PS Migration Effects on Crude Oil Composition in West and East Cameron, Offshore Louisiana*

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Abstract

A detailed geochemical study was initiated to determine the causes of variability in produced hydrocarbons in a relatively small geographic area in West and East Cameron, offshore Louisiana. Bulk chemical differences in produced condensates and oils from the East Cameron 64, 62, 49, and 46, and West Cameron 192 and 222 fields were found to be attributed primarily to phase separation during secondary migration and to current reservoir pressure and temperature conditions and biodegradation in shallow reservoirs. There is no evidence for multiple source rocks in the studied area. The source rock was not identified, but geochemical evidence indicates the oils are sourced from a rock with mixed type II/III kerogen. It is proposed that overpressured reservoirs produce greater volumes of oil (and with a lower API gravity) relative to produced volume of gas because higher molecular weight hydrocarbons are better solubilized in methane under the overpressure conditions.

Based on oil cracking kinetics and present-day reservoir temperatures, if Oligocene or Lower Miocene source rocks generated the oils found in the study area, then oil accumulations might be expected at depths up to 18,000 feet. If the Cretaceous source rocks generated the oils, then current drilling depths are already near the maximum depth (14,500 to 16,500 feet.) at which oil is likely to be found. The study indicates that oil may be present in traps stratigraphically below the main field production. Integration of fluids composition data with geologic data may be useful in determining the timing of fault movement with respect to hydrocarbon charge for a given reservoir. Local field size geochemical studies can be valuable in development drilling in mature exploration areas.

<u>Authors' Note:</u>

This work was first published 23 years ago in a conference proceedings (from Latin Amer. Congress on Org. Geochemistry, Cancun Mexico, 253-255, 1996). The abstract above is from the proceedings. In the authors' opinions, this work demonstrates practical methodology using geochemistry and exploration impact of understanding the mechanistic reason for a gas condensate; evaporative condensate, production condensate, or thermal condensate. Gas-induced phase segregation of oil columns has proven to be a major pathway to hydrocarbon emplacement and alteration. The conventional paradigm at the time for shelf Gulf of Mexico was that drilling deeper would not yield black oil, only drier gas.

Early oil to gas cracking kinetics also feed this paradigm. Recognizing fractionation condensates from vertical migration opened the concept to drill deeper for black oil and reopened previous mature areas for exploration.

MIGRATION EFFECTS ON CRUDE OIL COMPOSITION IN WEST AND EAST CAMERON, OFFSHORE LOUISIANA

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Abstract-A detailed geochemical study was initiated to determine the causes of variability in produced hydrocarbons in a relatively small geographic area in West and East Cameron, offshore Louisiana. Bulk chemical differences in produced condensates and oils from the East Cameron 64, 62, 49, and 46 and West Cameron 192 and 222 fields were found to be attributed primarily to phase separation during secondary migration and to current reservoir pressure and temperature conditions and biodegradation in shallow reservoirs. There is no evidence for multiple source rocks in the studied area. The source rock was not identified, but geochemical evidence indicates the oils are sourced from a rock with mixed type II/III kerogen. It is proposed that overpressured reservoirs produce greater volumes of oil (and with a lower API gravity) relative to produced volume of gas because higher molecular weight hydrocarbons are better solubilized in methane under the overpressure conditions. Based on oil cracking kinetics and present-day reservoir temperatures, if Eocene/Oligocene or Lower Miocene source rocks generated the oils found in the study area, then oil accumulations might be expected at depths up to 18,000 ft. If the Cretaceous source rocks generated the oils, then current drilling depths are already near the maximum depth (14,500 to 16,500 ft.) at which oil is likely to be found. The study indicates that oil may be present in traps stratigraphically below the main field production. Integration of fluids composition data with geologic data may be useful in determing the timing of fault movement with respect to hydrocarbon charge for a given reservoir. Local field size geochemical studies can be valuable in development drilling in mature exploration areas.

INTRODUCTION

A study was initiated to investigate how secondary migration, thermal maturity, and source rock affect liquids composition variability found in produced hydrocarbons in parts of West and East Cameron areas, offshore Louisiana. The fields West Cameron 192 and 222 and East Cameron 64, 62, 49, and 46 have a cumulative production of 2.9 trillion cubic feet of gas and 49 million barrels of condensate and oil principally from Upper and Lower Miocene strata. Many of these fields have been on production for nearly 20 years and produce mostly gas with some liquids. The range of liquid hydrocarbon quality (API gravity and GOR) and quantity is considerable in this relatively small geographic area. It was hoped that a systematic study of the liquid and gas hydrocarbons would provide information on the variability in quality and quantity that could be used in a predictive manner for field development. The information determined from this investigation suggested potentially deeper production in overpressured zones that has been supported by recent drilling.

Condensate, oil, and gas samples were collected from Miocene reservoirs to determine thermal maturity and possible oil-oil correlations. Collection of condensates associated with primarily gas-producing wells can be helpful in establishing the maturity of the gases and if the gases have been altered by biodegradation (James and Burns, 1984). The gas samples were analyzed for molecular composition and stable carbon isotopes of methane, ethane, and propane. The condensate and oil samples were analyzed for bulk geochemical parameters (API gravity, percent sulfur, and metals) and detailed geochemical analyses (n-alkane distributions, biomarkers, and stable carbon isotopes of saturate and aromatic hydrocarbon fractions).

CONCLUSIONS

1. The gases are primarily thermogenic and are derived from source(s) with maturity between 1.2 and 1.6 percent Ro. The stable carbon isotopic value indicates a mixture of thermogenic and biogenic gas in some shallower reservoirs.

2. The gases appear to be not associated with condensate or oil generation but were derived from Type III and/or Type II dispersed kerogen during post oil window maturation.

3. The condensates and light oils in the study area are derived from source(s) with thermal maturity from 0.9 to 1.2 percent Ro (late oil window maturity) and are thus generally less mature than that of the gas. Based on reservoir temperature data, all the oils are currently reservoired at depths above expected thermal destruction of oil, and therefore, oils have not suffered in-reservoir maturation. The high API gravity condensates and oils are postulated to be primarily a product of evaporative fractionation of lower API gravity parent oils.

4. Condensate (API gravity 49.3) produced from the Middle Miocene (9210 ft.) at WC216 may be an evaporative fractionation daughter product and the WC215 produced oil (API gravity 32.6) from the Middle Miocene (11,300 ft.) the residual oil from that evaporative fractionation process. The same relationship is invoked for WC177 condensate and light oil.

5. Biomarker and stable carbon isotope data suggest that Miocene reservoired EC64, WC177, WC66, and WC34 oils have a common source and correlate to each other. These oils indicate a possible correlation to Paleocene- and Eocene-sourced oils which are reservoired in the Wilcox Formation, onshore Louisiana and Mississippi.

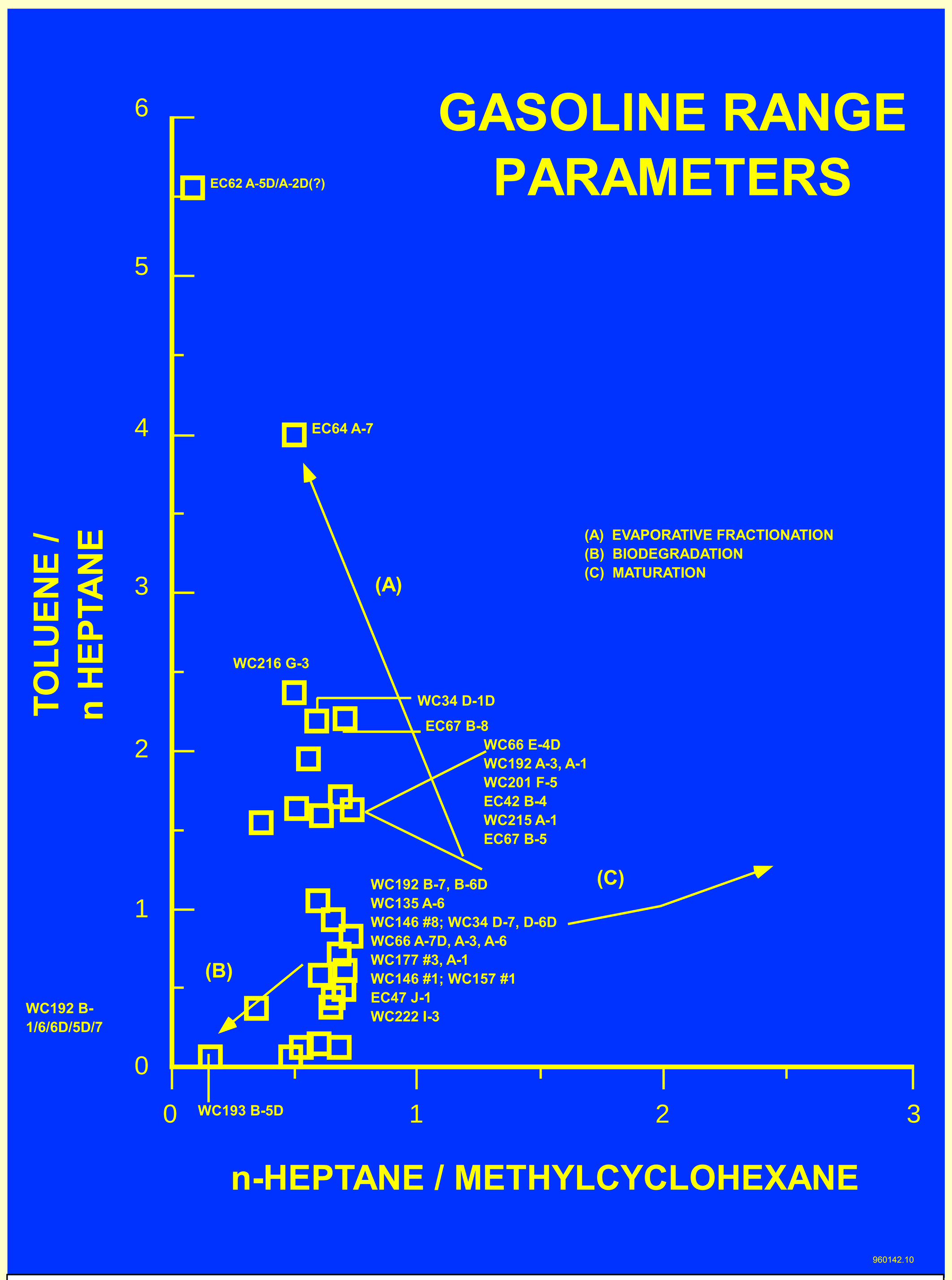
6. The migration scenario envisioned for the studied fields in the East and West Cameron area is one of stratigraphically lower oil reservoirs (deeper than currently producing) filled with higher maturity gas (i.e., post oil window gas) and subsequent faulting of the reservoirs. Remigration of the gas cap with solubilized hydrocarbons occurred along faults and was trapped as stratigraphically higher hydrocarbon accumulations. The faulting and remigration may have been multistage and reservoir pressure and temperature conditions control fluid density (Fig. 1).

7. Bulk chemistry differences in produced condensates and oils from the studied fields in the East and West Cameron area are attributed to alteration during remigration and to current reservoir conditions. There is no evidence for multiple source rock types in the studied area. It is proposed that overpressured zones produce greater volumes of oil (and with a lower API gravity) relative to produced volume of gas since higher molecular weight hydrocarbons are better solubilized in methane under the overpressure conditions. The effect of overpressure in retarding oil cracking and preserving liquid hydrocarbons is not necessarily the reason for greater volumes of oil produced from overpressured zones in this study area. However, the effect of overpressure on hydrocarbon preservation (e.g., Domine and Enguehard, 1992) needs further research and may be important in preservation of overpressured subsalt hydrocarbons (Ermolkin *et al.*, 1989) in the Gulf of Mexico.

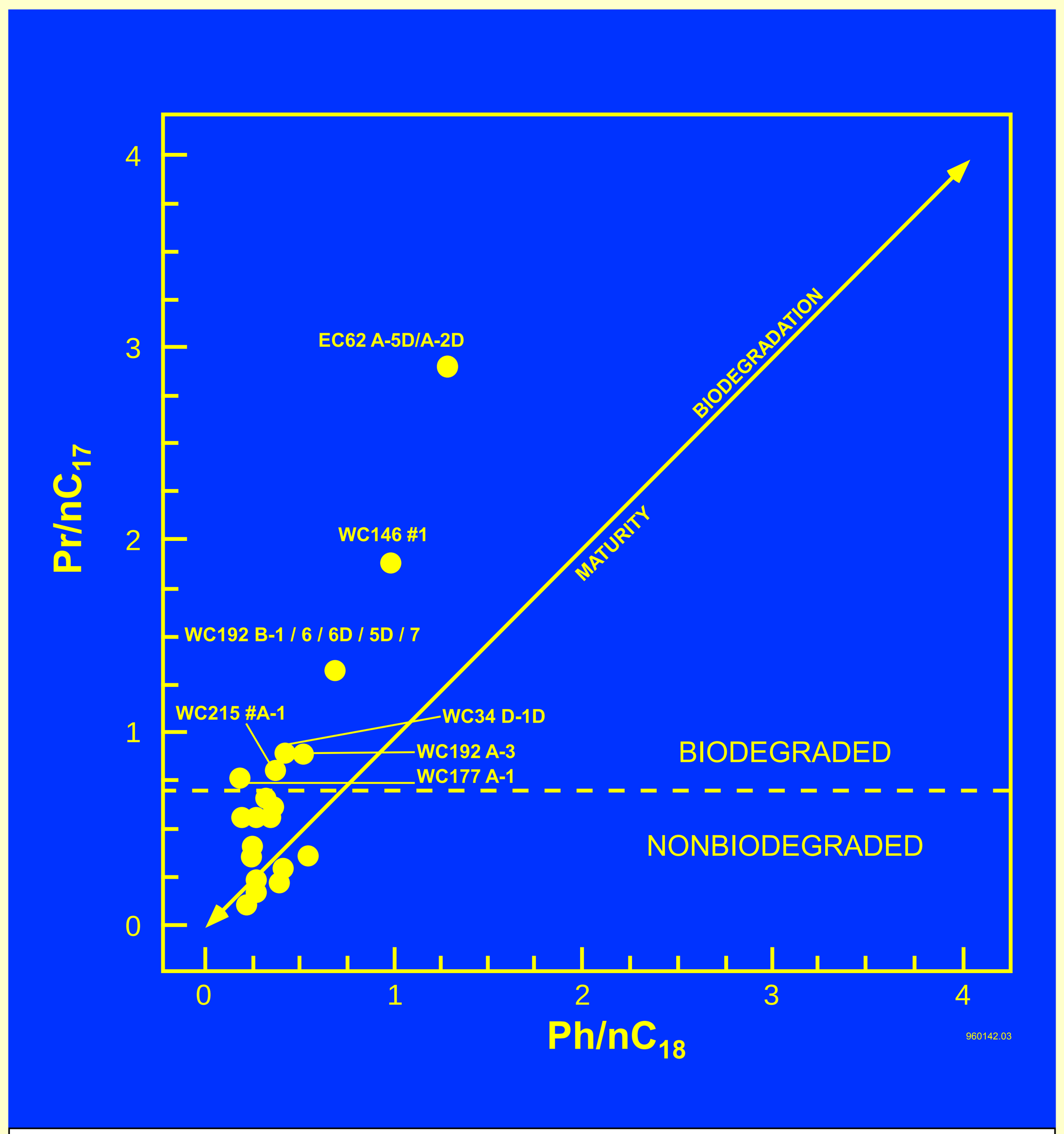
8. Based on oil cracking kinetics and present-day temperatures, if Lower Tertiary or Lower Miocene source rocks generated the oils found in the study area, then oil accumulations might be expected at depths up to 18,000 ft. If the Cretaceous source rocks generated the oils, then current drilling depths are already near the maximum depth (14,500 to 16,500Êft.) at which oil is likely to be found.

References

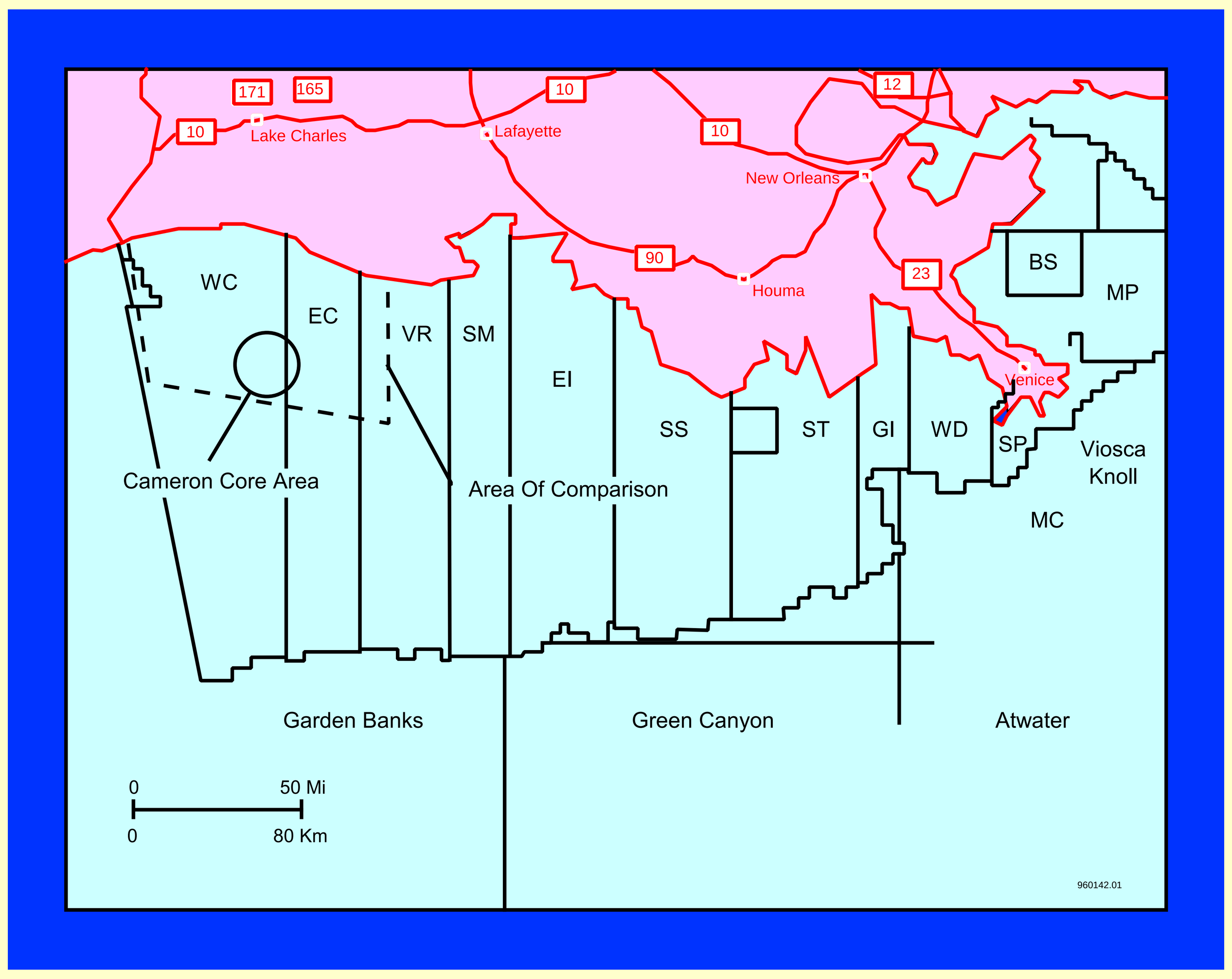
Domine F. and Enguehard F. (1992) Kinetics of hexane pyrolysis at very high pressures-3. Application to geochemical modeling, Org. Geochem. 18, 41-49.
Ermolkin V. I., Sorokova E. I., and Modelevsky M. M. (1989) Petroleum potential of subsalt complex in the Pricaspian Depression of the USSR, Energy Explor. Exploit, 7, 413-425.
James A. T. and Burns B. J. (1984) Microbial Alteration of Subsurface Natural Gas Accumulations, Bull. Am. Assoc. Pet. Geol. 68, 957-960.

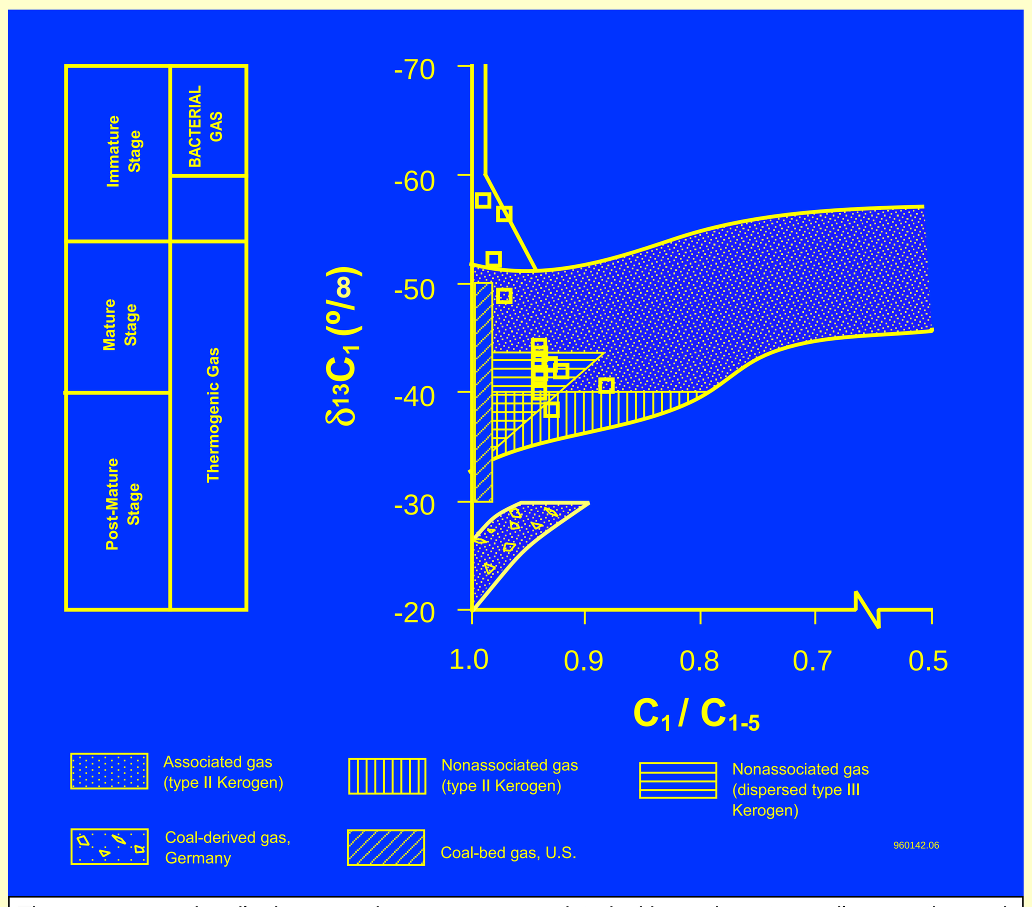


The toluene/n-heptane versus n-heptane/methylcyclohexane plot indicates that most oils are affected by the migration process of evaporative fractionation but possible todifferent degrees. A toluene/n-heptane value greater than 0.4 suggests fractionation by evaporative fractionation as determined empirically from Gulf Coast oils with toluene/n-heptane ration below 0.4 may be least altered oils or have suffered no evaporative fractionation (WC47 #J-1, WC222 #I-3, WC146 #1, and WC157 #1). Samples with toluene/n-heptane values between 0.4 and 1.0 are considered to be altered by evaporative fractionation (i.e., WC177 #3 and #A-1), and samples with a ration greater than 1.0 are considered highly altered (i.e., EC67 #B-5 and EC64 #A-7) by evaporative fractionation.

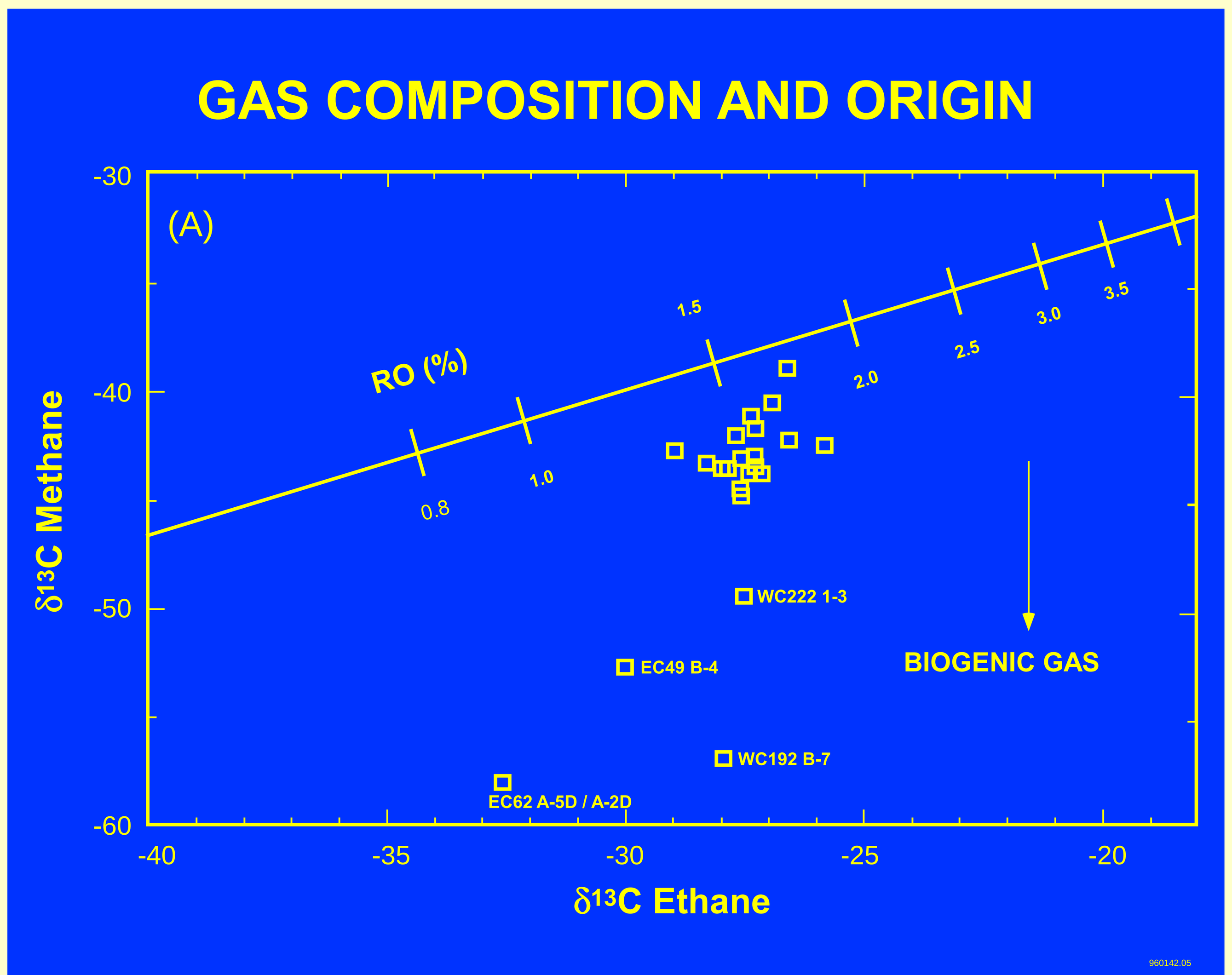


C_{19} isoprenoid pristane: nC_{17} ratio value the C_{20} isoprenoid phytane: nC_{18} ratio. Biodegradation line is empirical data from Gulf Coast oils after Thompson and Kennicutt (1990). Most collected samples have not suffered biodegradation.

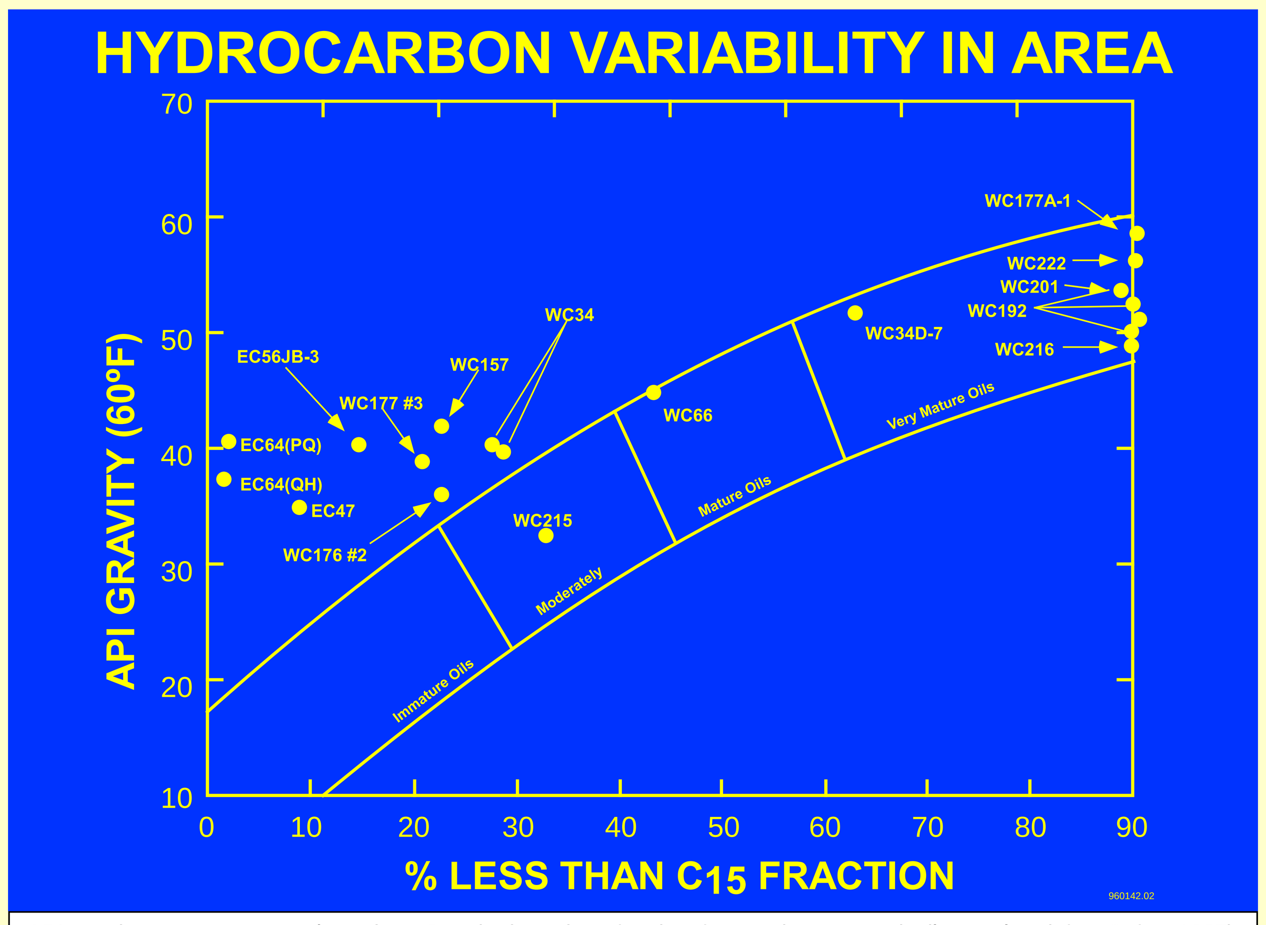




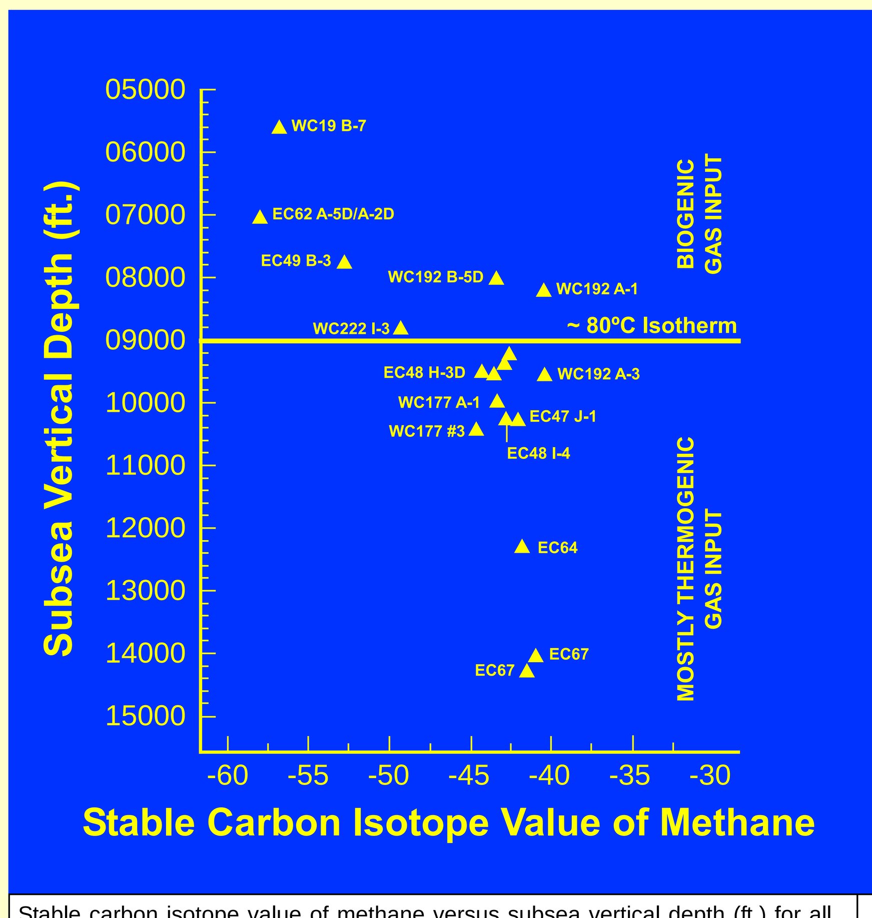
The gases are primarily thermogenic gases nonassociated with condensate or oil generation and are most likely derived from Type II and Type III dispersed kerogen. Some gas associated with condensate generation may be mixed with the nonassociated gases.



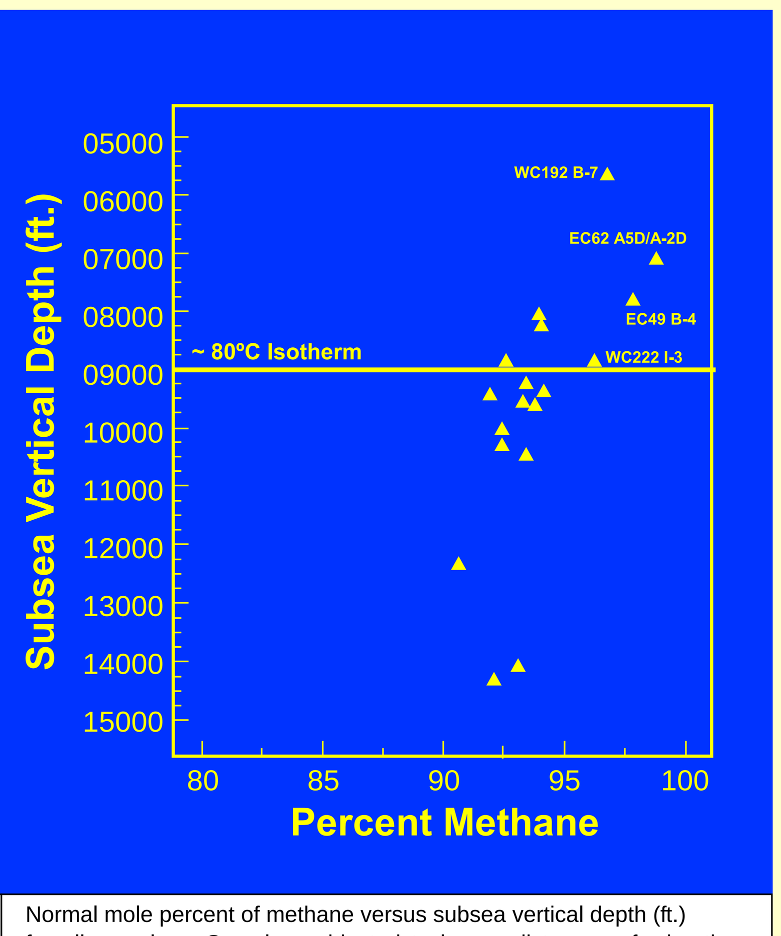
The isotopic values for most of the gases indicate they are of thermogenic origin and derived from a source(s) which is in the late to post oil window maturity (1.2 to 1.6 percent Ro). The stable isotopic values for methane are similar to those encountered from the Miocene in WC40 (nonassociated with condensate) and WC71 (associated with condensate) (Rice and Threlkeld, 1990).



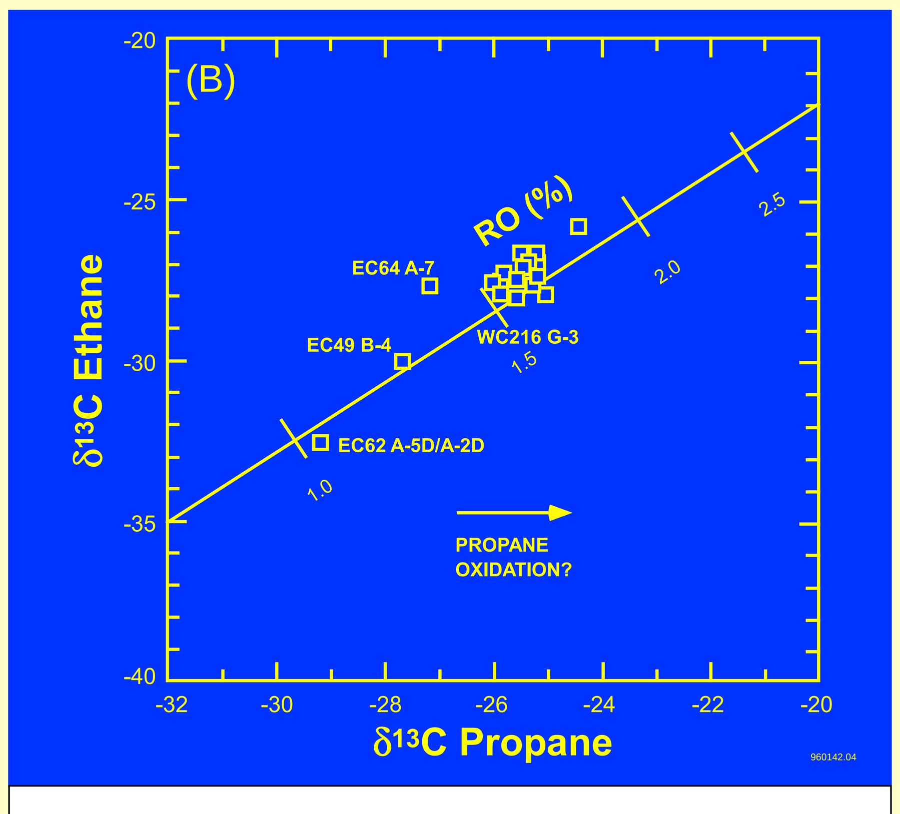
API gravity versus percent less than C_{15+} hydrocarbon fraction for condensate and oil samples (after Sofer, 1987). Samples which fall off the general trend to the left indicate samples which have experienced a loss of low molecular weight n-alkanes.



Stable carbon isotope value of methane versus subsea vertical depth (ft.) for all samples. The stable carbon isotope value of gases shallower than approximately 9,000 ft. indicate increased contribution of biogenic gas.

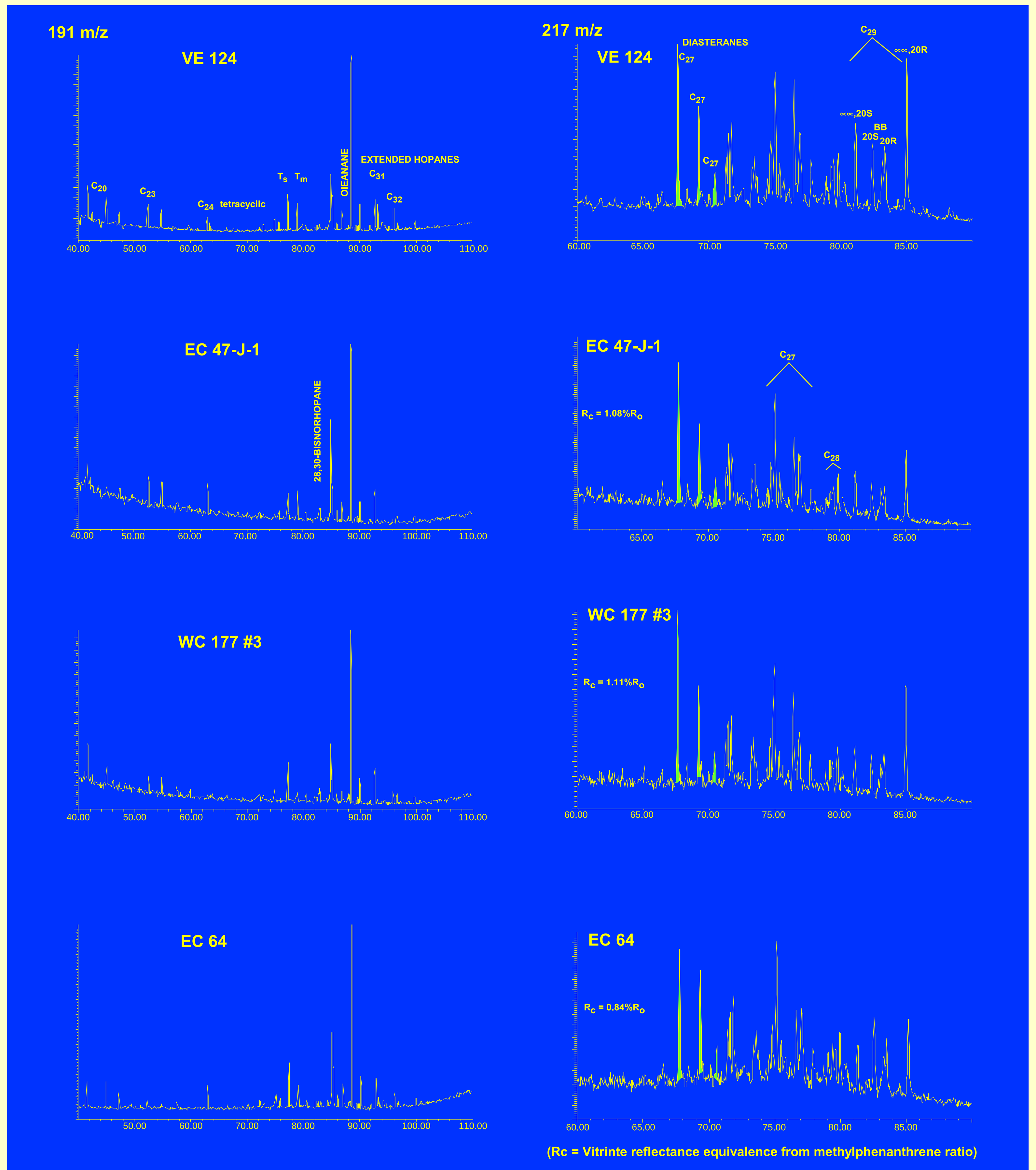


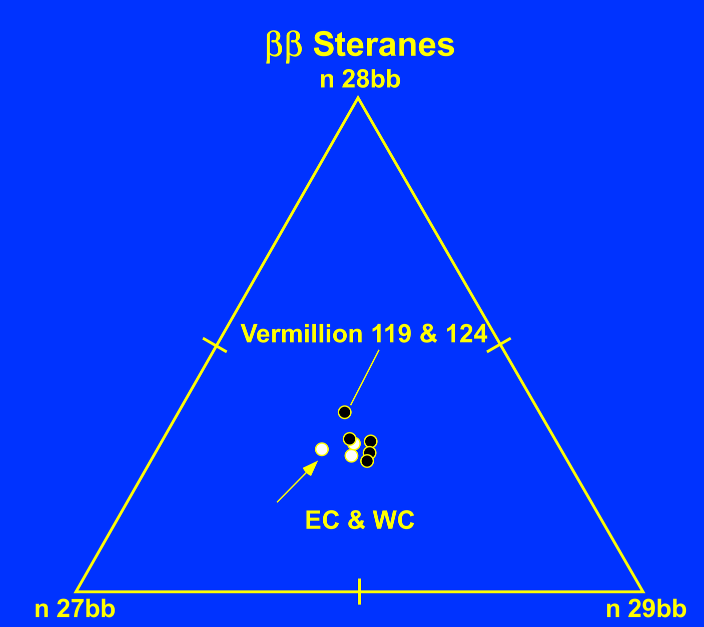
Normal mole percent of methane versus subsea vertical depth (ft.) for all samples. Samples subjected to longer distances of migration may result in higher percentages of lower molecular weight gas components (i.e., methane).



A. Stable carbon isotope value of methane versus ethane and relative maturity in equivalent vitrinite reflectance values (after Berner and Baber, 1987). Biogenic gas is isotopically lighter than thermogenic gas and pulls the methane value off the trend line.
B. Stable carbon isotope value of ethane versus propane and relative maturity in equivalent vitrinite reflectance values (after Berner and Faber, 1987).

COMMON SOURCED OILS IN AREA

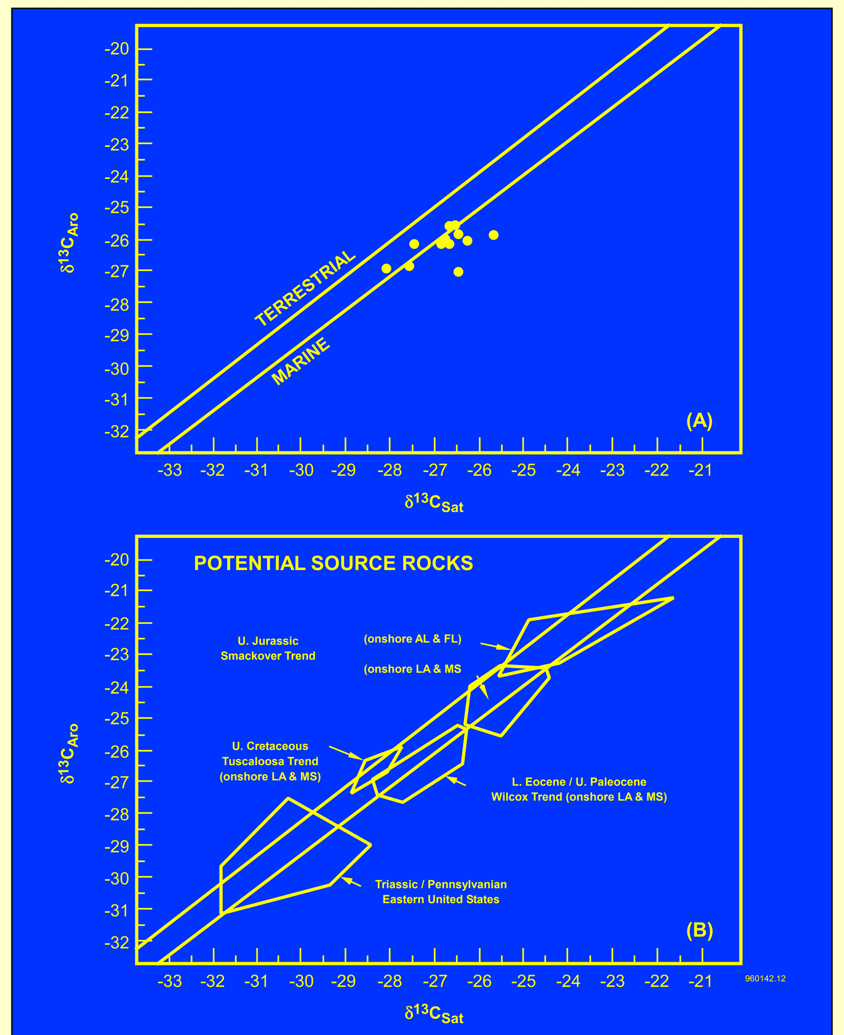




The C_{31} 22S/22(S+R) hopane maturity ratio is near an equilibrium value of 0.60 for most of the samples, indicative of at least 0.55 percent Ro maturity (Mackenzie et al., 1988; Boreham et al., 1988; Rullkötter and Marzi, 1988). The C_{29} sterane maturity ratios 20S/20(S+R) and ββ/(αα+ββ) have values far less than equilibrium, indicative of maturity lower (0.6 to 0.7 percent Ro) than that estimated from gasoline hydrocarbon parameters (0.9 to 1.2 percent Ro.) (Rullkötter and Marzi, 1988; Mackenzie et al., 1988). The low sterane concentrations and low maturity indicated from sterane biomarker ratios were previously proposed by Thompson and Kennicut (1990) as due to elimination of indigenous steranes followed by extraction of lower maturity steranes during the evaporative fractionation. The calculated vitrinite reflectance based on the C_{29} sterane 20S/20R ratio (Bein and Sofer, 1987) is also anomalously low for the above reasons. The vitrinite reflectance calculated from the methlyphenanthrene ratio (Radke et al., 1982) is slightly lower than indicated from the gasoline hydrocarbon parameters. Based on experimental data (Larter and Mills, 1991), vitrinite reflectance calculated from methylphenanthrene ratio may be relatively little altered between phase separation residual oils and daughter products. The $C_{20}/(C_{27} + C_{20})$ triaromatic sterane ratio is highly variable but suggests low thermal maturity (<0.80 percent Ro) for the samples (Mackenzie et al., 1981; Mackenzie et al., 1988).

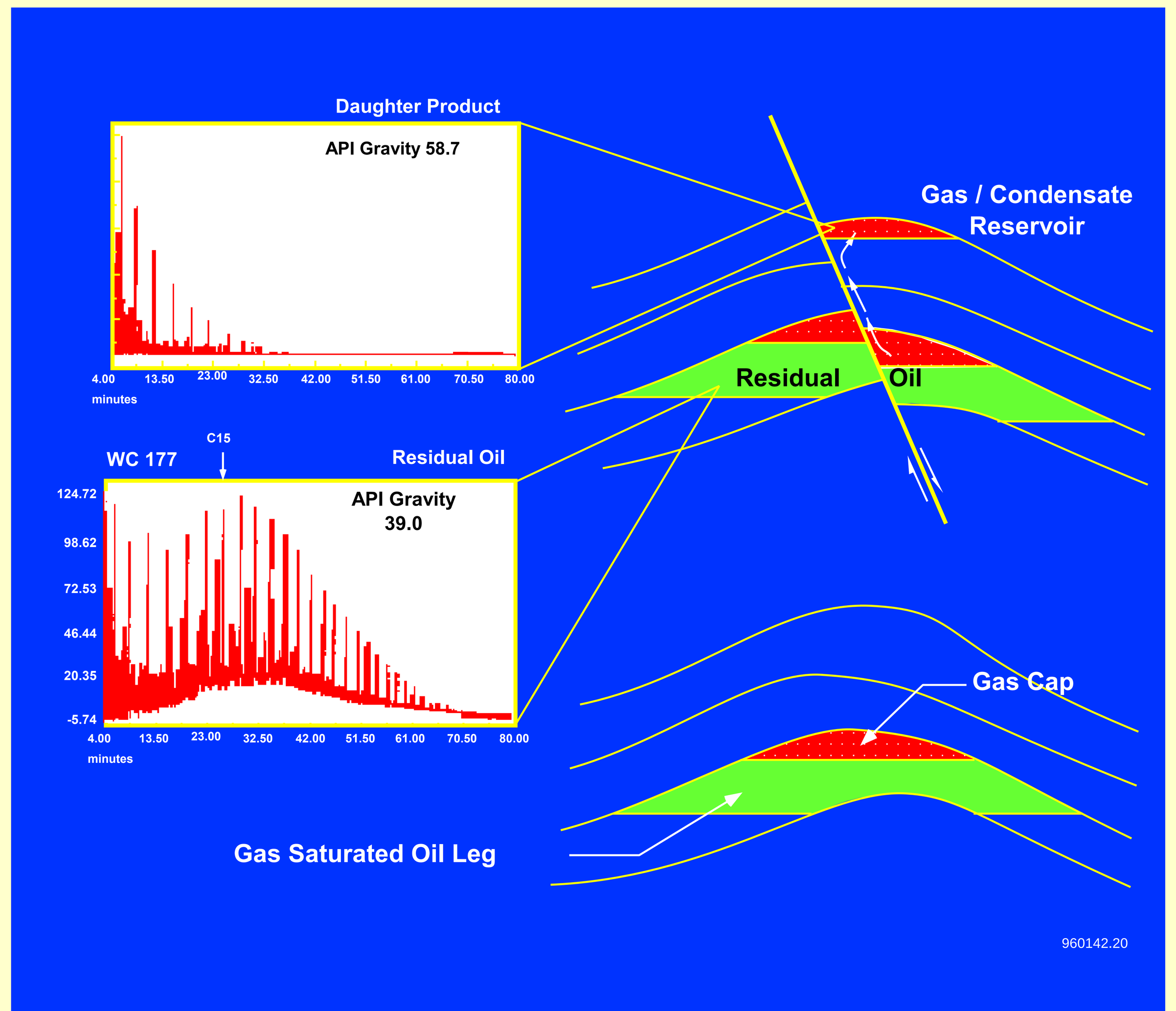
The high ratio of hopanes/steranes and low tricyclic to pentacyclic terpane ratio suggest a nonmarine organic matter origin (Moldowan et al., 1985; Philp et al., 1989). All the samples contain 28,30-bisnorhopane, which may indicate marine or near marine setting; however, this biomarker can also be found in terrestrial source rocks (Wenger et al., 1990; Noble et al., 1985). The presence of 28, 30-bisnorhopane is important in that this compound is found in the Paleocene/Eocene Wilcox reservoired oils of onshore Louisiana and Mississippi but is not found in any of the onshore Mesozoic reservoired (and supposedly Mesozoic-sourced) oils of Arkansas, Louisiana, Mississippi, and Alabama (Wenger et al., 1990). Therefore, the presence of 28, 30-bisnorhopane, as suggested by Kennicutt et al. (1992), may support a Tertiary source for the oils. 18α(H)-oleanane, a higher plant indicator (Ekweozor et al., 1979), is not as prevalent in the East and West Cameron oils as it is in onshore Wilcox reservoired oils (Wenger et al., 1990), and this may indicate a greater marine influence for oils with increasing distance offshore. Biomarker data suggests a strong correlation between EC67 #A-7, VE119, VE124, WC34, WC66 and WC177 #3 oils.

OIL CORRELATION AND SOURCE



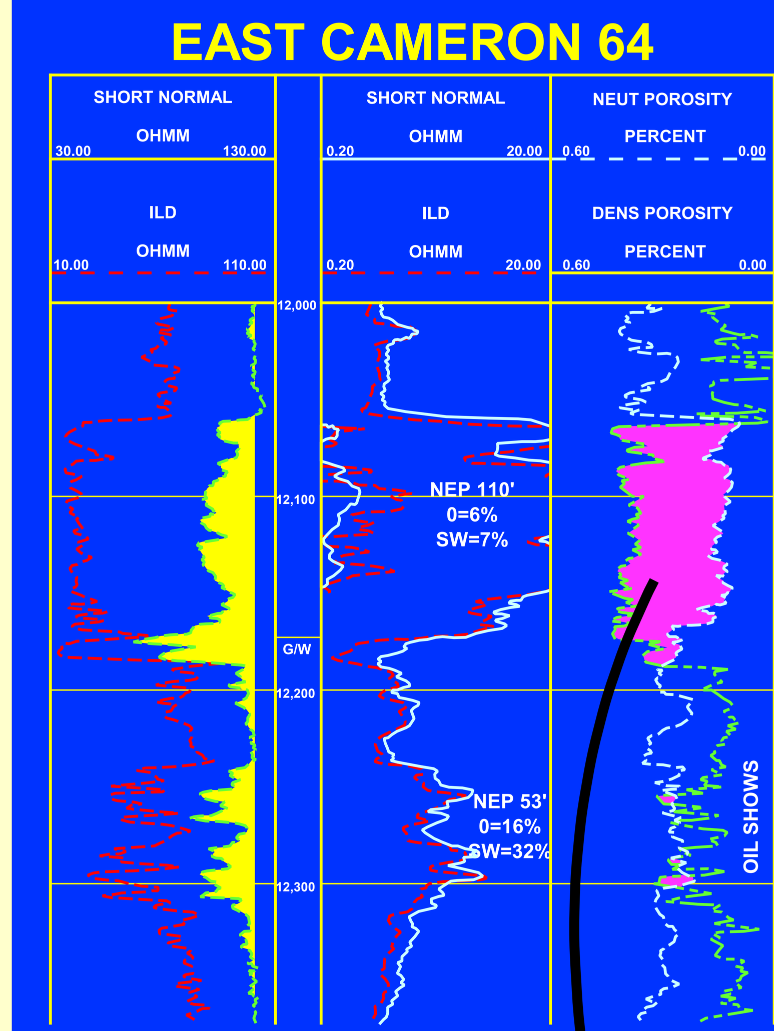
Stable Carbon Isotopes of Oils
Stable carbon isotopes of the saturate and aromatic hydrocarbon fractions indicate that most of the East and West Cameron oils are derived primarily from a marine source (Sofer, 1984). The isotopic values are all close enough (approximately 1 ppt difference) to suggest a common source for the oils (Sofer, 1984; Fuex, 1977). The oils are most similar to the Lower Eocene/U. Paleocene Wilcox reservoired (and possibly generated) oils of onshore Louisiana and Mississippi (Wenger et al., 1990)

MIGRATION MECHANISM



The samples from the WC177 #3 and #A-1 wells show a residual oil-gas/condensate daughter product evaporative fractionation-type relationship. The deeper (10,424 ft.) sample from the OC sand is depleted in light hydrocarbons, and the shallower sample (9,971 ft.) is enriched in light hydrocarbons.
The proposed scenario for migration of the East and West Cameron condensates is that oil reservoirs were injected by late to post oil window maturity allochthonous gas and subsequently remigrated up faults (Thompson et al., 1990). During remigration, the high maturity gas escaped, stripping off low molecular weight hydrocarbons. The shallower reservoirs hence contain gas with condensate derived from a normal oil in a deeper reservoir.

DEVELOPMENT DRILLING APPLICATION



EAST CAMERON 64 LOWER PQ INTERVAL

RESERVOIR CONDITIONS:
- 10,000 PSI
- 280º FARENHEIT

HYDROCARBON COMPOSITION:
- 38º API GRAVITY
- 3000 GOR
- 8,900 PSI BUBBLE POINT

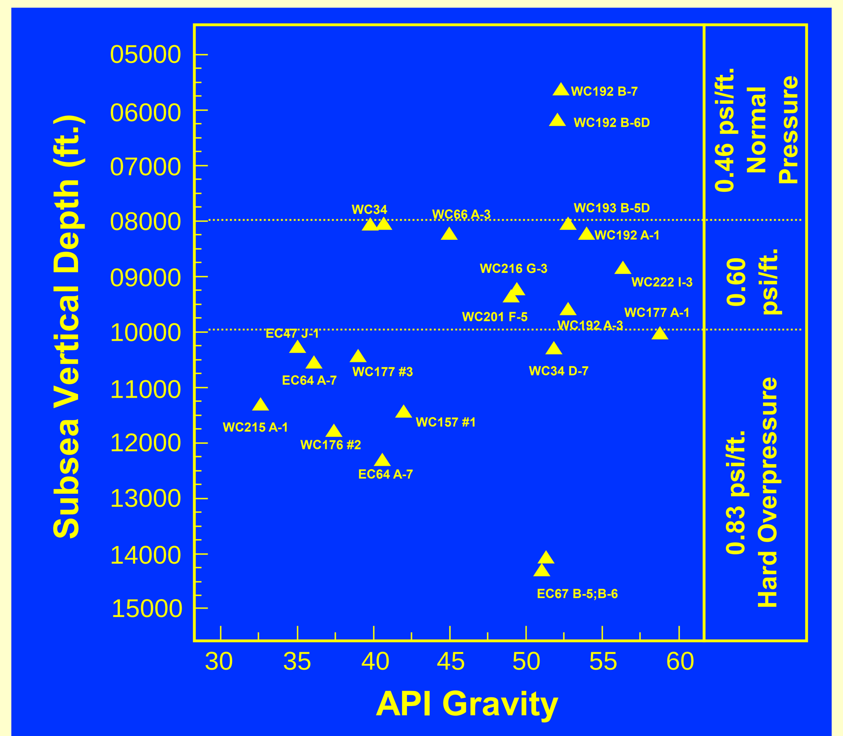
INITIAL RATES:
- 2,400 BOPD
- 7.0 MMCFGD
- 6,750 PSI FLOWING TUBING PRESSURE

ESTIMATED OPTIMUM RATE:
- 3,000 BOPD
- 9.0 MMCFGD

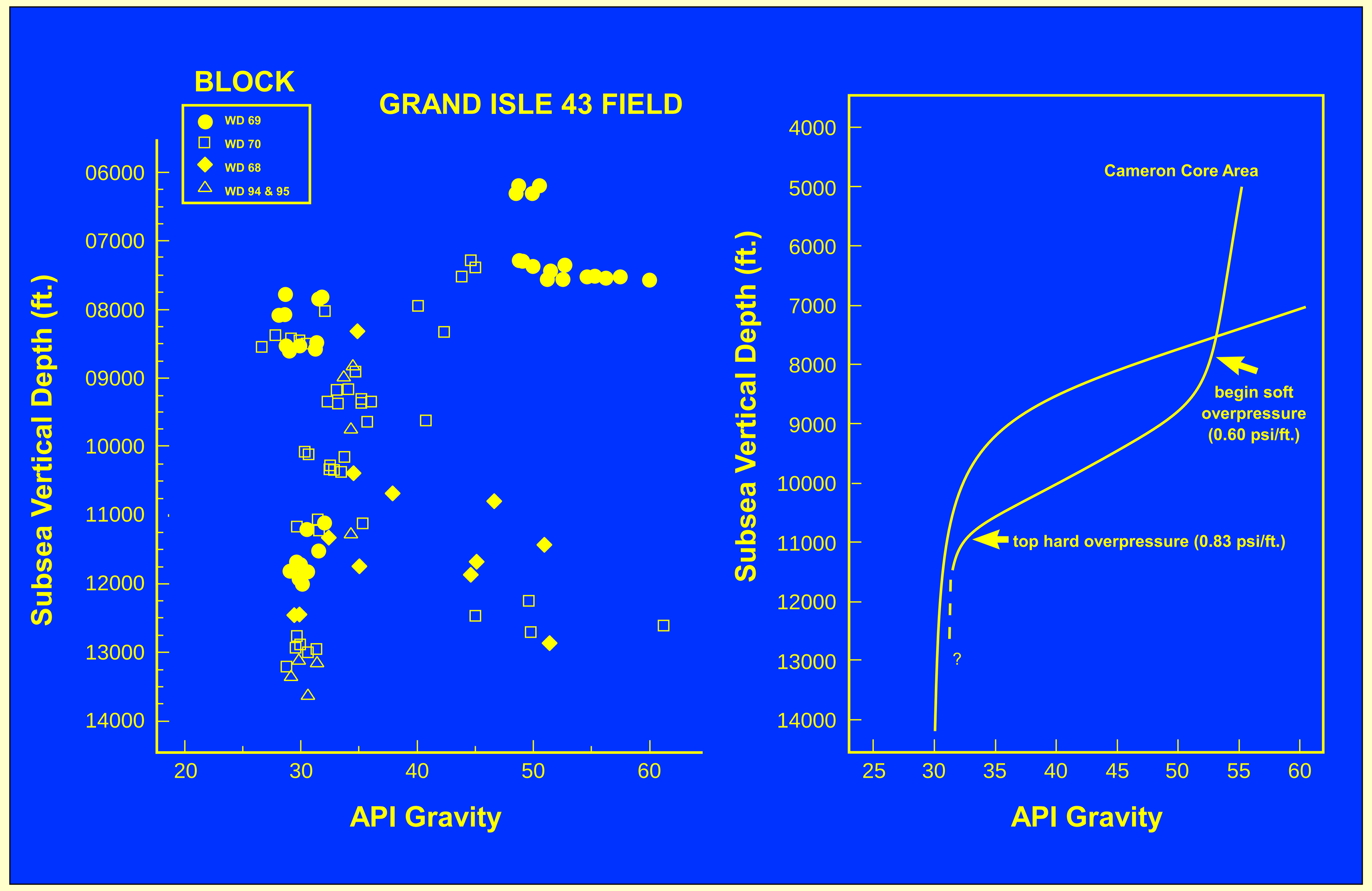
DEVELOPMENT DRILLING APPLICATION:

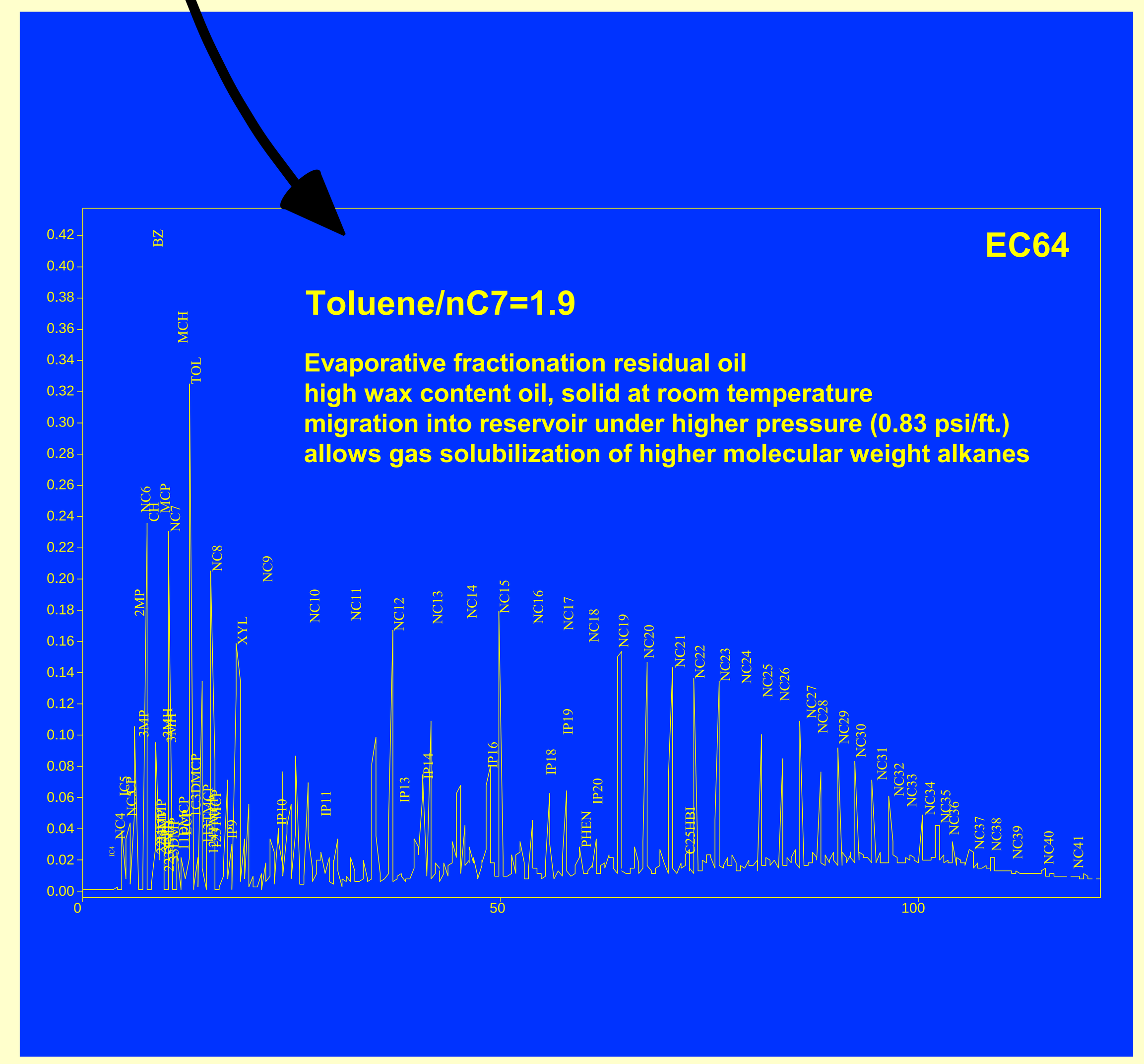
SCREEN FIELDS FOR:
- TRENDS IN PRODUCE FLUID PROPERTIES AND LIGHT HYDROCARBON GEOCHEMISTRY THAT SUPPORT EVAPORATIVE FRACTIONATION.
- HIGH GRADE DEEPER PROSPECTS WHICH DEMONSTRATE A GEOPHYSICAL ANOMALY (AVA).

PVT CONTROL ON HYDROCARBON COMPOSITION

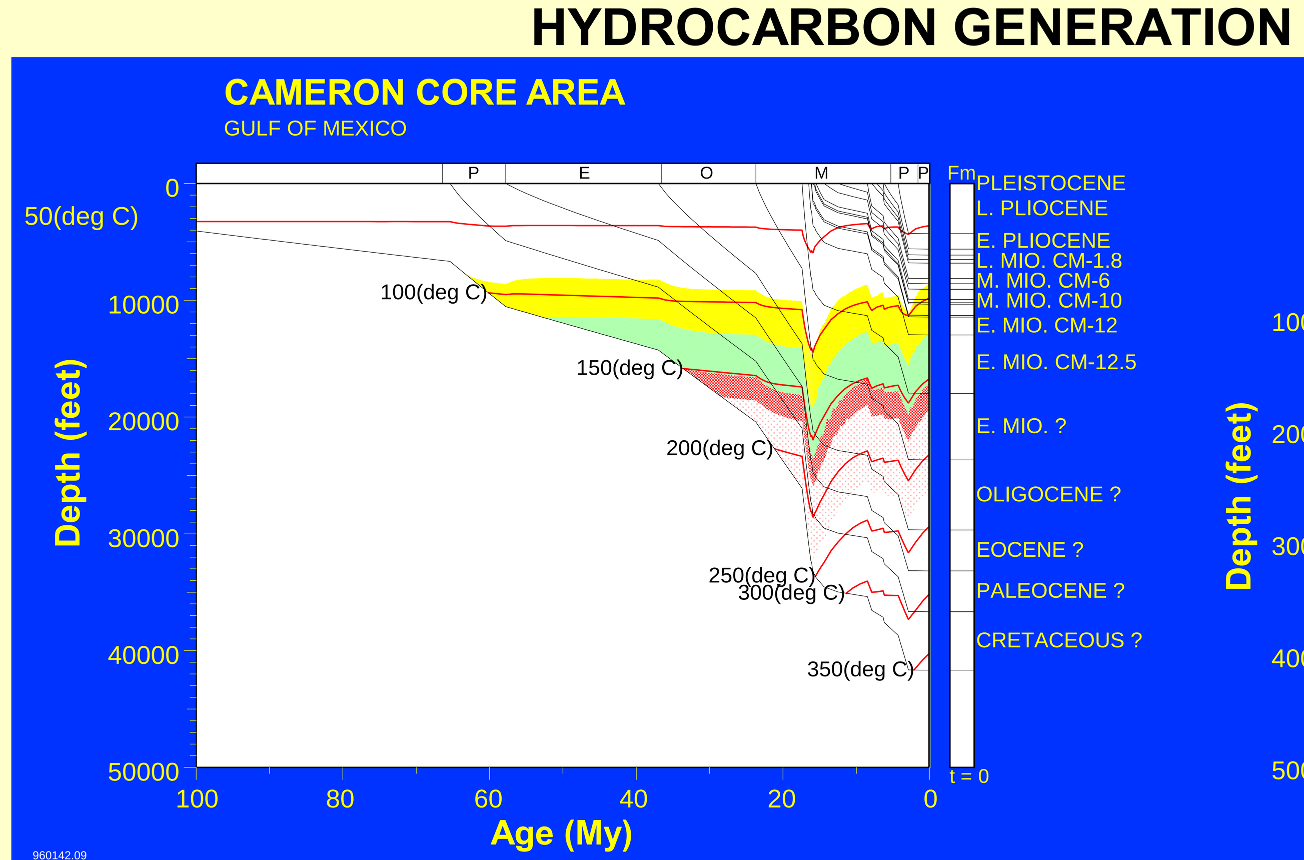


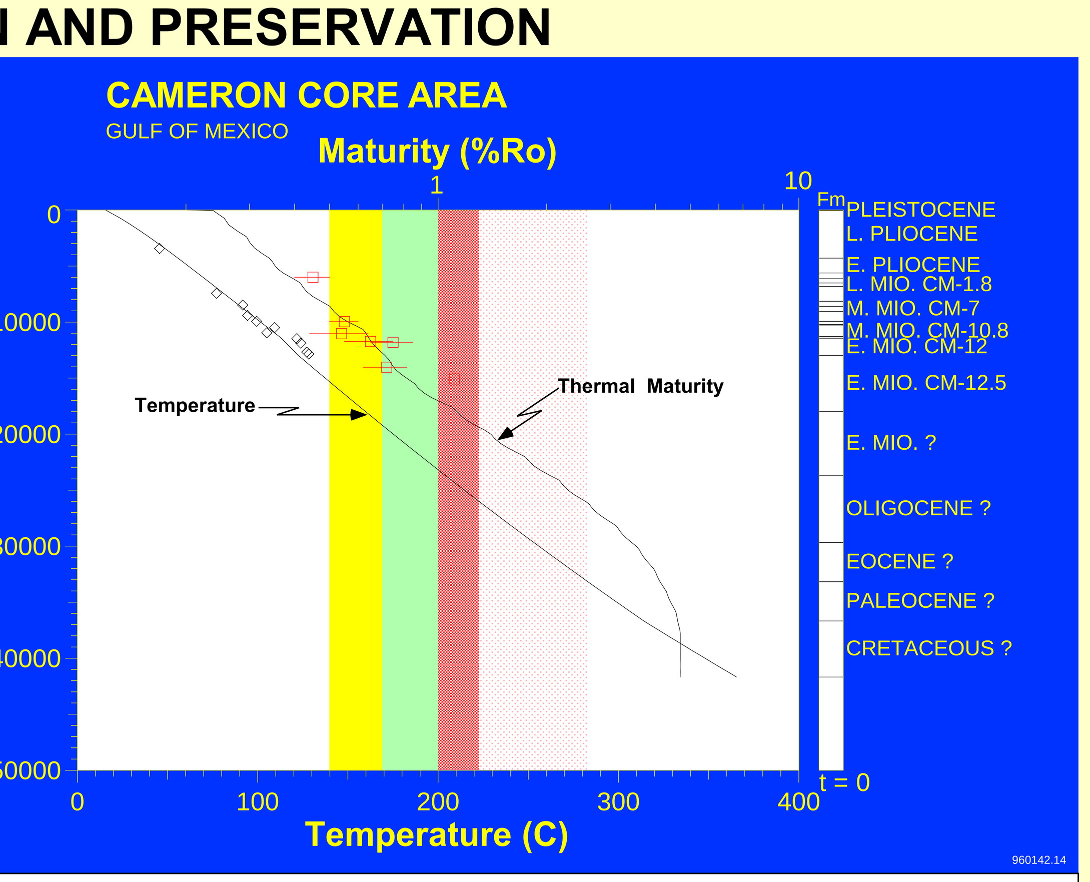
API gravity versus subsea vertical depth (ft.) for several of the oils in the Cameron area. The oils were determined to all be approximately of the same level of thermal maturity and composition differences are not due to differences in maturation. The differences are related to the pressure and temperature conditions of the migrating fluid. This same type trend can be observed in other areas of the Gulf Coast, but the API gravity change from heavy to lighter will occur at different depths dependent upon the local geothermal and pressure gradient. The samples from EC67 well are anomalously low gravity with respect to the trend; however, these oils are from a reservoir that is downthrown on a major fault through the area. The implication is that the fluids were implaced under lower pressure and temperature conditions prior to faulting.

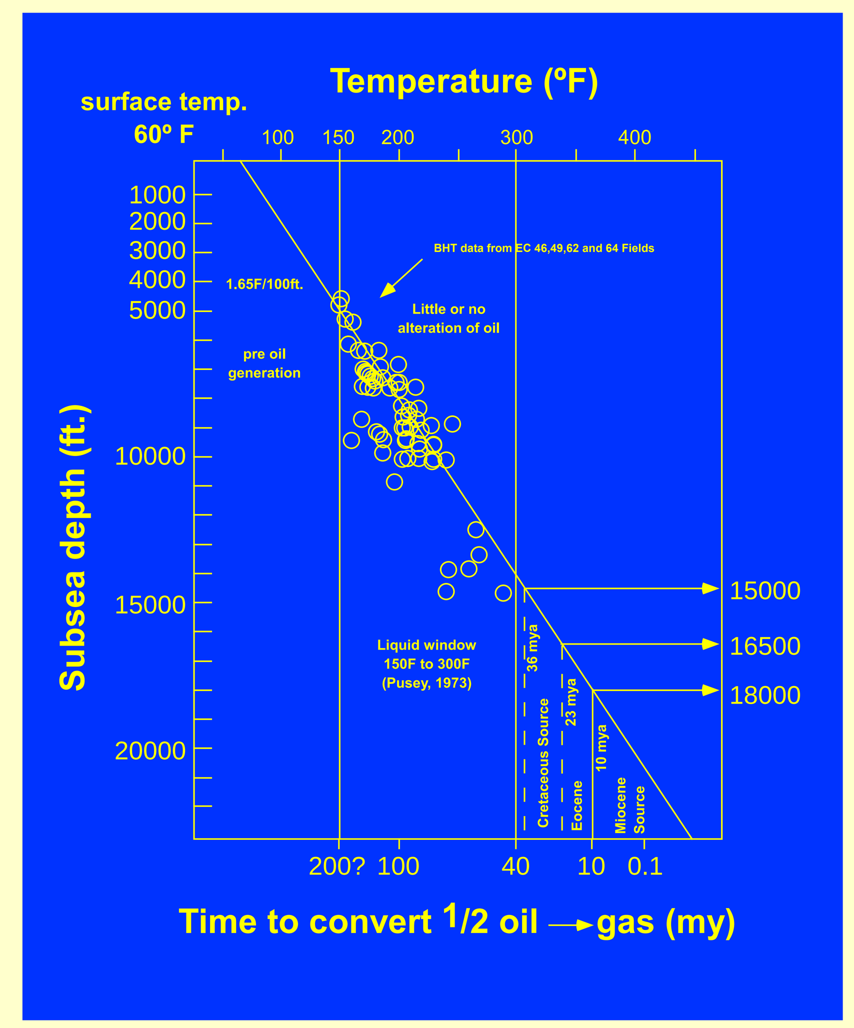




HYDROCARBON GENERATION AND PRESERVATION







A major question is oil preservation and to what depths, if possible, deeper oil pools (residual oils from evaporative fractionation) still exists. Since the source rock is still greatly debated, the oil preservation question can be discussed in terms of possible timing scenarios for generation from different source rock units. For purpose of discussion and comparison, an average geothermal gradient based on bottom hole temperatures and production data of 1.65ºF/100 ft., a surface temperature of 60ºF, and oil cracking kinetics of Mackenzie and Quigley (1988) (e.g., 230 KJ/mole) are used. An average geothermal gradient may not be correct for the area. Detailed temperature data indicates that for the West Cameron 216 and 177 areas, the geothermal gradient may be closer to 1.2ºF/100 ft. down to approximately 10,000 ft. (or top of over pressure) and 2.0ºF/100 ft. below 10,000 ft. Lower limit of oil preservation depths are given in terms of depths at which one-half of the oil is preserved. If the Oligocene or Lower Miocene source rocks generated the oils (10 mya to present), then oil preservation to a depth of 18,000 ft. (approximately 360ºF) is possible. If the Eocene source rocks generated the oils (23 to 10 mya), then oil preservation depths range from 18,000 to 16,500 ft. If the Cretaceous source rocks generated the oils (36 to 23 mya), then the lower limit of oil preservation depth ranges from 16,500 to 14,500 ft. A conclusion which might be drawn is that regardless of source, maximum limit of sizable oil accumulations in the East and West Cameron area is 18,000 ft.