Call for Bids NS15-1 – Exploration history, geologic setting, and exploration potential: *Eastern Region*

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1. Overview

The NS15-1 Call for Bids includes nine parcels that are clustered into three geographically and geologically distinct areas (Figure 1.1). Parcels 1, 2, 3, and 4 are located on the outer shelf and slope along the southwestern most parts of the Scotian margin, adjacent to and seaward of Georges Bank (Western Region). Parcels 5, 6, and 7 are located on the outer shelf and upper slope of the central Scotian margin, west of the Sable Island and the Sable Subbasin (Central Region). Parcels 8 and 9 are located above existing oil and gas discoveries on the shelf in the Sable Subbasin, north and east of Sable Island – these being the Penobscot oil discovery in fluvial-deltaic sandstones of the Missisauga Formation and the Eagle discovery in chalks of the Wyandot Formation (Figure 1.2), respectively (Eastern Region). This document descripts the exploration history, geologic setting, and exploration potential for the ***Eastern*** region.

4. Eastern Region

Geological setting

Parcels 8 and 9 are located in the Sable Subbasin where all 23 of offshore Nova Scotia's Significant Discoveries have been made (Figure 1.0). For a detailed geological examination of the Sable Subbasin, refer to the NS12-1, CNSOPB (2012) and NS13-1, CNSOPB (2013) call for bids packages. The following abridged regional discussion includes updates and brief overviews from portions of those reports. The CNSOPB has adopted the seismic horizon nomenclature proposed in the Play Fairway Analysis, OETRA (2011). The Scotian Basin stratigraphic column indicates the key mapped horizons in this section (Figure 1.1). The digital seismic data set used for interpretation and mapping in this section has the 3D survey areas outlined in red (Figure 4.1). The CNSOPB program numbers are listed on this figure.

Rifting

Rifting of the Scotian Margin began in the Middle Triassic and continued into the Early Jurassic forming a widespread region of horsts and grabens throughout the central and northeast Scotian Margin as discussed in detail in call for bids NS13-1. In this study area, basement structuring transitions from the LaHave Platform into distinct basement features such as the Missisauga Ridge which separates the rapidly deepening Abenaki Subbasin to the north with the gradually deepening basement shoulder faults of the Sable Subbasin to the south (Figure 4.2). Basement faults flank the grey shaded basement ridges with darker grey shaded ridges indicating deeper burial. The brown shaded region outlines deeper areas of the Sable Subbasin where significant autochthonous and allochthonous salt, combined with deep burial, makes it challenging to interpret basement. Several deeply buried basement ridges such as the Venture and Alma ridges underlie this area with the prominent Alma Ridge coinciding with a portion of the present day shelf break. An interpreted drawing of a composite north-south seismic line illustrates the basement horst blocks and their influence on subsequent infilling of the subbasins (Figure 4.3). The dashed lines labeled A to D indicate various shelf edge canyon systems as the delta

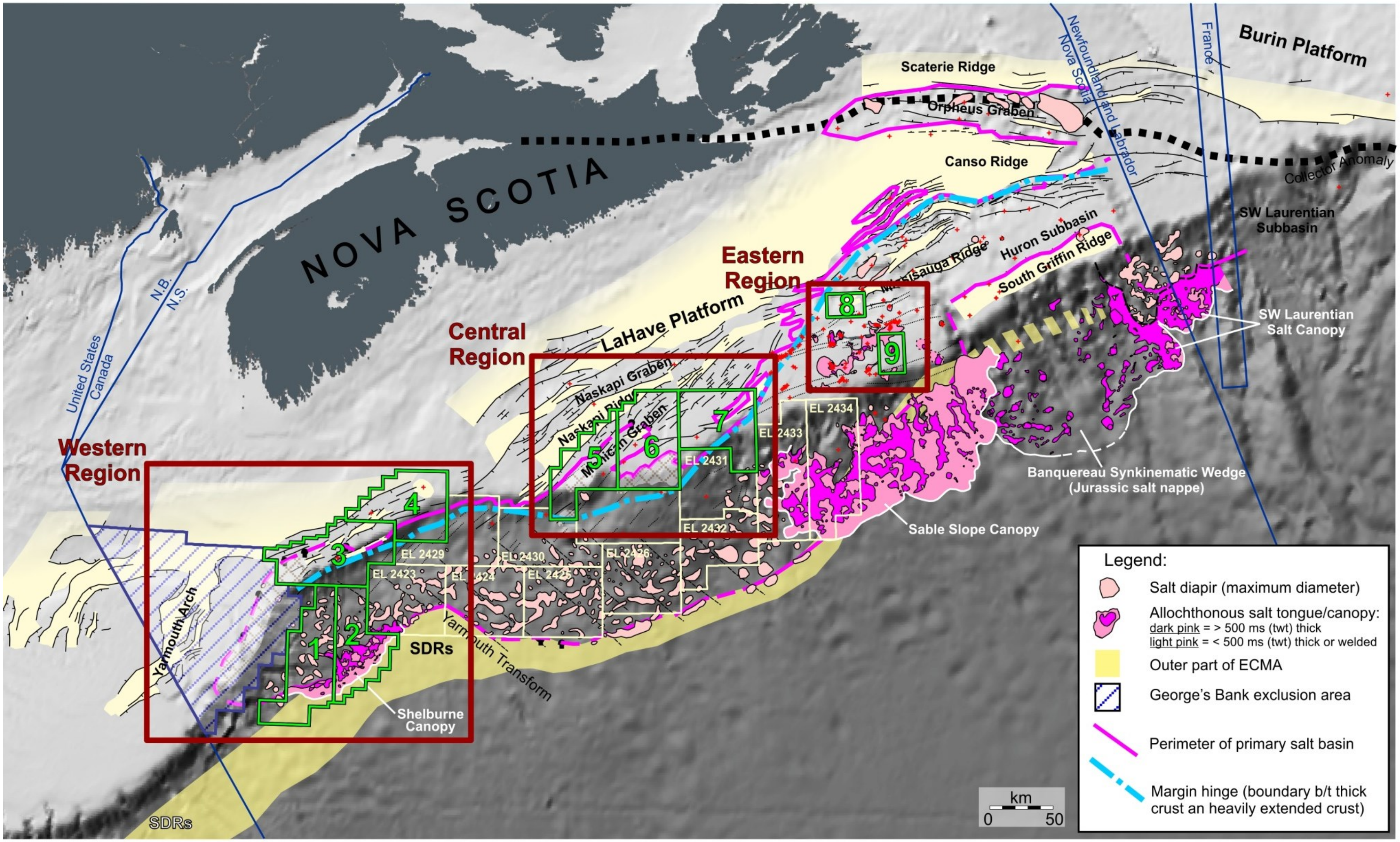

Figure 1.1 Basemap of the Scotian margin showing distribution of key structural elements. Some faults north of the Naskapi Ridge are from Wade and MacLean (1990). Most other elements are from Deptuck and Kendell (in prep).

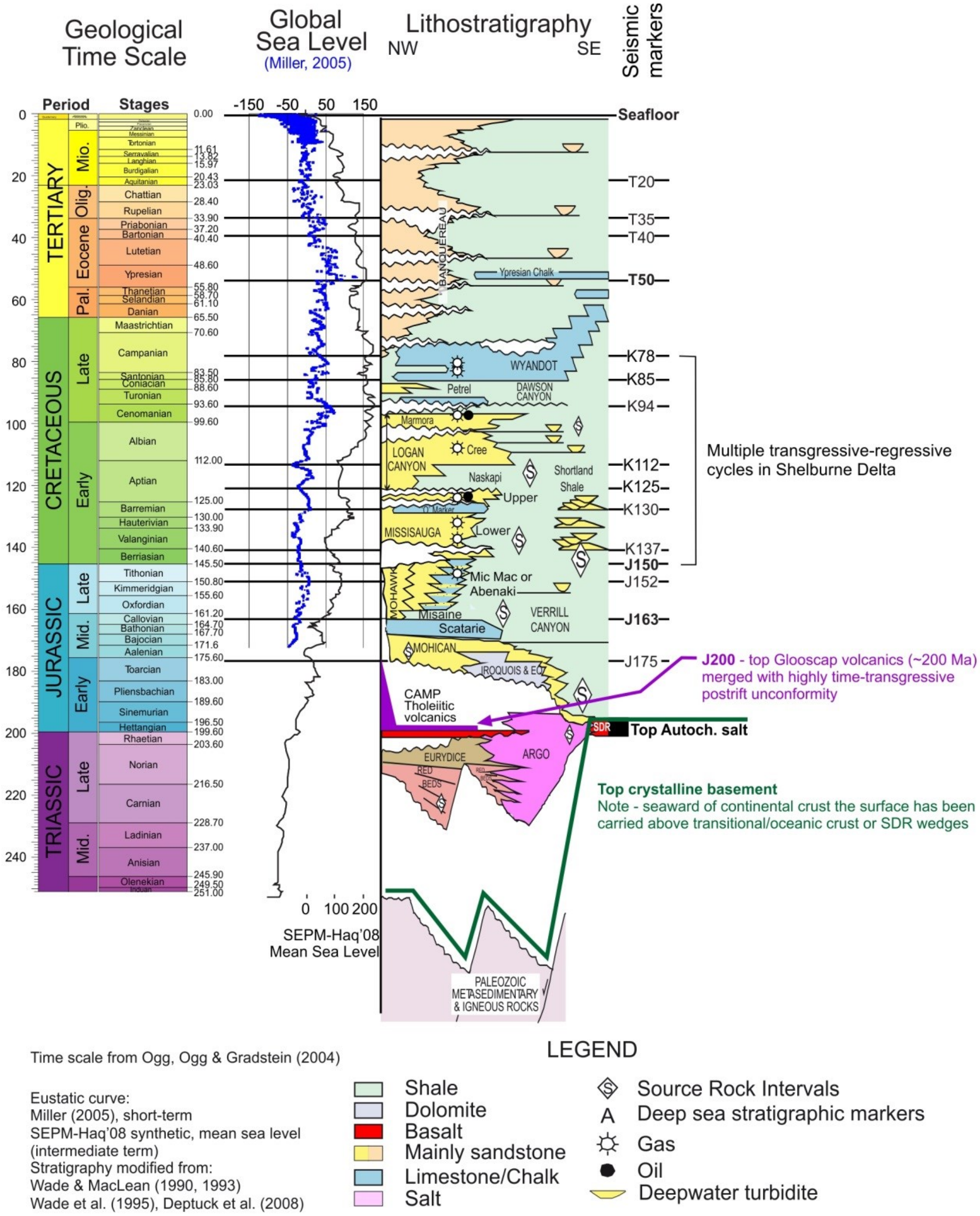

Figure 1.2 Stratigraphic column adpated from OETR (2011), with key seismic markers.

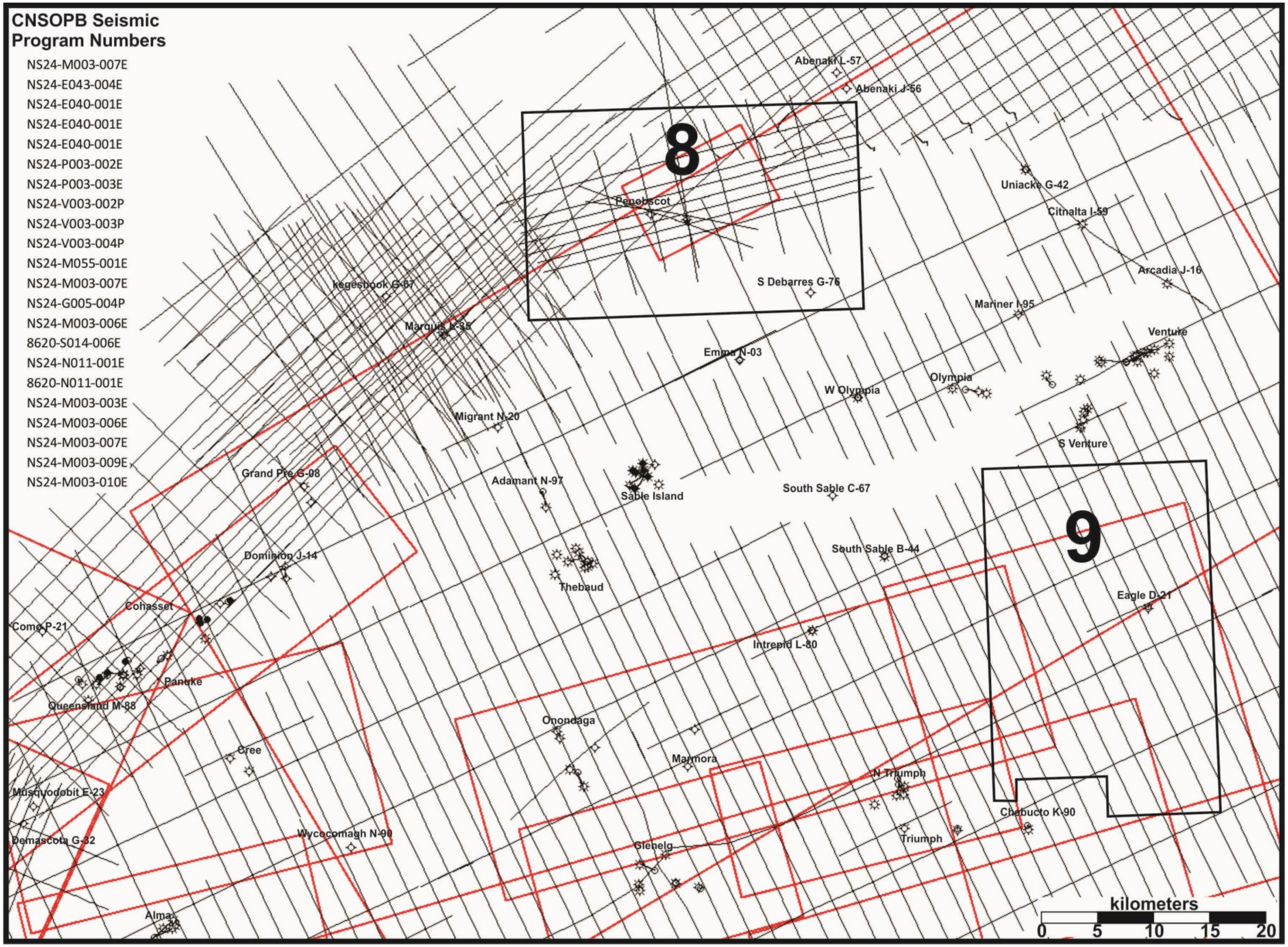

Figure 4.1 Seismic database used for mapping in this section. Red boxes indicate 3D surveys.

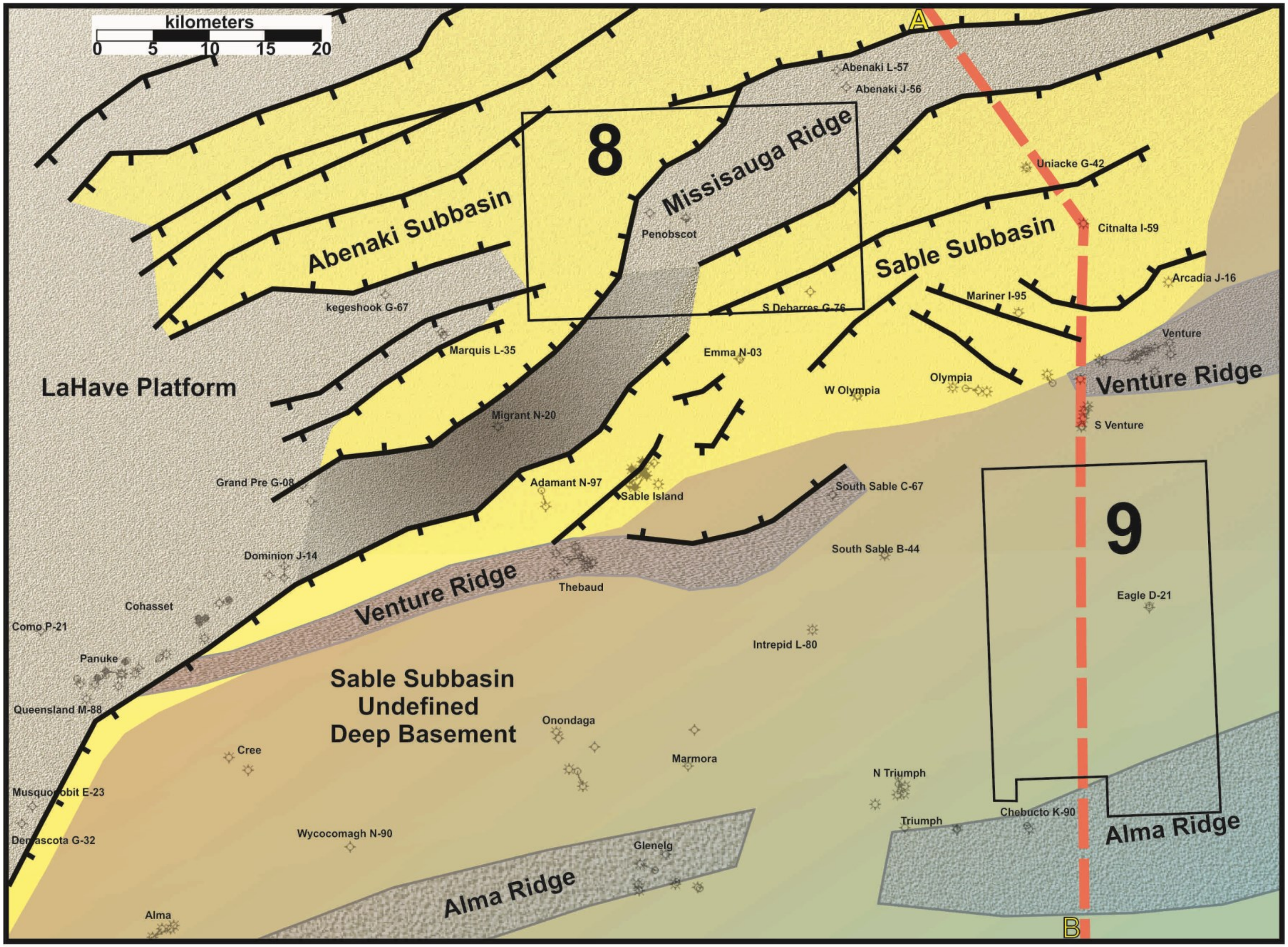

Figure 4.2 Basement ridges and faults indicating where the LaHave Platform opens and accommodates the Abenaki and Sable Subbasins. The brown shaded portion of the deep Sable Subbasin is poorly imaged and sparsely interpreted.

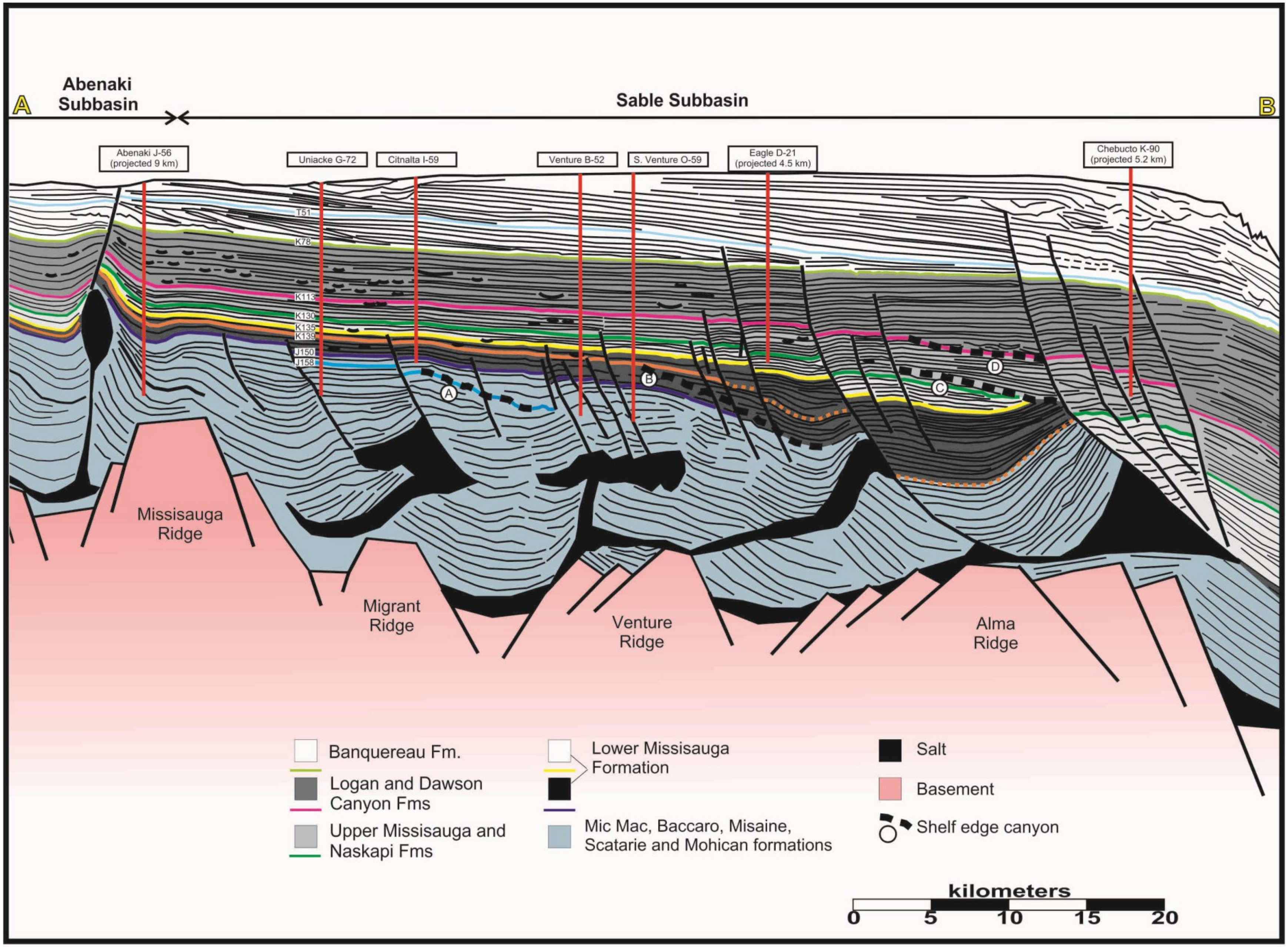

Figure 4.3 Interpreted seismic line drawing through Abenaki and Sable Subbasins.

progrades basinward. The location of this line drawing is indicated by the red dashed line in Figures 4.2 and 4.4.

Salt

Autochthonous synrift salt deposition on the Scotian Margin is interpreted to be bounded by the basement highs which then influenced the focusing and early uprising of allochthonous salt bodies. Sediment loading and downbuilding by Early Jurassic systems loaded the salt which was often pinned in the basinward direction by basement ridges. Salt contact with these basement horsts forced the salt to climb vertically through the sedimentary section eventually forming either solitary salt diapirs or canopies (Figure 4.4). The green shaded areas indicate the presence of allochthonous salt but do not differentiate thickness. Portions of these salt regions may be welded out. The strike trend of the allochthonous salt lies in the same south west to northeast trend as the basement ridges.

Jurassic

The Early Jurassic Mohican Formation is the initial post rift fill in the Scotian Basin, followed in the Middle and Late Jurassic by siliciclastics of the Mic Mac Formation and coeval limestone deposits of the Abenaki Formation. This thick Mic Mac section is a significant reservoir for discovered hydrocarbons.

Thick carbonate platforms with fringing reef development are also present during the Middle to Late Jurassic. Carbonate development is highly influenced by the basement architecture. A map on a Kimmeridgian marker (J155) shows an extensive carbonate platformal area shaded red with a steep, rimmed bank edge in the southeast near Panuke that reflects the southern limit of the LaHave platform (Figure 4.5). This carbonate bank edge broadens eastward as the LaHave Platform basement structure opens into several basement ridges. As the Missisauga Ridge plunges deeper to the northeast from the LaHave Platform at Dominion J-14, the carbonate bank veers north towards Grand Pre G-08 and then east towards Marquis L-35. The J155 is deeply buried, heavily faulted due to salt tectonics, and not currently interpreted over the southern portion of this map area.

A map on the Tithonian seismic marker (J150) shows a similar stacked, steep, rimmed bank edge near Panuke that continues towards Grand Pre G-08 where the proximity of several basement highs and the LaHave platform results in broadening of the bank edge slope, forming an accretionary ramp that is not rimmed (Figure 4.6). While Marquis L-35 and Kegeshook G-67 are underlain by the LaHave platform, Penobscot on Parcel 8 is influenced by the Missisauga Ridge. The J150 is deeply buried, strongly affected by salt tectonics, and not currently interpreted over the southern portion of this map area.

Cretaceous

The Missisauga Formation was deposited throughout the Latest Jurassic and Early Cretaceous. This sand rich sequence of fluvial deltaics can be divided into upper and lower members which are separated by an interval of generally thin Hauterivian/Barremian oolitic limestones known as the "O" Marker (K130). The oil reservoir section discovered at Penobscot lies just below the O marker in the Lower Missisauga Formation where structuring results from drape over the Missisauga Ridge (Figure 4.7). Thick deposits of lower Missisauga sediments (K130-J150) are located basinward of the carbonate bank system (Figure 4.8). A number of wells such as those drilled in the West Venture, Citnalta, Olympia, West Olympia, Intrepid and Glenelg Significant Discoveries have encountered considerable reservoir quality sandstone and net gas pay within the Lower Missisauga. Three Sable Offshore Energy Project fields are also currently producing gas from the Lower Missisauga: Thebaud, Venture and South Venture. This isopach continues to thicken southward under Parcel 9.

The end of the Cretaceous period in the Scotian Basin saw a rise in sea level, basin subsidence and deposition of marine marls and chalky mudstones of the Wyandot Formation (K78). This surface shows evidence of widespread mass transport system that reworked the chalk and moved it down slope towards the basin as

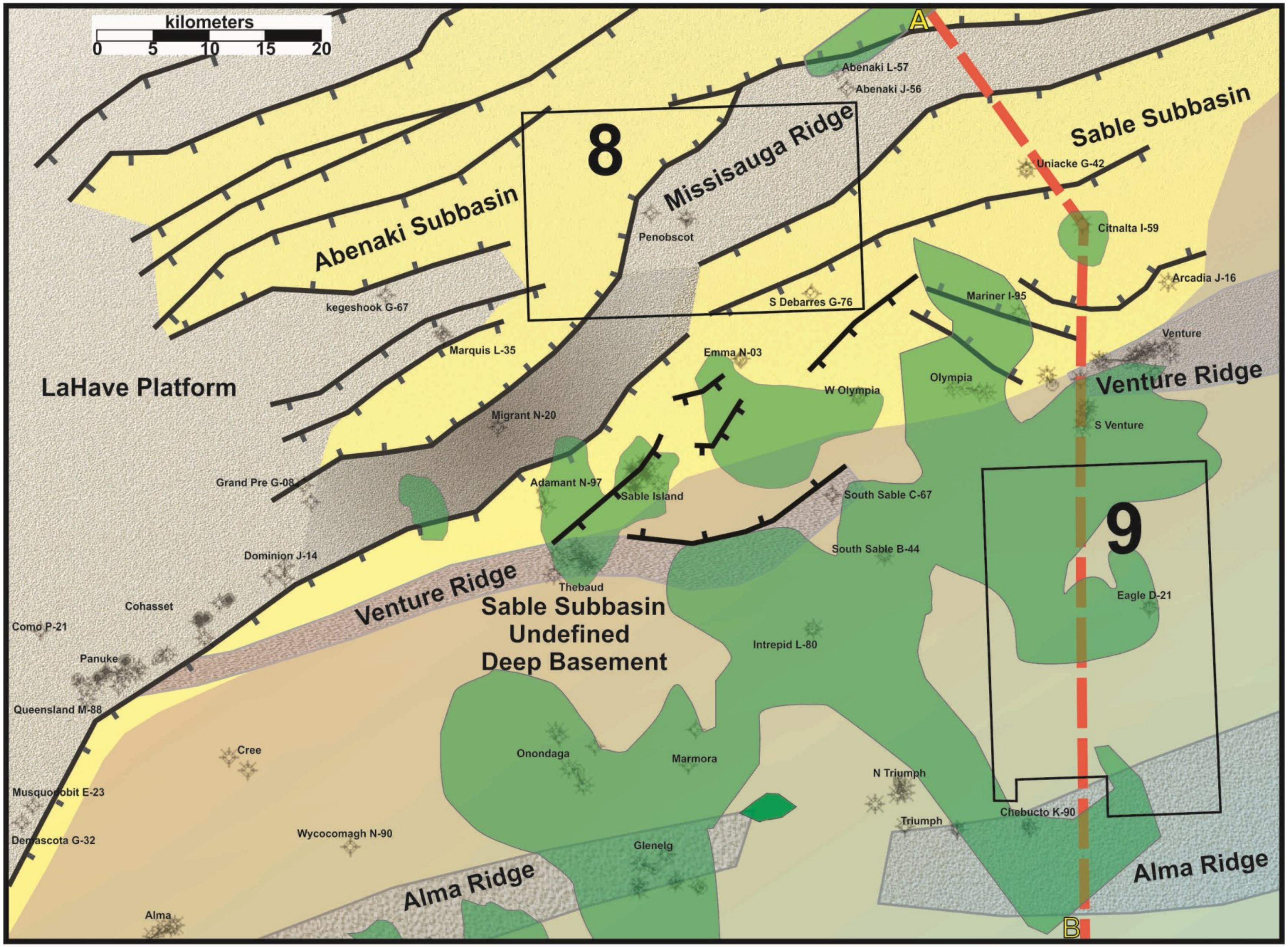

Figure 4.4 Allochthonous salt overlying basement map. Salt thickness is not differentiated and some areas may be welded out.

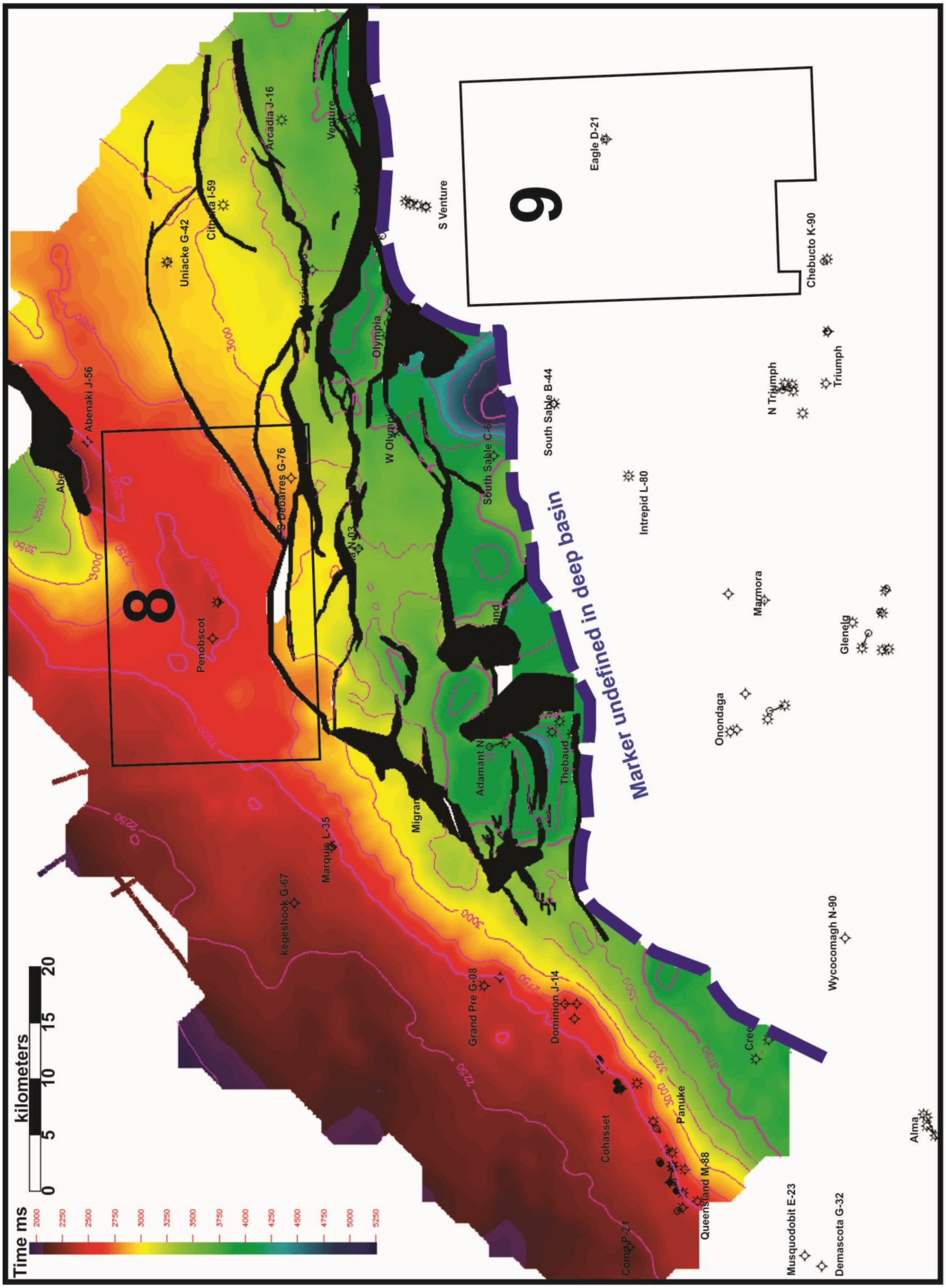

Figure 4.5 Kimmeridgian (J155) time map.

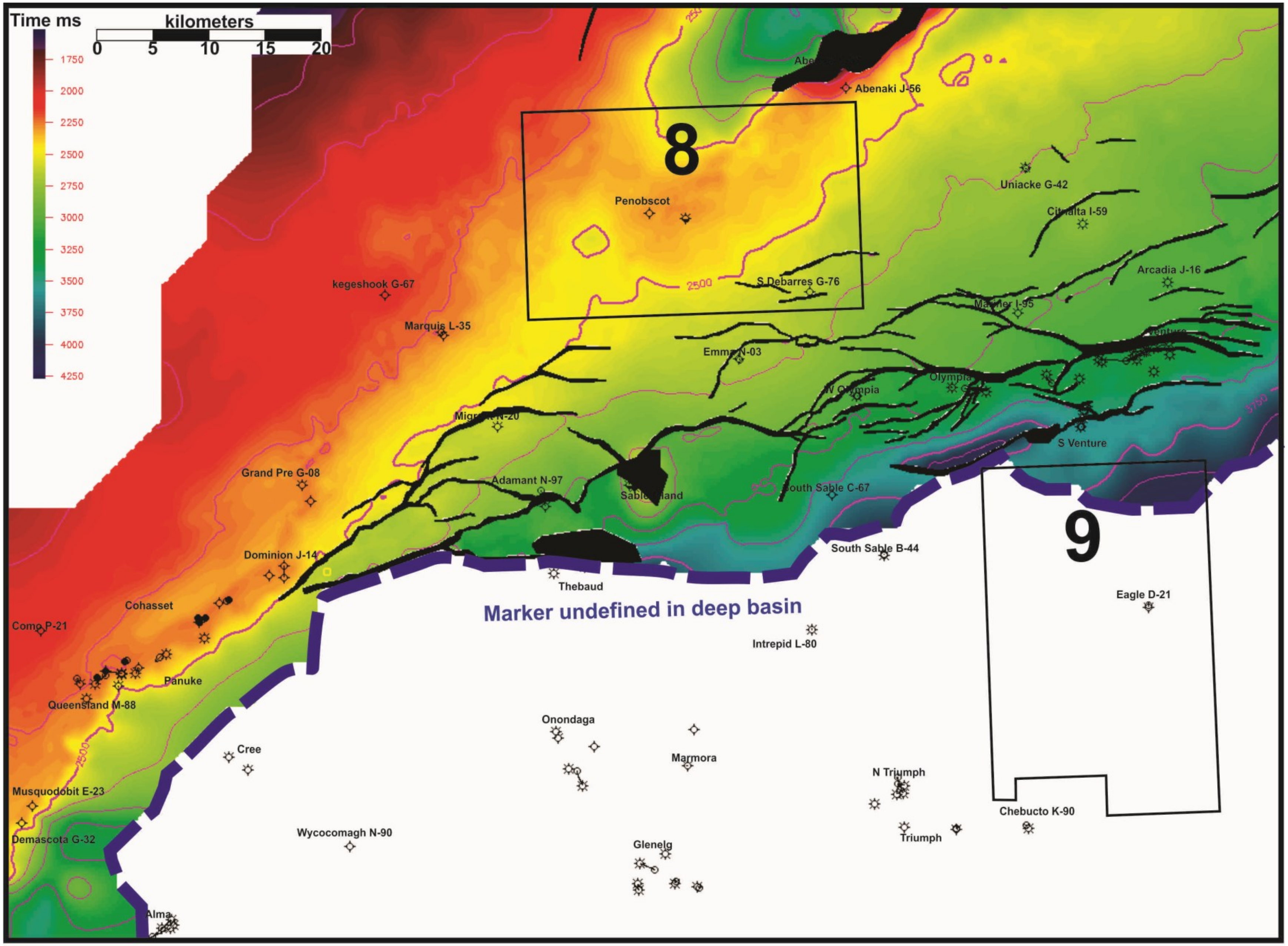

Figure 4.6 Tithonian (J150) time map.

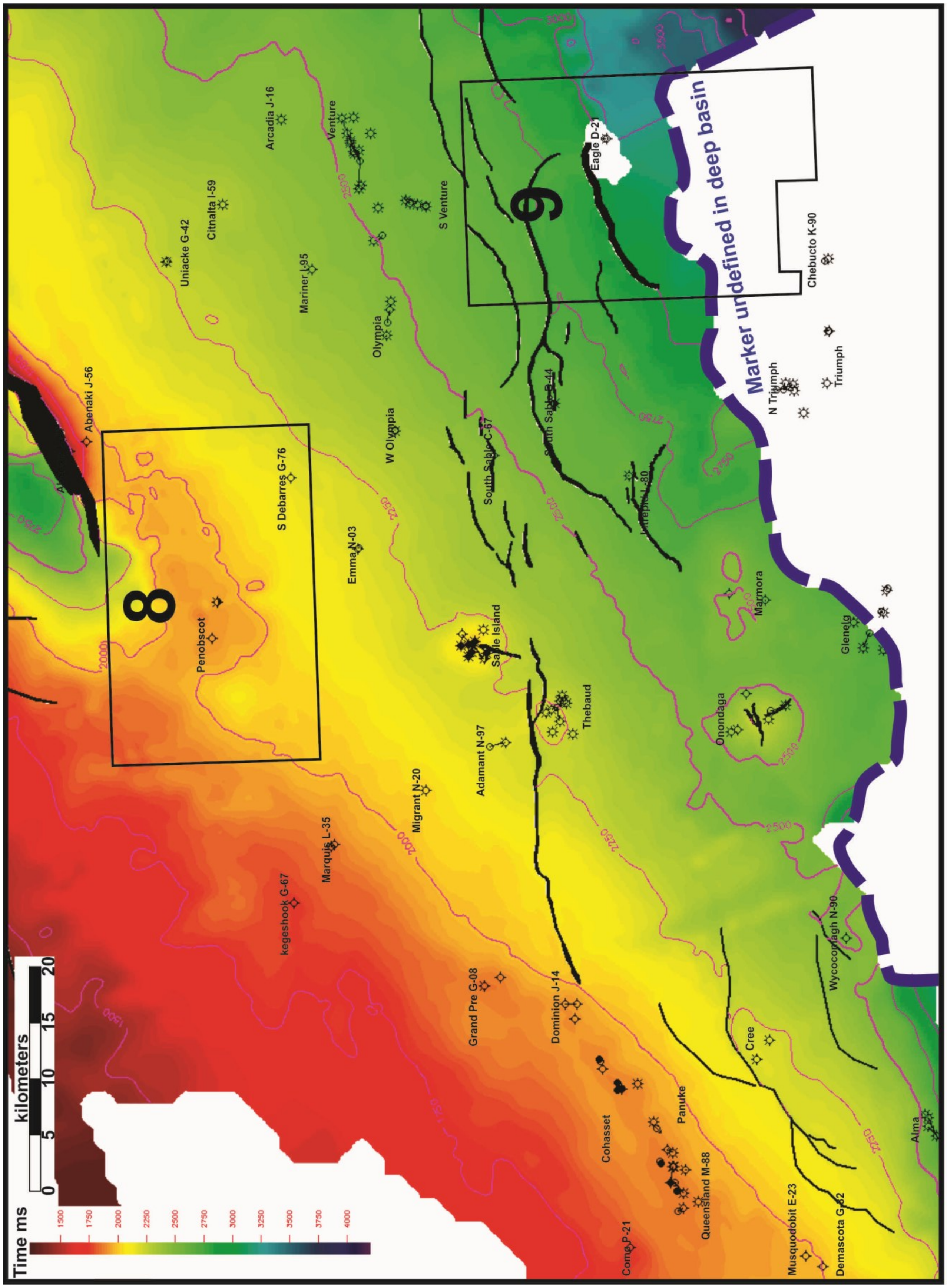

Figure 4.7 O Marker (K130) time map.

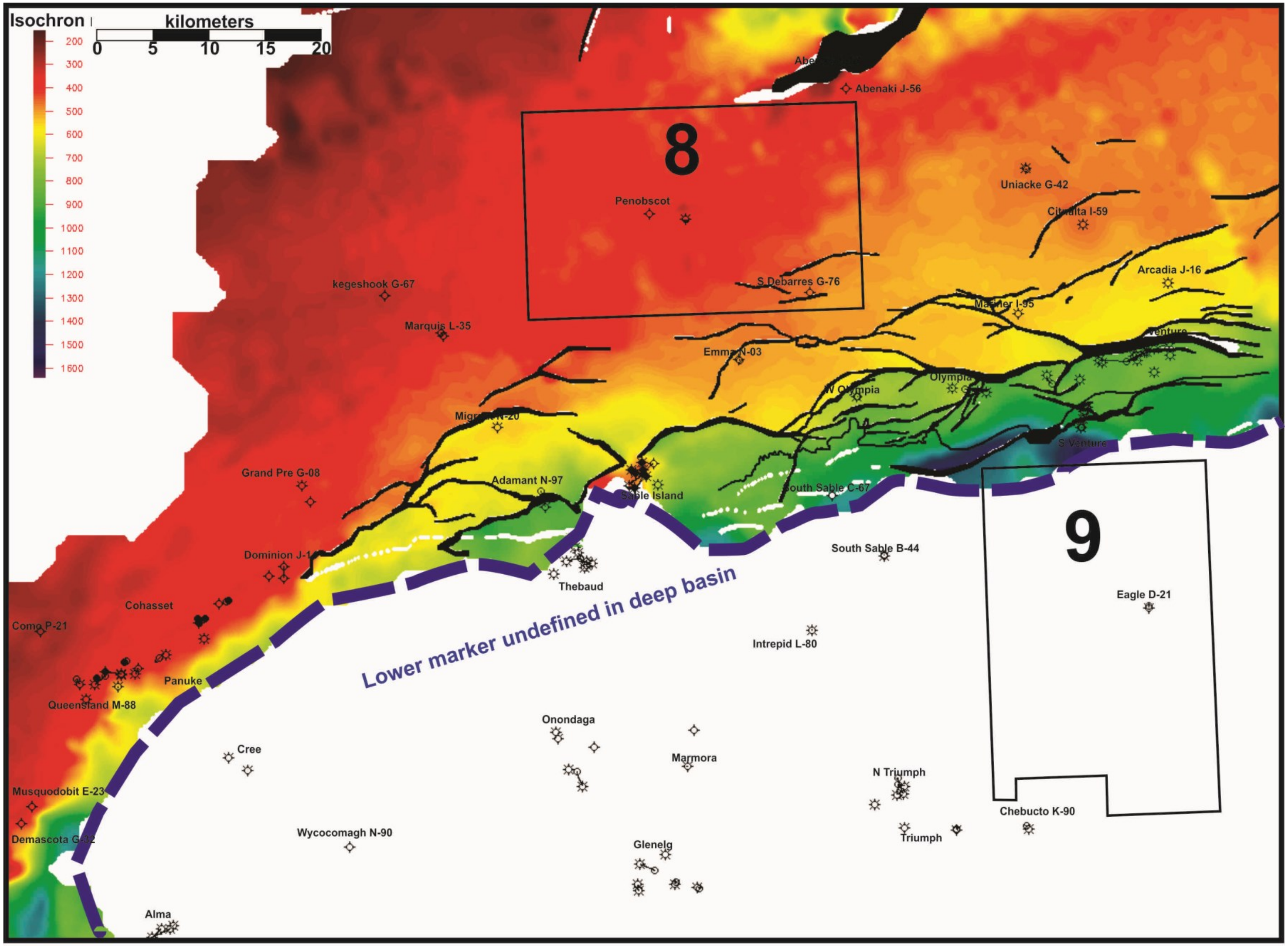

Figure 4.8 Lower Missisauga (K130-J150) isochron map.

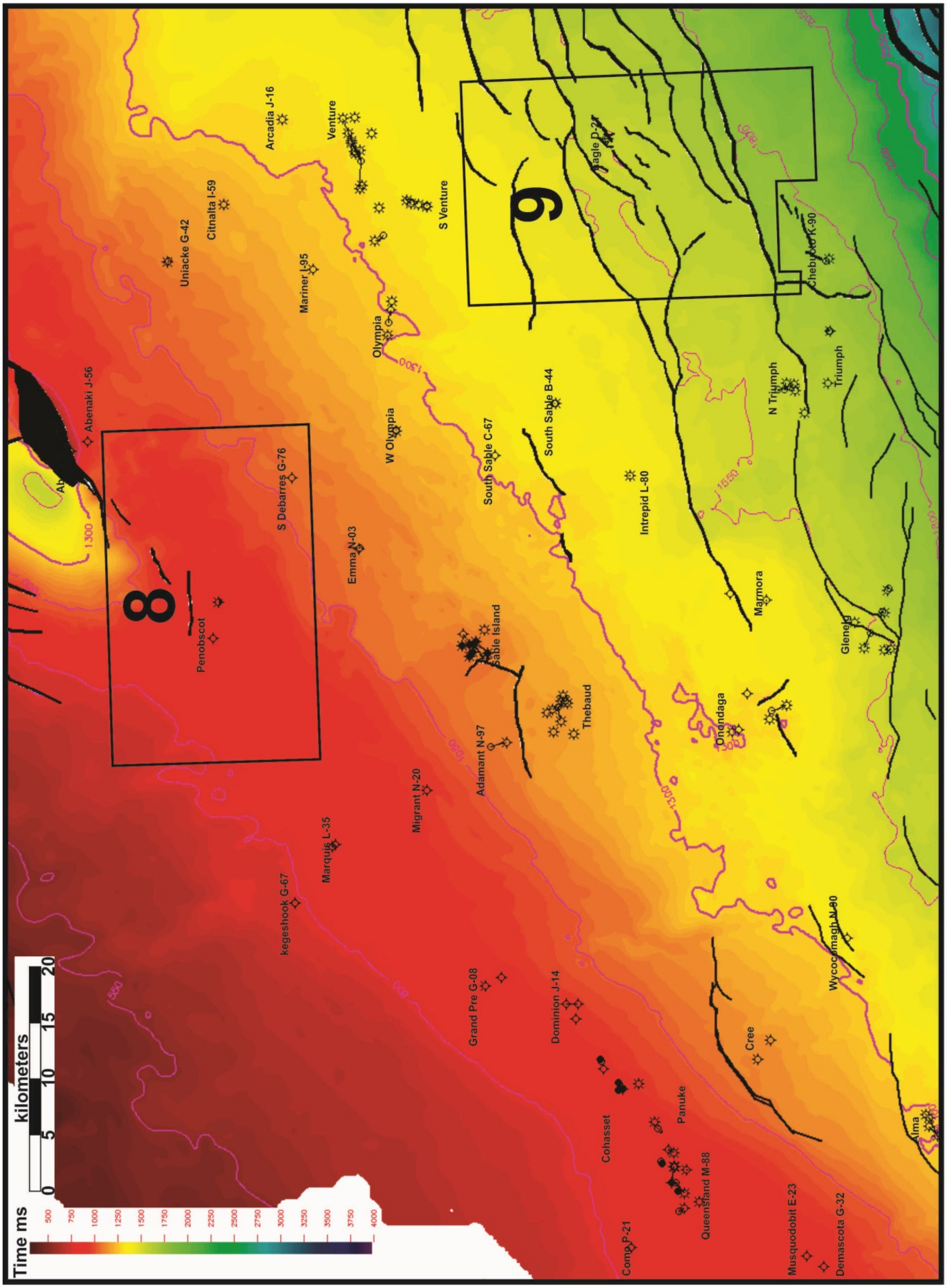

Figure 4.9 Wyandot (K78) time map

described in Smith et al (2010) (Figure 4.9). This chalk comprises the reservoir at the Eagle gas discovery in Parcel 9 although there is no evidence of mass transport processes within the chalk section at this location.

Parcel 8 – Penobscot

Parcel Description and Exploration History

Parcel 8 flanks the northern extent of the Sable Subbasin in present day water depths varying from 50 m to 250 m and encompasses the Penobscot oil discovery (Figure 4.10). The initial well on the Penobscot structure, L-30, was drilled by Petro-Canada-Shell in 1976 to a depth of 4237.5 m in 138 m of water. Hydrocarbons were recovered by Repeat Formation Tester (RFT) from four lower Missisauga sands overlaid by the O marker. A seismic dip line through the L-30 well indicates the Sand 1 marker in blue (Figure 4.11). A time map interpreted on Sand 1 shows why Shell-Petro-Canada drilled B-41 3 km to the northwest in 1977 considering it to be up-dip on the same structure as L-30 (Figure 4.12). The B-41 well reached a total depth of 3414 m in 118 m of water but no significant hydrocarbon shows were encountered and no formation tests were run. The stratigraphic tops in B-41 were within 10 m of the tops in the L-30 well suggesting that B-41 was not substantially up-dip of L-30. Recent 3D reprocessing and depth conversion demonstrate that B-41 was probably drilled into a separate closure.

Approximately 13 km to the southeast from L-30, Shell Canada Resources drilled South Desbarres O-76 in 69 m of water on a separate structure on April 16, 1984. The well reached TD within the Mic Mac Formation at a depth of 6041 m. No significant hydrocarbon bearing zones were encountered and the well was abandoned on Oct. 13, 1984. A regional cross-section shows the correlation of several key geological horizons between Penobscot and South Desbarres (Figure 4.13).

After the licence was relinquished by Shell, Nova Scotia Resource Limited (NSRL) obtained an Exploration Licence over the Penobscot prospect in 1989 and acquired 66 km^2 of 3D seismic data (CNSOPB program number NS24-N011-001E). The interpretation report for this survey, completed in 1991, including synthetics, depth conversions and maps, is available through the Geophysical Data section under the Data tab on the Call for Bids website. A second report completed in 1992 that included further mapping and reserve estimates is also available. This report identified additional potential northeast of the original mapped Penobscot prospect that has yet to be tested.

The Penobscot 3D seismic data is now owned by the Province of Nova Scotia who has made the digital SEGY data available free to the public through the CNSOPB's Geoscience Research Center (GRC). The Provincial Government also reprocessed this 3D seismic to improve data quality. Instructions for downloading both of these data sets can be found in the Digital Data section. A number of other seismic surveys have been acquired over portions of the parcel since the early 1980s. Interpretation reports are available for most of these programs.

As a result of the NS07-1 Call for Bids, a licence containing the Penobscot field was awarded to Ammonite Corporation under a "promote license" scenario where the 25% work deposit was deferred for 3 years. Ammonite returned the parcel to Crown on December 31, 2012 with no deposit being paid.

Geology

The Penobscot reservoir sands are located below the 'O' limestone marker in the early Cretaceous Missisauga Formation. Penobscot L-30 encountered seven hydrocarbon bearing moderate to well sorted, fine to coarse grained reservoir sands. The interpreted environment of deposition for these reservoirs varies from distributary channel to shoreface. The sands vary in thickness from a few metres to over 70 m and can be correlated, with varying degrees of confidence, between Penobscot L-30 and Penobscot B-41, located 3.2 km to the west. The thicker shoreface sands can generally be correlated with higher confidence and are interpreted to have the greatest lateral continuity (Figure 4.14).

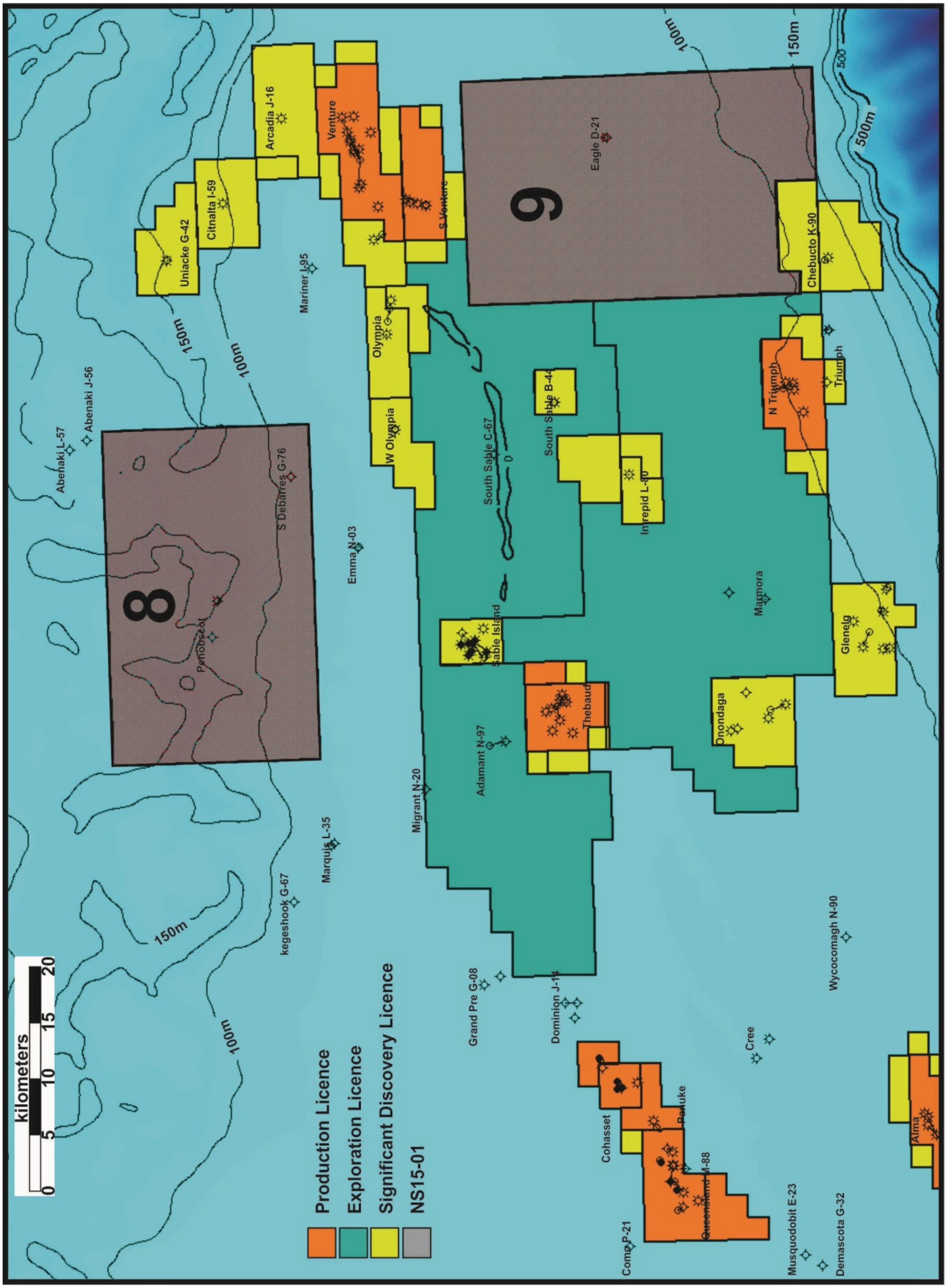

Figure 4.10 NS15-01 Sable Subbasin parcel locations with existing licences and bathymetry.

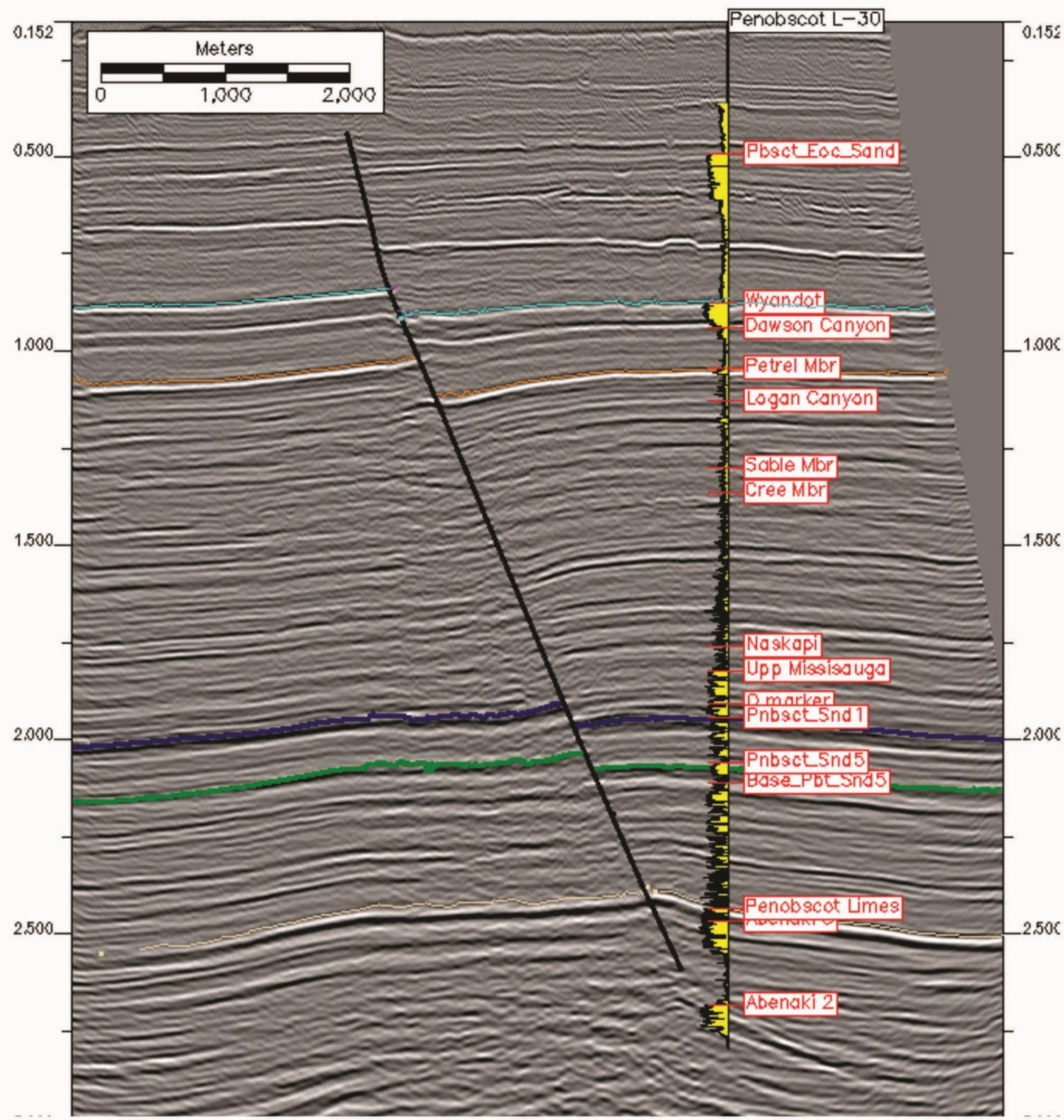

Figure 4.11 Penobscot seismic time line in dip direction.

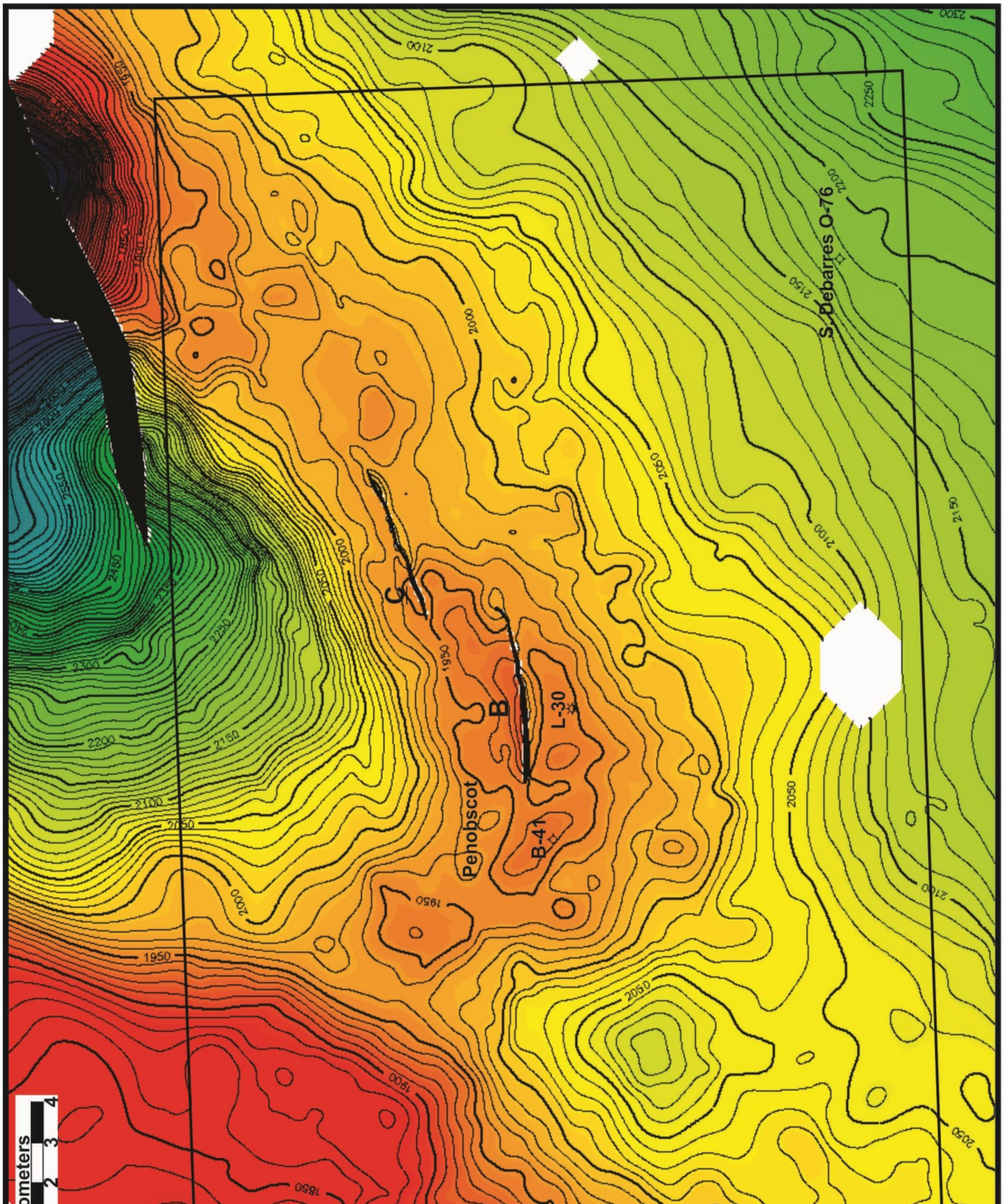

Figure 4.12 Penobscot Sand 1 time map.

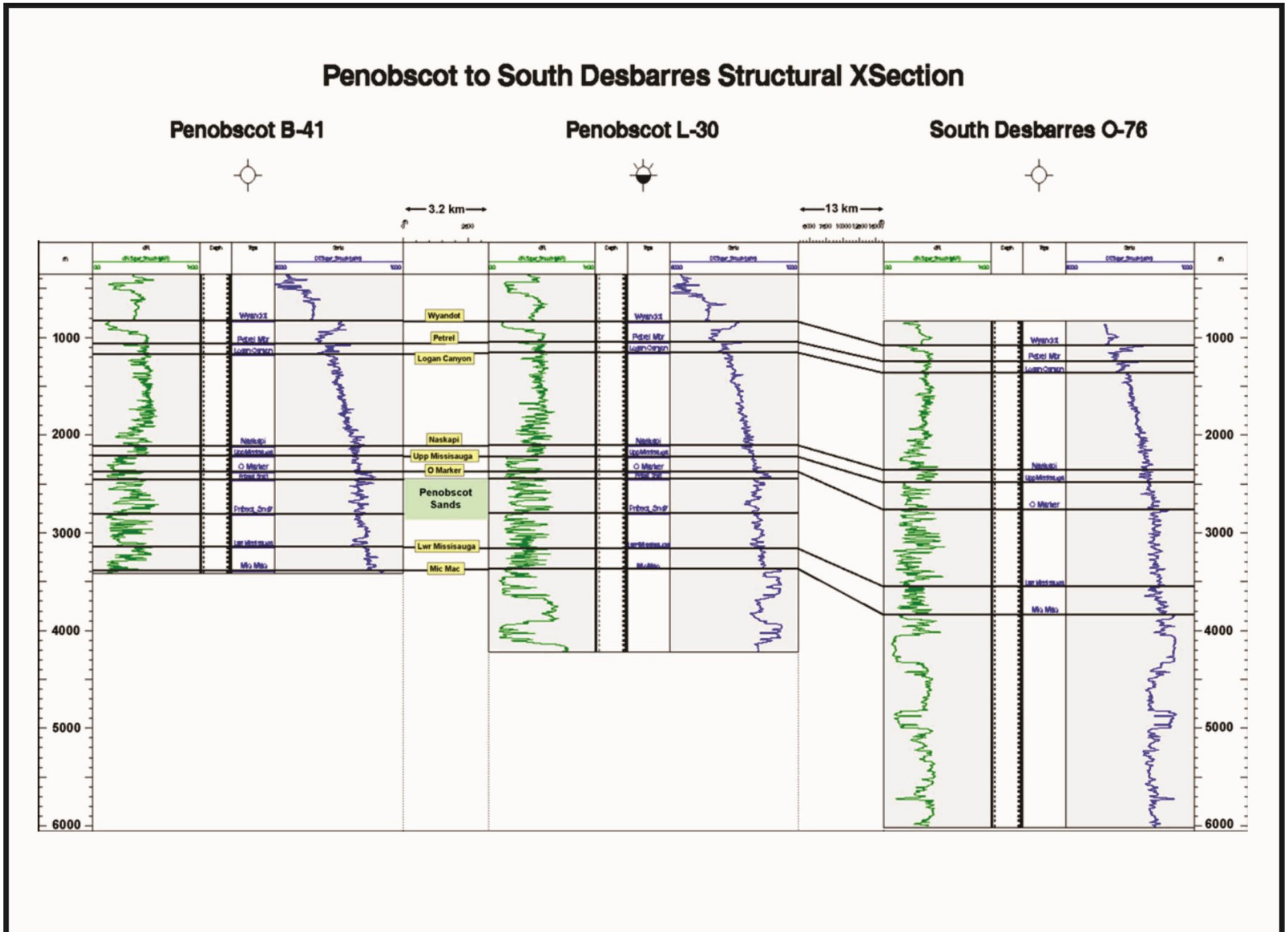

Figure 4.13 Penobscot to South Debarres structural cross section.

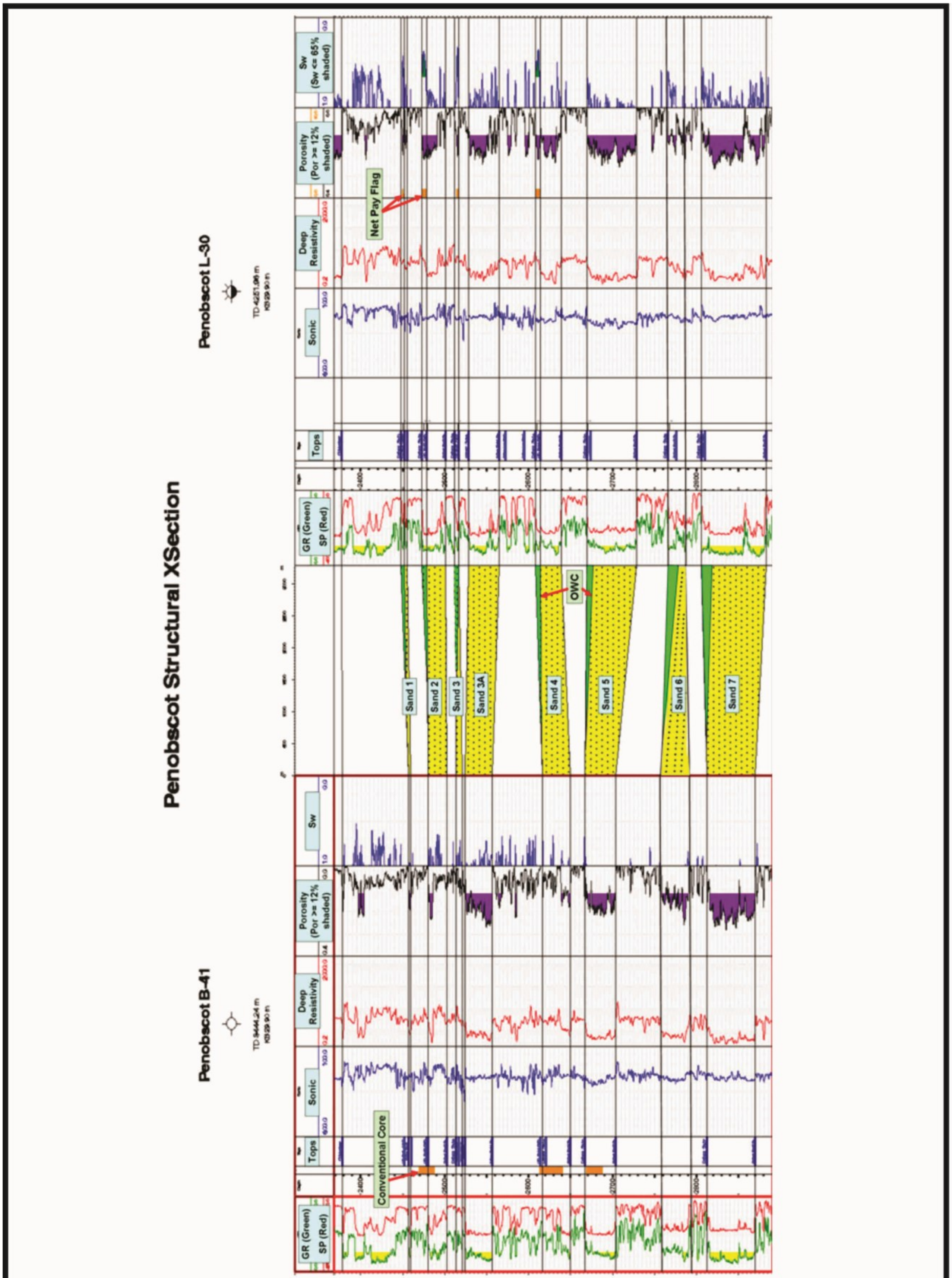

Figure 4.14 Penobscot structural cross section.

The Penobscot field can be subdivided into two parts. The L-30 well region south of the main Penobscot fault which recovered oil and gas from several zones via RFT, and two separate untested closures located to the north and northeast (Figure 4.12). The reservoirs encountered in the southern region are interpreted to be trapped in a 4-way dip closure created on the downthrown side of a down-to-the-basin growth fault. The northern closure is on the upthrown side of the main Penobscot fault and is primarily fault dependent. The northeastern structure requires closure against a different fault. Top seal is provided by the overlying marine shales.

The Verrill Canyon shales are believed to be the source rock for the Penobscot structure. The main fault system exhibits evidence of early movement within the Jurassic period. This early movement may have created a conduit for the migration of generated hydrocarbon fluids into the system.

Formation Evaluation

Petrophysical assessments were conducted on the two Penobscot wells.

Penobscot – Formation Evaluation

A complete suite of the primary logging measurements were acquired in both Penobscot L-30 and Penobscot B-41. Two conventional cores were cut in L-30; however, both cores were cut well below the reservoir interval. In B-41 four conventional cores were cut within the Penobscot reservoir interval (Table 4.1).

Core#	Interval (m MD)	Recovery
1	2499.4 – 2517.6m	17.4m
2	2642.6 – 2660.9m	14.3m
3	2660.9 – 2670.0m	8.2m
4	2699.0 – 2717.9m	3.05m

Table 4.1 Penobscot B-41 conventional cores.

Routine core analysis was conducted on the 4 cores. Average core porosity of the reservoir interval is 20%, with a maximum of 32%. Average permeability of the reservoir interval is 120 mD (arithmetic average) with a maximum of over 1000 mD.

No Drill Stem Tests (DSTs) were conducted in either Penobscot L-30 or B-41; however, a number of Repeat Formation Tests (RFTs) were run in the L-30 reservoir sands (Table 4.2).

Penobscot L-30 – Fluids Recovered from RFT (Sands 1 - 5 Only)					
Sand #	**Depth (m)**	**Oil/Condensate (cc)**	**Gas (ft^3)**	**Water (cc)**	**Remarks**
1	2480.2	3400 cc cond.	1.0	nil	
2	2504.8	900 cc oil	Nil	8,000	
2	2509.4	nil	Nil	10,250	Sample taken below Oil-Water Contact (OWC)
2	2509.4	nil	Nil	3,750	Sample taken below OWC
3	2545.4	100 cc oil	0.5	10,000	<1 m above OWC[1]
4	2639.3	3,800 cc cond.	10.0	5,200[2]	
4	2639.3	3,000 cc cond.	5.0	Nil	
5	2700.5	nil	Nil	10,250	Transition zone[3]
5	2700.5	nil	Nil	3,750	Transition zone[3]
5	2700.8	nil	Nil	9,700	Transition zone[3]

[1.] Recovered mainly water due to proximity of OWC, i.e. RFT taken <1 m above OWC.

[2.] Both RFTs run at this depth recovered considerable condensate and gas. The water recovered from this RFT is likely mud filtrate and not formation water. [3.] These RFTs were taken only 2 m above the interpreted OWC in sand 5. The upper portion of sand 5, at the L-30 location, is within the transition zone and has a high water saturation (Sw ~70%) resulting in water recovery on RFT.

Table 4.2 Penobscot L-30 RFT results.

Seven normally pressured hydrocarbon bearing sands were encountered in Penobscot L-30 within the middle Missisauga Formation. The RFT fluid recoveries indicate that most sands appear to contain light oil/condensate and gas. It is unclear if the gas is solution gas or free gas. Based on a petrophysical assessment using available log, core and RFT data (Table 4.3), it appears that light oil/condensate is the primary reservoir fluid. Each L-30 sand was interpreted to have a separate log defined oil-water contact (Figure 4.13).

Reserves Estimate

The Penobscot field is directly analogous to the Cohasset/Panuke oil fields located on the Scotian Shelf approximately 60 km to the southwest. Cohasset and Panuke produced over 44 MMBbls of light sweet oil from high quality, relatively thin, reservoir sands located within the Logan Canyon and upper Missisauga formations. The fields were on production from 1992 to 1999. The total volume of oil produced from Cohasset was 28.3 MMBbls and total Panuke production was 16.2 MMBbls demonstrating that relatively modest offshore oil fields can be economically viable.

Penobscot is interpreted to comprise three separate oil accumulations. The southern accumulation (South Penobscot) was tested by the Penobscot L-30 well and contains high confidence oil reserves. The two potential accumulations to the north (North & Northeast Penobscot) have not been drilled and are termed possible reserves. The CNSOPB conducted a probabilistic resource assessment of South Penobscot and North/Northeast Penobscot reporting in place and recoverable reserves (Tables 4.4 and 4.5).

Penobscot L-30 – Reservoir Properties					
Sand	**Top (m MD)**	**Base (m MD)**	**Net Pay (m TVD)**	**Net Pay Por. (%)**	**Sw (%)**
1	2477.6	2484.9	1.2	19	49
2	2503.0	2530.9	4.6	21	46
3	2542.0	2546.6	2.1	18	41
3A	2558.5	2594.6	Wet	N/A	N/A
4	2638.0	2669.0	4.3	19	45
5*	2699.2	2758.5	01	N/A	N/A
6*	2795.5	2805.4	01	N/A	N/A
7*	2835.3	2912.8	01	N/A	N/A

***** Penobscot L-30 was drilled on the flank of the South Penobscot structure and thus encountered relatively thin oil columns at the L-30 location. There is approximately 15 m of additional structural relief, for each of the Penobscot sands, updip of L-30. Sands 5 -7 have interpreted oil-water contacts within a few metres of the top of each sand. As a result, the top portion of these sands is transitional and has high water saturation (~70%). Sands 5 – 7 appear to have very thin (<0.5 m) oil pay over water at the very top of the each sand which supports the interpretation that the sands are transitional at the L-30 location.

Table 4.3 Penobscot L-30 Reservoir Properties.

South Penobscot - Original Oil in Place			
P90	**P50**	**P10**	**Mean**
6.2 E6M3	10.3 E6M3	14.5 E6M3	10.4 E6M3
39.3 MMBbls	64.9 MMBbls	91.3 MMBbls	65.3 MMBbls
North & Northeast Penobscot - Original Oil in Place			
P90	**P50**	**P10**	**Mean**
6.0 E6M3	12.4 E6M3	21.3 E6M3	13.1 E6M3
37.7 MMBbls	77.9 MMBbls	134.1 MMBbls	82.4 MMBbls
Total Penobscot - Original Oil in Place			
P90	**P50**	**P10**	**Mean**
12.2 E6M3	22.7 E6M3	35.8 E6M3	23.5 E6M3
77.0 MMBbls	142.8 MMBbls	225.4 MMBbls	147.7 MMBbls

Table 4.4 Penobscot oil in place.

South Penobscot - Recoverable Oil in Place			
P90	**P50**	**P10**	**Mean**
2.1 E6M3	3.6 E6M3	5.2 E6M3	3.6 E6M3
13.4 MMBbls	22.4 MMBbls	32.8 MMBbls	22.8 MMBbls
North & Northeast Penobscot Recoverable Oil in Place			
P90	**P50**	**P10**	**Mean**
2.1 E6M3	4.3 E6M3	7.6 E6M3	4.6 E6M3
13.0 MMBbls	26.8 MMBbls	47.5 MMBbls	28.8 MMBbls
Total Penobscot - Recoverable Oil in Place			
P90	**P50**	**P10**	**Mean**
4.2 E6M3	7.9 E6M3	12.8 E6M3	8.2 E6M3
26.4 MMBbls	49.2 MMBbls	80.3 MMBbls	51.6 MMBbls

Table 4.5 Penobscot recoverable oil in place.

Exploration Potential

While no hydrocarbons were encountered at the B-41 step out well, additional potential exists within similar untested closures to the north and northeast of the discovery. There is also potential within the Jurassic carbonate bank that extends beneath the parcel. Although tight carbonates were encountered in the L-30 well, there is potential for porosity development at the margin edge. The analogous Cohasset - Panuke oil reservoir sands are draped over the carbonate reef buildup containing the Deep Panuke producing gas field.

Additional subtle and low relief anticlinal structures similar to Penobscot may be present on the parcel. These structures are often difficult to identify on seismic (in the time domain). Due to the subtle nature of these features, accurate seismic interpretation and depth conversion are necessary in order to define these structures.

Parcel 9 - Eagle

Parcel Description and Exploration History

Parcel 9, known as Eagle, is in the central portion of the Sable Subbasin in present day water depths varying from 20 m to 170 m, with most of the block in less than 100 m. (Figure 4.10). Eagle D-21 is the only well that has been drilled on this parcel.

In the early 1970s, Shell Canada acquired a large offshore acreage position, which included the Eagle area, and acquired 2D seismic which was used to define the Eagle prospect. The Shell et al Eagle D-21 well was spudded on April 22, 1972 approximately 22 km southeast of Sable Island in 51 m of water. The well reached a total depth of 4660 m in the early Cretaceous lower Missisauga Formation encountering 52 m of net gas pay in the late Cretaceous Wyandot Chalk Formation. Gas was recovered from all three well tests.

In July, 1999 Mobil Oil Canada, partnered with Shell Canada and Imperial Oil, acquired a number of Exploration Licences in the Sable Subbasin that included the Eagle discovery. The partnership acquired seismic data over a number of their licences, including the northern portion of the current Eagle block. In 2002, following the merger between Exxon and Mobil, ExxonMobil and partners Shell and Imperial acquired 700 km^2 of 3D seismic over the Eagle discovery and large portion of Parcel 9. In July, 2004 ExxonMobil's Exploration Licence, a portion of which covered Eagle, expired and the land reverted to crown.

As a result of the NS07-1 call, a licence containing the Eagle field was awarded to Ammonite Corporation under a "promote license" scenario where the 25% work deposits was deferred for 3 years. Ammonite returned the parcel to Crown on December 31, 2012 with no deposit being paid.

Geology

A seismic dip line through the D-21 well shows a salt cored, faulted rollover anticline with 3 antithetic faults (Figure 4.15). The structure is bounded on the north and northwest by a major northeast-southwest trending growth fault. The Eagle gas reservoir is located within late Cretaceous limestones of the Wyandot Formation. The reservoir is a thick, continuous package of limestones, marls and chalks representing deposition on a stable, shallow, open-marine continental shelf. Well data indicates that the Wyandot carbonates are generally lime mudstones that are soft, chalky, fossiliferous, pyritic, argillaceous and interbedded with marls and calcareous grey shales and mudstones. A time map on the Wyandot shows closure around a series of fault (Figure 4.16). An acoustic amplitude map shows a dimming, indicated in red, of the Wyandot reflection that roughly corresponds to the mapped closure of the gas charged chalk (Figure 4.17). This dimming may result from an increase in porosity within the chalk.

The top seal is provided by the overlying shales of the Banquereau Formation. The lateral extent of the reservoir to the east, south and southwest is probably limited by a combination of structural and stratigraphic trapping due to the generally low matrix permeability of the reservoir. The bounding faults seal as the Wyandot reservoir is juxtaposed against shales and tight limestones of the Dawson Canyon Formation.

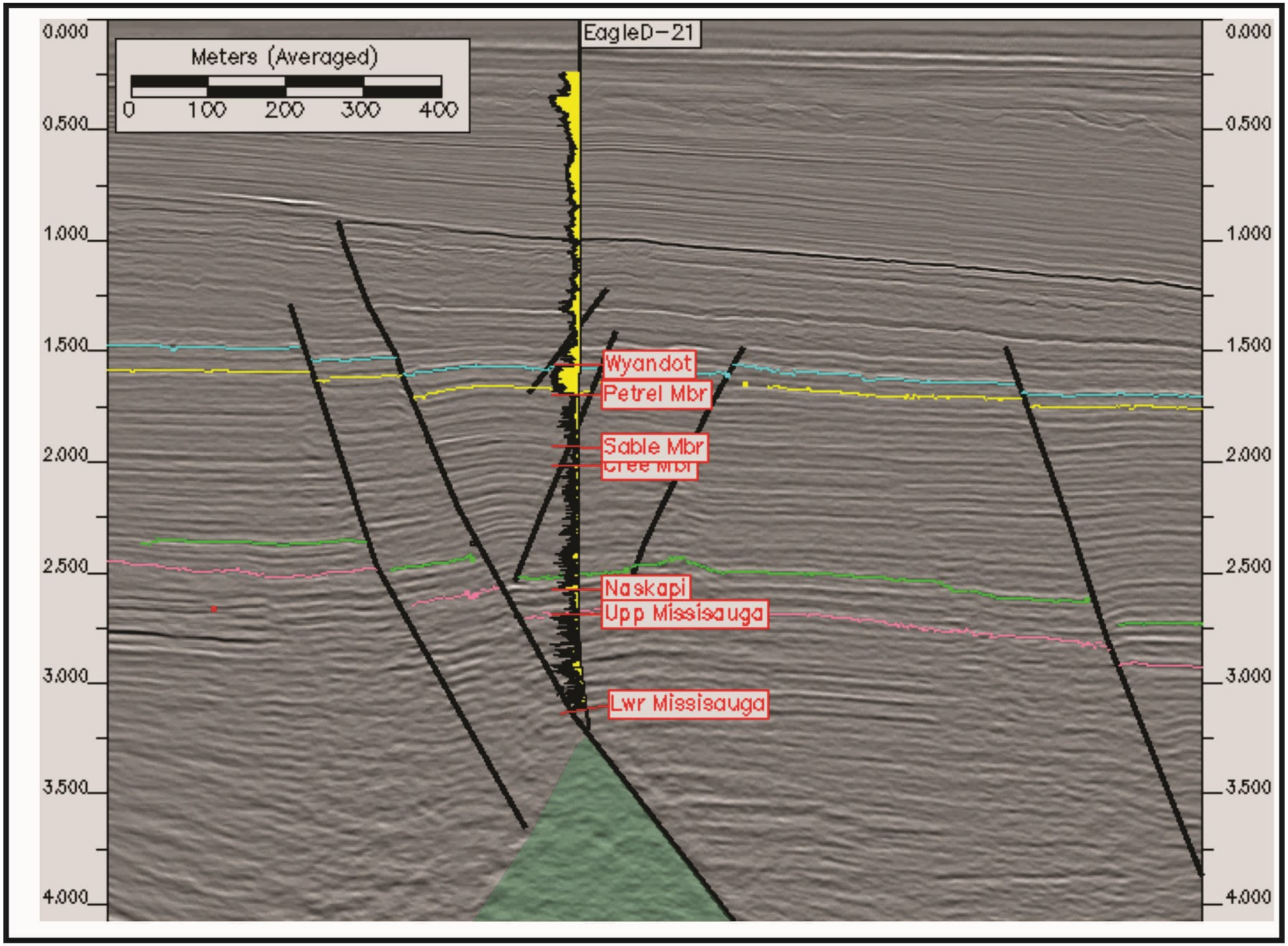

Figure 4.15 Seismic time section in dip direction over the Eagle gas discovery.

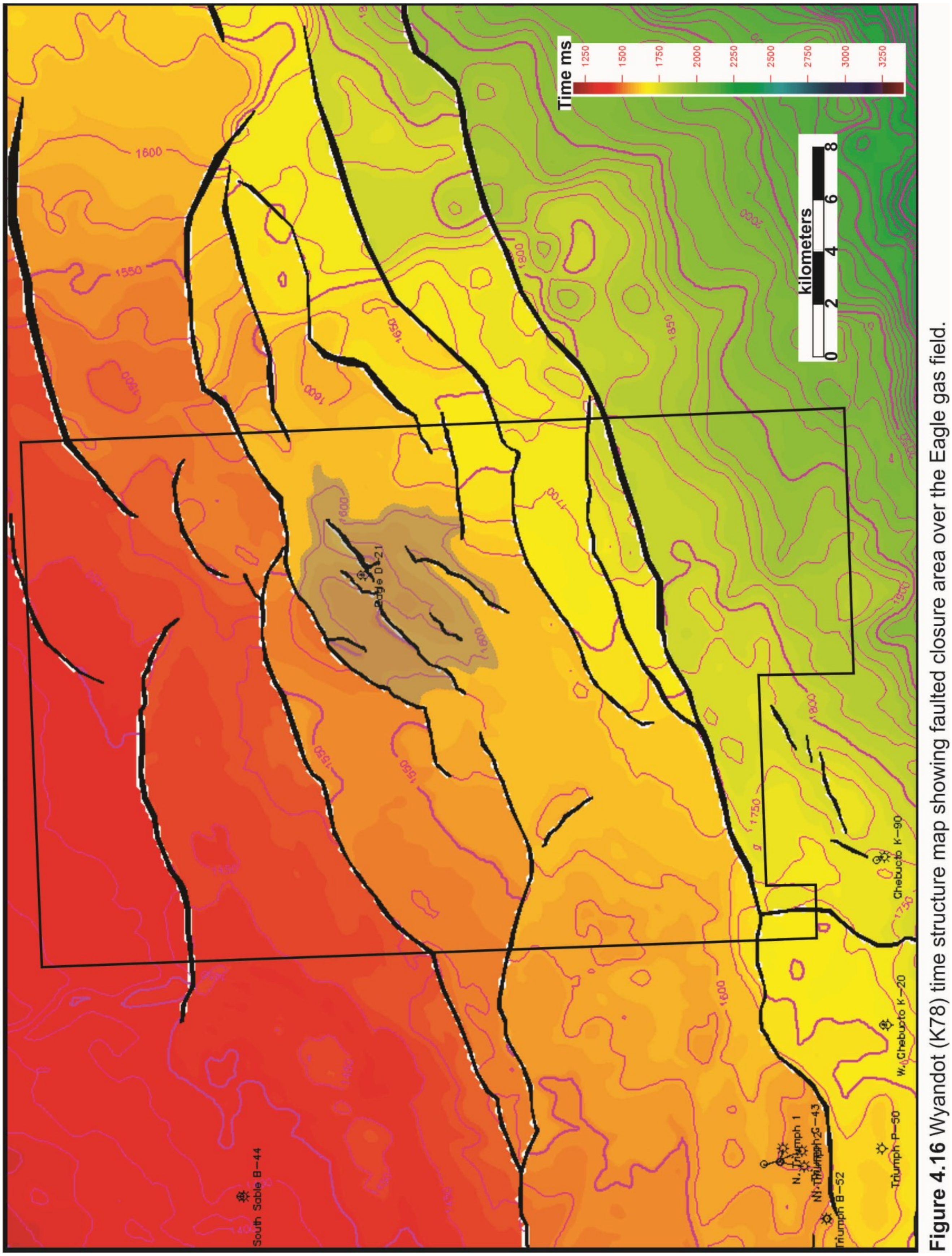

Figure 4.16 Wyandot (K78) time structure map showing faulted closure area over the Eagle gas field.

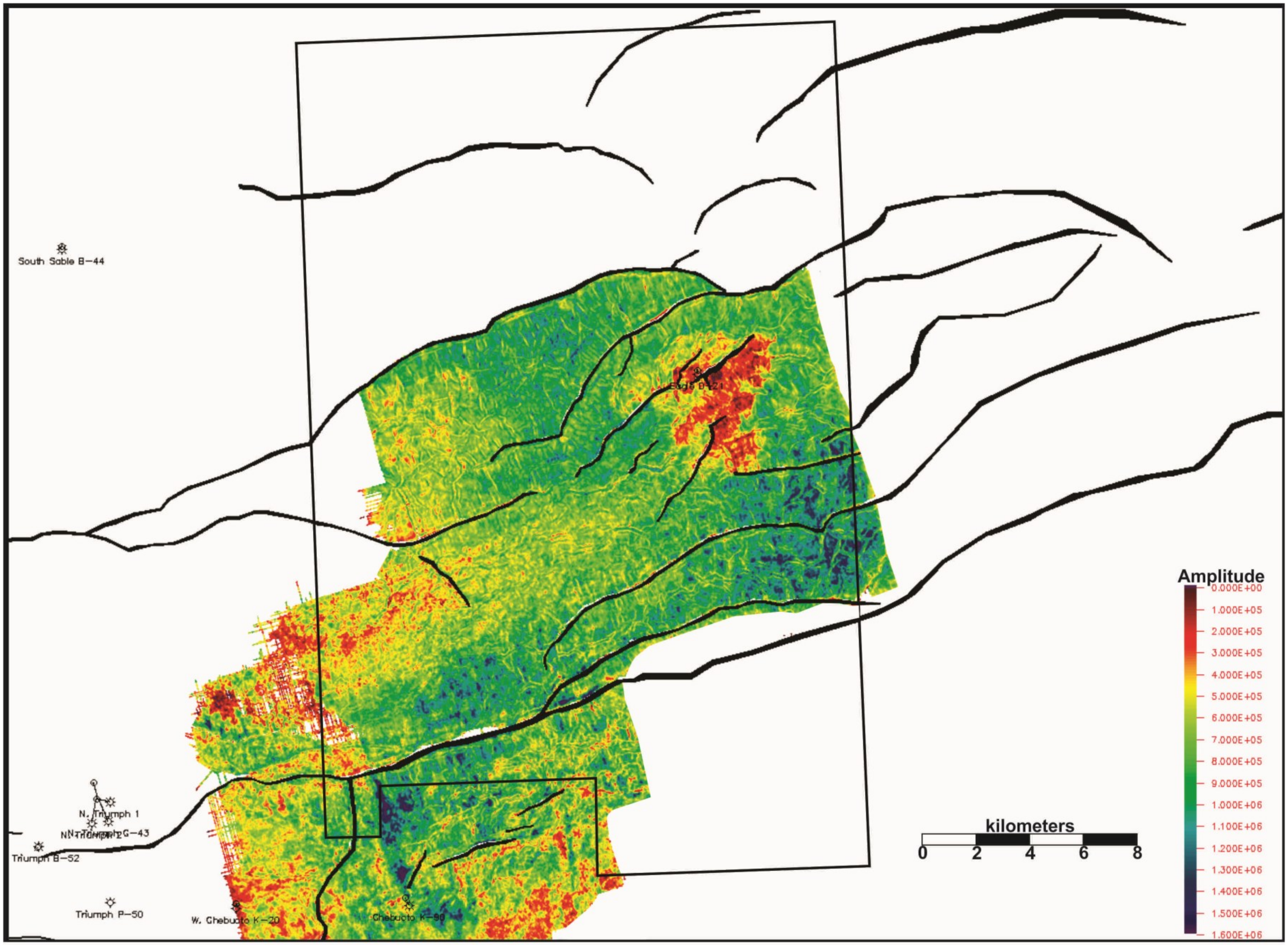

Figure 4.17 Wyandot (K78) seismic amplitude map showing a low amplitude anomaly corresponding to the Eagle field.

Formation Evaluation

A detailed petrophysical assessment was conducted on Eagle D-21. A few minor scattered gas shows were encountered in the Missisauga Formation from 4100 m to 4660 m (TD); however none of these sands are interpreted to contain significant hydrocarbon accumulations. The main reservoir in Eagle is the Wyandot Formation which has a gross thickness of 190 m at the D-21 well and consists of interbedded limestones, marls and chalks. The Wyandot reservoir is normally pressured but slight overpressuring was detected near the base of the well in the Missisauga Formation.

A complete suite of primary logging measurements were acquired over most of the well, including the Wyandot Formation (Figure 4.18) and 3 continuous conventional cores were cut in the Wyandot reservoir interval (Table 4.6).

Core#	Interval (m MD)	Recovery
1	1638.6 – 1649.0 m	9.4 m
2	1649.0 – 1658.4 m	8.8 m
3	1658.4 – 1667.6 m	8.7 m

Table 4.6 Eagle conventional core intervals.

Routine core analysis indicated porosities ranging from 19 to 36% with an average of 28%, while permeabilities range from 0.2 to 50 mD with an average of 0.6 mD. Core plugs containing fractures typically had the highest permeability. Core permeabilities are generally <2.0 mD, however all plugs had measured permeabilities above the 0.1 mD reservoir cutoff typically used for gas reservoirs.

Three production tests were conducted in the Wyandot Formation (Figure 4.18) with each zone being acidized prior to testing to improve deliverability (Table 4.7). PT#2 consisted of a 9.5 hours flow period and 12 hours shut-in time. Analysis of the transient data from this test suggests a low permeability zone consistent with core permeability, initial reservoir pressure of 2350 psi, and very low total skin value.

The reservoir properties obtained from this test were used to generate models to assess gas recovery from different well configurations. It was concluded that recovery from a multi-staged horizontal well could be significantly higher than a vertical well (15 – 20 times) and capable of delivering gas at substantially higher rates. This multi-staged horizontal well model also suggests that the production rate drops rapidly during the first few years of production but the decline rate decreases to low values after this initial production period. This production profile enables production rate to be sustained at lower values for a longer period of time.

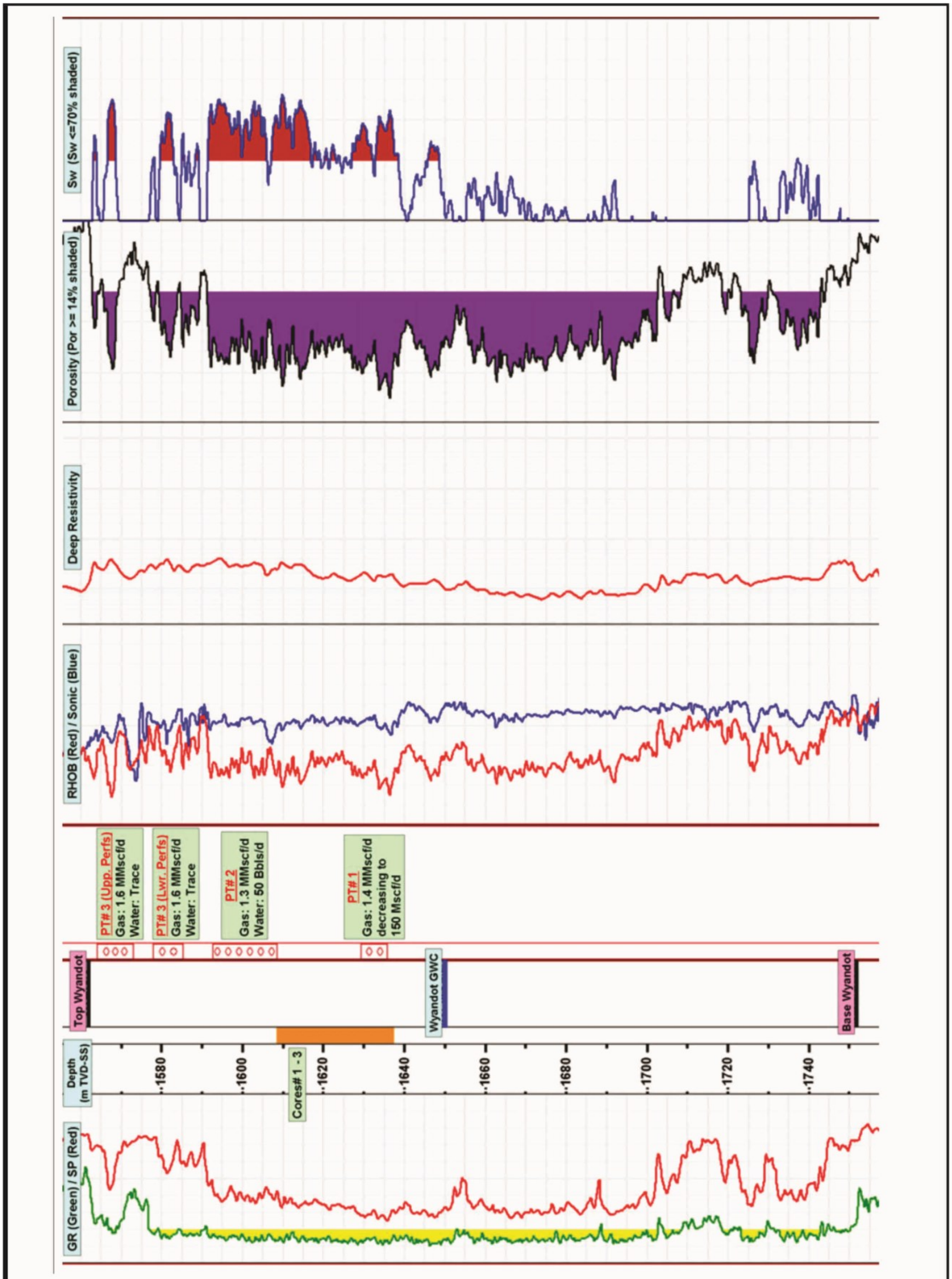

Figure 4.18 Eagle D-21 petrophysical evaluation.

Production Test#	Top (m MD)	Base (m MD)	Gas Rate (Mscf/d)	Condensate Rate (M3/d)	Condensate Rate (Bbls/d)	Water Rate (M3/d)	Water Rate (Bbls/d)
1	1659.6	1666.0	1600.6	0	0	Trace	Trace
2	1622.8	1638.6	1300.3	0	0	8*	50*
3 (upper perfs)**	1594.1	1603.2	1400.4 decreasing to 150	0	0	0	0
3 (lower perfs)**	1608.1	1615.4					

* The salinity of the recovered water in PT# 2 was 16,000 ppm while the salinity of the formation water is estimated to be 85,000 ppm, which suggests the produced water is likely mud filtrate.

** In PT# 3 the upper and lower perforations were tested together.

Table 4.7 Eagle D-21 production tests.

A petrophysical assessment of the Eagle D-21 well was conducted using all available log, core and test data (Table 4.8). A log defined gas-water contact (GWC) was interpreted at 1680.3 m MD / -1650.1 m TVD-SS. Due to the limited matrix permeability of the Wyandot a considerable transition zone, caused by capillary pressure effects, is evident on logs. This transition zones extends approximately 30 m above the GWC.

Zone	Top (m MD)	Base (m MD)	Net Pay (m TVD)	Net Pay Por. (%)	Net Pay Perm. (mD)	Sw (%)
Wyandot	1592.3	1782.2	52	27	0.50	54

Table 4.8 Eagle D-21 petrophysical assessment.

Reserves Estimate

Eagle has reservoir characteristics that are similar to the Ekofisk field in the Norwegian sector of the North Sea (Table 4.9). Ekofisk is an offshore chalk reservoir that has produced commercially for many years. The Ekofisk field is located in water depths ranging from 70 to 75m (Eagle water depth approximately 50m). Ekofisk has been on production since 1971 and contains vast reserves of both oil and natural gas.

Field	Age	Primary Lithology	Porosity (%)	Matrix Permeability (mD)
Eagle	Late Cretaceous	Chalk	19 – 36	0.2 – 1.4
Ekofisk	Late Cretaceous	Chalk	25 – 40	0.1 - 10

Table 4.9 Eagle and Ekofisk comparison.

Due to the nature of chalk reservoirs, enhanced production techniques such as acidizing, hydraulic fracturing and multiple fracture horizontal wells, are often required to improve production. The CNSOPB conducted engineering studies of the Eagle field and estimated that recovery factors of up to 60% are possible if the field is developed using multiple fracture horizontal wells. The results of this reservoir simulation were used to guide the recovery factors used in the Eagle probabilistic resource assessment (Tables 4.10 and 4.11).

Eagle - Original Gas in Place			
P90	**P50**	**P10**	**Mean**
25.3 E9M3	35.4 E9M3	47.3 E9M3	36.0 E9M3
892 Bcf	1,250 Bcf	1,670 Bcf	1,270 Bcf

Table 4.10 Eagle probabilistic resource assessment results for original gas in place.

Eagle - Recoverable Gas in Place			
P90	**P50**	**P10**	**Mean**
8.0 E9M3	13.3 E9M3	20.4 E9M3	13.8 E9M3
283 Bcf	471 Bcf	720 Bcf	489 Bcf

Table 4.11 Eagle probabilistic resource assessment results for recoverable gas in place.

Exploration Potential

On Parcel 9, in addition to the Eagle reservoir, a number of exploration prospects have been observed on the top Missisauga time map (Figure 4.19). These prospects have been described by ExxonMobil within their Eagle/Chebucto Seismic Interpretation Report (Seismic Program# NS24-E40-1E). The West Australia prospect has simple closure west of the Eagle field on the same bounding fault. The North Eagle prospect has simple closure along the same fault as South Sable B-44. They are interpreted to contain a number of stacked sands trapped within simple and fault dependent closures mapped at several levels within the Logan Canyon and Mississauga. The Reliance prospect is located below the TD of Eagle D-21 and is a large, high relief, crestally faulted closure within the early Cretaceous lower Missisauga Formation.

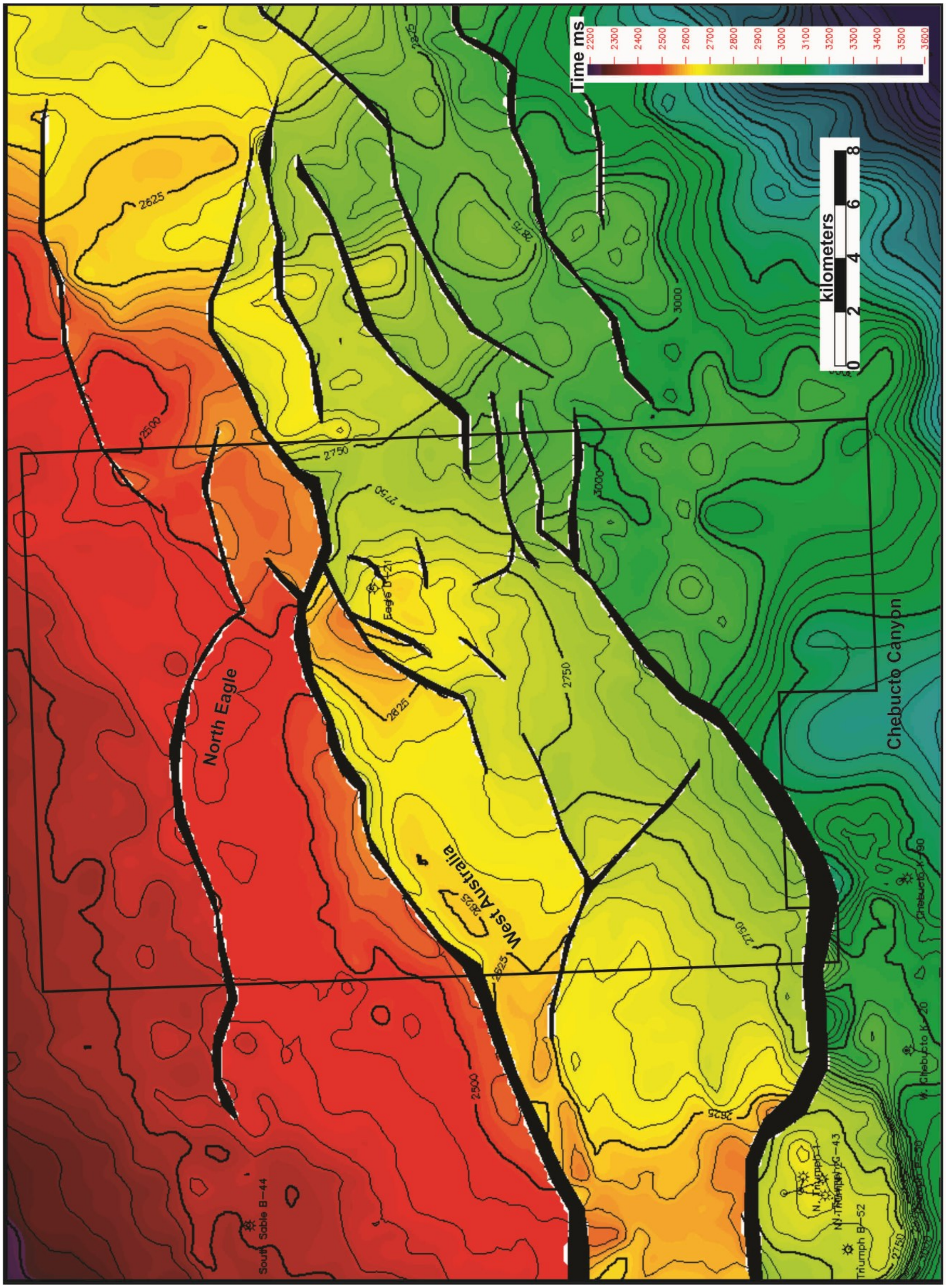

Figure 4.19 Top Missisauga time (K125) structure map.

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