

GEORGES BANK PETROLEUM EXPLORATION

Atlantic Outer Continental Shelf

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GEORGES BANK PETROLEUM EXPLORATION ATLANTIC OUTER CONTINENTAL SHELF

Ten wells were drilled on Georges Bank, offshore from New England, from 1976 through 1982 (table 1, figure 1). The first two wells were Continental Offshore Stratigraphic Test (COST) wells, drilled during 1976 and 1977 by energy company consortiums to gain geologic information prior to offshore Federal petroleum exploration leasing. After leases were awarded, eight industry exploration wells were drilled in 1981 and 1982. None of these encountered significant concentrations of oil or natural gas, and drilling has not resumed since 1982. Records and data from the wells are maintained by the Minerals Management Service (MMS), Department of the Interior, at the Gulf of Mexico OCS Region office, 1201 Elmwood Park Boulevard, New Orleans, Louisiana 70123-2394, (504) 736-0557. Summaries and analyses of data from the industry exploration wells are contained in eight **Geological and Operational Summary** publications accompanying this report.

Table 1. Georges Bank wells

| Protraction Diagram | Block | Well No. | Well Type or COST No. | Operator | Spud Date | Measured Depth (ft) |
|---------------------|-------|----------|-----------------------|------------------|-----------|---------------------|
| NK 19-9 | 975 | 1 | Exploration | Exxon | 11-25-81 | 14,605 |
| NK 19-11 | 79 | - | COST G-1 | Ocean Production | 04-06-76 | 16,071 |
| NK 19-12 | 133 | 1 | Exploration | Exxon | 07-24-81 | 14,118 |
| NK 19-12 | 141 | - | COST G-2 | Ocean Production | 01-06-77 | 21,874 |
| NK19-12 | 145 | 1 | Exploration | Conoco | 05-13-82 | 14,500 |
| NK19-12 | 187 | 1 | Exploration | Tenneco | 03-12-82 | 18,127 |
| NK 19-12 | 273 | 1 | Exploration | Mobil | 06-30-82 | 15,580 |
| NK 19-12 | 312 | 1 | Exploration | Mobil | 12-08-81 | 20,000 |
| NK 19-12 | 357 | 1 | Exploration | Shell | 04-14-82 | 19,427 |
| NK 19-12 | 410 | 1 | Exploration | Shell | 08-10-81 | 15,568 |

Names of protraction diagrams are: NK 19-9, Corsair Canyon; NK 19-11, Hydrographer Canyon; NK 19-12, Lydonia Canyon. COST is Continental Offshore Stratigraphic Test.

LEASING HISTORY

Federal offshore Lease Sale 42, held on December 18, 1979, was the only successful North Atlantic Planning Area (Georges Bank) lease offering. Sixty-three blocks were leased to companies for

bonus bids totaling \$816,516,546. Subsequent sales (Numbers 52, 82, and 96) were canceled. Beginning in 1982, the United States Congress enacted a series of one-year leasing moratoria on portions of the Outer Continental Shelf, and these grew in area to include Federal waters

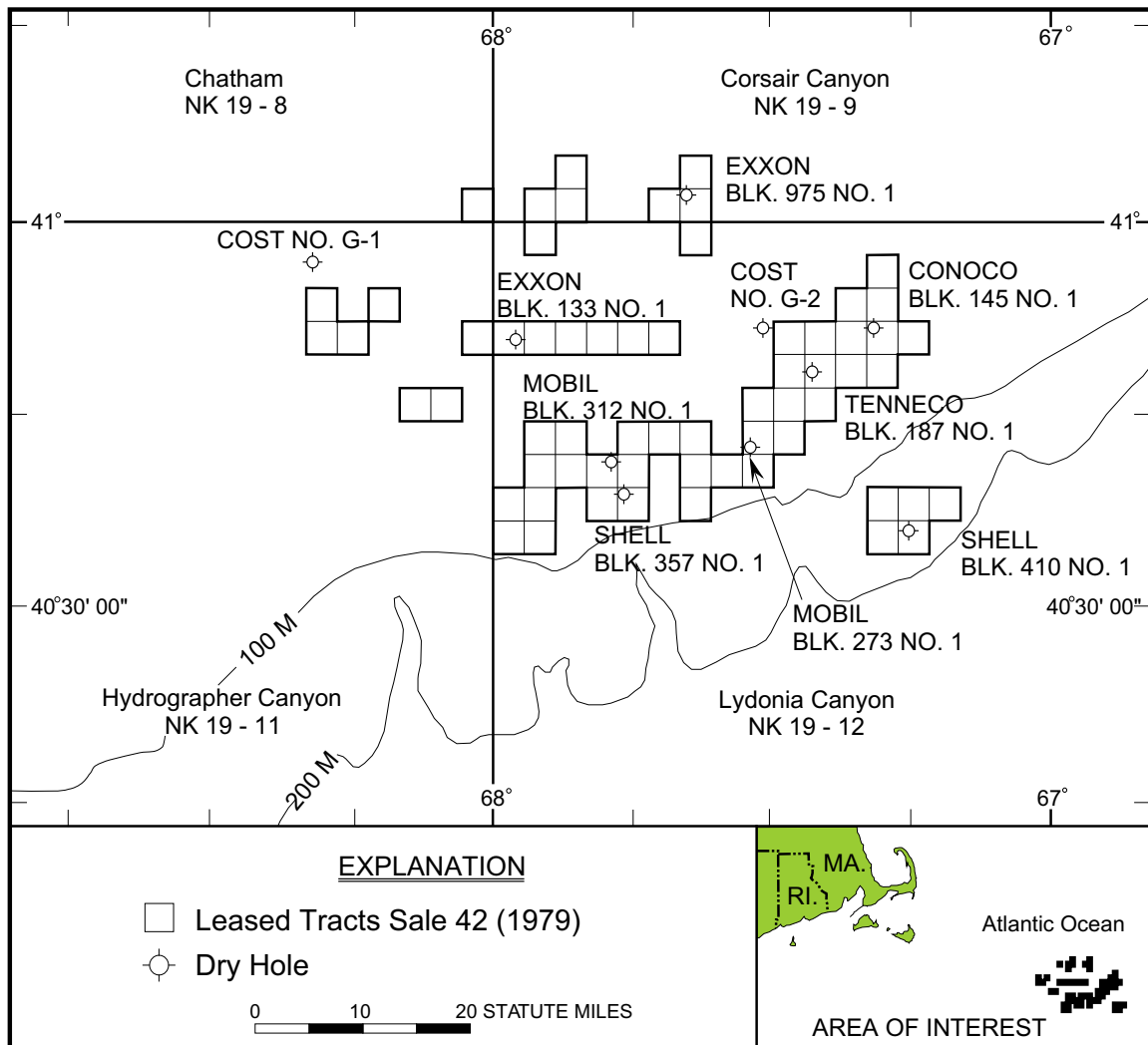


Figure 1. Map of the North Atlantic offshore area showing well locations. Bathymetry in meters.

along the entire United States Atlantic coast. On June 12, 1998, President Clinton issued an executive order that prevents the leasing of any area currently under moratorium until June 30, 2012. All of the 1979 Georges Bank leases have now been relinquished or have expired.

Since 1988, a leasing moratorium has also been in effect on the Canadian portion of Georges Bank, which is underlain by the East Georges Bank Basin, to the northeast of the Yarmouth Arch (figure 2). Texaco, BP-Amoco, and Chevron hold three large exploration concessions there. Exclusive exploration rights belonging to these companies remain intact but are suspended for the duration of the moratorium. This moratorium was reviewed in 1996 through 1999, and the review committee recommended that the suspension of exploration be extended to 2012, matching the adjoining U. S. moratorium. The Nova Scotian and Canadian governments accepted this recommendation.

EXPLORATION HISTORY

Seismic service companies acquired more than 100,000 line miles of seismic data by permit in the North Atlantic Planning area since 1966 (figure 3). Between 1966 and 1990 there were two accelerated periods of seismic data acquisition. More than 40,000 line miles were shot from 1974 through 1977 as companies evaluated the basin before Lease Sale 42. In 1981 and 1982, more than 33,000 line miles were shot in the years that the exploration wells were drilled.

The COST G-1 well was drilled 89 statute miles east-southeast of Nantucket Island in Block 79 of OCS protraction diagram NK 19-11 (Hydrographer Canyon). Drilling took place from April through July of 1976 to a measured depth of 16,071 feet. (All depths cited in this report are measured depths, i.e., relative to kelly bushing.) From January through August of the following year, the COST G-2 well was drilled 43 miles farther east-southeast in Block 141 of NK 19-12 (Lydonia Canyon) to a measured depth of 21,874 feet. Water depths were 157 and 272 feet, respectively. Both wells were intentionally drilled off-structure, that is, at locations where petroleum accumulations are unlikely, according to analysis of seismic data.

The COST wells were intended to provide stratigraphic and other geologic and engineering data useful to companies and the Government in preparing for the North Atlantic lease sale. In addition, evaluation of subsequently drilled industry wells would be aided by comparison with COST well analytic results, and all the wells could be correlated by means of seismic data and wireline logs.

The up-dip G-1 well (figure 4) penetrated Cenozoic and Mesozoic siliciclastic sedimentary rocks to a depth in excess of 9,000 feet (Upper Jurassic); interbedded Middle and Lower (?) Jurassic siliciclastics and limestone from about 9,000 to about 12,000 feet; and below that to total depth, Lower Jurassic (?) and Triassic (?) interbedded siliciclastics, dolomite, anhydrite, and minor limestone.

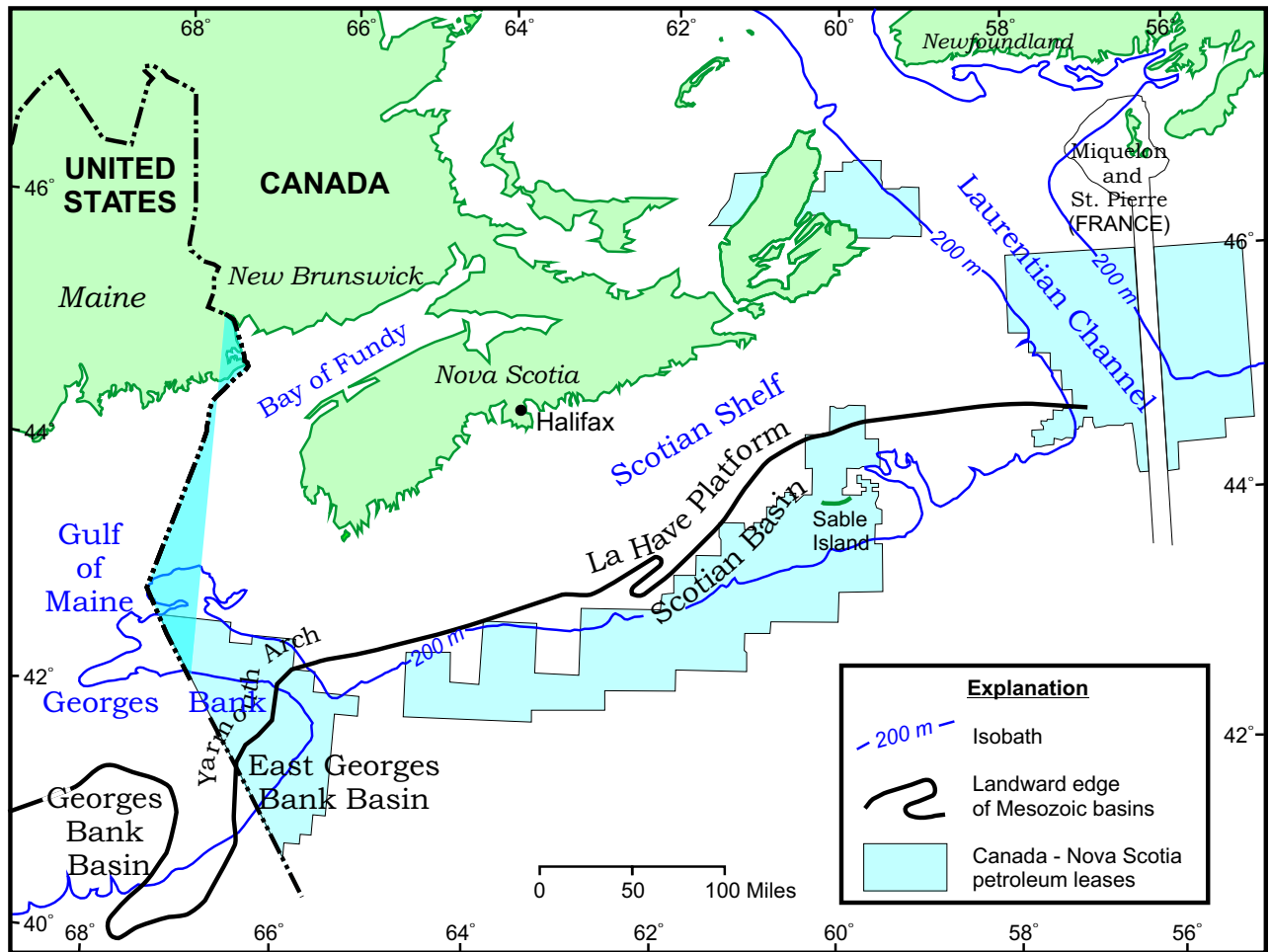


Figure 2. Map of Georges Bank and the Scotian Shelf, showing sedimentary basin locations, areas of Canadian petroleum leases, and 200-meter (shelf-edge) isobath.

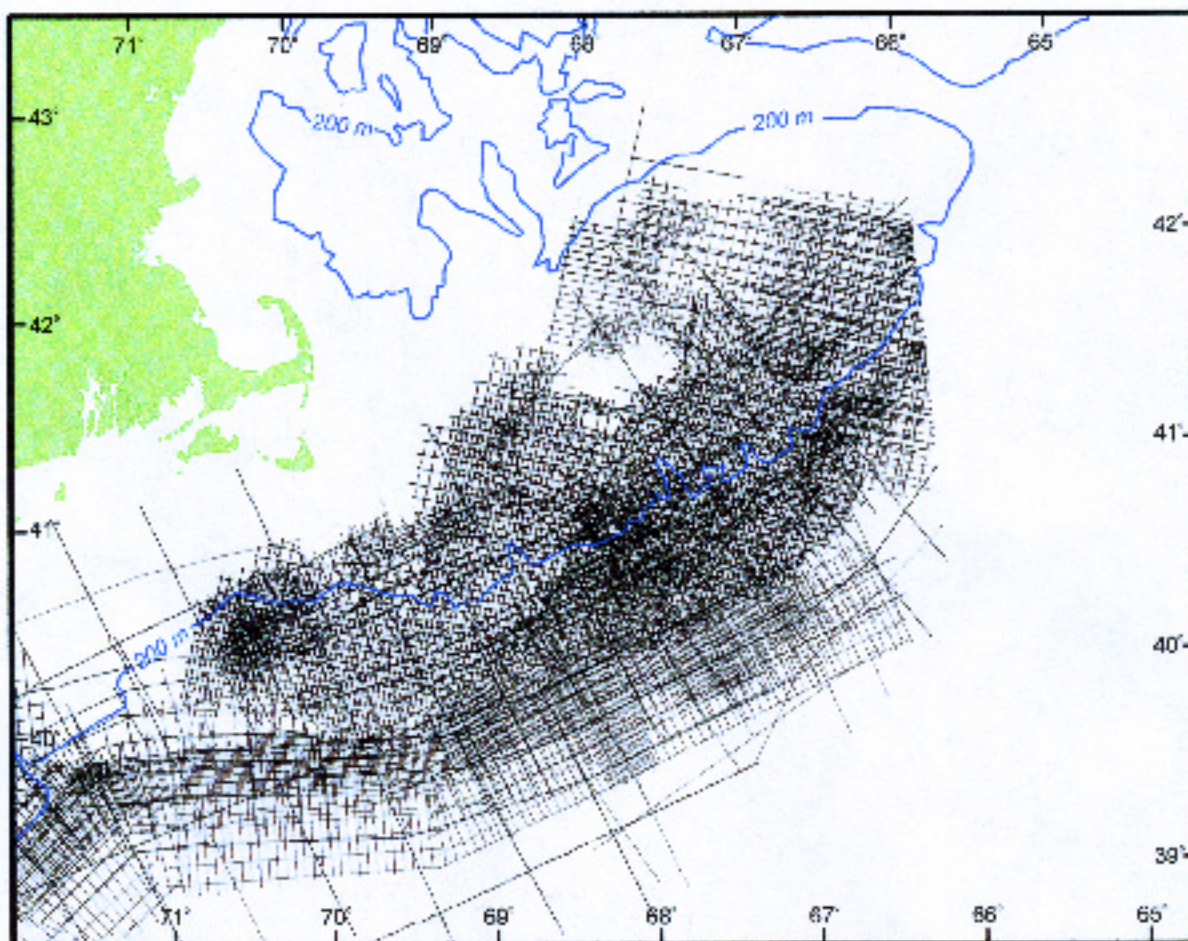


Figure 3. Map of Georges Bank showing seismic data coverage and 200-meter isobath.

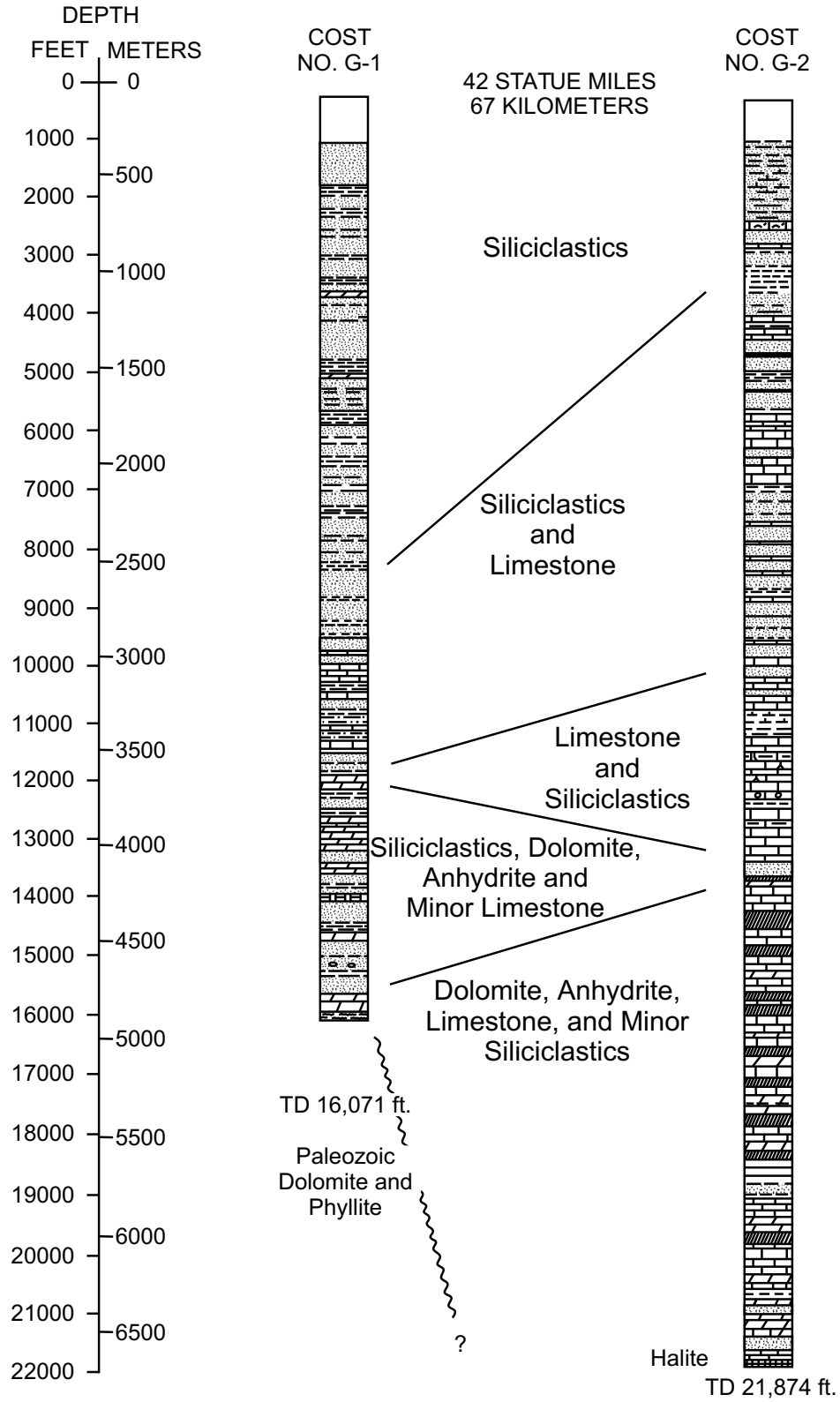


Figure 4. Lithologic columns of the Georges Bank COST G-1 and G-2 wells. Adapted from Amato and Simonis (1980).

The well bottomed in metamorphic basement at a measured depth of 16,071 feet.

The down-dip G-2 well encountered a higher proportion of carbonate rocks. Limestone began at about 2,400 feet (Upper Cretaceous) and was interbedded with siliciclastics to about 10,000 feet. Below that, in Middle Jurassic (?) to Upper Triassic (?) strata, the proportion of siliciclastics was subordinate, and limestone dominated to about 13,500 feet, with dolomite and anhydrite, subordinate limestone, and minor siliciclastics below that to total depth. This well bottomed in Upper Triassic or Lower Jurassic halite and anhydrite at a depth of 21,874 feet.

Federal regulations direct the Department of the Interior to release COST well geologic data to the public 60 days after a lease is granted within 50 nautical miles of well sites. Leases from OCS Sale 42 were granted in February of 1980, and the Conservation Division of the U.S. Geological Survey (USGS) released open file reports on the two wells (Amato and Bebout, 1980; Amato and Simonis, 1980). In 1982 the Geologic Division of USGS released Geological Survey Circular 861 (Scholle and Wenkam), which covered both wells. These publications are available from USGS Information Services, Box 25286, Denver Federal Center, Denver, CO 80225, Tel: 303-202-4700; Fax: 303-202-4693.

Eight exploration wells were drilled on the 63 Georges Bank leases during 1981 and 1982. All wells (figure 1) were within 42 miles of one another in the main, unnamed

subbasin, where the sedimentary section is thickest. Water depths ranged from 209 to 453 feet, and measured well depths from 14,118 to 20,000 feet. The companies' exploration targets, stated in their Exploration Plans, were mostly identified as Middle or Upper Jurassic (one Lower Jurassic) oolite banks, reefal buildups, and carbonate drape structures over basement highs or salt swells. Some predrilling interpretations predicted enhanced porosity, caused by dolomitization. The seismic features, from which these targets were inferred, were all high-amplitude reflectors with apparent structural closure. Located between two and three seconds, two-way travel times, the crests of these features were expected to be between 9,000 and 16,000 feet. These depths are within the Jurassic carbonate section of the COST G-2 well and the interbedded Jurassic carbonate and siliciclastic section of the G-1 well.

Hydrocarbons were not discovered on Georges Bank, and target-depth rocks in the exploration wells were similar to coeval COST well strata. Instead of reservoir-quality, porous carbonates, low-porosity micrites, wackestones, and packstones were the usual limestone types encountered. As in the COST wells, dolomite and anhydrite interbeds are common below about 12,000 feet (figure 4). At these depths, the Exxon Lydonia Canyon (LC) Block 133 No. 1 well encountered intrusive and extrusive volcanic rocks interbedded with limestone. The Exxon Corsair Canyon 975 No. 1 well penetrated halite and anhydrite interbedded with limestone below about 13,000 feet. In these two wells, seismic

velocity contrasts between volcanics and limestone and between anhydrite and halite would produce high-amplitude reflectors. For other Georges Bank exploration well sites, the company-targeted, high-amplitude reflectors appear to be associated with anhydrite-limestone or anhydrite-siliciclastic velocity differences, rather than being hydrocarbon-related “bright spots.”

Since petroleum exploration began in Canadian waters offshore from Nova Scotia in the 1950's, over 290,000 line-miles of 2D and 3D seismic data have been collected. One hundred and sixty-seven wells have been drilled (102 exploration, 26 delineation, 38 production, and 1 special relief), and 24 significant petroleum discoveries have been made, mostly natural gas. Most reservoirs are in Lower Cretaceous and Upper Jurassic deltaic sandstones at depths of 9,000-16,000 feet, and many are overpressured (below about 13,500 feet). Traps are anticlinal and/or fault-related.

Near Sable Island, the small Panuke multifield oil project is undergoing abandonment after recovering 44.4 million barrels of “Scotian Light” crude oil. Also near the island, a Mobil, Shell, and Exxon consortium, operating as Sable Offshore Energy Inc. (SOEI), is developing six gas fields. Three fields are producing gas, which is shipped to Country Harbor, N.S., by way of the 30-inch Maritimes and Northeast Pipeline. The most recent discovery, announced in February 2000 by PanCanadian Petroleum Ltd., is also near Sable Island. In well tests, gas flowed at rates up to 55 million cubic feet per day.

This discovery is the first in an Upper Jurassic reef play that goes from offshore Newfoundland to Florida.

A third phase of petroleum exploration is beginning in most areas of the Nova Scotian offshore, including the Upper Paleozoic Sydney and Magdalena Basins and previously unexplored deepwater Tertiary and Cretaceous basins with salt structures analogous to those of the Gulf of Mexico. Further information can be obtained from the Canada-Nova Scotia Offshore Petroleum Board's Internet site, <http://www.cnsopb.ns.ca>. The Geological Survey of Canada's BASIN database, <http://agcwww.bio.ns.ca/BASIN>, contains offshore geological and geophysical information but requires subscription for access to specific and comprehensive data and interpretations.

On the basis of data available through the end of 1983, the Geological Survey of Canada (Wade and others, 1989) estimated the total resource potential of the Scotian Basin to be 18.1 Tcf gas, 366.1 MMBbls condensate, and 707.6 MM Bbls oil. This estimate does not include the Laurentian Subbasin of the Scotian Basin, for which MacLean and Wade (1992) have more recently estimated 8 to 9 trillion cubic feet of gas and 600 to 700 million barrels of oil. The Canadian government has not assessed the petroleum resources of the East Georges Bank Basin, the Fundy Basin, or the Maritimes and Sydney Basins.

BIOSTRATIGRAPHY

The paleontological staff of the Atlantic OCS Region examined well cuttings from five of the eight Georges Bank exploration wells. The staff used foraminifera, calcareous nannofossils, palynomorphs, and dinocysts to identify biostratigraphic ages. Cutting samples were supplemented by core examination, where possible. Biostratigraphic interpretation generally followed Canadian workers' adaptation of Tethyan practice (e.g., Bujak and Williams, 1977; Woollam and Riding, 1983; Riding, 1984, Davies, 1985). European stages, rather than formation names, were used for the Georges Bank biostratigraphic framework. In addition, the staff identified depositional paleoenvironments and, for some wells, unconformities and depositional hiatuses, on the basis of missing stages.

The MMS Atlantic paleontologists faced several difficulties. The Mesozoic section is thoroughly oxidized and reworked, containing many disconformities. Older, eroded and recycled microfossils that were reincorporated into younger sediments had to be recognized in order to avoid dating an interval as older than it is. Uphole microfossils, caved from higher in the well, had to be recognized in order to avoid dating an interval as too young. Other difficulties include documentation of guide fossils. During the 1980's, the biostratigraphy of the Atlantic margin was not well established, compared with other more thoroughly studied basins. In Georges Bank wells, diagnostic fossils become sparse with increasing well depth; paleontologically barren sections extend

for hundreds and even thousands of feet. The sparseness is partly explained by the deltaic and shallow, marginal-marine character of the pre-Late Cretaceous Mesozoic section. In general, these are not good environments for the production and preservation of marine microfossils. Evaporite intervals also tend to be devoid of fossils.

Altogether, the biostratigraphic portions of the well reports for the eight industry wells and the two COST wells should be regarded as subject to increasing error with greater well depth. Only four wells penetrated identified Lower Jurassic and older rocks. The depth of this section ranges from 11,190 feet (Mobil LC Block 312 No. 1) to 17,000 feet (Shell LC Block 410 No. 1R). Generally, stratigraphic units and their depths should be relatively consistent among closely spaced wells in a little-deformed basin. However, among Georges Bank wells, apparent inconsistencies between well biostratigraphic "tops" become greater with increasing well depth.

The greatest disagreements are between analyses done by different groups of paleontologists. The COST G-1 and G-2 and Conoco LC Block 145 No.1 wells were done by International Biostratigraphers, Inc., the Mobil LC Block 273 No.1 and Shell LC Block 357 No.1 by the operating oil companies, and the remaining five wells by the MMS Atlantic office paleontological staff. The paleontological staff of the Atlantic OCS Region office initially examined only well-cutting samples from the Exxon LC Block 133 No. 1 well in 1982. Based on

dinoflagellate cysts, they assigned Early Jurassic ages to strata in the deepest portion of the well. Subsequently, the operator submitted splits from a conventional drill core (12,258 to 12,326 feet). After a restudy, the staff concluded that the core samples are Middle Jurassic (Bajocian) in age and that all deeper cutting samples represent reworked sediments that incorporate geologically older, redeposited dinocysts.

A further consequence of the inherent difficulties and the inconsistent biostratigraphic interpretation among the paleontologists from different organizations is that the eight burial history diagrams for the industry wells have dissimilar profiles.

THERMAL MATURITY

Within Georges Bank Basin, rocks are thermally mature for oil generation at about 8,000 feet, for wet gas at about 17,000 feet, and for dry gas at about 21,000 feet. However, rocks at all well depths are organically lean, and kerogens are mixed Type II and Type III, becoming more Type III rich with increasing depth.

Geothermal gradients for the 10 Georges Bank wells, based on uncorrected bottomhole logging temperatures, range from 1.06 °F/100 ft (Conoco LC Block 145 No. 1) to 1.34 °F/100 ft (Cost G-2) and average 1.26 °F/100 ft. These results are about the same as for wells on the Canadian Scotian Shelf (~1.2 °F/100 ft), to the northeast, and in Baltimore Canyon Trough (~1.2 °F/100 ft), to the southwest, and are higher than for Southeast Georgia

Embayment (~0.9 °F/100 ft), farther southwest (Amato and Bebout, 1980).

In the 1970's and 1980's the Atlantic OCS Region Resource Evaluation staff used the thermal alteration index (TAI) of Staplin (1969) to estimate sedimentary thermal maturity for petroleum generation. The index uses alteration colors of organic material in transmitted light as indicators of thermal maturity. In the TAI numerical index, a value of 2.6 (Jones and Edison, 1978) indicates borderline maturity for generating oil, and values of 3.1 to 3.5 indicate the range for production of condensate and wet gas. In seven of the eight Georges Bank exploratory wells for which TAI analyses are available, the depth to borderline thermal maturity ranges from 9,450 (Mobil LC Block 273 No.1 well) to 13,300 feet (Shell LC Block 410 No.1R) and averages 11,139 feet. Analyses for five of the wells indicate depths of 12,450 to 13,950 feet for fully mature TAI values of 2.9-3.1.

The service companies that provided geochemical analyses for the COST G-2 well obtained conflicting results. GeoChem Laboratories, Inc. did the most extensive TAI analysis and did not find mature alteration colors in any well samples (TD 21,874 ft). Core Laboratories, Inc., reported TAI values sufficient for oil generation between 8,500 and 12,300 feet; they believed that deeper samples were contaminated. M.A. Smith (1980) states that alteration colors are mature (orange-brown) near TD of the well.

Vitrinite reflectance data are available for only 4 of the 10 wells, and they indicate threshold maturity at shallower depths than indicated by TAI. Vitrinite reflectance is based on the reflectivity (R_o) of polished sedimentary vitrinite grains. A value of 0.6 percent indicates borderline thermal maturity for oil generation, whereas 1.0 to 1.5 percent indicates the time-temperature range for production of condensate and wet gas. Vitrinite reflectance values in excess of 2 percent are in the dry gas generation range. Three of the four Georges Bank wells for which there are vitrinite reflectance data, COST G-1, Mobil LC Block 312 No.1, and Shell LC Block 410 No.1R, have threshold maturity values at depths of 6,500 to 9,000 feet. In the fourth well, the COST G-2, R_o increases from 0.5 to 1.04 percent (immature to fully mature) at 8,769 feet. Averaging the G-2 result with that of the other three wells produces a depth to the onset of thermal maturity of 8,167 feet. All four wells have peak-generation R_o values of about 1.0 percent at depths of 8,769 to 13,000 feet.

The thermal color index (TCI), developed by Texaco, Inc. in the mid-1980's, is another method for quantifying thermal maturity. Its developers claim superior accuracy, compared with TAI, because TCI is based on spectral analysis of transmitted light from amorphous kerogens, rather than an operator's determinations of color from a variety of kerogen types (van Gijssel, 1990). TCI is also supposed to be superior to vitrinite reflectance analysis because amorphous kerogens are more widely distributed than vitrinite in sedimentary rocks. TCI has not

been widely accepted by most geochemical laboratories, which continue to use vitrinite reflectance.

In an effort to resolve the contradictory COST G-2 thermal maturity data, Texaco applied the TCI technique to the well's kerogen slides. Stated in terms of vitrinite reflectance equivalence, the oil window ($R_o=0.65$ percent) begins at 7,750 feet, wet gas ($R_o=1.35$ percent) begins at 17,000 feet, and dry gas ($R_o=2.0$ percent) begins at 21,000 feet (Smith and van Gijssel, 1990; van Gijssel, 1990).

Petroleum geochemical techniques have evolved since the Georges Bank wells were drilled, and we believe that the TCI maturity data, supported by vitrinite reflectance, are more reliable than the TAI analyses done twenty years ago. Because the 10 wells are closely spaced in a little-deformed subbasin, we also believe that the COST G-2 TCI data best represent the thermal maturity of the subbasin.

A burial history diagram for the COST G-2 well, generated using Plate River Associates' BasinMod® software, is shown in figure 5. In this diagram, the post-rift event is the uplift, erosion, and hiatus associated with the post-rift unconformity (Schlee and Klitgord, 1988). The magnitude of the uplift and duration of the event are strictly diagrammatic. The petroleum generation maturity windows are based on TCI data, expressed as vitrinite reflectance values, and the calculated present-day heat flow (57 mW/m^2). The heat-flow value is based on corrected well-bore temperature data from the COST G-2 well (Amato and

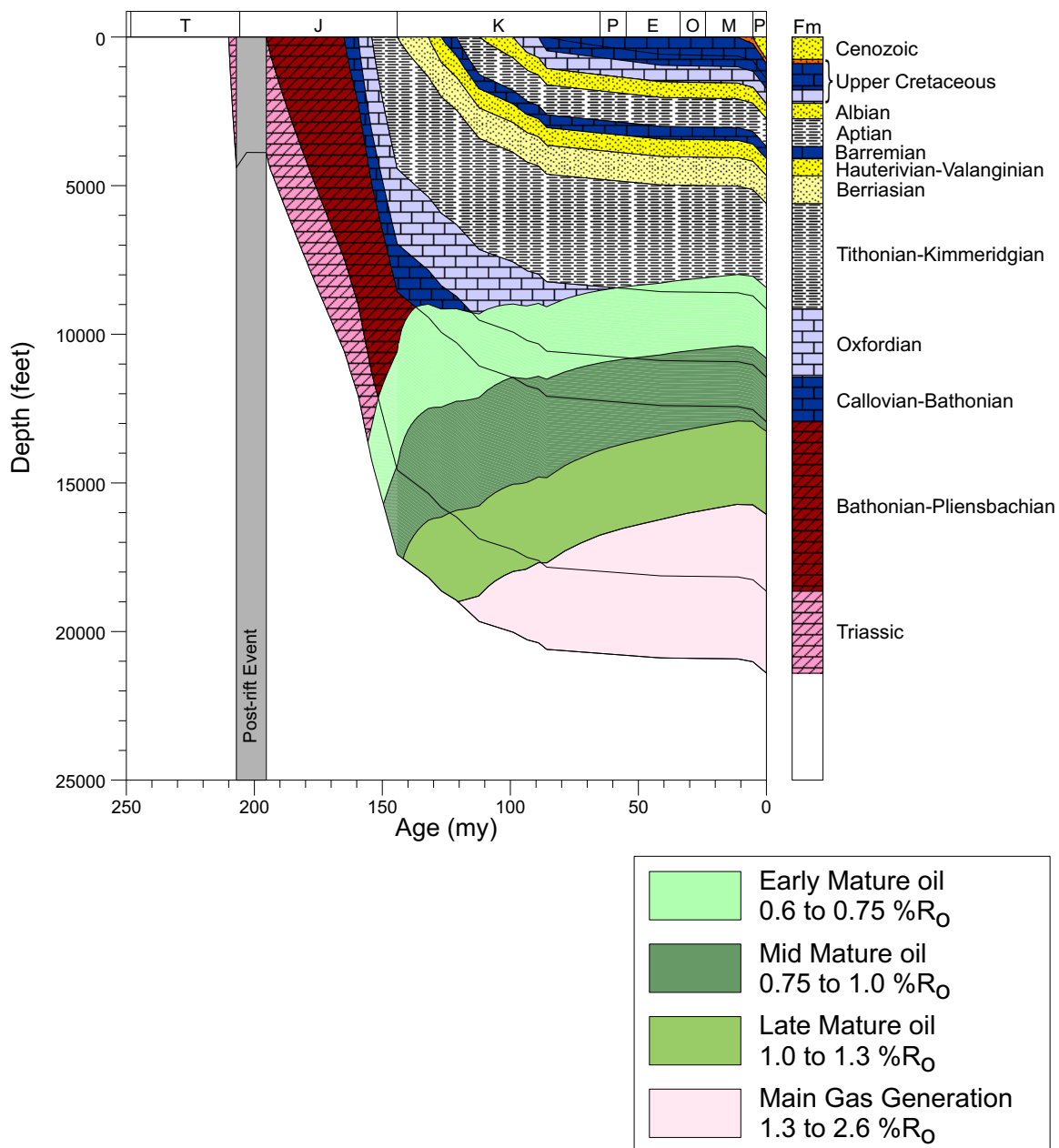


Figure 5. Burial history diagram for the COST G-2 well, constructed with Platte River Associates' BasinMod® software. Tops of Callovian and younger stages, taken from U.S. Geological Survey Open-File Report 80-269, are based on MMS Atlantic OCS Region paleontological analysis. Tops of Bathonian (?) and older units from U.S. Geological Survey Circular 861 are based on seismic stratigraphy. The Mesozoic time scale is after Gradstein and others, 1995, and the Cenozoic times scale is after Berggren and others, 1995. The post-rift event consists of the uplift, erosion, and hiatus associated with the post-rift unconformity. Magnitude of the uplift and duration of the event are strictly diagrammatic. Petroleum maturity windows are based on TCI kerogen analysis expressed as vitrinite reflectance (R_O) values.

Simonis, 1980). According to this model, petroleum generation, given adequate source rock, began in about the Middle Jurassic Epoch at well depths of 12,000 feet in the COST G-2 well.

Figure 6 is a BasinMod® diagram showing corrected borehole temperatures, a temperature profile, measured vitrinite values, and a regression fit of thermal maturity to depth. In the well, early maturity for oil generation ($R_o = 0.6$ percent) begins in Upper Jurassic rocks near 8,500 feet and main gas generation ($R_o = 1.35$ percent) begins in Middle Jurassic rocks near 16,500 feet. These depths are within 750 and 500 feet, respectively, of agreement with Texaco's TCI data.

ORGANIC RICHNESS

Sedimentary units encountered by drilling in Georges Bank Basin are organically lean, according to total organic carbon (TOC) analyses from 7 of the 10 wells. Most samples have less than 1 percent TOC. Only one sample from the 7 wells has a value of more than 3 percent. Data from all but one well show organic richness decreasing with depth. The exception is the Tenneco LC Block 187 No. 1 well, which shows as much as 1.65 percent TOC in Upper Triassic units deep in the well. In general, most Cretaceous samples are between 0.25 and 1.5 percent; most Upper and Middle Jurassic samples are between 0.2 and 0.6 percent; most Lower Jurassic samples are between 0.1 and 0.3 percent; and most Triassic samples are less than 0.2 percent. Carbonate and evaporite lithologies are

associated with low organic carbon abundance. In summary, the source rock potential in the currently drilled portion of Georges Bank Basin at sufficient depths for thermal maturity, 8,000 to nearly 22,000 feet (the deepest drilling), is poor.

ORGANIC MATTER TYPES

For petroleum exploration, the organically lean section encountered in Georges Bank Basin diminishes the relevance of organic matter type analysis. However, MMS and industry performed many kerogen analyses on well cuttings and cores in the 1980's.

Kerogen is disseminated sedimentary organic matter that has not been converted to petroleum. In assessing source-rock potential, the Atlantic OCS Office staff classified kerogen as algal-amorphous, herbaceous, woody, or coaly, using a microscope and transmitted light. The staff examined samples from six of the eight industry wells and service companies examined the two COST wells. In the six wells, the highest abundance of algal-amorphous kerogens is reported to be in the uppermost 5,000 to 8,000 feet, ranging to over 30 percent of total kerogens. Below about 10,000 feet, algal-amorphous abundances generally range from zero to 5 percent. Herbaceous kerogens are generally between 20 and 30 percent, and woody kerogens are generally between 20 and 40 percent at all well depths. Coaly matter generally ranges from 20 to 60 percent and increases with depth.

These relationships are also evident in the COST G-1 visual kerogen data; however, the service company (GeoChem) analyst

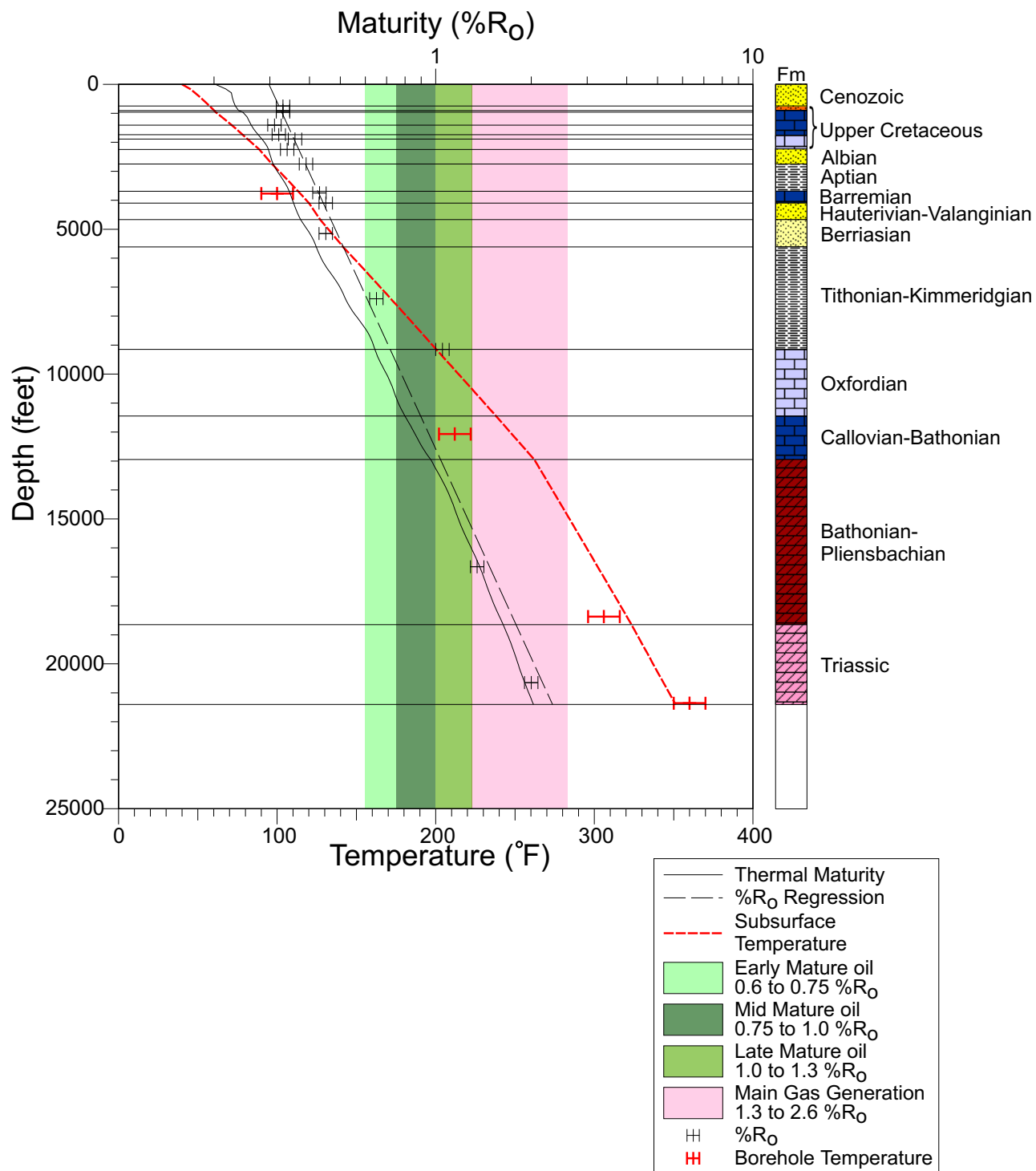


Figure 6. BasinMod® diagram for the COST G-2 well displaying petroleum maturity windows, borehole temperatures, temperature profile, vitrinite reflectance values, and thermal maturity profile. The heavy red crosses with error bars are corrected borehole temperatures taken from well logs. The dashed red graph line represents the temperature profile calculated using the model assumptions. Black crosses with error bars are TCI kerogen maturity measurements expressed as R₀ values. The dashed black line is a regression fit to the TCI data. The solid black graph line represents thermal maturity as modeled by BasinMod®. Petroleum maturity windows are based on TCI.

recognized a higher proportion of algal-amorphous kerogen throughout this well, compared with the industry wells. Algal-amorphous kerogens are mostly in the 20 to 40 percent range down to 6,000 feet and in the zero to 30 percent range from 6,000 feet to total depth (Smith and Shaw, 1980; Miller and others, 1982). In the COST G-2 well, the kerogen analyses furnished by two service companies are contradictory and not consistent with the other wells (Smith, 1980, Miller and others, 1982). GeoChem Laboratories reported that in the G-2 well, algal-amorphous, herbaceous, woody, and coaly relative abundances are fairly consistent at all depths, with proportions of about 40, 15, 20, and 25 percent, respectively. Core Laboratories, Inc., reported that algal-amorphous kerogens are nearly absent in the well but that inertinite (coaly) is the dominant kerogen type throughout, especially below 8,500 feet, accounting for as much as 90 percent of the organic matter.

The lack of consistency among kerogen studies is likely caused by variation in analyst assumptions and techniques. Differences include deciding what material should be ignored because it is caved from higher in the drill hole, recycled, and redeposited from older strata, or introduced from the platform in drilling the well.

M. A. Smith (1995) reports a more recent COST G-2 visual kerogen analysis done by Geo-Strat, Inc., to resolve these contradictions. In this restudy, the analyst used 18 organic matter types, rather than the 4 types previously employed.

However, most of the recognized kerogen was algae and amorphous algal debris, plant tissue, and amorphous herbaceous debris, vitrinite (wood), and inertinite (coal). That is, these organic matter types correlate well with the previously used four types, algal-amorphous, herbaceous, woody, and coaly. The practical difference is that, previously, algal-amorphous was one category, and now a portion of that is classed as herbaceous matter. Consequently, the Geo-Strat study identifies only 4 to 8 percent of total kerogens as algal in all but two well samples. Total herbaceous matter (amorphous herbaceous plus plant tissue) amounts to about half of total kerogens down to 11,500 feet; 20 percent to 15,500 feet, 70 percent to 19,500 feet, and 35 to 60 percent to total depth. Woody kerogens are about 20 percent to 11,500 feet, 35 percent to 15,500 feet, and 10 to 20 percent to total depth. Coaly matter increases from about 5 percent at shallow depths to about 20 percent near total depth.

Among the COST G-2 kerogen analyses done by different parties, Core Labs' analysis appears to be so different that it can be rejected. GeoChem's and Geo-Strat's results are similar, allowing for different definitions of algal and herbaceous matter. However, Geo-Strat's relative abundances are more variable throughout the well.

Thermal pyrolysis and molecular geochemical analysis data relevant to relative kerogen abundance are available for the COST G-1 and G-2 and the Exxon LC Block 133 No. 1 and the Tenneco LC Block 187 No. 1 wells. Kerogen relative

abundance is reflected in the hydrogen index ($HI=S_2/TOC$) and the atomic hydrogen-to-carbon ratio (H/C). From higher to lower HI and H/C, the order of kerogen types is algal, amorphous, herbaceous, woody, and coaly. Hydrogen index values of less than 200 and hydrogen-to-carbon ratios less than 1.0 suggest that woody and coaly organic matter equals or exceeds herbaceous and algal-amorphous matter and that the primary expelled hydrocarbon will be gas. For Exxon LC Block 133 No. 1 well samples, the HI ranged from 0 to 143 and for Tenneco LC Block 187 No. 1 well samples, the H/C ranged from 0.11 to 0.76, suggesting mixed algal-herbaceous and woody-coaly kerogens, with the latter generally in greater abundance. The 50 HI values of the Exxon well are extremely variable throughout; however, in general, they decrease in magnitude with depth, indicating decreasing algal-amorphous and increasing woody and coaly abundances seen in the optical kerogen analysis. Only a descriptive summary of the H/C ratios of the Tenneco well is available, and there is no statement about whether the ratio changes with depth.

We believe that the Geo-Strat kerogen studies on the COST G-2 well (Smith, 1995) are more reliable than the optical kerogen analyses of this well described in the 1980 U. S. Geological Survey Open-File Report 80-269 and the 1982 U. S. Geological Survey Circular 861. Further, we believe that the Geo-Strat data represent the basin better than the eight industry well kerogen studies done in the early 1980's by the MMS Atlantic OCS

Region office and contained in the accompanying well reports.

The final step of Geo-Strat's kerogen procedure is to combine the data for each sample interval and assign an organic matter index (OMI) number. The OMI values are then plotted against well depth to provide a profile of oil and gas proneness for the stratigraphic column. The index ranges from 1, strongly oil prone, to 8, strongly gas prone. The scale is also divided into Type I, Type II, Type II-Type III mix, and Type III organic matter fields. For the COST G-2 well (figure 7), most samples are between 4.35 and 5.25, which is within the Type II-Type III mixed field, indicating the probability of both oil and gas. However, index values increase with depth, indicating the higher likelihood of natural gas deep in the well.

FUTURE EXPLORATION

It is nearly 18 years since the last petroleum exploration well was drilled on Georges Bank, and the area is currently under a leasing moratorium. However, in recent years companies have made 24 gas-condensate discoveries in the Canadian Scotian Basin, to the northeast, and six fields are being developed. A third cycle of exploration activity is underway along the eastern Canadian margin that includes previously unexplored areas and plays.

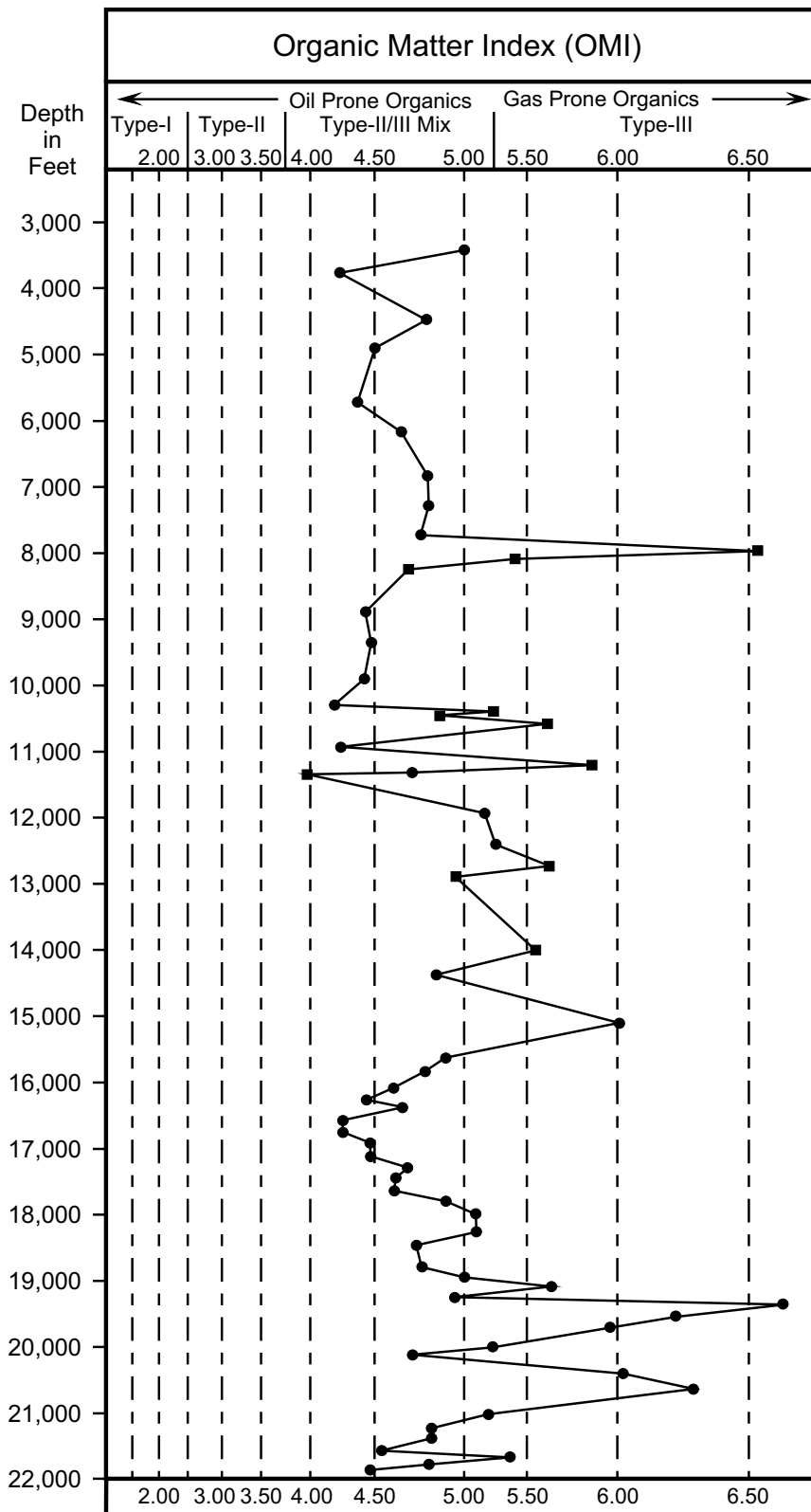


Figure 7. Organic matter index (OMI) for the COST G-2 well. Index values are calculated from kerogen type analysis, which recognizes 18 kinds of kerogen. Data from Schwab and others, 1990.

When petroleum exploration does resume in Georges Bank Basin, new, state-of-the-art seismic data acquisition and processing will have high priority. The goal will be better resolution of deep structures (below three seconds, two-way travel time). Although seismic data from the 1970's and 1980's show deep features, they are difficult to interpret owing to poor resolution and spatial distortion and displacement. The Georges Bank stratigraphic section is thinner than that of Baltimore Canyon Trough or the Scotian Basin. Record lengths of six to seven seconds, two-way-time, will adequately image this Upper and Middle Jurassic part of the section, as well as the underlying Triassic-Early Jurassic rift basins. With modern seismic data, good resolution will be achievable for the entire sedimentary section.

Well data suggest that identified organic source rock is the major component missing from the Georges Bank hydrocarbon system. Untested and poorly tested facies, including lacustrine shales and marls of Early Mesozoic rift basins, relict Upper Paleozoic basins, and the Cretaceous paleo-continental slope, may provide source rocks capable of charging the petroleum system. Deeper drilling may also be effective in Georges Bank Basin. Most of the gas discoveries near Sable Island in the Scotian Basin are associated with overpressure, generally at about 13,500 feet. Severely overpressured gas was encountered, but not tested, at 17,807 feet in the Texaco Hudson Canyon Block 642 No. 1 well in Baltimore Canyon

Trough (Amato and Bielak, 1990). Deeper drilling in Georges Bank Basin, likely below 20,000 feet, may also find overpressured gas. Gas-condensate or dry gas is the most likely hydrocarbon at these depths, with temperatures in excess of 300 °F.

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