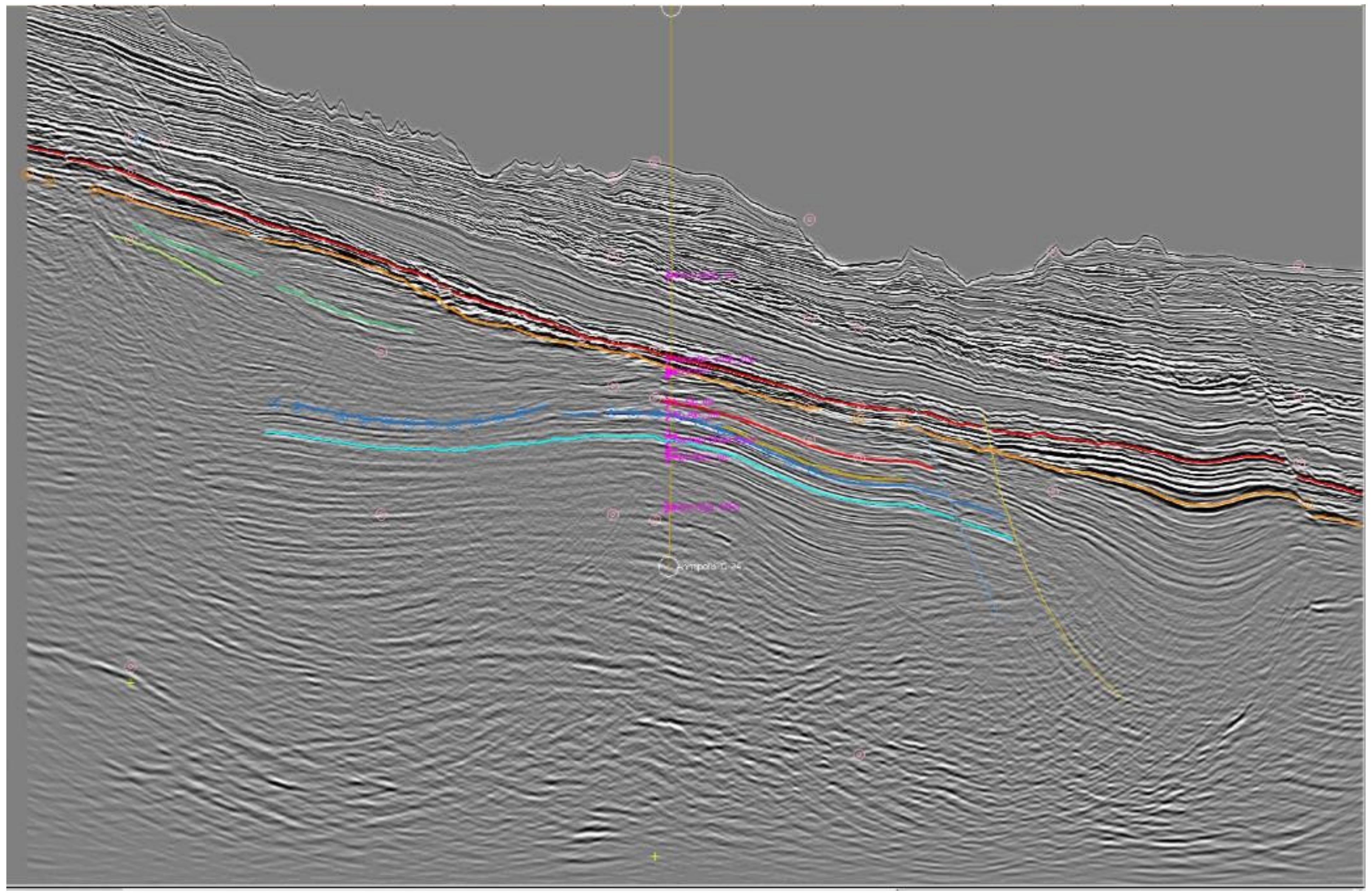


Figure 36: Annapolis dip line

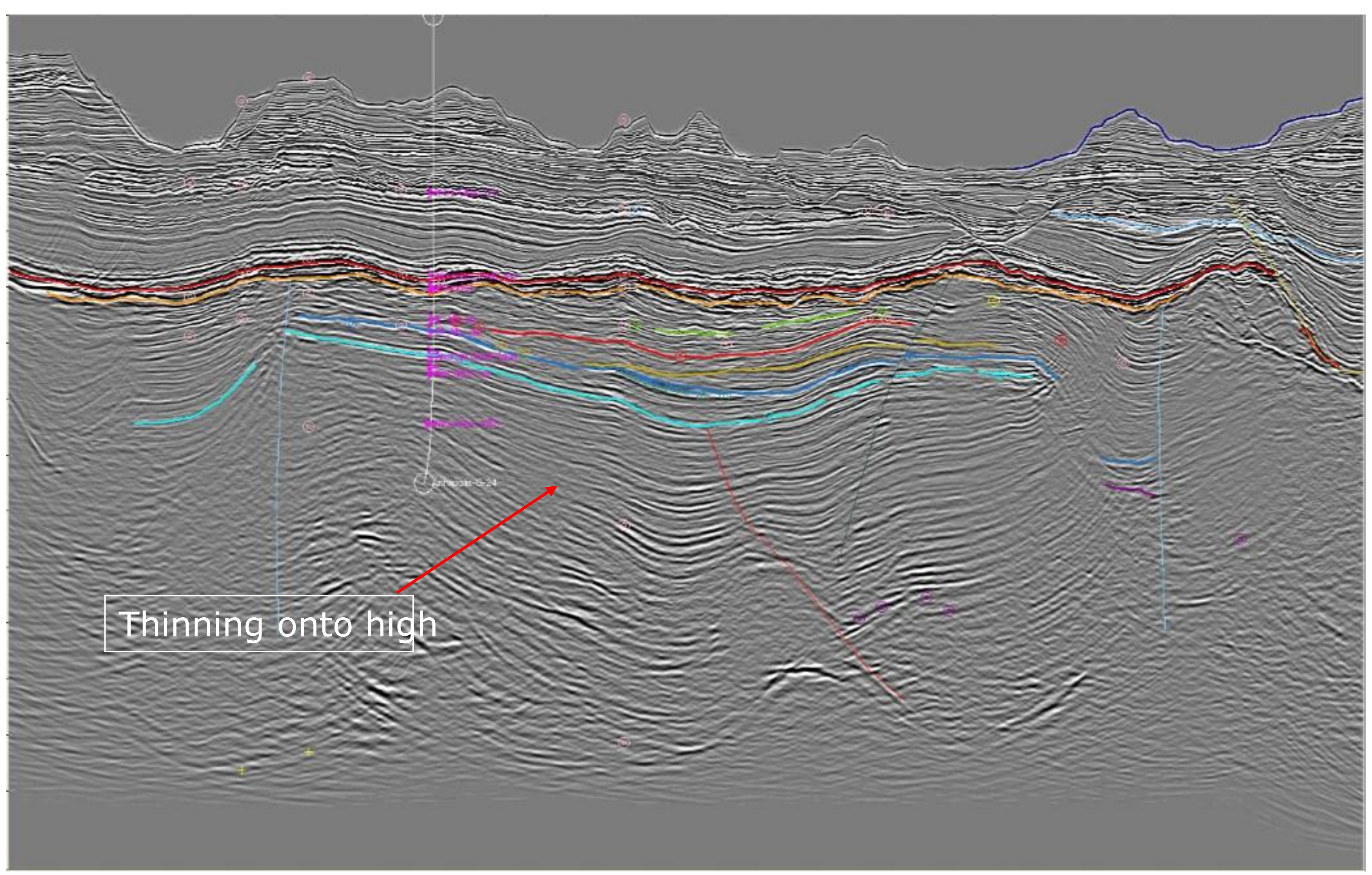


Figure 37: Annapolis strike line

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 of 'working' dip closed structures.

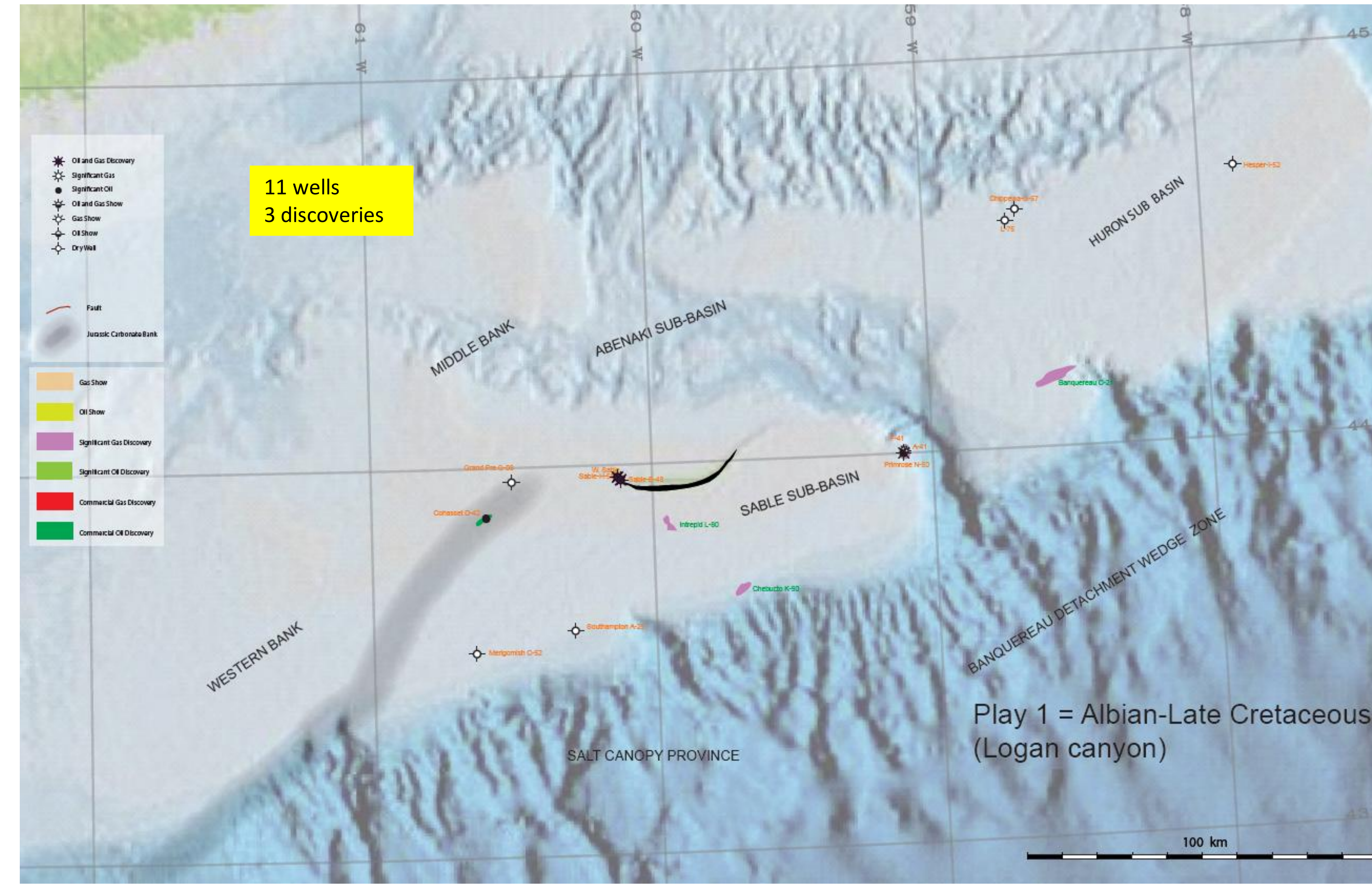


Figure 38: Logan Canyon fields and discoveries

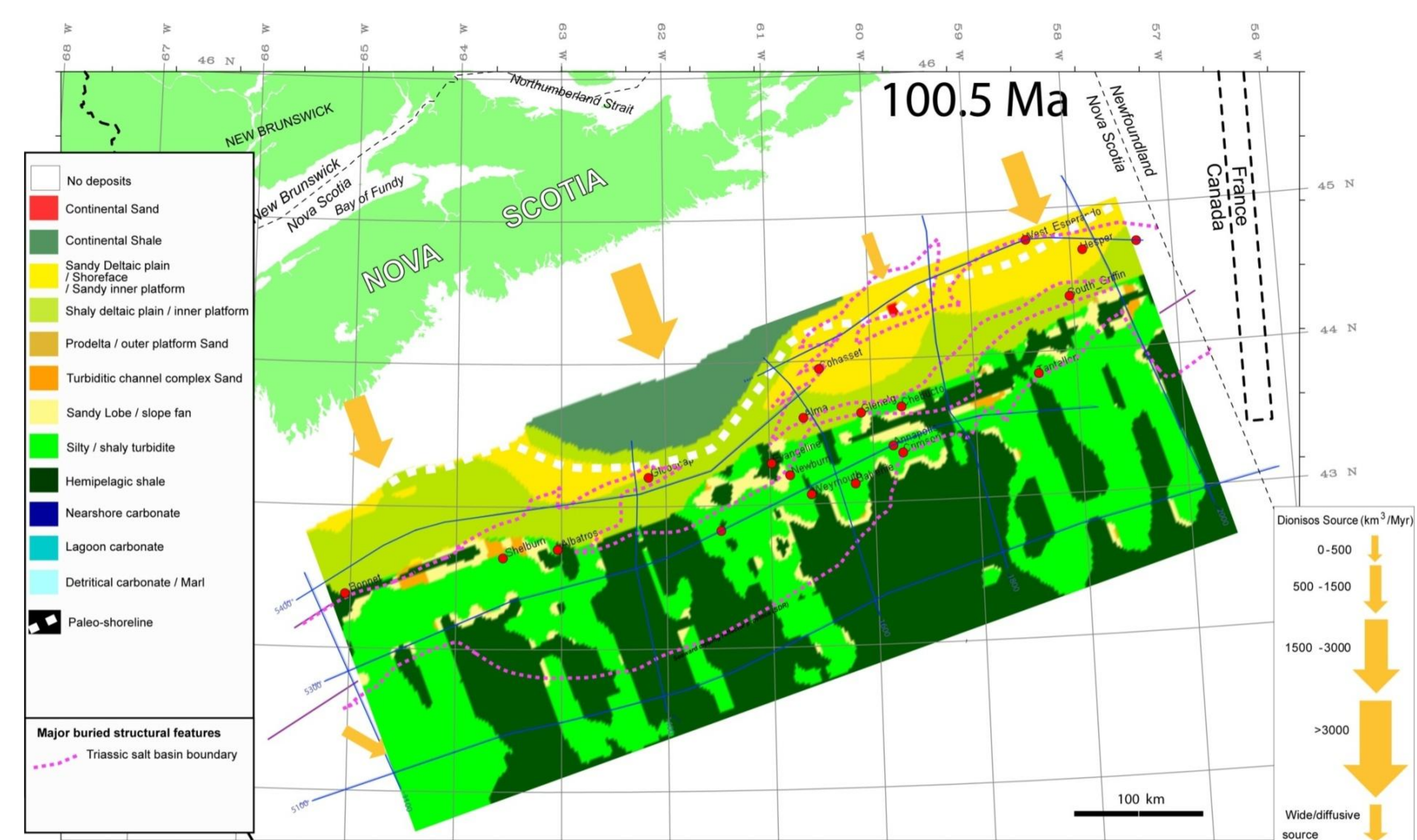


Figure 39: Dionisos simulation map @ 100.5 Ma

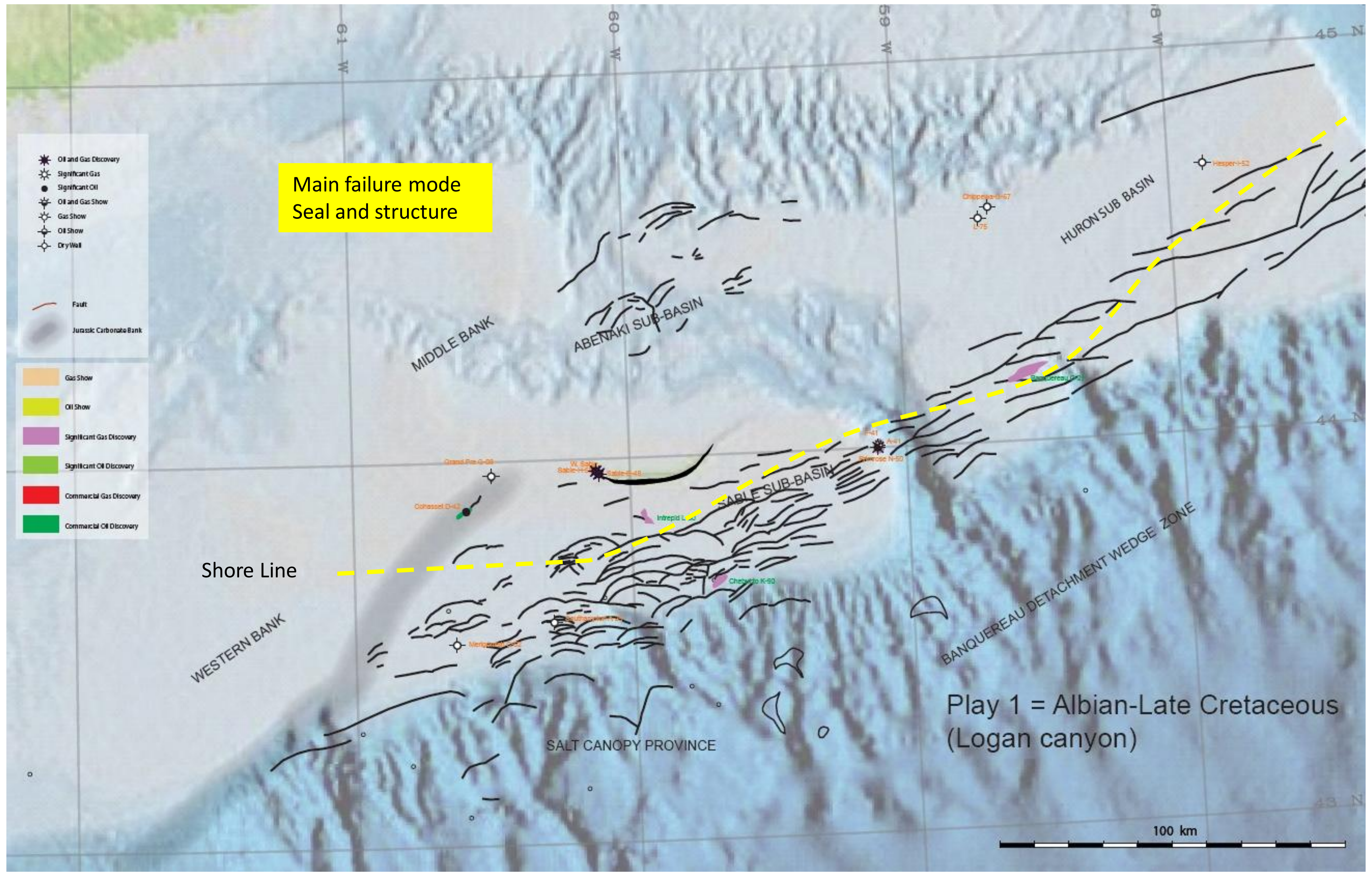


Figure 40: Logan Canyon - Faulting

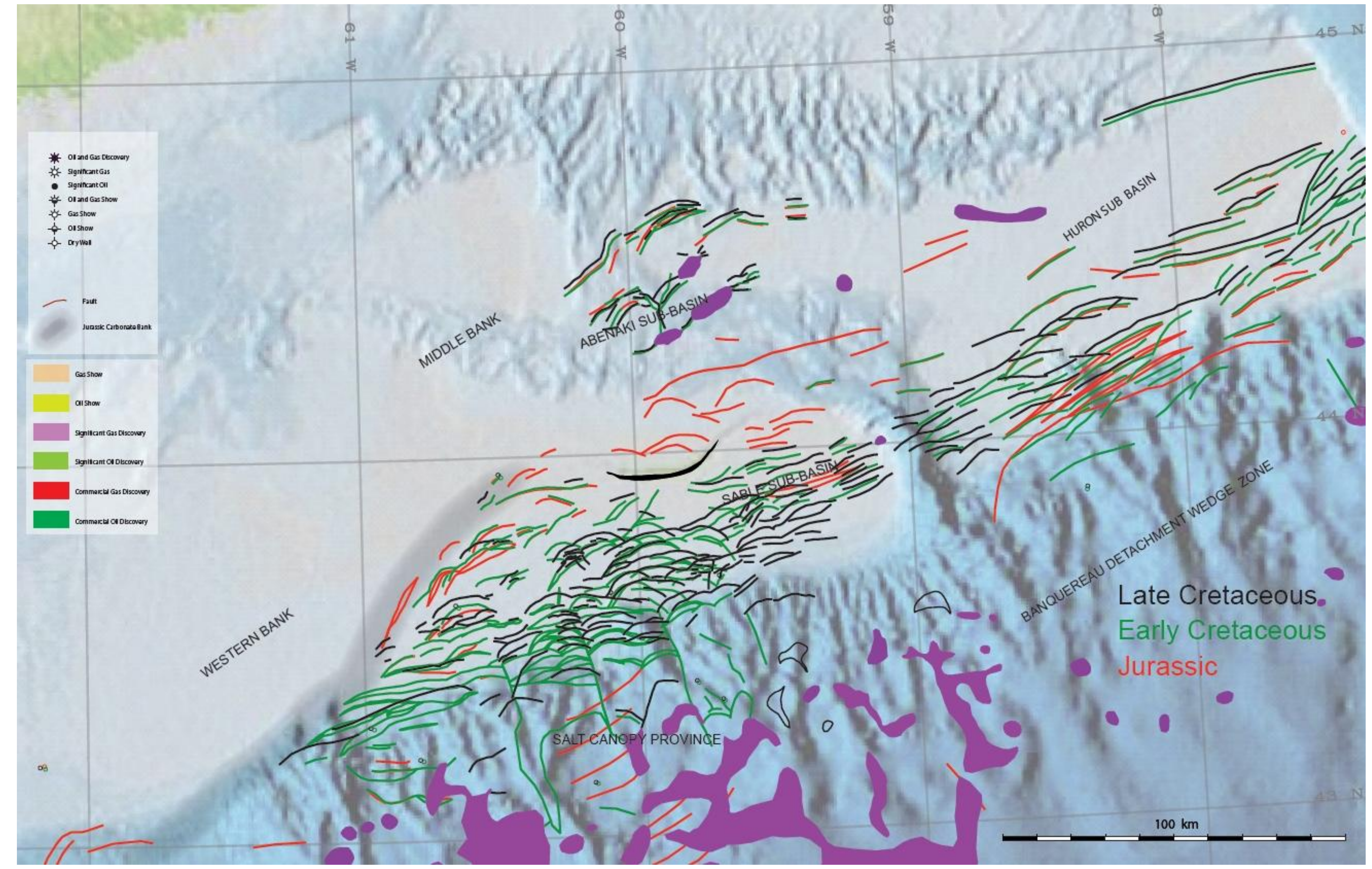


Figure 42: Faulting and salt structures

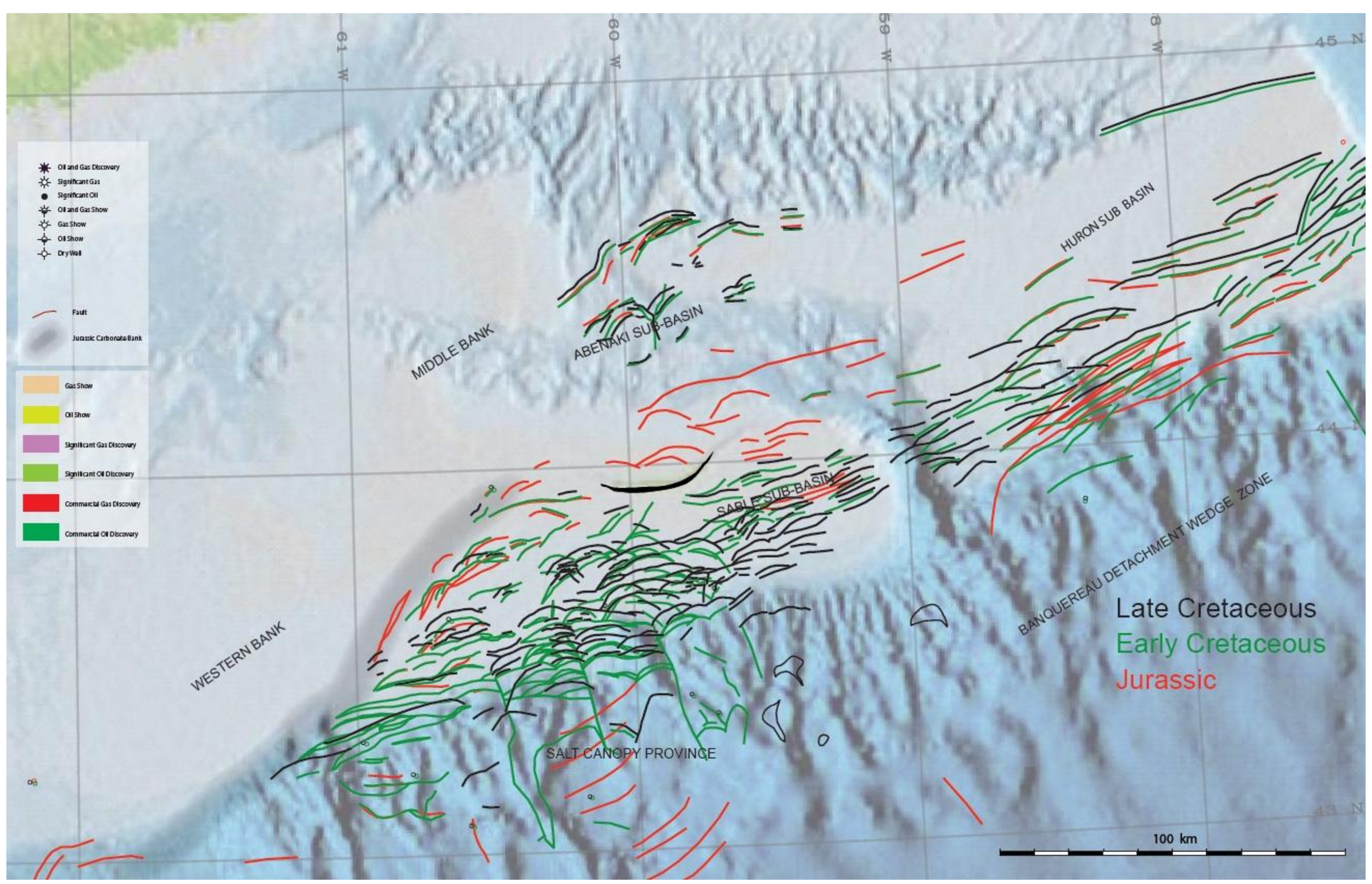


Figure 41: Three (3) stages of faulting

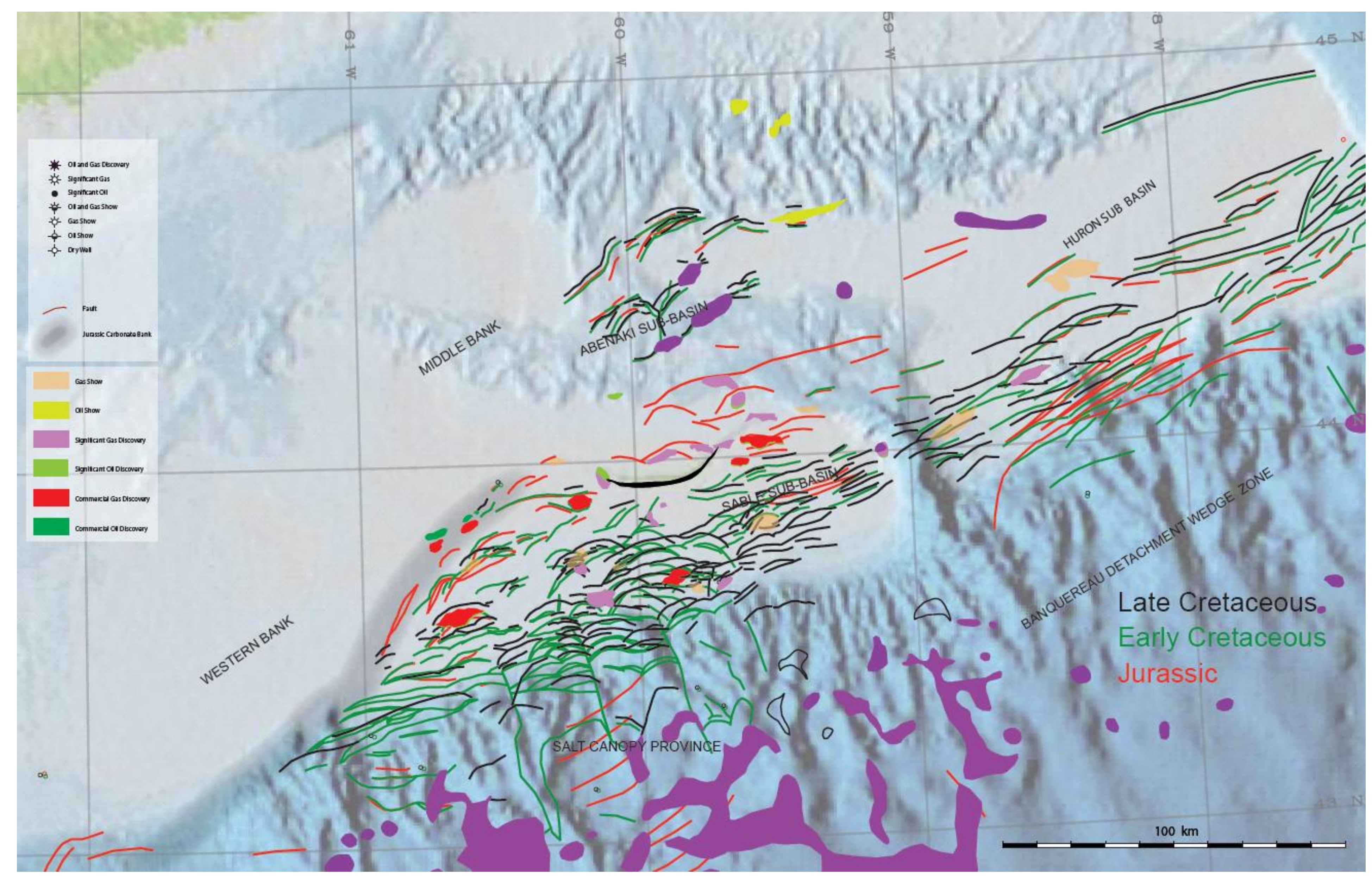


Figure 43: Faulting, salt structures and distribution of fields

Logan Canyon Play Tests – Seal & Faults

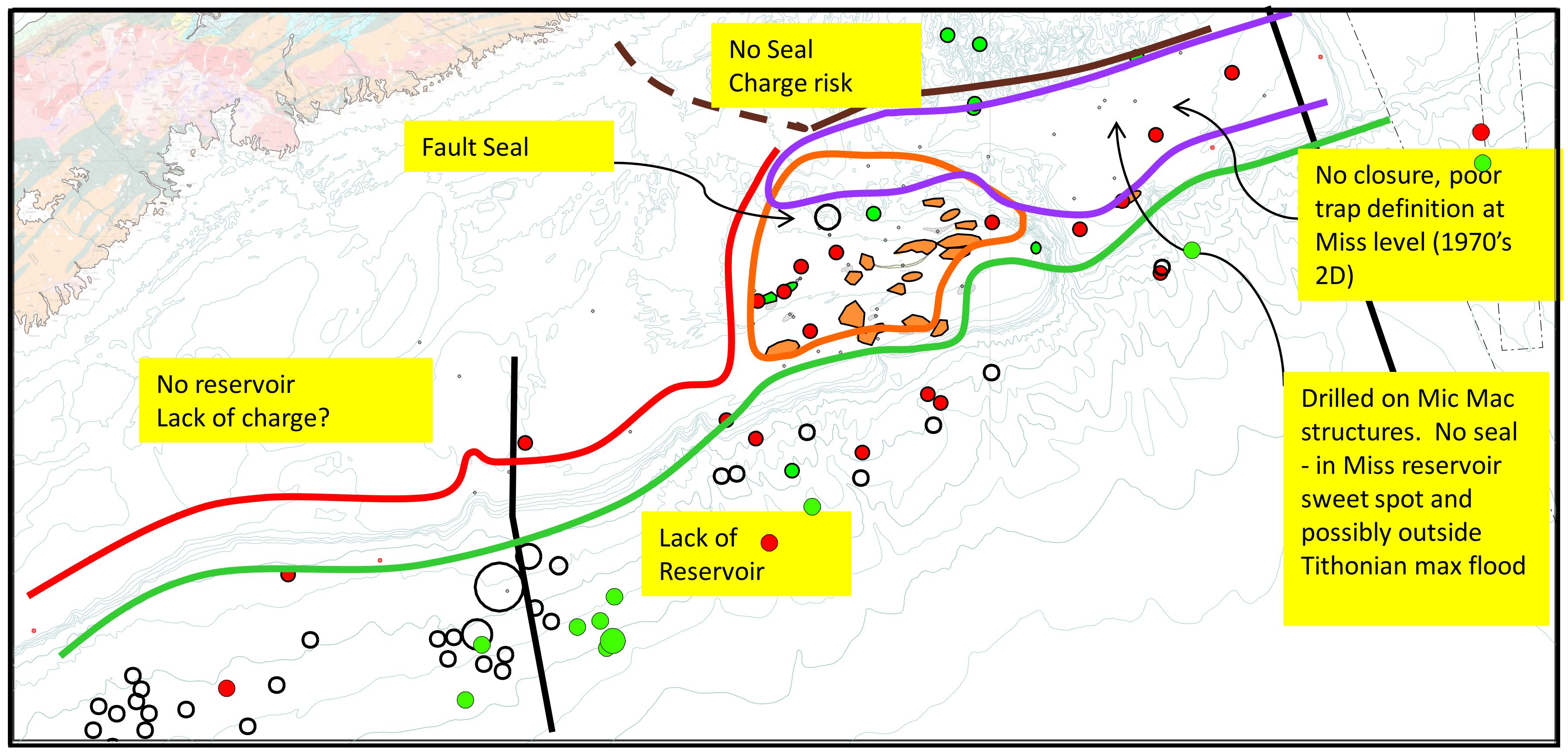


Figure 44: Main well failure modes

Conclusion

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.