SANTA MARIA BASIN PROVINCE (012)

By Marilyn E. Tennyson

INTRODUCTION

The Santa Maria Basin Province of California encompasses the area from the Santa Lucia and the San Rafael Mountains on the southwestern flank of the southern Coast Ranges to the northern Santa Ynez Mountains in the Western Transverse Ranges. It includes northern Santa Barbara County, western San Luis Obispo County, and southwestern Monterey County. Its northeastern boundary lies along the Sur-Nacimiento Fault and its southern boundary is along the Santa Ynez fault; it extends westward to the 3-mile limit of the State waters along the coast. The province is about 150 mi long and 10–50 mi wide and covers an area of roughly 3,000 sq mi.

The Santa Maria Basin, floored by Mesozoic rocks of the Franciscan complex, Coast Range ophiolite, and Great Valley sequence, occupies the central part of the province. Around the margins of the basin, Great Valley sequence sedimentary rocks are present beneath upper Oligocene to lower Miocene nearshore sandstone (Vaqueros Formation), bathyal mudstone (Rincon Formation), and volcanic rocks (Tranquillon and Obispo Formations). In the center of the basin, lower Miocene nonmarine sediments (Lospe Formation) shed from uplifted blocks along basin-forming faults are present locally, resting in part on Franciscan rocks interpreted to have been exposed in the footwalls of early Miocene extensional faults. Bathyal marine, mostly clastic-poor Miocene sedimentary rocks (Point Sal and Monterey Formations) blanket the region, filling in early Miocene extensional lows and onlapping structural paleohighs. Uppermost Miocene to Quaternary marine and nonmarine clastic units (Sisquoc, Foxen, Careaga, and Paso Robles Formations) record filling of the basin and emergence of flanking uplifts. Large folds in the central part of the basin (Casmalia-Orcutt Anticline, San Antonio-Los Alamos Valley Syncline, Lompoc-Purisima Anticline, Santa Rita Syncline) are associated with north-verging reverse faults of Pliocene and Quaternary age. The thickness of the deformed basin fill in the central Santa Maria Basin probably approaches 15,000 ft in growth synclines in the footwalls of reverse fault systems. Oil accumulations, typically relatively heavy and sulfur rich, are mostly trapped in fractured Monterey Formation anticlines, in fractured Monterey truncated by an unconformity along the northeastern flank of the basin, or in Pliocene sandstone lenses above an unconformity on the northeastern basin margin.

The Huasna and Pismo Basins, northeast of the Santa Maria Basin, are synclinal depocenters filled with a Neogene section similar to that in the Santa Maria Basin but contain a greater proportion of sandstone. Small oil accumulations and tar sands are present in these basins.

Four plays are considered in this province: (1) the Anticlinal Trends–Onshore Play (1201), comprising any part of the section in anticlinal traps, normal-fault traps on the crests of anticlines, and structural traps in the footwalls of reverse faults that cut the anticlines; (2) the Anticlinal Trends–Offshore State Waters Play (1211), which comprises the offshore extension of the preceding play; (3) the Basin Margin Play (1202) in the northeast, including traps with a stratigraphic component along and above the unconformity that truncates the Monterey Formation; and (4) the Diagenetic Play (1204), a hypothetical play comprising fractured reservoirs in quartz-phase siliceous rocks sealed by overlying unfractured or less-fractured opal CT-phase rocks, above the diagenetic transition between the two rock types. A fourth play, the subthrust play, was originally defined but was combined with the Anticlinal Trends Play.

Exploration in the Santa Maria Basin Province began in the late 1800's, guided by the occurrence of seeps and tar sands and application of the concept of oil occurrence in anticlines. The first discovery was the Orcutt oil field in 1901 (cumulative production plus reserves of about 180 MMBO), followed over the next 14 years by Lompoc (46 MMBO), Casmalia (50 MMBO), Arroyo Grande (10 MMBO), West Area of Cat Canyon (152 MMBO), East Area of Cat Canyon (43 MMBO), and Gato Ridge Area of Cat Canyon (52 MMBO). No major discoveries were made between 1915 and 1934, when the stratigraphically-trapped Santa Maria Valley field (184 MMBO) was discovered. From 1940 till the present, ten more significant accumulations were discovered, ranging in size from about 2 MMBO to 70 MMBO. All accumulations discovered since the mid-1970's have been relatively small, a few million barrels at most. There is minor gas associated with most of the oil accumulations, but no non-associated gas. The oil is generally heavy, averaging about 20¡ API, although gravities between about 10û and 35û API are present.

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CONVENTIONAL PLAYS

1201. ANTICLINAL TRENDS–ONSHORE PLAY

1211. ANTICLINAL TRENDS–OFFSHORE STATE WATERS PLAY

This confirmed structural play comprises areas along the crests of major and minor anticlines where Monterey Formation is overlain by younger sealing strata. The steeper limbs of the anticlines are typically cut by reverse faults; the play also includes anticlines and updip fault truncations in the footwall blocks of these faults. It extends offshore through State waters into the Federal offshore. The onshore boundary approximately parallels the eroded edge of the Monterey Formation around structural uplifts.

Reservoirs: The principal reservoirs consist of fractured chert, porcelanite, or dolomite in the middle and upper Miocene Monterey Formation. Net thickness in discovered accumulations in the Monterey in this play averages about 865 ft and ranges from 50 to 3,000 ft. Porosity in the Monterey is reported to range from 6 percent to 33 percent. Other reservoirs include shallow marine sandstones of the Miocene to Pliocene Sisquoc and Pismo Formations (porosity 20-35 percent, permeability 40-2000 mD, reservoir thickness 20-600 ft), lower to middle Miocene turbidite sandstone of the Point Sal Formation (porosity 15-35 percent, permeability 10-300 mD, reservoir thickness 50-500 ft) and minor fractured sandstone reservoirs in the lower Miocene Lospe Formation (porosity 15-42 percent, permeability 10-1000 mD) and Jurassic to Cretaceous Great Valley sequence and (or) Franciscan assemblage (porosity 24 percent).

Source rocks: The principal source rocks are organic-rich siliceous, dolomitic, and phospatic mudstones of the middle to upper Miocene Monterey Formation. The total thickness of the Monterey is usually about 2,000 ft, although it ranges from 0 to more than 3,000 ft (drilled thickness, uncorrected for dip) within the area of the play. The Monterey contains up to about 17 percent TOC, mostly Type II; TOC averages about 5 percent (Isaacs, 1984); Mero (1991) reported 3 percent at Point Arguello field. Vitrinite reflectance data are not very useful because the Monterey contains little vitrinite. Even where vitrinite reflectance measurements have been made on rocks at maximum burial which have probably generated oil, R_O values are only 0.42 percent (Isaacs, 1984). Alternate measures of maturity suggest that the rocks are marginally mature to mature. The Rincon Shale could be a source rock if it is present near the base of the Miocene section in the structurally lowest undrilled parts of the play. TOC values reported for the Rincon in the Santa Barbara Basin are 0.21-0.5.7 percent; R_o and pyrolysis data suggest that it is immature in surface samples (Stanley and others, 1992).

Timing and Migration of Hydrocarbons: Migration was Pliocene(?) to Quaternary because the trapping structures are of that age range, the regional sealing formation (Sisquoc) is uppermost Miocene through lower Pliocene, and burial sufficient to mature the Monterey was probably not achieved until a thick section of Pliocene rocks was deposited in growth synclines where maturation probably took place. Migration pathways and distance of migration are undocumented, but many workers assume that oil and associated gas migrated as much as a few miles out of major synclines into flanking anticlinal traps. Additionally or alternatively, migration could have been near-vertical (up faults or steeply dipping fracture systems) or along short migration paths wherever zones of rock with adequate reservoir properties are present.

Traps: The primary traps are latest Miocene to Quaternary broad-crested asymmetrical anticlines and minor reverse- and normal-fault traps in the crestal regions of the anticlines, sealed by mudstone of the Sisquoc or Pismo Formation or by unfractured or clay-rich Monterey intervals. The anticlines contain accumulations from less than 1 MMBO to at least 284 MMBO. The crestal fault traps and footwall traps are generally small, with only a few tens or, rarely, hundreds of feet of offset on faults cutting the crests of the anticlines. In the footwall blocks of the reverse faults that cut some anticlines, footwall anticlines or updip fault truncation traps are present. Subsurface structure is not sufficiently well known to state the typical sizes of these traps, although all accumulations found so far in them are less than 1 MMBO in volume.

Exploration status: The first discovery in the play (Orcutt Field) was made in 1908. Eleven additional accumulations greater than 1 MMBO have been discovered, eight of them by 1947. The last significant onshore discovery was in 1985; that accumulation (La Laguna Area of Barham Ranch field) has estimated known production plus reserves of 2.8 MMBO, with growth estimated to as much as 8+ MMBO. Beginning in 1980, 14 additional discoveries were made in the Federal offshore, ranging from 1.5 to 284 MMBO as presently estimated; additions to these reserves are likely. The largest onshore accumulation is Orcutt field (180 MMBO); the next largest is the West Area of the Cat Canyon field (~100 MMBO). Offshore, the largest accumulations are Point Arguello (284 MMBO), Point Pedernales (77 MMBO), and Rocky Point, San Miguel, and Point Sal, all greater than 60 MMBO (Minerals Management Service, unpub. estimates, 1993). Oil is the principal type of hydrocarbon produced. Oil gravity averages about 20¡

API and ranges from less than 10¡ to about 35¡ API. Minor amounts of associated gas are produced with the oil. The depths of the accumulations are between about 1,300 ft and 10,000 ft.

Resource potential: No remaining significant (more than about 1-2 MMBO) anticlinal targets are evident onshore, but some are probably present in the State waters on known anticlinal trends that trend into State waters from the onshore and Federal offshore. There may be a few small accumulations trapped in small folds in the deep onshore subsurface; several possible prospects are evident on a proprietary structure contour map of the top of the Monterey Formation. Footwall prospects are probably numerous but poorly constrained by geophysical or drill-hole data and are probably mostly small (1-5 MMBO?). Using an empirically determined approximate recovery factor of 50 bbl/acre ft of gross pay, a prospect area of 1,000 acres and a thickness of 500 ft, the largest onshore accumulation that could be present is estimated to be about 25 MMBO, although such an accumulation is considered unlikely. In the State waters, accumulations up to about 50 MMBO are considered possible using a postulated area of 2,500 acres and thickness of 400 ft, based on the sizes of prospects mapped by the California State Lands Commission (Williams, 1982, 1983) and on the reservoir thickness in nearby Point Pedernales field.

1202. BASIN MARGIN PLAY

This confirmed combination stratigraphic and structural oil play comprises (1) traps in Pliocene sandstone wedges shed southwestward from emergent areas on the northeast flank of the province, overlying the eroded top of the Monterey Formation with slight angular unconformity, and (2) overlap truncation traps in the Monterey itself. Its boundaries are defined by the limits of the area where the Monterey is eroded beneath the Pliocene and (or) the limits of shallow marine sandstone in the lower to middle Pliocene Sisquoc, Santa Margarita, Foxen, and Pismo Formations along the northeast margins of the Santa Maria Basin, the Huasna Basin, and the Pismo Basin.

Reservoirs: The principal reservoirs consist of (1) shallow marine sandstone of the Sisquoc, Santa Margarita, Pismo, and Foxen Formations, and (2) fractured reservoirs in the Monterey Formation. Fractured Mesozoic sandstone of the Great Valley sequence locally acts as a reservoir. The net thickness of individual sandstone reservoirs is about 45 to 1000 ft. Porosity ranges between about 22 percent and 35 percent in these units in producing pools. The net thickness of Monterey reservoirs in this play is 200 to 1000 ft.

Source rocks: The principal source rocks are organic-rich, siliceous, dolomitic, and phospatic mudstones of the middle to upper Miocene Monterey Formation. The total thickness of the Monterey is usually about 2,000 ft, although it ranges from 0 to over 4,000 ft of drilled thickness, uncorrected for dip, within the area of the play. The Monterey contains up to about 17 percent TOC, mostly Type II, averaging about 5 percent (Isaacs, 1984). Vitrinite reflectance data are not useful because the Monterey contains too little vitrinite. Even where vitrinite reflectance measurements have been made on rocks at maximum burial which have probably generated oil, R_o values are below the levels at which oil is though to be generated (Isaacs, 1984). Alternate measures of maturity suggest that the rocks are marginally mature to mature. These include data from silica and clay diagenesis and organic geochemical data. The Rincon Shale could also be a source rock if it is present near the base of the Miocene section in the structurally lowest undrilled parts of the play. TOC values reported for the Rincon in the Santa Barbara basin are 0.21-0.5.7 percent (Stanley and others, 1992).

Timing and migration of hydrocarbons: Migration was Pliocene(?) to Quaternary, because trapping structures in this and another play are of that age range, the regional sealing formation (Sisquoc) is uppermost Miocene through lower Pliocene, and burial sufficient to mature the Monterey was probably not achieved until a thick section of Pliocene rocks was deposited in growth synclines where maturation probably took place. Migration pathways and distance of migration are undocumented, but oil and associated gas may have migrated as much as several miles, updip out of the Santa Maria Valley Syncline into traps to the north.

Traps: Traps are formed by (1) overlap of eroded, fractured Monterey by sealing mudstone of Pliocene age (e.g., Main area of the Santa Maria Valley field), (2) Pliocene sandstones of the Sisquoc, Foxen, or Pismo Formations sealed by overlapping or enclosing mudstone, or (3) updip tar-seal traps, (e.g., Arroyo Grande field). Discovered accumulations are trapped at depths of 700 to 5,200 ft. Minor faults with a few tens or hundreds of feet of vertical separation enhance closure in some cases (e.g. Main area of Santa Maria Valley field). The accumulations trapped in Pliocene sandstone are either relatively thick basal sandstones unconformably resting on top of the Monterey (Brooks or Thomas sands in East and Sisquoc areas of Cat Canyon field, up to 1,000 ft thick; basal Sisquoc in Guadalupe field) or thinner, stacked sands in the middle and upper Sisquoc or Foxen Formation, interbedded with mudstone (West and Central areas of Cat Canyon field, Guadalupe field).

Exploration status: The first discovery in the play (Tiber Area of Arroyo Grande Field) was made in 1906. Eight additional accumulations greater than 1 MMBO have been discovered, six of them by 1950. The largest accumulation is the Main area of the Santa Maria Valley field (184 MMBO); the next largest is the Sisquoc Area of the Cat Canyon field (70 MMBO). The last discovery > 1 MMBO was in 1972 (Bradley Area of Santa Maria Valley field; 23 MMBO). Oil is the principal type of hydrocarbon produced. Oil gravity averages about 13-14û API and ranges from less than 10¡ to about 17¡ API. Minor amounts of associated gas are produced with the oil. The depths of the accumulations are between 750 and 7,000 ft.

Resource potential: The greatest potential of this play is in the offshore State waters, where additional reserves of at least 15-20 MMBO probably lie, based on the area available and comparison with the adjoining Guadalupe field. Onshore, any remaining discoveries in the Santa Maria Basin will be small, based on exploration results in the last 20 years and the lack of large undrilled areas. Exploration in the parts of the play in the Pismo and Huasna Basins has been less thorough, and it is possible, but not likely, that a few-million-barrel field could be found there, probably in a stratigraphic trap.

1204. DIAGENETIC PLAY (HYPOTHETICAL)

This hypothetical oil play comprises areas just below a diagenetic transition from opal-CT to quartz phase chert within the Monterey Formation, below which the formation is more pervasively fractured than it is above; the less densely fractured rock above the transition would act as the seal. The play extends subhorizontally throughout the basin in clay-poor facies of the Monterey Formation below roughly 5,000 ft, encompassing mostly synclinal troughs. (Areas where this diagenetic transition has been uplifted by young deformation are included in the Anticlinal Trends Play.) The play extends offshore through State waters into the Federal offshore. On seismic reflection lines offshore it is about 4,800 ft below the sea bottom (D. Mayerson, Minerals Management Service, oral commun., 1994).

Reservoirs: The presumed reservoir consists of fractured quartz-phase chert in the middle and upper Miocene Monterey Formation. Net pay thickness in this play is uncertain but would probably range up to a few hundred feet, based on the net pay thickness (200-400 ft) reported in the offshore Point Arguello field (Sorenson and others, 1992) where the Monterey is entirely within the quartz chert phase, or on the one known possible occurrence of an accumulation in this play, the Jesus Maria field (0.46 MMBO, where net pay is 290-500 ft thick (California Division of Oil and Gas, 1991).

Porosity in the Monterey is reported to range from 6 percent to 33 percent. Permeability is difficult to estimate but is probably in the range 10-15 mD (Regan and Hughes, 1949; Mannon and Heck, 1985).

Source rocks: The principal source rocks are organic-rich siliceous, dolomitic, and phospatic mudstones of the middle to upper Miocene Monterey Formation. The total thickness of the Monterey is usually about 2,000 ft, although it ranges from 0 to more than 3,000 ft (drilled thickness, uncorrected for dip) within the area of the play. The Monterey contains up to about 17 percent TOC, mostly Type II; TOC averages about 5 percent (Isaacs, 1984); Mero (1991) reported 3 percent at Point Arguello field. Vitrinite reflectance data are not very useful because the Monterey contains little vitrinite. Even where vitrinite reflectance measurements have been made on rocks at maximum burial which have probably generated oil, R_o values are only 0.42 percent (Isaacs, 1984). Alternate measures of maturity suggest that the rocks are marginally mature to mature. In this particular play, the Monterey Formation should be mature because the temperature range at which the diagenetic transition from opal-CT to quartz takes place is very similar to the range at which oil generation begins. The Rincon Shale could also be a source rock if it is present near the base of the Miocene section in the structurally lowest undrilled parts of the play. TOC values reported for the Rincon outside the province in the area west of Santa Barbara are 0.21-0.5.7 percent (Stanley and others, 1992).

Timing and migration of hydrocarbons: Migration was Pliocene(?) to Quaternary because trapping structures in other plays in this province are of that age range, the regional sealing formation in the other plays (Sisquoc Formation) is uppermost Miocene through lower Pliocene, burial sufficient to mature the Monterey was probably not achieved until a thick section of Pliocene rocks was deposited in growth synclines where maturation probably took place, and the CT-quartz seismic reflector cuts across structures of Pliocene or younger age (Ogle and others. 1987). Migration pathways and distance of migration are undocumented but would probably be a few miles at most, from synclinal troughs updip to the intersection of the CT-quartz transition and the Monterey on fold limbs. Migration could also have been near-vertical, up faults or steeply dipping fracture systems.

Traps: The postulated traps in this play are subhorizontal zones of fractured rock that cut across regional structure. Traps could contain accumulations from less than 1 million barrels to several tens of millions of barrels, based on deposit simulation. The postulated seal is the less-fractured CT-phase Monterey Formation above the diagenetic transition.

Exploration status: No systematic exploration for accumulations in this play is known to have been conducted. It is possible that the Main Area of the Jesus Maria field in fact is trapped by a diagenetic boundary at depths of 2,500 to 3,000 ft, although it is informally reported to be a truncation trap between two members of the Monterey Formation. Offshore, most unsuccessful exploration wells located on anticlinal crests did not penetrate the CT-quartz boundary (Mayerson and Crouch, 1994). A well near Paso Robles in the southernmost Salinas Basin may have tested the concept; results are rumored to have been characterized by the operator as encouraging.

Qualitative evaluation of resource potential: This is a very high risk play because the adequacy of the diagenetic boundary as a seal is undemonstrated and because quartz-phase Monterey may not be sufficiently fractured away from anticlinal crests. If the play is viable, it could contain accumulations up to tens of millions of barrels or more; the volume of prospective, mostly undrilled, rock in the synclines is very large.

UNCONVENTIONAL PLAYS

There are no unconventional plays described in this province report. However, unconventional plays listed in the surrounding provinces may include parts of this province. Individual unconventional plays are usually discussed under the province in which the play is principally located.

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