Detection of Pay Zones and Pay Quality, Gulf of Mexico: Application of Geochemical Techniques

Daniel M. Jarvie, Alejandro Morelos, and Zhiwen Han

Humble Geochemical Services, P. O. Box 789, Humble, Texas 77347

ABSTRACT

Testing of stacked-sand pay zones in the Gulf of Mexico (GoM) and other basins with similar depositional systems (*e. g.*, offshore Nigeria, Bohai Bay) is quite costly when up to 11 sands need to be evaluated in order to determine testing and completion intervals. Other reservoir types such as fractured shale, carbonate, and fresh water reservoirs present challenging interpretation problems as well, especially in terms of assessing native hydrocarbon quality prior to testing and completion. With high daily rig rates and test costs, the ability to minimize idle time and testing expenses has direct economic impact on the cost of operating a well. In addition, identifying any potential bypassed pay zones provides additional economic benefit.

A variety of potential pay zone types is present in the GoM ranging from biogenic, thermogenic dry gas, wet gas, or condensate to normal, heavy, waxy, or biodegraded crude oils. Assessment of GoM sands is complicated by the fact that they are typically unconsolidated sediments and are often drilled with oil-based or synthetic muds, which make it difficult to evaluate the presence of reservoired hydrocarbons using conventional logging techniques.

Simple and inexpensive geochemical analyses provide information on reservoir hydrocarbons *directly from prospective reservoir rock samples in about 15 minutes*, thereby enhancing well site decision-making processes. Geochemical analyses of frozen cuttings or sidewall core (SWC) samples confirm the presence of native hydrocarbons and provide an assessment of hydrocarbon type (gas or oil) and quality (*e. g.*, GOR, viscosity, API gravity).

The first goal of geochemical analyses for well site decision making is to identify or confirm prospective pay zones including any potential bypassed pay, in either water or oil-based mud systems. The second goal is to identify the likely type and quality of pay. Further, the comparison of condensates in rocks to produced fluids can be used to assess vertical fractionation of reservoirs, seal effectiveness, and for correlation or oil typing purposes. Finally, vertical connectivity of reservoirs, which may also play a role in completion decisions, can be assessed using these data.

INTRODUCTION

Reservoirs in the Gulf of Mexico (GoM) are often vertically-stacked sands with interbedded shales. Shales may provide a vertical seal to a reservoir compartment. The lateral variation in both the sands and shales makes the identification and assessment of these reservoirs very difficult from well to well. This is not an uncommon occurrence as stacked sand pay zones are found, for example, in offshore Nigeria, Bohai Bay (where up to 17 vertically stacked sands are sometimes found), and other fluvial/deltaic depositional systems.

Identification and evaluation of these pay zones in terms of hydrocarbon type such as gas, condensate, normal, or heavy oil and oil quality including physico-chemical properties such as GOR, viscosity and API gravity are crucial components in testing and completing a well. Reservoir compartmentalization can also play a role in completion and ultimately, in developing a field. Standard or even state-of-the-art MWD logging techniques only provide inferences about rock fluids and often require hours of circulation time. Other inexpensive techniques, such as fluorescence from a solvent cut of cuttings or SWC provide some chemical evidence of pay, but do not distinguish type or quality. Of course, productive zones usually can be identified from testing operations, but it is quite expensive to test multiple pay zones. This is further complicated by the presence of synthetic or oil-based muds (OBM) commonly used in drilling these wells. Thus, the decision making process may require testing all prospective zones or trying to complete some zones without testing.

Analysis of the fluids including hydrocarbons within a given reservoir often first occurs when reservoir intervals are tested and even then, not all potentially productive zones may be tested. Until a gas or liquid sample is recovered, no compositional information on the actual gas or hydrocarbon fluids in the reservoir is available to aid in assessing the reservoir. Two simple geochemical techniques, however, can be used to assess the hydrocarbon fluids in cuttings or SWC samples. These techniques include thermal extraction gas chromatography (TEGC) and total petroleum hydrocarbon (TPH) analyses. Both of these analyses are completed *directly on reservoir rock samples* without any sample preparation. These analyses can be completed at nearby, shored-based laboratories or in geochemical logging trailers. The latter is especially useful in overseas locations, where laboratories may not be available or provide the quality and timely analyses needed to make testing and completion decisions. While it still may be necessary to export samples for detailed analyses, the initial geochemical data that impacts drilling decisions can be addressed quickly.

These geochemical tests may be used to:

- confirm prospective pay zones and identify any otherwise unidentified (bypassed) pay zones
- identify the type of products (gas, light, normal, or heavy oil) in a given reservoir

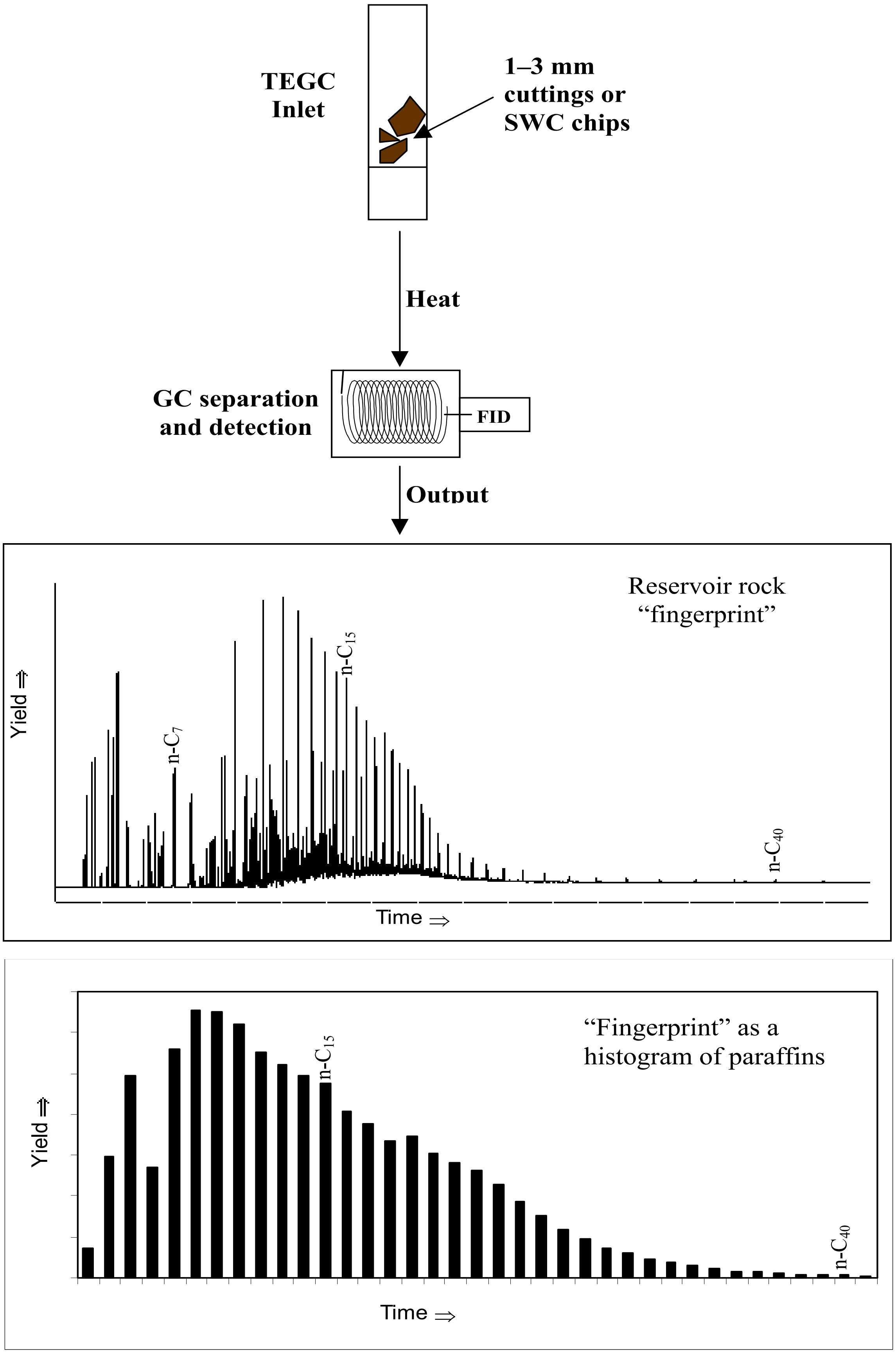

Figure 1. *Diagrammatic illustration and examples of thermal extraction gas chromatography (TEGC).* **(A)** *diagram of TEGC technique;* **(B)** *TEGC "fingerprint" of crude oil;* **(C)** *histogram of the normal paraffins only by distribution and yield.*

- identify the quality of hydrocarbons in terms of GOR, viscosity, API gravity, % wax, and pour or cloud points
- identify alteration effects in light hydrocarbons such as fractionation indicative of potential, deeper oil pay zones
- assess oil and source type based on light hydrocarbons or extended paraffins
- provide an assessment of vertical reservoir compartmentalization

Most important, these tests and interpretations are available in a time frame suitable to make testing and completion decisions. While logging while drilling (LWD) techniques are approximated as immediate, often 4–5 hours per run are required for accurate results. Geochemical analysis can be completed in 10-15 minutes per sample.

TEGC analysis provides a detailed compositional "fingerprint" of the hydrocarbon composition directly from analysis of rock samples. Thermal extraction is achieved by thermal vaporization of the hydrocarbons trapped or adsorbed in the rock matrix directly into a GC for separation and detection of material that is vaporized (Fig. 1A). A gas chromatographic (GC) fingerprint is a measure of the relative hydrocarbon yields and their distribution (Fig. 1B) or for illustrative purposes a histogram of yield by compound (Fig. 1C). This fingerprint also includes nonhydrocarbon components of a crude oil such as the resins and asphaltenes, although these and other complex hydrocarbons are not necessarily resolved as peaks. These compounds often elute as a hump beneath the resolved hydrocarbons and are often referred to as the "unresolved complex mixture" (UCM). The resulting fingerprint of resolved and UCM is qualitatively assessed to determine if pay is present and its type and quality. For example, these data were utilized by Schafer (1992) to locate a low resistivity pay zone in the presence of OBM in a GoM well. Recent advances in this technology utilizing fast gas chromatography techniques provide high-resolution results from cuttings or SWC samples in a 10–20 minute analysis time making it very amenable for decision-making in drilling operations (Jarvie, 2000; Jarvie, 2001).

An OBM will have a definitive, recognizable fingerprint that usually dominates a portion of the total fingerprint. The presence of producible hydrocarbons can be identified by their presence "around and through" the mud fingerprint. Condensate can be detected by the presence of hydrocarbons in the front end (light paraffin) portion of the GC fingerprint (Jarvie, 1995), whereas the presence of low quality, biodegraded oil can be ascertained by a qualitative assessment of the unresolved complex mixture (UCM) eluting underneath resolved compounds in the GC fingerprint (Jarvie, 1995). Using high temperature GC analysis, the presence of high molecular weight waxes (HMWW) (C_{40}+ paraffins) can be detected. These waxes can precipitate in the well flow or delivery lines causing production down time or shut-ins.

This same TEGC technique can be used for correlation purposes as shown by Jarvie and Walker (1997) or for prediction of GOR values via correlations based on light hydrocarbons (Jarvie, 2001). Likewise, fractionation of light hydrocarbons from gas exsolution in deeper oil reservoirs can be assessed from light hydrocarbon data (Thompson, 1988). When samples are fresh or frozen at the well site, light hydrocarbons can be detected even in unconsolidated GoM sediments. In addition, this technique can be applied to address questions of reservoir continuity similar to the whole oil techniques demonstrated by Kaufman (1990), using either high-resolution TEGC or the standard split injection GC analysis of a quick solvent extract of a reservoir rock.

A second technique provides the TPH yields of petroleum present in reservoir rocks. Cuttings or SWC chips are thermally volatilized directly into a hydrocarbon detector (flame ionization detector or FID) without any separation by GC. A portion of the hydrocarbons elute under isothermal temperature conditions whereas others elute at higher temperatures from utilization of a linear temperature program. The resulting thermogram provides quantitative yield and qualitative assessment of the hydrocarbon type present in the reservoir (Fig. 2). These data can be used to determine potential pay zones and prediction of physico-chemical properties such as viscosity and API gravity. Recent advances (Jones, 2000) have added the ability to predict apparent water saturations from these data in carbonate reservoirs found in Saudi Arabia.

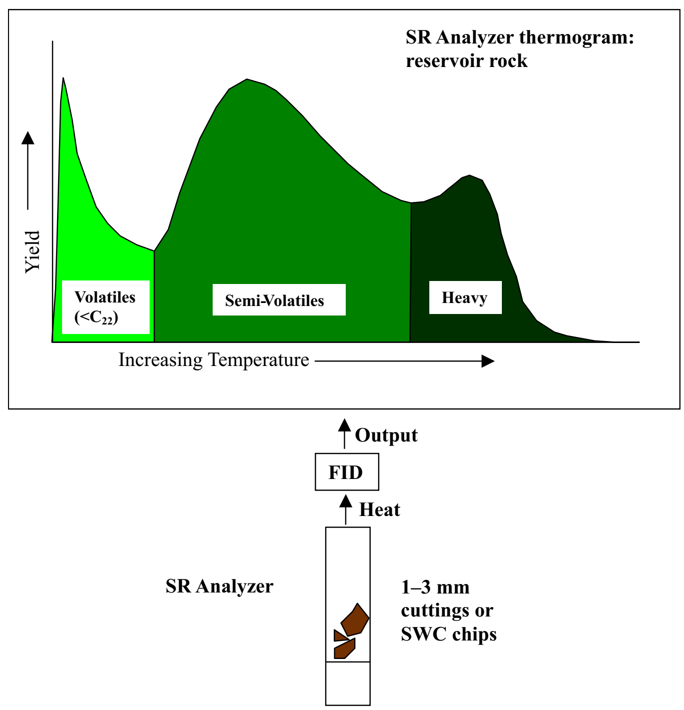

Figure 2. *Diagrammatic illustration of thermal distillation and pyrolysis yields from cuttings or SWC chips of reservoir rock samples; the resulting thermogram provides a relative assessment of oil quality based on the distribution of volatile, semi-volatile, and heavy oil constituents in the reservoir.*

DISCUSSION

Prediction of Reservoir Intervals

Identifying reservoirs in the GoM is not as difficult as in some geological provinces where difficult to log reservoirs may be present, *e. g.*, fractured shales. However, low resistivity sands found in the GoM present a challenge to evaluation techniques especially in wells drilled with OBM. High normalized oil contents are usually used to identify potentially commercial production zones by simple TOC and Rock-Eval measurements (Jarvie and Baker, 1984). When zones exceed 100 mg oil/g TOC, the interval is either productive or is contaminated with OBM. If OBM is used in the well, the entire well bore will likely be contaminated. This requires the use of TEGC to "look through" the OBM for reservoired hydrocarbons.

TEGC can be used to assess the presence and quality of pay in stacked reservoirs and low resistivity sands in either water-based mud or OBM drilling. Figure 3 illustrates the presence of 3 different product types in sands A–B, C–D, and E; however, this sequence could be in any order. This qualitative predictive capability permits the assessment of condensate and light oil pay in zones A–B and C–D, respectively, and low quality, biodegraded oil in E. Using these data testing and completion could be avoided in sand "E."

Freezing samples at the well site will enhance detection of light hydrocarbons, which is useful for detecting gas or condensate pay zones. Volatile hydrocarbons such as pentane (n–C_5) can be detected, if present (Figs. 4A–B, sands "C" and "D" in Fig. 3). Thus, condensate production can be assessed from very high quality (well preserved) samples and is particularly unaffected by OBM. In unfrozen, unconsolidated reservoir rocks, usually only the presence of C_8+ (octane and higher) hydrocarbons can be detected. However, the presence of a high quality crude oil is easily discerned from these data even in the presence of contamination from OBM. It is always useful to have a sample of the mud itself and any organic additives when trying to determine the presence of reservoired hydrocarbons.

Assessment of Oil-Water Contacts and Cap Rocks

Through the oil-water contact (OWC) and into the water phase, oil quality will diminish and appear as a poor quality, biodegraded oil (Fig. 5, sand "E" in Fig. 3). For example, this technique was used to determine OWC in the Asphalto Field, California (Jarvie, 1995). By evaluating various depths in a GoM reservoir sand, transition zones can be tracked by reservoir rock fingerprinting using TEGC. SWC are preferred for this assessment especially in the typical, unconsolidated sands of the GoM.

Similarly, the efficacy of seal rocks can be evaluated by fingerprinting of these rocks. In an effective seal, the cap rock fingerprint will be very paraffinic near the top of the reservoir and then diminish to near background a few feet into the lower part of the seal. Cuttings are readily used for seal evaluation since seals are usually more lithified than unconsolidated sand pay zones. Shales as thin as 2 ft. have been identified as seals in deepwater GoM wells.

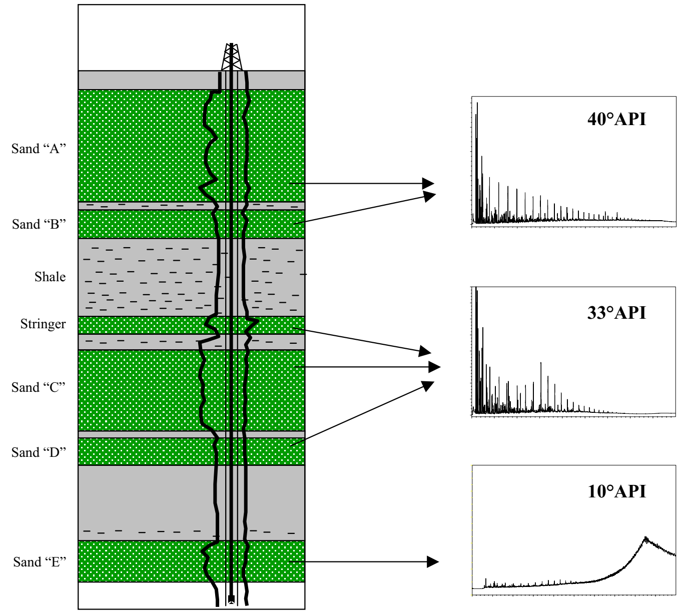

Figure 3. *Diagrammatic illustration of stacked sand reservoirs found in the Gulf of Mexico and elsewhere in the world. A fingerprint of the hydrocarbons in these zones is indicative of potential production and oil quality.*

Assessment of Reservoir Fluids in Presence of Contamination

Oil-based or synthetic-based mud systems will cause difficulties in assessing well logs and will also generate a response on the TEGC system. In these cases the fingerprint is evaluated by the looking "around" or "through" the organics in the mud. The most common muds in the Gulf of Mexico use Nova-Dril or Nova-Plus, which contains predominantly 16–18 carbon-range hydrocarbons. While this obliterates the central portion of the GC fingerprint, by looking at the fringes of the fingerprint a condensate, light, normal, or waxy oil can be readily identified (Figs. 6A–C).

Other common contaminants in GoM muds include walnut hulls (found in commercial mud additives such as Wal-Nut®, Nut-Plug®, etc.). Walnut hulls have a characteristic low temperature pyrolysis shoulder with a Tmax of between 335–360°C. The TEGC fingerprints are atypical of hydrocarbon-bearing formations (Fig. 7A), but the presence of crude oil can be discerned by comparison to the walnut hull fingerprint (Fig. 7B).

Similarly, diesel is often added to muds to aid drilling. Diesel is composed of normal paraffins commonly found in crude oils, but has a characteristic narrow distribution ranging from about n–C_{12} to n–C_{20} (Fig. 8A). When crude oil is

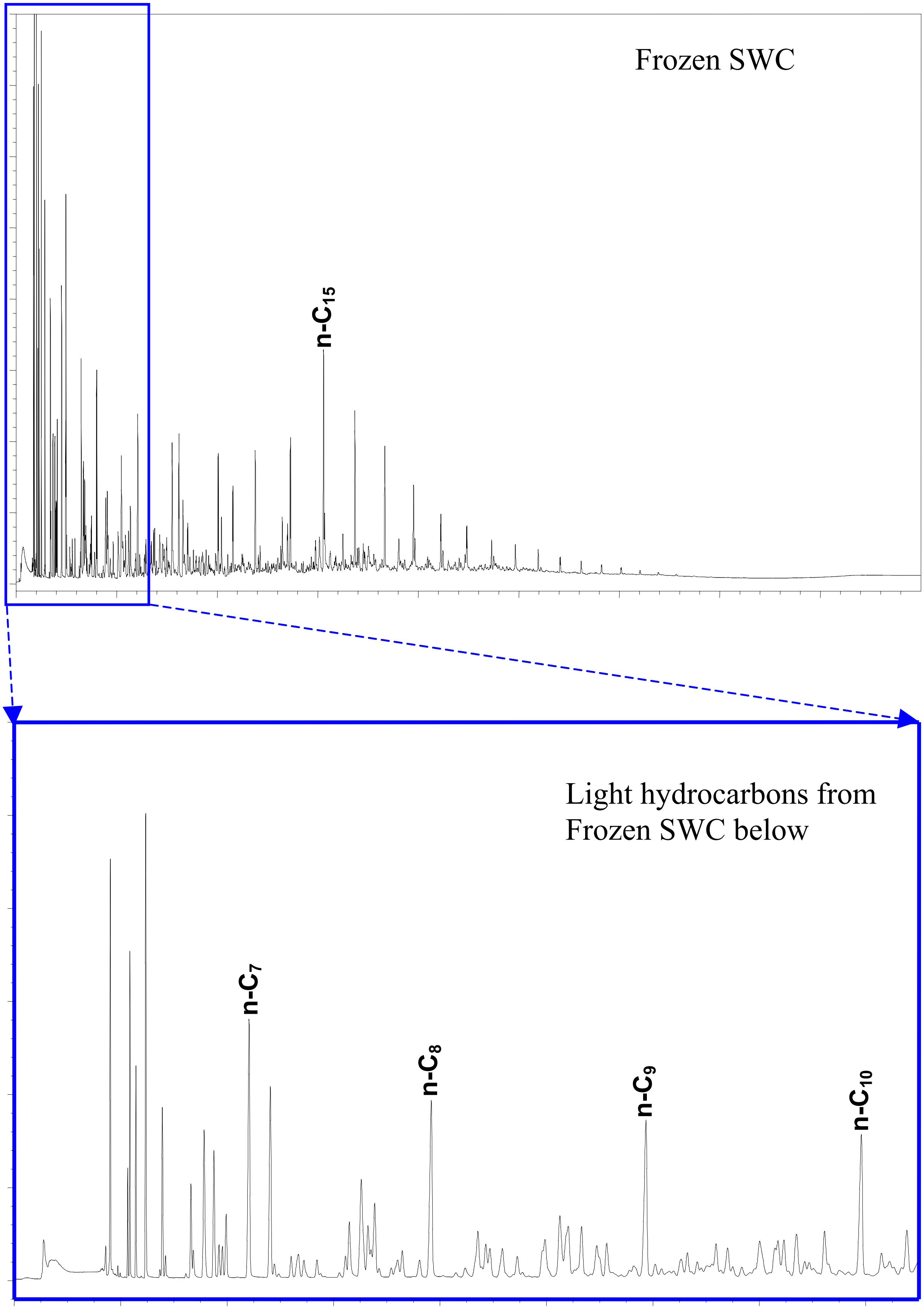

Figure 4. *Thermal extraction gas chromatographic (TEGC) fingerprint of a frozen SWC sample from the GoM:* **(A)** *the whole oil fingerprint extending from about C_4 to about C_{38}, and* **(B)** *the light hydrocarbons from about C_4 to C_{10}.*

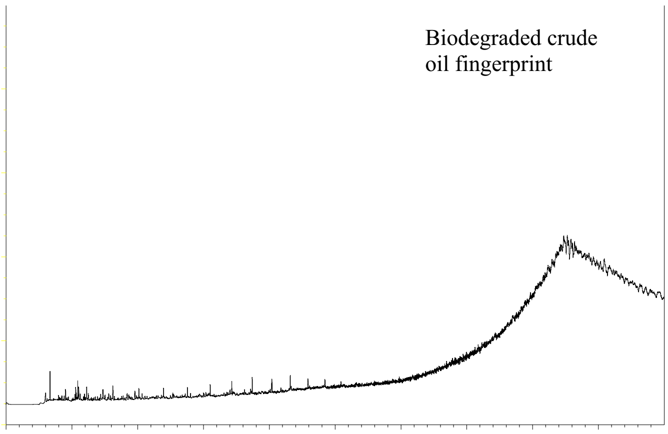

Figure 5. *TEGC fingerprint of a poor quality oil in a reservoir sand.*

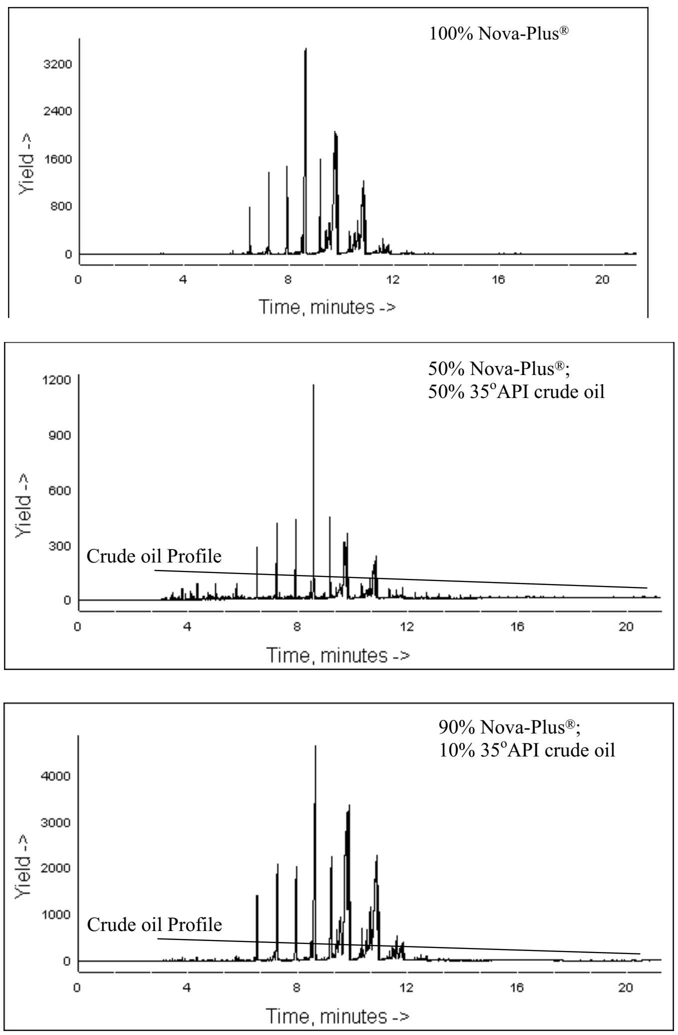

Figure 6. *TEGC fingerprints of Nova-Plus®:* **(A)** *Nova-Plus® only;* **(B)** *50:50 mix of Nova-Plus® and a 35° API gravity crude oil; and* **(C)** *90:10 mix.*

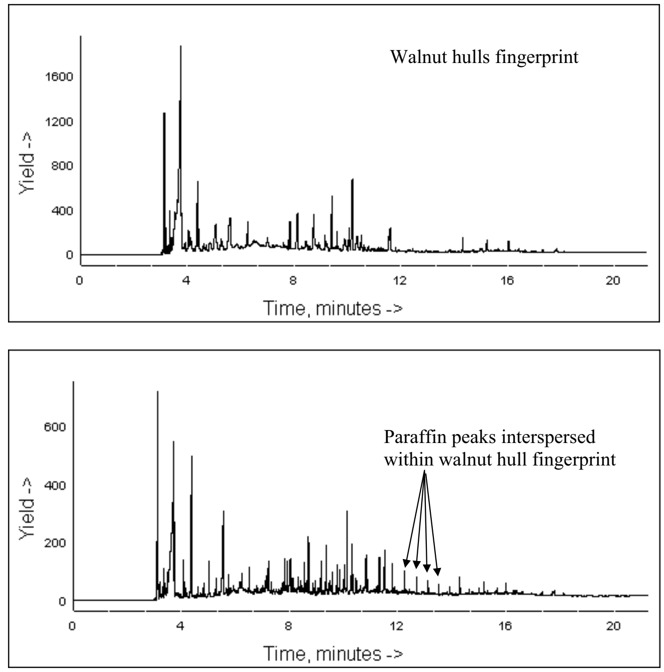

Figure 7. *TEGC fingerprints of walnut hulls:* **(A)** *Wal-Nut® only;* **(B)** *about a 50:50 mix of Wal-Nut® and 35° API gravity crude oil.*

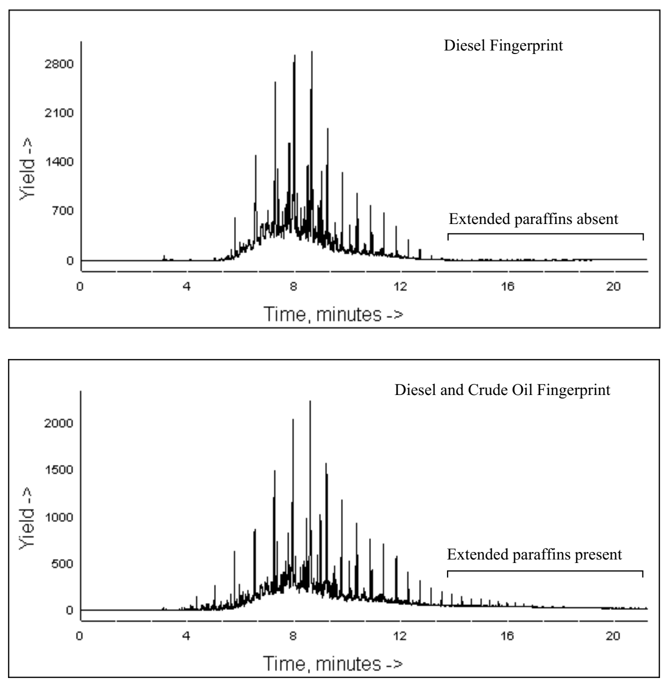

Figure 8. *TEGC fingerprints of diesel:* **(A)** *diesel only;* **(B)** *50:50 mix of diesel and 35° API gravity crude oil.*

encountered, the diesel will take on a broader profile extending either into the light hydrocarbon range for potential condensate production or into the C_{20}+ range for normal crude oils (Fig. 8B); condensates would have C_{12}– hydrocarbons present in abundance.

Another geochemical technique that has been utilized uses a sulfur detector coupled to a GC to look through a sample at sulfur in a crude oil, where the mud system itself was sulfur-free (Baskin, 2000). Thus, any sulfur compound fingerprint was from crude oil, not the mud. A sample of the mud alone is essential in these assessments; thus, samples of the mud should be collected at regular intervals for background evaluation.

Combining the TEGC system with a mass spectrometer (MS) allows biomarker work to be completed. While biomarkers are commonly used for correlation studies, the purpose in reservoir rock evaluation is to determine whether potentially producible hydrocarbons are present within an OBM-impregnated reservoir rock. This requires analysis of the mud alone followed by analysis of the rock. OBM usually does not have biomarkers present or has an unusual and unique distribution, whereas reservoired oil will have commonly identified biomarkers present. Combining thermal extraction with fast GCMS analysis, TEGCMS results can be obtained in as little as 20 minutes and can be used to show the presence of native hydrocarbons (Fig. 9).

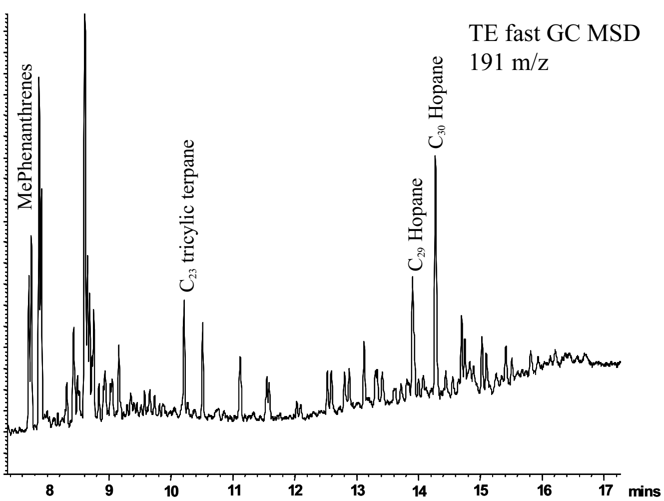

Figure 9. *TEGCMS 191 m/z ion chromatogram showing presence of biomarkers in reservoir rock thermal extract indicative of native hydrocarbons that are not mud derived.*

Detection of High Molecular Weight Waxes

High molecular weight waxes (HMWW) (paraffins in the C_{40}+ range) can cause severe production problems and downtime, if they are not identified in the reservoir. Crude oil samples containing HMWW can easily be fractionated during the flow or sampling processes. It is extremely difficult to ascertain whether a given oil sample is representative of the producing horizon from DST, MDT, or even well head samples as these compounds may precipitate out of the oil. For example, the most obvious condition for wax precipitation is a reduction in temperature, *e. g.*, at the sediment-ocean interface. The Joilet Field in the GoM is a good example of this problem as HMWW waxes were not detected in oil samples from the field, likely due to sampling difficulties. The resulting repairs caused by wax precipitation in flow lines cost over $80 million, not including lost production. Analysis of the reservoir rock sample by TE high temperature (HT) GC avoids gross discrimination in sampling procedures providing a fingerprint of these HMWW waxes to about C_{75}+ (Fig. 10). This technique can be used with internal standards to compute quantitative yields of various paraffin groups. This approach was used on productive reservoir rock samples, where oils were subsequently produced and tested to correlate the quantitative yield of the TEHTGC C_{31}+ fraction to pour points (Fig. 11).

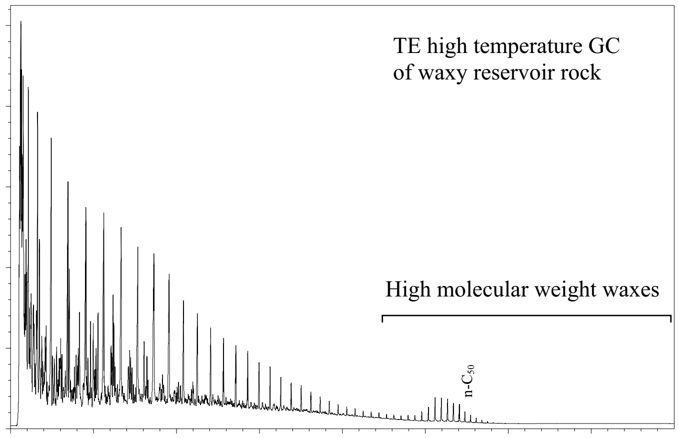

Figure 10. *TEGC fingerprint of reservoir rock containing high molecular weight waxes (>C_{40}+ paraffins) that are particularly problematic due to precipitation in flow lines.*

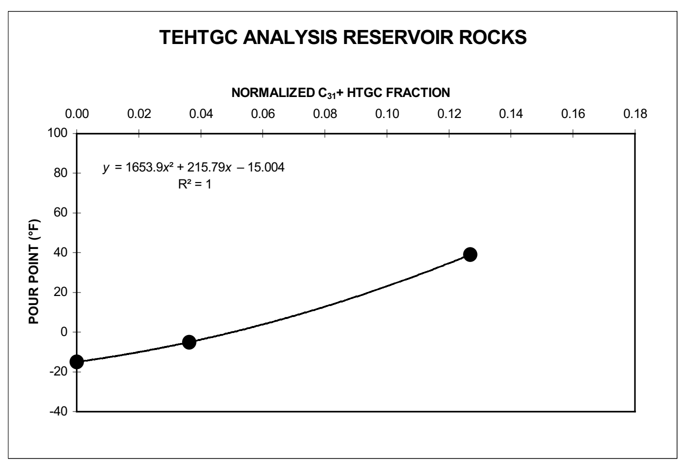

Figure 11. *Correlation of C_{31}^{+} paraffin fraction from TEHTGC to measured pour points of reservoir fluids.*

Correlation of Light Hydrocarbons in Rocks to Crude Oils

Typical rock extractions using organic solvents require concentration of the sample by evaporation of the solvent. Unfortunately, this often results in loss of most light hydrocarbons ($<C_{10}$). A strength of TEGC analysis is the ability to preserve light hydrocarbons. In frozen samples or tight shales, hydrocarbons down to approximately butane (C_4) can be detected. Using a high-resolution (HR) mode, TEHRGC analysis can be used to obtain a condensate-range C_7 analysis that is useful for correlating hydrocarbons in rocks to those in crude oils (Jarvie and Walker, 1997; Odden *et al.* 1998). An example is shown from a shale source rock that matches the oil found in a reservoir above the source (Fig. 12). The high trans-1,2-dimethylcyclopentane (t-12-DMCP) peak is indicative of oil from a clay-rich, low sulfur marine kerogen. This carbonate oil reservoir was discovered as bypassed pay. Light hydrocarbon correlations are particularly useful as many condensates are biomarker poor, the main oil-to-source correlation tool. The light hydrocarbons have proven useful for calculating oil expulsion temperatures (BeMent, 1995; Mango, 1997) and for predicting gas-to-oil ratios (GOR) (Jarvie, 2001; Mango and Jarvie, 2001). In addition fractionation of light hydrocarbons will be apparent from TEHRGC fingerprints as elevated aromatic content. Fractionation may result from the exsolution of gas from oil reservoirs and such alteration identified in the TEHRGC will provide an indication of a deeper oil pay.

Total Petroleum Hydrocarbons (TPH) of Reservoir Rocks: Viscosity and API Predictions

A viscosity and API gravity estimate can be obtained on cuttings or SWC where no organic contamination is present, *i. e.*, water-based muds. Using an SR Analyzer® the volatile hydrocarbons in a reservoir rock sample are thermally desorbed directly in a detector. The semi-volatiles and non-volatiles are vaporized by temperature programming the sample to 600°C. While there is no compound separation, different areas of the thermogram represent different molecular weight range of hydrocarbons. This may be broken into 3 areas depending on the temperature program: (1) light hydrocarbons to about C_{22}; (2) mid-range hydrocarbons to about C_{40}; and (3) $C_{40}+$ hydrocarbons (waxes) plus resins and asphaltene fractions of oils (see Fig. 2). Free-flowing oils will have a higher concentration of the lightest and middle fractions, whereas heavier oils (<20 API) will have much higher concentrations of the nonvolatile, high molecular weight products. This technique is used to predict viscosity directly from reservoir rock samples (Fig. 13A). Since viscosity and API gravity are generally well correlated, a prediction of API gravity is also possible (Fig. 13B). API prediction fails when high molecular weight waxes ($C_{40}+$ paraffins) are present, as they will elute in the highest temperature fraction falsely suggesting a low gravity oil; however, viscosity predictions are still valid.

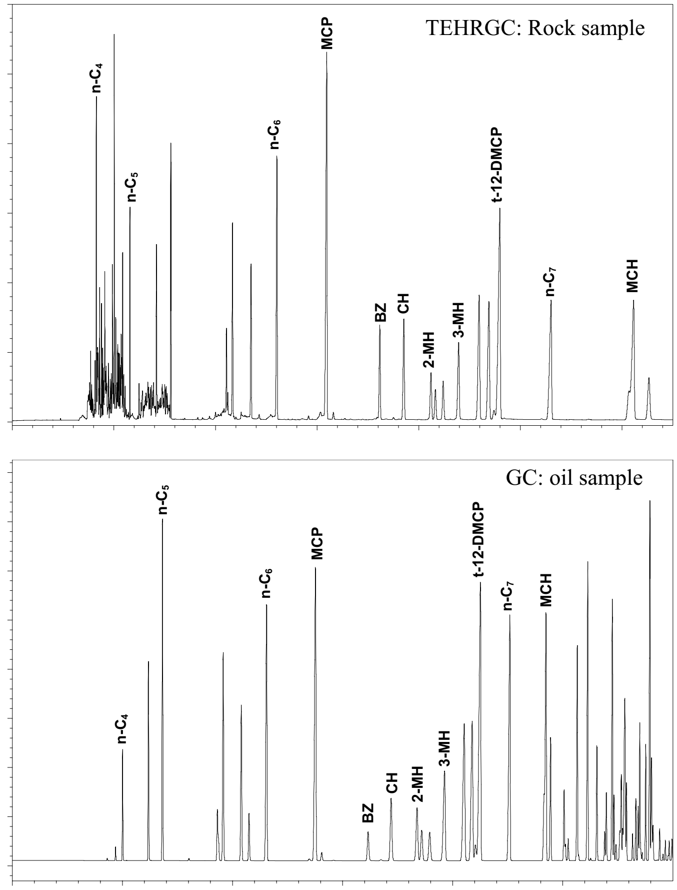

Figure 12. *Correlation of light hydrocarbons* **(A)** *in rock sample to* **(B)** *recovered crude oil sample.*

Addition of a sulfur detector aids in the assessment of oil quality. A sulfur detector can be added to either the TEGC WorkStation or SR Analyzer. High sulfur content (>1–2%) confirms the presence of a lower quality crude oil.

Vertical Reservoir Connectivity

Reservoir compartmentalization can also be assessed from TEGC data using a slightly different approach to the analysis. Reservoir compartmentalization studies using organic geochemistry were popularized by a GCAGS paper presented in 1990 (Kaufman, 1990). This GC technique uses slight compositional variations within crude oil samples to ascertain any minute differences among oils. A similar approach was used by Halpern (1995), but utilizing light hydrocarbons. In either case these analyses use the null hypothesis that the oils are different and, if this can be proven by demonstrating differences between sets of peak ratios, then the oils are not likely in the same reservoir compartment. If the null hypothesis is proven incorrect, then the reservoir compartments are most likely connected. While commonly used in field development and production studies because no well shut-in or production losses are inherent to the technique, a similar approach can be used to assess vertical communication between reservoirs in a well using SWC samples. In these cases either the whole reservoir rock fingerprint can be utilized

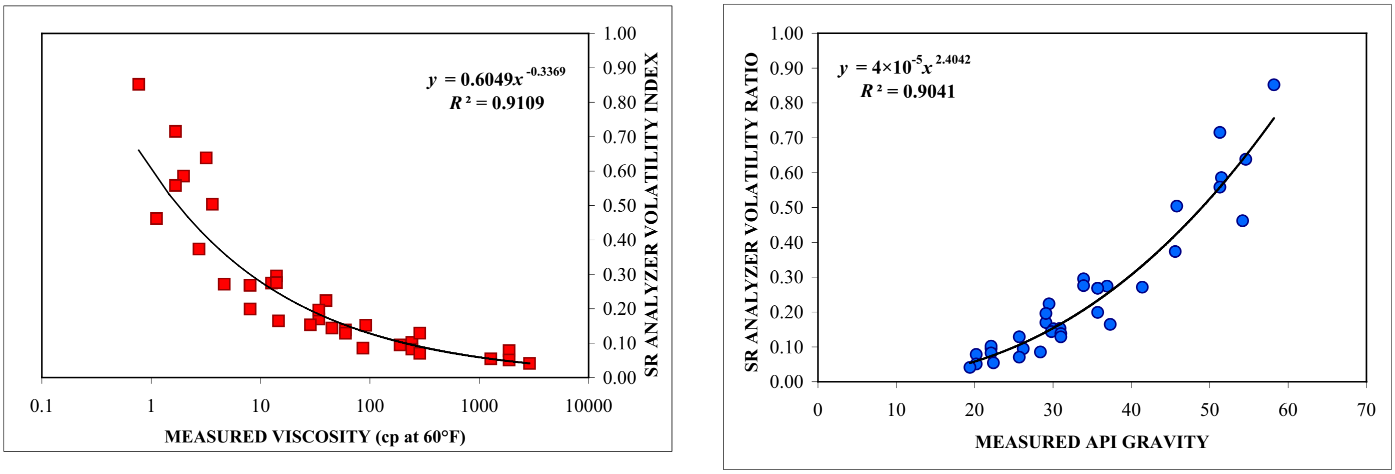

Figure 13. *Calculated physico-chemical properties from reservoir rock samples using SR Analyzer:* **(A)** *viscosity prediction from volatility index, and* **(B)** *API prediction from volatility ratio.*

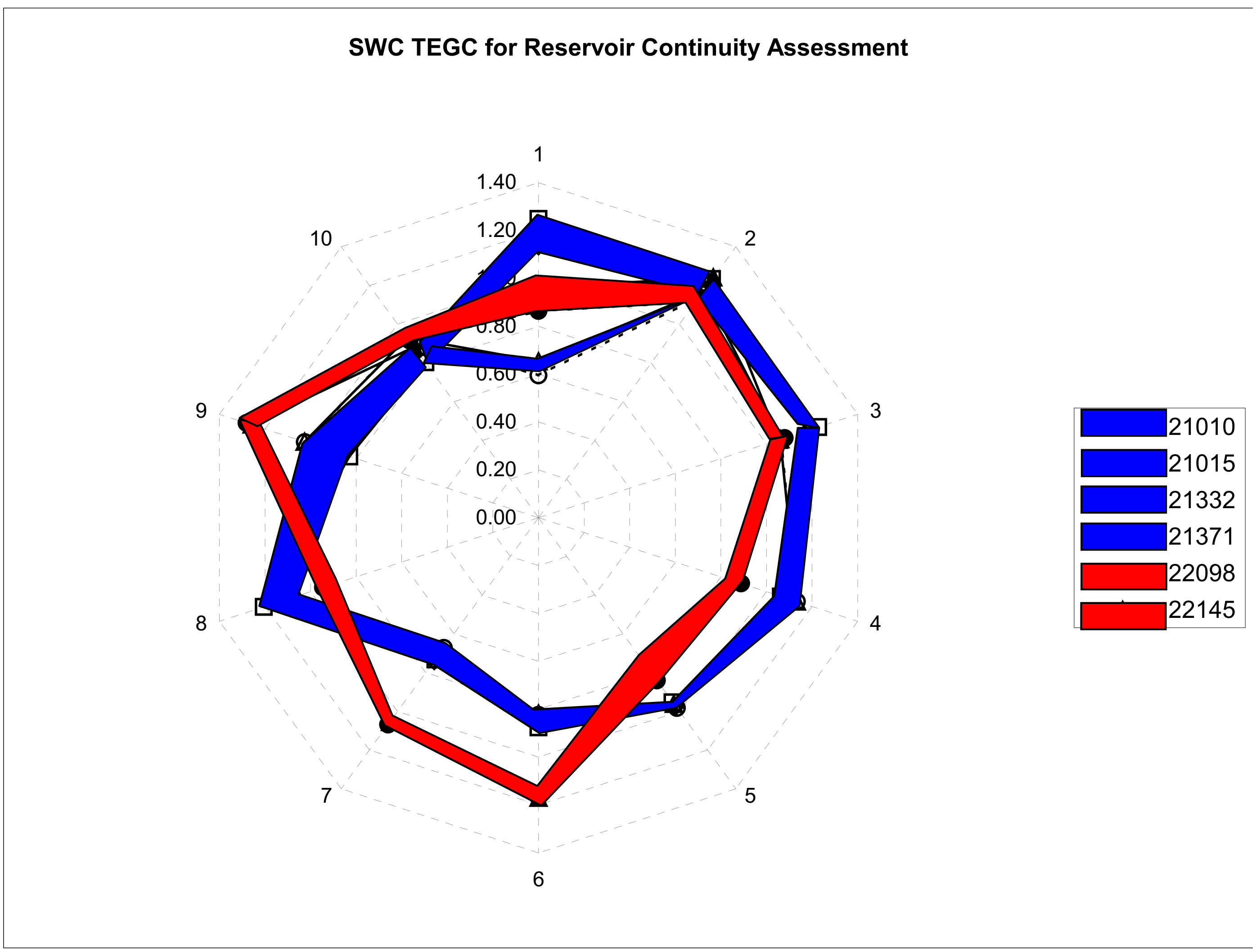

Figure 14. *Polar (star) plot of selected peak ratios from high resolution TEGC fingerprinting of reservoir rock samples showing apparent continuity in 21,000 ft. reservoirs and segregation of the 22,000 ft. reservoir.*

from slower ramp TEGC analysis or via the light hydrocarbons from TEHRGC analysis following the Halpern approach. In either case compartmentalization can be tentatively assessed prior to testing and completion.

A homogenized sample is required for this analysis in order to obtain a representative aliquot of the reservoir fluids imbibed on unconsolidated sands. Shale stringers are to be avoided as they will cause slight variations in composition due to hydrocarbons trapped in pore spaces and adsorbed to clays. Figure 14 illustrates similarities and differences found among SWC from 3 different sands. The 21,000 ft. sands are likely in communication, whereas the 22,000 ft. sand appears distinctly different, *i. e.*, beyond the limits of experimental error. Thus, two upper reservoirs are likely connected and the lowermost one is in a separate compartment isolated by a shale seal.

THE FUTURE

While there will be increased development of down-hole tools and instruments, surface based instrument technologies will also improve. Increased speed of analyses and miniaturization of equipment is well underway by a variety of analytical instrumentation manufacturers and researchers. Recent advances in GC technology have shown the functionality of matchbox-sized GCs and MS systems.

The use of mud gas logging has greatly enhanced the ability of geochemists to identify the quality and extent of gas reservoirs and proximity to oil (Ellis, 1999). While mud gas logging is common at the well site, it is not quantitative. A quantitative approach normalizes all gas yields and works extremely well at predicting gas compartmentalization when carbon isotopes of those gases are also available. Carbon isotopic analysis requires sophisticated and carefully calibrated instrumentation that is currently only found in select shore-based laboratories. New miniaturized technologies likely will enable these techniques to be used at the rig or nearby shore-based laboratories in the next few years.

Likewise, fluid inclusion instrumentation is evolving in terms of availability for well site use. Fluid inclusion analysis involves looking at fluids encapsulated in rock matrices. These fluids contain a wealth of information regarding the history of fluids, their properties, migration routes, and proximity to pay indicators. This technology is amenable to well site use with new instrument designs that have been implemented (Don Hall, personal communication).

REFERENCES CITED

Baskin, D., 2000, Economic Impact of Exploration and Production Geochemistry, SPE Workshop, Milan, Italy, May 2000.

Bjoroy, M., H. Solli, K. Hall, and P. Leplat, 1985, Analysis of source rocks, reservoir rocks, and cap rocks by combined thermal extraction and pyrolysis — gas chromatography, in Petroleum Geochemistry in Exploration of the Norwegian Shelf, ed. B. M. Thomas, NPF-Graham and Trotman, pp. 327–337.

Ellis, L., A. Brown, M. Schoell, M. Haughr, 1999, Mudgas isotope logging while drilling: A new field technique for exploration and production, 19th International Meeting on Organic Geochemistry, 6–10 September, 1999, Istanbul, Turkey, oral presentation.

Halpern, Henry, 1995, Development and Applications of Light-Hydrocarbon-Based Star Diagrams, AAPG Bull., Vol. 79, No. 6, pp. 801–815.

Jarvie, Daniel M., 2001, Fast Gas Chromatographic Analysis of Oil and Rock Samples, Org. Geochem., submitted.

Jarvie, Daniel M., 2001, Williston Basin Petroleum Systems: Inferences from Oil Geochemistry and Geology, The Mountain Geologist, Vol. 38, No. 1.

Jarvie, D. M., B. Leroux, P. R. Walker, and W. D. Weldon, 2000, Fast Chromatographic Analysis of Oil and Whole Rock Samples: 10 minute, high resolution assessment of oil quality, 219th Amer. Chem. Soc. Meeting, March 26–30, 2000, San Francisco, CA, oral presentation.

Jarvie, D. M., and P. R. Walker, 1997, Correlation of oils and source rocks in the Williston Basin using classical correlation tools and thermal extraction high resolution C_7 gas chromatography, 18th International Meeting on Organic Geochemistry, September 22–26, 1997, Maastricht, The Netherlands, oral presentation.

Jarvie, D. M. and D. R. Baker, Application of the Rock-Eval III Oil Show Analyzer to the study of gaseous hydrocarbons in an Oklahoma gas well, 187th ACS National Meeting, St. Louis Missouri, April 8–13, 1984.

Jones, P., 2000, POPI: a well site geochemical logging technique, World Petroleum Congress, Calgary, Alberta, Canada

Kaufman, R. L., A. S. Ahmed, and, Robert J. Elsinger, 1990, Gas Chromatography as a Development and Production Tool for Fingerprinting Oils from Individual Reservoirs: Applications in the Gulf of Mexico, in GCSSEPM Foundation Ninth Annual Research Conference Proceedings, pp. 263–282.

Mango, F. D. and D. M. Jarvie, 2001, GOR Prediction from Oil Composition, 20th International Meeting on Organic Geochemistry, Nancy, France, submitted.

Mango, F. D., 1997, The light hydrocarbons in petroleum: a critical review, Org. Geochem., Vol. 26, No. 7/8, pp. 417–440.

Odden, W., R. L. Patience, and G. W. van Graas, 1998, Application of light hydrocarbons (C_4–C_{13}) to oil/source rock correlations: a study of the light hydrocarbon compositions of source rocks and test fluids from offshore Mid-Norway, Org. Geochem., Vol. 28, No. 12, pp. 823–847.

Schafer, Daniel, 1992, Rock and Oil Properties Used to Confirm and Differentiate Proven Pay and Low Resistivity Pay in a Well Drilled with Oil-Base Mud, Offshore Gulf of Mexico, AAPG National Convention 1992, Calgary, oral presentation (abstracts book, p. 114).

Thompson, K. F. M., 1988, Gas-condensate migration and oil fractionation in deltaic systems, Marine and Pet. Geol., Vol. 5, pp. 237–246.