Upper Pleistocene Aggradational Play

UPL A1, #0141

Hyalinea "B"/*Trimosina* "B" through Sangamon fauna

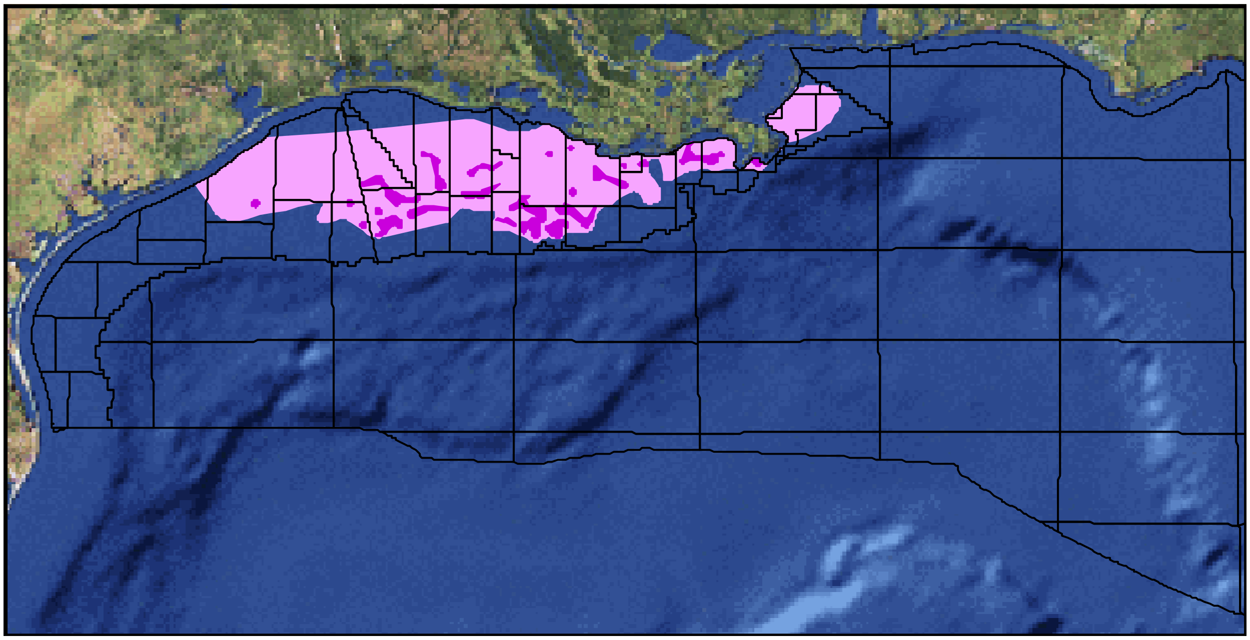

Figure 117. UPL A1 map showing location of play. Play limit shown in light magenta; hydrocarbon limit shown in dark magenta.

Overview

The Upper Pleistocene Aggradational Play (UPL A1) contains reserves of 2,658.996 Bcfg and 108.780 MMbo (581.911 MMBOE) in 205 sands in 71 fields. Comparing the 12 GOM aggradational plays, UPL A1 ranks second in gas reserves (24%). The play extends discontinuously across the modern GOM shelf from the Brazos to Chandeleur Area (Figure 117).

Description

UPL A1 is defined by (1) an aggradational depositional style representing sediment buildup in continental to shallow marine shelf environments and (2) the UPL-1, UPL-2, UPL-3, and UPL-4 Chronozones, the tops of which are defined by the *Hyalinea* "B"/*Trimosina* "B", *Trimosina* "A" 2nd occurrence, and *Trimosina* "A" 1st occurrence biozones, and Sangamon fauna, respectively (Figure 8).

UPL A1 extends discontinuously across the modern GOM shelf from the northeastern portion of the Brazos Area offshore Texas to the Chandeleur Area east of the modern Mississippi River Delta (Figure 117). Hydrocarbons have been encountered in scattered, discontinuous clusters within the play area.

The sediments of UPL A1 were supplied mainly from ancestral Mississippi River Deltas. The areas occupied by the older Middle Pleistocene Aggradational Play (MPL A1) and UPL A1 are very similar, with UPL A1 showing noticeable basinward and westward shifts.

Shallow, between 1,500 and 3,000 ft, subsea, gas sands have become an attractive trend for several exploration companies. This trend is noted for being largely ignored by exploration companies because the gas was considered too under pressured to be economic. In general, the shallow gas was not logged and was avoided as a shallow drilling hazard. The shallow gas causes good seismic hydrocarbon indicators (bright spots), and the sands are characterized by very high porosity and permeability. Faulted traps are frequently associated with hydrocarbon seeps at the seafloor. With 3-D seismic data, drilling risks are very low.

Play Limits

UPL A1 extends onshore in an updip direction. In some areas, namely from the northern High Island to Eugene Island Area, the play becomes so shallow that it is no longer logged. The play does not extend farther to the west in offshore Texas because of an apparent lack of shelf source sands during UPL time. At its farthest northeast extent, the play pinches out. UPL A1 deposits grade into the sediments of the Upper Pleistocene Progradational Play (UPL P1) in a downdip direction.

Depositional Style

UPL A1 is characterized by stacked, blocky, sand-dominated successions representing sediment buildup on a (1) stream plain (e.g., fluvial channel/levee complexes, crevasse splays, and point bars); (2) delta plain (e.g., distributary channel/levee complexes, crevasse splays, distributary mouth bars, bay fill, intertidal deposits, and beach/barrier island deposits); and (3) shallow marine shelf (e.g., delta fringe sands and delta slump deposits). Additionally, retrogradational, reworked sands with a thinning and backstepping log signature locally cap the play. Because these retrogradational sands are poorly developed, discontinuous, and not correlatable for any significant distance, they are included as part of UPL A1.

The UPL aggradational interval varies from less than 100 to more than 10,800 ft in thickness, with net sand thicknesses as much as approximately 1,800 ft. Individual sand-dominated successions range from 50 to more than 500 ft in thickness. Intervening shaly sections are typically less than 100 ft thick. Thicker shale intervals occur locally but are not common. Thicker sands typically display a sharp- or gradational-based, blocky log character. Most of these successions indicate sand-rich, fluvial and paralic depositional settings. The aforementioned blocky successions are interstratified with locally upward-fining and upward-coarsening sand and shale intervals that typically display spiky log signatures. Most of these intervals represent deltaic facies (e.g., distributary mouth bar and distributary channel/levee complexes).

Hydrocarbon-bearing sands are considered sparse relative to the play's large area. This is likely the result of a lack of sealing shales in this sand-rich, depositional environment, as evidenced by only 72 discovered fields over an extensively drilled, relatively large play area (Figure 117).

Structural Style

Just under half of the fields in UPL A1 are structurally associated with salt diapirs—shallow, intermediate, and deep depths—with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Other less common structures in the play include anticlines, growth fault anticlines, and normal faults. Some fields also contain hydrocarbon accumulations trapped by permeability barriers and updip pinchouts or facies changes.

Quantitative Attributes

On the basis of reserves calculations, UPL A1 contains 81% gas and 19% oil. The 205 sands in the play comprise 315 reservoirs, of which 250 are nonassociated gas, 50 are undersaturated oil, and 15 are saturated oil. All reserves are proved and estimated to be 2,658.996 Bcfg and 108.780 MMbo (581.911 MMBOE) (Table 51). These reserves account for 15% of the reserves for the UPL Chronozone.

	No. of Sands	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
Proved	205	108.780	2,658.996	581.911
Cum. production	192	87.977	2,276.956	493.129
Remaining proved	139	20.804	382.041	88.782
Unproved	0	0.000	0.000	0.000

Table 51. UPL A1 reserves and cumulative production.

Cumulative production from UPL A1 totals 2,276.956 Bcfg and 87.977 MMbo (493.129 MMBOE) from 192 sands in 68 fields. UPL A1 production accounts for 15% of the UPL Chronozone's total production. Remaining proved reserves in the play are 382.041 Bcfg and 20.804 MMbo (88.782 MMBOE) in 139 sands in 47 fields.

Table 52 summarizes that water depths of the fields in UPL A1 range from 18-338 ft, and play interval discovery depths vary from 750-5,850 ft, subsea. Additionally, porosity and water saturation range from 19-39% and 16-52%, respectively.

205 Sands	Min	Mean	Max
Water depth (ft)	18	179	338
Subsea depth (ft)	750	2,666	5,850
Reservoirs per sand	1	2	13
Porosity	19%	33%	39%
Water saturation	16%	28%	52%

Table 52. UPL A1 sand attributes. Values are volume-weighted averages of individual reservoir attributes.

Exploration History

UPL A1 has a 52-year history of discoveries (Figure 118). The first sands in the play were discovered in 1947 and 1948 in the Ship Shoal 32 Field. The maximum number of sands discovered in any year occurred in 1987 with 18 sands from four fields. However, the maximum yearly reserves of 160.572 MMBOE were added in 1973 with the discovery of 14 sands from six fields. Sand discoveries averaged about 1 per year for the first 24 years of the play's history. However, from 1971 through 1998, the average increased to about 7 per year.

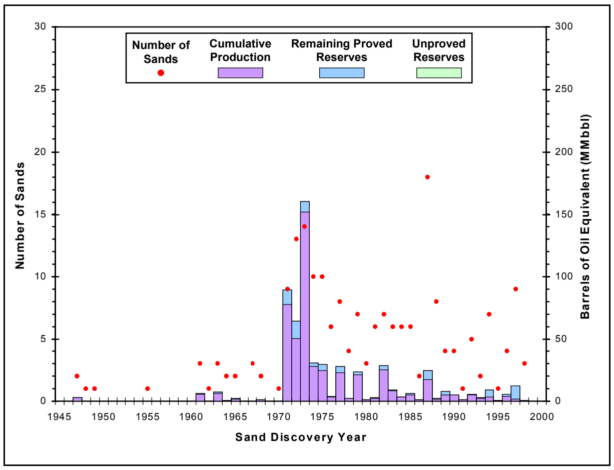

Figure 118. UPL A1 exploration history graph showing reserves and number of sands discovered by year.

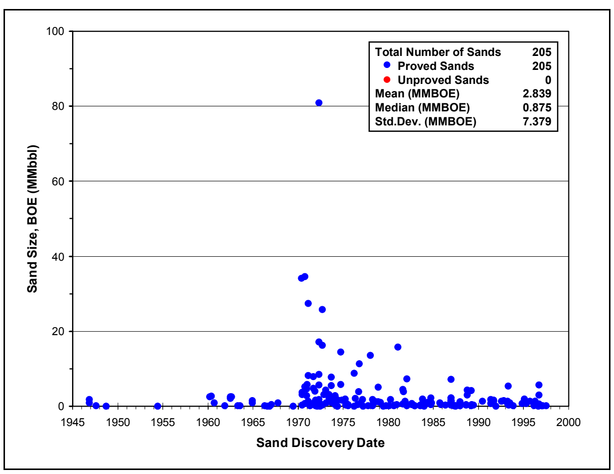

Figure 119. UPL A1 sand discovery graph showing the size of sands discovered by year.

The largest sand in the play was discovered in 1973 in the Eugene Island 342 Field and contains an estimated 80.932 MMBOE (Figure 119). All sands containing more than 20 MMBOE were discovered in the early 1970's. The mean sand size for the play is 2.839 MMBOE. Since the first Atlas database cutoff of January 1, 1995, 17 sands have been discovered, the largest of which is estimated to contain 5.619 MMBOE.

Production History

UPL A1 has a 48-year history of production (Figure 120). Oil and gas production began in 1947. Both oil and gas production fluctuated at relatively low yearly values throughout the 1950's and 1960's, reflecting the play's one per year average of sand discoveries during those decades. In fact, oil and gas production ceased from 1960 through 1963. However, when the sand discovery average increased in the early 1970's, so did oil and gas production. After reaching peak values in the mid-1970's, yearly oil production values have declined to about half. Gas production peaked locally in the mid- to late-1970's, subsequently declined, and then increased again to its largest peak in 1994. Gas production has since sharply declined.

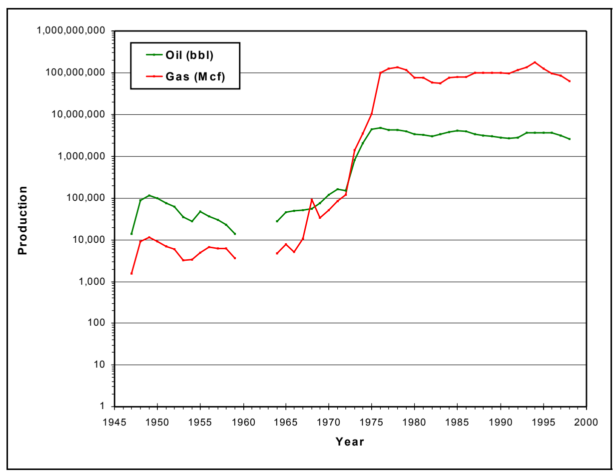

Figure 120. UPL A1 production graph showing oil and gas production by year.