Objectives & Scenarios

The basin modeling study use TemisFlow 1D and 2D software.

It aims at improving further the knowledge on the active petroleum systems of offshore Nova Scotia by expanding the work carried out in the frame of the 2011 Play Fairway Analysis to neighboring areas through:

- Integration of petroleum systems elements into the model (source rock layers, plays systems, etc.)
- Thermal and pressure modelling
- Maturity modeling for kitchen areas identification
- Description of migration processes and hydrocarbon fluids composition evolution through geological time
- Identification of potential accumulation locations

The 1D models provide a preliminary calibration at well location with the highest stratigraphic resolution. It is also dedicated to the study of the Grand Bank area (Newfoundland) and of the deep offshore domain.

The 2D models tested alternative geological scenarios, evaluating their impact on the petroleum system quality:

- **Scenario 1 / Reference Scenario** (Shallow Tithonian horizon, Tithonian source rock is Type II/III, reference crust model)
- **Scenario 2:** Upper Continental Crust shrunk vertically (stretched horizontally
- **Scenario 3:** More proficient Tithonian source rock (Type II)
- **Scenario 4:** Deep Tithonian horizon

Lithologies TemisFlow 2D

Mixed Lithologies	Shale (%)	Sand (%)	Carbonate Nearshore (%)	Carbonate Mudstone (%)
L01	100	0	0	0
L02	80	20	0	0
L03	60	40	0	0
L04	40	60	0	0
L05	20	80	0	0
L06	0	100	0	0
L07	70	0	30	0
L08	50	20	30	0
L09	30	40	30	0
L10	10	60	30	0
L11	40	0	60	0
L12	20	20	60	0
L13	0	40	60	0
L14	0	0	100	0
L15	80	0	0	20
L16	60	20	0	20
L17	40	40	0	20
L18	20	60	0	20
L19	50	0	30	20
L20	30	20	30	20
L21	10	40	30	20
L22	20	0	60	20
L23	0	20	60	20
L24	60	0	0	40
L25	40	20	0	40
L26	20	40	0	40
L27	30	0	30	40
L28	10	20	30	40
L29	0	0	60	40
L30	40	0	0	60
L31	20	20	0	60
L32	0	40	0	60
L33	10	0	30	60

A set of 36 lithologies is used in the various Temis2D models built. 6 of them are pure lithologies, the rest of them being mixed lithofacies, their lithology composition being defined by a percentage of four pure poles which are Sand, Shale, Carbonate Nearshore and Carbonate Mudstone.

The lithology mixing scheme is identical to the one defined in the frame of the 2011 Play Fairway Analysis for the 2D basin modeling of the Project.

It allows us to leverage the 2011 Dionisos modeling results while converting the continuous lithology distribution as provided by Dionisos software into a
discrete spatial facies model as required for basin modeling studies.

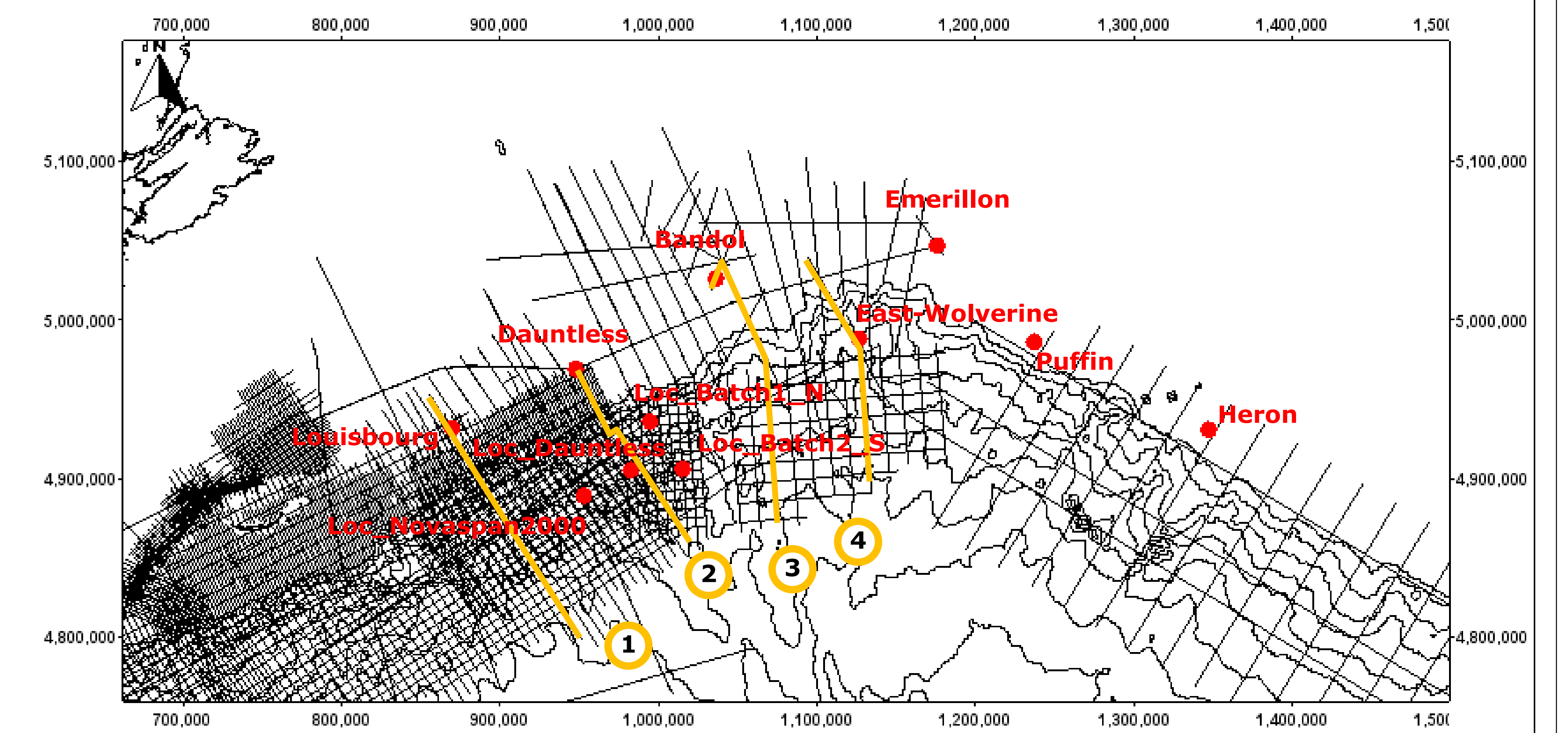
Petrophysical laws attached to each lithotype have been kept identical to the ones used in the frame of the 2011 Play Fairway Analysis for the sake of modeling results consistency.

Other Pure Lithologies
Chalk
Salt
Source Rock

Lithologies TemisFlow 1D

Lithologies implemented on 1D models directly depends on well reports. Due to the higher stratigraphic resolution, a special attention has been paid to carbonate rocks. On the contrary the library of mixed clastic lithologies has been simplified because migration processes are not modeled in 1D (see the section dedicated to the 1D modeling for more details).

Location Map



1 Louisbourg Section
2 Dauntless Section
3 Bandol Section
4 East-Wolverine Section

Thermal Basement

A thermal basement model has been defined for each modeled well (Temis 1D) and cross-section (Temis 2D), allowing for a fully coupled thermal computation between the Upper Mantle, the Crust and the sediments.

The thermal basement features the same thermal characteristics for each of the 4 cross-sections (Temis 2D) which have been modeled. Alternative crust geometry has been tested in a 4th scenario. In Temis 1D the lithospheric model is slightly different given that for the first time pre-salt sediments have been tentatively integrated to the geological model (see the section dedicated to the 1D modeling for more details).

The crust undergoes regular thinning from North-West to South-East. A rifting event between 225 and 200 Ma has been implemented in the thermal model. The impact on the temperature & maturity fields is taken into account with the rise of the 1330°C isotherm and the thinning of the crust in the oceanic domain.

Timeline	Age	Upper Crust (thickness varies laterally)	Lower Crust (thickness varies laterally)	Upper Mantle (lithospheric mantle)	Bottom thermal boundary condition
Before Rifting	Before 225 Ma	Initial Continental Crust (20 km)	Initial Continental Crust (12 km)	93 km	Isotherm 1330°C at base of Upper Mantle
End of Rifting	200 Ma	Oceanic Crust (4 km)	Oceanic Crust (2.4 km)		Rise of Isotherm 1330°C
		Continental Crust (up to 10-20 km)	Continental Crust (up to 10 km)		
After Rifting	After 200 Ma	Stable thickness	Stable thickness		Progressive deepening of the isotherm 1330°C down to the initial base of Upper Mantle

Chemical Scheme

Compound	Color	Compound Type	Mobility	Lumping Class	Thermal Stability
C1C5		Hydrocarbon	Mobile	GAS	Stable
C6-C13		Hydrocarbon	Mobile	OIL	Unstable
C14+		Hydrocarbon	Mobile	OIL	Unstable
Non-HC		Non Hydrocarbon	Mobile	/	Stable
NSO-Oil		Hydrocarbon	Mobile	OIL	Unstable
NSO-SR		Hydrocarbon	Immobile	/	Unstable
Precoke		Solid OM	Immobile	/	Unstable

Maturation of kerogens can generate 7 families of chemical components presented in the table above.

- The "Non-HC" fraction mainly corresponds to CO2. "C" refers to the number of carbon in aliphatic chains.
- "NSO" refers to Nitrogen/Sulfur/Oxygen rich molecules. This chemical fraction also contains heavy oils.
- C1-C5 corresponds to the ***GAS*** and {C6-C13; C14+; NSO-Oil} correspond to the ***OIL***.

A "mobile" fraction may migrate in reservoir layers while an "immobile" is solid or so viscous that it remains in the source rock.
An "unstable" fraction may be altered by secondary cracking to generate lighter compounds such as C6-C13 or C1-C5.

C1-C5	C6-C13	C14+	NSO-Heavy Oil
326 kg/m3	841 kg/m3	897 kg/m3	980 kg/m3

Average Densities at Surface Conditions (for the 4 mobile hydrocarbons classes)

Source Rocks and Kerogen types

	Name	Kerogen Type	Hydrogen Index (mg/gC)	S2 (mg/gC)	TOC (%)
1	Naskapi	Brent (Type III)	235	4.70	2
2	Mississauga	Brent (Type III)	235	4.70	2
3	Tithonian	Intermediate (Type II / III)	424	21.20	5
4	Misaine	Intermediate (Type II / III)	424	12.72	3
5	Pliensbachian	Menil (Type II)	600	30.00	5

Five source rock levels were implemented into the various 2D models built. Each of them is assumed to feature a constant thickness of 50m throughout the model.

Sorted by chronological order:

- Pliensbachian (196 Ma)
- Misaine (or Callovian 166 Ma)
- Tithonian (148 Ma)
- Mississauga (or Valanginian 136 Ma)
- Naskapi (or Aptian 122 Ma)

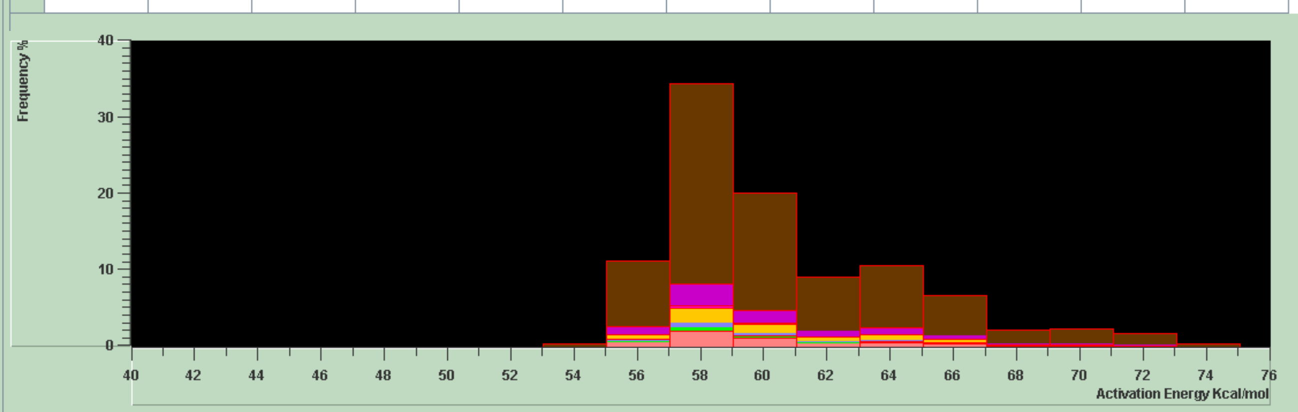
The same source rocks and kerogens are used both in 1D and 2D models. However the distribution of kerogen types and of TOC values may be adapted to the context and objective of each model. For example the 5 source rock layers are implemented in all the 1D models (if the stratigraphic layer exists – no hiatus or erosion), even if geochemical data do not indicate the presence of organic-rich layer at the well location.

Kinetics scheme

Type III kerogen

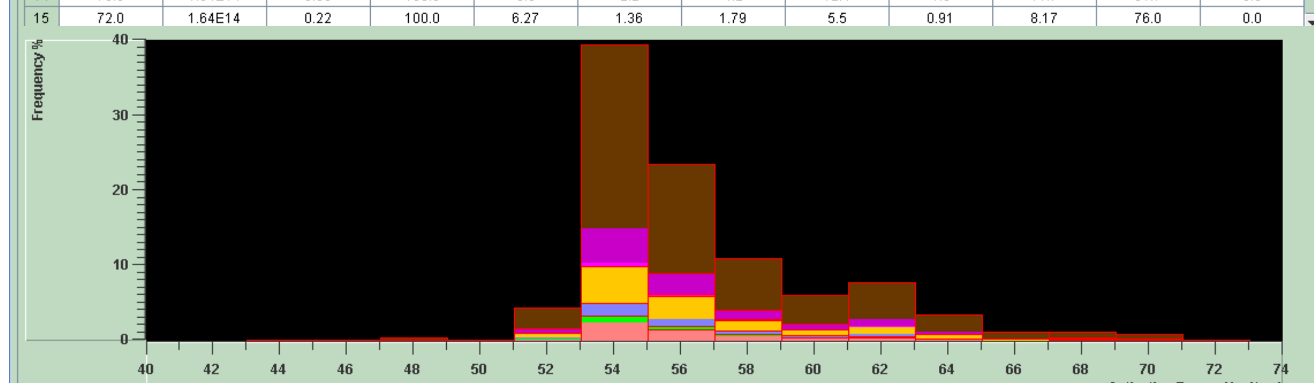
(Brent –Dogger; North Sea) -Vandenbrouke et al., 1999

	Activation Energy Kcal/mol	Arrhenius Coefficient 1/s	Frequency %	Sums of Fractions %	C1-C5 %	C6-C13 %	C14+ %	Non-HC %	NSO-Oil %	NSO-SR %	Precoke %	Coke %
1	54.0	3.1E15	0.51	100.0	6.27	1.36	1.79	5.5	0.91	8.17	76.0	0.0
2	56.0	3.1E15	11.32	100.0	6.27	1.36	1.79	5.5	0.91	8.17	76.0	0.0
3	58.0	3.1E15	34.51	100.0	6.27	1.36	1.79	5.5	0.91	8.17	76.0	0.0
4	60.0	3.1E15	20.17	100.0	6.27	1.36	1.79	5.5	0.91	8.17	76.0	0.0
5	62.0	3.1E15	9.15	100.0	6.27	1.36	1.79	5.5	0.91	8.17	76.0	0.0
6	64.0	3.1E15	10.72	100.0	6.27	1.36	1.79	5.5	0.91	8.17	76.0	0.0
7	66.0	3.1E15	6.77	100.0	6.27	1.36	1.79	5.5	0.91	8.17	76.0	0.0
8	68.0	3.1E15	2.3	100.0	6.27	1.36	1.79	5.5	0.91	8.17	76.0	0.0
9	70.0	3.1E15	2.38	100.0	6.27	1.36	1.79	5.5	0.91	8.17	76.0	0.0
10	72.0	3.1E15	1.74	100.0	6.27	1.36	1.79	5.5	0.91	8.17	76.0	0.0
11	74.0	3.1E15	0.43	100.0	6.27	1.36	1.79	5.5	0.91	8.17	76.0	0.0



Type II-III kerogen (mix)

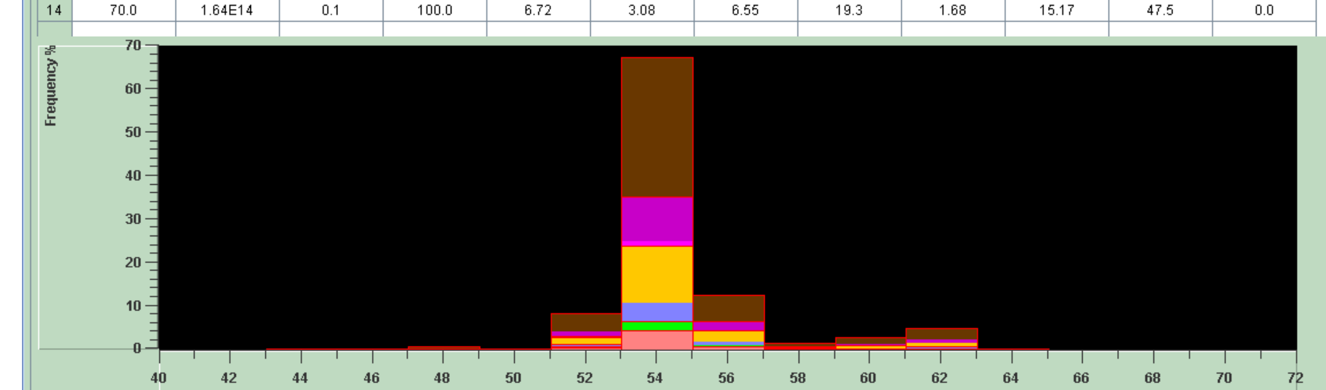
	Activation Energy Kcal/mol	Arrhenius Coefficient 1/s	Frequency %	Sums of Fractions %	C1-C5 %	C6-C13 %	C14+ %	Non-HC %	NSO-Oil %	NSO-SR %	Precoke %	Coke %
1	44.0	1.64E14	0.09	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
2	46.0	1.64E14	0.11	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
3	48.0	1.64E14	0.44	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
4	50.0	1.64E14	0.16	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
5	52.0	1.64E14	4.49	100.0	6.5	2.2	4.2	12.4	1.3	11.7	61.7	0.0
6	54.0	1.64E14	39.35	100.0	6.5	2.2	4.2	12.4	1.3	11.7	61.7	0.0
7	56.0	1.64E14	23.55	100.0	6.5	2.2	4.2	12.4	1.3	11.7	61.7	0.0
8	58.0	1.64E14	10.92	100.0	6.5	2.2	4.2	12.4	1.3	11.7	61.7	0.0
9	60.0	1.64E14	6.04	100.0	6.5	2.2	4.2	12.4	1.3	11.7	61.7	0.0
10	62.0	1.64E14	7.82	100.0	6.5	2.2	4.2	12.4	1.3	11.7	61.7	0.0
11	64.0	1.64E14	3.53	100.0	6.5	2.2	4.2	12.4	1.3	11.7	61.7	0.0
12	66.0	1.64E14	1.17	100.0	6.5	2.2	4.2	12.4	1.3	11.7	61.7	0.0
13	68.0	1.64E14	1.22	100.0	6.5	2.2	4.2	12.4	1.3	11.7	61.7	0.0
14	70.0	1.64E14	0.89	100.0	6.5	2.2	4.2	12.4	1.3	11.7	61.7	0.0
15	72.0	1.64E14	0.22	100.0	6.27	1.36	1.79	5.5	0.91	8.17	76.0	0.0



Type II kerogen

(Mesnil-2 –Toarcian; France) -Behar et al., 1997

	Activation Energy Kcal/mol	Arrhenius Coefficient 1/s	Frequency %	Sums of Fractions %	C1-C5 %	C6-C13 %	C14+ %	Non-HC %	NSO-Oil %	NSO-SR %	Precoke %	Coke %
1	44.0	1.64E14	0.17	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
2	46.0	1.64E14	0.22	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
3	48.0	1.64E14	0.88	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
4	50.0	1.64E14	0.32	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
5	52.0	1.64E14	8.47	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
6	54.0	1.64E14	67.38	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
7	56.0	1.64E14	12.58	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
8	58.0	1.64E14	1.67	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
9	60.0	1.64E14	2.93	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
10	62.0	1.64E14	4.92	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
11	64.0	1.64E14	0.28	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
12	66.0	1.64E14	0.03	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
13	68.0	1.64E14	0.05	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0
14	70.0	1.64E14	0.1	100.0	6.72	3.08	6.55	19.3	1.68	15.17	47.5	0.0



Kerogen maturation follows "kinetic schemes" specific to each kerogen type. The maturation process is divided in "n" parallel chemical reactions (11 to 15 in that case) which have their own reaction speeds. Reaction speed is calculated with the Arrhenius Law and depends on: the Activation Energy, the Arrhenius Coefficient (specific to each chemical reaction), and the temperature. Each reaction generates chemical fractions defined by the chemical scheme.
Tables and graphs detail the 3 kinetic schemes used in this study (Type III, Type II-III, Type II). These schemes are derived from the PFA2011 study.
Secondary cracking reactions also follow kinetics laws.

1D Modeling

Description of 1D models

Ten (10) 1D models have been integrated in the study:

- 6 wells with calibration data (vitrinite and temperature):
    - 1 in eastern Nova Scotia Shelf (Dauntless-D-35)
    - 2 in Laurentian Channel (Bandol-1 in the shelf domain, East-Wolverine-G-37 in the deep offshore domain)
    - 3 in the Grand Banks (New Found Land, on the shelf, from the West to the East: Emerillon-C-56, Puffin-B-90, Heron-H-73)
- 4 “pseudo wells” located in the deep offshore part of the Laurentian Basin

All the 1D models share the same stratigraphy. The depth markers were defined as follow:

- For the first time pre-salt sediments and/or metasediments (Paleozoic to Triassic) were integrated to 1D models. The “top basement” is not the base of the salt (J200) but a deeper marker estimated with maps from the Geological Survey of Canada (“Depth to Basement of the Continental Margin of Eastern Canada”, used in 1D models only).
- 11 depth markers were interpreted by geophysics: Seabed / T29 / T50 / K94 / K101 / K130 / K137 / J150 / J163 / top salt (specially picked for the 1D modeling) / J200. In one pseudo-well top and base of the allochthonous salt have been provided too.
- From 15 to 25 well markers are provided by sedimentological logs reinterpreted in 2014 (cf. previous chapters), plus the log Dauntless (studied in the 2011). The number of available markers mainly depends on the oldest formation reached by the well.

Depending on the context, the origin and the resolution of the model vary:

- For Puffin-B-90 which was not included in the sedimentological study and which is relatively far from available seismic lines (about 10 km north and east of the closest line), well markers and facies attributions are reinterpreted from available well reports (Well History Report and Paleontological Summary). Deep horizons from the Callovian to J200 (base of the salt) are extrapolated from nearest seismic lines.
- For the 5 other wells, well markers for drilled formations come from sedimentological logs. Deep horizons down to J200 are exported from the seismic study.
- For the 4 pseudo-wells, only the seismic interpretation is available.

The same lithology library has been used in all the 1D models. It has been modified from the one used in 2D models (higher resolution of 1D models). Facies distribution is directly based on well logs and on conceptual models (for undrilled sections).

The 5 potential source rocks are implemented in the 1D models, however source rocks effective thicknesses are not taken into account (maturity modeling only). Even if the source rocks are not identified in the wells, a SR potential has been defined at corresponding stratigraphic levels (except if the layer is missing or eroded). The geochemical scheme is the same as the one used in the 2D models. Note that the Lower Jurassic SR (Pliensbachian and / or Toarcian) is Type II in the deep offshore basin, and type II-III on the Shelf (where the source rock potential is likely very low, like in Heron).

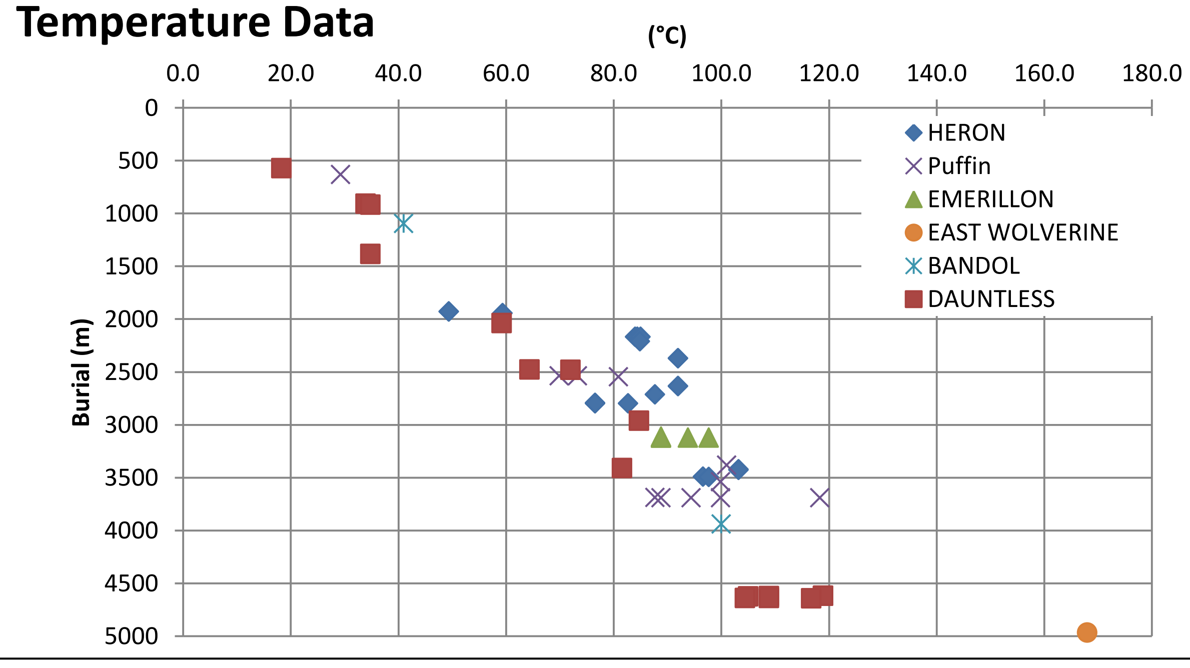
Like in 2D models, the whole lithosphere and the rifting event are considered for improving the thermal modeling through geological times. The present day crust thickness comes from the Geological Survey of Canada (map “Crustal Thickness, Seismicity, and Stress Orientation of the Continental Margin of Eastern Canada”).

Calibration Data

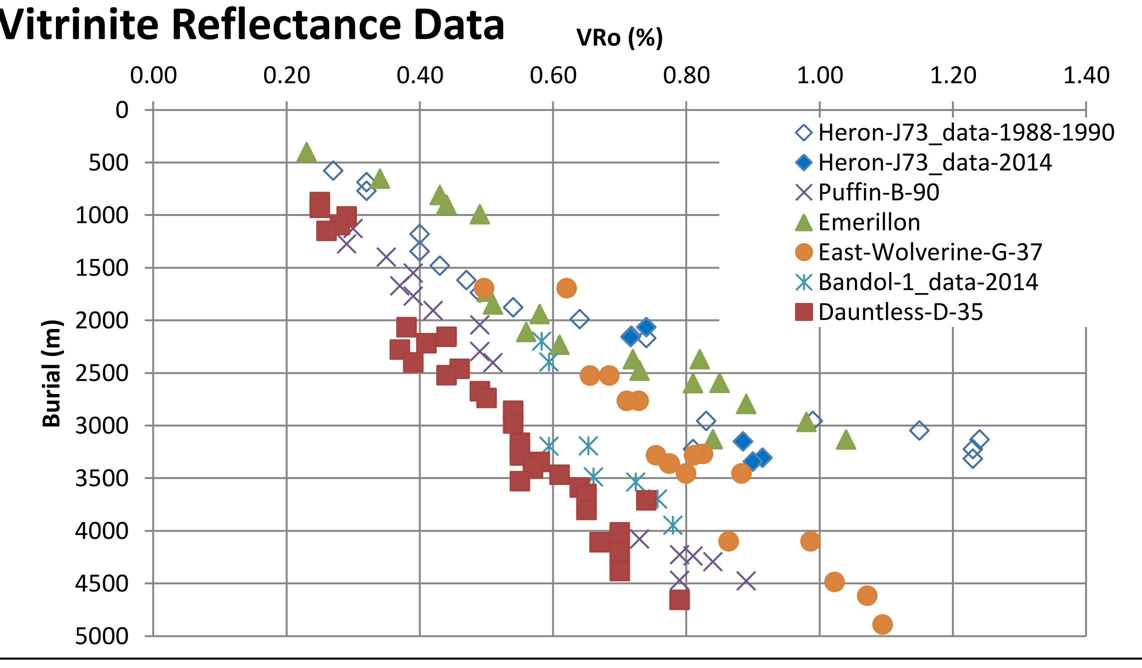
Only Temperature and Vitrinite Reflectance data are calibrated. The pressure modeling is not feasible in1D models not associated to a 3D model. Temperature and vitrinite reflectance data are available in the 6 wells.

- Most of the temperature data come from log measurements (not corrected BHT). Such data often underestimate the formation temperature by 10°C / 10%, up to 20% in some case. In the example of Heron the temperature vary between 76°c and 92°C in the interval 2600-2800 m. The model is usually “calibrated” when the temperature trend is close or above control points. Single data points are always questionable.
- Vitrinite reflectance data are uncertain too. Depending on the sampled maceral and on the laboratories, values can be significantly over or underestimated (>25%).
    - In the example of Heron, some vitrinite reflectance data seem strongly overestimated: at 3662 m. The vitrinite reflectance has been measured at 1.23 in 1988, 0.81 in 1990, and about 0.89 in 2014 (at 3291 m). In that case the “real” vitrinite reflectance is certainly between 0.8 and 0.9 according to the model (no higher heat flow or major erosion in the past).
    - In the example of Dauntless, on the contrary, the vitrinite reflectance is likely underestimated. Present day temperatures are too high to fit the measured vitrinite reflectance (and as mentioned before BHT are scarcely overestimated).
    - Despite uncertainties, several maturity trends are clearly identifiable, particularly on VRo data: Dauntles, Bandol and Puffin are “cooler” than Heron and Emerillon. East Wolverine seems rather “hot” too, despite its distal location.

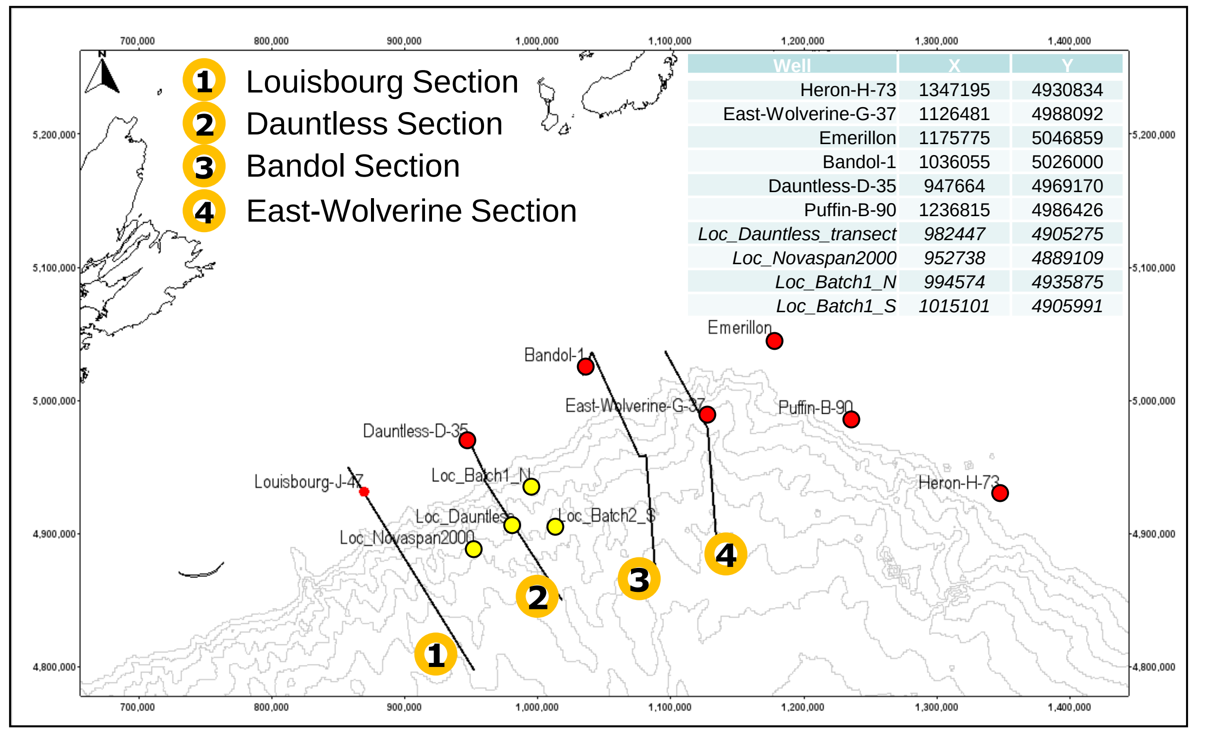
Temperature Data



Vitrinite Reflectance Data

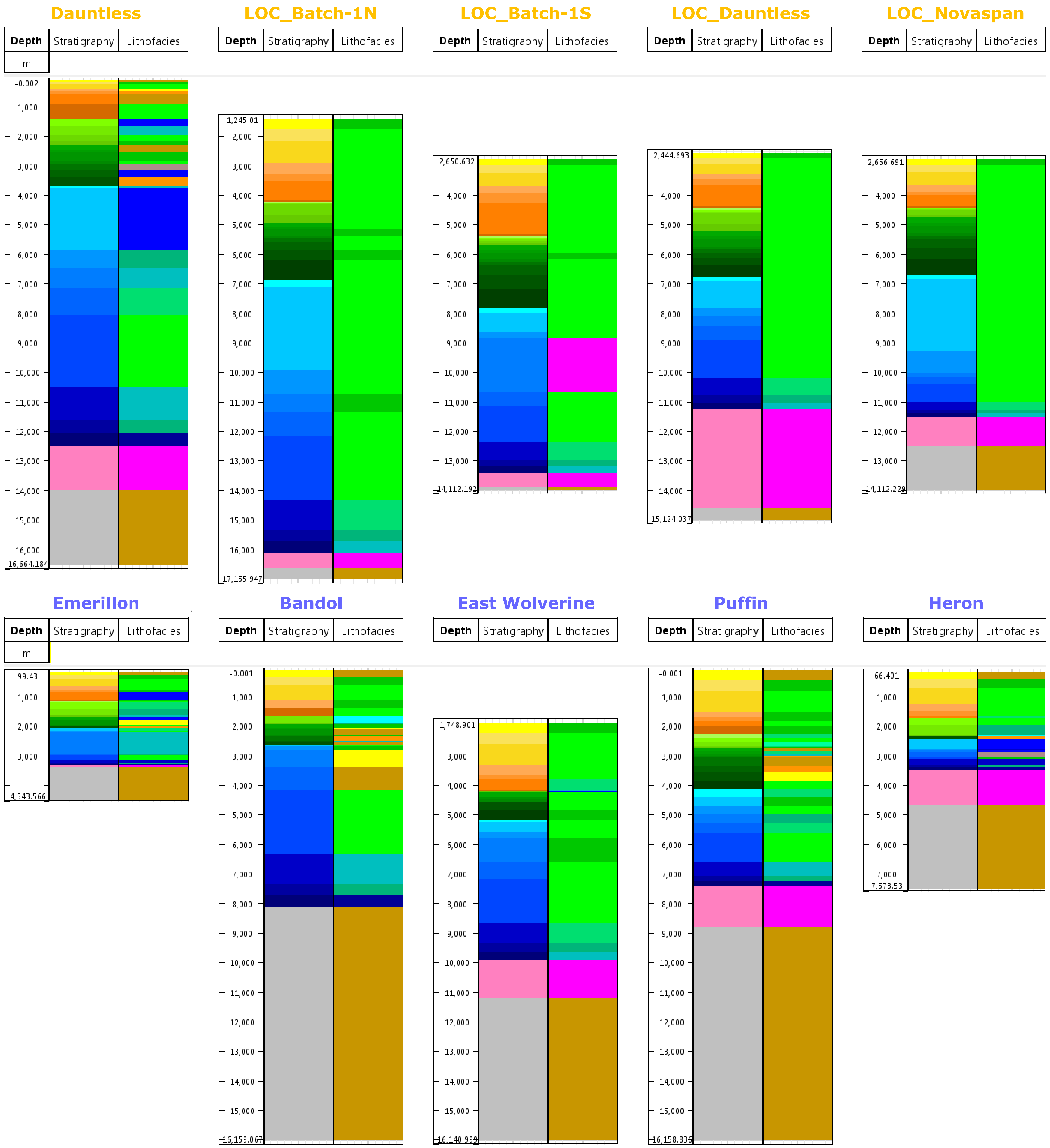


	Age (Ma)	Seismic Horizon	Source Rock (top horizon)
Top Sediment-Seabe	0	X	
i_top Miocene	5.3		
i_mid Miocene	11.6		
i_top Oligocene	23		
T29	29	X	
i_top Eocene	33.9		
T50	50	X	
i_intra Campanian unc	65.5		
i_intra Campanian unc	74		
i_Santonian mfs	83.5		
K94_top-Petrel	94	X	
i_Cenomanian fs	98		
K101	101	X	
i_Early Albian unc	108		
i_Albian-Aptian boun	112		
i_intra Aptian mfs	122		NASKAPI SR (type III)
i_Aptian-Barremian u	125		
K130	130	X	
i_intra Hauterivian mf	133		LOWER CRETACEOUS SR (type III)
K137	137	X	
i_K147	147		TITHONIAN SR (mainly type II-III)
K150	150	X	
i_Callovian mfs	160		
J163	163	X	
i_Bathonian mfs 166	166		MISAINE SR (type II-III)
i_J170-unc	170		
i_Toarcian mfs J181	181		
i_Pliensbachian mfs J1	186		LOWER JURASSIC SR (type II-III or type II)
i_J188	188		
top-salt	190	(X)	
i_mid-salt	195		
J200	200	X	
i_presalt-subdiv-1	230		
i_presalt-subdiv-1	260		
Top Basement	300		



BASIN MODELING

Laurentian sub-basin study - CANADA – June 2014



- Top Sediment-Seabe
- i_top Miocene
- i_mid Miocene
- i_top Oligocene
- T29
- i_top Eocene
- T50
- i_intra Campanian unc
- i_intra Campanian unc
- i_Santonian mfs
- K94_top-Petrel
- i_Cenomanian fs
- K101
- i_Early Albian unc
- i_Albian-Aptian boun
- i_intra Aptian mfs
- i_Aptian-Barremian u
- K130
- i_intra Hauterivian mf
- K137
- i_K147
- K150
- i_Callovian mfs
- J163
- i_Bathonian mfs 166
- i_J170-unc
- i_Toarcian mfs J181
- i_Pliensbachian mfs J1
- i_J188
- top-salt
- i_mid-salt
- J200
- i_presalt-subdiv-1
- i_presalt-subdiv-1
- Top Basement

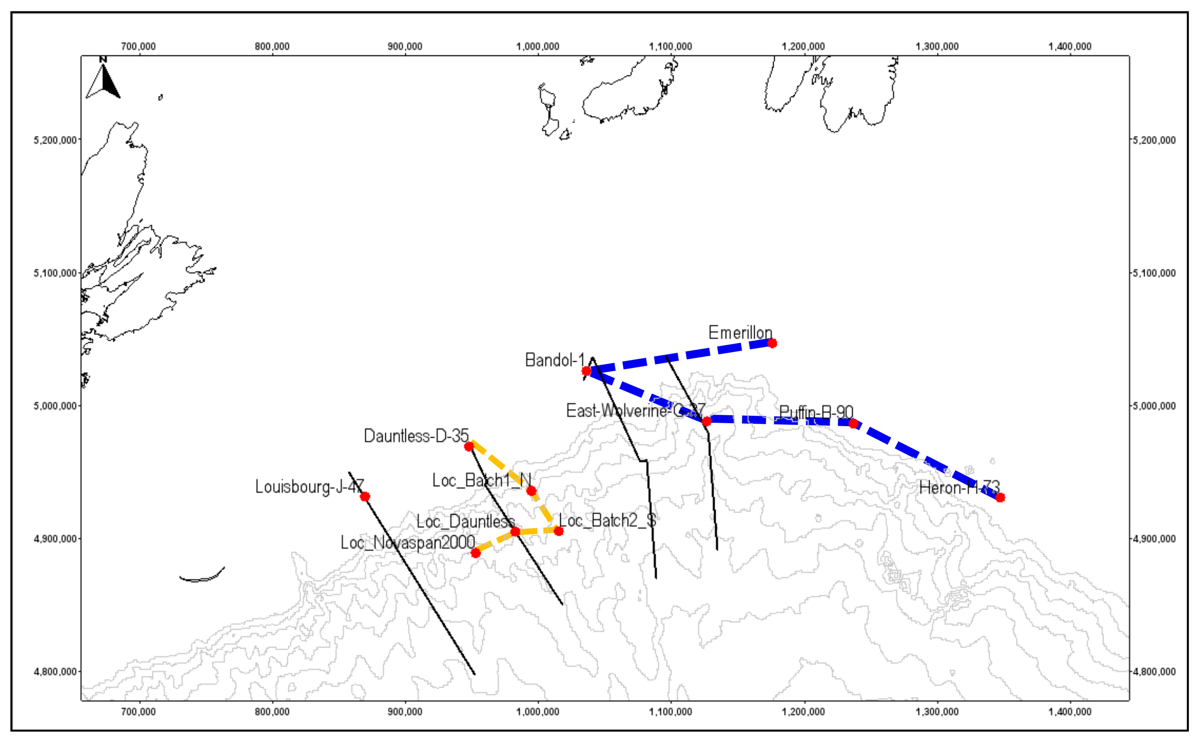
Stratigraphy

1	01_hiatus	
10	10_shale	
13	13_30sa_70sh	
15	15_50sa_50sh	
17	17_70sa_30sh	
20	20_sandstone	
25	25_50marl-50sh	
30	30_marl	
35	35_50chalk-50sh	
40	40_chalk	
45	45_50lim-50sh	
50	50_limestone (late di...	
55	55_50lim-50sa	
60	60_limestone (early d...	
70	70_dolostone (early d...	
90	90_salt	

Petrophysical Facies

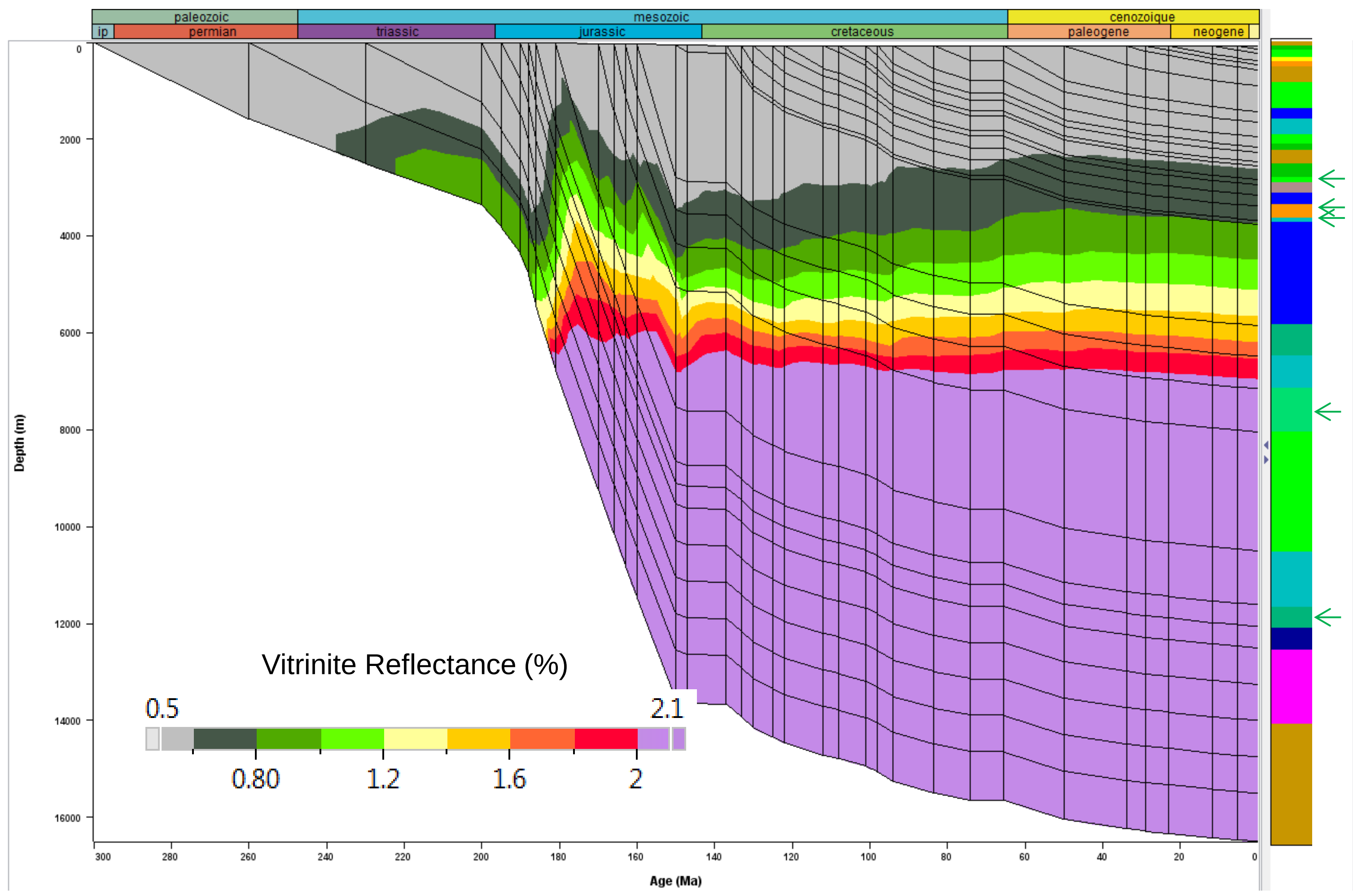
Thermal boundary conditions - Basement

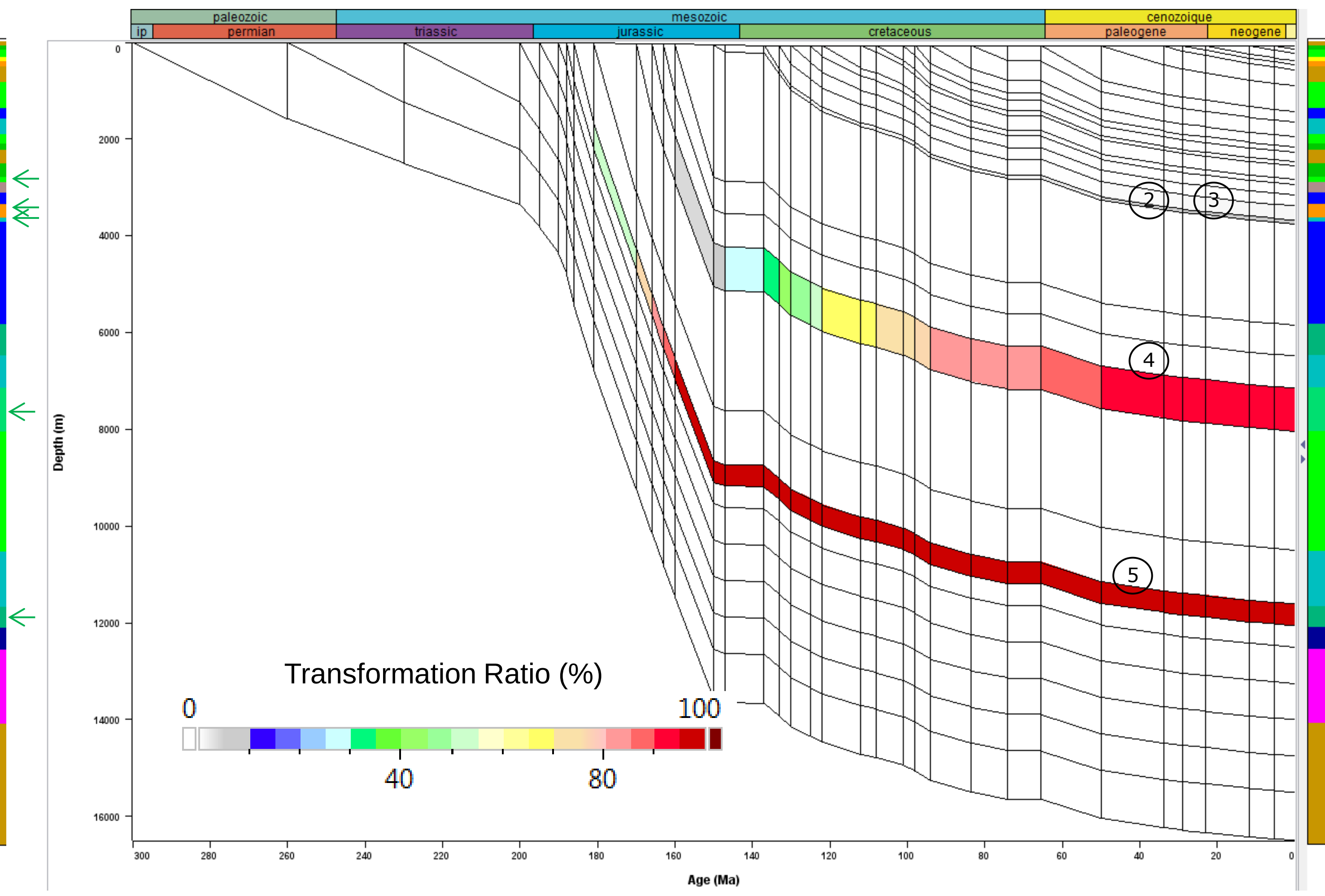
Well Pseudo-welll	Sea botom (m)	Sea botom temperature (present, °C)	Pre salt sediments thickness (m)	Beta Factor (crust thickness ratio = initial / present) Initial = 40km	Upper crust radiogenic heat production (W/m³)
Dauntless-D-35	69	1	5000	3	1.0E-6
Loc_Batch1_N	1401	4	500	4.5	1.0E-6
Loc_Batch1_S	2763	3	500	7	6.06E-7
Loc_Dauntless_transect	2569	3.5	500	6	8.0E-7
Loc_Novaspan2000	2769	3	3000	6	8.0E-7
Emerillon	143	4	1000	2	3.5E-6
Bandol-1	93	2	8000	3	1.5E-6
East-Wolverine-G-37	1890	4	5000	4.5	1.0E-6
Puffin-B-90	106	2	7000	3.5	1.5E-6
Heron-H-73	140	3	3000	2	3.5E-6

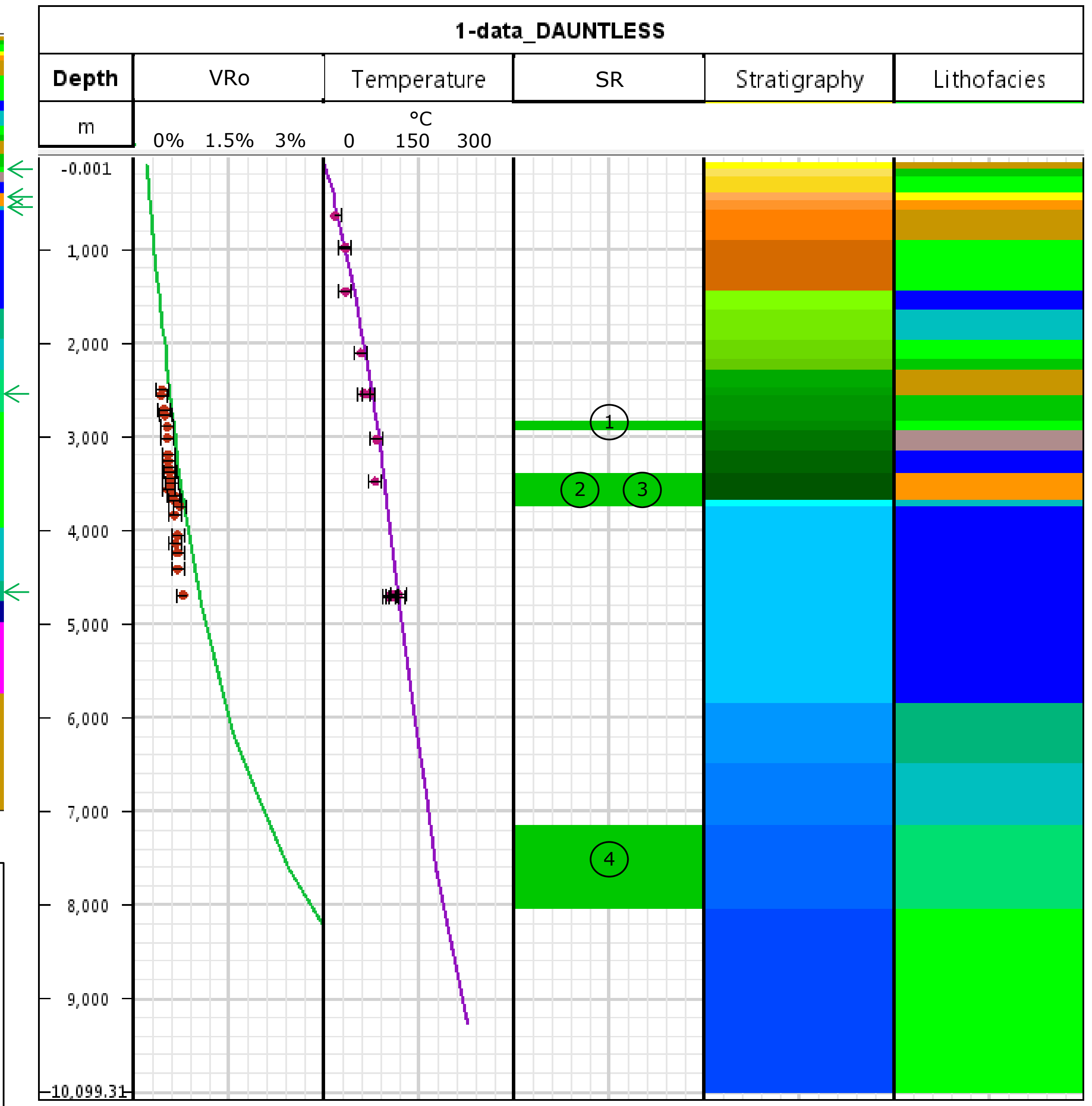


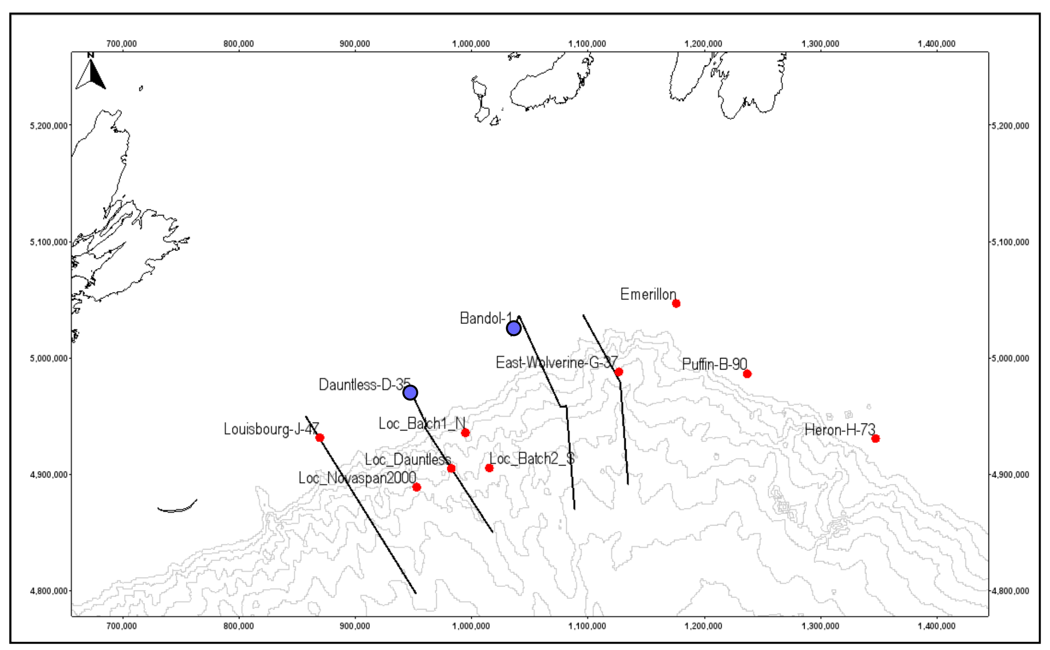
Stratigraphy and lithology logs – Boundary conditions **PLATE 9.5**

BASIN MODELING









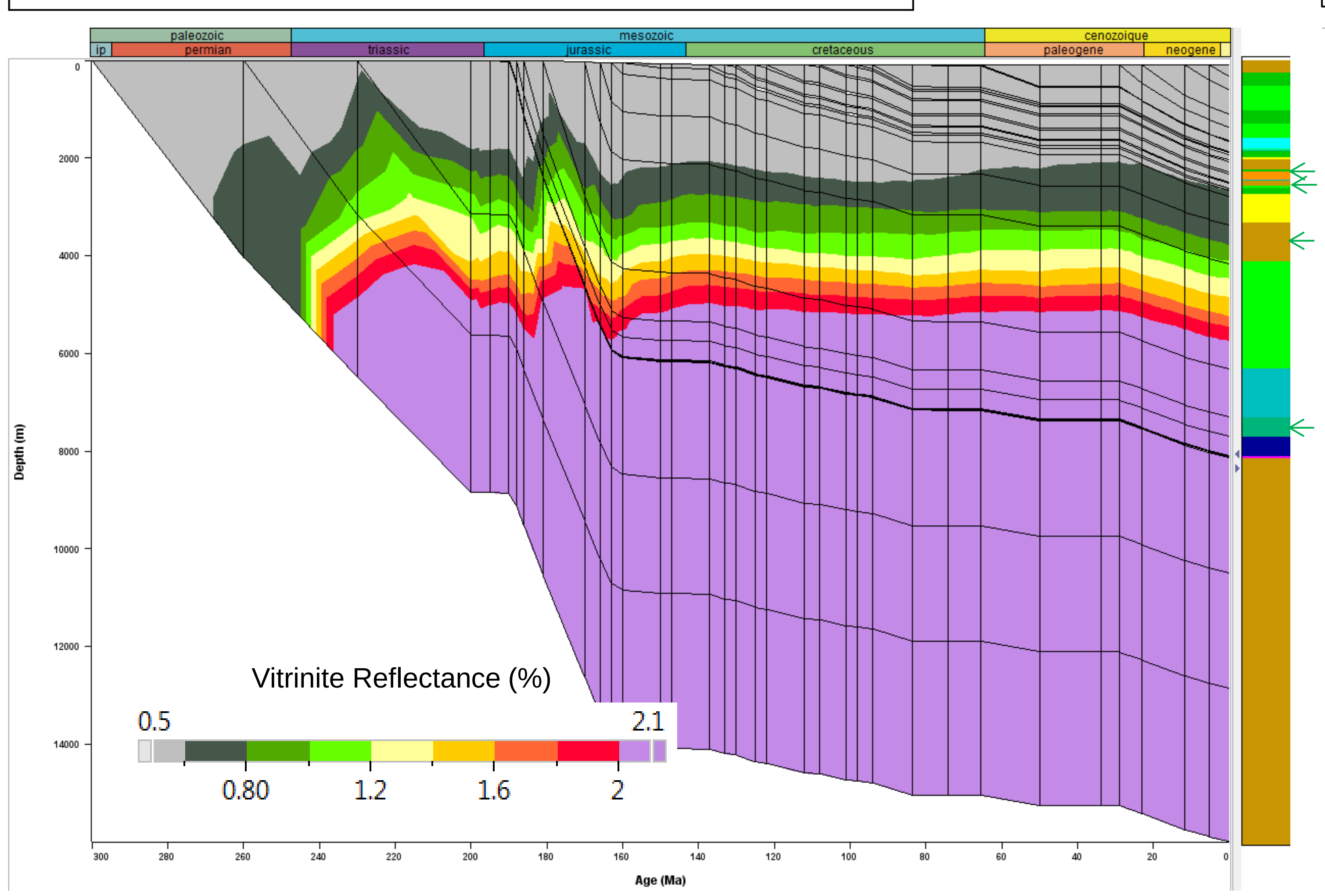
Dauntless-D-35

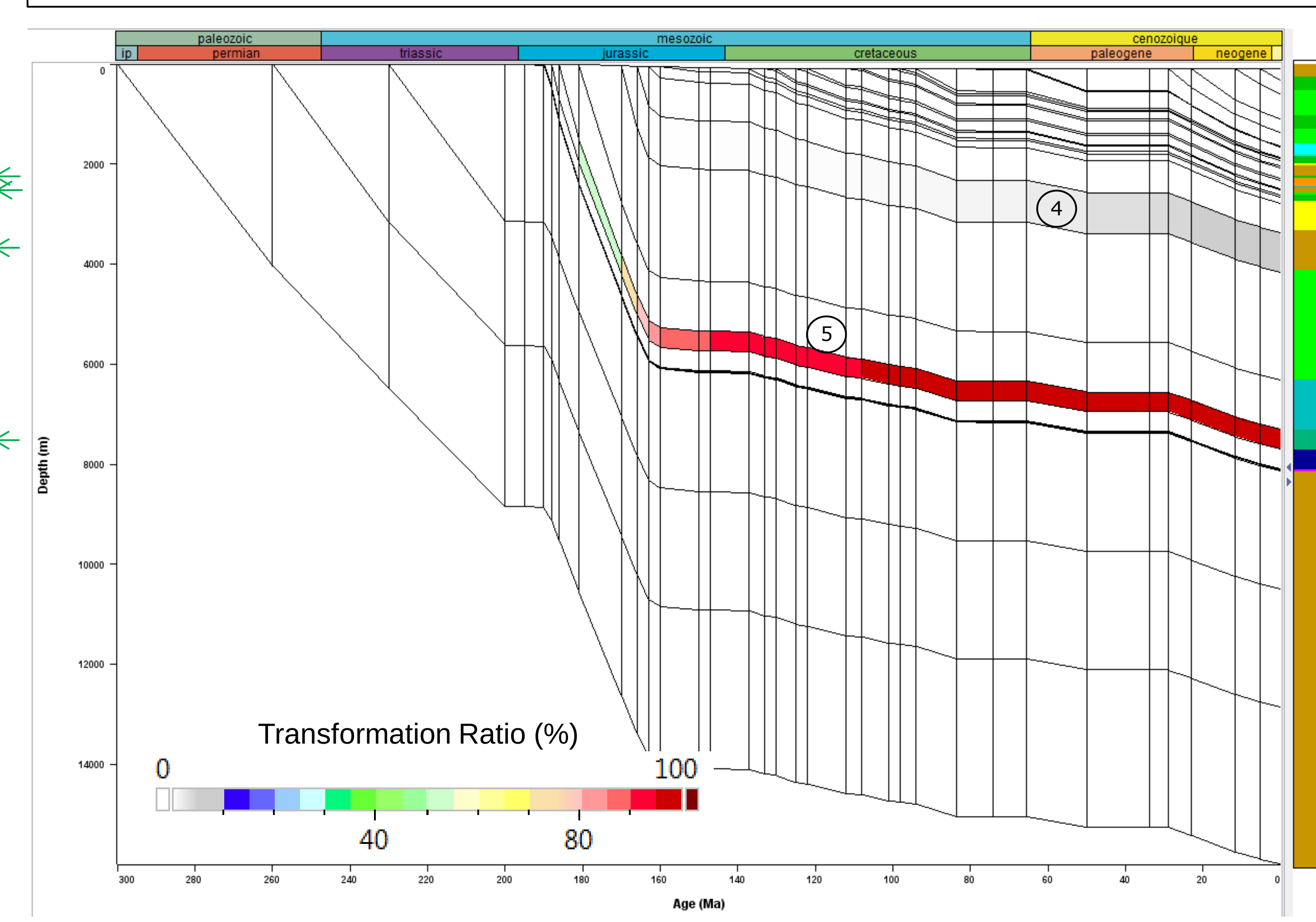
The burial curve shows a classical passive margin evolution. Highest burial rates occurred during the Jurassic just after the rifting.

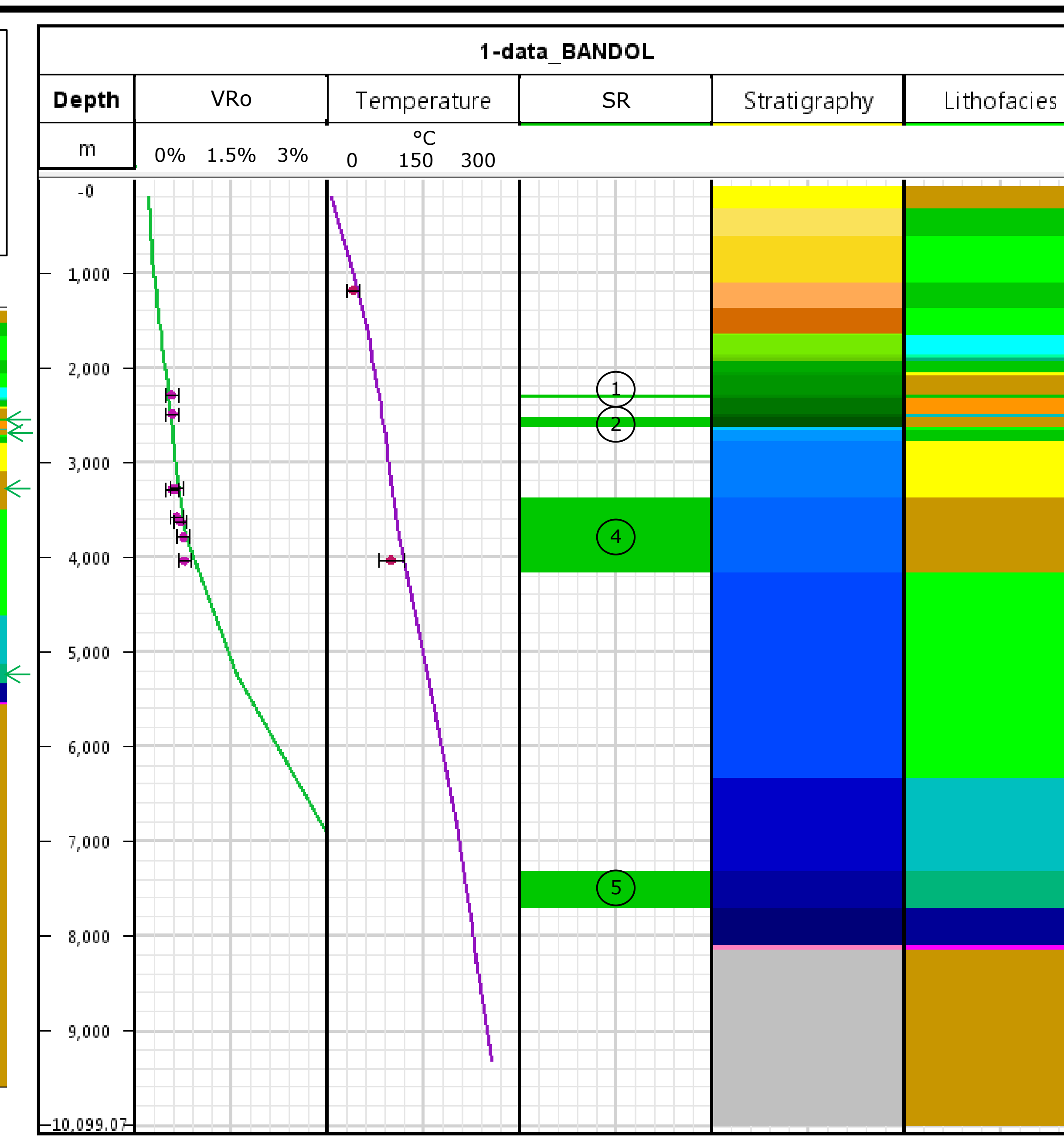
The potential Lower Jurassic SR is overmature since that time (TR=100%) while the maturity in the Middle Jurassic SR (“Misaine”) progressively increased: entrance within the oil window during the Late Jurassic, the wet gas window during the Aptian, the dry gas window at the end of the Cretaceous (TR=90%). Shallower SR are just entering the maturity window (TR<10%) and have not expelled significant amounts of hydrocarbons.

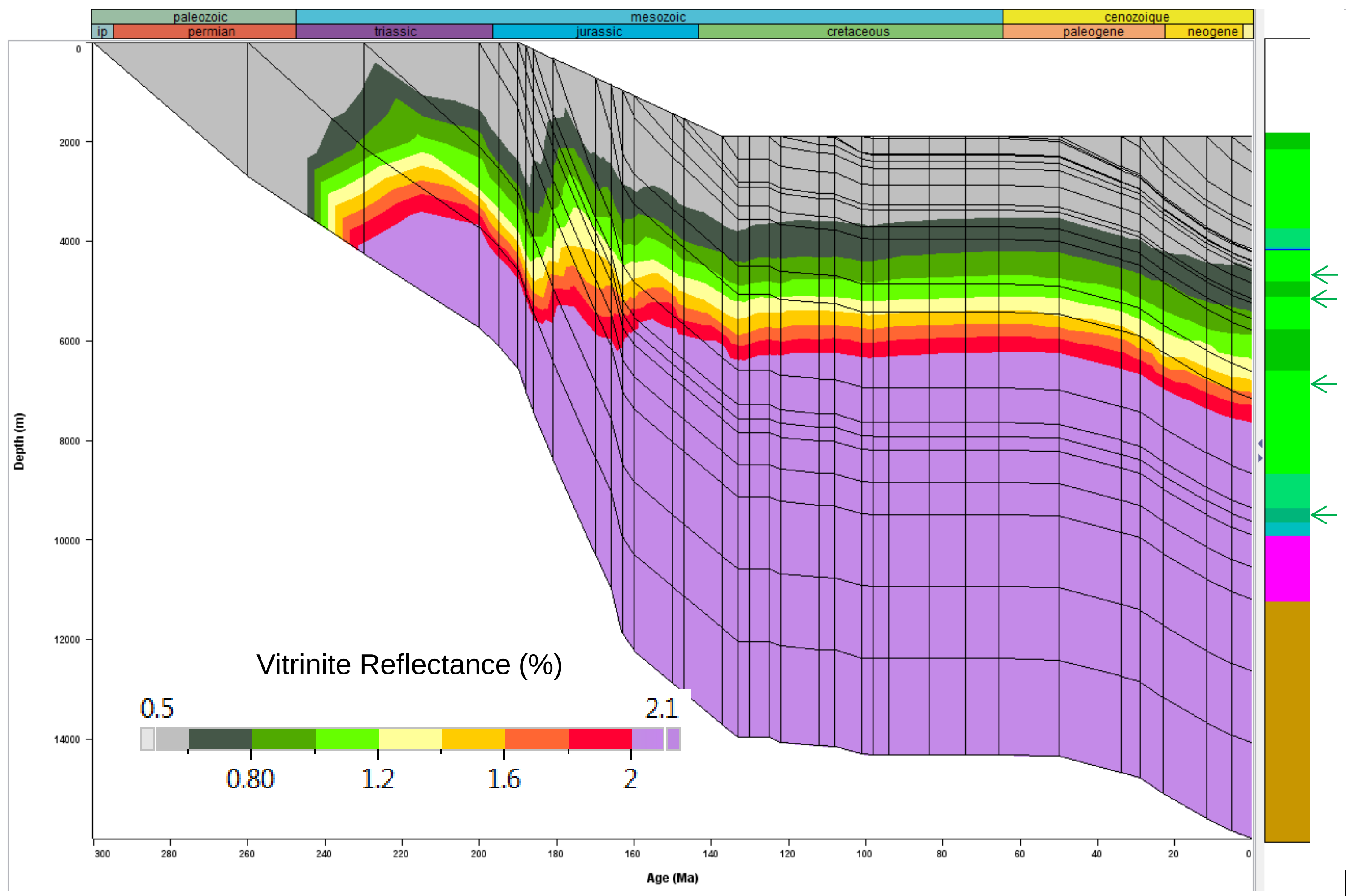
Bandol-1

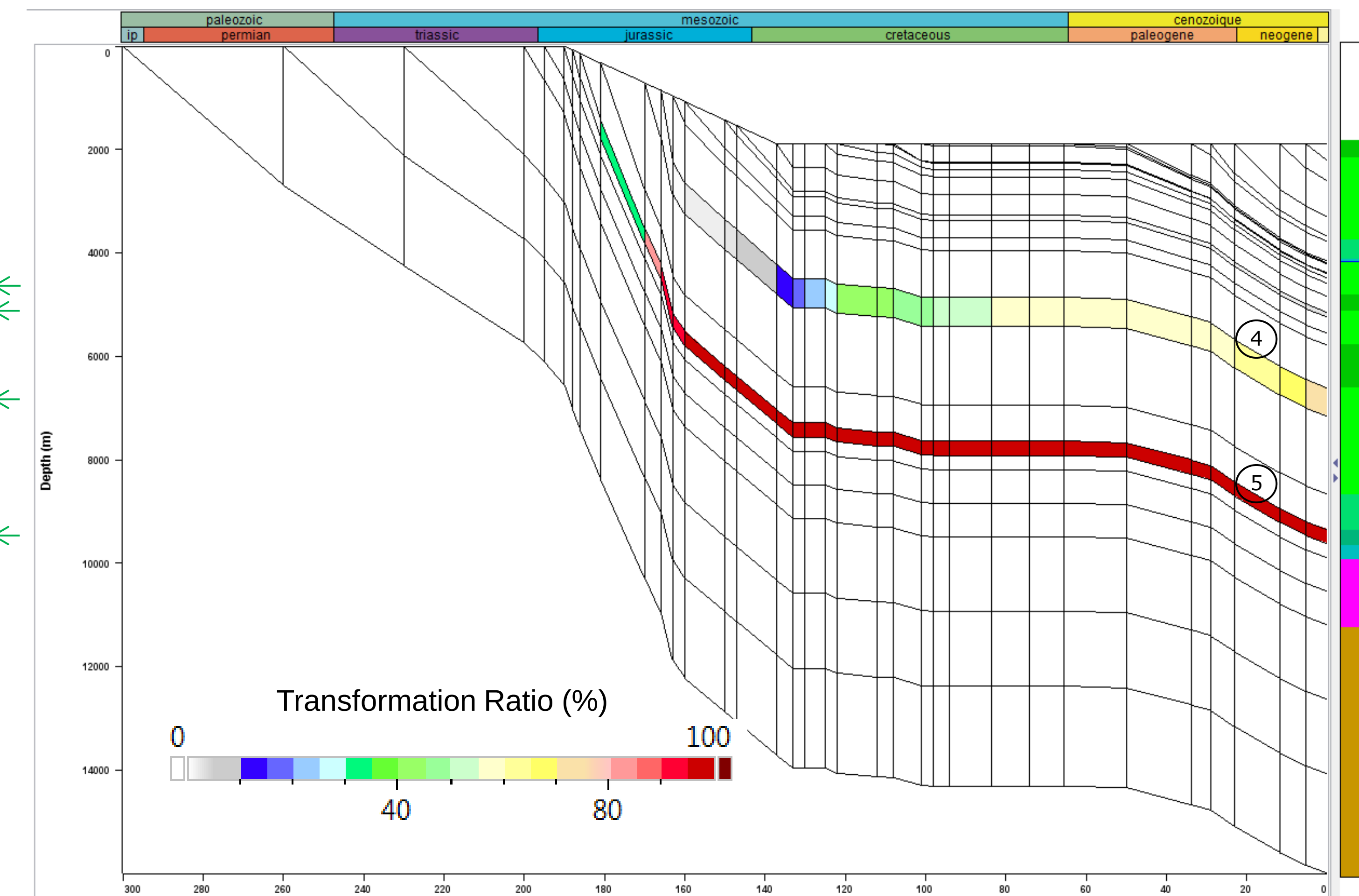
The burial curves and maturity trends are similar in Bandol-1 and Dauntless-D-35, although the pre-salt sequences could be thicker in Bandol (there is possibly no salt layer in Bandol), while the Jurassic source rocks are shallower. As a consequence the Upper Jurassic SR is just entering the maturity window at present day (TR<10%). The Lower Jurassic SR is overmature since the Latest Jurassic or the Cretaceous.

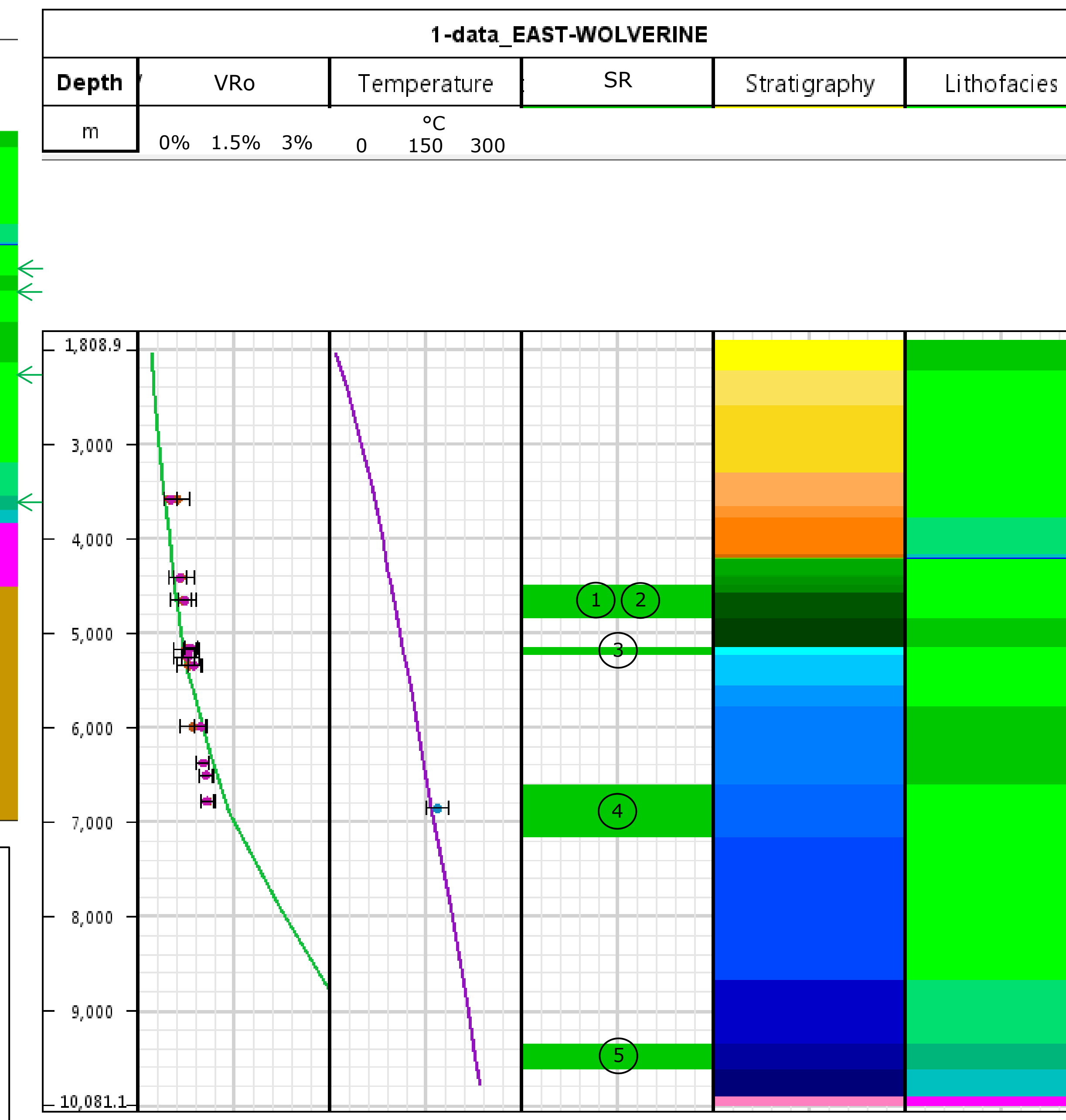


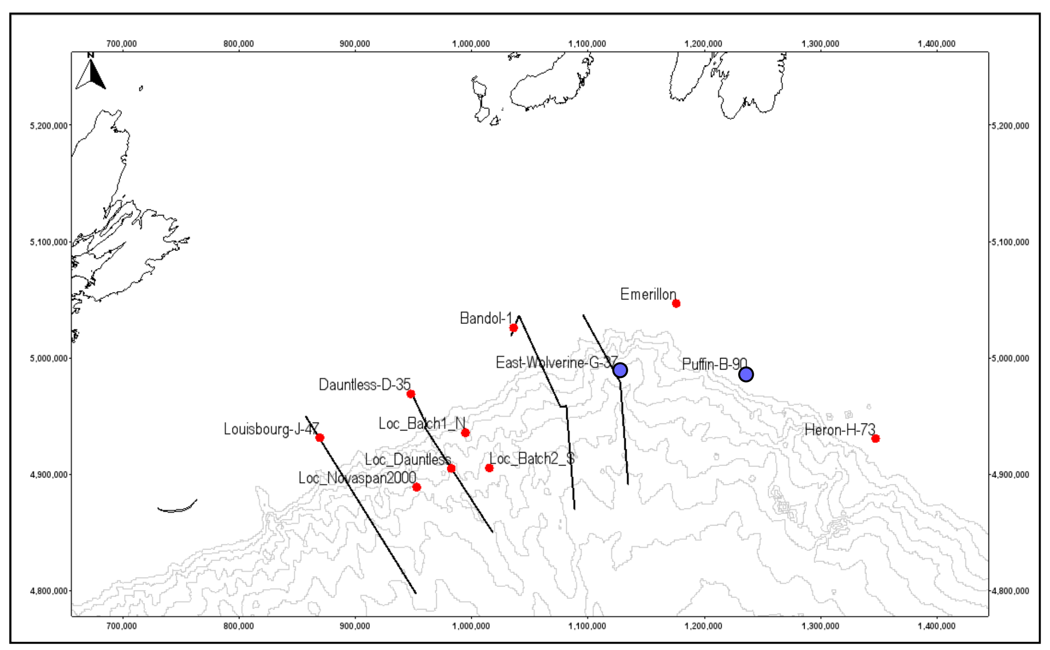












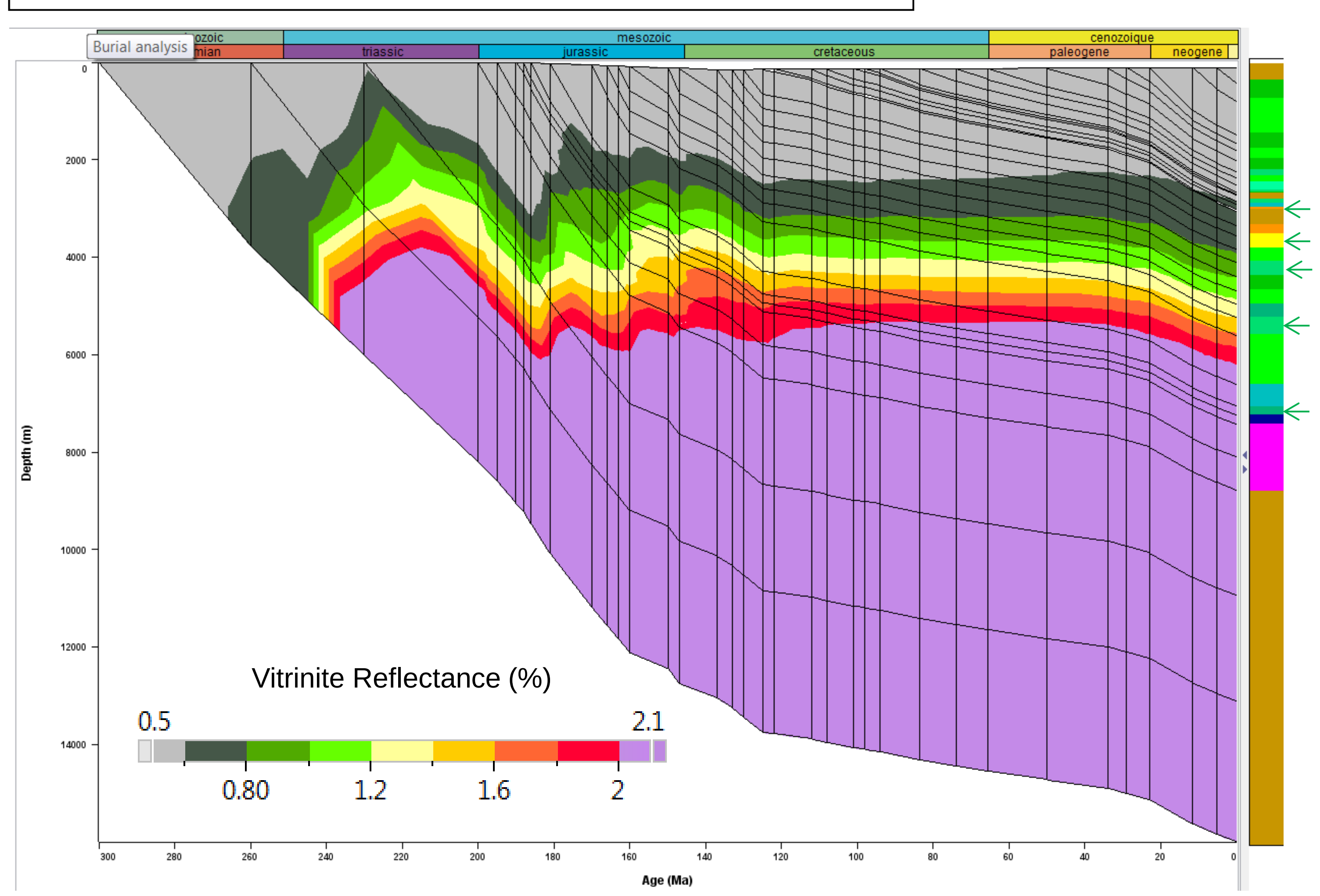
East Wolverine-D-35

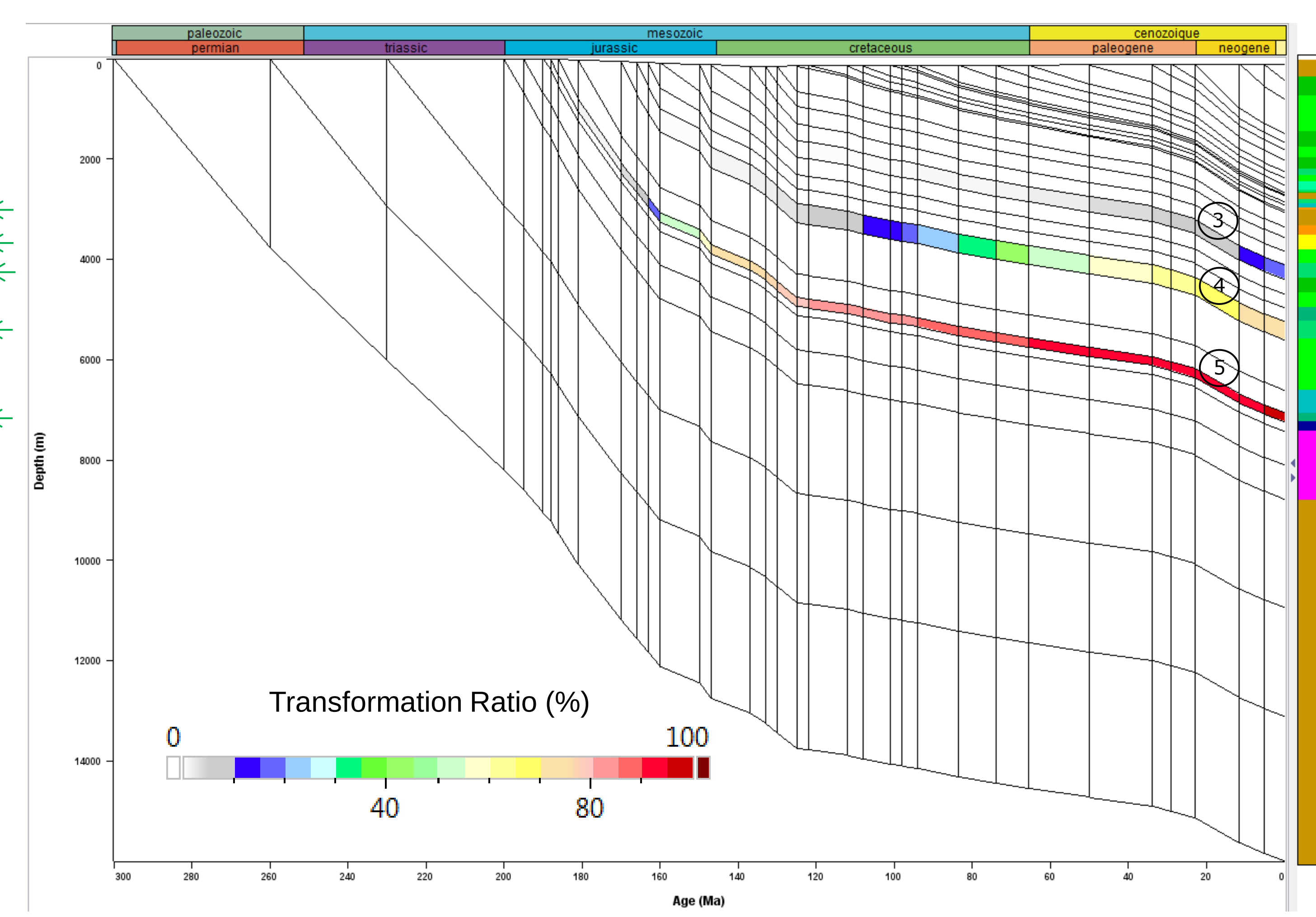
East Wolverine is the only studied well drilled in the deep offshore domain. Like in Dauntless and Bandol, the highest burial rates occurred during the Jurassic just after the rifting. However a second increase of the burial rate has occurred since the Eocene (up today), after a long and quiet period from the Aptian to the Paleocene possibly related to the Early Cretaceous Avalon uplift (frequent hiatus/condensed layers, no major erosion).

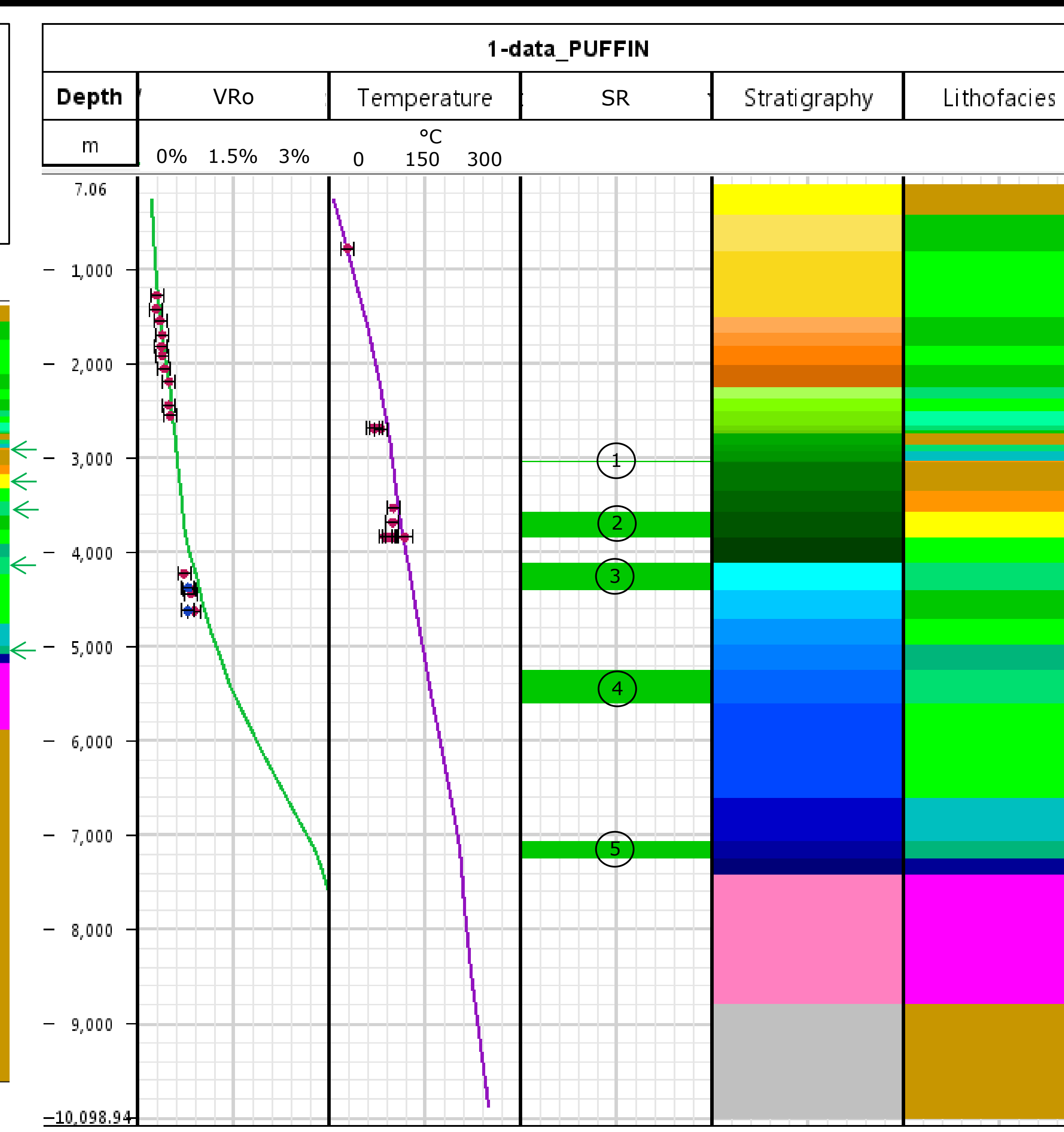
The potential Lower Jurassic SR is overmature since the Jurassic (TR=100%) while the maturity in the Middle Jurassic SR progressively increased: entrance within the oil window during the Earliest Cretaceous, the wet gas window during the Miocene (TR = 70%). Shallower SRs are immature.

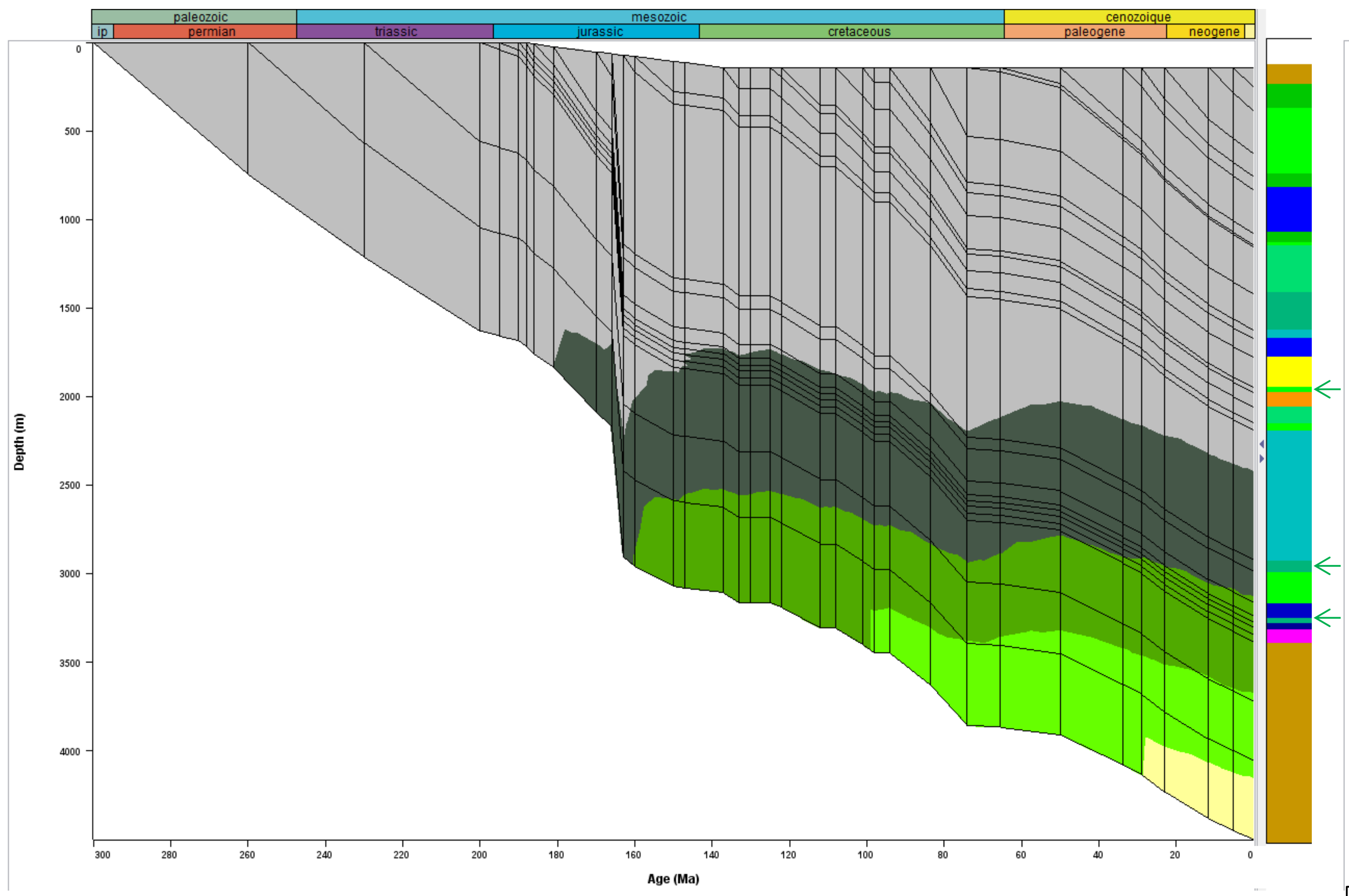
Puffin-B-90

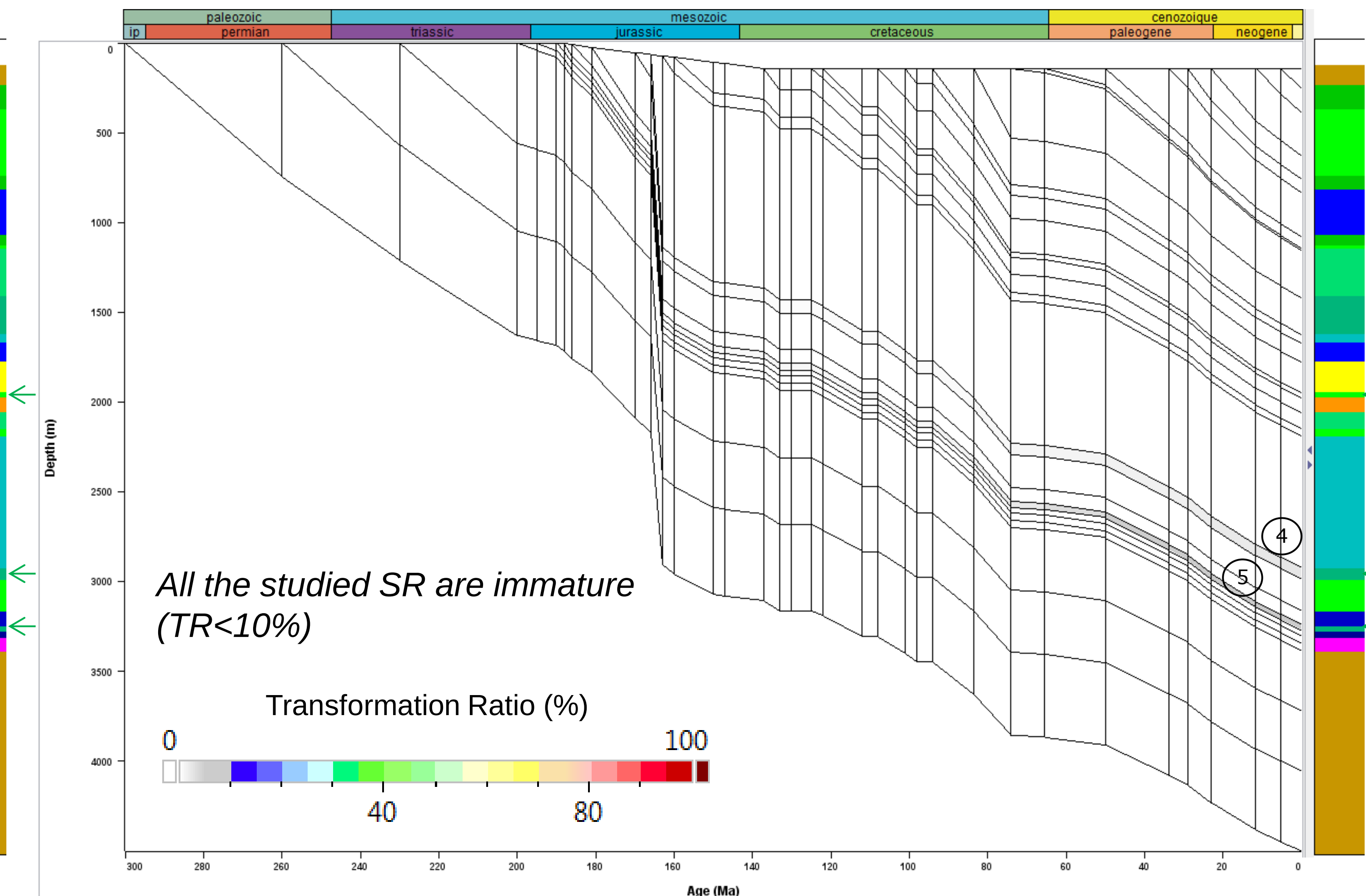
Puffin is in the Grand Banks domain (North of the transform fault). The burial curves and maturity trends are similar in Puffin and East Wolverine, although Puffin is located on the platform where the pre-salt sequences are very thick. The Lower Jurassic SR is overmature since Late Cretaceous times while the Upper Jurassic SR is within the wet gas window since Oligocene times (TR = 70%). The Tithonian SR is within the oil window (TR<20%).

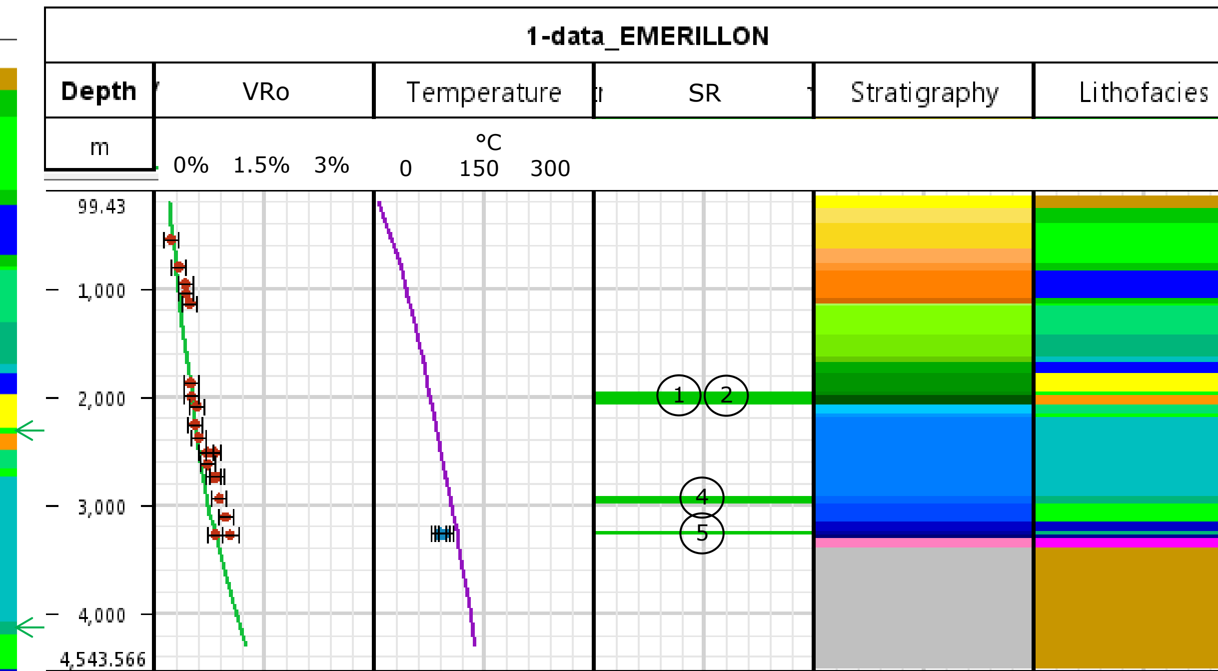


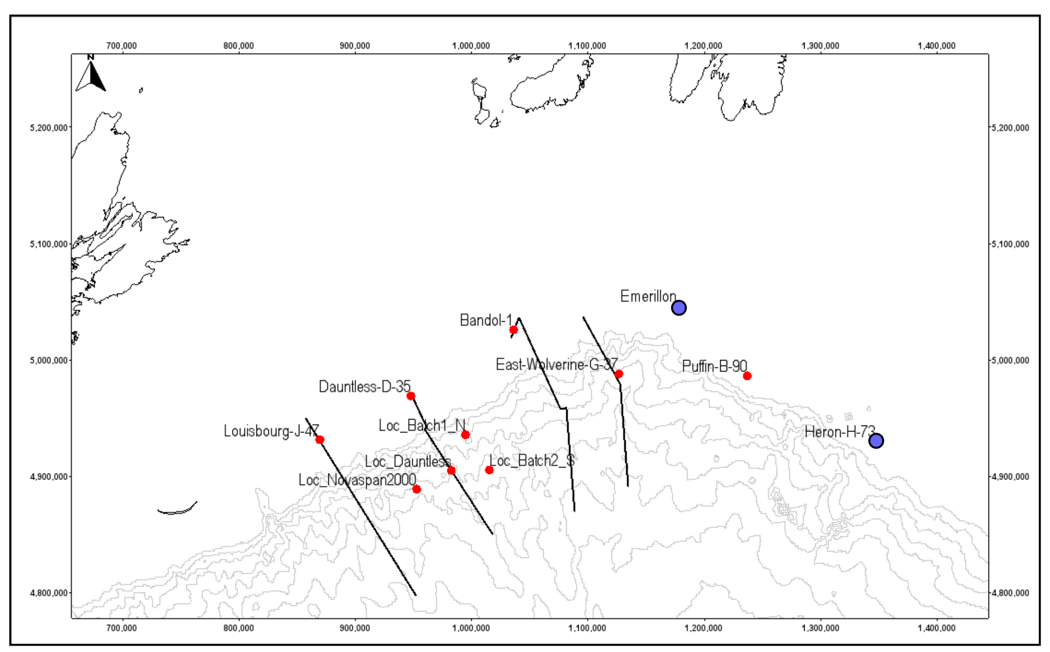












Emerillon and Heron-H-73

Heron and Emerillon are located on the continental shelf of the Grand Banks. These wells are drilled in zones where the sedimentary cover is thinner (margins of the basin and/or structural high). Sedimentations rates are smaller than in other studied wells.

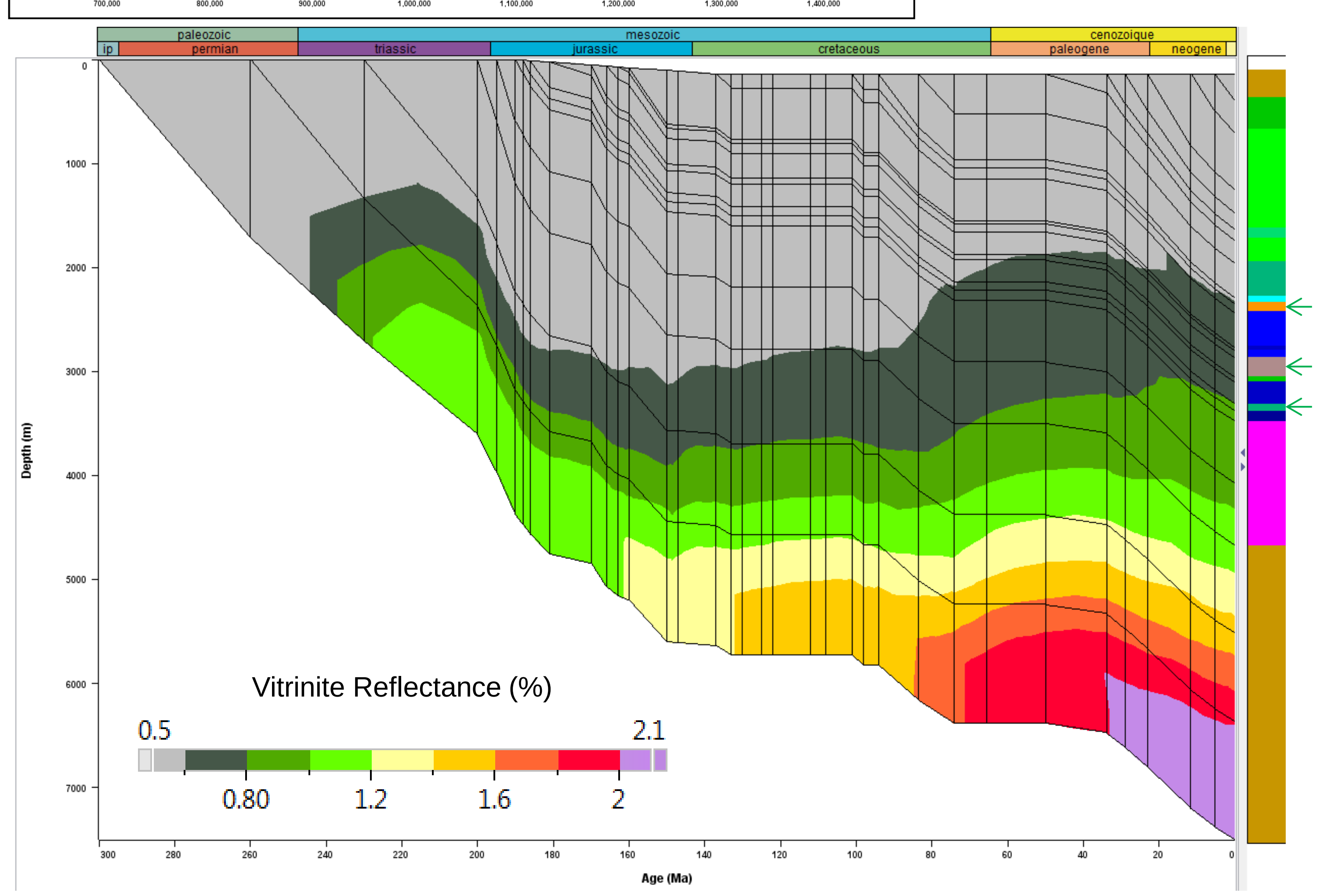
The burial rates increased 3 times:

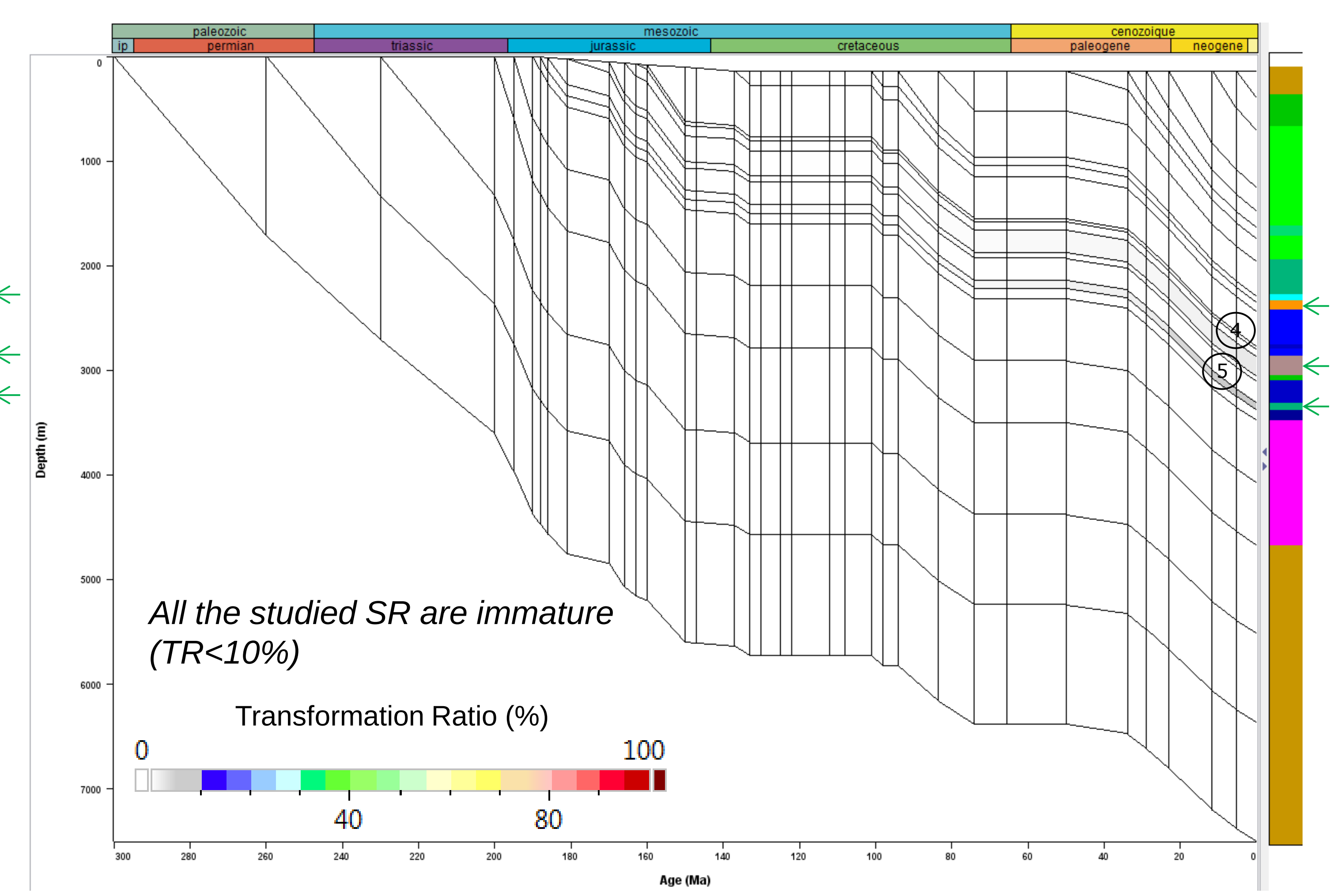
- Just after the Early Jurassic rifting (with possibly a delay in Emerillon), like everywhere in the study area
- During the late Cretaceous (Cenomanian to Santonian)
- Since the Eocene (up today), like in East Wolverine and Puffin (Grand Banks)

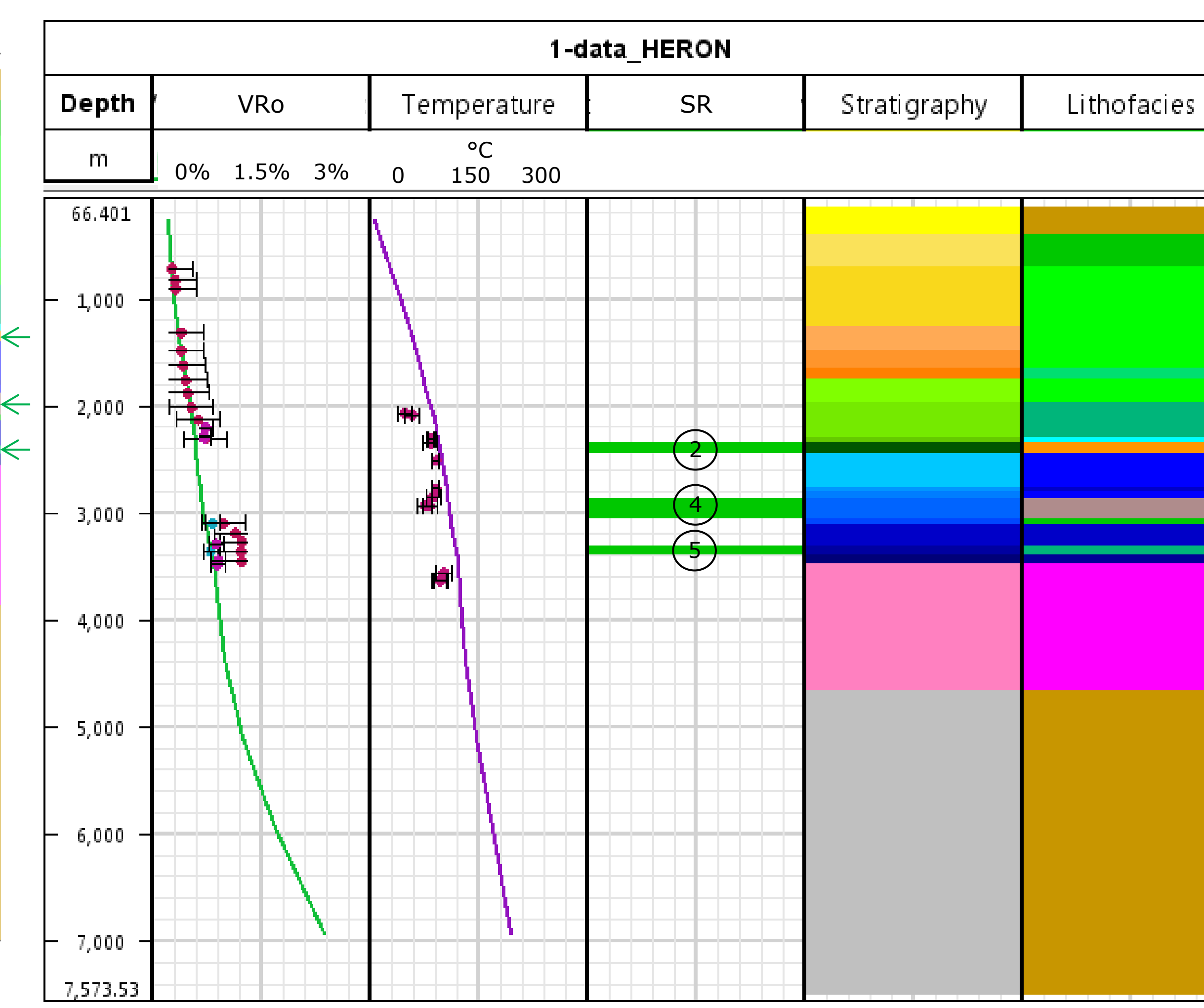
At the location of studied wells small erosion phases (about 100m?) are possible, particularly in Heron during the Early Cretaceous (Grand Banks Avalon uplift) and during the Paleogene. These events cannot be sufficient for significantly affecting the thermal history of sediments.

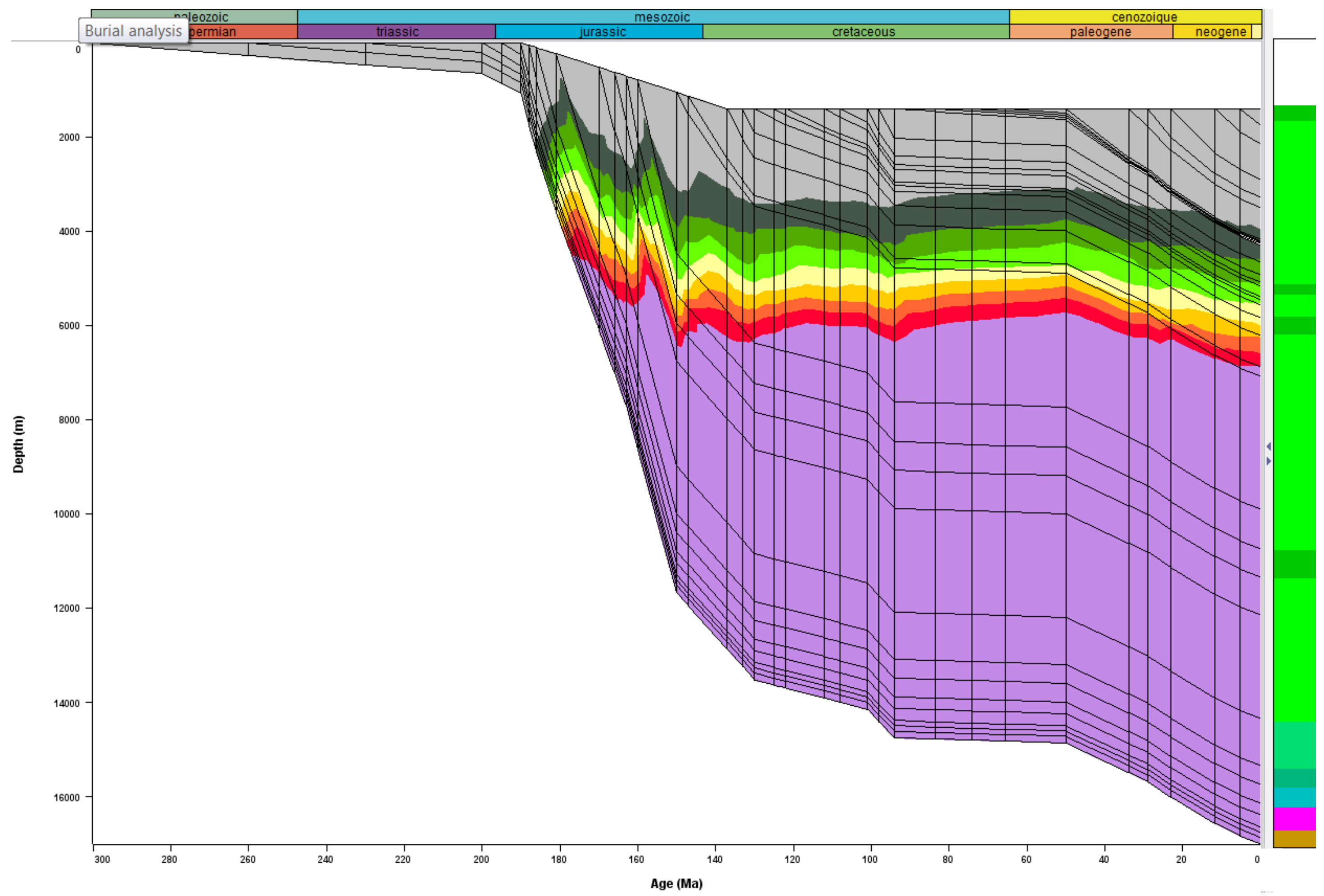
The successive burial phases delayed the increase of the maturity level (progressive increase through geological times). At present day the Lower Jurassic SR is within the oil window (Vro = 0.6 to 0.9%), however the presence of Type II-III to III kerogens implies a very low transformation ratio (TR<10%). The small amount of generated hydrocarbons is confirmed by Tmax values close to 435°C. Shallower SRs are completely immature.

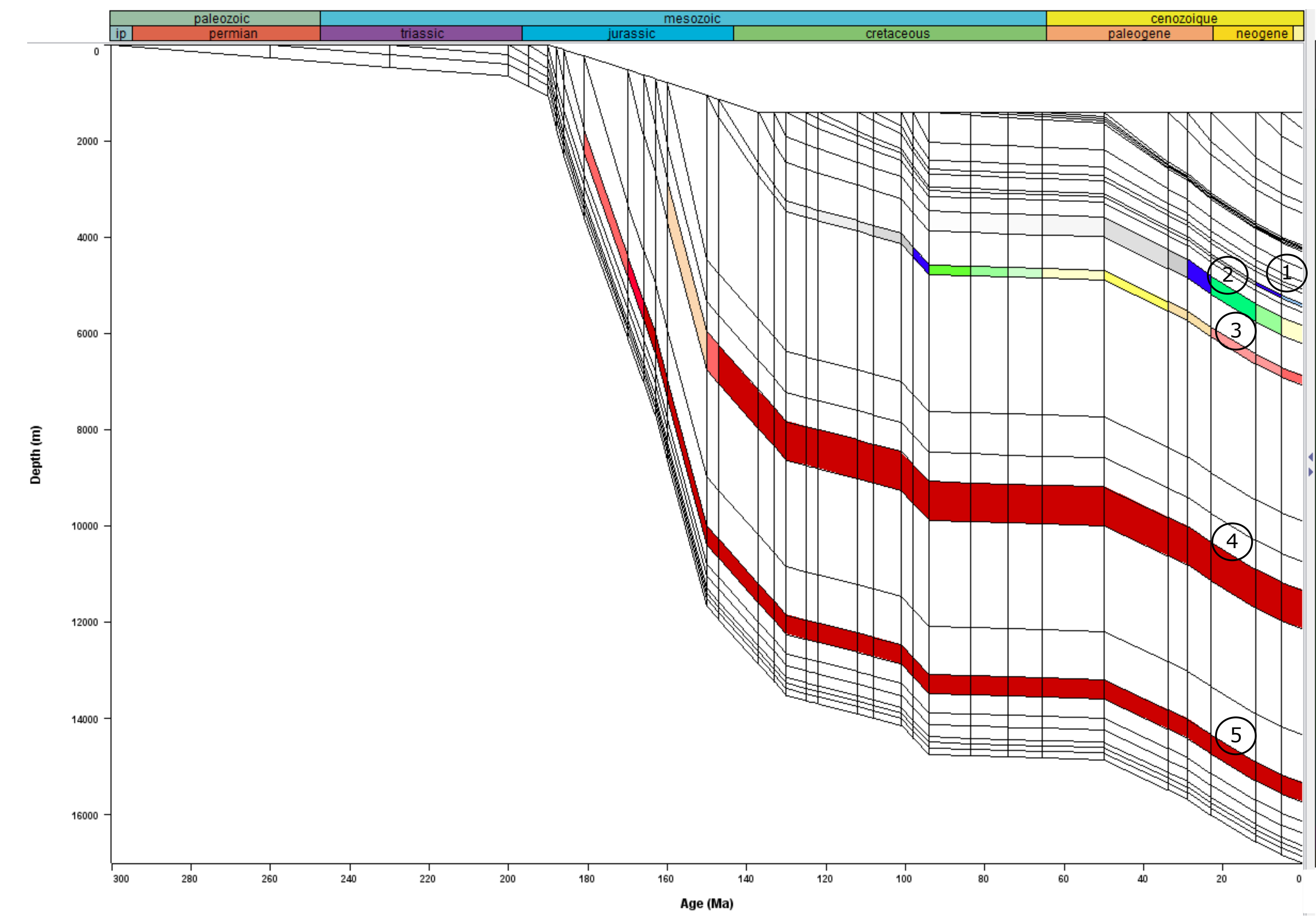
Without hydrocarbon migrating from deeper parts of the basin, there is no significant active petroleum system in Emerillon and Heron. Mature-enough SRs might only exist in pre-salt sequences.

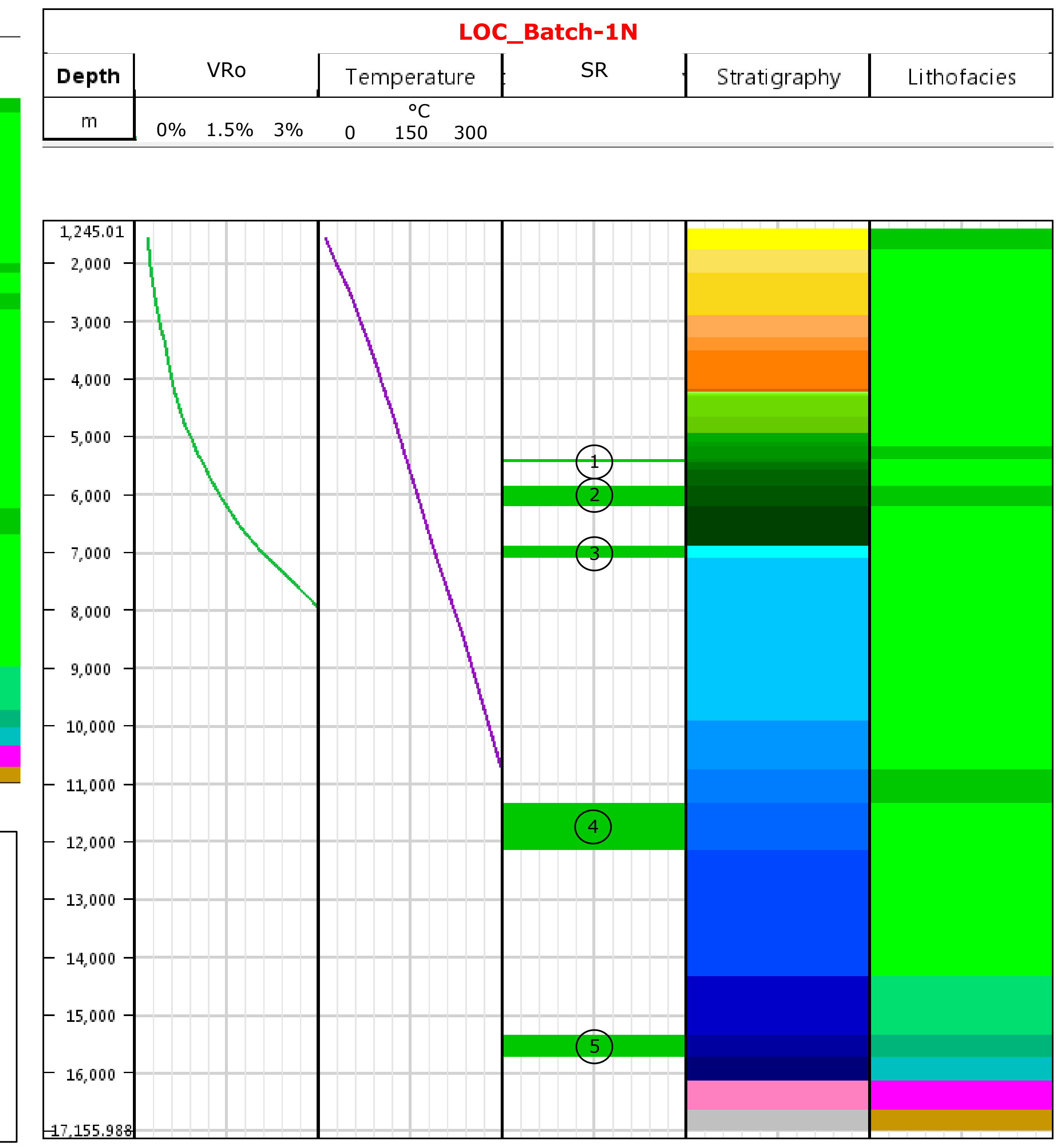


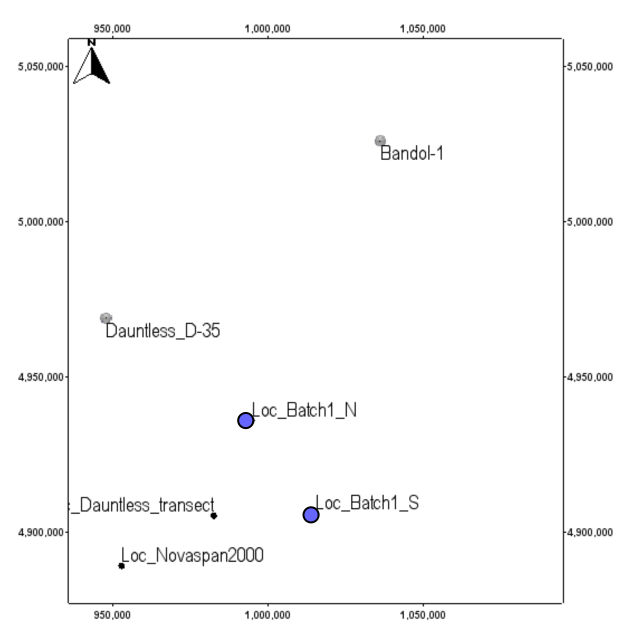












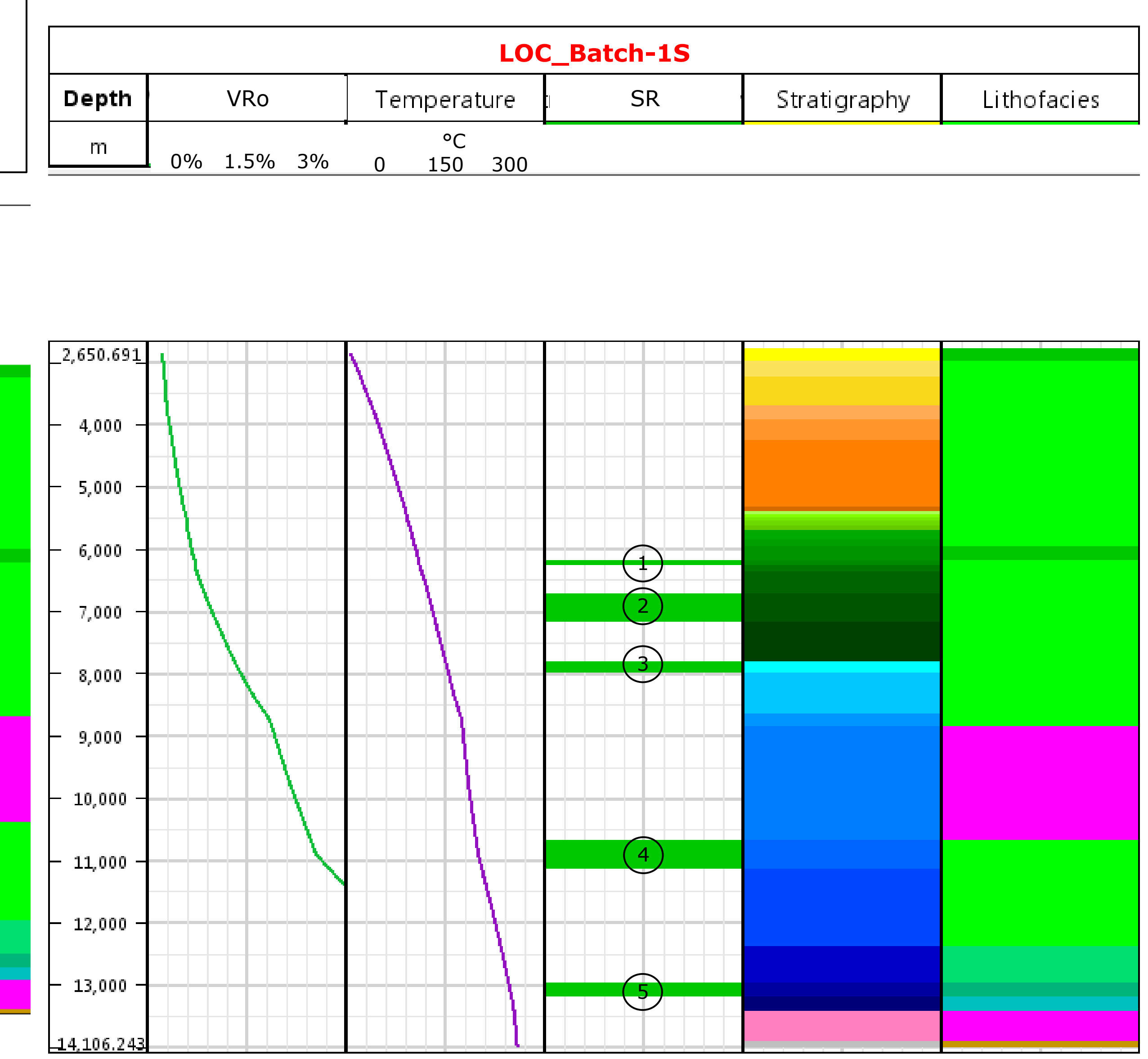
LOC_Batch-1N (pseudo well)

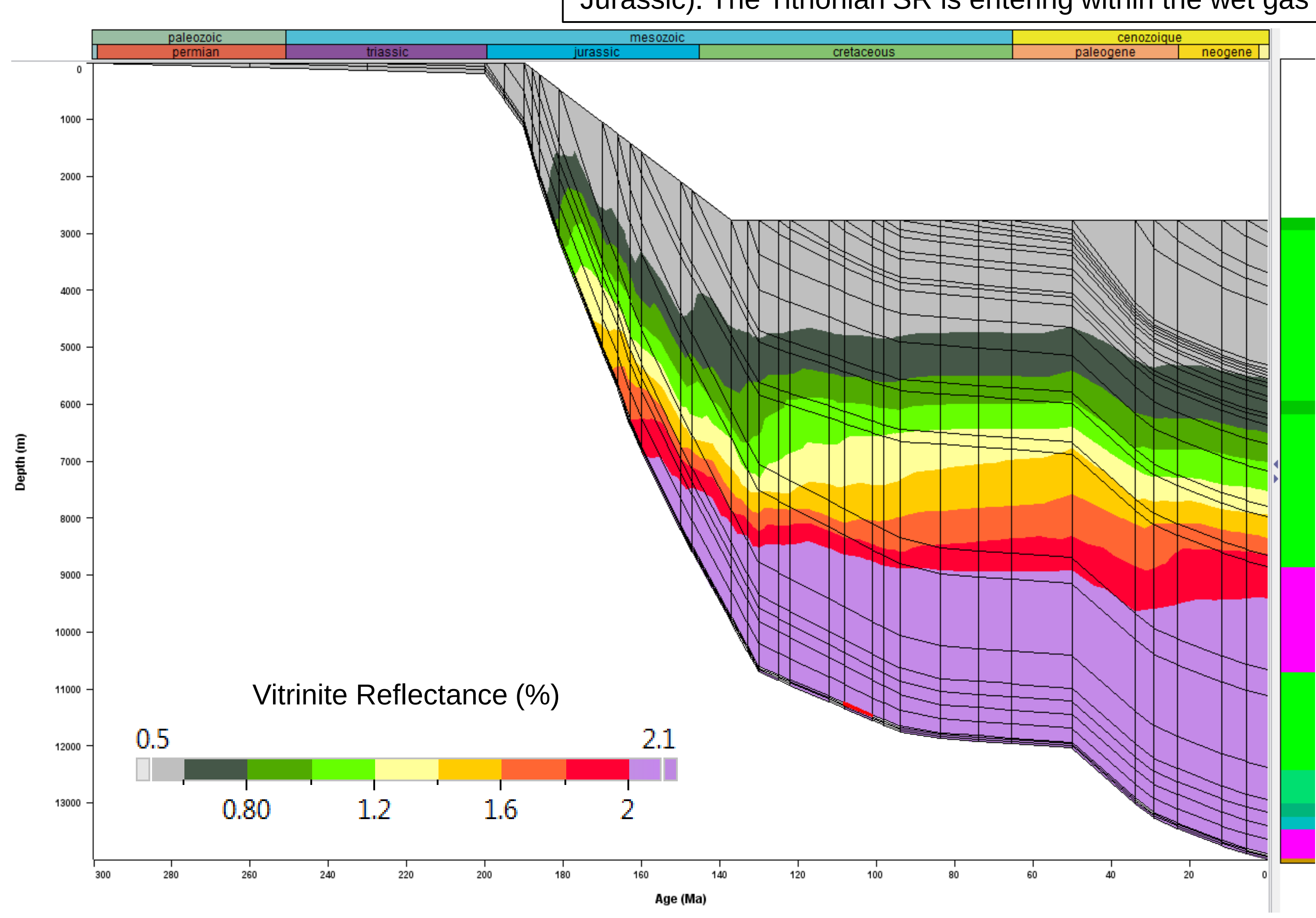
This pseudo well is located in the northern most part of the Nova Scotia continental slope, south of the Laurentian Channel. There the post-rift sedimentary cover is extremely thick, while the existence of presalt sequences is questionable: the area is already in the transition zone between continental and oceanic domains. Without surprise the highest burial rate occurred just after the rifting during the Jurassic (strong thermal subsidence and massive sedimentation). A second increase of the burial has started since the Eocene. The 5 source rocks have potentially generated and expelled hydrocarbons:

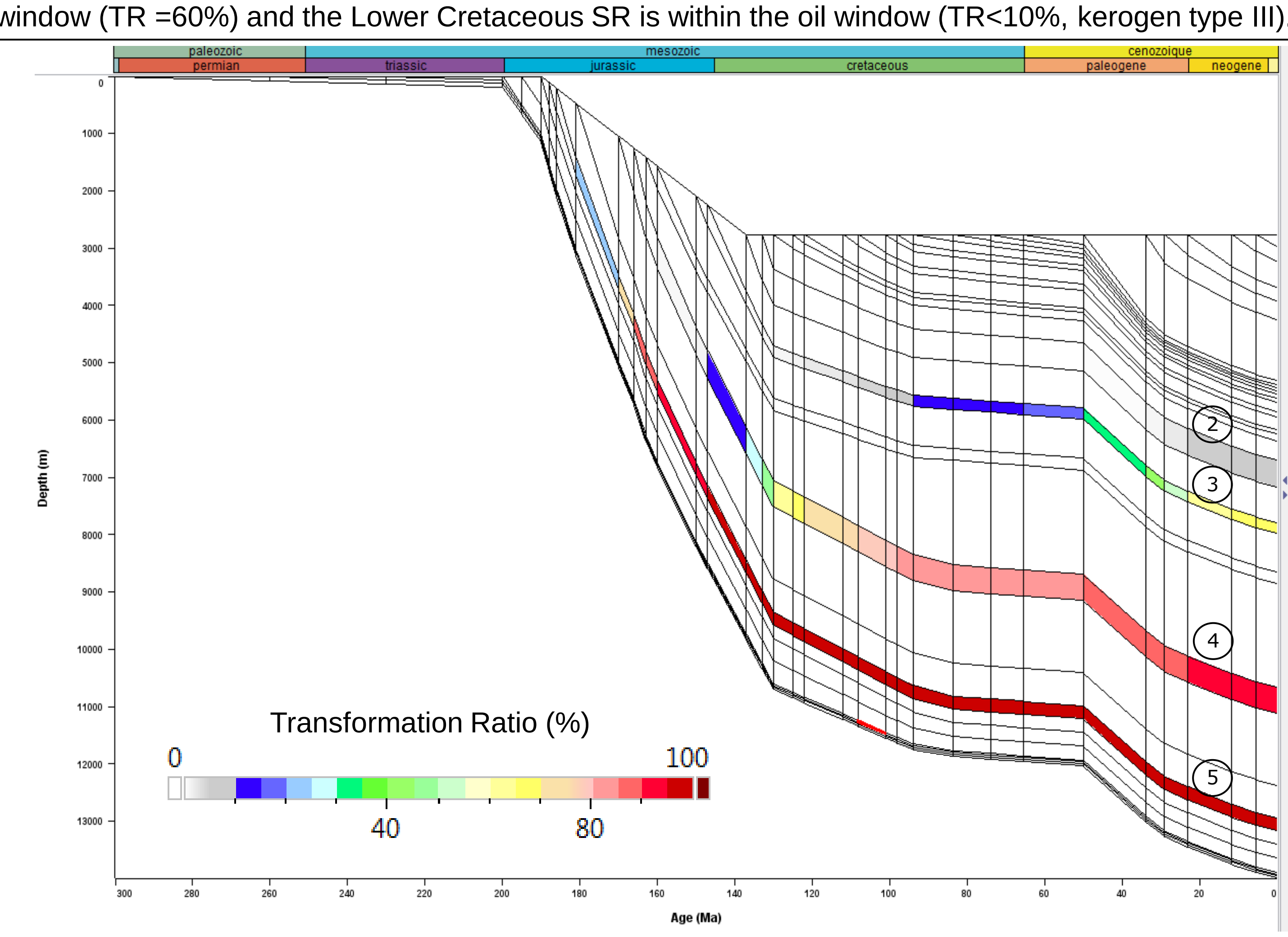
- The Naskapi SR is twithin the oil window since the Neogene
- The Lower Cretaceous SR is entering within the wet gas window at present day. (TR > 50%)
- The Tithonian SR is entering the dry gas window (TR > 75%, entrance winthin the oil window during the Albian)
- "Misaine" and Lower Cretaceous SRs are overmature since the Jurassic.

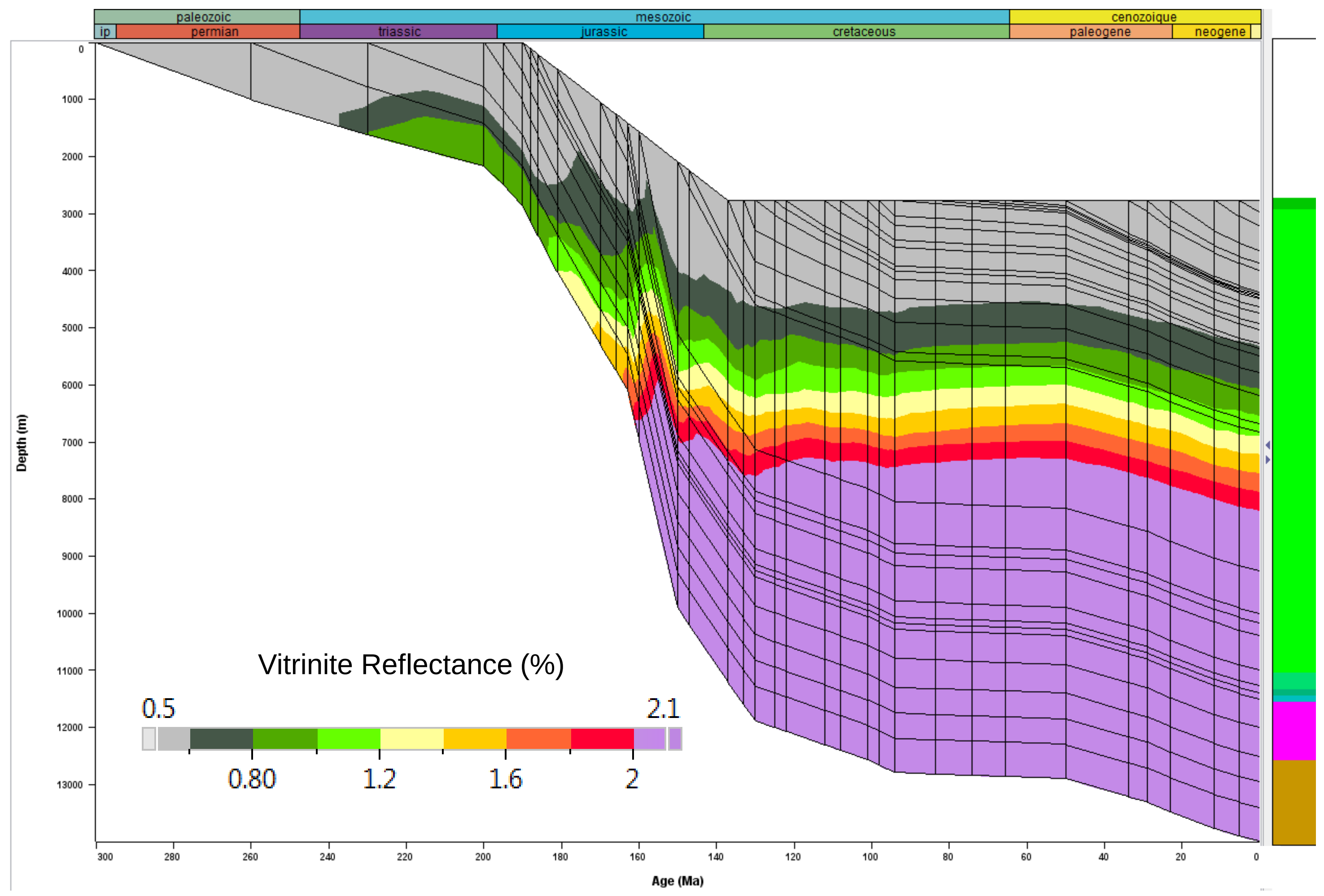
LOC_Batch-1S (pseudo well)

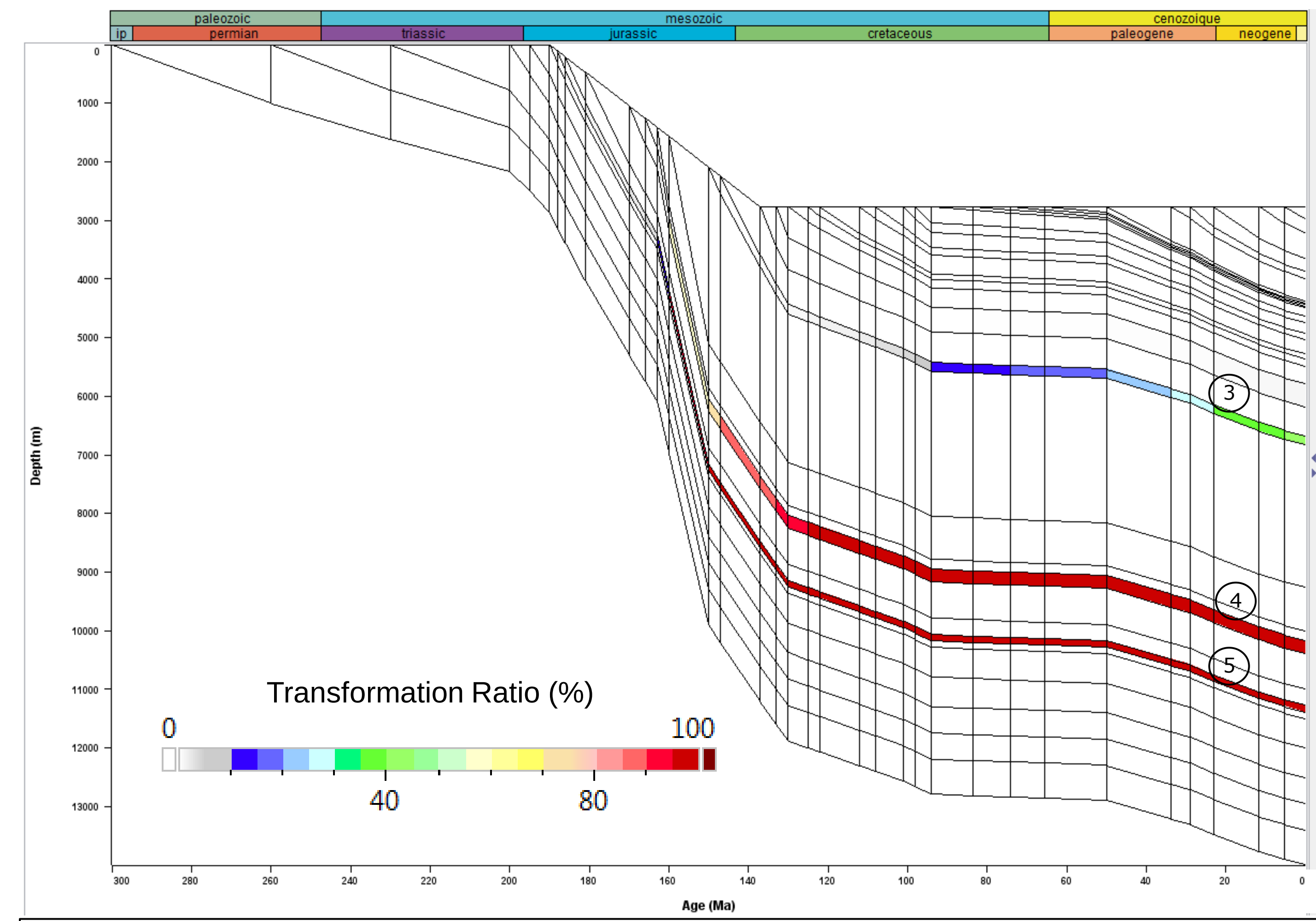
LOC_Batch-1S is the only studied location where alochthonous salt has been identified (about 1500 m of salt likely intercalated within Middle Jurassic units). The burial curve is similar to the one obtained in LOC_Batch-1N, although the sedimentary column is thinner (distal position).
The thin crust induces a lower heat flow in the area. Moreover the presence of alochthonous salt locally decreases the thermal gradient. As a consequence maturity levels are lower at this location. However deep SRs are still overmature ("Misaine" SR since the Miocene, and Lower Jurassic SR since the Jurassic). The Tithonian SR is entering within the wet gas window (TR =60%) and the Lower Cretaceous SR is within the oil window (TR<10%, kerogen type III).

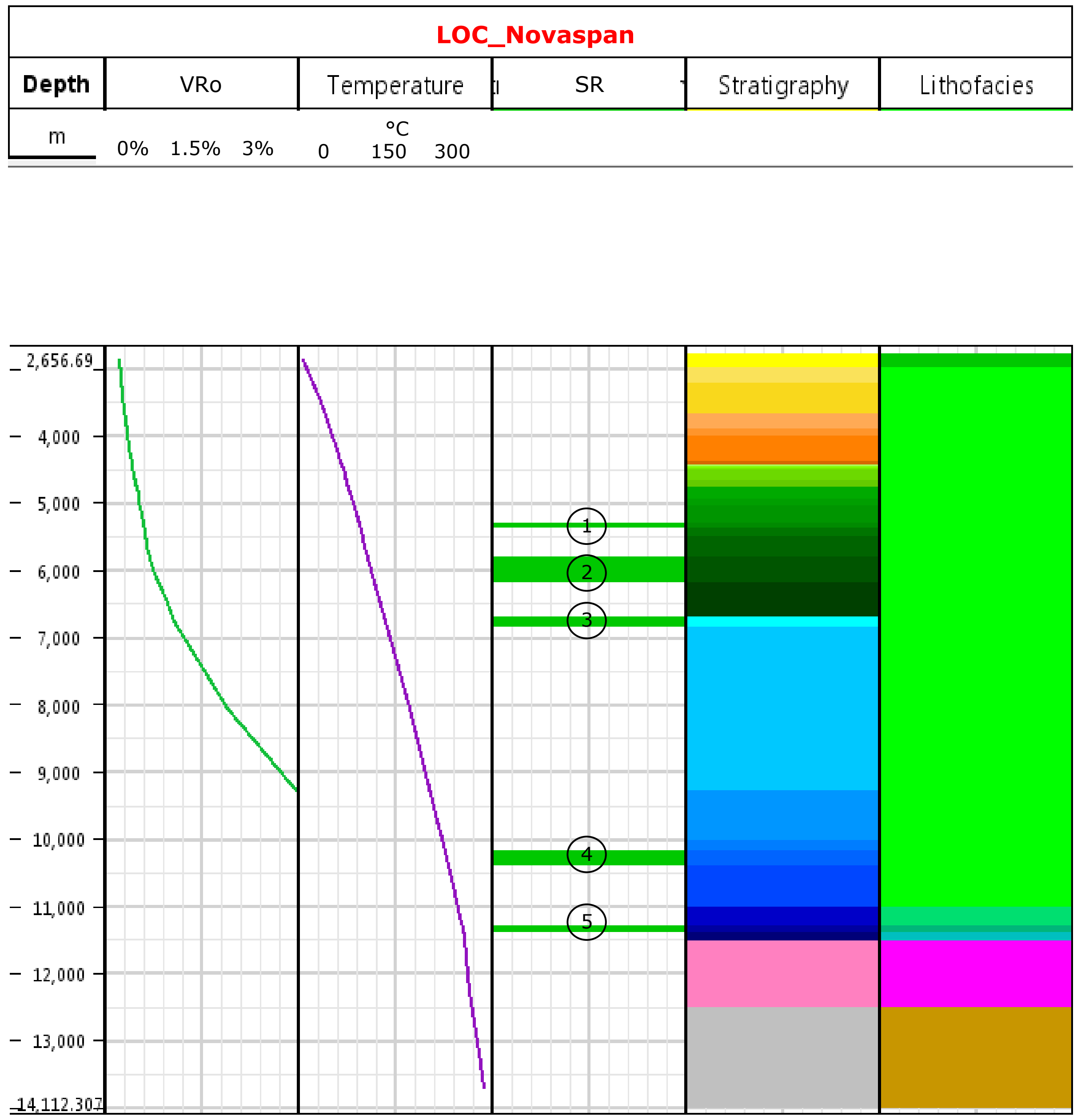


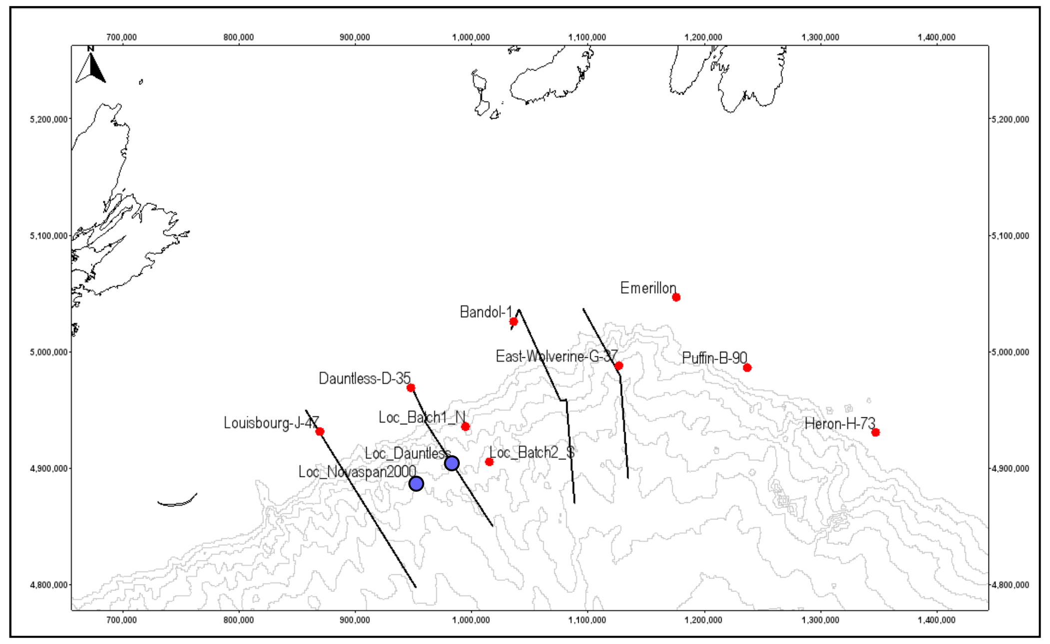












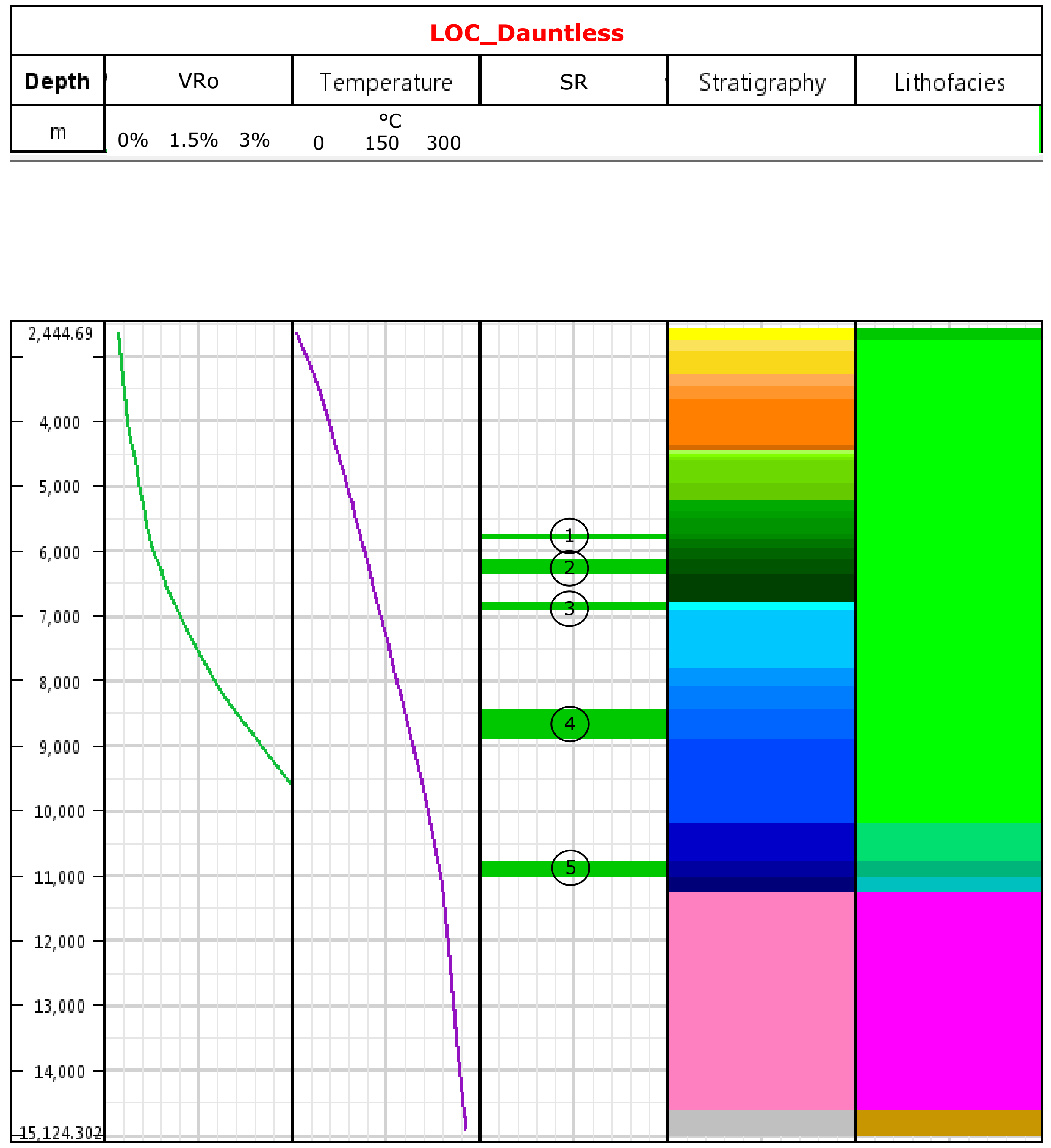
LOC_Novaspan-2000 (pseudo well)

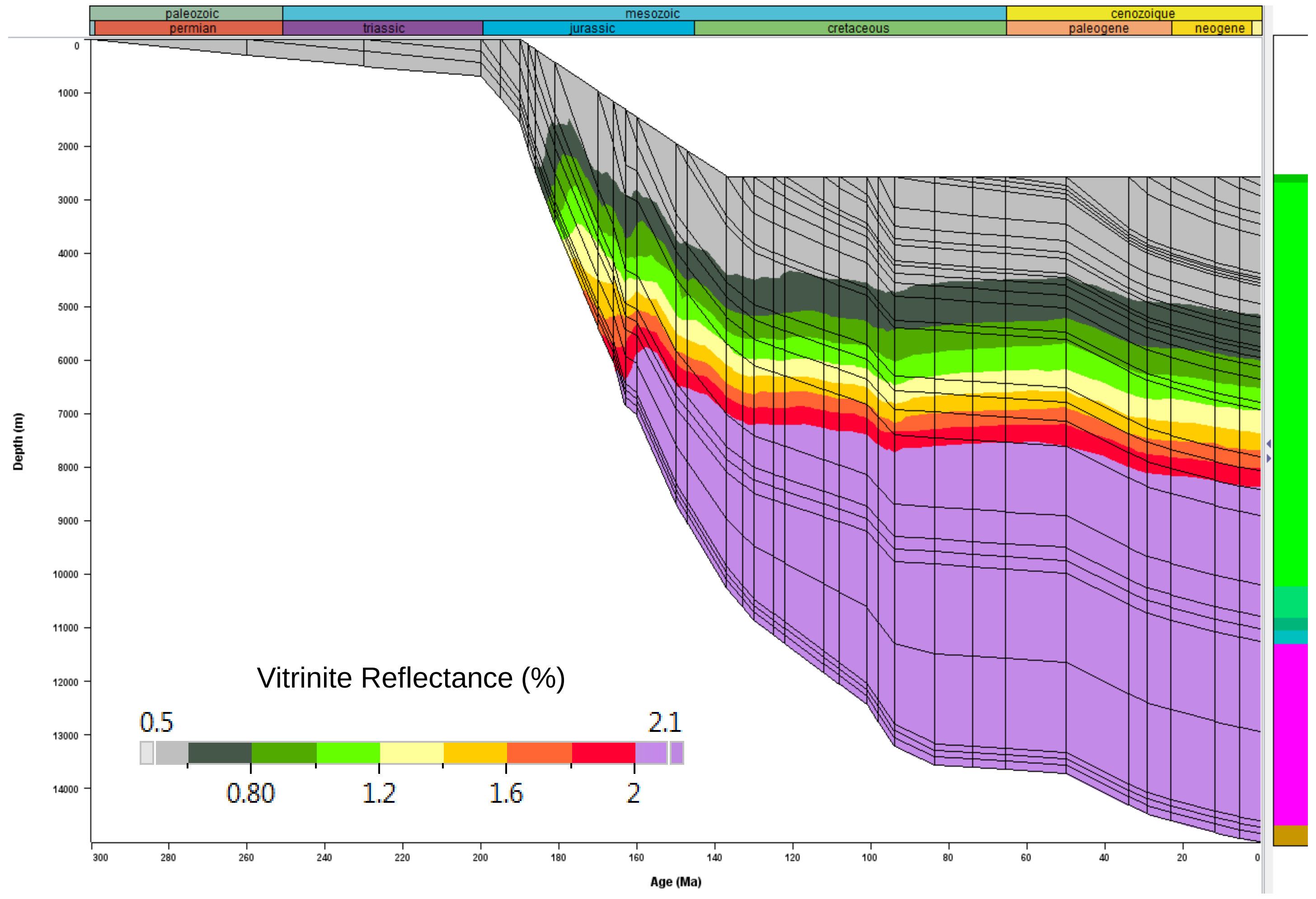
The burial curve is similar to the one obtained in the other pseudo wells of the deep offshore Laurentian Basin: massive burial during the Jurassic, progressive decrease of the burial rate during the Lower Cretaceous, Upper Cretaceous hiatus, and new increase of the burial rate since the Eocene.

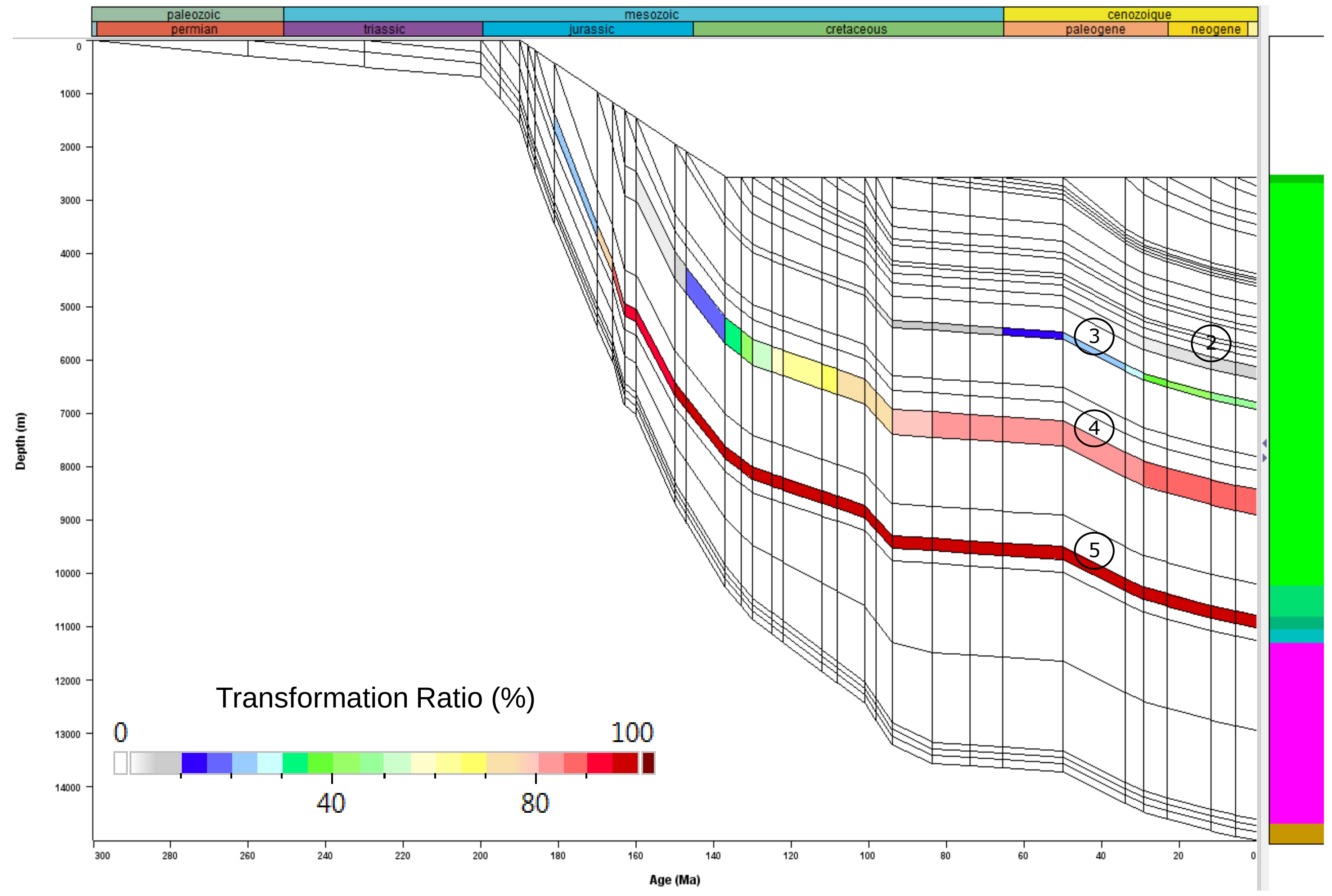
Middle and Lower Jurassic SRs are overmature since the Jurassic. The Tithonian SR is within the oil window since Cretaceous times (slow increase of the maturity level). Shallower source rocks are immature.

LOC_Dautless (pseudo well)

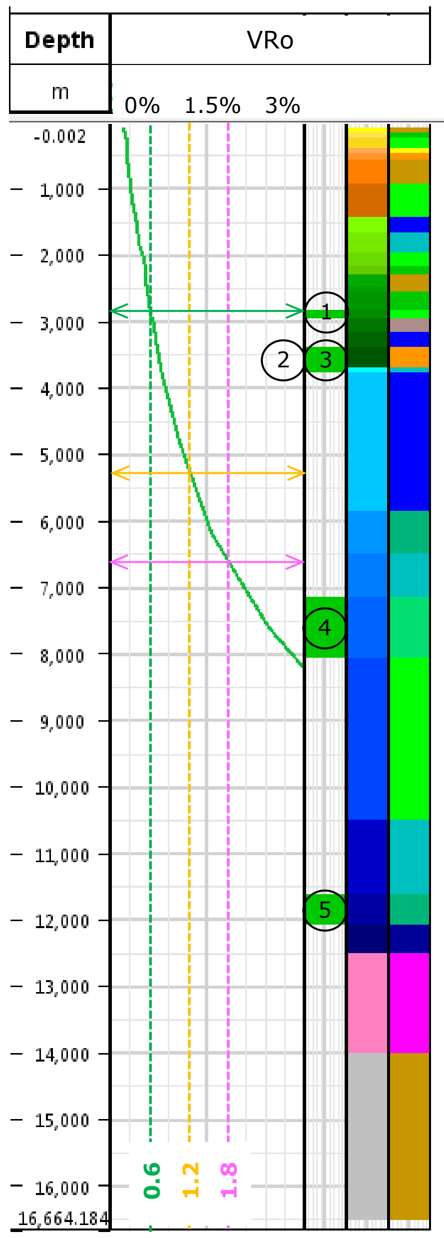
In this localion, Jurassic source rocks are slightly less deep and less mature. The Lower Jurassic SR is still overmature since Jurassic times, but the TR in the "Misaine" SR is about 80-90% (in the dry gas window since Eocene times). Like in LOC_Novaspan-2000 the Tithonian SR is within the oil window since Cretaceous times (slow increase of the maturity level) and shallower source rocks are immature or early mature.



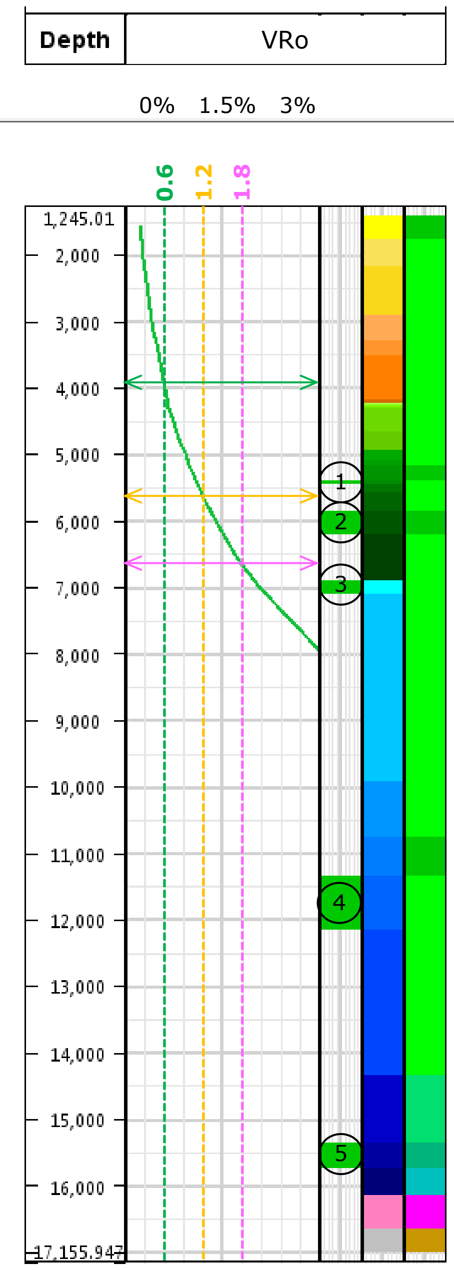




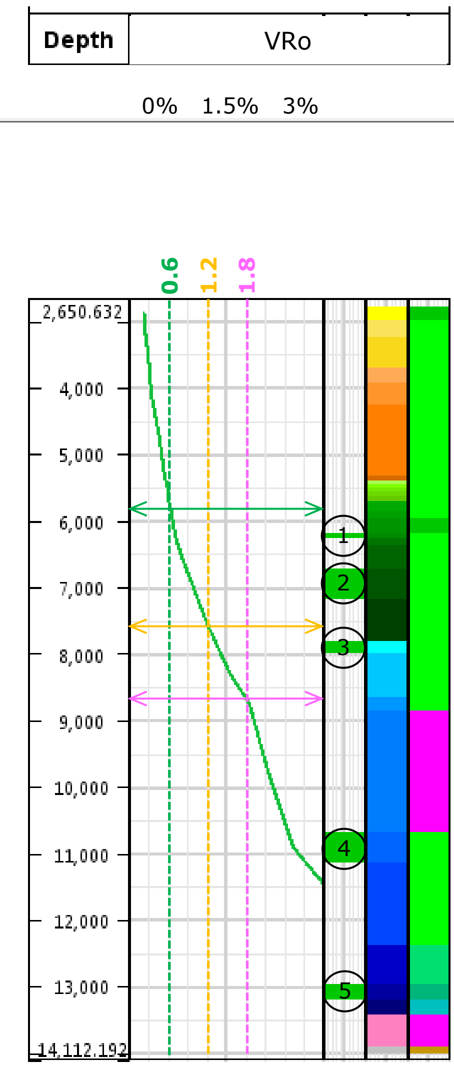
Dauntless



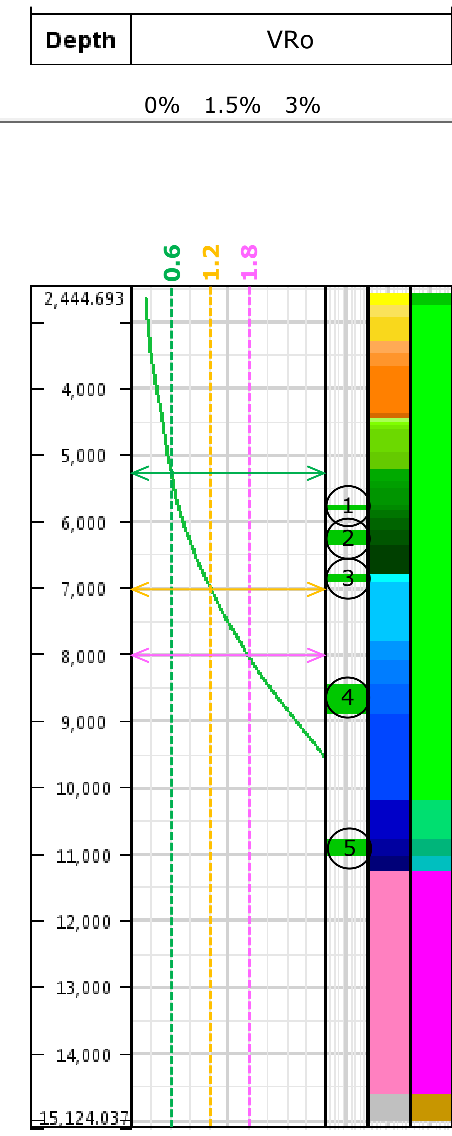
LOC_Batch-1N



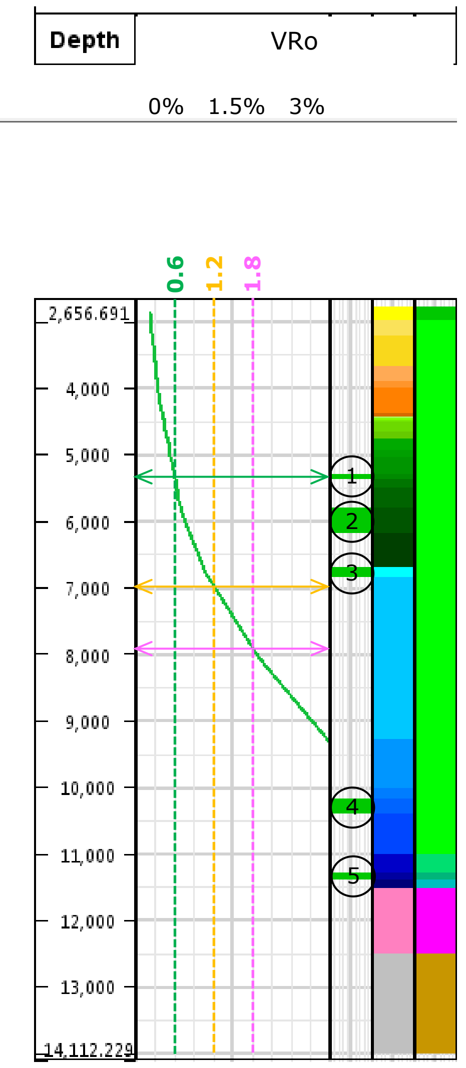
LOC_Batch-1S



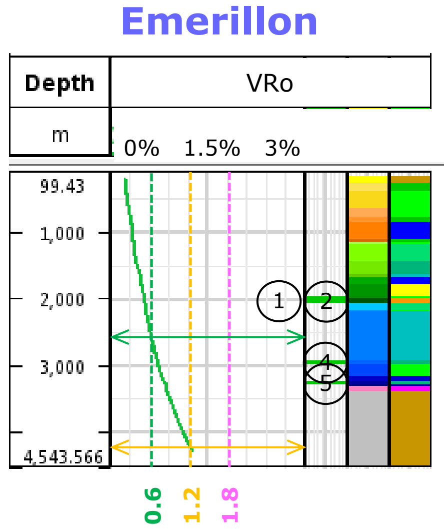
LOC_Dauntless



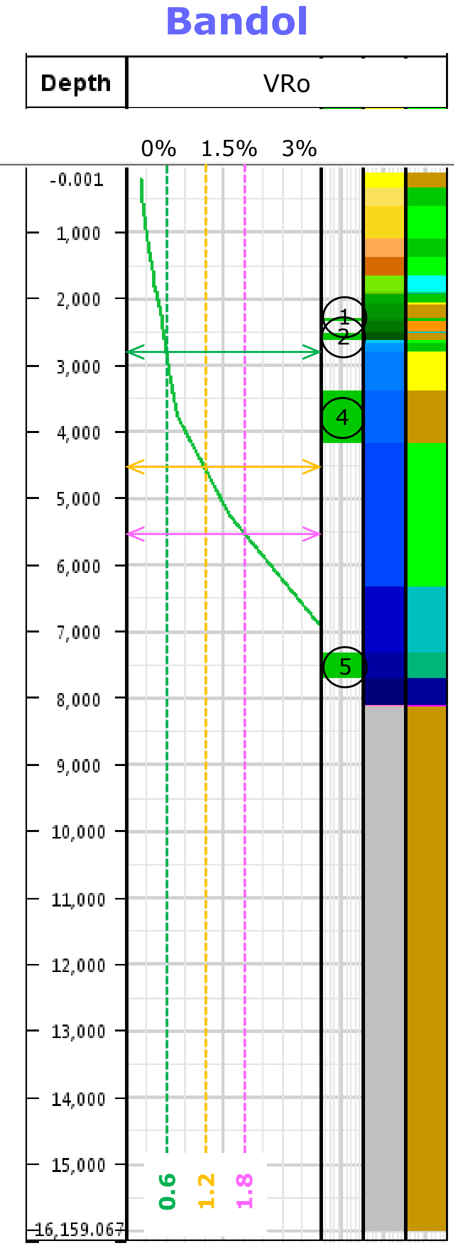
LOC_Novaspan



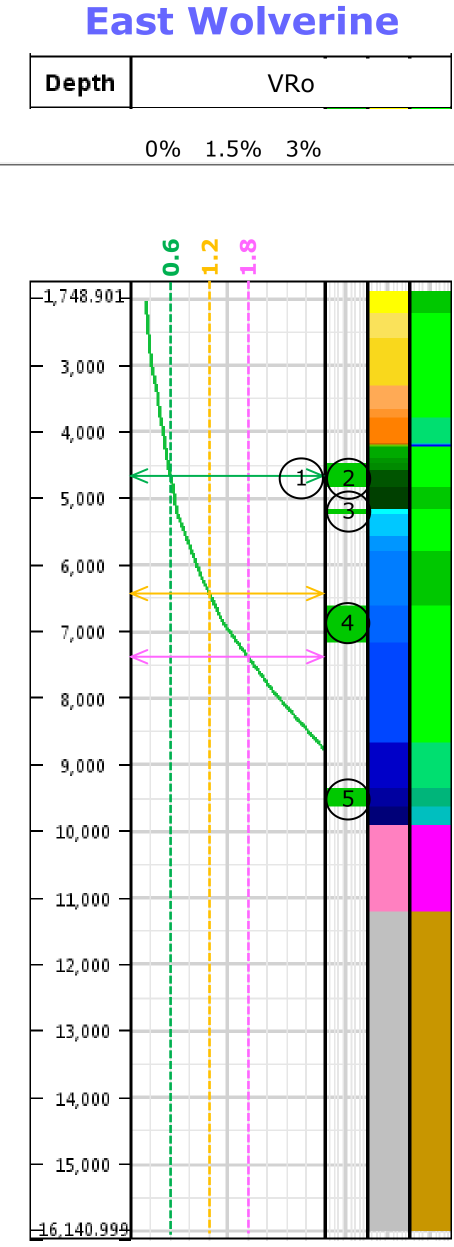
Emerillon



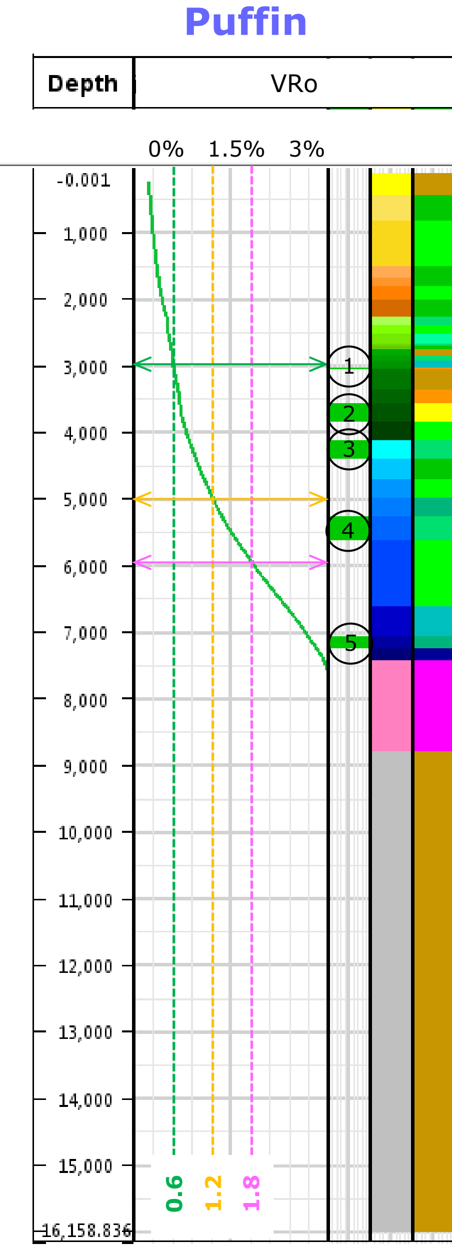
Bandol



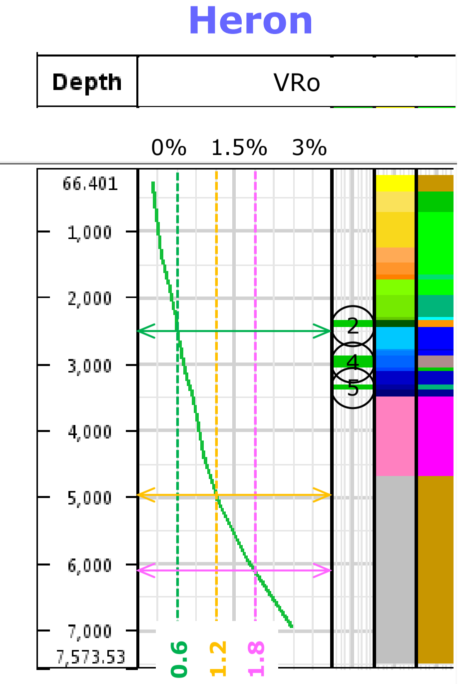
East Wolverine



Puffin



Heron



Conclusions on maturity levels

Pre-Salt

Pre-Salt sediments may have a petroleum potential in the shallow parts of the Grand Banks domain (Heron, Emerillon) where maturity levels reach the oil and the wet gas windows.

Lower Jurassic

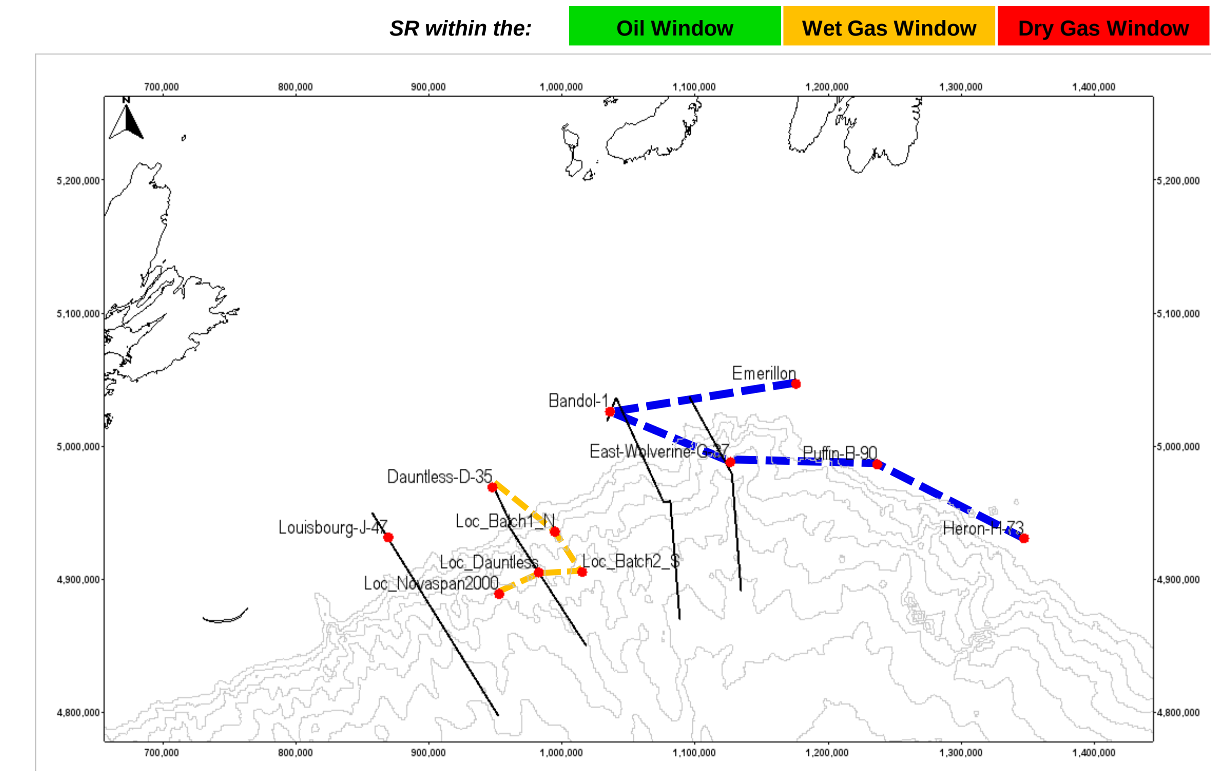
- The presence of Toarcian and Pliensbachian sediments is proved in the basin, at least in Heron and possibly in Emerillon (Grand Banks), which strengthen tentative correlations with Moroccan and Portuguese conjugate margins. However geochemical data suggest that the source rock potential is very low in proximal parts of the basin (low TOC and HI, Type II-III kerogen) : organic-rich Lower Jurassic SRs must be looked for in deeper parts of the basin (in the center of the rift grabens), likely in the deep offshore domain.
- Except in Emerillon and Heron where Lower Jurassic sediments are within the oil window (Grand Banks continental platform, wells located on structural highs), the Lower Jurassic SR is always overmature and often overcooked in studied locations. Even below large salt canopies that may locally reduce the thermal gradient, the Lower Jurassic is often too deeply buried and too early mature (since Jurassic times) for actively contributing to current petroleum systems. The only possible scheme is an early migration of the oil and the gas generated during the Jurassic followed by a possible dismigration of the hydrocarbons toward new-formed accumulations (in Cretaceous and Cenozoic reservoirs).
- Consequently, in the deep offshore basin, the Lower Jurassic SR could directly contribute to active petroleum systems only where the burial does not exceed 5000 to 6000 m (up to 7000 to 8000 m in case of large salt canopies, particularly toward the East where the heat flow decreases with the thinning of the continental crust).
- Between the Jurassic rift margins (Heron, Emerillon) and the deep Laurentian Basin, it likely exists a domain where the source rock is still active (VRo<2%), particularly in the northern part of the basin where the burial rate has increased since the Eocene. The main question is: do organic-rich sediments were deposited in these "intermediary" parts of the basin?
- Given the great depth of the basin, the presence of gas or gas with condensate in Lower Jurassic potential petroleum systems is more likely than the occurrence of oil, even if Type II SRs existed in the central parts of the grabens.

Other Source Rocks

If they exist, Lower Cretaceous to Middle Jurassic SRs would contribute to active petroleum systems. However in the deep offshore basin Upper and Middle Jurassic SRs are often overmature. Shallow SR (including the Lower Cretaceous SR in the shelf zone) are generally immature or early mature (TR<10% in type III kerogens) and cannot contribute to efficient petroleum systems (at least at studied locations). Zones with an increased burial since Eocene times could be more attractive (more recent generation and expulsion).

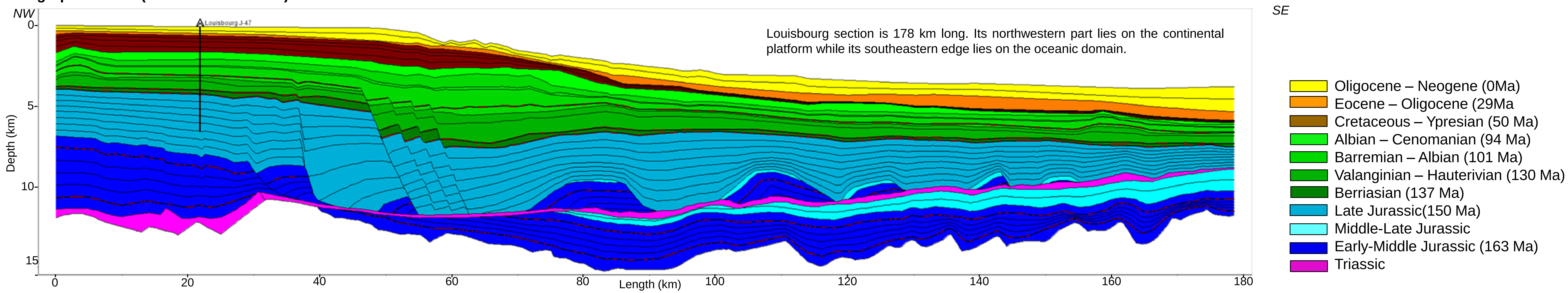
Well Pseudo-welll	1 NASKAPI SR	2 LOWER CRETACEOUS SR	3 TITHONIAN SR	4 MISAINE SR	5 LOWER JURASSIC SR
Dauntless-D-35	immature				
Loc_Batch1_N					
Loc_Batch1_S					
Loc_Dauntless_transect					
Loc_Novaspan2000	immature				
Emerillon	immature	immature	Hiatus / Erosion		
Bandol-1	immature	immature	Hiatus / Erosion		
East-Wolverine-G-37	immature	immature			
Puffin-B-90	immature				
Heron-H-73	Hiatus / Erosion	immature	Hiatus / Erosion		

SR within the: Oil Window | Wet Gas Window | Dry Gas Window

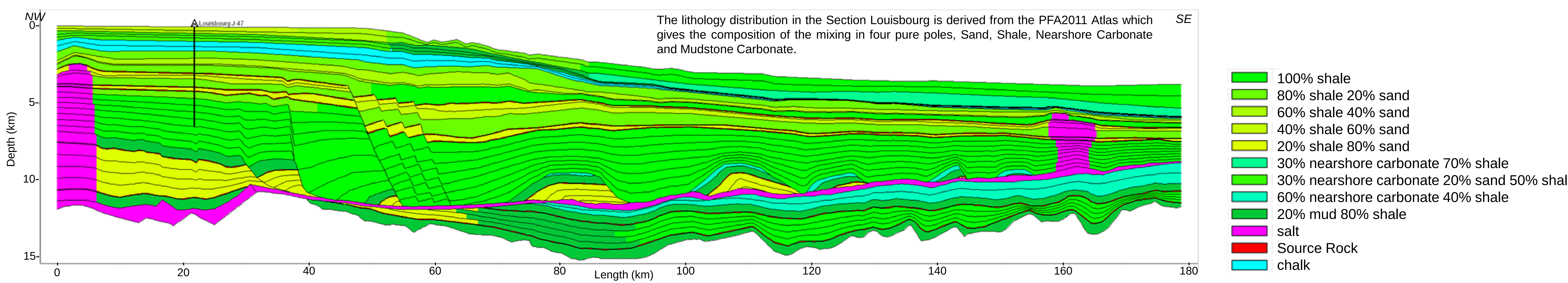


2D Modeling
Louisbourg Section

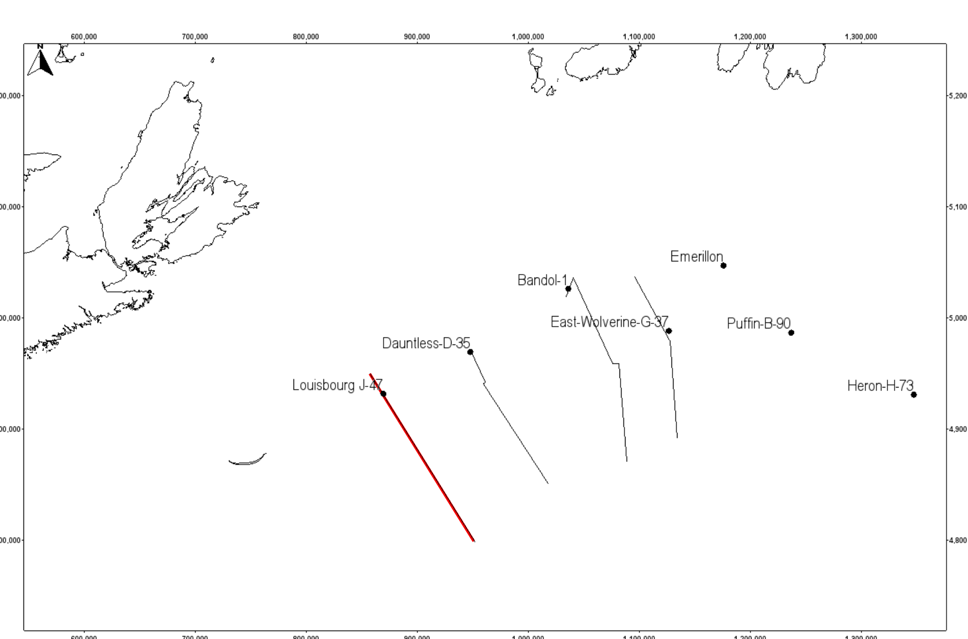
Stratigraphic Model (Reference Scenario)



Lithological Model (Reference Scenario)

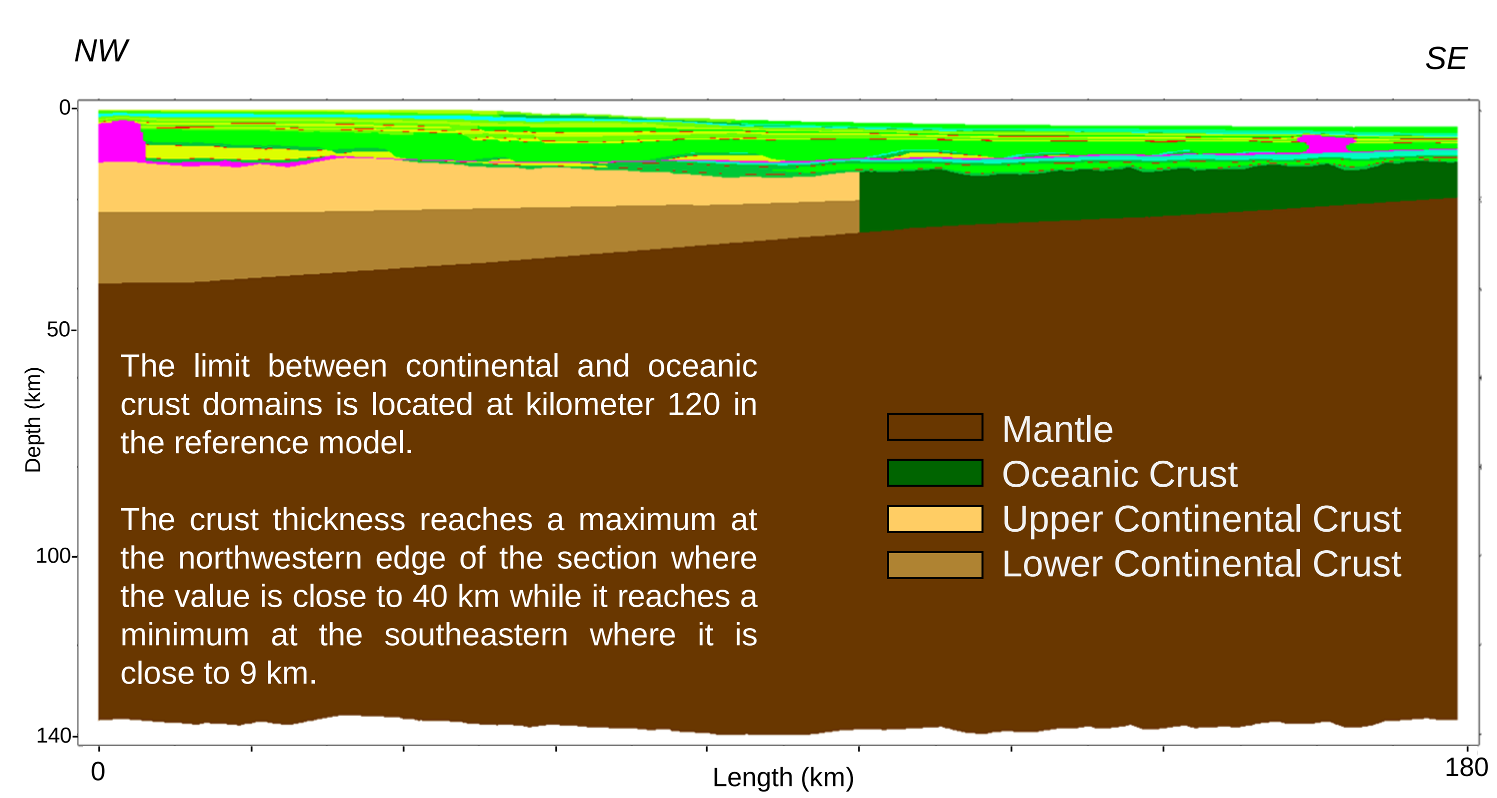


Location Map

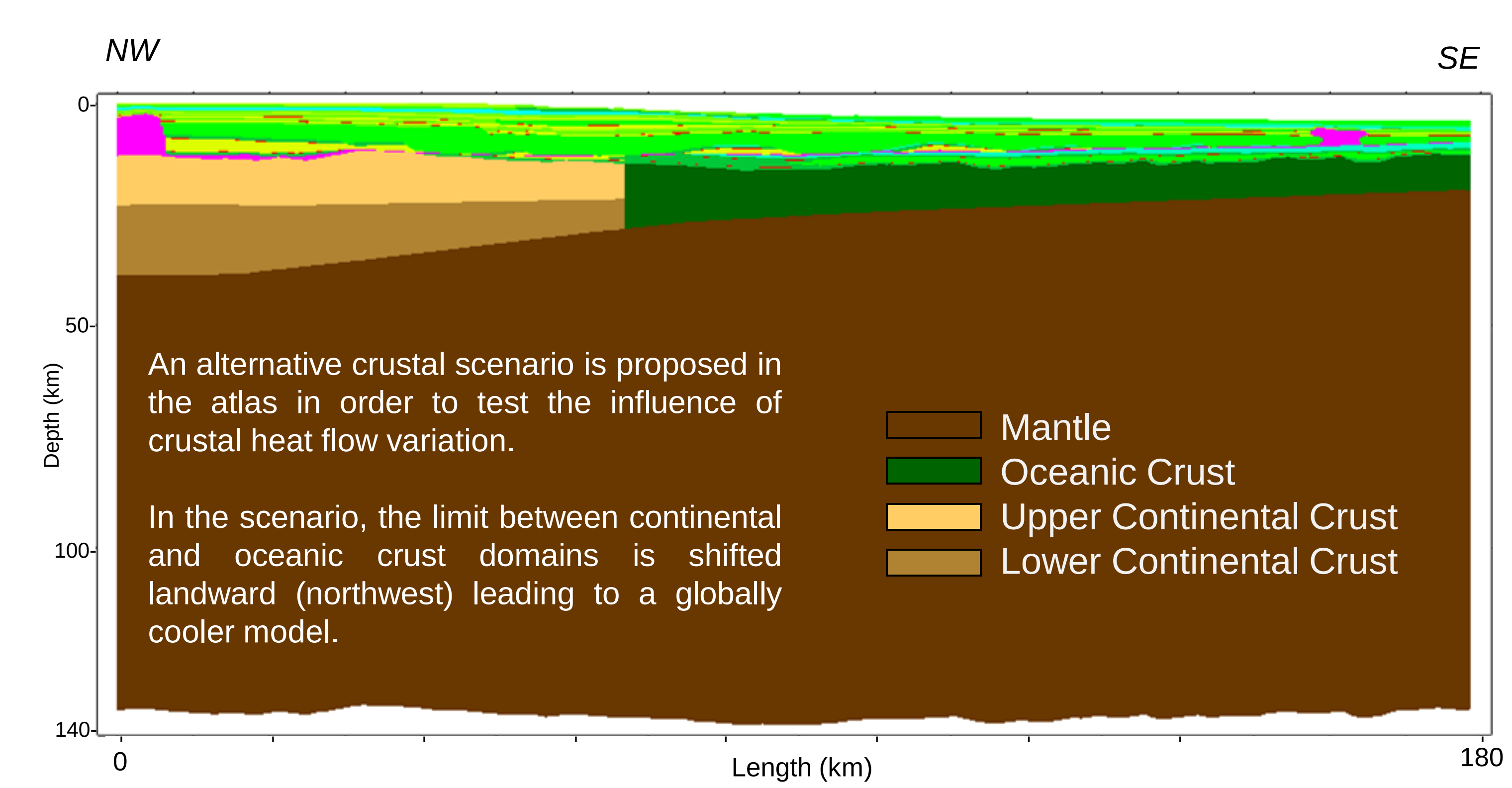


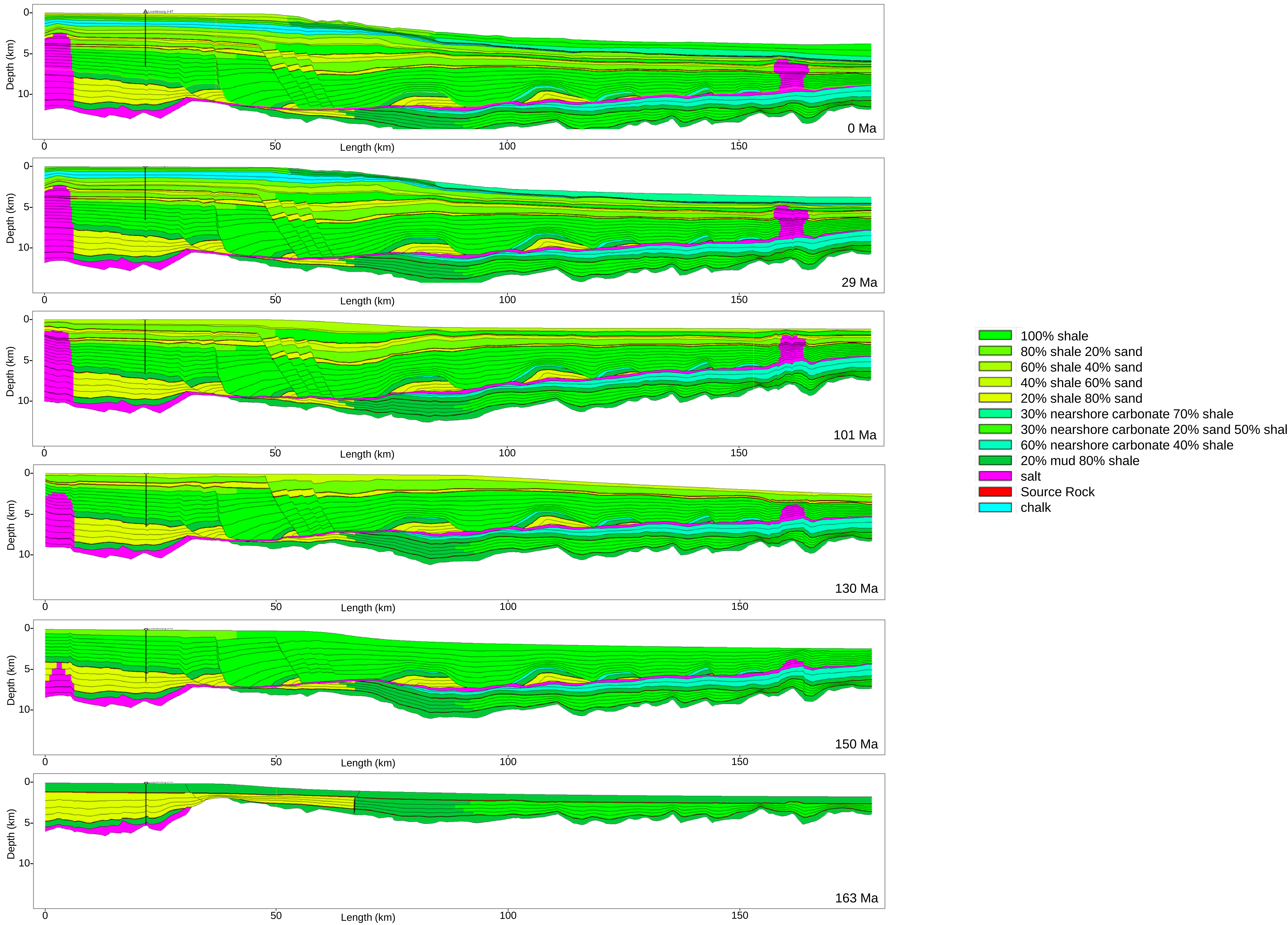
Louisbourg section trace intersects Louisbourg J-47 well location. The well features pressure, temperature & vitrinite measurements which have been used for calibration purposes.

Thermal Basement Model – Scenario 1 (= Reference Scenario)



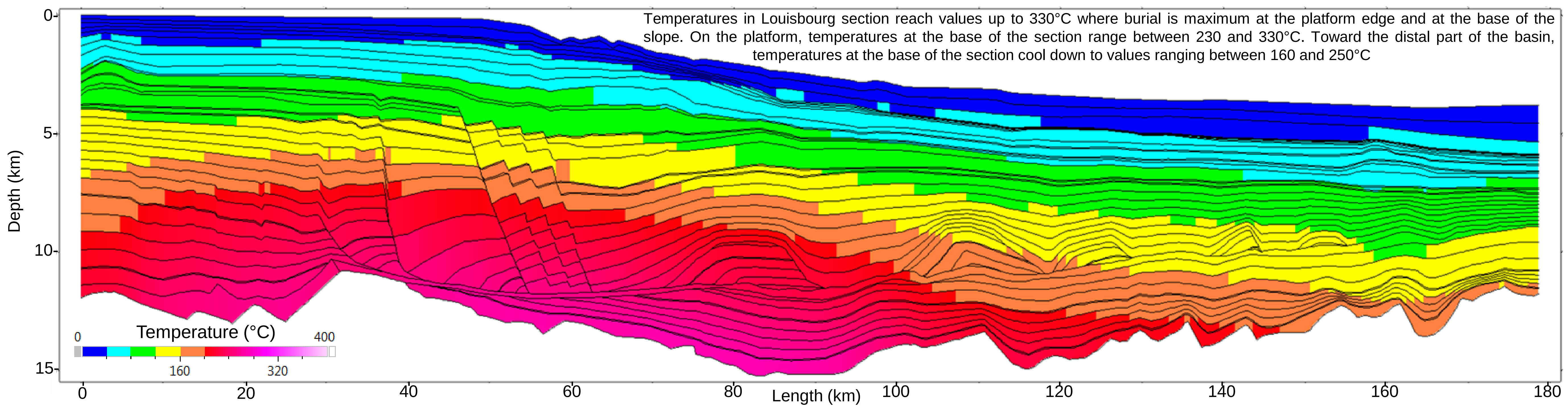
Thermal Basement Model – Scenario 2 (= Heat Flow Variation)





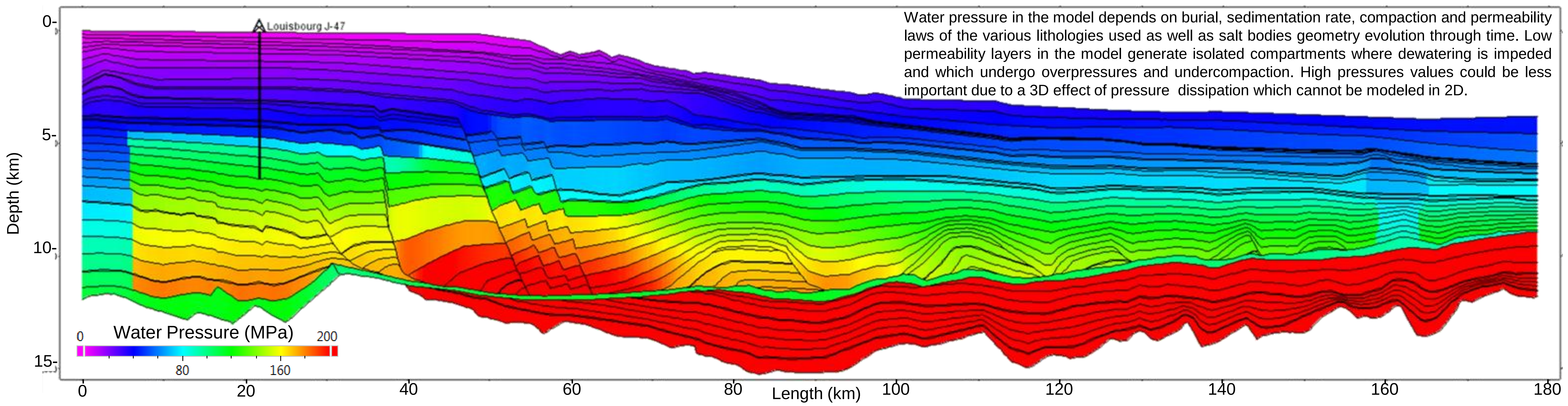
Restoration Scenario of Louisbourg Section – Reference Scenario **PLATE 9.14**

Temperature (Reference Scenario)



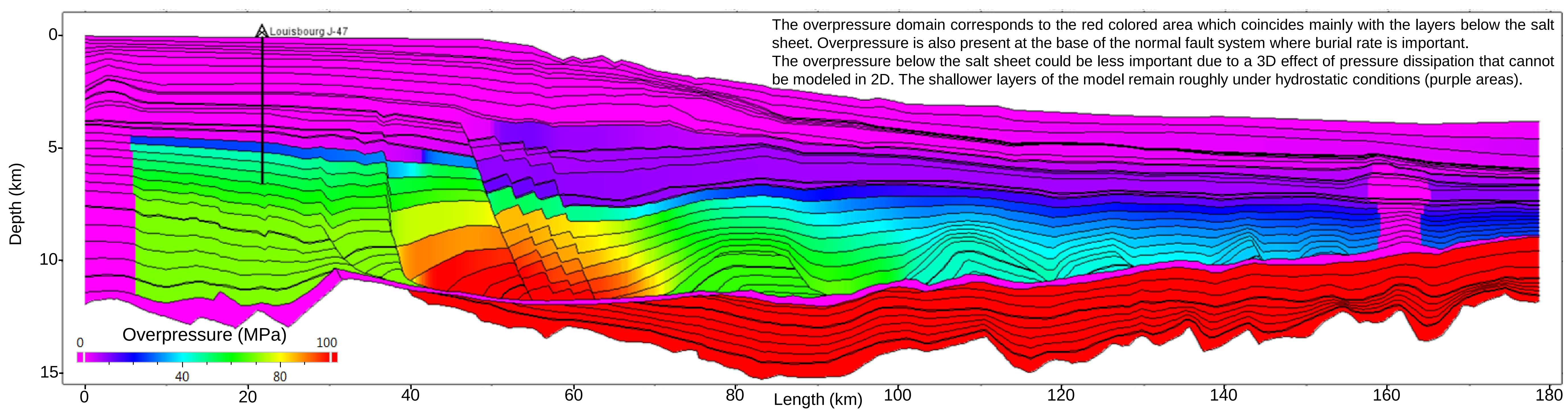
Temperatures in Louisbourg section reach values up to 330°C where burial is maximum at the platform edge and at the base of the slope. On the platform, temperatures at the base of the section range between 230 and 330°C. Toward the distal part of the basin, temperatures at the base of the section cool down to values ranging between 160 and 250°C

Water Pressure (Reference Scenario)



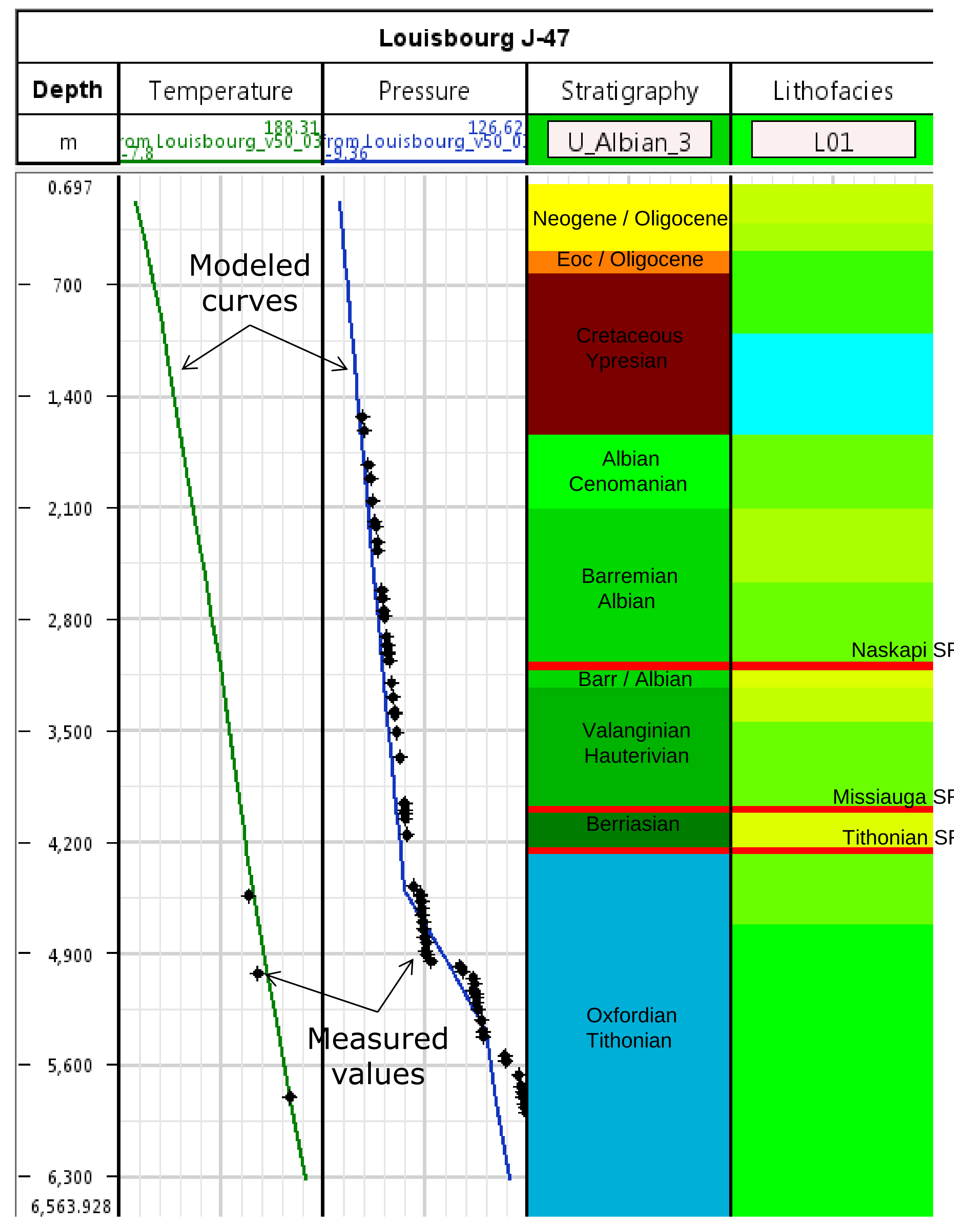
Water pressure in the model depends on burial, sedimentation rate, compaction and permeability laws of the various lithologies used as well as salt bodies geometry evolution through time. Low permeability layers in the model generate isolated compartments where dewatering is impeded and which undergo overpressures and undercompaction. High pressures values could be less important due to a 3D effect of pressure dissipation which cannot be modeled in 2D.

Overpressure (Reference Scenario)



The overpressure domain corresponds to the red colored area which coincides mainly with the layers below the salt sheet. Overpressure is also present at the base of the normal fault system where burial rate is important.
The overpressure below the salt sheet could be less important due to a 3D effect of pressure dissipation that cannot be modeled in 2D. The shallower layers of the model remain roughly under hydrostatic conditions (purple areas).

Calibration (Reference Scenario)



Temperature & Pressure models are calibrated versus available observed data at Louisbourg J-47 well location:

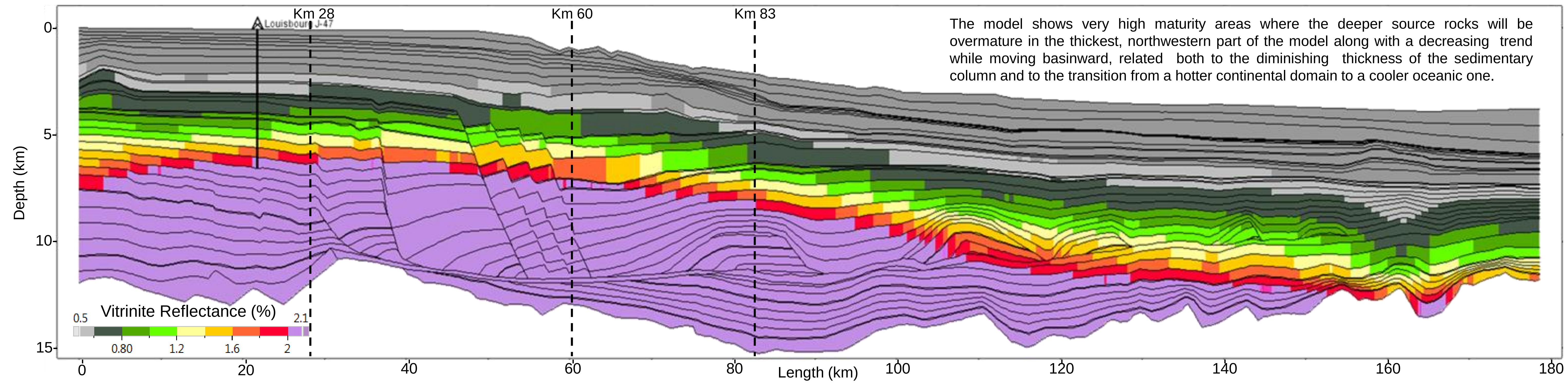
- Observed data is represented with dots
- Simulated data is represented with continuous, thick lines

Temperature calibration at Louisbourg J-47 well location falls under the measurements uncertainty range.

Pressure calibration at J-47 well is satisfactory: the overpressure around 4,900m is reproduced by a less permeable shaly layer suggested in the PFA 2011.

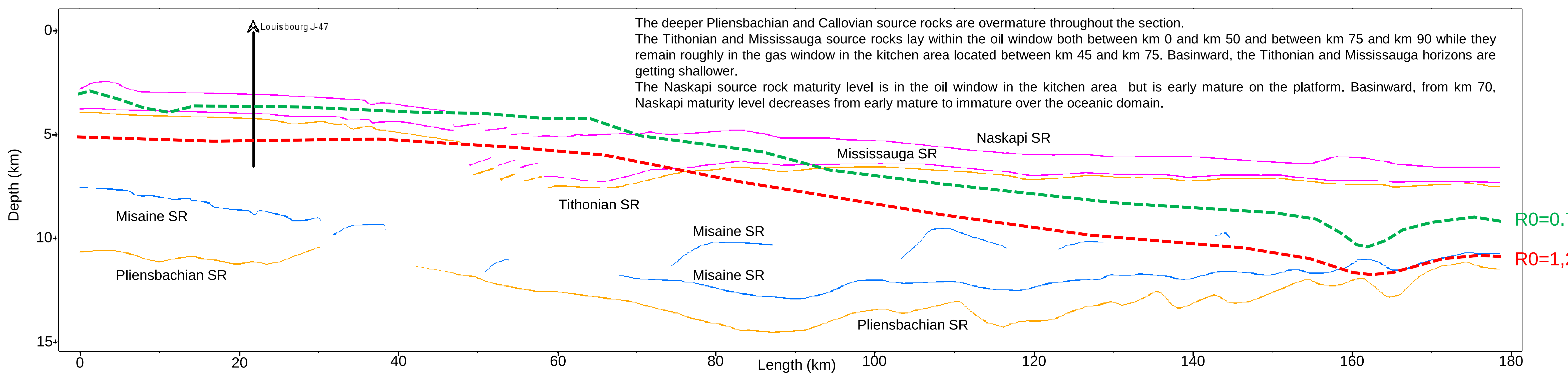
Temperature and Pressure Calibration of Louisbourg Section – Reference Scenario **PLATE 9.15**

Vitrinite Reflectance(Reference Scenario)



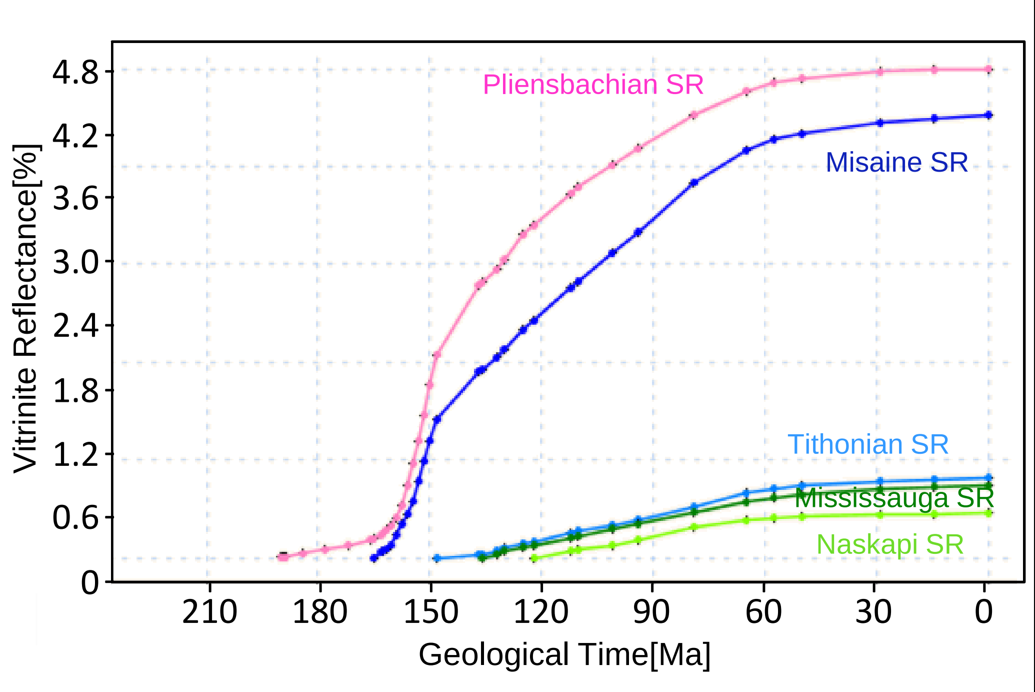
The model shows very high maturity areas where the deeper source rocks will be overmature in the thickest, northwestern part of the model along with a decreasing trend while moving basinward, related both to the diminishing thickness of the sedimentary column and to the transition from a hotter continental domain to a cooler oceanic one.

Oil & Gas Windows

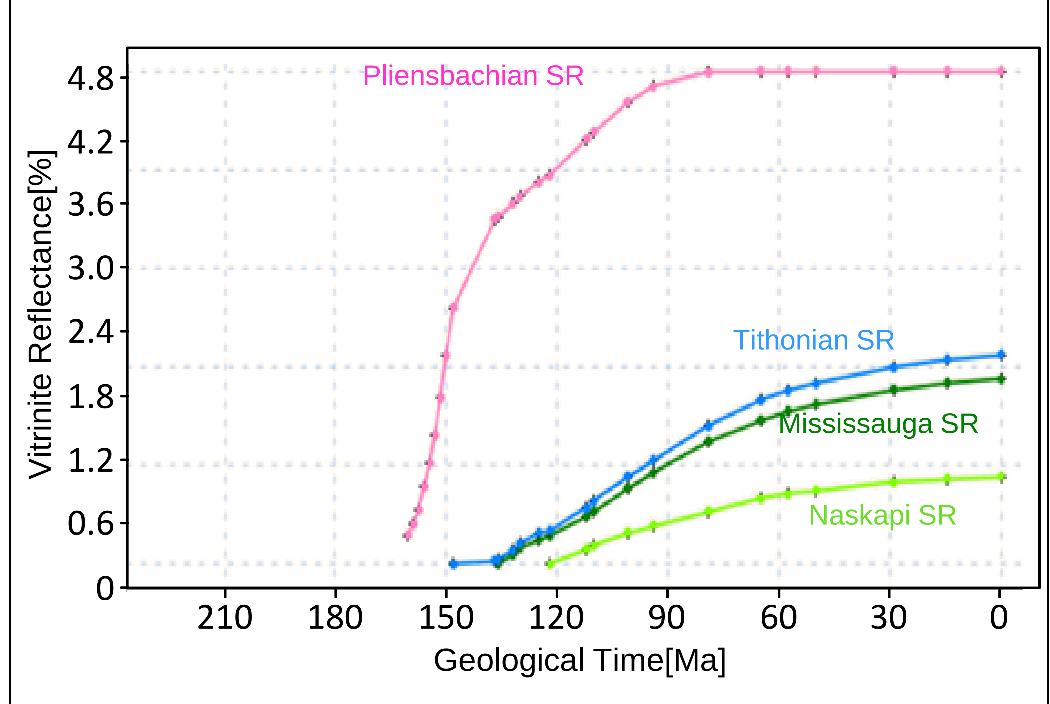


The deeper Pliensbachian and Callovian source rocks are overmature throughout the section.
The Tithonian and Mississauga source rocks lay within the oil window both between km 0 and km 50 and between km 75 and km 90 while they remain roughly in the gas window in the kitchen area located between km 45 and km 75. Basinward, the Tithonian and Mississauga horizons are getting shallower.
The Naskapi source rock maturity level is in the oil window in the kitchen area but is early mature on the platform. Basinward, from km 70, Naskapi maturity level decreases from early mature to immature over the oceanic domain.

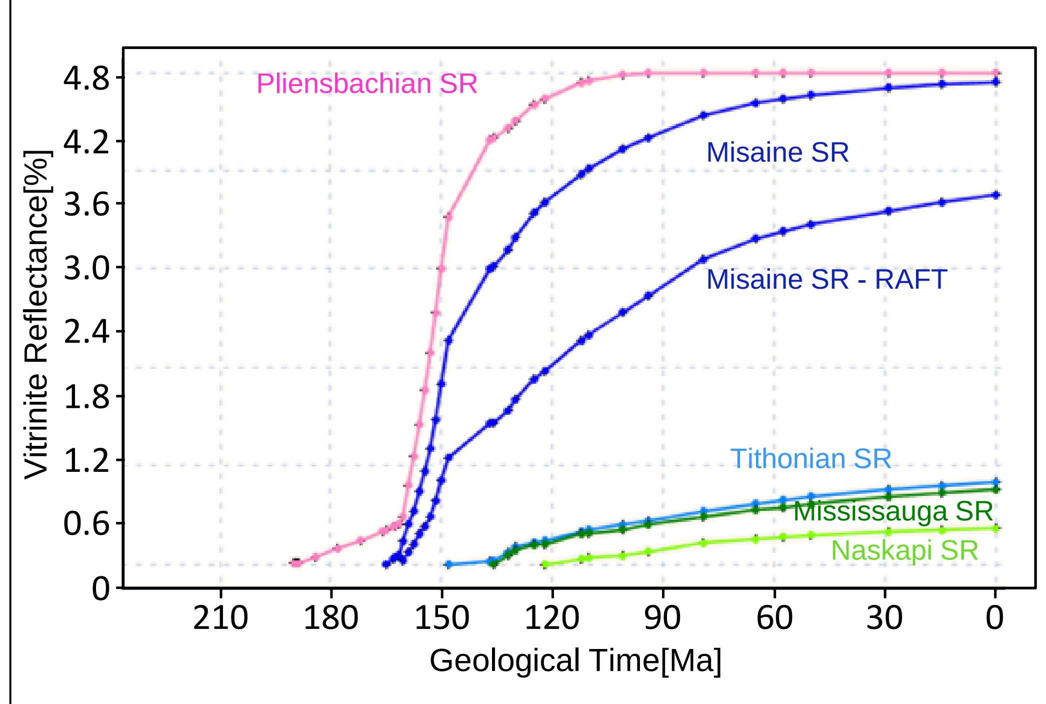
Vitrinite Reflectance through time at Km 28 Location



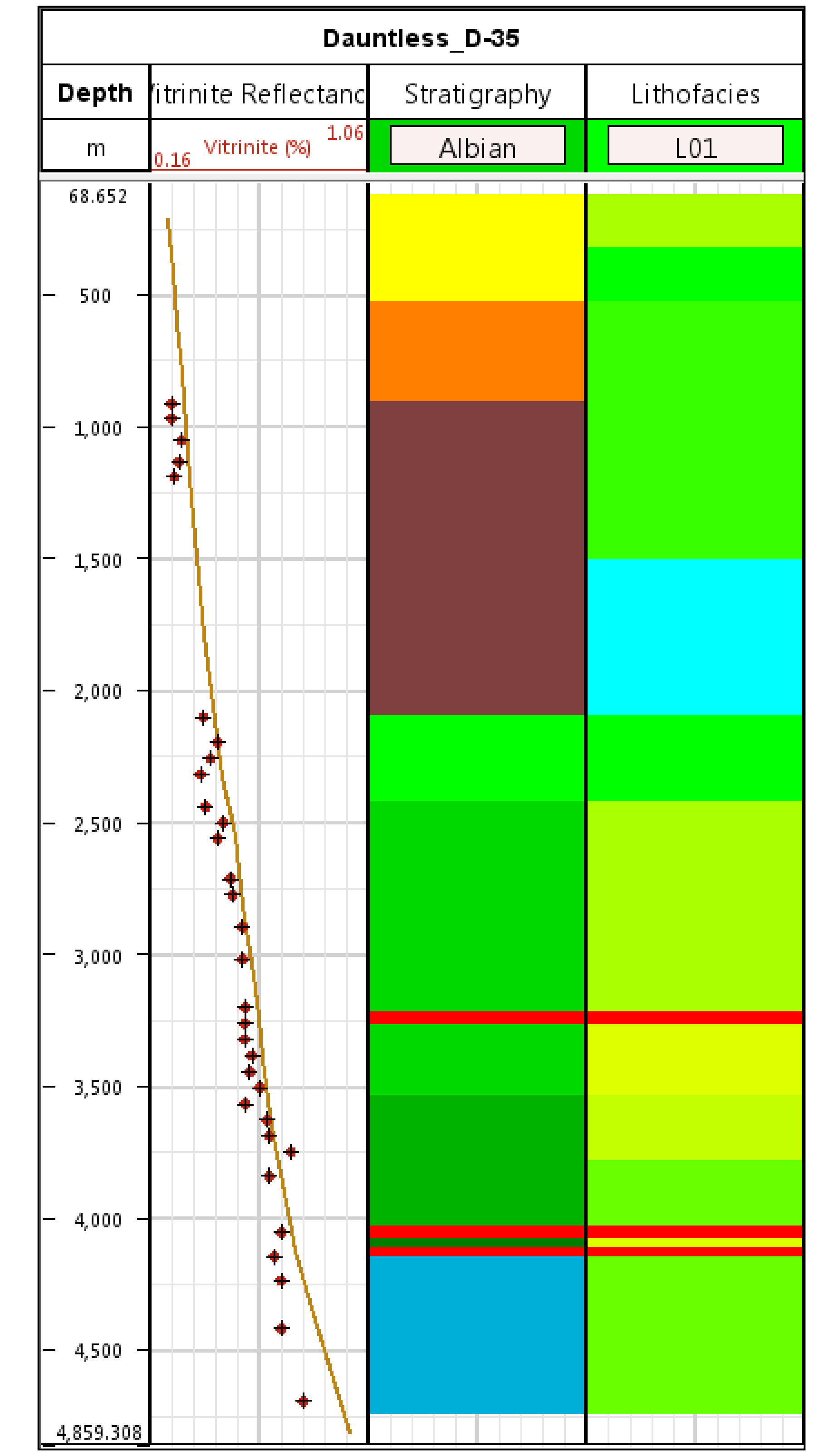
Vitrinite Reflectance through time at Km 60 Location



Vitrinite Reflectance through time at Km 83 Location



Calibration (Reference Scenario)

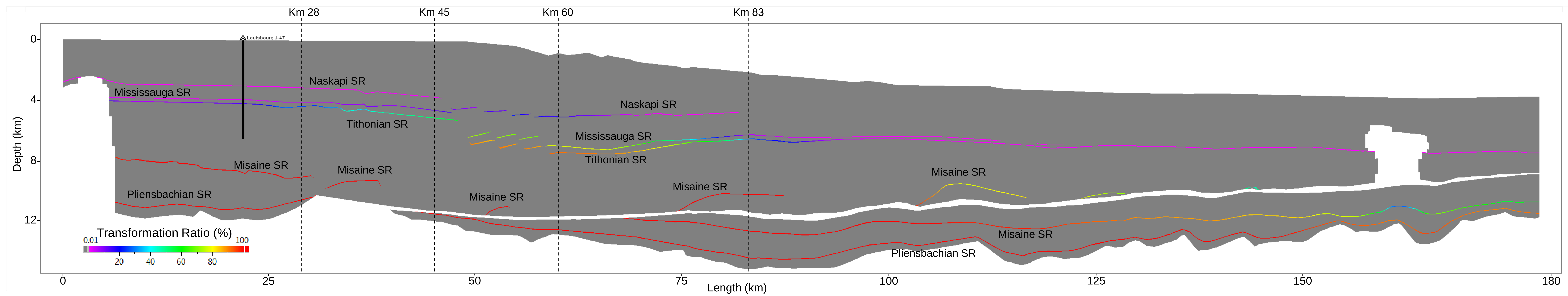


Vitrinite model is calibrated versus available observed data at Louisbourg J-47 well location:

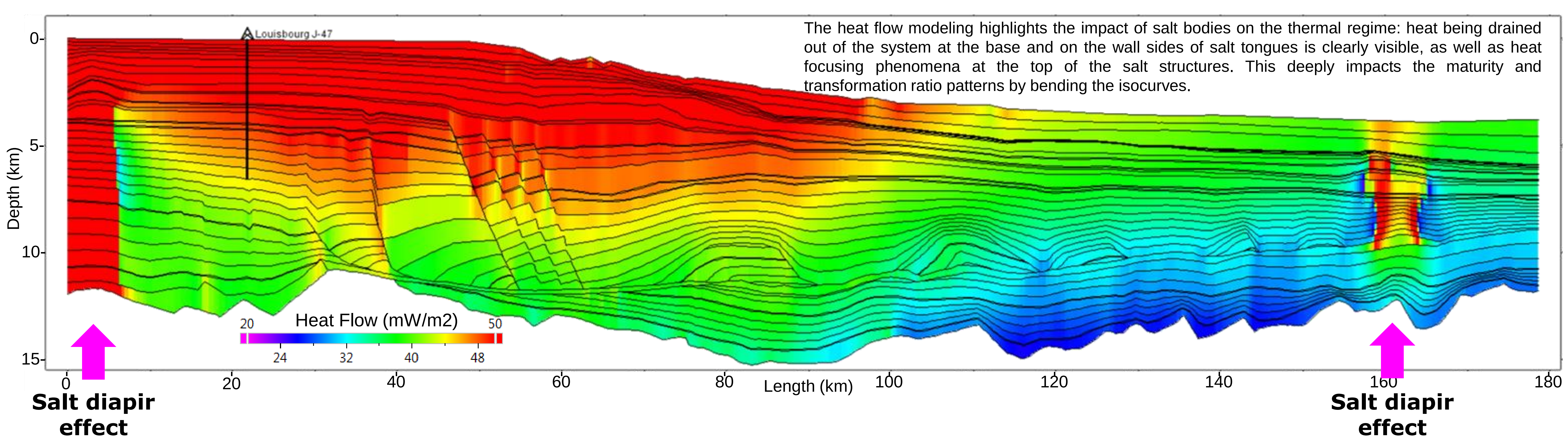
- Observed data is represented with dots,
- Simulated data is represented with thick line.

Vitrinite calibration at Louisbourg J-47 well location falls under the measurements uncertainty range.

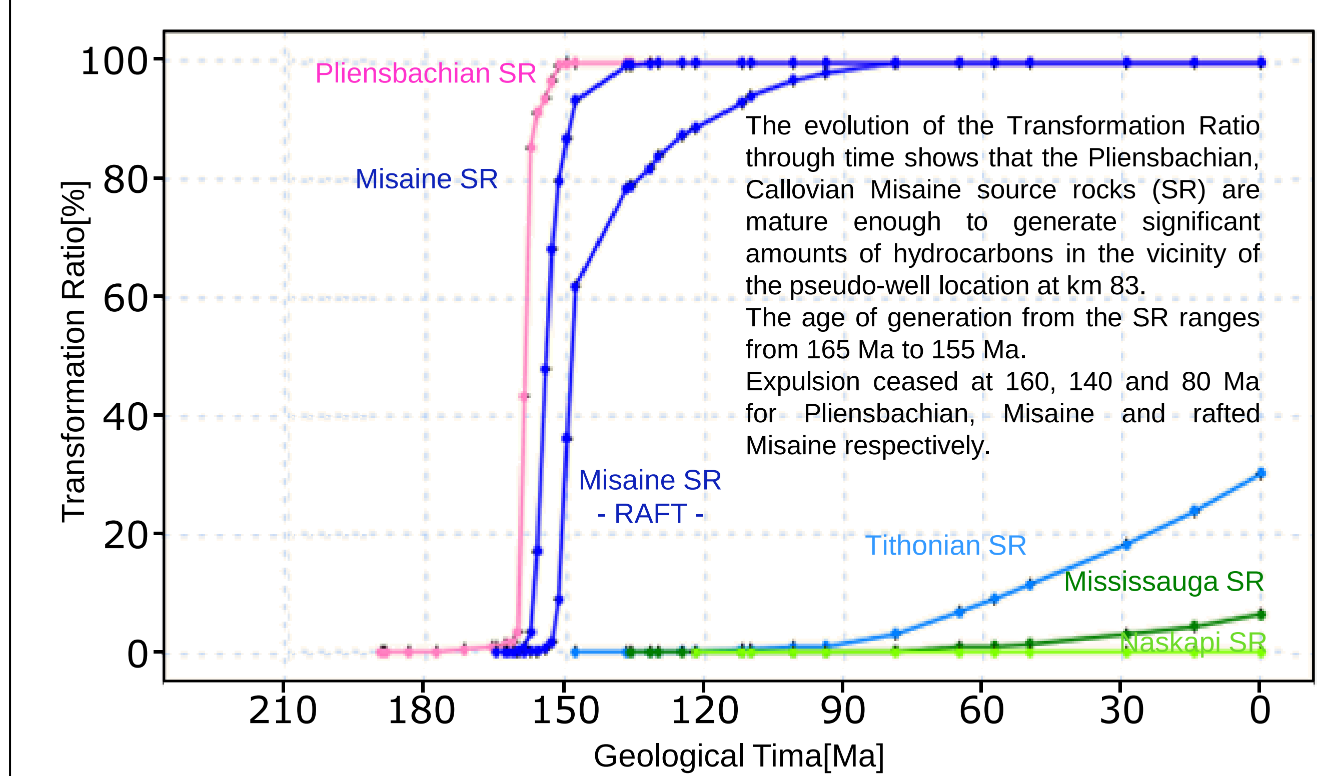
Transformation Ratio (Reference Scenario)



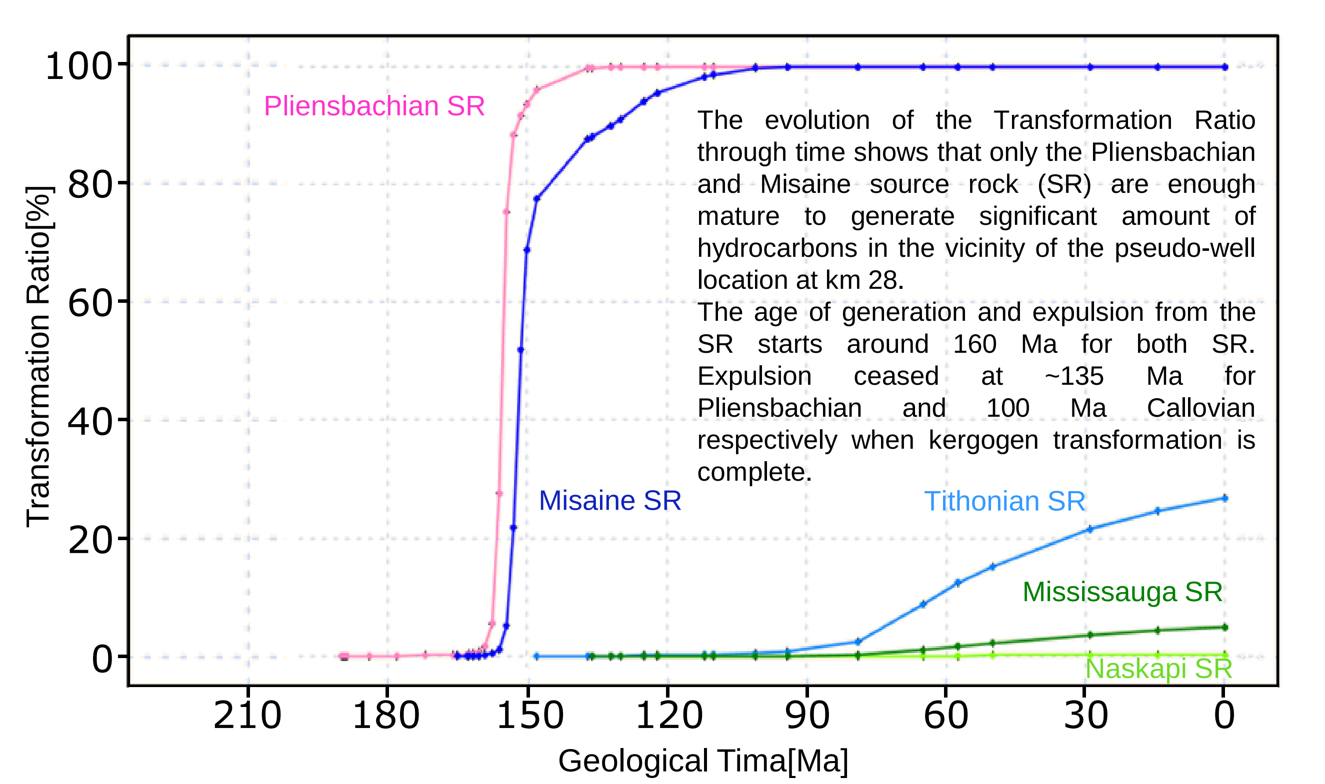
Heat Flow (Reference Scenario)



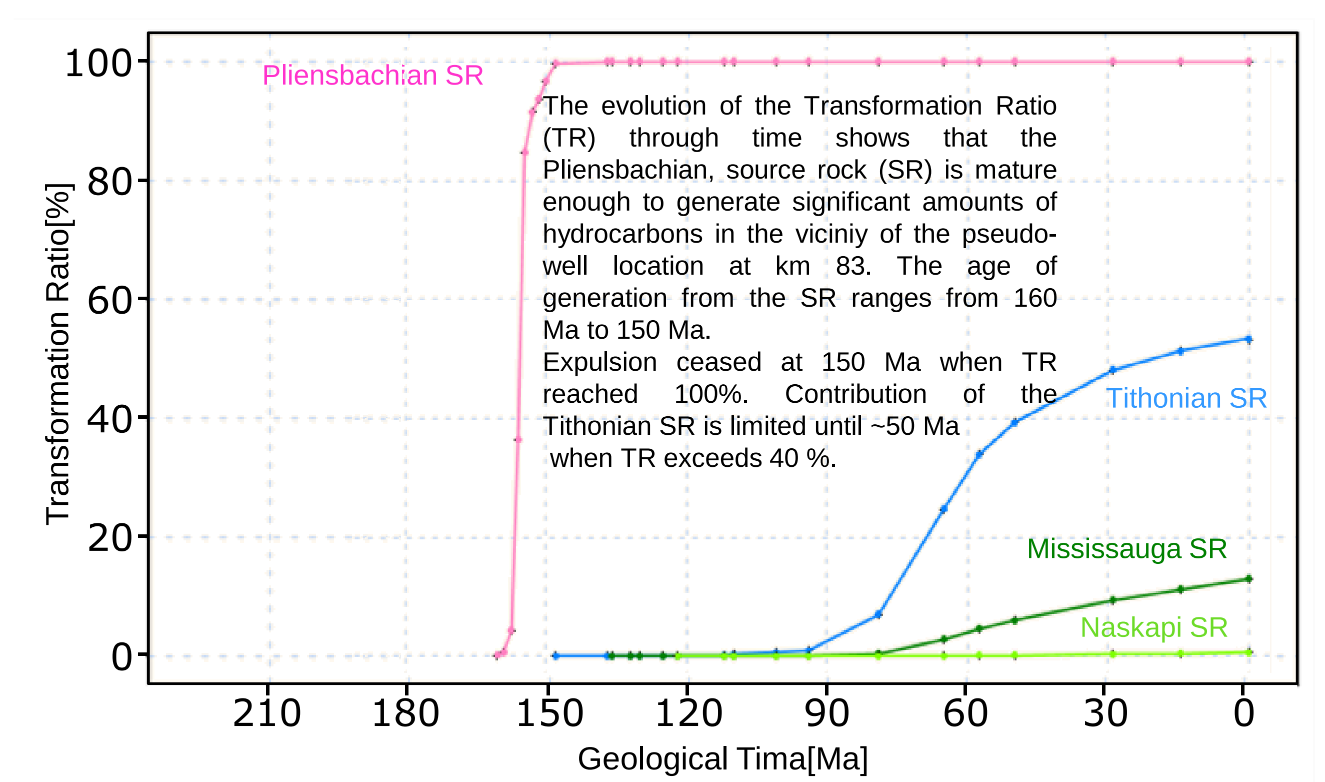
Transformation Ratio through time at km 83 Location



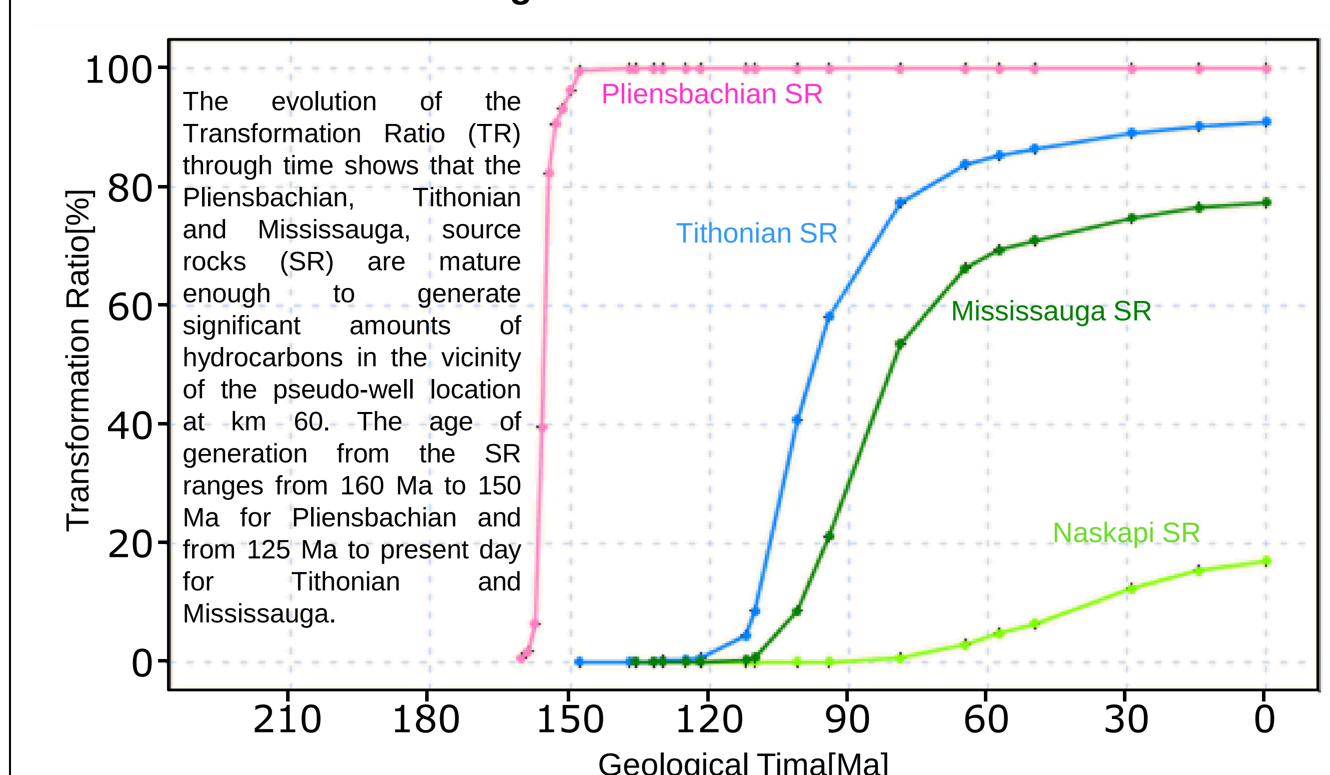
Transformation Ratio through time at km 28 Location



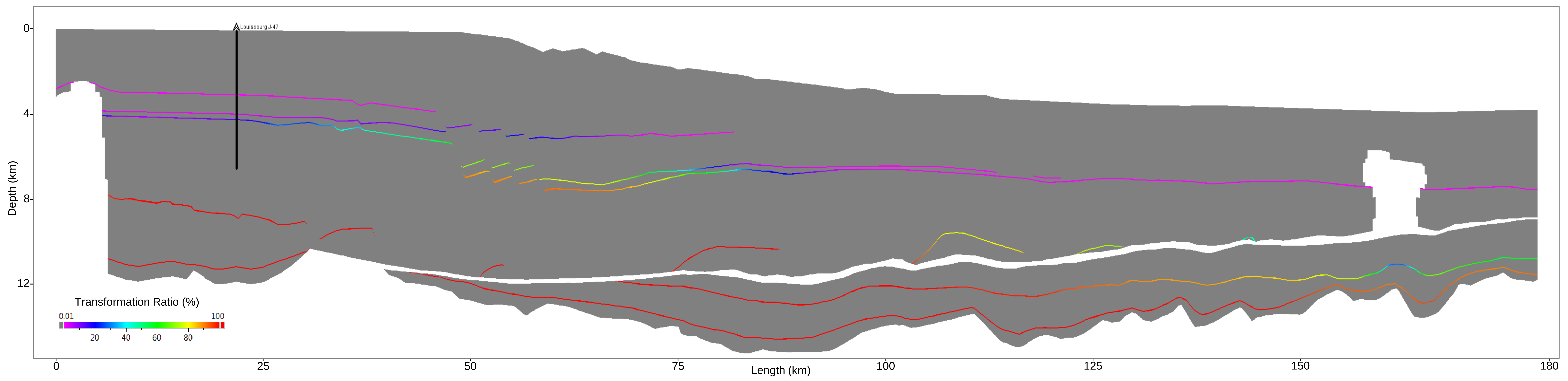
Transformation Ratio through time at km 45 Location



Transformation Ratio through time at km 60 Location

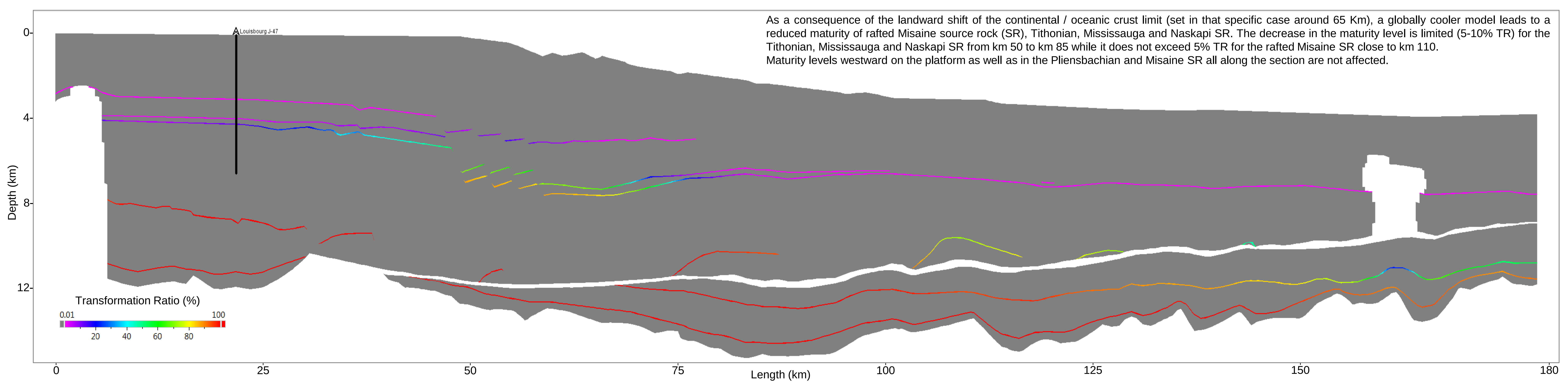


Transformation Ratio (Reference Scenario)

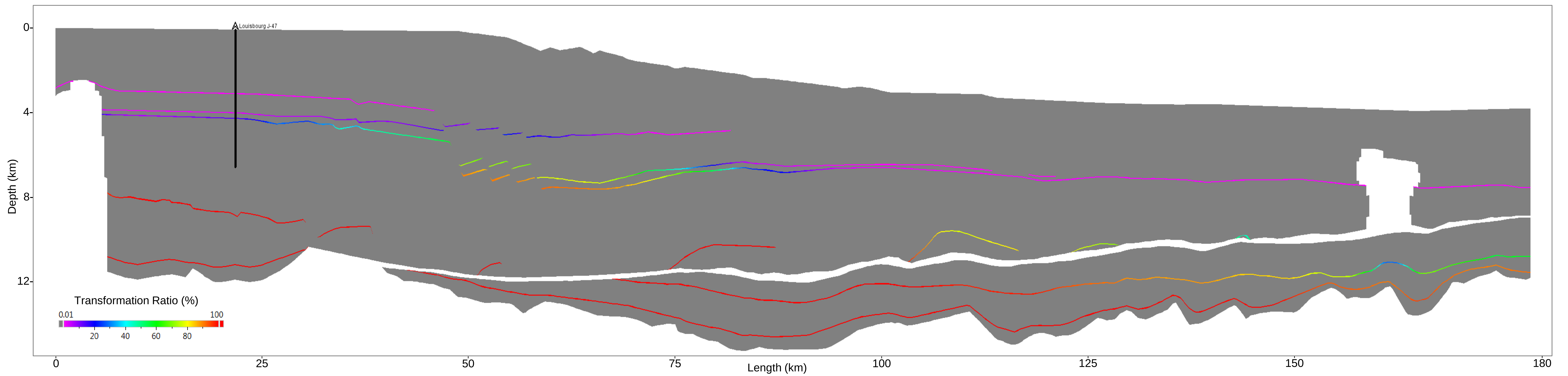


Transformation Ratio (Scenario 2 = Heat Flow variation)

As a consequence of the landward shift of the continental / oceanic crust limit (set in that specific case around 65 Km), a globally cooler model leads to a reduced maturity of rafted Misaine source rock (SR), Tithonian, Mississauga and Naskapi SR. The decrease in the maturity level is limited (5-10% TR) for the Tithonian, Mississauga and Naskapi SR from km 50 to km 85 while it does not exceed 5% TR for the rafted Misaine SR close to km 110.
Maturity levels westward on the platform as well as in the Pliensbachian and Misaine SR all along the section are not affected.

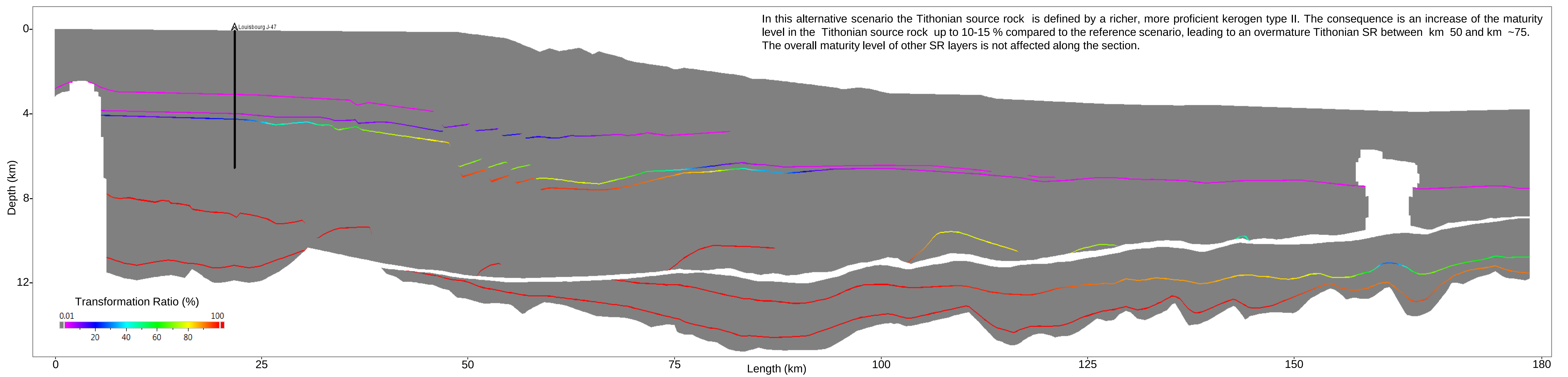


Transformation Ratio (Reference Scenario)

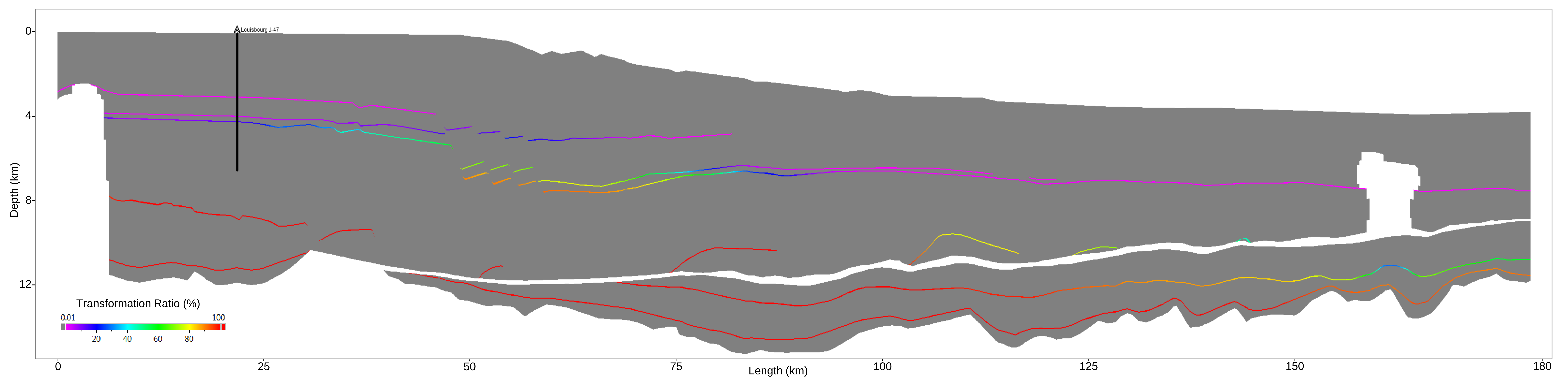


Transformation Ratio (Scenario 3 = Tithonian Type II)

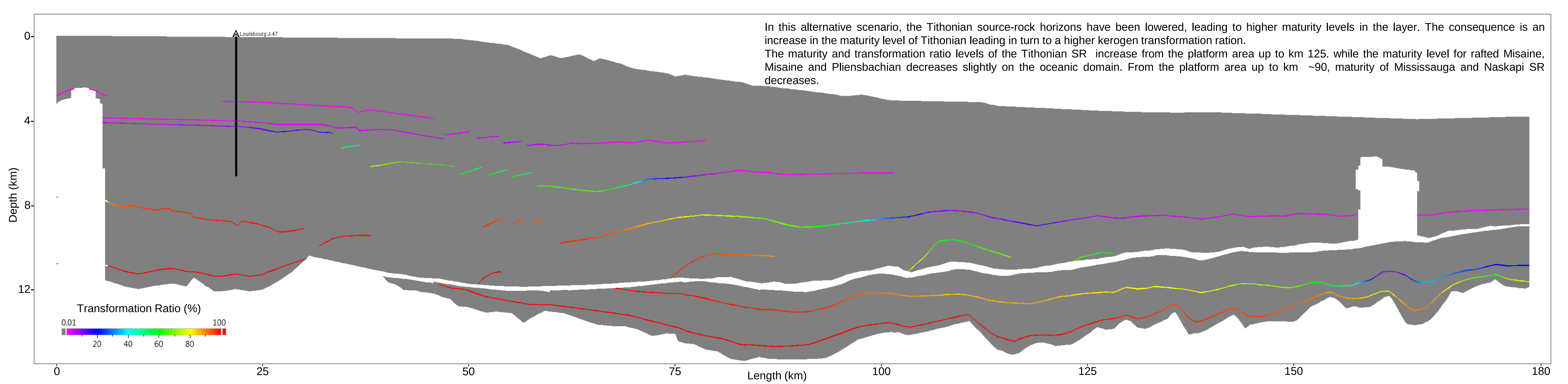
In this alternative scenario the Tithonian source rock is defined by a richer, more proficient kerogen type II. The consequence is an increase of the maturity level in the Tithonian source rock up to 10-15 % compared to the reference scenario, leading to an overmature Tithonian SR between km 50 and km ~75. The overall maturity level of other SR layers is not affected along the section.



Transformation Ratio (Reference Scenario)

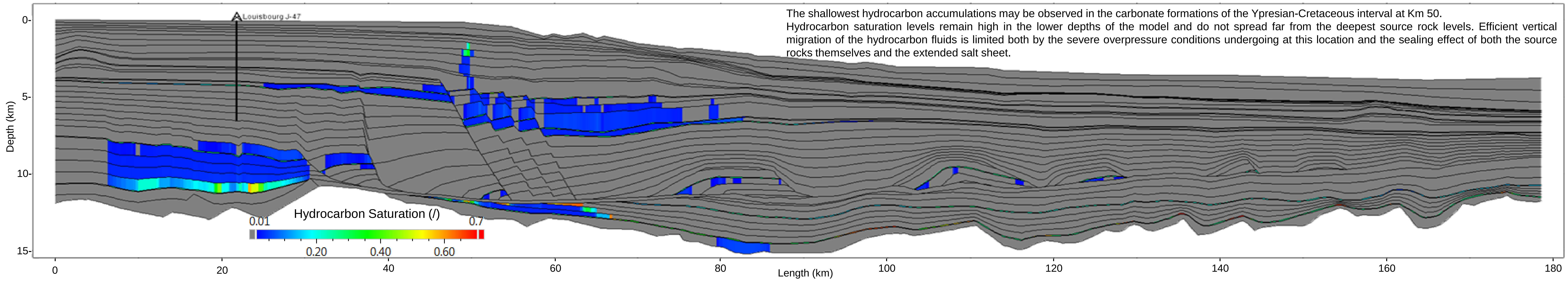


Transformation Ratio (Scenario 4 = Deep Tithonian)



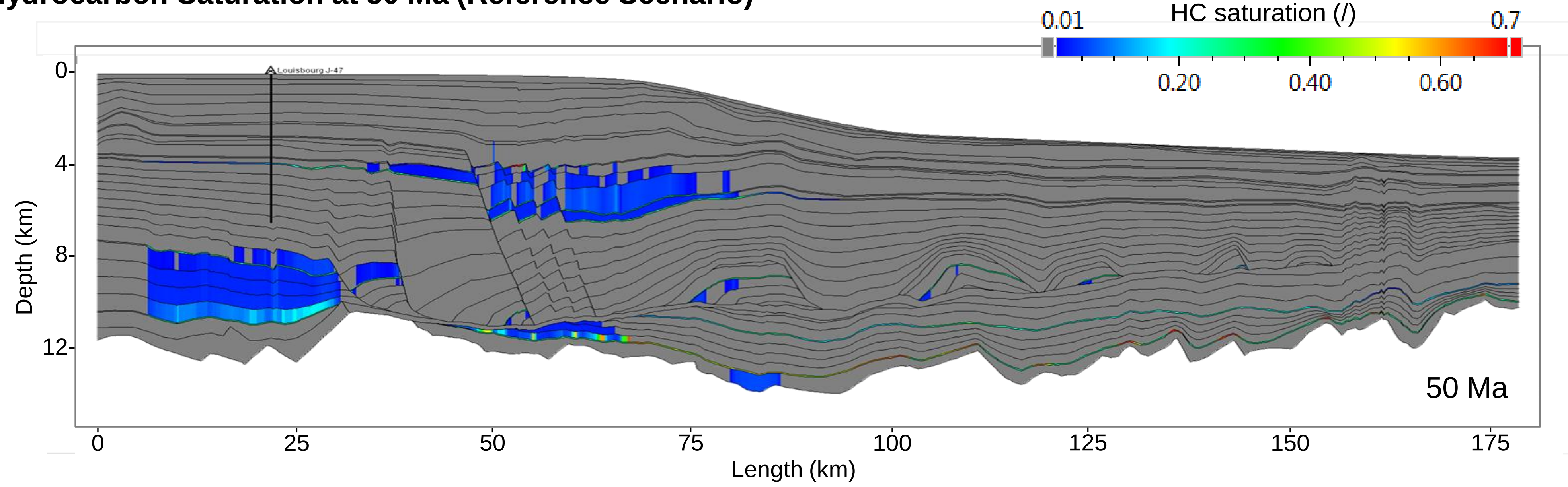
In this alternative scenario, the Tithonian source-rock horizons have been lowered, leading to higher maturity levels in the layer. The consequence is an increase in the maturity level of Tithonian leading in turn to a higher kerogen transformation ration.
The maturity and transformation ratio levels of the Tithonian SR increase from the platform area up to km 125. while the maturity level for rafted Misaine, Misaine and Pliensbachian decreases slightly on the oceanic domain. From the platform area up to km ~90, maturity of Mississauga and Naskapi SR decreases.

Hydrocarbon Saturation at Present Day (Reference Scenario)



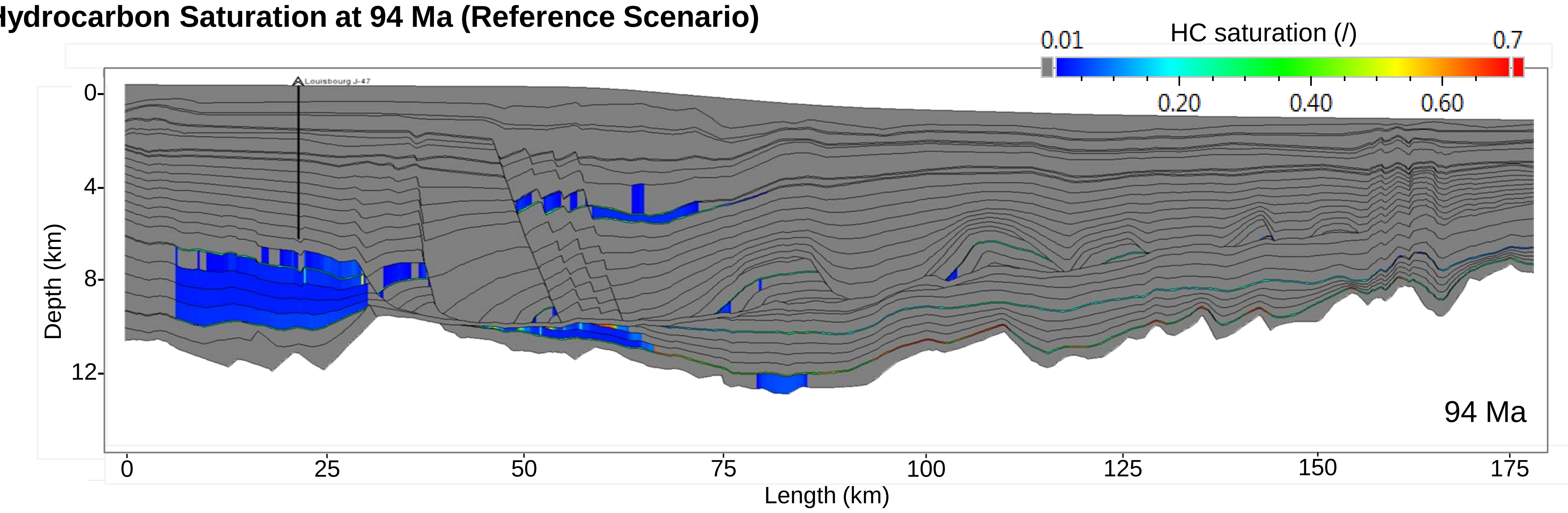
The shallowest hydrocarbon accumulations may be observed in the carbonate formations of the Ypresian-Cretaceous interval at Km 50. Hydrocarbon saturation levels remain high in the lower depths of the model and do not spread far from the deepest source rock levels. Efficient vertical migration of the hydrocarbon fluids is limited both by the severe overpressure conditions undergoing at this location and the sealing effect of both the source rocks themselves and the extended salt sheet.

Hydrocarbon Saturation at 50 Ma (Reference Scenario)



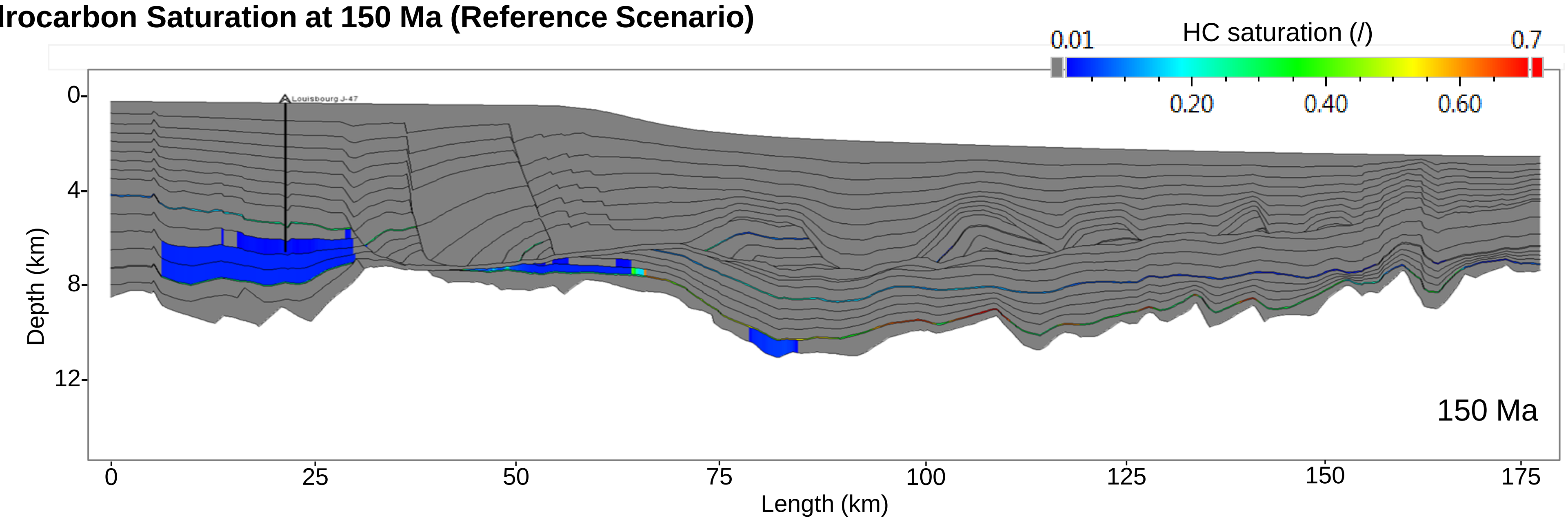
At 50 Ma, hydrocarbons from Tithonian-Berriasian continue to spread laterally from the kitchen area. They now extend on the platform within the Berriasian layer (from km 35 to km 50) and towards the rollover anticline in front of the normal fault system between km 70 and km ~80. Accumulations appear below the Naskapi SR from which hydrocarbon fluids begin to dismigrate above the Naskapi layers between km 50 and km 60.

Hydrocarbon Saturation at 94 Ma (Reference Scenario)



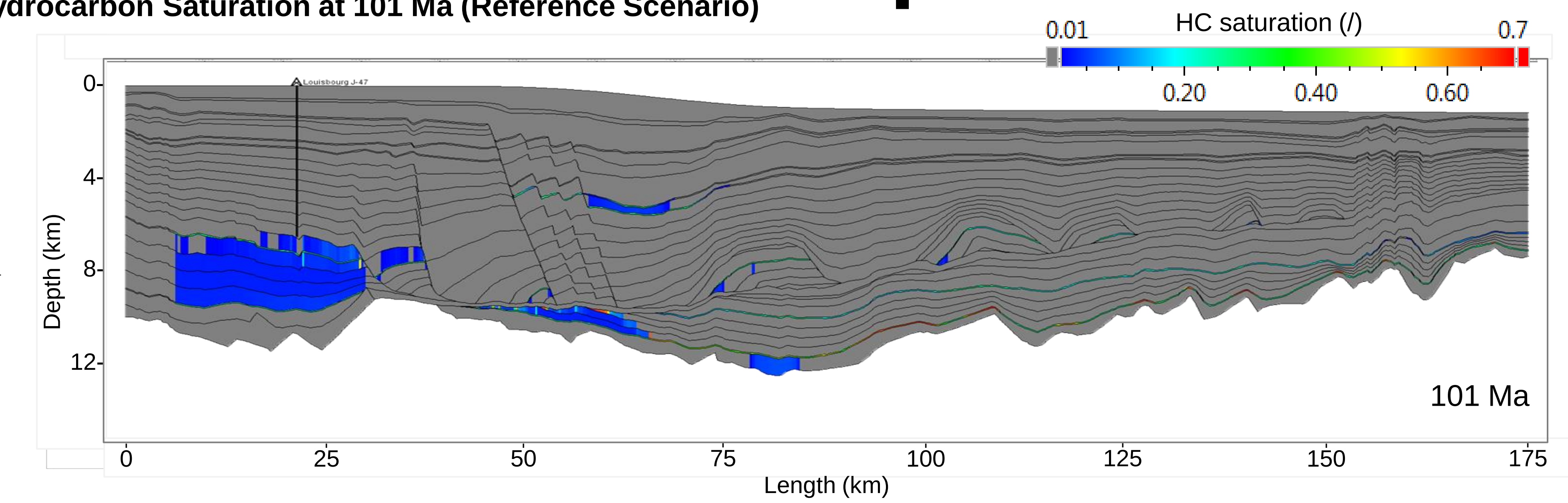
Hydrocarbon fluids expulsion begins from the Tithonian layer in the kitchen area and extends to the faulted area between km 50 and km 60. Maturity reached by Berriasian Mississauga SR is important enough to initiate hydrocarbon fluids expulsion in the Valanginian-Hauterivian layers at km 65 location.

Hydrocarbon Saturation at 150 Ma (Reference Scenario)



Hydrocarbon fluids expulsion begins from the deeper, more mature source rock levels.

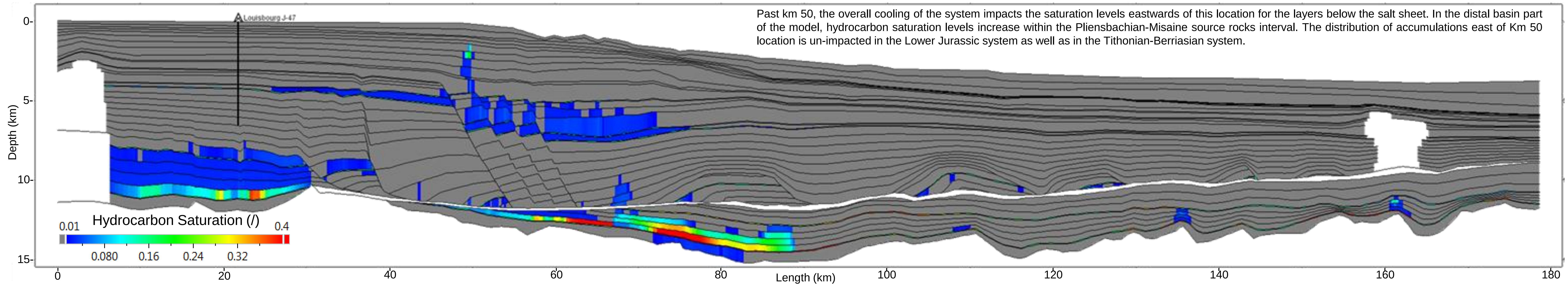
Hydrocarbon Saturation at 101 Ma (Reference Scenario)



Hydrocarbon fluids expulsion from the Pliensbachian source rock level starts spreading throughout the section as maturity conditions become more favorable. Same goes for the Misaine source rock layer, the expulsion phenomenon being reinforced by the emergence, between km 20 and km 30, of accumulations below Misaine SR which increase fluid pressure below the SR and consequently favors the upward expulsion of fluids. Tithonian SR begins to be mature enough in the kitchen area from km 70 to km 80 to expel fluids to the Berriasian layer.

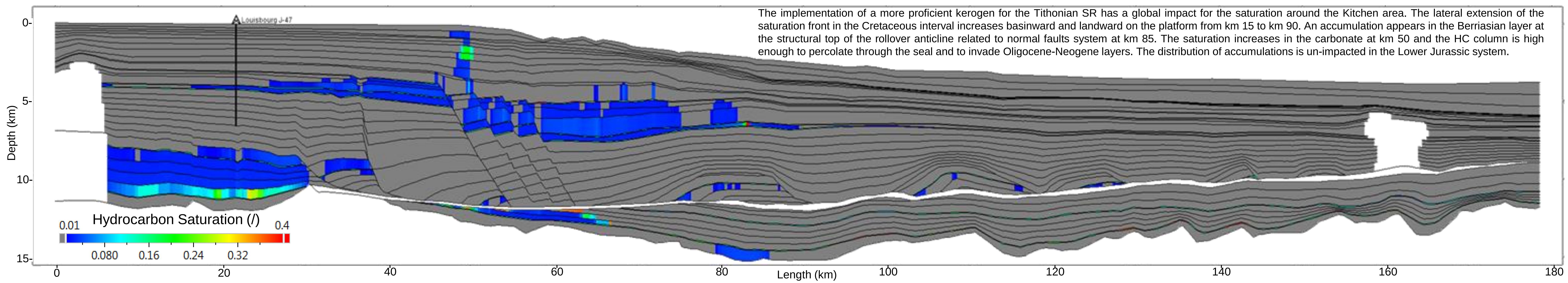
Hydrocarbon Saturation (Scenario 2 = Heat Flow variation)

Past km 50, the overall cooling of the system impacts the saturation levels eastwards of this location for the layers below the salt sheet. In the distal basin part of the model, hydrocarbon saturation levels increase within the Pliensbachian-Misaine source rocks interval. The distribution of accumulations east of Km 50 location is un-impacted in the Lower Jurassic system as well as in the Tithonian-Berriasian system.



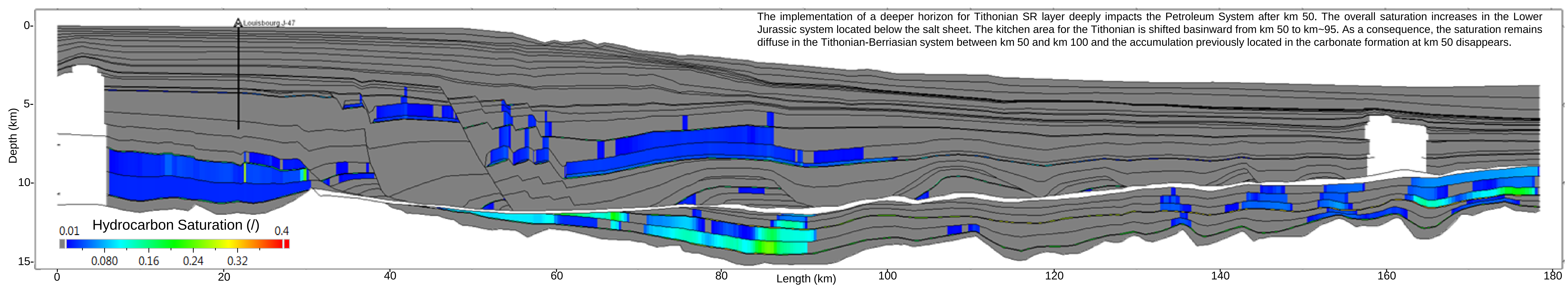
Hydrocarbon Saturation (Scenario 3 = Tithonian Type II)

The implementation of a more proficient kerogen for the Tithonian SR has a global impact for the saturation around the Kitchen area. The lateral extension of the saturation front in the Cretaceous interval increases basinward and landward on the platform from km 15 to km 90. An accumulation appears in the Berriasian layer at the structural top of the rollover anticline related to normal faults system at km 85. The saturation increases in the carbonate at km 50 and the HC column is high enough to percolate through the seal and to invade Oligocene-Neogene layers. The distribution of accumulations is un-impacted in the Lower Jurassic system.

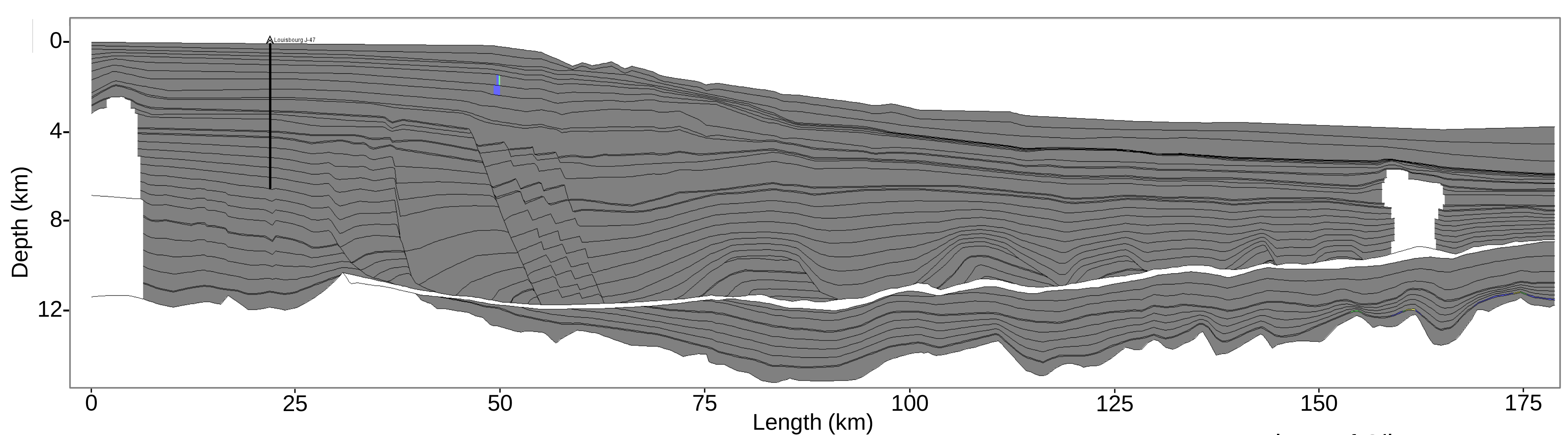


Hydrocarbon Saturation (Scenario 4 = Deep Tithonian)

The implementation of a deeper horizon for Tithonian SR layer deeply impacts the Petroleum System after km 50. The overall saturation increases in the Lower Jurassic system located below the salt sheet. The kitchen area for the Tithonian is shifted basinward from km 50 to km~95. As a consequence, the saturation remains diffuse in the Tithonian-Berriasian system between km 50 and km 100 and the accumulation previously located in the carbonate formation at km 50 disappears.



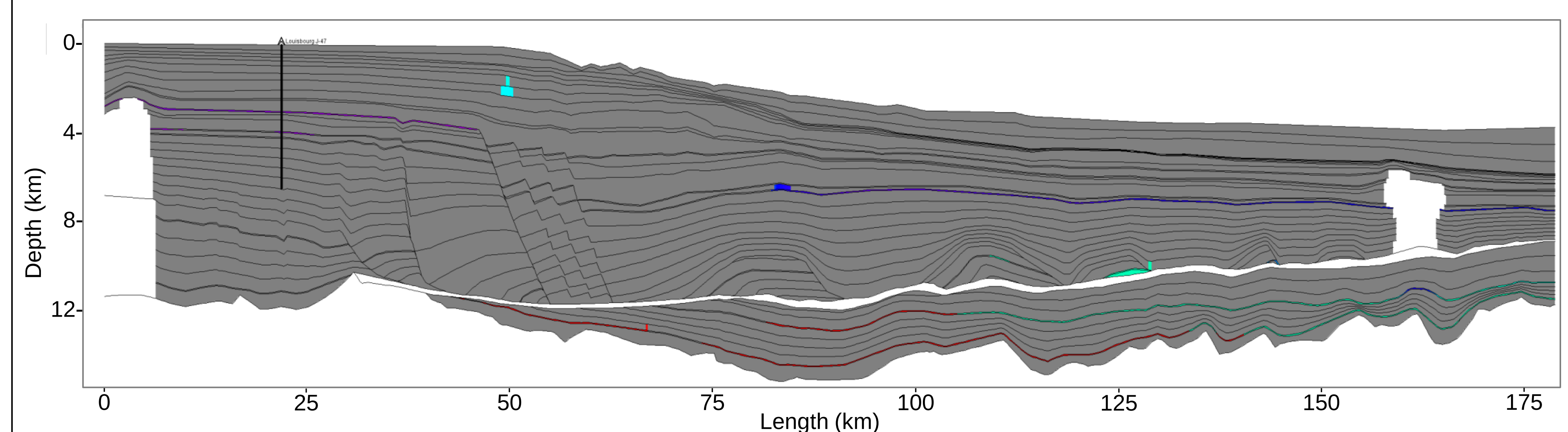
Volume of Oil per Area (Reference Scenario)



Mass of Oil is less than ~5bbl/m² in the model. The over-mature state of the deepest source rocks layers which are the main contributors to the Petroleum System, the types of kerogen defined as well as the thermal conditions favorable to secondary cracking explain this result.

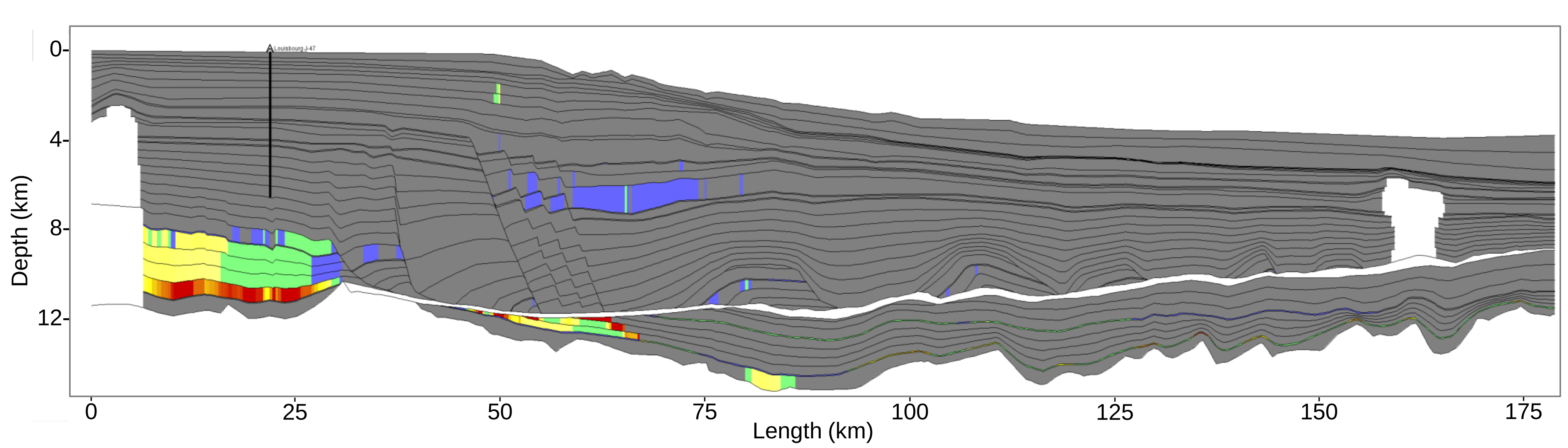
Slight quantities of oil may be expected in the accumulation within the Cretaceaous-Ypresian carbonate formation located at Km 50 and another potential small one in the rollover anticline area at km 80.

API Gravity - Oil (Reference Scenario)



API Gravity of the oil varies between 36 API (Km 17) in the Cretaceous-Ypresian accumulations and 28 API (Km 45) in the Berriasian accumulation.

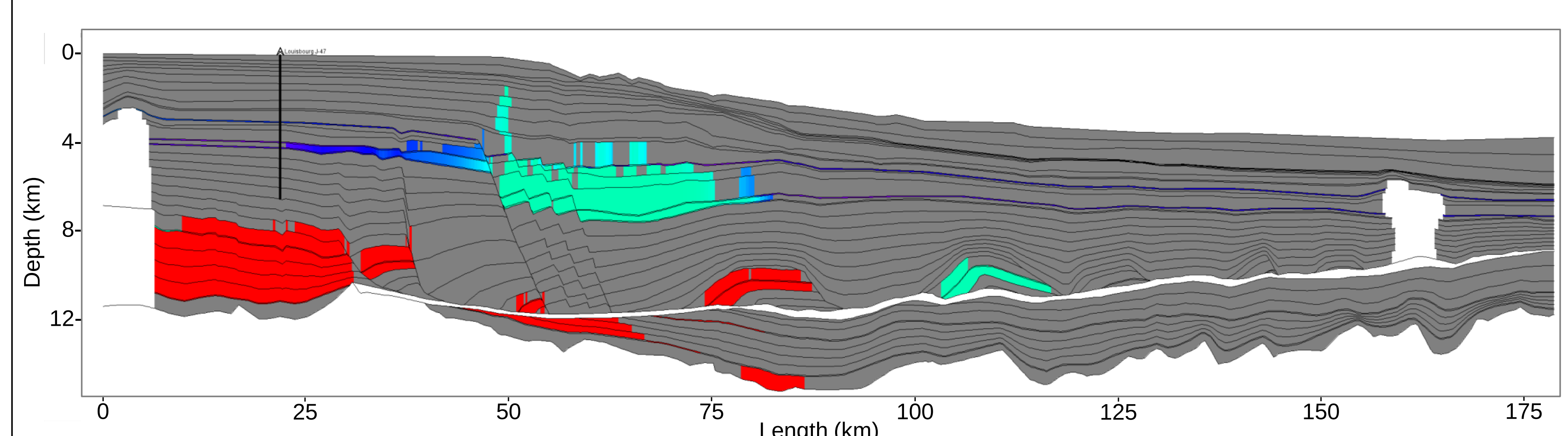
Volume of Gas per Area (Reference Scenario)



Gas is present in rather massive quantities in the lower depths of the model. If out of a source rock layer and not marked of by a structural element, these gas quantities should be considered as diffuse distributions which have dissipated through geological time.

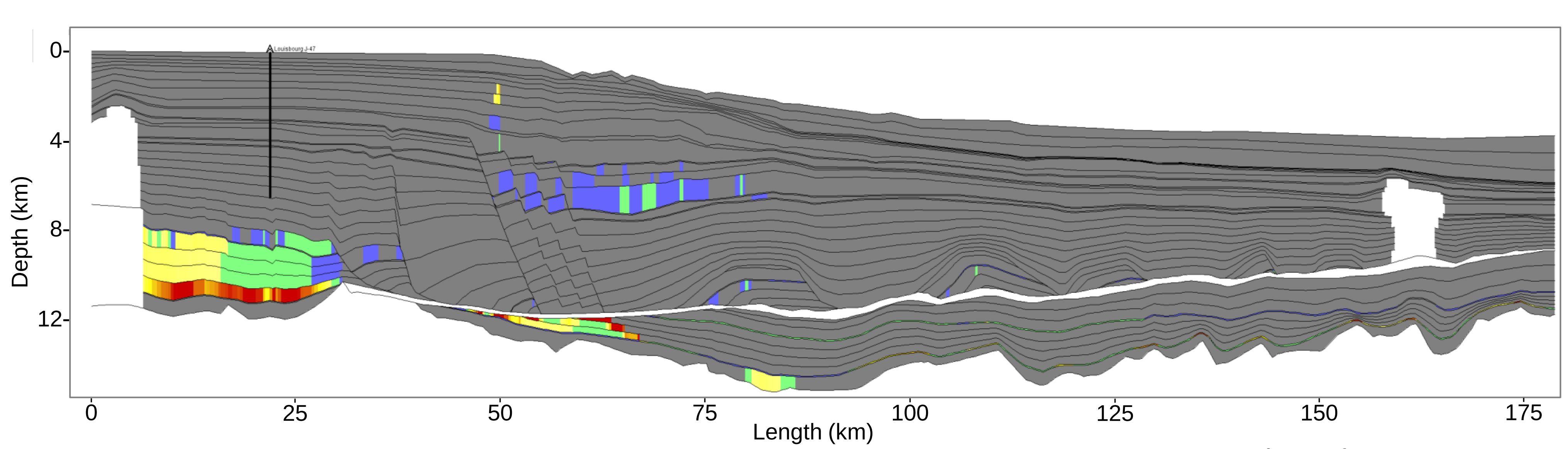
Accumulations picked in the previous slides showcasing saturation levels (ie Cretaceous-Ypresian carbonate at Km 50) are filled predominately with gas which comes up in rather large quantities.

API Gravity - Condensates (Reference Scenario)



API Gravity of gas condensates varies between 28 to 38 API (Km 20 to km 85) in the Upper Jurassic-Cretaceous system while it exceeds 60 API in the Lower Jurassic system, except in one rafted block at km 110 where API only reaches 36-38 API.

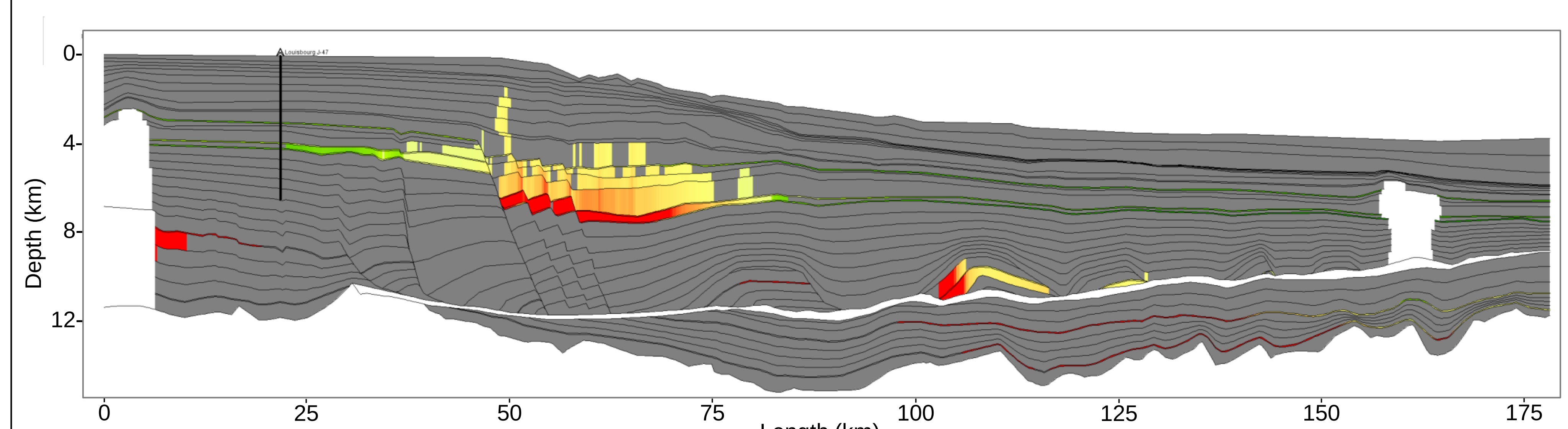
Volume of HC per Area (Reference Scenario)



As stated here above, the total volume of hydrocarbon in the model is entirely made of gas.

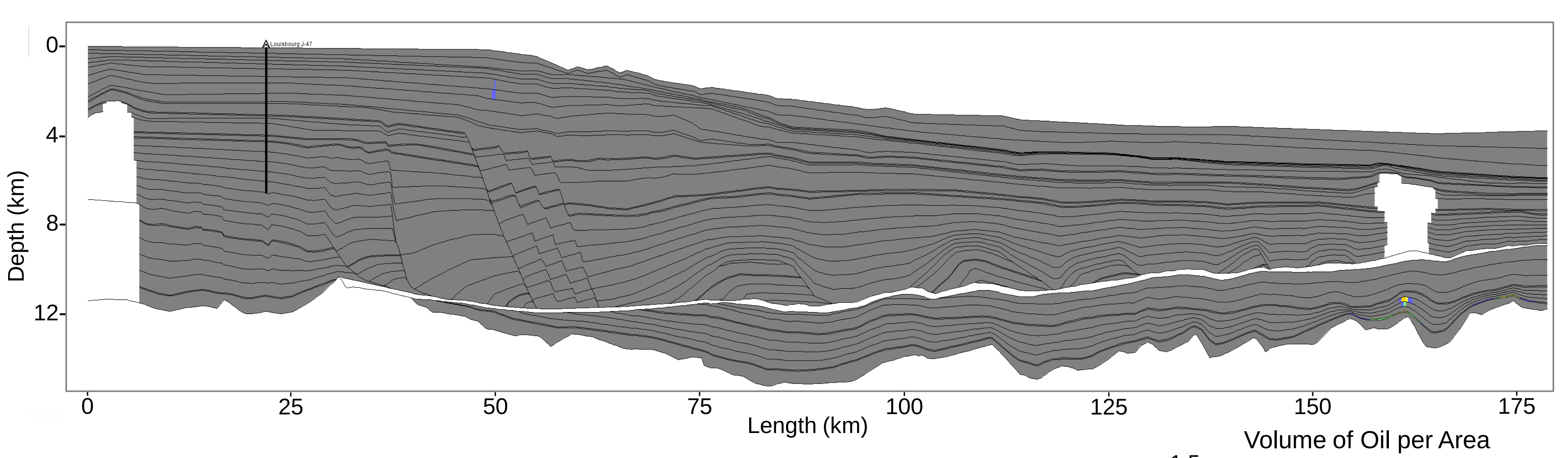
Total hydrocarbon volume is derived from the associates accumulated hydrocarbon masses using an average density.

GOR feed (Reference Scenario)

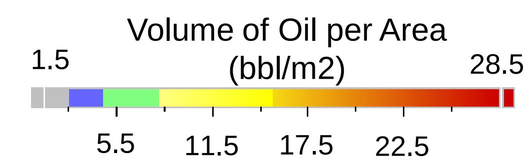


GOR Feed variable is the ratio between the mass of gas and the mass of oil accumulated in a given cell of the model. The mass of gas outweighs the masses of oil and condensates in most parts of the model except in the shallowest sections of the upper source rock layers and above the Tithonian SR level between Km 25 and Km 40 where oil is predominant. Yet the associated masses of oil are insignificant.

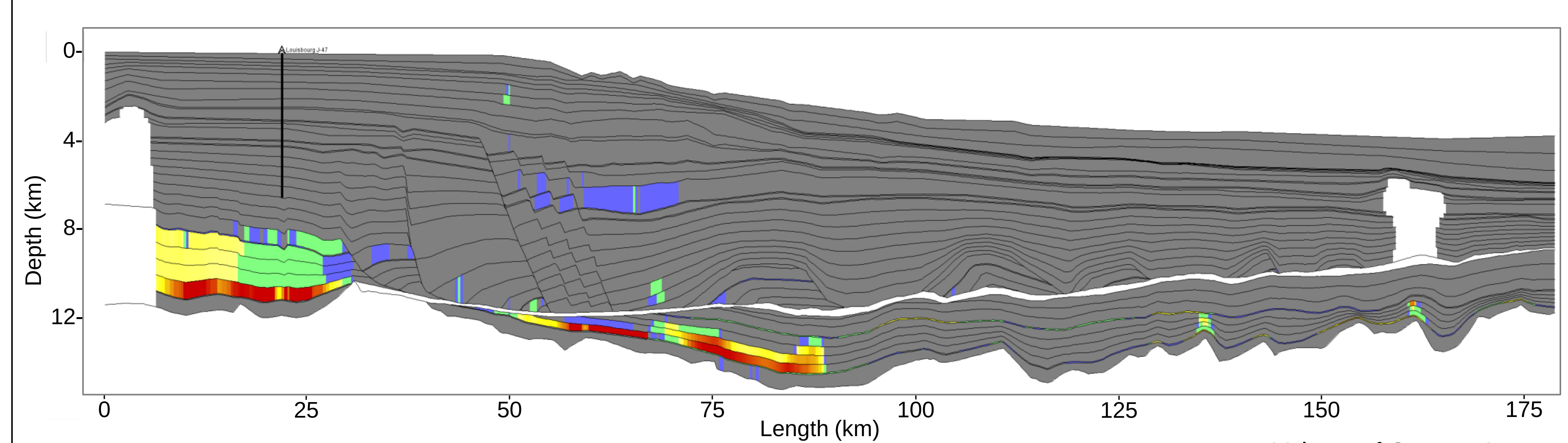
Volume of Oil per Area (Scenario 2 = Heat Flow variation)



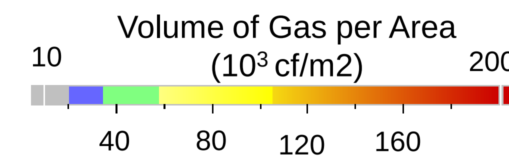
The overall cooling of the system has no significant impact on the oil distribution on the whole section.



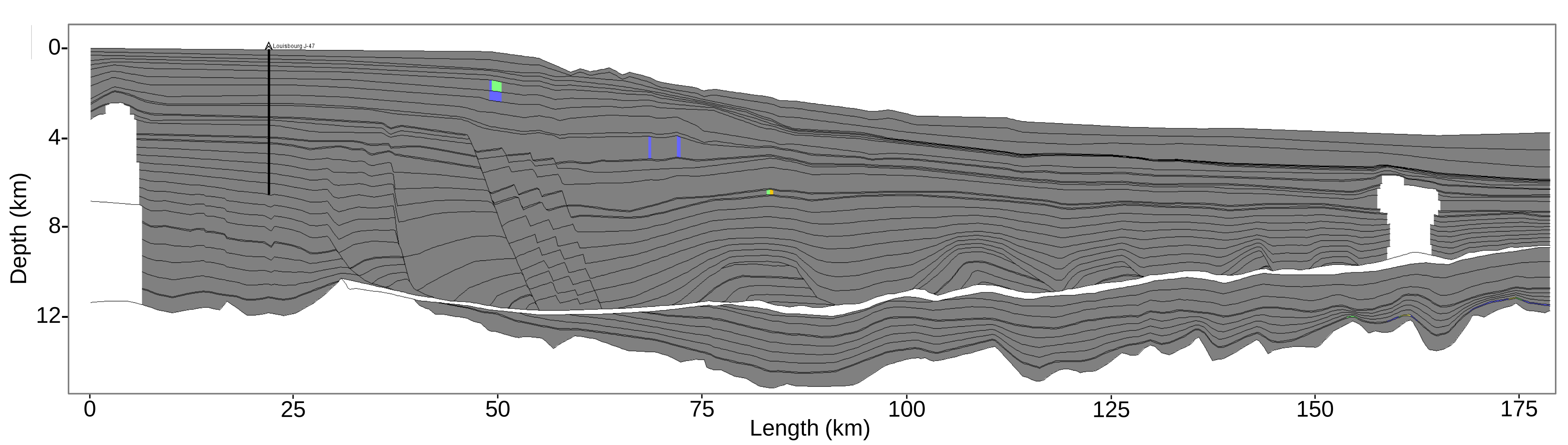
Volume of Gas per Area (Scenario 2 = Heat Flow variation)



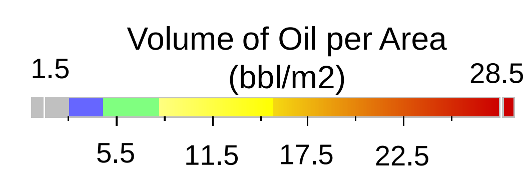
The overall cooling of the system has no significant effect on the gas accumulations except in the Lower Jurassic system below the salt sheet between km 50 and km 90 and around km 135 and km 165 locations.



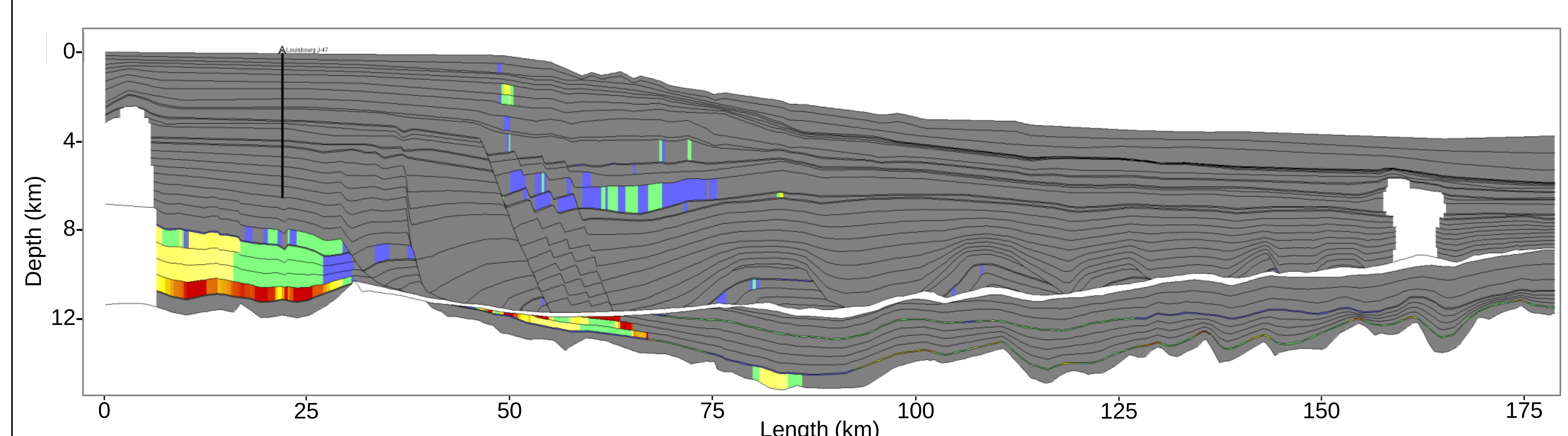
Volume of Oil per Area (Scenario 3 = Tithonian Type II)



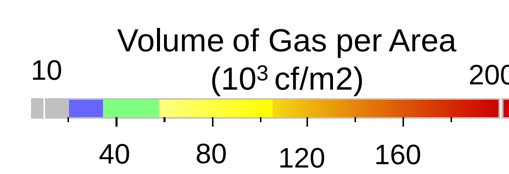
The implementation of a more proficient kerogen for the Tithonian source rock impacts the masses accumulated between km 50 and km 85. Masses reach values up to ~8bbl/m2 in the Cretaceous-Ypresian accumulation at km 50 and up to ~17bbl/m2 in the Berriasian layer at km 85.



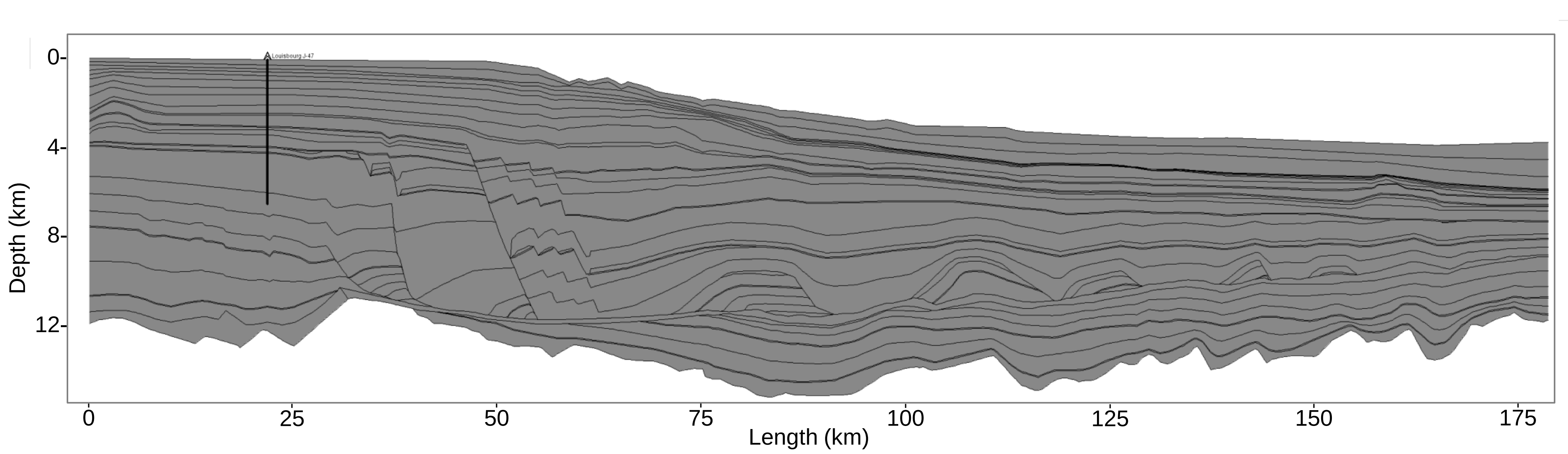
Volume of Gas per Area (Scenario 3 = Tithonian Type II)



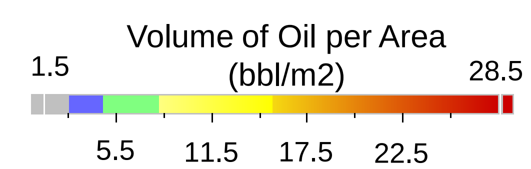
The implementation of a more proficient kerogen for the Tithonian source rock impacts the masses accumulated in the Tithonian Cretaceous sytem between km 25 and km 85. Masses are at least doubled compared to the reference scenario.
A slight volume increase of gas also occurs in the rafted blocks.



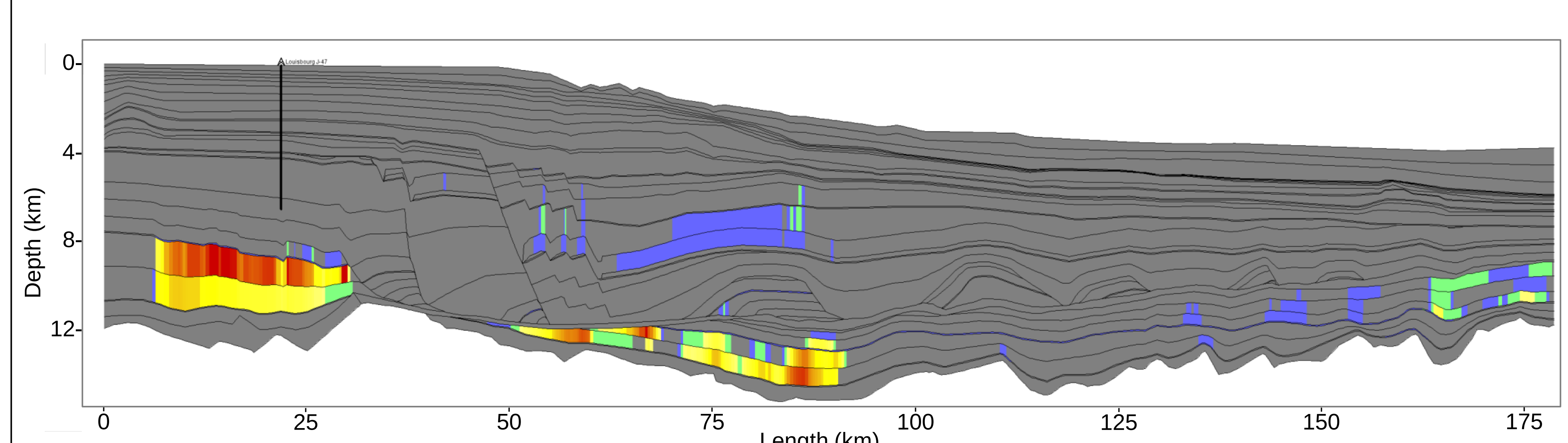
Volume of Oil per Area (Scenario 4 = Deep Tithonian)



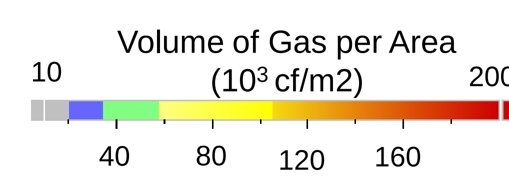
The implementation of a deeper defining horizon for the Tithonian layer deeply impacts the Petroleum System while almost no significant accumulation remains in the system.



Volume of Gas per Area (Scenario 4 = Deep Tithonian)



The implementation of a deeper defining horizon for the Tithonian layer deeply impacts the Lower Jurassic system. On the platform (km 15 to km 30), below the salt sheet (km 50 to km 90) and also at the basinward edge of the section (km 130 to km 178), the volume of free gas increases massively.
For the Tithonian-Cretaceous system, the global volume does not significantly change but its distribution is shifted basinward.



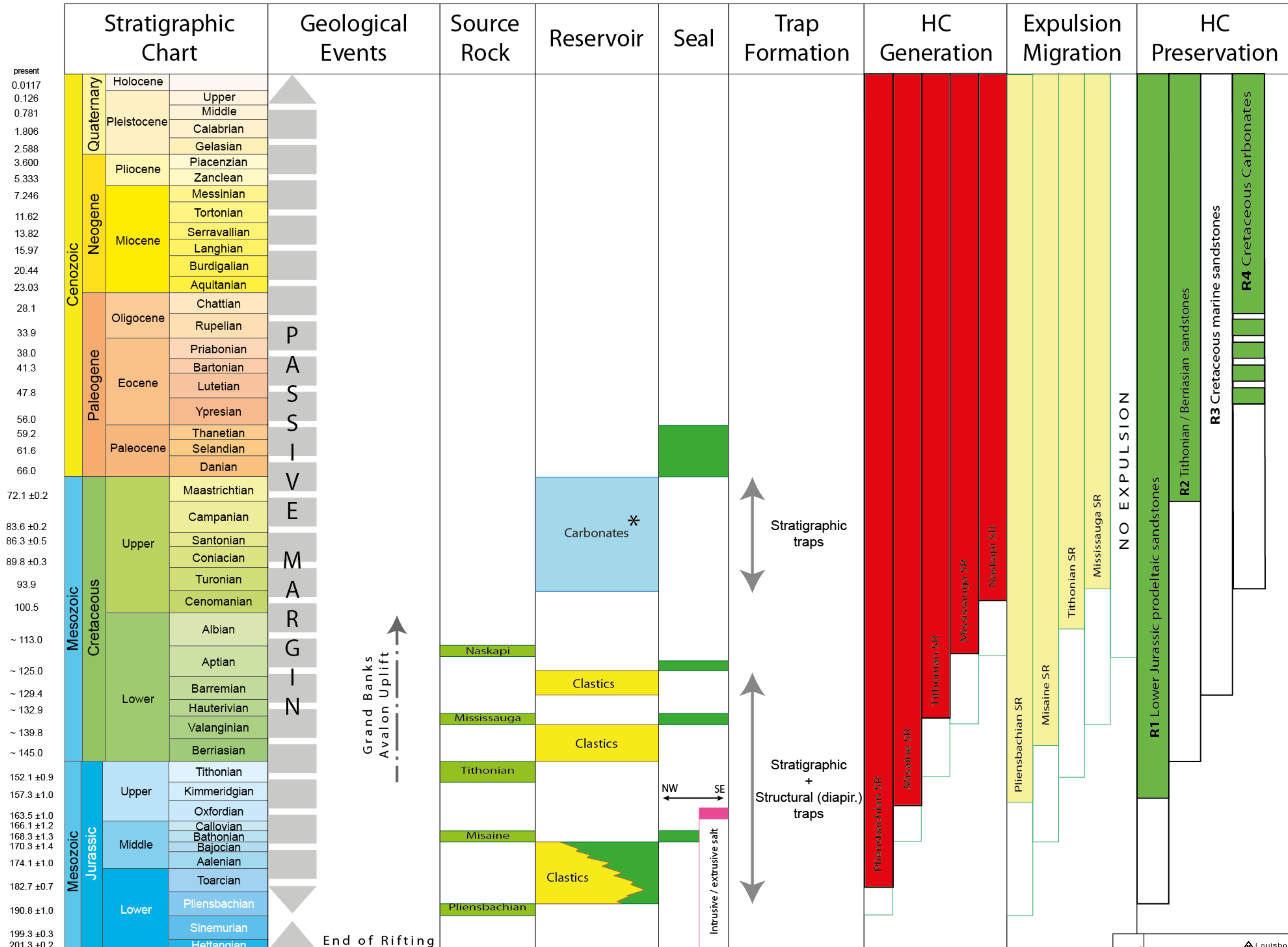
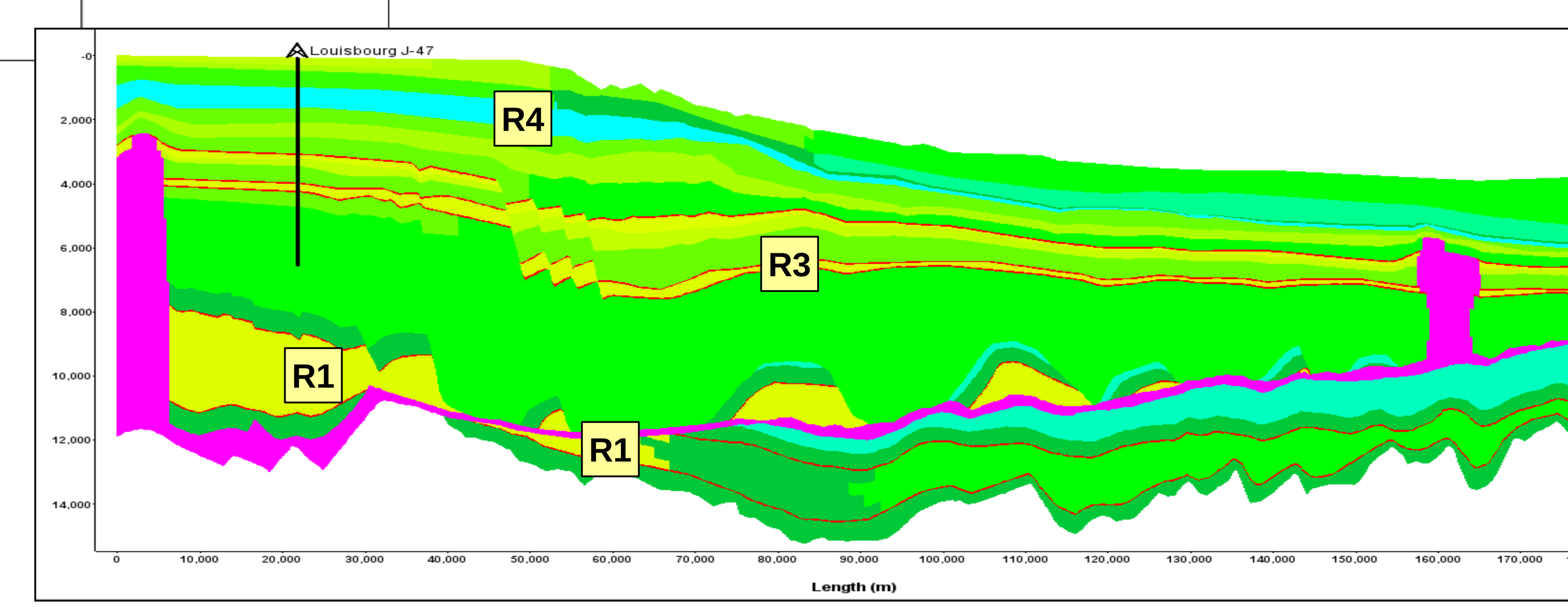


Chart drafted by K.M. Cohen, S. Finney, P.L. Gibbard
(c) International Commission on Stratigraphy, January 2013
http://www.stratigraphy.org/ICSchart/ChronostratChart2013-01.pdf



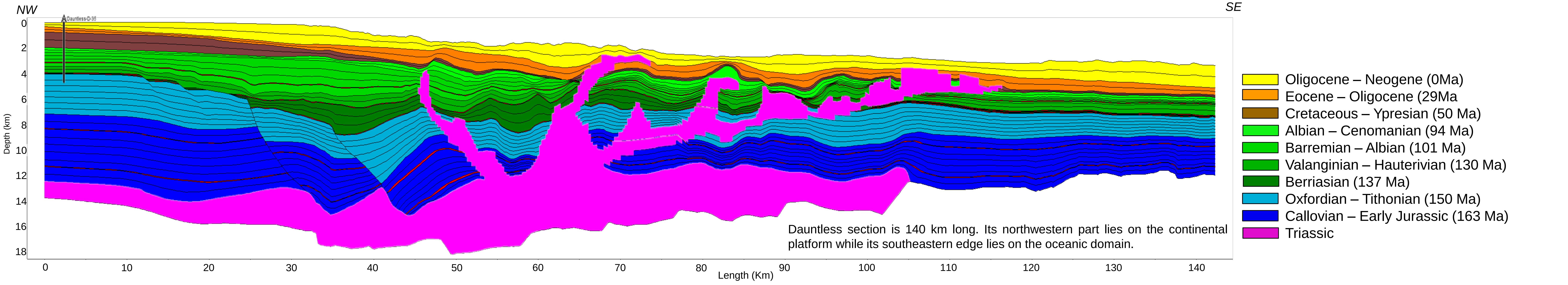
* The Cretaceous/Tertiary carbonates are the main accumulation system modeled in TemisFlow for the Louisbourg section

Petroleum System Chart for Louisbourg Section

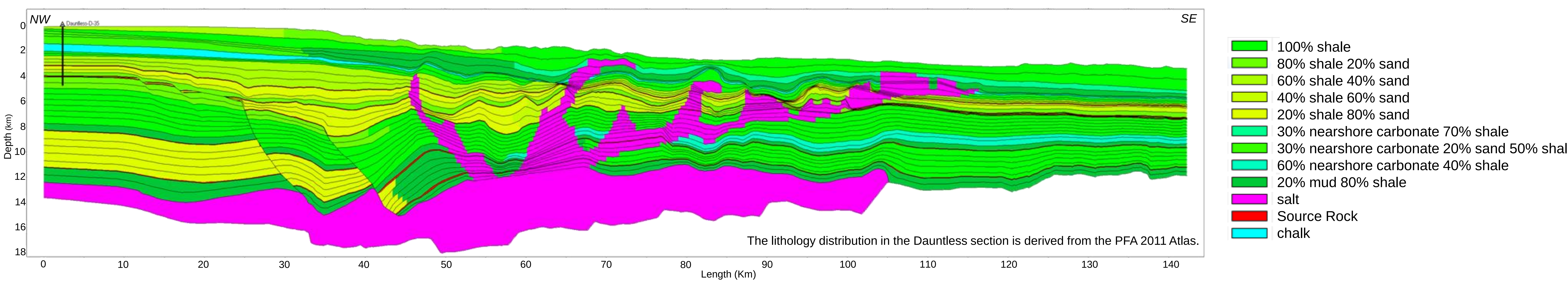
PLATE 9.25

2D Modeling
Dauntless Section

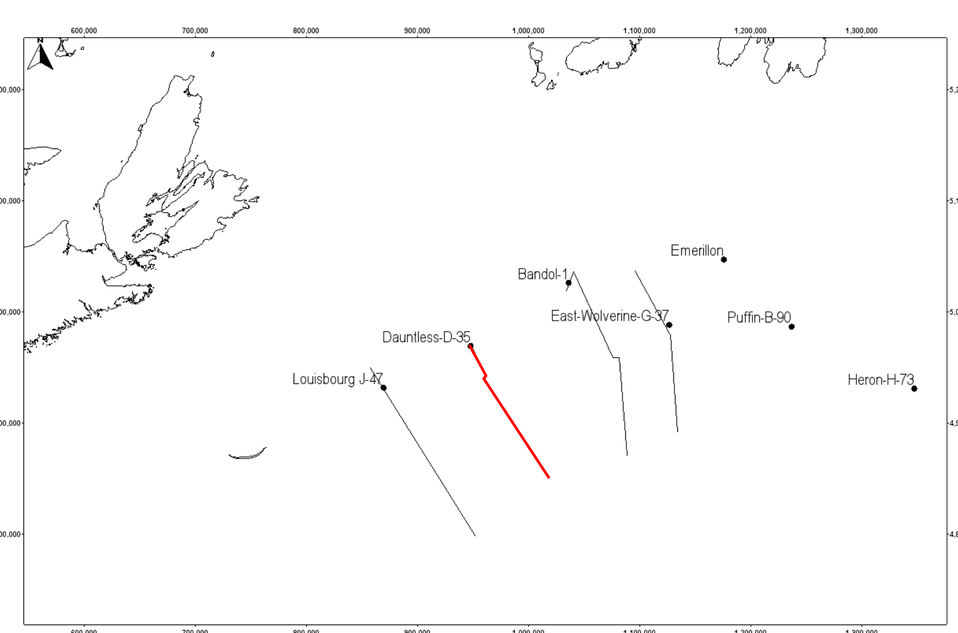
Stratigraphic Model (Reference Scenario)



Lithology Model (Reference Scenario)

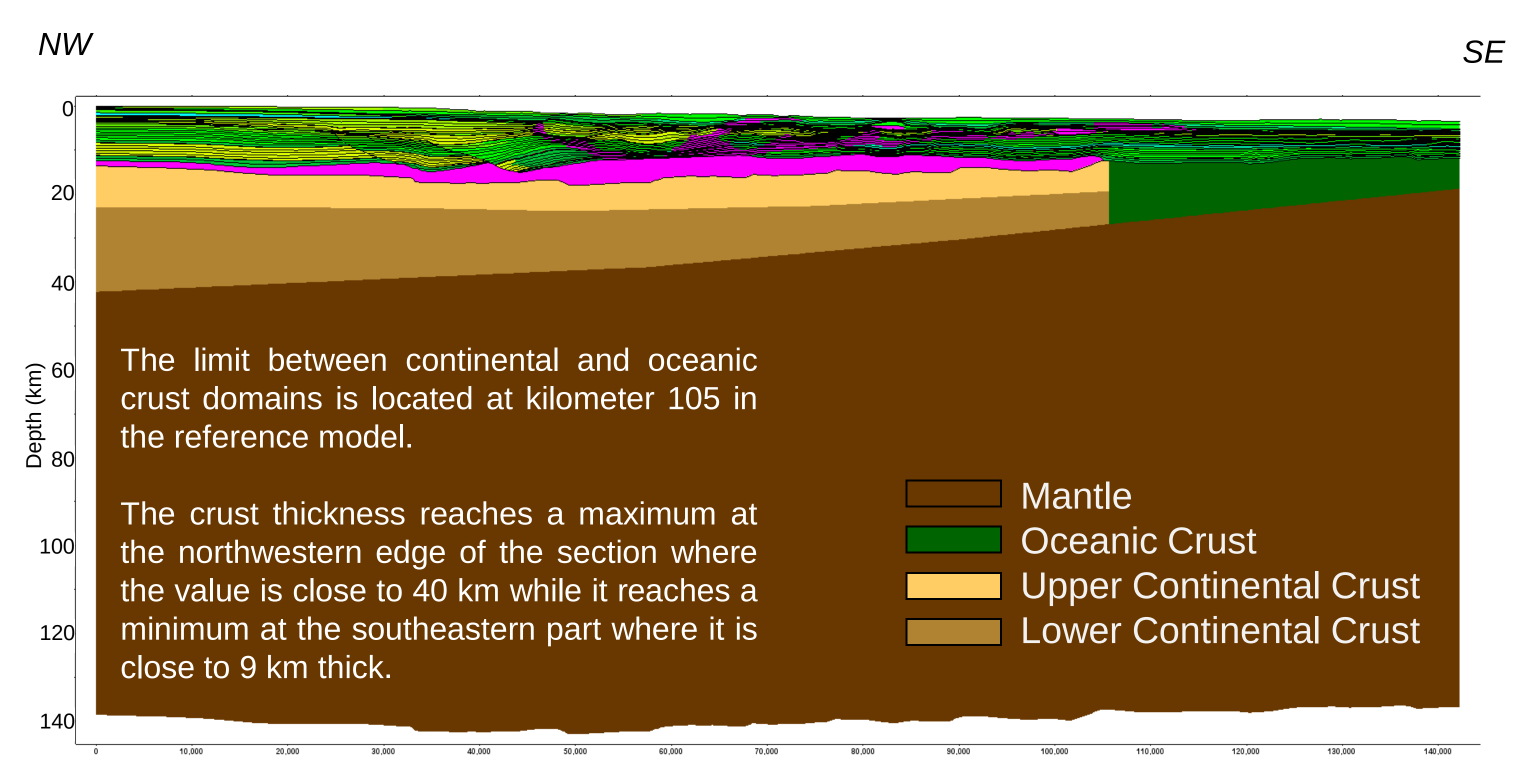


Location Map

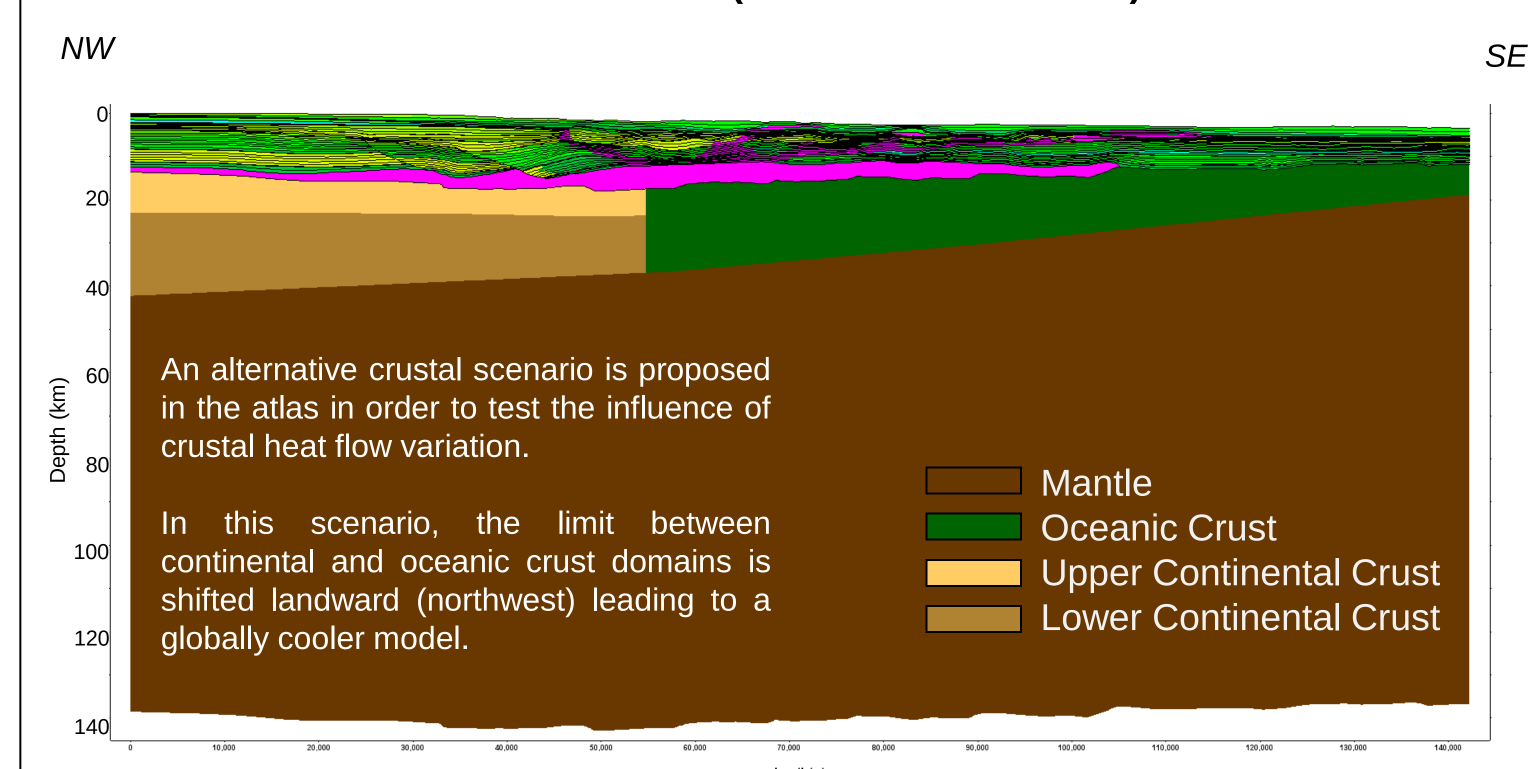


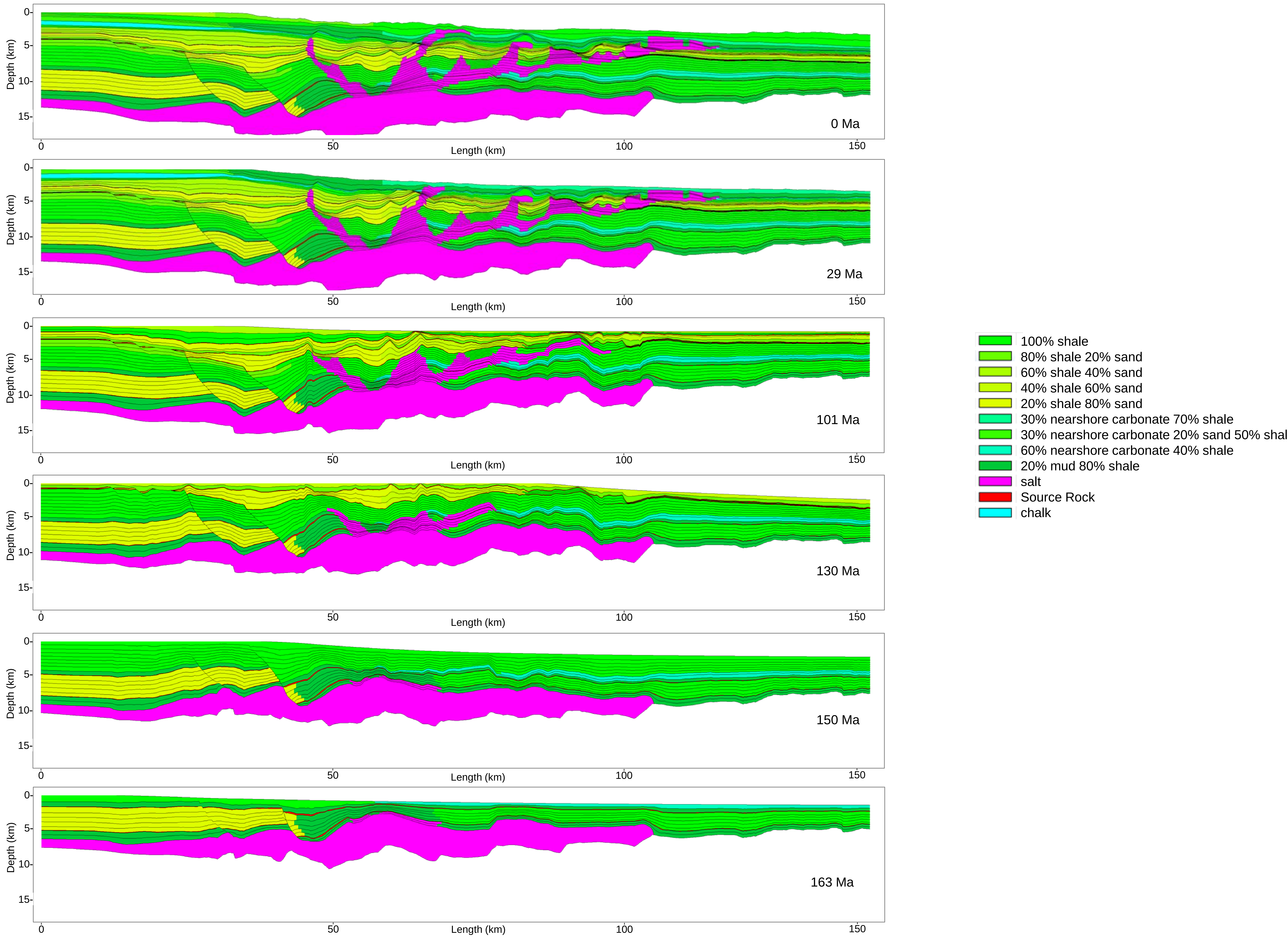
Dauntless section trace intersects Dauntless D-35 well location. The well features pressure, temperature & vitrinite measurements which have been used for calibration purposes.

Thermal Basement Model – Scenario 1 (= Reference Scenario)



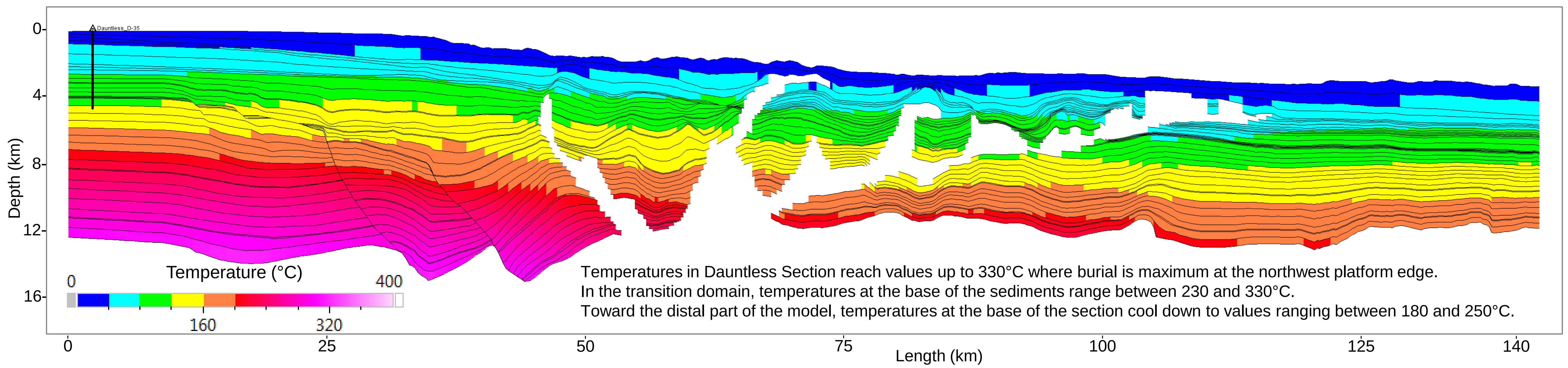
Thermal Basement Model – Scenario 2 (= Heat Flow Variation)





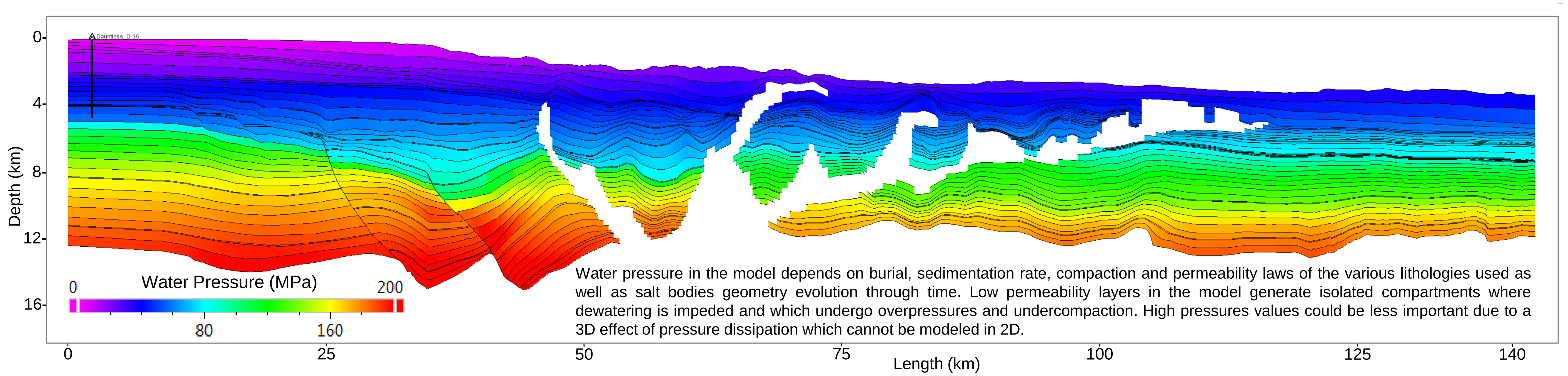
Restoration Scenario of Dauntless Section – Reference Scenario

Temperature (Reference Scenario)



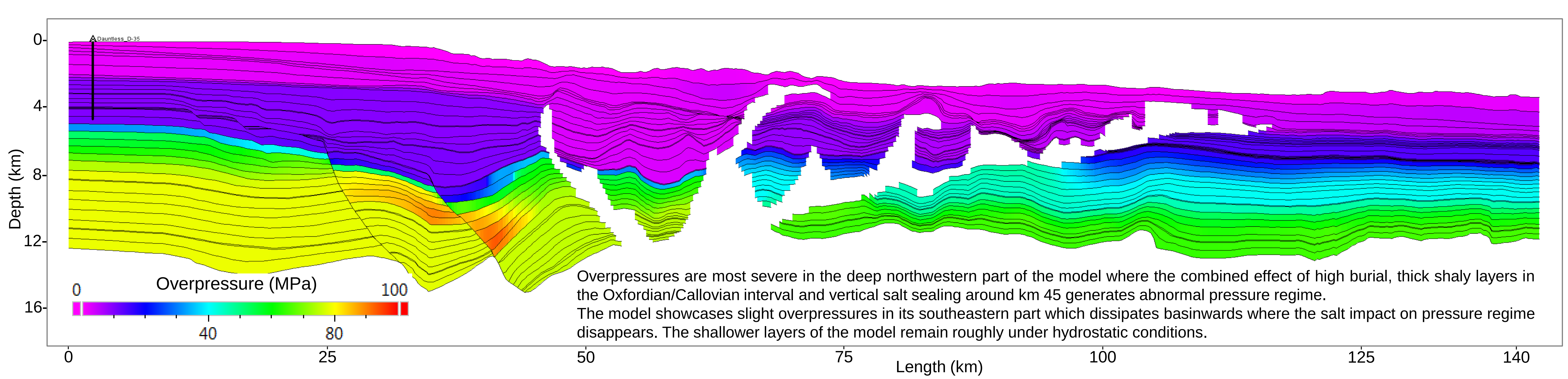
Temperatures in Dauntless Section reach values up to 330°C where burial is maximum at the northwest platform edge.
In the transition domain, temperatures at the base of the sediments range between 230 and 330°C.
Toward the distal part of the model, temperatures at the base of the section cool down to values ranging between 180 and 250°C.

Water Pressure (Reference Scenario)



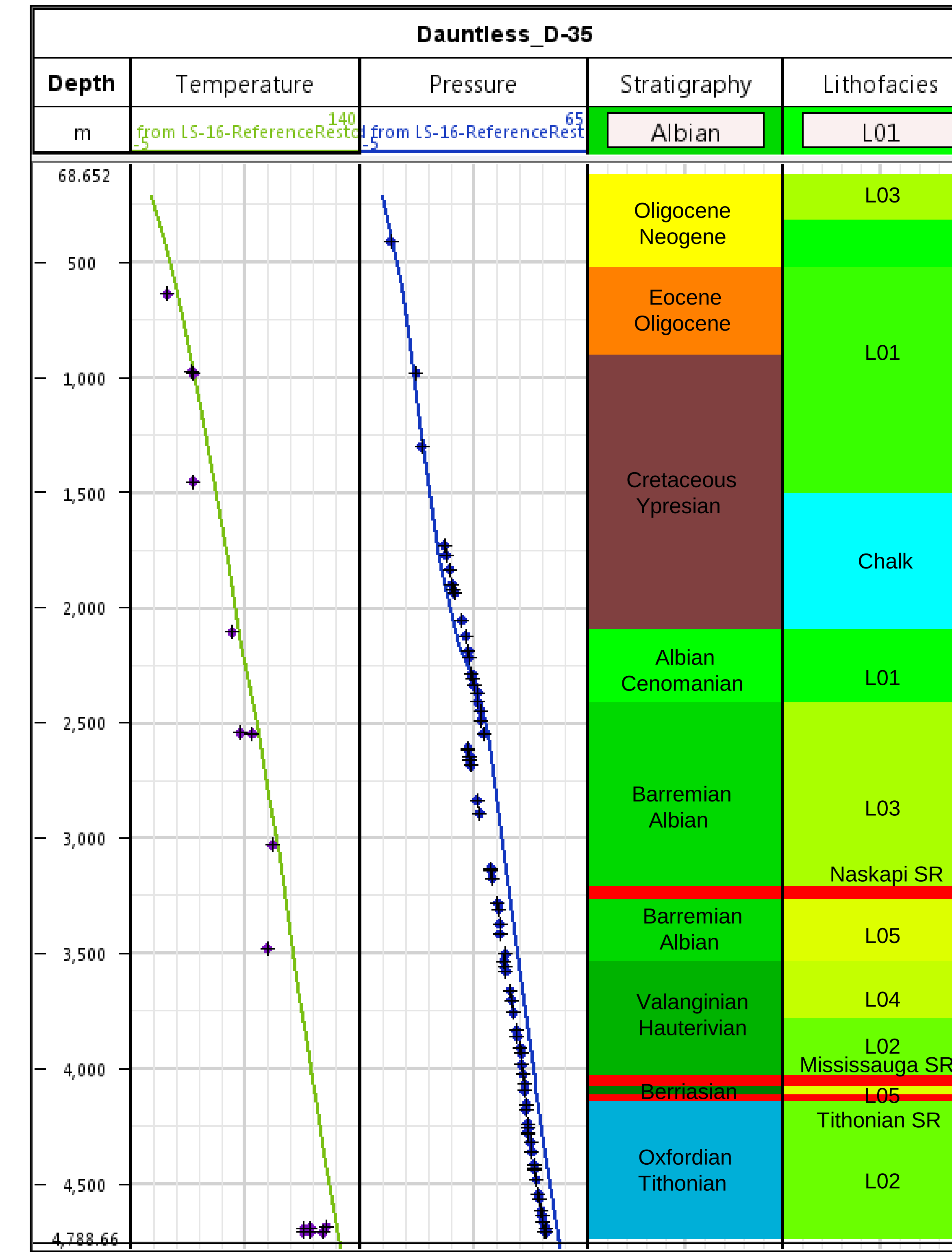
Water pressure in the model depends on burial, sedimentation rate, compaction and permeability laws of the various lithologies used as well as salt bodies geometry evolution through time. Low permeability layers in the model generate isolated compartments where dewatering is impeded and which undergo overpressures and undercompaction. High pressures values could be less important due to a 3D effect of pressure dissipation which cannot be modeled in 2D.

Overpressure (Reference Scenario)



Overpressures are most severe in the deep northwestern part of the model where the combined effect of high burial, thick shaly layers in the Oxfordian/Callovian interval and vertical salt sealing around km 45 generates abnormal pressure regime.
The model showcases slight overpressures in its southeastern part which dissipates basinwards where the salt impact on pressure regime disappears. The shallower layers of the model remain roughly under hydrostatic conditions.

Calibration (Reference Scenario)



Temperature & Pressure models are calibrated versus available observed data at Dauntless D-35 well location:

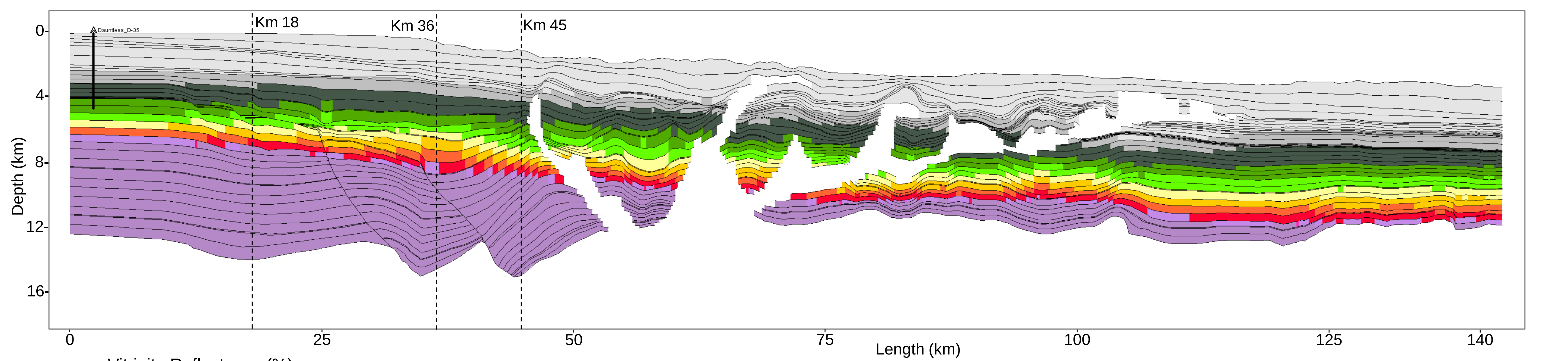
- Observed data is represented with dots
- Simulated data is represented with continuous, thick lines

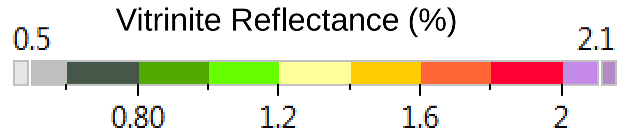
Temperature calibration at Dauntless D-35 well location falls under the measurements uncertainty range.

Pressure calibration at Dauntless D-35 well is satisfactory: the pressure drop around 2,500m may corresponds either to a measurement artifact or to the presence of a thin porous sandy interval deposited during Albian times, the latter not being implemented in the PFA 2011 Dionisos facies model.

Dauntless D-35 measured pressure data picks the initial trend of the deeper modeled overpressure regime.

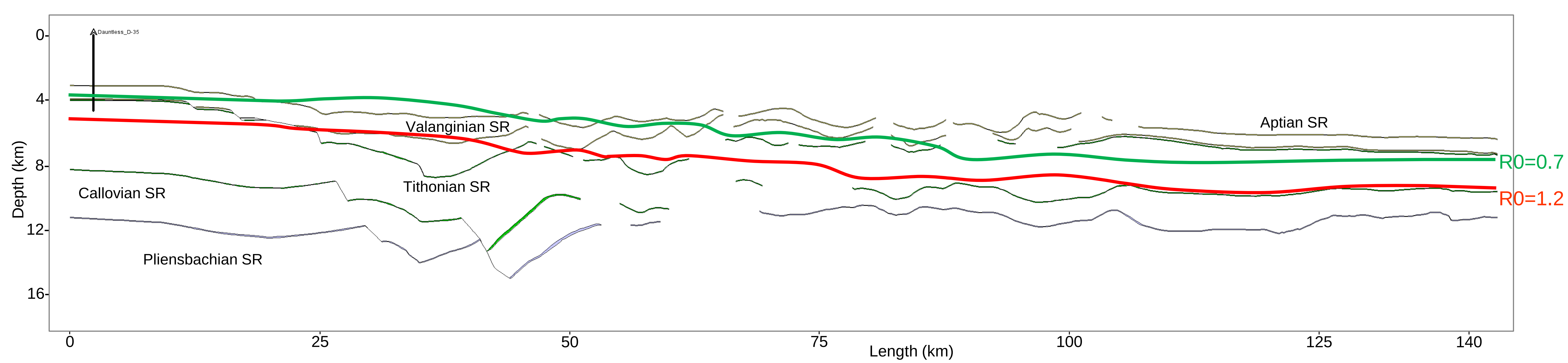
Vitrinite Reflectance (Reference Scenario)





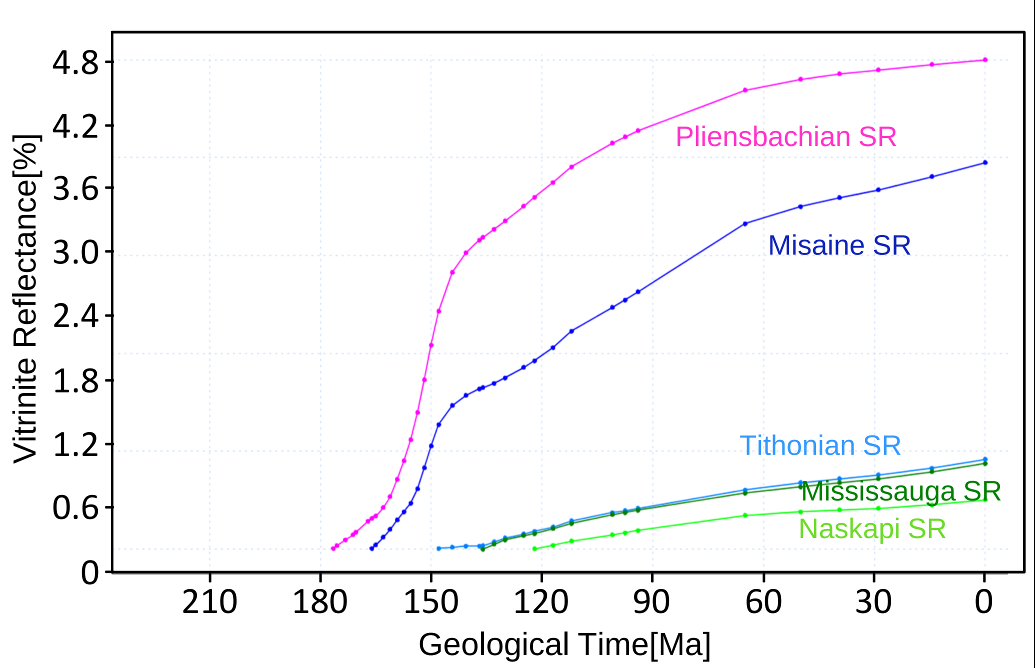
The model shows very high maturity areas in the thickest, northwestern part of the model where the deepest source rock layers will reach an overmature state as well as a decreasing trend while moving basinward, related both to the diminishing thickness of the sedimentary column and to the transition from a hotter continental domain to a cooler oceanic one.

Oil & Gas Windows

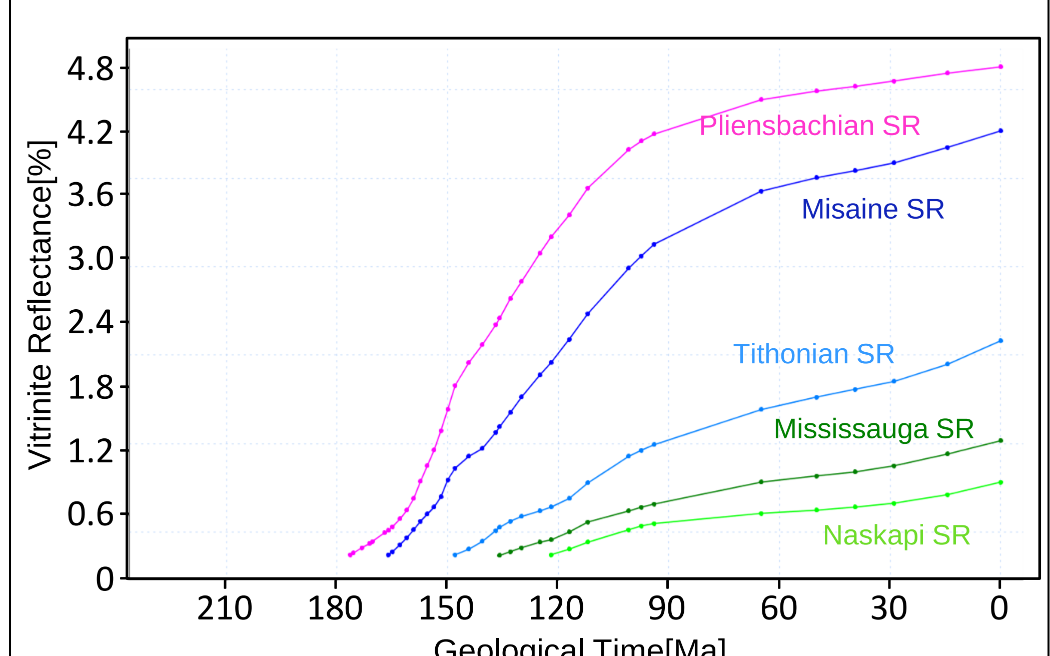


The deeper Pliensbachian and Callovian source rocks are overmature throughout the section.
The Tithonian source rock lays within the oil window between km 0 and km 45 while it remains roughly in the gas window eastwards, the Tithonian horizon getting deeper there.
The Upper Valanginian and Aptian source rocks maturity level ranges from immature from the northeastern end of the section to tentatively oil prone in its central part to immature again in the basin part where their defining horizons get shallower.

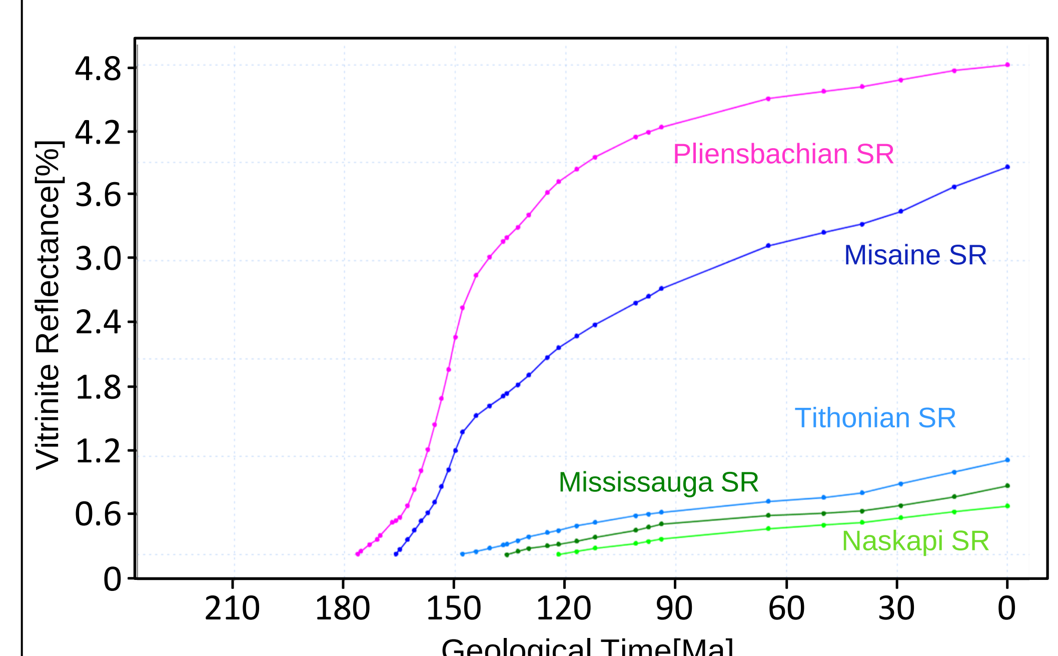
Vitrinite Reflectance through time at Km 18 Location



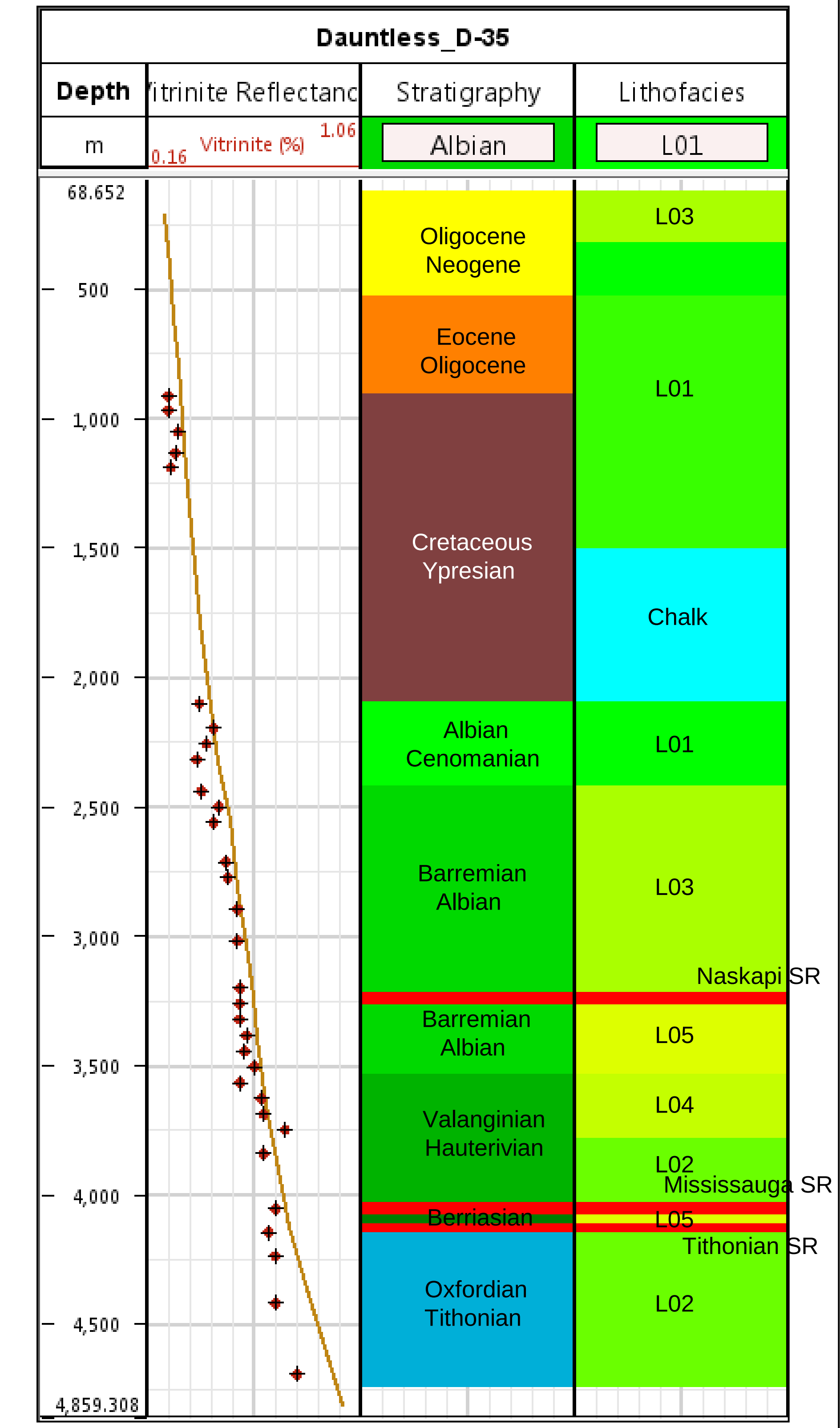
Vitrinite Reflectance through time at Km 36 Location



Vitrinite Reflectance through time at Km 45 Location



Calibration (Reference Scenario)

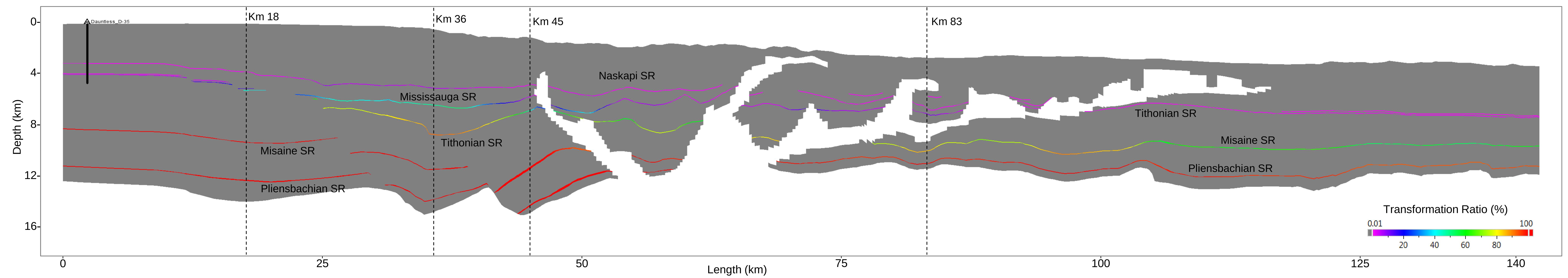


Vitrinite model is calibrated versus available observed data at Dauntless D-35 well location:

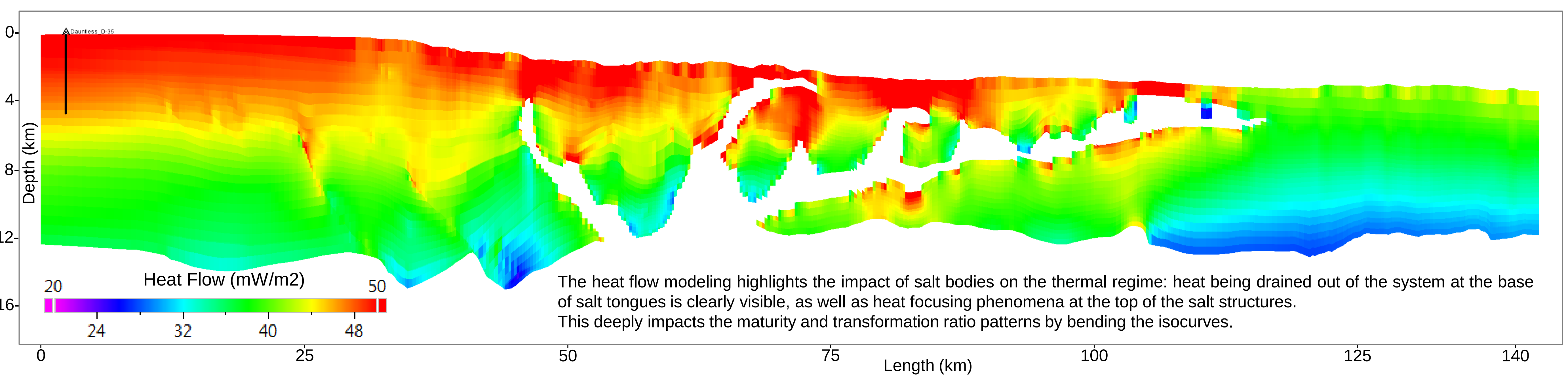
- Observed data is represented with dots,
- Simulated data is represented with thick line.

Vitrinite calibration at Dauntless D-35 well location falls under the measurements uncertainty range.

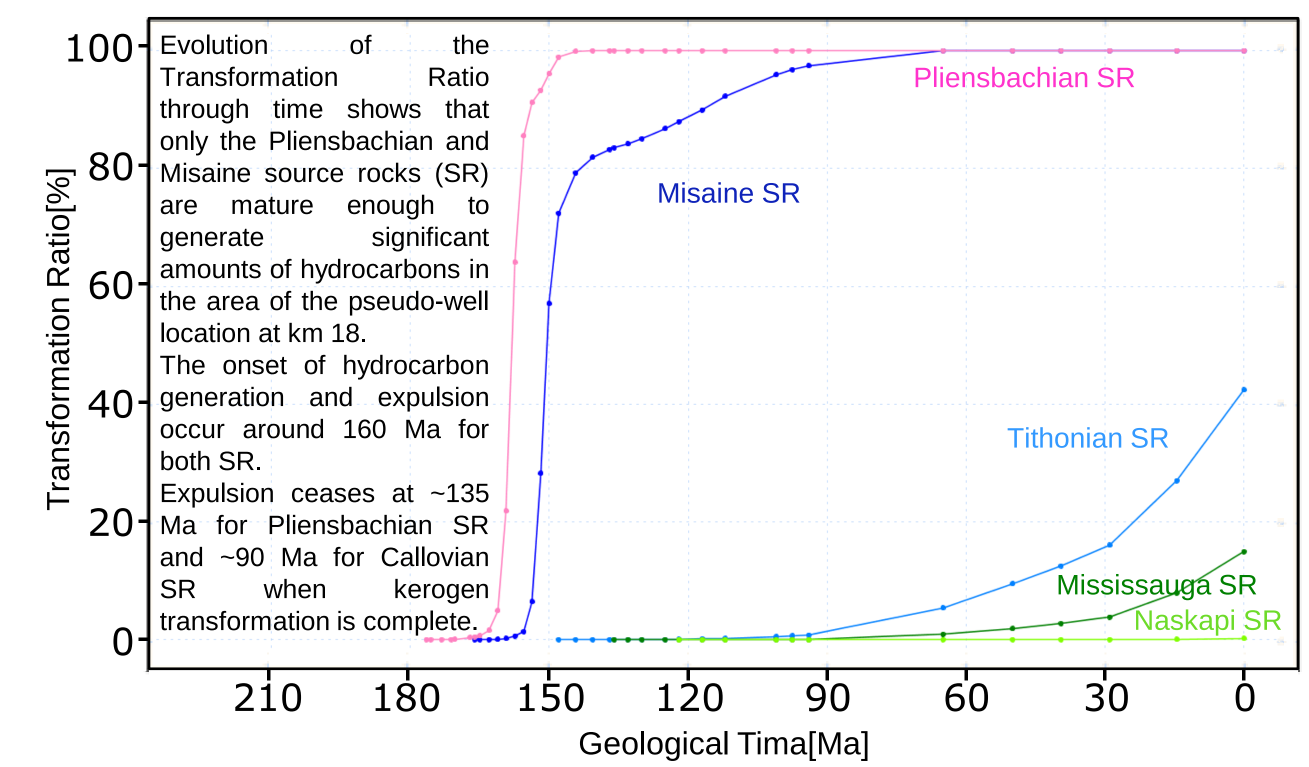
Transformation Ratio (Reference Scenario)



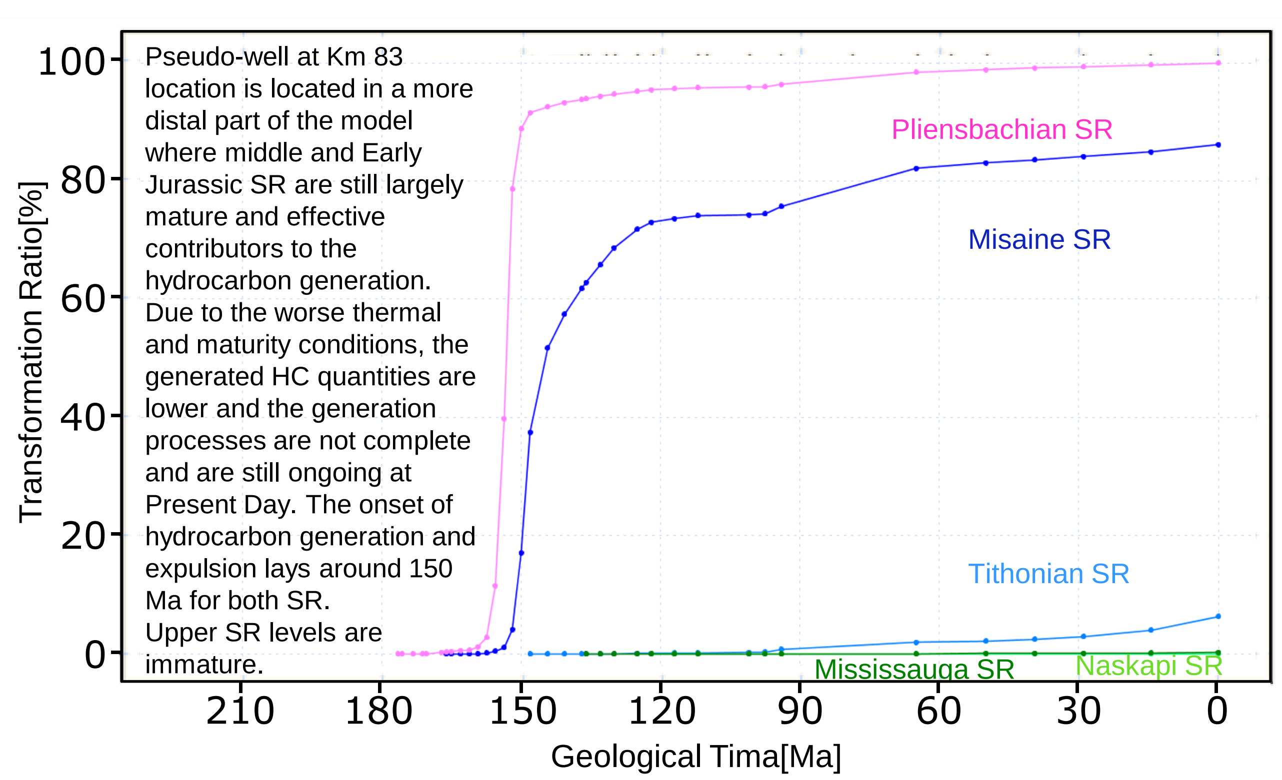
Heat Flow (Reference Scenario)



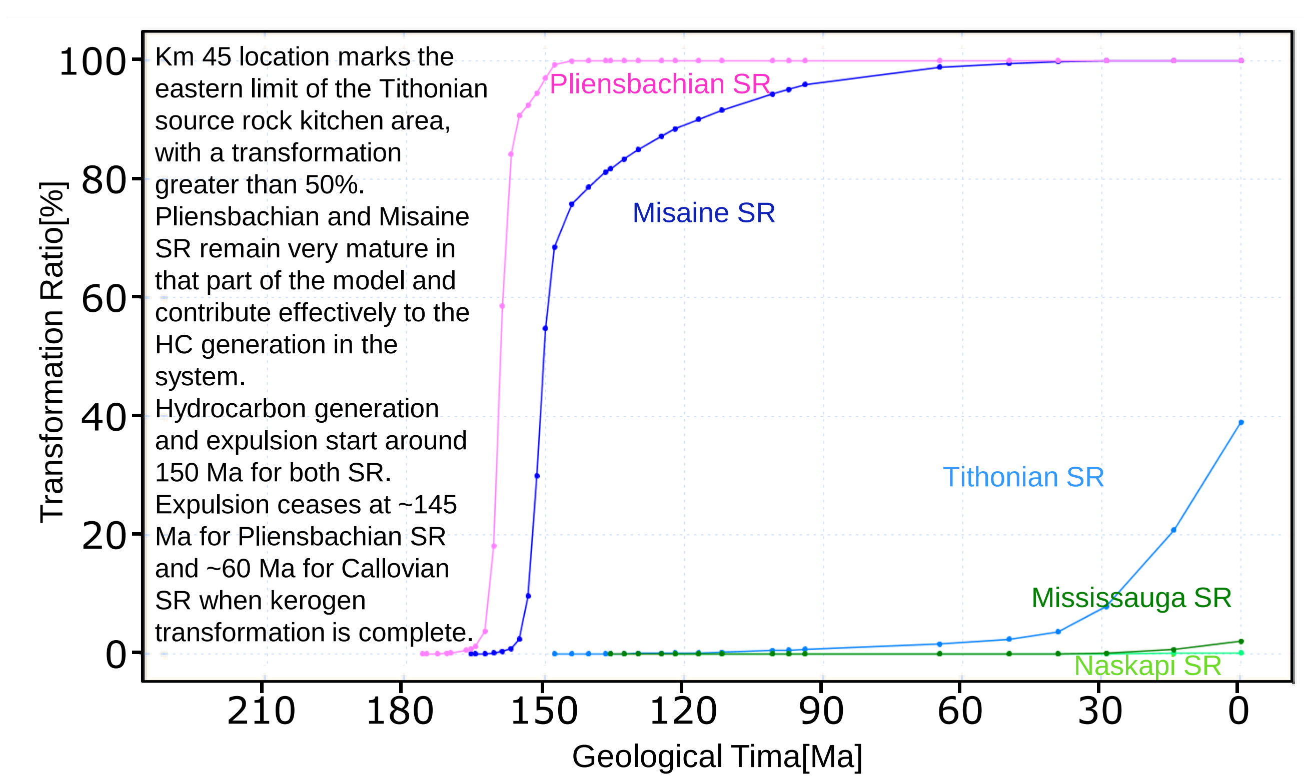
Transformation Ratio through time at km 18 Location



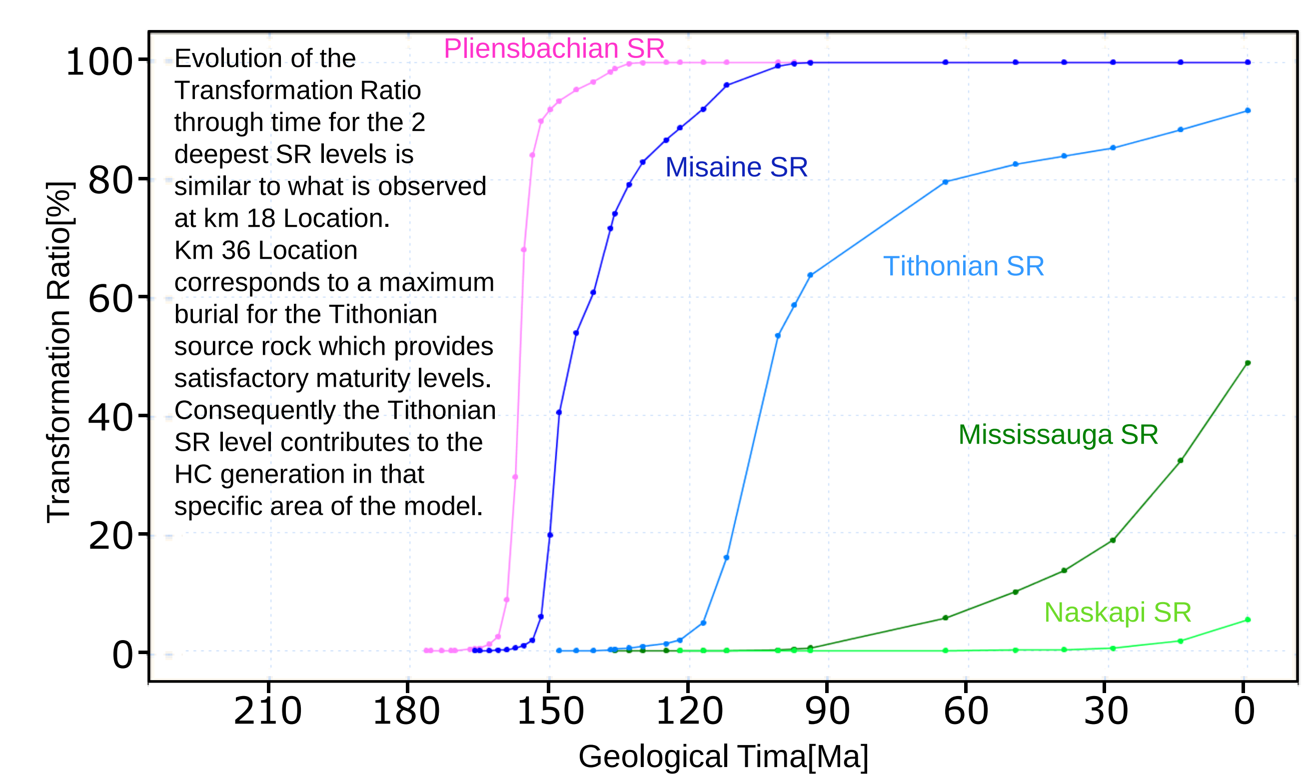
Transformation Ratio through time at km 83 Location



Transformation Ratio through time at km 45 Location

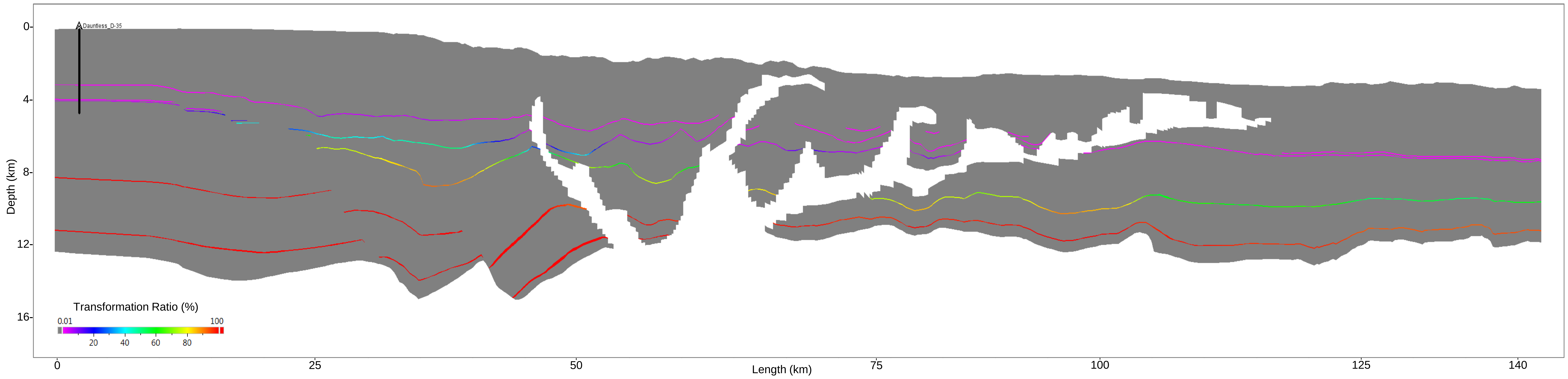


Transformation Ratio through time at km 36 Location

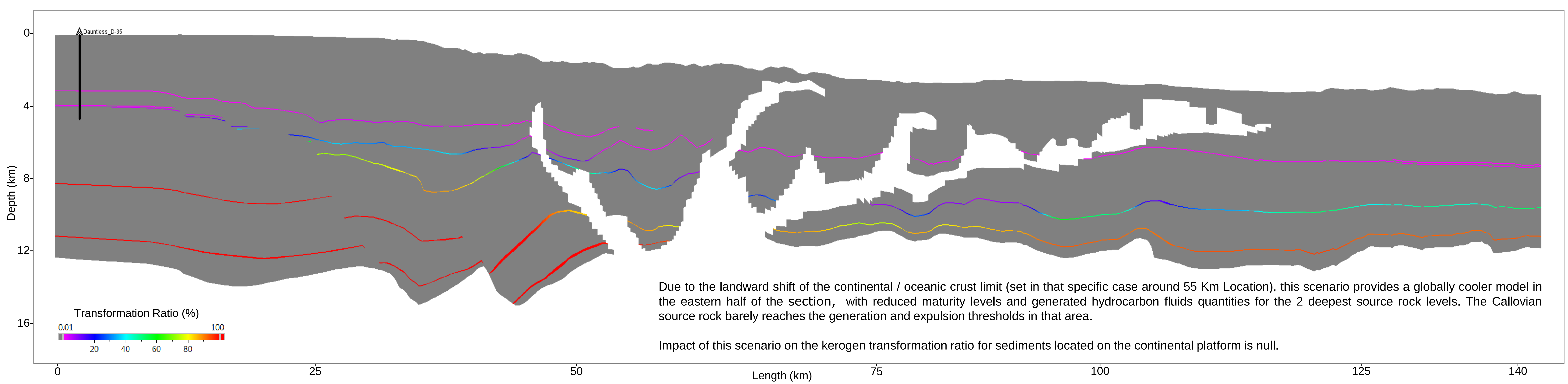


Transformation Ratio of Dauntless Section – Reference Scenario **PLATE 9.31**

Transformation Ratio (Reference Scenario)



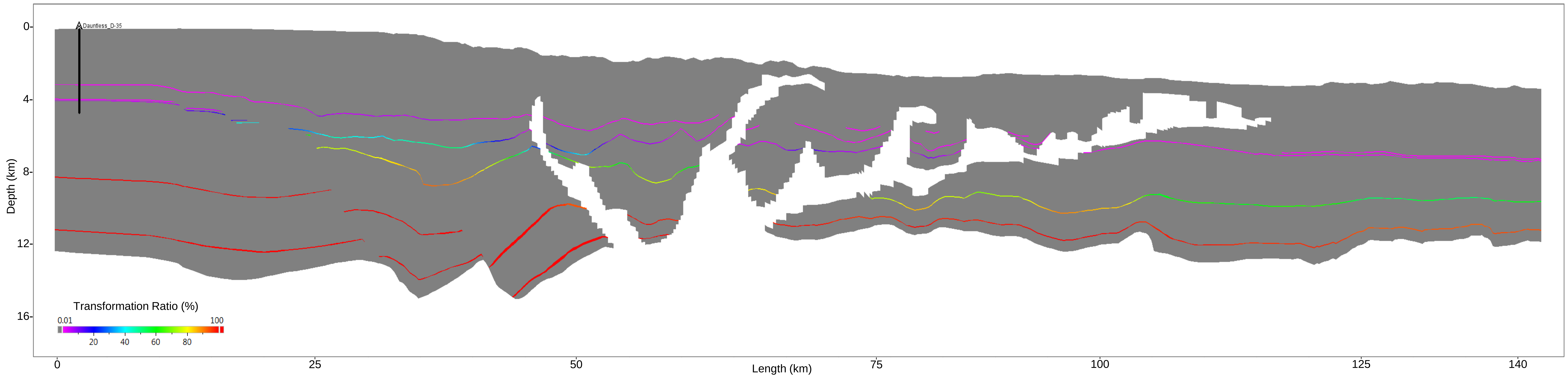
Transformation Ratio (Scenario 2 = Heat Flow variation)



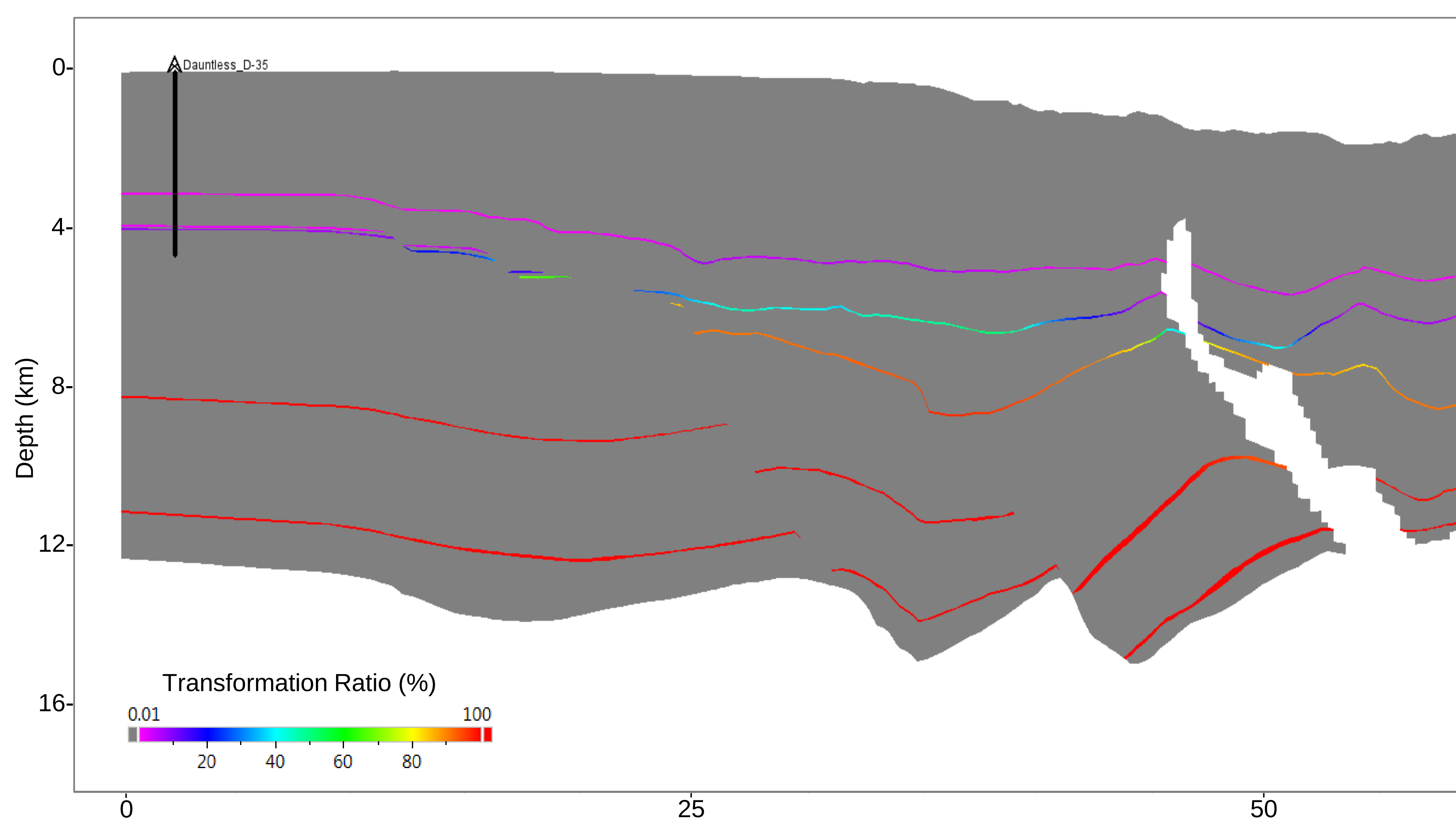
Due to the landward shift of the continental / oceanic crust limit (set in that specific case around 55 Km Location), this scenario provides a globally cooler model in the eastern half of the section, with reduced maturity levels and generated hydrocarbon fluids quantities for the 2 deepest source rock levels. The Callovian source rock barely reaches the generation and expulsion thresholds in that area.

Impact of this scenario on the kerogen transformation ratio for sediments located on the continental platform is null.

Transformation Ratio (Reference Scenario)

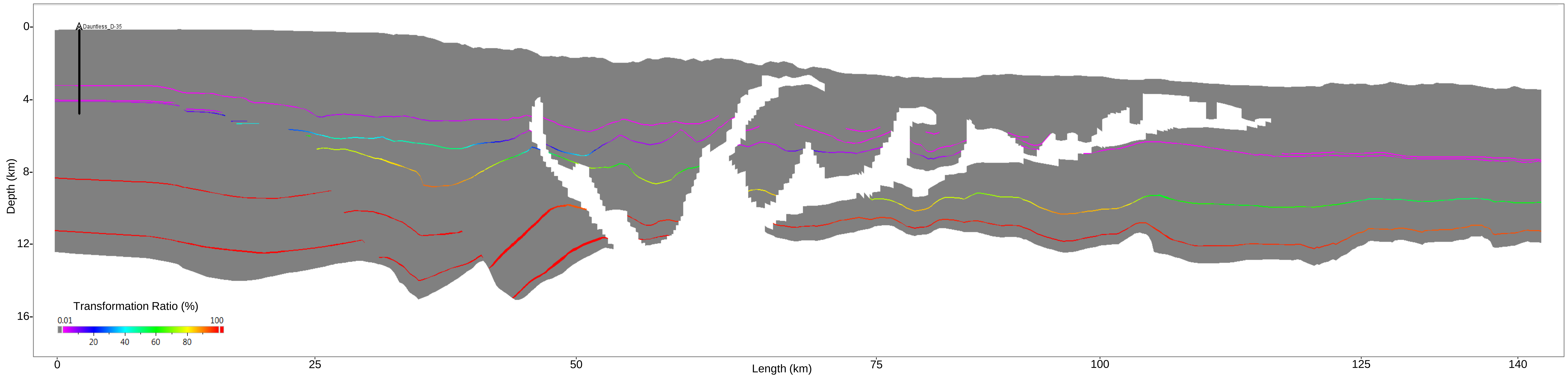


Transformation Ratio (Scenario 3 = Tithonian Type II)

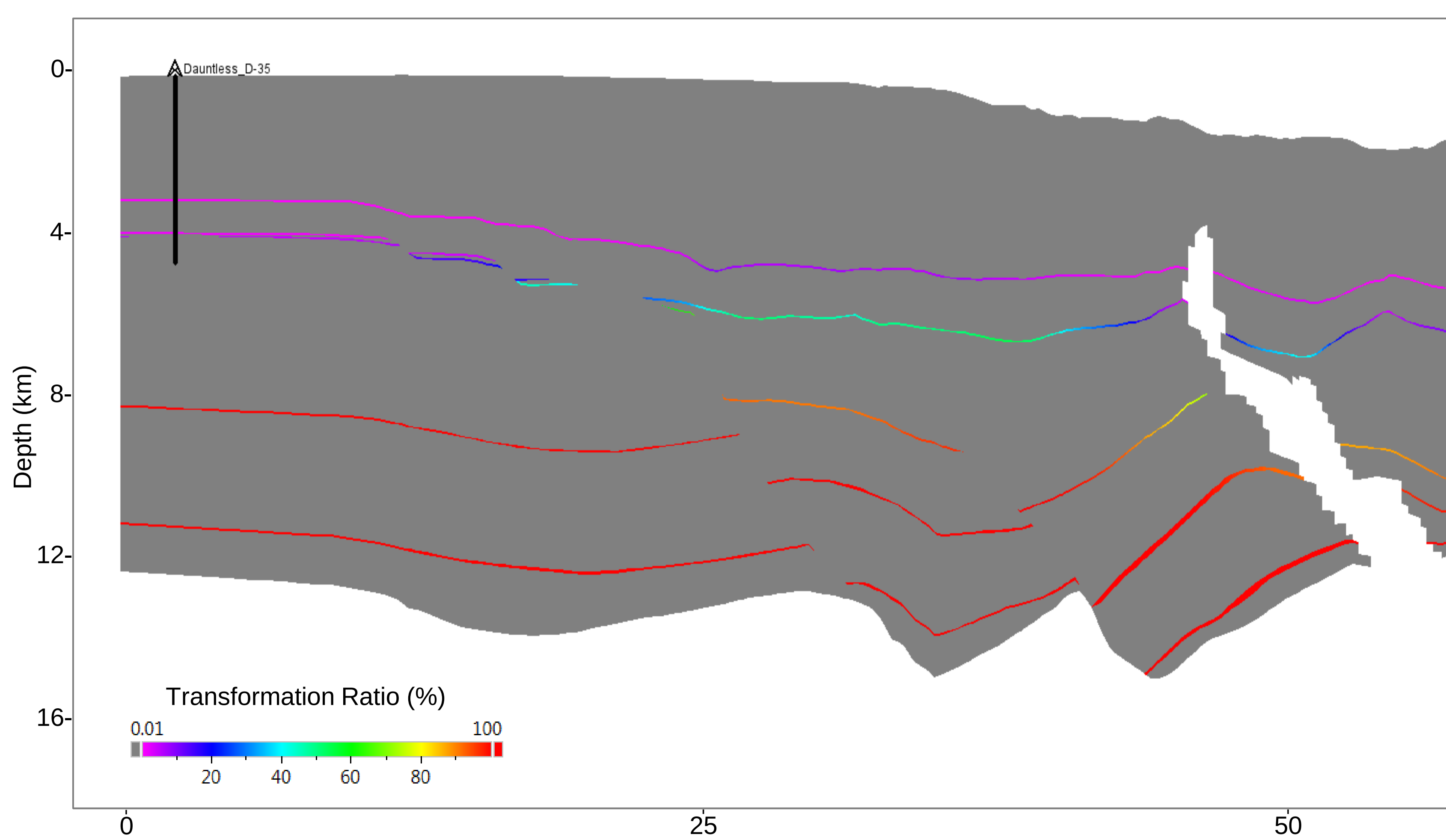


In this alternative scenario the Tithonian source rock is defined by a richer, more proficient kerogen type II. This directly impact the maturity level and he overall generated hydrocarbon quantities which increase up to 15-20 % compared to the reference scenario leading to an overmature Tithonian SR between km 25 and km ~42 and locally close to km ~57 location. Eastward, the maturity level and the generated hydrocarbon fluids quantities decrease above the oceanic domain.

Transformation Ratio (Reference Scenario)

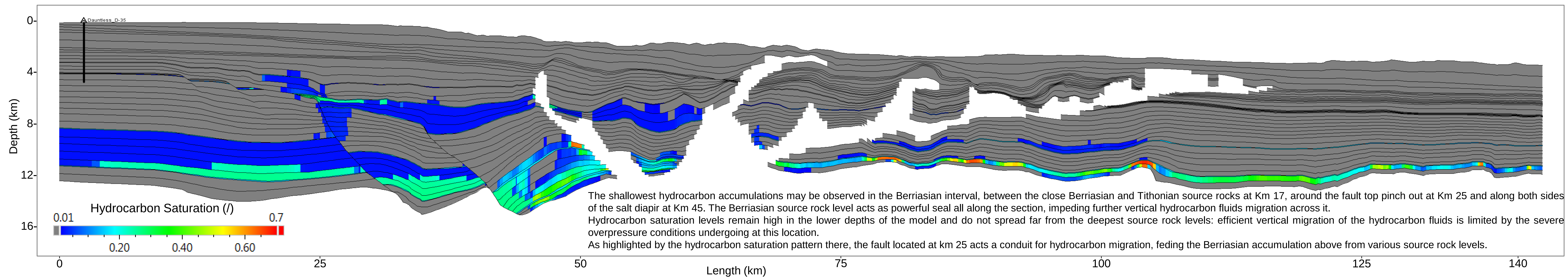


Transformation Ratio (Scenario 4 = Deep Tithonian)



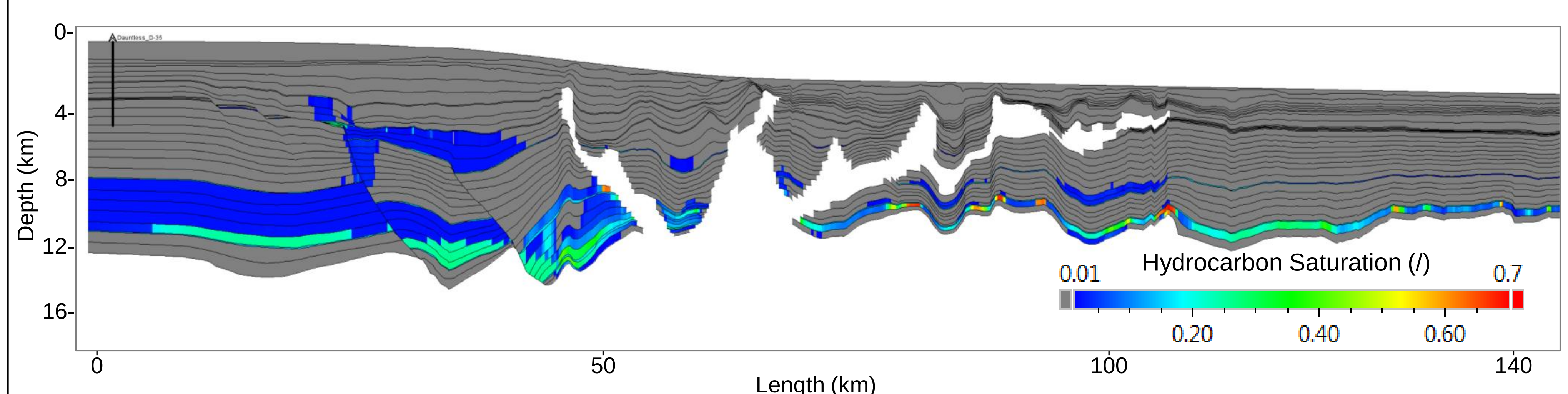
In this alternative scenario the Tithonian source rock horizons have been lowered, leading to higher maturity levels and generated hydrocarbon fluids quantities for the layer. Between Km 20 and Km 45 the Tithonian source rock is overmature and showcases a high Transformation Ratio, making it an effective contributor the hydrocarbon generation in the system. From Km 45 and eastward, the maturity levels decreases and the Tithonian source rock level gradually crosses the gas & oil windows. Past Km 105, even though the layer remains in the oil window, the transformation ratio is not high enough to produce hydrocarbon expulsion.

Hydrocarbon Saturation at Present Day (Reference Scenario)



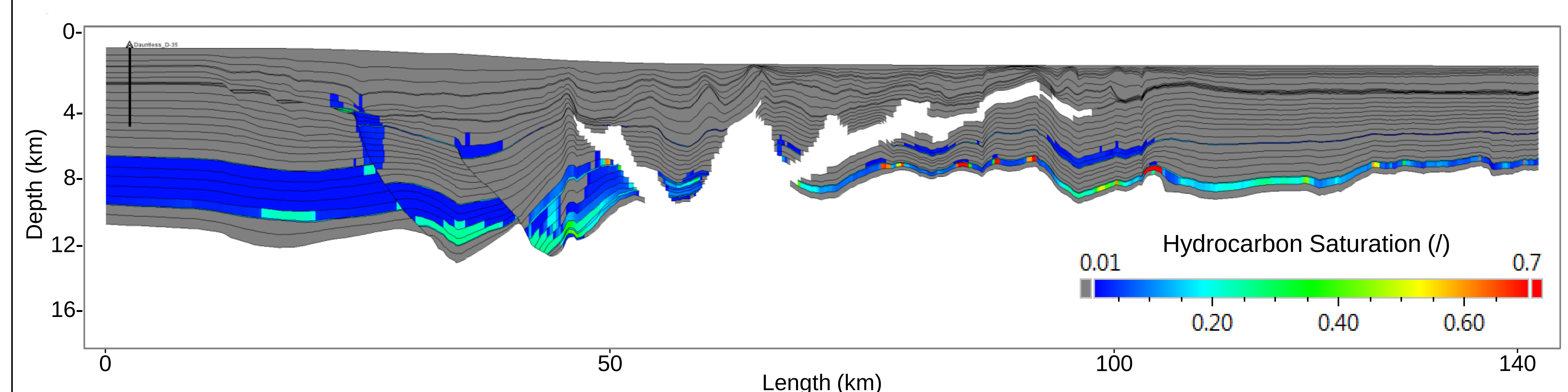
The shallowest hydrocarbon accumulations may be observed in the Berriasian interval, between the close Berriasian and Tithonian source rocks at Km 17, around the fault top pinch out at Km 25 and along both sides of the salt diapir at Km 45. The Berriasian source rock level acts as powerful seal all along the section, impeding further vertical hydrocarbon fluids migration across it.
Hydrocarbon saturation levels remain high in the lower depths of the model and do not spread far from the deepest source rock levels: efficient vertical migration of the hydrocarbon fluids is limited by the severe overpressure conditions undergoing at this location.
As highlighted by the hydrocarbon saturation pattern there, the fault located at km 25 acts a conduit for hydrocarbon migration, feding the Berriasian accumulation above from various source rock levels.

Hydrocarbon Saturation at 65 Ma (Reference Scenario)



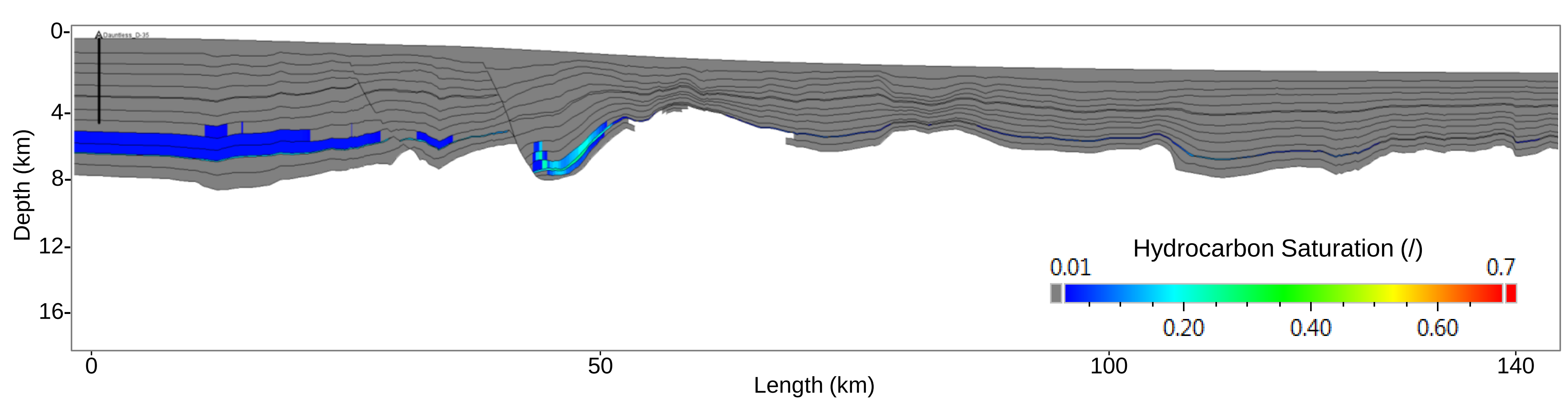
Infilling of the Berriasian accumulation located at Km 25 continues. The contribution of the Tithonian source rock layer to the infilling of Berriasian accumulations increases as the layer matures.
The accumulation located along the salt diapir at km 50 grows in size.
Entrapment of the hydrocarbon fluids below the Callovian source rock becomes more noticeable as overpressure conditions are getting more severe.

Hydrocarbon Saturation at 101 Ma (Reference Scenario)



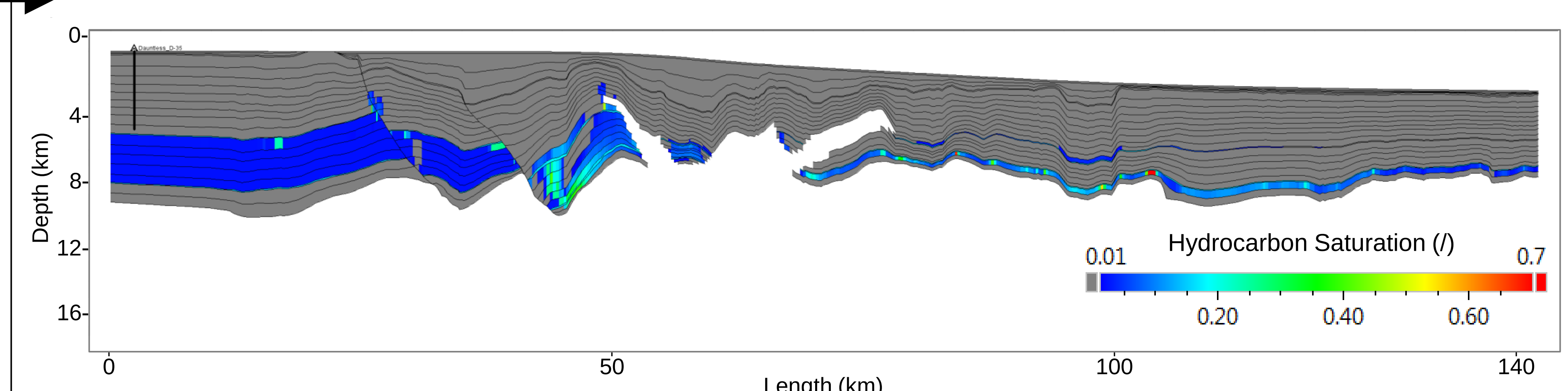
The Tithonian source rock layer is on the onset of hydrocarbon expulsion.
Hydrocarbon flow across the fault located at km 25 begins to fill the Berriasian accumulation, which is fed from 3 layers (Pliensbachian, Misaine and Tithonian source rocks). An accumulation is beginning to form at Km 50 along the salt diapir: it is being fed from both Pliensbachian and Misaine source rock layers.
Vertical migration patterns remain very limited in the basin part of the section.

Hydrocarbon Saturation at 160 Ma (Reference Scenario)



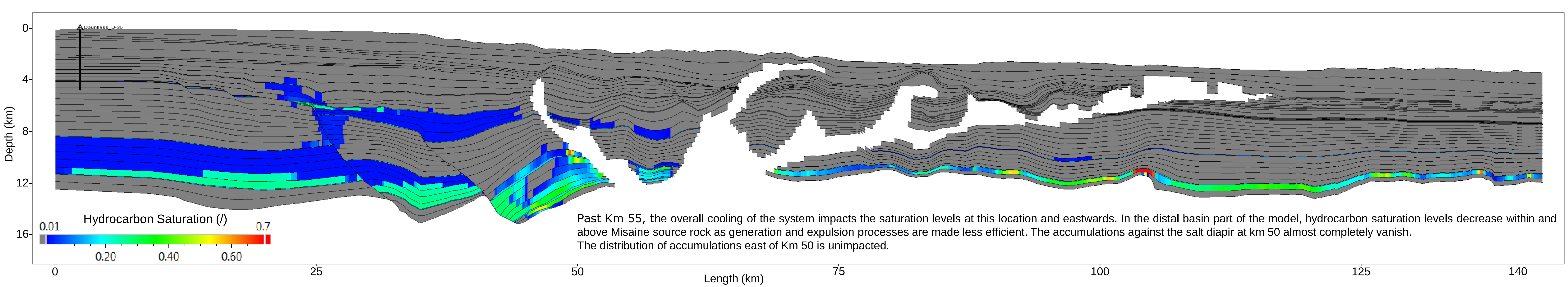
Hydrocarbon fluids expulsion begins from the deeper/more mature source rock levels entering the oil window.

Hydrocarbon Saturation at 136 Ma (Reference Scenario)



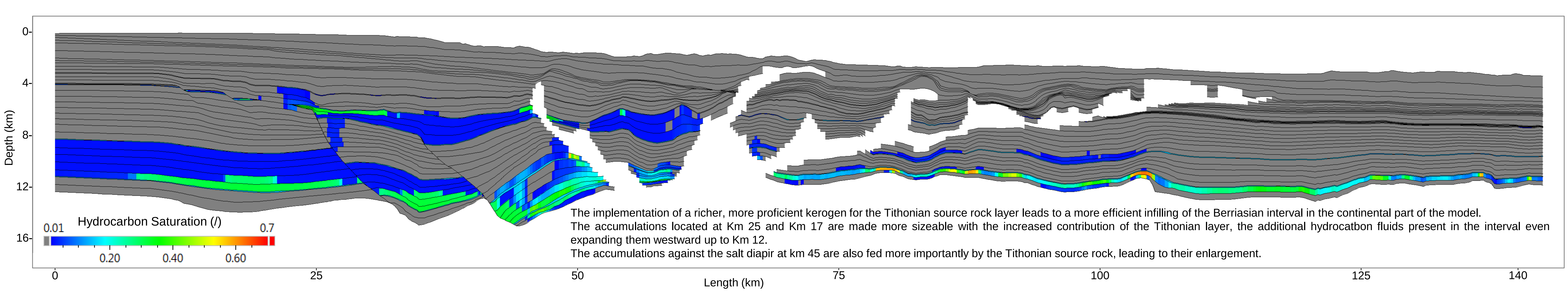
Hydrocarbon fluids expulsion from the Pliensbachian source rock level spreads throughout the section as maturity conditions become more favorable. Same goes for the Misaine source rock layer.
Migration through the fault plane located at Km 25 has begun, while the hydrocarbon column retained against the fault located at Km 28 is not high enough to overcome the capillary pressure barrier imposed by the neighboring sediments for initiating vertical migration.

Hydrocarbon Saturation (Scenario 2 = Heat Flow variation)



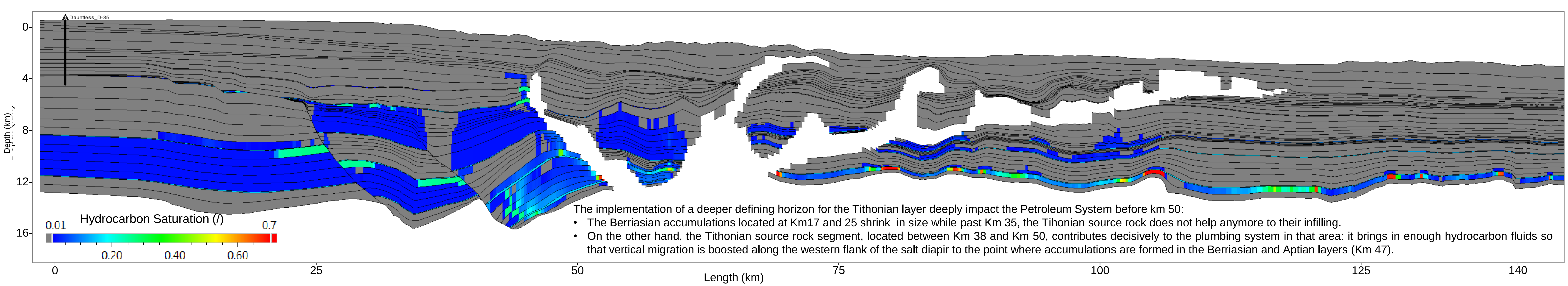
Past Km 55, the overall cooling of the system impacts the saturation levels at this location and eastwards. In the distal basin part of the model, hydrocarbon saturation levels decrease within and above Misaine source rock as generation and expulsion processes are made less efficient. The accumulations against the salt diapir at km 50 almost completely vanish.
The distribution of accumulations east of Km 50 is unimpacted.

Hydrocarbon Saturation (Scenario 3 = Tithonian Type II)



The implementation of a richer, more proficient kerogen for the Tithonian source rock layer leads to a more efficient infilling of the Berriasian interval in the continental part of the model.
The accumulations located at Km 25 and Km 17 are made more sizeable with the increased contribution of the Tithonian layer, the additional hydrocatbon fluids present in the interval even expanding them westward up to Km 12.
The accumulations against the salt diapir at km 45 are also fed more importantly by the Tithonian source rock, leading to their enlargement.

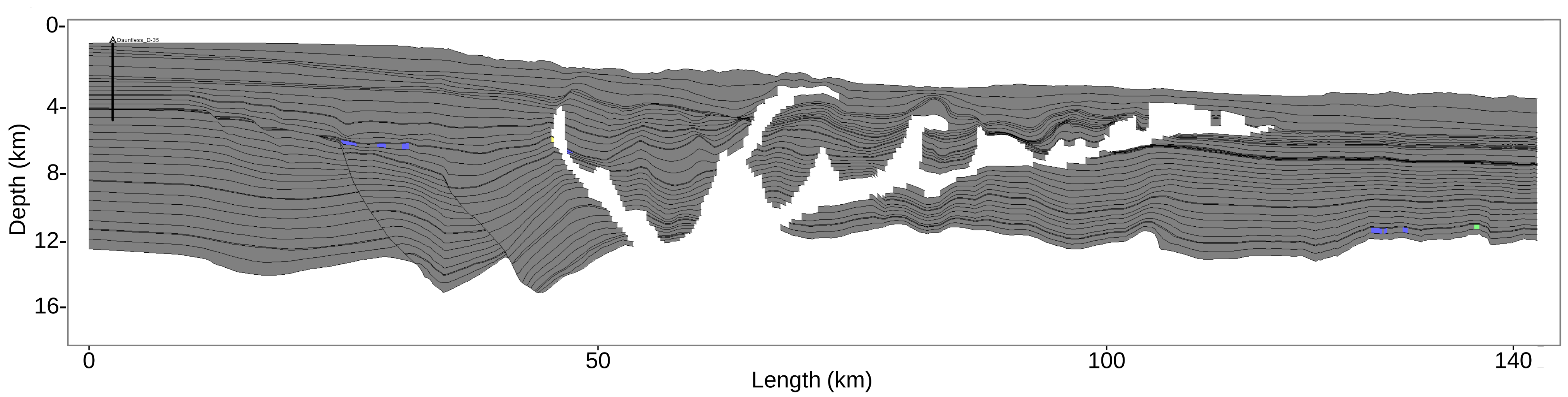
Hydrocarbon Saturation (Scenario 4 = Deep Tithonian)



The implementation of a deeper defining horizon for the Tithonian layer deeply impact the Petroleum System before km 50:

- The Berriasian accumulations located at Km17 and 25 shrink in size while past Km 35, the Tihonian source rock does not help anymore to their infilling.
- On the other hand, the Tithonian source rock segment, located between Km 38 and Km 50, contributes decisively to the plumbing system in that area: it brings in enough hydrocarbon fluids so that vertical migration is boosted along the western flank of the salt diapir to the point where accumulations are formed in the Berriasian and Aptian layers (Km 47).

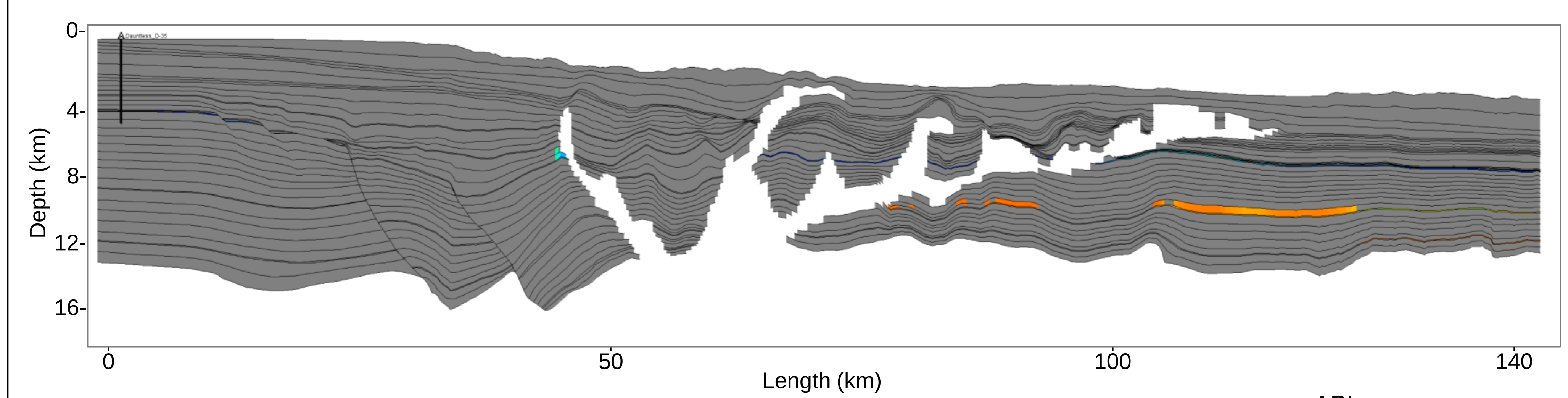
Volume of Oil per Area (Reference Scenario)



Mass of Oil is less than ~3.57bbl/m² in the model. The over-mature state of the deepest source rocks layers which are the main contributors to the Petroleum System, the types of kerogen as well as the thermal conditions favorable to secondary cracking explain this result.
Slight quantities of oil may be expected though in the Berriasian accumulations located at Km 25 and the ones located against the salt diapir at Km 45.

Volume of Oil per Area (bbl/m2)
1.5 – 5.5 – 11.5 – 17.5 – 22.5 – 28.5

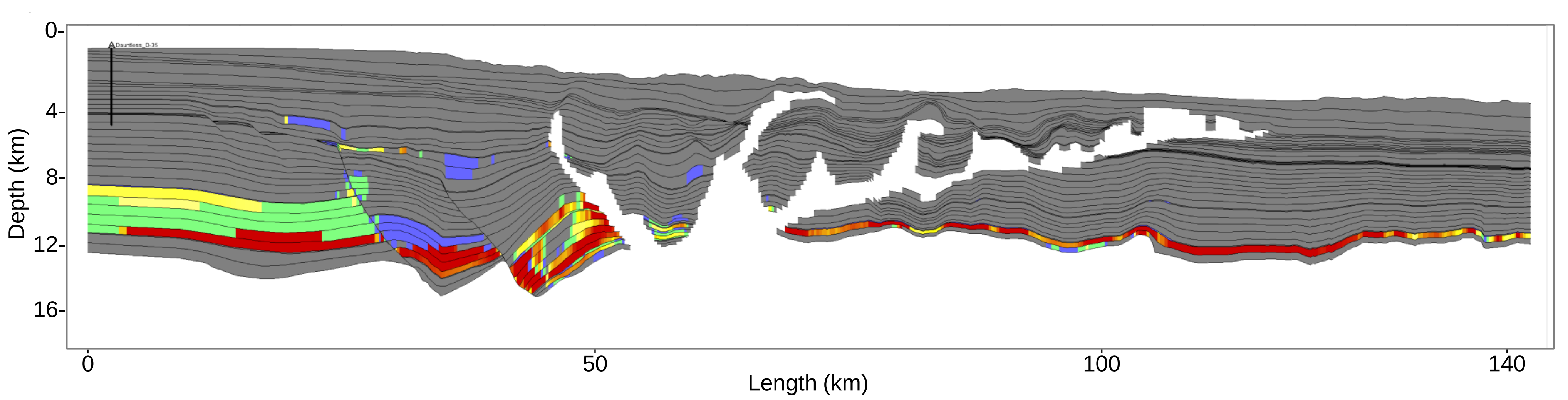
API Gravity - Oil (Reference Scenario)



API Gravity of the oil in the Berriasian accumulations varies between 26° API (Km 17) and 28° API up to 30 (Km 45).

API
20 – 24 – 32 – 40

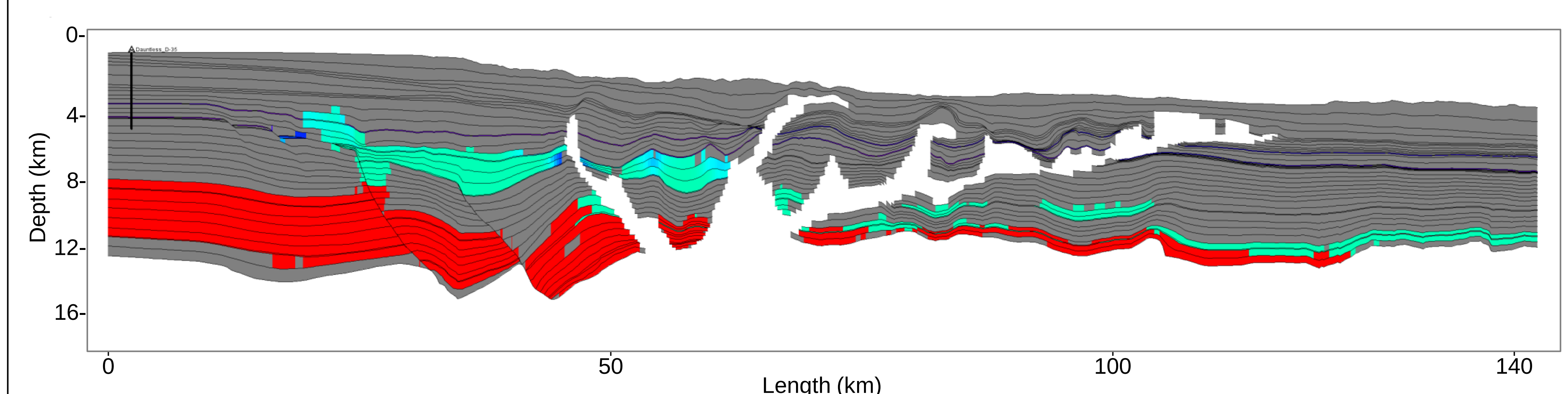
Volume of Gas per Area (Reference Scenario)



Gas is present in rather massive quantities in the lower depths of the model. If out of a source rock layer and not marked of by a structural element, these gas quantities should be considered as diffuse distributions which have dissipated through geological time.
Accumulations picked in the previous slides showcasing saturation levels (ie Berriasian accumulations around Km 25, accumulations against the fault diapir at Km 45) are filled predominantly with large quantities of gas.

Volume of Gas per Area (10^3 cf/m2)
10 – 40 – 80 – 120 – 160 – 200

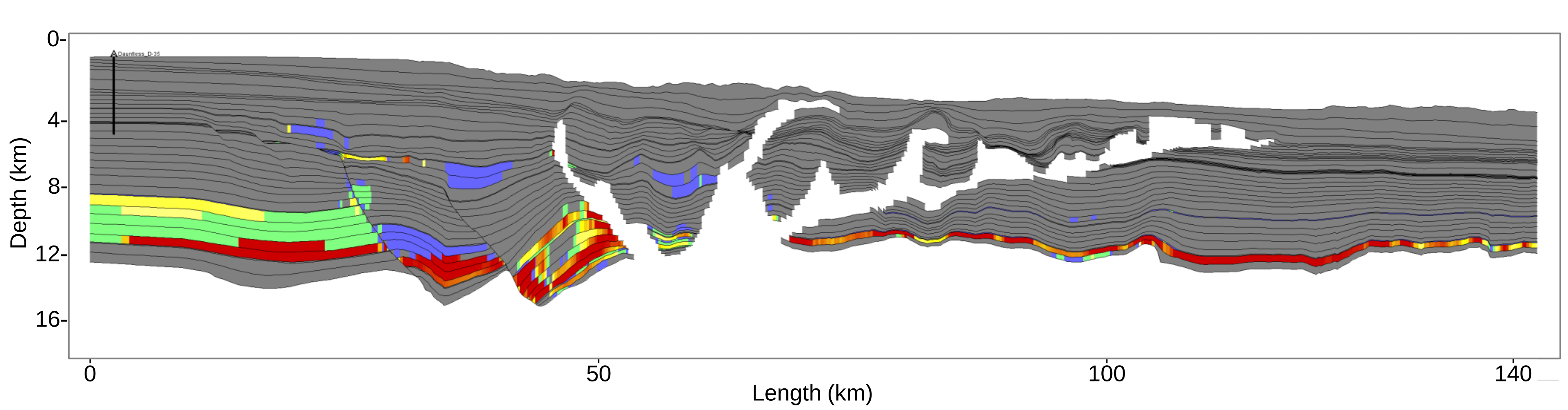
API Gravity - Condensates (Reference Scenario)



API Gravity of gas condensates in the Berriasian accumulations varies between 32° API (Km 17) up to 44° API (Km 45).

API
20 – 32 – 48 – 60

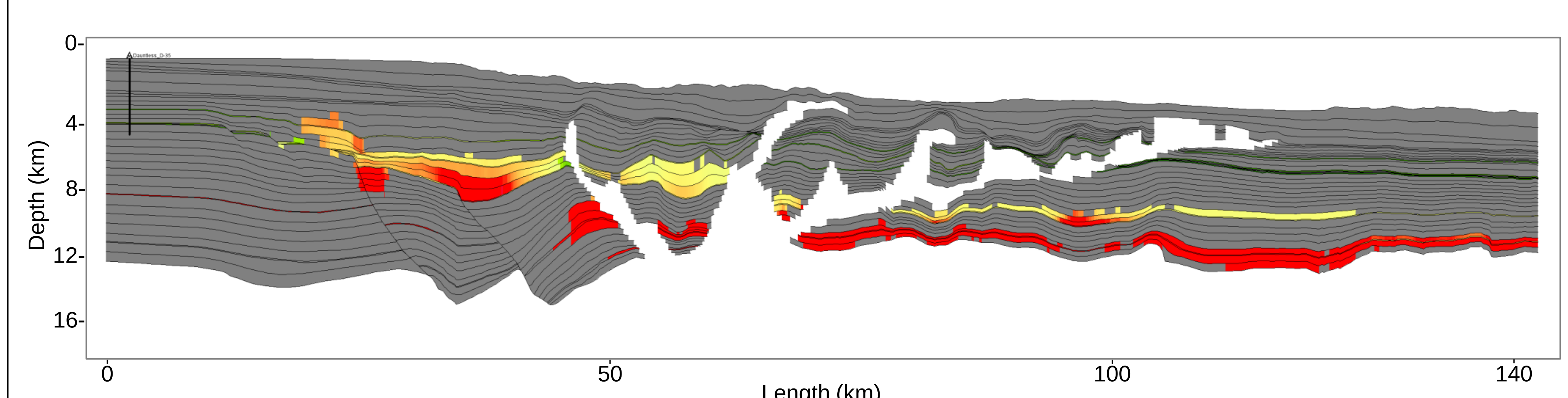
Total Volume of Hydrocarbon per Area (Reference Scenario)



As stated here above, the total volume of hydrocarbon in the model is entirely made of gas.
Total hydrocarbon volume is derived from the associates accumulated hydrocarbon masses using an average density.

Volume of HC per Area (bbl/m2)
1.5 – 5.5 – 11.5 – 17.5 – 22.5 – 28.5

GOR Feed (Reference Scenario)

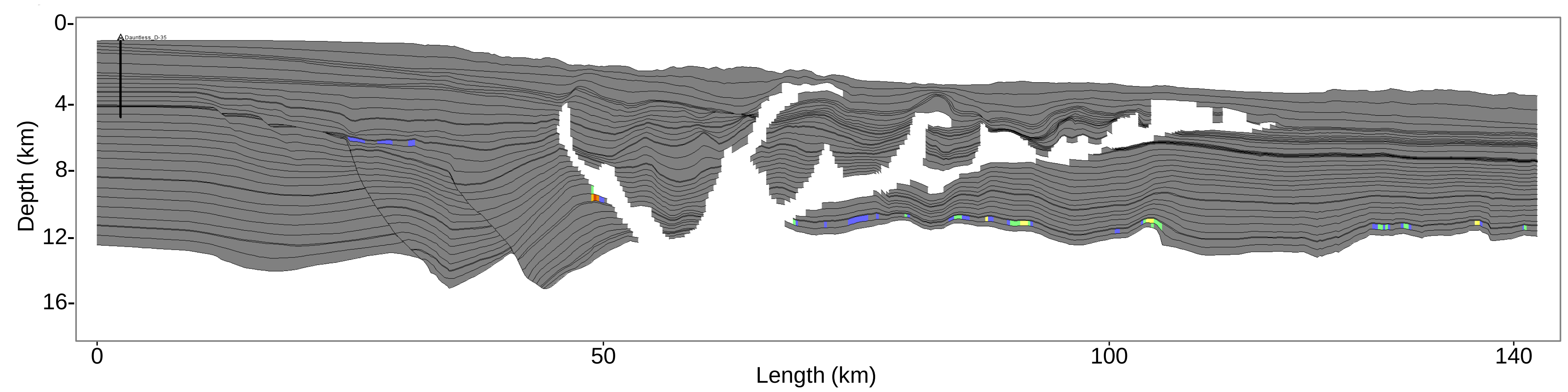


GOR Feed variable is the ratio between the mass of gas and the mass of oil accumulated in a given cell of the model. The mass of gas largely outweighs masses of gas and condensates as observed before with GOR exceeding 5 throughout the model, except:

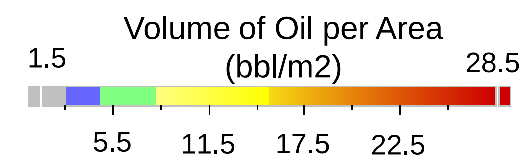
- within the shallower Tithonian, Mississauga and Naskapi source rock layers where slight remaining generated oil quantities can be spotted. Yet the associated masses are very low.
- in the accumulation located along the salt diapir at Km 45 which showcase high oil content.

GOR Feed (g/g)
0 – 8 – 16 – 20

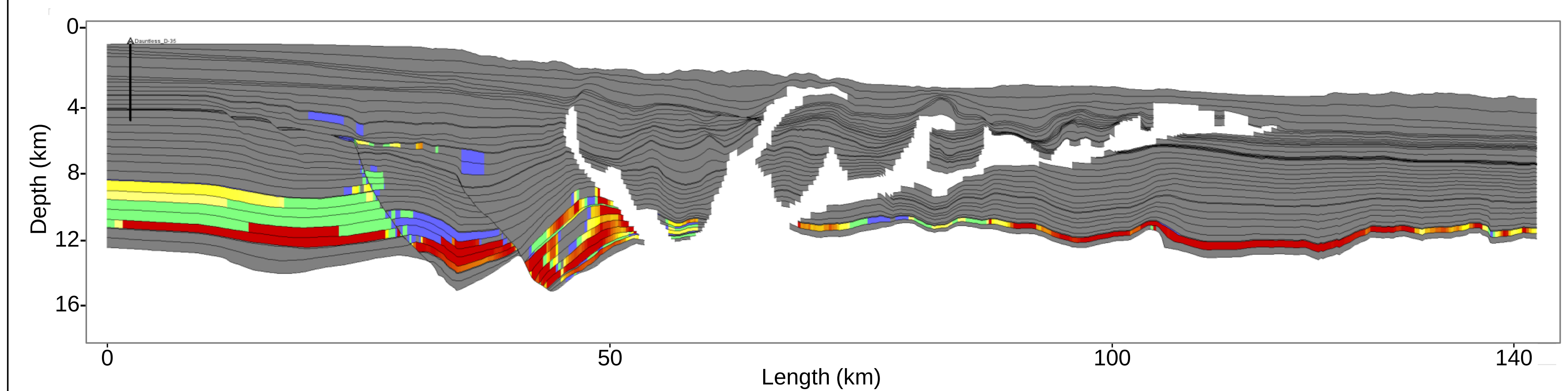
Volume of Oil per Area (Scenario 2 = Heat Flow variation)



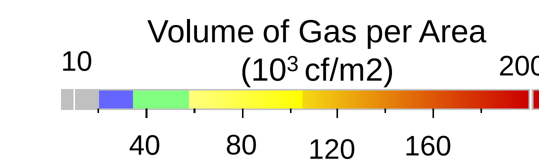
The overall cooling of the system, past Km 55, impacts positively the oil distribution below Pliensbachian SR in the basinward part of the system (km 70 to km 140), and above Misaine SR at km 50 where accumulations up to ~25 bbl/m2 are observed along the western wall of the salt diapir.



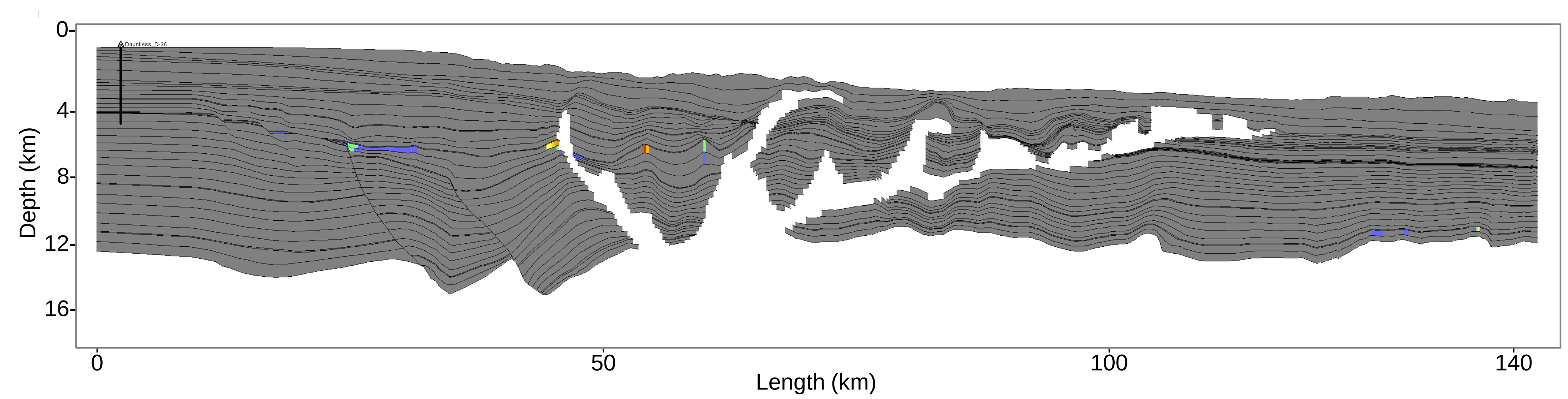
Volume of Gas per Area (Scenario 2 = Heat Flow variation)



The overall cooling of the system past Km 55 reduces slightly the quantity of gas produced below the eastern salt tongue (km 70 to km 105), even though the generated quantities remain very high.

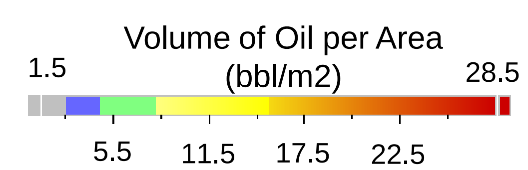


Volume of Oil per Area (Scenario 3 = Tithonian Type II)

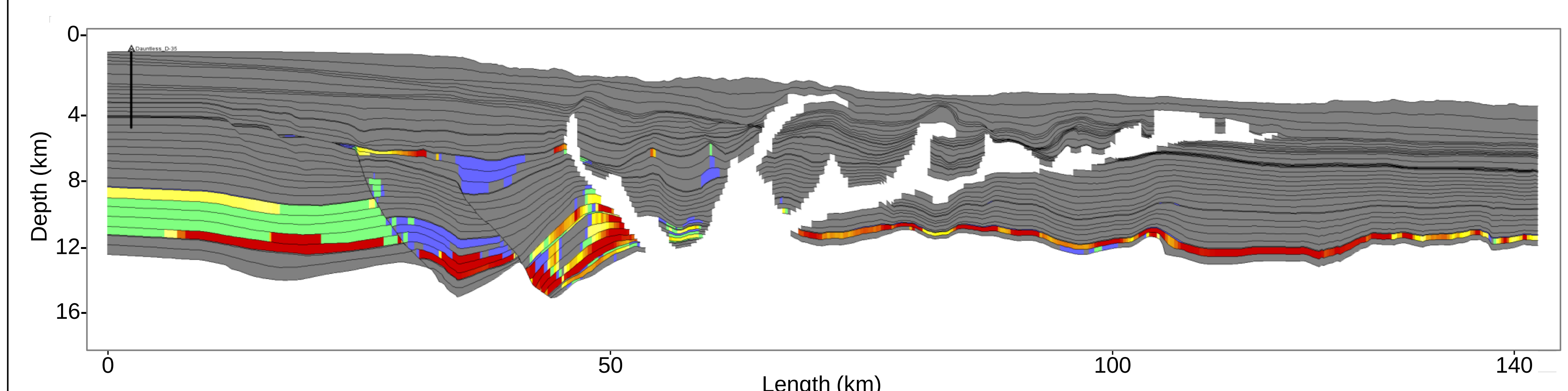


The implementation of a richer, more proficient kerogen for the Tithonian source rock impacts the masses accumulated between km 45 and km 65. Oil Masses reach values up to ~30bbl/m2 below the Berriasian SR at km 55 location while a mass of oil up to ~17bbl/m2 is observed against the salt diapir at km 45 location.

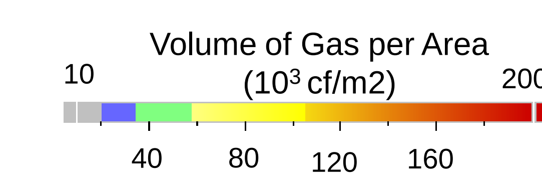
The mass of oil remains un-impacted in the other areas of the section.



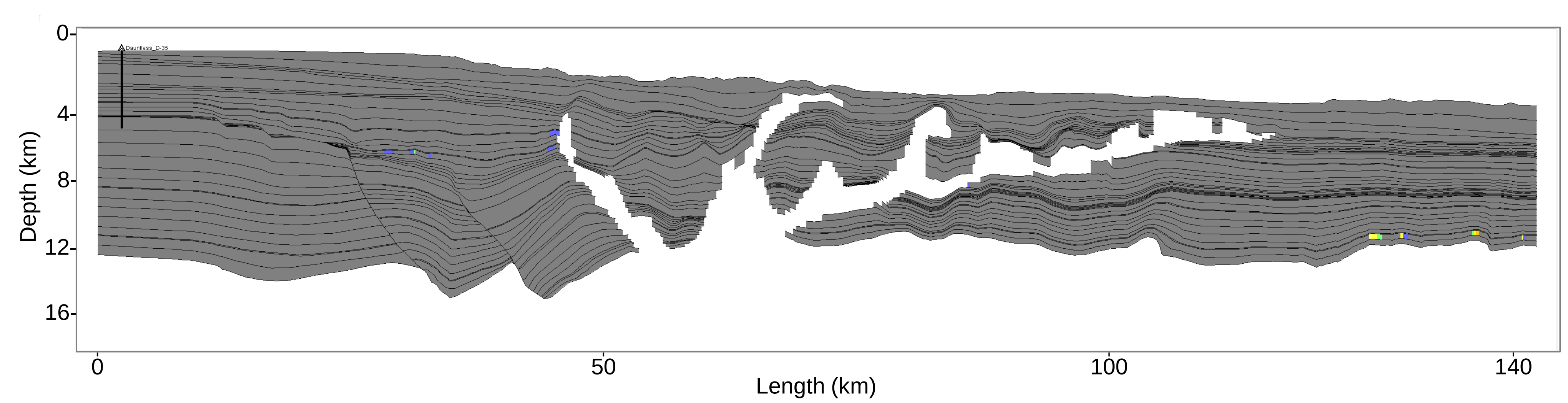
Volume of Gas per Area (Scenario 3 = Tithonian Type II)



The implementation of a richer, more proficient kerogen for the Tithonian source rock has a reduced impact on the overall volume of free gas. This impact is restricted to the kitchen area between km ~25 and km 65 and takes the form of a slight increase of the gas volume in layers included between Tithonian and Berriasian SR.

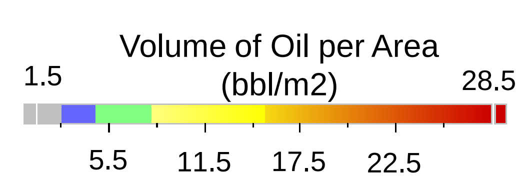


Volume of Oil per Area (Scenario 4 = Deep Tithonian)

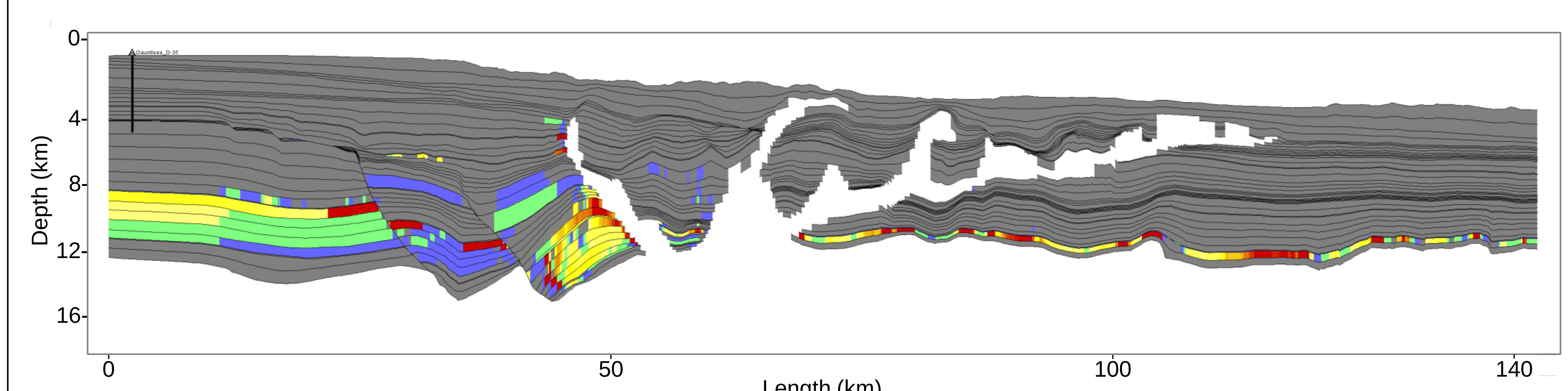


The implementation of a deeper defining horizon for the Tithonian layer sligthly impacts the Petroleum System before km 50 and after km 130.

The masses of oil observed below Berriasian SR layer are doubled locally at km ~32 while some masses of oil are observed against the salt diapir at km 45 in the layers below Berriasian and Naskapi SR. East of km 130, masses of oil observed in the layer below Pliensbachian SR are 2 to 4 times higher than in reference model.

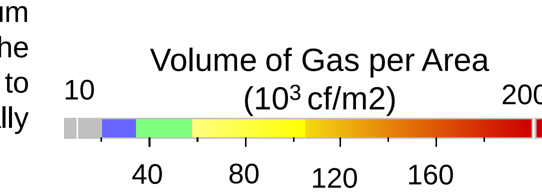


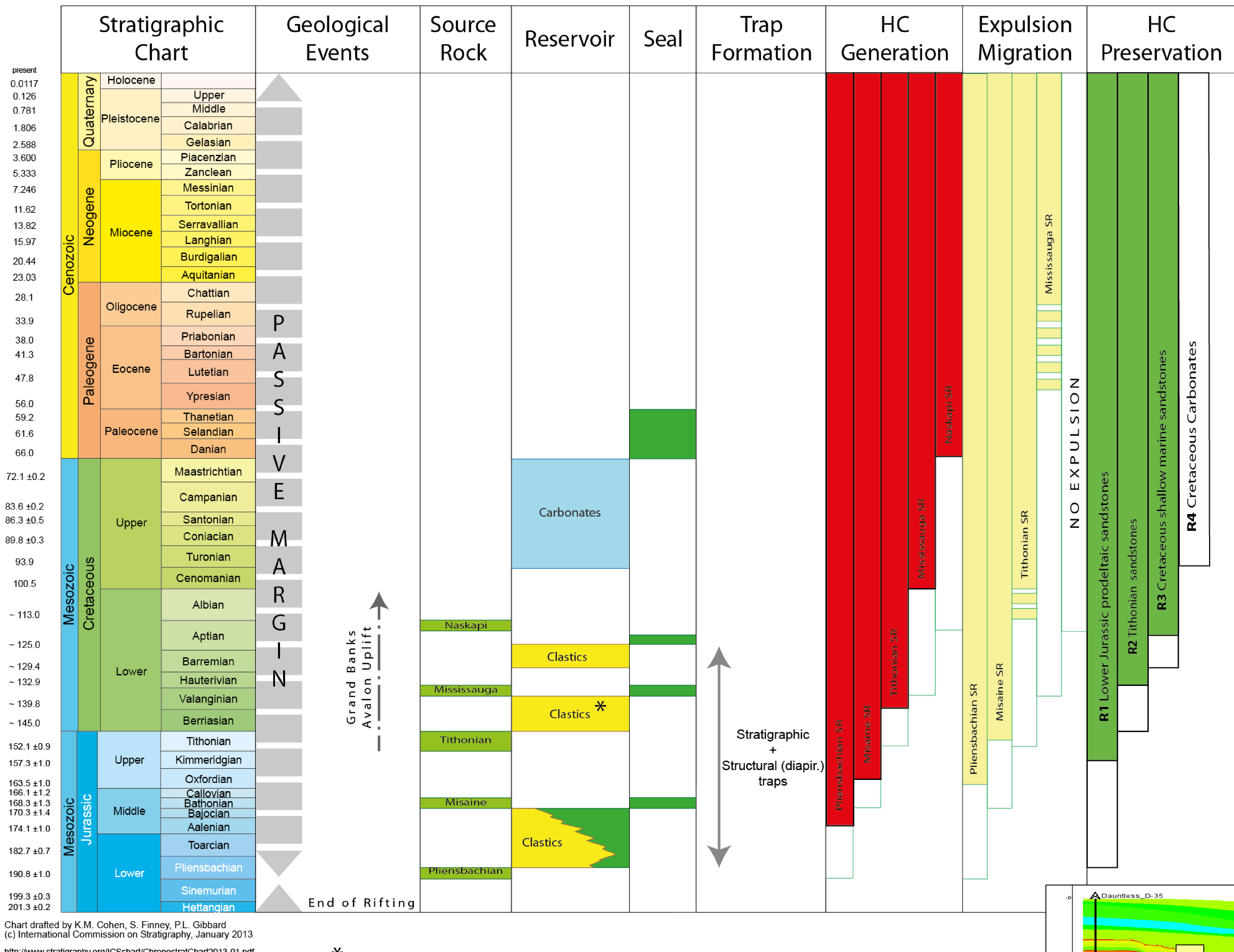
Volume of Gas per Area (Scenario 4 = Deep Tithonian)

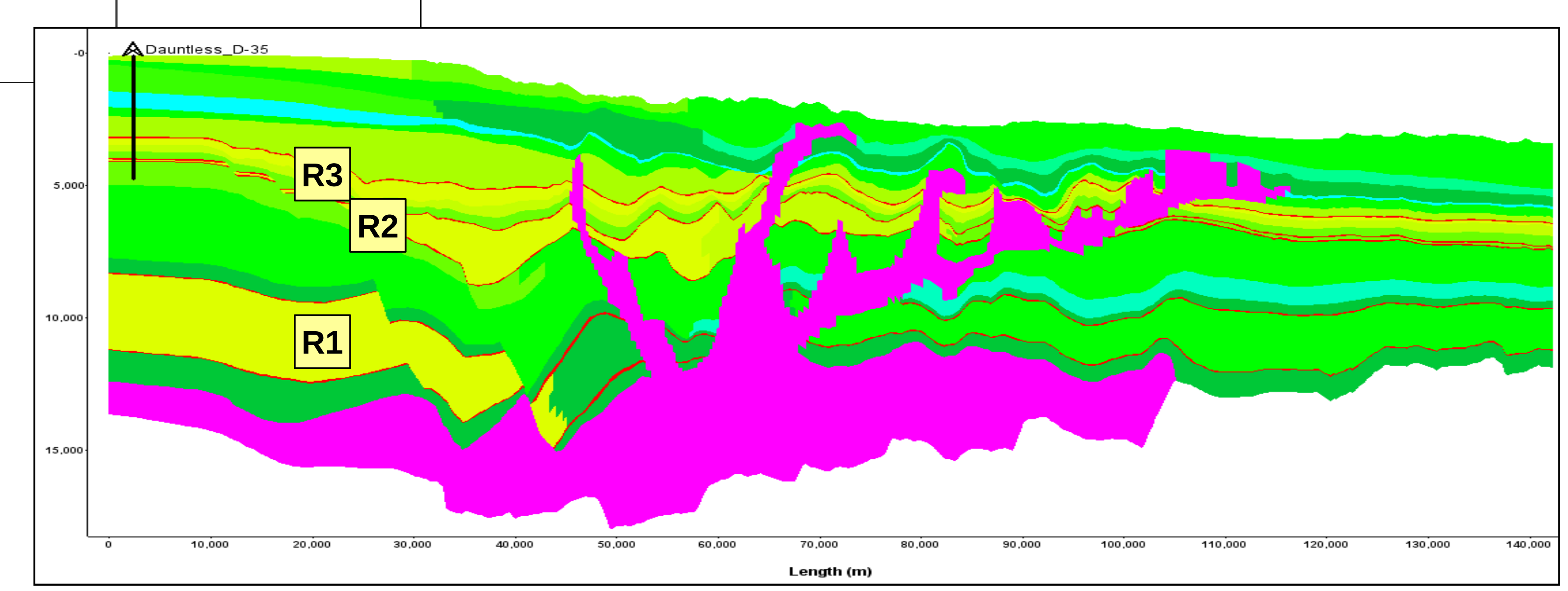


The implementation of a deeper defining horizon for the Tithonian layer deeply impacts the Petroleum System on the overall section. The global volume of gas in the ante-Callovian layers is clearly lower on the whole section while accumulations of gas, related to the Tithonian contribution, are observed up to Barremian-Albian layers along the westernmost salt diapir at km 45. These accumulations reach locally volumes up to 200,000 cf/m2.

A slight decrease in gas volume is observed between km 25 and km 35.



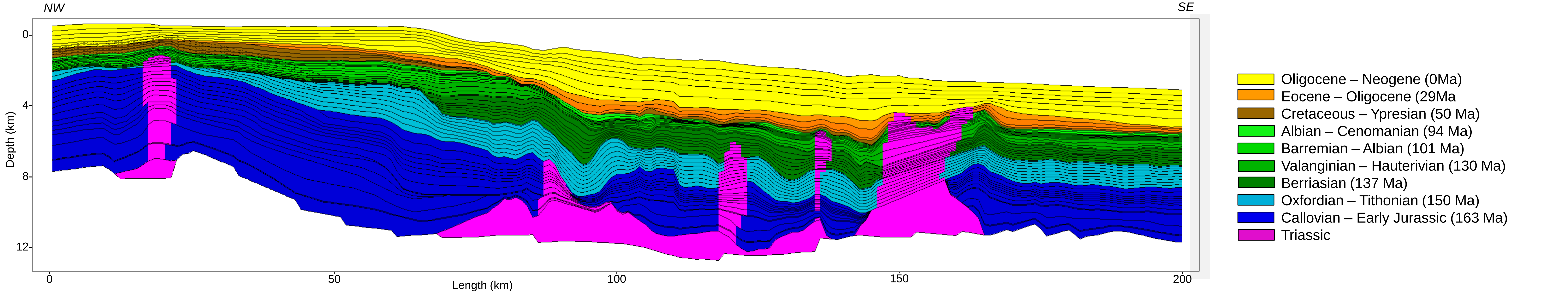




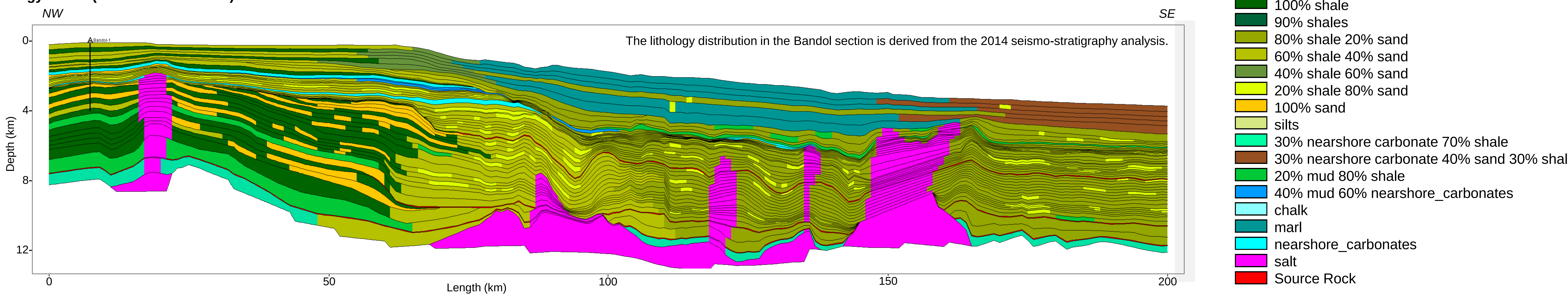
* The Tithonian / Berriasian sandstones contain the main accumulations modeled in TemisFlow for the Dauntless section

2D Modeling
Bandol Section

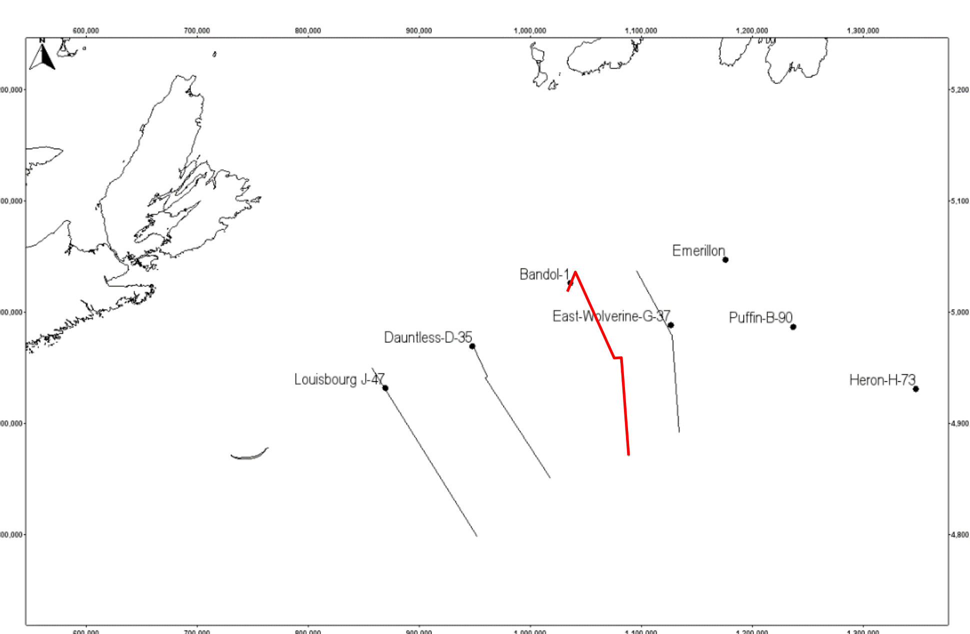
Stratigraphic Model (Reference Scenario)



Lithology Model (Reference Scenario)

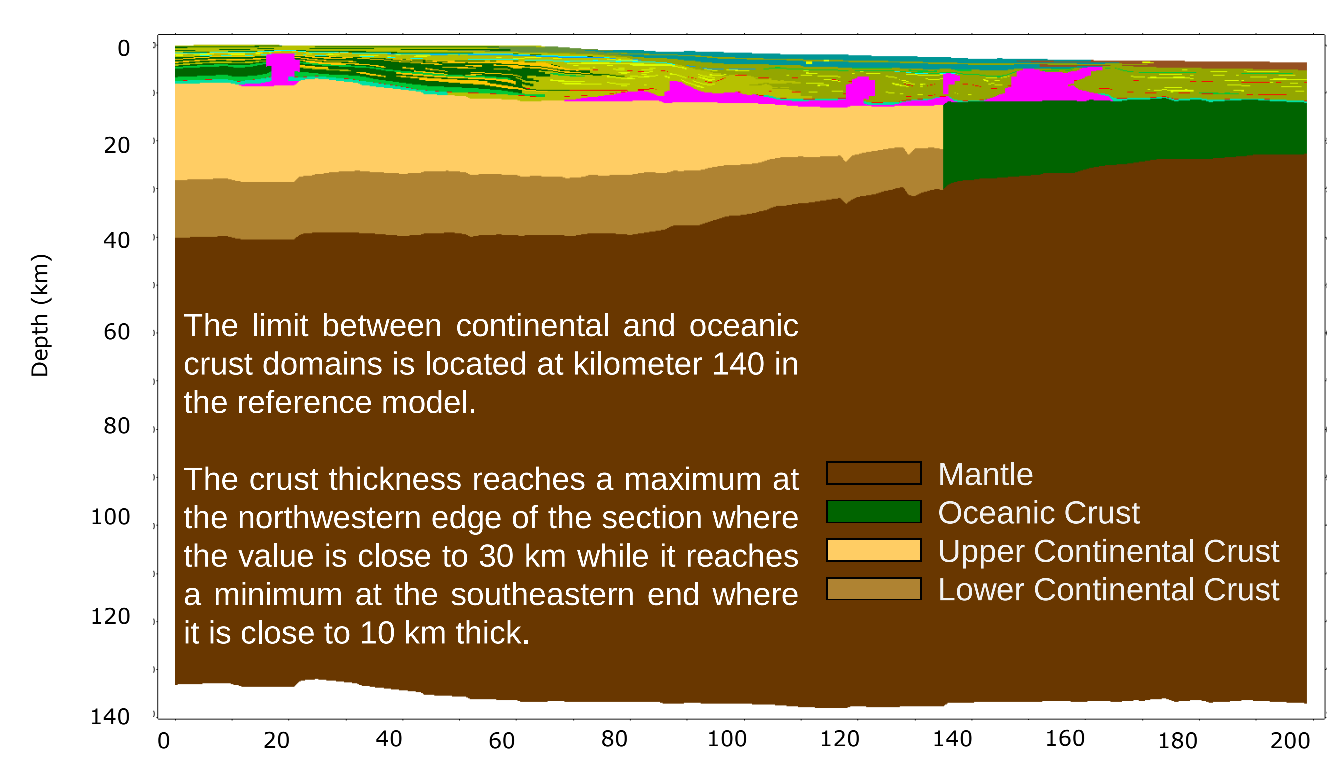


Location Map

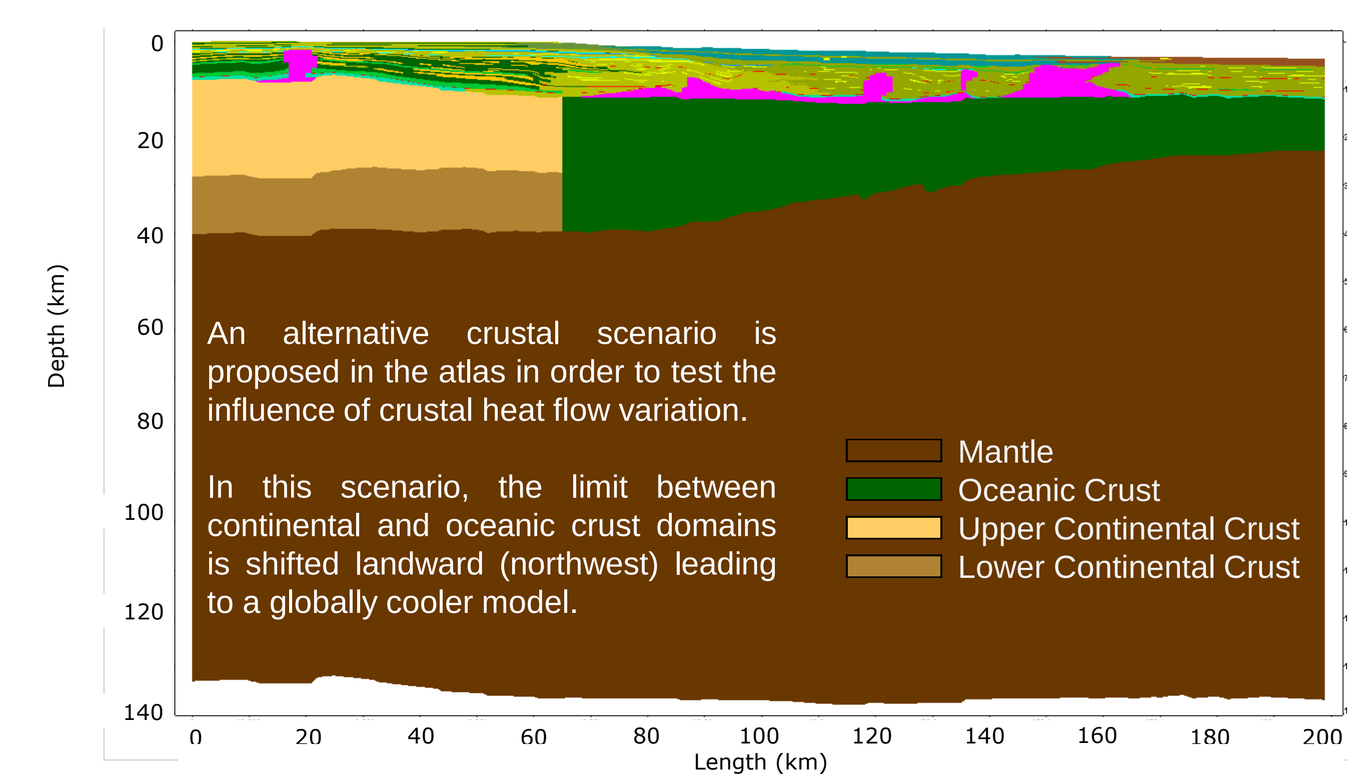


Bandol section trace intersects Bandol-1 well location. The well features mud weight, temperature & vitrinite measurements which have been used for calibration purposes.

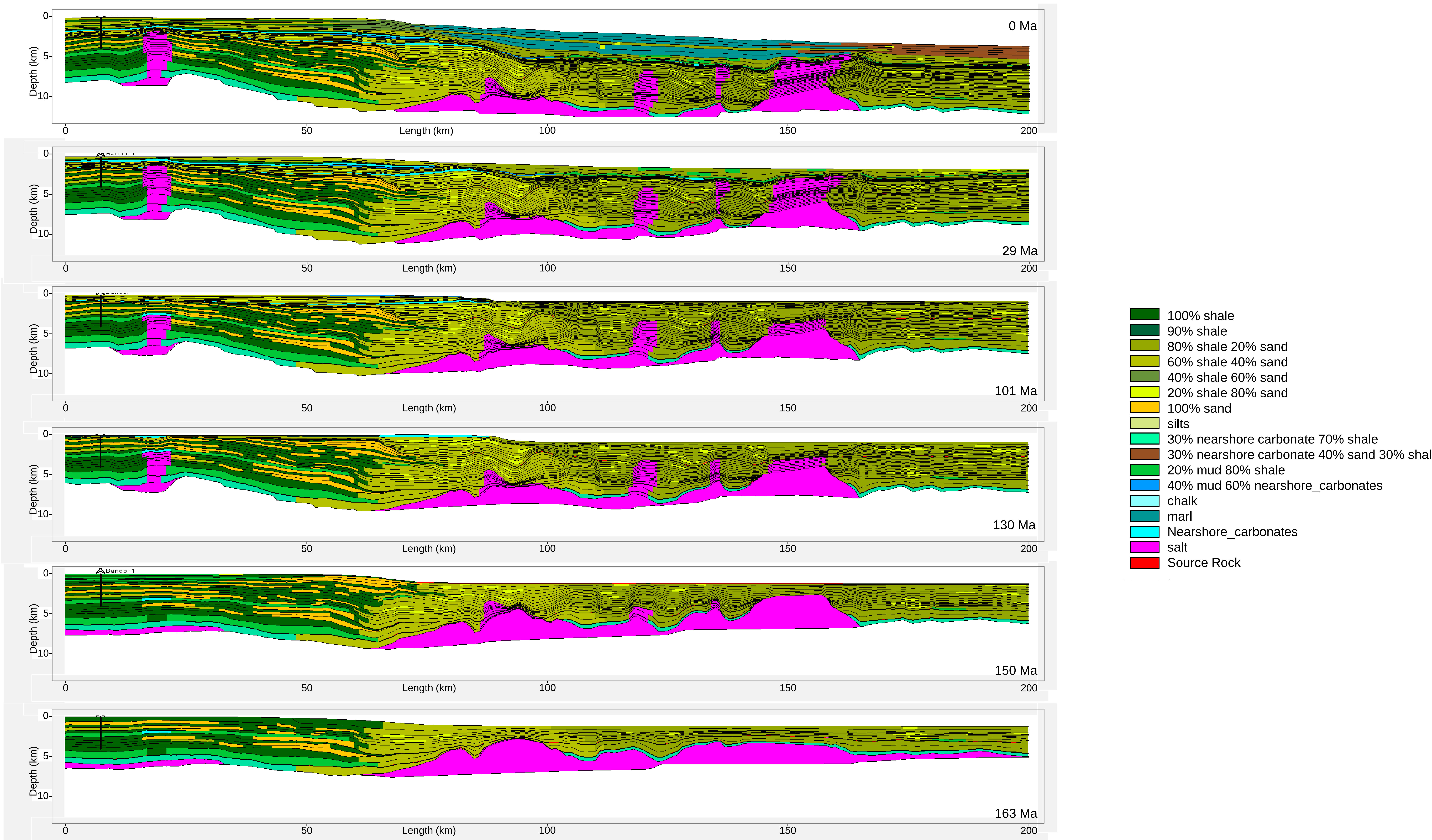
Thermal Basement Model – Scenario 1 (= Reference Scenario)



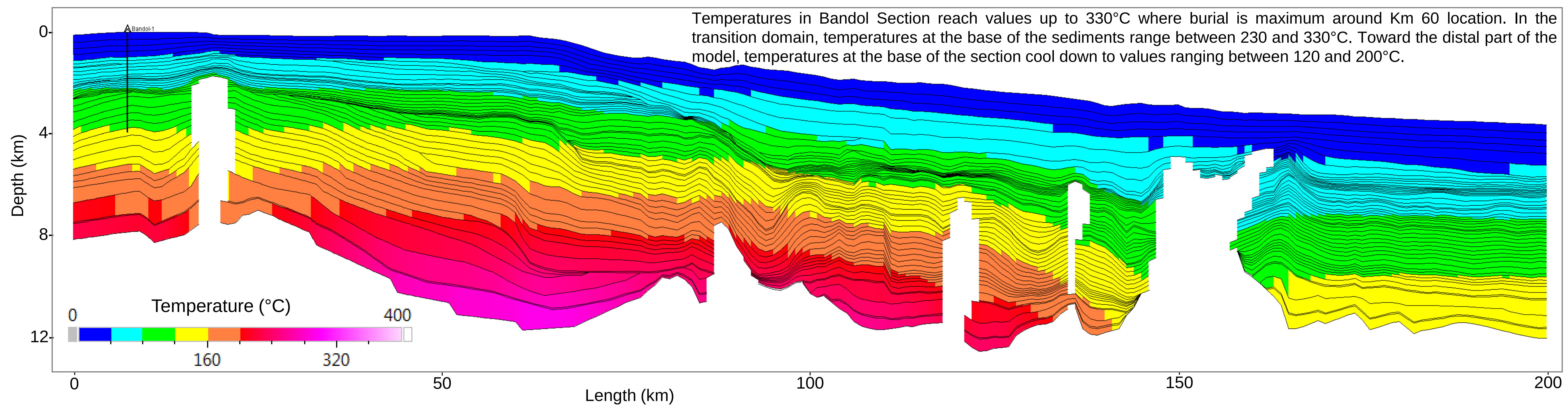
Thermal Basement Model – Scenario 2 (= Heat Flow Variation)



Stratigraphy, Lithology, Basement Model and Location Map of Bandol Section **PLATE 9.41**

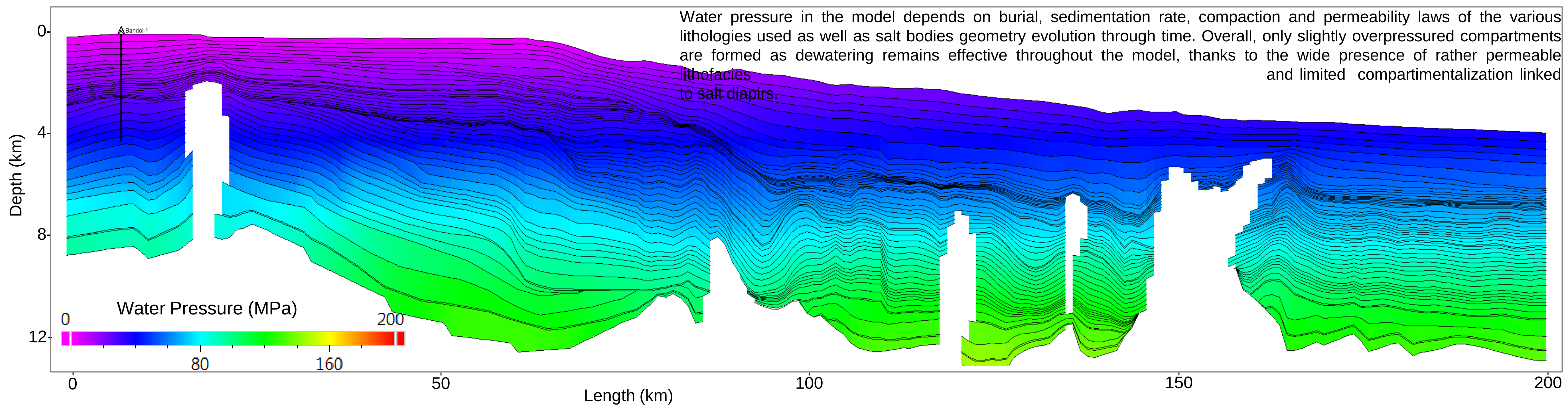

0 Ma
29 Ma
101 Ma
130 Ma
150 Ma
163 Ma
Bandol-1
Depth (km)
Length (km)
0
5
10
50
100
150
200
100% shale
90% shale
80% shale 20% sand
60% shale 40% sand
40% shale 60% sand
20% shale 80% sand
100% sand
silts
30% nearshore carbonate 70% shale
30% nearshore carbonate 40% sand 30% shale
20% mud 80% shale
40% mud 60% nearshore_carbonates
chalk
marl
Nearshore_carbonates
salt
Source Rock

Temperature (Reference Scenario)



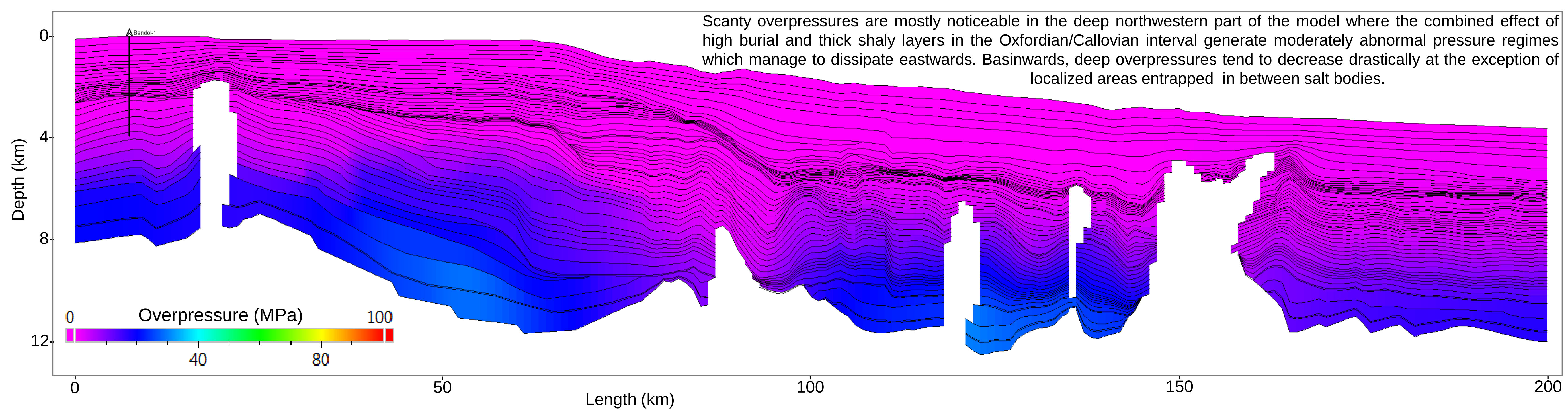
Temperatures in Bandol Section reach values up to 330°C where burial is maximum around Km 60 location. In the transition domain, temperatures at the base of the sediments range between 230 and 330°C. Toward the distal part of the model, temperatures at the base of the section cool down to values ranging between 120 and 200°C.

Water Pressure (Reference Scenario)



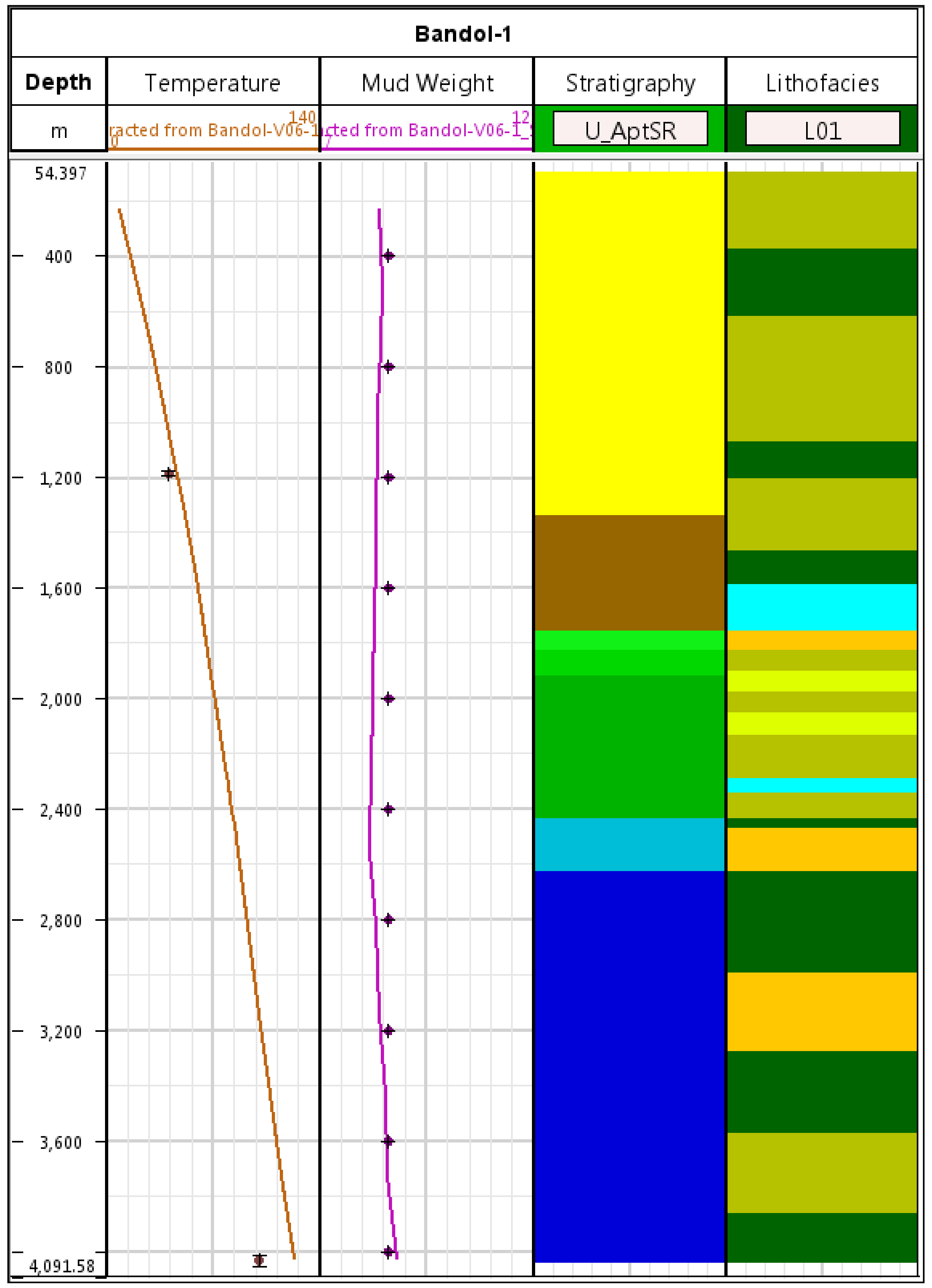
Water pressure in the model depends on burial, sedimentation rate, compaction and permeability laws of the various lithologies used as well as salt bodies geometry evolution through time. Overall, only slightly overpressured compartments are formed as dewatering remains effective throughout the model, thanks to the wide presence of rather permeable lithofacies and limited compartimentalization linked to salt diapirs.

Overpressure (Reference Scenario)



Scanty overpressures are mostly noticeable in the deep northwestern part of the model where the combined effect of high burial and thick shaly layers in the Oxfordian/Callovian interval generate moderately abnormal pressure regimes which manage to dissipate eastwards. Basinwards, deep overpressures tend to decrease drastically at the exception of localized areas entrapped in between salt bodies.

Calibration (Reference Scenario)



Temperature & Pressure models are calibrated versus available observed data at Bandol-1 well location:

- Observed data is represented with dots
- Simulated data is represented with continuous, thick lines

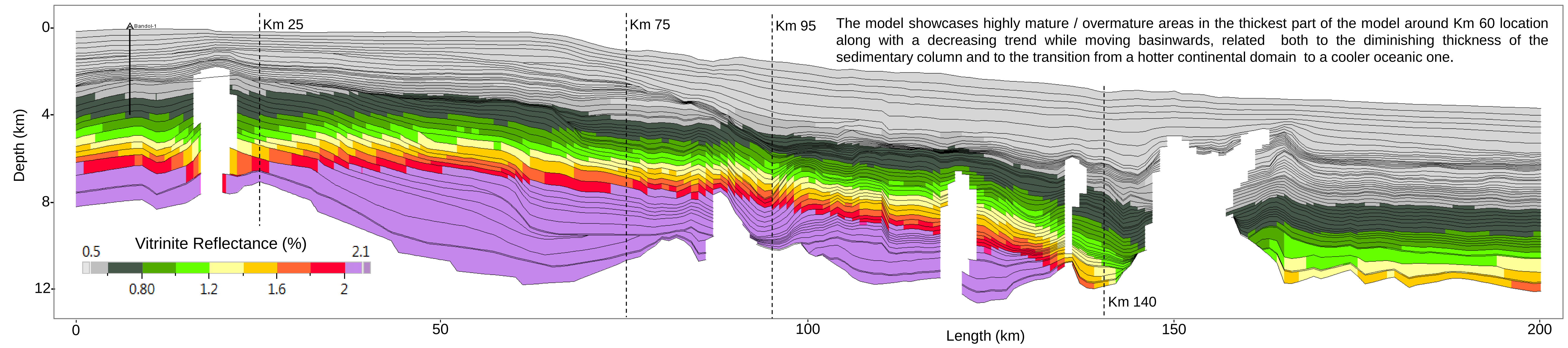
Temperature calibration is satisfactory.

Pressure calibration is satisfactory: the mud weight profile remains linear as the pressure distribution along the well path is roughly hydrostatic as illustrated by the 2D overpressure model.

BASIN MODELING

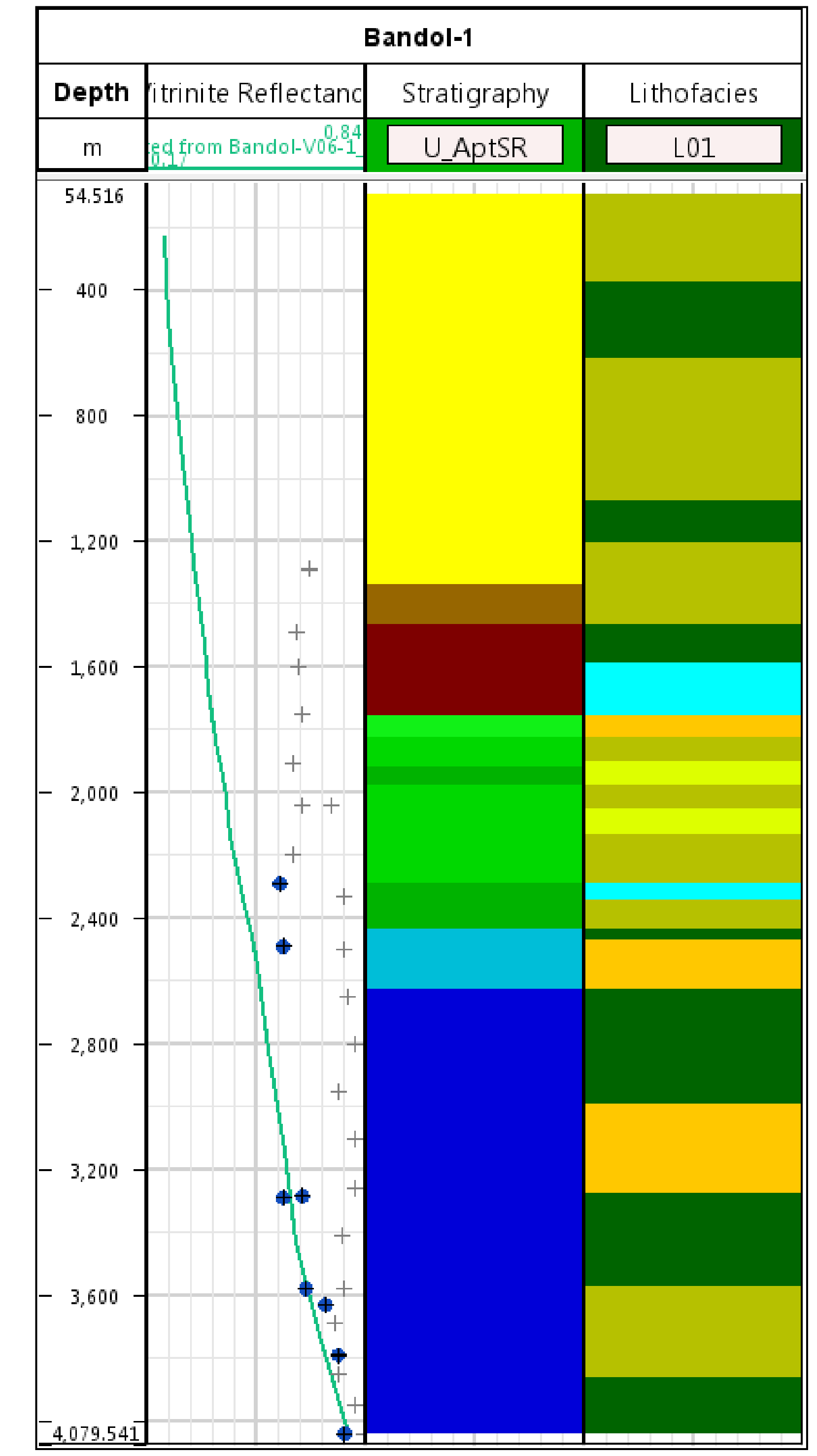
Laurentian sub-basin study - CANADA – June 2014

Vitrinite Reflectance (Reference Scenario)



The model showcases highly mature / overmature areas in the thickest part of the model around Km 60 location along with a decreasing trend while moving basinwards, related both to the diminishing thickness of the sedimentary column and to the transition from a hotter continental domain to a cooler oceanic one.

Calibration (Reference Scenario)

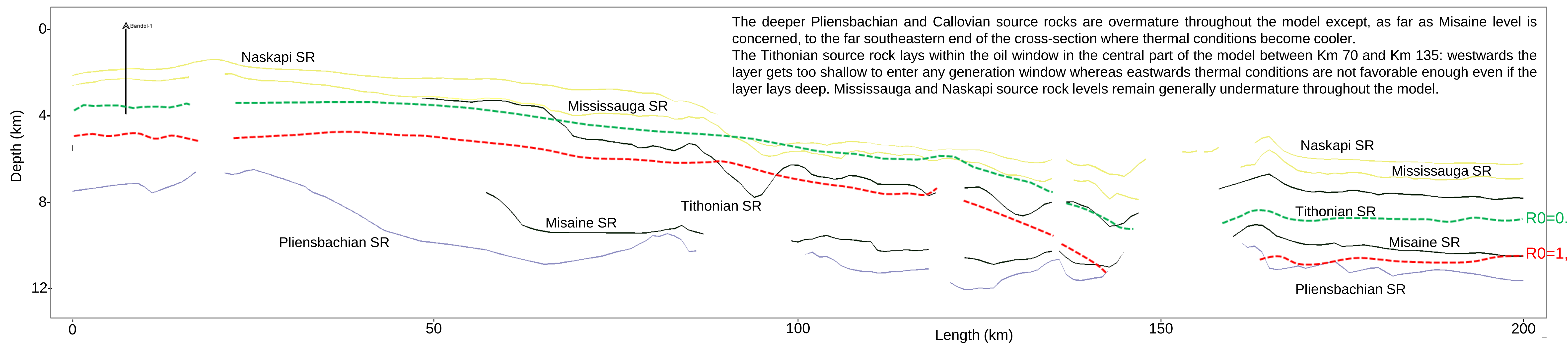


Vitrinite model is calibrated versus available observed data at Bandol-1 well location:

- Observed data is represented with dots,
- Simulated data is represented with thick line.

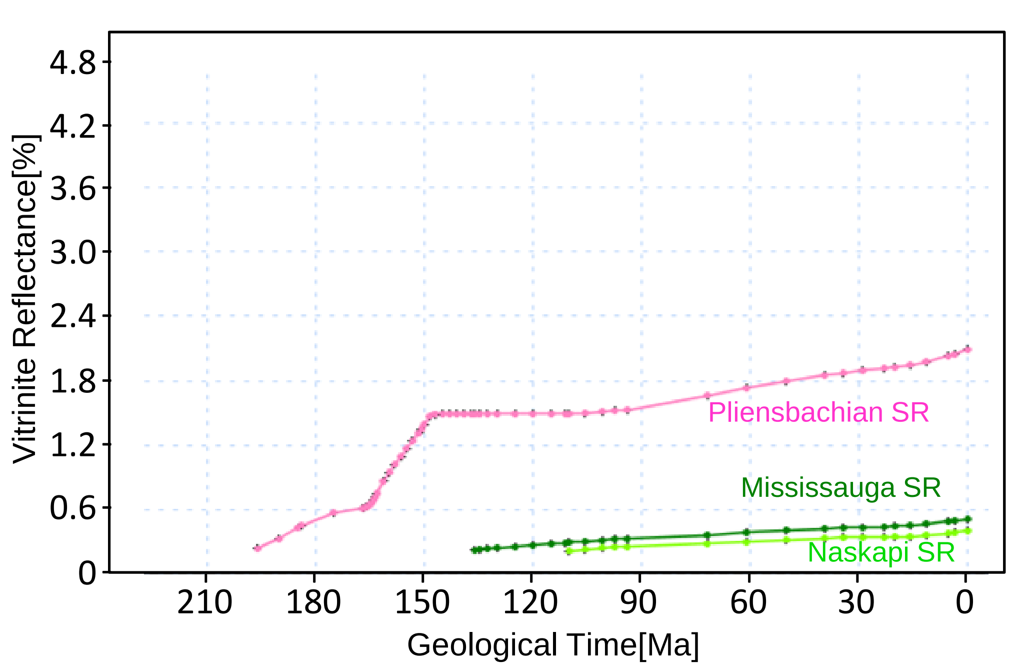
Vitrinite calibration at Bandol-1 well location falls under the measurements uncertainty range.

Oil & Gas Windows

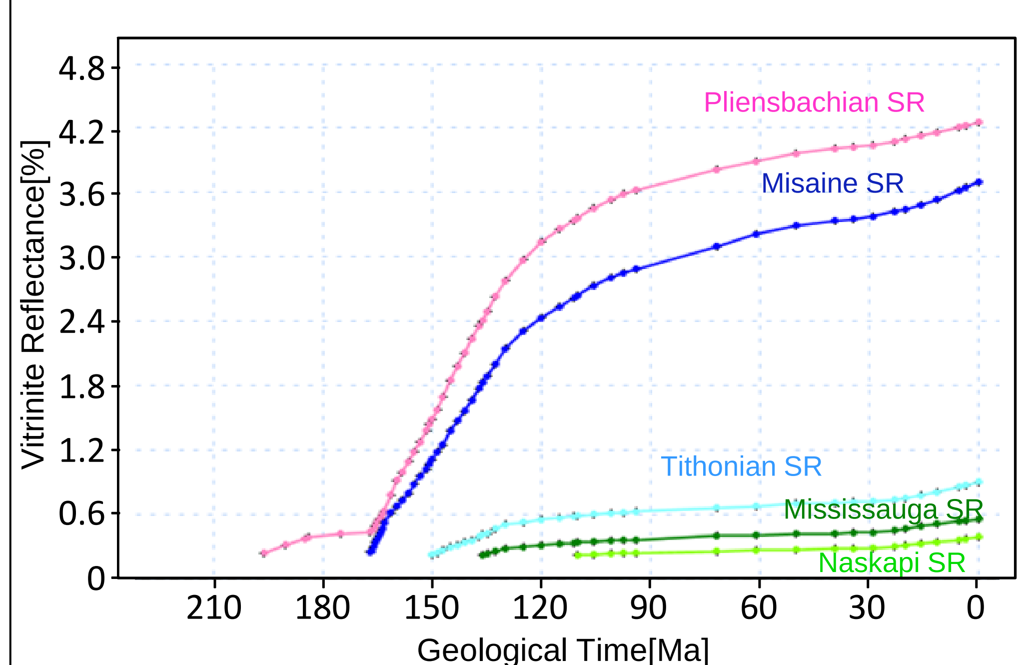


The deeper Pliensbachian and Callovian source rocks are overmature throughout the model except, as far as Misaine level is concerned, to the far southeastern end of the cross-section where thermal conditions become cooler.
The Tithonian source rock lays within the oil window in the central part of the model between Km 70 and Km 135: westwards the layer gets too shallow to enter any generation window whereas eastwards thermal conditions are not favorable enough even if the layer lays deep. Mississauga and Naskapi source rock levels remain generally undermature throughout the model.

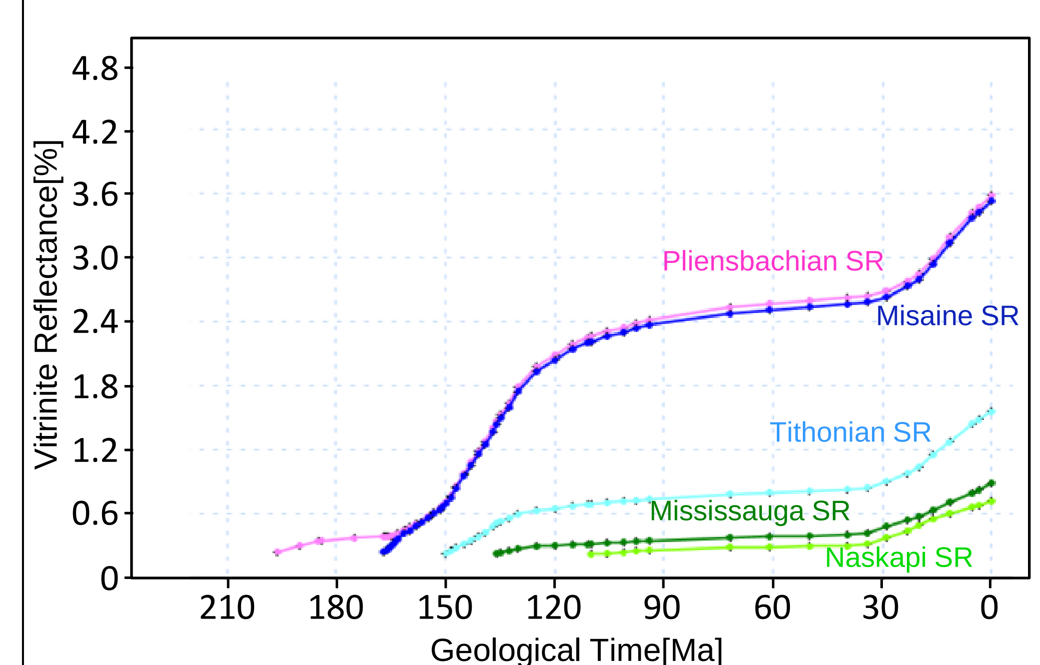
Vitrinite Reflectance through time at Km 25 Location



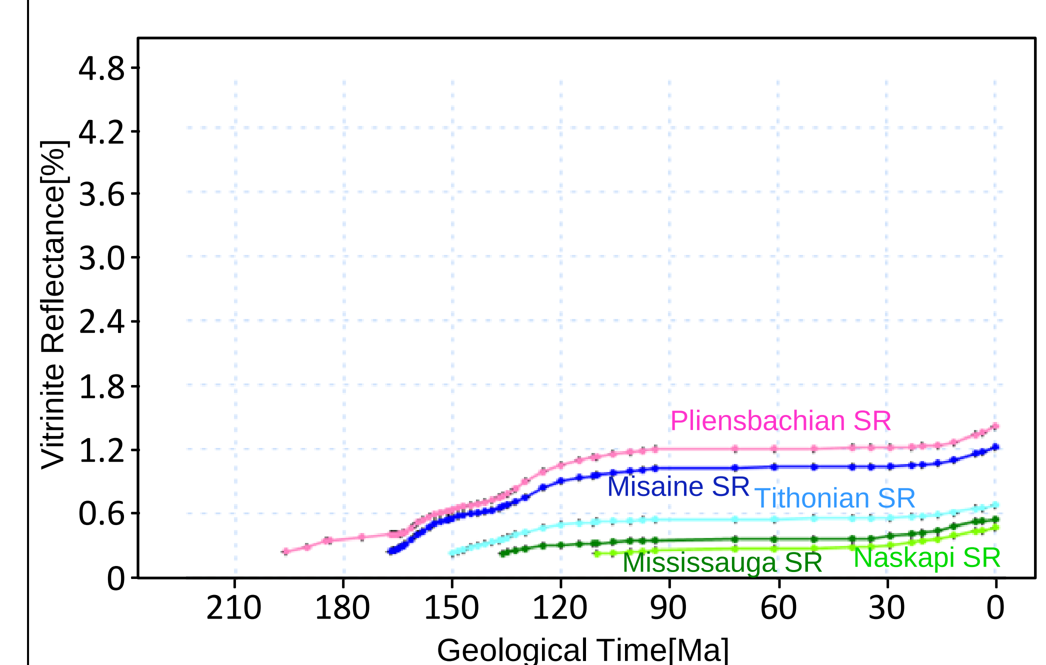
Vitrinite Reflectance through time at Km 75 Location



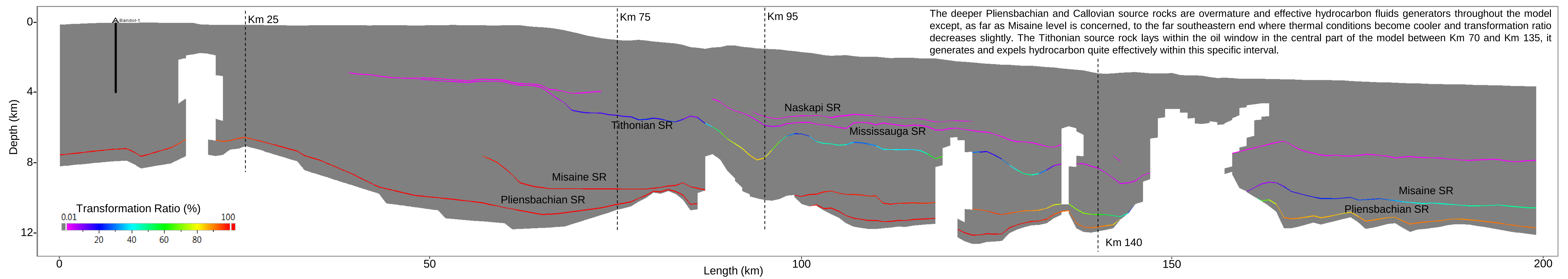
Vitrinite Reflectance through time at Km 95 Location



Vitrinite Reflectance through time at Km 140 Location

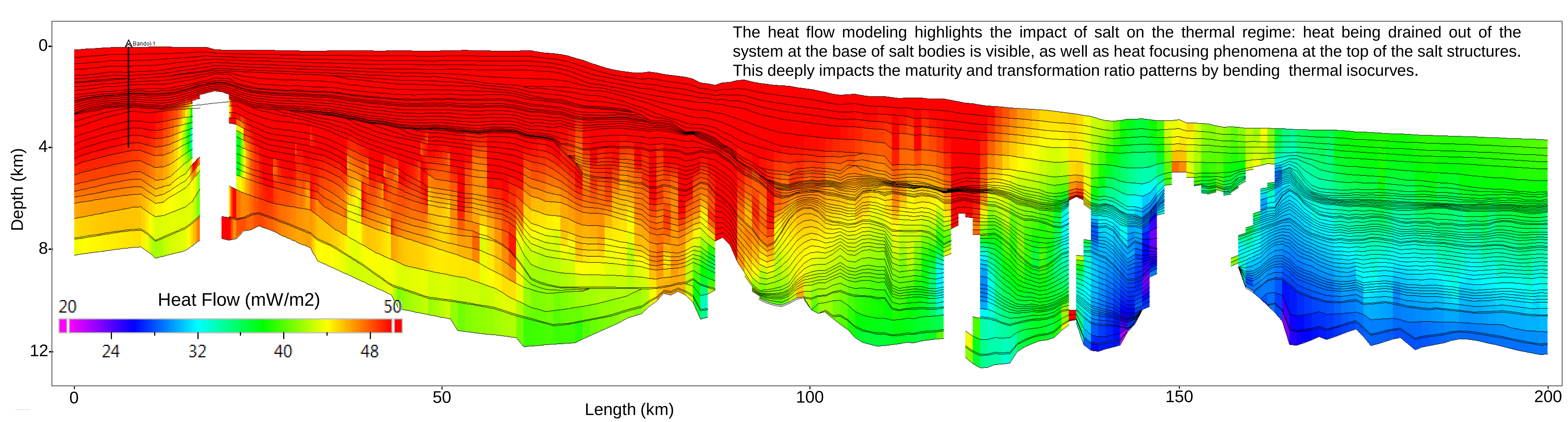


Transformation Ratio (Reference Scenario)



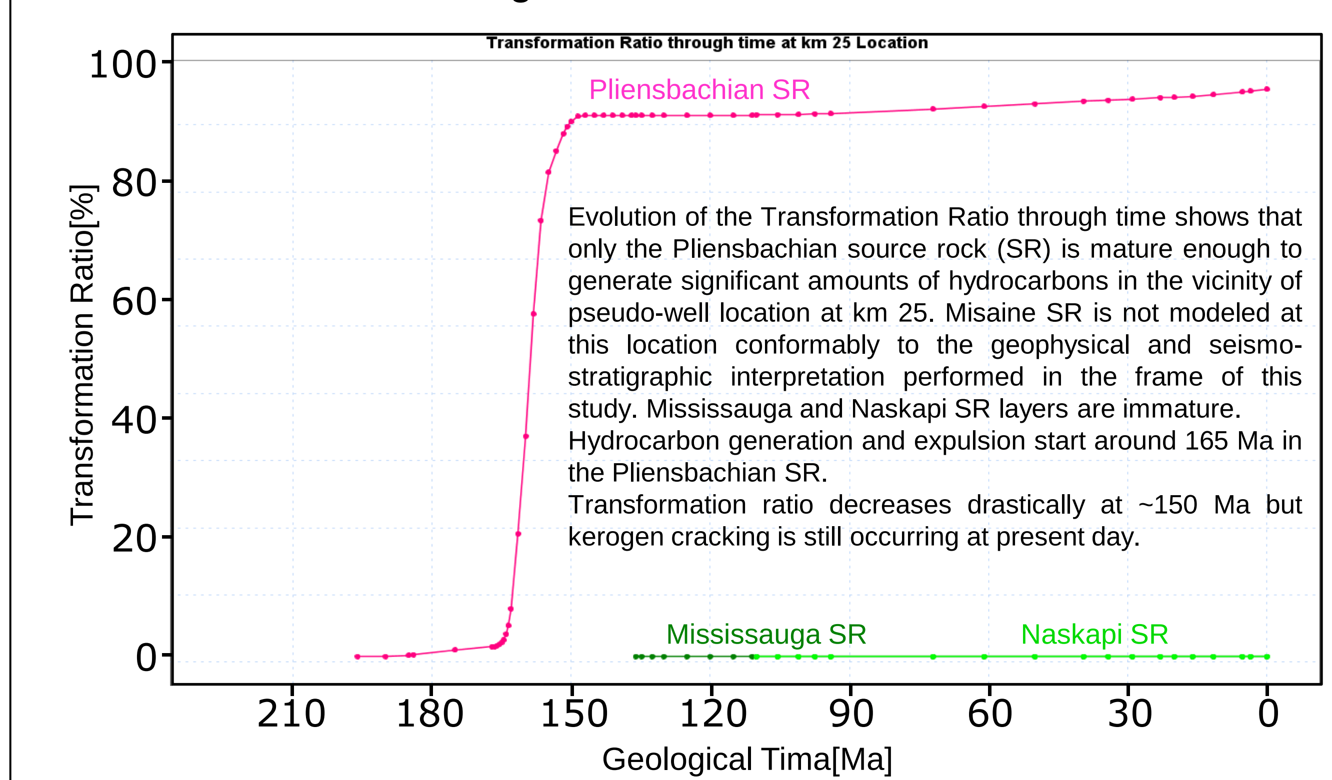
The deeper Pliensbachian and Callovian source rocks are overmature and effective hydrocarbon fluids generators throughout the model except, as far as Misaine level is concerned, to the far southeastern end where thermal conditions become cooler and transformation ratio decreases slightly. The Tithonian source rock lays within the oil window in the central part of the model between Km 70 and Km 135, it generates and expels hydrocarbon quite effectively within this specific interval.

Heat Flow (Reference Scenario)



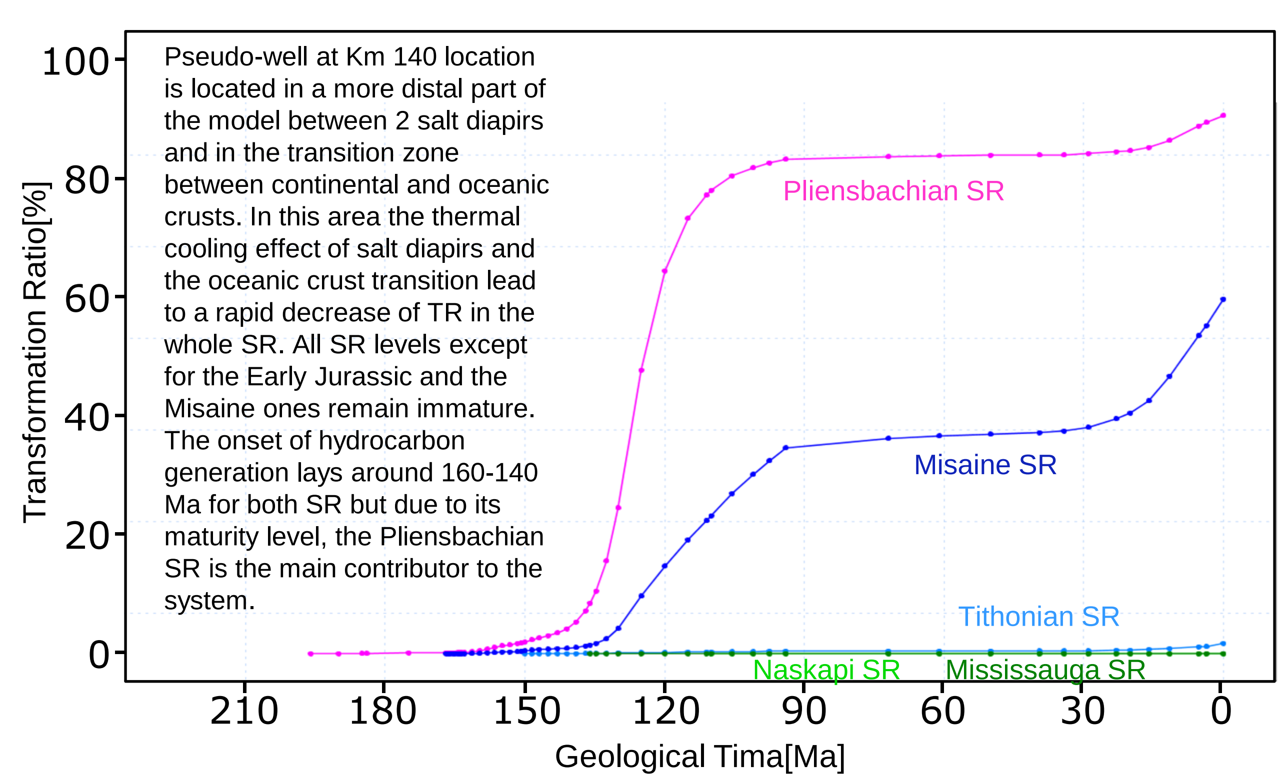
The heat flow modeling highlights the impact of salt on the thermal regime: heat being drained out of the system at the base of salt bodies is visible, as well as heat focusing phenomena at the top of the salt structures. This deeply impacts the maturity and transformation ratio patterns by bending thermal isocurves.

Transformation Ratio through time at km 25 Location



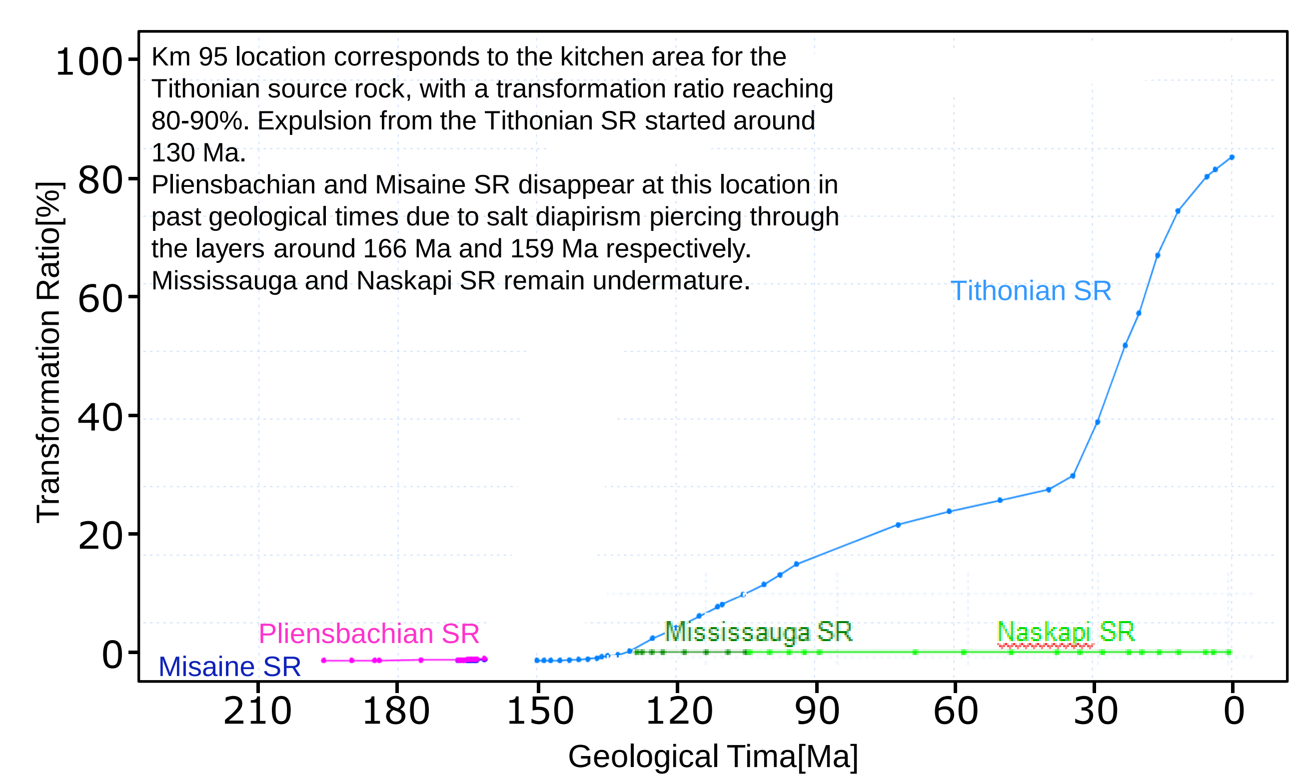
Evolution of the Transformation Ratio through time shows that only the Pliensbachian source rock (SR) is mature enough to generate significant amounts of hydrocarbons in the vicinity of pseudo-well location at km 25. Misaine SR is not modeled at this location conformably to the geophysical and seismo-stratigraphic interpretation performed in the frame of this study. Mississauga and Naskapi SR layers are immature. Hydrocarbon generation and expulsion start around 165 Ma in the Pliensbachian SR. Transformation ratio decreases drastically at ~150 Ma but kerogen cracking is still occurring at present day.

Transformation Ratio through time at km 140 Location



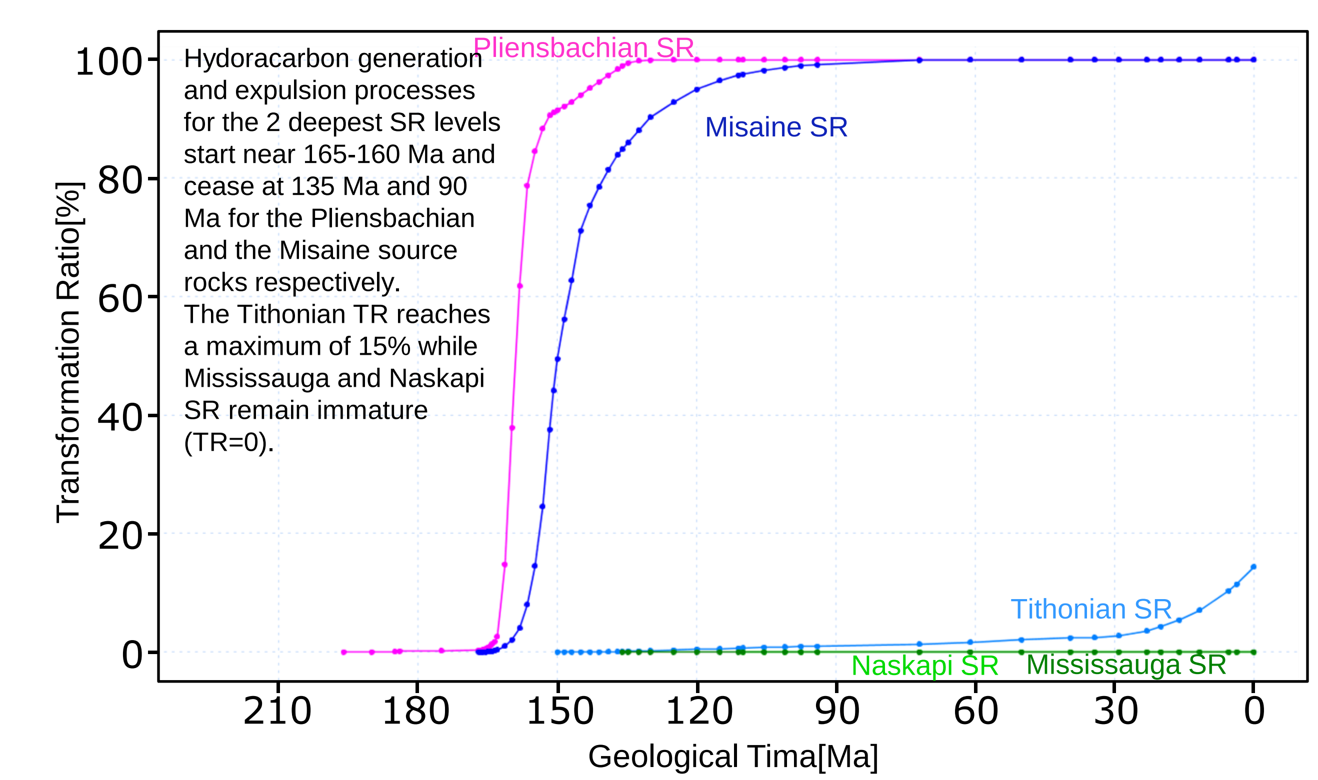
Pseudo-well at Km 140 location is located in a more distal part of the model between 2 salt diapirs and in the transition zone between continental and oceanic crusts. In this area the thermal cooling effect of salt diapirs and the oceanic crust transition lead to a rapid decrease of TR in the whole SR. All SR levels except for the Early Jurassic and the Misaine ones remain immature. The onset of hydrocarbon generation lays around 160-140 Ma for both SR but due to its maturity level, the Pliensbachian SR is the main contributor to the system.

Transformation Ratio through time at km 95 Location



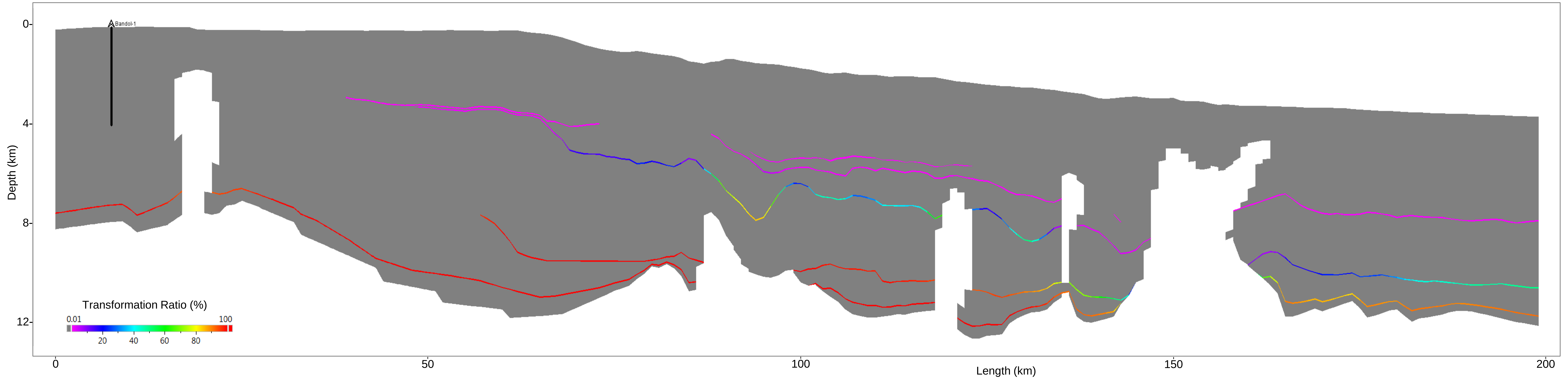
Km 95 location corresponds to the kitchen area for the Tithonian source rock, with a transformation ratio reaching 80-90%. Expulsion from the Tithonian SR started around 130 Ma. Pliensbachian and Misaine SR disappear at this location in past geological times due to salt diapirism piercing through the layers around 166 Ma and 159 Ma respectively. Mississauga and Naskapi SR remain undermature.

Transformation Ratio through time at km 75 Location



Hydoracarbon generation and expulsion processes for the 2 deepest SR levels start near 165-160 Ma and cease at 135 Ma and 90 Ma for the Pliensbachian and the Misaine source rocks respectively. The Tithonian TR reaches a maximum of 15% while Mississauga and Naskapi SR remain immature (TR=0).

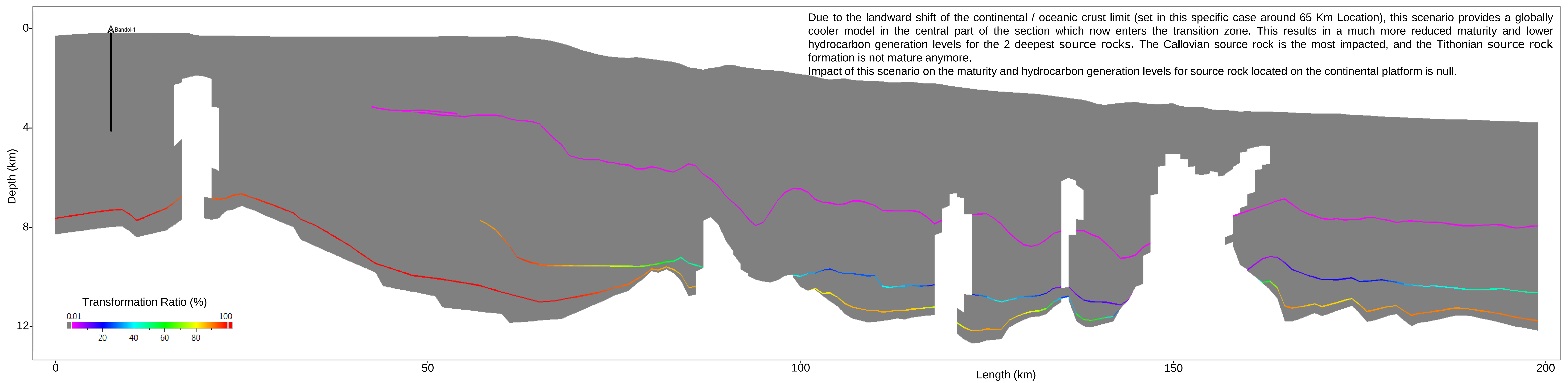
Transformation Ratio (Reference Scenario)



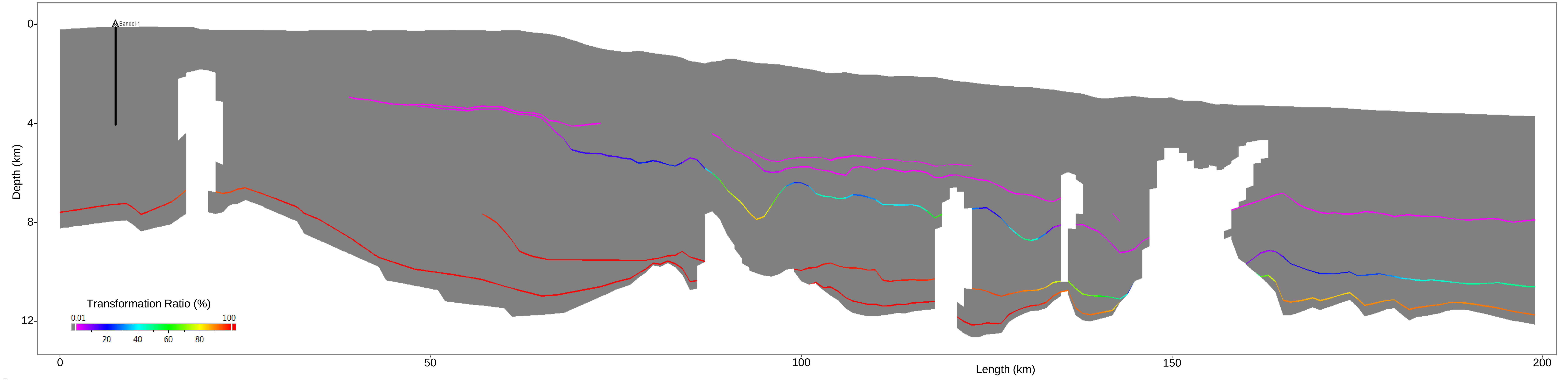
Transformation Ratio (Scenario 2 = Heat Flow variation)

Due to the landward shift of the continental / oceanic crust limit (set in this specific case around 65 Km Location), this scenario provides a globally cooler model in the central part of the section which now enters the transition zone. This results in a much more reduced maturity and lower hydrocarbon generation levels for the 2 deepest source rocks. The Callovian source rock is the most impacted, and the Tithonian source rock formation is not mature anymore.

Impact of this scenario on the maturity and hydrocarbon generation levels for source rock located on the continental platform is null.

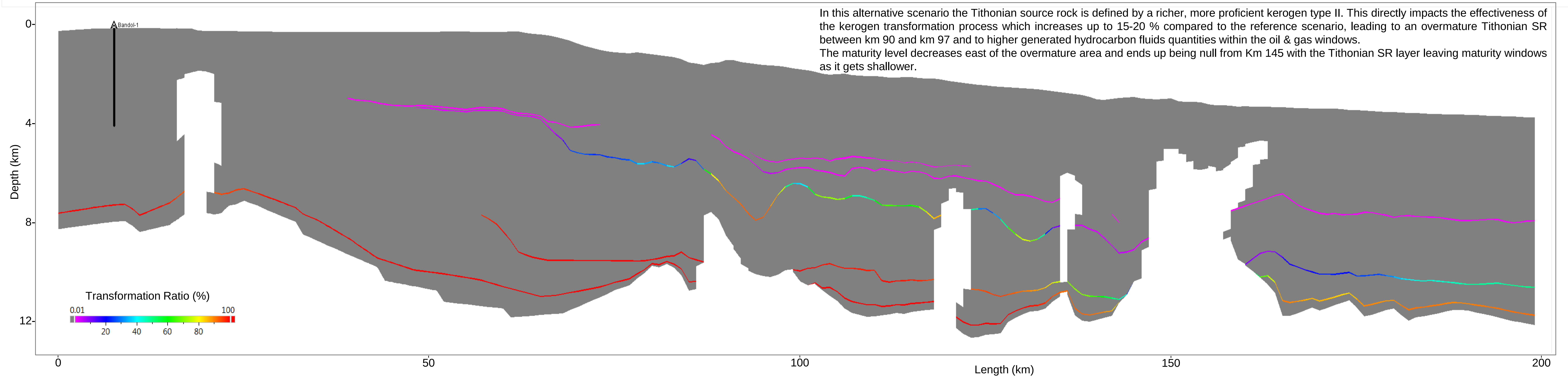


Transformation Ratio (Reference Scenario)

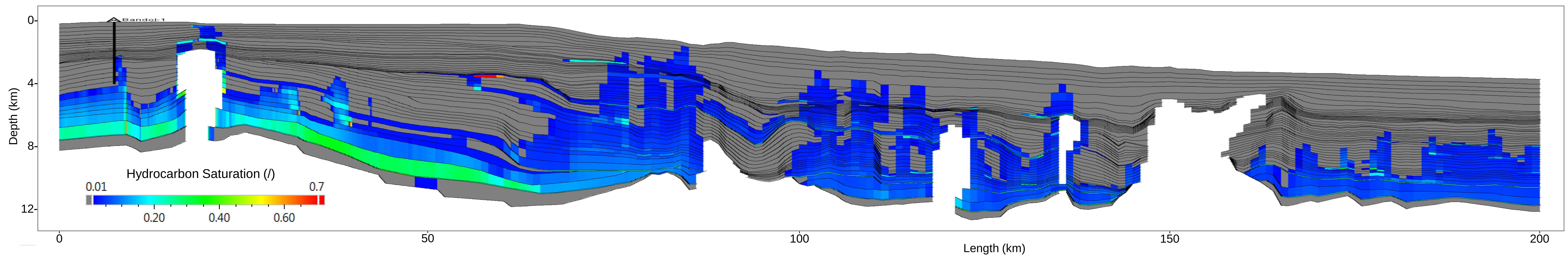


Transformation Ratio (Scenario 3 = Tithonian Type II)

In this alternative scenario the Tithonian source rock is defined by a richer, more proficient kerogen type II. This directly impacts the effectiveness of the kerogen transformation process which increases up to 15-20 % compared to the reference scenario, leading to an overmature Tithonian SR between km 90 and km 97 and to higher generated hydrocarbon fluids quantities within the oil & gas windows.
The maturity level decreases east of the overmature area and ends up being null from Km 145 with the Tithonian SR layer leaving maturity windows as it gets shallower.

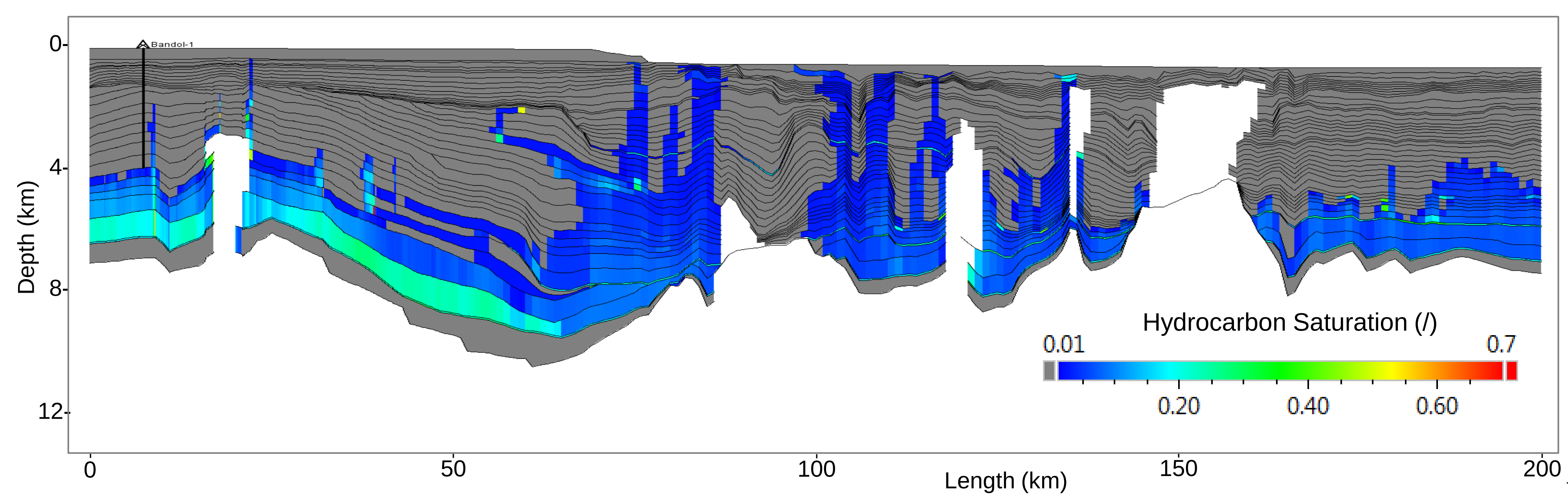


Hydrocarbon Saturation at Present Day (Reference Scenario)



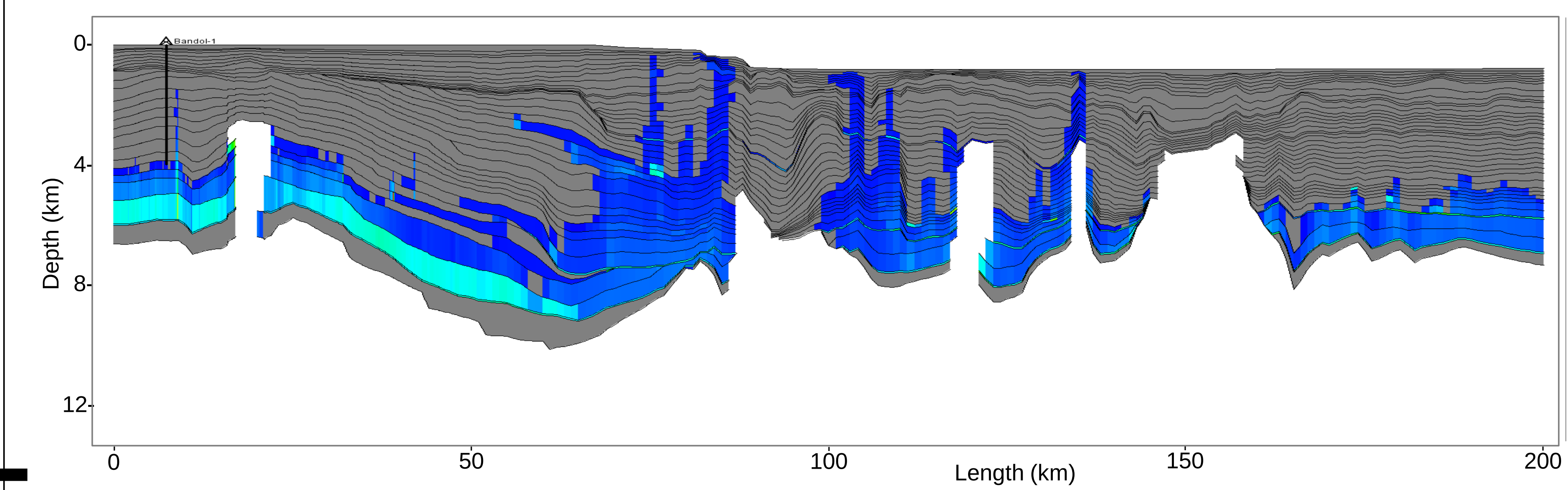
The shallowest hydrocarbon accumulations may be observed in the Cretaceous/Ypresian interval within the chalk deposits at Km 20 and Km 75.
Another significant accumulation is located at Km 60 within the Oxfordian/ Tithonian sand bodies which acted as an efficient plumbing system. The accumulation is sealed by the shaly Tithonian layer.
Additional accumulations are found along diapir flanks (at Km 15, Km 25 and Km 135 for instance in the Callovian/Jurassic interval) and in tiny, localized stratigraphic traps (at Km 30 and Km 39 in the Callovian/Jurassic interval, at Km 115 in the Oxfordian/ Tithonian interval).

Hydrocarbon Saturation at 72 Ma (Reference Scenario)



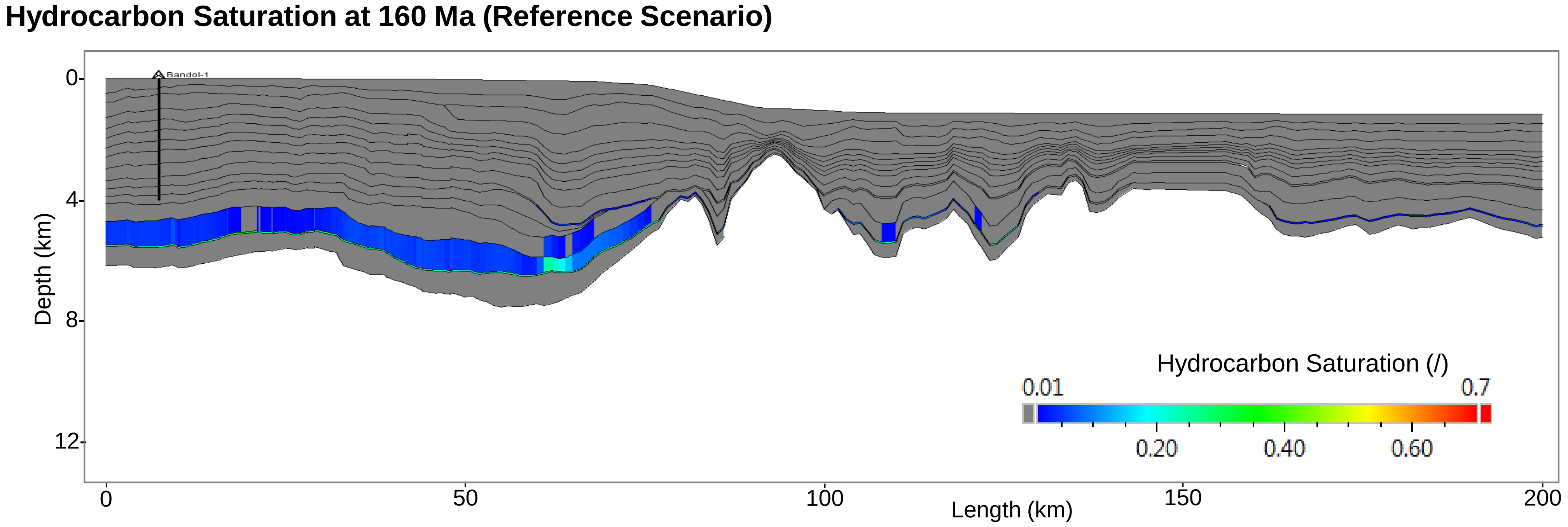
Vertical migration continues, allowing some hydrocarbons to seep to the surface while some noticeable accumulations begin to form (top of the diapir at Km 135 or against the diapir flank at Km 136 just below the Tithonian source rock layer which also acts as a seal there).
Around Km 60 migration through the massive Oxfordian/ Tithonian sand bodies goes on and generates additional accumulations.
At Km 20 hydrocarbon pressure becomes sufficient for overcoming capillary pressure barriers and piercing through the shaly Callovian layers.

Hydrocarbon Saturation at 101 Ma (Reference Scenario)



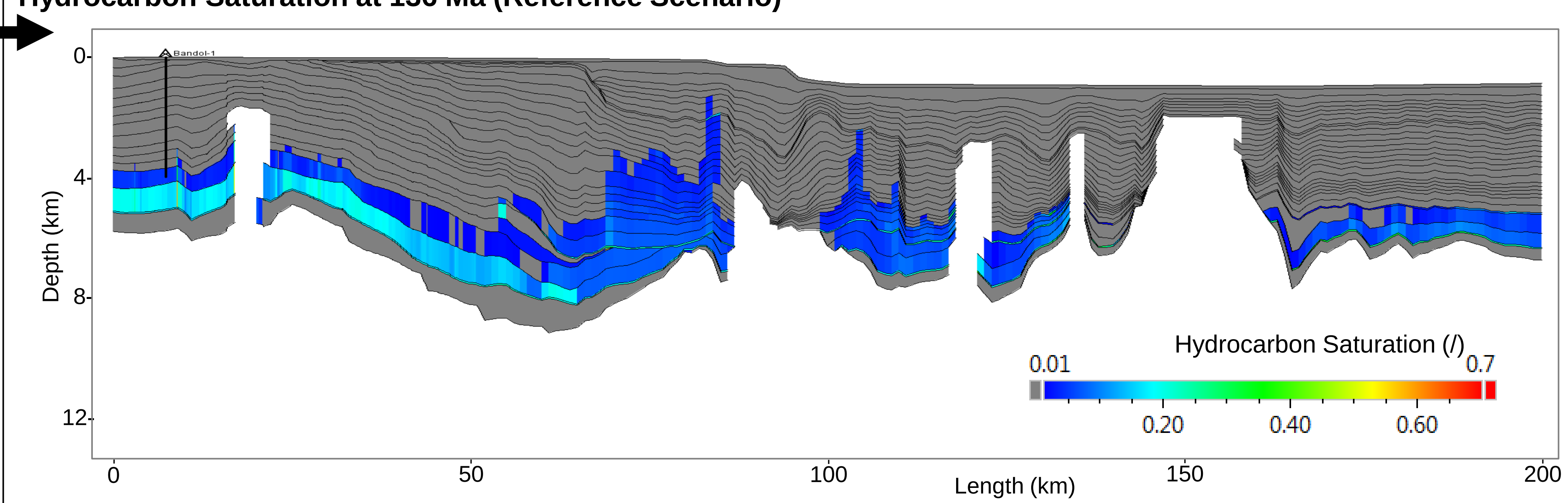
The vertical migration process described at the previous time step continues and spreads to other locations of the section. It is even strengthened by the contribution of the Tithonian SR layer to the overall quantity of expelled hydrocarbon fluids, allowing the latter to reach shallower layers through higher hydrocarbon pressure.
Salt bodies favor this vertical migration process by focusing hydrocarbon fluids.
Lateral migration starts through highly permeable sand bodies in the Oxfordian/ Tithonian interval at Km 70 location.

Hydrocarbon Saturation at 160 Ma (Reference Scenario)



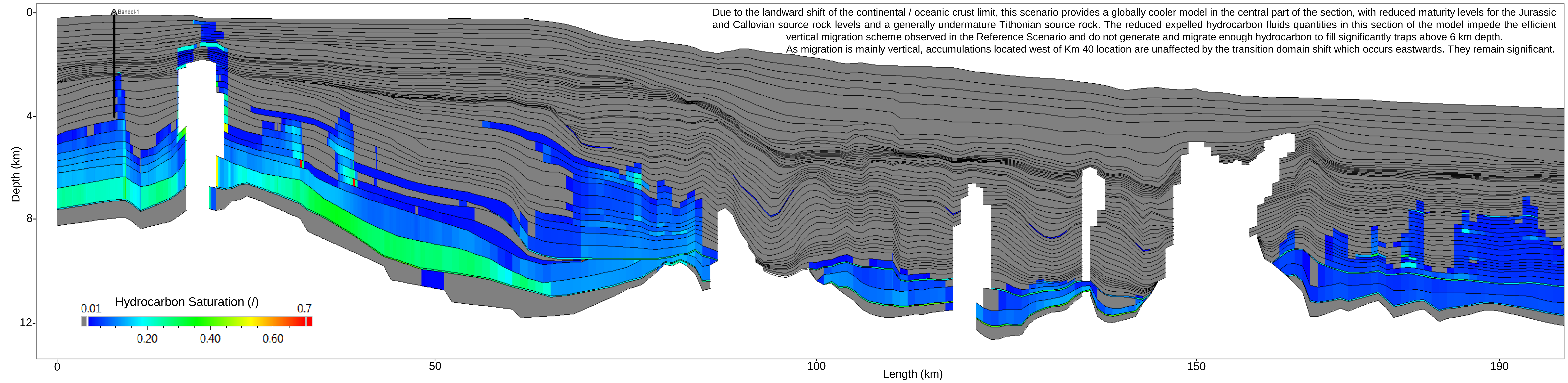
Hydrocarbon fluids expulsion begins from the deepest, more mature source rock level (Pliensbachian).

Hydrocarbon Saturation at 136 Ma (Reference Scenario)

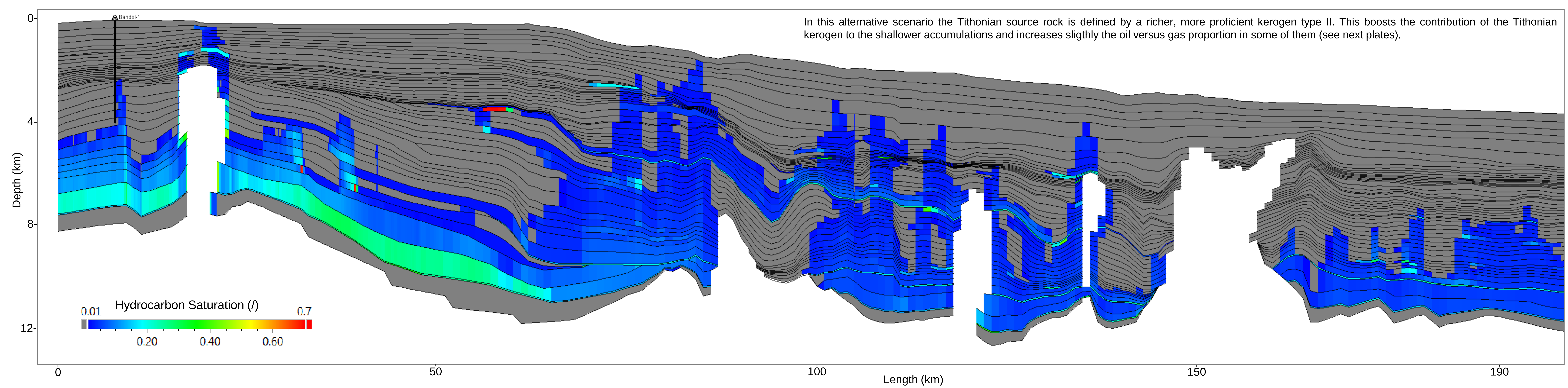


Hydrocarbon fluids expulsion from the Pliensbachian source rock level spreads throughout the section as maturity conditions become more favorable. Misaine source rock layer expels hydrocarbon fluids in the central part of the model.
Between Km 70 and Km 115, the combined effect of a rather permeable sedimentary column, favorable pressure conditions and significant free hydrocarbon fluids quantities initiate an efficient vertical migration process with fluids successfully piercing through capillary barriers on a 2 to 4 km long vertical pathway.

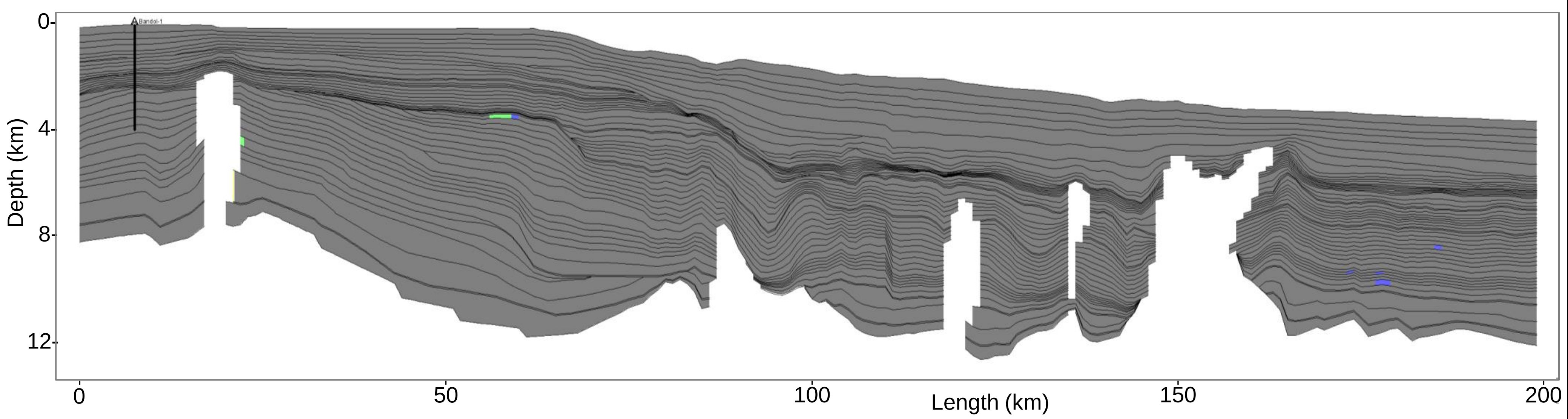
Hydrocarbon Saturation (Scenario 2 = Heat Flow variation)



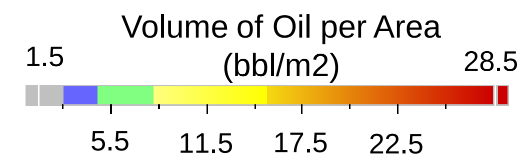
Hydrocarbon Saturation (Scenario 3 = Tithonian Type II)



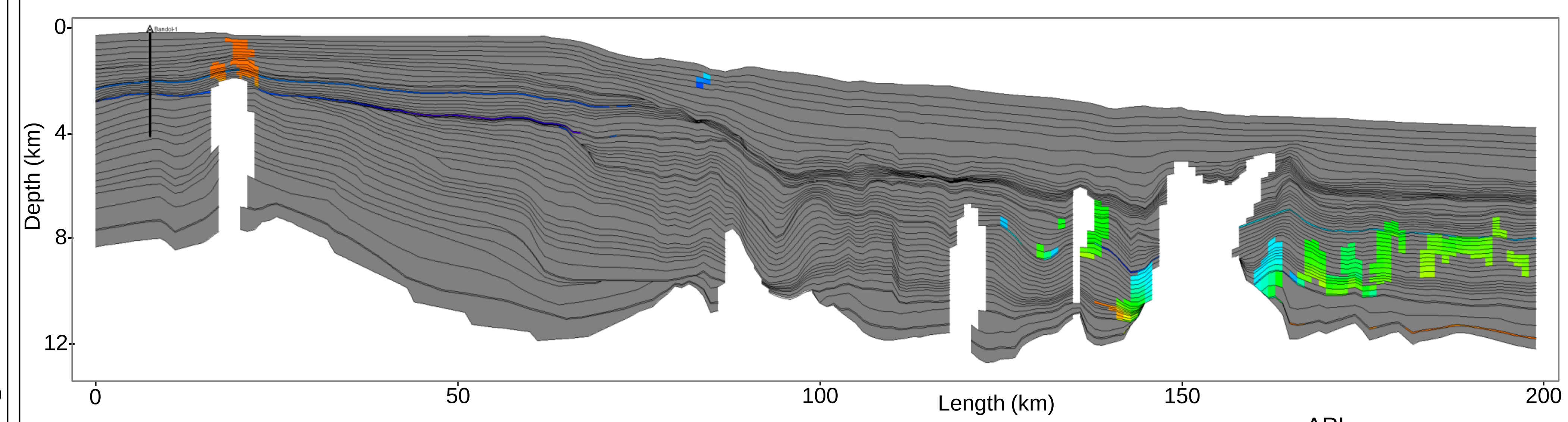
Volume of Oil per Area (Reference Scenario)



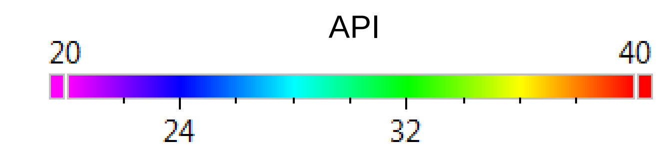
Mass of Oil is less than ~3.57bbl/m² in the model. The over-mature state of the deepest source rocks layers which are the main contributors to the Petroleum System, the types of kerogen as well as the thermal conditions are favorable to secondary cracking and explain this result.
Fair quantities of oil may be expected within the Oxfordian/ Tithonian sand bodies located at Km 60 and in the accumulation located against the salt diapir at Km 25.



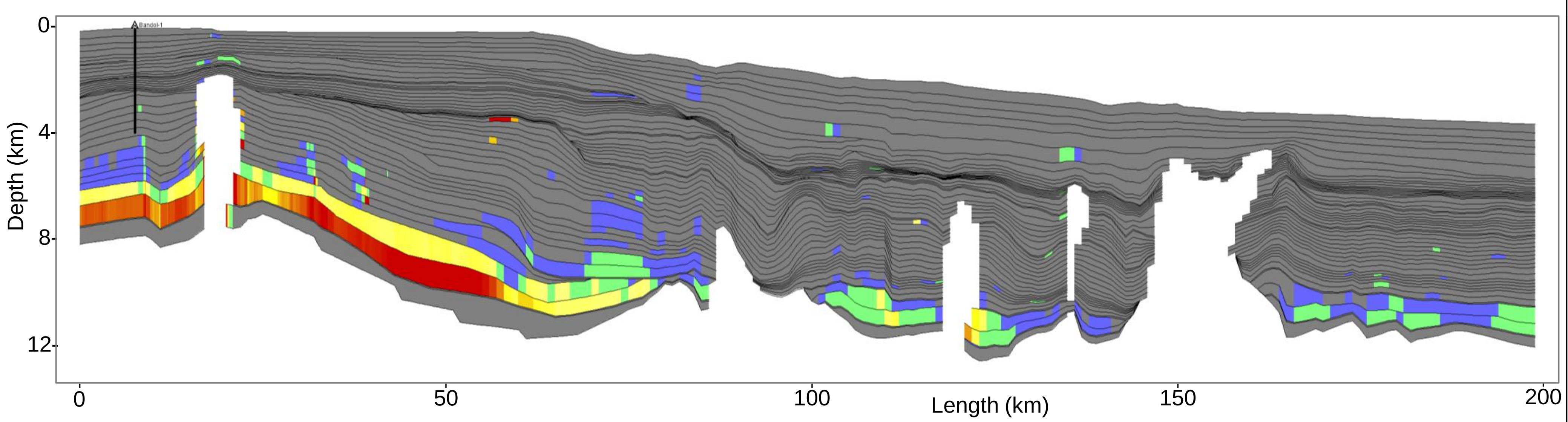
API Gravity - Oil (Reference Scenario)



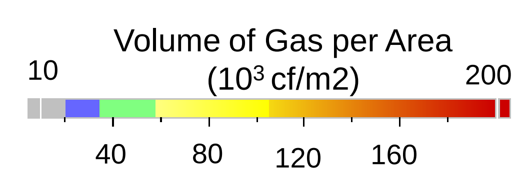
API Gravity of the oil in the Berriasian accumulations varies between 38° API in the shallower hydrocarbon saturated areas to 28° API in the deeper ones.



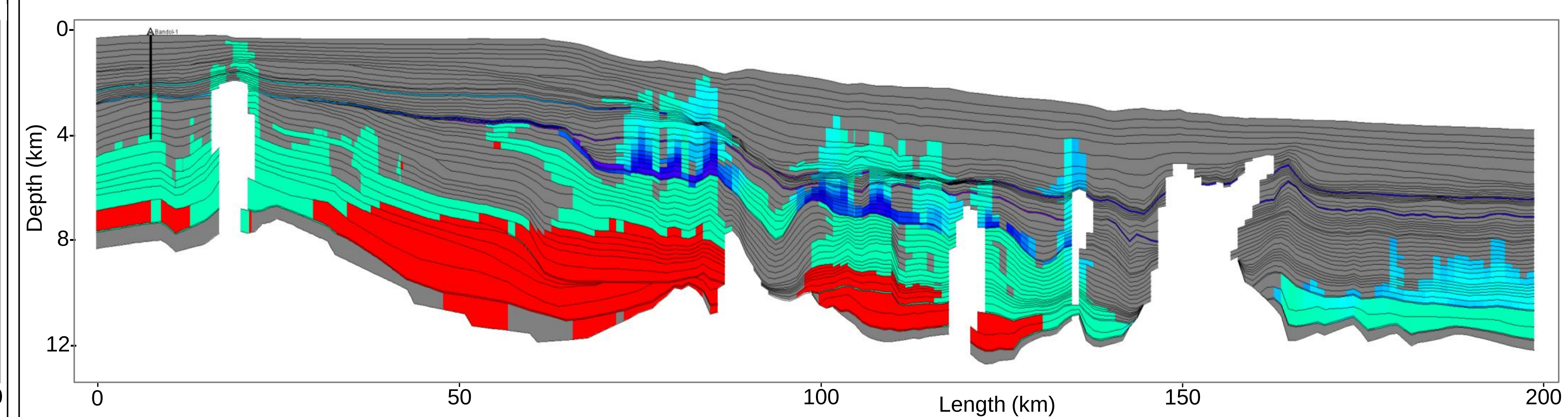
Volume of Gas per Area (Reference Scenario)



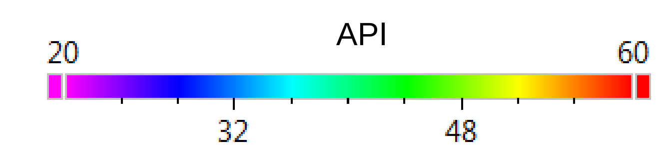
Gas is present in rather massive quantities in the lower depths of the model. If out of a source rock layer and not marked of by a structural element, they should be considered as diffuse distributions which have dissipated through geological time.
Accumulations picked in the previous slides displaying HC saturation distributions are filled predominately with gas in rather large quantities.



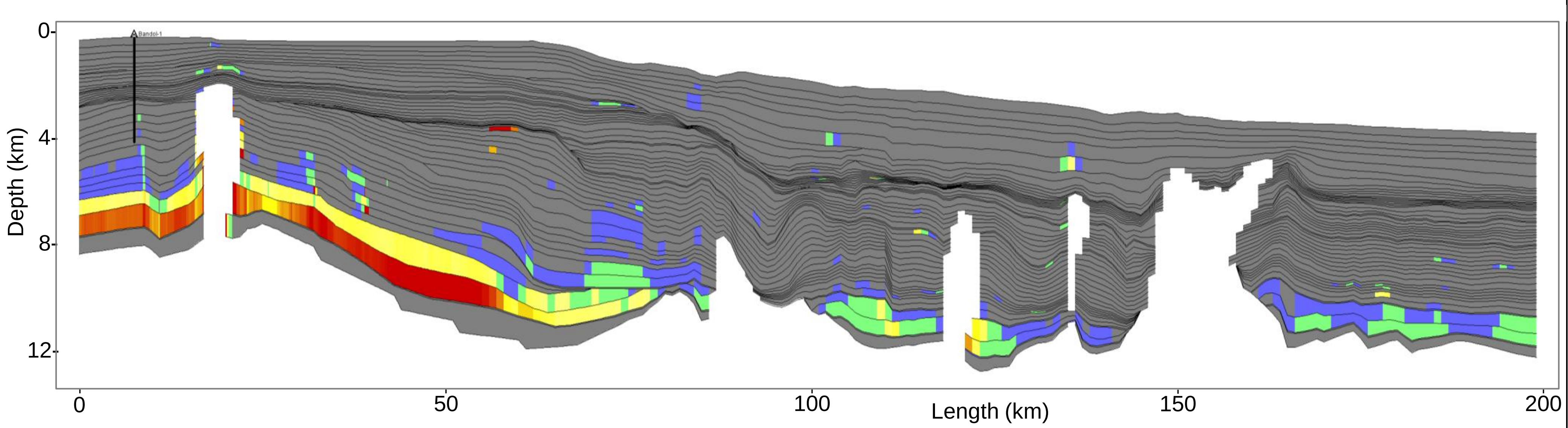
API Gravity - Condensates (Reference Scenario)



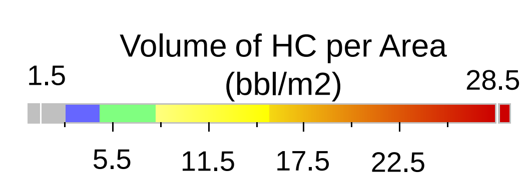
API Gravity of gas condensates in the Berriasian accumulations varies between 32° API up to 44° API.



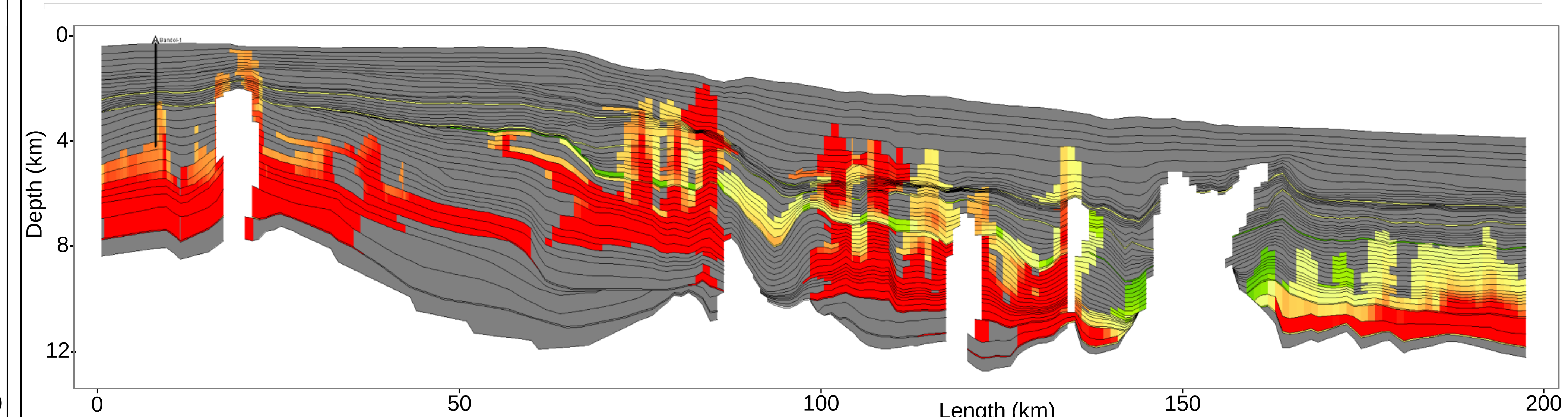
Total Volume of Hydrocarbon per Area (Reference Scenario)



As stated here above, the total volume of hydrocarbon in the model is entirely made of gas.
Total hydrocarbon volume is derived from the associates accumulated hydrocarbon masses using an average density.



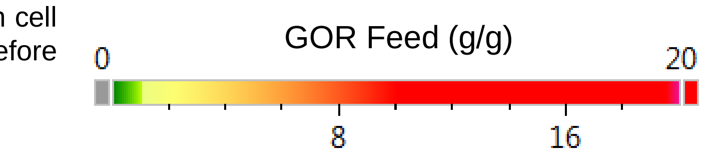
GOR Feed (Reference Scenario)



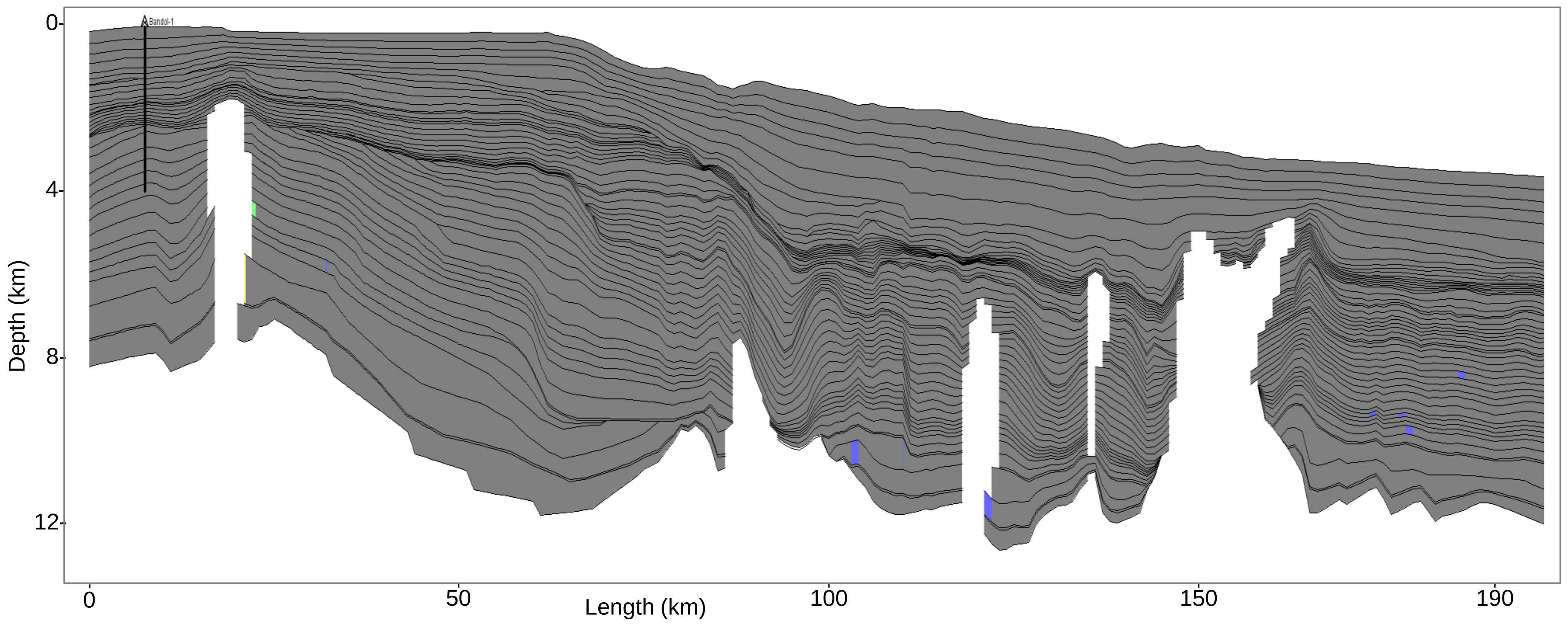
GOR Feed variable is the ratio between the mass of gas and the mass of oil accumulated in a given cell of the model. The mass of gas largely outweighs masses of gas and condensates as observed before with GOR exceeding 5 in most parts of the model except:

- in the Tithonian source rock layer on the shelf and past Km 160,
- Near salt diapir flanks where the cooling effect of the salt reduces the gas vs oil proportion.

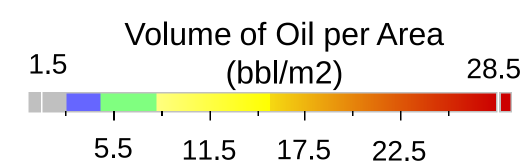
Yet the masses of oil associated to those greenish areas remain quite negligible.



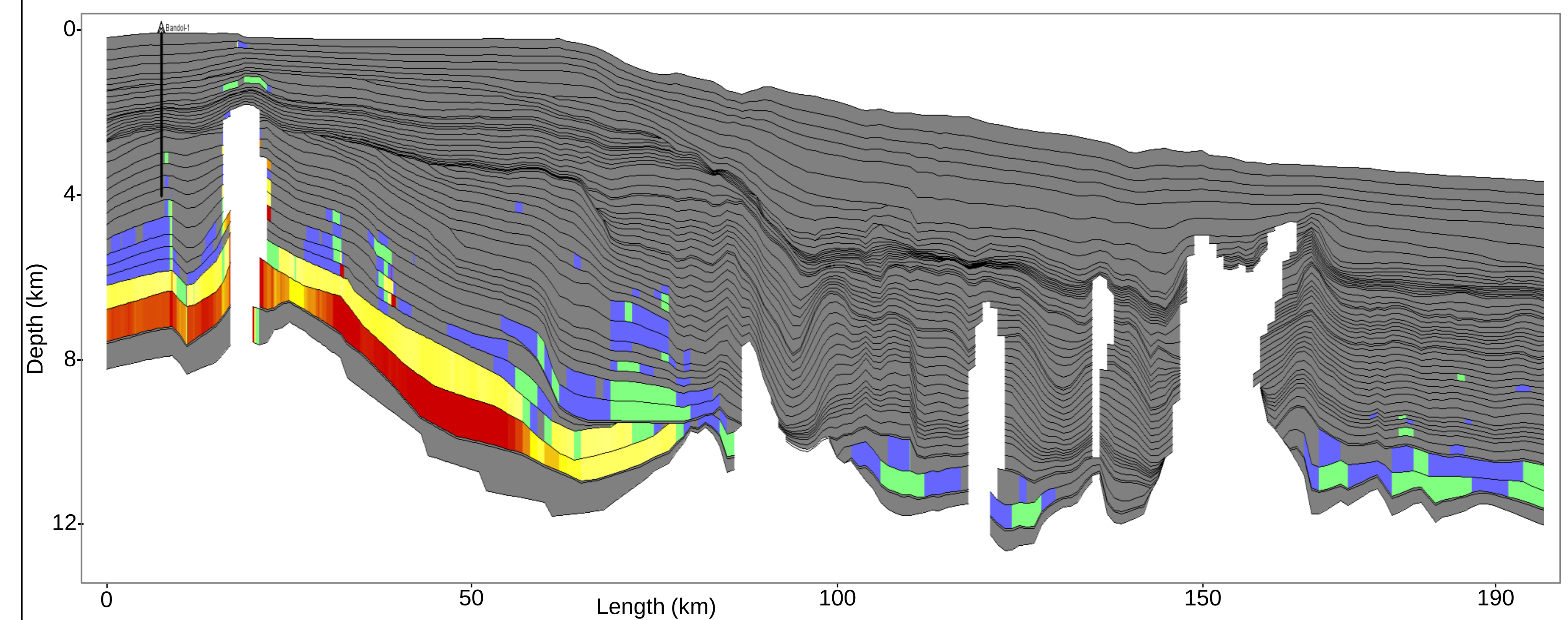
Volume of Oil per Area (Scenario 2 = Heat Flow variation)



By impacting negatively the hydrocarbon generation process in the central part of the model, this scenario obliterates the oil-prone accumulation which exists in the reference scenario at Km 60.

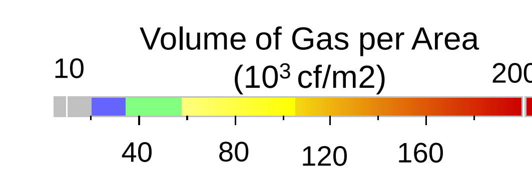


Volume of Gas per Area (Scenario 2 = Heat Flow variation)

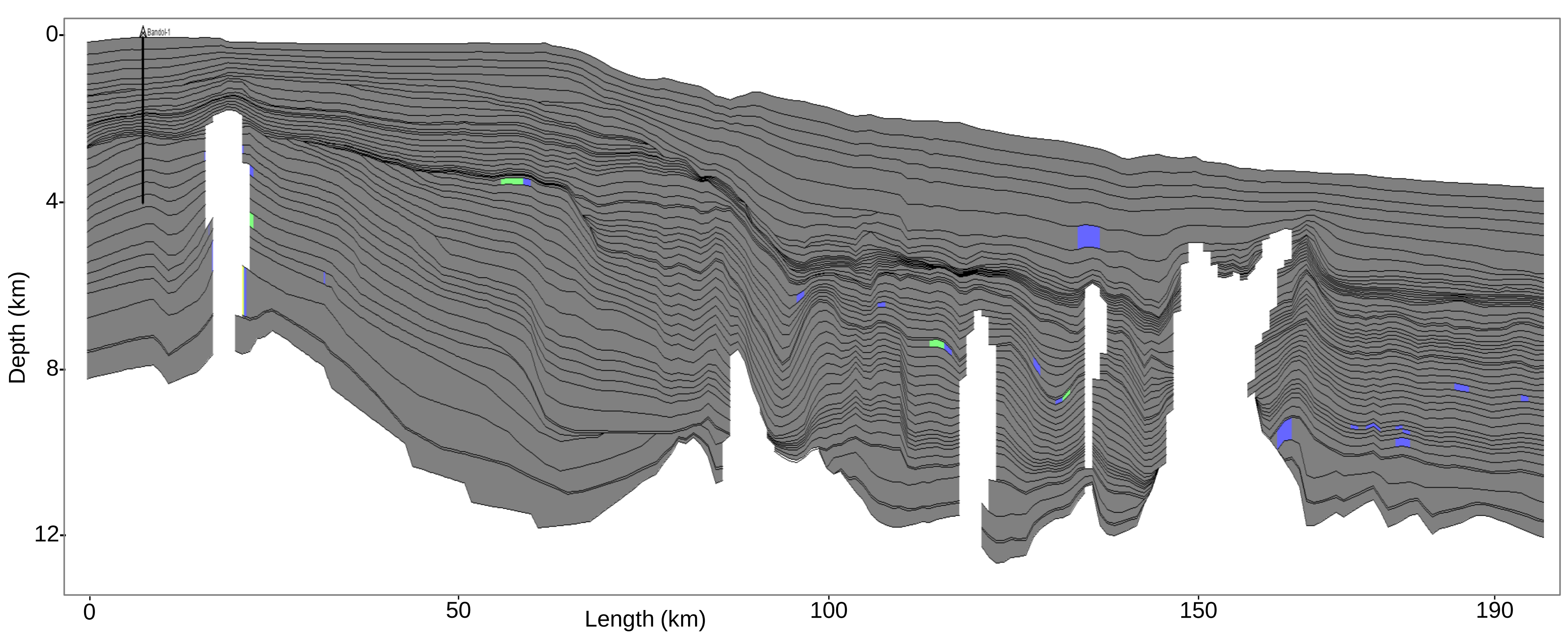


By impacting negatively the hydrocarbon generation process in the central part of the model, this scenario obliterates most of the gas accumulations located above 6 km depth in the central part of the model which were picked in the reference scenario

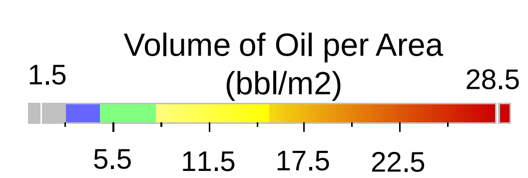
As migration is mainly vertical, accumulations located west of Km 40 location are unaffected by the transition domain shift and remain significant.



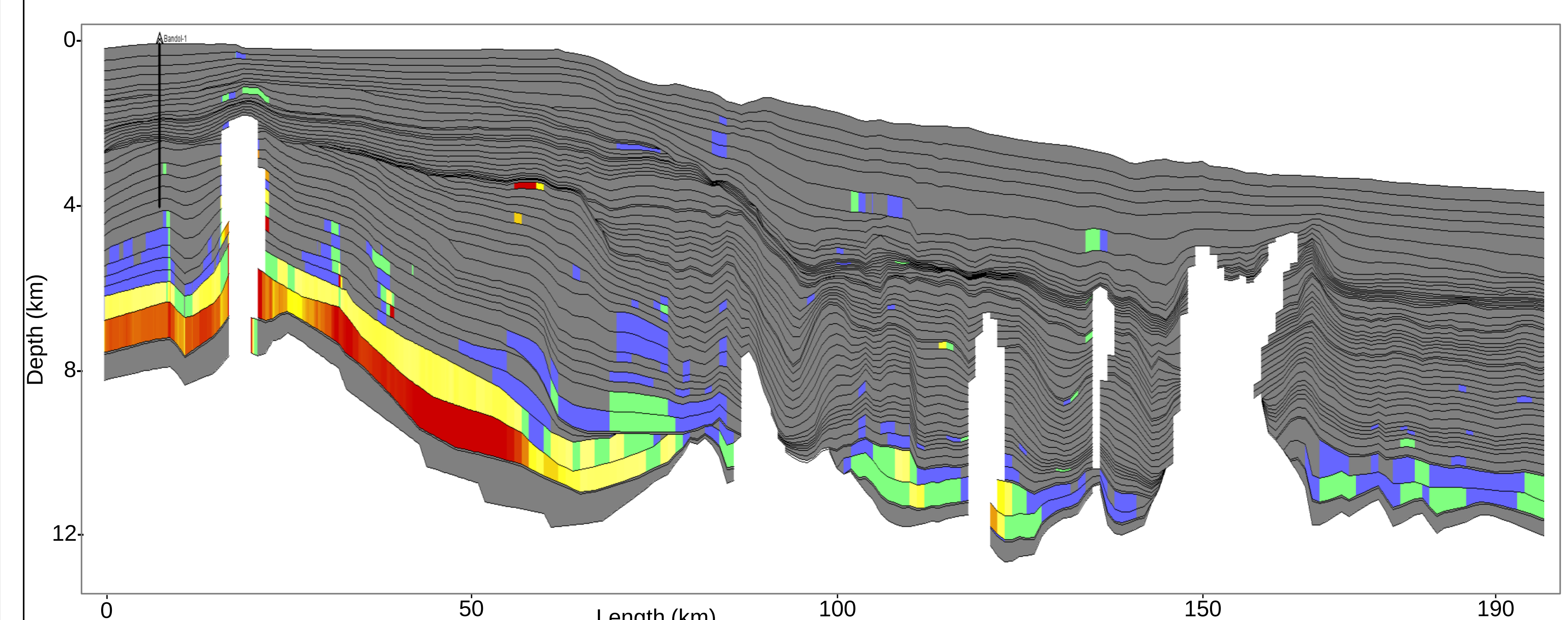
Volume of Oil per Area (Scenario 3 = Tithonian Type II)



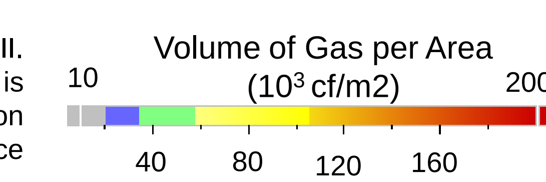
In this alternative scenario the Tithonian source rock is defined by a richer, more proficient kerogen type II. This increases the oil content in some accumulations which were previously only gas-prone as at Km 115 and Km 135 within the Callovian interval for instance.



Volume of Gas per Area (Scenario 3 = Tithonian Type II)



In this alternative scenario, the Tithonian source rock is defined by a richer, more proficient kerogen type II. Accumulation locations remain the same than in the reference model. A slight shift in the oil and gas proportion is observed where the Tithonian SR becomes the main contributor as seen in the Oxfordian/ Tithonian accumulation located at Km 60. In this hypothesis the available volume of gas is reduced somewhat compared to the reference scenario.



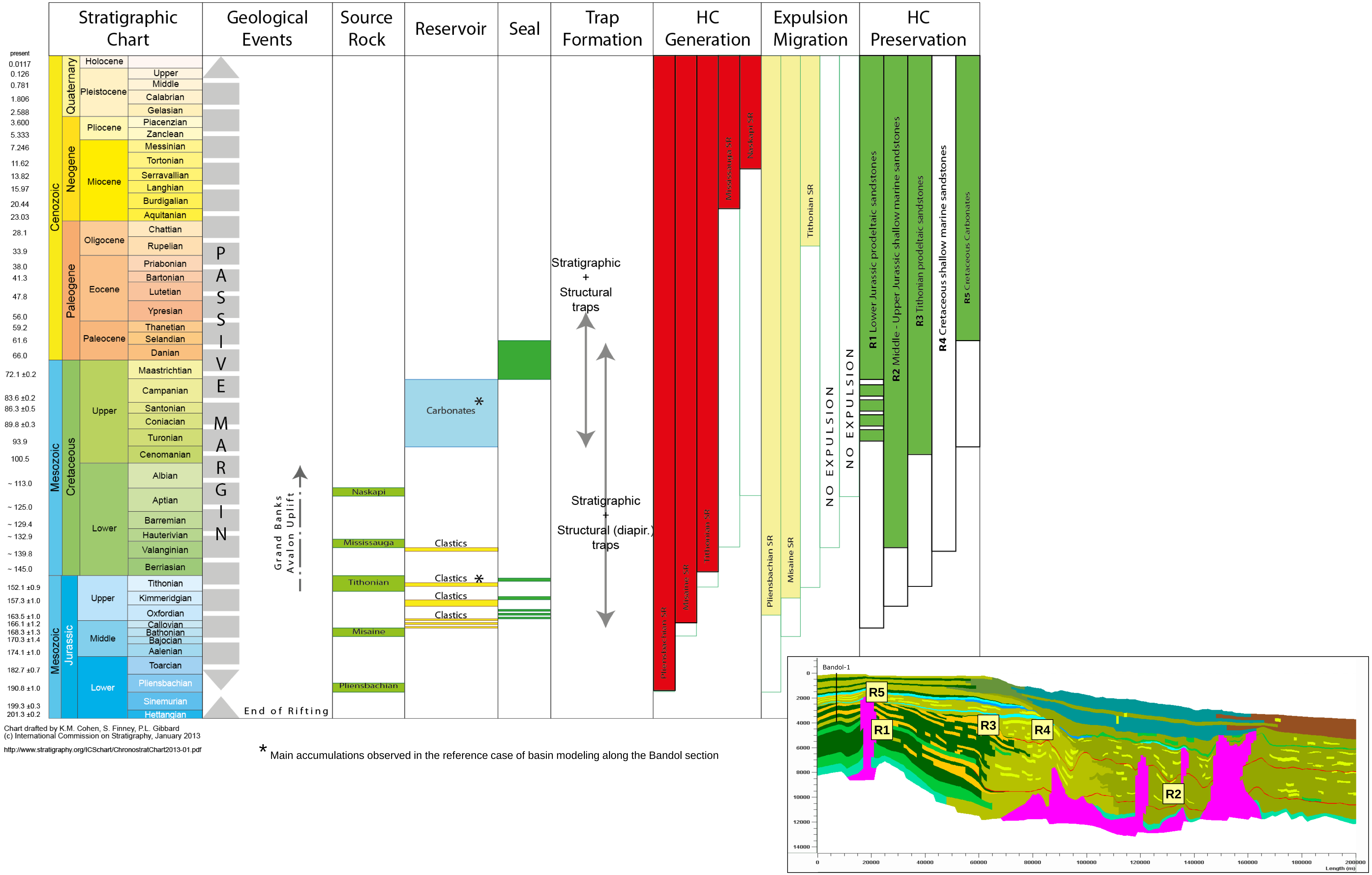
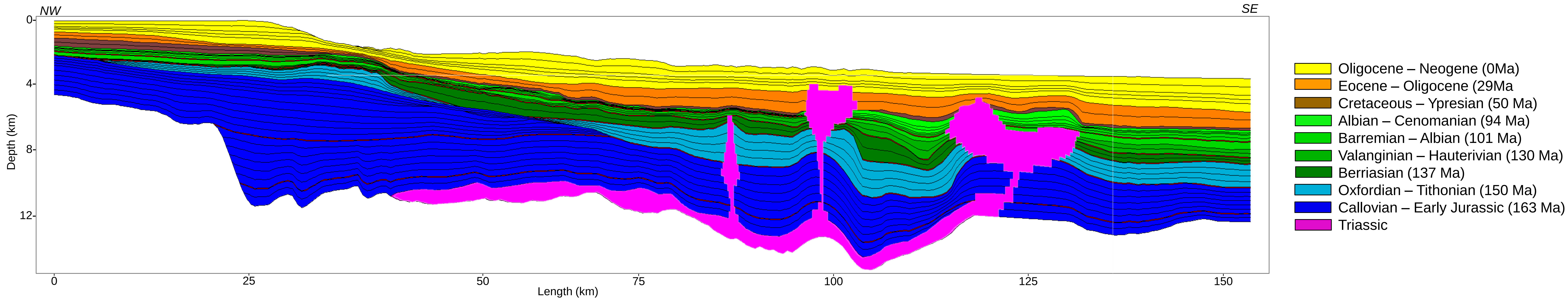


Chart drafted by K.M. Cohen, S. Finney, P.L. Gibbard
(c) International Commission on Stratigraphy, January 2013
http://www.stratigraphy.org/ICSchart/ChronostratChart2013-01.pdf

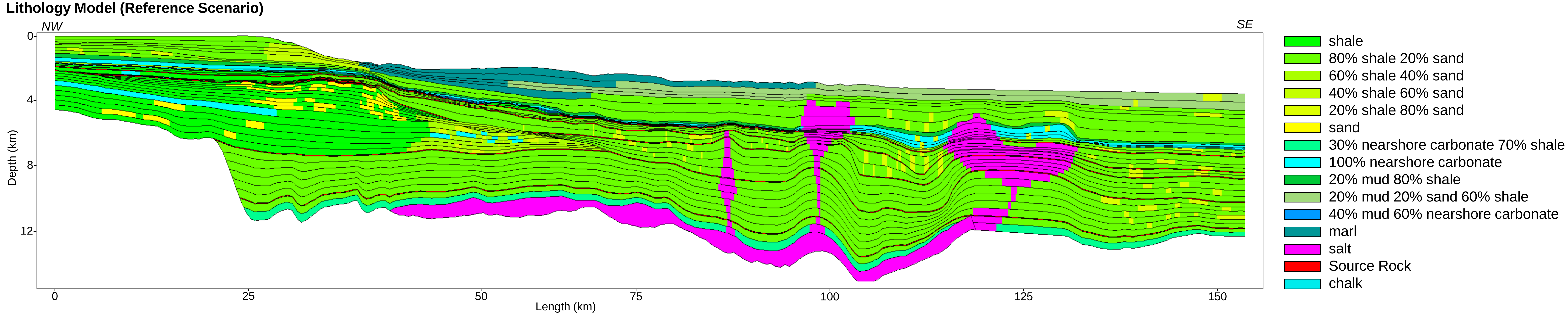
* Main accumulations observed in the reference case of basin modeling along the Bandol section

2D Modeling
East-Wolverine Section

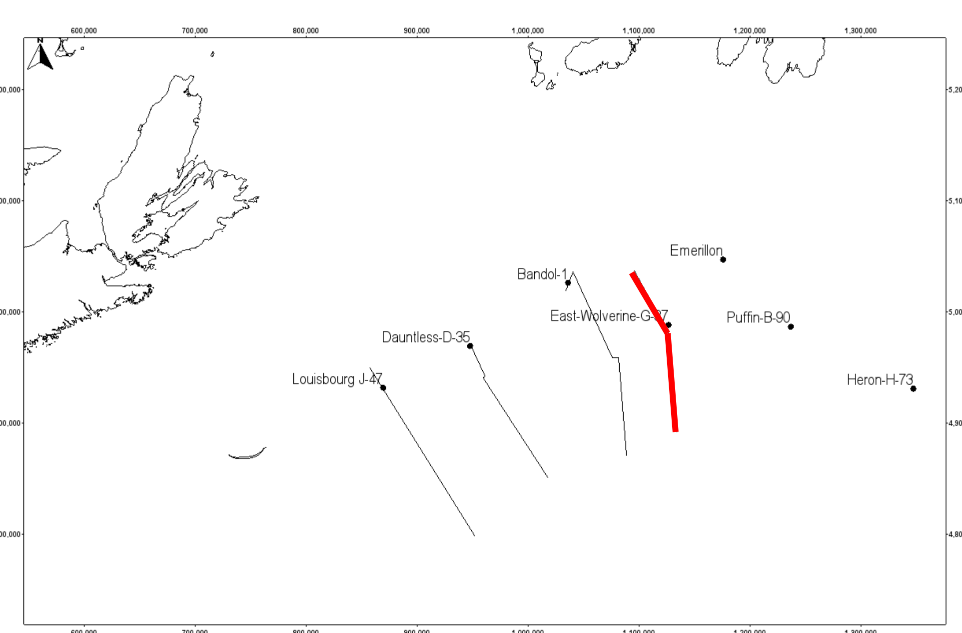
Stratigraphic Model (Reference Scenario)



Lithology Model (Reference Scenario)

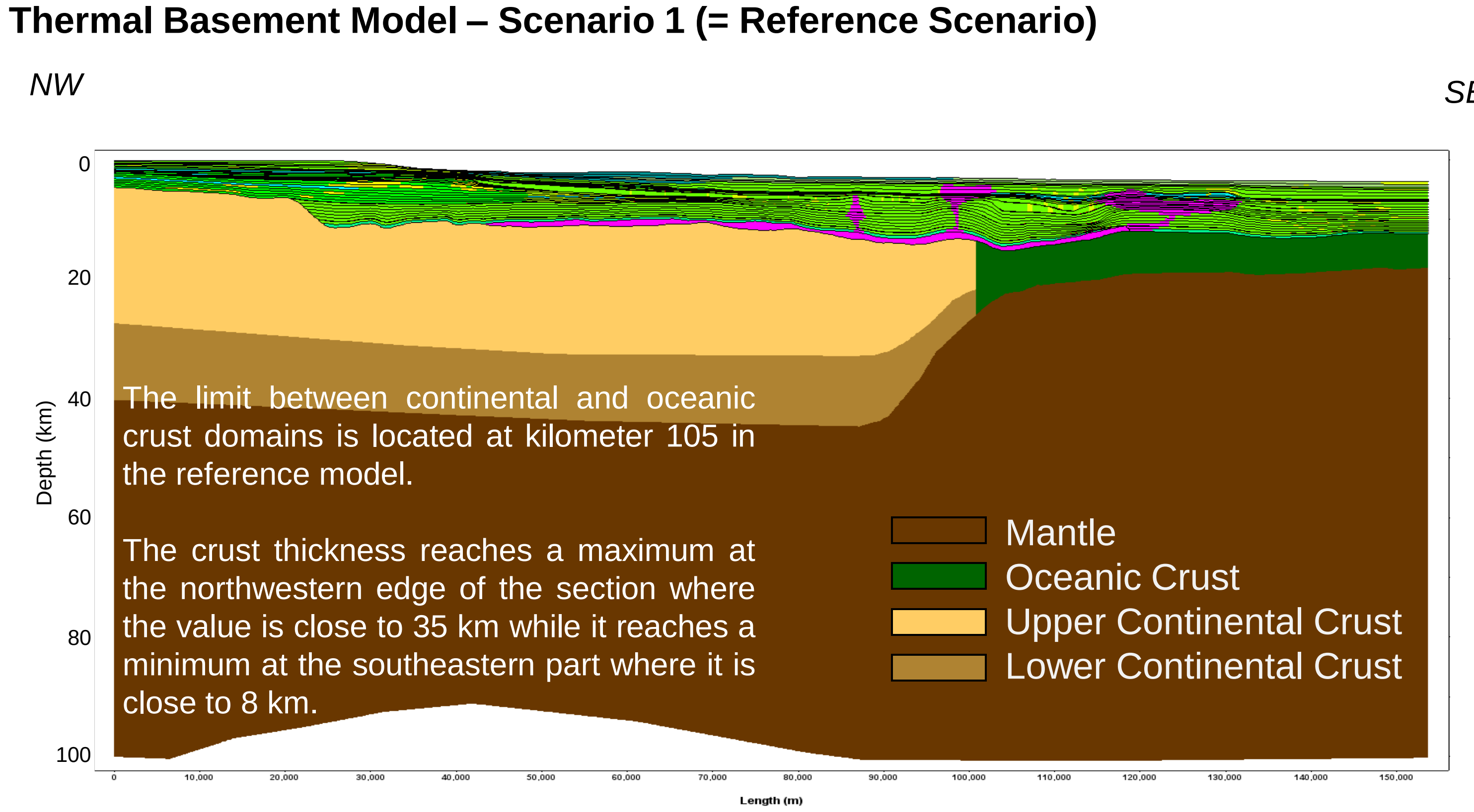


Location Map



East-Wolverine section trace intersects East-Wolverine G-37 well location. The well features temperature & vitrinite measurements which have been used for calibration purposes.

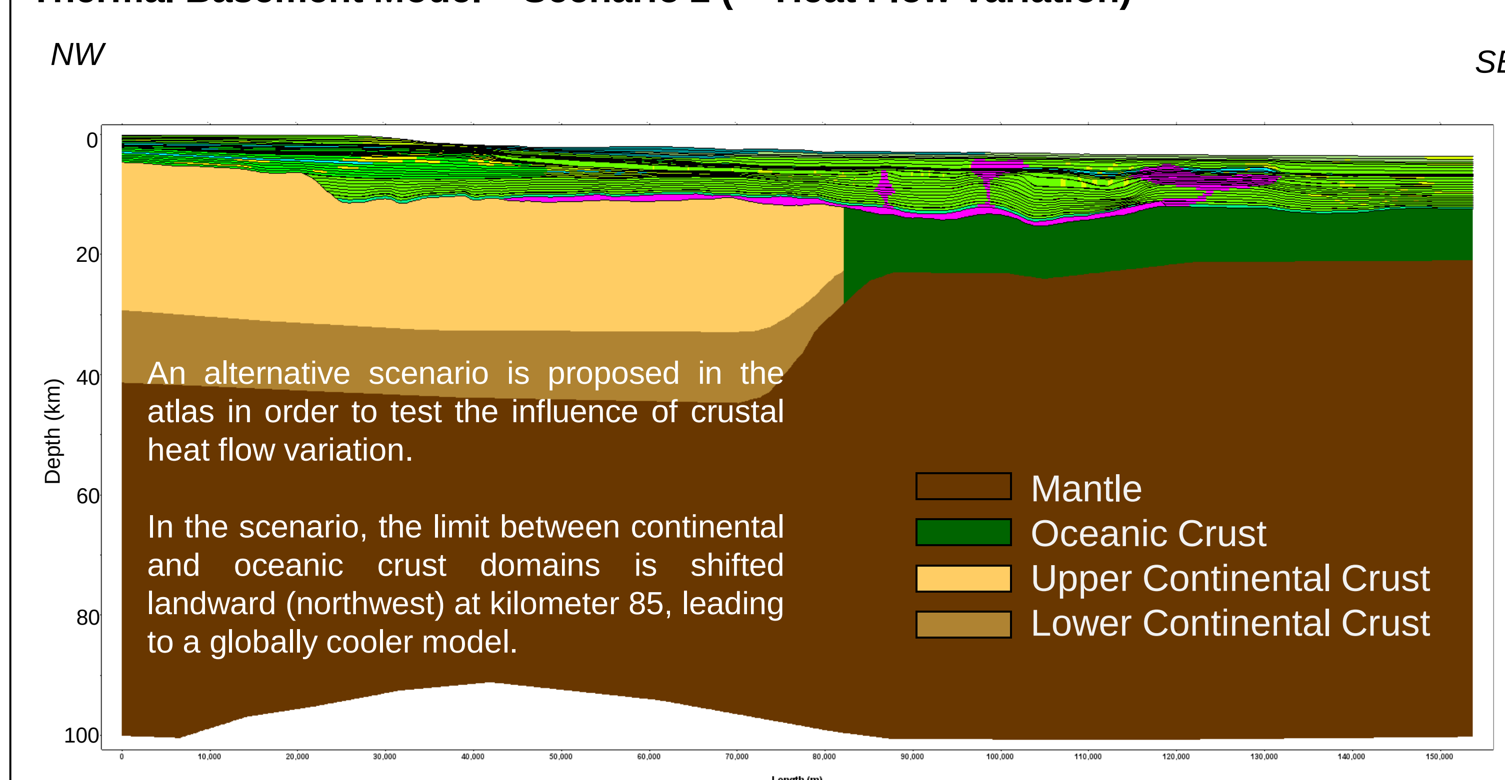
Thermal Basement Model – Scenario 1 (= Reference Scenario)



The limit between continental and oceanic crust domains is located at kilometer 105 in the reference model.

The crust thickness reaches a maximum at the northwestern edge of the section where the value is close to 35 km while it reaches a minimum at the southeastern part where it is close to 8 km.

Thermal Basement Model – Scenario 2 (= Heat Flow Variation)



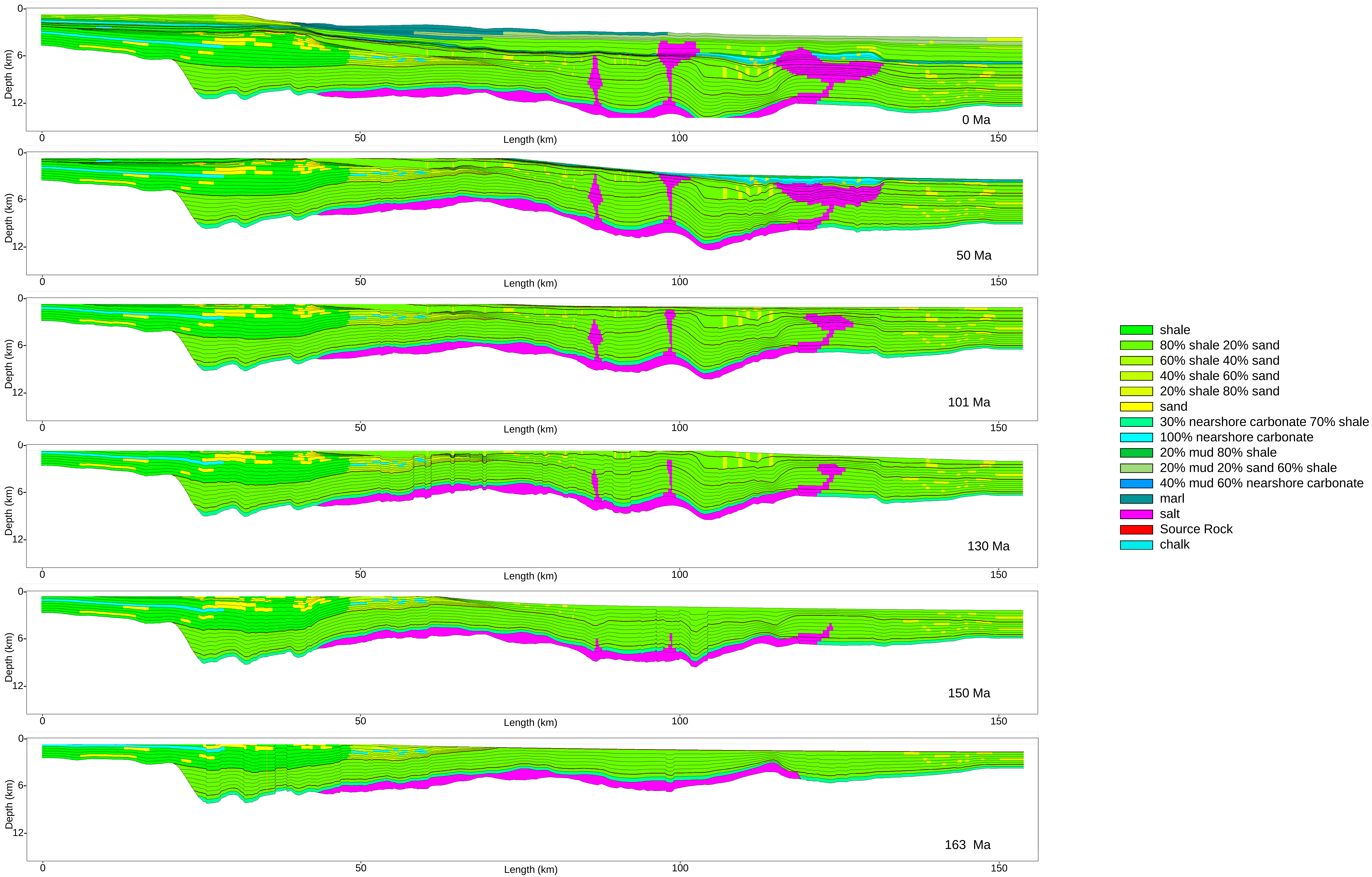
An alternative scenario is proposed in the atlas in order to test the influence of crustal heat flow variation.

In the scenario, the limit between continental and oceanic crust domains is shifted landward (northwest) at kilometer 85, leading to a globally cooler model.

Stratigraphy, Lithology, Basement Model and Location Map of Wolverine Section **PLATE 9.54**

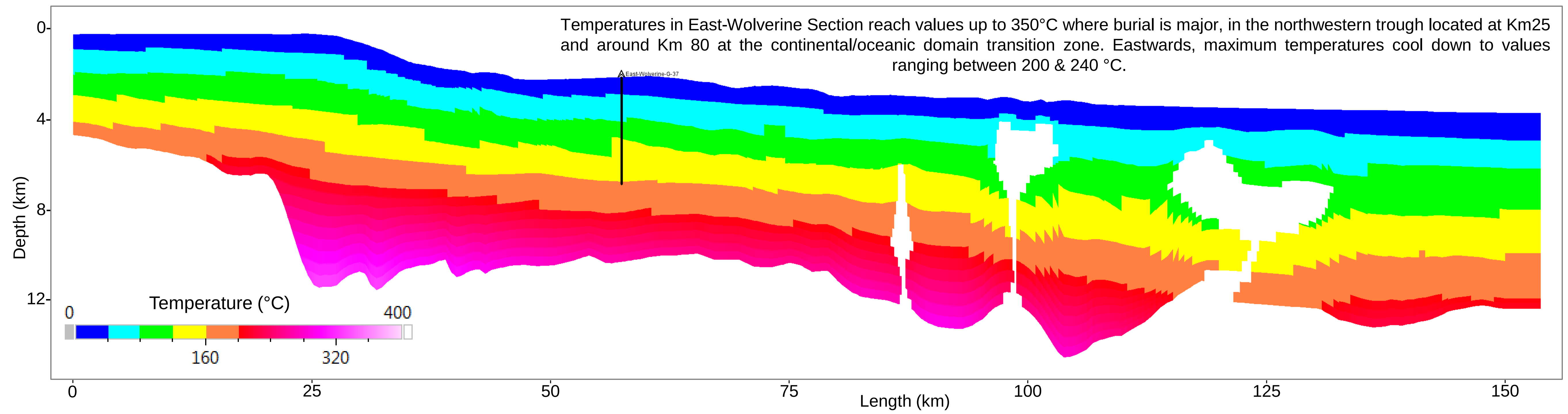
BASIN MODELING

Laurentian sub-basin study - CANADA – June 2014

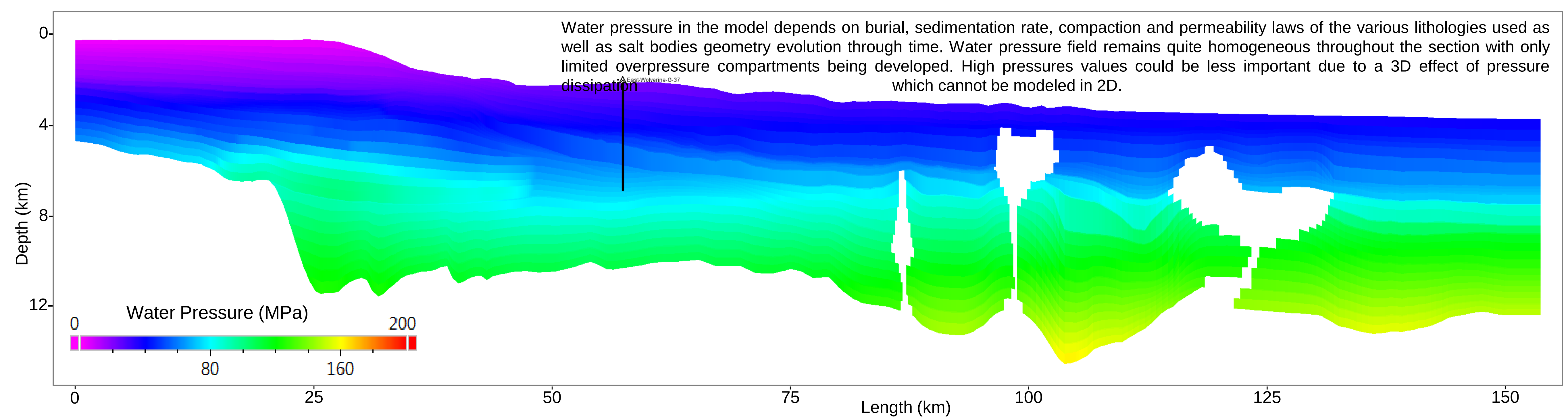


Restoration Scenario of East-Wolverine Section – Reference Scenario **PLATE 9.55**

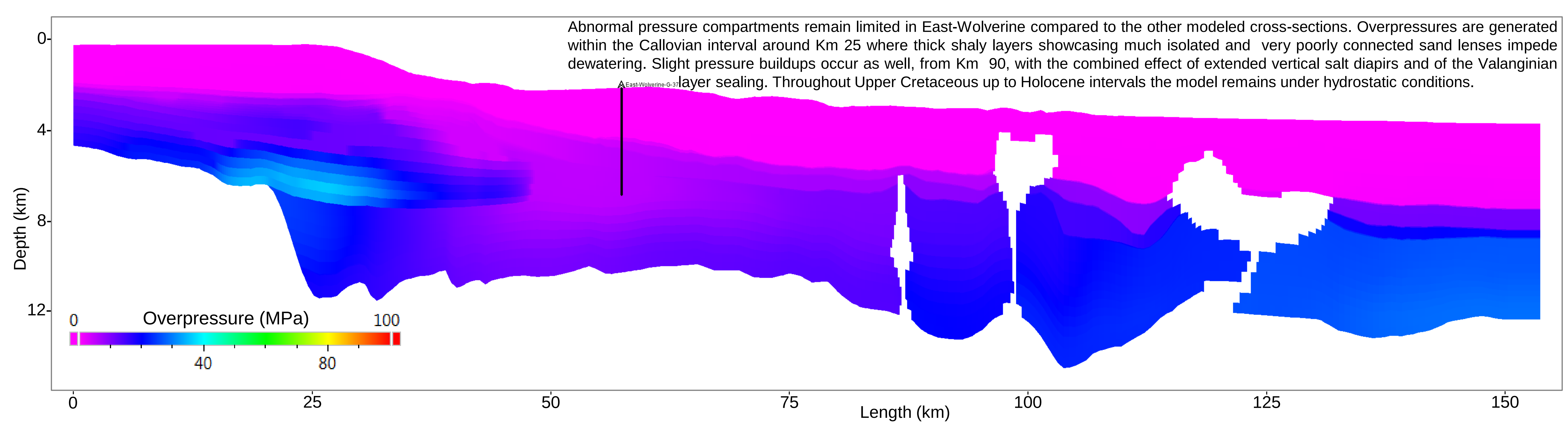
Temperature (Reference Scenario)



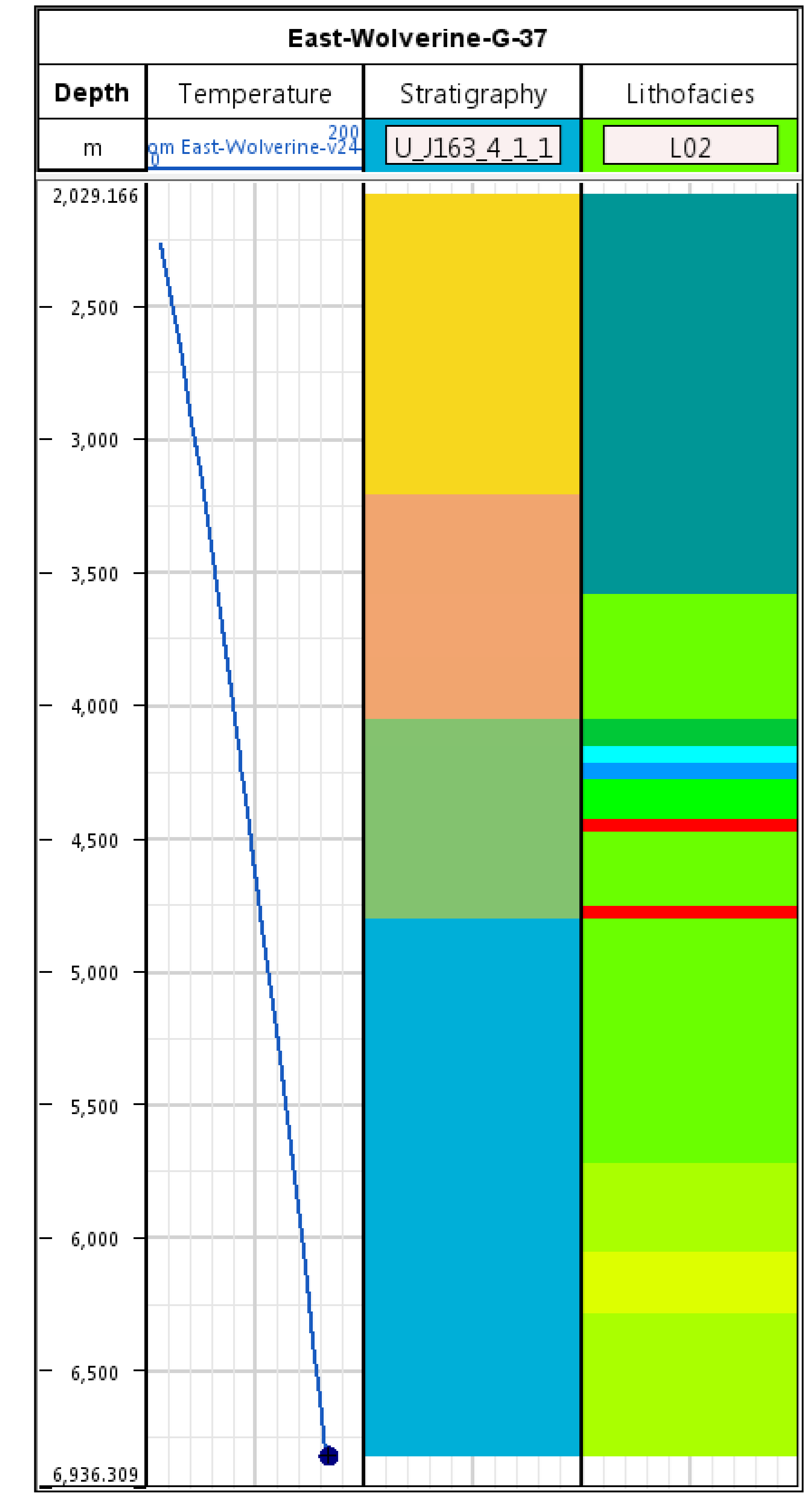
Water Pressure (Reference Scenario)



Overpressure (Reference Scenario)



Calibration (Reference Scenario)



Temperature model is calibrated versus available observed data at East-Wolverine-G37 well location:

- Observed data is represented with dots
- Simulated data is represented with continuous, thick lines

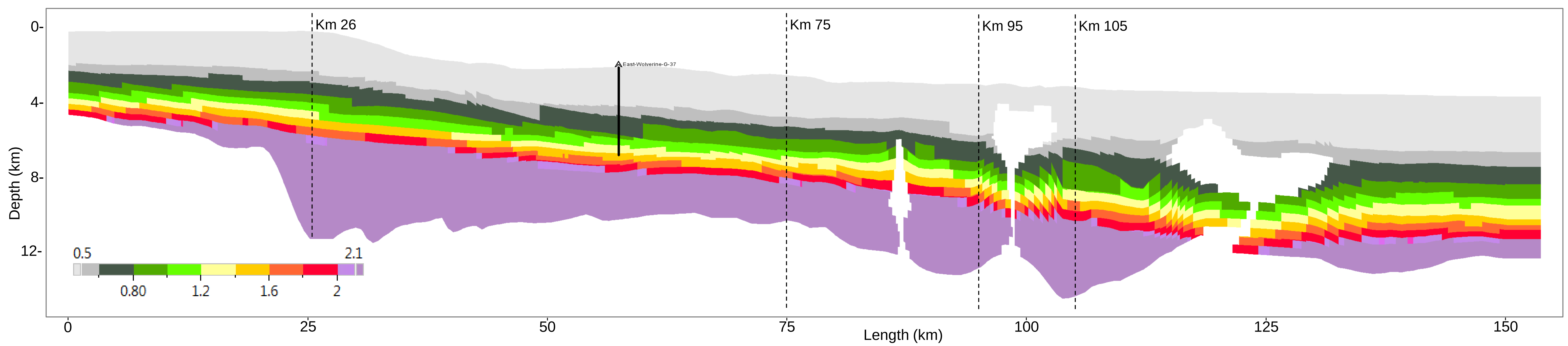
Temperature calibration is only controlled by a single BHT value.

No Pressure calibration is available.

BASIN MODELING

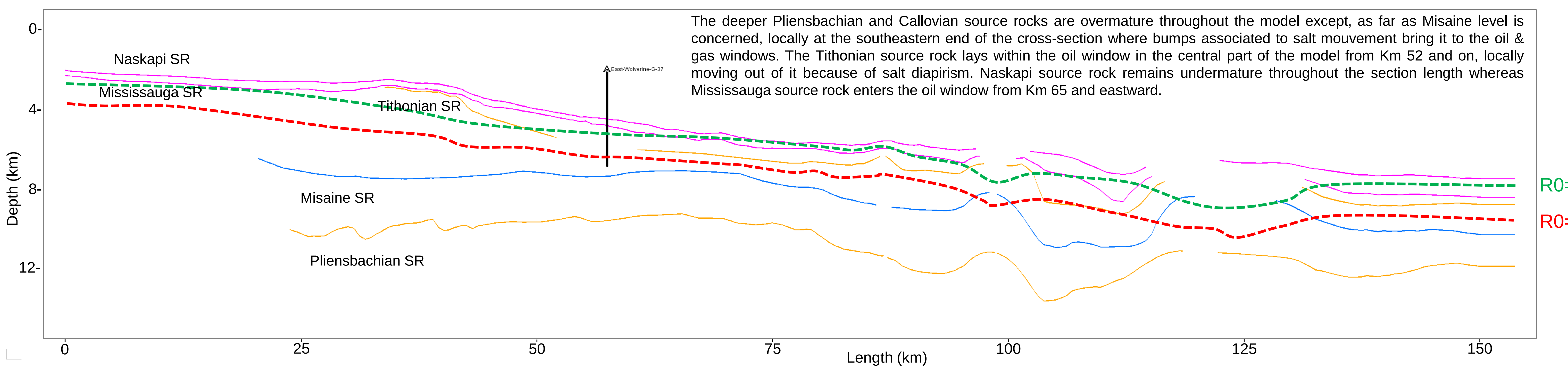
Laurentian sub-basin study - CANADA – June 2014

Vitrinite Reflectance (Reference Scenario)



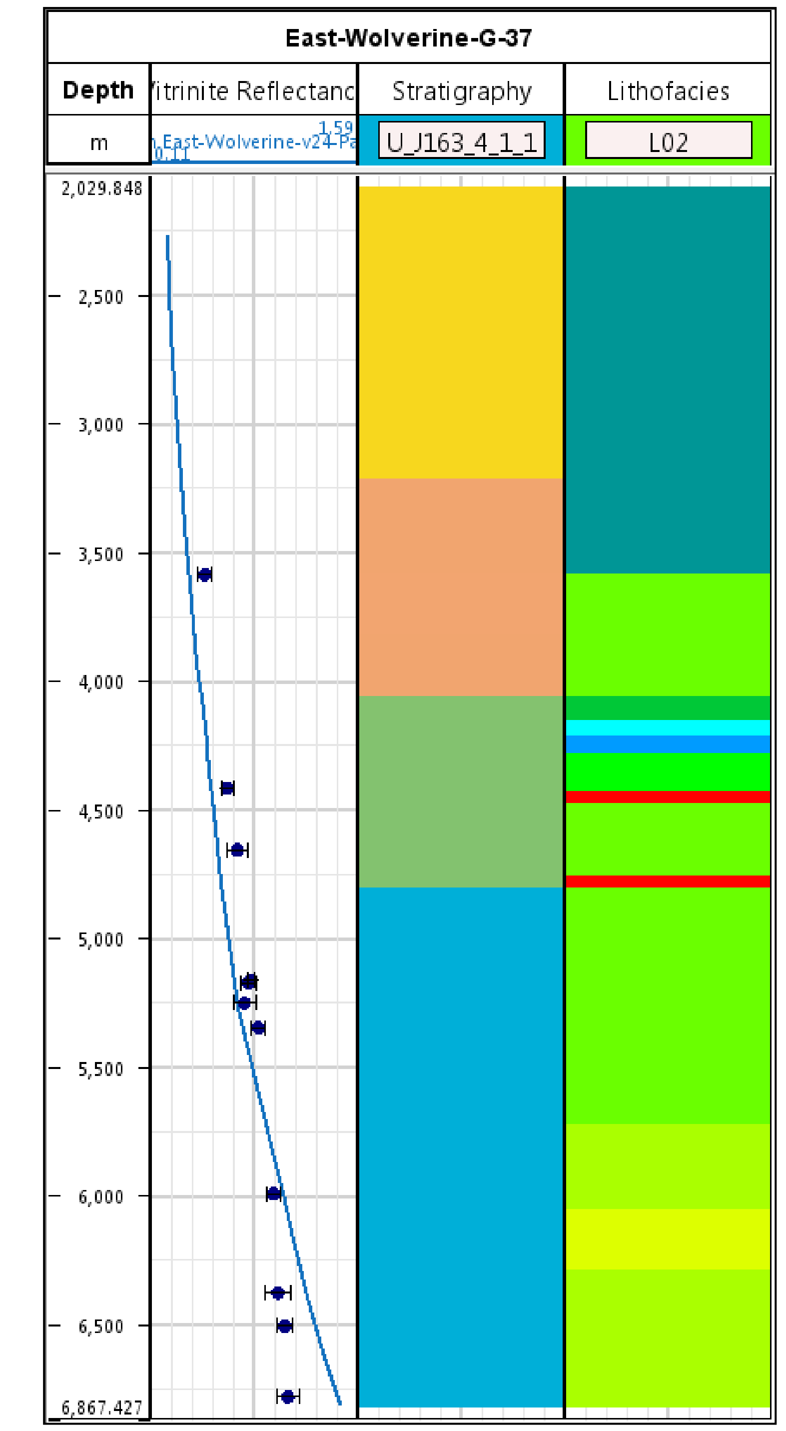
The model showcases highly mature / overmature areas in its deepest parts starting around Km 25 location along with a decreasing trend while moving basinwards. The latter is related both to the diminishing thickness of the sedimentary column and to the transition from a hotter continental domain to a cooler oceanic one.

Oil & Gas Windows



The deeper Pliensbachian and Callovian source rocks are overmature throughout the model except, as far as Misaine level is concerned, locally at the southeastern end of the cross-section where bumps associated to salt mouvement bring it to the oil & gas windows. The Tithonian source rock lays within the oil window in the central part of the model from Km 52 and on, locally moving out of it because of salt diapirism. Naskapi source rock remains undermature throughout the section length whereas Mississauga source rock enters the oil window from Km 65 and eastward.

Calibration (Reference Scenario)

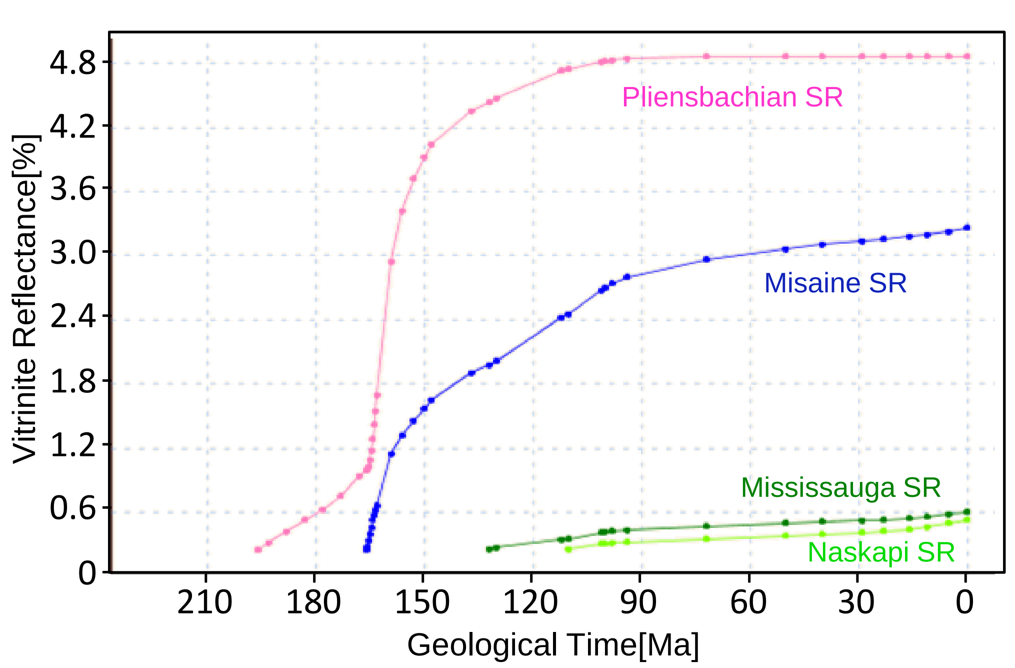


Vitrinite model is calibrated versus available observed data at East-Wolverine-G37 well location:

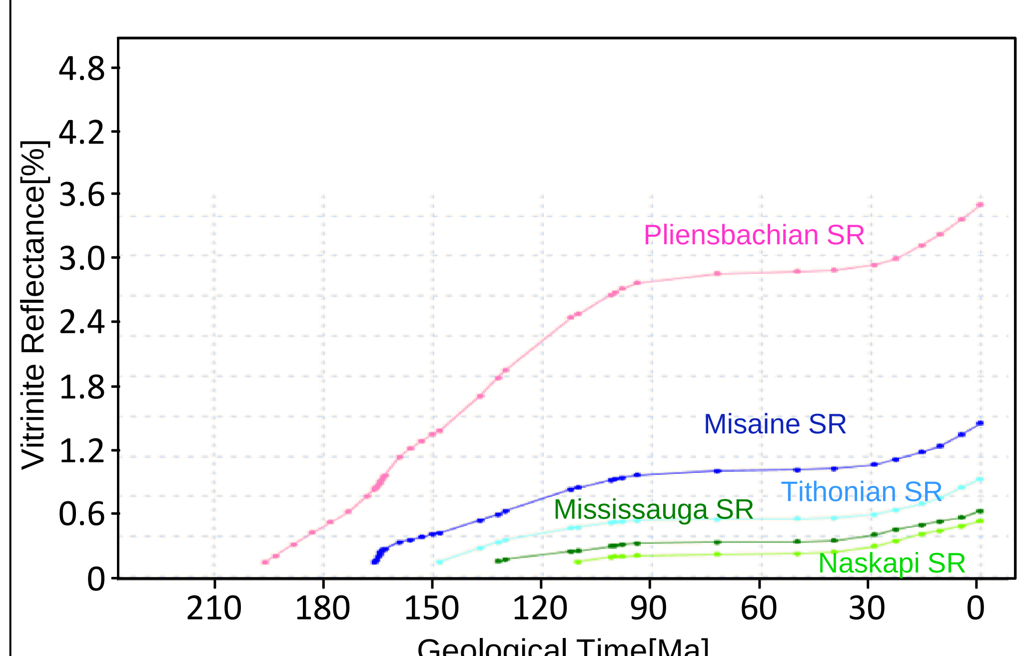
- Observed data is represented with dots,
- Simulated data is represented with thick line.

Vitrinite calibration at East-Wolverine-G37 well location falls under the measurements uncertainty range.

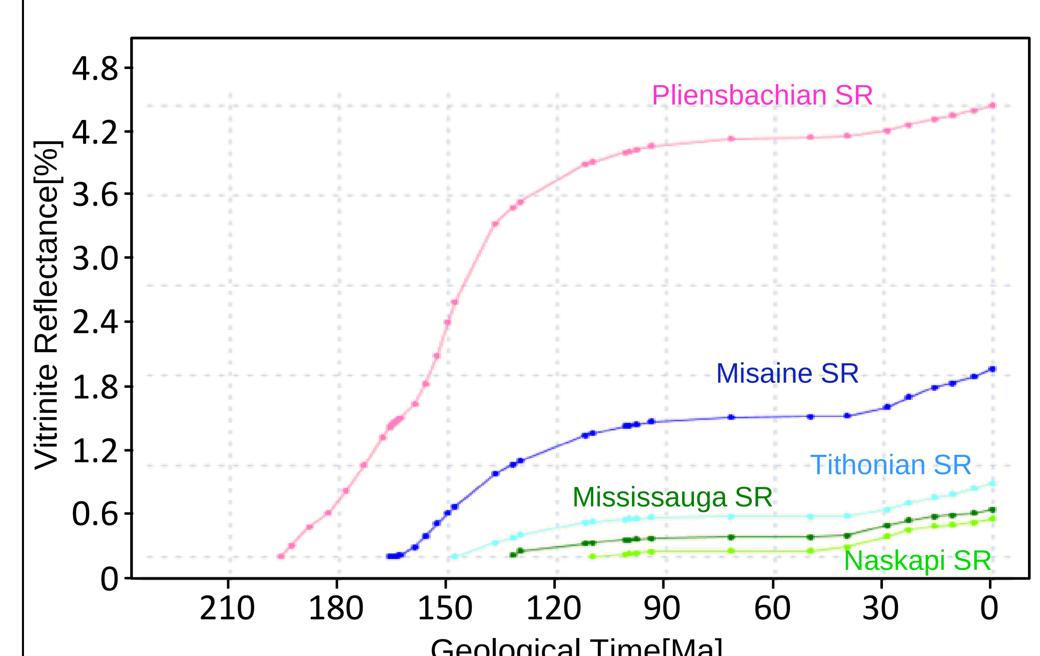
Vitrinite Reflectance through time at Km 26 Location



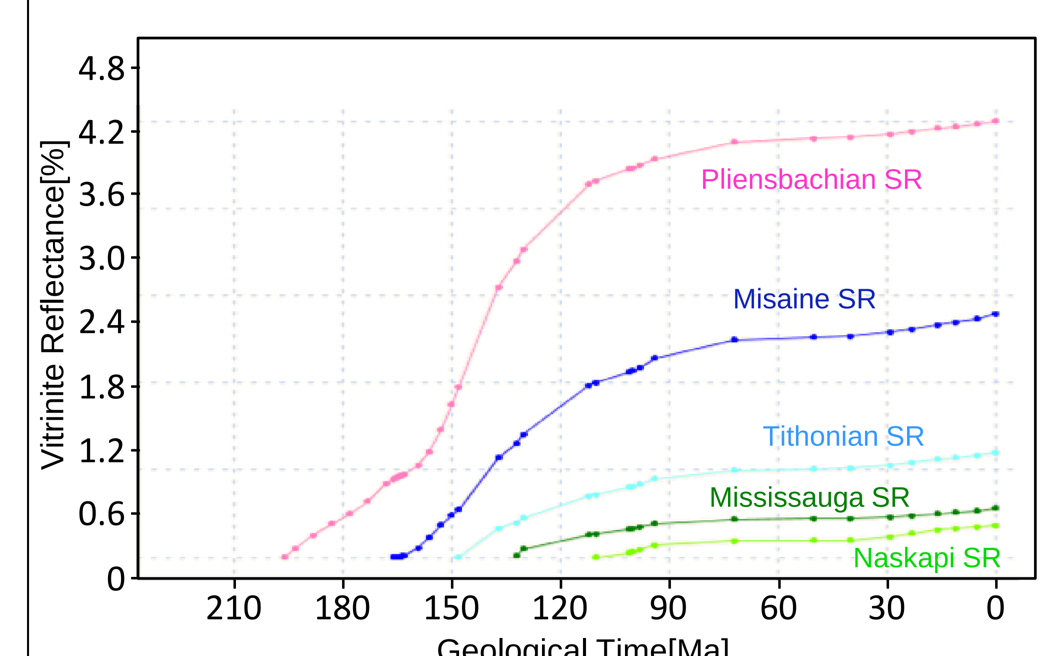
Vitrinite Reflectance through time at Km 64 Location



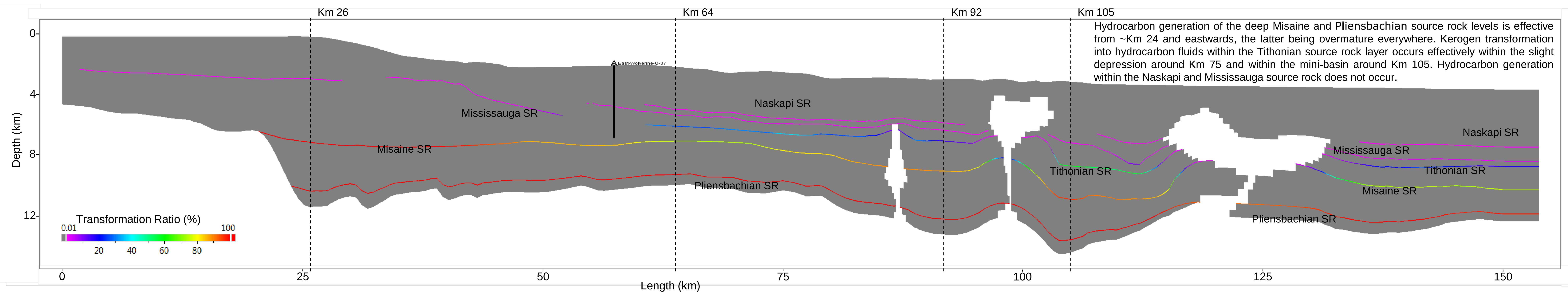
Vitrinite Reflectance through time at Km 95 Location



Vitrinite Reflectance through time at Km 105 Location

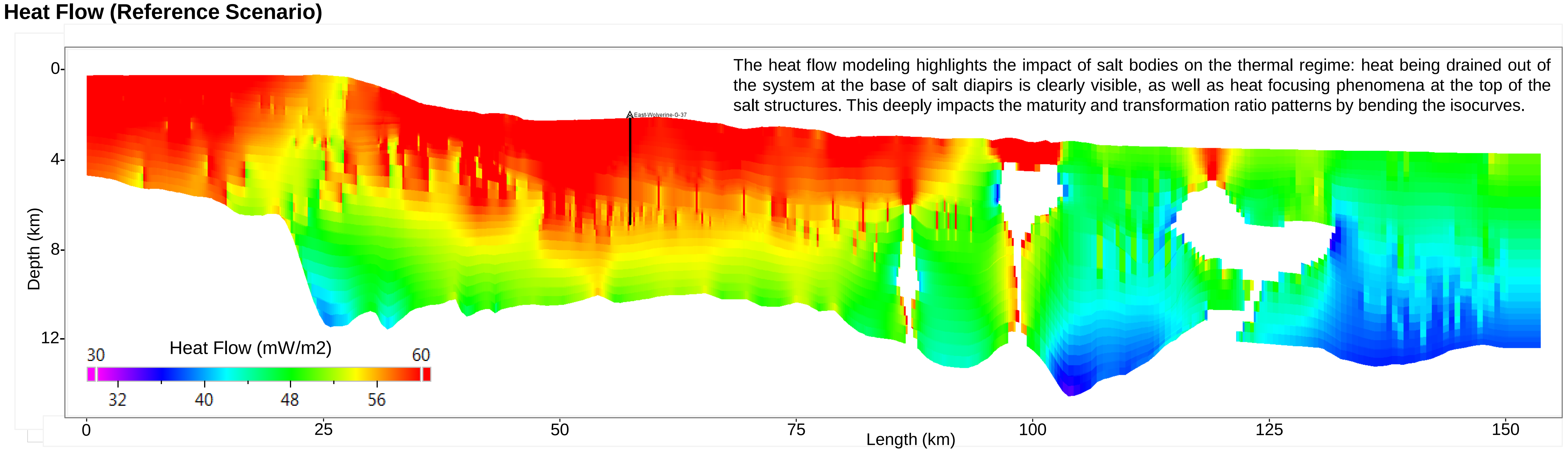


Transformation Ratio (Reference Scenario)



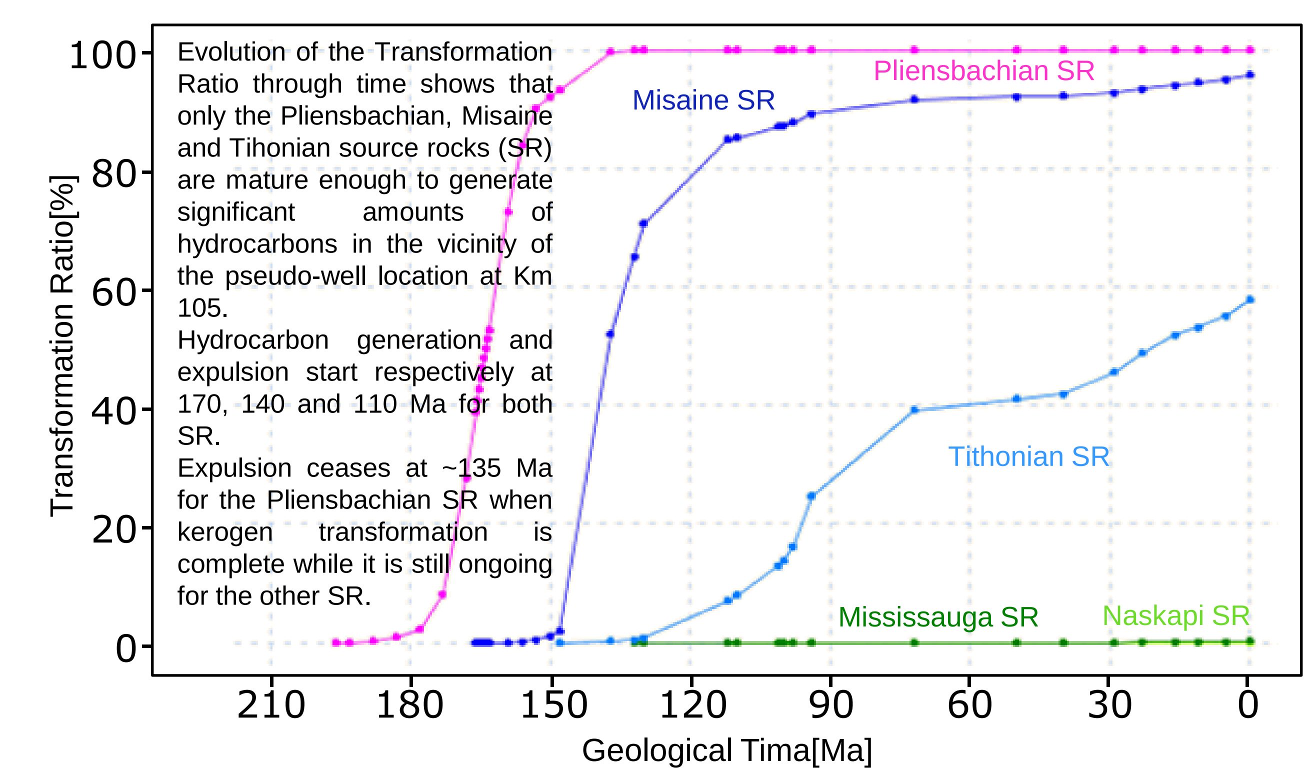
Hydrocarbon generation of the deep Misaine and Pliensbachian source rock levels is effective from ~Km 24 and eastwards, the latter being overmature everywhere. Kerogen transformation into hydrocarbon fluids within the Tithonian source rock layer occurs effectively within the slight depression around Km 75 and within the mini-basin around Km 105. Hydrocarbon generation within the Naskapi and Mississauga source rock does not occur.

Heat Flow (Reference Scenario)



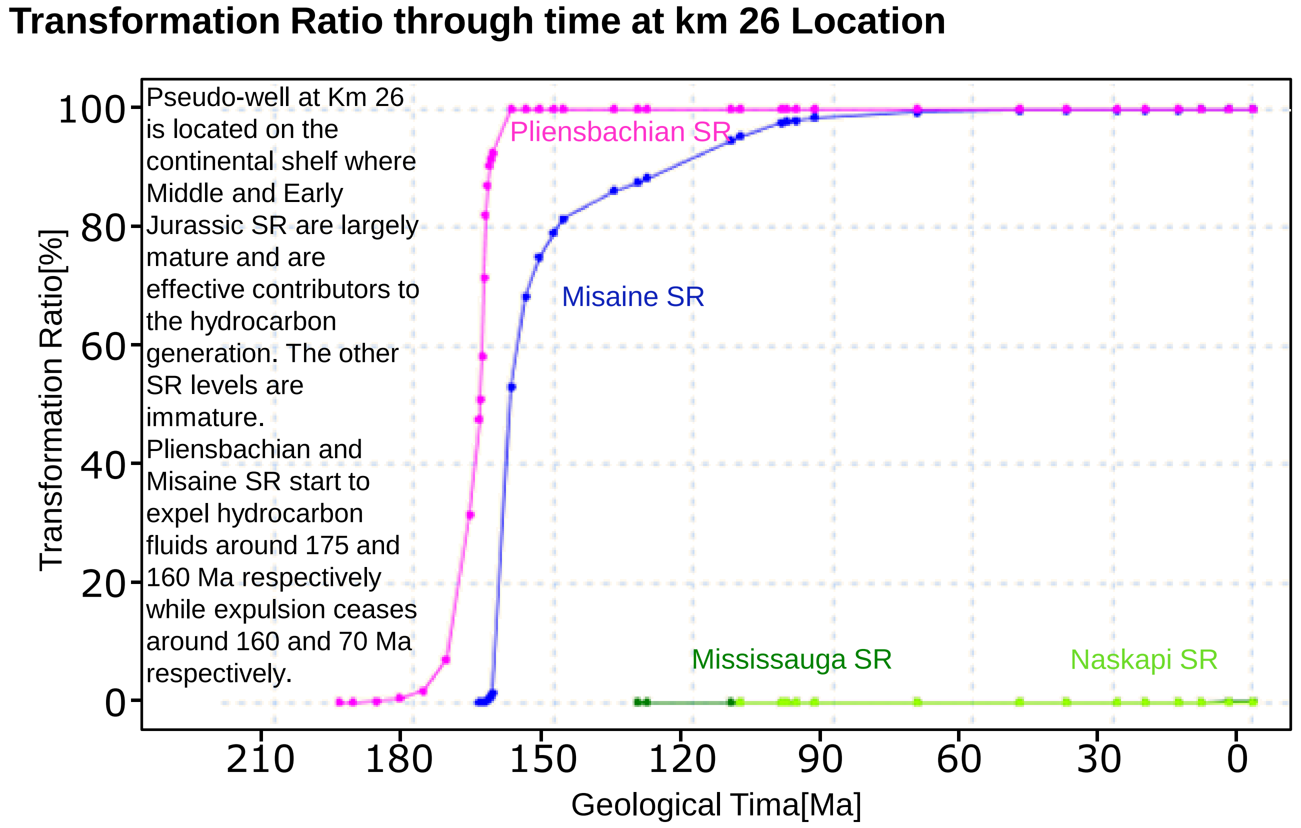
The heat flow modeling highlights the impact of salt bodies on the thermal regime: heat being drained out of the system at the base of salt diapirs is clearly visible, as well as heat focusing phenomena at the top of the salt structures. This deeply impacts the maturity and transformation ratio patterns by bending the isocurves.

Transformation Ratio through time at km 105 Location



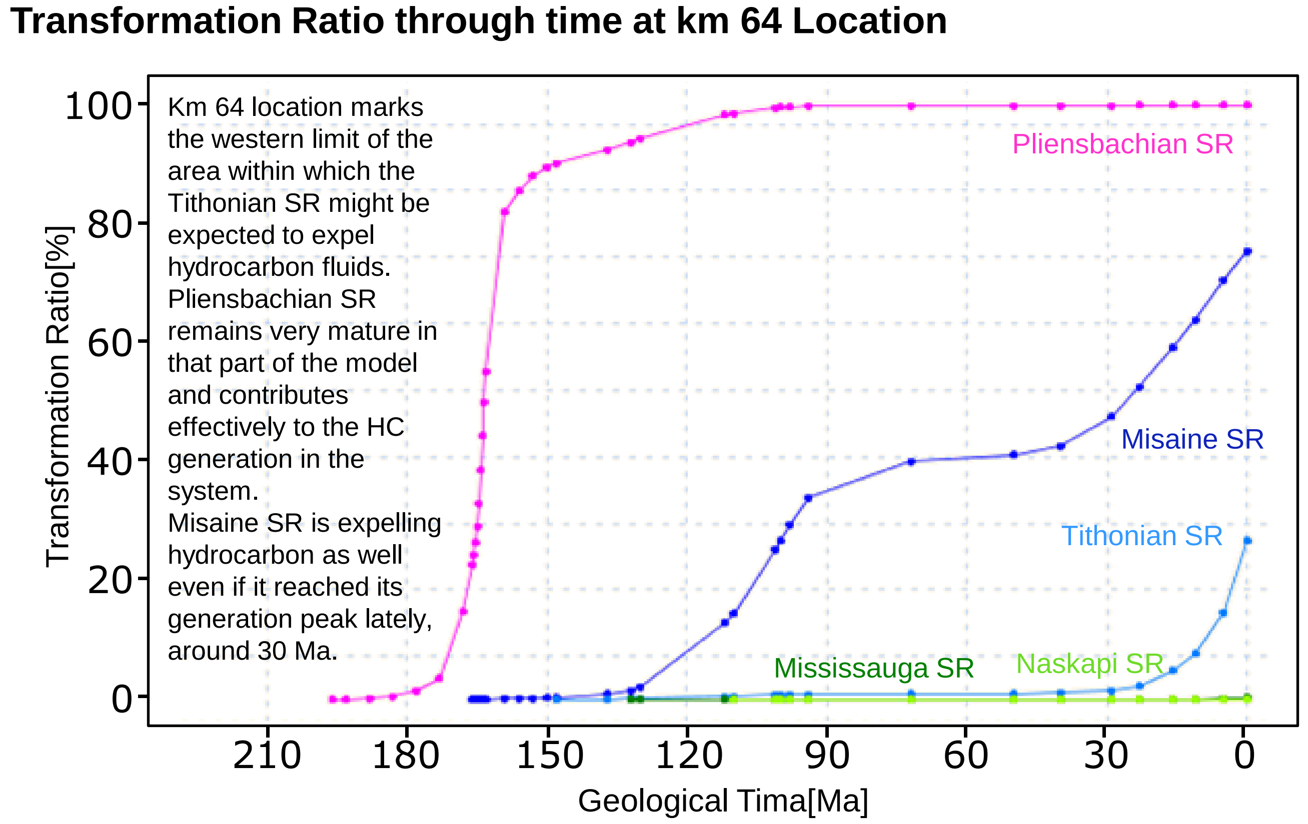
Evolution of the Transformation Ratio through time shows that only the Pliensbachian, Misaine and Tihonian source rocks (SR) are mature enough to generate significant amounts of hydrocarbons in the vicinity of the pseudo-well location at Km 105.
Hydrocarbon generation and expulsion start respectively at 170, 140 and 110 Ma for both SR.
Expulsion ceases at ~135 Ma for the Pliensbachian SR when kerogen transformation is complete while it is still ongoing for the other SR.

Transformation Ratio through time at km 26 Location



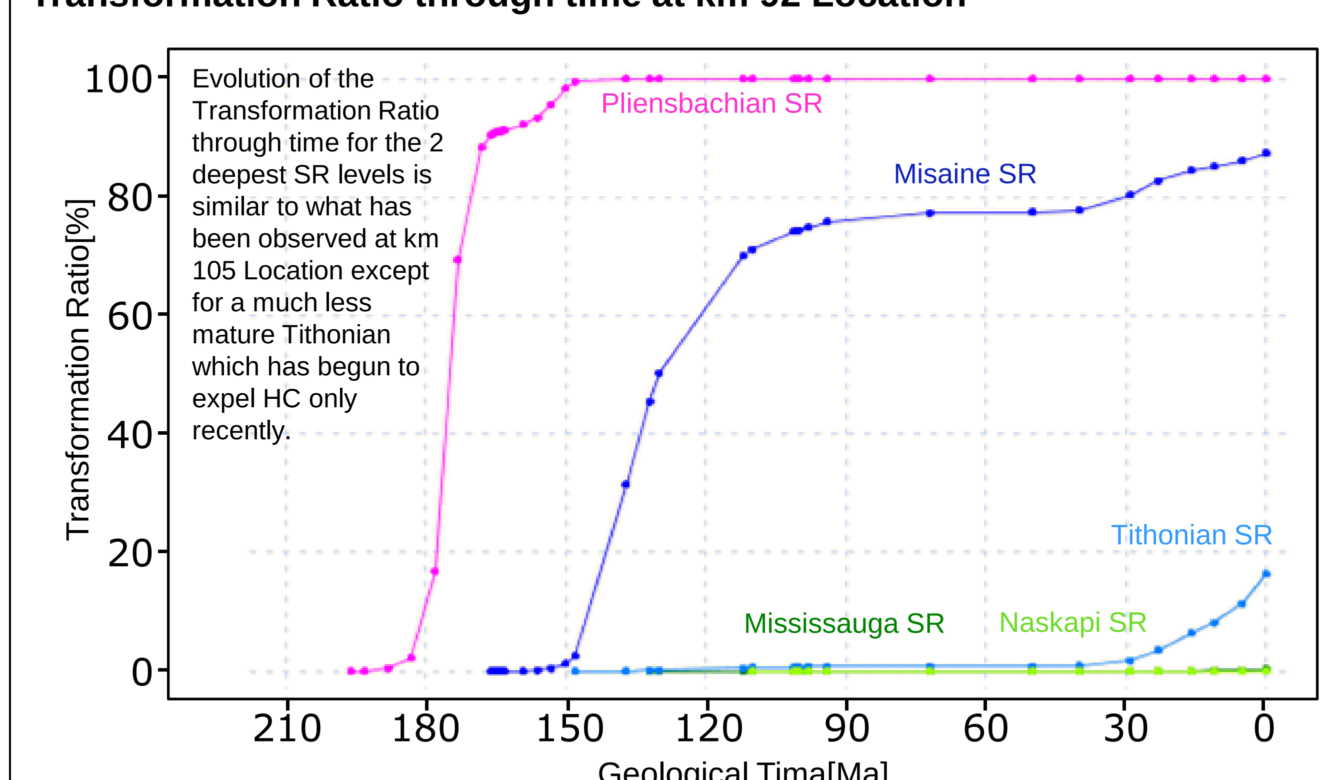
Pseudo-well at Km 26 is located on the continental shelf where Middle and Early Jurassic SR are largely mature and are effective contributors to the hydrocarbon generation. The other SR levels are immature.
Pliensbachian and Misaine SR start to expel hydrocarbon fluids around 175 and 160 Ma respectively while expulsion ceases around 160 and 70 Ma respectively.

Transformation Ratio through time at km 64 Location



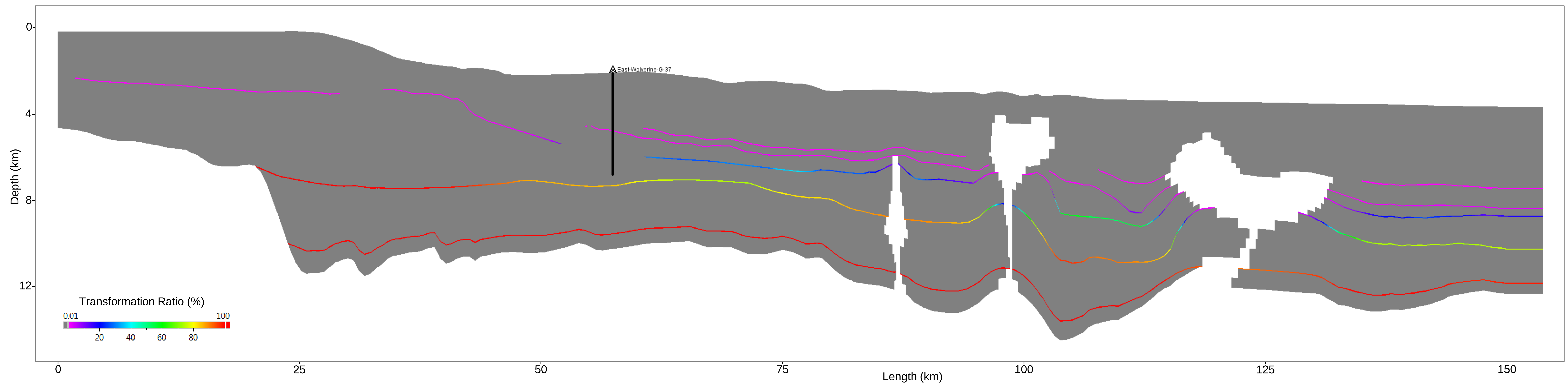
Km 64 location marks the western limit of the area within which the Tithonian SR might be expected to expel hydrocarbon fluids.
Pliensbachian SR remains very mature in that part of the model and contributes effectively to the HC generation in the system.
Misaine SR is expelling hydrocarbon as well even if it reached its generation peak lately, around 30 Ma.

Transformation Ratio through time at km 92 Location

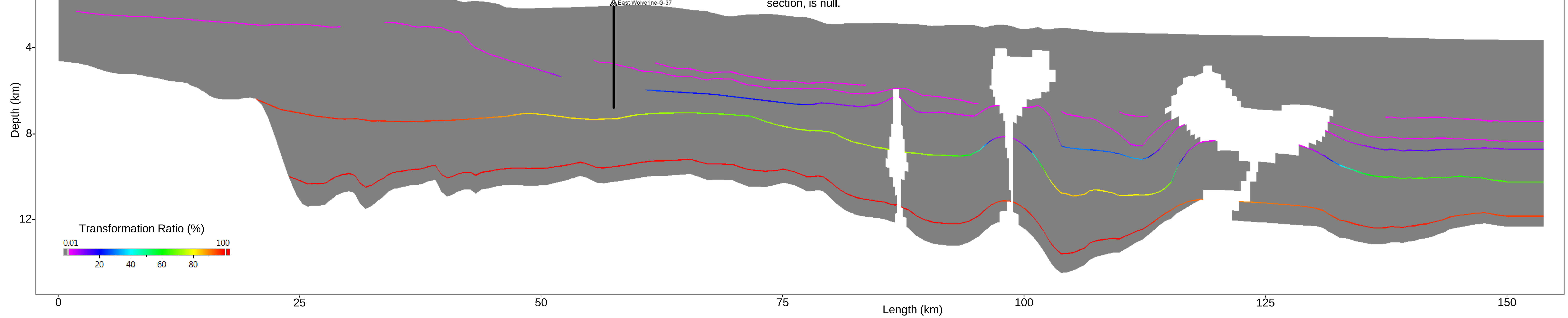


Evolution of the Transformation Ratio through time for the 2 deepest SR levels is similar to what has been observed at km 105 Location except for a much less mature Tithonian which has begun to expel HC only recently.

Transformation Ratio (Reference Scenario)



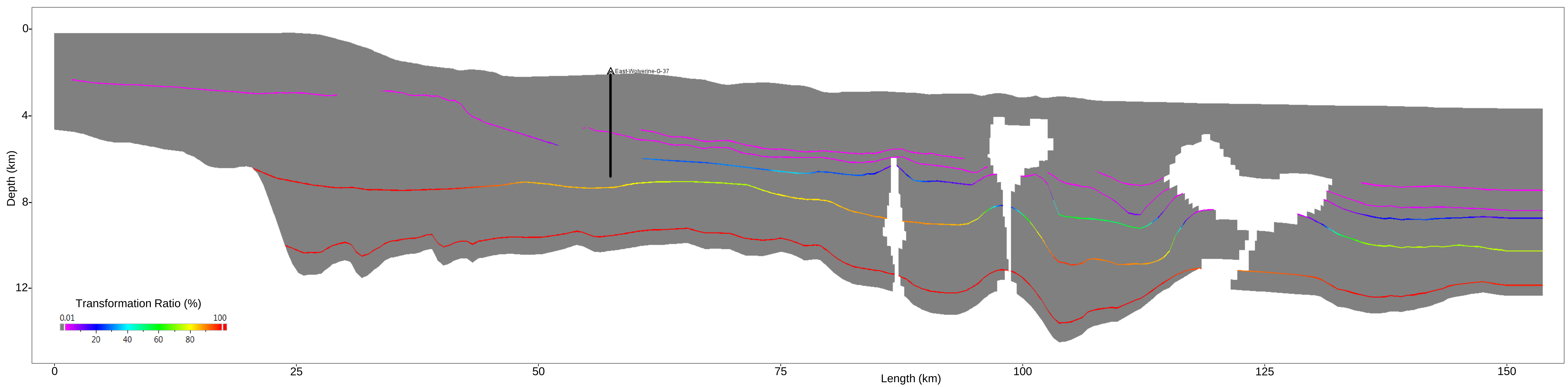
Transformation Ratio (Scenario 2 = Heat Flow variation)



As a consequence of the landward shift of the continental / oceanic crust limit (set in that specific case around 85 Km), a globally cooler model leads to a reduced maturity for Misaine and Tithonian source rocks (SR). While the decrease in hydrocarbon generation is limited for Misaine SR, it reaches up to 50% for Tithonian SR.

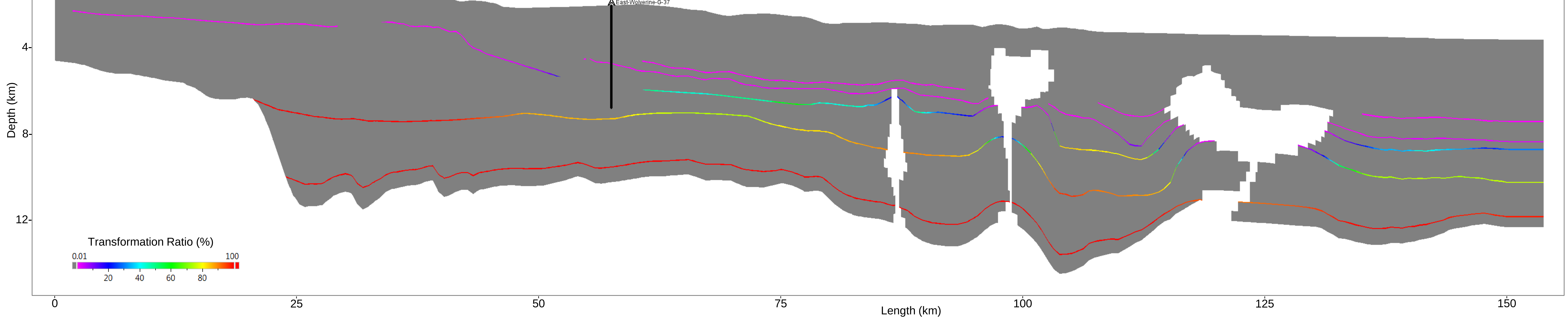
Impact of this scenario on both, the hydrocarbon generation for source rock located on the continental platform and, the Pliensbachian SR throughout the section, is null.

Transformation Ratio (Reference Scenario)



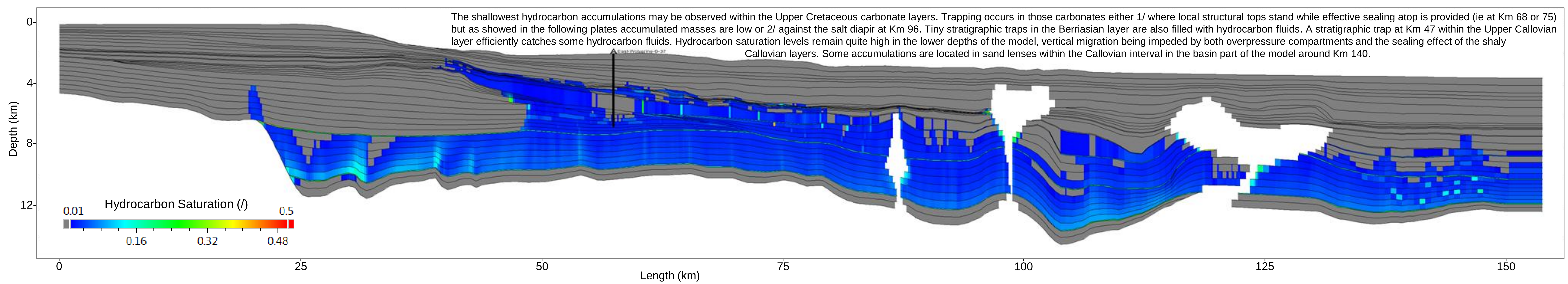
Transformation Ratio (Scenario 3 = Tithonian Type II)

In this alternative scenario the Tithonian source rock is defined by a richer, more proficient kerogen type II. The consequence is an increase of the transformation ratio for the Tithonian SR up to 20 % compared to the reference scenario, leading to increased generated hydrocarbon quantities, specifically in the mini-basin located around Km 105.
The overall hydrocarbon generation level of other SR is not affected along the section.

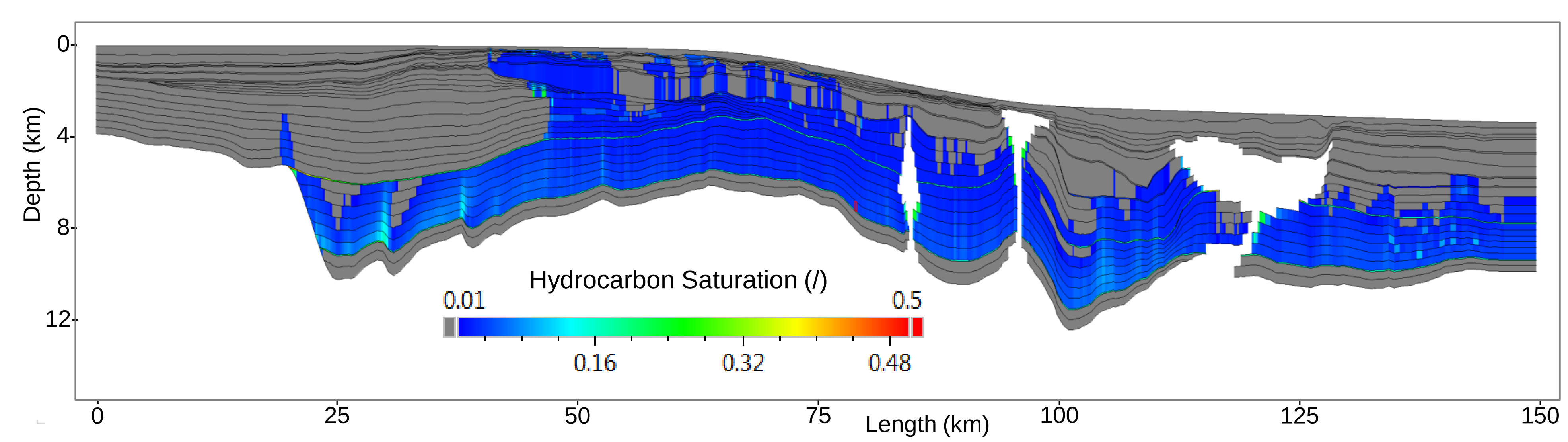


Hydrocarbon Saturation at Present Day (Reference Scenario)

The shallowest hydrocarbon accumulations may be observed within the Upper Cretaceous carbonate layers. Trapping occurs in those carbonates either 1/ where local structural tops stand while effective sealing atop is provided (ie at Km 68 or 75) but as showed in the following plates accumulated masses are low or 2/ against the salt diapir at Km 96. Tiny stratigraphic traps in the Berriasian layer are also filled with hydrocarbon fluids. A stratigraphic trap at Km 47 within the Upper Callovian layer efficiently catches some hydrocarbon fluids. Hydrocarbon saturation levels remain quite high in the lower depths of the model, vertical migration being impeded by both overpressure compartments and the sealing effect of the shaly Callovian layers. Some accumulations are located in sand lenses within the Callovian interval in the basin part of the model around Km 140.

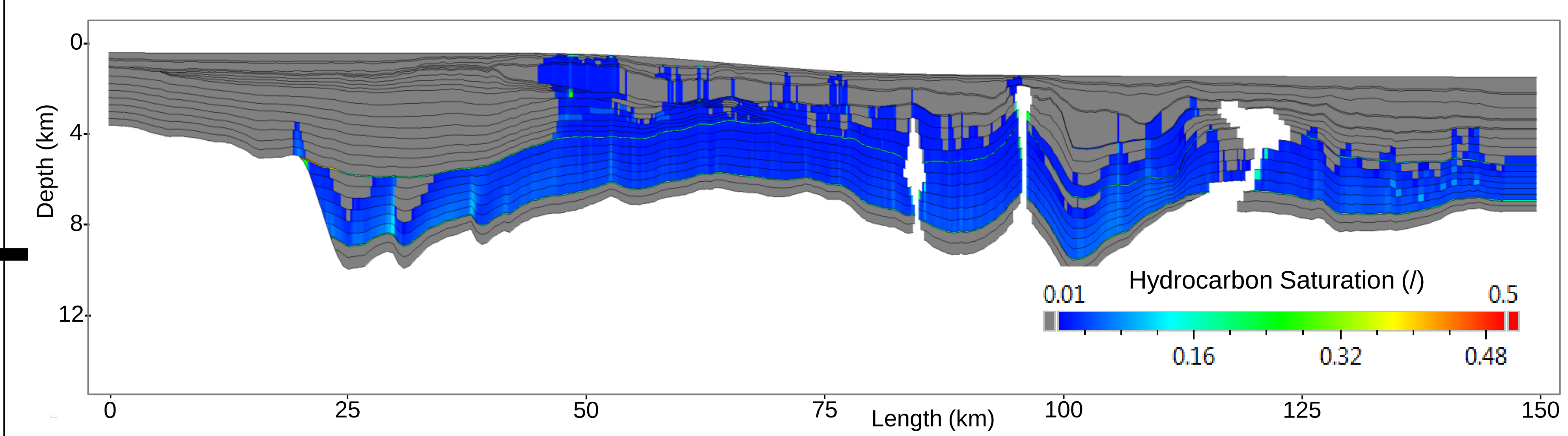


Hydrocarbon Saturation at 50 Ma (Reference Scenario)



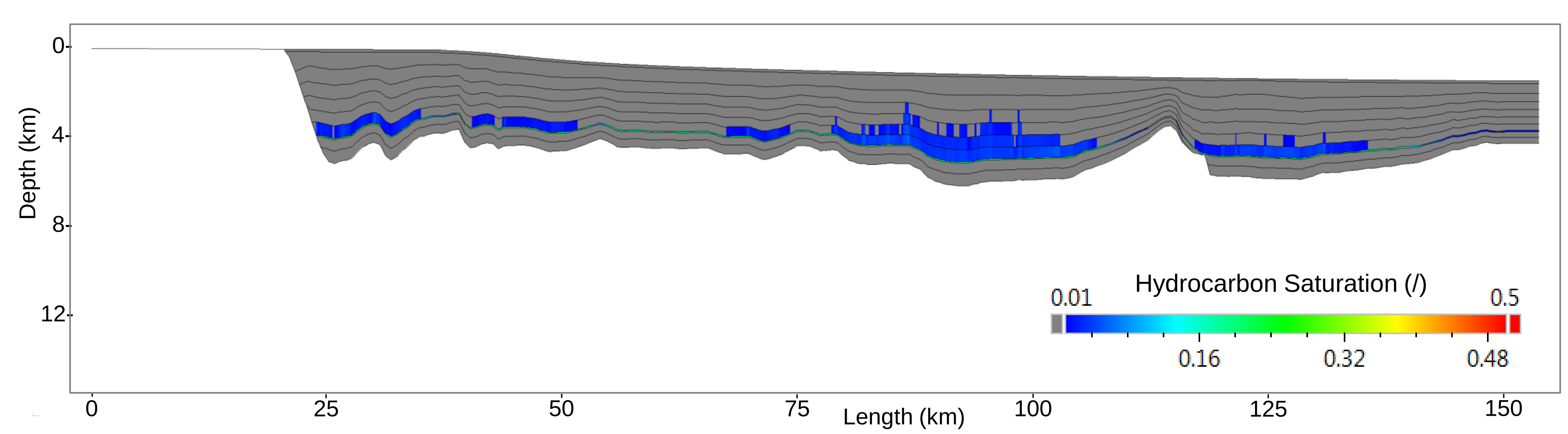
Vertical hydrocarbon flow resumes throughout the section as hydrocarbon fluids begin reaching the Upper Cretaceous carbonate layers.
Leaking from the Upper Callovian accumulation at Km 47 ceases as the seal gains efficiency through porosity and permeability reduction with burial.
Fluid retention against salt diapirs flanks continues.
Overpressure buildup in the Callovian interval around Km 25 and Km 15 impedes expelled hydrocarbon fluids from moving freely upwards.

Hydrocarbon Saturation at 101 Ma (Reference Scenario)



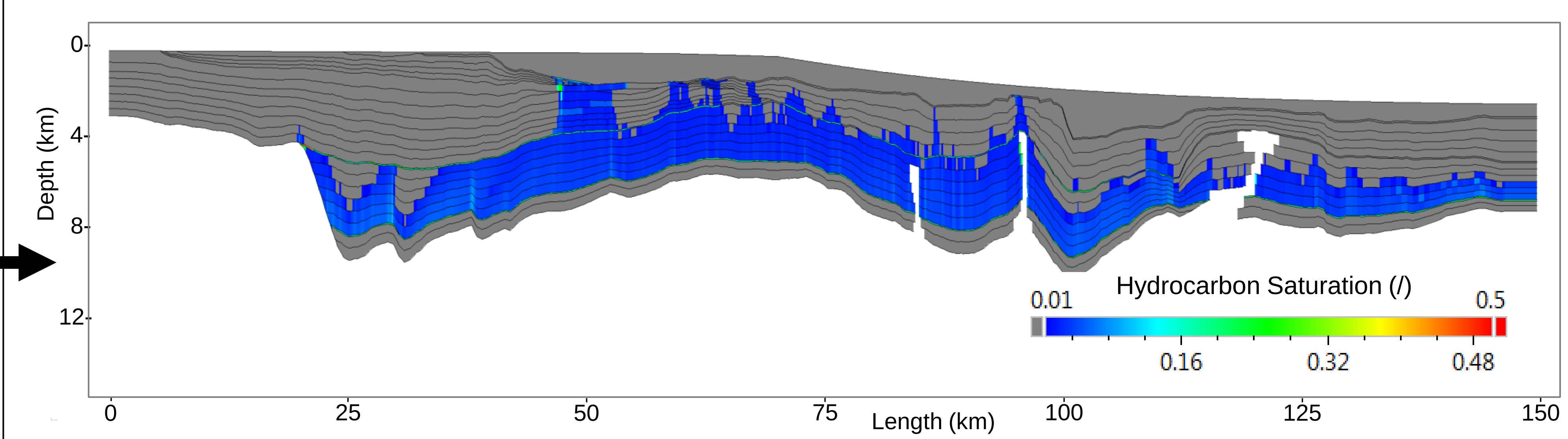
Vertical hydrocarbon flow resumes throughout the section.
Isolated sand lenses within the upper Tithonian make up for efficient migration conduits which allow hydrocarbon fluids to reach the shallowest intervals.
Within the Upper Callovian accumulation at Km 47, hydrocarbon pressure buildup allows for the fluids to pierce through the Oxfordian seal, eventually leaking to the sea bottom. Fluid retention against salt diapirs flanks continues.
Tithonian source rock does not yet generate hydrocarbon fluids.

Hydrocarbon Saturation at 166 Ma (Reference Scenario)



Hydrocarbon fluids expulsion begins from the deepest and most mature Pliensbachian source rock level entering the oil window.

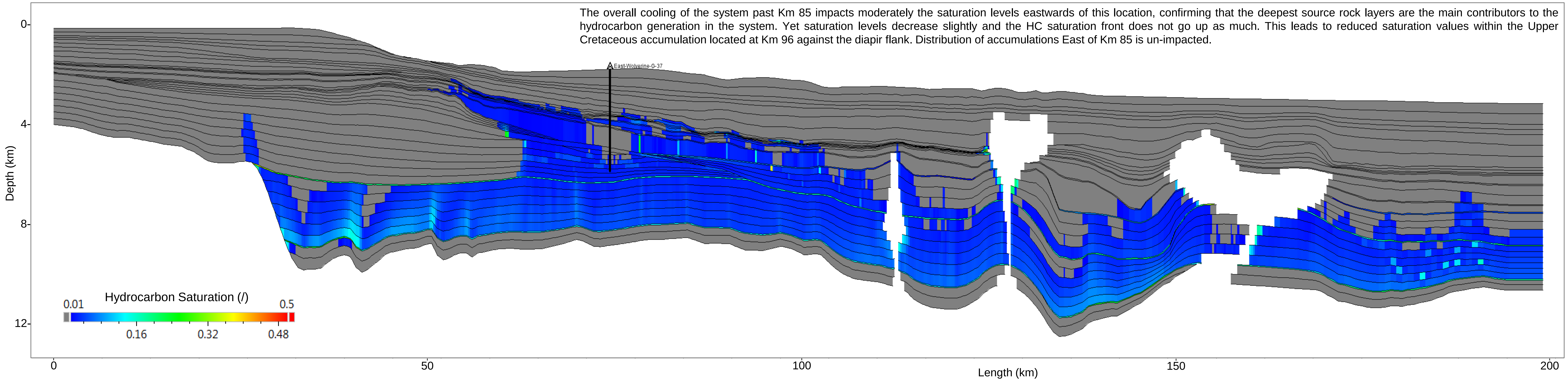
Hydrocarbon Saturation at 137 Ma (Reference Scenario)



Hydrocarbon fluids expulsion from the Pliensbachian source rock level spreads throughout the section as maturity conditions become more favorable. Misaine source rock layer begins expelling and contributes to the further vertical migration of hydrocarbon fluids columns.
At Km 47 an accumulation begins to form within a stratigraphic trap located in the Upper Callovian interval, the Oxfordian shaly layers atop acting as an encasing seal.
Some hydrocarbon fluids are retained against diapirs flanks at Km 90 and 120.

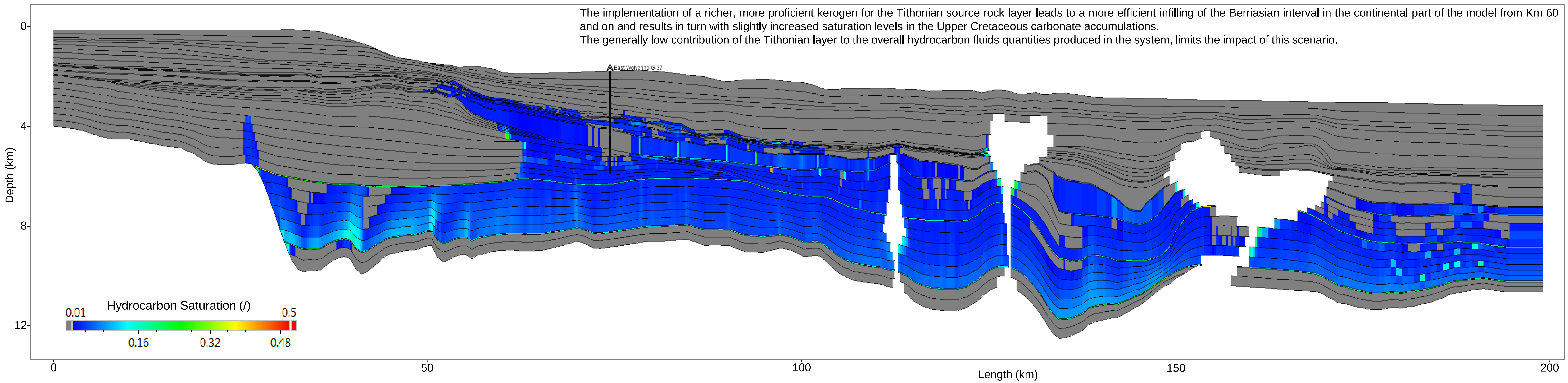
Hydrocarbon Saturation (Scenario 2 = Heat Flow variation)

The overall cooling of the system past Km 85 impacts moderately the saturation levels eastwards of this location, confirming that the deepest source rock layers are the main contributors to the hydrocarbon generation in the system. Yet saturation levels decrease slightly and the HC saturation front does not go up as much. This leads to reduced saturation values within the Upper Cretaceous accumulation located at Km 96 against the diapir flank. Distribution of accumulations East of Km 85 is un-impacted.

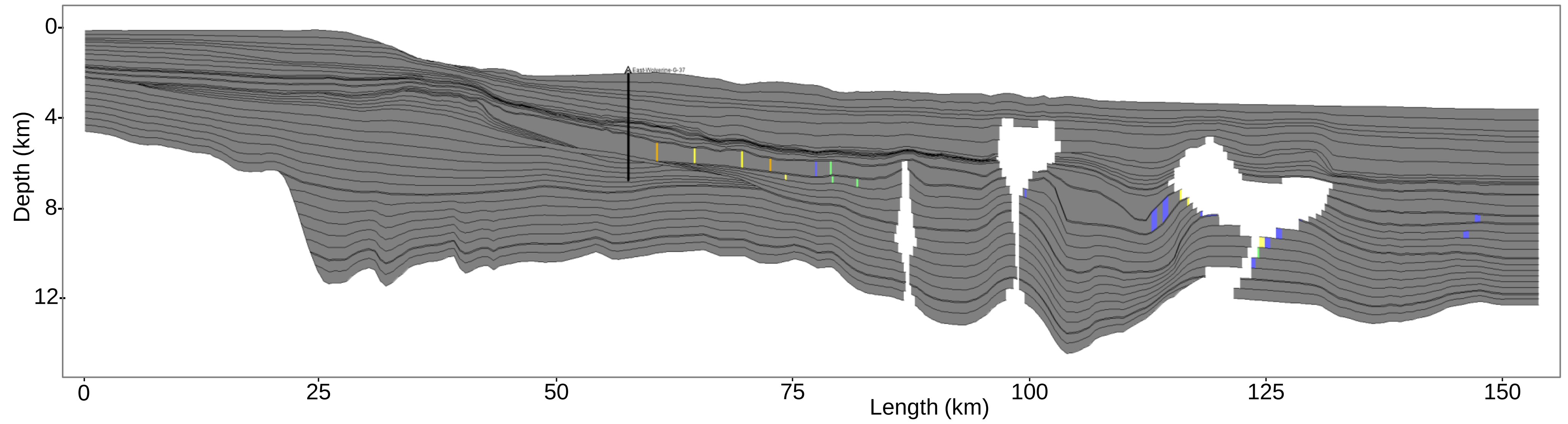


Hydrocarbon Saturation (Scenario 3 = Tithonian Type II)

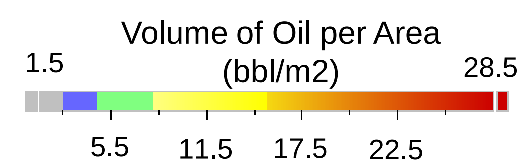
The implementation of a richer, more proficient kerogen for the Tithonian source rock layer leads to a more efficient infilling of the Berriasian interval in the continental part of the model from Km 60 and on and results in turn with slightly increased saturation levels in the Upper Cretaceous carbonate accumulations.
The generally low contribution of the Tithonian layer to the overall hydrocarbon fluids quantities produced in the system, limits the impact of this scenario.



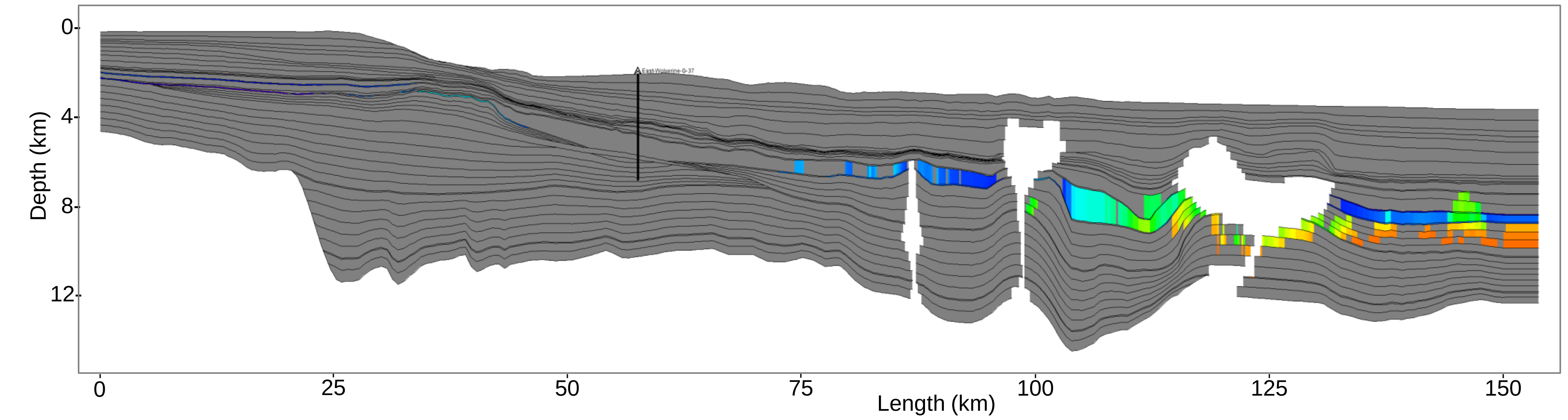
Volume of Oil per Area (Reference Scenario)



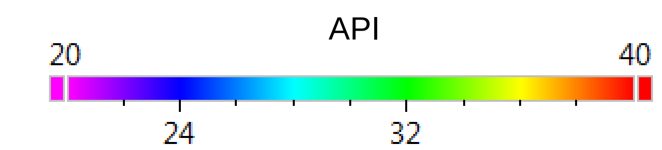
Mass of Oil is less than ~5.5bbl/m² in the model, except within some sand lenses in the Berriasian interval where accumulated masses reach up to 20 bbl/m². Those traps which are of stratigraphic nature would be tricky to confirm, save for a more detailed facies model. The over-mature state of the deepest source rocks layers which are the main contributors to the Petroleum System, the types of kerogen as well as the thermal conditions favorable to secondary cracking explain the absence of hydrocarbon liquids elsewhere.



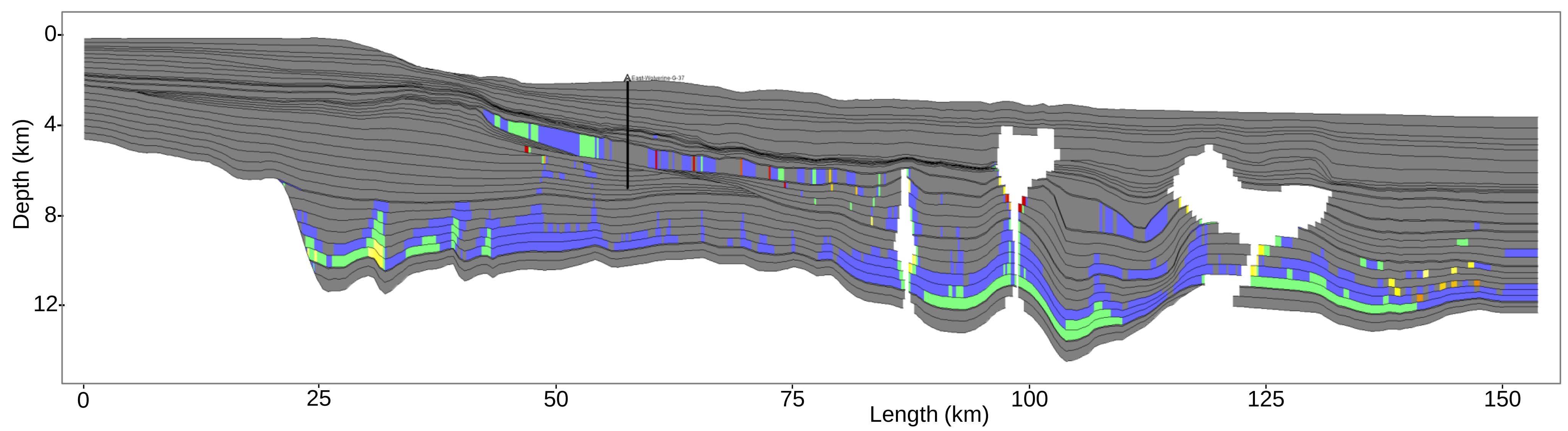
API Gravity - Oil (Reference Scenario)



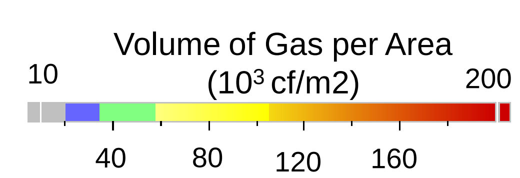
API Gravity of the oil varies between 24° API (Km 90) in the Berriasian interval and 38° API in the Oxfordian/Tithonian interval (Km 150).



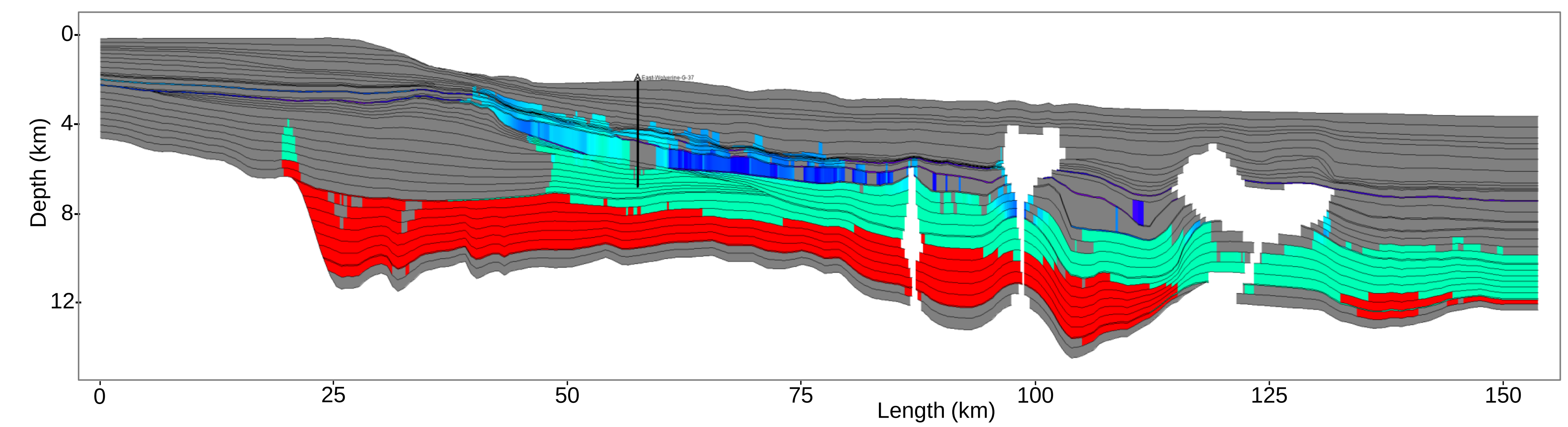
Volume of Gas per Area (Reference Scenario)



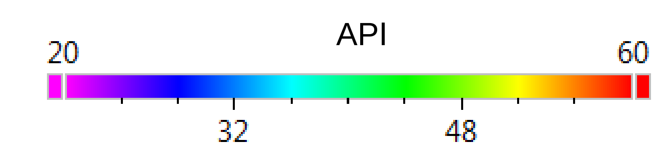
Gas is present in rather substantial quantities in the lower depths of the model. If out of a source rock layer and not marked of by a structural element, these gas quantities should be considered as diffuse distributions which have dissipated through geological time.
Accumulations picked in the previous slides displaying saturation levels are filled predominately with gas.



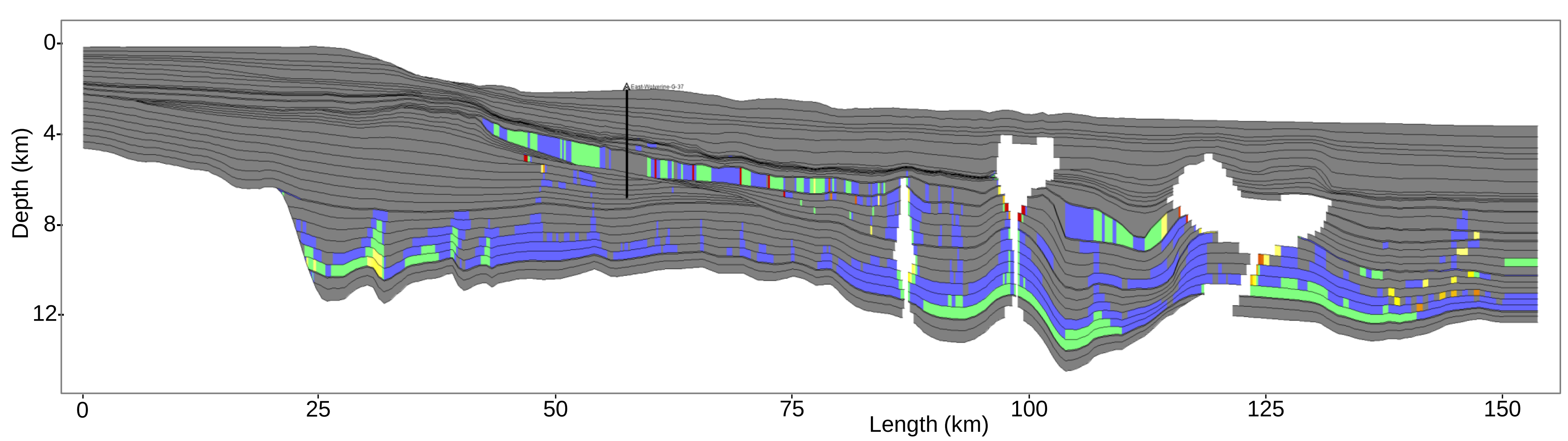
API Gravity - Condensates (Reference Scenario)



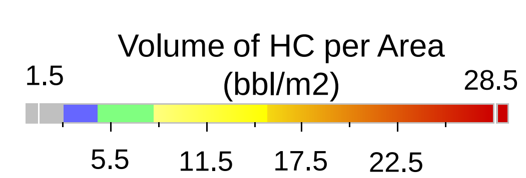
API Gravity of gas condensates varies between 32° and 40° API in the Upper Jurassic-Cretaceous system while it exceeds 60° API in the Lower Jurassic system.



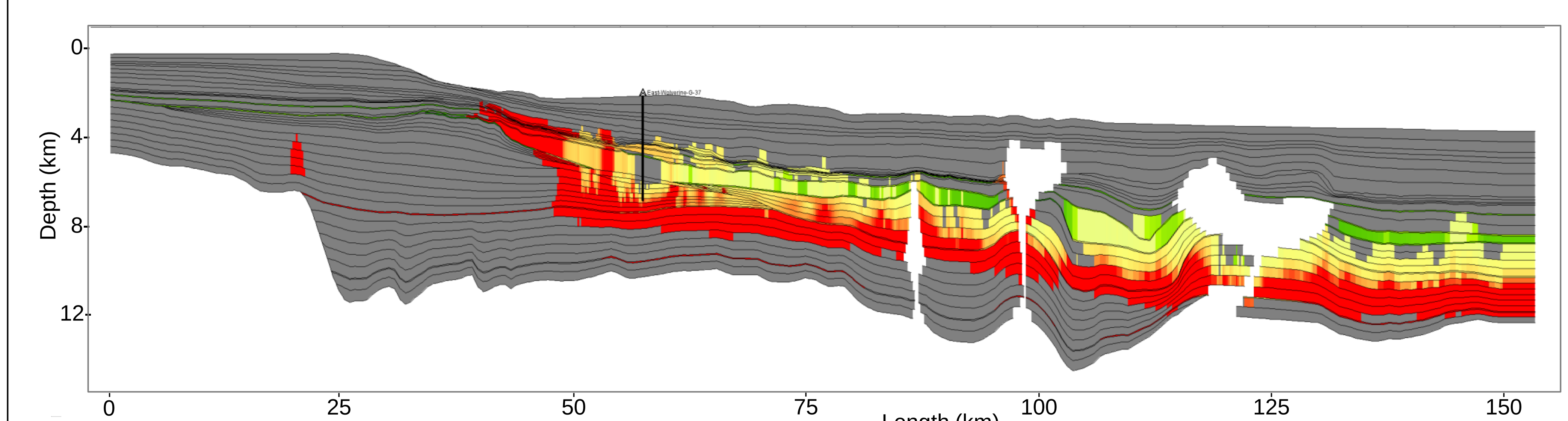
Total Volume of Hydrocarbon per Area (Reference Scenario)



As stated here above, the total volume of hydrocarbon in the model is entirely made of gas.
Total hydrocarbon volume is derived from the associates accumulated hydrocarbon masses using an average density.

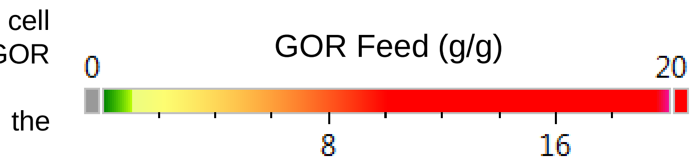


GOR Feed (Reference Scenario)

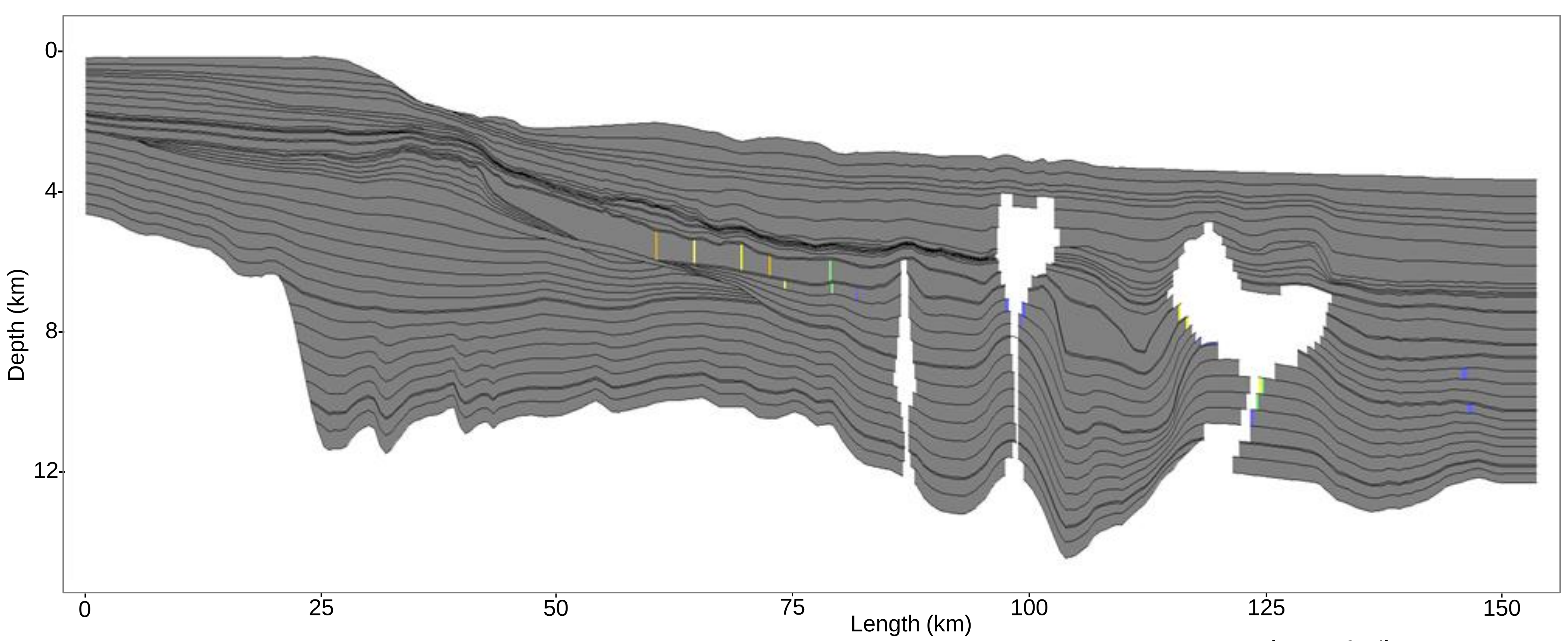


GOR Feed variable is the ratio between the mass of gas and the mass of oil accumulated in a given cell of the model. The mass of gas outweighs masses of gas and condensates as observed before with GOR exceeding 3 in most parts of the model except:

- in the Mississauga SR layer where it lays within the oil window and in the shallowest parts of the Tithonian SR. Yet the masses of oil associated to those greenish areas remain negligible.
- in the Berriasian interval within the sand lenses related accumulations, where oil might prevail locally.

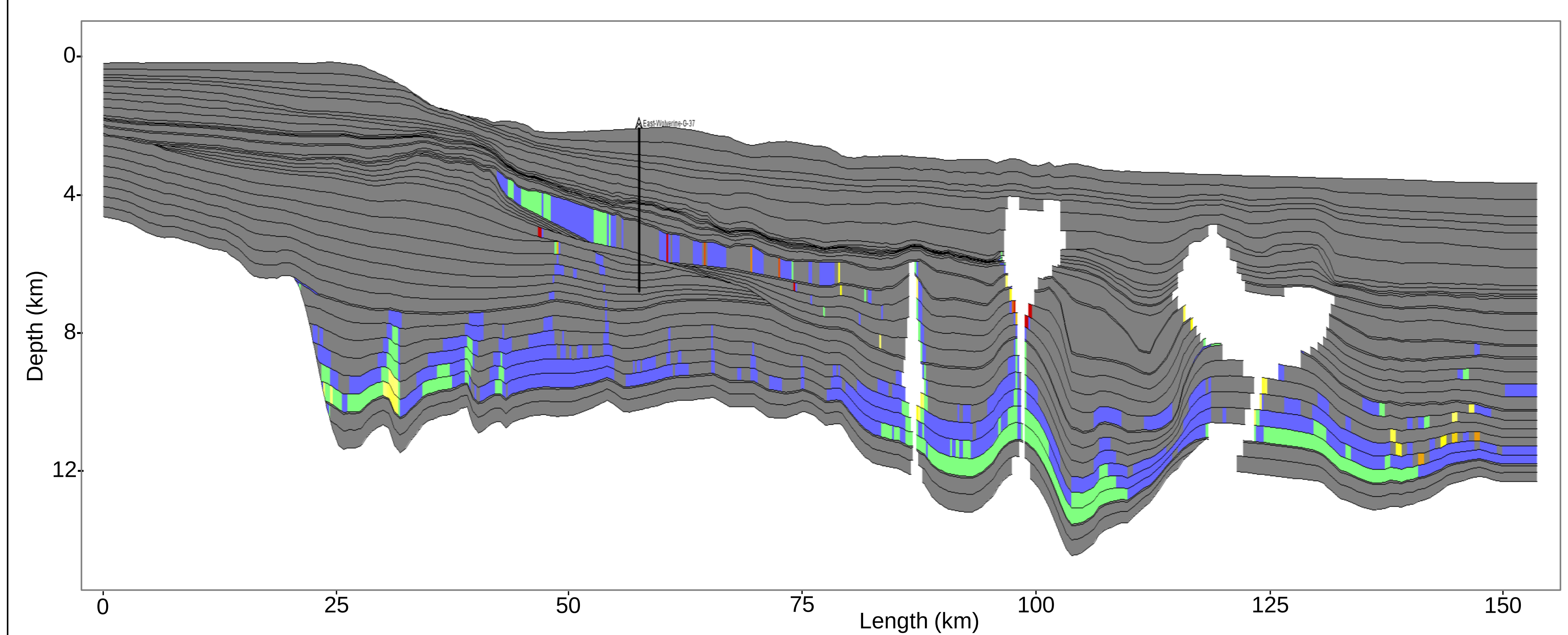


Volume of Oil per Area (Scenario 2 = Heat Flow variation)



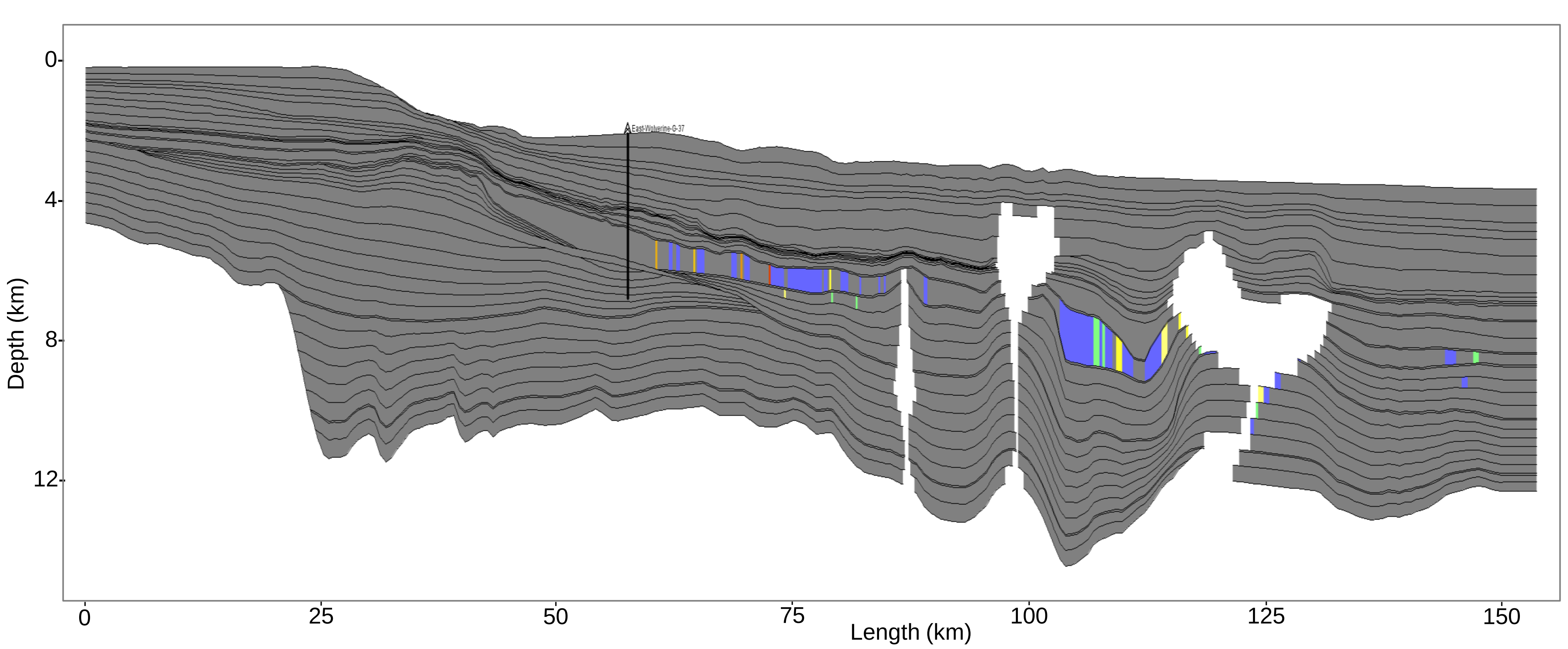
The overall cooling of the system has a limited impact on the overall oil distribution, only reducing slightly the accumulated masses in the easternmost Berriasian oil spots.

Volume of Gas per Area (Scenario 2 = Heat Flow variation)



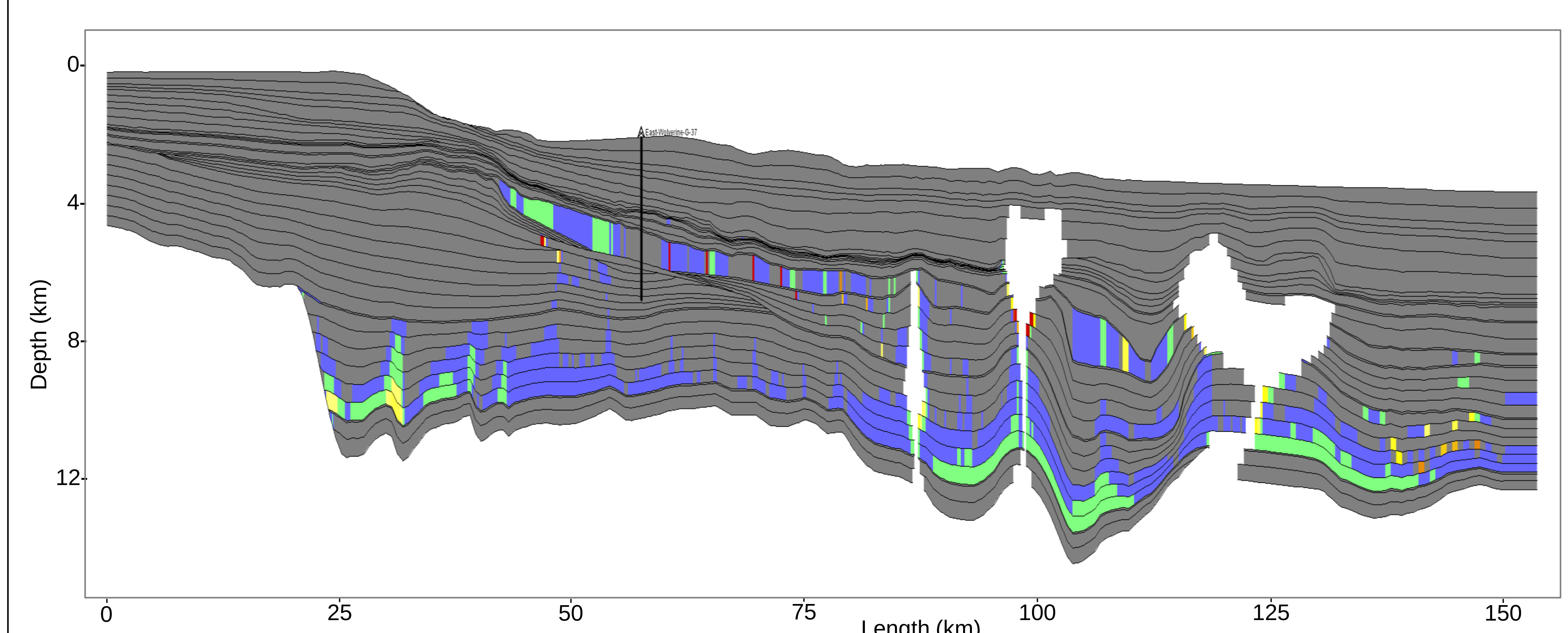
The overall cooling of the system only has a slight effect on the accumulated masses of gas east of Km 85 in the Lower Jurassic System.

Volume of Oil per Area (Scenario 3 = Tithonian Type II)

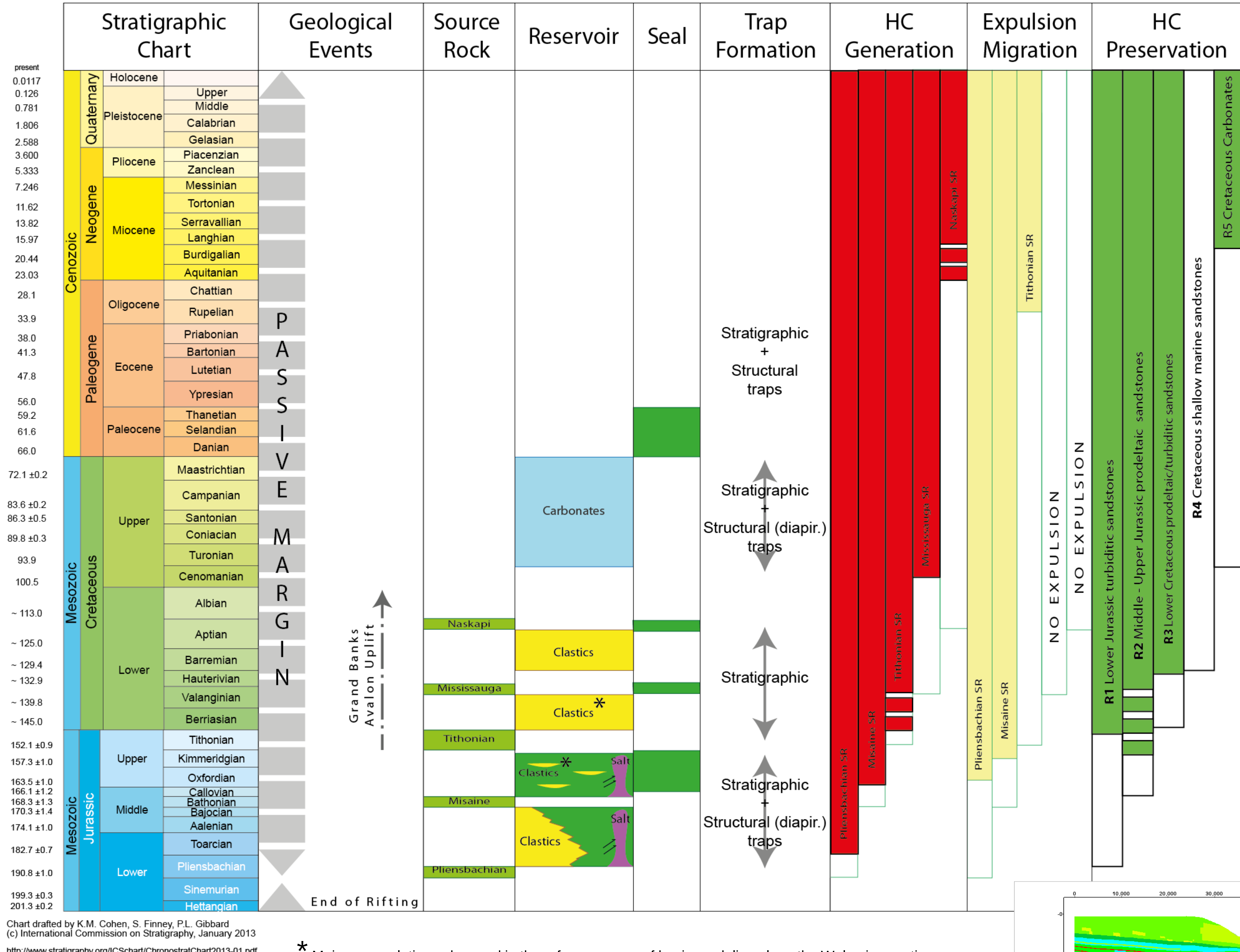


The definition of a more proficient kerogen for the Tithonian source rock moderately impacts the oil masses accumulated in the Tithonian Cretaceous sytem west of Km 85, redistributing them and increasing slightly the overall available oil quantity in the interval.
The new kerogen is also much more proficient oil-wise in the mini-basin located around Km 110, increasing sensibly available oil quantities in the Berriasian interval there.

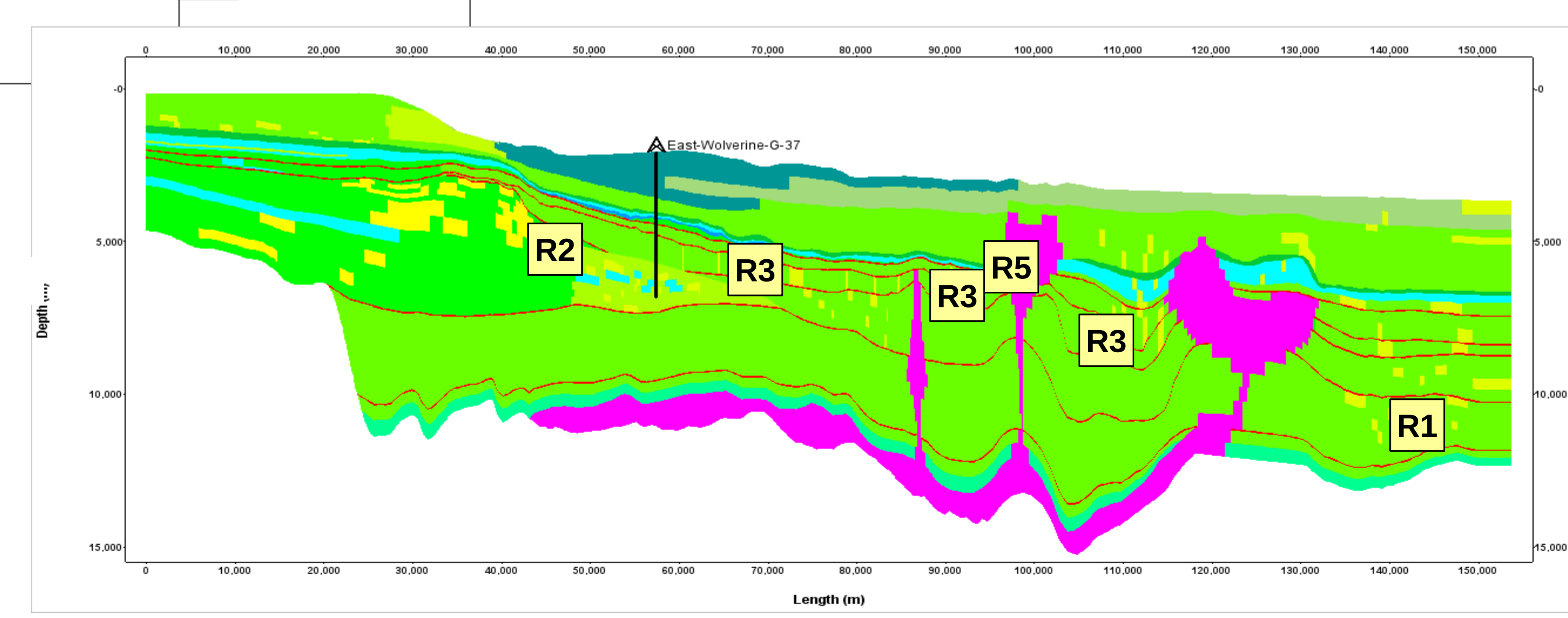
Volume of Gas per Area (Scenario 3 = Tithonian Type II)



The definition of a more proficient kerogen for the Tithonian source rock moderately impacts the oil masses accumulated in the Tithonian Cretaceous sytem west of Km 85, redistributing them and increasing slightly the overall free gas quantity in the interval.
Yet the new kerogen is more proficient in the mini-basin located around Km 110, increasing the available gas quantities in the Berriasian interval.



* Main accumulations observed in the reference case of basin modeling along the Wolverine section



CONCLUSION

Source Rocks

As showcased by the **Synthetic Petroleum System Chart** here below, the models feature the following 5 source rock levels:

- Naskapi (or Aptian 122 Ma) – Type III kerogen
- Mississauga (or Valanginian 136 Ma**)** – Type III kerogen
- Tithonian (148 Ma) - Type II/III kerogen
- Misaine (or Callovian 166 Ma) – Type II/III kerogen
- Pliensbachian (196 Ma) – Type II kerogen

Maturity modeling shows that the potential Lower and Middle Jurassic source rocks (Pliensbachian and Misaine) are generally overmature throughout the studied area, given their high burial depth ranging approximately from 7,000m to 10,000m. Even below large salt canopies that may locally reduce the thermal gradient, the Lower and Middle Jurassic source rocks are buried deeply enough to remain well below the gas windows, even getting overcooked locally: overcooking occurs for the Pliensbachian source rock around 6,000m burial in the continental domain and around 8,000m burial in the transition zone.
Due to high burial rates after the rifting event, maturity processes start early during Middle to Late Jurassic times, ending generally during Cretaceous.

The Tithonian source rock layer is overall immature, except at some specific locations which are usually depressions associated to the normal fault system at the shelf edge: at such locations it is entering the oil window and contributes to the generation of hydrocarbon fluids in the system.

The Lower Cretaceous source rocks (Naskapi and Mississauga) remain mostly immature or early mature (TR<10% with type III kerogens) throughout the studied area and as such they cannot be considered as effective contributors to the hydrocarbon production in the petroleum systems.

Synthetic Petroleum System Chart (for the whole study area)

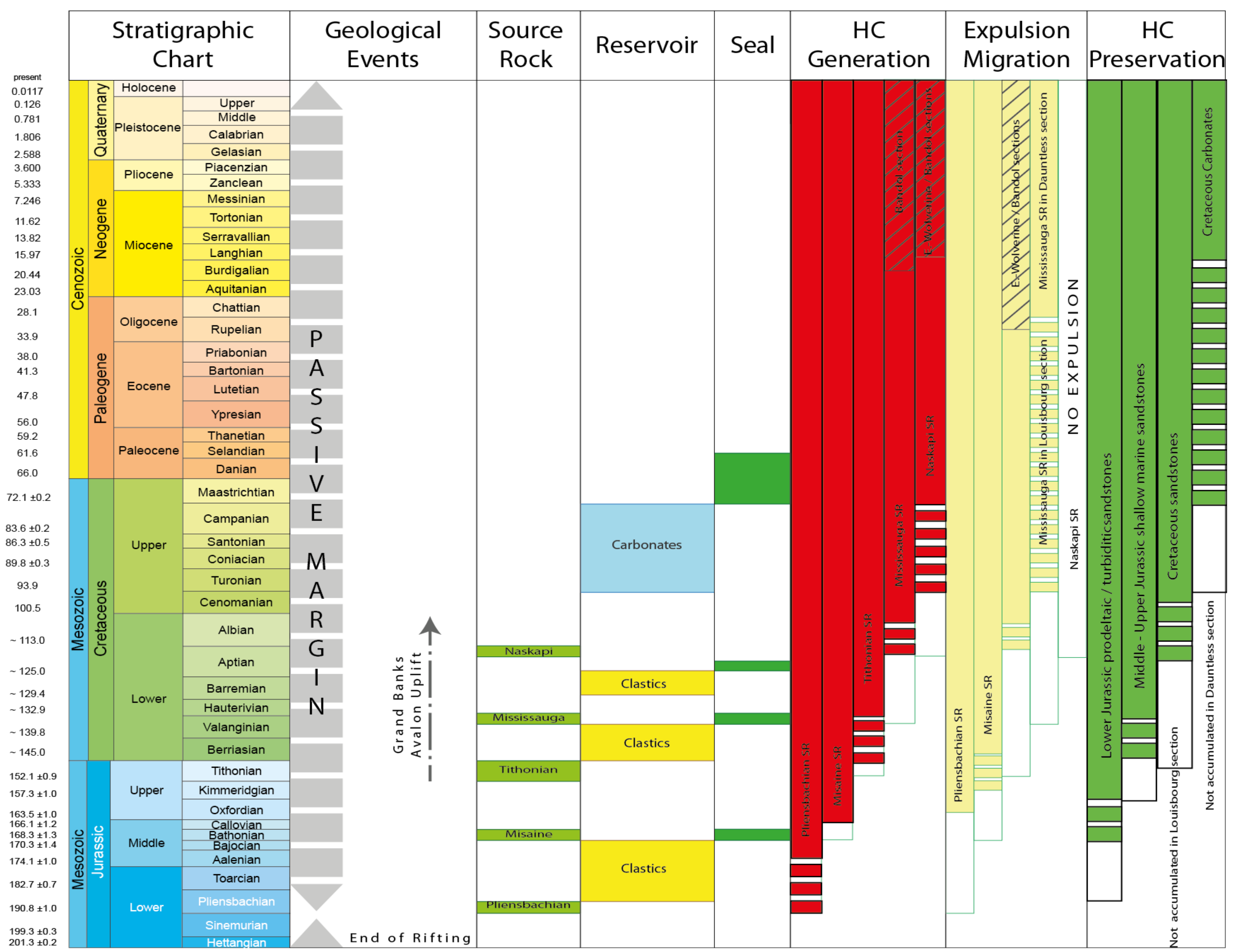


Chart drafted by K.M. Cohen, S. Finney, P.L. Gibbard
(c) International Commission on Stratigraphy, January 2013
http://www.stratigraphy.org/ICSchart/ChronostratChart2013-01.pdf

Hydrocarbon Migration

Along studied sections the hydrocarbons in place originate mainly from the Lower (Pliensbachian) and Middle (Misaine) Jurassic source rocks, which are the main contributors to the overall hydrocarbon quantities produced in the petroleum systems of the study area. Nevertheless the real potential of Jurassic source rocks is poorly constrained in the Laurentian Basin.

The onset of the migration processes lays between ~160 Ma for the Lower Jurassic source rocks and between ~95 Ma and ~25 Ma for the Lower Cretaceous ones. The hydrocarbon expulsion from Lower Jurassic source rocks is maximum during the Late Jurassic and the Early Cretaceous.

Large quantities of hydrocarbon fluids (in the form of gas and to a lesser extent of condensates) remain trapped within the Jurassic layers, hardly being able to pierce through the thick shaly middle-jurassic series deposited along the platform and in the distal areas in the basin. The preservation of those large gas quantities is to be questioned. They could be considered as diffuse accumulations which have dissipated through geological time and, at Present, no commercial value should be attached to them because of the great depth (>10km depth with a water depth ranging from 0 to 4km). Additionally those series may experience severe overpressure conditions.

From those deep intervals migration patterns are mostly vertical. The migration toward Cretaceous reservoirs is usually slow and progressive. The hydrocarbon saturation front progression is locally eased by:

- The occurrence of salt diapirism which drains fluids upwards,
- The normal faults system located at the shelf edge,
- The contribution of the Tithonian layer, where the Tithonian source rock is mature enough.

The existence of such features is a key element in the occurrence of active petroleum systems.

Finally, the formation of the best traps in Upper Cretaceous and Berriasian intervals precedes the slow inflow of hydrocarbon fluids, making the timing of trap creation versus fluid migration relatively favorable (despite the early generation/expulsion in Jurassic source rocks. Most of the accumulations in Cretaceous layers are completely filled during the Neogene, but the onset of the infilling is often Late Cretaceous (the existence of two successive infilling events is possible).

Dismigration is observed mainly in the Berriasian interval where permeable pro-deltaic sandy lithofacies allow the hydrocarbon fluids, originally stacked below the Valanginian seal , to migrate laterally in pinch-outs west of the normal fault system (see Dauntless section).

The amount of hydrocarbons that reaches Cretaceous accumulations is relatively small in comparison with what remains dispersed in Jurassic units. On the basis of studied sections the chance to find large drainage areas is rather low, particularly in the salt basin.

Reservoirs & Plays

The migration patterns described in the **Charge & Migration** section is efficient to fill:

- **Carbonate reservoirs in the Upper Cretaceous interval**, the shaly Paleocene series stacked atop acting as a seal. Such traps have a structural component attached to them as they are located usually on top of salt diapirs apexes.
- **Sandy clastic reservoirs in the Berriasian interval** which are sealed by the efficient Mississauga (Valangian) layer.
- **Sandy clastic reservoirs in the Upper Jurassic interval,** sealed by the Tithonian layer. Those traps have a strong stratigraphic component attached to them, being pro-deltaic sands (see East-Wolverine section) or turbiditic sand lenses in the basin part of the sections (see Bandol section). Their viability could be confirmed through a more detailed and constrained facies model.

Many traps have a mixed origin, stratigraphic and structural.

Reservoirs are mostly charged with gas, the oil occurrence remaining very low throughout all 2D models built. The predominance of gas in the models has several explanations:

- The Pliensbachian source rock would be the main contributor to petroleum systems (according to studied sections). Due to its rapid and considerable burial, this source rock maturated very early (from Middle to Later Jurassic) and got overmature during the Lower Cretaceous. As a consequence, it quickly injected gas into the system.
- Oil generated by the Pliensbachian SR (assumed to be a type II source rock) remained in Jurassic units for tens of million years (the vertical migration is slow according to the model). The severe secondary cracking of the oil produced large amount of gas before the hydrocarbon migration into Cretaceous reservoirs.
- Shallower source rocks, including the Misaine SR and the Tithonian SR, would contain type II-III or type III kerogens. Terrigenous organic matter usually produces more gas than oil, including at low maturity levels.

Still some oil accumulations may be delineated:

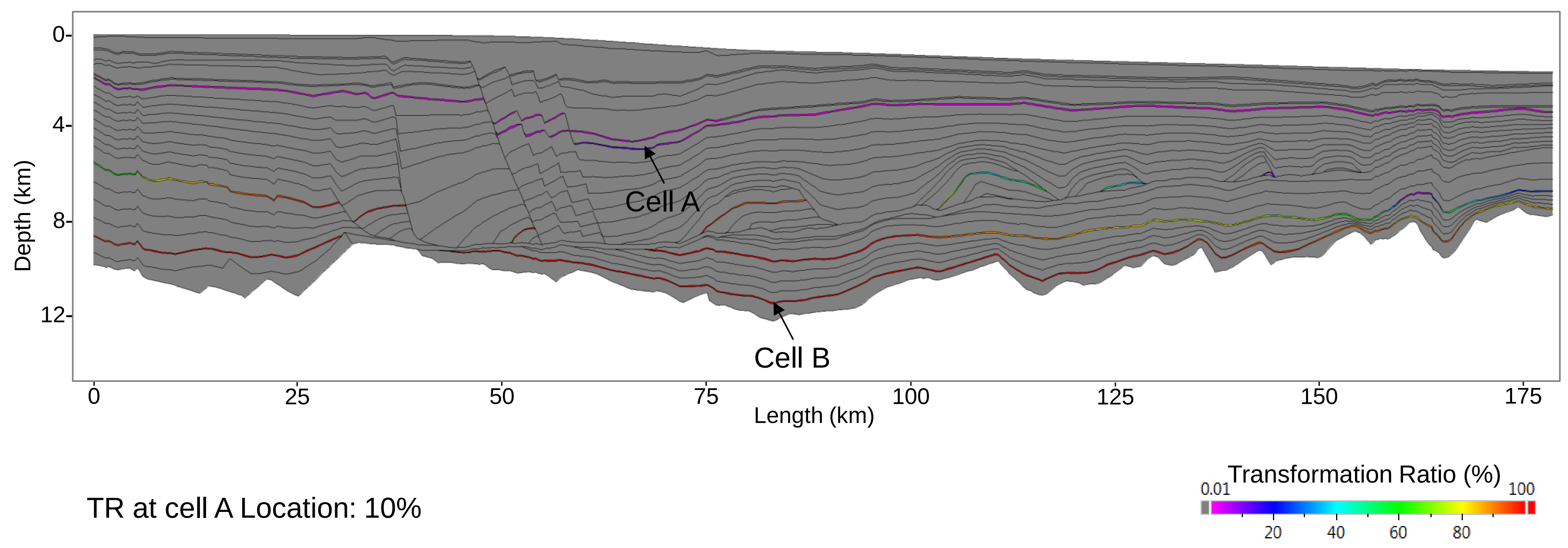
- Within pro-deltaic sands in the Berriasian interval, the oil being sourced from the Tithonian layer (see Bandol and East-Wolverine sections),
- In Upper Cretaceous carbonates (see Bandol section),
- In Upper Jurassic reservoirs against salt diapirs (see Bandol section).

According to the models, the presence of oil is also possible at the easternmost fringe of the salt basin, close to the continental/oceanic crust boundary, where the burial of Jurassic source rocks is somehow smaller, and where the presence of salt canopies and of a crust poorer in radioactive elements, reduces the thermal gradient. However no large oil accumulations are modeled in this domain.

Reservoirs which may contain some oil quantities are all subjected to temperatures exceeding 80°C, sheltering them from the occurrence of biodegradation processes.

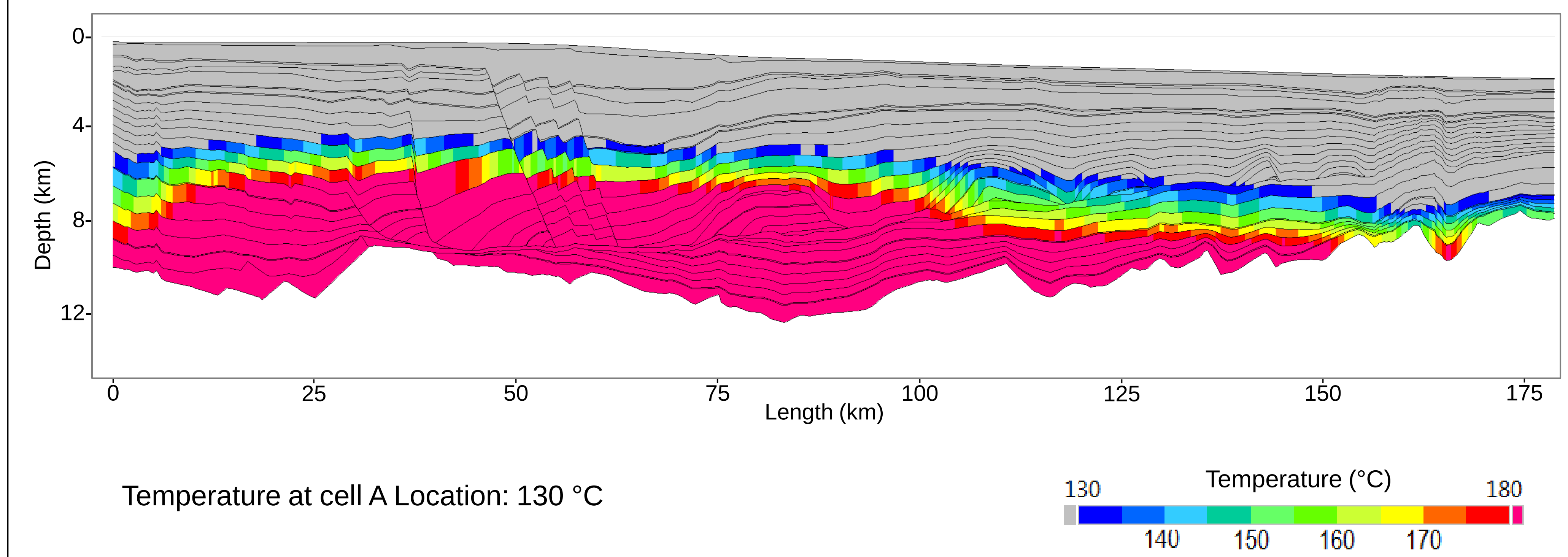
APPENDIX

Transformation Ratio at 110 MA – Reference Scenario



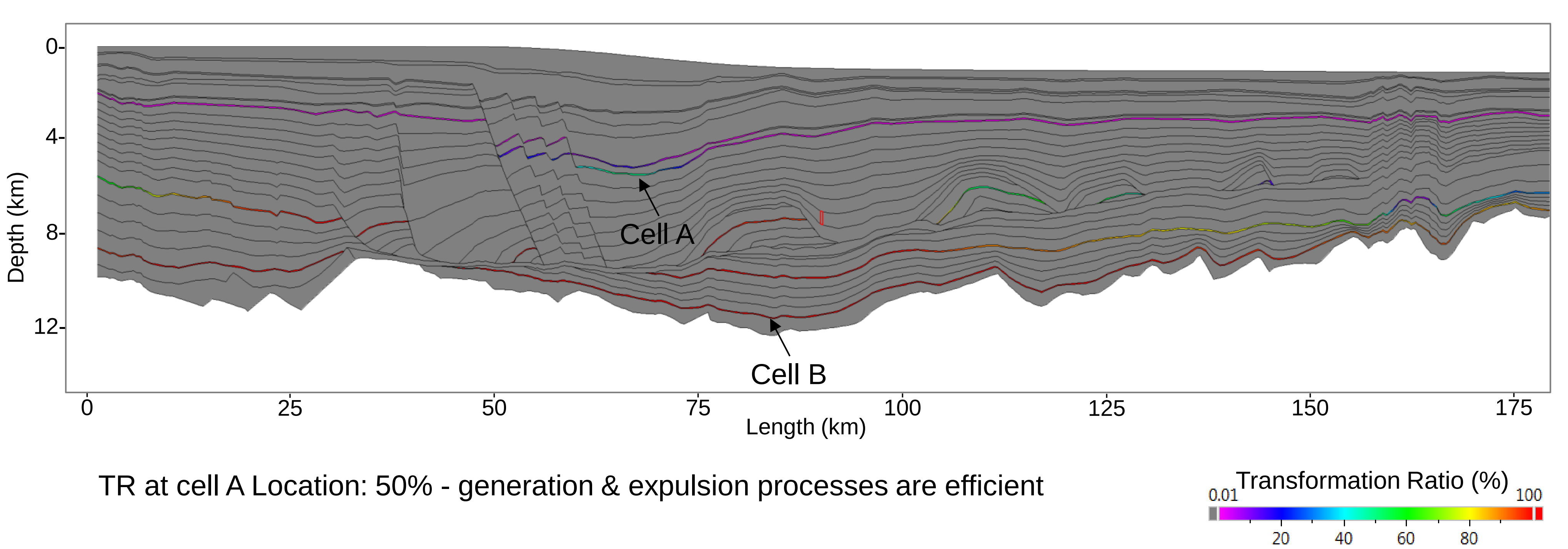
TR at cell A Location: 10%

Temperature at 110 MA – Reference Scenario



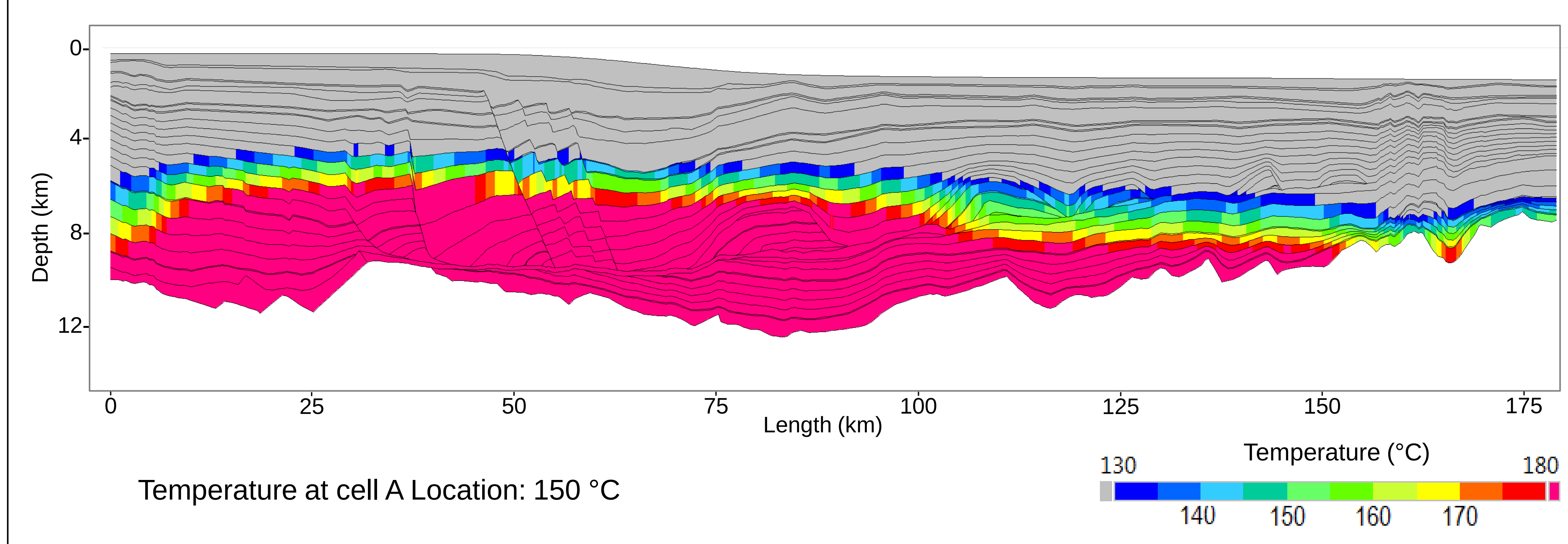
Temperature at cell A Location: 130 °C

Transformation Ratio at 101 MA – Reference Scenario



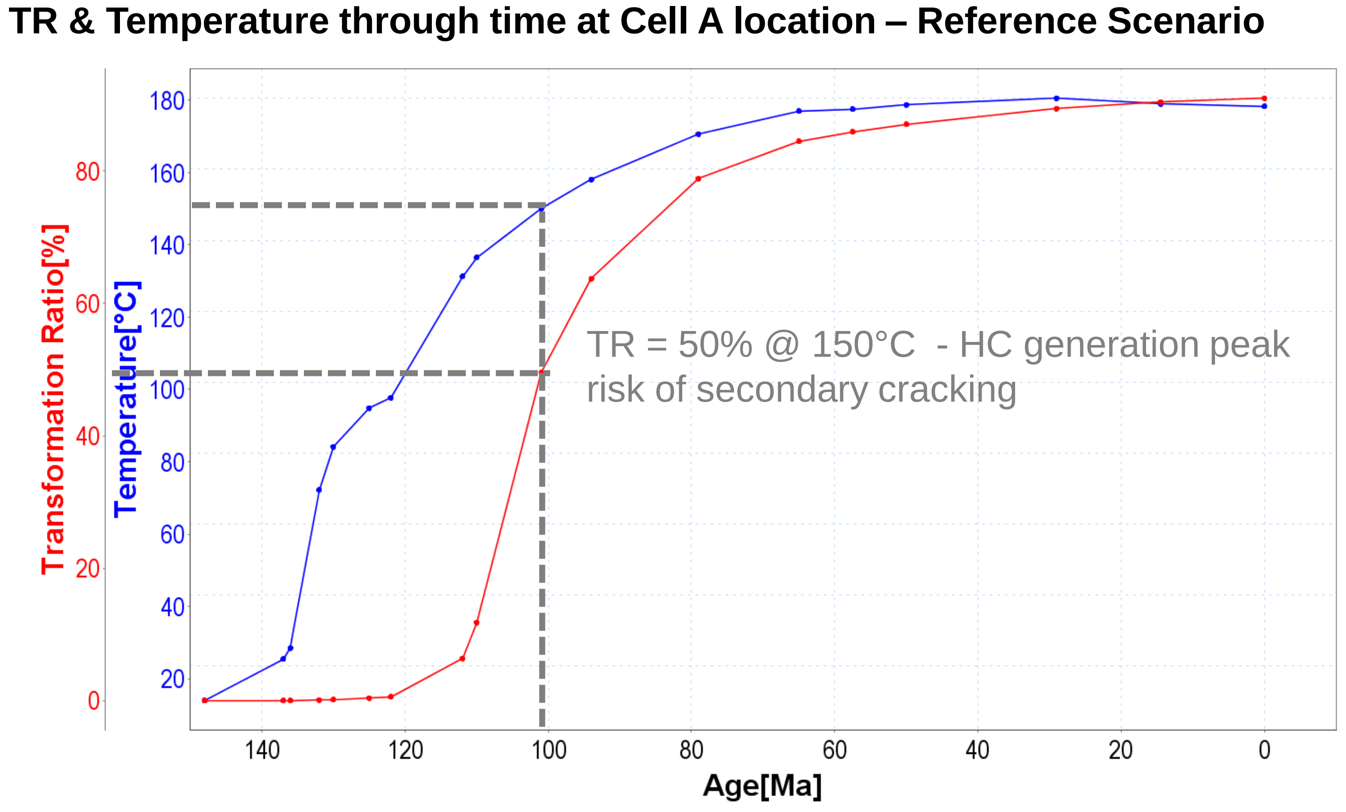
TR at cell A Location: 50% - generation & expulsion processes are efficient

Temperature at 101 MA – Reference Scenario

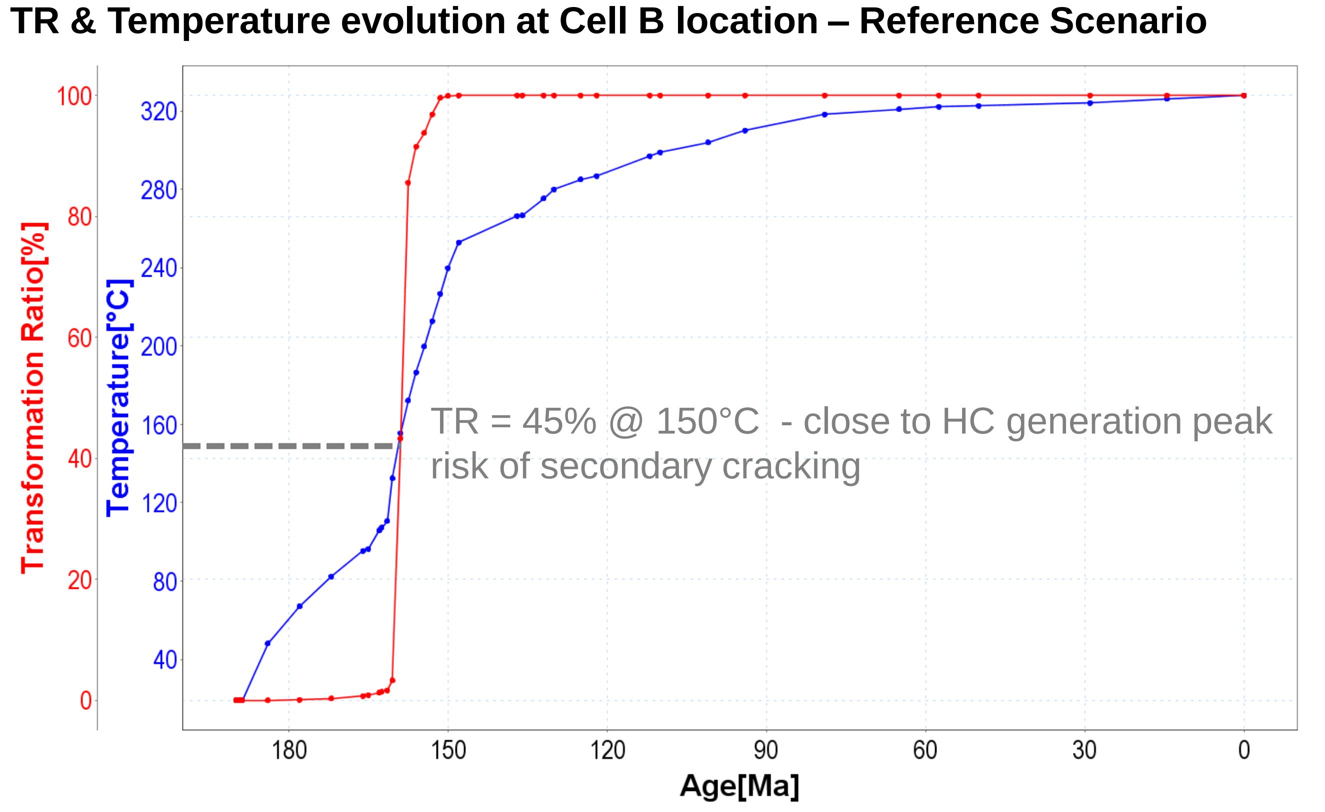


Temperature at cell A Location: 150 °C

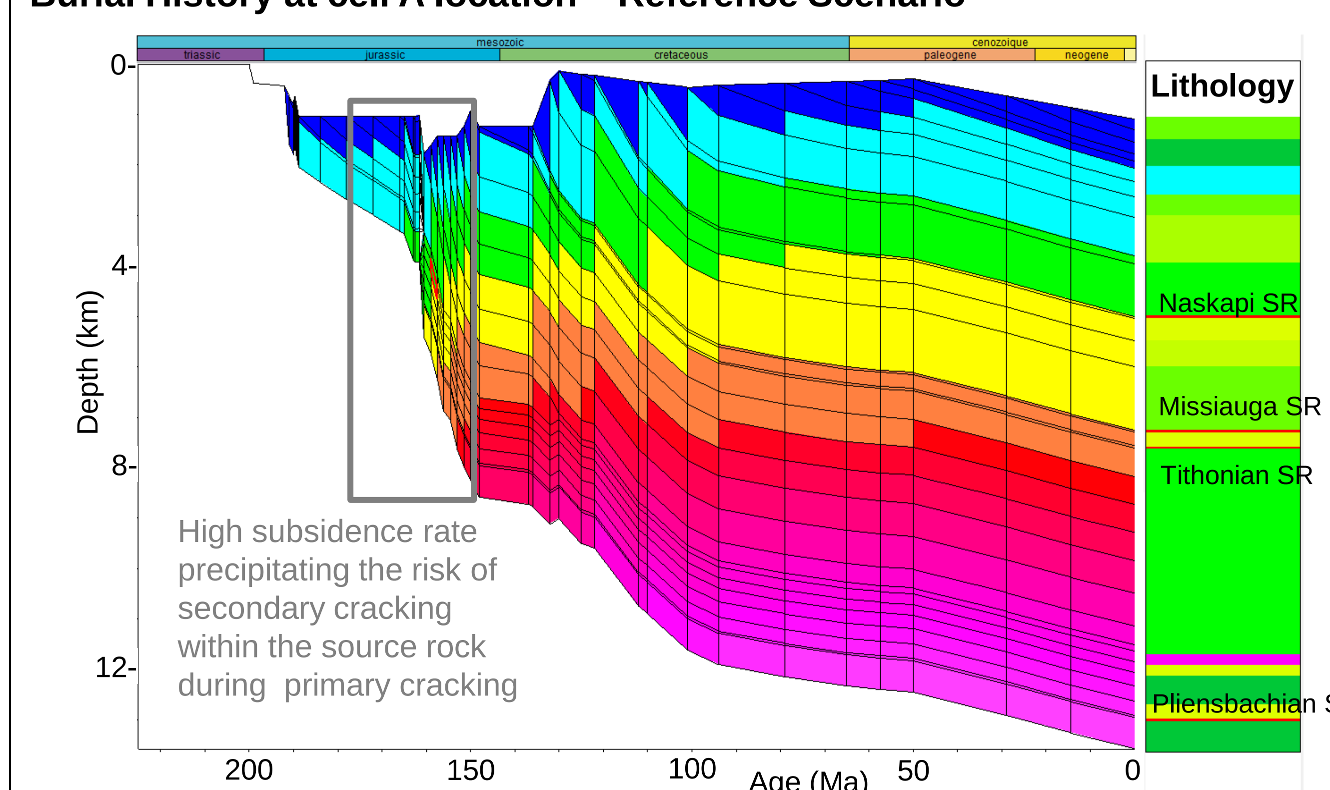
TR & Temperature through time at Cell A location – Reference Scenario



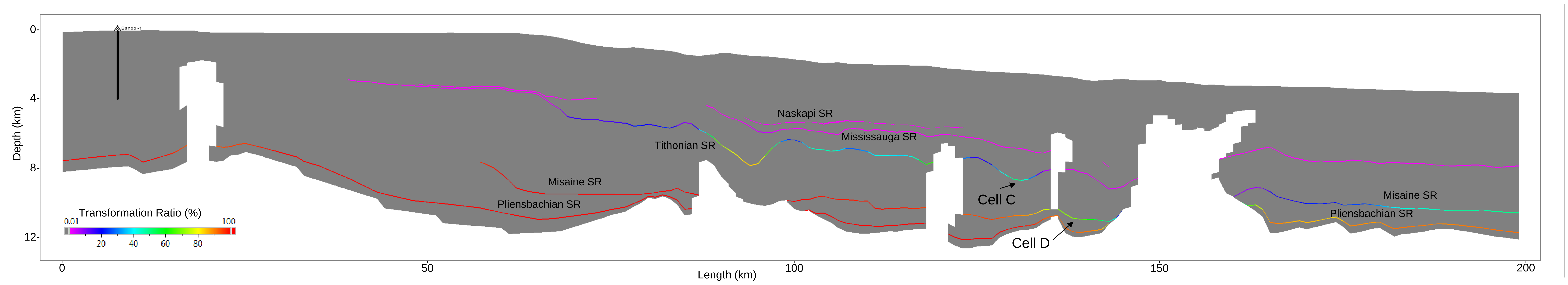
TR & Temperature evolution at Cell B location – Reference Scenario



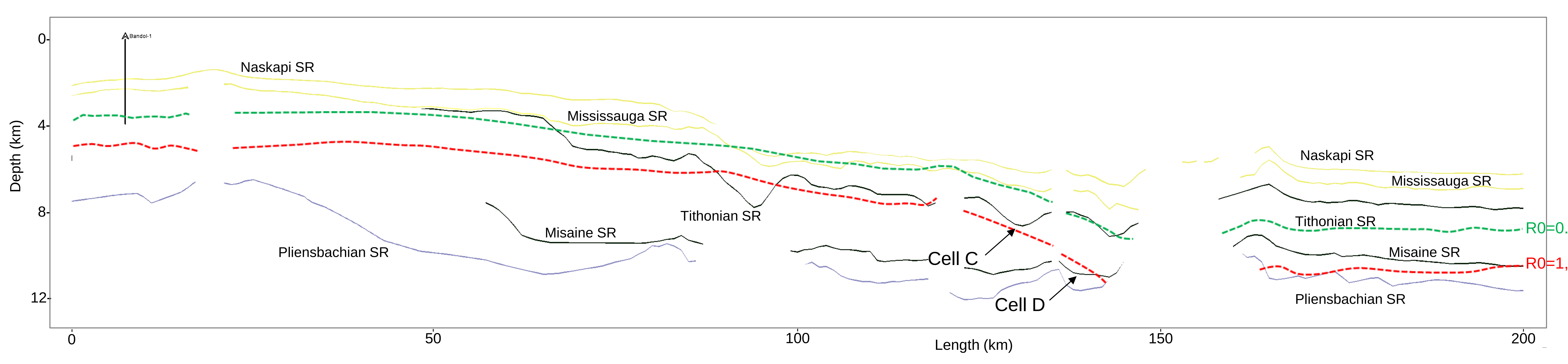
Burial History at cell A location – Reference Scenario



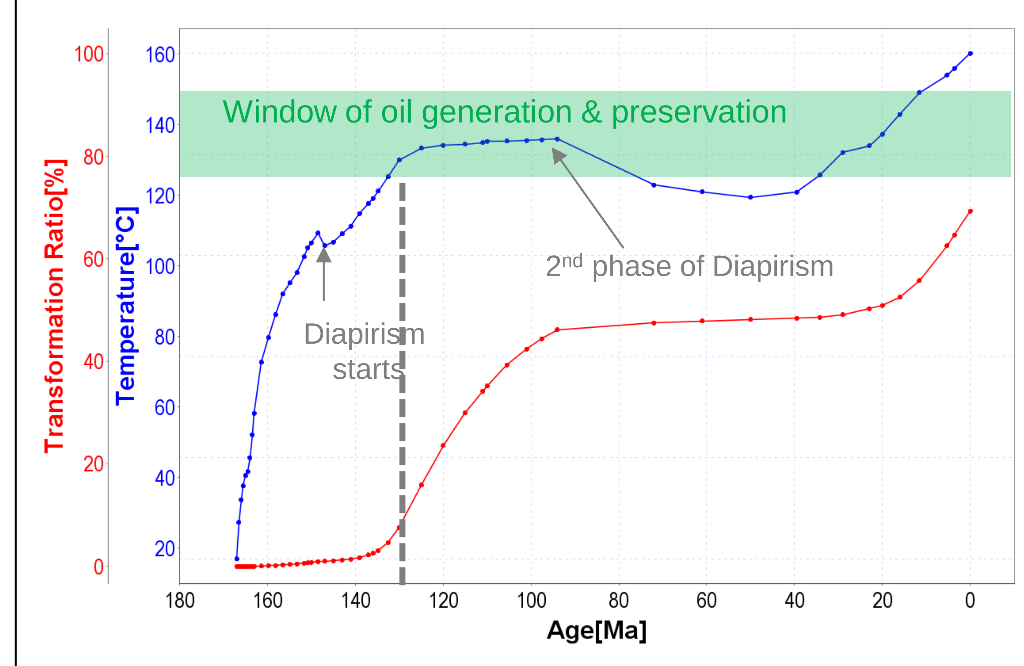
Transformation Ratio (Reference Scenario)



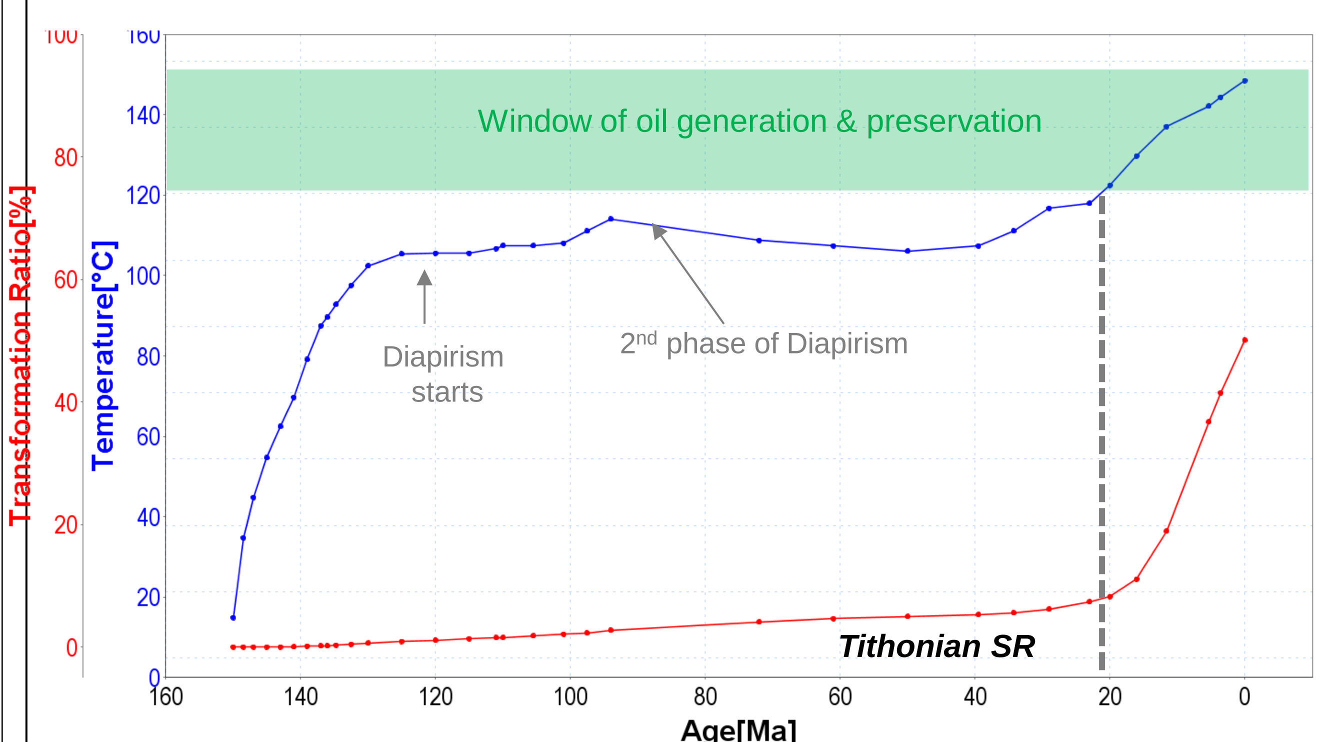
Oil & Gas Windows (Reference Scenario)



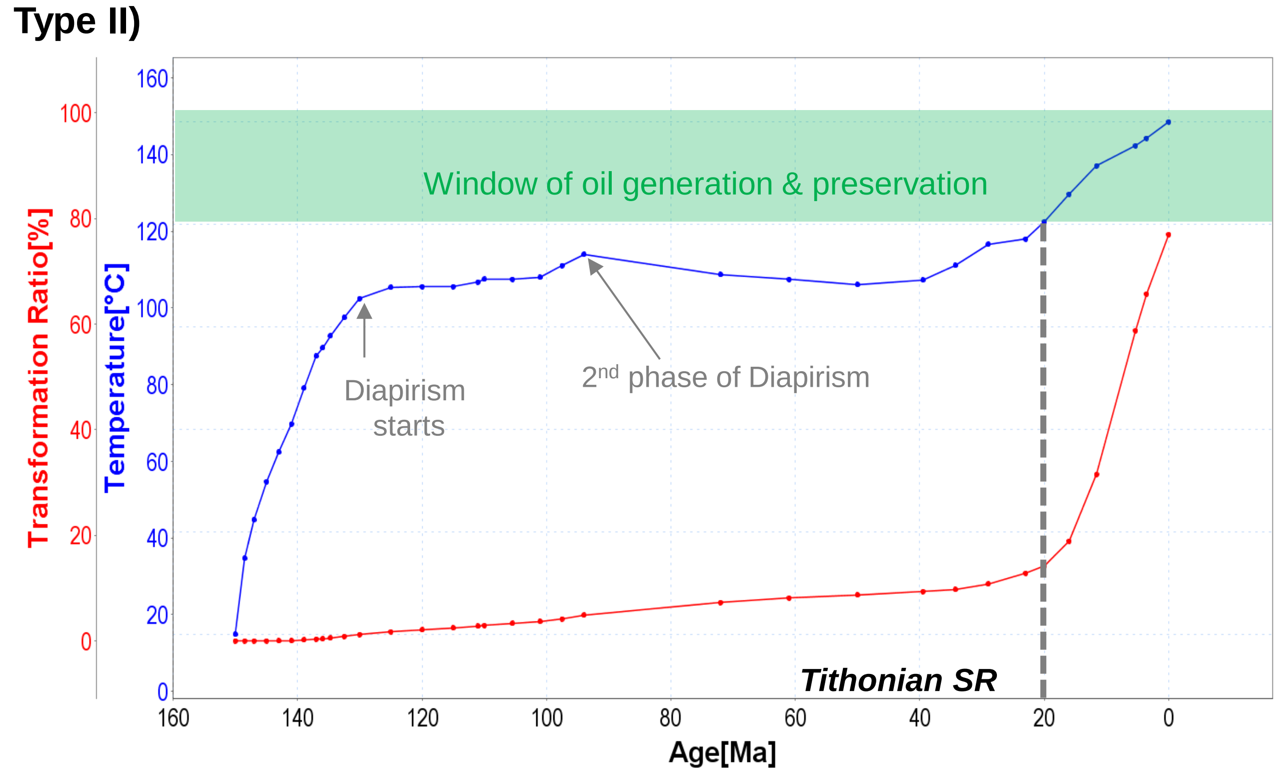
TR & Temperature time at Cell D location (Ref. Scenario)



TR & Temperature time at Cell C location (Reference Scenario)



TR & Temperature through time at Cell C location (Scenario 3: Tithonian Type II)



General comments on secondary cracking occurence

The Transformation Ratio and Temperature history extractions perfomed on this plate and on the previous one aim at explaining why, even though some source rock Layers are well within the oil window, so little oil is accumulated within the various models built. Thereupon the following observations can be made:

- On the one hand, the Temperature and TR profile through time extracted at one location in the Tithonian SR layer of Louisbourg section (at the max. burial in the kitchen – Cell A) and at two locations in Bandol section (1 in the Tithonian layer – Cell C and 1 in the Callovian Misaine Layer – Cell D, both between major salt diapirs) indicate that Oil generation starts when T>=120°C, in the frame of the reference scenario hypothesis (Tithonian Kerogen is Type II/III).
- On the other hand, the risk of secondary cracking starts to get high past 150°C.

Conclusion is that in order to observe some substantial oil being migrated (and eventually accumulated in a second stage), the generating source rock layer should stay within the [120°C;150°C] range during most of the primary cracking process. Yet, given the high sedimentation rate observed on each and every model built, this condition is almost never met.
Most of the primary cracking processes tend to occur above 150°C, the source rock layers usually crossing the [120°C;150°C] range in a matter of 10 Ma. This leaves the large remaining hydrocarbon potential within the SR layer subjected to secondary cracking. Actually past the 150°C temperature limit, secondary cracking of the oil is triggered as soon as the oil is being generated in the source rock itself, or just upon its expulsion.

Under some specific conditions though, oil might be generated and preserved upon generation & expulsion:

- At Cell C location (Reference Scenario) in Bandol Section, the Tithonian kerogen is cracked below the 150°C temperature limit thanks to the cooling effect of the neighbouring salt bodies. Primary cracking is only half-way completed though at Present Day.
- Using a more reactive Type II kerogen for the source rock layer allows for a higher quantity of oil to be generated and expelled at cell C location.