3rd RAI Response for Oil Well Permit Application 1366

Submitted to: Florida Department of Environmental Protection

Prepared by:

The Carol Group, Inc.

Century Oil Co., Inc.

Clementi Environmental Consulting, LLC

For: Kanter Real Estate, LLC

2601 South Bayshore Drive, Suite 1450

Miami, Florida 33133

August 17,2016

Received by Florida DEP 8/18/2016

1. **Will the main drilling contractor/consultant responsible for the surface, intermediate and production casing/cementing programs also be responsible for setting the conductor casing? [377.22(2)(a), F.S. and 62C-27.005, F.A.C.]**

For purposes of safety oversight and planning continuity, it is important that the drilling contractor/consultant understand not only the drilling plan, but that it be the entity responsible for setting the conductor casing and for the surface, intermediate and production casing/cementing programs. Yes, the main drilling contractor/consultant responsible for the surface, intermediate and production casing/cementing programs will also be responsible for setting the conductor casing. This entity is Pollister Drilling Corp., and the chief consultant responsible is Pollister Drilling Corp.'s President, Ed Pollister. His resume was submitted previously.

2. **Please explain, based on soils and prevailing shallow subsurface how the conductor can actually be driven 200 feet into the limestone without encountering refusal at a shallower depth. [377.22(2)(a), F.S. and 62C-27.005, F.A.C.]**

Based on site soils and the prevailing shallow subsurface, a 30-inch .625 wall Conductor casing will actually be driven into the limestone until refusal which is anticipated to occur at 50 - 60 ft. If refusal does occur at 50 - 60 feet then a 17 ½-inch Pilot Hole will be drilled to 100 – 150 feet. An additional 26-inch .625 wall Conductor casing will be driven through the pilot hole to a depth of 200 feet. There will be additional protection measures put in place to protect the Biscayne Aquifer, the Gray Limestone Aquifer, and the semi-confining layer by then drilling a surface casing to 1000 ft. See **Attachment 2(a),** Composite USGS Technical Information and **Attachment 2(b)**, AMEC Borings Report, which describe the subsurface conditions. See also **Attachment 2(c),** Wellbore Schematic and Drilling Procedure.

3. **Describe the measures that will be taken to prevent hydraulic connection between the Biscayne Aquifer and the possible GLA during setting of the conductor. [377.22(2)(a), F.S. and 62C-27.005, F.A.C.]**

It is important to protect the Biscayne Aquifer and the Gray Limestone Aquifer from both the well drilling activities as well as potential migration of fluids from the semi confining layer just beneath it. The conductor casing, a 30-inch .625 wall steel pipe, will prevent the sides of the well hole from caving into the wellbore. This 30-inch pipe will be driven to refusal which should occur around 50 - 60 ft. If refusal does occur at 50 - 60 feet then a 17 ½-inch Pilot Hole will be drilled to 100 – 150 feet. An additional 26-inch .625 wall Conductor casing will be driven through the pilot hole to a depth of 200 feet. Then a 23-inch hole will be drilled to 1000 feet. This will be below the semi confining layer. An 18 5/8" inch 87.5# J 55 ST&C casing will be set at 1000 feet. It will be cemented with 441 sx. lead cement and 410 sx. tail cement plus 200 sx. top off. A 17-½ inch hole will be drilled to 1800 feet. A 13 3/8-inch 54.5# J 55 ST&C casing will be set at 1800 feet. It will be cemented with 200 sx. lead cement and 200 sx. tail cement plus 200 sx. top off. This casing will protect both the semi-confining layer from contamination and will also provide an added layer of protection for the Biscayne Aquifer and the Gray Limestone Aquifer. Nothing from the Well will be able to enter the semi-confining layer, and nothing from the semi-confining layer will be able to enter the Biscayne Aquifer or the Gray Limestone Aquifer. See **Attachment 2(c),** Wellbore Schematic and **Attachment 3,** Casing and Cementing Plan. In addition, a licensed professional geologist will monitor the driving and drilling activities and will verify the bottom of the Biscayne Aquifer, the bottom of the Gray Limestone Aquifer, and the bottom of the semi-confining layer before cementing occurs.

Received by Florida DEP 8/18/2016

According to the wellbore diagram, the 13-3/8-inch surface casing will traverse the Biscayne Aquifer, the GLA, the SCU, the ICU and the UFA prior to landing in a competent confining unit below the deepest Underground Source of Drinking Water (USDW) and above the Boulder Zone.

4. **Explain the measures that will ensure that water from the UFA will not enter the Biscayne Aquifer by direct connection or surface spillage. [377.22(2)(a), F.S. and 62C-27.005, F.A.C.]**

The casing and cementing process as developed will ensure that each aquifer is isolated. The Well is comprised of multiple casing layers. See **Attachment 2(c)**, Wellbore Schematic. It is important to understand the site geology and for the driller to anticipate each aquifer and geologic formation that will be encountered and plan accordingly. Information from the USGS documents, **Attachment 4(a)**, and data from DEP derived from several deep wells drilled east of the oil well site, **Attachment 4(b)**, were reviewed in developing the drilling plan as well as the fluids plan and the cementing plan. Proper sealing of annular spaces with cement will create a hydraulic barrier to both vertical and horizontal fluid migration. Once the surface casing is set, the cement will be given time to cure. The wellbore will then be drilled down to the next zone where the casing will be set. The casing string isolates the freshwater zones and the groundwater from the inside of the Well. The surface casing is the first line of defense, and each additional casing string further protects the aquifers. The cementation of the casing adds the most value to the protection of the groundwater.

The exact depth of the base of the USDW and the characteristics of the monitor zones will be evaluated by lithologic sampling at 10-foot intervals, and water quality sampling during geophysical logging. The Florida standard of 10,000 tds will be verified by testing.

The drilling contractor will need to ensure that the drilling mud is of sufficient weight at all times to prevent the rise of water from the Floridan Aquifer. The drilling contractor will supervise the drilling activities and through testing will ensure mud is appropriate for the Well. It is anticipated that the Floridan Aquifer will be encountered around 1600 to 1900 feet. The well driller will anticipate encountering the Floridan Aquifer around 1500 feet and will be prepared to make necessary adjustments. See **Attachment 4(c),** Pembroke Pines PBSJ Report.

5. **How will the surface casing plan and mud/drilling fluids plan be modified if lost circulation zones are encountered when drilling the surface casing borehole through the limestone of the UFA? [377.22(2)(a), F.S. and 62C-27.005(1)(a), F.A.C.]**

Lost circulation is an issue to plan for in the drilling program. A lost circulation plan has been developed. See **Attachment 5(a).** This lost circulation plan includes the procedures to be followed in case lost circulation is encountered. All well drilling personnel will be familiarized with the plan. The surface casing plan and mud drilling fluids plan companies will be familiar with the procedure in the event that lost circulation zones are encountered when drilling the surface casing borehole through the limestone of the UFA. The actual fluids program, as revised (**Attachment 5(b)**) and cementing program, as revised (**Attachment 5(c)**) contracts, when executed, will contain the contingency for lost circulation, and an additional pricing structure and delivery method will be negotiated.

The contractor will take appropriate steps to address lost circulation depending on the site-specific circumstances encountered. Proper control of lost circulation while drilling involves keeping the well hole full to help prevent a kick, avoiding differential sticking of drill pipe, sealing off the loss zone, and regaining circulation. The contractor may also add lost-circulation material to the drilling mud if appropriate under site conditions. Anticipated actions and materials are included in the lost circulation plan.

Refer to the attached Equipment Layout Sheet C-2.03 provided in the Application Update submitted June 15, 2016.

6. **Please reconcile the dimension given on the left side of 100 feet and the dimension of 223.3 feet given on the right side (for a clearly smaller distance). Resubmit this sheet after clearing up this discrepancy.**

Please see the revised Sheet C-2.03, included as **Attachment 6**.

In addition, Kanter has revised the synopsis of its application materials to reflect issues raised in this Request for Additional Information. The revised application synopsis is included as **Attachment 7**.

Attachment 2(a) Composite USGS Technical Information

Mineral Resources On-Line Spatial Data

Geologic units in Broward county, Florida

Shelly sediments of Plio-Pleistocene age (Pliocene/Pleistocene) at surface, covers < 0.1 % of this area

Shelly sediments of Plio-Pleistocene age - Tertiary-Quaternary Fossiliferous Sediments of Southern Florida - Molluskbearing sediments of southern Florida contain some of the most abundant and diverse fossil faunas in the world. The origin of these accumulations of fossil mollusks is imprecisely known (Allmon, 1992). The shell beds have attracted much attention due to the abundance and preservation of the fossils but the biostratigraphy and lithostratigraphy of the units has not been well defined (Scott, 1992). Scott and Wingard (1995) discussed the problems associated with biostratigraphy and lithostratigraphy of the Plio-Pleistocene in southern Florida. These "formations" are biostratigraphic units. The "formations" previously recognized within the latest Tertiary-Quaternary section of southern Florida include the latest Pliocene - early Pleistocene Caloosahatchee Formation, the early Pleistocene Bermont formation (informal) and the late Pleistocene Fort Thompson Formation. This section consists of fossiliferous sands and carbonates. The identification of these units is problematic unless the significant molluscan species are recognized. Often exposures are not extensive enough to facilitate the collection of representative faunal samples to properly discern the biostratigraphic identification of the formation. In an attempt to alleviate the inherent problems in the biostratigraphic recognition of lithostratigraphic units, Scott (1992) suggested grouping the latest Pliocene through late Pleistocene Caloosahatchee, Bermont and Fort Thompson Formations in to a single lithostratigraphic entity, the Okeechobee formation (informal). In mapping the shelly sands and carbonates, a generalized grouping as Tertiary-Quaternary shell units (TQsu) was utilized. This is equivalent to the informal Okeechobee formation. The distribution of the Caloosahatchee and Fort Thompson Formation are shown on previous geologic maps by Cooke (1945), Vernon and Puri (1964) and Brooks (1982). The Nashua Formation occurs within the Pliocene - Pleistocene in northern Florida. However, it crops out or is near the surface is an area too small to be shown on a map of this scale. Lithologically these sediments are complex, varying from unconsolidated, variably calcareous and fossiliferous quartz sands to well indurated, sandy, fossiliferous limestones (both marine and freshwater). Clayey sands and sandy clays are present. These sediments form part of the surficial aquifer system

Lithology: limestone; sand; clay or mud

Anastasia Formation (Pleistocene) at surface, covers < 0.1 % of this area

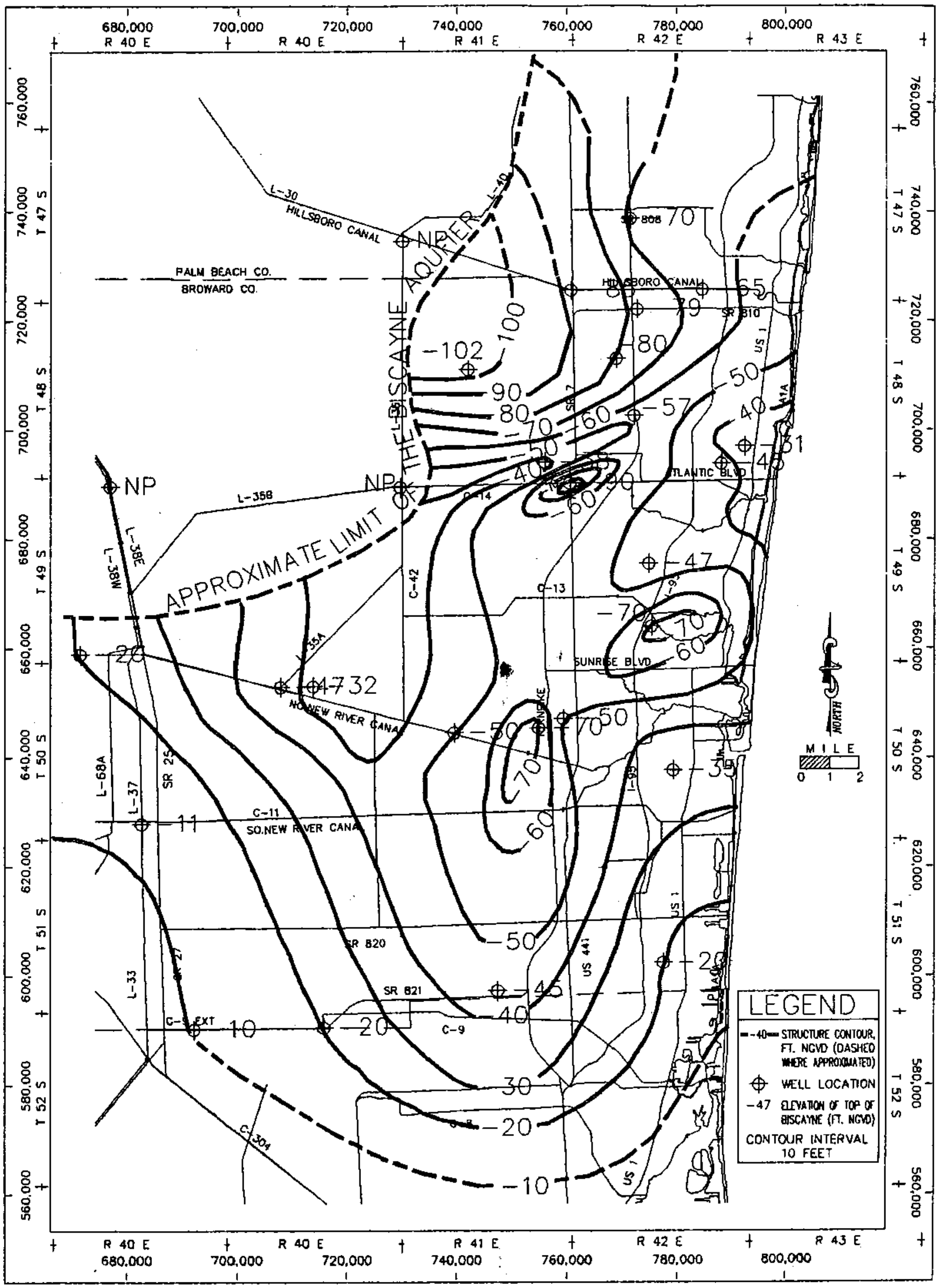
Anastasia Formation - The Atlantic Coastal Ridge is underlain by the Anastasia Formation from St. Johns County southward to Palm Beach County. Excellent exposures occur in Flagler County in Washington Oaks State Park, in Martin County at the House of Refuge on Hutchinson Island and at Blowing Rocks in Palm Beach County. An impressive exposure of Anastasia Formation sediments occurs along Country Club Road in Palm Beach County (Lovejoy, 1992). The Anastasia Formation generally is recognized near the coast but extends inland as much as 20 miles (32 kilometers) in St. Lucie and Martin Counties. The Anastasia Formation, named by Sellards (1912),is composed of interbedded sands and coquinoid limestones. The most recognized facies of the Anastasia sediments is an orangish brown, unindurated to moderately indurated, coquina of whole and fragmented mollusk shells in a matrix of sand often cemented by sparry calcite. Sands occur as light gray to tan and orangish brown, unconsolidated to moderately indurated, unfossiliferous to very fossiliferous beds. The Anastasia Formation forms part of the surficial aquifer system.

Lithology: calcarenite; sand; limestone

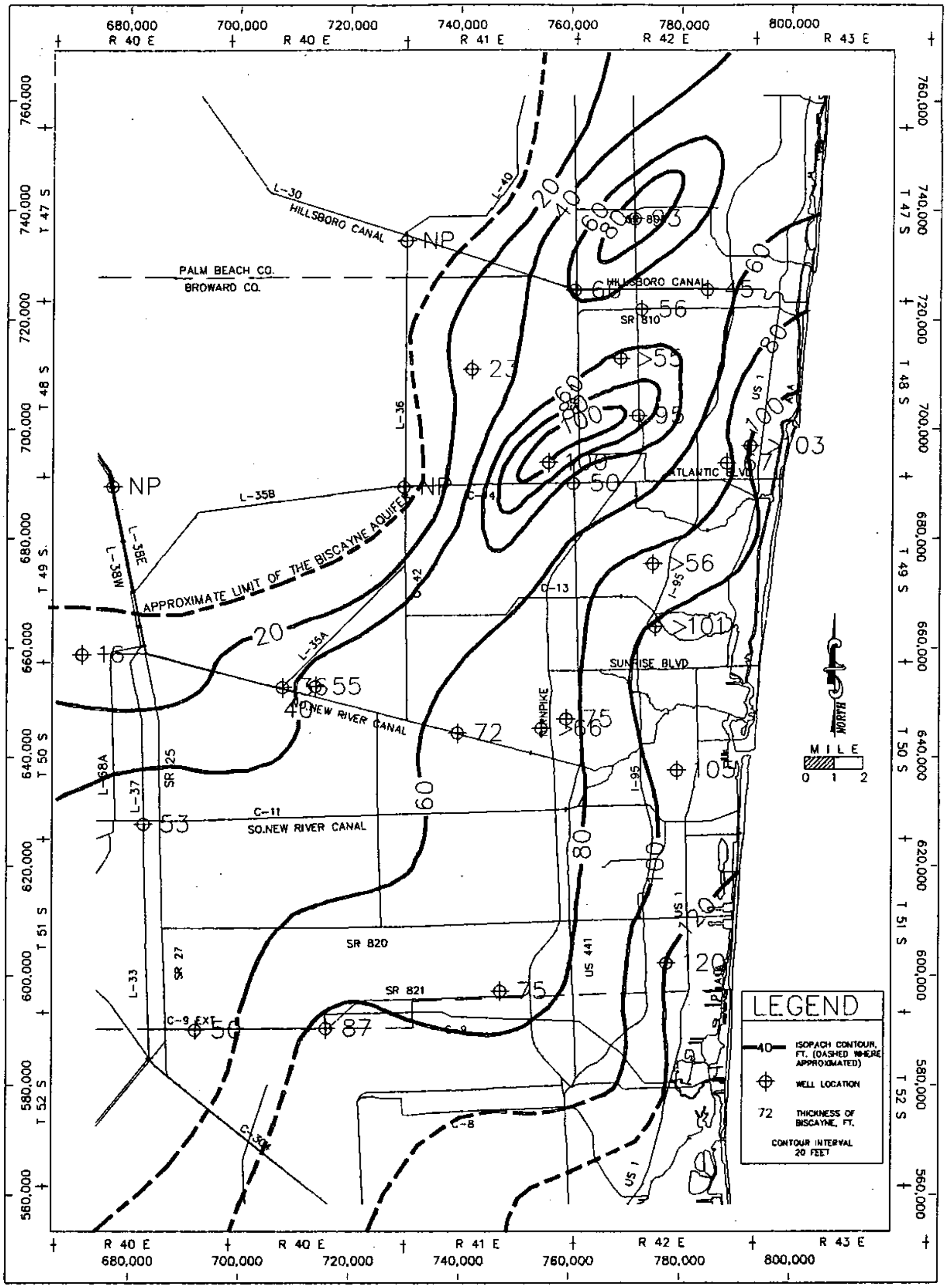
Miami Limestone (Pleistocene) at surface, covers < 0.1 % of this area

Miami Limestone - The Miami Limestone (formerly the Miami Oolite), named by Sanford (1909), occurs at or near the surface in southeastern peninsular Florida from Palm Beach County to Dade and Monroe Counties. It forms the Atlantic Coastal Ridge and extends beneath the Everglades where it is commonly covered by thin organic and freshwater sediments. The Miami Limestone occurs on the mainland and in the southern Florida Keys from Big Pine Key to the Marquesas Keys. From Big Pine Key to the mainland, the Miami Limestone is replaced by the Key Largo Limestone. To the north, in Palm Beach County, the Miami Limestone grades laterally northward into the Anastasia Formation. The Miami Limestone consists of two facies, an oolitic facies and a bryozoan facies (Hoffmeister et al. [1967]). The oolitic facies consists of white to orangish gray, poorly to moderately indurated, sandy, oolitic limestone (grainstone) with scattered concentrations of fossils. The bryozoan facies consists of white to orangish gray, poorly to well indurated, sandy, fossiliferous limestone (grainstone and packstone). Beds of quartz sand are also present as unindurated sediments and indurated limey sandstones. Fossils present include mollusks, bryozoans, and corals. Molds and casts of fossils are common. The highly porous and permeable Miami Limestone forms much of the Biscayne Aquifer of the surficial aquifer system.

Lithology: limestone; sandstone; sand



BISCAYNE AQUIFER TOP ELEVATION



BISCAYNE AQUIFER THICKNESS

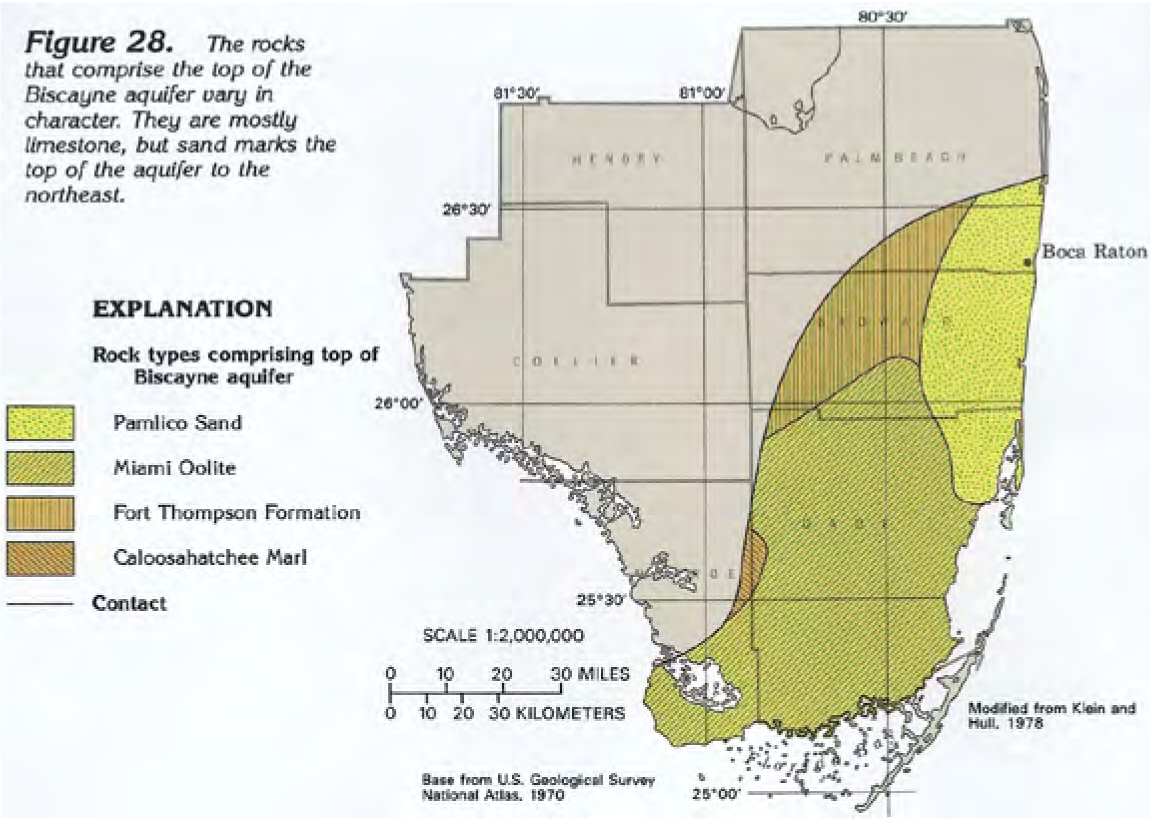


Figure 28. *The rocks that comprise the top of the Biscayne aquifer vary in character. They are mostly limestone, but sand marks the top of the aquifer to the northeast.*

Attachment 2(b) AMEC Borings Report

May 15, 2014

Ms. Carol Howard
The Carol Group, Inc.
712 Sunset Pointe Drive
Lake Placid, Florida 33852

SUBJECT: EXPLORATORY DUE-DILIGENCE DRILLING PROGRAM
Kantor Property
Sections 11, 14 and 22; Township 51S; Range 38E
Broward County, Florida

Dear Ms. Howard:

AMEC Environment & Infrastructure, Inc. (AMEC) was contracted by The Carol Group, Inc. on February 4, 2014 to conduct a due-diligence drilling program on a portion of the Kantor Properties located within Sections 11, 14, and 22; Township 51S; and, Range 38E in Broward County, Florida (**Figures 1** and **2**). The purpose of the program is to evaluate the potential for producing marketable quality limestone from the site.

LOCATION AND SETTING

The subject site is located within the central portion of the Florida Everglades which is a subtropical coastal wetland that extends 160 km from Lake Okeechobee to Florida Bay in southeastern Florida. A system of canals and levees were constructed to control surface water flow and completely compartmentalized the central everglades into a series of enclosed basins called Water Conservation Areas (WCAs). The subject site is located entirely within WCA-3A and the South Florida Water Management District levee systems L-67A, L-67B, and L-67C.

GEOLOGIC OVERVIEW

The geologic setting at the subject property includes a surficial layer of peat/muck and fresh water marl/sand of Holocene Age. This is underlain by the Fort Thompson Formation of Pleistocene Age which is comprised of alternating layers of marine, brackish and fresh-water marl, limestone and sandstone, and the Tamiami Formation of Miocene Age which consists of light gray to tan, fossiliferous sands, light gray to green, fossiliferous sandy clays and clayey sands, and white to light gray, poorly consolidated, sandy, fossiliferous limestone.

DRILLING INVESTIGATION

AMEC conducted a drilling program on April 16 through 18, 2014 to determine the presence of marketable-grade limestone at the subject site. The Carol Group Inc. obtained General Permit No. 14283 on March 4, 2014 to construct exploratory borings at 12 potential drill locations on the levee system managed by the South Florida Water Management District (**Appendix A**). Six borings were constructed by Cascade Drilling to depths ranging from 87 to 107 feet below land surface (BLS) at drill locations 1, 3, 5, 7, 9, and 11 utilizing sonic drilling technology (**Figure 3**). The drill locations were chosen to provide results from a broad areal extent of the property that was accessible with drill rig.

<u>Drill Locations</u>

DL #1: Latitude – 26° 0' 57.33" (26.01592481), Longitude – 80° 30' 23.29" (80.50646892)

DL #3: Latitude – 26° 0' 15.33" (26.00425881), Longitude – 80° 30' 55.20" (80.51533157)

DL #5: Latitude – 25° 59' 34.88" (25.99302295), Longitude – 80° 31' 25.33" (80.52370227)

DL #7: Latitude – 25° 58' 53.97" (25.98165757), Longitude – 80° 31' 56.86" (80.53246193)

DL #9: Latitude – 26° 0' 30.86" (26.00857265), Longitude – 80° 30' 27.92" (80.50775616)

DL #11: Latitude – 25° 58' 52.77" (25.98132445), Longitude – 80° 30' 36.54" (80.51014995)

The borings were initially constructed with a four-inch-diameter core barrel that was advanced at 10-foot increments, followed by a six-inch-diameter outer casing advanced to the same depth to keep the borehole open and to ensure there is no sample contamination from the shallower material. Each boring was then pressure grouted with an injection pipe subsequent to completion with a mixture of Portland cement and bentonite powder. The outer casing was then retrieved to approximately 3 feet above top of rock and the grout injection pipe removed. The overburden portion of the boring was grouted with the same mixture through a tremie pipe inserted to approximately 3 feet below top of rock.

Drill location 1 was initially constructed to a depth of 107 feet BLS to determine the vertical extent of limestone. Subsequent drill locations 3, 5, 7, 9, and 11 were constructed from 87 to 97 feet BLS since contiguous limestone was not encountered below a depth of approximately 80 to 90 feet below grade. The depth to rock and total depth of each drill location are detailed below.

<u>Boring Data:</u>

DL #1: Total Depth = 107 feet, Top of Rock = 15 feet BLS

DL #3: Total Depth = 97 feet, Top of Rock = 15 feet BLS

DL #5: Total Depth = 87 feet, Top of Rock = 15 feet BLS

DL #7: Total Depth = 87 feet, Top of Rock = 15 feet BLS

DL #9: Total Depth = 87 feet, Top of Rock = 12 feet BLS

DL #11: Total Depth = 87 feet, Top of Rock = 15 feet BLS

Four-inch-diameter core samples were collected into plastic sleeves during boring construction at 10-foot depth intervals and placed in wooden core boxes for logging and subsequent laboratory analysis. The core samples were inspected by an on-site AMEC Professional Geologist for color, rock/soil type, structure, hardness, and clay content and geologic logs prepared for each drill location (**Appendix B**).

The lithology generally consisted of overburden material associated with construction of the levees from land surface to 10 feet BLS; black peat/muck and sandy marl from 10 to 15 feet BLS; light gray, moderately dense, oolitic, fossiliferous limestone from 15 to 20 feet BLS; and, light gray, massive, fossiliferous limestone from 20 to 75 feet BLS with intermittent silty sand layers at 40 and 65 feet BLS that comprise the Fort Thompson Formation, and interbedded greenish gray, sandy clay with abundant shells and gray, very dense, fossiliferous limestone to the depth of the borings which comprise the Tamiami Formation.

The entire extent of the limestone strata were below the surficial water table and due to the high transmissivity of the limestone units, yielded extremely wet core samples. As a result, the laboratory results may lower the recovery and quality values. Thus, the actual field results (operation) should produce higher values than the laboratory results.

LABORATORY ANALYTICAL RESULTS

Limestone samples were collected at varying depths from each boring for laboratory analysis of bulk specific gravity and moisture content to determine the limerock bearing ratio (LBR) and the suitability for FDOT road base and construction materials. The laboratory samples from each core boring were prepared by blending the upper 10 feet, middle, and bottom 10 feet of limestone material, which yielded a composite value for the entire strata. The results are included in the table below:

TABLE-1: Summary of Limestone Quality

Drill Location	Carbonate Content (%)	CaCO3 Content (%)	FDOT Minimum Specification (%)	Maximum Density (PCF)	Optimum Moisture Content (%)	LBR	FDOT Minimum LBR Specification (%)
DL-1	59.1	51.1	70%	129.2	7	100	100
DL-3	61.7	56.2	70%	128.9	6.5	150	100
DL-5	64.5	61.3	70%	131.2	9.2	123	100
DL-7	79.8	72.0	70%	129.6	7.6	110	100
DL-9	72.7	68.3	70%	129.6	8.2	110	100
DL-11 (0-37 ft)	76	0	70%	132.8	7.8	94	100
DL-11	73.4	66.5	70%	127.4	5.5	65	100

TABLE 2: Summary of Specific Gravity Testing

Drill Location	Bulk Spec Gravity	SSD Spec Gravity	Apparent Spec Gravity	Absorption (%)
DL-1	1.66	1.98	2.44	19
DL-3	1.86	2.1	2.44	13
DL-5	1.72	2.01	2.41	17
DL-7	1.81	1.95	2.1	7
DL-9	1.86	2.09	2.43	13
DL-11	1.97	2.14	2.39	9

The results indicate that five of the six samples passed the FDOT requirements for road base material. The sixth boring (D-11) failed the proctor test for LBR; however, it is believed that based on the moisture content, specific gravity and overall appearance of the sample, this boring would also pass FDOT roadbase requirements. To further verify this, a sample from D-11 was prepared consisting of only the upper 37 feet of limestone material. The results showed a marked improvement in LBR value, thus indicating the boring would pass FDOT LBR as mined with the surrounding area. Typically, better results are ascertained from open pit testing (bulk) than core sampling due primarily to minimizing the percent fines encountered in coring and some effect of washing the sample during excavation. Furthermore, this more accurately represents the actual mining conditions and typically yields better overall results.

In addition, samples from each boring were submitted for laboratory analysis of calcium carbonate in an effort to determine limestone quality and potential for cross marketing additional products (**Appendix B**). The analytical results indicated that the limestone is of sufficient quality for multiple products such as cement kiln feed, agricultural lime, and water treatment pond neutralization.

CONCLUSIONS

The drilling and sampling results revealed that the limestone encountered on the subject site does meet the FDOT requirements for roadbase material. It is also believed that this material would be suitable to meet FDOT specifications for aggregate, although it is uncertain at this point what the specific yield would be on the site in reference to available aggregate material. A bulk test pit would be required to quantify the specific aggregate yield on the subject property. The average thickness of limestone within the tested area is approximately 70 +/- feet, thus yielding a potential gross tonnage per acre (100% insitu) in excess of 140,000 tons. This tonnage may, however, be impacted by local mining constraints and permitting requirements.

Should you have any questions or require additional information, please do not hesitate to contact me at (813) 636-1524.

Sincerely,
AMEC Environment & Infrastructure, Inc.

Gary E. Kihn, PG
Senior Geologist

Dennis Kenney, PG, CPG
Environmental Manager

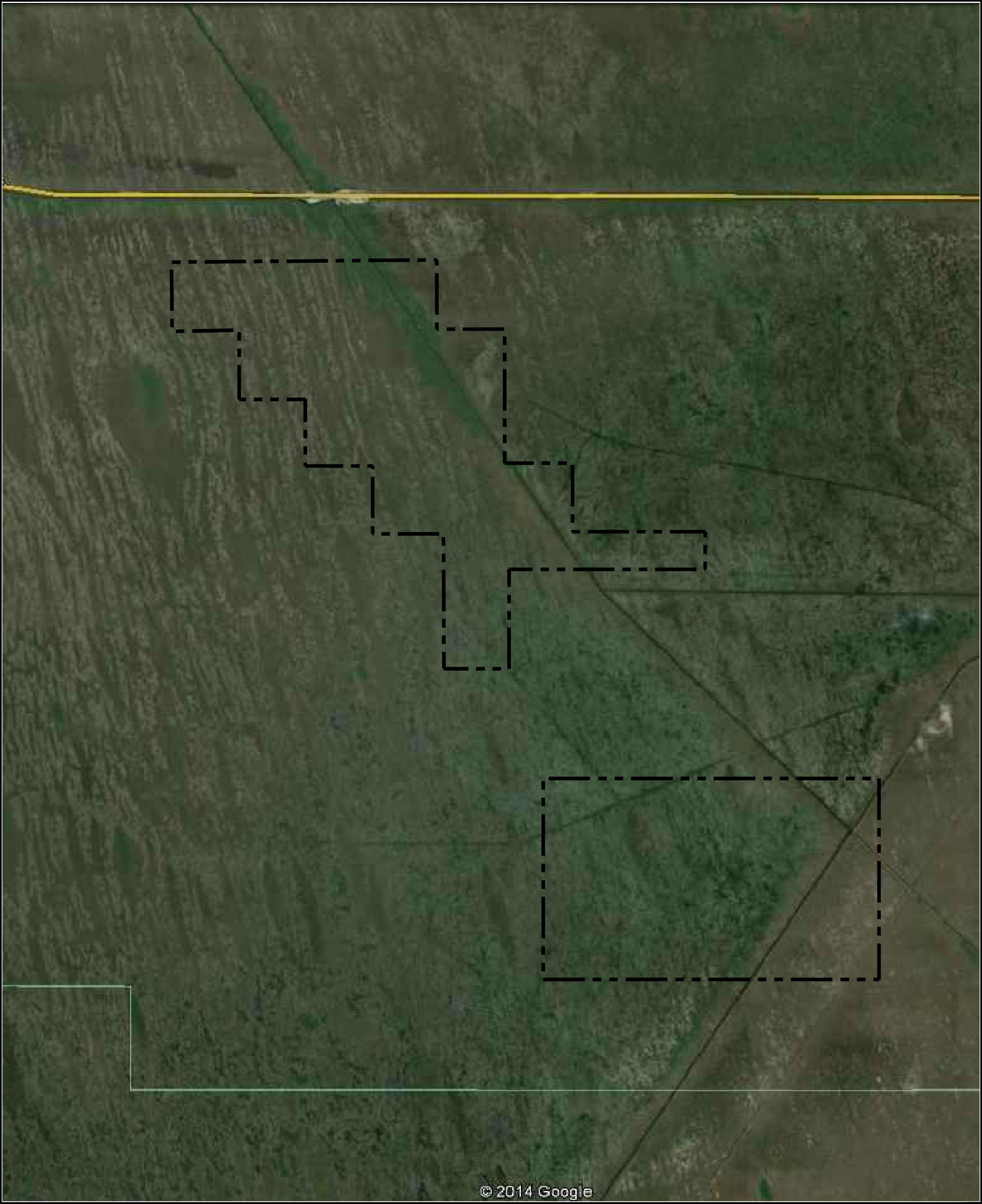
GK/DK/slk

FIGURES

AMEC Environment & Infrastructure, Inc.
2000 E. Edgewood Dr., Ste #215 Lakeland, FL 33803
Phone: 863.667.2345 Fax: 863.667.2662
www.amec.com CA-5392

FIGURE 1
SITE LOCATION
KANTER PROPERTY
BROWARD COUNTY, FLORIDA

DATE: 5/16/2014	REVISED: 5/16/2014	DRAWN BY: MNB	SCALE: NTS	PROJECT NO.: 20061

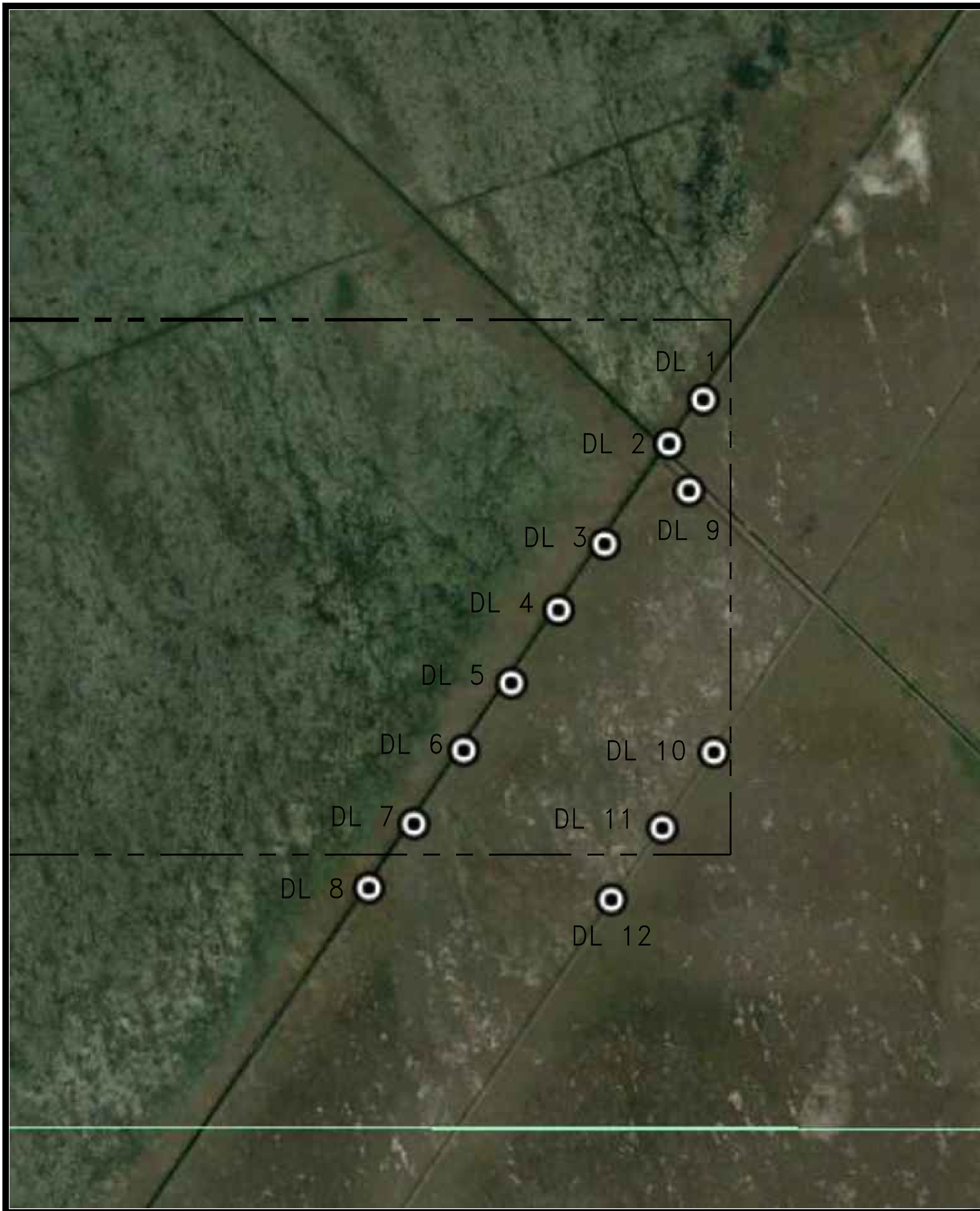


amec

AMEC Environment & Infrastructure, Inc.
2000 E. Edgewood Dr., Ste #215 Lakeland, FL 33803
Phone: 863.667.2345 Fax: 863.667.2662
www.amec.com CA-5392

FIGURE 2
PROPERTY LOCATION
KANTER PROPERTY
BROWARD COUNTY, FLORIDA

DATE: 5/16/2014	REVISED: 5/16/2014	DRAWN BY: MNO	SCALE: NTS	PROJECT NO.: 20061



amec
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Phone: 863.667.2345 Fax: 863.667.2662
www.amec.com CA-5392

FIGURE 3
DRILL LOCATION
KANTER PROPERTY
BROWARD COUNTY, FLORIDA

DATE:	REVISED:	DRAWN BY:	SCALE:	PROJECT NO.:
5/16/2014	5/16/	MNO	NTS	20061

APPENDIX A

SFWMD GENERAL PERMIT NO. 14283

SFWMD NOTICE GENERAL PERMIT NO. 14283

Rev: 9/99

(NON-ASSIGNABLE)

DATE ISSUED: **March 4, 2014**

AUTHORIZING: **TEMPORARY VEHICULAR ACCESS FOR SOIL BORINGS LOCATED WITHIN THE L-67A, L-67B AND L-67C RIGHTS OF WAY IN SPECIFIED LOCATIONS.**

LOCATED IN: **BROWARD COUNTY, SECTION 11, 14 & 22 TOWNSHIP 51S RANGE 38E**

ISSUED TO: **KANTER PROPERTIES**
712 SUNSET POINTE DRIVE
LAKE PLACID, FL 33852

Attention: CAROL ANN HOWARD

This permit is issued pursuant to Application No. **14-0225-1** dated **February 25, 2014** and permittee's agreement to hold and save the South Florida Water Management District and its successors harmless from any and all damages, claims or liabilities which may arise by reason of the construction, maintenance or use of the work or structure involved in the Permit. Said application, including all plans and specifications attached thereto, is by reference made a part hereof. The permittee, by acceptance of this permit, hereby agrees that he/she shall promptly comply with all orders of the District and shall alter, repair or remove his/her use solely at his/her expense in a timely fashion. Permittee shall comply with all laws and rules administered by the District. This permit does not convey to permittee any property rights nor any rights or privileges other than those specified herein, nor relieve the permittee from complying with any law, regulation, or requirement affecting the rights of other bodies or agencies. All structures and works installed by permittee hereunder shall remain the property of the permittee.

This permit is issued by the District as a revocable license to use or occupy District works or lands. It does not create any right or entitlement, either legal or equitable, to the continued use of the District works or lands. Since this permit conveys no right to the continued use of the District works or lands, the District is under no obligation to transfer this permit to any subsequent party. By acceptance of this permit, the permittee expressly acknowledges that the permittee bears all risk of loss as a result of revocation of this permit.

WORK PROPOSED MUST BE COMPLETED ON OR BEFORE March 31, 2015.

Otherwise, this permit is void and all rights there under are automatically canceled unless permittee applies for, in writing, a request for extension to the construction period and such request is received by the District on or before the expiration date and such request is granted, in writing, by the District.

SPECIAL CONDITIONS (SPECIFIC PROJECT CONDITIONS) AND LIMITING CONDITIONS ON ATTACHED SHEETS ARE A PART OF THIS DOCUMENT.

FILED ON March 4, 2014

BY Daniel Boyar
DEPUTY CLERK

BY: [signature]
Dan Thayer, Bureau Chief
Land Resources Bureau
South Florida Water Management District

Original Mailed to Permittee on __________ **by** __________ .

C: Keith Price
MIAMI FIELD STATION
(305) 513-3420, Extension 7106

PERMIT NO. 14283
March 4, 2014

SPECIAL CONDITIONS ARE AS FOLLOWS:

1. PRIOR TO COMMENCEMENT OF CONSTRUCTION OR UTILIZATION OF THE DISTRICT'S RIGHT OF WAY, THE PERMITTEE IS REQUIRED TO CONTACT THE DISTRICT'S FIELD REPRESENTATIVE LISTED ON THE FACE OF THIS PERMIT AND SCHEDULE A PRE-CONSTRUCTION MEETING.
2. ANY SOIL BORINGS LOCATED WITHIN 15 FEET OF THE TOE OF THE LEVEE SHALL CONFORM WITH THE GROUTING/TECHNICAL REQUIREMENTS (U.S. ARMY CORPS OF ENGINEERS PROCEDURES FOR DRILLING AND EARTH EMBANKEMENTS REGULATION NO. 1110-1-1807) ATTACHED HERETO.
3. IF STORM, HURRICANE OR EMERGENCY CIRCUMSTANCES ARE DEVELOPING, THE DISTRICT WILL ATTEMPT TO PROVIDE A FORTY-EIGHT (48) HOUR NOTICE. THE PERMITTEE WILL BE CONTACTED BY TELEPHONE OR A VISIT TO THE CONSTRUCTION SITE WHEREIN THE PERMITTEE WILL BE INFORMED OF THE EMERGENCY SITUATION. THE PERMITTEE IS PUT ON NOTICE THAT THE 48-HOUR NOTICE IS A WARNING THAT THE DISTRICT MAY OR MAY NOT BE ABLE TO PROVIDE TO THE PERMITTEE.
4. IF STORM, HURRICANE OR EMERGENCY CIRCUMSTANCES HAVE DEVELOPED, THE DISTRICT WILL CALL BY TELEPHONE OR VISIT THE SITE TO PLACE THE PERMITTEE ON A 24-HOUR ALERT. AT THIS TIME THE PERMITTEE AND THE PERMITTEE'S CONTRACTOR(S) AND SUB-CONTRACTOR(S) MUST BEGIN SECURING THE PROJECT SITE PER THE DISTRICT APPROVED CONTINGENCY PLANS.
5. IT SHOULD BE NOTED THAT THE DISTRICT'S HURRICANE, STORM EVENT AND/OR EMERGENCY ALERT MAY DIFFER FROM THE NATIONAL HURRICANE CENTER OR THE LOCAL NEWS AND WEATHER. THE DISTRICT TAKES INTO CONSIDERATION THE NUMEROUS FACTORS CONCERNING CONSTRUCTION WITHIN THE CHANNEL AND CANAL RIGHTS OF WAY. AS SUCH UPON THE DISTRICT'S NOTIFICATION TO THE PERMITTEE OF A PENDING EMERGENCY, STORM EVENT OR HURRICANE, THE PERMITTEE HAS TWENTY-FOUR (24) HOURS OR LESS TO COMPLY WITH DISTRICT ORDERS AND THE PREVIOUSLY SUBMITTED DISTRICT, APPROVED CONTINGENCY PLAN.
6. THIS TEMPORARY AUTHORIZATION IS FOR THE USE OF THE PERMITTEE AND THE PERMITTEE'S CONTRACTOR(S)/SUB-CONTRACTOR(S) ONLY.
7. THE PERMITTEE IS RESPONSIBLE FOR PROVIDING AND UTILIZING ACCEPTABLE DUST CONTROL MEASURES DURING THE DURATION OF THIS PERMIT.
8. NO VEHICULAR MAINTENANCE/REPAIR ACTIVITIES OR SUBSTANCES OR PARTS ASSOCIATED WITH THE REPAIR OR MAINTENANCE OF VEHICLES/EQUIPMENT WILL TAKE PLACE, BE USED, STORED OR DISCARDED WITHIN THE RIGHT OF WAY NOR SHALL THE DISTRICT'S RIGHT OF WAY BE USED FOR STORAGE OR PARKING OF EQUIPMENT, ASSOCIATED MACHINERY OR CONSTRUCTION TRAILERS.
9. THE PERMITTEE SHALL MAINTAIN INSURANCE COVERAGE TO THE AMOUNTS AND LIMITS SPECIFIED BY THE DISTRICT THROUGHOUT THE DURATION OF THE PERMIT AND IS RESPONSIBLE FOR PROVIDING THE DISTRICT WITH RENEWED/UPDATED CERTIFICATES REFERENCING PERMIT NUMBER 14283. INSURANCE COVERAGE WILL REMAIN IN EFFECT UNTIL SUCH TIME AS ALL ACTIVITIES WITHIN THE DISTRICT'S RIGHT OF WAY HAVE CEASED, THE RIGHT OF WAY RESTORED TO THE SATISFACTION OF THE DISTRICT AND THE PERMITTEE IS NOTIFIED BY THE DISTRICT THAT INSURANCE COVERAGE MAY BE CANCELLED.
10. THE PERMITTEE IS ADVISED THAT FAILURE TO MAINTAIN THE RIGHT OF WAY IN ACCORDANCE WITH THE TERMS AND CONDITIONS OF THE PERMIT IS GROUNDS FOR IMMEDIATE PERMIT REVOCATION.
11. THE PERMITTEE AND THE PERMITTEE'S CONTRACTORS SHALL MAINTAIN THE DISTRICT'S VEHICULAR ACCESS AT ALL TIMES THROUGHOUT THE PROJECT LIMITS. IF, IN THE PERMITTEE'S OPINION, IT WILL BE NECESSARY FOR THE DISTRICT'S VEHICULAR ACCESS TO BE BLOCKED, IMPEDED OR ALTERED AT ANY TIME, PRIOR WRITTEN PERMISSION FROM THE DISTRICT WILL BE REQUIRED. IN THIS EVENT, IT WILL BE NECESSARY FOR THE PERMITTEE TO PROVIDE A DETAILED SEQUENCE OF EVENTS OUTLINING THE ACTIVITIES THAT WILL IMPEDE THE DISTRICT'S ACCESS AND FOR WHAT PERIOD OF TIME THE DISTRICT'S ACCESS WOULD BE IMPEDED OR BLOCKED.
12. THE PERMITTEE IS HEREBY PLACED ON NOTICE THAT SUCH A REQUEST TO IMPEDE OR BLOCK THE DISTRICT'S VEHICULAR ACCESS MAY NOT BE GRANTED BY THE DISTRICT IF THE PROPOSED CLOSURE INTERFERES WITH THE DISTRICT'S OPERATION AND MAINTENANCE ACTIVITIES. THE PERMITTEE SHOULD CONTACT THE DISTRICT'S AREA FIELD REPRESENTATIVE APPEARING ON THE FACE OF THIS PERMIT REGARDING ANY PROPOSED VEHICULAR ACCESS RESTRICTIONS.
13. IT IS THE RESPONSIBILITY OF THE PERMITTEE TO MAKE PROSPECTIVE BIDDERS AWARE OF THE TERMS AND CONDITIONS OF THIS PERMIT. IT SHALL BE THE RESPONSIBILITY OF THE PERMITTEE'S CONTRACTORS TO UNDERSTAND THE TERMS AND CONDITIONS OF THIS PERMIT AND GOVERN THEMSELVES ACCORDINGLY.
14. THE PERMITTEE IS PUT ON NOTICE THAT PRIOR TO THE PLACEMENT OF ADDITIONAL FACILITIES OR ALTERATIONS TO EXISTING FACILITIES OTHER THAN THOSE AUTHORIZED BY THIS PERMIT, A MODIFICATION OF THIS PERMIT WILL FIRST BE REQUIRED.

CONTINUED SPECIAL CONDITIONS ARE AS FOLLOWS:

15. THIS PERMIT SHALL NOT BECOME VALID UNTIL ALL OTHER REQUIRED SOUTH FLORIDA WATER MANAGEMENT DISTRICT, LOCAL, COUNTY AND/OR STATE PERMITS OR OTHER AFFECTED PARTIES' APPROVALS HAVE BEEN OBTAINED. THE PERMITTEE SHALL COMPLY WITH ANY MORE STRINGENT CONDITIONS SET FORTH IN OTHER REQUIRED PERMITS AND APPROVALS.
16. A COPY OF THE PERMIT PACKAGE WILL BE KEPT AT THE JOB SITE UNTIL COMPLETION OF ALL PHASES OF CONSTRUCTION AND ACCEPTANCE OF THE CONSTRUCTED FACILITIES AND RESTORATION OF THE RIGHT OF WAY BY THE DISTRICT'S FIELD REPRESENTATIVE.
17. THE PERMITTEE SHALL BE RESPONSIBLE FOR THE REMOVAL OF ALL CONSTRUCTION MATERIALS AND DEBRIS FROM THE DISTRICT'S CANAL AND RIGHT OF WAY; AND, FOR THE REPAIR, REPLACEMENT AND RESTORATION OF ANY SECTIONS OF THE DISTRICT'S RIGHT OF WAY DAMAGED OR DISTURBED RESULTING FROM THE AUTHORIZED ACTIVITY. RESTORATION SHALL BE TO THE SATISFACTION OF THE DISTRICT AND MAY INCLUDE PLACEMENT OF FILTER FABRIC CLOTH, RIP-RAP AND/OR GRADING/RE-SHAPING, SEEDING, RE-SODDING WITH BAHIA, ARGENTINE OR OTHER SPECIES RECOGNIZED BY THE DISTRICT AS A DROUGHT TOLERANT SPECIES.
18. SHOULD THE AUTHORIZED ACTIVITIES OR PLACEMENT OF THE AUTHORIZED FACILITIES WITHIN THE DISTRICT'S RIGHT OF WAY OR MAINTENANCE OF SAME ATTRIBUTE TO SHOALING, EROSION OR WASH-OUTS OF THE DISTRICT'S RIGHT OF WAY, BERM OR SIDE SLOPE OF THE CANAL, IT IS THE PERMITTEE'S SOLE RESPONSIBILITY AND EXPENSE TO, UPON NOTIFICATION FROM THE DISTRICT, IMMEDIATELY TAKE APPROPRIATE STEPS TO RESTORE THE RIGHT OF WAY TO THE SATISFACTION OF THE DISTRICT.
19. AT NO TIME SHALL THE PERMITTEE PLACE PERMANENT OR SEMI-PERMANENT ABOVE-GROUND ENCROACHMENTS OR FACILITIES WITHIN ANY PORTION OF THE DISTRICT'S RIGHT OF WAY INCLUDING AND NOT LIMITED TO THE 40 FOOT WIDE STRIP OF LAND LYING PARALLEL TO THE CANAL AS MEASURED FROM THE TOP OF THE EXISTING CANAL BANK LANDWARD, UNLESS OTHERWISE SPECIFICALLY AUTHORIZED IN THIS PERMIT.
20. THE PERMITTEE IS PUT ON NOTICE THAT THE DISTRICT HAS NO CONTROL OVER THE SALE OR TRANSFER OF REAL OR PERSONAL PROPERTY. THEREFORE, IT IS THE SOLE OBLIGATION OF A PERMITTEE TO DISCLOSE THE EXISTENCE OF THIS RIGHT OF WAY OCCUPANCY PERMIT, INCLUDING ITS TERMS AND CONDITIONS TO PROSPECTIVE PURCHASERS. UPON CONVEYANCE OF THE PROPERTY, THE NEW OWNER MUST SUBMIT A WRITTEN REQUEST THAT THE DISTRICT TRANSFER THE PERMIT INTO HIS/HER NAME(S).
21. THIS PERMIT SHALL EXPIRE ON MARCH 31, 2015.
22. IMMEDIATELY UPON COMPLETION OF THE AUTHORIZED WORK, THE PERMITTEE SHALL CONTACT THE DISTRICT'S FIELD REPRESENTATIVE LISTED ON THE FACE OF THIS PERMIT SO THAT A FINAL INSPECTION MAY BE SCHEDULED.

END.

DEPARTMENT OF THE ARMY
U.S. Army Corps of Engineers
Washington, DC 20314-1000

CECW-CE

Regulation
No. 1110-1-1807

1 March 2006

Engineering and Design
PROCEDURES FOR DRILLING IN EARTH EMBANKMENTS

1. **Purpose.** This regulation establishes policy and requirements and provides guidance for drilling in dam and levee earth embankments and/or their earth foundations.

2. **Applicability.** This regulation applies to all major subordinate commands (MSC), district commands, laboratories and field operating activities having Civil Works and/or Military Program responsibilities. It applies to in-house and contracted efforts.

3. **References.**

a. EM 1110-1-1804 Geotechnical Investigations.

b. EM 1110-1-1906 Soil Sampling.

c. EM 1110-2-3506 Grouting Technology.

d. UFGS-02210 (August 2004) Subsurface Drilling, Sampling, and Testing.

e. ASTM D1452-80 (2000) Standard Practice for Soil Investigation and Sampling by Auger Borings.

f. ASTM D1586-99 Standard Test Method for Penetration Test and Split-Barrel Sampling of Soils.

g. ASTM D1587-00 Standard Practice for Thin-Walled Tube Sampling of Soils for Geotechnical Purposes.

4. **Distribution.** This regulation is approved for public release; distribution is unlimited.

5. **Background.** In the past, compressed air and various drilling fluids have been used as circulating media while drilling through earth embankments and their foundations. Although these methods have been used successfully in accomplishing the intended purposes, there have been many incidents of damage to embankments and foundations. While using air (including air with foam), there have been reports of loss of circulation with pneumatic fracturing of the embankment as evidenced by connections to other borings and blowouts on embankment slopes. While using water as the circulating

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This regulation supersedes ER 1110-2-1807, 30 September 1997 medium, there have been similar reports of erosion and/or hydraulic fracturing of the embankment or foundation materials.

6. **Policy.**

a. This regulation provides guidance for drilling in earth embankments and their soil and soft rock foundations. It identifies acceptable and prohibits unacceptable techniques and circulating media and prescribes personnel requirements and approved drilling methods.

b. Personnel involved in drilling into or through dam and levee earth embankments shall be senior, well qualified, and experienced in the processes and procedures outlined within this regulation. Designs shall be prepared and approved by geotechnical engineers and/or engineering geologists. Drillers and mud engineers shall be industry specialists and experts in their fields.

c. Drilling in embankments or their foundations using compressed air (including air with foam) or any other gas or water as the circulating medium is prohibited. This prohibition shall apply whether drilling is done with hired labor or with contract drilling. Further, it will apply regardless of the purpose of drilling, whether for investigations, grouting, instrumentation installation, or any other reason.

d. Auger drilling is an acceptable method for advancing a hole through an earthen embankment. If auger tools are used, either bucket, continuous flight, or hollow stem augers shall be used, and under no circumstances shall drill fluid circulation be used. Hollow stem augers may be used with Standard Penetration Test equipment.

e. Cable tool (churn) drilling and rotary drilling may also be used when auger drilling is impracticable. If the cable tool method is used, drilling tools shall be restricted to hollow sampling (drive) barrels in earth embankment and overburden materials. If rotary drilling is used, an engineered drilling fluid (or mud) shall be used. If rotary drilling with fluid is selected as the drilling method, procedures detailed in Appendix A shall be used.

f. ResonantSonic^{SM} drilling is an acceptable method for advancing a hole through an earthen embankment. If ResonantSonic^{SM} drilling is selected as the drilling method, procedures detailed in Appendix B shall be used.

g. Exemptions to or deviations from these prohibitions and requirements may be made only in special circumstances and when all other acceptable alternatives have been exhausted. Drilling through pervious rockfill or gravel sections of an embankment or foundation could be considered an appropriate instance for exemption. Granting of an exemption should not be taken lightly since inappropriate drilling has caused serious dam safety consequences. It is the responsibility of the District Dam Safety Officer (DSO) to assure compliance with the restrictions and procedures outlined in this regulation.

h. Written requests for waivers to this regulation must be submitted for approval to the DSO before beginning the work. This request shall include details of the design, drilling personnel, equipment and procedures to be used, as well as detailed descriptions and cross sections of the embankment and the foundation materials to be penetrated. The DSO shall assure that documentation for each waiver request receives an independent technical review prior to his decision to grant or reject the request. Finally, the DSO shall notify CECW-CE prior to granting any exemption or deviation from these requirements.

FOR THE COMMANDER:

JOHN R. McMAHON
Colonel, Corps of Engineers
Chief of Staff

2 Appendices
APP A - Rotary Drilling Procedures for Earth Embankments
APP B - ResonantSonic^{SM} Drilling Procedures For Earth Embankments

APPENDIX A
ROTARY DRILLING PROCEDURES FOR EARTH EMBANKMENTS

A-1. Purpose. This appendix prescribes materials and procedures to be followed when using rotary drilling equipment and methods for sampling and/or advancing a drill hole through an embankment to set casing.

A-2. Procedure.

a. Holes into or through an embankment shall be drilled with a noncoring type roller (preferred), fishtail or other suitable bit as necessary to drill a minimum 5-1/2 inch diameter hole in the embankment and overburden. Where practicable, openings or nozzles directing flow of the circulation fluid should be upward or side discharge. A commercial drilling mud shall be used as the drilling fluid. The mud shall have sufficient consistency and weight to prevent caving and minimize intrusion of the drilling mud into the embankment and overburden. Thorough washing out and removal of all cuttings during drilling is essential.

b. Upon reaching foundation rock, an NW size, 3-1/2 inch O.D. x 3 inch I.D., flush-joint casing shall be inserted in the hole and firmly seated in rock. After seating the casing, drilling mud shall be flushed from inside the casing. However, mud shall be maintained outside the casing until it is removed from the hole after backfilling. Every effort shall be made to avoid loss of circulation and embankment damage. This shall include careful control of the following:

(1) Excess drill penetration rate or down pressure may cause embankment damage. What constitutes "normal" and "excessive" drilling parameters can be expected to vary considerably from embankment to embankment and from hole to hole. Normal drilling parameters should be established during initial drilling of an embankment in a relatively clean hole.

(2) A drilling rate of not more than 5 ft penetration in five minutes should be maintained when drilling in clay. To prevent damage from clay buildup on the drill rods or balling of the bit and overloading (clogging) the annulus of the hole, the drill stem should be slowly raised and cleaned if clay buildup occurs.

(3) Surges in pumping rate or pressure should be avoided. Pump pressure and drill down-pressure readings must be continually monitored. If the pump pressure increases by 50 percent during the drilling of any 5 ft increment, the bit should be picked up slowly and the hole allowed to clean.

(4) Attempt to drill through any tight sections. Do not advance the hole by rapid raising and lowering of the drill tools. Raise or lower drill tools slowly to prevent pressure changes that cause caving.

(5) Run the pump for 15 seconds with the bit on the bottom of the hole before adding a joint of drill rod.

(6) Operate the pump at the lowest rate that will assure adequate cooling and cleaning of the bit and removal of cuttings.

A-3. Drilling Fluid Mix. The initial drilling fluid mix shall be as follows, using materials similar or equal to the Baroid industrial drilling products listed:

a. To 100 gallons of water add:

20 lbs. (one-half sack) HY-SEAL®
25 lbs. (one-half sack) MICATEX
10 lbs. (one-fifth sack) QUIK-GEL®
5 lbs. (one-fifth sack) JELFLAKE®
1 pint CON DET®

b. If severe loss of drilling fluid occurs, double the amounts of HY-SEAL®, MICATEX, and JELFLAKE®. MICA (MICATEX) is available from GEO Drilling Fluids, Inc. A mixing tub or holding tank large enough to hold an adequate quantity (at least 1.5 times the hole volume) of drilling fluid mix should be maintained on site. This will insure that the hole is filled with drilling fluid and kept open at all times.

c. The maximum allowable mud weight is 72 lbs/ft^3. Drilling mud viscosity also should be monitored continually using a Marsh funnel and should be maintained within 60 to 70 seconds. Drilling mud should be weighed every 15 minutes, adding water or new mix while drilling to maintain minimum weight (hydrostatic head and solids content), viscosity (pressure in the annulus while circulating) and filtration (filter cake restriction of the annulus). When drilling mud weight reaches 72 lbs/ft^3, stop drilling and pumping and mix a new batch of drilling mud.

d. Adjustments should be made to this initial mix during the drilling operation if problems or unfavorable results occur such as clay buildup. If significant loss of drilling fluid or other problems continue, the use of rotary drilling shall be discontinued and a new tactic developed in consultation with the DSO and CECW-CE.

A-4. Backfilling Holes.

a. After the rock section of the hole has been grouted to refusal, the casing should be pulled to approximately 3 ft above top of rock. The grout injection pipe should then be pulled to near top of rock. Backfilling of holes in overburden and/or an earthen embankment shall be accomplished by injection of grout through a tremie pipe or hose inserted to a depth below top of rock. The backfill or grout mix should be changed to an appropriate mix that approximates the properties of the undisturbed embankment. The hole should then be backfilled (grouted) to a level not to exceed approximately 50 ft above the casing bottom. The estimated quantity for backfill grout shall always be calculated before starting backfilling operations, and injection quantities shall be monitored continuously. If the estimated quantity per linear foot of hole is exceeded by a meaningful amount at any time, operations shall be halted. The casing should then be pulled to the top of the grout and the backfill allowed to set. Prescribed backfilling operations can then resume. The casing should then be slowly pulled a maximum of 15 ft above top of rock, the injection pipe pulled approximately 5 ft above top of rock, and the hole again grouted to a level not to exceed 50 ft above casing bottom.

b. The injection pipe and casing should then be withdrawn in increments not to exceed approximately 50 ft, keeping the hole filled with the backfill mix to a level not to exceed approximately 50 ft above casing bottom at all times. After the casing has been removed, the hole should be periodically checked for a period of 24 hours and kept full of backfill mix until the material has set.

c. Backfilling of holes in an embankment in which an instrument has been installed will be in accordance with prescribed procedures for that instrument, but will follow techniques and requirements as described above when practicable.

APPENDIX B
RESONANTSONIC^{SM} DRILLING PROCEDURES FOR EARTH EMBANKMENTS

B-1. Purpose. This appendix describes materials and procedures to be followed when using ResonantSonic^{SM} drilling (also known as rotary sonic drilling and sonic drilling) equipment and methods for sampling and/or advancing a drill hole through an embankment to set casing.

B-2. Procedure.

a. A ResonantSonic^{SM} drill uses high frequency mechanical oscillations, developed in the special drill head, to transmit resonant vibrations and rotary power through the specially designed drill tooling to the drill bit allowing it to achieve drilling penetration without the need for drilling fluids or air. Frequencies in the range of 50 Hz to more than 180 Hz are generated. The driller adjusts the frequency to match the natural frequency of the drill tooling, causing no dampening of the vibratory wavelength to the bit. Drill pipe acceleration rates exceeding 500g's and forces up to 200,000 lbs are efficiently transmitted to the drill bit face to create an effective cutting action. The sonic vibratory action fluidizes the soil particles, destroying the shear strength and pushing the particles away from the tip of the drill bit and along the sides of the drill string. This localized liquefaction process allows for penetration of overburden formations. The drill bit can be designed to either push all the soils into the borehole wall or modified to allow a continuous core to enter the steel pipe of the drill. Core samples can be continuously retrieved of both unconsolidated and consolidated formations with significant detail and accuracy. The core samples can be analyzed to provide a precise and detailed stratigraphic profile of any overburden condition including dry or wet saturated sands and gravels, cobbles and boulders, clays, silts and hard tills. Recovery of a sample is as consistently close to 100% as any other boring methodology. The ResonantSonic^{SM} rig utilizes a dual line of drill pipe. The inner string of drill rods has the core barrel(s) attached. All overburden core sampling is done ahead of the outer string of drill casing with no fluid or air added to insure accurate, representative, undiluted samples. After the core barrel has been advanced, the outer drill casing is advanced to the same depth. This can best be accomplished with water; however, dry casing advancement methods can also be employed. With the outer casing left in place to hold the hole open, the core barrel is then removed from the borehole. The core sample can then be extracted into plastic sleeves, stainless steel sample trays, wooden core boxes or virtually any container. The outer drill casing ensures there is no sample contamination from uphole material by sealing it off prior to each sample run. Various sample diameters can be acquired with this method; however, for drilling in embankments a minimum sample diameter of 4 inches is recommended.

b. The outer casing also serves to hold the borehole open for installation of monitoring wells, piezometers, vents, observation wells, instrumentation or other downhole equipment. The outer drill casing has nominal diameters of 6 inches and 8 inches, allowing ample space to install 2 inch and 4 inch wells with a 1 inch or 1-1/4 inch tremie pipe to place sand packs, seals, slurries and grouts into the annular space between the well screen/riser and the outer casing and borehole annulus. The drill bits used on the outer drill casing are open and are 5-7/8 inches through 8-1/2 inches in diameter, depending on borehole size requirements. Most practitioners are also capable of performing conventional sampling (ASTM D1586 and ASTM D1587) through the ResonantSonic^{SM} drill string.

B-3. Ease and Appropriateness of Use. An experienced operator is required for this method. Equipment maintenance, downtime, and mobilization costs are typically higher with ResonantSonic^{SM} drilling than with other drilling techniques; however, for deep holes in well-compacted soil, this method will usually out perform the alternatives from the standpoint of production rate, sample quality, and overall cost per foot.

B-4. Use of Drilling Fluids. Circulation of drilling fluid is not required with ResonantSonic^{SM} drilling. Water may be used for two main reasons, to facilitate penetration in very tough soil materials when the in-situ moisture content is not high enough to facilitate the shearing of the material, and to control heave in the bottom of the hole. Using water for ResonantSonic^{SM} drilling in embankments should be avoided and should only be used as a last resort to facilitate the penetration in very tough, dry material. The amount of water used for any purpose should be gravity fed to the collar of the hole. The volume of water introduced should be closely monitored and held to no more than would raise the water level in the hole to15 feet above the phreatic water level.

B-5. Limitations. When a drill bit is used, ResonantSonic^{SM} drilling forces most of the soil cuttings into the borehole wall, which may create problems for subsequent logging, in-situ permeability testing, and monitoring well performance. Based upon moderate field experience, some bottom heave and sample growth problems have been reported. The typical set-up requires two large trucks positioned end-to-end, so site access and space issues must be considered. Although smaller, modular (trailer or skid mounted) ResonantSonic^{SM} drills are available with limited capabilities.

B-6. Backfilling Holes. The backfilling procedures described in paragraph A-4 Backfilling Holes shall also apply to holes drilled with the ResonantSonic^{SM} technique.

40E-6.381. Limiting Conditions.

The District's authorization to utilize lands and other works constitutes a revocable license (including both notice general permits and standard permits). In consideration for receipt of that license, Permittees shall agree to be bound by the following standard limiting conditions, which shall be included within all permits issued pursuant to this chapter:

(1) All structures on District works for lands constructed by Permittee shall remain the property of Permittee, who shall be solely responsible for ensuring that such structures and other uses remain in good and safe condition. Permittees are advised that other federal, state and local safety standards may govern the occupancy and use of the District's lands and works. The District assumes no duty with regard to ensuring that such uses are so maintained and assumes no liability with regard to injuries caused to others by any such failure.

(2) Permittee solely acknowledges and accepts the duty and all associated responsibilities to incorporate safety features, which meet applicable engineering practice and accepted industry standards, into the design, construction, operation and continued maintenance of the permitted facilities/authorized use. This duty shall include, but not be limited to, Permittee's consideration of the District's regulation and potential fluctuation, without notice, of water levels in canals and works, as well as the Permittee's consideration of upgrades and modifications to the permitted facilities/authorized use which may be necessary to meet any future changes to applicable engineering practice and accepted industry standards. Permittee acknowledges that the District's review and issuance of this permit, including, but not limited to, any field inspections performed by the District, does not in any way consider or ensure that the permitted facilities/authorized use is planned, designed, engineered, constructed, or will be operated, maintained or modified so as to meet applicable engineering practice and accepted industry standards, or otherwise provide any safety protections. Permittee further acknowledges that any inquiries, discussions, or representations, whether verbal or written, by or with any District staff or representative during the permit review and issuance process, including, but not limited to, any field inspections, shall not in any way be relied upon by Permittee as the District's assumption of any duty to incorporate safety features, as set forth above, and shall also not be relied upon by Permittee in order to meet Permittee's duty to incorporate safety features, as set forth above.

(3) Permittee agrees to abide by all of the terms and conditions of this permit, including any representations made on the permit application and related documents. This permit shall be subject to the requirements of Chapter 373, F.S., and Chapter 40E-6, F.A.C., including all subsequent rule and criteria revisions. Permittee agrees to pay all removal and restoration costs, investigative costs, court costs and reasonable attorney's fees, including appeals, resulting from any action taken by the District to obtain compliance with the conditions of the permit or removal of the permitted use. If District legal action is taken by staff counsel, "reasonable attorney's fees" is understood to mean the fair market value of the services provided, based upon what a private attorney would charge.

(4) This permit does not create any vested rights, and except for governmental entities and utilities, is revocable at will upon reasonable prior written notice. Permittee bears all risk of loss as to monies expended in furtherance of the permitted use. Upon revocation, the Permittee shall promptly modify, relocate or remove the permitted use and properly restore the right of way to the District's satisfaction. In the event of failure to so comply within the specified time, the District may remove the permitted use and Permittee shall be responsible for all removal and restoration costs.

(5) This permit does not convey any property rights nor any rights or privileges other than those specified herein and this permit shall not, in any way, be construed as an abandonment or any other such impairment or disposition of the District's property rights. The District approves the permitted use only to the extent of its interest in the works of the District. Permittee shall obtain all other necessary federal, state, local, special district and private authorizations prior to the start of any construction or alteration authorized by the permit. Permittee shall comply with any more stringent conditions or provisions which may be set forth in other required permits or other authorizations. The District, however, assumes no duty to ensure that any such authorizations have been obtained or to protect the legal rights of the underlying fee owner, in those instances where the District owns less than fee.

(6) Unless specifically prohibited or limited by statute, Permittee agrees to indemnify, defend and save the District (which used herein includes the District and its past, present and/or future employees, agents, representatives, officers and/or Governing Board members and any of their successors and assigns) from and against any and all lawsuits, actions, claims, demands, losses, expenses, costs, attorneys fees (including but not limited to the fair market value of the District's in-house attorneys' fees based upon private attorneys' fees/rates), judgments and liabilities which arise from or may be related to the ownership, construction, maintenance or operation of the permitted use or the possession, utilization, maintenance, occupancy or ingress and egress of the District's right of way which arise directly or indirectly and are caused in whole or in part by the acts, omissions or negligence of the Permittee or of third parties. Permittee agrees to provide legal counsel acceptable to the District if requested for the defense of any such claims.

(7) The District does not waive sovereign immunity in any respect.

(8) The Permittee shall not engage in any activity regarding the permitted use which interferes with the construction, alteration, maintenance or operation of the works of the District, including:

(a) discharge of debris or aquatic weeds into the works of the District;
(b) causing erosion or shoaling within the works of the District;
(c) planting trees or shrubs or erecting structures which limit or prohibit access by District equipment and vehicles, except as may be authorized by the permit. Permittee shall be responsible for any costs incurred by the District resulting from any such interference, as set forth in (a), (b), and (c), above.
(d) leaving construction or other debris on the District's right of way or waterway;
(e) damaging District berms and levees;
(f) the removal of District owned spoil material;
(g) removal of or damage to District locks, gates, and fencing;
(h) opening of District rights of way to unauthorized vehicular access; or
(i) running or allowing livestock on the District's right of way.

(9) The District is not responsible for any personal injury or property damage which may directly or indirectly result from the use of water from the District's canal or any activities which may include use or contact with water from the District's canal, since the District periodically sprays its canals for aquatic weed control purposes and uses substances which may be harmful to human health or plant life.

(10) Permittee shall allow the District to inspect the permitted use at any reasonable time.

(11) Permittee shall allow, without charge or any interference, the District, its employees, agents, and contractors, to utilize the permitted facilities before, during and after construction for the purpose of conducting the District's, routine and emergency, canal operation, maintenance,

and construction activities. To the extent there is any conflicting use, the District's use shall have priority over the Permittee's use.

(12) This permit is a non-exclusive revocable license. Permittee shall not interfere with any other existing or future permitted uses or facilities authorized by the District.

(13) The District has the right to change, regulate, limit, schedule, or suspend discharges into, or withdrawals from, works of the District in accordance with criteria established by the Big Cypress Basin, the District, or the U.S. Army Corps of Engineers for the works of the District.

(14) If the use involves the construction of facilities for a non exempt water withdrawal or surface water discharge, the applicant must apply for and obtain a water use or surface water management permit before or concurrently with any activities which may be conducted pursuant to the right of way occupancy permit.

(15) The District shall notify the local ad valorem taxing authority of the lands affected by the permitted use, where the Permittee owns the underlying fee and derives a substantial benefit from the permitted use. The taxing authority may reinstate such lands on the tax roll. Failure to pay all taxes in a timely manner shall result in permit revocation. Such permit revocation shall not alleviate the responsibility of the Permittee to pay all taxes due and payable.

(16) Permittee shall provide prior written notice to their successors in title of the permit and its terms and conditions.

(17) Permittee authorizes the District to record a Notice of Permit through filing the appropriate notice in the public records of the county or counties where the project is. Governmental entities and utilities are not subject to this provision.

(18) Permittee shall be responsible for the repair or replacement of any existing facilities located within the District's right of way which are damaged as a result of the installation or maintenance of the authorized facility.

(19) All obligations under the terms of this permit authorization and any subsequent modifications hereto shall be joint and several as to all owners.

(20) It is the responsibility of the Permittee to make prospective bidders aware of the terms and conditions of this permit. It shall be the responsibility of the Permittee's contractors to understand the terms and conditions of this permit and govern themselves accordingly.

(21) It is the responsibility of the Permittee to bring to the attention of the District any conflict in the permit authorization or permit conditions in order that they may be resolved prior to the start of construction. In resolving such conflicts the District's determination will be final.

(22) Special Conditions that are site specific shall be incorporated into every Permit as may be necessary in the best interest of the District.

(23) The District is not responsible for the repair of or claims of damage to any facilities and uses which may incur damage resulting from the District's utilization of its rights of way or use by third parties. Improvements placed within the right of way are done so at the sole risk of the owner.

Rulemaking Authority 373.044, 373.113 FS. Law Implemented 373.085(1), 373.086, 373.103, 373.109, 373.129, 373.1395, 373.603, 373.609, 373.613 FS. History--New 9-3-81, Formerly 16K-5.01(2), 16K-5.02(2), 16K-5.03(2), 16K-5.04(4), 16K-5.05, Amended 5-30-82, 12-29-86, 12-24- 91, 9-15-99, 8-12-13.

NOTICE OF RIGHTS

As required by Sections 120.569(1), and 120.60(3), Fla. Stat., following is notice of the opportunities which may be available for administrative hearing or judicial review when the substantial interests of a party are determined by an agency. Please note that this Notice of Rights is not intended to provide legal advice. Not all the legal proceedings detailed below may be an applicable or appropriate remedy. You may wish to consult an attorney regarding your legal rights.

RIGHT TO REQUEST ADMINISTRATIVE HEARING

A person whose substantial interests are or may be affected by the South Florida Water Management District's (SFWMD or District) action has the right to request an administrative hearing on that action pursuant to Sections 120.569 and 120.57, Fla. Stat. Persons seeking a hearing on a District decision which does or may determine their substantial interests shall file a petition for hearing with the District Clerk within 21 days of receipt of written notice of the decision, unless one of the following shorter time periods apply: 1) within 14 days of the notice of consolidated intent to grant or deny concurrently reviewed applications for environmental resource permits and use of sovereign submerged lands pursuant to Section 373.427, Fla. Stat.; or 2) within 14 days of service of an Administrative Order pursuant to Subsection 373.119(1), Fla. Stat. "Receipt of written notice of agency decision" means receipt of either written notice through mail, or electronic mail, or posting that the District has or intends to take final agency action, or publication of notice that the District has or intends to take final agency action. Any person who receives written notice of a SFWMD decision and fails to file a written request for hearing within the timeframe described above waives the right to request a hearing on that decision.

Filing Instructions

The Petition must be filed with the Office of the District Clerk of the SFWMD. Filings with the District Clerk may be made by mail, hand-delivery or facsimile. **Filings by e-mail will not be accepted.** Any person wishing to receive a clerked copy with the date and time stamped must provide an additional copy. A petition for administrative hearing is deemed filed upon receipt during normal business hours by the District Clerk at SFWMD headquarters in West Palm Beach, Florida. Any document received by the office of the SFWMD Clerk after 5:00 p.m. shall be filed as of 8:00 a.m. on the next regular business day. Additional filing instructions are as follows:

- Filings by mail must be addressed to the Office of the SFWMD Clerk, P.O. Box 24680, West Palm Beach, Florida 33416.
- Filings by hand-delivery must be delivered to the Office of the SFWMD Clerk. **Delivery of a petition to the SFWMD's security desk does not constitute filing. To ensure proper filing, it will be necessary to request the SFWMD's security officer to contact the Clerk's office.** An employee of the SFWMD's Clerk's office will receive and file the petition.
- Filings by facsimile must be transmitted to the SFWMD Clerk's Office at (561) 682-6010. Pursuant to Subsections 28-106.104(7), (8) and (9), Fla. Admin. Code, a party who files a document by facsimile represents that the original physically signed document will be retained by that party for the duration of that proceeding and of any subsequent appeal or subsequent proceeding in that cause. Any party who elects to file any document by facsimile shall be responsible for any delay, disruption, or interruption of the electronic signals and accepts the full risk that the document may not be properly filed with the clerk as a result. The filing date for a document filed by facsimile shall be the date the SFWMD Clerk receives the complete document.

Initiation of an Administrative Hearing

Pursuant to Rules 28-106.201 and 28-106.301, Fla. Admin. Code, initiation of an administrative hearing shall be made by written petition to the SFWMD in legible form and on 8 and 1/2 by 11 inch white paper. All petitions shall contain:

1. Identification of the action being contested, including the permit number, application number, District file number or any other SFWMD identification number, if known.
2. The name, address and telephone number of the petitioner and petitioner's representative, if any.
3. An explanation of how the petitioner's substantial interests will be affected by the agency determination.
4. A statement of when and how the petitioner received notice of the SFWMD's decision.
5. A statement of all disputed issues of material fact. If there are none, the petition must so indicate.
6. A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the SFWMD's proposed action.
7. A statement of the specific rules or statutes the petitioner contends require reversal or modification of the SFWMD's proposed action.
8. If disputed issues of material fact exist, the statement must also include an explanation of how the alleged facts relate to the specific rules or statutes.
9. A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the SFWMD to take with respect to the SFWMD's proposed action.

A person may file a request for an extension of time for filing a petition. The SFWMD may, for good cause, grant the request. Requests for extension of time must be filed with the SFWMD prior to the deadline for filing a petition for hearing. Such requests for extension shall contain a certificate that the moving party has consulted with all other parties concerning the extension and that the SFWMD and any other parties agree to or oppose the extension. A timely request for extension of time shall toll the running of the time period for filing a petition until the request is acted upon.

If the District takes action with substantially different impacts on water resources from the notice of intended agency decision, the persons who may be substantially affected shall have an additional point of entry pursuant to Rule 28-106.111, Fla. Admin. Code, unless otherwise provided by law.

Mediation

The procedures for pursuing mediation are set forth in Section 120.573, Fla. Stat., and Rules 28-106.111 and 28-106.401-.405, Fla. Admin. Code. The SFWMD is not proposing mediation for this agency action under Section 120.573, Fla. Stat., at this time.

RIGHT TO SEEK JUDICIAL REVIEW

Pursuant to Sections 120.60(3) and 120.68, Fla. Stat., a party who is adversely affected by final SFWMD action may seek judicial review of the SFWMD's final decision by filing a notice of appeal pursuant to Florida Rule of Appellate Procedure 9.110 in the Fourth District Court of Appeal or in the appellate district where a party resides and filing a second copy of the notice with the SFWMD Clerk within 30 days of rendering of the final SFWMD action.

SOUTH FLORIDA WATER MANAGEMENT DISTRICT

Dear Permittee:

Subject: Issuance of a Right of Way Occupancy Permit

Enclosed please find the Right of Way Occupancy Permit issued pursuant to application for permit.

Your attention is directed to review all of the terms, Limiting Conditions, Special Conditions and drawings contained in the Right of Way Occupancy Permit. Please note that this Permit shall not become valid until all other required permits/approvals are obtained from the South Florida Water Management District; U.S. Army Corps of Engineers; other local, county and/or state agencies; or other affected parties. The Permittee understands and shall comply with any more stringent conditions set forth in other required permits and approvals.

In particular, please note that as local and regional water management needs change, District rights of way may need to be restored or otherwise changed to meet these needs. As a result, facilities authorized by Right of Way Occupancy Permits may be subject to future removal pursuant to Limiting Conditions (3) and (4).

In the event you object to the terms, Limiting or Special Conditions, please refer to the enclosed "Notice of Rights" which addresses the procedures you must follow should you desire a public hearing or other review of the agency action. If an objection is not filed as specified in the "Notice of Rights", prior to construction of the authorized facilities or engaging in the authorized uses, then in addition to waiving important legal administrative rights, you will be deemed to have concurred with the District's terms, Limiting and Special Conditions.

Please contact this office should you have any questions or require assistance on this matter.

I HEREBY CERTIFY that a "Notice of Rights" has been furnished by U.S. Mail to the Permittee.

Jorge R. Patino, Section Administrator
Right of Way Section
Land Resources Bureau

/cr
Enclosures

Application to the South Florida Water Management District for Issuance of a Right of Way Occupancy Permit

RECEIVED
FEB 25 2014
RIGHT OF WAY DIVISION

Post Office Box 24680, West Palm Beach, FL 33416-4680
Telephone (561) 686-8800 FL WATS Line 1-800-432-2045
Attention: Right of Way Permitting

Application No. 14-0225-1-

Permittee/Owner(s) Full Name (include all Permittee/Owner(s) if applicable) Kanter Properties				
Email Address choward@thecarolgroupinc.com				
Street Address 712 Sunset Pointe Drive	City Lake Placid	State FL	ZIP 33852	Telephone No. 9416620184
Agents' Name (if applicable) Carol Ann Howard				
Email Address choward@thecarolgroupinc.com				
Street Address 712 Sunset Pointe Drive	City Lake Placid	State FL	ZIP 33852	Telephone No. 9416620184

REQUESTED USE

- ☒ New Permit
- ☐ Modification of Existing Permit (Permit Number) ____________
- ☐ Proposed ☐ Existing ☐ Both

LOCATION OF PROJECT
(Note: Copy of recent property/boundary survey and aerial map of property tied to a well-known landmark must be provided)

Work or Land (canal or levee) Involved L-67A, L-67C, Miami Canal		County Broward	Section 11,14,22, 23,26,27	Township 51 South	Range 38 East
Lot No.	Block No.	Subdivision Name			

DESCRIPTION OF PROJECT
(Note: Check all uses/facilities that apply)

- ☐ Bridge
- ☐ Fencing
- ☒ Other (include description below)
- ☐ Bulkhead/Seawall
- ☐ Landscaping
- ☐ Culvert
- ☒ Temporary Use (access/storage)
- ☐ Dock
- ☐ Utility Installation

Conduct soil borings at up to twelve locations. Utilize levee road ways to access locations, utilize existing levee access ramps for access to soil boring site.

40E-6.381 LIMITING CONDITIONS

The District's authorization to utilize lands and other works constitutes a revocable license (including both notice general permits and standard permits). In consideration for receipt of that license, permittees shall agree to be bound by the following standard limiting conditions, which shall be included within all permits issued pursuant to this chapter:

1) All structures on District works or lands constructed by permittee shall remain the property of permittee, who shall be solely responsible for ensuring that such structures and other uses remain in good and safe condition. Permittees are advised that other federal, state and local safety standards may govern the occupancy and use of the District's lands and works. The District assumes no duty with regard to ensuring that such uses are so maintained and assumes no liability with regard to injuries caused to others by any such failure.

2) Permittee solely acknowledges and accepts the duty and all associated responsibilities to incorporate safety features, which meet applicable engineering practice and accepted industry standards, into the design, construction, operation and continued maintenance of the permitted facilities/authorized use. This duty shall include, but not be limited to, permittee's consideration of the District's regulation and potential fluctuation, without notice, of water levels in canals and works, as well as the permittee's consideration of upgrades and modifications to the permitted facilities/authorized use which may be necessary to meet any future changes to applicable engineering practice and accepted industry standards. Permittee acknowledges that the District's review and issuance of this permit, including, but not limited to, any field inspections performed by the District, does not in any way consider or ensure that the permitted facilities/authorized use is planned, designed, engineered, constructed, or will be operated, maintained or modified so as to meet applicable engineering practice and accepted industry standards, or otherwise provide any safety protections. Permittee further acknowledges that any inquiries, discussions, or representations, whether verbal or written, by or with any District staff or representative during the permit review and issuance process, including, but not limited to, any field inspections, shall not in any way be relied upon by permittee as the District's assumption of any duty to incorporate safety features, as set forth above, and shall also not be relied upon by permittee in order to meet permittee's duty to incorporate safety features, as set forth above.

3) Permittee agrees to abide by all of the terms and conditions of this permit, including any representations made on the permit application and related documents. This permit shall be subject to the requirements of Chapter 373, F.S., and Chapter 40E-6, F.A.C., including all subsequent rule and criteria revisions. Permittee agrees to pay all removal and restoration costs, investigative costs, court costs and reasonable attorney's fees, including appeals, resulting from any action taken by the District to obtain compliance with the conditions of the permit or removal of the permitted use. If District legal action is taken by staff counsel, "reasonable attorney's fees" is understood to mean the fair market value of the services provided, based upon what a private attorney would charge.

4) This permit does not create any vested rights, and except for governmental entities and utilities, is revocable at will upon reasonable prior written notice. Permittee bears all risk of loss as to monies expended in furtherance of the permitted use. Upon revocation, the permittee shall promptly modify, relocate or remove the permitted use and properly restore the right of way to the District's satisfaction. In the event of failure to so comply within the specified time, the District may remove the permitted use and permittee shall be responsible for all removal and restoration costs.

5) This permit does not convey any property rights nor any rights or privileges other than those specified herein and this permit shall not, in any way, be construed as an abandonment or any other such impairment or disposition of the District's property rights. The District approves the permitted use only to the extent of its interest in the works of the District. Permittee shall obtain all other necessary federal, state, local, special district and private authorizations prior to the start of any construction or alteration authorized by the permit. Permittee shall comply with any more stringent conditions or provisions which may be set forth in other required permits or other authorizations. The District, however, assumes no duty to ensure that any such authorizations have been obtained or to protect the legal rights of the underlying fee owner, in those instances where the District owns less than fee.

6) Unless specifically prohibited or limited by statute, Permittee agrees to indemnify, defend and save the District (which used herein includes the District and its past, present and/or future employees, agents, representatives, officers and/or Governing Board members and any of their successors and assigns) from and against any and all lawsuits, actions, claims, demands, losses, expenses, costs, attorneys fees (including but not limited to the fair market value of the District's in-house attorneys' fees based upon private attorneys' fees/rates), judgments and liabilities which arise from or may be related to the ownership, construction, maintenance or operation of the permitted use or the possession, utilization, maintenance, occupancy or ingress and egress of the District's right of way which arise directly or indirectly and are caused in whole or in part by the acts, omissions or negligence of the Permittee or of third parties. Permittee agrees to provide legal counsel acceptable to the District if requested for the defense of any such claims.

7) The District does not waive sovereign immunity in any respect.

8) The permittee shall not engage in any activity regarding the permitted use which interferes with the construction, alteration, maintenance or operation of the works of the District, including:

a) discharge of debris or aquatic weeds into the works of the District;

b) causing erosion or shoaling within the works of the District;

c) planting trees or shrubs or erecting structures which limit or prohibit access by District equipment and vehicles, except as may be authorized by the permit. Permittee shall be responsible for any costs incurred by the District resulting from any such interference, as set forth in (a), (b), and (c), above.

Permittee shall be responsible for any costs incurred by the District resulting from any such interference, as set forth in a), b), and c), above;

d) leaving construction or other debris on the District's right of way or waterway;

e) damaging District berms and levees;

f) the removal of District owned spoil material;
g) removal of or damage to District locks, gates, and fencing;
h) opening of District rights of way to unauthorized vehicular access; or
i) running or allowing livestock on the District's right of way.

9) The District is not responsible for any personal injury or property damage which may directly or indirectly result from the use of water from the District's canal or any activities which may include use or contact with water from the District's canal, since the District periodically sprays its canals for aquatic weed control purposes and uses substances which may be harmful to human health or plant life.

10) Permittee shall allow the District to inspect the permitted use at any reasonable time.

11) Permittee shall allow, without charge or any interference, the District, its employees, agents, and contractors, to utilize the permitted facilities before, during and after construction for the purpose of conducting the District's, routine and emergency, canal operation, maintenance, and construction activities. To the extent there is any conflicting use, the District's use shall have priority over the permittee's use.

12) This permit is a non-exclusive revocable license. Permittee shall not interfere with any other existing or future permitted uses or facilities authorized by the District.

13) The District has the right to change, regulate, limit, schedule, or suspend discharges into, or withdrawals from, works of the District in accordance with criteria established by the Big Cypress Basin, the District, or the U. S. Army Corps of Engineers for the works of the District.

14) If the use involves the construction of facilities for a non exempt water withdrawal or surface water discharge, the applicant must apply for and obtain a water use or surface water management permit before or concurrently with any activities which may be conducted pursuant to the right of way occupancy permit.

15) The District shall notify the local ad valorem taxing authority of the lands affected by the permitted use, where the permittee owns the underlying fee and derives a substantial benefit from the permitted use. The taxing authority may reinstate such lands on the tax roll. Failure to pay all taxes in a timely manner shall result in permit revocation. Such permit revocation shall not alleviate the responsibility of the permittee to pay all taxes due and payable.

16) Permittee shall provide prior written notice to their successors in title of the permit and its terms and conditions.

17) Permittee authorizes the District to record a Notice of Permit through filing the appropriate notice in the public records of the county or counties where the project is located. Governmental entities and utilities are not subject to this provision.

18) Permittee shall be responsible for the repair or replacement of any existing facilities located within the District's right of way which are damaged as a result of the installation or maintenance of the authorized facility.

19) All obligations under the terms of this permit authorization and any subsequent modifications hereto shall be joint and several as to all owners.

20) It is the responsibility of the permittee to make prospective bidders aware of the terms and conditions of this permit. It shall be the responsibility of the permittee's contractors to understand the terms and conditions of this permit and govern themselves accordingly.

21) It is the responsibility of the permittee to bring to the attention of the District any conflict in the permit authorization or permit conditions in order that they may be resolved prior to the start of construction. In resolving such conflicts the District's determination will be final.

22) Special Conditions that are site specific shall be incorporated into every permit as may be necessary in the best interest of the District.

23) The District is not responsible for the repair of or claims of damage to any facilities and uses which may incur damage resulting from the District's utilization of its rights of way or use by third parties. Improvements placed within the right of way are done so at the sole risk of the owner.

Rulemaking Authority 373.044, 373.113 FS. Law Implemented 373.085(1), 373.086, 373.103, 373.109, 373.129, 373.1395, 373.603, 373.609, 373.613 FS. History—New 9-3-81, Formerly 16K-5.01(2), 16K-5.02(2), 16K-5.03(2), 16K-5.04(4), 16K-5.05, Amended 5-30-82, 12-29-86, 12-24-91, 9-15-99

In compliance with provisions of Chapter 373, Florida Statutes and Chapter 40E-6, Florida Administrative Code, application is hereby made for a Right of Way Occupancy Permit in accordance with support drawings, data and incidental information filed with this application and made a part of this application. I hereby certify that all information contained in or made a part hereof is true and correct to the best of my knowledge, that any permit issued shall require that the permitted use be constructed and operated in accordance with such information.

I further certify that I have read the Standard Limiting Conditions appearing on this application and understand that said conditions will be incorporated within any permit issued pursuant to the application, unless expressly waived by the Governing Board. I further acknowledge that the SFWMD may incorporate additional special conditions as may be necessary in the best interest of the District.

In signing this application, I acknowledge that failure to comply with all conditions of this permit may result in permit revocation, financial assurance or bond forfeiture, and remedial action against me by the SFWMD. I assume full responsibility for the actions of all my employees, agents and persons, whether under direct contractual obligation to me or indirectly, with respect to compliance with the conditions and limitations contained within this application or within a permit issued as a result of this application.

NOTE: Either Permittee/Owner – or – Agent can sign

Permittee/Owner's Name (print or type)	Permittee/Owner's Name (sign)	Date
CAROL ANN HOWARD	Carol Ann Howard	2-20-2014
Agent Name (print or type)	Agent Name (sign)	Date

Please be sure the following accompany the submittal of your application:

Application Processing Fee (if applicable)

8 ½" x 11" Drawings describing the use or facilities

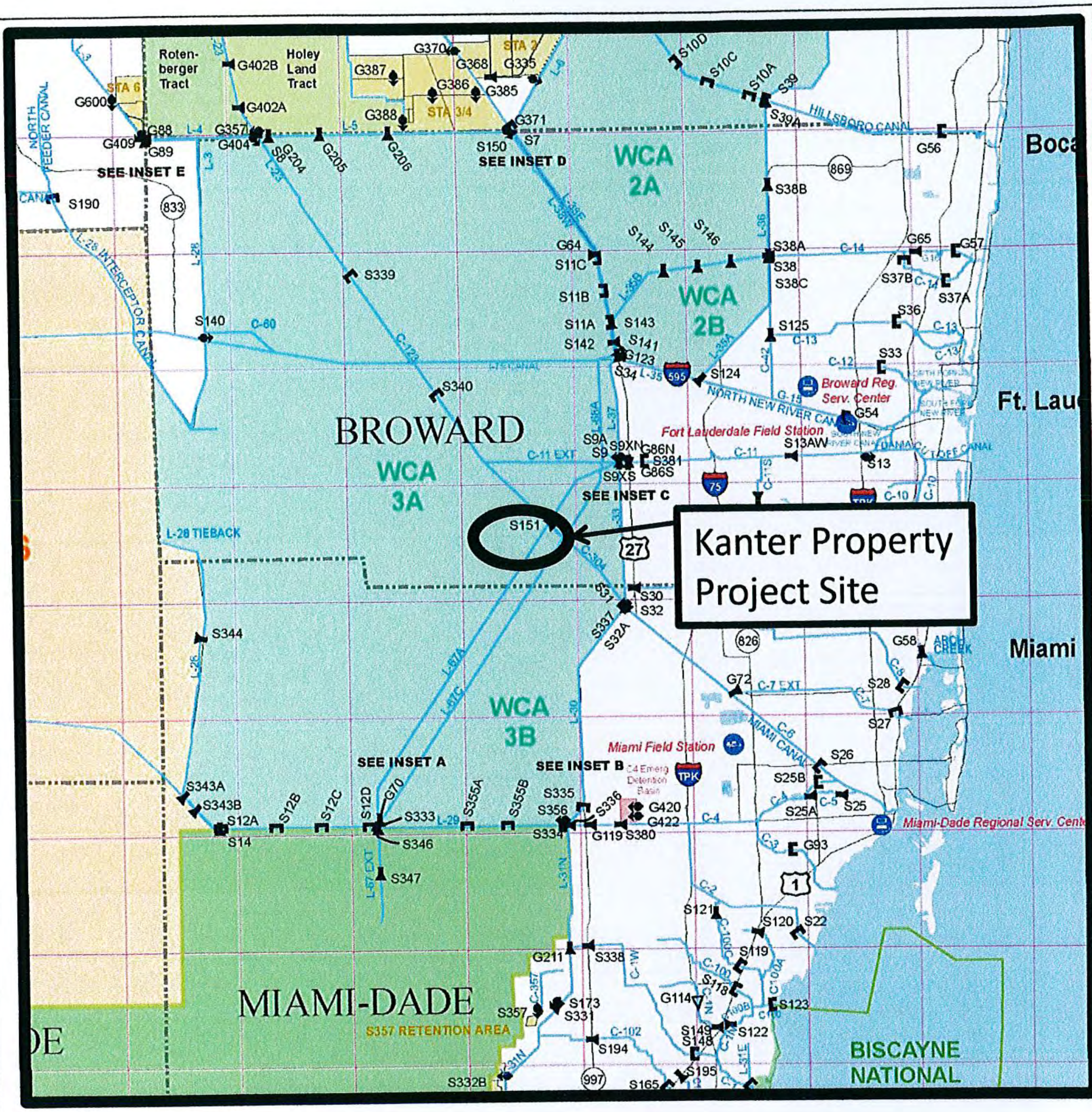
All other information as outlined in the Criteria Manual

Submit the original application package and 3 duplicates

RECEIVED
FEB 25 2014
RIGHT OF WAY DIVISION

RECEIVED
FEB 25 2014
RIGHT OF WAY DIVISION

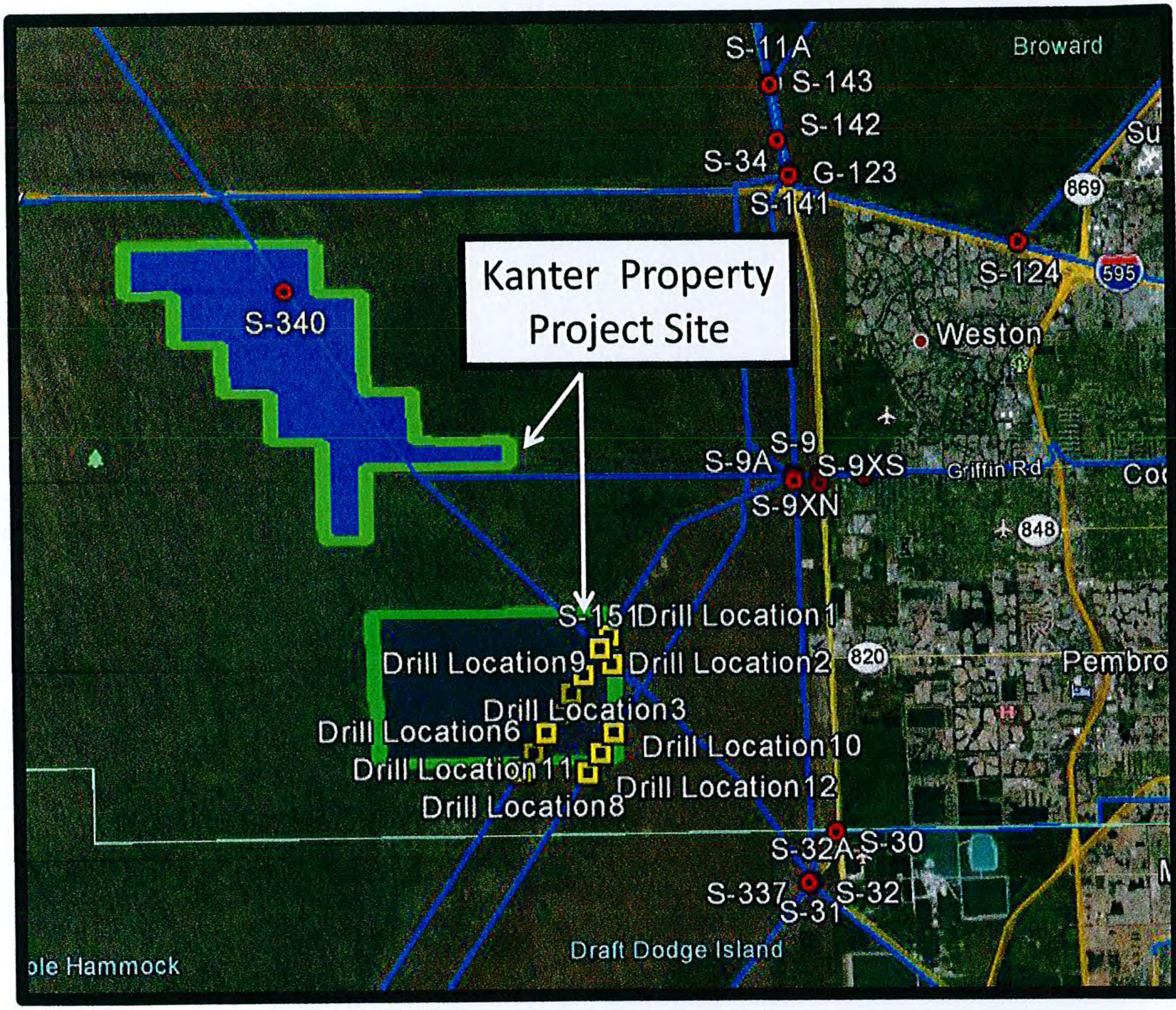
14-0225-1-



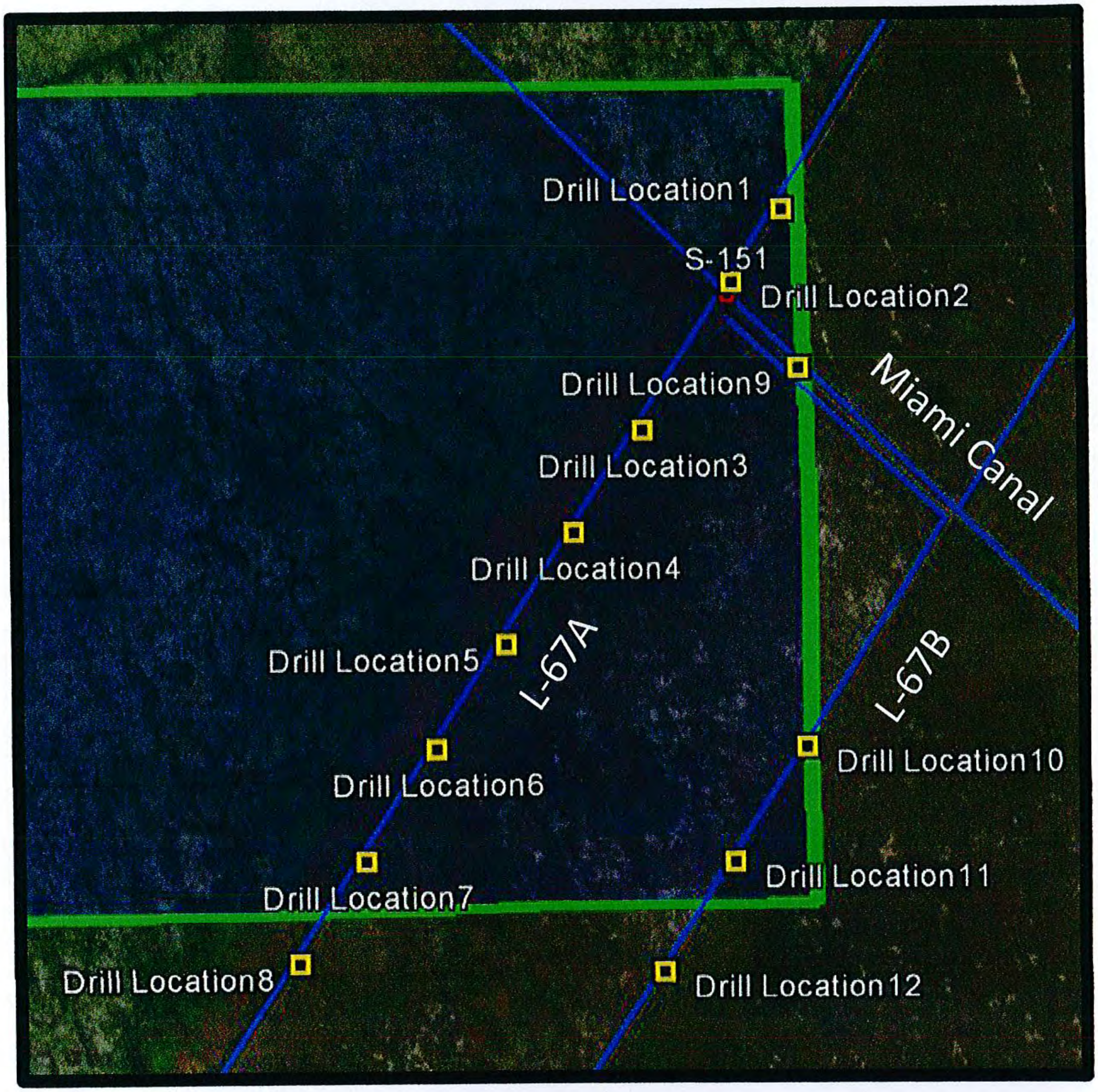
RECEIVED
FEB 25 2014
RIGHT OF WAY DIVISION

14-0225-1-

SHEET NUMBER	DATE Feb 19, 2014	Kanter Property	THE CAROL GROUP
Loc Map	PROJECT NO.		Professional Engineers and Surveyors
	FILE NO.	Broward County, FL	712 SUNSET POINTE DRIVE LAKE PLACID, FL 33852 (239) 243-4044
	SCALE		



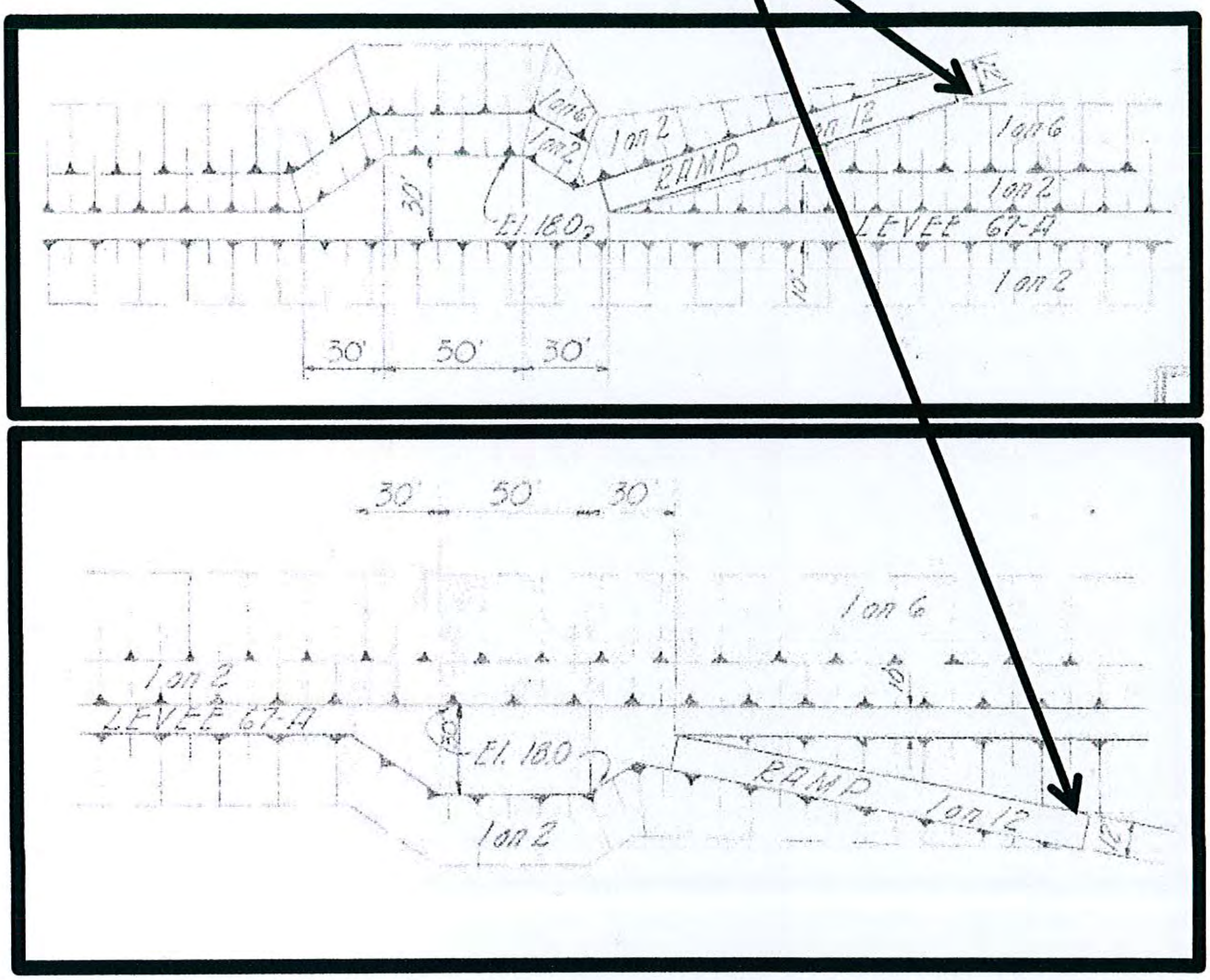
SHEET NUMBER	DATE Feb 19, 2014	Kanter Property	THE CAROL GROUP
Vic Map	PROJECT NO.	Broward County, FL	*Professional Engineers and Surveyors*
	FILE NO.		712 SUNSET POINTE DRIVE LAKE PLACID, FL 33852 (239) 243-4644
	SCALE		



Soil Boring Sites
Located at Existing Levee Ramps

SHEET NUMBER	DATE: Feb 19, 2014	**Kanter Property** **Soil Boring Locations** **Broward County, FL**	THE CAROL GROUP *Professional Engineers and Surveyors* 712 SUNSET POINTE DRIVE LAKE PLACID, FL 33852 (239) 243-4044
C.1	PROJECT NO. FILE NO. SCALE		

Soil Boring to be taken at lower end of Levee Access Ramp



Typical Ramp Details
L-67A and L-67C

SHEET NUMBER	DATE Feb 19, 2014	Kanter Property	THE CAROL GROUP
C.2	PROJECT NO.		Professional Engineers and Surveyors
	FILE NO.		712 SUNSET POINTE DRIVE
	SCALE	Broward County, FL	LAKE PLACID, FL 33852
			(239) 243-4044

Soil Boring to be taken at lower end of Levee Access Ramp at these locations

DRILL ID	LATITUDE	LONGITUDE
Drill Location1	26.01592481	-80.50646892
Drill Location2	26.01235505	-80.50953964
Drill Location3	26.00425881	-80.51533157
Drill Location4	25.99892684	-80.51946598
Drill Location5	25.99302295	-80.52370227
Drill Location6	25.98759733	-80.52798042
Drill Location7	25.98165757	-80.53246193
Drill Location8	25.97647549	-80.53650318
Drill Location9	26.00857265	-80.50775616
Drill Location10	25.98744059	-80.505513
Drill Location11	25.98132445	-80.51014995
Drill Location12	25.97554114	-80.51472966

SHEET NUMBER			
C.3	DATE Feb 19, 2014 PROJECT NO. FILE NO. SCALE	**Kanter Property Soil Boring Sites Broward County, FL**	THE CAROL GROUP *Professional Engineers and Surveyors* 712 SUNSET POINTE DRIVE LAKE PLACID, FL 33852 (239) 243-4644

CERTIFICATE OF LIABILITY INSURANCE

DATE (MM/DD/YYYY): 2/20/2014

THIS CERTIFICATE IS ISSUED AS A MATTER OF INFORMATION ONLY AND CONFERS NO RIGHTS UPON THE CERTIFICATE HOLDER. THIS CERTIFICATE DOES NOT AFFIRMATIVELY OR NEGATIVELY AMEND, EXTEND OR ALTER THE COVERAGE AFFORDED BY THE POLICIES BELOW. THIS CERTIFICATE OF INSURANCE DOES NOT CONSTITUTE A CONTRACT BETWEEN THE ISSUING INSURER(S), AUTHORIZED REPRESENTATIVE OR PRODUCER, AND THE CERTIFICATE HOLDER.

IMPORTANT: If the certificate holder is an ADDITIONAL INSURED, the policy(ies) must be endorsed. If SUBROGATION IS WAIVED, subject to the terms and conditions of the policy, certain policies may require an endorsement. A statement on this certificate does not confer rights to the certificate holder in lieu of such endorsement(s).

PRODUCER	CONTACT NAME: Lauren Adami	
Greyling Insurance Brokerage 450 Northridge Parkway Suite 102 Atlanta GA 30350	PHONE (A/C, No, Ext): (770) 552-4225	FAX (A/C, No): (866) 550-4082
	E-MAIL ADDRESS: jerry.noyola@greyling.com	
	INSURER(S) AFFORDING COVERAGE	NAIC #
	INSURER A: Sentinel Insurance Company, LTD	11000
INSURED	INSURER B: Hartford Casualty Insurance	29424
The Carol Group Inc. 712 Sunset Pointe Drive Lake Placid FL 33852	INSURER C: RLI Insurance Company	13056
	INSURER D:	
	INSURER E:	
	INSURER F:	

COVERAGES CERTIFICATE NUMBER: 13-14 REVISION NUMBER:

THIS IS TO CERTIFY THAT THE POLICIES OF INSURANCE LISTED BELOW HAVE BEEN ISSUED TO THE INSURED NAMED ABOVE FOR THE POLICY PERIOD INDICATED. NOTWITHSTANDING ANY REQUIREMENT, TERM OR CONDITION OF ANY CONTRACT OR OTHER DOCUMENT WITH RESPECT TO WHICH THIS CERTIFICATE MAY BE ISSUED OR MAY PERTAIN, THE INSURANCE AFFORDED BY THE POLICIES DESCRIBED HEREIN IS SUBJECT TO ALL THE TERMS, EXCLUSIONS AND CONDITIONS OF SUCH POLICIES. LIMITS SHOWN MAY HAVE BEEN REDUCED BY PAID CLAIMS.

INSR LTR	TYPE OF INSURANCE	ADDL INSR	SUBR WVD	POLICY NUMBER	POLICY EFF (MM/DD/YYYY)	POLICY EXP (MM/DD/YYYY)	LIMITS	
A	GENERAL LIABILITY X COMMERCIAL GENERAL LIABILITY CLAIMS-MADE X OCCUR GEN'L AGGREGATE LIMIT APPLIES PER: POLICY X PRO-JECT LOC			20SBAAF7385	11/21/2013	11/21/2014	EACH OCCURRENCE	$ 1,000,000
							DAMAGE TO RENTED PREMISES (Ea occurrence)	$ 1,000,000
							MED EXP (Any one person)	$ 10,000
							PERSONAL & ADV INJURY	$ 1,000,000
							GENERAL AGGREGATE	$ 2,000,000
							PRODUCTS - COMP/OP AGG	$ 2,000,000
								$
A	AUTOMOBILE LIABILITY ANY AUTO ALL OWNED AUTOS SCHEDULED AUTOS X HIRED AUTOS X NON-OWNED AUTOS			20SBAAF7385	11/21/2013	11/21/2014	COMBINED SINGLE LIMIT (Ea accident)	$ 1,000,000
							BODILY INJURY (Per person)	$
							BODILY INJURY (Per accident)	$
							PROPERTY DAMAGE (Per accident)	$
								$
A	X UMBRELLA LIAB X OCCUR EXCESS LIAB CLAIMS-MADE DED X RETENTION $ 10,000			20SBAAF7385	11/21/2013	11/21/2014	EACH OCCURRENCE	$ 1,000,000
							AGGREGATE	$ 1,000,000
								$
B	WORKERS COMPENSATION AND EMPLOYERS' LIABILITY Y/N ANY PROPRIETOR/PARTNER/EXECUTIVE OFFICER/MEMBER EXCLUDED? (Mandatory in NH) If yes, describe under DESCRIPTION OF OPERATIONS below	N/A		20WECAG8591	11/21/2013	11/21/2014	X WC STATU-TORY LIMITS OTH-ER	
							E.L. EACH ACCIDENT	$ 1,000,000
							E.L. DISEASE - EA EMPLOYEE	$ 1,000,000
							E.L. DISEASE - POLICY LIMIT	$ 1,000,000
C	Professional Liability incl. Pollution Liability			RDP0012775	11/21/2013	11/21/2014	Per Claim	$1,000,000
							Aggregate	$2,000,000

DESCRIPTION OF OPERATIONS / LOCATIONS / VEHICLES (Attach ACORD 101, Additional Remarks Schedule, if more space is required)

South Florida Water Management District is named as an Additional Insured with respects to General Liability where required by written contract.

RECEIVED
FEB 25 2014
RIGHT OF WAY DIVISION

14-0225-1-

CERTIFICATE HOLDER	CANCELLATION
South Florida Water Management District	SHOULD ANY OF THE ABOVE DESCRIBED POLICIES BE CANCELLED BEFORE THE EXPIRATION DATE THEREOF, NOTICE WILL BE DELIVERED IN ACCORDANCE WITH THE POLICY PROVISIONS.
	AUTHORIZED REPRESENTATIVE David Collings/JERRY *David H. Collings*

ACORD 25 (2010/05)
INS025 (201005).01

APPENDIX B

BORING LOGS

Project No: 20061
Project: Kanter Property
Address: Levee L-67A
City, State: Weston, Florida

Log of Boring: DL-1

Client: The Carol Group, Inc.
Geologist/Engineer: Gary E. Kihn, P.G.
Compiled by: Gary E. Kihn, P.G.

Depth	Symbol	SOIL DESCRIPTION	Sample #	Blow Counts	N-value	LAB TEST RESULTS / REMARKS
0		Gravel fill for levee	1		100%	
10		Peat/muck with sandy marl, black	2		100%	
15		Limestone, light gray (2.5Y, 7/2), oolitic, fossiliferous, massive, hard	3		100%	Fort Thompson Formation (Qf)
20		Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard	4		100%	
25			5		100%	
30			6		100%	
35			7		100%	
40			8		100%	
45		Limestone with silty sand, light gray (2.5Y, 7/2), fossiliferous	9		50%	
50		Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard	10		100%	
55			11		100%	
60			12		100%	

Drilled by: Cascade Drilling, L.P.
Drill Method: Sonic
Drill Date: April 16, 2014, 0900 - 1300
Borehole Location: N26° 0' 57.33", W80° 30' 23.29"
Borehole Size: 6"

WR = Weight of Rod
WH = Weight of Hammer
R = Penetration Refusal
Datum:
Sheet: 1 of 2

MC = % moisture content
-#200 = % passing #200 sieve
OC = % organic content
LL = liquid limit
PI = plasticity index

Project No: 20061
Project: Kanter Property
Address: Levee L-67A
City, State: Weston, Florida

Log of Boring: DL-1

Client: The Carol Group, Inc.
Geologist/Engineer: Gary E. Kihn, P.G.
Compiled by: Gary E. Kihn, P.G.

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Depth	Symbol	SOIL DESCRIPTION	Sample #	Blow Counts	N-value	LAB TEST RESULTS / REMARKS
65		Limestone with silty sand, light gray (2.5Y, 7/2), fossiliferous	13		100%	
		Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard				
70			14		100%	
75		Sandy Clay, greenish gray (GLEY1, 5/10Y), abundant shells	15		100%	Tamiami Formation (Tt)
80		Limestone, gray (GLEY1, 6/N), fossiliferous, massive, very hard	16		100%	
85			17		100%	
		Sandy Clay, greenish gray (GLEY1, 5/10Y), abundant shells				
90			18		100%	
95			19		100%	
100			20		100%	
		Limestone, gray (GLEY1, 6/N), fossiliferous, massive, very hard				
105			21		100%	
		End of boring				
110						
115						
120						

Drilled by: Cascade Drilling, L.P.
Drill Method: Sonic
Drill Date: April 16, 2014, 0900 - 1300
Borehole Location: N26° 0' 57.33", W80° 30' 23.29"
Borehole Size: 6"

WR = Weight of Rod
WH = Weight of Hammer
R = Penetration Refusal
Datum:
Sheet: 2 of 2

MC = % moisture content
-#200 = % passing #200 sieve
OC = % organic content
LL = liquid limit
PI = plasticity index

Project No: 20061
Project: Kanter Property
Address: Levee L-67A
City, State: Weston, Florida

Log of Boring: DL-3

Client: The Carol Group, Inc.
Geologist/Engineer: Gary E. Kihn, P.G.
Compiled by: Gary E. Kihn, P.G.

amec

Depth	Symbol	SOIL DESCRIPTION	Sample #	Blow Counts	N-value	LAB TEST RESULTS / REMARKS
0		Gravel fill for levee				
5			1		100%	
10		Peat/muck with sandy marl, black	2		100%	
15		Limestone, light gray (2.5Y, 7/2), oolitic, fossiliferous, massive, hard	3		100%	Fort Thompson Formation (Qf)
20		Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard	4		100%	
25			5		100%	
30			6		100%	
35			7		100%	
40			8		100%	
		Limestone with silty sand, light gray (2.5Y, 7/2), fossiliferous				
45		Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard	9		100%	
50			10		100%	
55			11		100%	
60			12		100%	

Drilled by: Cascade Drilling, L.P.
Drill Method: Sonic
Drill Date: April 16, 2014, 1345 - 1745
Borehole Location: N26° 0' 15.33", W80° 30' 55.20"
Borehole Size: 6"

WR = Weight of Rod
WH = Weight of Hammer
R = Penetration Refusal
Datum:
Sheet: 1 of 2

MC = % moisture content
-#200 = % passing #200 sieve
OC = % organic content
LL = liquid limit
PI = plasticity index

Project No: 20061
Project: Kanter Property
Address: Levee L-67A
City, State: Weston, Florida

Log of Boring: DL-3

Client: The Carol Group, Inc.
Geologist/Engineer: Gary E. Kihn, P.G.
Compiled by: Gary E. Kihn, P.G

amec

Depth	Symbol	SOIL DESCRIPTION	Sample #	Blow Counts	N-value	LAB TEST RESULTS / REMARKS
65		Limestone with silty sand, light gray (2.5Y, 7/2), fossiliferous	13		100%	
70		Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard	14		100%	
75			15		100%	
80		Sandy Clay, greenish gray (GLEY1, 5/10Y), abundant shells	16		100%	Tamiami Formation (Tt)
85		Limestone, gray (GLEY1, 6/N), fossiliferous, massive, very hard	17		100%	
90		Sandy Clay, greenish gray (GLEY1, 5/10Y), abundant shells	18		100%	
95			19		100%	
100		End of boring				
105						
110						
115						
120						

Drilled by: Cascade Drilling, L.P.
Drill Method: Sonic
Drill Date: April 16, 2014, 1345 - 1745
Borehole Location: N26° 0' 15.33", W80° 30' 55.20"
Borehole Size: 6"

WR = Weight of Rod
WH = Weight of Hammer
R = Penetration Refusal
Datum:
Sheet: 2 of 2

MC = % moisture content
-#200 = % passing #200 sieve
OC = % organic content
LL = liquid limit
PI = plasticity index

Project No: 20061
Project: Kanter Property
Address: Levee L-67A
City, State: Weston, Florida

Log of Boring: DL-5

Client: The Carol Group, Inc.
Geologist/Engineer: Gary E. Kihn, P.G.
Compiled by: Gary E. Kihn, P.G.

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Depth	Symbol	SOIL DESCRIPTION	Sample #	Blow Counts	N-value	LAB TEST RESULTS / REMARKS
0		Gravel fill for levee				
5			1		100%	
10		Peat/muck with sandy marl, black	2		100%	
15		Limestone, light gray (2.5Y, 7/2), oolitic, fossiliferous, massive, hard	3		100%	Fort Thompson Formation (Qf)
20		Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard	4		100%	
25			5		100%	
30			6		100%	
35			7		100%	
40		Limestone with silty sand, light gray (2.5Y, 7/2), fossiliferous	8		100%	
45		Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard	9		100%	
50			10		100%	
55			11		100%	
60			12		100%	

Drilled by: Cascade Drilling, L.P.
Drill Method: Sonic
Drill Date: April 17, 2014, 0800 - 1145
Borehole Location: N25° 59' 34.88", W80° 31' 25.33"
Borehole Size: 6"

WR = Weight of Rod
WH = Weight of Hammer
R = Penetration Refusal
Datum:
Sheet 1 of 2

MC = % moisture content
-#200 = % passing #200 sieve
OC = % organic content
LL = liquid limit
PI = plasticity index

Project No: 20061
Project: Kanter Property
Address: Levee L-67A
City, State: Weston, Florida

Log of Boring: DL-5

Client: The Carol Group, Inc.
Geologist/Engineer: Gary E. Kihn, P.G.
Compiled by: Gary E. Kihn, P.G.

Depth	Symbol	SOIL DESCRIPTION	Sample #	Blow Counts	N-value	LAB TEST RESULTS / REMARKS
		Limestone with silty sand, light gray (2.5Y, 7/2), fossiliferous				
65		Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard	13		100%	
70		Sandy Clay, greenish gray (GLEY1, 5/10Y), abundant shells	14		100%	Tamiami Formation (Tt)
75			15		100%	
80		Limestone, gray (GLEY1, 6/N), fossiliferous, massive, very hard	16		100%	
85			17		100%	
		End of boring				
90						
95						
100						
105						
110						
115						
120						

Drilled by: Cascade Drilling, L.P.
Drill Method: Sonic
Drill Date: April 17, 2014, 0800 - 1145
Borehole Location: N25° 59' 34.88", W80° 31' 25.33"
Borehole Size: 6"

WR = Weight of Rod
WH = Weight of Hammer
R = Penetration Refusal
Datum:
Sheet: 2 of 2

MC = % moisture content
-#200 = % passing #200 sieve
OC = % organic content
LL = liquid limit
PI = plasticity index

Project No: 20061
Project: Kanter Property
Address: Levee L-67A
City, State: Weston, Florida

Log of Boring: DL-7

Client: The Carol Group, Inc.
Geologist/Engineer: Gary E. Kihn, P.G.
Compiled by: Gary E. Kihn, P.G.

Depth	SOIL DESCRIPTION	Sample #	Blow Counts	N-value	LAB TEST RESULTS / REMARKS
0	Gravel fill for levee	1		100%	
5		2		100%	
10	Peat/muck with sandy marl, black				
15	Limestone, light gray (2.5Y, 7/2), oolitic, fossiliferous, massive, hard	3		100%	Fort Thompson Formation (Qf)
20	Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard	4		100%	
25		5		100%	
30		6		100%	
35		7		100%	
40	Limestone with silty sand, light gray (2.5Y, 7/2), fossiliferous	8		100%	
	Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard				
45		9		100%	
50		10		100%	
55		11		100%	
60		12		100%	

Drilled by: Cascade Drilling, L.P.
Drill Method: Sonic
Drill Date: April 17, 2014, 1200 - 1545
Borehole Location: N25° 58' 53.97", W80° 31' 56.86"
Borehole Size: 6"

WR = Weight of Rod
WH = Weight of Hammer
R = Penetration Refusal
Datum:
Sheet: 1

MC = % moisture content
-#200 = % passing #200 sieve
OC = % organic content
LL = liquid limit
PI = plasticity index

Project No: 20061
Project: Kanter Property
Address: Levee L-67A
City, State: Weston, Florida

Log of Boring: DL-7

Client: The Carol Group, Inc.
Geologist/Engineer: Gary E. Kihn, P.G.
Compiled by: Gary E. Kihn, P.G.

Depth	Symbol	SOIL DESCRIPTION	Sample #	Blow Counts	N-value	LAB TEST RESULTS / REMARKS
65			13		100%	
70		Silty Sand, light gray (2.5Y, 7/2), with limestone fragments	14		100%	Tamiami Formation (Tt)
75			15		100%	
80–85			16		0%	
90–120		End of boring				

Drilled by: Cascade Drilling, L.P.
Drill Method: Sonic
Drill Date: April 17, 2014, 1200 - 1545
Borehole Location: N25° 58' 53.97", W80° 31' 56.86"
Borehole Size: 6"

WR = Weight of Rod
WH = Weight of Hammer
R = Penetration Refusal
Datum:
Sheet 2 of 2

MC = % moisture content
-#200 = % passing #200 sieve
OC = % organic content
LL = liquid limit
PI = plasticity index

Project No: 20061
Project: Kanter Property
Address: Miami Canal
City, State: Weston, Florida

Log of Boring: DL-9

Client: The Carol Group, Inc.
Geologist/Engineer: Gary E. Kihn, P.G.
Compiled by: Gary E. Kihn, P.G.

Depth	Symbol	SOIL DESCRIPTION	Sample #	Blow Counts	N-value	LAB TEST RESULTS / REMARKS
0–7		Gravel fill for levee	1		100%	
7–10		Peat/muck with sandy marl, black	2		100%	Fort Thompson Formation (Qf)
10–15		Limestone, light gray (2.5Y, 7/2), oolitic, fossiliferous, massive, hard	3		100%	
15–41		Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard	4		100%	
			5		100%	
			6		100%	
			7		100%	
			8		100%	
41–44		Limestone with silty sand, light gray (2.5Y, 7/2), fossiliferous	9		100%	
44–60		Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard	10		100%	
			11		100%	
			12		100%	

Drilled by: Cascade Drilling, L.P.
Drill Method: Sonic
Drill Date: April 17, 2014 (1600) - April 18, 2014 (0845)
Borehole Location: N26° 0' 30.86", W80° 30' 36.54"
Borehole Size: 6"

WR = Weight of Rod
WH = Weight of Hammer
R = Penetration Refusal
Datum:
Sheet 1 of 1

MC = % moisture content
-#200 = % passing #200 sieve
OC = % organic content
LL = liquid limit
PI = plasticity index

Project No: 20061
Project: Kanter Property
Address: Miami Canal
City, State: Weston, Florida

Log of Boring: DL-9

Client: The Carol Group, Inc.
Geologist/Engineer: Gary E. Kihn, P.G.
Compiled by: Gary E. Kihn, P.G.

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Depth	Symbol	SOIL DESCRIPTION	Sample #	Blow Counts	N-value	LAB TEST RESULTS / REMARKS
		Limestone with silty sand, light gray (2.5Y, 7/2), fossiliferous	13		100%	
65		Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard				
70			14		100%	
75		Sandy Clay, greenish gray (GLEY1, 5/10Y), abundant shells	15		100%	Tamiami Formation (Tt)
80		Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard	16		100%	
		Sandy Clay, greenish gray (GLEY1, 5/10Y), abundant shells				
85			17		100%	
		End of boring				
90						
95						
100						
105						
110						
115						
120						

Drilled by: Cascade Drilling, L.P.
Drill Method: Sonic
Drill Date: April 17, 2014 (1600) - April 18, 2014 (0845)
Borehole Location: N26° 0' 30.86", W80° 30' 36.54"
Borehole Size: 6"

WR = Weight of Rod
WH = Weight of Hammer
R = Penetration Refusal
Datum:

MC = % moisture content
-#200 = % passing #200 sieve
OC = % organic content
LL = liquid limit
PI = plasticity index

Project No: 20061
Project: Kanter Property
Address: Levee L-67C
City, State: Weston, Florida

Log of Boring: DL-11

Client: The Carol Group, Inc.
Geologist/Engineer: Gary E. Kihn, P.G.
Compiled by: Gary E. Kihn, P.G.

Depth	Symbol	SOIL DESCRIPTION	Sample #	Blow Counts	N-value	LAB TEST RESULTS / REMARKS
0		Gravel fill for levee				
5			1		100%	
10		Peat/muck with sandy marl, black	2		100%	
15		Limestone, light gray (2.5Y, 7/2), oolitic, fossiliferous, massive, hard	3		100%	Fort Thompson Formation (Qf)
20		Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard	4		100%	
25			5		100%	
30			6		100%	
35			7		100%	
40		Limestone with silty sand, light gray (2/5Y, 7/2), fossiliferous	8		100%	
		Limestone, light gray (2.5Y, 7/2), fossiliferous, massive, hard				
45			9		100%	
50			10		100%	
55			11		100%	
60			12		100%	

Drilled by: Cascade Drilling, L.P.
Drill Method: Sonic
Drill Date: April 18, 2014, 0900 - 1230
Borehole Location: N25° 58' 52.77", W80° 30' 36.54"
Borehole Size: 6"

WR = Weight of Rod
WH = Weight of Hammer
R = Penetration Refusal
Datum:
Sheet: 1 of 2

MC = % moisture content
-#200 = % passing #200 sieve
OC = % organic content
LL = liquid limit
PI = plasticity index

Project No: 20061
Project: Kanter Property
Address: Levee L-67C
City, State: Weston, Florida

Log of Boring: DL-11

Client: The Carol Group, Inc.
Geologist/Engineer: Gary E. Kihn, P.G.
Compiled by: Gary E. Kihn, P.G.

Depth	Symbol	SOIL DESCRIPTION	Sample #	Blow Counts	N-value	LAB TEST RESULTS / REMARKS
65			13		100%	
70			14		100%	
75		Silty Sand, gray (GLEY1, 6/N), with limestone fragments	15		100%	Tamiami Formation (Tt)
80			16		100%	
		Limestone, gray (GLEY1, 6/N), fossiliferous, massive, very hard				
85		Sand, gray (GLEY1, 6/N), medium grained	17		100%	
		End of boring				
90						
95						
100						
105						
110						
115						
120						

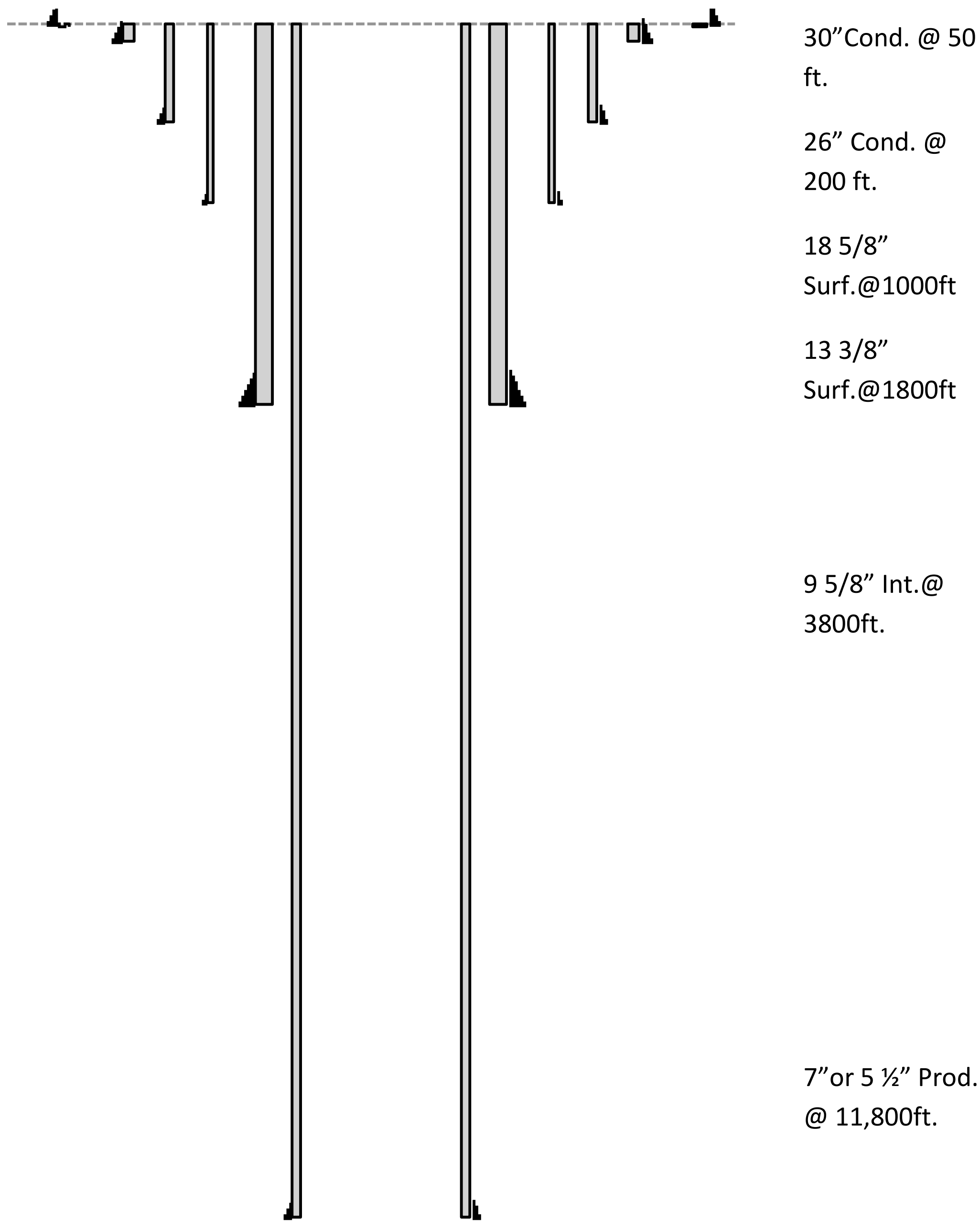
Drilled by: Cascade Drilling, L.P.
Drill Method: Sonic
Drill Date: April 18, 2014, 0900 - 1230
Borehole Location: N25° 58' 52.77", W80° 30' 36.54"
Borehole Size: 6"

WR = Weight of Rod
WH = Weight of Hammer
R = Penetration Refusal
Datum:
Sheet 2 of 2

MC = % moisture content
-#200 = % passing #200 sieve
OC = % organic content
LL = liquid limit
PI = plasticity index

Attachment 2(c) Wellbore Schematic and Revised Drilling Procedure

Received by Florida DEP 8/18/2016


30”Cond. @ 50 ft.
26” Cond. @ 200 ft.
18 5/8” Surf.@1000ft
13 3/8” Surf.@1800ft
9 5/8” Int.@ 3800ft.
7”or 5 ½” Prod. @ 11,800ft.

Permit # 1366
Kanter Sunniland 23-2
Century Oil Co., Inc.
Drilling Procedure
Broward County, Florida

Revised 8/4/16

DRILLING PROCEDURE

1. MIRU PDC Rig #3
2. NU on 30" conductor pipe.
3. Drill 17 ½" pilot hole to 100 ft.
4. Drive 26" .625 wall conductor to 200 ft.
5. Drill 23" hole to 1000 ft. TOH Run 18 5/8" 87.5#/ft. J55 casing. Cement to surf. Per recommendation. WOC 8 Hours.

6. Drill with 17 ½" rock bit, 9" drill collars, 6" drill collars, and 4 1/2" HWDP. Drill down to 1800' while running both pumps @ 95 spm for a combined flow rate of 600 to 800 gpm. Weight on bit from 5k-25k at a rotary speed of 60-100 rpm.

7. At 1800' sweep hole and circulate clean. POOH Run USDW log. Trip back in to 1800'. Circulate & condition mud at POOH.

8. RU casing crew, tools & stabbing board. PU and run Float shoe, one joint of 13 3/8", 54.5# J55 BT&C of casing, Float Collar, and 13 3/8", 54.5# J55 BT&C casing down to 1800'. Note: centralize w/bow springs 6' above FS, and one per joint latched over the next three casing collars.

9. Circulate & condition mud for 1 ½ casing volumes. Mix & pump cement per recommendation. Pump LEAD cement until cement is seen at surface and immediately switch over to TAIL cement. Displace TAIL cement with fresh water. Note: When cement gets to surface divert cement to open top tank.

10. After displacement, Top Off annulus with 50sx. of TAIL cement. If cement falls or fails to circulate, notify FDEP in Fort Myers.

11. Make rough cut/final cut on conductor & casing. Weld on 13 3/8" SOW x 13 3/8" 3M C-22 wellhead. Test well head to 1000#.

12. NU Annular BOP. Test annular preventer to 1000# (High)/200#(Low). Test all floor valves, IBOP, & mud lines back to mud pumps to 3000# (High)/250#(Low).

13. RIH w/ 12 ¼" bit and slick BHA to top of cement.

14. Pressure test casing to 1000#. Drill out float collar, cement, and float shoe.

15. Drill new hole from 1800' – 2100' with both pumps for a combined flowrate of 500-800 gpm. Vary bit weight from 5k-35k at a rotary speed of 80 rpm. POOH for button bit to drill Boulder Zone cap & Boulder Zone.

16. RIH w 12 ¼" button bit drill though Boulder Zone (2100'-3500') with lost returns. Take surveys every 500'.

17. POOH & LD 9" D.C.

18. RU casing crew with tools & stabbing board. RIH w/FS, 1 jt. 9 5/8" 47#, L-80 of casing, FC, & 9 5/8" 47#, L-80 casing down to 3800'.

19. RU cement crew, cement plug container, & iron. Mix & pump cement per recommendation. Reciprocate to casing 15' and displace cement with mud. Bump plug 500# over differential pressure. Bleed back to check floats. RD cementers.

20. ND flowlines & turn buckles. RU stack lift. Break bolts @ wellhead & spacer spool. Pick up BOP's & set casing slips. Make rough cut on casing & remove spacer spool & DSA. Make final cut on casing & NU 13 5/8", 3M x 11", 5M, C-22 casing spool. Finish NU "B" section. Set BOP's & RD stack lift. NU BOP's.

21. Test "B" section flange & pack off to 2000#. Test all rams, choke manifold, & related valves to 3000# (High)/250# (Low). Test annular preventer to 1000# (High)/250# (Low). Test all floor valves, IBOP, & mud lines back to mud pumps to 3000#(High) /250# (Low).

22. RIH w/8 ½" PDC bit, 6" DC;s, & 5" DP's down to top of cement. Test casing to 1500#. Drill out FC, cement, & FS. Drill 10' of new hole & circulate bottoms up until clean. Test casing shoe to 10.5# EMW.

23. Drill down through Sunniland. Take surveys every 500'. Make frequent wiper trips every 30 hrs or however the hole dictates. Drill to 11,800' (TD) & POOH.

24. RU Well Loggers & RIH and log well per Geologist recommendations.

25. Upon evaluation, either run production casing and cement or P&A as per FDEP.

26. RD & Move out.

Attachment 3 Casing and Cementing Plan

Kanter 23-2 Casing and Cementing Details

Rev. 8/5/16

30" .625 wall Conductor driven to 200 ft. or refusal, anticipate refusal @ 50-60 ft.

17 1/2" Pilot hole drilled to 100-150 ft.
26" .625 wall Conductor driven to 200 ft. through pilot hole

23" Hole drilled to 1000 ft.
18 5/8" 87.5# J 55 ST&C casing set @ 1000 ft.
Cemented with 441 sx. Lead cem. & 410 sx. Tail cem. + 200 sx. top off

17 1/2" Hole drilled to 1800 ft.
13 3/8" 54.5# J 55 ST&C casing set @ 1800 ft.
Cemented with 200 sx. Lead cem. & 200 sx. Tail cem. + 200 sx. top off

12 1/4" Hole drilled to 3800 ft.
9 5/8" 47# L 80 LT&C casing set @ 3800 ft.
Cemented with 200 sx. Lead cem. & 200 sx. Tail cem.

8 1/2" Hole drilled to 11,800 ft. (TD)
5 1/2" 17# L 80 LT&C or 7" 29# L 80 LT&C casing run to 11,800 ft.
Cemented with 150 sx. Lead cem. & 400 sx. Tail cem.

Attachment 4(a) USGS Documents

Received by Florida DEP 8/18/2016

Chapter 1

Assessment of Undiscovered Oil and Gas in the Onshore and State Waters Portion of the South Florida Basin, Florida—USGS Province 50

***Click here to return to* Volume Title Page**

By Richard M. Pollastro, Christopher J. Schenk *and* Ronald R. Charpentier

National Assessment of Oil and Gas Project:

Petroleum Systems and Assessment of the South Florida Basin

Compiled by Richard M. Pollastro *and* Christopher J. Schenk

U.S. Geological Survey Digital Data Series 69-A

Supersedes U.S. Geological Survey Open-File Report 00-317

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U.S. Geological Survey

U.S. Department of the Interior
Gale A. Norton, Secretary

U.S. Geological Survey
Charles G. Groat, Director

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Assessment of Undiscovered Oil and Gas in the Onshore and State Waters Portion of the South Florida Basin, Florida—USGS Province 50

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Abstract

Low-gravity, high-sulfur oils are produced from the Lower Cretaceous Sunniland Formation in 10 active fields in the South Florida Basin, Florida. Cumulative production in these 10 fields through 1997 was greater than 106 million barrels of oil (MMBO). Oil is sourced mainly from cyclic, organic-rich carbonate units within the Sunniland Formation and was probably generated at low thermal maturity because of the nature of the marine algal kerogen. Interbedded, porous shelf limestones and dolomites form the primary reservoirs, and cyclic evaporites throughout the section provide excellent seals. At depths in excess of 15,000 ft, two wells along the Sunniland trend have recorded gas and condensate shows and provide evidence for gas potential in the Upper Jurassic(?) and Lower Cretaceous Wood River Formation.

Two stacked total petroleum systems, each with a single assessment unit, are recognized for the South Florida Basin. The two petroleum systems are separated stratigraphically by a major regional evaporite seal, the Lower Cretaceous Punta Gorda Anhydrite. The younger petroleum system and corresponding assessment unit above the Punta Gorda seal is designated as the South Florida Basin Sunniland–Dollar Bay total petroleum system (TPS) and Lower Cretaceous Shoal-Reef Oil assessment unit (AU). The second system below the regional anhydrite seal is the South Florida Basin Pre-Punta Gorda TPS and Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU. The two assessment units are correlative to the oil and gas plays defined for the 1995 USGS assessment (Gautier and others, 1995).

Offshore, in the basin's depocenter, source rocks of the Sunniland–Dollar Bay TPS generated low-gravity oils during the Paleocene-Eocene and are presently in the main oil generation window; onshore, however, modeling indicates that organic matter in beds of the Sunniland Formation have generated and expelled only 20 percent of the oil. In the onshore and offshore State waters of the South Florida Basin, the mean total undiscovered volume of petroleum resource in the Lower Cretaceous Shoal-Reef Oil AU is estimated at 279 million barrels of oil equivalent (MMBOE), of which 272 MMBO is oil in oil fields. In contrast, nonassociated gas comprises 258 MMBOE (1,545 billion cubic feet of gas or BCFG) of the 423 MMBOE of mean undiscovered resource volume estimated for the Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU of the Pre-Punta Gorda TPS. The geology and field-size distributions of plays of the Upper Jurassic Smackover Formation were used as analogs for evaluating the hypothetical Pre-Punta Gorda AU. Undiscovered gas volume of the Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU is attributed mainly to deep dolomite, and possible pinch-out, basal clastic reservoirs within the Upper Jurassic(?) and Lower Cretaceous Wood River Formation that were sourced by intraformational, organic-rich carbonate beds.

Introduction

In 1995, the USGS completed an assessment of undiscovered oil and gas resources for onshore portions and State waters of the United States (Gautier and others, 1995). As part of the 1995 USGS National Oil and Gas Assessment, a geologic play-level assessment was completed for USGS petroleum Province 50, the Florida Peninsula Province (Pollastro, 1995; Pollastro and Viger, 1998). Subsequently in 2000, the USGS performed an objective, geologic-based assessment of undiscovered oil and gas in the Florida Peninsula Province (USGS Province 50) that incorporated a different geological approach, referred to as the total-petroleum-system-assessment-unit method 2000 (Klett and others, 1997; U.S. Geological Survey World Energy Assessment Team, 2000), rather than the assessment by play used by the USGS in 1995 (Gautier and others, 1995). The total-petroleum-system-assessment-unit approach is an accepted, effective, proven method used in the recently released U.S. Geological Survey World Petroleum Assessment 2000 compared to the play-level approach because the assessment unit may also represent a play or group of plays. The advantage of the petroleum system approach is that it incorporates the unit of assessment within the higher level context of the total petroleum system. This allows for a much better understanding of the essential elements and processes within the petroleum system that relate to source, generation, migration, accumulation, and trapping of the undiscovered petroleum resource(s). It is the purpose of this report to assess the undiscovered oil and gas resources in the South Florida Basin, USGS Province 50, over a forecast period of 30 years using the best geological information and scientific theory available to the USGS; however, the USGS did not have access to seismic survey data for the South Florida Basin.

Geologic and Petroleum Production Overview

The South Florida Basin is a structurally simple basin containing a thickness of 25,000 ft or more of sediment and is the area of greatest petroleum potential in the Florida Peninsula Province. The depocenter of the basin apparently lies northwest of the Florida Keys under present-day Florida Bay. The basin is bounded by large-scale, positive structural elements, the most prominent being the Peninsular arch (fig. 1). The Peninsular arch is a crystalline basement high of Paleozoic age plunging south-southeast along the axis of the Florida Peninsula that delineates part of the north-northeast boundary of the South Florida Basin. The Peninsular arch controlled the deposition of Jurassic and Cretaceous sediments that onlap and wedge or pinch out against the arch (fig. 2).

Other major positive structural elements include the Florida escarpment in the offshore Gulf of Mexico, which separates the Florida Shelf from the deep Gulf Basin. The Florida escarpment represents a major barrier reef complex of continual reef growth from the Cretaceous to Holocene. A third major structural element that defines the South Florida Basin is the Tampa-Sarasota arch, a 150-mi-long, basement-involved, northeast-southwest-trending feature that extends from west-central Florida onshore to the Gulf offshore approaching the Florida escarpment. Smaller positive structural elements that directly influenced the type and distribution of carbonate depositional facies within the South Florida Basin are the Pine Key arch and Largo high to the south, and the Lee-Collier swell, Charlotte high, and 40 Mile Bend high in the more central part of the basin (fig. 1 and fig. 4).

Sedimentation in the South Florida Basin kept pace with subsidence, producing nearly continuous carbonate-evaporite deposition from the Jurassic(?) to the present (fig. 3). The earliest sediments are Late Jurassic(?)-age marginal clastics, possibly of continental origin (Applin and Applin, 1965); these basal clastics are underlain by Jurassic basement volcanics, most of rhyolitic composition (Barnett, 1975). Onshore, and along the "Sunniland trend" where the Upper Sunniland produces at depths of about 11,500 ft, the sedimentary section is about 15,000 to 17,000 ft thick and consists of about 7,000 to 9,000 ft of Late Jurassic- through Early Cretaceous-age rocks, 3,000 ft of Late Cretaceous-age rocks, and 5,500 ft of Tertiary age rocks (fig. 3).

The South Florida Basin covers some 80,000 mi^2 and incorporates the southernmost one-third or more of the peninsula of Florida including the Florida Keys and the easternmost Gulf of Mexico. The basin generally has a low (1.0° to 1.2°F/100 ft) geothermal gradient; however, the gradient of some onshore oil fields may reach 1.5°F/100 ft (Reel and Griffin, 1971). Onshore, the basin exhibits only subtle structures with no major faults or vertical fractures identified to date. However, more complex structural elements, including basement fault blocks, are believed to exist in the offshore part of the basin, particularly within the uppermost Jurassic and lowest Cretaceous part of the stratigraphic section shown by Faulkner and Applegate (1986). The presence of major fault systems and large structural features could provide pathways for hydrocarbon migration and increase the potential for large accumulations offshore. Moreover, if similar structural features extend into the onshore and State waters portion of south Florida, a greater potential for additional, and perhaps larger, accumulations than were previously interpreted may be expected in the lower part of the stratigraphic section and corresponding assessment unit.

All commercial oil production in the South Florida Basin is from the Lower Cretaceous Sunniland Formation. A total of 14 Sunniland oil fields (10 active and 4 abandoned or shut in) are located in Lee, Hendry, Collier, and Dade Counties (fig. 4). Cumulative production in the 10 presently active fields through 1997 was greater than 106 million barrels of oil (MMBO) (table 1).

The first Sunniland oil field discovery was the Sunniland field in 1943; the largest field is West Felda field, discovered in 1966, with total production through 1997 of more than 44 million barrels of oil (MMBO) (table 1). Although no new exploration wells have been drilled in the South Florida Basin within the last decade, a total of five single horizontal legs have been added to preexisting vertical wells within Bear Island and Racoon Point fields, resulting in increased total production for both fields (Ed Garrett, Florida Geological Survey, written commun., 2000).

Comparison of 2000 South Florida Basin Total-Petroleum-System Assessment to the 1995 USGS National Oil and Gas Play-Based Assessment

The 1995 USGS National Oil and Gas Assessment (1995 USGS assessment) of technically recoverable, undiscovered

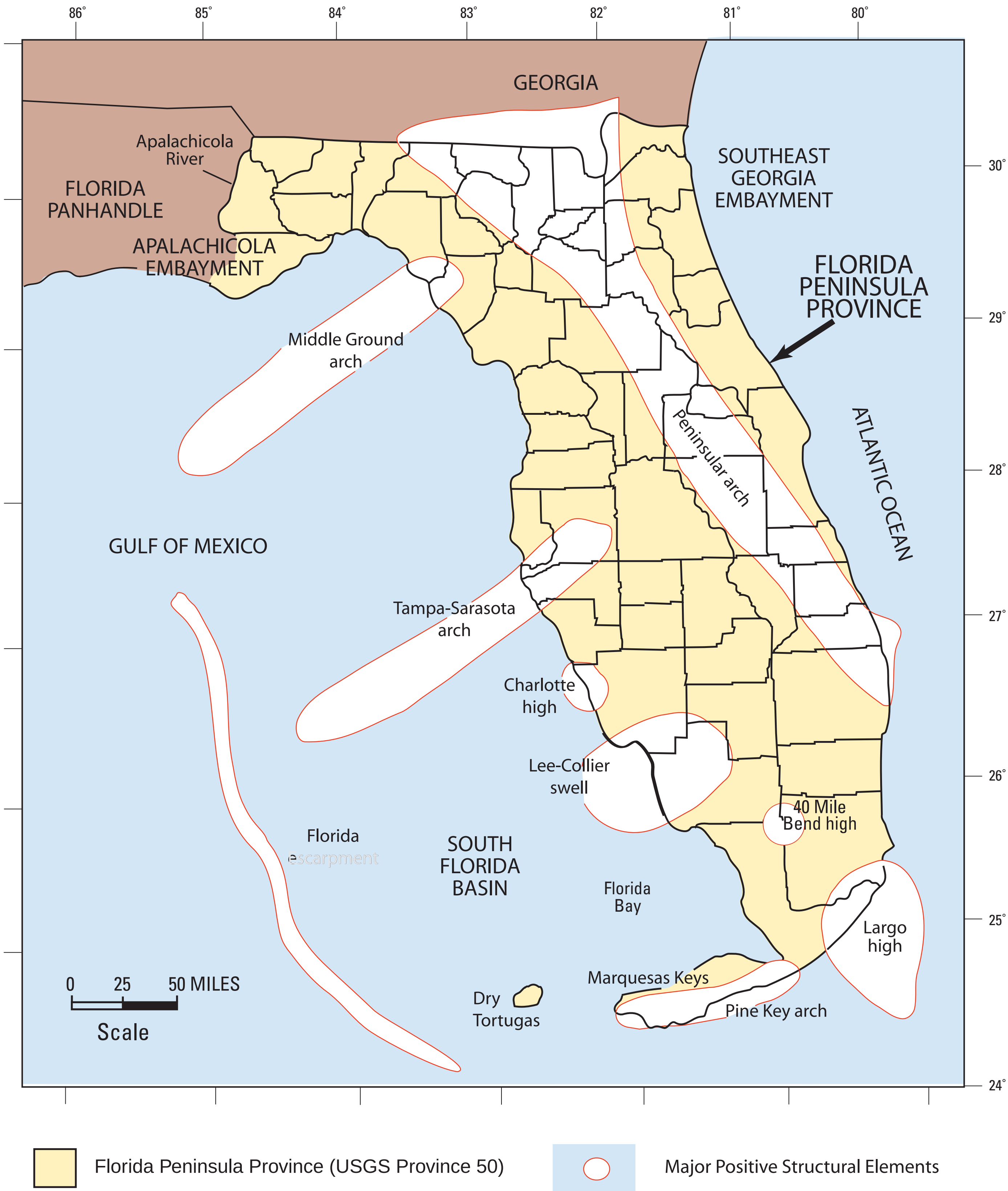

Figure 1. Map showing Florida Peninsula Province (USGS Province 50) and major positive structural elements of the South Florida Basin.

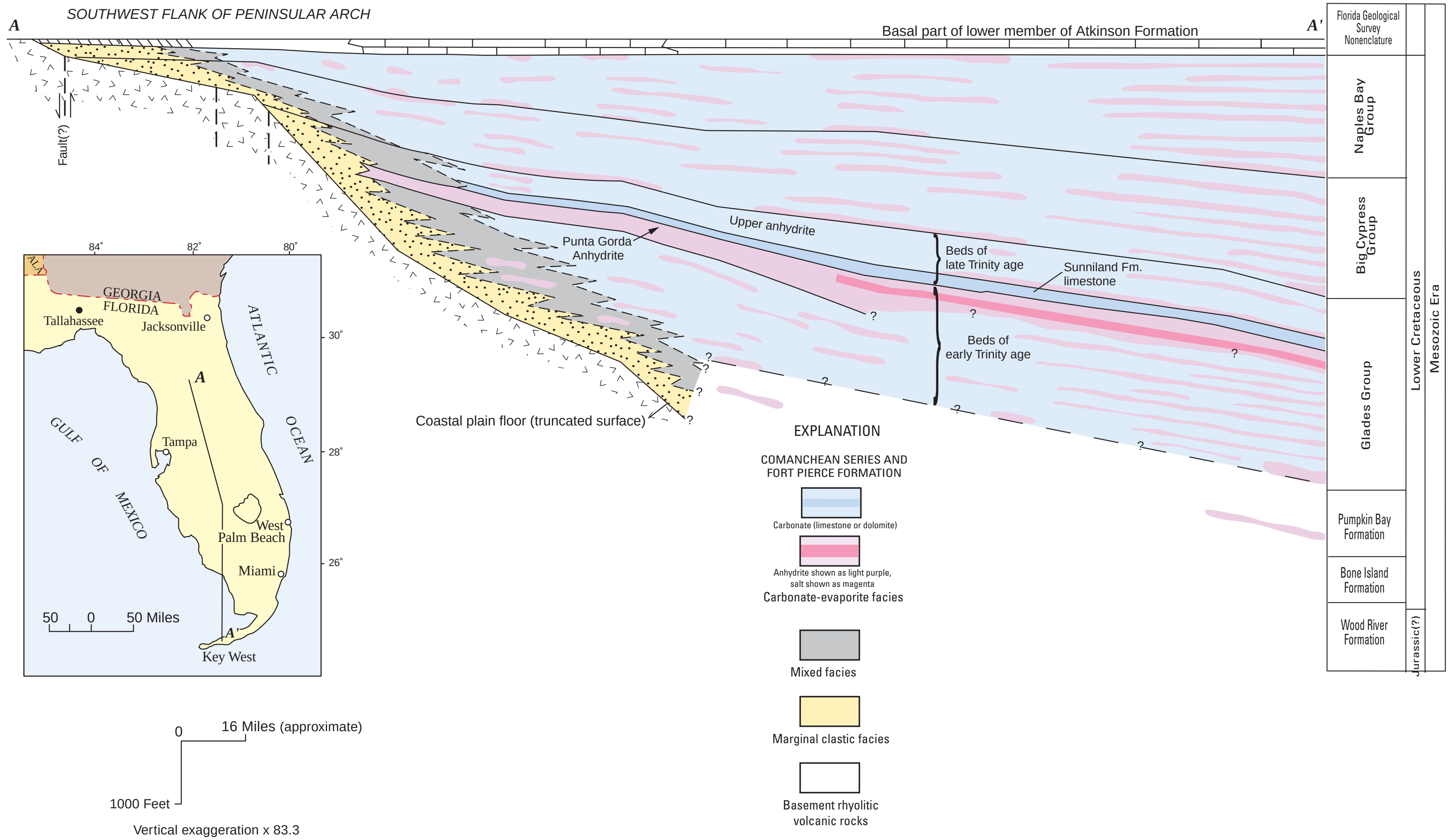

Figure 2. Simplified cross section of Late Jurassic- and Early Cretaceous-age rocks from central Peninsular arch across South Florida Basin to Key West. Stratigraphic nomenclature from Applin and Applin (1965) and Florida Geological Survey. Modified from Applin and Applin (1965).

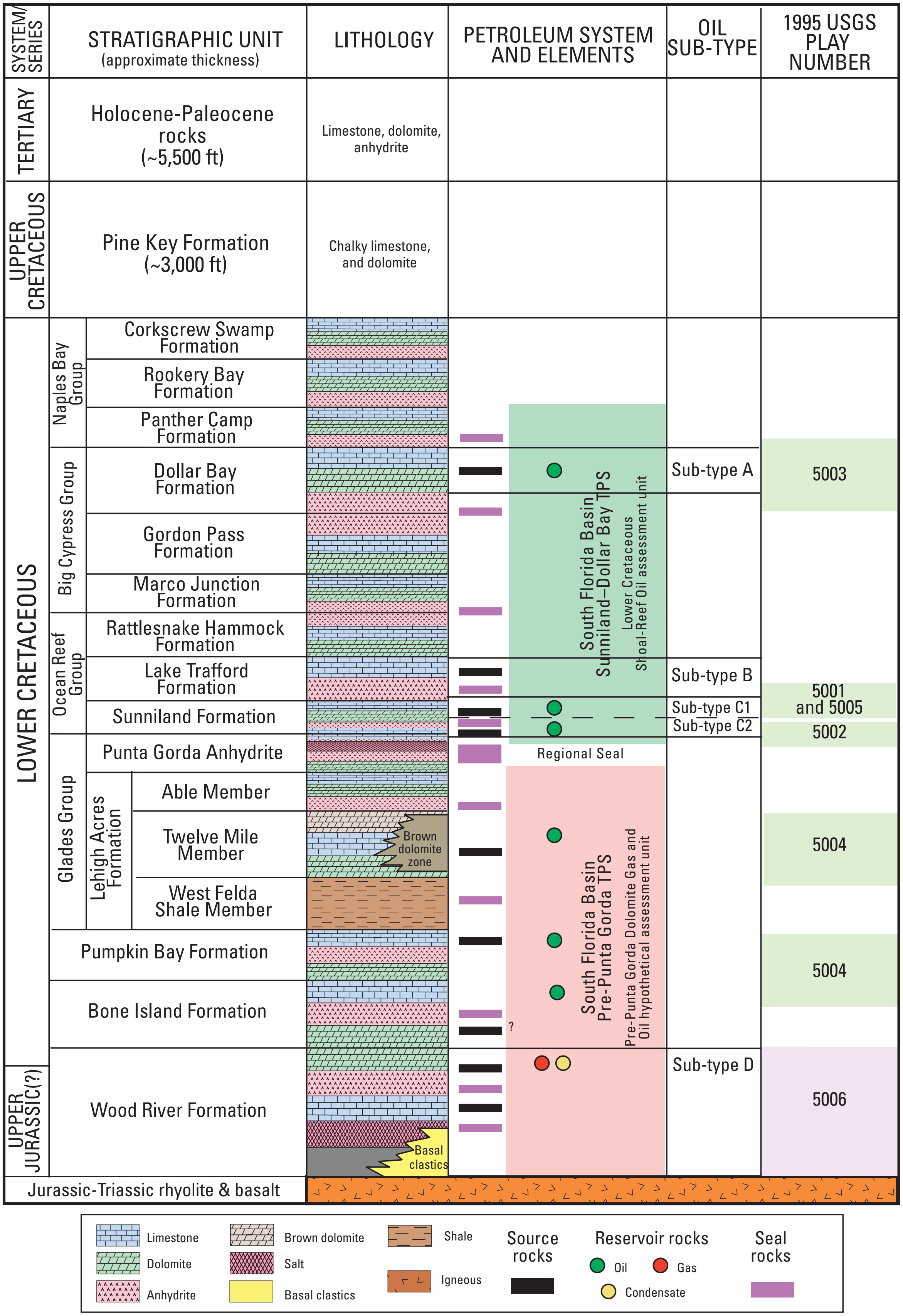

Figure 3. Stratigraphic section of South Florida Basin along Sunniland trend showing relation to petroleum-system elements, total petroleum systems (TPS), oil sub-types, and 1995 USGS plays. Modified from Faulkner and Applegate (1986).

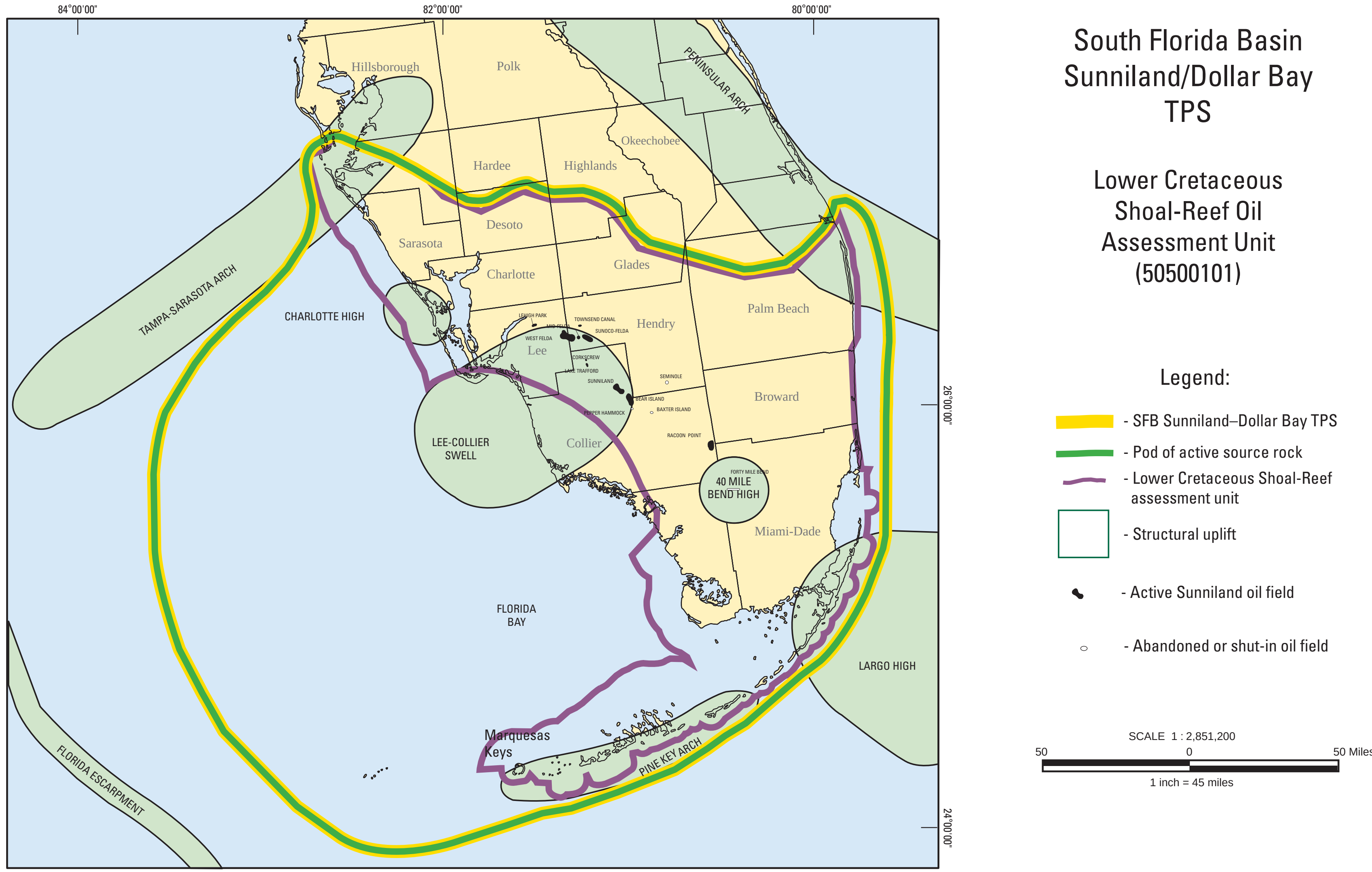

Figure 4. Map of South Florida Basin showing boundaries of Sunniland–Dollar Bay total petroleum system (TPS) and Lower Cretaceous Shoal-Reef Oil assessment unit.

Table 1. Cumulative (CUM) oil and gas produced from active south Florida Sunniland fields through 1997.

[MBO, thousand barrels of oil; MMCFG, million cubic feet of gas. Data from Oil and Gas Section, Florida Geological Survey (Ed Garrett, Florida Geological Survey, 2000, written commun.)]

SOUTH FLORIDA SUNNILAND FIELDS	CUM OIL (MBO)	CUM GAS (MMCFG)
Sunniland	18,447	1,825
Sunoco Felda	11,598	982
West Felda	44,163	3,474
Lake Trafford	280	0
Bear Island	11,622	969
Lehigh Park	5,568	571
Mid-Felda	1,513	10
Racoon Point	11,610	1,430
Townsend Canal	535	0
Corkscrew	1,065	0
Total	106,401	9,261

oil and gas resources in U.S. onshore and State waters (Gautier and others, 1995) was based on the best geologic information and theory available to the USGS at that time. Assessments of undiscovered oil and gas by the USGS are based largely upon published and commercially available data. Seven major data sources were used in the 1995 USGS assessment, and updates of these sources, where possible, were used in the present assessment. These data sources include both published and unpublished USGS data; Significant Oil and Gas Fields of the United States database commercially available from NRG Associates, Inc. (NRG); the Well History Control System (WHCS) database commercially available from IHS Energy Group, Denver, Colo.; production and other data from the literature; State records; proprietary company reports; and other data obtained by USGS geologists. In addition, it should be particularly noted that this petroleum system assessment of the South Florida Basin was not based on seismic prospect evaluation because seismic survey data were not available to the USGS.

The hydrocarbon play served as the basic unit of assessment for the 1995 USGS assessment. Six conventional plays were defined for Province 50, the Florida Peninsula Province, and within the South Florida Basin (Pollastro, 1995; Pollastro and Viger, 1998). A play consists of a group of geologically related petroleum accumulations. Particular emphasis in play analysis is placed on similarities of the rocks in which the accumulations occur (Schmoker and Klett, 2000). Two of the six plays defined in the 1995 USGS assessment of the South Florida Basin are confirmed, or proven, plays: the Upper Sunniland Tidal Shoal Oil play (1995 USGS assessment code 5001) and Lower Sunniland Fractured Dark Carbonate Oil play (5002) (Pollastro, 1995; Pollastro and Viger, 1998). The remaining four plays were hypothetical: the Dollar Bay Shoal-Reef Dolomite Oil play (5003), Lower Cretaceous Carbonate Composite Oil play (5004), Extended Upper Sunniland Tidal Shoal Oil play (5005), and Wood River Dolomite Deep Gas play (5006). All plays other than the Wood River Dolomite Deep gas play (5006) were assessed in the 1995 USGS assessment. At the time of the 1995 USGS assessment, Play 5006 was assigned a combined low probability, based on charge, reservoir, trap and seal that was below the required probability for quantitative assessment (Pollastro, 1995).

For the present analysis of Florida Peninsula Province and the South Florida Basin, we applied a different approach in defining the basic level of assessment of domestic undiscovered oil and gas. Here we use subdivisions of the total petroleum system (TPS), termed assessment units (AU's), a method used and described in the USGS World Petroleum Assessment 2000 (Magoon and Schmoker, 2000). A TPS might equate to a single AU, or, if necessary to achieve homogeneity with respect to geology or discovery history, it might be subdivided into two or more assessment units. An assessment unit is thus a mappable volume of rock sharing similar geologic traits within the TPS (Schmoker and Klett, 2000). Therefore, an assessment unit may actually define a play or may constitute a specific group of plays within the TPS.

In the 2000 USGS total-petroleum-system assessment of the South Florida Basin, two stacked petroleum systems, each with a single assessment unit, are designated for the South Florida Basin. The two TPS's are represented in the stratigraphic section of figure 3. The two TPS's are separated stratigraphically by a major regional evaporite seal, the Lower Cretaceous Punta Gorda Anhydrite. The younger TPS assessment unit is designated as the South Florida Basin Sunniland–Dollar Bay TPS (USGS code 505001) and corresponding Lower Cretaceous Shoal-Reef Oil assessment unit (50500101). The second and older total petroleum system is the South Florida Basin Pre-Punta Gorda TPS (505002) and corresponding Pre-Punta Gorda Dolomite Gas and Oil hypothetical assessment unit (50500201). The two assessment units are correlatable to the plays defined for the 1995 USGS assessment (Pollastro, 1995), which are also shown in figure 3. The Lower Cretaceous Shoal-Reef Oil AU corresponds to 1995 USGS assessment plays 5001, 5002, 5003, and 5005. Similarly, the Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU corresponds to plays 5004 and 5006.

Total-Petroleum-System Elements of the South Florida Basin

The total petroleum system is comprised of four critical elements: source, reservoir, seal, and trap. In the petroleum-producing formations of south Florida, most traps are stratigraphic in nature; however, deposition of the reservoir facies was controlled, in part, by basement relief. Specific units identified as a critical rock-unit element(s) of the petroleum system are shown in figure 3. Formations or units having potential for petroleum generation and accumulation in the South Florida Basin range in age from Late Jurassic(?) through Early Cretaceous and are also identified in the stratigraphic column of figure 3. The youngest rocks identified as having potential for petroleum generation and accumulation are within the Lower Cretaceous Dollar Bay Formation of the Big Cypress Group, and the oldest are of Late Jurassic(?) age immediately overlying basement rocks.

Source rocks of the South Florida Basin are mainly fine-grained, organic-rich carbonates; these source rocks may occur as thick, dark-colored units or as multiple thin, dark laminated beds within one formation or member. Source rocks are commonly beds within the same formation as the producing reservoir(s). Oils of the South Florida Basin can be classified as one "superfamily" of oil and commonly contain high (2–4 percent) sulfur. In a recent detailed study, however, J.G. Palacas (oral commun., 2000) identified four distinctive stratigraphic oil sub-types (not to be confused with organic matter kerogen types) from oils collected from field production and from oil shows in wells throughout the South Florida Basin. These oil sub-types were designated as Dollar Bay sub-type (A), Lake Trafford sub-type (B), Sunniland sub-type (C), and Wood River sub-type (D) and were probably derived from slightly different organic facies (fig. 3). Sub-type A, Dollar Bay oil, is the least mature oil, averaging about 17° API gravity. Sub-type C, Sunniland oils, average about 26° API gravity, and mature condensate of sub-type D, Wood River oil, is about 52° API gravity.

Reservoir rocks of the South Florida Basin total petroleum systems are mainly porous carbonate grainstones and dolomites; however, a potential for gas in pinch-outs of deep, Upper Jurassic basal clastics must also be considered. Grainstone reservoirs are commonly porous (10–30 percent) and permeable, skeletal bioclastic shelf carbonates deposited as rudistid shoals, banks, mounds, and beach facies in a tidal flat or back reef environment (Halley, 1985; Mitchell-Tapping, 1986, 1987; Richards, 1988). Other porous reservoir facies include patch reefs. Many of these bioclastic grainstones were deposited on subtle bathymetric highs that likely reflect basement-involved structure or differential basement erosional features. Grain constituents consist of mollusk (rudistid) fragments, pellets, forams, ooids, and peloids. Large skeletal fragments are almost exclusively rudistids. Commonly, skeletal fragments of the shoals or mounds have been leached by subaerial exposure, leaving large pores. Dolomitic reservoirs usually consist of fine-grained, sucrosic dolomite with high intercrystalline porosity. These reservoirs were originally skeletal grainstones, packstones, and wackestones that were diagenetically replaced by dolomite (Mitchell-Tapping, 1986, 1987; Richards, 1988).

Seal rocks, mainly evaporites and impermeable ("tight") micritic carbonates, are common throughout the South Florida Basin (fig. 3); multiple seals can be present within any one formation. Anhydrite and salt of the Punta Gorda Anhydrite form the major regional seal throughout the South Florida Basin. All seals within, or overlying, petroleum-producing formations of the South Florida Basin are highly efficient. This is particularly demonstrated by the criteria for subdivision of oil sub-types among producing units and the remarkable well-to-well correlation of these oils, often where reservoirs are stratigraphically juxtaposed to one another but separated by a seal (fig. 3).

Two total petroleum systems and corresponding assessment units are designated here for the South Florida Basin. They are (1) the Sunniland–Dollar Bay TPS (505001) and Lower Cretaceous Shoal-Reef Oil AU (50500101), and (2) the Pre-Punta Gorda TPS (505002) and Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU (50500201). As mentioned previously, the two assessment units closely correspond to two specific groupings of the 6 plays identified for the 1995 USGS assessment (Pollastro, 1995; Pollastro and Viger, 1998).

South Florida Basin Sunniland–Dollar Bay TPS and Lower Cretaceous Shoal-Reef Oil Assessment Unit

Overview

The Sunniland–Dollar Bay TPS and Lower Cretaceous Shoal-Reef Oil AU is a composite of stratigraphic units that incorporates all mature source rock, and all reservoir rocks, seal rock, and accumulations within the Dollar Bay, Lake Trafford, and Sunniland Formations. Additionally, petroleum-system elements from other formations of the Big Cypress and Ocean Reef Groups are included in the TPS and assessment unit (fig. 3). The geographic boundaries of the Sunniland–Dollar Bay TPS and Lower Cretaceous Shoal-Reef Oil AU are outlined in figure 4. Three of the four stratigraphic plays (5001, 5002, and 5005) of the 1995 USGS assessment (Pollastro, 1995); Pollastro and Viger, 1998) that comprise the Lower Cretaceous Shoal-Reef Oil AU apply to the Sunniland Formation; the fourth play (5003) applies to the Dollar Bay Formation. The boundaries of the assessment unit define a geographic area of potential discoveries for all accumulations within this group of stratigraphic plays. Moreover, the Lower Cretaceous Shoal-Reef Oil AU focuses on discoveries within bioclastic shoals, mounds, and patch reefs mostly within the upper part of the Sunniland Formation, with a lesser amount in the Dollar Bay Formation, and a small contribution of undiscovered resource attributed to accumulations within fractured carbonate of the lower part of the Sunniland Formation. Elements and processes of the Sunniland–Dollar Bay TPS are summarized in the events chart of figure 5.

The Lower Cretaceous Dollar Bay Formation, the uppermost unit of the Big Cypress Group (fig. 3), is the youngest formation in the onshore portion of the South Florida Basin that shows characteristics favorable for petroleum generation

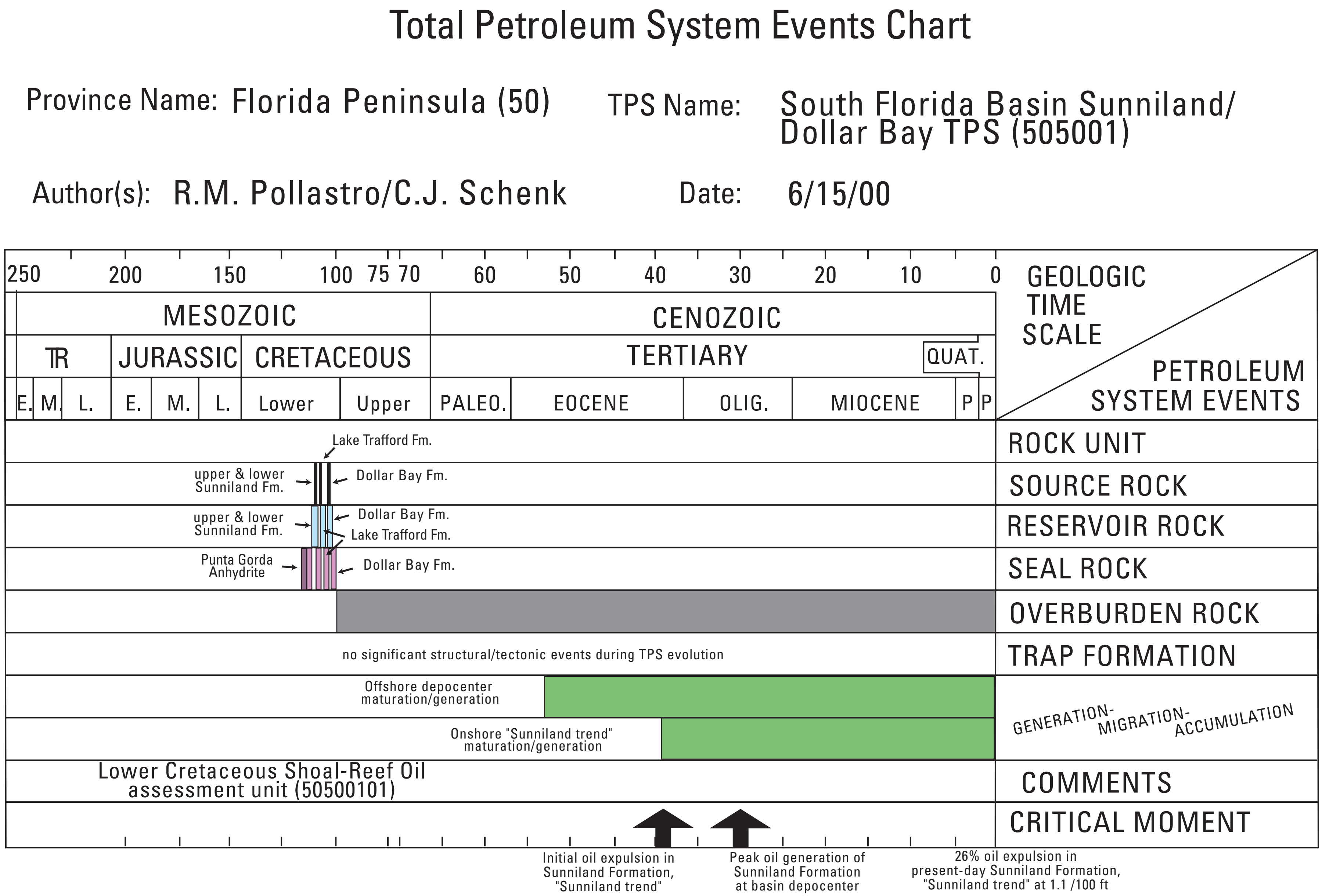

Figure 5. Total petroleum system (TPS) events chart for South Florida Basin Sunniland–Dollar Bay TPS and Lower Cretaceous Shoal-Reef Oil assessment unit.

and accumulation. The unit lies about 1,500 ft or more above the Sunniland Formation and is as much as 620 ft thick in some parts of the basin. Onshore, the unit ranges in thickness from about 475 ft to 550 ft. Numerous wells penetrating the Dollar Bay Formation in south Florida have reported low-gravity (17° API) oil shows or tarry residues in both limestone biohermal deposits and an upper dolomite section (Winston, 1971); however, undiscovered accumulations are hypothetical because no commercial production has been recorded from the Dollar Bay. Similar to the Sunniland, the Dollar Bay consists mostly of evaporite-carbonate cycles. These evaporite-carbonate beds formed during a transgressive-regressive cycle; some thin beds of calcareous shale, salt, and lignite are also present (Applin and Applin, 1965; Mitchell-Tapping, 1990). In certain areas of the basin, however, limestone is the dominant lithology of the formation. Production in the Dollar Bay Formation will most likely be from leached limestones in the middle part of the formation or from a dolomite section in the upper part.

Known only in the subsurface, the Lower Cretaceous Sunniland Formation is the basal unit of the Ocean Reef Group (fig. 3). Onshore, the formation is relatively uniform in thickness and consists of limestone, dolomite, and anhydrite. The upper part of the Sunniland Formation produces heavy, marginally mature crude oils from porous bioclastic debris mounds, banks, and shoals on the eastern margin of the South Florida Basin. The region of productive reservoir facies of the upper Sunniland Formation is defined, in part, by eight fields (Bear Island, Corkscrew, West Felda, Lehigh Park, Mid-Felda, Raccoon Point, Sunniland, and Sunoco-Felda) that have each produced more than one MMBO and five smaller fields. These smaller fields are abandoned or shut in. Combined, these fields form an arcuate northwest-southeast trend, the “Sunniland trend,” which is about 20 mi wide and 150 mi long. Generally, the updip limit of the Sunniland extends to about 50 to 60 mi northeast of the producing trend.

Source Rocks and Thermal Maturity

Oil and tarry residues recorded in Dollar Bay wells are believed by some to have originated within the formation (Palacas, 1978a, 1978b; Winston, 1971). The total organic carbon (TOC) content of the Dollar Bay Formation ranges from very lean to fairly rich, with some beds containing more than 3 weight percent TOC (Palacas, 1978a, 1978b). The Dollar Bay Formation is located updip and to the northeast of the Sunniland trend. This suggests that the unit is thermally immature and has probably not generated hydrocarbons of commercial quality and quantity (Montgomery, 1987). Other studies strongly disagree, however, and predict that the Dollar Bay Formation has been overlooked and should be a considered a primary oil target with good potential (Winston, 1971; Palacas, 1978a, 1978b; Mitchell-Tapping, 1990).

Offshore, in the more central part of the basin where the Dollar Bay Formation lies at depths >10,000 ft, the formation should be more thermally mature. Onshore, API gravities of oil from the Dollar Bay within the Lower Cretaceous Shoal-Reef Oil AU are expected to be low, probably ranging from 15° to 20° (Mitchell-Tapping, 1990). Sulfur content is similar to those of Sunniland-type oils (2–4 percent). Moreover, the inferred presence of patch reefs and more complex structures in the Federal offshore, and greater depth and higher thermal maturity of the Dollar Bay Formation in the Federal and State offshore portions of the basin, enhances the potential for new field discoveries and commercial oil production in this portion of the basin.

Oils produced from the Sunniland Formation are immature, having API gravities that range from about 21° to 28° and average 25° to 26°; the gas-to-oil ratio (GOR) is about 85 ft^3/bbl (Palacas, 1984; Palacas and others, 1984; Tootle, 1991). Source rocks include organic-rich, dark laminated limestone beds in the upper Sunniland and a dark, micritic carbonate unit (informally referred to as the dark carbonate interval) in the lower part of the Sunniland Formation. Organic matter in these source beds is mostly hydrogen rich, amorphous, marine algal, commonly with high sulfur content. TOC ranges from 0.4 to 12.0 weight percent and averages about 1.8 percent (Palacas, 1984). Greater than 80 percent of the organic matter within these source rocks is composed of algal-amorphous kerogen (oil-prone, Type IIs) (Palacas and others, 1984). The hydrocarbon-generating potential of the lower Sunniland dark carbonate facies ranges from poor in wells updip from the producing trend where thermal maturities are low, to good just downdip, to excellent near the depocenter of the basin where thermal maturity is greatest (Applegate and Pontigo, 1984).

Burial History and Petroleum Generation

Petroleum generation-expulsion for the Dollar Bay and Sunniland Formations of the South Florida Basin is modeled in figure 10. Onshore at Sunniland field, the Dollar Bay has generated and expelled less than 10 percent of its oil. Modeling of the Sunniland onshore along the “Sunniland trend” shows that the Sunniland source beds have only generated and expelled about 20 percent of its hydrocarbons as oil (fig. 10).

Reservoirs

Undiscovered oil accumulations in the Dollar Bay portion of the assessment unit will most likely be in tidal shoal deposits and patch reefs that were deposited in a tidal-flat, lagoonal, restricted-marine setting, and in a subtidal-platform, open-marine setting (fig. 6). These reservoirs include (1) porous, leached, and dolomitized grainstones in the upper parts of isolated debris mounds, (2) isolated patch reefs in the middle part of the Dollar Bay Formation, and (3) a porous dolomite in the upper part (Mitchell-Tapping, 1990). Measured porosities (from core) of these rocks range from about 10 to 30 percent and permeabilities from 5 to 60 millidarcies (fig. 7). Traps are

Figure 6. Reconstructive model of paleoenvironments in southern Florida Peninsula during deposition of Lower Cretaceous Dollar Bay Formation. Modified from Mitchell-Tapping (1990).

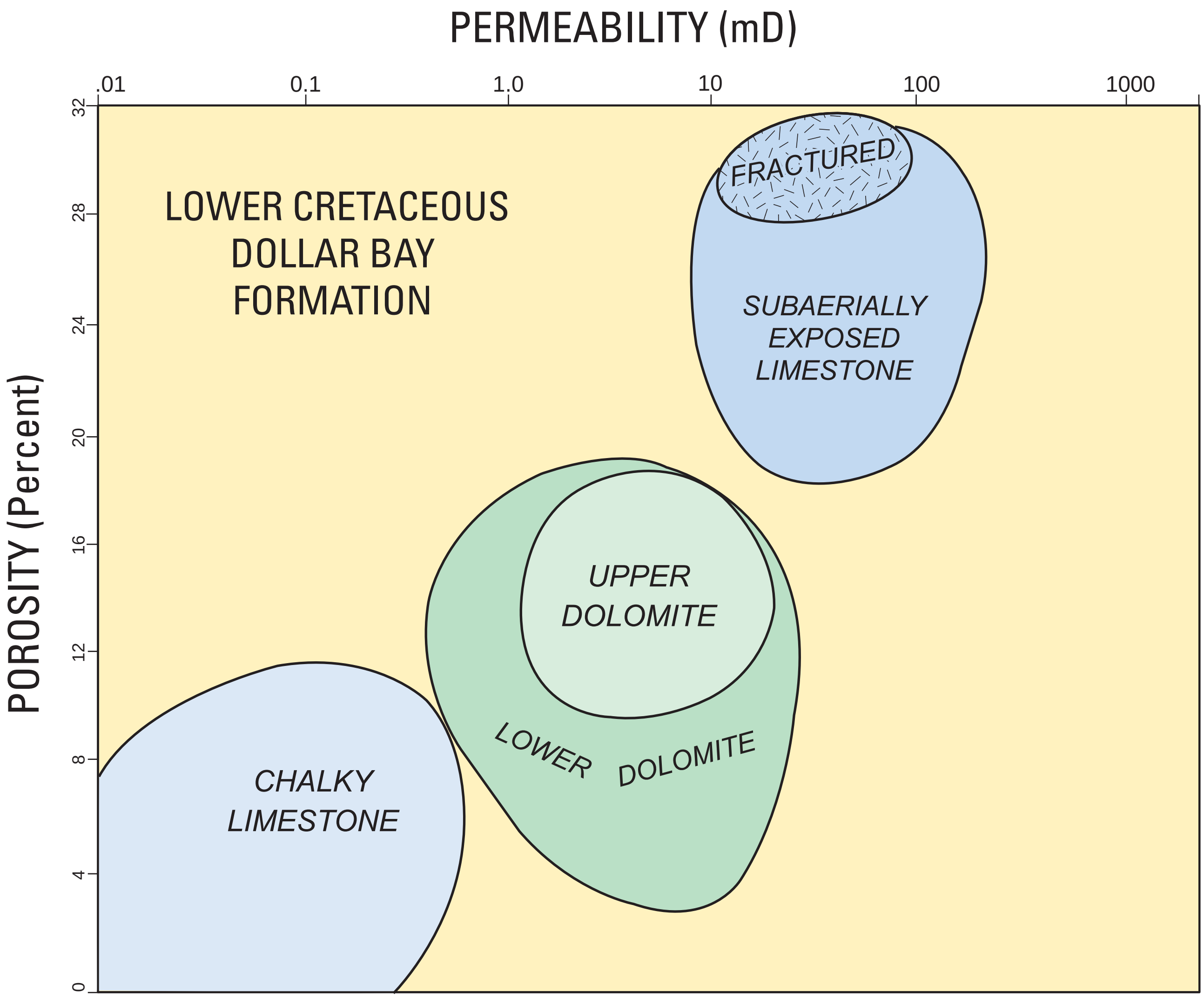

Figure 7. Relationship of porosity and permeability to lithology and diagenesis in Lower Cretaceous Dollar Bay Formation, South Florida Basin. Modified from Mitchell-Tapping (1990).

created because these reservoirs are overlain by impermeable, micritic, tidal-flat deposits, and in some cases argillaceous lime mudstones and anhydrite. The formation is underlain by thick, dense nodular and nodular-mosaic anhydrites of the Gordon Pass Formation (fig. 3).

Reservoir facies in the upper Sunniland Formation are bioclastic buildups consisting of fossil-shell hash (skeletal grainstones). These bioclastic buildups represent probable storm deposition as shoals in a regionally restricted, back-reef lagoonal area in the warm, shallow marine-shelf setting of the eastern South Florida Basin during the late Early Cretaceous (Mitchell-Tapping, 1984, 1987). The buildups of tidal shoals were deposited on subtle bathymetric highs, probably related to underlying basement structure. Later, the upper parts of many of these shoals were subaerially exposed, leached, and subsequently dolomitized during a low sea-level stand, further enhancing the reservoir quality of the upper porous zones.

Individual bioclastic buildups vary in thickness between about 40 and 100 ft (Means, 1977; Montgomery, 1987). Depth to the upper Sunniland tidal shoal reservoirs in the producing trend is from about 11,200 to 11,600 ft (fig. 8). Most mounds are sealed by overlying impermeable lagoonal mudstones and wackestones, some of which have been dolomitized (fig. 9). Primary (interparticle) and secondary (dissolution and intercrystalline from dolomitization) porosity ranges from 10 to 25 percent and averages 15 to 18 percent (Mitchell-Tapping, 1984, 1987). Impermeable micritic carbonate and nodular anhydrite beds within the upper Sunniland enclose and seal many of the individual porous reservoir mounds. Moreover, the entire Sunniland Formation is sealed above and below by thick anhydrite units (fig. 2 and fig. 3). Most hydrocarbon traps are stratigraphic; however, some mixed stratigraphic/structural traps have been recognized.

The Lower Cretaceous Shoal-Reef Oil AU of the Sunniland–Dollar Bay TPS includes some hydrocarbon potential within the lower Sunniland from the “dark carbonate” unit.

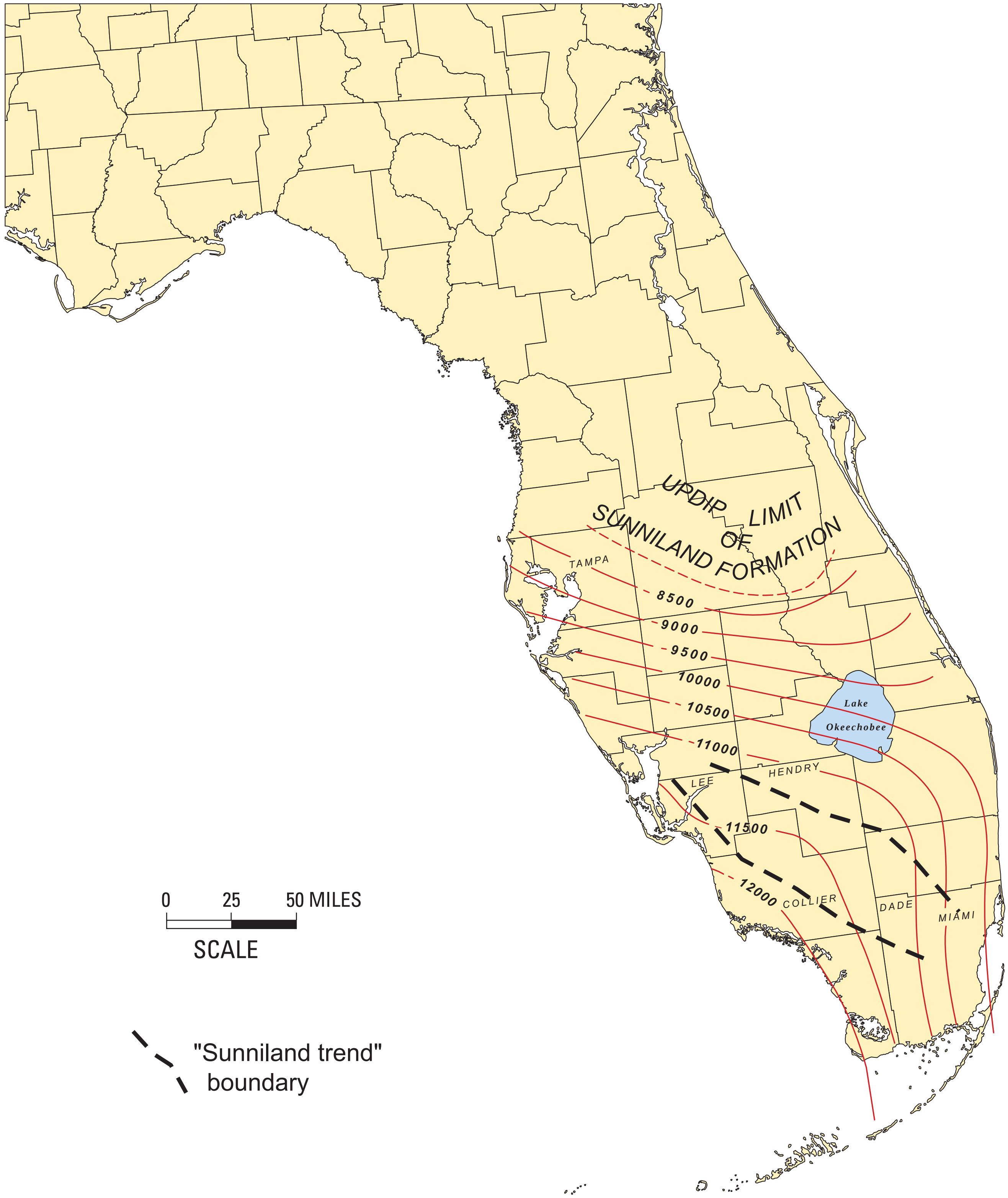

Figure 8. Structure contour map on top of Sunniland Formation, South Florida Basin. Modified from Oglesby (1965).

Figure 9. Map showing updip limit and distribution of limestone, dolomite, and evaporite in Sunniland Formation, South Florida Basin, Florida Peninsula. Modified from Mitchell-Tapping (1986)

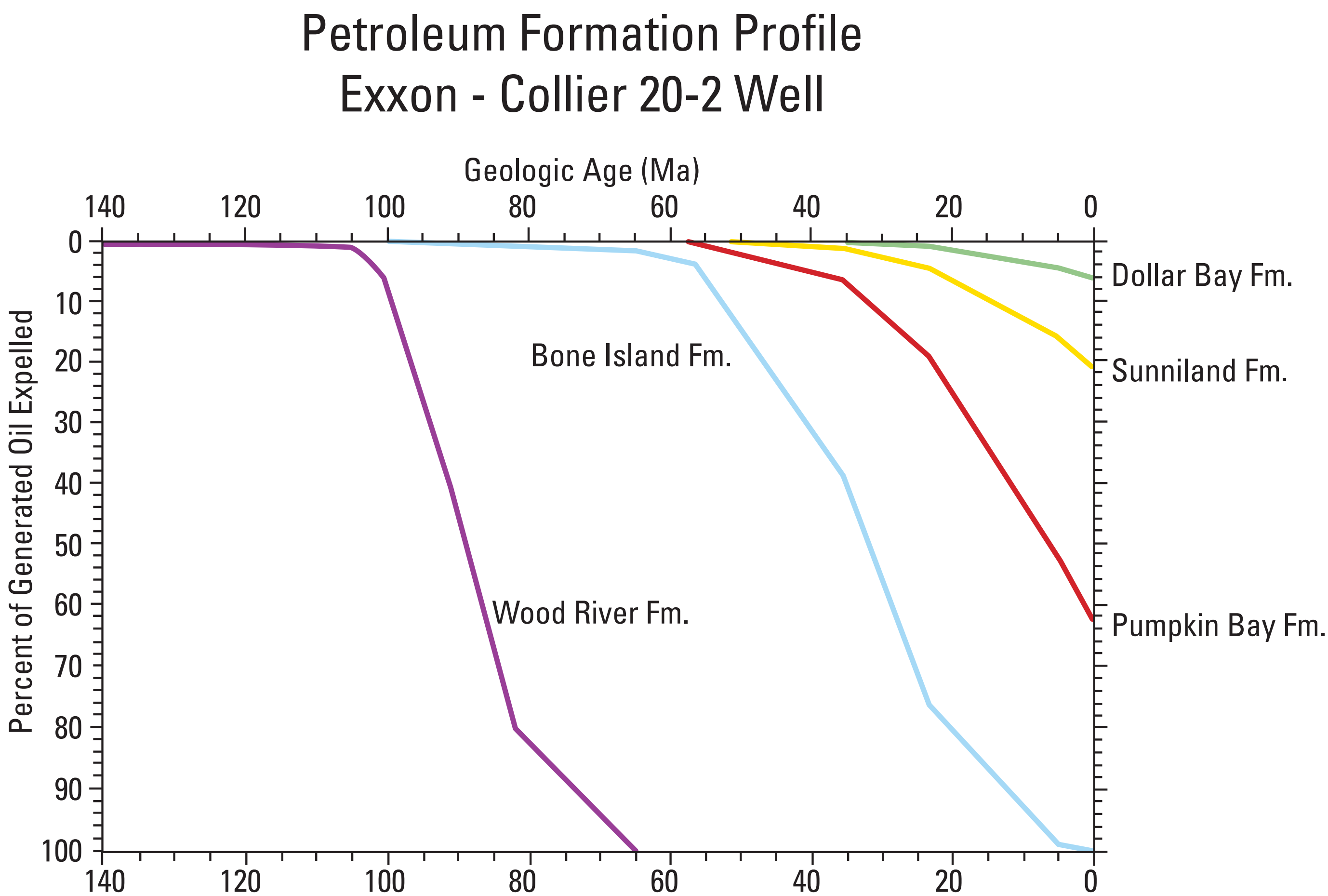

Figure 10. Calculated model for oil generation and expulsion for selected units in Exxon-Collier 20-2 well, Sunniland field, Collier County, South Florida Basin, Florida. Model assumes Type IISB kinetics (oil prone), a constant geothermal gradient of 1.1°F/100 ft, and a constant surface temperature of 70°F.

The one-well Lake Trafford field, Collier County, has produced commercial quantities (about 300,000 barrels) of oil from the lower Sunniland in fractured limestone, commonly referred to as the rubble zone (Means, 1977), at a depth of about 11,800 ft. Indigenous hydrocarbons are produced from brown and medium-dark-gray micritic and argillaceous limestones with total carbonate content averaging 76 weight percent, and ranging from 50 to 98 weight percent. Matrix porosity of the producing rubble zone from the discovery well, as measured by well logs, is about 9 volume percent, and the pore space is oil saturated. Core of the rubble zone from the discovery well has been described as burrowed, fractured, and stylolitized (Lloyd, 1992); these characteristics are thought to be responsible for enhancing the porosity and permeability for commercial production. Potentially productive fractured reservoirs are sealed by impermeable, micritic, tidal-flat, lime mudstones and underlain by the impermeable Punta Gorda Anhydrite.

Seal Rock

Seals are both local and regional and most are intraformational evaporites or impermeable ("tight") micritic carbonates (fig. 3). Thick evaporites (anhydrite and salt) of the Punta Gorda Anhydrite form the major regional seal throughout the South Florida Basin. Moreover, the Punta Gorda regional seal is the primary stratigraphic unit that divides the two total petroleum systems designated here for the South Florida Basin (fig. 3).

Geographic Extent and Boundary Conditions

Boundaries for the Sunniland–Dollar Bay TPS (505001) and Lower Cretaceous Shoal-Reef Oil AU (50500101) are shown in figure 4. The area of the pod of active source rock in figure 4 represents a combined minimum thermal maturity for all source units within the Sunniland–Dollar Bay TPS, the oldest and most mature source in this TPS being the lower Sunniland dark carbonate. The minimum mean vitrinite reflectance (R_o) value used here as an indicator of thermal maturity for carbonate source rocks with Type IIs organic matter (marine, algal, high sulfur) was 0.55 percent. This minimum R_o value delineates source rocks that have generated early, immature (14° to 17° API gravity), high-sulfur oil.

The geographic extent of the assessment unit contributed by the Dollar Bay Formation is based on (1) interpretations of well-log data from a series of onshore wells reporting numerous shows (Winston, 1971; J.G. Palacas, oral commun., 2000), (2) on the paleoenvironmental reconstructions of Winston (1971) and Mitchell-Tapping (1990) of the reservoir tidal shoal and patch reef facies, and (3) petroleum generation and expulsion modeling of this study and the burial history and depositional environments reported by Faulkner and Applegate (1986).

The assessment unit includes a hypothetical extension of bioclastic buildups to the east and south of the present productive Sunniland trend. This hypothetical extension forms a southwest-to-northeast arcuate trend approximately 20 mi wide and 250 mi long from the State waters of the Marquesas Keys northeast through the Florida Keys and along the southeastern Atlantic Coast of the Florida Peninsula to Broward County (fig. 4). Bioclastic mounds of smaller size than those in the main trend are predicted to have accumulated on subtle structural highs in this updip, less thermally mature area of the basin to the east and far south. Prominent positive structural elements include the Pine Key arch and the Largo high (fig. 1 and fig. 4). Some heavy oil shows having low API gravity (10°–14°) have been reported in wells in the northern part of assessment unit; however, 22° API gravity oil was reported in shows from wells near the Marquesas Keys in the west and southernmost part of the assessment unit (Faulkner and Applegate, 1986; Lloyd, 1992). Also, limestone of the upper part of Sunniland may have been replaced by anhydrite in an area between the two locations along the Keys where shows have been recorded, thus reducing the probability for new discoveries in this area.

The northern and updip limit for potential Sunniland fields within the assessment unit was delineated by the deposition of micritic limestone of the intertidal, lagoonal-mudflat facies of the Sunniland, an area where no bioclastic buildups are expected. Moreover, the dark carbonate source in the lower part of the Sunniland Formation is also absent. Because new field discoveries within this assessment unit are heavily weighted on the Upper Sunniland, the downdip western boundary of the assessment unit north of the Florida Keys is limited by an area where wells show that the Sunniland limestone is replaced by anhydrite. This is best outlined in the isopach of the Sunniland limestone by Ogelsby (1965) shown in figure 11, the cross section reported by Feitz (1976), and the core study and cross sections by Halley (1985).

Onshore, the dark carbonate facies of the lower Sunniland Formation varies in thickness from zero at the updip limit of the Sunniland to >150 ft in the producing trend. Areas incorporated into the assessment unit are those where conditions for the dark carbonate include (1) dark carbonate unit thickness >60 ft (see Applegate and Pontigo, 1984; Lloyd, 1992), (2) good source-rock potential (average TOC >1.5 weight percent), and (3) evidence of "rubble zone" or fracturing (Montgomery, 1987). The assessment unit allows some potential for small undiscovered fields in the lower Sunniland, particularly northwest of the Lake Trafford field. Expected depths of production for new field discoveries within the lower Sunniland part of the assessment unit are estimated between 10,000 and 13,000 ft.

Exploration and development of the Sunniland Formation has been minimal within the past 2 decades. Combined geological analysis and some exploration with sparse well distribution within this petroleum system and assessment unit result in a high probability for the discovery of oil accumulations of moderate size in the Sunniland Formation, particularly along the Sunniland trend or fairway.

The boundary of the Lower Cretaceous Shoal-Reef Oil AU was constrained by the State waters political boundary of the State of Florida and the following geologic conditions:

1. The updip limit of Sunniland and Dollar Bay Formations to the north along the Peninsular arch,
2. The northeastern extent of oil shows in the Dollar Bay Formation and absence of lower Sunniland dark carbonate source rock as reported by Lloyd (1992) and Winston (1971) and by Palacas (2000, oral commun.),
3. The updip and eastern transition to marginally mature source beds within Sunniland Formation (R_o<0.55 percent),
4. The southern limit of porous facies and locations of reported oil shows in Sunniland and Dollar Bay Formations (Lloyd, 1992; Winston, 1971), and
5. Western and southeastern limit of Sunniland limestone beyond which it is replaced by anhydrite (fig. 11).

South Florida Basin Pre-Punta Gorda Total Petroleum System and Pre-Punta Gorda Dolomite Gas and Oil Hypothetical Assessment Unit

Overview

The Pre-Punta Gorda TPS and corresponding Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU are outlined on the map of figure 12; stratigraphic elements of the petroleum system and assessment unit are shown in figure 3 and figure 13. The Pre-Punta Gorda TPS is a hypothetical petroleum system based on geologic interpretation and geochemical evidence that adequate source rock, reservoirs, and seal rock of

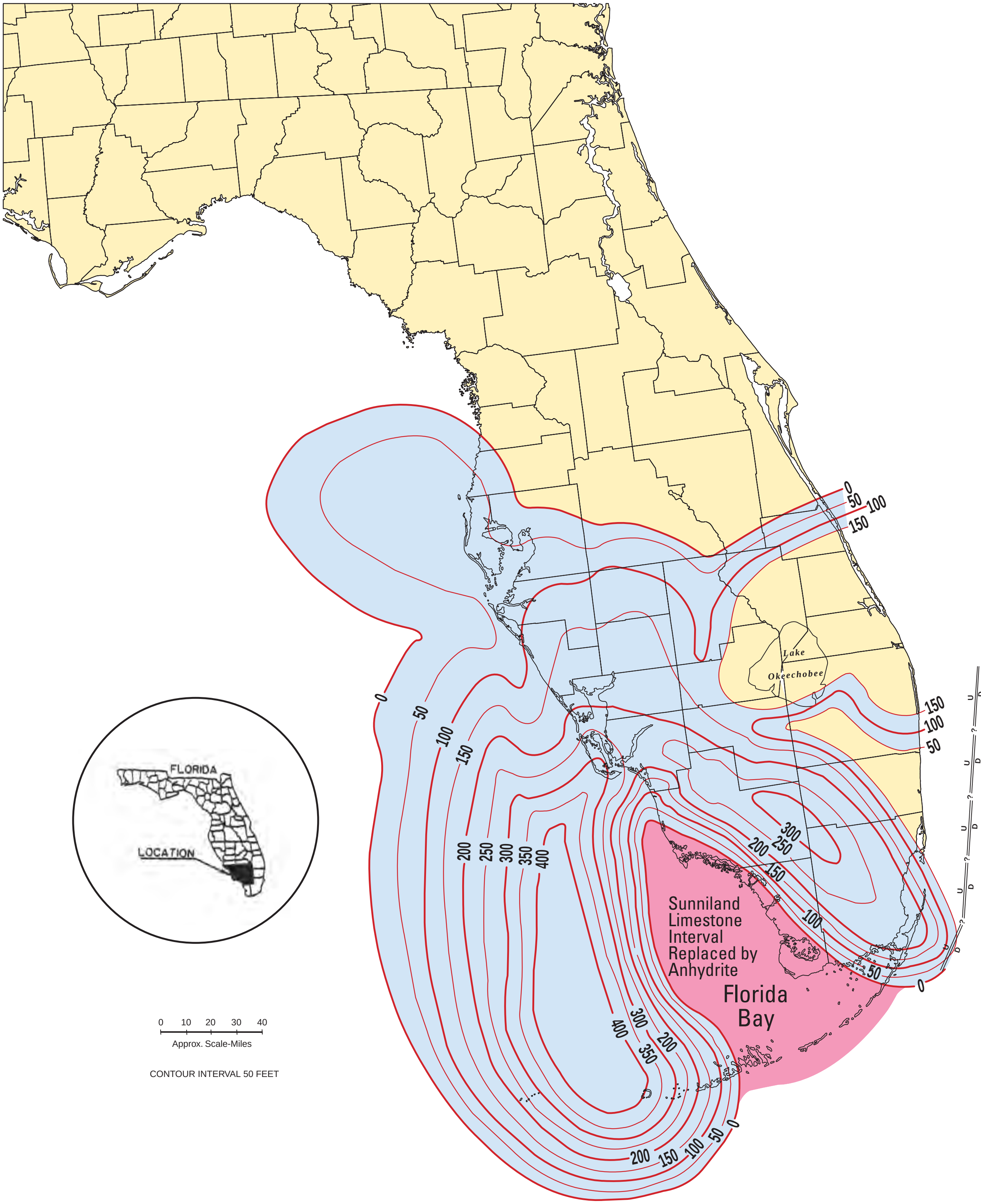

Figure 11. Isopach of Sunniland Formation limestone thickness in South Florida Basin. Note area to southwest in Florida Bay where limestone is replaced by anhydrite. Modified from Oglesby (1965).

Late Jurassic(?) and Early Cretaceous age are present below the Punta Gorda Anhydrite in the South Florida Basin. The Pre-Punta Gorda TPS and Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU incorporate the hypothetical Lower Cretaceous Carbonate Composite Oil (5004) and Wood River Dolomite Deep Gas (5006) plays of the 1995 USGS assessment (Pollastro, 1995; Pollastro and Viger, 1998). However, the Pre-Punta Gorda AU focuses particularly on new field discoveries of deep gas within the Wood River Formation.

Three potential petroleum-producing units exist within this hypothetical assessment unit in the South Florida Basin: (1) the Lower Cretaceous “brown dolomite zone” of the Twelve Mile Member of the Lehigh Acres Formation, (2) a potentially porous dolomite unit within the underlying Pumpkin Bay Formation, also Lower Cretaceous, and (3) dolomite of the Upper Jurassic(?) and Lower Cretaceous Wood River Formation (fig. 3). The first two Lower Cretaceous units are assessed for undiscovered accumulations of oil derived mainly from organic-rich beds in the upper part of the Pumpkin Bay Formation. In contrast, deeper reservoirs within dolomites of the Wood River are expected to contain gas and condensate, possibly derived from organic-rich (>1.0 percent TOC) intervals within the Wood River Formation.

The informally named brown dolomite of the Lehigh Acres Formation lies about 300 ft below the base of the Punta Gorda Anhydrite and about 1,000 ft below the Sunniland Formation (fig. 3). The unit is best developed (about 100 ft thick) and most porous (10 to 22 percent) onshore in Charlotte County and surrounding counties at a depth of about 12,000 ft. Oil shows are reported, and because it is about 1,000 ft lower in the stratigraphic section than the Sunniland Formation oils from the brown dolomite are predicted to have API gravities in the range of about 20° to 50° and source beds within the Lehigh Acres Formation should have greater thermal maturities than those that generate Sunniland oils.

The Pumpkin Bay Formation is thickest (as much as 1,200 ft thick) in the northern part of the assessment unit, as measured from reference wells in State waters near Charlotte Harbor and onshore in Collier and Hendry Counties. Geochemical and thermal maturity measurements indicate that the Pumpkin Bay has good source-rock potential (Means, 1977; Applegate and others, 1981; Palacas and others, 1981; Attilio and Blake, 1983; Faulkner and Applegate, 1986; Applegate, 1987; Montgomery, 1987).

The Upper Jurassic(?) and Lower Cretaceous Wood River Formation is greater than 2,700 ft thick and comprised mostly of limestone and dolomite overlying a basal clastic section. The Wood River averages about 1,700 ft thick and is the lowest sedimentary unit in the South Florida Basin (fig. 3); it is considered to include rocks deposited during Louann through Cotton Valley time (Montgomery, 1987). The few wells that have penetrated this formation show that a 100- to 150-ft-thick clastic unit forms the basal part of the Wood River Formation and consists of dark-red shale and fine- to coarse-grained arkosic sandstone and calcareous sandstone (Applegate and others, 1981). These basal clastics possibly represent fan, fan-delta, and fluvial-lacustrine and marine deposits and are equivalent to the basal Fort Pierce Formation of Applin and Applin (1965). Below the basal clastic sequence in Collier County is a rhyolite porphyry with an age of 189 Ma. Overlying these clastic rocks is a thick sequence of anhydrite, microcrystalline dolomite, some limestone, and occasional interbedded salt stringers, indicating marine transgression (Applegate and others, 1981; Montgomery, 1987).

One well, the Mobil-Phillips Seminole C, near Seminole field in Hendry County, produced measurable gas (referred to as minor gas production by Montgomery, 1987) and water at depths of about 15,700 ft from perforations in a dolomite zone averaging about 8 percent porosity. Moreover, logs from the well measured higher porosities and increased resistivities just above the perforated section, possibly indicating the presence of gas (Applegate and others, 1981; Palacas and others, 1981; Montgomery, 1987). Although formation damage occurred in the well bore, this well was categorized by the site geologist as having potential for commercial gas production (J.G. Palacas, oral commun., 1994, 2000). Additionally, shows of gas and condensate having 52° API gravity were recorded and sampled in the Exxon Collier 20-2 well at Sunniland field, Collier County.

Source Rocks and Thermal Maturity

Source-rock studies by Palacas and others (1981) suggest that organic-rich beds in the upper Pumpkin Bay Formation are likely source rocks for petroleum that could be reservoired both within the middle and upper part of the Pumpkin Bay and in the porous brown dolomite zone of the Lehigh Acres Formation. Palacas and others (1981) identified organic-rich, argillaceous carbonate beds with high (0.43–3.2 weight percent) TOC in the upper Pumpkin Bay and concluded that these beds had the greatest petroleum-generating potential of all rocks older than the Punta Gorda Anhydrite.

The TOC contents of these rocks, however, varies within the basin. Most rocks within the Twelve Mile Member of the Lehigh Acres Formation contain insufficient organic matter (average about 0.3 percent TOC) to have generated commercial amounts of petroleum. Some richer source beds occur within this unit, however, having marginal (about 0.5 weight percent TOC) to good (greater than 2.0 weight percent TOC at West Felda field) source rock.

Potentially commercial gas production reported from the Mobil-Phillips Seminole C well in dolomite of the Wood River Formation near Seminole field, and a good gas/condensate show in the Wood River from the Bass Collier 12-2 well in the Sunniland field, indicate a sufficient source rock in the Wood River Formation. Moreover, Palacas and others (1981) measured TOC as high as 1.85 percent in thin Wood River intervals, and Faulkner and Applegate (1986) found that the Wood River Formation in the Bass Collier 12-2 well contains as much as 1.15 percent TOC at a depth greater than 16,000 ft. Marine beds, generally regarded as potential petroleum

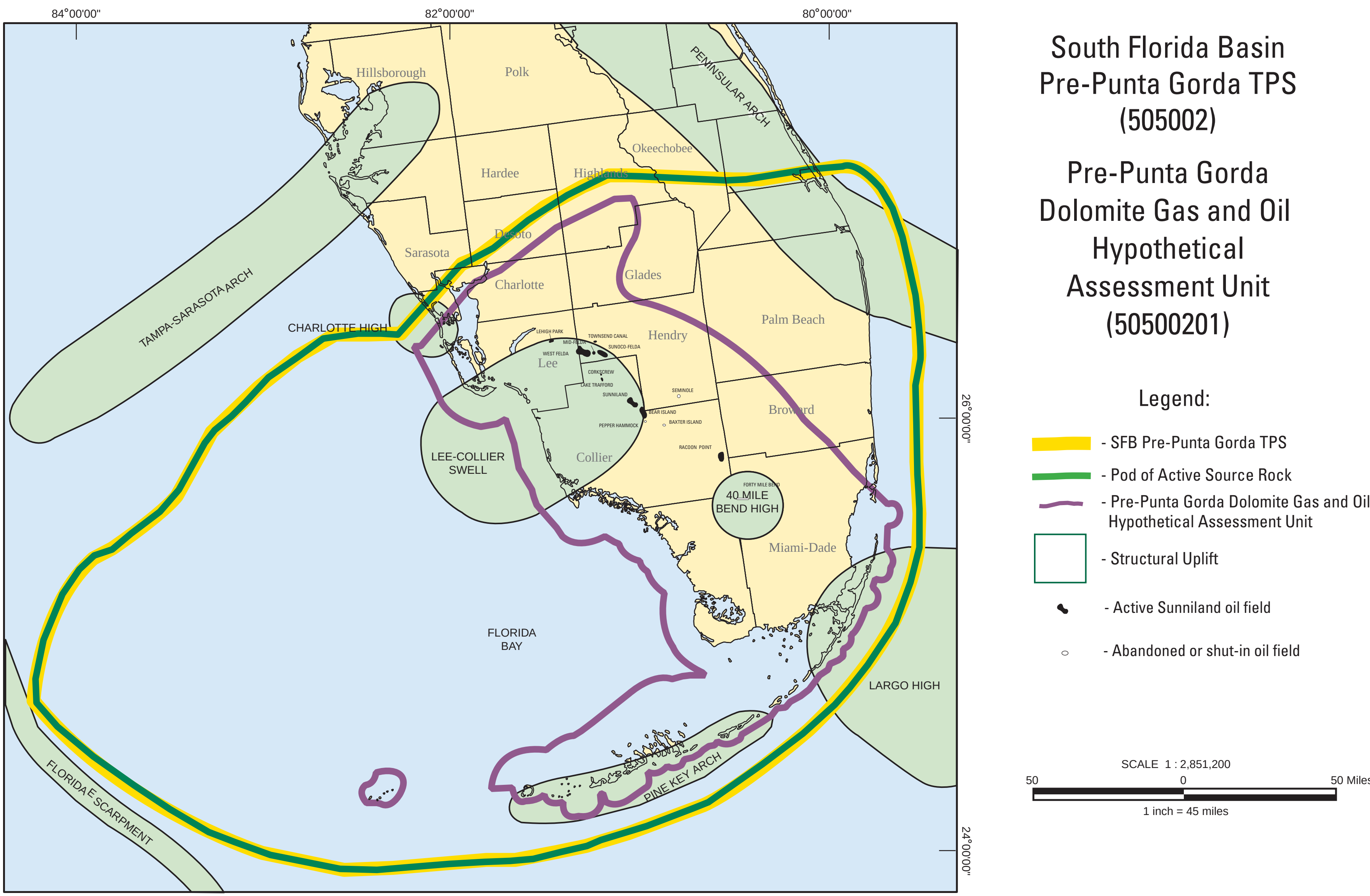

Figure 12. Map of South Florida Basin showing boundaries of Pre-Punta Gorda total petroleum system (TPS) and Pre-Punta Gorda Dolomite Gas and Oil hypothetical assessment unit.

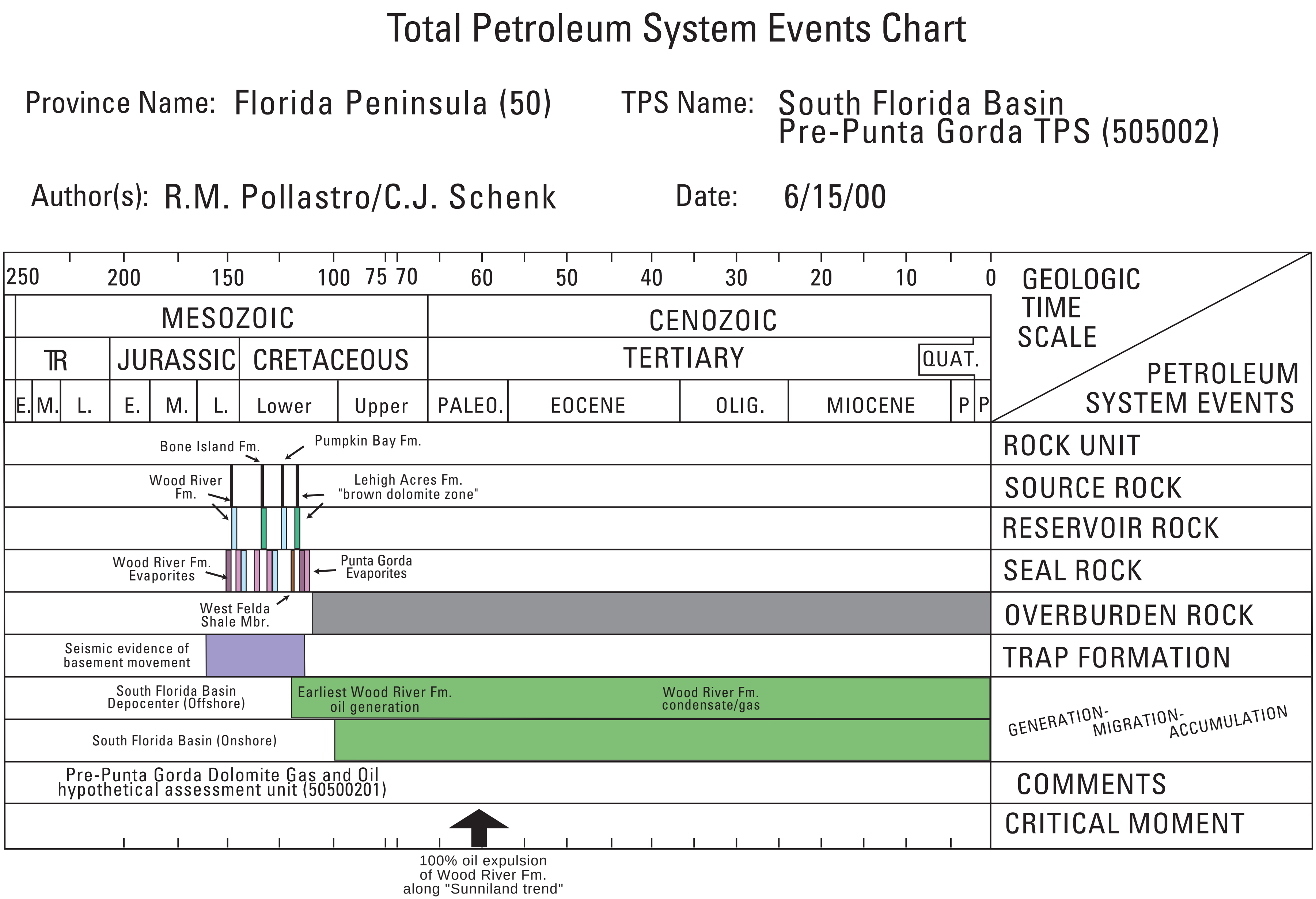

Figure 13. Total petroleum system (TPS) events chart for South Florida Basin Pre-Punta Gorda TPS and Pre-Punta Gorda Dolomite Gas and Oil hypothetical assessment unit.

sources, are predominant within the Wood River. Some evidence also exists for lacustrine deposition in the basal clastics. The depositional environment of the Wood River Formation, especially in the southern areas, probably favored reef growth; thus a combination of source, seal, and reservoir should be present.

The thermal maturation level favorable for oil generation is greater in this assessment unit than in the overlying Sunniland–Dollar Bay TPS. Oils of the Pumpkin Bay are predicted to be marginally to moderately mature having API gravities ranging between 25° and 50°, with higher GOR than Sunniland oils.

Burial History and Petroleum Generation

Figure 10 shows the results of a petroleum formation (expulsion) model for Type IIS kerogen calculated for the deep (total depth of 17,200 ft) Exxon Collier 20-2 well in Sunniland field, Collier County, where shows of gas and condensate were reported. The model used a geothermal gradient of 1.1°F/100 ft and a mean annual surface temperature of 70°F. In the modeled well of figure 10, the uppermost Pumpkin Bay is presently in the peak oil generation phase and has expelled over 60 percent of its oil. According to the model, the Bone Island Formation has expelled all oil within the past 5 million years and the Wood River Formation expelled all oil by the end of the Late Cretaceous (about 65 Ma). A summary of the Pre-Punta Gorda TPS linking the essential petroleum-system elements and processes is shown in the events chart of figure 13.

Reservoirs

Reservoir rocks consist of sucrosic dolomite and exhibit “pinpoint” intercrystalline to vuggy secondary porosity in beds found at least 50 ft below the top of the Twelve Mile Member of the Lehigh Acres Formation. As much as 50 ft of porous dolomite has been found onshore where the brown dolomite zone reaches a maximum thickness of about 100 ft. An area having the highest potential for discoveries onshore is defined by the porous zones shown by Applegate (1987) in Charlotte, Lee, Hendry, Collier, Highlands, and Glades Counties and adjacent State waters. Oil shows were observed in the Bass Collier 12-2 well in Collier County in dolomite having sonic well-log porosities ranging from 10 to 22 percent and core porosities as high as 18 volume percent. Good potential for new field discoveries is also predicted offshore in both State and Federal waters. In particular, oil stains were noted in wells where about 350 ft of mostly porous dolomite has been penetrated near the Marquesas Keys (Faulkner and Applegate, 1986; Lloyd, 1992).

Core porosities for the Pumpkin Bay are as high as about 20 percent, and sonic well-log porosities measure slightly higher. Porosities are generally lower in the Pumpkin Bay Formation than in potential reservoirs found in younger units.

Although no reservoir studies have been performed, documented evidence of good porosities within some lithologies in the Wood River Formation at depths >15,000 ft suggest that the unit has good potential for accumulations of gas in deep reservoirs. Moreover, the thick (1,700 ft on average) section allows for the presence of multiple horizons with reservoir potential. The basal clastics (fan, fan-delta, and fluvial-lacustrine and marine deposits) of the Wood River Formation are considered possible deep-gas and pinch-out reservoirs along the Peninsular arch. Porous dolomite, as described in the Mobil-Phillips Seminole C well near Seminole field, where minor gas production was recorded from dolomite having about 8 percent porosity with subsequent log analysis measuring 20 to 23 percent porosity zones, provides further evidence that the Wood River is a potential prospect for new field discoveries of deep gas.

Seal Rock

As in the Lower Cretaceous Shoal-Reef Oil AU, seal rocks are both local and regional, and most are intraformational evaporites or impermeable (“tight”) micritic carbonates. For example, the Wood River Formation contains interbedded anhydrite, salt stringers, and micritic limestones that could act as excellent seals for porous dolomite reservoirs. The Punta Gorda Anhydrite, however, is the major overlying seal for the Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU. As described earlier, the Punta Gorda Anhydrite is a regional seal that divides the two total petroleum systems in the South Florida Basin (fig. 3).

Geographic Extent and Boundary Conditions

The Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU is delineated by two areas having geologic conditions favorable for discoveries that, when combined, constrain the assessment unit boundary. One area favorable for discoveries is in the northern half of the assessment unit and is centered around the main producing portion of the Sunniland trend; a second favorable area is in the southern half of the assessment unit and lies over the Florida Keys and Florida Bay, extending southwest to the Marquesas Keys. The northern part of the assessment unit, mostly in Charlotte, Lee, Collier, and Hendry Counties, includes an area for potential discoveries where Applegate (1987) outlines porous brown dolomite and an area where the Pumpkin Bay Formation is shown to contain live oil in porous (6–16 percent porosity) dolomite. The northern segment of the assessment unit also corresponds to an area of brown dolomite where high porosity is caused by epigenetic dolomitization from an active geothermal lineament system (Saul, 1987).

The Pumpkin Bay Formation is mostly limestone except at its northern limit, where it is dolomite. Within the South

Florida Basin, the Pumpkin Bay is as thick as 1,200 ft in offshore Florida State waters of Charlotte Harbor; the formation is projected to thicken westward in Federal offshore waters and into the basin depocenter in Florida Bay (Faulkner and Applegate, 1986). Projections suggest that the formation is as much as 1,500 ft thick in this area and that good reservoirs exist within a thick porous dolomite zone (300–350 ft thick; pinpoint intercrystalline to vuggy secondary porosity as great as 25 percent) in the middle to upper part of the formation at depths from about 12,500 ft to >15,000 ft. Onshore, the Pumpkin Bay Formation is found at depths from about 12,500 to 14,000 ft.

The southern part of the assessment unit represents an area of potential discoveries where oil shows are reported from porous (25 percent porosity) brown dolomite of the Lehigh Acres Formation. Several oil shows are reported in thick, porous dolomite sections in the southern segment of the assessment unit (Faulkner and Applegate, 1986; Applegate, 1987; Lloyd, 1992), and in patch-reef and back-reef facies of the Wood River Formation, as interpreted by Faulkner and Applegate (1986).

Two shows having significant volumes of gas and gas/condensate are reported in porous dolomite of the Wood River Formation in a well at Seminole field and a well at Sunniland field, respectively. Organic geochemistry studies of well samples from the Wood River Formation indicate that the hydrocarbon-generating potential of the unit ranges from poor (<0.25 percent TOC) to excellent (>1.0 percent TOC) (Palacas and others, 1981; Faulkner and Applegate, 1986). Potential new field discoveries within the Wood River Formation may be in porous (8 percent or greater) dolomite reservoirs enclosed by anhydrite, salt stringers, and (or) micritic limestone at depths from about 15,000 to 19,000 ft onshore and in State waters. Some potential gas discoveries may lie within the basal clastics, perhaps as pinch-outs, along the Peninsular arch sourced by organic-rich lacustrine beds. The assessment unit includes areas of the southern part of basin where reef growth occurred. It is possible that gas in the Wood River Formation in the area of the Sunniland trend may have originated in deeper parts of the basin and migrated updip. Moreover, published seismic cross sections in Federal offshore areas of the South Florida Basin show faulting that extends from basement, through the Wood River, and into the Lower Cretaceous Bone Island Formation (Faulkner and Applegate, 1986). These structures could extend into the State waters and onshore to create several structural traps and hydrocarbon accumulations that are larger than the stratigraphic traps characteristic of fields currently producing from the Sunniland Formation.

General geologic and other conditions that constrain the assessment unit boundary include, but are not limited to, the following:

1. Western boundary delineated by State waters boundary and general absence of brown dolomite within the Lehigh Acres Formation,
2. South-southeastern boundary determined by State-Federal offshore waters boundary, and
3. Northeast boundary is updip limit of Punta Gorda Anhydrite, Wood River Formation, and brown dolomite of the Lehigh Acres Formation.

Assessment Methodology and Results

Background

USGS methodology for the assessment of undiscovered conventional oil and gas resources focuses on developing probability distributions of sizes and numbers of undiscovered oil and gas fields within each assessment unit. These distributions are the basis for the calculation of undiscovered oil and gas resources.

There are many approaches to determining the distributions of sizes and numbers of undiscovered oil and gas fields within an assessment unit, but there are two commonly used methods. The first involves interpretation of geologic prospects from seismic data, the second is an analysis of historic exploration and production information. In the Lower 48, the USGS typically does not have access to 2-D or 3-D seismic-survey grids that would allow for the development of a distribution of seismic prospects or prospect leads that can be volumetrically modeled and geologically risked to arrive at distributions of sizes and number of undiscovered oil and gas fields. Rather, we use the existing exploration and production data and the elements and processes of the petroleum system and assessment units (source rocks, timing of generation, migration, reservoirs, traps, seals) as a guide to the estimation of probability distributions of sizes and numbers of undiscovered fields. For hypothetical assessment units, we arrive at the distributions of sizes and numbers of undiscovered fields using analog data sets from other assessment units of the South Florida Basin and other U.S. basins where the elements of the petroleum system are similar. An assessment based on an analysis of historic production and exploration data may have more uncertainty related to the distributions of sizes and number of undiscovered fields than an assessment based on a distributions of sizes and numbers of geologically risked prospects interpreted from a set of closely spaced seismic lines. Capturing this geologic uncertainty with probability distributions of sizes and numbers is the crux of resource assessment. The volume of undiscovered oil and gas calculated from these distributions is given as the mean of the distribution, and the uncertainty is demonstrated by the range from the F_{95} to the F_5 of the distribution.

For the assessment of the South Florida Basin, the historic exploration and production data are from the Lower Cretaceous Shoal-Reef Oil AU, which contains eight oil fields greater than or equal to 0.5 MMBO (the minimum field size used in this assessment) and about 220 wildcat wells that can be used to examine past exploration and as a guide to future exploration and potential discoveries. The Pre-Punta Gorda

Dolomite Gas and Oil hypothetical AU is hypothetical, with no discovered oil or gas fields of the minimum size, and only a limited number of wells have partially penetrated the Pre-Punta Gorda part of the sedimentary section. For this hypothetical assessment unit, we utilized analog and exploration production data sets and geologic knowledge from the Upper Jurassic Smackover Formation of the onshore Gulf Coast (Schenk and Viger, 1995). The source, reservoirs, and trapping in the Smackover fields are considered similar to postulated Pre-Punta Gorda fields in the South Florida Basin.

Data Sources

The oil and gas well data were extracted from the IHS Energy Group (1999), Well History Control System (WHCS) database, including information on total depth, production formation, formation at total depth, perforation zones, production tests, final well classification, and production data. The reserves and production data for oil fields in the South Florida Basin were taken from the NRG Associates (1997) database.

USGS methodology requires the actual field size for each discovered oil and gas field. We arrive at the actual sizes of oil and gas fields by combining the "known" field size (cumulative production plus reserves) taken from the NRG Associates, Inc. database with an estimate of reserve growth. Reserve growth of existing fields is estimated using the method of Klett and Ahlbrandt (2000). The algorithm was based on reserve growth of fields in the lower 48 States of the United States. The addition of the reserve-growth contribution to the known field size produces a grown field size, which we believe is closer to the actual size of an oil or gas field. Grown field sizes were used throughout this analysis.

Wildcat-well data were derived from the IHS Energy Group (formerly Petroleum Information Corporation or PI) WHCS database. These wells include only those designated by initial well classification as wildcat wells, thus they do not include development or infill wells. We use the historical record of wildcat drilling as a proxy for the degree of exploration activity in an assessment unit.

We used two different methods to calculate distributions of undiscovered resources; a Monte Carlo simulation method (Charpentier and Klett, 2000) and the analytical probability method (Crovelli, 1999) were used to independently test the results of the input data. The two methods produced results to within 0.1 percent of each other at the mean. The results of the Monte Carlo simulations are given in Appendix C and Appendix D.

Lower Cretaceous Shoal-Reef Oil Assessment Unit

The geologic model for Lower Cretaceous Shoal-Reef Oil AU, as described in the earlier sections on geology and petroleum system elements, is one of reefs, shoals, carbonate mounds, bioherms, and related features, forming mainly stratigraphic traps sourced from organic-rich, calcareous units interbedded with the carbonates. Several stratigraphic horizons contain potential reservoirs in this assessment unit, and the main known hydrocarbon-bearing interval is the Sunniland Formation (fig. 3 and fig. 5); the Dollar Bay Formation is another unit with similar facies development with potential shoal-reef reservoirs.

The data for new-field wildcat wells in this assessment unit show that of the approximately 220 new-field wildcats, about half were drilled in a 15-year period between 1967 and 1985 (fig. 15). The number of new-field wildcats per year has dropped dramatically since that period (fig. 14 and fig. 15). The data for discovered field size and new-field wildcats (fig. 16) demonstrates that overall, as is the case in many basins worldwide, the size of oil and gas fields decreases with increasing numbers of wildcats as the larger fields generally are found early in the exploration history of an assessment unit. This relation is clearly shown on the plot of field size and discovery year in figure 17, where the sizes of discovered fields decreases with time. Plots of cumulative volumes of discovered oil with wildcat wells (fig. 18) and with discovery year (fig. 19) demonstrate that, although fields continue to be discovered, the fields are smaller, as shown by the flattening of the curve of cumulative oil volumes.

The exploration and production data illustrate that eight oil fields greater than or equal to minimum size (500,000 barrels) were discovered in the assessment unit between 1943 and 1985 and that the rate of discovery has been somewhat constant through time with respect to wildcat drilling. This discovery history also reflects the exploration methods in effect during this time period. Exploration was initially accomplished mainly with rank wildcats and evolved to drilling prospects interpreted from 2-D seismic surveys. The surge in exploration from 1965 to 1980 (fig. 15) probably reflects the use of 2-D seismic surveys combined with new concepts related to carbonate porosity and reservoir potential. In the future, exploration may be guided principally by interpretations of 3-D seismic surveys.

Input Data

The assessment input data for the Lower Cretaceous Shoal-Reef Oil AU is shown in Appendix A. Details on the data sheets and assessment model are described in Schmoker and Klett (2000). For the entire onshore and offshore State waters of the South Florida Basin, we used a minimum undiscovered field size of 0.5 MMBO. This minimum field size was determined after reviewing the historical data for the South Florida Basin, in particular, and for the United States in general. This value probably represents a minimum economic field size for this area given the characteristics of the hydrocarbons, especially the low API gravities, high sulfur content and water production, and the depths to production.

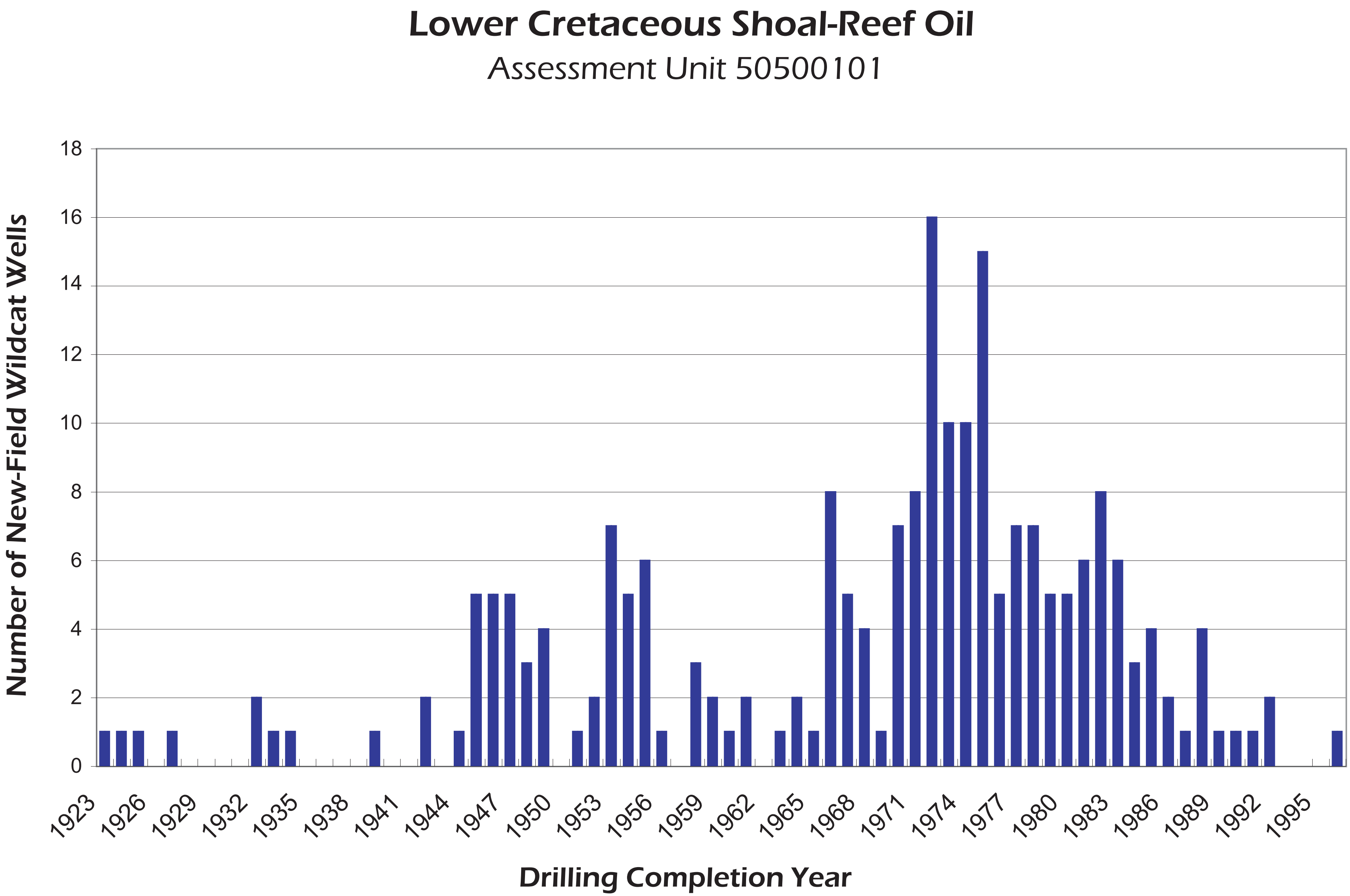

Figure 14. Plot of new-field wildcat wells versus drilling completion year for Lower Cretaceous Shoal-Reef Oil assessment unit, South Florida Basin, Florida.

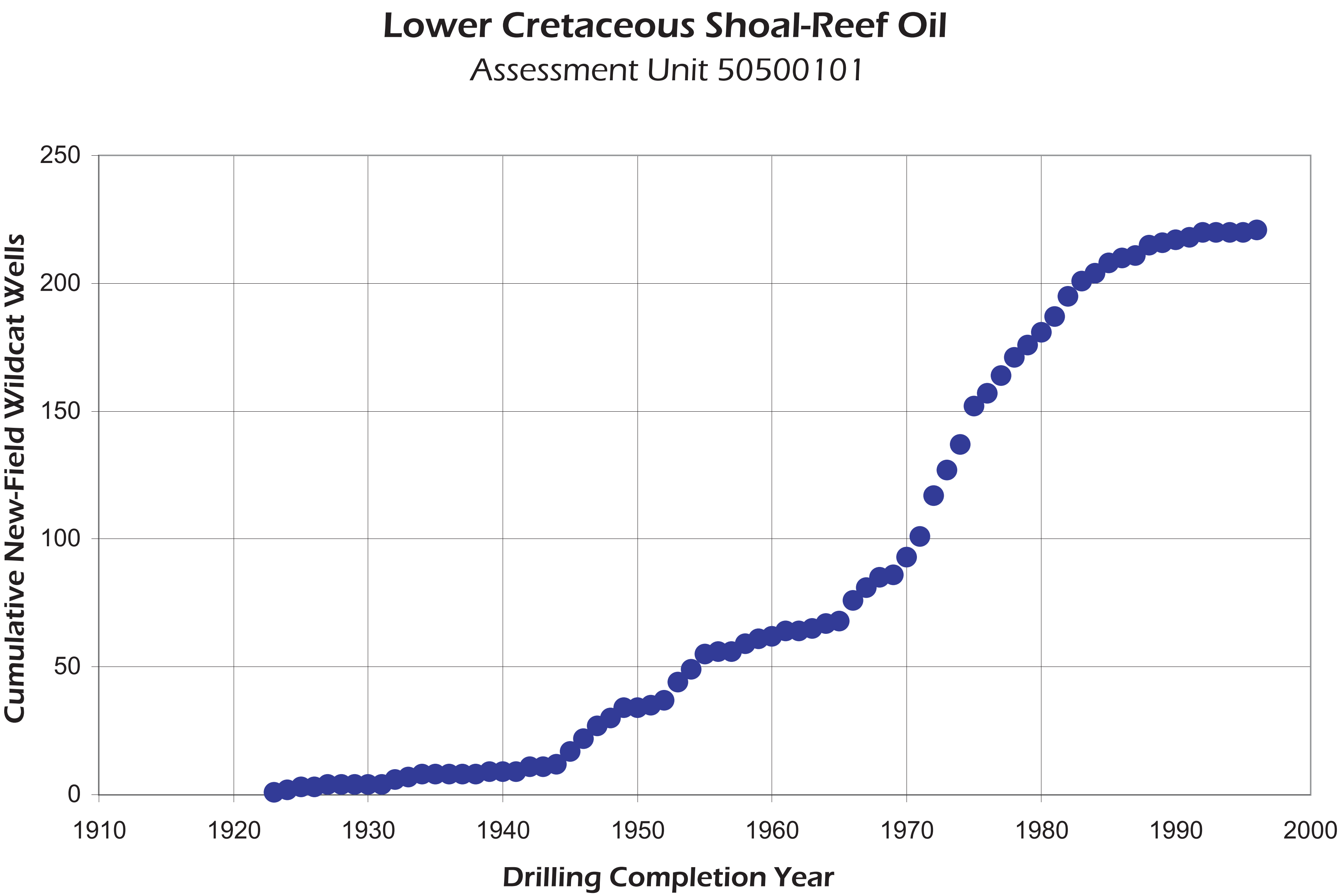

Figure 15. Plot of cumulative new-field wildcat wells versus drilling completion year for Lower Cretaceous Shoal-Reef Oil assessment unit, South Florida Basin, Florida.

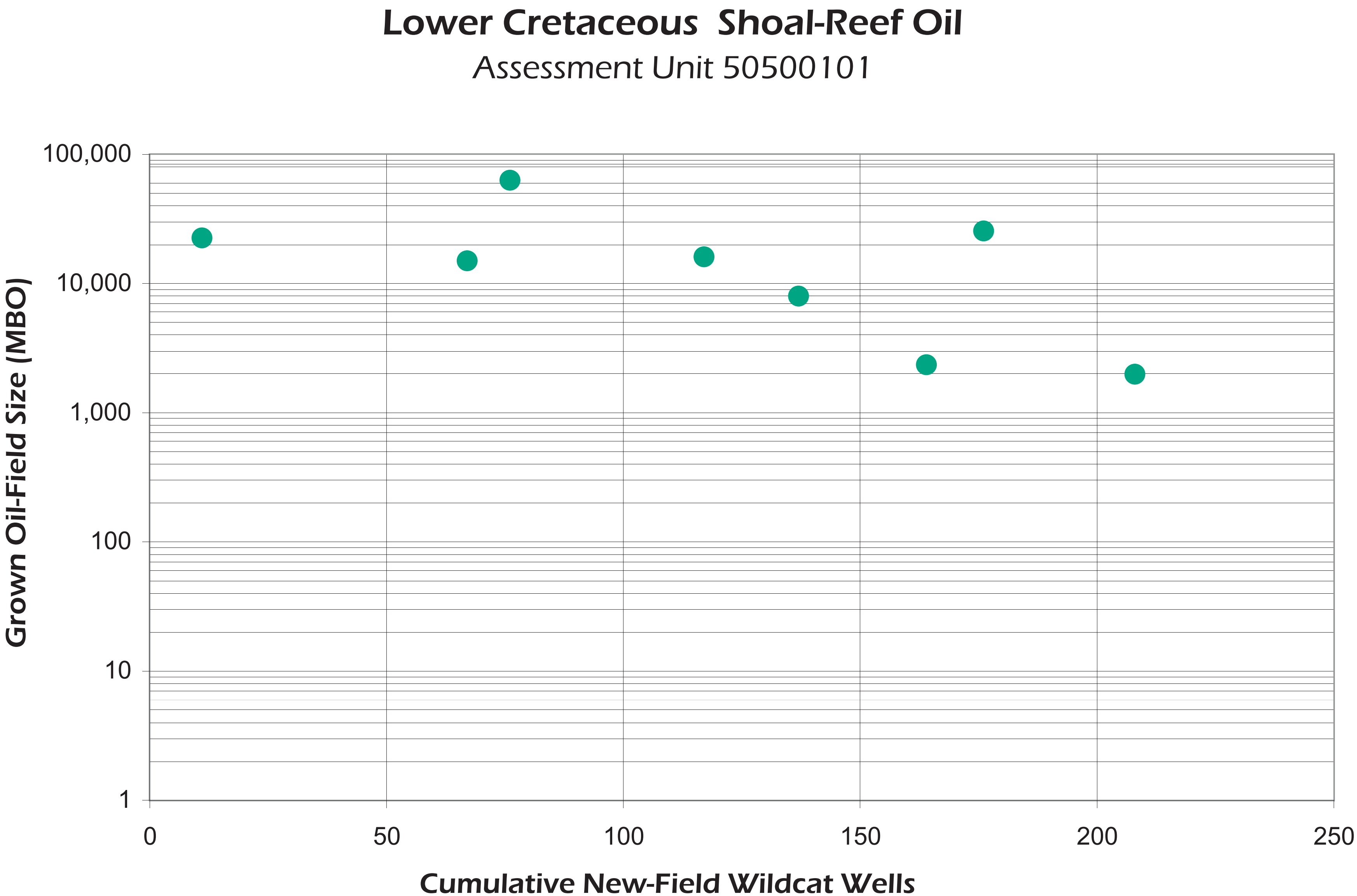

Figure 16. Plot of grown oil-field size versus cumulative new-field wildcat wells for Lower Cretaceous Shoal-Reef Oil assessment unit, South Florida Basin, Florida.

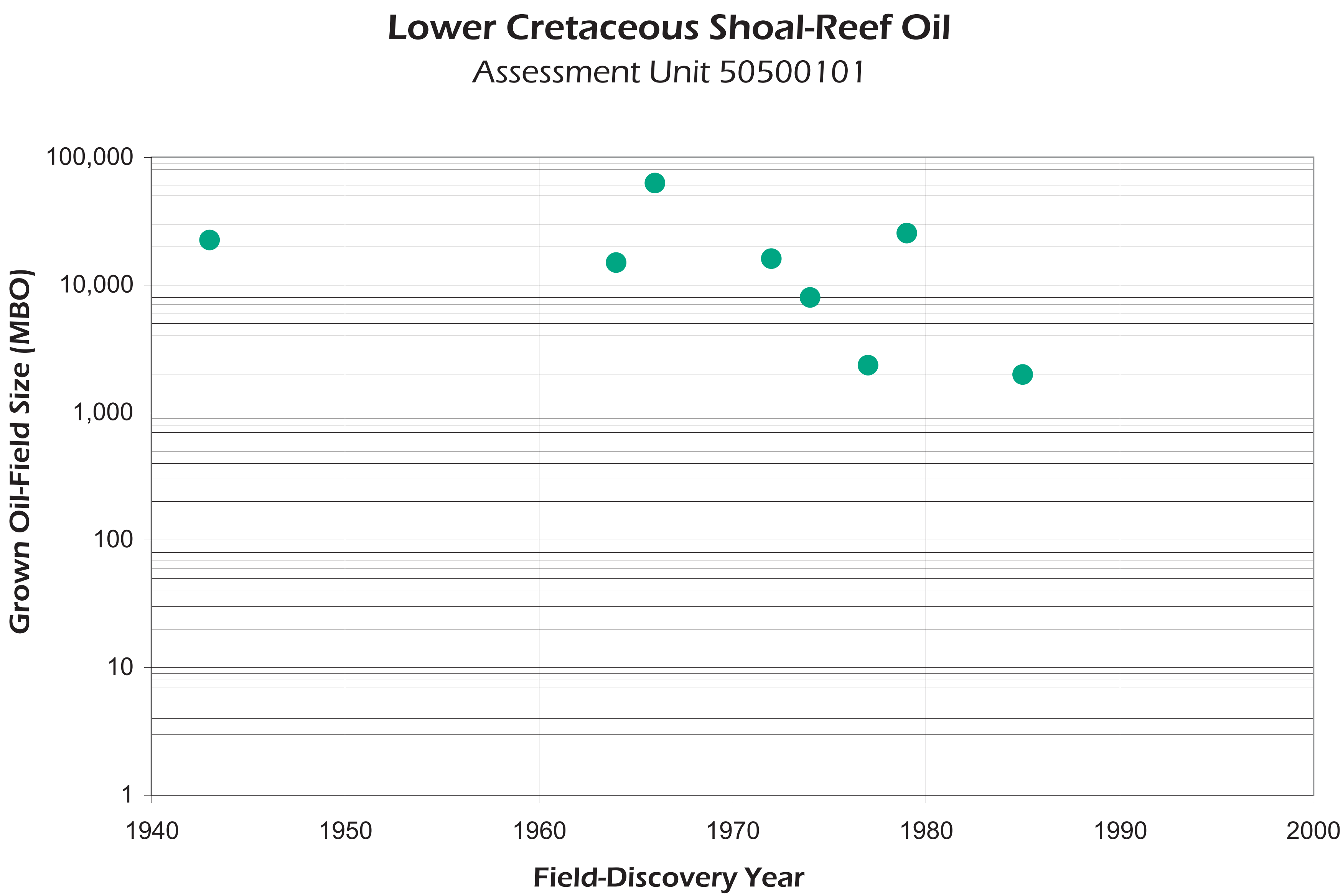

Figure 17. Plot of grown oil-field size versus field-discovery year for Lower Cretaceous Shoal-Reef Oil assessment unit, South Florida Basin, Florida.

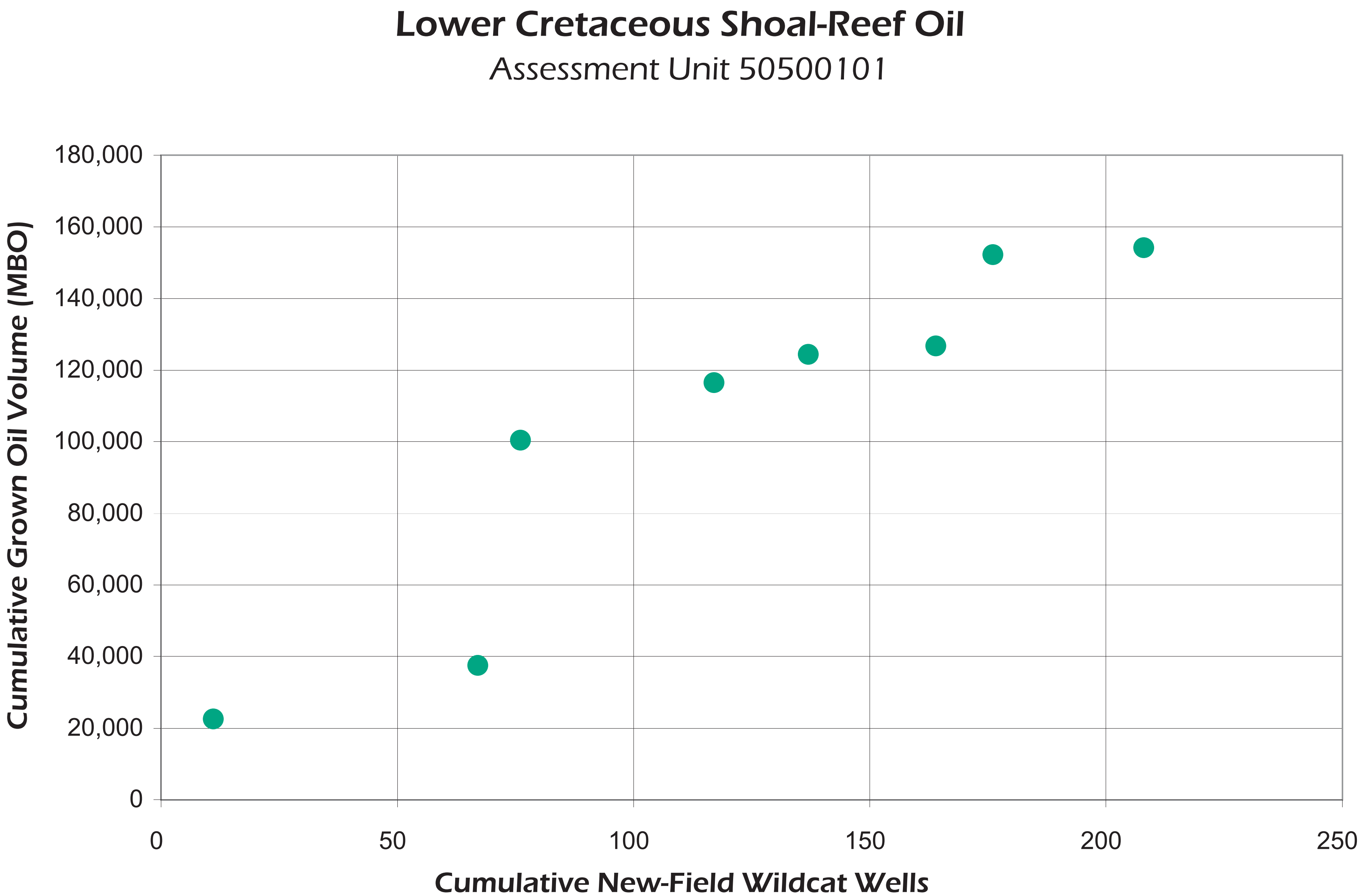

Figure 18. Plot of cumulative grown oil volume versus new-field wildcats for Lower Cretaceous Shoal-Reef Oil assessment unit, South Florida Basin, Florida.

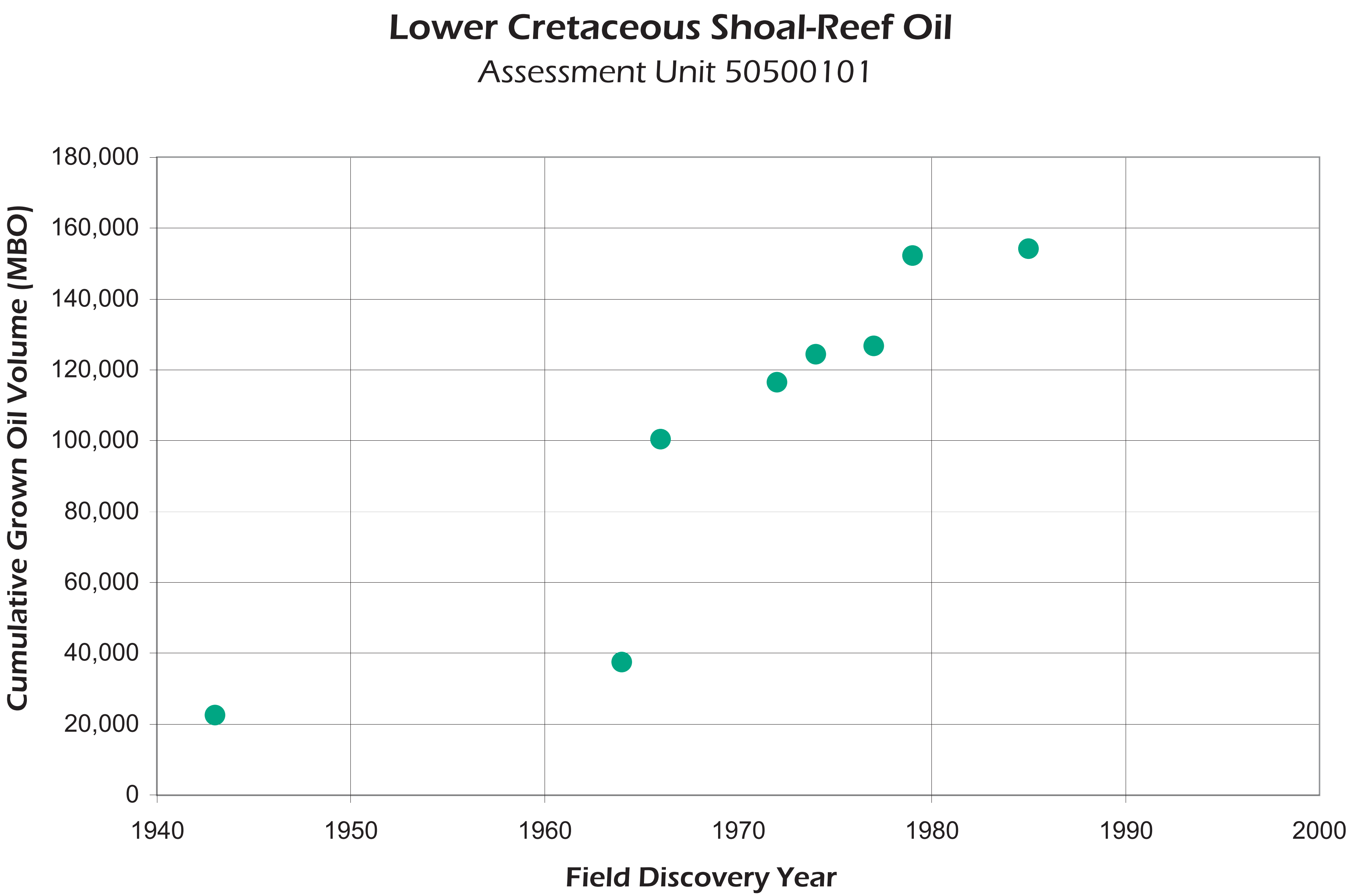

Figure 19. Plot of cumulative grown oil-field volume versus field-discovery year for Lower Cretaceous Shoal-Reef Oil assessment unit, South Florida Basin, Florida.

The historic production data indicate that the median size of fields has decreased through time from 19 MMBO for the first four fields (first discovery half) to 5 MMBO for the second four discovered fields (second discovery half) (Appendix A). We estimated that the median size for undiscovered fields would be 5 MMBO for the Lower Cretaceous Shoal-Reef Oil AU. The median size is generally expected to decrease with time, but we feel that the introduction of 3-D seismic data for this assessment unit may help retain the median size to values about 5 MMBO.

The next step is to determine the minimum, median, and maximum values of numbers of undiscovered fields in the assessment unit. For the minimum number, we estimated that at least two fields greater than minimum size would be discovered in the assessment unit. For the median number, we estimated that, although only eight fields have been discovered to date, most of the drilling was concentrated in the Sunniland “fairway,” and there is much room for exploration for potential reservoirs away from this trend. In addition, although the Sunniland interval remains the most potentially prospective interval in this assessment unit, other stratigraphic intervals, particularly the Dollar Bay Formation, may also have potential for undiscovered resources. We estimate that the median number of fields remaining to be discovered in the assessment unit is 25, with a maximum of 75 fields remaining to be discovered. We took into account that some potentially prospective intervals may be stacked and that exploration may result in one field discovery with several productive intervals; therefore, this avoided any “double counting” of numbers of undiscovered fields in this assessment unit.

Coproduct ratios, such as the gas/oil ratio (GOR) and the natural gas liquids/gas ratio (LGR) for oil fields, are important because our methodology uses these ratios to calculate gas in oil fields and NGL in oil and gas fields, which can have significant implications for the economic viability of fields, especially small fields. The coproduct ratios are given in Appendix A for the Lower Cretaceous Shoal-Reef Oil AU. Other ancillary data, such as API gravity, sulfur content, drilling depths, and water depth are also shown on the input form (Appendix A).

Assessment Results

The Monte Carlo simulation (Appendix C), verified by the analytical probability method, provided the following results for the Lower Cretaceous Shoal-Reef Oil AU of the South Florida Basin (table 2): oil in undiscovered oil fields ranges from an F_{95} (95 percent chance) of 43.22 MMBO to an F_5 (5 percent chance) of 615.03 MMBO, with a mean volume of undiscovered oil of 272.54 MMBO. The coproduct ratios (Appendix A) were used to calculate a range of associated gas in undiscovered oil fields from 4.05 BCFG (F_{95}) to 72.43 BCFG (F_5), with a mean volume of associated gas of 28.78 BCFG in undiscovered oil fields. Using the LGR, the volume of NGL in oil fields was calculated to range from 0.23 MMBNGL (F_{95}) to 4.52 MMBNGL (F_5), with a mean NGL of 1.72 MMBNGL in undiscovered oil fields.

These results indicate that for the Lower Cretaceous Shoal-Reef Oil AU, a mean of about 272 MMBO is undiscovered. With a total of about 120 MMBO already discovered, approximately one third of the oil has been discovered in this assessment unit.

Pre-Punta Gorda Dolomite Gas and Oil Hypothetical Assessment Unit

The hypothetical Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU was defined to include undiscovered gas in the Wood River Formation and minor oil accumulations in stratigraphic traps of the Lehigh Acres and Pumpkin Bay Formations, all below the regional Punta Gorda Anhydrite seal. Presently, there are no oil or gas fields in this assessment unit; several wells have penetrated the stratigraphic section with a few significant gas and condensate shows in Wood River dolomites. For this assessment unit, we used the geology and field-size distributions of plays of the Upper Jurassic Smackover Formation of the onshore areas of Alabama and Mississippi from the 1995 USGS assessment (Schenk and Viger, 1995) as analogs for developing the sizes and numbers of undiscovered fields.

Input Data

The input data for the Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU are shown in Appendix B. In our analysis of the risk involved with the geologic elements of this assessment unit, we concluded that there was a 10 percent chance that the hydrocarbon charge was inadequate to charge a field of minimum size within the assessment unit. Based on thermal maturity modeling (fig. 10) and reported gas and condensate shows, we interpret this assessment unit, in contrast to the first, to contain significantly more gas than oil, in terms of equivalent volumes (i.e., BOE).

Similar to the Lower Cretaceous Shoal-Reef Oil AU, a minimum field size of 0.5 MMBOE was chosen for both undiscovered gas and oil of the Pre-Punta Gorda AU. The Smackover Formation analog provided the geologic basis for the median size of 4 MMBOE, which we adopted for undiscovered gas and oil fields (Schenk and Viger, 1995). Smackover Formation fields, as with most field-size distributions, show a significant decrease in discovered field size with time, and the median size for this assessment unit reflects the downward trend of Smackover field size with time (fig. 20 and fig. 21).

The numbers of undiscovered fields were again based on the numbers of Smackover fields, the geology and petroleum-system elements of this assessment unit, and the geographical scale of the assessment unit. We estimate that more gas fields are present than oil fields by three to one. The median number

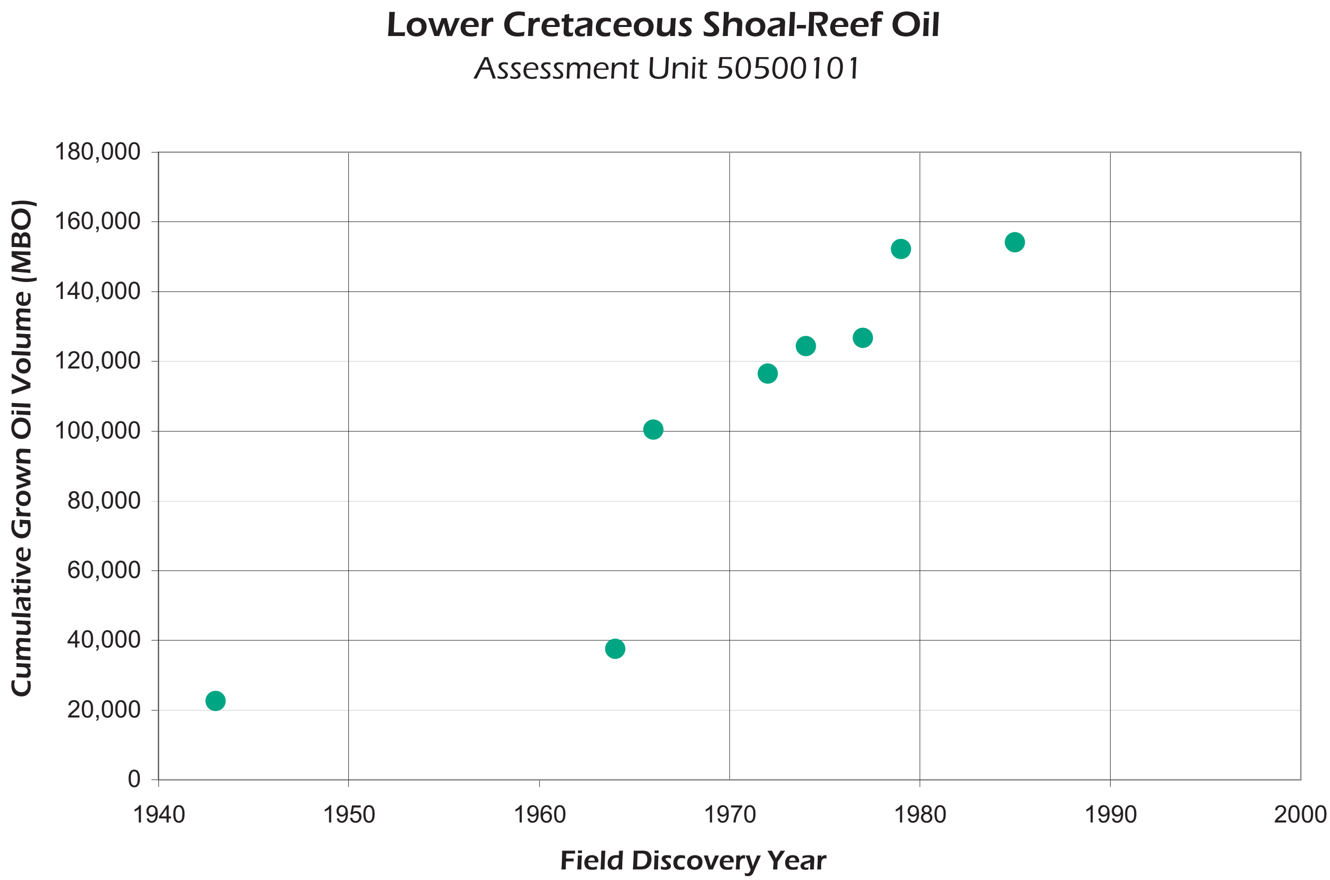

Figure 20. Plot of known oil accumulation size versus year of discovery and cumulative number of exporatory wells for the Smackover Formation of the Mississippi-Louisiana Salt Basins from Schenk and Viger (1995). Median oil accumulation size is 4 million barrels of oil (MMBO).

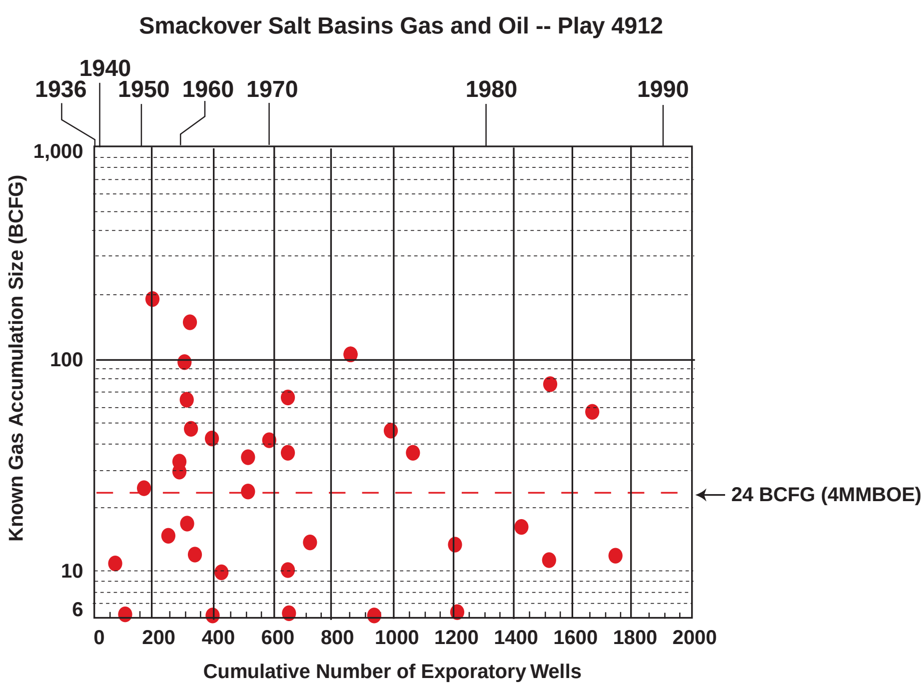

Figure 21. Plot of known gas accumulation size versus year of discovery and cumulative number of exporatory wells for the Smackover Formation of the Mississippi-Louisiana Salt Basins from Schenk and Viger (1995). Median gas accumulation size is 24 billion cubic feet of gas (BCFG) or 4 million barrels of oil equivalent (MMBOE).

Table 2. Assessment summary of undiscovered oil and gas from the Monte Carlo simulation in South Florida Basin, Florida, USGS Province 50, Florida Peninsula, from USGS total-petroleum-system-assessment-unit (TPS-AU) analysis.

[MMBOE, million barrels of oil equivalent. For this assessment, 6,000 cubic feet of gas equals 1 barrel of oil equivalent (BOE). MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids]

South Florida Basin (USGS Province 50--Florida Peninsula Province)

Sunniland–Dollar Bay TPS (500101) - Lower Cretaceous Shoal-Reef Oil AU (50010101)

	Mean	F_{95}	F_{50}	F_5
Oil in oil fields (MMBO)	272.54	43.22	238.94	615.03
Gas in oil fields (BCFG)	28.78	4.05	23.36	72.43
NGL in oil fields (MMBNGL)	1.72	0.23	1.36	4.52
AU SUBTOTAL (MMBOE)	**(279.06)**			

Pre-Punta Gorda TPS (500102) -Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU (50010201)

	Mean	F_{95}	F_{50}	F_5
Oil in oil fields (MMBO)	78.69	0.00	57.50	231.16
Gas in oil fields (BCFG)	83.78	0.00	56.30	259.78
NGL in oil fields (MMBNGL)	4.99	0.00	3.27	15.94
Gas in gas fields (BCFG)	1,545.41	0.00	1,288.97	3,951.48
NGL in gas fields (MMBNGL)	68.01	0.00	54.77	181.55
AU SUBTOTAL (MMBOE)	**(423.14)**			
MEAN TOTAL UNDISCOVERED RESOURCE (MMBOE)	**(702.20)**			

of 25 undiscovered gas fields (Appendix B) corresponds to a similar density of Smackover gas fields adjusted for the area of the assessment unit (Schenk and Viger, 1995). The median of eight oil fields further implies an assessment unit dominated by gas; oil is postulated only for the younger stratigraphic formations of lower thermal maturity in this assessment unit (fig. 3). The coproduct ratios and other ancillary data for the Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU are given in Appendix B.

Assessment Results

The Monte Carlo simulation (Appendix D), provided the following fully risked results for the Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU (table 2). Oil in undiscovered oil fields has a range 0.00 MMBO (F_{95}) to 231.16 MMBO (F_5), with a mean volume of undiscovered oil of 78.69 MMBO. The coproduct ratios (Appendix B) were used to calculate a range for associated gas in undiscovered oil fields from 0.00 BCFG (F_{95}) to 259.78 BCFG (F_5), with a mean volume of associated gas of 83.25 BCFG (13.88 MMBOE) in undiscovered oil fields. Using the LGR, the volume of NGL in oil fields was calculated to range from 0.00 MMBNGL (F_{95}) to 15.94 MMBNGL (F_5), with a mean NGL volume of 4.99 MMBNGL in oil fields. The largest undiscovered oil field is expected to be between 4.04 MMBO (F_{95}) and 121.61 MMBO (F_5), with a mean expectation of 38.61 MMBO.

For nonassociated gas (gas in gas fields), the Monte Carlo simulation and the analytical probability method provided the following results: total nonassociated gas volume in undiscovered gas fields ranges from 0.00 BCFG (F_{95}) to 3,951.48 BCFG (F_5), with a mean volume of undiscovered nonassociated gas of 1,545.41 BCFG (257.57 MMBOE) (table 2). The LGR (Appendix B) was used to calculate a range of NGL in undiscovered gas fields from 0.00 MMBNGL (F_{95}) to 181.55 MMBNGL (F_5), with a mean volume of 68.01 MMBNGL in undiscovered gas fields. In summary, the total mean volume of undiscovered resource in the Pre-Punta Gorda Dolomite Gas and Oil AU is 423.14 MMBOE.

The Monte Carlo simulation provides an estimate of the range of mean field size for the largest gas field expected in this assessment unit, which had a range from 76.48 BCFG (F_{95}) to 1,232.37 BCFG (F_5), with a mean of 452.11 BCFG. This estimate of the largest expected undiscovered gas field in the entire assessment unit represents a field of about 75 MMBOE, an estimated field size that is larger than any field yet discovered in the South Florida Basin. The degree of uncertainty of the sizes of undiscovered gas fields is shown by the spread in the resource distribution (table 2). The zeros in the F_{95} fractiles reflect that there is a 10 percent chance of no fields >0.5 MMBOE in the Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU.

Summary of Total-Petroleum-System Assessment of Undiscovered Oil and Gas Resources in the South Florida Basin

The results of our petroleum system assessment of the South Florida Basin are summarized in table 2. The assessment resulted in a mean volume of undiscovered oil of 272.54 MMBO for the Lower Cretaceous Shoal-Reef Oil AU and 78.69 MMBO for the Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU. The summed mean values of undiscovered oil resource is 351.23 MMBO for the South Florida Basin (272.55 MMBO plus 78.69 MMBO). For gas, the results provide a mean value for undiscovered nonassociated gas of 1,545.41 BCFG (about 258 MMBOE). For the South Florida Basin, the mean value for total associated gas in undiscovered oil fields is 112.56 BCFG (about 19 MMBOE), the mean value for NGL in undiscovered oil fields is about 6.71 MMBNGL, and the mean value of NGL in undiscovered gas fields is 68.01 MMBNGL. The total undiscovered petroleum resource (oil, gas, and natural gas liquids) for the South Florida Basin has a mean value of 702.20 MMBOE (table 2).

Comparison of Results of the 1995 USGS Play-Based Assessment to the 2000 Total-Petroleum-System-Assessment-Unit Assessment

A comparison of results for undiscovered oil and gas resources performed in the last decade (Pollastro, 1995, and this study) for the South Florida Basin, and Florida Peninsula Province (USGS Province 50) is summarized in table 3. The current 2000 USGS total-petroleum-system assessment, using assessment units, results in a total mean resource volume of about 702 MMBOE, compared to a total of about 377 MMBOE from the play-based assessment for the 1995 USGS National Oil and Gas Assessment (Pollastro, 1995). Although the present assessment of undiscovered resources of south Florida is almost twice as large as the 1995 USGS assessment, the difference is explained in this section.

As described in earlier sections of this report and illustrated in figure 3, four stratigraphic plays, 5001, 5002, 5003, and 5005 of the 1995 USGS assessment comprise the Lower Cretaceous Shoal-Reef Oil AU (Sunniland–Dollar Bay TPS); three of these plays apply to the Sunniland Formation and the fourth to the Dollar Bay Formation. Similarly, the Pre-Punta Gorda TPS and Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU incorporates the hypothetical Lower Cretaceous Carbonate Composite Oil (5004) and Wood River Dolomite Deep Gas (5006) plays of the 1995 USGS assessment (Pollastro, 1995; Pollastro and Viger, 1998). As in figure 3, table 3 also shows how the plays defined in the 1995 USGS assessment relate to the 2000 TPS-AU assessment of this report.

Collectively, the four plays comprising the Lower Cretaceous Shoal-Reef Oil AU were assessed lower (about 23 percent) in our present 2000 USGS assessment (279 MMBOE) than as assessed separately and summed (365 MMBOE) in the 1995 USGS assessment (table 3). The difference is attributed to more heavily weighted discoveries of oil in tidal shoal deposits of the upper Sunniland Formation, particularly along the main "Sunniland trend" or fairway; the potential for new field discoveries in Dollar Bay Formation shoals and patch reefs thus were reduced from the USGS assessment by Pollastro (1995).

The most significant difference between the current study and the 1995 USGS play-based assessment of the South Florida Basin (Pollastro, 1995) is the assessment of the Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU of the Pre-Punta Gorda TPS. In this assessment unit, a mean total undiscovered petroleum resource was estimated at about 423 MMBOE, of which about 258 MMBOE (about 1,545 BCFG), or 61 percent, is nonassociated gas. Moreover, about 68 MMBNGL accompanying the gas was calculated from the coproduct ratio (table 2 and table 3). The nonassociated gas and NGL of the Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU were assessed within porous dolomite and possible clastic pinch-out reservoirs in the Upper Jurassic(?) and Lower Cretaceous Wood River Formation—a play which was recognized and defined in the 1995 USGS assessment but not assessed (Pollastro, 1995).

In summary, a total of about 702 MMBOE undiscovered oil and gas is estimated for the South Florida Basin, as compared to a total of about 377 MMBOE from the 1995 USGS assessment (Pollastro, 1995); an increase of 86 percent. Much of the increase in undiscovered resource is due to our addition of deep, nonassociated gas in the Wood River Formation. In contrast, this assessment resulted in a decrease of mean undiscovered oil in shoal and patch reef reservoirs of the Dollar Bay Formation and in the lower Sunniland Formation.

Table 3. Comparison of assessment results for the 1995 USGS National Oil and Gas Assessment using play analysis (Pollastro, 1995) to the present total-petroleum-system-assessment-unit (TPS-AU) study of the South Florida Basin, Florida.

[MMBOE, million barrels of oil equivalent. For this assessment, 6,000 cubic feet of gas equals 1 barrel of oil equivalent (BOE). MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. Resources are rounded to nearest whole number]

1995 Play-Based Assessment		2000 TPS-AU Assessment	
Play name (number)	Mean resource (MMBOE)	Mean resource (MMBOE)	TPS-AU name (number)
Upper Sunniland Tidal Shoal Oil (5001)	258	279 [272.5 MMBO + 29 BCFG (4.8 MMBOE) + 1.7 MMBNGL]	Sunniland–Dollar Bay TPS (500101) - Lower Cretaceous Shoal-Reef Oil AU (50010101)
Lower Sunniland Fractured Dark Carbonate Oil (5002)	12		
Dollar Bay Shoal-Reef Dolomite Oil (5003)	67		
Extended Upper Sunniland Tidal Shoal (5005)	28		
Subtotal	**365**	**279**	
Lower Cretaceous Carbonate Composite Oil (5004)	12	423 [79 MMBO + 1,628 BCFG (271 MMBOE) + 73 MMBNGL]	Pre-Punta Gorda TPS (500102) - Pre-Punta Gorda Dolomite Gas and Oil hypothetical AU (50010201)
Wood River Dolomite Deep Gas (5006)	not assessed		
Subtotal	**12**	**423**	
TOTAL	**377**	**702**	

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Appendix A—Assessment Data Input, Lower Cretaceous Shoal-Reef Oil Assessment Unit (50500101)

Introductory Statement

Contained in this Appendix are the detailed input characteristics, selected ancillary data, and country or other land-parcel allocations of undiscovered resources for the Lower Cretaceous Shoal-Reef Oil assessment unit (50500101). These data were used in the calculations of the undiscovered resources and may be of use to those pursuing further analysis of the results.

Seventh Approximation Data Form

SEVENTH APPROXIMATION
NATIONAL ASSESSMENT OF OIL AND GAS RESOURCES
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS

Date:…………………………..	5/22/2000		
Assessment Geologist:……..	C.J. Schenk and R.M. Pollastro		
Region:………………………..	North America	Number:	5
Province:………………………	Florida Peninsula	Number:	5050
Total Petroleum System:……	South Florida Basin Sunniland/Dollar Bay	Number:	505001
Assessment Unit:……………	Lower Cretaceous Shoal-Reef Oil	Number:	50500101
* Notes from Assessor	Lower 48 Growth Function		

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) **or** Gas (≥20,000 cfg/bo overall):… Oil

What is the minimum field size?………. 0.5 mmboe grown (≥1mmboe)
(the smallest field that has potential to be added to reserves in the next 30 years)

Number of discovered fields exceeding minimum size:………… Oil: 8 Gas: 0
Established (>13 fields) ____ Frontier (1-13 fields) X Hypothetical (no fields) ____

Median size (grown) of discovered oil fields (mmboe):
1st half 19 2nd half 5.1 ____
Median size (grown) of discovered gas fields (bcfg):
1st 3rd ____ 2nd 3rd ____ 3rd 3rd ____

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an undiscovered field ≥ minimum size………………	1.0
2. **ROCKS:** Adequate reservoirs, traps, and seals for an undiscovered field ≥ minimum size……	1.0
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered field ≥ minimum size	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3):……...……....…. 1.0

4. **ACCESSIBILITY:** Adequate location to allow exploration for an undiscovered field ≥ minimum size…………………………………………………..………………..……..………… 1.0

UNDISCOVERED FIELDS

Number of Undiscovered Fields: How many undiscovered fields exist that are ≥ minimum size?:
(uncertainty of fixed but unknown values)

	min. no. (>0)	median no.	max no.
Oil fields:…………………………………	2	25	75
Gas fields:………………………………			

Size of Undiscovered Fields: What are the anticipated sizes (**grown**) of the above fields?:
(variations in the sizes of undiscovered fields)

	min. size	median size	max. size
Oil in oil fields (mmbo)………………..……	0.5	5	200
Gas in gas fields (bcfg):……………………			

Assessment Unit (name, no.)
Lower Cretaceous Shoal-Reef Oil, 50500101

AVERAGE RATIOS FOR UNDISCOVERED FIELDS, TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Fields:	minimum	median	maximum
Gas/oil ratio (cfg/bo)………………………..………	50	100	200
NGL/gas ratio (bngl/mmcfg)…………………...….	30	60	90

Gas fields:	minimum	median	maximum
Liquids/gas ratio (bngl/mmcfg)….…………..……..			
Oil/gas ratio (bo/mmcfg)…………………………..…			

SELECTED ANCILLARY DATA FOR UNDISCOVERED FIELDS
(variations in the properties of undiscovered fields)

Oil Fields:	minimum	median	maximum
API gravity (degrees)…………………….…………	15	25	35
Sulfur content of oil (%)………………………...…..	0.5	1.5	4
Drilling Depth (m) ……………...…………….……..	2500	3500	4500
Depth (m) of water (if applicable)……………...…..	0	30	100

Gas Fields:	minimum	median	maximum
Inert gas content (%)…………………………....……			
CO_2 content (%)…………………………………...….			
Hydrogen-sulfide content (%)……………………...…….			
Drilling Depth (m)……………………………………			
Depth (m) of water (if applicable)………………….			

Assessment Unit (name, no.)
Lower Cretaceous Shoal-Reef Oil, 50500101

ALLOCATION OF UNDISCOVERED RESOURCES IN THE ASSESSMENT UNIT
TO COUNTRIES OR OTHER LAND PARCELS (uncertainty of fixed but unknown values)

1. Florida represents 100 areal % of the total assessment unit

Oil in Oil Fields:	minimum	median	maximum
Richness factor (unitless multiplier):……………..…	1	1	1
Volume % in parcel (areal % x richness factor):…	100	100	100
Portion of volume % that is offshore (0-100%)……	26	30	34

Gas in Gas Fields:	minimum	median	maximum
Richness factor (unitless multiplier):……………..…			
Volume % in parcel (areal % x richness factor):…			
Portion of volume % that is offshore (0-100%)……			

2. Florida Peninsula, Province 50 represents 100 areal % of the total assessment unit

Oil in Oil Fields:	minimum	median	maximum
Richness factor (unitless multiplier):……………..…	1	1	1
Volume % in parcel (areal % x richness factor):…	100	100	100
Portion of volume % that is offshore (0-100%)……	26	30	34

Gas in Gas Fields:	minimum	median	maximum
Richness factor (unitless multiplier):……………..…			
Volume % in parcel (areal % x richness factor):…			
Portion of volume % that is offshore (0-100%)……			

Appendix B—Assessment Data Input, Pre-Punta Gorda Dolomite Oil and Gas Hypothetical Assessment Unit (50500201)

Introductory Statement

Contained in this Appendix are the detailed input characteristics, selected ancillary data, and country or other land-parcel allocations of undiscovered resources for the Pre-Punta Gorda Dolomite Gas and Oil assessment unit (50500101). These data were used in the calculations of the undiscovered resources and of may be of use to those pursuing further analysis of the results.

Seventh Approximation Data Form

SEVENTH APPROXIMATION
NEW MILLENNIUM WORLD PETROLEUM ASSESSMENT
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS

Date:…………………………..	5/22/2000		
Assessment Geologist:……..	R.M. Pollastro and C.J. Schenk		
Region:………………………..	North America	Number:	5
Province:………………………	Florida Peninsula	Number:	5050
Total Petroleum System:……	South Florida Basin Pre-Punta Gorda	Number:	505002
Assessment Unit:……………	Pre-Punta Gorda Dolomite Gas and Oil Hypothetical	Number:	50500201
* Notes from Assessor	Plays 4910 and 4912 as analogs		

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) **or** Gas (≥20,000 cfg/bo overall):… Gas

What is the minimum field size?………. 0.5 mmboe grown (≥1mmboe)
(the smallest field that has potential to be added to reserves in the next 30 years)

Number of discovered fields exceeding minimum size:………… Oil: 0 Gas: 0
Established (>13 fields) ____ Frontier (1-13 fields) ____ Hypothetical (no fields) X

Median size (grown) of discovered oil fields (mmboe):
1st 3rd ____ 2nd 3rd ____ 3rd 3rd ____
Median size (grown) of discovered gas fields (bcfg):
1st 3rd ____ 2nd 3rd ____ 3rd 3rd ____

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an undiscovered field ≥ minimum size………………	0.9
2. **ROCKS:** Adequate reservoirs, traps, and seals for an undiscovered field ≥ minimum size……	1.0
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered field ≥ minimum size	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3):…….……….…. 0.9

4. **ACCESSIBILITY:** Adequate location to allow exploration for an undiscovered field ≥ minimum size…………………………………………………………………………………… 1.0

UNDISCOVERED FIELDS

Number of Undiscovered Fields: How many undiscovered fields exist that are ≥ minimum size?:
(uncertainty of fixed but unknown values)

	min. no. (>0)	median no.	max no.
Oil fields:…………………………………	1	8	24
Gas fields:………………………………	2	25	75

Size of Undiscovered Fields: What are the anticipated sizes (**grown**) of the above fields?:
(variations in the sizes of undiscovered fields)

	min. size	median size	max. size
Oil in oil fields (mmbo)…………………….	0.5	4	300
Gas in gas fields (bcfg):……………………	3	24	2000

Assessment Unit (name, no.)
Pre-Punta Gorda Dolomite Hypothetical Gas and Oil, 50500201

AVERAGE RATIOS FOR UNDISCOVERED FIELDS, TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Fields:	minimum	median	maximum
Gas/oil ratio (cfg/bo)………………………...………	500	1000	2000
NGL/gas ratio (bngl/mmcfg)……………………...….	30	60	90

Gas fields:	minimum	median	maximum
Liquids/gas ratio (bngl/mmcfg)….……………..……..	22	44	66
Oil/gas ratio (bo/mmcfg)………………………….….			

SELECTED ANCILLARY DATA FOR UNDISCOVERED FIELDS
(variations in the properties of undiscovered fields)

Oil Fields:	minimum	median	maximum
API gravity (degrees)…………………….………….	20	35	50
Sulfur content of oil (%)………………………...…..	0.5	1.5	4
Drilling Depth (m) ……………...…………….……..	3200	4200	5200
Depth (m) of water (if applicable)……………...…..	0	30	100

Gas Fields:	minimum	median	maximum
Inert gas content (%)…………………………....….			
CO_2 content (%)……………………………….....….			
Hydrogen-sulfide content (%)………………...…….			
Drilling Depth (m)……………………………………	4500	5500	6500
Depth (m) of water (if applicable)…………………	0	30	100

Assessment Unit (name, no.)
Pre-Punta Gorda Dolomite Hypothetical Gas and Oil, 50500201

ALLOCATION OF UNDISCOVERED RESOURCES IN THE ASSESSMENT UNIT
TO COUNTRIES OR OTHER LAND PARCELS (uncertainty of fixed but unknown values)

1. Florida represents 100 areal % of the total assessment unit

Oil in Oil Fields:	minimum	median	maximum
Richness factor (unitless multiplier):……………..…	1	1	1
Volume % in parcel (areal % x richness factor):…	100	100	100
Portion of volume % that is offshore (0-100%)……	33	36	39

Gas in Gas Fields:	minimum	median	maximum
Richness factor (unitless multiplier):……………..…	1	1	1
Volume % in parcel (areal % x richness factor):…	100	100	100
Portion of volume % that is offshore (0-100%)……	33	36	39

2. Florida Peninsula, Province 50 represents 100 areal % of the total assessment unit

Oil in Oil Fields:	minimum	median	maximum
Richness factor (unitless multiplier):……………..…	1	1	1
Volume % in parcel (areal % x richness factor):…	100	100	100
Portion of volume % that is offshore (0-100%)……	33	36	39

Gas in Gas Fields:	minimum	median	maximum
Richness factor (unitless multiplier):……………..…	1	1	1
Volume % in parcel (areal % x richness factor):…	100	100	100
Portion of volume % that is offshore (0-100%)……	33	36	39

Appendix C—Monte Carlo Assessment Output—Lower Cretaceous Shoal-Reef Oil Assessment Unit (50500101)

Introductory Statement

Contained in this Appendix are detailed descriptions of the probability distributions of the results of the assessment of AU 50500101, the Lower Cretaceous Shoal-Reef Oil assessment unit. These details may be of use to those pursuing further analysis of the results. Each distribution is documented by two pages. On the first page are the distribution parameters, most importantly the mean, as well as a graph of the probability density function. The second page lists the percentiles (fractiles) of the distribution at 5-percent intervals.

Also included in Appendix C are the descriptions of probability distributions of the input based on the input parameters documented in Appendix A. Each of the distributions used in calculating the results is documented by its parameters and a graph of the probability density function. Note that, for the distribution of size of undiscovered oil fields, the parameters of both the shifted and unshifted lognormal distributions are given. The accompanying graph is that of the unshifted distribution.

Forecast Results

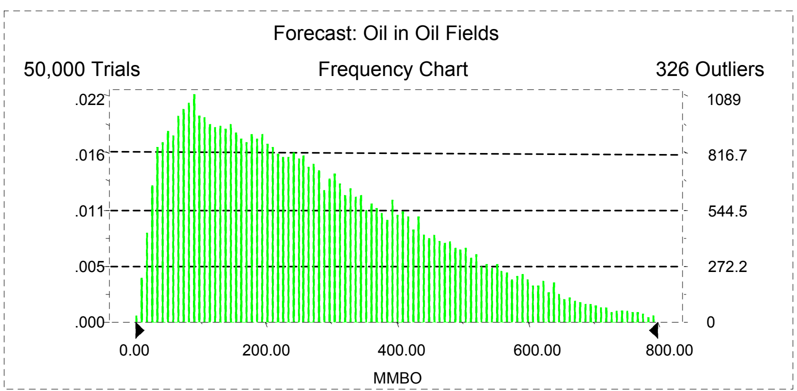
Forecast: Oil in Undiscovered Oil Fields

Summary:

Display range is from 0.00 to 800.00 MMBO
Entire range is from 3.36 to 1,143.91 MMBO
After 50,000 trials, the standard error of the mean is 0.81

Statistics:

	Value
Trials	50000
Mean	272.54
Median	238.94
Mode	---
Standard Deviation	180.93
Variance	32,734.41
Skewness	0.78
Kurtosis	3.13
Coefficient of Variability	0.66
Range Minimum	3.36
Range Maximum	1,143.91
Range Width	1,140.55
Mean Standard Error	0.81



Forecast: Oil in Undiscovered Oil Fields (cont'd)

Percentiles:

Percentile	MMBO
100%	3.36
95%	43.22
90%	65.14
85%	84.89
80%	104.04
75%	125.05
70%	146.28
65%	168.20
60%	191.06
55%	213.83
50%	238.94
45%	263.99
40%	291.61
35%	320.88
30%	353.73
25%	390.37
20%	428.25
15%	474.42
10%	532.37
5%	615.03
0%	1,143.91

End of Forecast

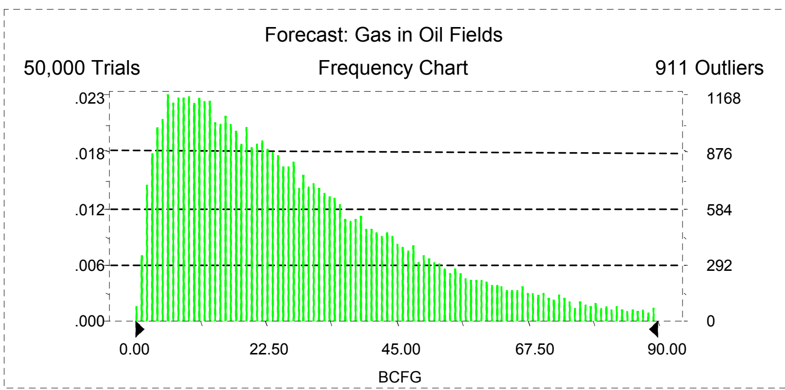
Forecast: Gas in Undiscovered Oil Fields

Summary:

Display range is from 0.00 to 90.00 BCFG
Entire range is from 0.30 to 174.06 BCFG
After 50,000 trials, the standard error of the mean is 0.10

Statistics:

	Value
Trials	50000
Mean	28.78
Median	23.36
Mode	---
Standard Deviation	22.05
Variance	486.35
Skewness	1.36
Kurtosis	5.30
Coefficient of Variability	0.77
Range Minimum	0.30
Range Maximum	174.06
Range Width	173.76
Mean Standard Error	0.10



Forecast: Gas in Undiscovered Oil Fields (cont'd)

Percentiles:

Percentile	BCFG
100%	0.30
95%	4.05
90%	6.15
85%	8.11
80%	10.05
75%	12.03
70%	14.06
65%	16.23
60%	18.51
55%	20.90
50%	23.36
45%	26.02
40%	28.95
35%	32.11
30%	35.61
25%	39.79
20%	44.62
15%	50.69
10%	59.16
5%	72.43
0%	174.06

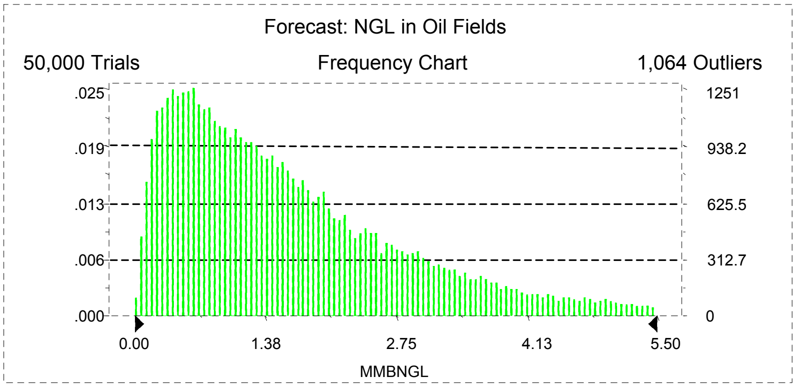
End of Forecast

Forecast: NGL in Undiscovered Oil Fields

Summary:

Display range is from 0.00 to 5.50 MMBNGL
Entire range is from 0.02 to 12.57 MMBNGL
After 50,000 trials, the standard error of the mean is 0.01

Statistics:	Value
Trials	50000
Mean	1.72
Median	1.36
Mode	---
Standard Deviation	1.39
Variance	1.93
Skewness	1.54
Kurtosis	6.25
Coefficient of Variability	0.81
Range Minimum	0.02
Range Maximum	12.57
Range Width	12.56
Mean Standard Error	0.01



Forecast: NGL in Undiscovered Oil Fields (cont'd)

Percentiles:

Percentile	MMBNGL
100%	0.02
95%	0.23
90%	0.35
85%	0.46
80%	0.58
75%	0.69
70%	0.81
65%	0.94
60%	1.07
55%	1.21
50%	1.36
45%	1.52
40%	1.69
35%	1.89
30%	2.10
25%	2.37
20%	2.68
15%	3.07
10%	3.60
5%	4.52
0%	12.57

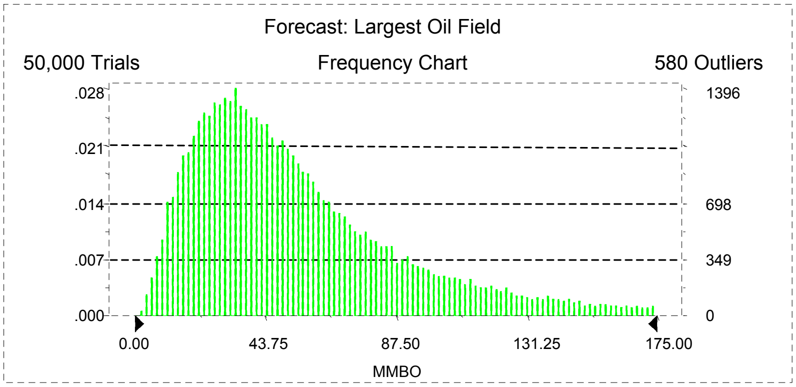
End of Forecast

Forecast: Largest Undiscovered Oil Field

Summary:

Display range is from 0.00 to 175.00 MMBO
Entire range is from 1.86 to 200.00 MMBO
After 50,000 trials, the standard error of the mean is 0.17

Statistics:	Value
Trials	50000
Mean	55.94
Median	46.51
Mode	---
Standard Deviation	37.06
Variance	1,373.67
Skewness	1.29
Kurtosis	4.59
Coefficient of Variability	0.66
Range Minimum	1.86
Range Maximum	200.00
Range Width	198.13
Mean Standard Error	0.17



Forecast: Largest Undiscovered Oil Field (cont'd)

Percentiles:

Percentile	MMBO
100%	1.86
95%	13.51
90%	18.30
85%	22.22
80%	25.75
75%	29.15
70%	32.45
65%	35.71
60%	39.12
55%	42.76
50%	46.51
45%	50.66
40%	55.01
35%	60.01
30%	65.81
25%	72.75
20%	81.30
15%	92.31
10%	108.16
5%	133.76
0%	200.00

End of Forecast

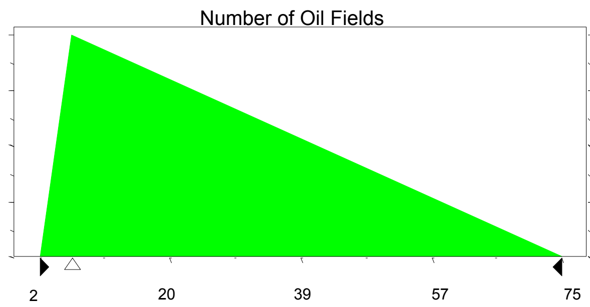
Assumptions

Assumption: Number of Undiscovered Oil Fields

Triangular distribution with parameters:

Minimum	2
Likeliest	7
Maximum	75

Selected range is from 2 to 75
Mean value in simulation was 28

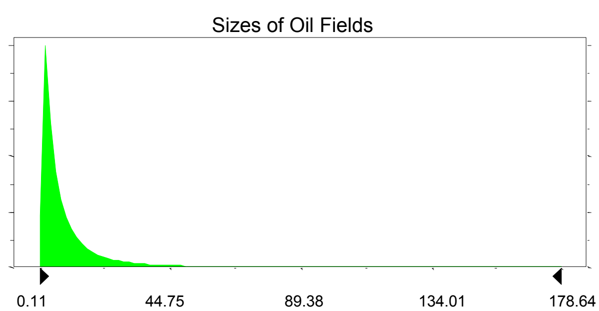


Assumption: Sizes of Undiscovered Oil Fields

Lognormal distribution with parameters:		Shifted parameters
Mean	9.55	10.05
Standard Deviation	17.89	17.89

Selected range is from 0.00 to 199.50	0.50 to 200.00
Mean value in simulation was 9.25	9.75

Assumption: Sizes of Undiscovered Oil Fields (cont'd)

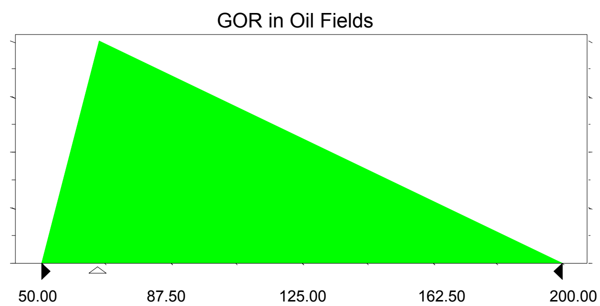


Assumption: GOR in Undiscovered Oil Fields

Triangular distribution with parameters:

Minimum	50.00
Likeliest	66.67
Maximum	200.00

Selected range is from 50.00 to 200.00
Mean value in simulation was 105.57

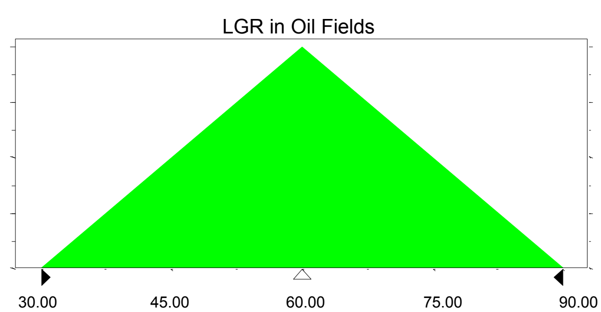


Assumption: LGR in Undiscovered Oil Fields

Triangular distribution with parameters:

Minimum	30.00
Likeliest	60.00
Maximum	90.00

Selected range is from 30.00 to 90.00
Mean value in simulation was 59.94



Appendix D—Monte Carlo Assessment Output—Pre-Punta Gorda Dolomite Oil and Gas Hypothetical Assessment Unit (50500201)

Introductory Statement

Contained in this Appendix are detailed descriptions of the probability distributions of the results of the assessment of AU 50500201, the Pre-Punta Gorda Dolomite Gas and Oil hypothetical assessment unit. These details may be of use to those pursuing further analysis of the results. All distributions in this Appendix are fully risked. They include the probability of there being no oil or gas fields of minimum size or larger. Each distribution is documented by two pages. On the first page are the distribution parameters, most importantly the mean, as well as a graph of the probability density function. The second page lists the percentiles (fractiles) of the distribution at 5-percent intervals.

Also included in Appendix D are the descriptions of probability distributions of the input based on the input parameters documented in Appendix B. Each of the distributions used in calculating the results is documented by its parameters and a graph of the probability density function. Note that, for the distribution of size of undiscovered oil fields and for the distribution of size of undiscovered gas fields, the parameters of both the shifted and unshifted lognormal distributions are given. The accompanying graph is that of the unshifted distribution.

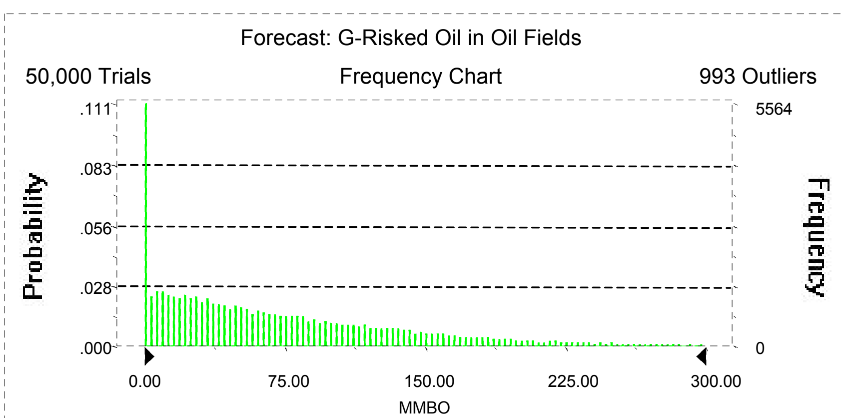
Forecast Results

Forecast: Geologic-Risked Oil in Undiscovered Oil Fields

Summary:

Display range is from 0.00 to 300.00 MMBO
Entire range is from 0.00 to 786.78 MMBO
After 50,000 trials, the standard error of the mean is 0.35

Statistics:	Value
Trials	50000
Mean	78.69
Median	57.50
Mode	0.00
Standard Deviation	77.35
Variance	5,982.29
Skewness	1.63
Kurtosis	6.73
Coefficient of Variability	0.98
Range Minimum	0.00
Range Maximum	786.78
Range Width	786.78
Mean Standard Error	0.35



Forecast: Geologic-Risked Oil in Undiscovered Oil Fields (cont'd)

Percentiles:

Percentile	MMBO
100%	0.00
95%	0.00
90%	0.00
85%	7.82
80%	13.81
75%	20.27
70%	26.87
65%	33.77
60%	41.00
55%	49.13
50%	57.50
45%	66.77
40%	77.07
35%	87.80
30%	100.54
25%	114.85
20%	131.77
15%	152.18
10%	181.41
5%	231.16
0%	786.78

End of Forecast

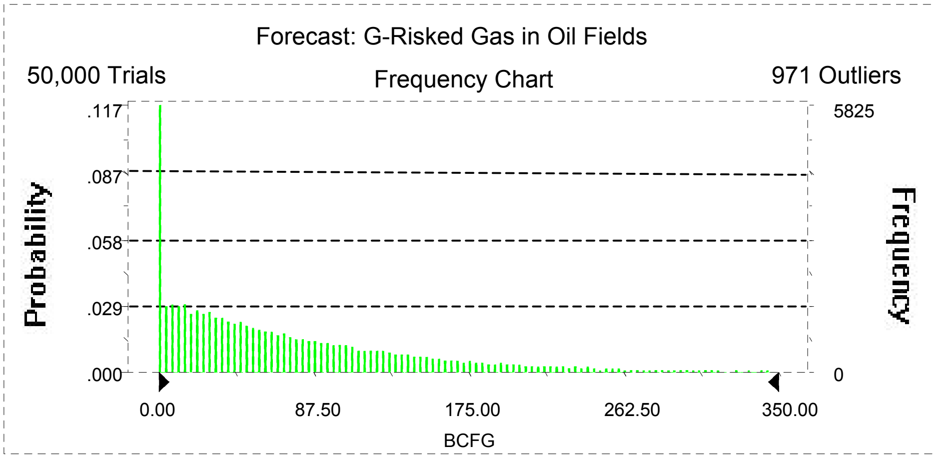
Forecast: Geologic-Risked Gas in Undiscovered Oil Fields

Summary:

Display range is from 0.00 to 350.00 BCFG
Entire range is from 0.00 to 959.60 BCFG
After 50,000 trials, the standard error of the mean is 0.40

Statistics:

	Value
Trials	50000
Mean	83.25
Median	56.30
Mode	0.00
Standard Deviation	90.17
Variance	8,129.94
Skewness	2.13
Kurtosis	9.84
Coefficient of Variability	1.08
Range Minimum	0.00
Range Maximum	959.60
Range Width	959.60
Mean Standard Error	0.40



Forecast: Geologic-Risked Gas in Undiscovered Oil Fields (cont'd)

Percentiles:

Percentile	BCFG
100%	0.00
95%	0.00
90%	0.00
85%	7.42
80%	13.37
75%	19.33
70%	25.86
65%	32.59
60%	39.80
55%	47.79
50%	56.30
45%	65.54
40%	76.03
35%	87.92
30%	101.37
25%	117.29
20%	135.85
15%	160.51
10%	196.84
5%	259.78
0%	959.60

End of Forecast

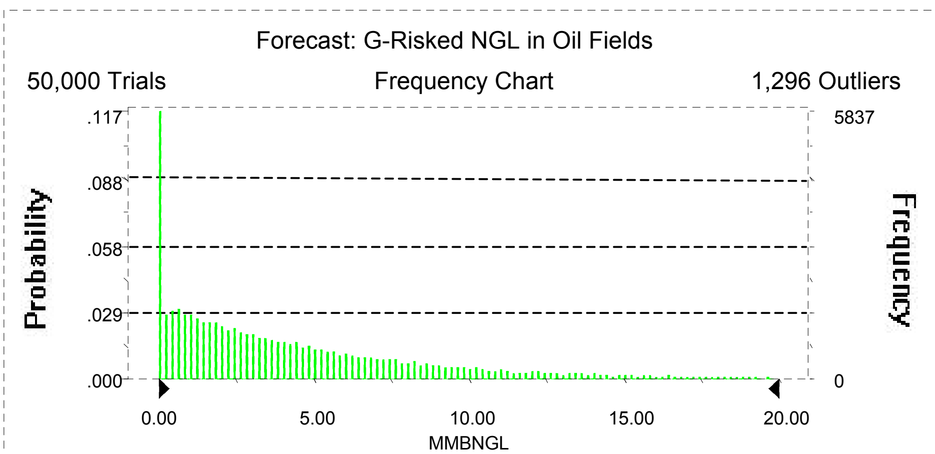
Forecast: Geologic-Risked NGL in Undiscovered Oil Fields

Summary:

Display range is from 0.00 to 20.00 MMBNGL
Entire range is from 0.00 to 68.38 MMBNGL
After 50,000 trials, the standard error of the mean is 0.03

Statistics:

	Value
Trials	50000
Mean	4.99
Median	3.27
Mode	0.00
Standard Deviation	5.64
Variance	31.84
Skewness	2.41
Kurtosis	12.36
Coefficient of Variability	1.13
Range Minimum	0.00
Range Maximum	68.38
Range Width	68.38
Mean Standard Error	0.03



Forecast: Geologic-Risked NGL in Undiscovered Oil Fields (cont'd)

Percentiles:

Percentile	MMBNGL
100%	0.00
95%	0.00
90%	0.00
85%	0.43
80%	0.76
75%	1.11
70%	1.48
65%	1.88
60%	2.30
55%	2.77
50%	3.27
45%	3.83
40%	4.45
35%	5.14
30%	5.95
25%	6.92
20%	8.09
15%	9.62
10%	11.89
5%	15.94
0%	68.38

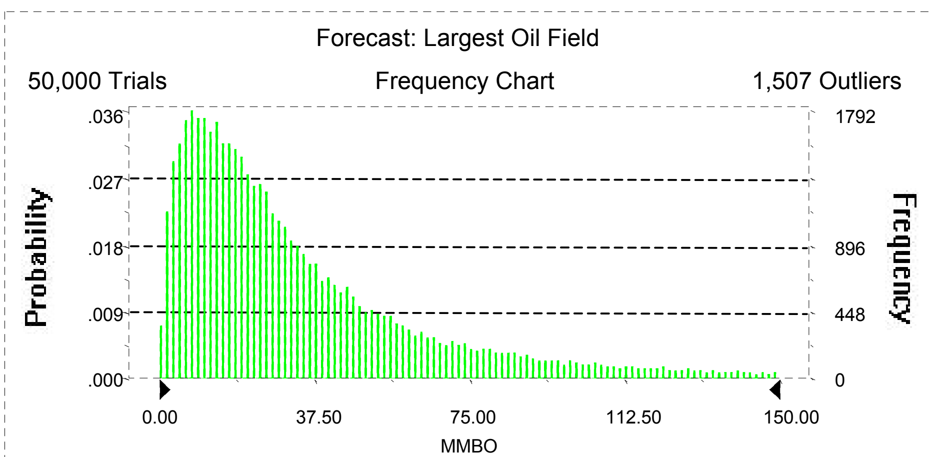
End of Forecast

Forecast: Largest Undiscovered Oil Field

Summary:

Display range is from 0.00 to 150.00 MMBO
Entire range is from 0.52 to 299.61 MMBO
After 50,000 trials, the standard error of the mean is 0.18

Statistics:	Value
Trials	50000
Mean	38.61
Median	25.43
Mode	---
Standard Deviation	41.02
Variance	1,682.59
Skewness	2.52
Kurtosis	11.14
Coefficient of Variability	1.06
Range Minimum	0.52
Range Maximum	299.61
Range Width	299.09
Mean Standard Error	0.18



Forecast: Largest Undiscovered Oil Field (cont'd)

Percentiles:

Percentile	MMBO
100%	0.52
95%	4.04
90%	6.44
85%	8.54
80%	10.66
75%	12.87
70%	15.06
65%	17.43
60%	19.87
55%	22.53
50%	25.43
45%	28.60
40%	32.31
35%	36.65
30%	41.87
25%	48.15
20%	56.48
15%	68.23
10%	86.26
5%	121.61
0%	299.61

End of Forecast

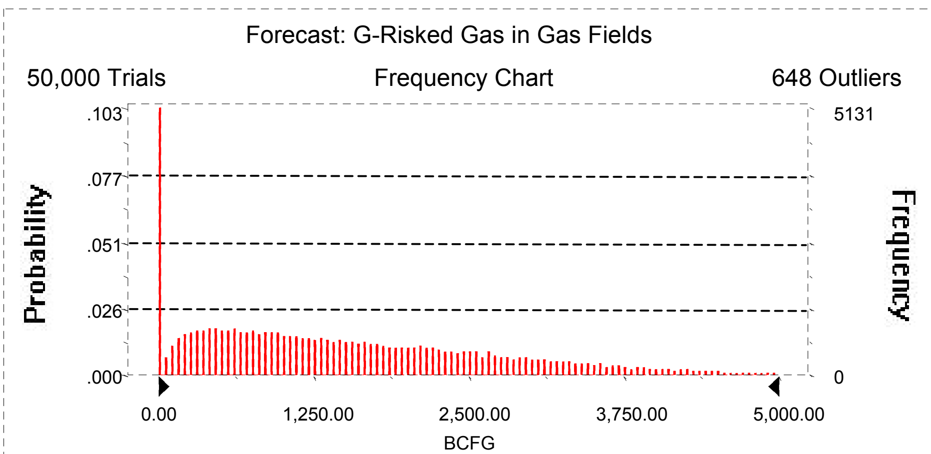
Forecast: Geologic-Risked Gas in Undiscovered Gas Fields

Summary:

Display range is from 0.00 to 5,000.00 BCFG
Entire range is from 0.00 to 8,837.54 BCFG
After 50,000 trials, the standard error of the mean is 5.66

Statistics:

	Value
Trials	50000
Mean	1,545.41
Median	1,288.97
Mode	0.00
Standard Deviation	1,266.44
Variance	########
Skewness	0.91
Kurtosis	3.56
Coefficient of Variability	0.82
Range Minimum	0.00
Range Maximum	8,837.54
Range Width	8,837.54
Mean Standard Error	5.66



Forecast: Geologic-Risked Gas in Undiscovered Gas Fields (cont'd)

Percentiles:

Percentile	BCFG
100%	0.00
95%	0.00
90%	0.00
85%	240.93
80%	383.88
75%	522.23
70%	662.26
65%	808.38
60%	959.29
55%	1,116.40
50%	1,288.97
45%	1,471.04
40%	1,662.65
35%	1,866.24
30%	2,091.40
25%	2,325.76
20%	2,594.55
15%	2,922.48
10%	3,330.87
5%	3,951.48
0%	8,837.54

End of Forecast

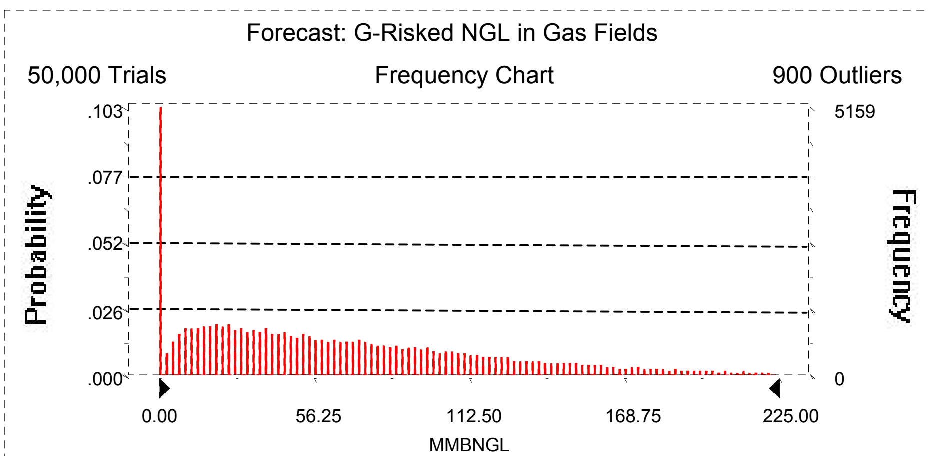
Forecast: Geologic-Risked Liquids in Undiscovered Gas Fields

Summary:

Display range is from 0.00 to 225.00 MMBNGL
Entire range is from 0.00 to 509.88 MMBNGL
After 50,000 trials, the standard error of the mean is 0.26

Statistics:

	Value
Trials	50000
Mean	68.01
Median	54.77
Mode	0.00
Standard Deviation	58.54
Variance	3,426.85
Skewness	1.15
Kurtosis	4.49
Coefficient of Variability	0.86
Range Minimum	0.00
Range Maximum	509.88
Range Width	509.88
Mean Standard Error	0.26



Forecast: Geologic-Risked Liquids in Undiscovered Gas Fields (cont'd)

Percentiles:

Percentile	MMBNGL
100%	0.00
95%	0.00
90%	0.00
85%	10.13
80%	16.24
75%	22.01
70%	27.84
65%	34.22
60%	40.55
55%	47.43
50%	54.77
45%	62.73
40%	71.21
35%	79.93
30%	89.94
25%	100.63
20%	113.14
15%	128.54
10%	149.60
5%	181.55
0%	509.88

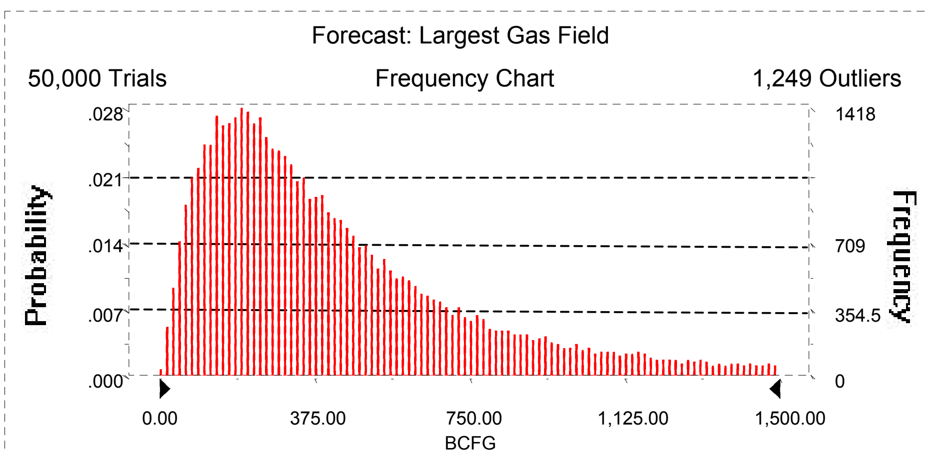
End of Forecast

Forecast: Largest Undiscovered Gas Field

Summary:

Display range is from 0.00 to 1,500.00 BCFG
Entire range is from 6.25 to 1,999.94 BCFG
After 50,000 trials, the standard error of the mean is 1.63

Statistics:	Value
Trials	50000
Mean	452.11
Median	345.64
Mode	---
Standard Deviation	364.20
Variance	########
Skewness	1.60
Kurtosis	5.67
Coefficient of Variability	0.81
Range Minimum	6.25
Range Maximum	1,999.94
Range Width	1,993.69
Mean Standard Error	1.63



Forecast: Largest Undiscovered Gas Field (cont'd)

Percentiles:

Percentile	BCFG
100%	6.25
95%	76.48
90%	110.53
85%	140.14
80%	168.25
75%	195.63
70%	222.12
65%	249.79
60%	279.49
55%	310.89
50%	345.64
45%	383.94
40%	424.71
35%	471.72
30%	526.95
25%	592.77
20%	674.07
15%	783.84
10%	945.60
5%	1,232.37
0%	1,999.94

End of Forecast

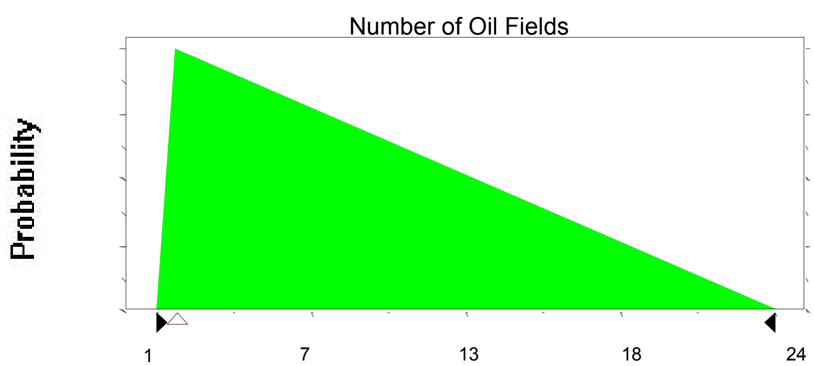
Assumptions

Assumption: Number of Undiscovered Oil Fields

Triangular distribution with parameters:

Minimum	1
Likeliest	2
Maximum	24

Selected range is from 1 to 24
Mean value in simulation was 9

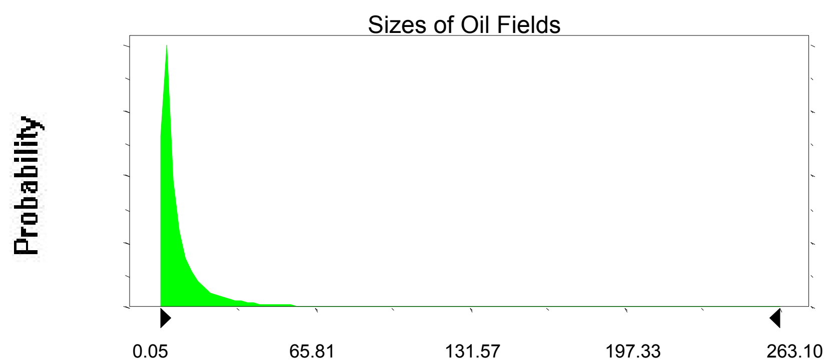


Assumption: Sizes of Undiscovered Oil Fields

Lognormal distribution with parameters:		Shifted parameters
Mean	9.87	10.37
Standard Deviation	26.02	26.02

Selected range is from 0.00 to 299.50 — 0.50 to 300.00
Mean value in simulation was 9.38 — 9.88

Assumption: Sizes of Undiscovered Oil Fields (cont'd)

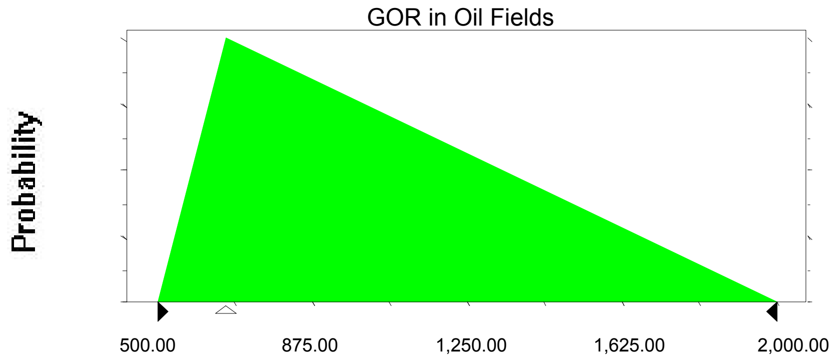


Assumption: GOR in Undiscovered Oil Fields

Triangular distribution with parameters:

Minimum	500.00
Likeliest	666.67
Maximum	2,000.00

Selected range is from 500.00 to 2,000.00
Mean value in simulation was 1,056.58

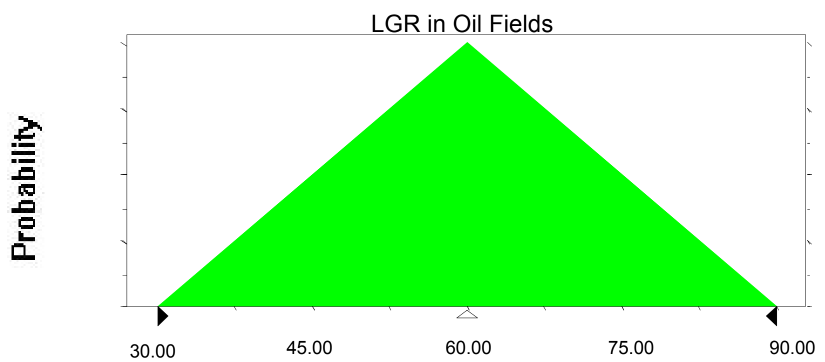


Assumption: LGR in Undiscovered Oil Fields

Triangular distribution with parameters:

Minimum	30.00
Likeliest	60.00
Maximum	90.00

Selected range is from 30.00 to 90.00
Mean value in simulation was 59.91



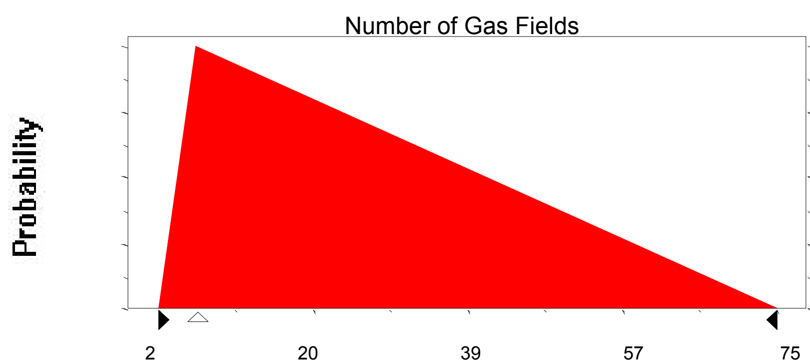
Assumption: Number of Undiscovered Gas Fields

Triangular distribution with parameters:

Minimum	2
Likeliest	7
Maximum	75

Selected range is from 2 to 75
Mean value in simulation was 28

Assumption: Number of Undiscovered Gas Fields (cont'd)



Chapter 2

1995 USGS National Oil and Gas Play-Based Assessment of the South Florida Basin, Florida Peninsula Province

Click here to return to **Volume Title Page**

By Richard M. Pollastro

National Assessment of Oil and Gas Project:

Petroleum Systems and Assessment of the South Florida Basin

Compiled by Richard M. Pollastro *and* Christopher J. Schenk

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By Richard M. Pollastro

Overview

The Florida Peninsula, USGS Province 50, as defined by the 1995 USGS National Oil and Gas Assessment (Gautier and others, 1995), includes all of the State of Florida east of the Apalachicola River and the adjoining State waters; the part of the Florida panhandle west of the Apalachicola River is part of Province 49 (fig. 1). The boundary in the panhandle between Province 50 and Province 49 is a generally north-south-trending line between the counties of Gadsden, Liberty, and Franklin to the east and the counties of Jackson, Calhoun, and Gulf to the west. Province 50, inclusive of State waters, is approximately 150 mi wide and about 400 mi long totaling about 60,000 mi^2. It is bounded to the north by the State boundary with Georgia and to the east, south, and southwest by the boundaries of Florida State waters. The State water boundaries extend to 10.36 statute miles on the Gulf of Mexico side of Florida and to 3 miles on the Atlantic Ocean side (the Gulf-Atlantic boundary line extends westward from the Marquesas Keys along lat 24°35′N., and then turns southward, just west of the Dry Tortugas, along the 83rd west meridian) (fig. 1).

Six conventional hydrocarbon plays were delineated in the South Florida Basin of Province 50 (fig. 2) for the purposes of the 1995 USGS National Oil and Gas Assessment (Gautier and others, 1995; Pollastro and Viger, 1998). The Upper Sunniland Tidal Shoal Oil play (5001) and the Lower Sunniland Fractured “Dark Carbonate” Oil play (5002) are confirmed plays. At the time of the 1995 National Oil and Gas Assessment, about 103 million barrels of oil (MMBO) had been produced from these known plays.

The remaining four plays in the 1995 assessment are hypothetical. They are the Dollar Bay Shoal-Reef Dolomite Oil play (5003), the Lower Cretaceous Carbonate Composite Oil play (5004), the Extended Upper Sunniland Tidal Shoal Oil play (5005), and the Wood River Dolomite Deep Gas play (5006). The easternmost portion of the Smackover Alabama/Florida Updip Oil play (4911) also extends into the Florida Peninsula Province but has been assigned to the Louisiana-Mississippi Salt Basins Province 49; therefore, this play is not shown or defined in this report.

About 370 MMB of undiscovered oil were estimated in the assessment using a play-based methodology from the five plays of the South Florida Basin; an additional 57.5 billion cubic feet of gas (BCFG) or 10 million barrels of oil equivalent (MMBOE) were estimated as gas in oil fields (table 1). Most of the 370 MMBO was from the Lower Cretaceous Sunniland Formation with the two Upper Sunniland Tidal Shoal Oil plays (5001, 5005) estimated to contain 281 million barrels of undiscovered oil.

In 2000, the South Florida Basin was again assessed using the total-petroleum-system method, an approach to assessment of undiscovered oil and gas outlined in detail by the U.S. Geological Survey World Energy Assessment Team (2000). In the total-petroleum-system method, the assessment unit (a subset of the total petroleum system) is used rather than the play as the basic unit to assess the volume of undiscovered oil and gas. The results of the 2000 USGS assessment of the South Florida Basin using the total petroleum system are described in an accompanying report on this CD-ROM.

Hydrocarbon Play Descriptions

Play 5001—Upper Sunniland Tidal Shoal Oil Play

Known only in the subsurface, the Lower Cretaceous Sunniland Formation is the basal unit of the Ocean Reef Group (fig. 2). Onshore, the formation is relatively uniform in thickness and consists of limestone, dolomite, and anhydrite. The upper part of the Sunniland Formation produces heavy, marginally mature varieties of crude oil onshore from porous bioclastic debris mounds, banks, and pods on the eastern margin of the South Florida Basin. The region of productive reservoir facies of the upper Sunniland Formation is defined in part by eight fields that have either produced more than one million barrels of oil (MMBO), or have estimated ultimate recoveries

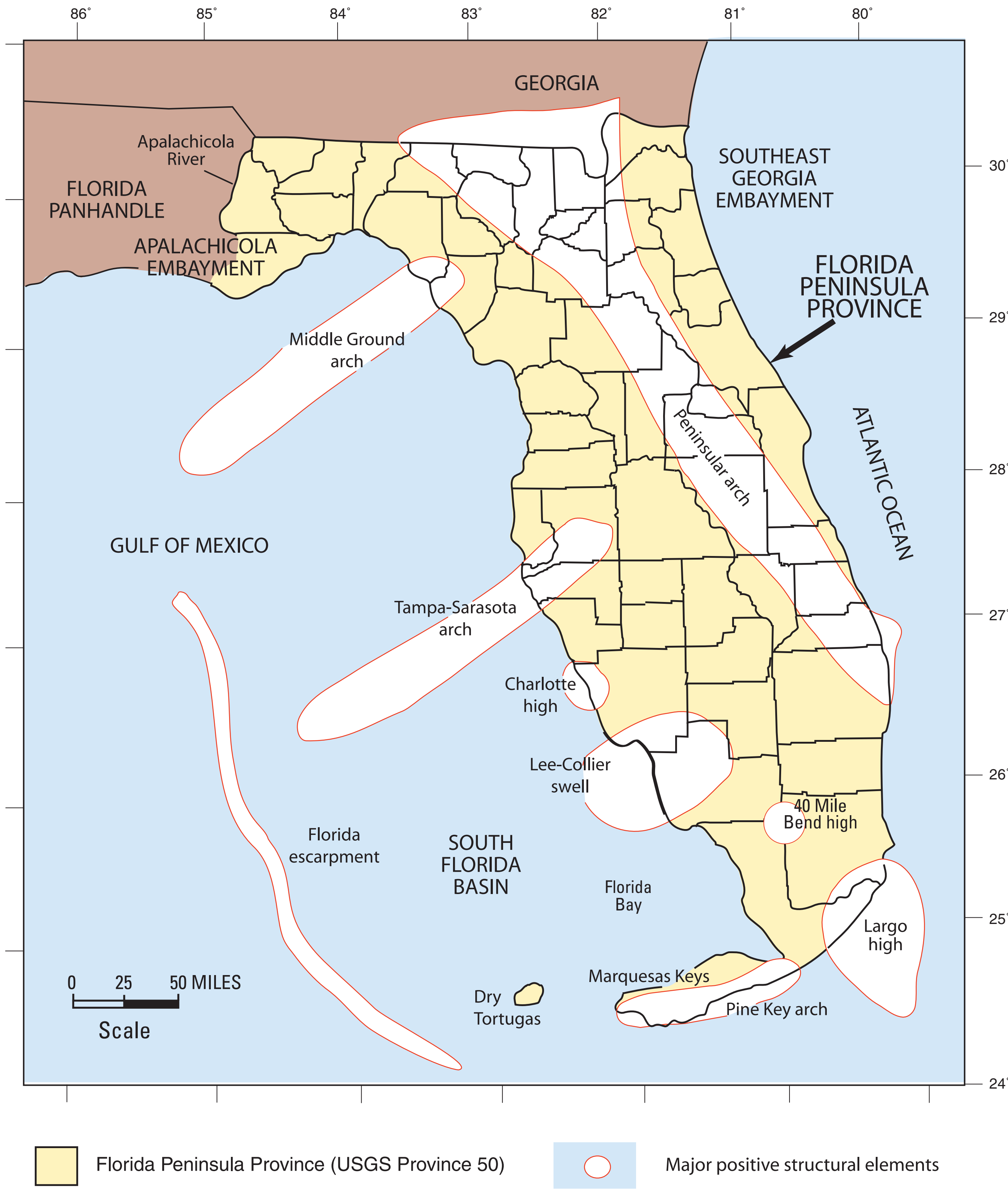

Figure 1. Map showing Florida Peninsula Province (USGS Province 50) and major positive structural elements of the South Florida Basin.

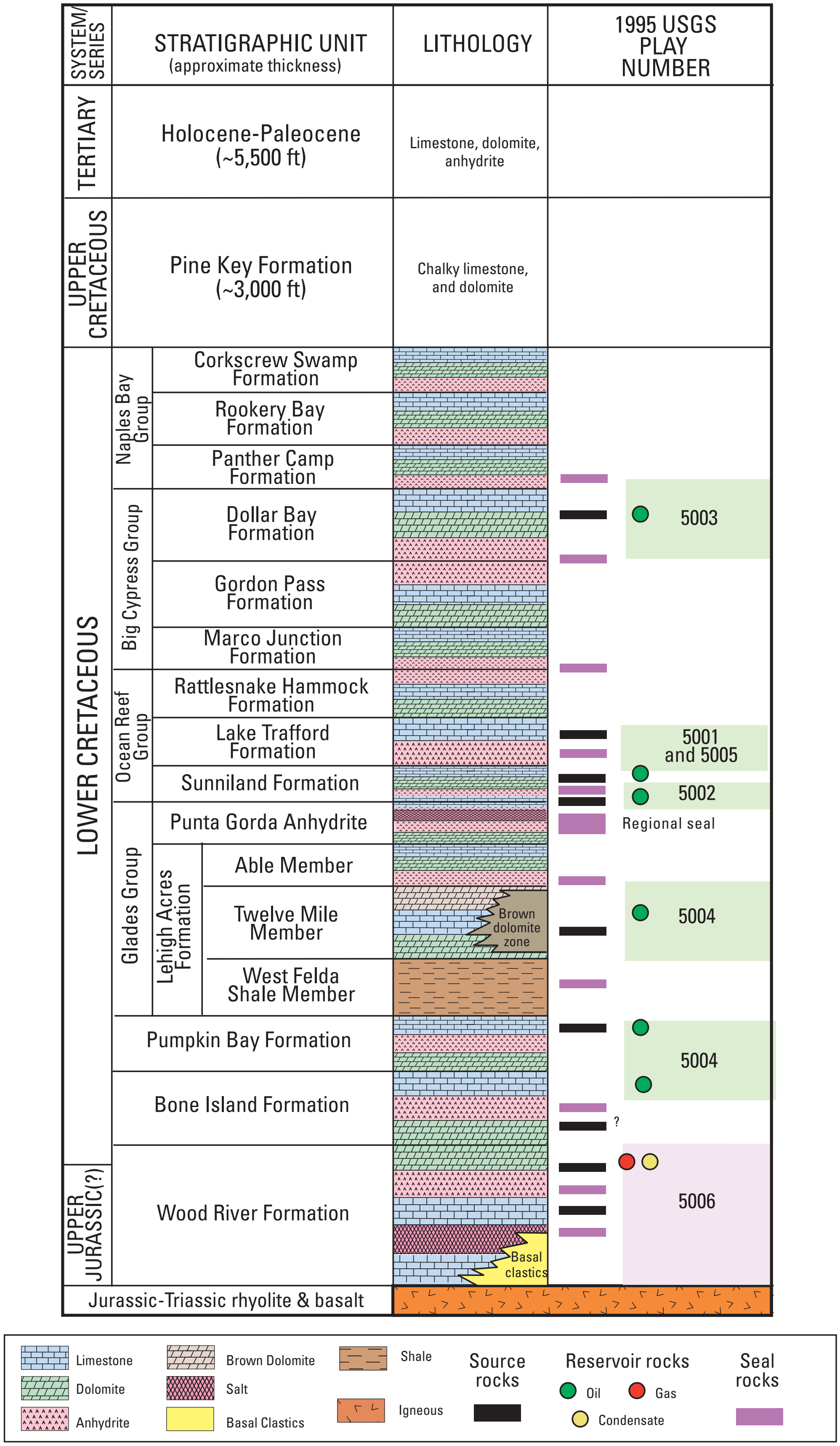

Figure 2. Stratigraphic section of South Florida Basin along Sunniland trend showing 1995 USGS plays. Modified from Faulkner and Applegate (1986).

Table 1. Summary of results of 1995 National Oil and Gas Assessment of undiscovered oil and gas by play, Florida Peninsula Province.

[Play 5006 was highly risked and, thus, not assessed. MMBO, million barrels of oil; BCFG, billion cubic feet of gas]

Size of undiscovered accumulations (MMBO)

Play number	5001	5002	5003	5004	5005
Median	15	2	10	2	4
F_5 largest	110	8	65	20	25
Mean	***22.4***	***2.5***	***13.9***	***3.1***	***6.6***

Number of undiscovered accumulations

Play number	5001	5002	5003	5004	5005
Minimum	2	1	1	1	1
Median	8	4	8	8	6
Maximum	30	20	40	20	30
Mean	***11.3***	***4.8***	***4.8***	***3.4***	***4.9***

Estimate of undiscovered oil in oil fields (MMBO)

Play number	5001	5002	5003	5004	5005	TOTAL
F_{95}	20.6	0	0	0	0	
F_{50}	172.8	6.9	0	0	0	
F_5	594.9	42.8	387.5	50.3	129.7	
Mean	***253.7***	***12.2***	***66.2***	***10.7***	***27.3***	***370.1***

Estimate of undiscovered gas in oil fields (BCFG)

Play number	5001	5002	5003	5004	5005	TOTAL
F_{95}	1.73	0	0	0	0	
F_{50}	14.52	0.58	0	0	0	
F_5	61.87	3.60	31.00	25.15	11.02	
Mean	***21.30***	***1.00***	***5.30***	***15.30***	***14.59***	***57.5***

(EUR) of at least 1 MMBO, and five additional smaller fields. When combined, these fields form an arcuate northwest-southeast trend, the “Sunniland trend,” which is about 20 mi wide and 150 mi long (fig. 3). Generally, the updip limit of the Sunniland is about 50 to 60 miles northeast of the producing trend. The first upper Sunniland Formation oil field discovery was the Sunniland field in 1943; the largest oil field is the West Felda, discovered in 1966, with total production (through July 1993) of more than 44 MMBO. Cumulative production for all upper Sunniland Formation reservoirs through July 1993 was about 103 MMBO.

The northern and updip play boundary for the Upper Sunniland Tidal Shoal Oil play (5001) is delineated by an area in which the upper Sunniland Formation consists of only micritic limestone and contains no reservoir mounds within its intertidal lagoonal-mudflat facies. Moreover, the lower part of the Sunniland dark carbonate source rock is absent. The downdip southern boundary of the play is delineated by an area where wells penetrate an anhydrite-cemented, nonporous sabkha-like facies (fig. 3).

The reservoir facies in the upper Sunniland Formation consist of isolated fossil-shell hash (skeletal grainstones) that may represent storm deposition as shoals in a regionally restricted, back-reef lagoonal area in the warm, shallow marine-shelf setting of the eastern South Florida Basin during the late Early Cretaceous (Mitchell-Tapping, 1987). These tidal shoals were deposited on subtle bathymetric highs that were probably related to underlying basement structure. Later, the upper portions of these porous shoal mounds were subaerially exposed, leached, and dolomitized during a low sea-level stand, further enhancing the reservoir quality of the upper porous zones. Individual debris mounds are about 40 to 100 ft thick (Means, 1977; Montgomery, 1987). Depth to the upper Sunniland Formation tidal shoal reservoir rocks in the producing trend is about 11,200 to 11,600 ft. Most mounds are sealed by overlying impermeable lagoonal mudstones and wackestones, some of which have been dolomitized. Porosities of primary (interparticle) and secondary (dissolution and dolomitization) origin range from 10 to 25 percent and average 15 to 18 percent (Mitchell-Tapping, 1987). Impermeable micritic carbonate and nodular anhydrite beds within the upper Sunniland Formation enclose and seal many of the individual porous reservoir mounds. Moreover, the entire Sunniland Formation is sealed above and below by thick anhydrite units (fig. 2). Most hydrocarbon traps are stratigraphic; however, some mixed stratigraphic/structural traps are present.

The different types of crude oils produced from the grainstone units of the upper Sunniland Formation are immature, having API gravities that range from about 21° to 28° and average 25°–26°; the average gas-oil ratio (GOR) is about 85:1 (Palacas and others, 1984; Tootle, 1991). The source rocks are a dark, micritic carbonate unit (informally referred to as the “dark carbonate” interval) in the lower part of the Sunniland Formation. These micritic carbonates are commonly algal laminated and have total organic carbon (TOC) ranging from less than 0.4 to 3.0 weight percent. Potential source rocks (as identified by more than 0.4 weight percent TOC) average 1.8 weight percent TOC. More than 80 percent of the organic matter in these source rocks is composed of algal-amorphous (oil-prone) kerogen (Palacas, 1984; Palacas and others, 1984). The hydrocarbon-generating potential of the lower Sunniland dark carbonate facies ranges from poor in wells located updip from the producing trend, to good in wells located just downdip, to excellent near the depocenter of the basin (Applegate and Pontigo, 1984). Onshore, the dark carbonate facies varies in thickness from zero at the updip limit of the Sunniland Formation to more than 150 ft in the producing trend. Oil produced from reservoirs in the Sunniland trend was probably generated downdip where the organic matter in the dark carbonate facies is more abundant and more mature. The petroleum then migrated updip and accumulated in the porous grainstone facies of the upper Sunniland (Palacas and others, 1984).

Exploration and development of the upper Sunniland Formation has been minimal based on the drilling history and well distribution within the play area. The eight oil fields in the upper Sunniland Formation that have produced, or have EUR’s, more than 1 MMBO are Bear Island, Corkscrew, West Felda, Lehigh Park, Mid-Felda, Raccoon Point, Sunniland, and Sunoco-Felda. Historical data for these eight accumulations are plotted in figure 4 and figure 5 showing relations among known accumulation size, number of exploratory wells, date of discovery, and cumulative known volume. At least three of these eight fields are located in the Big Cypress Swamp drainage and (or) National Reserve, an area of critical environmental concern (Lloyd, 1992). Sensitive environmental and political issues in south Florida have likely discouraged full resource development; however, the success of wells drilled in the past few decades, indicate that the Upper Sunniland Tidal Shoal Oil play has good potential.

The 1995 USGS Assessment estimated undiscovered oil accumulations in the Upper Sunniland play along the main fairway trend (5001) to be of moderate size, having a median size of 15 MMBO and total undiscovered oil estimated at about 254 million barrels (table 1).

Play 5002—Lower Sunniland Fractured “Dark Carbonate” Oil Play

The existence of the Lower Sunniland Fractured “Dark Carbonate” Oil play is based on the discovery of the Lake Trafford field in Collier County. Lake Trafford field is located immediately southeast of Corkscrew field (fig. 6). The dark carbonate unit of the lower part of the Sunniland Formation is believed to contain the primary source beds for oil produced in the tidal shoal grainstone units of the upper part of the Sunniland Formation (plays 5001 and 5005). Although no minimum size (more than 1 MMBO) oil accumulations were proven, the one discovery well (Mobil Oil Corporation; spudded March 1969) used to define the Lake Trafford field

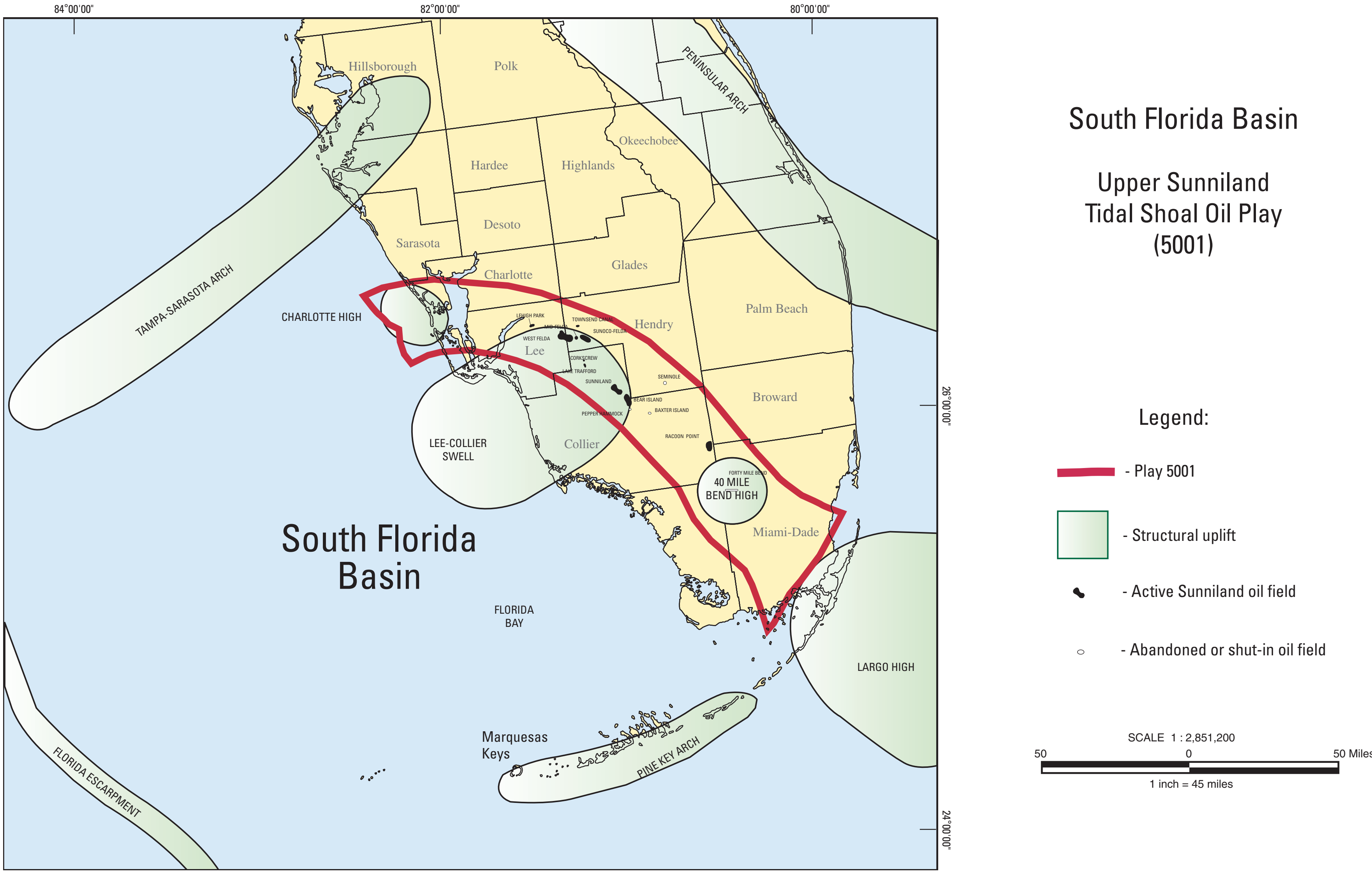

Figure 3. Map of South Florida Basin showing structural uplifts, known oil fields, and boundaries of Upper Sunniland Tidal Shoal Oil play (5001).

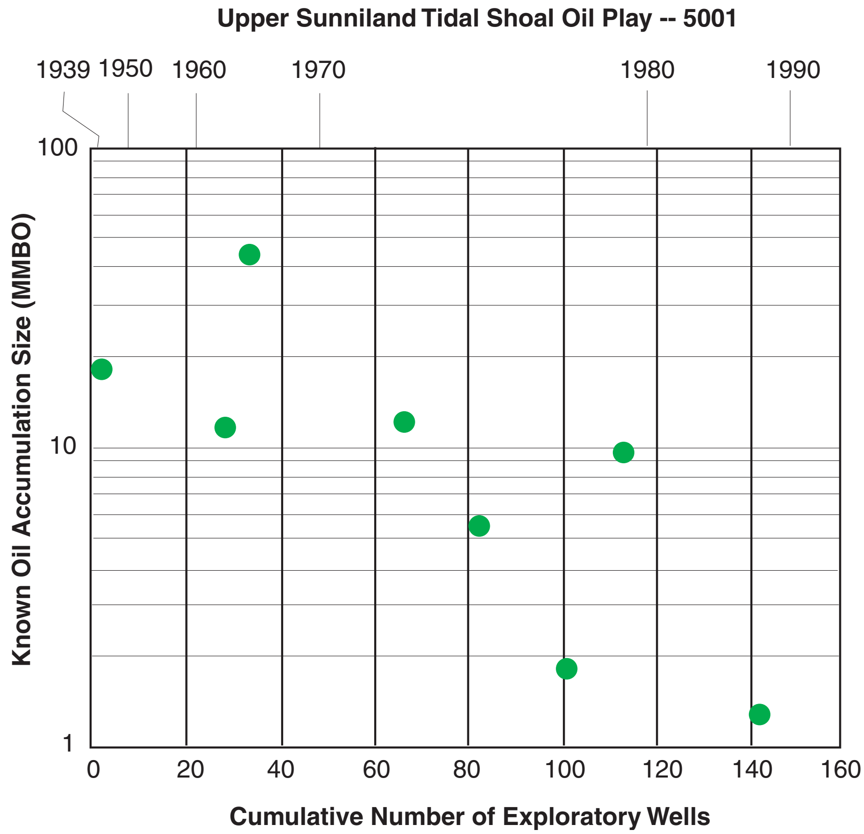

Figure 4. Historical plot for South Florida Basin exploration showing known oil accumulation size (>1 MMBO) versus cumulative number of exploratory wells and discovery year.

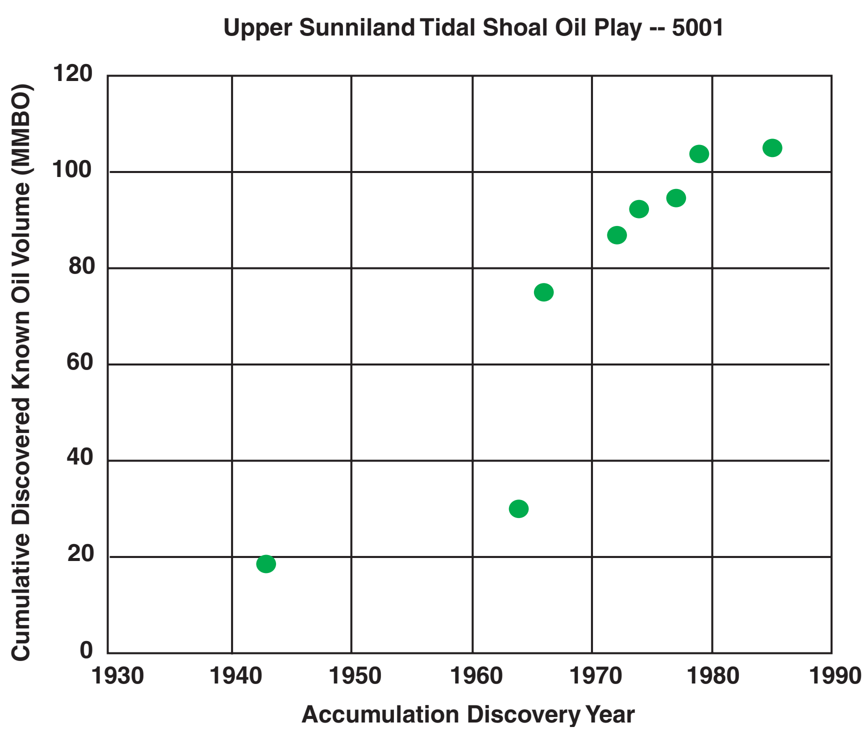

Figure 5. Historical plot for South Florida Basin exploration showing cumulative discovered known oil volume versus discovery year for accumulations >1 MMBO.

produced commercial quantities of oil from fractured limestone at a depth of about 11,800 ft. The producing zone is commonly referred to as the "rubble zone" of the dark carbonate unit in the lower Sunniland Formation (Means, 1977). The matrix porosity of the producing zone, as measured by well logs, is about 9 volume percent, and the pore space is oil saturated. Core recovered from the rubble zone in the discovery well was described as burrowed, fractured, and stylolitized (Lloyd, 1992); these characteristics would increase the porosity and permeability of the rocks, thus increasing the likelihood of commercial production from them. In March 1988, the discovery well was shut in after producing about 278,000 barrels of oil. Two offset vertical wells, located to the northwest and south of the producing well, and a recent horizontal test well were dry holes. Based on the production history of the one vertical well, horizontal wells penetrating the rubble zone of the dark carbonate unit are estimated to produce a few hundred barrels of oil per day. Owner/operator Brian Richter (oral commun., 1994) reported that the horizontal test well missed the targeted pay zone; however, subsequent successful horizontal tests have reopened the field.

The play boundary is defined by two factors: (1) the thickness of the dark carbonate unit, partly determined from the examination of cross sections and observations of structural isopachs (Applegate and Pontigo, 1984), and (2) evidence (in core recoveries from reference wells) (Lloyd, 1992; Mitchell-Tapping, 1984) of the presence of rocks that possess favorable source-rock characteristics and either the presence of the rubble zone or evidence of fracturing (Montgomery, 1987). This play is assigned moderate potential for undiscovered oil resources. The area of the play that has the best potential for undiscovered oil resources is northwest of the Lake Trafford field. Expected depths of production within the play area are estimated between 10,000 and 13,000 ft, with a median depth of about 11,800 ft. Potentially productive fractured reservoir rocks are present in the lower dark carbonate zone of the lower Sunniland Formation and are enclosed by impermeable, micritic, tidal-flat, lime mudstones. The unit is sealed below by the Punta Gorda Anhydrite.

Indigenous hydrocarbons are produced from brown and medium-dark-gray micritic and argillaceous limestones whose total carbonate content average 76 weight percent and range from 50 to 98 weight percent. These micritic carbonates are commonly algal laminated and have TOC values ranging from less than 0.4 to 3.0 weight percent. Potential source beds (more than 0.4 weight percent TOC) within the unit average about 1.8 weight percent TOC. Oil produced from the well in the Lake Trafford field has an API gravity of about 26°, similar to oil in upper Sunniland producing wells (API gravity ranging from 21° to 28°). Inasmuch as oils in the upper Sunniland Formation are derived from source rocks in the lower dark carbonate, the similarity in API gravities is to be expected. Similarly, lower Sunniland oils are expected to have a GOR range similar to that of upper Sunniland oils (about 80:1 to 100:1).

Median size for undiscovered fields of the dark carbonate play was estimated at 2.5 MMBO with a mean total undiscovered oil resource estimated at 12.2 million barrels (table 1).

Play 5003—Dollar Bay Shoal-Reef Dolomite Oil Play

The delineation of the hypothetical Dollar Bay Shoal-Reef Dolomite Oil play (fig. 7) is based on (1) interpretations of well-log data obtained from a series of onshore wells reporting numerous shows (Winston, 1971) and (2) the paleoenvironmental reconstructions of Winston (1971) and Mitchell-Tapping (1990) of the reservoir tidal shoal and patch reef facies; the data of Faulkner and Applegate (1986) were also used to delineate this play.

In the onshore portion of the South Florida Basin, the youngest formation that shows characteristics favorable for petroleum generation and accumulation is the Lower Cretaceous Dollar Bay Formation, the uppermost unit of the Big Cypress Group (fig. 2). The unit lies 1,500 ft or more above the Sunniland Formation and is as much as 620 ft thick in some parts of the basin. Onshore, the unit ranges in thickness from about 475 ft to 550 ft. Many wells penetrating the Dollar Bay Formation in south Florida have reported low-gravity (about 17° API) oil shows or tarry residues in both limestone biohermal deposits and an upper dolomite section; however, there has been no commercial production from this play. Like the Sunniland Formation, the Dollar Bay commonly consists of evaporite-carbonate cycles of anhydrite, dolomite, and limestone. These evaporite-carbonate beds formed during a transgressive-regressive cycle; some thin beds of calcareous shale, salt, and lignite are also present (Applin and Applin, 1965; Mitchell-Tapping, 1990). In certain areas of the basin, however, limestone is the dominant lithology of the formation. Speculative production in the Dollar Bay Formation will be from leached limestone units in the middle part of the formation or from a dolomite section in the upper part of the formation.

Mitchell-Tapping (1990) stated that reservoirs exist in tidal shoal deposits and patch reefs in a tidal flat, lagoonal, restricted-marine setting, and in a subtidal platform, open-marine setting. Potential reservoirs include (1) porous, leached, and dolomitized grainstone units in the upper portions of isolated debris mounds, (2) isolated patch reefs in the middle part of the Dollar Bay Formation, and (3) a porous dolomite unit in the upper part of the formation (Mitchell-Tapping, 1990). These potential reservoirs have measured porosities of about 10–30 percent and permeabilities of about 5–60 millidarcies. Traps are created because these reservoirs are draped with impermeable, micritic, tidal-flat, and in some cases argillaceous lime mudstone units and anhydrite. The formation is underlain by thick, dense nodular and nodular-mosaic anhydrite units of the Gordon Pass Formation.

Oil and tarry residues recorded in wells that penetrate the Dollar Bay Formation are believed to originate within the formation (Palacas, 1978a, 1978b; Winston, 1971). The

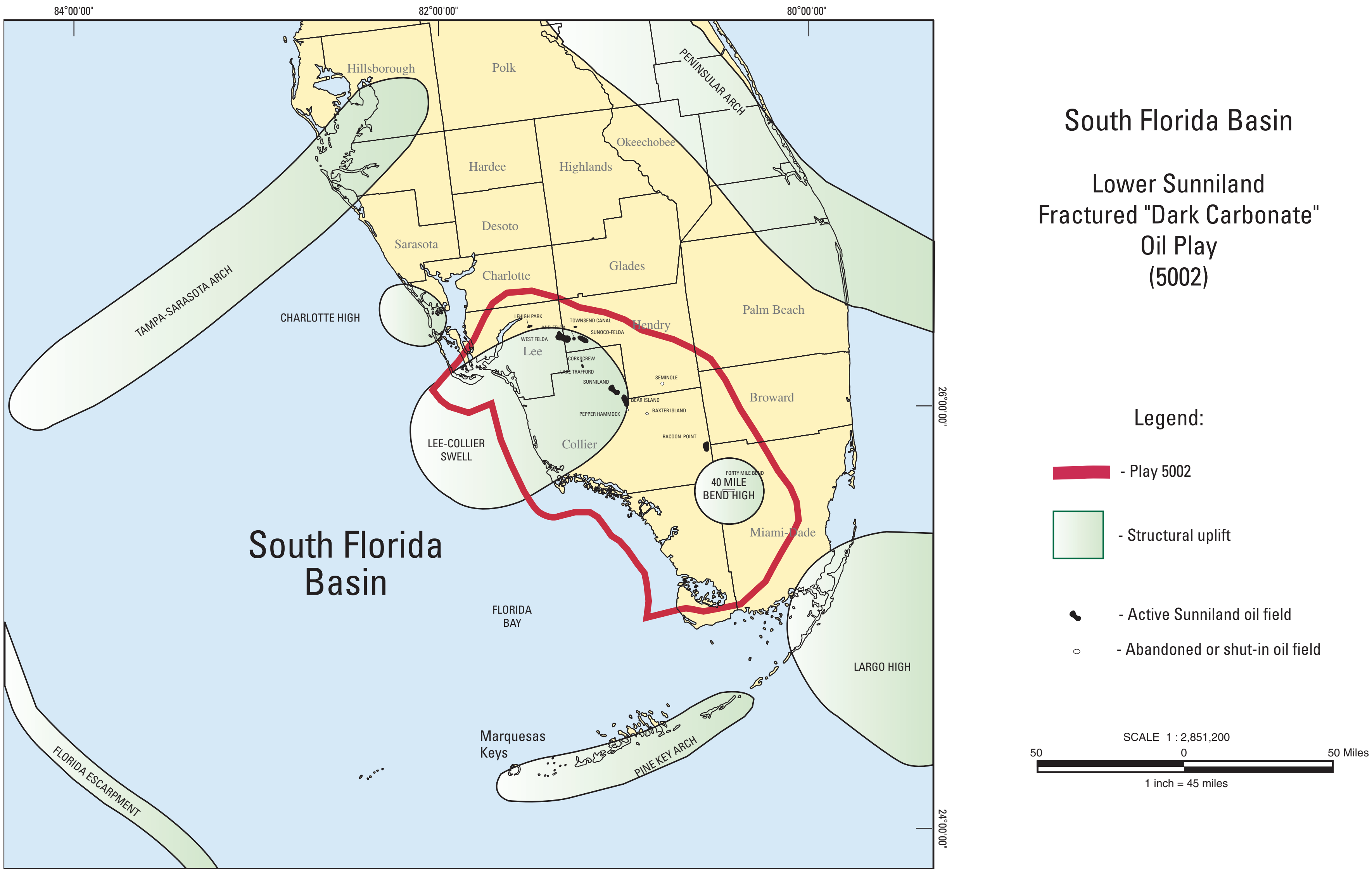

Figure 6. Map of South Florida Basin showing structural uplifts, known Sunniland oil fields, and boundaries of Lower Sunniland Fractured "Dark Carbonate" Shoal Oil play (5002).

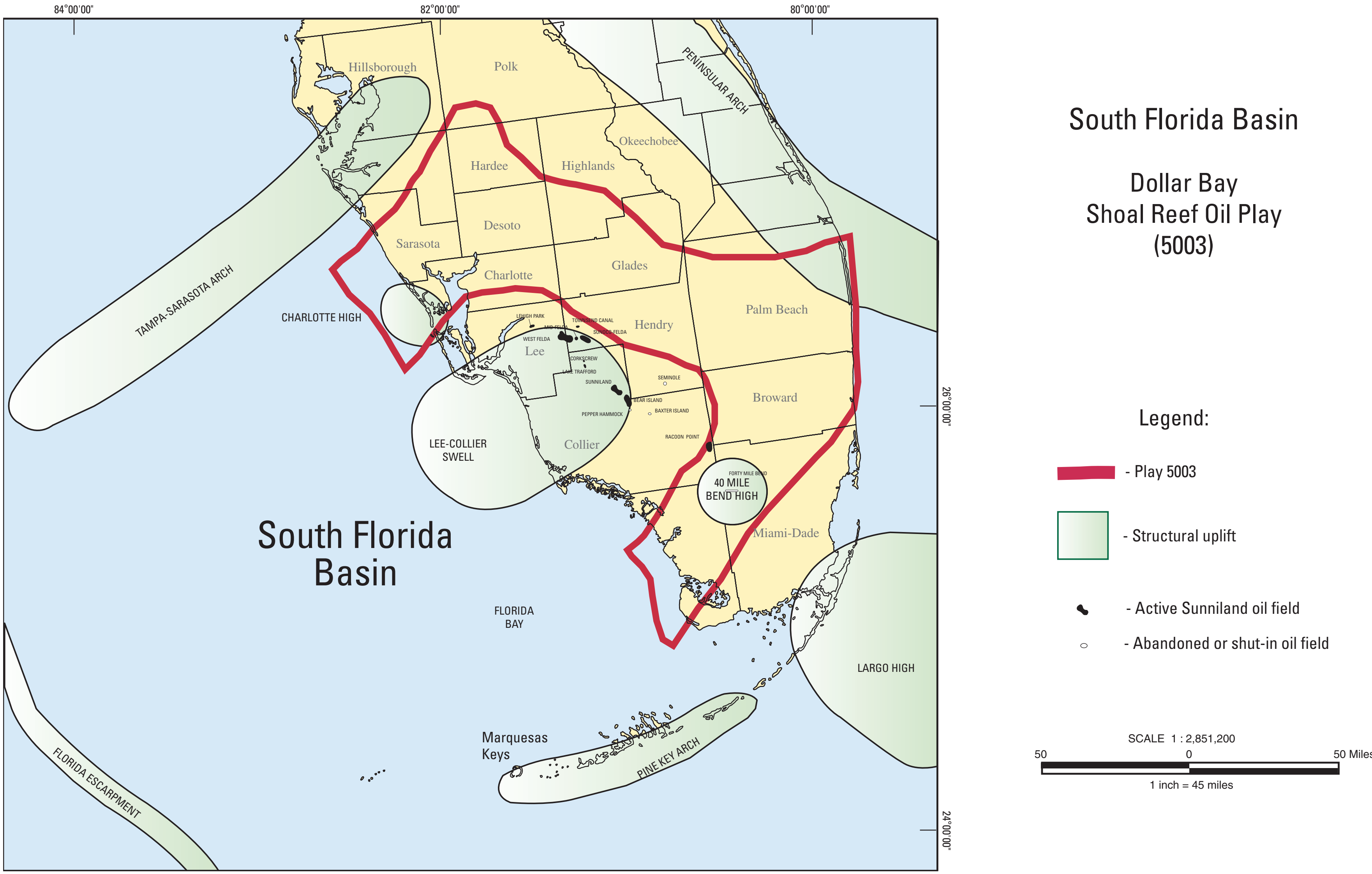

Figure 7. Map of South Florida Basin showing structural uplifts, known Sunniland oil fields, and boundaries of Dollar Bay Shoal Reef Oil play (5003).

organic-matter content of the Dollar Bay Formation ranges from very lean to fairly rich, with some beds containing more than 3 weight percent TOC; the average TOC of the Dollar Bay is about 0.6 weight percent (Palacas, 1978a, 1978b). Most petroleum explorationists infer that rocks of the Dollar Bay Formation located updip and to the northeast of the Sunniland trend are thermally immature and probably have not generated hydrocarbons of commercial quality and quantity (Montgomery, 1987). Others strongly disagree, however, and predict that the Dollar Bay Formation has been overlooked and should be a considered a primary oil target with good resource potential (Winston, 1971; Palacas, 1978a, 1978b; Mitchell-Tapping, 1990).

Offshore, in the more central portion of the basin where the Dollar Bay Formation lies at depths of more than 10,000 ft, the formation rocks should be more thermally mature. Based on one major show that consisted of 15 ft of free oil, API gravity measured 17° at a depth of about 10,000 ft. Thus, API gravities of oil from this play are expected to be low and probably range from 15° to 20° (Mitchell-Tapping, 1990); sulfur contents are similar to those of Sunniland-type oils (2–4 percent). Moreover, the inferred presence of patch reefs and more complex structures in the Federal offshore region, and the increased thermal maturity of rocks of the Dollar Bay Formation in the offshore portion of the basin, enhance the potential for new field discoveries and commercial oil production.

The Dollar Bay Formation was assessed to have the second largest volume of undiscovered oil with a total mean volume of about 66 MMBO. The median number of discoveries was 8 at a median field size of 10 MMBO (table 1).

Play 5004—Lower Cretaceous Carbonate Composite Oil Play

The hypothetical Lower Cretaceous Composite Oil play comprises two units in the South Florida Basin: the Lehigh Acres Formation brown dolomite zone and a potentially porous dolomite unit within the underlying Pumpkin Bay Formation (fig. 2). Both units in this play are believed to contain oil mainly derived from organic-rich beds in the upper part of the Pumpkin Bay Formation.

The play is divided into two separate areas: one is centered in Lee County and intersects the Sunniland trend, and the other is centered near the Marquesas Keys) (fig. 8). The northern part (Lee County and vicinity) includes the area (outlined by Applegate, 1987) containing porous brown dolomite and an area within the Pumpkin Bay Formation that contains live oil in porous dolomite (6–16 percent porosity). The section is thickest (as much as 1,200 ft thick, as measured from reference wells in State waters near Charlotte Harbor and onshore in Collier and Hendry Counties) in these areas and has good to excellent source-rock potential (determined from geochemical and thermal-maturity measurements) (Means, 1977; Applegate and others, 1981; Palacas and others, 1981; Attilio and Blake, 1983; Faulkner and Applegate, 1986; Applegate, 1987; Montgomery, 1987). The rocks of the northern area (fig. 8) possess high porosity caused by epigenetic dolomitization in an active geothermal lineament system (Saul, 1987). Several oil shows were reported in thick, porous dolomite beds in the southern part of the play centered near Marquesas Keys (Faulkner and Applegate, 1986; Lloyd, 1992).

The informally named brown dolomite zone refers to a dolomite unit commonly found within the Twelve Mile Member of the Lower Cretaceous Lehigh Acres Formation (Aptian). The brown dolomite lies about 300 ft below the base of the Punta Gorda Anhydrite and about 1,000 ft below the Sunniland Formation (fig. 2). The unit is best developed onshore in Charlotte County and surrounding counties where it is thickest (about 100 ft) and most porous (10–22 percent) and at a depth of about 12,000 ft (fig. 8). Good oil shows were reported in this unit, and because it is about 1,000 ft lower in the stratigraphic section than the Sunniland Formation, oil from the brown dolomite is predicted to have a higher API gravity (20°–50°?) and higher thermal maturity than oil from the Sunniland Formation.

Reservoirs consist of sucrosic dolomite and exhibit pinpoint to vuggy porosity in beds at least 50 ft below the top of the Twelve Mile Member of the Lehigh Acres Formation. As much as 50 ft of porous dolomite have been found onshore where the brown dolomite zone reaches a maximum thickness of about 100 ft. An onshore area (in Charlotte, Lee, Hendry, Collier, Highlands, and Glades Counties, and adjacent State waters) with the highest resource potential is defined by the porous zones delineated by Applegate (1987). Good oil shows were observed in dolomite penetrated by the Bass Collier 12-2 well in Collier County; porosities determined from a sonic log ranged from 10 to 22 percent and core porosities were as high as 18 volume percent. State and Federal waters are predicted to have high resource potential. In particular, oil stains were noted in about 350 ft of mostly porous dolomite penetrated by wells located near the Marquesas Keys (Faulkner and Applegate, 1986; Lloyd, 1992).

The thickest and deepest sedimentary interval with significant reservoir potential in the South Florida Basin is the Lower Cretaceous Pumpkin Bay Formation. The formation is composed of limestone, except at its northern limit where dolomite is the dominant lithology. Within Province 50, the Pumpkin Bay Formation is as much as 1,200 ft thick in offshore Florida State waters of Charlotte Harbor; the formation is projected to thicken westward in Federal offshore waters and into the basin depocenter (Faulkner and Applegate, 1986). Onshore, the Pumpkin Bay Formation is found at present depths from about 12,500 to 14,000 ft. Core porosities for rocks of the Pumpkin Bay Formation are as high as 20 percent, and sonic well-log porosities are slightly higher. Porosities are generally lower in the Pumpkin Bay Formation than in potential reservoirs found in younger units. Generally, rocks with the highest resource potential in the Pumpkin Bay Formation are located in the Pulley Ridge area of Federal offshore

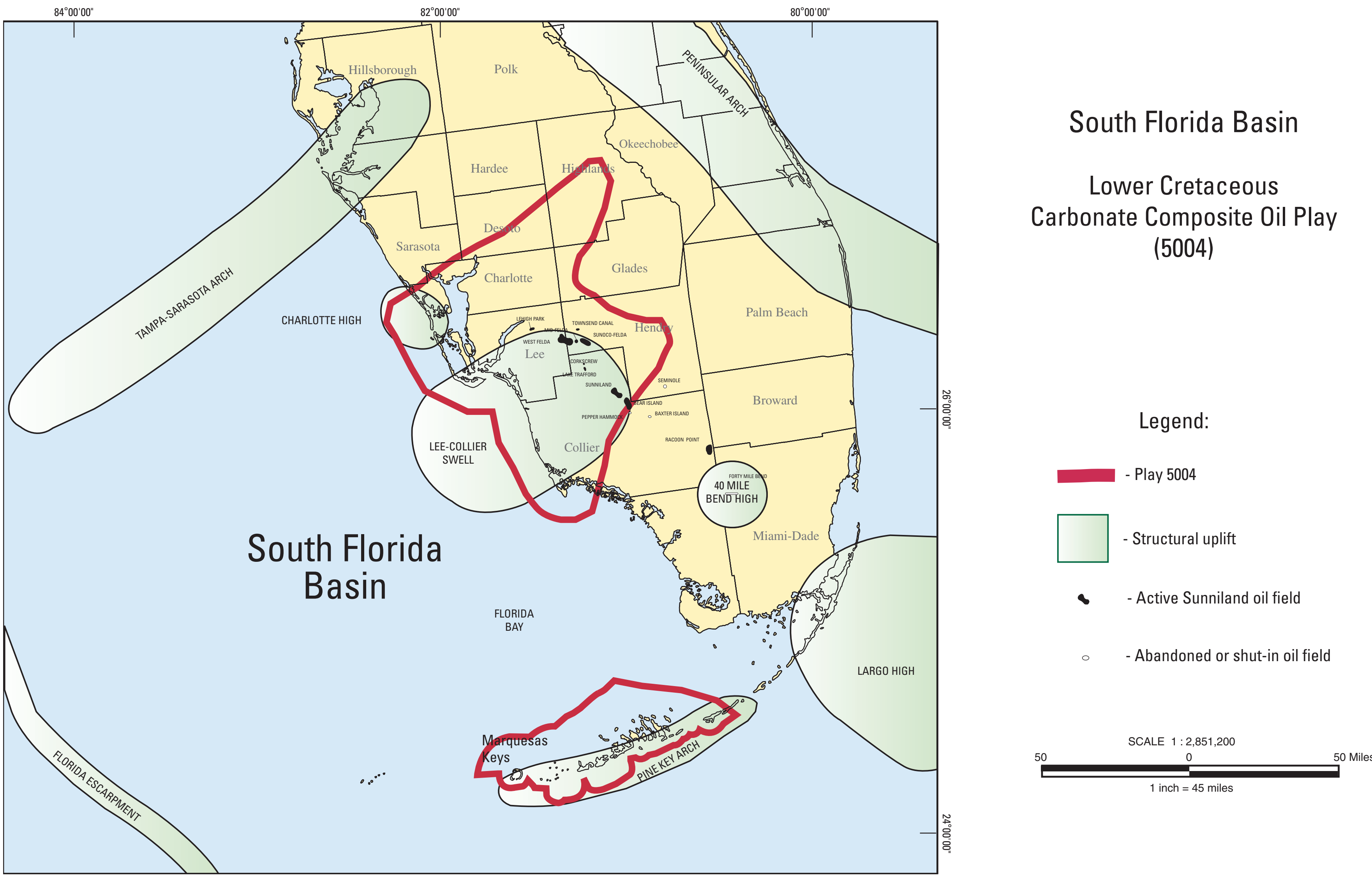

Figure 8. Map of South Florida Basin showing structural uplifts, known Sunniland oil fields, and boundaries of Lower Cretaceous Carbonate Composite Oil play (5004).

waters (Faulkner and Applegate, 1986). Projections indicate that the formation is as much as 1,500 ft thick in this area and that the best reservoirs exist within a thick porous dolomite zone (300–350 ft thick; pinpoint to vuggy porosity as high as 25 percent) in the middle and upper parts of the formation; depths range from about 12,500 ft to more than 15,000 ft.

Source-rock studies by Palacas and others (1981) indicate that organic-rich beds in the upper Pumpkin Bay Formation are likely source rocks for oils. These oils could be trapped in reservoirs that exist within the middle and upper parts of the Pumpkin Bay and in the porous brown dolomite zone. Palacas and others (1981) identified organic-rich, argillaceous carbonate beds with high (0.43–3.2 weight percent) TOC in the upper Pumpkin Bay and concluded that these beds had the greatest petroleum-generating potential of all rocks older than the Punta Gorda Anhydrite.

The TOC contents of these rocks, however, vary within the basin. Most rocks within the Twelve Mile Member of the Lehigh Acres Formation contain insufficient organic matter (average of about 0.3 percent TOC) to have generated commercial amounts of petroleum. Some richer source beds are present within this unit, however, having marginal (about 0.5 percent TOC) to good source potential. Particularly, more than 2.0 percent TOC is contained in a relatively thin (about 1 ft thick) limestone bed in the West Felda field.

The thermal-maturation level for oil generation is higher in this play than that for the upper and lower Sunniland plays (5001 and 5002). Thus, oils of this play are expected to be marginally to moderately mature and to have higher API gravities (25° to 50°) and higher GOR's than Sunniland oils.

Total mean volume of undiscovered oil in the Lower Cretaceous Carbonate Composite Oil play was estimated at about 11 MMBO. The median number of new discoveries is eight accumulations having a median field size of 2 MMBO (table 1).

Play 5005—Extended Upper Sunniland Tidal Shoal Oil Play

This hypothetical play is an eastward and southward extension (fig. 9) of the productive Sunniland trend in the Upper Sunniland Tidal Shoal Oil play (5001). Thus, reservoir and source rocks are the same as those of play 5001. This play forms a southwest-to-northeast-oriented arcuate trend approximately 20 mi wide and 250 mi long that extends from the State waters of the Dry Tortugas northeast, through the Florida Keys and along the southeastern Atlantic Coast of the Florida Peninsula to Broward County. Bioclastic mounds smaller than those found in currently productive units of the upper part of the Sunniland Formation accumulated on subtle structural highs in this updip, less thermally mature area of the basin to the east and far south. Prominent positive structural elements include the Pine Key arch and the Largo high. Some low API gravity (10°–14°) heavy-oil shows have been reported in wells in the northern portion of the play area; however, 22° API gravity oil was reported in shows from wells near the Marquesas Keys in the west and southernmost part of the play area (Faulkner and Applegate, 1986; Lloyd, 1992).

The Extended Upper Sunniland Tidal Shoal Oil play (5005) is delineated by an area that may contain porous tidal-shoal facies that formed on topographic/bathymetric highs. The dark carbonate source unit in the lower part of the Sunniland Formation thins toward the eastern and southern margins of the basin south of the play, making it less favorable than the proven Upper Sunniland Tidal Shoal Oil play (5001). The Sunniland Formation rocks in this area are also less thermally mature than in play 5001. The eastern and southern Atlantic coastal boundaries of the play are delineated by the Florida State waters 3-mi boundary, and the northern, Gulf of Mexico boundary is delineated by the 10.36 mi Florida State waters boundary.

Total mean volume of undiscovered oil in the Extended Upper Sunniland Tidal Shoal Oil play was estimated at about 27.3 MMBO with an additional 14.6 BCF of associated gas. The median number of new discoveries is six accumulations having a median field size of 4 MMBO (table 1).

Play 5006—Wood River Dolomite Deep Gas Play

In the hypothetical Wood River Dolomite Deep Gas play (fig. 2 and fig. 10), the Upper Jurassic(?) and Lower Cretaceous Wood River Formation averages about 1,700 ft thick and stratigraphically is the lowest sedimentary unit in the South Florida Basin. The few wells that have penetrated this formation show that a 100- to 150-ft-thick clastic unit forms the basal part of the Wood River Formation and consists of dark-red shale and fine- to coarse-grained arkosic sandstone and calcareous sandstone (Applegate and others, 1981). These basal clastic units may represent fan, fan-delta, and fluvial-lacustrine or marine deposits. Below the basal clastic sequence in Collier County is a rhyolite porphyry with an age of 189 Ma. Overlying these clastic rocks is a thick sequence of anhydrite, dolomite, and limestone with occasional interbedded salt stringers, indicating marine transgression (Applegate and others, 1981).

The Mobil-Phillips Seminole "C" well near Seminole field (fig. 10) in Hendry County produced measurable gas and water flows at depths of about 15,700 ft from perforations in a dolomite zone averaging about 8 percent porosity. Moreover, logs from the well indicated higher porosities and increased resistivities just above the perforated section, possibly indicating the presence of gas (Applegate and others, 1981; Palacas and others, 1981). Although formation damage occurred in the well bore, this well had potential for commercial gas production (J.G. Palacas, oral commun., 1994); the occurrence of a potentially commercial well indicates a possible source of deep gas. Marine beds, generally regarded as potential petroleum sources, are predominant in the formation, and the

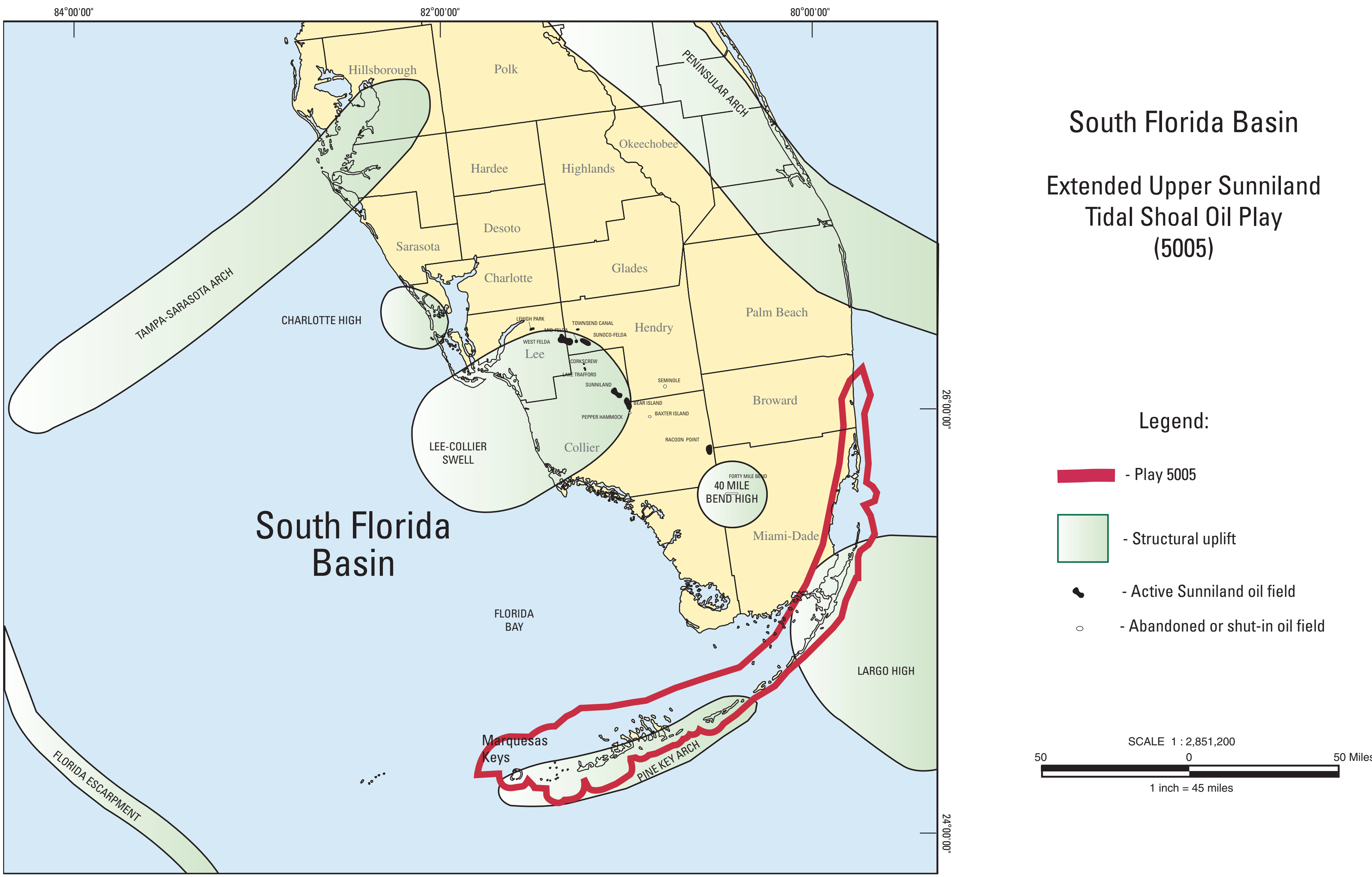

Figure 9. Map of South Florida Basin showing structural uplifts, known Sunniland oil fields, and boundaries of Extended Upper Sunniland Tidal Shoal Oil play (5005).

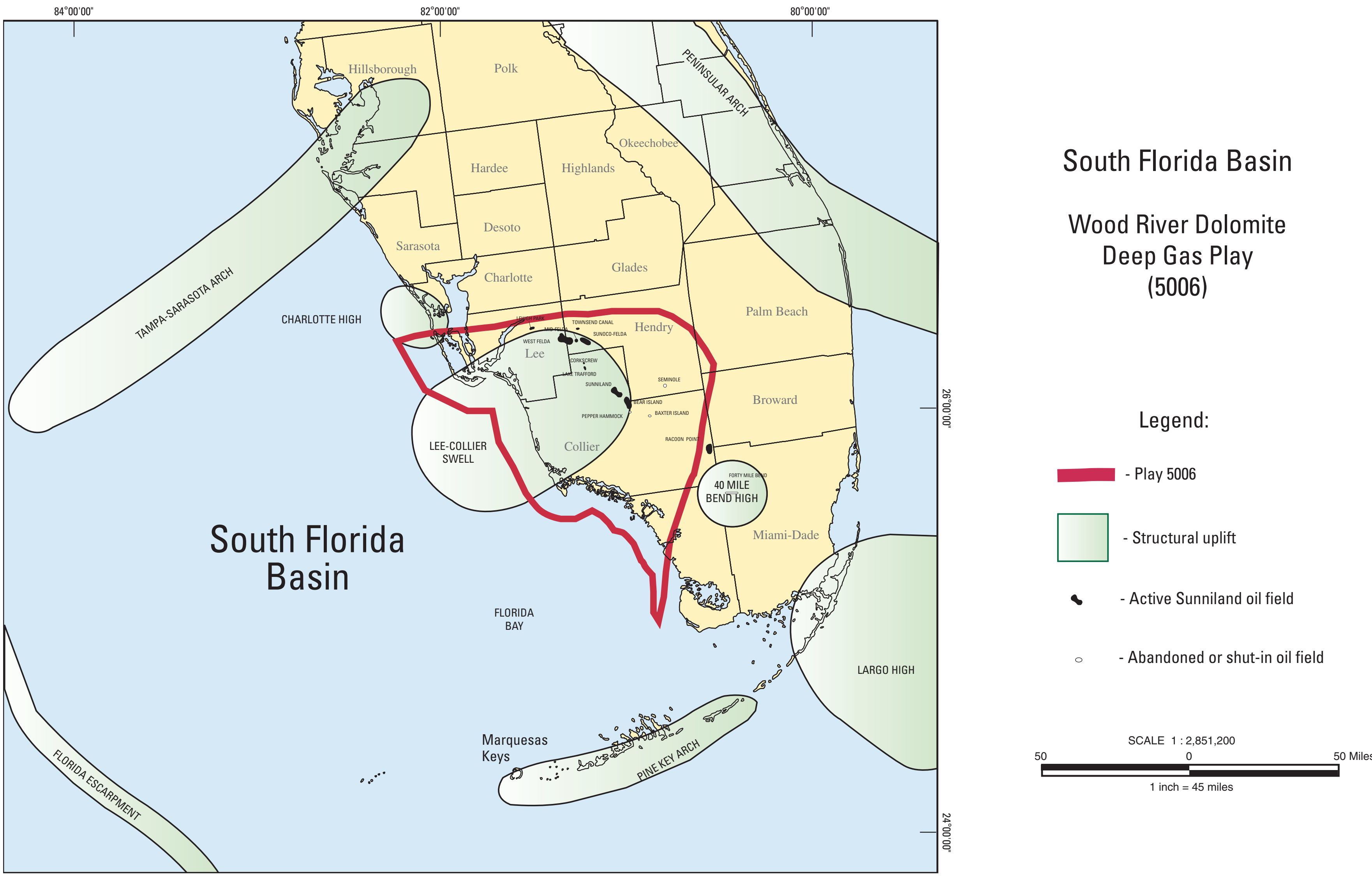

Figure 10. Map of South Florida Basin showing structural uplifts, known Sunniland oil fields, and boundaries of Wood River Dolomite Deep Gas play (5006).

depositional environment, especially in the southern part of the play area, probably favored reef growth; thus a source, a seal, and a reservoir should be present.

Organic geochemistry studies of well samples from the Wood River Formation indicate that the hydrocarbon-generating potential of the unit ranges from poor to excellent (Palacas and others, 1981; Faulkner and Applegate, 1986). The scarcity of wells penetrating the Wood River Formation, however, limits and evaluation of each of the geologic and petroleum system components of the play and, therefore, the play is considered hypothetical and was risked heavily. The rocks of potential reservoirs in the Wood River are porous (8 percent or greater) dolomite units enclosed by anhydrite, salt stringers, and (or) micritic limestone at depths of about 15,000–19,000 ft onshore and in State waters. The play area includes areas of the southern part of basin where reef growth is favored (fig. 10). It is possible that gas in the Wood River Formation in the area of the Sunniland trend may have originated in deeper parts of the basin and migrated updip, perhaps as a single large accumulation. The Wood River Dolomite Gas play was risked for charge, reservoir, and trap. The combined risk probability of the play was 0.1, which categorized the play as high risk and was not assessed in the 1995 USGS Assessment.

Summary

The 1995 USGS National Oil and Gas Assessment defined six conventional plays in the Florida Peninsula Province (USGS Province 50), all within the South Florida Basin. Five of these plays were assessed, all which were oil plays of Cretaceous age. The sixth was a deep gas play in dolomite of the Upper Jurassic(?) and Lower Cretaceous Wood River Formation and was highly risked, thus not assessed.

A mean total undiscovered resource of 370.1 MMBO and 57.5 BCFG (about 6 MMBOE) was estimated from the five oil plays of the South Florida Basin. The upper Sunniland Formation along the main "fairway" where eight fields of >1 MMBO have been discovered was estimated to contain the most (254 MMBO or about 70 percent) of the total estimated mean undiscovered oil in the South Florida Basin. The less mature, Dollar Bay Shoal-Reef play ranked second with a total estimated 66 MMBO. The future of Florida's moderate potential for undiscovered resources may be limited by environmental and political controls that discourage oil and gas exploration and development within the South Florida Basin.

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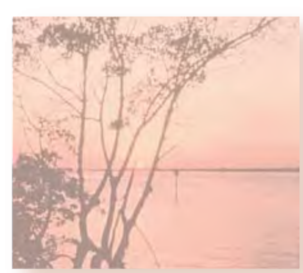

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