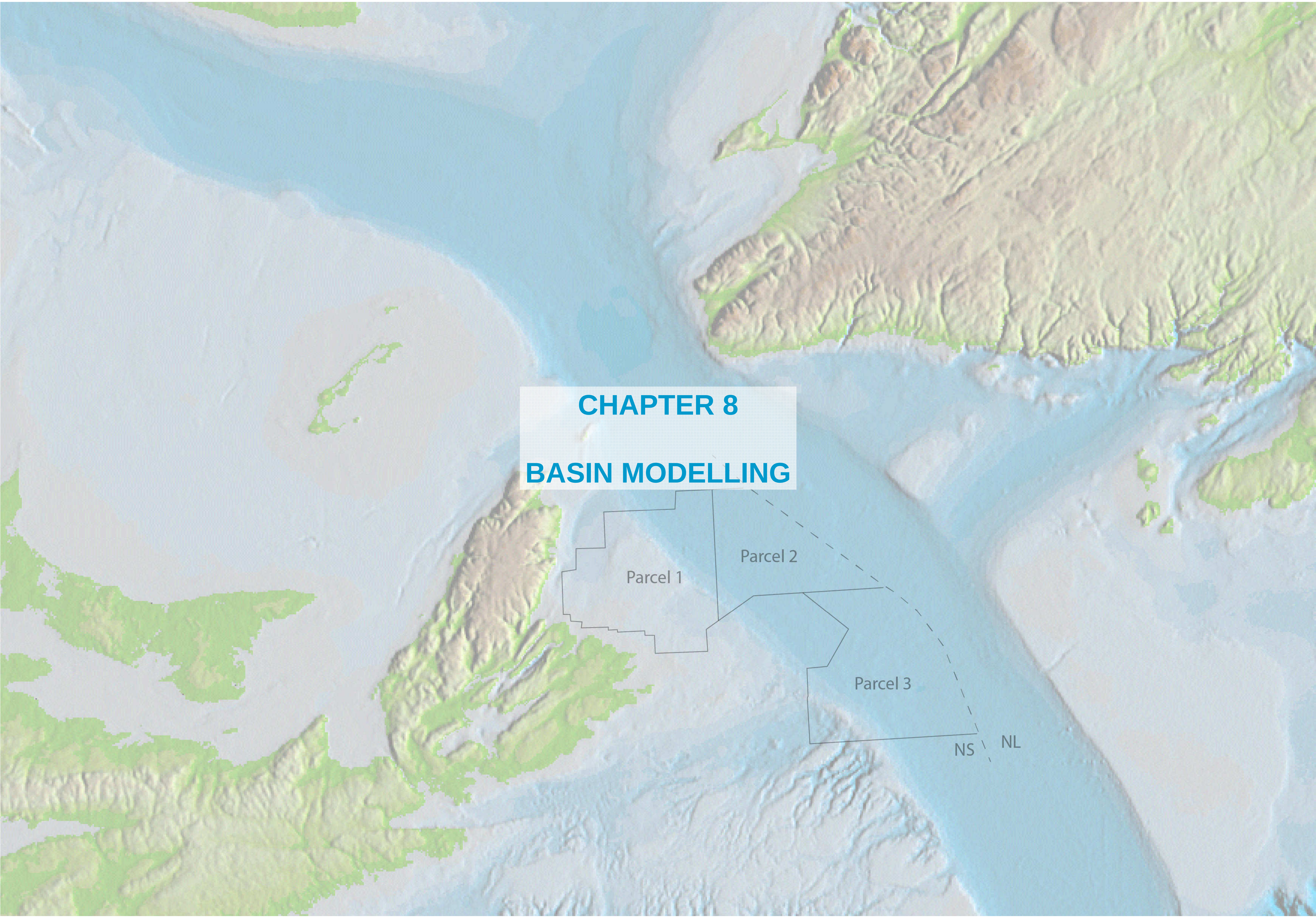
CHAPTER 8

BASIN MODELLING



Principles and Workflow

General Principles and Workflow:

Basin modeling is numerical forward modeling of physical and chemical processes in sedimentary basins over geological time spans. Based on the geometrical reconstruction of sedimentary basins, it simulates and predicts the thermal regimen and fluid flows (water and hydrocarbons) through time in order to assess source rock maturity, pore pressure and hydrocarbon charge. The main objective of basin modeling is to estimate exploration risk for hydrocarbon charge by testing various assumptions regarding source rock characteristics, impact of faults, lithofacies, permeability, etc.

The first step of basin modeling is geometrical reconstruction, a 3D structural restoration (generally vertical shear displacement) that takes into account internal stratigraphic architecture, eroded thicknesses, paleo-bathymetries, lithofacies distribution and their associated compaction laws. The structural and facies models depict static petroleum system elements such as source rock, reservoirs, seal and traps. The reconstruction defines burial and porosity/permeability evolution, drainage areas and migration pathways.

The second step addresses thermal regime history and maturity calibration. It provides a first estimate of the basin's hydrocarbon potential by estimating hydrocarbon mass expelled through time. The thermal model is constrained at the base with lithospheric characteristics (geometrical and radiogenic heat production) and at the top with a definition of paleo-temperature. The present day thermal regime is calibrated using well temperatures while the past thermal regime is calibrated on maturity indicators (generally vitrinite data).

The third step of basin modeling is fluid flow simulation and calibration of hydrocarbon accumulation. Hydrocarbon migration is driven through a generalized Darcy law that takes into account permeability, relative permeability, viscosity, hydrodynamism, capillarity and buoyancy. As a consequence, hydrocarbon migration is conditioned by internal stratigraphic architecture, lithofacies distribution and water pressure gradient (hydrodynamism). Calibration consists in recreating hydrocarbon accumulations known in the basin (and even shows and seeps) in order to be predictive.

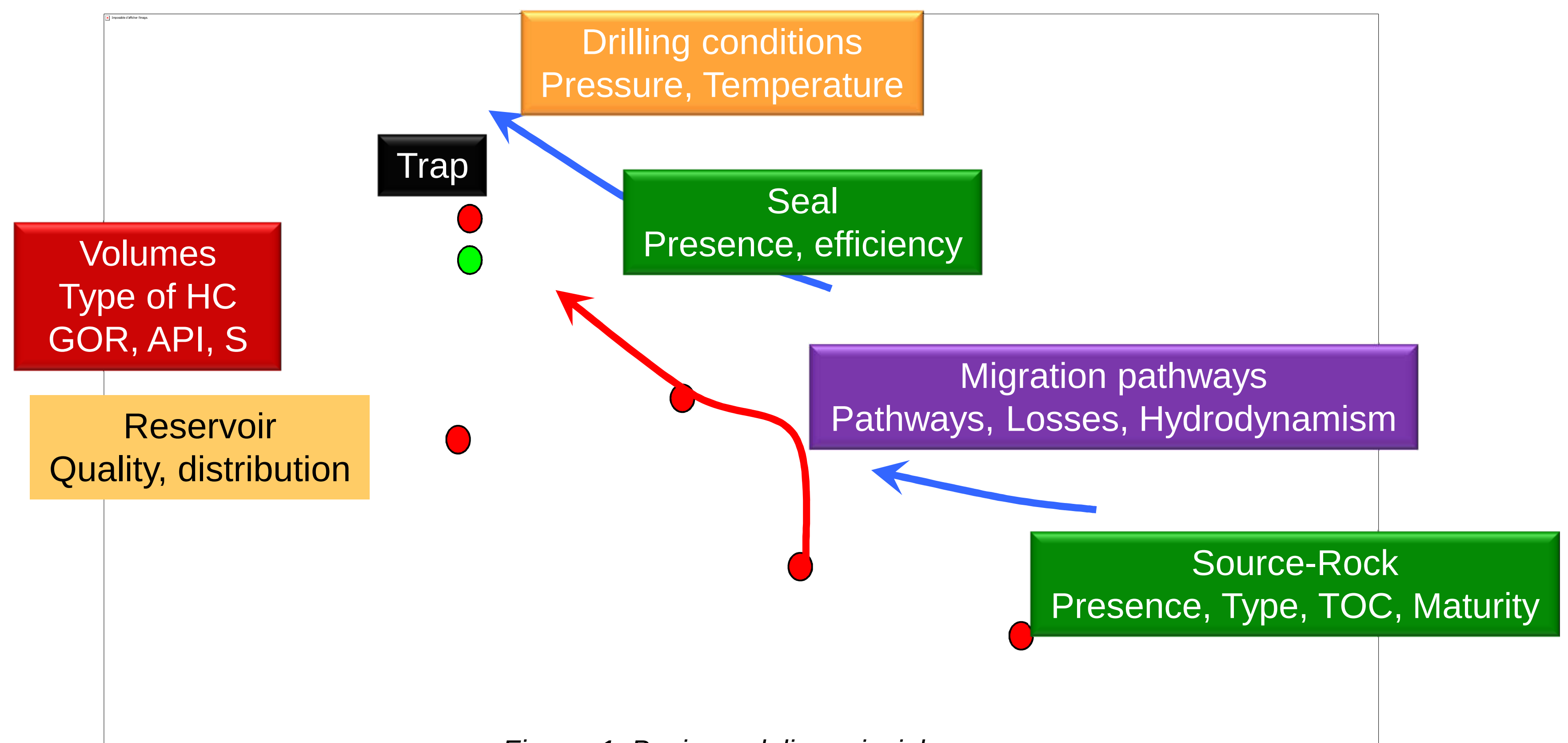


Figure 1: Basin modeling principles

Workflow

Main Inputs

Model Construction

Structural maps of tectono-sequences

Lithosphere geometry

Eroded thickness maps (major erosion)

Paleobathymetry maps

Lithofacies distribution (GDE)

Source rock characteristics (TOC, HI, net thickness, kerogen type)

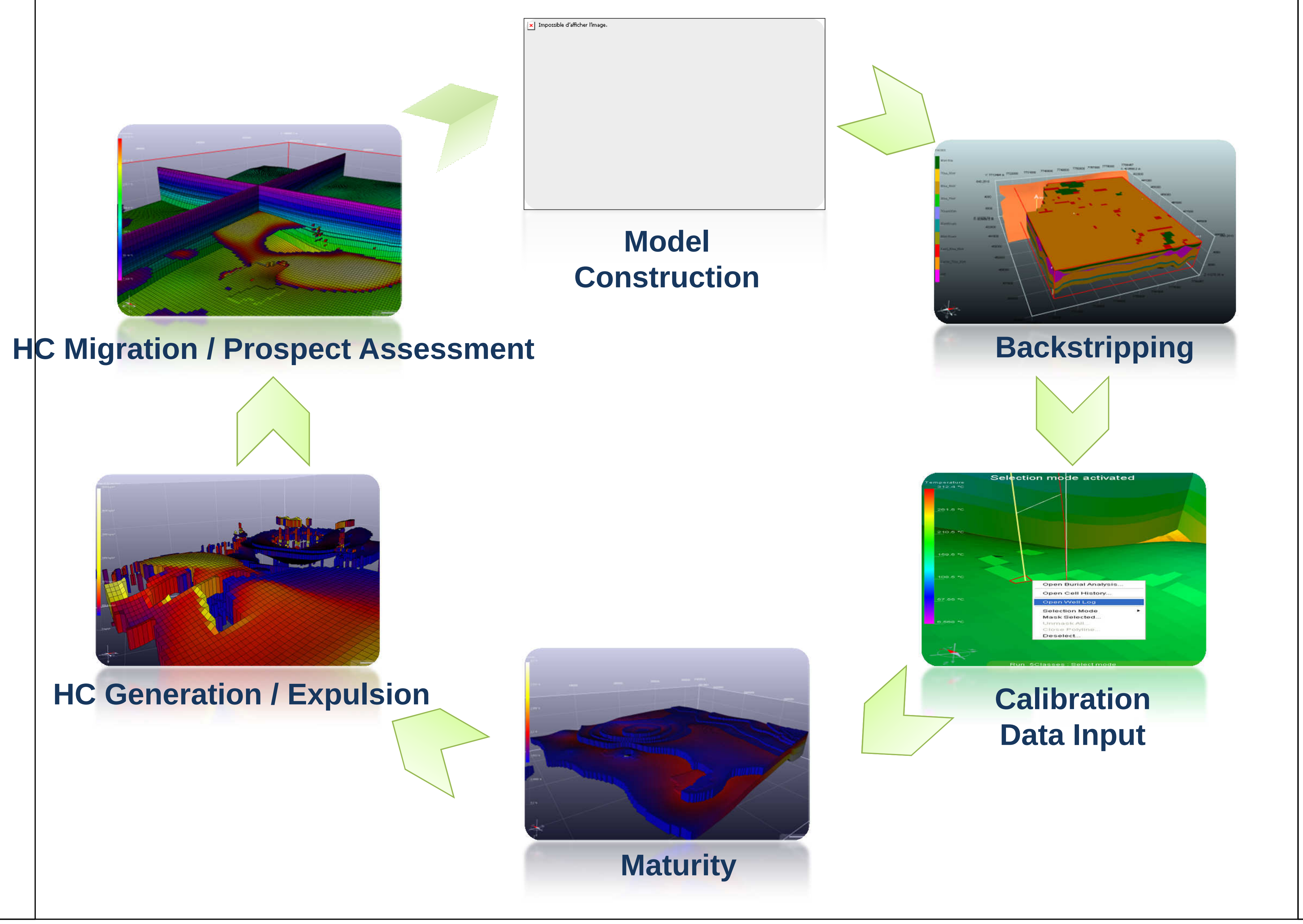
Calibration Data

Average Porosity/Permeability

Maturity: Vitrinite Reflectance, SCI (spore color index), TAI (thermal alteration index), Tmax, AFTA (appatite fission track)

Pore-Pressure: Direct measurements: RFT (repeat formation tester), MDT (modular dynamic tester), DST (drill stem tester). Indirect measurements: mud weight, petrophysical methods, seismic interval velocities, etc.

Hydrocarbon fluids and field volumes



Main Ouputs

3D basin temperature and heat flow history

3D basin pore-pressure

Source rock maturity and timing (Ro and TR)

Hydrocarbon volume expulsion

Hydrocarbon migration pathways

Hydrocarbon mass and volume trapped

Fluid type (oil, condensate and gas),

API°, GOR, BO

Hydrocarbon volumes and fluid components in place (reservoir condition) and in standard condition (surface)

Etc.

Figure 2: Basin modeling workflow

CHAPTER 8.1

INTRODUCTION

Introduction

Objectives:

Sydney Basin is an under-explored Carboniferous basin with only three exploration wells (F-24 and P-05 located north of Sydney, NS and P-91 near Saint-Paul Island). In this context, the basin modeling objective was to assess the basin's hydrocarbon potential. The aim was to identify leads and to estimate associated risks. To do so, basin modeling will, first, evaluate source rock maturity, timing and hydrocarbon quantity expelled, and secondly, hydrocarbon volume in place, fluid types (oil, gas and components) at standard condition if hydrocarbon accumulations exist.

This 3D basin model is based on sedimentological, petrophysical and structural analyses done earlier in this study and detailed in previous chapters. It simulates and predicts thermal regimen, pore-pressure, hydrocarbon migration pathways and trapping.

In this study, one of the main challenges was to assess if large hydrocarbon accumulations could be preserved until present day. The long time period required for preservation of resources is a risk that needs to be tested in a dynamic migration modeling tool. Only advanced Darcy flow migration modeling can address this question, and is the reason why the Temisflow software was selected.

Tool: TemisFlow™

The IFP Group pioneered the development and use of Petroleum System Analysis and Basin Modeling techniques in the late 1980's. These techniques include the modeling of burial, thermal history, oil and gas generation and migration processes with the TemisFlow technology. TemisFlow is the leading industrial tool in its domain, widely used by oil and gas companies and consulting firms around the globe. With a long proven track record, TemisFlow is the next-generation solution for basin modeling. It excels in assessing regionally-controlled petroleum systems while identifying local drilling opportunities and quantifying the associated commercial and technical risks. (*http://www.beicip.com/basin-modeling-and-petroleum-system-analysis*).

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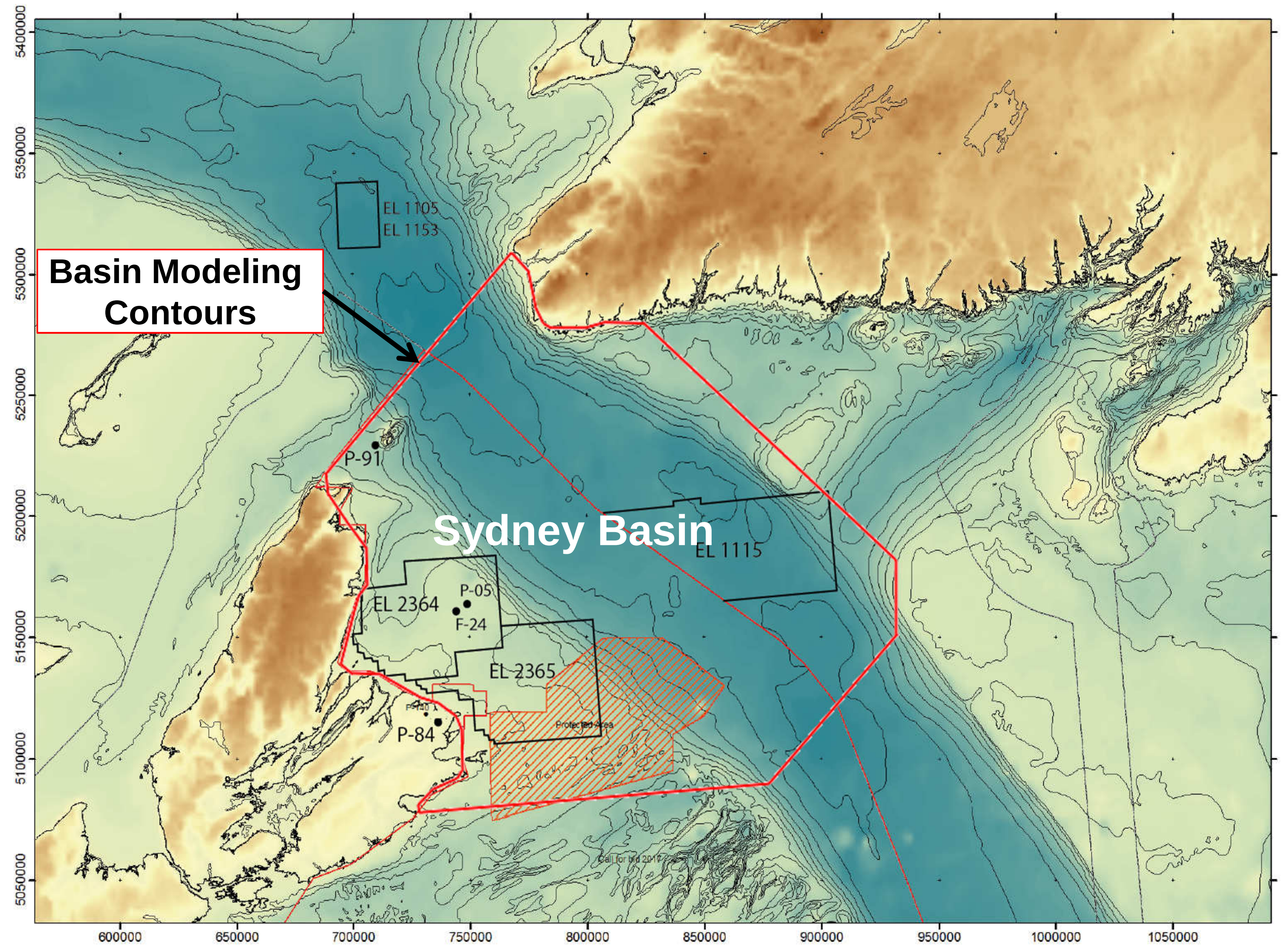


Figure 3: Basin modeling study area contours

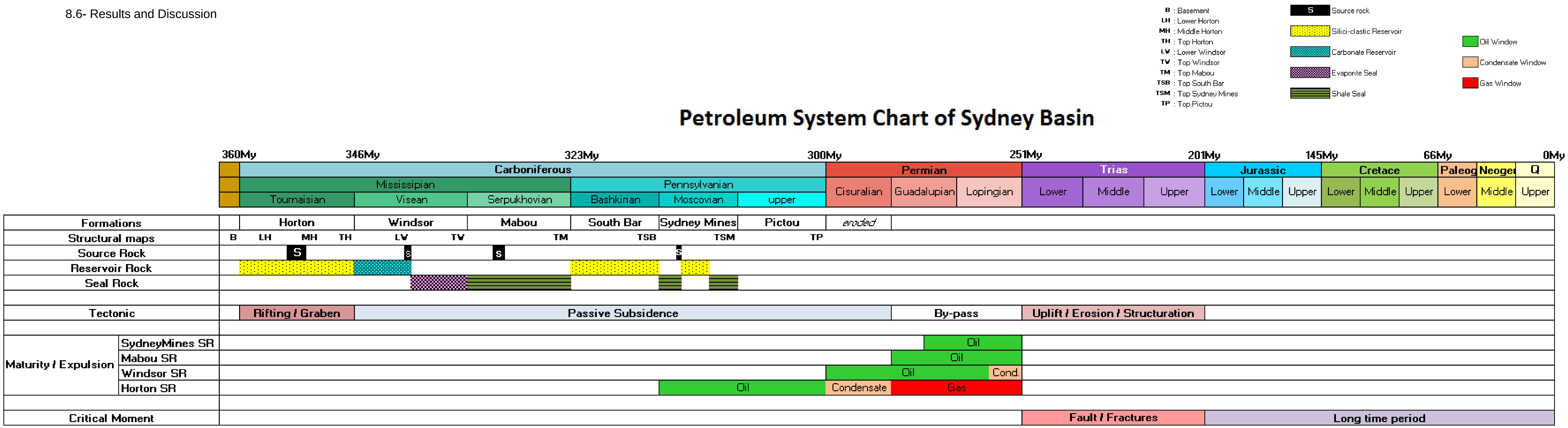
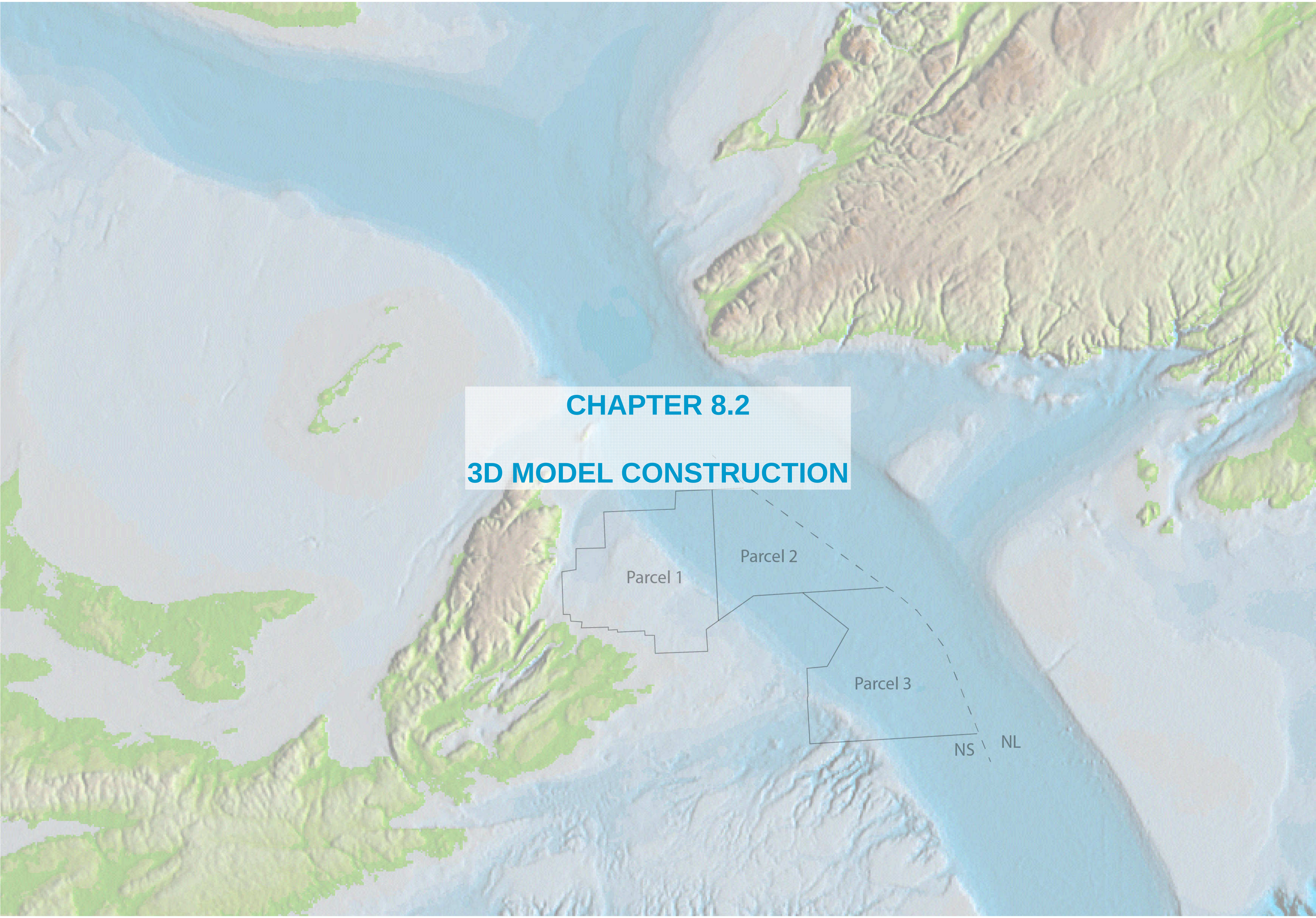


Figure 4: Petroleum system chart of Sydney Basin (based on this study)

CHAPTER 8.2

3D MODEL CONSTRUCTION



3D Model Construction

Structural Model:

The Temisflow structural model was built from seismic horizons (structural maps in depth (m)), paleo-bathymetries and the Triassic eroded thickness map. Internal stratigraphic architecture (between two horizons) was defined to incorporate source rock layers and maps derived from numerical stratigraphic modeling (Dionisosflow). Grid cell size resolution is 1x1km.

- Structural maps are based on the 2D seismic line interpretations (*Fig.1, Chapter 5*) and cover the entire study area. The depth maps are the foundation of the 3D model architecture for basin modeling. Horizon ages originate from the stratigraphic interpretation (*Fig.1, Chapter 3*).
- Paleo-bathymetries maps were defined using thickness maps and elevations were accentuated during the Triassic uplift event.
- The Triassic eroded thickness map (Figure 7) was estimated from the maturity model (Temisflow) at well locations and mapped using preserved sediment thickness maps (Pictou and Sydney Mines sequence). Uplift is related to the Atlantic ocean rifting and dated from a tectono-stratigraphic analysis and AFTA analysis (Ryan and Zentilli, 1993).

Facies Model:

Lithofacies distribution maps are GDE maps derived from sedimentological analysis (Chapter 6) and numerical stratigraphic modeling (Chapter 7). Only the Windsor interval comes from the numerical stratigraphic model. Special attention was placed on modeling the Windsor interval because its sealing capacity was identified as a key parameter for hydrocarbon preservation in the Horton play.

- Sedimentological analysis, based on outcrop and well data, defined eight (8) GDE maps: three (3) for Horton, two (2) for Windsor, one (1) for Mabou, one (1) for South Bar and one (1) for Sydney Mines.
- The numerical stratigraphic model (Dionisosflow) predicted facies distribution for the Windsor interval. Three (3) GDE maps (lower, middle and upper Windsor) were extracted from the model to improve the internal stratigraphic architecture and facies distribution.

Related lithofacies properties such as compaction and porosity/permeability laws were calibrated to measurements at well locations and from outcrop data (Chapter 3). Petrophysical parameters were adjusted to take into account upscalling effects.

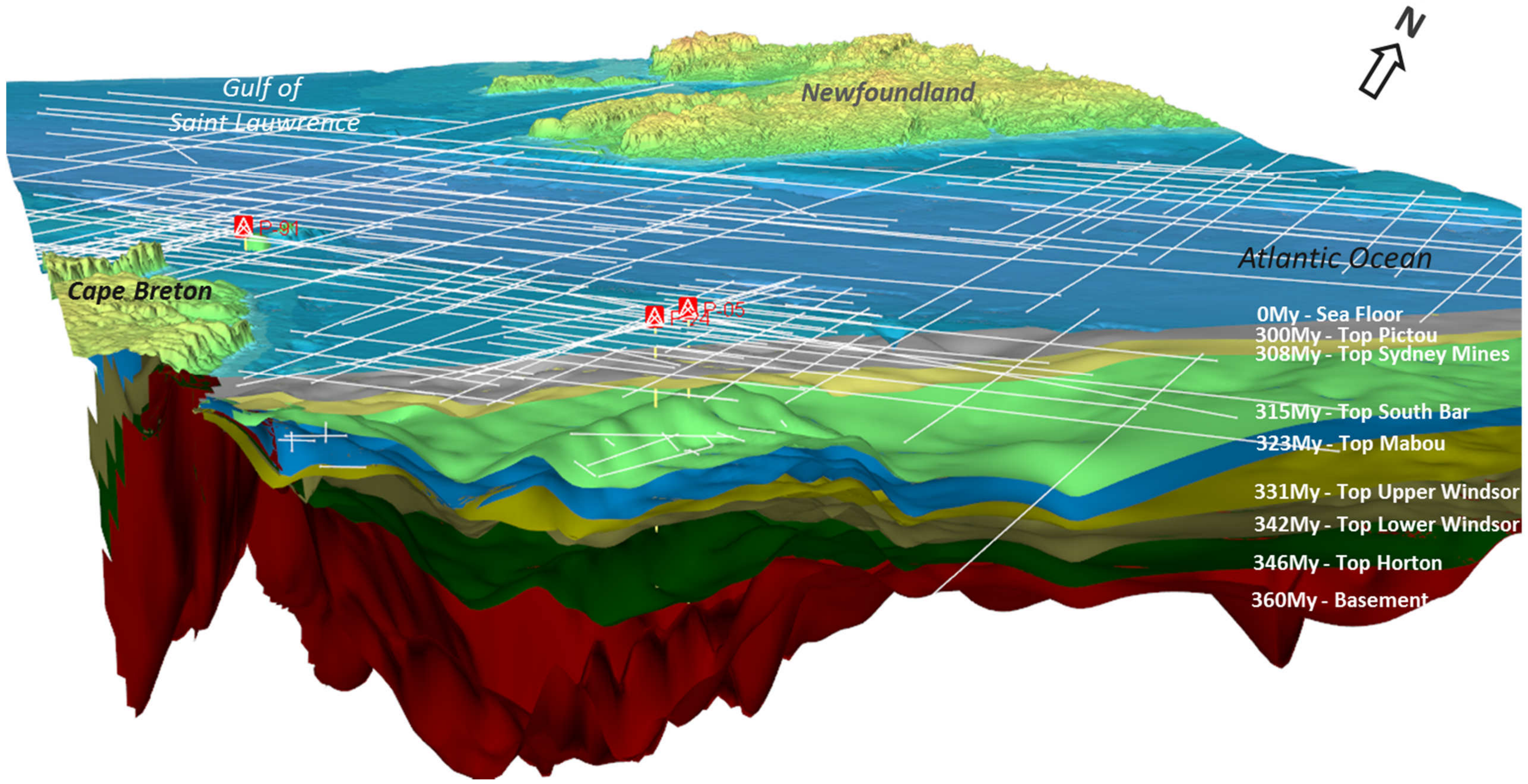


Figure 5: 3D view of structural maps showing the locations of wells and 2D seismic lines

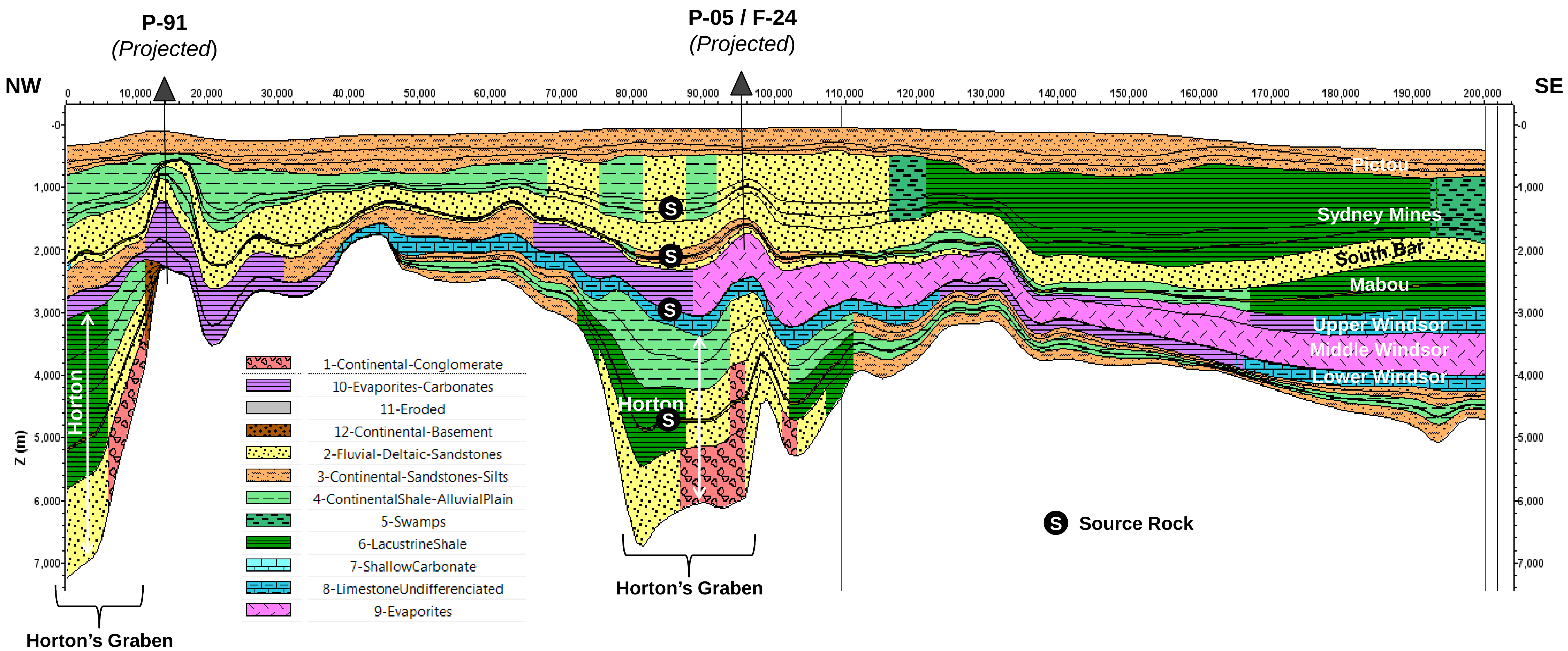


Figure 6: NW-SE cross-section showing layering and facies distribution

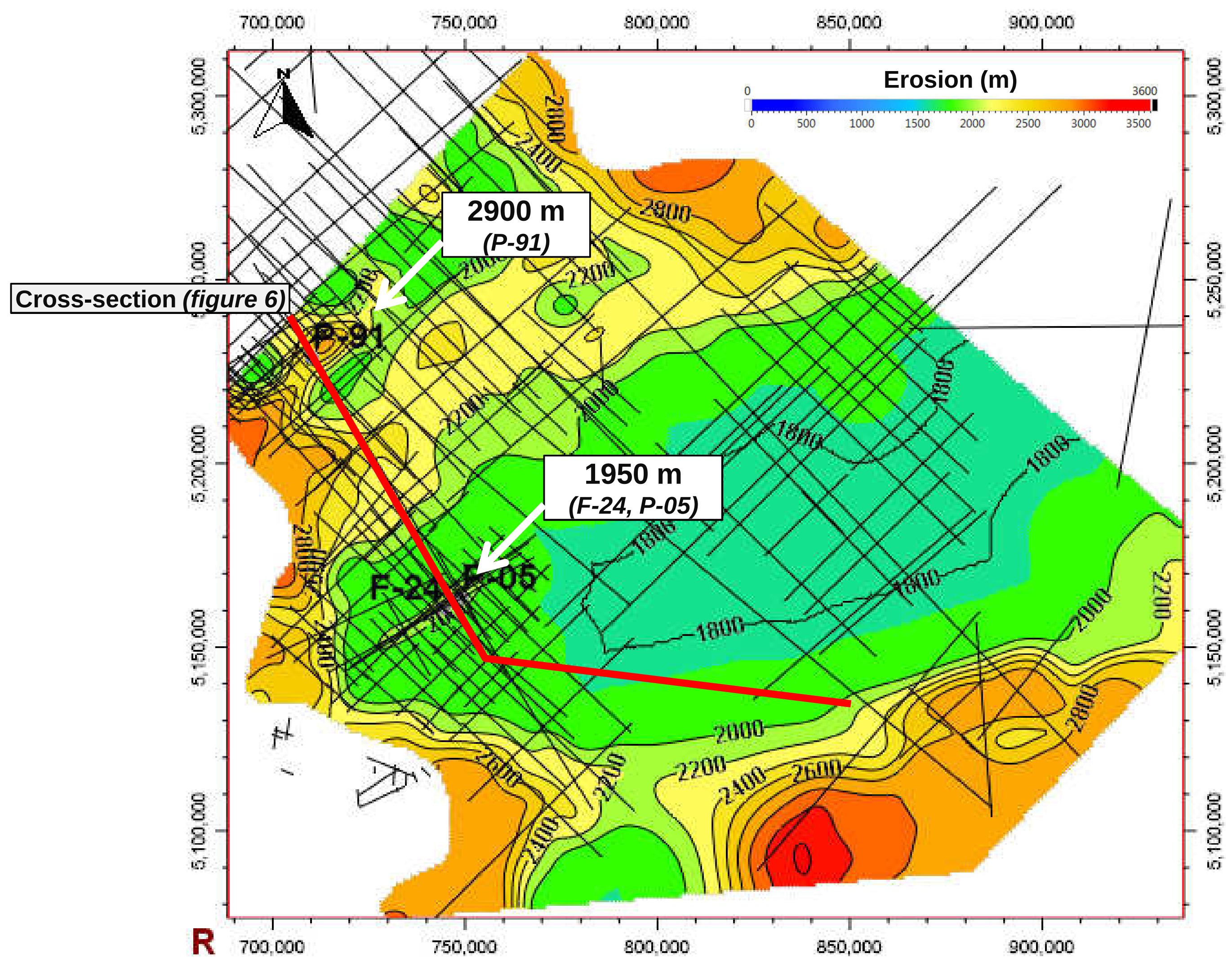
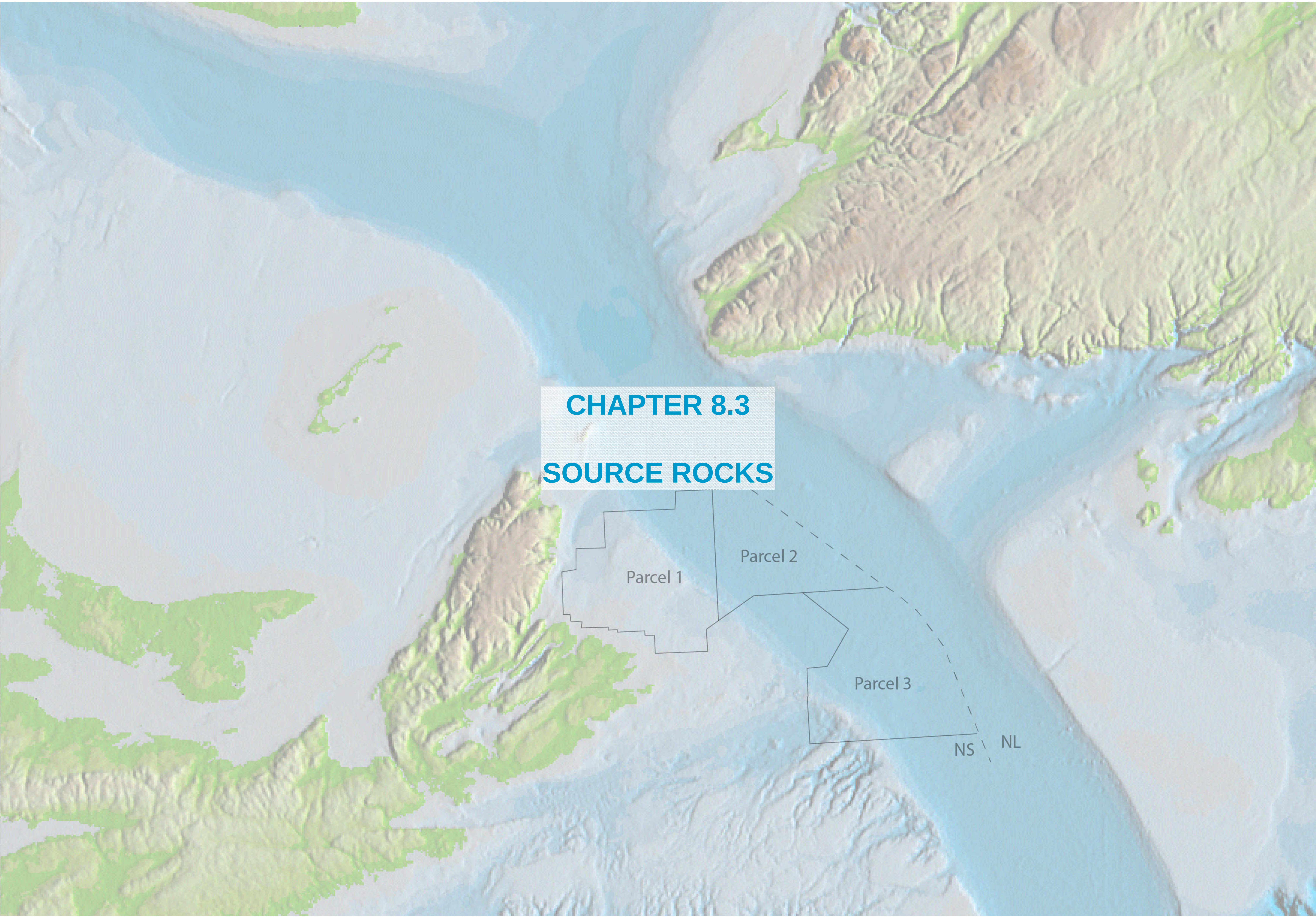
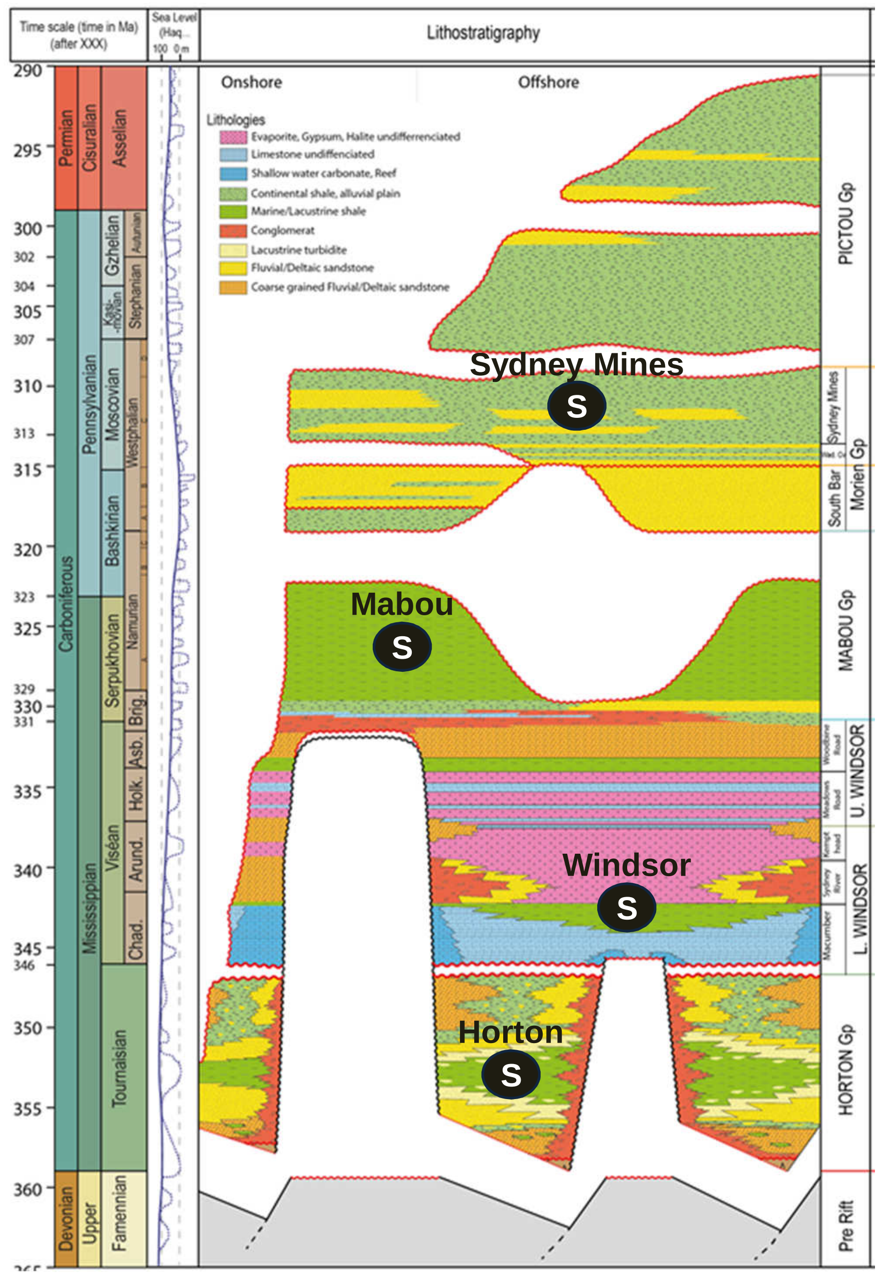


Figure 7: Triassic eroded thickness map

CHAPTER 8.3

SOURCE ROCKS





S Source Rocks

Sydney Mines source rock: The Sydney Mines Formation hosts organic rich intervals associated with calcareous shale and coals in a meandering floodplain and shallow lake environment. Hydrocarbon potential is excellent but is of very limited thickness (only 1m effective thickness in the onshore). TOC ranges from 6 to 25% and HI from 200 to 660 mgHC/g (Fowler, M., Webb, J., 2017, Smith & Naylor, 1990; Gibling & Kalkreuth, 1991). A thicker Sydney Mines interval could be expected offshore. A conservative effective thickness of 6m has been chosen, with a TOC of 10% and an HI of 450 mgHC/g in a type III/II kerogen.

Mabou source rock: The Mabou Group is largely dominated by fine grained clastic deposits in a humid environment with some rapid marine transgression where lean organic shale layers were deposited. Indeed, well F-24 highlights an effective thickness of about 30m with an average TOC of 2.5% and an HI of 150 mgHC/g. Kerogen is expected to be type III/II according to the deposit environments and HI/OI graph. Vitrinite data (Ro 0.95%) shows that source rock is mature and suggests a higher initial HI.

Lower Windsor source rock: The Windsor interval exhibits an important marine influence with carbonate and evaporite deposits. Marine organic-rich intervals with terrestrial influences were deposited in the lower Windsor Formation (Mossman, 1992; Fowler and Webb, 2017). Several samples from onshore Nova Scotia (KH-1, M-3 wells) suggest a TOC range from 1.2% to 2.6% with HI around 200mgHC/g and a cumulative effective thickness from 10 to 50m. Higher source rock potential could be expected in the offshore portion of the basin.

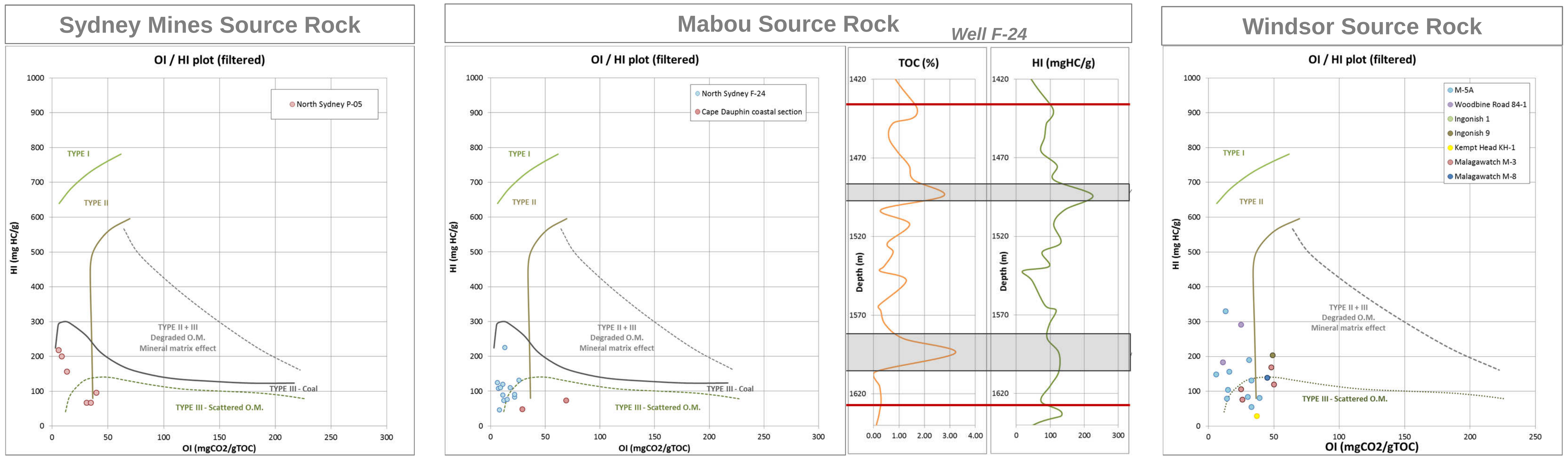


Figure 8: HI/OI graphs for Sydney Mines, Mabou and Windsor source rocks

Horton source rock: The Horton Formation is contained in a half grabens where sediments were deposited in lacustrine environments with marine incursions trapping thick, rich organic matter. Samples from Nova Scotia in analogous grabens (Big Marsh (Antigonish Basin), Upper Falmouth (Minas Basin), Lake Ainslie and Malagawatch areas) show oil prone shales with type I to type II signatures (Fowler, M., Webb, J., 2017, Smith and Naylor, 1980). Excellent potential of oil prone type II and type I organics was measured in Cape Saint-Laurent, and samples from the Bay Road quarry host rich aliphatic organic matter associated with lacustrine samples. Here below, the graph Tmax/HI as well as the graph OI/HI show mixed kerogen with a large type II and I components. Extrapolation of initial HI tends to around 650 mg/g of HC. TOC log and HI at Big Marsh location allows to estimate 65m of net thickness, average TOC of 6%. As a consequence, Horton source rock was considered to be present in half graben only in the model with 50m net thickness, TOC of 7% and initial HI of 650 mgHC/g in a mixed type II / I kerogen.

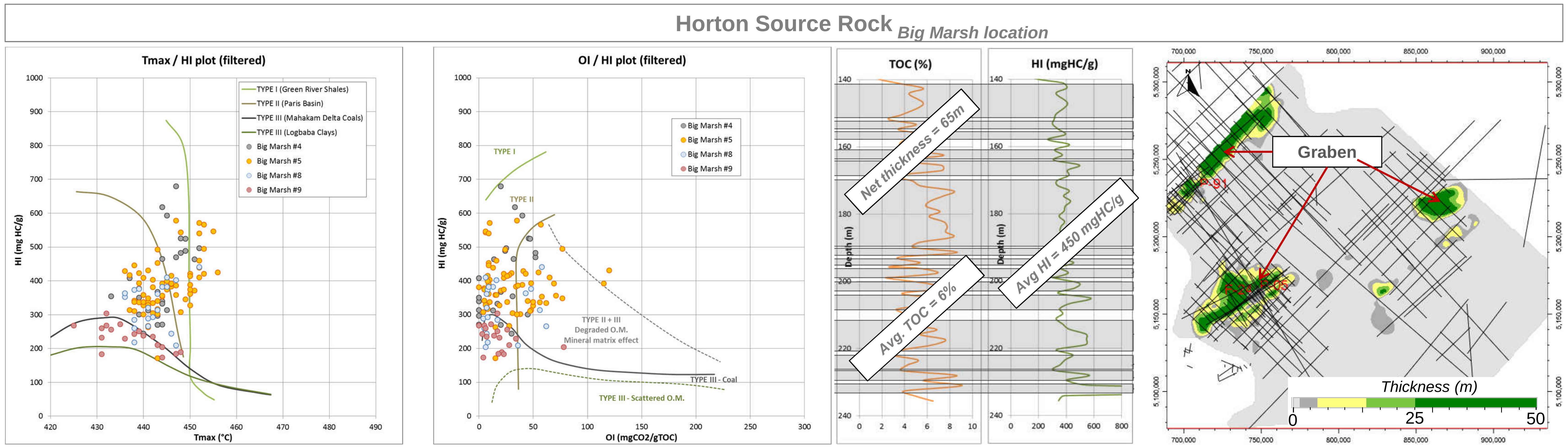
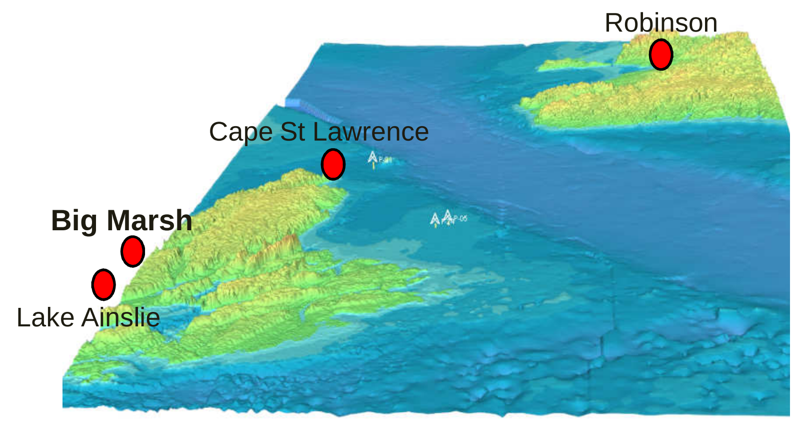
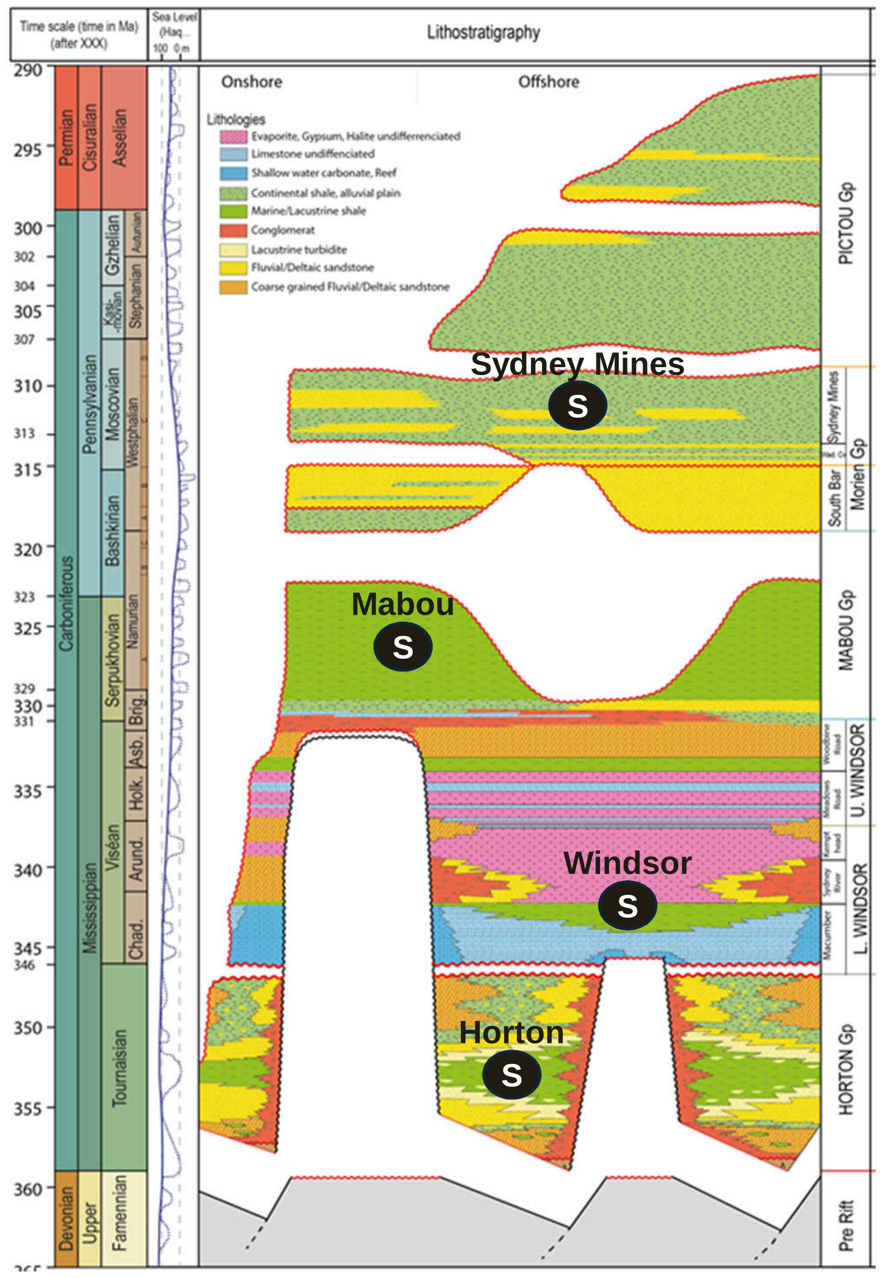


Figure 9: HI/OI graphs, Tmax/HI, Average TOC, net thickness and distribution of Horton source rock.



Data Location



S Source Rocks

The table below summarizes source rock input parameters that were considered for basin modeling. Source rock is one layer in the model and the table shows average effective thickness of each source rocks. Properties are given at initial conditions (before maturation). SPI (Source Production Index) gives source rock potential; SPI is fair above 1 t/m2, good above 3 t/m2 and excellent above 5 t/m2. According to the SPI, Horton source rock has an excellent potential whereas the other source rocks have low potential.

Source Rock	Lithofacies	Avg Effective thickness (m)	Avg TOC0 (wt%)	Kerogen type	Avg HI0 (mgHC/g)	SPI (T/m2)
Sydney Mines	Flood plain and Shallow Lakes	6 m	10%	III / II	450	**0.6**
Mabou	Organic-lean shales	30 m	2.5%	III / II	300	**0.4**
Lower Windsor	marine shales/evaporites	10 m	3%	II	500	**0.3**
Horton	Lacustrine shales	50 m	7%	I / II	650	**5.2**

SPI range
Excellent >5
Good [3-5]
Fair [1-3]
Low [0-1]
Negligible [0-0.25]

Figure 10: Table of source rock parameters

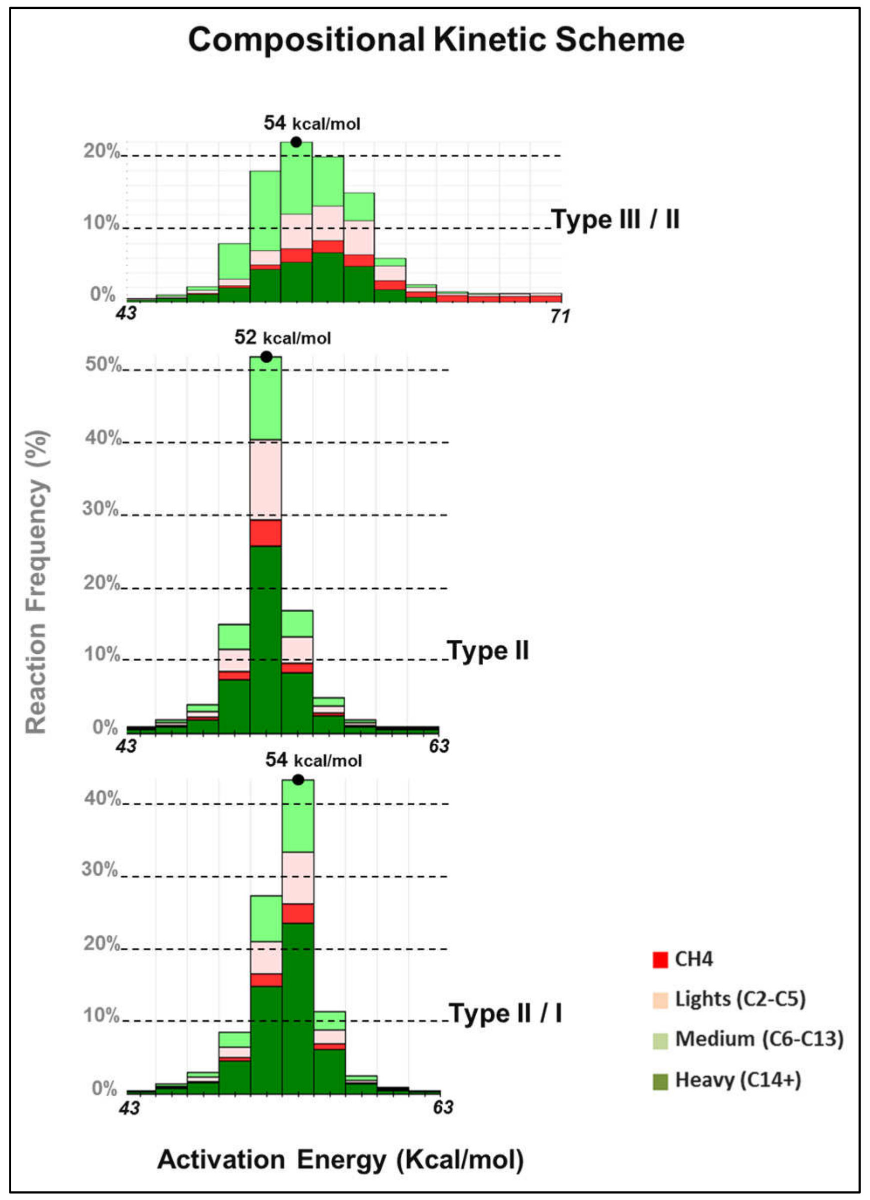


Figure 11: Histogram of source rock kinetic schemes

Source rock kinetics used for modeling are based on a source rock analogs database from the IFP library. Type III / II kerogen properties of the Sydney Mines and Mabou Formations were based on 50% ARE* and 50% Ptbeds**. Type II kerogen of lower Windsor was based on Upanema***. Type II / I kerogen of Horton was based on 50% Upanema and 50% PTBeds.

The kinetic scheme of each source rock is detailed below. The histogram shows reaction frequency (thermal cracking) as a function of activation energy (temperature) and associated products from kerogen (Heavy (C14+), Medium (C6-C13), Light (C2-C5) and Methane (CH4)).

The graph below shows the source rock transformation rate as a function of temperature for each source rock and for reference examples (Type I (Upanema), Type II (PTBEds) and Type III (ARE)).

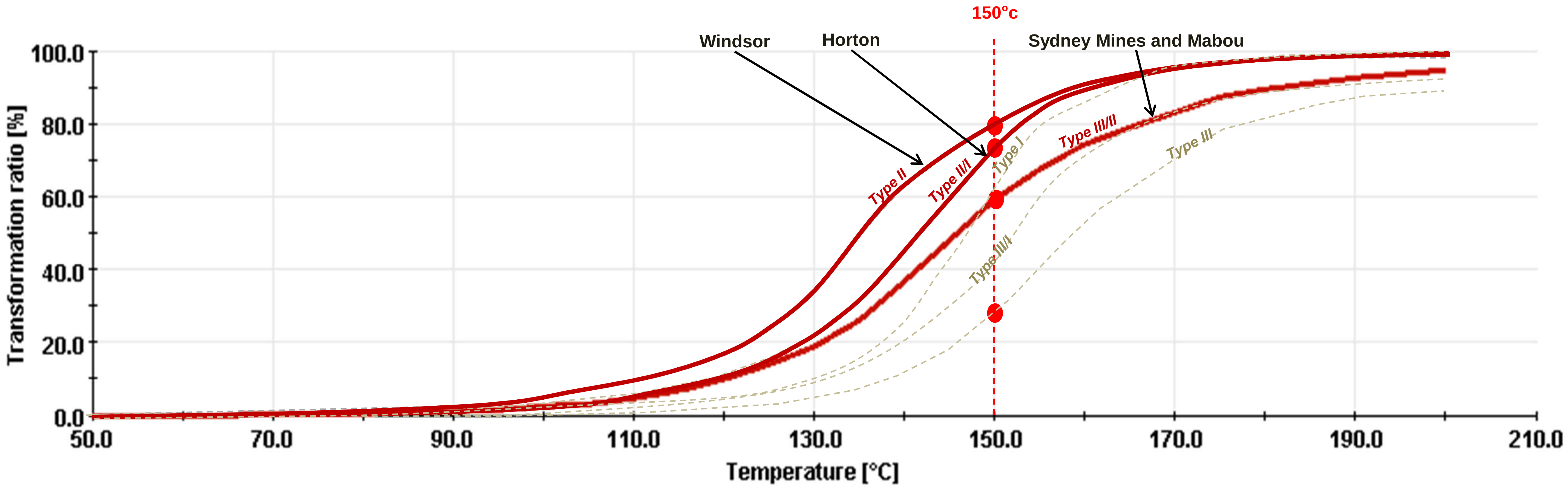


Figure 12: Graph of source rock transformation rate as a function of temperature

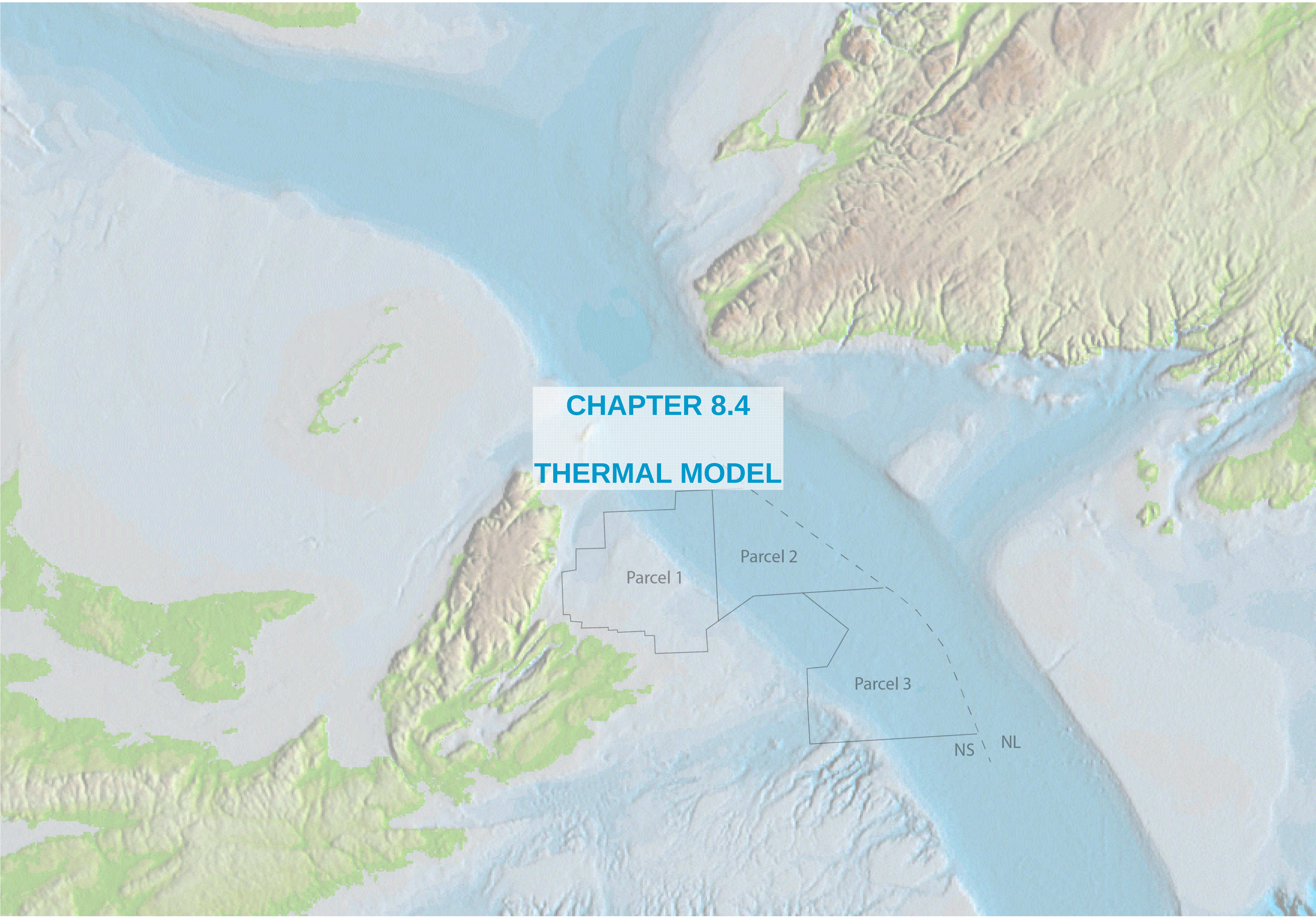
* ARE (type III): Dogger. North Sea - Open system kinetics - Ungerer 1990 (Org. Geoch. vol 16) - Elemental analysis derived from the IFPen database and Vandenbrouke et al. 1999 (Org. Geoch. vol 30)

** PTBeds (type II): Aptian. Brazil - Open system kinetics - Penteado et al. 2007 (Org. Geoch. vol 38) - Elemental analysis not available

*** Upenama (Type I): Aptian. Brazil - Open system kinetics - Penteado et al. 2007 (Org. Geoch. vol 38) - Elemental analysis derived from Penteado et al. 2007 (Org. Geoch. vol 38).

CHAPTER 8.4

THERMAL MODEL



Thermal Model Inputs and Calibration

The history of the sedimentary basin thermal regime is constrained by the properties and thickness of the mantle, lower crust and upper crust at the base, and by surface temperature and paleo-surface temperature at the top.

Crustal Model

Upper and lower crust thicknesses are estimated to be 14km each from gravity and magnetic analysis (PL 4.1.2, Chapter4).

Radiogenic heat production values are taken from the Temisflow library and indicate a major contribution from the upper crust (3.5 10^{-6} w/m²), minor from the lower crust (0.4 10^{-6} w/m²) and no contribution from mantle.

The total lithosphere thickness estimate is based on published regional data (Mooney, 2015) and was adjusted to 138km using well temperature data (wells P-91, F-24 and P-05).

Paleo-Surface Temperature

Paleo-surface temperature was defined from paleo-climate combined with the paleo-latitude evolution of Sydney Basin (www.paleolatitude.org). The paleo-climate graph (Wygrala, 1989) gives mean surface temperature as a function of age and latitude. The evolution of Sydney Basin's latitude was plotted on the paleo-climate graph to extract the evolution of basin surface temperature.

Temperature and Maturity Calibration

Basin temperature and maturity have been calibrated with wells P-91, P-05 and F-24. Vitrinite data show a higher maturity state compared to the present thermal regime. We interpret maturity state as the result of a higher burial state condition before the Triassic uplift. Basin modeling simulation estimates the eroded thickness to be around 2km at the locations of wells P-05 and F-24, and 3km at well P-91 (see eroded thickness map above, Figure 3).

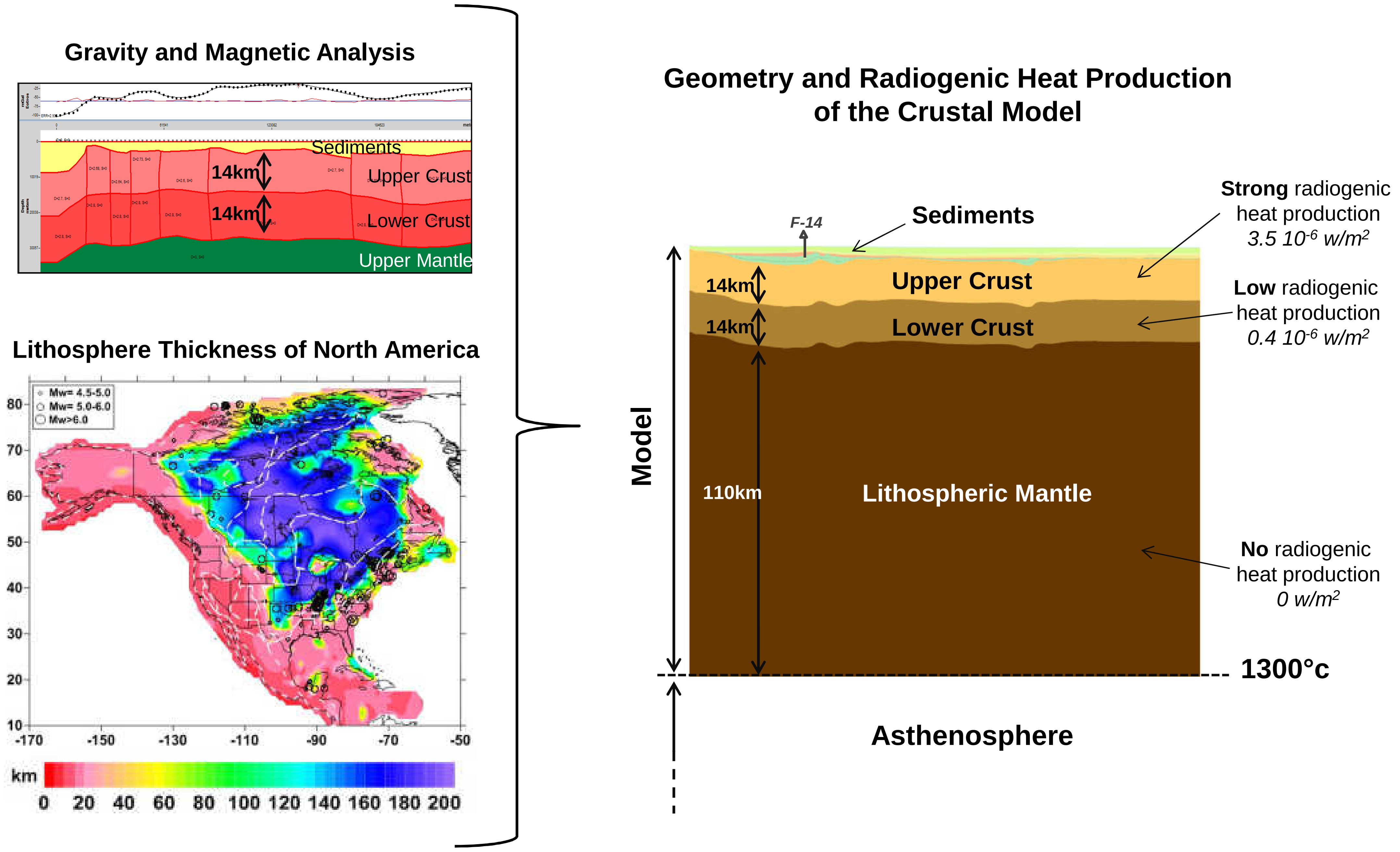


Figure 14: Lithosphere geometry and properties

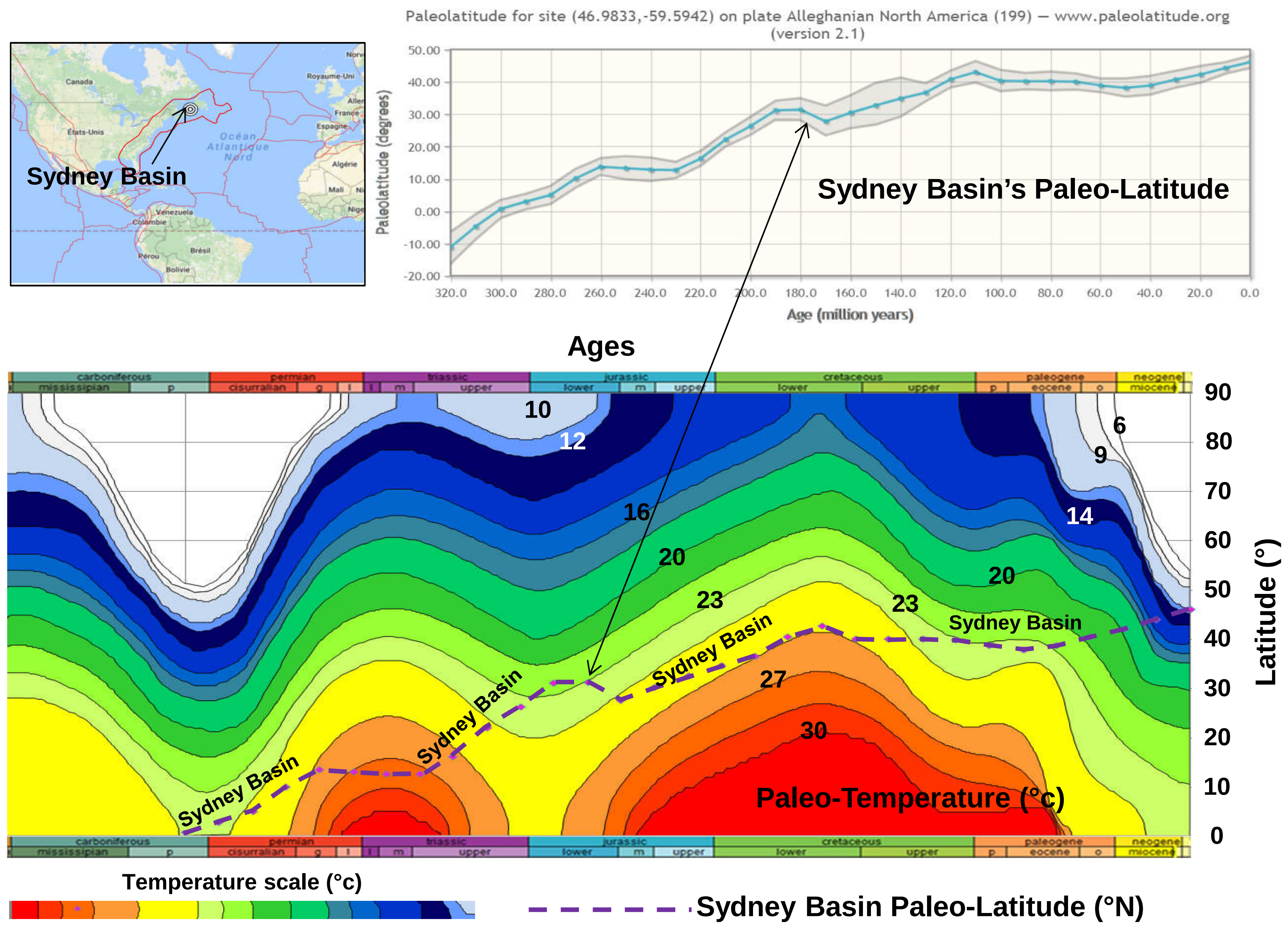


Figure 13: Paleo-surface temperature

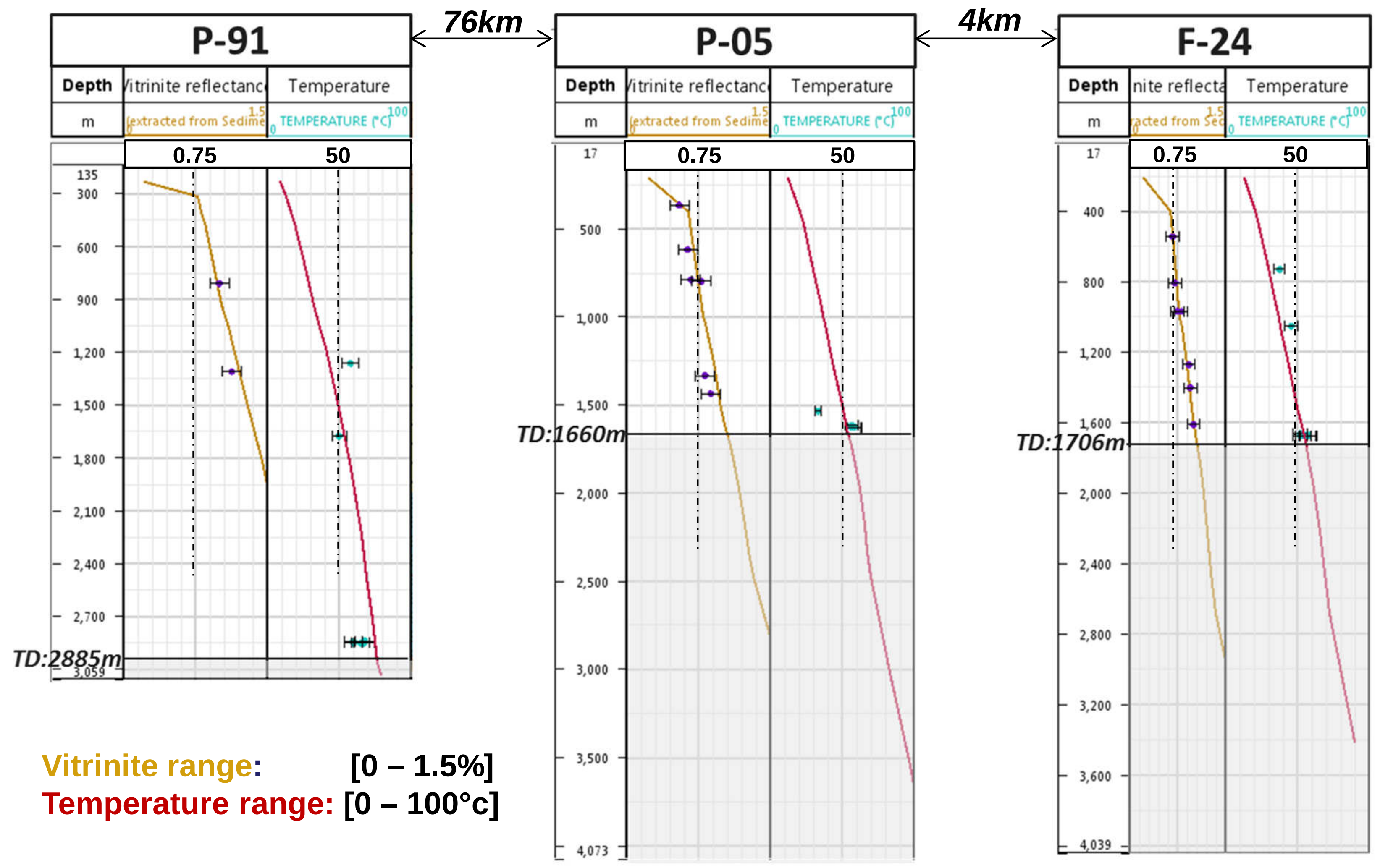


Figure 15: Thermal and Maturity calibration

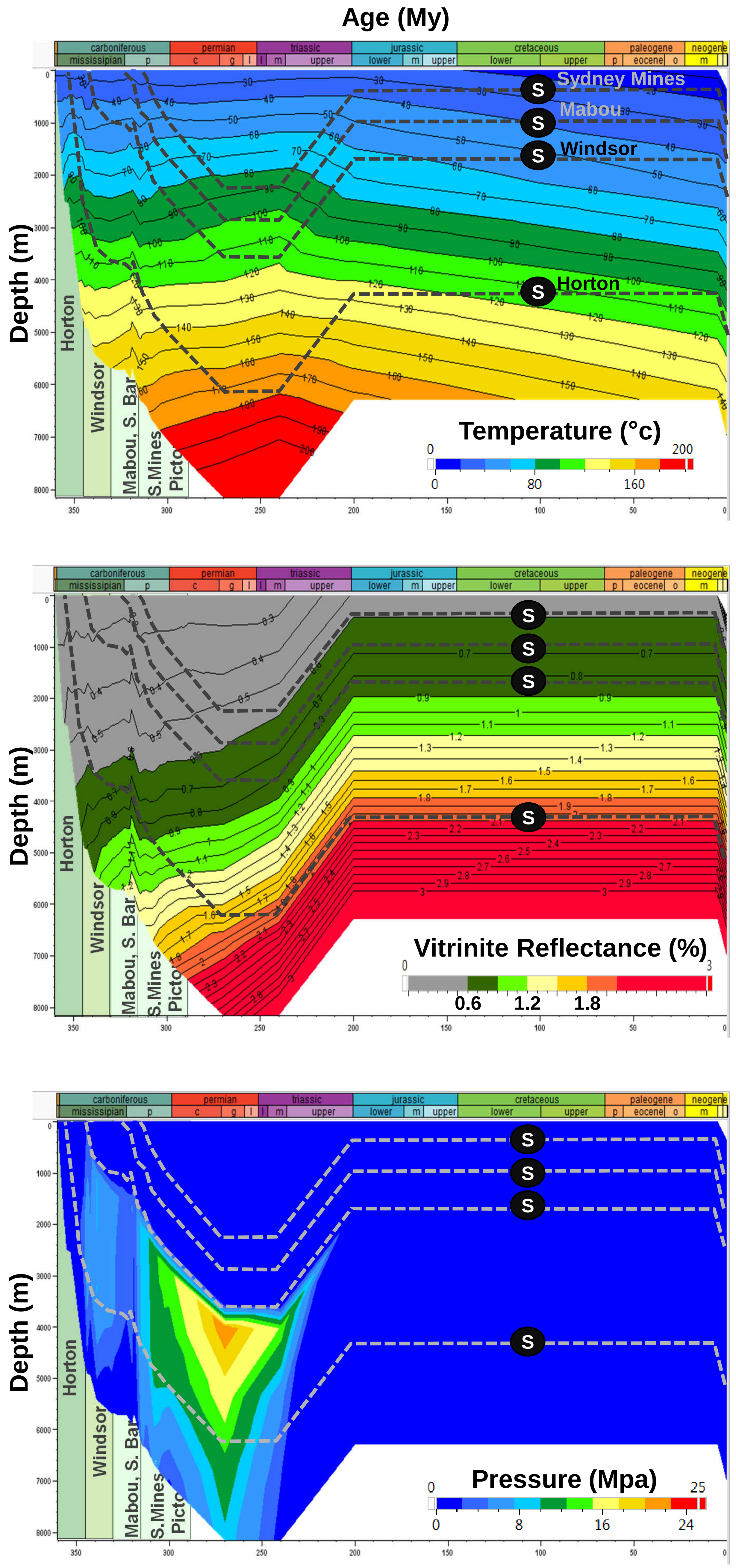


Figure 16: Burial history near Saint-Paul Island

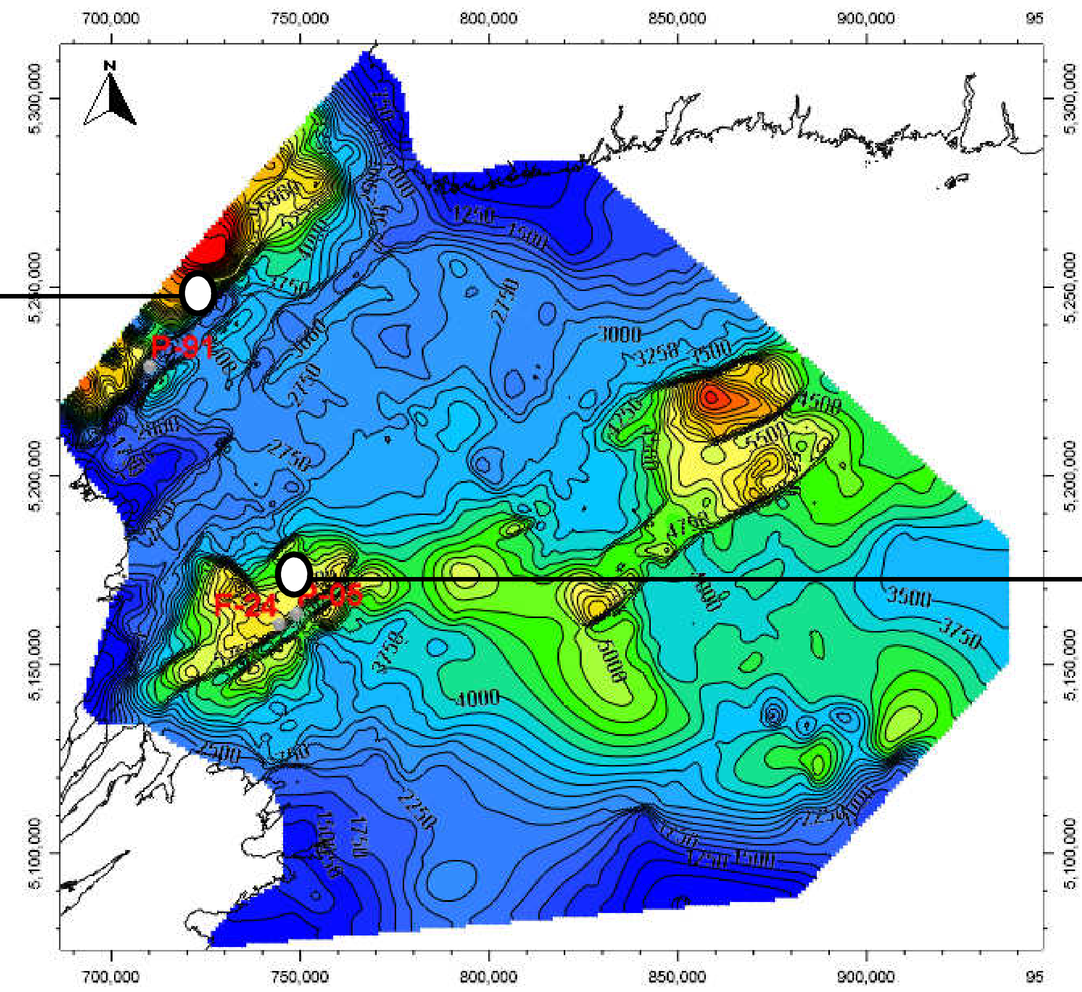
Burial History

Both points are located in grabens; one is close to well P-91 and the other is near wells F-24 / P-05. They show almost same history: maximum maturity was reached during Permo-Trias periods. It corresponds to the maximum burial state achieved before widespread Triassic erosion began as a consequence of regional uplift (see eroded thickness map, Figure 3). Differences exist only in maturity state. Indeed, the north graben shows a higher maturity state than the south graben due to greater burial. Horton source rock in the north graben reached 6.5km with vitrinite reflectance at 2% whereas the south graben reached 5.5km with vitrinite reflectance at 1.7%. Other source rocks, such as Windsor, Mabou and Sydney Mines, reached oil window maturity during Permo-Trias for both locations.

The temperature evolution shows that Horton source rock exceeded 150 – 160°C during the Permian, which triggered the onset of secondary thermal cracking. Source rock reached the gas window consistent with vitrinite reflectance. Climatic influence is observable in the burial / temperature evolution, showing for example a clear decrease in temperature from Jurassic until present day resulting from paleo-latitude evolution and global climate change.

Over-pressures occurred in the grabens during burial from the Carboniferous to Triassic periods due to high sedimentation rates and the low permeability of Windsor rocks. Maximal over-pressures ranged from 15MPa to 22Mpa in the graben. Subsequently, over-pressure lessened to a hydrostatic state during erosion in the Triassic.

S Source Rocks ------ Source rock stratigraphic level



Basement Depth

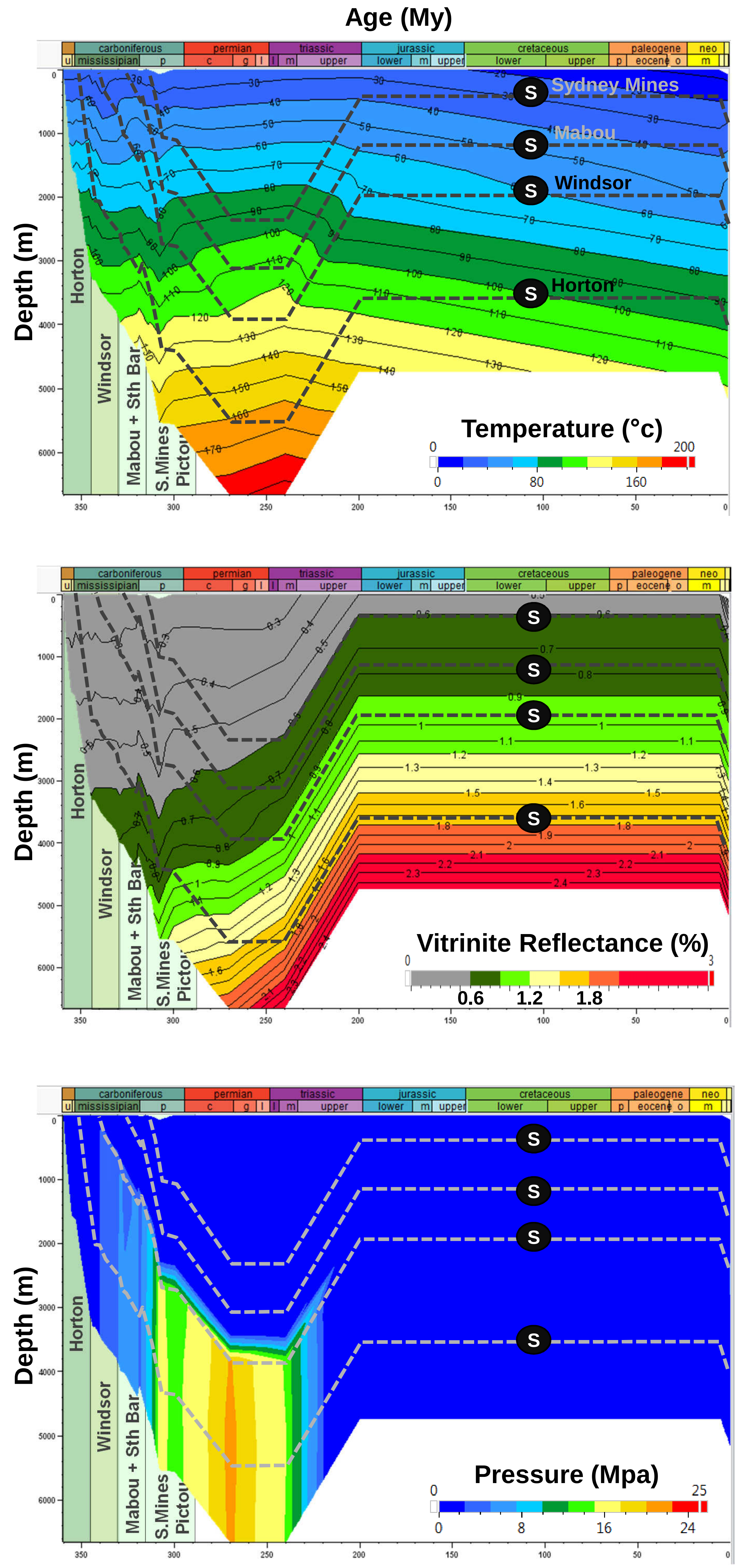


Figure 17: Burial history near wells P-05 and F-24

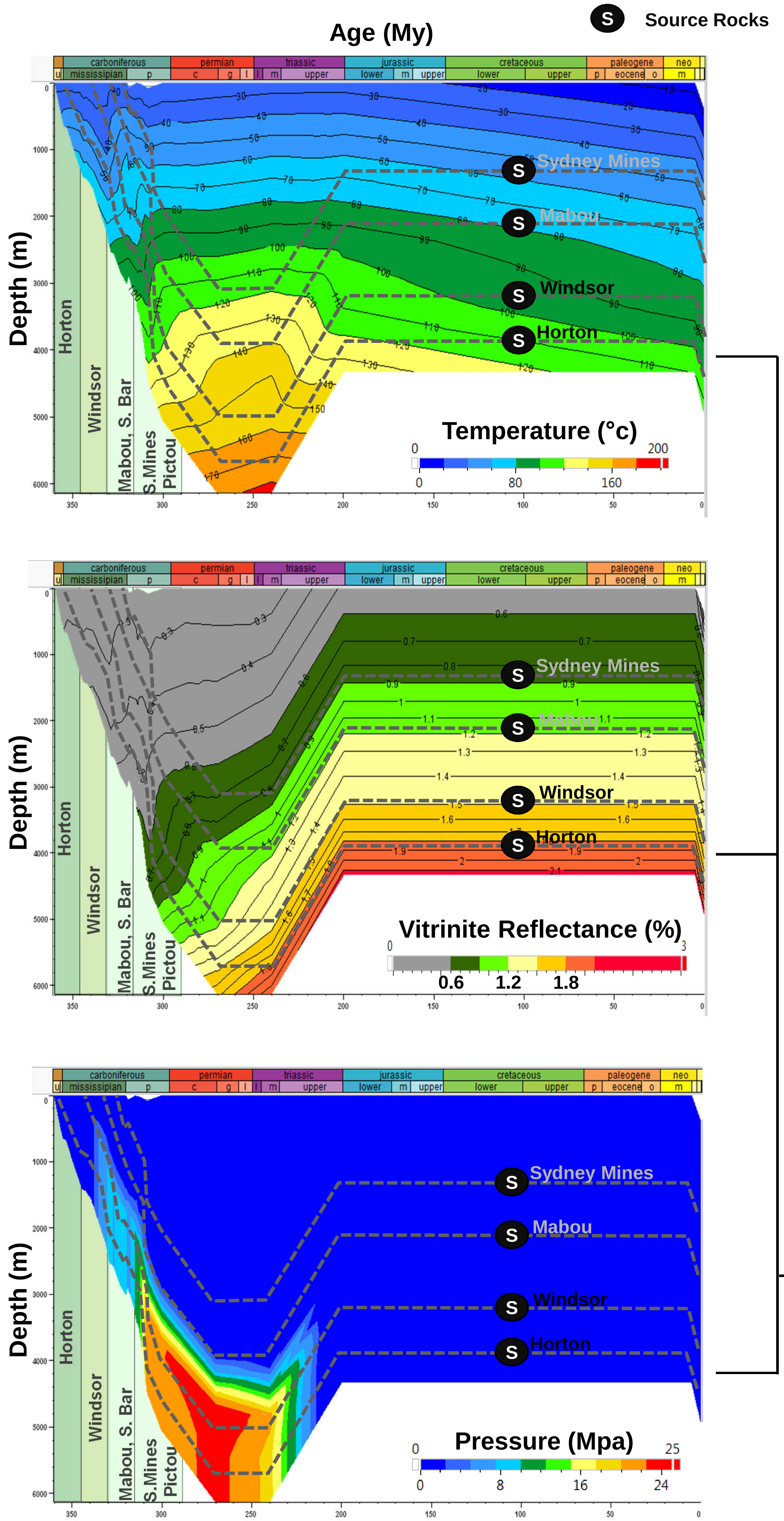


Figure 18: Burial history at the basin center

Burial History

The diagrams on the left correspond to the center of the basin and show the post graben depocenter. The diagrams on the right illustrate a northern and structurally shallower sub-basin. Horton source rock was probably not deposited at these locations. Nevertheless, the source rock stratigraphic level has been maintained on the burial graphs to indicate the evolution of Horton rocks in these location for an alternative stratigraphic interpretation.

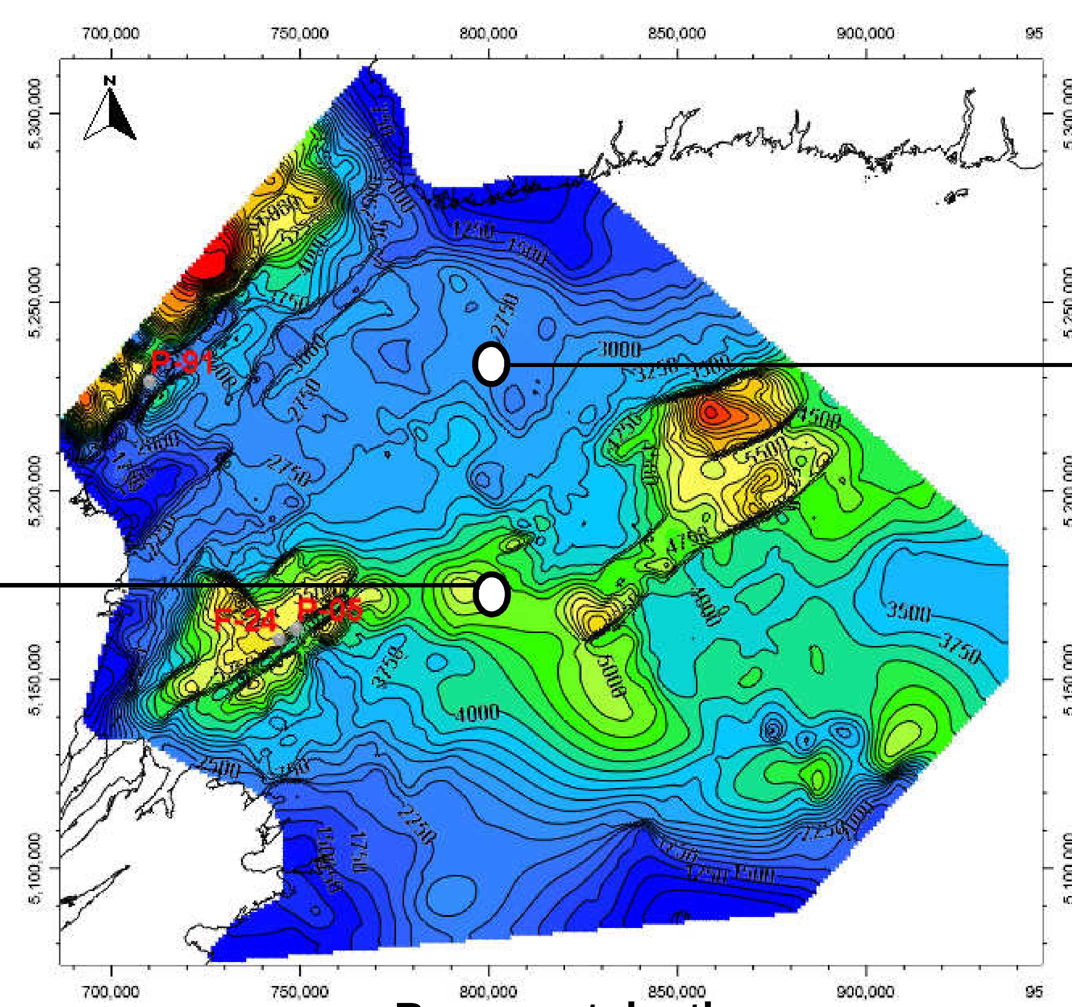
For both locations, maximum maturity state was again achieved during Permo-Trias periods. Results show that the maximum burial state was reached before extensive Triassic erosion developed in response to regional uplift.

On the figures at left (depocenter), the stratigraphic level of the Horton source rock reached the condensate to gas window with vitrinite reflectance at 2%. Windsor source rocks reached the condensate window and attained a vitrinite reflectance around 1.5%. Mabou source rocks reached the oil to condensate window with vitrinite reflectance at 1.2% and Sydney Mines source rock reached the oil window. The deeper part of the basin exceeded 150 – 160°c and resulted in secondary thermal cracking during the Permian. Over-pressures occurred from the Carboniferous to Triassic due to high sedimentation rates and low permeability of Windsor rocks. Maximum over-pressures ranged from 20MPa to 25Mpa. Over-pressure decreased to a hydrostatic state during the Triassic erosional event.

On the figures at right (shallower location), the maximum attained maturity state is the oil window for Windsor source rock and early oil window for Mabou and Sydney Mines source rocks. The maximum temperature reached was 120°C. Over-pressure existed but was limited approximately 10MPa to 15Mpa during the Permian, diminishing quickly to a hydrostatic state during erosion.

The burial / temperature evolution demonstrates climatic influences, showing for example a clear decrease in temperature from the Jurassic until present day resulting from paleo-latitude migration and global climate change. A blanketing effect is also observable during high sedimentation rates in the Carboniferous (thermal disequilibrium).

S Source Rocks ------ Source rock stratigraphic level


Basement depth

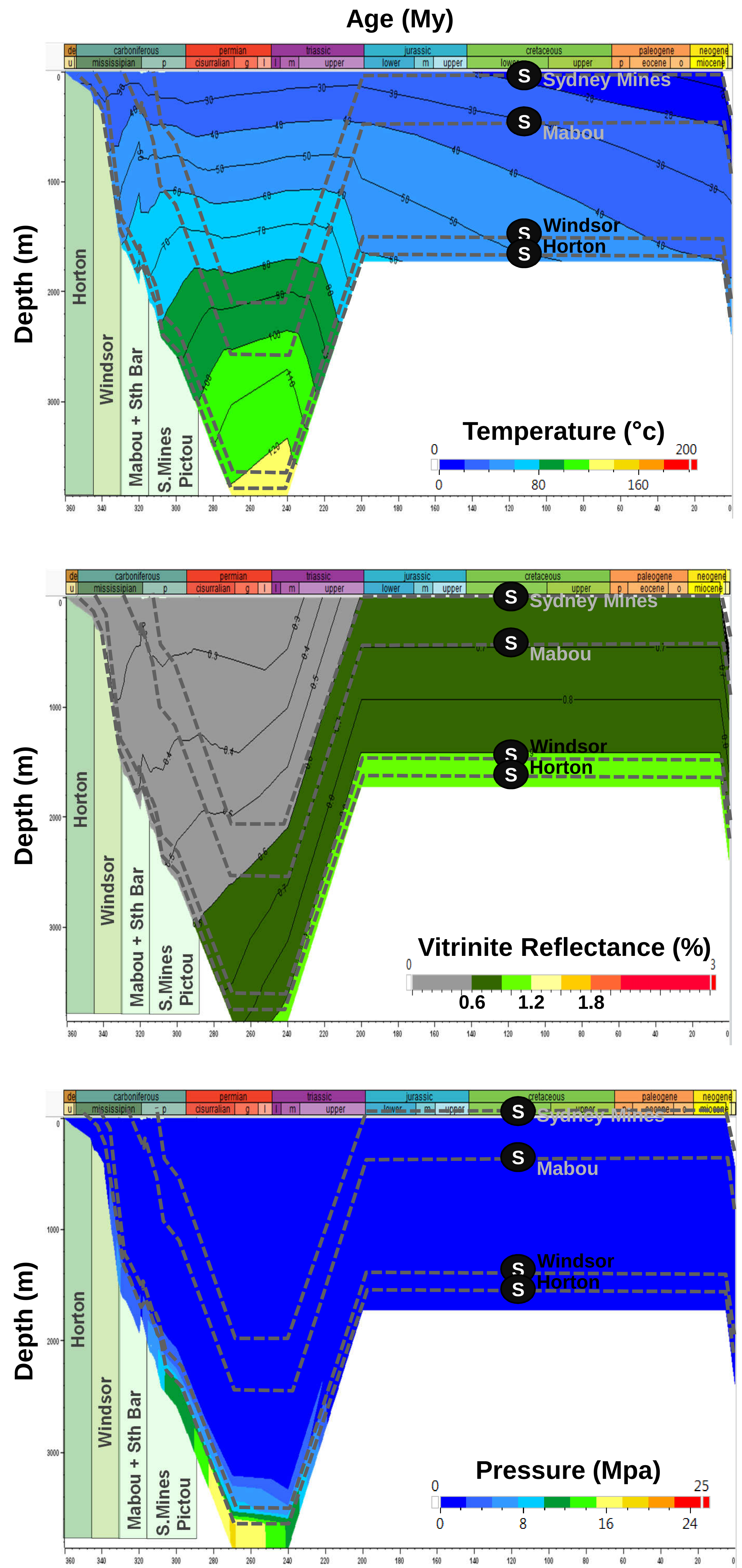


Figure 19: Burial history of the shallower portion

Sydney Mines Source Rock

Source Rock	Lithofacies	Avg Effective thickness (m)	Avg TOCO (wt%)	Kerogen type	Avg HIO (mgHC/g)	SPI (T/m2)
Sydney Mines	Flood plain and Shallow Lakes	6 m	10%	III / II	450	0.6

Figure 20 shows source rock temperature, maturity and hydrocarbon mass expulsion at present day. It constitutes a first hydrocarbon assessment of the Sydney Basin.

Note: Vitrinite reflectance indicates the maximum source rock maturity state reached during the basin's history and provides maturity windows for oil, condensate or gas. Transformation ratio is a function of kerogen types linked to a specific kinetic scheme. It gives the source rock generation percentage. Expulsion quantifies the hydrocarbon mass expelled from the source rock.

Temperature (°C)

The present day temperature of Sydney Mines source rocks is low, ranging from 20 to 60°C. As a consequence, probable oil accumulations above this formation may be affected by biodegradation which occurs between 10 and 70°C, with peak degradation between 20 and 40°C. Maximum temperatures were reached in the center of the basin along a SW-NE axis extending from wells F-24 and P-05 to the northeast.

Vitrinite (%)

Calculated vitrinite values range from 0.7 to 1%. This demonstrates that the source rock reached the early oil window for the entire study area, and the oil window in the center of the basin near wells F-24 and P-05.

Transformation Ratio (%)

The kerogen transformation ratio is low, typically below 15% over most of the basin. Higher transformation ratios (30-40%) are observed in the center of the basin near wells F-24 and P-05.

Hydrocarbon Expulsion (kg/m2)

Hydrocarbon mass expelled is low, due to low transformation ratios and low source rock potential. Maximum values in the center of the basin are only 200kg/m2. Expelled hydrocarbons consist primarily of medium to heavy oil.

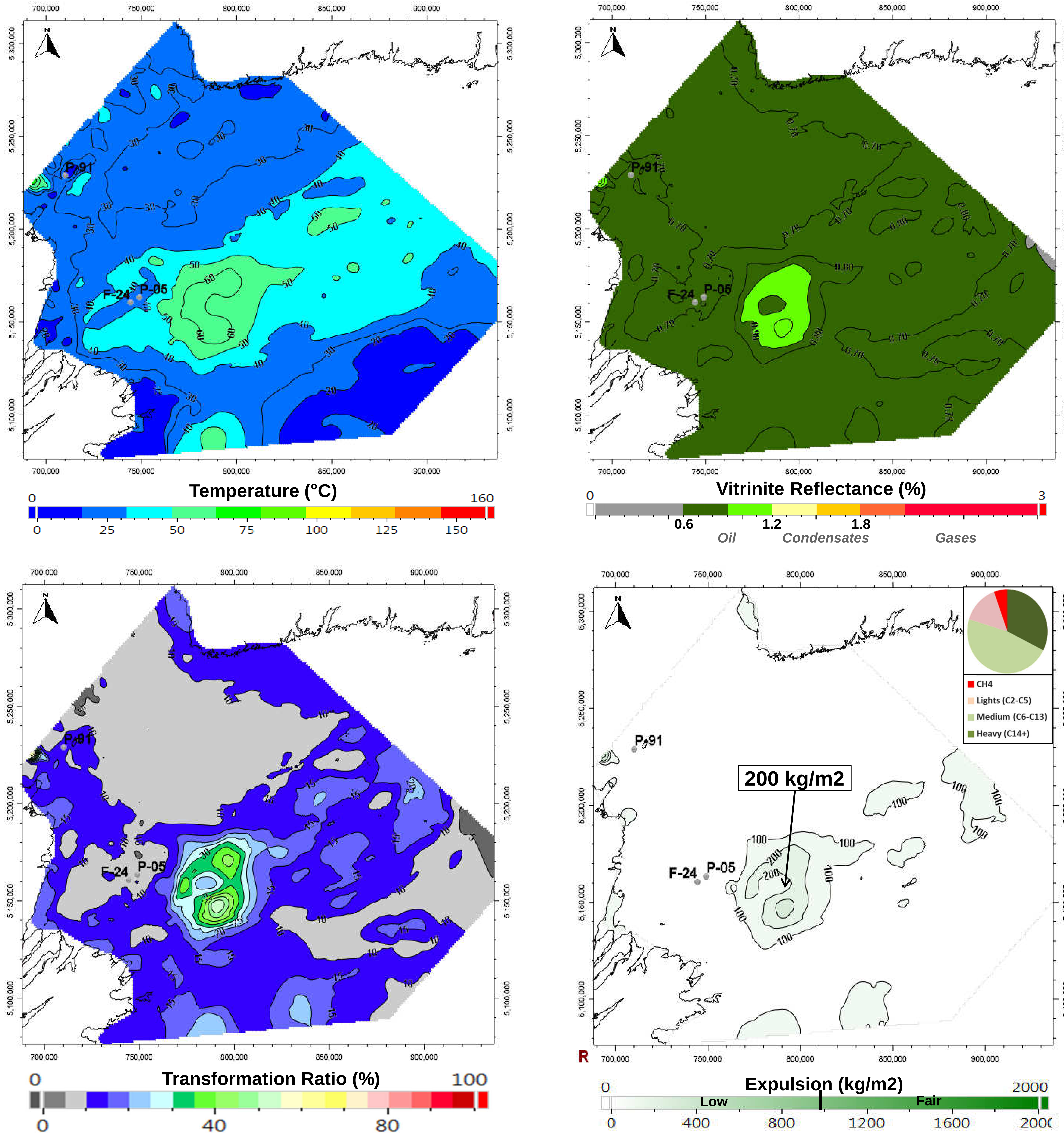


Figure 20: Thermal and maturity model results for the Sydney Mines source rock

Mabou Source Rock

Source Rock	Lithofacies	Avg Effective thickness (m)	Avg TOC0 (wt%)	Kerogen type	Avg HI0 (mgHC/g)	SPI (T/m2)
Mabou	Organic-lean shales	30 m	2.5%	III / II	300	0.4

Figure 21 shows source rock temperature, maturity and hydrocarbon mass expulsion at present day. It constitutes a first hydrocarbon assessment of the Sydney Basin.

Note: Vitrinite reflectance indicates the maximum source rock maturity state reached during the basin's history and provides maturity windows for oil, condensate or gas. Transformation ratio is a function of kerogen types linked to a specific kinetic scheme. It gives the source rock generation percentage. Expulsion quantifies the hydrocarbon mass expelled from the source rock.

Temperature (°C)

The present day temperature of Mabou source rock is low, ranging from 20 to 80°C. The highest temperatures occur in the center of the basin. As a consequence of low temperatures, biodegradation may have affected probable related oil accumulations above the Mabou Formation (biodegradation occurs at temperatures between 10 and 70°C with maximum biodegradation at 20-40°C).

Vitrinite (%)

Calculated vitrinite values range from 0.8 to 1.3%. Vitrinite values indicate the Mabou source rock reached the early oil window over most of the study area, and reached the mature oil to condensate window along an axis extending northeast from wells F-24 and P-05.

Transformation Ratio (%)

The kerogen transformation ratio is moderate for a large portion of the basin extending east from well P-05, where values range from 40 to 75%. Transformation ratios in the remainder of the study area are low, with values ranging from 15 to 20%.

Hydrocarbon Expulsion (kg/m2)

Hydrocarbon masses expelled from Mabou source rocks are slightly higher and more widespread than those expelled from the Sydney Mines Formation. Nevertheless, quantities are low. Maximum values in the center of the basin are only 300kg/m2 and consist primarily of medium to heavy oil.

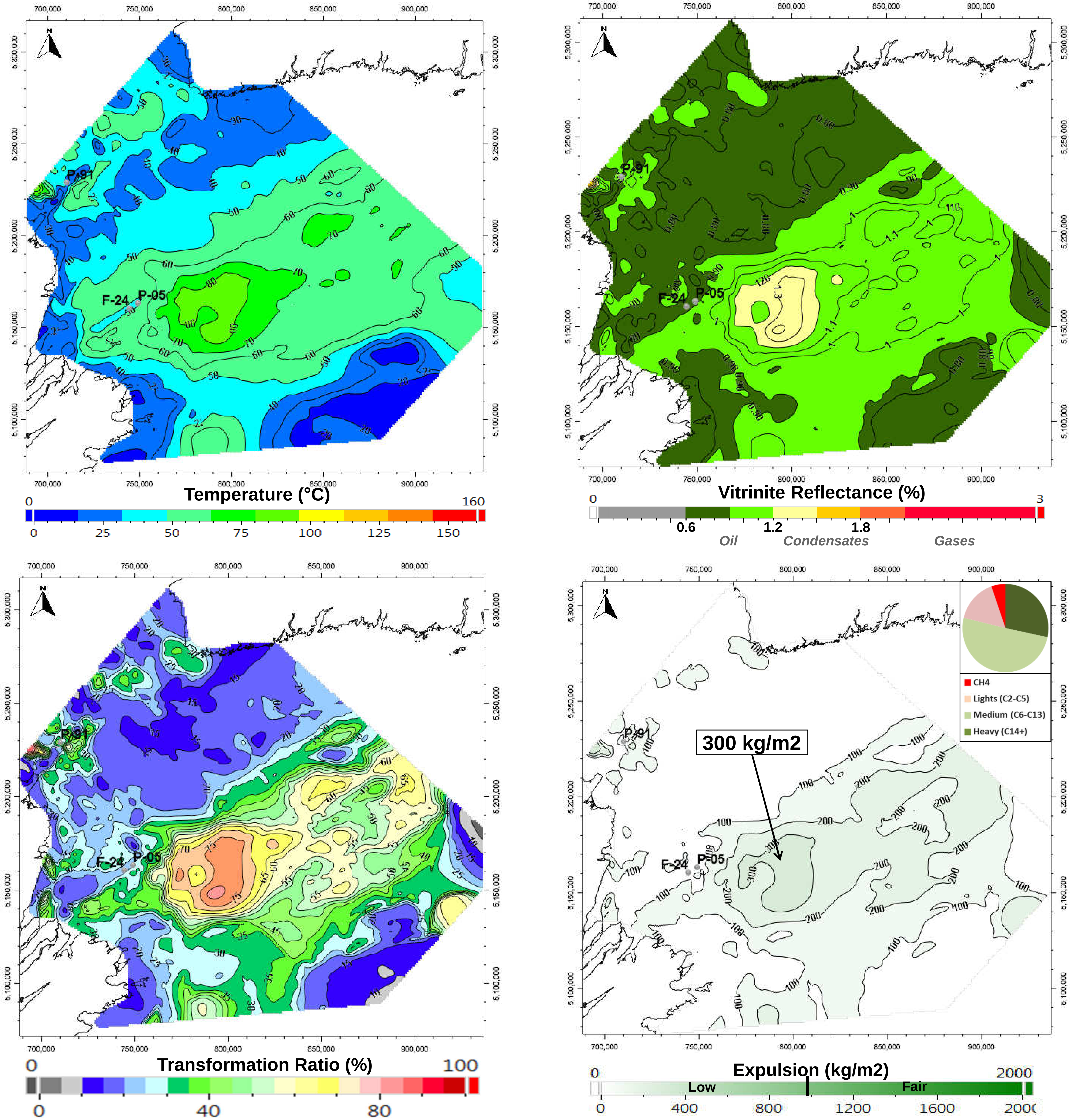


Figure 21: Thermal and maturity model results for Mabou source rock

Windsor Source Rock

Source Rock	Lithofacies	Avg Effective thickness (m)	Avg TOC0 (wt%)	Kerogen type	Avg HI0 (mgHC/g)	SPI (T/m2)
Horton	Lacustrine shales	50 m	7%	I / II	650	5.2

Figure 22 shows source rock temperature, maturity and hydrocarbon mass expulsion at present day. It constitutes a first hydrocarbon assessment of the Sydney Basin.

Note: Vitrinite reflectance indicates the maximum source rock maturity state reached during the basin's history and provides maturity windows for oil, condensate or gas. Transformation ratio is a function of kerogen types linked to a specific kinetic scheme. It gives the source rock generation percentage. Expulsion quantifies the hydrocarbon mass expelled from the source rock..

Temperature (°C)

Present day temperatures of Windsor source rock range from 30°c to 100°c. The highest temperatures occur in the center of the basin. Biodegradation may also affect probable related oil accumulations above Windsor source rocks since biodegradation occurs between 10 and 70°C with maximin biodegradation occurring 20 and 40°C.

Vitrinite (%)

Calculated vitrinite values range from 0.8 to 1.8%. Most of the basin is within the oil window while a large portion in the center of the basin (east of well P-05) is in the condensate window.

Transformation Ratio (%)

The kerogen transformation ratio ranges from 40 to 95% over much of the study area. The eastern part of the basin, east of well P-05, has a consistent transformation ratio of 90-95%.

Hydrocarbon Expulsion (kg/m2)

Despite elevated transformation ratios, hydrocarbon mass expelled is generally low, primarily due to limited effective thickness. Values are restricted to approximately 200 to 300kg/m2. Expelled hydrocarbons consist mainly of heavy oil.

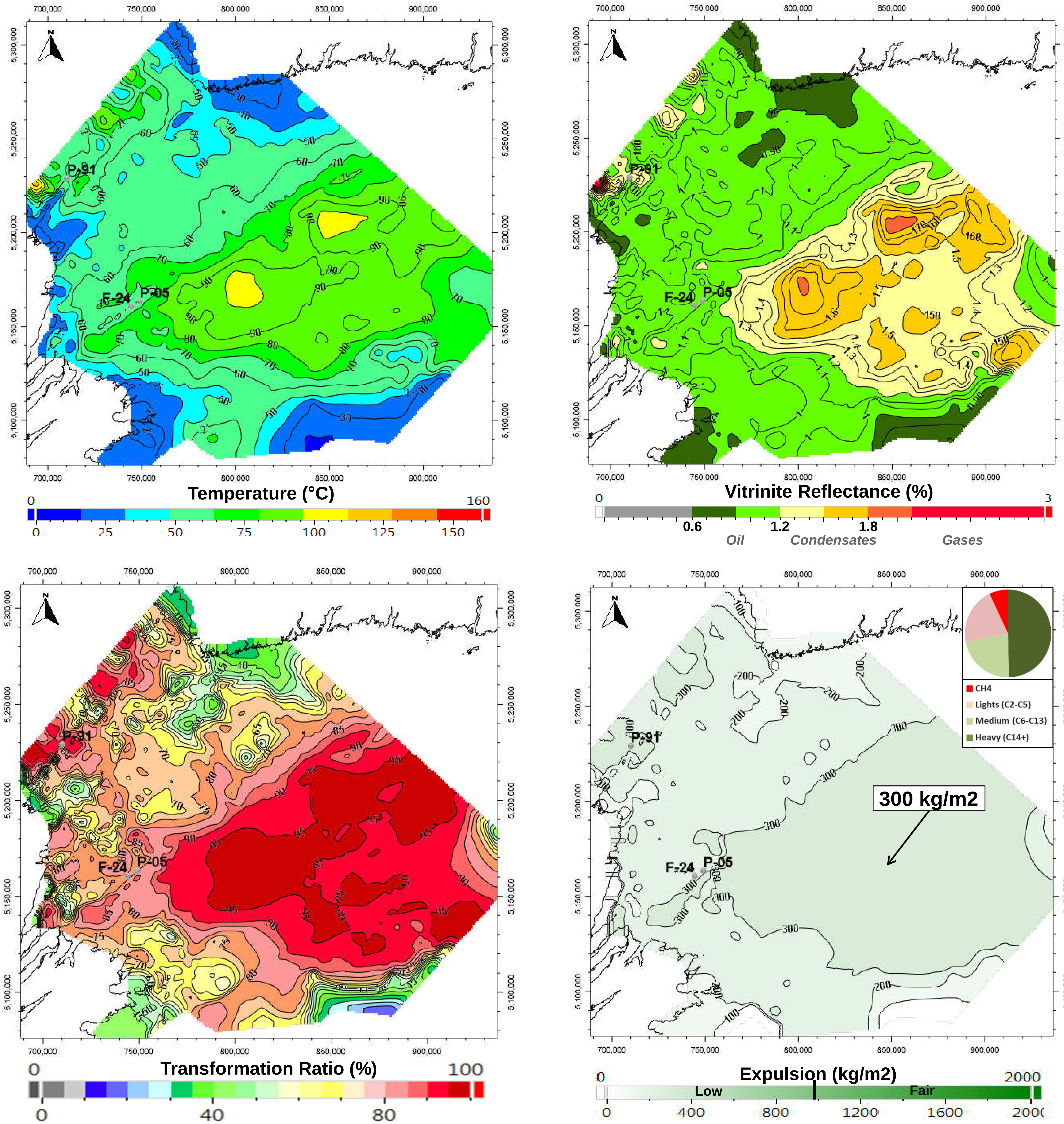


Figure 22: Thermal and maturity model results for Windsor source rock

Horton Source Rock

Source Rock	Lithofacies	Avg Effective thickness (m)	Avg TOC0 (wt%)	Kerogen type	Avg HI0 (mgHC/g)	SPI (T/m2)
Lower Windsor	marine shales/evaporites	10 m	3%	II	500	0.3

Figure 23 shows source rock temperature, maturity and hydrocarbon mass expulsion at present day. It constitutes a first hydrocarbon assessment of the Sydney Basin. Even if Horton source rock is limited to grabens as indicated in the geological model, the Horton has been considered a continuous layer in order to provide an idea of the potential of this stratigraphic level.

Note: Vitrinite reflectance indicates the maximum source rock maturity state reached during the basin's history and provides maturity windows for oil, condensate or gas. Transformation ratio is a function of kerogen types linked to a specific kinetic scheme. It gives the source rock generation percentage. Expulsion quantifies the hydrocarbon mass expelled from the source rock.

Temperature (°C)

Present day temperature of Horton source rocks ranges from 30 to 110°C. The highest temperature attained (100 to 115°C) occurs in the northwest part of the basin near the Saint-Paul well, in a graben structure located along the Cabot Fault.

Vitrinite (%)

Calculated vitrinite values reach the condensate to gas window for large parts of the basin, with maximum values between 1.8 and 2.2% observed within the graben along the Cabot Fault and at the center of the basin. The remainder of the basin is within the oil to condensate window, where vitrinite values range from 0.9 to 1.6%.

Transformation Ratio (%)

The kerogen transformation is 95-100% along the Cabot Fault, above 90% for the southern half of the basin and between 40-90% elsewhere.

Hydrocarbon Expulsion (kg/m2)

Hydrocarbon masses expelled are very good at the graben locations. Expelled mass reaches 5000kg/m2 in these locations, which thus have excellent hydrocarbon source potential.

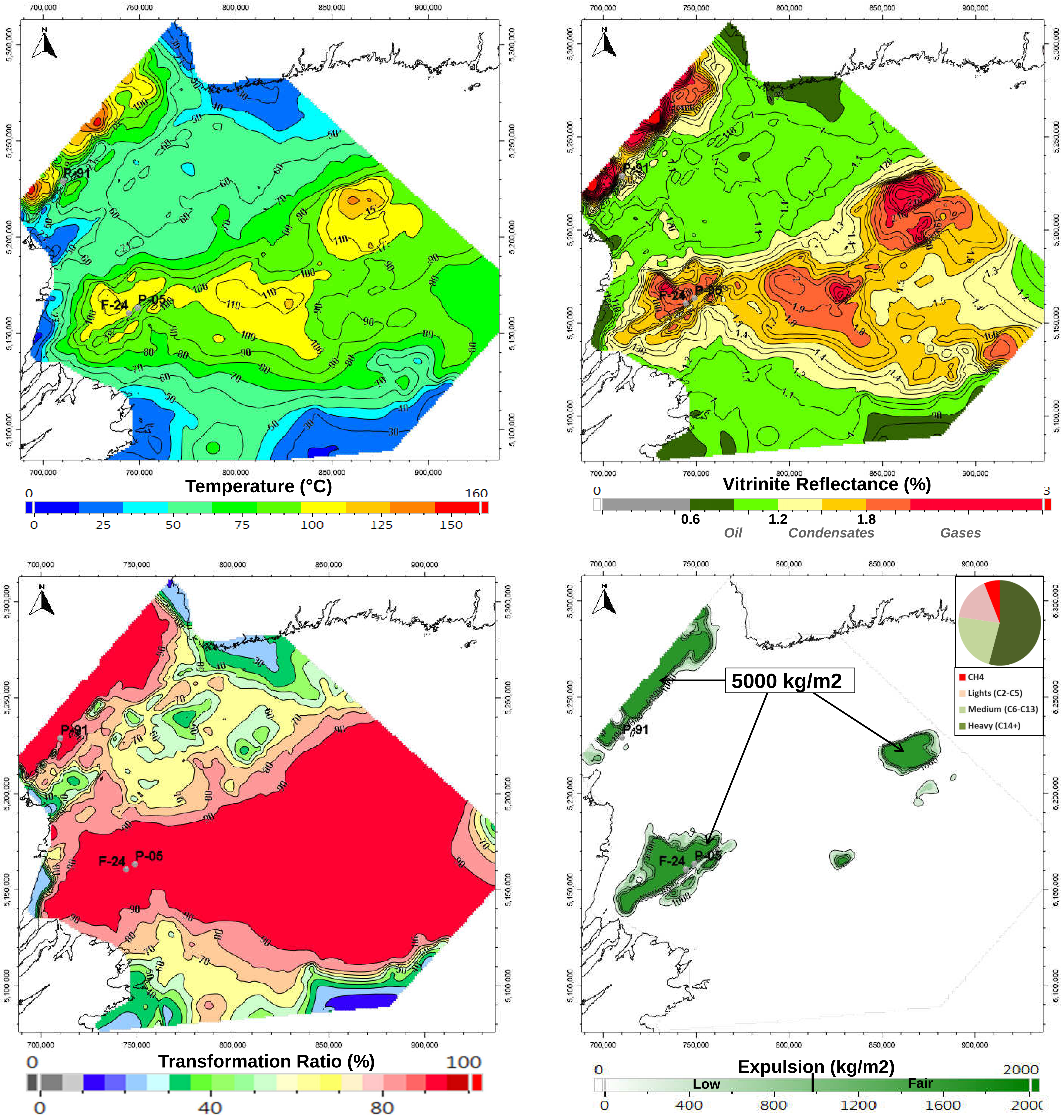
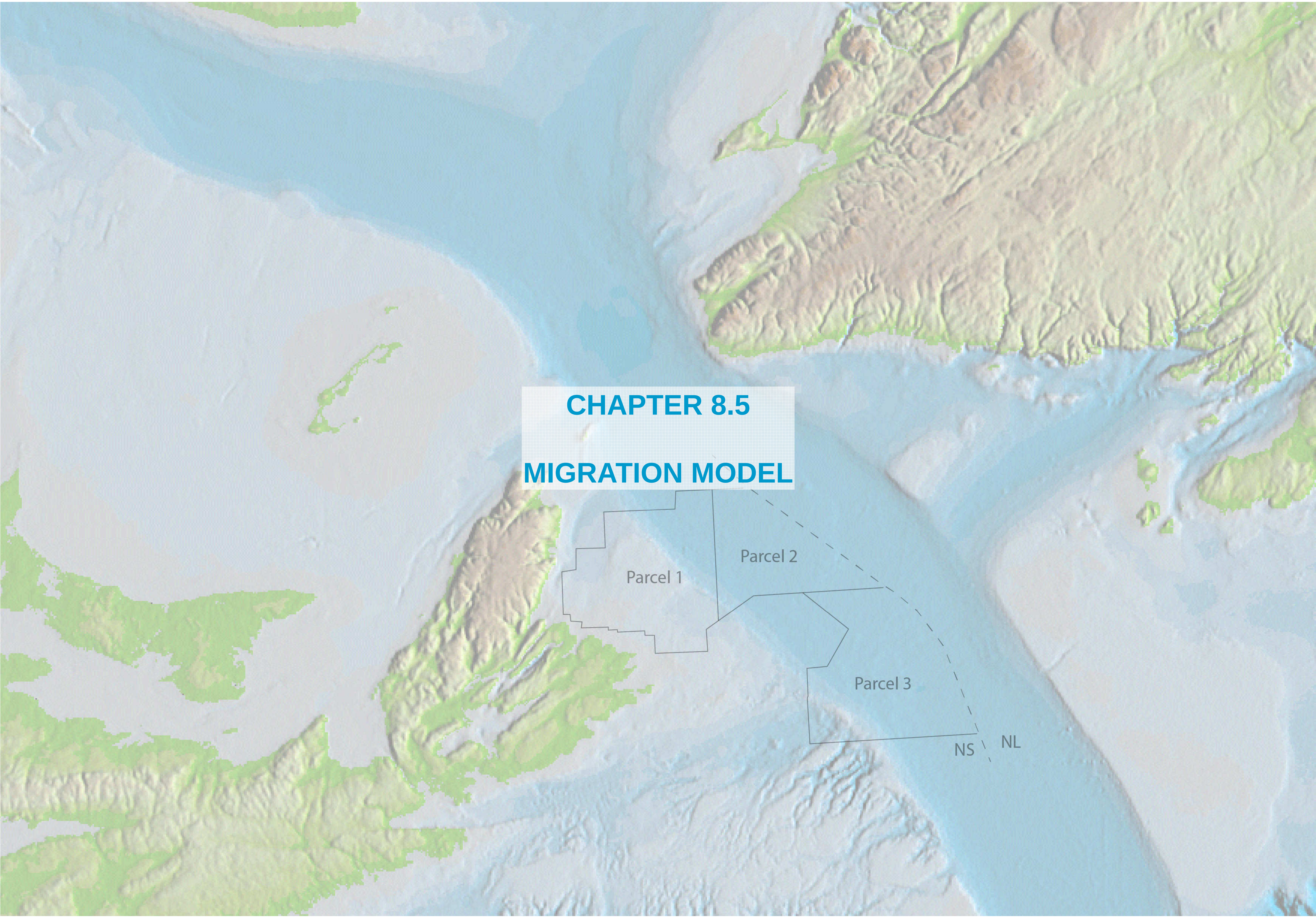


Figure 23: Thermal and maturity model results for Horton source rock

CHAPTER 8.5

MIGRATION MODEL



Hydrocarbon Presence (3D view)

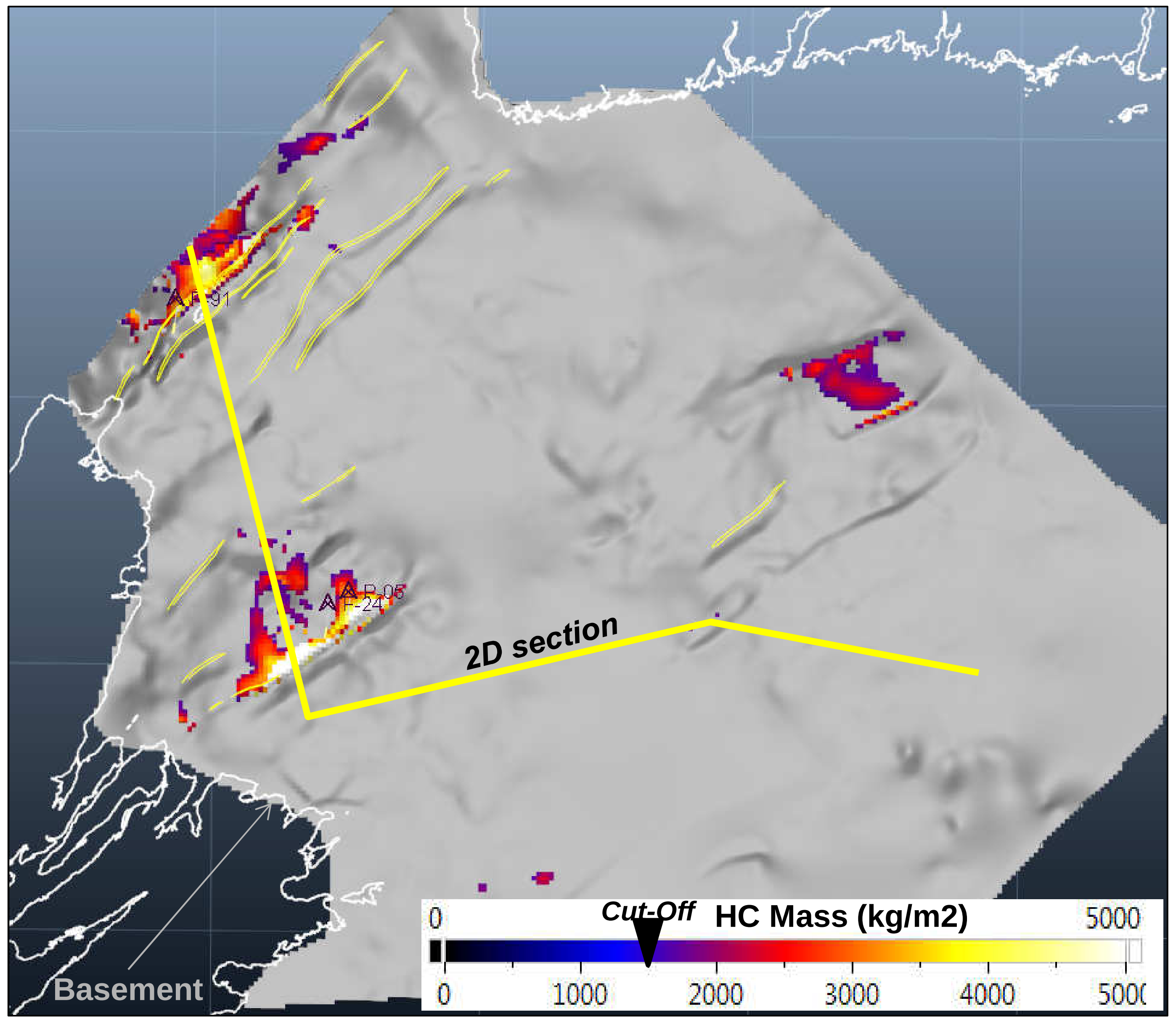


Figure 24: Overview of hydrocarbon presence at present day

Hydrocarbon Presence (3D view):

Figure 24 shows hydrocarbons in the Sydney Basin at present day. A hydrocarbon mass cut-off was applied (1500 kg/m2) in order to display locations with clear hydrocarbon accumulations.

Hydrocarbons are extant at present day. Trap and seal capacity allows the formation of significant hydrocarbon accumulations in Sydney Basin. Hydrocarbon accumulations are primarily located adjacent to graben structures, mainly in the Horton Formation, and are sealed by Windsor series rocks. Accumulations are located below the TD of wells P-05, F-24 and near to well P-91 (Figure 25).

No evident hydrocarbon accumulations were identified above the Windsor Formation mainly due to the low source rock potential of the Windsor, Mabou and Sydney Mines Formations. It should be noted that the low density of the seismic coverage makes identification of traps very uncertain at all levels. The results from this modelling should be seen as indicative of the probability that hydrocarbons can be trapped and preserved at a number of levels. The post Windsor section may contain effective traps charged by either post-Windsor or Horton source rocks. The key point is that the charge risk is relatively low at a play level in this basin. The Horton lacustrine source rocks were deposited in Mississippian age grabens and the imaging of these with the current seismic database is difficult. There may well be alternative interpretations that identify other such grabens, which could also be prospective.

2D Cross-Section (from the 3D Model):

Figure 25, extracted from the 3D model, provides cross sections through the two main hydrocarbon accumulations in the basin. Wells P-05, F-24 and P-91 were projected along the sections.

The 2D cross-sections display lithofacies distribution, vitrinite reflectance and hydrocarbon mass. The lithofacies cross section shows that the Horton play has source rock, reservoir and seal. The vitrinite values show that grabens are primarily in the condensate to gas window except at the top of the Horton sequence (where hydrocarbons are predicted to have accumulated), which is in the late oil to condensate window from the Jurassic to present day. The hydrocarbon mass cross section highlights quantity and stratigraphic position of the hydrocarbon accumulations. Below wells P-05 and F-24, hydrocarbons are trapped in an anticline structure in the upper part of Horton Formation. Close to the well P-91, hydrocarbons are trapped partly as pinch out against the large Saint-Paul Fault.

2D Cross-Section *(from the 3D Model)*

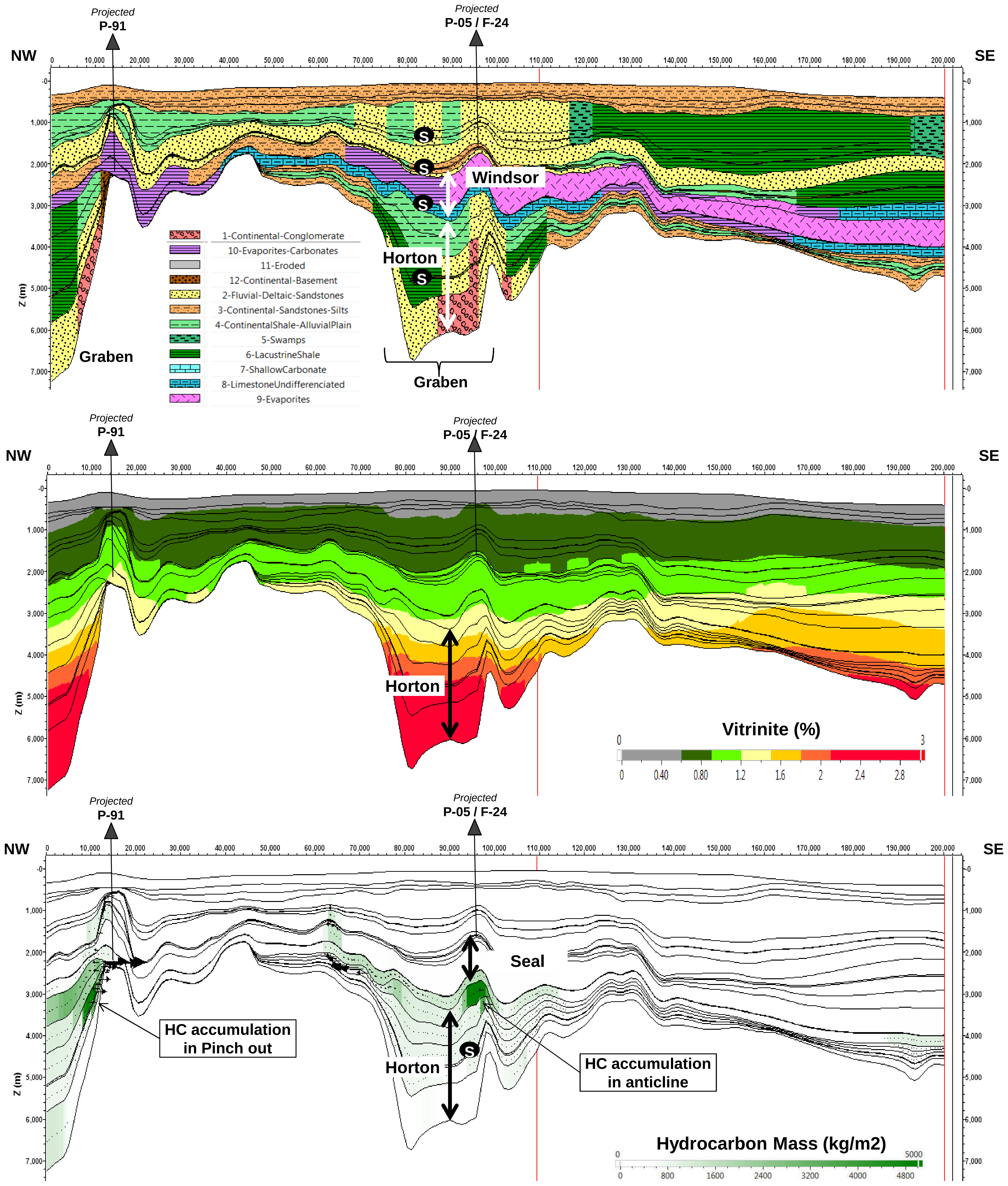


Figure 25: 2D cross-section extracted from the 3D model showing lithofacies, vitrinite and hydrocarbon (HC) mass

Zones of Interest

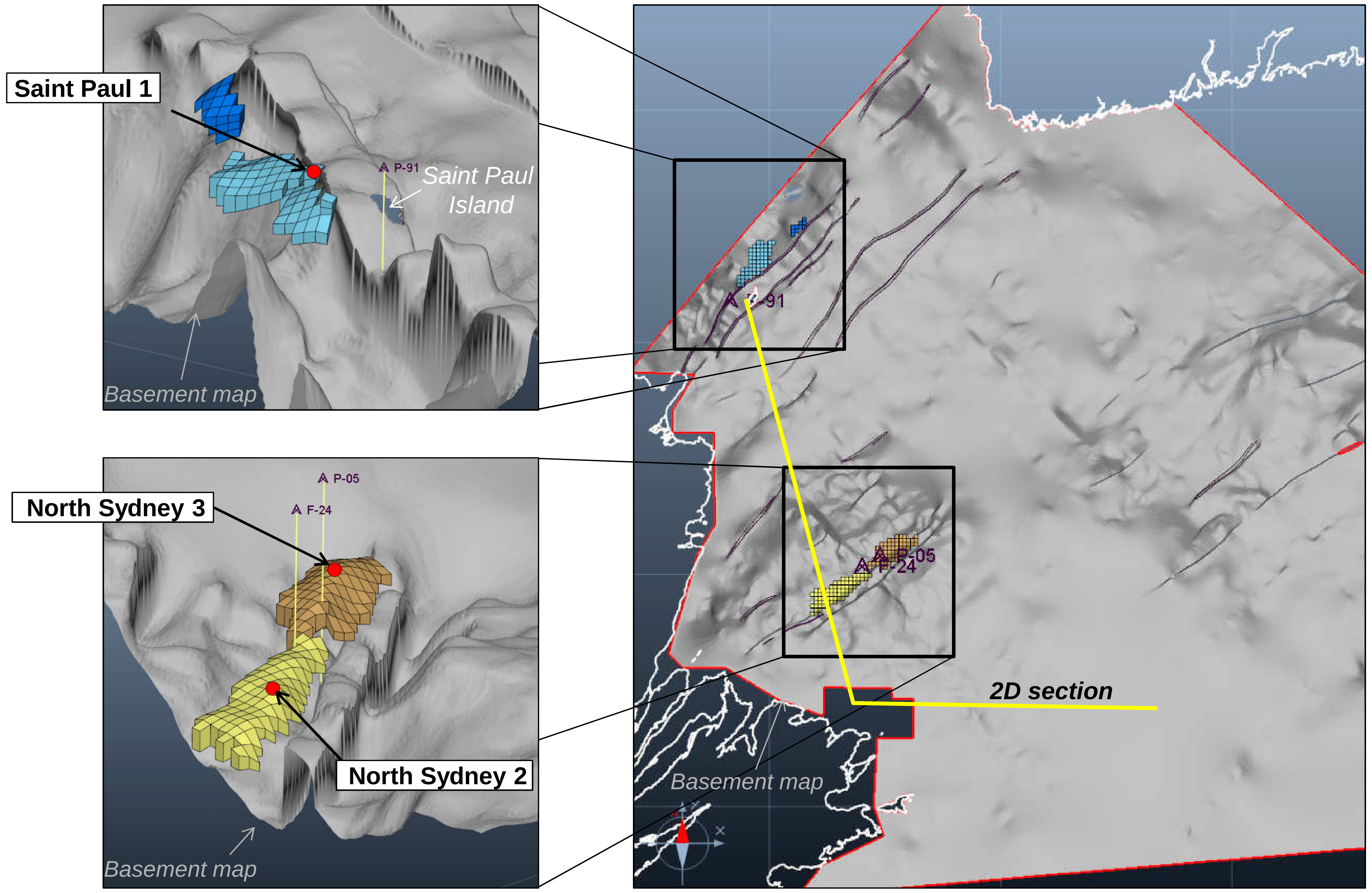


Figure 26: Zones of Interest in 3D view

Zones of Interest:

Figure 26 shows the areas where the TEMIS modelling predicts effective traps based on the input data. It is important to note that TEMIS uses a mathematical methodology for identifying effective traps, which is critically dependent on the input maps, facies models and rock properties. As such it produces only one expression of possible traps due to the model's sensitivity to details of the history of the rock properties of the geo cellular model. It combines petroleum system elements such as reservoir, seal, trap and hydrocarbon charge simulated in the 3D migration model. Three large zones of interest are clearly identified in the Sydney Basin. The first, named Saint-Paul 1, is located in the Horton Formation above the north graben along the Saint-Paul Fault. The second and the third zones of interest are located above the graben at wells P-05 and F-24 in the Horton Formation, and are trapped in the anticline. We underline that a more conventional "manual" assessment using structure maps combined with reservoir and fluid properties may well produce alternative results. The TEMIS modelling however, provides at least one credible expression of the resource potential within Sydney Basin.

Migration History (extracted from the 3D Model):

Figure 27 depicts the evolution of hydrocarbon migration from generation to accumulation in a 2D cross section extracted from the 3D model.

Step 1. Section shows the basin during deposition of the Sydney Mines Formation (Upper Carboniferous). This marks the beginning of the generation/expulsion process for Horton source rock.

Step 2. Section shows the basin at maximum burial just prior to regional uplift generating erosion (Permian). This period corresponds to the end of Horton source rock expulsion. Hydrocarbons are largely disseminated in the Horton Formation, migrating upward and filling probable inside reservoirs.

Step 3. Section shows the basin after structural deformation linked to Triassic regional uplift. Hydrocarbons are migrating to the top of the structures and accumulating in two main structures. One accumulation is located in the upper part of Horton Formation just below the Windsor series and is trapped by an anticline located below wells P-05 and F-24. A second accumulation, located in the upper part of Horton Formation below Windsor series, is trapped against the Saint-Paul Fault near by well P-91.

Step 4. Section shows the Sydney Basin at present day. Hydrocarbon accumulations remain present in these structures.

Migration History (extracted from the 3D Model)

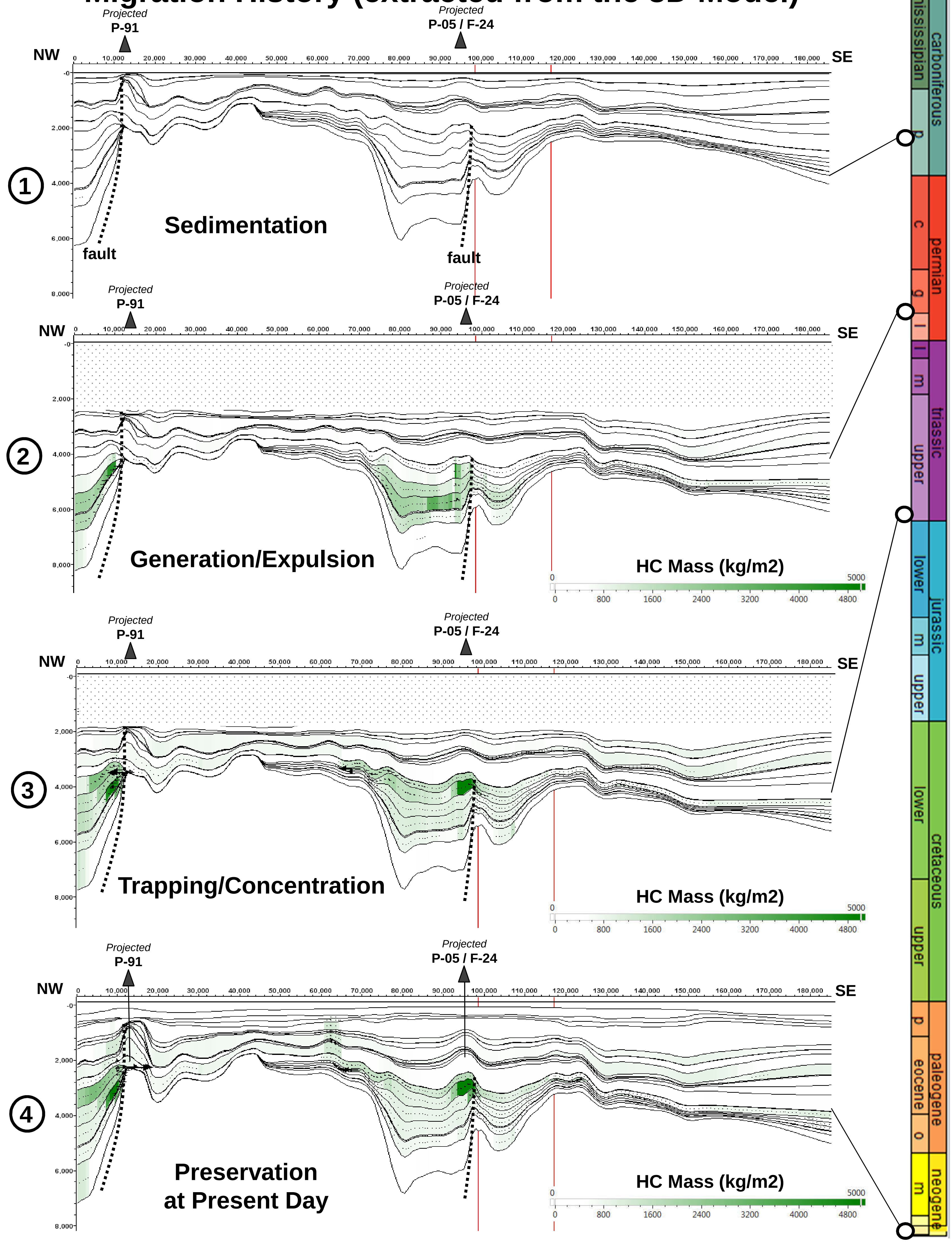


Figure 27: 2D cross-section extracted from the 3D model showing hydrocarbon mass history

Hydrocarbon Accumulations (Horton)

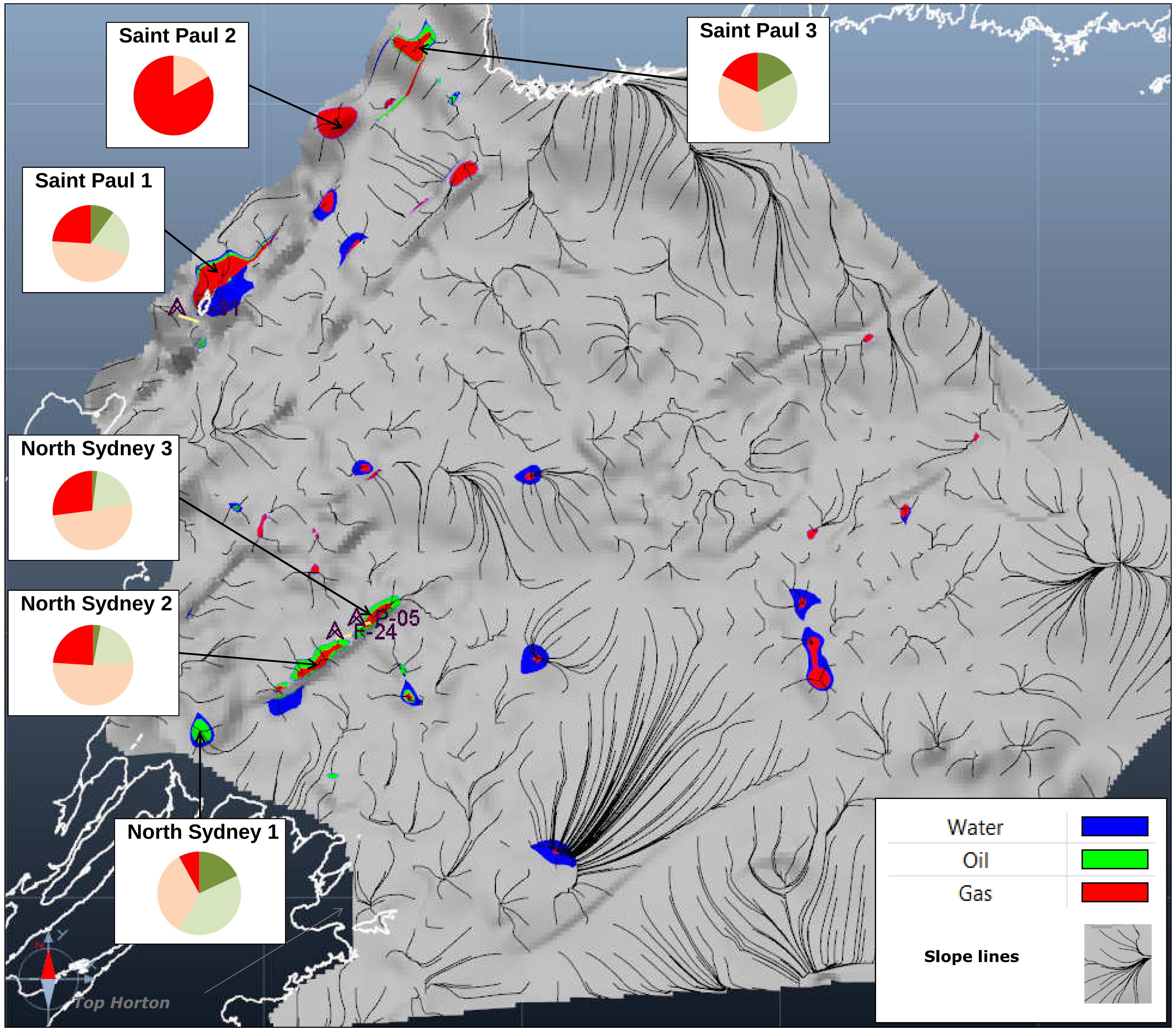


Figure 28: Hydrocarbon (oil and gas) trapped for the Horton play and drainage areas

Hydrocarbon Accumulation:

Figure 28 shows hydrocarbon accumulations and associated phases (oil, gas). It shows the traps and contacts identified by TEMIS (OWC, GWC and OGC). Slope lines indicate drainage areas of top Horton structures.

The northern sector is more gas prone due to its elevated burial-induced state of maturity (see burial history, PL 8.4.2).

Occasional minor hydrocarbon accumulations develop due to a redistribution process which concentrates disseminated hydrocarbons.

Six large accumulations are shown on the map from southwest to northeast: North Sydney 1, 2, 3 and Saint-Paul 1, 2, 3. These hydrocarbon accumulations have more than 200 MMB of oil, or more than 3 Tcf of gas.

Hydrocarbon Mass Histogram:

Figure 29 is a histogram showing the hydrocarbon mass and component percentage [CH4, Lights (C2-C5), Medium (C6-C13) and Heavy (C14+)] for the accumulations listed above.

Saint Paul 1 is the largest hydrocarbon accumulation in the basin. The charge is 10% heavy oil, 20% medium oil, 46% condensate and 24% gas. North Sydney 1 and 2 have large hydrocarbon accumulations with higher proportions of lighter components. Saint Paul 2 consists only of condensates and gas.

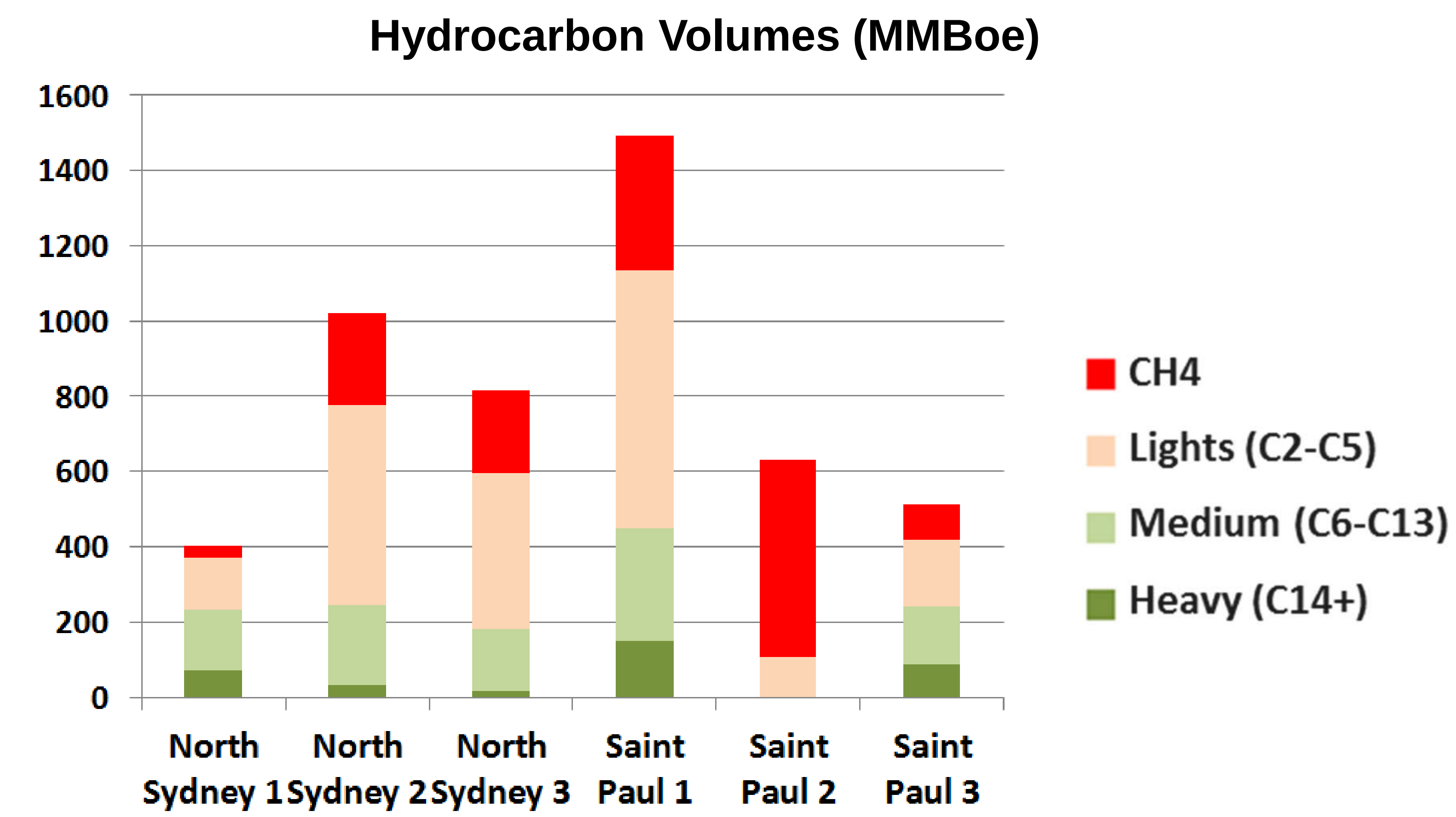
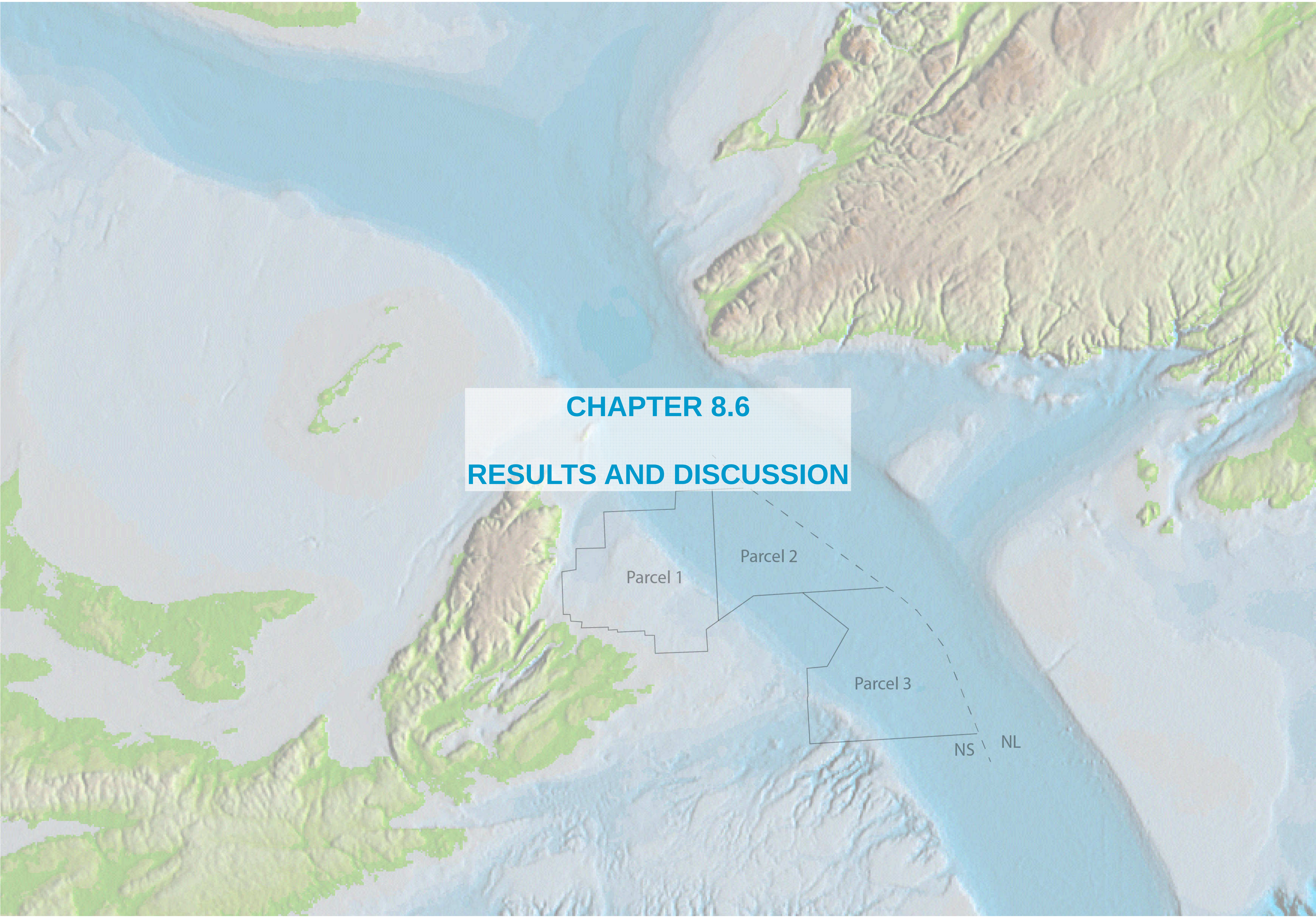


Figure 29: Histogram of hydrocarbon volume trapped and fluid components

CHAPTER 8.6

RESULTS AND DISCUSSION



Overview of the Horton Play

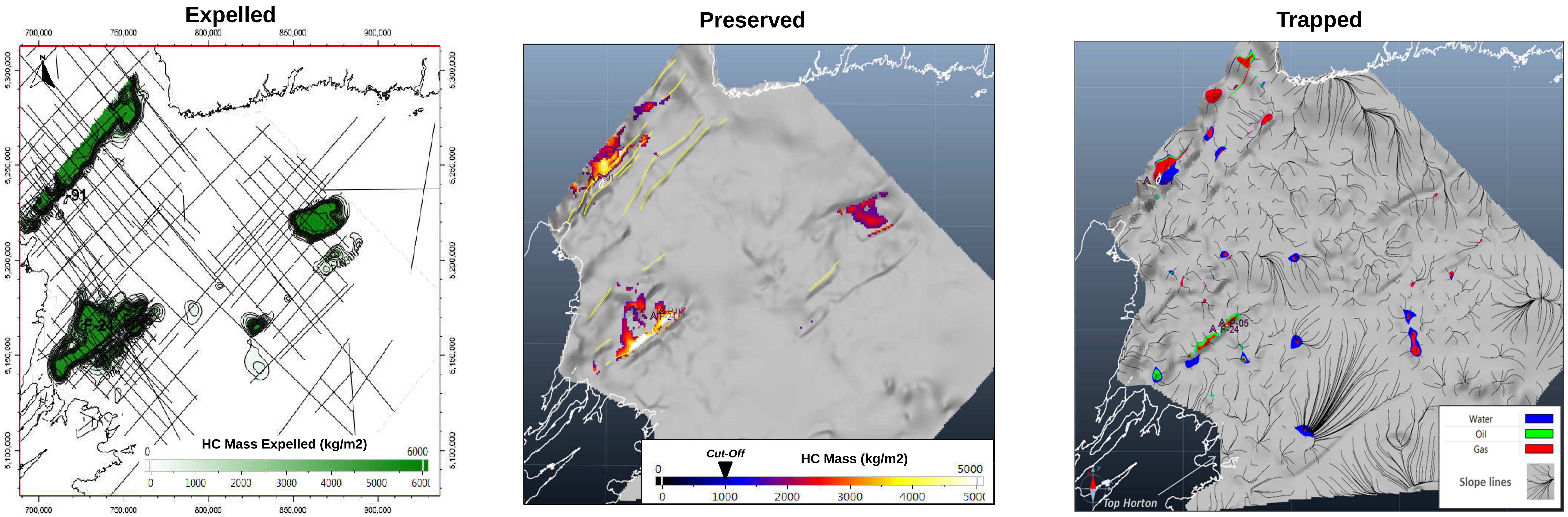


Figure 30: Hydrocarbons expelled / preserved / trapped for the Horton play

Figure 30 shows an overview of the Horton play. 3D migration results predict that the Horton play is likely to be the most effective. The three maps show the charge process from expulsion to trapping.

HC Expelled:

The hydrocarbon mass expelled from Horton source rocks is large. Suitable organic matter characteristics coupled with high transformation ratios yield an excellent source rock potential. Even if hydrocarbon expulsion is limited to the graben, the mass expelled is 172 BBOE. Figure 31 shows the quantity and composition of the hydrocarbons expelled from the source rock relative to primary cracking of organic matter.

HC Preserved:

Preserved hydrocarbons is an estimate of the charge present in the rock matrix at present day (i.e. this represents all hydrocarbons trapped present day in reservoir and non-reservoir rocks). Hydrocarbons may be lost in migration pathways and disseminated in the basin but not necessarily accumulated. In total, 23% of expelled hydrocarbons are predicted to be preserved. The rest was lost over time from Jurassic to present day by outflow from the basin edge or to surface. The histogram shows the average hydrocarbon mass quantity and hydrocarbon components resulting from migration and secondary cracking.

HC Trapped:

Hydrocarbons trapped represents the volume of hydrocarbon that have accumulated in structural / stratigraphic traps. The "traps" shown in Figure 30 should be considered as potential leads at this stage. In total, 4.5% of all expelled hydrocarbons are predicted to be trapped. This is equivalent to 8 BBOE. The histogram shows both the volumes and phase mix of the hydrocarbon present in traps.

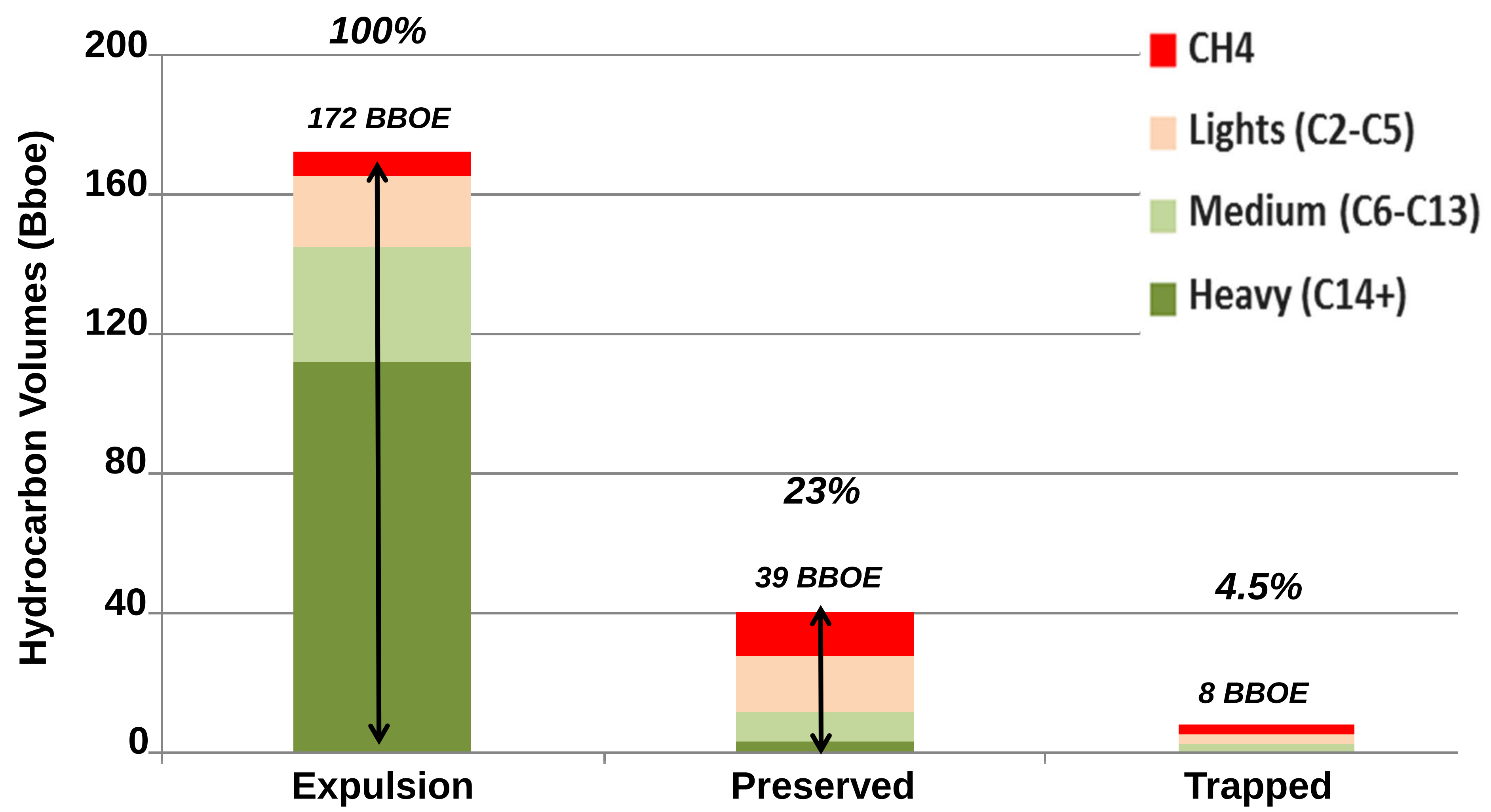


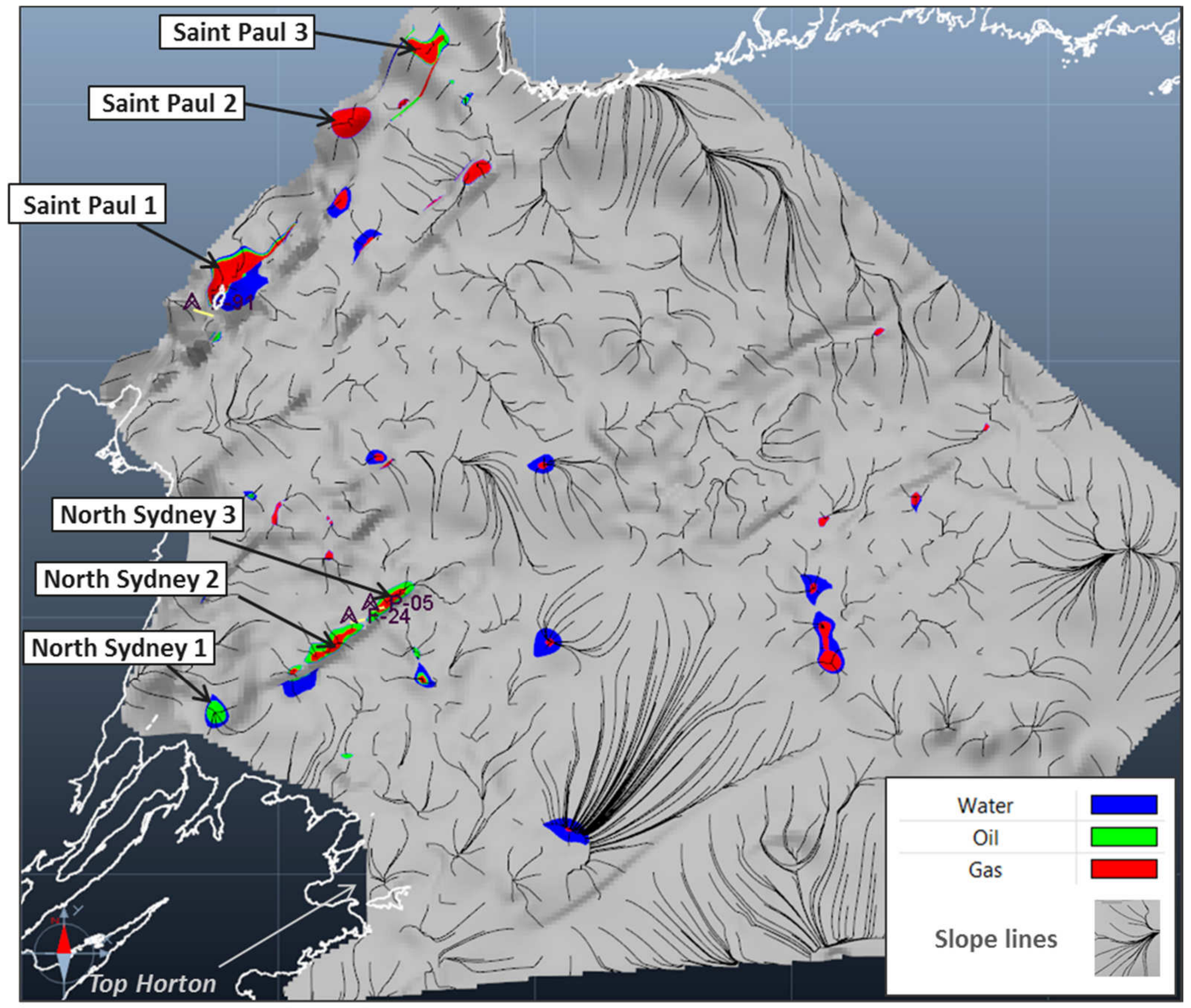
Figure 31: Histogram showing hydrocarbons expelled / preserved / trapped for the Horton play

Hydrocarbon Volumes and Fluid Types

Leads	Coordinates		Hydrocarbon in place						PVT properties			Standard Condition	
	X	Y	Liquid Volumes (MMBl)	Gas Volumes (MMm3)	Heavy Oil (C14+) %	Medium Oil (C6-C13) %	Light Oil (C2-C5) %	Gas (CH4) %	API°	GOR (mg/g)	BO (rm3/sm3)	Oil Volumes (MMBOE)	Gas Volumes (Tcf)
North Sydney 1	712600	5140000	460	0	18	40	34	8	37	90	1,30	350	0.2
North Sydney 2	737000	5154000	1 250	50	3	21	52	24	42	460	1,90	690	1.9
North Sydney 3	748600	5163000	940	52	2	20	51	27	43	570	2,00	510	1.8
Saint Paul 1	713600	5235000	500	420	10	20	46	24	40	2 170	1,85	460	6.4
Saint Paul 2	741600	5273000	0	210			17	83					3
Saint Paul 3	759600	5286000	420	82	17	30	35	18	37	810	1,70	270	1.4

**Component* Mass Percentages

Figure 32: Table showing for each lead: location, hydrocarbon volumes in reservoir condition, hydrocarbon components, API°, GOR, BO and hydrocarbon volumes in standard condition (surface condition).



Leads	Reservoir properties						
	Formation	Water depth (m)	Depth top (m)	Net Thickess (m)	Average Porosity (%)	Temperature (°c)	Overpressure (Mpa)
North Sydney 1	Horton / LowerWindsor	40	1500	100	8	69	2
North Sydney 2	Horton	54	2620	100	9	86	2
North Sydney 3	Horton	62	2580	100	9	85	2
Saint Paul 1	Horton / LowerWindsor	90	1890	100	8	75	3
Saint Paul 2	Horton / LowerWindsor	500	2920	100	6	91	4
Saint Paul 3	Horton / LowerWindsor	370	2240	100	8	69	2

Figure 33: Reservoir properties summarized by lead

For each lead, Figure 32 lists the coordinates of the top reservoir, hydrocarbon volumes in place (millions of barrels for liquids and cubic meters for gas), hydrocarbon components in mass percentage, API° (density), GOR (gas/oil ratio in mass), BO (oil volume factor) and hydrocarbon volumes at standard condition (surface condition) with oil in millions of barrels and gas in Tcf.

Figure 33 summarizes the reservoir properties for each lead with water depth (m), top reservoir depth (m), estimated reservoir net thickness (m), average expected porosity (%), reservoir temperature (°C) and reservoir overpressure (Mpa).

The listed leads are hydrocarbon accumulations containing more than 200 million barrels of oil or more than 2 Tcf of gas. North Sydney 1 is pure oil and Saint Paul 2 is pure gas. The other accumulations host oil and gas composed mainly of light components which give API° in the 37 to 42 range. Overpressure is low and is generally close to the hydrostatic curve due to the long period of relaxation (see Burial History, PL 8.4.2). Water depths are less than 100m for leads North Sydney 1, 2, 3 and Saint-Paul 1. Average total porosity, between 6 and 9%, is relatively low.

Petroleum System Analysis of the Two Main Leads

The graphs illustrate hydrocarbon accumulations in the Horton play based on basin modeling results. They detail the source rock expulsion and reservoir filling history as well as Horton reservoir temperature and evolution of porosity. The timing of secondary cracking is shown on the graphs, which resulted in hydrocarbon transformation into lighter components.

North Sydney 2 and 3:

The upper graph synthesizes the hydrocarbon trapping history of the North Sydney 2 and 3 leads. As previously described, these two targets are in the Horton play and are defined by a Horton source rock, an internal Horton reservoir and a Windsor seal.

Hydrocarbon expulsion extended from middle Carboniferous to the end of the Permian with an expulsion peak during the Pictou period (Early Permian). Expulsion occurred largely after the Windsor seal was already deposited. Primary migration filled internal Horton reservoirs from the end of the Carboniferous to the Permian.

Burial continued to increase during the Permian and temperature increased. This triggered secondary cracking of hydrocarbons in the Horton graben. Secondary cracking affected both disseminated and accumulated hydrocarbons and generated lighter components.

Following expulsion of most of the hydrocarbons, a regional uplift occurred with a light compressive component. This developed an anticline along the horst structure. This reconfiguration created new drainage patterns which focused the hydrocarbons to the top of the new anticline structures and concentrated liquids and gas in the Horton reservoir sealed by Windsor series rocks.

Note: Erosion of approximately 2km slightly increased porosity through mechanical rebound of the matrix. Trapped hydrocarbon volumes are also increased slightly due to remobilized hydrocarbons originating from deeper rocks.

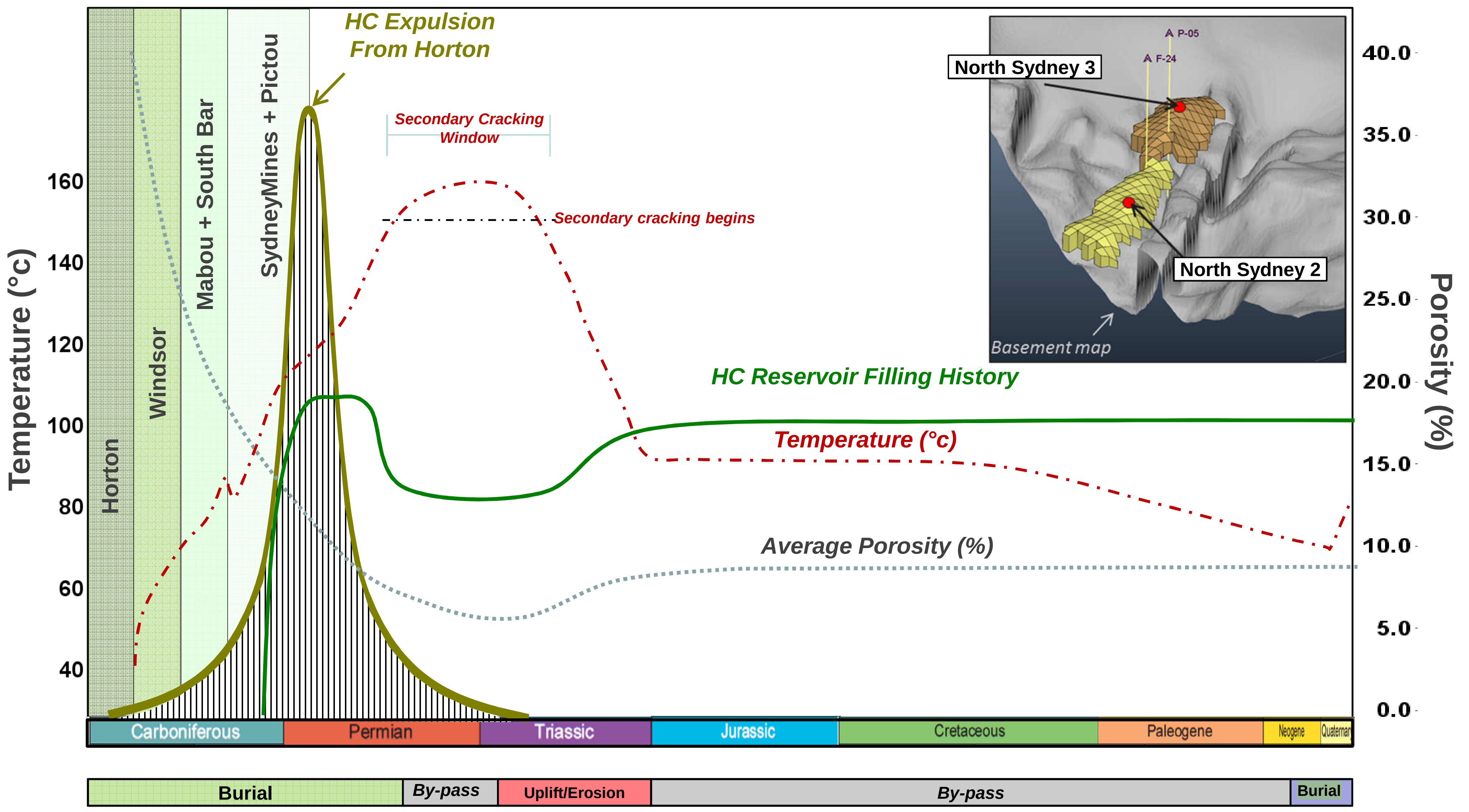


Figure 34: Lead history of North Sydney 2 and 3

Saint Paul 1:

The lower graph synthesizes the hydrocarbon trapping history of the Saint-Paul 1 lead. This target is in the Horton play defined by a Horton source rock, an internal Horton reservoir and a Windsor seal.

Hydrocarbon expulsion extended from middle the Carboniferous to the end of the Permian with an expulsion peak during the Pictou period (Early Permian). Expulsion occurred largely after the Windsor seal was already deposited. Primary migration filling internal Horton reservoirs was more long-lived than for the North Sydney 1 and 2 leads, and extended from the early Permian to the early Triassic.

Burial continued to increase during the Permian and temperatures rose. This triggered secondary cracking of hydrocarbons in the Horton graben. Secondary cracking affected both disseminated and accumulated hydrocarbons and generated lighter components. Temperature in this area was higher than at North Sydney 1 and 2 due to deeper burial. As a result, secondary cracking was more intense and the resulting leads are more gas prone. For example, the Saint-Paul 2 hydrocarbon accumulation hosts only gas.

Nevertheless, Saint Paul 1 has non-negligible proportion of oil which is preserved from the secondary cracking process due to the reservoir's low burial depth. Early hydrocarbon flows contain heavier components while later (younger) flows tend to have lighter components due to the secondary cracking that takes place in the deeper part of the graben.

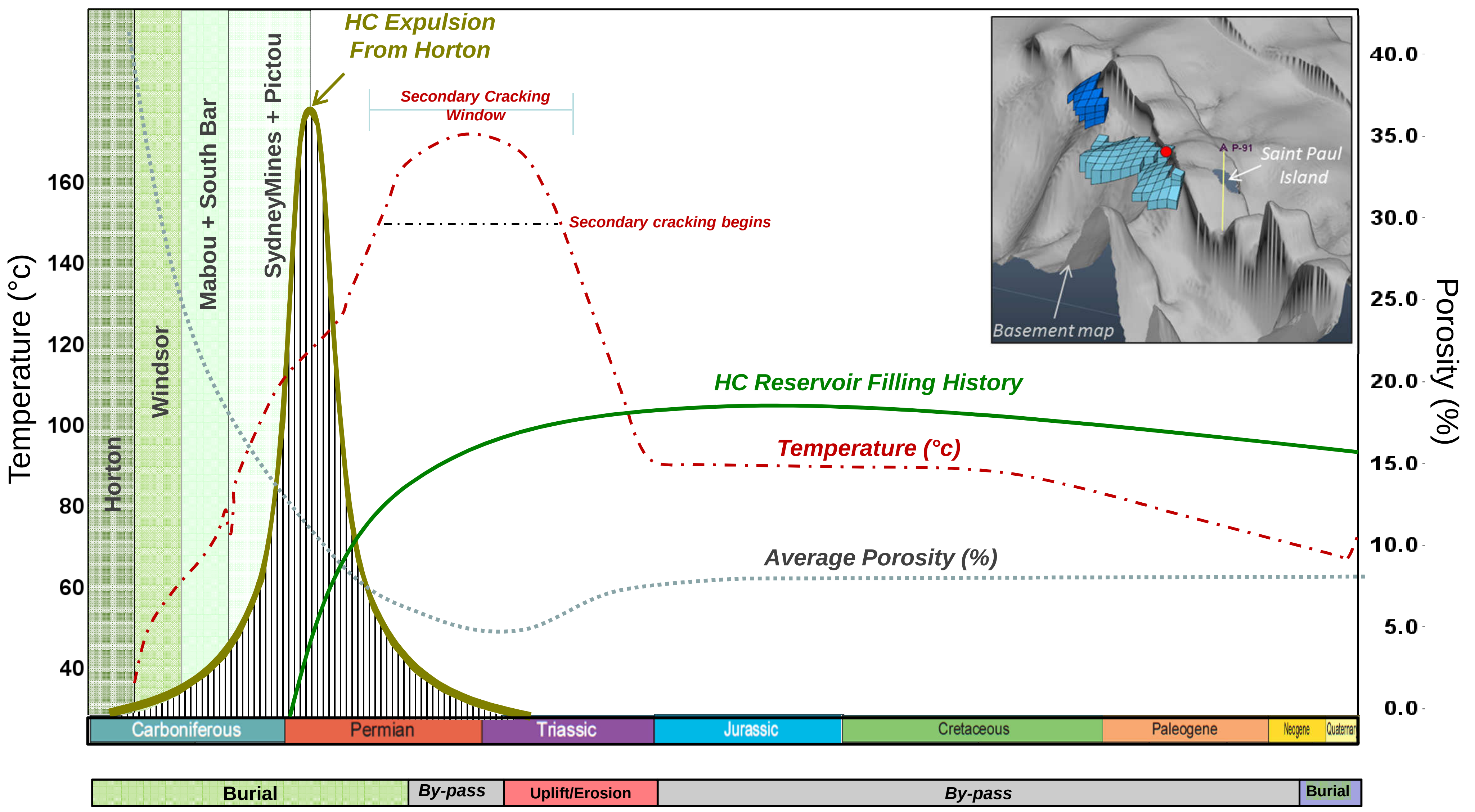


Figure 35: Lead history of Saint-Paul 1

Sensitivity Scenarios

Additional scenarios were evaluated to establish a better understanding of the hydrocarbon charge in the Horton play. Four sensitivity scenarios were examined. The scenarios considered uncertainties in the effects of Windsor group lithofacies distribution, permeability of carrier beds, and duration of erosion on migration. Scenario "GDE" is based on the GDE map for lithofacies distribution including the Windsor interval. Scenario "Reference" uses the GDE maps for all sequences apart from the Windsor, which is based on the Dionisosflow results for Windsor interval. "High permeability" increases permeability by five. Scenario "Timing Erosion" has erosion taking place over a longer period, from the Triassic to the Miocene.

The map in Figure 37 summarizes the results of the four scenarios, giving ranges for oil and gas volumes at standard condition and API° density for each lead. Additionally, bullets give information about depth of top Horton, water depth and total expected porosity.

The sensitivity scenarios show that hydrocarbon volumes can vary by a factor of 3 times the reference scenario or more, but hydrocarbons are still preserved in large quantities. The oil/gas ratio varies according to the migration properties which modify the timing of the charge. Indeed, a later charge will consist of a lighter product. According to the variations observed in the different scenarios, estimated volumes in North Sydney 2 and 3 and Saint-Paul 1 appear to be the most consistent and carry the greatest confidence.

Leads	Scenarios	Standard Condition		API°
		Oil Volumes (MMBOE)	Gas Volumes (Tcf)	
North Sydney 1	GDE	170	0.1	39
	Reference	350	0.3	37
	High Permeability	320	0.2	33
	Timing Erosion	430	0.5	38
North Sydney 2	GDE	340	1.9	48
	Reference	690	1.9	42
	High Permeability	500	1.6	40
	Timing Erosion	680	2.8	44
North Sydney 3	GDE	250	0.9	48
	Reference	510	1.8	43
	High Permeability	340	1.3	39
	Timing Erosion	560	2.6	43
Saint Paul 1	GDE	230	6.4	43
	Reference	460	5.4	40
	High Pemeability	400	5	39
	Timing Erosion	350	5.6	42
Saint Paul 2	GDE		1.4	
	Reference	120	3	47
	High Pemeability	430	1	45
	Timing Erosion		3	
Saint Paul 3	GDE	130	0.7	39
	Reference	270	1.4	37
	High Pemeability	250	1.5	38
	Timing Erosion	340	1.9	42

Figure 36: Table of oil and gas volumes and API° by sensitivity scenario per lead

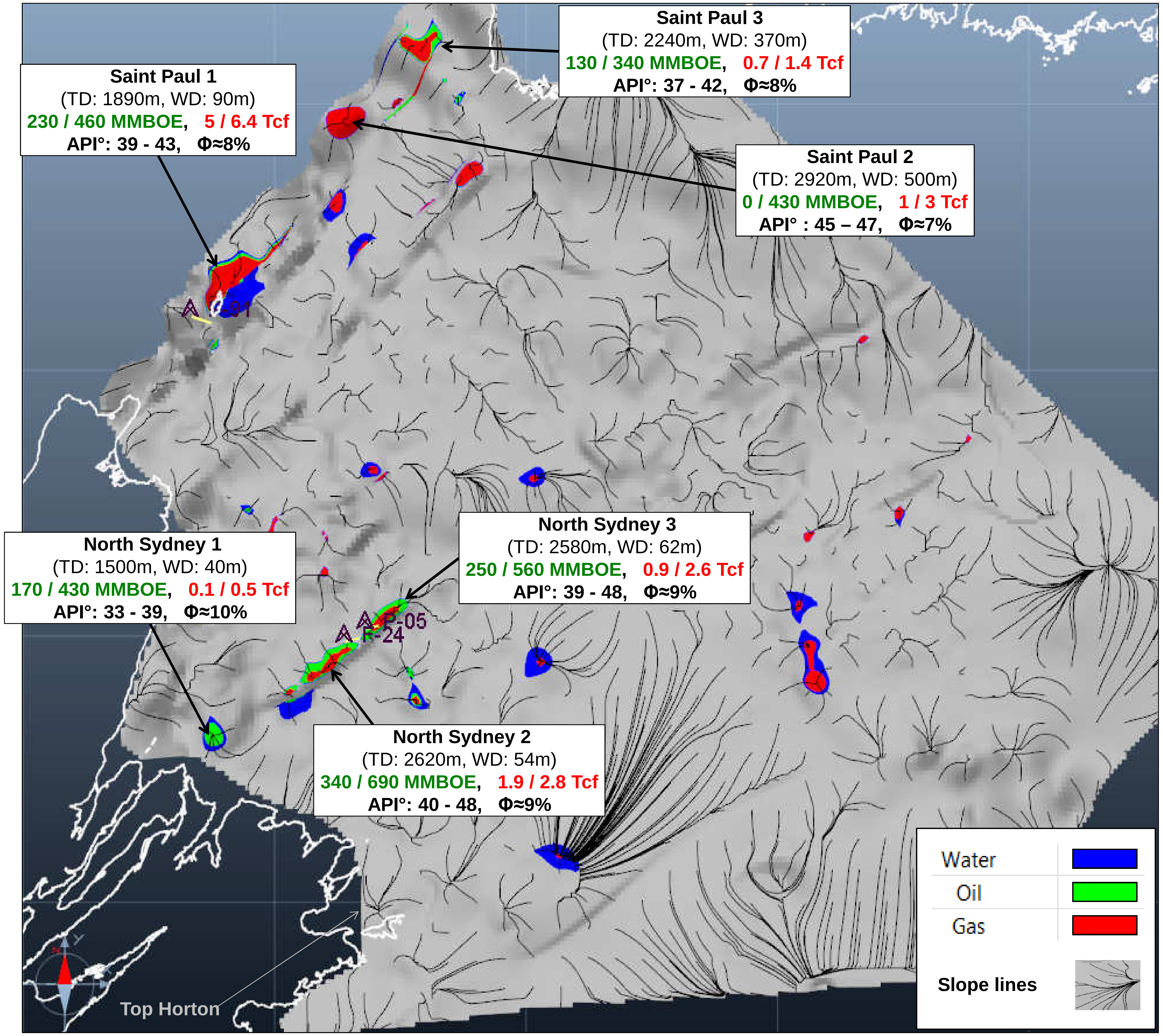


Figure 37: Summary of predicted hydrocarbons and volume ranges in the Horton play

Alternative Scenarios for Mabou Source Rock

An additional scenario for the Mabou source rock was tested to investigate the possibility of more optimistic source rock properties for the Mabou interval. A richer organic matter layer is potentially present in the basin depocenter. Indeed, observations of the Rocky Brooke Formation in the Deer Lake Basin of western Newfoundland indicate very rich organic matter in lacustrine shales of the lower Mabou. Based on these observations, an additional scenario using lacustrine source rock characteristics with higher average TOC% was tested. The table below gives a summary of the source rock parameters used for this alternative scenario:

Source Rock	Lithofacies	Avg Effective thickness (m)	Avg TOC0 (wt%)	Kerogen type	Avg HI0 (mgHC/g)	SPI (T/m2)
Mabou	Organic-lean shales	30 m	4%	I / II	500	1.4

This play is defined with a Mabou source rock, South Bar reservoir and the Sydney Mines Formation acting as a seal. The simulation shows two main hydrocarbon accumulations in the basin: hydrocarbon volumes are 210 MMB for South Bar 1 and 230 MMB for South Bar 2. Both host mainly oil at 25° API° with porosity of 11 to 13%.

Expelled hydrocarbons were largely lost through time. Only ~2% of the expelled hydrocarbons from Mabou would be trapped at present day. This low trapping efficiency is due to poor seal capacity and the large time period between expulsion and the present day. The critical risk for this play is the presence of a long lived effective seal.

Figure 38 illustrates hydrocarbon accumulations in the South Bar reservoir. It details timing of source rock expulsion and reservoir filling history as well as South Bar reservoir temperature and porosity evolution.

Hydrocarbon expulsion extends from the early Permian to the late Triassic. Maximum expulsion occurred during the late Permian to early Triassic when burial was greatest. Source rock transformation ratio reached approximately 80% in the center of the basin during maximum burial just prior to regional uplift.

Hydrocarbon migration flow is low through the Mabou Formation, which is composed mainly of fine grained sediments. As a consequence, the reservoir filled progressively through time and concentrated hydrocarbons from the Jurassic to Cretaceous periods. Reservoir filling reached a peak during the Jurassic for South Bar 1 and during the Paleogene for South Bar 2. Accumulated hydrocarbons are preserved in place until the present day.

Temperature in the South Bar reservoir is quite low at around 50°c during the Neogene. As a result, a risk of biodegradation is present for the oil currently in place.

Hydrocarbon seeps have been identified in Sydney Basin from satellite imagery. These seeps are located above predicted hydrocarbon accumulations in South Bar and have been predicted in the simulation (see insert, Figure 40)

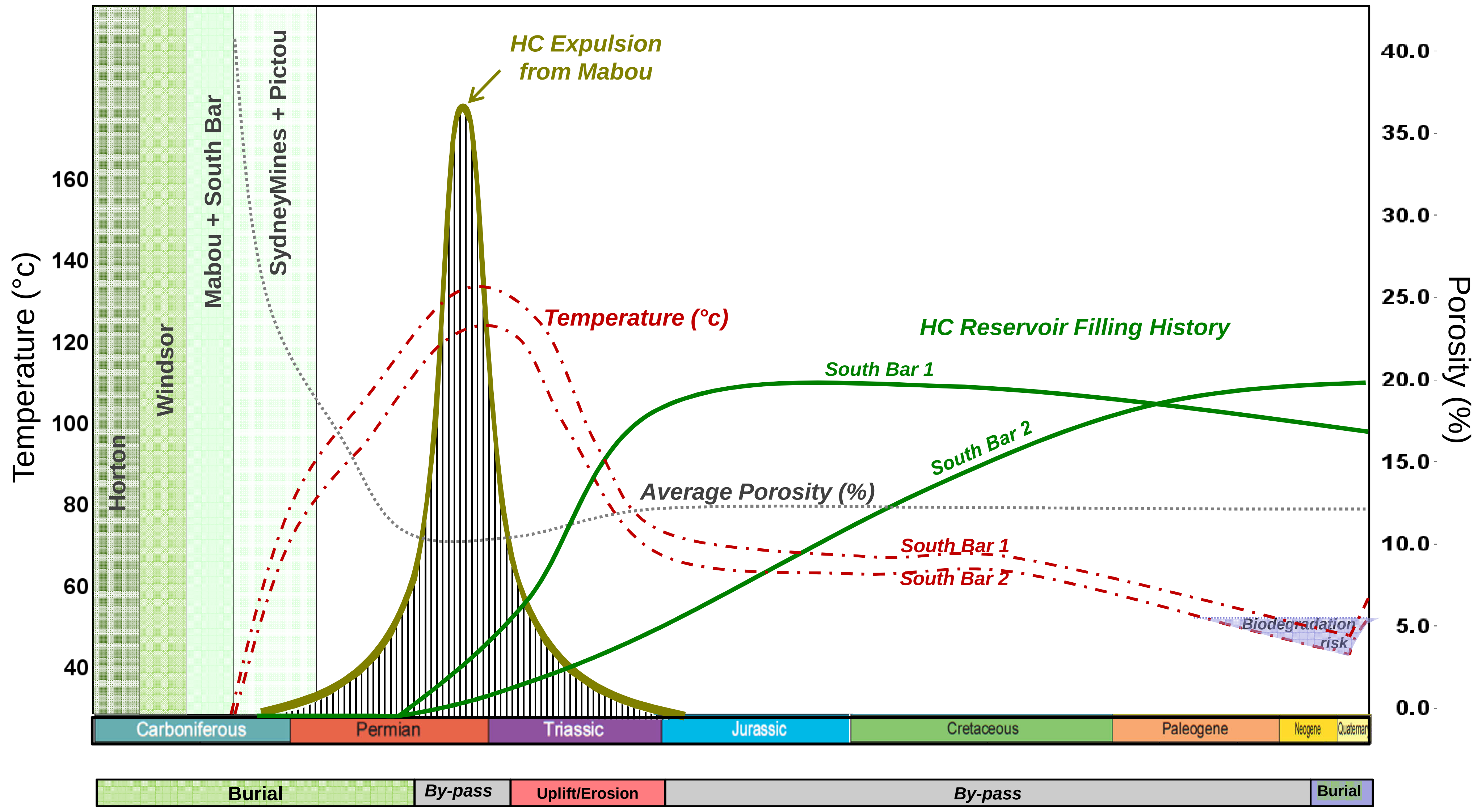


Figure 38: South Bar leads history

Maturity and Expulsion

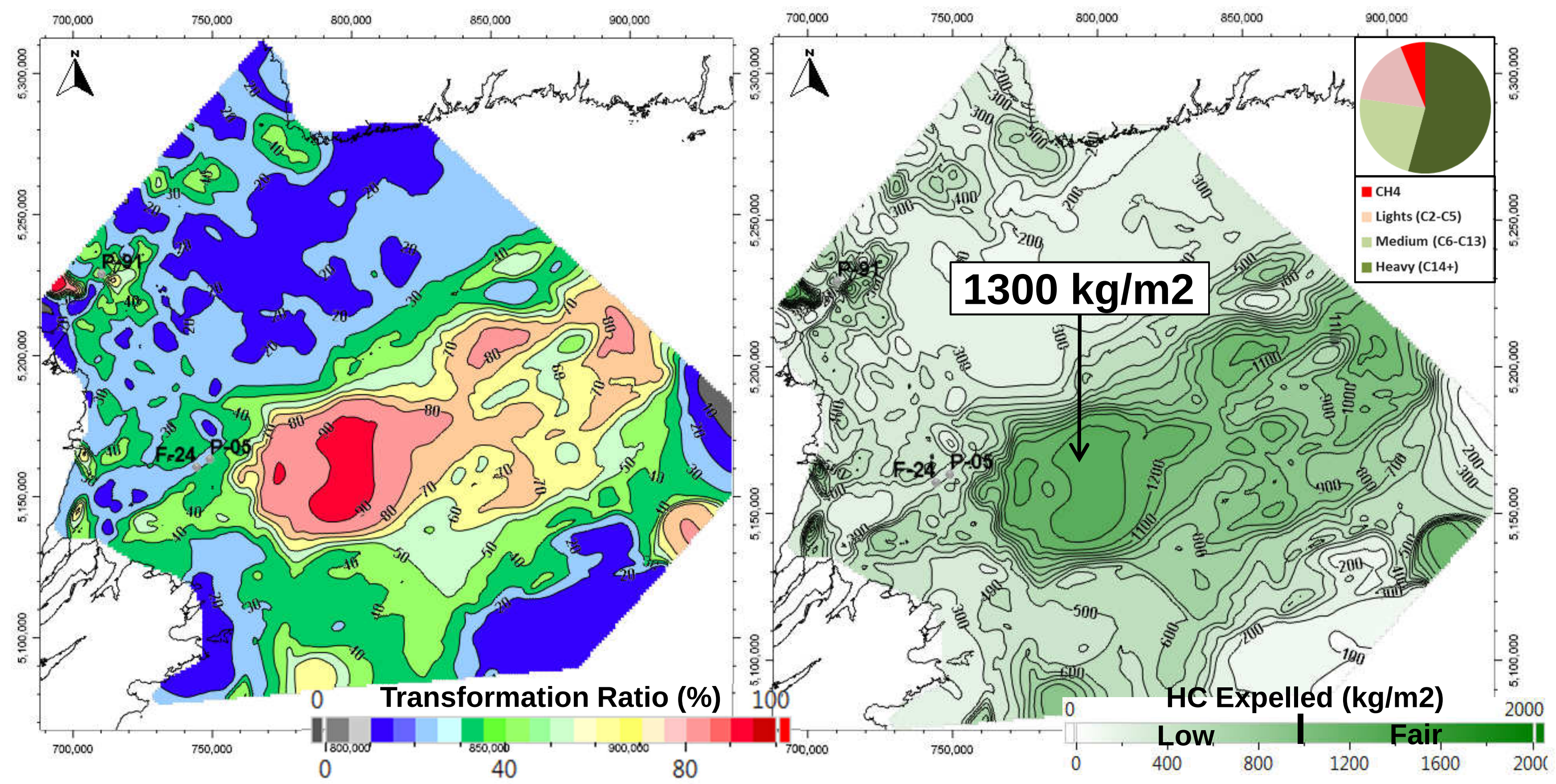


Figure 39: Transformation ratio and hydrocarbon mass expelled

South Bar Hydrocarbons accumulation

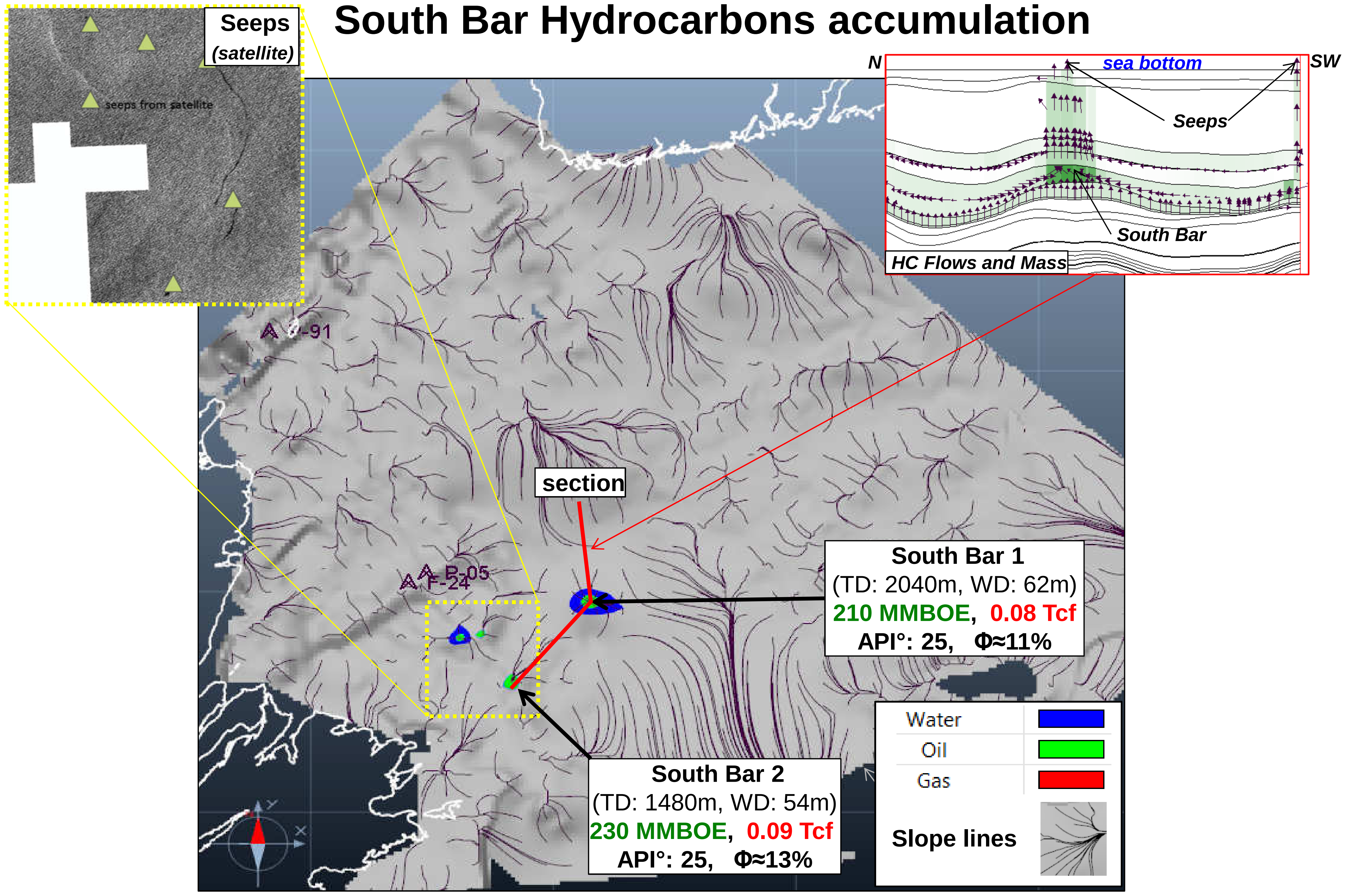


Figure 40: Predicted hydrocarbons in South Bar according to the optimistic scenario for Mabou source rock and seeps observed / simulated

Why no hydrocarbon accumulations around Graben East ?

No large hydrocarbon accumulations exist around Graben East because of the absence of efficient drainage areas to guide hydrocarbons to large structural traps. Structures are small, communicate by spill point and leak outside the model to the east or north.

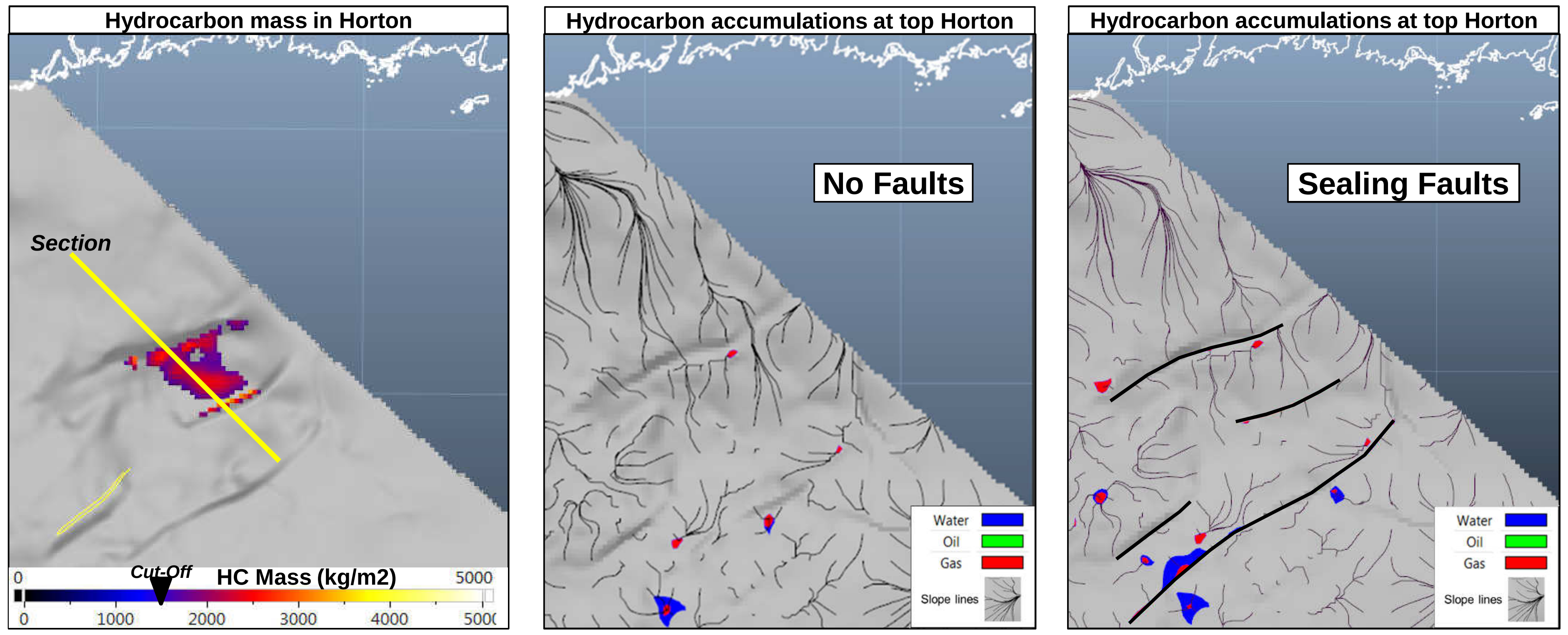


Figure 41: Hydrocarbon accumulations in Graben East

The map at left shows hydrocarbon mass in the basin at present day filtered by cut-off to highlight the largest accumulations. Most of the hydrocarbons are in fact disseminated in the matrix of non reservoir facies. The two other maps display accumulated hydrocarbons in structural traps and point out probable accumulations where two scenarios are considered: with no fault and with sealing fault. Both scenarios show gas prone area with very small structures. No clear differences are observed between these two scenarios.

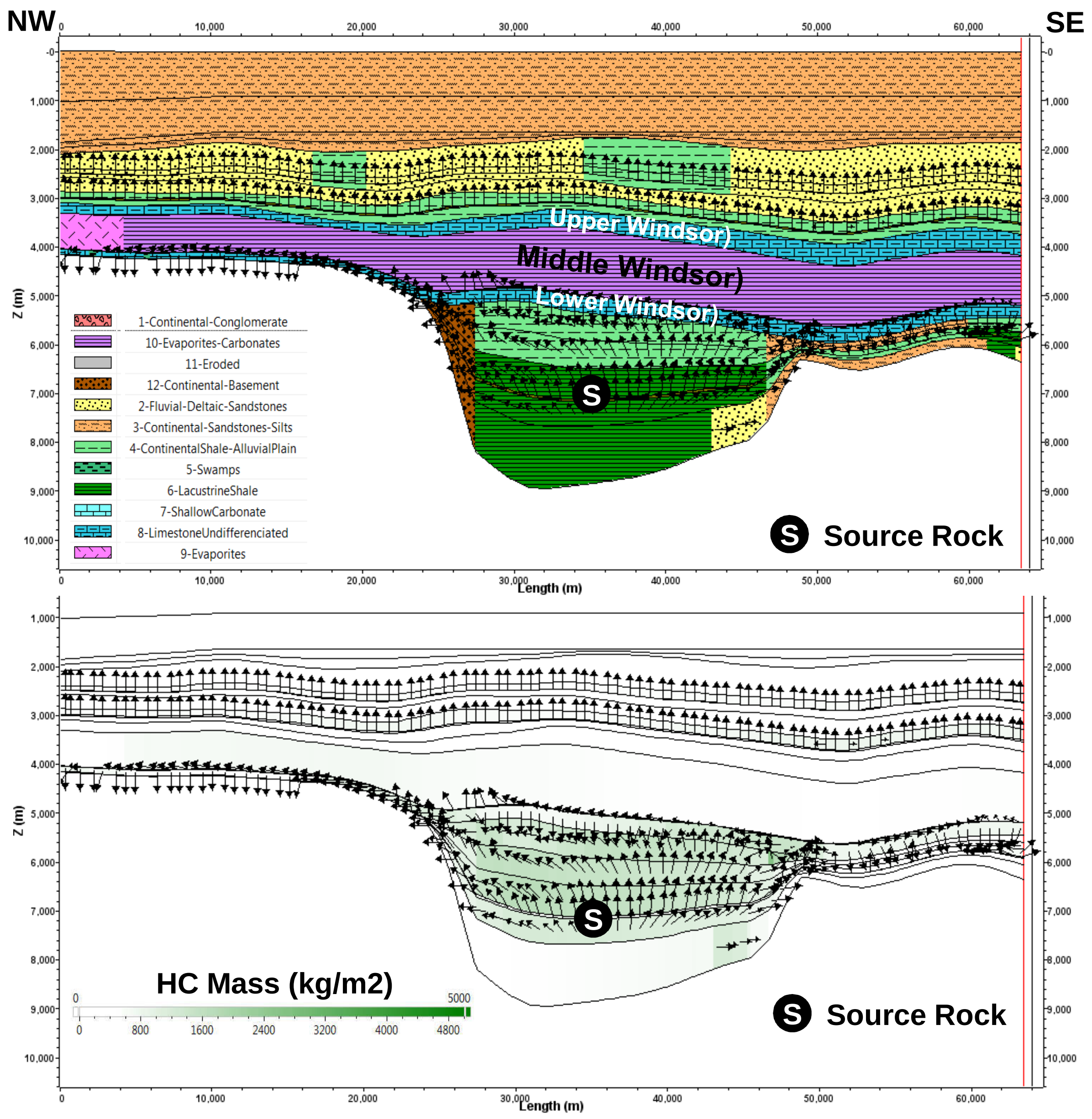


Figure 42: 2D section: hydrocarbon mass and flow through Graben East

The 2D cross section was extracted from the 3D model at the end of Triassic in order to highlight maximum hydrocarbon flows. Sections display lithofacies distribution and hydrocarbon mass and flow vectors.

No clear structural traps exist along the section. Middle Windsor constitutes a good seal (continuous and thick) but lower Windsor could act as a drain preventing stratigraphic trapping.

Hydrocarbons are located in the graben and flows are guided by regional slopes mainly to the northwest side through lower Windsor, consisting mainly of carbonates.

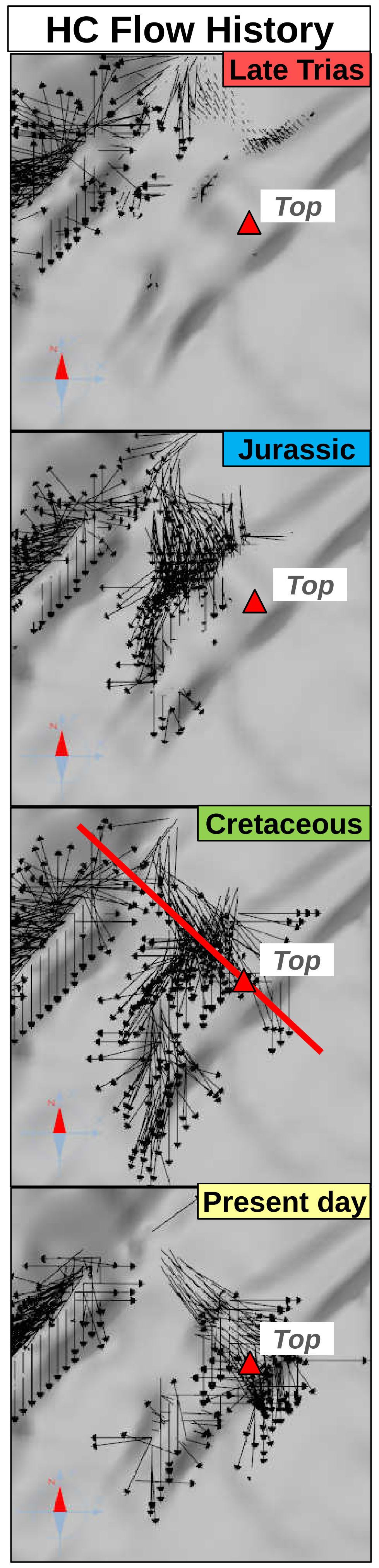
Comments: Another stratigraphic configuration can exist for lower Windsor where evaporites are directly deposited on basement favoring stratigraphic traps. Nevertheless, this area appears to lack significant structural closures that could trap large hydrocarbon accumulations.

Different scenarios (no faults, sealing faults or considering stratigraphic traps thanks to the middle Windsor) demonstrate that hydrocarbon accumulations are always minimal due to limitations in drainage area and trap size.

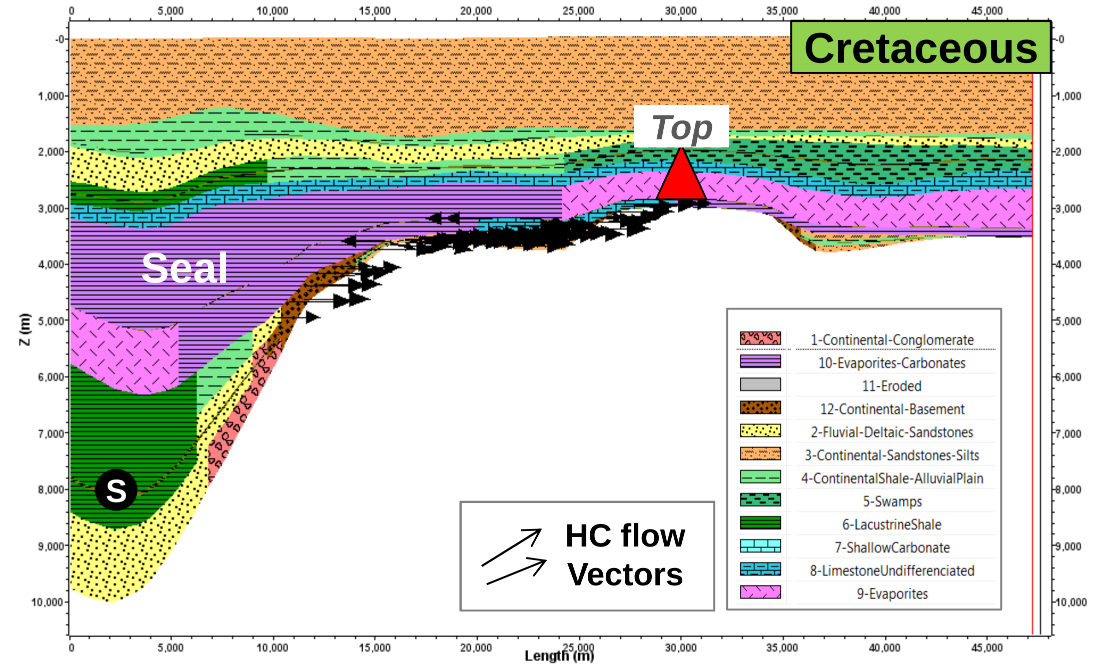
Potential charge east of Saint-Paul Island ?

The simulation shows that hydrocarbon flows exist at the location named “Top” in the sketch “HC Flow History” and move from Saint-Paul graben to the structural top following migration pathways (structural slope and carrier beds). Nevertheless, no large hydrocarbon volumes exist due to limited reservoir thickness. Hydrocarbon seal is efficient at this location and structural traps exist but the reservoir presence is uncertain (see “Seismic Stratigraphy and GDE mapping”, Chapter 6) and likely insufficient to accumulate large hydrocarbon volumes.

Reservoir presence is thus the main play risk at this location. Assuming an alternative hypothesis such as carbonate reservoirs or fractured reservoirs (e.g. tectonic effects during fault activation) might make this structure a potential lead for exploration.



Sketch on the left shows hydrocarbon flow history (black vectors) from Triassic to present day moving from Saint-Paul graben to the top of the structure. The extracted cross-section below displays hydrocarbon flows through lithofacies distribution during the Cretaceous. The bottom map shows hydrocarbon flows (green vectors) at present day in a 3D view.



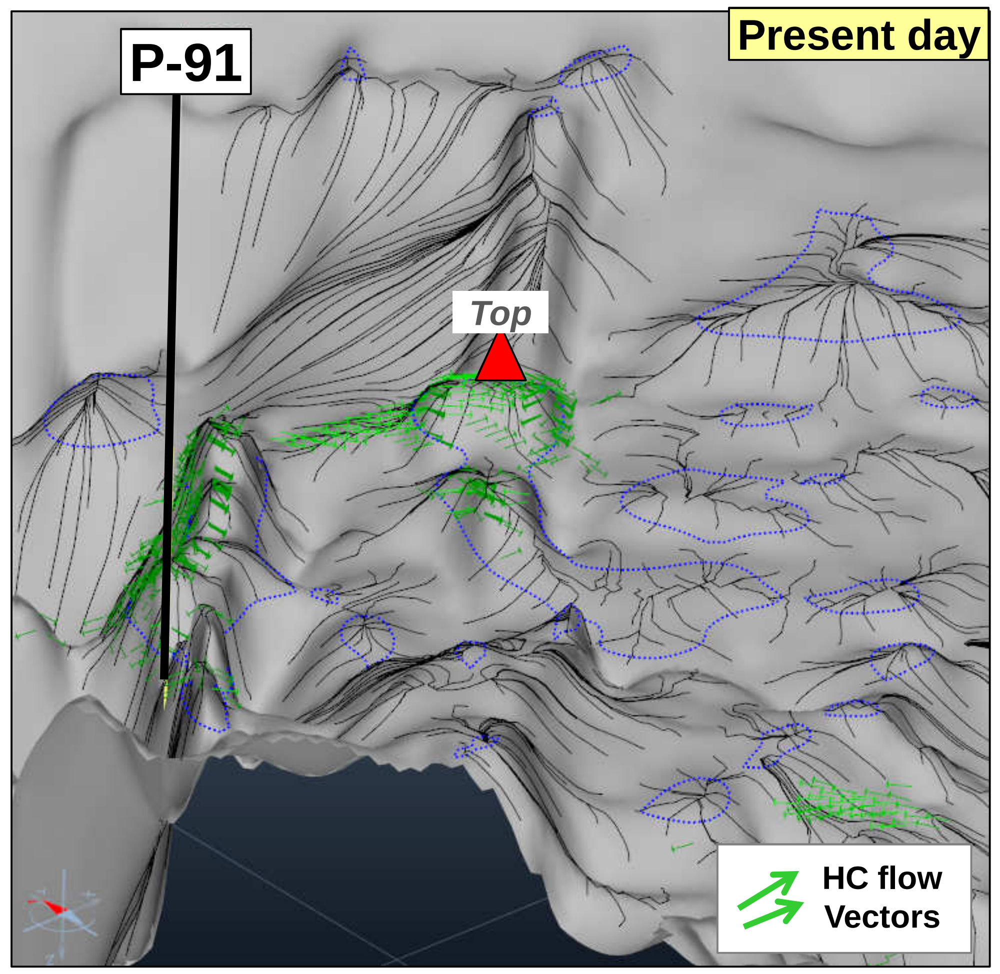
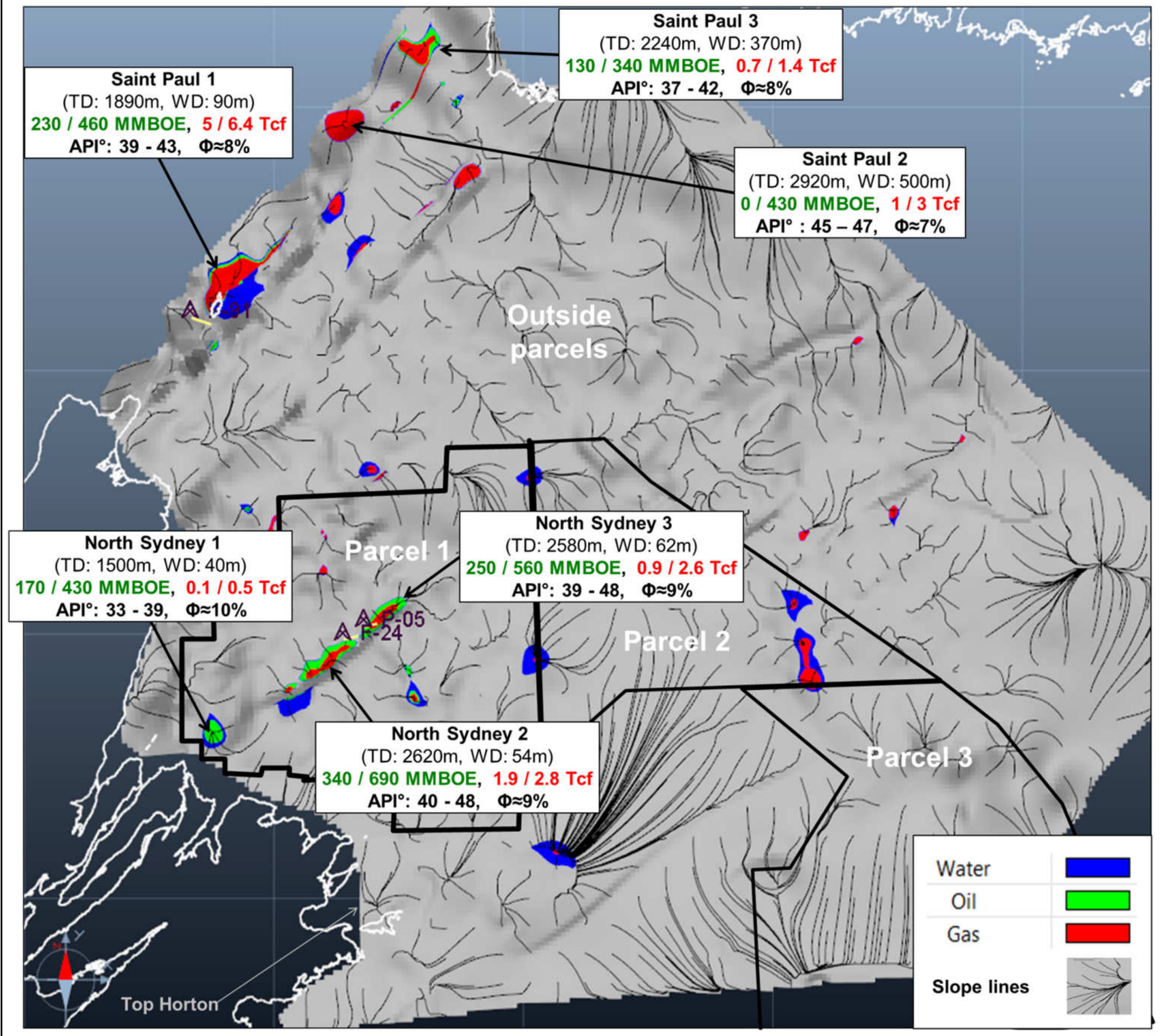
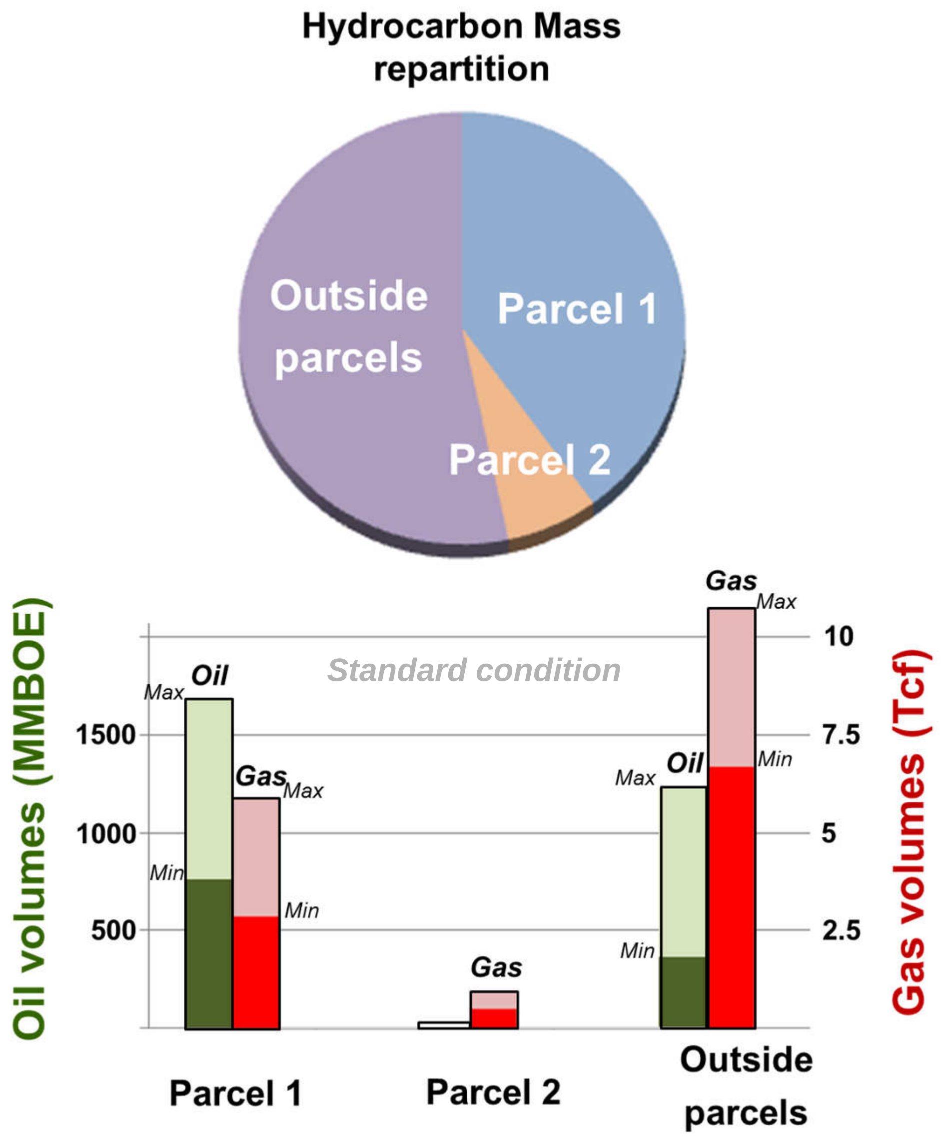


Figure 43: Sketches showing a probable lead east of Saint-Paul Island

Conclusion

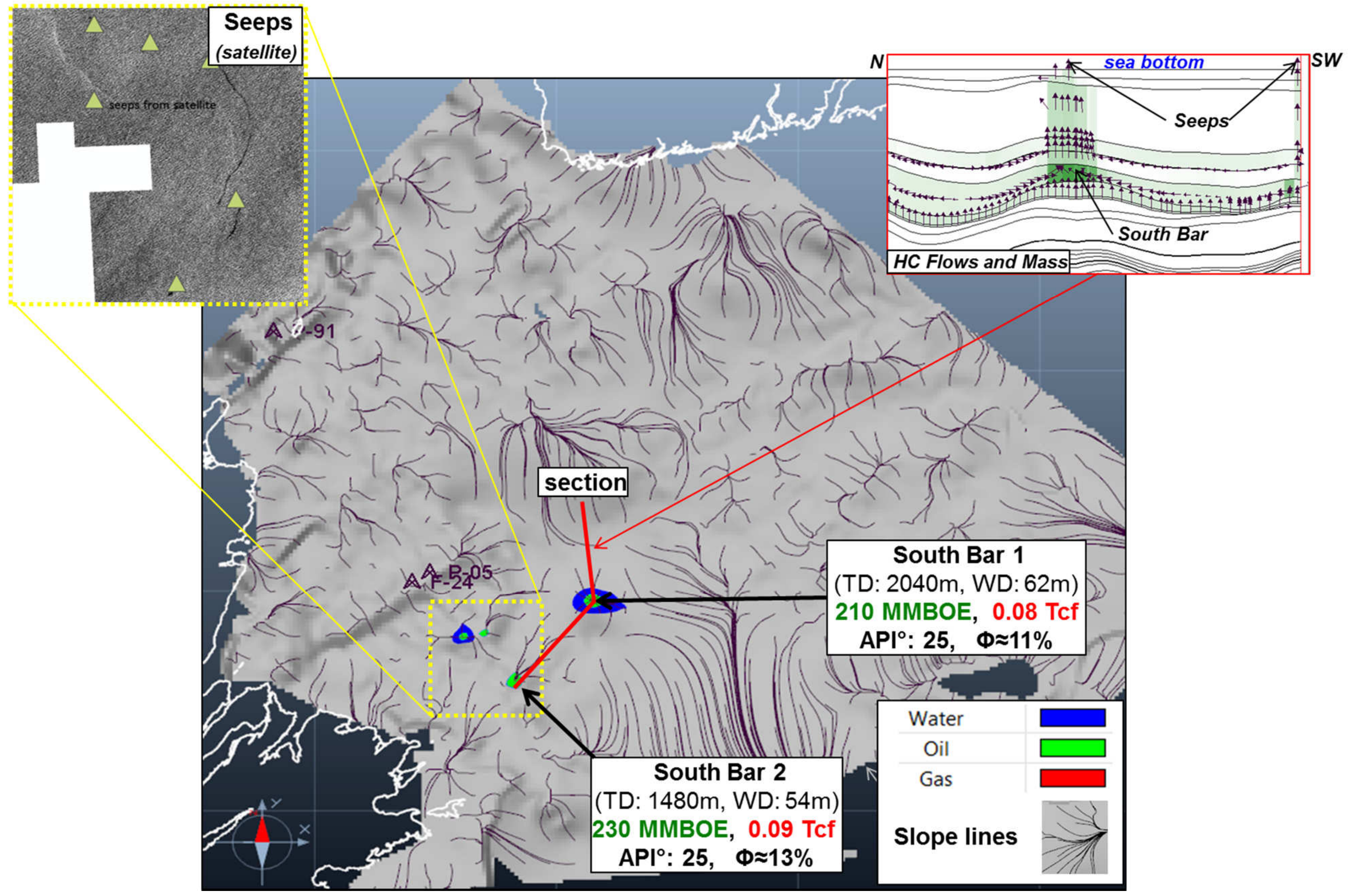
The Horton Play





Mabou /South Bar Play

(alternative scenario)



- In conclusion, the under-explored Sydney Basin may host significant hydrocarbon accumulations, particularly in the Horton play. Two drilled wells (F-24 and P-05) were stopped just above likely hydrocarbon accumulations located several hundred meters below, in the Horton Formation. In addition, well P-91 was very close to a probable large gas accumulation near Saint-Paul Island.

- Sydney Basin is composed of Paleozoic formations with four main plays from base to top: the Horton, Windsor, Mabou/SouthBar and Sydney Mines plays. The Horton Formation, deposited in a half graben, has the best source rock potential while the other formation have only very low potential. Peak hydrocarbon generation occurred in the early Triassic just before regional uplift associated with approximately 2-3 km of erosion.

- The main risks in the basin are hydrocarbon preservation through the Mesozoic and Cenozoic erathems, seal integrity, reservoir quality and tectonic timing. These risks were assessed during the study. Tectonic timing and deformation style were studied in the regional tectonic section (Chapter 2). Reservoir qualities were estimated by petrophysical study and regional data (Chapter 3). Seal integrity was evaluated in forward stratigraphic modeling simulations (Chapter 6) and hydrocarbon charge and preservation were assessed by Darcy flow migration modeling through basin modeling technology (Chapter 8).

- Results of the basin modeling show that the Horton play is the only working play in Sydney Basin given the stated assumptions of source rock inputs and basin modeling results. The reference model shows that Windsor seal integrity has been maintained until the present day. The northern sector of the basin is more gas prone than further south due to its higher state of maturity (burial effect). The total hydrocarbon volume for the Horton play is 2900 MMBOE of oil at 33 to 48° API° with largest accumulations around 500 MMBoe, and 17 Tcf of gas. Alternative scenarios were used to assess the uncertainties associated with the estimated oil and gas volumes.

- Surface seeps observed in the southern Sydney Basin prompted the consideration of an alternative scenario for Mabou source rock properties. In this scenario, significant hydrocarbon accumulations can be identified in the southern parts of the basin as well.

- Horton-derived hydrocarbon accumulations are linked principally to Mississippian graben structures identified in the seismic interpretation. Due to the variable quality of the seismic data used in this project, different seismic interpretations are possible for significant parts of the Sydney Basin, especially through the Mississippian section (See for example CNSOPB Call for Bids interpretation). Based on the basin modeling results presented herein, all Mississippian grabens could be expected to host significant hydrocarbons if interpreted in additional locations.

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